NASA CONTRACTOR REPORT

NASA CR-2518

NASA CR-2518

POTASSIUM TOPPING CYCLES FOR STATIONARY POWER

R. J. Rossbach

Prepared by
GENERAL ELECTRIC COMPANY
Cincinnati, Ohio 45215
for Lewis Research Center

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION • WASHINGTON, D. C. • MARCH 1975

1. Report No.	2. Government Accession No.	3. Recipient's Catalog No.
NASA CR-2518		

4. Title and Subtitle	5. Report Date
POTASSIUM TOPPING CYCLES FOR STATIONARY POWER	March 1975
	6. Performing Organization Code
7. Author(s)	8. Performing Organization Report No.
R. J. Rossbach	GESP-741
	10. Work Unit No.
9. Performing Organization Name and Address General Electric Company P.O. Box 15132 Cincinnati, Ohio 45215	11. Contract or Grant No. NAS 3-17354
	13. Type of Report and Period Covered Contractor Report
12. Sponsoring Agency Name and Address National Aeronautics and Space Administration, Washington, D.C. 20546 and Office of Coal Research, 2100 M Street, N.W., Washington, D.C. 20240	14. Sponsoring Agency Code

15. Supplementary Notes

Final Report. Project Manager, Martin U. Gutstein, Power Systems Division, NASA Lewis Research Center, Cleveland, Ohio

16. Abstract

In this program, a design study was made of the potassium topping cycle powerplant for central station use. Initially powerplant performance and economics were studied parametrically by using an existing steam plant as the bottom part of the cycle. Two distinct powerplants were identified which had good thermodynamic and economic performance. Conceptual designs were made of these two powerplants in the 1200 MWe size, and capital and operating costs were estimated for these powerplants. A technical evaluation of these plants was made including conservation of fuel resources, environmental impact, technology status, and degree of development risk. It was concluded that the potassium topping cycle could have a significant impact on national goals such as air and water pollution control and conservation of natural resources because of its higher energy conversion efficiency.

17. Key Words (Suggested by Author(s))	18. Distribution Statement
Potassium topping cycle; Advanced cycle; Pressurized furnace; Fluidized bed furnace; Coal; Stationary power	Unclassified - unlimited STAR category 31 (rev.)

19. Security Classif. (of this report)	20. Security Classif. (of this page)	21. No. of Pages	22. Price*
Unclassified	Unclassified	129	$5.75

* For sale by the National Technical Information Service, Springfield, Virginia 22151

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TABLE OF CONTENTS

SUMMARY

General Electric has performed A Study of Potassium Topping Cycles for Stationary Power under NASA Contract NAS3-17354 for NASA and the Office of Coal Research. The following objectives were established for this program:

1. To conduct preliminary assessments of the capital cost of a variety of potassium-steam topping cycles.

2. To prepare conceptual designs of selected topping cycle powerplants.

3. To perform technical and economic evaluations of topping cycle powerplants based upon the conceptual designs.

Task I included preliminary analyses of several variations of a basic topping cycle powerplant, and the selection of promising configurations for which conceptual designs were done in Task II. A computer code was written to calculate topping cycle performance and capital and operating costs. This code was used to analyze a large variety of topping cycle plants to identify on an approximate basis those cycles that appear to offer high plant efficiency and low capital costs.

Based on the results of Task I, four topping cycles were considered as most promising. These included cycles with a conventional coal fired furnace, a supercharged furnace and two fluidized bed furnaces, one pressurized and one at atmospheric pressure. The pressurized furnace system is compatible with clean fuel derived from coal gasification plants. This was the first choice for conceptual design. The second choice was the pressurized fluidized bed system because it had the lowest cost of electricity.

In Task II, conceptual designs were made for the two selected topping cycle systems. The potassium components, boiler, turbine, and condenser/steam generator, received the most attention since the cost estimates were to be based on the conceptual designs. Selection of conventional steam powerplant components and the layout of the overall powerplants were done by the Installation, Service and Engineering group of General Electric who are familiar with conventional powerplant practices.

Task III was the economic and technical evaluation of these two conceptually designed plants. The fluidized bed plant had about 18% higher (coal pile to bus bar) efficiency than the pressurized boiler plant, due to the conversion efficiency of the coal gasification plant required for

the pressurized boiler system. The pressurized fluidized bed boiler was judged to be the major development risk and cost.

The pressurized fluidized bed topping cycle system would use 21% less fuel and have 35% less heat rejection than a conventional steam plant of the same power output due to its higher coal-to-busbar conversion efficiency. Assuming an adequate development program, it was estimated that a demonstration topping cycle powerplant could be operational in ten years.

INTRODUCTION

By 1990 the installed capacity of United States powerplants will be four times the capacity of 1970, based on the historic growth rate of doubling every ten years. Because oil and natural gas are in short supply, the principal sources of energy for future electric power production are coal and uranium. Although there has been a trend away from coal to oil and natural gas for central-station powerplants because these fuels were cheap, this trend will probably reverse because forecasters predict only a few decades supply of domestic oil or natural gas at present consumption rates while they forecast hundreds of years of coal reserves. The trend away from coal was caused by several factors, including: air quality regulations issued in accordance with the Clean Air Act of 1970 which limit the amount of SO_2 and NO_x emissions in stack gases; the Coal Mine Health and Safety Act of 1969, which has resulted in a slowdown of production in underground mines; and public sentiment against surface mining which imposes limitations on the amount of coal that can be produced by that method. Since coal is our most plentiful fossil fuel it will have to be used for central station powerplants. Unfortunately only a small fraction of this country's coal has a low enough sulfur content (less than about 0.9% sulfur) to meet the standards for SO_2 emissions but there are several options for attacking this problem. Potential solutions include the production of clean fuel by liquifaction or gasification of coal, the use of a fluidized bed of coal and limestone in the furnace, and SO_2 stack gas scrubbers with a conventional pulverized coal furnace.

Because of the impending fuel shortage there is considerable interest in utilizing fossil fuel resources more effectively by improving the efficiency of central-station powerplants and minimizing environmental impact by controlling stack gas emissions and reducing heat discharges. The potassium topping cycle can accomplish both of these objectives because this cycle permits the use of heat from combustion gases at a higher temperature than is possible with a conventional steam powerplant. The higher cycle temperature increases powerplant efficiency and therefore the topping cycle rejects less heat to the atmosphere than a conventional steam powerplant with the same power output.

The potassium technology was developed on the Advanced Rankine Cycle Program for Space Power. Potassium boiling and condensing data have been obtained by the General Electric Company over the past ten years in three separate test facilities designed for heat transfer experimentation. A concurrent potassium turbine program included the design, fabrication and testing of two and three stage potassium turbines. Although potassium boilers, turbines, pumps, valves and condensers were tested for thousands of hours on the space program, it will be necessary to scale those components up to commercial powerplant size and extend the design life to values required for commercial power stations.

For central station application, the heat of condensation of the potassium cycle would be rejected to a steam generator, which would produce steam at conditions comparable with those of modern steam powerplants. Fraas (ref. 1,2) has described the potassium topping cycle studies done at ORNL and concludes that the concept is feasible and attractive.

The main advantage of the potassium topping cycle is a higher thermal efficiency, over 50%, compared with 40% for a conventional steam plant. For a given power output, the topping cycle uses 20% less fuel and rejects only two thirds as much heat as a conventional steam plant. The topping cycle can be integrated with a coal gasification plant or can use coal directly. The liquid metal technology developed for the topping cycle concept will be applicable to fusion powerplants when that technology becomes feasible.

In this program, a design study was made of potassium topping cycles for central station use. Initially powerplant performance and economics were studied parametrically using an existing steam plant as the bottom part of the cycle. Two distinct powerplants were identified which had good thermodynamic and economic performance. Conceptual designs were made of these two powerplants in the 1200 MWe size, and capital and operating costs were estimated for these powerplants. A technical evaluation of these plants was made including conservation of fuel resources, environmental impact, technology status and degree of development risk.

PRELIMINARY ANALYSES OF POTASSIUM-STEAM TOPPING CYCLES

Selection of Reference Steam Powerplant

The Bull Run Steam Plant is a TVA coal-fired steam powerplant having a capacity of 950 MWe and was constructed near Knoxville, Tennessee in the 1961-1966 time period. The steam cycle has 2413 N/cm^2 (3500 psig) and 811 K (1000°F) turbine inlet conditions with one reheat to 811 K (1000°F) and "once through" condenser cooling. Reference 3 contains a complete description of this powerplant, including component designs, operating conditions, performance and capital costs. The thermal efficiency of the plant is 40.7 percent with river cooling water. It was recommended and approved that the Bull Run Steam Plant be selected as the reference steam plant for the topping cycle study.

Analyses of Potassium-Steam Topping Cycle

BASIC POTASSIUM-STEAM TOPPING CYCLE

A computer code was written to calculate on a parametric basis the performance of potassium-steam topping cycles and estimated component costs. A schematic diagram of the cycle is shown in Figure 1, and the code is described in Appendix A.

The performance of a topping cycle with 1033 K (1400°F) potassium turbine inlet temperature and a conventional furnace is shown in Table 1, and a detailed computer print out for this case is presented in Appendix B. This cycle was called the "base case" because it was the initial topping cycle to be investigated. Parametric variations were made subsequently to determine the effects on performance and costs. The cycle efficiency of 44.4 percent is about 14 percent higher than the steam plant alone which was calculated to have an efficiency of 38.8 percent with a wet cooling tower.

A cost summary for the base case topping cycle is shown in Table 2, for a system with a conventional furnace.

Recommended Powerplants for Conceptual Design

The topping cycle code was used to determine the sensitivity of topping cycle performance and costs to cycle variations; this work is described in Appendix C. Based on the results of the parametric study, six cycles were identified as candidates for conceptual design. Three of these had conventional furnaces, the base case and two with higher potassium turbine inlet temperature, as this was the most significant parameter in the sensitivity study. The other three were topping cycle

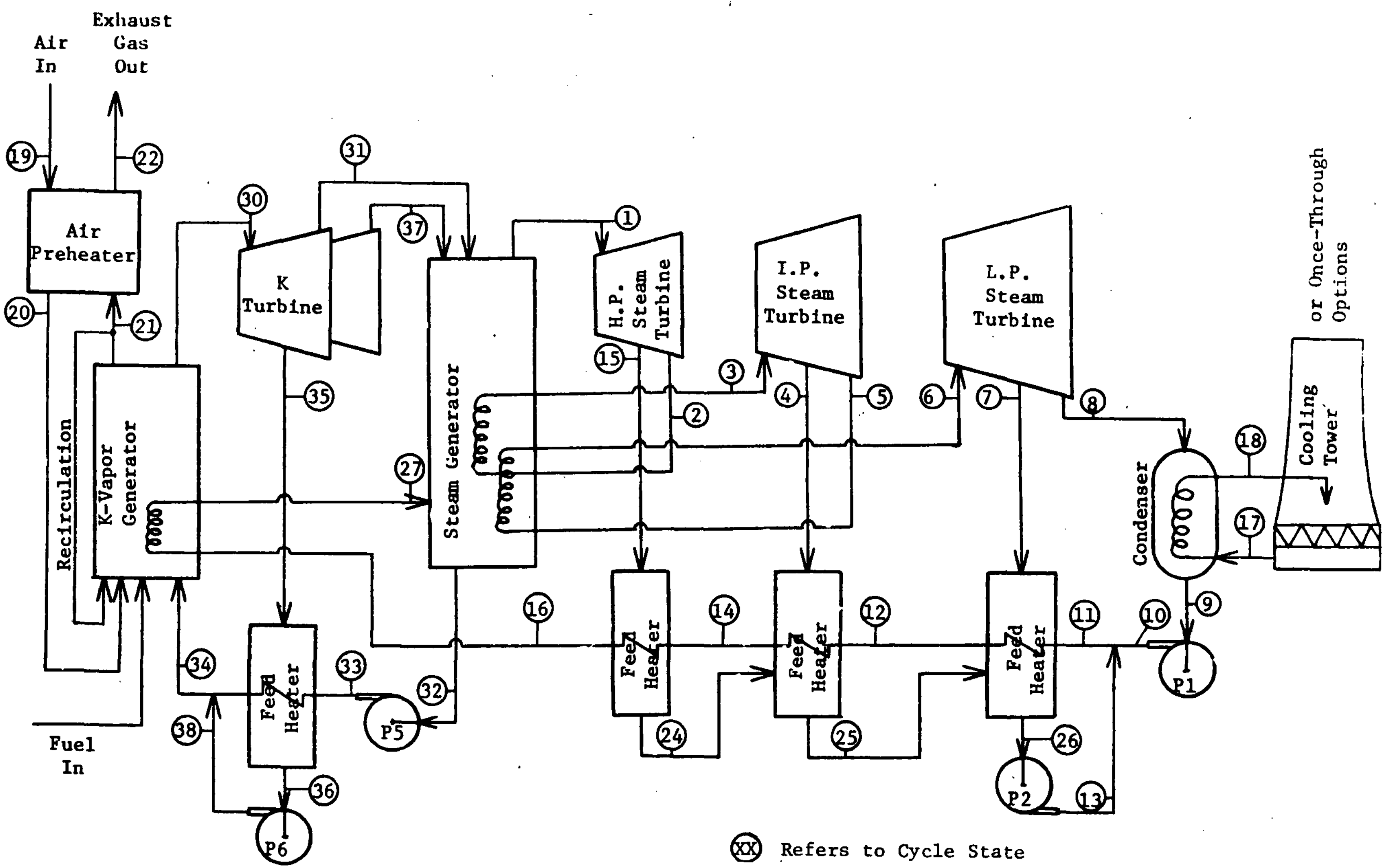

Figure 1. - Topping Cycle Flow Schematic
for Computer Program

TABLE 1. - PERFORMANCE SUMMARY-CONVENTIONAL BOILER

(Base Case)

Steam Turbine Inlet Pressure, N/cm^2 (psia)	2424 (3515)
Steam Turbine Inlet Temperature, K (°F)	811 (1000)
Steam Reheat Pressure, N/cm^2 (psia)	372 (540)
Steam Reheat Temperature, K (°F)	811 (1000)
Steam Condensing Temperature, K (°F)	330 (135)
Steam Flow Rate, kg/s (lb/hr)	820.7 (6.5×10^6)
Potassium Turbine Inlet Pressure, N/cm^2 (psia)	10.46 (15.17)
Potassium Turbine Inlet Temperature, K (°F)	1033 (1400)
Potassium Condensing Pressure, N/cm^2 (psia)	1.6/0.76 (2.4/1.1)
Potassium Condensing Temperature, K (°F)	866/811 (1100/1000)
Potassium Flow Rate, kg/s (lb/hr)	902.8 (7.15×10^6)
Steam System Output, MWe	914
Potassium System Output, MWe	289
Total Output, MWe	1203
Cycle Efficiency, percent	44.4

TABLE 2. - COST SUMMARY - CONVENTIONAL BOILER

(Base Case)

FPC Class	Description		Cost (MM$)
310	Land and Land Rights		0.479
311	Structures and Improvements		50.132
312	Boiler Plant Equipment		119.009
	Boiler	54.032	
313	Potassium Plant Equipment (Excl. Furnace)		39.455
314	Turbogenerator Units		42.341
315	Accessory Electric Equipment		11.154
316	Miscellaneous Powerplant Equipment		4.729
35X	Transmission Plant		8.234
397	Communications		0.400
	Total Direct Cost		275.934
	Indirect Construction		7.726
	Total Construction Cost		283.660
	Engineering and Design		25.529
	G & A		17.587
	Interest		23.260
	Total Project Cost		350.036
	Wages		1.200
	Supplies		0.288
	Maintenance		4.428
	Capital		21.002
	Depreciation		8.751
	Insurance		0.420
	Taxes		8.226
	Operating Cost Per Year		42.316
	Fuel Cost		25.852
	Limestone Cost		1.470
	Total Annual Operation Cost		69.637
	Cost of Electricity Mills/MJ (Mills/KWH)		2.299 (8.278)

systems with a pressurized fluidized bed furnace, a pressurized furnace and an atmospheric pressure fluidized bed furnace. These cycles are shown in Table 3.

Case 1 is the base case described earlier. Cases 2 and 3 are for a conventional furnace with potassium turbine inlet temperatures of 1116 and 1200 K (1550 and 1700°F), with condensing temperature of 839 K (1050°F). Case 4 is for a pressurized boiler using a clean fuel from a coal gasification plant. The potassium turbine inlet temperature is 1033 K (1400°F), and the gas turbine inlet temperature is 1255 K (1800°F), which is attainable today. The pressure in the furnace was assumed to be 241 N/cm^2 (350 psia). Case 5 is for a pressurized fluidized bed furnace at 91 N/cm^2 (132 psia). The gas turbine inlet temperature was limited to 1144 K (1600°F) to permit sulfur removal in the fluidized bed. The last case is for a fluidized bed furnace at atmospheric pressure, the cycle conditions being the same as the base case. Shown in successive columns are cycle efficiency, capital and yearly fuel costs, and the cost of electricity for two fuel costs, $0.38 and $0.76 per GJ ($0.40 and $0.80 per million Btu).

Of these six cycles, four systems were considered as candidates for conceptual design based on the results in Table 3 that the type of furnace has the largest effect on the cost of electricity; cycles 1 and 3 were dropped from further consideration. A summary of the four candidate systems is given in Table 4. The capital costs are shown in Table 5 and the operating costs are summarized in Table 6 for the four powerplants.

Although the conventional furnace system has a lower cost of electricity (including a nominal amount for an SO_2 stack gas scrubber) than the pressurized boiler system using gasified coal (see Table 6), it is felt that the two powerplants are not comparable on that basis because of the uncertainties of the cost and effectiveness of stack gas SO_2 scrubbers. However, on the basis of using gasified coal in both plants, the pressurized boiler plant has the lower cost of electricity. The plants with fluidized bed boilers are attractive because they have the lowest cost of electricity (see Table 6), but they are not yet as well developed as the combined coal gasification-pressurized boiler technology, especially the pressurized fluidized bed. In addition it must be verified that the non-vitrified ash in the pressurized fluidized bed is soft enough not to cause erosion of the gas turbine.

The pressurized boiler system was most attractive because the technology has been developed in naval boilers (ref. 4), the capital cost was lowest of all the systems investigated and the system is compatible with fuel derived from coal gasification. Therefore, the first choice for conceptual design was the topping cycle system with a pressurized furnace. The second choice was the supercharged fluidized bed system with the atmospheric fluidized bed system as an alternate if fly ash erosion of the gas turbines is considered to be a problem.

TABLE 3. - PERFORMANCE AND COST SUMMARY OF POTASSIUM TOPPING CYCLES

Case	Description	η (%)	Costs (10^6 \$) Direct	Total	Fuel	Electric Cost Mills/MJ (Mills/KWH) 38¢/GJ (40¢/10^6 Btu) Coal	76¢/GJ (80¢/10^6 Btu) Coal
1	Base Case-Conventional Furnace	44.42	275.9	350.0	25.85	2.299 (8.278)	3.15 (11.35)
2	Conventional Furnace $T_{K\ in}$ = 1116K (1550°F) $T_{K\ out}$ = 839 K (1050°F)	47.18	276.2	350.4	24.35	2.248 (8.093)	3.06 (10.99)
3	Conventional Furnace $T_{K\ in}$ = 1200 K (1700°F) $T_{K\ out}$ = 839 K (1050°F),	48.84	280.8	356.2	23.50	2.243 (8.074)	3.02 (10.87)
4	Pressurized Boiler T_{gas} = 1255 K (1800°F)	50.07	230.0	283.8	45.86*	2.658 (9.568)*	3.41 (12.29)*
5	Pressurized Fluidized Boiler T_{gas} = 1144 K (1600°F)	48.95	245.1	310.9	23.45	2.047 (7.368)	2.82 (10.16)
6	Atmospheric Pressure Boiler (Same cycle as Base Case, Table 1)	44.42	263.5	334.3	25.85	2.219 (7.987)	3.07 (11.06)

*Gas from coal has conversion cost of 38¢/GJ (40¢/10^6 Btu) included.

TABLE 4. - COMPARISON OF CANDIDATE POWERPLANTS WITH DIFFERENT TYPES OF POTASSIUM BOILERS

Item	Optimized Conventional	Pressurized	Atmospheric Fluidized Bed	Pressurized Fluidized Bed
Temperature, K (°F)	1116 (1550)	1033 (1400)	1033 (1400)	1033 (1400)
Fuel	Pulverized Coal	Coal-Derived Fuel	Pulverized Coal	Pulverized Coal
Fuel Equip.	Pulverizers Coal Handling Ash Handling Fuel Oil System	Coal Gasification Plant*	Pulverizers Coal Handling Ash Handling	Pulverizers Coal Handling Ash Handling
SO_2 Removal	Wet Scrubber	In Gasification Plant	In Fluid Bed	In Fluid Bed
NO_x Control	Recirculation, Staged Burning	Low Btu Fuel	In Fluid Bed	In Fluid Bed
Gas Temp. Limit	NO_x Rate	NO_x Rate	SO_2 Removal Rate	SO_2 Removal Rate
Boiler Cost, $\$10^6$**	58	38	62	51
Potassium Power, MW	425	288	288	282
Steam Power, MW	775	708	912	731
Gas Power, MW	0	204	0	187
Total Powerplant Cost, $\$10^6$	350	284	334	311
Cost of Electricity,** Mills/MJ (Mills/KWH)				
Pulverized Coal at 38¢/GJ (40¢/10^6 Btu)	2.25 (8.09)		2.22 (7.99)	2.05 (7.37)
Low Btu Gas at 76¢/GJ (80¢/10^6 Btu)	2.86 (10.31)	2.66 (9.57)		

*Taken into account by increased fuel cost.
**Preliminary Estimate.

TABLE 5. - SUMMARY OF PRELIMINARY ESTIMATES OF CAPITAL COSTS

(Millions of Dollars)

FPC CLASS	DESCRIPTION	OPTIMIZED CONVENTIONAL		PRESSURIZED BOILER		ATMOSPHERIC FLUIDIZED BOILER		PRESSURIZED FLUIDIZED BOILER	
310	LAND AND LAND RIGHTS		0.48		0.48		0.48		0.48
311	STRUCTURES AND IMPROVEMENTS		50.12		50.12		50.12		50.12
312	BOILER PLANT EQUIPMENT		124.42		57.91		106.63		80.05
	BOILER	58.46		38.00		61.58		51.24	
313	POTASSIUM AND GAS EQUIPMENT		39.55		54.68		39.46		52.94
	POTASSIUM COMPONENTS (EXCLUSION OF BOILER)	39.55		36.95		39.46		36.69	
	GAS TURBINE UNITS	0.00		17.73		0.00		16.25	
314	STEAM TURBOGENERATOR UNITS		37.15		36.06		42.34		36.99
315	ACCESSORY ELECTRIC EQUIPMENT		11.15		11.15		11.15		11.15
316	MISCELLANEOUS POWER PLANT EQUIPMENT		4.73		4.73		4.73		4.73
35X	TRANSMISSION PLANT		8.23		8.23		8.23		8.23
397	PLANT COMMUNICATION		0.40		0.40		0.40		0.40
	TOTAL DIRECT COST		276.23		223.76		263.54		245.09
	INDIRECT CONSTRUCTION COSTS		7.74		6.26		7.38		6.86
	TOTAL CONSTRUCTION COST		283.97		230.02		270.92		251.95
	ENGINEERING AND DESIGN		25.56		20.70		24.38		22.68
	GENERAL AND ADMINISTRATIVE		17.61		14.26		16.80		15.62
	INTEREST DURING CONSTRUCTION		23.29		18.86		22.22		20.66
	TOTAL PROJECT COST		350.43		283.84		334.32		310.91

TABLE 6. - SUMMARY OF PRELIMINARY ESTIMATES OF OPERATING COSTS

(Cost in Millions of Dollars Per Year)

Description	Optimized Conventional	Pressurized Boiler	Atmospheric Fluidized Boiler	Pressurized Fluidized Boiler
Wages	1.20	1.20	1.20	1.20
Supplies	0.29	0.29	0.29	0.29
Maintenance	2.43	1.97	2.32	2.16
Capital Costs	21.02	17.03	20.06	18.66
Depreciation	8.76	7.10	8.36	7.77
Insurance	0.42	0.34	0.40	0.37
Taxes	8.24	6.67	7.86	7.31
Sulfur Removal Operation Costs	1.38	0.00	0.84	0.76
Total	43.75	34.60	41.33	38.52
Fuel Costs	24.35	45.86	25.85	23.45
Total Annual Cost	68.10	80.46	67.18	61.97
Cost of Electricity, Mills/MJ (Mills/KWH)				
Pulverized Coal at 38¢/GJ (40¢/10^6 Btu)	2.25 (8.09)		2.22 (7.99)	2.05 (7.37)
Low Btu Gas at 76¢/GJ (80¢/10^6 Btu)	2.86 (10.31)	2.66 (9.57)		

CONCEPTUAL DESIGN OF PROMISING POTASSIUM-STEAM TOPPING CYCLES

Selected Powerplants for Conceptual Design

The two systems selected for conceptual design are summarized in Table 7, and detailed performance calculations are presented in Appendix D. These cycles are slightly different than those discussed in the preceeding section. The potassium condensing temperature was raised to 866 K (1100°F) to reduce costs, the steam temperature was raised to 839 K (1050°F) because the fireside corrosion problem is removed from the steam generator and a second reheat station was added to improve performance. The gas turbine pressure ratio was reduced to 15 to be more consistent with projected designs and the potassium turbine inlet temperature was increased to 1116 K (1550°F) for the topping cycle with the pressurized furnace. For the system with a pressurized fluidized bed the gas turbine inlet temperature was increased to 1200 K (1700°F) as the maximum bed temperature at which sulfur removal was adequate, but the potassium turbine inlet temperature was kept at 1033 K (1400°F) to have adequate heat transfer temperature difference in the bed.

Pressurized Furnace Powerplant Conceptual Design

POTASSIUM BOILER

The conceptual design of the pressurized furnace potassium boiler is illustrated in Figure 2. The boiler shown is one of eight modules required for the entire 1200 MW plant. The module is contained within a 4.34 m (14.25 ft) diameter cylindrical shell, enlarged at the gas discharge section to 6.25 m (20.5 ft) diameter. Overall height of the pressure vessel is 11.3 meters (37 feet). The size and proportions of this vessel were determined as a reasonable mutual accommodation of a number of requirements including the following:

1. Cycle air flow rate and heat input for eight boiler modules.

2. Axial velocity limits for a high efficiency swirl type gas burner.

3. Pressure drop through the combustion chamber and heat transfer passes.

4. Limitation of tube length in order to accommodate tube and pressure vessel differential expansion.

TABLE 7. - CYCLES SELECTED FOR CONCEPTUAL DESIGN

Description	Pressurized Boiler	Pressurized Fluidized Boiler
Gas Turbine Inlet Temp., K (°F)	1255 (1800)	1200 (1700)
Furnace Pressure, N/cm^2 (ATM)	152 (15)	91 (9)
Potassium Turbine Inlet Temp., K (°F)	1116 (1550)	1033 (1400)
Condenser/Boiler Min. Temp. Diff., K (°F)	← 28 (50) →	
Potassium Condensing Temp., K (°F)	← 866 (1100) →	
Potassium Feed Heater Temp. Rise, K (°F)	← 0 (0) →	
Steam Throttle Pressure, N/cm^2 (psia)	← 2413 (3500) →	
Number of Reheats	← 2 →	
Heat Rate, Dimensionless (Btu/kw-hr)	1.894 (6464)	2.004 (6840)
Efficiency, %	52.8	49.9

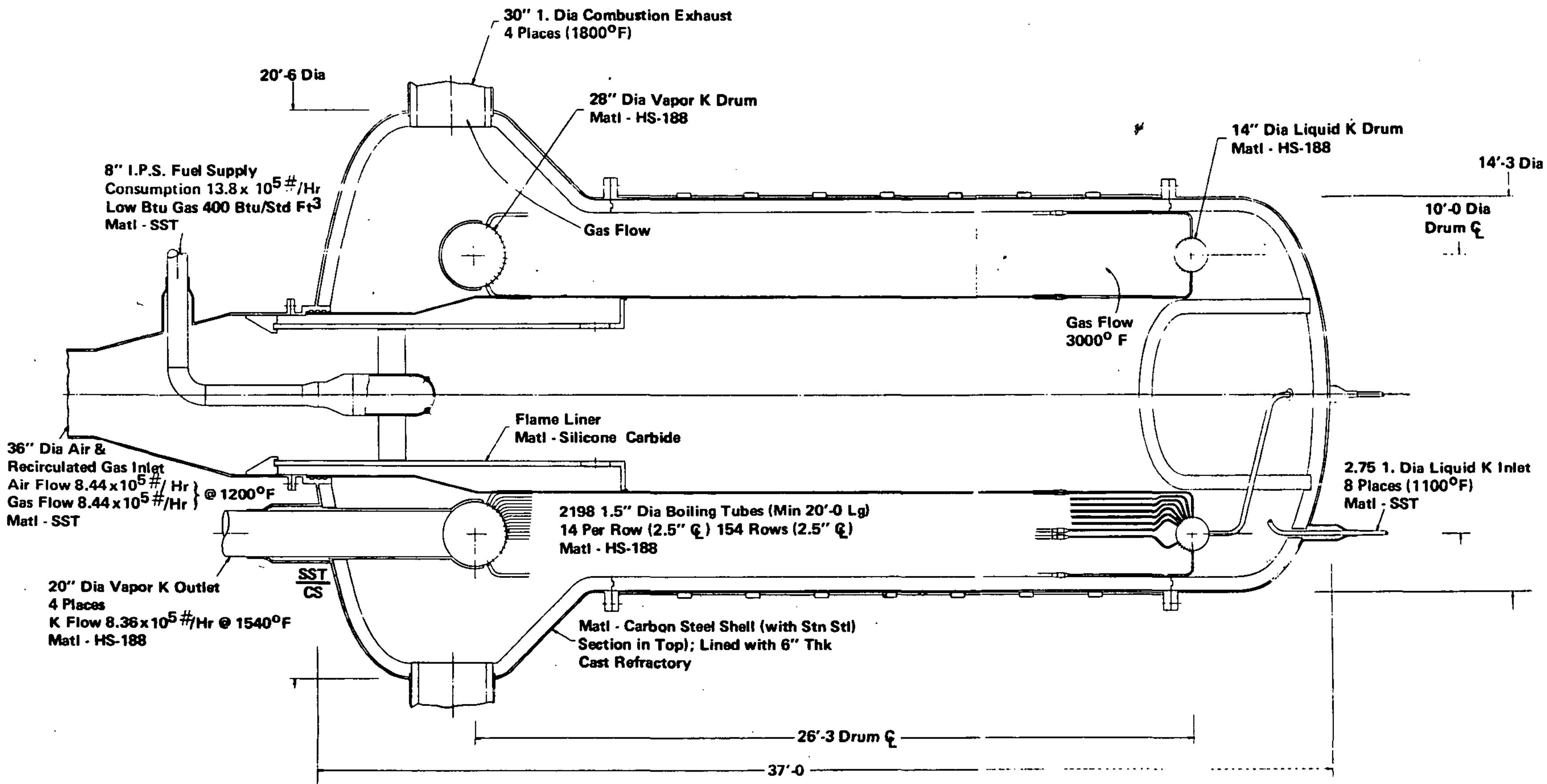

Figure 2. Schematic of Pressurized Potassium Boiler (221R918)

5. Tube surface requirements.

6. Tube spacing requirements for meeting header ligament stress limits.

7. Vapor velocity level limits inside the tubes, discharge header and discharge ducts.

8. Insulation thickness requirements inside of vessel.

9. Maintenance of vessel components within size limits for shop fabrication and shipment to installation site.

The tubes occupy the annular region between the central combustion chamber and the refractory lining of the pressure vessel. These tubes are welded into toroidal headers for liquid feed (lower) and vapor discharge (upper). The gas burner structure is at the top of the unit. Combustion gases flow downward through the combustion chamber, then turn upward and pass over the tubes in a direction parallel to the tube axes before leaving through four ducts joined into the enlarged upper section of the boiler shell. The inner ring of tubes is fabricated into a membrane wall which contains the combustion chamber and which receives radiant heat from the hot pressurized gases. At their lower ends the boiler tubes are of reduced diameter (0.95 cm) (3/8 in.). This section of the tubes carries only liquid, and the small diameter tube ends are bent before entering the inlet header in order to accommodate differential expansion between tubes. Since the tube bundle is suspended from the vapor exit ducts attached to the upper header and the only connection between the shell structure and the lower header is through the few flexible liquid feed tubes, there is no important differential thermal expansion problem between the tubes and the shell. Equalization of gas flow distribution through the main portion of the tube bundle is promoted by the incorporation of an enlarged diameter section of tube (or a suitable bushing attached to the tube) at the transition between the 0.95 cm (3/8 in.) diameter tubes and the 3.81 cm (1.5 in.) diameter tubes. These short enlarged sections create an orificing effect as the gas enters the main heat transfer region of the tube bundle. The enlargement of the upper part of the boiler pressure vessel is for the purpose of creating a discharge plenum for the combustion gases as they pass from the tube bundle space. This also helps to maintain a uniform flow distribution over the tube bundle annulus.

The material selected for the potassium tubes, headers and outlet ducts is Haynes 188, (nominal composition: 22Cr-22Ni-14.5W-0.1C-0.1La-0.35Si-Bal. Co). This cobalt base, high chromium alloy has exceptionally good resistance to sulphidation corrosion which might be expected on the fire-side of the boiler tubing. It also has excellent strength and oxidation resistance for a ductile, fabricable and weldable tubing alloy; and similar cobalt base alloys (i.e., HS-25) have demonstrated very satisfactory alkali metal compatability at temperatures above 1550°F. Thus, HA-188 is probably the best available alloy with the widest margin of property capabilities beyond those considered necessary for boiler application.

At the reference cycle condition of 1255 K (1800°F) gas outlet temperature, and 1116 K (1550°F) potassium vapor temperature, it is possible to design the boiler for once through operation without exceeding 1186 K (1675°F) metal temperature at the high quality end of the tubing. The boiler heat transfer surface, as determined by the data shown in Table 8, has been sized for this condition. An alternate possibility is to design the boiler as a recirculating type, with a liquid drain provided from the upper header, a phase separator in the vapor discharge flow and a recirculating pump. This would provide a greatly increased internal heat transfer coefficient at the upper ends of the tubes and would permit higher levels of combustion gas outlet temperature without overtemperaturing the tubes.

Other advantages of a recirculating type boiler are that it is easier to start up and control, it provides a higher average tube heat flux,thus reducing the tube surface, and it has a lower peak metal temperature.

Further, significant corrosion and mass transfer benefits are derived from the use of a recirculating boiler:

1. The carryover of dust-like solid solute particles is avoided by boiling only a small portion of the recirculating liquid. When all the liquid is evaporated, as in a once-through boiler, solute contained in the liquid either must be conducted by the vapor as it leaves the boiler tubes or must be deposited on the tube surfaces.

2. The recirculation of a large portion of the boiler liquid, saturated with solute, minimizes the potential for corrosion in the boiler by minimizing the solubility potential; such corrosion is more likely to occur in a once-through boiler in which all incoming liquid metal is a potentially corrosion aggresive condensate liquid with very little dissolved solids to fill the liquid's solubility capability.

3. Mixing of a small portion of boiler feed liquid with a large volume of recirculating boiler liquid results both in dilution and in fast heating of the boiler feed. This is accomplished out of direct contact with the boiler tube walls where corrosion and thermal fatigue effects would otherwise occur.

It has been demonstrated by ORNL[(5)] that recirculating potassium boilers have operated for very extended periods without boiler corrosion but that once-through boilers are troubled with the above solution corrosion and dust carry over problems.

The problem of NO_x limitation is a critical one in the design of this boiler. Standard successful design features for NO_x control include staged combustion and exhaust gas recirculation. Staged combustion can be provided for by the incorporation of the inlet air flow bypass annulus (SiC sleeve) around the primary combustion zone. Thus, the burning of the gas fuel in the immediate wake of the burner injection head, down-

TABLE 8. - POTASSIUM PRESSURIZED BOILER

1116 K (1550°F) Vapor Temperature

8 Modules Required for 1200 MW Plant

1.	Fuel - Low Heating Value Gas	14.9 MJ/m^3 (400 Btu/SCF)
2.	Fuel Rate	17.4 kg/s (13.8×10^4 lb/hr)
3.	Heat Input From Fuel	280 MW (955×10^6 Btu/hr)
4.	Inlet Gas Pressure	173 N/cm^2 (250 psia)
5.	Air Flow Rate	104 kg/s (826×10^3 lb/hr)
6.	Air Pressure	152 N/cm^2 (221 psia)
7.	Air Temperature	708 K (815°F)
8.	Air Source	Gas Turbine
9.	Air/Fuel Ratio	6:1 (on weight basis)
10.	Gas Temp. Entering Tube Bundle	1922 K (3000°F max.)
11.	Exhaust Gas Temperature	1255 K (1800°F)
12.	Exhaust Gas Flow	124 kg/s (982×10^3 lb/hr)
13.	Est. Gas Side ΔP	10 N/cm^2 (15 psi)
14.	"K" Inlet Temperature	866 K (1100°F)
15.	"K" Inlet Pressure	$\sim$ 34 N/cm^2 ($\sim$ 50 psia)
16.	"K" Flow Rate	100 kg/s (7.9×10^5 lb/hr)
17.	"K" Disc. Temperature	1116 K (1550°F)
18.	"K" Disc. Pressure	21 N/cm^2 (30.9 psia)
19.	Heat Input to "K"	206 MW (704×10^6 Btu/hr)
20.	Heat Transfer Surface	1542 m^2 (16,600 ft^2)

TABLE 8. - POTASSIUM PRESSURIZED BOILER (CONT'D.)

1116 K (1550°F) Vapor Temperature

8 Modules Required for 1200 MW Plant

21.	Overall Heat Transfer Coefficient	340 Wm^{-2} K^{-1} (60 $Btu/ft^2/°F/hr$)
22.	LMTD	∿ 444 K (∿ 800°F)
23.	Tubes - HA-188 Material	3.81 cm OD., 0.46 cm wall (1.5" OD., 0.180" wall)
24.	Pressure Shell	Refractory lined reinf. steel

stream of the primary air swirl vanes, will be rich, and combustion will be completed in the lean region downstream of the injection ports for the bypass air.

Forced recirculation of 1255 K (1800°F), or higher, furnace combustion discharge gases is a difficult problem, involving expensive high temperature fans. To avoid this it is proposed to operate the boiler modules in pairs, which receive flow from the gas turbines in series. Thus, the first boiler will operate with slightly more than 100% excess air, which can be used to dilute and reduce the temperature of the primary combustion gases. For the reference cycle using low Btu gas fuel, which includes a large percentage of inert gas, the first boiler burned-gas-temperature after dilution of primary zone gases will be approximately 1700 K (2600°F). The second boiler will operate with very little excess air, but dilution and burned gas temperature reduction is accomplished by the cooled burned gas from the first boiler. The post-mixing burned-gas-temperature in this boiler will be approximately 1866 K (2900°F). Preliminary calculations indicate that with this approach NO_x emissions can be held within EPA regulations for gaseous fuel (86 ng/J) (.2 lb $NO_2/10^6$ Btu). A materials list for this boiler is presented in Table 9.

HIGH PRESSURE TURBINE

The conceptual design of the high pressure potassium turbine is shown in Figure 3. This is a double-flow, single-stage machine operating between an inlet condition of 1116 K (1550°F), 21 N/cm^2 (30 psi) and a discharge condition of 1005 K (1350°F), 7.6 N/cm^2 (11 psi). The aerodynamic design is that of a high efficiency, free vortex turbine with a small degree of reaction at the bucket root. Ten nozzle groups are provided at the inlet, for each of which a control valve (not shown) will be provided. The turbine angular velocity is 188 rad/s (1800 rpm), and the bucket speed at the root of the bucket is 290 m/s (950 ft/sec). Disc diameter is 305 centimeters (120 inches).* The rotor construction is that of discs and spacer rings joined by curvic couplings held together by tie bolts. Material for the buckets, discs, spacer rings and tie bolts is TZM molybdenum alloy. The bucket root centrifugal stress level is approximately 27,580 N/cm^2 (40,000 psi), and the wheel and fir tree dove tail stresses have been determined to be of approximately the same magnitude, which is estimated to be safely within the 1-2% creep stress limit of TZM alloy for a thirty year life at 1005 K (1350°F) temperature. The connection between the end spacer rings and the A-286 shaft is by means of a "half barrel" type of curvic coupling, which maintains concentricity while permitting radial differential thermal expansion between the coupled parts. This construction was thoroughly proof tested in the three stage potassium turbine program[6].

TZM molybdenum alloy was successfully used in small scale turbines to demonstrate the potassium cycle. Scaling to 36 inch diameter appears feasible using present technology. To attain larger diameters would probably require the use of powder metallurgy and hot isostatic pressing followed by upset forging, cross

*Can be reduced to 36 inches by modularization.

TABLE 9. - MATERIALS SELECTION FOR THE PRESSURIZED FURNACE

Component	Material
Pressure Shell	Low Carbon Steel (Refractory Insulated)
Stack	AISI Type 304
Air Inlet	AISI Type 304
Flame Liner	Silicon Carbide
Burner and Supports	AISI Type 304
Flame Liner Supports	AISI Type 304
Upper Center Head and Ports	AISI Type 304
Upper Dome	Low Carbon Steel (Refractory Insulated)
Exhaust Duct	Low Carbon Steel (Refractory Insulated)
Lower Dome	Low Carbon Steel (Refractory Insulated)
Boiler Tubes	HA-188
Boiler Drum	HA-188
Vapor Outlet	HA-188
Lower Inner Flame	Silicon Carbide
Inner Combustion Baffle	HA-188

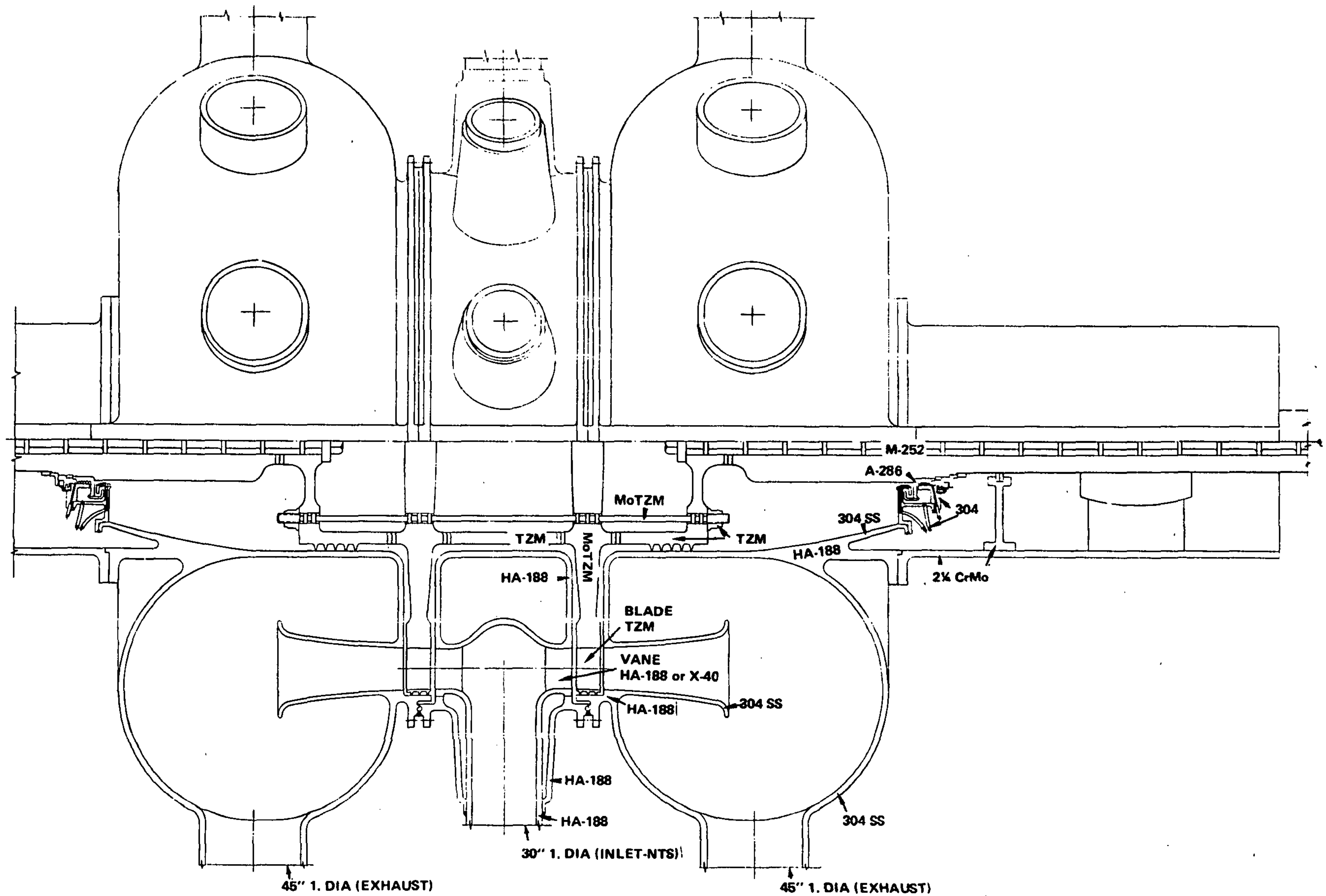

Figure 3. Schematic of High Pressure Potassium Turbine (221R915)

rolling and sector forging. Particular attention must be paid to these factors; control of MoO_3 smoke which issues from the surface of the part when forged in air, the low ductility of this alloy at temperatures below 500-700°F, the dissimilarity in thermal expansion between this alloy and the superalloys used for mating parts. The accommodation of these characteristics along with the high strength margin advantages of TZM molybdenum alloy will require considerable integrated development effort between designers, materials engineers and metal processing sources. The oil lubricated bearings are supported from cylindrical extensions of the horizontally split shell structure. These extensions are of sufficient length to accept the temperature difference between the oil cooled bearing support stations and the exhaust casing. Bearing pedestal structures will support the turbine at the horizontal centerline at the bearing stations. One of these supports will permit longitudinal thermal expansion. The one adjacent to the generator will be axially fixed.

To seal the rotating shaft against leakage of air or other noncondensable gas into the potassium vapor flow stream, a dynamic seal of the type successfully used in previous General Electric mercury and potassium turbine designs is employed. In this seal, potassium liquid is introduced into a rotating annulus. Liquid discharging from the seal is mixed with a flow of argon buffer gas. Separation of the gas and liquid is accomplished externally and the components recycled. Practically no gas leaks through the rotating seal.

Design data relating to the turbine is presented in Table 10. Table 11 presents a materials list. It will be noted that Haynes 188 alloy is employed for the high temperature static parts and 304 stainless steel and low alloy chrome molybdenum steel are used where temperatures are lower.

LOW PRESSURE TURBINE

The low pressure turbine conceptual design is illustrated in Figure 4. It is a three stage double flow turbine. The rotor is constructed from superalloy discs, spacer rings and shafts which are joined by bolting with rabbets for maintaining concentricity. Superalloy buckets are assembled to the wheels by fir tree dovetails. The disc diameter is approximately 305 centimeters (120 inches)* The turbine angular velocity is 126 rad/s (1200 rpm). Bucket root and wheel temperatures range from 955 K (1260°F) to 866 K (1100°F) in the three stages. Stress levels (wheel, bucket root, and dovetail) range from approximately 12,400 N/cm^2 (18,000 psi) in the first stage to about 24,100 N/cm^2 (35,000 psi) bucket root and dovetail stress in the last stage. These stress levels are compatible with the estimated .2% creep limits of the wheel and bucket materials specified (see Table 12) for thirty years life at the temperatures involved.

The bearing, shaft seal, and mounting arrangement of this turbine are similar to those discussed above for the high pressure turbine. Flexible connections to the two condensers attached to the exhaust casings will be required.

*Can be reduced to 40 inches by modularization. Superalloy discs of this size have been forged.

TABLE 10. - POTASSIUM HIGH- AND LOW-PRESSURE TURBINE DESIGNS

Stage	High Pressure Unit	Low Pressure Units		
	1	1	2	3
Inlet Temp., K (°F)	1116 (1550)	1005 (1350)	959 (1266)	914 (1186)
Inlet Pressure, N/cm^2 (psia)	21.28 (30.86)	8.04 (11.66)	5.00 (7.25)	3.03 (4.39)
Flow Rate, kg/s (lb/sec)	404 (888)	185 (407)	185 (407)	185 (407)
Enthalpy Drop, KJ/kg (Btu/lb)	168.8 (72.6)	82.3 (35.4)	82.3 (35.4)	82.3 (35.4)
Wheel Speed, m/s (ft/sec)	335.3 (1100)	234.7 (770)	249.9 (820)	265.2 (870)
Tip Diameter, m (in)	4.04 (159)	4.26 (167.8)	4.71 (185.4)	5.22 (205.4)
Hub Diameter, m (in)	3.07 (121)	3.21 (126.3)	3.25 (127.8)	3.22 (126.8)
Blade Height, m (in)	0.48 (19)	0.53 (20.75)	0.73 (28.8)	0.998 (39.3)
Exit Quality, dim.	0.916	0.96	0.927	0.895
Angular Velocity, rad/s (RPM)	188.5 (1800)	125.7 (1200)	125.7 (1200)	125.7 (1200)

TABLE 11. - MATERIALS SELECTION FOR THE HIGH PRESSURE POTASSIUM VAPOR TURBINE

Component	Material*
Inlet Casing	HA-188
Nozzle Vanes	HA-188 or X-40
Inner Nozzle Support	HA-188
Turbine Casing, Exhaust Nozzle & Scroll	HA-188
Exhaust Nozzle Extension	AISI TP 304
Turbine Exhaust Scroll	AISI TP 304
Center Torque Tube	TZM
Turbine Disc	TZM
Disc Tie Bolt	TZM
Turbine Blades	TZM
Cup Shaft	TZM
Main Shaft	A-286
Shaft Tie Bolt	M-252
Cup Seal Stator	AISI TP 304
Cup Seal Rotor	A-286
Bearing & Seal Housing & Supports	2-1/4 Cr-Mo

*	Composition										
Material	C	Fe	Ni	Co	Cr	W	Mo	Ti	Al	Zr	Other
HA-188	.10	-	22	Bal	22	14.5	-	-	-	-	0.35Si,0.1La
X-40	.50	2.0	10.5	Bal	25	7.5	-	-	-	-	
AISI TP 304	.08	Bal	10	-	19	-	-	-	-	-	
TZM	.015	-	-	-	-	-	Bal	0.5	-	0.08	
A-286	.08	Bal	25.5	-	15.3	-	1.3	2.1	0.3	-	
M-252	.15	5.0	Bal	10.0	19.0	-	9.8	2.5	1.0		
2-1/4 Cr-Mo											

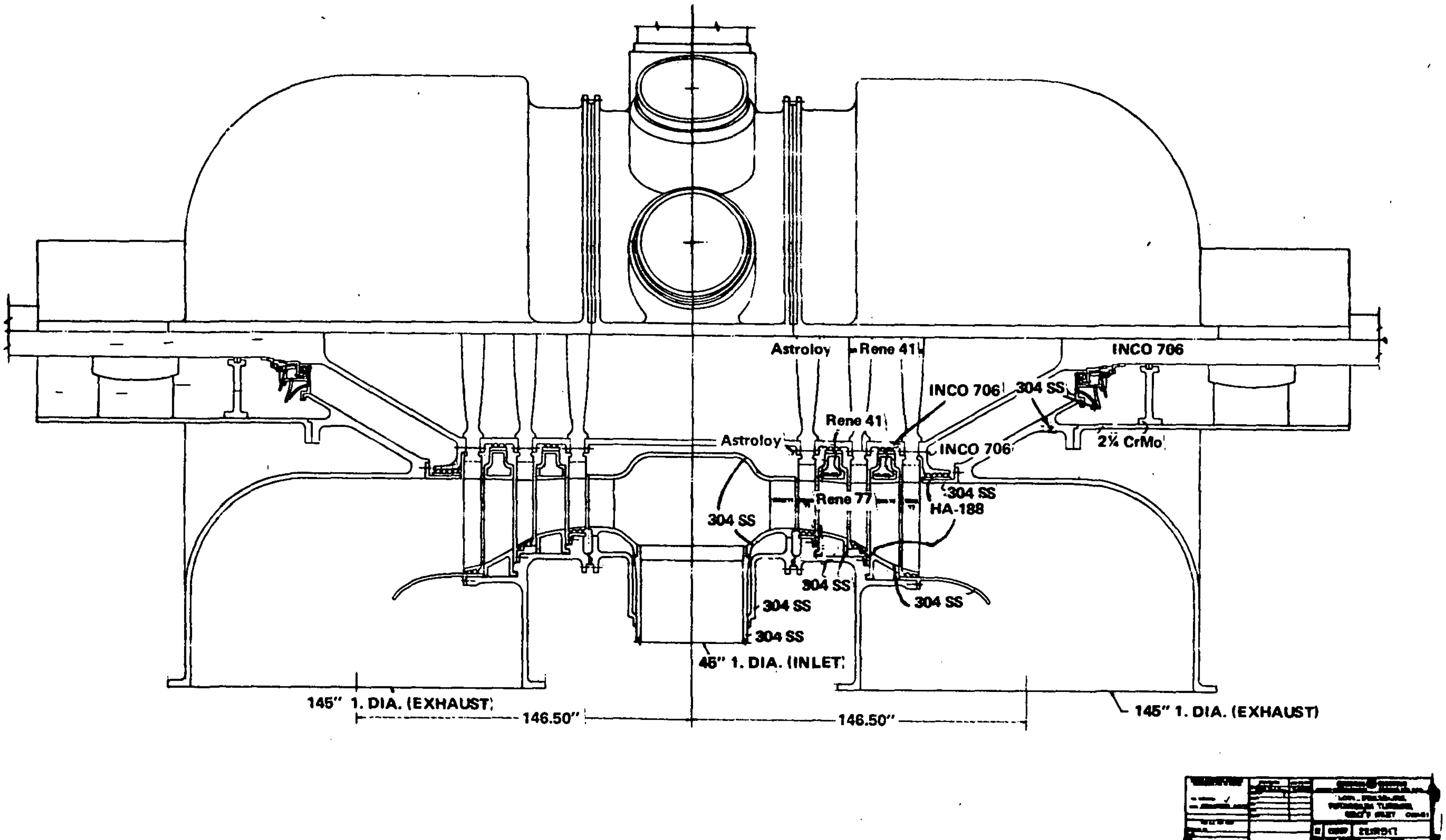

Figure 4. - Schematic of Low Pressure Potassium Turbine

TABLE 12. - MATERIALS SELECTIONS FOR THE LOW PRESSURE POTASSIUM VAPOR TURBINE

Component	Material
1st Stage Nozzle Inlet & Casing	AISI TP 304
Nozzle Vanes	HA-188 or X-40
Turbine Blades	Rene' 77
Turbine Casings	AISI TP 304
Turbine Tip Seals	HA-188
Interstage Seals	HA-188
Inner & Outer Nozzle Bands	AISI TP 304
Center Spool	Astroloy
Stage 1 Disc	Astroloy
Stage 1-2 Spacer	Rene' 41
Stage 2 Disc	Rene' 41
Stage 2-3 Spacer	INCO 706
Stage 3 Disc	INCO 706
Stage 1 Bolts	Astroloy
Stage 2 Bolts	Rene' 41
Stage 3 Bolts	INCO 706
Turbine Man Shaft	INCO 706
Turbine Exhaust Scroll	AISI TP 304
Bearing & Seal Casing & Supports	2-1/4 Cr-Mo
Cup Seal Stator	AISI TP 304
Cup Seal Rotor	A-286

POTASSIUM CONDENSER/STEAM GENERATOR

The potassium condenser/steam generator in the topping cycle is the interface between the potassium system and the steam system. The exhaust vapor from the potassium turbines gives up its heat of condensation to the water in three heat exchangers which make up the potassium condenser/steam generator. These heat exchangers are (1) a high pressure boiler, (2) an intermediate pressure reheater, and (3) a low-pressure reheater.

A conceptual design for the potassium condenser/steam generator is shown in Figure 5. Four units of this type are required for a 1200 MWe plant. Each module is small enough in width to be shipped to the plant site by rail. The overall design approach was to contain the high-pressure water inside tubes with condensing potassium outside the tubes. The tube bundles for the three heat exchangers are located within a single shell, and flow partitions separate the tube bundles on the shell side. The potassium condenser shell is made up of two ten-foot-high sections which would be welded together at the plant site. As indicated in Figure 5, the flow of potassium vapor to each tube bundle assembly is controlled with three sets of louvers located above the heat exchangers.

A preliminary thermal-hydraulic analysis was performed for each of the three heat exchangers in order to estimate the required heat transfer area, total number of tubes, tube inside and outside diameters, and tube lengths. The results of the analysis, along with additional pertinent data, are presented in Table 13. This heat exchanger is made of 304 stainless steel, or Incoloy 800.

As shown in Figure 5, high pressure feed water to the boiler enters the potassium condenser in a single pipe which penetrates the shell. The feedwater then flows into three headers where the water is distributed to 990 tubes in parallel. The water in the boiler tubes makes two passes through the potassium where it is heated to the steam turbine inlet temperature of 839 K (1050°F). In each of the two reheaters, steam enters the tube bundle from manifolds and makes a single pass through the potassium vapor where it is heated to 839 K (1050°F). The inside diameters and number of tubes are determined by heat transfer and pressure drop constraints.

POTASSIUM DUMP TANKS

The potassium storage or dump tank is shown on Figure 6. Four (4) separate tanks have been employed in the plant conceptual design. This not only reduces the quantity of potassium in a single container, thus decreasing the risk from a major spill, but allows purification of potassium (i.e., gettering of oxygen from the potassium by hot trapping) in one container while others are in the normal operating mode. It further provides flexibility in plant operation if maintenance on a particular unit is necessary.

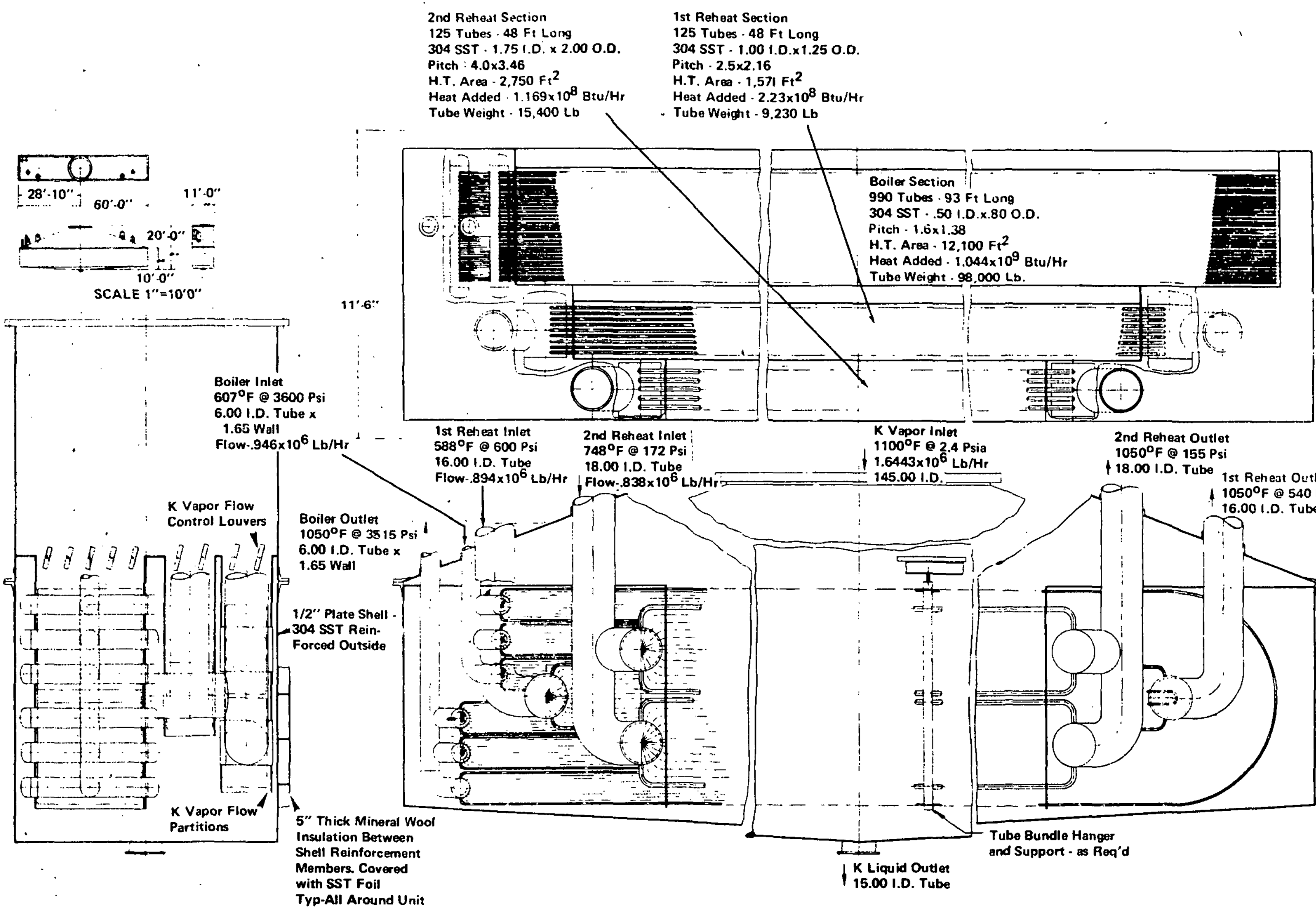

Figure 5. Schematic of Potassium Condenser/Steam Generator (221R831)

TABLE 13. - PRESSURIZED FURNACE CYCLE

Potassium Condenser/Steam Generator Module

4 Modules Required for 1200 MW_e Plant

		Boiler	RH #1	RH #2
1.	Potassium Temp., K (°F)	866 (1100)	866 (1100)	866 (1100)
2.	Potassium Press., N/cm^2 (psia)	1.65 (2.4)	1.65 (2.4)	1.65 (2.4)
3.	Potassium H.T. Coeff., Wm^{-2} K^{-1} ($Btu/hr-ft^2-°F$)	56745 (10,000)	56745 (10,000)	56745 (10,000)
4.	Heat Transfer Rate, MW (Btu/hr)	306 (1.044×10^9)	65 (2.23×10^8)	34 (1.17×10^8)
5.	H_2O Inlet Temperature, K (°F)	593 (607)	582 (588)	671 (748)
6.	H_2O Outlet Temperature, K (°F)	839 (1050)	839 (1050)	839 (1050)
7.	Log. Mean ΔT, K (°F)	108 (194)	111 (199)	86 (155)
8.	H_2O Inlet Pressure, N/cm^2 (psia)	2482 (3600)	414 (600)	119 (172)
9.	H_2O Outlet Pressure, N/cm^2 (psia)	2424 (3515)	372 (540)	107 (155)
10.	Overall H.T. Coeff., Wm^{-2} K^{-1} ($Btu/hr-ft^2-°F$)	2525 (445)	4046 (713)	1555 (274)
11.	Tube Inside Dia., cm (in.)	1.27 (0.5)	2.54 (1.0)	4.45 (1.75)
12.	Tube Outside Dia., cm (in.)	2.03 (0.8)	3.18 (1.25)	5.08 (2.00)
13.	Number of Tubes	990	125	125
14.	Tube Length, m (ft)	28.3 (93)	14.6 (48)	14.6 (48)
15.	Steam-Side H.T. Area, m^2 (ft^2)	1124 (12,100)	146 (1571)	255 (2750)
16.	Tube Weight, kg (lb)	44453 (98,000)	4187 (9230)	6985 (15,400)
17.	H_2O Flow Rate, kg/s (lb/hr)	119 ($.946 \times 10^6$)	113 ($.894 \times 10^6$)	106 ($.838 \times 10^6$)

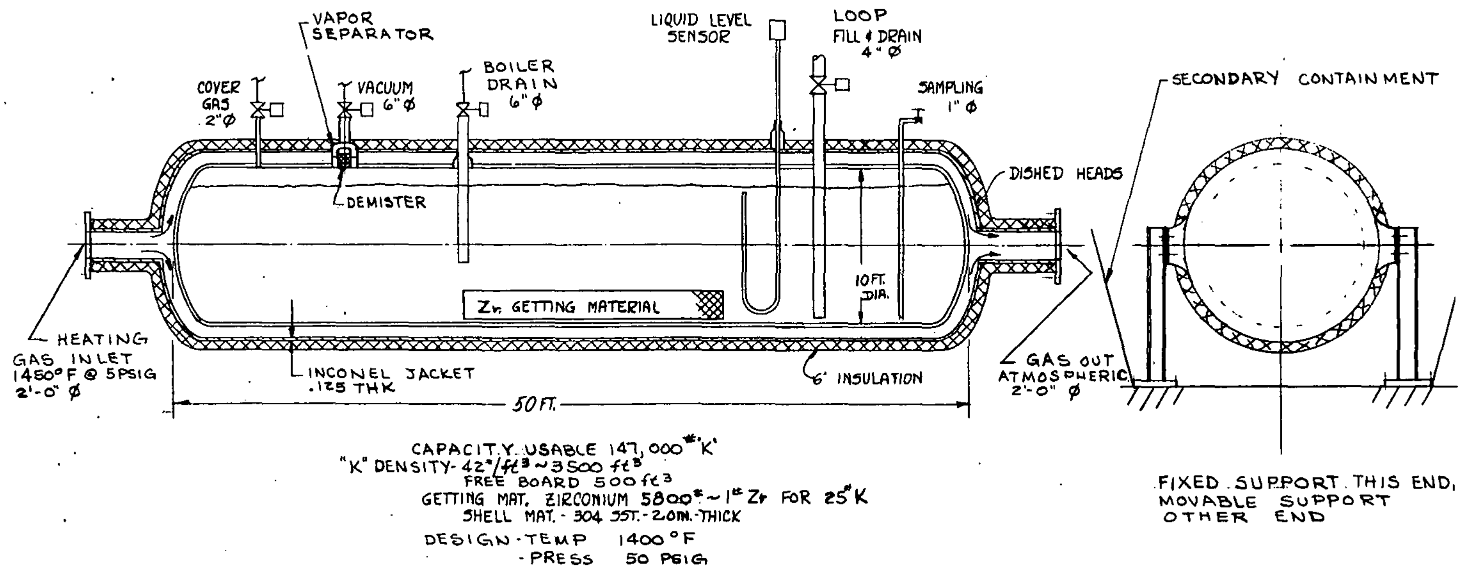

Figure 6. Potassium Dump Tank (SK 128C8095)

Storage tanks are sized to hold sufficient liquid to adequately fill the system. Since potassium has a high affinity for oxygen, it will remove this gas from the internal walls of the piping system and components. In this sense, it is very desirable to hot flush a liquid metal loop with potassium. In a large two phase system containing a recirculating type boiler, the boiler tube bundle is normally hot flushed at 533 K (500°F) and a gettering cycle then runs in the dump tank after the boiler is drained.

The gettering or hot trapping cycle in the dump tank consists of elevating the potassium to 1033 K (1400°F). This is accomplished by heating the dump tank and holding the above temperature for about 24 hours. Potassium samples are extracted periodically from the tank and analyzed for oxygen content. When the oxide level is acceptable, the gettering cycle is complete.

Since the dump tank is not normally designed to contain enough potassium to flood both the boiler and condenser tubes at the same time, a separate hot flush cycle is conducted on the condenser in a similar manner to the cycle conducted on the boiler. Condenser tubes are heated to 533 K (500°F) with auxiliary heaters during the flushing operation.

The vapor piping between boiler and turbine and turbine and condenser is not hot flushed due to its large volume and complications which would result from flooding the turbine with liquid. As a result oxygen picked up from these components during initial operation of the system must be removed by the hot traps installed in the boiler and condenser. These traps provide a continuous gettering function during system operation. System purity is continuously monitored by in-line oxygen sensors. A sudden increase in oxygen level after the system has been in operation normally indicates a leak in the condenser region where the pressure is below atmospheric. In this event, the complete system is dumped to the storage tank and leak tests conducted to determine the location and extent of damage.

In the case of small tanks electric heaters are normally employed to elevate the tank and its potassium inventory to gettering temperature. With large tanks this does not appear to be an economical method and accessory air heaters utilizing clean fuel are contemplated. These may be either direct or indirect fired units. The storage tank then requires an insulated jacket through which the hot air can be conducted and in turn transfer heat to the tank walls by convection.

The solubility of oxygen in potassium increases with increasing temperature. Its presence in solution has an adverse effect on the walls of material conducting the fluid. The higher the concentration the greater will be the corrosive effects. The storage tank provides an excellent point to remove oxygen from the potassium, and thus, it is equipped with a gettering material such as zirconium which has a higher affinity for the oxygen than the potassium at elevated temperatures. The zirconium is normally installed in the tank in the form of multiple sheets in a closely spaced array, or chips installed in a wire mesh basket may be utilized. In either case the design must allow for a maximum of zirconium surface area exposed to the potassium. From experimental data[7] it has been concluded that one part of zirconium to 25 parts of potassium by weight will provide a capability to getter oxygen from 800 ppm to < 50 ppm. Such a capability in a sealed system should meet normal 30 year getter life requirements. Of course, care of and monitoring of the getter are important to assure effective getter capability under extenuating circumstances. Oxygen concentration in the system is usually maintained below 20 ppm. After a hot flushing procedure, concentration of 50 ppm or higher can be obtained. The storage tank contains a sampling system whereby potassium can be removed for laboratory analysis. This is done prior to and after a hot trapping operation. Approximately 8 to 16 hours is normally required to decrease the oxygen concentration to acceptable levels.

In addition to being a storage tank from which the system is filled, and part of the potassium purity control system, the tank also acts as normal and emergency dump container. Valving separates the dump tank from the two phase system during normal operation. In the event of a leak in the potassium system it is sometimes necessary to remove the potassium from the entire system as fast as possible. The system is designed for gravity drainage of all components and piping to the dump tank. Separate drain lines from major high temperature components such as the boiler are provided and sized to handle the dump via gravity in a short time. The tank is equipped with special thermal shock resisting valves on these lines, and thermal sleeves at the tank nozzles are designed to eliminate failure under such conditions. An equalizing cover gas system insures that cover gas pressure will not interfere with gravity drainage. Sump tank temperature is held at some intermediate temperature during operation so that thermal shock during an emergency dump will not be excessive.

For additional safety, the storage tank may require individual secondary containment. In any event, an isolated area, which can be sealed off to prevent the entrance of air and ventilated to the air scrubbing systems, appears desirable. Since the tank must be at the lowest point in the system, a concrete lined pit for each tank appears practical and feasible.

PLANT CONCEPTUAL LAYOUT - CYCLE #1 - PRESSURIZED BOILER SYSTEM

The conceptual plant layout of a 1200 MW electric generating plant is shown on Figures 7, 8, and 9. This layout is predicated on the use of pressurized gas fired boiler modules and is a ternary cycle utilizing potassium vapor turbines, steam turbines and gas turbines to generate useful electrical power. Cycle #1 utilizes a single potassium high pressure (21 N/cm^2) double ended turbine and two low pressure (10.5 N/cm^2) double ended potassium turbines each driving generators. Two gas turbines driving compressors for boiler combustion air supply and electrical generators are employed. A single multi-stage steam turbine generator provides the remainder of the electrical power.

Potassium System. - Prior to attempts to prepare a plant layout some basic rules governing arrangement of potassium components were established as follows:

1. The potassium system with all of its components would be housed in an area separated as much as possible from the steam portion of the plant by fire resistant walls. This area would be kept as small as practically possible since it must be ventilated through a scrubbing system to remove potassium oxide smoke in the event of a leak.

2. Gravity drainage of potassium from components and piping to the storage tanks is required.

3. Potassium vapor piping runs from the boilers to the high pressure turbine should be as short as possible. This will keep heat loss to a minimum, keep pressure drop low, reduce thermal expansion problems, and keep high temperature piping and insulation costs to a minimum.

4. The high-pressure, high-temperature gas piping from the boilers to the gas turbines should be as short as possible. The reasoning in Item 3 above applies here also.

5. The low-pressure potassium ducting from the high-pressure turbine exhausts to the low pressure turbine inlets should be as short as possible. The same reasons as Item 3 above pertain.

6. The potassium condensers should be placed as close to the low pressure turbine discharge as possible.

7. With short, large-diameter vapor piping runs, expansion loops become impossible. Therefore, adequate and reliable expansion joints (bellows type) must be developed. Bellows joints must be installed in a manner to result in minimum forces on the turbine frames.

8. Turbine manifold inlet nozzles are assumed to be fixed points.

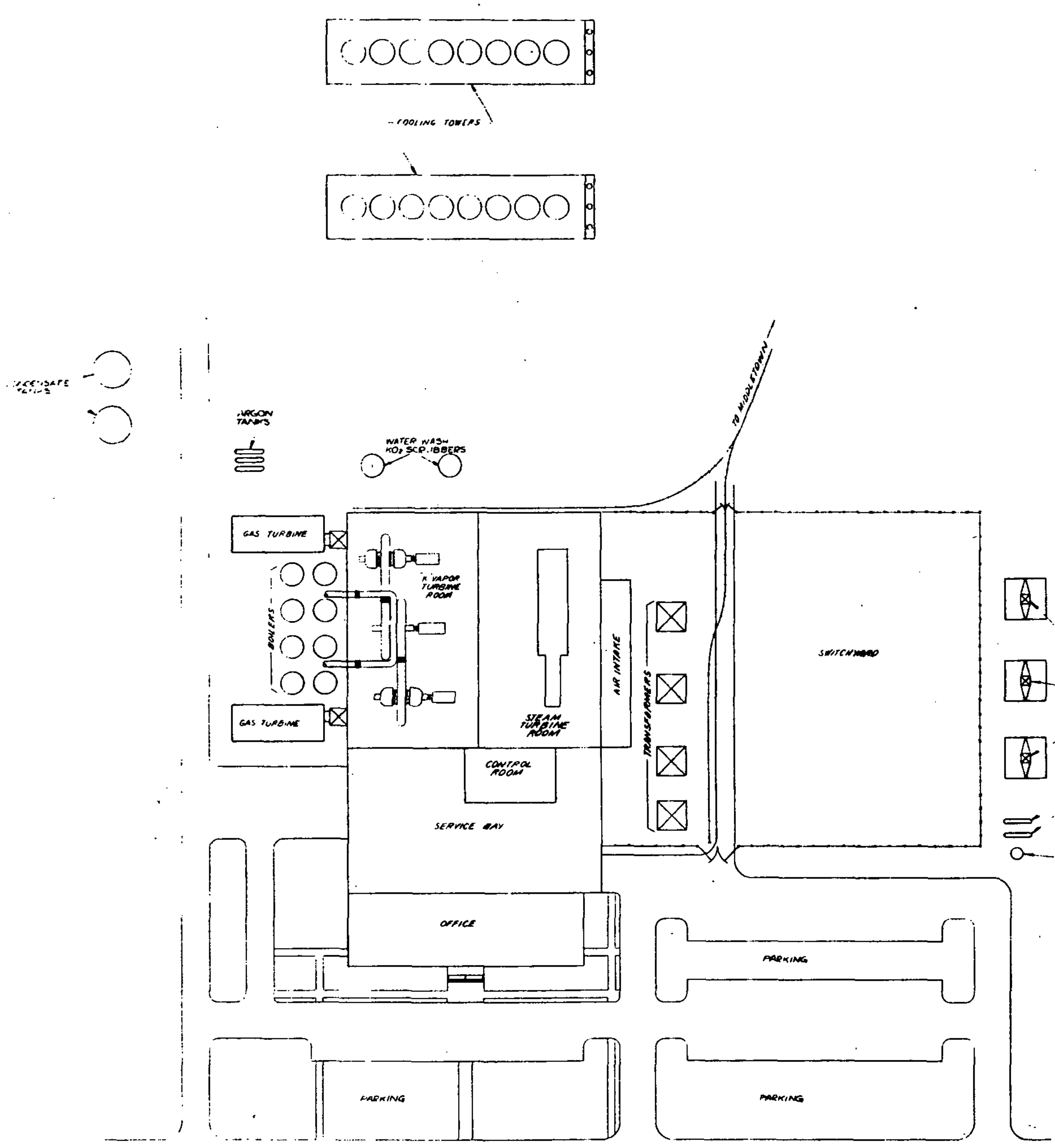

Figure 7. Potassium Pressurized Boiler Combined Powerplant (SK 707E811)

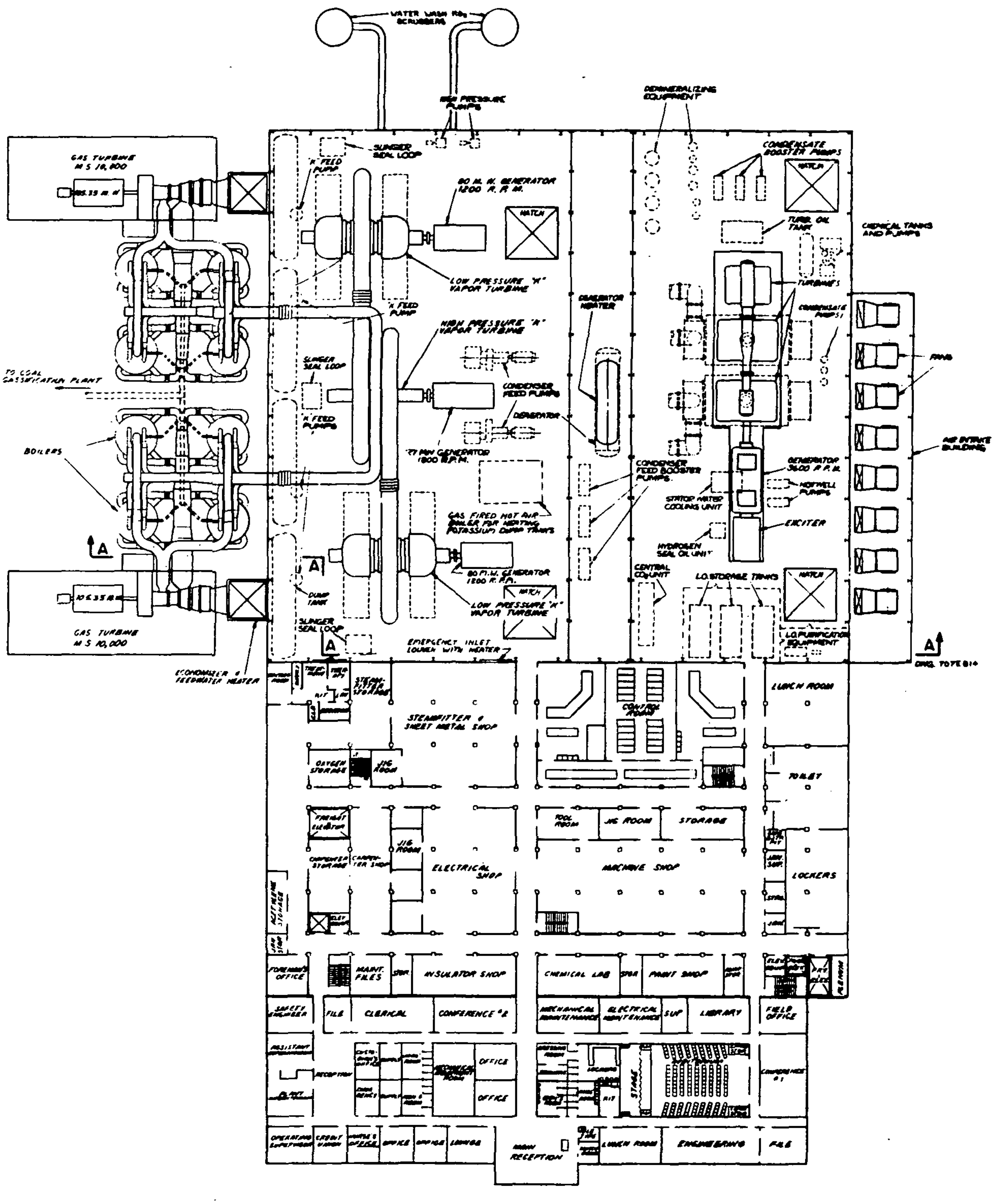

Figure 8. Potassium Pressurized Boiler Combined Powerplant (SK 707E813)

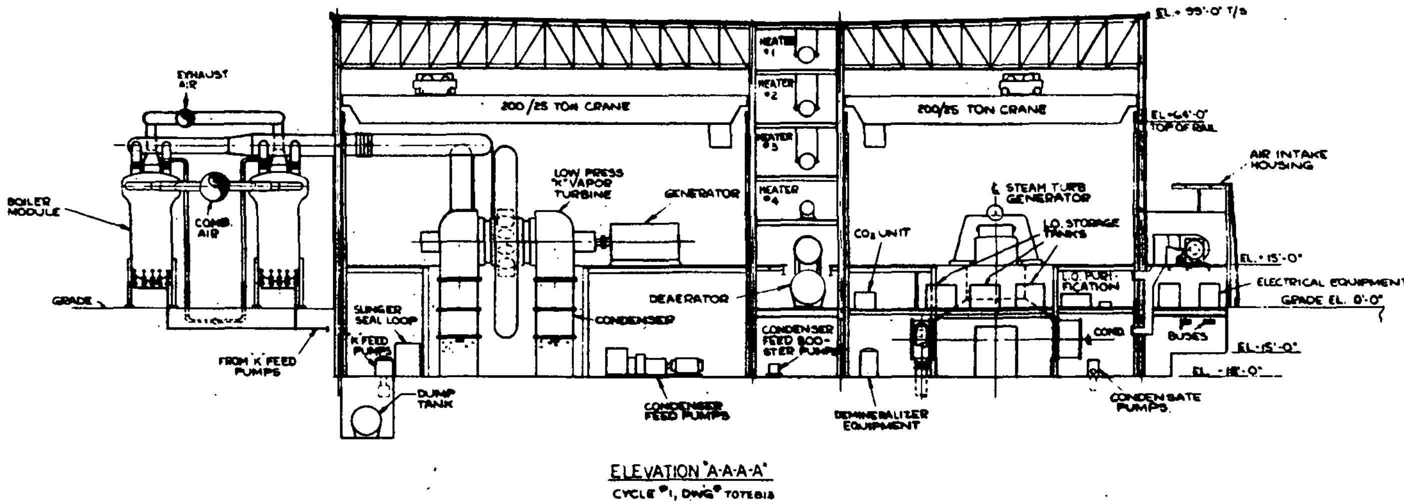

Figure 9. Potassium Pressurized Boiler Combined Powerplant (SK 707E814)

9. Boiler discharge vapor nozzles are assumed to be fixed points. The size and weight of these units makes floating type supports impractical.

With the above guidelines, initial layouts of the potassium system and gas turbines were made, shown on Figure 10. This layout assumed the use of four (4) gas turbine/compressors with the eight boiler modules placed in pairs between the turbines. Subsequent changes (increases) in the boiler pressure made possible the use of a conceptual design gas turbine with a 15:1 compression ratio. Since two of these machines would provide the necessary air flow for all boilers, nesting of the eight boiler modules together with gas turbines outboard of this nest was possible. This considerably reduced the length of boiler to turbine vapor piping.

Low-pressure potassium turbines were placed directly above their respective condensers (i.e., one condenser for each low pressure turbine exhaust hood, total of four). High-pressure turbine exhausts discharging downward were taken under the turbine floor and brought up into the bottom of the low pressure turbine inlet manifold. By off-setting the turbines, adequate space for this large ducting was available, and interference with the below floor condenser/steam generators eliminated.

Vapor piping from the boilers to the high pressure turbine was established at an elevation for adequate overhead clearance on the turbine floor, and boilers were elevated to match their discharge vapor nozzles with two main vapor headers which enter the turbine manifold at the three and nine o'clock positions.

Although not shown on the layouts, consideration will have to be given to bypass ducting and valves which would allow operation of the two low-pressure turbines in the event a high-pressure turbine outage is encountered during plant operation. Under these conditions boiler firing rate would be reduced to provide the lower pressure vapor.

A by-pass system for shunting potassium vapor directly to the condenser/steam generator should be considered, at least for initial or pilot plant designs. This will allow considerably more flexibility in startup, system check-out and general plant operation. It does, however, impose additional requirements on the condenser design (i.e., condenser must be designed for maximum boiler temperature) and requires additional valves, piping and control.

Potassium piping (liquid) from condenser wells to pumps via flowmeters back to the boiler inlets is not shown. Boiler drain lines, dump tank system fill lines, and dump tank charging and interconnecting headers are not shown. These systems present no major problems, however, large valves and expansion loops or joints will be required. Large liquid sodium valves are presently under development as a part of the Breeder Reactor sodium systems and knowledge gained there will be utilized in the selection of potassium valves. The same is true of flowmeters. Electromagnetic types are most commonly used.

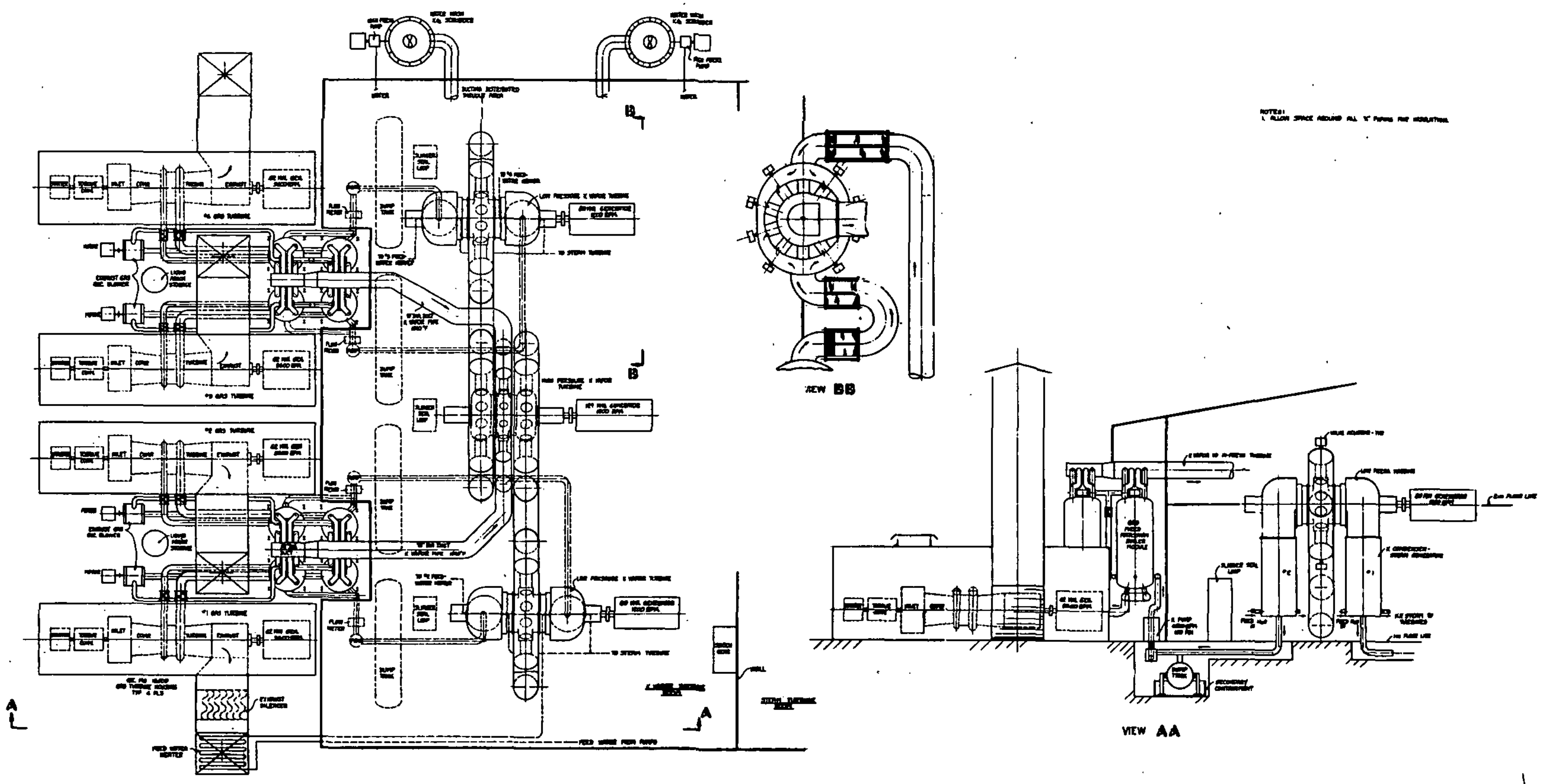

Figure 10. Pressurized Boiler Powerplant (221R830)

Potassium pumps are indicated on the layouts. These are of the centrifugal type as manufactured by companies for the LMFBR program. Four (4) pumps are indicated on the layout. Each would have a capacity of $\sim$ 0.28 m^3/s (4500 gpm) at adequate head to feed the boilers. Much larger pumps have been built for sodium service and the selection of four units rather than two was primarily based on ability to provide adequate power turn-down and redundancy for reliability.

The extent of the heating of potassium piping will depend on operating procedures. Electric heating has normally been employed utilizing calrod type heaters beneath insulation. Since potassium freezes at 337 K (147°F), any stagnant potassium not capable of receiving heat input from the main stream would require continuous heating and temperature monitoring. Assuming the piping systems (main liquid runs) are filled from the storage tank at 533 K (500°F) and circulation is started shortly thereafter, heating of main runs may not be necessary. Preheating all potassium containing lines does assist in the baking out of surface absorbed gases from the containing materials during initial evacuation of the system (i.e., removal of air). In GE's small 3 MW experimental plant all piping was preheated. This included a hot gas system for preheating the potassium condenser. If necessary, auxiliary heaters might be used to heat the water in the condenser tube bundle prior to startup. After startup this system could be shutdown. Preheating of the condenser will also reduce the possibility of failure due to thermal shock at startup.

Other systems not shown in the plant layout but included in cost estimates are as follows:

1. Vacuum system for initial evacuation of the potassium system and removal of noncondensibles from the potassium system (condenser).

2. Separation systems for removal of potassium vapor, liquid and dust from the noncondensible gas removed from the condenser.

3. Argon reclamation system. The potassium turbine requires a gas buffer seal between the potassium system and the bearing lube system. The argon gas entering this buffer flows across labyrinth seals to the bearing oil sump and the potassium slinger seal system. The argon gas must be removed from both of these systems to prevent a pressure buildup in either system which would result in potassium being forced into the oil or vice-versa. Due to the large quantity of gas required, systems for recovering the gas from the potassium system and the oil system are required. Removing the gas from the potassium system requires a complex series of heaters, coolers and filters to prevent plugging of components and piping with frozen potassium. Removal of oil vapor from the gas require coolers, separators, filters, and sieves. After the gas has passed through these systems, it enters a compressor inlet receiver tank. A hermetically sealed (diaphram type) compressor recompresses the gas so that it can again be fed to the turbine buffer seal. The recovery of gas

from the oil system has never proven to be economically successful due to the inability to remove all oil vapor. The use of a face type seal on the oil side of the potassium/oil gas buffer would eliminate gas leakage into the turbine oil sump and eliminate this problem.

Each potassium turbine will be equipped with a lube system and potassium system to provide potassium specifically for the slinger type potassium seal. Slinger seal potassium systems are indicated on the layout drawing, located on the first floor beneath each potassium turbine.

The safety and environment problems associated with the operation of a potassium vapor system require special attention. During the initial design of General Electric's 3 MW Potassium Turbine Test Facility the insuring agency along with G.E. established design criteria for safe storage, handling and general operation of the facility. These criteria were briefly as follows:

1. No sprinkler systems were to be installed in potassium containing areas.

2. All potassium containing components or piping should have secondary containment. In the case of the boiler, the furnace-box was construed to be the secondary containment. In the case of components and piping located inside of the building structure the building was construed to be the secondary containment.

3. Secondary containment areas should be vented to the atmosphere through a scrubbing system to prevent an excess of potassium oxide smoke from being emitted to the atmosphere. Scrubbing systems should be 98% effective.

4. Instrumentation for the detection of airborne potassium oxide along with interlock control systems so that automatic fail safe shutdown results were required.

Safe procedures for handling and storage of alkali metals have been established for years. Experience gained with EBR-2 fast breeder reactor experiments in the United States and Dounreay fast breeder reactor experiment in Great Britain are good indications of the feasibility of handling large quantities of alkali metal in a safe fashion. The world wide commitment to the development of liquid metal fast breeder reactors further exemplifies the confidence level in the handling and storage of these materials.

Although GE experience with the operation of a 3 MW plant for approximately seven years resulted in no serious injury to operating personnel, major damage to equipment or pollution of the atmosphere, to infer that risks are not involved in the operation of such a system would be misleading. Many small system leaks did occur during the operating life of this research and development facility, however, the safety equipment (i.e., oxide smoke detectors and water wash type scrubber) performed their job in a satisfactory manner.

The safety problems involved in a LMFBR are far greater than those involved with a potassium topping cycle since radioactive material is present. The general philosophy of safety employed in the design of a potassium topping cycle would, however,be very similar to that used in a LMFBR Power Generating Plant. The use of Nuclear codes and RDT standards are not necessary, however the design of high temperature components with emphasis on cyclic thermal stress analysis, exacting quality control in the area of raw materials, fabrication, joining, testing and cleaning are required. GE has established computer programs covering thermal stress analysis and specifications for establishing quality control in all of the above areas.

Potassium Oxide Scrubbers. - A potassium oxide scrubber installation is indicated on the proposed 1200 MW Plant Layouts. Duct work to the various secondary containment areas is not indicated, however, these would be included. The scrubber capacity will depend largely on the volume of secondary containment areas which it services. The type of potassium boiler used and operating procedures for emergency shutdown will also affect the scrubber system.

For instance, a pressurized boiler experiencing a tube leak will allow the furnace gases to enter the potassium system, since the gas pressure is much higher than the potassium pressure. This inward leakage of gas, including some air, must be indicated and stopped as soon as possible or potassium system pressure will drive toward the boiler gas pressure, resulting in the eventual rupture of the potassium containment system at the weakest point. Due to the large volume of the boiler tube bundle vapor piping and condenser such a pressure buildup would be very slow (i.e., in the case of a small tube leak). Automatic pressure controls would have plenty of time to actuate pressure dump systems to avoid a pressure buildup above boiler and loop design pressure. The oxygen admitted during this process will rapidly combine with the potassium and, if substantial, may result in an oxide plug at some point in the system. It is, however, expected that this oxide will remain in the boiler and that a gettering cycle on the dumped boiler potassium alone would be required. Stoppage of the fuel supply to the boiler and venting the gas pressure to the atmosphere, plus closing off the compressed air supply, would bring the boiler to atmospheric pressure. Assuming that the potassium vapor pressure at this time is still above atmospheric pressure, potassium vapor or liquid (depending on the location of the leak and pressure) would start to leak into the combustion chamber and, assuming oxygen remained in the chamber, a fire and the resulting oxide smoke would be emitted from the open vent valve. If this valve were closed at this time, along with the inlet air valve, the fire would stop as soon as the oxygen was used up. A buildup of pressure in the combustion chamber might occur, however, it is doubtful if it would come near the design pressure of the combustor casing. After a suitable cool down period, the vent valve would again be opened and the combustion chamber vented to the scrubber. In the scheme outlined a large scrubber capacity does not appear necessary for the boiler. In the case of a combustor boiler designed for operation at atmospheric pressure, the same system could be utilized as long as the combustor (furnace box) is designed airtight and capable of withstanding maximum potassium pressure obtainable during normal operation (15 psig).

The size of the scrubber required is, therefore, determined largely by the secondary containment volume of the building. Along these lines manufacturers were contacted to determine the size and cost of oxide scrubbers. The cost estimates in the section ECONOMIC AND TECHNICAL EVALUATION (p. 61) include 2 - 550,000 CFM venturi type scrubbers. This type of unit was selected for its high scrubbing efficiency. These units would provide ventilation for the building area containing potassium components and piping. In the event of a potassium leak, water pumps would be automatically started as directed by sensing instrumentation located at appropriate points throughout the building. A closed loop water system would be utilized and a storage tank or pond, where the water could be neutralized, would be provided.

A leak in the potassium condenser/steam generator may appear to be a formidable problem at first glance. However, proper design, utilizing knowledge gained from years of experimenting with water/alkali metal reactions, plus adequate control systems and operating procedures greatly reduce the operating risk. Fraas discusses these problems in reference 8 and concludes that the risks are manageable.

Turbo-Compressors. - The turbine compressors shown on the plant layout drawing are advanced gas turbine units which are presently in the conceptual design stage. As a packaged unit, these turbines contain inlet air silencer, starter, compressor (15:1), combustor, turbine, generator, exhaust ducting with provisions for a waste heat exchanger and exhaust silencer. Modification to these units would be necessary so that compressor discharge air can be ducted to the boiler combustor, and hot gas leaving the boiler ducted to the turbine inlet. Due to the high temperature and pressure of the gases leaving the boilers, piping design must be done carefully.

The water economizer and feedwater heater are located in the turbine exhaust gas stream. Water piping to and from these heat exchangers is not shown. Routing, however, will be based on keeping as much of this piping out of the potassium areas as possible. Final entrance to the potassium condenser/steam generator must, however, be made in the potassium area.

Additonal thought will have to be given to the number of gas turbines/compressors to be used from the standpoint of plant turndown and outage for maintenance.

Steam System. - The steam system, with the exception of potassium condenser/steam generator, presents no major design problems. The turbogenerator layouts, along with condenser, condensate pumps, heaters, boiler feed pumps, water treatment equipment, etc., were taken from a proposal recently prepared by GE Steam Turbine and Generator Division for a 750 MW steam plant.

The steam condenser cooling water system utilizes mechanical draft type wet cooling towers. Vendors studies of the requirements in this area resulted in the mechanical draft type units; although the initial cost of these units is less than a hyperbolic tower, operating and maintenance costs would be higher. Further study in this area appears necessary prior to a final selection.

Fuel System. - The layouts are predicated on the use of a clean fuel (low Btu gas) and indicate a main underground supply. The location of the coal gasification plant on or off the plant property was not considered.

Service Areas. - The plant layouts indicate the type and location of various services. These include office, maintenance shops, parking areas, railroad spurs, etc. The land area required for the complete plant (not including a coal gasification facility) was estimated at 1.4 km^2 (350 acres).

Pressurized Fluidized Bed Boiler Powerplant Conceptual Design

POTASSIUM BOILER

In Figure 11 the design concept for the pressurized fluidized bed potassium boiler for cycle number 2 is illustrated. The boiler unit shown in the drawing, which is one of eight boiler modules required for the 1200 MW system, consists of four vertically stacked beds. These beds operate in parallel with respect to the air, coal, limestone, and potassium flows. A tabulation of values for the major design parameters is presented in Table 14.

The potassium flow circuit of the boiler consists of 120 layers of involute tubes in each bed, each layer composed of 75 curved tubes, approximately seven feet long joined at their outside ends to vertical liquid feed header pipes and joined at their inside ends to a common central vapor discharge drum. The tubes are one inch O.D. located both horizontally and vertically on two inch centers. An effect of tube stagger can be achieved by vertically offsetting alternate tubes in each layer. Because of the high sensitivity of the potassium vaporization temperature to pressure level at the 1033 K (1400°F) inlet vapor temperature level, it is important to minimize boiler tube pressure drop. A pressure drop of 3.4 N/cm^2 (5 psi) will result in 55.6 K (100°F) difference in vaporization temperature. Thus a high pressure drop in the embedded tubes will result in local overtemperaturing of the tubes. The proposed concept avoids this problem through the use of short horizontal tubes, low tube mass flow rates, pumped recirculation boiling (as opposed to once through boiler which requires increased tube pressure drop), and individual orificing of the tubes at the inlet end. By proper orificing the effect of the gravitational head differences between tube layers can be cancelled. Insulation will be provided on the vertical feed tubes to prevent overtemperaturing of these tubes in the lower portion of the bed.

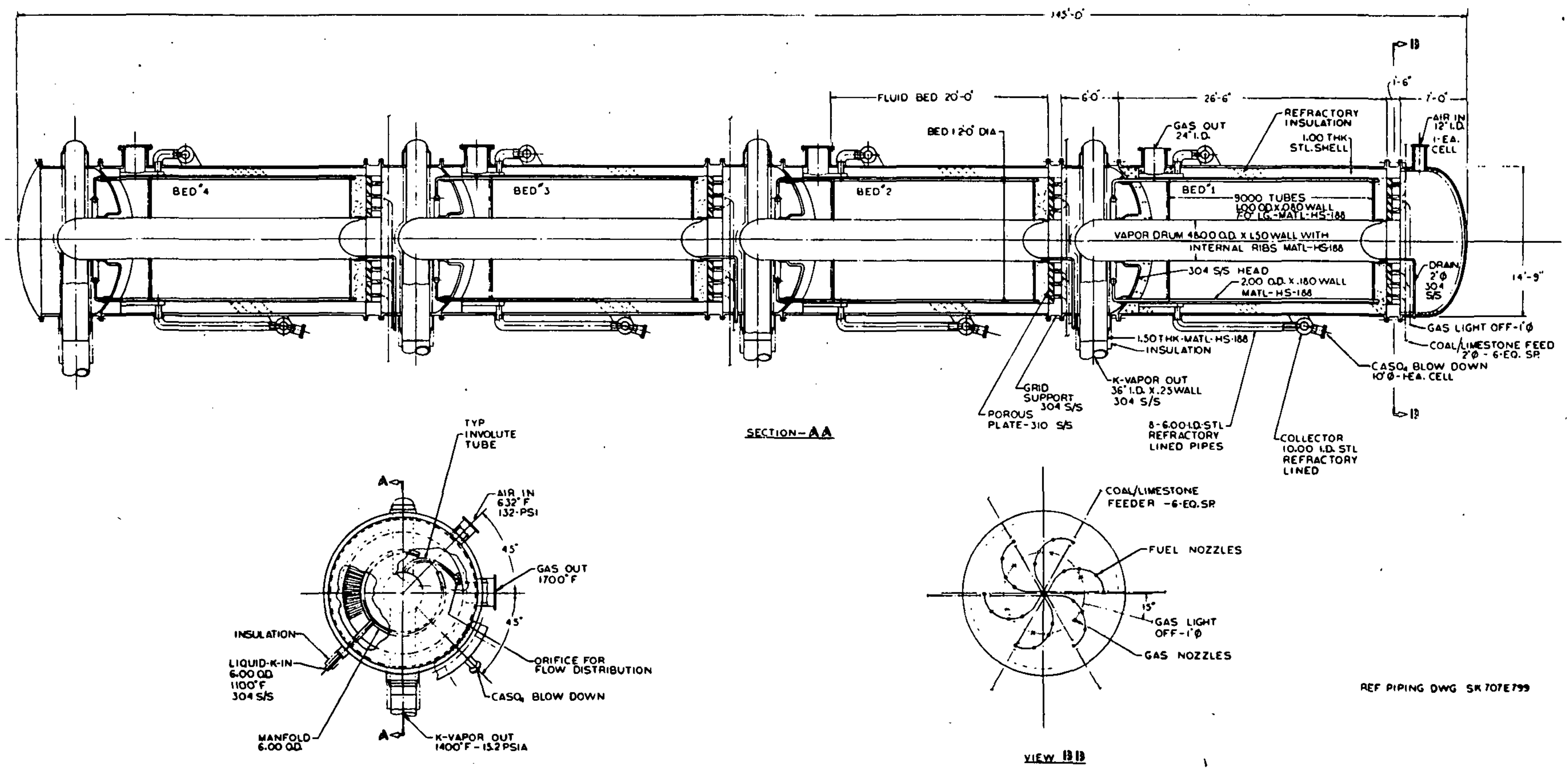

Figure 11. Potassium Pressurized Fluidized Bed Boiler (221R923)

TABLE 14. - POTASSIUM PRESSURIZED FLUIDIZED BED BOILER

1033 K (1400°F) Potassium Turbine Inlet Temp.

1200 MW (8 Modules)

1.	Total Heat Transferred to Potassium	1.74 GW (5.95 x 10^9 Btu/hr)
2.	Total Potassium Flow Rate	846 kg/s (6.7 x 10^6 lbs/hr)
3.	Total Combustion Air Flow Rate	884 kg/s (7.0 x 10^6 lbs/hr)
4.	Bed Pressure	91 N/cm^2 (132 psia)
5.	Bed Temperature	1200 K (1700°F)
6.	Bed Discharge Gas Temperature	1200 K (1700°F)
7.	No. of Beds per Module	4
8.	Bed Outside Diameter	3.66 m (12 ft)
9.	Outside Diameter of Central Vapor Disch. Header	1.22 m (4 ft)
10.	Bed Depth	6.71 m (22 ft)
11.	Embedded Tube Configuration	Involute, 1" tubes on 2" centers, 120 layers
12.	Total Heat Transfer Surface per Bed	1533 m^2 (16,500 ft^2)
13.	Tube Heat Flux (Avg)	35623 W/m^2 (11,300 Btu/hr-ft^2)
14.	Heat Transfer Surface/Bed Volume	27.1 m^2/m^3 (8.25 ft^2/ft^3)
15.	Superficial Velocity thru Bed	1.07 m/s (3.5 ft/sec)
16.	Fluidized Bed Heat Transfer Coefficient, U	284 $Wm^{-2}K^{-1}$ (50 Btu/hr-ft^2-°F)
17.	Coal Feed Rate per Bed	2.6 kg/s (5.8 lbs/sec)
18.	Limestone Feed Rate per Bed	0.4 kg/s (.9 lbs/sec)
19.	Carbon Burn Up	Intra Bed

The pressure difference between the bed and the potassium vapor is sufficiently great to cause a compressive stress level in the central drum above the thirty year life stress rupture limit of 304 stainless steel. It is proposed to reinforce this drum internally with superalloy rings. The upper spherical end of the drum will be Haynes 188 material.

The selected level of superficial velocity of the combustion gases through the bed (1.1 m/s) corresponds to a value found by BCURA to be compatible with high uniform bed heat transfer, good combustion efficiency, and low NO_x and SO_2 emissions. It has also been determined that the 1200 K (1700°F) bed temperature is compatible with the 91 N/cm^2 (9 atm) pressure level from the standpoint of limestone calcination.

Although higher values of superficial velocity were considered, with corresponding reductions in bed diameter, it was found that no cost saving resulted because of the following:

1. The bed volume is controlled by the boiler tubing surface requirements. Thus, a reduction in bed diameter is offset by an increase in bed height.

2. The required transport disengaging height above the bed increases as superficial velocity increases.

3. Increased bed height results in cost increases resulting from more tube to header joints and greater length of vapor discharge header.

Design details relating to coal and limestone feeding, $CaSO_4$ removal, air injection, and combustion gas discharge have been discussed with various contractors subsequent to completion of the drawing of Figure 11. Their critical comments are considered very valuable and are summarized as follows:

1. Several feet of bed "free board height" should be provided between the top layer of embedded tubes and the gas discharge ports, in order to avoid overflow of bed material into the gas discharge. It was stated that since the assumed level of bed heat transfer coefficient is lower than test values they have experienced, the bed depth may be reduced somewhat to achieve this free board height without significant change in the overall boiler module height.

2. Air should be injected at the bottom of the bed through "mushroom" type injection nozzles. Coal feed should be introduced from the side of the bed into the bed space immediately above the air injection nozzles. One coal feed port for every ten square feet of bed cross sectional area is a good "rule of thumb".

3. Limestone should be introduced near the top of the bed and removed from the bed through openings in the air injector nozzle plate.

The arrangement of the fluidized bed boiler is shown in Figure 12, indicating external piping for the conceptual design. A materials list for this boiler is presented in Table 15.

POTASSIUM TURBINE

A conceptual design for the potassium turbine for cycle number 2 is shown in Figure 13. The construction features, bucket and wheel stress levels, disc diameters, etc., are very similar to those of the low pressure turbine for cycle number 1. This turbine has four stages as opposed to three for the latter design. Table 16 summarizes some of the design parameters. The first stage metal temperature is somewhat higher (about 33 K) than for the cycle number 1 low pressure turbine. However, the mechanical design appears to be comfortably within the capabilities of superalloy materials. In a final design it may be found desirable to incorporate condensate extraction features (grooved buckets, casing extraction ports) in order to maximize efficiency. The materials for this turbine are the same as for the low pressure turbine of the pressurized boiler cycle, with the additional fourth stage having the same material as the third stage shown in Table 12.

POTASSIUM CONDENSER/STEAM GENERATOR

A conceptual design of the potassium condenser/steam generator is shown in Figure 14. The overall design, including tube sizes and total number of tubes, is the same as that described in the section Pressurized Furnace Powerplant Conceptual Design (p. 14). The tube lengths, and hence the total heat transfer area, are larger in order to accommodate the higher potassium condenser heat transfer rate for this cycle. Design data for this component are presented in Table 17, and like the other condenser/steam generator, this component is made of 304 stainless steel or Incoloy 800 if stress corrosion cracking is considered to be a problem.

PLANT CONCEPTUAL LAYOUT - CYCLE #2 (PRESSURIZED FLUID BED BOILER)

The conceptual plant layout of a 1200 MW electric generating plant is shown in Figures 15, 16, and 17. A pressurized fluidized bed boiler (8 modules) is utilized along with potassium vapor turbines, steam turbines and gas turbines, all driving electric generators to form a ternary cycle. Cycle #2 utilizes two potassium low pressure (10.5 N/cm^2) double ended turbines each driving generators. Four gas turbines driving compressors (9:1 pressure ratio), to supply boiler combustion air and also drive electrical generators, are also employed. A single multiple stage steam turbine generator provides the remainder of the electrical power.

Potassium System. - The basic rules for the potassium system are the same as those outlined for the pressurized boiler cycle. Since four boiler modules are required for each potassium turbine, these units have been nested together so that potassium vapor piping can be kept as short as possible. The gas turbines have been located outboard of each boiler nest to keep hot gas piping as short as possible. A layout of the fluidized bed boilers with separators for collecting unburned fuel and

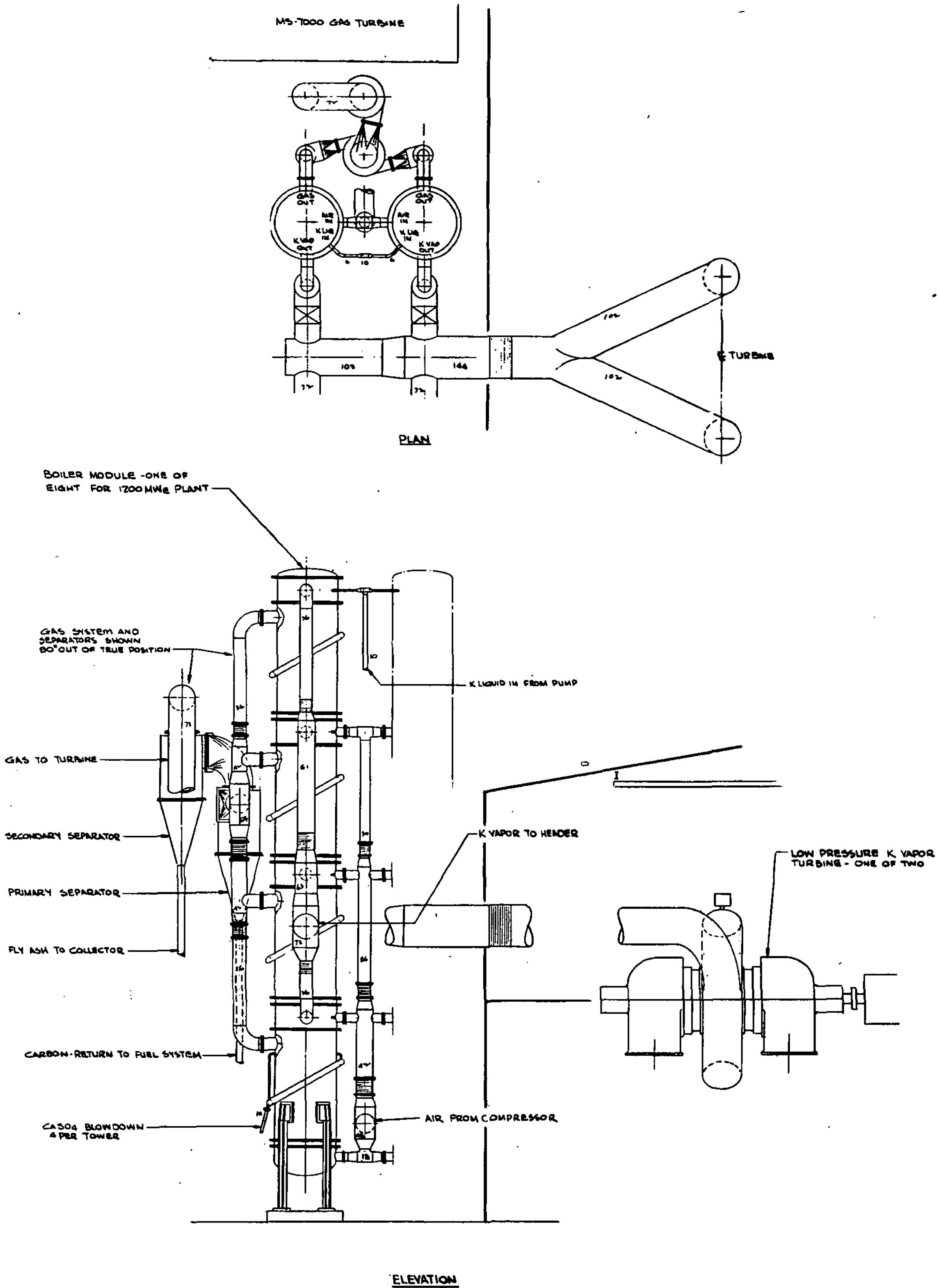

Figure 12. Potassium Pressurized Fluidized Bed Boiler Piping (SK 707E799)

TABLE 15. - MATERIALS SELECTION FOR THE PRESSURIZED FLUIDIZED BED BOILER

Component	Material
Pressure Shell	Low Carbon Steel (Refractory Insulated)
Bed Support Plate	AISI Type 304 or TP 310
Boiler Tubes	AISI Type 304
Upper Vapor Drum Support	HA-188
Center Vapor Drum Support	HA-188
Vapor Exhaust	AISI Type 304
Upper Pressure Head	AISI Type 304
Center Vapor Drum	AISI Type 304
Bed Discharge Tube	Low Carbon Steel (Refractory Insulated)
Fuel Supply Tubes	AISI Type 304

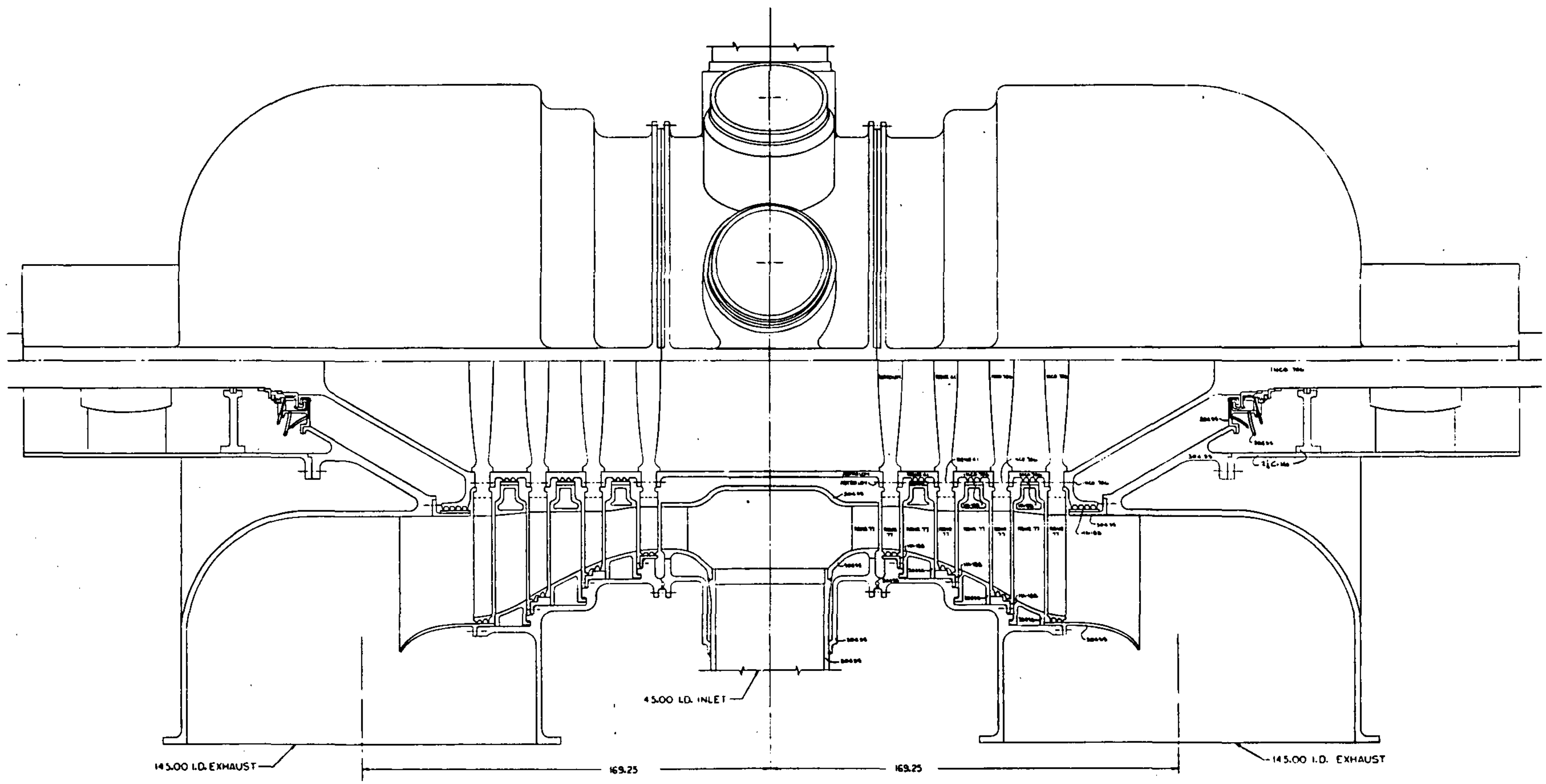

Figure 13. Potassium Turbine (2 Required) (221R919)

TABLE 16. - POTASSIUM TURBINE DESIGN

Stage	1	2	3	4
Inlet Temperature, K (°F)	1033 (1400)	988 (1319)	946 (1243)	905 (1170)
Inlet Pressure, N/cm^2 (psia)	10.47 (15.18)	6.81 (9.87)	4.35 (6.31)	2.73 (3.96)
Flow Rate, kg/s (lb/sec)	207 (457)	207 (457)	207 (457)	207 (457)
Enthalpy Drop, J/kg (Btu/lb)	74382 (32)	74382 (32)	74382 (32)	74382 (32)
Wheel Speed, m/s (ft/sec)	219 (720)	235 (770)	250 (820)	268 (880)
Tip Diameter, m (in.)	3.95 (155.4)	4.34 (170.8)	4.80 (189)	5.31 (209)
Hub Diameter, m (in.)	3.04 (119.6)	3.13 (123.2)	3.15 (124)	323 (127)
Blade Height, m (in.)	0.45 (17.9)	0.60 (23.8)	0.83 (32.5)	1.04 (41)
Exit Quality	0.964	0.933	0.904	0.876

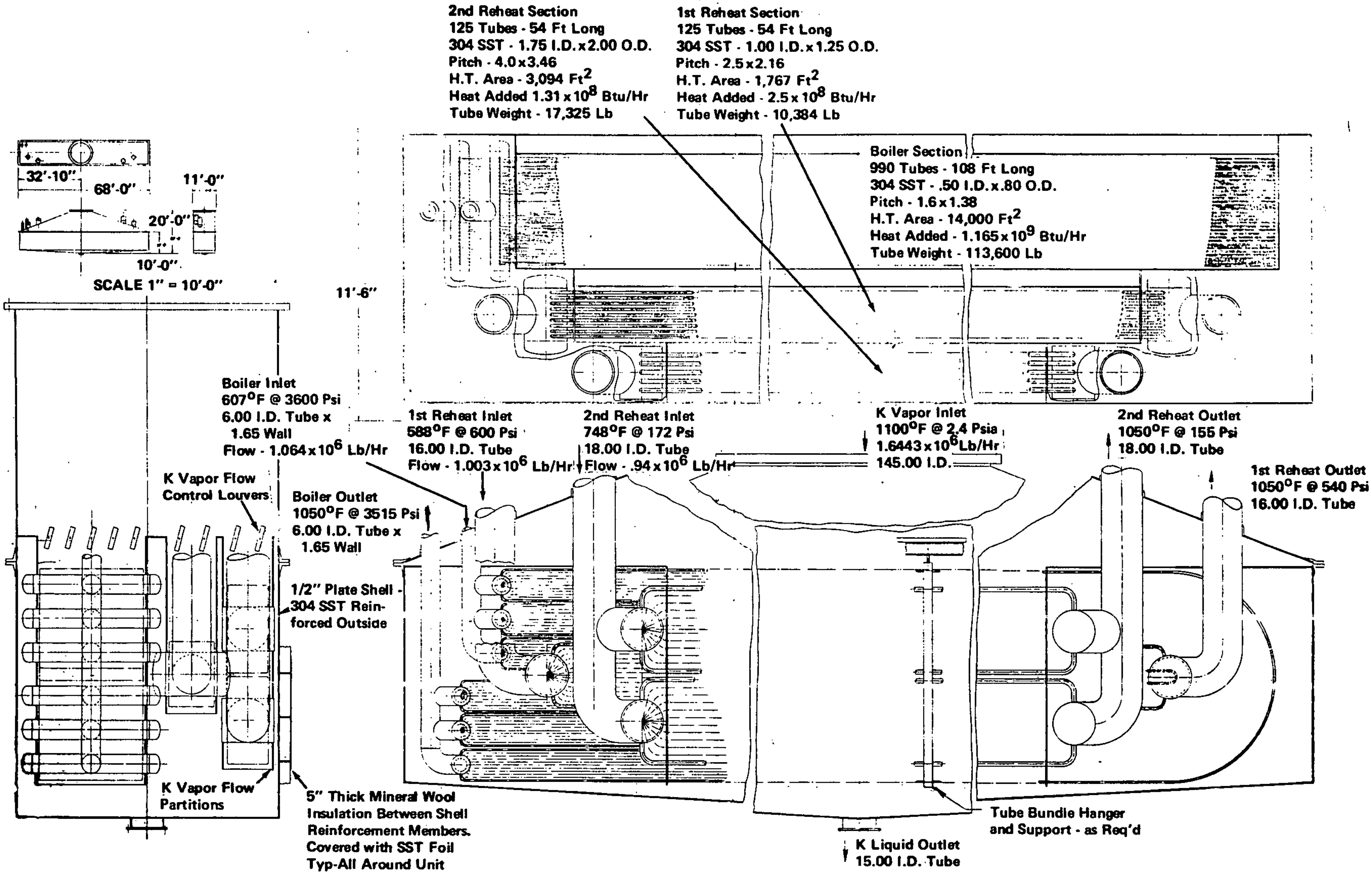

Figure 14. Potassium Condenser/Steam Generator (4 Required)
(221R832)

TABLE 17. PRESSURIZED FLUIDIZED BED CYCLE

Potassium Condenser/Steam Generator Module

4 Modules Required for 1200 MWe Plant

		Boiler	RH #1	RH #2
1.	Potassium Temp., K (°F)	866 (1100)	866 (1100)	866 (1100)
2.	Potassium Press., N/cm^2 (psia)	1.65 (2.4)	1.65 (2.4)	1.65 (2.4)
3.	Potassium H.T. Coeff., $Wm^{-2}K^{-1}$ ($Btu/hr-ft^2-°F$)	56745 (10,000)	56745 (10,000)	56745 (10,000)
4.	Heat Transfer Rate, MW (Btu/hr)	341 (1.165×10^9)	73 (2.5×10^8)	38 (1.307×10^8)
5.	H_2O Flow Rate, kg/s (lb/hr)	134 (1.064×10^6)	127 (1.003×10^6)	119 (0.94×10^6)
6.	H_2O Inlet Temp., K (°F)	606 (632)	582 (588)	671 (748)
7.	H_2O Outlet Temp., K (°F)	839 (1050)	839 (1050)	839 (1050)
8.	Log. Mean ΔT, K (°F)	104 (187)	111 (199)	86 (155)
9.	H_2O Inlet Press., N/cm^2 (psia)	2482 (3600)	414 (600)	119 (172)
10.	H_2O Outlet Press., N/cm^2 (psia)	2424 (3515)	372 (540)	107 (155)
11.	Overall H.T. Coeff., $Wm^{-2}K^{-1}$ ($Btu/hr-ft^2-°F$)	2525 (445)	4364 (769)	1702 (300)
12.	Tube Inside Dia., cm (in.)	1.27 (0.5)	2.54 (1.0)	4.45 (1.75)
13.	Tube Outside Dia., cm (in.)	2.03 (0.8)	3.18 (1.25)	5.08 (2.00)
14.	Number of Tubes	990	125	125
15.	Tube Length, m (ft)	32.9 (108)	15.2 (50)	14.9 (49)
16.	Steam-Side H.T. Area, m^2 (ft^2)	1301 (14,000)	152 (1634)	261 (2805)
17.	Tube Weight, kg (lb)	51484 (113,500)	4355 (9600)	7122 (15,700)

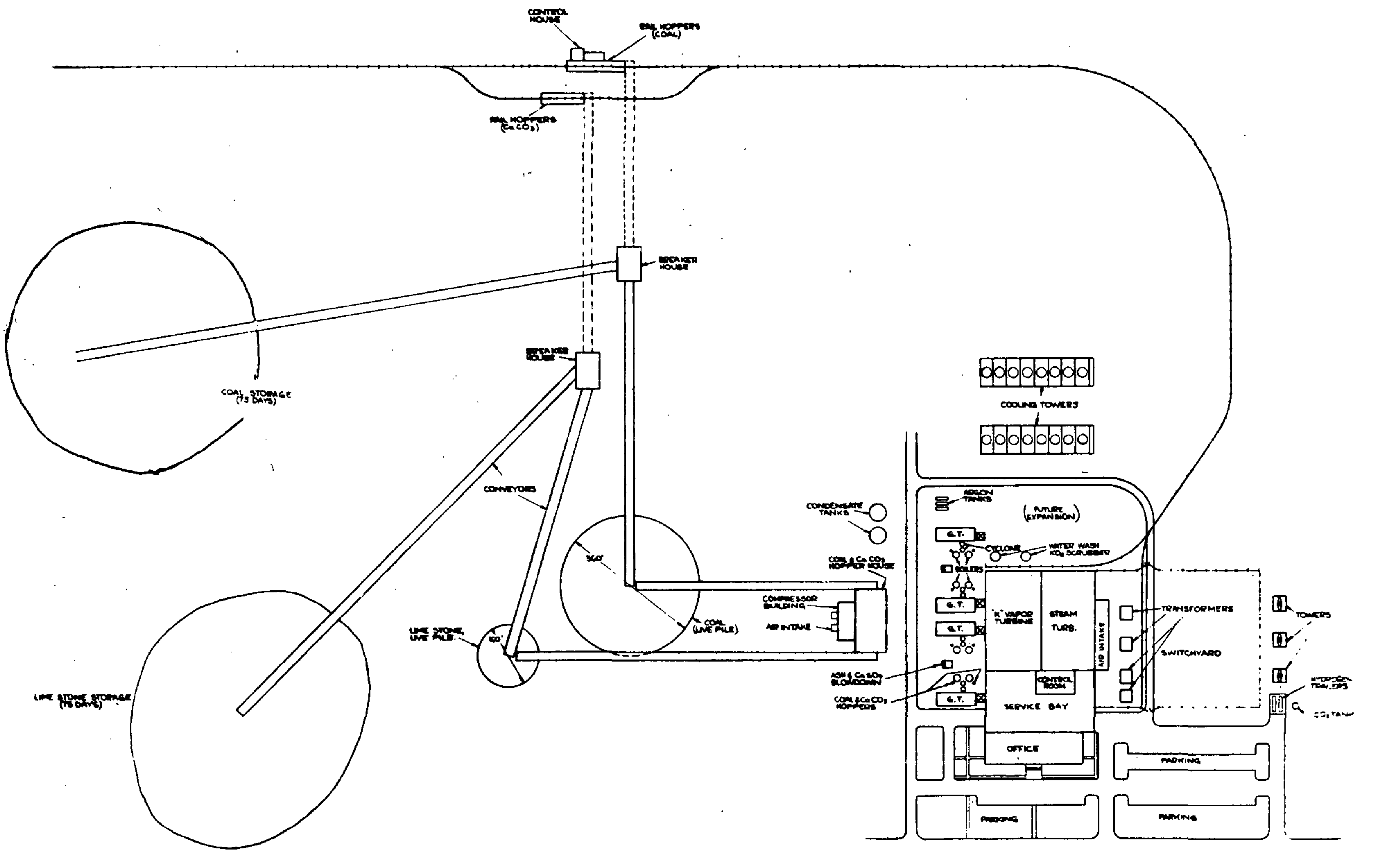

Figure 15. Potassium Pressurized Fluidized Bed Boiler Combined Powerplant (707E812)

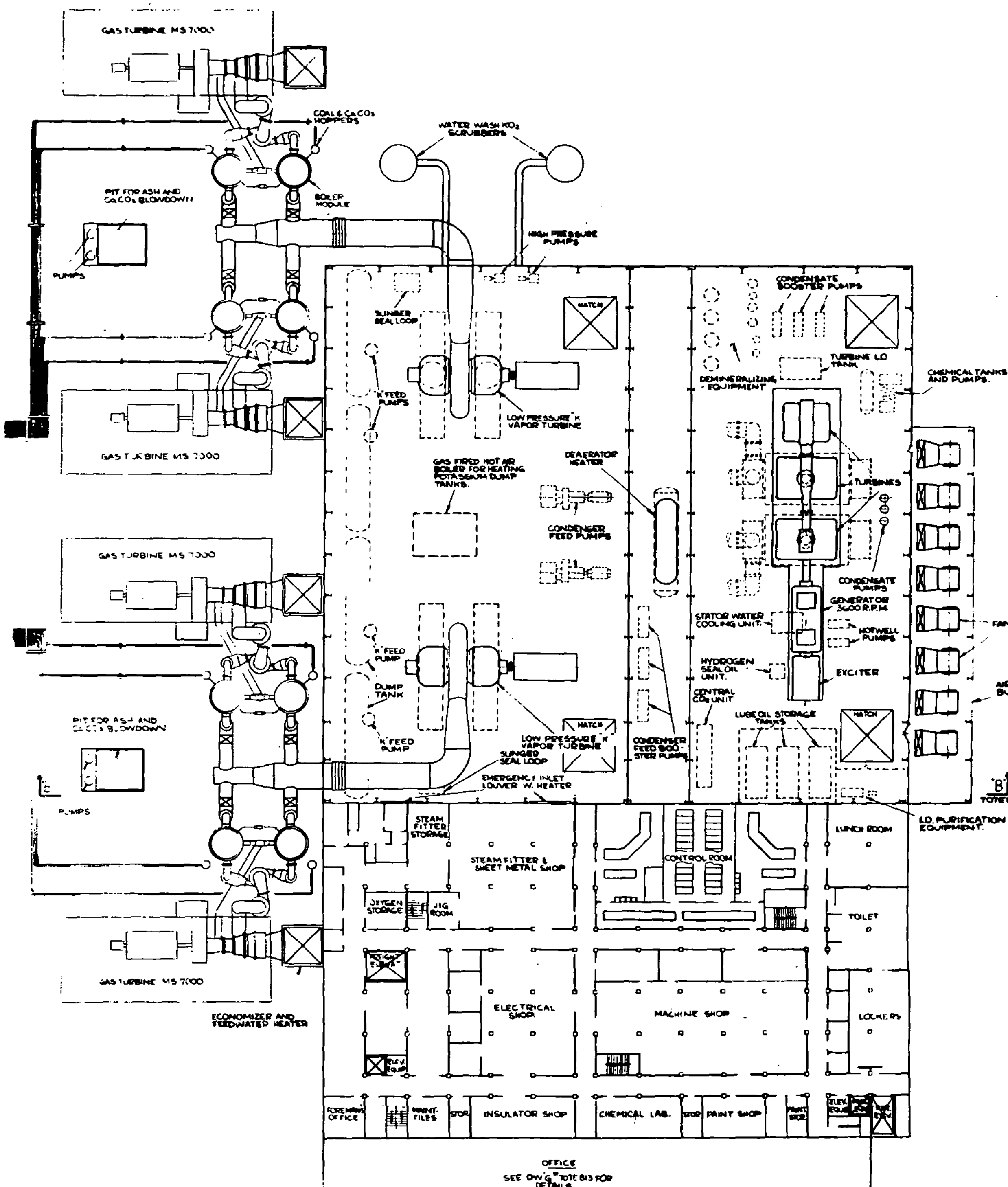

Figure 16. Potassium Pressurized Fluidized Bed Boiler Combined Powerplant (707E815)

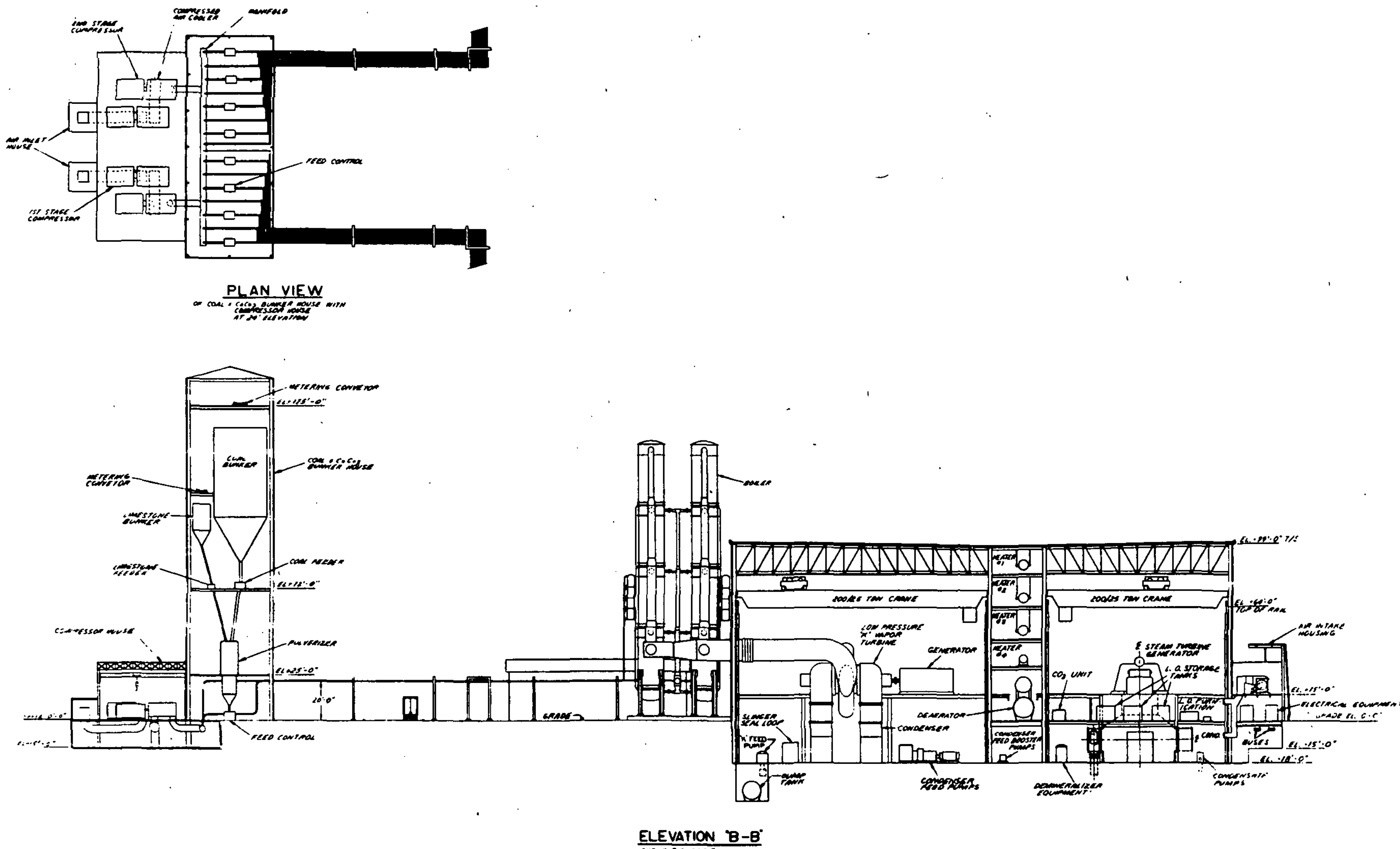

Figure 17. Potassium Pressurized Fluidized Bed Boiler Combined Powerplant (707E816)

fly ash is shown in Figure 12. Pipe sizes indicated on this drawing were calculated for the particular flow (i.e., air, gas and potassium) so that sizes shown are realistic. Because of lack of information on particle sizes, quantities of fuel carry over and fly ash, cyclone separator size indicated is approximate.

The system for removing the $CaSO_4$ is not indicated on the layouts. Whether this should be a continuous process or batch process was not determined. An ash and $CaSO_4$ pit along with storage areas are indicated on the plot plan. Since no process for regenerating the $CaSO_4$ was considered in this study, further considerations must be given to the handling (storage) and regeneration or ultimate disposal of the $CaSO_4$.

The remainder of the potassium system is basically the same as that covered in Cycle #1 and remarks in that section apply equally to Cycle #2. The lower boiler potassium vapor discharge pressure and temperature than Cycle #1 allow the use of stainless steel materials in the vapor piping region, however, the increase in vapor piping diameter and resulting stresses may not justify its use from a cost standpoint. It will be necessary to consider alternate design methods for supporting these highly stressed parts in stainless steel before reverting to the use of the higher strength alloys such as HA-188.

Potassium Oxide Scrubbers. - The scrubbing system for Cycle #2 is basically the same as that proposed for Cycle #1; scrubber capacity is based primarily on building volume.

Turbo Compressors. - The turbine-compressors shown on the layouts are General Electric Company's MS-7000 packaged generating units. As with Cycle #1, modifications to the unit would be required in the area of compressor discharge scroll, combustor and turbine inlet scroll. These modifications are considered to be feasible by the G.E. Gas Turbine Product Department. Four units as indicated would provide adequate plant turndown capability. Economizer and feed water heater exchangers are located in the turbine exhaust gas stream.

Steam System. - Layouts of the steam system are identical to Cycle #1.

Fuel System. - The fluidized bed boiler, of course, requires a complete coal storage handling, processing and injection system. Coupled with this are the same requirements for limestone. The plant layouts indicate the coal and limestone storage areas plus rail facilities for unloading from cars. From the respective breaker houses, coal and limestone are conveyed to the live piles. From these piles both are transferred to the bunker house. Here coal and limestone are metered from bunkers into a grinder. The grinder supplies a feed control unit with the proper size and mixture of fuel and limestone. The system for introducing fuel into each boiler bed utilizes compressed air. The compressors adjacent to the bunker house provide the air. Individual lines to each boiler module are indicated. Further fuel flow control is then done at each module. Compressors must be capable of producing a pressure higher than that in the boiler bed. This type of system requires considerable power for driving the compressors. A screw type metering pump fed by conveyors and located close to the boiler module may be a more economical method.

Service Areas. - The various plant services (offices, maintenance, shops, parking areas, etc.) are identical to the layouts for Cycle #1. Ash storage areas do require space not required with a clean fuel plant. These, along with the coal and limestone storage areas, greatly increase the amount of land required. Approximately 3.8 km^2 (950 acres) are required for the Cycle #2 plant.

ECONOMIC AND TECHNICAL EVALUATION

Potassium Component Costs

This section presents the estimated capital costs of those system components which are in the potassium portions of the plant. The ground rules for this program required that these capital cost estimates be made in 1972 dollars, for a developed technology, that is, after enough units have been built so as to remove any learning effect, and assuming large volume production of the special, high-temperature alloys required. This requirement can be met for steam and gas turbine components by soliciting budgetary estimates from present suppliers. The accuracy of these estimates is subject only to the variations in specification between a budgetary request and an actual purchase, and competitive market forces. The accuracy of these estimates is not usually affected by technological uncertainties.

In contrast, the cost estimates for the potassium components must be based on conceptual designs of components which have never been built. The basic cost estimation problem involves the scale-up of the components from present experience to the sizes required by these conceptual designs. The technical confidence ranges from very high for the pumps, a nearly off-the-shelf item, to somewhat less for the pressurized fluidized bed boiler, which is not even state-of-the-art for steam.

The components for which budgetary quotes were not available are:

1. Potassium boiler
2. Potassium turbogenerators
3. Condenser-steam generator
4. Dump tank
5. Potassium pumps

The boiler, condenser-steam generator, and dump tank are much alike in that they all contain large, complex welded structures. The dump tank structure is similar to the shell of the condenser-steam generator, while the condenser-steam generator and the potassium boiler both have complex, welded tubular heat exchanger internals. The condenser-steam generator has operating conditions similar to the Liquid Metal Fast Breeder Reactor (LMFBR) steam generators. The turbine and pump are, however, unique components. The turbine resembles a large steam turbine in size, although not in materials. The pump is similar to those designed for the LMFBR program.

METHODS USED

In general, the approach used to cost each component for which a budgetary quote was not available was as follows. First, calculate the weight of each material. Then, using estimated material prices and scrap factors, calculate the material cost. Second, identify either a similar steam component for which labor and material costs were available, or a similar liquid metal component for which labor and material costs were also available. Third, using subjective judgment, estimate from the "similar" component a labor cost to build the potassium component. Lastly, add a percentage profit and add up the cost of materials, labor, and profit.

It is difficult to estimate the accuracy of these methods. Earlier unpublished work, as well as information from General Electric's Nuclear Energy Division (NED), indicates that the cost of heat transfer components such as the boiler tube bundles and the condenser/steam generator should be fairly accurate, say ± 30%. The costs of the potassium turbines are probably not as well estimated, with perhaps ± 50% being reaslistic. It should be noted that cost estimates for the scale-up of components to full commercial size from development hardware is notoriously inaccurate. It was assumed for this study that, by maintaining internal consistency, valid comparisons of competing potassium topping cycle systems can be made.

CONDENSER-STEAM GENERATOR

This component, to be made of 304 stainless steel, is shown in Figures 5 and 14 for cycles 1 (pressurized boiler) and 2 (pressurized fluidized bed), respectively. Table 18 shows the cost estimates for these potassium condenser-steam generators. The cost of similar units (from an earlier, unpublished study) had been estimated by General Electric's Nuclear Energy Division (NED) based on their experience in the LMFBR application. A new material cost quote was obtained for the 304 stainless steel tubing in large quantities. The labor cost, including quality assurance, was estimated using a ratio of the labor/material costs taken from the earlier study. An NED learning curve showed that the fully developed unit would cost 80% of the first unit, and this percentage decrease was used.

POTASSIUM BOILERS

Supercharged Boiler (Fig. 2). - The supercharged boiler for Cycle 1 consists of 8 modular units, each containing 2114 3.81 cm (1.50 in.) diameter boiler tubes made out of HA-188. The rest of the structure consists primarily of a welded pressure vessel of 304 stainless steel and carbon steel which is insulated by a 15.24 cm (6.0 in.) thick lining of refractory. The estimate is shown in Table 19. The high material cost is due to the $18.74 per kilogram ($8.50 per pound) cost of HA-188 in high quality boiler tube. The labor estimate was made by assuming an all stainless heat exchanger and using the NED condenser-boiler cost split between labor and materials. The labor cost so found was increased by

TABLE 18. - CONDENSER-STEAM GENERATORS

	Cycle 1	Cycle 2
304 SST Wt-kg (lbs)	117709 (259500)	128913 (284200)
Material Cost @ 3.73 \$/kg (1.69 \$/lb)	\$ 438,600	\$ 480,300
Labor (Including O/H, G&A, Engr'g) NED Labor/Material Ratio	937,700	1,026,800
Profit @ 9%	136,100	149,100
Total FOB Cost First Unit	\$1,512,400	\$ 1,656,200
Unit Cost* @ 80%	\$1,210,000	\$ 1,325,000
Insulation Area	286 m^2 (3082 ft^2)	323 m^2 (3480 ft^2)
Cost @ 430 $\$/m^2$ (40 $\$/ft^2$)	\$ 123,000	\$ 139,000
For 4 Units		
FOB	$\$4.84 \times 10^6$	$\$5.30 \times 10^6$
Insulation	0.49×10^6	0.56×10^6
Total	$\$5.33 \times 10^6$	$\$5.86 \times 10^6$

*Fully developed unit.

TABLE 19. - PRESSURIZED BOILER COSTS

(8 Units Required)

A. MATERIAL COSTS

Material	Gross Weight kg	(lb)	Cost/Weight \$/kg	(\$/lb)	Cost
HA-188	78,473	(173,000)	18.74	(8.50)	\$1,470,000
304 SS	8.868	(18,550)	2.76	(1.25)	24,000
Carbon Steel	63,958	(141,000)	0.55	(0.25)	35,000
Silicon Carbide	5,988	(13,200)	1.10	(0.50)	7,000
Refractory Lining	110,769	(244,200)	0.33	(0.15)	37,000
					\$1,573,000

[If this were all stainless steel, cost would be about \$ 319,000]

B. LABOR COSTS

Using NED percentages for stainless steel assembly:

319,000 is 29% of \$1,100,000

so 62% (Labor) is 682,000

C. COMBINE AND ACCOUNT FOR LEARNING CURVE

Class	1st Unit Cost	Unit Cost*	8 Units
Materials	\$ 1,573,000	\$ 1,573,000	\$ 12,584,000
Labor	1,023,000 (1)	818,000	6,544,000
Profit	257,000	236,000	1,888,000
FOB Price	2,853,000	2,627,000	21,016,000
Install Lining at Site (A.P. Green Co.)	8,400	8,400	67,000
Total	\$ 2,861,400	\$ 2,635,400	\$ 21,083,000

(1) This is 1.5 times \$682,000 to account for HA-188 component fabrication.

*Fully developed unit.

50% to account for the lesser workability of HA-188 compared with 304 stainless steel. The labor cost was then decreased by 20% to account for a learning curve effect, although the material cost was left unchanged (the $18.64/kg HA-188 price already includes a learning curve effect). The cost of insulation (refractory) was determined from information from A.P. Green Co. for their "Mizzou" brand of gunning refractory.

Pressurized Fluidized Bed Boiler (Fig. 11). - The pressurized fluidized bed boiler for Cycle 2 is a tall, modular structure originally with the heat transfer bundle made out of HA-188. However, later in the study, it was decided that at the potassium temperature of 1033 K (1400°F) 304 stainless steel could be used for the heat transfer bundle, especially if local reinforcing members of Astroloy were used. This use of 304 stainless steel rather than HA-188 allowed a significant cost reduction (nearly 50 million dollars).

Table 20 shows the cost estimate used for this component. The labor cost assumes that the complexity is similar to the NED costed condenser-boiler, and no allowance was made for the small amounts of high temperature alloy since so much carbon steel was also used. Insulation was assumed to be the same "Mizzou" brand gunning mixture specified for the pressurized boiler.

Dump Tanks and Potassium Inventory (Fig. 6). - The dump tank is a cylindrical vessel with an insulated jacket surrounding it. Hot gas can be circulated between the vessel and the jacket in order to control the temperature between the melting point of the potassium and the hot-trapping temperature ($\sim$ 1033 K (1400°F)). Zirconium material for gettering is placed in the tank, however there are no other internals except inlet and exit pipes and control equipment. Table 21 shows the cost breakdown. The factory labor estimate was based on the labor for the stainless steel shells of the condenser-boiler as estimated by NED (45% of the material cost before adding engineering, O/H, G&A, etc.). The zirconium was not included in the material total used to compute the labor. No learning curve was applied to this component, since it is as close to a conventionally constructed unit as any of the potassium components. The insulation used is the same as that for the condenser boiler.

POTASSIUM FEED PUMPS

The potassium feed pumps are very similar to the sodium pumps used in the LMFBR program and for many liquid metal test loops. A quotation of $250,000 for a 9000 GPM pump was received from Byron-Jackson Pump Division of the Borg-Warner Co., based on the non-nuclear section of the boiler code. Four are required.

POTASSIUM TURBINES

Cycle 1 (Pressurized Furnace) Turbines. - For this cycle, one high pressure turbine, operating between 1116 K (1550°F) and 1005 K (1350°F) was combined with two low-pressure turbines, operating between 1005 K (1350°F and 866 K (1100°F).

TABLE 20. - PRESSURIZED FLUIDIZED BED BOILER COSTS

(For 1 Unit of 8 Required)

A. MATERIALS AND COSTS

Material	Finish Weight kg	Finish Weight (lbs)	Scrap Factor	Gross Weight kg	Gross Weight (lbs)	Unit Cost \$/kg	Unit Cost (\$/lb)	Cost (\$ x 10^{-3})
HA-188	16,000	(35,300)	1.15	18,420	(40,600)	18.74	(8.50)	345.1
304 SST	366,370	(807,700)	1.15	421,350	(928,900)	3.73	(1.69)	1569.8
Astroloy	12,750	(28,100)	1.25	15,920	(35,100)	22.05	(10.00)	351.2
Carbon Steel	129,730	(286,000)	1.25	162,160	(357,500)	0.55	(0.25	89.4
Insulation	192,100	(423,500)	1.00	192,100	(423,500)	0.33	(0.15)	63.6
	716,950	(1,580,600)						2419.0

B. LABOR COSTS

Use NED percentages of material costs (less insulation) of \$2.356 x 10^6

\$2.356 x 10^6 is 29% of \$8.124 x 10^6

so 62% (Labor) is \$5.036 x 10^6

C. COMBINE AND ACCOUNT FOR LEARNING CURVE

Class	1st Unit Cost	Unit Cost*	8 Units
Materials	\$2.419 x 10^6	\$2.419 x 10^6	\$19.352 x 10^6
Labor	5.036 x 10^6	4.029 x 10^6	32.232 x 10^6
Profit	0.746 x 10^6	0.645 x 10^6	5.160 x 10^6
Total	\$8.201 x 10^6	\$7.093 x 10^6	\$56.744 x 10^6
To Install Insulation			\$ 0.144 x 10^6
Total			\$56.888 x 10^6

*Fully developed unit.

TABLE 21. - POTASSIUM DUMP TANK AND INVENTORY COSTS

(1 Unit Cost; 4 Units Required)

A. MATERIALS AND COSTS

1. Factory Materials

304 SST; 62140 kg @ 2.76 (137,000 lbs @ 1.25)	=	$ 171,200
Inconel 600; 5220 kg @ 5.51 (11,500 lbs @ 2.50)	=	28,800
Zirconium; 2670 kg @ 30.86 (5880 lbs @ 14.00)	=	82,300
		$ 282,300

2. Site Material

Insulation; 200 m^2 @ 430.57 (2140 ft^2 @ 40.00)	=	$ 85,600
Potassium; 66680 kg @ 2.76 (147,000 lbs @ 1.25)	=	183,800
		$ 269,400

B. COST ESTIMATE

Material (not including Zirconium)	$ 200,000
Labor (NED labor without burden/material ratio) @ 45% of Material above	90,000
Zirconium	83,300
Overhead (@ 150% of Labor)	135,000
Total Direct Cost	$ 507,300
Engineering (15)	76,100
Total	$ 583,400
E&A (15%)	87,500
Total	$ 670,900
Profit (10%)	67,100
Total Factory Price	$ 738,000
Site Material	269,000
Total Cost	$1,007,000

A. Low-Pressure Turbine (Figure 4). - The cost technqiue used was quite different for the turbines than for the other components. This component is quite similar in size to the low pressure unit of a cross-compound steam turbine. The GE price book values for large steam turbo-generators were correlated by GE-ESP with the number of low-pressure turbine last stage bucket rows (N_{LSB}) which is always an even number (2-8) and the length of the last stage blades (L_{LSB}). This correlation, including a factor for 1972 prices is:

$$\text{Cost } (\$ \times 10^6) \cong 2.337\ N_S \times 0.02214\ P_{WR}\ (\text{MWe})$$

(N_S is Number of shafts, 2 for cross compound)

Generators correlate as (approximate GE prices)

$$\text{Cost } (\$ \times 10^6) \cong 0.066\ N_S + 0.00872\ P_{WR}\ (\text{MWe})$$

Therefore turbines alone cost:

$$\text{Cost } (\$ \times 10^6) \cong 2.271\ N_S + 0.01342\ P_{WR}\ (\text{MWe})$$

The split between high pressure and low pressure sections was based on the weight split of the Bull Run turbines, where 70% of the weight was in the low pressure unit. Each unit has 1 shaft, so:

$$C_{LP}\ (\$ \times 10^6) = 2.271 + 0.01032\ P_{WR}\ (\text{KWe})$$

The power of these units is proportional to the number of last stage bucket rows and blade size:

$$P_{WR}\ (\text{MWe}) = 0.133\ N_{LSB}\ L_{LSB}^2$$

Therefore:

$$C_{LP}\ (\$ \times 10^6) = 2.271 + (0.001373)\ (N_{LSB})\ (L_{LSB})^2$$

The split between factory material and labor was taken from ORNL-CONCEPT-I (ref. 9) cost code models as 47% material and 53% labor (including profit). These figures, along with the estimated material costs, are shown in Table 22 for the low pressure, cycle 1 turbine. The labor, compiled as above, is multiplied by 1.5 to account for the harder-to-work materials (an arbitrary assumption).

B. High-Pressure Turbine (Figure 3). - Although the material costs were estimated as detailed above, the labor was arbitrarily set as equal to the material cost (about 73% of the low pressure unit labor cost) even though this unit weighs only 56% of the low pressure unit. Table 23 shows these results.

Cycle 2 (Fluidized Bed) Turbine (Figure 13). - This cycle used two double flow units, handling potassium from 1033 K (1400°F) to 866 K (1100°F). Table 24 shows the cost estimate, prepared in essentially the same way as the low-pressure cycle 1 turbines.

TABLE 22. - LOW PRESSURE POTASSIUM TURBINE COSTS

A. MATERIAL COST (per Unit)

Material	Weight kg	(lb)	Cost/Weight $/kg	($/lb)	Cost
304 SS	309,360	(682,000)	2.76	(1.25)	$ 852,000
Astroloy	39,200	(86,400)	22.05	(10.00)	864,000
HA-188	13,060	(28,800)	13.23	(6.00)	173,000
Rene' 77	17,780	(39,200)	17.64	(8.00)	313,000
Cr-Mo Steel	25,580	(56,400)	0.66	(0.30)	17,000
Inco 706	69,130	(152,400)	14.33	(6.50)	991,000
Rene' 41	35,930	(79,200)	16.53	(7.50)	594,000
					$3,804,000

B. LABOR COST (Includes Profit)

Low Pressure Steam Turbine Section with same size last stage bucket.

$$C = 2.271 + (0.001373)\ (2)\ (38.4)^2$$
$$= \$6.320 \times 10^6$$

Factory Material (47%) ref. 9 $\quad \$2.972 \times 10^6$

Factory Labor (53%) ref. 9 $\quad \$3.348 \times 10^6$

C. TOTAL COST

Material	$\$3.804 \times 10^6$ + profit =	$\$4.146 \times 10^6$
Labor	$\$3.348 \times 10^6 \times 1.50^{(1)}$ =	$\$5.022 \times 10^6$
	Total	$\$9.168 \times 10^6$

Two Turbines: $18,336,000

(1) Materials harder to work than for steam turbines.

TABLE 23. - HIGH PRESSURE POTASSIUM TURBINE COSTS

A. MATERIAL COST

Material	Weight kg	Weight (lb)	Cost/Weight $/kg	Cost/Weight ($/lb)	Cost
304 SS	69,670	(153,600)	2.76	(1.25)	$ 192,000
M252	2,720	(6,000)	15.43	(7.00)	42,000
A286	16,870	(37,200)	5.51	(2.50)	93,000
Astroloy	13,060	(28,800)	22.05	(10.00)	288,000
TZM	45,720	(100,800)	26.46	(12.00)	1,210,000
HA-188	108,860	(240,000)	13.23	(6.00)	1,440,000
Rene' 77	3,810	(8,400)	17.64	(8.00)	67,000
Cr-Mo Steel	23,950	(52,800)	0.66	(0.30)	16,000
Total					$3,348,000

B. ESTIMATED COST

Material (same method as L.P. turbine)	$3,348,000
Labor (larger than if scaled by weight)	3,348,000
Profit	662,000
	$7,358,000

TABLE 24. - CYCLE 2 POTASSIUM TURBINE COSTS

A. MATERIAL COST (Per Unit)

Material	Finish Weight kg	Finish Weight (lbs)	Scrap Factor	Gross Weight kg	Gross Weight (lbs)	Unit Cost \$/kg	Unit Cost (\$/lb)	Cost ($\$ \times 10^{-3}$)
304 SS	323,780	(713,800)	1.2	388,550	(856,600)	2.76	(1.26)	1070.7
HA-188	16,150	(35,600)	1.2	19,370	(42,700)	13.23	(6.00)	256.3
Astroloy	32,250	(71,100)	1.2	38,690	(85,300)	22.05	(10.00)	853.2
Inco 706	89,450	(197,200)	1.2	107,320	(236,600)	14.33	(6.50)	1538.2
Rene' 41	29,980	(66,100)	1.2	35,970	(79,300)	16.53	(7.50)	594.9
Rene' 77	58,700	(129,400)	1.4	82,190	(181,200)	17.64	(8.00)	1449.3
Cr/Mo Steel	18,960	(41,800)	1.2	22,770	(50,200)	0.66	(0.30)	15.0
	569,270	(1,255,000)						5777.6

B. LABOR COST (Including Profit)

Low pressure steam turbine section with same size last stage bucket.

$$C = 2.271 + (0.001373)(2)(41.25)^2$$
$$= \$6.943 \times 10^6$$

Factory Materials (47%) ref. 9	$\$ 3.266 \times 10^6$
Factory Labor (53%) ref. 9	$\$ 3.678 \times 10^6$

C. TOTAL COST

Material $\$5.778 \times 10^6$ + Profit	$\$ 6.356 \times 10^6$
Labor $\$3.678 \times 10^6 \times 1.50$(1)	$\$ 5.517 \times 10^6$
Total	$\$11.873 \times 10^6$

For Two Units: $23,746,000.

(1) Materials harder to work than for steam turbines.

SUMMARY OF POTASSIUM COMPONENT COSTS

The direct costs of the potassium components are summarized in Table 25. It is obvious that much of the preceeding data depends on judgment rather than solid fact. Nevertheless, these results certainly are of the right magnitude, and are probably accurate to ± 50%. If they are, the contribution of this error to the total powerplant cost will be much less (15 to 20%), still a large variation, but within the limits of accuracy often quoted for this type of estimate.

For the purposes of ranking potassium plants, the systematic methods used should provide a valid comparison even if the absolute values are slightly in error. That is,any large difference between the cycle 1 and cycle 2 plant costs would be meaningful.

The aid of more equipment vendors would be needed to improve the potassium component cost estimates. More work is especially needed in the area of turbine manufacturing methods and costs.

TABLE 25. - SUMMARY OF DIRECT COSTS OF POTASSIUM COMPONENTS

	Millions of Dollars			
	Pressurized Boiler Cycle		Pressurized Fluidized Bed Boiler Cycle	
Boilers	(8)	21.1	(8)	56.9
Turbines	(3)	25.7	(2)	23.7
Condensers	(4)	4.8	(4)	5.3
Pumps	(4)	1.0	(4)	1.0
Dump Tank	(4)	4.0	(4)	4.0
		56.6		90.9

Powerplant Costs

This section reports the estimated capital cost of the two selected powerplant configurations and an estimate of the cost of electricity generated by each. These costs are all based on 1972-1973 dollars (no inflation to the next decade) and assume a developed technology (no allowance for development).

METHODS USED

This section contains a summary of the methods used to estimate the capital, operating, and fuel costs for the two selected powerplants.

Direct Cost Estimates. - The direct cost for the two powerplants was estimated by the Project Engineering Operation, Installation and Service Engineering Department of the General Electric Company (IS&E). The costs of potassium components were estimated as discussed in the above section. All other costs were compiled by IS&E from suppliers of the individual component, or by their recent experience on similar equipment. In addition IS&E estimated the site labor and material required to erect the powerplant. Site-related items were estimated for the Northeastern U.S., to simulate the USAEC Middletown Site.

Indirect Cost Estimates. - In Task I, the indirect cost estimates were based on the data given in ref. 10. These estimates were based on average values, and applied as a percent to the direct cost and total construction cost. Table 26 shows these percentages as well as the IS&E results expressed as equivalent percentages. Note that the IS&E values, which were used in Task III, are not much larger than those assumed for Task I.

Operating Cost Estimates. - In Task I the operating cost estimates were based on the correlations reported in ref. 10. The following items were included:

Wages	\$1000/MWe
Supplies	\$ 240/MWe
Maintenance	0.88% of direct cost
Capital Costs	6% of project cost
Depreciation	2.5% of project cost
Insurance	0.12% of project cost
Taxes	2.35% of project cost

Fuel costs were calculated from the cycle data using an 80% load factor (7008 hours/year). Sulfur removal costs were computed from literature supplied by various system vendors.

For Task III, each of the above items was reevaluated. Wages, supplies, and maintenance were grouped into two classes, operating expenses and maintenance expenses. The 1971 operating data for seven large (800-1600 MWe) coal-fired plants were compared (ref. 11). The average operating expenses were 0.487 mills/kwh and the average maintenance expenses were 0.436 mills/kwh for a total of 0.923 mills/kwh. (The overall

TABLE 26. - INDIRECT COST ESTIMATES

Description	Applied To:	Task I	Pressurized Boiler Cycle	Pressurized Fluidized Bed Boiler Cycle
Indirect Construction Costs	Direct Cost	2.8%	3.3%	3.1%
Engineering Costs	Direct and Indirect	9.0%	11.5%	11.5%
Administrative and General Expenses	Direct and Indirect	6.2%	6.8%	6.7%
Interest During Construction	Direct and Indirect	8.2%	9.0%	9.1%

average of all reported plants was 0.94 mills/kwh).

These values were used for the pressurized fluidized bed powerplant. This implies that the potassium topping cycle plants will be no more expensive to operate and maintain than present large coal-fired plants. An additional 2.2 mills/kg ($2.00 per ton) of limestone was added to operating expense to account for the disposal of this material (ref. 12). It was also noted that gas fired plants require only about 65 to 75% as many personnel as coal-fired plants, so, for the pressurized boiler powerplant, a reduction of 25% was used on the combined operating and maintenance expenses, giving a value of 0.692 mills/kwh. This reduction was taken primarily in operating expenses, to account for the smaller coal handling crew required.

The capital cost, or investment cost, was computed using formulae from ref. 13. Using several different sets of bond interest, tax rate, return to stockholders, and bond/stock split for a utility company, it was decided to use the recommended value from ref. 13 of 7.2%. This figure is arrived at by assuming that the utility is profitable, has a large fraction of its capital from bonds (whose interest is not taxable as profit), and pays a reasonable dividend on its stock (from its taxable earnings). It is specifically not the interest rate on utility bonds (currently about 8%) nor the return to the investor in utility stocks. Several different calculations were made for a range of postulated company structures. The investment cost ranged from 9% to 5%, so that the 7.2% actually used appears reasonable.

Depreciation was computed using the recommended value from ref. 13, 1.02%. This is a sinking-fund method calculation for a 30 year period with a 7.2% rate of return on money (that which the utility pays for its capital). Note that the sum of capital cost and depreciation is 8.02%, slightly less than the similar value used in Task I.

Insurance and taxes were calculated with the same factors used in Task I.

Fuel costs were based on 8.4096×10^9 kwh per year (7008 hours at 1200 MWe) and either 38¢/GJ (40¢/10^6 Btu) for coal or 76¢/GJ (80¢/10^6 Btu) for gas from coal. These values were those selected by OCR for this study.

Limestone for the pressurized fluidized bed boiler powerplant was consumed at a rate of 15% of the coal by weight and priced at 5.5 mills/kg ($5.00/ton) (ref. 12).

SUMMARY OF CAPITAL COSTS

Table 27 shows the capital cost of both cycles. The following differences are noteworthy. First, the pressurized fluidized bed boiler cycle requires more land for coal yards and limestone facilities. Second, the combined potassium components and boiler plant equipment are almost twice as large for the pressurized fluidized bed boiler cycle as for the

TABLE 27. - CAPITAL COST SUMMARY

(Millions of Dollars)

FPC CLASS	DESCRIPTION	PRESSURIZED BOILER CYCLE		PRESSURIZED FLUIDIZED BED BOILER CYCLE	
310	Land and Land Rights		2.073		5.617
311	Structures and Improvements		26.299		26.303
312	Boiler Plant Equipment		15.521		77.305
313	Potassium and Gas Equipment		93.429		127.746
	Potassium Components	(51.138)		(93.897)	
	Gas Turbine Units	(42.291)		(33.849)	
314	Steam Generator Units		30.468		37.862
315	Accessory Electric Equipment		8.835		8.835
316	Miscellaneous Powerplant Equipment		3.849		4.505
35X	Transmission Plant		5.533		5.534
397	Plant Communication		0.400		0.400
	Total Direct Cost		186.407		294.107
	Indirect Construction Cost		6.151		9.706
	Total Construction Cost		192.558		303.813
	Engineering and Design		22.722		35.850
	General and Administrative		13.286		20.963
	Interest During Construction		17.908		28.255
	Total Project Cost		246.474		388.881

pressurized boiler cycle. This is due to the more expensive boiler as well as the coal handling facilities required by the fluidized bed boiler cycle but not by the pressurized boiler cycle. All other costs are either similar or identical. The total cost of the pressurized fluidized bed boiler cycle is 58% higher than the pressurized boiler cycle.

SUMMARY OF COST OF ELECTRICITY

Table 28 shows the estimated cost of electricity based on the capital costs and the methods discussed above.

The cost of electricity for the pressurized fluidized bed boiler cycle is slightly lower than that for the pressurized boiler cycle, despite the much higher capital cost. This difference is due to the much lower cost for coal versus gas from coal. In essence, the pressurized fluidized bed boiler cycle economically combines the functions of both the gasification plant and the electric powerplant.

TABLE 28. - OPERATING COST SUMMARY

(Costs in Millions of Dollars Per Year)

Description	Pressurized Boiler Cycle	Pressurized Fluidized Bed Boiler Cycle
Operating Expenses	2.084	3.996
Maintenance Expenses	3.585	3.586
Capital Costs	17.746	27.999
Depreciation	2.514	3.967
Insurance	0.296	0.467
Taxes (Not including income)	5.792	9.139
TOTAL	32.017	49.154
Limestone Cost	0.000	2.476
Fuel Costs	42.415	22.450
TOTAL ANNUAL COST	74.432	74.080
Cost of Electricity (Mills/kwh)	9.073	9.028
Fuel Cost, ¢/GJ (¢/10^6 Btu)	76 (80)	38 (40)
Fuel Form	Gasified Coal	Ground Coal

Technical Evaluation

Major technical considerations relating to a comparative evaluation of the clean fuel pressurized boiler system and the coal burning pressurized fluidized bed system include the following:

1. Conservation of fuel resources
2. Environmental impact
3. Status of technology
4. Degree of development risk and associated costs

CONSERVATION OF FUEL RESOURCES

The basic fuel resource involved with both of the alternative systems is coal. Therefore, a logical basis of comparison is that of overall system efficiency, defined as useful output power divided by the heating value represented in the raw coal supply required to support the system operation. In the case of the gaseous fuel system this efficiency will be the thermal efficiency of the power system times the energy conversion efficiency of the coal gasification plant. Since the pressurized fluidized bed system uses coal directly, the overall efficiency of coal utilization is simply the thermal efficiency of the powerplant.

The most economical coal derived gaseous fuel for the pressurized boiler topping cycle system is low Btu gas produced from the water gas reaction and other associated reactions. In the most economical process air is used to oxidize some of the coal to furnish heat required to maintain the endothermic water gas reaction. The gasification plant for processing the coal fuel is located at the site of the powerplant. Thus, little gas transportation penalty results from the low heating value of the fuel gas. The inherent advantages of this type of fuel for the pressurized boiler topping cycle include the following:

1. The gasification process can be carried out at a pressure level which is close to optimum for the power cycle. This facilitates an efficient integration of the powerplant and the gasification plant. The fact that the volume flow of air required for the gasification process is of the order of half the volume flow of delivered fuel gas is very favorable from the standpoint of efficiency and specific output of the gas turbine portion of the power system, after allowance for the air compression power supplied for gasification.

2. Capital costs for the low Btu gasification processes are lower than for medium and high Btu processes.

3. The fuel energy conversion efficiency achievable in a low Btu gasification process is higher than for medium and high Btu processes. At the current state of the art (Lurgi fixed bed process) a value of 77% fuel energy conversion efficiency from coal to product gas is attainable. For advanced processes, such as partial oxidation, 86% energy conversion efficiency is

projected[14]. These efficiency values account for the heat equivalent of the process air compression work, assuming compression is accomplished by electrically driven compressors fed from the power system output, and also account for all process steam requirements.

4. The presence of a substantial quantity of nitrogen, carbon dioxide, and water vapor inert gases in the fuel is favorable from the standpoint of NO_x generation in the boiler, since it results in reduced adiabatic combustion temperature.

In Figure 18 the overall thermal efficiency of the pressurized boiler potassium-steam-gas power system combined with a low Btu coal gasification plant having a fuel energy conversion efficiency of .80 is plotted against gas turbine inlet temperature and gas turbine pressure ratio. Values for the potassium and steam cycle parameters are indicated. These curves are based on the assumption of a minimal gas turbine cooling penalty which is estimated to be characteristic of advanced developmental cooled turbine designs. If the gasification plant energy conversion efficiency is raised to the projected level of .86, the overall efficiency curves will be raised 7% (3-1/2 points).

The system thermal efficiency of a pressurized fluidized bed boiler potassium-steam-gas power system is plotted in Figure 19 for a range of values of gas turbine inlet temperature and potassium inlet temperature (steam conditions are indicated). The boiler pressurization level is 9.0×10^5 N/m^2 (nine atmospheres), which is a reasonably conservative projection of the potential capability of the technology, and is close to an optimum value from a cycle standpoint at the 1200 K (1700°F) gas turbine inlet temperature. This temperature is limited to the boiler bed temperature, which must remain safely below the coal ash fusion temperature, and which must remain in a range which is compatible with high sulfur dioxide removal in the bed. A peak development value for this temperature is estimated to be 1255 K (1800°F).

The comparative levels of overall system thermal efficiency of the gaseous fuel and coal fuel potassium-steam-gas topping cycle systems, which are indicated by Figures 18 and 19, lead to the following conclusion.

From the standpoint of conservation of coal resources, the pressurized fluidized bed coal burning technology appears to offer the highest potential. The margin of overall efficiency advantage of the coal burning topping cycle system is, for the two reference cycles of the section CONCEPTUAL DESIGN OF PROMISING POTASSIUM-STEAM TOPPING CYCLES (p. 14), in the range of 10 to 15 percent.

ENVIRONMENTAL IMPACT

Key factors in the evaluation of the environmental impact of the alternate potassium topping cycle power systems include (1) emission rates of NO_x and SO_2; (2) thermal pollution; and (3) any environmental hazards peculiar to the specific plants.

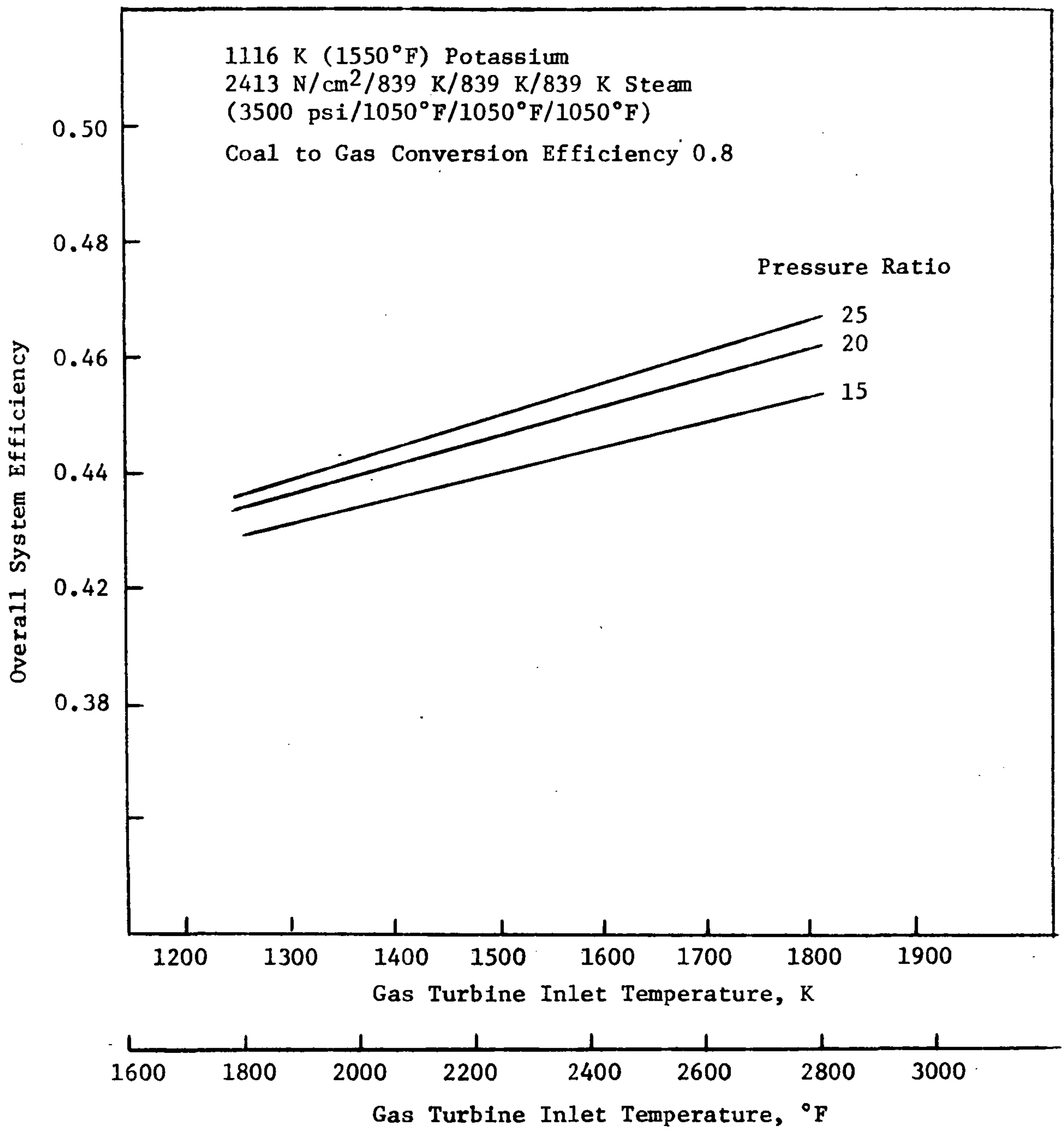

Figure 18. - Performance of Pressurized Boiler Topping Cycle

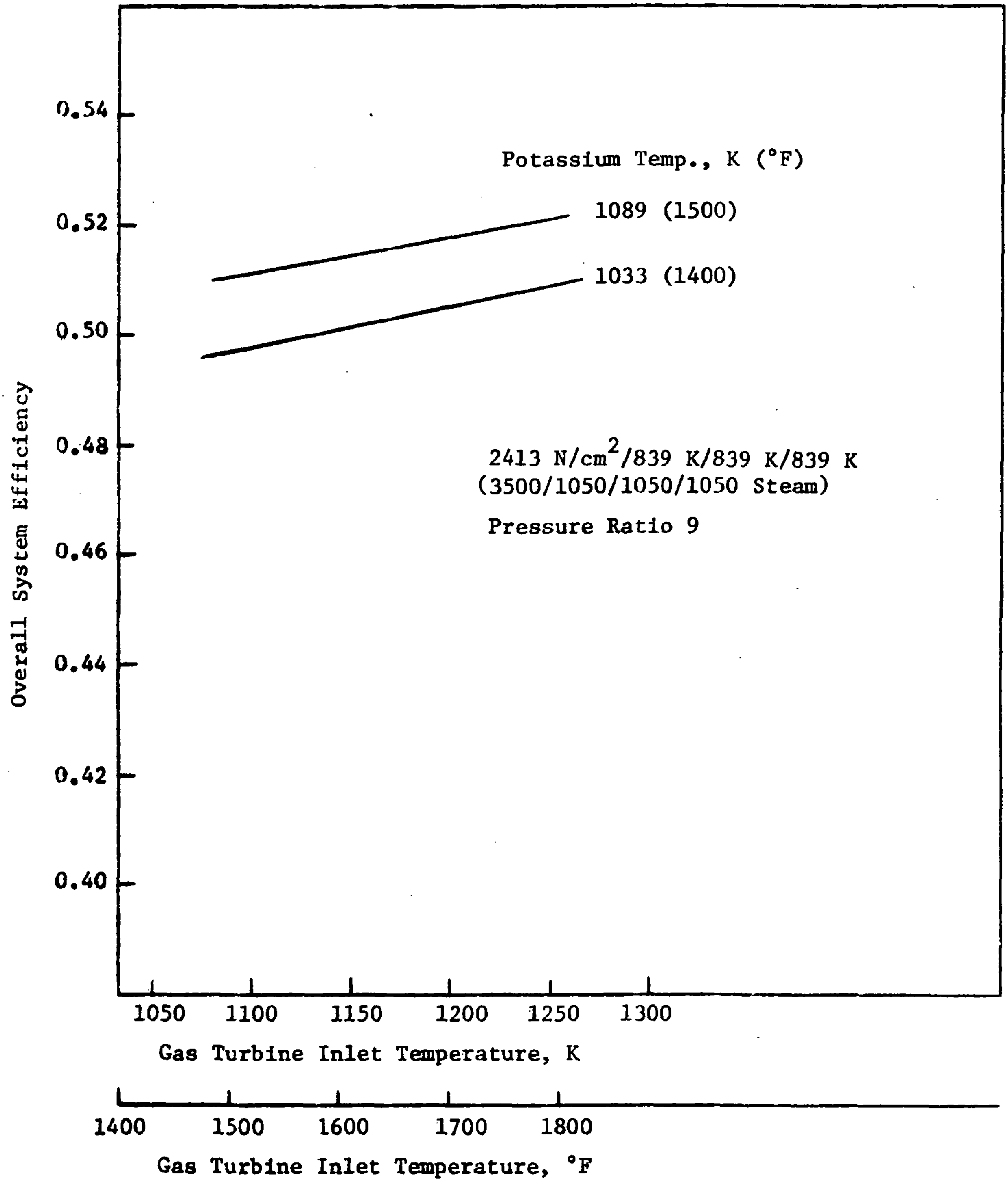

Figure 19. - Performance of Pressurized Fluidized Bed Topping Cycle

NO_x Emissions Gaseous Fuel Cycle. - For the gaseous fuel plant careful design and considerable experimental development work will be required to bring the NO_x emissions from the pressurized boiler within EPA regulation limits. The problem is in general similar to that currently being experienced with gas turbine combustors. Certain important differences exist, however, between the ordinary gas turbine combustor and the pressurized boiler combustor:

1. Low Btu coal gas contains a large percentage of inert gas (nitrogen, water vapor, and carbon dioxide), which is unaffected by the combustion reactions and which receives a substantial portion of the heat of combustion thus lowering the adiabatic flame temperature well below the level attained in the primary reaction zone with conventional gas turbine fuels, (at a given level of combustor air inlet temperature).

2. The total air supply rate from the gas turbine to the pressurized boilers will be closer to the stoichiometric value required for the combustion of the total fuel supplied. By contrast conventional gas turbines normally pass a substantial flow of excess air through the combustion system which can be employed for dilution and temperature reduction of primary zone gases.

From the standpoint of limiting NO_x generation, (1) above is a favorable factor, and (2) is unfavorable. Preliminary calculations have been made to evaluate the adiabatic flame temperature level of the combustion chamber of the reference pressurized boiler system using low Btu gas fuel. The composition of this fuel is shown in Table 29, for a typical system. These calculations show an adiabatic flame temperature of approximately 2200 K (3500°F) under the reference cycle condition of 15/1 pressure ratio, and with no excess air. The gas residence time in the combustion chamber prior to cooling by heat transfer to the boiler tubes is approximately 100 milliseconds. Under these conditions excessive amounts of NO_x are generated - more than 1.3 μg NO_2/J (3 lb $NO_2/10^6$ Btu).

One means to reduce the NO_x generation rate without encountering major performance penalties is the gas turbine - boiler air flow circuit shown in Figure 20. The boilers are arranged in pairs which receive flow in series from the gas turbines. The first boiler in the pair operates with excess air which can be used for dilution and reduction of adiabatic flame temperature. The inlet flow to the second boiler in the pair has essentially no excess air but does have cooled combustion gas which serves asa diluent for flame temperature reduction. Since the stoichiometric fuel air ratio for the typical low Btu gas fuel of Table 29 is 1 kg fuel for 1.3 kg air, a situation providing equal heat liberation rates in the two boilers would provide a ratio of 2.6 kg air to 1 kg fuel in the first boiler (100% excess air), and a ratio of 3.6 kg combustion gas to 1 kg fuel in the second boiler. The first boiler flame temperature, after dilution, would be approximately 1700 K (2600°F) and the second boiler flame temperature 1866 K (2900°F). Closer equalization of these two temperatures could be achieved by burning more fuel in the

TABLE 29. - COMPOSITION OF LOW BTU GAS*

Constituent	Out of Second Stage		Out of Scrubber	
	kg/s	lb/hr	kg/s	lb/hr
H_2	0.68	5366	Same	Same
CO	13.02	103158	Same	Same
CO_2	9.41	74541	Same	Same
CH_4	1.50	11866	Same	Same
H_2O	4.82	38166	Same	Same
N_2	32.78	259639	Same	Same
H_2S	0.46	3641	0.008	61
NH_3	0.19	1470	0.027	216
COS	0.09	751	0.063	499
	62.95	498598	62.31	493512

*From E. Damon, Foster Wheeler Corp.

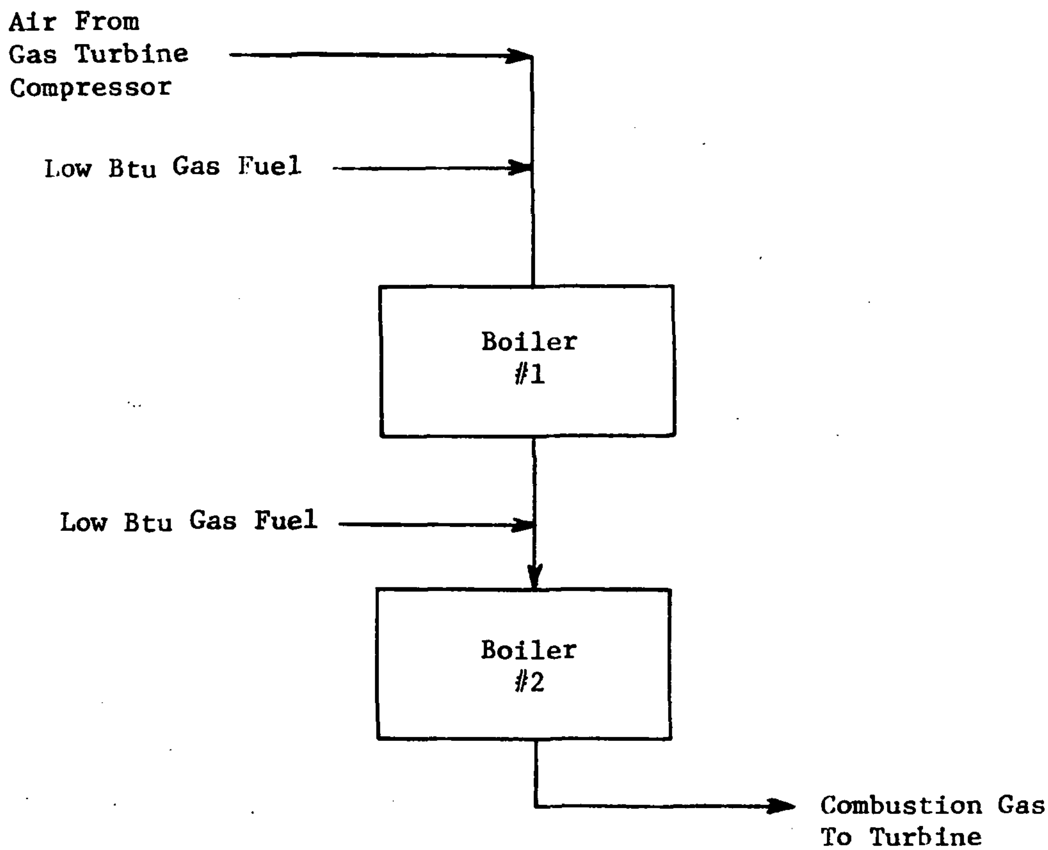

Figure 20. - Paired Boiler Series Flow Arrangement for NO_x Control

first boiler than in the second. However, equal NO_x generation rates in the two boilers would require a somewhat lower flame temperature in the first boiler than in the second because of the higher oxygen concentration in the burned gas.

With this approach it appears possible to reduce combustion chamber peak temperatures to levels at which NO_x control within the gas fuel limit of 0.086 μg NO_2/J (.2 lb $NO_2/10^6$ Btu) is possible. An advantage of the use of series flow in paired boilers is the avoidance of the design problem of recirculating 1255 K (1800°F) gas. A possible disadvantage is the reduction in the number of independently operable boiler modules.

With the gas fueled pressurized boiler cycle the problem of NO_x emissions control will become increasingly difficult as the gas turbine inlet temperature is raised, and also as the gas turbine pressure ratio is raised. This factor, in conjunction with the status of turbine cooling technology, may well limit the extent to which the efficiency gains attainable by high gas turbine inlet temperature and high pressure ratio (Figure 18) can be realized in practice.

Coal Burning Cycle. - One of the characteristics of the fluidized bed boilers is that combustion occurs at a temperature level well below that at which thermal NO_x is generated (in any significant amount) by the hot air mechanism. However, important amounts of NO_x can be generated in fluidized bed combustors as a result of reaction between the fuel-bound nitrogen and the combustion air(15).

In a fluidized bed coal combustor operating with a stoichiometric fuel-air ratio, a NO_x concentration of approximately 400 ppm in the exhaust gases corresponds to the EPA limit of 0.3 μg NO_2/J (.7 lb $NO_2/10^6$ Btu) for coal fuel. Under some conditions NO_x emissions from fluidized bed boilers have exceeded three times this value(15,16). Most of the published data, however, apply to atmospheric pressure type boilers. Pressurized bed boilers have consistently demonstrated lower NO_x emissions than atmospheric fluidized bed boilers(17). This is believed to be a combined result of the influence of pressure on the NO_x generation and NO_x reduction reactions and of the influence of increased bed depth and intra-bed residence time. Low superficial velocity, which is generally characteristic of pressurized beds, also results in increased residence time, and, probably, in reduced NO_x generation(16). Unfortunately there is an inverse relationship between NO_x emissions and SO_2 emissions, since SO_2 promotes the reduction of NO_x(15).

The following factors have been identified as being important determinants of the level of NO_x emissions from coal burning fluidized bed boilers:

1. Pressure Level - Increased pressure tends to reduce NO_x.

2. Amount of Excess Air - Reducing conditions are favorable for less NO_x. Thus, it is desirable to minimize the amount of excess air supplied.

3. Coal Particle Size - Increasing the coal particle size has been found to result in reduced NO_x generation.

4. Air and Coal Feed Distribution - Two stage combustion, wherein the coal is initially introduced into a sub-stoichiometric region of the bed, with secondary air injection to complete combustion, has been found to result in reduced NO_x emissions.

In summary it can be said that although control of NO_x emissions from fluidized bed boilers will continue to be a matter for research and development, there have been reports of very encouraging results on NO_x emissions from pressurized fluidized bed boilers. Reference 18 reports levels of 50 to 150 ppm in the effluent gases from a fluidized bed boiler operating at 6.0×10^5 N/m^2 (six atmospheres). This permits a prediction that the NO_x emission problem is a solvable one.

Insofar as the reference cycles of the section CONCEPTUAL DESIGN OF PROMISING POTASSIUM-STEAM TOPPING CYCLES (p. 14) for the gas fired and coal fired potassium-steam-gas topping cycle power systems are concerned, it may be stated that there is a high level of probability that NO_x emissions from both systems can be controlled within regulation limits. Neither system can be said at this point in time to have any marked potential comparative advantage.

SO_2 Emissions-Gas Fueled System. - Sulfur dioxide emission control in the gas fueled pressurized boiler system depends upon efficient scrubbing of the fuel gas obtained from the coal gasifier. Table 29 indicates the degree of sulfur compound removal achieved at the gas scrubber exit of a typical low Btu coal gasification process. This table indicates values of 1.2×10^{-4} kg H_2S/kg fuel gas and 10^{-3} kg COS/kg fuel gas in the scrubbed gas. These amounts correspond to 0.043 μg SO_2/J (.1 lb $SO_2/10^6$ Btu) from the H_2S combustion and 0.215 μg SO_2/J (.5 lb $SO_2/10^6$ Btu) from COS combustion. The total SO_2/J ($SO_2/10^6$ Btu) is one half the EPA limit of 0.516 μg SO_2/J (1.2 lb $SO_2/10^6$ Btu) for coal fuel. By refinements to the gas scrubbing system the SO_2 emissions can be reduced substantially, probably at increased cost.

In general, it may be stated that adequate technology exists to reduce SO_2 emissions from low Btu coal gas fuel to levels well below existing regulations for coal fuel.

Fluidized Bed Coal Burning System. - For a fluidized bed coal burning boiler the SO_2 emissions can be related to the percentage of sulfur in the coal and the percentage SO_2 removal in the bed in the manner indicated in Figure 21. From this figure it may be seen, for example, that 60% removal effectiveness will bring the SO_2 emissions to the regulation level of 0.516 μg SO_2/J (1.2 lb $SO_2/10^6$ Btu) in 1% sulfur coal. For 6% sulfur coal a removal effectiveness of 90% is required. Realizing adequate sulfur removal effectiveness, subject to other design requirements, such as operating the bed at a high temperature level for good thermal efficiency, making use of available limestone supplies, and limitation of excess air for reasons of performance and NO_x emission control, is one of the key problems to be solved in the development of fluidized bed boiler technology.

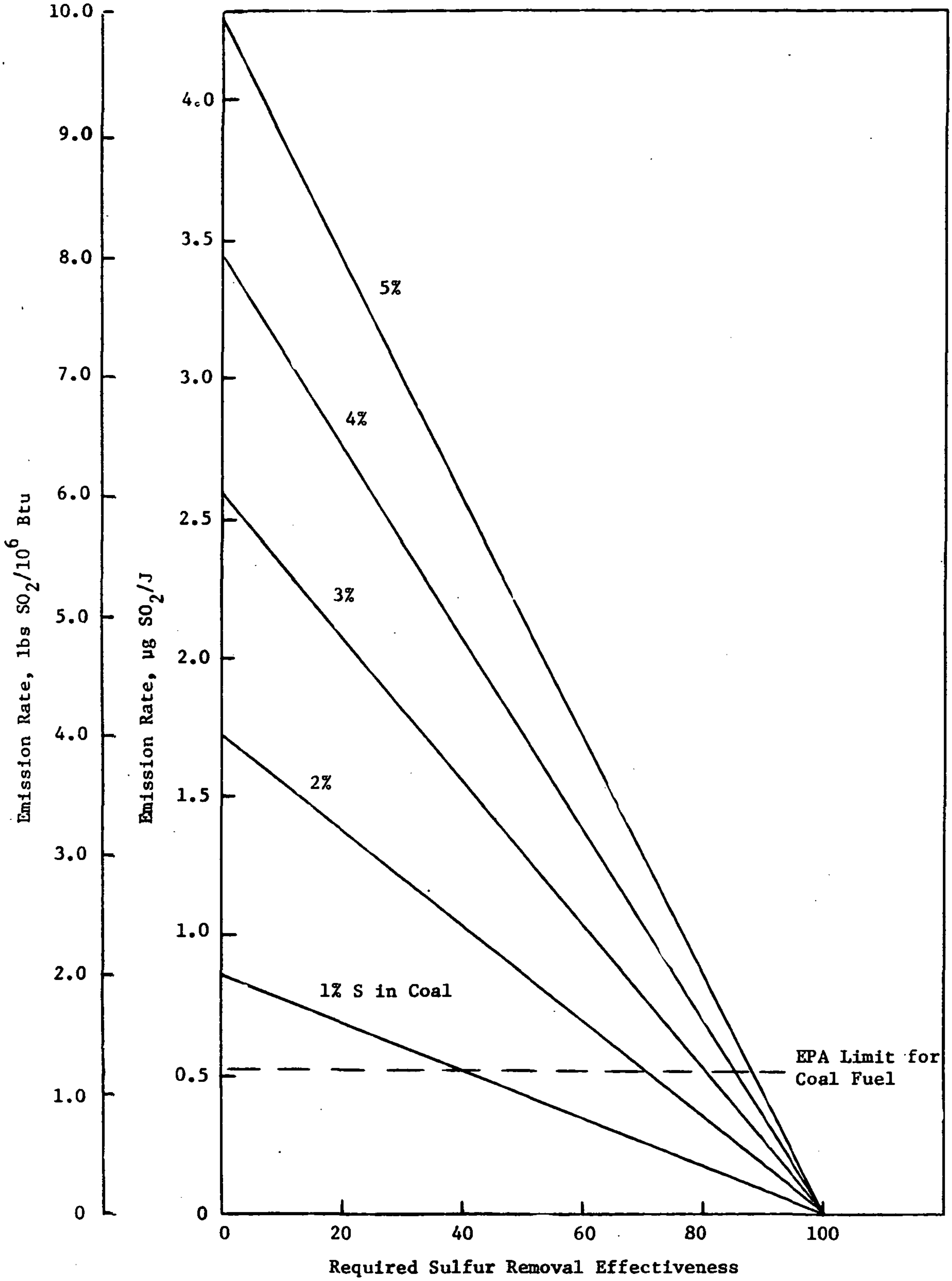

Figure 21. - SO_2 Emission Rate versus Fluid Bed Sulfur Removal Effectiveness and Sulfur Content of Fuel

The following factors have been found to influence the sulfur removal effectiveness of fluidized bed boilers.

1. Bed Temperature - Maximum sulfur removal in atmospheric fluidized bed boilers has been obtained at bed temperatures between 1061 K and 1144 K (1450°F and 1600°F). However, it has been reported (ref. 18) that a removal effectiveness as high as 97% has been obtained in a pressurized bed 6.0×10^5 N/m^2 (6 atmospheres) at 1255 K (1800°F) temperature. In this connection it is important to note that as bed pressure increases the temperature required for calcination of the limestone also increases. Since limestone calcination is essential for effective sulfur dioxide removal the bed temperature must be high enough to accomplish this. This condition appears to be met by the reference cycle of the section CONCEPTUAL DESIGN OF PROMISING POTASSIUM-STEAM TOPPING CYCLES (p. 14) (9.0×10^5 N/m^2 1200 K) (9 atmospheres 1700° F).

2. Ca/S Ratio - Increasing the mole ratio of calcium to sulfur in the feed to the combustor increases the degree of sulfur removal. At Ca/S ratios in the range of 2 to 3 a sulfur removal efficiency at 90% has been achieved (ref. 18).

3. Fluidizing Velocity - Low levels of fluidizing velocity, which correspond to long intra-bed residence time, are favorable for high SO_2 removal effectiveness. Results reported in reference 18 show a decrease in removal effectiveness from 90% to 70% for an increase in fluidizing velocity from 0.6 m/s (2 ft/second) to 1.8 m/s (6 ft/second).

Stone Type and Source. - Dolomite, which contains $MgCO_3$ as well as $CaCO_3$, has been found to be more effective in sulfur removal than limestone, for the same Ca/S ratio (ref. 18). $MgCO_3$ is more readily reduced to the oxide than $CaCO_3$ and this property apparently increases the stone porosity and promotes the reaction between the stone and SO_2. Limestones from different sources have demonstrated markedly different SO_2 removal effectiveness values in fluidized bed combustors. Tymochtee dolomite is particularly effective at temperatures above 1144 K (1600°F). When regenerated bed stone is employed, the effectiveness deteriorates on successive cycles of usage. Stone particle size has been shown to have an effect on reactivity but the available data is contradictory. Relatively large stone (greater than 300 microns) is believed to be best for deep beds, such as pressurized designs. The residence time of large stone is longer than for fine stone, and introduction of the stone near the top of the bed, where it can be most effective in SO_2 removal, and extraction of stone at the bottom of the bed is the presently recommended practice (ref. 18). Stone movement through the bed in a direction counter current to the bed gas stream is feasible only for the coarser grades of stone.

Bed Depth. - Increasing bed depth, which, like reducing fluidizing velocity, increases the intra-bed residence time, has been found to improve sulfur removal effectiveness. Another effect of increased bed depth is believed to be that of preventing the prevalence of reducing conditions, which usually occur in the vicinity of the coal admission ports near the bottom of the bed, throughout the bed. It is important that excess oxygen be present near the top of the bed where the stone is introduced. Such conditions are most favorable for SO_2 removal.

Excess Air. - Excess air is favorable for SO_2 removal, particularly at elevated bed temperature (above 1255 K). However, excess air is unfavorable for NO_x removal.

In summary, it can be stated that the problem of achieving adequate SO_2 removal, consistent with meeting other design requirements, is a critical one for the pressurized fluidized bed designer. This problem is currently and will continue to be a subject for research and development. Demonstrated sulfur removal efficiencies above 90% have been achieved under conditions approximately those of the pressurized fluidized bed reference system cycle, (6.0×10^5 N/m^2, 1255 K) (6 atmospheres, 1800°F). This justifies the prediction that design of such systems to meet EPA regulations can be accomplished.

With respect to the SO_2 emission problem, some preference must be given to the gas fueled topping cycle system, because of the present availability of high efficiency gas scrubbing technology.

Thermal Pollution. - Both of the topping cycle systems which have been studied and defined in terms of the reference cycles of the section CONCEPTUAL DESIGN OF PROMISING POTASSIUM-STEAM TOPPING CYCLES (p. 14) are based on the use of cooling towers for waste heat rejection. With this manner of heat rejection there should be no serious thermal pollution problem for either cycle.

The topping cycle reduces thermal pollution by increasing the thermal efficiency of power generation. Cycle calculations indicate a thermal efficiency of 0.392 for a conventional, modern steam plant compared with 0.528 for a potassium topping cycle plant with a supercharged furnace. Assuming that both powerplants have coal gasification to control sulfur emissions, the heat inputs from fuel are 2551 and 1894 MW respectively for 1000 MW plant output. The heat rejection to the atmosphere, including condensate cooling, is 1551 and 894 MW, respectively. Therefore, only 74% as much fuel is required and only 58% as much heat is rejected by the topping cycle powerplant.

The topping cycle powerplant with a fluidized bed combustor has a calculated thermal efficiency of 0.499, which means 2004 MW heat addition and 1004 MW heat rejection for 1000 MW plant output. Assuming that the conventional steam plant could also have a fluidized bed combustor, the topping cycle uses 79% as much fuel and rejects only 65% as much heat as the conventional steam plant.

Special Environmental Hazards. - In general the hazards of the alternate topping cycle systems are similar to those of conventional steam and gas turbine powerplants. The presence of the potassium flow loop will introduce some degree of additional hazard. Potassium is flammable, and care must be taken to avoid leaks, to quickly detect them and to minimize their effects should they occur. Modularization of the potassium components and flow loops will aid in this. Potassium oxide and hydroxide are caustic and toxic and evacuation systems to safely channel and water scrub any such accidental plant emission must be provided. Fraas[8] concludes that a well designed potassium topping cycle system would present unusual and difficult but manageable problems.

STATUS OF TECHNOLOGY

The technologies involved in the gas fueled pressurized boiler system and in the coal fueled pressurized fluidized bed boiler system can be outlined as follows:

<u>Gas Fueled Pressurized Boiler System</u>

- Steam Turbine
- Gas Turbine
- Potassium Turbine
- Potassium Two Phase Loop Metallurgy and Fluid Purification
- Potassium Boiler
- Potassium Condenser - Steam Generator
- Potassium Boiler Feed Pump
- Low NO_x Combustion
- Low Btu Coal Gas Production and Purification
- Potassium Valves, Expansion Joints
- Controls

<u>Coal Fueled Pressurized Fluidized Bed Boiler System</u>

- Steam Turbine
- Gas Turbine
- Potassium Turbine
- Potassium Two Phase Loop Metallurgy and Fluid Purification
- Potassium Condenser - Steam Generator
- Potassium Boiler Feed Pump
- Pressurized Fluidized Boiler (Bed Side)
- Potassium Boiler (Potassium Side)
- Potassium Valves, Expansion Joints
- Controls

For both systems the potassium technology is available for the selected cycle conditions at the 3 MWt level. The basis for this statement is the extensive development work on potassium Rankine cycle space power system components conducted by the General Electric Company under contract to NASA. Reports covering this work are listed in references 19 thru 33. Because of the size limitation on disc forging of super alloys and refractory alloys the potassium turbines will be modularized, permitting the use of 40 inch discs for the fluidized bed powerplant and 36 inch discs for the pressurized boiler powerplant. There may be a cost penalty associated with modularization. In this way the presently available technology for superalloys can be used. Large molybdenum alloy turbine discs pose a particularly involved problem. It may be advisable to design for use of only superalloy materials. In addition to the large disc problem, other materials and process efforts required in connection with applying and extending the successful efforts of the past to large stationary powerplants include the following:

1. Determination of the compatibility of boiler and condenser materials with operating environments including both fireside corrosion and alkali metal effects. The possibility of fireside corrosion of the boiler tubes in the fluidized bed packed with limestone is an area of particular concern.

2. Acquisition of long term mechanical property design data on critical materials such as potassium containment materials and potassium turbine rotating parts materials.

3. Development of seamless tubing manufacturing and quality control processes for new boiler materials.

4. Design and construction of module size full scale turbine seals, boilers (gas fired, pressurized), condenser-steam generators, and inlet control valves.

Steam turbine and gas turbine technology is available for both reference systems. Advances in long life, high-temperature turbine cooling technology will be required for realization of the potential efficiencies indicated (Figure 18) for the gas fueled system at gas turbine inlet temperatures in the range of 1366 K to 1922 K (2000°F to 3000°F). For the pressurized fluidized bed boiler system the projected condition of erosion and deposit free gas turbine operation has yet to be proven by actual gas turbine operation on the scrubbed gases from fluidized bed boiler. Present favorable estimates of this potential problem area are based on British turbine cascade tests[17].

Gas fired pressurized boiler technology (fireside) is available. As indicated above, materials properties for long, high-temperature life operating under the required stress and temperature conditions in the required fireside and potassium side environments require detailed evaluation. However, the related experience is sufficient in both the fireside corrosion and potassium areas that no serious basic problems are anticipated.

Low NO_x combustor technology for application to the gas fueled pressurized boiler is generally available, but requires careful design, and, also probably development effort for the specific application.

Low Btu coal gasification and purification technology is currently available for a coal energy conversion efficiency of 77%, and advances in this technology to permit efficiencies as high as 86% can be expected.

Pressurized fluidized bed boiler technology for application to the reference cycle is in a very early stage of development, at least in this country. Many aspects of this technology require better definition including basic heat transfer, control, sulfur removal, NO_x generation control, limestone regeneration, coal and limestone feeding. Boiler tube fireside corrosion in the bed containing large amounts of $CaSO_4$ requires careful evaluation, although preliminary British data for stainless steel and other alloys, such as high chromium and cobalt alloys, are very encouraging(17). However, basic feasibility has been established and reports of the British effort indicate that pressurized fluidized beds have been operated at pressure levels as high as 6.0×10^5 N/m^2 (6 atmospheres) at 1255 K (1800°F) bed temperature with NO_x and SO_2 emissions within EPA regulations.

In general, it may be stated that insofar as present availability of required technology is concerned the gas fueled pressurized boiler system is ahead of the pressurized fluidized bed system. However, as indicated above, the latter system is believed to possess a greater future potential for efficient low cost coal energy conversion.

DEGREE OF DEVELOPMENT RISK AND ASSOCIATED COSTS

In the previous section the status of the various elements of the technology required for the gas fueled pressurized boiler potassium-steam-gas power system and for the coal fueled pressurized fluidized bed boiler system has been summarily evaluated, and the technological elements requiring future development have been identified. The largest area of undeveloped basic technology is that of the pressurized fluidized bed potassium boiler and its closely associated feeding, limestone regenerating, particulate removal auxiliary components. This major component involves development risks in connection with a number of potential problems, including fireside tube corrosion, sulfur removal, limestone regeneration, NO_x emissions, combustion efficiency, stability, and uniformity, transient and part load operation, and assured delivery of a nonerosive and nondeposit-forming gas flow to the gas turbine. Because of this situation the gas fired pressurized boiler system offers, at this point in time, a more readily available body of basically proven technology than does the coal fired system. Both systems share risk in connection with the scaling up of the potassium flow loop components from the size of the laboratory units which have been proven, to that of a 1200 MW size powerplant. (The proposed modular approach to the design of potassium components for this plant will, of course, ease this problem.) This scaling up will involve important manufacturing process changes, and, also, for economic reasons, some changes in material selections. The most critical potassium technology related problem areas are large potassium turbine disc manufacturing, and assurance of reliability and steam leak incident damage control in the potassium condenser/steam generator.

For each of the two systems the recommended development programs are listed in Tables 30 and 31. These programs have been divided into two categories, basic development problems and design verification programs. The latter category covers many of the previously mentioned problems associated with scaling up proven potassium component technology. The estimated costs include only the work necessary to bring the elements of the technology to a state of readiness for design and construction of a pilot plant. They do not include the costs of such a plant.

TABLE 30. - GAS FUELED PRESSURIZED BOILER SYSTEM DEVELOPMENT PROGRAMS

Basic Development Problem Programs	Est. Dev. Time	Est. Dev. Cost
1. Large Superalloy Turbine Disc	5 years	$\$ 3.0 \times 10^6$
2. Large TZM Molybdenum Turbine Disc	3 years	$\$ 3.5 \times 10^6$
3. Low NO_x Pressurized Combustor	1.5 years	$\$ 0.5 \times 10^6$
Design Verification Programs		
1. Potassium Boiler	2 years	$\$ 1.5 \times 10^6$
2. Potassium Condenser/Steam Generator	2 years	$\$ 1.7 \times 10^6$
3. Potassium Control Valves	2 years	$\$ 0.8 \times 10^6$
4. Turbine Shaft Seal	2 years	$\$ 0.5 \times 10^6$
5. Materials & Processes	5 years	$\$ 5.0 \times 10^6$
6. Potassium Component Facility		$\$ 3.0 \times 10^6$
Total Development Cost		$\$19.5 \times 10^6$

TABLE 31. - COAL FIRED PRESSURIZED FLUIDIZED BED BOILER SYSTEM DEVELOPMENT PROGRAMS

Basic Development Problem Programs	Est. Dev. Time	Est. Dev. Cost
1. Pressurized Fluidized Bed Potassium Boiler	5 years	$40.0 x 10^6
This is a very large and complex program involving both fireside and potassium side phenomena. (The unknowns are almost entirely on the fireside). Fireside corrosion problems of boiler tubing embedded in $CaSO_4$ require investigation.		
2. Large Superalloy Turbine Disc	5 years	$ 3.0 x 10^6
3. Gas Turbine Erosion Test	2 years	$ 1.0 x 10^6
Design Verification Programs		
1. Potassium Condenser/Steam Generator	2 years	$ 1.7 x 10^6
2. Potassium Control Valves	3 years	$ 0.8 x 10^6
3. Turbine Shaft Seal	2 years	$ 0.5 x 10^6
4. Materials & Processes	5 years	$ 5.0 x 10^6
5. Potassium Component Facility		$ 3.0 x 10^6
Total Development Costs		$55.0 x 10^6

CONCLUSIONS AND RECOMMENDATIONS

As discussed in the section Powerplant Costs (p. 74), the capital costs of the pressurized fluidized bed system are $143 million more than those of the pressurized boiler system for a 1200 MW powerplant; the cost of the coal gasification plant is not included in this cost comparison. The annual operating costs are equal for the two topping cycle systems because the higher capital costs of the fluidized bed powerplant tend to offset the higher fuel costs for the pressurized boiler powerplant.

The potassium topping cycle powerplant can have a significant impact with regard to national goals such as air and water pollution, and conservation of natural resources. The major air pollution problem with burning coal is the formation of SO_2 and its subsequent release to the atmosphere in the stack gas. The potassium topping cycle powerplant with a supercharged furnace would use clean gas from a coal gasification plant and the problems of SO_2 and particulate emissions would be eliminated. The CO and NO_x emissions can be controlled by the design of the combustion system.

An alternate potassium topping cycle powerplant with a fluidized bed combustor would use coal directly, without gasification, and the sulfur would be removed by chemical reaction with limestone in the fluidized bed combustor. NO_x would be controlled by removing heat in the bed with potassium boiler tubes, thus limiting the combustion temperature rise.

Considering conservation of fuel resources and thermal pollution, the pressurized fluidized bed topping cycle system has a coal to busbar efficiency of 0.499 compared with 0.392 for a coal burning steam powerplant calculated for comparable conditions. This means the topping cycle system would use 21% less fuel and reject 35% less heat than a steam plant of the same power output. The pressurized boiler topping cycle system has a coal to busbar efficiency of 0.422 (0.8 x 0.528) due to the coal to gas conversion efficiency of 80%. This means that the pressurized boiler system would use 18% more coal than the fluidized bed system. Considering the large number of powerplants that will be build in the next thirty years, and the scarcity of fuel, the 18% better fuel consumption of the pressurized fluidized bed system, compared with the pressurized boiler system, make the development of the fluidized bed boiler a consideration, in spite of its greater development cost.

Since most of the components are common to both systems and the pressurized boiler technology is developed, it is recommended that the pressurized boiler topping cycle be developed through the pilot plant stage. It is also recommended that the pressurized fluidized bed boiler be developed in parallel. Then, if the fluidized bed program is successful, the pilot plant could be retrofitted with a fluidized bed boiler before proceeding to the demonstration powerplant. If technical progress is not limited by funding, the estimated starting date of a demonstration plant is 1983 to 1985.

APPENDICES

Appendix A. - Potassium-Steam Topping Cycle Code

A computer code was written to calculate the performance of potassium-steam topping cycles; a schematic diagram of the cycle is shown in Figure 1. The steam cycle includes high, intermediate and low pressure turbines with extraction from each for feedwater heating. The steam cycle can have up to two reheat stations. Although most of the heat added to the steam comes from the condensing potassium, there is provision for a water economizer where heat from the furnace can be added to the water directly. Various steam condensate cooling schemes can be used including run-of-river, and wet or dry cooling towers.

The potassium cycle includes a turbine which has provision for condensing at two temperature levels. The lower temperature potassium vapor provides heat to the steam until the steam temperature reaches a pinch-point temperature difference between the steam and condensing potassium vapor, the value of which is specified by input. The higher temperature potassium vapor supplies the rest of the heat to the steam including reheat if specified. The output of the steam system is specified by input to the code, and the potassium flow rates and power output are determined by the heat requirements of the steam cycle. The potassium cycle has provision for extraction for feed heating if desired.

The furnace calculations determine the air and fuel flow rates required to provide the heat requirements of the cycle. A pinch-point temperature difference between the furnace gas and the potassium boiling temperature can also be specified. An air preheater is inlcuded in the cycle, the effectiveness of which is usually calculated to maintain the desired stack gas temperature.

The component efficiency assumptions used in the cycle performance code are shown in Table 32. The efficiencies for the steam components were taken from reference 10. The efficiencies for the potassium turbines are lower for larger pressure ratios due to the presence of condensed liquid and the associated loss. The efficiency levels are based on calculated results from a turbine design code which gives performance levels in agreement with small size potassium turbine tests[21].

The cost portion of the code makes use of cost correlations for each component in the entire cycle. In order to do this, certain additional assumptions and calculations are required. As an example, the feedwater heaters are accounted for by using a heat balance in the performance portion of the code. In the cost section, assumptions are made of the heat transfer coefficients (based on a wide range of operational

TABLE 32. - COMPONENT EFFICIENCIES

Component	Efficiency	Source
Steam Cycle Turbines		
HP	.854	(Ref. 10)
IP	.88	
	.891	(Ref. 10)
LP	.92	
	.927	(Ref. 10)
Generator	.985	(Ref. 10)
Pumps	.85	(Ref. 10)
Potassium Cycle Turbines		
Sta. 30 to 35	.90	(Ref. 21)
Sta. 30 to 31	.85	
Sta. 30 to 37	.80	
Potassium Pumps	.80	(Ref. 34)

*See Figure 1 for locations of stations 30, 31, 35, and 37.

data) and the heat transfer area calculated. The costs are then computed by a correlation involving the unit's heat transfer surface area.

All steam system components were modeled using the correlating equations of reference 10. In numerous cases, however, modifications were made to match the reference steam plant, Bull Run Unit 1. All costs for steam components are calculated in dollars appropriate to the Bull Run site (rural Tennessee) and time period (1962-1966). Since the costs for this study were calculated for the second half of 1972 (1972.5) at the USAEC Model site, Middletown USA (a fictitious site in the Northeast), cost transforms were made for each component to generate revised costs. The technique used was basically that of the CONCEPT code (ref. 9) in which the cost associated with each component is broken down into fractions for site labor, site material, factory labor, and factory material. From published sources, the rates of each class were retrieved both for the Bull Run time and location, and for Middletown USA in 1972.5. By applying these rates, the cost of each component can be transformed in time and space. This calculation was incorporated into the code. Typical escalation (for a modified Bull Run plant) was a factor of 2.05, the cost rising from $\$126 \times 10^6$ to $\$258.8 \times 10^6$. Other features of the code include the calculation of operating costs, expressed as $/year as well as mills/kwh.

In developing the cost models for Task I, it was decided that conceptual designs for the potassium components were required before the cost models could be used with confidence. Preliminary studies of pulverized coal, pressurized gas and fluidized bed type of potassium vapor generators were made so that adequate cost models could be generated.

To improve the potassium turbine cost models, layout drawings were prepared for the limiting conditions. Flow path designs were calculated for the potassium turbines for the 1033 K (1400°F) and 1200 K (1700°F) topping cycles. The 1033 K (1400°F) cycle has four 126 rad/s (1200 rpm) turbines of six stages each, with vapor extraction after the fourth stage. The 1200 K (1700°F) cycle has two single-stage high pressure (HP) turbines at 188 rad/s (1800 rpm) and four seven-stage low pressure (LP) turbines at 1061 K (1450°F) turbine inlet temperature and 126 rad/s (1200 rpm), with vapor extraction after the fifth stage. Preliminary mechanical design of these turbines was done to evaluate their feasibility and estimate their cost.

Costs were estimated from the weight and specific material cost, and from estimates of the labor required to build them. The similarity, in size, of the potassium turbines to the low pressure sections of the steam turbines was used to estimate the labor costs.

For each potassium component an estimate of the cost for a specific design was made, and was scaled to other power levels using trends noted for similar steam components.

During the performance analysis study several modifications were made to the topping cycle performance code. For the systems with pressurized furnaces, a compressor and gas turbine were added to the system. The furnace acts as the gas turbine combustor; after providing heat for boiling potassium, the combustion gases enter the gas turbine which drives the compressor and also an electrical generator. The gas turbine exhaust is used to heat the feed water in an economizer, resulting in only a small waste of heat in the stack. The other modification is in the feedwater heater calculations. The number of extractions from the steam turbines was increased and a parallel flow system was designed so that some of the feedwater heating could be done by the gas turbine exhaust gas. The revised topping cycle schematic diagram is shown in Figure 22.

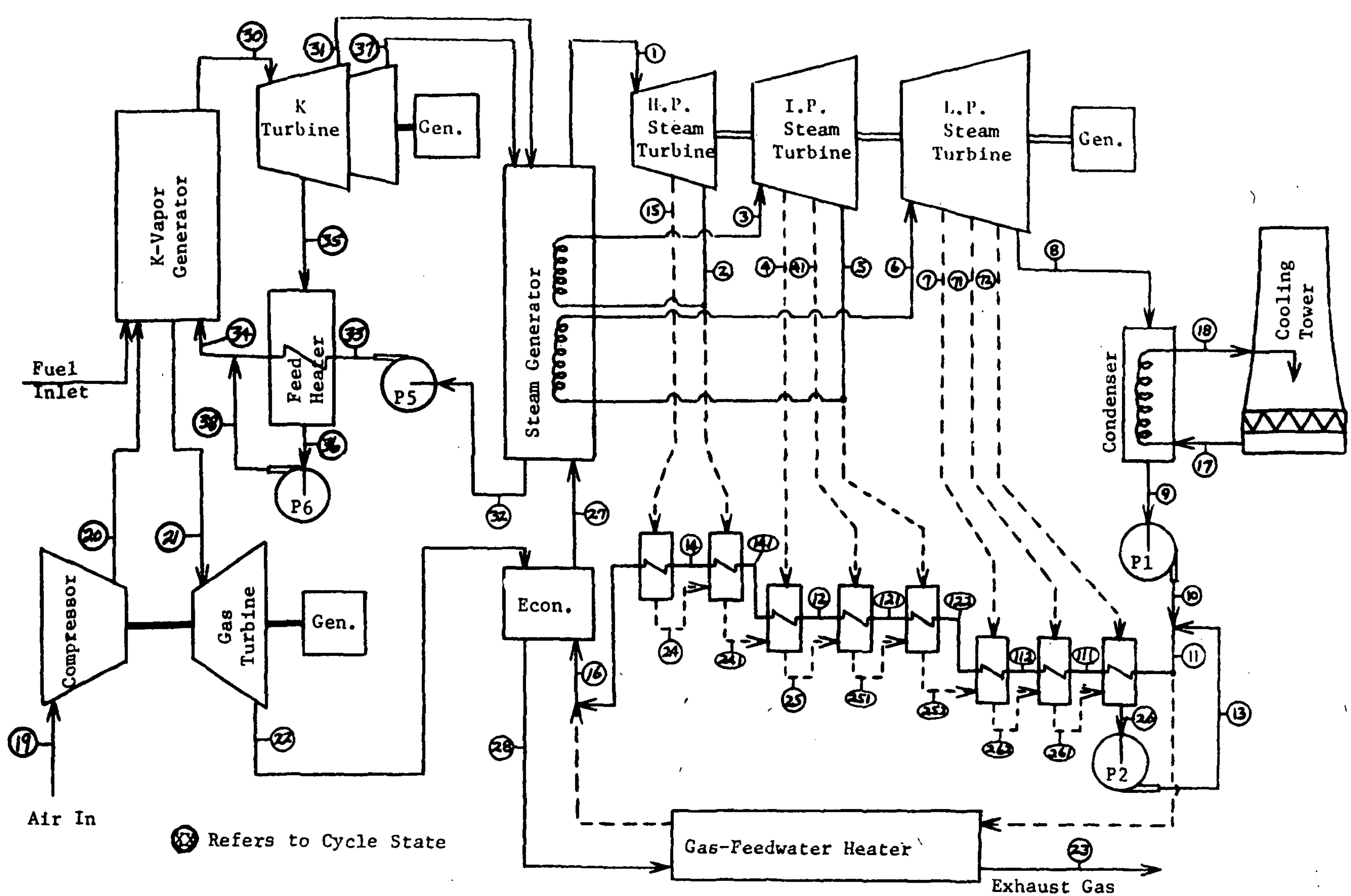

Figure 22. - Schematic for Pressurized Furnace Potassium Topping Cycle

Appendix B. - Topping Cycle Performance Calculation Code - Base Case

The topping cycle performance calculation code was described in Appendix A. A list of nomenclature is presented in Table 33. A printout of the performance code for the base case is shown in Table 34 in three pages. The first page lists all the input specified for this case. The second page shows the fluid state conditions at the various stations in the cycle, which correspond to the schematic diagram, Figure 1. The third page lists the output values calculated by the program. Both conventional and S.I. units are shown.

TABLE 33. - NOMEMCLATURE

TOPPING CYCLE PERFORMANCE CODE - INPUT VALUES

ETAT1	Steam turbine efficiency from sta. 1 to sta. 2
ETAT2	Steam turbine efficiency from sta. 3 to sta. 4
ETAT3	Steam turbine efficiency from sta. 3 to sta. 5
ETAT4	Steam turbine efficiency from sta. 6 to sta. 7
ETAT5	Steam turbine efficiency from sta. 6 to sta. 8
ETAGEN	Generator efficiency
MW	Steam plant net output, MWe
ETAP	Water pump efficiency
ETAP2	Potassium pump efficiency
ETA6	Potassium turbine efficiency from sta. 30 to sta. 35
ETA7	Potassium turbine efficiency from sta. 30 to sta. 31
ETA8	Potassium turbine efficiency from sta. 30 to sta. 37
ETAF	Efficiency term for furnace heat loss
FAIR	Fuel to air ratio
FHV	Fuel heating value, Btu/lbm (J/kg)
E	Preheater effectiveness
WX	Exhaust gas recirculation ratio
DTPP	Pinch point temp. diff., T37-Tsteam, °F (K)
P1	Steam pressure at sta. 1, psia (N/cm^2)
P2	Steam pressure at sta. 2, psia (N/cm^2)
P3	Steam pressure at sta. 3, psia (N/cm^2)
P4	Steam pressure at sta. 4, psia (N/cm^2)
P5	Steam pressure at sta. 5, psia (N/cm^2)
P6	Steam pressure at sta. 6, psia (N/cm^2)
P7	Steam pressure at sta. 7, psia (N/cm^2)
P10	Water pressure at sta. 10, psia (N/cm^2)
P15	Steam pressure at sta. 15, psia (N/cm^2)
P27	Water pressure at sta. 27, psia (N/cm^2)
P30	Potassium pressure at sta. 30, psia (N/cm^2)
P31	Potassium pressure at sta. 31, psia (N/cm^2)
P33	Potassium pressure at sta. 33, psia (N/cm^2)
P34	Porassium pressure at sta. 34, psia (N/cm^2)
P35	Potassium pressure at sta. 35, psia (N/cm^2)
P37	Potassium pressure at sta. 37, psia (N/cm^2)
T1	Steam temperature at sta. 1, °F (K)
T3	Steam temperature at sta. 3, °F (K)
T6	Steam temperature at sta. 6, °F (K)
T12	Water temperature at sta. 12, °F (K)
T14	Water temperature at sta. 14, °F (K)
T16	Water temperature at sta. 16, °F (K)
T17	Condenser water inlet temp., °F (K)
T21	Gas temp. leaving furnace, °F (initial value) (K)
T27	Water temperature at sta. 27, °F (K)
T30	Potassium temperature at sta. 30, °F (K)
T32	Potassium temperature at sta. 32, °F (K)
T34	Potassium temperature at sta. 34, °F (K)
A3	Code for sulfur extraction
A6	Code for condenser water cooling
CASEND	Program control

TABLE 33. - NOMENCLATURE (Cont'd.)

DTT	Temp. diff. in condenser, T8-T18, °F (K)
DTR	Temp. change in cooling water, T18-T17, °F (K)
DTA	T17-dry bulb air temp., °F (K)
DTSC	Subcooling, T8-T9, °F (K)
TDB	Dry bulb air temperature, °F (K)
TWB	Wet bulb air temperature, °F (K)
RUNTYP	Program control
DTGK	Pinch point temp. diff., gas to potassium, °F (K)

TABLE 33. - NOMENCLATURE (Cont'd.)

TOPPING CYCLE PERFORMANCE CODE - CYCLE PARAMETERS

WB2	Bleed flow fraction at station 2
WB4	Bleed flow fraction at station 4
WB7	Bleed flow fraction at station 7
W1	Steam flow rate at station 1, lbs/hr (kg/s)
QBOIL	Enthalpy change across steam boiler, Btu/lb (J/kg)
QRHT1	Enthalpy change across 1st reheater, Btu/lb (J/kg)
QRHT2	Enthalpy change across 2nd reheater, Btu/lb (J/kg)
QCOND	Enthalpy change across condenser, Btu/lb (J/kg)
PUMP1	Enthalpy change across main feedwater pump, Btu/lb (J/kg)
PUMP2	Enthalpy change across secondary feedwater pump, Btu/lb (J/kg)
WOUT	Total <u>gross</u> work from steam system, Btu/lb (J/kg)
WNET	Net work from steam system, Btu/lb (J/kg)
ETAS	Steam system efficiency
STHR	Steam heat rate, (Btu/hr)/kw (W/kw)
HKSGI	Enthalpy of steam at boiler pinch-point, Btu/lb (J/kg)
WCOND	Condensing water flow rate, lb/hr (kg/s)
QKVAP	Enthalpy change across furnace in potassium, Btu/lb (J/kg)
QREJ	Heat injected to steam boiler, Btu/hr (W)
WKOUT	Total gross heat rate of K-turbine, Btu/hr (W)
PUMP5	Main K-pump power, Btu/hr (W)
PUMP6	Secondary feed pump power, Btu/hr (W)
WKNET	Net potassium system power, Btu/hr (W)
W30	Potassium flow rate at station 30, lb/hr (kg/s)
W31	Potassium flow rate at station 31, lb/hr (kg/s)
W35	Potassium <u>bleed</u> flow rate at station 35, lb/hr (kg/s)
W37	Potassium flow rate at station 37, lb/hr (kg/s)
PMW	Net power of potassium system, MW
ETAK	Potassium system efficiency
QADD	Total power transferred from the furnace to the potassium and steam (water) lines, Btu/hr (W)
WAIR	Combustion air flow rate, lb/hr (kg/s)
WFUEL	Fuel flow rate, lb/hr (kg/s)
HAIRMX	Enthalpy of gas at combustion, Btu/lb (J/kg)
TAIRMX	Temperature of gas at combustion, °F (K)
TGAS2	Temperature of gas after vaporizing potassium °F (K)
TGAS3	Temperature of gas after heating liquid K, °F (K)
TGAS4	Temperature of gas leaving the furnace, °F (K)
ETAB	Furnace efficiency
TMW	Total cycle power, MW
ETA	Total cycle efficiency

TABLE 34. - COMPUTER PRINT-OUT FOR BASE CASE

CASE 1 TOPPING CYCLE INPUT VALUES 06/12/73 21:02EDT

NO.	PARAMETER	STD. UNITS	S.I. UNITS	NO.	PARAMETER	STD. UNITS	S.I. UNITS
1.	ETAT1	0.854		31.	P33	35.00	24.13
2.	ETAT2	0.880		32.	P34	33.00	22.75
3.	ETAT3	0.891		33.	P35	10.00	6.89
4.	ETAT4	0.920		34.	P37	1.10	0.76
5.	ETAT5	0.927		35.	T1	1000.00	810.93
6.	ETAGEN	0.985		36.	T3	1000.00	810.93
7.	AW	914		37.	T6	703.80	646.37
8.	ETAP	0.850		38.	T12	275.00	408.15
9.	ETAP2	0.800		39.	T14	377.00	464.82
10.	ETA6	0.900		40.	T16	513.00	540.37
11.	ETA7	0.850		41.	T17	60.70	289.09
12.	ETA8	0.800		42.	T21	656.00	619.82
13.	ETAF	1.000		43.	T27	705.00	647.04
14.	FAIR	0.0060		44.	T30	1400.00	1033.15
15.	FHV	11900.0	2.76609E+07	45.	T32	1000.00	810.93
16.	E	0.700		46.	T34	1001.00	811.48
17.	WX	0.300		47.	A3	1.	
18.	DTPP	50.0	27.8	48.	A6	2.	
				49.	CASEND	1	
19.	P1	3515.00	2423.51	50.	DTT	20.00	11.11
20.	P2	600.00	413.69	51.	DTR	22.50	12.50
21.	P3	540.00	372.32	52.	DTA	20.00	11.11
22.	P4	200.00	137.90	53.	DTSC	1.00	0.56
23.	P5	172.00	118.59	54.	TDB	78.00	298.71
24.	P6	172.00	118.59	55.	TWB	72.50	295.65
25.	P7	50.00	34.47	56.	RUNTYP	BOTH	
26.	P10	3600.00	2482.11	57.	DTGK	100.00	55.56
27.	P15	800.00	551.58				
28.	P27	3600.00	2482.11				
29.	P30	15.17	10.46				
30.	P31	2.41	1.66				

TABLE 34. - COMPUTER PRINT-OUT FOR BASE CASE (Cont'd.)

* CYCLE CALCULATIONS - PART I : FLUID STATE SUMMARY

STATION NO.	P (PSIA)	T (DEG-F)	H (BTU/LB)	S (BTU/LB/DF)	X	V (FT3/LB)
1	3515.0	1000.0	1421.7	1.47013		
2	600.0		1255.2			
3	540.0	1000.0	1519.1	1.72803		
4	200.0		1395.9			
5	172.0		1377.6			
6	172.0	703.3	1377.7	1.74315		
7	50.0		1253.0			
8	2.5	135.0	1052.1			
9	2.5	134.0	102.0			0.01627
10	3600.0	144.3	112.8			
11			161.1			
12	3600.0	275.0	251.2			
13			261.6			
14	3600.0	377.0	355.3			
15	800.0		1278.1			
16	3600.0	513.0	502.4			
17	14.7	92.5	60.5			
18	14.7	115.0	83.0			
19		78.0				
20		750.5	294.5			
21		962.5	349.2			
22		290.0	179.8			
23						
24	800.0		509.8			
25	200.0		355.5			
26	50.0	281.0	250.2			0.01727
27	3600.0	705.0	789.8			
28						
29						
30	15.2	1400.0	1188.8	1.11437		
31	2.4		1071.2		0.88261	
32	1.1	1000.0	283.7			0.02232
33	35.0		283.8			
34	33.0	1001.0	283.9			
35	10.0		1157.4		0.96671	
36	10.0	1322.1	345.6			0.02378
37	1.1	1000.5	1039.3		0.85570	
38			345.7			

TABLE 34. - COMPUTER PRINT-OUT FOR BASE CASE (Cont'd.)

THE STEAM SYSTEM		STD. ENG.	S.I.
1. STEAM BLEED FLOW FRACTION @ STA. 15,	WB2 =	0.19147	0.19147
2. STEAM BLEED FLOW FRACTION @ STA. 4 ...	WB4 =	0.07167	0.07167
3. STEAM BLEED FLOW FRACTION @ STA. 7 ...	WB7 =	0.06213	0.06213
4. TOTAL STEAM FLOW RATE @ STA. 1	W1 =	6.4674E+06	8.1657E+02
5. HEAT ADDED TO PRIMARY STEAM	QBOIL =	919.3	2.1370E+06
6. HEAT ADDED IN FIRST REHEAT	QRHT1 =	213.4	4.9608E+05
7. HEAT ADDED IN SECOND REHEAT	QRHT2 =	0.0	3.5596E+01
8. HEAT REJECTED IN CONDENSER	QCOND =	641.1	1.4902E+06
9. FEEDWATER PUMP WORK	PUMP1 =	8.5974	1.9984E+04
10. AUX. FEEDWATER PUMP WORK	PUMP2 =	4.3433	1.0096E+04
11. STEAM TURBINE OUTPUT	WOUT =	502.6279	1.1683E+06
12. NET STEAM TURBINE OUTPUT	WNET =	489.6872	1.1383E+06
13. STEAM SYSTEM EFFICIENCY	ETAS =	0.4323	0.4323
14. STEAM HEAT RATE	STHR =	8015.39	2347.51
15. STEAM ENTHALPY @ BOILER PINCH-POINT,	HKSGI =	1381.99	3.2123E+06
16. COOLING WATER FLOW RATE	WCOND =	1.8461E+08	2.3309E+04
THE POTASSIUM SYSTEM		**STD. ENG.**	**S.I.**
17. HEAT ADDED TO POTASSIUM	QKVAP =	9.0498E+02	2.1036E+06
18. HEAT REJECTED TO STEAM BOILER	QREJ =	5.4674E+09	1.6013E+09
19. GROSS POWER OF POTASSIUM TURBINE ...	WKOUT =	1.0025E+09	2.9361E+08
20. POWER OF MAIN POTASSIUM PUMP	PUMP5 =	1.2516E+06	3.6655E+05
21. POWER OF AUX. POTASSIUM FEED PUMP,	PUMP6 =	5.1211E+01	1.4998E+01
22. NET POWER FROM POTASSIUM SYSTEM	WKNET =	1.0013E+09	2.9325E+08
23. POTASSIUM FLOW RATE @ STA. 30	W30 =	7.1482E+06	9.0253E+02
24. POTASSIUM FLOW RATE @ STA. 31	W31 =	2.0791E+06	2.6250E+02
25. POTASSIUM BLEED FLOW RATE @ STA. 35,	W35 =	4.0467E+02	5.1094E-02
26. POTASSIUM FLOW RATE @ STA. 37	W37 =	5.0687E+06	6.3997E+02
27. NET ELECTRIC POWER FROM K-SYSTEM	PMW =	288.9678	288.9678
28. POTASSIUM SYSTEM EFFICIENCY	ETAK =	0.1548	0.1548
THE COMBUSTION SYSTEM		**STD. ENG.**	**S.I.**
29. HEAT TRANSFERRED IN FURNACE	QADD =	8.3276E+09	2.4389E+09
30. COMBUSTION AIR FLOW RATE	WAIR =	1.1768E+07	1.4858E+03
31. FUEL FLOW RATE	WFUEL =	7.7667E+05	9.8063E+01
32. GAS ENTHALPY @ COMBUSTION	HAIRMX =	867.24	2.0158E+06
33. GAS TEMP. @ COMBUSTION	TAIRMX =	2800.98	1811.47
34. GAS TEMP. AFTER K-VAPORIZATION	TGAS2 =	1519.26	1099.41
35. GAS TEMP. AFTER LIQUID K-HEATING ...	TGAS3 =	1395.46	1030.63
36. GAS TEMP. LEAVING THE FURNACE	TGAS4 =	963.63	790.72
37. COMBUSTION EFFICIENCY	ETAB =	0.9010	0.9010
OVERALL VALUES		**STD. ENG.**	**S.I.**
38. TOTAL CYCLE POWER	TMW =	1202.97	1202.97
39. TOTAL CYCLE EFFICIENCY	ETA =	0.44423	0.44423

Appendix C. - Variation of Performance and Cost with Cycle Conditions

The topping cycle code described previously was used to determine the sensitivity of topping cycle performance and costs to cycle variations. In Table 35 are shown the cycle variations that were made. The values in the left hand column are those associated with the base case. The other values were used one at a time in the parametric study; a total of 15 cases were therefore examined, in addition to the base case. The principal performance results are shown in Figure 23, where the base case value of each parameter is indicated by a round symbol. As expected, the most significant parameter was potassium turbine inlet temperature; increasing it from 1033 to 1200 K (1400 to 1700°F) increased cycle efficiency from 0.444 to 0.473 or 6.5%.

The base case topping cycle assumed two potassium condensing temperatures, 811 K (1000°F) to supply heat to the pressurized water until it reaches the pinch point temperature difference, and 866 K (1100°F) to supply the rest of the heat, including steam reheat. The upper right plot shows the effect of varying the lower condensing temperature. Although the plot shows cycle efficiency gains by condensing at temperatures lower than 811 K (1000°F), the potassium vapor pressure is less than 0.7 N/cm^2 (1 psia) and the large volume flow rates make the potassium turbine design more difficult.

The third parameter that had a significant effect was the water economizer temperature rise, shown in the lower plot of Figure 23. This result indicates that the water economizer should not be used but rather the water should be heated by the condensing potassium. This variation increased the cycle efficiency from 0.444 to 0.457, or 2.9%. All other cycle variations had a small effect on performance.

The cycle variations run in the performance sensitivity study described above were run with the cost model to determine the sensitivity of system costs with cycle variations. The results are shown in Table 36. The base case is a topping cycle with 1033 K (1400°F) potassium turbine inlet temperature and 811 K (1000°F) for the lower potassium condensing temperature. The steam cycle is the Bull Run cycle selected previously. Each case has a single variation from the base case, which is described in the first two columns. The cycle efficiencies are based on a wet cooling tower to cool the condenser. The capital and yearly fuel costs are given in millions of dollars, the fuel assumed to cost \$0.38 per GJ (\$0.40 per million Btu). The last column shows the cost of electricity in mills per kw hr. The plant size is 1200 MW.

TABLE 35. - TOPPING CYCLE VARIATIONS

Potassium Turbine Inlet Temperature, K (°F)	1033 (1400)		1116 (1550)		1200 (1700)
Potassium Condensing Temperature, K (°F)	811 (1000)		866 (1100)		783 (950)
Minimum ΔT Between K and H_2O, K (°F)	28 (50)		14 (25)		56 (100)
Potassium Feed Heating ΔT, K (°F)	0 (0)	56 (100)		111 (200)	167 (300)
H_2O Economizer Temperature Rise, K (°F)	107 (192)		48 (87)		0 (0)
Steam Pressure, N/cm^2 (psia)	2424 (3515)		1724 (2500)		1034 (1500)
No. of Steam Reheats	1		2		0

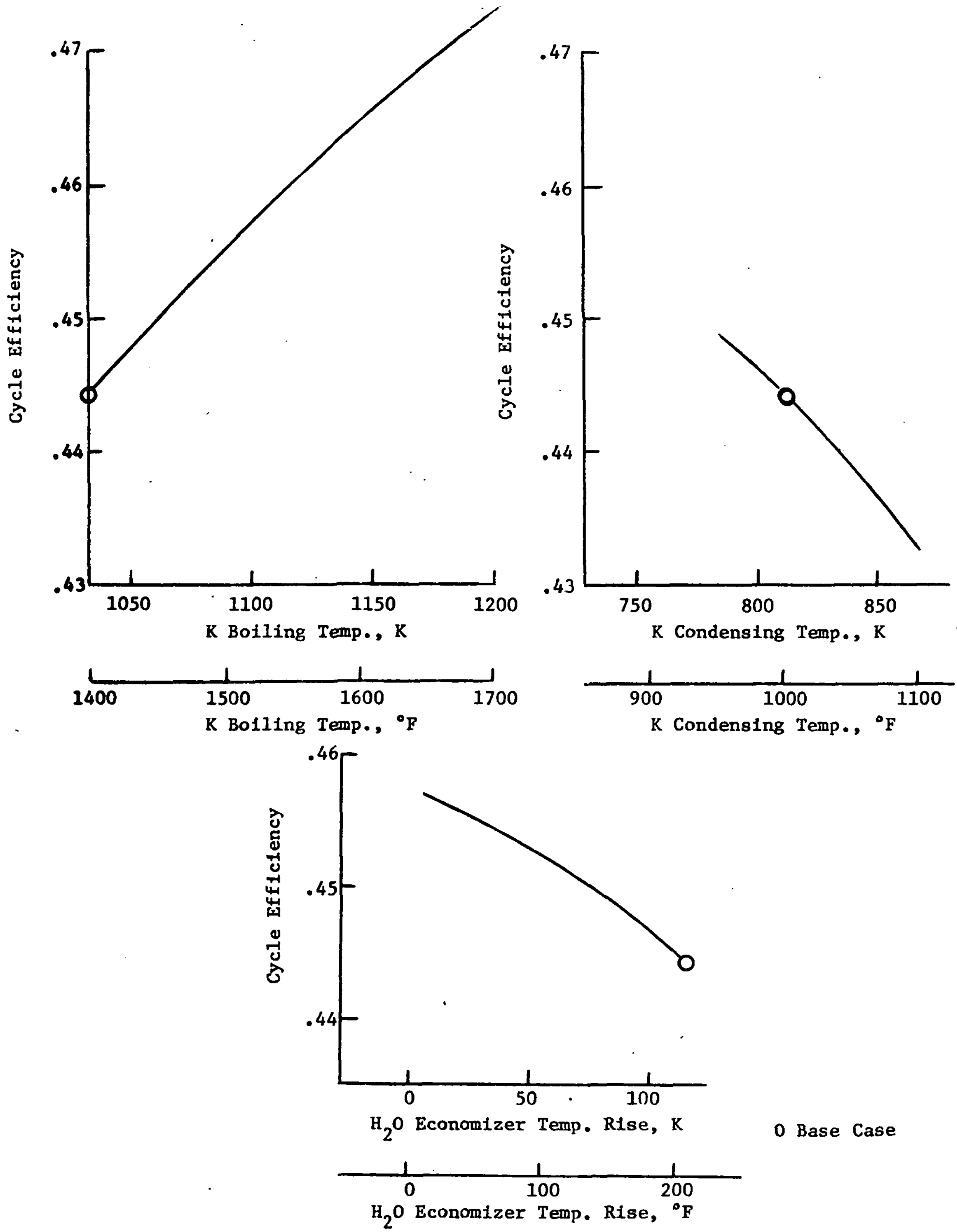

Figure 23. - Variation of Cycle Efficiency With Cycle Parameters (Based on Constant Stack Gas Temperature)

TABLE 36. - PERFORMANCE VARIATION STUDY RESULTS

Case	Description	Parameter Value	η(%)	Costs (10^6\$) Direct	Costs (10^6\$) Total	Costs (10^6\$) Fuel	Elec Cost Mills/MJ	Elec Cost Mills/KWH
1.	Base Case		44.42	275.9	350.0	25.85	2.299	8.278
2.	Raise K Temperature	1116 K (1550°F)	46.01	280.3	355.6	24.94	2.294	8.257
3.	Raise K Temperature	1200 K (1700°F)	47.32	286.5	363.4	24.26	2.296	8.267
4.	Change K Cond. Temperature	866 K (1100°F)	43.25	265.8	337.2	26.55	2.275	8.190
5.	Change K Cond. Temperature	783 K (950°F)	44.91	288.5	366.0	25.57	2.351	8.465
6.	Pinch Pt. ΔT	13.9 K (25°F)	44.46	275.8	349.9	25.82	2.299	8.276
7.	Pinch Pt. ΔT	55.6 K (100°F)	44.35	276.0	350.1	25.90	2.301	8.283
8.	K Feed Heating	55.6 K (100°F)	44.48	276.4	350.7	25.81	2.302	8.286
9.	K Feed Heating	111 K (200°F)	44.44	277.2	351.6	25.83	2.306	8.301
10.	K Feed Heating	167 K (300°F)	44.33	278.3	353.0	25.90	2.313	8.328
11.	Water Econ. ΔT	48 K (87°F)	45.23	277.5	352.1	25.37	2.292	8.252
12.	Water Econ. ΔT	0 K (0°F)	45.69	278.5	353.3	25.14	2.287	8.233
13.	Steam Pressure	1724 N/cm^2 (2500 psia)	44.20	278.0	352.7	25.98	2.314	8.332
14.	Steam Pressure	1034 N/cm^2 (1500 psia)	43.27	284.3	360.7	26.52	2.365	8.515
15.	No. Steam Reheats	2	44.54	275.2	349.1	25.79	2.293	8.256
16.	No. Steam Reheats	0	43.78	280.2	355.4	26.22	2.334	8.403

These results indicate that the optimum potassium turbine inlet temperature is about 1116 K (1550°F). Increasing the potassium lower condensing temperature to 866 K (1100°F) gave the lowest cost of electricity according to the cost model, due to eliminating the low pressure end of the potassium turbine.

Appendix D. - Performance Calculations for Selected Cycles

Computer print-outs for the cycles selected for conceptual design are presented as Tables 37 and 38. Table 37 is for the supercharged furnace topping cycle and Table 38 is for the pressurized fluidized bed cycle. These calculations were made with the modified code shown in Figure 22, and additional nomenclature is presented in Table 39.

TABLE 37. - POTASSIUM PRESSURIZED-BOILER
COMBINED CYCLE DATA

CASE 1 TOPPING CYCLE INPUT VALUES 12/11/73 15:13EST

NO.	PARAMETER	STD. UNITS	S.I. UNITS	NO.	PARAMETER	STD. UNITS	S.I. UNITS
1.	ETAT1	0.854		31.	P33	51.00	35.16
2.	ETAT2	0.880		32.	P34	49.00	33.78
3.	ETAT3	0.891		33.	P35	10.00	6.89
4.	ETAT4	0.920		34.	P37	2.41	1.66
5.	ETAT5	0.927		35.	T1	1050.00	838.71
6.	ETAGEN	0.985		36.	T3	1050.00	838.71
7.	MW	582		37.	T6	1050.00	838.71
8.	ETAP	0.350		38.	T12	406.00	480.93
9.	ETAP2	0.800		39.	T14	476.00	519.82
10.	ETA6	0.900		40.	T16	508.00	537.59
11.	ETA7	0.850		*41.	T17	60.70	289.09
12.	ETA8	0.800		*42.	T21	1800.00	1255.37
13.	ETAF	1.000		*43.	T23	250.00	394.26
14.	FAIR	0.7660		44.	T30	1550.00	1116.48
15.	FHV	2000.0	4.64889E+06	45.	T32	1100.00	866.48
16.	E	0.700		46.	T34	1101.00	867.04
17.	WX	0.300		47.	A3	0.	
18.	DTPP	50.0	27.8	48.	A6	3.	
19.	P1	3515.00	2423.51	49.	CASEND	1	
20.	P2	600.00	413.69	50.	DTT	5.00	2.78
21.	P3	540.00	372.32	51.	DTR	20.00	11.11
22.	P4	420.00	289.58	52.	DTA	17.40	9.67
23.	P5	172.00	118.59	53.	DTSC	1.00	0.56
24.	P6	155.00	106.87	54.	TDB	78.00	298.71
25.	P7	116.00	79.98	55.	TWB	72.60	295.71
26.	P10	3600.00	2482.11	56.	RUNTYP	BOTH	
27.	P15	800.00	551.58	57.	DTGKMN	100.00	55.56
28.	P27	3600.00	2482.11	58.	IREAD	0	
29.	P30	30.86	21.28	59.	CFFILE	TCCEFSPF	
30.	P31	2.41	1.66	60.	CRABRV	CRABFILE	

VALUES ADDED FOR EXTRA FEED-HEATERS AND SUPERCHARGER UNIT

NO.	PARAMETER	STD. UNITS	S.I. UNITS	NO.	PARAMETER	STD. UNITS	S.I. UNITS
61.	ETACP	0.850		70.	T121	359.00	454.82
62.	RC	15.00		71.	T122	329.00	438.15
63.	ETAGT	0.900		72.	T141	439.00	499.26
64.	K	0.9000		73.	T28	560.00	566.48
65.	P41	295.00	203.40	74.	A4	2	
66.	P71	78.00	53.78	75.	CSFUEL	0.8000	
67.	P72	39.00	26.89	76.	WC	0.0300	
68.	T111	256.00	397.59	77.	DATA FILE	JPPBDATA	
69.	T112	300.00	422.04				

TABLE 37. - POTASSIUM PRESSURIZED-BOILER COMBINED CYCLE DATA (Cont'd.)

CASE 1 CYCLE FLUID STATE SUMMARY 12/11/73 15:13EST

STATION NO.	P (PSIA)	T (DEG-F)	H (BTU/LB)	S (BTU/LB/DF)	X	V (FT3/LB)
1	3515.0	1050.0	1459.3	1.49544		
2	600.0	587.5	1282.0			
3	540.0	1050.0	1546.2	1.74628		
4	420.0		1511.2			
5	172.0	746.3	1399.3			
6	155.0	1050.0	1556.6	1.88903		
7	116.0		1513.8			
8	1.5	115.0	1113.8			
9	1.5	114.0	82.0			0.01618
10	3600.0	124.8	92.8			
11		137.0	113.9			
12	3600.0	406.0	385.6			
13			245.9			
14	3600.0	476.0	460.9			
15	800.0		1306.4			
16	3600.0	508.0	496.7			
17	14.7	90.0	58.0			
18	14.7	110.0	78.0			
19		78.0				
20		806.7	308.8			
21		1800.0	577.1			
22		832.4	315.4			
23		250.0	170.0			
24	800.0		509.8			
25	420.0		429.6			
26	39.0	265.7	234.6			0.01714
27	3600.0	666.7	707.4			
28		560.0	246.3			
29						
30	30.9	1550.0	1195.2	1.08483		
31	2.4		1032.9		0.83871	
32	2.4	1100.0	302.5			0.02275
33	51.0		302.7			
34	49.0	1101.0	302.7			
35	10.0		1110.6		0.91104	
36	10.0	1322.1	345.6			0.02378
37	2.4	1100.3	1042.5		0.84967	
38			345.8			
41	295.0		1464.5			
71	78.0		1459.2			
72	39.0		1374.3			
111	3600.0	256.0	232.1			
112	3600.0	300.0	276.4			
121	3600.0	359.0	336.6			
122	3600.0	329.0	305.8			
141	3600.0	439.0	420.7			
241	600.0		471.7			
251	295.0		392.3			
252	172.0		342.2			
261	78.0		280.3			
262	116.0		309.9			

TABLE 37. - POTASSIUM PRESSURIZED-BOILER COMBINED CYCLE DATA (Cont'd.)

	THE STEAM SYSTEM		STD. ENG.	S.I.
A 01	STEAM BLEED FLOW FRACTION @ STA. 15,	WB15 =	0.01758	0.01758
A 02	STEAM BLEED FLOW FRACTION @ STA. 2 ...	WB2 =	0.01911	0.01911
A 03	STEAM BLEED FLOW FRACTION @ STA. 4 ...	WB4 =	0.01213	0.01213
A 04	STEAM BLEED FLOW FRACTION @ STA. 41,	WB41 =	0.01721	0.01721
A 05	STEAM BLEED FLOW FRACTION @ STA. 5 ...	WB5 =	0.01017	0.01017
A 06	STEAM BLEED FLOW FRACTION @ STA. 7 ...	WB7 =	0.00878	0.00878
A 07	STEAM BLEED FLOW FRACTION @ STA. 71,	WB71 =	0.01387	0.01387
A 08	STEAM BLEED FLOW FRACTION @ STA. 72,	WB72 =	0.03904	0.03904
A 09	TOTAL STEAM FLOW RATE @ STA. 1	W1 =	2.9070E+06	3.6704E+02
A 10	HEAT ADDED TO PRIMARY STEAM	QBOIL =	1195.5	2.7789E+06
A 11	HEAT ADDED IN FIRST REHEAT	QRHT1 =	254.5	5.9164E+05
A 12	HEAT ADDED IN SECOND REHEAT	QRHT2 =	145.3	3.3777E+05
A 13	HEAT REJECTED IN CONDENSER	QCOND =	889.5	2.0677E+06
A 14	FEEDWATER PUMP WORK	PUMP1 =	10.9308	2.5408E+04
A 15	AUX. FEEDWATER PUMP WORK	PUMP2 =	1.8326	4.2599E+03
A 16	STEAM TURBINE OUTPUT	WOUT =	706.4704	1.6422E+06
A 17	NET STEAM TURBINE OUTPUT	WNET =	693.7070	1.6125E+06
A 18	STEAM SYSTEM EFFICIENCY	ETAS =	0.4348	0.4348
A 19	STEAM HEAT RATE	STHR =	7968.58	2333.80
A 20	STEAM ENTHALPY @ BOILER PINCH-POINT,	HKSGI =	1459.46	3.3924E+06
A 21	COOLING WATER FLOW RATE	WCOND =	1.2953E+08	1.6355E+04

	THE POTASSIUM SYSTEM		STD. ENG.	S.I.
B 01	HEAT ADDED TO POTASSIUM	QKVAP =	8.9246E+02	2.0745E+06
B 02	HEAT REJECTED TO STEAM BOILER	QREJ =	3.3487E+09	9.8074E+08
B 03	GROSS POWER OF POTASSIUM TURBINE ...	WKOUT =	7.0933E+08	2.0775E+08
B 04	POWER OF MAIN POTASSIUM PUMP	PUMP5 =	1.1628E+06	3.4056E+05
B 05	POWER OF AUX. POTASSIUM FEED PUMP,	PUMP6 =	0.	0.
B 06	NET POWER FROM POTASSIUM SYSTEM	WKNET =	7.0817E+08	2.0741E+08
B 07	POTASSIUM FLOW RATE @ STA. 30	W30 =	4.5460E+06	5.7398E+02
B 08	POTASSIUM FLOW RATE @ STA. 31	W31 =	1.5905E+06	2.0082E+02
B 09	POTASSIUM BLEED FLOW RATE @ STA. 35,	W35 =	0.	0.
B 10	POTASSIUM FLOW RATE @ STA. 37	W37 =	2.9554E+06	3.7315E+02
B 11	NET ELECTRIC POWER FROM K-SYSTEM	PMW =	204.3801	204.3801
B 12	POTASSIUM SYSTEM EFFICIENCY	ETAK =	0.1746	0.1746

	THE COMBUSTION SYSTEM		STD. ENG.	S.I.
C 01	HEAT TRANSFERRED IN FURNACE	QADD =	4.0571E+09	1.1882E+09
C 02	COMBUSTION AIR FLOW RATE	WAIR =	4.9383E+06	6.2351E+02
C 03	FUEL FLOW RATE	WFUEL =	3.7827E+06	4.7761E+02
C 04	GAS ENTHALPY @ COMBUSTION	HAIRMX =	974.79	2.2658E+06
C 05	GAS TEMP. @ COMBUSTION	TAIRMX =	3164.88	2013.64
C 06	GAS TEMP. AFTER K-VAPORIZATION	TGAS2 =	1934.78	1330.25
C 07	GAS TEMP. AFTER LIQUID K-HEATING ...	TGAS3 =	1798.28	1254.42
C 08	GAS TEMP. LEAVING THE FURNACE	TGAS4 =	1584.86	1135.85
C 09	COMBUSTION EFFICIENCY	ETAB =	0.5363	0.5363
C 10	NET SUPERCHARGER POWER GAIN	AMW =	413.16	413.16
C 11	FEEDWATER HEATERS FLOW FRACTION	FWHS =	0.39153	0.39153

	OVERALL VALUES		STD. ENG.	S.I.
D 01	TOTAL CYCLE POWER	TMW =	1170.66	1170.66
D 02	TOTAL CYCLE EFFICIENCY	ETA =	0.52812	0.52812
D 03	SYSTEM HEAT RATE (BTU/KW-HR)	HTRATE =	6462.55	
D 04	PARASITIC POWER LOSS	XMWINT =	28.88740	28.88740

TABLE 38. - POTASSIUM PRESSURIZED FLUIDIZED BED COMBINED CYCLE DATA

CASE 2 TOPPING CYCLE INPUT VALUES 12/11/73 15:13EST

NO.	PARAMETER	STD. UNITS	S.I. UNITS	NO.	PARAMETER	STD. UNITS	S.I. UNITS
1.	ETAT1	0.854		31.	P33	35.00	24.13
2.	ETAT2	0.880		32.	P34	33.00	22.75
3.	ETAT3	0.891		33.	P35	10.00	6.89
4.	ETAT4	0.920		34.	P37	2.41	1.66
5.	ETAT5	0.927		35.	T1	1050.00	838.71
6.	ETAGEN	0.985		36.	T3	1050.00	838.71
7.	MW	750		37.	T6	1050.00	838.71
8.	ETAP	0.850		38.	T12	406.00	480.93
9.	ETAP2	0.800		39.	T14	476.00	519.82
10.	ETA6	0.900		40.	T16	508.00	537.59
11.	ETA7	0.850		*41.	T17	60.70	289.09
12.	ETA8	0.800		*42.	T21	1700.00	1199.82
13.	ETAF	1.000		*43.	T23	250.00	394.26
14.	FAIR	0.0660		44.	T30	1400.00	1033.15
15.	FHV	11900.0	2.76609E+07	45.	T32	1100.00	866.48
16.	E	0.700		46.	T34	1101.00	867.04
17.	WX	0.300		47.	A3	3.	
18.	DTPP	50.0	27.8	48.	A6	3.	
19.	P1	3515.00	2423.51	49.	CASEND	4	
20.	P2	600.00	413.69	50.	DTT	5.00	2.78
21.	P3	540.00	372.32	51.	DTR	20.00	11.11
22.	P4	420.00	289.58	52.	DTA	17.40	9.67
23.	P5	172.00	118.59	53.	DTSC	1.00	0.56
24.	P6	155.00	106.87	54.	TDB	78.00	298.71
25.	P7	116.00	79.98	55.	TWB	72.60	295.71
26.	P10	3600.00	2482.11	56.	RUNTYP	BOTH	
27.	P15	800.00	551.58	57.	DTGKMN	100.00	55.56
28.	P27	3600.00	2482.11	58.	IREAD	2	
29.	P30	15.17	10.46	59.	CFFILE	TCCEFSPF	
30.	P31	2.41	1.66	60.	CRABRV	CRABFILE	

VALUES ADDED FOR EXTRA FEED-HEATERS AND SUPERCHARGER UNIT

NO.	PARAMETER	STD. UNITS	S.I. UNITS	NO.	PARAMETER	STD. UNITS	S.I. UNITS
61.	ETACP	0.850		70.	T121	359.00	454.82
62.	RC	9.00		71.	T122	329.00	438.15
63.	ETAGT	0.900		72.	T141	439.00	499.26
64.	K	0.8700		73.	T28	560.00	566.48
65.	P41	295.00	203.40	74.	A4	1	
66.	P71	78.00	53.78	75.	CSFUEL	0.4000	
67.	P72	39.00	26.89	76.	WC	0.0200	
68.	T111	256.00	397.59	77.	DATA FILE	JPPBDATA	
69.	T112	300.00	422.04				

TABLE 38. - POTASSIUM PRESSURIZED FLUIDIZED BED COMBINED CYCLE DATA (Cont'd.)

STATION NO.	P (PSIA)	T (DEG-F)	H (BTU/LB)	S (BTU/LB/DF)	X	V (FT3/LB)
1	3515.0	1050.0	1459.3	1.49544		
2	600.0	587.5	1282.0			
3	540.0	1050.0	1546.2	1.74628		
4	420.0		1511.2			
5	172.0	746.3	1399.3			
6	155.0	1050.0	1556.6	1.88903		
7	116.0		1513.8			
8	1.5	115.0	1113.8			
9	1.5	114.0	82.0			0.01618
10	3600.0	124.8	92.8			
11		138.0	114.8			
12	3600.0	406.0	385.6			
13			245.9			
14	3600.0	476.0	460.9			
15	800.0		1306.4			
16	3600.0	508.0	496.7			
17	14.7	90.0	58.0			
18	14.7	110.0	78.0			
19		78.0				
20		623.5	262.2			
21		1700.0	549.0			
22		917.5	337.4			
23		250.0	170.0			
24	800.0		509.8			
25	420.0		429.6			
26	39.0	265.7	234.6			0.01714
27	3600.0	695.9	764.8			
28		560.0	246.3			
29						
30	15.2	1400.0	1188.8	1.11437		
31	2.4		1071.2		0.88261	
32	2.4	1100.0	302.5			0.02275
33	35.0		302.6			
34	33.0	1101.0	302.7			
35	10.0		1157.4		0.96671	
36	10.0	1322.1	345.6			0.02378
37	2.4	1100.3	1078.1		0.89056	
38			345.7			
41	295.0		1464.5			
71	78.0		1459.2			
72	39.0		1374.3			
111	3600.0	256.0	232.1			
112	3600.0	300.0	276.4			
121	3600.0	359.0	336.6			
122	3600.0	329.0	305.8			
141	3600.0	439.0	420.7			
241	600.0		471.7			
251	295.0		392.3			
252	172.0		342.2			
261	78.0		280.3			
262	116.0		309.9			

TABLE 38. - POTASSIUM PRESSURIZED FLUIDIZED BED COMBINED CYCLE DATA (Cont'd.)

THE STEAM SYSTEM		STD. ENG.	S.I.
A 01	STEAM BLEED FLOW FRACTION @ STA. 15, WB15 =	0.01847	0.01847
A 02	STEAM BLEED FLOW FRACTION @ STA. 2 ... WB2 =	0.02006	0.02006
A 03	STEAM BLEED FLOW FRACTION @ STA. 4 ... WB4 =	0.01272	0.01272
A 04	STEAM BLEED FLOW FRACTION @ STA. 41, WB41 =	0.01805	0.01805
A 05	STEAM BLEED FLOW FRACTION @ STA. 5 ... WB5 =	0.01063	0.01063
A 06	STEAM BLEED FLOW FRACTION @ STA. 7 ... WB7 =	0.00919	0.00919
A 07	STEAM BLEED FLOW FRACTION @ STA. 71, WB71 =	0.01453	0.01453
A 08	STEAM BLEED FLOW FRACTION @ STA. 72, WB72 =	0.04059	0.04059
A 09	TOTAL STEAM FLOW RATE @ STA. 1 .... W1 =	3.7616E+06	4.7494E+02
A 10	HEAT ADDED TO PRIMARY STEAM .... QBOIL =	1187.3	2.7599E+06
A 11	HEAT ADDED IN FIRST REHEAT .... QRHT1 =	254.0	5.9051E+05
A 12	HEAT ADDED IN SECOND REHEAT .... QRHT2 =	144.7	3.3641E+05
A 13	HEAT REJECTED IN CONDENSER .... QCOND =	883.0	2.0525E+06
A 14	FEEDWATER PUMP WORK .... PUMP1 =	10.8505	2.5221E+04
A 15	AUX. FEEDWATER PUMP WORK .... PUMP2 =	1.9163	4.4554E+03
A 16	STEAM TURBINE OUTPUT .... WOUT =	703.6187	1.6355E+06
A 17	NET STEAM TURBINE OUTPUT .... WNET =	690.8514	1.6058E+06
A 18	STEAM SYSTEM EFFICIENCY .... ETAS =	0.4356	0.4356
A 19	STEAM HEAT RATE .... STHR =	7955.17	2329.87
A 20	STEAM ENTHALPY @ BOILER PINCH-POINT, HKSGI =	1459.46	3.3924E+06
A 21	COOLING WATER FLOW RATE .... WCOND =	1.6638E+08	2.1007E+04

THE POTASSIUM SYSTEM		STD. ENG.	S.I.
B 01	HEAT ADDED TO POTASSIUM .... QKVAP =	8.8614E+02	2.0598E+06
B 02	HEAT REJECTED TO STEAM BOILER .... QREJ =	4.1131E+09	1.2046E+09
B 03	GROSS POWER OF POTASSIUM TURBINE ... WKOUT =	6.0286E+08	1.7656E+08
B 04	POWER OF MAIN POTASSIUM PUMP .... PUMP5 =	9.1284E+05	2.6735E+05
B 05	POWER OF AUX. POTASSIUM FEED PUMP, PUMP6 =	4.4190E+01	1.2942E+01
B 06	NET POWER FROM POTASSIUM SYSTEM .... WKNET =	6.0195E+08	1.7630E+08
B 07	POTASSIUM FLOW RATE @ STA. 30 .... W30 =	5.3211E+06	6.7184E+02
B 08	POTASSIUM FLOW RATE @ STA. 31 .... W31 =	1.9505E+06	2.4627E+02
B 09	POTASSIUM BLEED FLOW RATE @ STA. 35, W35 =	3.4920E+02	4.4090E-02
B 10	POTASSIUM FLOW RATE @ STA. 37 .... W37 =	3.3702E+06	4.2553E+02
B 11	NET ELECTRIC POWER FROM K-SYSTEM ..... PMW =	173.7247	173.7247
B 12	POTASSIUM SYSTEM EFFICIENCY .... ETAK =	0.1277	0.1277

THE COMBUSTION SYSTEM		STD. ENG.	S.I.
C 01	HEAT TRANSFERRED IN FURNACE .... QADD =	4.7153E+09	1.3810E+09
C 02	COMBUSTION AIR FLOW RATE .... WAIR =	1.0197E+07	1.2875E+03
C 03	FUEL FLOW RATE .... WFUEL =	6.7301E+05	8.4974E+01
C 04	GAS ENTHALPY @ COMBUSTION .... HAIRMX =	887.50	2.0629E+06
C 05	GAS TEMP. @ COMBUSTION .... TAIRMX =	2870.37	1850.02
C 06	GAS TEMP. AFTER K-VAPORIZATION ..... TGAS2 =	1777.04	1242.62
C 07	GAS TEMP. AFTER LIQUID K-HEATING ... TGAS3 =	1698.67	1199.08
C 08	GAS TEMP. LEAVING THE FURNACE ...... TGAS4 =	1438.66	1054.63
C 09	COMBUSTION EFFICIENCY .... ETAB =	0.5888	0.5888
C 10	NET SUPERCHARGER POWER GAIN .... AMW =	276.08	276.08
C 11	FEEDWATER HEATERS FLOW FRACTION ..... FWHS =	0.41138	0.41138

OVERALL VALUES		STD. ENG.	S.I.
D 01	TOTAL CYCLE POWER .... TMW =	1170.91	1170.91
D 02	TOTAL CYCLE EFFICIENCY .... ETA =	0.49899	0.49899
D 03	SYSTEM HEAT RATE (BTU/KW-HR) ...... HTRATE =	6839.83	
D 04	PARASITIC POWER LOSS .... XMWINT =	28.89272	28.8[illegible]

TABLE 39. - ADDITIONAL NOMENCLATURE FOR REVISED CODE

ETACP	Compressor efficiency
RC	Compressor pressure ratio
ETAGT	Gas turbine efficiency
K	Ratio of gas turbine to compressor pressure ratios
P41	Steam pressure at station 41, psia (N/cm^2)
P71	Steam pressure at station 71, psia (N/cm^2)
P72	Steam pressure at station 72, psia (N/cm^2)
T111	Water temperature at station 111, °F (K)
T112	Water temperature at station 112, °F (K)
T121	Water temperature at station 121, °F (K)
T122	Water temperature at station 122, °F (K)
T141	Water temperature at station 141, °F (K)
T28	Gas temperature at station 28, °F (K)
IREAD	Program key
CFFILE	Cost factor file
CRABRV	Cost output file
A4	Furnace type indicator
CSFUEL	Cost of fuel $\$/10^6$ Btu
WC	Cooling flow fraction
DATA FILE	Name of input data file
AMW	Gas turbine output, MWe
FWHS	Fraction of feed heating by steam
HTRATE	Heat rate, Btu/Kw-hr
XMWINT	Parasitic power, MWe

REFERENCES

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