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Burns and Roe Enterprises, Inc.

Technical Report

KAZAKSTAN EXPANDED ENERGY PROGRAM

HEAT AND POWER SYSTEM EFFICIENCY IMPROVEMENTS

ERMAKOVSKAYA & EKIBASTUZ PLANTS

FINAL REPORTS

December 1995

Prepared by: Burns and Roe Enterprises, Inc.

Submitted to: U.S. Agency for International Development
The Government of Kazakstan

Contract No. : CCN-0002-Q-09-3154-00
Heat and Power System Efficiency Improvements
Delivery Order No.9, Task 2

Burns and Roe Company
800 Kinderkamack Road, Oradell, New Jersey 07649
(201) 265-2000 Telecopier (201) 986-4459 Telex 215058 Cable BURNS ROE ORA

January 19, 1996

Mr. Iqbal Chaudhry
Energy Officer
U.S. Agency for International Development
AID/EEUD/E&I/EI
Room 440 - NS, Department of State
320 21st Street NW
Washington, D.C. 20523

Subject: Kazakstan - Final Report
Expanded Energy Program
Heat and Power System Efficiency Improvements
Ermakovskaya and Ekibastuz Plants

Dear Mr. Chaudhry:

In January 1995, Burns and Roe started a study in Kazakstan to determine Heat and Power Plant Efficiency Improvements. Four plants were selected for the study by Kazakstan's Ministry of Energy and Coal, and Kazakstanenergo, namely:

Ermakovskaya in Pavlodar, block 3
Ekibastuz #1, block 3
Karaganda #2, block 3
Ust - Kamenogorsk, block 7

This final report submittal covers Ermakovskaya and Ekibastuz plants. Karaganda and Ust-Kamenogorsk final reports will be issued on January 26, 1996.

Enclosed please find 3 copies of the subject report. Also, a copy of the report is being forwarded to Mr. Barry Primm, USAID Almaty Mission.

All comments generated by USAID (Almaty Mission and Rolf Manfred) and Kazakstan's Ministry of Energy and Coal, and Kazakstanenergo have been incorporated into the final edition.

In addition, please be advised that the subject report has been translated to Russian and it is also being distributed in Almaty to the Ministry of Energy and Coal and Kazakstanenergo.

Please let me know if you have any questions.

Sincerely,

N. Popovic
Project Director

cc: All w/att
G. Weynand, USAID
B. Primm, USAID, Almaty
S. Gerges, Burns and Roe

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KAZAKSTAN EXPANDED ENERGY PROGRAM

TASK 2

HEAT AND POWER SYSTEM EFFICIENCY IMPROVEMENT

ERMAKOVSKAYA POWER PLANT

ABBREVIATIONS

CIS	Community of Independent States
USAID	U.S. Agency for International Development
CCE	Capital Cost Estimate
CHP	Combined Heat and Power
TES	Thermal Electric Station
LHV	Lower Heating Value
OD	Outside Diameter
PA	Primary Air
PC	Pulverized Coal
NDE	Non Destructive Examination
HP	High Pressure
IP	Intermediate Pressure
LP	Low Pressure
NO_x	Nitrogen Oxides
SO_2	Sulfur Dioxide
ESP	Electrostatic Precipitators
I&C	Instrumentation and Controls
OFA	Overfire air or bulk furnace air staging
LNB	Low NO_x burner
VM	Volatile matter
FC	Fixed carbon
HGI	Hardgrove Grindability Index, HGI = (K_{po} -0.32)/0.0149

WEIGHTS AND MEASURES

at abs. or g	atmosphere absolute or gage
Gcal	Gigacalorie (10^9 cal)
MW	Megawatt (10^6 Watt)
kW	kilowatt (10^3 Watt)
kg	kilogram
kV	kilovolt
kWh	kiloWatt hour
MVAR	Megavolt-Ampere Reactive
kg/cm^2	kilograms per square centimeter
t/h or te/h	tons per hour
RPM	Rotations per minute
BTU	British Thermal Unit
MMBTU	Million BTU heat input

CONVERSION FACTORS

1 GCal = 4.187 GJ = 3.968 x 10^6 BTU = 1,163 kWh

ERMAKOVSKAYA PLANT

1.0 INTRODUCTION AND OBJECTIVE

The dissolution of the Soviet Union in 1991 resulted in the formation of five new independent republics in Central Asia: Kazakstan, Kyrgyzstan, Uzbekistan, Turkmenistan and Tajikistan. Of these, Kazakstan is the largest republic in terms of physical size and second largest in population. Its physical size (area) is more than the area of the other four republics combined.

Kazakstan is a vast country with an abundance of valuable resources, including abundant energy reserves and a large industrial base. Unfortunately, the collapse of the former Soviet Union has resulted in economic dislocations throughout the central Asian republics including Kazakstan. The transition from a command economy to a market economy has been painful to the population. Industries which are no longer subsidized and protected by the former Soviet Union must be able to survive in a more competitive market place. This has resulted in a severe economic recession. The current economic recession has adversely affected the country's economy, including the slowdown in the energy industries.

The majority of the thermal and heating plants in Kazakstan are over 20 years old and are operating with obsolete equipment or with components requiring renovation. Maintenance schedules do not allow for high availability of the units. In addition, many plants are obliged to fire non-design fuel (e.g. coal with ash content exceeding the maximum design specification). These problems combine to decrease power and heat production levels by as much as 20-40% from the design capacities. The impact of the reduced power production has been moderated in the past few years by a decrease in demand due to industrial recession. Reduced heat production often results in domestic heating black-outs.

The shortfall in energy production will continue if the plants are not rehabilitated in the future; and as Kazakstan grows into a market-led economy, the demand will accelerate and lack of available energy will, potentially, become the limiting factor in the economic development of the country.

Increasing the efficiency of existing plants, extending their life and implementing a consumer energy saving program are the most cost effective means for increasing energy independence. However, the necessary renovation and maintenance costs are large. A plan for a consumer energy savings program is being developed separately by a joint effort of the Ministries of Economy and the Ministry of Energy and Coal. This separate effort is also supported by USAID.

USAID has recognized the seriousness of these problems, and has authorized this task for Burns and Roe to assess the situation relative to Heat and Power Plant Efficiency Improvements. The work covered by this report addresses the assessment of selected units at four different locations in Kazakstan. The Erkamovskaya Electric Generation (Power) Plant, Block No. 3 is one of the selected plants for energy efficiency improvements study.

The objective of this project is to assess the costs and benefits of the efficiency and energy production improvements which can be achieved by renovating and extending the life of the selected units. The effect of improving the quality of the coal on plant performance was also determined and is included in Appendix I. This report may serve as a basis for domestic and foreign investment considerations.

The work covered by this report included the following tasks:

- Background data related to the project was collected and analyzed. Meetings were held with Kazakstani engineers to discuss the collected data.

- A condition assessment was performed to identify the major plant systems and components which require rehabilitation or modernization.

- An engineering analysis was performed to recommend state-of-the-art technology for increasing the availability and performance of the selected units. These analyses also include development of capital cost estimates and implementation schedules.

- A detailed rehabilitation and modernization program is outlined and recommendations are made for life extension of the unit. The effect of coal quality improvement on increased plant performance is also included.

- The results of the engineering analysis will be reviewed with Kazakstani authorities. The Kazakstani authorities may extrapolate the results of this analysis to other fossil plants in the country.

2.0 KAZAKSTAN ENERGY SECTOR STRATEGY

The Kazakstan Power System currently consists of 64 electric power stations with a total capacity of 16,026 MWe. These 64 plants include 40 Thermal Electric Power Stations (TES), with a capacity of 13,897 MWe. The other 24 plants are electric generating stations and hydroelectric power stations. The TES units provide district heat or process steam to the industries in addition to electric power generation whereas the remaining 24 plants only provide electric power. The main fuel used in these plants is coal. A breakdown of the fuel usage is shown below:

Fuel	Percent
Coal	74.3%
Petroleum (Oil, etc.)	12.2%
Natural Gas	14.5%

The main goals of Kazakstan Energo, as determined by the Ministry of Energy and Fuel Resources are:

1. To refurbish the current power plants operating in Kazakstan to improve their efficiency, reliability, and reduce emissions to the environment.

2. To commission new generating facilities with environmental controls to meet the future shortfall in production capacities.

3. To institute energy savings and conservation programs for consumers of heat and electricity.

4. To upgrade the current power plants with state of the art technology.

5. To gradually bring the prices of heat and electricity up to the current world price levels in a transition to a market based economy.

6. To develop a new management structure for the power, heat generation, and distribution industry.

Kazakstan currently imports electricity from Russia and other central Asian countries. In 1992, Kazakstan imported 14 billion kWh of electricity. The gap between demand and installed capacity is approximately 2,000 MW. Thus, there is a great need to install new generating capacity and to refurbish the existing plants. Over the next 20 years, Kazakstan plans to create a reserve capacity of approximately 20 to 25 percent.

During this period of upgrading and installing new capacities, a major focus will be placed on environmental issues and energy conservation. As new legislation is enacted to help preserve the environment, the power sector must upgrade its environmental control equipment at heat and power generating stations. Installation of NO_x and SO_2 reducing technologies and improved ash collection equipment will be required on all new and refurbished power plants.

The amount of pollutants released into the atmosphere can also be reduced by instituting energy conservation programs as these programs would result in curtailing energy demand and hence energy production. These programs could consist of gradual increase in tariffs on electric and thermal energy, sanctions on the irrational use of energy resources, incentives to utilities that conserve energy, and installation of more energy efficient appliances and industrial processes. Another benefit of energy conservation program is the decreased demand for new energy production capacities which will defer the capital investment for construction of new facilities into the future. This will result in substantial financial benefit to the power generation industry in Kazakstan.

3.0 BLOCK NO. 3 EQUIPMENT DESCRIPTIONS AND EVALUATIONS

3.1 STEAM BOILERS DESCRIPTION AND EVALUATION

Block No. 3 consists of a supercritical steam pressure 300 MW_e turbine generator with double block boilers. The boilers are the once through type (OT), with the designation PP-950-255-2K (P-39-2) of the "T" type configuration and manufactured by the Podolsk Machine Building Co. The total main steam flow from the block is 950 te/h and the total reheat steam flow is 760 te/h. The corresponding temperatures for main and reheat steam are 545°C, with a main steam pressure of 255 at abs. The economizer receives feed water at a temperature of 265°C. The boilers have opposed wall horizontal swirl type burners and a balanced draft, dry bottom furnace.

The table below shows the design and current operating parameters of the boilers:

Parameter	Units	Design	Current	
		For Both Boilers	Boiler 3A	Boiler 3B
Main steam flowrate, total	te/h	950	432	411
Main steam pressure	at.abs.	255	238	238
Main steam temperature	°C	545	542	542
Reheat steam flow, total	te/h	760		
Reheat steam pressure	at.abs	40		
Reheat steam temperature	°C	545		
Feedwater temp. to economizer	°C	265	214	214
Comb. air temp. to main airheater	°C	30	31	31
Comb. air temp. lvg. main airheater	°C	331	295	295
Fluegas temp. lvg. main airheater	°C	130	150	150
Boiler efficiency, LHV basis	%	91.8	88.65	80.95

The Block 3 boilers have over 150,000 operating hours. They are experiencing a higher than normal frequency of tube ruptures and other problems.

The boilers and their auxiliaries present serious problems. Because of the deteriorated condition of the boilers, an insufficient quantity of steam is generated. Therefore, the units are operated with the top heaters out of service so that the steam which should be extracted for the heaters may be retained in the turbines to provide additional generation. This mode of operation results in lower turbine cycle efficiencies.

Steaming Rate

Perhaps the most important issue regarding the boilers is steam generation rates. Currently, the two Block 3 boilers are unable to produce their Maximum Continuous Rating (MCR) capacity. There are several problems which are working together to cause this situation. These are discussed below:

a) Coal Quality

The quality of the coal being provided by the mines at Ekibastuz is now typically poorer than originally anticipated by the design. Coal mineral matter percentages are higher; therefore, percentages of fixed carbon, volatile matter and coal heating values are lower. This means more coal must be pulverized to meet the energy needs of the boilers, and more combustion air is needed to assure complete combustion. Unfortunately, more pulverized coal is needed than the hammer mills can provide, and more air is needed than the fans can handle, limiting boiler output. Increased convective pass fluegas velocities, and increased fluegas flyash content result in increased tubing erosion metal loss.

b) Unburned Fuel in Ash

Obviously, the amount of unburned coal in the ash from a coal-fired boiler should be minimal. Coal in the ash is coal which costs the utility money but produces nothing of value. Based on discussions with the plant engineers at Ermakovskaya, the ash there typically contains about 4 or 5% unburned carbon. This translates directly into a heat loss impact on boiler efficiency. With the coal mills failing to meet the needs of the boiler, this unburned coal also leads to a reduction in MW output.

c) Air Infiltration

The unmeasured air which leaks in through worn seals on the fans and air heaters, and through corrosion/erosion induced holes in the boiler setting has a profound effect on the thermal performance of the boiler. The air which leaks in does not contribute to the combustion process because it does not pass through the burners. This infiltration air contributes very little to the processes taking place in the boiler, but absorbs considerable heat as it is heated from near ambient to a much higher fluegas temperature. The infiltration air also adversely affects I.D. fan performance. The fans have a fixed amount of drive motor power available to deliver flue gas up the stack. Power expended moving infiltration air is not available to move flue gas.

d) **Boiler Pressure**

Boiler main steam pressure is deficient. This adversely affects steam turbine output and heat rate.

e) **Boiler Slagging**

Uncontrollable furnace tubewall slagging deposits due to lack of or inadequate number of furnace wall blowers, increased coal mineral matter content, too high furnace burner zone heat release rates, unequal fuel and air distribution between burners.

All of the above-described problems work together to reduce the overall boiler efficiency and to reduce the boiler steam output to the steam turbine. Although this situation can be partially corrected by repairing the air-infiltration leaks, the other problems must also be addressed. More mill capacity can improve pulverized coal fineness (reducing unburned fuel in the ash) and also assure that adequate fuel quantities are prepared to meet the boilers' needs. Replacing the existing bare tubing with extended surface primary superheater and economizer tube banks (kept clean with adequate sootblowers) will improve heat transfer performance of these heating surfaces. Hopefully, all these measures can work together to provide an adequate steaming rate.

Availability

Ermakovskaya, Block 3 has been in operation for well over 150,000 hours, and is beginning to show signs of age-induced deterioration (in the form of outages due to failure of boiler pressure parts). Those areas where operating experience suggests possible degradation due to low cycle fatigue, creep etc., should be subjected to NDE to identify specific areas needing further attention. Repairs should be accomplished, where necessary, or replacements, if required.

Coal Pulverizers

The coal for the plant is mined at Ekibastuz and shipped to the Ermakovskaya plant at Pavlodar via trains. Even when Ermakovskaya was first put in operation, the coal from the Ekibastuz region was not of a very high quality. Over the years of operation, the coal provided to the Ermakovskaya plant from Ekibastuz has diminished in quality. Ash content has increased and heating values have fallen. At the same time, air infiltration into the boiler setting has reduced the boiler efficiency. The leakage is through cracks in the boiler casing caused by expansion and contraction, openings in the casing caused by sulfuric acid corrosion and abrasive coal ash erosion, leaks in the casing penetrations, leakage in the airheater seals, etc. All of these factors make it necessary to burn more coal to achieve the same steaming rate. Unfortunately as the delivery of more coal to the boiler is limited by the capacity of the currently installed pulverizers, replacement of these pulverizers is required. The existing four high speed horizontal shaft hammer mills per boiler should be replaced with four new larger medium speed vertical shaft roller mill pulverizers with integral dynamic (rotating) classifiers for improved pulverized coal fineness. This will make it necessary to remove the existing hammer mills and associated equipment.

This modified arrangement would be sized to provide one spare pulverizer to permit on-line maintenance, and would increase coal flow with 3-mill operation to achieve full load steaming capacity, even with the low quality coal now delivered from the mine.

Forced Draft (FD) and Induced Draft (ID) Fans (one each per boiler)

There is insufficient FD and ID fan capacity due to serious leakage in the air and fluegas equipment and ductwork. Even with the leakage controlled to reasonable levels, the poor quality of the coal requires more combustion air to be sent to the burners (Leakage air does not pass through the burners). Finally, the pollution control equipment which must be used to control the emissions of atmospheric pollutants will affect the draft loss through the ductwork and equipment, which must be overcome by the ID fans. This pollution control equipment will be selected later, so the ID fan requirements have not yet been established. To be safe, all fans should be performance tested and the results compared to the performance needed when the pollution control equipment is installed. Then the decision can be made to either refurbish or replace the fans. In the interim, the cost of refurbishment, foundation skids, etc. will be recommended for addition to the budget for the FD fans. The cost of replacement will be added for the ID fans when the fan requirement is established.

Heating Surfaces/Wall Blowers and Sootblowers

Since it is currently not possible to achieve Maximum Continuous Rating (MCR) due to the various problems, attention should be directed toward increasing heat transfer to achieve higher,design-rated steaming rates and higher,design-rated superheat and reheat temperatures. To achieve this, extended surface primary superheater and economizer tube banks should be retrofitted with in-line centers, replacing the existing bare tube banks on staggered centers. The extended surface tubing will maintain the effective surface and heat transfer, but may also increase the possibility of fouling.

The Ekibastuz coal has a relatively abrasive ash. Because of this, the existing boilers may be operated without sootblowers in the convection passes. One boiler has sootblowers. The 3b boiler also has wall blowers for removing slag in the furnaces. With the retrofit of extended surfaces in the convection passes, it will be necessary to add sootblowers to the convection passes of both boilers to avoid fouling of the extended surfaces. This is particularly important with the high ash of the Ekibastuz coals. A full complement of wall and sootblowers will need to be installed on boiler 3a.

Furnace Ash Hopper Tubing

The horizontal tubing in the Block 3 boiler furnaces hopper walls should be replaced with vertical tubing to improve ash and slag evacuation, and to improve resistance to slag falls.

It is understood that the Plant is replacing the horizontal circuits of the Block 2 furnace tubehopper walls with vertical circuits.

Low NO_x Burners and Overfire Air

Although the environmental assessment will be done later, it is almost certain that low NO_x burners with or without overfire air ports will be a part of the planned boiler emission control program. The spacing of the retrofit burners may have to be increased so as to reduce the burner zone heat release rate and consequently the furnace slagging deposits.

Tube Penetration Seals

The current condition of the tube penetration seals is unsatisfactory. Tube penetration seals of furnace and backpass roof tubes, and in backpass tube banks for superheaters, reheaters, and economizers are leaking and permitting air infiltration.

Air Heaters

Refurbish and repair rotary, regenerative, bi-sector vertical shaft air heaters two per boiler, including radial and circumferential seals, cold end sectors of rotors, sootblowers, etc. as required.

Condition Assessment of Pressure Parts

A boiler condition assessment should be done on furnace, SH, RH tubing and water/steam-cooled thick-walled pressure parts; i.e., headers, desuperheater piping, integral piping etc.

One of the sources of boiler unavailability is frequent furnace tube ruptures (156 in 1993, 177 in 1994 for the total of 16 boilers). Also the two boilers of unit 3 have average operating periods in excess of 150,000 hours, each. Thus a non-destructive (ND) examination of the pressure parts of one of the two boilers of Block 3 appears warranted. Following a review of the findings, remedial action should be undertaken.

Furnace and Boiler Setting

Setting leaks are a major problem. Air infiltration is impacting on fan capability, boiler efficiency, and unit peak capacity. Consequently, setting refurbishment is a priority item. This would include the refurbishment of the following on each boiler:

> Boiler refractory, insulation, casing (BRIC) refurbishing as needed, of furnace vertical walls, tube hopper slopes, furnace and backpass roof, two symmetrical backpasses walls, boiler outlet fluegas ducts and flyash hoppers.

Certain routine maintenance activities, including routine repairs and replacements, replenishment of lubricants,etc., are stipulated. These items should be accomplished in good order, and on schedule or as soon after as is possible.

Unequal fuel and combustion air distribution between burners

Both the primary air/pulverized coal (PA/PC) as well as the secondary air maldistribution between individual burners will have to be improved to (a) eliminate local reducing atmosphere furnace conditions and resulting slag type deposits and (b) to reduce unburnts in ash and increased carbon monoxide production. These requirements take on added importance with the retrofit of LNBs.

3.2 STEAM TURBINE GENERATORS

General

Many problems with the turbines and auxiliaries have been identified from discussions with plant personnel, and from review of documentation received. These problems have resulted in an increase in Block heat rate, higher operating costs, increased unscheduled outages and lost generation due to equipment failure. Some of the problems will require increased future inspections and deficiency corrections of internal and external components of the turbine, which will result in Block outage time and increased maintenance expenses.

The eight steam turbines at the Ermakovskaya power plant have a combined design capacity of 2400 MW. However, the total working output for the plant at the time of the Burns and Roe team visit was only 1550 MW. This was mainly due to the problems with the quality of coal burned and the air inleakages described under paragraph 3.1. However it was noted that with relatively "good coal", the mineral matter content of which does not exceed 40%, a total gross generating output of 2160 MW can be achieved. The maximum steam generating capability of the steam boilers with such a coal and the corresponding maximum power output of the eight turbines are shown in Table 3-1.

TABLE 3-1

MAXIMUM CURRENT GENERATING CAPABILITY OF THE ERMAKOVSKAYA UNITS

Block No.	1	2	3	4	5	6	7	8
Steam Flow (t/h)	700	800	970	960	1000	1000	980	980
Turbine Output (MW)	210	240	280	260	300	300	280	290
No. of Oper. Hrs. to 1/1/95	175,075	170,326	169,462	165,954	150,522	151,869	149,094	145,310

The operating data for the plant collected for the year 1994 indicates that the plant output is at its maximum during the winter months. The total electrical generation, the peak loads, and the monthly average loads supported by the plant during 1994 are shown in Table 3-2.

TABLE 3-2

SEASONAL GENERATION AND LOADS FOR ERMAKOVSKAYA (1994)

MONTH	AVERAGE LOAD (MW)	PEAK LOAD (MW)	GENERATION (10^3 kWh)
January	1844	2080	1281564
February	1969	2070	1182982
March	1708	1965	1133058
April	1456	1770	960321
May	1485	1770	998237
June	1275	1535	830887
July	1230	1430	800434
August	1507	1780	984591
September	1151	1550	774441

October	1493	1505	785665
November	1752	1875	907926
December	1604	1880	1125899

From the above table, it can be seen that the average 1994 load on the plant was 1539.5 MW. Plant personnel indicated that the expected average output from the plant through the year 2005 is estimated at 1900 MW due to the reconstruction of the various power blocks.

The reconstruction plan includes rehabilitating the units in the following order: Blocks 2, 3, 4, 1, 5, 6, 7, 8. Reconstruction of all units is expected to be completed by the year 2016.

Because of block 2 and block 3 were the first units to be rehabilitated it was decided to examine these units in detail. Since the reconstruction plan has already been developed for block 2 Burns and Roe has reviewed it as to its appropriateness but more significant effort was made to evaluate block 3 and to develop recommendations for its reconstruction.

Description of Turbines

The Ermakovskaya block 2 and 3 turbines are nominal 300 MW, 3000 rpm, single reheat, tandem compound condensing machines, designed to receive 977 te/h of supercritical throttle steam at a pressure of 232 at abs. and temperature of 540°C at normal full load operation. There are three separate turbine elements on a single shaft; one single flow high pressure (HP) section, one single flow intermediate pressure/low pressure (IP/LP) section, and one double flow low pressure (LP) section. A cross sectional drawing for the turbine is shown in Figure 3-1.

The number of stages in the turbine are 11 in the HP section, 12 in the IP/LP section and 5 in each half of the double flow LP section. Interstage steam sealing strips are provided to minimize bypass of steam around rotor blades and diaphragm nozzles.

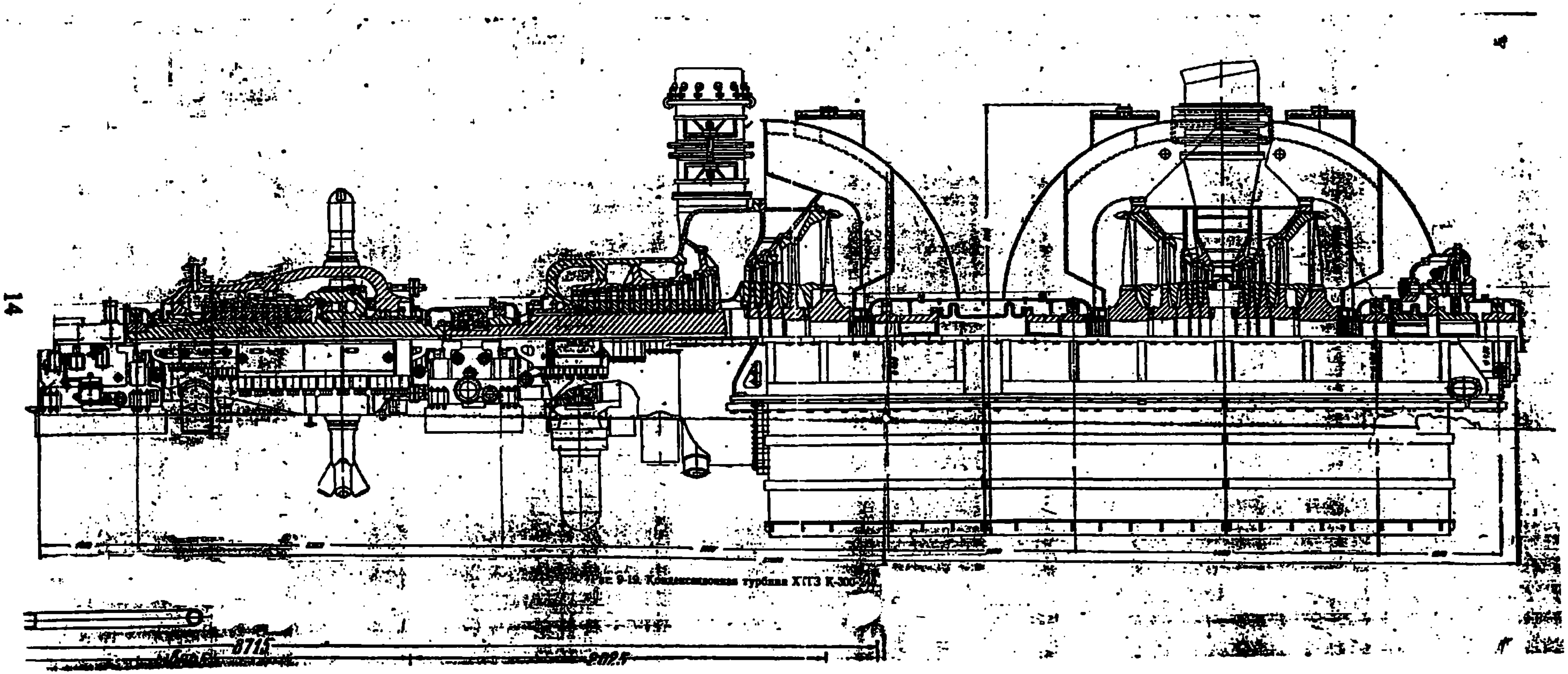
Exhaust steam from the HP turbine is passed through the reheater in the boiler, and returned to the IP/LP section of the turbine. After passing through the IP section stages, some of the steam continues through the LP stages of the IP/LP section of the turbine. The remaining steam is distributed to the double flow LP section of the turbine via cross-over pipes.

Steam is extracted from nine stages of the turbine, and directed to six stages of low pressure feedwater heating, three stages of high pressure feedwater heating, a feedwater pump turbine, and deaerator. The thermal cycle diagram for the existing steam turbine is shown in Figure 3-2.

Exhaust steam from the LP sections of the turbine is condensed at approximately 0.0374 at abs. in a two pass shell-and-tube surface condenser, located under the LP turbine.

Condensate from the condenser is heated through nine stages of feedwater heating and is delivered to the boiler at the rate of 977 te/h and a temperature of 276°C.

Figure 3-1 Cross Section of Turbine



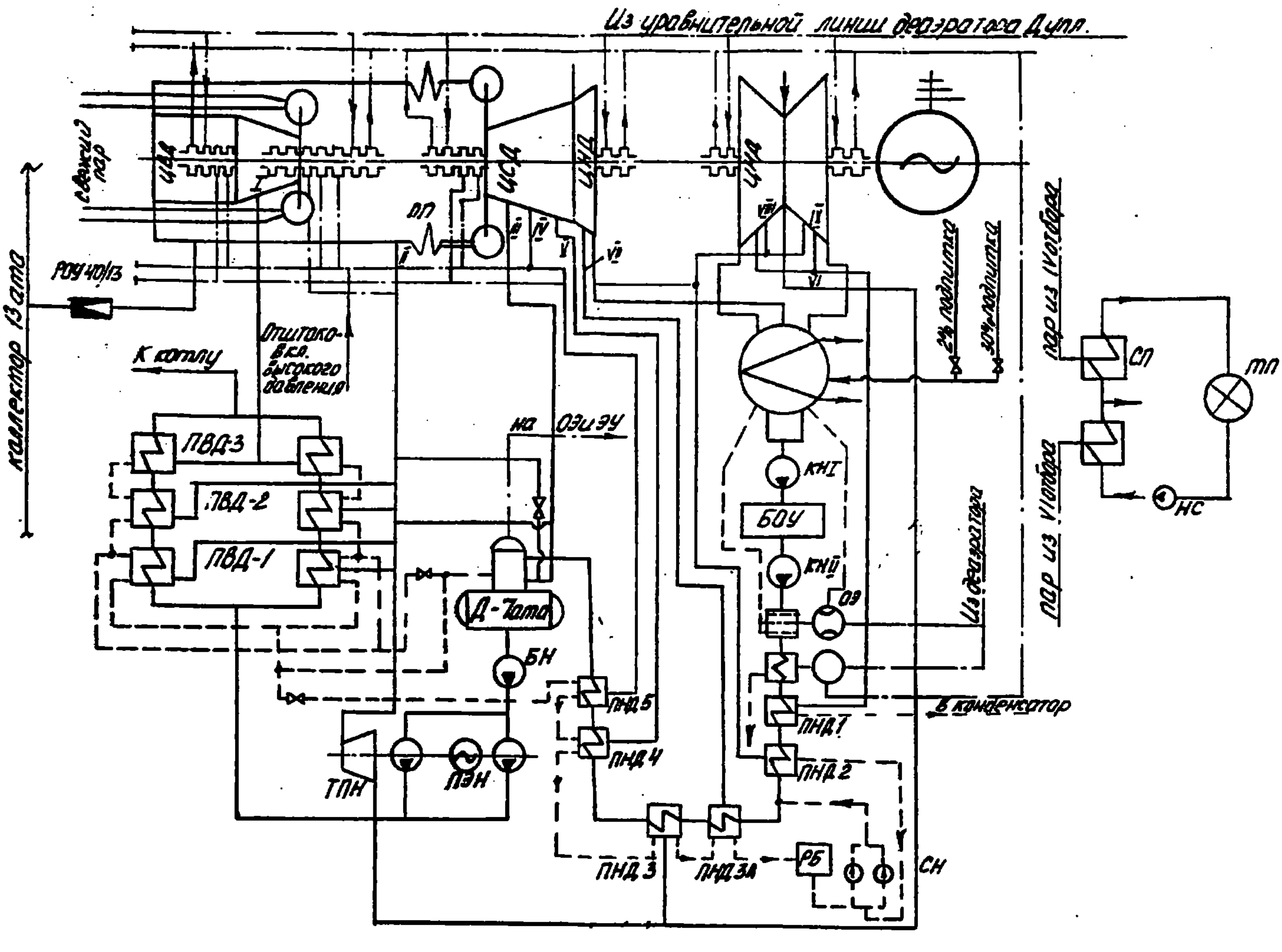


Figure 3-2 Thermal Cycle Diagram

Design/Current Performance of Block 3

The K-300-240 steam turbines used at the Ermakovskaya power plant were originally designed for the conditions shown in the first column of Table 3-3. This column indicates that the original main steam and hot reheat steam temperatures were 560 and 565°C, respectively. Because of the various problems from the effect of using these high temperatures in critical thick walled pressure components (steam generator headers, HP/IP turbine shells, etc.) the then Soviet regulatory agency officially lowered the main steam and hot reheat steam temperatures to 540/540°C. This change is reflected in the second column of Table 3-3.

TABLE 3-3

TECHNICAL CHARACTERISTICS OF THE STEAM TURBINE

	Original Design	Modified Conditions
Type	K-300-240	K-300-240
Nominal Output, MW	300	300
Main Steam Pressure, kg/cm^2(a)	240	240
Main Steam Temperature, °C	560	540
Hot Reheat Temperature, °C	565	540
Maximum Output, MW	320	300
Main Steam Flow at above Output, t/h	950	940
Number of Extractions	9	9
Extraction Configuration	3HPH+D+6LPH	3HPH+D+6LPH
Condenser Pressure, kg/cm^2(a)	0.035	0.035
Specific Heat Consumption kcal/kWh	1830	1955
Turbine Manufacturer	Kharkov	Kharkov
Overall Length of T-G, m	35.8	35.8
Number of Turbine Bearings	5	5
Generator Model	TVG-300	TVG-300
Generator Cooling Medium	H_2	H_2

Even though the unit has operated during the last 24 years with these lower steam conditions the specific heat consumption (heat rate) of the turbine has degraded significantly due to various reasons. Operating data for the year 1994 obtained from the plant for all blocks indicates that the Block 3 steam turbine was running for a period of 5317 hours, with average monthly load varying between 172 MW and 231 MW. During the months of August and September Block 3 was not utilized. In addition the actual operating data indicated that the average heat rate of the unit varied between 1943 and 2604 kcal/kWh. Block 3 heat rate at the time of our visit was about 2240 kcal/kWh.

In order to establish the actual current degradation of the turbine heat rate and to see how close the above stated heat rate can be substantiated, Burns and Roe has performed calculations based on the available efficiency data and operating mode for Block 3. Although official performance test data was not available for Turbine No. 3, such a test was recently conducted on Block No. 4. Since these units are similar to one another, and have been subject to the same operating and maintenance conditions, their condition should be similar, with the following exceptions:

> Block No. 3 Turbine has the lowest HP and IP efficiency of all turbines and has been running with the second stage blades removed in the LP section.
>
> Block No. 3 has been running with one string of high pressure feedwater heaters out of service.

The actual HP and IP turbine efficiency figures determined by the plant personnel as of January 1, 1995 for the various steam turbine units are shown in Table 3-4.

Utilizing the differences between the design and actual internal efficiencies and assuming an average efficiency degradation for the LP section to be between those of the HP and IP section, the degradation of heat rate within each of the three turbine sections was calculated. This required first the calculation of the portion of the electric output generated in the individual turbine sections. The percent efficiency degradation multiplied by the work done in the corresponding turbine section were added up and applied to the modified heat rate of 1955 kcal/kWh. This methodology of calculating the actual heat rate was also used to the results and data of the Block 4 performance testing to serve as a check of the appropriateness of the calculation, and a good correlation was found.

TABLE 3-4

TURBINE STEAM FLOW PATH EFFICIENCIES
(As of January 1, 1995)

Turbine Block	HP Efficiency		IP Efficiency	
	Actual	Normative	Actual	Normative
#1	72.7	75.0	83.8	90.0
#2	70.6	75.6	75.7	89.0
#3	69.9	73.0	74.7	89.6
#4	72.0	80.0	82.9	89.0
#5	75.8	79.2	86.3	89.0
#6	N/A	N/A	N/A	N/A
#7	74.0	79.0	85.9	89.5
#8	72.8	80.0	85.4	89.5

Finally, the effect of operating the block 3 turbine with a closed-out string of high pressure feedwater heaters was factored in resulting in a further degradation of heat rate. Combination of all the above conditions resulted in a degraded current heat rate of 2222 kcal/kWh.

Based on the obtained figure the heat rate was found to be degraded by

$$\frac{2222 - 1955}{1955} \times 100 = 13.6\%$$

if the modified heat rate of 1955 kcal/kWh (shown in Table 3-3 is used as a base. However, based on the original design heat rate of 1830 kcal/kWh the current heat rate degradation of the block 3 turbine is 392 kcal/kWh or

$$\frac{2222 - 1830}{1830} \times 100 = 21.4\%$$

As far as the turbine output is concerned it was reported that the maximum output that can be obtained from the block 3 steam turbine is 280 MW. The closing out of one high pressure feedwater heater results in a power increase of about 20 MW. The 280 MW output is only possible when the main steam flow to the turbine is about 976 t/h.

Condition Assessment

a) Block 3 Problems

Many problems with turbines and auxiliaries have been identified from discussion with plant personnel, and from review of documentation received. Some of these problems have resulted in an increase in block heat rate, which in turn results in higher operating costs. Other problems increase the probability of unscheduled outages resulting in lost generation due to equipment failure. Some of the problems will require increased future inspections and deficiency corrections of internal and external components of the turbine, which will require unit outage time and result in increased maintenance expenses. Significant problems, which have been identified relative to Number 3 turbine and auxiliaries, are outlined below:

Turbine Steam Path/Blading

As it can be seen from the efficiencies shown in Table 3-4, the components of the steam path in block 3 have significantly deteriorated. The causes of the deterioration are simply wear due to age, but also the result of moisture erosion of the last stage blades, solid particle erosion of the first stage blades, as well as some problems due to water induction. The following significant failures of turbine blades were reported on block 3:

- Failure of the 3rd stage blades in October, 1986. These blades were replaced.
- Failure of 2nd stage blade in the low pressure section in November, 1992. The turbine has been operated without 2nd stage blades for two years.
- Failure of two blades in the 4th stage in January, 1994.
- Solid particle erosion on first stage blades.
- Considerable erosion problem on last stage blades, requiring repair approximately every 6 to 8 years.

A 5 mm buildup of solid particles in the first stage of was reported. Attempts were made to remove the deposits by reducing the load to 60 MW and running the turbine at reduced steam conditions of 60 kg/cm^2 and 300-310°C for about 6-8 hours. In the past (before 1986), this operation had to be performed once or twice a year. In 1986 the plant changed to oxygenated water chemistry which improved this situation. Now similar operation is still performed but less frequently, only about once or twice in four years. The first stage blades had to be changed once (this is also true for block 2, 5 and 7).

The last stage blades (1050 mm long) repeatedly erode requiring replacement every 6-8 years. The last stage blade shroud is also frequently breaking causing additional shaft vibration, and damage to condenser tubes. In addition to the above, a decrease in efficiency originates from the increased interstage leakages within the turbine due to wear. Furthermore the gland steam leakage from the labyrinth seals was reported to be twice than that of the original design values.

Water Induction

It was reported that Block 3 had water induction incidents originating from LP Heater No. 2 at the 8th extraction point. After the incident a valve was installed in the extraction line. This water induction incident caused failure of the blades in the 3rd stage of the Low Pressure Turbine. Presently, Extraction No. 9 appears to be the only extraction to contain no automatically actuated valves for protection against water induction into the turbine, and the serious damage which could be inflicted on the turbine in such an event. All other extraction steam lines have non-return and isolation valves installed.

Turbine Thrust Bearing

The thrust bearing consists of eight Babbited metal segments, and its condition is significantly deteriorated. Part of the problem may have been caused by the high pressure differential between stages of the turbine due to the water induction. However, the deterioration is mainly due to shell misalignment problems which causes excessive rubbing between the contact points for the segment supports which actually became essentially flat surfaces. This causes increases both in temperature and turbine vibration. The thrust bearing should have been replaced but unfortunately replacement parts are not readily available.

Turbine Support and Alignment

There are serious alignment problems associated with the No. 3 turbine. During turbine start-up, misalignment of the turbine shells at the support between the HP and IP sections causes failure of the labyrinth steam seals and bearing oil seals, thereby increasing leakage across the seals. Leaking oil flows out onto the floor. Because of the close proximity of the bearing glands to the turbine glands, condensate is easily cross-contaminated with oil. The problem soon reappears even after a startup following a major overhaul. This problem also exists with Block 2 turbine.

Turbine Control and Monitoring Equipment

A large percentage of the 11 breakdowns of the block 3 turbine in 1994 (Block 2 had only 6 breakdowns) were due to problems at the valves in the control systems of the turbine as well as vibration problems. The steam turbine regulating valves often had failures at the valve stems, operators and bushings. A slow closure of a regulating valve on the Block 1 steam turbine once caused a catastrophic accident overspeeding and throwing the turbine apart, requiring a complete replacement of the unit. The automatic regulation system and instrumentation on Blocks 2, 3, 4, 7 and 8 have not been replaced since each of these units were put into operation.

The instrumentation on turbine protection and monitoring is outdated, worn, and requires replacement. The existing vibration instrument measures in three directions (horizontal, vertical, axial), however the vibration equipment does not provide exact vibration figures at the bearing surface. The units RPM monitoring equipment does not provide reliable monitoring during startup. In addition the unit has no turbine stress evaluator (TSE) equipment and no life consumption curves exist for the unit. Turbine starts are based on manual operation and procedures based on the following startup metal temperature classification:

Cold start < 150°C
Warm start < 350 > 150°C
Hot start > 350°C

Metal temperature increases do not exceed rates between 100-150°C/hr. Observation point for metal temperatures are at the top and bottom of the cylinders (heavy wall thickness turbine components) and at various points at the flange connections at the turbine horizontal joints.

b) Metal Control

The metal control laboratory personnel has been interviewed to assess the procedures and equipment the plant has to control metal conditions. In general the plant has quite a large array of non-destructive examination (NDE) and destructive examination (DE) equipment for the testing and inspection of the turbine, steam generator, and main steam piping components. These equipment include the following:

MIR-2 X-ray impulse apparatus
UD-2-12 Ultrasonic flaw detector
UDM-1M Ultrasonic flaw detector
MD-10C Magnetic flaw detector
DMI-ChM Magnetic particle defectoscopy instrument
VDL-3M Eddy-current flaw detector
VDBK-1 Eddy-current flaw detector
VD-5M Eddy-current flaw detector
VPI Hardness tester
CLU Portable Steeloscope
TIC-3, TIC-101, UT-93P Thickness Gages
R-50 Tensile-testing machine
I05003-0.3 Pendulum hammer
TK-2 Rockwell hardness tester
TS-2M Brinell hardness tester
TKC-1M Super Rockwell hardness tester
M1M-7 Metallographic microscope
MBC-9 Biological microscope
"SPECTR" Stationary steeloscope

"Belarus-2" Photographical magnifying apparatus
Grinding-polishing machine

As far as the steam turbines are concerned the plant personnel indicated that visual and magnetic particle testing are carried out on the main castings and steam pipes and valves. This usually occurs every 4 years during the turbine overhaul periods. These tests are done on the turbine HP and IP shells and valve bodies to detect and/or observe cracks and cavities. In addition, ultrasonic testing of the turbine blades are carried out. The turbine nozzle boxes are examined visually. Visual inspections of these areas may also be performed during intermediate repairs.

Periodic NDE examinations, utilizing the magnetic particle method, performed on the Block 3 turbine every four years since 1978, indicated that a very large number of cracks were found in various components of the turbine as follows:

Examination performed in 1978: 73 cracks found, with dimensions of up to 20 mm (0.78 in) in length and 9 mm (0.35 in) in depth.

Examination performed in 1982: 93 cracks found, with dimensions of up to 150 mm (5.9 in) in length and 12 mm (0.47 in) in depth.

Examination performed in 1986: 30 cracks found, with dimensions of up to 130 mm (5.11 in) in length and 54 mm (2.12 in) in depth.

Examination performed in 1990: 122 cracks found, with dimensions of up to 150 mm (5.9 in) in length and 34 mm (1.33 in) in depth.

Examination performed in 1994: 26 cracks found, with dimensions of up to 56 mm (2.2 in) in length and 35 mm (1.37 in) in depth.

These cracks occurred in various turbine components, including the shells, and various turbine valve bodies and connecting steam piping. The distribution of total cracks found in the Block 3 turbine between the years 1978 and 1994 are shown below:

HP section	:	108 cracks
IP section	:	62 cracks
LP section	:	4 cracks

Auxiliary Turbine Components (such as valves, piping) : 170 cracks

All of the above total of 344 cracks have been repaired, as reported by plant personnel. However, because of the history of crack development and repair in this turbine, periodic NDE inspections will be required in the future. The discovery of additional cracks can be expected.

There is currently no replication type creep testing capability at this plant. As the plant is getting older such testing capability would be highly desirable to monitor potential creep cavitation of critical components which operate with units approaching the end of their park resource operating hours. Utilization of such testing equipment would enable the plant to better predict potential failures or to perform predictive maintenance operations. This is particularly applicable to a plant with many boilers and turbines.

c) Spare Parts

Lack of spare parts was reported by plant personnel to be a problem. An adequate supply of appropriate spare parts, located at the plant, is important to facilitate rapid maintenance when needed. This is particularly true when failure of a part results in an unscheduled outage, and time is of the essence in completing the repair to return the unit to service as rapidly as possible.

Turbine Assessment

The Block 3 steam turbine is now the second oldest machine at Ermakovskaya (since Unit 1 had to be replaced in 1973). It was placed into operation in 1970. At the time of the Burns and Roe team visit this unit has accumulated a total operating time of about 170,000 hours. It is similar in construction to blocks 2 and 4 which have a double casing HP and single casing IP section (all other turbines at the plant have double casing HP and IP sections).

Other than some blade and valve replacements the turbine is basically operating with the same components including the control and monitoring systems, for 25 years. The allowable park resource (the officially extended life) for the types of units operating at the Ermakovskaya plant is 220,000 hours. The block 3 steam turbine was originally designed to operate with high temperatures of 560/565°C (main steam and superheat steam) similar to many Russian design units. Because operation of the units at these high temperature caused considerable cracking problems in thick walled critical steam generator components, these parameters have been officially lowered to 540/540°C in 1971. Operation at the initially high temperature conditions also caused some cracking in the thick walled turbine components. The number of cracks found in the various turbine components even after the lowering of the steam temperatures is very large. (The 344 cracks mentioned in paragraph b) above does not include cracks discovered prior to 1978). In the 12 year period from 1978 through 1990 the total number of cracks found in various parts of the unit amounts to 318 (somewhat lower than those found in block 2 for the corresponding period, since block 2 has been operating for a year longer than block 3). Of course all these cracks have been repaired by either grinding or grinding and welding. Because of the more frequent shutdown and startup of the unit due to breakdowns and due to economic dispatch, additional cracking and more accelerated life consumption of the turbine metal can be expected. The plant estimated a remaining life of about 40,000 hours. This seems to be in agreement with our assessment. However, to be able to better predict the rate of life consumption and to avoid any catastrophic failures more frequent monitoring of the metal condition of a unit would be required. This could be best performed with the use of replication type creep testing equipment which the plant currently does not have. In addition, because of the advanced age and wearout of various components more frequent maintenance and increased maintenance costs are expected. Data on unscheduled shutdowns for all units indicates that the block 3 block has an increased number of forced shutdowns in recent years. As indicated above, eleven breakdowns in 1994 were associated with turbine related problems.

It should be noted that the internal efficiencies of the HP and IP sections of block 3 are the worst among all the turbines at the Ermakovskaya Plant (see Table 3-4 above). This is an indication that the condition of the steam flow path has significantly degraded and it is ready for replacement. The LP section is plagued with frequent last stage blade erosion and shroud breakage. In fact the LP section has been running with the LP 2nd stage blading removed contributing to the low efficiency (and high heat rate of this unit). (As of this writing it is our understanding that the 2nd stage blading was reinstalled in the LP section of block 3 utilizing the 2nd stage blading from the LP section of the currently shutdown block 2 turbine). The interstage and gland sealing steam leakages are double than the original design.

One of the most annoying problems which plant operators are faced with is a shell support misalignment problem at the sliding support between the HP and IP housings. Even after capital repairs the bearing oil and steam gland seals are quickly broken causing cross contamination of condensate and oil, and also oil leaks to the floor. In addition the thrust bearing should have been replaced but there are no spares readily available on the market. This contributes to excessive vibration problems for block 3. The plant personnel and metal laboratory personnel are doing their best to keep the unit in operation and try to follow the assigned maintenance programs (yearly, intermediate and overhaul) as closely as possible. However, block 3, because of the above unsatisfactory factors would not be likely to provide long time reliable and efficient service without major repairs and replacements.

3.3 AUXILIARY PLANT SYSTEMS

a) Plant Condenser

The condenser for block 3 is a Type K-15240 single pressure surface condenser with two water passes which is connected to the three exhaust connections of the steam turbine. The technical characteristics of the condenser are shown in Table 3-5.

TABLE 3-5

TECHNICAL CHARACTERISTICS OF THE CONDENSER

Type		K-15240
Design Steam Flow, t/h		563.64
Condenser Pressure, kg/cm^2(a)		0.035
Circulating Water Flow, t/h		34805
Circulating Water Design Temperature, °C	12	
Specific Steam Load, kg/m^{2}h	37	
Cooling Ratio	61.75	
Condenser Surface Area, m^2	15240	
Condenser Active Tube Length, mm	8850	
Circulating Water Velocity in Tubes, m/sec	1.86	
Number of Tubes		18528
Tube diameter OD/ID, mm		28/24 and 28/26
Tube Material	L-68	
Hydraulic Resistance, m w.c.	4	

The original tubes have been replaced in 1990 and therefore the tube condition is satisfactory. The allowable plugging in the condenser is 10%. However, the plant reported problems with the tube-to-tube sheet joints. Circulating water can find its way into the condenser steam space through rolled tube joints. This will require the checking of tubes for leakage and repair plugging, or replacement as necessary based on the results of the leak check.

It was reported by plant personnel that considerable amounts of dirt accumulates in the condenser tubes, especially during Spring and Summer. It appears that a condenser tube cleaning system (such as the Tapprogge type) should be installed at this unit. Currently only Block 6 has an on-line tube cleaning system, the other units use a high pressure air/water gun for intermittent cleaning of condenser tubes.

In addition, the condenser is experiencing excessive air in-leakages lately. This is because of the more frequent startups and restarts of the unit. Sometimes plant personnel have no time to fix leakages. Average air in-leakage is about 68 kg/h. At the time of our visit the actual air in-leakage into the vacuum system was 96 kg/h on Block 3. When there is no time to fix leaks the plant just starts up more air ejectors. There are two (2)-75 kg/h steam jet air ejectors and one (1) 65 kg/h water jet air ejector for Block 3. Air in-leakages usually occur at the low pressure glands and at the horizontal flange of the LP turbine cylinder.

b) Feedwater Heaters

The unit utilizes two strings of 3 high pressure heaters and one string of low pressure heaters. The HP heaters were manufactured by the Taganrog boiler plant and contain steam cooling, condensing and drain cooling zones, and spiral coils. Because they are designed for very high pressures they have heavy wall thicknesses. The low pressure heaters are also vertical heaters but designed with different tubing configuration. The original tubing was a copper based metal. Some heaters were replaced with Stainless Steel tubing. There is a program at the plant for replacing all feedwater heater tubing. Block 6 was the first unit the feedwater heaters of which were replaced with SS tubing. Allowable tube plugging on heaters is 10%. The LP heaters on Block 3 still have L-68 tubes. The heater TTD and DC figures are worse for the plant (5-7°C for TTD, and 7-10°C for DCA) than for corresponding US units. The feedwater heaters have served during their long operating lives and show signs of wear. Tube breaks in one of the LP heaters has contributed to the water induction problem at the Block 3 steam turbine.

c) Deaerator

There are two deaerators per power block at Ermakovskaya Plant. The deaerator storage tanks have a 5 minute storage capacity at a feedwater flow corresponding to 300 MW output. There have been no problems reported for the deaerators, and they appear to be in satisfactory condition.

d) Boiler Feed Pumps

There are many problems at the plant with the boiler feed pumps. There are two types of pumps: turbine driven feedpumps and electrically driven pumps. In addition there are also motor driven feedwater booster pumps.

According to discussions with plant personnel at least three feedwater pumps have problems in the plant every month. The block 3 turbine driven feedpump is not particularly efficient (it is running with an efficiency of about 80%). The 12.4 MW drive turbine operates satisfactorily. However, the main pump as well as the electrically driven feedpump which is driven by an 8000 kW motor through a hydraulic coupling and a speed increasing gear at about 6000 rpm have vibration problems. The natural wear and tear of the pump components stemming from their age is compounded by bad maintenance. This is not because of the maintenance plan followed by the plant but rather the inability of the maintenance people to obtain the required spare parts. Therefore, the plant must make the spare parts themselves. However, these parts do not exactly correspond to the design of the pumps and usually have no proper heat treatment. The electrically driven feed pump operates with an efficiency of only 77% and has also problems with its hydraulic coupling. Both the turbine driven and electrically driven feedpumps should be replaced. The 3-50% capacity feedwater booster pumps operate satisfactorily.

e) Condensate Pumps, Condensate Booster Pumps and Drain Pumps

There are three vertical 3-stage condensate pumps, model KCB-500-85, driven by 250 HP motors at a speed of 970 rpm. The pumps' cavitation reserve is 1.6 m w.c. These pumps operate with an efficiency of 75%. The condensate pumps transfer condensate to the suction of the condensate booster pumps through the unit's condensate polisher system.

The three condensate booster pumps are similar in construction to those of the condensate pumps except that they have a higher head and operate at a speed of 1480 rpm. They are 5-stage vertical pumps, Type KCB 500-220, and operate with an efficiency of 75% and deliver condensate from the condensate polishers to the deaerator. They are driven by 500 kW electric motors.

The design of the drain pumps utilized by the plant are similar to that of the condensate booster pumps. They have the same head but smaller flow rate. They operate with pump efficiency of only 73%, and have an auxiliary power consumption of 154 kW at their design operating conditions.

No serious problems were reported by plant personnel for any of these pumps other than they are old and require careful maintenance. They appear to be in satisfactory condition.

f) Circulating Water Pumps

There are two circulating water pumps provided for each of the units at Ermakovskaya. Normal operating speed is 485 rpm. Each of the two pumps deliver circulating water from the end of an intake canal to each half of the condenser. Two pumps can deliver a total flow of 43200 m^3/h. The circulating water pumps are vertical, two speed, and have adjustable vanes. The maximum operating pump head is 11 m w.c. Two main problems were reported for these pumps. One was cavitation damage at the impeller with the original cast iron material containing high percentage of carbon. This problem was eliminated by changing to stainless steel material. The other problem is the wearout of the rubber bearing supporting the pump shaft. The rubber bearing was designed to be lubricated with clean water, and it is difficult to find and procure a replacement rubber for the bearing. However, it was noted that the lubricating water is taken from the pump discharge. This water can be contaminated with silt and abrasive material especially during spring. Therefore it appears that a filter should be installed in the lubricating water line upstream of the bearing.

3.4 PLANT INSTRUMENTATION AND CONTROLS SYSTEM

General

There are a number of problems with the instrumentation and controls at the Ermakovskaya Plant. Since the startup of the plant there has been no renovation of the equipment for automatic control and supervisory systems on Blocks 2, 3, 4, 7 and 8. At the present, the documentation on these systems does not correspond with the equipment. This is because in the course of operating the plant, repairs, replacements and other changes were made without updating drawings.

Work began on March of 1995 updating the controls and instruments as needed on Block 2. Block 3 will need similar attention.

a) Load Control

Block 3 turbine uses a conventional mechanical governor with a 4% droop. Main steam pressure is adjusted by varying the feedwater pressure. The boiler fuel controllers, when in automatic, are used to vary the fuel flow rate to the boiler for main steam temperature control. The pulverized coal fuel is stored in an intermediate hopper and the transport medium from mill to hopper and from hopper to burner is air from the air heater. There is no oxygen dilution for the transport air, but they have never had any explosions in the fuel preparation system.

Coal must be delivered in equal amounts to each burner, even under low loads. Coal flow is controlled by volumetric feeder speed.

b) Combustion Control

This is purely a manual function carried out by varying the position of the forced draft fan radial inlet vanes remotely from the control room. An O_2 indicating system driven by the oxygen analyzers assists the block operator in setting the correct combustion air flow rate. Additional indicators of excess air are air-side resistance of the air heaters and air pressure after the forced draft fan. Vacuum in the upper section of the furnace is also used as a combustion performance indicator.

The original oxygen analyzers are extractive type and consequently slow acting. The type of O_2 monitor currently in use is a paramagnetic device with about a 3 to 4 minute delay in reading. As part of the pilot plant upgrade, the O_2 monitors will be replaced by high temperature zirconium oxide cells which have a much faster time response.

c) Furnace Pressure Control

There is no automatic control of furnace pressure. The position of the induced draft fan inlet vanes is varied remotely from the control room to adjust the value of the furnace pressure. Normal vacuum is 3 to 4 mm. Hg.

d) Steam Temperature Control

Steam flow is divided into two parallel paths, with steam crossovers at the first and second spray attemperator stages. There is an attemperation system in the parallel steam paths to the first and second stage desuperheaters using spray water attemperation valves each with its own dedicated controller. The spray water source is feedwater.

Superheater outlet temperature and a derivative of superheater inlet temperature are compared to the setpoint to form the control deviation.

There is a need for automatic control of the superheater attemperators over a wider range than is currently used. The setpoint is currently set at the nominal superheater temperature; therefore it does not operate automatically during startup, thus forcing the operator to manually control the spray. If close attention is not given by the operator, overheating will occur.

e) Boiler Interlock and Protection System

A basic interlock system using electrical relays is in existence. Protection is effected via electrical relays for the following conditions: high and low steam temperature, forced draft fan not in service, induced draft fan not in service, no primary air fan in service, air heaters off, flame failure, loss of feedwater flow and loss of reheat steam flow. The flame failure circuit will start mazut flow to the burners automatically if the unit is burning coal.

f) Burner Management System

There is no burner management system as such. However, each boiler is equipped with electronic flame scanners, four sensors per boiler, two on the front, and two on the rear furnace wall.

g) Stack Emissions Monitoring

There are no NO_x, SO_2, CO, or CO_2 measurements on these units, however the units do have opacity monitoring. Due to the increasingly stringent requirements being promulgated by the financing institutions a complete continuous emissions monitoring system will be required in the future. The existing opacity monitoring system does not work well, and is not relied upon. Currently NO_x is monitored by calculation.

Since all boilers discharge their flue gases into a single stack, it is difficult to identify gases from individual boilers. Without the ability to monitor flue gas emissions from each boiler, it is further impossible for plant maintenance staff to determine which boilers are operating efficiently, and which may need repair or adjustment.

NO_x monitors will be added to the block 3 boiler flues as part of the block 3 pilot plant upgrade.

h) Turbine Control System

The original mechanical governors are still in operation. Each turbine is equipped with 2 stop valves and 2 interceptor valves. Contained within each stop valve are 3 governor valves and within each interceptor valve are 2 governor valves. Control is provided by a hydraulic water system. Speed sensors control the turbine speed by adjusting the governor valves position. The boiler operator manually changes steam flow to adjust the load. This equipment is old and subject to breakdown and should be refurbished.

i) Turbine Interlock and Protection System

The following protection interlocks are installed: excessive movement at thrust bearing overspeed, low steam temperature, low lubricating oil pressure, high water level in HP feedheaters, generator electrical faults, low hydrogen seal oil pressure, loss of vacuum and low hydraulic pressure. All of the above protection and interlocks are effected via electrical relays. Overspeed protection is provided via overspeed rings and the hydraulic fluid system.

The turbine is protected against water ingress from the feedwater heaters by fast-acting non-return valves and isolating valves in the bleed steam lines which are activated electrically by electrical sensors on the feedwater heaters.

There is no stress monitoring on the turbine but casing temperatures at various points are measured and recorded. Turning gear is provided which turns the rotor at 3 to 4 revolutions per minute. Currently there is no turbine trip for high vibration, because the vibration monitors do not function properly. This situation has caused turbine damage and must be rectified.

j) Turbine Supervisory System

The following supervisory measurements are made on the turbines: thrust bearing position, eccentricity, casing expansion, relative expansion, and turbine speed by a digital electronic system. Lack of bearing oil temperature monitors have caused failure of turbine bearings because of a loss of oil cooling. This situation should be corrected.

k) Feedwater Heating Controls

The condenser hotwell level and the levels in the feedwater heaters are controlled using automatic regulators. All of the actuators are electrically operated. All heaters and the condenser are equipped with water level gage glasses. Most extraction points are equipped with a check valve to prevent water ingress. These valves are equipped with hydraulic accelerators to improve the valve operating time. Extraction number 9 does not have a check valve.

l) Plant Alarm System

This is the original system which still operates in a satisfactory manner. The system is not prioritized hence many alarms can appear for a single cascading failure. A standard, simple ISA sequence is used for display and control of the lamps and the horn.

m) Local Panels

Each local turbine panel contains pressure gages for main steam and each extraction steam pressure as well as control water and lubrication oil pressure. The local generator panels contain gages for generator frequency, hydrogen pressure and generator cooling.

n) Thermal Insulation Detector

The boiler furnaces tubewall insulation has deteriorated as has the air/flue gas duct system. Visual examination has indicated that other plant systems also have deteriorated insulation. A portable optical temperature detector would be a useful device in locating and determining missing or deteriorating insulation.

3.5 AIR POLLUTION CONTROL

Emissions of particulates, sulfur dioxide (SO_2) and nitrogen oxides (NO_x) and the impact of these emissions on ambient air quality are of concern to the power plants and the surrounding communities. At the Ermakovskaya power plant dust collection equipment is provided to remove a major portion of the fly ash from the flue gas before discharge. The following table shows the concentrations of NO_x and SO_2 in the flue gas for all boilers at the Ermakovskaya plant.

Boiler No.	NO_x Concentration, g/Nm^3		SO_2 Concentration, g/Nm^3	
	Min.	Max.	Min	Max.
1A	0.833	0.9512	0.894	0.956
1B	0.654	0.890	0.667	0.854
2A	0.540	0.659	0.835	0.944
2B	0.692	0.742	0.803	0.994
3A	0.580	0.842	0.867	1.083
3B	0.566	0.735	1.107	1.210
4A	0.560	0.760	0.735	1.133
4B	0.623	0.715	0.995	1.345
5A	0.786	0.860	1.160	1.398
5B	0.694	0.760	1.285	1.599
6A	0.756	0.793	0.852	1.388
6B	0.652	0.721	0.902	1.291
7A	0.529	0.652	1.162	1.251
7B	0.649	0.726	1.034	1.109
8A	0.589	0.887	0.701	1.298
8B	0.762	0.958	0.762	0.896

Note: Measurements were made with "Eduiometer" instruments using methods developed by the Thrizhanovsky ENIN Institute.

From this table it can be seen that the boilers from block No. 3 (3A and 3B) have one of the lowest concentrations of NO_x, while it's SO_2 concentrations are slightly higher than the average. Currently, there is no NO_x or SO_2 control equipment installed at the Ermakovskaya Plant.

In order to remove fly ash from the flue gas, Electrostatic Precipitators (ESP's) are used at the Ermakovskaya power plant. The existing ESP's have 7.5 meter high plates, with 3 fields. The maximum collection efficiency of these units, when firing Ekibastuz coal, is 97.5%. Due to the deterioration of these units, the current collection efficiency is much lower. Because of lack of mechanical system of replacing suspended electrodes and the general deterioration of the ESP units, they need to be replaced with new units.

4.0 REHABILITATION PROGRAM

4.1 STEAM BOILERS REHABILITATION RECOMMENDATIONS

a) Coal Pulverizers

It is recommended that the existing four high speed, horizontal shaft hammer mills per boiler be replaced with four new larger medium speed vertical shaft roller mill pulverizers per boiler. This will make it necessary to remove the existing hammer mills and associated equipment.

The following new equipment, will be required:

1) Foundations (Reinforced Concrete and Steel Rafts)

2) Pulverizers and Dynamic Classifiers with electric motor or hydraulic drive

3) Coal Piping to Mills

4) Gravimetric Coal Feeders and Electric Motor Drives (optional, recommended but not mandatory. Not included in the cost estimate.)

5) Hot Primary Air and Coal Piping and Valves

6) Cold Tempering Air Piping and Valves

7) Pulverizer Drives, Electrical Equipment etc.

8) Misc. Drives for Feeders, Classifiers, With Switchgear, Controls, etc.

9) Retain Existing Hot P/A Fans and Seal Air Fans

b) Forced Draft (FD) and Induced Draft (ID) Fans

All fans should be performance tested and the results compared to the performance needed when the pollution control equipment is installed. Then the decision can be made to either refurbish or replace the fans. In the interim, the cost of refurbishment, foundation skids, etc. will be recommended for addition to the budget for the FD fans. The cost of replacement will be added for the ID fans when the fan requirement is established.

c) Heating Surfaces/Wall Blowers and Sootblowers

Extended surface primary superheater and economizer tube banks will be retrofitted with in-line centers, replacing the existing bare tube banks on staggered centers.

It will be necessary to add sootblowers to the convection passes of both boilers to avoid fouling of the extended surfaces. This is particularly important with the high ash of the Ekibastuz coals. A full complement of wall and sootblowers will need to be installed on boiler 3a.

d) Furnace Ash Hopper Tubing

The horizontal tubing in the Block 3 boiler furnaces hopper walls should be replaced with vertical tubing to improve ash and slag evacuation, and to improve resistance to slag falls.

e) Low NO_x Burners

Low NO_x burners should be installed on both boilers of Block No. 3. These will be internally fuel/secondary air staged burners, preferably without the need for using bulk furnace air staging (OFA), so as to avoid the need for substoichiometric furnace burner zone firing conditions and associated corrosion and slagging problems.

f) Tube Penetration Seals

Tube penetration seals of furnace and backpass roof tubes, and in backpass tube banks for superheaters, reheaters, and economizers are leaking and must be refurbished and tightened.

g) Air Heaters

Refurbish and repair the rotary, regenerative, bi-sector vertical shaft air heaters, including radial and circumferential seals, cold end sectors of rotors, sootblowers, etc. as required.

h) Condition Assessment of Pressure Parts

A boiler condition assessment should be done on furnace, SH, RH tubing and water/steam-cooled thick-walled pressure parts; i.e., headers, desuperheater piping, integral piping etc.

An NDE examination of the pressure parts of one of the two boilers of Block 3 appears warranted. Following a review of the findings, remedial action will be recommended.

i) Furnace and Boiler Setting

Boiler refractory, insulation, casing (BRIC) should be refurbished as needed, for furnace vertical walls, tube hopper slopes, furnace and backpass roof, two backpasses walls, boiler outlet fluegas ducts and flyash hoppers.

Improvements in Boiler Thermal Performance

a) General

Boiler thermal performance would improve following the implementation of rehabilitation measures due to reduced air in-leakage, increased heat transfer surface, improved sootblowing, improved air heater performance, reduced air heater leakage, improved coal pulverizer performance, NDE of pressure parts and consequent repairs, improved F.D. and I.D. fan performance, and new boiler feed pumps. The rehabilitated boilers will gain approximately 15 years in life extension.

b) Main Steam Output

Deficient boiler output currently restricts the plant to achieve full output. Maximum total steam flow is approximately 843,000 kg/hr or about 89 percent of design rated Maximum Continuous Rating (MCR). Following rehabilitation, output is anticipated to return to MCR (Total 950,000 kg/hr of two boilers).

c) Boiler Efficiency

Current boiler efficiency is 86~87 percent. Boiler efficiency (Lower Heating Value basis) is anticipated to return the design to 91.8 percent following rehabilitation. This is an improvement of 5~6 percent. However, the higher than design coal mineral matter content (44% by wt. now, versus 39% of the design coal) will have an adverse effect on boiler efficiency.

d) Ekibastuz Coal Cleaning

We attach in the Appendix I a concise coal slagging, fouling, erosion and ash corrosion propensity study, which clearly indicates the merits of coal mineral matter reduction for the improvement of the present serious furnace slagging problem.

4.2 STEAM TURBINE GENERATOR REHABILITATION RECOMMENDATIONS

Based on the assessment of the current performance and condition of the block 3 steam turbine the following major replacements and modifications are recommended:

a) Steam Turbine

Block 3 turbine has experienced various problems over the years. They still continue, and are likely to result in additional deterioration of efficiency, increased frequency of unscheduled outages, and increased time out of service for inspection and repair. Accordingly, it is recommended that plan be made to replace the main turbine, complete with ancillary systems and components, from main steam stop valve inlet to exhaust hood connection to main condenser, including instrumentation and controls, control valves, lube oil system, steam seal system, extraction steam system, heater drain system, and interconnecting piping.

The replacement turbine for the block 3 block should be a nominal 310 MW new unit type K-310-240-3 which has a turbine heat rate of 7988 Btu/kWh (2013 kcal/kWh). Installation of this new turbine will not only resolve the current problems due to deterioration of the existing turbine but will improve the operating performance of the unit. Compared to how the unit can operate today the following are the output and heat rate improvements:

	Current	New	Improvement	
			Unit	%
Output, MW	280	310	30	10.7
Heat Rate, kcal/kWh	2222	2013	209	9.4

Therefore, the new unit would operate with a turbine cycle efficiency of 42.7%.

b) Generator

At this point it appears that the existing generator can be retained since the power will only increase about 3% over the 300 MW original rating, and plant personnel indicated that the original generator design allowed to increase power to 340 MW in the past. It is anticipated that a small increase of the hydrogen coolant pressure will be required. The existing generator must be inspected, and the necessary repairs and refurbishment should be accomplished. The generator manufacturer should be asked to verify that the generator can meet the new requirement (310 MW). If not, then the generator must be replaced with a new 310 MW generator.

c) Turbine Sliding Support

Installation of the new turbine will undoubtedly solve the thrust bearing and vibration problems. However, based on modifications needed for the support arrangement between the new HP and IP turbine shells, it is recommended that the design of the turbine support mounts be reviewed by the turbine manufacturer (and if necessary redesigned) to eliminate or prevent any future turbine shell alignment problems.

d) NDE Equipment

Since at present no replication type creep monitoring equipment exist at the plant it is recommended that such equipment as well as boroscopes be purchased as soon as possible in order to better be able to predict metal degradation and detection of minor cracks in thick walled pressure parts of the 8 turbines (and 16 boilers). This equipment should be used between now and the time of the actual replacement of the Unit 3 turbine.

e) Water Induction Protection

It is recommended that the steam cycle steam and water systems; e.g., extraction steam, heater drains, etc. be reviewed for compliance with standard industry practice and turbine manufacturer's recommendations for water induction protection. Any system or component which does not incorporate appropriate water induction features should be upgraded to avoid future water induction incidents.

Water induction protection features could be in the form of an automatic motor operated shutoff valve and non-return valve in the extraction line if a heater is not installed in the condenser neck. If a heater is located in the condenser neck, it may be feasible to install an automatic heater bypass in the condensate system to prevent water backup into the extraction line in the event of condensate leakage into the steam side of the heater.

f) Spare Parts

It is recommended that based on the recommendations of cognizant plant engineering management, the stipulation of the manufacturers of major plant equipment, and other considerations, an adequate inventory of spare parts for the upgraded (and existing) equipment be established.

4.3 AUXILIARY PLANT SYSTEMS

Based on the assessment of the current condition of the plant auxiliary equipment the following additional modifications and replacements are recommended:

a) Condenser

- Replace previously plugged tubes.
- Replace existing leaking tubes.
- Correct existing air inleakages and institute a more formal air inleakage detection program to systematically detect and eliminate air ingress into the vacuum space of the condenser.
- Retrofit circulating water side of condenser with sponge ball (Taprogge type) tube cleaning system

b) Feedwater and Condensate System

- Replace the feedwater heaters (single string of low pressure heaters and two strings of high pressure heaters) corresponding to new design conditions based on extraction points on the replacement turbine. The new heaters should be designed with optimized TTD and DCA.

- The steam generator feedpumps (both turbine driven and motor driven) should be replaced with modern more efficient ones.

- The condensate polishing system should be replaced.

- The feedwater booster pumps, condensate and condensate booster pumps should be maintained, repaired or replaced as part of the plant's routine maintenance activities. These pumps and the existing drain pumps should be reviewed to establish compatibility and/or required modifications for use with the new revised steam turbine cycle.

c) Circulating Water Pumps

- Add new filters to the lubrication water system of the rubber bearings of the circulating water pump shafts.

4.4 PLANT INSTRUMENTATION AND CONTROLS

Recommended action involves the repair and replacement of the Block 3 instrumentation and controls, as necessary, plus the implementation of additional I&C improvements. The following plant instrumentation and control improvements are recommended, based on an assessment of Block 3, and discussions with cognizant plant engineering management.

1. Four high temperature O_2 analyzers, (in-situ type, positioned near the furnace exit planes) to achieve optimum combustion efficiency.

2. Good quality portable combustion analyzer (CO, SO_2, NO_x, combustibles)

3. Replace portions of the boiler control system with modern single loop controllers to achieve automatic control of the steam pressure and temperature throughout the load range.

4. NO_x emissions monitoring equipment for the boiler to determine the effectiveness of NO_x reduction initiatives.

5. Particulate emissions monitoring for boiler flue gas to determine the effectiveness of the scrubbers and electrofilters.

6. SO_2 emissions monitoring equipment for the boiler.

7. A heat spy for measuring heat leakages and electrical hot spots.

8. Non-contact type flow meters to measure mazut consumption by the boiler.

9. Refurbish the existing superheat and reheater attemperator control valves.

10. New turbine control and supervisory system including turbine stress monitor.

11. Moisture monitoring equipment to determine the quantity of moisture in the boiler flue gas in order to perform combustion calculations.

The above list was developed during the condition assessment of Block 3 and is considered necessary for rehabilitation and modernization. Implementation of these recommendations will extend the plant life and yield an improvement in reliability and availability and reduce maintenance costs.

4.5 AIR POLLUTION CONTROL RECOMMENDATIONS

Ermakovskaya Plant was engineered and constructed with due consideration of the environmental laws and regulations in place at the time of construction. Accordingly, particulate removal systems were installed on the Ermakovskaya boilers.

In recent years, further consideration has been given to the environment. New legislation has been enacted and new regulations have been implemented which have imposed more stringent requirements for pollution control. This will require the particulate removal system to be more efficient. In addition, nitrogen oxide control measures such as low NO_x burners and overfire air ports will need to be retrofitted in the boiler.

As stated in the Boiler Rehabilitation Recommendation section (4.1), new low NO_x burners, preferably without overfire air should be installed. A total of 24 burners (12 per boiler) will be required. These burners will reduce the NO_x emissions from the block when used in conjunction with or without the overfire air system. The LNBs together with the pulverizer dynamic classifiers will also help improve combustion efficiency of the boilers.

No sulfur dioxide control (removal) equipment is recommended at this time. The coal currently being fired (Ekibastuz), is a very low sulfur coal. It only contains approximately 0.6% sulfur. If the coal being fired at the plant changes to a high sulfur coal, a Flue Gas Desulfurization System (FGD) may be required to handle this problem.

In order to increase the ash collection efficiency of the ESP's, modifications need to be performed. The current ESP's should be replaced with new units with 5 field and 12 meters high plates. In addition, a new control system for the ESP's will also help to increase the collection efficiency. Burns and Roe has included the cost of replacing the existing ESP's with the new ESP's (5 field and 12 meter high plates) in the Block No. 3 rehabilitation cost estimates.

4.6 REHABILITATION BENEFITS

The table below summarizes the anticipated benefits of implementing the Rehabilitation recommendations described in Sections 4.1 to 4.5.

REHABILITATION BENEFITS

CHARACTERISTIC	BEFORE	AFTER	% IMPROVEMENT
Boiler Main Steam Flow, kg/HR	843,000	950,000	12.7
Boiler Efficiency, LHV basis %	86~87	91.8	5~6
Turbine/Generator Output, MWe	280	310	10.7
Heat Rate, Kcal/kWh	2222	2013	9.4
Plant Life Extension	-	15 years	
Plant Capacity Increase	280	310	10.7
Increase in Plant Availability	-	10 to 12%	10 to 12%

Benefits will also be realized from the Instruments and Control System modifications. The implementation of these recommendations will improve the general operations of the block by increasing its availability and reliability, decreasing Operating and Maintenance costs, and extending the life of the block. The implementation of air pollution control recommendations will help improve the air quality (environment) in the vicinity of the plant. The Low NO_x burners will lower the NO_x discharge from the block and should allow the block to meet future environmental pollution limits. In addition, the improvements to the ESP's will greatly reduce the amount of particulates that are expelled into the atmosphere from the plant stack.

The improved boiler and steam turbine efficiencies will result in decreasing the fuel consumption for a given quantity of electric power generation (MW hrs). This will have the double benefit of fuel cost savings as well as reduction in pollutants discharged to the environment. The estimated 15 years life extension of major plant components (boilers, turbines, condensers, feed pumps, feedwater heaters, etc) as a result of the plant rehabilitation will defer the potential capital expenditure needed to replace the plant capacity. If no rehabilitation were to be performed and the plant had to be retired in the near future as it is already 25 years in operation (from 1970), it will require substantial capital investment. The plant rehabilitation will also result in reducing the potential cost of replacement power to be purchased when Block 3 plant were to be shutdown due to unplanned (forced) outages.

One additional benefit of Block 3 rehabilitation is an increase in plant availability and reliability due to major renovation and upgrade of critical plant components such as boilers, turbines, auxiliary plant equipment and Instrumentation and controls upgrades. It is estimated that the Block 3 availability and reliability will improve by 10 to 12 percent as a result of the proposed Block 3 rehabilitation.

5.0 CAPITAL COST ESTIMATES

Cost estimates for the various rehabilitation items have been developed based on Burns and Roe inhouse estimates for similar size jobs or from vendor estimates. The estimates are based on the following scope of supply and are expressed in 1995 U.S. dollars.

Scope of Supply

Replacement of existing 8 Hammer Mills with 8 new Vertical Spindle Roller Mills
Installation of New Rotating (Dynamic) Classifiers
Replacement of Boiler Setting (refractory, insulation & casing) for 2 Boilers
Replacement of two (2) Boiler Convective Heating surfaces with extended surface
Repair of (4) Air Heaters
Installation of New Low NO_x Burners and overfire air nozzles
Replacement of two (2) Ash Hoppers with vertical tube walls
Repair of two (2) Forced Draft Fans
Replacement of two (2) Induced Draft Fans
Retrofit of a total of 192 furnace wall blowers and retractable sootblowers (two boilers)
Installation of 160 Tubewall Blowers
Repair or replace boiler tube penetration seals
Replacement of 10% of the steam system valves
Replacement of Steam Turbine with new 310 MW turbine
Installation of Turbine Extraction Valves and Water Induction Protection
Retubing 10% of Condenser Tubes
Replacement of Feedwater Heaters
Replacement of two (2) Boiler Feed Pumps
Installation of a Condenser Cleaning System
Installation of a Demineralizer System and Condensate Polishers
Procurement of new NDE equipment
Replacement of two (2) Electrostatic Precipitators
Install Emissions and Air Flow Monitoring Equipment
Install Boiler and turbine Monitoring Equipment
Miscellaneous Instrumentation and Controls System Upgrades
Replacement of 28 km of Power Cable
Replacement of 80 cubicles of MCC's
Replacement of Auxiliary Switchgear

The project cost estimate is conceptual in nature, and was based on information obtained during Burns and Roe's site visit in March 1995.

Direct Cost

Pricing for major equipment and materials were developed from Burns and Roe historical data and vendor estimates for similar sized projects escalated to October 1995. The pricing is based on major equipment and material being supplied by Western manufacturers and transported to the project site.

Bulk materials (concrete, piping, valves, etc.) were assumed to be available locally in the quantities and sizes necessary to support the project requirements.

Construction Labor

Labor costs were generated by using U.S. Gulf Coast manhour estimates for the work to be performed and applying a productivity factor. The productivity factor was developed based on Burns and Roe's observations at the site and previous studies performed in NIS countries. Based on our site visit, we expect the skilled labor required to complete the project will be available locally to the project and within Kazakstan.

Indirect Costs

Ocean freight costs and insurance costs have been assumed at 7% of material costs.

Contingency has been added to the estimate to provide for risks and uncertainties associated with the scope of work at the conceptual stage of design. Contingency was applied to the direct labor and material costs.

Other Costs

Additional costs such as Engineering, Construction Management, Start-up Costs, Construction Equipment, Interest During Construction, and Escalation have not been included in the base cost but are presented for information purposes. These costs are listed on sheet 3 of the cost estimate. These costs are applicable to similar electric power plant rehabilitation projects in the United States. However, they may have to be modified for reconstruction projects in Kazakstan based on local construction practices and traditions.

CONCEPTUAL COST ESTIMATE
REHABILITATION OF 300 MW BLOCK No. 3
COAL FIRED POWER PLANT ERMAKOVSKAJA, KAZAKSTAN

ITEM	LABOR COST $	WESTERN MAT'L $	LOCAL MAT'L COSTS	TOTAL COST
BOILERS				
Remove Existing Burners (12 per Boiler 24 Total)	85,200		2,600	87,800
Install New Low NOx Burners & OFA System	159,100	5,940,000	152,500	6,251,600
Remove Existing Hammer Mills (4 per Boiler 8 Total)	74,400		2,200	76,600
Remove Existing Hammer Mill Foundations	53,800		1,600	55,400
Remove PA/PC Ductwork (2 Units)	84,600		2,500	87,100
Install New Roller Mill Foundations (8)	55,800		31,300	87,100
Install New Roller Mills (8)	194,000	2,400,000	77,800	2,671,800
Install New Classifiers (8 Total)	158,600	680,000	25,200	863,800
Install New PA/PC Ductwork (2 Units)	127,200	350,000	14,300	491,500
Boiler Refractory, Insulation, Lagging & Casing Repair (2 Units)	178,800	1,800,000	59,400	2,038,200
Tube Penetrations & Seals (2 Units)	77,400	480,000	16,700	574,100
Dismantle Horizontal Conv, SH, Econo Tube Banks (2 Units)	164,400		4,900	169,300
Install New Extended Surface for Mat'l Removed Above (2 Units)	229,200	7,100,000	146,600	7,475,800
Replace Sootblowers (16 per Unit 64 Total)	131,500	480,000	18,300	629,800
Repair Air Heaters (2 per Boiler 4 Total)	157,200	1,320,000	44,300	1,521,500
Repair Forced Draft Fans (1 per Unit 2 Total)	55,400		54,300	109,700
Remove Old Induced Draft Fans (2 Total)	26,400		800	27,200
Replace Induced Draft Fans (2 Total)	79,900	1,200,000	38,400	1,318,300
Remove Existing Boiler Ash Hoppers	41,900		1,300	43,200
Install New Boiler Ash Hoppers	50,800	440,000	14,700	505,500
Install Tubewall Blowers (80 per Boiler 160 Total)	203,200	2,250,000	73,600	2,526,800
Perform Non-Destructive Testing (Allowance)	50,000			50,000
Perform a Draft Plant Assessment on a Boiler Train (Allowance)	50,000			50,000
TOTAL BOILER WORK	**2,244,500**	**18,500,000**	**628,200**	**21,372,700**
TURBINE GENERATOR				
Remove Existing Turbine & Piping	219,400	0	6,600	226,000
Install New 310 MW Turbine & Accessories (No Generator)	429,600	16,577,000	340,100	17,346,700
Install Turbine By-Pass System	128,200	850,000	29,300	1,007,500
Repair Extraction & Drain Systems	127,200	1,200,000	39,800	1,367,000
Procure NDE Equipment	0	30,000	0	30,000
Modify Turbine Pedestal	134,100	0	21,000	155,100
Repair & Replace 10% of Steam System Valves	79,200	1,050,000	33,900	1,163,100
TOTAL TURBINE WORK	**1,117,700**	**19,707,000**	**470,700**	**21,295,400**

CONCEPTUAL COST ESTIMATE
REHABILITATION OF 300 MW BLOCK No. 3
COAL FIRED POWER PLANT ERMAKOVSKAJA, KAZAKSTAN

ITEM	LABOR COST $	WESTERN MAT'L $	LOCAL MAT'L COSTS	TOTAL COST
FEEDWATER SYSTEM				
Modify Condenser Neck/Turbine Exhaust	23,100	50,000	2,200	75,300
Install New Filters for Circ Water Pumps	15,700	20,000	1,100	36,800
Remove Existing Boiler Feed Pumps	39,800		1,200	41,000
Install New Boiler Feed Pumps	107,500	779,640	26,600	913,740
Remove Existing Feedwater Heaters	68,300		2,000	70,300
Install New Feedwater Heaters	184,900	1,800,000	39,700	2,024,600
Retube Condenser	214,400	586,000	24,000	824,400
Install Condenser Cleaning System	188,900	1,300,000	29,800	1,518,700
Install Demin System & Polisher	123,700	600,000	21,700	745,400
TOTAL FEEDWATER SYSTEM WORK	**966,300**	**5,135,640**	**148,300**	**6,250,240**
INSTRUMENTATION & CONTROLS				
Install Emissions Monitoring Equipment	64,500	565,000	12,600	642,100
Install Air Flow Monitoring Equipment	47,300	285,000	6,600	338,900
Install Boiler Monitoring Equipment	55,000	413,000	9,400	477,400
Install Turbine Monitoring Equipment	42,700	210,000	5,100	257,800
Miscellaneous Instrumentation & Controls	38,000	130,500	3,400	171,900
TOTAL INSTRUMENTS & CONTROLS	**247,500**	**1,603,500**	**37,100**	**1,888,100**
ELECTRICAL SYSTEM				
Install New Power Cable (28 KM)	168,000	284,400	13,600	466,000
Remove & Replace Existing MCC's (80 cubicles)	64,400	185,900	7,500	257,800
Replace Auxilliary Switchgear (65 cells)	83,300	238,000	9,600	330,900
Replace Auxilliary Transformer (40 KV/6.3/6.3)	116,700	625,000	22,300	764,000
Replace Excitation Transformers (1000 KVA)	12,600	46,000	1,800	60,400
Replace Excitation System	43,300	125,000	5,000	173,300
TOTAL ELECTRICAL WORK	**488,300**	**1,504,300**	**59,800**	**2,052,400**
ENVIRONMENTAL SYSTEM				
Remove Existing Precipitators	73,100		2,200	75,300
Install New Electrostatic Precipitators	265,200	5,627,500	147,300	6,040,000
TOTAL ENVIRONMENTAL WORK	**338,300**	**5,627,500**	**149,500**	**6,115,300**
SUBTOTAL	**5,402,600**	**52,077,940**	**1,493,600**	**58,974,140**
Freight				4,101,200
Contingency (10%)				5,887,400
TOTAL COST OF REHABILITATION				**68,962,740**
			$/KW	**222**

ALL COSTS ARE SHOWN IN 1995 DOLLARS

IF THIS PROJECT WERE TO BE CONSTRUCTED IN THE USA
THE FOLLOWING ADDITIONAL COSTS WOULD APPLY:

DIRECT COSTS FROM PREVIOUS PAGE				**68,962,740**
Engineering Costs				3,538,448
Construction Management Costs				1,769,224
Start-Up Costs				1,179,483
Construction Equipment Costs				1,750,000
Interest During Construction				5,517,019
Escalation				6,617,353
TOTAL COST INCLUDING THE ITEMS ABOVE		**$/KW**	**288**	**89,334,268**

1. Freight Costs are assumed to be 7% of the Material Costs
2. Construction Equipment Costs assumes Equipment to be available locally to the project
3. Engineering Costs are assumed to be 6% of the Material Costs
4. Construction Management Costs are assumed to be 3% of the Material Costs
5. Start-up Costs are assumed to be 2% of the Material Costs
6. Interest during construction is calculated at 8% per year for 2 years for 1/2 the direct cost
7. Escalation is assumed to be 4% per year for 2 years

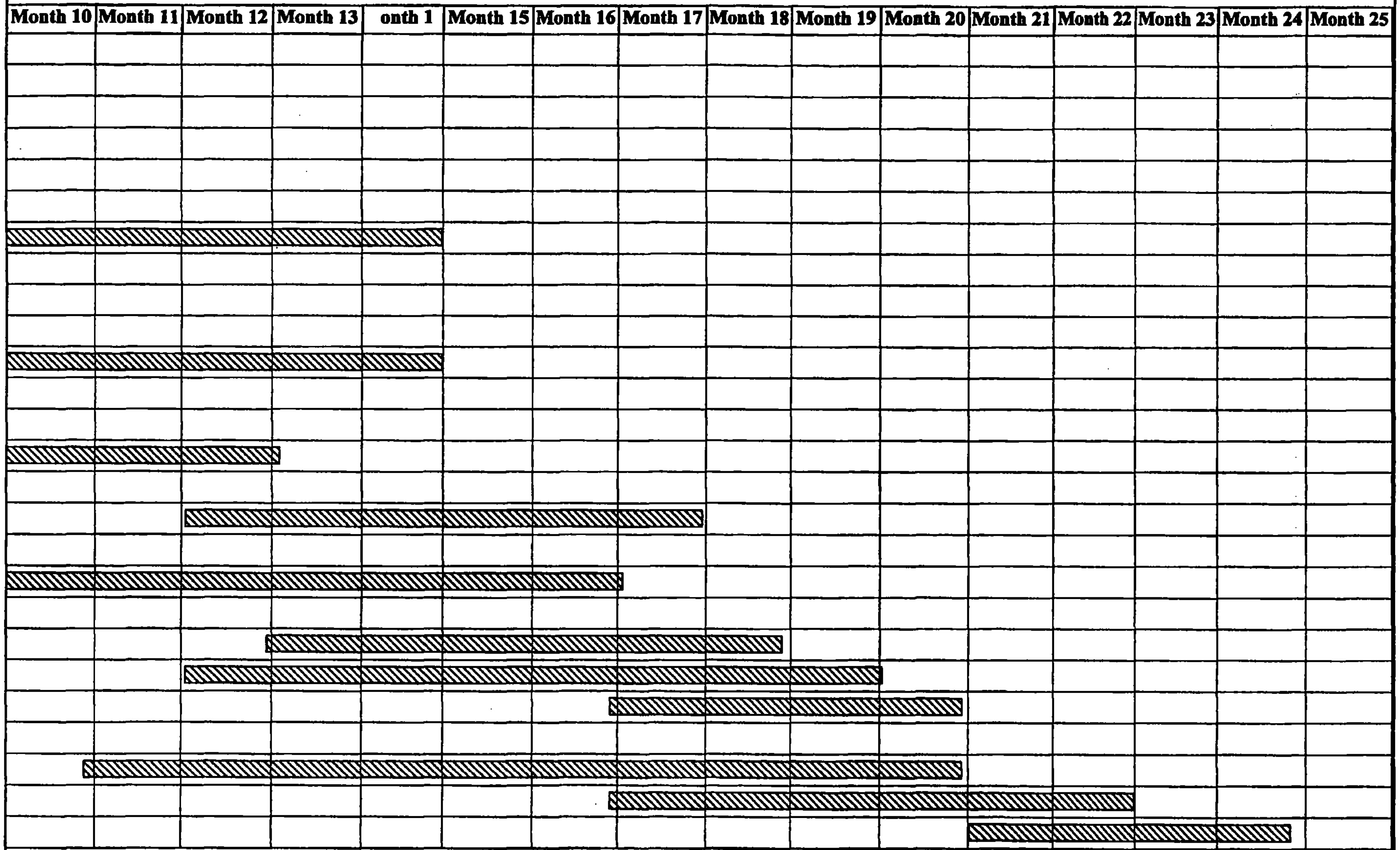
6.0 CONSTRUCTION SCHEDULE

The construction schedule for the rehabilitation recommendations described in Section 4.0 is shown on the following two pages. The overall duration of the reconstruction (rehabilitation) project is estimated at 24 months based on Burns and Roe past experience with similar rehabilitation projects. Time period of 24 months only includes the actual reconstruction of the power plant components and their startup and checkout activities. It does not include the engineering and design time required for rehabilitation of plant components such as boilers, turbines, auxiliary plant system components, Instrumentation and controls, and electrostatic precipitators (ESPs); nor does it include time required for procurement of the new equipment such as ESPs and new instruments and controls, or the time required for the NDE of boiler pressure parts.

CONSTRUCTION SCHEDULE FOR THE REHABILITATION OF THE ERMAKOVSKAYA PLANT BLOCK NO. 3

Tasks	Month 1	Month 2	Month 3	Month 4	Month 5	Month 6	Month 7	Month 8	Month 9
BOILER WORK (2 Boilers)									
Remove Boiler Mechanical Components (Burners, Tubes, etc.)	▨	▨	▨						
Remove Boiler Auxiliary Equipment (Mills, Fans, etc.)	▨	▨	▨	▨					
Remove Mill Foundations					▨	▨			
Install New Mech. Components Including Heat Transfer Surfaces				▨	▨	▨	▨	▨	
Install New Mills and Auxiliaries Including Fans							▨	▨	
Repair Boiler Casing, Refractories, Insulation, etc.						▨	▨	▨	▨
TURBINE GENERATOR									
Remove Existing Turbine and Auxiliaries		▨	▨	▨	▨				
Replace Recommended Piping System and Valves				▨	▨				
Install New Turbine and Auxiliaries								▨	▨
AUXILIARY PLANT SYSTEM									
Replace Feedwater Pumps				▨	▨	▨	▨		
Replace Feedwater Heaters								▨	▨
Condenser Modification (Neck, Tubing, Tube cleaning, etc.)					▨	▨	▨		
Replace Condensate Polishing System & Other Piping and Valves									
ENVIRONMENTAL									
Replace Electric Precipitators									▨
INSTRUMENTATION									
Install Emissions and Air Flow Monitoring Equipment									
Install Boiler and Turbine Monitoring Equipment									
Misc. Instrumentation & Controls System Upgrades									
ELECTRICAL WORK									
Repair and Replace Existing MCC's									
Power Cable & Misc. Electrical Work									
STARTUP AND CHECKOUT									

CONSTRUCTION SCHEDULE FOR THE REHABILITATION OF THE ERMAKOVSKAYA PLANT BLOCK NO. 3



7.0 EVALUATION OF EMAKOVSKAYA BLOCK 2 REHABILITATION

Burns and Roe engineers reviewed the plans for rehabilitation of Ermakovskaya Block 2 during their site visit. Block 2 was built and commissioned in 1969. Since then the turbine has been in operation for 184,400 hours, while the boiler has logged 164,800 operational hours to date. Due to this relatively large amount of operational time, this block has had numerous boiler and turbine failures. In 1994, the boiler had 28 forced outages. Most of these were furnace tube failures. In the same year, the turbine had 6 forced outages. These outages were caused by defective valves, vibration problems, and control system problems. Thus, it is evident that this Block is in dire need of rehabilitation. The Block 2 renovation plan as described by the plant engineers is as follows:

Item Description

A. Boilers (2) and Auxiliaries

1. Replacement of approximately 70 percent of the furnace tubewall heating surface.
2. Repair/replacement of the boiler setting (boiler tubewall refractory, insulation, and casing).
3. Replacement of boiler feedpumps.

B. Turbine and Auxiliaries

1. Replacement of existing steam turbine (300 MW nameplate rating) with new turbine (310 MW nameplate rating) with the same throttle conditions. (Same mainsteam pressures, temperatures, and steam flows)
2. Replacement of turbine piping adjacent to turbine and pedestal (steam, feedwater, condensate, cooling water, lubricating oil, etc.)
3. Condition assessment of high temperature, high pressure parts such as steam leads, high pressure steam and feedwater lines, etc.
4. Replacement of high pressure and low pressure feedwater heaters (two strings of 3 high pressure heaters each, and one string of 5 low pressure heaters).
5. Replacement of turbine drainage equipment.

C. Balance of Plant

1. Replacement of feedwater makeup treatment plant.

2. Replacement of auxiliary transformers (TPDHC-40000/20/b,3/6,3)

3. Replacement of auxiliary switchgear (65 cells)

4. Replacement of electrical distribution motor control centers. (80 @380 VAC 50 Hz).

5. Replacement of 4 @1000 kVA excitation transformers.

6. Replacement of excitation system.

7. Replacement of 28 km of power cable.

D. <u>Environmental</u>

1. Replacement of existing electrostatic precipitators (3 field x 7 meter high plates) with new units (5 field x 12 meter high plates).

E. <u>Instrumentation and Controls</u>

1. Replacement of the current control system with a modern Distributed Control System (DCS).

Currently, the net heat rate and capacity factor for block 2 are estimated at 2180 kcal/KWh and 39.5% respectively. It is anticipated that after the rehabilitation these indicators will improve substantially. This rehabilitation will also help reduce fuel consumption due to the recovery of efficiency losses from the deterioration of the equipment and will improve block 2 plant availability and reliability.

The rehabilitation of Ermakovskaya Block 2 was discussed with cognizant Ermakovskaya engineering management at the Plant. Burns and Roe generally concurs with these plans for the rehabilitation of Block 2, which will largely restore the output, efficiency and availability lost due to plant deterioration.

APPENDIX I

ERMAKOVSKAYA BOILER FURNACE SLAGGING COMPUTER ANALYSES

Ermakovskaya Boiler Furnace Slagging Computer Analyses

Burns and Roe was requested by Kazakenergo to make recommendations for the amelioration of the rather serious lower furnace slagging problem of the Ermakovskaya boilers. It was also suggested that our approach to the problem should include consideration for variable coal mineral matter (ash) content and variation of the chemical composition of Ekibastuz coal.

Burns and Roe conducted the furnace slagging study using five different ash contents of the coal ranging from 44% to 37% ash. The data for the five cases are shown in the following tables.

Technical Data:

Ekibastuz coal [now fired], proximate analyses:

Ekibastuz Coal	*#1*	*#2*	*#3*	*#4*	*#5*
Ash % by weight	49	46	43	40	37
Water " "	7	6	7	6	6
VM " "	12	13	13	14	14
FC " "	32	35	37	40	43
Total	**100**	**100**	**100**	**100**	**100**

Ekibastuz coal [now fired], ultimate analyses:

Ash % by weight	49	46	43	40	37
Water " "	7	6	7	6	6
Carbon " "	34	36.3	38	42	47
Hydrogen " "	3	3.1	3	4	4
Nitrogen " "	1	0.9	1	1	1
Sulfur " "	1	0.7	1	1	1
Oxygen " " [by diff.]	5	7	7	6	4
Total	**100**	**100**	**100**	**100**	**100**

LHV range 14 to 16 MJ/kg (3343 to 3821 kcal/kg or 6018 to 6878 BTU/lb)

SM

HHV	kcal/kg	3545	3700	3778	3860	4067
	BTU/lb	6380	6658	6800	6950	7320

Now fired coal mineral matter chemical analyses:

Ekibastuz Coal		*#1*	*#2*	*#3*	*#4*	*#5*
SiO_2	% by weight	55	60.00	57	60	60
Al_2O_3	" "	29	29.00	29	28	30
Fe_2O_3	" "	11	6.50	9	7	5
TiO_2	" "	1	1.00	1	1	1
CaO	" "	2	1.70	2	2	2
MgO	" "	0.7	0.70	0.7	0.7	0.7
K_2O	" "	0.7	0.65	0.7	0.7	0.7
Na_2O	" "	0.3	0.30	0.3	0.3	0.3
SO_3	" "	0.3	0.15	0.3	0.3	0.3
Total		**100**	**100**	**100**	**100**	**100**

Grindability Indices:

Russian K_{po} = 1.3					
HGI's assumed:	70	66	68	66	66

Fusibility temperatures of ash [assumed reducing atm.]:

Initial Deform.	°C	1145	1200	1150	1180	1400
Softening	°C	1300	1400	1350	1450	1500
Flow	°C	1350	1500	1400	1500	1550

Slagging Process Description of the Pn-950-255/545 Boiler

Slagging type furnace tubewall deposits have always been encountered with the firing of Ekibastuz coal, but the rate of deposition at any given load has increased due to the deteriorated condition of the boilers. The heavier deposits are located in the furnace burner zone, around the burners (eyebrow type deposits probably). In addition, the slagging deposits are also located in the corners of the furnaces, in the maximum furnace heatflux zone above the top horizontal row of burners, and at the upper furnace exit plane including the bottom part of the pendant radiant superheater platens. The full load furnace adiabatic flame temperature is estimated to be 1550 °C and the furnace exit gas temperature [FEGT] at the same load is estimated to be approx. 1250 °C.

The slagging process in the subject furnaces is influenced [among other factors], by the characteristics of the coal and its mineral matter chemical composition, the local oxidizing and/or reducing atmospheres, the combustion process, the pulverized coal fineness, the design of the furnace tubewall, and by the design of the burners, etc.

The tubewall deposition process starts with slag pieces of 100 to 200 mm size adhering to the fireside tube surfaces. These are loose deposits, relatively easily dislodged and fall to the furnace bottom and are removed by the bottom ash handling system. However, from time to time, pieces of slag on the tubewalls increase to larger sizes [500 to 1000 mm] and then fall to the furnace bottom into the tube hopper. Here they accumulate together with other slag pieces and some flyash particles. The slag accumulation proceeds gradually as the furnace tube hopper walls are covered by the slag accumulation, the furnace heat **absorption** falls for the same amount of furnace heat input, the furnace gas temperatures increase, thereby increasing the slag deposition rate on the tubewalls and also the furnace bottom slag accumulation. The slagging process continues until operators are forced to trip the firing.

According to plant personnel, the main reasons for the furnace slagging problem are:

- Deterioration in the Ekibastuz coal quality. Ash content increased from the design 38.7% by weight to a maximum of 59 %, LHV decreased from design of 3710 kcal/kg to approx. 3300 kcal/kg, and some changes occured over the years in the coal mineral matter chemical composition.

- Furnace tube hopper construction [meandering horizontal tubebands and tube hopper opening too narrow] and bottom ash removal system has inadequate capacity for the removal of the increased quantities of bottom ash.

- Insufficient burner zone height, thus resulting in rather high burner zone heat release rates. The distance between the centerline of horizontal burner rows should be increased.

- Possible local reducing atmosphere furnace conditions in the burner zone.

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- Unequal fuel and secondary [combustion] air distribution between burners.

- Insufficient coverage by furnace tubewall steam sootblowers. The existing cleaning equipment is not able to effectively remove slag accumulations around the burners and from the furnace corners.

Burns and Roe analyzed the cases using an inhouse computer program, which assesses the slagging, fouling, erosion and corrosion propensity of coal mineral matter, [ash] together with a correlation that aims to establish furnace cleanability for a given coal mineral matter. Please see the attached computer input/output sheets and 2 pages of graphs for each of the cases. The graphs illustrate the Halfinger Furnace Cleanability correlation. The correlation uses the ash content (lb/MMBTU), the base/acid ratio and the ash softening temperature, to arrive at a furnace cleanability assessment. The horizontal line drawn from the calculated Base/Acid ratio is connected with the calculated ash input [lb/million BTU]. The ash inputs (ash contents) are plotted both on the above referenced as well as the bottom horizontal lines. Please ignore the Base/Acid ratio of 1.2, this is an incidental baseline onto which the furnace ash "inputs" [lb/million BTU] have been plotted. The lines of specific slope represent increasing ash inputs [lb/million BTU] i.e. the higher the value of ash input the less steep the slope.

The horizontal line drawn from the calculated Base/Acid ratio is intersected with the specific sloping line originating from the calculated ash input [lb/million BTU]. The intersection point is transferred to the next graph, continued as a horizontal line and intersected with a vertical line originating from the inputted Ash Softening Temperature. The final intersection falls into a"furnace cleanability assessment" zone. The zone happens to be worse than doubtful in most of our referenced cases, due to the very high "ash input" [lb/million BTU] values. Either a reduction of "ash inputs" or an increase of the Ash Softening Temperatures would bring the cleanability assessment into more favorable cleanability zones. For all of the runs, the cleanability assessment is worse than doubtful or **doubtful, because of the high ash content.**

A quick review of the results clearly points to the fact that for all variations in coal mineral matter content and chemical composition of the mineral matter, **all of the slagging indices indicate a low or medium slagging propensity, except the ash content (lbs/MMBTU or kg/million kcal). That is, if the coal mineral matter content could be reduced by some physical or chemical means, prior to firing, then the slagging problem of the Ermakovskaya boiler furnaces would be substantially reduced.** This is a conclusion which has already been made without reviewing the results of these computer calculations, by the GRES technical personnel. Nevertheless, the results do seem to reinforce that conclusion.

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CALCULATIONS OF COMMON ASH
SLAGGING, FOULING, EROSION AND ASH CORROSION INDICES
AND REDUCING ATM. ASH FUSION TEMPERATURES

Date: 16-Nov-95

INPUT SHEET:

Coal Name: Ekibastuz #1

As Received Coal Ultimate Analysis	
Carbon	36.30
Hydrogen	3.10
Sulfur	0.70
Nitrogen	0.90
Oxygen	7.00
Ash	46.00
Moisture	6.00
Sum	100.00

Ash Analysis	
SiO_2	60.00
Al_2O_3	29.00
Fe_2O_3	6.50
CaO	1.70
MgO	0.70
Na_2O	0.30
K_2O	0.65
TiO_2	1.00
P_2O_5	0.00
SO_3	0.15
Sum	100.00

As Received Coal Proximate Analysis	
Fixed Carbon	35
Volatiles	13
Ash	46
Moisture	6
Sum	100.00

Hardgrove Grindability Index (HGI) 66

HHV (Btu/lb) 6658

Red. Atmos. Initial Deformation Temp.- F 2192
Red. Atmos. Softening Temp. - F 2552
Red. Atmos. Fluid Temp. - F 2732

* Note: Analysis does not total 100%

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CALCULATIONS OF COMMON ASH
SLAGGING, FOULING, EROSION AND ASH CORROSION INDICES
AND REDUCING ATM. ASH FUSION TEMPERATURES

Coal Name: Ekibastuz

Ash Nature: Bituminous

SLAGGING INDICES:	Value	Rating
Base/Acid Ratio	0.11	Low
Slagging Factor (Rs) (After Winegartner)	0.08	Low
Slagging Factor (Rs) (After Nolte & Horney)...	0.03	Low
T250 Temperature - F		
By Method of Nicholls and Reid	2878	Low
By Method of Watt and Fereday	2809	Low
Halfinger Furnace Cleanability	NA	Doubtful
Silica to Alumina Ratio	2.07	Low
Iron to Calcium Ratio	3.82	Low
% Calcium in Ash	1.70	Low
Ash Content (As Received) - Lbs/MMBtu	69.09	Severe
Red. Atmos. Initial Deformation Temp.- F	2192	Medium
Red. Atmos. Softening Temp. - F	2552	Low
Red. Atmos. Fluid Temp. - F	2732	Low
Delta (ID to F) Temp. - F	540	Low
Calc. Red. Atmos. Initial Deformation Temp.- F	~~2782~~	~~Low~~
Calc. Red. Atmos. Softening Temp. - F	~~2621~~	~~Low~~
Calc. Red. Atmos. Fluid Temp. - F	~~2740~~	~~Low~~
Calc. Delta (ID to F) Temp. - F	~~-42~~	~~High~~
Furnace Design Parameter: Max. Allowable Btu Input/Furn. Plan Area - Btu/Hr/Sq ft	1700000	NA
FOULING INDICES:	**Value**	**Rating**
Fouling Factor (Rf) (After Winegartner)	0.03	Low
Fouling Factor (Rf) (After Nolte & Horney)....	0.05	NA
% Sodium in Ash	0.30	Low
Sodium Modifier	1.70	Higher
% Ash in Dry Coal (Ash Contains 0.30 % Na2O)	48.94	NA
Ash Sodium plus Potassium Content in Dry Coal (in Equivalent % Na2O)..............	0.36	Medium
EROSION INDICES:	**Value**	**Rating**
Silica and Alumina in Ash - %	89.00	Severe

Ash Loading - Lbs/MMBTu	69.09	Severe
Max. Allowable Gas Velocity - Ft/Sec.	7.58	NA

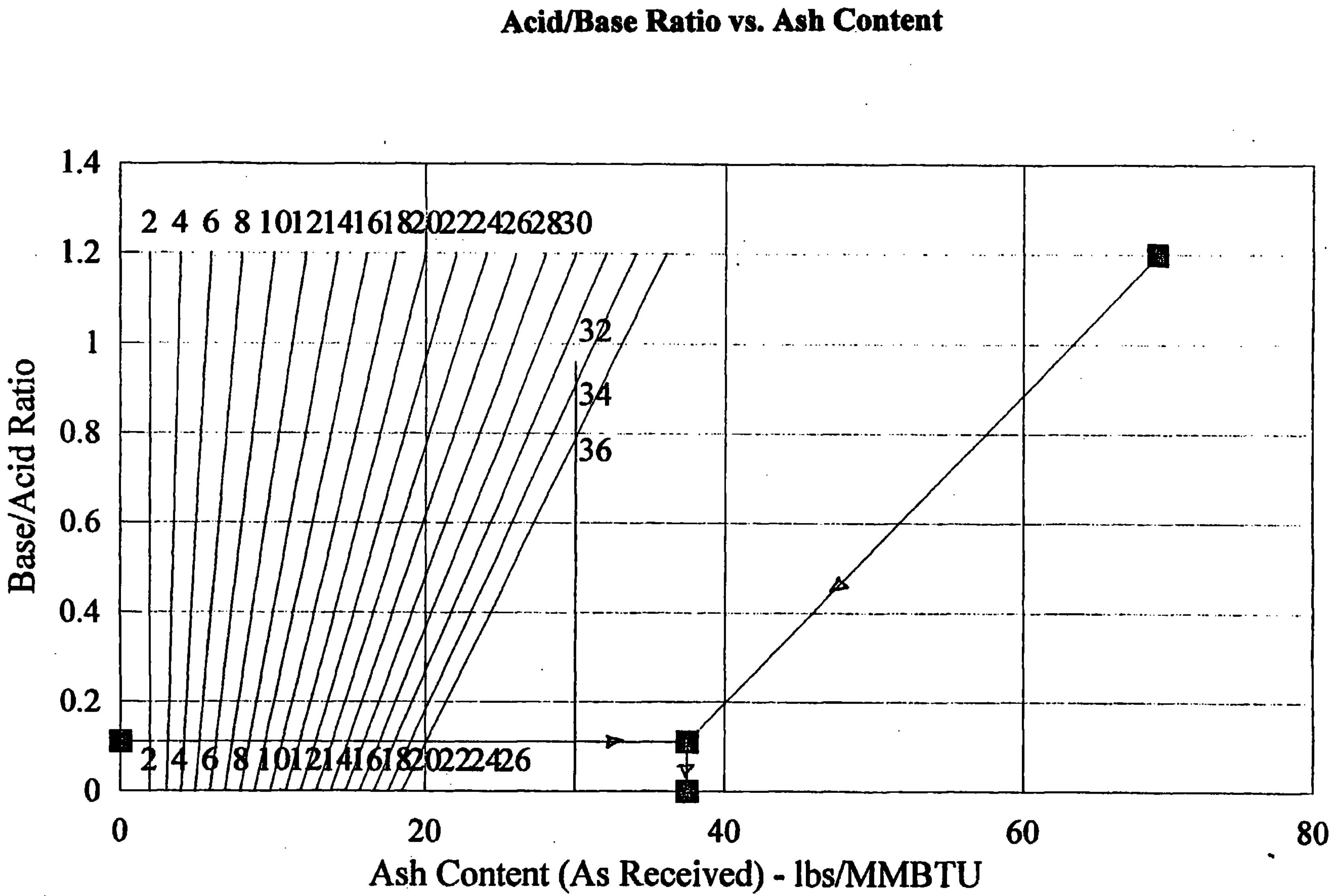
Note: When several indices are applied to the same coal, they often do not predict the same results.

NA: Not applicable

CALCULATIONS OF COMMON ASH
SLAGGING, FOULING, EROSION AND ASH CORROSION INDICES
AND REDUCING ATM. ASH FUSION TEMPERATURES

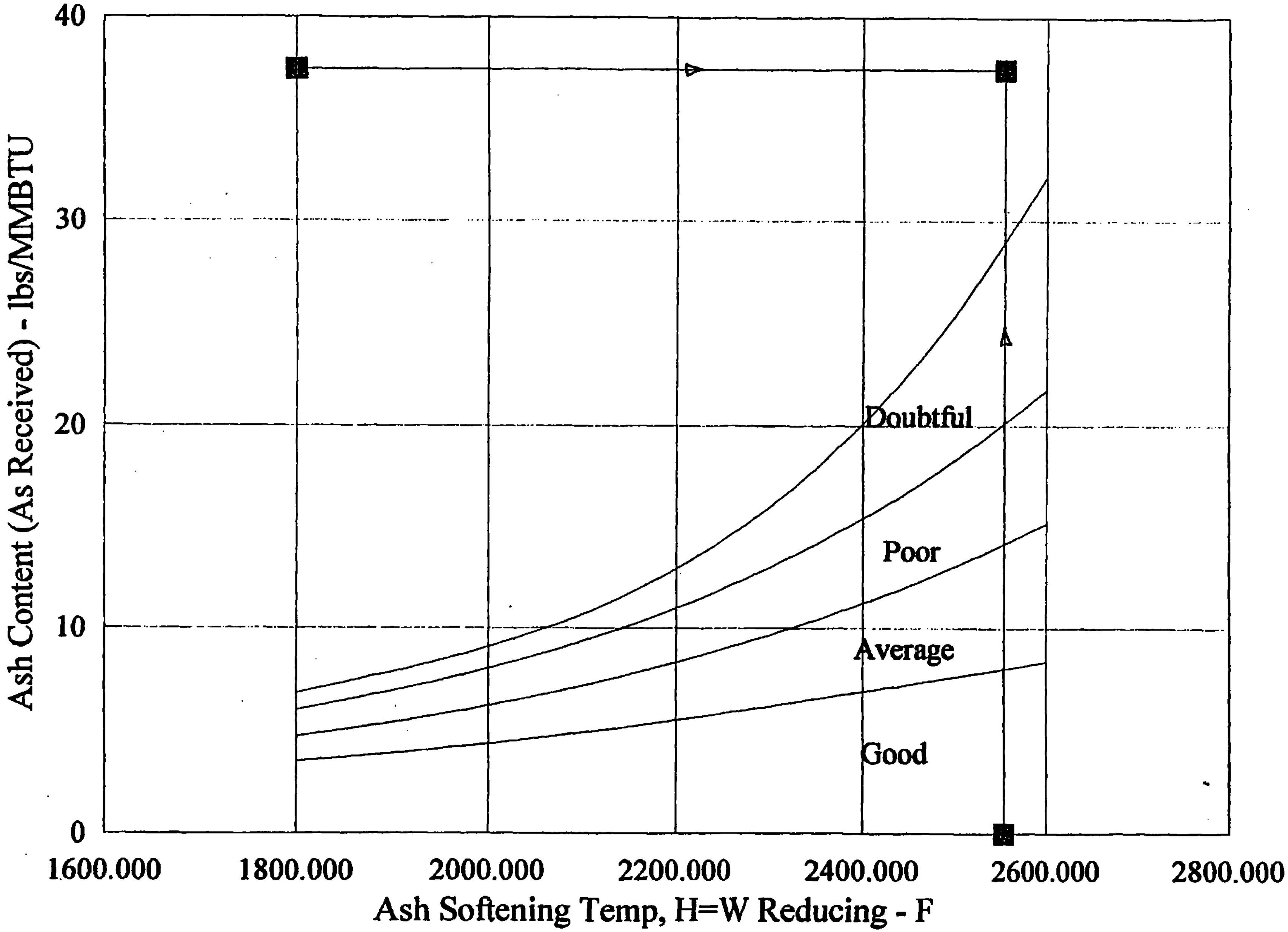
OUTPUT SHEET:

COAL ASH CORROSION INDICES:	Value	Rating
Hardgrove Grindability Index (HGI)....................	66	Low
FC/VM..	2.69	Medium
Alkalies/Alkaline Earth Ratio.................	0.40	Medium
Alkalies/CaO Ratio............................	0.56	Medium
Fe in Ash....................................	6.50%	Medium
Sulfur.......................................	0.70%	Low
Sulfur/Alkaline Earth Ratio...................	0.29	Medium



Acid/Base Ratio vs. Ash Content
1.4
1.2
1
0.8
0.6
0.4
0.2
0
Base/Acid Ratio
2 4 6 8 10 12 14 16 18 20 22 24 26 28 30
32
34
36
2 4 6 8 10 12 14 16 18 20 22 24 26
0
20
40
60
80
Ash Content (As Received) - lbs/MMBTU

Furnace Cleaning Assessment



CALCULATIONS OF COMMON ASH
SLAGGING, FOULING, EROSION AND ASH CORROSION INDICES
AND REDUCING ATM. ASH FUSION TEMPERATURES

Date: 16-Nov-95

INPUT SHEET: PAGE 1

Coal Name: Ekibastuz #2

As Received Coal Ultimate Analysis	
Carbon	34.00
Hydrogen	3.00
Sulfur	1.00
Nitrogen	1.00
Oxygen	5.00
Ash	49.00
Moisture	7.00
Sum	100.00

Ash Analysis	
SiO2	55.00
Al2O3	29.00
Fe2O3	11.00
CaO	2.00
MgO	0.70
Na2O	0.30
K2O	0.70
TiO2	1.00
P2O5	0.00
SO3	0.30
Sum	100.00

As Received Coal Proximate Analysis	
Fixed Carbon	32
Volatiles	12
Ash	49
Moisture	7
Sum	100.00

Hardgrove Grindability Index (HGI) 70

HHV (Btu/lb) 6380

Red. Atmos. Initial Deformation Temp.- F 2093
Red. Atmos. Softening Temp. - F 2372
Red. Atmos. Fluid Temp. - F 2462

* Note: Analysis does not total 100%

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CALCULATIONS OF COMMON ASH
SLAGGING, FOULING, EROSION AND ASH CORROSION INDICES
AND REDUCING ATM. ASH FUSION TEMPERATURES

OUTPUT SHEET:

Coal Name: Ekibastuz #2

Ash Nature: Bituminous

SLAGGING INDICES:	Value	Rating
Base/Acid Ratio	0.17	Low
Slagging Factor (Rs) (After Winegartner)	0.19	Low
Slagging Factor (Rs) (After Nolte & Homey)	0.07	Low
T250 Temperature - F		
By Method of Nicholls and Reid	2756	Low
By Method of Watt and Fereday	2689	Low
Halfinger Furnace Cleanability	NA	Doubtful
Silica to Alumina Ratio	1.90	Low
Iron to Calcium Ratio	5.50	Low
% Calcium in Ash	2.00	Low
Ash Content (As Received) - Lbs/MMBtu	76.80	Severe
Red. Atmos. Initial Deformation Temp.- F	2093	Medium
Red. Atmos. Softening Temp. - F	2372	Medium
Red. Atmos. Fluid Temp. - F	2462	Medium
Delta (ID to F) Temp. - F	369	Low
Calc. Red. Atmos. Initial Deformation Temp.- F	~~2577~~	~~Low~~
Calc. Red. Atmos. Softening Temp. - F	~~2485~~	~~Low~~
Calc. Red. Atmos. Fluid Temp. - F	~~2593~~	~~Low~~
Calc. Delta (ID to F) Temp. - F	~~16~~	~~High~~
Furnace Design Parameter: Max. Allowable Btu Input/Furn. Plan Area - Btu/Hr/Sq ft	1700000	NA

FOULING INDICES:	Value	Rating
Fouling Factor (Rf) (After Winegartner)	0.05	Low
Fouling Factor (Rf) (After Nolte & Homey)	0.05	NA
% Sodium in Ash	0.30	Low
Sodium Modifier	2.00	Higher
% Ash in Dry Coal (Ash Contains 0.30 % Na2O)	52.69	NA
Ash Sodium plus Potassium Content in Dry Coal (in Equivalent % Na2O)	0.40	High

EROSION INDICES:	Value	Rating
Silica and Alumina in Ash - %	84.00	High
Ash Loading - Lbs/MMBTu	76.80	Severe
Max. Allowable Gas Velocity - Ft/Sec.	4.53	NA

Note: When several indices are applied to the same coal, they often do not predict the same results.

NA: Not applicable

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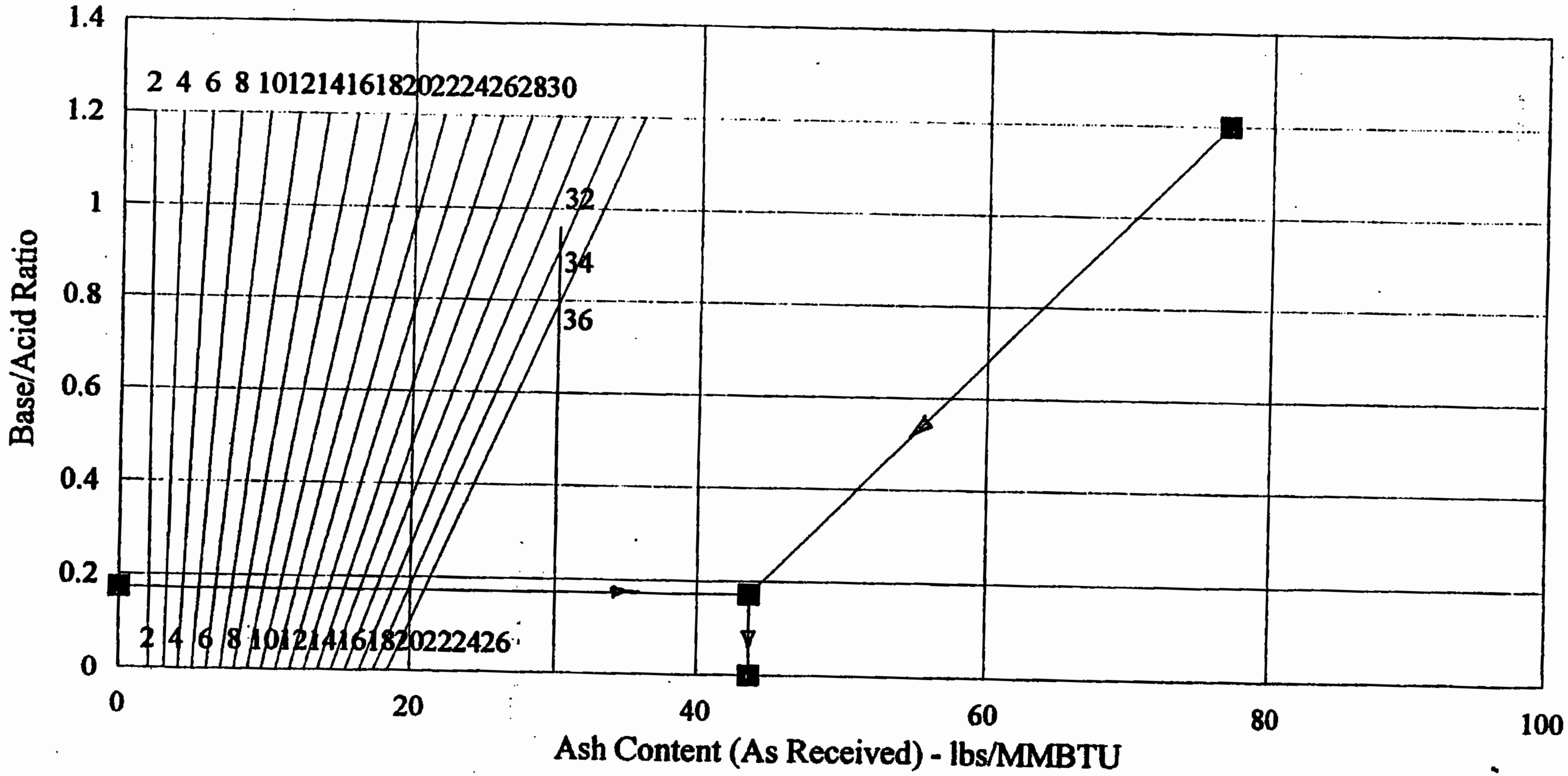
CALCULATIONS OF COMMON ASH
SLAGGING, FOULING, EROSION AND ASH CORROSION INDICES
AND REDUCING ATM. ASH FUSION TEMPERATURES

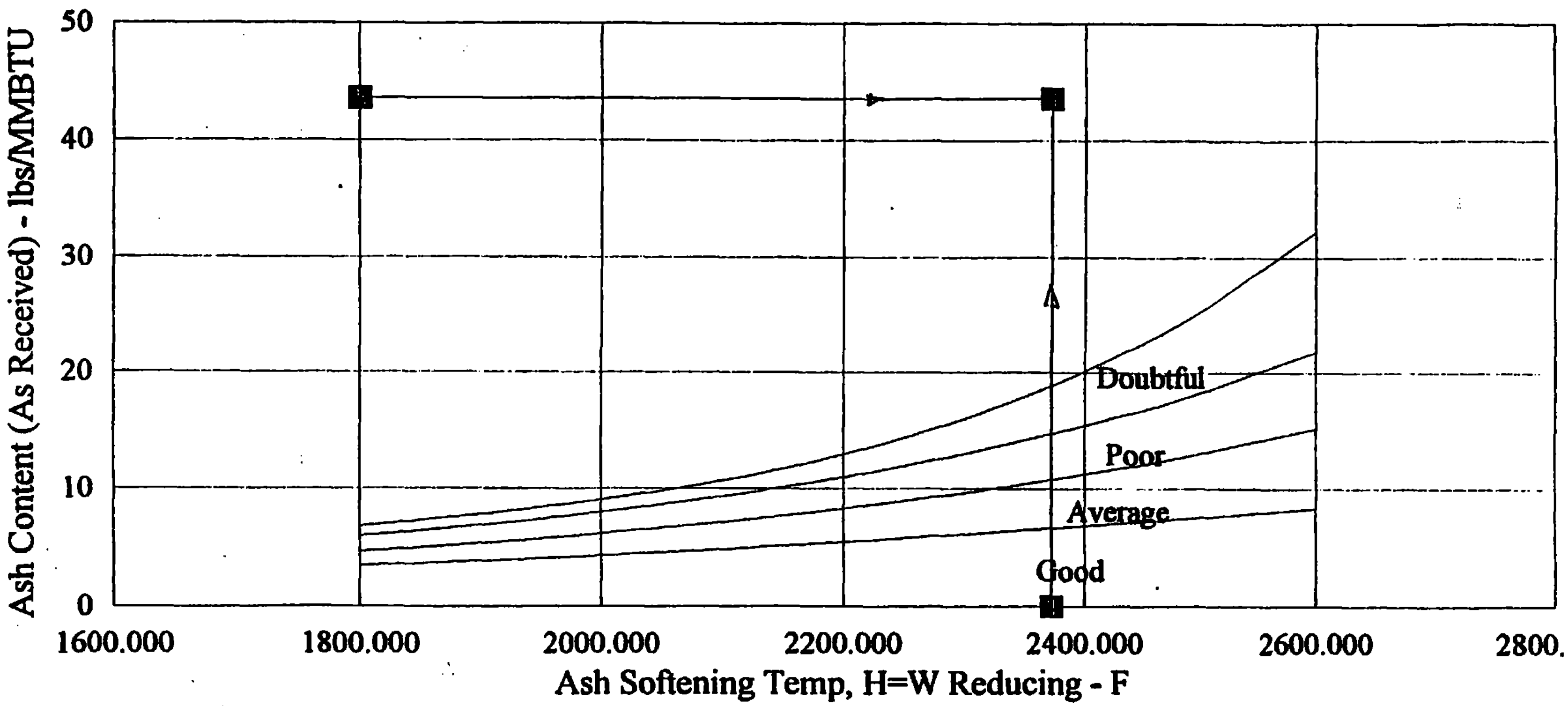
OUTPUT SHEET:

COAL ASH CORROSION INDICES:	Value	Rating
Hardgrove Grindability Index (HGI)....................	70	Low
FC/VM...	2.67	Medium
Alkalies/Alkaline Earth Ratio.................	0.37	Medium
Alkalies/CaO Ratio............................	0.50	Low
Fe in Ash.....................................	11.00%	Medium
Sulfur..	1.00%	Low
Sulfur/Alkaline Earth Ratio...................	0.37	Medium

Acid/Base Ratio vs. Ash Content



Furnace Cleaning Assessment



CALCULATIONS OF COMMON ASH
SLAGGING, FOULING, EROSION AND ASH CORROSION INDICES
AND REDUCING ATM. ASH FUSION TEMPERATURES

Date: 16-Nov-95

INPUT SHEET:

Coal Name: Ekibastuz #3

As Received Coal Ultimate Analysis	
Carbon	38.00
Hydrogen	3.00
Sulfur	1.00
Nitrogen	1.00
Oxygen	7.00
Ash	43.00
Moisture	7.00
Sum	100.00

Ash Analysis	
SiO2	57.00
Al2O3	29.00
Fe2O3	9.00
CaO	2.00
MgO	0.70
Na2O	0.30
K2O	0.70
TiO2	1.00
P2O5	0.00
SO3	0.30
Sum	100.00

As Received Coal Proximate Analysis	
Fixed Carbon	37
Volatiles	13
Ash	43
Moisture	7
Sum	100.00

Hardgrove Grindability Index (HGI) 68

HHV (Btu/lb) 6800

Red. Atmos. Initial Deformation Temp.- F 2102
Red. Atmos. Softening Temp. - F 2462
Red. Atmos. Fluid Temp. - F 2552

* Note: Analysis does not total 100%

CALCULATIONS OF COMMON ASH
SLAGGING, FOULING, EROSION AND ASH CORROSION INDICES
AND REDUCING ATM. ASH FUSION TEMPERATURES

OUTPUT SHEET:

Coal Name: Ekibastuz #3

Ash Nature: Bituminous

SLAGGING INDICES:	Value	Rating
Base/Acid Ratio	0.15	Low
Slagging Factor (Rs) (After Winegartner)	0.16	Low
Slagging Factor (Rs) (After Nolte & Horney)...	0.06	Low
T250 Temperature - F		
By Method of Nicholls and Reid	2811	Low
By Method of Watt and Fereday	2738	Low
Halfinger Furnace Cleanability	NA	Doubtful
Silica to Alumina Ratio	1.97	Low
Iron to Calcium Ratio	4.50	Low
% Calcium in Ash	2.00	Low
Ash Content (As Received) - Lbs/MMBtu	63.24	Severe
Red. Atmos. Initial Deformation Temp.- F	2102	Medium
Red. Atmos. Softening Temp. - F	2462	Low
Red. Atmos. Fluid Temp. - F	2552	Low
Delta (ID to F) Temp. - F	450	Low
Calc. Red. Atmos. Initial Deformation Temp.- F	~~2656~~	~~Low~~
Calc. Red. Atmos. Softening Temp. - F	~~2537~~	~~Low~~
Calc. Red. Atmos. Fluid Temp. - F	~~2649~~	~~Low~~
Calc. Delta (ID to F) Temp. - F	~~-7~~	~~High~~
Furnace Design Parameter: Max. Allowable Btu Input/Furn. Plan Area - Btu/Hr/Sq ft	1700000	NA

FOULING INDICES:	Value	Rating
Fouling Factor (Rf) (After Winegartner)	0.04	Low
Fouling Factor (Rf) (After Nolte & Horney)....	0.05	NA
% Sodium in Ash	0.30	Low
Sodium Modifier	2.00	Higher
% Ash in Dry Coal (Ash Contains 0.30 % Na2O)	46.24	NA
Ash Sodium plus Potassium Content in Dry Coal (in Equivalent % Na2O)...............	0.35	Medium

EROSION INDICES:	Value	Rating
Silica and Alumina in Ash - %	86.00	Severe
Ash Loading - Lbs/MMBTu	63.24	Severe
Max. Allowable Gas Velocity - Ft/Sec.	10.83	NA

Note: When several indices are applied to the same coal, they often do not predict the same results.
NA: Not applicable

CALCULATIONS OF COMMON ASH
SLAGGING, FOULING, EROSION AND ASH CORROSION INDICES
AND REDUCING ATM. ASH FUSION TEMPERATURES

OUTPUT SHEET:

COAL ASH CORROSION INDICES:	Value	Rating
Hardgrove Grindability Index (HGI)....................	68	Low
FC/VM..	2.85	Medium
Alkalies/Alkaline Earth Ratio.................	0.37	Medium
Alkalies/CaO Ratio............................	0.50	Low
Fe in Ash....................................	9.00%	Medium
Sulfur...	1.00%	Low
Sulfur/Alkaline Earth Ratio...................	0.37	Medium

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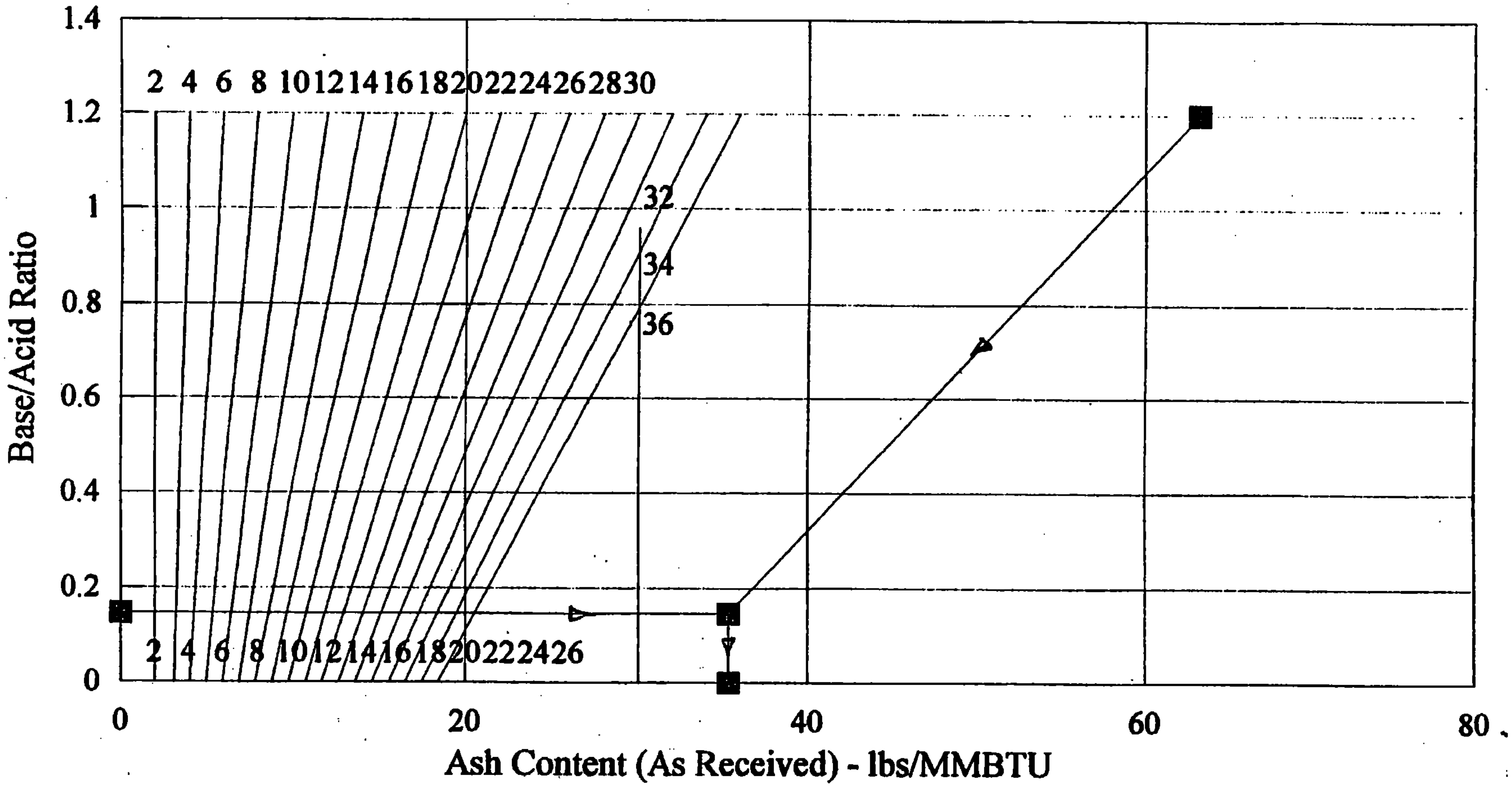
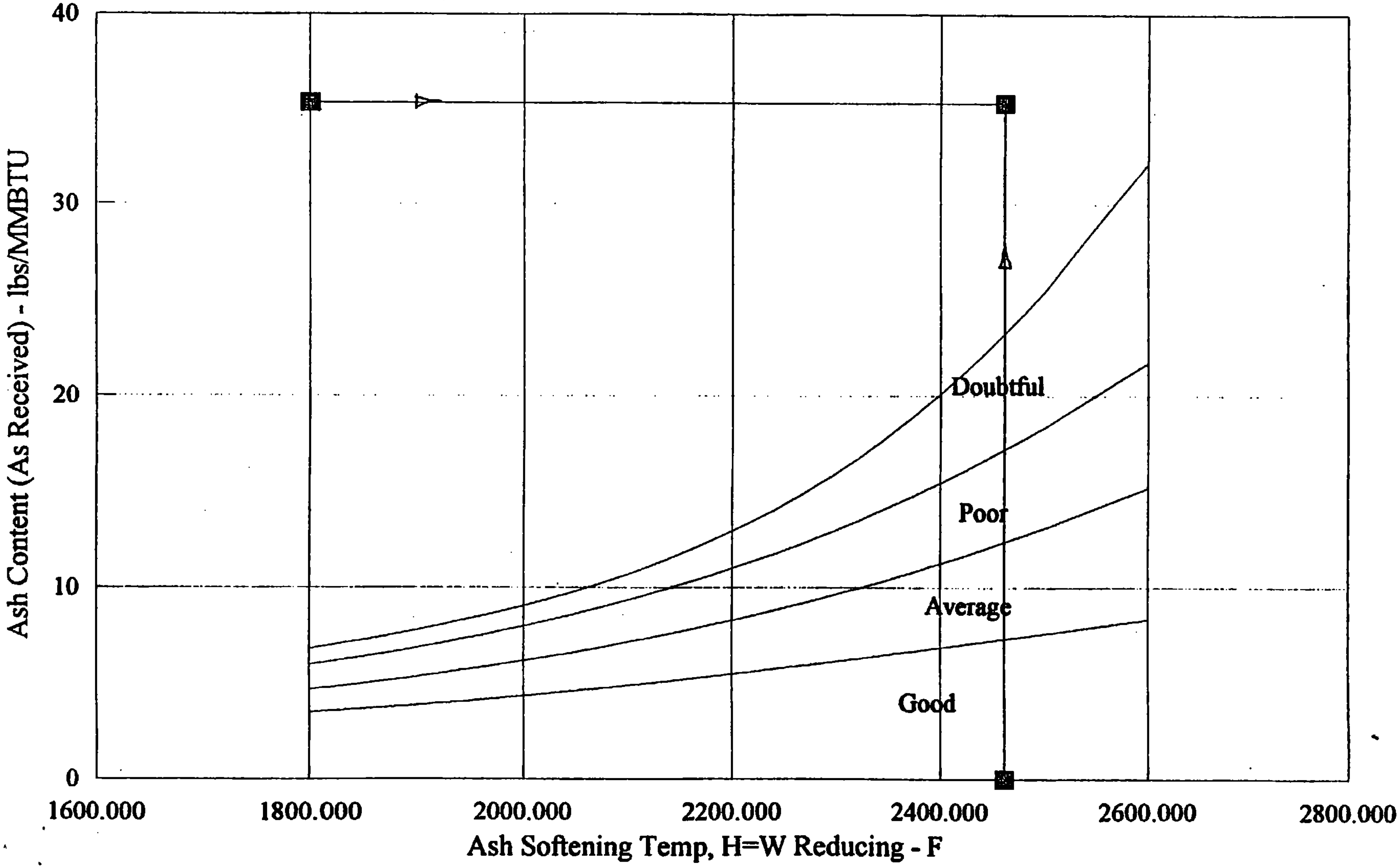
Acid/Base Ratio vs. Ash Content



Furnace Cleaning Assessment



CALCULATIONS OF COMMON ASH SLAGGING, FOULING, EROSION AND ASH CORROSION INDICES AND REDUCING ATM. ASH FUSION TEMPERATURES

Date: 16-Nov-95

INPUT SHEET:

Coal Name: Ekibastuz #4

As Received Coal Ultimate Analysis

Carbon	42.00
Hydrogen	4.00
Sulfur	1.00
Nitrogen	1.00
Oxygen	6.00
Ash	40.00
Moisture	6.00
Sum	100.00

Ash Analysis

SiO2	60.00
Al2O3	28.00
Fe2O3	7.00
CaO	2.00
MgO	0.70
Na2O	0.30
K2O	0.70
TiO2	1.00
P2O5	0.00
SO3	0.30
Sum	100.00

As Received Coal Proximate Analysis

Fixed Carbon	40
Volatiles	14
Ash	40
Moisture	6
Sum	100.00

Hardgrove Grindability Index (HGI) 66

HHV (Btu/lb) 6950

Red. Atmos. Initial Deformation Temp.- F 2156
Red. Atmos. Softening Temp. - F 2642
Red. Atmos. Fluid Temp. - F 2732

* Note: Analysis does not total 100%

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CALCULATIONS OF COMMON ASH
SLAGGING, FOULING, EROSION AND ASH CORROSION INDICES
AND REDUCING ATM. ASH FUSION TEMPERATURES

OUTPUT SHEET:

Coal Name: Ekibastuz #4

Ash Nature: Bituminous

SLAGGING INDICES:	Value	Rating
Base/Acid Ratio	0.12	Low
Slagging Factor (Rs) (After Winegartner)	0.13	Low
Slagging Factor (Rs) (After Nolte & Horney)	0.05	Low
T250 Temperature - F		
By Method of Nicholls and Reid	2863	Low
By Method of Watt and Fereday	2801	Low
Halfinger Furnace Cleanability	NA	Doubtful
Silica to Alumina Ratio	2.14	Low
Iron to Calcium Ratio	3.50	Low
% Calcium in Ash	2.00	Low
Ash Content (As Received) - Lbs/MMBtu	57.55	Severe
Red. Atmos. Initial Deformation Temp.- F	2156	Medium
Red. Atmos. Softening Temp. - F	2642	Low
Red. Atmos. Fluid Temp. - F	2732	Low
Delta (ID to F) Temp. - F	576	Low
Calc. Red. Atmos. Initial Deformation Temp.- F	~~2693~~	~~Low~~
Calc. Red. Atmos. Softening Temp. - F	~~2574~~	~~Low~~
Calc. Red. Atmos. Fluid Temp. - F	~~2706~~	~~Low~~
Calc. Delta (ID to F) Temp. - F	~~13~~	~~High~~
Furnace Design Parameter: Max. Allowable Btu Input/Furn. Plan Area - Btu/Hr/Sq ft	1700000	NA

FOULING INDICES:	Value	Rating
Fouling Factor (Rf) (After Winegartner)	0.04	Low
Fouling Factor (Rf) (After Nolte & Horney)	0.05	NA
% Sodium in Ash	0.30	Low
Sodium Modifier	2.00	Higher
% Ash in Dry Coal (Ash Contains 0.30 % Na2O)	42.55	NA
Ash Sodium plus Potassium Content in Dry Coal (in Equivalent % Na2O)	0.32	Medium

EROSION INDICES:	Value	Rating
Silica and Alumina in Ash - %	88.00	Severe
Ash Loading - Lbs/MMBTu	57.55	Severe
Max. Allowable Gas Velocity - Ft/Sec.	9.64	NA

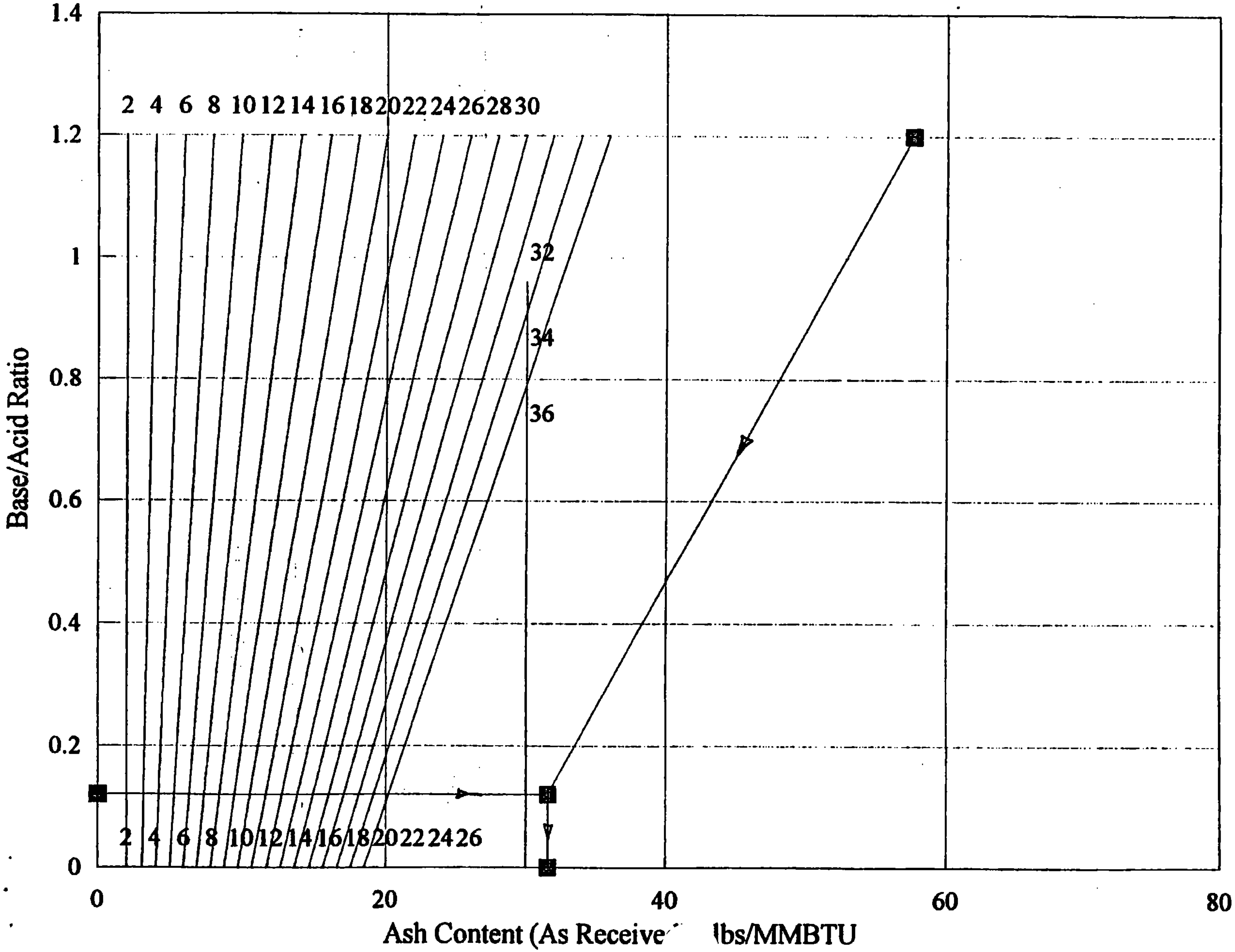
Note: When several indices are applied to the same coal, they often do not predict the same results.
NA: Not applicable

CALCULATIONS OF COMMON ASH
SLAGGING, FOULING, EROSION AND ASH CORROSION INDICES
AND REDUCING ATM. ASH FUSION TEMPERATURES

OUTPUT SHEET:

COAL ASH CORROSION INDICES:	Value	Rating
Hardgrove Grindability Index (HGI)....................	66	Low
FC/VM..	2.86	Medium
Alkalies/Alkaline Earth Ratio.................	0.37	Medium
Alkalies/CaO Ratio...........................	0.50	Low
Fe in Ash....................................	7.00%	Medium
Sulfur.......................................	1.00%	Low
Sulfur/Alkaline Earth Ratio..................	0.37	Medium

Acid/Base Ratio vs. Ash Content



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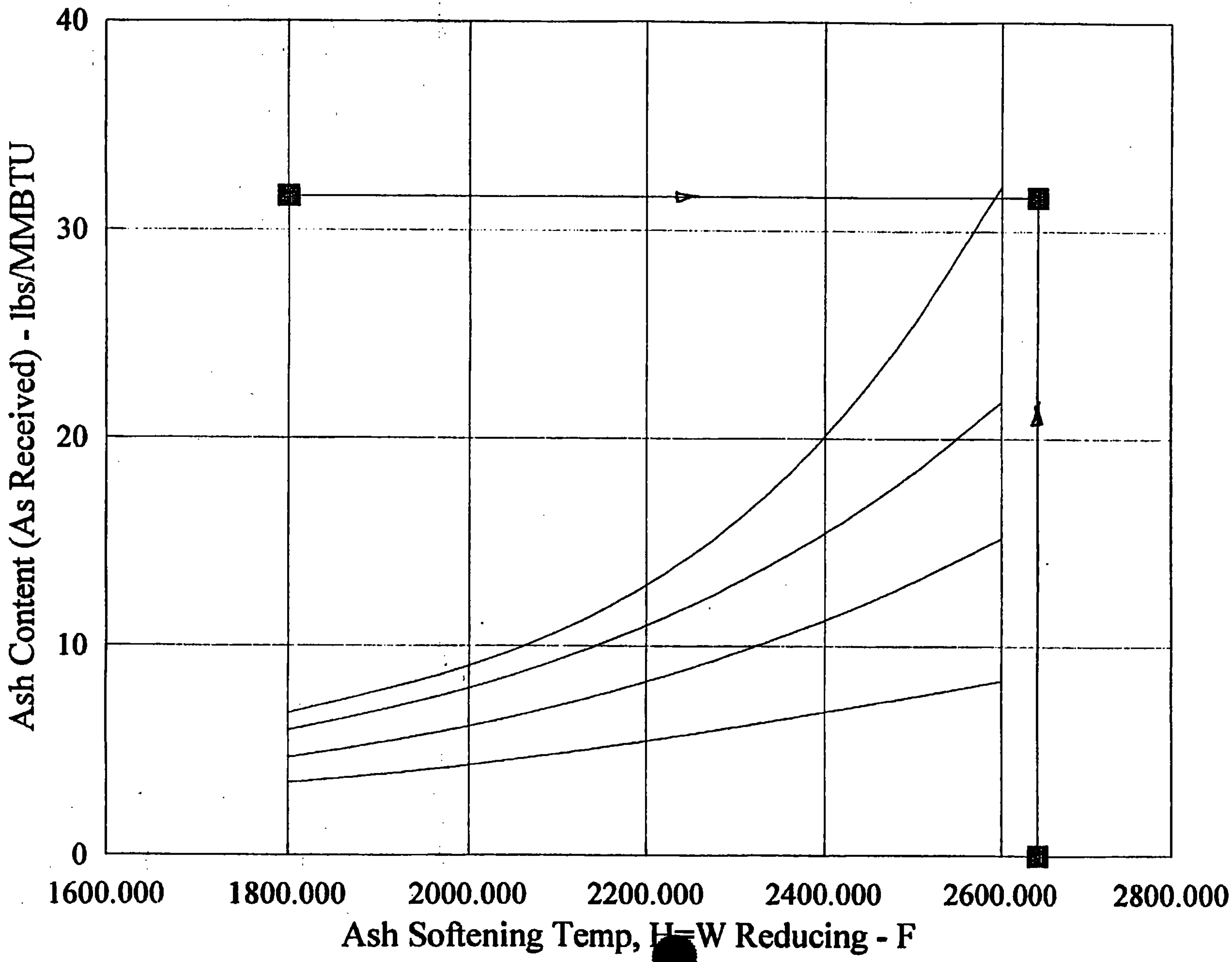
Furnace Cleaning Assessment



CALCULATIONS OF COMMON ASH
SLAGGING, FOULING, EROSION AND ASH CORROSION INDICES
AND REDUCING ATM. ASH FUSION TEMPERATURES

Date: 16-Nov-95

INPUT SHEET:

Coal Name: Ekibastuz #5

As Received Coal Ultimate Analysis*	
Carbon	47.00
Hydrogen	4.00
Sulfur	1.00
Nitrogen	1.00
Oxygen	4.00
Ash	37.00
Moisture	6.00
Sum	100.00

Ash Analysis	
SiO_2	60.00
Al_2O_3	30.00
Fe_2O_3	5.00
CaO	2.00
MgO	0.70
Na_2O	0.30
K_2O	0.70
TiO_2	1.00
P_2O_5	0.00
SO_3	0.30
Sum	100.00

As Received Coal Proximate Analysis	
Fixed Carbon	43
Volatiles	14
Ash	37
Moisture	6
Sum	100.00

Hardgrove Grindability Index (HGI) 66

HHV (Btu/lb) 7320

Red. Atmos. Initial Deformation Temp.- F 2552
Red. Atmos. Softening Temp. - F 2732
Red. Atmos. Fluid Temp. - F 2822

* Note: Analysis does not total 100%

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CALCULATIONS OF COMMON ASH
SLAGGING, FOULING, EROSION AND ASH CORROSION INDICES
AND REDUCING ATM. ASH FUSION TEMPERATURES

OUTPUT SHEET:

Coal Name: Ekibastuz #5

Ash Nature: Bituminous

SLAGGING INDICES:	Value	Rating
Base/Acid Ratio	0.10	Low
Slagging Factor (Rs) (After Winegartner)	0.10	Low
Slagging Factor (Rs) (After Nolte & Homey)...	0.04	Low
T250 Temperature - F		
By Method of Nicholls and Reid	2901	Low
By Method of Watt and Fereday	2820	Low
Halfinger Furnace Cleanability	NA	Doubtful
Silica to Alumina Ratio	2.00	Low
Iron to Calcium Ratio	2.50	High
% Calcium in Ash	2.00	Low
Ash Content (As Received) - Lbs/MMBtu	50.55	Severe
Red. Atmos. Initial Deformation Temp.- F	2552	Low
Red. Atmos. Softening Temp. - F	2732	Low
Red. Atmos. Fluid Temp. - F	2822	Low
Delta (ID to F) Temp. - F	270	Medium
Calc. Red. Atmos. Initial Deformation Temp.- F	~~2925~~	~~Low~~
Calc. Red. Atmos. Softening Temp. - F	~~2713~~	~~Low~~
Calc. Red. Atmos. Fluid Temp. - F	~~2790~~	~~Low~~
Calc. Delta (ID to F) Temp. - F	~~135~~	~~High~~
Furnace Design Parameter: Max. Allowable		
Btu Input/Furn. Plan Area - Btu/Hr/Sq ft	1700000	NA

FOULING INDICES:	Value	Rating
Fouling Factor (Rf) (After Winegartner)	0.03	Low
Fouling Factor (Rf) (After Nolte & Homey)....	0.05	NA
% Sodium in Ash	0.30	Low
Sodium Modifier	2.00	Higher
% Ash in Dry Coal (Ash Contains		
0.30 % Na2O)	39.36	NA
Ash Sodium plus Potassium Content in		
Dry Coal (in Equivalent % Na2O)...............	0.30	Low

EROSION INDICES:	Value	Rating
Silica and Alumina in Ash - %	90.00	Severe
Ash Loading - Lbs/MMBTu	50.55	Severe
Max. Allowable Gas Velocity - Ft/Sec.	12.66	NA

Note: When several indices are applied to the same coal, they often do not predict the same results.

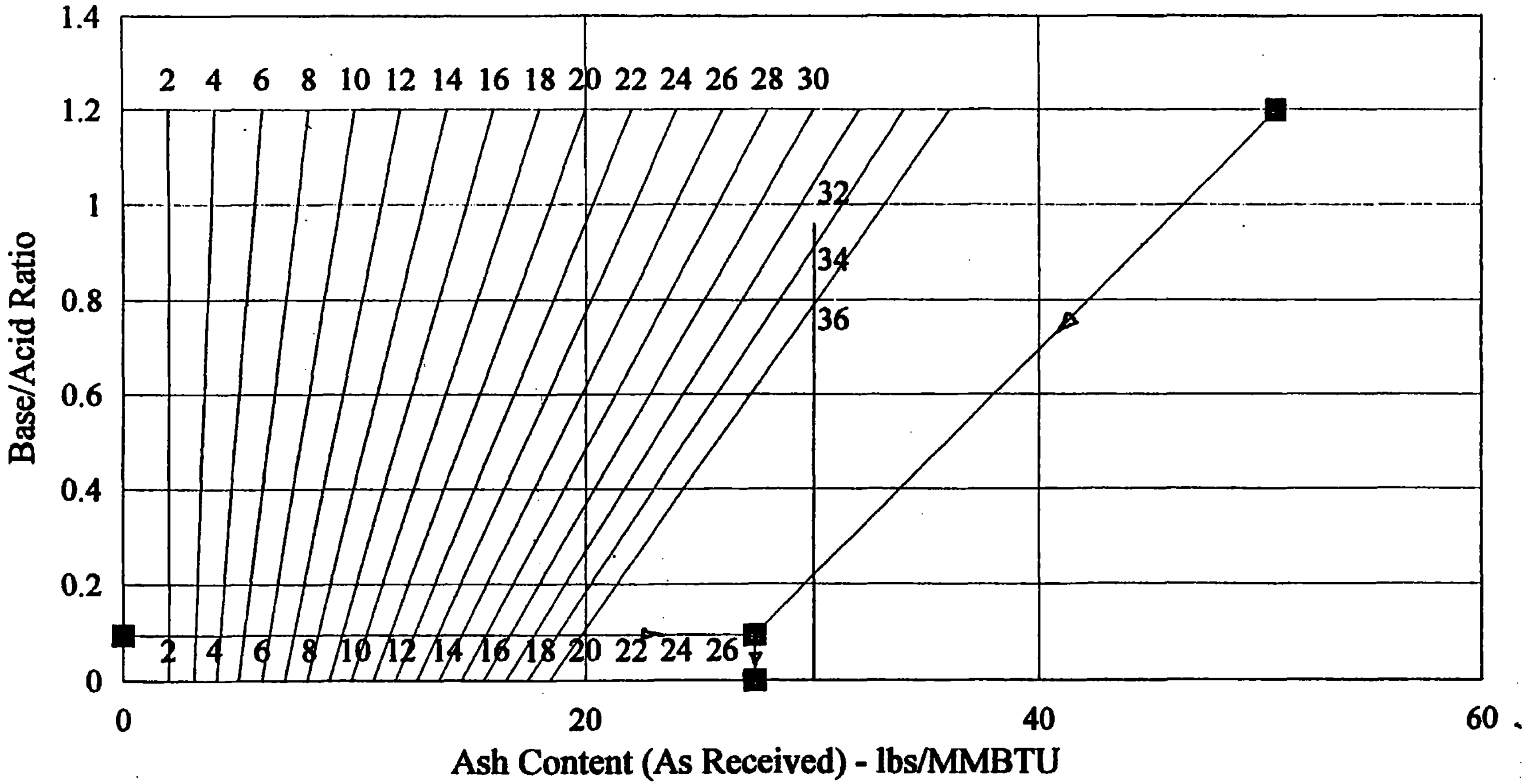
NA: Not applicable

CALCULATIONS OF COMMON ASH SLAGGING, FOULING, EROSION AND ASH CORROSION INDICES AND REDUCING ATM. ASH FUSION TEMPERATURES

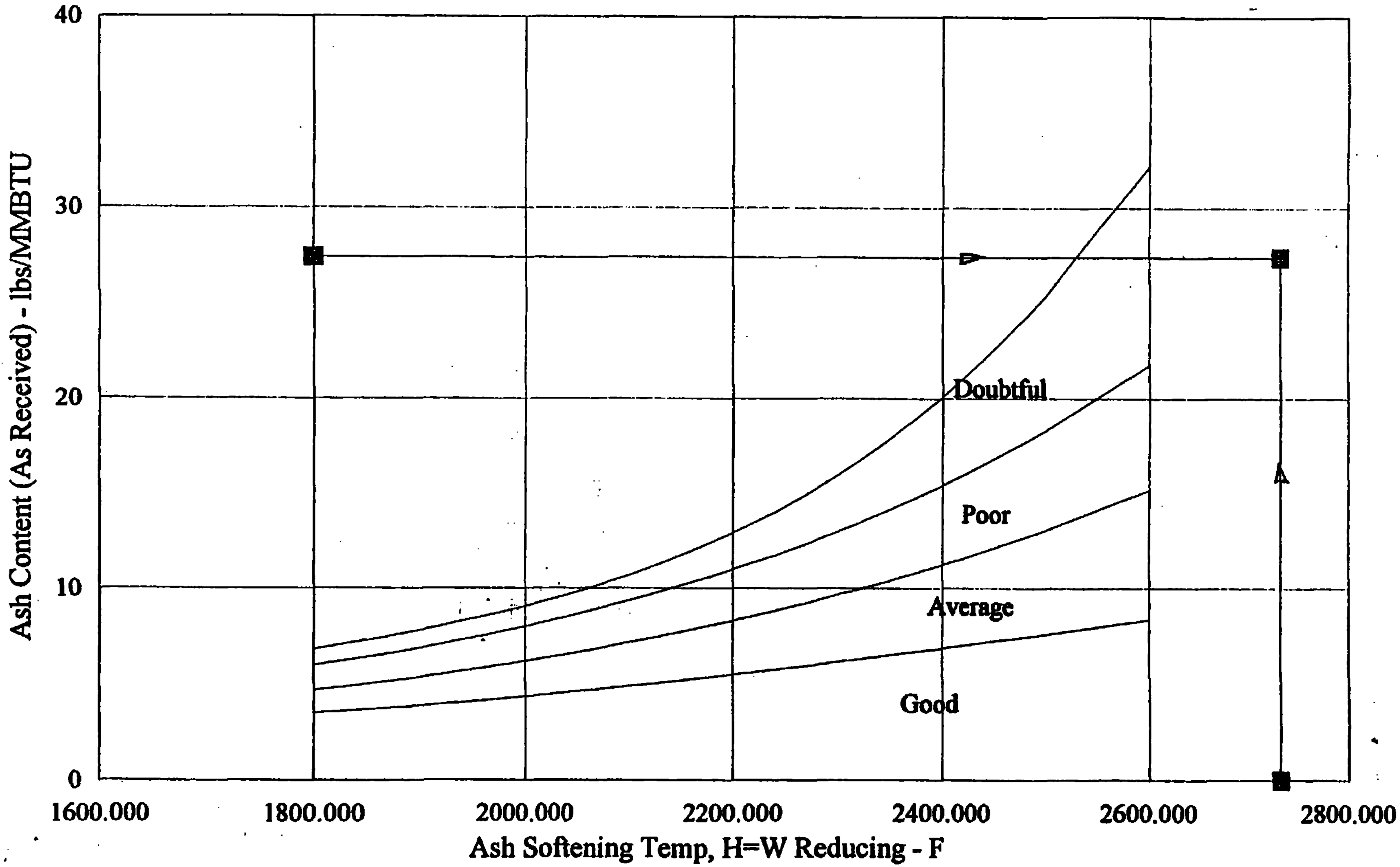
OUTPUT SHEET:

COAL ASH CORROSION INDICES:	Value	Rating
Hardgrove Grindability Index (HGI)....................	66	Low
FC/VM..	3.07	Medium
Alkalies/Alkaline Earth Ratio.................	0.37	Medium
Alkalies/CaO Ratio............................	0.50	Low
Fe in Ash....................................	5.00%	Medium
Sulfur..	1.00%	Low
Sulfur/Alkaline Earth Ratio...................	0.37	Medium

Acid/Base Ratio vs. Ash Content



Furnace Cleaning Assessment



Burns and Roe Enterprises, Inc.

Technical Report

KAZAKSTAN EXPANDED ENERGY PROGRAM

HEAT AND POWER SYSTEM EFFICIENCY IMPROVEMENTS

EKIBASTUZ PLANT
BLOCK NO. 3

FINAL REPORT

December 1995

Prepared by:	Burns and Roe Enterprises, Inc.
Submitted to:	U.S. Agency for International Development The Government of Kazakstan
Contract No. :	CCN-0002-Q-09-3154-00 Heat and Power System Efficiency Improvements Delivery Order No.9, Task 2

TABLE OF CONTENTS

EKIBASTUZ EXPANDED ENERGY PROGRAM

TASK 2

HEAT AND POWER SYSTEM EFFICIENCY IMPROVEMENT

EKIBASTUZ POWER PLANT NO. 1

ABBREVIATIONS

CIS	Community of Independent States
USAID	U.S. Agency for International Development
CCE	Capital Cost Estimate
CHP	Combined Heat and Power
TES	Thermal Electric Station
LHV	Lower Heating Value
OD	Outside Diameter
PA	Primary Air
PC	Pulverized Coal
NDE	Non Destructive Examination
HP	High Pressure
IP	Intermediate Pressure
LP	Low Pressure
NO_x	Nitrogen Oxides
SO_2	Sulfur Dioxide
ESP	Electrostatic Precipitators
I&C	Instrumentation and Controls
OFA	Overfire air or bulk furnace air staging
LNB	Low NO_x burner
VM	Volatile matter
FC	Fixed carbon
HGI	Hardgrove Grindability Index, HGI = (K_{po} -0.32)/0.0149

WEIGHTS AND MEASURES

at abs. or g	atmosphere absolute or gage
Gcal	Gigacalorie (10^9 cal)
MW	Megawatt (10^6 Watt)
kW	kilowatt (10^3 Watt)
kg	kilogram
kV	kilovolt
kWh	kiloWatt hour
MVAR	Megavolt-Ampere Reactive
kg/cm^2	kilograms per square centimeter
t/h or te/h	tons per hour (metric)
RPM	Rotations per minute
BTU	British Thermal Unit
MMBTU	Million BTU heat input

CONVERSION FACTORS

1 GCal = 4.187 GJ = 3.968 x 10^6 BTU = 1,163 kWh

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EKIBASTUZ BLOCK 3 REHABILITATION

1.0 INTRODUCTION AND OBJECTIVE

The dissolution of the Soviet Union in 1991 resulted in the formation of five new independent republics in Central Asia: Kazakstan, Kyrgyzstan, Uzbekistan, Turkmenistan and Tajikistan. Of these, Kazakstan is the largest republic in terms of physical size and second largest in population. Its physical size (area) is more than the area of the other four republics combined.

Kazakstan is a vast country with an abundance of valuable resources, including abundant energy reserves and a large industrial base. Unfortunately, the collapse of the former Soviet Union has resulted in economic dislocations throughout the central Asian republics including Kazakstan. The transition from a command economy to a market economy has been painful to the population. Industries which are no longer subsidized and protected by the former Soviet Union must be able to survive in a more competitive market place. This has resulted in a severe economic recession. The current economic recession has adversely affected the country's economy, including the slowdown in the energy industries.

The majority of the thermal and heating plants in Kazakstan are over 20 years old and are operating with obsolete equipment or with components requiring renovation. Maintenance schedules do not allow for high availability of the units. In addition, many plants are obliged to fire non-design fuel (e.g. coal with ash content exceeding the maximum design specification). These problems combine to decrease power and heat production levels by as much as 20-40% from the design capacities. The impact of the reduced power production has been moderated in the past few years by a decrease in demand due to industrial recession. Reduced heat production often results in domestic heating black-outs.

The shortfall in energy production will continue if the plants are not rehabilitated in the future; and as Kazakstan grows into a market-led economy, the demand will accelerate and lack of available energy will, potentially, become the limiting factor in the economic development of the country.

Increasing the efficiency of existing plants by refurbishing of plant equipment, extending service life and implementing a consumer energy saving program are the most cost effective means for increasing energy independence. However, the necessary renovation costs are large. A plan for a consumer energy savings program is being developed separately by a joint effort of the Ministries of Economy and the Ministry of Energy and Coal. This separate effort is also supported by USAID.

USAID has recognized the seriousness of these problems, and has authorized this task for Burns and Roe to assess the situation relative to Heat and Power Plant Efficiency Improvements. The work covered by this report addresses the assessment of selected units at four different locations in Kazakstan. The Ekibastuz Electric Generation (Power) Plant No. 1, Block No. 3 is one of the selected units for energy efficiency improvements study.

The objective of this project is to assess the costs and benefits of the efficiency and energy production improvements which can be achieved by renovating and extending the life of the selected units. This report may serve as a basis for domestic and foreign investment considerations.

The work covered by this report included the following tasks:

- Background data related to the project was collected and analyzed. Meetings were held with Kazakstani engineers to discuss the collected data.

- A condition assessment was performed to identify the major plant systems and components which require rehabilitation or modernization.

- An engineering analysis was performed to recommend appropriate modern technology for increasing the availability and performance of the selected units. These analyses also include development of capital cost estimates and implementation schedules.

- A detailed rehabilitation and modernization program is outlined and recommendations are made for life extension of the unit. The effect of coal quality improvement on increased plant performance is also included.

- The results of the engineering analysis will be reviewed with Kazakstani authorities. The Kazakstani authorities may extrapolate the results of this analysis to other fossil plants in the country.

2.0 KAZAKSTAN ENERGY SECTOR STRATEGY

The Kazakstan Power System currently consists of 64 electric power stations with a total capacity of 16,026 MWe. These 64 plants include 40 Thermal Electric Power Stations (TES), with a capacity of 13,897 MWe. The other 24 plants are electric generating stations and hydroelectric power stations. The TES units provide district heat or process steam to the industries in addition to electric power generation whereas the remaining 24 plants only provide electric power. The main fuel used in these plants is coal. A breakdown of the fuel usage is shown below:

Fuel	Percent
Coal	74.3%
Petroleum (Oil, etc.)	12.2%
Natural Gas	14.5%

The main goals of Kazakstan Energo, as determined by the Ministry of Energy and Fuel Resources are:

1. To refurbish the current power plants operating in Kazakstan to improve their efficiency, reliability, and reduce emissions to the environment.

2. To commission new generating facilities with environmental controls to meet the future shortfall in production capacities.

3. To institute energy savings and conservation programs for consumers of heat and electricity.

4. To upgrade the current power plants with state of the art technology.

5. To gradually bring the prices of heat and electricity up to the current world price levels in a transition to a market based economy.

6. To develop a new management structure for the power, heat generation, and distribution industry.

Kazakstan currently imports electricity from Russia and other central Asian countries. In 1992, Kazakstan imported 14 billion kWh of electricity. The gap between demand and installed capacity is approximately 2,000 MW. Thus, there is a great need to install new generating capacity and to refurbish the existing plants. Over the next 20 years, Kazakstan plans to create a reserve capacity of approximately 20 to 25 percent.

During this period of upgrading and installing new capacities, a major focus will be placed on environmental issues and energy conservation. As new legislation is enacted to help preserve the environment, the power sector must upgrade its environmental control equipment at heat and power generating stations. Installation of NO_x and SO_2 reducing technologies and improved ash collection equipment will be required on all new and refurbished power plants.

The amount of pollutants released into the atmosphere can also be reduced by instituting energy conservation programs as these programs would result in curtailing energy demand and hence energy production. These programs could consist of gradual increase in tariffs on electric and thermal energy, sanctions on the irrational use of energy resources, incentives to utilities that conserve energy, and installation of more energy efficient appliances and industrial processes. Another benefit of energy conservation program is the decreased demand for new energy production capacities which will defer the capital investment for construction of new facilities into the future. This will result in substantial financial benefit to the power generation industry in Kazakstan.

3.0 BLOCK NO. 3 DESCRIPTION AND EVALUATION

3.1 STEAM BOILER

Equipment Descriptions

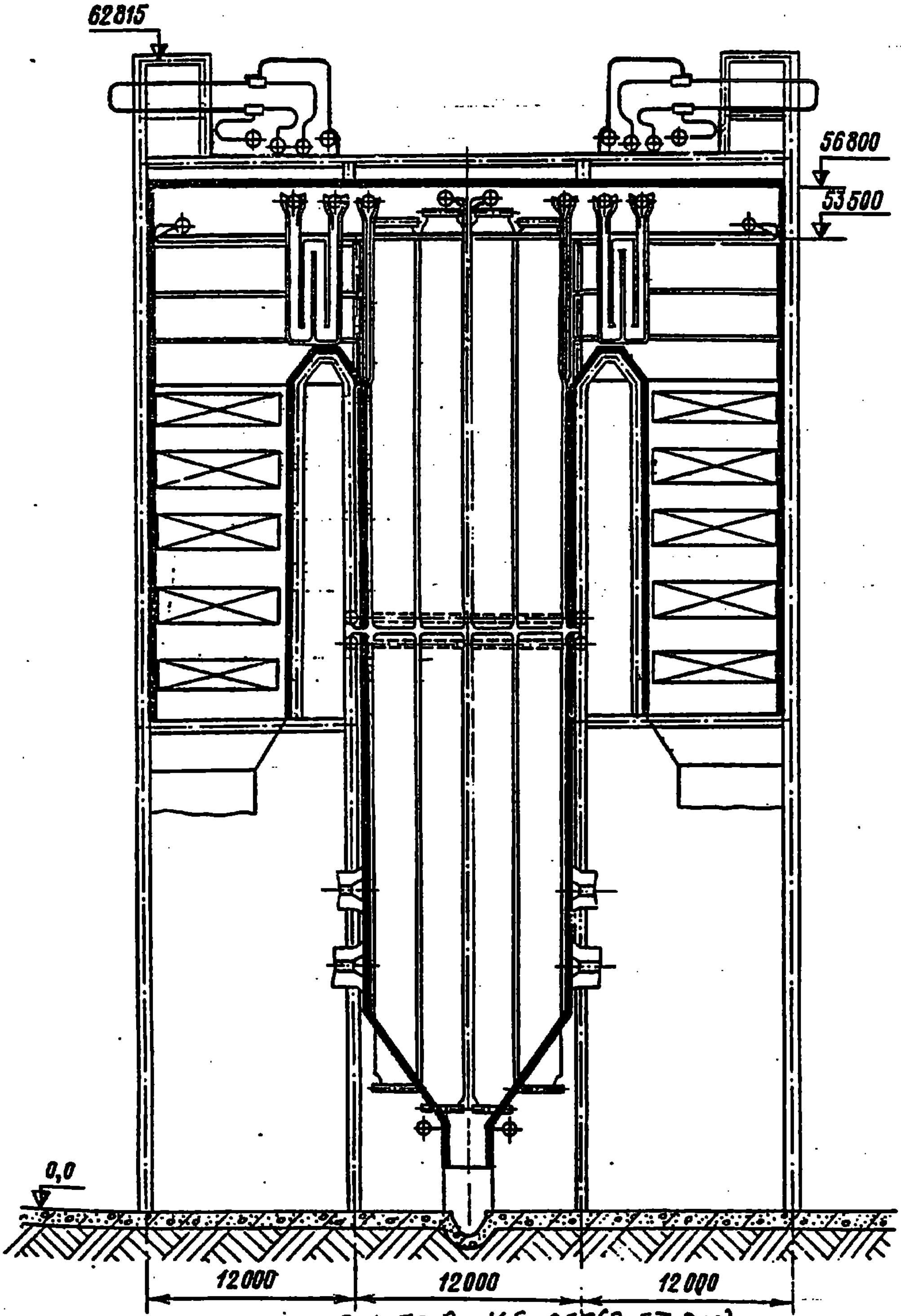
Block #3 consists of a 500 MWe supercritical main steam pressure turbine generator and a monoblock once-through (OT) boiler, type P-57-3M, manufactured by the Podolsk Machine Building Factory. The boiler is of the "T" configuration, with a balanced draft dry bottom ash disposal furnace and opposed wall horizontal pulverized coal swirl type burners. The boiler was designed to operate with medium volatile bituminous coal from the Ekibastuz open cast mines. Natural gas is the auxiliary fuel for start-up and load stabilization. A cross-sectional elevation of the boiler is shown in Fig. 3-1A & 1B. The furnace is rectangular in shape, 9840 mm deep, 22000 mm wide and consists of fully water cooled, vertical carbon steel tubewalls. The furnace, horizontal and vertical backpasses roof tubes are steam cooled. The boiler is top supported, allowing for cubic thermal expansion. The furnace is opposed wall horizontally fired, with a total of 24 (4 horizontal rows of 6) swirl type pulverized coal burners with a heat input per burner of 45x10e6 kcal/h. Table 3-1 shows the design and current performance of the Boiler.

TABLE 3-1

Thermal Performance Design vs Current

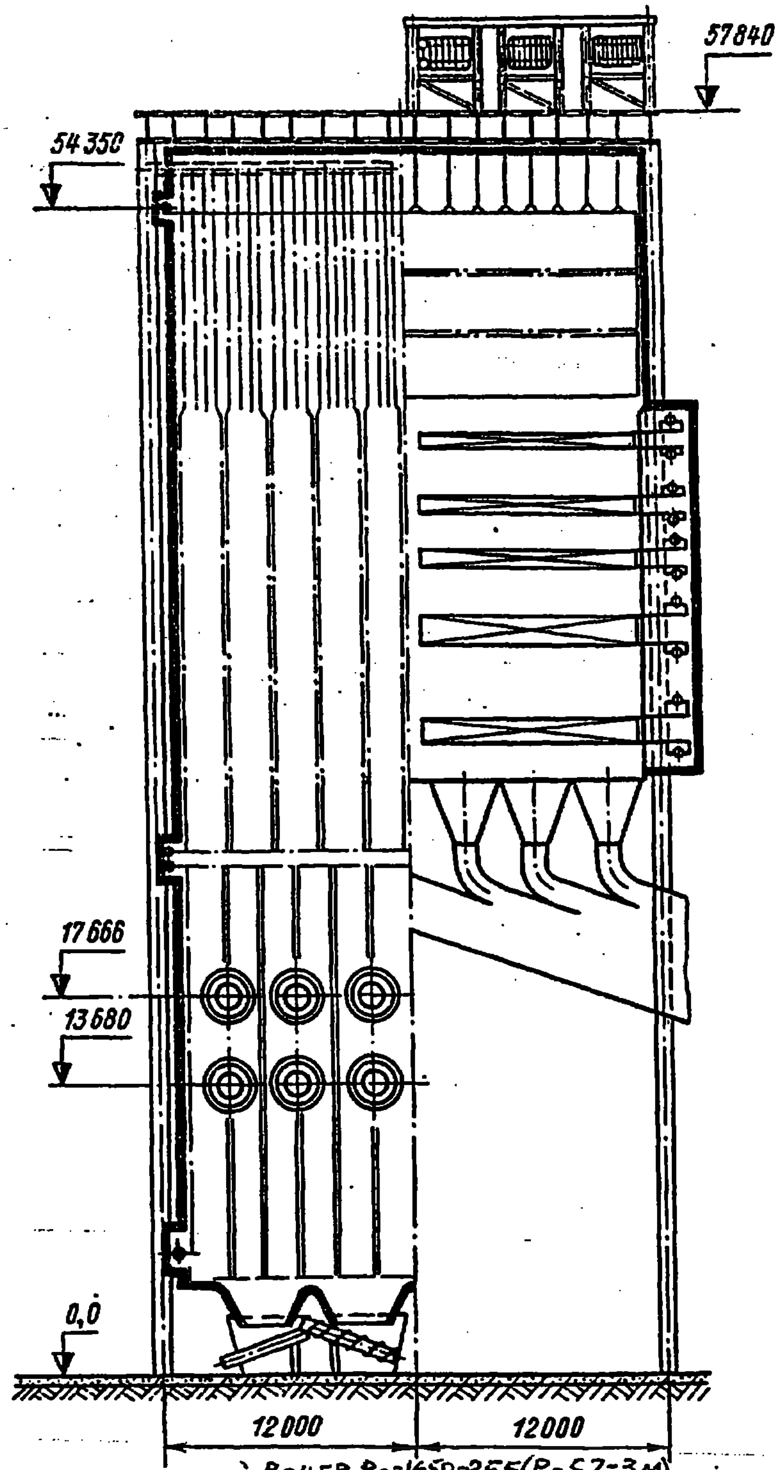
Parameter	Units	Design	Current
Main steam flowrate	te/h	1650	1206
Main steam pressure	at.abs.	255	223
Main steam temperature	°C	545	518
Reheat steam flow	te/h	1364	
Reheat steam pressure	at.abs.	40	
Reheat steam temperature	°C	545	
Feedwater temp. to economizer	°C	271	132
Comb. air temp. to main airheater	°C	50	30
Comb. air temp. leaving main airheater	°C	328	213
Fluegas temp. leaving main airheater	°C	145	155
Boiler Efficiency LHV basis	%	91.7	89.0

Figure 3-1A
BOILER LONGITUDINAL SECTION



BOILER Pp-1650-255 (P-57-3M)
Рис. 1. Котел Пп-1650-255 (П-57-3М).
LONGITUDINAL SECTION
Продольный разрез

Figure 3-1B
BOILER CROSS-SECTION



BOILER Pp-1650-255(P-57-3M)
Рис. 2. Котел Пп-1650-255 (П-57-3М).
CROSS-SECTION
Поперечный разрез

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The superheater heating surfaces can be divided into three parts: radiant, radiant/convective, and convective. The radiant primary superheater consists of furnace and convective passes rooftubes. The second stage horizontal convective tubebanks are positioned in the vertical rear passes and the finishing superheater pendant tubebanks are situated in the short horizontal convective passes, near to the vertical upper furnace exit plane. Main steam flow is divided into two parallel paths.

The two stage horizontal fully drainable convective reheater tubebanks are positioned in the rear vertical passes. Superheated steam final temperature is controlled by firing rate and trimmed by two stages of feedwater spray attemperators. The reheat steam final temperature is controlled by bi-flux heat exchangers, (superheat to reheat steam) and by a cold reheat steam bypass of the bi-flux heat exchangers. The two stage economizer consists of fully drainable horizontal bare tubebanks positioned in the convective rear passes, water in upflow and fluegas in downflow. The tubular type primary and secondary airheaters are situated in an extension of the boiler house enclosure with fluegas in the tubes in downflow and air over the tubes in crossflow. Cold end corrosion protection of the airheaters is by separate hot air recirculation fans, one for Primary Air (PA), one for Secondary Air (SA). Hot air is also recirculated into the forced draft fans suction from cooling air provided for structural support beams of horizontal tubebanks in the rear convective passes.

Based on the information and documentation received, Block #3 boiler does not have any sootblowers installed. It is understood that furnace slagging is not an operating problem and that the highly erosive mineral matter (ash) content of the Ekibastuz coal is non-fouling, therefore we are not recommending the retrofit of heating surface cleaning equipment. Furnace bottom ash is disposed as dry ash into refractory brick lined ash hoppers supported on the basement floor. The draft plant consists of two forced draft (FD) and two induced draft (ID) fans of radial flow centrifugal type, with electric motor drives and radial inlet vane control.

The boiler is supplied with raw coal from eight silos each with a scraper type volumetric feeder to eight type MMT-2600/2550/590 K high speed, horizontal shaft hammer mills with integral centrifugal classifiers, electric motor drives, and a coal throughput per mill of 36 te/h at TCMR load. Each pulverizer supplies the pulverized coal to three swirl burners through primary air/pulverized coal conduits (direct firing system). The pulverizers are pressurized. Primary air flow for the flash drying and conveying of the pulverized coal is provided by two primary air (PA) fans of radial flow centrifugal type. The fans are positioned upstream of the tubular primary airheaters and are boosting FD fan pressure.

Particulate emission control equipment consists of four Venturi wet scrubbers in series with two electrostatic precipitators (ESPs), all positioned upstream of the ID fans.

Condition Assessment of Boiler and Auxiliaries

- Block #3 was commissioned on March 30, 1982, and has been in operation for approximately 73,000 hours as of 1-1-1995, thus creep damage of the high operating metal temperature thick-walled pressure parts is not yet anticipated. However, there is some heating surfaces damage and high failure rates due to low cycle fatigue. Additional operating problems with pressure parts are the low quality of tube welds, high operating tube metal temperatures (tube failures due to overheating) and serious flyash erosion wear. Block #3 total number of starts was given as 482, with 74 cold starts out of this total.

- Block #3 boiler main steam output is derated by approximately 27% [1206 vs 1650 te/h]. The derating is postulated to be due to a coal capacity throughput shortfall of the existing high speed hammer mills. Another reason for the derate is a capacity shortfall of the induced draft (ID) fans. The shortfall is due to both an increased fluegas flowrate, caused by large amounts of unmeasured ambient air ingress into the boiler setting, as well as an increased fluegas-side draftloss through the tubular airheaters. The tubes are blocked up with deposits caused by substantial cold-end acid dewpoint corrosion attack. While the average fluegas exit temperature of the tubular airheaters, at full load, is approximately 145°C, there is significant fluegas temperature stratification. This is due to the design of the airheaters (Z configuration, two-flow/air in crossflow over tubes). One side at the exit plane has a fluegas temperature as low as 90°C, the other side a temperature as high as 200°C. The stratified low fluegas temperature causes accelerated acid dew point type corrosion attack, tube blockages by deposits, and corrosion products.

- Pressure and temperature of the final main steam are derated [223 vs 255 at.abs., 518 vs 545°C]. The pressure derate is postulated to be due to boiler feed pump problems. On a once-through type boiler the final main steam pressure is maintained by the boiler feed pump (BFP). We are told that the steam turbine drive of the BFP receives steam from the 4th stage extraction of the main steam turbine. Below a certain part load of the main steam turbine, the BFP drive turbine steam parameters are below design, thus resulting in low feedwater pressures to the boiler. Another possibility for the lower main steam pressure is a magnetite film build-up on the inside diameter of the furnace tube circuits, with consequently increased flow resistance. This is unlikely however, since the plant is using the combined [oxygen dosing] feedwater chemical treatment. The final main steam temperature derate is postulated to be due to the pulverizers coal throughput capacity shortfall. On an OT type boiler the final main steam temperature is controlled by the [coal] firing rate.

- Feedwater temperature to the economizer is substantially below design [132° C vs 271°C]. At least 2 of the 3 HP feedwater heaters must have been out of service when the performance data was recorded back in 1994. From the design data it appears that the boiler was not designed to operate continuously

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at full load with any of the HP heaters out-of-service. Even at the 27% derated main steam flow, the total heat input into the furnace is higher than design, with the substantially reduced feedwater inlet enthalpy to the economizer. Plant personnel have confirmed that they are forced to operate for extended time periods with one or two HP feedwater heaters out of service. These heaters are a major maintenance item, due to design/constructional defects, e.g., valves, flanges, tubing system, cover plates problems and they have very low availability's. The plant urgently needs improved design/construction high pressure feedwater heaters.

- Heating surfaces cleaning equipment: As per documentation received, Unit #3 boiler does not have any sootblowers installed. It seems to us that apart from high mineral matter content, the Ekibastuz coal has a low slagging & fouling propensity thus the furnace heating surfaces slagging and convective heating surfaces fouling is not a problem. Therefore, we have not allowed any cost for retrofitting furnace tubewall and/or retractable sootblowers.

- Pulverizer electric motors: The existing mill motors are rated at 1250 kWe each and 6 kV. The motors may be reutilized for the retrofit of the vertical spindle type medium speed pulverizers, since the specific power consumption of this mill type is much less than that of the high speed hammer mills [approx. 9.5 vs 17 kWh/te]. However the motors will operate at part load with lower efficiencies.

- Raw coal bunkers: The plant requires installation of vibrators onto the bunkers. This indicates coal bunker discharge flow problems. The solution with vibrators is undesirable because their use will result in fatigue type bunker wall failures. We suggest investigation into the possibility of modifying the tapered bottom of the coal bunkers, e.g., steeper slopes, metal coating, larger outlet opening, etc.

- Raw coal feeders: These are given as scraper type, i.e., postulated to be volumetric feeders. It is proposed to retrofit gravimetric coal feeders simultaneously with the retrofit of the medium speed pulverizers. On an OT type boiler, the monitoring of exact coal weight flow rates is important because the ratios of coal flow/feedwater flow and coal flow/combustion air flow are important control parameters.

- NO_x emissions control: In 1994 the maximum emission rate was 900 mg/nm3. This would require an approximate 37% reduction to comply with the local emission limit of 275 vppm or 565 mg/nm3. Such a reduction can be achieved with in-furnace combustion modifications. The maximum in-furnace emission reduction, using LNB's together with bulk furnace combustion air staging [use of OFA], is approximately 55%.

- The venturi scrubber fluegas exit temperature is ~50°C (winter) and 80°C (summer). The moisture content of fluegas exiting the scrubbers is 50~70

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mg/nm3 and low temperature corrosion attack metal loss of ducting downstream of scrubbers is about 1 mm/yr. Particulate collection efficiency of the scrubbers is approximately 96%.

- The electrostatic precipitators (ESP's) are inoperative due to serious damage caused by acid dew point temperature corrosion and sulphuric acid condensation.
- The convective passes horizontal tubebanks (low steam temperature reheater, economizer) and the vertical tubes of the tubular airheaters have substantial flyash erosion damage, metal loss and tubewall thinning.

3.2 STEAM TURBINE/GENERATOR

General

Many problems with the steam turbines have been identified from discussions with plant personnel and from review of documentation received. These problems have resulted in an increase in Block heat rate, resulting in higher operating costs and an increase in unscheduled outages resulting in lost generation due to equipment failure. Some of the problems will result in the need for increased future inspections and deficiency corrections of internal and external components of the turbine, which will require Block outage time and result in increased maintenance expense.

The eight steam turbines at the Ekibastuz Power Plant No. 1 have a combined design capacity of 4000 MW. However, the total working output of the plant at the time of the Burns and Roe visit was only in the range of 670 to 750 MW. This plant was designed with supercritical steam parameters, and as such, it should be operated as a base load plant since it is supposed to have the best efficiency thermal cycle among coal fired stations. However, the plant is plagued with frequent breakdowns and outages, requiring an unusual number of starts for a traditional base load supercritical plant. The most unreliable component of the plant was indicated by plant personnel to be the boilers. The boilers typically are removed from service for repair on the average every 270 hours. Most problems were noted by the plant personnel to be caused by the very abrasive coal burned at Ekibastuz, with an average ash content of about 42-43%. Due to the frequent shutdowns and the following startups, the turbine plant is also subjected to an increased number of transients which causes deterioration and increased life consumption of the equipment. A number of turbines have eroded last stage blades and are currently operating with the two last stage blading rows removed. In addition, some of the units are operating with their high pressure feedwater heaters bypassed. The maximum capability of the various blocks and the total accumulated operating hours at the time of our visit are shown in Table 3-2.

The actual number of operating hours of the various units and the actual number of unit starts (including those which are a consequence of unplanned outage) are shown in Table 3-3 and Table 3-4, respectively.

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TABLE 3-2 Maximum Generating Capability of the Ekibastuz Blocks								
Block No.	1	2	3	4	5	6	7	8
Turbine Output [MW]*	252	212	210	273	357	--	--	157
Number of Operating Hours**	83,181	73,868	72,872	70,538	63,423	67,640	65,570	67,785
Date of Initial Operation	4/80	12/80	4/81	5/82	12/82	4/83	12/83	12/84

* As of March 1995
** As of January 1, 1995

The operating data for the plant collected for the year 1994 indicates that the plant was operating with a weighted average load of 306 MW per unit, and that the plant capacity factor was a very low 19.4%. The total electrical energy generated, the average load, steam parameters, capacity factors and other operating data for the various blocks are shown in Table 3-5. The data shown in this table can give the reader an appreciation of the degraded operating condition of this plant, especially when it is noted that the projected capacity factor for the Ekibastuz Plant was 77%.

Because of the significantly degraded operating condition, the plant is embarking upon a 15 year rehabilitation program. The actual block rehabilitation plan will start with Block #3 in 1997-1998 followed by Blocks 4, 1, 2, 5, 6, 7 and 8 to be completed by 2009. Because the first unit to be rehabilitated is Block 3, this unit was selected by the plant personnel for evaluation by Burns and Roe. The following paragraphs will concentrate on the evaluation of the condition of the Block 3 turbine-generator and related plant auxiliaries in order to develop recommendations for their rehabilitation.

<u>Description and Performance Assessment</u>

a) Description of Turbine

Of the eight steam turbines operating at the Ekibastuz Plant three were manufactured by the Kharhov Turbine Plant and five by the Leningrad Turbine Plant. They are however basically the same Model K-500-240-2 turbines.

The Block 3 steam turbine was manufactured by the Kharkov Plant and it was installed in April 1981. It is a nominal 500,000 kW, 3000 RPM, single reheat, tandem compound condensing machine, designed to receive 1,570 t/h of supercritical main steam at a pressure of 232 ata and temperature of 540°C at normal full load operation. There are four separate turbine elements on a single shaft; one single flow high pressure (HP section, one single flow intermediate pressure section, and two double flow low pressure (LP) sections. A cross sectional drawing of the turbine is shown in Figure 3-2.

The number of stages in the turbine are: 10 in the HP section, 11 in the IP section, and 5 in each half of the two double flow LP sections. Interstage steam sealing strips are provided to minimize bypass of steam around rotor blades and diaphragm nozzles.

Exhaust steam from the HP turbine is passed through the reheater in the boiler, and returned to the IP section of the turbine. After exhausting from the IP section, the steam flow splits, with half passing through each of the double flow LP sections.

Steam is extracted from the turbine and directed to five stages of low pressure feedwater heating, three stages of high pressure feedwater heating, two feedwater pump turbines, and a deaerator. The thermal cycle diagram for the steam turbine is shown in Figure 3-3.

Exhaust steam from the LP sections of the turbine is condensed at approximately 0.035 ata in a two pass shell-and-tube type surface condenser located under the LP turbine sections.

Condensate from the condenser is heated through nine stages of feedwater heating, and feedwater is delivered to the steam generator at a design temperature of 271 °C.

TABLE 3-3
Total Number of Operating Hours
of Various Turbine Generators
(From Initial Start to January 1, 1995)

Year	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 7	Block 8	Total
1980	4,272	702	--	--	--	--	--	--	4,974
1981	4,806	5,785	4,248	82	--	--	--	--	14,921
1982	4,923	4,669	4,311	3,729	809	--	--	--	18,441
1983	5,456	4,324	4,903	6,191	7432	4,278	210	--	32,794
1984	6,014	3,711	7,352	6,460	3,105	5,930	5,820	1,096	39,488
1985	5,926	5,275	7,276	4,815	6,754	3,553	6,800	7,883	48,282
1986	6,535	6,724	4,952	6,381	7,244	7,806	7,485	6,862	53,989
1987	6,004	7,420	2,457	6,396	5,666	7,341	6,941	7,053	49,278
1988	4,632	4,411	6,200	7,405	5,997	7,649	7,613	6,997	50,904
1989	7,475	7,472	7,108	5,560	6,989	7,366	7,201	5,418	54,580
1990	6,770	6,907	5,087	7,149	5,314	2,517	6,880	7,422	48,046
1991	6,617	5,869	7,044	6,334	489	6,829	4,817	7,168	45,167
1992	4,777	4,286	5,741	4,218	5,574	7,160	5,471	5,287	42,514
1993	4,433	4,113	6,037	2,382	6,496	5,013	5,615	5,116	39,205
1994	4,541	2,200	156	3,436	1,554	2,198	717	7,483	22,285
Total	83,181	73,868	72,872	70,538	63,423	67,640	65,570	67,785	564,877

TABLE 3-4
Actual Number of Unit Starts
of Various Turbine Generators
(From Initial Start to January 1, 1995)

Year	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 7	Block 8	Total
1980	60	18	--	--	--	--	--	--	78
1981	67	71	62	12	--	--	--	--	212
1982	51	50	38	49	25	--	--	--	213
1983	41	46	23	45	66	66	7	--	294
1984	62	45	36	49	17	31	50	20	310
1985	39	46	33	39	33	33	31	44	298
1986	44	46	51	43	34	26	34	43	321
1987	36	28	29	26	26	43	21	32	241
1988	26	26	35	38	33	24	33	29	244
1989	42	22	27	19	29	34	31	25	229
1990	32	32	13	39	18	15	34	30	213
1991	39	33	41	37	11	33	33	40	267
1992	41	40	48	42	49	38	41	49	348
1993	49	41	46	30	42	30	39	36	313
1994	51	58	3	52	24	21	4	25	238
Total	680	604	485	520	407	394	358	374	3,822

TABLE 3-5
1994 OPERATING DATA FOR THE EKIBASTUZ TURBINE GENERATORS

Indicators	Dim.	K-500-240-2 Turbine Generators								Gross Plant	
		1	2	3	4	5	6	7	8	Norm	Actual
Generated Electrical Power	thous kWh	1,373,951	68,8572	63,533	107,6434	467,529	720,280	209,383	2,210,092		6809774
Average Electric Load	MW	303	313	407	313	301	328	292	295		306
Quantity of Hours in Operation	hour	4541	2200	156	3436	1554	2198	717	7483		22285
Capacity Factor	%	31.4	15.7	1.5	24.6	10.7	16.4	4.8	50.5		19.4
No. of Starts (including unplanned)	-	51	58	3	52	24	21	4	25		238
Main Steam Pressure	kgf/sq.cm.	178	157	218	173	135	187	219	175	240	180
Condenser Pressure	kgf/sq.cm.	0.0596	0.0463	0.0516	0.0581	0.0715	0.0538	0.0626	0.0665	0.0374	0.0612
Main Steam Temp.	°C	509	509	518	526	506	513	535	518	540	518
Hot Reheat Steam Temperature	°C	500	502	513	513	507	522	533	521	540	516
Temperature of feedwater	°C	186	144	132	165	176	199	160	153	240	167
Turbine Gross Heat Rate	kcal/kWh										2,270

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Figure 3-2
TURBINE CROSS-SECTION

ПРОДОЛЬНЫИ РАЗРЕЗ ТУРБИНЫ К-500-240-2

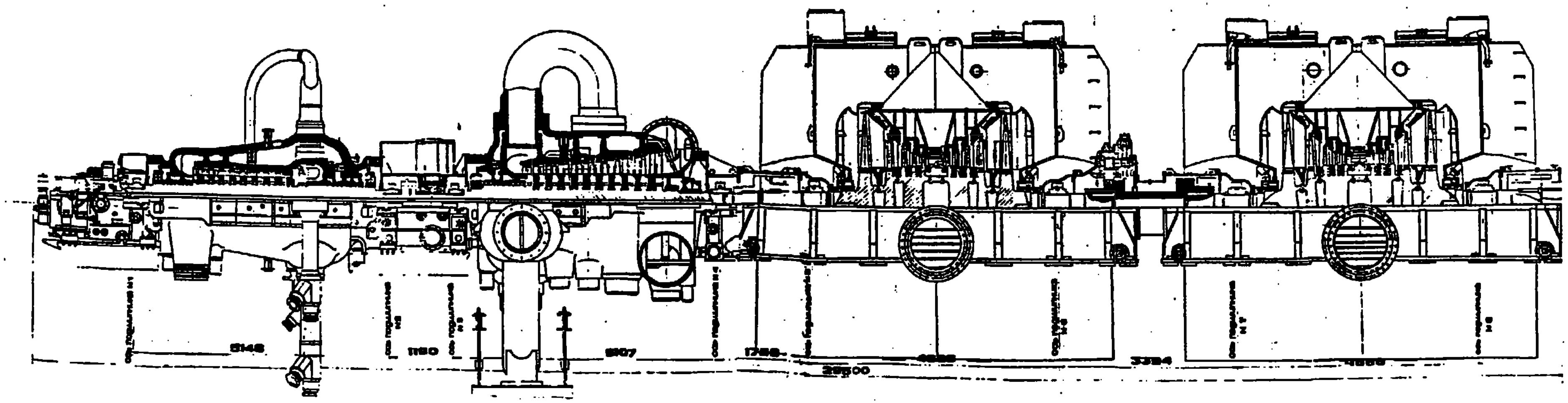

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Fig 3-3
TURBINE CYCLE SCHEMATIC

ТУРБОАГРЕГАТА К-500-240-2

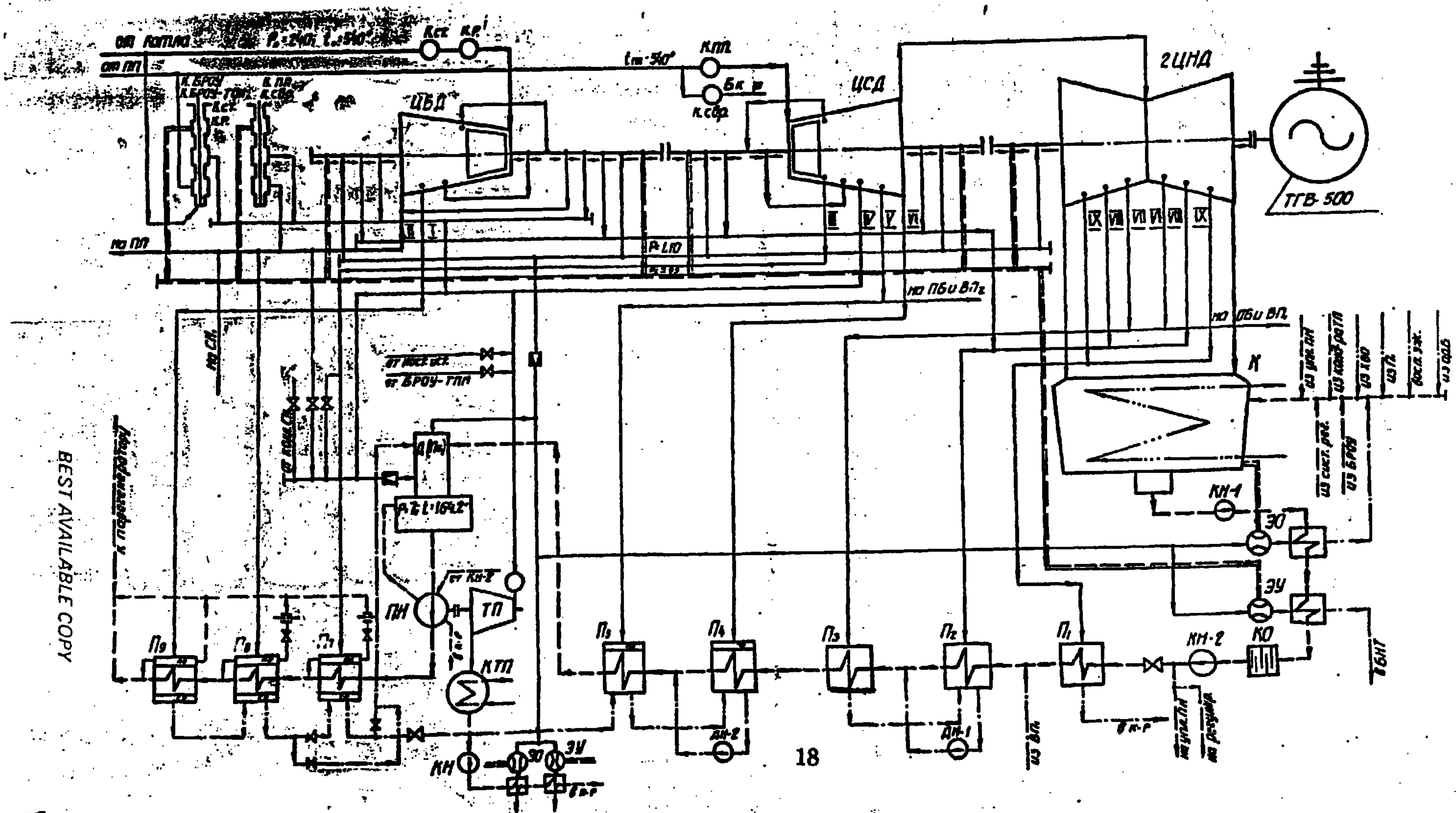

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TABLE 3-6

TECHNICAL CHARACTERISTICS OF THE STEAM TURBINE

Type	K-500-240-2
Nominal Output, MW	500
Main Steam Pressure, kg/cm^2 (a)	240
Main Steam Temperature, °C	540
Hot Reheat Steam Temperature, °C	540
Hot Reheat Steam Pressure, kg/cm^2 (a)	37.2
Main Steam Flow, t/h	1570
Number of Extractions	9
Extraction Configuration	3HPH+D+5LPH
Condenser Pressure, kg/cm^2 (a)	0.0357
Number of Stages	41
Specific Heat Consumption, kcal/kWh	1841
Number of Turbine Bearings	8
Overall Length of Turbine, m	29.5
Turbine Manufacturer	Kharkov
Generator Model	TGV-500-2
Generator Rating kVA	588200
Power Factor	0.85
Starter Voltage, V	20000
Starter Current, A	17000
Frequency, Hz	50
Generator Cooling Medium	H_2

b) Design and Current Performance of the Turbine

The technical characteristics of the K-500-240-2 steam turbine are shown in Table 3-6.

While the above table indicates that the steam turbine was designed with a cycle efficiency of 46.7 percent, the current operating efficiency of the cycle is far less than the above design figure. There are various reasons for the decreased cycle efficiency most of which are due to the inability of the boiler to supply sufficient quantities of steam at the design steam parameters. Other reasons are turbine and turbine cycle related.

As shown in Table 3-2 the current generating capability of Block 3 is only 210 MW. As can be seen from Table 3-5 this unit could produce an average of 407 MW in 1994 making it the block with the highest average output in that year. However, the block operated for only 156 hours in 1994. This is because on January 15, 1994 the turbine hall roof caved in and fell on top of the turbine, causing damage to it and its auxiliary equipment. This has caused a further reduction to the output capability of the block. Table 3-5 also indicates that the main steam pressure and main steam and hot reheat steam temperatures were much lower than design conditions. In addition the final feedwater temperature was less than about half its design value. This is because the block had to operate with the high pressure feedwater heater string out of service. This mode of operation increases the power output obtainable from the block. Plant personnel indicated that bypassing the high pressure heaters can add about 25 MW to the turbine output at full load. This output increase is indicated in Table 3-7.

TABLE 3-7

EFFECT ON TURBINE OUTPUT OF OPERATING WITH HIGH PRESSURE HEATERS BYPASSED

Turbine Output with HP HTRS in Service, MW	320	360	400	440	500
Turbine Output with HP HTRS Bypassed, MW	328.6	369.7	411.8	455	525
Output Increase, MW	*8.6*	*9.7*	*11.8*	*15*	*25*

Even though the operation without high pressure heaters in service increases the output somewhat, it also increases turbine cycle heat rate. Since recent performance test data was not available for Block 3, it was not possible to make a direct comparison of design and test heat rates to accurately assess current turbine performance. However, turbine performance curves (heat rate, steam flow, cycle heat input) for the load range between 300 and 500 MW prepared in 1990, were received from the power plant which were used in estimating heat rate degradation. Based on a review of available design and operating data it was concluded that performance degradation of Block No. 3 has occurred, and a rough estimate of the extent of that degradation was calculated. This was done to demonstrate that there is a need for refurbishment work on the turbine, in conjunction with boiler refurbishment.

The turbine heat rate for the 1994 operating conditions of Block 3 was determined from the best unit heat rate considering both the auxiliary load and steam generator efficiency. This heat rate was determined for a turbine output of 407 MW. The actual 1995 turbine heat rate however had to be determined at the new, even further reduced, unit output of 210 MW as given by the plant data for 1995. The determination of this heat rate utilized the performance curve, the values on which had to be extrapolated below the 300 MW range. Utilizing this curve a parallel curve was drawn through the actual operating point determined for 1994. The final estimate of turbine heat rate then utilized the heat rate read from the parallel curve at 210 MW, and finally it was adjusted to account for the effect on operating the block with the high pressure heaters bypassed. The various outputs and turbine heat rates determined as well as the original performance (design) figures are shown in Table 3-8.

From Table 3-8 it can be seen that compared to the original design conditions the current actual operating heat rate of the turbine is about 37% higher. It can also be seen that the full load heat rate of the turbine degraded by about 4% in 1990.

TABLE 3-8

DESIGN AND ESTIMATED TURBINE PERFORMANCE FIGURES

Time, Year	Design ('81)	1990	1/1994	3/1995
Turbine Output, MW	500	500	407	210
Turbine Heat Rate, kcal/kWh	1,841	1,915	2,081	2,529

This exercise does not quantify the heat rate deterioration with the unit operating under full load condition, which may be significantly less than at 210 MW. It does, however, provide an indication that turbine performance has deteriorated, and that turbine refurbishment should be undertaken in conjunction with restoration of the boiler in a program to restore the overall unit to "as new" efficiency and generating capacity.

Condition Assessment

a) Block 3 Problems

Many problems with Block 3 turbine have been identified from discussion with plant personnel, and from review of documentation received. Some of these problems tend to result in an increase in block heat rate, which in turn results in higher operating costs. Some of the problems tend to increase the probability of unscheduled outages and resulting in lost generation due to equipment failure. Others of the problems tend to result in the need for increased future inspections and deficiency corrections of internal and external components of the turbine. Significant problems, which have been identified relative to the turbine-generator are outlined in the following paragraphs.

Turbine Steam Path/Blading

The steam path components of the Block 3 turbine have significantly deteriorated. This is obvious from the heat rate estimates discussed above. The design and actual internal efficiencies of the intermediate pressure turbine cylinder for Blocks 2,3,4,6,7 and 8 are shown in Table 3-9. The actual efficiency values in this table are based on tests performed between 1990 and 1992. While no recent performance data exists it can be seen that of all blocks, even before the roof collapse in 1994, the Block 3 turbine IP section efficiency was the worst at 83%. Because of the deterioration of the blocks operating with the frequent startup regimen, the current internal efficiencies can be expected to be worse than in 1990. The degradation is expected to be even more pronounced in the High Pressure (HP) section of the turbine.

TABLE 3-9

INTERNAL EFFICIENCY OF INTERMEDIATE TURBINE SECTIONS

Block No.	2	3	4	5	6	7
Design Internal Efficiency, %	91.2	91.2	91.2	91.2	91.2	91.2
Actual Internal Efficiency, % (1990-1992)	90.0	83.0	84.0	86.0	90.0	87.0
Decrease in Efficiency,%	*1.2*	*8.2*	*7.2*	*5.2*	*1.2*	*4.2*

Plant maintenance data indicates that the No. 2 Low Pressure Cylinder of the Block 3 turbine experienced blade damage at the third stage in 1992 at which time the blades in each flow section were removed.

Plant data also indicates that last stage blade problems have caused severe vibrations on Blocks No. 4,5,6,7, and 8 turbines. These vibrations have caused failure of the blades and consequent damage to other internal turbine parts. Although the turbine manufacturer has proposed a new blading system utilizing titanium blades, sufficient funds to implement the refurbishment have not been available. These turbines are currently operating with last stage blades removed, a factor which contributes to degradation in turbine efficiency. While the last stage blades on Block 3 have not been removed at this time, the same problem is likely to occur at the No. 3 turbine as well, resulting in a long, costly forced outage to repair the damage. The removal of the last stage blades was estimated to result in an output loss of 25 MW.

In addition to the above, a decrease in efficiency also originates from the increased interstate leakages within the turbine due to wear over the service life of the turbine..

Vibration/Alignment

It was reported by plant personnel that as a result of the collapse of the Turbine Building roof, a significant amount of debris fell onto the No. 3 turbine/generator set and related turbine plant auxiliary equipment. The unit now experiences recurring vibration problems, probably due to increased misalignments of rotors and shells, and possible distortion of major components, resulting from collapse of the roof. The vibrations in turn appear to cause damage to the turbine and generator seals, resulting in oil leaks from the bearings and hydrogen leaks from the generator. This condition can present a serious fire and explosion hazard. In fact, a fire due to the oil and hydrogen leaks did occur on the day of the roof collapse.

Because the hydrogen leak is a serious problem, the plant personnel even considered to cool the generator with nitrogen. Although a proposed change of generator cooling medium from hydrogen to nitrogen would reduce the fire/explosion hazard, it would result in a significant derate of the unit, and would not alleviate the vibration, alignment, and seal leakage problems.

Bearings/Low Frequency Vibration

The plant personnel reported that the unit experiences low frequency vibrations when the load is reduced below 450 MW. As the block now always operates at part loads, this problem is continuous. The cause of low frequency vibration may be due to oil or steam distribution problems. An investigation into these causes by the turbine manufacturer indicated that while new modern self-adjusting bearings should be added to the HP and IP turbine, the unit also has steam distribution problems at the nozzle block. Vibration initiated the bearing problems and over heated bearings were among the most frequent causes of turbine shutdowns.

Steam Admission and Regulating System

Unit outage records indicates a large number of turbine shutdowns were due to the turbine regulation system failure itself, due to low pressure or clogged filters in the system, as well as problems with regulation system pumps. The steam admission valves and their actuating mechanisms were also the causes of turbine outages. This happened due to damaged rack rollers for the regulating valve shaft and enlarged clearances in the control valves.

Turbine Turning Gear

The turbine turning gear is in satisfactory condition. It currently has the capability to rotate the turbine rotor at a constant speed of 4 RPM during the period when the block is not in operation. However, there is no provision for "jogging" to rotate the rotor to specific angular positions when required during maintenance. Such a feature should be added as proposed by plant personnel to facilitate turbine maintenance work. The maintenance people would like to use the jogging feature in future repair plans when removing HP and IP rotor blades.

Flange Heating System

The turbine is equipped with a heating system for the flanges and stud bolts of the horizontal joints between the upper and lower shells of the HP and IP turbines cylinders. It was reported by plant personnel that this system could be modified to provide faster turbine warm-up with lower thermal stresses during startup of the unit. A modernized flange heating system is desirable since the turbine is operated in a frequent startup regimen.

In addition the block currently has no turbine stress monitoring system. Such a system is recommended at this plant now because of the current operating regimen (frequent startups and shutdowns).

Generator

The electric generator is not in a very good condition. As noted above the potential explosion hazard due to hydrogen leaks through the seal system is one reason. The generator rotor had problems which were corrected during the last overhaul. However, the plant outage data indicates many outages due to generator related problems such as water leaks (water leaking into generator relay shield, leak in stator), oil leaks at bearing 10 and increased temperature at bearings 11 and 12.

b) Metal Control

The metal control laboratory personnel have been interviewed to assess the procedures and equipment available at the plant to control metal conditions. In general the plant has quite a large array of non-destructive examination (NDE) and destructive examination (DE) equipment for the testing and inspection of the turbine, boiler, and main steam piping components. These equipment include the following:

UD2-12	Ultrasonic defectoscope
PMD-70	Magnetic defectoscope
EDP-4	Eddy Current flaw detector
UT-93P	Ultrasonic thickness meter
MMP	Metallographic microscope
KM-30	Pendulum hammer
P-20	Tearing machine
TS-2m	Thickness meter
2109 TD	Thickness meter
MPB-2	Microscope
Micrometers	
Sliding Calipers	
Express-analysator for carbon	
Photoelectrocolormeter	
Microscope	

Liquid penetrant testing, replication type creep testing equipment or boroscopes are not currently available at the plant. Because the turbine has been in operation for only 73,000 hours, no creep damage of high temperature thick walled pressure parts was anticipated. However, it should be noted that the current official design life of the K-500-240 turbines is the lowest of all turbines, as follows:

Component	Park Resources (hrs)
HP & IP Rotors	100,000
HP & IP Shells	100,000
Stop and Regulating Valves	100,000

Assuming the Block 3 turbine is to be operated with its average current operating hours the remaining official design life of the above components will be exhausted within about 5 years. It was customary in the former USSR countries to grant official extension of lives of various turbines, based on an assessment of the life consumption and the condition of a turbine by a testing laboratory (such as Ekaterinburg, or others). Plant personnel indicated that such a testing company was VTE (All Union Technical Institute), or Cybtech (which can make remaining life assessment for the heating surfaces within steam generators), but they expressed doubts about such companies coming to Ekibastuz without the prospects of large financial rewards.

NDE testing and visual examination of turbine components are carried out periodically on the HP and IP shells and valve bodies. The last time NDE was performed on Block 3 was in 1990. During this examination the following defects were found:

HP Turbine Shell: 7 cracks found, with dimensions of up to 250 mm in length and 28 mm in depth.

IP Turbine Shell: 7 cracks found, with dimensions of up to 230 mm in length and 34 mm in depth.

Left Steam Chest: 2 cracks found, with dimensions of up to 150 mm in length and 25 mm in depth.

All of the above cracks have been repaired, as reported by plant personnel. However, since cracks have been found, the discovery of additional cracks can be expected in the future, and a plan for NDE should be in place for implementation during unit outages. This is important for a plant with many blocks, but it is particularly so for Block 3 because it was noted by the plant personnel that during the last maintenance outage in 1994, following the January 15, 1994 incident, the shells of the turbine were not opened. Therefore it is currently not known whether or how many additional internal cracks may have developed during the last 5 years.

As it was noted above, currently there is no replication type creep testing capability existing at this plant. However, as the plant is getting older and if further life extension is to be granted for various components in the future, such testing capability would be highly desirable to monitor potential creep damage of critical components. Utilization of such testing equipment would enable the plant to better predict potential failures and to perform predictive maintenance. The replication equipment is particularly suitable for a plant with many boilers and turbines where it can be used more often.

In addition, the following additional NDE equipment is recommended to be able to efficiently handle the increased testing requirement of the many components at the Ekibastuz plant.

Ultrasound defectoscopes:

UD-2-12	6 units	Producer - "Volna"
UD-2-17	2 units	Kishnev
UDS-2 "Pora"	2 units	"Uraltexenergo", Ekaterinburg

Ultrasound thickness meters

UT-93-P	10 units	"Volna", Kishinev
UT-81	5 units	"Introtest", Moscow

Metallographic microscopes with the device to measure the micro solidity (of the last generation type "Neofot-21", GDR) 1 unit MIM, MMR Sankt-Petersburg

Quantitative structure analisators (type "Quantimet 360" and "Quantimet 720" of "Cambridge Instruments" and "Epiquant" of "Karl Zeiss, Jena") 1 unit

Technology, devices and meters for ultrasound measurement of the residual deformation - "Uraltexenergo", Ekaterinburg

Sets of reagents to carry out the colored defectoscoping and metallographic works (photo films, reagents, developer, fixing solution)

Magnetic powder visualisator of defectors VMP-40P 2 units "Infotex", Karaganda

Thickness meters:

TB-5042	4 units	"Tochpribor", Ivanovo
"UZIT-5"	2 units	Ekaterinburg
TK-2M	2 units	Ivanovo

In addition, a large number of ultrasound searchers will be necessary for control of pipes of the steam generator boiling surfaces and for control of the welded joints of the steam pipes.

c) Spare Parts, Operation and Maintenance

Lack of spare parts was reported by plant personnel to be a problem. An adequate supply of appropriate spare parts and trained maintenance staff is important to facilitate rapid maintenance when needed. This is particularly true when failure of a part results in an unscheduled outage, and time is of the essence in completing the repair to return the block to service as soon as possible. However, discussions with the Manager of Maintenance at the plant indicated that the procurement of spare parts has become a tedious job. He also noted that spare parts inventory using a computer should be introduced as soon as possible. Currently there is no such system in use at the plant. On some metal control efforts there is sometimes no follow-up because organizations such as VTE do not visit the plant anymore. In this case they just mark the date when something occurred for the record.

It was also noted that there is a major problem with the maintenance and operating staff. This is because a large number of skilled personnel are leaving for various reasons (such as moving to Russia). These people had special training and talent to operate and maintain the equipment. However, with the skilled labor force leaving, the plant must hire less skilled people from the street, which leads to a less efficient and less safe operation of the plant equipment. The lack of stress monitoring in the turbine and a somewhat faster than allowable heatup rate during startup of a block by less skilled personnel can result in an accelerated life consumption of thick walled pressure parts.

The maintenance operations have slowed down due to the combination of the lack of spare parts and the unavailability of funds and skilled personnel. For instance, a perfect example for this is the 1994 capital repair of block 3. The overhaul which usually require a duration of about 4-5 months was significantly extended for 7 months. Maintenance operations started on this unit in August 1994 but were not finished till March 9, 1995.

Maintenance plans for several power plants in the Ekibastuz region called for the establishment of a common repair facility which would house modern auxiliary equipment which could handle and repair all power plant components. The facility was aimed at serving the components of 5 plants:

Ekibastuz GRES-1
Ekibastuz GRES-2
Three other plants in the region

The establishment of this facility was conceived when it was realized that the cost of transportation of components and spare parts between manufacturers and the power plants exceeds the cost of maintenance. The construction of this facility, which is located within about 3-4 miles of the GRES-1 plant has started, and there is a railroad running by it and the Ekibastuz Plant. However, the building of the facility has never been completed due to lack of money, equipment and personnel. Therefore, the maintenance of the Ekibastuz Plant is performed at the old building at somewhat slower pace.

3.3 *AUXILIARY PLANT SYSTEMS*

a) Condenser

The condenser for Block 3 is a Type K-11520-2 single pressure surface condenser with two water passes which is connected to the two exhaust connections of the steam turbine. The technical characteristics of the condenser are shown in Table 3-10.

TABLE 3-10
TECHNICAL CHARACTERISTICS OF THE CONDENSER

Type	K-11520-2
Design Steam Flow (each half), t/h	430
Condenser Pressure, kg/cm^2 (a)	0.0357
Circulating Water Flow (each half), t/h	25,740
Circulating Water Design Temperature, °C	12
Specific Steam Load, kg/m^{2}h	37.6
Cooling Ratio	59.7
Condenser Surface Area (each half), m^2	11,520
Condenser Active Tube Length, mm	8,890
Number of Tubes, each half	14,720
Tube diameter OD/ID, mm	28/24 and 28/26
Tube Material	MNM-5-1
Hydraulic Resistance, m w.c	4

The condition of the original tubes are generally satisfactory except for some plugged tubes. The allowable plugging in the condenser is 10%. The plant reported occasional problems with the tube-to-tube sheet joints. Circulating water can sometimes find its way into the condenser steam space through tube joints. This will require the checking of tubes for leakage and repair plugging, or replacement as necessary based on the results of the leak check.

It was reported by plant personnel that considerable amounts of dirt accumulates in the condenser tubes, especially during Spring and Summer. It appears that a condenser tube cleaning system (such as the Tapprogge type) should be installed at this unit.

In addition, the condenser is experiencing excessive air in-leakages lately. This is because of the more frequent shutdown and restarts of the unit. Sometimes plant personnel have a limited amount of time to make repairs. The design allowable air in-leakage is 40 kg/h. However, the actual air in-leakage into the vacuum system currently is 97 kg/h on Block 3. When there is no time to repair leaks the plant just starts up another air ejector. Air in-leakages usually occur at the low pressure glands and at the horizontal flange of the LP turbine cylinders.

The components of the steam turbine bypass system connected to the condenser are showing signs of deterioration due to the frequent startups associated with the frequent outages. A thorough inspection of the turbine bypass valves should be performed, and valves should be replaced if necessary.

b) Feedwater Heaters

The unit utilizes a single string of 3 high pressure heaters and one string of low pressure heaters. The HP heaters were manufactured by the Atom'machinery-building Utility, Volgodonsk City plant and contain steam cooling, condensing and drain cooling zones, and spiral coils. Because they are designed for very high pressures they have high wall thickness. However, the plant reported that the Block 3 turbine is operating with the high pressure heaters bypassed, which as mentioned before, contributes to the degradation of turbine cycle efficiency. These heaters are a major maintenance item due to design and constructional defects, i.e., valves, flanges, tubing systems, internal supports, cover plate problems and have very low availabilities. These heaters require major rework or replacements.

The low pressure heaters were reported to be in generally satisfactory condition.

c) Deaerator Storage Tank

The plant has reported some cracks on the shell of the storage tank near the deaerator section but not at the deaerator column weld attachment. This will require careful examination and repair. It should be ensured that the unit has been repaired properly and that no such crack develops in the future.

d) Boiler Feed Pumps

There are many problems with the boiler feed pumps, especially since the roof collapsed on the various auxiliary equipment on January 15, 1994. There are 2 full capacity boiler feedpumps together with associated 2 booster pumps. The feedpumps are driven by their own auxiliary turbines, with the turbines discharging into their own auxiliary condensers. Besides the roof collapse problems, and natural wear and tear, the unreliability of the feedpumps also compounded by improper maintenance. This is not because of the maintenance plan followed by the plant but rather the inability of the maintenance people to obtain the required spare parts. Therefore the plant has resorted to making the spare parts themselves. However, these parts do not exactly correspond to the design of the pumps and usually have no proper heat treatment. Both turbine driven feedpumps should be replaced.

e) Boiler Feedpump Turbine Steam Extraction

Plant operating personnel reported that the Boiler Feedpump Turbine is receiving insufficient steam supply from the fourth stage extraction of the Main Turbine due to low extraction pressure.

Additional extraction piping connections from the No. III extraction connection on the main turbine could provide driving steam with higher pressure and temperature for the auxiliary turbines operating with the block at partial loads.

The current operating condition is unsatisfactory as the boilers produce steam at a pressure much lower than the required main steam pressure of 240 kg/cm^2 (a).

f) Condensate Pumps, and Drain Pumps

There are two stages of condensate pumps. The first stage pumps, Model KCB-1600-90 transfer condensate from the condenser to the suction of the second stage pumps, or condensate booster pumps, through the condensate polisher system. The booster pumps, Model KC-1600-220Y4, transfer the condensate to the deaerator through the low pressure feedwater heaters. These pumps are driven by 630 and 1250 kW motors, respectively. These pumps have a history of problems with overheated bearings, broken or leaking glands, as well as an overheated motor at booster pumps CP-IIB, and required frequent repairs. These pumps were further damaged during the roof collapse in January 1994.

The drain pumps of the LP HTR #2 are similar in construction to the first stage condensate pumps except they are sized for much smaller flow rate. Plant data indicates these pumps have insufficient capacity under certain plan operating conditions and they require replacement with higher capacity drain pumps.

3.4 PLANT INSTRUMENTATION AND CONTROLS

General

The instrumentation at the Ekibastuz plant is relatively new when compared to other Kazakstani plants we have inspected. The boiler control system, and the supervisory and protection systems, are well designed. Most control loops use electronic controllers. The lack of spare parts and insufficient maintenance significantly degraded performance of the control and supervisory systems. The recommended action involves addition of some instrumentation, particularly in the environmental control area and better instruments for the boiler control area. The following is a assessment of Ekibastuz Block 3 Instrumentation and Control System based on the information collected during the plant visit and discussions with the plant management.

(a) Load Control

Block 3 turbine uses a conventional mechanical governor with a 4% droop. The boiler temperature controllers, when in automatic, control the fuel flow rate to the boiler. The transport medium from mill to burner is primary air from the air heater. There is no oxygen dilution for the transport air, but they have never had any explosions in the fuel preparation and transport system. Steam pressure is varied using the feed pump speed controllers.

Since the coal caloric content is so low and ash content so high, mazut is sometimes co-fired with the coal in order to meet the boilers steam demand. There are no instruments installed to determine mazut flow to the burners.

The combustion control of the boilers is actually a manual operation. The boiler control system cannot "stay in automatic" within the present load range due to hardware and tuning limitations. The operators control the boiler according to the established procedures based upon adjustment and testing. Excess air, the main indicator of performance, is monitored by measuring the oxygen content of the flue gas after the reheater. Oxygen content is displayed on the boiler control board. Additional indicators of excess air are air-side resistance of the air heaters and air pressure after the forced draft fan. Fuel flow is controlled manually by observing steam temperature (and pressure) and coal feeder motor current. The mills are rated at 40 tons per hour, and the feeders at 50 tons per hour each.

(b) Combustion Air Flow control

This is purely a manual function carried out by varying the position of the forced draft fan radial inlet vanes remotely from the control room. An O_2 indicating system driven by the oxygen analyzers assists the block operator in setting the correct combustion air flow rate. Both forced draft fans discharge to a common header, then the secondary air is distributed to the burners. The vanes are positioned by observing the fan discharge header pressure. There is an automatic control system in place to balance the primary air fan vanes and the forced draft fan vanes, but it is not used since the boilers cannot get to full load.

(c) Furnace Pressure Control

Each of the two 60% induced draft fans is controlled by an automatic control system. The controlled variable is furnace pressure (vacuum). The low coal quality (high ash content) requires that both fans be run even at low loads. The control loop uses electronic controllers.

(d) Steam Temperature Control

Steam flow is divided into parallel paths, with steam crossovers at the first and second spray attemperator stages. There is an attemperation system in the parallel steam paths to

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the first and second stage desuperheaters using spray feedwater attemperation valves. Each spray valve has its own dedicated controller. Difficulties are sometimes experienced in maintaining the full value of live steam temperature. This is due to the valves leaking and hence not maintaining their control range. Partial closing of a serial manual stop valve is the usual stopgap solution. Superheater outlet temperature and a derivative of superheater inlet heat exchanger bypass temperature are compared to the setpoint to form the control deviation. The final reheat steam temperature regulating valves also leak, so they are not used at all.

(e) Boiler Interlock and Protection System

A basic interlock system using electrical relays is in existence. Protection is effected via electrical relays for the following conditions: high and low final steam temperature, both forced draft fans not in service, both induced draft fans not in service, no primary air fan in service, low mazut pressure, and air heaters off.

(f) Burner Management System

There is no burner management system as such. However, the burners are equipped with photoelectric scanners. The scanner circuits are designed such that a loss of flame for three seconds will start mazut flow to the burners. If there is still no flame after six seconds, the burner will trip.

(g) Stack Emissions Monitoring

There are no NO_x, SO_2, CO or CO_2 emission measurements on these blocks. There is an opacity monitor installed, but it doesn't work due to heavy fluegas particulate loading. Currently NO_x, CO_2 and CO emissions are measured periodically by laboratory analysis.

Since all boilers discharge their flue gases into a single stack, it is difficult to identify gases from individual boilers. Without the ability to monitor flue gas emissions from each boiler, it is impossible for the plant maintenance staff to determine which boilers are operating efficiently, and which may need repair or adjustment.

(h) Turbine Control System

Since these are Kharkov turbines, the control fluid is water. The original mechanical governors are still in operation. Each turbine uses 2 stop valves and 2 intercept valves with integral governors.

(i) Turbine Interlock and Protection System

The following protection interlocks are installed: excessive movement at thrust bearing, high steam temperature, low lubricating oil pressure, high water level in HP and LP feedheaters, no boiler feed pump in service, generator electrical faults, loss of either rotor or stator cooling, and low hydrogen seal oil pressure and a loss of vacuum. All of the above protection and interlocks are effected via electrical relays. Overspeed protection is provided via overspeed rings and the hydraulic fluid system. The turbine is protected against water ingress from the feedwater heaters by fast-acting non-return valves and isolating valves in the bleed steam lines which are activated electrically by electrical sensors on the feedwater heaters. There is no stress monitoring on the turbine but casing temperatures at various points are measured and recorded.

(j) Turbine Supervisory System

The following supervisory measurements are made on the turbines: thrust bearing position, eccentricity, vertical and horizontal vibration at all bearings, casing expansion, relative expansion, axial movement, bearing oil outlet temperature and turbine speed by a digital electronic system.

(k) Feedwater Heating Controls

The condenser hotwell level and the levels in the feedwater heaters are controlled using automatic regulators. All of the actuators are electrically operated. All heaters and the condenser are equipped with water level gage glasses. Each extraction point is equipped with a check valve to prevent water ingress. These valves are equipped with hydraulic accelerators to improve the valve operating time.

(l) Plant Alarm System

This is the original system which still operates in a satisfactory manner. A standard, simple ISA sequence is used for display and control of the lamps and the horn. The plant engineers are in the process of designing a solid state system to replace the relay based system because sometimes it overloads and shuts down.

(m) Thermal Insulation Detector

The boiler furnaces tubewall thermal insulation has deteriorated as has that of the air/flue gas duct system. Visual examination has indicated that other plant systems also have deteriorated insulation. A portable optical temperature detector would be a useful device in locating and determining missing or deteriorating insulation.

3.5 AIR POLLUTION CONTROLS

Emissions of particulates, sulfur dioxide (SO_2) and nitrogen oxides (NO_x) and the impact of these emissions on ambient air quality are of concern to the power plants and the surrounding communities. At the Ekibastuz power plant dust collection equipment is provided to remove a major portion of the fly ash from the flue gas before the flue gas is discharged to the environment. The dust collection equipment operates with a collection efficiency of about 96%. No equipment is provided to control either NO_x or SO_2 emissions.

In 1994, the plant's typical emission outputs were:

Emission	Amount, mg/nm^3
Ash	2,480
NO_x	900
SO_2	2,000

Kazakstani emission limits for new boilers are as follows:

Emission	Amount, mg/nm^3
Ash	100
NO_x	240
SO_2	400

Although the local requirement for maximum NO_x emission is 565 mg/nm^3, it is evident that in order to meet the imposed emission limits, major modifications to the Air Pollution Control equipment must be made.

The fly ash collection is achieved by the use of both wet venturi scrubbers and electrostatic precipitators. The ESPS are located downstream of the scrubbers. This arrangement has caused large scale corrosion of the ESP's. In 1987 a program was started to upgrade the ash collection efficiency of all the units at the plant. In this program the ESP's were removed and the venturi scrubbers were upgraded.

4.0 BLOCK NO. 3 REHABILITATION RECOMMENDATIONS

4.1 STEAM BOILER

Based on the assessment of the current condition of the steam boiler for Block 3, the following modifications are recommended:

- Dismantling and removal of 24 (4 horizontal rows of 6) swirl type pulverized coal burners.

- Retrofit (supply and installation) of 24 (4 horizontal rows of 6) double register type low NO_x pc burners (LNB's) together with 12 (2 horizontal rows of 6) overfire air (OFA) registers (optional) into prepared furnace tube openings. The heat input per low NO_x burner (LNB) is 45x10e6 kcal/h.

- Dismantling and removal of 8 (type MMT-2600/2550/590K) high speed, horizontal shaft hammer mills and integral centrifugal classifiers, electric motor drives, and steel foundation rafts. The existing 8 raw coal conduits to the mills and 24 PA/PC conduits to the burners (3 per mill) will be retained. The mill seal air fans and cold PA fans complete with electric motor drives, and all 8 mill electric motor drives will also be retained.

- Installation of medium speed, vertical shaft roller/tyre type mills complete with new drive motors and dynamic classifiers. (seven mills to provide full load (TCMR) coal throughput of approx. 41.2 te/h per mill and one spare mill). Maximum pulverizer coal throughput capacity required is 50 te/h.

- Refurbishing of boiler furnace tubewalls setting (refractory, insulation, casing) including the vertical furnace walls, tube hopper walls, sidewalls of horizontal convective pass, furnace and convective horizontal pass roof.

- Refurbishing of vertical convective passes walls refractory brick setting and casing as needed.

- Refurbishing of boiler outlet to tubular airheaters, tubular airheaters to Venturi wet scrubbers, scrubbers to ESP's, ESP's to ID fans suction side fluegas ducts, expansion joints, dampers and hanger supports as required. Alternatively dismantling and removal of the existing fluegas system and reconstruction with reinforced concrete ducting could also be performed. However, our cost estimate is based on refurbishing of the existing ducting system.

- Refurbishing of furnace and horizontal backpasses rooftubes superheater tube penetration seals as required.

- Refurbishing of horizontal drainable superheater, reheater, economizer tubebanks in the brick-set vertical convective passes tube penetration seals as required.

- Refurbishing of 2 Primary air and 2 Secondary air tubular airheaters (fluegas in tubes in downflow, air over tubes in crossflow) as required.

- Replacement of 2 axial flow, induced draft (ID) fan impellers and control vanes. As an alternative, dismantle/remove the existing 2 ID fans and install 4 new ID fans, together with modified fluegas ducting to/from the new fans. Our cost estimate is based on replacement of existing fans with new fans.

We have included in our cost estimate an allowance for repairing and refurbishing the existing forced draft fans.

Main purpose of the above listed refurbishment cost items is to restore boiler design output, increase availability, and improve operational reliability. Some of the items will also provide boiler efficiency improvement.

Time period scheduled by the power plant for the refurbishment activities of Block #3 is 1997-98.

4.2 STEAM TURBINE/GENERATOR

Based on the assessment of the current performance and condition of the Block 3 steam turbine, the following major replacements and modifications are recommended:

a) Steam Turbine

Block 3 turbine has experienced various problems, including a roof collapse on January 15, 1994. The turbine has problems with its steam distribution and control systems and has vibration problems. The block has been operated with drastically reduced load with the HP Heaters bypassed and with an increased turbine cycle heat rate. Its steam path has suffered efficiency degradation due to wear. In an effort to restore the block's capacity and operating efficiency, and to extend its life beyond its original design life, the following modifications and replacements are recommended.

- Replace main steam stop valves, regulating valves, and steam chest.
- Replace the HP cylinder and rotor.
- Replace reheat stop and intercept valves.
- Open the shell of the IP section and perform NDE and visual inspection to detect cracks or faults at rotor, lower and upper shell surfaces, and obtain approval for extended life from an approved laboratory and the turbine manufacturer. Repair any blade damage as required. Recondition internal seals to as new condition.
- Replace existing bearings with self adjusting modern types at the IP section. (Similar modern bearings are assumed to be furnished with the new HP section).

- Replace front standard and install new turbine control and supervisory system including (TSE) turbine stress monitoring system to be used for controlled startups and load changes.
- Modernize turbine flange and stud-bolt heating system of the HP and IP turbines to be able to provide more efficient startups.
- Check the existing conditions of the last stage blades and bands in the two LP sections. Replace blading as necessary. If last stages require replacement, replace them with titanium blades.
- Equip the turbine turning gear with jogging feature to enable it to be used during maintenance when removing and installing turbine blades.
- Refurbish turbine bypass system as required including turbine bypass valves.

b) Generator

- Replace the electric generator including the hydrogen seal and cooling systems.

c) NDE Equipment

Since there is no replication type creep monitoring equipment or boroscopes presently available at this plant, and in order to make the inspection and testing of the many components of the eight steam turbines (and associated steam boilers and steam piping) more efficient, it is recommended that these and the additional equipment described under paragraph 3.2) be purchased. Availability of such equipment becomes more desirable as the plant major equipment ages.

d) Spare Parts

It is recommended that, an adequate inventory of spare parts for the upgraded (and existing) equipment be established. This has also been recommended by cognizant plant engineering management, and the manufacturers of major plant equipment. In addition, a computerized spare parts inventory system should be implemented in the future when more money becomes available.

The purpose of the above changes and refurbishments is to restore the output capability of the turbine with increased reliability and availability, and to extend the turbine/generator operating life. Some of the refurbishment items will also provide turbine heat rate improvement.

4.3 AUXILIARY PLANT SYSTEMS

Based on the assessment of the current condition of the turbine plant auxiliary equipment the following additional modifications and replacements are recommended:

a) Condenser

- Replace previously plugged tubes and replace existing leaking tubes. It is estimated that approximately 25% of the condenser tubes will need replacement.

- Correct existing air inleakages and institute a more formal air inleakage detection program to systematically detect and eliminate air ingress into the vacuum space of the condenser.

- Retrofit circulating water side of condenser with sponge ball (Taprogge type) tube cleaning system.

b) Feedwater and Condensate System

- Replace the string of high pressure feedwater heaters with new ones.

- Replace the existing feedwater and booster pumps.

- Provide alternate steam supply piping from the No. 3 extraction of the main turbine to the auxiliary feedpump turbines to provide driving steam of adequate parameters to be utilized during part load operation. Also, inspect and refurbish blades and seals of the feedpump turbines, and recondition them as necessary.

- Inspect the deaerator to confirm its structural soundness and proper functioning.

- Replace the first and second stage condensate (and booster) pumps damaged during the January 1994 roof collapse.

- Replace the drain pumps of the LP HTR #2 with larger capacity drain pumps.

The time period scheduled for these and the turbine/generator rehabilitation items for Block 3 is during the years 1997-1998.

4.4 INSTRUMENTATION AND CONTROL

The following plant instrumentation and control improvements are recommended, based on an assessment of Block 3, and discussions with cognizant plant engineering management.

1. Four high temperature O_2 analyzers, (in-situ type, positioned near the furnace exit planes) to achieve optimum combustion efficiency.

2. Good quality portable combustion analyzer (CO, SO_2, NO_x, combustibles)

3. Replace portions of the boiler control system with modern single loop controllers to achieve automatic control of the steam pressure and temperature throughout the load range.

4. NO_x emissions monitoring equipment for the boiler to determine the effectiveness of NO_x reduction initiatives.

5. Particulate emissions monitoring for boiler flue gas to determine the effectiveness of the scrubbers and electrofilters.

6. SO_2 emissions monitoring equipment for the boiler.

7. A heat spy for measuring heat leakages and electrical hot spots.

8. Non-contact type flow meters to measure mazut consumption by the boiler.

9. Refurbish the existing superheat and reheater attemperator control valves.

10. New turbine control and supervisory system including turbine stress monitor.

11. Moisture monitoring equipment to determine the quantity of moisture in the boiler flue gas in order to perform combustion calculations.

The above list was developed during the condition assessment of Block 3 and is considered necessary for rehabilitation and modernization. Implementation of these recommendations will extend the plant life and yield an improvement in reliability and availability and reduce maintenance costs.

4.5 AIR POLLUTION CONTROLS

Rehabilitation of the steam boilers and turbine systems will be accompanied by improvements in the air pollution control systems with the objective of reducing emissions.

Present levels of emissions have been estimated at:

NO_x	900 mg/Nm^3
SO_2	2,000 mg/Nm^3
Ash	2,480 mg/Nm^{3*}

* with 96% efficient dust collection

Pollution control equipment options for reduction in these emissions are described below:

- NO_x emissions can be reduced to 400-450 mg/Nm^3 by modification to the combustion system. Application of low NO_x burners (LNB) together with combustion air staging (OFA) would be required to achieve this emission level.

- Reducing NO_x emissions to 240 mg/Nm^3 (the limit suggested for new boilers) requires post combustion NO_x controls. A 50% reduction in NO_x emissions (from 450 mg/Nm^3) could be achieved by ammonia or urea injection into the furnace. This technology, although low in capital investment requirements, adds significantly to the system operating costs.

- Reduction in SO_2 emissions would require post combustion controls. Reducing emissions from the uncontrolled level of 2000 mg/Nm^3 to the suggested level of 400 mg/Nm^3, an 80% reduction, requires the application of flue gas desulfurization technology. Lime based semi-dry scrubbing is the most likely technology to achieve this emission reduction.

- Reduction in particulate (ash) emissions to achieve the suggested limit of 100 mg/Nm3 would require dust collection equipment with a collection efficiency of 99.84%. This collection can be achieved utilizing a high efficiency electrostatic precipitation or a fabric filter system. Wet (venturi) scrubbing technology, is not capable of achieving such a collection efficiency.

Final recommendations for emission control equipment will depend primarily on the specific regulatory limits imposed by the regulatory agencies. These limits, and the optimum control technologies are the subject of a USAID funded investigation, Kazakstan Regional Environmental Improvement Study, presently in progress. Results of this program will be available in late 1996.

However, for this plant rehabilitation cost estimate, the cost of replacement of electrostatic precipitators have been included to meet the stringent government standards for particulate removal. The SO_x and NO_x control equipment recommendations will be made at the conclusion of the above referred Environmental Improvement Study.

4.6 *REHABILITATION BENEFITS*

The table below summarizes the anticipated benefits of implementing the Rehabilitation recommendations described in Sections 4.1 to 4.5.

REHABILITATION BENEFITS

CHARACTERISTIC	BEFORE	AFTER	% IMPROVEMENT
Boiler Main Steam Flow, t/h	1,206	1,650	36.8
Boiler Efficiency, %	89	91.7	2.7
Turbine/Generator Output, MWe	210	500	138%
Heat Rate, kcal/kWh	2,529	1,841	27.2
Plant Life Extension	-	15 years	
Increase in Plant Availability	-	10 to 12%	10 to 12%

Benefits will also be realized from the Instruments and Control System modifications. The implementation of these recommendations will improve the general operations of the block by increasing its availability and reliability, decreasing Operating and Maintenance costs, and extending the life of the block. The implementation of air pollution control recommendations will help improve the air quality (environment) in the vicinity of the plant. The Low NO_x burners will lower the NO_x discharge from the block and should allow the block to meet future environmental pollution limits. In addition, the replacement of the ESP's will greatly reduce the amount of particulates that are expelled into the atmosphere from the plant stack.

The improved boiler and steam turbine efficiencies will result in decreasing the fuel consumption for a given quantity of electric power generation (MW hrs). This will have the double benefit of fuel cost savings as well as reduction in pollutants discharged to the environment. The estimated 15 years life extension of major plant components (boilers, turbines, condensers, feed pumps, feedwater heaters, etc) as a result of the plant rehabilitation will defer the potential capital expenditure needed to replace the plant capacity. If no rehabilitation were to be performed and the plant had to be retired in the near future, it will require substantial capital investment. The plant rehabilitation will also result in reducing the potential cost of replacement power to be purchased when Block 3 plant were to be shutdown due to unplanned (forced) outages.

One additional benefit of Block 3 rehabilitation is an increase in plant availability and reliability due to major renovation and upgrade of critical plant components such as

boilers, turbines, auxiliary plant equipment and instrumentation and controls upgrades. It is estimated that the Block 3 availability and reliability will improve by 10 to 12 percent as a result of the proposed Block 3 rehabilitation.

5.0 CAPITAL COST ESTIMATES

Cost estimates for the various rehabilitation items have been developed based on Burns and Roe in-house estimates for similar size jobs or from vendor estimates. The estimates are based on the following scope of supply and are expressed in 1995 U.S. dollars.

Scope of Supply

- Replacement of existing 8 Hammer Mills with 8 new Vertical Spindle Roller/or Tyre type Mills
- Installation of new Dynamic (rotating)Classifiers
- Replacement of Boiler Setting (refractory, insulation & casing)
- Repair (4) Tubular Air Heaters
- Installation of new low NO_x Burners and overfire air nozzles
- Replacement of two (2) Induced Draft Fans
- Repair or replace tube penetration seals
- Repair flue gas duct system
- Replace HP Cylinder and Rotor.
- Replace Stop Valves, Regulating Valves, and Steam Chest.
- Replace RH Stop and Intercept Valves.
- Replace bearing with self-adjusting modern type for the HP and IP sections.
- Purchase additional NDE Equipment.
- Perform NDE Testing of the IP Turbine section (cracks, creep) - repair as necessary.
- Install Turbine Control and Supervisory System including Turbine Stress Monitoring.
- Modernize Turbine Flange and Studbolt Heating System for HP and IP turbines.
- Replace the valves in the Turbine Bypass (steam dump) System.
- Check the present condition of the last stage blades and bands in the LP Cylinders. Replace if necessary (cost of 4 sets of blade included).
- Replace Electric Generator and seal and cooling system.
- Equip the Turbine Turning Gear with Jogging Feature (cost of new turning gear included).
- Replace damaged or leaking tubes in the condenser (25% of tubing replaced).
- Replace HP Feedwater Heaters.
- Replace Feedwater Pumps.
- Provide Alternate Steam Supply Connection from the No. 3 Turbine Extraction to the Feedpump Turbines.
- Inspect Deaerator for structural soundness and proper functioning.
- Replace condensate pumps and booster pumps (2 condensate pumps and 2 booster pumps).
- Replace 2 Drain pumps for LP HTR #2.
- Remove existing wet scrubbers and precipitators
- Install two (2) new Electrostatic Precipitators
- Install Emissions and Air Flow Monitoring Equipment
- Install Boiler Emission Monitoring Equipment

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- Miscellaneous Instrumentation and Controls System Upgrades

The project cost estimate is conceptual in nature, and was based on information obtained during Burns and Roe's recent site visit.

Direct Costs

Pricing for major equipment and materials were developed from Burns and Roe's historical data and vendor estimates for similar sized projects escalated to October 1995. The pricing is based on major equipment and material being supplied by Western manufacturers and transported to the project site.

Bulk materials (concrete, piping, valves, etc.) were assumed to be available locally in the quantities and sizes necessary to support the project requirements.

Construction Labor

Labor costs were generated by using U.S. Gulf Coast manhour estimates for the work to be performed and applying a productivity factor. The productivity factor was developed based on Burns and Roe's observations at the site and previous studies performed in NIS countries. Based on our site visit, we expect the skilled labor required to complete the project to be available locally to the project and within Kazakstan.

Indirect Costs

Ocean freight costs and insurance costs have been assumed at 7% of material costs.

Contingency has been added to the estimate to provide for risks and uncertainties associated with the prices of the components at the conceptual stage of design. Contingency was applied to the direct labor and material costs.

Other Costs

Additional costs such as Engineers, Construction Management, Start-up Costs, Construction Equipment, Interest During Construction, and Escalation have not been included in the base cost but are presented for information purposes.

PRELIMINARY COST ESTIMATE
REHABILITATION OF 500 MW BLOCK No. 3
EKIBASTUZ COAL FIRED POWER PLANT KAZAKSTAN

ITEM	LABOR COST $	WESTERN MAT'L $	LOCAL MAT'L COSTS	TOTAL COST
BOILERS				
Remove Existing Burners (24 Total)	387,200		11,600	398,800
Install New Low NOx Burners & OFA System	1,224,300	14,618,000	396,100	16,238,400
Remove Existing Hammer Mills & Classifiers	198,400		6,000	204,400
Remove Existing Hammer Mill Foundations	143,400		4,300	147,700
Repair PA/PC Ductwork & Fans	225,600	753,200	29,400	1,008,200
Install New Roller Mill Foundations (8)	148,800		31,300	180,100
Install New Roller Mills (8)	517,400	5,623,000	184,200	6,324,600
Install New Classifiers	423,000	2,780,000	96,100	3,299,100
Boiler Refractory, Insulation & Casing Repair	796,800	4,255,000	151,600	5,203,400
Tube Penetrations & Seals	206,400	985,000	35,700	1,227,100
Repair Forced Draft Fans	147,800	621,900	54,300	824,000
Remove Old Induced Draft Fans	150,400		4,500	154,900
Replace Induced Draft Fans	293,100	3,428,000	111,600	3,832,700
Repair Flue Gas Ductwork	695,400	5,821,000	195,500	6,711,900
Perform Non-Destructive Testing (Allowance)	50,000			50,000
Perform a Draft Plant Assessment on a Boiler Train (Allowance)	60,000			60,000
TOTAL BOILER WORK	**4,056,500**	**24,267,100**	**904,500**	**29,228,100**
TURBINE GENERATOR				
Replace HP Cyliner & Rotor	500,000	7,300,000	234,000	8,034,000
Replace Stop Valves and Steam Chest	134,000	1,250,000	41,500	1,425,500
Replace RH Stop and Intercept Valves	122,700	900,000	30,700	1,053,400
Replace Bearings	12,300	50,000	1,900	64,200
Perform NDE Testing on IP and LP Sections	0	45,000	13,500	58,500
Supply NDE Testing Equipment	0	25,000	0	25,000
New Turbine Control System	134,400	1,000,000	34,000	1,168,400
Replace Front Standard & Heating Flange	135,200	1,268,000	42,100	1,445,300
Replace Turbine By-Pass System	38,200	425,000	13,900	477,100
Replace 4 Rows Last Stage Blading w/Titanium Blades	58,900	500,000	16,800	575,700
Install Turning Gear	6,000	25,000	900	31,900
TOTAL TURBINE WORK	**1,141,700**	**12,788,000**	**429,300**	**14,359,000**

PRELIMINARY COST ESTIMATE
REHABILITATION OF 500 MW BLOCK No. 3
EKIBASTUZ COAL FIRED POWER PLANT KAZAKSTAN

ITEM	LABOR COST $	WESTERN MAT'L $	LOCAL MAT'L COSTS	TOTAL COST
AUXILLIARY PLANT SYSTEMS				
Replace 25% of Condenser Tubes	181,900	875,000	19,700	1,076,600
Install Condenser Cleaning System	168,000	1,455,000	13,500	1,636,500
Replace HP Feedwater Heaters	209,800	1,800,000	36,300	2,046,100
Replace LP Heater Drain Pumps	8,500	64,000	1,400	73,900
Replace Feedwater Pumps	140,800	1,500,000	49,200	1,690,000
Provide Alternate Steam Extraction to BFP	38,500	150,000	2,700	191,200
Inspect Deaerator (Allowance)	0	20,000	600	20,600
Replace Condensate Pump Bearings & Glands	25,600	100,000	3,800	129,400
TOTAL AUXILLIARY SYSTEMS WORK	**773,100**	**5,964,000**	**127,200**	**6,864,300**
INSTRUMENTATION & CONTROLS				
Install Emissions Monitoring Equipment	172,000	565,000	14,700	751,700
Install Boiler Monitoring Equipment	74,700	255,900	6,600	337,200
Install Turbine Monitoring Equipment	57,900	145,300	4,100	207,300
Miscellaneous Instrumentation & Controls	101,300	817,500	18,400	937,200
TOTAL INSTRUMENTS & CONTROLS	**405,900**	**1,783,700**	**43,800**	**2,233,400**
ELECTRICAL SYSTEM				
Repair Plant Wiring & Cable	85,600	1,000,000	21,700	1,107,300
Replace Generator	230,100	14,000,000	284,600	14,514,700
TOTAL ELECTRICAL WORK	**315,700**	**15,000,000**	**306,300**	**15,622,000**
ENVIRONMENTAL SYSTEM				
Remove Existing Precipitator	194,900		3,900	198,800
Install New Electrostatic Precipitator	467,200	11,400,000	237,300	12,104,500
TOTAL ENVIRONMENTAL WORK	**662,100**	**11,400,000**	**241,200**	**12,303,300**
SUBTOTAL	**7,355,000**	**71,202,800**	**2,052,300**	**80,610,100**
Freight				5,054,300
Contingency (10%)				7,263,200
TOTAL COST OF REHABILITATION				**92,927,600**
			$/KW	**186**

ALL COSTS ARE SHOWN IN 1995 DOLLARS
IF THIS PROJECT WERE TO BE CONSTRUCTED IN THE USA
THE FOLLOWING ADDITIONAL COSTS WOULD APPLY:

DIRECT COSTS FROM PREVIOUS PAGE				**92,927,600**
Engineering Costs				4,836,608
Construction Management Costs				2,418,303
Start-Up Costs				1,612,202
Construction Equipment Costs				1,750,000
Interest During Construction				7,434,208
Escalation				8,878,314
TOTAL COST INCLUDING THE ITEMS ABOVE		**$/KW**	**240**	**119,857,233**

1. Freight Costs are assumed to be 7% of the Material Costs
2. Construction Equipment Costs assumes Equipment to be available locally to the project
3. Engineering Costs are assumed to be 6% of the Material Costs
4. Construction Management Costs are assumed to be 3% of the Material Costs
5. Start-up Costs are assumed to be 2% of the Material Costs
6. Interest during construction is calculated at 8% per year for 2 years for 1/2 the direct cost
7. Escalation is assumed to be 4% per year for 2 years

6.0 CONSTRUCTION SCHEDULE

The construction schedule for the rehabilitation recommendations described in Section 4.0 is shown on the following two pages. The overall duration of the reconstruction (rehabilitation) project is estimated at 24 months based on Burns and Roe past experience with similar rehabilitation projects. Time period of 24 months only includes the actual reconstruction of the power plant components and their startup and checkout activities. it does not include the engineering and design time required for rehabilitation of plant components such as boilers, turbines, auxiliary plant system components, instrumentation and controls, and electrostatic precipitators (ESPs); nor does it include time required for procurement of the new equipment such as ESPs and new instruments and controls.

CONSTRUCTION SCHEDULE FOR THE REHABILITATION OF THE EKIBASTUZ PLANT BLOCK NO. 3

Tasks	Month 1	Month 2	Month 3	Month 4	Month 5	Month 6	Month 7	Month 8
BOILER WORK								
Remove Boiler Mechanical Components (Burners, Tubes, etc.)								
Remove Boiler Auxiliary Equip. (Mills, Fans, etc.)								
Remove Mill Foundations								
Install New Mech. Components Including Heat Transfer Surfaces								
Install New Mills and Auxiliaries Including Fans								
Repair Boiler Casing, Refractories, Insulation, etc.								
TURBINE GENERATOR								
Purchase NDE Equipment and Test Selected Components								
Replace Various Turbine Components Including Piping and Valves								
Replace Electric Generator and Cooling System								
Install New Turbine Control System (Stress Monitoring)								
AUXILIARY PLANT SYSTEM								
Replace Feedwater and Condensate Pumps								
Replace Feedwater Heaters								
Replace Plugged Condenser Tubing and Install Tube Cleaning System								
Replace Condensate and Drain Pumps								
Install Extraction Steam Piping From No. 3 Turbine Extraction								
ENVIRONMENTAL								
Remove Venturi Scrubbers and Replace Electric Precipitators								
INSTRUMENTATION								
Install Emissions and Air Flow Monitoring Equipment								
Install Boiler and Turbine Monitoring Equipment								
Misc. Instrumentation & Controls System Upgrades								
STARTUP AND CHECKOUT								

CONSTRUCTION SCHEDULE FOR THE REHABILITATION OF THE EKIBASTUZ PLANT BLOCK NO. 3