FOIA Number: 2017-1095-F

FOIA MARKER

This is not a textual record. This is used as an administrative marker by the William J. Clinton Presidential Library Staff.

Collection/Record Group: Clinton Presidential Records

Subgroup/Office of Origin: Council of Economic Advisers

Series/Staff Member: Subject Files

Subseries:

OA/ID Number: 21624

FolderID:

Folder Title:
Kazakhstan - Efficiency [Energy & Climate Change] [3]

Stack:	Row:	Section:	Shelf:	Position:
S	21	4	11	2

PN. ACB-859
96292

Burns and Roe Enterprises, Inc.

Technical Report

KAZAKSTAN EXPANDED ENERGY PROGRAM

HEAT AND POWER SYSTEM EFFICIENCY IMPROVEMENTS

KARAGANDA & UST-KAMENOGORSK PLANTS

FINAL REPORTS

January 1996

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 30, 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
Karaganda and Ust-Kamenogorsk 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 Karaganda and Ust-Kamenogorsk plants. Ermakovskaya and Ekibastuz final reports were submitted to your officeon January 19, 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: <u>All w/att</u>
G. Weynand, USAID
B. Primm, USAID, Almaty
S. Gerges, Burns and Roe

C

TABLE OF CONTENTS

KAZAKSTAN EXPANDED ENERGY PROGRAM

TASK 2

HEAT AND POWER SYSTEM EFFICIENCY IMPROVEMENT

KARAGANDA 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
BMCR	Boiler Maximum Continuous Rating
LHV	Lower Heating Value
TMCR	Turbine Maximum Continuous Rating
T/G	Turbine Generator

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

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 Karaganda Electric Generation (Power) Plant 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. 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 determine the thermal efficiency of the system and identify the major plant systems and components which require rehabilitation or modernization.

- An engineering analysis was performed to recommend modern technology for increasing the availability and performance of the selected unit. This analysis also includes 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.

- A review of the Karaganda District Heating System piping was made with District Heating system engineers. Recommendations were developed to improve system efficiency and reliability based on the information provided by the DH system engineers.

- 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 and/or process steam to 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. Improvements in system thermal efficiency will also contribute to reduced emissions by reducing fossil fuel consumption.

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 PLANT DESCRIPTIONS AND EVALUATIONS

General

The Karaganda GRES #2 plant was commissioned and placed into service from 1962 to 1967. The plant has seven turbine generators which provide 608 MW of electrical power and 435 Gcal/h of heating steam extraction capability. All the turbines in the plant are supplied with main steam from a 90 ata main steam header. This header carries steam from sixteen pulverized coal boilers. These boilers have a combined steaming capacity of 3520 t/h.

The plant is subdivided into two sections. The first section consists of six type PK-10p-2 boilers and three turbine generators. One of the turbines is type K-50-90 with 50 MW electric generating capacity, while the other two are model K-100-90 with 100 MW electric generating capacity each. This section of the plant can generate 250 MW of electricity. The second section of the plant consists of nine boilers type PK-10p-2 and one boiler type PK-14-3. The second section also contains four turbine generators, three T-86-90/2.5 and one K-100-90. This section can generate 358 MW of electricity and 300 Gcal/h of heat for district heating. The remaining 135 Gcal/h of heating steam is provided from pressure reducing stations which take steam from the main header and reduce its pressure so the steam can be used in the district heating heat exchangers.

The plant management and the Burns and Roe team has jointly selected turbine No. 3 and boilers 7, 10, and 13 for further evaluation as a part of the renovation project for this plant.

3.1 STEAM BOILERS

The fifteen (15) PK-10p-2 boilers of Karaganda GRES #2 are nearly identical. Boiler 16 is type PK-14-3 with only 66,000 hours operating time. This boiler has not been included in this analysis due to its young age. Each boiler is of the natural circulation drum type, with a radiant balanced draft, dry bottom furnace. The boiler configuration is of the conventional two-pass without a furnace arch, a short horizontal convective pass, and a vertical rear-pass. The boilers were designed for operation in a combined heat and power (CHP) plant. The furnace is rectangular, 9785 mm wide and 7600 mm deep. The furnace tubewalls are fully water cooled, 76 mm OD by 6 mm nominal thickness carbon steel tubes on 95 mm centers, with refractory backing. The horizontal and rear convective passes rooftubes are steam cooled, 42 mm OD by 4.5 mm thick, and are also made of carbon steel material. Each boiler has two (2) steam/water drums, with 1300 and 300 mm ID's, both are made of carbon steel material. The downcomers are small diameter (108 mm OD by 7 mm thick) pipes. The horizontal short convective pass sidewalls and floor, the rear convective pass top portion front, rear and sidewalls, and the economizer enclosures in the vertical rear pass are refractory brick lined. The tubular airheater stages in the rear convective pass have metal casings.

The furnace is tangentially fired and has an indirect firing system. The boilers fuel/air injectors (burners) are positioned in the furnace sidewalls, each sidewall has two (2) pulverized coal/primary air injection port levels with the secondary air injection ports positioned above and below each coal injector with a total of eight (8) coal injection nozzles per boiler.

The superheater heating surfaces can be divided into radiant and convective parts. The radiant primary superheater (SH) consists of the furnace and convective passes roof tubes. The convective, pendant primary and secondary superheaters are positioned in the horizontal convective pass. Steamflow is divided into two parallel paths, with a steam side crossover between the 1st and 2nd stage SHs.

Superheated steam final temperature control is by spray attemperation. Drum saturated steam is condensed by feedwater prior to entering the 1st stage economizer. The steam condenser discharge water enters the 1st stage economizer, the condensate is then injected into the spray nozzles of the steam attemperators which are positioned between the 1st and 2nd stage of the superheater. The economizer (1st and 2nd stages) consists of horizontal fully drainable tube banks of bare staggered tubes, 32 mm OD by 3.5 mm thick and are made of carbon steel material. The water is in upflow and the fluegas is in downflow. Both economizer stages are positioned in the vertical rear convective pass. The economizer has a recirculation line installed. The tubular airheater (1st and 2nd stages) is also positioned in the rear convective pass, with fluegas in the tubes in downflow and combustion air in upflow across the tubes. The air heater has staggered tubes of 51 mm OD by 1.5 mm thick which are made of carbon steel material. Cold end corrosion protection of the airheater is provided by hot air recirculation into the FD fan suction side.

The draft plant of each boiler consists of two (2) forced draft (FD) and two (2) induced draft (ID) fans. The forced draft fans are the radial flow centrifugal type, with radial inlet vane control, and a constant speed electric motor drive. The induced draft fans are radial flow, centrifugal type with inlet louver damper control and constant speed electric motor drive.

The indirect firing system of each boiler consists of two (2) raw coal silos each with a dedicated volumetric coal feeder, two (2) tumbling ball mills size SBM 287/470 S-16 each with an external centrifugal classifier, two (2) ball mill exhauster fans of radial flow, (centrifugal type with constant speed electric motor drive) two (2) separating cyclones, a common pulverized coal storage bunker with pc feeders, PC/PA and hot PA conduits and dampers, hangers, etc. The ball mills operate with subatmospheric pressure. Each exhauster fan conveys the PA/PC mixture to one level of four (4) furnace coal injectors. The forced draft fans provide the hot PA supply to the ball mill inlets and also the cold tempering air for maintaining a constant classifier exit PA/PC mixture temperature. Cold tempering air can also be injected into the exhauster fans suction side.

Particulate emission control equipment consists of four (4) wet scrubbers per boiler on boilers 1 to 6 and electrostatic precipitators (ESP) for boilers 7 to 15. There are no provisions made for reducing NO_x and/or SO_x emissions. The boilers do not have continuous emission monitoring equipment installed.

Heating surface cleaning equipment consisting of steam operated furnace wall blowers and also retractable steam operated sootlances in the horizontal convective passes have been removed from the PK-10p-2 boilers. With the presently fired Ekibastuz bituminous coal their use is not needed.

The furnace operates at all loads without any severe slag type wall deposits and the highly erosive flyash cleans the convective surfaces of any fouling type deposits. Bottom ash handling equipment consists of a refractory lined, water impounded bottom ash hopper supported on the basement floor with a screw type slag discharge device feeding into the basement floor ash sluice system.

The boiler furnace, short horizontal convective pass, and top of the vertical convective pass are top supported, and the rest of the vertical convective pass is bottom supported, with a metallic expansion joint in-between. The main and surge steam/water drums are bottom supported from the boiler suspension steel structure. The table below, (TABLE 3-1) shows the major operating parameters of the boilers described.

TABLE 3-1

Thermal Performance Design vs Current

Parameter	Units	Design	Current
Live steam flow @ BMCR	te/h	220	166~206
Live steam pressure	at.abs.	100	97~102
Superheated steam temperature (derated)	°C	520	519~527
Feedwater temperature to economizer	°C	215	160~204
Combustion air temperature to airheater	°C	30	18~40
Fluegas temperature leaving airheater	°C	140	152~219
Excess air in fluegas @ economizer exit	%	20	21~25
Combustion air XS @ FD fan discharge	%	40	32~37
Boiler efficiency LHV basis	%	91.8	84.5~87.5

All the boilers are of the subcritical steam pressure type with a drum, thermosyphonic circulation, no reheater and are manufactured by Podolsk Machine Building Factory. Boilers 1 to 15 have an average operating times of 200,000 hours each, as of Sept. 1995.

The firing system consists of single flame envelop tangential burners with two (2) levels of pulverized coal injection nozzles, and indirect (pulverized coal storage) type firing system. The design fuel was Karaganda coke preparation plant bituminous coal concentrate with a (by weight) 38% mineral matter ash content , 8.5% moisture content, 36.5% VM as fired, LHV of 4003 kcal/kg as fired, HGI of 72 and an ash softening temperature of 1400 to 1500°C. Presently fired coal is also bituminous from the Ekibastuz open cast mine with a 41 to 44% (by weight) mineral matter content and 4.5 to 6% moisture content, 24.4% (by weight) VM as fired, LHV of 3560 to 3900 kcal/kg as fired, HGI of 76 and an ash softening temperature over 1500°C. Auxiliary fuel for start-ups/shutdowns and combustion stabilization is mazut with an approximate heat input capacity of 18% of full load heat input. Ignitors are steam atomized. **It is proposed that three (3) PK-10p-2 boilers 7, 10 and 13 from the second power plant section should be refurbished, to provide full TCMR steamflow to the turbine generator no. 3, with one boiler in stand-by mode.**

Condition Assessment

From the information received, the following assessments can be made:

- Creep and low cycle fatigue type failures of water and steam cooled thickwalled pressure parts and tubing.
- High mineral matter content of Ekibastuz coal and metal loss of convective heating surface tubebanks by highly erosive flyash.
- Milling circuit components, e.g. mill exhausters, PA/PC conduits, ball mill liners, classifiers and separating cyclones erosive wear.
- Unmeasured air ingress into boiler setting through horizontal convective pass rooftubes and vertical convective pass tubes penetration seals.
- Boiler setting (refractory, insulation, casing) deterioration. This is another significant source of false air ingress into the boiler.
- Induced draft (ID) fans housing and impeller erosive wear.
- Air and fluegas duct systems metallic expansion joints fatigue type failures and fluegas duct systems wear by highly erosive flyash.
- Tubular airheater cold end, also fluegas ducting low temperature corrosion attack.

3.2 STEAM TURBINE GENERATORS

General

The Karaganda GRES-2 plant started its operation in 1962 as a purely electric generating station. At its completion the plant had two 50 MW (K-50-90) and six 100 MW (K-100-90) condensing steam turbines. Each of the steam turbines were designed as non-reheat units with main steam parameters of 90 ata and 535°C. Even though the steam turbines were not district heating turbines, Units 1 through 6 had a capability for providing a small quantity (about 7.0 Gcal/h each) of thermal energy from a non-regulated extraction port which also supplied steam to one of the eight regenerative feedwater heaters in the steam cycle. The bank of steam to water heat exchangers using extraction steam from these ports was initially used to provide hot water heat to the local village called Topar in addition to the plant's own needs. At that time the nominal power generation capability of the plant was 700 MW.

As the need for thermal energy grew in the vicinity of the GRES-2 power plant, it became necessary to make modifications to the steam turbines in order to extract more steam to satisfy the increased heat demand. Therefore, the last three units were reconstructed to remove large quantities of steam from the turbine crossover pipes to provide 100 Gcal/h heat from each of these units. The modifications for turbines No. 7 and 8 were completed in 1979 and the reconstruction of turbine No. 6 was performed in 1985. Because of these modifications and the extraction of 100 Gcal/h heat, the designations of these turbines were changed from K-100-90 to T-86-90/2.5 indicating that the nominal electrical output of these units have been derated to 86 MW.

At the time of the Burns and Roe team visit, the first 50 MW unit had been decommissioned because of its age, and therefore the current nominal electrical output capability of the plant is 608 MW. The current nominal output of the various steam turbines and the accumulated total number of operating hours are shown in TABLE 3-2.

TABLE 3-2

GENERATING CAPABILITY OF THE KARAGANDA GRES-2 TURBINES

Steam Turbine No.	**2**	**3**	**4**	**5**	**6**	**7**	**8**
Date of Original Startup	8/62	1/63	9/83	10/64	6/65	12/65	7/67
Original Designation	K-50-90	K-100-90	K-100-90	K-100-90	T-100-90	T-100-90	T-100-90
Current Designation	K-50-90	K-100-90	K-100-90	K-100-90	K-86-90/2.5	T-86-90/2.5	T-86-90/2.5
Nominal Generating Capability MW/Gcal/h	50/0	100/0	100/0	100/0	86/100	86/100	86/100
Accumulated Operating Hours	249,621	243,054	240,173	231,338	230,124	228,363	221,690
Number of Capital repairs	10	9	8	9	6	6	6
Year of last capital repair	1992	1991	1994	1990	1993	1991	1993

From the previous table (TABLE 3-2) it can be seen that the steam turbines have a combined official nominal heat supply capability of 300 Gcal/h. The heat content of the controlled extraction steam is transferred to the district heating water in large newer district heating heat exchangers. The small heat exchangers utilizing unregulated steam extractions are no longer used.

Technical information received from the plant indicates that currently there are three separate district heating systems served by the plant. These and their maximum demands are shown below:

System	Current Maximum Demand (Gcal/h)
Topar	63.4
Greenhouses ("The 60-yr USSR")	172.1
The Town of Abai	150.5
Total:	386.0

There is also a small demand of heat (3 Gcal/h) which must be supplied in the form of steam. Together with the plant's own needs there is a total thermal demand of 412.8 Gcal/h. The plant currently has a nominal thermal output capability of 435 Gcal/h. However, the thermal demand in excess of the turbines' 300 Gcal/h capability is satisfied by the use of various pressure reducing stations. The plant data indicates that the current deficit in efficient hot water supply capability is about 86 Gcal/h.

The actual plant operating data for the months of 1994 is summarized in TABLE 3-3. From this table it can be seen that the total electric power generation was 3.97278×10^9 kWh and the thermal energy generation was 926,410 Gcal in 1994. The individual contribution of the steam turbines to the above total figures as well as other yearly average plant parameters are shown in TABLE 3-4.

TABLE 3-3

SEASONAL GENERATION AND LOADS FOR KARAGANDA GRES-2
(1994)

MONTH	Electrical Generation (10^3 kWh)	Peak Load (MW)	Average Load (MW)	Thermal Energy Gen. (Gcal)
January	409,846	625	551	166,904
February	383,901	615	571	154,776
March	410,144	610	551	140,776
April	283,165	535	393	87,367
May	277,821	490	373	26,231
June	295,622	515	411	6,622
July	276,995	500	372	6,872
August	291,491	455	392	6,774
September	269,792	440	375	21,158
October	322,022	525	433	57,634
November	377,501	625	524	105,304
December	374,480	640	503	145,992

TABLE 3-4

OPERATING PARAMETERS OF THE KARAGANDA TURBOGENERATORS

Unit	2	3	4	5	6	7	8
Electric Power Generation 10^3 kWh	368,764	686,784	335,104	709,136	644,448	561,792	666,752
Average Load, MW	42.5	87.9	93.7	88.0	76.17	80.6	84.2
Thermal Energy Generation, Gcal	0	0	0	0	225,369	210,028	207,743
Number of hours in Operation	8,760	7,813	3,576	8,055	8,461	6,972	7,923
Capacity factors, %							
Electric	84.19	78.40	38.25	80.95	85.54	74.57	88.50
Thermal	-	-	-	-	25.7	23.99	23.7
Number of Starts	3	4	4	3	3	6	4
Main Steam Pressure, ata	92	93	90	90	90	89	91
Main Steam Temperature, °C	512	515	515	517	513	516	513
Vacuum, %	96.5	94.3	95.8	96.0	95.5	95.4	94.7
Condenser Air Inleakage, kg/h	15.03	54.75	47.87	12.22	25.47	31.96	34.06
Final Feedwater Temperature, °C	210	173	213	215	194	213	192
Turbine Gross Heat Consumption, kcal/kWh	2,406	2,345	2,279	2,342	2,322	2,073	2,213

The Karaganda GRES-2 the plant management and the Burns and Roe team together have selected the No. 3 steam turbine generator for further, more detailed examination and assessment.

Description of the No. 3 Turbine Generator

The Karaganda Unit No. 3 Turbine was placed in service in January, 1963. It is a nominal 100,000 kW, 3000 RPM, non-reheat, tandem compound condensing machine, designed to receive 363 t/h of throttle steam at a pressure of 90 ata and temperature of 535°C at guaranteed full load conditions. The turbine was designed by LMZ. There are two separate turbine elements on a single shaft; one single flow high pressure (HP) section, and one double flow low pressure (LP) section. The cross sectional drawing of the turbine is shown in Figure 3-1.

The HP section of the turbine consists of 20 stages including the Rateau governing stage. The LP section consist of 5 stages in each flow. There are 8 extraction openings on the turbine downstream of the 7th, 10th, 13th, 18th and 20th stages in the HP cylinder, and 22nd, 23rd, and 24th stages in the LP cylinder. These uncontrolled extractions provide steam for the turbine regenerative feedwater heating system. The condensate leaving the main condenser is heated in 5 low pressure heaters, a deaerator, and 3 high pressure heaters. The design temperature of the final feedwater leaving the highest pressure feedwater heater is 217°C. The thermal cycle schematic for the No. 3 turbine is shown in Figure 3-2.

In addition to the regenerative feedwater heating steam, the turbine design also allows the extraction of up to 15 tons per hour of steam from the extraction port which supplies bleed steam for LP HTR #5. The 15 tons per hour of uncontrolled pressure steam can be utilized in a separate heat exchanger for producing hot water for district heating purposes.

Main steam to the HP turbine stages is provided from the steam generators through a main steam stop valve mounted on a separately installed steam chest. Steam from the steam chest flows through cross pipes to 4 governor valves which are installed on the HP section above the nozzle boxes. The steam exiting the HP section flows to the LP section through two cross-over pipes. The exhaust steam from the LP section is condensed in a 2-pass condenser at a design backpressure of 0.035 kg/cm^2abs. The design temperature of the circulating water entering the condenser under nominal load is 10°C.

The combined support-thrust bearing is located at the front of the HP turbine section. The other bearings are support bearings and are located as shown in Figure 3-1. The rotors of the HP and LP sections and the generator are connected by semi-flexible couplings.

The rotor disks of the 20 stages in the HP section are forged together with the rotor. The LP rotor is made up of the shaft with 10 stacked wheels. The turbine is furnished with a turning gear with an operating speed of 3.5 rpm.

Figure 3-1
TURBINE GENERATOR CROSS-SECTION

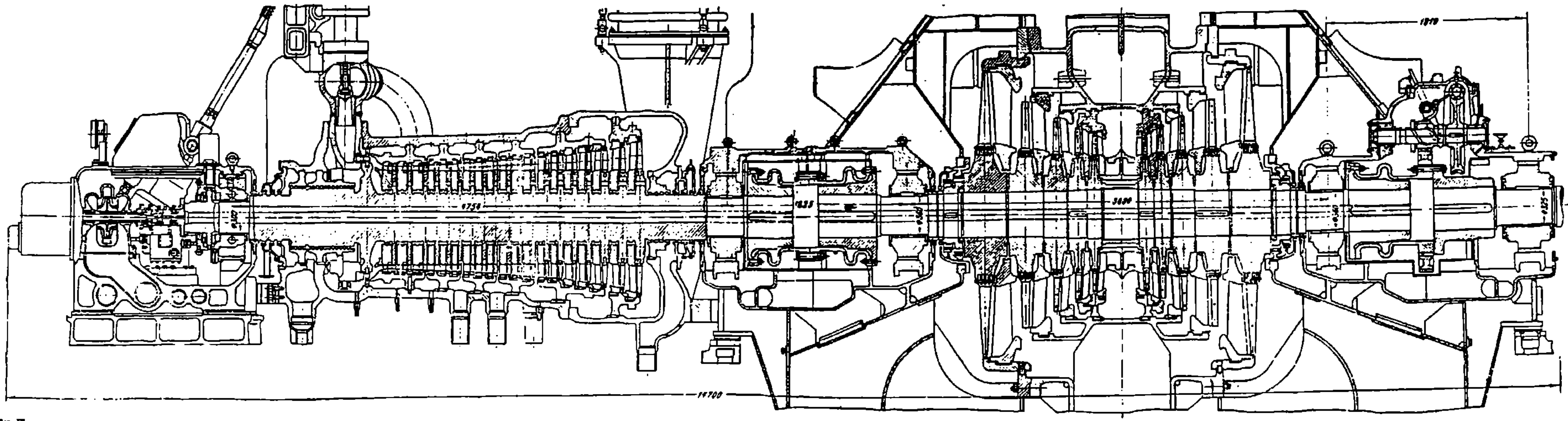
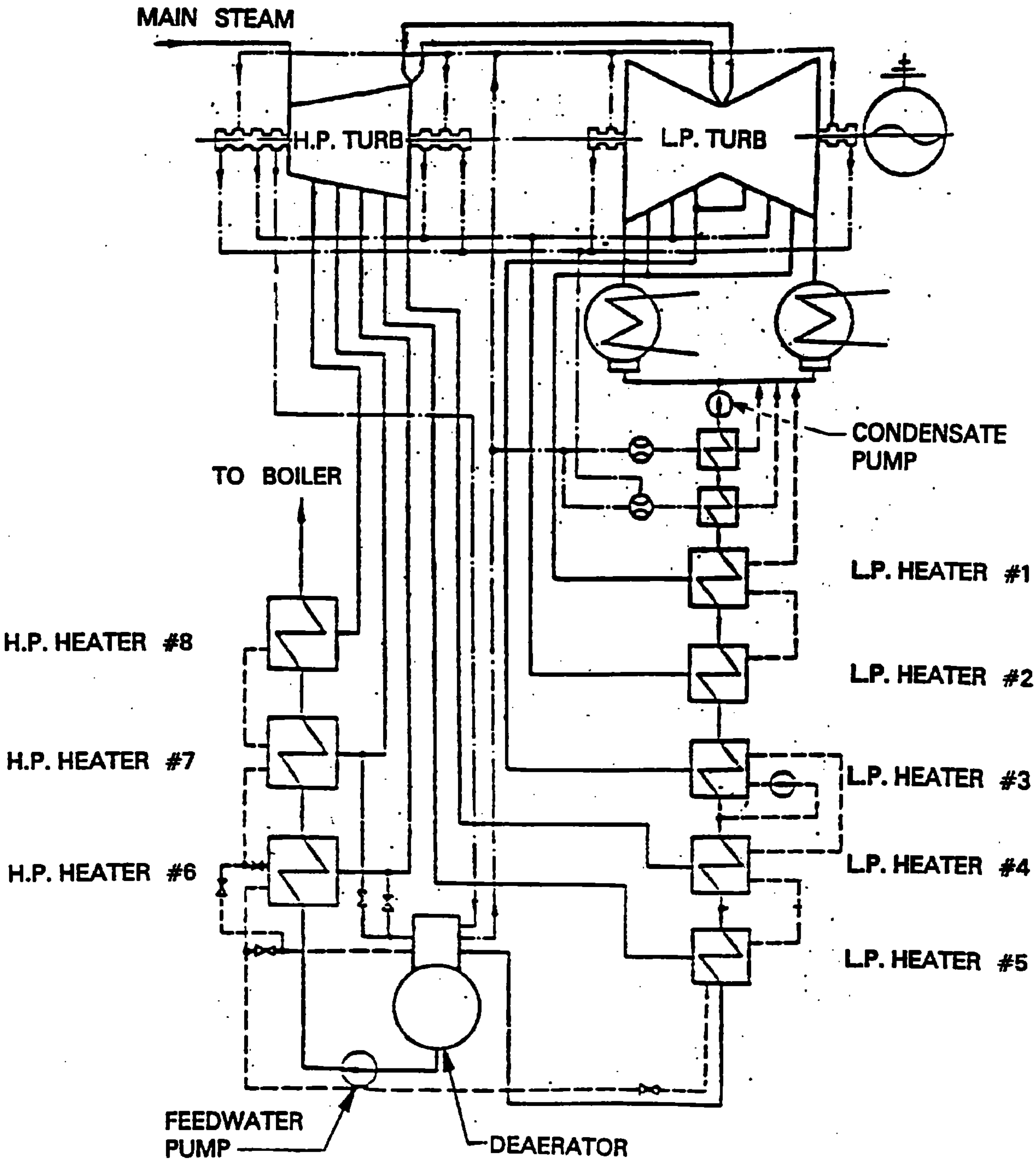


Figure 3-2
TURBINE CYCLE SCHEMATIC
KARAGANDA CHP PLANT



The turbine oil system is a combined system both for regulation and for bearing lubrication. The oil pressure in the regulating system is 20 kg/cm^2, and in the lubricating system it is 1 kg/cm^2. The electric generator is an AC type TVF-100-2 with hydrogen cooling, and is manufactured by the Electrosila Factory.

Design/Current Performance of Turbine No. 3

The technical characteristics and design parameters of the No. 3 steam turbine are shown in TABLE 3-5. This table indicates that the turbine main steam parameters are 90 ata and 535°C. While the turbine is usually operated with the original main steam pressure of 90 ata, the main steam temperature has been officially lowered to 515°C as of December 1, 1977 by the order of the Ministry of Power Engineering and Electrification.

The original guarantee performance figures as per the LMZ Turbine Instruction Manual No. 1267A are as follows:

Guaranteed Output (kW)	*Generator Efficiency (%)*	*Main Steam Flow (t/h)*	*Final FW Temp. (°C)*	*Heat Rate (kcal/kWh)*
100,000	99.0	363	217	2190
80,000	98.8	284	204	2240
60,000	98.5	212	188	2300

TABLE 3-5

TECHNICAL CHARACTERISTICS OF THE STEAM TURBINE

	Units	Original Design
Type	-	K-100-90
Nominal Output	MW	100
Main Steam Pressure	$kg/cm^2(a)$	90
Main Steam Temperature	°C	535
Main Steam Flow	t/h	363
Number of Extractions	-	8
Extraction Configuration	-	3HPH+D+5LPH
Condenser pressure	$kg/cm^2(a)$	0.035
Specific Heat Consumption	kcal/kWh	2190
Turbine Manufacturer	-	LMZ
Overall Length of Turbine	meters	14.7
Number of Turbine Bearings	-	4
Generator Model	-	TVF-100-2
Generator Cooling Medium	-	H_2

These figures are based on the original 90 ata and 535°C main steam parameters, a cooling water flow through the condenser of 16,000 m^3/h at an inlet temperature of 10°C with all feedwater heaters in service. The original guarantee conditions also state that if the main steam parameters are decreased not lower than 85 ata and 525°C, then the above outputs can still be delivered but at the expense of increased main steam flows.

Since no current performance tests were available for the No. 3 turbine, operating data and maintenance performance test data were reviewed in an effort to determine the heat rate degradation of the turbine. Performance test data was available for a test performed on Turbine 3 during 1991 following the overhaul. This test was based on the lowered main steam temperature of 515°C, and with the feedwater heaters in service. Following the application of correction factors, the test data resulted in a maximum output of 101 MW but with a main steam flow of 386.6 t/h. The heat rates obtained at the same outputs as given for the guarantee data (original design) showed the following comparisons:

	Heat Rates (kcal/kWh)	
Load (MW)	Original Design	1991 Test
100	2190	2251
80	2240	2263
60	2300	2317

The above comparison indicates that the full load turbine heat rate in 1991 following the last turbine overhaul was about 2.8% worse than the "as new" original design heat rate. However, this comparison is based on an abbreviated test right after the overhaul, and therefore it does not reflect the current performance degradation.

In the absence of sufficient performance test data, an estimate of the current heat rate of the turbine cycle was developed by review of the monthly Technical Report for Karaganda GRES #2 Operation for the months of 1994. This monthly report shows power actually generated, the average power generation, and a calculated average heat rate for each unit for each month. For the purpose of this performance estimate, the data given in these reports for February, March, and December of 1994 was averaged to estimate the actual average heat rate of 2299 kcal/kWh for the turbine cycle at an average generation rate of approximately 95% of full load during those months. For the purpose of this assessment, this is taken as the heat rate which reflects the current condition of the turbine.

The turbine manufacturer's guarantee data was then reviewed to develop an estimate of the "as new" turbine cycle heat rate at the generation rate of 95% of full load. The manufacturer's guarantee heat rates for generation rates of 100%, 80%, and 60% of full load were used to determine an estimated heat rate of 2202 kcal/kWh at 95% load, with the turbine in the "as new" condition. For the purpose of this assessment, this is taken as the heat rate reflecting the "as new" condition of the turbine.

Average condenser pressure, and main steam pressure and temperature during the operating months of February, March and December, 1994 were different than the corresponding values upon which the guarantees were based. To compensate for these differences, a correction of -6 kcal/kWh was applied to the 2299 kcal/kWh estimated current heat rate resulting in a corrected current heat rate of 2293 kcal/kWh.

With the above correction, the estimated degradation of turbine performance since the turbine was new is:

$$\frac{2293-2202}{2202} \times 100 = 4.13\%$$

It should be noted that based on the average yearly operating data for 1994 the turbine actual heat rate is 2345 kcal/kWh. This means that the turbine was operating with an average yearly heat rate 7.0 percent higher than turbine design heat rate. The actual operating heat rate of 2345 for turbine No. 3 was the worst heat rate among the 100 MW category turbines at the GRES #2 plant as can be seen in TABLE 3-4.

Condition Assessment

a) Unit 3 Problems

Many problems with the turbines and auxiliaries have been identified from discussions with plant personnel, and from review of documentation received. Some of these problems have resulted in an increase in unit heat rate, which in turn results in higher operating costs. Some of the problems increase the probability of unscheduled outages and result in lost generation due to equipment failure. Some of the problems would result in the need for increased future inspections, major replacements, and deficiency corrections of internal and external components of the turbine. Significant problems, which have been identified relative to turbine and auxiliaries, are outlined below:

Turbine Steam Path/Blading

From the above analysis of performance degradation it can be seen that the efficiency of the steam path has deteriorated. However, considering the more than double original design life of the turbine, it has performed fairly reliably. During the past 10 years and especially above 200,000 hours of operation, however, failures of the blading became more prominent. The data received from the plant on turbine problems and forced outages indicate that the mounting shoulders of the T-type root attachments of the LP rotor disks and blades operating in the phase transition zone have been destroyed. It was also reported that after about every 50,000 to 70,000 hours of operation an unacceptable erosion wear develops on the leading edges of the last stage blades requiring the replacement of these blades.

The forced outage records between 1985 and 1995 indicate the breakage of all blades at the 26th stage in 1990. The damage caused by this event required the replacements of the 26th and 27th stage diaphragms, the 26th stage blading, as well as the shroud of the 20th stage blading. In 1992 two blades of the last stage in the HP section broke, requiring the repair of the blading and replacement of the 20th stage diaphragm sealing ring.

Turbine Bearings/Vibration

Bearing vibration was reported to be a problem. One of the reasons for this was the problem of breakage and erosion wear of the blading as described above. Vibration initiated shutdowns of the turbine were reported in the list of defects for the past 10 year period in 1986, 1987, 1991 and

1992. The above problems as well as the age of the equipment resulted in excessive wear of the Babbit metal of bearing surfaces. In many instances the oil seals of the bearings have been damaged causing oil leakages at various bearings (No. 1, 3, 4 and 6).

Turbine Oil System

The turbine oil system supplies both control oil and lubricating oil to the turbine. The plant has reported a high sensitivity of the turbine hydraulic regulating system to the cleanliness of the oil. In 1990 this caused a false protection actuation of shaft driven control components. Oil system caused failures were also listed in the plant records in 1986 and 1992. The turbine regulating system and the main oil pump require frequent attention in order to keep the turbine running satisfactorily.

Turbine Water Induction and Valves

Water induction was not reported to be a problem. The extraction lines for feedwater heaters No. 3 through 8 all have automatic actuated non-return valves as well as isolation valves. No isolation capability is provided for the No. 1 and 2 LP heaters, and the isolation valves are motor operated only for the high pressure heater extraction lines. The automatic isolation feature apparently worked in 1994 when the LP HTR No. 4 was removed from service due to tube leakage. However, improved water induction features for the unit are still required.

In addition, the plant has reported a large number of problems with many of the valves operating in the turbine steam/feedwater cycle due to their age. These valves require replacement.

Electric Generator

The outages of the generator listed in plant maintenance and outage records are mainly due to leakage of hydrogen or the malfunction of the exciter. The seal oil system of the generator failed in 1989 because of a weld crack in the oil line. In another event, hydrogen circulation was also interrupted in the same year due to faulty valves. Loss of generator excitation system was also listed as an item requiring attention. The generator and motor repairs are often made difficult due to the unavailability of proper insulating materials. The generators of Units 3, 4 and 5 have served their lives (they accumulated over 2.5 times their original design operating hours) and the plant has planned their replacement together with the turbines, however, replacements were not made due to a lack of funds.

b) Metal Control

Metal control laboratory personnel were interviewed to assess the procedures and equipment the plant has to monitor metal conditions. The equipment for non-destructive examination (NDE) and destructive examination (DE) at the plant include:

UD2-12	Ultrasonic flaw detector
UD-1	Ultrasonic flaw detector
UD-3	Ultrasonic flaw detector
UT-93	Ultrasonic thickness gage
KWARTZ 6	Ultrasonic thickness gage
SLP-1	Universal steeloscope
SLU AL.2.851.047	Universal steeloscope
VRM-12	Hardness tester
VPI-2M6	Hardness meter

X-ray devices and gamma-ray detectors are not used for the detection of flaws in thick walled pressure parts of the equipment that operate under high pressure. Plant personnel also indicated they have endoscopes, and magnetic particle (MP) and liquid penetrant (LP) testing capability. Metallographic Laboratory equipment is placed at the service of Metal and Welding Department of KARAGANDAENERGO. The plant has no replication type creep detection capability.

Plant personnel indicated that at every 5 years interval, they would test for defects on the inside and outside surfaces of the turbines. Visual and ultrasonic testing of turbine blades and disks are performed. The schedule is made for such tests that it is coincident with the major overhaul periods. No testing is scheduled for the yearly and the intermediate repairs. In addition, they usually test 50% of the components during the first overhaul and the other 50% during the next overhaul. It would seem that more frequent testing in a plant with older units is needed and capability for replication type creep testing would also be needed. However, it was recognized by the plant staff that the turbine metal fatigue has occurred.

During the last testing of the turbine (Unit 3) which coincided with the last turbine overhaul in 1991 the following defects were found:

Turbine Stop Valve:	Shell crack with dimensions of 55 mm in length, 6 mm width, 8 mm depth.
Control Valve No. 1:	2 shell cracks: 133 mm long, 55 mm wide, 18 mm deep, and 55 mm long, 20 mm wide, 6 mm deep.
Control Valve No. 3:	4 shell cracks: 155 mm long, 20 mm wide, 20 mm deep; 95 mm long, 20 mm wide, 20 mm deep; 145 mm long, 25 mm wide, 30 mm deep; 115 mm long, 12 mm wide, 8 mm deep.
Control Valve No. 4:	Shell crack with dimensions of 133 mm length, 55 mm width, 18 mm depth.
HP Cylinder Nozzles:	Overwear

HP Cylinder Bolts:	2 bolts replaced.
HP Cylinder Upper:	Shell crack located after control stage with dimensions of 260 mm length, 54 mm width, and 58 mm depth.
Last Stage 25th, 30th Blades:	Overwear

During this testing metallographic examination of the turbine metal structure was not performed.

The park resource (currently extended life) of the type K-100-90 turbines is 270,000 hours, with the following main component lives:

HP Rotor	:	270,000 hrs
HP Cylinder	:	270,000 hrs
Stop and Regulating Valves	:	220,000 hrs

Therefore, the stop and regulating valves should have been replaced some time ago, and that the remaining life of the rest of the turbine would be about 3 years. While no metal testing data is available for the inspection of the turbine during previous years, the discovery of additional cracks can be expected based on experience with similar turbines.

Discussions with plant personnel indicated that the plant's reconstruction plans included the replacement of the high pressure cylinders, valves, rotors and the electrical generators of Units 3, 4 and 5 steam turbines starting with the year 1993. In fact, further information received from the plant confirmed that the Unit 3 turbine operates with the testing commission's recommendation to replace it. It is currently operated under the chief engineer's responsibility.

However, no such replacement has been accomplished so far because of lack of funds. It was also realized that 99% of the replacement parts are either manufactured in Russia or in the Ukraine and that the cost of spare parts was prohibitive due to age of the turbine. Furthermore because of the increase in heating demand in the vicinity of the plant, it is desirable to have future rehabilitation efforts satisfy the thermal demand, or at least reduce the deficit. Due to these circumstances the plant procured a new district heating turbine (KT-115/125-130) with a district heat load capability of 100 Gcal/h. This turbine is currently in storage.

As noted above, there is currently no replication type creep testing capability available at this plant. As the plant is increasing in age such testing capability would be highly desirable to monitor potential creep damage of critical components which operate at 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 where such equipment could be often used.

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 quickly as possible.

3.3 AUXILIARY PLANT SYSTEMS

It was reported by plant personnel that the reliability of the auxiliary equipment is very low and adversely affect the turbine availability. These equipment and systems are very old (240-245,000 hours) and have exhausted their useful lives. These systems and equipment include the components of the regenerative feedwater heating system, and the condenser and various system valves. The number of unplanned shutdowns on the No. 3 turbine up to 1995 was 179. A large number of these were in conjunction with the failure of auxiliary equipment. The mean time interval between failures of the auxiliary equipment ranges between 300 and 800 hours.

a) Condenser

The most unreliable part of the condensers reported for the Karaganda units is the tubing system. After about every 100,000 hours of operation the Latuny tube walls are destroyed. The tubes are exfoliated as the zinc comes out of the Latuny (L-68) compound. The allowable tube plugging is 10%. While the tubing in the condenser of the No. 3 turbine has been replaced before, the percentage of currently plugged tubes is about 7%, and increasing with further operation. In addition, the condenser has problems with air inleakage. As can be seen from TABLE 3-4 this unit has the lowest vacuum and the highest air inleakage among all the GRES-2 units. The most prominent locations of air ingress are the expansion joints, condensate pump glands, and various valves connected to the condenser operating under vacuum conditions. However, the condenser does not seem to require an on-line tube cleaning system.

b) Feedwater Heaters

The main problem with the feedwater heaters is the deterioration of the tube surfaces. The turbine water induction protection system successfully isolated LP heater No. 4 in 1994 when tube breakage caused the water level in the heater to rise. The low pressure heaters utilizes Latuny (L-68) tubing and the allowable tube plugging is 10%. The high pressure feedwater heaters (Type PV-250/180) are vertical heaters and have stainless steel tubes. However, due to their age they have also deteriorated to the point where they will require replacement for continued reliable operation. Because of this, the high pressure heaters need to be frequently removed from service. While this problem is applicable to other units of the GRES-2 plant as well, it is particularly severe at Unit 3. As shown in TABLE 3-4, the temperature of the final feedwater leaving the Unit 3 feedwater system was the lowest at 173°C which is 44°C lower than design temperature.

c) Pumps and Motors

The feedwater pumps are 5C-10 type with parameters of 270 m^3/h and 150 ata driven by ATM-2000-2 constant speed electric motors. They are of Russian manufacture. The pumps have been replaced in 1983. They operate with relatively low efficiency (design efficiency was 68%). They have been operating with low reliability due mainly to the unavailability or high cost of spare parts.

The condensate pumps are Type 10KSD5x3 horizontal pumps with 175 m^3/h, 123 m design parameters driven by 100 kW electric motors at a speed of 960 rpm. These pumps were manufactured in 1962 and operate with very low efficiency. Their condition has degraded and require replacement.

The heater drain pumps also operate with very low reliability, they show the signs of complete physical deterioration, and need replacement.

The circulating water pumps are type OP3-110-50 with 20,000 m^3/h design flow rate and 21 m w.c. head. They are driven by 1500 kW motors at 585 rpm. These pumps have no lubricating water problems, and they are protected by stainless steel screens. However, they too are very old and deteriorated and need replacement.

It was also found that the electric motors driving the various pumps are also in a bad state of repair. At the time of the Burns and Roe visit, approximately 60 motors were out of service in the plant. This was due to the unavailability of electric materials to repair the old electrical components.

d) Valves

Plant information collected indicated problems with the majority of valves, due to wear since the unit has accumulated over 243,000 operating hours. Most of the problems were experienced with the valves operating in the high and medium pressure systems.

3.4 INSTRUMENTS AND CONTROLS

General

The instrumentation at the Karagandinskaya plant is in general based on the philosophy of the 1950's and 1960's. Although we were unable to inspect the plant instrumentation due to a labor strike, through discussions with plant personnel we were able to ascertain the condition of the plant. Since the initial operation in 1962 almost all measuring and indicating devices have been replaced with newer more modern ones, although the overall philosophy has not changed.

a) Load Control

Turbine No. 3 uses an electronic governor with a centrifugal speeder gear to vary the speed setpoint. The boiler pressure controllers are used to vary the fuel flow rate to the boiler. The pulverized coal 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.

Combustion control of the boilers is provided manually by the operators according to established procedures and are 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 superheater. 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. Vacuum in the upper section of the furnace is also used as a combustion performance indicator.

The plant operators are preparing a scheme to control air flow automatically using O_2 as a trim. There is no direct combustion air flow measurement, but they use differential pressure across the air heater as an indication of air flow.

b) Air Flow Control

This is purely a manual function carried out by varying the position of the two forced draft fan radial inlet vanes remotely from the control room. An O_2 indicating system fed from an oxygen analyzer assists the unit operator in setting the correct combustion air flow rate. Each of the two 50% forced draft fans are electric motor driven, centrifugal type with radial flow. The original oxygen analyzers are extractive type and consequently slow acting.

c) Furnace Pressure Control

There is no automatic control of furnace pressure. The position of the two induced draft fans radial inlet vanes is varied remotely from the control room to adjust the value of the furnace pressure. Normal vacuum is 3-5 mm Hg.

The two induced draft fan loads must be balanced to prevent choking of the burner flame. The balancing of the fans is measured by the two induced draft fan ammeters. The two 50% induced draft fans are electric motor driven, constant speed, centrifugal type and radial flow design.

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 saturated steam taken from the drum which is then condensed in a heat exchanger where the cooling medium is the feedwater flow just before entry to the drum. Apart from the fact that increased attemperation will not impair cycle efficiency, the system lends itself to good controllability because there is inherent self regulation for changes in live steam flow. Superheater outlet temperature and a derivative of superheater inlet temperature are compared to the setpoint to form the control deviation. There is a small amount of valve leakage, but it is not serious.

e) Boiler Drum Level Control System

Two feedwater valves control drum level. The first valve is used for filling the drum and for start-up (burner ignition). Drum level is controlled manually. The second is used during high and full load operation employing a three element control scheme (feedwater flow, steam flow and drum level). The system operates properly.

f) 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 drum level, high and low steam temperature and loss of flame. The drum level tripping system sometimes causes false boiler trips, an average of one or two trips per year.

High superheater pressure (above 107 kg/cm^2) causes an automatic runback of coal feeder speed, which causes the startup of mazut, and opens the drum relief valve. Tripping the boiler will stop the pulverized coal feeders, close the feedwater valves, close the main steam valve, open the superheat steam vent and stops the forced draft fans. The induced draft fans continue to run.

g) 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 boiler will trip.

h) Boiler Blowdown

Boiler blowdown is accomplished in two ways, continuous and intermittent. Intermittent blowdown is performed manually under administrative control. However, continuous blowdown is regulated at 0.3 to 0.5% of steam flow by an electronic controller. The controller monitors steam flow and blowdown flow and the system works well. These readings are used to position the blowdown control valve.

i) Stack Emissions Monitoring

There are no NO_x, SO_2, CO, or CO_2 measurements on these units. There is an opacity monitor installed, but it doesn't work due to heavy particulate loading. Currently NO_x, CO_2, and CO 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 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 boiler flues as part of the pilot plant upgrade.

j) Turbine Control

The No. 3 turbine valves are controlled by an electric servo motor system with an electronic governor. There is one stop valve, four governor valves, and two startup bypass valves. Since this is not a reheat unit, there are no intercept valves. The intermediate pressure (IP) stage of this units steam flow is controlled by valves which control steam flow to the district heating system.

k) Turbine Interlock and Protection System

Interlocks of a basic nature are fitted. Protection applies to the following conditions: excess rotor axial movement, low steam temperature, low lubricating oil pressure, generator electrical faults, and loss of vacuum. All of the above protection and interlocks are effected via electrical relays. Overspeed protection is provided via overspeed rings. 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.

l) 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, bearing oil outlet temperature and turbine speed by a digital electronic system.

m) Feedwater Controls

The condenser hotwell level and the levels in the feedheaters 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.

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 Karaganda power plant dust collection equipment is provided to remove a major portion of the fly ash from the flue gas before discharge.

The plant uses Venturi scrubbers to remove the ash from the fluegas for boilers 1 to 6. Electrostatic precipitators are used on boilers 7 to 15. The current ash collection efficiency of the scrubbers is reported to be approximately 96.4%. Efficiency of the electrostatic precipitators is assumed to be similar.

Plant emission rates when firing Ekibastuz coal have been estimated from coal properties, dust collection efficiency and boiler design features. Estimated emissions, at 40% excess air, are:

Emission	Concentration, mg/Nm^3
Ash	2,500
SO_2	2,900
NO_x	765

Kazakstani emission limits for new boilers are as follows:

Emission	Concentration, mg/Nm^3
Ash	100
SO_2	400
NO_x	240

It is evident that in order to meet these limits, major investments in Air Pollution Control Equipment would be required.

Local limits for emission of pollutants into the environment and estimated mass emission limits have been provided by plant personnel. These are as follows:

Emission	Limit, g/sec	Estimated, g/sec
Ash	1,808	1,750
SO_2	1,566	1,530
NO_x	445	420

These mass emission limits and the reported emissions are apparently based on the annual emissions permitted by local authorities. It has not been established whether national emission limits will take precedence.

3.6 DISTRICT HEATING SYSTEM

General

The Karaganda plant provides heat in the form of hot water and steam to three district heating systems in the vicinity of the plant. The district heating systems serve the town of Topar, the town of Abai, and the Greenhouses. The demands for these systems and the design heat loads are as follows.

HEAT LOADS (Gcal/h)

SYSTEM	DESIGN	ACTUAL
Abai	100	150.5
Topar	125	63.4
Greenhouses	210	172.1
TOTAL	435	386.0

The heat source for the district heating systems is the extraction steam from crossover pipes of turbines No. 6, 7, and 8 and main steam from the pressure reducing stations. The steam extracted for district heating applications from all three turbines is cross connected so any turbine can supply the heat to any of the three districts, that is, Abai, Topar and the Greenhouses. The amount of heat extracted is as follows:

Source	Amount (Gcal/h)
Turbines No. 6, 7, and 8	300 (100 each)
Pressure Reducing Stations	135
TOTAL	435

The pressure reducing stations take steam from the main steam header and reduce its pressure (100 ata to approx. 12 to 16 ata) so that the steam can be used in the large district heating heat exchangers. These heat exchangers produce the hot water for the three district heating systems. A small amount of industrial steam is provided to a building materials company from the low pressure steam supply downstream of the pressure reducing stations. The industrial steam is delivered at a pressure and temperature of 6 ata and 210 to 250°C respectively. The industrial steam flow rate is 10 t/h. The condensate is not returned to the power plant from the building material company.

The Topar System

Topar is a small village located very close (approximately 3 km) to the power plant. This system has the smallest heat load of the three systems at 63.4 Gcal/h. The system has two pumping stations which distribute the hot water to the village. The village requires a flow rate of 1100 m^3/h of hot water from the power plant. The pumps at the pumping station are motor driven and are controlled by throttling the flow. These pumps are constant speed pumps.

The main transmission piping to the Topar pumping stations is 530 mm in diameter and has a wall thickness of 8 mm. The distribution piping from the pumping stations varies from 426 to 150 mm in diameter. Topar district heating piping is in relatively good shape. The lines have an operating pressure of 7.0 ata. The pressure drop to the last customer is estimated to be 2.5 ata $\pm$ 0.1 ata. The system operates under constant flow/variable temperature conditions. The heating schedule for the system is shown in TABLE 3-6.

There are no heat exchangers used in the individual houses in the Topar system. It is a direct (open) system. The hot water from the pumping stations flows to the houses and circulates in the radiators to provide heat. This water is also used to provide domestic hot water needs. The hot utilization water is taken directly from the district heating system. Thus, the hot tap water is identical with the water in the district heating pipes.

Makeup water for the system is taken from the lake located next to the power plant. This water is treated only with softeners to remove the hardness from the water. No chemicals are added to the water because it is also used for domestic purposes (for kitchens and bathrooms).

The present supply strategy is based on the constant flow principle where the flow in the district heating system is close to constant and the heat supply is adjusted by changing the supply temperature. If heat is needed in the network the supply temperature is increased correspondingly. Due to the constant flow system, the consumers will experience the increased heat supply with a certain time lag depending on the velocity of the DH-water and the distance from the heat supply source. The time lag will typically last from a few minutes for the nearest consumers to a number of hours for the most distant consumers. In some cases, the heat will reach the most distant consumers after the heat demand has actually ceased meaning an excess temperature at the consumers. As the consumers are normally left with poor heat regulation possibilities, this means the only way to regulate the indoor temperature will be by opening windows leading to a high energy loss.

The circulation of the water in the district heating system is done by constant flow pumps located at the power plant. The system is designed with a number of larger capacity pumps used for winter and a number of relatively smaller capacity pumps used during the summer for the hot water supply. A number of pumps are also located in the district at the two pumping stations as booster pumps or to overcome the large differences in ground level between the main network and certain consumer groups. The network is characterized by a large number of ring connections which means a relatively high supply security.

The distribution network is composed of many individual networks each connected directly to the main network, "Connection points". Buildings and industrial consumers are connected to the distribution network through the so called "Thermal points". The dwellings are normally connected through a "hydro elevator" which is a hydraulically open connection. The industrial consumers are normally connected through heat exchangers, which isolate the internal distribution system hydraulically from the district heating system.

The district heating hot water transmission piping system described above comes under the jurisdiction of the district heating company. The district heating company interfaces with both the power plant and the local distribution companies whose function also includes local servicing inside the buildings and the collection of the tariff for the heat and hot water energy consumption.

The accounting method for heat and hot water is such that only the few larger customers pay according to the actual heat they use. These customers have flow meters in their supply lines as well as thermometers in supply and return lines. The heat consumption is determined from the product of the flow rate and the supply and return temperature differential. The smaller customers pay for heat based on the floor area of their homes. They pay for domestic hot water based on the number of persons living in the household.

TABLE 3-6
TOPAR SYSTEM HEATING SCHEDULE

	District Heating Water °C				
	Without Wind Chill		With Wind Chill		
Outside Air Temp. °C	SUPPLY	RETURN	Y-1.05	Y-1.10	Y-1.0
8	60	47.7	43.1	44.3	45.4
7	60	47.3	45.1	45.4	47.7
6	60	4730	47.2	48.6	50.0
5	60	46.6	49.2	50.7	52.2
4	60	46.2	51.2	52.8	54.3
3	60	45.9	53.2	54.8	56.5
2	60	45.5	55.1	56.9	58.6
1	60	45.2	57.0	58.9	60.8
0	60	44.8	58.9	60.9	62.8
-1	60	44.5	60.8	62.9	64.9
-2	60	44.2	62.7	64.9	67.0
-3	62.4	45.6	64.6	66.8	69.0
-4	64.1	46.5	66.4	63.7	71.1
-5	65.9	47.5	68.3	70.7	73.1
-6	67.6	4834	70.1	72.6	75.1
-7	69.4	49.4	71.9	74.5	77.1
-8	71.1	50.3	73.7	76.4	79.0
-9	72.8	51.2	75.5	78.3	81.0
-10	74.5	52.1	77.3	80.1	82.9
-11	76.2	53.0	79.1	82.0	84.9
-12	77.8	53.8	80.8	83.3	86.8
-13	79.5	54.7	82.6	85.7	88.7
-14	81.2	55.6	84.3	87.5	90.7
-15	82.8	56.4	86.1	89.3	92.6
-16	84.5	57.3	87.8	91.1	94.5
-17	86.1	58.1	89.5	92.9	96.3
-18	87.8	59.0	91.2	94.7	90.2
-19	89.4	59.8	93.0	96.5	100.1
-20	91.0	60.6	94.7	98.3	102.0
-21	92.6	61.4	96.4	100.1	103.8
-22	94.2	62.2	98.0	101.9	105.7
-23	95.8	63.0	99.7	103.6	107.5
-24	97.4	63.8	101.4	105.4	109.3
-25	99.0	64.6	103.1	107.1	110.0
-26	100.6	65.4	104.7	108.9	110.0
-27	102.2	66.2	106.4	110.0	110.0
-28	103.8	67.0	103.0	110.0	110.0
-29	105.3	67.7	109.7	110.0	110.0
-30	106.9	68.5	110.0	110.0	110.0
-31	108.4	69.2	110.0	110.0	110.0
-32	110.0	70.0	110.0	110.0	110.0

The Abai System

The town of Abai is located approximately 20 km from the plant. The Abai hotwater district heating system has a total of 20,145 meters of double pipes (hot water supply and return pipes). The main transmission lines vary in diameter from 1000 mm to 150 mm. The distribution piping has smaller diameters. The system hotwater flow rate is 2400 m^3/h. Makeup to the system is provided in the same manner as the Topar system. The makeup for the Abai system is estimated to be 60 t/h. The system has three pumping stations with 3 pumps each. Two different model pumps are used in these stations. They have capacities of 1260 and 2500 m^3/h to satisfy various heat load conditions. Currently the system has a demand of 150.5 Gcal/h. The Abai system heating schedule is shown in TABLE 3-7.

The Topar district heating system is an open system whereas the Abai district heating system is a closed system. In a closed system the district heating hot water is used in radiators for space heating only. This water is returned to the plant after it has circulated through the radiators. Domestic hot water needs for kitchens and bathrooms are provided by individual hot water boilers located at the houses. However, because of lack of fuel and money, the individual hotwater boilers at the houses are not utilized nowadays, and people steal hotwater for domestic use from the Abai district heating system.

The transmission piping network is characterized by a number of ring connections, which cross each other at various "Node points". This allows a relatively high security of heat supply. In addition there are other node points or connecting points at which the piping systems of the various distribution systems are connected to the main transmission headers. However, there is a lack of instrumentation and control of flow and isolation capability at these node points, and there is a very minimal number of instrumentation and automatic control at the pumphouse and the dispatch center. Those that are available are quite old, either needing repair or recalibration. Without instruments which function properly to monitor and record such essential variables as flow rate, temperature, and pressure, it is difficult to accurately determine balance measurements and conduct effective energy efficient system operation.

The Abai district heating system is operated in the same manner as the Topar System, that is, on the constant flow principle where the hotwater flow in the system is close to constant and the heat supply is adjusted by changing the supply temperature. It has the same problems as described for the Topar system as far as the heat regulation and the time lag between heat demand and supply is concerned. The thermal energy billing methods and responsibility for collection of thermal energy tariff is similar to those of the Topar system.

TABLE 3-7
ABAI SYSTEM HEATING SCHEDULE

		District Heating Water Temp. °C				
Outside Temp. °C	Relative Heat Consumption	Supply	Return	Before Heat Exchanger	With Wind Chill	Inside Air Temp. °C
8	0.36	70.0	51.9	61.0	70.0	26.1
7	0.37	70.0	51.6	60.8	70.0	25.4
6	0.38	70.0	51.3	60.6	70.0	24.7
5	0.38	70.0	51.0	60.5	70.0	24.0
4	0.39	70.0	50.6	60.3	70.0	23.4
3	0.39	70.0	50.3	60.2	70.0	22.7
2	0.40	70.0	50.0	60.0	70.0	22.0
1	0.41	70.0	49.7	59.3	70.0	21.3
0	0.41	70.0	49.3	59.7	70.0	20.7
-1	0.42	70.0	49.0	59.5	70.0	20.0
-2	0.43	70.0	48.6	59.3	70.0	19.4
-3	0.43	70.0	48.3	59.2	70.0	18.7
-4	0.44	70.0	48.0	59.0	72.6	18.0
-5	0.46	72.1	49.1	60.6	74.8	18.0
-6	0.48	74.1	50.1	62.1	76.9	18.0
-7	0.50	76.1	51.1	63.6	79.0	18.0
-8	0.52	78.2	52.2	65.2	81.2	18.0
-9	0.54	80.2	53.2	66.7	83.3	18.0
-10	0.56	82.2	54.2	68.2	85.4	18.0
-11	0.58	84.2	55.2	69.7	87.5	18.0
-12	0.60	86.2	56.2	71.2	89.6	18.0
-13	0.62	88.2	57.2	72.7	91.7	18.0
-14	0.64	90.1	58.1	74.1	93.7	18.0
-15	0.66	92.1	59.1	75.6	95.8	18.0
-16	0.68	94.1	60.1	77.1	97.9	18.0
-17	0.70	96.0	61.0	78.5	99.9	18.0
-18	0.72	98.0	62.0	80.0	102.0	18.0
-19	0.74	99.9	62.9	81.4	102.1	18.0
-20	0.75	101.1	63.3	82.2	101.1	17.7
-21	0.75	100.1	62.3	81.2	100.1	16.7
-22	0.75	99.1	61.3	80.2	99.1	15.7
-23	0.75	98.1	60.3	79.2	98.1	14.7
-24	0.75	97.1	59.3	78.2	97.1	13.7
-25	0.75	96.1	58.3	77.2	96.1	12.7
-26	0.75	95.1	57.3	76.2	95.1	11.7
-27	0.75	94.1	56.3	75.2	94.1	10.7
-28	0.75	93.1	55.3	74.2	93.1	9.7
-29	0.75	92.1	54.3	73.2	92.1	8.7
-30	0.75	91.1	53.3	72.2	91.1	7.7
-31	0.75	90.1	52.3	71.2	90.1	6.7
-32	0.75	89.1	51.3	70.2	89.1	5.7

The Greenhouses

The third system that the Karaganda plant serves is the Greenhouses. The greenhouses are located approximately 3.4 km from the plant. There are six separate greenhouses in this system. This district heating system is the largest one served by the plant with a thermal demand of 171 Gcal/h. The heating schedule for the greenhouses is shown in TABLE 3-8.

The transmission lines that travel to the greenhouses are divided into two groups. The first group serves greenhouses No. 1 to 5. It consists of 3 lines, 2 supply and 1 return line. The supply lines have diameters of 500 mm, while the return line is 700 mm. The second group supplies greenhouse No. 6 only. It has one supply and one return line. Both lines have 700 mm diameters. The first group of transmission lines were constructed from 1977 through 1979, while the second group was constructed during 1982 through 1984 time period. All the piping is above ground.

The greenhouses are used to grow a wide variety of fruits and vegetables all year around. The greenhouses have a total floor area of 220,000 square meters. The system requires a maximum of 3000 m^3/hr hot water. The hotwater flow is changed (adjusted) at the power plant when requested by the greenhouses. Makeup water is needed at an estimated rate of 15 to 45 m^3/h.

TABLE 3-8
GREENHOUSE SYSTEM HEATING SCHEDULE

		District Heating Water Temp. °C		
Outside Air Temp. °C	Relative Heat Consumption	Supply	Return	With Wind Chill
10	.19	56.5	37.9	58.1
9	.21	59.6	39.1	61.2
8	.23	62.6	40.3	64.5
7	.25	65.5	41.4	67.4
6	.27	68.4	42.4	70.4
5	.29	71.3	43.4	73.5
4	.31	74.2	44.5	76.5
3	.33	77.0	45.4	79.4
2	.35	79.8	46.4	82.5
1	.37	82.6	47.3	85.2
0	.38	65.5	46.3	67.4
-1	.40	67.4	47.2	69.3
-2	.42	69.3	48.1	71.3
-3	.44	71.1	49.0	73.2
-4	.46	72.9	49.8	75.1
-5	.48	74.7	50.7	77.0
-6	.50	76.5	51.5	78.8
-7	.52	78.3	52.3	80.7
-8	.54	80.1	53.1	82.5
-9	.56	81.8	53.7	84.3
-10	.58	83.6	54.7	86.2
-11	.60	85.3	55.5	88.0
-12	.62	87.0	56.3	89.8
-13	.63	88.7	57.0	91.6
-14	.65	90.5	57.8	93.3
-15	.67	92.2	58.5	95.1
-16	.69	93.9	59.2	96.9
-17	.71	95.5	60.0	98.6
-18	.73	97.2	60.7	100.4
-19	.75	98.9	61.4	102.1
-20	.77	100.5	62.1	103.9
-21	.79	102.2	62.8	105.0
-22	.81	103.9	63.5	105.5
-23	.83	105.0	63.7	105.0
-24	.85	105.0	62.7	105.0
-25	.87	105.0	65.8	105.0
-26	.88	105.0	64.9	105.0
-27	.90	105.0	64.0	105.0
-28	.92	105.0	63.2	105.0
-29	.94	105.0	62.3	105.0
-30	.96	105.0	61.4	105.0
-31	.98	105.0	60.6	105.0
-32	1.00	105.0	59.7	105.0

Condition Assessment

All three district heating systems have been in operation for about 20 to 30 years. The general condition of the district heating piping for the Abai and Greenhouse systems is relatively poor. The piping is subjected to corrosion from the outside due to high humidity in the ducts and wet insulation. Water leakage from holes in the piping system which are not discovered and repaired accelerate the outside corrosion. Rain and sewage water also finds its way through the cracks in the concrete enclosure add to the corrosion process. The district heating pipes also corrode from the inside due to lack of water treatment, that is, due to dissolved oxygen, chlorides, and high conductivity of the water. All of the above result in accelerated rate of corrosion of the piping system.

The portion of the piping which is routed above ground has metal covers (jacket, either Aluminum or Zinc). The underground piping segments which are usually routed in concrete tunnels, have no metal jacket and the insulation is held in place by wires. The type of insulation used is either "diatom" or "mionvata" type. The diatom type system is of Russian manufacturer, and consist of brick shaped insulating blocks plus asbestos material. The "minovata" insulation is similar to mineral wool based insulation system and is held in place with wires.

For the aboveground piping, the age and the exposure of the joints of the metal jacketing often results in the ingress of rainwater and moisture to the carrier pipe. This causes both external corrosion of the bottom of the carrier pipe and sagging of the insulation within the jacketing. For the underground pipes, the occasional partial flooding of the tunnels causes the bottom portion of the pipes to be submerged. This also leads to the external corrosion of the carrier pipe. The district heating company would like to have the piping replaced with the preinsulated, bonded pipes used in most European countries.

Over the years, many of the piping sections have been replaced and repaired. In recent years, this program has slowed due to budget problems. Thus, many of the above and below ground piping network are in need of repair or replacement. Replacement of these piping sections with new preinsulated pipe would reduce both temperature and water losses.

The heating systems in the houses are only operated during the heating season (from October 15 to April 15) with a constant water flow. The Topar system return line supplies the domestic waste needs when heating system is shutdown during the summer months.

Heat Losses

The heat losses from all three district heating system can be divided into:

- Heat losses from the underground network including pipes, valves, chambers.

- Heat losses from the aboveground network including pipes, valves, chambers.

- Heat losses from other installations i.e., substations, pump stations etc.

Dispatcher

Authority resides within the distribution system to determine the amount of heat that the district heating system requires at any one time. A central dispatcher monitors the system and the outside air temperature. The dispatcher determines the outdoor temperature, and then based on a temperature chart, determines what the district heat supply temperature should be. The district heating system is designed to supply 150°C, but in reality only supplies a maximum of about 110°C. The dispatcher notifies the power plant operators what temperature they are to produce, and they are required to follow those directions.

District Heating System Instruments and Controls

A minimal number of instruments and automatic controls are available in the district heating systems. Those that are available are quite old, either needing repair or recalibration. Without instruments which function properly to monitor and record such essential variables as flow rate, temperature, and pressure, it is difficult to accurately determine balance measurements and conduct effective energy efficient system operation.

Control Systems

The main problem within the end-users is the lack of temperature control. Few buildings have any control device, and most are overheated for a significant portion of each year. The piping design used in each building is standard, with a venture device blending water to provide a reduced water temperature to the building. Since this device is incapable of changing with the season or outdoor temperature, it is dependent on the entering supply temperature to provide the correct amount of heat. In theory when water is blended or mixed, the heat to the building will be adequate but not excessive. But this system is not very effective, and many buildings residents open their windows while the heating system is operating. Opening windows serves as a control device, but obviously is not very effective, and causes additional heat to be expended.

Several control techniques can be used to improve or replace this system and provide proper control to the building. The best method involves adding temperature control to each terminal heating device or to each heated room. This provides good control, and allows each room to be controlled to a specific setpoint. As the outdoor temperature changes or the effects of the sun vary throughout the day, the control device will adjust the water temperature to maintain the room temperature.

Other Problems

Modifications to the heat generation methods used by the plant are also needed. Currently most of the heat is supplied by turbines No. 6, 7 and 8. Any additional heat that is required is taken from the main steam header. Taking steam from this location may reduce the electric generating capacity of the plant. The plant would like to install a new turbine with a district heating (nominal) capacity of 80 Gcal/h. With this new turbine, the plant would not need to use steam from the main steam header.

In the Abai system, the water makeup rate varies between 80 and 165 t/h. This high makeup rate is due to the leaking of various supply and return lines due to age. The other major factor is the use of radiator water for domestic needs. As was stated previously, the district heating water from the power plant is used for space heating requirements only. Per design all domestic hot water needs are satisfied by individual hot water boilers for Abai system. Due to the slowing of the Kazak economy, most people can not afford to pay for fuel to use in their hot water boilers. They steal hot water out of the radiator for domestic use.

Other items in need of repair are the pumps in the pumping stations. Many of these pumps are very old and are in need of repairs. Due to their old age, no spare parts are available. Thus, the best course of action would be to replace some of these pumps with new ones.

4.0 REHABILITATION RECOMMENDATIONS

4.1 STEAM BOILERS

The following items are recommended for rehabilitation of boilers 7, 10, and 13 at the Karaganda GRES #2:

- Condition assessment by nondestructive/destructive examination (NDE/DE) of the thickwalled pressure parts of all three (3) boilers for evidence of low-cycle fatigue and/or creep type failures. To be examined are the main and surge (small diameter) steam/water drums, final superheater inlet and outlet headers, steam attemperators and 1st stage economizer inlet headers.

- Condition assessment by NDE/DE of the thinwalled boiler pressure parts of all three (3) boilers for evidence of low cycle fatigue and/or creep type failures, tubewall thinning by erosion, water and/or fire side corrosion, etc. To be examined are the furnace tubewalls, radiant roof superheater tubes and pendant convective superheater tubebanks and economizer stages tubebanks. We also recommend investigating the feasibility of replacing the existing staggered bare tube arrangement economizer banks with extended surface (finned) in-line arrangement tubebanks.

- Repair or replacement of thick and thinwalled boiler pressure parts as per above assessments. According to plant personnel, up to 60~70% of furnace tubing may have to be replaced. In addition, the pendant convective final superheater tubebanks and possibly the inlet and outlet headers have creep type failures. The economizer horizontal convective tubebanks have severe erosion type damage and failures. Also the 1st stage economizer inlet header may have thermal shock type ligament cracks.

- Repair or replacement of boiler setting consisting of furnace tubewalls refractory, insulation, casing, drum enclosures insulation, horizontal and vertical convective passes refractory brick lining, casing, and tubular airheater stages metal casing.

- Refurbishment as required of the tube penetration seals in the horizontal and vertical convective fluegas passes.

- Repair or replacement of the tubular airheater tubebanks. Both airheater stages have severe tube erosion damage and the 1st stage tubebanks cold end has acid dew point low temperature corrosion damage was well.

- Repair or replacement of fluegas ducting from tubular AH exit to the ESP, from the ESP to ID fans, from ID fans to stack, including damper refurbishing and replacement of metallic expansion joints with elastomer fabric type joints, and repair of hangers etc.

- Condition assessment of the draft plant fans, including site performance tests. Repair or replacement of the severely erosion damaged induced draft (ID) fan housings and impellers.

- Repair or replace the erosion damaged milling circuitry components, e.g. milling circuit and burner PA/PC conduits, classifiers, separating cyclones, exhauster fan housings, and impellers. Ball mills refurbishment including trunnion seals, sealing air fans, trunnion bearings, drive system components, mill liners, lubrication system and electric motor drives.

- Retrofit of a low NO_x firing system which will include the dismantling and removal of the existing two (2) levels of four secondary air and coal injection nozzles. Installation of a low NO_x concentric firing system (LNCFS) with either close coupled or separate overfire air (CCOFA or SOFA). A retrofit system is preferred that will not necessitate modifications to the injection nozzle furnace tube openings.

- Repair or replacement of the particulate emission control equipment (ESPs) of all three boilers.

- Supplement and/or modernize the burner management and instruments and controls systems of all three boilers.

Additional (non-boiler island) item:

- Repair or replacement of the boiler feed pumps of all three boilers.

4.2 STEAM TURBINE GENERATOR

Based on the assessment of the current performance and condition of the No. 3 steam turbine the following major replacements and modifications are recommended:

a) Steam Turbine

The No. 3 turbine has experienced various problems, which are continuous in nature, and which 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 a plan be made to replace the main turbine, complete with ancillary systems and components, from the main steam stop valve inlet to exhaust hood and 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 unit for the No. 3 turbine would be the new KT-115/125-130 machine that the plant currently has in storage. This type of machine was manufactured by the Leningrad Machinery Company (LMZ) and was developed for the replacement of 25-100 MW units when rehabilitating older power plants.

This turbine is furnished with two controlled heat extractions for district heating and for industrial steam supply. The unit comes with a simplified regenerative feedwater heating circuit which allows the unit to be installed in existing power stations. This cycle is simple compared to the other models of the same designation because one low pressure heater and one high pressure heater are removed from the regenerative feedwater heating circuit.

This simplified steam turbine can be furnished in three different configurations (Type 1, 2 or 3) depending on the number and length of the last stage blades. The turbine in storage at the Karaganda Power Plant is a Type 2 and has 650 mm long last stage blades. This turbine is very effective in the heating regimes of operation, where good economics are possible because of small losses at the low pressure stages during maximum heat load. In addition, this unit has a condenser with built-in tube bundles which can be used to heat district heating water returning from the district heating network. The turbine can also operate with limited steam extraction flow to the high pressure heaters. This allows the increase of electrical and heating loads.

The KT-115/125-130 turbine's control system is electro-hydraulic. Compared to the old hydraulic systems the new system provides a wider range of automatic controls and increases the precision of maintenance of the controlled parameters. The turbine is equipped with the protection systems and signal systems, and also with the remote control systems which are used in turbine operation. The turbine KT-115/125-130 has technical and economical parameters on the same level as other modern heating turbines.

It should be noted that as the model number indicates this turbine was designed to operate with initial steam pressure of 130 kg/cm^2. The pressure in the main steam headers in the Karaganda plant, however, is only 90 kg/cm^2. Nevertheless the turbine can operate with main steam pressure of 90 kg/cm^2 and main steam temperatures between 500 and 535°C, but the steam flow and power output will be reduced compared to the original design.

Under these main steam conditions the turbine will have a nominal electric output of 90 MW and a total heat output of about 155 Gcal/h of which about 100 Gcal/h can be used to satisfy district heating hot water loads, and the rest can be extracted at about 10 ata as industrial steam supply if needed. Under such conditions the turbine will require about 400 t/h main steam flow. In addition, the unit can also be operated in the pure condensing mode of operation. Under the pure condensing mode with a main steam flow rate of 400 t/h the turbine output will be 105 MW.

Installation of this turbine not only increases the operating life of the plant by about 25 years, but more importantly it will reduce the approximately 86 Gcal/h of current deficit in the district heat supply. In addition, both the electric output capability and the operating efficiency of the No. 3

unit will be improved. The information collected from the plant indicates that when this turbine is operated with the district heating load, the average yearly guaranteed turbine heat consumption will be 1990 kcal/kWh. Therefore based on the current average 1994 actual annual average heat rate of the existing No. 3 unit the improvement is 2345-1990 = 355 kcal/kWh. The turbine electric output capability would be increased by 5%.

The above improvements are summarized in the table below:

	Current	New	Improvement	
			Unit	%
Electric Output, (Condensing Mode) MW	100	105	5	5.0
Heat Consumption (Average annual) kcal/kWh	2345	1990	355	15.1

Therefore, the new unit would operate with an overall turbine cycle efficiency of 43.2%.

b) Generator

In order to ensure the trouble-free operation of the new turbine, the generator, exciter, and the seal oil system should be replaced together with the steam turbine. The Unit 3 generator is 33 years old and was already planned to be replaced in 1993.

c) NDE Equipment

At the present time no replication type creep monitoring equipment exist at the plant. It is recommended that such equipment as well as additional boroscopes be purchased as soon as possible in order to better be able to predict metal degradation and to detect minor cracks in thick walled pressure parts of the 7 turbines (and 16 boilers). This equipment should be also used between now and the time of the actual replacement of the Unit 3 turbine.

d) 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, that an adequate inventory of spare parts for the upgraded (and existing) equipment be established.

4.3 AUXILIARY PLANT SYSTEM

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

a) Condenser

Replace the entire condenser with optimized conditions to match the new heat duty required by the new turbine exhaust.

In addition, institute a formal air inleakage detection program to systematically detect and eliminate air ingress into the vacuum space of (all) condenser(s).

b) Feedwater Heaters

All existing feedwater heaters should be removed and replaced as required by the new thermal cycle of the steam turbine.

c) Piping and Valves

All extraction and heater drain system piping and valves shall be replaced with those required by the thermal cycle of the steam turbine.

In addition, the main steam piping and isolation valves should be replaced from the boiler header to the new steam turbine.

The above replacements will eliminate the problems with the high and intermediate pressure valves. In addition, the extraction and feedwater heater drain systems shall have valves and protection logic to guard against turbine water induction. This shall be applicable for all feedwater heaters whether they are installed outside or inside the condenser neck and whether they are vertical or horizontal.

d) Pumps and Motors

The following pumps and motors should be replaced with ones optimized for the flows of the new simplified thermal cycle and with better efficiencies than those of the original equipment:

- Boiler feed pumps
- Condensate pumps
- Heater drain pumps

- Circulating water pumps

e) District Heat Supply Components

In addition to the component replacements described in the above paragraphs, the new thermal cycle of the KT-115/125-130 turbine will require the installation of the following major components:

- Two - 50% capacity district heating heat exchangers
- Three - 50% capacity district heating water circulating pumps
- District heating heat exchanger drain pumps.
- Interconnecting piping and valves between the turbine and the district heating condensers.
- Interconnecting piping and valves between district heating condensers and condensate system components.
- Interconnecting (hot water) piping and valves between the new district heating heat exchangers and the existing district heating water supply system piping.
- Instrumentation and controls for heat supply.

4.4 INSTRUMENTATION AND CONTROLS

The recommended action involves the repair and replacement of the instrumentation and controls, as necessary, plus the implementation of additional I&C equipment.

The following plant instrumentation and control improvements are recommended for the boiler and turbine systems.

- Vibration monitoring equipment, both portable and stationary to measure the vibration at the bearings of the turbine-generator.
- Coal flow measurement for the boiler to determine improvements in efficiency as reflected in decreased fuel consumption.
- Oxygen content measurement in the feedwater for improved control of feedwater chemistry.

- NO_x monitoring equipment to determine the effectiveness of NO_x reduction initiatives in the boilers.
- SO_2 monitoring equipment to determine the effectiveness of SO_2 reduction initiatives.
- Phosphate monitoring equipment in the feedwater for improved control of feedwater chemistry.
- PH monitoring of feedwater for improved feedwater chemistry control.
- Flame temperature monitoring to assist in adjusting boiler parameters for low NO_x burning and to decrease the level of unburned carbon in the ash.
- High temperature O_2 monitors to adjust the boiler for optimum efficiency.
- Instruments for measuring carbon content in ash (on-line) to determine the burners performance.
- Primary air flow monitors to balance flow to the mills.
- Secondary air flow monitors to balance flow to the burners.
- CO monitoring equipment to adjust the boilers for optimum efficiency.
- CO_2 monitoring equipment to determine excess air testing of the burners.
- Opacity monitoring equipment for flue gas after the boiler and ID fans to determine the effectiveness of the particulate control equipment.
- Moisture monitoring equipment to determine quantity of water in the flue gas, in order to perform combustion calculations.
- Flue gas flow monitoring to determine mass release rates of pollutants from the boiler.
- Portable combustion analyzer with peripherals to adjust the boiler parameters.
- Heat spy to quickly determine heat leakage points from the boiler and turbine and determine "Hot Spots" in electrical equipment.
- Oil in water monitoring to detect oil leakage from the oil coolers to the circulating water system.

- Salt monitoring to determine efficiency of boiler blowdown system.

This list was developed during the condition assessment and is considered necessary for rehabilitation and modernization. Installation of this instrumentation will extend the plant life and yield improvement in reliability and availability and reduce maintenance costs.

4.5 AIR POLLUTION CONTROL

Present levels of plant emissions have been estimated at:

NO_x	765 mg/Nm^3
SO_2	2,900 mg/Nm^3
Ash	2,500 mg/Nm^3 with 96.4% efficient dust collection

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

The Karaganda Power 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 boilers.

To achieve the Kazakstani emission limits (new boilers) described in Section 3.5 would require the following emission control efficiencies.

Emission	Limit, mg/Nm^3	Efficiency, %
NO_x	240	68.6
SO_2	400	86.2
Ash	100	99.85

- NO_x emissions can be reduced to about 400 mg/Nm^3 by modification to the combustion system. Application of a low NO_x firing system (LNCFS) referred to in paragraph 4.1 is recommended.

- Reducing NO_x emissions to 240 mg/Nm^3 (the limit suggested for new boilers) requires post combustion NO_x controls. A 40% reduction in NO_x emissions (from 400 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 and is not recommended at this time.

- Reduction in SO_2 emissions would require post combustion controls. Reducing emissions from the uncontrolled level to the suggested level of 400 mg/Nm^3 requires the application of flue gas desulfurization technology. Lime based semi-dry scrubbing is the most likely technology to achieve this emission reduction. Because of the low sulfur content of the Ekibastuz coal, flue desulfurization is not recommended at this time.

- Reduction in particulate (ash) emissions to achieve the suggested limit of 100 mg/Nm3 would require dust collection equipment with a collection efficiency of 99.85%. This collection can be achieved utilizing a high efficiency electrostatic precipitation or a fabric filter system. Replacement of the current ESP's with modern, high efficiency units is recommended.

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. NO_x control equipment recommended will achieve a substantial reduction in emissions.

4.6 DISTRICT HEATING SYSTEM

As described in Section 3.6, the Abai and Greenhouse hotwater district heating systems supplied by the Karaganda combined heat and power plant are suffering from internal and external piping corrosion, extensive water and heat losses due to leakages, poor and damaged insulation, and a lack of preventive maintenance. All three systems also suffers from inflexible load dispatching due to constant flow operation and lack of metering at the end users. The end users have no means to regulate the supply of heat other than opening of the windows which waste the thermal energy.

For all three district heating systems variable speed pump drives should be installed with automatic control (SCADA) system. In addition, the makeup water plant capacity for all three district heating systems should be increased after a detailed study.

The following additional recommendations are made for the three (Topar, Abai and Greenhouse) hotwater district heating systems.

Topar

- Install heat control and measuring devices (thermostats, control valves and energy meters) at the customers locations.

Abai

- Replace 3 DH water pumps in pumping station No. 2 because they are very old and need frequent maintenance.

- Repair and/or replace deteriorated water piping. A thorough piping inspection should be performed to determine which piping should be replaced. However, we have assumed that 20% of the piping will need to be replaced in preparing our cost estimates.

- Install flow, temperature, and pressure instrumentation at the various pumping stations.

- Install heat control and measuring devices (energy meters, thermostats and control valves) at the customer locations (apartment houses).

Greenhouses

- Replace DH circulation pumps with pumps that have the proper characteristics for the greenhouses.

- Install various heat control and measuring devices (energy meters).

- Install water flow regulators for the individual units in each greenhouse (3 way valves)

- Repair and/or replace approximately 6.6 km of 500 mm diameter hot water supply lines which feeds Greenhouses 1 through 5.

- A new energy control system should be installed to control the temperature of air inside the greenhouses. This system (SCADA) should include variable speed pump drives along with proper instrumentation and controls. The system should be changed from a variable temperature/constant flow system to variable flow and temperature. The installation of a computerized SCADA system and the variable speed pump drives will regulate the hot water flow according to the heat demands in specific sections of the network resulting in energy efficient operation.

4.7 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	166~206	220	~15.5
Boiler Efficiency, %	85~87.5	91.8	5~6
Turbine/Generator Output, MWe	100	105	5.0
Heat Rate, kcal/kWh	2345	1990	15.1
Units Life Extension	-	15 years	
Increase in Units 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 boiler and turbine by increasing its availability and reliability, decreasing Operating and Maintenance costs, and extending the life of the units. 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 boilers and should allow the plant 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 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 if certain units of the plant were to be shutdown due to unplanned (forced) outages.

One additional benefit of the 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 availability and reliability will improve by 10 to 12 percent as a result of the proposed rehabilitation.

The district heating system improvements will result in the following benefits.

- The district heating piping network rehabilitation will result in substantial reduction in heat and water losses due to improved piping and insulation of the system. It will minimize the external corrosion of the piping system and extend the piping life by at least 15 years.

- The installation of variable speed pump drives will reduce electric power consumption significantly resulting in substantial cost savings.

- The installation of automatic control system (SCADA) will improve the district heating system operation by providing automatic control, regulation and monitoring of system parameters which will result in energy efficient operation and substantial cost savings.

- Installation of heat controls and energy meters at the end user (customer) houses will reduce heat consumption resulting in energy savings for the system and financial savings for the end users. The reduced fuel consumption will also reduce enviornmental pollution.

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.

<u>Scope of Supply</u>

- Procurement of boiler and turbine NDE/DE equipment
- NDE/DE of boilers pressure parts*
- Replacement of 60% of furnace wall tubing*
- Repair/Replacement of boilers pressure parts including superheater and economizer inlet/outlet headers*
- Repair/Replacement of boilers setting (BRILC)*
- Refurbishment of tube penetration seals*
- Repair/Refurbishment of tubular airheaters*
- Repair/Replacement of fluegas ducting systems*
- Field testing/repair of Draft Plants (ID and FD Fans)*
- Repair/Replacement of Ball Mills and Auxiliary equipment*
- Retrofit of a low NO_x concentric firing system with either closed coupled or separate overfire air*
- Repair/Replacement of ESP's*
- Refurbishment of boilers burner management system*
- Repair/Replacement of boiler feed pumps*
- Replacement of No. 3 turbine with new model KT-115/125-130
- Replacement of electric generator and exciter for new turbine
- Replacement of Condenser for new turbine
- Replacement of feedwater heaters (2HP + 1D + 4LP)
- Replacement of 50% of the main steam piping
- Replacement of 50% of the extraction and drain piping and valves
- Replacement of three (3) condensate pumps and motors
- Replacement of two (2) Heater Drain Pumps
- Replacement of two (2) Circulating Water Pumps
- Installation of two (2) District Heating Heat Exchangers
- Installation of three (3) DH Water Circulating Pumps
- Installation of four (4) DH Heat Exchanger Drain Pumps
- Installation of interconnecting piping and valves (Turbine to DH heat exchangers (DHX), DHX to Condensate System, and to DH water system)
- Install Instruments and Controls for heat supply regulation

*To be performed on all three boilers

- Installation of various boiler and turbine I&C components
- Repair or replacement of damaged DH piping and piping insulation
- Replacement of varioius DH booster pumps
- Installation of a SCADA System and variable speed pump drives
- Installation of heat controls and energy meters at end users

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 prices 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.

PRELIMINARY COST ESTIMATE
REHABILITATION OF BOILERS No.'s 7, 10 & 13 and TURBINE No. 3
KARAGANDA COMBINED HEAT & POWER PLANT KAZAKSTAN

ITEM	LABOR COST $	MAT'L $	LOCAL MAT'L COSTS	TOTAL COST
REHABILITATION OF BOILERS				
Remove Existing Burners (24 Total)	120,000		3,600	123,600
Install New Low NOx Burners & OFA System	725,000	1,300,000	50,600	2,075,600
Refurbish Existing Ball Mills & Classifiers	372,000	396,000	23,000	791,000
Repair PA/PC Ductwork & Fans	524,000	987,000	45,300	1,556,300
Boiler Refractory, Insulation & Casing Repair	490,000	955,000	43,400	1,488,400
Tube Penetrations & Seals	142,000	185,000	9,800	336,800
Repair Air Heaters	625,000	859,000	54,300	1,538,300
Replace 60% of Wall Tubing, SH & Economizer Banks	825,000	1,535,000	70,800	2,430,800
Repair Induced Draft Fans	126,000	375,000	15,000	516,000
Repair Flue Gas Ductwork	185,000	680,000	26,000	891,000
Perform Non-Destructive Testing (Allowance)	150,000			150,000
Perform Draft Plant Assessments on (3) Boiler Trains (Allowance)	90,000			90,000
TOTAL BOILER WORK	**3,529,000**	**5,972,000**	**287,600**	**9,788,600**
REHABILITATION OF TURBINE GENERATOR				
Remove Existing Steam Turbine & Accessories	280,000			280,000
Install New 105 MW Turbine & Generator	459,000	12,000,000	373,800	12,832,800
Supply NDE Testing Equipment	0	25,000	0	25,000
TOTAL TURBINE WORK	**739,000**	**12,025,000**	**373,800**	**13,137,800**
DISTRICT HEATING SYSTEM				
ABAI				
Replace District Heating Booster Pumps	5,000	140,000	5,000	150,000
Replace/Repair District Heating Piping	200,000	3,100,000	100,000	3,400,000
Install Instruments & Controls		200,000		200,000
GREENHOUSES				
Install Circulating Pumps	15,000	250,000	15,000	280,000
Replace/Repair District Heating Piping	300,000	2,300,000	200,000	2,800,000
Install Instruments & Controls		200,000		200,000
TOPAR				
Install Instruments & Controls		200,000		200,000
ALL SYSTEMS				
Expand Make-up Water System for District Heating	150,000	1,000,000	50,000	1,200,000
New SCADA System with Variable Speed D.H. Pumps		500,000		500,000
TOTAL DISTRICT HEATING SYSTEM	**670,000**	**7,890,000**	**370,000**	**8,930,000**

PRELIMINARY COST ESTIMATE
REHABILITATION OF BOILERS No.'s 7, 10 & 13 and TURBINE No. 3
KARAGANDA COMBINED HEAT & POWER PLANT KAZAKSTAN

ITEM	LABOR COST $	MAT'L $	LOCAL MAT'L COSTS	TOTAL COST
AUXILLIARY PLANT SYSTEMS				
Replace Existing Condenser	252,800	1,600,000	55,600	1,908,400
Replace HP Feedwater Heaters	184,000	450,000	16,000	650,000
Replace LP Feedwater Heaters	169,600	325,000	11,800	506,400
Replace Feedwater Pumps (2)	48,000	550,000	1,400	599,400
Replace Main Steam Piping	94,400	187,000	2,800	284,200
Install New Extraction and Drain Piping/Valves	37,600	63,000	1,100	101,700
Replace Condensate Pumps (3)	78,800	162,000	2,400	243,200
Replace Heater Drain Pumps	20,000	35,000	1,700	56,700
Install District Heating Heat Exchangers within the Powerplant (2)	198,000	1,325,000	5,900	1,528,900
Install District Heating Water Circ Water Pumps in the Powerplant (3)	104,800	489,000	3,100	596,900
Install District Heating Heat Exch Drain Pumps in the Powerplant (4)	33,600	63,500	2,900	100,000
Install D. H. Heat Exch Piping/Valves within the Powerplant	68,800	84,000	2,100	154,900
TOTAL AUXILLIARY SYSTEMS WORK	**1,290,400**	**5,333,500**	**106,800**	**6,730,700**
INSTRUMENTATION & CONTROLS				
Install Emissions Monitoring Equipment (3 Systems)	516,000	1,695,000	44,200	2,255,200
Install Boiler Monitoring Equipment (3 Units)	224,200	767,700	19,800	1,011,700
Install Turbine Monitoring Equipment	115,700	290,600	8,100	414,400
Miscellaneous Instrumentation & Controls (3 Units)	202,700	1,635,000	36,800	1,874,500
TOTAL INSTRUMENTS & CONTROLS	**1,058,600**	**4,388,300**	**108,900**	**5,555,800**
ELECTRICAL SYSTEM				
Repair Plant Wiring & Cable	432,000	1,645,000	21,700	2,098,700
TOTAL ELECTRICAL WORK	**432,000**	**1,645,000**	**21,700**	**2,098,700**
ENVIRONMENTAL SYSTEM				
Remove Existing Precipitator (3)	453,600		9,100	462,700
Install New Electrostatic Precipitator (3)	1,041,000	6,450,000	149,800	7,640,800
TOTAL ENVIRONMENTAL WORK	**1,494,600**	**6,450,000**	**158,900**	**8,103,500**
SUBTOTAL	**9,213,600**	**43,703,800**	**1,427,700**	**54,345,100**
Freight				3,297,900
Contingency (10%)				4,711,200
TOTAL COST OF REHABILITATION				**62,354,200**

ALL COSTS ARE SHOWN IN JANUARY 1996 DOLLARS

02/02/96

SHEET 2 OF 3

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

DIRECT COSTS FROM PREVIOUS PAGE				**62,354,200**
Engineering Costs				3,260,706
Construction Management Costs				1,630,353
Start-Up Costs				1,086,902
Construction Equipment Costs				1,750,000
Interest During Construction				4,988,336
Escalation				6,005,640
TOTAL COST INCLUDING THE ITEMS ABOVE				**81,076,137**

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

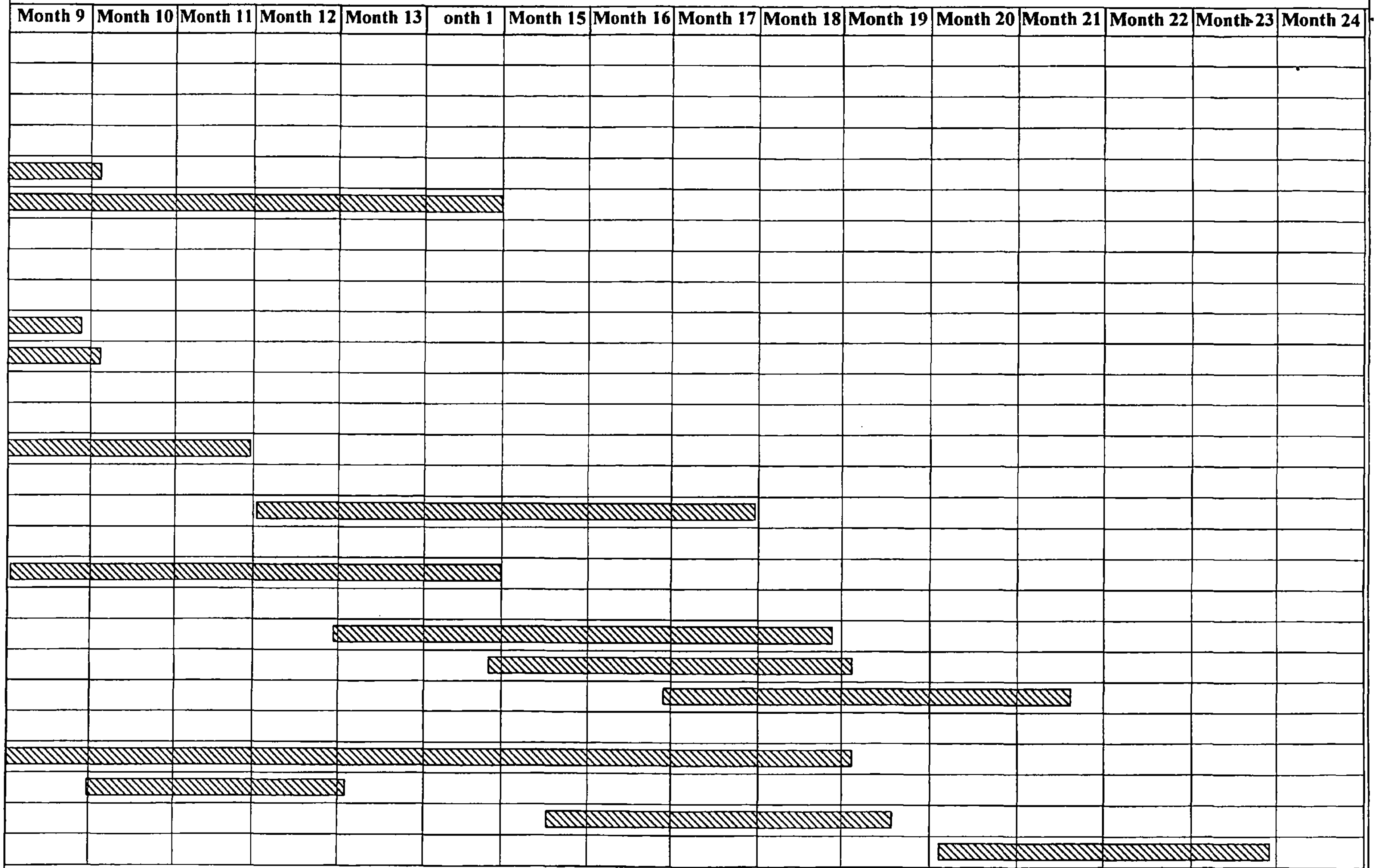
6.0 CONSTRUCTION SCHEDULE

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 KARAGANDA PLANT

Tasks	Month 1	Month 2	Month 3	Month 4	Month 5	Month 6	Month 7	Month 8
BOILER WORK								
Test and Remove Deteriorated Boiler Components (Burners, Tubes, etc.)								
Test and Remove Boiler Auxiliary Equip. (Mills, Fans, etc.)								
Install New Mech. Components Including Heat Transfer Surfaces								
Refurbish Mills and Auxiliaries								
Repair Boiler Casing, Refractories, Insulation, etc.								
TURBINE GENERATOR								
Perform NDE Tests on selected Components								
Replace Various Piping System Components and Valves								
Install New Turbine/Generator and Auxiliaries								
Install New DH Interconnection Piping, Valves, and Components								
AUXILIARY PLANT SYSTEM								
Replace Feedwater and Condensate Pumps								
Replace Feedwater Heaters								
Replace Condenser								
Replace Associated Condensate Piping and Valves								
ENVIRONMENTAL								
Replace Electrostatic Precipitators								
INSTRUMENTATION								
Install Emissions and Air Flow Monitoring Equipment								
Install Boiler and Turbine Monitoring Equipment								
Misc. Instrumentation & Controls Systems Upgrades								
DISTRICT HEATING SYSTEM								
Repair and/or Replace Deteriorated Piping Sections								
Install New District Heating Pumps								
Install New Instruments and Control System (SCADA)								
STARTUP AND CHECKOUT								

CONSTRUCTION SCHEDUL OR THE KARAGANDA PLANT



Burns and Roe Enterprises, Inc.

Technical Report

KAZAKSTAN EXPANDED ENERGY PROGRAM

HEAT AND POWER SYSTEM EFFICIENCY IMPROVEMENTS

UST-KAMENOGORSK THERMAL ELECTRIC STATION

FINAL REPORT

January 1996

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

61

TABLE OF CONTENTS

KAZAKSTAN EXPANDED ENERGY PROGRAM

TASK 2

HEAT AND POWER SYSTEM EFFICIENCY IMPROVEMENT

UST-KAMENOGORSK THERMAL ELECTRIC STATION

6?

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

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

63

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 UST-Kamenogorsk Thermal Electric Station 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. 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 determine the district heating system deficit for the Ust-Kamenogorsk districts. After establishing the heating capacity deficit, recommendations were made to install new line 7 which includes Boiler No. 16 and Turbine No. 12. This analysis also included development of capital cost estimates and implementation schedules.

- A review of the Ust-Kamenogorsk District Heating System piping was made with District Heating system engineers. Recommendations were developed to improve system efficiency and reliability based on the information provided by the DH system engineers.

- The results of the engineering analysis will be reviewed with Kazakstani authorities. The Kazakstani authorities may extrapolate the results of this analysis to other combined heat and power 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 STATION DESCRIPTION AND EVALUATION

3.1 STEAM BOILERS

General

The Ust-Kamenogorskaja TES was commissioned in 1947 to supply electric power and district heating to the City of Ust-Kamenogorsk. The Plant was designed to run on a heating time-table with 4300 to 5200 hours of operation per year. At present, the Plant has eleven (11) pulverized coal fired boilers (No. 5-15) with a total design steaming capacity of 2230 te/h and eight (8) steam turbines with a total gross power output of 241.5 MWe. The boilers were designed to fire Kuznetsk basin high volatile bituminous coal. The presently fired high volatile bituminous coal is from the Shubarkul mine, Kazakstan. The water and mineral matter contents of this coal are similar to those of the design coal, but the calorific value is somewhat less (see comparison later).

- Boilers No. 5 to 10 are type CKTI-75-39F, manufactured by Barnaul Boiler Manufacturing Co. The design parameters of these boilers are 75 te/h steamflow each at 39 at.g. pressure and 435°C temperature, 150°C feedwater temperature to the economizer, 150°C airheater exit fluegas temperature and 90.7% boiler efficiency (LHV basis). These are drum type natural circulation boilers, with a conventional two-pass configuration, balanced draft radiant furnace with fully water cooled tubewalls, and spaced tubes with refractory backing. The superheater is a pendant style (non-drainable). The horizontal drainable three stage economizer has a bare tube staggered arrangement with water in upflow and fluegas in downflow. The three stage airheater is the tubular type, fluegas in the tubes and air over the tubes in crossflow. The economizer and airheater tubebanks are located in the rear convective passes. The furnace has a dry bottom ash disposal system. The boilers are top supported, allowing for cubic thermal expansion. The indirect (pulverized coal storage) coal firing system consists of a single subatmospheric operating pressure ball mill per boiler. These mills are model SBM 250/390 with an external static classifier, separating cyclone, pulverized coal storage bin with PC feeders, pulverized coal/primary air (PC/PA) conduit system, and a mill fan which is a combined exhaust/primary air fan. Each boiler furnace has three swirl type horizontal PC burners in a single row, positioned in the front wall plus two start-up PC burners, one in each furnace sidewall. The draft plant of each boiler consists of a single forced draft and induced draft fan. All of the fans of each boiler are radial flow, centrifugal type, with electric motor drive. Each boiler furnace has six tubewall sootblowers three in each sidewall. Particulate emission control equipment consists of wet venturi type scrubbers, a single venturi and two scrubbers per boiler.

- Boilers No. 11 to 14 are type BKZ-320-140, and are also manufactured by Barnaul. The design parameters of these boilers are 320 te/h steamflow each at 140 at.abs. pressure, and 555°C airheater exit fluegas temperature and 91.2% boiler efficiency (LHV basis). These boilers are also of the drum type with natural circulation and a conventional two-pass configuration, balanced draft radiant furnace with fully water cooled tubewalls, and tangent tubes with insulation and casing. The superheater stages are pendant, non-drainable, with a spray type desuperheater interstage. The spraywater is generated from condensed saturated steam in a heat exchanger using feedwater from the first stage economizer outlet as the cooling medium. The horizontal drainable two-stage economizer has a bare staggered tube arrangement with water in upflow and fluegas in downflow. The three stage airheater is the tubular type with fluegas in the tubes and air over the tubes in crossflow. The economizer and airheater tubebanks are located in the rear convective passes. The furnace has a dry bottom ash disposal system. The furnace and top of the rear convective pass are top supported, allowing for cubic thermal expansion. The lower portion of the rear convective pass is bottom supported, with a metal expansion joint to compensate for the downward/upward thermal expansions situated between the last stage tubular airheater and second stage economizer. The indirect (pulverized coal storage) coal firing system consists of two subatmospheric pressure ball mills per boiler. These mills are model SBM 287/470 with an external static classifier, and separating cyclone. Each boiler has a single, common pulverized coal storage bin with PC feeders. Each boiler has two PC/PA conduit systems and two mill fans which are combined exhaust/primary air fans for conveying the PC/PA mixture to the burners. Each boiler furnace has eight swirl type horizontal PC burners arranged in two rows of four and positioned in the furnace frontwall. Each burner has a steam atomized mazut gun for start-up and combustion stabilization. The draft plant of each boiler consists of two FD and ID fans. Hot air recirculation from the final stage airheater air outlet into the FD fan suction side is used to protect the cold end of the tubular airheater from low temperature corrosion attack. All the fans are radial flow, centrifugal type, with an electric motor drive. The number of installed furnace tubewall sootblowers is not indicated in the documentation we have received. No retractable sootlances are installed for the pendant superheater stages and no heating surfaces cleaning equipment is shown for the economizer and tubular airheater heating surfaces in the rear convective passes of the boilers. Particulate emission control equipment consists of four venturi wet scrubbers per boiler.

- Boiler No. 15 is type TPE-430/D, manufactured by Taganrog Machine Building Co. The design parameters of this boiler are 500 te/h steamflow at 140 at.abs. pressure and 560°C temperature, 230°C feedwater temperature to the economizer, 130°C airheater exit (diluted) fluegas temperature and 90.5% boiler efficiency (LHV basis). The boiler is of the drum type with natural circulation and large bore downcomers with small bore supply tubes to the bottom furnace tubewall headers. The boiler configuration is the conventional two-pass, with a short horizontal convective pass and a furnace arch with a modern aerodynamic layout. The radiant furnace operates with a balanced draft and is constructed with fully water cooled tube-fin-tube welded (membrane) walls, insulation and lagging. The superheater consists of four stages with three interstage spray type desuperheater stations. The low steam temperature superheater stages are radiant wall type (furnace, horizontal and vertical convective passes roof, convective passes rear and sidewalls, furnace rear, front and sidewalls at the level of the lower furnace horizontal exit plane), the third stage superheaters is of the nondrainable pendant convective type. The spraywater is generated from condensed saturated steam in a heat exchanger using feedwater (prior to entering the economizer) as the cooling medium. The horizontal drainable two-stage economizer has extended heating surfaces (fins) and a staggered tube arrangement with water in upflow and fluegas in downflow. The boiler has two vertical shaft rotary regenerative bi-sector airheaters (type RPV-68 Ljungstrom license) in counterflow with combustion air in upflow and fluegas in downflow. Each rotor has three sectors, two hot and one cold. The cold sector heating surface is enameled. Hot air recirculation from after the airheater air side outlet is fed into the FD fan suction side and is used for airheater cold-end corrosion protection. The rotor speed is 2 rpm, with an electric motor drive. The economizer stages are positioned in the vertical rear convective pass and the two regenerative airheaters are positioned immediately below the economizer fluegas side exit.

The indirect (pulverized coal storage) coal firing system consists of two subatmospheric pressure ball mills per boiler, model SBM 320/570. Each of the mills has an external static (centrifugal) classifier, separating cyclone, and pulverized coal storage bin with PC feeders. The two separating cyclones are cross-connected to the two pulverized coal storage bins. Each bin has four PC feeders for a total of eight per boiler. **The coal drying medium is hot fluegas taken from the furnace frontwall, above the lower furnace horizontal exit plane by two high temperature fluegas ducts of stainless steel construction and discharging into each ball mill raw coal inlet side. Classifier exit mixture temperature control is by cold fluegas recirculation, using a recirculating fan, with a fluegas tap-off downstream of the two ID fans and discharging into the hot fluegas-to-ball mills lines.** The boiler has two fluegas/PC conduit systems and two mill fans which are combined PC and fluegas mixture circulating/conveying fans (for conveying the fluegas/PC mixture to the burners). The boiler furnace has a total of eight "flat-flame" pc burners, four burners each in the front and rear furnace walls, arranged in single horizontal rows. Heat input capacity of each burner is 46.5 MWt. Each burner consists of two hot combustion (secondary) airducts with an included angle of 60 degrees, a pulverized coal/fluegas injector, a steam atomized mazut gun for ignition and load stabilization and a flame scanner. Each mill fan also supplies vented fluegas plus evaporated coal moisture together with some carryover pulverized coal to four vent burner openings arranged in one of the furnace sidewalls with a total of eight vent burner openings per furnace.

The draft plant of the boiler consists of two FD and three ID fans. All fans are radial flow centrifugal type, with electric motor drive. The number of installed furnace tubewall sootblowers is not indicated in the documentation we have received and neither is the number of installed retractable sootlances. No heating surfaces cleaning equipment is indicated for the economizer and for the two rotary regenerative airheaters. Particulate emission control equipment consists of five venturi wet scrubbers per boiler. A water impounded bottom ash/slag hopper supported on the basement floor is installed below the furnace tube hopper. Four combined electric motor driven screw conveyors/ash crushers are installed per bottom hopper for the removal of the bottom ash. The type of seal between the furnace tube hopper and the water impounded bottom ash hopper is not indicated.

Table 3-1 shows a comparison of the Kuznetsk and Shubarkul coals that have been used at the plant.

TABLE 3-1

Kunzetsk Basin and Shubarkul Mine Bituminous Coals Characteristics Comparison			
Parameter	***Unit***	***Kuznetsk grades G&D***	***Shubarkul***
Volatiles DAF	% by wt.	38 to 45	45
LHV	kcal/kg	5240 to 5450	4700
Total moisture (max.)	% by wt.	18.2	20
Grinding factor, Russian (Kpo)	---	1.23 to 1.35	1.30
HGI (=Kpo-0.32/0.0149)	---	61 to 69	66
Ultimate analysis, as fired:			
Carbon	% by wt.	55.5 to 58.7	48.5
Hydrogen	% by wt	3.9 to 4.2	3.4
Oxygen	% by wt	8.9 to 9.7	14.8
Nitrogen	% by wt	1.7 to 1.9	0.9
Sulphur	% by wt	0.3 to 0.5	0.4
Total moisture	% by wt	12 to 12.7	15.0
Mineral matter	% by wt	13.2 to 17	17.0
Mineral matter chemical composition:			
SiO2	% by wt	N/A	67.0
Al2O3	% by wt	N/A	23.0
Fe2O3	% by wt	N/A	3.5
TiO3	% by wt	N/A	1.1
CaO	% by wt	N/A	2.0
MgO	% by wt	N/A	1.0
K2O	% by wt	N/A	1.2
Na2)	% by wt	N/A	0.5
SO3	% by wt	N/A	0.1
Ash fusibility temperatures (assumed in a reducing atmosphere):			
Initial deformation	°C	1030 to 1260	1350
Softening	°C	1050 to 1300	1450
Hemispherical	°C	1100 to 1400	N/A
Flow	°C	1550	1500

N/A = Not Available

Condition Assessment

- Type CKTI-75-39F (Boilers No. 5 to 10)

  These six boilers were installed between 1952 and 1957, and their operating periods range from 166,000 to 137,000 hours, as of March 31, 1995. Boiler #9 had the largest number of total starts (864) while boiler #10 has the least (623), also as of March 31, 1995. The other four CKTI boilers had an average of 730 total starts. Breakdown of the total number of starts by type (cold, warm, hot, restart) is not provided. The steam outputs of these boilers are significantly derated (by an average 27%), the LHV basis boiler efficiencies have also deteriorated substantially from the design of 90.7% to an average of 75.6%. Each of the boilers has an average of 5 to 6 annual unscheduled shutdowns due to equipment breakdowns. The main operating problems are furnace and boiler refractory/insulation/casing damage, furnace tubing cold side low temperature corrosion attack, unmeasured ambient air ingress into the furnace/boiler setting, excessive superheater tube metal temperatures, and low temperature corrosion attack of economizer and tubular airheater tubebanks. We postulate, based on the long periods of operation, that the final superheater tubebanks and outlet headers have some initial creep damage and that the first stage economizer inlet headers have fatigue cracks. Plant personnel have not reported any fatigue type cracks of the steam/water drums to the BRC team. Low quality (shop/field) welds of boiler tubes are another source of frequent breakdowns. Considering the very high (90%) total SiO_2 plus Al_2O_3 content of the now fired Shubarkul coal mineral matter (ash), both the convective pressure parts as well as the firing system components, e.g., PC/PA conduits, classifiers, separating cyclones, ball mill liners, must have substantial erosion wear type metal loss. Erosive wear is likely to affect the availability of the wet venturi scrubbers and the ID fans.

- Type BKZ-320-140 (Boilers No. 11 to 14)

  These four boilers were installed between 1966 and 1970 with operating periods ranging from 168,000 to 138,000 hours as of March 31, 1995. Boiler #11 had the largest number of total starts (359), and boiler #14 the least (276), also as of March 31, 1995. The other two boilers had an average of 330 total starts. Again, breakdown by type of starts is not provided. Steam outputs of these boilers are also derated (by an average of 16%) and the LHV basis boiler efficiencies have deteriorated from the design 91.2% to an average of 84.9%. The number of average annual unscheduled shutdowns of these boilers, due to equipment breakdowns is similar to that of the CKTI boilers. The main operating problems are also the same as for the CKTI boilers. Some initial creep damage of high temperature metal pressure parts is anticipated due to the relatively long operating periods. We also anticipate fatigue type cracking of the first stage economizer inlet headers at tube ligaments and a slight possibility of some fatigue damage of the steam/water drums. Metal loss due to erosive wear of convective pressure parts, firing system components, particulate emission control equipment and ID fans must also be a significant operating problem due to the erosion propensity of the coal mineral matter.

- Type TPE-430/D (Boiler No. 15)

  This modern non-reheat utility boiler was installed in March of 1991 and had an operating period of approximately 15,000 hours and a total of 66 starts as of March 31, 1995. Considering the low number of operating hours and total starts, it is somewhat unexpected that the steam output is derated by 23% and that the boiler efficiency (LHV basis) has deteriorated by 5% from the design value of 90.5%. According to Plant personnel, the main operating problems of the boiler are (a) furnace tube failures by dry-out/overheating, due to boiler mal-operation (very likely operation with too low steam/water drum water level or even worse, complete loss of drum water level) and (b) low quality boiler tube weld joints. The listed operating problems however, do not explain the substantial steam output derate and the deteriorated boiler efficiency. The furnace has a fully welded tubewall construction, thus unmeasured ambient air ingress into the setting should not occur. The steam output derate may be due to deficient coal throughput capacity of the ball mills or due to draft plant capacity deficiency.

3.2 STEAM TURBINE GENERATORS AND AUXILIARIES

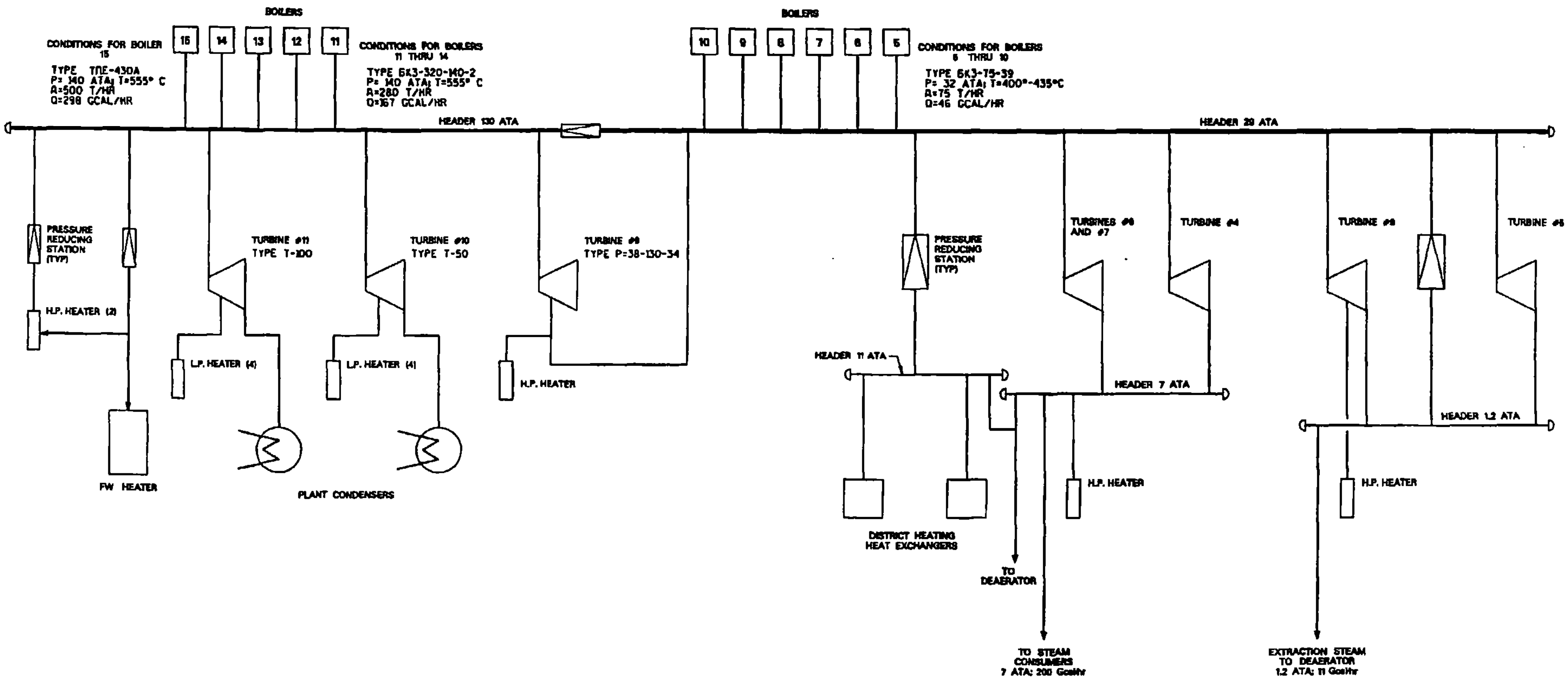
Plant Description

The Ust-Kamenogorsk TES currently consists of 8 operating steam turbines with an electric generation capacity of 241.5 MW. All turbines are of the heat supply type (back-pressure or district heating). The rated heat supply capability for these units is 596 Gcal/h. In addition to this nameplate capability the plant also provides thermal energy of 454.9 Gcal/h from main steam headers through pressure reducing stations. The total present nameplate heat supply capability of the plant is thus 1050.9 Gcal/h.

The net electric energy produced is distributed to consumers through the electric power distribution system. Thermal energy is distributed to various industrial, commercial and residential customers in the form of steam or hot water through a network of transmission and distribution piping.

There are a total of 15 steam boilers in the plant which provide main steam to the turbines via two main steam headers. The low pressure header operates at a pressure of 29 ata, and the high pressure header at 130 ata. Boilers No. 5 through 10 feed steam to the low pressure header, while boilers No. 11 through 15 supply steam to the high pressure header. The two headers are connected through a pressure reducing station. Steam turbines No. 4 through 8 receive steam from the low pressure header, and turbines No. 9 through 11 receive main steam from the high pressure header. Figure 3-1 schematically illustrates the arrangement of the energy supply scheme of the Ust-Kamenogorsk plant.

Figure 3-1
UST- KAMENOGORSK ENERGY SUPPLY SCHEME



OU/USTKAM.DOH

Turbine No. 1 and 2 (manufactured by Westinghouse) and turbine No. 3 (a Ljungstrom design) have been removed from service and dismantled. The existing units No. 4 through 11 were placed in service between 1941 and 1970. Some of these units underwent modifications during their operating lives. The year of initial service, the original and modified designations, the present operating parameters, number of operating hours, and other relevant information are given in Table 3-2.

Turbine No. 4 was manufactured by the Kaluga Turbine Plant and was placed into operation in 1959 with a nameplate rating of 6 MW. Its original designation was AP-6-5 and it was designed for main steam parameters of 35 ata and 435°C. Since it actually receives steam from the low pressure header at only 29 ata and 400°C, it has been derated to 3.5 MW. This turbine exhausts to the 7 ata discharge header, which feeds steam to various services as outlined below. There are no extractions from this turbine. There have been no modifications made to this turbine since it was installed.

Turbine No. 5 was manufactured by Metropolitan Vickers in 1943 and was placed in operation at this plant in 1951 as a 20 MW (AK-20) turbine which was designed for a main steam pressure of 35 ata and temperature of 435°C. While originally this turbine was a condensing unit, in 1982 it was converted to operate in the back-pressure mode. This conversion included removal of the blades of the last six stages of the turbine, removal of the condenser, and rerouting of the turbine exhaust to the 1.2 ata discharge header which supplies steam to services as outlined below. The turbine has a new designation, P-10-29/1.5, and a revised nameplate capacity of 10 MW. There are no extractions from this turbine. The new main steam parameters for the unit are 29 ata pressure and 400°C temperature. The maximum steam flow for the unit is 80 t/h.

Turbines No. 6 and 7 were manufactured by the Kirov Plant in 1951 with a type designation of DK-20-120. Unit 6 started its operation at the Ust-Kamenogorsk Plant in 1951 and Unit 7 in 1952. They were condensing units with industrial and district heating extractions and had a nameplate capacity of 12 MW. Turbine No. 6 was converted from condensing to backpressure type in 1970, and Turbine No. 7 was similarly converted in 1974. These conversions included replacement of the diaphragms of the HP section to accommodate revised steam flows, elimination of the steam extractions, replacement of the LP rotor with a shaft thereby deactivating the LP turbine, renovation of the control system, removal of the condenser, and rerouting the turbine exhaust to the 7 ata header. The current nameplate capacity of each of these turbines is 8 MW, and they have a main steam flow rate of 150 t/h. They have been redesignated as P-8-29/7 type following the conversions.

Turbine No. 8 was manufactured by the UTMZ as an At-25-2 unit and placed in operation in 1954 with a nameplate rating of 25 MW. It was designed to receive steam from the low pressure header at 29 ata and 400°C, and exhaust to a condenser. However, in 1966 the turbine was converted from a condensing too backpressure type. This conversion included the replacement of

TABLE 3-2

OPERATING CAPABILITY OF THE UST-KAMENOGORSK TURBINES

Steam Turbine No.	4	5	6	7	8	9	10	11
Year of Initial Service	1959	1951	1951	1952	1954	1967	1966	1970
Original Designation	AP-6-5	AK-20	DK-20-120	DK-20-120	AT-25-2	P-38-130/34	T-50-130	T-100-130
Rated Original Generating Capacity, MW	6	20	12	12	25	38	50	100
Current Designation	P-3.5-29/7	P-10-29/1.5	P-8-29/7	P-8-29/7	P-25-29/1.7	P-38-130/34	T-50-130	T-100-130
Current Rated Electric Capacity, MW	3.5	10	8	8	25	38	48.8	100
Main Steam Flow, t/h	60	80	150	150	220	470	265	460
Current Main Steam Pressure, ata	29	29	29	29	29	130	130	130
Current Main Steam Temperature °C	400	400	400	400	400	555	555	555
Turbine Backpressure $kg/cm^2(a)$	7	0.5	7	7	0.7	39	0.035	0.035
Accumulated Operating Hours, Hr	118,407	195,263	258,872	256,695	198,910	191,244	166,477	154,917
Number of Starts	466	488	379	328	344	246	298	212
Year of Last Capital Repair	1991	1992	1994	1992	1995	1995	1991	1993

the diaphragms and the rotor of the HP section to accommodate revised steam flows, replacing the LP rotor with a shaft thereby deactivating the LP turbine, removal of the condenser, rerouting the turbine exhaust to 1.2 ata header and the replacement of the control system. The nameplate capacity remains unchanged at 25 MW. The turbine has one steam extraction to an HP heater. The turbine exhaust steam from the 1.2 ata header is used to heat district heating water in main DH water heat exchangers. The current designation of this turbine is P-25-29/1.7.

Turbine No. 9 was manufactured by UTMZ in 1966 as a P-38-130/34 model and was placed in operation in 1967 with a nameplate rating of 38 MW. The unit was designed for main steam parameters of 130 ata pressure, 555°C and a main steam flow rate of 470 t/h. The turbine receives steam from the high pressure header and exhausts to the same 29 ata header which supplies steam to turbine No. 4 through 8, to pressure reducing stations and to HP heaters. The HP heaters were replaced in 1986, but no modifications have been performed on this turbine and no input/output limitations have been imposed since its initial installation.

Turbine No. 10 was manufactured by UTMZ in 1965. It is a T-50-130 district heating unit and it was placed in operation in 1966 with a nameplate rating of 50 MW. It receives steam from the high pressure header at 130 ata and 555°C, and exhausts to a condenser. The turbine has 7 extractions which supply steam to HP heaters 5 through 7, LP heaters 1 through 4, and hot water heaters 1 and 2. In 1991 the blades of the 21st stage were removed because of erosion and cracking, and the turbine currently operates under this condition. As a result, the electrical capacity was reduced by 1.2 MW in the condensing regime and 3.8 MW in the heating regime. The turbine has a nominal heat supply capability of 92 Gcal/h.

Turbine No. 11 was also manufactured by UTMZ (in 1969). It was placed in operation at the plant in 1970 as a T-100-130 district heating unit with an electric nameplate capacity of 100 MW. The design steam parameters are 130 ata, 555°C, and the turbine has a maximum steam flow capability of 460 t/h. It is a 3-cylinder unit with a 2-flow LP section. The maximum district heating capability of the controlled extractions is 160 Gcal/h. The turbine receives steam from the 130 ata header and exhausts to a condenser. The condenser has built-in tube banks which can be used to pre-heat make-up water for the district heating network. The turbine has 7 extractions which supply steam to HP heaters, a deaerator, LP heaters, and district hot water heaters. No modifications have been performed on this turbine since its initial installation.

In addition to the above operating turbines, there is also a nominal 80 MW district heating turbine (No. 12) at the plant in storage. This turbine was manufactured in 1993, has industrial steam and district heating steam extractions, but has not yet been installed due to lack of funds. The turbine pedestal and the condenser have been installed at the plant. Auxiliary equipment and piping have also not yet been purchased due to lack of funds.

The actual operating performance of the installed turbines based on the average 1994 data is shown in Table 3-3.

TABLE 3-3

OPERATING PARAMETERS OF THE UST-KAMENOGORSK TURBOGENERATORS
(Based on 1994 averages)

Unit No.	4	5	6	7	8	9	10	11
Electric Power Generation, 10^3 kWh	11,704	30,324	40,777	56,444	80,871	148,640	203,990	352,352
Average Electric Load, MW	3.0	8.0	6.9	7.9	17.6	27.4	42.3	78.4
Head Loads, Gcal/h								
Total	32	32	72	73	81		88	321
Industrial	32		72	73				
DH		31			81		86	131
Built-in Tube Bundles							2	1
Operating Hours, hrs	3,830	3,773	5,863	7,181	4,604	5,431	4,814	4,497
Electrical Energy Generated in the Heating Mode, 10^3 kWh	11,704	30,324	40,777	56,444	80,871	148,640	181,360	328,442
Number of Starts	17	11	16	10	15	11	8	6
Main Steam Pressure, ata	28.1	28.4	25.1	25.5	28.8	118.8	128.0	126.6
Main Steam Temp, °C	397	396	400	398	391	542	545	554
Industrial Steam extraction pressure, ata	6.4		6.4	6.6				
DH steam extraction pressure, ata		1.2			1.3		1.1/0.9	1.0/1.0
Back-pressure, ata	6.4	1.2	6.4	6.6	1.3	33.0		
Vacuum, %							95.3	95.3
Final feedwater Temperature, °C				140	148	227	225	219
Specific Heat Consumption, Kcal/kWh	1,000	920	986	1,000	1,026	979	1,420	1,389

Condition Assessment

a) Turbine Problems

The current installed electrical capacity of the Ust-Kamenogorsk Plant is 241.5 MW. However, the actual operating capacity in 1994 was lower than the above value due to certain limitations associated with equipment degradation. For instance the actual operating electrical capacity of the plant at the beginning of the year was set at 244 MW. This is because of the 5 MW limitation at the No. 8 turbine due to the breakage of the 20th and 21st stages, and 3.5 MW limitation at the No. 10 turbine due to the breakage of the 21st stage blading. By the end of the year, further degradation of output capability was noticed. This further degradation of about 9 MW was due to the deterioration of the No. 5 electric generator stay ring insulation. Thus the plant electric output capability at the end of the year 1994 was 224 MW. Thus the total degradation of the turbine output capability was:

$$\frac{241.5 - 224}{241.5} \times 100 = 7.25\%$$

Other problems with the individual units and auxiliaries are as follows:

- The No. 4 steam turbine is the smallest unit and is 36 years old. There was an accident in 1977 involving this turbine steam path components. As a result, the rotor and the diaphragms were replaced in 1978. However, the unit has had many problems with cracking of the steam chest, stop valve, diaphragm packings, and governing oil system. The cracking problem is still continuing, and even though the unit accumulated a relatively low number of operating hours compared to the other machines, (about 20% over its original design life). This unit should be removed from service as soon as new capacity will be available.

- Turbine No. 5 has accumulated a total operating time of 195,263 hours as of January 1, 1995. This is the oldest unit (52 years old) having been manufactured in 1943. The main problems are due to the extreme old age of this unit and include:

  - The steam path components (blades, nozzles, diaphragms, disks) have heavy corrosion wear.

  - The main oil pump does not provide sufficient pressure for turbine lubrication and control.

  - The steam distribution and control parts are worn.

  - There are no design drawings for some turbine components.

- No tools and equipment are available to perform replacements or to fabricate spare parts (all connections are in English measuring system, not in metric).

This turbine should be disassembled as soon as possible.

- Turbines No. 6 and 7 have accumulated the highest number of operating hours (258,872 hours and 256,695 hours, respectively), and are 44 years old. Besides the more than double original design operating life, these units have the following problems:

  - Lack of spare parts.
  - Excessive wear of spring couplings between the HP rotor and "LP" shaft.
  - Cracks at the steam intake.
  - Unsatisfactory condition of turbine sealing rings.
  - Worn turbine lube oil cooler tubing system.

  These units have very low remaining lives left.

- Turbine No. 8 was installed 41 years ago and has accumulated a total operating life of 198,910 hours, almost twice its original design life. As it was noted above the output capability of this unit has been degraded because of the complete absence of the 20th stage blades and the partial removal of the 21st stage blades. In addition, this turbine has the following problems:

  - Replacement of blades and disks of the 4th, 15th, 16th, 17th, 18th, 19th and 20th stages is required because of their wear and tear over the years.
  - Physical wear of main steam stop valve and pressure control actuator.
  - Wear of the tubing systems of the turbine oil cooler and the generator seal oil cooler.
  - Emergency (DC driven) oil pump for the generator seal oil system is required to be installed.
  - Shortage of funds prevents the delivery of spare parts to rehabiltiate the turbine.

It should also be noted that the electric generators of all of the above units (Units 4 through 8) also have exhausted their useful lives.

The relatively younger units (turbines No. 9, 10 and 11) operating with the higher steam pressure and temperatures have the following problems:

- The Unit No. 9 steam turbine has accumulated a total number of operating life of 191,244 hours. Therefore
  - The stop valves on regulating valves have exceeded their park resource which is 170,000 hours.
  - The steam leads to the turbine are very close to their extended useful life of 211,000 hours.
  - The cylinder and rotor also have very little remaining life (park resource 220,000 hours).
  - Turbine oil cooler tubing system needs replacement.
- The Number 10 steam turbine is about 29 years old and has been operating for 166,477 hours as of January 1, 1995. As noted above, the blades of the 21st stage were removed in 1991 because of wear and cracking, limiting the turbine output capability. The high pressure feedwater heaters of this unit were replaced in 1992 and the LP heater #4 was replaced in 1994. The main DH heat exchanger #2 tubes were also replaced in 1994. The No. 10 steam turbine has the following problems:
  - The blades in stages #21, 22 and 23 should be replaced (blade life is 100,000 hours).
  - The steam leads to the turbine have very little useful life remaining.
  - The LP feedwater heaters #1, 2 and 3 and the gland steam condenser tubes need replacement.
  - The expansion joints on the extraction steam lines to LP HTR #1 and #2 and to the main DH heat exchangers need replacement.
  - The turbine oil cooler tubing needs to be replaced due to leaks.
- The No. 11 steam turbine is the youngest operating unit at the plant with a total of 154,917 accumulated hours of operation. This unit was reported to have a very low

82

efficiency HP section mainly because the interstage seal strips at the shrouds and diaphragms are practically absent.

Correction of this problem was said to require the replacement of the 2nd through 8th stage diaphragms. In addition the following problems exist with the No. 11 turbine:

- The expansion joints in the extraction steam piping to the LP HTRS #1 and 2 and to the main DH heat exchangers need replacement.
- The HP feedwater heaters need replacement.
- The turbine stop valve needs to be replaced because of cracks.
- The tubes of the LP feedwater heaters and the gland steam condenser need to be replaced because of leaks.

The eight operating units had a total of 144 turbine generator related outages during the past 10 years. The dates and reasons for these outages are shown in Table 3-3.

The plant personnel does a good job in running the plant despite the many problems and the lack of spare parts. The plant maintenance records for the 1994 year indicates the following repair and availability figures:

	Duration (hours)				Availability Factor %
Turbine No.	Major Repair	Intern. Repair	Maintenance	Available Hrs	
4	-	-	365	8,395	95.83
5	-	-	640	8,120	92.69
6	1,291	-	749	6,720	76.71
7	-	-	475	8,825	94.58
8	-	-	1,731	7,029	80.24
9	-	-	262	8,498	97.01
10	-	-	375	8,385	95.72
11	-	-	14	8,746	99.84

Based on the above durations the plant shows a weighted availability factor for the turbines of 95.25%.

In addition to the problems of turbine generators themselves, there are problems with the turbine plant auxiliary equipment. Some of these components have been identified above under the

89

description of problems for the different turbines. Additional components or problems which would require attention include:

- Tube replacement for the No, 5, 6, 7 peaking DH heat exchangers.
- Tube replacement of the main steam jet air ejector for the No. 10 turbine condenser.
- Vacuum deaerator ejectors.
- Turbine oil cooler tubing leaks.
- The 5th phase 140 ata main steam pipe lines should be replaced (exhausted its service life).
- Many of the pumps in the turbine plant exhausted their useful lives and operate with poor efficiencies and without proper spare parts. These pumps should be replaced with new modern designs. The pumps requiring replacement are as follows:

  Pumps No. 1, 2 (1951 vintage)
  Pumps No. 3, 4 (1954 vintage)
  Pumps No. 5, 7 (1965 vintage)
  Circulating Pumps No. 6, 9 (1951-1954 production)
  Deaerated water pumps No. 1, 2 (1954 production)
  Condensate and feedpumps for the Unit 10 turbine cycle (1965 production)

- The deaerating columns of the low pressure deaerators No. 1 through 3 should be replaced because of shell wear and tear.

b) Metal Control

Metal control laboratory personnel were interviewed to assess the procedures and equipment the plant has to monitor metal conditions. The equipment for non-destructive examination (NDE) and destructive examination (DE) at the plant include:

Ultrasonic flow detector (UD2-12)
Magnetic Particle (MP) testing equipment
X-ray device
Hardness tester - portable
Hardness tester - stationary
Spectroanalific equipment
Chemical analysis equipment

The plant also has liquid penetrant (LP) testing equipment but it is not frequently used. There are no boroscopes or electronic microscopes at the plant. In addition there is no replication type creep testing equipment currently at the plant. In 1985 the plant invited outside testing agencies (Ekaterisburg, Cheljabinsk) to check the condition of the main steam piping at the elbows.

The plant follows the 1995 guidelines RD34.17.421 (Moscow) regarding the metal control of the main components of boilers, turbines and piping systems in thermal power plants. The metal control personnel usually look at the external parts of the turbines (outside of shell, stop valves, steam chest, regulating valves) during regular maintenance. However, examination of the internals of the turbines and valves, etc. can only be done during the capital repairs, about every four years.

According to the metal control personnel, the main problems with their aging turbines are the cracking of stop valves and the upper half of the turbine cylinders, as well as the erosion of the last stage blades. During the past 10 years the following defects have been found on the various turbines:

YEAR		DESCRIPTION OF DEFECTS
	TURBINE NO. 4	
1986		Cracks on cylinder cover with dimensions of between 70 mm to 330 mm long and up to 20 mm deep
1991		Cracks on cylinder cover with dimensions up to 90 mm long and 200 mm deep
1994		Cracks in the stop valve: 60 mm long and 25 mm deep
	TURBINE NO. 6	
1994		Cracks on cylinder cover with dimensions of up to 80 mm long and between 10-15 mm deep
	TURBINE NO. 7	
1992		Cracks on the turbine cylinder with dimensions between 80-100 mm long and 10-15 mm deep

YEAR		DESCRIPTION OF DEFECTS
	TURBINE NO. 8	
1987		Crack on the cylinder cover: 210 mm long and 5 mm deep
1994		A network of cracks on the stop valve cover with dimensions of up to 150 mm long and 25 mm deep
	TURBINE NO. 9	
1990		Cavities in the control valve fillets with diameters between 5-6 mm and depth between 4-6 mm.
		Cavities in the HP cylinder cover with diameters of 35 mm and depth between 5-7 mm.
		Cavities in the stop valve with diameters between 5-20 mm and depth up to 10 mm. Also surface cracks with lengths of up to 200 mm and 1-2 mm depth.
	TURBINE NO. 10	
1991		Three cracks in HP cylinder cover with dimensions up to 120 mm in length and 34 mm depth.
		Ten cracks in the IP cylinder cover with dimensions up to 180 mm in length and 40 mm depth.
	TURBINE NO. 11	
1993		Four cracks in the IP cylinder cover with dimensions of up to 240 mm in length and 27 mm depth
		Three cracks at the inner surface of the stop valve with dimensions of up to 200 mm in length and 50 mm in depth.

The piping sections between the turbine stop valve and the control valves for Turbine No. 9, 10 and 11 are made of 12 Cr-1Mo-1V material and have dimensions with ϕ243 x 30 mm, ϕ219 x 26

86

mm and ϕ133 x 17 mm. No defects have been reported for these pipe segments. However, there were cracks found on some of the high pressure (130-140 ata) main steam piping segments between the type BKZ-320 steam generators and the high pressure turbines between the years 1981 to 1995. No defects were found on these segments during the prior period between 1966 to 1981.

As noted above, there is currently no replication type creep testing capability at this plant. As the plant increases in age such testing capability would be highly desirable to monitor potential creep damage of critical components which operate with units approaching the end of their extended design life (park resource operating hours). Utilization of such testing equipment would enable the plant to better predict potential failures or to perform predictive maintenance.

3.3 INSTRUMENTATION AND CONTROLS

General

The instrumentation at the Ust-Kamenogorsk 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 Ust-Kamenogorsk Instrumentation and Control System based on the information collected during the plant visit and discussions with the plant management.

(a) 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 fed from an oxygen analyzer assists the unit operator in setting the correct combustion air flow rate. Each of the two 50% forced draft fans used for the HP boilers are electric motor driven, centrifugal type with radial flow. The original oxygen analyzers are extractive type and consequently slow acting. The low pressure boilers have only one forced draft fan, however both boilers use two speed fans with adjustable vanes.

(b) Primary Air Temperature Control

A portion of hot flue gas is injected into coal mills for temperature and oxygen control. This is to reduce the possibility of coal explosions. The PA fans are not, however, cross connected so that a single fan shutdown trips the boiler. This system uses electronic controllers and works satisfactorily.

(c) Furnace Pressure Control

Furnace pressure is controlled in a closed loop system using pressure as the controlled variable. Each induced draft fan is equipped with inlet vanes which are modulated to control furnace pressure.

(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 steam taken from the drum which is then condensed in a heat exchanger where the cooling medium is the feed water flow just before entry to the drum. Apart from the fact that increased attemperation will not impair cycle efficiency, the system lends itself to good controllability because there is inherent self regulation for changes in live steam flow. 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 valve is the usual stopgap solution. Superheater outlet temperature and a derivative of superheater inlet temperature are compared to the setpoint to form the control deviation.

(e) Drum Level Control System

There are five 500 ton per hour and one 250 ton per hour feedwater pumps. Each boiler has a single feedwater control valve. There is no startup valve. Drum level is controlled using a three element controller that is drum level, feedwater flow and steam flow. The controller is electronic, and works well. The controller setpoint is adjusted manually by the operation.

(f) Boiler Interlock and Protection

A basic interlock system using electrical relays is in place. Protection is effected for the following conditions: low drum level, high feedwater flow, loss of flame, two out of three induced draft fans tripped, both forced draft fans tripped, both air heaters off, high boiler vacuum, low steam injection pressure and low mazut pressure. Tripping the boiler will stop the coal feeders, close the mazut valves, stop the air heaters and stop the forced draft fans. One induced draft fan will continue to run after a trip. There is no history of missed trips, but sometimes a false trip occurs.

(g) Burner Management System

There is no burner management system as such. However, the boilers 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 boiler will trip.

(h) *Emissions Monitoring*

The plant has CO_2 and NO_x monitors, however the NO_x monitor is unreliable and not used. There is also an opacity monitor in place but it does not work and is not used.

(i) *Load Control*

These units are a conventional mechanical turbine governor with a centrifugal speeder gear to vary the load setpoint. The boiler pressure controllers are used to vary the fuel flow rate to the boiler. The pulverized coal 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 oxygen dilution for the transport air.

The firing system burners are positioned in the furnace sidewalls, and each sidewall has two pulverized coal/primary air injection ports with the secondary air injection ports positioned above and below each port. Coal must be delivered in equal amounts to each burner, even under low loads. Coal flow is controlled by volumetric feeder speed.

Combustion control of the boilers is provided manually by the operators according to established procedures and are 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 superheater. 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. Vacuum in the upper section of the furnace is also used as a combustion performance indicator. The original mechanical governors are still in operation.

3.4 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 Ust-Kamenogorsk power plant dust collection equipment is provided to remove a major portion of the fly ash from the flue gas before discharge. Ash collection is performed by venturi scrubbers on the boilers. The current efficiency of these units range from 96% to 97%.

From the year 1992 to 1994, the plant discharged the following amounts into the atmosphere:

Pollution Material	Ash	NO_x	SO_2	Burned Fuel	
Year	[t]	[t]	[t]	coal [t]	mazut [t]
1992	8,715	7,017	9,646	1,057,701	35,462
1993	7,217	7,022	9,430	1,089,972	32,759
1994	6,380	5,436	8,322	938,593	10,676

These discharge quantities can also be expressed as follows, assuming 40% excess combustion air:

Emission	Concentration, mg/Nm^3
Ash	950
SO_2	1200
No_x	830

Kazakstani emission limits for new boilers are as follows:

Ash	100
SO_2	400
No_x	240

It is evident that in order to meet these limits, major investments in Air Pollultion Control Equipment would be required.

Local limits for emission of pollutants into the environment are less stringent and it appears that the emission limits for new boilers will not be applied to Boiler #16 at this time.

There is no NO_x control equipment installed at the present time on the boilers. SO_2 reduction is achieved by the injection of alkali irrigation water into the boiler fluegas. The plant claims that this lowers SO_2 levels by 10 to 15%. There are no current plans to install a flue gas desulfurization system or No_x control equipment at the plant due to lack of funds and floor space.

3.5 DISTRICT HEATING SYSTEM

General Description

The district heating hot water transmission piping system has a total installed trench length of 46.135 km. There are six major piping systems which originate from the TES-1 power plant. The total trench length of 46.135 km is made up of the following:

Transm. Piping System Designation	Trench Length [km]
TM-1	4.452
TM-2	5.27
TM-3	9.134
TM-4/1	9.445
TM-4/2	4.694
TM-5	9.62
TM-6	3.52
Total	46,135

The largest diameter of the network piping is 820 mm. The above main piping systems are interconnected at various node points. Most of the piping is located underground in concrete trenches except portions of the M-5 transmission piping system which are above ground. The total maximum district water flow rate is 12500 m^3/h.

In addition to the power plant as the main heat source, there is also a boiler house located on the left bank of the Irtish River. This boiler house is also tied into the district heating network. The boiler house is rated at 220 Gcal/h heating capacity. The boilers in this facility are coal fired. The various boilers and their capacities are as follows:

3 steam boilers	20 t/h each
2 steam boilers	25 t/h each
4 steam boilers	50 t/h each
1 hot water boiler	50 Gacl/h

There is one pumphouse located in the piping network with district water circulating pumps in both the supply and return lines. The pumps are constant speed pumps driven by electric motors.

In addition to the hot water transmission piping, there is a steam piping system to deliver industrial steam to a number of customers in the vicinity of the TES-1 plant. These customers include a machinery plant, a meat plant, two metallurgical plants, dry cleaners, water treatment and laundry facilities, etc. There are at least three steam lines which originate from the plant, however only one line (a 325 mm diameter pipe to the machinery plant) comes under the jurisdiction of the district heating company which is called OBLTEPLOCOMMUNENERGY. The total industrial steam flow rate is estimated at 200 t/h. The condensate is not returned to the plant from any of the steam customers.

The district heating hot water transmission piping system described above also comes under the jurisdiction of the district heating company. The district heating company interfaces with both the plant and the local distribution companies whose function also includes local servicing inside the buildings and the collection of the tariff for the heat and hot water energy consumption.

The accounting method for heat and hot water is such that only a few larger customers pay according to the actual heat they use. These customers have flow meters in their supply lines as well as thermometers in supply and return lines. The heat consumption is determined from the product of the flow rate and the supply and return temperature differential. The smaller customers pay for heat based on the floor area of their homes. They pay for domestic hot water based on the number of persons living in the household.

While the original design of the hot water heating system was a closed system with separate secondary heat exchangers for space heating and domestic water generation, the current system is of the open type with an "elevator" at the local customers. The typical arrangement of the basement piping for h eat supply at the local customer is shown in Figure 3-2.

It should be noted that Altajencrgo has a plan to build another district heating power plant (TES-2), which will be connected to the current district heating network. The plant would have a nominal electric power output of 500 MW and would have five T-100 type district heating steam turbines. The plant peak heat output capability would be 1174 Gcal/h. However, the implementation of this plan could not proceed due to the lack of funds.

The temperature schedule of the hot water system supply and return temperatures, as well as the temperature after mixing at the local customer's premises (after the "elevator") as a function of the ambient outdoor temperatures is shown in Table 3-7.

92

Figure 3-2
TYPICAL DISTRICT HEATING CONNECTION
(At the Consumers House/Building)

UST- KAMENOGORSK DISTRICT HEATING SYSTEM

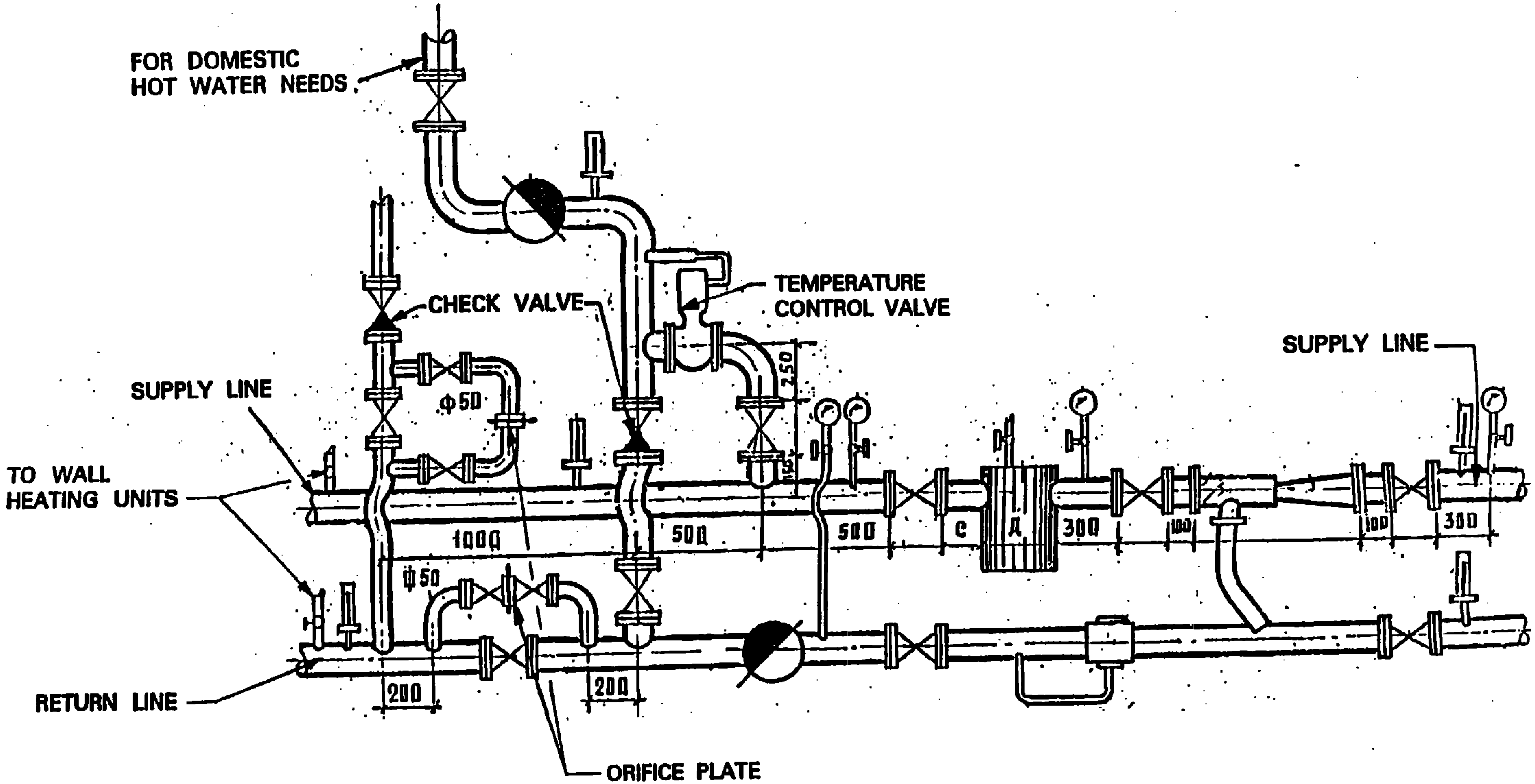


TABLE 3-7 (Continued)

UST-KAMENOGORSK DISTRICT HEATING TEMPERATURE SCHEDULE

Outside Temp. °C	Relative Head Consumption	DH Supply Temp. °C	DH Return Temp. °C	Temp. °C Before Heat Exchanger	Temp. °C With Wind Chill	Inside Air Temp. °C
-32	0.76	113.7	53.2	72.1	118.4	12.6
-33	0.76	112.7	52.2	71.1	117.3	11.6
-34	0.76	111.7	51.2	70.1	116.3	10.6
-35	0.76	110.7	50.2	69.1	115.2	9.6
-36	0.76	109.7	49.2	68.1	114.2	8.6
-37	0.76	108.7	48.2	67.1	113.1	7.6
-38	0.76	107.7	47.2	66.1	112.1	6.6
-39	0.76	106.7	46.2	54.1	111.0	5.6

DH System Condition and Problems

The age of the piping system components in the Ust-Kamenogorsk district heating network ranges between about 3 and 44 years. Many parts of the piping system have deteriorated due to corrosion, and the district heating company is forced to replace a portion of the network piping each year. The company would like to replace about 5 km (trench length) of the piping annually however, the actual replacement is only about 2 km (trench length) per year.

The portion of the piping which is routed above ground has metal covers (jacket, either Aluminum or Zinc). The underground piping segments which are usually routed in concrete tunnels, have no metal jacket and the insulation is held in place by wires. The type of insulation used is either "diatom" or "mionvata" type. The diatom type system is of Russian manufacture, and consist of brick shaped insulating blocks plus asbestos material. The "mionvata" insulation is similar to mineral wool based insulation system and is held in place with wires.

For the aboveground position of piping, the age and the exposure of the joints of the metal jacketing often results in the ingress of rainwater and moisture to the carrier pipe. This causes both external corrosion of the bottom of the carrier pipe and sagging of the insulation within the jacketing. For the underground pipes, the occasional partial flooding of the tunnels causes the bottom portion of the pipes to be submerged. This also leads to the external corrosion of the carrier pipe. The district heating company would like to have the piping replaced with the preinsulated, bonded pipes used in most European countries. This kind of piping usually consists of a carrier pipe with polyurathane foam insulation enclosed in a polyethylene jacketing.

a5

TABLE 3-7
UST-KAMENOGORSK DISTRICT HEATING TEMPERATURE SCHEDULE

Outside Temp. °C	Relative Heat Consumption	DH Supply Temp. °C	DH Return Temp. °C	Temp. °C, Before Heat Exchanger	Temp. °C With Wind Chill	Inside Air Temp. °C
10	0.29	70.0	46.7	54.0	70.0	27.2
9	0.30	70.0	46.3	53.7	70.0	26.5
8	0.30	70.0	46.0	53.5	70.0	25.7
7	0.31	70.0	45.5	53.2	70.0	25.0
6	0.31	70.0	45.1	52.9	70.0	24.4
5	0.32	70.0	44.7	52.6	70.0	23.7
4	0.32	70.0	44.3	52.3	70.0	23.0
3	0.33	70.0	43.8	52.0	70.0	22.3
2	0.33	70.0	43.3	51.7	70.0	21.7
1	0.34	70.0	42.9	51.4	70.0	210.
0	0.34	70.0	42.6	51.1	70.0	20.2
-1	0.36	71.4	42.9	51.8	73.9	20.0
-2	0.37	73.6	43.7	53.0	76.2	20.0
-3	0.39	75.7	44.5	54.3	78.5	20.0
-4	0.41	77.9	45.3	55.5	80.8	20.0
-5	0.42	80.0	46.1	56.7	83.0	20.0
-6	0.44	82.2	46.9	58.0	85.3	20.0
-7	0.46	84.3	47.7	59.2	87.5	20.0
-8	0.47	86.5	48.5	60.4	89.8	20.0
-9	0.49	88.6	49.3	61.6	92.0	20.0
-10	0.51	90.7	50.0	62.7	94.2	20.0
-11	0.53	92.8	50.8	63.9	96.5	20.0
-12	0.54	94.9	51.5	65.1	98.7	20.0
-13	0.56	97.0	52.3	66.3	100.9	20.0
-14	0.58	99.1	53.0	67.4	103.1	20.0
-15	0.59	101.2	53.7	68.6	105.3	20.0
-16	0.61	103.3	54.5	69.7	107.4	20.0
-17	0.63	105.4	55.2	70.9	109.6	20.0
-18	0.64	107.4	55.9	72.0	111.8	20.0
-19	0.66	109.5	56.6	73.1	114.0	20.0
-20	0.68	111.6	57.3	74.3	116.1	20.0
-21	0.69	113.6	58.0	75.4	118.3	20.0
-22	0.71	115.7	58.7	76.5	120.5	20.0
-23	0.73	117.7	59.4	77.6	122.7	20.0
-24	0.75	119.8	60.1	78.7	121.7	20.0
-25	0.76	120.7	60.2	79.1	120.7	19.6
-26	0.76	119.7	59.2	78.1	119.7	18.6
-27	0.76	118.7	58.2	77.1	118.7	17.6
-28	0.76	117.7	57.2	76.1	117.7	16.6
-29	0.76	116.7	56.2	75.1	116.7	15.6
-30	0.76	115.7	55.2	74.1	120.5	14.6
-31	0.76	114.7	54.2	73.1	119.4	13.6

5909-98C/UST.DOC/2/9/96

94

The district heating system is now an open type system as was described above. The water loss from the system can vary from 800 m^3/h with no leaks to 4500 m^3/h with extensive leaks. The normal loss used to average about 940 m^3/h, however, in recent years the losses from the system often exceed the design capability of the make-up system of 1500 m^3/h. The source of make-up water is artesian wells. Losses in excess of the design capacity of the make-up water system leads to the corrosion of the inside surfaces of the carrier pipes. Examination of the older piping sections by district heating company maintenance personnel indicated significant corrosion and excessive deterioration of the piping, requiring replacement of those sections.

It was also noted that operating the system with losses in excess of the capability of the make-up system will eventually lead to the degradation of the district heating water heat exchanger surfaces at the power plant.

As it was pointed out earlier in Section 3 of this report, the current thermal demand exceeds the capability of the heat sources. Therefore, because of the continued increase of the heat demand, new transmission lines with larger diameters should be developed, on at least critical positions of certain existing transmission pipe sections should be replaced with larger diameter piping when these sections exhausted their useful lives.

The district heating piping system uses three different kinds of expansion devices (loop type, watertight gland type, and bellows type) and the DH company reported no problems with any of them.

The problem with the industrial steam pipe is that it was not specifically designed for steam service, it was originally a 325 mm diameter water line. It is carrying steam with a temperature twice the original design. The carrier pipe is enclosed in 120° segments of preformed asbestos based insulation held in place by wires. The line is running underground in a trench and the DH company would like to replace the pipe and route it aboveground.

The DH water circulating pumps which are located in the system network boost the pressure both in the supply and return lines. The DH company reported no special problems with the pumps even though they are of 1970 vintage and are approaching the end of their design lives. However, there are no automatic means of controlling flow or pressure, the pumps are driven by constant speed motors.

The transmission piping network is characterized by a number of ring connections, which cross each other at various "Node points". This allows a relatively high security of heat supply. In addition there are other node points or connecting points at which the piping systems of the various distribution systems are connected to the main transmission headers. However, there is a lack of instrumentation and control of flow and isolation capability at these node points, and there is a very minimal number of instrumentation and automatic control at the pumphouse and the dispatch center. Those that are available are quite old, either needing repair or recalibration. Without instruments which function properly to monitor and record such essential variables as flow rate, temperature, and pressure, it is difficult to accurately determine balance measurements and conduct effective energy-efficient operation.

The District Heating company would also like to relocate the dispatch center. The new location would be adjacent to the pumphouse. This location is essentially toward the center of the expanding system. The new dispatch center will require computers and instrumentation (SCADA) system to monitor and control the dispatch of the transmission system and better be able to interface with the heat sources and heat consumers connected to the transmission system.

4.0 STATION RECOMMENDATIONS

4.1 ENERGY SUPPLY AND DEMAND SITUATION

As discussed in the previous sections, the major problem with the Ust-Kamenogorsk plant is that the present and projected demand for electric power and heat exceeds the capability of the plant. A contributing factor to the magnitude of this problem is the age and accumulated operating hours of the equipment. It must be recognized that a number of turbines and auxiliaries are at/or near the end of their service lives as described in the previous sections. As the units are retired, the electric power and heat generation capacity of the plant will decrease accordingly. For this reason, the overall capacity of the plant verses current and projected loads were assessed. This load assessment is then used as a basis for specific recommendations for completing the installation of line No. 7 (turbine No. 12 and boiler No. 16) and auxiliaries to alleviate or at least minimize present and future shortfalls in plant production capacity as compared with electric and heat demands.

During the Burns and Roe visit at the power plant, plant management indicated that there is a deficit in capacity of about 30%. Therefore, the utility would prefer adding new capacity. Burns and Roe's experience with other district heating plants in the former Soviet Union countries indicated there is a reluctancy of shutting down part of a plant for significant refurbishment of individual units, before additional capacity can be built. This is especially true for the CHP plants which are providing energy to customers whose peak demand is greater than the output capability of the plant. Ust-Kamenogorsk is one such plant.

It was also observed that the electrical output of the plant is decreased during the summer months to about half (119.5 MW). The loss of capability of 122 MW was due to the following limitations:

Cooling Water Shortage	:	77 MW (units with condensers)
Thermal Output Reduction	:	40 MW (on backpressure turbines)
Turbine Flow Path Degradation	:	5 MW (Unit 8)

While no detailed future load forecasts have been prepared by Burns and Roe, the plant personnel provided the following projected energy demands on the Ust-Kamenogorsk facility for the next 10 years:

YEAR	ELECTRIC POWER DEMAND (Million kWh)	THERMAL ENERGY DEMAND (Thousand Gcal)
1995	1200	3150
1996	1200	3175
1997	1225	3215
1998	1225	3315
1999	1250	3425
2000	1300	3550
2001	1350	3690
2002	1420	3830
2003	1480	3970
2004	1540	4110
2005	1600	4250

From a review of the above data, it can be seen that over the next five years, the electric power demand on the plant is projected to increase by 8.3%, and the district heating load by 12.7%. Over the next 10 years, the electric power demand on the plant is projected to increase by 33.3%, and the district heating load by 34.9%.

The above data was compared to the actual electrical and thermal energy generation in the previous years. The operating data received from the plant indicates the following actual energy production levels.

YEAR	Electric Energy Production [10^6 kWh]	Thermal Energy Production [10^3 Gcal]
1993	1075.9	3132.5
1994	925.1	2805.5

Therefore it can be seen that the 1995 electrical energy demand is about 29.7% greater than the 1994 actual generation, and the 1995 thermal energy demand is about 12.3% greater than the previous year generation. While these large differences are partially due to the 1994 fuel shortages, even if we consider the 1993 actual generating levels as representative values for the plant, the difference in electrical energy production and thermal energy production by the year 2000 will be 20.8% and 13.3%, respectively. Similarly by the next 10 years these differences will grow to 48.7% and 35.7%. This evaluation of course does not consider the retirement and remaining life of the existing units discussed in the previous subsection. When these factors are considered, electrical generation deficits of up to 42% and 78% may be expected by the year 2000 and 2005, respectively.

On the thermal energy supply side, it was noted by plant personnel that the plant has a thermal load deficit of about 30%. This plant mostly runs "wide open" and the temperature of the district heating supply water is lower than design. This means that the level of comfort inside of buildings is severely reduced during colder ambient conditions.

In order to substantiate the magnitude of the above deficit, the plant data provided for the installed and available capacities of industrial steam and hot water loads was reviewed. The installed total thermal capacity as of the end of 1994 is 1050.9 Gcal/h. The 596 Gcal/h of this figure is to be provided by the steam turbines, and the balance, or 454.9 Gcal/h, comes from pressure reducing units. The usable heating capacity of the system is obtained by reducing the installed capacity by certain limitations due to equipment conditions. The actual thermal output capacity is determined from the usable capacity after subtracting certain losses and the plant's own heating needs.

Plant data indicates that the installed heating capacity at the plant is reduced by 107 Gcal/h because of the overheating of the boiler superheater tubes. The available heating capacity would also be 20 Gcal/h lower than installed because of the problem mentioned previously with the No. 8 steam turbine (breakage of the 20th and 21st stage blades). However, some of this loss can be recovered by taking more steam from the pressure reducer due to the reduction of load on the No. 8 turbogenerator. The resulting total equipment limitation is 102.5 Gcal/h.

The station's own needs in the form of steam is 10.4 Gcal/h and the heating needs and losses in the form of hot water are 89 and 48.9 Gcal/h, respectively. The installed thermal capacity in the form of steam is 200 Gcal/h and in the form of hot water is 850.9 Gcal/h. Therefore, with the above values, the thermal output capabilities of the Ust-Kamenogorsk plant are as shown in Table 3-4.

TABLE 3-4

THERMAL OUTPUT CAPABILITIES OF THE U-K PLANT

Installed total heating capacity	1050.9 Gcal/h
In the form of steam:	200. Gcal/h
In the form of hot water:	850.9 Gcal/h
Limitation due to equipment conditions:	102.5 Gcal/h
Usable Thermal Capacity:	948.4 Gcal/h
Station's own needs and losses	
In the form of steam:	10.4 Gcal/h
In the form of hot water:	137.9 Gcal/h
Total:	148.3 Gcal/h

- Actual output capacity

Total:	800.1 Gcal/h
In the form of steam:	189.6 Gcal/h
In the form of hot water	610.5 Gcal/h

From the above table it can be seen that the maximum load that can be satisfied in the form of hot water, i.e. the district heating load is 610.5 Gcal/h. The operating data obtained from the plant indicates that during 1994 the maximum hot water heat load occurred on January 15, 1994 and its value was 659.3 Gcal/h. However during that day the ambient temperature was only -20°C, and the hot water supply temperature was only 95°C instead of 110°C as would be required under such conditions. When the heat load is transferred to the rated ambient temperature of the Ust-Kamenogorsk DH system the corresponding maximum heat load that the plant must satisfy is 856.1 Gcal/h. Therefore the current (1994) deficit in hot water heating load capability is:

$$\frac{856.1 - 610.5}{856.1} \times 100 = 28.7\%$$

Since the industrial steam load during that time was 118 Gcal/h, the total thermal load required for the plant was 974.1 Gcal/h. This figure is 17.8% higher than the 800.1 Gcal/h of total actual load that the plant can currently provide.

Looking at the energy need projection data provided by the plant above and assuming that the peak load after 1994 will increase proportionally with the increase in total annual load, the peak heat energy loads can be estimated accordingly as:

Year 1995 - 1094 Gcal/h
Year 2000 - 1233 Gcal/h
Year 2005 - 1476 Gcal/h

Without going into detailed load deficit calculations it can be seen that the current 28.7% gap between the peak thermal loads of the area served by the plant and the available thermal output capability will significantly widen as the older units are retired from service. For instance, if turbines No. 4 through 8 were forced into retirement by the year 2000, the resulting loss of energy supply from the extractions and turbine exhausts would be 344 Gcal/h as follows:

Turbine No. 4	33 Gcal/h
Turbine No. 5	33 Gcal/h
Turbine No. 6	83 Gcal/h
Turbine No. 7	83 Gcal/h
Turbine No. 8	112 Gcal/h
TOTAL	344 Gcal/h

Therefore the peak capacity deficit in that year could be 1233 - (610.5-344) = 966.5 Gcal/h.

It is clear from the above discussions of capacity and age of the equipment and the projections of future demand, that installation of additional plant capacity is required as soon as possible to meet electric power and industrial steam and district heating demands. One recommended solution, which could significantly alleviate this problem, would be to add additional electric power and heat generation capabilities by installing turbine No. 12 and boiler No. 16 (Line No. 7). This may be a very cost effective solution, since the turbine has already been purchased and its pedestal and condenser are already installed.

<u>Conclusions</u>

The results of the assessment made above of capacity versus demand in the future years lead to the following conclusions.

- If the turbine No. 12 and boiler No. 16 installation is not completed, annual electric consumption will likely begin to exceed supply capability of the plant before the year 2000.

- If Line No. 7 is installed in the near future, the deficit in plant peak capacity for district heating and industrial steam will be reduced considerably.

The plant personnel have made a decision to add additional electric power, district heating and industrial steam capacity to the Ust-Kamenogorsk Plant. This decision was followed up by installation of the turbine pedestal, installation of the condenser, and purchase of the turbine for a new Unit No. 12. This work was stopped due to lack of funds.

Based on our assessment of the age, accumulated operating hours, the condition of the equipment, production capability versus demand for the Ust-Kamenogorsk turbines, Burns and Roe concurs with the decision of plant personnel, and recommends installation of turbine No. 12, boiler No. 16 and auxiliaries. The installation of this turbine will add a nominal 80 MW (100 MW maximum) electric output capability and about 170 Gcal/h thermal load capability to the existing plant capacity.

It is recommended that the installation of Line No. 7 and auxiliaries be completed as soon as possible. Since this work has already been partially completed, it appears to be a cost effective first step in refurbishment of Ust-Kamenogorsk Plant. Once this step is accomplished, the plant can better afford to shut down existing turbines for refurbishment and for retirement of older smaller units.

4.2 STEAM BOILERS

Boiler No. 16 Design Parameters

The new boiler No. 16 is manufactured by the Barnaul Boiler Company. This boiler is type BKZ-420-13.8-560. The boiler is of the drum type with natural circulation, a conventional two-pass configuration with a short horizontal, and a vertical rear convection pass. The radiant balanced draft furnace tubewalls are fully water cooled, 60 mm dia. x 5.5 mm thick carbon steel tubes on 64 mm centers, with refractory backing, insulation and casing. The furnace dimensions are 7700 mm deep by 14,460 mm wide. The furnace has a coutant type tube hopper formed by the front and rear walls with a 50° angles to the horizontal. The superheater stages can be subdivided into radiant, radiant-convective and convective types. The following table shows the design parameters of the new boiler.

TABLE 4-1

Boiler #16 Design Thermal Performance Parameters

Parameter	Units	Design
Live steam flow	te/h	420
Live steam pressure	MPa abs. (at. abs.)	13.8 (140)
Superheated steam temperature	°C	560
Feedwater temperature to economizer	°C	230
Airheater exit fluegas temperature	°C	160
Combustion air temperature to burners	°C	330
Excess air in fluegas @furance exit	%	20
Excess air in fluegas leaving airheater	%	40
Boiler efficiency LHV basis	%	91.0

The boiler is designed to fire bituminous coal, with an "as fired" volatile matter minimum of 36%. The design coal source will be the Shubarkul mine, Kazakstan.

The three stage superheater is of the pendant non-drainable type and has steam-side crossovers and two stages of spray type desuperheaters. Spraywater is generated from condensed saturated steam in a heat exchanger using feedwater from the first stage economizer water outlet as the cooling medium. The horizontal drainable two-stage economizer has bare tubes in a staggered arrangement with water in upflow and fluegas in downflow. The three-stage airheater is the tubular type with fluegas in the tubes in downflow and combustion air over the tubes in upflow/crossflow. The economizer and airheater tubebank stages are located in the rear vertical convective pass.

The furnace has a dry bottom ash disposal system. The furnace, the short horizontal and the top portion of the rear vertical convective pass are top supported allowing for cubic thermal expansion. The lower portion of the rear convection pass is bottom supported, with a metal expansion joint to compensate for the downward/upward thermal expansion. The expansion joint is installed between the last stage of the tubular airheater and second stage economizer.

The indirect (pulverized coal storage) coal firing system consists of two subatmospheric pressure ball mills, model SBM320/570. Each mill has an external static classifier and separating cyclone. The boiler has a single common pulverized coal storage bin with eight PC feeders. The coal drying medium is a mixture of (1) hot fluegas, taken from the furnace frontwall above the lower furnace horizontal exit plane by two high temperature fluegas ducts of stainless steel construction and discharging into each ball mill raw coal inlet side and (2) hot primary air taken from the final stage tubular airheater. The mixture maximum oxygen content is limited to 16% by volume and the static centrifugal classifier exit mixture temperature is controlled at a maximum of 130°C. The boiler has two drying medium mixture/PC conduit systems, two mill fans which are combined exhaust/conveying fans for conveying the pulverized coal from the PC storage bin to the burners with a high concentration of pulverized coal. The boiler furnace has a total of twelve horizontal pulverized coal burners, eight swirl type burners located on the frontwall of the furnace in two lateral rows of four, plus four vent burners in the furnace sidewalls, in two lateral rows of two. Four overfire air nozzles are located in the furnace rear wall for the bulk staging of combustion air in two lateral rows of two nozzles. Each swirl type pulverized coal burner has a steam atomized mazut gun for start-up and combustion stabilization.

The draft plant of the boiler consists of two FD and ID fans. Hot air recirculation from the final stage airheater air outlet into the FD fan suction side is used as tubular airheater cold end low temperature corrosion protection. All fans of the boiler are radial flow centrifugal type with electric motor drive. Due to the low slagging propensity of the Shubarkul coal mineral matter, there are no furnace tubewall blowers installed. Retractable sootlances are not provided for the cleaning of the pendant radiant/convective and convective superheater stages. A shot-type heating surface cleaning system is installed in the rear convective pass, for the economizer and tubular airheater tubebanks. Particulate emission control equipment consists of four venturi wet scrubbers per boiler, designed by the R&D department of Kazakstanenergo and having a design collection efficiency of 99.4%. No equipment is provided for fluegas desulfurization.

4.3 STEAM TURBINE GENERATORS AND AUXILIARIES

Turbine No. 12 Design

Information on the No. 12 steam turbine was requested from the plant. This information indicates that the unit has both industrial steam extraction and district heating steam extractions. The turbine's main steam parameters match the steam parameters of the high pressure steam supply header currently installed in the plant. The turbines nominal electric output is 80 MW. The nominal thermal output steam flows and other relevant performance parameters are shown in TABLE 4-2. The values shown in this table are based on circulating water flow of 8000 m^3/h entering the turbine steam condenser at an inlet temperature of 20°C.

TABLE 4-2

TECHNICAL CHARACTERISTICS OF THE NO. 12 STEAM TURBINE

Type	PT-80/100-130/13
Nominal Output, MW	80
Main Steam Pressure, kg/cm^2(a)	130
Main Steam Temperature, °C	555
Nominal Industrial Extraction Steam Flow, t/h	185
Nominal District Heating Steam Extraction Flow, t/h	132
Main Steam Flow at Nominal Conditions, t/h	440
Maximum Main Steam Flow, t/h	470
Final Feedwater Temperature in Pure Condensing Mode, °C	230
Specific Heat Consumption in Pure condensing Mode at Nominal Output, kcal/kWh	2290
Regenerative Extraction Configuration	3HPH+D+4LPH
District Heating Stages	2 (1 LP + 1 HP)
Nominal Industrial Steam Extraction Pressure, kg/cm^2(a)	13
Rotational Speed, RPM	3000
Turbine Manufacturer	LMZ
Generator Model	TVF-110-2EVZ

Turbine No. 12 is a tandem-compound, non-reheat, regenerative, district heating turbine with a condensing tail manufactured by the Leningrad Turbine Plant (LMZ). The turbine is a two cylinder machine with a separate high pressure (HP) section and the low pressure (LP) cylinder. However, the LP cylinder consists of an IP and a LP section. It is designed to receive steam at 130 ata, 555°F throttle conditions. Figure 4-1 schematically illustrates the steam turbine and its auxiliary cycle components.

As can be seen from the figure the industrial steam extraction is provided from the HP turbine section exhaust at a pressure of 13 ata which is sufficient to supply the plant's existing industrial steam supply header at 7 ata. Water for district heating is heated in two stages, each of which receives heating steam from separate extractions of the IP turbine section.

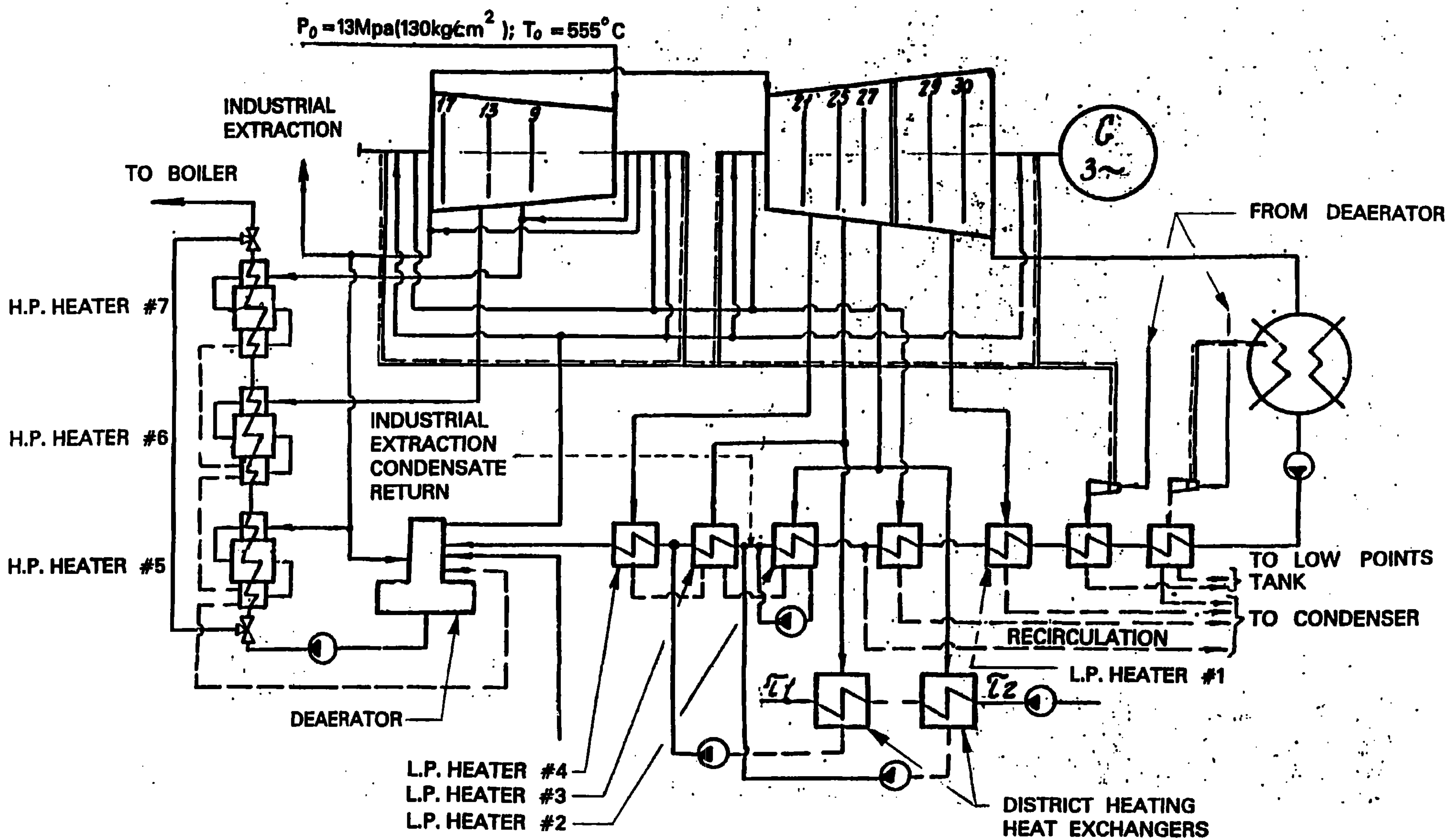
The pressure is controlled at the industrial steam extraction at the nominal value of 13 ata until the steam flow entering the IP section of the LP cylinder is below 221.5 t/h. When this steam flow rate is increased above this value, the industrial steam extraction pressure will increase up to 16 ata. The pressure in the industrial extraction can be varied at 13 $\pm$ 3 ata.

The nominal value of the district heating steam pressure in the upper DH extraction is 1.2 ata with two-stage district water heating. However, depending on heating load conditions, the pressure in the upper district heating extraction can be varied between 0.5 and 2.5 ata with two-stage district heating, and the pressure in the lower district heating extraction can be varied between 0.3 and 1.0 ata with single-stage district heating operation.

In addition to industrial and district heating extractions the turbine has regenerative feedwater heating extractions for 3 high pressure heaters, 4 low pressure heaters and a deaerator which operates at a pressure of 6 ata. Deaerator piping steam is provided from the exhaust of the HP turbine section. The district heating water heat exchangers both are provided with drain pumps which return condensate to the main feedwater cycle. Drains from the lower DH heat exchanger are pumped forward to the inlet of the No. 3 LP feedwater heater and the drains from the upper DH heat exchanger are returned to the No. 4 LP feedwater heater. The condensate return from the industrial steam supply is at a temperature of 100°C and is assumed to be returned to the feedwater system upstream of LP feedwater heater No. 3.

The turbine can be operated either in the pure condensing mode or the heating mode. In the heating regime the maximum electrical, industrial steam, and district heating outputs of the turbine are interdependent. For example, at a given main steam flow the greater rate of industrial steam and district heat production, the lower the maximum electric power generating capability. In order to track the performance of the steam turbine and to be able to determine the required main steam flows under different heat and electric load conditions, various regime diagrams have been developed by turbine manufacturers. One such diagram showing the performance characteristics of the No. 12 turbine operating with industrial steam and both district heating extractions (2 stage DH operation) is shown in Figure 4-2 for illustrative purposes. For example, assuming a district heating water return temperature of 52°C, the following generation capability values can be determined:

Figure 4-1
TURBINE NO. 12 AND AUXILIARIES
UST- KAMENOGORSK TGS PLANT



- At an electric power generation rate of 80 MW, and an output of 80 Gcal/h to the district heating system, the maximum rate of industrial steam production which could be achieved is 90 Gcal/h. This operation represents a total of 170 Gcal/h production for industrial steam and district heating.

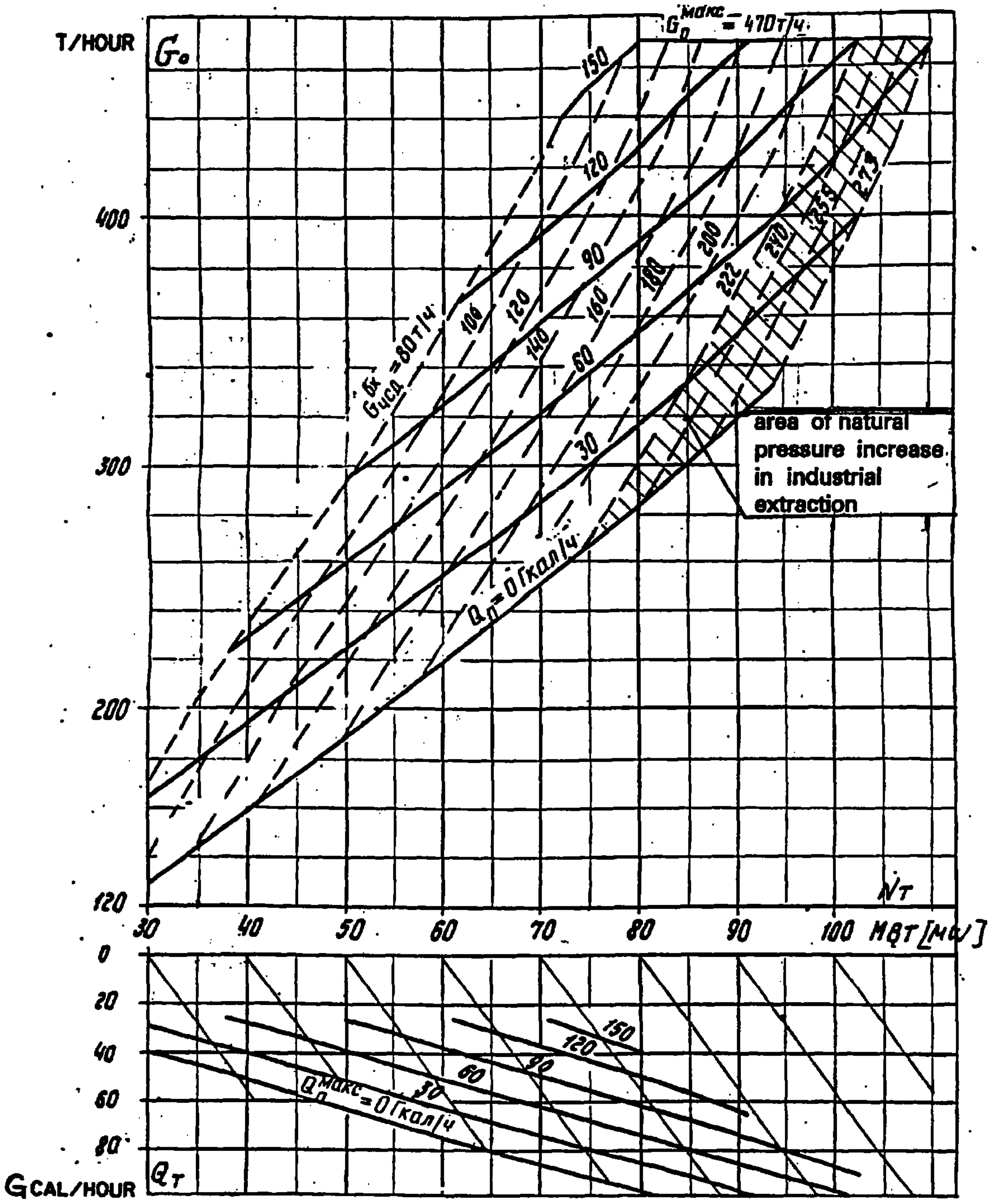
- At an electric power generation rate of 70 MW, and an output of 70 Gcal/h to the district heating system, the maximum rate of industrial steam production which could be achieved is 75 Gcal/h. This operation represents a total of 145 Gcal/h production for industrial steam and district heating.

- At an electric power generation rate of 80 MW, and an output of 95 Gcal/h to the district heating system, the maximum rate of industrial steam production of which could be achieved is 60 Gcal/h. This point of operation represents a total of 155 Gcal/h production for industrial steam and district heating.

As can be seen from the previous paragraph many load combinations of operating modes or regimes are possible. Some of these are usually guaranteed by the turbine manufacturer. The guaranteed performance figures in terms of specific steam rate (in heating regimes) and in terms of turbine heat rate (pure condensing regime) for five regimes are shown in Table 4-3. It should be noted that in this table the industrial extractions are given in terms of steam flow (t/hour) whereas the district heating extractions are given in terms of Gcal/h.

It should be noted that diagrams similar to the regime diagrams in construction have also been developed to show the specific heat consumption of the turbine under various electrical and heating load combinations. The specific heat consumption (or heat input changeable to power, measured in kcal/kWh) is analognons to the turbine heat rate (which is only defined in pure condensing modes), and for the No. 12 steam turbine it ranges between 1400 and 2600 kcal/kWh.

Figure 4-2
TURBINE NO. 12 REGIME DIAGRAM



CONDITIONS:

P_0 = 13Mpa(130kg/cm^2); T_0 = 555°C $P_п$ = 1,3Mpa(13kg/cm^2);

$P_{ВТО}$ = 0,12Mpa(1,2kg/cm^2); P_2 = 5Kpa(0,05kg/cm); $G_{пит}$ = G_0; = 52°C

LEGEND:

$P_п$ = industrial steam extraction pressure
$P_{ВТО}$ = upper extraction pressure for dist heating
P_2 = condenser pressure
$G_{ЧСД}$ = steam flow into I.P. section
$G_{пит}$ = feedwater flow
G_0 = main steam flow

109

TABLE 4-3

GUARANTEED PERFORMANCE OF THE PT-80/100-130/13 TURBINE

Regime, No.	*Turbine Output, MW*	*Industrial steam extraction*		*District heating extraction*		*District water return temperature, °C*	*Generator Efficiency, %*	*Feed water temperature °C*	*Guaranteed specific steam flow kg/kWh*
		pressure, $kg/sm^2(a)$	*steam flow, t/h*	*pressure * $kg/sm^2(a)$*	*Heat flow, Gcal/h*				
1	80	13	185	0.9	68	42	98.6	249	5.5
2	80	13	250	-	-	-	98.6	249	6.06
3	80	16	40	1.4	100	42	98.6	239	4.7
4	100	16	95	2.5	36	70	98.6	250	4.75
5**	80	-	-	-	-	-	98.6	230	heat rate 2290 kcal/kWh

*Pressure shown is in the upper (2nd stage) DH extraction

**Pure condensing mode

Turbine Auxiliaries

The following is a brief description of the turbine No. 12 auxiliaries:

- The condenser is a two pass design, type 80 KCS-1 with a total surface area of 3000m^2. The condenser requires a cooling water flow of 8000 m^3/h. Of the 3000 m^2 total tube surface area, 765 m^2 is the surface area of a built-in tube bank which can be used for district heating makeup water heating.

- Of the 4 LP feedwater heaters, the lowest pressure heater HTR. No. 1 is a horizontal heater and is located inside the condenser neck. LP heater No. 2 is a vertical heater, type PN-130-16-10-2. LP feedwater heaters No. 3 and 4 are both type PN-200-16-7-1.

- Of the 3 high pressure feedwater heaters, HP heaters No. 5 and No. 6 are type PV-425-230-23-1 and PV-425-230-35-1, whereas the highest pressure heater (FW HTR No. 7) is a vertical type PV-500-230-50-1.

- There is one 6 ata deaerating heater with storage tank provided for the No. 12 turbine.

- There are two district heating water heat exchangers provided (upper and lower stage), each with a tube surface area of 1300 m^2. They are type PCG-1300-3-8-10 heaters and are designed for a maximum flow rate of 2300 m^2/h.

- There are 3 condensate pumps type KC-80-155. The operating number of pumps depends on the steam flow into the condenser. The pumps are driven by 75 kW electric motors.

- There are two three-stage steam jet air ejectors for the condenser. They are type EP-3-701 ejectors. The condenser has one operating and one spare ejector. In addition, there is one EPI-1100-I type start-up ejector.

- There are 2 feedwater pumps provided with approximate flow rates of 320 m^3/h and 160 meter atmosphere head. They will be driven by electric motors.

- In addition to the above mentioned pumps there will be various drain pumps, DH water booster pumps and condenser circulating water pumps. The DH water heat exchangers each will have two type KN-KC-80-155 drain pumps, driven by 75 kW electric motors each. There will be two DH water booster pumps. The first stage pump will be type SE-5000-70-6 type driven by 500 kW electric motor, and the second stage pump will be type SE-5000-160 with an 1600 kW electric motor.

- The condenser circulating water pumps are type 24NDN driven by 500 kW motors. There are 2 pumps each sized for a flow rate of 5000 m^3/h and a total head of 26m.

- The electric generator for the turbine is type TVF-110-2 manufactured by the Electrosila company. The rotor is hydrogen cooled and the generator stator is water cooled.

In addition to the above equipment various piping systems will have to be installed together with valves and instrumentation and controls.

As it was noted earlier the turbine has already been procured by the plant and the turbine pedestal has been erected and the condenser installed. While foundations for other main components in the turbine room have also been provided, further construction and equipment procurement have been halted due to a lack of funds. Thus the plant already prepared a plan for the installation of the various components including a new boiler (No. 16) as noted in earlier sections.

It was noted earlier that in 1994 the electric capacity of the plant is severely curtained during the summer months, by 122 MW. About 63% of this figure is due to inadequate cooling water supply from the River. Therefore, the plant has embarked on a plan to build cooling towers as part of the plan to complete new line No. 7. Since the existing plant already has a shortage in cooling water supply, the operation of the new No. 12 turbine will certainly require the use of a new cooling tower. Therefore, cost allowance for at least one cooling tower must be made.

It is also recommended that the plant improve its NDE capabilities of existing units by purchasing additional boroscopes and replication type creep testing equipment. This will help the plant to predict metal degradation and to detect minor cracks in thick walled pressure parts of the turbines, boiler, and main steam piping without resorting to the more costly and sometimes not readily available outside laboratories.

4.4 INSTRUMENTATION AND CONTROLS

Since a new line number 7 will be installed, consisting of boiler number 16 and turbine Number 12, a standard instrumentation and controls system will be installed. The items below are new instruments for the environmental monitoring, and improved instruments for boiler control. The following plant instrumentation and control improvements are recommended based on discussions with cognizant plant engineering management.

- NO_x monitoring equipment for the #16 boiler to determine the effectiveness of NO_x reduction initiatives.

- SO_2 monitoring equipment to determine the effectiveness of SO_2 reduction.

- CO monitoring equipment to fine tune number 16 boiler for optimum efficiency.

- Instruments for analyzing particulate content in flue gas to monitor the environmental performance of boiler number 16.

- Flue gas flow monitoring equipment to determine mass release rates of pollutants from boiler number 16.

- In situ, high temperature O_2 monitoring equipment at number 16 boiler outlet to adjust boiler parameters for optimum efficiency.

- Sodium monitor for superheated steam to determine efficiency of boiler blowdown system.

- Oxygen monitor for feedwater for improved control of feedwater chemistry.

- Coal flow monitor for mills to determine if improvements in efficiency are reflected in decreased fuel consumption.

- Portable combustion analyzer with peripherals to adjust boiler number 16 parameters and determine optimum location for stationary instruments.

- Heat spy to quickly determine heat leakage points from number 16 boiler, number 12 turbine and isolate "Hot Spots" in electrical equipment.

The above list was developed during the condition assessment of the plant and is considered necessary for modernization. Installation of this instrumentation will extend the plant life and yield an improvement in reliability and availability and reduce maintenance costs.

4.5 AIR POLLUTION CONTROLS

The Ust-Kamenogorsk TES 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 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.

As was stated in section 4.1, low NO_x burners with overfire air nozzles will be installed on boiler No. 16. In addition, four wet venturi scrubbers will be used on the boilers to collect fly ash. The design collection efficiency of these scrubbers will be 99.3% according to the manufacturer.

113

These high efficiency scrubbers apparently utilize emulsifying agents to improve ash collection. This improvement in efficiency will reduce ash emissions to about 200 mg/Nm^3.

Installation of SO_2 reduction equipment has not been considered. SO_2 removal efficiency is expected to increase from the present level with the installation of the improved dust collection scrubbers but the extent of the improvement has not been quantified.

4.6 DISTRICT HEATING SYSTEM

Based on the information obtained during our plant visit and discussion with management personnel, the following are our recommendations regarding the rehabilitation of the DH transmission system:

- Replace 3.059 km (trench length) of the TM-1 piping
- Replace 0.713 km (trench length) of the TM-2 piping
- Replace 4.035 km (trench length) of the TM-3 piping
- Replace 5.224 km (trench length) of the TM-4/1 piping
- Replace 0.089 km (trench length) of the TM-4/2 piping
- Replace 6.371 km (trench length) of the TM-5 piping

- Replace 3 km length of industrial steam piping

- Install variable speed pump drives at the plant and the booster stations.

- Install motor operated isolation valves to divert flow between various transmission line sections and to be able to quickly isolate transmission and/or distribution branches for maintenance.

- Install instrumentation (flow meters, pressure and temperature transmitters) at the transmission system node points.

- Furnish new instrumentation and controls in the pumphouse for the district heating water circulating water pumps.

- Relocate the dispatch center to the area adjacent to the circulating water pumphouse. Equip the center with a modern SCADA system to monitor and control the operation of the entire DH system and to interface with the power plant, boiler house, and the distribution system.

4.7 REHABILITATION BENEFITS

The table below summarizes the anticipated benefits of implementing the installation of new line No. 7 described in Sections 4.1 to 4.6.

REHABILITATION BENEFITS

CHARACTERISTIC	BEFORE	AFTER	% IMPROVEMENT
Plant Main Steam Flow, t/h	1,650	2,070	25.4
Plant Output, MWe	241.5	321.5	33.1
Plant Heat Output Gcal/h	1050.9	1220.9	16.1

Benefits will also be realized from the Instruments and Control System modifications for boiler No. 16 and emission monitoring system. The implementation of these recommendations will improve the general operation of the plant by increasing its availability and reliability, decreasing Operating and Maintenance costs, and extending the life of the units. 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 plant and should allow the plant to meet future environmental pollution limits. In addition, the new venturi scrubbers will greatly reduce the amount of particulates that are expelled into the atmosphere from boiler No. 16.

The installation of the new line No. 7 will also result in reducing the potential cost of replacement power to be purchased if the other units of the plant were to be shutdown due to unplanned (forced) outages. As was stated in Section 4.1, the installation of the new line will also help reduce the deficit of heat capacity. The new turbine (No. 12) will increase the heat output of the plant by 16.1%. This addition will increase the comfort level of the population of Ust by the improved District Heating System.

The district heating system improvements will result in the following benefits.

- The district heating piping network rehabilitation will result in substantial reduction in heat and water losses due to improved piping and insulation of the system. It will minimize the external corrosion of the piping system and extend the piping life by at least 15 years.

- The installation of variable speed pump drives will reduce electric power consumption significantly resulting in substantial cost savings.

- The installation of automatic control system (SCADA) will improve the district heating system operation by providing automatic control, regulation and monitoring of system parameters which will result in energy efficient operation and substantial cost savings.

- Installation of flowmeters and pressure and temperature transmitters at the transmission system node points will balance the system load which will reduce energy waste by making the district heating system more responsive to the changes in heat demand in the various sections of the system. With a more responsive district heating system, end users will not need to open windows to control the comfort level. It will be controlled by the SCADA system.

- In addition, the Ust Kamenogorsk plant management had requested to increase the capacity of the following systems to meet the increased demand and to improve the environment.

    a) Increase the capacity of boiler feedwater makeup system from 300 t/h to 500 t/h to meet the increased makeup water demand due to addition of boiler No. 16.

    b) Increase the capacity of district heating makeup water system from the present level to 4000 t/h to meet the increased demand.

    c) Procure and commission a wastewater treatment system with a capacity of 120 t/h.

Burns and Roe did not have the opportunity to evaluate the above mentioned request for the systems expansion because the requests were made after the site visit. These system expansion needs should be verified during the future investigations. However, we have included funds in our cost estimates for these systems expansion.

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

- Drum type natural circulation boiler (Boiler No. 16)
- Two ball mills with electric motor drives
- Two volumetric raw coal feeders
- Two static, centrifugal mill classifiers
- Two separating cyclones
- Pulverized coal storage bin with screw conveyor and eight PC feeders
- Two mill circuit ducting systems, including pulverized coal conduits, storage bin to burners
- Two hot fluegas ducts from the furnace frontwall, above the horizontal furnace exit plane, to the ball mills raw coal inlets, with supports
- Eight burners, swirl type with mazut guns
- Four vent burners
- Four overfire air nozzles
- Ducts, FD fans to airheaters, airheaters to burners
- Flues, tubular airheater exit to venturi wet scrubbers, scrubbers to ID fans, ID fans to stack
- Tubular airheater, three-stage
- Two hot air recirculation duct systems to FD fans suction side
- Two FD fans with electric Motors
- Two mill exhaust/pc and fluegas conveying fans
- Four wet venturi scrubbers
- Boiler suspension structural steel
- Platforms, stairs and handrails
- Two raw coal silos
- Safety valves with silencers
- Bottom Ash Removal System for Boiler No. 16
- Feedwater stop and check valves
- Miscellaneous vent and drain valves
- Boiler refractory, insulation and casing
- Insulation and lagging for ducts and flues
- Burner management and flame safety systems
- Drag chain conveyor for furnace bottom ash removal
- Live steam attemperators with valves
- Electrical generator and exciter
- Three high pressure feedwater heaters

- One deaerator storage tank
- Four low pressure feedwater heaters
- Two boiler feed pumps and motors
- Three condensate pumps and motors
- Two feedwater heater drain pumps
- Main steam piping from 130 atm header to steam turbine No. 12
- Condensate and feedwater piping for turbine No. 12
- Extraction steam piping with extraction check and motor operated isolation valves
- Heater Drain piping
- Two DH water heat exchangers
- Four DH heat exchanger drain pumps
- Two DH water circulating (booster) pumps
- DH water piping between the DH heat exchangers and the tie-in point to the existing DH transmission piping
- One gland steam condenser
- Condenser Air Removal System (Air Ejectors)
- Two circulating water pumps
- Circulating water piping between cooling tower and condenser
- One cooling tower for turbine No. 12 heat sink
- One step-up transformer
- One auxiliary transformer
- Boroscopes (NDE)
- Replication type creep testing equipment (NDE)
- Emission Monitoring Equipment
- Boiler Monitoring Equipment
- New Turbine Governing System
- Miscellaneous Instruments and Controls
- Replacement of Damaged District Heating piping per Section 4.6
- Installation of variable speed pump drives
- Installation of motor operated isolation valves and flowmeters and pressure and temperature transmitters on DH piping sections
- Installation of DH Instrumentation and Controls including SCADA System
- Procurement and Commissioning of District Heating makeup water plant with a capacity of 4000 t/h
- Additional Makeup Water Treatment (Demineralizer) Plant (200 t/h capacity)
- Procurement and commissioning of Wastewater treatment plant with a capacity of 120 t/h
- Procurement and Commissioning of New Coal Handling System including Railcar dumper

The following items are not included in the cost estimates:

- New 180 meter high stack for the boilers
- Cost of Turbine No. 12 because it is already bought
- Ash Sluicing and Storage System for the entire plant
- Fish Protection System
- ID fans, FD fans and various pumps for all boilers and turbines except for Boiler No. 16 and Turbine No. 12
- Boilers and Turbines refurbishment for the rest of the units at the plant
- Station piping of main steam and feedwater system except for Turbine No. 12
- I&C for balance of plant except for Line No. 7 (Boiler No. 16 and Turbine No. 12)

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 December 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.

PRELIMINARY COST ESTIMATE
INSTALLATION OF NEW BOILER No. 16 and TURBINE No. 12
UST-KAMENOGORSK COMBINED HEAT & POWER PLANT KAZAKSTAN

ITEM	LABOR COST $	MAT'L $	LOCAL MAT'L COSTS	TOTAL COST
NEW BOILER No. 16				
Supply & Install New BZK-420 Natural Circulation Boiler	680,000	18,400,000	368,000	19,448,000
Supply & Install New Low NOx Burners & OFA System	100,800	1,200,000	24,000	1,324,800
Supply & Install New Ball Mills & Classifiers	135,200	1,380,000	27,600	1,542,800
Supply & Install New PA/PC Ductwork & Fans	112,000	1,654,000	33,080	1,799,080
Supply & Install New Bottom Ash Removal System	59,200	385,000	7,700	451,900
Supply & Install New Boiler Supports, Platforms, Handrail & Stairs	54,400	250,000	5,000	309,400
Supply & Install New Tubular Air Heater	92,000	965,000	19,300	1,076,300
Supply & Install New Boiler Refractory, Insulation & Casing	75,200	375,000	7,500	457,700
Supply & Install New Induced Draft Fans	36,000	680,000	13,600	729,600
Supply & Install New Flue Gas Ductwork w/ Insulation & Lagging	149,600	1,020,000	20,400	1,190,000
TOTAL BOILER WORK	1,494,400	26,309,000	526,180	28,329,580
REHABILITATION OF TURBINE GENERATOR				
Install New 80 MW Turbine	496,000	0	19,840	515,840
Supply & Install New Generator	188,000	4,985,000	7,520	5,180,520
Supply NDE Testing Equipment	0	35,000	0	35,000
TOTAL TURBINE WORK	684,000	5,020,000	27,360	5,731,360
AUXILLIARY PLANT SYSTEMS				
Complete Installation of Existing Condenser	49,600	0	7,440	57,040
Supply & Install New Circulating Water Pumps & Piping	312,000	585,000	11,700	908,700
Supply & Install New Coal Handling System incl Railcar Dump	288,000	3,445,000	68,900	3,801,900
Supply & Install New Demineralizer & Wastewater System	329,600	3,570,000	71,400	3,971,000
Supply & Install New HP Feedwater Heaters	187,200	340,000	6,800	534,000
Supply & Install New LP Feedwater Heaters	168,000	225,000	4,500	397,500
Supply & Install New Feedwater Pumps	48,000	600,000	12,000	660,000
Supply & Install New Main Steam Piping	96,000	934,000	18,680	1,048,680
Supply & Install New Extraction and Drain Piping & Valves	16,000	135,000	2,700	153,700
Supply & Install New Condensate Pumps	28,000	210,000	4,200	242,200
Supply & Install Miscellaneous Auxilliary Equipment	92,800	822,000	16,440	931,240
Supply & Install New Cooling Tower	209,600	2,615,000	52,300	2,876,900
TOTAL AUXILLIARY SYSTEMS	1,824,800	13,481,000	277,060	15,582,860

PRELIMINARY COST ESTIMATE
INSTALLATION OF NEW BOILER No. 16 and TURBINE No. 12
UST-KAMENOGORSK COMBINED HEAT & POWER PLANT KAZAKSTAN

ITEM	LABOR COST $	MAT'L $	LOCAL MAT'L COSTS	TOTAL COST
INSTRUMENTATION & CONTROLS				
Supply & Install Emissions Monitoring Equipment	41,600	480,000	9,600	531,200
Supply & Install Boiler Monitoring Equipment	28,000	275,000	5,500	308,500
Supply & Install New Turbine Governing System	36,800	110,000	2,200	149,000
Supply & Install Miscellaneous Instrumentation & Controls	102,400	644,000	12,880	759,280
TOTAL INSTRUMENTS & CONTROLS	**208,800**	**1,509,000**	**30,180**	**1,747,980**
ELECTRICAL SYSTEM				
Supply & Install New 110kv Substation	158,400	844,000	16,880	1,019,280
Supply & Install New Cable, Conduit & Cable Tray	418,000	1,432,000	28,640	1,878,640
Supply & Install New Instruments & Controls	172,000	622,000	12,440	806,440
TOTAL ELECTRICAL WORK	**748,400**	**2,898,000**	**57,960**	**3,704,360**
ENVIRONMENTAL SYSTEM				
Supply & Install (4) New Venturi Scrubbers for Boiler No. 16	316,000	1,630,000	32,600	1,978,600
TOTAL ENVIRONMENTAL WORK	**316,000**	**1,630,000**	**32,600**	**1,978,600**
DISTRICT HEATING SYSTEM				
Install District Heating Heat Exchangers, Piping & Valves	284,000	1,777,000	35,540	2,096,540
Install New Make-up Water System for District Heating	325,000	2,120,000	42,400	2,487,400
Install District Heating Water Circulating Water Pumps	116,000	545,000	10,900	671,900
Install District Heating Heat Exchanger Drain Pumps	37,600	69,000	1,380	107,980
Install District Heating Pump Variable Speed Drives	62,400	800,000	16,000	878,400
Supply & Install District Heating Instruments & Controls incl SCADA	52,000	1,038,000	20,760	1,110,760
Repair/Replace District Heating Piping	896,000	15,100,000	302,000	16,298,000
Repair/Replace District Heating Valves	9,000	97,000	1,940	107,940
Replacement of Industry Steam Distribution Piping	45,000	735,000	14,700	794,700
TOTAL DISTRICT HEATING WORK	**1,827,000**	**22,281,000**	**445,620**	**24,553,620**
SUBTOTAL	**7,103,400**	**73,128,000**	**1,396,960**	**81,628,360**
Freight				5,713,985
Contingency (10%)				8,162,836
TOTAL COST OF REHABILITATION				**95,505,181**

NOTES:

(1) ALL COSTS ARE SHOWN IN JANUARY 1996 DOLLARS
(2) PRICING DOES NOT INCLUDE A NEW STACK
(3) PRICING DOES NOT INCLUDE ASH STORAGE POND SYSTEM & FISH PROTECTION SYSTEM
(4) PRICING DOES NOT INCLUDE A NEW TURBINE. THE TURBINE IS ALREADY DELIVERED AND IN STORAGE AT THE PLANT SITE

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

DIRECT COSTS FROM PREVIOUS PAGE				**95,505,181**
Engineering Costs				4,897,702
Construction Management Costs				2,448,851
Start-Up Costs				1,632,567
Construction Equipment Costs				1,750,000
Interest During Construction				7,640,414
Escalation				9,109,977
TOTAL COST INCLUDING THE ITEMS ABOVE				**122,984,693**

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, and instrumentation and controls, nor does it include time required for procurement of the new equipment such as new instruments and controls, or the time required for the NDE of boiler pressure parts.

CONSTRUCTION SCHEDULE FOR [illegible]E UST KAMENOGORSK LINE NO. 7

Tasks	Month 1	Month 2	Month 3	Month 4	Month 5	Month 6	Month 7	Month 8
BOILER WORK (BOILER NO. 16)								
Install New Boiler and Associated Equipment								
Install New Mills and Associated Equipment								
TURBINE GENERATOR (TURBINE NO. 12)								
Install New Turbine/Generator and Auxiliaries								
AUXILIARY PLANT SYSTEM								
Install New Associated Feedwater Heater System								
Install New DH Interconnection Piping, Valves, and Components								
Install New Associated Condensate Piping and Valves								
ENVIRONMENTAL								
Install New Scrubber System (Boiler No. 16)								
INSTRUMENTATION								
Install Emissions and Air Flow Monitoring Equipment								
Install Boiler and Turbine Monitoring Equipment								
DISTRICT HEATING SYSTEM								
Repair and/or Replace Deteriorated Piping Sections								
Install New District Heating Pumps								
Install New Instruments and Control System (SCADA)								
STARTUP AND CHECKOUT								

CONSTRUCTION SCHEDULE FOR THE UST KAMENOGORSK LINE NO. 7