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ENERGY EFFICIENCY AUDIT REPORT

BUDAPEST CHEMICAL WORKS

Illatos Budapesti Vegyimüvek
Budapest, Hungary

MARCH 1992

PREPARED BY: RCG/HAGLER, BAILLY, INC.
Arlington, Virginia

and

EGI CONTRACTING & ENGINEERING
Budapest, Hungary

U.S. EMERGENCY ENERGY PROGRAM FOR EASTERN AND CENTRAL EUROPE

U.S. AGENCY FOR INTERNATIONAL DEVELOPMENT
BUREAU FOR EUROPE
WASHINGTON, D.C. 20523

USAID Contract EUR-0015-C-1007-00

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QUALITY ASSURANCE

The contents of this report include recommendations based on data provided by the client plant, measurements made on site, calculations, and engineering judgment. The conclusions reached were based on a limited engagement of only about one week's duration in the plant, and are not the product of an exhaustive engineering analysis. RCG/Hagler, Bailly, Inc. certifies that this report conforms to the level of best commercial practice for industrial energy audits of similar level of effort, as conducted in the United States. This report has been prepared under the guidance of a registered Professional Engineer, licensed to practice in the United States.

ACKNOWLEDGEMENT

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EXECUTIVE SUMMARY

This report presents the results of a preliminary energy audit carried out by a team of engineers from RCG/Hagler, Bailly, Inc. and EGI Contracting and Engineering - Institute for Energetics. The audit was conducted between April 11 and April 19, 1991 at Illatos Budapesti Vegyimüvek (Illatos) in Budapest, Hungary. For this assignment, RCG/Hagler, Bailly provided a complete set of portable instruments to conduct on-site measurements, and EGI provided all logistic support, including meeting arrangements and translation services.

Given the scope of the assignment and the resources available, the team decided to focus the audit on the sectors and areas that Illatos plant management considered as priorities. Thus, extensive efforts were devoted to ensuring that visible results could be realized in the short term in each area of focus. The approach and methodology used were adapted to provide continuous training of the audit team's counterparts in the plant. In addition to the focus areas, the team covered all activities and analyses that are part of a standard preliminary audit.

The energy audit focused on two areas: the energy efficiency of the boilerhouse and energy management improvement.

In 1990, the energy purchased by Illatos totalled 47,000 tones of oil equivalent, expressed as primary energy. Electricity use comprised 87 percent of this primary energy demand; the remaining 13 percent was natural gas use. If that energy was to be imported to Hungary at the international market price ($20 per barrel of oil), it would cost the Hungarian economy about $6.6 million in hard currency. At the March 1991 price of energy, the actual energy bill paid by this plant was 473,000,000 Forints.

The potential for energy savings is at least 15 percent of the gas energy use in the boilerhouse, and 15-20 percent of the steam energy demand in the process area and associated buildings. The potential electric energy savings in the latter area is at least 3 percent. This is equivalent to an annual savings of 20,000,000 Forints ($290,000).

The next page presents a list of the energy efficiency equipment that could be procured for this plant, according to the action recommendations listed in Chapter 3.

Equipment that Could be Procured by USAID as Part of the Energy Efficiency Program

Action ID	Equipment	Cost (US$)	Total Energy Cost Savings (US$/year)
A.1	Steam Meters	25,000	131,000
A.2	Flue Gas Analyzer	4,000	48,000
	Total		179,000

Illatos Budapesti Vegyimüvek is a chemical plant that produces a large number of halogenated products that are used as pesticides, herbicides, and pharmaceuticals. The major halogen used in the plant is chlorine, which is produced by the electrolysis of brine. The plant purchases active organic ingredients to be halogenated.

Illatos is part of a trust consisting of three plants. The other plants produce hide and bone glue (at Hidos, 200 km from Budapest, and elsewhere). The Illatos plant is the largest energy user of three because of its electrolysis operations. It employs about 600 workers.

The products produced by the plant can be considered high value-added products that yield viable profit margins. The plant's strategy is to develop the higher value-added segments of its production slate and to adapt to market conditions. The R&D Department plays a central role in that strategy. The plant has three subsections: synthesis of new molecules of pesticides and herbicides, screening of new biological molecules, and formulation of pesticides. The plant develops 5 to 10 new products each year.

1.1 PLANT PROCESS AREAS

Electrolysis of Brine

The Illatos plant is equipped with mercury electrolysis cell technology. This older technology has been supplanted by more electricity-efficient technologies such as diaphragm cells and more recently, membrane cells. However, it is not usually financially attractive to switch technologies simply for the electricity savings. This is because many improvements have been achieved in mercury cell technology, including the introduction of titanium anodes to replace graphite anodes, and the automatic control of the distance between the anode and the cathode. The Illatos plant has substituted its titanium anodes with graphite anodes, but has not adopted automatic distance control modifications, which it does not consider to be profitable.

The other process areas of the Illatos plant are:

- side chain chlorination
- side chain fluorination

- nitration plant
- reduction/hydrogenation
- analine dissociation.

Utility Section

Illatos has a large boilerhouse, which consists of two high-pressure fuel gas-fired boilers (20 t/h each) and one medium-pressure package boiler (12 t/h). A pressure reducing and desuperheating station brings the high-pressure steam to the necessary pressure and temperature. The boilerhouse formerly expanded steam in a turboalternator, but this piece of equipment was removed long ago. It was replaced with a diesel generator, and an automatic start-up system was installed for safety.

The utility section also includes:

- a demineralization station, which produces desalinated water for the boilerhouse and process areas
- two large Atlas Copco air compressors
- a closed-loop cooling water system provided with water pumps and cooling towers (one forced-draft block over a pond and two concrete hyperbolic shaped natural draft towers).

1.2 PLANT MANAGEMENT AND STAFF

The plant is managed by a general manager. Under the general manager are three main directorates: the Technical/Production Division, the Commercial Division, and the Financial/Administrative Division.

The Technical/Production Division has the following departments:

- New Investment Department
- Energy Department
- Production Department
- Safety Department
- Hidos Department (other plants)
- Maintenance Department.

1.3 ENERGY USAGE AND HISTORICAL DATA ANALYSIS

According to Illatos plant management, the plant's use of energy accounts for 11 percent of its production costs, at current prices. This relatively high percentage provides adequate

justification for making energy conservation a priority at the plant.

Historical data on energy use were provided on total energy consumption for 1990. The total primary energy use at the Illatos plant was 47,400 tones of oil equivalent in 1990. This primary energy use was computed by RCG/Hagler, Bailly using the following conversion factors, which represent the average efficiency of energy conversion equipment in Hungary. (For example, the electricity conversion factor includes the efficiency of the fuel-fired power plant plus auxiliary, transportation, and distribution losses.)

Energy	Unit	kg of Oil Equivalent
Electricity	kWh	0
Natural Gas	GJ	23.92
Steam/Hot Water	GJ	28.15
Compressed Air	000Nm^3	47.31

The following table shows the breakdown of primary energy use:

	Tons of Oil Equivalent	Percent of Total Energy
Total Primary Energy Use	47,400	100
Fuel Gas	6,300	13
Electricity	41,100	87

As can be seen from the above table, electricity is the largest energy user at the Illatos plant, consuming 87 percent of its primary energy. Of this amount, 71 percent is used for the electrolysis of brine to produce chlorine.

This primary energy use accounts for both activities of the Illatos plant: pesticides production on the one side and heat supply activity on the other. The following table gives a breakdown of heat use at this plant.

	GJ/Year	Percent

Total Heat/Steam Generated
Self Consumption of Boilerhouse
Process Energy Use
Sale of Steam

Based on 1990 energy consumption records and the March 1991 energy price, the plant's energy bill (including electricity and gas) is estimated at 473,000,000 Forint.

	Million Ft./year	% of Total Cost
Purchased Energy Cost	473	100
Electricity Costs	391	83
Demand Charge (Fixed)	92	
Energy Charge (Variable)	299	
Gas Costs	81	17
Demand Charge (Fixed)	12	
Energy Charge (Variable)	69	

Note: Numbers do not add due to rounding.

The recommendations made for improving the energy efficiency of the Illatos plant fall into three categories. Within each of these categories are a number of recommended actions that can be taken, which are noted here and described in detail in Chapter 3.

2.1 ENERGY MANAGEMENT IMPROVEMENT

These actions have been emphasized by Illatos management as a priority in a fast changing economic environment. The actions which fall into this category are coded by an "A." Illatos should be able to implement these in the next six months, with assistance from USAID's Emergency Energy Program.

Assessment of the Existing Energy Management System

The energy management system currently in place at Illatos suffers from the absence of metering of the many utilities throughout the plant. Energy management at the plant is currently limited to a cost allocation exercise for the purpose of invoicing. This exercise is based on standard coefficients that are applied to energy measurements at the point of entry to the plant.

For example, there is no steam metering throughout the plant, although the Energy Department is producing a very detailed steam balance. This steam balance is entirely calculated from natural gas consumption in boilers, which is converted into steam using a standard steam-to-fuel ratio (thus assuming a constant efficiency of the boilers), which is then broken down into the various users based on standard steam intensity factors.

Production is based on plans, and plant management exercises control over the process to see that each plan is carried out. These plans set performance targets, which are based on input and output quantities. For example, it is planned that the electrolysis plant should be operated at maximum capacity (i.e., 28,000 tons of chlorine a year).

Some data are collected on a monthly basis from the existing meters (basically, data on fuel gas, electricity, and water) and are processed by hand to produce a vast amount of figures, which are used to develop monthly reports. (Daily reports are also produced, but they are internal. In most cases, only the monthly reports are submitted to management.) The types of information

included in the reports are raw data, such as total gas consumption, total steam generation (calculated), total electricity consumption, total steam sales, etc. Ratios, performance indicators, and energy costs are not included in the monthly reports.
The way in which the costs of utilities are allocated to various process departments is not conducive to the practice of energy conservation. This is because such allocations are arbitrary and do not reflect the actual consumption of each product.

The monthly reports are primarily used to allocate the operating cost of a utility/Energy Department to the various end products. For this purpose, accurate allocations to each energy user are not required so long as the summation of all allocated costs represents the exact operating cost of the Energy Department. Thus, many estimations are made in the process of cost allocation.

We observed that this cost allocating process is quite far from a valuable energy management system that would address the plant's energy inefficiencies. It is thus recommended that the chemical plant develop a real energy management system based on meter readings. Such a system would provide input to the plant's cost allocation system.

Our assessment of energy management at Illatos is summarized below.

Energy Demand Management. Energy demand management focuses on the use of energy by the process departments as a function of production throughput, status of operation, various operating parameters, and other parameters not related to process operations. We observe that:

- There is a nascent energy demand system at the plant, which consists of surveying the plant's electrical demand using a desktop micro computer and data acquisition software.

- There is no energy demand management procedure at Illatos, as employed in Western market-oriented companies.

- For accounting purposes, the plant uses a cost allocation method based on standard energy intensities. This method is not accurate enough for energy management or for cost allocation in a market- or competition-oriented economy.

Energy Supply Management. Energy supply management focuses on the operations of the boilerhouse, which is in charge of supplying energy in various forms to inside and outside users, purchasing for this purpose natural gas, electric power, and water. We observe that:

- There is a lack of accurate energy and mass balance, especially for steam, condensate, compressed air, and water.
- No regular efficiency analyses are performed on such critical equipment as boilers.
- No cost calculations are regularly made on the utilities supplied by the boilerhouse.
- Energy Department reports are prepared manually.

Consequences of the Absence of Energy Management. The consequences of lacking a real energy management procedure are the following:

- High variability of energy consumption is indicated for a given level of production. To provide control of a process operation, energy is usually released in specific equipment provided with on/off valves for energy flow and a control device that limits the energy flow to the amount necessary to process operations.

  In the absence of real pressure to control the quantity of energy used, situations can arise where energy using equipment, on/off valves, or control devices are in poor condition, but still permit the process to operate, albeit at a higher energy cost. For example, the fouling of a steam heat exchanger can be overcome by increasing the steam pressure (therefore reducing its efficiency) at the end-use equipment. Likewise, the poor condition of an on/off steam valve will lead the operator to keep it on (therefore increasing losses), and the failure of the control device will lead to the over-consumption of energy.

- Maximization of plant safety and reliability occurs to the detriment of energy consumption. In the absence of real pressure to minimize the quantity of energy used for a given operation, there is a natural tendency of plant operators to maximize operational safety and

reliability. In other words, operators minimize potential problems, including operation supervision from management, by tuning up the equipment towards a higher energy intensity condition. The difference between actual energy use and the minimum theoretical energy use is known as the necessary "safety margin." At the Illatos plant, there is no real control or limitation of this safety margin. For example, negative pressure is necessary inside the brickwall boilers to avoid any ejection of hot flue gas through the holes of the brickwall, which could cause a fire hazard to both personnel and surrounding equipment. Thus, if there is no pressure to reduce the draft inside the boiler to a minimum safe level, the boiler operator will feel more secure with a level of draft that is higher than the optimum from an energy management point of view, consistent with safe operations.

Recommendations

Action A.1	Institute an Energy Management Information and Control System
Action A.2	Optimize Boiler Efficiency and Dispatch Boilers to Operate the Most Efficient Boilers in Priority Order
Action A.3	Institute a Steam Management Task Force
Action A.4	Try to Modulate Production to Reduce the Electrical Load During Peak Hours
Action A.5	Institute an Industrial Water Management Task Force

2.2 LOW-COST, SHORT-TERM ACTIONS

These actions constitute the second category in which USAID might be able to contribute under the Emergency Energy Program.

Recommendations

Action B.1	Return Condensate Straight to the Deaerator
Action B.2	Replace High-Pressure Feedwater Pumps

Action B.3	Install a Steam Pressure Control Valve on the Steam Line to the Feedwater Preheater and Deaerator

2.3 HIGH-COST OR LONG-TERM ACTIONS

These actions consist principally of technology improvement projects.

Recommendations

Action C.1	Revise the Existing Building Heating and Domestic Hot Water System
Action C.2	Improve the Instrument and Control Systems of Boilers
Action C.3	Install an Auxiliary Steam Turbine to Run a Cooling Water Pump
Action C.4	Install Cooling Water System Retrofit

ACTION A.1
INSTITUTE AN ENERGY MANAGEMENT INFORMATION AND CONTROL SYSTEM

1. PROCESS AREA

Plant management

2. RECOMMENDATIONS

Institute an energy management information and control system by implementing the following tasks:

- Install additional steam flow meters
- Install additional electric meters
- Treat the boilerhouse as a separate cost center
- Create an energy demand management procedure
- Create an energy supply management procedure
- Improve energy management reporting procedures
- Procure software and hardware to support the energy management improvement effort.

3. DESCRIPTION/RATIONALE

During the course of the audit, the authority of the energy manager came into question. The energy manager recognizes that he (and his team) have the capability to identify energy inefficiencies in the plant and to make recommendations for improvement. The plant's management is open to the idea that the energy manager needs some instruments (he has, for example, a power monitoring set and an ultrasonic flow meter) and needs outside support to investigate some specific problems (e.g., the ongoing study on the cooling water system). The problem, however, is in the implementation of his recommendations.

At best, some of his recommendations are included in the investment or maintenance budget for the following year, with little regard to the importance of the recommendation (some recommendations taken for the next year's budget may have a two-month payback). In this plant's budget allocation process, profitability ranks below the availability of money and the "equitable" distribution of funds to the various plant

departments. The perception of "equity" encompasses not only short-term profitability but also strategy.

At worst, some of the recommendations of the energy manager are not implemented at all. At this plant, the energy manager lacks the legitimate authority to force others (who do not respond to him) to implement his recommendations.

In the absence of a credible energy management system, the only way to get things done is to go through the legitimate channels of authority. However, it would be ineffective and even cause conflicts within the plant to reinforce the energy manager's authority in such a way. Thus, we recommend the institution of an energy management system, which will provide accurate and credible measures of inefficiencies, including cost inefficiencies.

Based on our experience, we believe that it is much more effective for the energy manager to reports inefficiencies using the reporting procedure embodied in an adeqate energy management system, than to directly increase his personal authority. In addition, the establishment of an energy management system is a prerequisite to any of the capital-intensive investments recommended as part of this energy audit report. To a great extent, it is much easier to procure energy conservation equipment (even if hard currency is in short supply) than having it installed properly and working efficiently (such as the automatic draft control on the BW1 boiler).

It is recommended that an energy management procedure be instituted according to the following guidelines:

Install Steam Meters Throughout the Plant to Measure Utilities' Consumption and Instruments to Report the Efficiency of Operations

To improve energy demand management in the plant, it is necessary to install steam meters in various locations:

- Boilerhouse (3 meters, 1 for each steam collector: 11b, 6b, 3b)
- Organic A plant (Building 63) : 2 meters (3b and 6b)
- Organic B plant (Building 57) : 2 meters (3b and 6b)
- Steam to the west part of the plant : 1 meter (3b)
- Steam to the south : 1 meter (3b)
- Steam to the east: 2 meters (3b and 6b)

Install Electric Meters to Monitor the Electricity Consumption of Various Production Departments

13 additional electricity meters were identified: 5 for the electrolysis department, 5 for the boilerhouse, and 3 for another busbar called the "japanese garden." For all these meters, current transformers already exist. Thus, the procurement of these meters would consist of the meter and the communication line to the existing power monitoring computerized system.

Treat the Boilerhouse as a Separate Cost Center

The boilerhouse should be treated as an entity or cost/profit center like the other process areas in the plant's accounts. Currently, the inefficiencies of the boilerhouse are hidden (or more precisely, diluted) by the existing energy cost allocation procedure. This is not because the Illatos plant's boilerhouse is very inefficient (its performance is within the average performance range of other boilerhouses that we visited in Hungary as part of this program). Rather, it is because everyone at the plant knows that the boilerhouse is potentially the main source of inefficiencies, as it is in any plant in the world.

The boilerhouse produces utilities such as steam, demineralized water, compressed air and cooling water. Like any process area, it is part of the boilerhouse management's responsibilities to calculate the price of utilities (based on the true operating cost), to measure the quantity of utilities produced, and to seek operating cost reductions through efficiency improvement. In many respects, the boilerhouse department should be held responsable for the price per unit of utilities, since it will reflect on the efficiency of operation at the boilerhouse. But the boilerhouse is not responsible for the quantity of utilities it has to supply to the process departments.

Create an Energy Demand Management Procedure

Once the utility meters are installed, each process unit should be subjected to a budget procedure specifying standards for energy use according to such criteria as:

- production throughput
- events such as start-up or shut-down procedures
- quality of raw material or finished product
- ambient temperature or seasonal variation
- availability of critical process equipment.

Each energy use will be a simple function of the determinant criteria: usually constant (e.g., x tons per day of steam in winter, y tons per day of steam in summer), proportional (e.g., energy = A x production), or linear (e.g., energy = A x production + B).

The establishment of such cost functions is one of the primary targets of an energy demand analysis:

- The energy cost function must be as close as possible to actual conditions; therefore, a statistical analysis may be useful as a first step (e.g., a regression analysis of energy use to various determinant factors).

- An analysis of the magnitude of each coefficient of the cost functions must be conducted to assess what kind of operating practices they reflect. For instance, in the case of poor efficiency and the absence of control, the constant coefficient will be high.

- The final energy cost function must be the result of discussions with the manager of each production section in the plant. The energy intensity must be realistic (i.e., achievable) and at the same time encourage efficient energy pratices. The production managers must agree on the cost function because the performance of their production sections will be evaluated by comparing the actual energy consumption with the value calculated using the energy cost function. The production managers will have to explain the differences. The purpose of these explanations is not a "personal justification"; rather, it is to determine the actions that must be taken (most often by the Maintenance Department) to reduce over-consumption.

  Data log sheets must be revised to include the key parameters which are listed in the energy cost functions. Energy consumption may be either metered or indirectly evaluated (through heat balances, for instance).

  The difference between actual and target consumption will be translated into Forint according to the marginal costs of utilities calculated by the Energy Department. The summation of all these differences will give an indication of the status of energy savings or over-consumption. This can be easily displayed as a trend graph.

Create an Energy Supply Management Procedure

The boilerhouse should be managed according to a simulation and optimization model similar to the one elaborated by RCG/Hagler, Bailly during the course of the audit (see Appendix B). This model links together the balance of various forms of energy such as fuel gas, steam, electricity and water. In addition, it calculates the efficiency of key equipment (e.g., boilers) and allows comparison with the expected efficiency. In many respects, operating limits, as experienced by plant operators, are as important as efficiency in the search for optimal operation. These actual operating limits must be compared with design operating limits.

Every year, the model can be used as support for negotiating the target performance of the boilerhouse to be incorporated in the next year's budget. For example, the boilers' efficiency will be determined by targets for temperature and excess air in stack gases.

The energy supply management model will calculate on a daily basis the marginal cost of steam and condensate and the total operating cost of the boilerhouse as well.

The first basis of energy management is the awareness by any energy user of the true cost of energy. Usually this true cost is defined on a marginal basis. The marginal cost of steam indicates how much energy is saved (or purchased) by the power plant if the end user reduces (or increases) its consumption by 1 unit (tonne/hr or GJ/hr). This marginal cost may vary with the configuration of the power plant. For example, when the Standard Kessel boiler is shut down, steam is more expensive.

A plant manager who knows the true cost of steam is in a better position to anticipate or delay steam use during a period when steam is expensive.

The energy model established by the audit team during the course of the audit calculates the marginal cost of steam (see Appendix B).

Improve Energy Management Reporting Procedures

Report 1: Monthly performance monitoring report. It is recommended that a monthly energy monitoring report be

prepared and submitted to the General Director. This report would show in a very simple way the status and trend of energy performance of the plant. This report should be only one page long, and would contain the following graphs:

- energy demand efficiency graph which displays the ratio of actual process energy demand to budgeted energy demand in process areas
- energy supply efficiency graph which displays the ratio of actual energy purchases to expected energy purchases (on a Forint basis)
- trend of the monthly energy purchases by the plant and net energy cost to the plant (energy purchased minus sales).

Report 2: Daily energy pricing report. The Energy Department should distribute to the Process Department a report indicating the price of utilities for the next week. It is expected that the process managers will modify their steam demand as a function of the price of steam. For example, the price of steam should increase if the condensates are not returned straight to the deaerator or if the Standard Kessel boiler is shut down for maintenance or because of high demand.

A daily report should be developed to compare energy to production for the key process areas, such as electrolysis and the boilerhouse. Only by tracking in the short run will management have the necessary information by which control actions can be taken. The steam meters required for these daily reports should be procured as part of this project.

Procure Software and Hardware to Support the Energy Management Improvement Effort

It is not recommended that full-time energy managers be appointed at the production department level. Once the energy demand management procedure is shaped, it can be operated by the existing cost control managers in each production department. In case of specific problems related to energy use, it is recommended that the production departments seek the assistance of the Energy Department.

A computer-based management information system should be installed to provide the information necessary for energy

management. This system must have hardware and software designed to calculate the necessary performance ratios and to present information to management in an easily understandable form. It was proven during the audit that adequate computer tools and state-of-the-art software permit the design of a valuable information and control system.

4. BENEFITS

Energy Savings

We estimate that an improved energy management system, together with specific management actions to control operational efficiency, can achieve energy savings of about 15 percent at the boilerhouse level and 15 to 20 percent at the process area level. The expected value of the energy savings is:

- gas - steam supply efficiency and management control to save 5 percent
  Forint 3.4 million per year ($48,000)
- electric: electricity management control to save 2 percent
  Forint 6 million per year ($83,000)
- total: Forint 9.4 million ($131,000) per year.

Other Benefits

Additional productivity benefits may result from the improved management control systems, but are not estimated in this report.

5. IMPLEMENTATION COSTS

Steam meters:	$25,000 for 5 sets of steam flow meters (USAID)
Electric meters:	$5,000 for 20 electric submeters (by Illatos)
Computer:	Already installed by Illatos
Computer programming:	By Illatos

Increased annual operations and maintenance costs: $20,000

Total estimated costs: $50,000

6. PAY BACK

Payback period (including investments by both USAID and Illatos) = capital cost/net annual cost savings

$50,000/($131,000 - $20,000) = 0.45 year

7. SCHEDULE

This action was agreed on for immediate implementation by the Plant Technical Director at the 4/26/91 meeting. Two components were identified to implement this action:

Component 1: Procurement of Additional Metering Equipment

Task 1 - completion date: April 29, 1991. Illatos prepares the specification of steam meters and submits them to EGI.

Task 2 - completion date: May 15, 1991. Illatos gets quotations from local suppliers. RCG/Hagler, Bailly gets quotations from U.S. manufacturers.

Task 3 - Completion date: May 30, 1991. Illatos reviews offers, finalizes specifications, and makes recommendation for the selection of a supplier.

Task 4 - Completion date: June 7, 1991. USAID gives clearance for equipment procurement based on RCG/Hagler, Bailly's financial and economic study and evaluation of quotations.

Task 5 - Completion date: June 8, 1991. RCG/Hagler, Bailly sends purchase orders for equipment.

Task 6 - completion date: August 1, 1991. Shipment of equipment arrives in Hungary. Illatos completes a flowsheet diagram displaying existing and new steam meters. Illatos prepares installation drawings of steam meters including supporting and linkage.

Task 7 - completion date: September 30, 1991. End of installation works by Illatos.

Task 8 - completion date: October 1, 1991. Daily readings of new steam meters reported in the energy management system. Monitoring of energy efficiency ratios such as steam supply to natural gas consumption.

Task 9 - completion date: April 1, 1992. Procurement and installation of other steam meters by Illatos. Pocurement and installation of electric meters.

Task 10 - completion date: September 15, 1992. Illatos assigns target values to steam consumption monitored by newly installed steam meters and monitors achievement as part of the energy management system.

Component 2: Design of the Energy Management System and Reports

Task 1 - completion date: May 15, 1991. Illatos defines a global energy efficiency performance index and begins monitoring its trends on a daily basis.

Task 2 - completion date: May 30, 1991. Illatos establishes a scope of work for a computerized energy management system based on RCG/Hagler, Bailly's recommendations. The scope of work will be broken down into functional areas and tasks.

Task 3 - completion date: June 15, 1991. Illatos receives proposals from local engineering service companies to implement the above scope of work.

Task 4 - completion date: June 30, 1991. Illatos reviews proposals, and assigns a service company to complete the scope of work according to work plan milestones and deadlines for deliveries.

Task 5 - completion date: August 30, 1991. The service company completes its work.

Task 6 - completion date: September 1, 1991. The first energy monitoring report (showing efficiency trends) is sent to upper management at the plant.

Task 7 - completion date: October 15, 1991. Illatos prepares its 1992 energy budget based on the new energy management system.

8. TECHNICAL RISK AND NEEDS

The technical level of plant staff is very high and is definitely not an obstacle to an improved energy management system. Plant staff have proven to be very receptive to the energy management concepts demonstrated during the course of the audit. Rather, the insufficiencies of the existing energy management system reflect more a problem of organization and equipment (hardware and software) than of technical capability of staff.

9. SPECIFICATION OF EQUIPMENT

Steam Meters

Mechanical Description

Flanges

Orifice plate
type round

Pressure differential transmitter

Steam pressure transmitter

Temperature transmitter

Circular chart recorder

number of pens	3 (flow, temperature, pressure)
disc speed	one round per day
scale	logarithmic scale for steam flow
installation	indoors
access to disc	door with window
extreme ambient temperature	-5°C to +50°C
power available	220 V 50Hz

Accessories
steam traps
temperature indicator
steam pressure indicator

Equipment procured by the plant
calibrated steam pipes (2x3m)
supporting

Boiler BW1

Normal Operating Conditions			
normal pressure	bar g		22
normal temperature	°C	390	
normal flow	t/h	7 - 17	
Dimension			
size of steam pipe	mm	125	
standard	DIN		

Boiler BW2

Normal Operating Conditions			
normal pressure	bar g		22
normal temperature	°C	390	
normal flow	t/h	7 - 17	
Dimension			
size of steam pipe	mm	125	
standard	DIN		

Boiler Standard Kessel

Normal Operating Conditions			
normal pressure	bar g		11
normal temperature	°C	240	
normal flow	t/h	4 - 12	
Dimension			
size of steam pipe	mm	150	
standard			DIN

11b Steam Outside the Boilerhouse

Normal Operating Conditions			
normal pressure	bar g		10
normal temperature	°C	270	
normal flow	t/h		0.2 - 1.5
Dimension			
size of steam pipe	mm	65	
standard			DIN

6b steam outside the boilerhouse

Normal Operating Conditions		
normal pressure	bg	6

normal temperature	°C	210
normal flow	t/h	2 - 7

Dimension

size of steam pipe	mm	200
standard		DIN

3b steam outside the boilerhouse

Normal Operating Conditions

normal pressure	bg	3
normal temperature	°C	200
normal flow	t/h	6 - 19

Dimension

size of steam pipe	mm	250
standard		DIN

ACTION A.2
OPTIMIZE BOILER EFFICIENCY AND DISPATCH BOILERS TO OPERATE THE MOST EFFICIENT BOILERS IN PRIORITY ORDER

1. PROCESS AREA

Boilerhouse

2. RECOMMENDATIONS

Tune up boiler efficiency and dispatch boilers to operate the more efficient boilers in priority order.

- Install an automatic draft control system on boiler BW 1 and have it in operation as soon as possible.
- Modify the setting of the low draft pressure switch to allow further optimization of the boiler. There should be at least two switches, one for the alarm and one for the safety shut-down of the burner. Shut-down should occur only if the pressure is 0 mm WG.
- Obdurate the viewing ports on boiler access doors (top of the boiler) and sample tube (air preheater exit).
- Add a column to the BW boilers' data log sheets for the pressure at the top of the furnace.
- Switch as soon as possible to the Standard Kessel boiler and modulate the steam demand by decreasing the pressure to 3 bar steam.
- Purchase a portable combustion gas analyzer to monitor excess air at the outlet of the boilers, and therefore, the overall efficiency of boilers (BW1, BW2, Standard Kessel).
- Add three columns to the BW boilers' log sheet: O_2 in % at the top of the furnace, CO in ppm at the top of the furnace, and O_2 in % at the exit of the air preheater.
- Add two columns to the Standard Kessel log sheet: O_2 in % and CO in % at the exit of the boiler.

3. DESCRIPTION/RATIONALE

There are three boilers in the boilerhouse:

- Boilers BW 1 and 2, which are old watertube boilers. These two boilers are identical. Only boiler No. 1 was operated and tested during the audit. These boilers were formerly 40b steam, coal-fired boilers, which have been converted to natural gas firing and 20b steam. These boilers are brickwalled and the pressure of combustion gas inside the boiler is negative. The boilers' maximum steam production is 20 t/h.

- A Standard Kessel boiler, which is a recently added 11b steam-fired tube package boiler. The pressure of the combustion gas is positive inside the boiler. This boiler was not operated at the time the audit was conducted, but it was started-up for the purpose of testing during the audit. Its maximum steam production is 12 t/h.

The audit produced the following findings:

- Boiler BW 1's efficiency was found to be 75% as a result of high excess air at the burner and air infiltration through the boiler. After the excess air was reduced at the burner and the draft inside the boiler was reduced, efficiency was brought up to 82%.

- The Standard Kessel boiler's efficiency was found to be 89%. Combustion excess air was tuned-up from 30% to 17%, with little impact on the efficiency of the boiler.

- Although the steam load would have permitted the operation of the Standard Kessel boiler (11 t/h demand for a maximum of 12 t/h), the boiler manager prefered to operate boiler BW 1 because he feared that a higher steam load would occur at night due to cold outside temperatures and possible precipitation.

- During the tune-up of boiler BW 1, the boiler tripped out several times because the low-pressure switch at the combustion gas set-up was set at a far too conservative set-point. The pressure of the combustion gas, which was found to be -23 mm WG at the top of furnace, was brought down to -10 mm WG by manually closing the flue gas damper at the end of the boiler. The audit team tried to reach a targeted -3 mm WG, but the boiler tripped out beyond -5 mm WG. The team concluded that because of a safety pressure switch,

this boiler could not be operated with a draft less than -10 mm WG at the top of the furnace. One day after the boiler tune-up, the flue gas damper at the end of the boiler was again found in a 100% open position, and the draft at the top of the boiler was back to -23 mm WG.

- Air infiltration is aggravated by the absence of an obturator on the viewing ports located on the access doors at the top of the boiler (at least three ports of 7 cm diameter).

The audit team reached the following conclusions:

- There is room for optimizing boiler BW 1's operating conditions with a possible reduction of 10% of gas consumption, as demonstrated during the audit.

- At the time of the audit, the Standard Kessel boiler was using 19% less gas than the BW 1 boiler for the same steam load. Even after tune-up, the Standard Kessel boiler was still using 9% less steam than boiler BW 1.

4. BENEFITS

Based on measurements conducted during the audit, the boilers' efficiencies were calculated by the audit team. The results are:

	overall thermal efficiency (%)	best boiler base 100	natural gas to steam ratio (GJ/ton)[1]
Boiler BW1			
before tune-up			
after tune-up			
Standard Kessel Boiler			

It was found that boiler 1 uses 10% more gas than boiler 3 for the same steam load (at identical enthalpys). Boiler 2 uses 5% more gas than boiler 3. Therefore, the Standard Kessel boiler

[1] Note: Enthalpy of steam is different for each boiler.

must be used in priority.

Total savings is 5% of annual gas consumption (Ft. 3.5 million, or $48,000).

5. IMPLEMENTATION COST

Equipment	Quantity	Unit Cost (Ft)
portable electronic combustion gas analyzer	1	

Total cost is estimated at $4,000.

6. PAY BACK

$4,000/$48,000/year = 1 month.

7. SCHEDULE

This action was approved by the plant's general manager at the 28/3/91 meeting for immediate implementation.

Task 1 - Completion Date: April 30, 1991

The Maintenance Department of Illatos puts the automatic draft control system of boiler BW 1 back into operation. This deadline was set by plant management.

The Maintenance Department obturates the viewing port on the access doors located on the boiler walls.

Task 2 - Completion Date: May 2, 1990

The Energy Department together with boilerhouse staff conducts tests on boiler BW 1 to reduce the draft, adjust the set point of the high-pressure security switch, and adjust the excess air at the burner. A column will be added to the boiler data logsheet to report the pressure of the flue gas at the top of the firebox.

The tune-up of excess air will be conducted by using the existing portable chemical analyzer (ORSAT).

Task 3 - Completion Date: May 10, 1991

Based on the audit report findings, assign the Standard Kessel boiler as the only boiler to be allowed to be in operation for the rest of the summer season.

Create a steam management team to analyze steam demand and recommend steps to keep steam demand below the Standard Kessel boiler's capacity during the summer season.

Task 4 - Completion Date: May 1, 1991

RCG/Hagler, Bailly prepares the specifications for a portable gas analyzer.

Task 5 - Completion Date: May 10, 1991

RCG/Hagler, Bailly obtains quotations from U.S. manufacturers (e.g., ENERAC, NEOTRONICS).

Task 6 - Completion Date: May 14, 1991

Illatos reviews offers, finalizes specifications, and makes recommendations for the selection of a manufacturer.

Task 7 - Completion Date: May 20, 1991

USAID gives clearance for equipment procurement based on RCG/Hagler, Bailly's financial and economic study and evaluation of quotations.

Task 8 - Completion Date: May 21, 1991

RCG/Hagler, Bailly sends purchase orders for equipment.

Task 9 - Completion Date: June 15, 1991

Shipment of equipment arrives in Hungary.

Illatos completes an operating procedure for the use of the portable gas analyzer, including where should it be stored, who

would use it, frequency of use, etc.

Task 10 - Complstion Date: July 1, 1991

Daily readings from the portable oxygen analyzer are reported on boiler data log sheets and processed by the Energy Department to monitor the efficiency of the boiler and combustion excess air.

Task 11 - Completion Date: September 1, 1991

Illatos assigns targets for boiler efficiency and combustion excess air, and monitors their achievement as part of the energy management system.

8. TECHNICAL RISK AND NEEDS

To avoid any disruption in the daily combustion gas monitoring procedure, the use of the existing chemical ORSAT gas analyzer as a back-up is recommended in the event of a failure of the electrochemical analyzer.

9. BACK-UP DATA AND CALCUALTIONS

10. SPECIFICATION OF EQUIPMENT

Electrochemical Portable Gas Analyzer

Physical description

case	ensure protection against chalk and dust
probe	high temperature probe

Electrical

battery	6V, rechargeable, quick recharge
AC	220V 50Hz

Display

LCD with backlight

Measured Parameters

Ambient temperature	0-150°C
Stack temperature	0-1100°C
Oxygen sensor	0-25%, electrochemical cell, life > 1 year
Nitrogen oxide	0-2000 ppm, electrochemical cell, life > 2 years
Carbon monoxide	0-2000 ppm, electrochemical cell, life > 2 years
Combustion gases	0-2.5%, semiconductor sensor, life > 5 years
Draft	piezoresistive sensor

Computed parameters

Excess air
Combustion efficiency
Carbon dioxide
Emissions (CO, NOx)

Printer

built-in thermal printer with form feed and line feed buttons

Miscellaneous

Fuels	3 or more fuels in memory + custom fuel
Messages	diagnostic and help messages in English
Calibration	Optional autozero on start-up

Parts

Oxygen Cell
CO Cell
Paper for Printer

ACTION A.3
INSTITUTE A STEAM MANAGEMENT TASK FORCE

1. PROCESS AREA

Energy Department

2. RECOMMENDATIONS

Institute a steam management task force that will investigate steam losses and establish an action plan and budget estimate which will address at least the following issues:

- rationalization of steam lines
- steam trap improvement and steam leak reduction
- insulation improvement of steam lines

3. DESCRIPTION/RATIONALE

Given the absence of steam metering, it is quite difficult to investigate steam consumption throughout the plant. However, it was possible to characterize seasonal variations in steam demand from monthly statistics:

- Steam demand may vary from 4 t/h in summer up to 20 t/h in winter for the same process load, based on an average 12 tons of steam by 1000 Nm3 of gas.

- Obviously, the peak demands in December and January are related to anti-freezing steam demand, which accounts for a 5 to 6 t/h demand at the boiler point.

- It is clear that building heating takes a large share of steam demand during the heating season, which spans from late October until mid-April. Building heating accounts for about 6 t/h of steam during the heating season (at the boiler point).

- Steam sales to the meat rendering plant may vary from 1 to 2 t/h, with an average of 1.5 t/h.

- The rest of the steam demand is attributed to process demand and steam losses throughout the plant. This demand may vary from 2.5 t/h in summer up to 6 t/h in winter. Looking at the plant activity over the year, there is not much reason for such a variation in process steam demand. This means that the actual process steam demand is probably constant. Therefore, the variation in steam demand is an effect of variable losses and the boiler's efficiency.

For example, the apparent low steam demand in summer (June, July) can be explained by the operation of the highly efficient Standard Kessel boiler instead of boiler BW 1. The Standard Kessel boiler produces roughly 25 percent more steam than the BW 1 boiler for the same amount of natural gas. Therefore, the actual process + loss steam demand varies from 3.2 t/h in summer to 6 t/h in winter.

Steam losses may vary as a function of ambient temperature, and to a much larger extent as a function of rain. It is clear that during the dry season (June, July), steam losses are minimal.

As a result, steam loss is assumed to vary between 0.5 t/h and 3 t/h. Actual process steam demand is around 3 t/h.

Rationalization of Steam Lines

The steam distribution system throughout the plant is aging and was designed when the chemical plant had a turbogenerator. Thus, the plant was interested in expanding steam through the generator to the lowest pressure requested by the end-user in order to maximize power generation. Since that time, the turbogenerator has been removed and the chemical plant continues to expand steam in the boilerhouse through letdown valves to supply the end-users with 3b, 6b and 11b steam. Therefore, many end-users receive three lines of steam (3b, 6b, 11b) or two lines (3b and 6b). In addition, it was found that each line is largely over-sized. This increases heat losses by a factor of 2 to 3.

As long as process steam demand is in the range of 3 t/h (see above), there is no way that a turboalternator will be economically profitable. Therefore, it is recommended that the chemical plant rationalize its steam lines by supplying 3b steam through the 6b steam collectors and having it expanded at the user point. The existing 3b line would be dismantled.

The chemical plant has already taken steps in that direction by retiring the 6b line to the west of the plant (only the 3b line

is in operation).

It is recommended that the 3b line supplying the east part of the plant be retired. Total line length is about 550 m, with an average nominal diameter of 80 mm.

Steam Line Insulation Retrofit

There are around 3000 meters of steam lines in the plant, with an average diameter of 80 mm. Those steam lines are running on pipe racks supported by massive concrete frames and are easy to examine. A quick survey shows that the existing insulation is in poor condition: many pipes are insulated with 60 mm thick mineral rock ropes rolled around pipes and covered with a bituminous (black color) jacket. In many places, the jacket has disappeared or is open, allowing water to pass through. Insulation ropes are loose and hanging. The residual efficiency of insulation is about 10 percent of the insulation property of a new well design insulation lagging. About 15 percent of the steam pipes are simply uninsulated. As a result, despite the high superheat temperature of steam at the boiler house, steam is delivered in saturated condition at the user point.

Condensate pipe insulation is so poor that there are reports of freezing pipes in winter. The engineering design of the steam lines is inadequate: a minimum distance between the pipes and supports (over slippers) is not respected, which makes it difficult to achieve a good insulation. The combination of intermittently used pipes (such as 11b) and poor insulation aggravates the corrosion problem with water infiltration.

From a financial point of view, it is not profitable to retrofit decaying insulation, even with a 10 percent residual efficiency. Therefore, it is recommended that the plant focus its insulation retrofit on uninsulated sections and on intermittently used pipes (such as 11b steam lines and cold temperature steam traced line).

Steam Trap Improvement and Steam Leak Reduction

The Illatos chemical plant has around 300 steam traps, about 50 percent of which are DN 15, 30 percent DN 20, and 20 percent DN 25. All of these steam traps are thermostatic membrane traps made by GESTRA, a West German manufacturer.

Our experience is that the technology of membrane steam traps has been very difficult to master, although the concept of this trap is quite old (many discouraged Western companies have prohibited

membrane and bellow steam traps). However, this type of trap has now proven to be efficient and reliable when conditions are favorable.

The presence of sediments and rust in the condensate is an adverse condition for this trap: the obturator of the trap is a ball attached to the membrane which has a very short displacement when the membrane contracts. Therefore, particulates may be caught between the ball and seat, thus creating higher forces to close the trap and damaging the contact surface between the ball and seat. Ultimately, the trap will leak permanently and the membrane will be destroyed under the effect of high temperature.

The manufacturer has overcome this problem by recommending the replacement of the membranes after a period of time. The chemical plant acknowledges that a campaign of membrane replacement (every two years) has a significant impact on its gas consumption (about 10 percent savings), but complains about the high cost of membrane, which must be paid for in hard currency.

We agreed with the plant energy manager that all traps installed on 6b and 11b steam line should be replaced by stainless built-in inverted bucket traps, which present less problems on sediment-charged condensates.

For the steam traps installed on 3b steam lines, most applications are for space heating and steam tracing (anti-freezing). For this application, it was found that specially designed membrane traps discharge condensates at a temperature well below the saturated temperature ("undercooling" trap). This is an energy saving feature that only thermostatic traps can offer (such as membrane traps). Therefore, it is recommended to keep that kind of trap and maintain them regularly.

4. BENEFITS

Energy Savings

Annual benefits of 5 percent of gas costs are estimated (Ft. 3.4 million, $48,000 per year).

5. IMPLEMENTATION COSTS

Approximately 250 inverted bucket steam traps at $120 each = $30,000.

Approximately 1,200 meters of insulation at $30 per meter = $36,000.

Insallation costs = $30,000.

Total = $96,000.

6. PAY-BACK

$96,000/$48,000/year = 2 years.

7. SCHEDULE

8. TECHNICAL RISK AND REFERENCE

9. BACK-UP DATA AND CALCULATION

ACTION A.4
TRY TO MODULATE PRODUCTION TO REDUCE THE ELECTRICAL LOAD DURING PEAK HOURS

1. PROCESS AREA

Boilerhouse

2. RECOMMENDATIONS

Optimize electricity consumption:

- Try to modulate production to reduce the electrical load during peak hours.

3. DESCRIPTION/RATIONALE

In a chlorine production plant, electricity is by far the major production cost item, and has a critical impact on the production economy (competitiveness) and level of profit.

Therefore, everything should be done to optimize electricity consumption.

4. BENEFITS

Most electrical energy is used in the electrolysis process, which is judged to be under proper control at this plant. It may be possible to reduce electrical energy costs by 5 percent by using a computerized electrical demand system. This would save Ft. 20 million per year ($270,000).

5. IMPLEMENTATION COST

The total cost of a system is estimated at $500,000.

6. PAY BACK

The payback is a little less than two years.

7. PLANNING

8. TECHNICAL RISK AND REFERENCE

9. BACK-UP DATA AND CALCULATION

ACTION A.5
INSTITUTE AN INDUSTRIAL WATER MANAGEMENT TASK FORCE

1. PROCESS AREA

Boilerhouse

2. RECOMMENDATIONS

Institute an industrial water management task force to reduce losses in the plant.

3. DESCRIPTION/RATIONALE

4. BENEFITS

Energy savings

Other benefits

5. IMPLEMENTATION COST

List of equipment	number	unit cost (Ft)

Total cost is estimated at

6. PAY BACK

7. PLANNING

8. TECHNICAL RISK AND REFERENCE

9. BACK-UP DATA AND CALCULATION

ACTION B.1
RETURN CONDENSATE STRATIGH TO THE DEAERATOR

1. PROCESS AREA

Boilerhouse

2. RECOMMENDATION

Open valves so that condensate is returned straight to the deaerator instead of to the water treatment system, thus making use of the heat of the condensate.

3. DESCRIPTION/RATIONALE

Because of the plant management's fear of pollution, all of the condensate returns (including condensate generated in the boilerhouse) are reprocessed in the demineralization station, thus wasting the heat content.

Currently, all condensate flows are directed to an insulated condensate tank located in the basement of the boilerhouse. The average temperature is 80°C. A water level control system triggers a condensate pump. Condensate may be directed to the deaerator (upper level of the boilerhouse) through an existing uninsulated 2" pipe. Condensate may be also directed outside the boilerhouse to the water treatment plant. Currently, the valve to the deaerator is closed and the valve to the water treatment plant is open.

The water treatment plant's laboratory regularly checks the quality of the condensate in the condensate tank through a sample valve. At the time this audit was conducted, condensate was not polluted and could have been directed to the deaerator.

It was reported that one condensate tank in the process area was polluted by benzene a few months prior to the audit. There is also a risk of condensate pollution by raw water at the level of the space heating heat exchanger and the domestic hot water heat exchanger since the pressure of water is usually higher than the pressure of steam.

Several options were envisioned:

- identification of sewage in polluted condensate at the production point

- segregation of condensate generated in the process area (polluted) from condensate generated in the boilerhouse (unpolluted) and direct return of condensate generated in the boilerhouse to the deaerator

- automatic monitoring of condensate quality (using an electrode measuring the resistivity of water) in the boilerhouse tank, which would command automatic valves to the deaerator and to the water treatment plant.

Given the low probability of condensate pollution, this last option is recommended for action.

4. BENEFITS

Energy savings of 3 percent of gas consumption are estimated from this last measure (Ft. 2 million per year, $28,000).

5. IMPLEMENTATION COST

None.

6. PAY BACK

Immediate

7. TECHNICAL RISK AND REFERENCE

This project has not been implemented because of technical risk. However, we do not believe that the risk to the boiler is large enough (the penalty for bringing in poor quality water) to warrant the energy waste that now occurs. The fact that the laboratory runs a full test of water quality during each shift should limit the potential risk to only eight hours of operation. Thus, the risk is very small, and worth taking to save such a significant amount of money.

ACTION B.2
REPLACE HIGH-PRESSURE FEEDWATER PUMPS

1. PROCESS AREA

Boilerhouse

2. RECOMMENDATION

Replace high-pressure boiler feed water pumps.

3. DESCRIPTION/RATIONALE

The feedwater pumps, which feed water to the high-pressure BW boilers, are aging oversized and costly from the viewpoints of both maintenance and energy.

Currently, there are three pumps of 60 kW each that are driven by 90 kW electric motors. Each pump has a nominal capacity of 29 m3/h, which is excessive given their steam production and an efficiency of around 50 percent. In addition, the pressure control system at the discharge side of the pump is based on three-way valves with return of the recirculated water straight to the deaerator.

The Illatos plant has already received a quotation for new feedwater pumps with a capacity of 19 m3/h, 57% efficiency, and driven by a 30 kW electric motor.

4. BENEFITS

Energy savings

The result of implementing this measure is a reduction of 30 kW, or 150 MWh per year, based on an annual 5000 hours of BW boiler operation.

Other Benefits

Maintenance cost savings are estimated at $500 per year.

5. IMPLEMENTATION COST

List of equipment	number	unit cost (Ft)

feedwater pump + electric motor	3	$8500

Total cost is estimated at $25,000

6. PAY BACK

$25,000/(6000 + 500)/yr = 3.8 years

7. PLANNING

8. TECHNICAL RISK AND REFERENCE

9. BACK-UP DATA AND CALCULATION

ACTION B.3
INSTALL A STEAM PRESSURE CONTROL VALVE ON THE STEAM LINE TO THE FEEDDWATER PREHEATER AND DEAERATOR

1. PROCESS AREA

Boilerhouse

2. RECOMMENDATION

Install a steam pressure control valve on the steam line to the feedwater preheater and deaerator.

3. DESCRIPTION/RATIONALE

Considering that the plant's boilers are firing natural gas, there is no reason to maintain a high temperature (130°C) at the entrance to the economizer. There is no risk of corrosion to the economizer.

It is recommended that the pressure of 3b steam to the water preheater and deaerator be reduced in order to attain a temperature of 90°C at the outlet of the feedwater preheater and 115°C in the deaerator. Therefore, the steam pressure should be reduced down to 1 bar g.

The benefit of this measure will be a higher heat recovery in the boiler economizer, and therefore, an improved efficiency of boilers BW 1 and 2.

4. BENEFITS

Energy savings are estimated at 1 percent of gas consumption (Ft. 690,000 per year, $10,000).

5. IMPLEMENTATION COST

List of equipment	number	unit cost (Ft.)

Pressure control steam valve 1 Ft. 500,000

6. PAY BACK

500,000/690,000/yr = 0.7 year

7. PLANNING

8. TECHNICAL RISK AND REFERENCE

9. BACK-UP DATA AND CALCULATION

ACTION C.1
REVISE THE EXISTING BUILDING HEATING AND DOMESTIC HOT WATER SYSTEM

1. PROCESS AREA

Energy Department

2. RECOMMENDATION

Revise the existing building heating and domestic hot water system.

3. DESCRIPTION/RATIONALE

Considering that building heating constitutes the largest steam load in the plant, it is recommended that the plant revise its building heating system.

At least in the administration building, the space heating system was found to be well designed and in good condition: a circulating hot water loop, flowing through a steam heat exchanger was provided with a temperature control steam valve and an undercooling steam trap. The temperature of the hot water is adjustable.

However, in some process areas and maintenance shops, there was "wild" space heating, using direct 3b steam through fintubes, and generally overheating the room (windows and doors must be open to let out the excess heat).

Also, when the steam line is kept under constant pressure to supply heat to the domestic hot water system, it is recommended that a domestic gas-fired heater be installed.

4. BENEFITS

Heating savings of up to 30 percent are possible from this measure.

5. IMPLEMENTATION COST

List of equipment	number	unit cost (Ft)

Total cost is estimated at

6. PAY BACK

7. PLANNING

8. TECHNICAL RISK AND REFERENCE

9. BACK-UP DATA AND CALCULATION

ACTION C.2
IMPROVE THE INSTRUMENT AND CONTROL SYSTEMS OF THE BOILERS

1. PROCESS AREA

Steam and Power Plant

2. RECOMMENDATION

Improve the instrument and control systems of the boilers:

- Install a combined oxygen and CO meter on boilers BW 1 and 2 (give priority to BW 1) to monitor the excess air of combustion (measurement at the top of the furnace).

3. DESCRIPTION/RATIONALE

This project consists of providing adequate instruments to ensure the control of combustion efficiency. However, there are many short-term measures that should be taken first and regular tune ups using portable instruments will address many of these needs.

4. BENEFITS

An efficiency improvement of 2 percent is estimated, assuming that short-term measures are already carried out (savings of Ft. 1.4 million, $20,000 per year).

5. IMPLEMENTATION COST

The cost is expected to average $30,000 per boiler, for a total cost of $90,000.

6. PAY BACK

The payback is about 4.5 years.

7. PLANNING

8. TECHNICAL RISK AND REFERENCE

9. BACK-UP DATA AND CALCULATION

ACTION C.3
INSTALL AN AUXILIARY STEAM TURBINE TO RUN A COOLING WATER PUMP

1. PROCESS AREA

Boilerhouse

2. RECOMMENDATION

Install an auxiliary steam turbine to run a cooling water pump.

3. DESCRIPTION/RATIONALE

As part of the investigation to reduce the operating cost of the boiler house, it was envisioned that a turbogenerator be installed to produce electric power while expanding steam pressure from the boiler down to the pressure requested by the end-user.

Considering the structure of steam demand, which is highly seasonal, and also the rather low steam demand, it is very unlikely that a turbogenerator has any chance to be financially and economically profitable.

However, it is recommended that the chemical plant take advantage of possible electric power savings by installing an auxiliary turbine on one of the large pumps of the boilerhouse.

4. BENEFITS

5. IMPLEMENTATION COST

List of equipment	number	unit cost (Ft)

Total cost is estimated at

6. PAY BACK

7. PLANNING

8. TECHNICAL RISK AND REFERENCE

9. BACK-UP DATA AND CALCULATION

ACTION C.4
INSTALL COOLING WATER SYSTEM RETROFIT

1. PROCESS AREA:

Cooling water system

2. RECOMMENDATION

- Suppress one cooling water loop (out of two existing).
- Improve the efficiency of existing cooling towers.
- Replace or retire inefficient cooling water pumps.
- Install adequate instrumentation to modulate the cooling water system as a function of heat load.

3. DESCRIPTION/RATIONALE

The cooling water system consists of two cooling water loops in parallel which supply cooling water to process areas.

One loop is equiped with two natural draft hyperbolic concrete cooling towers. The cooling towers are fed by two warm water pumps (normal/spare) in parallel, and cold water is pumped to the process area from the basin at the bottom of cooling tower by two pumps (normal/spare). Cold water flows through sand filters prior to being distributed in the plant.

The second loop is equiped with four forced-draft cooling tower blocks; each is provided with four fans located above a large basin. There, the pumping station consists of only three pumps (one warm water pump, one cold water pump, and one spare pump).

Usually 4 pumps are in operation, plus 16 fans, for a total power demand of 350 kW. The total cooling water flow is estimated at 540 m3/h (atmospheric towers) + 400 m3/h (forced draft towers) for a total of 940 m3/h, which is enough to evacuate 9400 th/h. This would be equivalent to a heating load in the plant of 16 t/h of steam. Considering that the process steam load in the plant is around 3 t/h, plus a maximum of 1000 kW of lost electrical work through bearings and freon machines, our conclusion is that the cooling water system is highly inefficient.

4. BENEFITS

5. IMPLEMENTATION COST

List of equipment	number	unit cost (Ft)

Total cost is estimated at

6. PAY BACK

7. PLANNING

8. TECHNICAL RISK AND REFERENCE

9. BACK-UP DATA AND CALCULATION

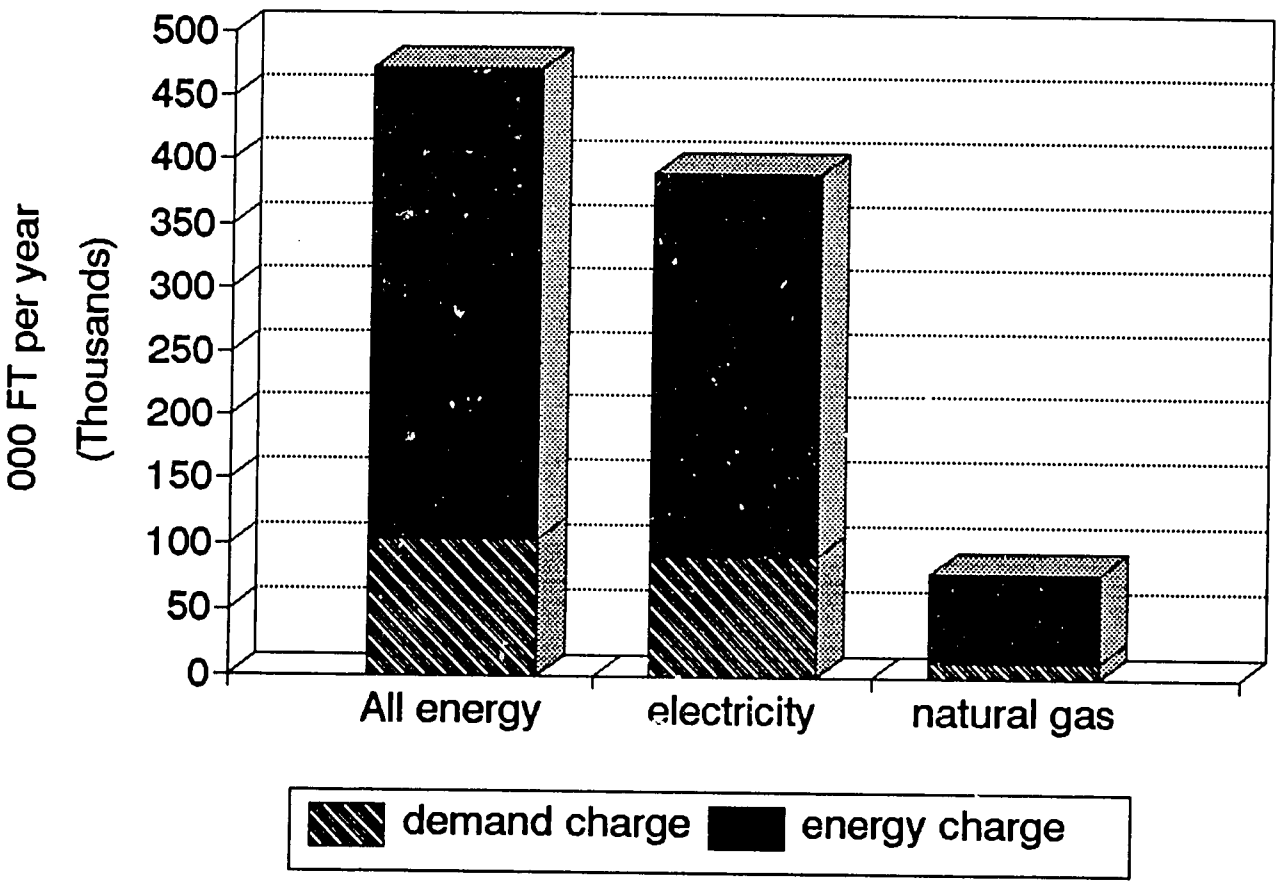
APPENDIX A: DATA PROVIDED BY THE PLANT

As part of the preliminary energy audit, RCG/Hagler, Bailly reviewed a number of standard Illatos reports. Because of the limitations on time and level of effort for this audit, only selected data were used. This appendix summarizes the types of reports used at Illatos.

- **Steam Production Monthly Report**
- **Daily Production/Sales/Purchases and Operation Report**
- **Fuel Gas Use Monthly Report**
- **Breakdown of Sales per Meter**

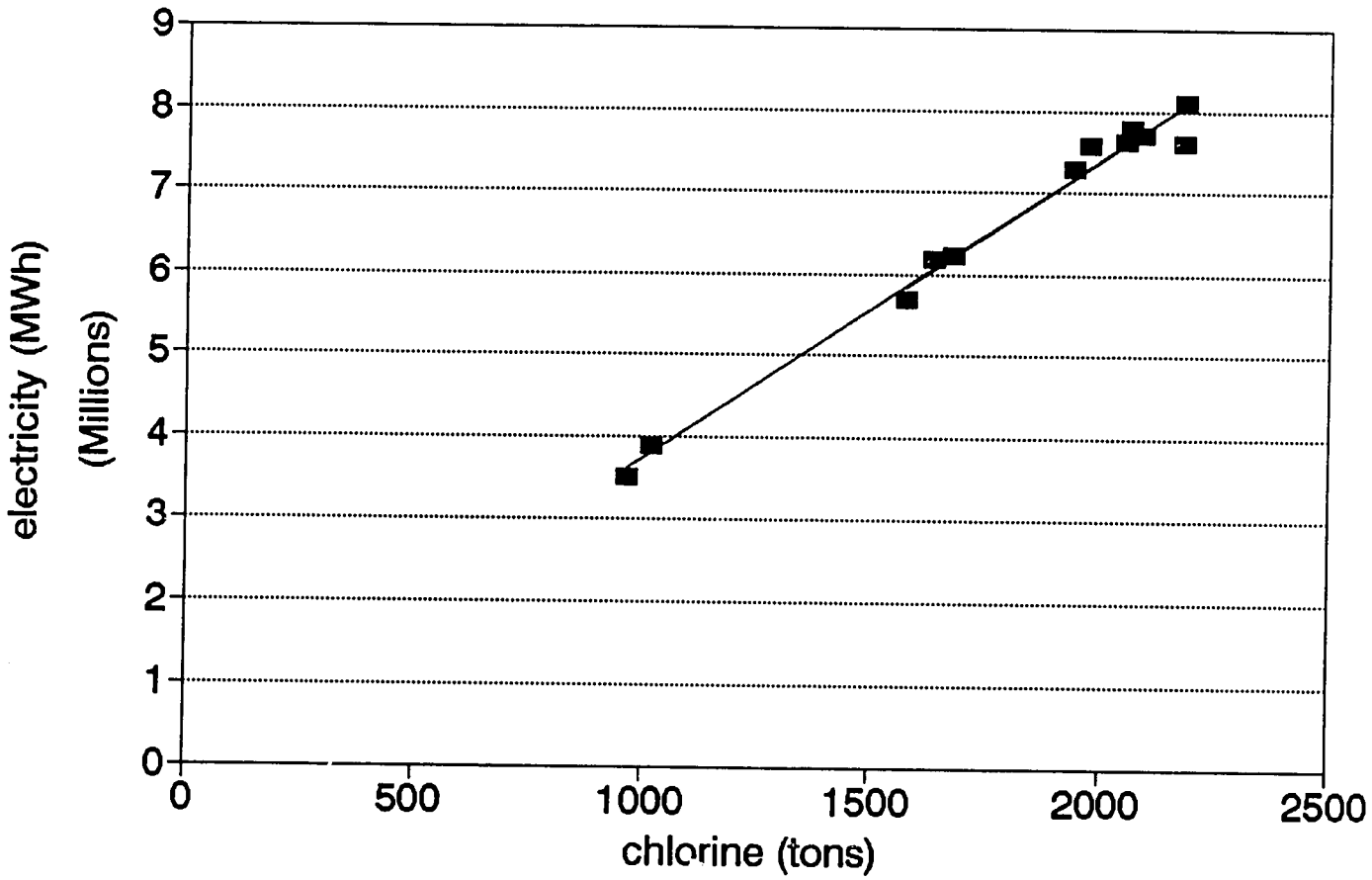
ILLATOS - ENERGY STATISTICS 1990

Annual energy cost (000 FT/year)



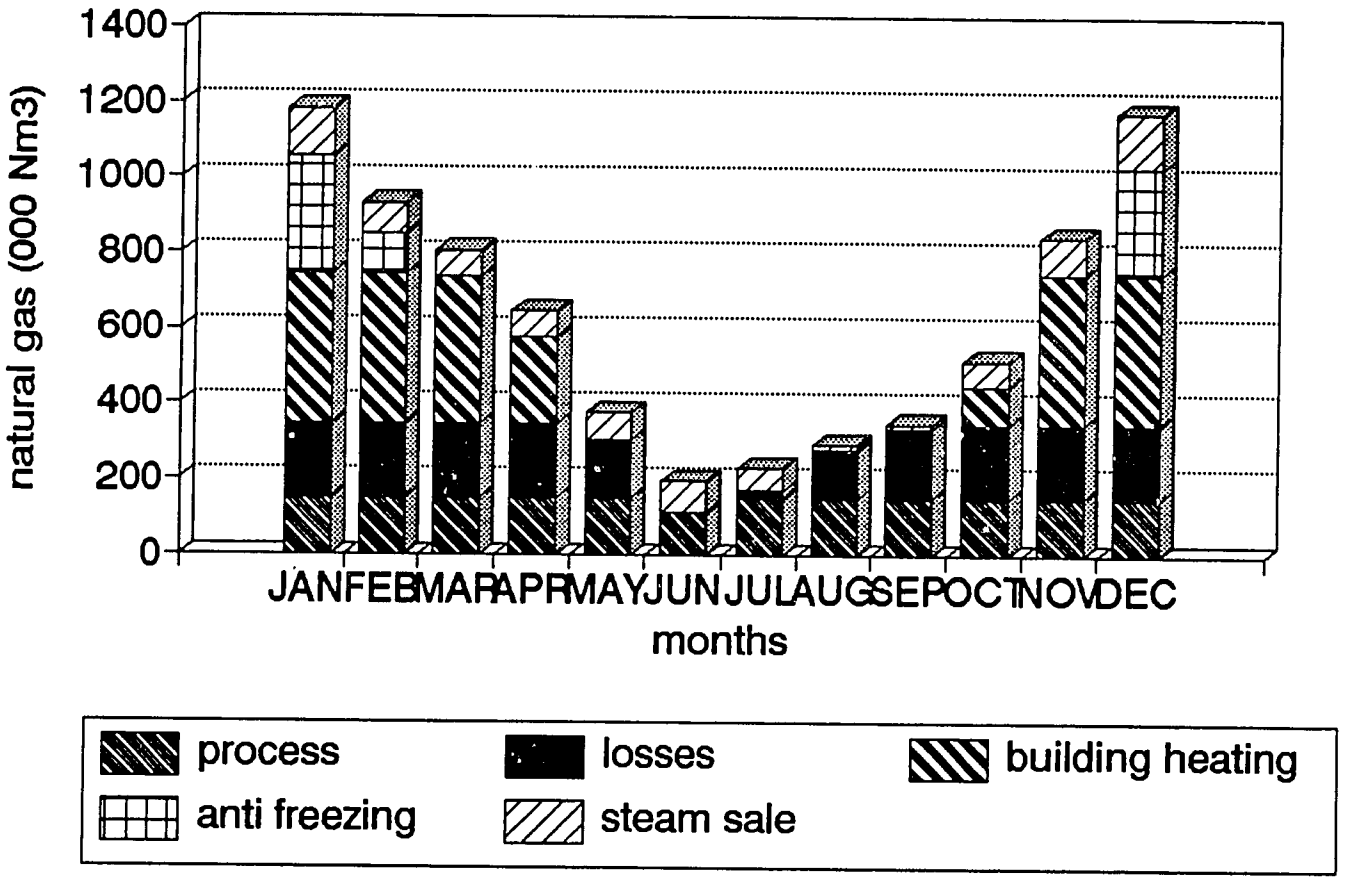
ILLASOS - ENERGY STATISTICS 1990

Electrolysis cost function



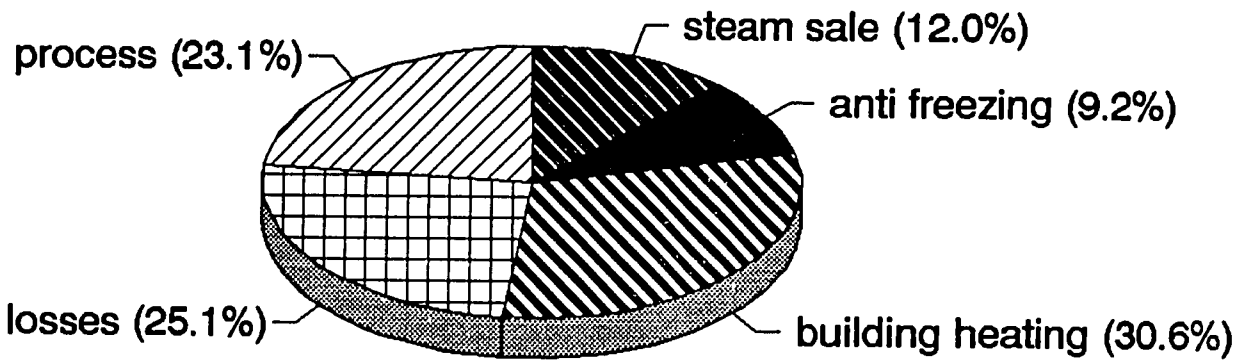
ILLATOS - ENERGY STATISTICS 1990

natural gas breakdown



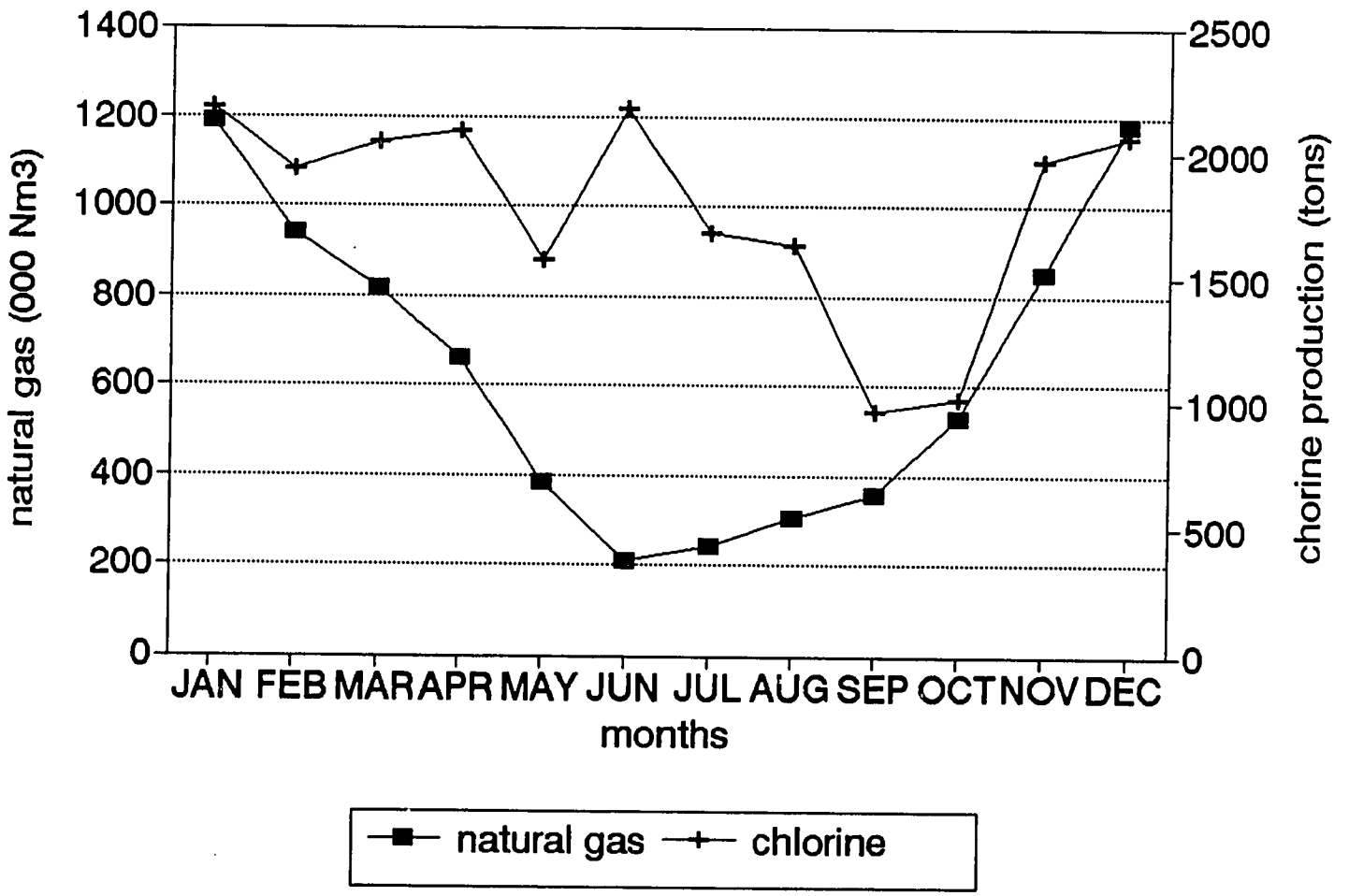
ILLASOS - ENERGY STATISTICS 1990

natural gas breakdown



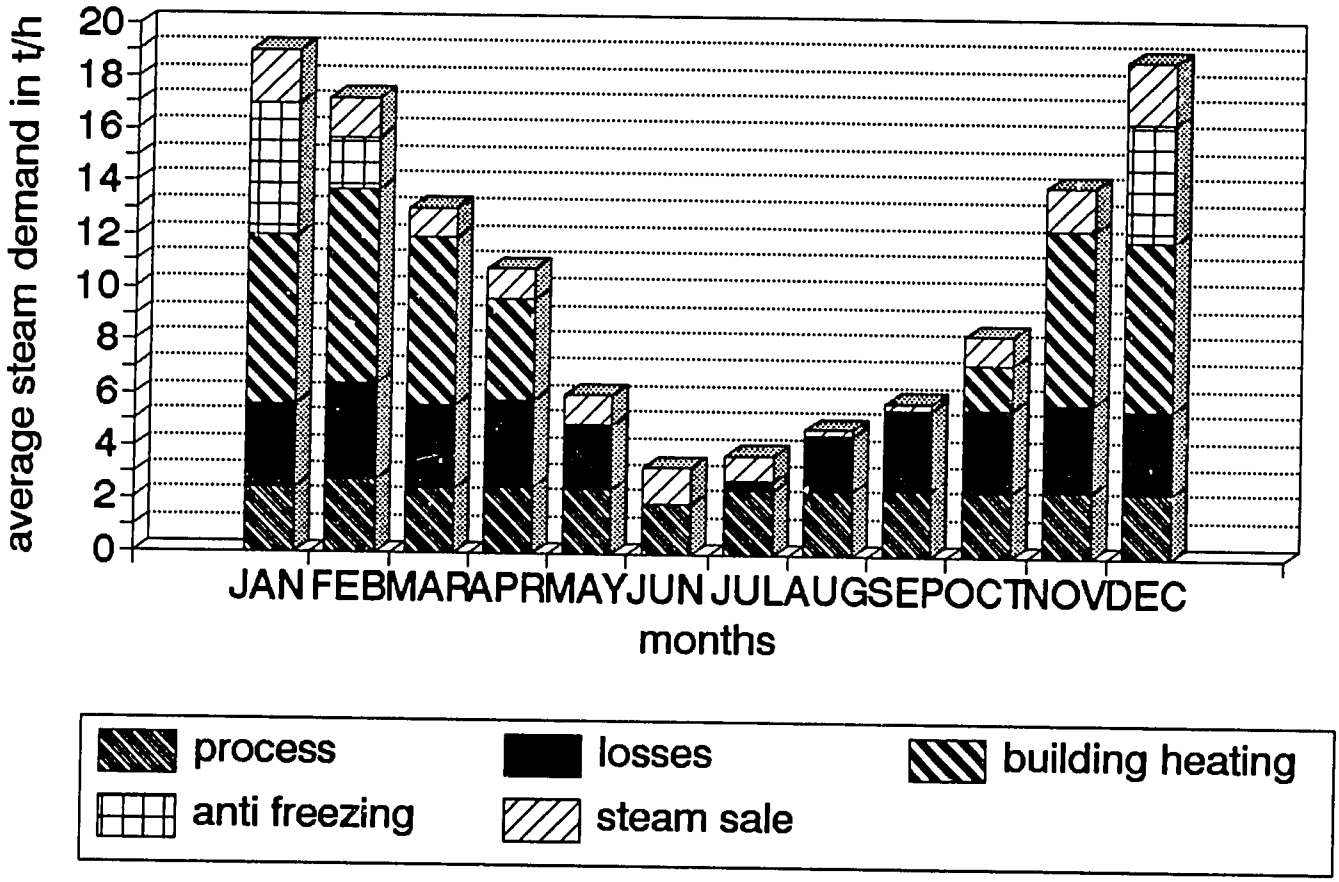
ILLASOS - ENERGY STATISTICS 1990

natural gas



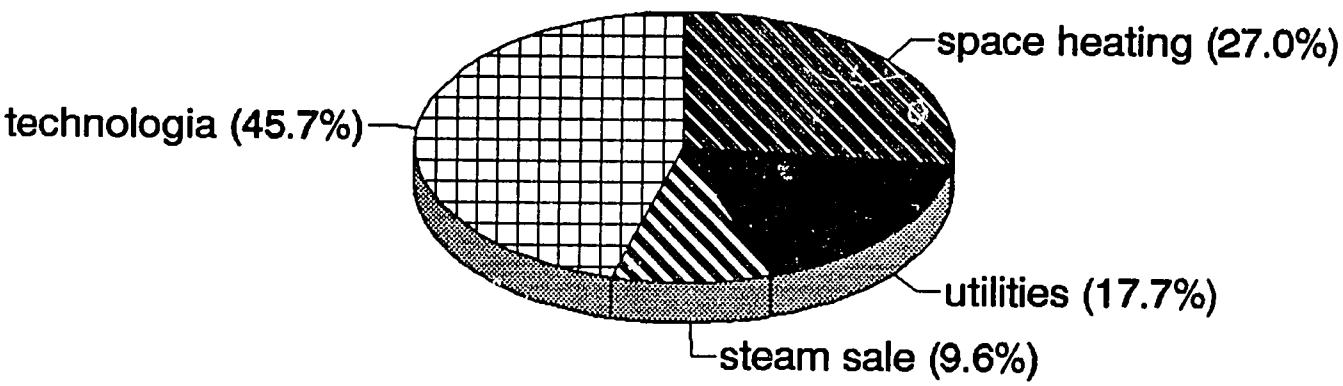
ILLATOS - ENERGY STATISTICS 1990

steam load



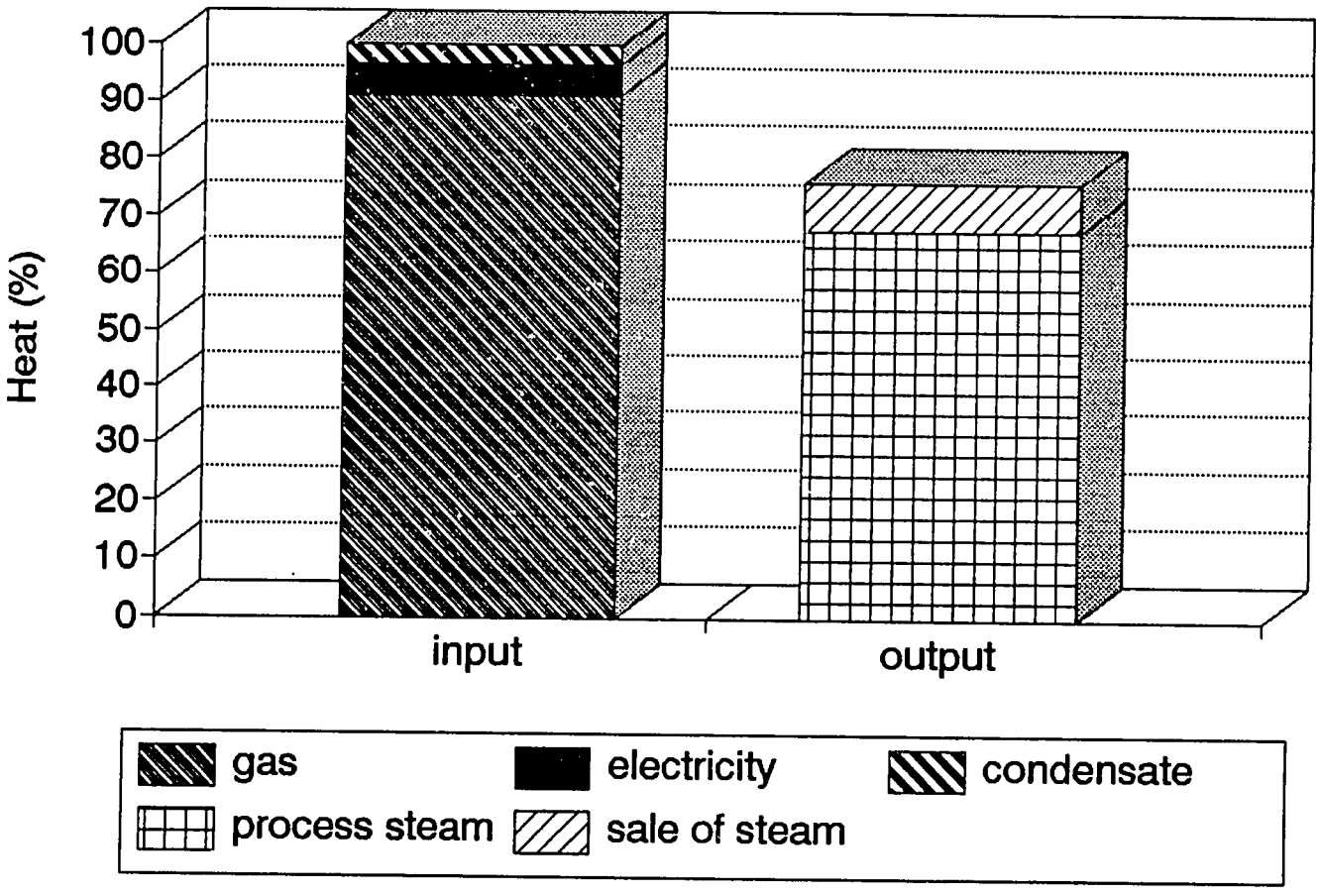
ILLASOS - ENERGY STATISTICS 1990

steam use allocation



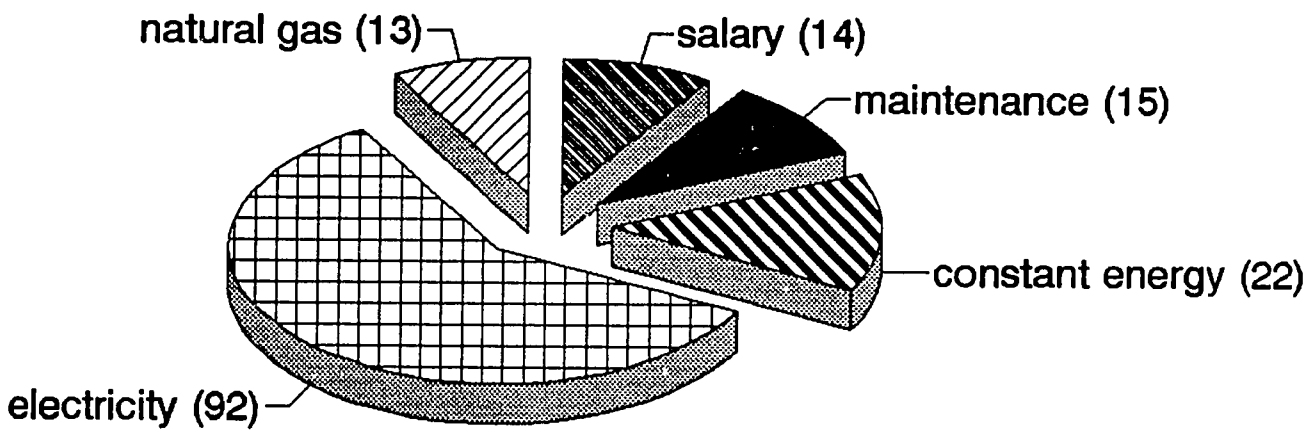
ILLATOS - BOILERHOUSE

Overall Thermal Efficiency



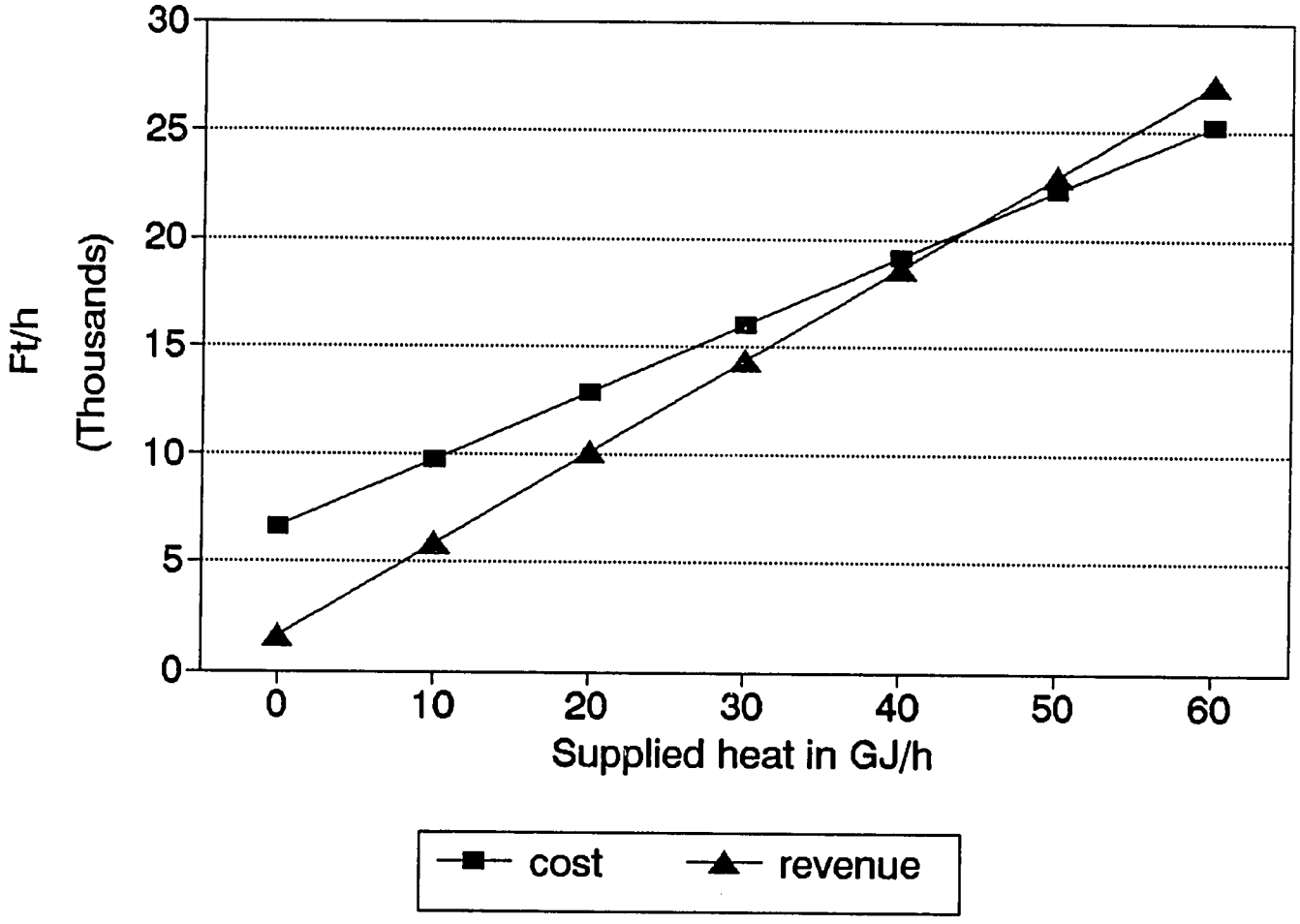
ILLATOS - BOILERHOUSE

Fixed cost structure (MFt/year)



ILLATOS - BOILERHOUSE

Operating Cost versus Revenue



APPENDIX B: BOILERHOUSE ENERGY MODEL

VEGYIMUVEK BOILERHOUSE

CASE STUDY

OUTSIDE CUSTOMER DEMAND FOR STEAM				t/h	t/h	MWth
		T/H	MWth	mini	max	max
3B STEAM		1.2	0.95	0.2	3.5	2.78
VEGYIMUVEK PROCESS HEAT AND POWER DEMAND						
11B STEAM	T/H	0.5	0.40	1	1	0.81
6B STEAM	T/H	2.0	1.59	2	2	1.58
3B STEAM PROCESS	T/H	2.0	1.59	2	3	2.38
3B STEAM BUILD.	T/H	5.0	3.97	0	6.5	5.16
3B STEAM ANTI FREEZING	T/H	0.0	0.00	0	5	3.97
DEMINERALISED WATER	T/H	10.0				
CONDENSATE RETURN	T/H	4.0	-3.32			
ELECTRICITY	KW	13700				
					20.85	16.69

PLANT EQUIPMENT IN OPERATION	#	max
# BOILER 1	1	1
# BOILER 2	0	1
# BOILER 3 STANDARD FASEL	0	1
# HP FEEDWATER MOTORPUMPS	1	3
# ATM COOLING WATER PUMPS	2	4
# FD COOLING WATER PUMPS	2	3
# FANS FD COOLING TOWERS	6	16

RESULTS – FUEL/HEAT USE

		measured	calculated
Purchased fuel gas	Nm3/h		1021
	GJ/h		37
	Ft/h		9637
Sale of steam	t/h		1.2
	GJ/h		3.4
	Ft/h		1461
NET FUEL/HEAT COST	Ft/h		8176

RESULTS – ELECTRIC POWER BALANCE

		measured	calculated
Purchased power	kW		14323
	Ft/h		44460

RESULTS – WATER BALANCE

		measured	calculated
Demineralised water	t/h		21.1
	Ft/h		910
Raw water	t/h		21
	Ft/h		64

OVERALL THERMAL EFFICIENCY

	unit	unit/h	GJ/h
Heat input			
Natural gas	Nm3	1021	36.5
Electricity	kWh	623	2.2
condensate	t	4	1.3
	subtotal		40.1
Heat output			
sale of steam	t	1	3.4
process steam	t	10	27.2
	subtotal		30.6
Overall boilerhouse efficiency		%	76

RESULTS – INTERNAL VARIABLES

		measured	calculated
burner load on:			
boiler 1	%		55
boiler 2	%		0
boiler 3	%		0
sale of steam	t/h		1.2
steam to process	t/h		9.5
steam raised	t/h		11.6
steam supplied	t/h		10.7
steam raised/steam supplied ratio			1.084
LP steam to deaer.	t/h		0.5

CONVERGENCE

		Guess	Calculated
steam to deaerator	t/h	0.47	0.47
boilers flow BW1&2	t/h	11.60	11.60
boilers flow Standard	t/h	0.00	0.00

CONSTRAINTS

CONTRACTUAL LIMI	value	maxi	mini	ACTION
demand				
fuel gas MWth	10.1	12.3		
Export steam MWth	1.0	2		
Elec power MWe	14.3	14.3		
Elec. power factor			0.9	
TECHNICAL LIMITS	**value**	**maxi**	**mini**	**ACTION**
Boilers steam flow	11.6	17.0		

INCREMENTAL COSTS

	fuel GJ/t	purchased elec kWh/t	demine water t/t	marginal cost Ft/t	marginal cost Ft/GJ
11b steam	3.35	0.08	1.005	929	293
6b steam	3.27	0.08	1.005	908	312
3b steam	3.27	0.08	1.005	908	317
condensate ret	-0.19	0.00	0.00	-51	-153

	dayly average Ft/GJ	peak hours Ft/GJ	day hours Ft/GJ	night hours Ft/GJ
11b steam	293	293	293	293
6b steam	312	312	312	312
3b steam	317	318	317	317
condensate ret	-153	-153	-153	-153

COST STRUCTURE EQUATION

	fuel GJ/h	elec kWh/h	demine water m3/h	total Ft/h
Variable Heat cost	34.3	0.8	10.6	9520.
Variable elec cost		13700		42527
Variable demine cost			10	432
Constant cost	2.2	622	0.3	2527.
Total cost	36.5	14323	21.1	55006

Total variable Heat cost	Ft/h	9521	14%
Total heat supplied	GJ/h	30.6	
Unit cost	Ft/GJ	311	
Total variable Elec cost	Ft/h	42527	61%
Total Elec supplied	kWh/h	13700	
Unit cost	Ft/kWh	3.10	
Total variable Demine cost	Ft/h	432	1%
Total Demine supplied	m3/h	10	
Unit cost	Ft/m3	43.20	
Power demand charge	Ft/h	10513	15%
Constant heat loss	Ft/h	2527	
Fuel gas demand charge	Ft/h	1432	
Heat constant cost	Ft/h	3960	6%
Maximum heat demand	MWth	16.7	
Unit cost	Ft/MWth/h	237	
	Ft/MWth/month	173210	
Total fixed cost for heat			
salary	MFt/year	14	
maintenance	MFt/year	15	
thermal energy	MFt/year	29	
total	MFt/year	58	
	Ft/h	6662	10%
Unit cost	Ft/MWth/h	399	
	Ft/MWth/month	291419	
Total fixed + variable operating cost	Ft/h	69654	100%

BREAK-EVEN POINT

		actual cost	market price
Energy charge	Ft/GJ	311	426
Demand charge	FT/MWth/h	399	95
Maximum Demand	MWth	17	
Break-even point	GJ/h	44	
Current demand	GJ/h	31	
Profit margin	Ft/h	-1561	
	Ft/GJ	-51	

ENERGY PURCHASE PRICES

	fuel gas Ft/GJ	boiler feedwater Ft/t	elec. energy Ft/kWh
Peak hours 18h-21h	264	43.2	4.7
Day 6h-18h 18h-22h	264	43.2	3.2
Night 22h-6h	264	43.2	2.35
dayly average	264	43.2	3.10
	kFt/MWth		kFT/MWe
monthly demand charge	84		537

ENERGY SELLING PRICES

	hours/day	steam Ft/GJ
Peak hours 18h-21h	3	425.7
Day 6h-18h 18h-22h	13	425.7
Night 22h-6h	8	425.7
average energy price		425.7
		kFt/MWth
monthly demand charge		68

DATA BASE

CHARACTERISTICS OF FLUIDS

Equip ID No	LIBELLE DES PARAMETRES	unite	No Instrum.	actual value	saturated condition vapor	saturated condition liquid	isentropic letdown 1	isentropic letdown 2
	20B STEAM AT BOILER 1/2							
	pressure	bar g	P01/P02	20				
	temperature	C	T01/T02	370	214.4	214.4		
	enthalpy	th/t		759.4	668.0	219.1		
	heat content 1/	GJ/t		3.175				
	11B STEAM AT BOILER 3							
	pressure	bar g	P03	8.5				
	temperature	C	T03	240	177.1	177.1		
	enthalpy	th/t		789.6	662.3	179.2		
	11B STEAM AT THE USER POINT							
	pressure	bar g		11				
	temperature	C		240	183.6	183.6		
	enthalpy	th/t		696.5	663.6	186.0		
	heat content 1/	GJ/t		2.912				
	6B STEAM AT THE USER POINT							
	pressure	bar g		5.5				
	temperature	C		200	161.6	161.6		
	enthalpy	th/t		680.1	658.7	163		
	heat content 1/	GJ/t		2.843				
	3B STEAM AT THE BOILER PLANT							
	pressure	bar g		2.5				
	temperature	C		200	138.5	138.5		
	enthalpy	th/t		683.8	652.2	139.2		
	3B STEAM AT THE USER POINT							
	pressure	bar g		2.5				
	temperature	C		200	138.5	138.5		
	enthalpy	th/t		683.8	652.2	139.2		
	heat content 1/	GJ/t		2.859				
	BOILERS STEAM DRUM							
	pressure	bar g		22				
	temperature	C		219.1	219.1	219.1		
	enthalpy	th/t		668.4	668.4	224.3		
	DEAERATED FEEDWATER							
	pressure	bar g	P07	2.2				
	temperature	C	T07	135.4	135.4	135.4		
	enthalpy	th/t		136	651	136		
	total dissolved solid	ppm		0				
	CONDENSATE RETURN							
	pressure	bar g		0				
	temperature	C		80				
	enthalpy	th/t		80				
	heat content 1/	GJ/t		0.334				
	DEMINERALISED WATER							
	pressure	bar g						
	temperature	C		32				
	enthalpy	th/t		32				
	AMBIANT AIR							
	pressure	bar g						
	temperature	C		25				
	enthalpy	th/t						

note 1: heat content of steam in GJ is based on the total enthalpy of steam

FUEL GAS

Equip ID No	PARAMETERS	unite	No instrum.	Valeur
	chemical composition			
	CO2	%vol		0.13
	H2	%vol		
	N2	%vol		0.89
	CH4	%vol		98.14
	C2H4	%vol		
	C2H6	%vol		0.61
	C3	%vol		0.16
	C4	%vol		0.07
	C5	%vol		
	H2S	%vol		0
	molecular weight			16.3
	sulfur content	% poids		0
		g/10th		0
	LHV calorific value	th/t		11750
		th/Nm3		8.551
		MJ/Nm3		35.76
	HHV calorific value	th/t		13042
		th/Nm3		9.492
		MJ/Nm3		39.69
	neutral air/fuel ratio	kg/10th		14.39
	neutral flue gas/fuel ratio	kg/10th		15.17
	flue gas specific gravity	kg/Nm3		1.23
	flue gas specific heat	kcal/kg.C		0.272

BOILER HEAT BALANCE

Equip ID No	PARAMETERS	unit	No instrum.					in	out	in	out	in
	CHARACTERISTICS							BOILER 1		BOILER 2		BOILE
	Maximum steam raised	t/h							17		17	
	Steam pressure	bar g							20		20	
	Pressure relief valves	bar g										
	Superheat temperature	C							370		370	
	HP steam enthalpy	th/t							759.4		759.4	
	Minimum steam raised	t/h							5		5	
	BASIC DATA – TEST											
	Steam flow	t/h	meter						10.5		10.5	
	Fuel gas flow	th/h	meter N.O.					7824.				
	Maximum fuel gas flow	th/h						15770		20903		8250
	Economiser											
	Feedwater side											
	Temperature	C						120.4	150.4	120.4	150.4	130.4
	flowrate	t/h						10.55	10.55			
	heat exchanged	th/h						316.5				
	Flue gas side											
	Temperature	C						210	179.5		170.5	
	excess air	%	=====>>					240				
	flue gas flow	kg/10th						49.70	49.70			
	heat exchanged	th/h							319.3			
	Air/flue gas preheater											
	Air side											
	Temperature	C						22	97	17	72	25
	enthalpy	th/t						5.255	23.30	4.059	17.26	5.973
	combustion air flow	kg/10th							30.21		30.21	
	heat exchanged	kcal/10th						545.4		399.0		0
	Flue gas side											
	Temperature measured	C	Thermoco						146		146	
	Temperature calculated	C						179.5		170.5		225
	enthalpy	th/t						49.01	39.84	46.55	39.84	61.40
	O2 total	% vol	Enerac						16.2			
	total excess air	%							308		308	
	total air flow	kg/10th							58.71		58.71	
	flue gas flow	kg/10th							59.49		59.49	
	flue gas specific heat	kcal/kg.C							0.272		0.272	
	Top of the furnace											
	oxygen	% vol	Enerac						11.5		11.5	
	combustion excess air	%							110		110	
	draft	mmWG							22.86		22.86	
	Blowdown total dissolved solid	ppm	TDS meter									
	Blowdown rate 1/	%							0.5		0.5	
	Other water/steam loss	t/h							0		0	
	Fixed heat loss	%							0.8		0.8	
	Blowdown enthalpy	th/t							224.3		224.3	

note 1: monitored every 4 hours by lab.

BOILERS HEAT BALANCE (CONT.)

Equip ID No	LIBELLE DES PARAMETRES		unite	plant instrum.					in	out	in	out	in
	VARIATION OF TOTAL EXCESS AIR												
	Threshold												
	steam flow		t/h							10		10	
	excess air		%	308					190		90		17
	Low point												
	steam flow		t/h							5		5	
	excess air		%						500		500		30
	VARIATION OF STACK GAS TEMPERATURE												
	Upper point												
	steam flow		t/h							15		15	
	temperature		C	146						137		137	
	Medium point												
	steam flow		t/h							10		10	
	temperature		C	146						135		135	
	Lower point												
	steam flow		t/h										
	temperature		C										
	HEAT BALANCE EQUATION												
	C=(X4*Q+X5)/(X0+X1*EA-TF*(X2+X3*EA))												
	X0								1.007		1.005		1.008
	X1								8E-05		6E-05		9E-05
	X2								4E-04		4E-04		4E-04
	X3								4E-06		4E-06		4E-06
	X4			=====>>					639.5		639.5		659.4
	X5								126.1		167.2		99
	EQUATION FUEL GAS/STEAM FLOW												
	Steam flow	Q	t/h							11.60		0	
	Feedwater flow		t/h	M07/08/09					11.66		0		0
	Total excess air	EA	% EA						190		910		47.33
	air infiltration		% EA						100		70		0
	air leakage through air preheater		% EA						70		100		0
	combustion excess air		% EA						20		740		47.33
	Air flowrate		t/h						23.86		0		0
	Stack temperature	TF	C							135.6		131	
	Fuel gas	C	10th/h						872.9		0		0
			Nm3/h						1020.		0		0
			m3/h @ 15 C						1076.		0		0
	Fuel gas load		%						55		0		0
	Gas to steam ratio		t/h/t						752.2		ERR		ERR
			GJ/t						3.145		ERR		ERR
	Efficiency on LHV		%							83.2		ERR	

BOILERS CONTINUOUS BLOWDOWN (NOT IN OPERATION)

Equip ID No	PARAMETRES	unit	No instrum.	in	out
	Liquid				
	flowrate	t/h		0.058	0.058
		% saumur			100
	enthalpy	th/t		224.3	224.3
	Flash steam				
	pressure	bar g	P09		2.5
	flowrate	t/h			0
		% flash			0
	enthalpy	th/t			652.2

STEAM LETDOWN

Equip ID No	ITEM	unit	No instrum.	in	out
	20B/11B				
	Steam				
	flowrate	t/h		0.450	0.5
	temperature	C			
	enthalpy	th/t		759.4	696.5
	Desuperheating water				
	flowrate	t/h	M10	0.050	
		%		11.01	
	enthalpy	th/t	T04	126	
	20B/6B				
	Steam				
	flowrate	t/h		11.15	12.74
	temperature	C			
	enthalpy	th/t		759.4	680.1
	Desuperheating water				
	flowrate	t/h	M10	1.596	
		%		14.31	
	enthalpy	th/t	T05	126	
	11B/6B				
	Steam				
	flowrate	t/h		0	0
	temperature	C			
	enthalpy	th/t		789.6	680.1
	Desuperheating water				
	flowrate	t/h		0.000	
		%		ERR	
	enthalpy	th/t		126	

WATER BALANCE

Equip ID No	ITEM	unit	No instrum.	in	out
	Water losses				
	sewed blowdown	t/h			0.058
	loss 20b	t/h			0
	loss 11b	t/h			0
	loss 6b	t/h			0
	other boiler house	t/h			0.2
	deaerator vent	t/h			0.1
	boilers loss				0
	Total loss	t/h			0.358
	Steam/water to process plant/sale				
	11b steam	t/h			0.5
	6b steam	t/h			2
	3b steam	t/h			8.2
	demineralised water to process	t/h			10
	Total demineralised water R	t/h		21.05	
	Water treatment balance				
	demineralised water	t/h			21.05
	condensate return	t/h		4	
	total raw water	t/h		21.37	

AUXILIARY TURBINES

Equip ID No	PARAMETERS	unite	plant instrum.	in	out
	FEEDWATER TURBOPUMP				
	number in operation			0	
	steam quality			20B	ATM
	maximum flow	t/h		2	
	minimum flow	t/h		0	
	power	kW			50
	equation				
	proportional coefficient				50
	constant				-50
	steam flow	t/h		0	0
	power	kW			0

AUXILIARY MOTORS

Equip ID No	PARAMETERS	unite	plant instrum.	Value		
TS1/2/3	HP FEEDWATER MOTORPUMPS				New pumps	
	number of motorpumps			3		
	number in operation			1		
	nominal flowrate	m3/h		29	19	
	temperature	C		130	130	
	density			0.935	0.935	
	head	m	P12	350	320	
	efficiency	%		50	57	
	nominal power	kW		51.72	27.17	
	power/flow equation W= f(QW)					
	constant			40.34		
	proportionnal coef.			0.392		
	quadratic coef.			0		
	feedwater flowrate					
	feedwater to boilers	t/h	M07/08	11.66		
	desuperheating water					
	letdown 20B/11B	t/h		0.049		
	letdown 20B/6B	t/h		1.596		
	letdown 11B/6B	t/h		0		
	total	t/h		13.30		
	feedwater flow per pump	t/h		29		
	power per pump	kW		51.72		
	return flow to deaerator	t/h		15.69		
TS5/6	LP FEEDWATER MOTORPUMPS					
	number of motorpumps			2		
	number in operation			0		
	nominal flowrate	m3/h		15		
	temperature	C		130		
	density			0.935		
	head	m	P16	150		
	efficiency	%		60		
	nominal power	kW		9.554		
	power/flow equation W= f(QW)					
	constant			7.452		
	proportionnal coef.			0.140		
	quadratic coef.			0		
	feedwater to boilers	t/h	M09	0		
	feedwater flow per pump	t/h		0		
	power per pump	kW		0		
	total feedwater pumps power	kW		51.72		
	BOILER FANS			OIL 1	OIL 2	OIL 3
	number of fans			2	2	2
	nominal power per boiler	kW		86	86	30
	nominal steam flow	t/h		30	30	40
	actual steam flow	t/h		11.60	0	0
	mechanical power on shaft	kW		71	0	0
	total electric power	kW		71		

AUXILIARY MOTORS

Equip ID No	PARAMETERS	unite	plant instrum.	Value	
	MAKE-UP FEEDWATER				
	number			1	
	nominal flowrate QV	m3/h		80	
	temperature	C		10	
	density			1	
	head	m WG		80	
	efficiency	%		0.68	
	nominal power W	kW		25.64	
	power/flow equation W = f(QW)				
	constant			20.00	
	proportionnal coef.			0.070	
	quadratic coef.			0	
	make-up water flow	t/h		21.05	
	electric power	kW		23.10	
	ATM COOLING WATER PUMPS				
	number of motorpumps			4	
	number in operation			2	
	nominal flowrate	m3/h		540	
	temperature	C		30	
	density			1	
	head	m		37	
	efficiency	%		81	
	nominal power	kW		67.21	
	power/flow equation W= f(QW)				
	constant			52.42	
	proportionnal coef.			0.027	
	quadratic coef.			0	
	cooling water flow	m3/h		540	
	feedwater flow per pump	t/h		540	
	total power	kW		134.4	
	F.D. COOLING WATER PUMPS				
	number of motorpumps			3	
	number in operation			2	
	nominal flowrate	m3/h		400	
	temperature	C		30	
	density			1	
	head	m		37	
	efficiency	%		43	
	nominal power	kW		93.79	93.82
	power/flow equation W= f(QW)				
	constant			73.15	
	proportionnal coef.			0.051	
	quadratic coef.			0	
	cooling water flow	m3/h		400	
	feedwater flow per pump	t/h		400	
	total power	kW		187.5	

AUXILIARY MOTORS (CONT'D)

Equip ID No	PARAMETERS	unit	plant instrum.	value
	OTHER AUXILIARIES	kW		155
	lighting/battery charging	kW		15
	well pumps	kW		36
	cooling tower fans	kW		24
	air compressor	kW		70
	miscellaneous	kW		10
	TOTAL AUXILIARIES	kW		622.8

RAW WATER TANK

Equip ID No	PARAMETERS	unite	plant instrum.	in	out
	Raw water make-up	t/h		21.37	
	enthalpy	th/t		15	
	condensate return	t/h		4	
	enthalpy	th/t		60	
	condensate from water preheater	t/h		1.693	
	enthalpy	th/t		109.2	
	total raw water	t/h			27.06
	enthalpy	th/t			27.54
	Raw water preheater (steam injection)				
	water flow	t/h		27.06	27.24
	enthalpy	th/t		27.54	32
	3b steam flow	t/h		0.184	
	enthalpy	th/t		683.8	

FEEDWATER PREHEATER USING BLOWDOWN (NOT IN OPERATION)

Equip ID No	ITEM	unit	No instrum.	in	out
	Feedwater side				
	flowrate	t/h		11.05	11.05
	temperature	th/t	T08/T09	32	32
	Blowdown				
	flowrate	t/h		0.058	0.058
	temperature	th/t		224.3	224.3

FEEDWATER PREHEATER USING STEAM

Equip ID No	ITEM	unit	No instrum.	in	out
	Feedwater				
	flowrate	t/h	T12	11.05	11.05
	temperature	C		32	120
	enthalpy	th/t		32	120
	3b steam				
	flowrate	t/h		1.693	1.693
	enthalpy	th/t		683.8	109.2

FEEDWATER DEAERATOR

Equip ID No	PARAMETERS	unite	plant instrum.	in	out
	DEAERATOR				
	Feedwater				
	flowrate	t/h		12.93	13.30
	enthalpy	th/t	T14	120	136
	Steam (LP/vent)				
	guessed flowrate	=======		0.471	
	calculated flowrate	t/h		0.471	0.1
	enthalpy	th/t		683.8	650

3B STEAM BALANCE

Equip ID No	PARAMETERS	unite	plant instrum.	in	out
	6b/3b letdown	t/h		10.74	
	deaerator	t/h			0.471
	raw water preheater	t/h			0.184
	feedwater preheater	t/h			1.693
	other boiler house	t/h			0.2
	net 3b steam available	t/h	M06		8.2
	for sale	t/h			1.2
	to buildings heating	t/h			5
	to in plant process use	t/h			2

6B STEAM BALANCE

Equip ID No	PARAMETERS	unite	plant instrum.	in	out
	20b/6b letdown	t/h		12.74	
	11b/6b letdown	t/h		0	
	6b/3b letdown	t/h			10.74
	process	t/h	M05		2
	losses	t/h			0

11B STEAM BALANCE

Equip ID No	PARAMETERS	unite	plant instrum.	in	out
	Standard Fasel boiler	t/h	=======	0	
	Standard Fasel boiler	t/h	M03	0	
	22b/11b letdown valve	t/h		0.5	
	11b/6b letdown valve	t/h			0
	to process use	t/h	M04		0.5
	losses	t/h			0

20B STEAM BALANCE

Equip ID No	PARAMETERS	unite	plant instrum.	in	out
	20b/11b letdown valve	t/h			0.450
	20b/6b letdown valve	t/h			11.15
	losses	t/h			0
	Total HP steam	t/h		11.60	
	steam generated	t/h	M01/M02=	11.60	

ELECTRICITY BALANCE

Equip ID No	PARAMETERS	unite	plant instrum.	in	out
	auxillaries consumption	kW			622.8
	Process plant power demand	kW			13700
	Purchased power	kW		14322	