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INDUSTRIAL ENERGY AUDITING MANUAL

Prepared for:
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Prepared by:
Hagler, Bailly & Company
Washington, DC USA

and

Reliance Energy Services
New York, NY USA

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FOREWORD

Most of this manual is based on a course book prepared for a 4-week industrial auditing training program held in Sri Lanka in March 1984. This program, sponsored by the Sri Lankan Ministry of Power and Energy and the United States Agency for International Development, combined classroom sessions with extensive in-plant training. Many aspects of this manual have thus been tested in real life situations and the lessons learned incorporated in this general version.

The large number of individuals both in the United States and abroad who have participated in the preparation of this document makes acknowledging individually all the considerable assistance and cooperation received impossible. Hagler, Bailly & Company and Reliance Energy Services wish, however, to express their appreciation to the 32 Sri Lankan engineers who endured the course; Dr. Mohan Munasinghe, Senior Energy Advisor to H.E., the President of Sri Lanka; and Pamela Baldwin of the Office of Energy of the U.S. Agency for International Development for the special contributions they have made.

Any comment on this manual will be welcomed and should be sent to: Director, International Services, Hagler, Bailly & Company (address on back cover).

CHAPTER 1: INTRODUCTION

The successful definition, implementation, and management of an industrial energy conservation program requires a proper framework and baseline for identifying and evaluating energy conservation opportunities. Energy cannot be saved until it is known where and how it is being used and when and where its efficiency can be improved. In most cases, the establishment of this baseline requires a comprehensive and detailed survey of energy uses and losses; this survey is generally known as the **energy audit.***

Having conducted an energy audit does not, however, constitute in itself an energy conservation program. A number of other conditions must also be met. First, there must be a will to save energy. Second, viable projects must be evaluated according to the company's financial guidelines. Third, financing must be available, and fourth, plant management and staff must be committed to continuing the energy rationalization effort well beyond project implementation, as the benefits of good projects can be lost as quickly as they are gained.

This manual is designed primarily to assist plant managers and engineers in carrying out energy audits and can also be used as a training manual. It describes an organized approach to identifying areas of potential energy efficiency improvement in a facility and determining how these improvements can be implemented at reasonable cost and within a reasonable time frame. It does not, however, deal with any of the other conditions (such as financing) for implementing a successful program.

The energy process described in this manual is carried out in two sequential phases: the preliminary energy audit and the detailed energy audit:

- **The Preliminary Energy Audit (PEA)** is essentially a preliminary data gathering and analysis effort. It consists of two parts: the energy management audit, through which the auditor becomes acquainted with investment decision criteria referencing energy conservation projects, and the technical energy audit. The technical part of the PEA uses only

*The term "survey" is being used more and more in conjunction with national (macro) level energy use studies and the term "audit" with site-specific analyses.

available data and is completed without sophisticated instrumentation. The PEA is conducted in a very short time frame (i.e., a day or a few days), during which the energy auditor relies on his experience to gather all relevant written, oral, or visual information that can lead to a quick diagnosis of the plant energy situation. The PEA focuses on the identification of obvious sources of possible improvement in energy use. Examples of easily identified possibilities are missing insulation, steam and compressed air leaks, inoperative instrumentation, and equipment operating unnecessarily. The typical output of a PEA is a set of recommendations on immediate low-cost actions that can be taken and, usually, a recommendation for a more extensive plant energy analysis -- the detailed energy audit.

- **The Detailed Energy Audit (DEA)**, which must always be conducted **after** a PEA, is an instrumented survey followed by a detailed plant energy analysis. Sophisticated instrumentation, including flow meters, psychrometers, flue gas analyzers, and infrared scanners, is used to enable the energy auditor to compute energy efficiencies and balances during typical equipment operation. The actual tests performed and the instruments required depend on the type of facility under study and the objective, scope, and level of funding of the energy management program. Thus, a detailed energy audit can take as little as 1 man-week or as much as several man-years in a sophisticated plant, such as a petrochemical complex, where expected savings justify such an effort. Types of tests conducted during a detailed energy audit include combustion efficiency tests and measurement of temperatures and air flows of major fuel-using equipment, determination of power factor degradation caused by various pieces of electrical equipment, and testing of process systems for operation within specification.

After obtaining the test results, the energy auditor checks and validates them using preliminary computation and existing support materials (tables, charts, calculators, computers). Then, he uses the results to build energy and mass balances, first for each major piece of equipment tested and then for the plant as a whole. From such balances, he can determine

how efficiently each piece of equipment is actually operating and whether there is room for energy cost reduction. Next, he analyzes the data, concentrating on identifying costs and benefits of selected options (actions, investments) for each opportunity. In some cases, the energy auditor will be unable to recommend a specific investment because of its magnitude or the associated risk. In such a case, the auditor will recommend specific feasibility studies (e.g., boiler replacement, furnace modification, steam system replacement, process changes). The detailed energy audit stops at this point; its final output is a detailed report presenting the auditor's recommendations, together with their associated costs, benefits, and implementation characteristics (timing, impact on production).

ORGANIZATION OF THIS MANUAL

Including this introductory Chapter 1, this manual is divided into five chapters:

- Chapter 2 summarizes the steps in an overall energy conservation and management program
- Chapter 3 discusses the objective, process, and application of the Preliminary Energy Audit
- Chapter 4 presents and discusses the various types of instruments used in the detailed energy audit
- Chapter 5 details the steps in detailed energy audits of boilers, steam systems, dryers, furnaces, power systems, and electrical systems.

CHAPTER 2: STEPS IN AN ENERGY AUDIT PROGRAM

This chapter provides background information on an energy audit program, which is designed to increase energy efficiency and reduce energy-related costs. In an Energy Audit, detailed data are collected and analyzed. Although sophisticated instruments are used to collect data, energy auditing is **not** an exact science. The energy auditor must also use his **knowledge and judgment** in collecting and interpreting data on energy use. The major steps in an energy management program are shown in Exhibit 2.1 and described in more detail below.

Step 1. Review Energy Management Program to Date

The first step is to review the existing energy program, if any, with senior corporate staff. The energy auditor can then decide what changes may be needed in the scope of the proposed detailed energy audit. If there is no formal program, the auditor will try to understand why.

Step 2. Conduct Preliminary Energy Audit

If a preliminary energy audit (PEA) has not been previously done, it should be done after the review. Details on conducting a PEA are provided in Chapter 3.

Step 3. Develop Action Plan, Including Detailed Energy Audit

On the basis of the review and the PEA, the energy auditor should develop an action plan, including a Detailed Energy Audit (DEA). The action plan should take account of:

- The management of energy-related matters within the facility
- Monitoring and reporting considerations
- Relationships with manufacturers' representatives
- The availability of resources for implementing the action plan

Exhibit 2.1

Major Steps in Implementing an Energy Audit Program

Step 1. **Review energy management program to date**

Step 2. **Conduct preliminary energy audit**

Step 3. **Develop action plan, including detailed energy audit**

Step 4. **Select scope of detailed energy audit**

- Manpower
- Testing procedures
- Instrumentation
- Cost

Step 5. **Complete preparatory work**

- Instrumentation repair/purchase
- Install test points
- Time frame

Step 6. **Carry out detailed energy audit field work**

- Conduct selected tests
- Collect data

Step 7. **Evaluate collected data**

Step 8. **Identify conservation opportunities**

- Operation and maintenance
- Capital-intensive measures

Step 9. **Develop action plan for implementation**

- Timetable
- Feasibility studies

Step 10. **Continue to monitor energy use**

Step 11. **Refine overall energy management program**

- the financial situation of the company
- personnel, in-house and external.

Step 4. Select Scope of Detailed Energy Audit

The next step is to determine the scope of the DEA. This step is necessary to finalize resource requirements in four (4) areas:

- Manpower
- Testing procedures
- Instruments
- Funding.

Manpower should be selected on the basis of a review of internal and external sources. Several agencies throughout the world have standard testing procedures for evaluating equipment performance, and the energy auditor may want to use these procedures as a guide. For example, the United States Association of Mechanical Engineers provides methods for testing steam generating plant and other mechanical equipment. British Standards are laid down for testing many industrial process plants.

Instrument needs will be dictated by their availability in the country, the extent of information needed, the testing procedures used, the equipment to be tested, and the location of proposed measuring positions. The auditor must often compromise on the instruments that he can choose because of lack of funds. He may be forced to use less accurate equipment that can be used more than once during the course of the audit. Typical instruments used for energy auditing are described in Chapter 4, and testing procedures are discussed in the case studies presented in Chapter 5.

The cost of the audit should be estimated ex ante. The cost will depend on the use of internal or external staff, the time required to complete the audit, and the sophistication of the instrumentation used. Typically, a detailed energy audit by outside consultants in the United States costs between 20,000 to 40,000 dollars for a plant with an energy bill of 1 to 2 million dollars (or about 5 percent of annual energy cost).

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Step 5. Complete Preparatory Work

The next step is to complete all preparatory work.

All instruments to be used should be serviced and/or repaired, additional instruments purchased, and all test measuring positions and connections completed.

The energy auditor should make sure that the time frame selected for the audit does not conflict with the operation of the equipment to be tested or the plant in general. The chosen testing date should be representative of normal plant operation.

Step 6. Carry Out Detailed Energy Audit Field Work

The energy auditor can now conduct the field work part of the DEA.

The field work consists of two (2) main tasks. The first task is to perform tests on selected equipment to evaluate its efficiency. Stated tests are detailed in Chapter 5 of this manual for selected equipment, including boilers, dryers, and electrical systems.

The second task is to gather data that will enable the energy auditor to evaluate all energy aspects within a facility. The energy auditor should use the PEA as a starting point, expanding on it to fill gaps in data, and to learn more about the operation of the plant. He conducts interviews with selected personnel, examines records, observes operations, and monitors and checks conditions. In this task, the energy auditor will often gather data, review them, gather data again, and review them again.

Step 7. Evaluate Collected Data

There are several areas in which energy data can be evaluated, such as energy purchasing and energy use. But because of the importance of energy conservation opportunities, this manual will concentrate on them. The steps involved in evaluating energy conservation opportunities are presented in Exhibit 2.2. Techniques for estimating potential

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Exhibit 2.2

Evaluation of Energy Conservation Opportunities

1. **Evaluate existing operating conditions**

   - Hours of operation
   - Method of operation
   - Energy requirements
   - Initial product specification
   - Final product specification under existing conditions

2. **Identify alternative method of operation**

   - Hours of operation
   - Method of operation
   - Energy requirements
   - Final product specification under alternative operating conditions

3. **Calculate energy consumption under alternative method of operation**

4. **Determine feasibility of alternative method of operation**

   - Product quality
   - Cost

5. **Estimate savings**

   - Difference in energy consumption
   - Energy cost savings

6. **Decide whether to implement alternative method**

   - Capital needs
   - Feasibility studies

7. **Implement**

savings from conserving energy in boilers, steam systems, dryers, furnaces, and electrical systems are discussed in Chapter 5.

Step 8. Identify Conservation Opportunities

The results of the evaluation step can be used to identify two types of conservation opportunities:

- Operation and maintenance (O&M) changes (low cost or "housekeeping" measures)
- Capital-intensive measures.

O&M opportunities are those that require little or no major capital investment and have rapid returns on investment. On a simple payback basis, O&M changes have paybacks of 1 year or less.

Capital-intensive measures require large capital investments (typically in excess of $25,000). Simple payback periods are usually more than 1 year. The energy auditor should use payback periods as a guideline when making his list of recommendations. He should also identify the company's attitude on capital-intensive projects as part of his detailed energy audit activities.

Step 9. Develop Action Plan for Implementation

The energy auditor will probably not have the authority to implement the measures identified, especially if capital requirements are large. Instead, he will complete a report for corporate decision-makers. The report, which will present the findings of his audit, will include an action plan.

The action plan should contain a timetable for implementation. It should be possible to implement some measures immediately (O&M changes). However, major capital-intensive measures may require feasibility studies before a decision can be made to implement them. The energy auditor should indicate the overall time frame, to give

decision-makers an idea of when energy cost savings will begin to show positive cash flow. He may also prepare terms of reference for additional work to be done (e.g., feasibility studies).

An action plan often includes an recommendation for a self-financing program. In a self-financing program, O&M changes are implemented and the resulting cost savings are invested directly in lower-cost capital-intensive measures to bring even more savings. Eventually, cost savings are used to pay for the most costly capital-intensive measures.

Step 10. Continue to Monitor Energy Use

Energy efficiency in a company should not begin and end with the DEA. To sustain its energy efficiency, a company must continue to monitor its energy use.

The DEA report should recommend improvements to the existing monitoring and reporting procedures for energy use. Very few, if any, companies have an adequate system of procedures in place. Without such a system, it is hard to spot changes in consumption that result from increases or decreases in efficiency.

Possible improvements that can be made to monitoring and reporting procedures include:

- Upgrading of instrumentation
- Introduction of energy reporting procedures
- Development of energy consumption indices
- Development of energy models.

Step 11. Refine Overall Energy Management Program

The major recommendations of the detailed energy audit should be refinements to the overall corporate energy management program. Because energy affects so many aspects of a company's operations, improvements in energy use will not take place without commitment at the highest levels of management. Management's perception of the state of energy use will determine the success of any energy management program.

The requirements for a successful overall corporate energy management program are detailed in Exhibit 2.3.

Recommendations may include:

- Appointing personnel to be responsible for energy
- Formally structuring a corporate energy management program
- Training staff and employees in energy awareness.

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Exhibit 2.3

Basic Requirements for Successful
Corporate Energy Management Program

- **Commitment at corporate level to energy conservation**
  - Resources, personnel, funds
  - Goals
- **Optimum use of resources**
  - Intercompany information system
  - Centralized technical support
  - Facilities management training
- **Identification of opportunities**
  - Quick payback items
  - Capital-intensive projects
  - Evaluation and relationship to production
- **Implementation of projects**
  - Self-financing program
  - Capital project selection
  - Specification and bid
- **Establishment of operational criteria**
  - Optimum production/energy targets
  - Operations and maintenance procedures
- **Monitoring and targeting**
  - Evaluation
  - Re-evaluation

CHAPTER 3: CONDUCTING A PRELIMINARY ENERGY AUDIT

The Preliminary Energy Audit (PEA) is usually one of the initial steps taken when implementing an energy conservation program. This chapter provides information on how to conduct a PEA. The PEA consists essentially of gathering and analyzing data. It uses only data that are available and its technical part is completed without the use of sophisticated instruments. The results of the PEA depend on the ability and experience of the person conducting the PEA, but they normally include the following:

- Development of energy consumption/cost data base for a facility
- Objective evaluation of plant condition
- Identification of major energy-using systems
- Understanding of company's decision-making for energy-related projects
- Action plan for future energy auditing work.

The PEA generally has five steps, as shown in Exhibit 3.1. The PEA outline presented assumes that the energy auditor has no prior knowledge of the structure of the facility to be audited and has no details of any energy management program that may exist. It does assume, however, that the energy auditor knows the physical size and main function of the plant before starting to collect data.

3.1 STEP 1: ORGANIZE RESOURCES

3.1.1 Manpower/Time Frame

A PEA is usually done by one experienced energy auditor. The time required to complete a PEA depends on several factors, including:

- Experience of the auditor
- Physical size of the facility
- Complexity of operations within the facility
- Availability and completeness of data
- Depth of analysis of available data
- Awareness of energy matters within the facility.

Exhibit 3.1

Steps in Conducting a Preliminary Energy Audit

1. **Organize resources**

   - Manpower/time frame
   - Instrumentation

2. **Identify data requirements**

   - Data forms

3. **Collect data**

   a. Conduct informal interviews

      - Senior management
      - Energy manager/coordinator
      - Plant engineer
      - Operations and production management and personnel
      - Administrative personnel
      - Financial manager

   b. Conduct plant walkthrough/visual inspection

      - Material/energy flow through plant
      - Major functional departments
      - Any installed instrumentation, including utility meters
      - Energy report procedures
      - Production and operational reporting procedures
      - Conservation opportunities

4. **Analyze data**

   a. Develop data base

      - Historical data for all energy suppliers
      - Time frame basis
      - Other related data
      - Process flow sheets
      - Energy-consuming equipment inventory

   b. Evaluate data

      - Energy use -- consumption, cost, and schedules
      - Energy consumption indices
      - Plant operations
      - Energy savings potential
      - Plant energy management program

Exhibit 3.1 (continued)

Preliminary Energy Audit

5. Develop action plan

- Conservation opportunities for immediate implementation
- Projects for further study
- Resources for detailed energy audit
  - systems for test
  - instrumentation -- portable and fixed
  - manpower requirements
  - time frame
- Refinement of corporate energy management program

Examples of time frames for completing a PEA are presented in Exhibit 3.2. These time frames assume that the necessary data are available and complete.

3.1.2 Instrumentation

To help collect technical data during the PEA, the energy auditor can use instrumentation. The contents of a basic instrument kit that should be carried by an energy auditor are listed in Exhibit 3.3.

Although two tape measures are included in the kit, the auditor should not spend too much time obtaining accurate measurements of floor areas. This information can be quickly estimated with an accuracy that is adequate for a PEA. Tape measures are better used to measure lengths of missing insulation and pipe diameters, etc.

Apart from the safety equipment, perhaps the most valuable tool is the flashlight. With it, the energy auditor can seek information in dark, inaccessible places that are often ignored by people in their day-to-day routine. Conservation opportunities are often found in such areas.

3.2 STEP 2: IDENTIFY DATA REQUIREMENTS

Before an energy auditor begins a PEA, he must know what data he needs to analyze for an action plan. Without data requirements, he may not collect the right information and as a result, the PEA will not be useful.

Information must be collected on everything that affects energy use in the facility. Such information includes, but is not necessarily limited to, the following:

- Energy consumption for all types of energy used by the facility
- Energy cost and prevailing rate schedules
- Operational schedules for the facility
- Product or function of the facility
- Physical properties of the facility

Exhibit 3.2

Time Required to Complete a Preliminary Energy Audit

Commercial facility	Data collection (days)	Data analysis (days)
Up to 10,000 m^2	1	1
10,000-30,000 m^2	1.5	1.5
Above 30,000 m^2	1.5 days plus 1 day per 20,000 m^2	1.5 days plus 1 day per 20,000 m^2
Industrial facility		
Single-product facility up to 10,000 m^2	1	1
Single-product facility 10,000-30,000 m^2	1.5	1.5
Single-product facility above 30,000 m^2	1.5 days plus 1 day per 20,000 m^2	1.5 days plus 1 day per 20,000 m^2
Multi-product facility up to 10,000 m^2	1 day plus 0.5 day per product	1 day plus 0.5 day per product
Multi-product facility 10,000-30,000 m^2	1.5 days plus 0.5 day per product	1.5 days plus 0.5 day per product
Multi-product facility above 30,000 m^2	1.5 days plus 0.5 day per product and 1 day per 20,000 m^2	1.5 days plus 0.5 day per product and 1 day per 20,000 m^2

NOTE: The above time frames should be considered the minimum requirements. The Preliminary Energy Audit is usually the first part of a Detailed Energy Audit, so time spent in compiling an accurate data base will save time on the full audit.

Exhibit 3.3

Preliminary Energy Audit Instrument Kit

Instrument	Number required
Tape measure -- 30 meters	1
-- 10 meters	1
Flashlight	3
Assorted tubing	
Stopwatch/chronometer	1
Ear protectors	2
Hard hat	2
Gloves	2 pairs
Pedometer	1
Assorted hand tools	

- Location of the facility
- Energy-consuming equipment within the facility, including production and environmental systems.

In addition to the above technical information, the auditor will obtain information on the **company's decision-making criteria** (e.g., maximum payback, minimum internal rate of return), as this information will be critical to present a realistic action plan to management.

3.2.1 Data Forms

Typical forms used to collect data on consumption and costs of energy, including rate schedules, are shown in Exhibits 3.4 through 3.11.

Forms used to compile data on production and prevailing climatic conditions are shown in Exhibits 3.12 and 3.13.

Details of energy-consuming equipment can be collected on forms similar to those shown in Exhibits 3.14 through 3.20.

The forms shown in Exhibits 3.4 through 3.20 cannot be used for every facility. In addition, they do not show the interaction between energy-using systems (for example, between a boiler, a steam distributor, and a steam consumer).

The energy auditor should develop diagrams for material/energy flow through the facility on a blank sheet, taking care to include all relevant information such as:

- Flow rate of energy/material
- Physical properties of energy/material entering and leaving any system
- Operating conditions of any system, including time of operation, temperature, pressure
- Changes of state of energy/material that may occur
- Desired goals of operation

Exhibit 3.4

General Information

Date _____

Audit period _____

Name of facility _____

Address _____

_____

Type of facility _____

Manager _____

Energy coordinator _____

Energy sources and utilities	Utility or supplier	Rate schedule* or present cost
Electricity		
Natural gas		
No. 2 fuel oil		
No. 4 fuel oil		
No. 6 fuel oil		
Propane		
Bituminous coal		
Anthracite coal		
Purchased steam		
Wood		
Waste fuel		

Location of nearest weather station _____

Normal annual cooling degree-days _____

*Note: Attach current rate schedules to this form.

Exhibit 3.5

HISTORICAL QUANTITY AND COST DATA FOR ELECTRICITY

BUILDING _____ UTILITY _____

METER SERIAL NO. _____ RATE SCHEDULE _____

LOCATION _____

BILLING PERIOD (1)	MAXIMUM DEMAND KW (2)	POWER FACTOR (3)	CONSUMPTION KWH (4)	TOTAL COST (5)	COST PER KWH (6)	CONSUMPTION G-JOULES (7)	COST PER G-JOULES (8)
ANNUAL							

Exhibit 3.6

HISTORICAL QUANTITY AND COST DATA FOR FUEL OIL

BUILDING _____

SUPPLIER _____

STORAGE CAPACITY _____ LITERS

FUEL OIL No. _____

MONTH (1)	INVENTORY, LITERS (2)	DELIVERIES, LITERS (3)	CONSUMPTION, LITERS (4)	COST PER LITERS (5)	TOTAL COST (6)	CONSUMPTION, G-JOULES (7)	COST PER G-JOULE (8)
END OF MONTH							
ANNUAL							

Exhibit 3.7

HISTORICAL QUANTITY AND COST DATA FOR PROPANE

BUILDING _____ SUPPLIER _____

METER SERIAL NO. _____ STORAGE CAPACITY _____ LITERS

LOCATION _____

MONTH (1)	INVENTORY, LITERS (2)	DELIVERIES, LITERS (3)	CONSUMPTION, LITERS (4)	COST PER LITERS (5)	TOTAL COST (6)	CONSUMPTION, G-JOULES (7)	COST PER G-JOULE (8)
END OF MONTH							
ANNUAL							

Exhibit 3.8

HISTORICAL QUANTITY AND COST DATA FOR COAL

BUILDING _____

SUPPLIER _____

STORAGE _____ TONNES

MOISTURE CONTENT % _____

HHV _____

GRADE OF COAL _____

ASH CONTENT % _____

MONTH (1)	INVENTORY, TONNES (2)	DELIVERIES, TONNES (3)	CONSUMPTION TONNES (4)	COST PER TONNES (5)	TOTAL COST (6)	CONSUMPTION G-JOULES (7)	COST PER G-JOULE (8)
END OF MONTH							
ANNUAL							

Exhibit 3.9

HISTORICAL QUANTITY AND COST DATA FOR PURCHASED STEAM

BUILDING _____

METER SERIAL NO. _____

LOCATION _____

UTILITY _____

RATE SCHEDULE _____

STEAM PRESSURE _____

CONDENSATE TEMPERATURE _____ °C

BILLING PERIOD (1)	SEND-OUT 1000 KILOGRAMS (2)	SEND-OUT (3)	CONDENSATE RETURN (4)	NET COST (5)	COST PER 1000 KILOGRAMS (6)	CONSUMPTION G-JOULES (7)	COST PER G-JOULE (8)
ANNUAL							

Exhibit 3.10

HISTORICAL QUANTITY AND COST DATA FOR WOOD OR WASTE FUELS

BUILDING _____ TYPE OF FUEL _____

SUPPLIER _____ UNITS _____

STORAGE CAPACITY _____ HEATING VALUE _____

MONTH (1)	INVENTORY, UNITS (2)	DELIVERIES, UNITS (3)	CONSUMPTION, UNITS (4)	COST PER UNITS (5)	TOTAL COST (6)	CONSUMPTION, G-JOULES (7)	COST PER G-JOULE (8)
END OF MONTH							
ANNUAL							

Exhibit 3.11

SUMMARY OF HISTORICAL ENERGY CONSUMPTION AND COST

BUILDING _____

AUDIT PERIOD _____

ALL ENERGY CONSUMPTION DATA ARE IN GIGAJOULES

MONTH	ELECTRICITY		FUEL OIL		OTHER		TOTAL	
	CONSUMPTION	COST	CONSUMPTION	COST	CONSUMPTION	COST	CONSUMPTION	COST
ANNUAL								

Exhibit 3.12

Other Factors Affecting Energy Use

Building	_____
Audit period	_____
Product	_____
Units of production	_____

Month	Operating hours	Monthly production
Annual		

Exhibit 3.13

Degree-Day Data

Building	_____
Audit period	_____
Source of weather data	_____
Degree-day base	_____

Month	Cooling degree-days
Annual	
Normal degree-days	

Exhibit 3.14

BOILERS

Total number boilers in building (s) _____

Type

☐ Steam at _____ BAR

Condensate Return ☐ Yes ☐ No Percent Return

Condensate used for heating domestic hot water ☐ Yes ☐ No

☐ Hot Water at _____ °C

☐ Other

	Boiler Identification	Fuel Type	Fuel Consumption/ hr	Energy Rating G-JOULES/HR	Use	Date Combust. Eff. Test.	Eff.
1.							
2.							
3.							
4.							
5.							

Metering equipment for fuel, running hours, steam, etc.

Meter Serial No.	Use	Date Last Calibrated

Exhibit 3.15

CENTRAL COOLING

Total number of systems in building(s) _____

Type

- ☐ Electric Reciprocating
- ☐ Electric Centrifugal
- ☐ Absorption
- ☐ Compressor driven by steam turbine
- ☐ Compressor driven by natural gas engine
- ☐ Other

Chiller Identification	Fuel Consumption Per hr.	Energy Rating G-JOULES/HR	Rated Capacity	Use	Date Last Inspection

Heat Dissipation Device

- ☐ Air cooled
- ☐ Water cooled
- ☐ Other _____
- ☐ Warm water to cooling tower
- ☐ Warm water to boilers

Metering equipment for energy consumption, running hours, water flow, etc.

Meter Serial No.	Use	Date Last Calibrated

Exhibit 3.16

Major Energy-Using Equipment

Electric equipment (reference)	Size (units)	Location	Use	Efficiency	Comments
Motor					
Motor					
Motor					
Pump					
Pump					
Pump					
Heater					
Heater					
Heater					
Compressor					
Compressor					
Compressor					
Other					
Other					
Other					

Exhibit 3.17

Major Energy-Using Equipment

Thermal equipment (reference)	Size (units)	Location	Use	Efficiency	Fuel type	Comments
Furnace						
Furnace						
Furnace						
Kiln						
Kiln						
Kiln						
Dryer						
Dryer						
Dryer						
Other						
Other						
Other						

Exhibit 3.18

Lighting Systems

Unit or area served	Type of luminaire (fixture)	Watts per luminaire	Quantity	Total watts	Method of control
Interior lighting					
Exterior lighting					

Exhibit 3.19

CONNECTED LOAD, ELECTRIC ENERGY

BUILDING(S) _____ Surveyed by: _____

AUDIT PERIOD _____ _____

Price per KWH: $ _____

	A	B	C	D	E	F	G	H
Energy Type	Equipment Description	Elec. Use per Device (kilowatts)	No. of Devices	Total Elec. Use (kilowatts)	Elec. Cost per Hour	Operating Hours per Year	Elec. Cost per Year	Total Elec. Yearly used KWH
ELEC.								
						TOTAL ANNUAL:		
							Energy Cost	Fuel Used

Column D = B x C Column E = D x Price per KWH

Column G = E x F Column H = D x F

Exhibit 3.20

CONNECTED LOAD, OIL ENERGY

BUILDING(S) _____ Surveyed by: _____

AUDIT PERIOD _____ _____

Price per Gallon: $ _____

	A	B	C	D	E	F	G	H
Energy Type	Equipment Description	Fuel Use per Device (liters/hr.)	No. of Devices	Total Fuel Use (liters/hr.)	Fuel Cost per Hour	Operating Hours per Year	Fuel Cost per Year	Total Fuel Yearly used Liters
OIL								
						TOTAL ANNUAL:		
							Energy Cost	Fuel Used

Column D = B x C Column E = D x Price per liters

Column G = E x F Column H = D x F

- Ideal operating conditions, if known
- Design rating of equipment, if known.

3.3 STEP 3: COLLECT DATA

3.3.1 Conduct Informal Interviews

When starting a PEA in a new facility, the energy auditor should first familiarize himself with its operation and organization. The best way to do that is to meet and talk informally with those people responsible for running the facility. An energy auditor rarely goes to a plant without an invitation from someone within the facility. The invitation may come from a number of people, but the first contact is usually the person to whom the energy auditor would direct his initial inquiries. That contact should be able to identify the people responsible for the information that the energy auditor needs to prepare his PEA.

There are several people that the energy auditor should seek out to ensure that he gets a full picture of energy affairs within the organization. These people include:

- Senior management with direct responsibility for energy
- Energy manager/coordinator
- Plant engineer
- Operations and production management and personnel
- Administrative personnel.

The structure and complexity of the organization will dictate how many people are interviewed and how much time is spent interviewing. In many instances, some of the functions described above are combined into one job. In facilities with a well-designed and established energy management program, the information that the energy auditor needs may be very easy to get. Other companies may not be fully aware of all implications of energy management and may have no energy program.

The type of information that an energy auditor should seek is indicated below.

3.3.1.1 Senior Management

In talking with senior management, the auditor should learn:

- Outline of company's attitude to energy management
- Whether an in-house energy management program exists
- Personnel responsible for administering the energy management program -- the energy coordinator
- Decision-making criteria for capital expenditures in productivity improvement projects.

3.3.1.2 Energy Manager/Coordinator

This position may not exist within a facility. In some cases, a company will have only a part-time energy manager. If there is an energy manager, he is the person from whom the energy auditor should obtain most of his information (e.g., mechanical or electrical engineer).

Information that the energy auditor should seek includes:

- Structure of in-house energy management program, including:
  - chain of command and position of energy manager within the facility's corporate organization
  - goals of energy management program
  - status of energy management program
  - work completed to date under energy management program, including energy monitoring and reporting procedures
  - whether a PEA was conducted previously, and if so, when
  - whether an energy management data base exists
  - whether an action plan for conservation exists
  - conservation opportunities identified and implemented
  - whether a full audit has been completed, and if so, when
  - conservation opportunities identified but not implemented because of (a) insufficient study, (b) lack of interest, (c) lack of capital, (d) no

economic viability, (e) lack of resources -- time or manpower -- to implement
- whether an adequate energy monitoring and reporting procedure exists
- whether the energy manager uses external as well as internal resources for implementation
- what ongoing actions are taken to maintain and improve energy efficiency and to implement new opportunties.

- Available information on energy-related matters, including:
  - physical layout of facility -- floor plan, if available
  - fuels used, consumption, rate schedules, costs
  - energy use within the facility (production and environmental)
  - operating function and schedule of the facility.

- Specifications of the facility, including:
  - size
  - age of building and equipment
  - names and locations of operating departments
  - schedule of operating hours for each department
  - function of each department
  - energy used within each department for production and environmental services
  - major energy-consuming systems within each department and the facility as a whole
  - line diagrams for major systems, if available
  - installed instrumentation, including utility meters
  - original equipment ratings and any changes, such as fuel switch or increased capacity
  - production indicator
  - production reporting procedures
  - maximum capacity of plant and its relation to energy consumption: (a) maximum kW demand, (b) electrical load factor, (c) fossil fuel load factor.

If the energy manager is unable to answer the above questions, then the energy auditor must determine who can answer the questions. Quite often, gaps will exist in the information collected that will impact on the evaluation that can be made. Where these gaps can be completed by further interview, then the energy auditor should be prepared to meet with other individuals who can supply the information.

3.3.1.3 Plant Engineer

Because the plant engineer is involved in all aspects of equipment and operation maintenance, he is very aware of what goes on throughout the facility. He should be able to supply information on the plant's physical details that the energy manager did not provide.

Other information he can supply includes:

- Condition of equipment and any operating problems
- Control systems
- Instrumentation
- Maintenance procedures.

Often, the plant engineer serves as the energy manager/coordinator because of his unique insight into the operations within a facility.

3.3.1.4 Operations and Production Management and Personnel

These people should supply missing information on how production equipment is run and the operating conditions required to meet production targets. This information includes:

- Specification of materials before and after the production process
- Final product specifications
- Actual operating conditions, including production rates, quality, temperatures, pressures, and cycle times
- Ideal operating conditions

- Optimum conditions and problems encountered in meeting them; for example, effect of wet steam on drying, availability of adequate steam supplies, pressures.

This information should be gathered at two levels -- management and operator level. Often, equipment is operated under conditions different from those that management specifies.

3.3.1.5 Administrative Personnel

Any lack of information on costing of energy, operating schedules, production reports, etc., can usually be obtained from the appropriate administrative personnel. They often supply the economic criteria by which the facility makes its decisions. This knowledge is important when the energy auditor is evaluating conservation opportunities.

3.3.2 Conduct Plant Walkthrough/Visual Inspection

The energy auditor tours the facility to objectively evaluate the plant conditions and operating procedures, and to gain understanding of the process flow. The key steps in completing a walkthrough/visual inspection are given in Exhibit 3.21. To achieve his goals, the energy auditor must personally collect information on the following:

- Material/energy flow through plant
- Major functional departments
- Major energy-consuming systems
- Any installed instrumentation, including utility meters
- Energy reporting procedures and any inadequacies
- Production and operational reporting procedures
- Energy conservation opportunities.

Information on some of the above can be collected using data collection forms like those presented in Exhibits 3.4 through 3.11. Other information can be collected through sketches made by the energy auditor during his inspection. To obtain maximum

Exhibit 3.21

Key Steps in a Plant Walkthrough/Visual Inspection

1. **Select facility person to accompany auditor on inspection**

2. **Obtain plant layout**

   - Use available print or develop sketch with facility personnel

3. **Mark sketch with material/energy flows, including:**

   - Material receiving and storage areas
   - Prime energy inputs, meter locations, storage areas
   - Major production areas, with materials/energy used
   - Warehouse and shipping departments for final products
   - Resource recycling systems
   - Waste disposal systems

4. **Mark sketch with major functional areas/departments**

5. **Identify and evaluate major energy-consuming systems by system of analysis:**

   - Process systems such as dryers, boilers, furnaces, etc.
   - Building envelope
   - Lighting
   - Ventilation
   - Heating
   - Cooling
   - Water systems, including steam and condensate distribution
   - Distribution systems such as compressed air, thermal fluids

6. **Identify and check operation of instrumentation associated with energy**

   - Utility meters
   - Process operations-related instruments

7. **Identify energy reporting procedures**

   - Charts, logs
   - Analysis conducted

8. **Identify production and reporting procedures**

   - Production charts
   - Operational logs
   - Operating conditions

9. **Identify conservation opportunities**

   Typical findings include:

   - Missing insulation
   - Leaking systems
   - Equipment running when not required
   - Equipment schedules not matching occupancy/production systems
   - Improperly adjusted or malfunctioning control systems

information from the PEA, the energy auditor should be accompanied on his visual inspection by someone from the plant who is familiar with the plant operations, systems, and procedures and, if possible, all aspects of the functions of each department. This person can be either the energy manager, the plant engineer, or someone from the maintenance department.

Before starting his visual inspection, the energy auditor should obtain a layout of the facility that identifies the major functional departments. This layout can be sketched by the energy manager or the person who will accompany the energy auditor on the tour, if no printed floor plan is available.

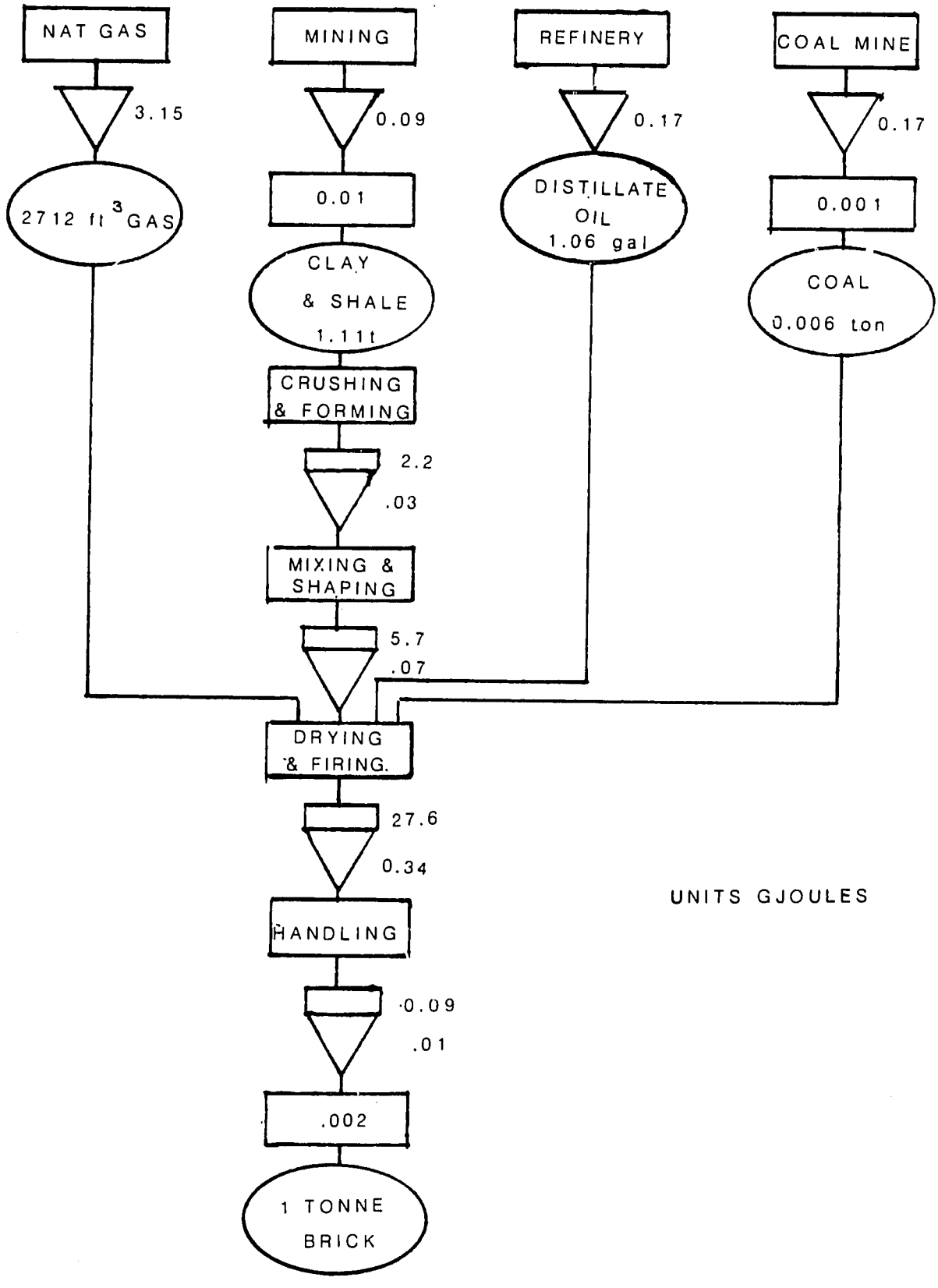
3.3.2.1 Material/Energy Flow Through Plant

The first element of the analysis is to determine how materials and energy flow through the facility. This can be sketched before starting the visual inspection. An example of material energy flow diagram is shown in Exhibit 3.22. The following areas must be located:

- Material receiving and storage areas
- Prime energy inputs into the facility, including:
  - transformer, electrical metering points, substations, distribution voltages
  - fossil fuel storage areas, metering points, and distribution systems
- Major production areas, together with materials and energy types used
- Warehouse and shipping departments for final products
- Resource recycling system areas
- Waste material disposal areas.

These areas should be marked on the layout of the facility.

MATERIAL AND ENERGY FLOW IN A BRICK PLANT



GROSS ENERGY REQUIREMENTS equals 4.03 GJ/TONNE

3.3.2.2 Major Functional Departments

At the same time, the major functional departments in the facility should be established and marked on the layout.

3.3.2.3 Major Energy-Consuming Systems

The energy auditor should start the visual inspection at the point where either the material or energy inputs into the facility. In general, it is preferable to start with the energy metering and storage facilities and follow their use through the facility.

For a facility that distributes a heating medium, such as steam for its process requirements, the energy auditor should start at the storage area for the fuel that supplies the source of heat. He should then follow the fuel supply to the equipment in which the distributed medium is heated. After examining the equipment and its associated controls, he should follow the heating medium distribution network to the various functional departments.

For a facility that uses fuel in a major process system such as a dryer or furnace, the energy auditor should inspect energy metering and storage facilities and then follow the material flows through the facility to each functional department.

Because the time available for the PEA is normally limited by financial considerations, the energy auditor must concentrate on the major energy consumers within the facility. To do this, he should consider a facility and its major functional departments as a combination of several energy-consuming systems as follows:

- Process systems such as dryers, boilers, and furnaces
- Large motors
- Building envelope
- Lighting
- Ventilation
- Heating
- Cooling

- Water systems, including steam and condensate distribution
- Distribution systems, such as compressed air and thermal fluids.

These systems interact to a certain extent, but each can be examined by the energy auditor on a stand-alone basis.

For each system, the energy auditor should inspect:

- Nameplate data
- Physical appearance
- Associated instrumentation
- Control systems
- Operating conditions
- External structure
- Internal structure, if possible.

The auditor should not conduct his analysis in isolation, but should talk with others to obtain information on potential operational improvements and problems.

The time spent examining each system should be based on the relative amount and type of energy consumed.

3.3.2.4 Instrumentation, Including Utility Meters

The auditor should check installed instrumentation for correct operation and to determine relative flows, pressures, and temperature cycles. All utility meters should be examined.

When specific consumption data are not available, the auditor can estimate the importance by asking either the person accompanying him or the operator of the system.

The auditor can estimate lighting loads by examining one fixture to determine type and rating and then adding up the number of fixtures. He can estimate saturated steam consumption from pipe sizing and pressure/temperature at the point of use.

3.3.2.5 Energy Reporting Procedures

If instruments are installed to measure energy use, there is usually a procedure for monitoring the readings. The energy auditor should find out what is done with the available information; if it is collated, he should examine the records.

3.3.2.6 Production and Reporting Procedures

Major production processes are usually monitored, and the energy auditor should determine what information is reported for each major product. This information is usually collected from some form of production report. Operational data collection sheets and logs are often used by production personnel. By examining them and by analyzing operation conditions at the time of the PEA, the auditor can identify possible conservation opportunities.

3.3.2.7 Conservation Opportunities

A thorough visual inspection of all parts of the facility will usually indicate obvious areas for energy efficiency improvement. The following typical examples -- found during a PEA -- represent opportunities for conservation:

- Missing or damaged insulation on heating surfaces
- Leaks of steam or other thermal fluids
- Equipment operating when not required
- Breaches in building structure
- Improperly adjusted or malfunctioning control systems
- Lighting systems used when not required
- Equipment schedules mismatched to occupancy production schedules.

The above list is by no means exhaustive; rather, it indicates the types of opportunities that generally exist and can easily be captured.

3.4 STEP 4: ANALYZE DATA

Once data are gathered, they must be analyzed. The steps in the analysis are:

- Develop an energy consumption-related data base for the facility
- Evaluate data base
- Prepare energy consumption indices
- Consider energy use in light of other factors, such as production and environmental conditions
- Estimate the energy conservation potential
- Review the overall facility energy management program.

3.4.1 Data Base Development

The major analysis step is the development of a data base on energy-related matters. The data base will be used many times in the course of energy management programs, and it must be as complete and accurate as possible. However, the data base will be continually refined as the energy management program progresses.

There are several items that should be included in an energy management data base:

- Historical data on consumption and cost of all energy supplies over a given time frame
- Historical production and other related data for the same time period as energy supplies
- Process flow diagrams
- Energy-consuming equipment inventory.

3.4.1.1 Historical Data for All Energy Supplies

The energy auditor should collect data for all forms of energy on a periodic basis. That basis is usually either a month or the periodic billing cycle of the energy supplier. In a PEA, it is normal to use data from the preceding 12 months of facility operation.

However, if more than 1 year of data is incorporated in the data base, the picture of energy use will be more complete. The data on energy consumption and costs must be converted to the same units of energy, which can be done by using data collection forms like those in Exhibits 3.4 through 3.11.

Because energy suppliers do not all bill on the same day, the facility should take its own readings from the meters. Where this can be done, all data will cover the same time period. Personnel should be encouraged to standardize the time and method of collecting these data.

3.4.1.2 Historical Production and Other Related Data

The energy auditor must determine how energy is used by the facility. To do this, he must compile a historical record of production for the same period as that for energy consumption and cost. Similarly, he can use other data that may affect the use of energy.

He can use two sources to obtain the data. One source is the facility's production records, operating schedules, scrap records, operating parameters, etc. The other source is records from external agencies, such as weather stations that contain information on prevailing climatic conditions or local energy suppliers. The energy auditor should not dismiss any potential factor that could significantly affect energy use.

3.4.1.3 Process Flow Diagrams

The visual inspection enables the energy auditor to identify the significant energy consumers within a complex. During the inspection, the auditor should try to produce a series of line diagrams for the flow of materials and energy through the facility.

Prior to his evaluation, the energy auditor should combine these notes and sketches into a series of process flow diagrams. He should mark details of physical size, instrumentation, and capacities, together with the date and operating conditions at the time of the inspection, on the process flow sheets. He should also note flow rates of materials and energy, if known.

The auditor should prepare the diagrams carefully so they can be used on a recurring basis to monitor operations.

If ideal or target conditions can be determined, they should be marked on the diagram.

3.4.1.4 Energy-Consuming Equipment Inventory

Because the time spent on a PEA is limited, it is not possible to compile a complete inventory of energy-consuming equipment within the facility. However, if the energy auditor has done his work thoroughly, he should have identified 80 percent of the consumers of energy within a facility.

The auditor should compile an inventory of the various equipment on the basis of the type of energy used. The rating or capacities of the equipment for the various energy sources should be totaled and compared with actual energy usage as found from the consumption data base.

3.4.2 Evaluate Data

Next, the energy auditor evaluates the data collected in the data base. The evaluation will permit him to draw conclusions and make recommendations for improving energy efficiency.

He can evaluate the data to determine the following:

- Energy use -- consumption, cost, and schedules
- Energy consumption indices
- Plant operations
- Energy savings potential
- Plant energy management program.

3.4.2.1 Energy Use and Relation With Other Factors

The auditor can use the data on energy consumption and cost in several ways. In the first evaluation, it is usual to determine the relative amounts of fuel used and their relative costs over the data base period. An example of this type of analysis is shown in Exhibit 3.23.

Such an analysis indicates the relative value of savings for each type of fuel and also indicates which type of fuel is the major source of energy.

A second evaluation is to analyze the existing rate schedules under which each type of fuel is purchased. Fuel suppliers charge in various ways for the energy provided. Some methods of costing used in rate schedules for following three energy sources are described below:

- Electricity
- Oil
- Gaseous fuels.

Electricity is normally the most expensive form of energy purchased. Electric power generation requires major capital investment and considerable operating expense. Because of this, electric utility companies have developed rate schedules that try to give them a fair rate of return for their money invested.

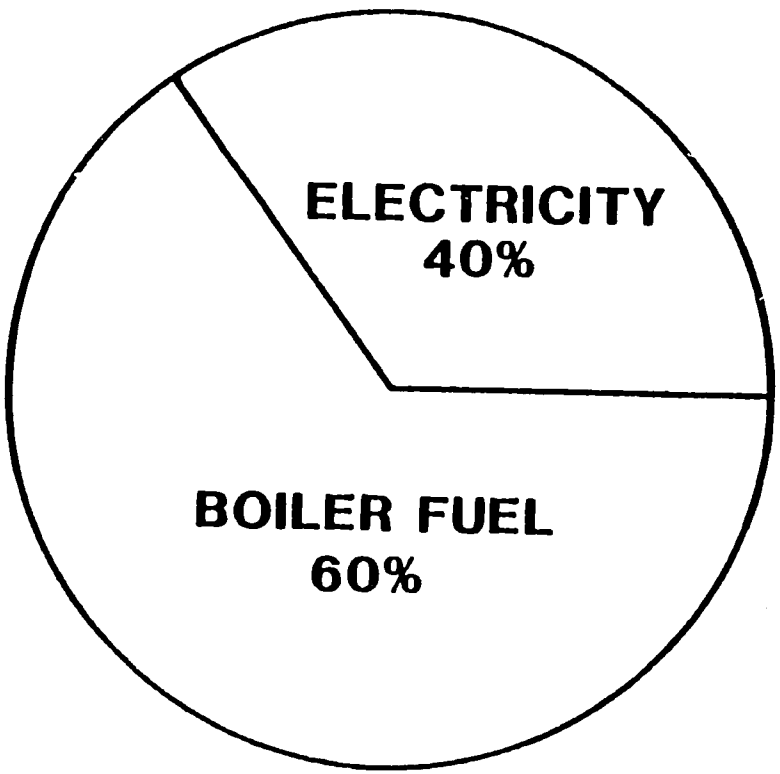
Customers are normally billed according to these rate schedules on the basis of maximum demand, power factor, and energy consumption. Customers may also be charged a flat rate fee per meter or per customer account to cover the utility's administrative costs. In many instances, utilities charge (or credit) customers depending on whether the utility's actual fuel costs are more (or less) than the projected costs embodied in the rate structure.

The **maximum demand charge** is based on the highest sustained consumption rate over a given time period. Usually, the time period is 15 minutes. The demand is normally measured in terms of kilowatts (kW) or kilovolt amperes (kVA). The charge is usually a cost per unit of demand.

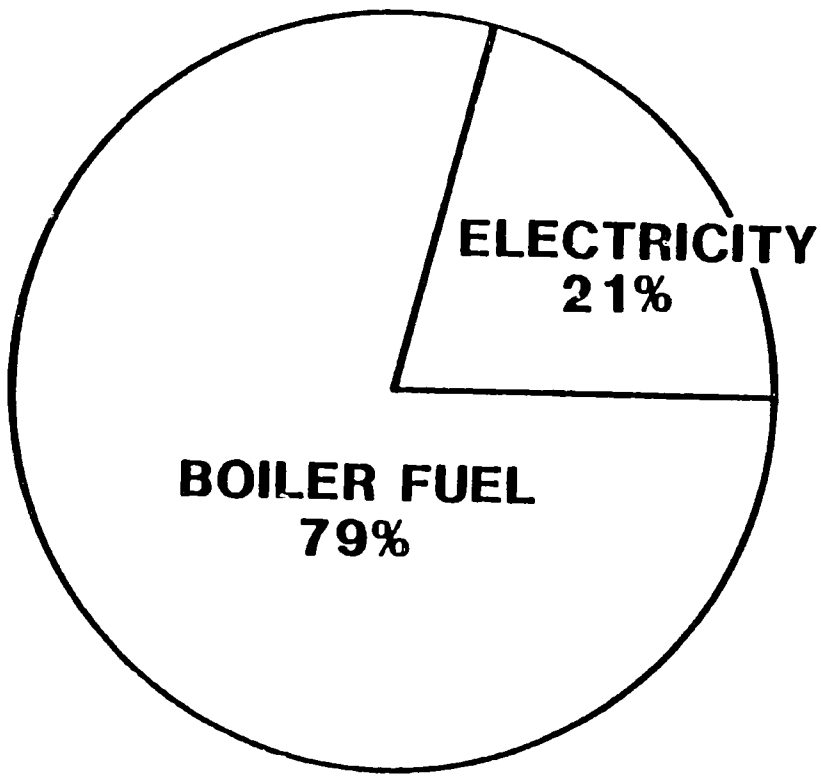
Exhibit 3.23

ENERGY DISTRIBUTION

BY COST



BY TYPE



TYPICAL MANUFACTURING FACILITY ENERGY DISTRIBUTION
BY COST AND TYPE OF ENERGY CONSUMED

Because of non-resistive electric customer loads (i.e., capacitive and inductive loads), a portion of the electric power generated and transmitted by the utility is lost, and not usefully consumed, by the customer. If **the power factor** --that is, the ratio of usefully consumed electric power to the amount of electric power that must be supplied to the customer -- falls below a predetermined level, typically 0.85, power factor charges are levied.

Consumption charges are based on the amount of electricity used in terms of kilowatt-hours. Charges are usually computed on a cost per unit of consumption. The charges are often assessed on a block basis, with a reduction in the amount charged for consumption above a stated level. As a utility company generates more electricity, the incremental cost per unit produced declines, up to a certain point; hence, the use of the block rate.

When determining a rate schedule, the utility company estimates what it will pay for fuel to generate electricity. Unfortunately, the charges on which it bases its calculations often change, so the utility passes on this change in the form of a fuel adjustment charge. The utility is normally obliged to pass along any reduction in fuel costs as well.

Most rate schedules are based on variations on the above charging methods. Scales of charges differ, depending on the type and size of the facility; for example, commercial and industrial facilities are usually charged different amounts for demand and consumption. Within sectors, there is often more than one rate schedule under which a facility can purchase power.

Oil is usually purchased on the basis of grade and quantity. Lighter oils usually cost more than heavier fractions, and low-sulfur oils generally are more expensive than high-sulfur oils. Because most facilities have fixed oil grade requirements, the cost of the oil depends on the amount of oil delivered and consumed. Price reductions are sometimes given for large-quantity consumption and deliveries.

Gaseous fuels are bought on the basis of delivery to a facility. The most common method worldwide is pipeline. Alternatively, gaseous fuels are delivered by truck as liquids under pressure.

When delivered by pipeline, a block tariff similar to that for electrical consumption is used, and an administrative charge often levied. Occasionally, charges are based on a predetermined rate of consumption, and any shortfall or excess consumption is charged at a higher rate.

Gas prices have often been linked to oil prices by some suppliers, and any price change is automatically passed on to the customer.

When delivery is made by truck, costs are generally assessed in a manner similar to that for oil.

Gas may be used with oil on a dual fuel basis. Fuel suppliers contract with consumers to supply gas at a less expensive rate, provided that the gas supply can be interrupted by the supplier for an extended period at times of peak demand. During an interruption, the facility would normally use a standby fuel such as oil.

To accurately determine the cost benefits from saving energy, the marginal **cost** of each energy source must be computed. A facility saves energy either by reducing its consumption of one or several energy sources or by substituting one energy source for another. To determine the cost savings resulting from a reduction in energy use, the energy auditor should therefore use the marginal cost of each fuel. The marginal cost of energy is defined as the cost of the last unit of energy consumed.

The marginal cost of electricity is the cost of the last kilowatt-hour consumed plus any fuel adjustment charge (variable charge). It is exclusive of any demand charge. The demand marginal cost is the cost of the last kilowatt or kilovolt ampere demand required. The marginal cost of oil is the cost of the last gallon or liter of oil consumed. The marginal cost of gas is the cost of the last unit of gas consumed plus any fuel adjustment charge.

The marginal cost is usually lower than the cost of energy obtained by dividing total consumption by total cost because it does not take into account fixed charges. Marginal costs are developed from information on the prevailing rate schedules obtained during the PEA.

3.4.2.2 Energy Consumption Norms or Indices

Energy norms or indices can be used to determine energy efficiency of operations and, subsequently, energy conservation potential. Norms are numbers that have been developed as indicators of energy efficiency. Care should be taken when using them, as they are only indicators of how energy-consuming systems may function. Unfortunately, no two systems will operate the same way, and variations in energy consumption are inevitable. Similarly, plants and equipment may not always be run in the same manner, and energy use will be affected as a result. For that reason, energy norms are developed internally over a period of time, using a large data base of information. Fundamental requirements to develop norms include consistent records collected from accurate monitoring and metering procedures.

Norms can be developed at both the macro (plant) and micro level (piece of equipment). Macro level norms usually are specific energy consumption indices -- for example, energy consumption per unit of product output from a plant. Micro level norms are developed for individual operating equipment -- for example, the norm for a dryer is moisture evaporated per unit of energy consumption.

In the following, typical indices for industrial facilities are discussed. How to develop indices and norms is presented next. The use of data bases to model plant and system operating characteristics is also discussed. Examples of typical norms are given for reference purposes in Appendix A6.

3.4.2.2a Typical Energy Norms or Indices

When assessing the energy performance of any equipment or system, the energy auditor uses some reference point as a guide to how well that system is performing. The reference point used can be an energy norm or index. For example, when conducting a test on medium-size firetube oil-fired boiler, he would expect an overall efficiency around 78 percent. If the overall efficiency is below that figure, conservation potential exists.

Energy norms can be developed on many bases. Typically, energy efficiency is calculated as a percentage. Industry is primarily concerned with manufacturing a product. When evaluating the energy performance of a particular manufacturer, it is common practice to make the assessment using an energy norm based on energy consumed per unit of product output. For example, the energy norm for producing one ton of cement, by the dry process, is 0.08 tons of oil equivalent.

Commercial facilities such as offices, schools, hospitals, and industrial administrative buildings do not have a product as such. Hence, a different type of index is used. The most common index is energy consumption per square meter of conditioned floor space. In some cases, like hotels or hospitals, energy consumption by guest or patient can also be used.

As interest in energy use has increased, so has the interest in norms and indices. Measurement of energy efficiency has developed so that the rather simplistic specific energy consumption based on one variable, such as unit output or floor area, is being replaced by indices where energy use is evaluated using several specific variables that affect consumption. Examples of specific variables include:

- Degree-day data for space-conditioned facilities
- Operating hours of primary equipment
- Raw materials used in products
- Operating temperatures.

3.4.2.2b Developing an Energy Index

As mentioned earlier, energy consumption indices can be developed either on a macro or micro basis. There are differences in approach to the development, although some procedures are common. The development of both types of index are discussed in the following paragraphs.

3.4.2.2c Macro Index Development

The key steps in developing a macro index are:

- Develop energy data base
- Select appropriate indicator
- Test indicator
- Implement monitoring system using index.

Developing an energy data base is an important step in the conduct of a PEA. Information is generally obtained from utility bills, although plant personnel sometimes read the utility meters. Information on production and other factors that may impact upon energy utilization, such as production, operating schedules, and degree-day data can also be incorporated into the energy data base. The data base should use historical data for the plant for operations over a period of at least 12 months. Ideally, longer periods are used to give better results. The information should be available on a utility billing period or monthly basis.

The data base should be analyzed to select an appropriate indicator to use for energy consumption. This is done by comparing energy use to variables felt to impact significantly upon energy use. Such variables include production, operating schedules, plant load factors, capacity utilization, degree-day data, etc.

Various techniques can be used to determine how appropriate the indicators are. Relationships between the variables chosen and energy use can be plotted geographically to determine whether significant trends exist. Statistical methods can be used to determine whether linear or other relationships exist between consumption and the variables being examined. The linear regression technique is used frequently, and this is discussed further in the section on energy modelling.

Example indices that can be used are discussed below.

3.4.2.2d Example Indices

One index is the **plant load factor.**

The **electrical load factor** for the plant is defined as:

$$= \frac{\text{kWh consumption in billing period} \times 100}{\text{kW demand in billing period} \times \text{hours in billing period}} \%$$

Typically, electrical load factors for a single-shift operation are between 40 percent and 60 percent, whereas those for three-shift operations are between 50 percent and 75 percent.

Load factor indicates how close to capacity a plant is running. It is used to determine when peak demand can be reduced. For instance, low load factors can be increased by rescheduling the source of the peak demand to periods of low electrical demand, reducing the overall peak with a corresponding cost saving.

When other fuel sources are used primarily by one major energy consumer, it is possible to determine the **fuel load factor**, provided the energy user's design fuel consumption rating is known.

The **load factor** is computed by:

$$= \frac{\text{Energy consumption in billing period} \times 100}{\text{hourly fuel rating of major user} \times \text{hours in billing period}} \%$$

Consistent units should be used for energy consumption and fuel rating per hour of major user.

Load factors for fuels other than electricity should be above 40 percent for single-shift operations. Three-shift operations should have load factors between 60 percent and 70 percent.

A second index that can be developed is the **energy consumption per unit of product output.** This is defined as:

$$= \frac{\text{Energy consumption in given time period}}{\text{production in same time period}}$$

Having selected the appropriate index, it is necessary to test the index. This is done by monitoring the energy consumption and the index for a period of time and determining how accurate and effective it is as an indicator. If the indicator does not prove to be a good parameter against which energy consumption efficiency can be measured, it is then necessary to select an alternate index and test it. If it proves to be successful, then a monitoring system should be established that provides management the index on a regular basis. The index should then be used by management to determine whether energy efficiency is being maintained at the plant level.

3.4.2.2e Micro Index Development

Indices that demonstrate the energy efficiency of individual equipment can also be developed. The key steps in developing micro indices are:

- Collect performance data
- Compute energy balance and efficiency
- Select appropriate indicator
- Test indicator
- Implement monitoring system.

The major differences between the macro and micro index development is in the first two steps: collection of performance data and computation of energy balance and efficiency.

Historical data on energy use of individual equipment is not often available, mainly because of lack of appropriate submetering within plants.

To successfully develop micro indices, submetering is required. If possible, all major energy-consuming equipment should be metered. In practice, however, most companies do not install submeters or individual machines but prefer to submeter departments, if at all.

In the absence of historical energy consumption data on individual equipment, energy performance can be measured by conducting appropriate tests to determine the energy efficiency. These tests, some of which are described in Section 5 of this manual, will normally require some instrumentation to be conducted. Requirements can be determined by checking standard efficiency test procedures are laid down by bodies such as the American Society of Mechanical Engineers and British Standards.

Tests should be completed and then energy balances and efficiencies calculated. The efficiency can then be used as an index. Alternatively, some specific energy consumption index such as kilogram of steam consumed per kilogram of moisture evaporated in a dryer can be developed.

Selection of the appropriate index may depend on the ease of conducting and repeatability of the test used to develop the index.

A compromise is sometimes needed when selecting the micro index between an index that is a reasonably accurate measure but readily obtainable as opposed to an exact index that is very time-consuming and very hard to obtain on a regular basis.

The last two steps of the development are the same as those for the macro index -- testing the index and implementing monitoring systems. As such, they are not discussed here.

3.4.2.2f Limitations of Simple Energy Indices

The concept of an "energy index" is derived from the energy auditing principle of determining the energy efficiency of a given process or plant. The energy index is usually expressed as the quotient of energy consumed and production in some convenient unit (e.g., kilograms, tons, number of units). An energy index expressed in this manner is easily derived and is easily understood, but there are a number of shortcomings associated with it that may lead to spurious results.

One major problem generally associated with this index is the inability to differentiate between contributors to plant energy consumption. Factors that contribute to energy

consumption in a plant or process may be either "internal" or "external" in nature. Internal factors are those that occur because of plant operation and may include such items as raw material mix, product mix, plant or department run time, and down time. External factors are those that occur beyond the control of plant operations. Such factors are generally weather-related.

All of these factors may be reflected **implicitly** in the energy index of energy consumption per unit of production. However, the factors are aggregated in the index, and their individual contributions -- which may be negligible, moderate, or extreme -- are masked. It is necessary to determine and quantify the significant factors that **explicitly** affect plant energy performance.

A further problem associated with the use of the simplistic energy index is the inability to use it to compare the energy efficiency and performance of plants or processes manufacturing different products, or manufacturing the same products in different ways. The use of the energy index for ranking may truly be a case of comparing apples with oranges.

3.4.2.2g Energy Modelling

One method used to overcome the inadequacies of the energy index is to develop energy consumption models. Linear regression techniques have been successfully applied in the past for the development of energy consumption models for a variety of types of process plants. These statistically valid models relate energy consumption to the various significant internal and external factors and take the form of the expression:

$$E = A_0 + A_1 X_1 + A_2 X_2 \ldots + A_n X_n$$

where E is energy consumption, A_0, A_1, . . . A_n are coefficients determined by regression, and X_1, X_2, . . . X_n are the significant variables affecting plant energy consumption (e.g., outside temperatures, moisture content of raw materials). Separate models should be generated for every different fuel type used by the facility. Application of linear regression techniques requires a number of data collection and analysis steps prior to the actual generation of the energy model.

The first step is to collect historical energy use data on the finest time step available, usually on a daily or weekly basis. A minimum time period of 12 months is required for successful modelling; however, up to 36 months of data should be included for best results. This may not be possible in all cases; in that event, utility billing data may be used.

Plant operating data should then be collected. These data may consist of raw material consumption, production by type of product, operating hours, scheduled maintenance hours, unscheduled down time hours, heating or cooling degree-days, or other values that the auditor feels may influence energy consumption. Regardless of the type of operating data collected, it must be collected on the same time periods as the energy use data. Prior to attempting to generate the model, all of the data should be checked for completeness.

To generate the model, a computer program capable of performing a stepwise multiple linear regression is required. A number of programs are commercially available to perform this task (see Exhibit 4.35).

The validity of the model, in a statistical sense, is determined by examination of the correlation coefficient. This number is generally provided by the linear regression program as one of the final results. The coefficient should be at least 0.90, but the model is generally more accurate when the coefficient exceeds 0.95. In addition, the actual energy use for the historical period should be compared with the energy use predicted by the model for that same period. The difference in actual and predicted values should not exceed plus or minus 10 percent for any individual point, to ensure usefulness of the model.

The model described above can be used for two major purposes. The primary use of the model is as a comparative tool to gauge actual plant energy performance against an "idealized" performance based on the plant's operating history. Because of the relatively simple procedure for using the model, unexpected increases in actual consumption over that predicted by the model may be readily identified, and problem areas corrected. Conversely, decreases in actual energy consumption over that predicted by the model may also be identified, allowing analysis of improved operating practices.

The second major use of the model is as a predictive tool. Energy costs can be planned and budgeted based on projected production rates and run time. However, because the model may require input data that may not be readily projected, its use as a predictive tool may be somewhat limited.

While the model produced may be statistically valid, certain limitations are inherent in any modelling technique. While these limitations do not make the models less useful or accurate, they do limit the indiscriminate use of the model. The model reflects the operation of the plant during the period reflected in the data used for its development. Substantial changes in plant operation, product or raw material mix, and run time and down time as compared with plant practice during the base period may reduce the statistical validity of the model as a comparative tool.

3.4.2.3 Plant Operations

The PEA provides information on the operation of a facility and the processes used in the manufacture of various goods. The energy auditor should evaluate these processes in terms of their energy consumption.

Production-related energy consumption indices indicate how energy use varies on a periodic basis. Where these indices vary widely from the mean, there may be opportunities to improve consumption.

The reason for deviation may not necessarily be related to plant operations. If sufficient information is available, the energy auditor should be able to identify the reason for consumption variations.

The energy auditor's visual inspection will enable him to determine whether a facility is poorly operated and maintained. The signs of poor operation will be obvious -- for instance, malfunctioning equipment, instrumentation and controls in disrepair, discarded materials littering the facility, dead light bulbs, and equipment operating when not required.

The scope for improvement will be greater in such a plant. However, even when opportunities can be identified, it may be difficult to implement measures aimed at improving operations. There are many reasons why plants are poorly operated and maintained, including:

- Lack of capital
- Lack of skilled management, operations, and maintenance personnel
- No formal maintenance program
- No established operational procedures
- Lack of interest by management and employees.

A poorly maintained plant is unlikely to have good records, so it may be difficult to determine operating conditions. If this is the case, the energy auditor should talk with more than one member of the operations staff, to determine whether they operate the plant in the same way.

3.4.2.4 Estimate of Energy Savings Potential

Estimating roughly (an accurate estimate is not possible after a PEA) the potential savings through energy conservation depends on the findings of the PEA and the experience of the energy auditor. The PEA is not an all-encompassing survey. Therefore, the energy auditor should try to identify general ways of saving energy. These ways include:

- Cleaning equipment
- Shutting down equipment when it is <u>not</u> required
- Changing operating schedules -- reducing heating times, idle times
- Adjusting wrongly set controls
- Repairing faulty controls
- Replacing damaged or missing insulation
- Improving combustion efficiency.

The savings potential can be estimated in percentage terms in most cases. For example, if a motor that runs 10 hours a day can be shut down for 5 hours, the savings would be

50 percent. If an operating heating temperature can be reduced by 1°C, energy savings of between 0.5 percent and 3 percent can be achieved, depending on the temperature differences involved.

Faulty controls can lead to energy waste through the extended use of energy-using devices or through overheating. They may also affect product quality. Estimates of savings should be based on the differences in the operating conditions observed during the PEA and those described by operations personnel. Replacing damaged or missing insulation will reduce heat loss from a heated surface by up to 90 percent.

Combustion efficiency improvements may be hard to estimate, but typically savings of between 1 percent and 3 percent are possible.

Usually, a PEA should enable the energy auditor to identify potential savings of 5 to 10 percent of overall energy consumption for a poorly maintained facility.

The PEA may also allow the auditor to identify conservation opportunities that will require detailed study in the detailed energy audit, such as:

- Improved combustion controls
- Heat recovery from waste gas streams
- Replacement of major energy-consuming equipment such as burners and boilers
- Power factor correction equipment.

It is not usual to estimate the savings potential for such measures at the end of the PEA. The energy auditor should, however, make a list of such opportunities. The number of opportunities listed is considered when deciding whether to conduct a detailed energy audit.

3.4.2.5 Plant Energy Management Program

As the final part of the PEA, the energy auditor should assess the plant's energy management program. He should identify the relative strengths and weaknesses of the

program, and recommend improvements at all levels. This evaluation should be addressed to the senior management of the facility to ensure that the necessary steps for improvement are taken.

The following conditions will be candidates for improvement by plant management:

- Lack of commitment from top management
- Lack of suitable plant personnel who understand the problem and are able to coordinate the program
- Lack of structured program
- Poor information and monitoring systems
- Lack of resources to implement recommendations.

3.5 STEP 5: DEVELOP ACTION PLAN

The energy auditor should prepare a report containing his findings and conclusions from the PEA. The highlight of the report should be an action plan on which future conservation work will be based.

The action plan should include as a minimim:

- Conservation opportunities for immediate implementation
- Projects for future study (with detailed work plan eventually)
- Recommendation on the detailed energy audit
- Resource requirements for a detailed energy audit
  - systems for testing
  - instrumentation
  - manpower
  - time frame
  - cost
- Refinements to existing corporate energy management program.

Summary

At the conclusion of the PEA and presentation of the subsequent report, the energy auditor must await management's decision on implementation of the recommendations contained in the action plan prepared.

If the PEA has been completed successfully, much valuable information will have been collected that lays the foundation for a successful detailed energy audit and energy management program. In addition, the plant should have a better understanding of how well it is succeeding with the goals and objectives of its overall energy management program, as well as some specific recommendations for immediate improvements.

Where management decides to act upon the recommendations in a short time period, this should indicate to the auditor that any major findings in a subsequent Detailed Energy Audit will receive similar attention, leading to implementation of conservation measures in a timely and cost-effective manner.

CHAPTER 4: INSTRUMENTATION

The Preliminary Energy Audit (PEA) will identify potential energy savings opportunities that merit additional study. This follow-up work is accomplished in the Detailed Energy Audit (DEA), which is a **more detailed, instrumented survey of energy-consuming equipment and systems.**

The PEA provides a "qualitative" measure of how efficiently the facility uses energy. **The Detailed Energy Audit provides the basis for a quantitative analysis of the energy performance of the facility.** To compile the operating data necessary to make this quantitative assessment, a variety of fixed and portable instrumentation is used.

The function and application of this instrumentation is covered in this section. In Chapter 5, the actual procedures for collecting and analyzing test data on a number of energy-consuming systems will be covered.

To make a detailed study of most equipment likely to be found in a plant, the energy auditor needs instruments that can measure the following:

- Temperature
- Flow
- Pressure
- Gas analysis
- Electricity
- Light levels
- Water analysis.

The instruments needed for a detailed energy audit are shown in Exhibit 4.1 and discussed in the remainder of this chapter.

4.1 TEMPERATURE MEASUREMENT

The most common parameter measured in energy studies is temperature. All evaluations of the heat content of a stream or the energy consumption of a process depend on

Exhibit 4.1

Detailed Energy Audit Instrument Kits

Instrument	Number required
Tape measure - 30 meters	1
5 meters	1
Flashlight	3
Assorted tubing	
Stopwatch/chronometer	1
Ear protectors	2
Goggles	2
Hardhats	2
Gloves	2
Pedometer	1
Assorted handtools	
Gas analyzer, chemical	1
Spare parts for above	2
Gas analyzer, chemical (Includes tubes)	1
Smoke test kit	1
Temperature indicator	1
(Probes for above) - Immersion	1
300 mm	1
600 mm	1
surface probe	1
Manometers - 0-75 mm	1
0-350 mm	1
0-1200 mm	1
Velometer and probes	1
Psychrometer - electric	1
Psychrometer - Mercury-in-glass	4
Spare thermometers for above	4
TDS meter	1
Clamp-on ammeters	1
Watt meter	1
Power factor meter	1
Light meter	1
Stethoscope	1
Infrared pyrometer	1

the temperature at each stage of the stream or in the process. The instruments commonly used for measuring temperature are:

- Liquid-in-glass thermometer (mercury thermometer)
- Psychrometer
- Dial thermometer (bimetal)
- Thermocouple
- Pyrometer.

The instrument used depends on the range of temperature to be measured, the severity of the environment, and how quickly the temperature must be measured.

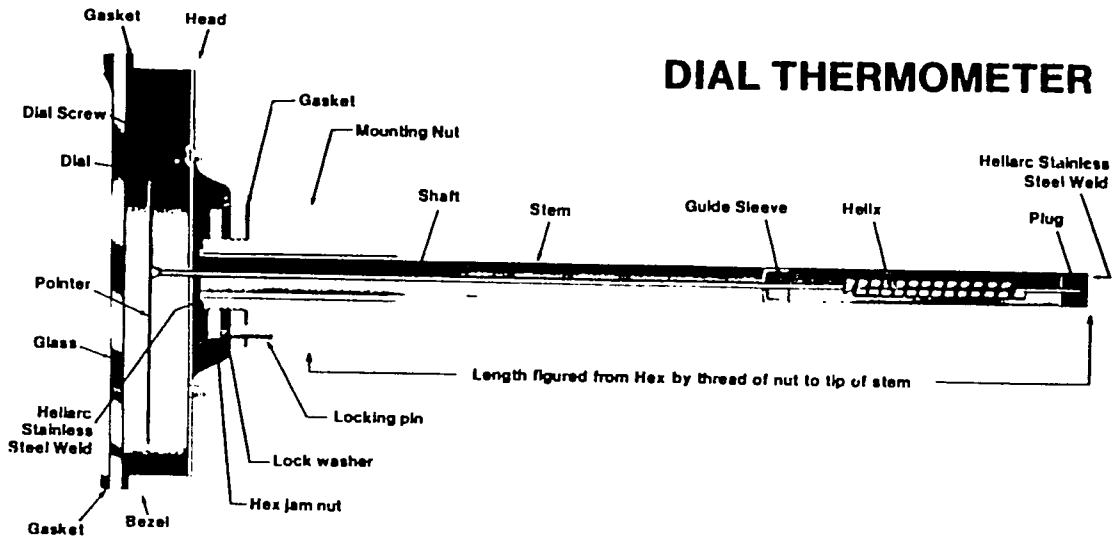
4.1.1 Liquid-in-Glass Thermometer

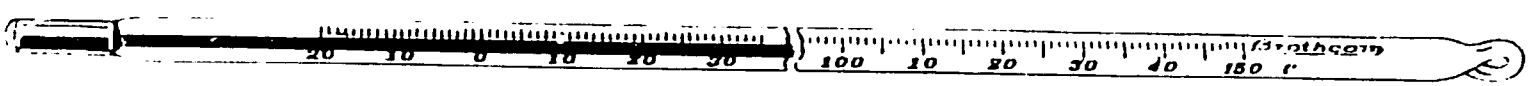
The simplest and most common device for measuring temperature is the liquid-in-glass thermometer. It normally uses mercury as the indicating fluid, although some organic fluids have become popular in recent years for applications below 32°C. Examples of typical liquid-in-glass thermometers are shown in Exhibit 4.2. Mercury thermometers can generally be used for temperatures from -35°C to 650°C, with an accuracy of 0.5°C to 0.75°C over the entire range. For special applications, these thermometers are available in laboratory-calibrated models that provide high accuracy.

The major drawbacks of the mercury thermometer are its slow response time and its fragility. It must be handled carefully, as it breaks easily. This fragility is a major disadvantage in many field applications where the auditor may have to insert the device in a duct or flue while performing a test. The slow response time is also a drawback in many field situations where access to a test location may be difficult, limiting the amount of time that an auditor can remain in position to take a temperature reading. The mercury thermometer is best used where it is not subject to mechanical damage or vibration and where access is relatively easy.

Exhibit 4.2

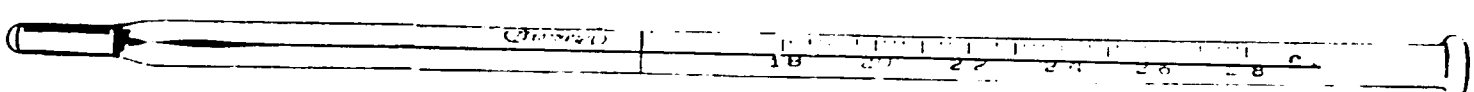
DIAL THERMOMETER





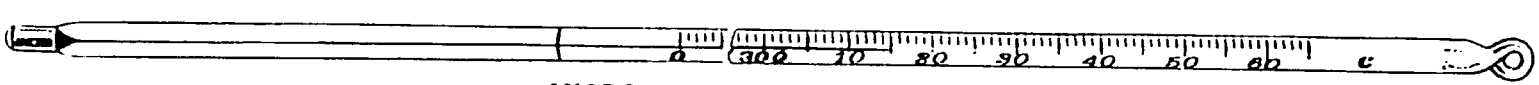
RED MERCURY MAGNIFYING Code: RM

The mercury column of code RM thermometers is magnified to approximately 1/16" across, and by internal reflection it appears as a bright red for easier reading. It is lens front tubing, somewhat triangular in cross section.



RED MERCURY ROUND Code: RR

By internal reflection the normal width mercury column appears as a bright red for easier reading. The tubing is round in cross section.



MICRO 4 to 5mm. O.D. Code: O

The thin 4 to 5mm. diameter and small sensitive mercury bulbs of Micro thermometers make them ideal for small sample distillations or where space is limited. They fit 3/16" stopper holes and the scale starts unobscured above the stopper. The thin diameter permits use of other tubes alongside. Micro thermometers are made shorter than Standard to reduce fragility.

MERCURY-IN-GLASS THERMOMETER

4.1.2 Psychrometer

A special application of the liquid-in-glass thermometer is for measuring relative humidity in conditioned spaces, air ducts, or discharge stacks from dryers. For this application, two thermometers are mounted in a device that permits simultaneous measuring of the air stream wet and dry bulb temperature, from which relative humidity can be calculated. The device used is called an aspirated psychrometer. Typical psychrometers are shown in Exhibit 4.3. The instruments include charts that can be used to determine humidity from the wet and dry bulb temperatures. For most conventional uses, the temperature range of the mechanical aspirated psychrometer is limited to 0°C to 50°C. At elevated temperatures, more sophisticated electronic devices are normally used.

The mechanical aspirated psychrometer is generally slow to react to changes in temperature, since it generally uses mercury-in-glass thermometers. The electronic psychrometer, however, is based on thermocouple and electronic moisture detection technologies. It provides a rapid analysis and direct digital readout of dry bulb temperature and relative humidity. The electronic devices generally operate at higher temperatures than thermometer-based psychrometers. An example of such a device is illustrated in Exhibit 4.3.

4.1.3 Dial Thermometer

The dial thermometer operates over a similar range to that of the liquid-in-glass thermometer. However, it can be used in places where a liquid thermometer cannot, as it is more rugged. The range of application is -100°C to 540°C, with an accuracy of 1 percent over the measured range. A dial thermometer with a reduced range is normally used to improve the accuracy of measurement. A typical dial thermometer is shown in Exhibit 4.2.

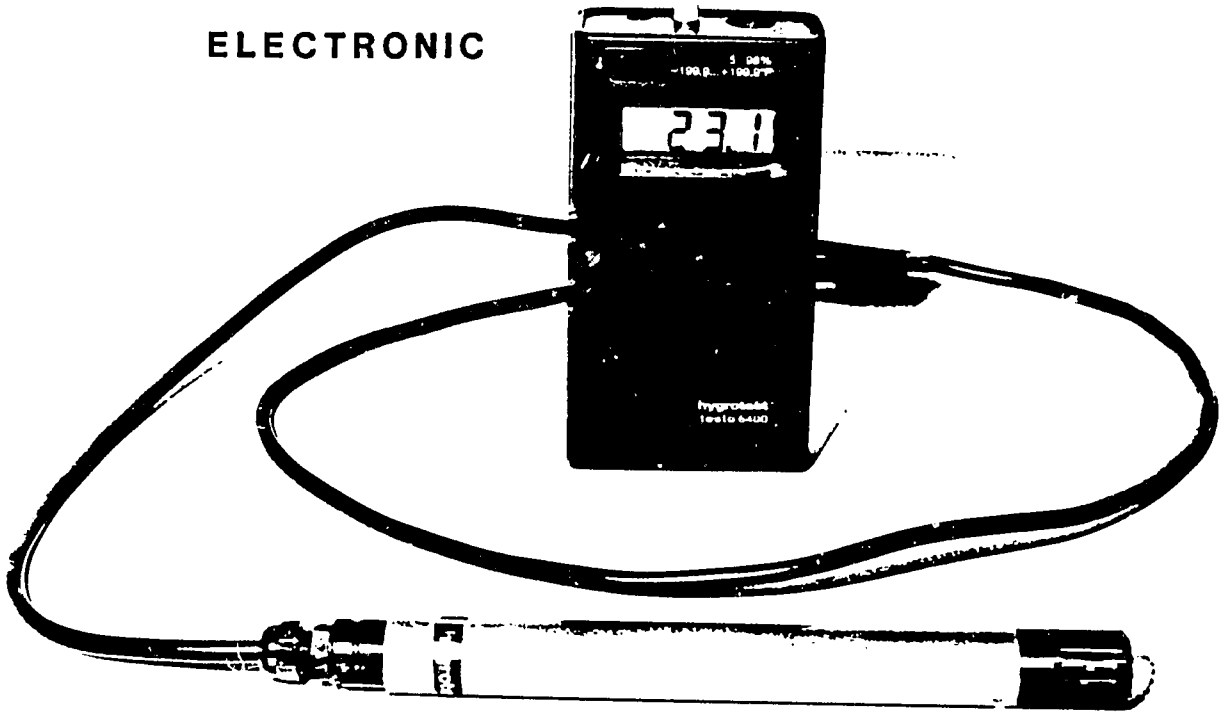
4.1.4 Thermocouple

Perhaps the most useful temperature measuring device is the thermocouple with electronic readout, as illustrated in Exhibit 4.4. Using the readout device and thermocouple

PSYCHROMETERS

EXHIBIT 4.3

ELECTRONIC



MECHANICAL

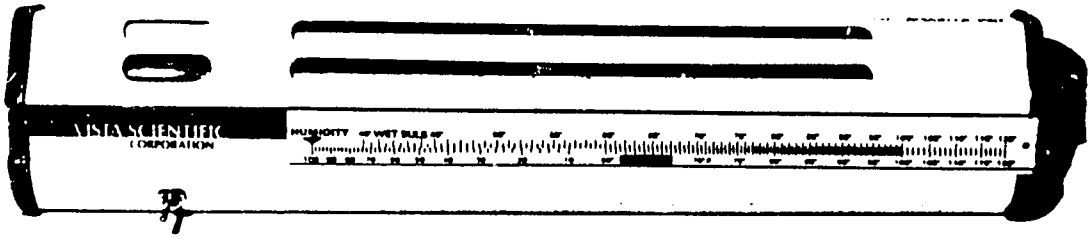
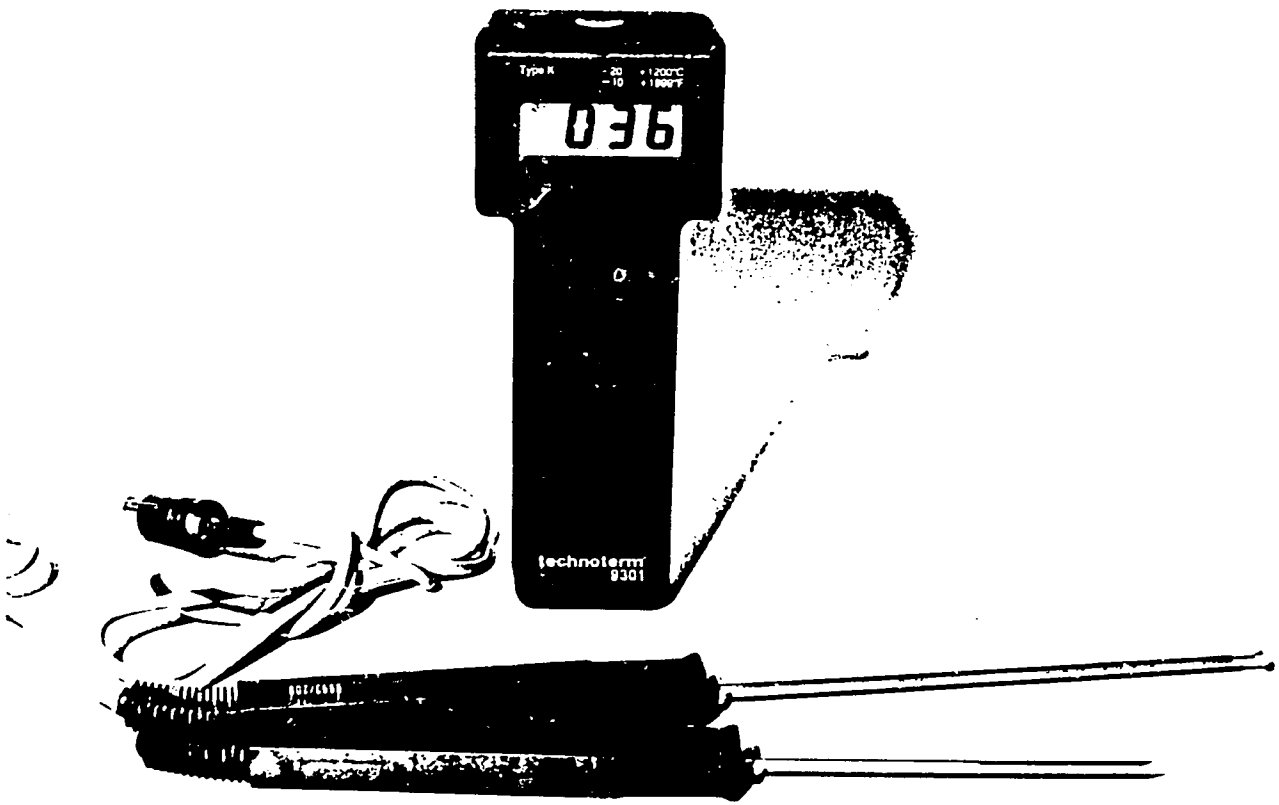


EXHIBIT 4.4

THERMOCOUPLE AND MATCHED THERMOMETER



probes in various configurations and composed of different materials, the energy auditor can determine the temperature of virtually any material with which he can make contact. Accuracy of thermocouple readings is generally about 0.25 percent of the reading.

A thermocouple consists of a pair of conductors of different metals or alloys, joined together at both ends. One end is placed in the area where the temperature is to be measured. The difference in temperature between that end (the measuring junction) and the other end (the reference junction) causes a voltage to be generated. The magnitude of the voltage is a function of the difference in temperatures between the measuring and reference junctions.

Several different combinations of metals are used in the manufacture of thermocouples. Seven types have been given letter designations by the Instrument Society of America, and temperature/voltage correlations have been published and recognized by standards organizations throughout the world.

The **Type B thermocouple** consists of two platinum/rhodium conductors (one at 6 percent rhodium, the other at 30 percent rhodium); it can be used over a temperature range of 0°C to 1,820°C in an oxidizing or inert atmosphere (continuous service) and in a vacuum (short service). This thermocouple produces a low voltage output and cannot be used in a reducing atmosphere (hydrogen or carbon monoxide) or in the presence of metallic or non-metallic vapors; it cannot be used with a metallic protection tube or in a thermometer well.

The **Type R thermocouple** consists of platinum and platinum/rhodium (13 percent) conductors and can be used over a temperature range of -50°C to 1,768°C. In other respects, it is similar in application to the Type B thermocouple; its chief advantage over the Type B thermocouple is its higher voltage output.

The **Type S thermocouple** consists of platinum and platinum/rhodium (10 percent) conductors. It can be used over the same range as the Type R and is similar in application to the Type B and Type R thermocouples. The Type S is the original thermocouple, and is the standard for measuring temperature between the melting points of antimony and gold (630°C to 1,064°C).

The **Type J thermocouple** consists of an iron conductor coupled to a conductor made of an alloy of 55 percent copper and 45 percent nickel. Its effective temperature range is -210°C to 760°C; above 540°C, the iron wire tends to oxidize and heavy gauge wire is required. This thermocouple type is satisfactory for continuous use in oxidizing, reducing, or inert atmospheres, but should not be used in high-temperature sulfurous atmospheres. The Type J thermocouple is commonly used because of its relatively low cost.

The **Type K thermocouple** is also known as a Chromel/Alumel thermocouple. Chromel is an alloy of 10 percent chromium and 90 percent nickel; Alumel is an alloy of 95 percent nickel plus aluminum, silicon, and manganese. The Type K can be used over a range of -270°C to 1,372°C in oxidizing and inert atmospheres; it is not suitable for use in reducing atmospheres. This is the most popular thermocouple used in industry.

The **Type T thermocouple** is of copper and constantan construction and is usable over a temperature range of -270°C to 400°C, which limits its industrial uses. It can be used in continuous service in a vacuum or in oxidizing, reducing, or inert atmospheres.

The final thermocouple type is **Type E**. This Chromel/constantan thermocouple is effective over a range of -270°C to 1,000°C and has the highest voltage output of any standard type of thermocouple. It can be used in oxidizing and inert atmospheres.

Thermocouples are available in a variety of configurations and designs for a large number of applications. Thermocouple probes (consisting of the thermocouple sheathed in a protective metal case and a handle) are available in various lengths and shapes.

The most commonly used thermocouple type is the Type K, described above. Its operating range (-270°C to 1,372°C) covers most of the temperatures encountered in audit work. Its only major limitation is that it cannot be used unprotected in a reducing atmosphere.

For situations where Type K thermocouples cannot be used, the auditor may want to select from the other combinations available. If the number of applications will be limited, it may not be economic to buy a dedicated readout device. In these cases, the auditor can use a voltmeter capable of reading the millivolt output of the thermocouple directly and convert that reading to temperature using the thermocouple reference

tables. The tables for the commonly available thermocouples are provided as Attachment 4.2, while the standard thermocouple types are shown with their temperature ranges and applications in Exhibit 4.5.

The auditor must be careful when using these tables, since the reference temperature is 0°C in all cases. In field situations, the reference temperature may be different. To determine the true reading, the measured reading must be adjusted to compensate for the effect of the actual ambient temperature. To do this, the auditor should subtract the voltage that would be generated by a compensated thermocouple at the ambient temperature from the reading obtained for the subject being measured.

Example: Using a Type K thermocouple, a reading for a gas stream of 21.846 millivolts is obtained. This is an uncompensated reading, because the temperature in the room is 20°C. Find the true stream temperature.

Answer: Use the thermocouple tables (Attachment 4.1) to determine the voltage output of a Type K thermocouple at 20°C. It is 1.019 millivolts. Therefore, the adjusted measured voltage is:

(V @ stream conditions) - (V @ 20°C) = 21.846 - 1.019 = 20.827 millivolts.

On the thermocouple tables, 20.827 millivolts equal a temperature of approximately 381°C.

In the example above, the actual temperature of the stream was 380°C, not 381°C as calculated. This slight inaccuracy is caused by the fact that the output of the thermocouple is not truly linear with temperature, so slight inaccuracies can occur using this method. Such variations are acceptable for normal audit work. If greater accuracy is required, the auditor should provide an ice bath reference junction to cancel the effect of ambient temperature or should buy an electronic readout device that automatically compensates for variations in ambient temperature using an electronic reference point.

Exhibit 4.5

Standard Thermocouple Application Chart

Thermocouple type	Temperature range	Atmosphere*				Millivolt output
		R	O	I	V	
B	0°C to 1,820°C 32°F to 3,310°F		X	X	X	0 to 13.814
R	-50°C to 1,768°C -60°F to 3,210°F		X	X		-0.226 to 21.108
S	-50°C to 1,768°C -60°F to 3,210°F		X	X		-0.236 to 18.698
J	-210°C to 760°C -350°F to 1,400°F	X	X	X	X	-8.096 to 42.922
K	-270°C to 1,372°C		X	X		-6.458 to 54.875
T	-270°C to 400°C -450°F to 750°F	X	X	X	X	-6.258 to 20.869
E	-270°C to 1,000°C -450°F to 1,830°F		X	X		-9.835 to 76.358

*R = reducing
O = oxidizing
I = inert
V = vacuum.

4.1.5 Pyrometers

All of the devices discussed above must have some contact with the medium being measured to be effective. However, there are many applications requiring temperature measurement where such contact is either impractical or dangerous. Examples include the measuring of moving materials or the examination of electrical switchgear for poor contacts by detecting hot spots. In these situations, the auditor requires a form of non-contact temperature measurement. Devices of this type measure the infrared radiation emitted by an object and convert the measured radiation to a usable temperature reading. There are four types of radiation pyrometers:

- Broadband pyrometer
- Optical pyrometer
- Bandpass pyrometer
- Ratio pyrometer.

The broadband and optical pyrometers are the most common pyrometers and are discussed in more detail than the bandpass and ratio pyrometers.

The **broadband pyrometer** is the simplest type, both in design and use. It measures radiation in all wavelengths in the visible and infrared regions, and is suitable for use over a temperature range of less than 0°C to above 3,000°C. The emissivity of the material to be measured is set on the emissivity control. The object is sighted in the same manner as a gun (some models use optical sighting instead of bead and groove sighting). The trigger is depressed, and a reading is indicated in the display. Some models have a digital display, while other models use a dial-type display.

An **optical pyrometer** measures by comparing the brightness of visible radiation of the object being measured with that of a reference. It operates over a narrow wavelength band and is useful in the temperature range of 600°C to above 3,000°C. The optical pyrometer is slightly more complex in operation than the broadband pyrometer. The instrument depends on the ability of the human eye to discern the difference in brightness between two sources of light. As with the broadband pyrometer, the object to be measured is sighted. The adjusting control is rotated until the brightness of the object measured equals that of the reference as viewed through the eyepiece. The

adjusting control is coupled to a temperature scale for direct reading. This instrument is used in high-temperature applications where the emissivity of the object being measured is close to unity. No provision is made for adjusting emissivity at the instrument.

A **bandpass pyrometer** operates over a selected range of wavelengths by using special filters to eliminate undesired wavelengths. This device is useful in measuring such materials as glass or plastic films. Since glass is not transparent to wavelengths above about 2.8 microns, the pyrometer must be sensitive only to those wavelengths to avoid measuring the temperature of materials behind the glass.

The **ratio pyrometer** measures the intensities of radiation emitted by the object at two wavelengths, using the ratio to compute the object's temperature.

While the broadband pyrometer, as noted above, is the simplest type to use, the biggest problem associated with pyrometers is determination of the proper emissivity of the material being measured. Emissivity for a given material varies between 0 and 1, depending on how closely it approximates the radiation characteristics of a perfect black body. The emissivity of many common substances can be determined. A typical table is provided for reference in Exhibit 4.6.

For materials not listed in the table, the auditor can determine the emissivity either by approximation of the emissivity with that of a known substance (which is not always a reliable method), or by directly calibrating the emissivity from that of a sample of the same material at a known temperature. For many materials, the emissivity can be determined by obtaining a sample of the material and measuring its surface temperature using a thermocouple or other reliable temperature measuring device. The next step is to aim the pyrometer at the material and read the temperature. If the reading does not agree with that of the thermometer, adjust the pyrometer emissivity setting until readings agree. The setting on the emissivity adjustment dial is the emissivity of the material under analysis and should be recorded for future reference. The auditor can now go to the field and obtain reliable temperature readings using the pyrometer.

The auditor should be aware of one other characteristic of the pyrometer to ensure that he obtains accurate results from the device. The pyrometer measures the average

Table of Total Emissivity

These tables are presented for use as a guide when making infrared temperature measurements with the OMEGASCOPE™ or other infrared pyrometers. The total emissivity (Є) for Metals, Non-metals and Common Building Materials are given.

Since the emissivity of a meterial will vary as a function of temperature and surface finish, the values in these tables should be used only as a guide when making relative or delta measurements.

The exact emissivity of a material should be determined when absolute measurements are required.

EXHIBIT 4.6

METALS

MATERIAL	TEMPERATURE (°F)	Є - EMISSIVITY
Alloys		
20-Ni, 24-CR, 55-FE, Oxidized	392	90
	932	97
60-Ni, 12-CR, 28-FE, Oxidized	518	89
	1040	82
80-Ni, 20-CR, Oxidized	212	87
	1112	87
	2372	89
Aluminum		
Unoxidized	77	02
	212	03
	932	06
Oxidized	390	11
	1110	19
Oxidized at 1110°F	390	11
	1110	19
Heavily Oxidized	200	20
	940	31
Highly Polished	212	09
Roughly	212	18
Commercial Sheet	212	09
Highly Polished Plate	440	04
	1070	06
Bright Rolled Plate	338	04
	932	05
Alloy A3003, Oxidized	600	40
	900	40
Alloy 1100-0	200-800	05
Alloy 24ST	75	09
Polished	75	09
Alloy 75ST	75	11
Polished	75	08
Bismuth, Bright	176	34
Unoxidized	77	05
	212	06
Brass		
73% Cu, 27% Zn, Polished	476	03
	674	03
62% Cu, 37% Zn, Polished	494	03
	710	04
83% Cu, 17% Zn, Polished	530	03
Matte	68	07
Burnished to Brown Color	68	40
Cu-Zn, Brass Oxidized	392	61
	752	60
	1112	61
Unoxidized	77	04
	212	04
Cadmium	77	02
Carbon		
Lampblack	77	95
Unoxidized	77	81
	212	81
	932	79
Candle Soot	250 95	
Filament	500	95
Graphitized	212	76
	572	75
	932	71
Chromium	100	08
	1000	26
Polished	302	06
Cobalt, Unoxidized	932	13
	1832	23
Columbium, Unoxidized	1500	19
	2000	24
Copper		
Cuprous Oxide	100	87
	500	83
	1000	77
Black, Oxidized	100	78
Etched	100	09
Matte	100	22
Roughly Polished	100	07
Polished	100	03
Highly Polished	100	02
Rolled	100	64
Rough	100	74
Molten	1000	15
	1970	16
	2230	13
Nickel Plated	100-500	37
Dow Metal	0-600	15
Gold		
Enamel	212	37
Plate (.0001)		
on .0005 Silver	200-750	11-14
on .0005 Nickel	200-750	07-09
Polished	100-500	02
	1000-2000	03
Haynes Alloy C, Oxidized	600-2000	90-96
Haynes Alloy 25	600-2000	86-89
Haynes Alloy X	600-2000	85-88
Inconel Sheet	1000	28
	1200	42
	1400	58
Inconel X, Polished	75	19
Inconel B	75	21
Iron		
Oxidized	212	74
	930	84
	2190	89
Unoxidized	212	05
Red Rust	77	70
Rusted	77	65
Liquid	2760-3220	42-45
Cast Iron		
Oxidized	390	64
	1110	78
Unoxidized	212	21
Strong Oxidation	104	95
	482	95
Liquid	2795	29
Wrought Iron		
Dull	77	94
	660	94
Smooth	100	35
Polished	100	28
Lead		
Polished	100-500	06-08
Rough	100	43
Oxidized	100	43
Oxidized at 1100°F	100	63
Gray Oxidized	100	28
Magnesium	100-500	07-13
Magnesium Oxide	1880-3140	16-20
Mercury	32	09
	77	10
	100	10
	212	12
Molybdenum	100	06
	500	08
	1000	11
	2000	18
Oxidized at 1000°F	600	80
	700	84
	800	84
	900	83
	1000	82
Monel, Ni-Cu	392	41
	752	44
	1112	46
Oxidized	68	43
Oxidized at 1110°F	1110	46
Nickel		
Polished	100	05
Oxidized	100-500	31-46
Unoxidized	77	05
	212	06
	932	12
	1832	19
Electrolytic	100	04
	500	06
	1000	10
	2000	16
Nickel Oxide	1000-2000	59-86
Palladium Plate		
(.00005 on .0005 silver)	200-750	16-17
Platinum	100	05
	500	05
	1000	10
Black	100	93
	500	96
	2000	97
Oxidized at 1100°F	500	07
	1000	11
Rhodium Flash		
(.0002 on .0005 Ni)	200-700	10-18
Silver		
Plate (.0005 on Ni)	200-700	06-07
Polished	100	01
	500	02
	1000	03
	2000	03
Steel		
Cold Rolled	200	75-85
Ground Sheet	1720-2010	55-61
Polished Sheet	100	07
	500	10
	1000	14
Mild Steel, Polished	75	10
Smooth	75	12
Liquid	2910-3270	28
Steel, Unoxidized	212	08
Oxidized	77	80
Steel Alloys		
Type 301, Polished	75	27
	450	57
	1740	55
303, Oxidized	600-2000	74-87
310, Rolled	1500-2100	56-81
316, Polished	75	28
	450	57
	1740	66
321	200-800	27-32
Polished	300-1500	18-49
w/BK Oxide	200-800	66-76
347, Oxidized	600-2000	87-91
350	200-800	18-27
Polished	300-1800	11-35
446, Polished	300-1500	15-37
17-7PH	200-600	44-51
Polished	300-1500	09-16
01020, Oxidized	600-2000	87-91
PH-15-7 MO	300-1200	07-19
Stellite, Polished	68	18
Tantalum		
Unoxidized	1340	14
	2000	19
	3600	26
	5306	30
Tin, Unoxidized	77	04
	212	05
Tinned Iron, Bright	76	05
	212	08

radiation emitted by everything within its field of view. The diameter of the field depends on the distance of the measured object from the front of the pyrometer, and it increases with distance. For this reason, the auditor should be as close to the object to be measured as is reasonably possible, consistent with safe practice. If the auditor is close to the object to be measured, he can limit the field of view and prevent the reading from being diluted by the surrounding environment. The field of view for a typical pyrometer designed to operate over long distances is shown in Exhibit 4.7. Manufacturers of pyrometers supply similar data to aid the user in determining the field of view at a given distance from the optics of the pyrometer.

A typical broadband pyrometer is shown in Exhibit 4.8. Other types of pyrometers are also available for specialized applications.

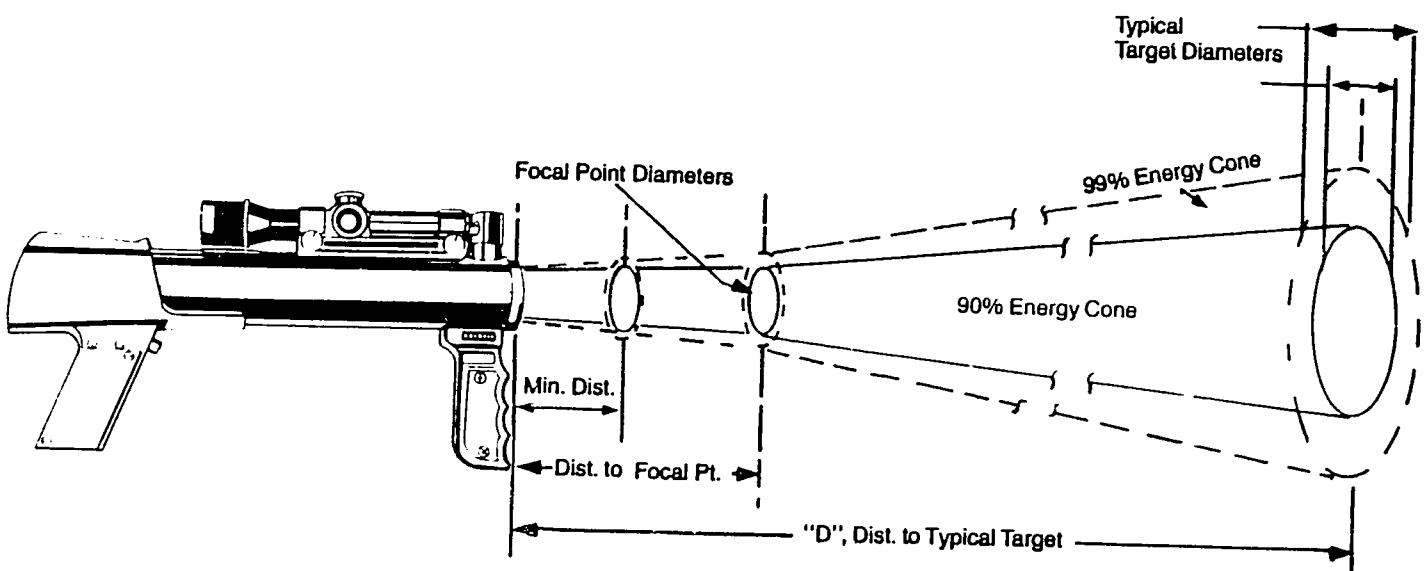
Summary

The table below summarizes the temperature ranges in which the five types of temperature measuring devices operate, together with the advantages and disadvantages of each.

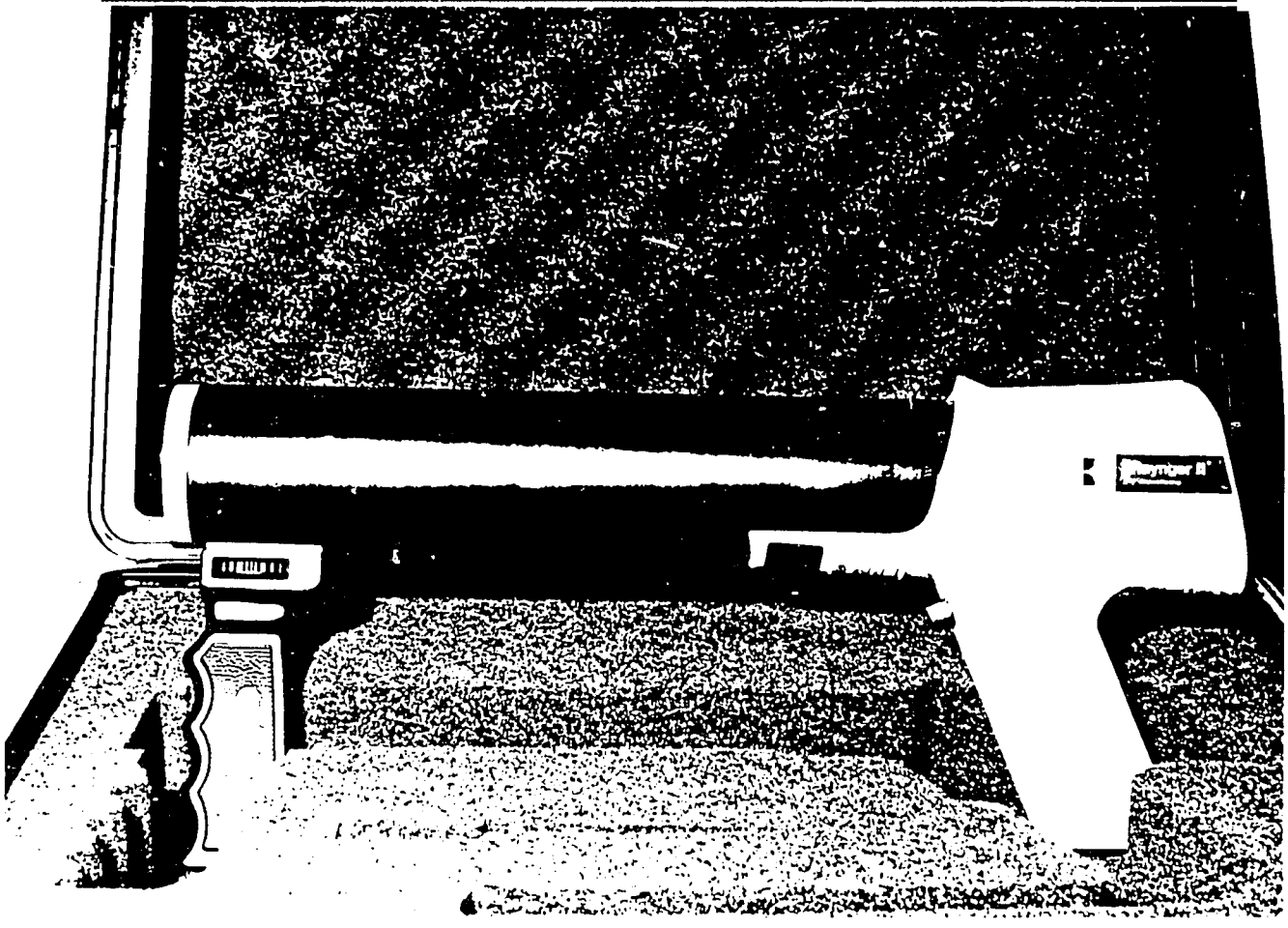
Measurement device	Temperature range (°C)	Advantages	Limitations
Mercury-in-glass thermometer	-35 to 650	Accuracy	Fragility; slow response
Dial thermometer	-100 to 540	Rugged; wide application	Accuracy; slow response
Thermocouple (type K)	-270 to 1,372	Wide application; fast response; accuracy	Expense; cannot be used in reducing atmosphere
Pyrometer (broadband)	0 to 3,000	Non-contact; fast response	Field of view; emissivity must be known

EXHIBIT 4.7

FIELD OF VIEW OF TYPICAL PYROMETER



	Min. Target Distance		Focal Point		Target Size
	Distance	Target Dia.	Distance	Target Dia.	Beyond Focal Point
90% energy cone	36"	.58"	78"	.67"	Targeted Dist/120
99% energy cone	36"	.92"	78"	1.34"	Targeted Dist/60



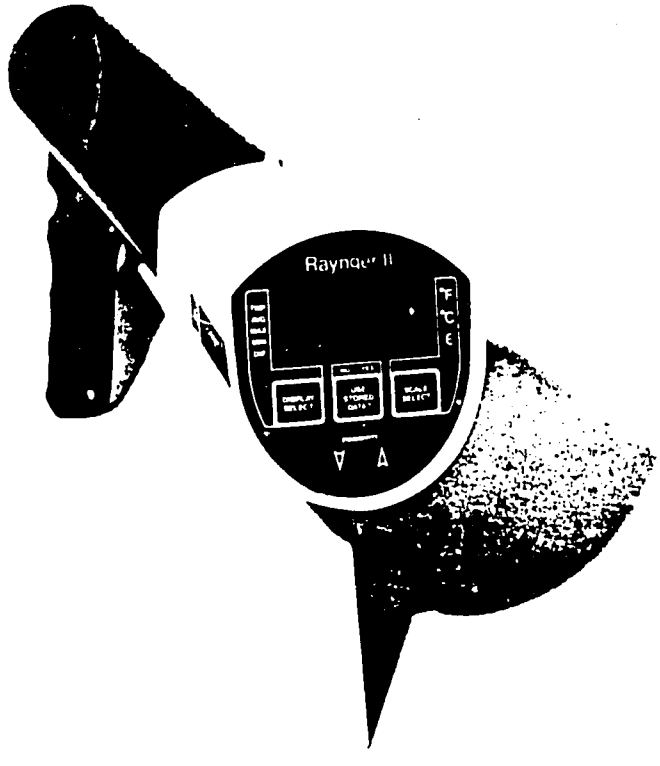


EXHIBIT 4.8 **BROAD BAND PYROMETER**

4.2 FLOW MEASUREMENT

In many audit situations, flow is the most difficult variable to measure. Flow instrumentation is either not installed where the auditor wants it, or the existing instrumentation is poorly maintained and out of calibration. To overcome this, the auditor must often estimate or calculate flow as a function of known or measurable parameters or from available manufacturer's data on the equipment being examined. Wherever possible, the auditor should try to obtain reliable flow data from installed instruments.

If no flow measuring equipment is installed, the facility should weigh the need for such equipment against the cost of buying and installing it and the level of accuracy required in the audit. If the facility decides to install instruments, the auditor should choose the type of meter and its location to ensure accuracy. This discussion is limited to the meters that the auditor uses most often. These meters are:

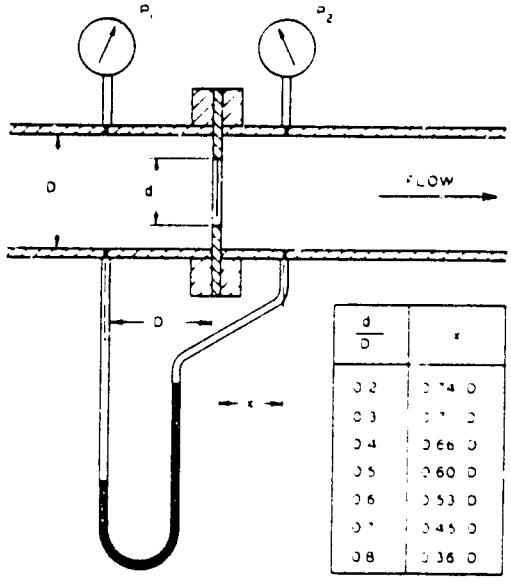
- Orifice type
- Pitot tube and manometer
- Velometer
- Ultrasonic (non-intrusive)
- Rotameter
- Turbine meter
- Positive displacement.

4.2.1 Orifice Meter

The most common device for measuring fluid flow is the **orifice meter.** It is generally permanently installed between pipe flanges, is relatively inexpensive, and -- when properly used -- is accurate enough for most applications. An orifice meter can be used to measure the flow of a variety of low-viscosity fluids and gases in pipelines where the range of maximum flow to minimum flow does not exceed a ratio of 3 to 1. The orifice meter arrangement is illustrated in Exhibit 4.9.

EXHIBIT 4.9

ORIFICE METER SHOWING LOCATION OF VENA CONTRACTA



$\frac{d}{D}$	x
0.2	0.74 D
0.3	[illegible] D
0.4	0.66 D
0.5	0.60 D
0.6	0.53 D
0.7	0.45 D
0.8	0.36 D

The orifice meter measures the pressure difference on both sides of the orifice plate. The equation that governs the relationship between flow and pressure drop across an orifice plate is:

$$W = kA_2 ((2gc) (d) (dp))^{0.5}$$

where W = mass flow rate

K = orifice plate constant, a function of plate geometry and Reynolds number

A_2 = orifice area

gc = gravitational constant

d = density of fluid

dp = absolute pressure drop across orifice plate, obtained by pressure taps.

This equation must be evaluated using a consistent set of units. A chart relating the dimensionless Reynolds number to the orifice constant for square-edged orifice plates is shown in Exhibit 4.10. This chart is valid only when the downstream pressure tap is mounted in the vena contracta, an area downstream of the orifice plate where the jet of fluid passing through the plate contracts to a minimum area.

The equation above is useful for fluid flow when the pressure drop is not more than a few percent of initial pressure. If the drop is greater, allowance must be made for the compressibility of the fluid. To make such allowances, the equation above is generally multiplied by an empirical compressibility correction factor given by the following formula:

$$Y = 1 - (0.41 + 0.35 B^4) (dp/Gp)$$

where B = the ratio of orifice diameter to pipe diameter

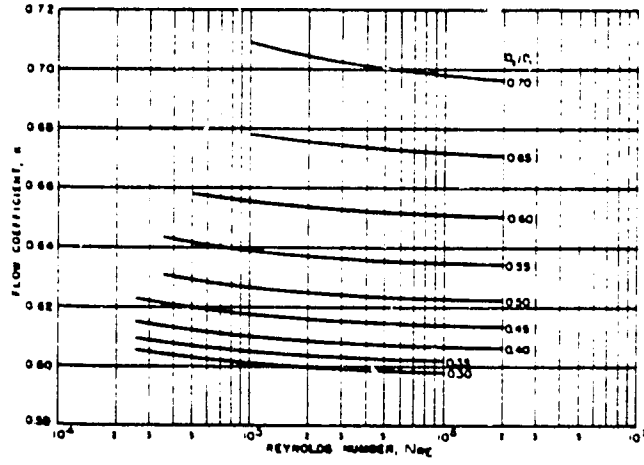
dp = pressure drop across the orifice

G = ratio of fluid specific heat at constant pressure to specific heat at constant volume

p = fluid pressure upstream of the orifice plate.

EXHIBIT 4.10

FLOW COEFFICIENT FOR ORIFICE PLATE FLOWMETER



4.2.2 Pitot Tube and Manometer

Another flow measurement device used primarily for gases is the **pitot tube,** used in conjunction with a **manometer.** The pitot tube is inserted into the fluid stream whose velocity is to be measured. The pitot tube operates on the principle that a gas flow across the end of an open tube causes a pressure drop. That pressure drop can be measured with the manometer. The manometer comes in either a portable configuration or one designed for permanent installation where it is known that the velocity profile of the flow stream is known to be flat.

The manometer is a U-shaped tube that is partially filled with a liquid, usually water or mercury. One end is generally open to the atmosphere, while the other end is connected to the pitot tube. The pressure drop is indicated by a difference in height between the two liquid columns. The pressure is in reference to atmospheric pressure (gauge pressure).

Using a water-filled manometer, air velocity is found from the following equation:

$$V = 420.4 \times (h/d)^{0.5}$$

where V = air velocity, meters per minute
h = height difference between columns, millimeters
d = density of air, kg per cubic meter.

This equation can be used to measure any flow by applying appropriate conversion factors. A pitot tube and manometer are illustrated in Exhibit 4.11.

4.2.3 Velometer

A device that operates on the same principle for gas flow measurement as the pitot tube and manometer is the **velometer.** This instrument is generally sold as a kit, with a number of probes available for use under differing flow conditions. Instead of using a manometer to measure pressure drop, the velometer has a built-in direct reading meter. A velometer is illustrated in Exhibit 4.12.

EXHIBIT 4.11

PITOT TUBE AND MANOMETER

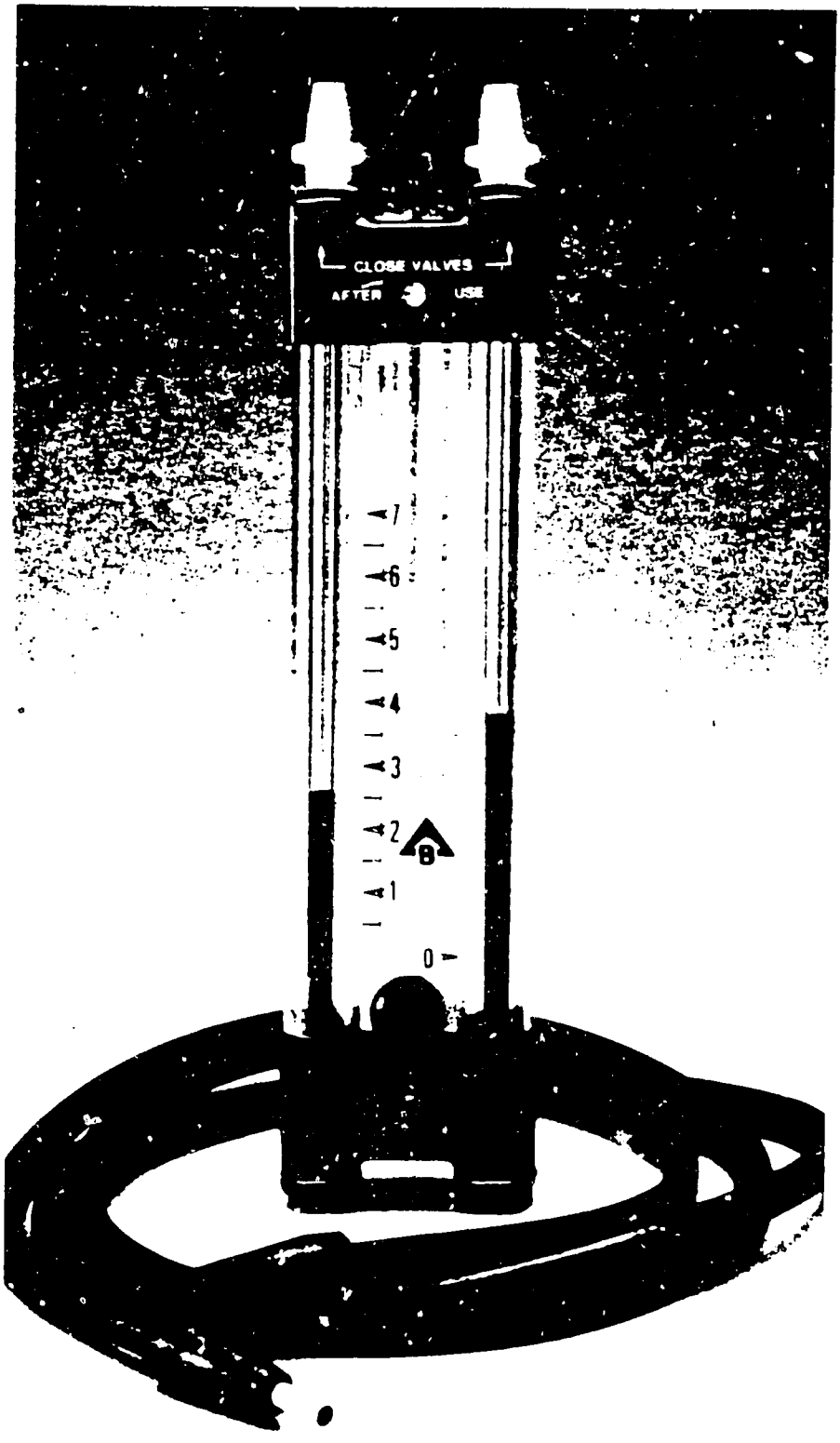
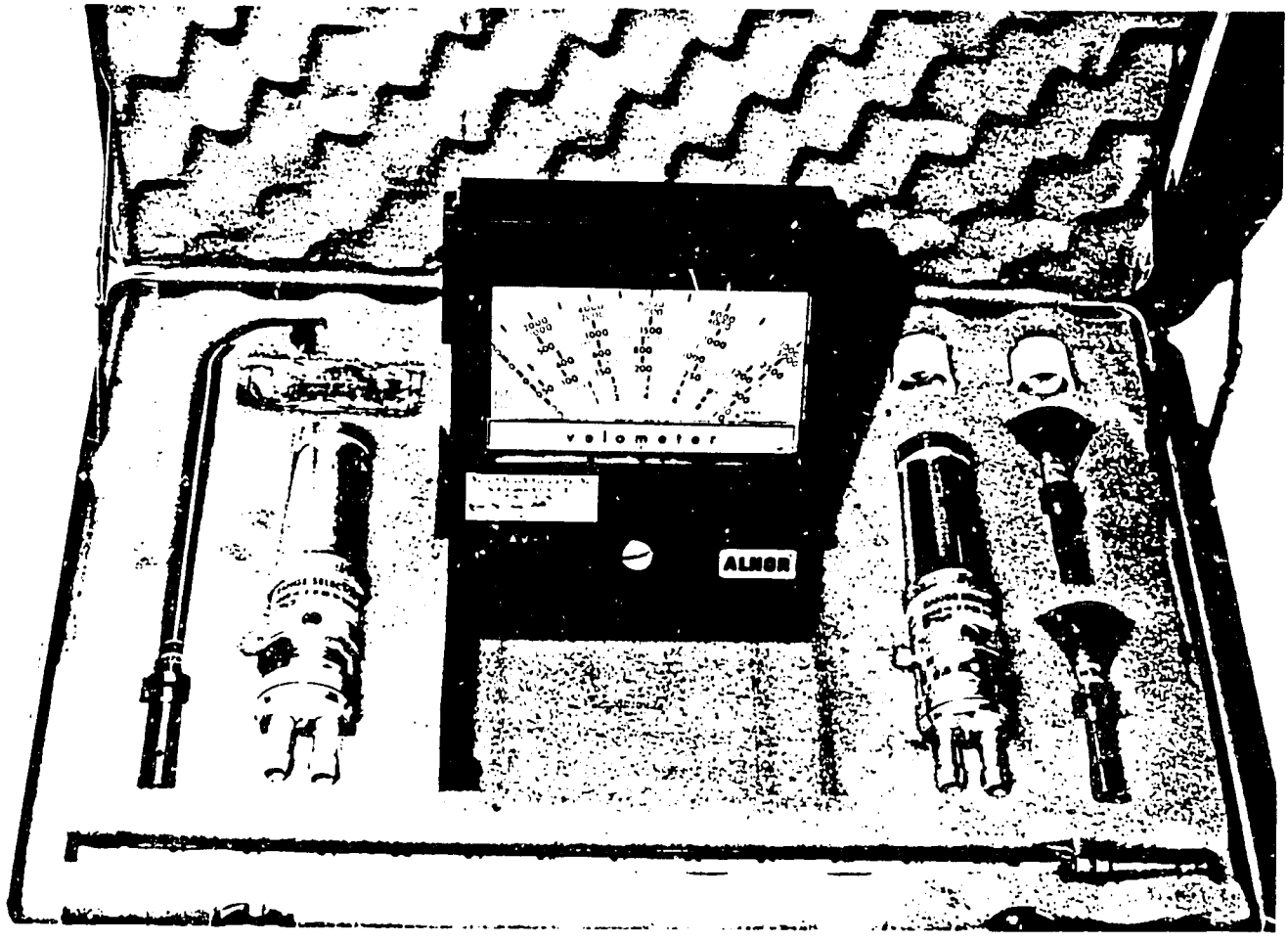


EXHIBIT 4.12

VELOMETER



The use of pitot tubes or velometer probes to measure flow has a serious drawback: velocity is measured at only one location. In practice, the velocity of a gas in a duct is not uniform across any section. Hence, a traverse is usually made to determine average velocity. The best method for measuring velocity is the equal area traverse method (see Exhibit 4.13).

Using this method for a circular duct, the cross-section is divided into six to eight concentric rings of equal areas. Measurements are taken at specified locations across two diameters at right angles to each other. For a rectangular duct, a similar approach is taken by dividing the duct into 16 to 64 equal rectangular areas and taking measurements at the center of each rectangle (see Exhibit 4.13). For both types of duct, the bulk velocity is found by using either the average of individual velocity readings, or the average of the square roots of the manometer indication; the auditor must not average the manometer indication directly. The volumetric flow rate through the duct can be determined by multiplying the average flow rate by the cross-sectional area of the duct.

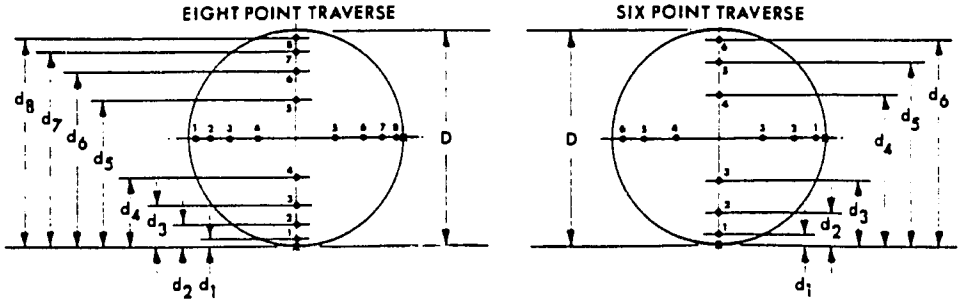
4.2.4 Ultrasonic Flow Meter

Easily used and portable instrumentation for liquid flow measurement is not as readily available. The **ultrasonic flow meter** consists of a set of transducers that are coupled with a display computer (see Exhibit 4.14). The transducers are clamped onto the pipe containing the liquid under study. One transducer injects an ultrasonic signal into the fluid that is detected by the other transducer, located downstream and on the opposite side of the pipe from the first transducer. Velocity is determined either by measuring the time required to receive the transmitted signal or by measuring the signal's frequency change owing to the Doppler effect.

The ultrasonic flow meter has several features that are valuable to the energy auditor. Chief among these is portability. Where permanently installed instrumentation is unnecessary or would interrupt plant operations, the ultrasonic instrument is non-intrusive. The accuracy of the device is excellent, at less than 0.5 percent error linear over the flow rate. Where a pipe network must be analyzed, spare transducer sets can be used

EXHIBIT 4.13

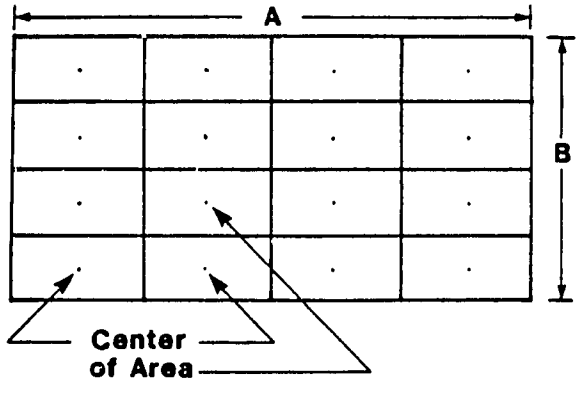
EQUAL AREA TRAVERSE FOR CIRCULAR DUCTS



Traverse Method	Probe immersion in Duct Diameters									
	d_1	d_2	d_3	d_4	d_5	d_6	d_7	d_8	d_9	d_{10}
6 point	0.043	0.147	0.296	0.704	0.853	0.957	–	–	–	–
8 point	0.032	0.105	0.194	0.323	0.677	0.806	0.895	0.968	–	–

EQUAL AREA TRAVERSE FOR RECTANGULAR DUCTS

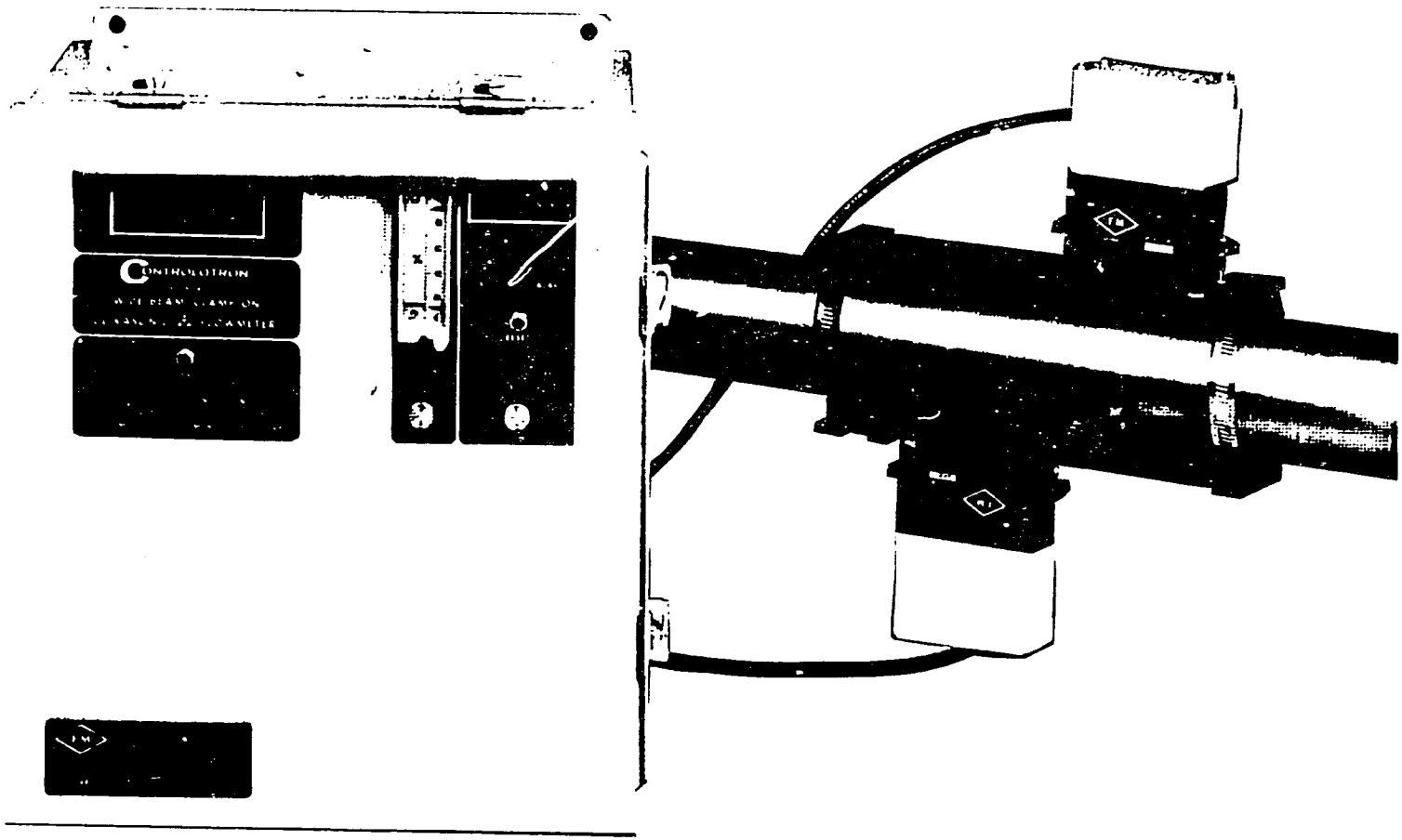
Use 16 to 64 Equal Area Rectangles



Made Measurement at Center of Rectangle

EXHIBIT 4.14

ULTRASONIC FLOWMETER



with a common display computer. By switching between transducer sets, almost simultaneous readings can be taken.

The ultrasonic flow meter has a number of disadvantages as well. The equipment is expensive to buy. In addition, its application may not be possible with very dirty liquids (those with large quantities of suspended solids). Finally, some types of flow meters may not be usable with sonically non-conductive (concrete) pipes.

There are four major types of ultrasonic flow meters:

- Clamp-on time difference
- Insertion (wetted) time difference
- Doppler flow meter
- Open channel insert.

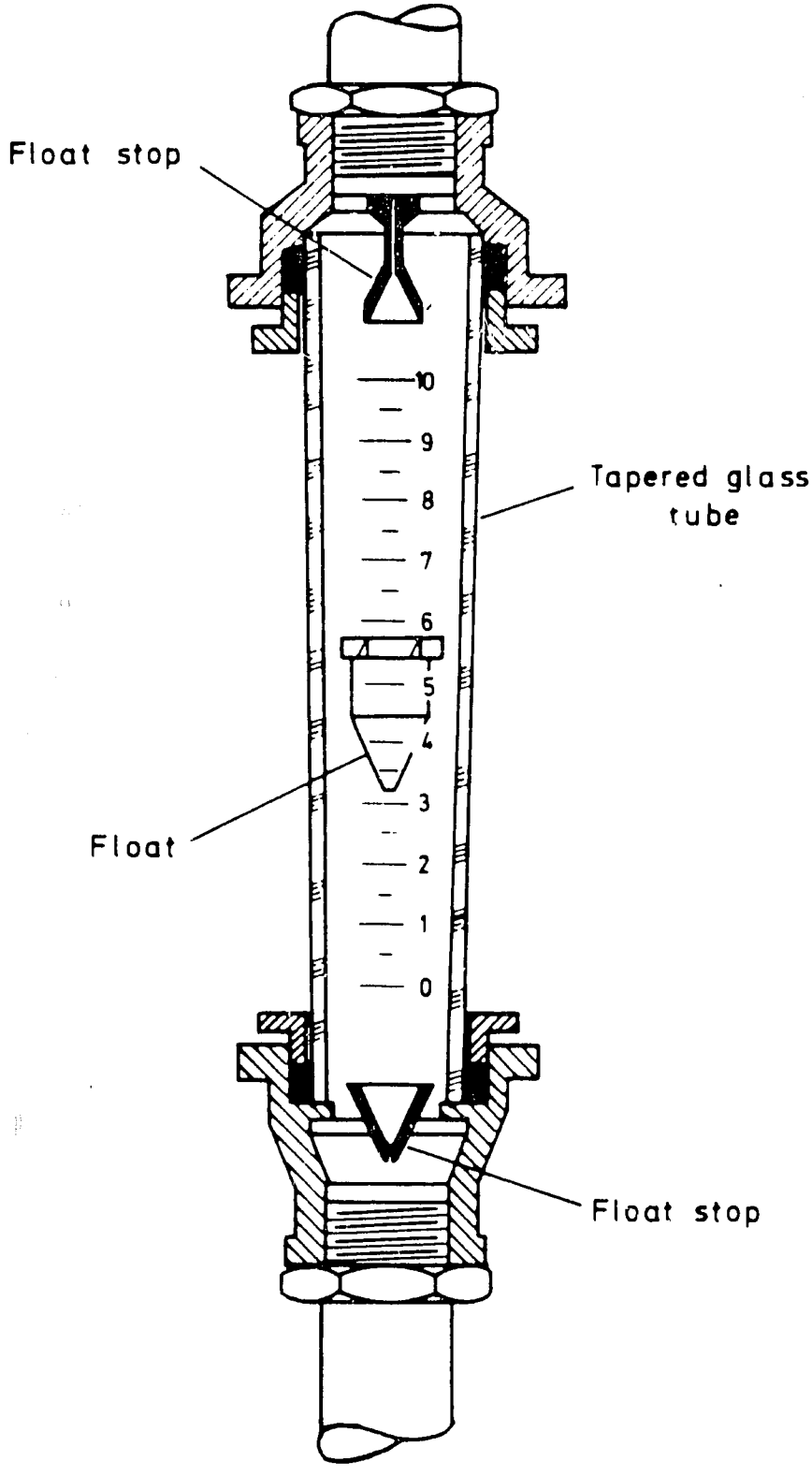
Types	Applications
Clamp-on time difference	Best for general use, clean and moderately aerated liquids, medium density organic slurries. Cannot be used with concrete pipe or heavily aerated or non-organic slurries.
Insertion (wetted) time difference	Same as above, but transducers inserted in stream. Can be used in all types of pipe. Transducer wells may clog, requiring process shutdown for repair.
Doppler flow meter	Primarily for metering of slurries. Cannot be used with clean or non-aerated liquids. Accuracy depends on uniformity of stream particle concentration.
Open channel insert	Primarily for waste water or effluent in partially filled open or closed conduits.

4.2.5 Rotameter

A less expensive gas and liquid metering instrument is the **rotameter**, illustrated in Exhibit 4.15. While this instrument is not as portable or readily installed as the ultrasonic

EXHIBIT 4.15

Rotameter



flow meter, it is easy to use. The rotameter consists of a float that is free to move vertically in a transport tube. The fluid to be measured enters at the bottom of the tube and passes through the annulus formed between the float and tube well. At any particular flow rate, the float will assume a defined position in the tube. Pre-calibrated rotameters may be obtained for specific fluids and are available in a range of sizes.

4.2.6 Turbine Flow Meters

Turbine flow meters are volumetric flow-rate sensing devices. They consist of a stainless-steel turbine rotor, encased in a non-magnetic meter body, which is suspended in the flow stream. The stream exerts a force on the blades of the turbine rotor, causing it to rotate. The rotational speed of the turbine is proportional to fluid velocity and hence to volumetric flow rate. A turbine flow meter is illustrated in Exhibit 4.16.

Turbine flow meters should be installed with straight lengths of pipe of at least 10 and 5 pipe diameter upstream and downstream, respectively. The choice of a flow meter depends on the characteristics of the fluids to be measured.

4.2.7 Positive Displacement Meters

For permanent installation, **positive displacement meters** are available (see Exhibit 4.17). These meters are useful for measuring the flow of liquids and gases. The fluid being measured flows into compartments of definite size. As the compartments fill, they rotate to allow the fluid to leave the meter. The flow rate through the meter is equal to the product of compartment size, number of compartments, and rate of rotation of the rotor. These meters are particularly useful in determining flow over long periods of time.

4.3 PRESSURE

Pressure measurements are useful for evaluating system operation. Measurement of furnace static pressure, pressure drop, or rise across filter fans and pumps provides

EXHIBIT 4.16

TURBINE FLOWMETER

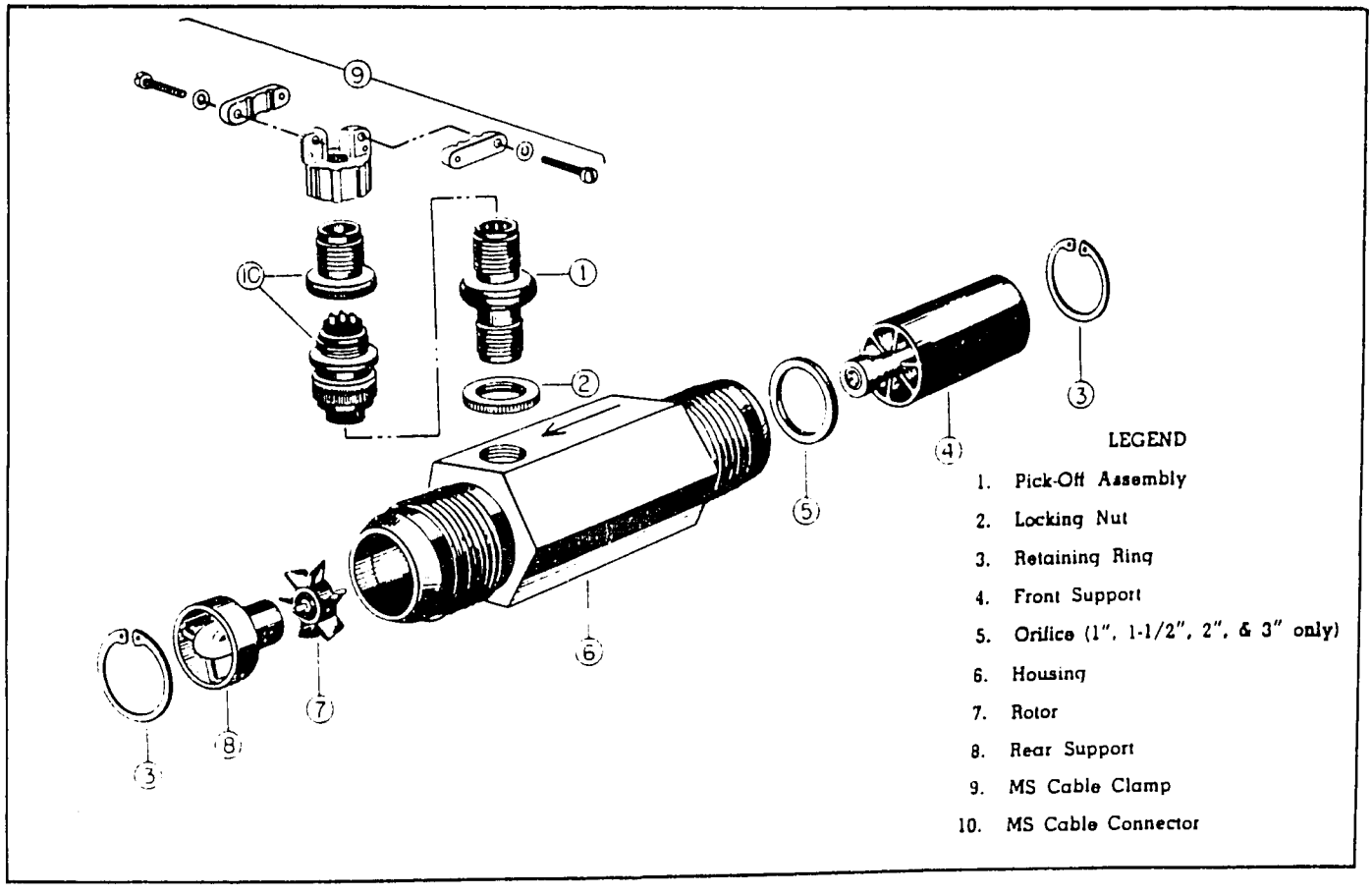
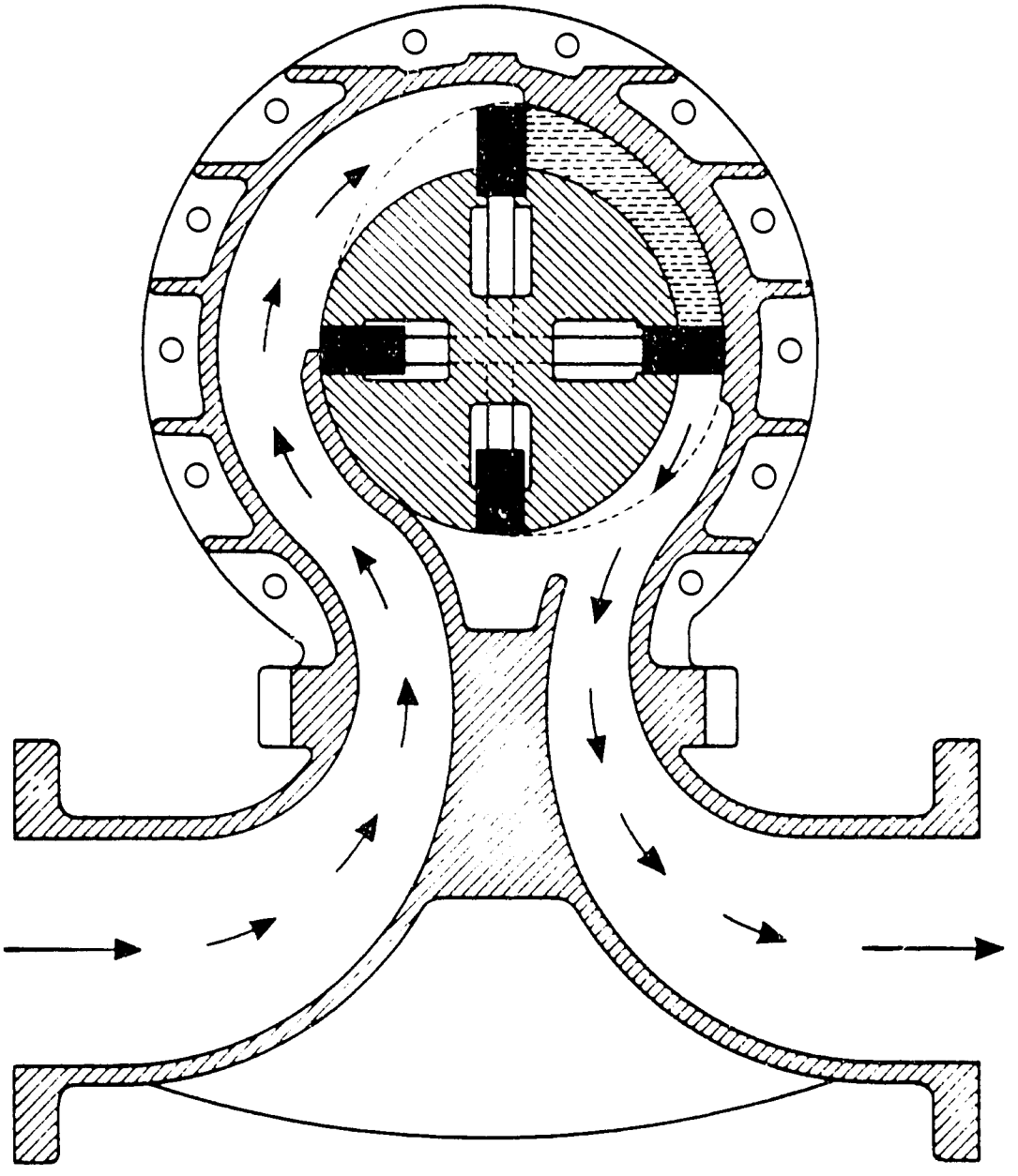


EXHIBIT 4.17



Positive displacement meter. Principle of operation

the auditor with additional information to aid his understanding of the operating characteristics of the system under study.

Most pressure gauges (Bourdon tubes, manometers, and bellows) really measure the difference in pressure between two points. They are usually arranged to measure the difference between atmospheric pressure and another pressure. This pressure difference is termed gauge pressure. The atmospheric pressure results from the weight of the air and water vapor above the surface of the earth. Standard atmospheric pressure (or standard barometric pressure) is:

760 mm Hg
10.44 meters of water column
101,325 N/m^2 (Newtons per square meter)
1.033 kg/cm^2 (kilograms per square centimeter)
1.013 bar.

The actual atmospheric pressure varies with weather, latitude, and altitude (about 0.8 bar less for each 300 meters above sea level).

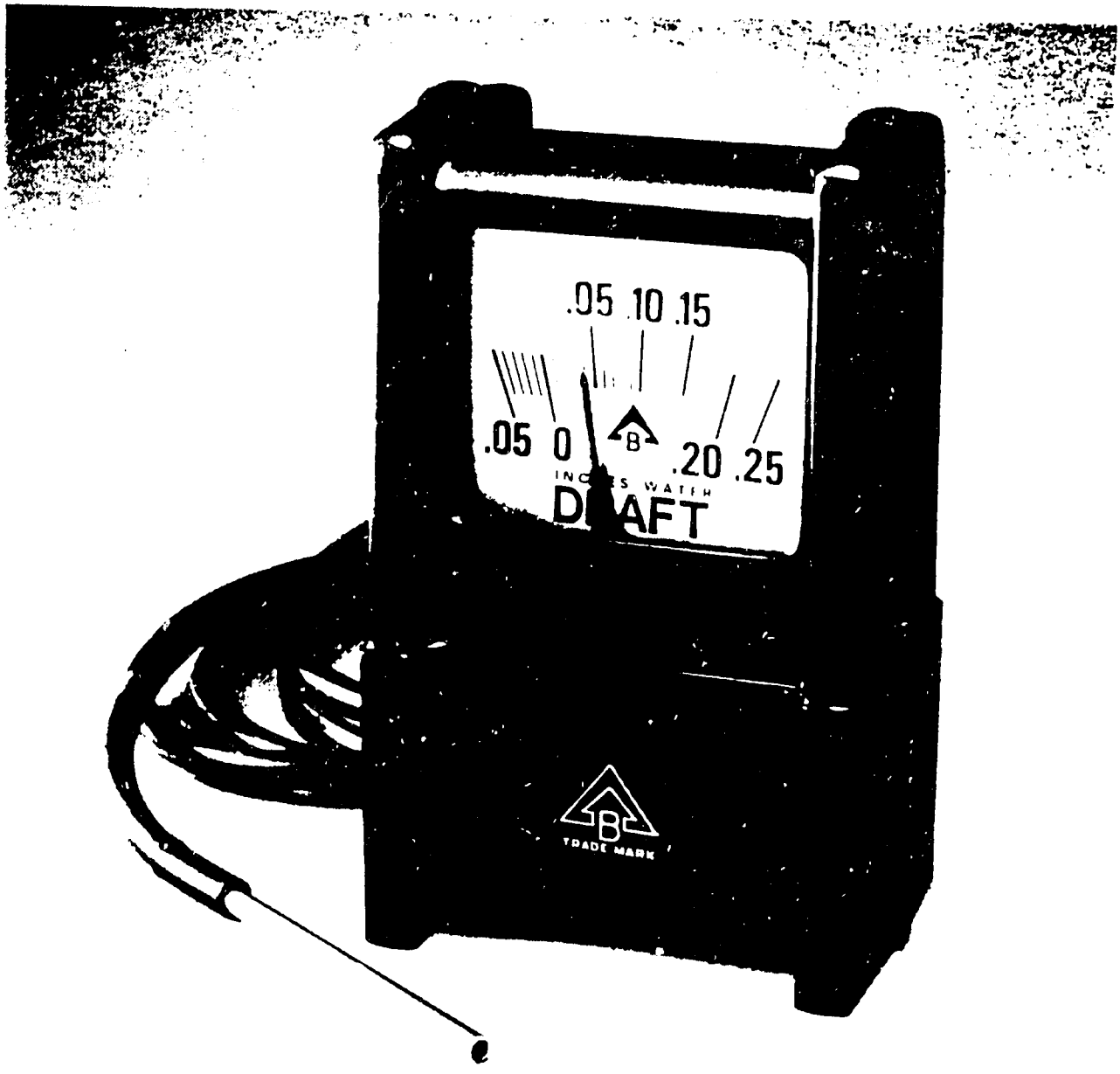
Absolute pressure is the sum of the gauge pressure and the atmospheric pressure. An absolute pressure of zero would exist only in a perfect vacuum.

It is important to determine the draft of furnaces and boilers at the firebox and at the stack. The draft indicates the pressure at which the combustion system operates. The intensity of the draft determines the rate at which combustion gases pass through the boiler or furnace, and the amount of air provided for combustion. Excessive draft can increase the stack temperature (causing incomplete heat transfer), while insufficient draft may cause smoking owing to insufficient combustion air.

Draft is measured with a pressure measurement device such as the manometer illustrated in Exhibit 4.11. In addition, special draft gauges, as illustrated in Exhibit 4.18, may be used.

EXHIBIT 4.18

DRAFT GAUGE



4.3.1 Draft Gauge

To use the **draft gauge**, the probe is inserted into the area where draft is to be measured (either the firebox or the flue). The draft is read directly from the scale. The amount of smoke in the combustion gases may be determined either by use of a pump and filter or by gas opacity measurements. The pump and filter method is well suited for portable measurements; the gas opacity method requires that the instrument be permanently or semi-permanently mounted.

Draft is normally measured in millimeters of water column. The correct values for each piece of equipment at a given load or firing rate must be determined from the manufacturer's original equipment data or from information available on similar equipment.

Manometers and draft gauges may also be used to test dryers, environmental control equipment, and other systems that use air or gas as a transport medium. These devices can be used to measure pressure drop across filters, which indicates the degree of cleanliness; static pressure in a duct, which indicates the work necessary to overcome system resistance; or pressure rise across a fan, which indicates the work being achieved. Draft gauges and manometers can be used to measure differential and static pressures in the range of 0 to 0.1 bar.

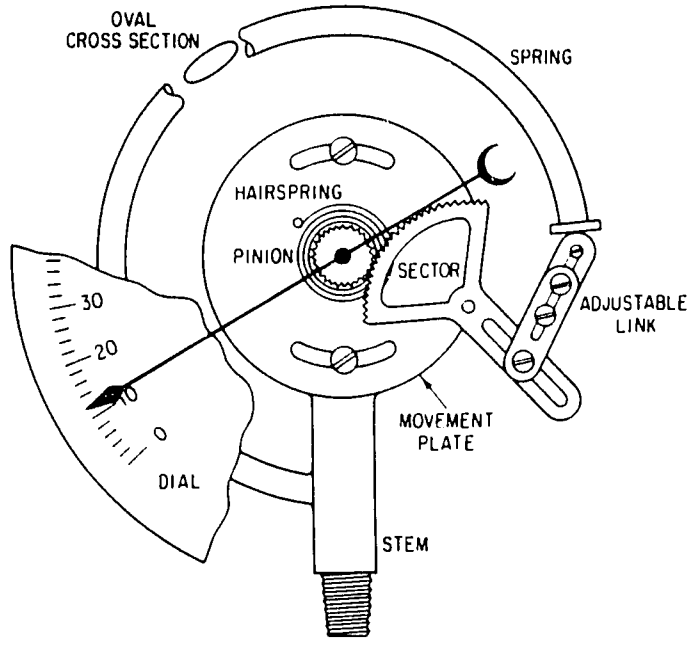
Pressure gauges used for monitoring steam and fluid systems are normally Bourdon tube pressure gauges. A Bourdon tube is closed at one end and has an internal cross-section that is not a perfect circle. If bent or distorted, the tube has the property of changing its shape with internal pressure variation. Typical configurations of Bourdon tubes are shown in Exhibit 4.19. Bourdon tube pressure indicators can be used to measure pressures in the range of 0 to 70 bar.

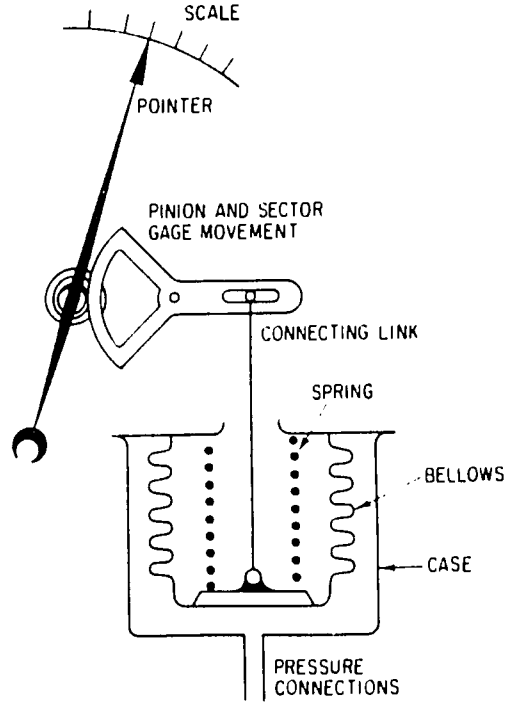
4.4 GAS ANALYSIS

The discussion of gas analysis will be limited to the analysis of boiler and furnace gases of combustion for the purpose of determining combustion efficiency. The discussion will center around the use of the Bacharach Fyrite Combustion Analyzer. The Fyrite

EXHIBIT 4.19

BOURDON PRESSURE GAUGE





is chosen because it is a particularly robust instrument, able to withstand the rigors of continuous use. In addition, the gas analysis fluids are usable for a large number of tests, but are easily replaced when depleted. The system is modular, and parts can be easily and inexpensively replaced.

A typical analyzer of this type is shown in Exhibit 4.20. The analyzer absorbs a sample of gases and determines their volumetric content. From a knowledge of the carbon dioxide and oxygen content of the gas sample, the temperature of the stack gas and the combustion air, and the type of fuel being burned, it is possible to determine the combustion efficiency of a fired vessel with reasonable accuracy.

Other types of gas analysis equipment are available and in regular use around the world. These analyzers include the traditional Orsat Gas Apparatus, which operates on the same principle as the Fyrite, electronic portable analyzers that use electrochemical cells as a measuring medium, and extremely sophisticated and accurate infrared analyzers for measuring carbon dioxide and carbon monoxide in the stack gases. For most plant environments, the Fyrite kit provides results that are accurate enough to make it suitable for evaluating plant equipment and the effect of conservation measures.

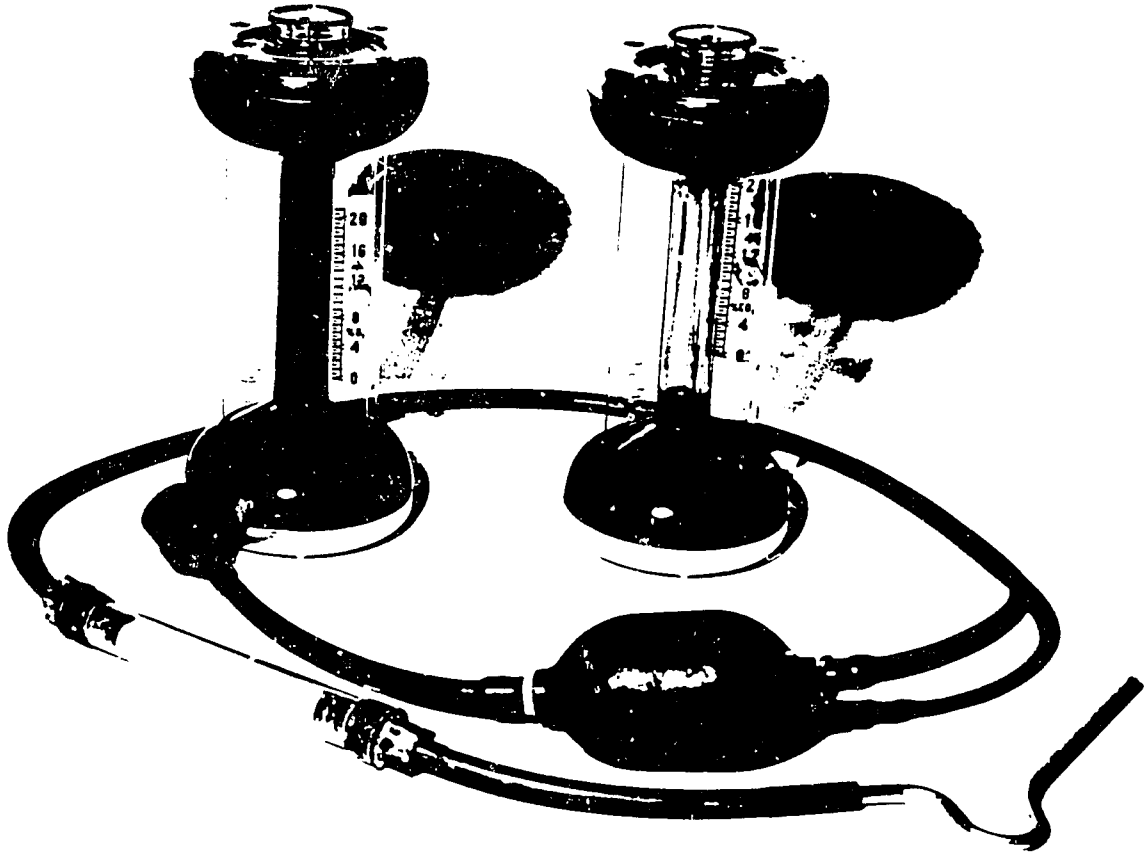
The measurement of combustion efficiency requires temperature and psychrometric measurements, and the analysis of combustion gases. The auditor should observe certain precautions and operating tips to ensure that the results obtained from the gas analysis are accurate to the limits of the instruments and can be repeated. To compare the operating efficiency of a fired vessel over a period of time, the test procedures and results must be consistent from test to test. For this reason, it is recommended that a small group at each site be trained in the principles of gas analysis and that they be the only ones to perform the required testing.

Before starting a combustion test, the auditor should first survey the equipment being tested to locate or identify the need for test points from which the gas samples and temperature measurements are to be made. The measurements to be taken for a complete combustion test are:

- Temperature of incoming combustion air
- Temperature of combustion gases

EXHIBIT 4.20

FYRITE GAS ANALYZER



- Firebox and stack draft
- Amount of smoke in combustion gases
- Composition of combustion gases by volume (in percent)
  - carbon dioxide (CO_2)
  - oxygen (O_2).

4.4.1 Temperature of Combustion Air

The auditor should measure the temperature of the incoming combustion air at the inlet to the forced draft fan that supplies the combustion air. If it is a natural draft unit, the temperature of the combustion air may be measured at the burner front where it enters the boiler. For this measurement, a mercury thermometer should be used. For some analyses, the moisture content of the air must be determined. If that is the case, an aspirated psychrometer must be used to determine the relative humidity, and then the moisture content of the air can be readily determined from a psychrometric chart.

4.4.2 Temperature and Composition of Combustion Gases

The point at which the temperature is measured and the sample of combustion gas is taken should be as close to the point of exit from the vessel as possible. By getting close to the exit point, the loss of temperature in the gas stream and the possibility of contamination from ambient air are minimized. The holes drilled for the sample points should be as close to the size of the gas sample and temperature probe diameters as possible to prevent the entrance of ambient air, which would dilute the sample. Separate points for measuring the temperature and taking the gas sample should be provided to prevent the test from being interrupted because probes have to be switched. The switching of gas and temperature probes also costs time, as the temperature probe must be allowed to restabilize at the operating temperature. A sheathed thermocouple with electronic readout should be used to measure the temperature of combustion gases.

4.4.3 Firebox and Stack Draft

The test points for firebox and stack draft depend on the type of unit being tested, the configuration of fans, and whether the firebox and stack are at, above, or below atmospheric pressure. As these conditions vary from unit to unit, the auditor should examine the installation of existing draft gauges or check the operating manuals to learn where readings should be taken and what typical values are to be expected.

4.4.4 Smoke in Combustion Gases

The smoke content of the combustion gases can be measured at the same point where gas samples are taken by using a special hand-operated pump to draw a controlled volume of the combustion gases through a filter paper. The smoke particles are deposited on the filter paper and their density compared with a standard for evaluation. A smoke pump and standard are shown in Exhibit 4.21. The reading on the standard that most closely approximates the test paper provides a rough indication of the operating condition of the combustion equipment. If the auditor uses the smoke content findings together with the results of the combustion analysis, he is in a position to make concrete recommendations for improvements in the unit's operation.

4.4.5 Composition of Combustion Gases

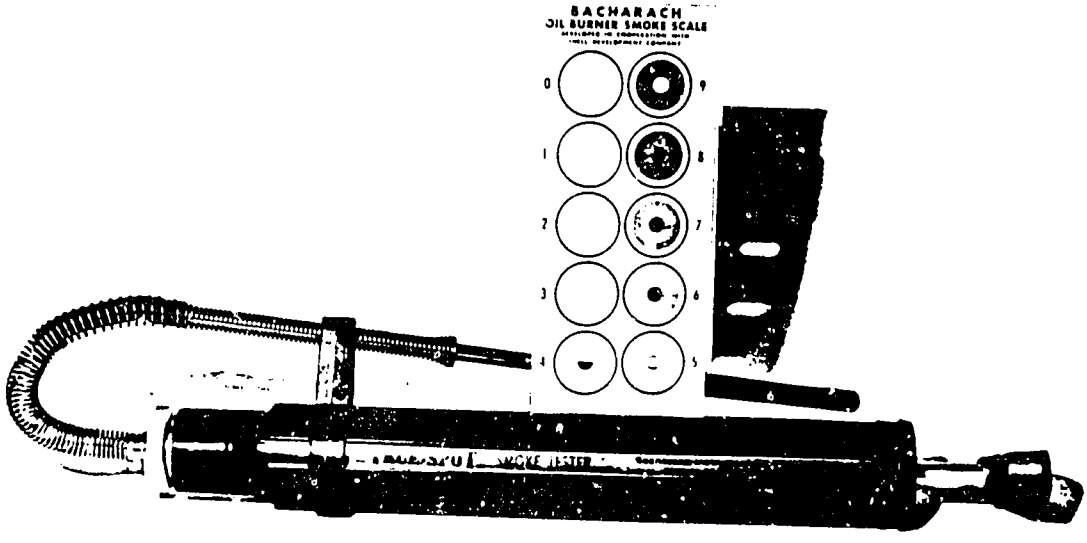
The smoke pump requires little maintenance. A tube of lubricating oil is provided with the pump and should be used as necessary to provide smooth operation with little effort. Experience in operating the pump will provide some guidelines for pump maintenance.

Once the test points have been established, the auditor should assemble the test equipment that will be used to perform the test and ensure that it is all in working condition. The primary area of concern is the gas analysis equipment. This equipment must be handled and maintained properly to ensure accurate test results. For the Fyrite kit, the auditor should be sure that:

- Chemicals in the gas sample cylinder are fresh
- Seals in the top and bottom dumbbells are in good condition

EXHIBIT 4.21

SMOKE TEST PUMP AND SCALES



- Sample hose and sample pump are air tight
- Sample pump check valves are working properly
- Scales for reading concentration of absorbed combustion gases are in place and are the proper scales for the gas to be analyzed
- The Fyrite has warmed up to ambient temperature before it is used to take any readings.

The auditor can easily check the sample hose and air pump for air tightness and proper operation by sealing off the sample end of the assembly with his finger and then operating the hand pump. If the pump remains deflated after it is released for a period of about 30 seconds, then the hose, connections, and check valves are in good condition and operating properly. If air is leaking at the connection of the fittings and hose, a light coating of petroleum jelly will often improve the seal. The connections at the filter can be wrapped with electrical tape to ensure an adequate seal. If the check valves do not hold, they must be replaced before testing, as they will allow ambient air to mix with the sample, giving erroneous results.

Loss of fluid from the Fyrite since it was last used can indicate a bad seal. As with the sample tubing, poor seals on the Fyrite can cause degradation of the gas sample. When the Fyrite is in regular use, the unit should be drained, cleaned, inspected, and recharged after approximately 75 tests have been completed. The O_2 and CO_2 analyzers should be cleaned at the same time to avoid confusion about when each unit was refurbished. In addition to replacing the fluids, the seals and gaskets should be carefully examined and replaced as needed. One note of caution: the fluids used for the analysis are highly corrosive and should be handled with care. Rubber gloves should be worn when recharging a Fyrite, and running water should be readily available for flushing if a spill occurs. **The auditor should read the manufacturer's instructions carefully before working on a Fyrite, or any piece of chemical analysis equipment, to acquaint himself with the potential hazards and required safety precautions.**

Because different fluids and ranges are required for the O_2 and CO_2 tests, the auditor must be sure that the proper scales are on the sample bottles. The fluid used for the O_2 test is blue-green, and the fluid for the CO_2 test is red; both tests use a 0 to 20 percent scale. When starting a test, the auditor should first release the pressure on

the cylinder by pressing down on the top; then he should properly zero the scale by lining up the bottom of the scale (zero line) with the top of the test fluid. The manufacturer suggests that the zero line be kept even with the top of the meniscus of the test fluid. During a prolonged period of testing, it is often necessary to reset the zero point of a sample bottle owing to residual absorption of the test gas. The zero point should be checked after 5 or 6 sequential tests.

The accuracy of the results of any test can be checked by comparing the results of the O_2 and CO_2 readings. For all fuels, the ratio of O_2 and CO_2 is fixed and can be determined by calculation. A simpler method is to use standard graphs that are available for many common fuels. A way of checking the results of a particular test is shown in Exhibit 4.22.

Example: The results of a combustion gas analysis show the concentrations of combustion products to be 6 percent for O_2 and 13 percent for CO_2. The fuel being burned is No. 6 fuel oil. Determine if the test results are reasonable.

Solution: Enter the graph at the left side at 6 percent O_2 and cross horizontally to the O_2 curve. From the point of intersection, travel vertically to the CO_2 curve and then horizontally left to the left-hand scale and read the percent CO_2. The value is approximately 11.5 percent, which is lower than the value obtained from the test. Since the two values do not agree, there has been an error in the test procedure. **If one of the test values is incorrect, it is most likely the O_2 reading, as it is more readily affected by atmospheric air.**

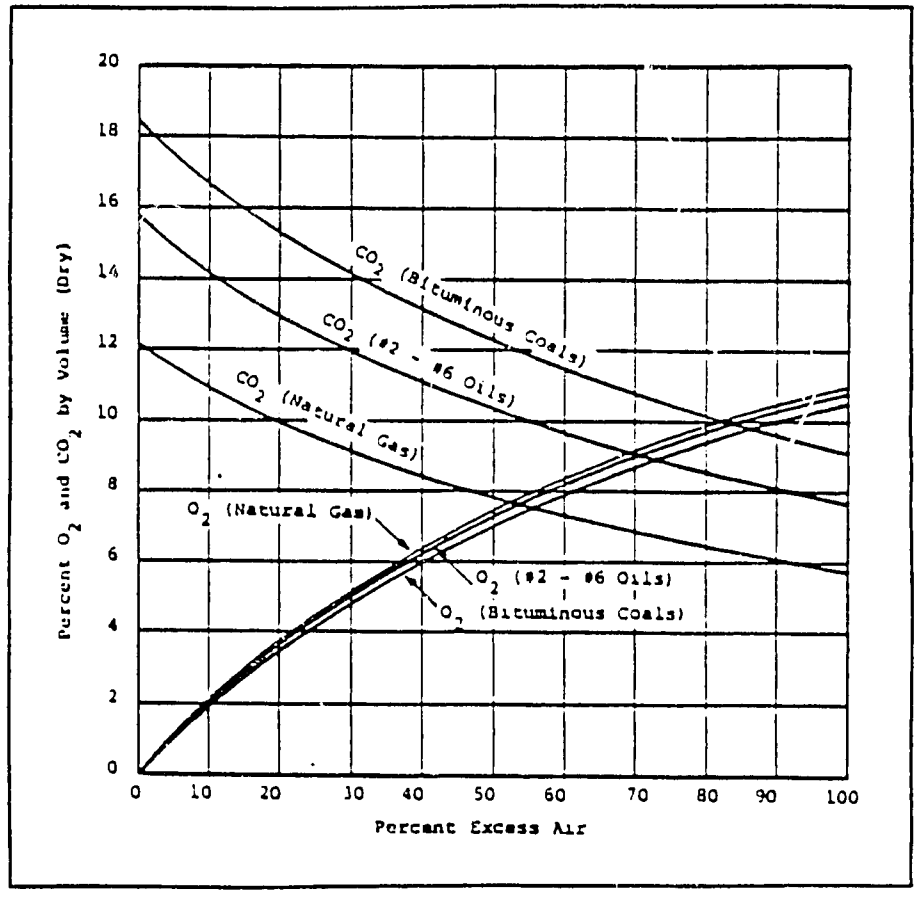
4.5 ELECTRICITY MEASUREMENT

There are four electrical measurements of particular interest in the conduct of a detailed energy audit. These measurements are:

- Amperage
- Voltage
- Wattage (or instantaneous demand)
- Power factor.

EXHIBIT 4.22

EXCESS AIR vs STACK GAS CONCENTRATIONS OF EXCESS O_2 AND CO_2



4.5.1 Amperage

Amperage is a measure of the flow of electrons in an electric current. The current carrying capacity of the conductor is called ampacity. Standard tables are available that show, for a given conductor size and insulation system, the maximum allowable current that will not cause damage to the insulation because of heat generated.

Amperage is measured using an **ammeter**. Several types of ammeters are available. The most common are the clamp-on type and the recording ammeter.

The clamp-on ammeter (see Exhibit 4.23) is a portable instrument providing direct read-out of the current flowing through a conductor. The **recording ammeter** (see Exhibit 4.24) is similar in operation, but it provides a graphical presentation of amperage in the circuit over a period of time. Both of these ammeters consist of a current transducer (the toroid) that is connected to the display portion of the device.

A current flowing in a conductor sets up a magnetic field at right angles to the conductor. The current transducer is placed within that magnetic field, and a current is induced in it. The magnetic field strength is proportional to the current in the conductor; the induced electric current in the current transducer is proportional to the magnetic strength. The current induced in the current transducer is measured by the ammeter, which is calibrated to give the actual current in the conductor.

Both the clamp-on and recording ammeters are easy to use. The scales for measurement differ (e.g., 0-300 amps, 0-1,000 amps), so the proper scale should be selected. The current transducer should be selected on the basis of the magnitude of the current to be measured. The current transducer must close around the conductor under study to ensure proper readings; it is slipped over the conductor feeding the load under study. For polyphase power systems, it is sometimes useful to obtain amperage readings on all phases to determine imbalances.

Safety precautions must be observed when measuring an electrical system. Care should be taken in any attempt to use a current transducer on any bare (uninsulated) electrical conductor. Insulated gloves should be worn.

EXHIBIT 4.23

CLAMP-ON AMMETER

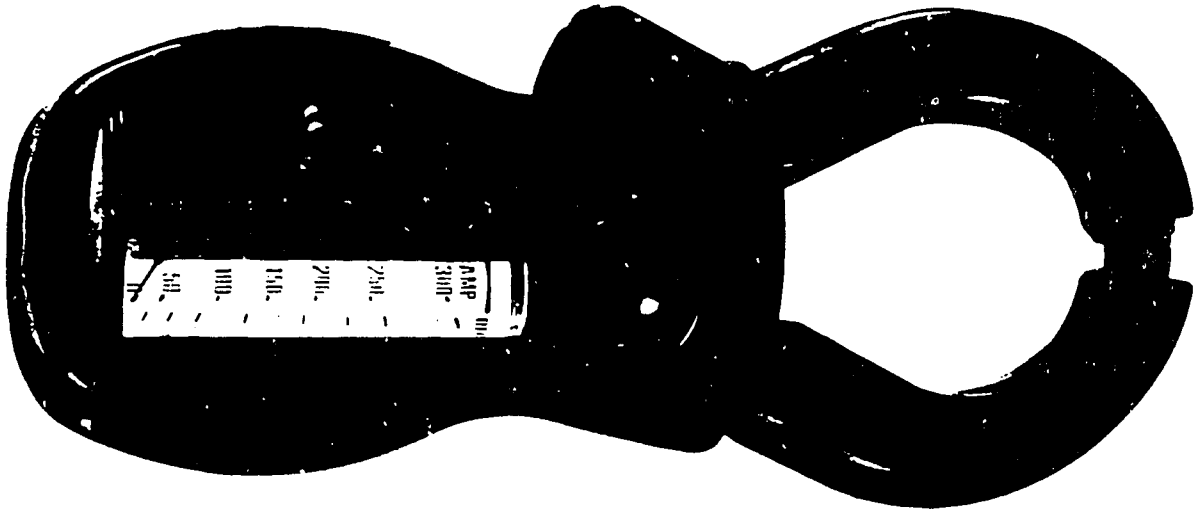
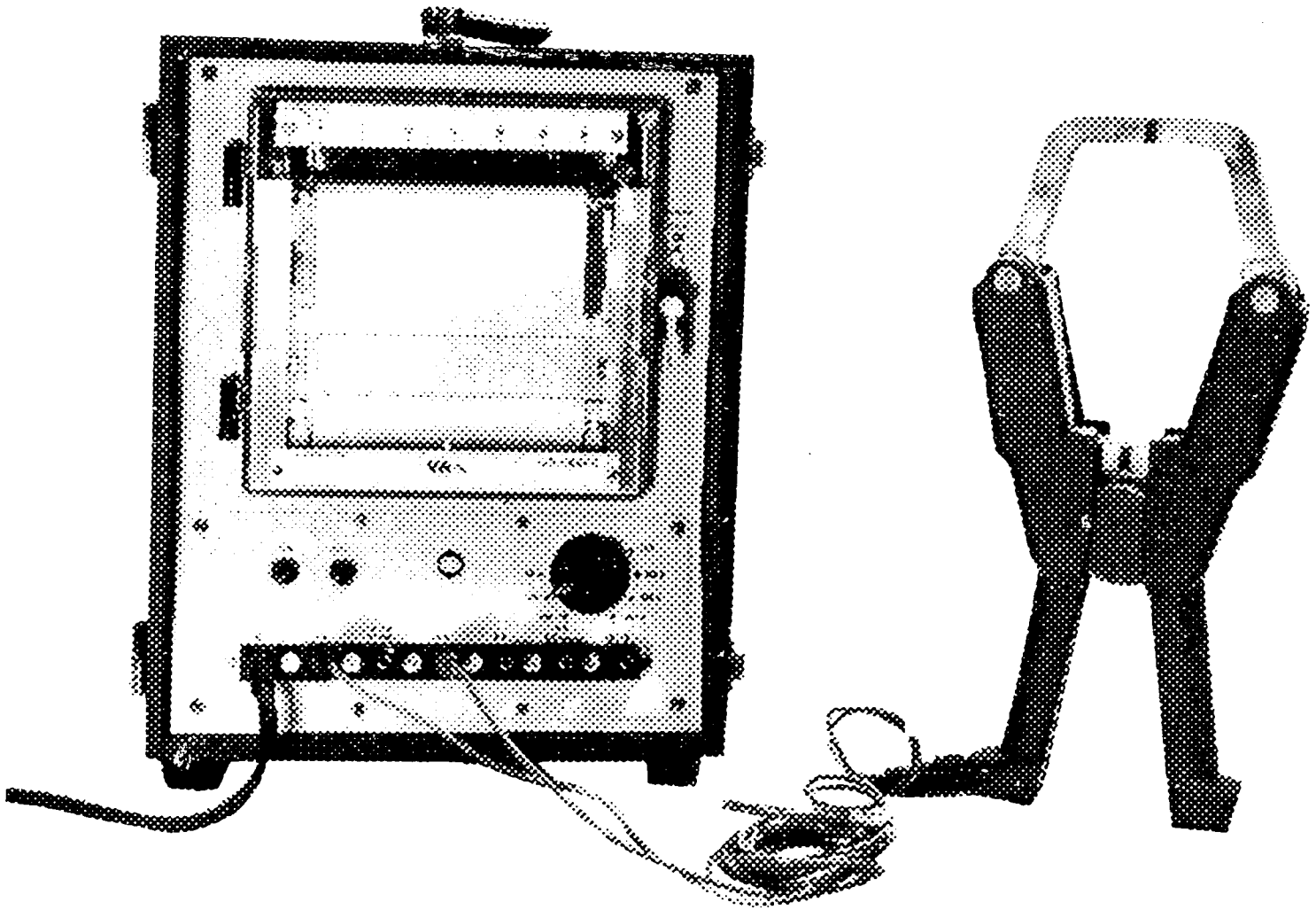


EXHIBIT 4.24

RECORDING AMMETER



4.5.2 Voltage

Voltage is a measure of the force used to move electrons in an electric current, and is generally constant. While voltage is not of primary importance in the conduct of a detailed energy audit, it should be measured to ensure the proper operation of facility voltage reduction and distribution systems.

The instrument used to measure voltage is the **voltmeter.** In some cases, voltage is measured in combination with amperage and/or resistance in a device called the electrical multimeter. A digital multimeter such as that shown in Exhibit 4.25 can be used for voltage measurement (by using accessory probes and selecting the proper voltage scales). The instrument is used by connecting the voltage probes to the conductor (not the insulation) under study. Voltage is read directly on the appropriate scale on the instrument.

Safety precautions must be observed when measuring any electrical system. Care must be taken in the presence of uninsulated electrical conductors to avoid shock. Insulated gloves should always be worn.

4.5.3 Wattage

Wattage is a measure of electrical power in a circuit. The **wattmeter** is used to determine directly the amount of power used by a piece of equipment. The recording ammeter or clamp-on ammeter can also be used to determine power consumption indirectly, since the apparent power in a circuit is equal to the product of current times voltage times the square root of the number of phases in the power system. (The actual power in a circuit is the product of apparent power and power factor.)

The wattmeter consists of three clip-on type terminals, one of which is distinguished by a mark (#1), a current transducer, and a display. To use the wattmeter, one connection is made to each leg of the polyphase power system at the device being measured, and the current transducer is connected around the same legs as the marked clip. Power in the circuit is read directly from the instrument. A sample wattmeter of the instantaneous clamp-on type is shown in Exhibit 4.26. Wattmeters are also available that provide records in the form of graphs or as totalizing meters.

EXHIBIT 4.25

DIGITAL MULTIMETER

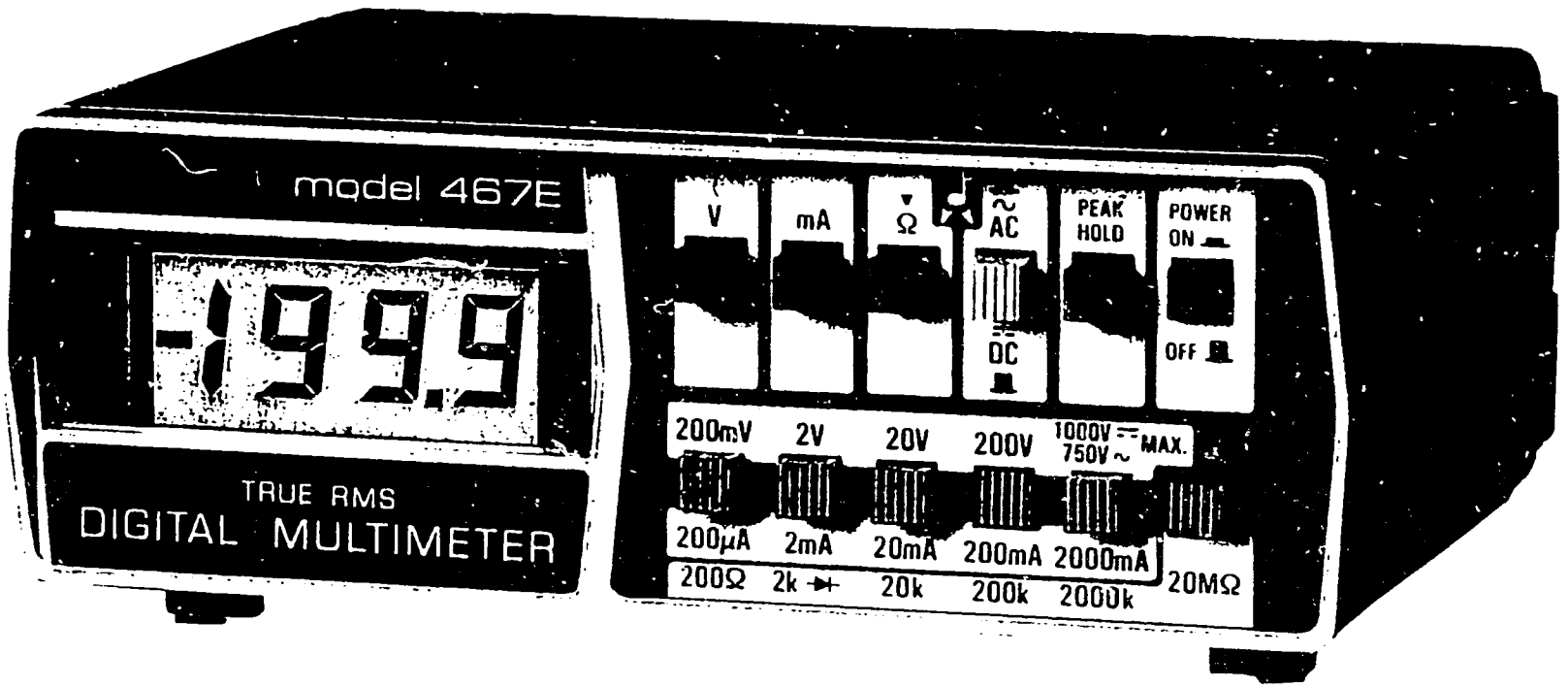
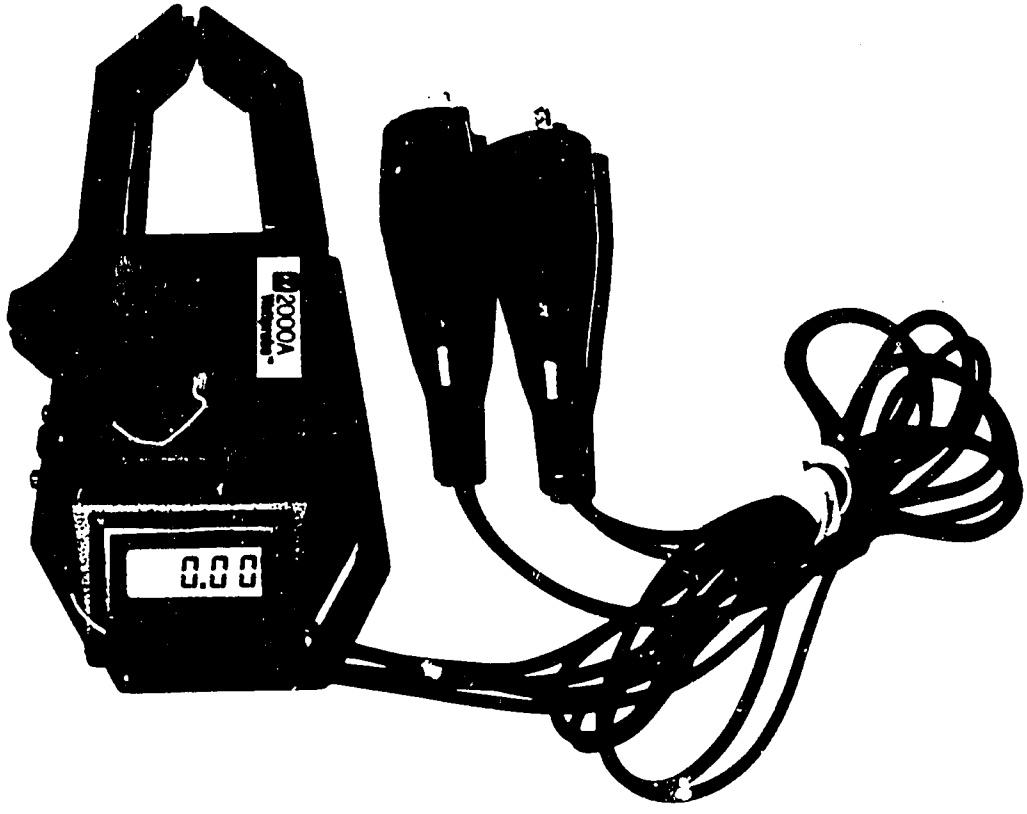


EXHIBIT 4.26

CLIP-ON WATTMETER



The wattmeter is used in a different manner for each type of power supply encountered. Some combinations are described below (see Exhibit 4.27):

- Active power, no neutral, balance load, three phase: clips are attached in arbitrary sequence to each leg; current transducer is clipped onto the same leg as the marked terminal. The instrument directly indicates active three-phase power.

- Active power, neutral, unbalanced load, three phase: the marked clip and the current transducer are connected to one of the three legs and the clip marked #2 is clipped to the neutral. The third clip is not used. The instrument measures the active power of one phase only; the process must be repeated for other phases. The measured values are added.

- Active power, single phase: use the same procedure as for neutral, unbalanced load, three phase.

- Active power, no neutral, unbalanced load, three phase: two clip-on wattmeters are needed. Clip #2 of both meters is connected to the same phase. The marked clip and current transducer is the first wattmeter are connected to one of the remaining phases, while the marked clip and current transducer for the other wattmeter are connected to the remaining phase. Clip #3 for both meters is unused. The measured values are added.

- Reactive power, no neutral, balanced load, three phase: the marked clip and clip #2 are connected to two phases; the current transducer is connected to the remaining phase. Clip #3 is not used. The reactive power is determined by multiplying the reading by 1.73.

- Reactive power, no neutral, unbalanced load, three phase: this measurement requires two wattmeters. The three terminal clips on the wattmeter are indicated as #1 (the marked clip) #2, and #3. The clips for each meter are connected as follows:

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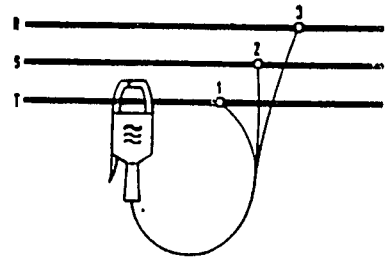
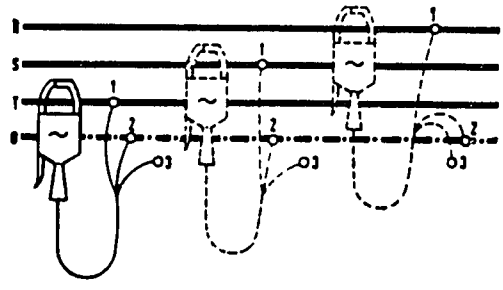
EXHIBIT 4.27

EXAMPLES OF WATTMETER USAGE

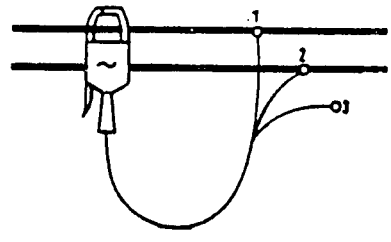
ACTIVE POWER NO NEUTRAL
BALANCED LOAD THREE PHASE



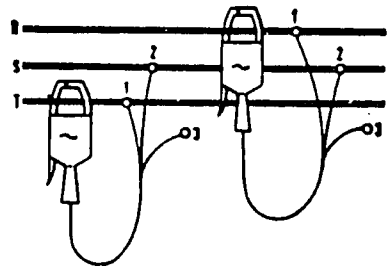
ACTIVE POWER NEUTRAL
UNBALANCED LOAD THREE PHASE



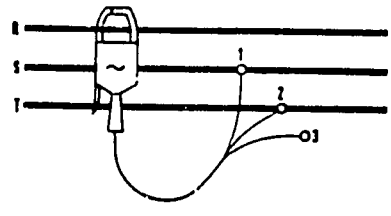
ACTIVE POWER SINGLE PHASE



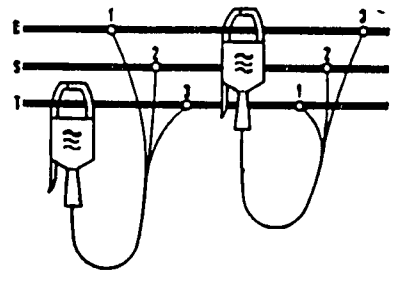
ACTIVE POWER NO NEUTRAL
UNBALANCED LOAD THREE PHASE



REACTIVE POWER NO NEUTRAL
BALANCED LOAD THREE PHASE



REACTIVE POWER NO NEUTRAL
UNBALANCED LOAD THREE PHASE



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Phase	Meter #1	Meter #2
1	Clip #1	Clip #3
2	Clip #2	Clip #2
3	Clip #3	Clip #1

The current transducer for each meter is connected to the same phase as Clip #3 for that meter. The reactive power is the difference between the two readings, divided by 1.73.

Safety precautions must be observed when measuring any electrical system. Care must be taken in the presence of uninsulated electrical conductors to avoid shock. Insulated gloves should always be worn.

4.5.4 Power Factor

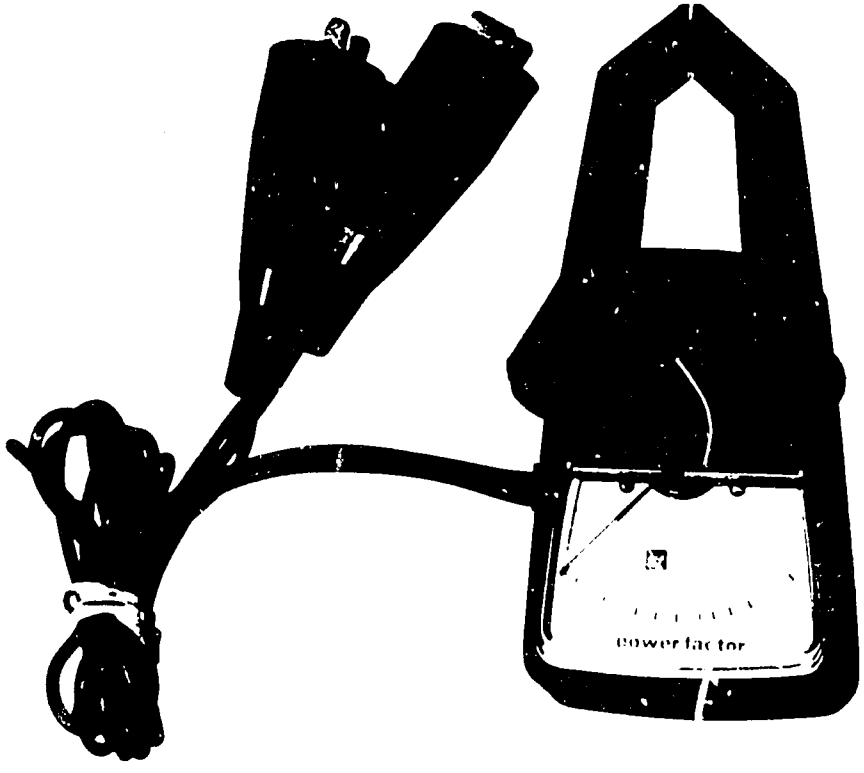
The final electrical measurement to be covered is power factor. A **power factor meter** is used for this measurement; an example of a clip-on power factor meter is presented in Exhibit 4.28. Physically, the clip-on power factor meter is very similar to the wattmeter previously discussed. The power factor meter has part of the wattmeter mechanism; it incorporates a current transducer and three clip-type terminals, one of which is distinguished by a mark (#1). A direct reading display is also provided.

The marked terminal and current transducers are connected to one of the three phases; the other two clips are connected to the other phases in phase order. The instrument is improperly connected if the indicating needle deflects in the wrong direction when activated (before connection of current transducer) (if this happens, exchange clips #2 and #3). The current transducer is connected to the same phase as clip #1.

Separate power factor measurements should be made for each phase when there is a gross imbalance in phase current. The power factor in the three-phase system is then computed by taking a weighted average of the power factor in relation to the phase current:

EXHIBIT 4.28

POWER FACTOR METER



$$\text{Three phase} = \frac{(A_1 \times PF_1) + (A_2 \times PF_2) + (A_3 \times PF_3)}{A_1 + A_2 + A_3}$$

where A = amperage in each phase

PF = power factor in each phase.

Safety precautions must be observed when measuring any electrical system. Care should be taken in any attempt to connect a clip or current transducer to any bare (uninsulated) electrical conductor. Insulated gloves should always be worn.

4.6 LIGHT LEVEL MEASUREMENT

The determination of proper light levels involves:

- Definition of space served by lighting unit
- Identification of type of lighting unit in use
- Measurement of light level on task.

A data form for light level survey measurements is presented in Exhibit 4.29. Each discrete area in the facility surveyed is indicated in the title area of the form. The location and principal use are noted in Columns 2 and 3, respectively.

The dimensions of the area are recorded in Column 4. Actual length and width are recorded. The distance refers to the height from the lighting unit to the floor; this may be different from ceiling height if the lighting fixtures are suspended from the ceiling.

The next six (6) columns describe the lighting fixtures in place. Space is provided to list the number, type (e.g., fluorescent, incandescent, HPS), watts per bulb, number of bulbs and ballasts per fixture, and watts per ballast. The more complete the data collected in this section, the easier it will be to evaluate the savings potential resulting from changes in the lighting system.

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EXHIBIT 4.29

PAGE ____ OF ____

CLIENT:		PLANT:
DATE:	PROJECT NO.:	DATA BY:
BUILDING/AREA SURVEYED:		
OUTSIDE CONDITIONS:		START TIME:

Lighting Survey

ITEM NO.	LOCATION	AREA PRINCIPAL USE	ROOM DIMENTIONS UNITS: _____	NUMBER OF FIXTURES	LAMP/FIXTURE DESCRIPTION					MEASURED LIGHT LEVELS (F.C.)	ANNUAL HOURS OF OPERATION
					BULB TYPE	WATTS PER BULB	NO. OF BULBS/ FIXTURE	NO. OF BALLASTS/ FIXTURE	WATTS/ BALLAST		
			L x W x H								
			L x W x H								
			L x W x H								
			L x W x H								
			L x W x H								

Particularly in the case of ballasts, it is not necessary to dismantle every fluorescent or mercury fixture to determine the ballast load. In the initial phase of a lighting survey, the auditor should check several ballasts. If they are all the same, it is reasonable to assume that the remaining ballasts are similar. Before starting the survey, the auditor should also ask the plant staff if a relamping or ballast replacement program is underway, as this information will provide some guidance in determining lamp/lighting loads.

Observed light levels are obtained using a **photometer**. This device is based on the photoelectric effect, whereby the intensity of certain wavelengths of light on certain materials causes a proportional voltage to be generated. A photometer incorporating a digital readout is illustrated in Exhibit 4.30.

The photometer provides a direct readout of light intensity, measured in foot-candles. A foot-candle is the illuminance on a surface one square foot in area on which there is a uniform flux of one lumen. The metric equivalent to the foot-candle is the lux, which is the illuminance on a surface one square meter in area on which there is a uniform flux of one lumen.

In use, the photometer is placed at the task and a measurement taken. For instance, readings in an office would be taken on the same plane as the desktop. In a plant, the readings would be taken at an operator's station or at a critical location in the machine. When using the photometer, the energy auditor must be careful to avoid shading the sensor with his body.

Suggested illumination levels for various tasks are presente in Exhibit 4.31.

Using the data form in Exhibit 4.29, measured light levels are recorded in the next to last column and annual hours of operation in the last column.

The data collected can then be used to calculate the total in place lighting load and the annual energy consumption associated with the lighting system. To calculate lighting load, use the following formula for each item listed on the data form:

EXHIBIT 4.30

LIGHT METER

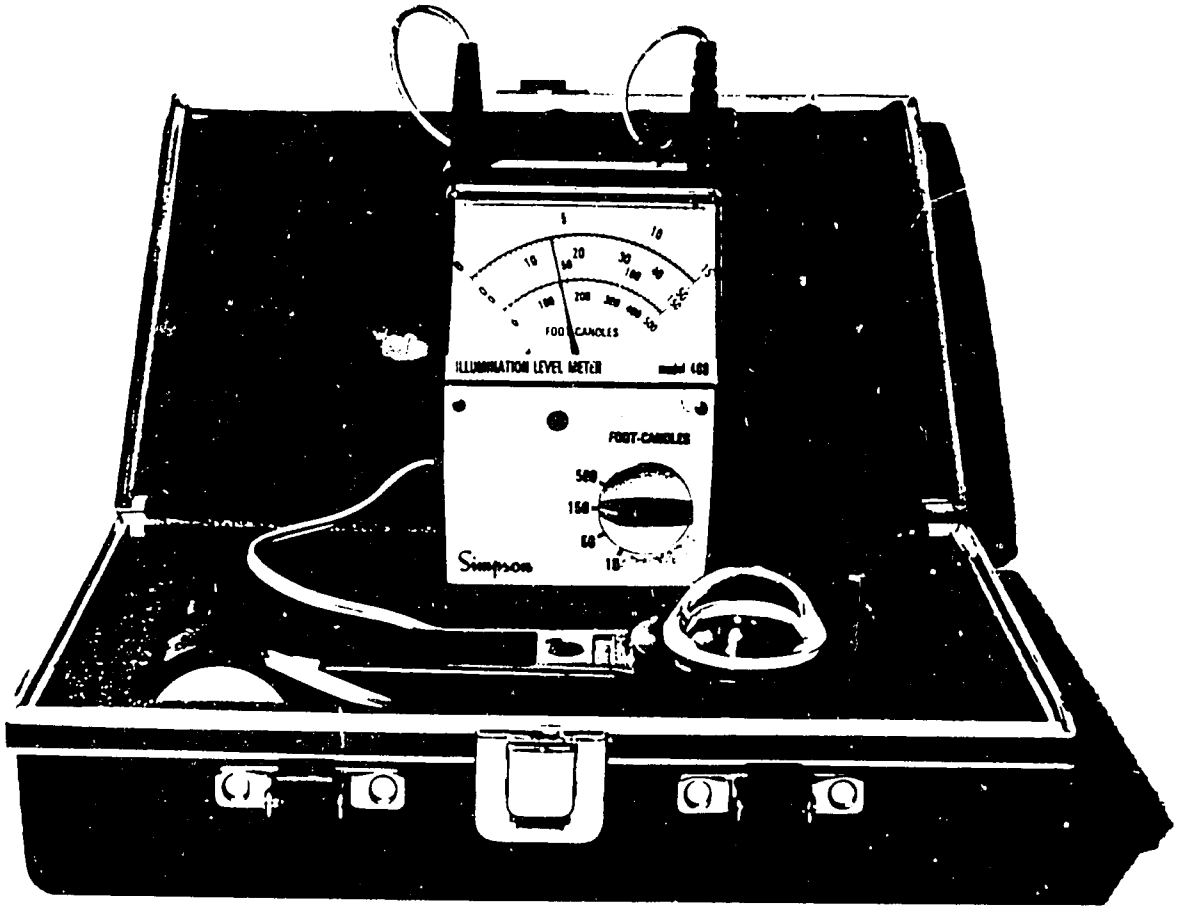


EXHIBIT 4.31

SUGGESTED LIGHT LEVELS FOR VARIOUS TASKS

TYPE, OCCUPANCY & AREA	FOOTCANDLES (MIN.-MAX.)
PROCESSING AND MANUFACTURING	
Bulk Unloading	30
General Process Equipment Areas	50
Mixing, Weighing, & Blending, Processing Bins & Tanks, Equipment Rooms	30
Refrigeration Compressors, Fans, Pumps & Air Compressors, Freezer Tunnels	5
Palletizing Equipment Area	30
Cleaning, Grading & Inspection of Raw Materials	70
Preliminary Sorting, Cutting Final Sorting, Inspection	100
Color Inspection & Appraisal	100-200
Machine Composition, Composing Room & Presses	100
Loading, Rail & Truck	20
Inside Truck Bodies & Freight Cars	10
PACKAGING	
Filling, Labeling, Packing, Wrapping	50
STORAGE	
Rough Bulky (spare equipment)	10
Medium (spare parts)	20
Fine (bins & racks)	50
Picking Stock, Classifying	30
WAREHOUSES	
DSSD Warehouse	15-25
Cold Storage Warehouse	

TYPE, OCCUPANCY & AREA	FOOTCANDLES (MIN.-MAX.)
UTILITY	
Boiler Plants, Compressors, Pump Rooms, Auxiliaries Condensers, Deaerator, Evaporator, Heater, Floors	30
Control Panels	50
Utility Tunnels	5
Cooling Tower	5
MAINTENANCE SHOP	
All Work Areas	50
LABORATORIES	
All Work Areas	100
ELECTRICAL EQUIPMENT & INSTRUMENT	
Switchgear, Indoor, Unit Substations	20
Motor Control Center, Central Control Room	
Aisle Lighting	50
Instrument & Repair Shop	100
OFFICE	
General Office	70-100
Private Office, Conference Room	70
Data Processing & Teletype	150
Drafting Rooms	150
Telephone Switchboard	50
Reception	30
Library - General	30
Reading Rooms	70
Rest, Toilet, & Locker Rooms	30
Aisles, Corridors & Stairways	20
Product Display Area	100
Night Lighting (Security)	1

Light load in kW = (number of fixtures) x ((bulbs per fixture) x (watts per bulb) + (ballasts per fixture) x (watts per ballast))/1,000.

The total lighting load for the facility can then be obtained by adding up the individual line items.

The annual energy consumption for the lighting system is determined by multiplying the light load by the annual hours of operation for each area surveyed. The total energy consumption for the facility is obtained in the same way as the total lighting load, by adding up each line.

Using the results of the survey and the suggested lighting levels provided in Exhibit 4.31, the auditor can determine what areas are overlit and where delamping can be accomplished to reduce energy consumption. Annual energy savings are calculated using the formulas presented above, substituting numbers for the bulbs and ballasts removed or disconnected.

4.7 WATER ANALYSIS

Many tests of boiler water and boiler feedwater may be conducted to determine the concentration of various ions. These tests are conducted as part of a comprehensive water treatment program to ensure the continued safe and efficient operation of the boiler. Typical of the tests conducted are those for alkalinity, chlorine, hardness, phosphate, sulfite, oxygen, pH, and total dissolved solids. In the area of energy management, the most useful test is that for total dissolved solids, or TDS.

Measurement of the TDS in the feedwater, condensate return, makeup water, and boiler water provides the auditor with a means of evaluating the condition of the boiler and the plant's steam distribution and condensate systems. While this is not a true combustion test, the amount of dissolved solids in boiler water is an indication of the heat transfer capability of the boiler. High concentrations of dissolved solids in the boiler water indicate the potential for fouling of boiler heat transfer surfaces. Also,

evaluating the ratios of the solids content of the makeup, return, and feedwater can indicate the pressure of leaks in the steam and condensate systems.

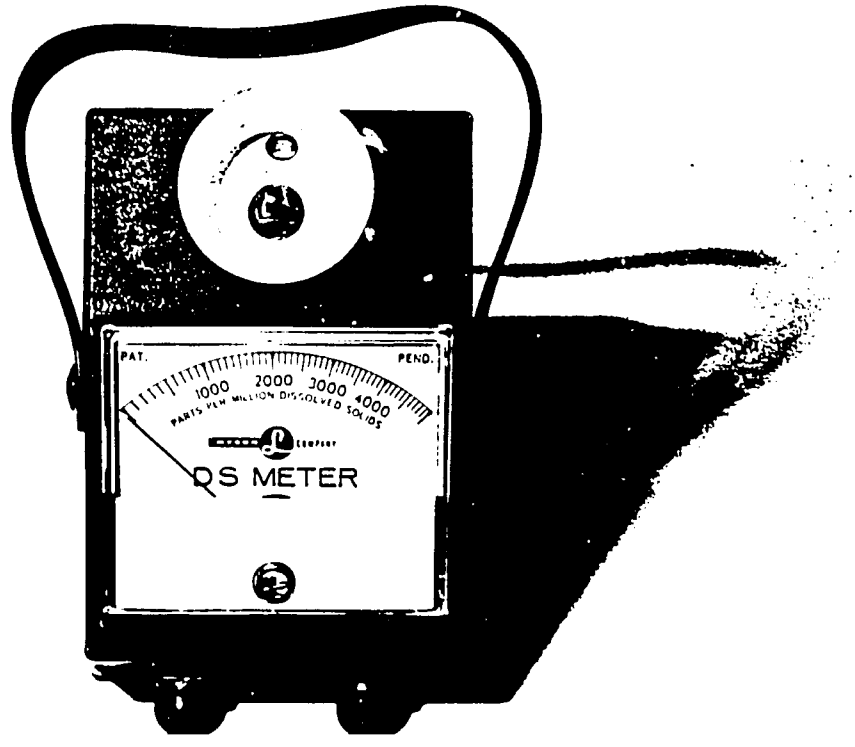
A **conductivity meter**, or **total dissolved solids (TDS) meter**, is used to determine the concentration of dissolved solids in the boiler water. An example of a conductivity meter is illustrated in Exhibit 4.32. The meter measures the electrical resistance (the inverse of conductivity) of a liquid sample. Since pure water is not a conductor, its electrical conductivity is zero. However, dissolved solids will increase the conductivity. The meter shown is calibrated to give a direct reading of dissolved solids in parts per million.

As with any water analysis, there is a certain amount of care that must be exercised to ensure accurate results. When collecting samples for analysis, the auditor should be sure to clean the sample bottle thoroughly several times with the sample fluid so that no residue is left from previous samples. Also, he should collect enough of a sample to rinse out the test cup on the TDS meter 3 or 4 times before taking a reading. Before taking a reading, he should also ensure that the meter is properly zeroed and that the battery is sufficiently charged to give accurate readings. The battery may be checked by selecting the "S" position on the range selector and then pushing the read button. The meter needle should deflect to the standard reading found on the bottom of the TDS meter. If this does not happen, replace the battery and retest. It is essential that the proper type of battery be used in the conductivity meter; carbon-zinc, not alkaline, is required in the meter shown. When testing a sample for the first time, select the highest scale on the meter and work down until the best reading is obtained. For this type of meter, the scale will read directly in parts per million (ppm) total dissolved solids.

The auditor should also provide a means to cool high-temperature samples below 100°C before placing them in an atmospheric sample container. Samples placed in the sample cup must be below 50°C to prevent damage to the meter. Collection of samples at elevated temperatures will result in a portion of the sample flashing off as steam, giving an increased concentration of solids in the remaining sample. As a result, readings will be erroneous and may possibly lead to incorrect conclusions and recommendations.

EXHIBIT 4.32

TOTAL DISSOLVED SOLIDS METER



To evaluate the boiler, the auditor should first collect a sample of boiler water from a blowdown point. Following the instructions in the paragraph above, he should obtain a reading of total dissolved solids in the boiler water. For most applications in boilers operating at pressures up to 40 bar, the boiler water solids content should be in the range of 2,500 to 3,000 ppm. If the concentration is lower, too much water is being blown down, and water, chemicals, and energy are being wasted. If the concentration is higher, it may cause fouling of heat transfer surfaces, which will reduce heat transfer efficiency and possibly cause boiler tube failure.

Next, the auditor should obtain samples and solids readings for the condensate return, makeup and boiler feedwater. From these readings, he can determine the percent of makeup water being supplied and thus evaluate the system losses. The percent makeup can be determined from the following formula:

$$\frac{\text{(makeup TDS) - (condensate TDS)}}{\text{(feedwater TDS) - (condensate TDS)}} \times 100 = \text{percent makeup.}$$

All units in the above formula are in parts per million (ppm) total dissolved solids. For most industrial applications, efforts should be made to reduce the makeup level to values below 20 percent.

4.8 PORTABLE INSTRUMENTATION FOR ENERGY AUDITING

The list presented in Exhibit 4.33 is by no means comprehensive, but indicates some available suppliers of portable industrial instrumentation in the United States. The United States itself is not the only supplier of instrumentation, and equipment may be available from other countries. The prices shown are best estimates for purchase in the United States. Some equipment may not be available locally. We do not endorse any instrumentation supplier and do not accept any responsibility for any problems with any instrumentation that may be purchased from any of the listed suppliers.

Exhibit 4.33

U.S. Suppliers of Portable Industrial Instrumentation

Type	Supplier	F.O.B. price[1] (U.S. dollars)
Flue gas analyzers		
Chemical CO_2, O_2 concentration combustion test kit, including smoke gun	Export Manager -- Bacharach Instruments 301 Alpha Drive Pittsburgh, PA 15238 Telephone: (412) 782-3500 Telex: 866407	300
Electrochemical digital Fyrizer Model 10	Export Manager -- Bacharach Instruments 301 Alpha Drive Pittsburgh, PA 15238 Telephone: (412) 782-3500 Telex: 866407	2,500
Electrochemical fuel efficiency monitor	Neotronics N.A. Inc. P.O. Box 370 411 Bradford Street, NW Gainsville, GA 30503 Telephone: (404) 535-0600	1,470
Temperature measurement		
Digital temperature indicator Model 9300	Tesoterm, Inc. P.O. Box 111509 Nashville, TN 37211-1509 Telephone: (615) 834-5082 Telex: 55-5112	200
Probes for above	Tesoterm, Inc. P.O. Box 111509 Nashville, TN 37211-1509 Telephone: (615) 834-5082 Telex: 55-5112	60-100
Digital temperature indicator -- Digital Series 450	Omega Engineering Inc. One Omega Drive Box 4047 Stamford, CT 06907 Telephone: (203) 359-7700 Telex: 996404	275

[1]As of August 1984.

Exhibit 4.33 (continued)

U.S. Suppliers of Portable Industrial Instrumentation

Type	Supplier	F.O.B. price[1] (U.S. dollars)
Temperature measurement (continued)		
Probes for above	Omega Engineering Inc. One Omega Drive Box 4047 Stamford, CT 06907 Telephone: (203) 359-7700 Telex: 996404	75-150
Infrared pyrometer -- Model 30 HT-3CPH (1,100°C-1,750°C)	Mikron Instrument Company Inc. P.O. Box 211 Ridgewood, NJ 07451 Telephone: (201) 891-7330	1,700
Infrared pyrometer -- Model 30 DHS - 19XC (600°C-1,700°C)	W. Wahl, Export Manager Wahl International Ltd. 5750 Hannum Avenue Culver City, CA 90230 Telephone: (213) 641-6931 Telex: 66-4406	2,250
Infrared pyrometer -- Model 30 OS-2000A (-30°C-1.400°C)	Omega Engineering Inc. One Omega Drive P.O. Box 4047 Stamford, CT 06907 Telephone: (203) 359-7700 Telex: 996404	1,900
Infrared pyrometer -- Model 8500 (0°C-700°C)	Tesoterm, Inc. P.O. Box 111509 Nashville, TN 37211-1509 Telephone: (615) 834-5082 Telex: 55-5112	1,125
Humidity measurement		
Electronic psychrometer Model 6400	Tesoterm, Inc. P.O. Box 111509 Nashville, TN 37211-1509 Telephone: (615) 834-5082 Telex: 55-5112	675

[1]As of August 1984.

Exhibit 4.33 (continued)

U.S. Suppliers of Portable Industrial Instrumentation

Type	Supplier	F.O.B. price[1] (U.S. dollars)
Humidity measurement (continued)		
Mechanical psychrometer	Vista Scientific Corporation 85 Industrial Drive Northampton Industrial Park Ivyland, PA 18974 Telephone: (215) 322-2255	125
Air/gas flow measurement		
Alnor velometers, Series 6000P	Alnor Instruments Company 7301 North Caldwell Avenue Niles, IL 60648 Telephone: (312) 647-7866 Telex: 72-4458	800
Hot wire anemometer	Alnor Instruments Company 7301 North Caldwell Avenue Niles, IL 60648 Telephone: (312) 647-7866 Telex: 72-4458	1,000
Pitot tube and manometer, Series 400	Dwyer Instruments Inc. P.O. Box 373 Michigan City, IN 46360 Telephone: (219) 872-9141	300
Draft measurement		
"U" tube manometers	Dwyer Instruments Inc. P.O. Box 373 Michigan City, IN 46360 Telephone: (219) 872-9141	25-100
TDS meter -- conductivity meter	John J. Berg, Export Manager Myron L. Company 6231C Yarrow Drive Carlsbad, CA 92008-4893 Telephone: (619) 438-2021 Telex: 695009	150

[1]As of August 1984.

Exhibit 4.33 (continued)

U.S. Suppliers of Portable Industrial Instrumentation

Type	Supplier	F.O.B. price[1] (U.S. dollars)
Electrical measurement		
Clamp-on ammeter	Epic, Inc. 150 Nassau Street New York, NY 10038 Telephone: (212) 349-2470	285
Clamp-on power factor meter	Epic, Inc. 150 Nassau Street New York, NY 10038 Telephone: (212) 349-2470	450
Clamp-on wattmeter	Epic, Inc. 150 Nassau Street New York, NY 10038 Telephone: (212) 349-2470	450
Clamp-on ammeter, Model 1000	T.I.F. Instruments, Inc. 3661 NW 74th Street Miami, FL 33147 Telephone: (305) 696-7100 Telex: 512302	175
Clamp-on wattmeter, Model 2000	T.I.F. Instruments, Inc. 3661 NW 74th Street Miami, FL 33147 Telephone: (305) 696-7100 Telex: 512302	400
Clamp-on power factor meter, Model 1000	T.I.F. Instruments, Inc. 3661 NW 74th Street Miami, FL 33147 Telephone: (305) 696-7100 Telex: 512302	400
Light meter	Simpson Electric Company (subsidiary of Katy Industries, Inc.) 853 Dundee Avenue Elgin, IL 60120 Telephone: (312) 697-2260 Telex: 72-2416	350

[1]As of August 1984.

4.9 MICROCOMPUTERS AND SOFTWARE FOR ENERGY AUDITING

Microcomputers can be used as a time-saving tool by energy auditors for both storage and organization of data and for analysis of the energy performance of energy-consuming systems. An overview of microcomputer hardware, programming languages, and a description of some "generic" types of programs that may be of use to energy auditors follows. A brief description of some computer programs that are currently available for energy use analysis is also presented.

4.9.1 Computer Hardware

Microcomputers have proliferated over the past 6 years. Advances in microprocessor technology have increased the capabilities of desktop computers enormously, while prices for these machines have plummeted. Microcomputers are available no bigger than a briefcase with the computing power of a machine that only 15 years ago filled an entire room.

All microcomputers have several common components. The key component is the microprocessor. This device, sometimes no bigger than a matchbox, directs the flow of data through the computer's memory. While there are literally dozens of different microcomputers available, all of them are based on one of perhaps a dozen individual microprocessors.

The simplest microprocessors are the so-called "8-bit processors." These microprocessors are capable of handling eight pieces of information simultaneously. Advances in microprocessors have spawned 16-bit and 32-bit processors, which are capable of handling more information at a faster rate than 8-bit processors and -- more importantly -- can address much larger computer memories.

The second element of any computer is its memory. Memory is measured in "bytes," and a number may be represented by one or two bytes of memory. A byte may consist of 8, 16, or 32 bits of information. Older 8-bit processors are capable of addressing up to 64K bytes of memory (one K = 1,024 bytes), or 65,536 bytes. More advanced processors can address up to several million bytes. It is important to consider the memory

available when writing a program or handling large amounts of data. Each number stored may consume one or two bytes; each word stored may consume one byte per letter; each program instruction may consume several bytes.

While there are many programs commercially available that require only 64K bytes of memory, newer programs typically require much more. Lotus "Sympony", for example, requires at least 320K and may use up to 704K of program memory on an IBM PC.

The third element of the microcomputer is the input/output device, typically a keyboard similar to a typewriter (for input) and a cathode ray tube (CRT) display, which resembles a television screen (for displaying computer output). This is the means by which the programmer or user communicates with the computer.

Some computers have additional storage space in the form of a magnetic storage medium called a disk. This storage space is different from most computer memory in that the data stored on the disk are permanent and are not lost when the computer is turned off. In most microcomputers, memory contents -- data and programs -- are destroyed when the computer is shut off. An exception is the memory in the Hewlett Packard portable computer, the HP110. It is possible to purchase memory boards for the IBM PC that return information when power is turned off. Programs and data can be stored for later use on the disks by telling the computer to "write" the information. It should be noted that almost every brand of computer stores information on disks in a different format; hence, it is generally not possible to exchange disks between different types of computers.

Some computers also have a printer, either built in or attached by means of an interface and cable. The printer produces a paper record (hard copy) of data and programs.

Other peripheral devices are available for some microcomputers, including modems (which allow computers to communicate with each other over telephone lines), plotters, and special interfaces to enable computers to control other devices or receive data from instruments.

There are some popular microcomputers that are available throughout the world, with large numbers of programs already written for them. These machines include:

- IBM Personal Computer (PC) or personal computer with hard disk (XT)
- Hewlett Packard Hp110 and other models
- Apple IIe, IIc, or Macintosh
- Tandy/Radio Shack Model 4, 12, 16B, 100, and 2000.

"Compatible" machines are also available in some countries. A compatible computer is said to be capable of running some or all of the same programs as the "original," but compatibility is often limited to specific programs or special hardware.

Hand held computers are also available. These are generally no bigger than a paperback book, and provide some of the capability of smaller microcomputers. They can be programmed in BASIC or in a machine-specific language and are usually battery-powered, enabling them to be taken into the field for immediate data entry and calculation of results. These machines include:

- Hewlett-Packard HP41C, HP41CV, HP41CX
- Hewlett-Packard HP71B, HP75D
- Casio
- Sharp
- Texas Instruments.

Hewlett-Packard computers are designed for use by engineers and scientists, and a library of over 5,000 programs developed by Hewlett-Packard and by users is available at nominal cost.

4.9.2 Programming Languages

While tens of thousands of computer programs have been written and are commercially available, it is sometimes necessary to program a computer to perform a particular task or set of calculations. There are two alternatives to programming: "pointing" to a selection among pictures or words on the screen, and typing instructions in simple English sentences. The Apple Macintosh has developed the first approach in its most advanced form. At present, there is only one program for the IBM PC that accepts commands in English sentences.

The general trend in microcomputer software is to make it unnecessary for the user to learn any computer languages. Software used to program with languages is often less flexible than newer, language-free software, in the use of large amounts of program memory.

Most microcomputers can be programmed in a language called BASIC. This language uses English words and mathematical notation to tell the computer how to carry out necessary instructions. In addition, different dialects of BASIC exist, requiring program modifications when switching from one type of machine to another.

FORTRAN, which is available as an option for most microcomputers, was originally developed for mainframe computers. An "interpreted" language runs slowly but allows a program to be stopped at any point in the middle of execution. A "compiled" language runs fast but does not allow a program to be stopped at any point. FORTRAN is available only as a compiled language whereas BASIC is available as both a compiled and an interpreted language -- an important advantage.

Other programming languages are available as well. PASCAL is a highly structured language that calls for more planning on the part of the programmer, but produces very fast and efficient compiled programs. COBOL is a compiled language used primarily for business applications. APL is a very concise and efficient language that handles matrices and matrix operations very quickly, but uses a totally non-English set of characters for commands.

It is beyond the scope of this manual to provide a course in computer programming. The energy auditor who is unfamiliar with this subject will find assistance in the documentation accompanying the microcomputer available to him, or in books that are available.

4.9.3 Generic Program Types

There are several types of programs that may be of use to energy auditors. While these programs are not specifically geared toward energy analysis, they can be readily adapted to this purpose.

The first generic type of program is the **spreadsheet** program. A spreadsheet program is a computer analog of a large piece of paper on which an auditor may be laying out data and making calculations and memoranda. The spreadsheet is arranged in rows and columns; the actual size of the spreadsheet available depends on the program used and the computer memory available; Lotus "Symphony" allows up to 256 columns by 8,000 rows. An auditor can enter his data into the computer as he would on a piece of paper. The spreadsheet allows new variables to be formulated as a function of data entered by the auditor and of other, previously defined functions. One major advantage of this system is that if a change is made to any number in the spreadsheet, all other numbers (as appropriate) are recalculated to reflect the change.

Spreadsheet programs allow the auditor to set up equations in a simple fashion, just by entering the formula. In addition, the programs generally have a number of useful functions built in: trigonometric functions, logarithmic and exponential functions (both natural and naperian), maximum or minimum value of a list of variables, and financial functions (e.g., net present value).

These programs can be used for a number of different types of calculations. The spreadsheet program allows the auditor to copy the formulae used on one row or column to any other row or column. Hence, for repetitive calculations using different data, the formulae need only be entered once and then copied throughout the spreadsheet. For instance, the results of a series of boiler tests can be computed after entry of the measured data.

Similarly, cash flow tables for calculation of internal rate of return may be set up to speed financial calculations. Because the spreadsheet program allows the auditor to store the spreadsheet data and formulae to a magnetic disk, an application can be used again and again, as needed, once it has been developed.

A spreadsheet program alone, without graphics or database capability, is increasingly a thing of the past. Spreadsheet programs are being superseded by "integrated" software with broader capabilities. There are still many non-integrated spreadsheet programs available, however. Different versions are available for use on different microcomputer systems. Some examples of spreadsheet programs are VisiCalc, SuperCalc, and FlashCalc.

Another useful type of program is the **data base program**, which is the computer analog of a filing cabinet. To explain the use of such a program, consider the example of an auditor conducting a preliminary energy audit, developing an inventory of electric motors in his facility. He would take a file folder and label it "Electric Motors." In the file folder would be a number of pieces of paper, each with data about a single motor: reference name, location, size and type, hours of operation, nameplate, voltage, amperage and power factor, phase, cycles, and test results. Each piece of paper is a "record," and each piece of information on the paper is a "field." The data base program allows the auditor to organize his information in exactly the same way.

Once all of the information is entered into the data base, it can be stored on a magnetic disk, but the use of the data base program does not end there. The auditor can use the data base program to display or print lists of the motors meeting certain requirements. For instance, if the auditor needs a list of all motors with power factor less than 0.80, the data base program can be instructed to display or print such a list. Similarly, the auditor can instruct the data base program to list motors in order of size or hours of operation.

Data bases can be set up to maintain inventories of other equipment in the facility as well (e.g., boilers, steam traps, lighting systems). Examples of popular data base programs currently available are Visi File, DB Master, dBaseII, dBase III, Knowledge Man, and RBase.

The third type of generic program is the **word processor**, which is the computer analog of a typewriter. The major difference, however, is that the typed material can be stored on a magnetic disk and edited, reformatted, or otherwise changed without the manual effort involved in retyping an entire page or report.

There are dozens of word processing programs currently available. Examples of popular programs are Applewriter, Wordstar, Word, Supertext, Homeword, and Bank Street Writer.

The final type of generic program that may be of use to the energy auditor is the so-called "integrated" program. This program incorporates the functions of the spreadsheet, data base, and word processor programs in a single package and allows the rapid transfer of data between the various functions. In addition, some integrated packages include

capabilities for the preparation of bar graphs, line graphs, pie charts, and other types of graphics for visual, rather than tabular, presentation of data. Examples of integrated software include Appleworks, Lotus 1-2-3, Symphony, Framework, and Context MBA. The primary function of integrated software is often its use as a spreadsheet, and limitations are imposed on the other functions.

4.9.4 Programs for Energy Auditors

Exhibit 4.34 presents capsule descriptions of some computer programs written especially for energy use analysts. The programs are presented according to type of analyses performed. It should be noted that this listing is by no means comprehensive, and new programs are introduced regularly. In addition, these programs may not be compatible with every type of computer system available. We do not endorse any computer program or software supplier and do not accept any responsibility for any problems with any software that may be purchased from any of the listed suppliers.

Exhibit 4.34

Examples of Programs for Energy Auditors
(U.S. companies)

Energy Monitoring and Modelling Programs

FASER — Fast Accounting for Energy Reporting (OmniComp, P.O. Box 882, Highland, CA 92346). This program performs energy accounting of utility invoices and meter readings. The program adjusts for varying billing periods and weather conditions, compares current cost and consumption with a selected baseline, and produces a variety of reports.

Superex Energy Accountant (Superex Business Software, 151 Ludlow Street, Yonkers, NY 10704). This program allows the energy auditor to monitor the energy consumption and costs of a number of facilities. The program automatically develops a mathematical model of each facility, allowing the comparison of energy use over periods of time while accounting for differences in facility use (e.g., weather conditions, plant utilization). The program also develops energy targets based on past energy use patterns.

Plant Utilities Accounting System (Institute for Scientific Analysis, 36 East Baltimore Pike, Media, PA 19063). This program produces monthly reports for each utility, showing actual consumption and costs and a comparison with budgeted costs. The data are presented on a cost center basis, and for the entire plant.

Stat Systems (PAR Software, P.O. Box 98, Odessa, Florida 33556). This program can be used for modelling using stepwise multiple linear regression techniques as well as performing other statistical analysis.

Boilers, Steam Systems, and Combustion Systems

MESA — Modular Energy System Analyzer (The MESA Company, Drawer M, Kemblesville, PA 19347). MESA is a program that simulates the performance of boilers and steam systems, including pumps, heat exchangers, generators, and valves. It allows the analysis of such design changes as replacement of pressure-reducing valves with turbine generators, installation of regenerative feedwater heaters, increased condensate return, and installation of other heat recovery devices.

COMBUST — Combustion Analysis (PSI/Systems, P.O. Box 3100, Andover, MA 01810). This program analyzes the combustion efficiency of a furnace.

BETH (Energy Incorporated, P.O. Box 736, Idaho Falls, ID 83401). This program determines power plant performance. It includes a number of modules, including steam tables, psychrometric properties, gas properties, boiler efficiency and combustion, and power plant unit operations.

Boiler Efficiency (LN Engineering, P.O. Box 2562, Kalamazoo, MI 49003). This program calculates the efficiency of gas-, oil-, or coal-fired boilers.

Heatalyzer (National Insulation Contractors Association, 1025 Vermont Avenue, NW, Washington, DC 20005). This program analyzes the performance of insulation on hot pipes, vessels, and ductwork. It determines heat loss, economic thickness of insulation, and payback period.

Exhibit 4.34 (continued)

Examples of Programs for Energy Auditors
(U.S. companies)

Boilers, Steam Systems, and Combustion Systems (continued)

Steamcalc (Software Systems, 5766 Balcones Drive, Austin, TX 78731). This program computes the thermodynamic properties of subcooled, saturated, and superheated steam.

Economic Analysis

Life Cycle Cost (MC2 Programs, 7000 SW 62nd Avenue, Miami, FL 33143). This program calculates total life-cycle cost of owning and operating energy equipment. It accounts for annual fuel and power requirements, operating and maintenance costs, and initial investment costs. In addition, separate inflation factors for each cost element are allowed.

Solar Energy Analysis

Solar F-Chart and Economic Analysis (MC2 Programs, 7000 SW 62nd Avenue, Miami, FL 33143). This program calculates the monthly heat demand and heat supplied by a solar collector system using the F-chart method. It can be used for the analysis of liquid or air systems for water heating or combined space and water heating. It also incorporates an economic analysis section that calculates a net present value of the system.

Micro-LOGIC 2000 — Solar Analysis System (Lennox Industries, P.O. Box 400450, Dallas, TX 75240). This program analyzes the performance of solar energy systems using the F-chart method.

Building Energy Consumption Analysis

HVAC Energy Consumption and System Simulation Program (MC2 Programs, 7000 SW 62nd Avenue, Miami, FL 33143). This program uses a modified ASHRAE simplified energy calculation procedure to estimate monthly and/or annual building energy consumption. It can simulate the performance of a wide variety of boilers, chillers, heat pumps, and terminal HVAC systems.

Heating Fuel Cost (MC2 Programs, 7000 SW 62nd Avenue, Miami, FL 33143). This program uses a modified degree-day method to estimate the annual fuel cost for oil, gas, or electric resistance heating. The program accounts for outdoor design temperature, indoor design temperature, percent heating plant oversize, and heating plant efficiency at full load.

SEA — Simplified Energy Analysis (FKAI, 13 Welby Road, New Bedford, MA 02745). This program allows the effect of energy conservation measures on building energy use to be calculated. The program is intended for use on commercial buildings of less than 10,000 square feet (1,000 square meters) and uses the ASHRAE procedure for energy calculations. It also performs a financial analysis of cost savings.

Exhibit 4.34 (continued)

Examples of Programs for Energy Auditors
(U.S. companies)

Programs for Hand-Held Computers

Hewlett-Packard has a library of over 5,000 programs available at nominal cost for use with its hand-held calculators. A number of programs that can be of use to energy auditors are listed below, with the program order number provided in parentheses after the program name. All of these programs are available through Hewlett-Packard Users' Library, 1000 NE Circle Boulevard, Corvallis, OR 97330.

Insulation Characteristics (41-01338-0). This program solves for either the surface temperature of the thermal insulation, emissivity of the insulation surface, or the apparent K factor. Convective, radiative, and total heat losses are calculated separately.

Airstream Energy Balances (41-02444-5). This program predicts the final temperature of two airstreams that mix, accounting for the air and water vapor enthalpies.

Combustion Calculations (41-01099-8). This program uses fuel composition, stack gas temperature, excess air, and boiler power to predict boiler efficiency, heat rate, flue gas composition, and a number of other variables of interest.

Heat Exchanger Calculations (41-01244-0). Given any two of the following, the program calculates the third: outlet temperatures, exchanger heat transfer coefficient, or heat transfer area. The program is suitable for countercurrent, 1 shell/2 tube passes, or 2 shell/4 tube passes heat exchangers.

Heat Loss or Gain by Pipe (41-01682-1). The program calculates heat gain or loss by an insulated or uninsulated pipe, and the temperature of the outside insulation wall.

Heating Values (41-01307-5). This program determines the heat of combustion of gas, liquid, or solid fuels, given the fuel composition.

Pipe Heat Loss and Economics (41-01511-2). The program calculates surface temperature and heat loss through bare or insulated pipe. An annual operating cost is calculated, as is a discounted payback period.

Thermodynamic Properties of Saturated and Superheated Steam (41-01693-8). The program calculates the thermodynamic properties of saturated and superheated steam over a wide range of temperatures and pressures.

Life Cycle Cost (41-02737-2). This program calculates the life-cycle cost of any energy-consuming installation. The program allows rapid changes in any of the main parameters for performance and sensitivity analyses.

Lighting Power Budget (41-01520-3). The program calculates the allowable energy budget for building lighting in accordance with the Illuminating Engineering Society's recommended procedures.

Power Factor Correction for Electrical Systems (41-02285-1). The program calculates capacitive kVAR to improve power factor, and capacitive kVAR for induction motors.

CHAPTER 5: CONDUCTING A DETAILED ENERGY AUDIT

This chapter describes the steps taken in the Detailed Energy Audit to test and evaluate five types of energy-consuming systems. The systems are:

- Boilers
- Steam systems
- Dryers
- Furnaces
- Electrical systems.

For each type of system, the instrumentation requirements, typical conservation opportunities, and sample methods for estimating savings are discussed. A reminder of the relationship of the PEA and the Detailed Energy Audit to the total energy management program is contained in Exhibit 5.1.

One case study -- that of an audit of a tire-making plant -- is presented in Appendix 5.A. The case study discusses the auditing procedures and provides the results of the detailed energy audit.

Exhibit 5.1

Major Steps in Implementing Energy Management Program

Step 1. **Review energy management program to date**

Step 2. **Conduct preliminary energy audit**

Step 3. **Develop action plan, including energy audit**

Step 4. **Select scope of energy audit**

- Manpower
- Systems for test and testing procedures
- Instrumentation

Step 5. **Complete preparatory work**

- Instrumentation repair/purchase
- Install test points
- Time frame

Step 6. **Carry out energy audit field work**

- Conduct selected tests
- Collect data

Step 7. **Evaluate collected data**

Step 8. **Identify conservation opportunities**

- Operation and maintenance
- Capital-intensive measures

Step 9. **Develop action plan for implementation**

- Timetable
- Feasibility studies

Step 10. **Continue to monitor energy use**

Step 11. **Refine overall energy management program**

5.1 DETAILED ENERGY AUDIT OF BOILERS

Boiler plants account for approximately 50 percent of the thermal energy used in industry. As such, this section will outline the procedure for evaluating boiler plants as part of an overall detailed energy audit, including a PEA analysis. The energy auditor does not normally conduct a full energy audit on just one energy-consuming system. However, he must evaluate an energy-consuming system as part of a detailed energy audit. The procedure for testing and evaluating boilers and identifying conservation opportunities is given in Exhibit 5.2 and described in the following paragraphs.

5.1.1 PRELIMINARY ENERGY AUDIT

The first step in evaluating a boiler is to conduct a PEA if one has not already been completed. The PEA is used to collect information through interviews with key personnel and by visual inspection. The information includes nameplate data as well as operational details, including fuels used and operating pressures and temperatures.

Nameplate data on the boiler plant are recorded on a form like that in Exhibit 5.3. Such data include the location and operating details of both boiler and burner, and characteristics such as fuel used, medium raised, and types of control.

This information can be collected from interviews and confirmed during the visual inspection, or it can be determined in the visual inspection alone.

The visual inspection allows the energy auditor to see for himself the condition of the plant and its auxiliary equipment and confirm interview information. The auxiliary systems associated with boilers should be checked:

- Boiler and burner
- Water system
- Fuel supply system
- Heated medium distribution
- Instrumentation systems.

Exhibit 5.2

Preliminary Energy Audit and
Energy Audit Procedures for Boiler Plant

Step 1. Preliminary energy audit

- Interview personnel
- Obtain nameplate information
- Obtain operational details, including fuel use, medium raised, temperature and pressure, and operating hours
- Conduct visual inspection of condition of boiler and auxiliaries; determine condition and readings of instrumentation
- Examine boiler house log
- Identify test points
- Determine type of test and instrumentation required
- Identify conservation opportunities from improved operation
- Develop action plan for energy audit

Step 2. Energy audit

- Prepare for audit
  - repair/install instrumentation as necessary
  - identify testing positions
  - select appropriate test day
- Perform test
  - testing procedures and techniques
  - data collection
- Evaluate data
  - calculate efficiency
  - determine improvements

Step 3. Identify conservation opportunities

- tune-up
- improved control
- heat recovery
- alternative fuels

Exhibit 5.3

Boiler Details

Location: _____

Boiler

	1	2	3
Manufacturer:			
Age (years):			
Type:			
Rating (kg/hr):			
Medium raised:			
Normal operating pressure (bar):			
Normal operating temperature (°C):			

Burner(s)

Number:			
Fuel(s) fired:			
Manufacturer:			
Age (years):			
Type:			
Draft:			
Atomization:			
Burner controls:			
Draft control (dampers):			

Points to check are listed in Exhibit 5.4.

The auditor can obtain further information by checking the following records:

- Boiler house log
- Water treatment reports.

The type of information to be collected is presented in Exhibit 5.5.

The energy auditor should consider the following information when deciding whether to test the boiler:

- Date of last efficiency check
- Installed instrumentation
- Operating condition.

The criteria for testing are given in Exhibit 5.6.

If testing is necessary, the energy auditor should identify the test points and decide what type of test is to be performed and the instrumentation needed.

The **types of test** include:

- Full commissioning test
- Efficiency test to standards established by bodies such as ASME, British Standards BS 845 or BS 2885
- Efficiency test by loss method
- Combustion test only.

The most common test is the efficiency test by the loss method. The other methods are used less frequently and are variations of the loss method. Although they can be more accurate, the extra cost and time required to carry them out are often not justified.

Boiler Evalua

Item	quipment	Commen
Physical appearanc		
	m	
	ium distribution	
External structure		
Safety equipr & instrument		
	n	
	ium distribution	
Valves, fitti & insulatic		
	n	
	um distribution	

Exhibit 5.5

Boiler House Log/Water Treatment Records

Operating conditions monitored	Yes	No	Comments
Flue gas analysis % CO_2			
% O_2			
% CO			
F.G. temp.			
Draft			
Smoke			
Flow metering, fuel			Units
Heating medium/steam			
Makeup water			
Boiler feedwater			
Condensate return			
Temp. heating medium/steam			
Fuel			
Makeup water			
Condensate return			
Pressure heating medium/steam			
Fuel			
Water condition TDS makeup			
Condensate			
Boiler feed			
Boiler water			
Alkalinity makeup			
Condensate			
Boiler feed			
Chlorides makeup			
Condensate			
Boiler feed			
Hardness makeup			
Condensate			
Boiler feed			
pH makeup			
Condensate			
Boiler feed			
Blowdown			

Exhibit 5.6

Criteria for Testing

1. Excessive smoke from stack

2. Three months since last efficiency check

3. High flue gas temperature reading from boiler log or indicator in stack; in excess of 250°C at high fire for firetube boiler rated at 4,000 kg/hr; in excess of 300°C at high fire for watertube boiler with working pressure of 16-30 bar

4. Installed flue gas analyzer indicates less than 9 percent carbon dioxide or more than 8 percent oxygen on high fire

5. No change in operating condition when burner firing rate is changed

6. Poor plant physical appearance

7. Little or no fitted instrumentation in working order

8. Manually adjusted burners

9. Draft readings at back of boiler in excess of -25 mm water gauge

Instruments needed for efficiency testing by the loss method are shown in Exhibit 5.7.

At the end of the PEA, the energy auditor will complete his evaluation and prepare an action plan; the plan normally includes a recommendation for a detailed energy audit unless the PEA indicates the that boiler is in good operating condition; for example, has properly working instrumentation and a documented operating efficiency of about 80 percent.

As a result of the PEA, the energy auditor may have identified conservation opportunities in two areas: those that can be implemented immediately and those that require further study. The measures that can be implemented immediately are operational and maintenance procedures involving only limited capital investment. Typically, simple payback periods will be less than 1 year.

Measures that can be implemented immediately include:

- Replacing damaged or missing insulation or increasing insulation on hot surfaces, including boiler and auxiliary equipment
- No longer maintaining reserve boilers at pressure
- Reducing blowdown requirements
- Reducing operating pressure of the boilers
- Reducing plant operating hours.

Techniques for estimating savings for some of the these measures are presented in the following exhibits:

Exhibit number	Measure
5.8 and 5.9	Installing insulation
5.10	Discontinuing reserve boilers at pressure
5.11	Reducing blowdown
5.12	Reducing operating pressure of the boilers

Reducing the plant operating hours can save energy. In making such a reduction, the energy auditor must be sure that there is still sufficient time for the plant to shut down and restart without imposing undue strain. He should not consider this measure

Exhibit 5.7

Boiler Efficiency Test Kit

Instrument	Type	Measurements
Flue gas analyzer	Portable or fixed	Either percent CO_2 or percent O_2; percent hydrocarbons or percent CO
Temperature indicator	Thermocouple Liquid in glass	Flue gas temperature Combustion air temperature
Smoke gun		Stack soot conditions
Draft gauge	Manometer, differential pressure	Amount of draft used or available
TDS meter	Conductivity	Boiler water TDS, feedwater TDS, makeup water TDS

Exhibit 5.8

Installing Thermal Insulation on Boiler and Ancillary Plant

The savings achieved by insulating bare surfaces or increasing the amount of insulation can be estimated using the calculation techniques presented below. Notes on assumptions and data used in the calculations are given at the end of the exhibit.

Calculation

Assumptions

Reduction in heat losses by insulation: ____ percent
($GJ = 3.6 \times 10^{-3} \times kWh$)

Data

Boiler operating hours: _____/yr

Boiler ancillaries operating hours: _____/yr

Boiler combustion efficiency: ____ %

Plant/ equipment	Shape/ position	h	Area (m^2)	dT (^oC)	Heat loss (kW)	Insulation proposed	Estimated cost
Boiler:							
				TOTAL		TOTAL	
Boiler ancillary:							
				TOTAL		TOTAL	

h = Surface heat loss coefficient.
dT = temperature difference between surface and surroundings.

Exhibit 5.8 (continued)

Installing Thermal Insulation on Boiler and Ancillary Plant

Energy Savings

Boiler = Heat loss x reduction in heat losses by insulation x plant operating time x 3.6×10^{-3}

= ( ) ( ) ( ) (3.6×10^{-3})

= _____ GJ/year

Ancillaries = (Heat loss/hr x reduction in heat losses by insulation x plant operating time) (3.6×10^{-3})/boiler combustion efficiency

= (( ) ( ) (3.6×10^{-3}))/( )

= _____ GJ/year

Total energy savings = ( ) + ( )

= _____ GJ/year

Cost savings = ($/GJ)

= ( ) ( )

= $_____/yr

Cost of Implementation

The total estimated cost of insulating = $ _____.

Energy savings = GJ/yr

Cost savings = $_____/yr

Exhibit 5.8 (continued)

Installing Thermal Insulation on Boiler and Ancillary Plant

Notes for Calculation

Assumptions

Reduction in heat losses by insulation. A percentage figure of 90 percent is normally used for the following:

- bare surface

  90 percent is used because it is equivalent to the economic thickness. If the surface is insulated and additional insulation is proposed, use a figure of 70 percent.

Data

(i) Boiler plant operating hours: used when insulating components have operating hours identical to the boiler (e.g., boiler shell, deaerator)

(ii) Boiler ancillaries operating hours: used when insulating ancillary plant may not operate the same hours as the boiler -- e.g., oil preheaters (one is standing by)

(iii) Boiler combustion efficiency: use actual value or estimate. For ancillary equipment supplying more than one boiler, use a weighted combustion efficiency based on the relative efficiencies of the boilers in question. For example, for two boilers with efficiencies and operating periods as follows:

Boiler 1: 75 percent efficiency, 30 percent use
Boiler 2: 80 percent efficiency, 70 percent use

Weighted combustion efficiency = ((0.75) (0.3) + (0.8) (0.7)) 100

= 78.5 percent.

(iv) Table heading "shape/position": surface heat losses depend on the shape of the surface and whether it is vertical or horizontal. Factors are given for orientation in Exhibit 5.8, together with values for surface heat loss coefficients; they should be used accordingly.

(v) Table heading "h": this is the surface heat transfer coefficient and can be obtained from the graphs or table shown in Exhibit 5.9.

(vi) Table heading "area": can be obtained by measurement and calculation for each area to be insulated.

(vii) Table heading "dT": calculate or measure the temperature difference between the surface and the surrounding air. If surface temperature is not measured, make a calculated estimate -- e.g., a condensate receiver surface temperature is going to be approximately 30° less than boiling point of water at atmospheric pressure (i.e., $70^{o}C$).

Exhibit 5.8 (continued)

Installing Thermal Insulation on Boiler and Ancillary Plant

(viii) Table heading "heat loss": calculate the heat loss using the following equation:

$$\text{heat loss } Q = h.A.dT.$$

(ix) Table heading "insulation proposed": abbreviate the type of insulation proposed to 10 digits (e.g., "g. fiber"). The following types of insulation can be used:

- preformed rigid fiber, such as glass fiber
- calcium silicate or magnesia
- polyurethane or polyisocyanurate.

Care must be taken to use insulation that has a working temperature in excess of the temperature of the surface to be insulated.

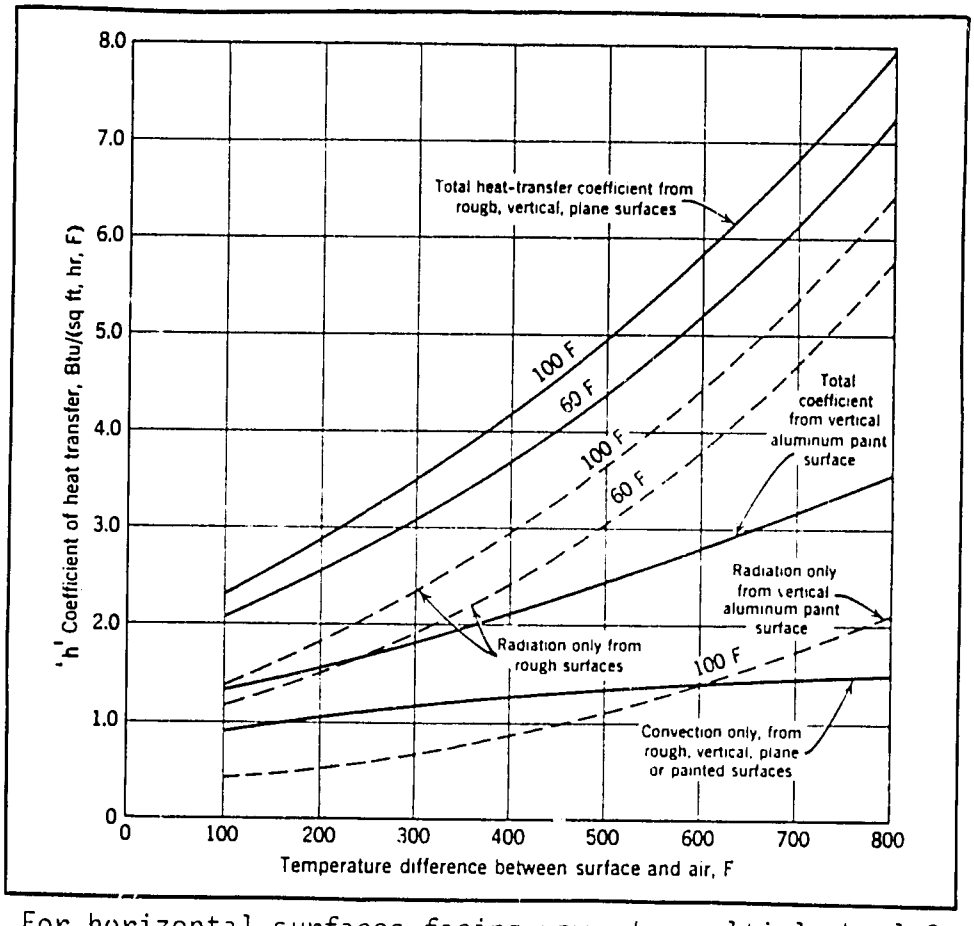
(x) For savings on the boiler itself, **do not** include the boiler combustion efficiency.

(xi) Energy savings: round up to nearest GJ.

(xii) Cost savings: round up to nearest dollar.

Exhibit 5.9

SURFACE LOSS COEFFICIENTS FOR PLANE SURFACES



For horizontal surfaces facing upwards, multiply by 1.3
For horizontal surfaces facing downwards, multiply by 0.65

Btu/sq ft,hr,°F x 0.006 equals kW/M hr,°C

Btu/hr(linear ft) x 0.001 equals kW(linear meter)

SURFACE LOSS COEFFICIENTS FOR BARE CYLINDERS

Btu/(hr) (linear ft) (deg F diff between pipe and surrounding air)

NOMINAL PIPE SIZE (In.)	HOT WATER				STEAM		
	120 F	150 F	180 F	210 F	5 psig 227 F	50 psig 300 F	100 psig 338 F
	TEMPERATURE DIFFERENCE*						
	50 F	80 F	110 F	140 F	157 F	230 F	268 F
½	0.46	0.50	0.55	0.58	0.61	0.71	0.76
¾	0.56	0.61	0.67	0.72	0.75	0.87	0.93
1	0.68	0.74	0.82	0.88	0.92	1.07	1.15
1¼	0.85	0.92	1.01	1.09	1.14	1.32	1.43
1½	0.96	1.04	1.15	1.23	1.29	1.49	1.63
2	1.18	1.28	1.41	1.51	1.58	1.84	1.99
2½	1.40	1.53	1.68	1.80	1.88	2.19	2.36
3	1.68	1.83	2.01	2.15	2.26	2.63	2.84
3½	1.90	2.06	2.22	2.43	2.55	2.97	3.22
4	2.12	2.30	2.53	2.72	2.85	3.32	3.59
5	2.58	2.80	3.08	3.30	3.47	4.05	4.39
6	3.04	3.29	3.63	3.89	4.07	4.77	5.16
8	3.88	4.22	4.64	4.96	5.21	6.10	6.61
10	4.76	5.18	5.68	6.09	6.41	7.49	8.12
12	5.59	6.07	6.67	7.15	7.50	8.80	9.53

*At 70 F db room temperature

N.B. These are surface loss coefficients per Linear foot

Exhibit 5.10

Discontinuing Use of Hot Reserve Boilers

In many facilities visited, there is boiler standby capacity kept at pressure, even though not on line. This is known as "hot reserve" conditions. It is recommended that this condition be discontinued. It is suggested, however, that the standby boilers be fired up once a week to ensure that they will function satisfactorily when called upon during an emergency condition.

The savings can be estimated using the calculation techniques presented below. Notes on assumptions and data used in the calculations are given at the end of the exhibit.

Calculation

Assumptions

The standby boiler(s) can be kept cold without any severe detrimental effects on operation.

Savings can be achieved only by reducing radiation losses from the hot reserve boiler(s).

Owing to the pressure decay of the boiler(s) during standby, only 65 percent of the radiation losses at normal operating pressure are considered.

Data

MCR of standby boiler(s)	=	_____ kW
Radiation losses at no load	=	_____ percent of MCR
Boiler combustion efficiency	=	_____ percent
Hours standby boiler(s) kept at pressure	=	_____ hrs/year
GJ	=	3.6×10^{-3} kWh

Radiation loss at no load = (% loss of MCR @ no load) x (MCR) (3.6×10^{-3})

= ( ) x ( ) x (3.6×10^{-3})

= _____ GJ

Energy Savings

$$= \frac{(\text{GJ}) \times (0.65) \times (\text{hours at pressure})}{(\text{boiler combustion efficiency})}$$

$$= \frac{(\quad) \times (0.65) \times (\quad)}{(\quad)}$$

= _____ GJ/year

Exhibit 5.10 (continued)

Discontinuing Use of Hot Reserve Boilers

Cost Savings

= (GJ/year) ($/GJ)

= ( ) ( )

= $_____/year

Energy savings = _____ GJ/year

Cost savings = $_____/year

Notes for Calculation

Assumptions

(i) If the boiler cannot be kept cold without detrimental effects on operations, **do not** recommend the measure.

(ii) A 65-percent savings level is used, as boilers lose pressure when in standby.

Data

(i) MCR is maximum continuous rating, and can be obtained from nameplate data or from the manufacturer, if not known.

(ii) Radiation losses at no load: use the following percentage losses:

Firetube dry back:	2 percent of MCR
Firetube wet back:	1½ percent of MCR
Watertube package:	1 percent of MCR
Watertube site-built:	3 percent of MCR.

(iii) Boiler combustion efficiency: use just the combustion efficiency for the particular boiler at the firing rate used when boiler is on standby.

(iv) Hours standby boiler(s) kept at pressure: this is the total hours per year that boiler(s) are kept at a hot reserve condition.

(v) Energy savings: round up to nearest GJ.

(vi) Cost savings: round up to nearest dollar.

Exhibit 5.11

Reducing Blowdown

Blowdown is often used excessively to control the level of total dissolved solids (TDS) in a boiler. Dissolved solids can be deposited as scale on the heat transfer surfaces in a boiler. A compromise between energy waste owing to blowdown and owing to scaling is reached by maintaining blowdown levels up to 3,000 parts per million for most industrial boilers.

The savings can be estimated using the calculation techniques presented below. Notes on assumptions and data used in the calculations are given at the end of the exhibit.

Calculation

Assumptions

Maximum acceptable TDS level = 3,500 ppm
Estimated mean TDS level = 3,000 ppm

Data

Boiler efficiency = _____ percent
Percent makeup water = _____ percent
Makeup TDS = _____ ppm)
Blowdown TDS = _____ ppm) from treatment company reports
Energy input to boilers = _____ GJ/year
Feedwater temperature = _____ °C
Boiler pressure = _____ bar
Heat content in city water = _____ kJ/kg

Percent Blowdown Loss

Present blowdown rate = (percent of makeup x makeup TDS)/(100 x blowdown TDS)

= (x)/100 x _____

= _____ kg/kg of steam produced

Heat required to raise kg of steam = hg @ boiler pressure - hw of feedwater

=

= _____ kJ/kg

Steam produced/year = (energy input to boilers x average boiler efficiency)/heat required to raise kg of steam

= (x)/( )

= _____ kg x 10^3/year

Exhibit 5.11 (continued)

Reducing Blowdown

Blowdown per year = blowdown rate x steam produced/year

= ( ) ( )

= _____ kg x 10^3/year

Heat content in blowdown = Sensible heat in blowdown - sensible heat of city water

=

= _____ kJ/kg

Percent blowdown loss = (Blowdown per year x net heat content of blowdown x 100)/ (energy input to boilers)

= (x x 100)/( )

= _____ percent

Blowdown rate @ 3,000 = (percent of makeup x makeup TDS)/100 x (3,000 - makeup TDS)

= (x)/(100) (3,000 -)

= _____ kg/kg of steam produced

Energy Savings = (Existing - new blowdown rate) x (steam produced/year) x (heat content in blowdown) (10^{-6})

= ( ) ( ) ( ) (10^{-6})

= _____ GJ/year

Cost Savings = (GJ/yr) ($/GJ)

= ( ) ( )

= $_____/yr

Implementation Costs

These should be minimal, other than to provide facilities to monitor the TDS level of the boilers on a regular basis.

Energy savings = _____ GJ/year

Cost savings = $_____/year

Exhibit 5.11 (continued)

Reducing Blowdown

Notes for Calculation

Assumptions

(i) Maximum acceptable TDS level: 3,500 ppm. N.B.: this is the present **maximum** level recommended by the American Boiler Manufacturers' Association.

(ii) Estimated mean TDS level: 3,000 ppm; operating at the above maximum should enable a mean of 3,000 ppm to be achieved.

Data

(i) Boiler efficiency: use measured efficiency or estimate for individual boilers, or weighted for total plant.

(ii) Percent makeup water: estimate this based on the condensate return systems, water metering, or the water treatment companies' reports. Percent makeup = (Feedwater chlorides/ raw chlorides) x 100.

(iii) Makeup TDS + boiler TDS: obtain these from water treatment companies' reports.

(iv) Energy input to boiler: unless percent makeup water and separate energy to individual boilers are available, conduct the exercise for total boiler plant.

(v) Heat content in city water: use sensible heat from steam tables for city water average temperature.

(vi) Heat required to raise steam: hg = total enthalpy of steam at boiler pressure (hf + hfg), from steam tables; hw = enthalpy of the feedwater from steam tables.

(vii) Energy savings: round up to the nearest GJ.

(viii) Cost savings: round up to nearest dollar.

Exhibit 5.12

Reducing Operating Pressure

Steam is generated at pressures normally dictated by the highest pressure/temperature requirements for a particular process. In some cases, the process does not operate all of the time, and there are periods when the boiler pressure could be reduced. The energy auditor should consider pressure reduction very carefully before recommending it. Adverse effects, such as an increase in water carryover from the boiler owing to pressure reduction, may negate any potential savings. Pressure should be reduced in stages, and no more than a 20-percent reduction should be considered.

The savings can be estimated using the calculation technique presented. Notes on assumptions and data used in the calculations are given at the end of the exhibit.

Assumptions

The existing boiler pressure is required for some plant operations for a period of _____ hours per year. At all other times, the steam pressure can be reduced from _____ bar to _____ bar.

Energy loss in distribution system = _____ percent

Data

Reduction in heat losses by reducing pressure = _____ percent (A)
Energy input to boilers = _____ GJ/yr
Total plant operating hours = _____ hrs/yr
Period of operation at reduced pressure = _____ hrs

Calculation

Operating at a reduced steam pressure will achieve energy savings by reducing the distribution system losses.

Existing energy loss due to distribution = (dist. loss %) x (GJ/yr)

= ( ) x ( )

= _____ GJ/yr (B)

Percentage of total hours that could be operated at lower pressure = (Hours of reduced pressure/total plant operating hours) x 100

= ( ) (100)/( )

= _____ percent (C)

Exhibit 5.12 (continued)

Reducing Operating Pressure

Energy Savings = (A x B x C)/100 x 100

= ( ) ( ) ( )/10^4

= _____ GJ/yr

Cost Savings = (GJ/yr) ($/GJ)

= ( ) ( )

= $_____/yr

Cost of Implementation

There is no additional cost associated with implementation of this measure other than resetting of pressure stats.

Energy savings = _____ GJ/year

Cost savings = $_____/year

Notes for Calculation

Assumptions

(i) The energy auditor must estimate the lowest practicable pressure that allows the boiler to operate efficiently and still provide steam to the terminal user at sufficient pressure.

(ii) Energy loss in distribution system: for well insulated system, use 10 percent; for poorly insulated system, use 20 percent.

Data

(i) Reduction in heat losses by reducing pressure: calculate the percent drop in pressure (i.e., for 6.9 bar to 5.5 bar).

Percent drop = (6.9 - 5.5)/6.9 = 20 percent.

Then read c. from the accompanying exhibit the "distribution loss reduction" and use this in the calculation. In this example, distribution loss reduction is 7 percent.

(ii) Boiler combustion efficiency: use known value if available.

Exhibit 5.12 (continued)

Reducing Operating Pressure

(iii) Period of operation at reduced pressure: delete if reduced pressure can be applied for total plant operating hours.

(iv) Percentage of total hours that can be operated at reduced pressure: Delete if not applicable.

(v) Energy savings: delete (C/100) if not applicable.

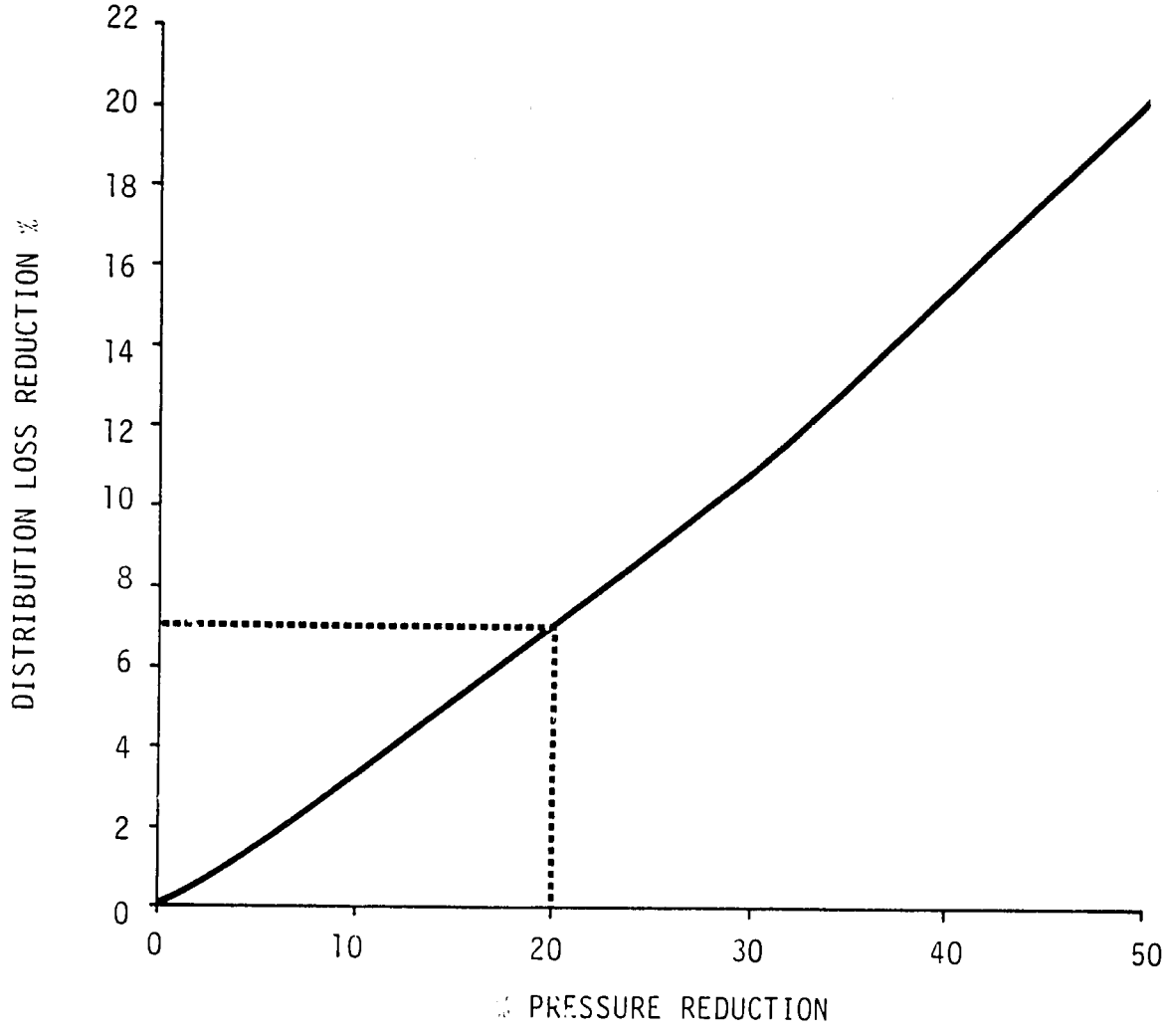
(vi) Energy savings: round up to nearest GJ/year.

(vii) Cost savings: round up to nearest $.

Exhibit 5.12

NOMOGRAPH TO SHOW REDUCTION IN DISTRIBUTION LOSS

AGAINST % DROP IN PRESSURE



for periods between shifts. A normal shutdown should be 10 to 12 hours. Savings are estimated as follows:

Energy savings = (Unnecessary operating hours) (Hourly energy use in GJ/hr)
= GJ/year.

Cost savings = (GJ/year) ($/GJ)
= $/year.

At the conclusion of the PEA, the energy auditor will be able to prepare his action plan for the detailed energy audit of the boiler plant. Normally, this plan will focus on a boiler efficiency test and energy-saving measures, some for immediate implementation and others requiring further study. The efficiency testing and further study areas are covered in the next step, the detailed energy audit.

5.1.2 DETAILED ENERGY AUDIT

Having completed his PEA of the boiler, the energy auditor can now conduct a detailed energy audit of the boiler if necessary. If the boiler is found to be operating at a high efficiency (for example, in excess of 80 percent), he may not have to test it. In the course of the audit, he will test boiler efficiency and investigate other factors of boiler operation to identify opportunities for reducing energy costs.

5.1.2.1 Measuring Boiler Efficiency

Before testing boiler efficiency, the auditor must complete some preparatory work. This work includes:

- Recalibrating all instrumentation to be used
- Ensuring that all test measuring positions are accessible
- Selecting an appropriate day for testing.

In his tests, the energy auditor uses a procedure in which the total losses as related to fuel input are determined. He then calculates efficiency as 100 percent minus the percentage of losses.

To determine boiler efficiency, the auditor must obtain temperature measurements, psychrometric measurements, and an analysis of the products of combustion. The procedures and instruments described here and in Chapter 4 apply to the testing of boiler systems; however, the same principles, procedures, and instruments may be applied to other combustion systems such as furnaces, kilns, and dryers. Typical points of measurement for boiler testing are shown in Exhibit 5.13.

A boiler's operating efficiency depends on the load imposed on it. To determine boiler combustion efficiency in an accurate manner, the auditor should test the boiler over its normal range of operating conditions. At a minimum, the boiler should be tested at low-fire, medium-fire, and high-fire conditions (at about one-third, two-thirds, and full load). To cover the complete range of boiler operating conditions, it should be tested at steps of 10 percent of full load over its operating range (e.g., 20, 30, 40, 50 percent of full load).

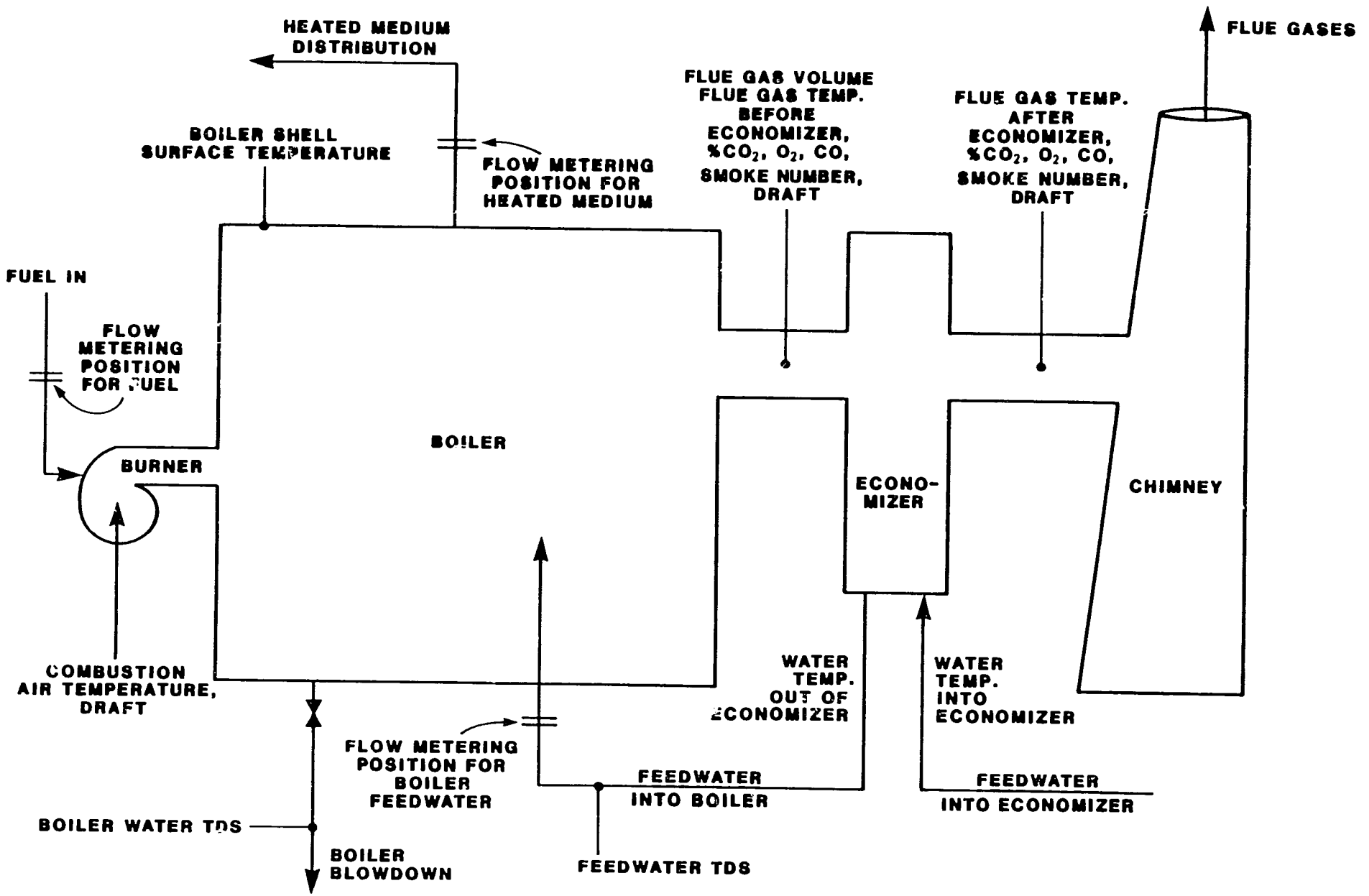
Before testing, the boiler should be allowed to come to a steady-state condition. It should then be operated at the load to be tested for 15 to 30 minutes prior to testing. Three sets of tests should be made at each load condition. The measurements taken at each load condition should be used to calculate combustion efficiency individually; the three efficiencies for each load are then averaged.

Combustion system testing requires the following data:

- Temperature of entering combustion air
- Temperature of combustion gases
- Composition of combustion gases
  - carbon dioxide (CO_2)
  - oxygen (O_2)
  - carbon monoxide (CO) for some fuels
- Firebox and stack draft

EXHIBIT 5.13

MEASURING POSITIONS FOR BOILER TESTING



- Amount of smoke in combustion gases
- Amount of dissolved solids in boiler water.

5.1.2.1a Temperature Measurement

The temperature of entering **combustion air** and **combustion gases** must be measured to determine the "net stack temperature." Any appropriate temperature measuring device may be used. It is recommended that a **mercury-in-glass thermometer** be used to determine entering **combustion air temperature**, while an appropriate **thermocouple** be used to measure the **temperature of the combustion gases**. See Chapter 4 for details of thermocouple applications.

Entering **combustion air temperature** should be measured at the point where it enters the system. In the case of a forced draft boiler, for instance, combustion air temperature is measured at the fan inlet. **Combustion gas temperature** should be measured at a point as close to the heat transfer section of the combustion system as possible. In a boiler, access to the stack at as close a point as possible to the breeching is recommended. The net stack temperature is the difference between the combustion gas temperature and the entering combustion air temperature.

5.1.2.1b Combustion Gas Analysis

Combustion gases are sampled at the same point where the flue gas temperature is taken. Because some flue stacks may have "dead spots," the auditor should use a velometer or other flow measurement device to ensure that the gas samples are well mixed.

Flue gases are analyzed for three components -- carbon dioxide, carbon monoxide, and oxygen. With good mixing of the fuel and air, perfect combustion is obtained when the flue gas analysis shows no carbon dioxide or oxygen and the maximum amount of carbon monoxide for the fuel type and flow rate. In practice, however, such combustion is rarely, if ever, achieved.

Several different devices are available for analyzing combustion gases. These devices may be divided into two categories:

- Chemical analysis
- Electrochemical analysis.

The **Fyrite analyzer** is a portable chemical analysis kit. The reasons for its use were outlined in Chapter 4. This analyzer is used by the energy auditor because it is rugged, reasonably accurate, and relatively inexpensive. Fyrite analyzers are available for carbon dioxide and oxygen analysis. A chemical reaction with the gas component being measured causes a volume change. This volume change indicates the quantity of that component in the gas sample. The steps involved in using the Fyrite for measuring oxygen and carbon dioxide are presented in Exhibit 5.14).

The Fyrite should be in good operating condition, and should have the proper amount of chemicals. Before starting a series of tests, the auditor should adjust the zero scale. To operate the Fyrite, hold it upright, depress the valve on the top, and release. Turn the indicator bottle upside down until all the fluid has run down and then turn the bottle right side up again. Repeat this operation three more times. Then hold the bottle at a 45-degree angle for about 5 seconds to drain fluid droplets from the inside surfaces. Hold the bottle level and depress the valve again. Adjust the zero scale to correspond to the top of the liquid column. (If the liquid level drops more than 1/2 inch (12 mm) after depressing the valve, repeat the procedure.)

The aspirator assembly consists of a length of tubing, a filter, and a rubber bulb. At one end of the tubing is a metal pipe; at the other is a rubber connecting tip. Insert the open end of the metal tube into the gas stream. At the start of the test, squeeze the rubber bulb about 20 times to purge the aspirator assembly of ambient gases.

To begin sampling, place the rubber connector flat against the valve on top of the Fyrite bottle. Depress the valve and steadily squeeze and release the aspirator bulb 18 times for oxygen analysis or carbon dioxide analysis. On the 18th squeeze, before releasing the rubber bulb, remove the connector from the top of the bottle. The sample is then trapped for analysis.

Turn the bottle upside down and then right side up, four times for oxygen and twice for carbon dioxide. This forces the gas sample through the absorbent chemical. Allow all the chemical to run back into the bottom of the bottle by holding it at a 45 degree

Exhibit 5.14

Steps in Use of Fyrite Gas Analyzer

1. Adjust zero percent scale

2. Purge gases from aspirator

3. Pump sample into bottle

4. Release aspirator from bottle

5. Invert and release bottle to mix sample

   - 4 times for oxygen
   - 2 times for carbon dioxide

6. Allow fluid to run into bottom of bottle

   - hold at 45-degree angle

7. Hold bottle upright and read gas content

8. Depress valve to set for next sample

9. Return to Step 3 for next analysis

angle for about 5 seconds. Holding the bottle upright, read the percent oxygen or carbon dioxide content of the gas from the scale. Before taking the next sample, depress the valve on top of the bottle.

Carbon monoxide readings should also be taken for certain types of fuels, notably natural gas, to ensure that complete combustion is taking place. Carbon monoxide content can be determined by chemical means using a Draeger. A gas sample is drawn into contact with a chemical reagent in a glass tube. The presence of carbon monoxide causes a stain to appear in the indicator tube; the length of the stain is compared to a calibrated scale to determine the percentage of carbon monoxide content. A fresh indicating tube must be used for each measurement.

As mentioned previously, **electrochemical devices** (also called **combustion computers**) can also be used to measure combustion efficiency. Compared with a Fyrite, these devices are less flexible because they are not as portable, they may need electrical power, they are not as robust, and they are much more expensive. These devices incorporate temperature measurement and gas analysis functions and directly calculate combustion efficiency. They incorporate a microprocessor and can be set for the type of fuel used.

An electrochemical device is faster and easier to use than a chemical analyzer. The electrochemical device has a gas sampling probe that is placed in the flue gas stream. This probe contains a thermocouple that measures stack temperature. The analyzer, which is connected to the probe by a length of tubing, uses a pump to draw the gas sample. The probe also a thermocouple to measure combustion air temperature. Hence, net stack temperature is automatically computed.

To use an electrochemical device, place the probe in the flue gas stream, activate the device and set it to the proper fuel type. The device can determine:

- Oxygen content of gas sample
- Carbon monoxide content of gas sample
- Net stack temperature
- Carbon dioxide content (computed)
- Percent excess air (computed)
- Combustion efficiency (computed).

The built-in pump also allows the device to be used for smoke testing.

5.1.2.1c Draft Measurement

In addition to measuring temperature and analyzing combustion gases, it is important to measure the draft at the firebox and at the stack. The draft indicates the pressure at which the combustion system operates. The intensity of the draft determines the rate at which combustion gases pass through the boiler or furnace, and the amount of air provided for combustion. Excessive draft can increase the stack temperature (causing incomplete heat transfer), while insufficient draft may cause smoking owing to a lack of combustion air.

Draft is measured with a pressure measurement device, such as the manometer or draft gauge and probe.

To use the **draft gauge**, insert the probe into the area where draft is to be measured (either the firebox or the flue), and read the draft directly from the scale.

5.1.2.1d Smoke Measurement

The amount of smoke in the combustion gases may be determined either by using a pump and filter or by measuring gas opacity. The pump and filter method is well suited for portable measurements; the gas opacity method requires that the instrument be permanently or semi-permanently mounted.

The **smoke test pump** is used to check smoke and soot conditions. To use the pump, place special filter paper in the pump sampling port. Then put the sample probe in the combustion gas stream, and pull the pump handle through ten strokes to draw a measured amount of gas through the filter paper. Remove the filter paper from the pump and compare it to the scales to determine the extent of incomplete combustion. The ten spots on the scale range in equal photometric steps from white (spot #1) to black (spot #10). For burners firing No. 2 oil, the filter should not be darker than spot #2, while for burners using heavy fuel oils, the filter can be comparable to spot #5.

5.1.2.1e Total Dissolved Solids Analysis

The final type of data needed for boiler testing is a measure of dissolved solids in the boiler water. High concentrations of dissolved solids in the boiler water indicate the potential for fouling of boiler heat transfer surfaces.

A **conductivity meter**, or **total dissolved solids (TDS) meter**, is used to determine the concentration of dissolved solids in the boiler water. The meter measures the electrical resistance (the inverse of conductivity) of a liquid sample. Since pure water is not a conductor, its electrical conductivity is zero. However, dissolved solids will increase the conductivity.

To measure total dissolved solids, take a sample of boiler water from a blowdown point. Use this sample to wash the sample cup on the meter several times. Then fill the cup to a point above the top electrode with the sample to be tested. Select the proper scale, and depress the measurement button. The meter will directly indicate the total dissolved solids concentration in the sample.

Other chemical tests of boiler water and boiler feed water may be performed to determine the concentration of various ions. These tests are performed as part of a program to specify proper water treatment for the boiler plant.

Test data on a boiler can be collected on forms similar to that shown in Exhibit 5.15.

At the end of the testing, the energy auditor should:

- Determine the efficiency of the existing plant
- Identify conservation opportunities.

The method for calculating boiler efficiency is given below.

EXHIBIT 5.15

Boiler Test Data

CLIENT:		PLANT:	
DATE:	PROJECT NO.:	DATA BY:	
NAMEPLATE DATA:			
Boiler No.			
Location			
Manufacturer			
Model No.			
Type			
Size			
Operating Pressure			
Medium Raised			
No. of Burners			
Burner Manufacturer			
Burner Type			
Control			
Draft			
Atomization			
Fuel/Fuels			
TEST DATA	Fuel:	Metered: Yes / No	Units:
Est HHV:	Units:	Steam Metered: Yes / No	Units:
Time			
Load (Units)			
Temperatures(°F/°C):			
Ambient Air			
At Boiler Outlet			
After Economizer			
Feedwater			
Condensate			
Make-up Water			
Smoke Number			
Total Dissolved Solids			
Boiler Water (PPM)			
Feedwater (PPM)			
Condensate (PPM)			
Make-up Water (PPM)			
Fuel Flow Rate			
Flue Gas Analysis			
% CO_2			
% O_2			
% CO			
Losses due to:			
Flue Gas			
Incomplete Combustion			
Combustion Efficiency			

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Exhibit 5.15 (continued)

Time			
Load (Units)			
Temperatures(°F/°C):			
Ambient Air			
At Boiler Outlet			
After Economizer			
Feedwater			
Condensate			
Make-up Water			
Smoke Number			
Total Dissolved Solids			
Boiler Water (PPM)			
Feedwater (PPM)			
Condensate (PPM)			
Make-up Water (PPM)			
Fuel Flow Rate			
Flue Gas Analysis			
% CO_2			
% O_2			
% CO			
Losses due to:			
Flue Gas			
Incomplete Combustion			
Combustion Efficiency			
Time			
Load (Units)			
Temperatures(°F/°C):			
Ambient Air			
At Boiler Outlet			
After Economizer			
Feedwater			
Condensate			
Make-up Water			
Smoke Number			
Total Dissolved Solids			
Boiler Water (PPM)			
Feedwater (PPM)			
Condensate (PPM)			
Make-up Water (PPM)			
Fuel Flow Rate			
Flue Gas Analysis			
% CO_2			
% O_2			
% CO			
Losses due to:			
Flue Gas			
Incomplete Combustion			
Combustion Efficiency			

5.1.2.2 Calculating Boiler Efficiency

To determine boiler efficiency, calculate the various losses of efficiency in the system. These losses can be tabulated as follows:

	Percent of gross caloric value
1. Overall thermal efficiency	_____
2. Losses owing to flue gases	_____
(a) dry gas	_____
(b) moisture & hydrogen	_____
(c) incomplete combustion	_____
3. Balance of account, including radiation, blowdown, and other unmeasured losses	_____
	_____
	100 percent

The **total flue gas losses** can be calculated by using combustion gas measurements.

The losses owing to dry and wet flue gases are determined using Exhibits 5.16, 5.17, and 5.18. From the flue gas analysis, the percentage excess combustion air and net stack temperatures can be found.

The relationship between carbon dioxide and oxygen is shown in Exhibit 5.16, while Exhibit 5.17 illustrates how excess air levels vary with oxygen. The flue gas loss of a boiler with respect to net stack temperature and excess air levels can be calculated from the table in Exhibit 5.18. The flue gas loss as a percentage of gross caloric value equals the percentage efficiency subtracted from 100.

Where carbon monoxide is measured, the loss owing to unburned fuel can be determined from Exhibit 5.19.

Radiation losses can be estimated on the basis of the operating load as a percentage of the maximum continuous rating (MCR) of the boiler. Radiation losses vary with the inverse of the load. Exhibit 5.20 gives typical radiation losses for common types of boilers.

EXHIBIT 5.16

CONVERSION CHART CARBON DIOXIDE-OXYGEN

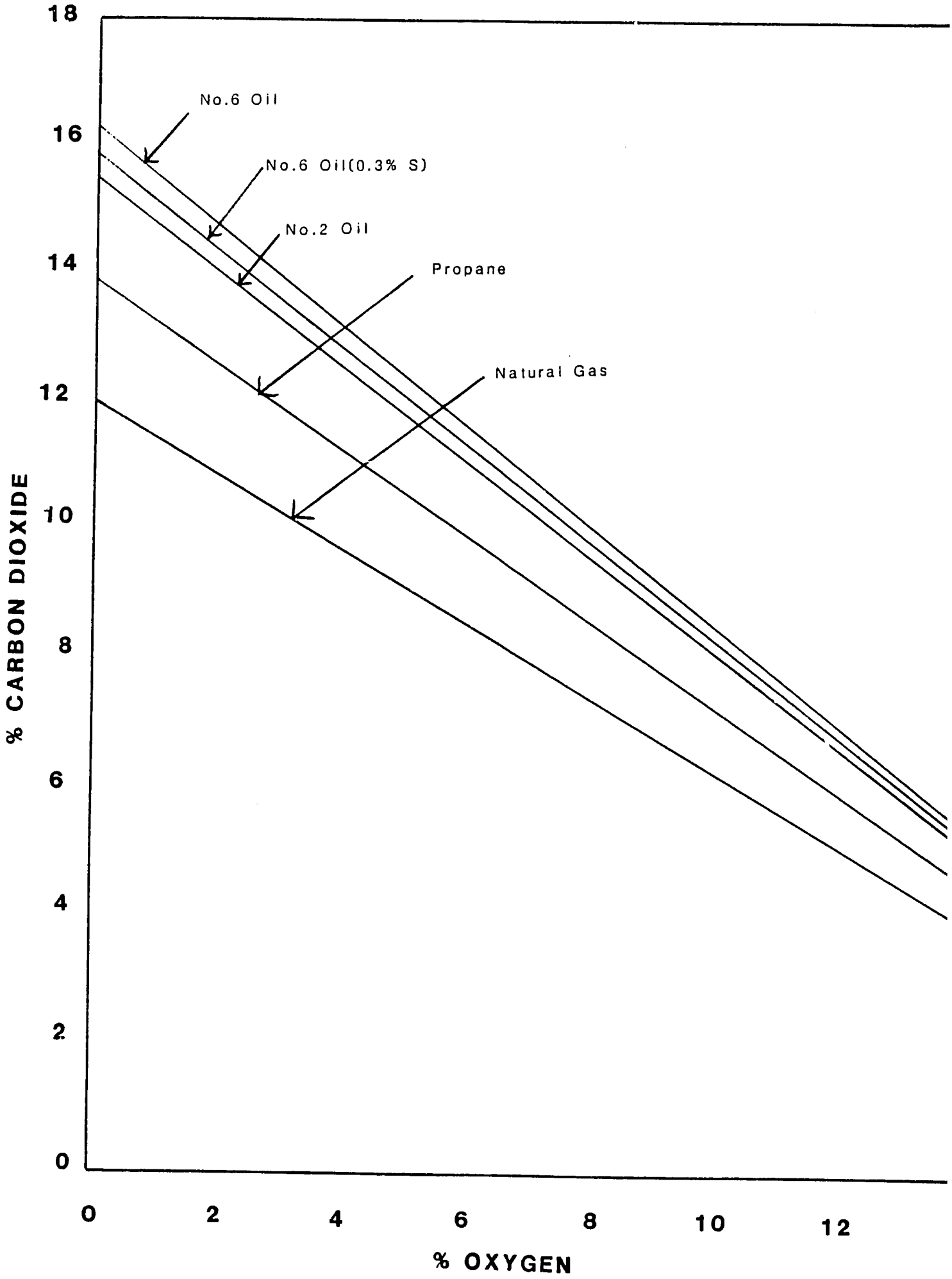


EXHIBIT 5.17 **CONVERSION CHART EXCESS AIR-OXYGEN**

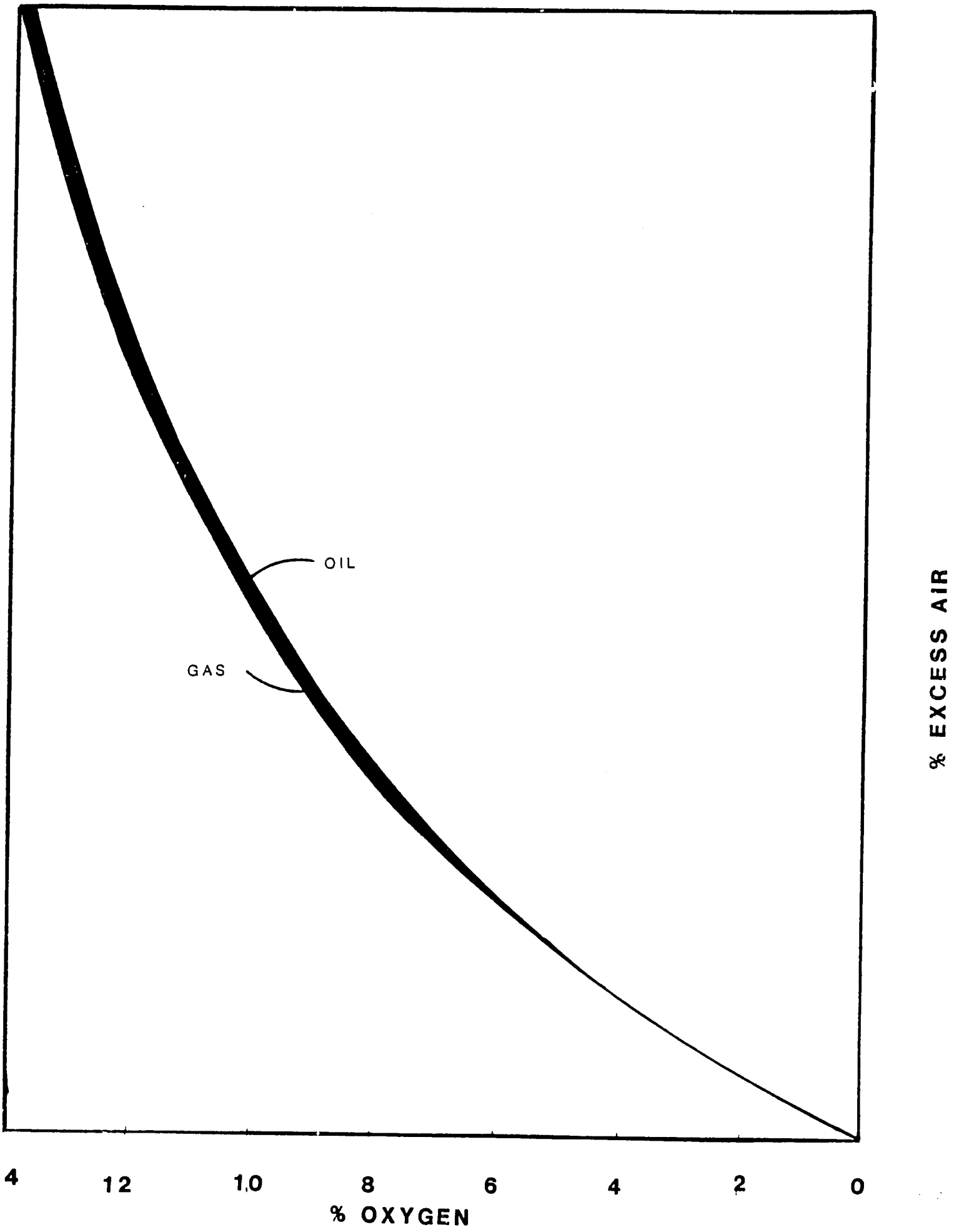


EXHIBIT 5.18

FUEL OIL EFFICIENCY TABLE

NET STACK TEMPERATURE (°C)

Percent Excess Air %	93	121	149	177	204	232	260	288	316	343	371	399
5.	89.8	88.7	87.6	86.5	85.5	84.4	83.3	82.2	81.2	80.1	79.0	77.
10.	89.6	88.5	87.3	86.2	85.1	84.0	82.9	81.7	80.6	79.5	78.4	77.
15.	89.4	88.2	87.1	85.9	84.7	83.6	82.4	81.2	80.1	78.9	77.7	76.
20.	89.2	88.0	86.8	85.6	84.4	83.2	81.9	80.7	79.5	78.3	77.1	75.
25.	89.0	87.8	86.5	85.3	84.0	82.8	81.5	80.2	79.0	77.7	76.5	75.
30.	88.9	87.6	86.3	85.0	83.6	82.3	81.0	79.7	78.4	77.1	75.8	74.
35.	88.7	87.3	86.0	84.6	83.3	81.9	80.6	79.2	77.9	76.5	75.2	73.
40.	88.5	87.1	85.7	84.3	82.9	81.5	80.1	78.7	77.4	76.0	74.6	73.
45.	88.3	86.9	85.4	84.0	82.6	81.1	79.7	78.2	76.8	75.4	73.9	72.
50.	88.1	86.7	85.2	83.7	82.2	80.7	79.2	77.8	76.3	74.8	73.3	71.
55.	88.0	86.4	84.9	83.4	81.8	80.3	78.8	77.3	75.7	74.2	72.7	71.
60.	87.8	86.2	84.6	83.1	81.5	79.9	78.3	76.8	75.2	73.6	72.0	70.
65.	87.6	86.0	84.4	82.7	81.1	79.5	77.9	76.3	74.6	73.0	71.4	69.
70.	87.4	85.7	84.1	82.4	80.8	79.1	77.4	75.8	74.1	72.4	70.8	69.
75.	87.2	85.5	83.8	82.1	80.4	78.7	77.0	75.3	73.6	71.8	70.1	86.
80.	87.0	85.3	83.5	81.8	80.0	78.3	76.5	74.8	73.0	71.3	69.5	67.
85.	86.9	85.1	83.3	81.5	79.7	77.9	76.1	74.3	72.5	70.7	68.9	67.
90.	86.7	84.8	83.0	81.2	79.3	77.5	75.6	73.8	71.9	70.1	68.2	66.
95.	86.5	84.6	82.7	80.8	78.9	77.1	75.2	73.3	71.4	69.5	67.6	65.
100.	86.3	84.4	82.5	80.5	78.6	76.6	74.7	72.8	70.8	68.9	67.0	65.

NOTE: May be used to calculate savings from changes in efficiency for No. 2, No. 6 Low Sulfur, and No. 6 (1. S) fuel oils. Based on higher heating value (HHV) and total flue gas loss, including latent and sensible loss due to water formed from fuel and sensible loss due to moisture in air. **CAUTION:** Do not calculate savings to changes in efficiency using efficiency values from two different sources. The various slide rules, grap tables and nomographs available may incorporate different assumptions.

EXHIBIT 5.19

GRAPH TO SHOW LOSS DUE TO INCOMPLETE COMBUSTION (%) AGAINST CARBON MONOXIDE (% VOL) FOR FUEL OIL

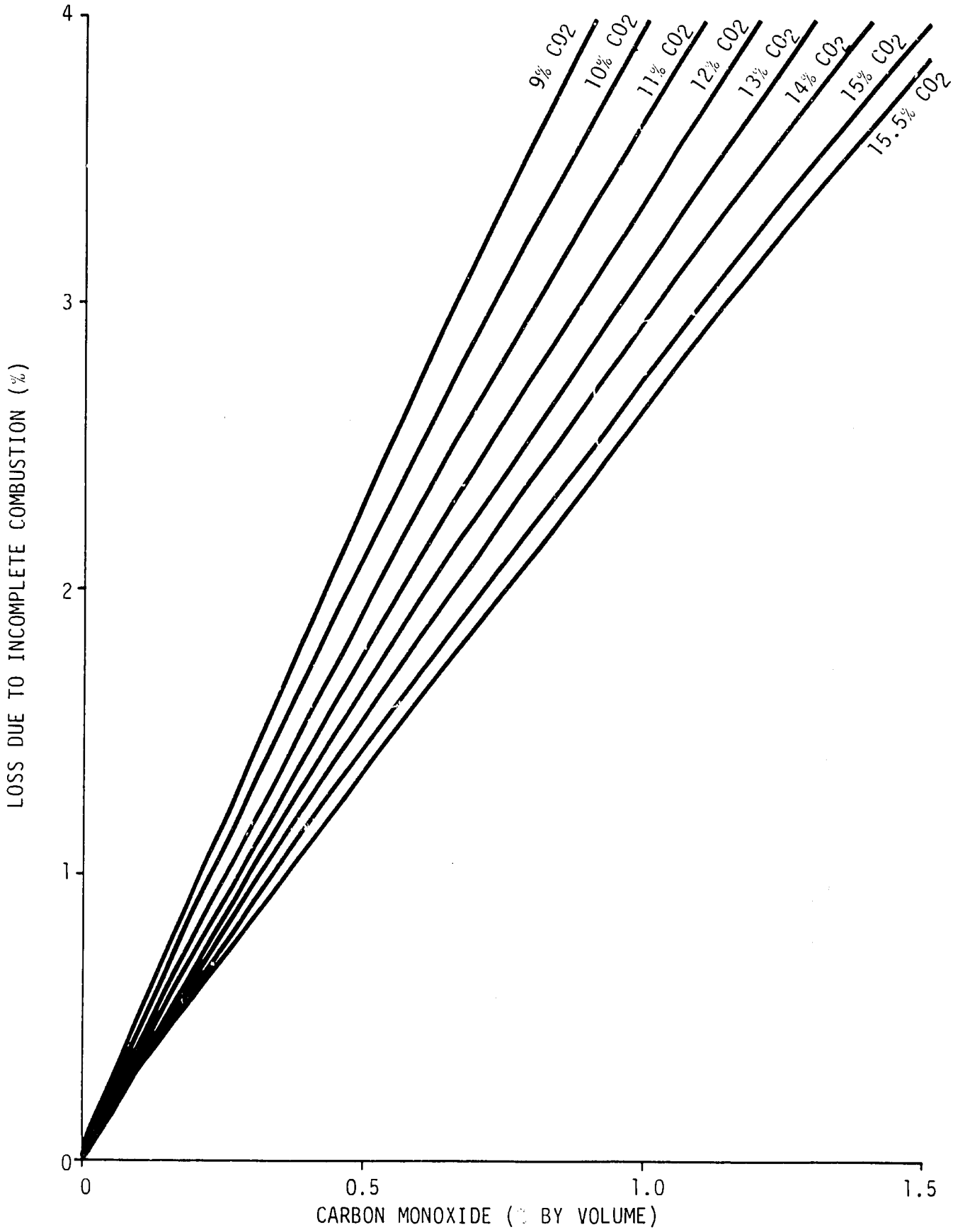


Exhibit 5.20

Radiation Losses for Boilers at Maximum Continuous Rating

Type	% of MCR
Firetube dry back	2.0
Firetube wet back	1.5
Watertube package	1.0
Watertube site-built	3.0
Lancashire	5.0
Lancashire brick set	3.5
Vertical boiler	5.0

The **blowdown loss** can be estimated from knowledge of water conditions, using the formula shown in Exhibit 5.21. This formula assumes that a constant level of total dissolved solids is maintained in the plant.

Overall boiler efficiency as a percentage can now be calculated by summing all losses and subtracting them from 100.

The boiler efficiency can be used when estimating opportunities for conservation that involve the boiler plant.

5.1.2.3 Identifying Opportunities for Reducing Energy Costs

Testing a boiler to determine its efficiency is not the only step taken during a detailed energy audit. A thorough examination of all auxiliary equipment should be conducted, and the boiler plant operation should be reviewed.

Equipment and operational aspects to investigate include:

- Current fuel usage and substitution possibilities
- Boiler load patterns and boiler sizing
- Steam pressure requirements
- Water treatment procedures
- Heat recovery opportunities, including blowdown, feedwater preheat
- Combustion control systems.

Because the main purpose of a detailed energy audit is to identify opportunities for reducing energy costs, this manual focuses on identifying and evaluating such opportunities.

When he has concluded all his tests, the energy auditor should have identified several opportunities for reducing energy costs, including:

- Switching fuels
- Improving boiler loading

Exhibit 5.21

Estimate of Blowdown

Assumptions

A constant TDS level is maintained in the boiler.

Data

A = maximum TDS maintained, ppm

B = feedwater TDS, ppm

M = percentage makeup water (i.e., total evaporation minus condensate returned), expressed as a percentage of total evaporation.

$$\text{Percent blowdown} = \frac{(B \times M)}{(A - B)} = _____\%$$

- Improving combustion efficiency from:
  - replacing burners
  - improving combustion control systems
  - repair, recalibration of instrumentation
- Recovering heat from blowdown
- Recovering heat from preheating feedwater
- Preheating combustion air
- Reducing heating requirements for fuel oil storage
- Replacing boilers.

These opportunities are discussed in the following paragraphs, and techniques for estimating savings are presented in the associated exhibits.

5.1.2.3a Switching Fuels

It is sometimes possible to reduce energy costs by switching to other fuels. There is no set guide on the savings that can be achieved; rather, each case must be reviewed on its individual merits.

Normally, the best time to consider switching fuels is when a change in the existing boiler plant is contemplated. Boilers are used over extended periods of time, typically in excess of 25 years.

Boilers do not operate at the same efficiency when firing different fuels. Oil-fired boilers are inherently more efficient than natural gas- or coal-fired boilers, because of different flame characteristics and their effect on heat transfer. Also, unburned fuel losses are normally higher with coal-fired boilers (see Exhibit 5.22).

The savings from switching fuels can be estimated in the following manner:

(i) <u>Calculate Useful Fuel Use</u>

= (existing fuel use) x (efficiency with old fuel) = useful fuel use.

Exhibit 5.22

Typical Boiler Plant Efficiencies

Firetube

0-15,000 kg/hr three-pass oil-fired	78.0%
Gas-fired	75.0%
Coal-fired	75.0%
0-15,000 kg/hr four-pass oil-fired	80.0%
Gas-fired	77.0%
Coal-fired	77.0%

Watertube

0-22,700 kg/hr oil-fired	78.0%
Gas-fired	75.0%
Coal-fired	75.0%
22,700-45,000 kg/hr oil-fired	80.0%
Gas-fired	78.0%
Coal-fired	78.0%

N.B.: Assumes boiler operates within 10 percent of maximum continuous rating at all times.

(ii) Calculate New Fuel Use

= (useful fuel use)/(efficiency with new fuel).

(iii) Calculate Existing Fuel Cost

(existing fuel use) x (existing fuel cost) = annual existing fuel cost.

(iv) Calculate New Fuel Cost

(new fuel use) x (new fuel cost) = annual new fuel cost.

(v) If new fuel cost is significantly less than old fuel cost (for example, less than half), the feasibility study should be completed.

The feasibility study should not be limited to the fuel cost difference, but should examine relative maintenance costs for the various fuels, long-term fuel availability and operator skills, and equipment conservation costs.

5.1.2.3b Improving Boiler Loading

In multi-boiler installations or facilities that have seasonal boiler capacity requirements, the loading of the boiler should be investigated. Boilers are often not matched to the load, resulting in excessively high radiation losses. In some situations, the loading problem can warrant the installation of a new boiler. The savings achieved by improving boiler loading can be estimated using the techniques given in Exhibit 5.23. The calculation uses only the combustion efficiency and radiation loss at MCR.

The cost of improving boiler loading will depend on whether a new boiler is required.

5.1.2.3c Improving Combustion Efficiency

Testing the boiler's efficiency will enable the energy auditor to determine what improvements can be made to combustion efficiency. Guides to acceptable combustion conditions with two types of burner are given in Exhibit 5.24.

Exhibit 5.23

Improvement in Boiler Utilization

Assumptions

A load of _____ kW occurs for _____ hours while the load could be met by a smaller boiler. The calculation is based on radiation losses only.

Data

Boiler combustion efficiency	=	_____ %
Maximum continuous rating (MCR) of larger boiler	=	_____ kW
Maximum continuous rating (MCR) of smaller boiler	=	_____ kW
GJ	=	3.6×10^{-3} kWh

Calculation

	Saving (kW/hr)
Boiler no.	
% MCR of boiler operating	
Radiation loss from boilers (kW)	
% MCR after rescheduling	
Radiation loss after resequencing (kW)	
Savings by rescheduling (kW)	_____
	_____

Reduction of radiation losses by rescheduling boilers = savings by rescheduling x hours of operation x 3.6×10^{-3}

= ( ) ( ) ( )

= _____ GJ/year

Energy Savings = $\frac{\text{Reduction of radiation losses}}{\text{Boiler combustion efficiency}}$

=

= _____ GJ/year

Exhibit 5.23 (continued)

Improvement in Boiler Utilization

Cost Savings= (GJ/yr) ($/GJ)

= ( ) ( )

= $_____/yr.

Energy savings = _____ GJ/yr

Cost savings = $_____/yr

Notes on Calculation

Boiler combustion efficiency: use value from testing. (i)

Maximum continuous rating: use nameplate data or manufacturer's information. (ii)

Radiation losses: use manufacturer's information, or see Exhibit 5.20. (iii)

Exhibit 5.24

Guidelines for Acceptable Combustion Conditions for Oil-Fired Burners

Burner	Firing rate	Percent CO	Percent CO_2	Percent O_2	Smoke number
Pressure jet	High	0.02	12-13	6-8	3-4
	Medium	0	10-11.5	7-9	2-3
	Low	0	8-9	9-11	1-3
Rotary cup	High	0.02	13-14	5-6	2-3
	Medium	0	10-12	7-9	1-3
	Low	0	8-10	9-11	1-2

The energy auditor must decide whether combustion efficiency can be improved by fine tuning the fuel-to-air ratio controls, or whether it is necessary either to fit automatic oxygen trim controls or replace the burner.

The techniques used for estimating the savings are all similar; they involve calculating the change in efficiency, as shown in Exhibit 5.25. The costs required to implement the measure will depend on the measure itself.

When considering an improvement in combustion efficiency, the energy auditor should always determine the optimum efficiency that can be obtained with the existing equipment. He should bear in mind that optimum efficiency, however, is achieved through a compromise between excess air, smoke, and unburned hydrocarbons. He should not try to minimize the excess air level at the expense of high smoke and soot conditions, which will impair heat transfer to the medium being heated.

The improvements that can be made are hard to predict and depend on the state of the existing burner itself. If the burner is very old, its design will limit the improvements that can be made either by adjustments or by fitting an oxygen trim control package to automatically moderate the excess air levels. In this case, it may be advisable to replace the burner altogether.

It is difficult to predict the savings achieved by repairing and recalibrating instrumentation because of the uncertainty of faulty instrumentation. However, any costs incurred are likely to be repaid very quickly. Typical savings are around 0.5-2 percent of the energy input.

To estimate savings, the energy auditor should determine energy use when the faulty instrumentation is in operation, and energy use when the instruments are repaired. The difference between the two consumption rates represents the energy saved. Energy use when instruments are faulty will depend on the error induced (for example, a faulty draft gauge may mean too much excess air is used).

Exhibit 5.25

Improvement in Combustion Efficiency

Data

Annual fuel use under existing conditions = _____ GJ/yr

Existing combustion efficiency = _____%

Anticipated combustion efficiency after implementing change = _____%

Calculation

Energy Savings = $\frac{\text{(Anticipated efficiency - existing efficiency) x fuel use}}{\text{Anticipated efficiency}}$

= $\frac{(\quad - \quad)(\quad)}{(\quad)}$

= _____ GJ/yr

Cost Savings = (GJ/yr) ($/GJ)

= ( )( )

= $_____/year

Energy savings = _____ GJ/year

Cost savings = $_____/year

The cost to implement change will depend on the change proposed. Similarly, the improvement in existing efficiency will depend on the proposed change. Do **not** expect new controls to make up for burners in disrepair.

Notes on Calculation

(i) **Existing combustion efficiency:** use measured value.

(ii) **Anticipated combustion efficiency:** use manufacturer's data or estimate using data from Exhibits 5.16, 5.17, and 5.18.

5.1.2.3d Recovering Heat From Blowdown

The energy auditor can calculate the savings achieved if a heat recovery system is used to capture heat in blowdown that normally is run to drain. The calculation technique is shown in Exhibit 5.26.

The cost of the heat recovery system will depend on the method of heat recovery chosen. The normal practice is to pass the blowdown water into a flash vessel, where flash steam is created. The flash steam is then used directly for heating in the feedwater tank or deaerator. The remaining blowdown water still contains heat, which can be recovered by passing the water through a heat exchanger to preheat makeup water. This measure is recommended when the plant operates for long time periods (for example, three shifts a day, 6 days a week).

5.1.2.3e Preheating Feedwater

One method of preheating feedwater was mentioned in the previous section on heat recovery from blowdown. Another method of preheating feedwater is to pass the flue gases through an economizer. This measure is recommended for plants operating for long time periods (for example, three shifts a day, 6 days a week).

The potential savings from preheating feedwater can be estimated from the graph in Exhibit 5.27. When evaluating this measure, the energy auditor must take account of the potential corrosion problems caused by sulfur in oil. If the flue gases are cooled through heating feedwater, the stack temperature may be low enough to cause acid formation by condensation.

A system has been designed that uses a circulating alkaline solution to fully condensate and neutralize all acid in the flue gases. The advantage of this system is that is allows the recovery of latent heat normally lost by fossil fuel combustion systems. However, the cost of such a system is extremely high because of the need to use non-corrosive materials.

Exhibit 5.26

Heat Recovery from Continuous Blowdown

Assumptions

Average overall boiler efficiency = _____%

60% of the heat in the blowdown can be recovered.
Boiler TDS is kept at a mean of 3,000 ppm.

Data

% makeup water = _____%
Makeup TDS = _____ ppm
Energy input to boilers = _____ GJ/year
Feedwater temperature = _____ °C
Heat content in blowdown = _____ kJ/kg

Calculations

Blowdown rate = $\frac{\text{\% of makeup x makeup TDS}}{\text{100 x (blowdown TDS)}}$

@ 3,000 ppm = $\frac{(\quad)(\quad)}{100 \times (3{,}000)}$

= _____ kg/kg of steam produced

Heat required to raise steam = _____ hg @ boiler pressure - _____ hw of feedwater

= ( ) - ( )

= _____ kJ/kg

Steam produced/year = $\frac{\text{Energy input to boilers x average efficiency}}{\text{heat required to raise kg of steam}}$

= _____ kg/yr

Blowdown per year = Blowdown rate x steam produced/year

= ( ) ( )

= _____ kg/yr

Heat available in blowdown = Sensible heat in blowdown - sensible heat of city water

= ( ) - ( )

= _____ kJ/kg

Exhibit 5.26 (continued)

Heat Recovery from Continuous Blowdown

Available heat in blowdown/year = (Blowdown/yr) (heat available/kg) (10^{-6})

$$= \frac{(_____)(_____)}{10^{-6}}$$

= _____ GJ/year

Energy Savings

Heat recoverable = (Heat in blowdown/year) (% of heat recovery)

$$= \frac{(_____)(60)}{100}$$

= _____ GJ/year

Cost Savings = (_____ GJ/yr) ($_____/GJ)

= ( ) ( )

= $_____/year

Energy savings = _____ GJ/yr

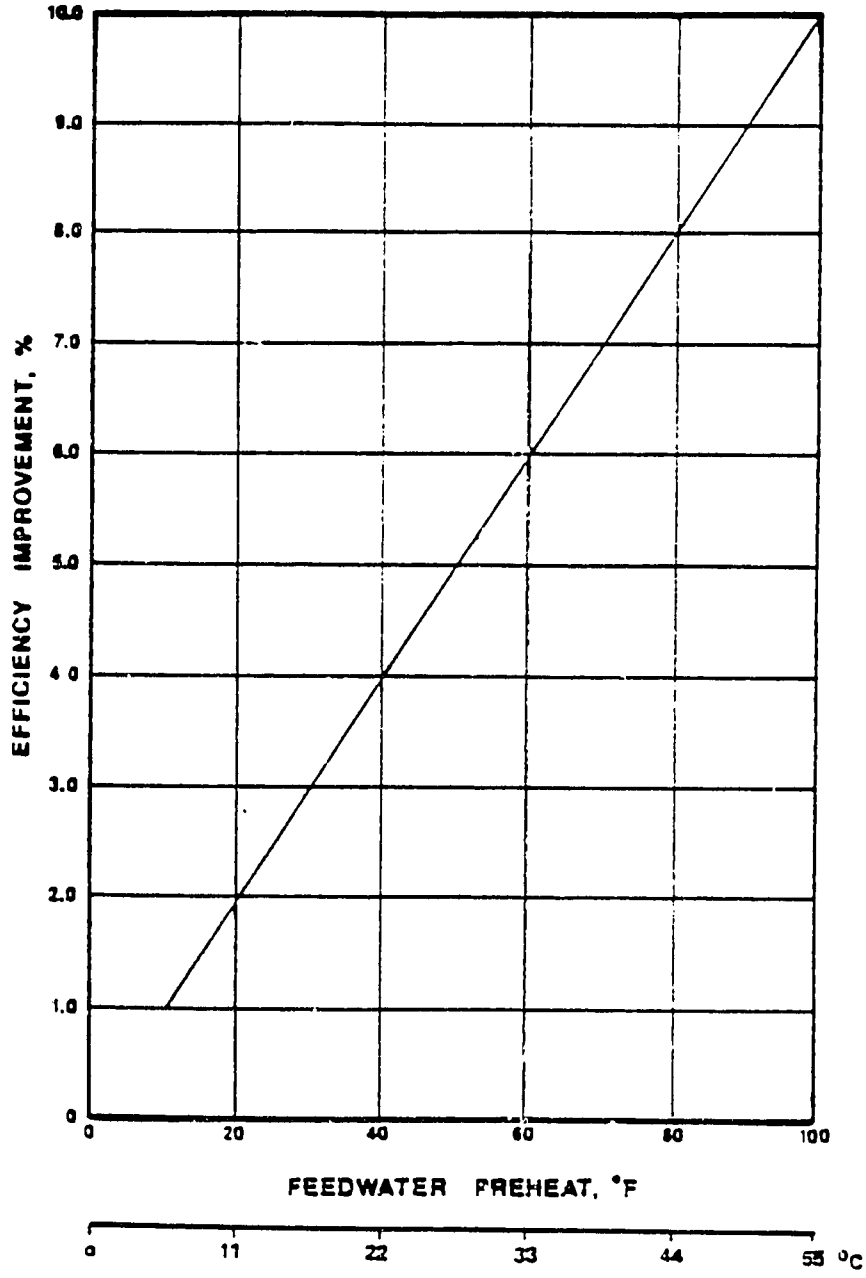
Cost savings = $_____/yr

Notes on Calculation

(i) Use boiler efficiency calculated from testing.
(ii) Obtain percent makeup and makeup TDS from water treatment records.
(iii) Use energy input from energy consumption data base.
(iv) Feedwater temperature from measurement or records.
(v) Heat content in blowdown is taken from steam tables (see steam tables).
(vi) Heat required to raise steam from steam tables (see steam tables).
(vii) Heat content of city water from steam tables (see steam tables).

EXHIBIT 5.27

Efficiency Improvement from Feedwater Preheating



5.1.2.3f Preheating Combustion Air

The savings achieved by preheating combustion air can be estimated from the graph in Exhibit 5.28.

This measure is recommended for plants operating long hours with relatively high flue gas temperatures. The factor limiting this measure is usually the temperature of the combustion air that the burner is capable of handling. Burners are often not equipped to handle air at temperatures in excess of 175°C without requiring major modifications.

5.1.2.3g Reducing Heating Requirements for Fuel Oil Storage

Oil often stored is at temperatures close to those needed for correct atomization. Two measures relating to fuel oil storage are sometimes identified during a detailed energy audit. One measure is to fit outflow heaters to heat oil close to the pumping outlet of the storage tank to a temperature that is just high enough to pump the oil to the burner tip. Booster heaters are then fitted at the burner to raise the oil to atomization temperature.

Savings from this measure depend on the quantity of oil stored compared with the quantity used, and on the pumping and atomization temperatures. Savings can be estimated from the following formula:

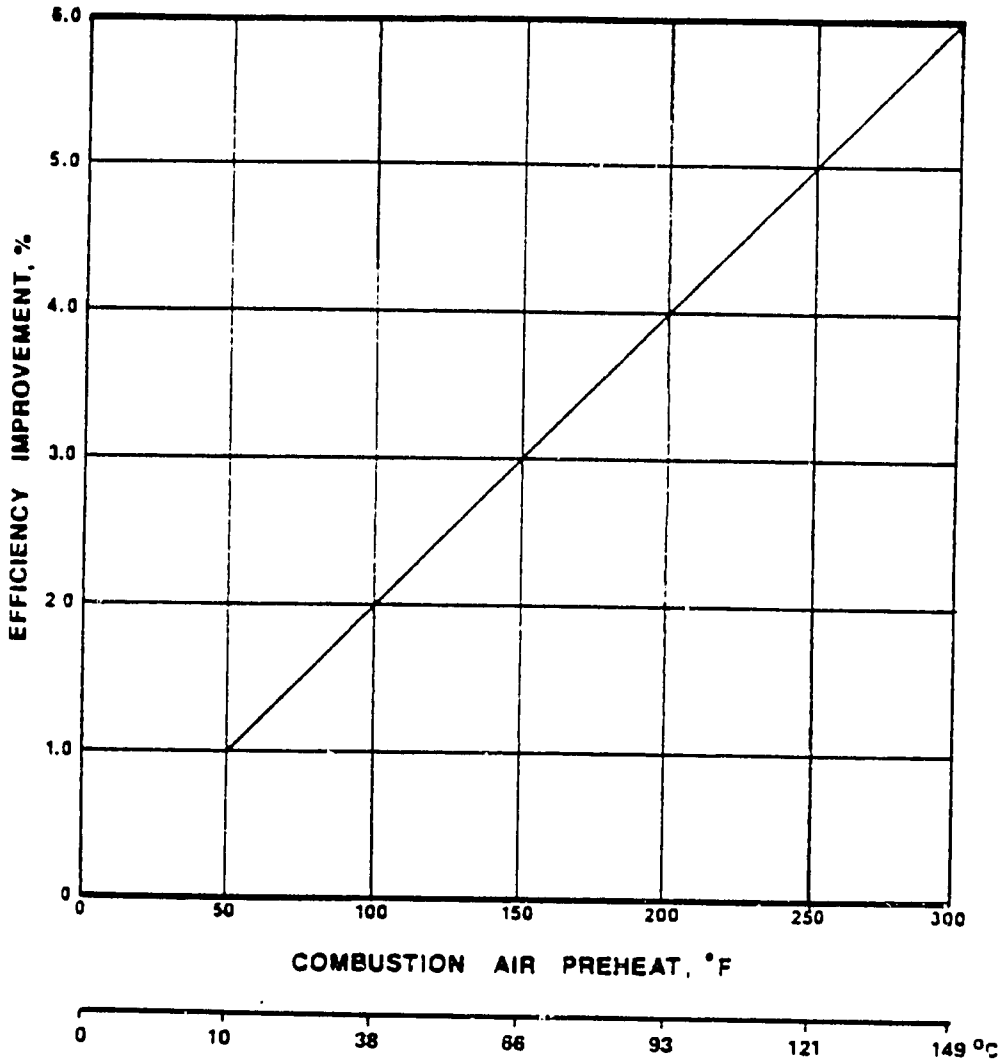
Energy savings = (mass of oil stored - oil used) (specific heat) (atomization - storage temperature) = ((kg/year) (kJ/kg/°C) (°C))/10^6 = GJ/year.

Cost savings = (GJ/year) ($/GJ) = $/year.

The second measure is to insulate the oil storage tank. Savings are estimated based on the temperature difference between the storage and ambient air, using the following formula:

EXHIBIT 5.28

Efficiency Improvement from Combustion Air Preheating



$$H = kA\ (To - Ta) \times hours$$

where

H = average total heat loss, watts/year
k = constant = 8.0 watts
A = tank area exposed to the air
To = oil storage temperature, ^{o}C
Ta = average annual ambient temperature, ^{o}C
Hours per year that oil is heated to storage temperature.

Fifty-millimeter-thick insulation will reduce heat losses by 80 percent; thus, savings = 0.8 (H) watts/year.

The cost of insulating depends on the insulation chosen and the labor used to install it. Tank insulation should be non-combustible and weather-proof.

5.1.2.3h Replacing Boilers

The potential savings from replacing a boiler plant will depend on the anticipated change in overall efficiency. A change in a boiler plant can be financially attractive because the:

- Existing plant is old and inefficient
- Plant is not capable of firing cheaper substitution fuel
- Plant is over- or under-sized for duty
- Plant design is not ideal for loading conditions.

These reasons will be apparent from the detailed energy audit, and an estimate of the savings can be made by calculating the change in efficiency:

$$= \frac{\text{(Existing fuel use) (efficiency of new plant - efficiency of existing plant)}}{\text{(efficiency of new plant)}}$$

= GJ/year.

The efficiency of the new plant can be found in the manufacturer's literature.

No decision to change a plant should be taken based on the detailed energy audit alone. When the results of the detailed energy audit indicate that it would be financially attractive to replace a boiler plant, a feasibility study should be conducted. The feasibility study should examine all implications from long-term fuel availability and cost to company growth plans. All financial and engineering factors should be considered. Boiler plants traditionally have a useful life of well over 25 years; hence, replacement must be carefully studied.

5.1.2.4 Summary

The steps outlined this section were presented for guidance only. Specific details and opportunities will depend on the individual plant; the energy auditor must remember to treat every plant on its individual merits. In doing so, he will be able to optimize the efficiency of the plant in every case. Example opportunities for conservation on boiler plants are presented in the case study in Appendix 5.A.

5.2 DETAILED ENERGY AUDIT OF STEAM SYSTEM

Boiler plants are used extensively by industry. Every boiler requires a distribution system to transport the medium heated by the boiler plant.

The purpose of this case study is to outline procedures used to evaluate steam systems during a Detailed Energy Audit. Steam is distributed to various processes via a pipeline network. A distribution system has three main elements -- pipes, insulation, and traps. Efficient energy use depends on their correct operation. In the following section, we first describe the preliminary energy audit of a steam system and then the Detailed Energy Audit.

5.2.1 PRELIMINARY ENERGY AUDIT

The steps taken in a PEA to evaluate a steam system are limited to a **visual inspection.** However, the inspection will enable the energy auditor to identify pipe size, distribution pressures, missing insulation, and leaks. These steps are often repeated during the detailed energy audit. Data collection forms are shown in Exhibit 5.29. Techniques for calculating savings are presented in the detailed energy audit section.

5.2.2 DETAILED ENERGY AUDIT

The energy performance of a steam system is evaluated by testing the system for:

- Steam pressure and temperature
- Improperly functioning steam traps
- Leaks and missing or damaged insulation.

5.2.2.1 Testing the Steam System

Steam pressure is measured by means of **pressure gauges.** Pressure gauges are described in Section 4.3 of the manual. The pressure is measured at existing pressure sensor

EXHIBIT 5.29

Steam and Condensate System Inspection Data

CLIENT:			PLANT:	
DATE:	PROJECT NO.:		DATA BY:	
UNITS:	TEMP.:	PRESSURE:	LENGTH:	PIPE SIZE:

PIPE INSULATION (Missing/Damaged)

LOCATION	SYSTEM TYPE *	PIPE SIZE	PRESSURE	TEMP	INSUL. TYPE	LENGTH OF SECTION

* S = Steam, CR = Condensate Return, HWS = Hot Water Supply, HWR = Hot Water Return

STEAM LEAKS

LOCATION	PRESSURE	LEAK SIZE (DIAMETER)	LENGTH OF STEAM PLUME

Exhibit 5.29 (continued)

Steam and Condensate System Inspection Data (cont.)

STEAM TRAPS Total Number Checked _____

LOCATION	EQUIPMENT OR APPLICATION	TRAP SIZE	TRAP TYPE	STEAM PRESSURE	DISCHARGE TEMP.	FAILURE TYPE *

* FC = Failed Closed, FO = Failed Open, SC = Short Cycling

OTHER STEAM DISTRIBUTION/CONDENSATE SYSTEM EQUIPMENT
(Condensate Receivers, Flash Tanks, Condensate Pumps, Control Valves, Steam Tracing, Etc.)

SYSTEM OR EQUIPMENT	LOCATION	COMMENTS & OPERATING DATA

points. A calibrated gauge head is used in place of existing heads. The existing head reading is noted, and then it is unscrewed from its position and replaced with the calibrated gauge head. The new reading is noted. A wide variation between the readings indicates that the existing gauge is defective. In addition, a steam pressure significantly lower than that expected for the steam line is an indication of a steam leak.

Steam temperature is measured using either a **surface probe thermocouple** or an **infrared pyrometer.**

The surface probe thermocouple is placed in direct contact with a bare portion of the steam line, and the pipe temperature is indicated on the thermocouple readout. This temperature will be slightly lower than the actual steam temperature, but the temperature difference will be very small. The energy auditor can use the temperature in conjunction with steam tables to verify steam pressure when it is not possible to measure pressure directly.

The infrared pyrometer is used to measure steam pipe temperature without making physical contact. The emissivity of the steam pipe is determined by reference to an emissivity table (see Exhibit 4.6). Alternatively, paint can be applied to the surface to be measured. The paint is manufactured to yield a known emissivity; the emissivity valve is set on the pyrometer.

To use the pyrometer, aim it at the point to be measured, and read the temperature indicated on the pyrometer unit readout.

Any steam main will condense some steam owing to radiation heat losses from the surface of the pipe. For example, a 100-mm (4-inch) insulated pipe 30 meters long in 10°C air will condense 16 kg of steam per hour. Although this amount probably represents less than 1 percent of the pipe capacity, at the end of an hour the pipe would contain not only steam but also 16 liters of water. Provision must be made to remove this water from the steam main, or the main would eventually become flooded. This is achieved by using drain pockets and steam traps.

Similarly, it makes good sense to run the steam main with a fall in the direction of the steam flow. Steam typically travels at velocities between 65 and 80 km per hour.

If condensate were draining in the opposite direction of steam flow, it would be difficult for the water to collect and hence be removed from the pipe. Also, it would make the steam wet and could cause water hammer. Water hammer occurs when a slug of water is forced along a pipe by steam flow. The slug of water is pushed by the steam until the pipe changes direction. The slug hammers against the pipe and can cause erosion and eventual pipe failure.

By allowing the flow to be in the same direction, drain pockets can be situated at regular intervals (30-50 meters), and draining can take place. Drain pockets must be of adequate size to collect the water. Small drain pockets will not cope with the problem, and the main will become waterlogged. A 100-mm drain pocket will serve mains up to 150 mm; a 150-mm drain pocket will serve a 200-mm main, and so on.

To clear drain pockets or points, the energy coordinator/plant engineer must select suitable **steam traps**. The choice of steam traps is fairly wide. Steam traps operate on different principles, but their basic function is to discharge condensate without passing live steam. The reason for differing operating principles is simply that steam plants operate in different fashions.

Although the basic function of the trap is to discharge condensate without waste of steam, steam traps also must deal with the problem of air that inhabits the steam system. Air fills the spaces left by steam in the steam distribution system. As steam condenses and is shut off (e.g., at the end of a working day), air infiltrates the piping system through valves, joints, etc. If the pipeline is to function correctly on restart-up, it is necessary to remove the air from the system, particularly from the steam trap. If the air is not removed, the trap can become airbound and condensate would not be removed from the system. Hence, traps must be capable of removing air from the distribution system.

Broadly speaking, there are four main groups of trap:

- Mechanical
- Thermostatic
- Thermodynamic
- Miscellaneous.

A brief description of each type follows.

5.2.2.1a Mechanical (see Exhibit 5.30)

Traps of this type operate mechanically, using the difference in density between steam and condensate. They open to condensate and close to steam by the action of a float that can be either a closed float (hollow ball) or a device shaped like a bucket with the open end facing either upward or downward. The movement of the float operates a valve.

5.2.2.1b Thermostatic (see Exhibit 5.31)

Thermostatic traps open or close, depending on their body temperatures. At any given pressure, steam has a fixed temperature, but condensate at the same pressure can cool down to a lower temperature. Thermostatic traps operate based on this temperature difference. The valve is operated by a thermostatic element of either the balanced pressure, liquid, or metallic type.

5.2.2.1c Thermodynamic (see Exhibit 5.32)

Thermodynamic traps work on the difference in velocity between condensate and steam flowing across a simple valve disc. They close to high-velocity steam, but open to lower-velocity condensate.

5.2.2.1d Miscellaneous

There are a few types of trap in this category. The most widely used are the impulse trap and the labyrinth trap. Impulse traps operate on the throttling effect of several small orifices in series on high-velocity steam or condensate.

EXHIBIT 5.30

MECHANICAL TRAP

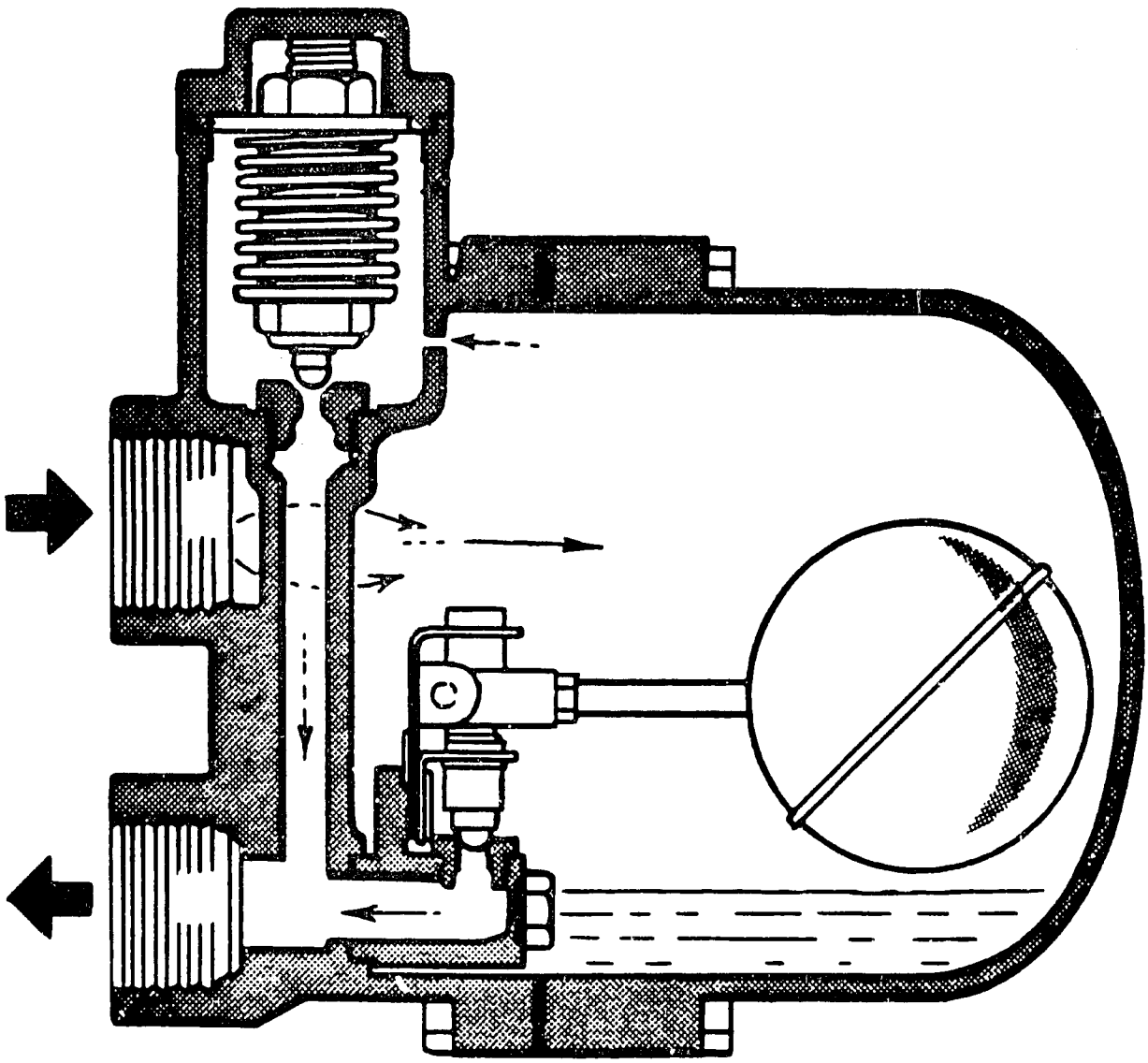


EXHIBIT 5.31

THERMOSTATIC TRAP

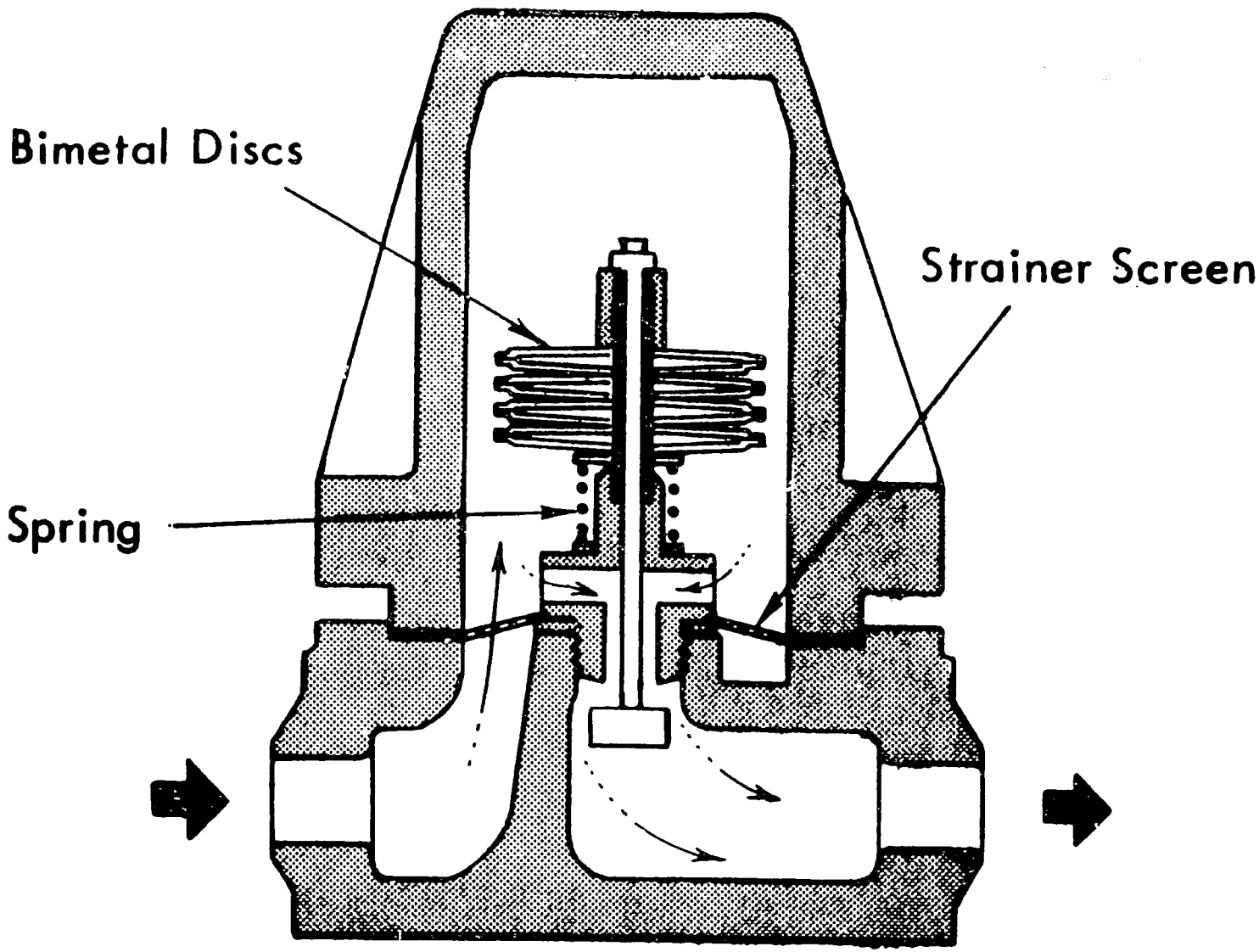


EXHIBIT 5.32

THERMODYNAMIC TRAP

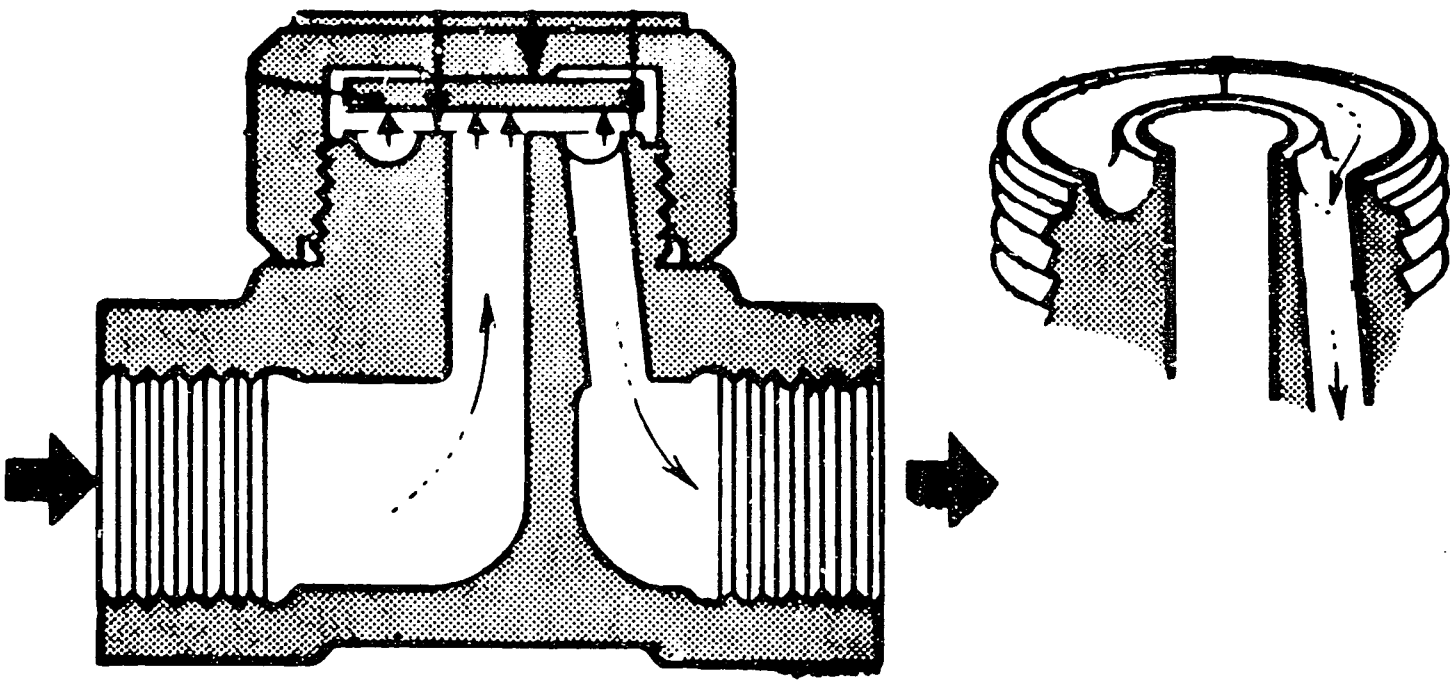


Exhibit 5.33 shows the characteristics of the various types of trap.

To ensure the highest efficiency for heating purposes and for removing condensate, it is imperative that the correct type of trap be selected. Points that should be considered are also presented in Exhibit 5.33.

Malfunctioning **steam traps** are identified either by **measuring the temperature** or **analyzing the sound** made by the trap.

If a steam trap is functioning properly, there is a significant temperature difference between its upstream and downstream (condensate) sides. If no temperature difference can be measured (using either a contact probe with a thermocouple or an infrared pyrometer), the steam trap has failed to open.

A steam trap can also be tested by means of sound. Different types of traps emit characteristic noises as they regularly cycle open or closed. The auditor can listen to these sounds using either industrial stethoscopes or ultrasonic detectors. Some training may be necessary to familiarize the energy auditor with the normal sounds that each type of steam trap makes.

The **thermostatic trap** normally makes a clicking sound when opening. There is usually a significant time delay between opening cycles.

The **float trap** normally operates quietly, and is thus difficult to test by means of sound.

The **thermodynamic trap** also makes a clicking sound. If the trap clicks almost continuously, it has failed.

Testing the distribution for leaks is usually accomplished by a visual inspection only. However, when walking the distribution system, note should be made of pressures along the mains.

The effectiveness of insulation is tested by measuring the base pipe temperature and insulation surface temperature with a contract thermocouple.

Exhibit 5.33

Characteristics of Steam Traps

Group	Type	Advantages	Disadvantages
Mechanical	Loose ball float	No working parts -- little maintenance.	Does not releast air automatically -- needs air cock; poor valve seating with ball.
Mechanical	Float and lever	Consistent operation; cannot air bind.	Subject to damage from water hammer; can be attacked by corrosive condensate; can be damaged by freezing; different duty size required.
Mechanical	Open top bucket	Robust; resists water hammer.	Does not automatically vent air with cock or vent.
Mechanical	Inverted bucket	Robust; resists water hammer.	Very slow air venting; must be primed with water; water lost by sudden pressure drop or superheated steam can freeze.
Thermostatic	Balanced pressure	Very small; free discharge of air; handles high condensate rates; not likely t· freeze; adjusts to fluctuating steam pressure; easy maintenance.	Damaged by water hammer, corrosive condensate; do not use on superheated steam.
Thermostatic	Liquid expansion	Discharge condensate at low temperature; readily discharges; can be used for superheat; not affected by vibration, steam pressure, pulsation, water hammer.	Damaged by corrosive condensate; can cause water log if improperly set.
Thermostatic	Bimetallic	Small; handles large volumes of condensate; free air discharge; not subject to freeze; can withstand water hammer, corrosive condensate; used over wide pressure range.	Slow response time can cause waterlogging.
Thermodynamic		Wide pressure range; use for superheated steam; not damaged by water hammer, vibration; not subject to freeze; small; handles large volumes of condensate; only one moving part; can be made to stand corrosive condensate.	Do not operate on low inlet pressure or high back pressure; subject to air binding on start-up; noisy.
Miscellaneous	Impulse	Small; handles large volumes; work over large pressure range; used on superheated steam; does not air bind.	Does not give dead shut off; subject to pulsing; can be noisy; subject to water hammer.

Exhibit 5.33 (continued)

Choosing the Right Steam Trap

The following is a series of questions that the energy auditor should ask prior to selecting steam traps for a particular operation:

1. What is the highest condensate rate to be handled?
2. What is the lowest condensate rate to be handled?
3. What is the pressure at the trap inlet?
4. Is there pressure at the outlet?
5. Is condensate returned under vacuum?
6. Does the condensate load fluctuate?
7. Is steam locking likely to occur?
8. Is air present in quantity?
9. Must condensate be discharged immediately?
10. Is the condensate return line above the drain?
11. Is there water hammer in pipeline?
12. Is the condensate corrosive?
13. Is the trap to be exposed to external conditions?
14. Is the steam supply superheated?
15. Is the steam supply thermostatically controlled?
16. Is there vibration or excessive movement in the distribution system?

Heat transmission is accomplished by three mechanisms: conduction, convection, and radiation. **Conduction** is the transfer of heat between two bodies in physical contact. **Convection** is the movement of a mass and its associated energy from one location to another. When the movement is not assisted by an outside force, the heat transfer is called natural convection; when a fan or blower is used to increase the rate of movement, it is known as forced convection. **Radiation** is the transfer of energy from a higher-temperature body to a lower-temperature body some distance away, without raising the temperature of the medium through which the heat passes.

A steady flow of heat through any medium of transmission is directly proportional to the temperature differential causing the flow, and inversely proportional to the resistance to heat flow of the bodies and the heat transfer medium. Insulation is used to increase the resistance to heat flow.

The ability of a material to conduct heat is known as its thermal **conductivity**, or **K factor**, and is expressed as energy per unit time per unit area per degree difference in temperature per unit of thickness. Typical units used are:

$$\frac{\text{Kilojoule - m}}{\text{m}^2 \text{ - hr - }^{o}\text{K}} \quad \text{or} \quad \frac{\text{Btu - inch}}{\text{ft}^2 \text{ - hr - }^{o}\text{F}}$$

Thermal conductance, or **C factor**, is the quantity of heat that flows per unit thickness per time unit per degree difference in temperature. Typical units used are:

$$\frac{\text{Kilojoule}}{\text{m - hr - }^{o}\text{K}} \quad \text{or} \quad \frac{\text{Btu}}{\text{ft - hr - }^{o}\text{F}}$$

Heat resistance, or **R factor**, is the reciprocal of conductance. The higher the R factor, the greater the resistance or insulating value of the material. In a system with several components and heat flowing through each in sequence, total resistance is the sum of the component R values. Hence:

$$\begin{aligned} R \text{ total} &= R_1 + R_2 + R_3 \ldots R_n \\ &= (1/C_1) + (1/C_2) + (1/C_3) + \ldots (1/C_n). \end{aligned}$$

The **overall heat transfer coefficient,** or the **U factor,** is similar to the C factor, but it includes the resistance of surface film between a fluid or gas and the insulated system.

There are five basic types of thermal insulation, which may be used alone or in combination. **Flake insulation,** such as vermiculite or expanded micra, is composed of small particles that finely divide the air space. **Fibrous insulation,** such as glass or rockwool, is composed of small-diameter fibers. **Granular insulation,** such as magnesia, calcium silicate, or diatomaceous earth, is composed of small granules that contain voids. **Cellular insulation,** generally made from glass, rubber, or plastic, is composed of small individual cells that finely divide the air space. Finally, **reflective insulation,** such as aluminum or stainless-steel foil, is composed of parallel thin sheets of foil having high thermal reflectance to restrict radiant heat transfer; the spacing is designed to reduce conductive or convective heat transfer.

Insulation is available in many different forms, including batts, blankets, boards, and blocks. In addition, different insulation materials have other properties that must be considered in selecting insulation: temperature limits, fire hazard classification, dimensional stability, and moisture absorption. The table in Exhibit 5.34 indicates the properties of some commonly used insulation materials.

Calcium silicate insulation products are made from a mixture of lime and silica, with various reinforcing fibers. They have exceptional strength and durability in medium- and high-temperature applications, and also have superior thermal performance at high temperatures.

Fiberglass insulation is supplied in more forms, sizes, and temperature operating capability than any other kind of insulation. While fiberglass insulation incorporating organic binders begins to oxidize at temperatures exceeding 200°C-260°C, the fiber matrix gives the product good integrity, and many fiberglass products are rated above the binder temperature.

Mineral fiber or rockwool insulating products are more heat-resistant than fiberglass and can be used at higher temperatures. However, when used above the binder burnout temperature, the products do not retain their physical integrity very well.

Exhibit 5.34

Industrial Insulation Types and Properties

Insulation type and form[1]	Temperature range (°C)	Thermal conductivity (w/m°C at T_{mean} (°F)) 25	90	250	Compressive strength (bar) at % deformation	Fire hazard classification of flame spread — smoke developed	Cell structure (permeability and moisture absorption)
Calcium silicate blocks, shapes, and P/C	to 815	2.57	2.84	3.67	6.9-17.2 at 5%	Noncombustible	Open cell
Glass fiber blankets	to 650	1.66-2.51	2.22-3.40	2.98-5.06	0.001-0.24 at 10%	Noncombustible to 25/50	Open cell
Glass fiber boards	to 540	1.53	1.94	3.54-4.23			
Glass fiber pipe covering	to 450	1.59	2.08	4.30			
Mineral fiber blocks and P/C	to 1,040	1.59-2.36	1.94-2.70	3.12-5.69	0.07-1.2 at 10%	Noncombustible to 25/50	Open cell
Cellular glass blocks and P/C	265 to 485	2.63	3.12	4.99	6.9 at 5%	Noncombustible	Closed cell
Expanded perlite blocks, shapes, P/C	to 815	—	3.19	4.37	6.2 at 5%	Noncombustible	Open cell
Urethane foam blocks and P/C	(-75 to -265) to 105	1.11-1.25	—	—	1.1-5.2 at 10%	25-75 to 140-400	95% closed cell
Isocyanurate foam blocks and P/C	to 175	1.04	—	—	1.2-1.7 at 10%	25-55 to 100	95% closed cell
Phenolic foam P/C	-40 to 120	1.59	—	—	0.9-1.5 at 10%	25/50	Open cell
Elastomeric closed cell sheets and P/C	-40 to 105	1.73-1.87	—	—	2.75 at 10%	25-75 to 115-490	Closed cell
MIN-K blocks and blankets	to 980	1.32-1.46	1.39-1.59	1.46-1.66	6.9-13.1 at 8%	Noncombustible	Open cell
Ceramic fiber blankets	to 1,425	—	—	2.63-3.74	0.03-0.07 at 10%	Noncombustible	Open cell

[1]P/C: pipe covering.

SOURCE: Manufacturers' literature.

Cellular glass insulation is composed of millions of sealed glass cells, and will not absorb liquids or vapors. While the material is load-bearing, it is also brittle, which makes installation more difficult and causes problems in vibrating or flexing applications.

Expanded perlite consists of a mineral (perlite) that has been expanded at high temperatures to form a structure of tiny air cells surrounded by a vitrified product. While the perlite materials have low moisture absorption as produced, the absorption increases significantly after heating and oxidation. Expanded perlite is rigid and load-bearing, but has lower compressive strengths, higher thermal conductivities, and is more brittle than calcium silicate.

There are three types of plastic foams used for insulation. **Polyurethane/isocyanurate foams** are rigid and offer the lowest thermal conductivities. Sealing is required, however, to resist the migration of an end water vapor back into the foam. These foams also suffer from problems of dimensional stability and fire safety. **Phenolic foams** provide additional levels of fire safety, but are about equivalent to the thermal conductivity of fiberglass. However, they are not usable over very wide temperature limits. **Elastomeric cellular plastics** offer a flexible, closed-cell material most suited to refrigeration piping, plumbing, and vessel applications. Smoke generation is a problem with these materials, and temperature ranges are restrictive.

Insulating refractories consist of two types, fiber and brick. **Ceramic fiber** refractories are made of alumina and silica, while insulating **firebrick** is manufactured from high-purity refractory clays, with alumina added to high-temperature grades.

The selection of new or additional insulation depends on a number of factors. The properties of the insulating material must be matched to the temperature of the surface to be insulated, with allowance for temperatures in excess of design conditions. The location of the insulation should also be considered, in terms of the surrounding environment, resistance to physical abuse, and required form of the insulation. The cost of the insulation is also important -- not only the initial cost, but also the maintenance cost.

There are a number of methods available for calculating the economic thickness of insulation. This involves a determination of the savings achieved by application of various thicknesses of insulation balanced against the increased cost of the insulation with

thickness. Exhibit 5.35 presents a graphic illustration of the determination of economic insulation thickness.

There are a number of methods for calculating the economic thickness of insulation, which are detailed in the following references:

- Economic Thickness of Industrial Insulation, Conservation Paper No. 46, 1976. Available from U.S. Government Printing Office, Washington, DC 20402 (stock number 041-018-00115-8).

- The Economic Thickness of Insulation for Hot Pipes, Fuel Efficiency Booklet No. 8, 1977. Available from U.K. Department of Energy Library, Thames House South, Millbank, London SW1P 4QJ, United Kingdom.

In addition, a computer program for determining the economic thickness of insulation is available from Thermal Insulation Manufacturers Association, 7 Kirby Plaza, Mount Kisco, NY 10549.

5.2.2.2 Estimating Potential Savings

5.2.2.2a Repairing Steam Leaks

During his visual inspection, the auditor should identify leaks by location and by the magnitude of the leak or the size of the orifice. The calculational procedure outlined in Exhibit 5.36 and chart shown in Exhibit 5.37 can be used to quantify the savings to be achieved by repair of steam leaks.

5.2.2.2b Installing or Replacing Insulation

The auditor should note missing insulation in terms of the size (diameter) of pipe, the length of missing or damaged insulation, and the temperature of the bare pipe. He can use the procedure in Exhibit 5.38 and table in Exhibit 5.39 to estimate the savings that will result from installing insulation on bare steam pipework or replacing damaged insulation.

EXHIBIT 5:35

ECONOMIC THICKNESS OF INSULATION

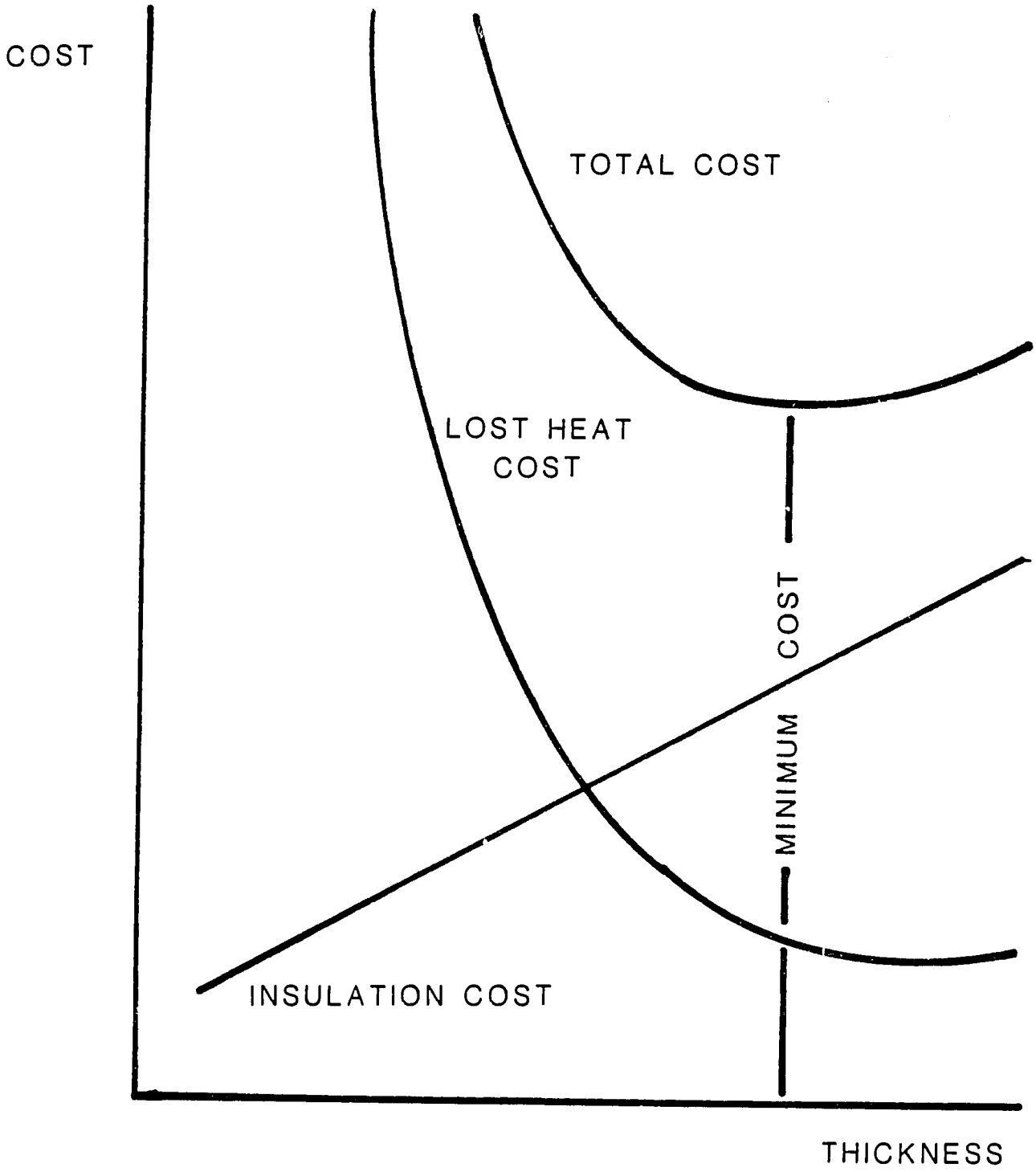


Exhibit 5.36

Repair of Steam Leaks

Assumptions

All losses will be saved when leaks are fixed.
Leakage rate in kg/hr = 0.4 (d^2) (p+1), where d = diameter (mm), p = pressure (bar).

Data

For leaks, see attached data sheets.

Heat content of steam = _____ kJ/kg at ____ bar pressure

Boiler efficiency = _____ percent

Steam system operating hours = _____ hrs/yr

Load factor = _____

Calculation

Energy savings

$$= \frac{\text{(Loss kg/hr) (hours) (heat content) (load factor)}}{\text{(boiler efficiency) } (10^6)}$$

$$= \frac{(\quad)(\quad)(\quad)(\quad)}{(\quad)(10^6)}$$

= _____ GJ/year.

Cost savings

= (GJ) ($/GJ)

= ( ) ( )

= $_____/year.

Cost of implementation

The cost of repairs to the steam distribution system are estimated to be $_____.

Simple payback

$$= \frac{\text{Cost of implementation}}{\text{annual savings}}$$

$$= \frac{(\quad)}{(\quad)}$$

= _____ years.

Exhbit 5.36 (continued)

Repair of Steam Leaks

Energy savings = _____ GJ
Cost savings = $_____/year
Cost of implementation = $_____
Simple payback = _____ years.

Data Sheet

Itemize data as collected.

Location	Pressure bar	Size of leak mm	Loss kg/hr

Notes for Calculation

Assumptions

Use leakage rate formula shown when unable to measure the size of the orifice through which steam is leaking. Otherwise, use Exhibit 5.37 to estimate steam leakage.

Data

(i) Complete data sheets to determine steam loss through each leak.

(ii) Calculate heat content of steam at each pressure distributed through the facility. The heat content is equal to enthalpy of steam at pressure -- enthalpy of boiler makeup water.

(iii) Boiler efficiency: use actual value or estimate of boiler supplying steam to leak area.

(iv) Steam system operating hours: use appropriate value for location in distribution system where leakage occurs.

(v) Load factor: use appropriate value for location where leakage occurs. If that portion of steam system is always used, use a load factor of 1.0.

Calculations

(i) Energy savings: repeat calculation for each leak, or sum hourly losses for leaks with the same steam pressure.

Data Sheet

(i) Loss kg/hr: estimate using Exhibit 5.37 or by the formula given under assumptions.

Exhibit 5.37

STEAM LOSS THROUGH LEAKS VENTED TO THE ATMOSPHERE

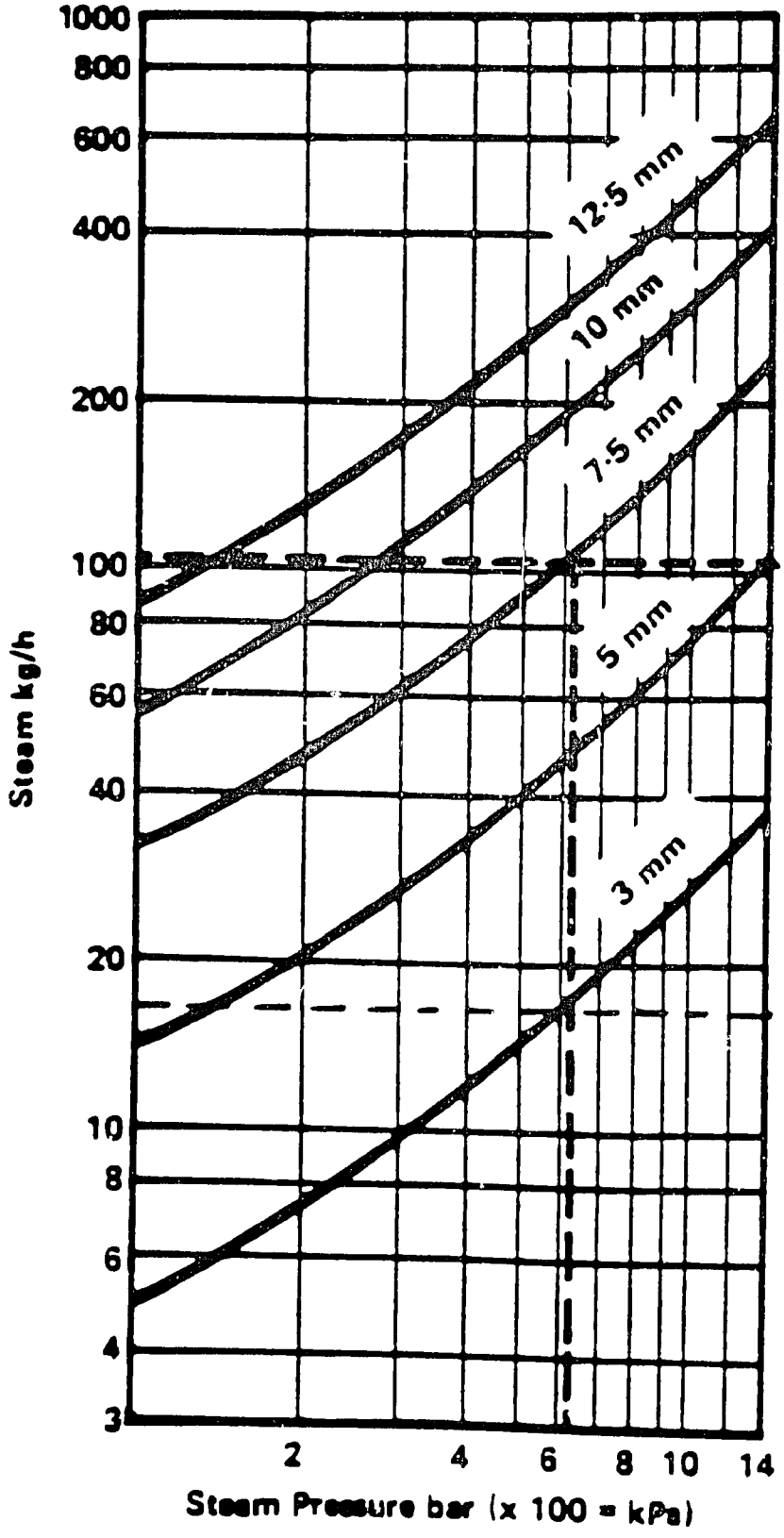


Exhibit 5.38

Pipework Insulation

Assumptions

Heat loss reduction by insulation = 90 percent
Pipework fittings equivalent length = 15 percent

Data

Operating hours = _____ hrs/year
Boiler efficiency = _____ percent
Missing insulation is detailed in data sheets following the calculation.

Calculation

Energy savings

$$= \frac{(\text{Wasted heat loss}) \times (\text{operating hours}) \times (0.9)}{(\text{boiler efficiency}) \times 10^6}$$

$$= \frac{(\quad)(\quad)(0.9)}{(\quad)(10^6)}$$

= _____ GJ/year

Cost savings

= (GJ/yr) ($/GJ)

= ( ) ( )

= $_____

Cost of implementation

This is estimated to be $_____ installed for the insulation required.

Simple payback

$$= \frac{\text{Cost of implementation}}{\text{annual savings}}$$

$$= \frac{(\quad)}{(\quad)}$$

= _____ years.

Exhibit 5.38 (continued)

Pipework Insulation

Energy savings = _____ GJ/yr

Cost savings = $_____/year

Cost of implementation = $_____

Simple payback = _____ years.

Data Sheet

Itemize data as collected.

Location	Pipe diameter OD mm	Length of bare pipe M	Heat loss kJ/hr/meter	Total loss kJ/hr	Pipe temp. (°C)	Hours of operation

Notes to Calculation

Assumptions

(i) Heat loss reduction by insulation: this assumes insulation over bare surface, and an economic thickness of insulation. If the surface is insulated and additional insulation is proposed, use 70 percent.

(ii) Pipework fittings equivalent length: add 15 percent to pipework length, if appropriate, to account for flanges, fittings, etc.

Data

(i) Operating hours: use the number of hours per year that the uninsulated pipework section of the steam distribution system is used.

(ii) Boiler efficiency: use measured boiler efficiency or estimate.

Calculations

(i) Energy savings: perform calculations for each length of uninsulated pipe; then sum individual savings.

Data Sheets

(i) Length of bare pipe: add 15 percent to measured length, if appropriate, to account for pipe fittings.

(ii) Heat loss (kJ/hr/meter): use the table in Exhibit 5.39 to determine heat loss between pipe and air.

(iii) Heat loss (kJ/hr): multiply heat loss (kJ/hr/meter) by length of pipe to determine hourly loss.

Exhibit 5.39

Heat Loss from Bare Horizontal Pipes
(Ambient temperatures 10°C to 21°C;
ambient still air 10°C to 21°C)

Temperature difference between pipe and air, °C	Heat loss, kJ/hours per meter, at pipe size (in mm diameter):									
	15	20	25	32	40	50	65	80	100	150
56	193	234	285	372	389	477	557	678	837	1,168
67	243	297	360	440	490	603	712	850	1,068	1,478
78	297	360	440	536	599	733	867	1,072	1,298	1,800
89	356	431	528	645	737	888	1,043	1,248	1,562	2,165
100	419	502	607	749	842	1,0[illegible]	1,214	1,440	1,805	2,508
111	482	590	712	867	976	1,202	1,411	1,687	2,152	2,939
125	574	687	837	1,026	1,156	1,419	1,671	1,997	2,512	3,488
139	662	808	980	1,197	1,344	1,650	1,943	2,240	2,935	4,078
153	758	917	1,122	1,378	1,545	1,901	2,244	2,688	3,383	4,698
167	867	1,051	1,285	1,574	1,762	2,169	2,567	3,019	3,936	5,372
180	984	1,185	1,470	1,779	2,001	2,433	2,910	3,454	4,283	5,979

5.2.2.2c Repairing or Replacing Steam Traps

The auditor can use the procedure in Exhibit 5.40 to estimate the savings that will result from repairing or replacing steam traps that fail.

5.2.2.3 Summary

An efficient distribution system is vital to minimize energy loss in transporting a heated medium from point of generation to point of use. The system is commonly ignored because it is not readily identified as a major consumer; individuals prefer to focus on prime movers such as the boilers or the process. Measures to maintain efficient operation are simple to implement and require no major investment. They should be part of any routine maintenance program.

Exhibit 5.40

Repair of Steam Traps

Assumptions

Average leakage per failed trap = 2.5 kg/hr

Data

Steam system operating hours = _____ hrs/yr
Number of failed traps = see data sheet following calculation
Boiler efficiency = _____ percent

Net heat content of steam at:

			Load factor
_____ bar	=	_____ kJ/kg	_____
_____ bar	=	_____ kJ/kg	_____
_____ bar	=	_____ kJ/kg	_____
_____ bar	=	_____ kJ/kg	_____

Calculation

Energy savings

$$= \frac{\text{(No. of traps) (leakage/trap) (hrs/yr) (heat content) (load factor)}}{\text{(boiler efficiency) } (10^6)}$$

$$= \frac{(\quad)(\quad)(\quad)(\quad)(\quad)}{(\quad)(10^6)}$$

= _____ GJ/year

Cost savings

= (GJ/yr) ($/GJ)

= ( ) ( )

= $_____/year.

Cost of implementation

The cost of replacement steam traps is estimated to be $_____ per trap installed, giving a total implementation cost of $_____.

Simple payback

$$= \frac{\text{Cost of implementation}}{\text{annual savings}}$$

$$= \frac{(\quad)}{(\quad)}$$

= _____ years.

Exhibit 5.40 (continued)

Repair of Steam Traps

Energy savings = _____ GJ

Cost savings = $_____/year

Cost of implementation = $_____

Simple payback = _____ years.

Data Sheet

Itemize data as collected.

Location	Steam pressure (bar)	Load factor	Operating hours

Notes to Calculation

Assumptions

(i) Average leakage per failed trap: use 2.5 kg/hr as an estimate if unable to measure steam leakage.

Data

(i) Steam system operating hours: use the annual operating hours of that portion of the steam distribution system where a failed trap exists.

(ii) Boiler efficiency: use measured value or an estimate.

(iii) Net heat content of steam: determine for each pressure of steam distributed through the facility from steam tables as enthalpy of steam at pressure -- enthalpy of feedwater.

(iv) Load factor: adjust operating hours with load factor to reflect actual operation of equipment served by trap. If equipment and steam system operating hours are identified, use 1.0 as the load factor.

Calculation

(i) Energy savings: repeat calculation for each steam pressure in the facility.

5.3 DETAILED ENERGY AUDIT OF DRYERS

A dryer is a heating unit designed to drive off volatile substances, such as organic solvents and water. Drying units operate at low to medium temperatures of 65°C to about 175°C.

Dryers may take one of several configurations:

- Direct-contact-fired dryer
- Indirect-contact-fired dryer
- Indirect-contact dryer using thermal fluid.

In the first two types, the dryer incorporates a combustion system. In the first type, hot combustion gases are used for drying, while in the second type, combustion gases pass through a heat exchanger, warming air or some other fluid that is used for drying. In the third type of system, the dryer does not have a combustion section, but uses a hot thermal fluid (such as steam or a proprietary thermal fluid such as Dowtherm) for drying. The steps taken in a PEA and detailed energy audit to test and evaluate dryers are discussed below.

5.3.1 PRELIMINARY ENERGY AUDIT

A PEA for a dryer is normally limited to interviews with key personnel and a visual inspection of the dryer. These procedures are used to collect nameplate data. Such data can be collated on forms similar to those presented in Exhibit 5.41.

In the **interview**, the energy auditor will determine the dryer configuration and the key operating characteristics, including throughput rates, operating schedules, and product specifications. He should determine what types of controls are fitted and what operating records are available.

The information collected from the interviews can be confirmed during the visual inspection. The **visual inspection** allows the energy auditor to see the condition of the

Exhibit 5.41

Dryer Details

Location: _____

Dryer

	1	2	3
Manufacturer:			
Age (years):			
Type (direct/indirect):			
Material dried:			
Throughput (specify units):			
Drying medium:			
Normal operating temperature (^{o}C):			
Moisture content in (%):			
Moisture content out (%):			

Burners or cylinders

Manufacturer:			
Number:			
Age:			
Type:			
Fuel/heating medium:			
Draft control:			

dryer and its associated equipment. Data collected during this time can be collated on forms such as Exhibit 5.42. He should also examine the following records:

- Dryer operating log
- Production records.

From the interview, inspection, and records, the energy auditor can determine what operating characteristics are monitored and how production quality and quantity vary.

He should obtain information on:

- Throughput rates
- Moisture contents of product in and out of dryer
- Fuel flow metering/consumption
- Temperature of dryer
- Scrap levels.

The energy auditor should use the PEA to determine whether to test the dryer as part of a detailed energy audit, based on:

- Date of last efficiency check
- Installed instrumentation
- Operational conditions.

If testing is necessary, the energy auditor should identify test points and decide on the type of test. Typical testing points are shown in Exhibit 5.43.

The normal procedure is to use the test to gather data so that an energy balance can be developed for the dryer.

5.3.2 DETAILED ENERGY AUDIT

If the PEA indicates that testing is necessary, the energy auditor evaluates dryer efficiency by building an energy balance. The energy balance is used to:

Dryer Evaluation Checklist

Item	Equipment	Comments
Physical appearance	Dryer shell	
	Burners/cylinders	
	Fuel system	
	Steam system	
	Condensate lines	
	Ventilation systems	
External structure	Dryer shell	
Safety equipment & instrumentation	Dryer	
	Burners/cylinders	
	Fuel system	
	Steam system	
	Condensate lines	
	Ventilation systems	
Valves, fittings & insulation	Dryer mechanicals	
	Burners/cylinders	
	Fuel system	
	Steam system	
	Condensate lines	
	Ventilation systems	

EXHIBIT 5.43

MEASURING POSITIONS FOR DRYER TESTING - DIRECT CONTACT

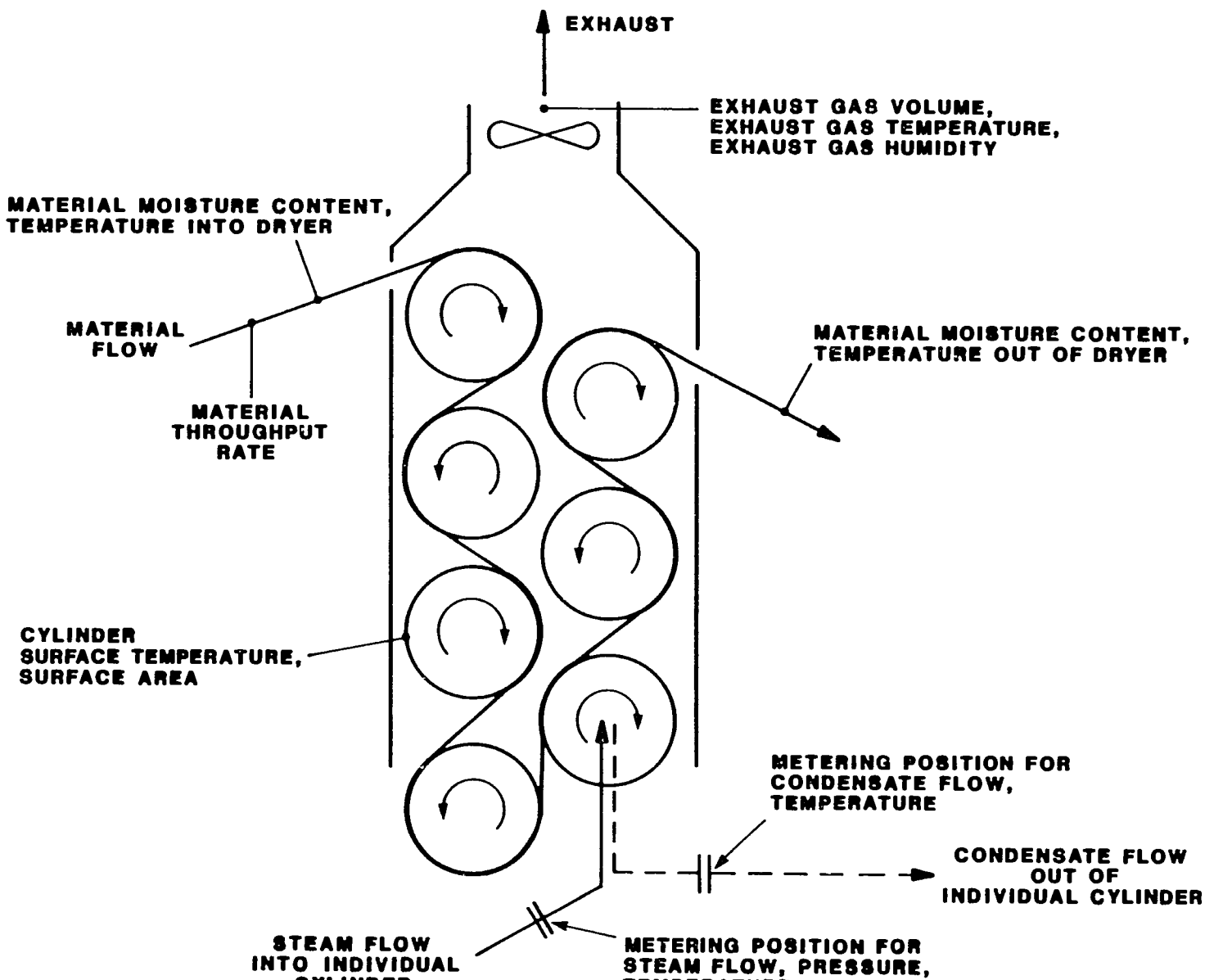
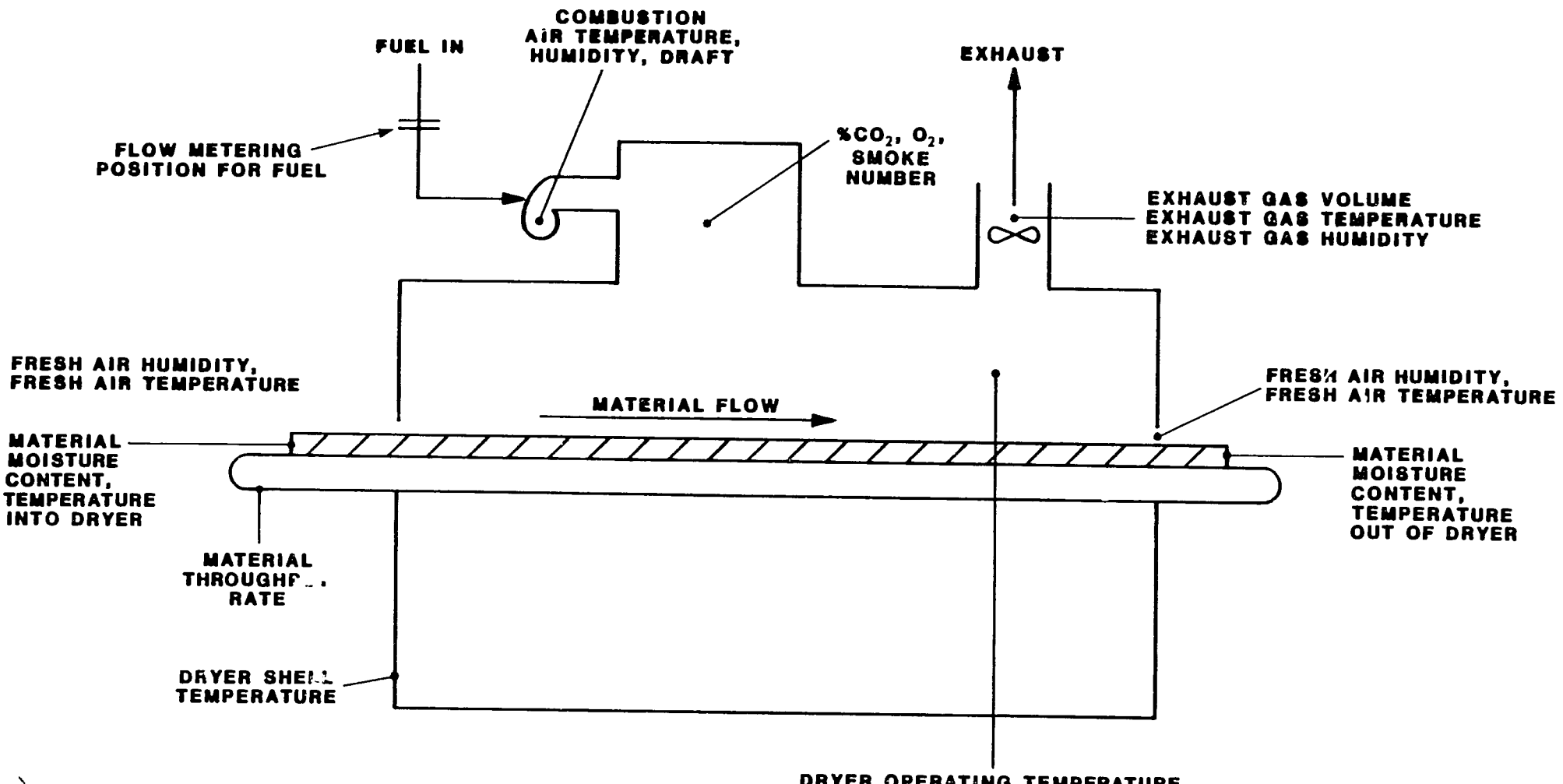


Exhibit 5.43 (continued)

MEASURING POSITIONS FOR DRYER TESTING - INDIRECT CONTACT



- Evaluate dryer energy performance
- Identify conservation opportunities.

5.3.2.1 Evaluating Dryer Performance

The auditor can evaluate dryer energy performance by measuring the following parameters:

- Fuel flow rate and usage (integrated rate)
- Quantity and temperature of steam or other thermal fluid used
- Combustion air volume, temperature, and humidity
- Exhaust air volume, temperature, and humidity
- Temperature and moisture content of material to be dried, measured before and after drying
- Dryer draft
- Temperature of dryer external surfaces
- Outside air infiltration.

A data collection form for dryer test results is shown in Exhibit 5.44.

Fuel flow rate and usage can be measured by **positive displacement meters or rotameters.** The positive displacement meter indicates total flow over a period of time. Hence, average flow rate is determined by noting the meter readings at the beginning and end of the test and dividing the difference between these readings by the elapsed time. A rotameter indicates the instantaneous flow rate. If the flow rate is steady, the rotameter indication can be multiplied by the elapsed time to yield fuel consumption.

If the dryer uses **steam or some other proprietary thermal fluid**, flow should be measured either by reading **meters** or determining the **condensate flow rate.**

Combustion air volume is measured by a **velometer or anemometer.** The flow is measured at the iniet to the combustion chamber by taking air velocity readings at a number of points in the combustion air duct.

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Exhibit 5.44

Dryer Test Data

Client: **Plant:**

Date: **Project No:** **Data by:**

Nameplate data:

Dryer no. _____

Manufacturer _____

Type _____

Size _____

Operating temperature/steam pressure _____

Operating speed/throughput _____

Material dried _____

No. of burners/cylinders _____

Burner type _____

Control _____

Draft _____

Atomization _____

Fuel/fuels/heating medium _____

No. of exhaust fans _____

Rating _____

No. of circulating fans _____

Rating _____

Exhibit 5.44 (continued)

Dryer Test Data

Test data	**Fuel:**	**Metered: Yes/No**	**Units:**
Estimated CV	**Units:**	**Steam pressure:**	**Flow:**

Time _____

Throughput _____

Material in _____

Temperature (°F/C) _____

Moisture content (%) _____

Material out _____

Temperature (°F/C) _____

Moisture content (%) _____

Fresh air dry bulb/wet bulb temperature (°F/C) _____

Fresh air humidity (%) _____

Dryer operating temperature (°F/C) _____

Steam/fuel input _____

Condensate output _____

Condensate temperature (°F/C) _____

Cylinder surface temperature (°F/C) _____

Cylinder surface area _____

Dryer surface temperature (°F/C) _____

Dryer surface area _____

Exhaust air dry bulb/wet bulb temperature (°F/C) _____

Exhaust air humidity (%) _____

Exhaust air flow rate _____

For a circular duct, the cross-section is divided into six or eight concentric rings of equal area (see Exhibit 5.45). Take measurements at specified locations across two diameters at right angles to each other. For a rectangular duct, divide the duct into 16 to 64 equal rectangular areas, depending on the duct size, and take measurements at the center of each rectangle (see Exhibit 5.46). For either type of duct, the auditor can find the bulk velocity by using the average of individual velocity readings. The volumetric flow rate is the product of average flow rate and duct cross-sectional area.

Combustion air temperature is measured using a **mercury-in-glass thermometer or a thermocouple**. Measure temperature at the combustion air chamber inlet. **Combustion air humidity** is measured by use of a **hygrometer or a psychrometer**. Take these measurements at the combustion air inlet.

Exhaust air volume, temperature, and humidity are measured at the dryer exhaust stack, using the same techniques as those used to measure combustion air.

The **temperature of the material to be dried** is measured either with a **thermocouple** with contact probe or an **optical pyrometer**. If the energy auditor uses a pyrometer, he must know the material's emissivity. He can determine emissivity by calibrating the pyrometer with thermocouple measurements.

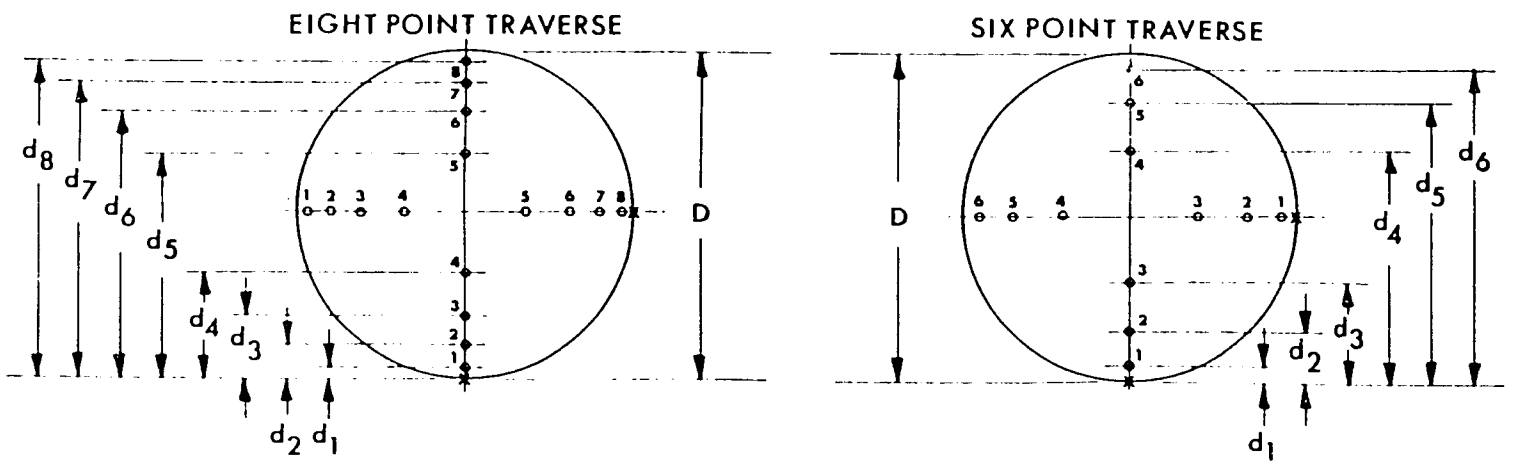
The **moisture content of the material** being dried, which must be determined before and after drying, can be measured in two ways. One way is to use a **contact hygrometer**, which gives a direct reading of the material moisture content. The second way is to take several samples of material before and after drying and determine the moisture content by drying them completely in a laboratory oven.

Dryer draft can be measured by inserting the probe of a **manometer or a draft gauge** into the combustion chamber or exhaust flue. The draft is measured in millimeters of water.

The **temperatures of external surfaces** are measured by using a **contact thermocouple probe or an optical pyrometer**. To use the optical pyrometer, the auditor must know the emissivity of the dryer surfaces. Pyrometer manufacturers offer a paint that can be used to mark the areas of the dryer to be measured. This paint dries to a dull

EXHIBIT 5.45

EQUAL AREA TRAVERSE FOR CIRCULAR DUCTS

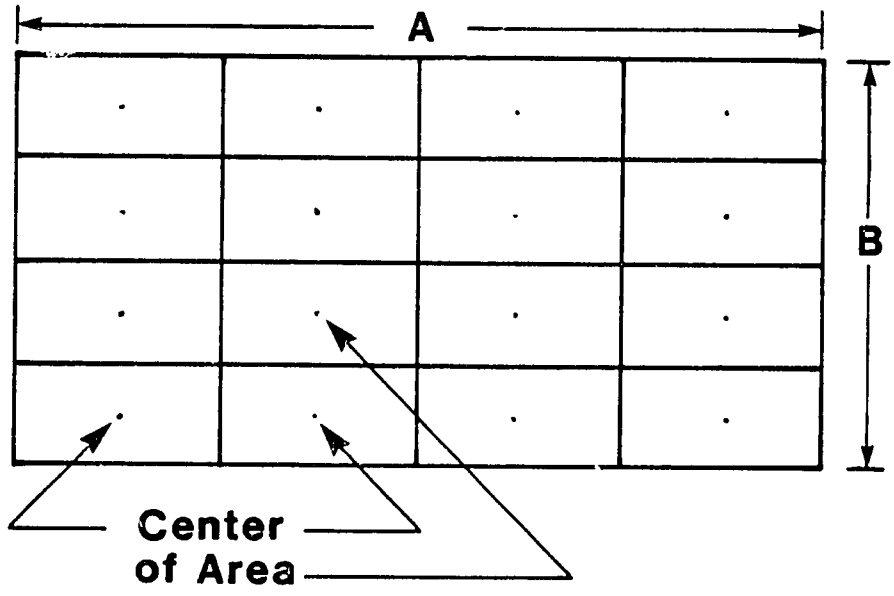


Traverse Method	Probe immersion in Duct Diameters									
	d_1	d_2	d_3	d_4	d_5	d_6	d_7	d_8	d_9	d_{10}
6 point	0.043	0.147	0.296	0.704	0.853	0.957	–	–	–	–
8 point	0.032	0.105	0.194	0.323	0.677	0.806	0.895	0.968	–	–

EXHIBIT 5.46

EQUAL AREA TRAVERSE FOR RECTANGULAR DUCTS

Use 16 to 64 Equal Area Rectangles



Made Measurement at Center of Rectangle

black finish of known emissivity, and is particularly useful for temperature measurement of moving parts.

If the dryer is largely open, outside air infiltration may be a problem. **Air infiltration** can be determined **by the difference** between the measured combustion air and the measured exhaust air, or it can be **measured directly** using a **velometer or anemometer.** The auditor should try to take these measurements at the feed and products ends, which may be open, particularly if he is measuring continuous dryers.

The auditor should take all of the above measurements to develop an energy balance for the dryer. A simple energy balance is illustrated in Exhibit 5.47.

The auditor can use the energy balance to determine the operating efficiency of the dryer. In general, dryers that operate up to about 175°C have operating efficiencies of 35 percent to 45 percent. With good operating practice and maintenance, these dryers can operate at 50 percent to 65 percent efficiency.

5.3.2.2 Identifying Opportunities for Improving Efficiency

The auditor can use the energy balance and the dryer measurements to identify opportunities for improving efficiency. These opportunities include improving insulation and recirculating exhaust air, which are discussed in the following paragraphs.

5.3.2.2a Improving Insulation

The auditor should inspect dryer insulation to determine whether it is adequate. He can determine the extent of loss through dryer walls by comparing the outside wall temperature with the internal temperature. Depending on the conditions within the dryer, a surface temperature of 50°C to 70°C and an inside temperature of 175°C indicate that the losses are reasonable. An estimate of energy loss per unit area is shown in Exhibit 5.48.

EXHIBIT 5.47

ENERGY BALANCE FOR DRYER

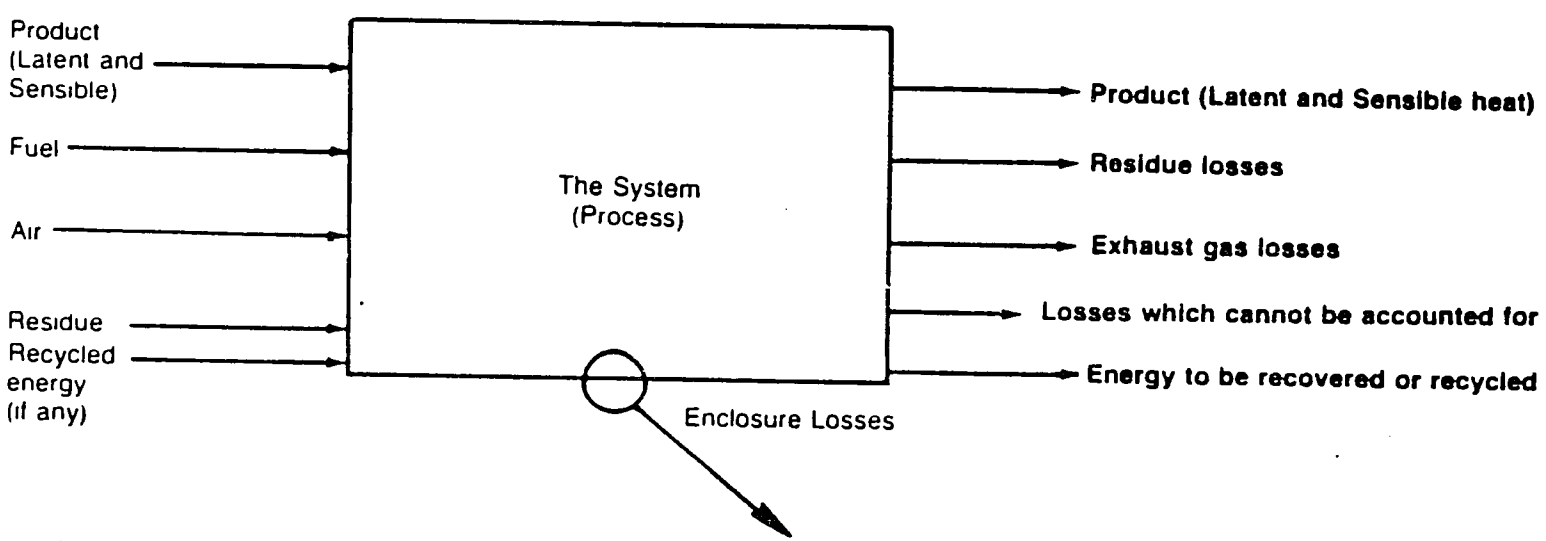
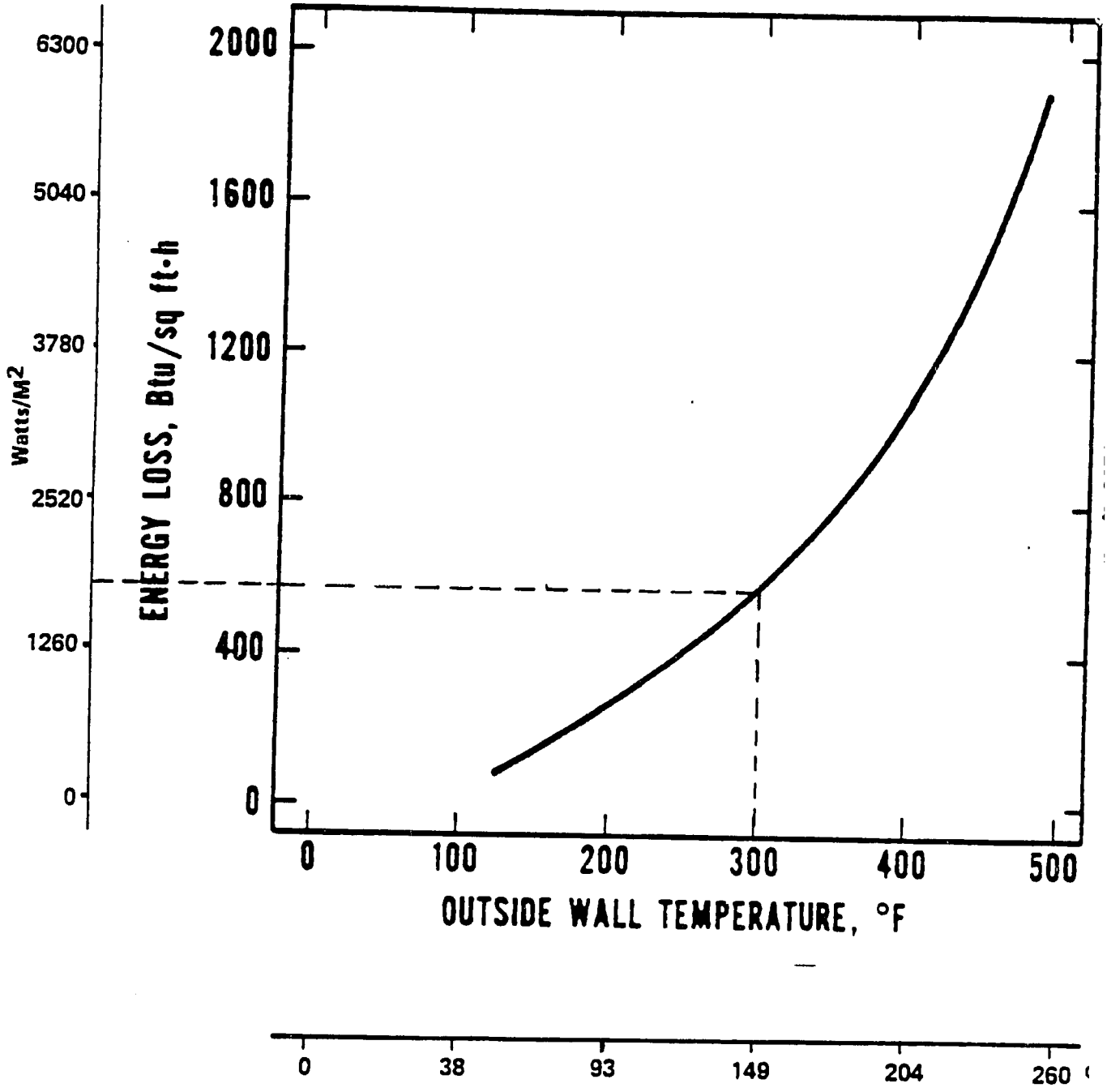


EXHIBIT 5.48

ENERGY LOSS FROM DRYER WALLS VERSUS OUTSIDE WALL TEMPERATURE



The auditor can use the following procedure to estimate the savings that will result from improving insulation:

- Determine temperature of dryer's outside surface
- Determine area that is uninsulated or has poor insulation
- Determine energy loss per unit area from table (example: outside wall temperature = 150°C, energy loss = 1,770 watts/m^2 = 6,373 kJ/m^2/hour)
- Calculate hourly energy loss as the product of energy loss per unit area and surface of badly insulated area (example: for a 100-square-meter surface, the heat loss is 6,373 x 100 = 637,300 kJ/hour)
- Calculate annual heat loss as the product of hourly heat loss and hours of operation (example: for 8,400 hours/year, the heat loss is 637,300 x 10^{-6} x 8,400 = 5,353 GJ/year)
- Assuming that insulation will reduce heat loss by 90 percent, calculate the annual reduction in heat loss (example: heat loss reduction = 5,353 x 0.9 = 4,818 GJ/year)
- If the dryer is steam heated and boiler efficiency is 80 percent, calculate fuel savings (example: fuel savings = 4,818/0.80 = 6,023 GJ/year)
- Calculate fuel savings (example: with fuel oil at 42,372 kJ/liter, fuel savings = 6,023 x 10^6/42,372 = 142,146 liters/year).

5.3.2.2f Recirculating Exhaust Air

The benefits of recirculating exhaust air are best explained by an example. In a paper dryer, which is illustrated in Exhibit 5.49, paper is doped continuously and then dried by air that is blown through a steam heater. Some of the exhaust air is recirculated to mix with the fresh air at the heater inlet.

A mass and energy balance of the dryer "as found" conditions is provided below:

Paper

Initial moisture content (from take-off reel) = 6 percent dry weight
Moisture content after dope bath = 23.6 percent dry weight

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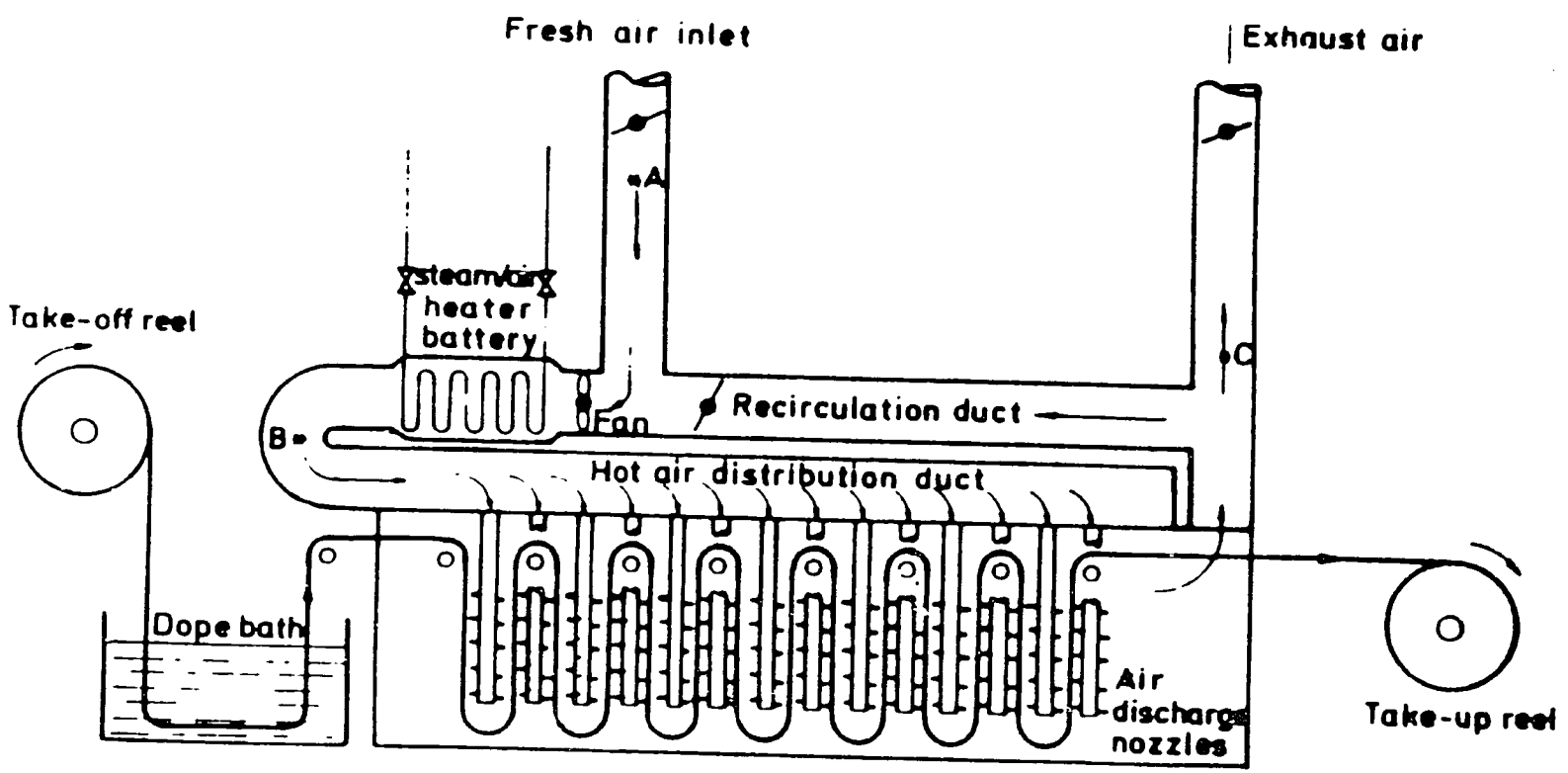
EXHIBIT 5.49

EXAMPLE PAPER DRYER



• Air measurement points

Moisture content after dryer	= 2.2 percent dry weight
Throughput rate, dry doped paper	= 360 kg/hour.

The dryer has three air streams. The first is the fresh air at the dryer inlet; the second is the dryer exhaust air; the third is the recirculating air stream, consisting of the fresh air and some of the exhaust air. A mass and energy balance of the three streams is calculated below:

Fresh air at dryer inlet

The psychrometric properties of the fresh air are obtained from the chart in Exhibit 5.50. The fresh air stream is indicated on the chart as Point "A."

Temperature -- dry bulb	= 20°C
Temperature -- wet bulb	= 16°C.

Moisture content	= 0.0097 kg/kg dry air
Enthalpy	= 44.8 kJ/kg dry air
Specific volume	= 0.843 M^3/kg dry air.

The same information is obtained and determined for the dryer exhaust air. This air stream is indicated as Point "C" on the psychrometric chart.

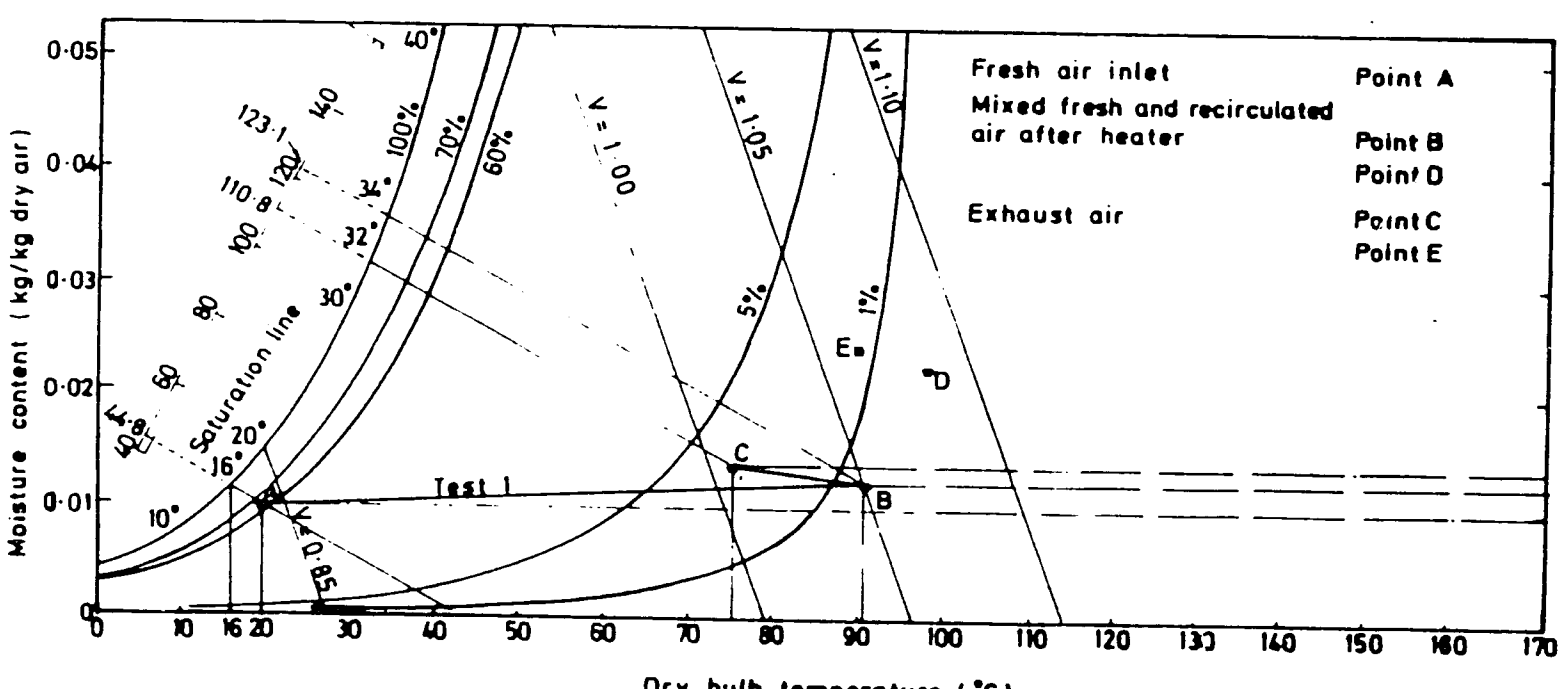
Dryer exhaust air

Temperature -- dry bulb	= 75°C
Temperature -- wet bulb	= 32°C
Moisture content	= 0.0136 kg/kg dry air
Enthalpy	= 110.8 kJ/kg dry air
Specific volume	= 1.008 $meter^3$/kg dry air.

The final air stream is the combined recirculated and fresh air stream, indicated by Point "B" on the psychrometric chart.

EXHIBIT 5.50

PSYCHROMETRIC CHART FOR DRYER EXAMPLE



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Mixed air

Temperature -- dry bulb	=	91°C
Temperature -- wet bulb	=	34°C
Moisture content	=	0.0120 kg/kg dry air
Enthalpy	=	123.1 kJ/kg dry air
Specific volume	=	1.050 meter^3/kg dry air
Measured air flow rate	=	49,300 m^3/hr (13.69 m^3/sec)
Mass flow rate = 13.69/1.050	=	13.04 kg dry air/sec.

Using the moisture balance information developed above, the auditor can determine the percent makeup and recirculated air in the mixed air stream. Each kilogram of air at the heater inlet consists of X kg of exhaust air plus (1 - X) kg of fresh air. From the moisture balance:

	X	(0.0136)	exhaust air
+	(1 - X)	(0.0097)	fresh air
=	1	(0.012)	mixed air.

Solving for X, the recirculated exhaust air is 59 percent of the mixed air stream, and the fresh air is 41 percent. The mass flow rate of fresh air is 5.347 kg per second.

The steam balance yields the following:

Steam

Flow rate (measured)	=	863.6 kg/hr at 1.86 bar gauge
Enthalpy	=	2,661.7 kJ/kg
Heat input to air	=	1,817,158 kJ/hr (504.8 kJ/sec)
Dryer surface heat loss	=	523,375 kJ/hr (145.4 kJ/sec).

The specific steam consumption is calculated as the steam used per kilogram of moisture evaporated. The moisture evaporated is the difference in paper moisture content before and after drying or (0.236 - 0.022) (360 kg/hour) = 77.04 kg/hour.

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The steam consumption, from above, is 863.6 kg/hour. Therefore, specific steam consumption is 863.6/77.04 = 11.21 kg steam/kg water evaporated.

The heat loss in the exhaust air is the heat used to raise the fresh air to the exhaust temperature.

Enthalpy of exhaust air at inlet moisture content = 101.4 kJ/kg dry air from the psychrometric chart.

Enthalpy of inlet air = 44.8 kJ/kg dry air.

Heat loss in exhaust air = 101.4 - 44.8 = 56.6 kJ/kg dry air.

Mass flow rate of makeup air = 5.347 kg dry air/second.

Heat loss = (56.6) (5.347) = 302.6 kJ/second.

The heat required to evaporate moisture equals the heat content of the quantity of water evaporated from the paper, superheated at exhaust partial pressure and temperature, minus the sensible heat content at the dryer inlet.

The moisture evaporated is 77.04/3,600 = 0.0214 kg/second.

From the psychrometric chart, the specific volume of dry air at the dryer exhaust temperature is 0.9884 m^3/kg; from the steam tables, the specific volume of steam at exhaust temperature is 4.144 m^3/kg. The moisture content of the exhaust air was previously found to be 0.0136 kg/kg dry air. Hence, the volume of moisture is (4.144) (0.0136) = 0.0564 m^3/kg.

The partial pressure of the water vapor is (1,013.25) (0.0564)/(0.9884) = 57.78 millibar.

From the steam tables (see Exhibit A.6), the total heat of vapor at the partial pressure and exhaust temperature is 2,644 kJ/kg. The sensible heat at the fresh air inlet temperature is 84 kJ/kg.

Hence, the heat added to the moisture in the dryer is 2,644 - 84 = 2,560 kJ/kg; the heat added to evaporate moisture is (0.0214) (2,560) = 54.8 kJ/second.

The heat balance of the dryer can be expressed as follows:

Heat input	kJ/sec	percent
(1) Heat to circulating air from steam	504.8	100.0
Heat output		
(1) Heat used to evaporate moisture	54.8	10.9
(2) Heat lost by exhaust air	302.6	59.9
(3) Heat lost in heat content of paper	2.7	0.5
(4) Other losses (by subtraction)	144.7	28.7
	504.8	100.0

Thermal efficiency = 54.8/504/8 = 10.9 percent.

The thermal efficiency of the dryer can be improved by increasing the percentage of recirculated exhaust air in the mixed air from 59 percent to 90 percent.

The mass and energy balances for the dryer after modification can be determined using the same methodology and calculation procedures as those used above:

Paper

Initial moisture content	= 6 percent
Moisture content after dope bath	= 23.8 percent dry weight
Moisture content after dryer	= 5.8 percent dry weight
Throughput rate, dry doped paper	= 360 kg/hour.

Fresh air at dryer inlet (Point "A")

Calculate in same way as for dryer "as found" condition.

Dryer exhaust air (Point "E")

Temperature -- dry bulb	= 90°C
Temperature -- wet bulb	= 38.5°C
Moisture content	= 0.0240 kg/kg dry air
Enthalpy	= 153.3 kJ/kg dry air
Specific volume	= 1.065 m^3 kg dry air.

Mixed air (Point "D")

Temperature -- dry bulb	= 98°C
Temperature -- wet bulb	= 38.2°C
Moisture content	= 0.0226 kg/kg dry air
Enthalpy	= 157.4 kJ/kg dry air
Specific volume	= 1.085 m^3/kg dry air
Measured air flow rate	= 49,300 m^3/hr (13.69 m^3/sec)
Mass flow rate	= 13.69/1.085 = 12.62 kg dry air/sec.

The percentage of fresh air and percentage of recirculated exhaust air in the mixed air stream are fixed at 17 percent and 90 percent, respectively. Hence, the mass flow rate of makeup air is (0.1) (12.62) = 1.262 kg dry air/sec.

The steam balance yields the following:

Steam

Flow rate (measured)	= 321.7 kg/hr at 1.86 millibar gauge
Enthalpy	= 2,661.7 kJ/kg
Heat input to air	= 677,448 kJ/hr (188.2 kJ/sec)
Dryer surface heat loss	= 166,852 kJ/hr (46.3 kJ/sec).

Moisture evaporation is thus (0.230 - 0.050) (360) = 64.80 kg/hr, and specific steam consumption is 321.7/64.8 = 4.96 kg steam/kg water evaporated.

The heat loss is calculated from the enthalpy of the exhaust air at inlet water content (117.5 kJ/kg dry air), and the enthalpy of the inlet air (44.8 kJ/kg dry air). The difference, 72.7 kJ/kg dry air, is multiplied by the mass flow rate of makeup air (1.262 kg/sec) to yield the heat loss of 91.7 kJ/sec.

The heat required to evaporate moisture is calculated from the moisture evaporation rate (64.8 kg/hr/3,600 = 0.0180 kg/sec); the specific volume of steam at the exhaust temperature (2.363 m^3/kg); the specific volume of dry air at the dryer exhaust temperature (1.031 m^3); and the moisture content of the dryer exhaust air (0.0240 kg/kg dry air). The volume of moisture in the exhaust air is (2.363) (0.0240) = 0.0567 m^3. The partial pressure of water vapor is (1,013.5) (0.0567)/(1.031) = 55.72 millibar.

The total heat of the vapor at this partial pressure and exhaust air temperature is 2,670.9 kJ/kg (from the steam tables); the sensible heat at the fresh air temperature is 84.2 kJ/kg. Hence, the heat added in the dryer is 2,670.9 - 84.2 = 2,586.7 kJ/kg. The heat rate to evaporate moisture is (0.0180) (2,586.7) = 46.6 kJ/sec.

The heat balance then becomes:

Heat input	kJ/sec	percent
(1) Heat to circulating air from steam	188.2	100.0
Heat output		
(1) Heat used to evaporate moisture	46.6	24.8
(2) Heat lost by exhaust air	91.7	48.7
(3) Heat lost in heat content of paper	3.8	2.0
(4) Other losses (by subtraction)	46.1	24.5
	188.2	100.0

Thermal efficiency = 46.6/188.2 = 24.8 percent.

The thermal efficiency of the dryer has increased from 10.9 percent to 24.8 percent. At the same time, steam consumption has dropped from 863.6 kg/hr to 321.7 kg/hr.

With 1.86 bar gauge steam produced from condensate at 80°C, the heat added by boiler fuel is 2,386.6 kJ/kg. With a boiler operating at 80 percent efficiency, fuel consumption is 2,983.2 kJ per kg of steam raised.

For a boiler operating 8,400 hours per year, the energy savings achieved by recirculating exhaust gas are $((2{,}983.2)\ (863.6 - 321.7)\ (8{,}400))/10^6 = 13{,}579$ GJ.

With fuel oil with a calorific value of 42,372 kJ/liter, the annual savings are $13{,}579 \times 10^6/42{,}372 = 320{,}471$ liters of fuel oil.

5.3.2.3 Summary

The essence of a successful detailed energy audit of a dryer is the determination of the energy balance. The auditor should not consider a conservation measure for a dryer without preparing an energy balance. He needs the energy balance to estimate the measure's impact and thus determine the potential benefits.

5.4 DETAILED ENERGY AUDIT OF FURNACES

Furnaces are among the most intensive consumers of energy. Because they operate at high temperatures, they are also some of the most inefficient users of energy. At the same time, they offer good scope for energy conservation. High temperatures usually mean that special materials are needed to contain the heat. Similarly, heat recovery devices must be constructed from materials that are capable of withstanding the heat and consequently are expensive.

The term furnace is used generically to describe energy systems that are used to heat materials to temperatures that will change either the physical or chemical properties of the material. The steps taken in testing, evaluating, and identifying conservation opportunities for a furnace during a PEA and detailed energy audit are given in Exhibit 5.51. These steps are described in the following paragraphs.

5.4.1 PRELIMINARY ENERGY AUDIT

The first step in evaluating a furnace is to conduct a PEA, if one has not already been completed.

As a starting point for the PEA, the energy auditor should collect nameplate data. A form for **nameplate data collection** during the PEA is presented in Exhibit 5.52. Information is needed on the furnace, its burners, combustion air systems, and operating characteristics.

The energy auditor can collect the information from interviews and confirm it during the visual inspection, or he can determine it in the visual inspection alone.

The **visual inspection** allows the energy auditor to see for himself the condition of the plant and its auxiliary equipment and confirm the interview information. In addition to the furnace, the auditor should check several auxiliary systems:

- Burners
- Air supply system

Exhibit 5.51

PEA and Energy Audit Procedures for Furnaces

Step 1. Preliminary energy audit

- Interview personnel
- Obtain nameplate information
- Obtain operational details, including fuel use, furnace atmosphere, and operating hours
- Conduct visual inspection of condition of furnace and auxiliaries; determine condition and readings of instrumentation
- Examine furnace log
- Identify test points
- Determine type of test and instrumentation required
- Identify conservation opportunities from improved operation
- Develop action plan for energy audit

Step 2. Energy audit

- Prepare for audit
  - repair/install instrumentation as necessary
  - identify testing positions
  - select appropriate test day
- Perform test
  - testing procedures and techniques
  - data collection
- Evaluate data
  - calculate efficiency
  - determine improvements

Step 3. Identify conservation opportunities

- tune-up
- improved control
- heat recovery
- alternative fuels

Exhibit 5.52

Furnace Details

Location: _____

Furnace

	1	2	3
Manufacturer:			
Age (years):			
Type:			
Throughput rating (kg/hr):			
Normal operating pressure (pos/neg):			
Normal operating temperature (^{o}C):			

Burner(s)

Number:			
Fuel(s) fired:			
Manufacturer:			
Age (years):			
Type:			
Draft:			
Atomization:			
Burner controls:			
Draft control (dampers):			

- Fuel supply system
- Furnace atmosphere control system
- Instrumentation systems.

A checklist to use during the visual inspection is provided in Exhibit 5.53.

Furtner information is available from checking the furnace operations log.

Information to be collected from the log is identified in Exhibit 5.54.

The energy auditor will determine whether to test the furnace as part of the detailed energy audit based on:

- Date of last efficiency check
- Installed instrumentation
- Operational conditions.

The criteria for testing are given in Exhibit 5.55.

If testing is necessary, the energy auditor should identify test points and decide what type of test to perform and the instrumentation needed. Typical measuring positions are shown in Exhibit 5.56.

The types of tests include:

- Full commissioning test
- Efficiency test to standards as laid down by bodies such as ASME and British Standards
- Efficiency test by loss method
- Combustion test only.

The most common test is the efficiency test by the loss method. The other methods are used less frequently and are variations of the loss method. Although they can be more accurate, the extra cost and time required to carry out the other tests are often not justified.

Exhibit 5.53

Furnace Evaluation Checklist 1

Item	Equipment	Comments
Physical appearance	Furnace	
	Burners	
	Fuel system	
	Atmosphere control system	
External structure	Furnace walls	
	Doors	
Safety equipment & instrumentation	Furnace	
	Burner	
	Fuel system	
	Fuel system	
	Atmosphere control system	
Valves, fittings & insulation	Burners	
	Fuel system	
	Distribution	
Product quality		

Exhibit 5.54

Furnace Evaluation Checklist 2:
Furnace Operations Log

Operating conditions monitored	Yes	No	Comments
Flue gas analysis % CO_2			
% O_2			
% CO			
F.G. temp.			
Draft			
Smoke			
Cycle time			
Flow metering, fuel			Units
Air flow			
Temperature			
Fuel			
Combustion air			
Operating temperature			
Furnace pressure			
Material throughput			
Material physical properties in			
Material physical properties out			
Scrap level			

Exhibit 5.55

Criteria for Testing

1. Excessive smoke from stack

2. Three months since last efficiency check

3. High flue gas temperature reading from furnace log or indicator in stack

4. No change in operating condition with change of burner firing rate

5. Physical appearance poor, with badly sealed doors and flames escaping from furnace, poor insulation and refractories

6. Little or no fitted instrumentation in working order

7. Manually adjusted burners

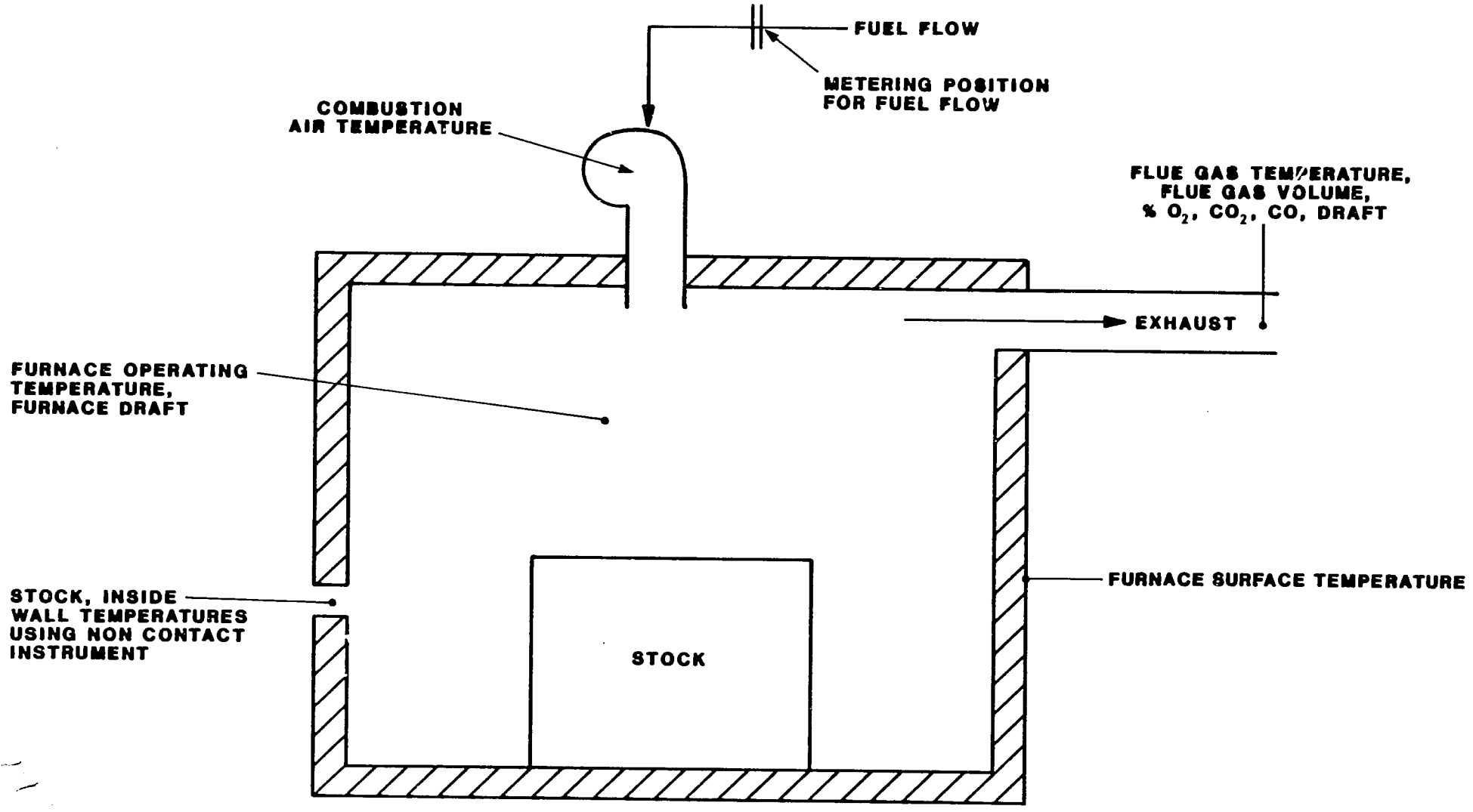
8. Large fluctuations in furnace draft readings (plus or minus 25 mm water gauge)

9. Installed flue gas analyzer indicating very high percentage of carbon dioxide, very low percentage of oxygen (less than 2 percent), or carbon monoxide in excess of 20 ppm

10. Product quality problems.

Exhibit 5.56

MEASURING POSITIONS FOR FURNACE TESTING



Instrumentation needed for efficiency testing by the loss method is listed in Exhibit 5.57.

At the conclusion of the PEA, the energy auditor will complete his evaluation and prepare an action plan; the plan normally includes a recommendation for a detailed energy audit unless the PEA indicates that the furnace is operating at optimum efficiency.

The energy auditor may have identified conservation opportunities, including:

- Reducing losses from openings and leaks
- Reducing losses during recycling and idle equipment shutdown.

These measures are discussed below, and techniques are given for estimating savings.

5.4.1.1 Estimating Losses from Openings and Leaks

Heat losses through openings can be estimated from the size of the opening. The amount of heat loss is linearly proportional to the area of the opening, and is approximately proportional to the fourth power of the absolute temperature. Heat loss as a function of furnace temperature is shown in Exhibit 5.58. Chain curtains can be used to reduce the loss by 80 percent; the auditor can estimate the savings using the following steps:

i) Estimate or measure area of opening
ii) Determine heat loss per unit area for furnace operating temperature from Exhibit 5.58
iii) Annual heat loss = (heat loss/unit area) (area of opening) (hours) = watts/year.

Losses resulting from cold air leakage into the furnace are serious. The "chimney effect" of a furnace and flue can cause a slight negative pressure at the bottom of the furnace combustion chamber. The pressure is lowest at the furnace floor and rises to the local barometric pressure where the flue exhausts to the atmosphere. The difference in pressure is related to the furnace temperature, the height of the stack above the furnace floor, and the size of the opening through which the cold air is infiltrating. Heat losses per square meter of opening are shown in Exhibit 5.59.

Exhibit 5.57

Furnace Efficiency Test Kit

Instrument/measure	Type	Readings
Flue gas analyzer	Chemical absorption Electrochemical	Percent CO_2, O_2 Percent hydrocarbons or CO
Temperature indicator	Thermocouple	Flue gas temperature; combustion air temperature; furnace atmosphere temperature
	Surface probe	External wall temperature
Mass gas flow	Pitot tube, anemometer	Flue gas volume
Smoke gun		Stack soot conditions
Draft gauge	Manometer	Amount of draft; furnace pressure
Pyrometer	Infrared	Material temperature; internal and external wall pressure
Flow meter	Positive displacement or rotameter, orifice	Fuel input
Ammeter	Clip-on	Electric current, voltage
Power factor meter	Clip-on	Power factor

EXHIBIT 5.58

ENERGY LOSS BY RADIATION THROUGH OPENINGS

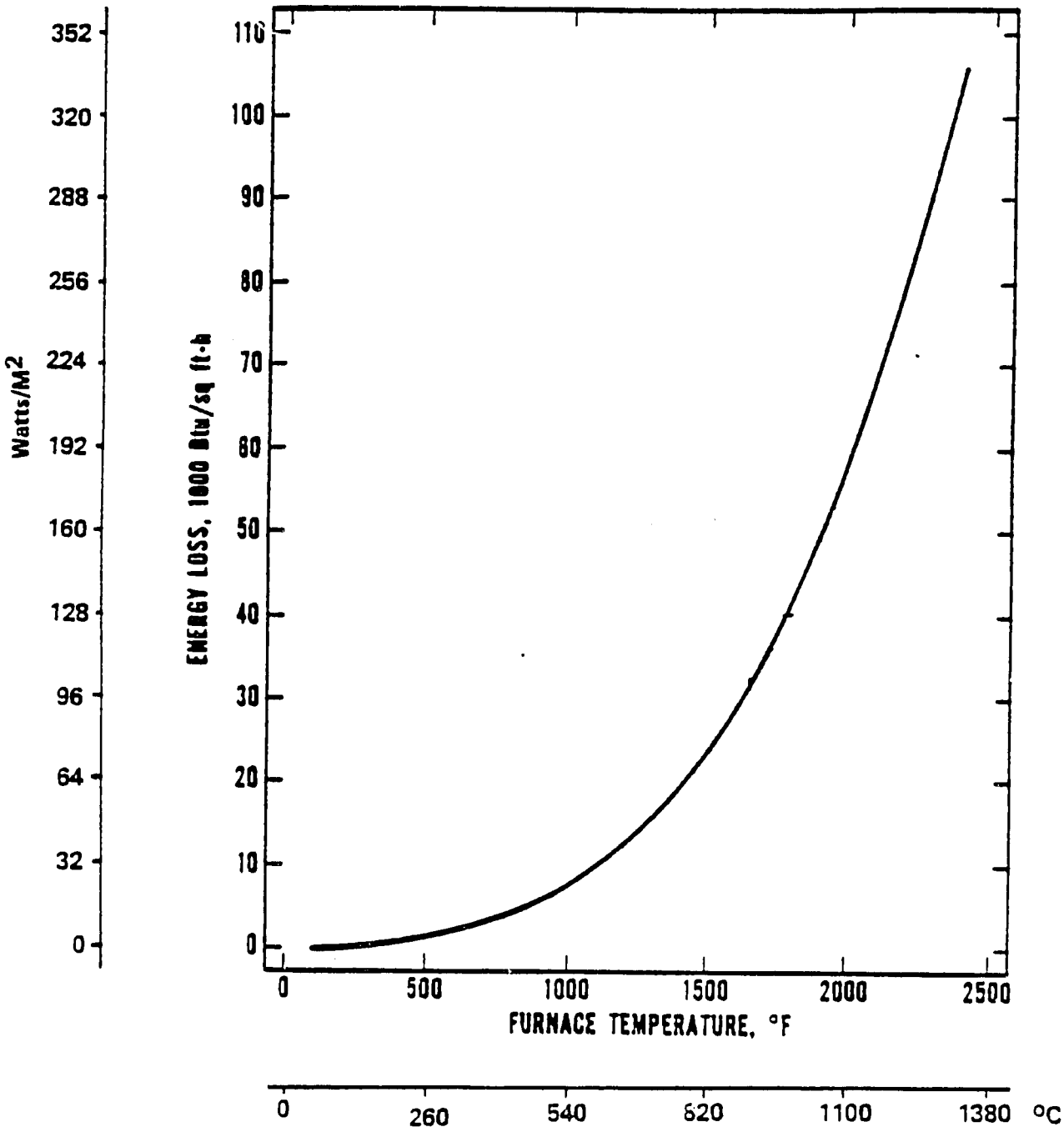


Exhibit 5.59

Heat Loss Owing to Chimney Effect

Furnace temperature (°C)	Heat loss in kJ/hr per square meter of opening for furnace floor to flue exhaust height of:					
	1.8 m	2.4 m	3.0 m	3.6 m	4.8 m	6.0 m
425	4,417	4,899	5,883	6,385	7,474	8,458
650	6,741	8,458	9,211	9,944	12,017	13,503
875	10,049	12,519	13,733	15,576	18,653	21,458
1,100	12,896	16,183	18,004	20,244	22,694	26,127
1,350	16,560	19,888	22,191	25,143	28,472	31,779

For intermediate height or temperature of operation, interpolate the results above.

The cold air may be infiltrating because of poorly adjusted dampers or door seals in need of repair. Ninety percent of the heat loss can be prevented through modification when the seals are very poor. If the seals are good, 50 percent of the loss can be prevented.

The auditor can estimate the savings using the following steps:

i) Calculate area of opening
ii) Estimate or measure flue exhaust height above furnace floor
iii) For furnace operating temperature and flue height, obtain heat loss from Exhibit 5.59
iv) Heat loss per year is calculated = (area of opening) (heat loss/unit area) (operating hours/year) = watts/year
v) Savings = (percent saved) (yearly heat loss).

5.4.1.2 Estimating Losses During Recycling and Idle Equipment Shutdown

The auditor may be able to identify opportunities for reducing losses during recycling and idle equipment shutdown by reviewing operating practices. In the absence of specific data, it is very difficult to quantify savings associated with these measures. The auditor needs such information as:

- Time needed to cool furnace to room temperature and several intermediate temperatures with burners off
- Rate of fuel use when idling furnace at operating and intermediate temperatures
- Reheat times from room temperature and intermediate temperatures
- Fuel needed to reheat from intermediate temperatures
- Maximum rate of temperature change that will not result in equipment damage.

With this information, decisions on equipment operation can be made and significant energy savings can be achieved. As an example of the potential savings, Exhibit 5.60 shows data for an oil-fired slab heat treating furnace operating at 1,230°C.

Exhibit 5.60

Operational Data for Oil-Fired Slab Heat Treating Furnace

Temperature (°C)	Cooling time (hours)	Reheat time (hours)	Total time (hours)	Idling power (GJ/hr)	Reheat energy (GJ)
1,230	0.0	0.0	0.0	10,970	0
1,120	1.3	1.1	2.4	10,024	24,268
1,010	2.8	1.8	4.6	8,969	47,481
900	4.4	2.5	6.91	7,913	68,583
785	6.3	3.0	9.3	6,963	88,630
675	8.3	3.5	11.8	6,013	106,568
565	11.0	4.0	15.0	4,957	122,394
455	14.0	4.5	18.5	4,011	137,166
345	18.0	5.0	23.0	2,956	152,993
230	23.0	5.5	28.5	2,006	167,765
120	32.0	6.0	38.0	950	183,592
10	60.0	6.5	66.5	0	198,363

The following example shows how these data can be used. The furnace is not required for 24 hours. According to Exhibit 5.60, the furnace can cool to 345°C and be reheated to 1,230°C.

The furnace can be shut off for 18 hours, reheated from 345°C to 1,230°C in 5 hours, and held at 1,230°C for 1 hour. The energy used in that time is:

= (shutdown energy) + (reheat) + (idle)
= (18 x 0) + (152,993) + (10,970)
= 163,963 GJ.

If the furnace had idled for 24 hours, the energy use would have been:

= (24 x 10,970)
= 163,963 GJ.

Energy savings = (263,280 - 163,963) = 99,317 GJ.

5.4.2 DETAILED ENERGY AUDIT

Before the furnace is tested, the auditor must complete some preparatory work, including:

- Recalibrating all instrumentation to be used
- Ensuring that all test positions are accessible
- Selecting an appropriate day for testing.

When the preparatory work is completed, testing can begin. The energy auditor uses a test procedure in which some of the losses are determined. He then calculates an energy balance for the furnace and estimates losses not measured by the difference.

5.4.2.1 Testing Furnace Efficiency

To test a furnace's efficiency, the auditor must measure various parameters:

- Fuel usage rate
- Temperature of operation
- Flue gas composition
- Gas flow.

Testing should be done over a period of not less than 4 hours for a cycle time of 8 hours or more. Readings should be taken at least every half hour.

The methods of measuring these parameters and the instruments used are discussed in the following paragraphs.

5.4.2.1a Fuel Usage Rate

Fossil fuel use in a furnace can be measured using:

- Positive displacement totalizing meter
- Orifice plate differential pressure cell and flow indicator
- Rotameter.

Alternatively, when fuel is discharged through a nozzle (such as a pressure jet burner), the flow rate can be estimated it the pressure in the fuel line and the nozzle size are known. The rate of discharge through standard nozzles is shown in Exhibit 5.61.

The **most accurate measure** is obtained using the **positive displacement meter.** The meter should be read hourly during the test period. The meter can be used for several furnaces if the appropriate pipework fittings are installed in the fuel line of each furnace.

Flow rate indicators such as **orifice plates and rotameters** are less expensive than totalizing meters, but are sufficiently accurate where flow conditions are reasonably steady over prolonged periods.

Exhibit 5.61

FLOW RATE FOR NOZZLE SIZES

Pipe Size (mm)	Orifice Diameter (mm)	Liters Per Minute at Pressure (bar)									
		0.69	1.38	2.07	2.76	3.45	4.14	5.52	6.90	13.79	27.59
6.35	2.38	2.65	3.79	4.54	5.30	5.87	6.43	7.57	8.33	11.73	16.65
	3.18	4.92	7.00	8.71	9.84	10.98	12.11	14.38	15.52	22.71	31.04
	3.97	7.57	10.98	13.25	15.14	17.03	18.93	22.33	24.60	38.42	49.21
9.53	4.76	11.36	15.90	19.68	22.71	25.36	28.01	32.17	35.96	50.72	71.92
	5.56	15.14	21.57	26.00	30.66	34.07	37.85	43.15	47.31	68.13	94.63
	6.35	20.06	28.39	34.82	40.12	44.66	49.21	56.78	63.21	90.48	124.91
	7.94	31.04	44.28	54.13	62.45	69.64	75.70	88.19	98.79	136.26	196.82
12.70	9.53	45.42	64.35	78.73	91.22	104.44	111.28	128.69	143.83	204.39	287.66
	11.11	62.07	87.06	105.98	124.91	140.05	151.40	174.11	196.82	280.09	393.64
19.05	12.70	80.24	113.55	140.05	158.97	177.90	196.82	227.10	253.60	355.79	507.19
25.40	15.88	128.69	181.68	215.75	253.60	280.09	306.59	355.79	397.43	560.18	194.85
	19.05	177.90	253.60	314.16	359.58	405.00	442.85	510.98	571.54	809.99	143.07
38.10	22.23	242.24	352.01	423.92	488.27	548.83	601.02	696.44	775.93	1097.65	1551.85
	25.40	317.94	454.20	556.40	639.67	719.15	787.28	908.40	1014.38	1438.30	2028.76
	28.58	363.36	518.55	624.53	726.72	806.21	889.48	1021.95	1143.07	1612.41	2286.14
50.80	34.93	529.90	749.43	908.40	1059.80	1173.35	1286.90	1495.08	1657.38	2346.70	3015.66
	38.10	673.73	946.25	1173.35	1343.68	1495.08	1627.55	1911.43	2119.60	2990.15	4239.20
76.20	44.45	968.96	1370.17	1695.68	1953.06	2195.30	2407.26	2785.76	3065.85	4390.60	6510.20
	50.80	1271.76	1816.80	2225.58	2558.66	2876.60	3149.12	3633.60	4057.52	5753.20	8099.90
101.60	63.50	1987.13	2838.75	3482.20	4004.53	4496.58	4920.50	5677.50	6339.88	8970.45	12679.75

It is important to size the metering device in relation to the flow rate of the fuel. Low flow rates require meters that indicate small amounts of flow, whereas relatively large flow rates do not need such accuracy. The minimum indicator should be approximately 1 percent of actual hourly flow rate.

Instantaneous electrical energy use in furnace operations can be measured using either a clamp-on wattmeter or an ammeter. For purely resistance heating furnaces, the ammeter reading multiplied by the applied voltage will give the power consumption in a single-phase circuit. For those heating elements that are wired in three-phase circuits, the power is calculated as (volts) (amps) (1.73).

If the circuit contains inductances, then the ammeter reading alone is not sufficient. In addition, the power factor must be measured using a power factor meter. Power consumption is given as (volts) (amps) (power factor) (1.73).

If the temperature control system is a throttling system, such as a variable inductance transformer or silicon-controlled rectifier, then a kilowatt-hour meter like that used by utility companies is necessary.

5.4.2.1b Temperature

Temperature measurement is required for a number of items in furnace operation, including:

- Material/stock temperature
- Flue gas temperature
- Ambient/combustion air temperature
- Internal/external furnace wall temperatures.

To complete the measurements, two types of instrument -- a non-contact and a contact -- are required. The most commonly used instruments are the pyrometer (non-contact) and the thermocouple (contact).

The **type of thermocouple** chosen depends on the furnace atmosphere (reducing or oxidizing) and the operating temperature. Details of thermocouple applications are given in Exhibit 5.62.

The **pyrometer** is normally used to **measure the stock and wall temperatures.** If there is no way of viewing the inside of the furnace, then the temperature of the furnace atmosphere can be measured with a thermocouple instead of a pyrometer. Because furnaces often have similar wall constructions, tables and charts have been developed relating heat losses and surface temperatures. An example of such a chart is given in Exhibit 5.63.

The pyrometer measures temperature based on the radiation of bodies, with the radiation a function of temperature. Because of differing properties, not all materials radiate the same amount of energy at equal temperatures. Hence, a pyrometer must be used that corrects for this property emissivity. Emissivity values are presented in Chapter 4 of this manual.

Ambient and combustion air temperatures can be measured using either **thermocouples, mercury-in-glass thermometers, or bimetallic thermometers.** The latter two types are usually limited in upper temperature range. Also, if the combustion air intake is in a location that is difficult to reach, it may be easier to use a thermocouple and compensating cables to bring the reading back to a more convenient position.

A **thermocouple** is used to measure the **flue gas temperature.** The thermocouple should be positioned as close to the furnace combustion chamber exit as possible. If the flue gases pass from the furnace into a secondary heat exchange device, such as a recuperator, then the temperature should be measured at the exit of the heat exchanger as well. Both measurements are required to assess the operation of the heat exchanger.

5.4.2.1c Flue Gas Composition

Furnace flue gas can be analyzed using the same types of instrument as those used to sample boiler flue gases:

Exhibit 5.62

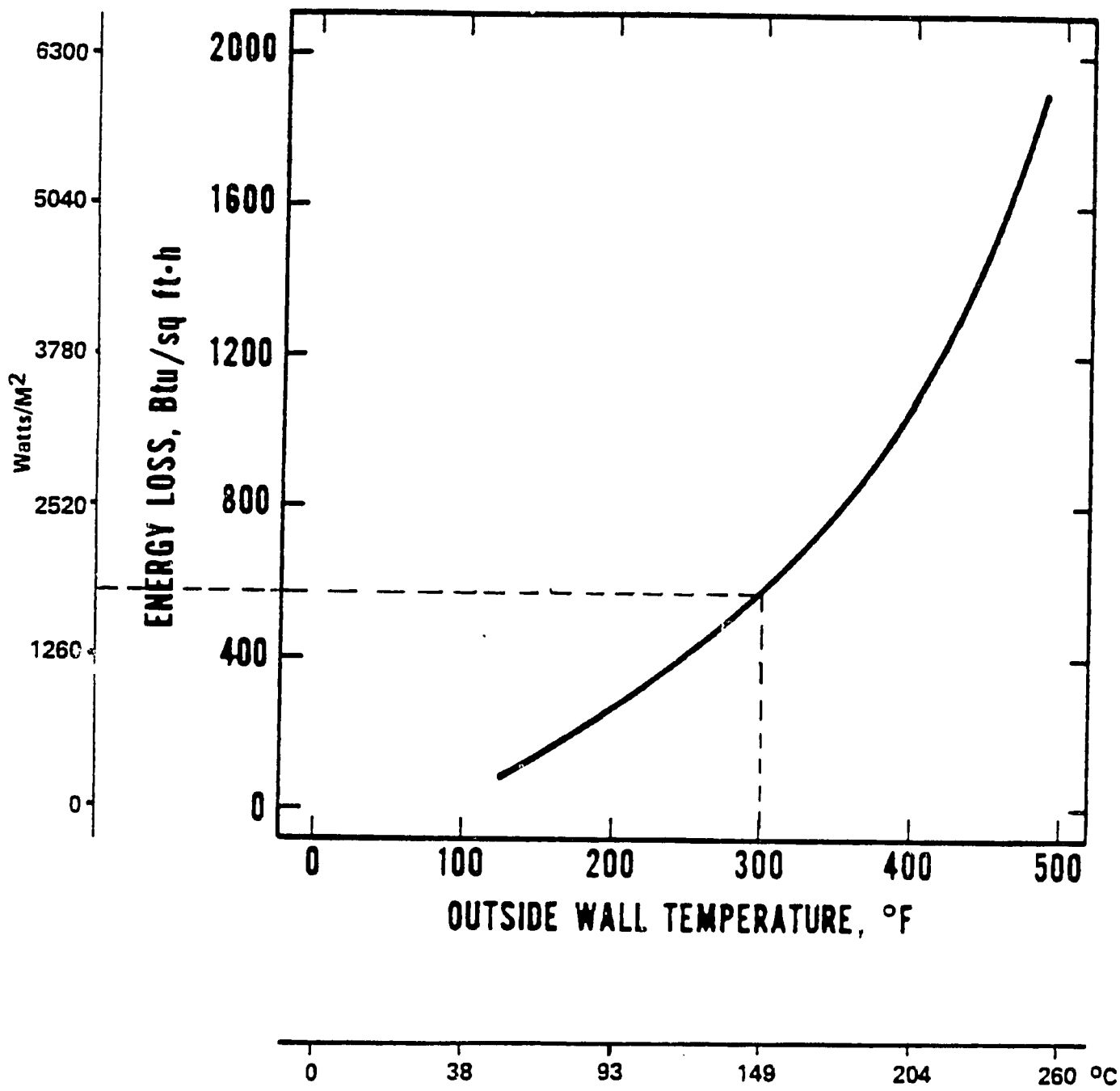
Standard Thermocouple Application Chart

Thermocouple type	Temperature range	Atmosphere* R	O	I	V	Millivolt output
B	0°C to 1,820°C 32°F to 3,310°F		X	X	X	0 to 13.814
R	-50°C to 1,768°C -60°F to 3,210°F		X	X		-0.226 to 21.108
S	-50°C to 1,768°C -60°F to 3,210°F		X	X		-0.236 to 18.698
J	-210°C to 760°C -350°F to 1,400°F	X	X	X	X	-8.096 to 42.922
K	-270°C to 1,372°C		X	X		-6.458 to 54.875
T	-270°C to 400°C -450°F to 750°F	X	X	X	X	-6.258 to 20.869
E	-270°C to 1,000°C -450°F to 1,830°F		X	X		-9.835 to 76.358

*R = reducing
O = oxidizing
I = inert
V = vacuum.

Exhibit 5.63

HEAT LOSS THROUGH FURNACE WALLS



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- Chemical absorption devices (for example, the Fyrite or Orsat)
- Electrochemical devices (for example, an oxygen analyzer using a zirconium cell).

The energy auditor is likely to use a **Fyrite or electronic analyzer** (see Chapter 4 for details). In the past, the Orsat analyzer was the **standard instrument used** to evaluate flue gases. A great deal of skill, time, and practice are needed to operate the all-glass Orsat successfully. It analyzes separately for carbon dioxide, oxygen, and carbon monoxide. Because of the relative difficulty of use and its fragility, the Orsat has declined in popularity and is seldom used by the energy auditor.

All flue gas sampling should be done at a point as close to the furnace combustion chamber exit as possible. In this way, the auditor can reduce the risk of cold air infiltration that could dilute the flue gas sample and introduce error into the analysis.

Where the excess air level is 200 percent or above, the gas flow **must** be measured directly at air intake or at some other convenient location in the system to avoid inaccurate results that occur with chemical analyses.

5.4.2.1d Gas Flow

The common methods used by the energy auditor to measure **gas/air flow** are the **pitot tube or anemometer**. Differential pressure devices such as orifice plates cause slight pressure drops that can adversely affect readings in combustion air systems where the pressure is typically 24-100 mm water gauge.

The pitot tube can be used in ducts of 100 mm diameter and above for a wide range of gas velocities. It can be used at elevated temperatures provided that the tube material is suitable for the temperature levels involved (see Chapter 4 for details).

Anemometers are of two types: hot wire and mechanical. **The mechanical anemometer** uses a fan or turbine where rotatory speed is a function of the velocity of the fluid being measured. The mechanical anemometer is used for low-temperature applications (90°C and below).

The hot wire anemometer indicates gas velocity by measuring the cooling effect of a gas stream on an electrically heated wire. It is usually limited to low-temperature applications, but special models are available for use at temperatures up to 750°C. The method of sampling is similar to the pitot tube.

Data for furnace testing purposes can be collected on a form similar to that shown in Exhibit 5.64.

After completing his tests, the energy auditor must next evaluate the collected data and:

- Determine energy balance for furnace
- Identify conservation opportunities.

5.4.2.2 Determining Furnace Energy Balance

The development of a simplified energy balance for a furnace is best described by means of an example. The simplified method does not take into account the heat content of combustion air, and it determines wall losses by subtraction. The calculations are few in number and are not complex. In estimating an energy balance, there are three different energy sources that must be considered:

- Heat of combustion
- Sensible heat
- Process heat.

The heat of combustion is the energy released when fuel is burned. There are two heating values for any given fossil fuel -- the gross calorific or higher heating value and the net calorific or lower heating value.

The gross calorific value is that which would be given by burning all fuel to carbon dioxide and water and then condensing all water produced to 25°C to recover the heat of vaporization. The net calorific value is the gross valve minus the heat of vaporization of the water in the combustion products.

Exhibit 5.64

Furnace Test Data Collection Form

Date: _____

Time: _____

Location: _____

Fuel type: _____

Item	Units	Test 1	Test 2	Test 3
Flue gas analysis				
% CO_2				
% O_2				
% CO				
% hydrocarbons				
Flue gas temperature				
Ambient temperature				
Draft temperature				
Draft combustion chamber				
Draft furnace				
Flue flow rate				
Wall material/emissivity				
Inside wall temperature				
Outside wall temperature				
Stock temperature in				
Stock temperature out				
Stock material				
Stock throughput				
Stock emissivity				
Temperature				
Before heat exchanger				
After heat exchanger				
Furnace dimensions (L x H x W)				
Wall thickness				
Wall materials				

If the energy auditor measures the fuel flow and knows the heating value for a fuel, he can calculate the heat of combustion as follows:

Energy input = fuel use x gross heating value = kJ/hr.

The sensible heat is heat that is contained in a material because of its temperature. Sensible heats are estimated using a base temperature, normally 25°C or 15°C. At the base temperature, the material is considered to have no sensible heat. The sensible heat is calculated from:

$$H = M \times Cp \times \text{temperature difference}$$

where

H = sensible heat in kJ

M = mass of material in kg

Cp = specific heat of the material in kJ/kg°C

Temperature difference = (temperature of material - base temperature) °C.

Specific heats for common substances are given in Exhibit 5.65.

Process heat is defined as the heat required to cause a physical or chemical change in the material. For example, the heat required to turn water to steam at the same temperature and pressure is approximately 1,110 kJ. This information is normally found in standard references.

To illustrate the energy balance, the following example is presented for a paint drying furnace with an incinerator.

The energy and mass flows are shown in Exhibit 5.66. The furnace is used to dry paint on steel. The paint is 48 percent solvent and 52 percent solids.

Collected data include the following:

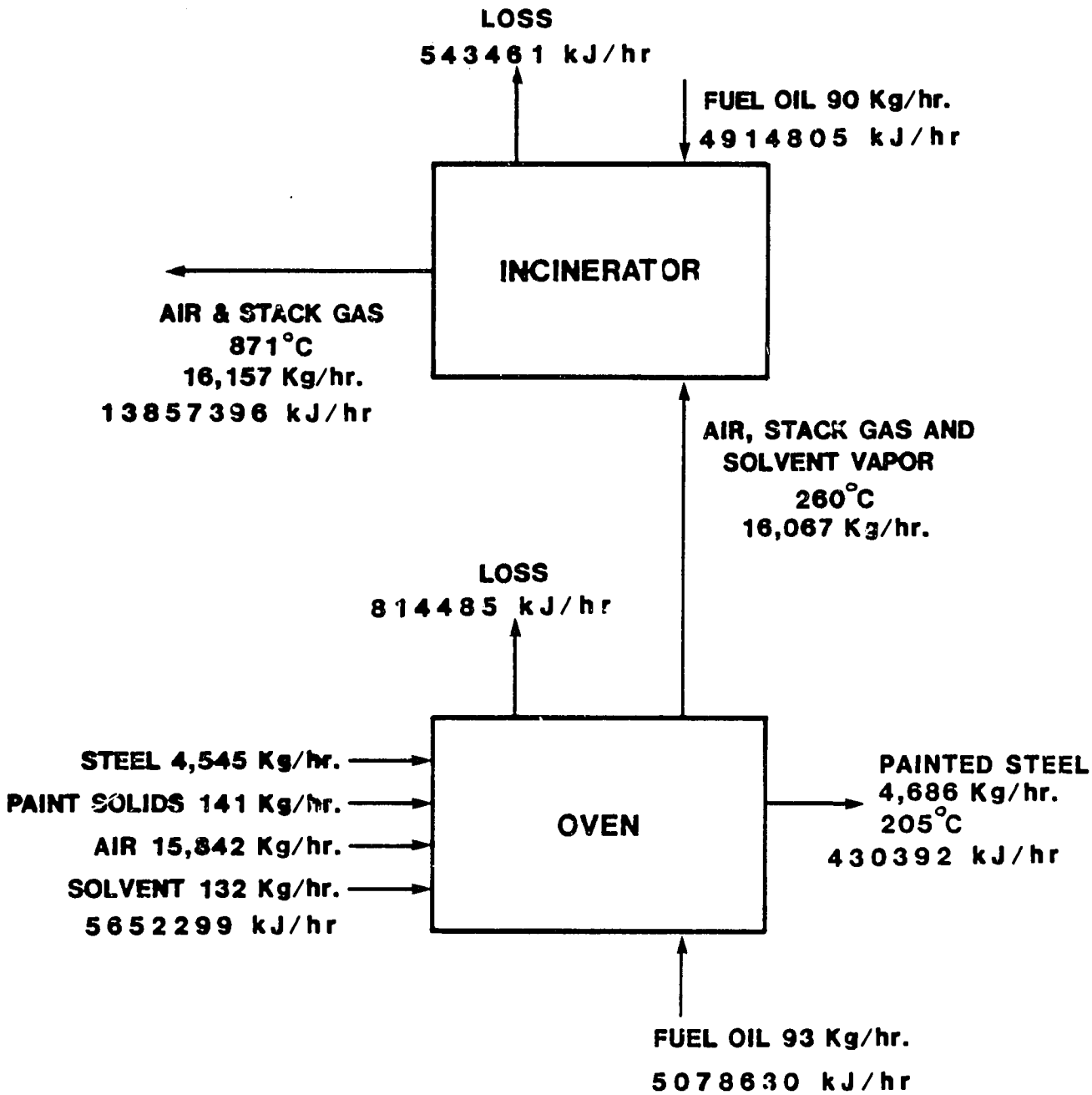
Exhibit 5.65

Specific Heats of Common Substances

Material	Temperature °C	Specific heat at constant pressure kJ/kg/K
Air	Up to 300°C	1.038
Alumina	100°C	0.963
Alumina	1,500°C	1.13
Aluminum	Up to 100°C	0.963
Brickwork	--	0.837
Carborundum brick	Up to 100°C	0.67-0.837
Cellulose (dry)	--	1.34-1.549
Cement	--	0.796-0.837
Chalk	Up to 100°C	0.796
Charcoal	Up to 100°C	0.67-1.005
Clay (dry)	Up to 100°C	0.921
Coal	--	1.047
Coke	--	1.089
Concrete	Up to 156°C	0.67
Concrete	Up to 800°C	0.921
Copper	Up to 600°C	0.427
Cork	--	2.052
Firebrick	Up to 1,000°C	0.963-1.089
Flue gases (average)	Up to 350°C	1.005
Fuel oil	--	1.675-1.926
Gas oil		2.01-2.052
Glass silicate	Up to 100°C	0.796-0.837
Glass silicate	Up to 700°C	1.005-1.089
Glass wool	--	0.67
Graphite	--	0.837
Ice	-10°C	2.219
Ice	-60°C	1.633
Iron	Up to 400°C	0.544
Kerosene	--	1.968
Leather	--	1.507
Limestone	--	0.921
Magnesia brick	100°C	0.921
Magnesia brick	1,500°C	0.837
Mercury	--	0.138
Quartz	350°C	1.172
Rubber (vulcanized)	--	1.759
Rubber (loaded)	--	1.13-2.01
Salt (rock)	Up to 45°C	0.921
Silica brick	Up to 1,500°C	0.837-0.963
Silica (fused)	--	1.34
Silk	--	1.382
Steam	Up to 600°C	2.01
Stoneware	Up to 100°C	0.796
Sugar	20°C	1.13
Sulfur	--	0.837
Tin	--	0.23
Water	15°C	4.19
Wood (soft)	--	1.759-2.722
Wood (oak)	--	2.387

Exhibit 5.66

PAINT DRYING FURNACE ENERGY BALANCE



Mass of steel	= 4,545 kg/hr
Mass of paint solids	= 141 kg/hr
Mass of solvent	= 132 kg/hr
Solvent heat of combustion	= 42,820 kJ/kg
Solvent heat of vaporization	= 431 kJ/kg
Fuel to furnace	= 93 kg/hr
Fuel to incinerator	= 90 kg/hr
Air input	= 15,842 kg/hr
Temperature of steel	= 205°C
Temperature of flue gas	= 871°C.

The mass and energy inputs can be tabulated as follows:

	kg/hr	kJ/hr
Steel	4,545	0*
Paint solvents	141	0*
Solvent	132	5,652,299
Fuel	183	9,993,435
Air	15,842	0*
Total	20,843	15,645,734

*Inputs are assumed to be at base temperature; hence, no sensible heat.

The mass outputs can be tabulated as follows:

	kg/hr
Air	
Stack gas	15,842
Solvent	183
	16,157

The energy outputs are calculated as follows:

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The sensible heat in the stack gas is given by H = M x Cp x temperature difference.

At 871°C = 16,157 x 1.005 x (871 - 21) = 13,800,504 kJ/hr.

The heat vaporization of the solvent must be added to this:

H = mass of solvent x heat of vaporization
= 132 x 431
= 56,892 kJ/hr.

Total stack loss is the sum of the above:

= 13,800,504 + 56,892
= 13,857,396 kJ/hr.

The heat in the painted steel leaving the furnace is given by:

H = (4,544 + 141) x (0.502) x (204 - 21)
= 430,392 kJ/hr.

Summing the two above items:

= 142,287,788 kJ/hr.

If this value is subtracted from the total heat input, it gives a difference of 1,357,946 kJ/hour, which is the amount of energy lost by radiation and convection from the furnace, incinerator, and ductwork.

The total energy output is thus:

	kJ/hr	percent
Paint solids	430,392	2.7
Stack gas	13,857,396	88.6
Other losses	1,357,946	8.7
Total	15,645,734	100.0

5.4.2.3 Identifying Conservation Opportunities

As illustrated above, the stack gases are a major source of heat loss. Therefore, reducing stack losses is one conservation measure that the auditor can identify during a detailed energy audit of a furnace. Others include:

- Controlling excess air
- Recovering heat from stack gases
- Improving furnace insulation
- Continuously monitoring efficiency
- Increasing oxygen level.

Techniques for estimating savings for these measures are presented in the following paragraphs.

5.4.2.3a Controlling Excess Air

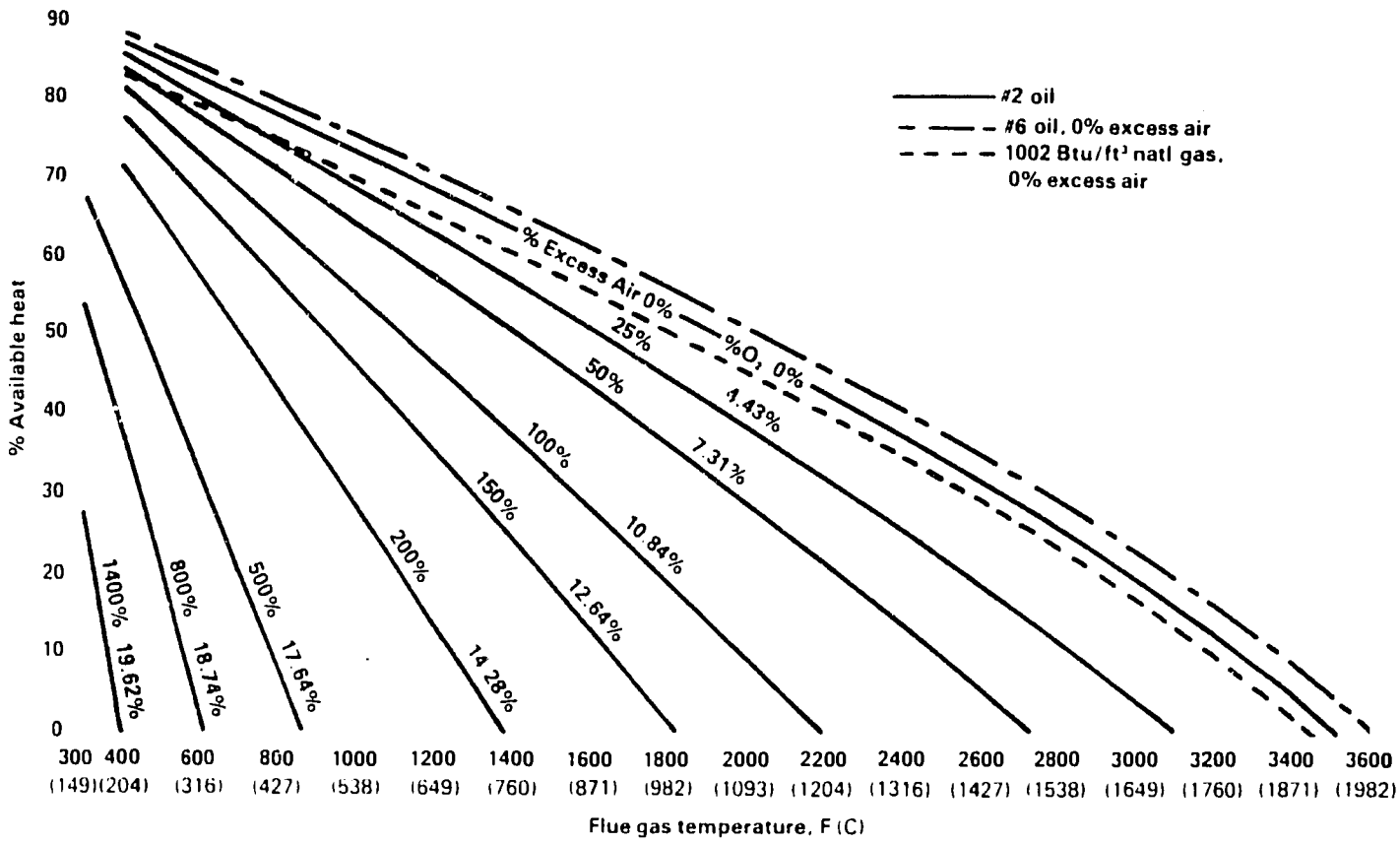
The effect of excess air on furnace stack loss is shown in Exhibit 5.67 for various exhaust temperatures. Too little air can also cause a major heat loss. Savings achieved by reducing excess air can be hard to estimate. If the air is reduced but the fuel rate remains the same, the flame temperature will increase and provide a more rapid heating rate and an energy-saving shorter cycle. However, the reduction in excess air will also raise the stack temperature and thus increase stack loss. If air and fuel are adjusted to maintain the stack temperature, furnace gas velocity will decline and turbulence in the furnace will be reduced. As a result, the heat transfer rate to the stack will suffer, which can increase cycle times. The auditor must thus calculate the heat balance under the new operating conditions to determine the net effect of the change.

5.4.2.3b Recovering Heat from Stack Gases

Heat can be recovered from exhaust stack gases in several ways, including heat exchangers and/or recuperators.

Exhibit 5.67

EXCESS AIR EFFECT ON STACK LOSS



In most cases, the recovered exhaust is used to:

- Preheat combustion air
- Preheat excess air for use in the furnace.

The percentage fuel excess air savings achieved by preheating combustion air for various flue gas temperatures are given in Exhibit 5.68. The temperature to which combustion air can be preheated is somewhat limited by the burners fitted to the furnace. To take full advantage of this measure, it is sometimes necessary to replace the existing burners in addition to fitting a heat exchanger to recover the heat. Before final implementation is considered, a feasibility study should be completed.

5.[illegible].2.3c Improving Insulation

Furnace insulation that is inadequate or in poor condition can waste large amounts of energy in a form that is not readily recoverable. The auditor can get an indication of the importance of the losses by measuring the temperature of the outside furnace walls and roof. A temperature of 70°C to 121°C for a furnace operating in excess of 350°C indicates that the losses are reasonable. A temperature of 260°C or higher means that the losses are probably quite large. An estimate of the energy loss per unit of area per hour as a function of outside wall temperature is shown in Exhibit 5.69.

The savings achieved through insulation can be calculated either on the basis of a given outside surface temperature or a given thickness of insulation. The calculation used is based on:

$$Q = U A (Ti - Ta)$$

where

Q = heat loss watts
U = overall heat transfer coefficient $W/m^2\ ^oC$
A = unit area m^2
Ti = furnace operating temperature ^oC

Exhibit 5.68

POTENTIAL SAVINGS BY COMBUSTION AIR PREHEATING

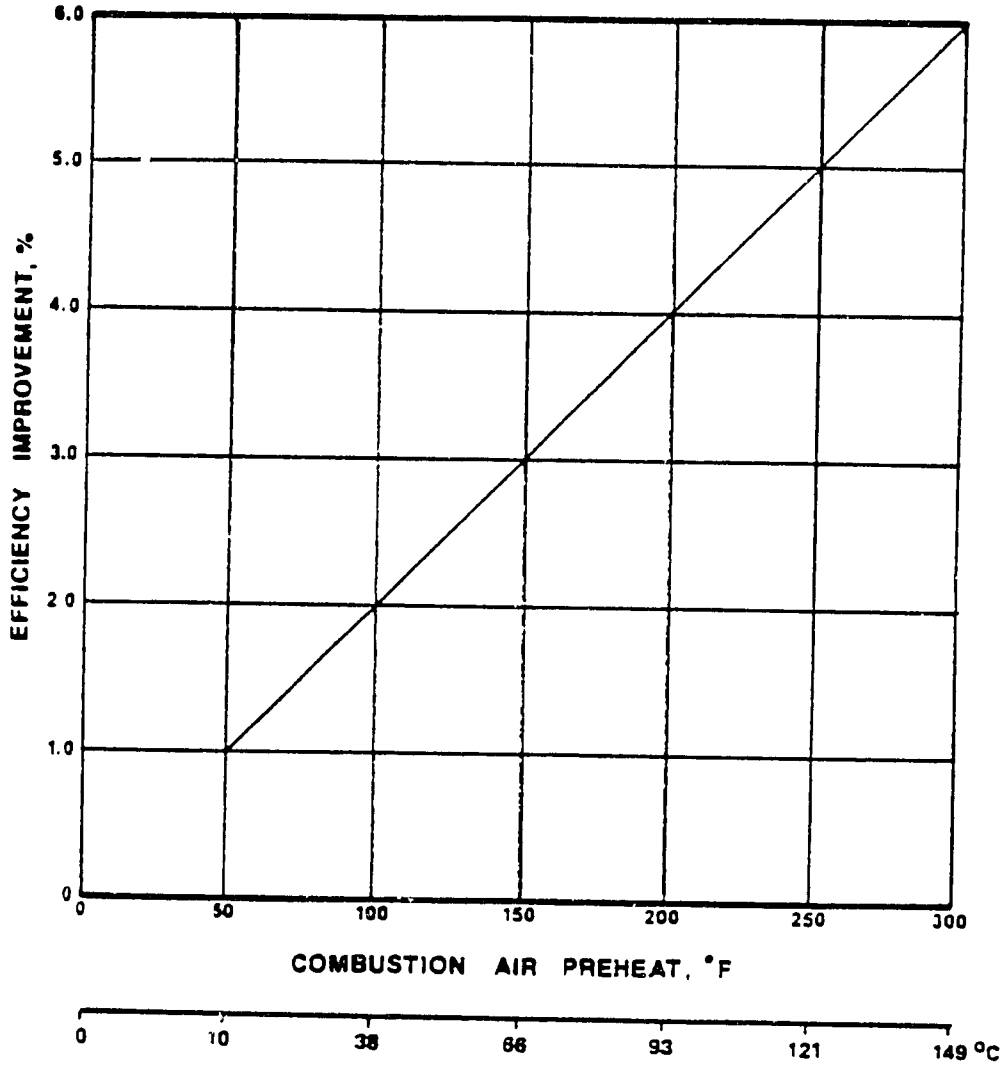
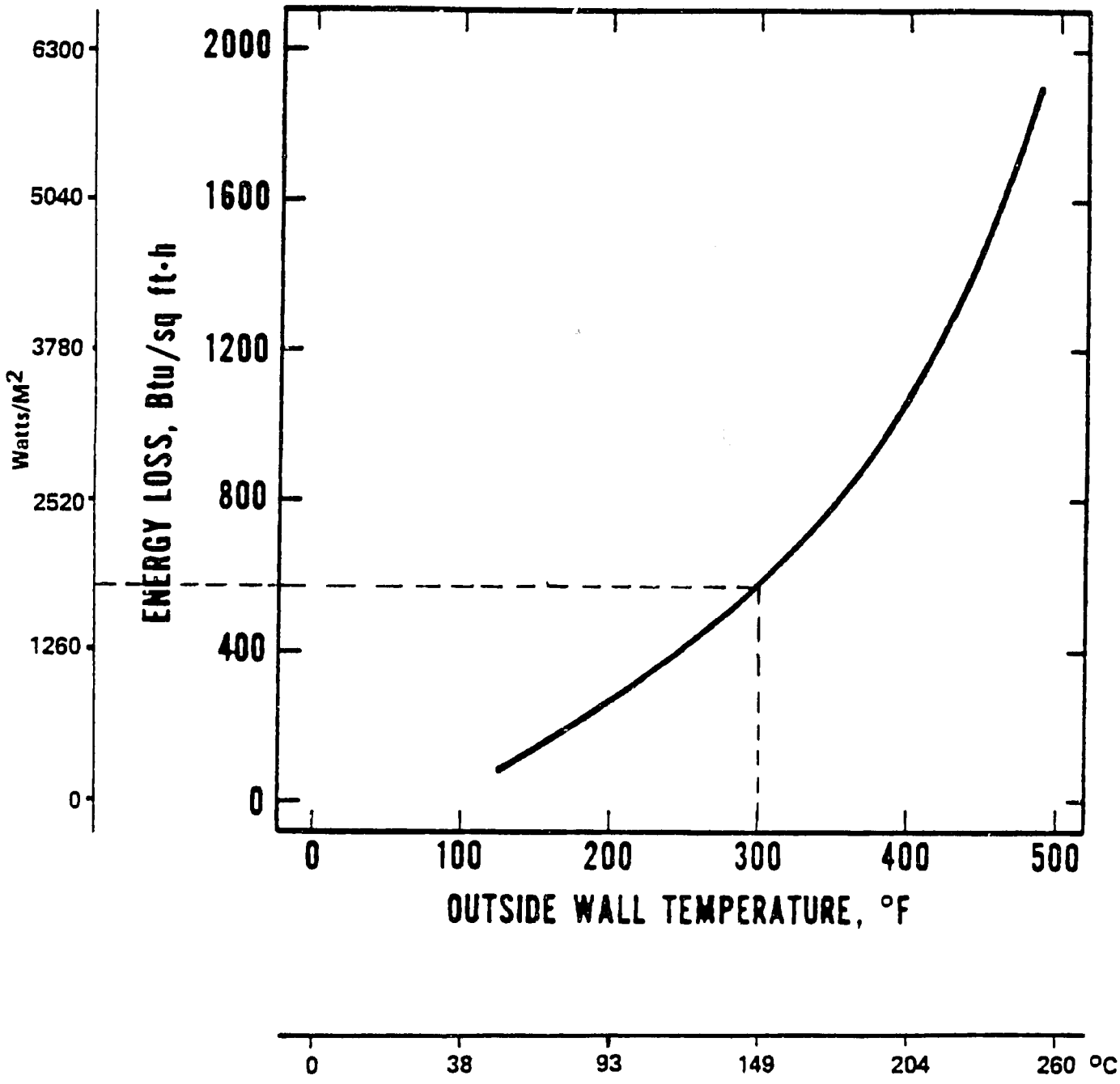


Exhibit 5.69

ENERGY LOSS THROUGH FURNACE WALLS



Ta = ambient air temperature.

"U" is calculated by

$$U = Rsi + Ri + \ldots\ldots + Rn + Rso$$

where

Rsi = inside wall surface resistance

Ri = resistance of material = Li/Ki

where

Ki = thermal conductivity ($W/mm/m^2\ ^oC$)

Li = thickness m

Rn = resistance of material n = Ln/Kn

Rso = outside wall surface resistance.

The energy auditor can select either approach and perform the above calculation to determine the thickness of insulation needed or the heat loss reduction for a given thickness of insulation. He can then evaluate the cost-effectiveness of the measure.

5.4.2.3d Continuously Monitoring Efficiency

Savings resulting from continuous efficiency monitoring are hard to predict. They depend on current operating practices and the sophistication of the monitoring system chosen. The auditor could calculate the savings based on the relative change in efficiency:

$$= \text{(existing fuel use)} \frac{\text{(new efficiency - old efficiency)}}{\text{(new efficiency)}}$$

= new fuel use (GJ/year).

5.4.2.3e Increasing Oxygen Level

Substituting commercial oxygen for combustion air reduces the volume of heat-absorbing nitrogen flowing through the combustion process, and thus reduces losses. Potential savings are shown in Exhibit 5.70. The normal practice is to increase oxygen levels from 21 percent to 25-30 percent.

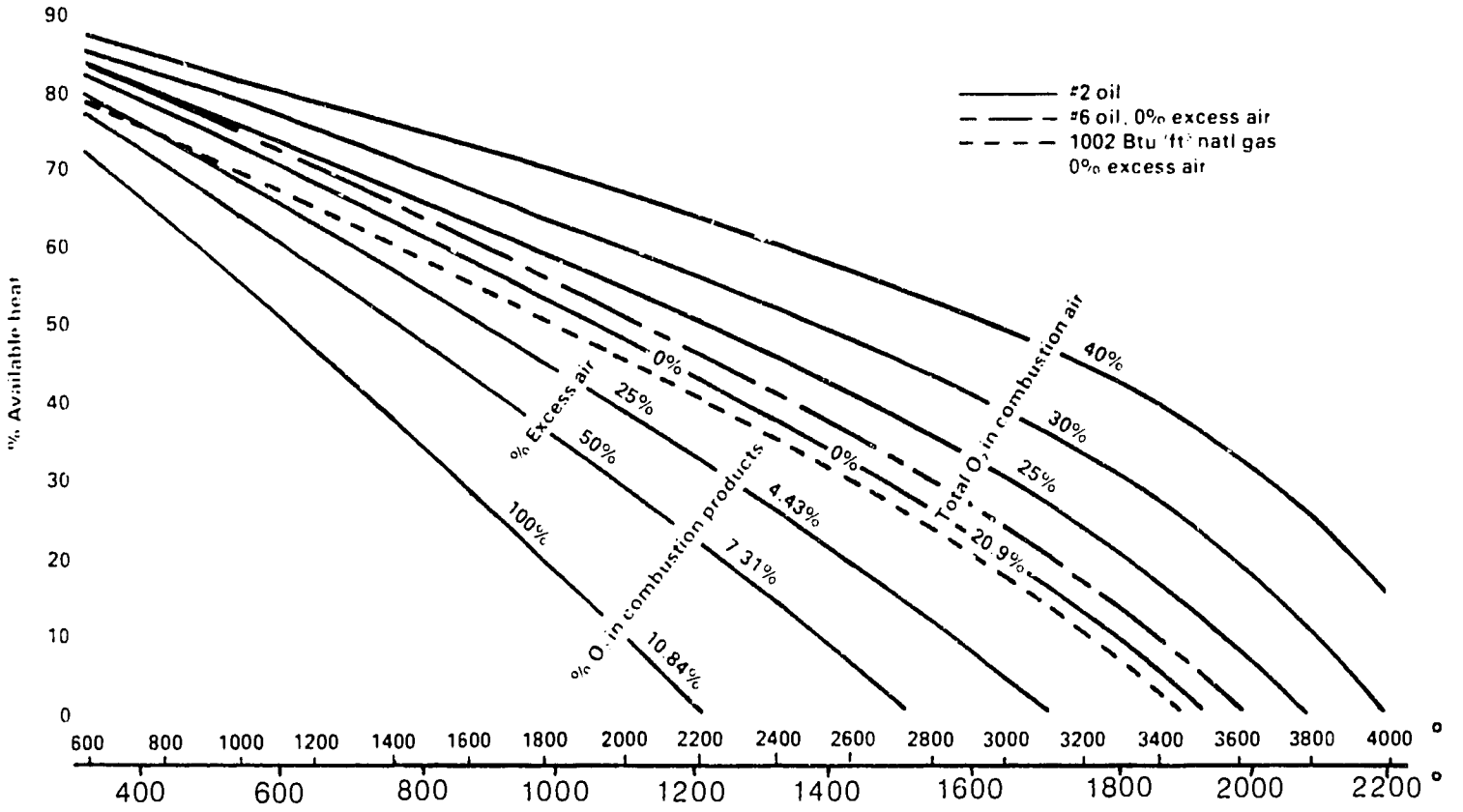
A full feasibility study should be conducted to determine all implications of this measure, including the cost and availability of oxygen, the flammability limits, and extra safety precautions that are needed.

5.4.2.4 Summary

Conservation in furnace operation usually involves specialized equipment that requires major capital investment. Any new furnace or retrofit will require the use of high-temperature materials, and as a consequence, the cost savings expected from the conservation measure must be large to justify implementation. Low-cost measures carried out for an existing furnace are usually very attractive, although they do not always offer the same amount of savings as the installation of a new furnace or the retrofitting of an existing furnace does. If a plant is considering the installation of a new furnace, it should be sure that all major energy-saving features are incorporated. Retrofitting such features is very costly.

Exhibit 5.70

SAVINGS POSSIBLE BY OXYGEN ENRICHMENT



5.5 ELECTRICAL SYSTEMS

Electrical energy is the most expensive form of purchased energy. For this reason, its use must be confined to the minimum for efficient operation. Because of its great flexibility, electricity offers advantages over conventional fossil fuels. The inexperienced energy auditor often neglects electricity when he has completed a detailed energy audit of a facility, even though efforts to conserve electricity can result in significant cost savings.

This section outlines procedures for evaluating electrical energy use and electricity consuming systems as part of an overall detailed energy audit. The procedures assume that most facilities use AC power, either single-phase or three-phase.

The electricity bill cannot be controlled by managing consumption alone, because energy use is only one of several factors that affect the bill.

To test electrical systems and identify conservation opportunities during a full energy audit, the energy auditor should take the steps described below. The steps include completion of a preliminary audit prior to the detailed energy audit.

5.5.1 PRELIMINARY ENERGY AUDIT

The first step in a PEA of an electrical system is to **review the current utility tariff** and latest electricity bill. Industrial electricity bills commonly comprise several billing elements in addition to the base consumption charge. In most cases, the energy user will have direct control over only three of the elements -- maximum demand, consumption, and power factor penalty. The remaining elements are fixed charges that must be paid regardless of the plant operating mode.

Industrial electricity use is charged according to either maximum demand, consumption, or power factor penalty, based on the supplied voltage and assessed demand. Under these tariffs, charges are levied for:

- Maximum demand in kVA
- Consumption in kWh
- Fuel price adjustment per kWh.

The rate charged depends on which of these tariffs is applicable to the facility being audited.

Opportunities for saving electricity are limited to:

- Reducing the maximum demand
- Reducing the consumption.

Maximum demand can be reduced only after the auditor understands what constitutes the maximum demand charge. The basic misunderstanding associated with the **maximum demand charge** is the assumption that the charge is based on an instantaneous peak. It is not; instead, a fixed time period is used. Although the time period varies from utility to utility, the maximum demand is usually measured over a 15- to 30-minute period. An analogy to measuring maximum demand is provided below:

> A car travels at 60 kmph for 15 minutes, then slows to 30 kmph for 15 minutes. Its average speed is 45 kmph. This speed over any 30-minute period (equivalent to a maximum demand period of 30 minutes) is classified as the maximum demand.

The meter installed to measure maximum demand is an integrating meter (i.e., it adds up the number of kWh recorded in the time period in question). For example:

> A plant is on a 15-minute period cycle. In the worst 15 minutes of the month, it uses 500 kWh. The maximum demand for that month will be 2,000 kW. A 15-minute period is one-fourth of an hour. The meter automatically multiplies by 4 to bring the number of kW used in that month's peak 15 minutes to an hourly (and therefore a kilowatt-hourly) basis. If the maximum demand period is 30 minutes, the meter will multiply by 2 to bring the number of kW consumed in 30 minutes to a kW per hour basis. It follows that

the longer the time period used to establish the maximum demand, the easier it is to deal with the problem of control.

Consumption can easily be reduced by following a simple guideline -- **if equipment does not need to be operating, switch it off.** The PEA and detailed energy audit give the energy auditor an opportunity to establish operating schedules for electrically driven equipment and to match them to production requirements.

After reviewing the current utility tariff, the auditor should next **determine the plant load factor.** Load factor is defined as the ratio of electrical consumption to maximum demand. The load factor can be calculated from each monthly electricity bill or by averaging over a year. The billing period load factor is given by:

$$= \frac{\text{(Number of kWh consumed in billing period)}}{\text{(maximum demand in billing period) (hours in billing period)}}$$

The formula for the annual load factor is given by:

$$= \frac{\text{(Number of kWh consumed in year)}}{\text{(average monthly maximum demand) (hours in year)}}$$

A low plant load factor may be a sign of opportunities for controlling demand. Demand charges usually average 25 percent of an energy bill.

Having checked the utility bill and determine the load factor, the energy auditor should then **develop a line diagram** for the electrical distribution system. This is best done by visual inspection. From the interview and/or the utility bill, the energy auditor can identify the incoming supply voltage. He should begin his line diagram at the point of incoming supply, noting the number of transformers and associated voltages. Any electrical metering should be marked on the diagram. The supply should be followed to any substations and from there to any load control centers. The visual inspection is best made in the company of the facility's electrical engineer.

Having developed the line diagram, the auditor's next step is to **identify the major electrical energy users** for each load control center. The information can be compiled in data collection forms like those shown in Exhibit 3.16. One electrical-using system that can be readily identified is the lighting system. Rather than determining the

energy used for lighting throughout the plant, the auditor should study each area served by lighting and identify the tasks performed in that area. A form for collecting data on lighting systems is presented in Exhibit 3.18.

As part of the visual inspection or during interviews with plant personnel, the energy auditor should try to complete the next two steps of the PEA: **establishing current operating hours** for the equipment and **determining production schedules.**

The **identification of conservation opportunities** may be limited to one type of measure -- matching equipment operating hours to production schedules -- during the PEA, since the auditor may not be able to determine by a visual inspection how efficiently the electrical equipment is operating. Nonetheless, he should be able to identify several areas for investigation, including:

- Maximum demand reduction through load shedding
- Sizing/loading of electrical motors
- Energy-efficient motors
- Lighting reductions
- Automatic control of operations.

The evaluation of these opportunities requires the use of instrumentation and a full energy audit.

At the conclusion of the PEA, the energy auditor should develop an **action plan for the detailed energy audit.** The action plan should focus on those electrical systems that are to be tested during the audit.

5.5.2 DETAILED ENERGY AUDIT

The first step of the detailed energy audit is to ensure that all instruments to be used during the detailed electrical energy audit are in a good state of repair. Detailed electrical energy audits normally require portable instrumentation. Four types of instruments are required -- a kilowatt-hour meter, a wattmeter, a power factor meter, and a light meter. A clamp-on ammeter/voltmeter can be substituted for the wattmeter.

Power factor meters are necessary because of the relationship between power consumption and applied voltage and current in alternating current circuits. The relevance of power factor and alternating currents is discussed below.

5.5.2.1 Determining Power Factor

Power factor is a term that relates to AC electrical systems only. In a system of alternating voltages and currents, power factor is defined as the cosine of the phase angle that exists between the voltage applied to a circuit and the current that flows through that circuit. Hence, power factor is always a number whose value ranges from zero to plus or minus one. The relationship between the voltage and current of any specified load can also be expressed as the following ratio:

$$\text{Power factor} = \frac{\text{useful power}}{\text{magnetizing or apparent power}} = \cos r$$

The magnetizing power or current does not contribute to the active power and is purely reactive. Therefore, any electromagnetic device that draws excitation for its magnetic circuit from an AC system will have a lagging power factor. This lagging reactive power is not entirely useless, for it establishes the working flux while the useful power supplied the losses and power to perform the work.

A large proportion of the electrical machinery used in industry has an inherently low power factor, which means that the utilities have to generate much more current than is theoretically required. In addition, transformers and cables have to carry this extra current. When the overall power factor of a generating station's load is low, the system is inefficient and the cost of electricity correspondingly high. To overcome this and at the same time ensure that the generators and cables are not overloaded with reactive current, the utilities often offer reduced terms to consumers whose power factor is high, or impose penalties for a low power factor.

By commonly agreed convention, if the voltage waveform leads the current waveform, the power factor is considered lagging and the circuit is defined as inductive. When the current leads voltage, a leading power factor exists, and the circuit is capacitative.

Unity power factor, when the voltage and current sinusoids are in phase, occurs for resistive circuits.

Most industrial and commercial electrical equipment presents an inductive load to the utilities; hence, efforts to change power factors are always directed toward bringing them more to the unity figure.

Owing to the nature of the machinery that generates AC voltage, the power factor of the connected circuits has a direct bearing on the cost of such generation. Also, inordinately low power factors require oversized distribution networks. Hence, power factor is an item to optimize when trying to minimize the cost of electrical use.

5.5.2.1a Why Power Factor Is Important

In the generation of AC power via an alternator, regardless of energy source (hydro, fossil fuel, or nuclear), the prime mover supplies those components of voltage and current that are in phase with each other; the limiting factor on any generator is the amount of current it can supply. Any out-of-phase components must be supplied by excitation of the alternator's field. This external excitation is derived by means of an additional source of energy (DC generator) at a greater cost and lower efficiency than that supplied by the prime mover. The utilities pass on this additional cost to their customers according to the customer's power factor. A typical tariff would apply a penalty for demand taken at a power factor of 0.8 or less.

Machinery or equipment with a low power factor includes:

- Induction motors of all types (which form by far the greatest industrial load on AC mains)
- Power transformers and voltage regulators.

Their low power factor can be corrected, which will save on electricity charges if a penalty tariff is in force.

In addition to the penalty, low power factors are undesirable for another reason. At a given constant voltage, the Root Mean Square current required for a specified amount of useful work increases as the power factor decreases. This increasing current requirement necessitates yet larger ratings of the alternator, the transformers and switch gear, and the distribution network from power plant to customer.

5.5.2.1b How and Where Power Factor is Modified

For inductive loads, the power factor is corrected toward the unity figure by placing capacitances across the input lines feeding the affected equipment. The capacitances can either be fixed-value, commercially available capacitors, or three-phase synchronous motors with their fields appropriately excited to achieve the desired power factor.

To improve the power factor, equipment drawing reactive power (kVAr) of approximately the same magnitude as the load kVAr, but in phase opposition (leading), is connected in shunt with the load. The resultant kVAr is now smaller and the new power factor ($\cos \phi_2$) is correspondingly larger. Obviously, $\cos \phi_2$ is controlled by the magnitude of the kVAr that has been added, which allows any desired power factor to be obtained by varying the leading kVAr (see Exhibit 5.71).

As previously stated, there are two types of equipment from which leading kVAr can be drawn:

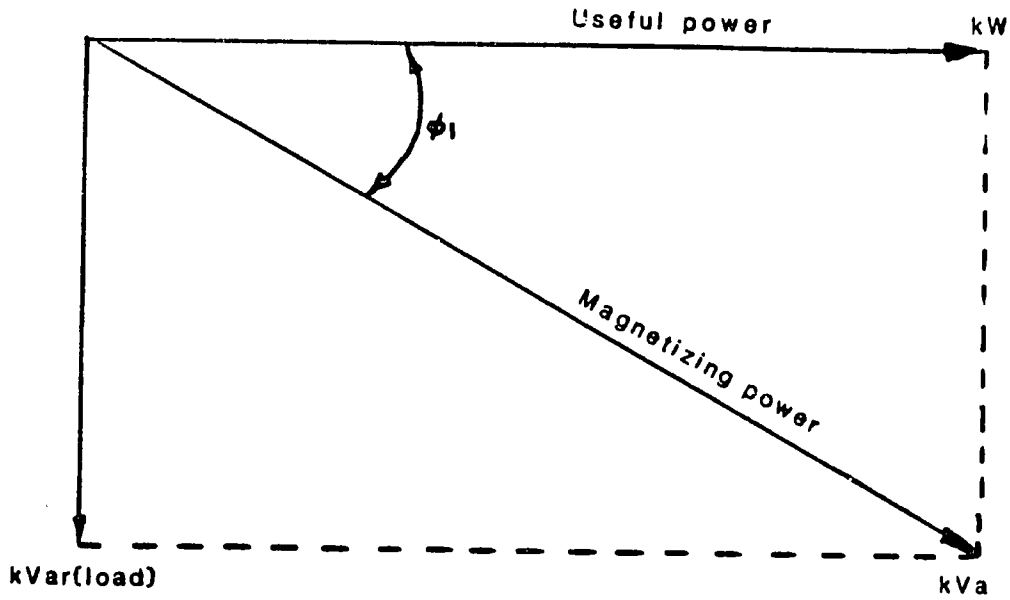
- Synchronous motors and synchronous condensors
- Static capacitors.

5.5.2.2 Testing Electricity-Using Equipment

When only limited instrumentation is available, unknown parameters of a power system can be calculated on the basis of known quantities. The relationships between power system parameters are given in Exhibit 5.72.

Exhibit 5.71

VECTOR RELATIONSHIPS IN AC POWER SYSTEMS



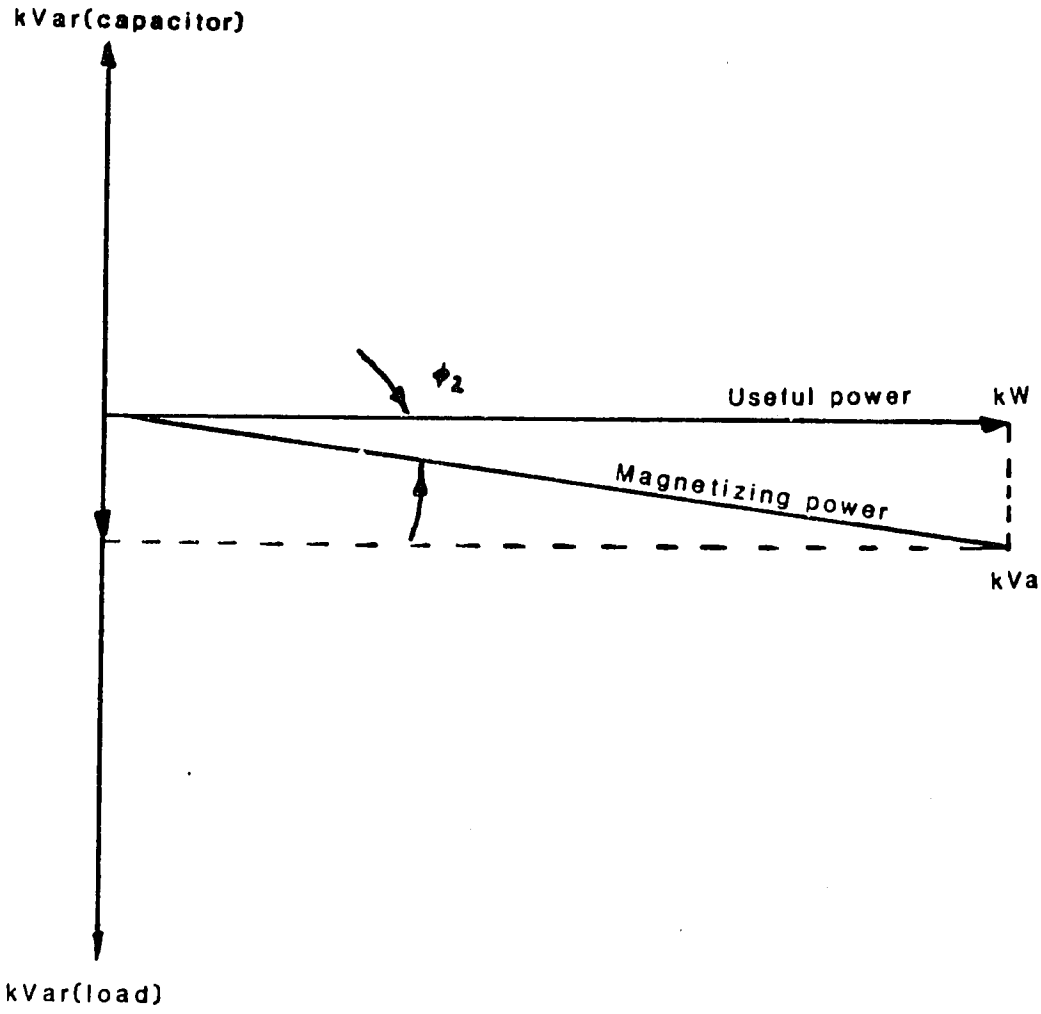


Exhibit 5.72

Electrical Formulae for Electrical Circuits

Desired data	Single phase	Three phase	Direct current
Kilowatts	E x I x Cos r/1,000	E x I x 1.73 x Cos r/1,000	E x I/1,000
kVA	E x I/1,000	E x I x 1.73/1,000	not applicable
Horsepower output	E x I x Cos r x Eff/746	E x I x 1.73 x Cos r x Eff/746	E x I x Eff/746
Amps when horsepower not known	HP x 746/E x Cos r x Eff	HP x 746/E x Cos r x 1.73 x Eff	HP x 746/E x Eff
Amps when kW known	kW x 1,000/ E x Cos r	kW x 1,000/E x Cos r x 1.73	kW x 1,000/E
Amps when kVA known	kVA x 1,000/E	kVA x 1,000/E x 1.73	not applicable

Notes

i) E = volts; I = amps; Cos r = power factor; Eff = efficiency.

ii) Values should be measured simultaneously.

The auditor should complete the testing of all large electricity-using equipment for voltage, power factor, and current using portable instrumentation. The data should be recorded on forms similar to those in Exhibits 5.73 and 4.30. The testing techniques are presented in Chapter 4 of the manual. The equipment should be tested when it is fully loaded and at no load. The greatest misconception usually associated with electrical machinery is that if a machine is not loaded and is running idle, it draws very little power. By conducting tests of synchronous motors, synchronous condensors, and static capacitors, the energy auditor can establish the efficiency of the installed machinery.

During the detailed energy audit, the main utility meter should be read at regular intervals (once per hour) unless other recording instruments can be used on the main electrical supply into the plant. Such readings can provide an indication of demand profile at the facility. Some utility companies are able to offer their customers printouts of the facility demand over the billing period. These printouts can be evaluated by the customer to determine the profile and can be used as a guide to identify demand control opportunities.

5.5.2.3 Identifying Conservation Opportunities

Opportunities for conservation of electricity include:

- Demand control through load shedding
- Correcting power factor
- Turning off unnecessary equipment
- Selecting adequately sized motors
- Changing lighting systems
- Switching to energy-efficient motors.

5.5.2.3a Demand Control Through Load Shedding

Maximum demand control requires knowledge of when electrical load demand occurs and how equipment is operated. Some of this information can be determined from load factors, and some from the inventory. The energy auditor must know the tariff

Exhibit 5.73

Electrical Equipment Data Collection Form

CLIENT:		PLANT:	
DATE:	PROJECT NO.:	DATA BY:	
UNITS:	PRESSURE:	FLOW:	TEMPERATURE:

EQUIPMENT TYPE			
NAMEPLATE DATA, MOTORS:			
HP			
VOLTS (AC/DC)			
AMPS			
SERVICE CLASS			
EFFICIENCY			
NAMEPLATE DATA, DRIVEN EQUIPMENT			
RATED FLOW OR LOAD			
UNITS			
DISCHARGE PRESSURE			
FIELD DATA:			
INDICATED LOAD			
UNITS			
MOTOR VOLTS			
MOTOR AMPS			
MOTOR POWER FACTOR			
TEMPERATURE (SPECIFY LOCATION)	(ACTUAL/NORMAL)	(ACTUAL/NORMAL)	(ACTUAL/NORMAL)
1.	/	/	/
2.	/	/	/
3.	/	/	/
4.	/	/	/
5.	/	/	/
PRESSURES (SPECIFY LOCATION)	(ACTUAL/NORMAL)	(ACTUAL/NORMAL)	(ACTUAL/NORMAL)
1.	/	/	/
2.	/	/	/
3.	/	/	/
4.	/	/	/
5.	/	/	/
	/	/	/

time period over which demand is charged, so he can identify the equipment that can remain turned off until the period of peak or maximum demand has passed.

Savings from shedding electrical loads are calculated from the actual kilowatt load shed. For example, if a 10-horsepower motor with an efficiency of 85 percent is shut off, the savings would be approximately 8 kilowatts.

Controlling maximum demand requires an interface with utility metering. There are two types of interface systems. During periods of maximum demand, one type triggers an alarm, after which the equipment can be shut down manually. The second type automatically turns off pre-selected electrical loads.

With a fall in demand, the alarm on the first type of system will cease, and equipment can be turned back on manually. The second type will turn on equipment automatically when the demand falls below a pre-selected level.

The cost of each system depends on several factors, including the incoming electrical supply, the type of meter fitted by the utility company, and the number of alarms. Typically, an installed eight-load automatic controller costs $40,000.

Payback periods will depend on the amount of demand that can be cut during peak periods.

5.5.2.3b Correcting Power Factor

The economics of power factor correction depend on the tariff structure and the existing power factor at the facility. Power factor correction should always be regarded as an investment with two main objectives:

1. Reducing electricity costs
2. Freeing transformer, cable, and switch gear capacity.

Under a system of power factor penalty charges, a reduction in electricity costs will often produce a sufficient return on capital by itself, as will freeing transformer, cable,

and switch gear capacity. Obviously, where both objectives are sought, a good economic case can be made for power factor correction.

Where tariffs are based on a basic standing charge per kVA, plus a charge for each unit (kWh) supplied, the most economical degree of correction is found when the final power factor is approximately 0.98.

In a single or two-part tariff with a bonus or penalty clause, correcting to a power factor of between 0.90 and 0.97 is generally found to be the most economical.

The financial benefits of installing power factor correction capacitors will naturally vary in each instance, but capital expenditure on correction equipment can be recovered in the first 18 to 30 months.

The first step in designing a power factor scheme is to obtain accurate details of the load conditions with values of kW, kVA, and power factor at light, average, and full load, together with the type of load. This information is available from the utiltiy bills or by using a power factor meter.

Calculating capacitor size. Having determined the desired power factor and knowing the present load conditions, the energy auditor can use the correction factor in Exhibits 5.74 and 5.75 to estimate the size of the capacitor required. The factors are derived for the formula:

$$kVAr = kW\ (\tan \ddot{O}1 - \tan \ddot{O}2)$$

where kVAr = capacitor rating (required kVAr to be applied to the system)

kW = load in kilowatts

$\ddot{O}1$ = initial or existing angle of lag (phase angle)

$\ddot{O}2$ = required corrected angle of lag (phase angle)

$\tan \ddot{O}1 - \tan \ddot{O}2 = \frac{kVAr}{kW}$ = correction factor

The tangents corresponding to power factor ($\cos \ddot{O}$) are given in Exhibit 5.74.

Exhibit 5.74

POWER FACTOR ANGLE CONVERSION TABLE

POWER FACTOR RANGE 0.21 to 0.61

POWER FACTOR (cos Ø)	TANGENTS CORRESPONDING TO POWER FACTOR (cos Ø)									
	0	1	2	3	4	5	6	7	8	9
0·20	4·899	4·873	4·848	4·824	4·799	4·775	4·750	4·726	4·703	4·679
0·21	4·656	4·632	4·610	4·587	4·565	4·542	4·520	4·499	4·477	4·456
0·22	4·434	4·413	4·392	4·372	4·351	4·330	4·310	4·291	4·270	4·251
0·23	4·231	4·212	4·193	4·174	4·155	4·136	4·118	4·099	4·081	4·063
0·24	4·045	4·027	4·019	3·992	3·975	3·957	3·940	3·923	3·906	3·890
0·25	3·873	3·857	3·840	3·824	3·808	3·792	3·776	3·761	3·745	3·729
0·26	3·714	3·699	3·683	3·668	3·653	3·639	3·624	3·610	3·595	3·580
0·27	3·566	3·552	3·538	3·524	3·510	3·496	3·483	3·469	3·455	3·442
0·28	3·429	3·415	3·402	3·389	3·376	3·363	3·351	3·338	3·325	3·313
0·29	3·300	3·288	3·275	3·263	3·251	3·239	3·227	3·215	3·203	3·191
0·30	3·180	3·168	3·157	3·145	3·134	3·122	3·111	3·100	3·089	3·078
0·31	3·067	3·056	3·045	3·034	3·024	3·013	3·002	2·992	2·981	2·971
0·32	2·961	2·950	2·940	2·930	2·920	2·910	2·900	2·890	2·880	2·870
0·33	2·861	2·851	2·841	2·832	2·822	2·813	2·803	2·794	2·784	2·775
0·34	2·766	2·757	2·748	2·739	2·730	2·721	2·712	2·703	2·694	2·685
0·35	2·676	2·668	2·659	2·651	2·642	2·633	2·625	2·617	2·608	2·600
0·36	2·592	2·583	2·575	2·567	2·559	2·551	2·543	2·535	2·527	2·519
0·37	2·511	2·503	2·495	2·488	2·480	2·472	2·464	2·457	2·449	2·442
0·38	2·434	2·427	2·419	2·412	2·405	2·397	2·390	2·383	2·375	2·368
0·39	2·361	2·354	2·347	2·340	2·333	2·326	2·319	2·312	2·305	2·298
0·40	2·291	2·285	2·278	2·271	2·264	2·258	2·251	2·244	2·238	2·231
0·41	2·225	2·218	2·212	2·205	2·199	2·192	2·186	2·180	2·173	2·167
0·42	2·161	2·155	2·148	2·142	2·136	2·130	2·124	2·118	2·112	2·106
0·43	2·100	2·094	2·088	2·082	2·076	2·070	2·064	2·058	2·052	2·047
0·44	2·041	2·035	2·030	2·024	2·018	2·012	2·007	2·001	1·996	1·990
0·45	1·985	1·979	1·974	1·968	1·963	1·957	1·952	1·946	1·941	1·936
0·46	1·930	1·925	1·920	1·914	1·909	1·904	1·899	1·894	1·888	1·883
0·47	1·878	1·873	1·868	1·863	1·858	1·853	1·848	1·843	1·838	1·833
0·48	1·828	1·823	1·818	1·813	1·808	1·803	1·798	1·794	1·789	1·784
0·49	1·779	1·774	1·770	1·765	1·760	1·755	1·751	1·746	1·741	1·737
0·50	1·732	1·727	1·723	1·718	1·714	1·709	1·705	1·700	1·696	1·691
0·51	1·687	1·682	1·677	1·673	1·669	1·665	1·660	1·656	1·651	1·647
0·52	1·643	1·638	1·634	1·630	1·626	1·621	1·617	1·613	1·608	1·604
0·53	1·600	1·596	1·592	1·588	1·583	1·579	1·575	1·571	1·567	1·563
0·54	1·559	1·555	1·551	1·547	1·542	1·538	1·534	1·530	1·526	1·523
0·55	1·519	1·515	1·511	1·507	1·503	1·499	1·495	1·491	1·487	1·483
0·56	1·480	1·476	1·472	1·468	1·464	1·460	1·457	1·453	1·449	1·445
0·57	1·442	1·438	1·434	1·430	1·427	1·423	1·419	1·416	1·412	1·408
0·58	1·405	1·401	1·397	1·394	1·390	1·386	1·383	1·379	1·376	1·372
0·59	1·369	1·365	1·361	1·358	1·354	1·351	1·347	1·344	1·340	1·337
0·60	1·333	1·330	1·326	1·323	1·320	1·316	1·313	1·309	1·306	1·302
0·61	1·299	1·296	1·292	1·289	1·286	1·282	1·279	1·275	1·272	1·269

Exhibit 5.74 (continued)

POWER FACTOR ANGLE CONVERSION TABLE
POWER FACTOR RANGE 0.62 to 1.00

POWER FACTOR (cos Ø)	TANGENTS CORRESPONDING TO POWER FACTOR (cos Ø)									
	0	1	2	3	4	5	6	7	8	9
0·62	1·266	1·262	1·259	1·256	1·252	1·249	1·246	1·243	1·239	1·236
0·63	1·233	1·230	1·226	1·223	1·220	1·217	1·213	1·210	1·207	1·204
0·64	1·201	1·197	1·194	1·191	1·188	1·185	1·182	1·179	1·175	1·172
0·65	1·169	1·166	1·163	1·160	1·157	1·154	1·151	1·148	1·144	1·141
0·66	1·138	1·135	1·132	1·129	1·126	1·123	1·120	1·117	1·114	1·111
0·67	1·108	1·105	1·102	1·099	1·096	1·093	1·090	1·087	1·084	1·081
0·68	1·078	1·075	1·072	1·069	1·067	1·064	1·061	1·058	1·055	1·052
0·69	1·049	1·046	1·043	1·040	1·037	1·035	1·032	1·029	1·026	1·023
0·70	1·020	1·017	1·015	1·012	1·009	1·006	1·003	1·000	0·997	0·995
0·71	0·992	0·989	0·986	0·983	0·981	0·978	0·975	0·972	0·970	0·967
0·72	0·964	0·961	0·958	0·956	0·953	0·950	0·947	0·945	0·942	0·939
0·73	0·936	0·934	0·931	0·928	0·925	0·923	0·920	0·917	0·914	0·912
0·74	0·909	0·906	0·904	0·901	0·898	0·895	0·893	0·890	0·887	0·885
0·75	0·882	0·879	0·877	0·874	0·871	0·869	0·866	0·863	0·861	0·858
0·76	0·855	0·853	0·850	0·847	0·845	0·842	0·839	0·837	0·834	0·831
0·77	0·829	0·826	0·823	0·821	0·818	0·815	0·813	0·810	0·808	0·805
0·78	0·802	0·800	0·797	0·794	0·792	0·789	0·787	0·784	0·781	0·779
0·79	0·776	0·774	0·771	0·768	0·766	0·763	0·760	0·758	0·755	0·753
0·80	0·750	0·747	0·745	0·742	0·740	0·737	0·734	0·732	0·729	0·727
0·81	0·724	0·721	0·719	0·716	0·714	0·711	0·708	0·706	0·703	0·701
0·82	0·698	0·695	0·693	0·690	0·688	0·685	0·682	0·680	0·677	0·675
0·83	0·672	0·669	0·667	0·664	0·662	0·659	0·656	0·654	0·651	0·649
0·84	0·646	0·643	0·641	0·638	0·636	0·633	0·630	0·628	0·625	0·622
0·85	0·620	0·617	0·615	0·612	0·609	0·607	0·604	0·601	0·599	0·596
0·86	0·593	0·591	0·588	0·585	0·583	0·580	0·577	0·575	0·572	0·569
0·87	0·567	0·564	0·561	0·559	0·556	0·553	0·551	0·548	0·545	0·543
0·88	0·540	0·537	0·534	0·532	0·529	0·526	0·523	0·521	0·518	0·515
0·89	0·512	0·510	0·507	0·504	0·501	0·498	0·496	0·493	0·490	0·487
0·90	0·484	0·482	0·479	0·476	0·473	0·470	0·467	0·464	0·461	0·459
0·91	0·456	0·453	0·450	0·447	0·444	0·441	0·438	0·435	0·432	0·429
0·92	0·426	0·423	0·420	0·417	0·414	0·411	0·408	0·405	0·402	0·398
0·93	0·395	0·392	0·389	0·386	0·383	0·379	0·376	0·373	0·370	0·366
0·94	0·363	0·360	0·356	0·353	0·350	0·346	0·343	0·339	0·336	0·332
0·95	0·329	0·325	0·322	0·318	0·314	0·310	0·307	0·303	0·299	0·296
0·96	0·292	0·288	0·284	0·280	0·276	0·272	0·268	0·264	0·259	0·255
0·97	0·251	0·246	0·242	0·237	0·233	0·228	0·223	0·218	0·213	0·208
0·98	0·203	0·198	0·192	0·187	0·181	0·175	0·169	0·163	0·156	0·150
0·99	0·143	0·135	0·127	0·119	0·110	0·100	0·090	0·078	0·063	0·045
1·00	0	0	0	0	0	0	0	0	0	0

Exhibit 5.75

POWER FACTOR IMPROVEMENT TABLE

Original Power Factor	Corrected Power Factor																				
	0.80	0.81	0.82	0.83	0.84	0.85	0.86	0.87	0.88	0.89	0.90	0.91	0.92	0.93	0.94	0.95	0.96	0.97	0.98	0.99	1.0
0.50	0.982	1.008	1.034	1.060	1.086	1.112	1.139	1.165	1.192	1.220	1.248	1.276	1.306	1.237	1.369	1.403	1.440	1.481	1.529	1.589	1.732
0.51	0.937	0.962	0.989	1.015	1.041	1.067	1.094	1.120	1.147	1.175	1.203	1.231	1.261	1.292	1.324	1.358	1.395	1.436	1.484	1.544	1.687
0.52	0.893	0.919	0.945	0.971	0.997	1.023	1.050	1.076	1.103	1.131	1.159	1.187	1.217	1.248	1.280	1.314	1.351	1.392	1.440	1.500	1.643
0.53	0.850	0.876	0.902	0.928	0.954	0.980	1.007	1.033	1.060	1.088	1.116	1.144	1.174	1.205	1.237	1.271	1.308	1.349	1.397	1.457	1.600
0.54	0.809	0.835	0.861	0.887	0.913	0.939	0.966	0.992	1.019	1.047	1.075	1.103	1.133	1.164	1.196	1.230	1.267	1.308	1.356	1.416	1.559
0.55	0.769	0.795	0.821	0.847	0.873	0.899	0.926	0.952	0.979	1.007	1.035	1.063	1.093	1.124	1.156	1.190	1.227	1.268	1.316	1.376	1.519
0.56	0.730	0.756	0.782	0.808	0.834	0.860	0.887	0.913	0.940	0.968	0.996	1.024	1.054	1.085	1.117	1.151	1.188	1.229	1.277	1.337	1.480
0.57	0.692	0.718	0.744	0.770	0.796	0.822	0.849	0.875	0.902	0.930	0.958	0.986	1.016	1.047	1.079	1.113	1.150	1.191	1.239	1.299	1.442
0.58	0.655	0.681	0.707	0.733	0.759	0.785	0.812	0.839	0.865	0.893	0.921	0.949	0.979	1.010	1.042	1.075	1.113	1.154	1.202	1.262	1.405
0.59	0.619	0.645	0.671	0.697	0.723	0.749	0.776	0.802	0.829	0.857	0.885	0.913	0.943	0.974	1.006	1.040	1.077	1.118	1.166	1.226	1.369
0.60	0.583	0.609	0.635	0.661	0.687	0.713	0.740	0.766	0.793	0.821	0.849	0.877	0.907	0.938	0.970	1.004	1.041	1.082	1.130	1.190	1.333
0.61	0.549	0.575	0.601	0.627	0.653	0.679	0.706	0.732	0.759	0.787	0.815	0.843	0.873	0.904	0.936	0.970	1.007	1.048	1.096	1.156	1.299
0.62	0.516	0.542	0.568	0.594	0.620	0.646	0.673	0.699	0.726	0.754	0.782	0.810	0.840	0.871	0.903	0.937	0.974	1.015	1.063	1.123	1.266
0.63	0.483	0.509	0.535	0.561	0.587	0.613	0.640	0.666	0.693	0.721	0.749	0.777	0.807	0.838	0.870	0.904	0.941	0.982	1.030	1.090	1.233
0.64	0.451	0.474	0.503	0.529	0.555	0.581	0.608	0.634	0.661	0.689	0.717	0.745	0.775	0.806	0.838	0.872	0.909	0.950	0.998	1.068	1.201
0.65	0.419	0.445	0.471	0.497	0.523	0.549	0.576	0.602	0.629	0.657	0.685	0.713	0.743	0.774	0.806	0.840	0.877	0.918	0.966	1.026	1.169
0.66	0.388	0.414	0.440	0.466	0.492	0.518	0.545	0.571	0.598	0.626	0.654	0.682	0.712	0.743	0.775	0.809	0.846	0.887	0.935	0.995	1.138
0.67	0.358	0.384	0.410	0.436	0.462	0.488	0.515	0.541	0.568	0.596	0.624	0.652	0.682	0.713	0.745	0.779	0.816	0.857	0.905	0.965	1.108
0.68	0.328	0.354	0.380	0.406	0.432	0.458	0.485	0.511	0.538	0.566	0.594	0.622	0.652	0.683	0.715	0.749	0.786	0.827	0.875	0.935	1.078
0.69	0.299	0.325	0.351	0.377	0.403	0.429	0.456	0.482	0.509	0.537	0.565	0.593	0.623	0.654	0.686	0.720	0.757	0.798	0.846	0.906	1.049
0.70	0.270	0.296	0.322	0.348	0.374	0.400	0.427	0.453	0.480	0.508	0.536	0.564	0.594	0.625	0.657	0.691	0.728	0.769	0.817	0.877	1.020
0.71	0.242	0.268	0.294	0.320	0.346	0.372	0.399	0.425	0.452	0.480	0.508	0.536	0.566	0.597	0.629	0.663	0.700	0.741	0.789	0.849	0.992
0.72	0.214	0.240	0.266	0.292	0.318	0.344	0.371	0.397	0.424	0.452	0.480	0.508	0.538	0.569	0.601	0.635	0.672	0.713	0.761	0.821	0.964
0.73	0.186	0.212	0.238	0.264	0.290	0.316	0.343	0.369	0.396	0.424	0.452	0.480	0.510	0.541	0.573	0.607	0.644	0.685	0.733	0.793	0.936
0.74	0.159	0.185	0.211	0.237	0.263	0.289	0.316	0.342	0.369	0.397	0.425	0.453	0.483	0.514	0.546	0.580	0.617	0.658	0.706	0.766	0.909
0.75	0.132	0.158	0.184	0.210	0.236	0.262	0.289	0.315	0.342	0.370	0.398	0.426	0.456	0.487	0.519	0.553	0.590	0.631	0.679	0.739	0.882
0.76	0.105	0.131	0.157	0.183	0.209	0.235	0.262	0.289	0.315	0.343	0.371	0.399	0.429	0.460	0.492	0.526	0.563	0.604	0.652	0.712	0.855
0.77	0.079	0.105	0.131	0.157	0.183	0.209	0.236	0.262	0.289	0.317	0.345	0.373	0.403	0.434	0.466	0.500	0.537	0.578	0.626	0.685	0.829
0.78	0.052	0.078	0.104	0.130	0.156	0.182	0.209	0.235	0.262	0.290	0.318	0.346	0.376	0.407	0.439	0.473	0.510	0.551	0.599	0.659	0.802
0.79	0.026	0.052	0.078	0.104	0.130	0.156	0.183	0.209	0.236	0.264	0.292	0.320	0.350	0.381	0.413	0.447	0.484	0.525	0.573	0.633	0.776
0.80	0.000	0.026	0.052	0.078	0.104	0.130	0.157	0.183	0.210	0.238	0.266	0.294	0.324	0.355	0.387	0.421	0.458	0.499	0.547	0.609	0.750
0.81		0.000	0.026	0.052	0.078	0.104	0.131	0.157	0.184	0.212	0.240	0.268	0.298	0.329	0.361	0.395	0.432	0.473	0.521	0.581	0.724
0.82			0.000	0.026	0.052	0.078	0.105	0.131	0.158	0.186	0.214	0.242	0.272	0.303	0.335	0.369	0.406	0.447	0.495	0.555	0.698
0.83				0.000	0.026	0.052	0.079	0.105	0.132	0.160	0.188	0.216	0.246	0.277	0.309	0.343	0.380	0.421	0.469	0.529	0.672
0.84					0.000	0.026	0.053	0.079	0.106	0.134	0.162	0.190	0.220	0.251	0.283	0.317	0.354	0.395	0.443	0.503	0.646
0.85						0.000	0.027	0.053	0.080	0.108	0.136	0.164	0.194	0.225	0.257	0.291	0.328	0.369	0.417	0.477	0.620
0.86							0.000	0.026	0.053	0.081	0.109	0.137	0.167	0.198	0.230	0.264	0.301	0.342	0.390	0.450	0.593
0.87								0.000	0.027	0.055	0.083	0.111	0.141	0.172	0.204	0.238	0.275	0.316	0.364	0.424	0.567
0.88									0.000	0.028	0.056	0.084	0.114	0.145	0.177	0.211	0.248	0.289	0.337	0.397	0.540
0.89										0.000	0.028	0.056	0.086	0.117	0.149	0.183	0.220	0.261	0.309	0.369	0.512
0.90											0.000	0.028	0.058	0.089	0.121	0.155	0.192	0.233	0.281	0.341	0.484
0.91												0.000	0.030	0.061	0.093	0.127	0.164	0.205	0.253	0.313	0.456
0.92													0.000	0.031	0.063	0.097	0.134	0.175	0.223	0.283	0.426
0.93														0.000	0.032	0.066	0.103	0.144	0.192	0.252	0.395
0.94															0.000	0.034	0.071	0.112	0.160	0.220	0.363
0.95																0.000	0.037	0.079	0.126	0.186	0.329
0.96																	0.000	0.041	0.089	0.149	0.292
0.97																		0.000	0.048	0.108	0.251
0.98																			0.000	0.060	0.203
0.99																				0.000	0.143
																					0.000

Example: A 100-kW load at 0.6 power factor is to be corrected to 0.97 power factor:

Correction factor = 1.082 (obtained from Exhibit 5.75).
Therefore, required kVAr to be aplied to the system is:
100 x 1.082 = 108.2 kVAr capacitor rating required = 108 kVAr.

Since there is a manufacturing tolerance of -0/+10 percent on the rating of power capacitors, a practical figure should be chosen based on standard ratings.

The points to be considered in any power factor installation are:

1. Reliability of the equipment to be installed
2. Probable life
3. Capital cost
4. Maintenance costs
5. Running costs
6. Space required and ease of installation.

In normal installations, the capital cost of rotating power factor machinery is generally too high, and the wear and tear inherent in all rotary machines involves additional expense for maintenance. However, when a large synchronous motor can be used in place of an inductor motor in some full-time applications, such as centrifugal chilling, its installation would be cost-effective.

Capacitors have none of these disadvantages. Compared with other forms of correction, their initial cost is very low, their upkeep costs are minimal, and they can be used with the same high efficiency on all sizes of installations. They are compact, reliable, convenient to install, and lend themselves to individual, group, or automatic methods of correction.

Consequently, power factor correction by capacitors is by far the most satisfactory and economical method.

5.5.2.3c Turning Off Unnecessary Equipment

Turning off unnecessary electrical equipment can produce large savings for very little cost. To identify these opportunities, the auditor must analyze when equipment **does** operate and when it **should** operate. For example, ventilation exhaust fans often run continuously, even though the department they serve operates only 8 or 16 hours a day. Similarly, conveyors may run empty during break periods. Energy and cost savings will be realized if the equipment can be shut off.

The savings are estimated from the size and efficiency of the equipment and the number of hours it can be turned off, as follows:

$$\text{Energy savings (kWh)} = \frac{\text{(HP) (0.746) (hours off)}}{\text{(efficiency)}}$$

$$= \text{kWh}$$

$$\text{Cost savings (\$)} = \text{kWh} \times \$/\text{kWh}.$$

The time available between equipment shutdown and startup can be a limiting factor. For example, shutdown of production-related equipment should not be considered for periods of less than 15 minutes. Motors under 20 horsepower are designed for no more than six starts per hour. Larger motors are designed for even fewer starts. Any savings can quickly be lost if motors burn out and have to be replaced.

It is often assumed that if electrical machinery is not loaded and is running idle, then it uses very little power. This assumption is **not true**, as the following examples illustrate.

(1) Centrifugal pump

No load	=	36 hp
Full load	=	44 hp
Efficiency	=	18 percent.

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(2) **Machine in maintenance shop**

No load	=	3.7 hp
Full load	=	4.1 hp
Efficiency	=	10 percent.

(3) **Blower**

No load	=	71 hp
Full load	=	78 hp
Efficiency	=	9 percent.

To save energy, idle machinery must be turned off.

Another misconception that arises (particularly with respect to large motors or large groups of motors) is that switching equipment back on negates any savings, owing to maximum demand charges. This assumption is also untrue. Although there is a surge of current when a motor is switched on, this surge is usually only about five to six times the full load current and of only a 3- to 4-second duration. Maximum demands are calculated over 15- to 30-minute periods. Therefore, six times full load for 4 seconds would result in the equivalent of 24 seconds of normal running.

In the very worst case, the demand would be increased by 5.1 percent. For this to happen, all of the following conditions must be met:

1. 80 percent of the facility's demand (i.e., all normally running motors) occurs simultaneously
2. All motors require 10 seconds to reach full speed
3. Locked rotor current (LRC) for all motors is seven times the full load current (FLC); the locked rotor current does not decrease during the full 10-second starting
4. Demand is billed in kVA, not kW
5. The billed demand is one integrated 15-minute peak per month. (For one integrated 30-minute billed peak, the above 5.1 percent drops to 2.55 percent).

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The motor starting current (LRC) was assumed to be seven times the full load current (FLC), based on the following values:

HP	RPM	LRC
1/2	1,750	10 x FLC
5	1,750	6.5 x FLC
10	1,750	6 x FLC
Avg.	1,750	7 x FLC

15-minute demand calculations

a) Base case

1,000 kVA load for 15 min. **without** motor starting

$P_1 \times t = 1{,}000 \times 15 = 15{,}000$ kVA-Min.

b) 1,000 kVA load for base case **with** motor starting

$P_2 \times t = 1{,}000 \times 14.84 = 14{,}840$ kVA-Min.

$5{,}800 \times .16 = 928$ kVA-Min.

15,768 kVA-Min.

Maximum 15-minute demand increase = 768 x 100/15,000 = **5.1 percent.**

Maximum 30-minute demand increase = 768 x 100/30,000 = **2.55 percent.**

5.5.2.3d Selecting Adequately-Sized Motors

The oversizing of motors is usually subjected to much criticism. However, provided an oversized motor is switched off when it is not running, oversizing does not represent a serious problem. On the other hand, overspeed is a notorious waste of power.

Oversizing horsepower. It is a well-known fact that a motor on full load runs more efficiently than a motor on half load. What is not well known is that within limits, a

large motor on half load can be more efficient than a small motor on full load. Furthermore, the oversized motor is more likely to deal with momentary overloads without burning out. It will maintain its speed better on full machine output, it will run cooler and it will have a better power factor. Although motors should not deliberately be oversized, the matter must be viewed in perspective.

It has also been argued that larger motors increase initial costs; such a view can be a misconception, particularly when overall operation and maintenance are taken into account. For instance, the facility may have installed ½-, 1-, 3-, 5-, 7½-, 10,- 15-, 20-, and 25-horsepower motors. Rationalization might justify keeping only 1-, 5-, 10-, 15-, and 25 hp motors in storage, thus reducing the spares that have to be carried and preventing capital from being tied up.

A set of typical motor performance curves illustrates that down-sizing motors to attain greater operating efficiency is not necessarily a valid exercise. See Section 5 of the Energy Demand Management and Conservation Training Manual for details on motor performance.

For example, a 10-hp motor that is developing 7½-hp operates at 86 percent efficiency. A 7½-hp motor operating at full rating is 84 percent efficient. Therefore, it would not be cost effective to replace the motor because it is undersized. In fact, a 15-hp motor operating at 7½-hp is 89 percent efficient.

Manufacturers provide performance curves for their motor types. The energy auditor should use caution in suggesting that motors be downsized as a means of saving energy.

Excessive speed. The energy auditor must study very carefully the speeds at which machinery operates, particularly fans, blowers, and centrifugal pumps. With certain types of machinery, the power used is proportional to the speed. With fans, blowers, and centrifugal pumps, the power used is proportional to the cube of the speed.

It is in this area that oversized motors and the resultant effects of speed have their most wasteful effect. Imagine, for example, a situation in which a designer of an air conditioning system allows a margin when specifying size and speed for a fan. The fan manufacturer, to protect himself, adds a margin when specifying the motor, and

the motor manufacturer also protects himself with a small margin when supplying the motor to drive the fan.

At the power consumption of a fan or blower is proportional to the cube of the speed, the power waste can be enormous. If the speed of the fan could be reduced by a ratio of 6:5, 42 percent of the power could be saved:

$$\begin{array}{lcr} 6 \times 6 \times 6 & = & 216 \\ 5 \times 5 \times 5 & = & \underline{125} \\ & & 91 \end{array}$$

92 x 100/216 = 42 percent.

Often, too, the fan is specified by the amount of air it will move, with the engineer assuming that the manufacturer has designed the fan with the correct aerodynamic blade configuration. Unfortunately, this is not always the case. Fans are often installed that carry the designed load because they are oversized and running at higher speeds than they should be.

Two other laws apply to any fans at constant air density:

1. The pressure (static, velocity, and total) varies with the square of the speed of the fan
2. The air capacity is directly proportional to the speed of the fan.

In terms of fan efficiency, the horsepower is determined by the following formula:

$$\text{Air hp} = \frac{m^3/\text{minute} \times \text{total pressure in mmwg}}{2122 \times \text{hp input}}$$

In many applications of fans, air is circulated without encountering resistance, and no static pressure is developed. The static efficiency is zero, and its calculation is meaningless. The efficiency of the fan is thus calculated on the total or dynamic pressure:

$$\text{Mechanical or total efficiency} = \frac{m^3/\text{minute} \times \text{total pressure in mmwg}}{2122 \times \text{hp input}}$$

The following simple example covers the three laws pertaining to speed. A certain fan delivers 340 m^3 per minute at a static pressure of 25 mmwg when operating at a speed of 400 rpm and requires an input of 4 hp. If, in the same installation, 425 m^3 per minute are desired, what must the speed, static pressure, and power be?

Speed	=	400 x 425/340 = 500 rpm
Static pressure	=	25 x (500)2/(400)2 = 39 mmwg
Power	=	4 x (500)3/(400)3 = 7.81 hp.

Centrifugal pumps follow the same laws as fans. The power varies with the cube of the speed. The use of centrifugal pumps as a replacement for reciprocating pumps has become widespread and sometimes has nothing to do with efficiency. For example, a small output against high pressure means either a large diameter impellor or a multi-stage small diameter configuration, neither of which is efficient. The problem is often compounded when the impellor wears, resulting in a drop of outlet pressure. If the pump is belt-driven, the simplest way to overcome the problem is to speed up the pump. The real answer is to repair the pump. Otherwise, the system will eventually have to be shut down, resulting in a large loss of service plus a costly replacement. In the intervening period, power has been wasted.

The speed of fans and pumps should be checked and, where possible, reduced. Where direct drives are installed, the scope is limited, but where belt or chain drives are installed, the matter is relatively simple.

The energy auditor must remember that reducing speed does not necessarily reduce output. In fact, in a great many cases, the reverse can be true. Slowing down machinery invariably reduces maintenance problems and breakdowns, and therefore both costs and service interruptions.

5.5.2.3e Switching to Energy-Efficient Motors

Switching to more efficient motors is a measure that should be considered when existing motors fail. The improvements in efficiency are not normally significant enough to warrant outright replacement of a fully working motor. The savings can be calculated on the basis of the efficiency change anticipated and the current consumption. To estimate the current consumption, the auditor must know the motor's operating hours. The savings calculation is shown below:

$$\text{Savings (kWh)} = \frac{\text{(New efficiency - old efficiency)}}{\text{(new efficiency)}} \text{(hp) (0.746) (hours)}$$

$$= \text{kWh/year.}$$

5.5.2.3f Changing Lighting Systems

The efficiency of many existing lighting systems can be significantly improved by ensuring that all of the light being paid for is put to use.

The first step in evaluating an existing system is to check the facility's operating schedule. It is likely that there are many periods of time during a work week when it is not necessary to maintain light levels in the building. During these periods, lighting can be provided at reduced levels or can be eliminated completely.

The second step in the evaluation is a visual inspection to determine the condition of the fixtures. Dirty fixtures, broken or aged diffusers, and old bulbs near the end of their life all contribute to reduced lighting system efficiency. During this inspection, the auditor should also check the condition of the building walls and ceilings. Dirty walls or dark painted surfaces reduce the amount of reflected light and force the lighting system to work harder to achieve a given light level.

Next, a lighting level survey should be undertaken. The first phase of this survey is to determine what the actual light levels are throughout the facility at representative work locations -- in storage areas, corridors, offices, and other plant locations. Next, the measured lighting levels from areas where similar work is being performed should be compared to determine the lowest reasonable level at which worker productivity is

still acceptable. Exhibit 4.32 shows the recommended illumination levels for a variety of work activities. Note that these levels are only recommendations and should be considered to be the maximum to be supplied. The values can be modified to meet the needs of a particular application.

The results of the lighting survey will provide the basis for all future recommendations for changes to the existing lighting system. One recommendation may be for delamping and reduction in light level. A second recommendation could be replacement of incandescent with fluorescent or conventional fluorescent bulbs with high-efficiency tubes. The most costly recommendation would be outright replacement of part or all of the existing system with an alternative system.

One common technique employed to maintain lighting system efficiency is group relamping on a scheduled basis. Group relamping entails the replacement of all the lamps in a defined area on a predefined schedule that takes acount of a lamp characteristic known as "lumen depreciation." According to this lamp characteristic, the amount of light produced by a lamp will degrade over the life of the lamp at a predictable rate. Instituting group relamping programs enables the user to ensure a uniform light level over the lamps' useful life cycle, thereby reducing the total number of fixtures required as well as providing for planned replacement of lamps and maintenance of fixtures.

Significant energy savings can be achieved either by reducing the total number of active fixtures in the existing system or by replacing present lamps with more efficient ones. Lamp replacement runs the range from simple bulb changing to complete replacement of the existing system. In most plants, the final program is to likely incorporate a variety of elements, resulting in a program somewhere betwen the two extremes.

In the case of the incandescent lamps, there are three basic options. The first is to relamp with an incandescent lamp of lower wattage or different design that better directs the generated light. The second alternative is to use one of the many direct screw-in replacement fluorescent bulbs to relamp the incandescent fixture. Replacing a 60-watt incandescent saves 38 watts with no loss of light. The cost of a replacement lamp is $15 in the United States. Payback periods are usually around 1 year. The final alternative is the outright replacement of the present lamp and fixture with a completely new light source, either fluorescent or HID. The option chosen in a

particular situation will depend on the lighting requirements and the local implementation costs. Replacement of incandescents with HIDs usually has a payback period of between 1 and 2 years in facilities that operate on a three-shift basis.

Recent advances in the design of fluorescent lamps and ballasts offers many direct replacement high-efficiency lamps to choose from. The energy auditor should review the use of a particular replacement lamp in a specific application against the constraints imposed by the manufacturer for its application. Some high-efficiency lamps, for instance, cannot be used in environments where the ambient temperature is below 15°C. High-efficiency lamps can be justified, as the incremental cost increase over a standard lamp is around $0.50 to $0.75 in the United States. If ballast replacement is included, outright replacement is difficult to justify. Paybacks are usually in excess of 7 years.

For existing HID systems, the opportunities for retrofit are more limited, owing to the many different types of ballast and bulb-mounting systems in use. Where these systems are inadequate, the solution will generally involve outright replacement. In the case of replacement, the energy auditor should ensure that the new system provides adequate lighting for minimum operating cost and maximum flexibility of control.

The auditor can rapidly estimate the potential annual savings achievable from reduction in lighting load by using Exhibit 5.76. When performing the calculation for discharge type lamps, he should include the load of any disconnected ballasts. This exhibit can also be used to compare lighting systems by entering the kW for each system and comparing operating costs.

The ability to control lighting systems is the key to savings. Unfortunately, in many facilities, no provision was made at the time of construction for control of the lighting systems. In most cases, a single switch or breaker controls an entire floor or bay, making it difficult to regulate lighting levels as a function of area use. Under these circumstances, the auditor should evaluate the economics of adding circuits for system control.

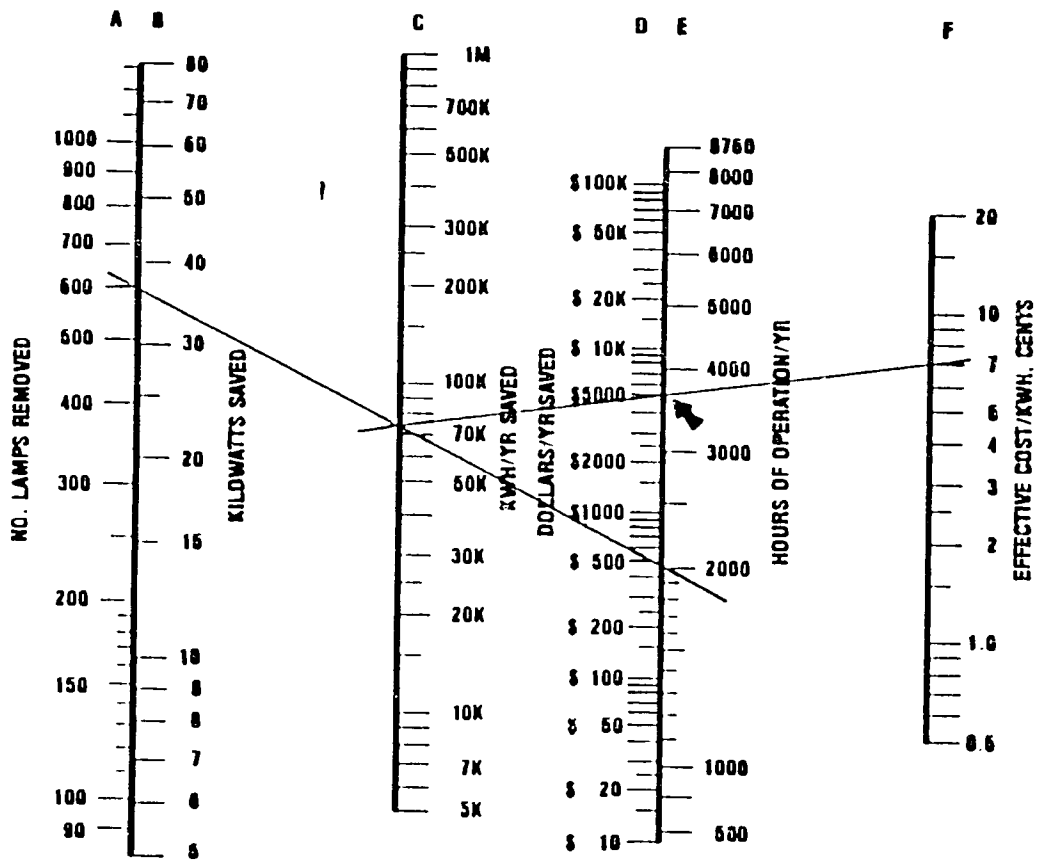
Numerous devices are available on the market today to aid in the control of plant lighting systems. These devices range from simple time clocks to sophisticated sensors that determine whether a space is occupied and turn lights on and off automatically.

Exhibit 5.76

NOMOGRAPH FOR DETERMINING APPROXIMATE ENERGY SAVED BY REMOVING LAMPS

ENERGY EQUALS MONEY—

Here is a conversion chart that tells you how much you will actually save in dollars based on the geographical costs of KWH and as a function of square footage of your building.



INSTRUCTIONS FOR NOMOGRAPH

1. Locate number of lamps to be removed on scale A.
2. Place straightedge from number of lamps to hours of operation per year on scale E.
3. Mark intersection with scale C. This is the number of KWH that will be saved per year, including air conditioning.
4. Place straightedge from mark made in step 3 to effective cost per KWH on scale F.
5. Mark intersection with scale D. This is the approximate dollar savings per year realized by removing the lamps.

COMMENT:

1. If the number of lamps to be removed is more than 1000, divide the number by 10 and use the nomograph. Then multiply the savings by 10. If the number of lamps is less than 100, multiply the number by 10, use the nomograph, and divide the savings by 10.
2. Kilowatts saved (scale B) includes an allowance of ½ watt of air conditioning for each watt of lighting, which is typical of medium-sized installations.
3. Effective cost per KWH (scale F) should be determined by allowing for fixed charges, fuel adjustments, power factor charges, and any other charges made by the utility, the whole divided by KWH used to get the effective cost per KWH.

EXAMPLE:

600 lamps are to be removed from a lighting system. The system is operated 2000 hours/year, and the effective cost per KWH is 7¢.

Connect 600 on scale A with 2000 on scale E. The intersection with scale C is at 72,000 KWH, which is the amount saved per year. From this intersection, run a line (B) to 7¢ on scale F. The intersection with scale D is at $5000, which is the dollar amount that will be saved in energy per year.

For most commercial and industrial applications, the best control devices are time clocks and photocells.

Time clocks are devices that are programmed to turn the lights on and off in a particular area according to a predetermined schedule. This schedule normally tracks the facility's daily operating schedule, with allowance on each end for those who arrive early or leave late. Additional levels of control can be imposed to accommodate the various lighting requirements of normal operation, plant clean-up, and security tours.

Photocells are generally used to control outside security lighting systems and exterior lighting as a function of ambient light levels. This method of control is preferable to time clock control for outside lighting, as conventional time clocks cannot readily account for seasonal variations in daylight hours or for local conditions caused by severe weather. Time clocks and photocells have relatively low capital investment requirements (typically less than $100), and if lamps can be grouped together, energy savings can justify the capital expenditure in less than 12 months.

Reliance Energy Services

ENERGY AUDIT REPORT
FOR
SRI LANKA TYRE CORPORATION
KELANIYA, SRI LANKA
FINAL REPORT

Prepared by:

EDMAC Staff
Ministry of Power and Energy, Colombo

In Collaboration with

Hagler, Bailly & Company
Washington, D.C.

and

Reliance Energy Services
New York, New York

Consultants Financed by United States Agency for International Development (U.S. A.I.D.)

An Activity Undertaken for the
Industrial Energy Conservation Program (IECP)

A Component of the National Energy Demand Management and Conservation Program (NEDMCP)

SRI LANKA
June, 1984

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FOREWORD

This Audit Report is part of the Industrial Energy Conservation Program (IECP) component of a comprehensive National Energy Demand Management and Conservation Program (NEDMCP) undertaken by the Energy Efficiency Demand Management and Conservation (EDMAC) task force of the Ministry of Power and Energy if Sri Lanka.

The four phase IECP was launched by EDMAC in late 1982. Phase I, sensitization, was completed in 1983, and Phase II, which is receiving assistance from the United States Agency for International Development (USAID), has entailed extensive training of plant staff and government officials in energy management for the last twelve months, including on-site training in energy audit techniques.

The major objective of Phase III of the IECP is the implementation of specific projects with the potential for significant energy cost savings.

In Phase IV, scheduled for 1985, the IECP will be entirely self-sustaining, with private and government institutions providing energy audit consulting services, while EDMAC plays a catalytic and policy oriented role.

This report details findings of an energy audit at the Sri Lanka Tyre Corporation, undertaken in March 1984.

The plant was selected jointly by EDMAC and USAID consultants in December 1983 based upon their suitability for auditing and relevance to the Sri Lankan industrial sector.

The energy consuming systems examined during the audit are common to many industrial plants and it is envisioned that similar audit evaluations can be conducted in the majority of the industrial facilities in Sri Lanka, resulting in major conservation savings.

ACKNOWLEDGEMENTS

The energy audit was performed under a joint program sponsored by the Energy Efficiency Demand Management and Conservation (EDMAC) task force, Ministry of Power and Energy, Sri Lanka, the Bureau for Science and Technology, U.S. Agency for International Development (USAID), Washington, D.C., U.S.A., and the USAID Mission to Sri Lanka, Colombo, Sri Lanka.

Technical assistance was provided by consultants from Hagler, Bailly and Company, Washington, D.C., U.S.A., and Reliance Energy Services, New York, U.S.A.

EXECUTIVE SUMMARY

This report details savings from reducing energy consumption at the Sri Lanka Tyre Corporation. Savings estimates are based upon the findings of an energy audit training program conducted under joint sponsorship by EDMAC and USAID in March, 1984.

Potential savings identified in this report, excluding replacement of the boiler plant*, represent 6.82 million Rupees based upon current marginal costs. The energy use reduction is equivalent to 15.9% of the 1983 energy usage. Capital costs required to implement the recommended changes are estimated to be 2.64 million Rupees, giving a simple payback of 0.4 years for the program. A summary of the savings is shown in Exhibit 1.

The training program began with a classroom session, lasting two days. The purpose of this session was to instruct course participants in the use of portable instrumentation, and in the data collection and test procedures. During eight days of site work, the engineers were responsible for testing the wide range of equipment within the plant, including the boiler and ancillary equipment, calender dryers, process equipment, motors and ventilation systems.

The balance of the training program was held in the classroom and consisted of the analysis of the collected data, formulation of energy conservation strategies, and calculation of the savings possible by implementation of the recommended measures. This session lasted a further twelve days.

The energy savings mentioned above and discussed in detail in the report can be achieved by implementation of projects identified during the course of the audit and data analysis.

In order to identify the areas where improvement in energy utilization are possible, the plant was analyzed in the following manner:

A visual inspection of the plant was conducted to familiarize the auditors with the basic layout of the plant, and to identify the most obvious sources of waste. This was followed by the collection of readily available energy related data.

*Boiler plant replacement would save a further 10.6 million Rupees or 33.6% of the energy use at the Tyre Company. The boiler replacement scheme is the subject of an associated feasibility study and hence no costs relating to this measure are presented in this report.

This Preliminary Energy Audit (PEA) included collection of the following types of information:

- energy use by fuel type and source delivered
- energy costs
- inventory of major energy consuming equipment in the plant
- operating schedules for the major departments in the plant
- details on current energy management programs
- information on energy conservation projects being considered, underway, or previously implemented

The PEA data was used to develop a plan for the instrumented testing of major energy consuming process equipment. This equipment was then tested to determine the level of energy waste and the amount of energy that could be usefully recovered.

To ensure full audit coverage of the plant, the plant was divided into a number of discrete areas. Each team of audit engineers was responsible for conducting tests on equipment in each of the areas. The areas were:

- boiler plant, steam distribution and condensate return systems
- electrical distribution and motors
- lighting and environmental systems
- compressed air system
- chilled water plant
- compounding department
- Tyre Building
- calendering department
- vulcanization department

Reliance Energy Services

EXHIBIT 1

	ENERGY DATA				COST DATA	
ITEM	ENERGY SAVED GJ*	COST SAVED Rs	% OF SAVINGS JG*	% OF SAVINGS Rs	TOTAL COST	SIMPL PAYBA YEAR
1. Reduce Blowdown	6107	703,465	4.5	4.0	5,000	-
2. Steam Pipe Insulation	7890	908,849	5.8	5.2	850,000	0.9
3. Steam Leaks	11196	1,289,667	8.2	7.4	200,000	0.2
4. Steam Traps	1261	145,255	0.9	0.8	60,000	0.4
5. Return Condensate	11526	1,327,680	8.5	7.6	25,000	-
6. Power Factor Con.	508KVA	548,640	-	3.1	325,200	0.6
7. Compressed Air Leaks	1661	682,854	1.2	3.9	100,000	0.1
8. Reservoir Vol. Red.	94	38,644	0.1	0.2	15,000	0.4
9. Insul. of Boiler	2954	340,271	2.2	2.0	266,913	0.8
10. Replace Boilers	(92365)	(10,639,524)	67.9	60.9	NA	-
11. Reschedule Depts.	400KVA	432,000	-	2.5	NA	-
12. M G Set Replace	625	260,871	0.5	1.5	375,000	1.4
13. Chillers	348	143,216	0.3	0.8	420,000	2.9
Totals Excluding Boiler	43,672	6,821,412				
Totals Including Boiler	136,037	17,460,936	100.0	100.0	2,642,113**	

*GJ = 10^9 Joules

**Does Not Include Cost For Boiler Replacement

These areas comprise the major process and service functions within the plant.

Analysis of the data collected enabled identification of the potential for energy conservation. This was followed by the formulation of strategies to achieve the energy savings. Each strategy was then further analyzed to estimate the implementation cost required to achieve the savings.
The analysis of implementation and cost savings permit the development of an energy conservation action plan.

The major findings and recommendations of the study are as follows:

- o Electricity is used to provide motive power, compressed air, chilled water and environmental services. It accounts for about 17% of the energy use at SLTC.

- o Fuel Oil is used for steam generation in boiler plant. The steam is used for process heating and drying. Fuel oil consumption represents about 83% of the energy use at the plant.

- o As a cost item, electricity forms 46% of the energy bill, fuel oil 54%.

- o Improvements are needed in the existing energy management program to ensure conservation opportunities are implemented. The improvements include:

  - Hiring a full time employee to assist Mr. P. P. Subasinghe. The duties of the assistant should be confined to energy management, and in the short term focus upon implementing measures with short payback periods. In the longer term he should be responsible for conducting energy analysis on an on going basis.

  - Purchase of instrumentation to support conservation activities including a combustion analysis kit, water test kit, and an electrical equipment test kit.

  - Developing a new energy monitoring system to evaluate energy use on a departmental basis, that will permit energy costs to be assigned by use rather than as overhead.

  - Determining an energy consumption index that accurately reflects energy usage within SLTC. The existing index of energy consumption per standard type is inadequate and does not track energy efficiency within the plant accurately. Separate indices should be developed for electricity and fuel oil.

  - Establishing an energy awareness program for all employees, including posters highlighting conservation methods, distributing information on the cost of energy wastage, possible extension of the incentive schemes given to boiler operators to include other production departments based upon their ability to save energy.

- Improvements in energy utilization at STLC can be made to reduce energy use close to 49%, under existing operating schedules and production output if measures identified in this report are implemented. The measures identified include replacing the existing boiler plant. This item is subject of a separate feasibility study and costs etc. are not discussed here. Potential savings of about 34% of energy use at SLTC can be saved. Efficiency tests showed the boiler efficiency to be 54.1%. The existing plant is in a poor state of repair and near the end of its useful life. Because of this, major capital expenditure which would be necessary to improve the efficiency of the plant is not recommended.

- In the short term, significant energy savings can be made with the plant by reducing the amount of water blown down from the boiler drums. Blow down is done to reduce the level of total dissolved solids (TDS) in boiler water to prevent scaling of the heat transfer surfaces. Currently TDS levels of 175 ppm are maintained as against international standards of 3500 ppm. Little investment is required to implement this measure. Instrumentation for monitoring TDS on a daily basis can be purchased for approximately Rs5000 and blowdown rates adjusted accordingly by the boiler operators.

- A major improvement is required in the operation and maintenance of the steam distribution and condensate return system. Areas for improvement include:
  - insulation
  - repair of leaks
  - repair of steam traps
  - returning condensate to the boiler

  Estimated savings from the rehabilitation of the steam system are 11.6% of the energy use in 1983. All measures are relatively easy to implement, requiring investment of approximately Rs1.1 million, including costs for supply of material and labor to install new materials.

- Overall plant power factor was measured at 0.8. By raising this to 0.95, electrical demand savings would be in excess of Rs500,000 per annum. This measure requires the installation of power factor correction equipment, either static capacitors or using synchronous motors. Estimated capital costs are Rs325,000.

- The compressed air system is in a similar state of repair to the steam distribution system. There are numerous leaks around the system and compressed air is used indiscriminately for comfort cooling by the employees. Savings of Rs680,000 are possible through repairing leaks.

- Electrical consumption can be reduced by implementation of the following measures:
  - reducing the chilled water reservoir volume
  - replacing ac-dc motor generator sets with thyristor drives
  - installing a cooling tower to recirculate condensor water

A total savings of about Rs442,000 is possible for an estimated expenditure of Rs810,000. Implementation will require the purchase of the necessary replacement thyristors and design, purchase and installation of a suitable cooling tower.

As a first step in implementing the measures identified, a three-phase action plan has been developed. The plan, shown in Exhibit 2, is based upon the relative cost benefits and ease of implementation associated with each measure.

EXHIBIT 2

IMPLEMENTATION ACTION PLAN

Phase	Item	Time Frame	Action Required
1	Assistant Energy Conservation Engineer	Immediate	Recruit either in-house or outside.
1	Energy Monitoring Program	On installation of new metering	Establish guidelines for energy monitoring, production monitoring by department
1	Employee Awareness Program	Immediate	a. Post conservation stickers about plant - available from EDMAC. b. Hold informal meeting with factory personnel to outline conservation program c. Collate data on individual department energy performance. d. Advise of cost of energy conservation actions.
1	Boiler Blowdown	Immediate	a. Reduce blowdown to 1 time per 4 hours - 30 seconds duration. b. Purchase TDS monitoring equipment. c. Check TDS 1 time per shift and adjust blowdown until 3000 ppm.
1	Condensate Return	Immediate	Install pipework to reconnect condensate receiving tanks to condensate return system
1	Steam Leaks	Immediate	Locate leaks and plan program to repair as part of maintenance on week-end shutdown
1	Compressed Air Leaks	Immediate	Locate leaks and plan program to repair as part of maintenance on week-end shutdown
1	Insulate Pipework	Immediate	a. Identify missing insulation b. Contact local suppliers c. Order materials d. Install using in-house labor or subcontract

EXHIBIT 2 (Cont'd)

IMPLEMENTATION ACTION PLAN

Phase	Item	Time Frame	Action Required
1	Steam Traps	Immediate	a. Identify faulty traps b. Contact local suppliers c. Order materials d. Install using in-house labor or subcontract.
1	Boiler Replacement	Immediate	a. Feasibility study (underway) b. Take action based on findings of feasibility study
2	Power Factor Correction	Immediate	a. Contact local suppliers and CEB b. Specify static capacitors or synchronous motors c. Order materials d. Install using in-house labor or subcontract
2	Chilled Water Reservoir	Immediate	a. Reduce volume by either altering controls or by filling with bricks
2.	Cooling Tower	Immediate	a. Contact local engineering design for cost-estimate for tower and initial design b. Specification and bid for final design, construction and installation c. Select contractor d. Install
2	M.G. Sets	Immediate	a. Contact local suppliers or CEB b. Specification and budget pricing c. Select rep cements d. Purchase and install using in-house labor

EXHIBIT 2 (Cont'd)

IMPLEMENTATION ACTION PLAN

Phase	Item	Time Frame	Action Required
3	Areas Requiring Further Study	(see below)	
3	Reschedule Departments	Immediate	a. Set up management team to investigate b. Interview production personnel to determine labor needs, production schedules, etc. c. Prepare report on findings d. Implement if cost effective
3	Insulate Existing Boilers	Await Feasibility Study and results	a. Insulate if no decision to replace within 18 months.
3	Raise Chilled Water Temperature	Immediate	a. Monitor existing chilled water temperature pattern at users b. Compare to requirements c. Adjust as possible
3	Chilled Water Recirculation from Tread Aggregator	Immediate	a. Monitor chilled water flow and temperatures through tread aggregator and compare to requirements b. Install recirculation system c. Adjust till optimized
3	Calender Drying	Immediate	a. Check cord specification and condition daily b. Check moisture contents in and out of calender daily for extended period c. Determine whether drying required d. Reduce number of heated cylinders
3	Pipework Layout in Vulcanization Department	Immediate	a. Establish operating needs for vulcanization process for superheated hot water, steam. b. Monitor system performance including scrap, etc. c. Re-evaluate system efficiency

1. BACKGROUND

1.1 Introduction

Reliance Energy Services have produced this report as part fulfillment of their contract with USAID to provide energy audit training to 32 Sri Lankan engineers. The report summarizes energy conservation opportunities identified during an energy audit training program, completed at the Sri Lanka Tyre Corporation (SLTC) plant at Kelaniya in March, 1984. Data collected during the field work has been used to estimate energy savings that can be achieved through implementation of the measures recommended.

The energy audit training was conducted in the following manner:

First, the Sri Lankan engineers received instructions in energy audit techniques in classroom sessions. Half of the 32 were then assigned to perform an actual plant audit at SLTC.

To collect the necessary information to compile this report, the sixteen engineers were split into three teams. Each team was under the guidance of either a USAID consultant or a member of the EDMAC unit.

The teams then followed a systematic approach through which they collected data. The approach used entails, as an initial step, conducting a visual inspection and collation of readily available energy related data. This is known as a Preliminary Energy Audit (PEA). The PEA permits identification of major energy consuming systems that can be evaluated using portable instrumentation during a full Energy Audit.

The plant had been previously visited in December 1983 by members of the training program to conduct a rudimentary PEA. Subsequently, in January and February 1984, members of the EDMAC unit had collected background information that enabled an early determination of areas on which to focus the Energy Audit.

The key areas identified were:

- Boiler Plant
- Steam Distribution and Condensate Return
- Compounding and Extrusion, including chilled water
- Calendering
- Tyre Building
- Vulcanization
- Electrical Systems, including compressed air, lighting and ventilation

Each of the three teams carried out instrumented tests in the above areas, and it is from that test data that the report has been generated.

Each major energy consuming system is tested as part of an Energy Audit to determine its relative energy efficiency and to identify energy cost reduction opportunities.

Having collected the data, it is analyzed to estimate cost benefits arising from implementation of the recommended measures.

An important part of the Energy Audit process is the interviewing of plant personnel to establish procedures, schedules and operation details. During the Energy Audit personnel from the following departments were interviewed by various members of the three teams:

Corporate management
Plant engineering
Operations and maintenance
Production
Quality control
Services

Discussions were also held with representatives from B.F. Goodrich, who are providing technical assistance to SLTC to determine what recommendations they had made regarding energy conservation.

Reliance Energy Services would like to thank the management of the Sri Lanka Tyre Corporation for allowing its facility to be used for training purposes, Palita P. Subasinghe, Senior Power Engineer, for all his kind assistance, members of the EDMAC team and all participants of the training program.

1.2 Plant Description

The Sri Lanka Tyre Company is located on a sizeable tract of land in Kelaniya, about 10 kilometers from Colombo. The company is engaged primarily in the manufacture of tyres and tubes for automobiles, motorcycles and scooters, trucks, and agricultural vehicles. A plant layout identifying major functional departments is shown in Exhibit 3. A brief process description follows.

Raw materials in the form of natural and synthetic rubbers are received, graded, and stored. Rubber is selected for manufacture into tyres based on the requirements of the particular tyre and the properties of the rubber. In a sequence of mixing and milling, the rubber is plastisized and mixed with chemicals and additives, chiefly carbon black and sulphur. The mills consist of rotating cylinders, operating at different speeds which masticate the rubber mix purely by mechanical work. These mills are cooled using chilled water to prevent unwanted chemical reactions and scorching from frictional heating. The rubber is then cooled and dried in a festooner dryer.

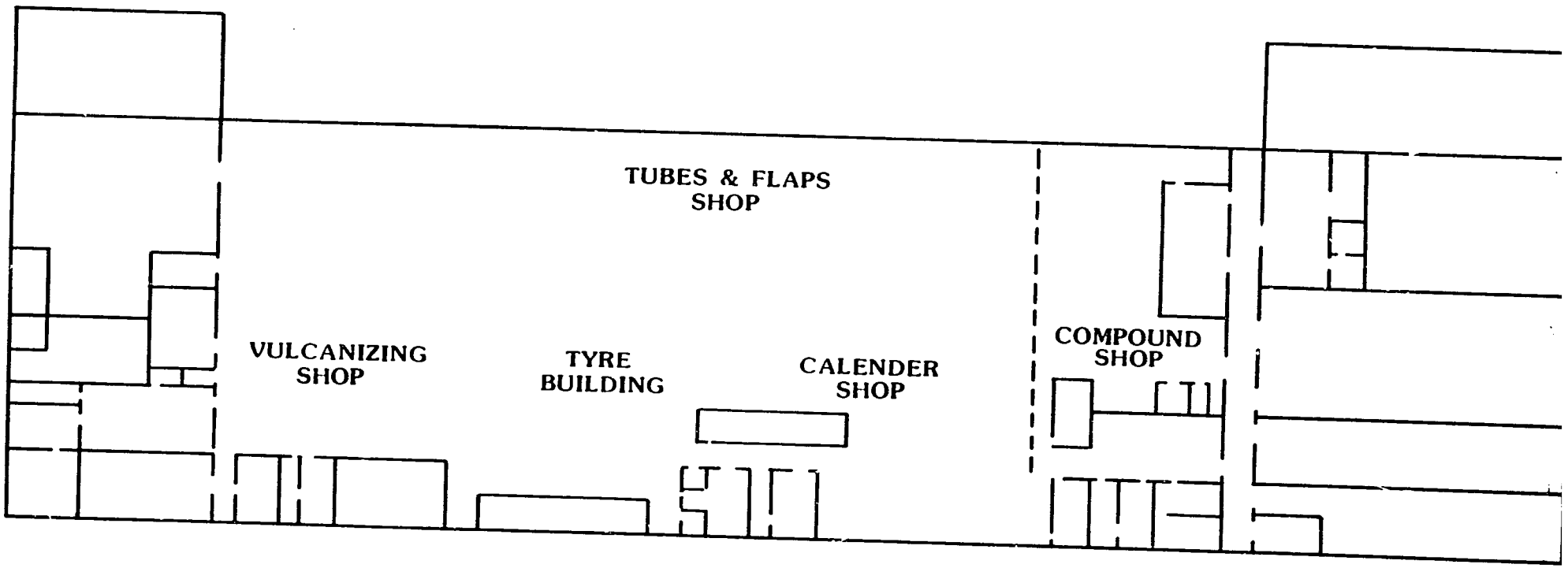
In the extrusion step that follows, the rubber is again milled and then formed into the tread and sidewall shapes. A portion of the rubber is sent to a calendering operation where it is bonded mechanically to nylon fabric to form the cord. Another portion of the rubber is bonded mechanically to copper coated steel wire to form the bead.

In the tyre building step, the cord, sidewalls, tread, and bead are assembled into a "carcass", which bears little resemblence to the finished tyre. This step is very labor-intensive,and involves a great deal of training for operators to become skilled in this process.

EXHIBIT 3

SRI LANKA TYRE CORPORATION

PRODUCTION PLANT LAYOUT



Using pneumatic presses, the carcass is formed into a shape resembling the final tyre. From there, the carcass is placed in a vulcanizer. Vulcanization is the last manufacturing step. Two types of machines are used in this process. The first type, uses a curing bag, a thick walled rubber tube, similar to an inner tube, which is inserted inside the tyre. The vulcanizer contains a mould with the tyre tread and sidewall patterns. Under high temperature, the tyre is formed by melting the rubber into its final form; in addition, a chemical reaction between rubber and sulphur occurs, imparting the desired strength, flexibility and durability characteristics to the tyre. Steam and superheated hot water are used to provide heat to this process. The alternate type of machine used in this step is the Bag-o-matic, which does not require the preliminary forming step or the use of the curing bag. The Bag-o-matic machine is slightly less energy-intensive than the curing bag vulcanization process.

The next stage in the process is quality control, where tyres are inspected and tested. The finished tyre is then stored in a warehouse area prior to shipment.

The manufacture of tubes follows a similar sequence of operation, except that additional extrusion steps take place, and a separate type of vulcanization machine is use.

The physical plant consists of a number of buildings, including the factory, and a number of workshops, administrative office buildings, and employee service buildings. This audit is limited to the first three of these.

The factory was built with support from the USSR; hence most of the equipment within the plant is of Soviet or Eastern Bloc manufacture. The original design employee complement was 550; at present, about 2,000 are employed. Since the original construction in the later 1960's, additional manufacturing capacity has been provided. Currently, the Sri Lanka Tyre Company is participating in a technical assistance program with B.F. Goodrich, at an annual cost of Rs.12 million.

1.3 Operating Schedules

The operation of the tyre factory is broken into a number of process departments. While the operation of the factory as a whole is 24 hours per day, six days per week, (0600 Monday morning through 0600 Sunday morning), exclusive of holidays, individual operating schedules are given in the table below:

	Operating Schedule	
Department	Shifts/Day	Days/Week
Compounding	3	6
Extrusion	2	6
Calendering	1	6
Tyre Building	3	6
Vulcanizing	3	6
Tube Making	2	6

Normal Shift times are: 0600-1400, 1400-2200, 2200-0600 and, as can be seen, are of eight hours duration. Meal times are not staggered; in addition, production is halted for a period before and after shift changes.

To provide steam and chilled water at the start of production on Monday morning, services commence operation several hours before the 0600 Monday start-up time.

1.4 Production Data

Sri Lanka Tyre Company is engaged in the production of tyres, tubes and flaps. The table below reflects the relative production of each type of product for the three years 1981 through 1983. For internal accounting purposes, the plant measures production on the basis of "standard tyres". A standard tyre is equivalent to 33kg of product; these data are shown below as well.

	1981	1982	1983
Tyres:			
Scooter and Motorcycle	544	2,587	3,668
Car and Jeep	89,400	93,402	99,948
Truck	88,206	95,521	97,478
Agricultural	26,724	25,716	25,591
Total Tyres	204,874	217,226	226,685
Bearcat	1,419	2,727	1,117
Tubes:			
Car	61,682	68,872	70,622
Truck	79,912	89,186	86,675
Agriculture	3,181	2,803	2,208
Total Tubes	144,775	160,861	159,505
Flaps	19,519	18,768	22,546
Carpet	1,754	Nil	Nil
Standard Tyres	155,951	165,387	170,444

1.5 Energy Consumption and Costs

The tables below show the energy consumption by type for the year 1983. The costs shown are the use multiplied by the marginal energy costs as billed during the first quarter 1984. This data applies to the tyre factory only, and does not include energy utilization at the water treatment plant.

Consumption and Costs

	Units	Consumption	Annual Cost Rs.(1)	Total Cost %
Electricity	kWh	12,493,800	18,490,824	38.0
Peak	kVA	3,500	3,780,000	7.8
Fuel Oil	gal	1,222,259	26,400,079	54.2
			48,670,903	100.0

Thermal Equivalents

	Annual Energy Equivalent GJ	Marginal Energy Cost Rs/GJ	Total Energy %
Electricity	44,978	411.11	16.5
Fuel Oil	229,296	115.19	83.5
	274,274		100.0

Conversion to GJ

Electricity - 0.0036 x kWh
Fuel Oil - 0.1876 x gallons

(1) Based on costs in first quarter 1984.

Electricity is purchased from the Ceylon Electricity Board (CEB) under the IP-3 Rate Schedule (Industrial Power). The current charge for electricity is Rs. 1.48 per kilowatt-hour (inclusive of all adjustments). In addition a demand charge of Rs. 90.00 per kilovolt-ampere (kVA) is levied. There is no separate charge for kilowatt demand; hence the levied demand charge accounts for power factor.

Fuel oil is purchased from the Ceylon Petroleum Corporation (CPC). Currently, fuel oil with a viscosity of 1000 seconds is used; this has a heating value of 10,178 kcal/kg. The fuel has a specific gravity of 0.96. The cost is Rs. 21.61 per gallon.

1.6 Major Energy Systems

Energy is consumed by several major energy systems. A listing of the major users is given in Appendix 3. Electricity is used predominantly for motive power, chilled water generation, compressed air and lighting. Fuel oil is burned to produce steam that is used almost exclusively for process requirements.

The boiler plant comprises three water tube boilers, each rated at 6.5 tonnes per hour at a working pressure of 16 bar. Each boiler has an associated economizer. The economizer is used for feedwater preheating by heat recovery from the stack gases.

The steam generated is supplied to the production areas at two pressures, 16 and 8 bar, where approximately 95% is used for process needs. The other 5% is used for cooking and water heating.

The single largest consumer of steam is the vulcanization department, which accounts for about 85% of the plant steam needs. Steam is used at 16 bar to generate superheated hot water at 175°C in three shell and tube heat exchangers. It is also used directly inside the vulcanizers at 16 and 8 bar.

The vulcanization process consumes about 80% of the overall steam generated. Flash steam is generated at 3 bar from condensate and used in the calendering department. The remaining steam is used for making flaps and mats in plattens, in the laboratory, and in the compounding department for heating chemicals.

Chilled water is produced at 16°C in an ammonia refrigeration plant rated at 500 tons. Approximately 200-300 tons of refrigeration are normally used. The chilled water is used for cooling mills in the compounding, extrusion and calendering departments.

Compressed air is produced in three reciprocating compressors capable of supplying up to 90 M^3 per minute of compressed air at 7 bar. The compressed air is used in all departments for penumatic cylinders, instrumentation and controls.

Lighting is provided predominantly by mercury vapor lamps. The estimated lighting load is 375 kW. Lighting is only used part of the day in certain areas where natural lighting is insufficient.

The main electric consumers are AC-DC motors in the various departments. The largest motors are used in the compounding and extrusion departments, for mixing rubber and chemicals and for forming the several components that make up a tyre.

2. FINDINGS

The following sections summarize the findings of the energy audit. Two distinct areas are focused upon, the first the management of energy within SLTC and secondly energy utilization within specific systems and departments.

2.1 Energy Management Program

2.1.1 Structure

An energy management program was established in 1981. The program is under the direction of Mr. P. P. Subasinghe, Senior Power Engineer. As Senior Power Engineer, the amount of time that can be devoted to the program is extremely limited. At the time of the audit, for example, the Tyre plant had only two electrical engineers including Mr. Subasinghe himself.

The effect of the lack of manpower with time to spend on energy-related matters means that the program has not been able to establish sufficient direction. Management has stated that it is willing to provide funding for energy conservation projects and they will be given a high priroity. This view is supported by its encouragement of various agencies to review the energy status of the plant. Despite the reviews and management's positive view of energy conservation the plant is unable to document any energy savings.

There are two possible reasons why SLTC cannot demonstrate energy savings at the plant. The first is that projects that have been implemented may not have had sufficient impact to offset any fall off in energy efficiency that may have occured elsewhere in the plant. Secondly, the plant energy monitoring system and consumption index may not be adequate to indicate any savings that are being acheived.

2.1.1 Achievements

Based upon discussions with plant personnel during the Energy Audit measures that have been implemented include:

- increasing chilled water temperature from 15°C to provide 18°C at the process
- using a more effective chemical peptizer to aid plastication of the rubber, thereby reducing energy in the mixing process
- elimination of part of the cooling cycle in the vulcanization process
- constant monitoring of product quality and specification
- improving natural lighting by using clear fibreglass sheets for roofing, and cutting back on artificial lighting
- staggering machine start up
- eliminating pipe leaks
- insulating pipe lines
- using an incentive scheme to reward boiler operators for efficient operation

2.1.3 Monitoring

Plant energy use is monitored on a monthly basis, and efficiency gauged using an index of energy consumption per standard tyre. No attempt is made to break out energy use for any stage of production and costs are assigned as overhead rather than by function.

Steps have been taken to improve the monitoring program by purchase of four oil meters to be fitted in the boilerhouse to measure oil flow to individual boilers. Although other metering instrumentation is fitted much of it is old and obsolete or spares are difficult to obtain.

2.2 Energy Utilization

2.2.1 Boiler Plant

The boiler plant consists of three watertube boilers of Russian manufacture. The boilers are each rated to produce 6.5 tonnes of steam per hour at a pressure of 16 bar. In normal operation, one boiler operates at high fire, one at low to medium fire, and the third is under maintenance. Duty is rotated every six months. The average steam demand is of the order of 7.5 tonnes per hour, with instantaneous peaks up to 10 tonnes occuring for periods of less than two minutes. In a normal work week, the boilers are fired at 0430 Monday morning and continue operation until all processing is completed on Sunday morning.

The boilers fire fuel oil with a viscosity of 1000 seconds. Fuel oil is obtained from Ceylon Petroleum Corporation (CPC).

The Boiler plant is in generally poor condition owing to a number of factors. The main cause is the apparent lack of regular and formal preventive maintenance procedures. This is compounded by the difficulty in obtaining spare parts for the boiler and ancillary systems.

The overall boiler plant efficiency is estimated to be 54.1% for both boilers firing at the time of the test. This was determined by measurement of fuel and feedwater flow rates for both boilers. An attempt was made to measure combustion efficiency using chemical analysis, but these results are not reliable. The high degree of smoking by the boilers necessitated the approach taken. Measurements taken with a Bacharach True-Spot Smoke Tester showed the smoke number of be in excess of 9 on a scale of 1 to 9, on all firing rates for both boilers. This was observed even when the combustion air dampers were adjusted to provide maximum combustion air.

A number of factors contribute to the poor efficiency of the boiler plant. The fuel oil is heated to 110°C prior to firing, but even though this temperature is recommended by CPC, it is evidently too low.

The boiler burners are of the pressure jet type, with steam atomization. Each boiler employs two burners. The burner housings are in poor condition, being bent and distorted. This causes uneven distribution of oil with respect to primary and secondary combustion air supply. The burners

overfire and the flame impinges on the back wall of the combustion chamber, causing soot deposit.

The burners are manually controlled. Observation of plant practice indicated that only the oil flow is adjusted when the firing rate changes; the combustion air supply is not adjusted. In addition, only one of the two burners is adjusted, causing uneven firing.

The boiler brickwork is also in poor condition, showing signs of deterioration by acid corrosion. This is due to the high sulphur content of the fuel oil fired and the soot depositing on the brickwork.

The incomplete combustion and uneven firing causes soot buildup and pressurization within the combustion chamber. As a result, the relief vent is permanently open. In addition, sootblowing must occur every four hours to remove soot deposit buildup. The boilers are not well-insulated. The boiler shell itself is bent and distorted. In addition, there are numerous steam leaks and leaking valves in the boiler plant. Many pipes have missing or damaged insulation.

Makeup water is supplied from the pumping plant located at the river. The water is softened by base exchange. At the time of the plant visit, no condensate was being returned to the boiler and 100% makeup water was being used. Feedwater is supplied from a deaerator, which heats the water to 88°C. This temperature is not high enough to ensure removal of dissolved oxygen. Feedwater is pumped to the boiler using an electric pump. A steam driven feedwater pump is used during power outages; because this pump is undersized it cannot be used except during these times.

Tests of total dissolved solids (TDS) levels in the boiler feedwater indicate that the boilers are being blowndown too frequently. The company should purchase a conductivity meter to measure boiler TDS and blowdown only when necessary.

The boilers are each fitted with economizers for preheating boiler feedwater. The economizers draw outside air, reducing their ability to achieve maximum heat transfer.

As a general comment, the state of boiler plant instrumentation and safety equipment is poor. Boiler water level alarms, both high level and low level, are inoperative, which is extremely dangerous. It is recommended that these conditions be remedied immediately.

A major upgrading of the boiler plant is required. While replacement of the boiler burners may increase combustion efficiency, the design of the boilers may require complete rebuilding of the front of the boilers to accomodate the new burners. This replacement may not increase combustion efficiency sufficiently to warrant the expense. It is recommended that a complete boiler plant replacement be undertaken.

2.2.2 Steam Distribution and Condensate Return System

The steam distribution and condensate return systems are generally in poor condition. The steam distribution system has numerous leaks and areas where insulation is missing or damaged. In addition, there are few steam traps, and in particular none on the main 8 bar and 16 bar distribution lines. Of the steam traps existing, none are maintained regularly. In the main steam lines are uninsulated near the point of consumption. In a number of areas insulation thickness is inadequate and valves, flanges and other fittings are uninsulated. At the time of the site visit, no condensate was being returned to the boilers. Condensate is collected in recesses in several areas in the plant and then sent to drain.

The major use of steam is in the vulcanizing department. Steam is used directly at 8 bar and 16 bar, and is also used to generate superheated hot water. A separate power unit within the main plant produces superheated hot water in a bank of heat exchangers. The heat exchangers are poorly insulated. Instrumentation in the area is poor and generally not functioning. In addition, a number of problems exist in producing superheated hot water at the temperatures and in the quantities required by the vulcanizers. Variations in superheated hot water supply have adverse effects on product quality.

It should be noted that the steam traps serving the vulcanizers are malfunctioning. The steam traps incorporate an air relief valve, which, in many cases, passses live steam to the atmosphere.

Part of the condensate from the steam used to produce superheated hot water is used to produce flash steam for use in the calender dryer. It was noted that the steam pipework from the flash vessel to the calender dryer was flooded. In addition, many of the steam traps serving the dryer were inoperative or leaking steam.

Steam control valves are generally oversized, which contributes to the erosion of valve seats. This is particularly serious in the vulcanizing area.

2.2.3 Compounding Department

Energy use in the compounding department is primarily electricity for motive power and chilled water. The compounding department is responsible for the production of rubber by addition of carbon black, sulfur and other chemicals to the raw rubber. In the process, the raw rubber is masticated in compounding mills, to impart the desired properties and ensure mixing of rubber and additives.

There are two compounding mills in this department, one of 430 hp and one of 215 hp. A single festooner mill uses a 215 hp motor. All of these motors are of the synchronous type.

There is little scope for savings in this area. One possible opportunity is to ensure that operators in this department do not run the mills unnecessarily when no rubber is being processed. Another is to ensure that the chilled water supply to idling units is shut down.

2.2.4 Extrusion Department

Energy use in the extrusion department is primarily electricity for motive power and chilled water. The extrusion process supplies additional mastication of the rubber prior to incorporation into the tyre carcass. A number of warming mills operate on a common shaft from a single motor generator. Low power factor was observed on some smaller motors in this area.

2.2.5 Calendering Department

Energy used in the calendering department is electricity and steam. Both are used in the calendering process. This department is responsible for the production of rubberized tyre cord. The cord is made by impregnating nylon fabric with rubber under conditions of heat and pressure.

The nylon fabric is dried and heated by passage through a drying chamber prior to the actual calendering operation. A number of problems were observed in this drying operation. First, the nylon fabric was tested and found to be within the dryness specification before drying.

The dryer is an enclosed chamber which contains several stands of steam heated cylinders. There are a number of major steam leaks within the dryer, from steam traps and from rotary joints. The net effect is that the dryer vents live steam to the atmosphere, and very little drying actually occurs. The dryer outlet also vents air heavily laden with water vapor, causing the fabric to be rewetted. Finally, due to the distance between the dryer outlet and the calender mill, the nylon fabric has cooled to ambient temperature again while travelling this distance. It is recommended that SLTC perform tests to determine if the drying operation is needed and if the cord quality drops if the step is eliminated. Based on observations made during the site visit, SLTC would probably be able to eliminate this drying step.

It was further observed, with respect to the dryer, that the incoming steam line is flooded. In addition, steam traps have failed and live steam is passed through to the condensate line.

2.2.6 Tyre Building Department

The tyre building department incorporates a labor-intensive step to assemble the tyre from its component parts. No specific recommendations can be made for this area.

2.2.7 Vulcanizing Department

In the Vulcanizing department, the assembled tyre carcass is subject to high temperature and pressure to cause the chemical reaction (vulcanization) and physical changes required to produce the finished tyre through the use of steam, at 16 and 8 bar, superheated hot water and chilled water. Two types of vulcanizing machines are used in this department. The first type, shear strip vulcanizers, are older machines requiring the use of a curing bag. The second type, the "Bag-O-Matic" vulcanizers are much newer and

incorporate a thin-walled bladder which serves the purpose of the curing bag. The Bag-O-Matic machines are more energy efficient than the shear strip machines and require a shorter cycle time.

A number of problem areas were observed in this department. The major problem is in the distribution of superheated hot water to the vulcanizer. Because of uneven and almost random time demands by the vulcanizers for superheated hot water during the process regime, there is difficulty in maintaining the temperature and quantities of hot water required. The problem is compounded by the lack of controls and functioning instrumentation in the Power Unit. Vulcanization capacity has been added without increasing the superheated hot water production capacity of the Power Unit.

While this is more of a process problem than an energy problem, the difficulty is reflected in energy use, since it contributes to products which do not meet quality standards and are rejected, causing waste. It is recommended, therefore, that SLTC investigate, through B.F. Goodrich and other resources, avenues for improvments in this area, including controls and process scheduling.

Another problem identified is that of surface heat losses from the vulcanizing machines. Air from the ventilation system serving the vulcanizing area impinges directly on the vulcanizers, causing an excessive heat loss. This is compounded by the lack of surface insulation on the vulcanizers. It is recommended that the distribution pattern of the ventilation air be changed to reduce this problem.

Feeder lines to the vulcanizers are uninsulated, causing a large drop in temperature along the feeder line. These lines should be insulated immediately. Many of the steam traps serving the vulcanizers are operating improperly. Some pass steam to the atmosphere, due to the relief vent being unsecured; others pass steam into the condensate system, due to malfunction. Both of these problems should be corrected immediately.

Steam and superheated hot water supply lines to inactive vulcanizers should be secured, as a number of these machines were found to be leaking. The leaks should be repaired, as well.

During the site visit, a number of two-tyre vulcanizers were found to be processing only a single tyre. This practice should be discouraged, as it is extremely wasteful because steam and superheated hot water is supplied to both chambers.

2.2.8 Tube Manufacturing

The tube manufacturing section of the plant was not operating (except for the tube vulcanization) at the time of the site visit. It is expected that this department experiences many of the same problems as the others, particularly in the extrusion areas.

2.2.9 Electrical Systems

In general, electrical systems in the plant were found to be in good condition. A number of areas for improvement were identified, however.

Overall plant power factor was estimated to be in the 80-85 percent range. A number of motors were observed to be running at low load, and low power factor. It is possible to increase overall power factor by installation of a capacitor bank at the incoming factor; or to improve the power factor of the culprit motors by installation of local capacitors. In addition, the existing synchronous motors can be used for power factor correction by adjustment of motor excitation. It is also recommended that the installed power factor meters, which are inoperative, be replaced.

Examination of current plant operations and scheduling revealed that there may be a savings in peak demand available through the rescheduling of some departments. The departments are extrusion and calendering. This would ensure that certain motors in the rescheduled departments are not used simultaneously.

A number of points need to be considered before rescheduling, to determine if a net savings would be accrued to the plant. These factors include employee shift premiums, and the ability of the plant to respond to potential changes in production priorities.

During the site visit, it was observed that motors in some areas operate unnecessarily. This includes exhaust fans operating when the department or process area served are inactive. This practice should be discouraged.

2.2.10 Compressed Air Systems

Compressed air for the plant is provided by three 180 kW air compressors. While the compressors themselves are adequate, the use of the compressed air within the plant is not efficient.

The compressed air distribution system is poor, with numerous leaks. In addition, compressed air is used by employees for personal comfort cooling. Finally, local compressed air control valves are not secured when the compressed air is not needed; the valves generally serve a length of rubber tubing. It is recommended that compressed air leaks be repaired and that a spring loaded valve be fitted to the ends of the rubber tubing. The use of compressed air for comfort cooling should be discouraged.

2.2.11 Chilled Water Plant

The chilled water plant consists of five 100 ton ammonia compressors which are manually started and sequenced. Automatic controls for supply temperatures and sequencing should be considered. Chilled water is used to cool process equipment, particularly mills. Chilled water is produced at 14°C for use in the plant. Chilled water is required to be about 16°C at the mills, in order to prevent scorching. The chiller plant operates continously during plant operation hours, but is started at midnight Monday morning to provide sufficient chilled water for plant needs.

The supply temperature of the chilled water has been increased gradually, at Mr. Subasinge's suggestion, to reduce energy consumption. The limiting factor, however, is the tendency of the milled rubber in the compounding department to exhibit undesirable properties when the mill rolls are not

kept cool enough. Mr. Subasinghe should continue in his efforts to increase chilled water temperature until the maximum temperature that does not cause problems is reached. The temperature controls should then be maintained at this level.

Heat is rejected from the condenser of the chiller plant by a once-through cooling system employing river water. Since the river water must be pumped some distance, savings can be achieved by installation of a cooling tower.

The chilled water is returned from the plant into a 250 cubic meter reservoir. During the hours before plant startup on Monday morning the chiller plant operates for the sole purpose of cooling down this reservoir; during these hours, a bypass valve allows the chilled water to be circulated between the evaporator and the reservoir without being pumped through the plant.

The reservoir may be oversized for plant needs based on pumping capacity. It is suggested that the reservoir volume be gradually reduced, and the start-up time shortened, to achieve energy savings.

It was noted that the chiller plant operates during normal working hours with the bypass valve open. Chilled water cirulates between the chiller and the reservoir. The reservoir water temperature was found to be less than the return chilled water temperature. Chiller plant operators must close this bypass when the process operations are in use.

Losses of ammonia from the system were observed, as were uninsulated areas of pipework and ancillary equipment. These conditions should be remedied.

There may be an opportunity to recycle chilled water in the tread aggregator. Currently, a once-through spray system is used to cool the tread. It may be possible to recirculate the chilled water, by the way of a sump, to reduce requirements in this area, and achieve energy savings. In addition, there may be an opportunity for chilled water cascading. This involves using the chilled water discharge from one process as supply to another which can use chilled water at a higher temperature than the first process.

2.2.12 Lighting and Environmental Systems

Lighting is primarily by mercury vapor luminaires, which is supplemented by daylight. Translucent panels are being added to the roof to admit more natural light. This ongoing program was initiated by Mr. Subasinghe.

Savings may be achieved by conversion of luminaires to high pressure sodium. Because of the color of the lighting, however, caution should be taken in initiating HPS luminaires in the bead making area, since the copper coated wire used there cannot be seen in the light produced from high pressure sodium lamps.

Few lights are used unnecessarily, or left on when the area was unoccupied. The tyre storage area is an exception to this, however, and lights were observed to be in use when the area was unoccupied.

As mentioned above, some ventilation system motors operate unnecessarily. This practice should be eliminated. In addition, some ventilation air flows were noted to be quite high. Energy savings can be made by adjusting the pullies to reduce air flow.

3. RECOMMENDATIONS

The following sections present recommendations for improving energy efficiency at SLTC. Recommendations have been made in two areas, energy management and energy utilization. The measures in the energy management area detail improvements in the existing company energy management program designed to foster an ongoing committment to energy conservation at SLTC. The measures in the energy utilization area represent real cost reduction opportunities at SLTC. Opportunities are identified in three distinct groups - those measures that have simple paybacks of less than one year, those with simple paybacks over one year and those opportunities that offer significant potential but require further investigation and study before any firm committment to implement can be made.

3.1 Energy Management

3.1.1 Structure

The structure of the existing energy management program is reasonably sound but there is scope for improvement. A greater committment of resources should be made by SLTC, both in terms of manpower and funds. The following paragraphs discuss specific recommendations felt necessary to bring about implementation of measures identified and to be able to demonstrate the savings associated with the measures:

Because of Mr. Subasinghe's other duties, he is unable to give the program all the attention it warrants. Hence, it is recommended that SLTC provide a full-time assistant to Mr. Subasinghe, whose duties would be related solely to energy conservation and management.

The assistant should have an engineering background but have knowledge of economics. His duties would be to coordinate all energy management activities under the supervision of Mr. Subasinghe, and to take a very active role in the implementation phase of the program. He should be responsible for developing an energy data base and for data collection within the facility. He should initially focus his time upon three things:

- Implementation of identified projects with quick paybacks and projects requiring further study.
- Establishing a new monitoring and reporting system.
- Developing an employee awareness program.

After these projects are under way, he should concentrate upon:

- Implementation of identified projects with extended paybacks.
- Developing an energy index that better describes energy use with respect to production, product mix and operational parameters that impact energy efficiency.
- Conducting the energy audit process on a continuous basis thereby maintaining energy efficiency.
- Establishing energy targets and norms for individual energy consuming equipment and processes within SLTC.

Funding should be provided by SLTC to allow the purchase of instrumentation for testing purposes to ensure that energy consuming equipment is operating at peak efficiency. While it is recognized that SLTC has allocated funds for the purchase of flow metering equipment for the boiler plant, additional equipment is required.

This instrumentation should include:

- Combustion analysis equipment including flue gas analyser, temperature indicating equipment and draft gauge.
- Water test kit including equipment for measurement of TDS, dissolved oxygen pH levels, sulphite and chlorides as a minimum.
- Electrical measuring equipment to measure volts, amps, power factor, and kilowatts.

3.1.2 Monitoring

A new energy monitoring system should be developed that seek to evaluate energy use on a departmental basis. Also, variables such as operating hours, production and product mix, should be tracked on the same time frame. Using installed metering should permit the monitoring to take place on a weekly basis.

When the new monitoring program is in place, then data should be used to develop a new energy index for the plant. Rather than combining energy as at present, separate indices should be established for electricity and oil. One method that can be used to develop indices is the multilinear regression technique. This uses historical data to develop a model for the plant based upon energy use. However, sufficient historical data must be available to ensure the model's validity.

3.1.3 Awareness

To succeed in energy conservation efforts, it is necessary for all employees to take part in the energy management program. To do this an energy awareness program for company employees is needed. This program should take the form of both formal and informal activities which will increase employee participation and cooperation in achieving an overall reduction in plant energy use.

These activites should include:

- Posters highlighting easy conservation methods such as turning unwanted lights off, value of compressed air leaks.
- Informing operations employees of the value of energy wastage.
- Possible incentive schemes for departments demonstrating energy conservation.

3.2 Energy Utilization

Energy savings shown have been developed at the basis of existing production levels and operating schedules. Cost savings have been calculated on the basis of market marginal costs in effect for the first quarter of 1984. No attempt has been made to predict future fluctuations in energy costs.

3.2.1 Measures With Simple Paybacks Under One Year

The following recommendations for energy cost reduction measures in this section have simple paybacks under one year.

3.2.1.1 Reduce Blowdown

Measurements of the boiler drum water indicated very low levels of TDS. On average, the level was found to be 175 ppm. The American Association of Boiler Manufacturers' recommended level of TDS for boilers similar in design and pressure to those at SLTC is 3000 ppm. Raising the TDS through reduction of blowdown will give energy savings as outlined in Appendix 15. To implement this measure successfully SLTC should purchase a TDS meter to monitor water conditions on a daily basis.

Energy Savings	= 6,107 GJ/Year
Cost Savings	= Rs 703,465/Year
Cost of Implementation	= Rs 5,000
Simple Payback	= 0.01 Years

3.2.1.2 Steam and Condensate Pipe Work Insulation

Insulation of bare steam and condensate pipework, flanges and valves throughout the plant will reduce radiation losses and boiler loading. Appendix 16 gives details of areas where insulation is missing. Implementation can be carried out using in-house labor.

Energy Savings	= 7890 GJ/Year
Cost Savings	= Rs 908,849/Year
Cost of Implementation	= Rs 850,000
Simple Payback	= 0.9 Years

3.2.1.3 Repair of Steam Leaks

Energy can be saved by a steam leak repair program throughout the distribution system. Appendix 17 shows the location of leaks. Implementation of the measure can be done using in-house labor.

Energy Savings	= 11196 GJ/Year
Cost Savings	= Rs 1,289,667/Year
Cost of Implementation	= Rs 200,000
Simple Payback	= 0.2 Years

3.2.1.4 Repair of Steam Traps

There are a number of steam traps that have failed and are passing steam. A program for steam trap maintenance including testing and repair will give reduced steam requirements. Appendix 18 gives the location of the faulty traps. Implementation can be done using in-house labor.

Energy Savings	= 1261 GJ/Year
Cost Savings	= Rs 145255/Year
Cost of Implementation	= Rs 60,000
Simple Payback	= 0.4 Years

3.2.1.5 Return Condensate to Boilerhouse

Condensate that is currently run to drain can be returned to the boiler and reduce energy consumption for steam generation. The implementation of this measure is easy to do and only entails some repiping. Appendix 19 gives details of the estimated savings.

Energy Savings	= 11526 GJ/Year
Cost Savings	= Rs 1,327,680/Year
Cost of Implementation	= Rs 25,000
Simple Payback	= 0.1 Years

3.2.1.6 Power Factor Correction

Overall plant power factor is 0.8 and can be raised to 0.95 by installing static capacitors, or by using the synchronous motors. Appendix 21 gives details of the potential savings.

Energy Savings	= 508 KVA
Cost Savings	= Rs 548,640/Year
Cost of Implementation	= Rs 325,200
Simple Payback	= 0.6 Years

3.2.1.7 Repair of Compressed Air Leaks

A compressed air system maintenance program will realize significant savings through repair of leaks from pipework fittings. Many of the leaks were found to consist of hoses that were used for comfort cooling by the employees. They should be made aware of the costs of compressed air wastage. Appendix 22 details the location of the leaks.

Energy Savings	= 1661 GJ
Cost Savings	= Rs 682854/Year
Cost of Implementation	= Rs 1000,000
Simple Payback	= 0.1 Years

3.2.1.8 Reduction in Reservoir Volume

The plant uses a reservoir of chilled water (250 cubic meter volume) to ensure on-time starting on Mondays. The capacity of the chilled water reservoir can be reduced without adverse effect on production start up on Monday mornings. Appendix 24 outlines savings.

Energy Savings	= 94 GJ
Cost Savings	= Rs 38644/Year
Cost of Implementation	= Rs 15,000
Simple Payback	= 0.4 Years

3.2.2 Measures with Simple Paybacks Over One Year

3.2.2.1 Use of Cooling Tower to Recirculate Condenser Water

The existing ammonia chilling plant has a once through condenser water system which consumes a lot of water. Condenser water can be recirculated to the Chiller Plant via a cooling tower rather than running the water to drain. Appendix 23 gives details. To implement this will require some engineering design for the exact type of cooling tower.

Energy Savings	= 348 GJ
Cost Savings	= Rs 143,216/Yr
Cost of Implementation	= Rs 420,000
Simple Payback	= 2.9 Years

3.3 Projects Requiring Further Study

3.3.1 Replacement of Existing Boiler Plant

The existing boilers have very low efficiencies due to poor combustion conditions, and state of repair. Significant energy savings could be made by replacement of the plant. The work involved to determine the best option for the new plant is beyond the scope of this study. A feasibility study is being prepared examining the options available. It is estimated that energy savings will be significant enough to give a good rate of return on investment. The numbers shown in Appendix 26 indicate potential savings based on replacement with a plant using the same fuel.

Energy Savings	= 92,365 GJ/Year
Cost Savings	= Rs 10,639, 524/ Yr

3.3.2 Thermal Insulation of Boiler Plant

Energy can be saved by insulating the existing boilers to reduce their radiation losses. However this measure should be considered with respect to replacement of the existing plant before any decision is made to implement.

Energy Savings	= 2954 GJ
Cost Savings	= Rs 340271/Year
Cost of Implementation	= Rs 266913
Simple Payback	= 0.8 Yrs

3.3.3 Demand Savings Through Rescheduling Department Operating Schedules

Demand savings can be realized by rescheduling the operations in the extrusion and callendering department to three shift operations. Appendix 25 details proposed changes. Because this would involve changes in labor requirements it is recommended that this be studied further before the measure be implemented. The energy cost savings are presented to indicate potential if the measure can be implemented.

Energy Savings	= 400 KVA
Cost Savings	= Rs 432,000/Year

ITEM	ENERGY DATA: ENERGY SAVED GJ	ENERGY DATA: COST SAVED Rs	ENERGY DATA: % OF SAVINGS GJ	ENERGY DATA: % OF SAVINGS Rs	COST DATA: DESIGN COSTS	COST DATA: SUPPLY COST	COST DATA: INSTALLATION COST	COST DATA: TOTAL COST	COST DATA: MAINTENANCE COST	COST DATA: USEFUL LIFE YRS
1. Reduce Blowdown	6107	703,465	4.5	4.0	-	5,000	-	5,000	-	25
2. Steam Pipe Insulation	7890	908,849	5.8	5.2	50,000	600,000	200,000	850,000	50,000	15
3. Steam Leaks	11196	1,289,667	8.2	7.4	-	100,000	100,000	200,000	50,000	15
4. Steam Traps	1261	145,255	0.9	0.8	-	54,00	6,000	60,000	20,000	10
5. Return Condensate	11526	1,327,680	8.5	7.6	-	15,000	10,000	25,000	20,000	15
6. Power Fact Con.	508KVA	548,640	-	3.1	32,500	219,525	73,175	325,200	10,000	20
7. Compressed Air Leak	1661	682,854	1.2	3.9	-	75,000	25,000	100,000	20,000	
8. Reservoir Vol. Red.	94	38,644	0.1	0.2	-	7,500	7,500	15,000	1,000	20
9. Insul. of Boiler	2954	340,271	2.2	2.0	16913	187,500	62,500	266,913	20,000	15
10. Replace Boilers	(92365)	(10,639,524)	67.9	60.9	NA	NA	NA	NA	NA	25
11. Reschedule Depts.	400KVA	432,000	-	2.5	NA	..NA	NA	NA	NA	NA
12. M G Set Replace	625	260,871	0.5	1.5	37,500	253,125	84,375	375,000	20,000	15
13. Chillers	348	143,216	0.3	0.8	42,000	30,000	78,000	420,000	20,000	20
Totals Excluding Boiler	43,672	6,821,412								
Totals Including Boiler	136,037	17,460,936	100.0	100.0	178,913	1,816,650	646,550	2,642,113*	231,000	

*Does Not Include Cost For Boiler Replacement

GJ = 10^9 x Joules

APPENDIX 2

SUMMARY OF SAVINGS BY FUEL TYPE

FUEL	ANNUAL SAVINGS		GJ SAVINGS*	COST SAVINGS Rs
Electricity	908	kVA	-	980,640
Electricity	663,889	kWh	2,390	982,369
1000 secs Fuel Oil	710,549	Gal.	133,299	15,354,711
Totals			135,689	17,317,720

CONVERSION TO GJ*

Electricity - 0.0036 x kWh

1000 secs Fuel Oil - 0.1876 x gallons

APPENDIX 3

INVENTORY OF MAJOR EQUIPMENT

COMPOUNDING DEPARTMENT

Item	HP	(kW)
Banbury Mixers (2)	each 770 HP	(574 kW)
Plasticising Mill (1)	215 HP	(160 kW)
Compounding Mill (2)	each 430 HP	(321 kW)
Festooner Mill (1)	215 HP	(160 kW)
Festooner Dryer	65 HP	(48 kW)
Strainer		(100 kW)

EXTRUSION DEPARTMENT

Mills (3)	each 470 HP	(351 kW)
Mills (2)	each 430 HP	(321 kW)
Motor Generator		(160 kW)

CALENDERING DEPARTMENT

Calender Drive (DC)	250 kW
Dryer (Main)	19 kW
Dryer (Intermediate)	11 kW
Squeegee Calender (DC M.G.)	100 kW

TUBE MAKING

Motor Generator	160 kW
Strainer	100 kW
Mills (2)	125 kW
Mill	165 kW

TYRE BUILDING

Motor Generator	75 kW
Motor Generator	32 kW

BOILER PLANT

3 Boilers, each 6.5 tonnes/hour steam at 16 bar

CHILLED WATER PLANT

5 Compressors	each 100 kW
Chilled Water Pump	35 kW
Condenser Water Pump	46 kW

COMPRESSED AIR PLANT

3 Compressors	each 180 kW

APPENDIX 4

BOILER DETAILS

LOCATION: Boiler House

Boiler	1	2	3
Manufacturer:	Not known	Not known	Not known
Age (years):	20	20	20
Type:	Water Tube	Water Tube	Water Tube
Rating (T/hr):	6.5	6.5	6.5
Medium raised:	Steam	Steam	Steam
Normal operating pressure (bar):	16	16	16

Burners			
Number:	2	2	2
Fuel fired:	Fuel oil	Fuel oil	Fuel oil
Manufacturer:	Not known	Not known	Not known
Age (years):	20	20	20
Type:	Pressure Jet	Pressure Jet	Pressure Jet
Draft:	Induced	Induced	Induced
Atomization:	Steam	Steam	Steam
Burner controls:	Manual	Manual	Manual
Draft control (dampers):	Manual	Manual	Manual

APPENDIX 5

BOILER COMBUSTION TESTS

Boiler No: 1 of 3

Date of Test: 3/12/84

Test Results

Fuel Fired: 1000 secs Fuel Oil

Item	Unit	Measurement
Firing Rate		Medium
CO_2 in Flue Gases	%	9.9
O_2 in Flue Gas	%	9.8
Flue Gas Temperature Before Econ	°C	291
Flue Gas Temperature After Econ	°C	181
Ambient Air Temperature	°C	39
Smoke Number		7.5
Feedwater into Econ	°C	75
Feedwater out of Econ	°C	87.5

Measurement	Instrument
% CO_2 in Flue Gases	Fyrite
% O_2 in Flue Gases	Fyrite
Flue Gas Temperature Before/After Eron	Electronic Thermometer
Ambient Air Temperature	Mercury in Glass Thermometer
Smoke Number	Truespot Smoke Pump
Feed Water Temp Before/After Econ	Electronic Thermometer

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APPENDIX 5 (Cont'd)

BOILER COMBUSTION TESTS

Boiler No: 3 of 3

Date of Test: 3/9/84

Test Results

Fuel Fired: 1000 seconds fuel

Item	Unit	Measurement
Firing Rate		High
CO_2 in Flue Gases	%	10.5
O_2 in Flue Gases	%	4.8
Flue Gas Temperature Before Econ	°C	300
Flue Gas Temp After Ec n	°C	185
Ambient Air Temperature	°C	38
Smoke Number		9

Measurements/Readings From:

Measurement	Instrument
% CO_2 in Flue Gases	Fyrite
% O_2 in Flue Gases	Fyrite
Ambient Air Temp	Mercury in Glass Thermometer
Smoke Number	Truespot Smoke Pump
Flue Gas Temperature Before/After Econ	Electronic Themometer
Feedwater Temperature Before/After Econ	Electronic Themometer

APPENDIX 6

BOILER EFFICIENCY TESTS

Date: March 17, 1984
Boilers 1 and 3 firing

Fuel Type: 1000 seconds Fuel Oil

Boiler Number	Burner Location	Pressure Bar	Equivalent Oil Flow liter per minute
1	Left	0.6	3.9
1	Right	0.3	2.75
3	Left	0.3	2.75
3	Right	0.5	3.55

Nozzle Sizes = 3 mm diameter

Steam Pressure

Boiler 1	=	14	bar
Boiler 3	=	14.7	bar
Average	=	14.35	bar

Feedwater Flowrate = 8440 kg per hour

Instrumentation - Pressure gauge
Ultrasonic flow meter

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APPENDIX 7

CALENDERING TESTS

Chamber Temperatures

Location	Readings 1	2	3	
Side walls °C =	39	36.2	39.2	
	40	38.7	43.5	
	47.8	38.1	39.2	
Top °C =	46	49.2	47.8	49.2

Steam Temperature in = 90°C
Condensate Out = 81°C
Fabric Temperature In = 34°C
Fabric Temperature Out = 88°C
Exhaust Temperature = 100°C
Humidity Inside Dryer = 100°C

Moisture Content of Fabric In = 0.92%
Moisture Content of Fabric Out = 0.46%
Fabric Specification Moisture Content = 2.5% before
Fabric Specification Moisture Content = 1.0% after

APPENDIX 8

CHILLER TESTS

Condenser Number 1

	Measurement	Instrument Reading
Inlet Water	29.7°C	-
Outlet Water	33.7°C	34
NH_3	80.6°C	-
NH_3	32.9°C	-

Chilled Water Heat Exchanger - 1

Inlet	22.3	20.5
Outlet	18.4	16.0

Chilled Water Heat Exchanger - 2

Inlet	22.4	-
Outlet	18.2	15

Return Water to Reservoir =	17.6°C
Condenser Water Outlet =	32.4°C
Condenser Water Flow Rate =	672 gpm

APPENDIX 9

ELECTRICAL MEASUREMENTS

Location	Nameplate Data			Measured Data		
	HP/kW	V	A	V	A	PF
Plasticate Mill	215	400	275	386	187	0.85
Festooner	215	400	275	-	-	-
Strainer						
10 Worm Drive	100kW	400	189	380	-	0.75
MG Set Drive Motor	75kW	400	130	-	-	-
2 x 60" Mill Main Drive	125kW	400	225	386	186	0.87
MG Set Motor	160kW	400	279		85	-
MG Set CC6 Motor	160kW	400	279	388	107	0.58
Chiller Comp. 1	100kW	400	186	386	128	0.87
Chiller Comp. 2	100kW	400	186	385	127	0.83
Chiller Comp. 3	100kW	400	186	382	131	0.82
Chiller Comp. 4 & 5	100kW	400	186	-	-	-
Chiller Condensor						
Pump 1	40kW	400	71	388	81	0.87
Pump 2 & 3	40kW	400	71	-	-	-
Chiller Evaporator						
Pump 1	40kW	400	71	388	63	0.95
Pump 2	40kW	400	71	393	52	0.90
Pump 3	40kW	400	71	-	-	-
S.H.W. Feed-Water						
Pump 1	27kW	400	46	-	40	-
Pump 2	27kW	400	46	-	-	-
Calender Warming						
Mill 1 x 84"	165kW	400		-	-	-

APPENDIX 10

BOILER WATER TESTS AND ESTIMATE OF BLOWDOWN

Assumptions

A constant T.D.S. is maintained in the boiler.

Data

Boiler Feedwater TDS	=	25	=	B
Make Up Water TDS	=	25		
Boiler Drumwater TDS	=	175	=	A
Percentage Make Up	=	100%	=	M

Calculation*

$$\text{Percent Blowdown} = \frac{(B \times M)}{(A - B)}$$

$$= \frac{25 \times 100}{175 - 25}$$

$$= 16.7\%$$

*Calculation technique similar to Exhibit 5.20, Energy Audit Manual

APPENDIX 11

BOILER SURFACE TEMPERATURE MEASUREMENTS

Boiler Number 1

Location	Measurement 1	2	3
Side Walls °C =	102	104	95
	107	110	92
	93	106	97
Rear °C =	103	102	110
	94	96	98
Front °C =	97	99	100

Boiler Number 3

Location	Measurement 1	2	3
Side Walls °C =	115	107	95
	92	99	102
	97	101	102
Rear °C =	104	100	93
	96	95	95
Front °C =	102	101	102

APPENDIX 12

ESTIMATE OF BOILER RADIATION LOSS

Radiation losses from the boiler can be estimated using the data from Appendix 14.

Boiler Surface Temperature	=	100°C
Surface Area of Sidewalls	=	16.5 m^2 x 2
Surface Area of Front and Back	=	13.1 m^2 x 2
Surface Area of Top	=	7.9 m^2 x 2
Heat Transfer Coefficients Front, Back and Sidewalls	=	12.79
Heat Transfer Coefficients, Top	=	14.8
Ambient Air Temperature °C	=	40
Conversion of kWh to Joules	=	0.0036
Operating Hours	=	6912
Heat Losses	=	h x a x dt
Total Loss Per Year	=	$\frac{(65,946)}{(1000)}$ x 6912 x 0.0036
for 1 boiler	=	1641 GJ
Boiler Input	=	229,296 GJ
% Radiation Loss for Plant	=	$\frac{1641}{229,296}$ x 100 x 2
	=	1.4%

APPENDIX 13

BOILER EFFICIENCY CALCULATION

The following efficiency calculation is based upon measured values of oil flow through nozzles and water flow into the boilers. Metering of individual boilers was not possible and so the efficiency developed is based on total flow rates.

Data

Boiler Number One Operating Pressure	=	14 bar
Boiler Number Two Operating pressure	=	14.7 bar
Metered Water Flow Rate	=	8440 kg/hour
Feed water Temperature	=	88°C
Boiler Number One Oil Pressure left burner	=	0.6
Boiler Number One Oil Pressure right burner	=	0.3
Boiler Number Three Oil Pressure left burner	=	0.3
Boiler Number Three Oil Pressure right burner	=	0.5
Nozzle Sizes	=	3 mm
Flow Rate at 0.6 bar thro 3mm Nozzle	=	3.90 liters per min.
Flow Rate at 0.3 bar thro 3mm Nozzle	=	2.75 liters per min.
Flow Rate at 0.3 bar thro 3mm Nozzle	=	2.75 liters per min.
Flow rate at 0.5 bar thro 3mm Nozzle	=	3.55 liters per min.
Total Flow		12.95 liters per min.

Calorific Value of 1000secs Oil	=	43075.2 kJ/kg
Specific Gravity	=	0.96
Enthalpy of Steam at 14.35 bar	=	2790.7 kJ/kg
Enthalpy of Water at 88°C	=	369 kJ/kg
Blowdown Rate (see Appendix 10)	=	0.167 kg/kg
Dryness fraction assumed	=	0.98

Calculation

$$\text{Boiler Efficiency} = \frac{(\text{Heat Content of Steam + Water leaving}) - \text{Heat Content of Water Entering}}{(\text{Heat Content of Fuel In})}$$

$$\text{Heat Content of Steam Out} = \frac{(\text{Dryness Fraction} \times \text{Enthalpy of Steam at Boiler Pressure})\ (\text{Mass of Steam})}{}$$

APPENDIX 13 (Cont'd)

Heat Content of Water Leaving Boiler = (1-dryness Fraction)x(Enthalpy of Water at Boiler Pressure)x(Mass of Steam)+(Enthalpy of Water at Boiler Pressure)x(Mass of water in blowdown)

Heat Content of Water Into Boiler = (Mass of Steam + Mass of Blowdown) (Enthalpy at Feedwater Temp)

Heat Content of Fuel In = (Calorific value) x (mass of fuel used)

Heat Content of Steam = (0.98) (2,790.7) (7,030.52) kJ/hr
= 19,227,671 kJ/hr

Heat Content of Water Out = (0.02)(835)(7030.52)+(835)(0.167) (8,440)
= (117,410) + (1,176,916)
= 1,294,326 kJ/hr

Heat Content of Water Into Boiler = (8,440) (369)
3,114,360 kJ/hr

Heat Content of Fuel In = (43,075.2) (12.95) (60) (0.96)
= 32,130,653 kJ

Boiler Efficiency = $\frac{((19,227,671 + 1,294,326) - (3,114,360))\ 100}{(32,130,653)}$
= 54.1%

APPENDIX 14

INSTALLING THERMAL INSULATION ON BOILER AND ANCILLARY PLANT

Assumptions

Reduction in heat losses by insulation: 90 percent

Data

Boiler operating hours: 6912/yr
Boiler ancillaries operating hours: 6912/yr
Boiler efficiency: 54.1 %

Plant/ equipment	Shape/ Position	h	Area (m2)	dT (°C)	Heat Loss (Watts)	Insulation Proposed	Estimated cost
Boiler:							
1, 2, and 3	Side wall	12.79	16.5	60	12662	40 mm cal	
	Side wall	12.79	16.5	60	12662	Silicate	3275 Rs/m^2
	Lower top	14.8	7.9	60	7015	and 15 mm	
	Lower top	14.8	7.9	60	7015	cement	
	Top	16.63	6.5	60	6486	finish	
	Front	12.79	13.1	60	10053		
	Back	12.79	13.1	60	10053		
			TOTAL		65946	TOTAL	266,913

APPENDIX 14 (Cont'd)

Energy Savings

Boiler = Heat loss/hr x 0.9 x plant operating time / 10^6
= (65946 x 3.6) (0.9) (6912) / 10^6
= 1477 GJ x 2 boilers
= 2954 GJ

Total energy savings = (1477) + (1477)
= 2954 GJ

Cost savings
= (2954) (115.19)
= Rs. 340,271/yr

Cost of Implementation

The total cost of insulating is estimated to be Rs. 266,913.

Simple Payback = $\frac{266,913}{340,271}$
= 0.8 years

Energy savings	= 2954 GJ/Year
Cost savings	= Rs. 340,271/Yr
Cost of Implementation	= Rs 266,913
Simple Payback	= 0.8 Years

APPENDIX 15

REDUCING BLOWDOWN

Blowdown is often used excessively to control the level of total dissolved solids (TDS) in a boiler. Dissolved solids can be deposited as scale on the heat transfer surfaces in a boiler. A compromise between energy waste owing to blowdown and owing to scaling is reached by maintaining blowdown levels up to 3,000 parts per million for most industrial boilers.

Calculation*

Assumptions

Maximum acceptable TDS level = 3,500 ppm
Estimated mean TDS level = 3,500 ppm

Data

Boiler efficiency	=	54.1	percent (See Appendix 13)
Percent makeup water	=	100	percent
Makeup TDS	=	25	ppm)
Blowdown TDS	=	175	ppm) from treatment company reports
Energy input to boilers	=	229296	GJ/year
Feedwater temperature	=	88	°C
Boiler pressure	=	16	bar
Heat content in city water	=	126	kJ/kg
Heat content of 98% Steam 16 bar	=	2738	kJ/kg
Heat content of Feedwater	=	369	kJ/kg

*Calculation technique similar to Exhibit 5.11, Energy Audit Manual

Present blowdown rate $= \frac{(\text{Percent Makeup} \times \text{Makeup TDS})}{(100 \times \text{Blowdown TDS})}$

$= \frac{(100 \times 25)}{100 \times 175}$

$= 0.167$ kg/kg of steam produced

Heat required to raise kg of steam = hg @ boiler pressure -hw of feedwater

= 2738 - 369

= 2369 kJ/kg

Steam produced/year $= \frac{(\text{Energy input to boilers} \times \text{average boiler efficiency}}{\text{Heat Required to Raise kg of Steam}}$

$= \frac{(229296 \times 0.541)}{(2369)\ (10^6)}$

$= 52.4$ kg x 10^6 kg/year

Reducing Blowdown

APPENDIX 15 (Cont'd)

Blowdown per year = blowdown rate x steam produced/year
= $(0.167)(52.4 \times 10^6)$
= $8.74 \text{ kg} \times 10^6$ /year

Heat content in blowdown = Sensible heat in blowdown-sensible heat of city water
= 859 - 126
= 733 kJ/kg

$$\text{Percent blowdown loss} = \frac{(\text{Blowdown/Yr} \times \text{Net Heat Content of Blowdown} \times 100)}{\text{Energy Input to Boilers}}$$

$$= \frac{(8.74 \times 106 \times 733 \times 100)}{229{,}296 \times 10^6}$$

= 2.8 percent

$$\text{Blowdown rate @ 3,000} = \frac{(\text{Percent of Makeup} \times \text{Makeup TDS})}{100 \times (3{,}000 - \text{makeup TDS})}$$

$$= \frac{(100 \times 25)}{(100)\ (3{,}000 - 25)}$$

= 0.008 kg/kg of steam produced

Energy Savings

= (Existing - new blowdown rate) x (steam produced/year)x(heat content in blowdown)
= $(0.167 - 0.008) + (52.4 \times 10^6)(733)$
= 6107 GJ/year

Cost Savings

= (GJ/year) (Rs./GJ)
= (6107) (115.19)
= Rs.703465/yr

Implementation Costs

To provide an instrument to monitor the TDS level of the boilers on a regular basis should cost approximately Rx 5000.

Energy savings	= 6107 GJ/year
Cost savings	= Rs703,465/year
Cost of Implementation	= Rs 5,000
Simple Payback	= 0.01 years

APPENDIX 16

PIPEWORK INSULATION

Assumptions

Heat Loss Reduction by Insulation =90%
Pipework Fittings Equivalent Length =0.4M

Data

Boiler Plant Operating Hours =6912hrs/yr
Boiler Efficiency =54.1%
Missing insulation is detailed in data sheets following the calculation.

Calculation

Energy Savings

$$= \frac{(\text{Wasted Heat Loss}) \times (\text{Operating hrs}) \times (0.9)}{\text{Boiler Eff.} \times 10^6}$$

$$= \frac{(190601 \times 3.6)(6912)(0.9)}{0.541 \times 10^6}$$

= 7890 GJ/year

Cost Savings

= (GJ/yr)(Rs/GJ)
= (7890)(115.19)
= 908,849 Rs/year

Cost of Implementation

This is estimated to be 850,000Rs installed for the insulation required.

Simple Payback

$$= \frac{850,000}{908,849}$$

= 0.9 years

ENERGY SAVINGS	= 7890 GJ/yr
COST SAVINGS	= Rs908,849/year
COST OF IMPLEMENTATION	= Rs850,000
SIMPLE PAYBACK	= 0.9 years

DATA SHEET

Location	Pipe Dia OD mm	Length of Bare Pipe M	Heat Loss W/M	Total Loss W	PipeTemp °C	Hours of Operation
Boiler House						
Boiler 1						
Membrane Valve	80	0.3	880	264	175	6912
Safety Valve	80	0.3	880	264	175	6912

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APPENDIX 16 (Cont'd)

DATA SHEET

Location	Pipe Dia OD mm	Length of Bare Pipe M	Heat Loss W/M	Total Loss W	PipeTemp °C	Hours of Operation
Boiler 3						
Membrane Valve	80	0.3	880	264	175	6912
Safety Valve	80	0.3	880	264	175	6912
Main Header	150	0.4	1450	580	175	6912
Flange on 8 Bay Header	100	0.4	1000	400	175	6912
PRV - 16 bar	100	0.4	1000	400	175	6912
Relief Valve (16 bar)	50	0.4	625	250	175	6912
Gate Valve 8 bay	150	0.4	1450	580	175	6912
2 Valves-16 bar	50	0.8	625	500	175	6912
By Pass Valve 16 bar	80	0.4	880	352	175	6912
Pipe to Deareator 2.75 bar	80	7.0	880	6160	175	6912
Soot Blower 16 bar	80	4.0	880	3520	175	6912

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APPENDIX 16 (Cont'd)

DATA SHEET

Location	Pipe Dia OD mm	Length of Bare Pipe M	Heat Loss W/M	Total Loss W	PipeTemp °C	Hours of Operation
Heat Exchanger Room						
Trench	150	2.00	1100	2200	175	6912
Valves	80	0.75	660	495	150	6912
Calender Line	80	0.3	660	198	150	6912
Header-8 bar	80	3.00	660	1980	150	6912
Hot water tank line	50	10.00	475	4750	150	6912
3 Bar Line at header	80	3.00	660	1980	150	6912
Distilled Water line	25	20.00	275	5500	150	6912
By Pass line	80	0.5	660	330	150	6912
Deaereator line	80	12.00	660	7920	150	6912
CALENDER						
Main Supply	80	7.00	660	4620	150	6912
Dryer dist.	40	30.00	375	11250	150	6912
Tyre Vulcanization						
Headers	50	10.00	475	4750	150	6912
Distribution Lines (total)	20	300.00	225	67500	150	6912
Tube Vulcanization						
Distribution Lines (total)	20	10.00	225	2250	150	6912
Header	50	5.00	475	2375	150	6912
Tread Extruder						
3 Bar Line	25	2.00	275	550	150	6912
3.5 Bar Line to the Canteen	50	120.00	475	57000	150	6912
Flap Extruder	25	3.00	275	825	150	6912
Tube Extruder	80	0.5	660	330	125	6912

APPENDIX 17

REPAIR OF STEAM LEAKS

Assumptions

All losses will be saved when leaks are fixed.

Leakage Rate in kg/hr = 0.4 (d2) (p+1)

where d = mm, p = bar

Data

For leaks see attached data sheets

Net Heat Content at 16 bar	=2670 kJ/kg
8 bar	=2648 kJ/kg
2.5 bar	=2591
2.0 bar	=2581
0.5 bar	=2519
Boiler Efficiency	=54.1
Steam System Operating hrs.	=6912 except 2.5 bar and 0.5 bar=2308 hours
Load Factor	=0.8

Calculation

Energy Savings

$$= \frac{(\text{Loss kg/hr})(\text{Hours})(\text{Heat Content})(\text{Load Factor})}{(\text{Boiler Efficiency})\ (10^6)}$$

16 bar

$$= \frac{(309.4)\ (6912)\ (2670)\ (0.8)}{(0.541)\ (10^6)}$$

= 8444 GJ

8 bar

$$= \frac{(96.3)(6912)(2648)(0.8)}{(0.541)\ (10^6)}$$

=2606 GJ

2.5 bar

$$= \frac{(12.6)(2304)(2591)(0.8)}{(0.541)\ (10^6)}$$

=109 GJ

2.0 bar $= \frac{(1.2)(6912)(2581)(0.8)}{(0.541)\ (10^6)}$

$= 32$ GJ

0.5 bar $= \frac{(0.6)(2304)(2519)(0.8)}{(0.541)\ (10^6)}$

$= 5$ GJ

Cost Savings

=(GJ)(Rs/GJ)

=(11196)(115.19)

=1,289,667 Rs/year

Cost of Implementation

The cost of repairs to the steam distribution system are estimated to be 200,000 Rs. The majority of the leaks can be fixed using in house labor.

Simple Payback

$= \frac{200,000}{1,289,667}$

= 0.2 years

Energy Savings	= 11196 GJ
Cost Savings	= Rs1,289,667/year
Cost of Implementation	= Rs200,000
Simple Payback	= 0.2 years

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APPENDIX 17 (Cont'd)

DATA SHEET

Location	Pressure bar	Size of Leak mm	Loss kg/hr
Safety Relief Boiler #3	16	1	6.8
Flow Measuring Orifice	16	0.5	1.7
8bar PRV	8	0.5	0.9
Main Valve	16	1	6.8
Air Vent	16	0.5	1.7
Steam Pump	16	1	not working
Economizers (3)	16	1	20.4
Valves (5)	16	1	34.0
Steam Header	16	1	6.8
Oil Preheater	16	1	6.8
3.5 bar PRV	8	1	3.6
Main Feed to PV	16	1	6.8
Regulator Valve	16	1	6.8
Water for Batteries	8	1	3.6
Instrumentation	8	1	3.6
S.D Duct Tunnel (Header)	16	1	6.8
Flash Vessel	2	1	1.2
Vulcaniser 1	16	1	6.8
2	16	1	6.8
	16	1	6.8
3	8	1	3.6
	16	1	6.8
4	8	0.5	0.9
5	16	1	6.8
6	8	1	3.6
	16	1	6.8
7	8 bar	1	3.6
	16 bar	1	6.8
8	16 bar	1	6.8
9	16 bar	1	6.8
10	16 bar	1	6.8
11	8	1	3.6
12	16	1	6.8
13	16	1	6.8
14	8	2	14.4
	16	2	27.2

APPENDIX 17 (Cont'd)

Location	Pressure bar	Size of Leak mm	Loss kg/hr
15	8	1	3.6
16	8	1	3.6
	16	1	6.8
17	8	1	3.6
18	8	2	14.4
	16	1	6.8
19	8	1	3.6
20	-	-	-
21	8	1	3.6
	16	1	6.8
22	16	1	6.8
23	16	1	6.8
24	16	1	6.8
25	8	0.5	0.9
26	8	1	3.6
	16	1	6.8
27	8	1	3.6
	16	1	6.8
28	8	1	3.6
	16	1	6.8
Bag'O'matics 1			
BOM 1	16	1	6.8
BOM 2	16	1	6.8
	8	1	3.6
BOM 3	16	1	6.8
	16	1	6.8
BOM 4	16	1	6.8
Pre Cal Drier	2.5	1 (6 points)	8.4
Steam traps	2.5	1	1.4
Calender valve	2.5	1	1.4
Condenser	0.5	0.5 (3 points)	0.6
Cal rollers	2.5	1 (6 points)	1.4
rubber mat valve	8	1	3.6
pipe	8	1	3.6

Total Leakage at	16 bar =	309.4	kg/hour
	8 bar =	96.3	kg/hour
	2.5 bar =	12.6	kg/hour
	2.0 bar =	1.2	kg/hour
	0.5 bar =	0.6	kg/hour

APPENDIX 18

REPAIR OF STEAM TRAPS

Assumptions

Average Leakage Per Failed Trap = 2.5 kg/hr

Data

Steam system operating hours = 6912/year except 1.8 bar steam
1.8 bar Steam operating hours = 2304 hrs/yr
Number of Failed Traps = see Data Sheet following calculation
Boiler Efficiency = 54.1 %

Net Heat Content of Steam at:
- 16 bar = 2670 kJ/kg
- 8 bar = 2648 kJ/kg
- 2.7 bar = 2610 kJ/kg
- 1.8 bar = 2597 kJ/kg

Load Factors:
- 16, 2.7 bar = 1
- 8 bar, 1.8 bar = 0.8

Calculation

Energy Savings

$$= \frac{(\text{Number of Failed Traps})(\text{Leakage})(\text{Hours})(\text{Heat Content})(\text{Load Factor})}{(\text{Boiler Efficiency})\ (10^6)}$$

16 bar

$$= \frac{(2)(2.5)(6912)(2670)(1)}{(0.541)\ (10^6)}$$

= 171 GJ

8 bar

$$= \frac{(9)(2.5)(6912)(2648)(0.8)}{(0.541)(10^6)}$$

= 609 GJ

2.7 bar

$$= \frac{(1)(2.5)(6912)(2610)(1)}{(0.541)(10^6)}$$

= 83 GJ

1.8 bar

$$= \frac{(18)(2.5)(2304)(2597)(0.8)}{(0.541)(10^6)}$$

= 398 GJ

Total Savings = (171) + (609) + (83) + (398)
= 1261 GJ

Cost Savings

= (GJ) (Rs/GJ)
= (1261) (115.19)
= 145,255 Rs/year

APPENDIX 18 (Cont'd)

Cost of Implementation

The cost of replacement steam traps is estimated to be 2000 Rs per trap installed giving a total implementation cost of Rs 60,000.

Simple Payback

$$= \frac{60,000}{145,255}$$
$$= 0.4 \text{ years}$$

Energy Savings	= 1261 GJ
Cost Savings	= 145,255 Rs/Year
Cost of Implementation	= 60,000 Rs
Simple Payback	= 0.4 years

DATA SHEET

Location	Steam Pressure Bar	Load Factor	Operating Hours
Boiler Room 1	16	1	6912
Main Header - 1	16	1	6912
Vulcanizers 9	8	0.8	6912
Calender 18	1.8	0.8	2304
Power Room Flash Vessel - 1	2.7	1	6912

APPENDIX 19

RETURN CONDENSATE TO BOILER HOUSE

Condensate from the Vulcanization processes, calendering and superheated hot water system is currently collected in condensate receivers and then run to drain. A condensate return pipework system is installed and in a good state of repair. Condensate should be returned to the boiler.

Assumptions

Condensate Temperature = 80°C
MakeUp Water Temperature = 30°C
Feedwater Temperature = 88°C
75% of Condensate can be returned.

Data

From other appendices as indicated

Steam Production $= \frac{(229,296)(0.541)(10^6)}{((.98)(2791)+(835x0.02)-369)}$
= 52,058,490 kg/year
= 126,086 GJ/year

Losses due to leaks =2,274,324 kg/year
Appendix 17 = 11196 x 0.541 = 6057 GJ

Loss due to Failed Traps = 0 kg/yr
Appendix 18 = 1261 x 0.541 = 682 GJ
Loss due to Insulation = 0 kg/year
Appendix 16 = 7890 x 0.541 = 4268 GJ

Loss due to Condensate
- balance of mass = 49,784,166 kg/year
assume 70°C = $(293-126)(10^{-6})(49,784,166)$
= 8314 GJ

75% of Condensate can be returned to the boiler

Energy Savings $= 0.75 \frac{(8314)}{(0.541)}$

= 11,526 GJ

Cost Savings

= (GJ) (Rs/GJ)
= (11526)(115.19)
= 1,327,680 Rs/year

APPENDIX 19 (Cont'd)

Cost of Implementation

Very little is required to reconnect the condensate return system to the condensate recovery tanks in the power room. The estimated cost is 25,000 Rs for new fittings, piping and insulation.

Simple Payback

$$= \frac{25,000}{1,327,680}$$

= 0.1 year

Energy Savings	= 11,526 GJ
Cost Savings	= 1,327,680 Rs/Yr
Cost of Implementation	= 25,000 Rs
Simple Payback	= 0.1 years

400

APPENDIX 20

REPLACE MOTOR GENERATOR SETS BY THYRISTORS

Motor generator sets have inherent low efficiencies and they can be replaced by thyristors to give energy savings.

Assumptions

Efficiency of M G Sets	= 0.6 - site date indicated efficiency of 0.39 for sample measured
Efficiency of Thyristor	= 0.85

Data

Operating Hours	= 2304 for Extrusion and Calendering 6912 for main plant
Load Factors	= 0.8
Ratings - extrusion mg	= 160kW
Squeegee calender mg	= 100kW
Tube of dept mg	= 160kW
Tyre Building	= 75 kW 32 kW

Calculation

Useful work produced by extrusion mg	= 0.6 x 160 x 2304 x 0.8 = 176,947 kWh
Using Thyristor @ 0.85 efficiency	= 176,947 x 0.85 = 150,405
Savings	= 176,947 - 150,405 = 26542 kWh x 0.0036 = 96 GJ
Cost Savings	= (GJ)(Rs/GJ) = 39,282 Rs/year

Similar Savings can be made on the mg sets in the calendering, tube and tyre building departments to give energy savings as follows:

	GJ	Rs
Extrusion	96	39,282
Calendering	60	24,667
Tube	287	117,989
Tyre Building	192	78,933
Totals	635	260,871

APPENDIX 20 (Cont'd)

Cost of Implementation

The costs for thyristor drives is estimated to be 75,000 Rs installed, giving a total cost of 375,000 to implement this measure.

Simple Payback

$$= \frac{375,000}{260,871}$$

= 1.4 years

Energy Savings	= 634 GJ
Cost Savings	= Rs260,871/Yr
Cost of Implementation	= Rs375,000
Simple Payback	= 1.4 years

406

APPENDIX 21

POWER FACTOR CORRECTION

The power factor for the plant was measured at 0.8. This can be raised by installing capacitors to bring savings based upon reduced demand charges.

Data

Measured Power Factor	= 0.8
Proposed Power Factor	= 0.95
Average Demand	= 3217 kVa
Current Demand Charge	= 90 Rs per kVa

Calculation

Power Factor $= \frac{kW}{kVA}$

kW = kVA x Power Factor

Existing kW = 3217 x 0.8

kW = 2574

If P. F. raised to 0.95, can estimate new kVA based upon existing kW

New kVA $= \frac{kW}{\text{Power Factor}}$

$= \frac{2574}{0.95}$

= 2709 kVA

kVA Savings = 3217 - 2709

= 508 kVA

Cost Savings

= (kVA saved) (Rs/kVA) (months/year)

= (508) (90) (12)

= 548640 Rs/year

Cost of Implementation

Capacitors can be purchased at an installed cost of 300 Rs per kVAr. A total of 1084 kVAr are required to raise the power factor to 0.95 giving an implementation cost of 325,200

Simple Payback $= \frac{325,200}{548,640}$

= 0.6 years

Energy Savings	= 508 GJ
Cost Savings	= Rs548,640/Yr
Cost of Implementation	= Rs325,200
Simple Payback	= 0.6 years

APPENDIX 22

Assumptions

Flow Rate in M^3/min	= $(0.0094)(d^2)(p+1)$
where d	= mm
p	= bar

Data

Compressor Operating Hours	= 6912 hours
Load Factor	= 0.80
Compressor Rating	= 20 m^3/min @ 7.5 bar x 3
Compressor kW	= 180 x 3 (rated) 142 kW (measured)
$1m^3/m$	= 4.73 kW
Leakage	= 17.642 m^3/min (see data sheets) for locations

Energy Savings

= (Loss in m^3/m)(Hours Operation)
(kw/m^3/min)(Load Factor)
= (17.642)(6912)(4.73)(0.8)
= 461426.65 kWh/year x 0.0036
= 1661 GJ/year

Cost Savings

= (GJ/yr)(Rs/GJ)
(1661)(411.11)
= 682854 Rs./year

Cost of Implementation

The cost to fix all compressed air leaks is estimated to be 100,000 Rs, for some fittings.

Simple Payback

$$= \frac{100,000}{682,854}$$
= 0.1 year

Energy Savings	= 1661GJ
Cost Savings	= Rs682,854/Yr
Cost of Implementation	= Rs100,000
Simple Payback	= 0.1 years

APPENDIX 22 (Cont'd)

COMPRESSED AIR LEAKS - TYRE PLANT

DATA SHEETS

Location	Size of Leak (mm)	Pressure Bar	Loss M^3/Min kW
1) Maintenance Work Shop	0.2	7	0.003
2) Boiler room	0.3	7	0.007
3) Workshop A	0.2	7	0.003
4) Tyre Repair Shop	0.2	7	0.003
5) Curing Bag Shop	0.2	7	0.003
6) Curing Bag			
Joining M/C	0.7	7	0.037
7) Tube Shop	0.2	7	0.003
8) Quality Control	0.2	7	0.003
9) Curing Bag	2.0	7	0.3
Removing M/C			
1100-28			
750-16			
10) Type Vulcanizing			
4-6-2	2.0	7	0.3
4-5-4	0.7	7	0.37
4-4-3	2.0	7	0.3
11) Bag'O'matic			
7	0.2	7	0.003
6	0.2	7	0.003
3	2.0	7	0.3
5	2.0	7	0.3

APPENDIX 22 (Cont'd)

COMPRESSED AIR LEAKS - TYRE PLANT

DATA SHEETS

Location	Size of Leak (mm)	Pressure Bar	Loss M^3/Min kW
12) Tube Forming			
1	1.0	7 bar	0.075
6	1.0	7 bar	0.075
8	1.0	7 bar	0.075
10	1.0	7 bar	0.075
13) Tube Forming			
Press 4-H	2.0	7 bar	0.3
14) Power Unit	8.0	7 bar	4.81
15) Type Building M/C	2.0	7 bar	0.003
9-1	0.2	7 bar	0.003
A	0.2	7 bar	0.003
C	0.2	7 bar	0.003
3-11-1	0.2	7 bar	0.003
3-11-3	0.7	7 bar	0.037
3-12-4	0.2	7 bar	0.003
3-11-3	2.0	7 bar	0.3
3-12-3	0.2	7 bar	0.003
3-12-2	0.2	7 bar	0.003
16) Bead Making M/C	2.0	7 bar	0.3
17) Tube Joining M/C	0.2 + 0.2	7 bar	0.003
18) tube Extruder	8.0	7 bar	4.81
19) Squeegee M/C	8.0	7 bar	4.81
20) Calender Drier	0.2	7 bar	0.003
21) Banburning Mixer	2.0	7 bar	0.3
22) Plasticating Mixer	0.7	7 bar	0.037
23) Valve Rubberizing M/C	0.2	7 bar	0.003

APPENDIX 23

USE OF COOLING-TOWER VERUS RUNNING WATER TO DRAIN

Assumptions

Cooling Tower Pump Efficiency	= 80%
Cooling Tower Height	= 30 Feet
Pumping Head Loss	= 10%
Make Up Water	= 20%

Data

Conderser Water to Drain	= 672 gpm
Water Treatment Plant Pump	= 90 hp; 1500 gpm
Average Water from WTP	= 38 x 10^6 monthly; 1016 gal. per minute
River Water Pumps	= 2 x 25 hp
Tank Water Pumps	= 55 kW (1172 gpm)

Calculation

Energy Required to Pump Water from River to Tank = $\frac{\text{(Volume of Condensor Water)} \times \text{(Load Factor)} \times \text{Pump Rating)}}{\text{(Capacity of River Water Pump)}}$

Load Factor $= \frac{1016}{1500} = 0.68$

$= \frac{(672) \times (0.68) \times (140 \times 0.746)}{(1500)}$

= 32 kW

Energy Required to Pump Return Water From Tower To Condenser Inlet

Pressure assuming 30 ft tower + 10% loss	= 33 ft of water
1 ft of water	= 0.4339 psig
33 ft	= 0.4339 x 33
	= 14 psig
Liquid Horsepower Required	$= \frac{\text{(gal/min) (pressure)}}{(1430)}$
	$= \frac{(672)\ (14)}{(1430)}$
	= 6.57 hp
Pump Horsepower	$= \frac{6.57 \times 0.746}{0.8}$
	= 6.1 kW

APPENDIX 23 (Cont'd)

Energy to supply 20% Make Up $= \frac{\text{(Water Volume) x (Pump Rating)}}{\text{(Capacity of Tank Pump)}}$

$= \frac{(672 \times 0.2) \times (104)}{(1173)} = 11.9$ kW

Energy to Run Tower = (6.1) + (11.9)
= 18 kW

Energy Savings = (Pumping from River) - (Tower Consumption)
= 32 - 18 = 14 kW

Energy Savings
= (kW) (Hours/Operation)
= (14) (6912)
= 96,768 kWh x 0.0036
= 348 GJ

Cost Savings = (GJ/Year (Rs/GJ)
= (348) (411.11)
= 143,216 Rs/Year

Cost of Implementation

The cost of a natural draught cooling tower designed and built in Sri Lanka is estimated to be Rs420,000.

Simple Payback $= \frac{420,000}{143,216}$

= 2.9 Years

Energy Savings	= 348 GJ/Year
Cost Savings	= Rs143,216/Yr
Cost of Implementation	= Rs420,000
Simple Payback	= 2.9 Years

APPENDIX 24

REDUCTION IN RESERVOIR VOLUME

The Tyre plant has a chilled water reservoir of 250 m^3. The reservoir is cooled down prior to start up on a Monday morning. The reserve can be reduced to one hour of pumping capacity to give energy savings.

Assumptions

Water Temperature at start of cool down = 26°C

Data

Chilled water temperature required	= 20°C
Reservoir capacity	= 250,000 litres
Chiller Capacity	= 100 tons or 1,266,090 GJ
Density of Water	= 980 kg/m^3
Chiller Pump Capacity	= 1591 Litres/min
Chiller Rating	= 100 kW

Calculation

Energy to be removed = (250 x 980)(4.2)(26-20)
= 6,174,000 kJ

Current time required to cool $= \frac{6,174,000}{1,266,090}$
= 4.876 hours

Chiller Pump Capacity $= \frac{1591 \times 60 \times 980}{1000}$ kg/hr
= 93,551 kg/hr

Cooldown time required for 1 hour $= 4.876 \times \frac{93551}{(250 \times 980)}$
= 1.86

Savings = 4.876 - 1.861
= 3.0 hours

Energy Savings = (Chiller Compressor) + (Condenser Pump) + (Chilled Water Pump)
= (100 kW) + (46 kW) + (35)
= 181 kW/hour
= 181 x 3
= 543 x 48 x 0.0036
= 94 GJ/year

Cost Savings = (GJ) (Rs/GJ)
= (94) (411.11)
= 38,644 Rs/Yr

Cost of Implementation

There are two possible methods of implementing this measure. One method is to alter float level controls, the other is to add bricks to the reservoir, therby reducing its volume. Both methods do not require major expenditure. Implementation costs are estimated to be 15,000 Rs.

Simple Payback $= \frac{15,000}{38,644}$
$= 0.4$ years

Energy Savings	= 94 GJ/Year
Cost Savings	= Rs38,644/Yr
Cost of Implementation	= Rs15,000
Simple Payback	= 0.4 Years

APPENDIX 25

DEMAND SAVINGS THROUGH LOAD RESCHEDULING

At present the various production departments operate on the following schedules:

	Hrs/Yr	Current Operating Days	Actual kW	Proposed Operating Days
Compounding	6912	Mon-Sat 3-shifts	1919	Mon-Sat 3-Shifts
Extrusion	4608	Mon-Sat 2 shifts	832	Mon-Thurs 3-Shifts
Calendering	2304	Mon-Sat 1 shift	380	Fri-Sat 3-Shifts
Tyre Building	6912	Mon-Sat 3 shifts	107	Mon-Sat 3-Shifts
Tube Dept.	6912	Mon-Sat 3 shifts	545	Mon-Sat 3-Shifts
Vulcanizing	6912	Mon-Sat 3 shifts	855	Mon-Sat 3-Shifts

This means the peak demand occurs when all departments are operating simultaneously. By rescheduling the extrusion and calendering departments for 3 shift operations, it would be possible to meet production requirements in 4 days in the extrusion department and 2 days in the calendering department. By doing that, a peak demand reduction of 380 kW is possible.

Assuming the power factor is improved to 0.95 then the kVa reduction is 400.

Cost Saviings

= (kVa) (Rs/kVA) (12)
= (400) (90) (12)
= 432,000 Rs/Year

Cost of Implementation

The costs to implement this measure are difficult to determine. Further study is required into the potential for operating the two respective departments on a three shift basis. This may involve increased labor costs, but these may be offset due to other savings that may accrue due to elimination of heat up times and provision for maintenance hours during the week.

Energy Savings	= 400 kVA
Cost Savings	= Rs432,000/Yr

APPENDIX 26

REPLACEMENT OF BOILER PLANT

Assumptions

It is assumed a plant firing the same fuel will be used, all measures relating to the steam system will be implemented including repair of leaks, traps and insulation and condensate will be returned to the boiler. The anticipated efficiency of the new plant is 78%.

Data

Boiler Efficiency	= 54.1%
Savings through implementation	= 31,873 GJ
Current Boiler fuel use	= 229,296 GJ

Calculation

Heat Condensate Steam Generated By Existing Plant = 0.541 x (229296 - 31873)
= 106,806 GJ

Energy required using new plant $= \frac{106806}{0.78}$
= 136,931

Energy Savings = 229,296 - 136,931
= 92,365 GJ

Cost Savings = (GJ) (Rs/GJ)
= (92,365) (115.19)
= 10,639,524 Rs/Year

Cost of Implementation

This measure requires a feasibility study to fully examine all possibilities for implementation. The calculation presented here is illustrative only of the potential savings that may be realized and to provide incentive for a feasibility study.

Energy Savings	=	92,365 GJ
Cost Savings	=	Rs10,639,524/Yr

APPENDIX A: BASIC CONCEPTS USED IN ENERGY AUDITING

This appendix provides the minimum necessary background information on basic engineering and energy conservation principles as they relate to plant energy auditing. The appendix is divided into six sections:

- Section 1: Review of Thermodynamics
- Section 2: Fundamental Principles of Combustion
- Section 3: Psychrometric Charts and Steam Tables
- Section 4: Heat Transfer
- Section 5: Electric Power
- Section 6: Energy Balances, Efficiency, and Norms.

SECTION 1: REVIEW OF THERMODYNAMICS

A.1.1 First Law of Thermodynamics

The basis of energy balance equations is the first law of thermodynamics: that energy can neither be created nor destroyed. For engineering purposes, the conversion of energy into mass, or vice-versa, is neglected; the first law may be stated as follows:

> The net increase in the energy content of a particular system in a given period is equal to the energy content of the material leaving the system, plus the work done on the system, plus the heat added to the system.

For example, if water with a heat content of 100 kcal and 3,000 kcal of heat enters a system, and the system does 200 kcal of work and delivers steam with a heat content of 2,000 kcal, (3,100-2,200) = 900 kcal have been lost through surface losses and blowdown. To estimate the quantity of waste heat, consider a system of known volume (e.g.,

a boiler, into which and out of which material is flowing). If U_{in} denotes the internal energy of the material entering the system, U_{out} denotes the internal energy of the material leaving the system, Q denotes the heat added to the system, and W' denotes the work done **by** the system (the negative of the work done **on** the system), the first law of thermodynamics may be written:

$$Q - W' = U_{in} - U_{out}. \tag{A.1}$$

Several energy terms have been neglected, such as kinetic energy, electrical energy, magnetic energy, and gravitational energy, that may be of importance in specific applications but need not be considered for the simple applications in this section.

It is convenient to work in terms of time rates, so the notation is used that a quantity written with a dot over it is the time rate of change of that quantity (e.g., $\dot{U}$). Many quantities are treated on a per-kilogram basis, and values of various quantities per kilogram are denoted by lower-case letters (e.g., u will denote internal energy per pound). Finally, in rewriting eq(A.1), we shall segregate W' into two factors: W" (the work that is done in moving volumes in and out of the system against pressure) and W (which is all other work). W" is $(p\dot{V})_{out} - (p\dot{V})_{in}$).

Using these changes, eq(A.1) can be rewritten as a rate equation:

$$\dot{Q} - \dot{W} = \dot{U}_{in} - \dot{U}_{out} + (p\dot{V})_{in} - (p\dot{V})_{out}. \tag{A.2}$$

Here, $(p\dot{V})_{in}$ represents the rate of work that must be done on the system to push the inbound volume flow $\dot{V}$ into the system, and $(p\dot{V})_{out}$ is the rate at which the system does work on its surroundings pushing material out at the volumetric rate $\dot{V}_{out}$. If we define the energy term enthalpy as H = U + pV, this equation can be rewritten:

$$\dot{Q} - \dot{W} = \dot{H}_{in} - \dot{H}_{out}. \tag{A.3}$$

If it is assumed that the system is in a steady state in the sense that the rate of mass flow in is the same as the rate of mass flow out, and if q is defined as Q divided by the mass of the mass throughput and similarly define w, h, etc.,

$$\dot{q} - \dot{w} = \dot{h}_{in} - \dot{h}_{out}. \tag{A.4}$$

This equation describes the rate at which enthalpy per kilogram is added to the material passing through the system in terms of the heat added to a kilogram of throughput and the work done per kilogram of throughput.

The first law of thermodynamics does not impose limitations on the fraction of the available energy that can be used in a desired way. The second law of thermodynamics has the effect of imposing such limitations.

A.1.2 Second Law of Thermodynamics

The second law of thermodynamics says that the entropy* of an isolated system cannot decrease; that is, that in an isolated system, forces and temperature differentials will tend to dissipate themselves, and in any event will not grow spontaneously. For instance, the first law of thermodynamics would permit the use of waste heat in spent steam at 120°C to melt preheated steel. The second law says it cannot be done; that unless energy is put into the system as a whole, the heat will flow from the hot steel to the warm steam, not vice-versa.

In most waste heat engineering applications, this qualitative understanding is all that is required. However, for some special cases, an "availability analysis" is useful, and the following discussion is included to familiarize the reader with the language of such analyses. The concept of availability is a tool for analyzing usefulness of energy in our waste heat (in second-law terms). The availability is defined (assuming that velocity, gravitational, and other contributions to energy can be neglected) by:

$$B = H - T_0 S \tag{A.5}$$

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*Entropy can be thought of as a measure of "disorder" in a closed thermodynamic system. The second law states that an isolated system cannot spontaneously increase its system order.

where B = the availability

H = the enthalpy

S = the entropy

T_o = the temperature of the lowest-temperature reservoir that we have available for "dumping" heat.

For most purposes, T_o is the ambient temperature, or the temperature of a cooling pond. Eq(A.5) may be written as a rate equation:

$$\dot{B} = \dot{H} - T_o\dot{S} \tag{A.6}$$

On a per-pound basis, write the rate of change of availability may be written as:

$$\dot{b} = \dot{u} + p\dot{v} - T_o\dot{s} \tag{A.7}$$

where the convention is followed of using lower-case letters for per-pound quantities and using the dot to indicate time rate of change. In deriving (A.7), the equation for h (i.e., for H per unit mass) has been used:

$$h = u + pv. \tag{A.8}$$

The availability has particular significance because the change in the availability of something (e.g., 1,000 kcal of steam) in a given process is the maximum possible useful work or heat that can be extracted from it in the given process. An example of the use of this concept is as follows. Suppose exhaust air at 40°C is being used as a source of heat for warming intake air. If the outside temperature is 35°C, very little heat can be retrieved; if the outside air is 0°C, quite a lot can be retrieved.

To examine the usefulness of this concept, consider a system in which these have $\dot{m}$ pounds per unit time passing through some device that will be used to recover useful energy. To know what the maximum power is that can be develop, denote this power as $\dot{W}_{max}$ (since power is the rate of doing work):

$$\dot{W}_{max} = -\dot{m}\,(b_{out} - b_{in}). \tag{A.9}$$

or

$$\dot{W}_{max} = \dot{B}_{in} - \dot{B}_{out}. \tag{A.10}$$

Written out, eq(A.10) is:

$$W_{max} = \dot{m}\,(u_{in} + (pv)_{in} - T_o s_{in} - u_{out} - (pv)_{out} + T_o s_{out}).$$

The equation indicates that the larger the specific internal energy and pressure at inlet, the more work is possible, while the more entropy is produced within the system, the less work is possible. Thus, high quality of energy is characterized by high internal energy and high pressure, but the quality is reduced by increased entropy. The internal energy is a function of temperature, so high temperatures represent high internal energy. In the next part of this section, elementary thermodynamics are applied to a few practical problems.

The great preponderance of energy requirements is met by burning fossil fuels at atmospheric pressure. When the chemically correct amount of air is mixed with hydrocarbon fuels, the resulting temperature is above 300°C. If the combustion takes place in a boiler where steam is generated at 10.5 bar (that is, at 186°C), 85 percent of the chemical energy in the fuel can be transferred to energy in the steam. Only 15 percent of the total input energy has been lost, but the availability has been decreased by 66 percent. How could the destruction of that potential to do work have been avoided? And furthermore, what difference does it make?

The answer to the first question is that the combustion process could have been carried out at a higher pressure (say 5 or 6 bar, 500 or 600 kilopascal),the products could have been expanded through a gas turbine, and a quantity of work produced. Then, the turbine exhaust gases could have been passed through a waste heat boiler to generate steam at the same pressure and temperature at which it was produced previously. Whether this scheme is practical depends on the relative needs for mechanical work and for process heat in the plant and the respective demand profiles for the two commodities. Although it is institutionally awkward, it is sometimes possible to sell generated power to neighbor plants or to the local electric utility. This approach to making use of the work potential of fossil fuels is one that will become more prevalent as

its implications are better understood, arrangements for sharing power are developed, and fuel costs continue to rise.

The answer to the second question posed above is that it is important to make use of the work potential of fossil fuel combustion because work is more scarce and more expensive than heat. Since the average efficiency of all power plants in the United States is about 30 percent, and other heat engines are also very inefficient, mechanical work is worth over three times as much as an equivalent quantity of heat.

SECTION 2: FUNDAMENTAL PRINCIPLES OF COMBUSTION

Combustion may be defined as that chemical process in which an oxidant is reacted rapidly with a fuel to liberate stored energy as thermal energy, generally in the form of high-temperature gases. Small amounts of electromagnetic energy (light), electric energy (free ions and electrons), and mechanical energy (noise) are also released during the combustion process. Except for special applications, the oxidant for combustion is oxygen in the air.

Conventional hydrocarbon fuels contain primarily hydrogen and carbon, in elemental form or in various compounds. Their complete combustion produces mainly carbon dioxide and water; however, small quantities of carbon monoxide and partially reacted flue constituents (gases and liquid or solid aerosols) may form. Most conventional fuels also contain small amounts of sulfur, oxidized to SO_2 or SO_3 during combustion, nitrogen compounds oxidized to NO_x, and noncombustible substances (i.e., mineral matter (ash), water, and inert gases), which are released.

The rate at which a fuel is combusted depends on: (1) reaction rate of combustible fuel constituents with oxygen; (2) rate at which oxygen is supplied to fuel (mixing of air and fuel); and (3) temperature in the combustion region. The reaction rate is fixed by fuel selection. Increasing either the mixing rate or temperature will increase the rate of combustion.

In <u>complete combustion</u> of hydrocarbon fuels, all hydrogen and carbon in the fuel is oxidized to H_2O and CO_2. Generally, for complete combustion, it is necessary to

supply **excess oxygen,** or **excess air,** beyond that theoretically required to oxidize the fuel. Excess oxygen or air is usually expressed as a percentage of the air theoretically required to completely oxidize the fuel.

In **stoichiometric combustion** of a hydrocarbon fuel, fuel is reacted with the exact amount of oxygen required to oxidize all carbon, hydrogen, and sulfur in the fuel to CO_2, H_2O, and SO_2. Hence, exhaust gas from stoichiometric combustion theoretically contains no incompletely oxidized fuel constituents or oxygen. The percentage of CO_2 contained in products of stoichiometric combustion is the maximum attainable, referred to as **stoichiometric CO_2, ultimate CO_2,** or **maximum theoretical percentage of carbon dioxide.**

Stoichiometric combustion (i.e., combustion at zero excess oxygen without formation of incompletely combusted fuel products) is seldom realized in practice, owing to imperfect mixing and finite reaction rate. Thus, economy and safety dictate that most combustion equipment operate with some **excess air.** The use of excess air ensures that fuel is not wasted and that combustion equipment is sufficiently flexible to provide complete combustion despite variations in fuel properties and in the supply rates of fuel and air. Therefore, in practice, combustion equipment is designed and operated to ensure **complete but not stoichiometric combustion.** The exact quantity of excess air supplied to any particular combustion equipment depends on such factors as: (1) expected variations in fuel properties and in fuel and air supply rates; (2) equipment application; (3) degree of operator supervision required or available; and (4) control requirements. For maximum efficiency, combustion at low excess air is desirable.

Incomplete combustion occurs when any fuel element is not completely oxidized in the combustion process. For example, a hydrocarbon may not completely oxidize to carbon dioxide and water, but may form partially oxidized compounds such as carbon monoxide, aldehydes, and ketones. Conditions that promote incomplete combustion include: (1) insufficient air and fuel mixing (causing local fuel-rich and fuel-lean zones); (2) insufficient air supply to the flame (providing less than the required quantity of oxygen); (3) insufficient reactant residence time in the flame (preventing completion of combustion reactions); (4) flame impingement on a cold surface (quenching combustion reactions); and (5) a too-low flame temperature (slowing combustion reactions).

Incomplete combustion represents inefficient fuel use, may be hazardous (owing to production of carbon monoxide), and contributes to air pollution.

A.2.1 Combustion Reactions

Combustion reactions of oxygen with combustible elements and compounds in fuels occur in accordance with fixed chemical principles, including:

1. The formation of specific products when two or more reactants are reacted under fixed conditions

2. Law of matter conservation (the mass of each element in the reaction products must equal the mass of that element in the reactants)

3. Law of combining weights (chemical compounds are formed by elements combining in fixed weight relationships).

Oxygen for combustion is normally obtained from air, a physical mixture of nitrogen, oxygen, and small amounts of water vapor, carbon dioxide, and inert gases. For practical combustion calculations, dry air is considered to consist of 20.95 percent oxygen and 79.05 percent inert gases (e.g., nitrogen, argon) by volume, or 23.15 percent oxygen and 76.85 percent inert gases by weight. For calculation purposes, nitrogen is assumed to pass through the combustion process unchanged (although small quantities of nitrogen oxides are known to form). Oxygen and air requirements for stoichiometric combustion of some pure combustible materials (or constituents) found in common fuels vary significantly (see Exhibit A.1).

A.2.2 Heating Values

Combustion results in release of thermal energy or heat. The quantity of heat generated by complete combustion of a unit of specific fuel is constant, and known as the **heating value**, **heat of combustion**, or **calorific value** of that fuel.

Exhibit A.1

Combustion Reactions of Common Fuel Constituents

Constituent	Molecular symbol	Combustion reactions	Stoichiometric oxygen and air requirements: kg/kg fuel* O_2	kg/kg fuel* Air	m^3/m^3 fuel O_2	m^3/m^3 fuel Air
Carbon (to CO)	C	$C+0.5a \longrightarrow CO$	1.33	5.75	--	--
Carbon (to CO_2)	C	$C+O_2 \longrightarrow CO_2$	2.66	11.51	--	--
Carbon monoxide	CO	$CO+0.5a_2 \longrightarrow CO_2$	0.57	2.47	0.50	2.39
Hydrogen	H_2	$H_2+0.5a_2 \longrightarrow H_2O$	7.94	34.28	0.50	2.39
Methane	CH_4	$CH_4+2O_2 \longrightarrow CO_2+2H_2O$	3.99	17.24	2.00	9.57
Ethane	C_2H_6	$C_2H_6+3.5O_2CO_2+3H_2O$	3.72	16.09	3.50	16.75
Propane	C_3H_8	$C_3H_8+5O_2=3CO_2+4H_2O$	3.63	15.68	5.00	23.95
Butane	C_4H_{10}	$C_4H_{10}+6.5O_2=4CO_2+5H_2O$	3.58	15.47	6.50	31.14
--	C_nH_{2n+2}	$C_nH_{2n+2}+(1.5n+0.5) \longrightarrow nCO_2+(n+1)H_2O$	--	--	1.5n+0.5	7.18n+2.39
Ethylene	C_2H_4	$C_2H_4+3O_2 \longrightarrow 2CO_2+2H_2O$	3.42	14.78	3.00	14.38
Propylene	C_3H_6	$C_3H_6+4.5O_2 \longrightarrow 3CO_2+3H_2O$	3.42	14.78	4.50	21.53
--	C_nH_{2n}	$C_nH_{2n}+1.5O_2 \longrightarrow nCO_2+nH_2O$	3.42	14.78	1.50n	7.18n
Acetylene	C_2H_2	$C_2H_2+2.5a_2 \longrightarrow 2CO_2+H_2o$	3.07	13.27	2.50	11.96
--	C_nH_{2m}	$C_nH_{2m}+(n+0.5m)O_2 \longrightarrow nCO_2+mH_2O$	--	--	n+0.5m	4.78n+2.39m
Sulfur (to SO_2)	S	$S+O_2 \longrightarrow SO_2$	1.00	4.31	--	--
Sulfur (to SO_3)	S	$S+1.5O_2 \longrightarrow SO_3$	1.50	6.47	--	--
Hydrogen sulfide	H_2S	$H_2S+1.5O_2 \longrightarrow SO_2+H_2O$	1.41	6.08	1.50	7.18

*Atomic weights; H=1.008; C=12.01; O=16.00; S=32.06.

The heating value of a fuel may be determined directly by measuring the heat evolved during combustion of a known quantity of the fuel in a calorimeter, or it may be estimated from chemical analysis of the fuel and the heating value of the several chemical elements in the fuel.

Higher heating value, or **gross heating value,** is determined when water vapor in the products of fuel combustion is condensed, and the latent heat of vaporization of water is included in the fuel's heating value. Conversely, **lower heating value,** or **net heating value,** is obtained when latent heat of vaporization is not included. When the heating value of a fuel is specified without designating higher or lower, it generally means the higher heating value. (Lower heating value is mainly used for internal combustion engine fuels (see Exhibit A.2.) The difference between higher and lower heating values becomes increasingly important as you move from gaseous fuels to light liquid fuels to heavy liquid fuels. On a dry basis, the difference for gaseous fuels can be roughly 10 percent. For heavy liquid fuels, the difference is usually 1 percent.

With incomplete combustion, not all fuel is completely oxidized, and thus heat released is less than the heating value of the fuel. Thus, the quantity of heat produced per unit of fuel consumed decreases, implying lower combustion efficiency.

Not all heat released during combustion can be utilized effectively. The largest heat loss is in the form of increased temperature (thermal energy) of hot exhaust gases above the temperature of incoming air and fuel. There are generally other heat losses, including radiation and convection heat transfer from outer walls of combustion equipment to the environment.

A.2.3 Gaseous Fuels

Although various gaseous fuels have been used as energy sources in the past, heating and cooling applications are presently limited to natural and liquefied petroleum gases.

Exhibit A.2

Heating Values of Substances
Occurring in Common Fuels

Substance	Molecular symbol	Higher heating values,* kcal/kg	Higher heating values,* Btu/lb	Lower heating values,* kcal/kg	Lower heating values,* Btu/lb
Carbon (to CO)	C	2,194	3,950	2,194	3,950
Carbon (to CO_2)	C	7,829	14,093	7,829	14,093
Carbon monoxide	CO	2,415	4,347	2,415	4,347
Hydrogen	H_2	33,942	61,095	28,346	51,023
Methane	CH_4	13,264	23,875	11,942	21,495
Ethane	C_2H_6	12,402	22,323	11,343	20,418
Propane	C_3H_8	12,038	21,669	11,076	19,937
Butane	C_4H_{10}	11,845	21,321	10,932	19,678
Ethylene	C_2H_4	12,020	21,636	11,264	20,275
Propylene	C_3H_6	11,693	21,048	10,937	19,687
Acetylene	C_2H_2	11,946	21,502	11,538	20,769
Sulfur (to SO_2)	S	2,211	3,980	2,211	3,980
Sulfur (to SO_3)	S	3,300	5,940	3,300	5,940
Hydrogen sulfide	H_2S	3,943	7,097	3,632	6,537

*All values corrected to 16°C (60°F), (30 in. Hg), dry. For gases saturated with water vapor at 16°C (60°F), deduct 1.74 percent of the heating value.

A.2.3.1 Types and Properties

Natural gas is a nearly odorless and colorless gas that accumulates in upper parts of oil wells and in gas wells. Raw natural gas is a mixture of methane (55 percent to 98 percent), higher hydrocarbons (primarily ethane), and noncombustible gases. Some constituents -- primarily water vapor, hydrogen sulfide, helium, liquefied petroleum gases, and gasoline -- are removed prior to distribution.

Typical composition of natural gas distributed for use as fuel include: methane, CH_4 (70 to 96 percent); ethane, C_2H_6 (1 to 14 percent); propane, C_3H_8 (0 to 4 percent); butane, C_4H_{10} (0 to 2 percent); pentane, C_5H_{12} (0 to 0.5 percent); hexane, C_6H_{14} (0 to 2 percent); carbon dioxide, CO_2 (0 to 2 percent); oxygen, O_2 (0 to 1.2 percent); and nitrogen, N_2 (0.4 to 17 percent).

Composition of a natural gas depends primarily on its geographical source. Composition of gas distributed in a given location may vary slightly, as gas is drawn from various sources, but a fairly constant heating value is usually maintained for control and safety purposes. The local gas utility is the best source of current gas composition data for a particular area. Heating values of natural gases vary from 8,000 to 10,700 kcal/m^3 (900 to 1,200 Btu/ft^3), but the usual range is 8,900 to 9,340 kcal/m^3 (1,000 to 1,050 Btu/ft^3).

Liquefied petroleum gases consist primarily of propane and butane, normally obtained as a byproduct of oil refinery operations or by stripping natural gas. Propane and butane are gaseous under usual atmospheric conditions, but can be liquefied by moderate pressure at normal temperatures.

Three liquefied petroleum gases are commercially available as fuels: butane, propane, and a mixture of the two.

Commercial propane consists primarily of propane but generally contains about 5 to 10 percent propylene. It has a heating value of about 11,980 kcal/kg (21,560 Btu/lb), or about 22,250 kcal/m^3 (2,500 Btu/ft^3) of gas. At atmospheric pressure, commercial propane has a boiling point of about -40°C (-40°F). Propane is generally available in cylinders, bottles, tank trucks, or tank cars.

Commercial butane consists primarily of butane but may contain up to about 5 percent butylene. It has a heating value of about 11,770 kcal/kg (21,180 Btu/lb), or about 28,500 kcal/m^3 (3,200 Btu/ft^3) of gas. At atmospheric pressure, butane has a relatively high boiling point of about 0°C (32°F), which means that butane cannot be used in cold weather unless gas temperature is maintained above 0°C (32°F) or butane partial pressure is decreased by dilution with lower boiling point gases. Butane is usually available in bottles, tank trucks, or tank cars, but not in cylinders.

Commercial propane-butane mixtures with varying ratios of propane and butane are available. Their properties generally fall between those of propane and those of butane.

Manufactured gases are combustible gases produced from coal, coke, oil, liquefied petroleum gases, or natural gas.

A.2.4 Liquid Fuels

Significant liquid fuels include various fuel oils for firing combustion equipment and engine fuels for total energy systems. Liquid fuels, with few exceptions, are mixtures of hydrocarbons derived from crude petroleum by refining processes. In addition to hydrocarbons, crude petroleum usually contains small quantities of sulfur, oxygen, nitrogen, vanadium, other trace metals, and impurities such as water and sediment. Petroleum refining produces a variety of fuels and other products. Nearly all lighter hydrocarbons are refined into fuels (e.g., liquefied petroleum gases, gasoline, kerosine, jet fuels, diesel fuels, light heating oils). Heavy hydrocarbons are refined into residual fuel oils and other products (e.g., lubricating oils, waxes, petroleum coke, asphalt).

Crude petroleums from different oil fields vary in hydrocarbon molecular structure. Crude is **paraffin-base** (principally chain-structured, paraffin hydrocarbons), **naphthene-** or **asphaltic-base** (containing relatively large quantities of saturated, ring-structured naphthenes), **aromatic-base** (containing relatively large quantities of unsaturated, ring-structured aromatics), or **mixed-** or **intermediate-base** (between paraffin- and naphthene-base crudes). Except for heavy fuel oils, crude type has little significant effect on resultant products and combustion applications.

A.2.5 Solid Fuels

Solid fuels include coal, coke, wood, and waste products of industrial and agricultural operations. Of these, only coal is widely used for heating and cooling applications.

The complex composition of coal makes classification into clear-cut types difficult. Chemically, it consists of carbon, hydrogen, oxygen, nitrogen, sulfur, and a mineral residue called ash. A chemical analysis provides some indication of coal quality, but does not define its burning characteristics sufficiently. The coal user is principally interested in available heat per pound of coal and amount of ash and dust produced, but also in handling and storing properties and burning characteristics (see Exhibit A.3).

SECTION 3: PSYCHROMETRIC CHARTS AND STEAM TABLES

Psychrometry is the branch of thermodynamics that deals with the properties of moist air and the use of those properties in the analysis of processes involving moist air. The processes include:

- Drying
- Humidification
- Dehumidification
- Dehydration.

A psychrometric chart depicts the properties of moist air in a graphical manner. A sample psychrometric chart for sea level atmospheric pressure (1.013 bar) is presented in Exhibit A.4. (Psychrometric properties vary with barometric pressure or height above sea level, and charts are available for these conditions.)

The psychrometric chart contains the following data:

- Dry bulb temperature (^{o}C)
- Wet bulb temperature (^{o}C)
- Dew point (saturation) temperature (^{o}C)
- Moisture content (kg/kg dry air)

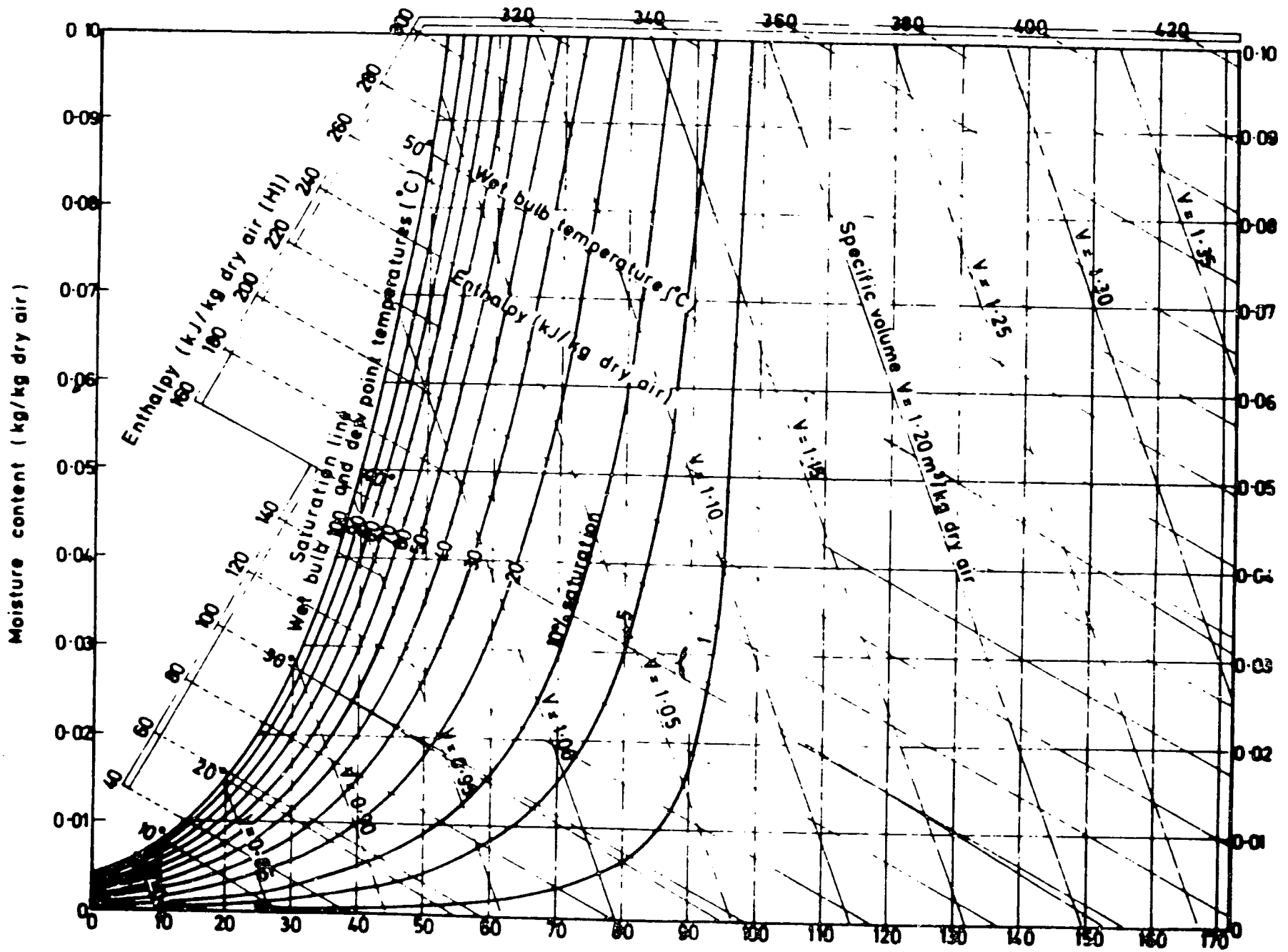
Exhibit A.3

Typical Ultimate Analyses for Coals

Rank	Kcal/kg, as received	Btu/lb as received	Constituents, percent by weight				
			Oxygen	Hydrogen	Carbon	Nitrogen	Sulfur
Anthracite	7,060	12,700	5.0	2.9	80.0	0.9	0.7
Semianthracite	7,560	13,600	5.0	3.9	80.4	1.1	1.1
Low-volatile bituminous	7,970	14,350	5.0	4.7	81.7	1.4	1.2
Medium-volatile bituminous	7,780	14,000	5.0	5.0	81.1	1.4	1.5
High-volatile bituminous A	7,670	13,800	9.3	5.3	75.9	1.5	1.5
High-volatile bituminous B	6,940	12,500	13.8	5.5	67.8	1.4	3.0
High-volatile bituminous C	6,110	11,000	20.6	5.8	59.6	1.1	3.5
Subbituminous B	5,000	9,000	29.5	6.2	52.5	1.0	1.0
Subbituminous C	4,720	8,500	35.7	6.5	46.4	0.8	1.0
Lignite	3,830	6,900	44.0	6.9	40.1	0.7	1.0

Exhibit A.4

Pyschrometric Chart



- Relative humidity (percent)
- Specific volume (m^3/kg dry air)
- Enthalpy (kJ/kg dry air).

At any fixed atmospheric pressure, knowledge of any **two** moist air properties allows determination of **all** of the remaining properties.

As an example, consider moist air with a dry bulb temperature of 70°C and a wet bulb temperature of 40°C. In practice, dry bulb and wet bulb temperatures are the most readily determined properties of moist air; a psychrometer is used for their measurement.

As shown in Exhibit A.5, the condition of the moist air is indicated by the dot at the intersection of the 70°C dry bulb temperature line and the 40°C wet bulb temperature line.

The dew point temperature is determined by drawing a horizontal line through the point, which intersects the 100 percent saturation line on the left. The dew point temperature is about 35°C. (The numbers on the 100 percent saturation line indicate **both** wet bulb and dew point temperatures.)

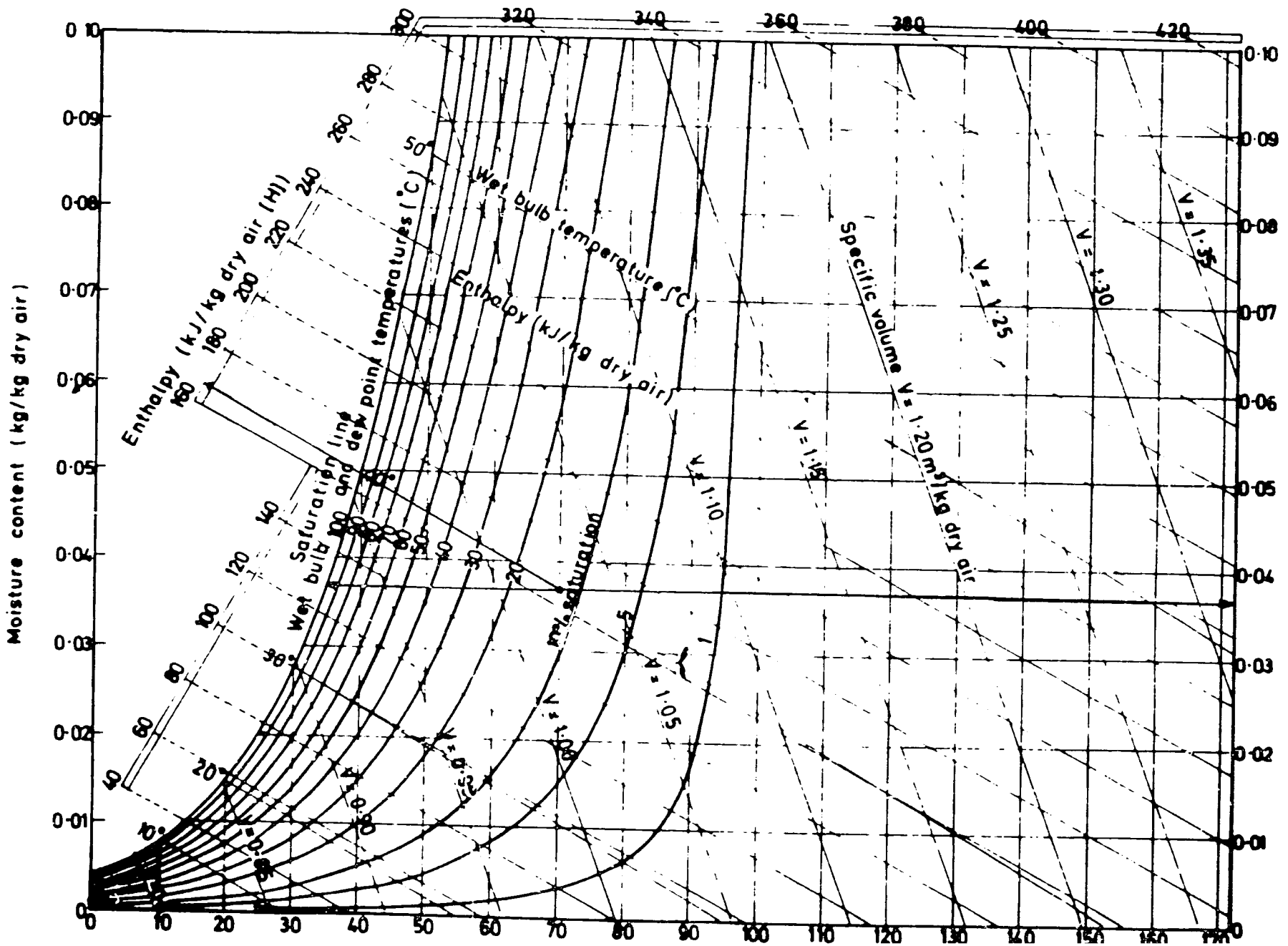
The moisture content is found by extending the same horizontal line to the right, where it intersects the moisture content scale. The moisture content is thus about 0.0375 kg per kg of dry air.

The relative humidity is found from the series of specific volume lines that are drawn from the upper left to the lower right. The point falls between the V = 1.00 and V = 1.05 lines. Hence, specific volume is 1.025 m^3/kg dry air.

Finally, the enthalpy is found by extending a line from the specific volume point to the enthalpy scale, ascending from right to left as shown. The enthalpy falls between 160 and 180 kJ per kg of dry air; hence, enthalpy is estimated at 170 kJ per kg of dry air.

Exhibit A.5

Example Pyschrometric Chart



A.3.1 STEAM TABLES

Steam tables provide a reference for the properties of saturated steam. An example of a steam table is shown in Exhibit A.6.

The properties of steam are determined from the table as follows. The steam's pressure and temperature (if superheated) must be known. The first two columns indicate the pressure of the steam in bar or kilopascals.

The next two columns indicate the properties of saturated water and saturated steam at the steam pressure and saturation temperature.

The specific volume is indicated in cubic meters per kilogram (m^3/kg). Enthalpy is shown in kilojoules per kilogram (kJ/kg).

SECTION 4: HEAT TRANSFER

Heat or thermal energy transfer from one region to another is by three modes: conduction, convection, and radiation. Each is important in the design or application of heating, air-conditioning, or refrigeration equipment. Heat transfer is one of the transport phenomena, which include mass transfer, momentum transfer or fluid friction, and electrical conduction. Transport phenomena have similar rate equations; flux is proportional to a potential difference. In heat transfer by conduction and convection, the potential difference is the temperature difference. Heat, mass, and momentum transfer -- owing to their similarities and interrelationship in many common physical processes -- receive unified treatment in some textbooks.

<u>Thermal conduction</u> is the mechanism of heat transfer whereby energy is transported between parts of a continuum owing to transfer of kinetic energy between particles or groups of particles at the atomic level. In gases, conduction is the result of elastic collision of molecules; in liquids and electrically nonconducting solids, it is believed to be primarily the result of longitudinal oscillations of the lattice structure. Thermal conduction in metals occurs like electrical conduction, through motions of free electrons. The Second Law of Thermodynamics shows that thermal transfer occurs in the direction

Exhibit A.6

Steam Tables

Metric SI Units

Pressure			Temperature	Specific Enthalpy			Specific Volume Steam
bar		kPa	°C	Water (h_f) kJ/kg	Evaporation (h_{fg}) kJ/kg	Steam (h_g) kJ/kg	m^3/kg
0·30		30·0	69·10	289·23	2336·1	2625·3	5·229
0·50	absolute	50·0	81·33	340·49	2305·4	2645·9	3·240
0·75		75·0	91·78	384·39	2278·6	2663·0	2·217
0·95		95·0	98·20	411·43	2261·8	2673·2	1·777
0	gauge	0	100·00	419·04	2257·0	2676·0	1·673
0·10		10·0	102·66	430·2	2250·2	2680·4	1·533
0·20		20·0	105·10	440·8	2243·4	2684·2	1·414
0·30		30·0	107·39	450·4	2237·2	2687·6	1·312
0·40		40·0	109·55	459·7	2231·3	2691·0	1·225
0·50		50·0	111·61	468·3	2225·6	2693·9	1·149
0·60		60·0	113·56	476·4	2220·4	2696·8	1·083
0·70		70·0	115·40	484·1	2215·4	2699·5	1·024
0·80		80·0	117·14	491·6	2210·5	2702·1	0·971
0·90		90·0	118·80	498·9	2205·6	2704·5	0·923
1·00		100·0	120·42	505·6	2201·1	2706·7	0·881
1·10		110·0	121·96	512·2	2197·0	2709·2	0·841
1·20		120·0	123·46	518·7	2192·8	2711·5	0·806
1·30		130·0	124·90	524·6	2188·7	2713·3	0·773
1·40		140·0	126·28	530·5	2184·8	2715·3	0·743
1·50		150·0	127·62	536·1	2181·0	2717·1	0·714
1·60		160·0	128·89	541·6	2177·3	2718·9	0·689
1·70		170·0	130·13	547·1	2173·7	2720·8	0·665
1·80		180·0	131·37	552·3	2170·1	2722·4	0·643
1·90		190·0	132·54	557·3	2166·7	2724·0	0·622
2·00		200·0	133·69	562·2	2163·3	2725·5	0·603
2·20		220·0	135·88	571·7	2156·9	2728·6	0·568
2·40		240·0	138·01	580·7	2150·7	2731·4	0·536
2·60		260·0	140·00	589·2	2144·7	2733·9	0·509
2·80		280·0	141·92	597·4	2139·0	2736·4	0·483
3·00		300·0	143·75	605·3	2133·4	2738·7	0·461
3·20		320·0	145·46	612·9	2128·1	2741·0	0·440
3·40		340·0	147·20	620·0	2122·9	2742·9	0·422
3·60		360·0	148·84	627·1	2117·8	2744·9	0·405
3·80		380·0	150·44	634·0	2112·9	2746·9	0·389
4·00		400·0	151·96	640·7	2108·1	2748·8	0·374
4·50		450·0	155·55	656·3	2096·7	2753·0	0·342
5·00		500·0	158·92	670·9	2086·0	2756·9	0·315
5·50		550·0	162·08	684·6	2075·7	2760·3	0·292
6·00		600·0	165·04	697·5	2066·0	2763·5	0·272
6·50		650·0	167·83	709·7	2056·8	2766·5	0·255
7·00		700·0	170·50	721·4	2047·1	2769·1	0·240
7·50		750·0	173·02	732·5	2039·2	2771·7	0·227
8·00		800·0	175·43	743·1	2030·9	2774·0	0·215
8·50		850·0	177·75	753·3	2022·9	2776·2	0·204
9·00		900·0	179·97	763·0	2015·1	2778·1	0·194
9·50		950·0	182·10	772·5	2007·5	2780·0	0·185
10·00		1000·0	184·13	781·6	2000·1	2781·7	0·177
10·50		1050·0	186·05	790·1	1993·0	2783·3	0·171
11·00		1100·0	188·02	798·8	1986·0	2784·8	0·163
11·50		1150·0	189·82	807·1	1979·1	2786·3	0·157
12·00		1200·0	191·68	815·1	1972·5	2787·6	0·151
12·50		1250·0	193·43	822·9	1965·4	2788·8	0·148
13·00		1300·0	195·10	830·4	1959·6	2790·0	0·141
13·50		1350·0	196·62	837·9	1953·2	2791·1	0·136
14·00		1400·0	198·35	845·1	1947·1	2792·2	0·132
14·50		1450·0	199·92	852·1	1941·0	2793·1	0·128
15·00		1500·0	201·45	859·0	1935·0	2794·0	0·124
15·50		1550·0	202·92	865·7	1928·8	2794·9	0·119
16·00		1600·0	204·38	872·3	1922·4	2795·7	0·117
17·00		1700·0	207·17	885·0	1912·1	2797·1	0·110
18·00		1800·0	209·90	897·2	1901·3	2798·5	0·105
19·00		1900·0	212·47	909·0	1890·5	2799·5	0·100
20·00		2000·0	214·96	920·3	1880·2	2800·5	0·0949
21·00		2100·0	217·35	931·3	1870·1	2801·4	0·0906
22·00		2200·0	219·65	941·9	1860·1	2802·0	0·0868
23·00		2300·0	221·85	952·2	1850·4	2802·6	0·0832
24·00		2400·0	224·02	962·2	1840·9	2803·1	0·0797
25·00		2500·0	226·12	972·1	1831·4	2803·5	0·0768
26·00		2600·0	228·15	981·6	1822·2	2803·8	0·0740
27·00		2700·0	230·14	990·7	1813·3	2804·0	0·0714

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of decreasing temperature. In solid opaque bodies, the significant heat transfer mechanism is thermal conduction, since there is no net material flow in the process. With flowing fluids, thermal conduction dominates in the region very close to a solid boundary where the flow is **laminar** and parallel to the surface, and there is no eddy motion.

Thermal convection may involve energy transfer by eddy mixing and diffusion in addition to conduction. Consider heat transfer to a fluid flowing inside a pipe. If the Reynolds number* is sufficiently great, three different flow regions will exist. Immediately adjacent to the wall is a **laminar sublayer** where heat transfer occurs by thermal conduction; outside the laminar sublayer is a transition region called the **buffer layer,** where both eddy mixing and conduction effects are significant; beyond the buffer layer and extending to the center of the pipe is the **turbulent region,** where the dominant mechanism of transfer is eddy mixing.

In most equipment, the main body of the fluid is in turbulent flow, and the laminar layer exists at the solid walls only. In cases of low-velocity flow in small tubes, or with viscous liquids such as oil (i.e., at low Reynolds numbers), the entire flow may be laminar with no transition or eddy region.

When the fluid currents are produced by sources external to the heat transfer region (for example, a blower or pump), the solid-to-fluid heat transfer is termed **forced convection.** If the solid flow is generated internally by nonhomogeneous densities owing to temperature variation, the heat transfer is termed **free** or **natural convection.**

In conduction and convection, the transfer of heat takes place through matter. For **radiant heat transfer,** there is a change in energy form, from internal energy at the source to electromagnetic energy for transmission, then back to internal energy at the receiver. Whereas conduction and convection are affected primarily by temperature difference and somewhat by temperature level, the heat transferred by radiation increases rapidly with an increase in the temperature level.

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*The Reynolds number (NRE) is a dimensionless number used as a measure of a system's flow characteristics. It is equal to the density of the fluid, times its velocity, times a characteristic length (often a pipe diameter), divided by the fluid viscosity. The higher the Reynolds number, the more turbulent the flow characteristics.

A.4.1 Overall Heat Transfer

In most steady state heat transfer problems, more than one heat transfer mode may be involved. It is convenient to combine the various heat transfer coefficients into an overall coefficient so that the total heat transfer may be calculated from the terminal temperatures. The solution to this problem is much simpler if the concept of **thermal circuit and thermal resistance** is employed.

Heat conductivity and electrical conductivity are very similar and obey the same laws. Conductance is a particular value taking account of thickness or length as well as the physical properties of the material. The specific conductance or "conductivity" is the conductance per unit length or unit thickness per unit temperature increase in unit time. The resistance to heat or electrical flow must vary directly with the length or thickness of the material and inversely as the conductivity.

$$R = \frac{\text{Thickness}}{\text{Conductivity}} \qquad R = \frac{L}{K}$$

The resistance to heat flow through a heating surface is built up of several resistances: the condensate film, any air blanket, the metal wall itself, scale, etc. In just the same way, the resistance of an electrical current is built up of the generator resistance, the feeders, the distribution wires, the motor resistance, etc.

In an electrical circuit, the total overall resistance is found by adding together the component resistances. Similarly, in heat flow, the overall resistance to heat transfer can be found by adding together the individual resistances.

$$\text{Overall resistance} = \frac{\text{Thickness of metal}}{\text{Conductivity of metal}} + \frac{\text{Thickness of condensate film}}{\text{Conductivity of water}} + \text{etc.}$$

(a) $R = L_1 + L_2 + L_3 + L_4 + \text{etc.}$

Conductance and resistance are reciprocals, so that

(b) $\text{Conductance} = \frac{1}{\text{Resistance}}$

For heat flow problems, it is necessary to know the overall conductance -- that is, the heat that will flow, not the resistance offered to flow. The conductance is found by combining the two formulae (a) and (b) just given:

$$\text{Conductance} = U = \frac{1}{R} = \frac{1}{L_1 + L_2 + L_3 + L_4 + \text{etc.}}$$

The conductance U is called the **overall heat transfer coefficient** or **heat transfer rate.** As the conductivity is expressed with the dimensions kcal/(m^2·hr·°C/unit thickness), the heat transfer rate will be measured in kcal/(m^2·hr·°C). Copper has an extremely high thermal conductivity of 32,500 kcal/(m^2·hr·°C) per cm thickness, while air has a thermal conductivity of only 2.5 kcal/(m^2·hr·°C) per cm thickness (see Exhibit A.7).

In the following example, the resistance offered to heat flow by an imaginary heating surface is examined. Assume that we have a heating surface is made of steel 0.635 cm thick, in a steam-heated water heater.

Assume that there is a film of condensate 0.25 mm thick on the steam side, and that this film is blanketed by a film of air also 0.25 mm thick. (Actually, this will not be a true "film" of air. Diffusion of air molecules into the steam and steam molecules into the air is very rapid. There will be an increasing concentration of air nearer the heating surface. Considering the point of discussion, however, it will be assumed that there is actual air film.) Also assume that there is 0.25 mm of scale on the water side and a stagnant film of water 0.25 mm thick between the scale and the body of the water. (In addition to these films, there may be another and very resistant film in evaporators if a film of steam forms on the liquid side of the heating side of the heating surface.) This information can be tabulated as follows:

Item	Thickness, cm	Conductivity, kcal/m^2/hr/°C/cm thickness
Air	L_1 = 0.025	k_1 = 2.5
Condensate	L_2 = 0.025	k_2 = 50
Steel	L_3 = 0.635	k_3 = 3,840
Scale	L_4 = 0.025	k_4 = 25
Water film	L_5 = 0.025	k_5 = 50

The heat transfer rate will be:

Exhibit A.7

Thermal Conductivities

Material	$Btu/ft^2/hr/^oF$ difference/ inch thickness	$Kcal/m^2/^oC$ difference/ cm thickness
Copper	2,620	32,500
Steel	310	3,840
Water	4	50
Scale	1 to 12	12 to 150
Air	0.2	2.5

$$U = \frac{1}{\frac{0.025}{2.5} + \frac{0.025}{50} + \frac{0.635}{3{,}840} + \frac{0.025}{25} + \frac{0.025}{50}} = 82.2 \text{ kcal/m}^2 \text{ hr } ^\circ\text{C}.$$

If copper is used in the above example instead of steel, the same equation can be used by substituting 5,040 (copper) for 595 (steel). The overall heat transfer rate will become:

$$U = \frac{1}{\frac{0.01}{0.2} + \frac{0.01}{4} + \frac{0.25}{2{,}620} + \frac{0.01}{0.2} + \frac{0.01}{4}} = \frac{1}{\frac{0.025}{2.5} + \frac{0.025}{50} + \frac{0.635}{32{,}500} + \frac{0.025}{25} + \frac{0.025}{50}}$$

$$= 83.2 \text{ kcal/m}^2 \text{ hr } ^\circ\text{C}.$$

Thus, although copper is more than 8 times better than steel as a conductor, and although the heating surface is 0.635 cm thick, the effect of using copper instead of steel is quite negligible in this example. The difference is negligible because the resistant films, so long as they are substantial, are so important that the thickness or material of the heating surface has little effect. If the films have been reduced, it may be worthwhile to use copper or brass instead of steel.

With respect to heat transfer, the choice of metal is not the most important factor. The choice of metal in construction of the heat exchanger should be based on the effects of contamination and cleanliness of the materials flowing in the system.

A.4.2 Effect of Scale

Scales vary in composition, and the published figures of the resistance of scale to heat transfer are very conflicting. Apart from the effect of the material composing the scale, other effects may be introduced. During the course of a week's operation, the heat transfer rate of two evaporators in an existing factory can decrease significantly (see Exhibit A.8). These evaporators are descaled each weekend. The material being evaporated is an impure sugar solution entering with 85 percent water and leaving after concentration with 30 percent water. The evaporators are continuous, not batch.

It is almost impossible to measure the thickness of the scale, which is deposited much more heavily in certain parts of the tubes. Weighing the amount of scale removed

Exhibit A.8

	Evaporator (kcal/(m^2·hr·^{o}C))		
	Double effect short tube evaporator	Double effect long tube climbing film	Average of two evaporators
Monday	1,270	1,370	1,320
Tuesday	1,030	1,270	1,150
Wednesday	980	1,070	1,030
Thursday	930	1,070	1,000
Friday	780	880	830

If x = the overall resistance of the clean tube and any air or liquid films and y = the conductivity of the scale, then the conductivity of the scale can be found as follows:

$$\frac{1}{x + \frac{0.003}{y}} \quad ; \quad \frac{1}{x} = 1{,}320$$

$$\frac{1}{x + \frac{0.003}{y}} \quad ; \quad \frac{1}{x} = 830$$

$y = 6.7$ kcal/(m^2 · hr · ^{o}C/cm)

gives an average thickness as 0.003 cm, if spread evenly over the heating surface. (The scale is actually confined almost entirely to the first effect.)

Calculation of the conductivity of the scale shows that it has a lower conductivity than the published figures. The scale composition is not very usual, however; it is a mixture composed chiefly of calcium sulfate with varying proportions of calcium carbonate and calcium phosphate.

It is possible that scale, by insulating the heating surface, upsets the circulation of the evaporator.

Fortunately, steam users can pass the burden of designing heat transfer plants to the manufacturers, who -- by long experience -- have a store of data that enables them to foretell heat transfer rates for various materials and applications with fair certainty. The user must always remember, however, that the working of any heat transfer plant depends on the elimination or reduction of the resistant films.

It is equally important to reduce the resistance caused by the film of water on the steam side of a heat exchanger plate or tube. It is essential to remove the water formed by the condensation of steam by positioning the heat exchanger to drain efficiently, and to install the most suitable condensate trapping equipment.

A.4.3 Overall Heat Transfer Rate

The separate estimation of the constituents of the resistance to heat flow is seldom practical, and the published data are meager and conflicting. The only thing that matters is the overall rate; bearing in mind that it is the films that matter, the overall rate can be increased.

The heat transfer rate per ^{o}C of temperature difference not only increases with higher average temperature, but increases with greater temperature differences. It seems that this improvement at higher temperature occurs mainly because of a reduction in viscosity of the heated liquid, thus making the liquid flow more easily and the liquid films thinner (see Exhibit A.9). Increased fluid velocities also increase overall heat

Exhibit A.9

Overall Heat Transfer Rates

Plant	Conditions	Btu/ft^2/hr/ ^{o}F difference[1]
Condenser	Water flowing at 1 ft/sec[2]	150 to 400
Condenser	Water flowing at 2 ft/sec	200 to 500
Condenser	Water flowing at 4 ft/sec	250 to 750
Boiler	Gas to water	2 to 8
Economizer	Gas to water	1 to 5
Superheaters	Gas to steam	2 to 6
Tank coils	Temperature difference 50°F[3]	100 to 225
Tank coils	Temperature difference 100°F	175 to 300
Tank coils	Temperature difference 200°F	225 to 475
Air heater	Convection only	2
Air heater	Air velocity 1 ft/sec	3
Air heater	Air velocity 5 ft/sec Temperature difference 100°F	5
Air heater	Air velocity 10 ft/sec	8

[1]To convert Btu/ft^2/hr/^{o}F difference to kcal/m^2/hr/^{o}C difference, multiply by 4.885.
[2]To convert ft/sec to m/s, multiply by 0.3048.
[3]To convert ^{o}F difference to ^{o}C difference, divide by 1.8.

transfer rates (see Exhibit A.10). And, quite naturally, overall heat transfer coefficients also depend significantly on the product being heated or cooled (see Exhibit A.11).

A.4.4 Logarithmic Mean Temperature Difference

In all types of heaters where the temperatures change on one or both sides of the heating surface, the temperature difference is not a constant figure, and there must be a way of arriving at the correct average temperature figure. There are several possible possibilities.

Consider, for example, a simple batch heating job in a tank or vat, heated by steam and properly trapped and vented. The steam temperature is constant; the temperature of the material in the vessel can be assumed to be more or less uniform, but is rising with time. At first, when the temperature difference is great, the liquid will heat up quickly. The hotter it gets, the less the temperature difference and the slower the temperature increase. The mean temperature difference could be found by taking temperatures every minute and averaging the result, which -- had the time intervals been constant and sufficiently frequent -- would be the true mean, or average, temperature difference.

Now consider a heat exchanger. Here there is a flow, but time is not a factor. The operation is continuous and is independent of time. The steam temperature is constant, but the liquid temperature rises along the length of the heat exchanger. It might be possible to take temperatures at regular equal intervals along the heat exchanger and thus obtain the true average temperature difference. The temperatures all along the heat exchanger will vary with varying rates of flow, and such a reading of multiple temperatures would generally be impractical.

Now consider a long-pipe room heater using hot water. The room temperature will be virtually constant, but the water temperature will fall along the length of the pipe. This fall in water temperature will be rapid at first and will diminish as the temperature of the water drops. The temperature at even distances along the pipe could be measured to find the true mean temperature difference.

Exhibit A.10

Reasonable Practical Heat Transfer Rates

Operation (on water or dilute liquors)	$Btu/ft^2/hr/^oF$ difference[1]
Heat exchangers and condensers with low-velocity liquid	150
Heat exchangers and condensers with high-velocity liquid	300
Tank coils, low pressure with natural circulation	100
Tank coils, high pressure with natural circulation	200
Tank coils, low pressure with assisted circulation	200
Tank coils, high pressure with assisted circulation	300
Natural circulation evaporators with low-pressure steam	300
Natural circulation evaporators with high-pressure steam	500
Assisted circulation evaporators	750
Space heating by water -- convection only	1.5
Space heating by steam -- convection only	2
Space heating by steam -- 10 ft/sec air velocity	8

[1]To convert $Btu/ft^2/hr/^oF$ difference to $kcal/m^2/hr/^oC$ difference, multiply by 4.885.

Overall Heat Transfer Coefficient "U"

Fluid in coil	Product being heated or cooled	Coefficient "U" Btu/hr/ft^2/degree F[1] Agitated	Not agitated
Water*	Water	100-130	25-80
	Milk	100-130	25-80
	Ice cream mix (12% butterfat)	60-100	15-30
	Cream (40% fat)	40-80	10-25
	Skim condensed milk (30% solids)	60-100	15-30
	Buttermilk	60-100	15-30
	Air	3-7	1-3
	Oil, medium	10-30	4-9
	Sugar solution	18-50	7-22
	Tar	15-20	5-12
Steam	Water	120-300	100-150
	Milk	120-170	100-150
	Ice cream mix (12% fat)	80-120	40-60
	Cream (40% fat)	60-95	30-50
	Skim condensed milk (30% solids)	80-120	40-60
	Air	3-8	2-4
	Oil, medium	35-95	8-40
	Sugar solution	60-180	16-68
	Tar	45-65	10-30
Flooded	Oil, No. SAE30	8-20	2-10
	Water	70-110	35-55
Refrigerant-12 (Freon) or	Milk	70-100	35-55
Refrigerant-717 (ammonia)	Ice cream mix (12% butterfat)	50-70	25-40
	Cream (40% fat)	30-55	15-30
	Skim condensed milk (30% solids)	50-70	25-70
	Air	2-7	1-3
	Sugar solution	30-70	12-25
	Water	60-80	30-45
Dry expansion**	Milk	60-80	30-45
	Ice cream mix (12% butterfat)	35-50	20-35
Refrigerant-12 (Freon) or	Cream (40% fat)	28-38	15-25
Refrigerant-717 (ammonia)	Skim condensed milk (30% solids)	35-50	20-35
	Oil, No. SAE30	6-18	1-8
	Sugar solution	30-70	12-25
	Air	2-7	1-3

[1]To convert Btu/ft^2/hr/^{o}F difference to kcal/m^2/hr/^{o}C difference, multiply by 4.885.

*Based on approximately 8 gpm per tube in double embossed coil or 4 gpm per tube in single embossed coil.

**Based on approximately 1.1 to 1.6 tons per circuit for single embossed and 2.5 to 4.0 tons per circuit for double embossed coil.

Owing to the curvature of the temperature/time or temperature/distance lines, **the arithmetical mean of the two temperature differences at the beginning and end of the heat exchanger would clearly be wrong.** Fortunately, it has been found that a single relation between the initial and final temperature differences will give the true mean temperature difference in all of these curved temperature relations whether in respect of time or distance. The formula is:

$$LMTD = (DT1 - DT2)/\ln(DT1/DT2)$$

where DT1 = the difference between the inlet temperature on one side of the heat exchanger and the outlet temperature on the other side of the heat exchanger

DT2 = the difference between the outlet temperature on the one side and the inlet temperature on the other.

The logarithmic-mean temperature difference usually differs only slightly from the arithmetic-mean temperature difference, but in the case of drastic temperature changes, the difference can be significant.

SECTION 5: ELECTRIC POWER

A.5.1 Alternating Currents

Alternating currents as used for commercial purposes are the result of an alternating electromotive force produced by an alternator. This force can be represented as a rotating vector at a specified speed, namely the angular frequency, with the resulting output following a sine waveform.

A.5.2 Electrical Power and Energy (see Exhibit A.12)

Exhibit A.12

Power Factor Angle

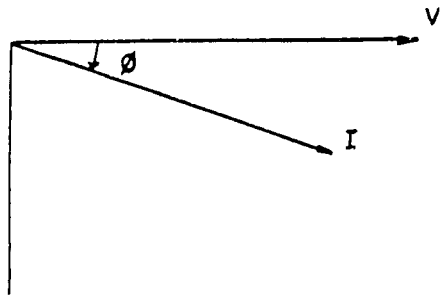
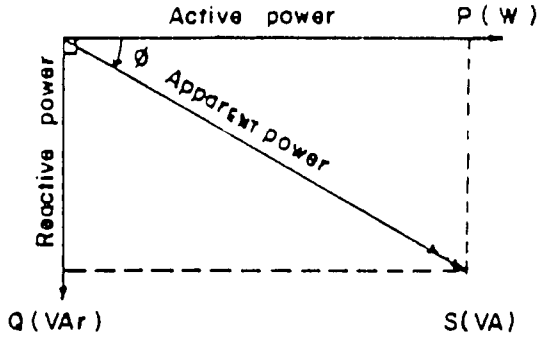


Exhibit A.13

Apparent, Active, and Reactive Power



A.5.2.1 Power Factor Angle (ϕ)

Power factor angle is the angular difference between the voltage and the current through a load and depends on the load characteristics.

A.5.2.2 Power Factor

The cosine of the power factor angle ϕ is defined as the power factor of the corresponding load (see Exhibit A.13).

A.5.2.3 Apparent Power (S)

Apparent power is defined as follows·

Single phase	$(S = V_p \times I_p)$
Three phase	$(S = V^3 V_L I_L)$

V_p = phase voltage
I_p = phase current

V_L = line to line voltage
I_L = line current.

Apparent power is measured in Volt-Amperes (VA).

A.5.2.4 Active Power (P)

Active power is the component of the apparent power that may be usefully converted into another form of energy and is measured in watts (W).

Single phase	$(P = V_p I_p \cos \phi)$
Three phase	$(P = \sqrt{3} V_L I_L \cos \phi)$

($\cos \phi$ = power factor)

A.5.2.5 Reactive Power

All electrical equipment making use of an electromagnetic field requires power to set up and maintain this field, apart from the real or active power consumed by the equipment. This component of the apparent power is known as the reactive power.

The reactive power and the real power are 90° out of phase. Reactive power is measured in Volt-Amperes - reactive (VAr).

Single phase Q	$= V_p \; I_p \; \text{Sin} \; \phi$
Three phase Q	$= 3V_L \; I_L \; \text{Sin} \; \phi.$

The following relationships are also relevant:

$$S^2 = P^2 + Q^2$$

$$\text{Cos} \; \phi = \frac{P}{P^2 + Q^L}$$

$$\tan \phi = Q/P.$$

A.5.2.6 Energy Consumption

The energy consumption (J) is the product of the real power (P) (usually in kilowatts) and time (t) (usually in hours).

$$J = P \times t \qquad \text{kWh.}$$

A.5.2.7 Electric Heating

Electric heat is defined as follows:

Single phase:	$H = V_p \times I_p$ watts
Three phase:	$H = \sqrt{3}\ V_L\ I_L$ watts.

A.5.3 Measurement and Improvement of Power Factor

A.5.3.1 Power Factor Measurement

The simplest method of measuring the power factor is to measure the real power P using a wattmeter and the voltage and the current using a voltmeter and ammeter. A typical circuit is given in Exhibit A.14.

$$\cos \phi = \frac{W}{V \times I}$$

For a three-phase load, the power factor of each phase is determined and the average is calculated. Meters for reading power factor directly are also available.

A.5.3.2 Effects of a High Power Factor Angle ϕ (a low power factor Cos ϕ) (see Exhibit A.15)

(i) Registration of a high maximum demand (kVA or apparent power)
(ii) Resulting higher current drawn from the supply
(iii) Increased losses in transformers and distribution system of both the user and the supply authority
(iv) Under utilization of installation facilities
(v) Poor voltage regulation.

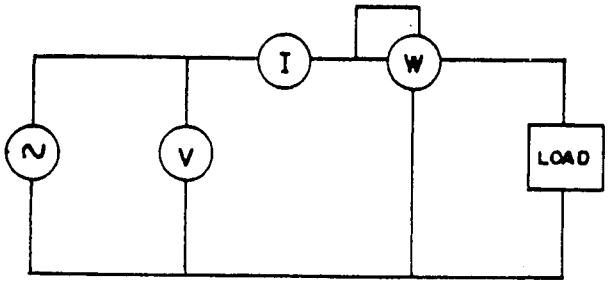
As seen from Exhibit A.15:

$I \quad I_L$

$S_1 \quad S_o$.

Exhibit A.14

Power Factor Measurement



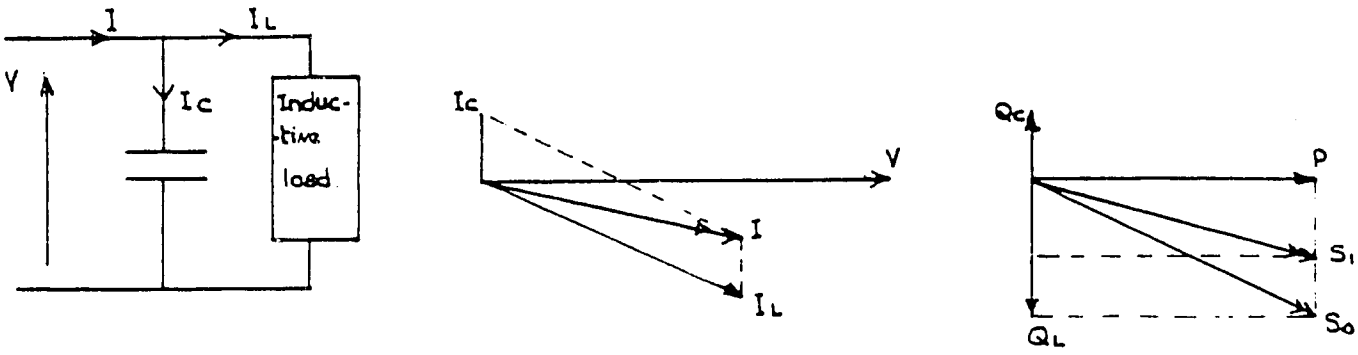
W - wattmeter reading

V - voltmeter reading

I - amneter reading

Exhibit A.15

Power Factor Correction



I_L = Load current

I_C = Capacitor current

I = Resultant current

S_o = Apparent power W/O capacitor

P = Load active power

Qr = Load reactive power (lagging)

Q_C = Leading reactive power taken by capacitor

S_1 = Apparent power with capacitor

Example: Consider the case of a plant with a maximum demand of 350 kVA that is operating with a power factor of 0.65. The objective is to raise the power factor to 0.95. The supply voltage is 400 V, 3-phase.

Present current $= \dfrac{350 \times 10^3}{\sqrt{3} \times 400} = 505.18$ A

Real power demand, P $= 350 \times 0.65 = 227.5$ kW.

Present reactive power, $Q_1 = 350 \times \text{Sin } \phi_1 = 265.97$ kVAr.

Reactive power demand with improved power factor:

$$
\begin{aligned}
Q_2 &= P \tan \phi_2 \quad \text{Cos } \phi_1 = 0.65 \\
&= 227.5 \times 0.33 \quad \text{Sin } \phi_1 = 0.76 \\
&= 74.77 \text{ kVAr} \quad \text{Cos } \phi_2 = 0.95 \\
&\qquad \tan \phi_2 = 0.33.
\end{aligned}
$$

Reactive power requirement:

$$
\begin{aligned}
&= Q_1 - Q_2 \\
&= 191.2 \text{ kVAr.}
\end{aligned}
$$

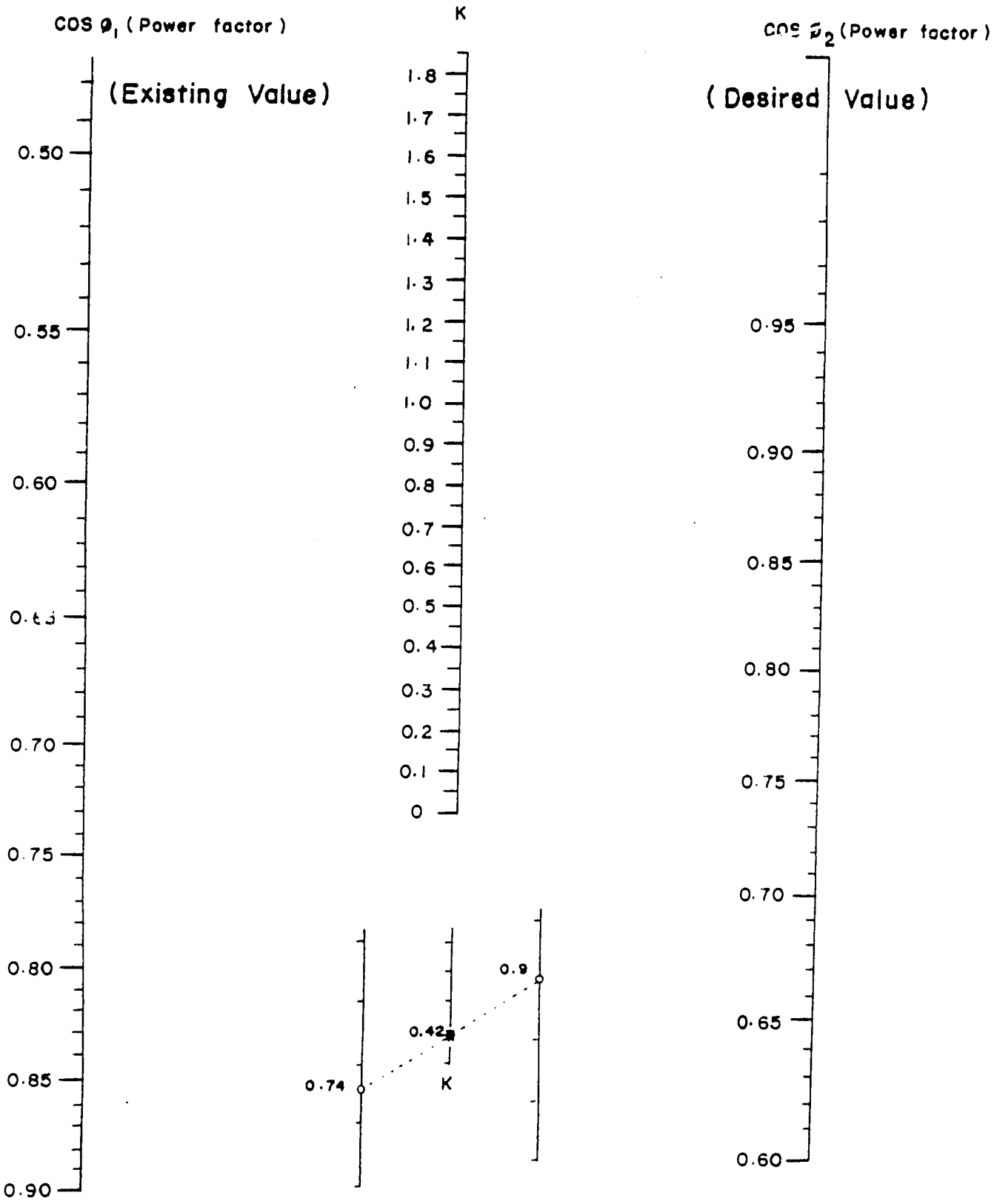
A 400 V 3-phase capacitor bank of 191.2 kVAr is required.

In practice, the kVAr required to correct the power factor of a given load (in kW) from the existing value to a desired value can be conveniently worked out using the nomogram in Exhibit A.16.

Draw a straight line from the existing value of Cos ϕ on the left to the desired value of Cos ϕ on the right. This line will intersect the middle scale at a point denoting a multiplying factor K. Multiply the existing load in kW by K to obtain the required kVAr capacity.

Exhibit A.16

Nomogram to Calculate Capacitor Ratings
For Power Factor Correction



SECTION 6: ENERGY BALANCE, EFFICIENCY, AND NORMS

A.6 THE ENERGY BALANCE

The energy balance is basically the global equation(s) that translates the principle of conservation of energy (first law of thermodynamics) applicable to a given operation, process, or plant.

The basic energy balance equation is:

Heat in + work in = heat out + work out.

The energy balance is a useful guide to the efficient operation of process plant and other industrial equipment. It can be used to indicate the scope for energy conservation, since it identifies and evaluates the ways in which energy is consumed in each step of the process.

Energy balances are generally built:

1. To evaluate losses and inefficiencies in the operation of existing plant and equipment
2. To evaluate the energy use in each process stage for comparison with an alternative system of known energy consumption.

The first evaluation often results in identifying improvements in the efficiency of existing equipment by operational changes (no or low capital expenditure). The second evaluation is used when a comparison is to be made with a new plant or system, and is usually associated with large capital expenditure projects.

In building energy balances, a detailed knowledge of the process operations is essential to determine the type of measurements to be taken.

Energy balances are multiform and may answer a large variety of questions, such as:

- How much heat is currently used to dry a given product, and what would be the minimum theoretical requirement for this operation? By taking the right measurements (e.g., mass flows, temperatures of product in, product out, drying air in, drying air out, dryer surface) and using the right tools (such as steam tables or psychrometric charts; see Section 3), it is possible to answer these two questions.
- What would be the optimum amount (from an energy consumption standpoint) of cooling water required to reduce the temperature of a hot organic liquid stream from T_2 to T_1? By knowing the characteristics of the heat exchanger (heat transfer coefficients and available heat transfer surface area), organic liquid flow rate, specific heats, and temperature, it is simple to determine this optimum value for the cooling water flow.

Providing answers to such questions often raises other questions about each process. In the above examples, the following questions could be asked:

1. Could the initial moisture content of the product to be dried be reduced before processing?
2. What is the amount of heat being transferred from the organic liquid to the cooling water, and can this heat be used elsewhere in the manufacturing operation?

A.6.1 Building an Energy Balance

The **first step** is to identify the subject of the energy balance. For reasons of simplicity, assume that energy balances must be established for each major energy-using piece of equipment identified during the preliminary audit (see Chapter 3) (i.e., boilers, steam systems, furnaces, kilns, ovens, dryers, large mechanical systems, air conditioning systems, and lighting). The **second step** is to identify what is needed to build the required energy balance; that is:

- Identify all operations in which energy (heat or work) is either introduced or removed from the balance object
- Identify each input and output energy stream.

The **third step** is to gather the data necessary to build the balance. Some data may already be available; some may never have been gathered. In any case, it is highly recommended that **all required instrumented measurements be made** within as short a period of time as possible, which must be as close as possible to "normal operation," although this concept may be hard to define in some cases. For example, if the object of the energy balance is a furnace, the following measurements should be made: product flow and temperature, combustion product composition, flue gas composition and temperature, combustion air temperature, furnace surface temperature, and mechanical equipment electric consumption (e.g., fans, drive). The appropriate instruments should be selected according to the guidelines provided in Chapter 4.

When all data have been collected, the energy balance building process can start. The two following examples illustrate how energy balances are built.

A.6.1.1 Example 1: Heat Balance for a Heat Exchanger

In the case of the shell-and-tube heat exchanger, construction of a heat balance is relatively simple (see Exhibit A.17). In this example, water is being used to cool an organic liquid, benzene, which is entering the exchanger at 90°C and a flow rate of 100 m^3/hr. The heat lost by the hot benzene equals the heat gained by the cool water, plus any heat that might be lost via convection to the surroundings. The fundamental equation for determining the heat gained or lost by a fluid stream is:

$$q = mC_p dt$$

where q = the heat gained or lost (kcal/hr)

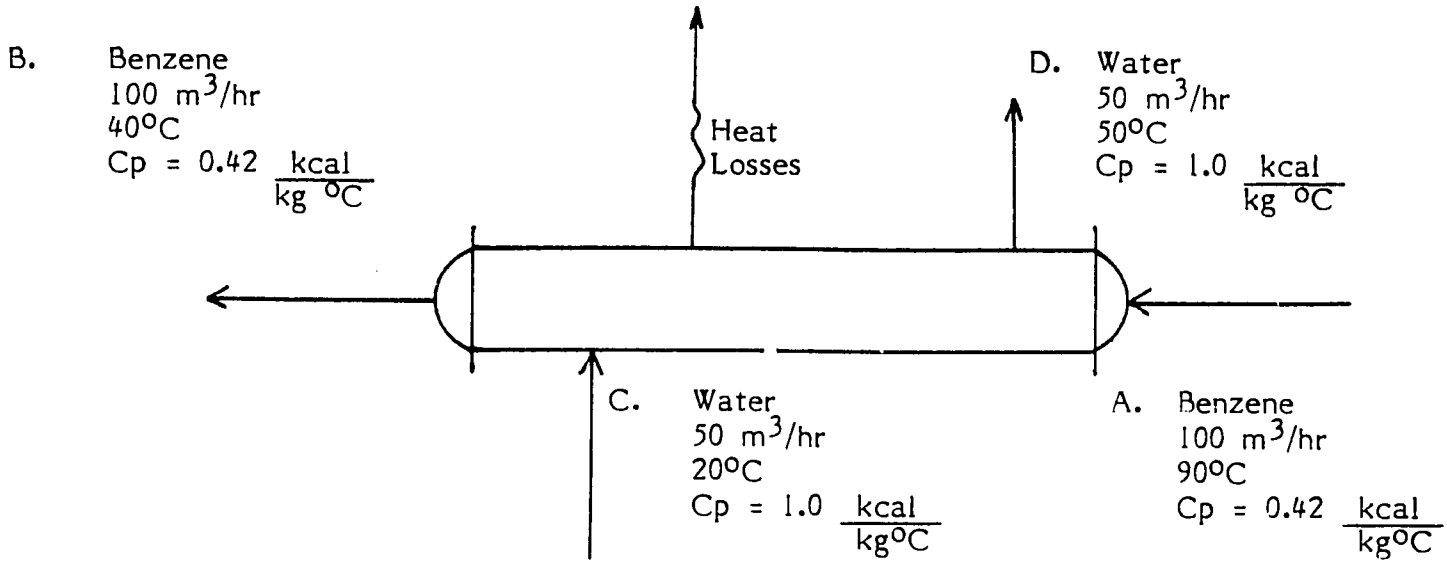
m = the mass flow rate (kg/hr)

C_p = the specific heat (kcal/kg °C)

dt = the difference in inlet and outlet fluid temperatures (°C).

Exhibit A.17

Shell-and-Tube Heat Exchangers



Heat Balance

$$q = m\ Cp\ dt$$

$$q\ (\text{Benzene}) = q\ (\text{Water}) + q\ (\text{Losses})$$

$$m\ Cp\ dt = m\ Cp\ dt + qL$$

qb:

$(100\ m^3/hr)\ (879\ kg/m^3)\ (.42\ kcal/kg^oC)\ (90 - 40^oC) = 1.85 \times 10^6\ kcal/hr$

qw:

$(50\ m^3/hr)\ (1{,}000\ kg/m^3)\ (1.0\ kcal/kg\ ^oC)\ (50 - 20^oC) = 1.50 \times 10^6\ kcal/hr$

qL:

$$qL = qb - qw$$

$$1.85 \times 10^6 - 1.50 \times 10^6 = .35 \times 10^6\ kcal/hr$$

For the sake of simplicity, the fluid density and specific heat were assumed constant over the temperatures involved. The heat balance indicates that roughly 81 percent of the heat transferred by the hot benzene is captured by the cooling water. The remaining 19 percent of the heat is lost to the surroundings.

A.6.1.2 Example 2: Cake Baking

A good example of the use of a heat balance in a low-temperature process is the baking of cakes. The cake-baking process is direct and simple. An electric oven is used, with the cake being continuously circulated through the oven on reusable steel trays. Each steel tray weighs 15 kg and holds four 0.5 kg cakes. Twelve trays and 48 cakes go through the 10-kW oven every hour. The cake is baked when the dough temperature reaches 150°C.

The dimensions of the oven are 1 m by 3 m by 4 m; during operation, its surface temperature is 30°C (room temperature is 20°C). The specific heat of the dough is known to be 0.8 kcal/kg °C.

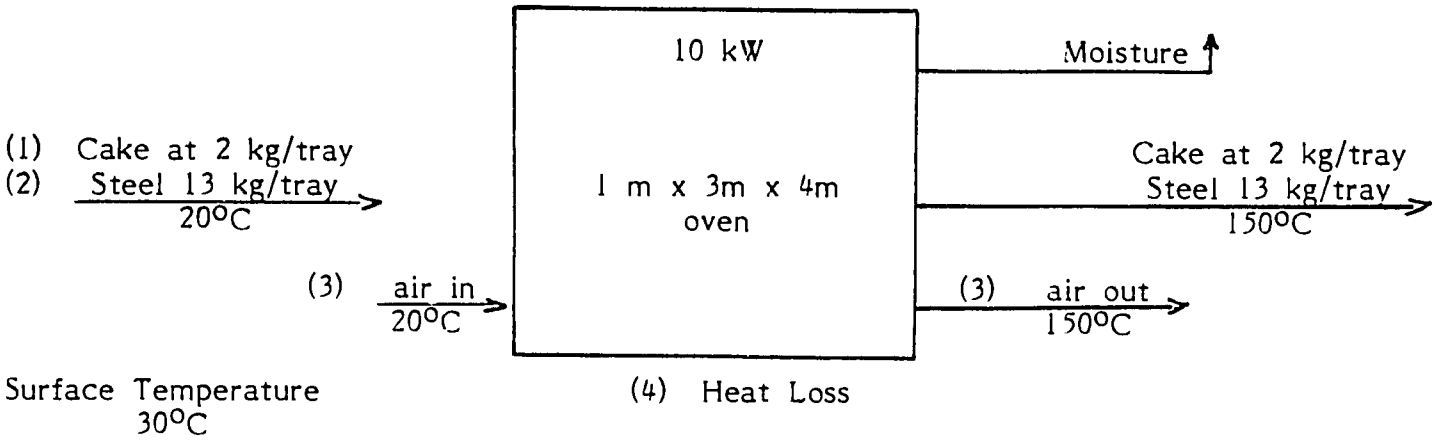
The process energy balance takes into account heat losses to the surroundings, the heat required to bake the cake and heat the steel trays, and an estimated air change once every hour (see Exhibit A.18). These results show two important energy inefficiencies in the process: the amount of energy required to heat the steel tray, and the excessive energy losses. The overall efficiency of the process -- that is, the heat used to bake the cake divided by the energy input -- is only 36 percent. Improvements to the process can be made by reducing the weight (but maintaining the strength) of the steel trays, insulating the oven, and reducing the number of air changes in the process. It should be noted that the loss of moisture in the dough during the baking process was not considered in this example, but could be an important consideration.

A.6.2 Finalizing the Energy Balance

The first balance built from measurements, or the preliminary balance, must be validated, which is in fact rather simple; the basic equation (energy in = energy out) must be

Exhibit A.18

Energy Balance of a Cake-Baking Oven



Energy in:

Electricity 10 kW = 8,598 kcal/hr.

Notes	Energy Out	
1	Cake = (0.5 kg/cake) (4 cake/tray) (12 trays/hr) (0.8 kcal/kg °C) (150-20°C)	= 2,496 kcal/hr
2	Steel = (15 kg/tray) (12 tray/hr) (0.11 kcal/kg °C) (150-20°C)	= 2,573 kcal/hr
3	Air = (12 m^3) (1 airchange/hr) (1.18 kg/m^3) (0.24 kcal/kg °C) (150-20°C)	= 530 kcal/hr
4	Heat loss = (10 kcal/hr m^2 °C) (26 m^2) (30-20°C)	= 2,600 kcal/hr
		8,199 kcal/hr

Balance = in - out = 8,598 - 8,199 = 399 kcal/hr (4.6%).

Notes

1. Assumes a constant cake weight and specific heat.
2. Assumes specific heat of steel is 0.11 kcal/kg °C.
3. Assumes one air change per hour.
4. Assumes a heat transfer coefficient of 10 kcal/hr m^2 °C. The oven has an external surface area of 26 m^2.

satisfied by computing independently each member of the left and the right side of the equation. If this is done honestly (do **not** compute a term of this equation by using differences!), and the answers are within a few percent of each other, the balance can be considered valuable.

However, it may happen that incorrect computations or measurements compensate each other and still allow the basic equation to be balanced. To ensure that this is not the case, expertise and experience are required.

In most cases, however, common sense is enough to indicate if something is wrong in the computation. Another, more expensive way, to validate and check the accuracy of an energy balance is to have it done by two different individuals at different dates but under similar conditions. This would be justified in extreme cases only (e.g., when the balance cannot be established the first time, 20 percent difference or more) or when common sense cannot be satisfied by the results.

A.6.1.3 The Use of the Energy Balance

Energy balances are primarily used to evaluate energy efficiencies as illustrated in the examples above. From the energy balance of a boiler, for example, the following efficiencies can be computed:

- Combustion efficiency
- Heat to steam efficiency
- Overall boiler efficiency.

A.6.2 ESTIMATING ENERGY CONSERVATION POTENTIAL

The efficiency computations are the basis for estimating energy-saving potential. The basic method is to compare the efficiency computed from the balance with what a good performance should be. Such a performance is often referred to as a "norm" or a "standard." For example, a 50-tonnes of steam per hour, 45-atm watertube boiler operating at 80 percent of its rated capacity and burning furnace oil should have an

efficiency of 82-84 percent. If the balances gives an efficiency of 79 percent, 3 to 5 percentage points translate into 4 to 6 percent potential fuel savings. However, norms and standards are not easy to find or to establish. Norms can be established for a given piece of equipment (e.g., a boiler, a dryer, an electric motor), a given operation (e.g., drying in a cement kiln), or a given product (e.g., raw steel). In the case of drying, the norm can be either 600 kcal/kg of water evaporated (theoretical minimum) or 750 kcal/kg of water evaporated (good average performance). In the case of steel, the theoretical consumption is 1.7 Gcal/ton, and a good performance is 6.0 Gcal/ton. Both numbers can be used as norms, as most plans in LDCs consume between 8 and 12 Gcal/ton.

There is no such thing as a "directory" of norms. Rather, technical manuals and equipment suppliers' brochures should be used to define them. In addition, norms are not fixed or constant over time and across processes. They must take into account such factors as actual operating procedures and technological evolution.

Examples of norms are presented in Exhibit A.19.

Exhibit A.19

Typical Energy Norms and Indices for Industrial Plants

The following norms and indices are supplied for reference purposes only. They are **not** to be used as absolute minimum or theoretical energy requirements. They can be used as indicators against which a plant's operating performance can be judged, but true conservation potential should be determined via the detailed energy audit process.

BRICK MAKING

National average	2.2 GJ/tonne conventional
Fletton brick	1.2 GJ/tonne
Non-Fletton	
• Average	3.6 GJ/tonne
• Commons	1.8 GJ/tonne
• Facing and engineering	3.9 GJ/tonne
Fletton facing bricks in annular kiln	1.5 GJ/tonne
Fletton common bricks in annular kiln	1.4 GJ/tonne
Non-Fletton facing bricks in tunnel kiln	4.6 GJ/tonne
Non-Fletton facing bricks in annular kiln	5.9 GJ/tonne

BULK REFRACTORIES

Unfired fire clay	0.8-1.6 GJ/tonne
Unfired high aluminum	3.6 GJ/tonne
Unfired basic cement	31.0 GJ/tonne

CONTINUOUS KILN

Fireclay ladle bricks	7.8 GJ/tonne
Fireclay for steel industry	9.0 GJ/tonne
Fireclay saggers for pottery industry	17.2 GJ/tonne
Fireclay shapes from china clay for pottery industry	19.6 GJ/tonne

Exhibit A.19 (continued)

Typical Energy Norms and Indices for Industrial Plants

Magnesite-chrome bricks	25.0 GJ/tonne
Pitch impregnated magnesite bricks	28.0 GJ/tonne

INTERMITTENT KILNS

Fire clay shapes for steel industry	19.3 GJ/tonne
Fire clay shapes for pottery industry	21.2 GJ/tonne
Fire clay saggers for pottery industry	16.1 GJ/tonne

CEMENT

Cement kiln:	
• wet process	6.1 GJ/tonne
• dry process	3.3 GJ/tonne

POTTERY INDUSTRY

Bone china	249 GJ/tonne
Vitor feed hotelware	51.1 GJ/tonne
Vitreous sanitaryware	47.1 GJ/tonne
Electrical porcelain	84.4 GJ/tonne
Glazed wall tiles	16.8 GJ/tonne
Unglazed floor tiles	10.7 GJ/tonne

GLASS INDUSTRY

Glass melting and annealing flat glass	10.39 GJ/tonne
Glass melting -- containers	13.52 GJ/tonne
Glass melting -- insulation glass fiber	14.6 GJ/tonne
Glass melting -- reinforcement glass fiber	15.0 GJ/tonne
Glass melting -- lead crystal	59.5 GJ/tonne
Glass melting -- domestic and scientific glassware	15.7 GJ/tonne
Glass melting -- glass tubing	12.2 GJ/tonne

FOOD INDUSTRY

Beer Brewing	2.98 MJ/liter total
Fuel	2.63 MJ/liter
Electricity	0.35 MJ/liter

Exhibit A.19 (continued)

Typical Energy Norms and Indices for Industrial Plants

Malting

Barley drying	0.337 GJ/tonne
Kilning, steeping	3.900 GJ/tonne
Electricity	0.541 GJ/tonne

Dairy Industry

Pasteurized milk	4 MJ/gallon
Sterilized milk	13 MJ/gallon
Cheese making	14.5 MJ/gallon

PAPER INDUSTRY

Paper and board making	30 GJ/tonne
Newspaper	4.5 GJ/tonne
Magazines	8.2 GJ/tonne

COKE MAKING 2.2-2.8 GJ/tonne

CHEMICALS

Fertilizer Industry

Ammonia

Gross energy requirement includes natural gas used as feedstock	41.0 GJ/tonne
Process energy requirement -- heat supplied	14.5 GJ/tonne

Nitric Acid

Single-pressure operation	
• Medium	10.58 GJ/tonne
• High	11.86 GJ/tonne
Split-pressure operation	
• Atmospheric/medium	11.1 GJ/tonne
• Medium/high	11.98 GJ/tonne

Exhibit A.19 (continued)

Typical Energy Norms and Indices for Industrial Plants

Ammonium Nitrate

Gross energy requirement includes feedstock energy	20.81 GJ/tonne
Process energy requirement	1.1 GJ/tonne

Urea

Gross energy requirement conventional solution recycle (includes energy in feedstock)	31.71 GJ/tonne
Stripping process recycle)	29.3 GJ/tonne

Sulfuric Acid

From elemental sulfur	-3.2 GJ/tonne

Phosphoric Acid

Process energy:	
• 50% phosphoric acid by "wet" process	
• Dihydrate (DH) process	5.07 GJ/tonne
• Hemihydrate (HH) process	0.99 GJ/tonne
• Hemihydrate dihydrate (HDH) process	1.03 GJ/tonne
Gross energy (includes feedstock):	
• DH process	-1.45 GJ/tonne
• HH process	-6.76 GJ/tonne
• HDH process	-6.05 GJ/tonne

Potash

Gross energy	5.0 GJ/tonne

Superphosphates

Gross energy requirements (includes feedstock):

• Single superphosphate	0.9 GJ/tonne
• Triple superphosphate	1.7 GJ/tonne

Exhibit A.19 (continued)

Typical Energy Norms and Indices for Industrial Plants

Compound Fertilizers

Gross energy requirements (includes feedstock)	
• 11:50:0 MAP (mono-ammonium phosphate)	6.94 GJ/tonne
• 17:17:17:	11.92 GJ/tonne

IRON CASTING INDUSTRY

Iron casting average	44. GJ/tonne
Range	14-60 GJ/tonne
Melting furnaces	
• Cupola	4.8-6.9 GJ/tonne of melt
• Rotary furnace, oil-fired	6.2-10.3 GJ/tonne of melt
• Rotary furnace, gas-fired	6.6-11.0 GJ/tonne of melt
• Electric	10.3 GJ/tonne of melt

ALUMINUM CASTING

Primary metal production via Hall-Herout process	199 GJ/tonne
Secondary metal including metal loss	15.8 GJ/tonne plus 50 GJ/tonne metal loss 65.8
Aluminum strip, including metal loss	51.5 GJ/tonne
Aluminum extrusion, including metal loss	41.5 GJ/tonne
Aluminum foil	19.6 GJ/tonne
Pressure die castings from solid metal, including metal loss	50 GJ/tonne
Pressure die castings from liquid metal, including metal loss	37 GJ/tonne
Gravity die castings, including metal loss	50 GJ/tonne

Exhibit A.19 (continued)

Typical Energy Norms and Indices for Industrial Plants

ZINC AND LEAD INDUSTRIES

Primary extraction zinc	50 GJ/tonne
Primary extraction lead	15 GJ/tonne
Zinc processing	
Galvanized strip and wire	37 GJ/tonne
Galvanized shape	59 GJ/tonne
Die cast	26 GJ/tonne
Flat rolled	5 GJ/tonne
Lead processing	
Bullion refining	2 GJ/tonne
Secondary recovery	14 GJ/tonne
Secondary refining	2 GJ/tonne
Cable, pipe, sheet	3 GJ/tonne
Battery grid	3 GJ/tonne
Lead tetraethyl	2 GJ/tonne

TEXTILE INDUSTRY

Woolen and worsted average	95 GJ/tonne
Worsted spinning mills	50 GJ/tonne
Wool combing mills	34 GJ/tonne
Weaving and finishing	120 GJ/tonne
Woolen mills	168 GJ/tonne
Carpet yarn spinning	14 GJ/tonne
Cotton spinning	20 GJ/tonne
Cotton spinning and finishing	58 GJ/tonne
Cotton weaving	30 GJ/tonne
Industrial fabrics weaving	27 GJ/tonne
Cotton weaving and finishing	39 GJ/tonne
Hot air dryers range humidity levels	0.04-0.1 kg water/kg air
Optimum humidity level	0.1 kg water/kg air
Cylinder dryer specific evaporation	10-15 kg/hour/m^2 fabric
Steater specific evaporation	18-25 kg/hr/m^2 fabric
J box-specific consumption	0.3 kg steam/kg of cloth

Exhibit A.19 (continued)

Typical Energy Norms and Indices for Industrial Plants:
Typical Operating Temperatures and Hot Water Use by Textile Machinery

Machine	Operating temperature °C	Water required liter/kg material
Sizing	90	2
Rope washing	50-60	10-17
Kier boiler open	50-90	3-8
Kier boiler pressure	50-90	5-10
Continuous bleaching saturator	50-70	1-2
Continuous bleaching rope washing	50-60	10-15
Continuous bleaching open-width washing	50-60	10-15
Cloth mercerizing	50-70	25
Yarn mercerizing	70	15
Jigger desize and bleach	50-80	5-8
Jigger dyeing	40-70	18-20
Winch desize and bleach	50-80	45-60
Winch dyeing	40-70	45-80
Package machine boiling	50-90	10
Package machine dyeing	40-90	20-25
Beam machine scouring	50-80	30-40
Beam machine dyeing	50-90	35
Jet dyeing	80-90	25-30
Continuous dyeing	40-90	22-25
Open width soapers	60-80	10
Water mangle	50-60	3
Starch padding	90	2

Exhibit A.19 (continued)

Typical Energy Norms and Indices for Industrial Plants:
Steam Consumption in Textile Mills

Machine		Kg/kg of cloth
Pressure kier	Range	0.9-3.6
	Average	1.6
Ager	Range	2.5-10.0
	Average	4.5
Jigger	Range	0.6-4.7
	Average	2.0
Hot flue	Range	0.9-6.1
	Average	2.6
Drying cylinders (point)	Range	1-3
	Average	2.0
Yarn dyeing	Range	5-11.2
	Average	6.2
Two cylinder sizing	Range	1.6-3.2
	Average	2.3
Multi-cylinder sizing	Range	1.5-5.6
	Average	2.7
Hot air sizing	Range	2.2-7.4
	Average	4.2
Cylinder drying	Range	1.6-7.4
	Average	2.9
Stentor	Range	1.9-11.2
	Average	4.0
Float dryer	Range	2.1-12.8
	Average	5.9
Caustic recovery evaporator		
Single effect	Range	1.2-1.5
	Average	1.3
Double effect	Range	0.6-0.9
	Average	0.7
Triple effect	Range	0.5-0.7
	Average	0.5

Exhibit A.19 (continued)

Typical Energy Norms and Indices for Industrial Plants:
Energy Consumption for Weaving

Fabric	Machine consumption, GJ/tonne			
	Battery loom	Air jet loom	Sulzer loom	Lancs loom
Shirting	8.64	7.92	5.76	3.96
Sheeting	2.88	0.00	3.6	2.52
Fine print fabric	10.1	6.12	5.0	5.0
Satin drill	3.6	2.2	1.8	1.8
Nylon taffeta	29.5	11.5	14.4	14.4

Exhibit A.19 (continued)

Typical Energy Norms and Indices for Industrial Plants:
Energy Use in Spinning Operations

Operation	50 Tex GJ/tonne
Blow room	0.43
Carding	0.79
Draw frames	0.22
Speed frames	0.22
Ring frames	2.52
Total for ring spinning	4.2
Lighting	0.36
Air conditioning	0.79

Exhibit A.19 (continued)

Typical Energy Norms and Indices for Industrial Plants:
Energy Use for Wet Processing and Finishing

Material	Weight and width		GJ/tonne
	Kg/m	m	
Dyed polyester cotton shirting	0.1	1	3.6
Dyed cotton shirting	0.1	1	2.9
Dyed knitted nylon shirting	0.1	2	1.1
Dyed polyester sheeting	0.2	2	1.8
Dyed cotton satin drill	0.2	0.9	2.2
White tubular knitted underwear	0.09	--	1.1
Dyed tubular knitted underwear	0.09	--	1.8
Polyester jersey	0.2	1.35	3.6
Nylon taffeta	0.05	0.9	2.2
Polyester-cotton print cloth	0.1	0.9	3.6
Cotton print cloth	0.1	0.9	3.6