A COMBINED LIMITED ENERGY STUDY OF ELECTRICAL ENERGY DEMAND AND USE AND HEATING SYSTEMS AT PINE BLUFF ARSENAL, ARKANSAS

VOLUME I
NARRATIVE REPORT

FINAL SUBMITTAL

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1.0 INTRODUCTION

1.1 AUTHORIZATION

Architectural-engineering services for the Energy Engineering Analysis Program (EEAP) - Southeast Region were authorized by the US Army Corps of Engineers, Mobile District Contracting Division under Indefinite Delivery Contract Number DACA01-94-D-0038. Engineering services for the Combined Limited Energy Study of Electrical Energy Demand and Usage and Heating Systems at Pine Bluff Arsenal (PBA) were authorized by Delivery Order Number 4 from the US Army Engineer District, Little Rock. Reynolds, Smith and Hills, Inc. (RS&H) received the Notice to Proceed for Delivery Order Number 4 on September 12, 1995.

1.2 OBJECTIVES

The primary purpose of this contract is to conduct a detailed study of the boilers, air compressors and large electric motors in the production areas of PBA and develop projects to improve the efficiency of these systems. This study includes comprehensive field investigations of the boiler and compressed air plants; boiler efficiency testing; survey and analysis of the steam distribution system; measurement of electric motor power consumption; identification of Energy Conservation Opportunities (ECO's); energy and labor savings calculations; cost estimates and economic analysis of the ECO's.

1.3 WORK ACCOMPLISHED

The entry interview was conducted at the PBA Department of Public Works (DPW) office on January 29, 1996. RS&H conducted two field investigations to obtain the data required to analyze all of the boiler, compressor and electric motor ECO's. The initial field investigation, personnel interviews and data collection was performed at PBA from January 29, 1996 through February 1, 1996. The second field investigation was performed during the week of March 26 - 29, 1996. Information obtained during these site visits indicated that an enormous amount of energy was being wasted from leaks in the steam distribution system.

Consequently, a no-cost modification to the Scope of Work was requested and approved to include investigation and analysis of a project to repair or replace the existing steam piping distribution system. A subsequent field investigation was performed May 13 - 17, 1996 to survey the steam distribution system serving the production facilities located in Section 3, Areas 1, 2, 3 and 4.

Energy and labor savings calculations, cost estimates and economic analyses have been completed for all of the ECO's. All Interim Submittal Review Comments were resolved and the results were used to finalize all sections of the Final Submittal for this study. This submittal contains the methodology for field investigations and data analysis, ECO project evaluations, results of the evaluations, and recommendations for improvements in the heating system, the steam distribution system, the compressed air system and large electric motors at PBA. The Final Submittal for this study includes the following volumes:

- Volume ES; an executive summary that gives a brief overview of the results of this study.
- Volume I; a narrative report containing the methodology for field investigations and data analysis, ECO project evaluations, results of the evaluations, and recommendations for improvements in the heating system, the steam distribution system, the compressed air system and large electric motors at PBA.
- Volume II; appendices with ECO calculations, cost estimates, back-up data, a copy of the Scope of Work.
- Volume III; appendices containing copies of the field investigation forms.
- Volume IV; programming documentation for all recommended ECO's and combination of ECO's, based on direction provided by PBA.

2.0 FACILITY DESCRIPTION

2.1 GENERAL DESCRIPTION

Pine Bluff Arsenal (PBA) covers about 14,900 acres and is located approximately 35 miles southeast of Little Rock, Arkansas. PBA is a government-owned, government-operated (GOGO) installation established in 1941 to produce incendiary munitions. The Arsenal's mission now includes the design, manufacture, renovation, and demilitarization of signaling and screening smoke, riot control agents, incendiary munitions and chemical/biological defensive items. PBA also provides support for training operations for active and reserve military units.

There are five main functions within the arsenal: production, incineration, water treatment, bomb storage and administrative/housing. The scope of work for this project includes the boilers and electric motor-operated equipment associated with the production, incineration and water treatment processes.

Figure 2.1-1 shows a partial schematic site plan of PBA. The production areas are broken down into the following sections and areas:

- Area 3, Section 1 - Production area, Building Numbers 31-XXX
- Area 3, Section 2 - Production area, Building Numbers 32-XXX
- Area 3, Section 3 - Production area, Building Numbers 33-XXX
- Area 3, Section 4 - White phosphorous production area, Building Numbers 34-XXX
- Area 4, Section 2 - Demilitarization (incinerator) area, Building Numbers 42-XXX
- Area 4, Section 4 - Load, assemble and pack (LAP) area, Building Numbers 44-XXX

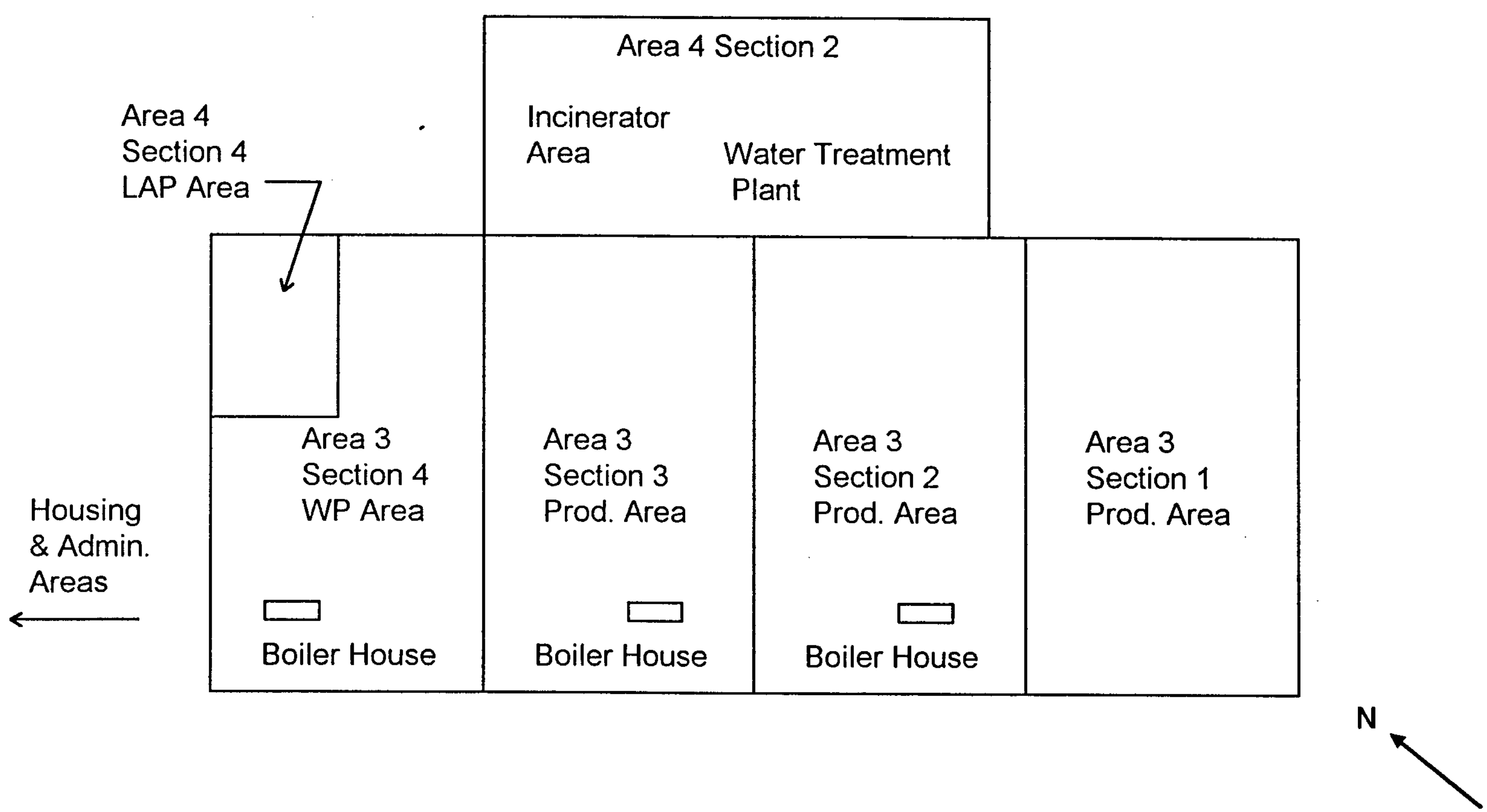
Throughout this report these areas and sections will be referred to as Area 31 for Area 3, Section 1; Area 32 for Area 3, Section 2; Area 42 for Area 4, Section 2; etc.

2.2 BOILERS

There are five boiler houses that provide steam to the various production areas. The steam is utilized for space (comfort) heating, process heating and process humidification. The boilers in Buildings 32-060, 33-060 and 34-140 are connected through a manifold and provide steam to Areas 31, 32, 33, and 34. The boilers in Building 42-960 serve Area 42 (the incinerator area) and the boilers in Building 44-120 provide steam to Area 44 (LAP area).

Building 32-060 (Boiler House No. 2) and Building 33-060 (Boiler House No. 3) each contain two Babcock & Wilcox (B&W) field-erected boilers. The boilers are rated at a capacity of 311

Figure 2.1-1
Pine Bluff Arsenal Partial Schematic Site Plan



horsepower (HP), have a design operating pressure of 160 pounds per square inch gauge (psig) and can be fired by natural gas or Number 2 fuel oil. Natural gas was the only fuel used in 1995. The natural gas meters for these buildings are reportedly broken and have not been recently read. These boilers were manufactured in 1942 with natural draft burners and later modified by adding forced draft burners which allows operation up to approximately 200 percent of rated capacity. These boilers are now operated between 110 percent and 125 percent of their original rated capacity and at a pressure of about 125 psig. The existing arrangement of the burner control linkage (jack shaft) appears to have been installed without the ability to adjust the air-fuel ratio over the entire load range. Field tests showed that these boilers were operating with high amounts of excess air and their average operating efficiencies were 74 to 75 percent.

The Arsenal has two new boilers on site that have not been installed. These boilers were manufactured by York-Shipley and are rated at 600 horsepower each. PBA plans to remove the two existing boilers located in Building 32-060 and install the new boilers in the near future.

Building 34-140 (Boiler House No. 4) contains three Babcock & Wilcox boilers that are similar to the boilers in 32-060 and 33-060 but are slightly smaller. These boilers are rated at a capacity of 249 HP each and a design operating pressure of 160 psig. Boiler Number 2 is not operational due to a leak in the flue breaching stack. This unit has not been repaired because it is contaminated with asbestos insulation. There is no deaerator for the boilers in this building. Natural gas was the only fuel used in 1995. The natural gas meter for this building is also reportedly broken.

Like the other boilers, the boilers in Building 34-140 were manufactured in 1942 and later modified to allow operation up to approximately 200 percent of rated capacity. The existing arrangement of the burner control linkage (jack shaft) appears to have been installed without the ability to adjust the air-fuel ratio over the entire load range. The controls for these boilers are set for operation at a pressure of 125 psig. However, during the tests they were operating at about 140 psig. The average operating load for these boilers is approximately 160 percent of the original rated capacity. The field tests showed that these boilers were operating with very high amounts of excess air and their average efficiencies were only about 72 percent.

There is a pending Energy Conservation Investment Program (ECIP) project to construct a new boiler facility in Area 3, Section 4. The new boiler facility will contain two, dual fuel, fire tube boilers rated at 350 horsepower each and all necessary peripheral equipment. The existing boilers in Building 34-140 will be phased out of service and demolished when the new ECIP funded boilers are operational.

Building 42-960 contains two fire tube boilers designed to provide 40 horsepower at 150 psig. These boilers were manufactured in 1978 by Aztec Superior. They operate automatically, turning on at about 40 psig and off at around 50 psig. These boilers provide space heating for the buildings in the incinerator area. Field tests showed that these boilers were operating at an efficiency of about 79 percent.

Building 44-120 contains two fire tube boilers designed to provide 100 horsepower at 150 psig. Boiler Number 1 was manufactured in 1969 by Ray Burner and is not currently utilized. Boiler Number 2 is a Cleaver Brooks (CB) model CBH manufactured and installed in 1989. This boiler operates at a pressure of about 30 psig to provide space heating for the LAP area. Field tests indicated that the controls for Boiler No. 2 were performing well and the boiler was operating at an efficiency of about 83 percent.

2.3 STEAM DISTRIBUTION SYSTEM

The production facilities in Areas 31, 32, 33, and 34 utilize steam from a main distribution system. The boilers in Buildings 32-060, 33-060 and 34-140 are connected by about two miles of manifold pipe (the "high line") and provide steam to each of these areas via sets of branch pipes. The main steam header is called the "high line" because it is mounted approximately 30 feet above ground on wooden utility poles. The branch distribution piping is typically mounted about two feet above ground level. When the pipes cross a road, they are raised to approximately 15 feet.

Most of the steam distribution pipe is Schedule 40 steel with screwed fittings on pipes three inches diameter and smaller and flanged fittings on pipes larger than three inches. The pipes are covered with approximately two and one-half inch thick fiberglass or asbestos insulation and a metal jacket. The steam heat tracing pipes located in the white phosphorus area are made of one-half inch diameter stainless steel tubing and utilize compression type fittings.

There is a total of approximately eight miles of steam distribution piping serving the production facilities in Areas 31, 32, 33, and 34, including the main header piping.

2.4 AIR COMPRESSORS

The production facilities in Areas 31, 32, 33, and 34 utilize compressed air from a main distribution system. Buildings 32-060, 33-060 and 34-140 each contain two Ingersoll-Rand, Type XLE, Model 16&10x7 air compressors that supply the main distribution system. These compressors are double-acting, two stage, water-cooled, reciprocating type compressors with 150 horsepower synchronous motors. Each of these compressors is rated to supply approximately 825 standard cubic feet of air per minute (SCFM) at a pressure of 130 psig. The actual operating pressure for these compressors is about 120 psig.

Process air for the incinerator operations is provided by a relatively new compressor (installed in 1993) located in Building 42-961. The Sull-Air Model 16BS-75L compressor is rated for 100 psig operation (110 psig maximum) and is driven by a 75 horsepower induction motor. The actual operating pressure noted during the survey was 110 psig. The Sull-Air compressor was installed to replace the Ingersoll-Rand, Type LLE, Model 12&7-1/4x5 air compressor located in Building 42-960. This unit was manufactured in 1978 and is no longer utilized.

2.5 HISTORICAL ENERGY USE AND COST

The primary energy sources utilized at PBA are natural gas and electricity. Natural gas is supplied to the Arsenal through a single-metered supply line. The monthly readings from the main meter are the basis for determining the total monthly natural gas consumption at PBA and the monthly billing by the natural gas supplier. The natural gas is then distributed to approximately 75 buildings within the Arsenal.

There are three electric substations that provide electric service to PBA. The Arsenal receives two electric bills each month, one for Substations A and B combined and one for Substation C. Substation A serves the water plant, incinerator and LAP facilities (Areas 42 and 44); Substation B serves the production facilities (Areas 31, 32, 33 and 34) and Substation C serves the administration and housing areas of the Arsenal. The facilities served by Substations A and B use approximately 70 percent of the total electricity consumed at PBA. The Scope of Work for this project is confined to the production areas, so only the electric energy use for Substations A and B will be considered in this report.

The monthly consumption of natural gas and electricity at PBA is presented in Figure 2.5-1. This figure shows there is a natural gas base load of about 35,000 million British thermal units (MBtu) per month during the summer, due to steam leaks and process energy requirements. Natural gas consumption increases to over 83,000 MBtu per month during the winter because of space heating requirements.

Electricity use in the production areas at PBA is much lower than natural gas use. Figure 2.5-1 indicates the facilities served by Substations A & B have an electric base load of approximately 3,600 MBtu per month during the winter. Their consumption rises to about 6,500 MBtu per month during the summer due to space cooling requirements. The electric base load is due to compressor motors, fan and pump motors for the incinerator and water plant pump motors.

Figure 2.5-1

PBA Monthly Energy Consumption

Electricity is for Substations A & B Only

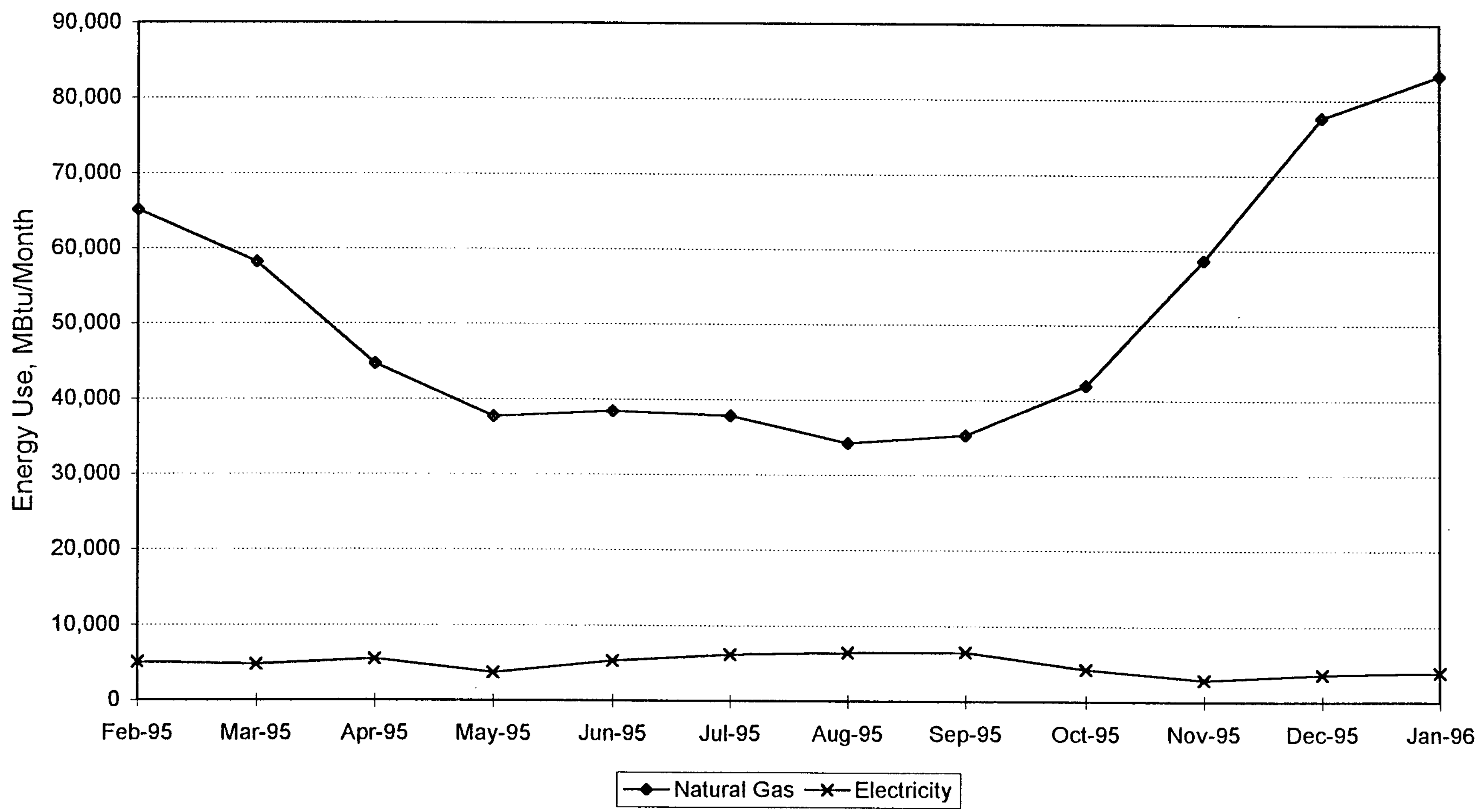


Figure 2.5-2 shows natural gas is by far the main energy source for the Arsenal. The natural gas energy consumption is broken down by end user and described in greater detail in Section 3.2. The annual energy cost apportionment is presented by Figure 2.5-3. The electricity cost per MBtu at PBA is about six times higher than the cost of natural gas. The higher unit cost explains why electricity only accounted for nine percent of the annual energy use, but represented 36 percent of the annual energy cost.

Daily electric demand profiles for the facilities served by Substations A and B are presented by Figures 2.5-4 through 2.5-11. Fifteen minute demand data are shown for one work-day and one weekend day for winter, spring, summer and fall of 1995. The work-day graphs show the Arsenal staff arrives at about 0600 hours and begins to turn on lights and equipment. The staff begins turning off the lights and equipment at about 1500 hours and by 1700 hours the arsenal is mostly shut down. The graphs showing weekend days and non-working Fridays are a good indicator of the base electrical demand at PBA. These figures show the base electrical demand was about 1600 kilowatts (kW) in the winter, 1800 kW in the spring, 2000 kW during the summer and 1600 kW during the fall.

Figure 2.5-2

PBA Annual Energy Use, 2/95 - 1/96

Electricity for Substations A & B only

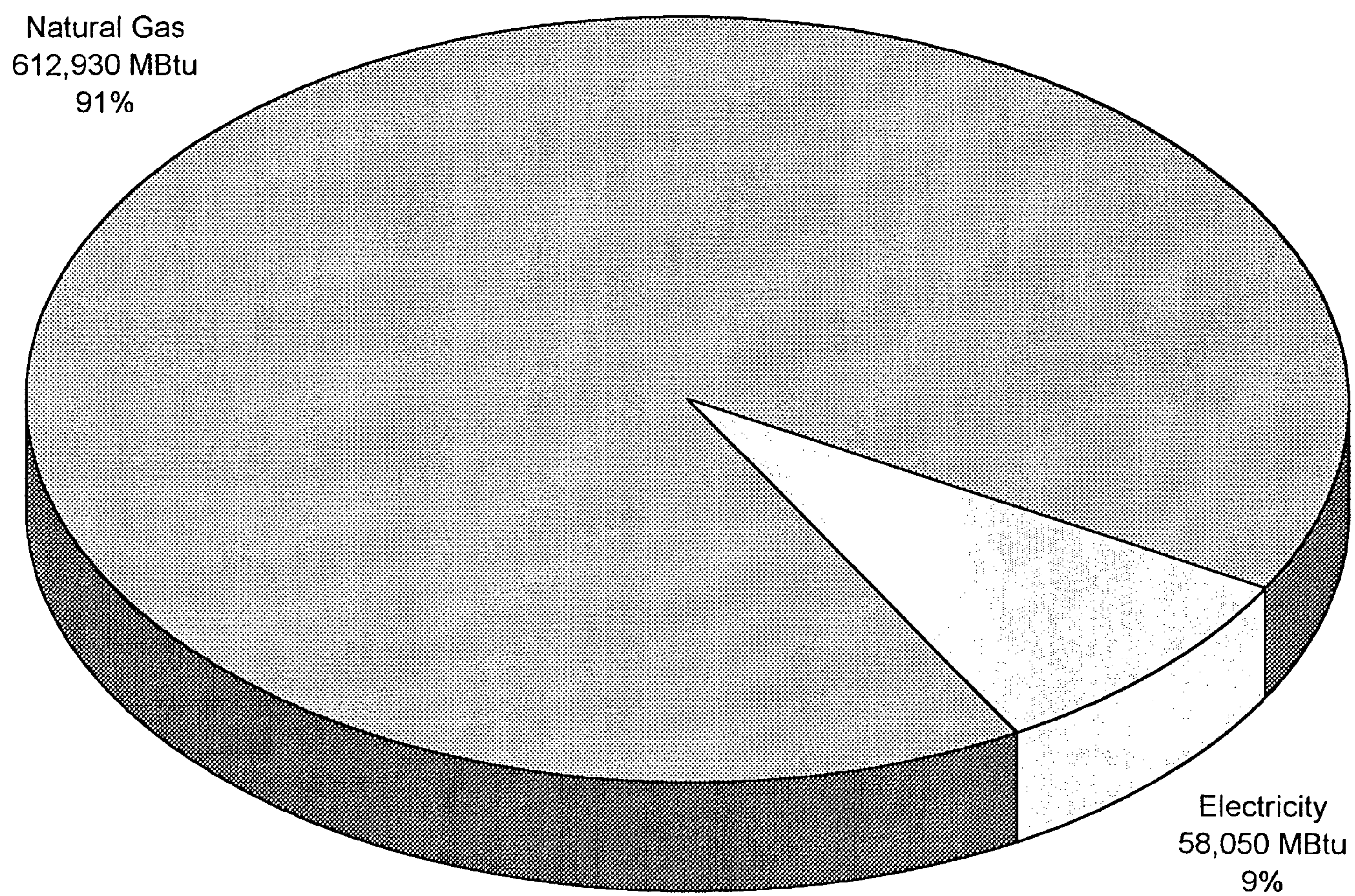


Figure 2.5-3

PBA Annual Energy Cost, 2/95 - 1/96

Electricity for Substations A & B only

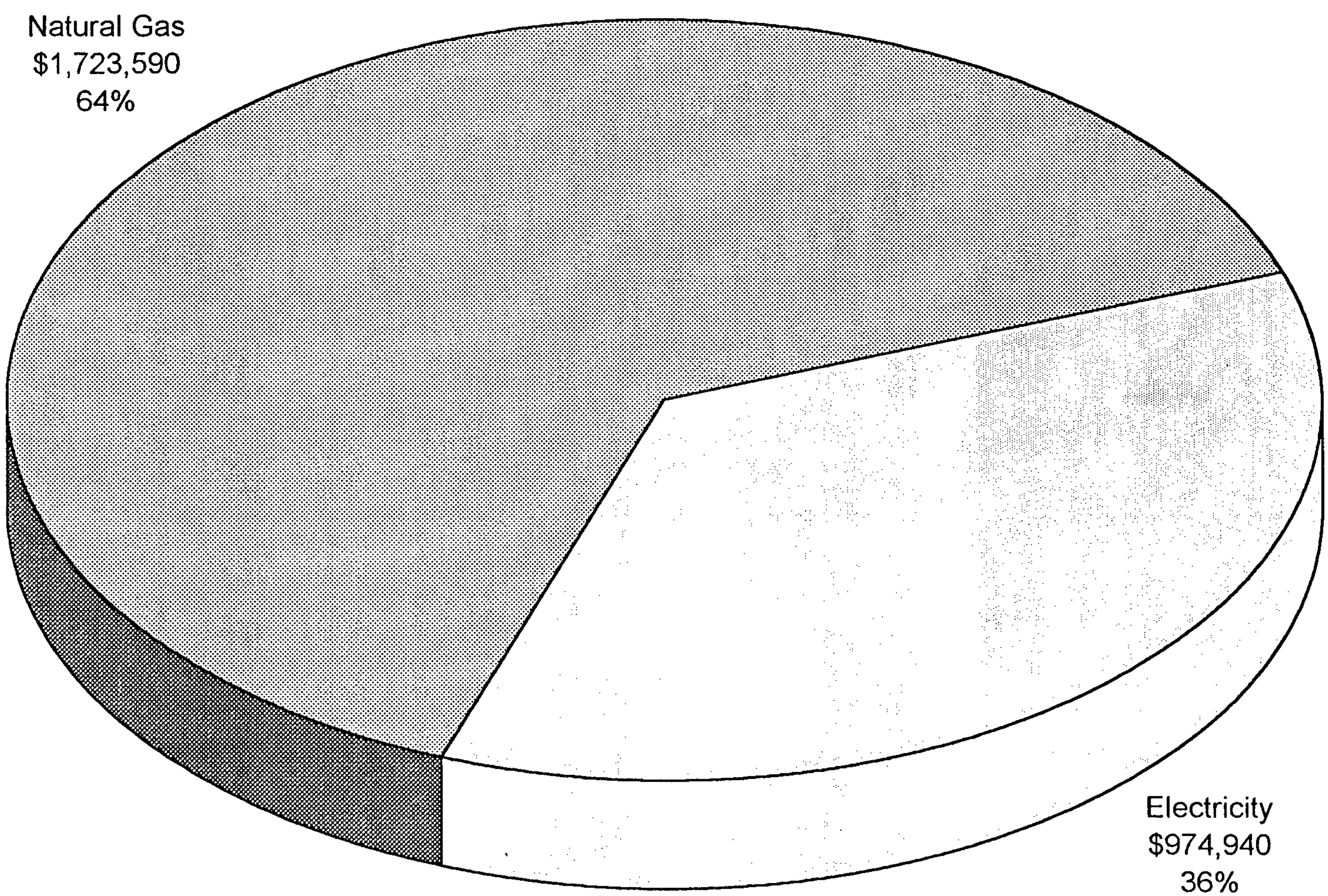


Figure 2.5-4
PBA Demand Data, Tuesday 1/17/95

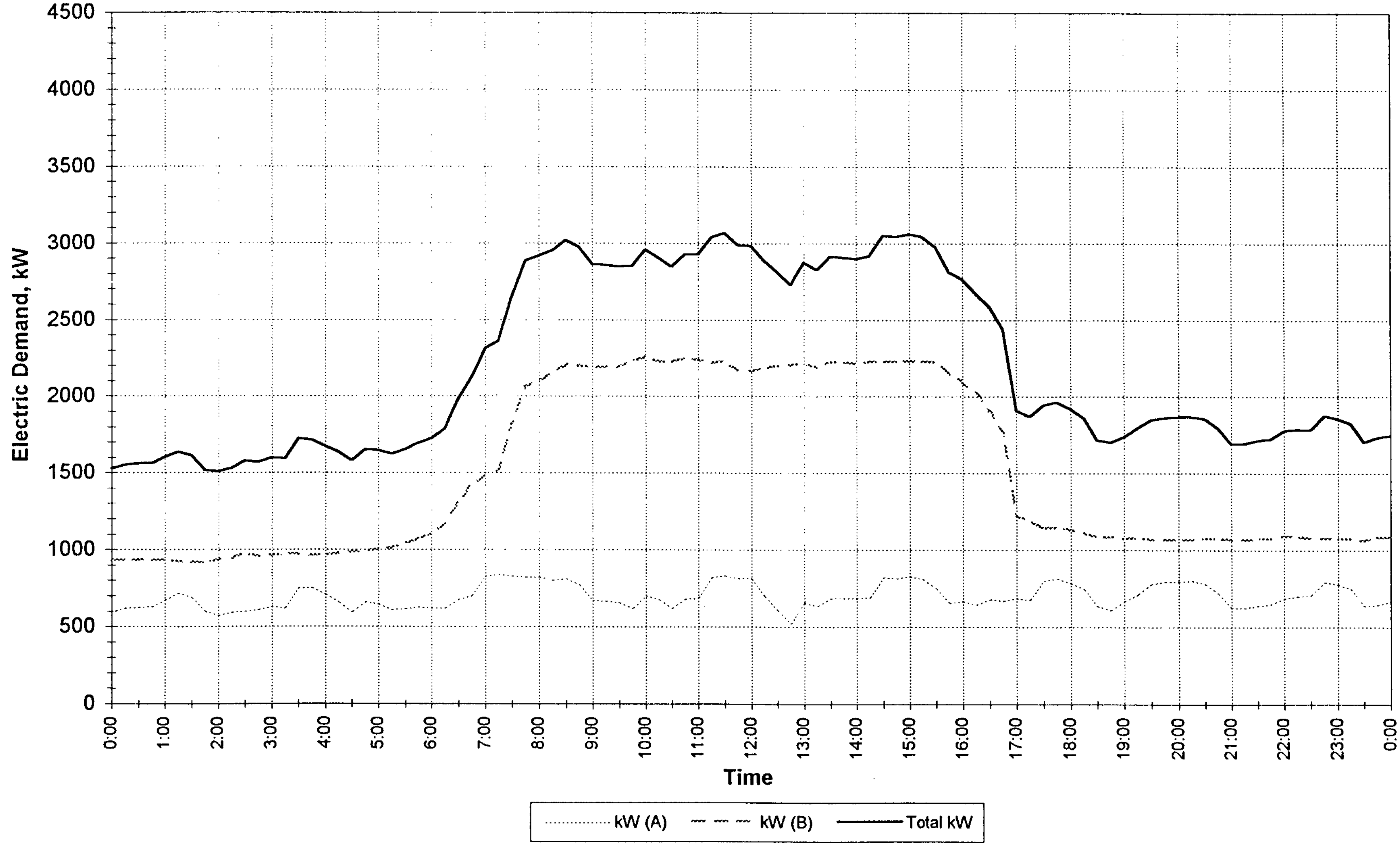


Figure 2.5-5
PBA Demand Data, Sunday 1/22/95

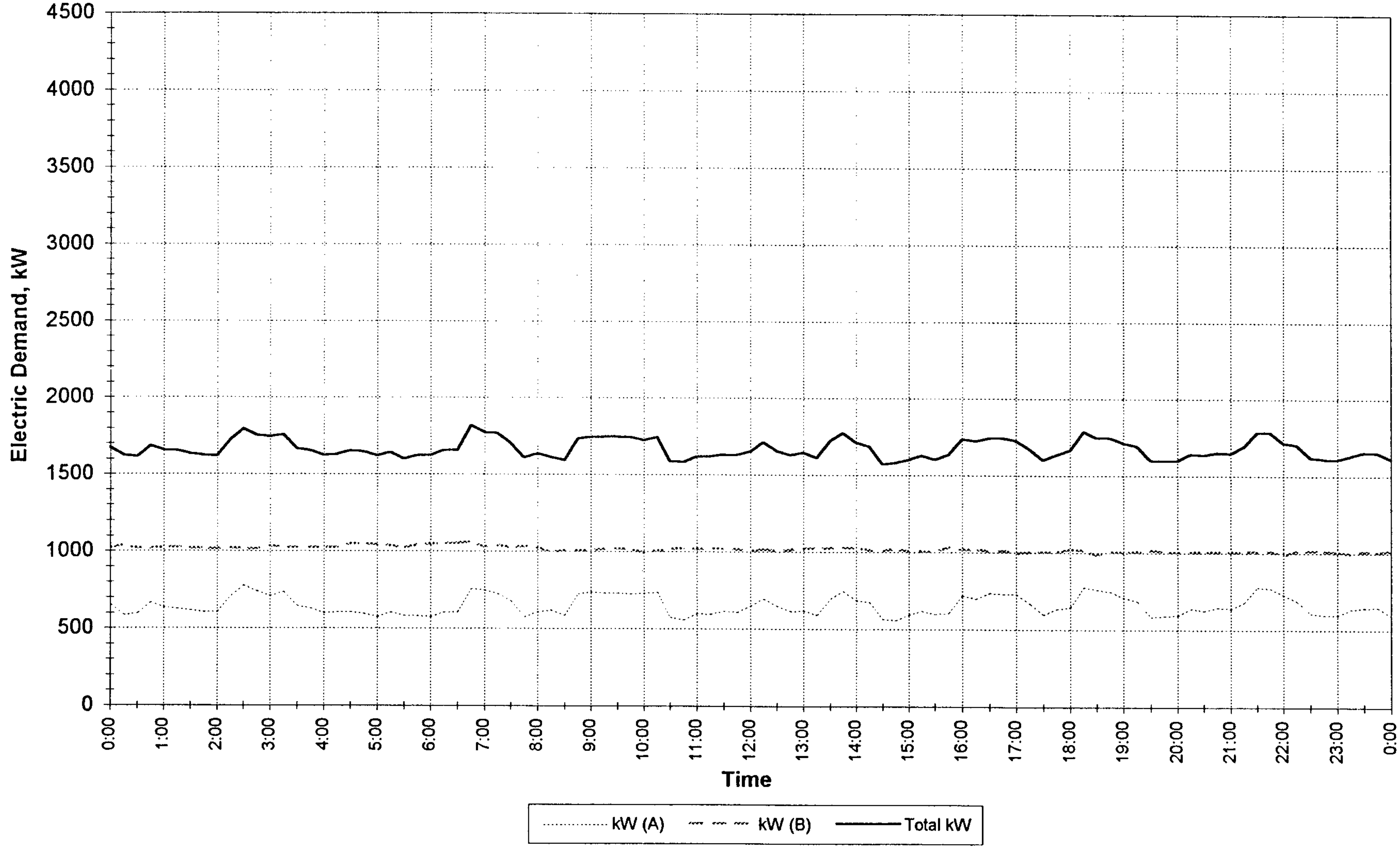


Figure 2.5-6
PBA Demand Data, Monday 4/17/95

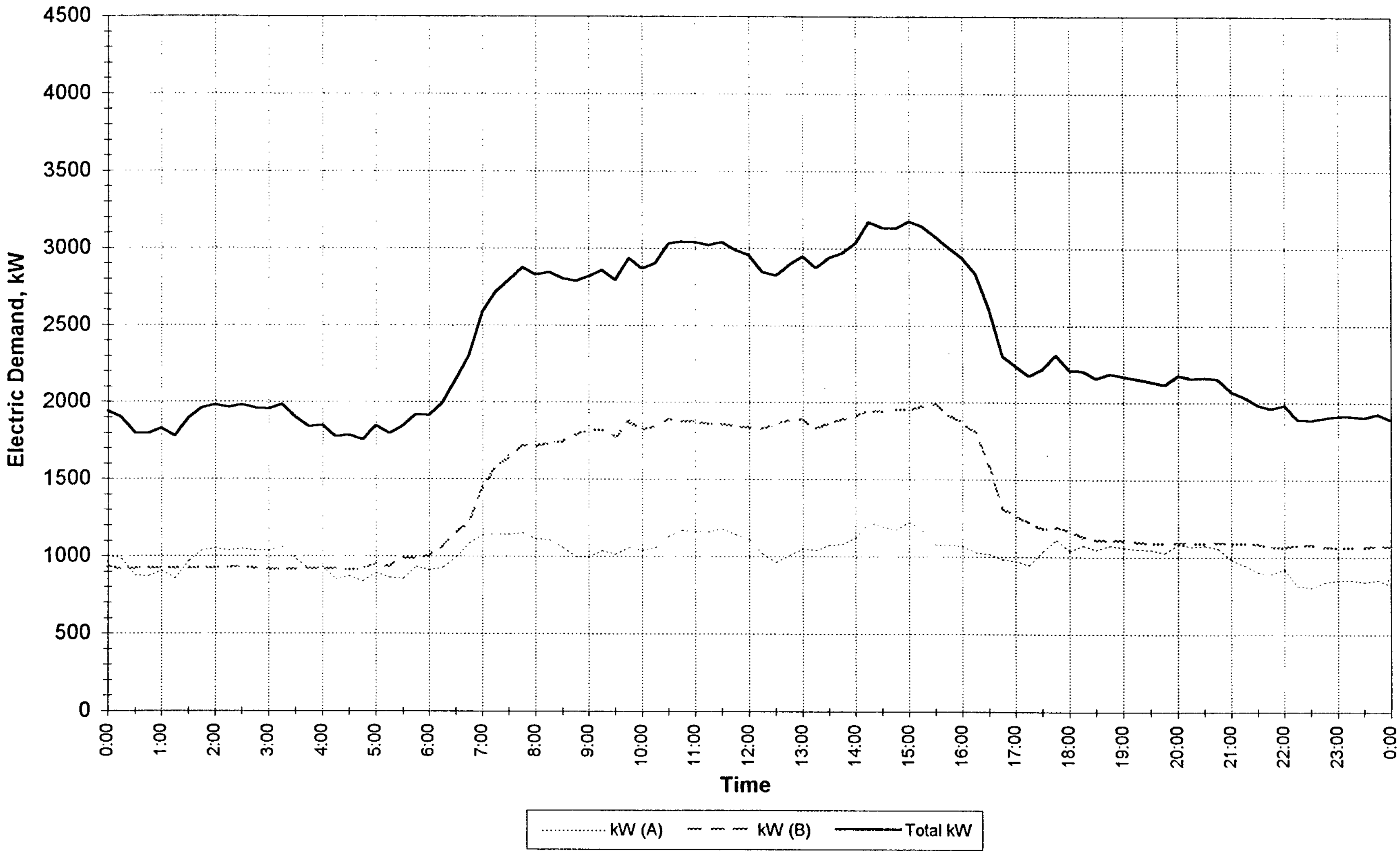


Figure 2.5-7
PBA Demand Data, Sunday 4/16/95

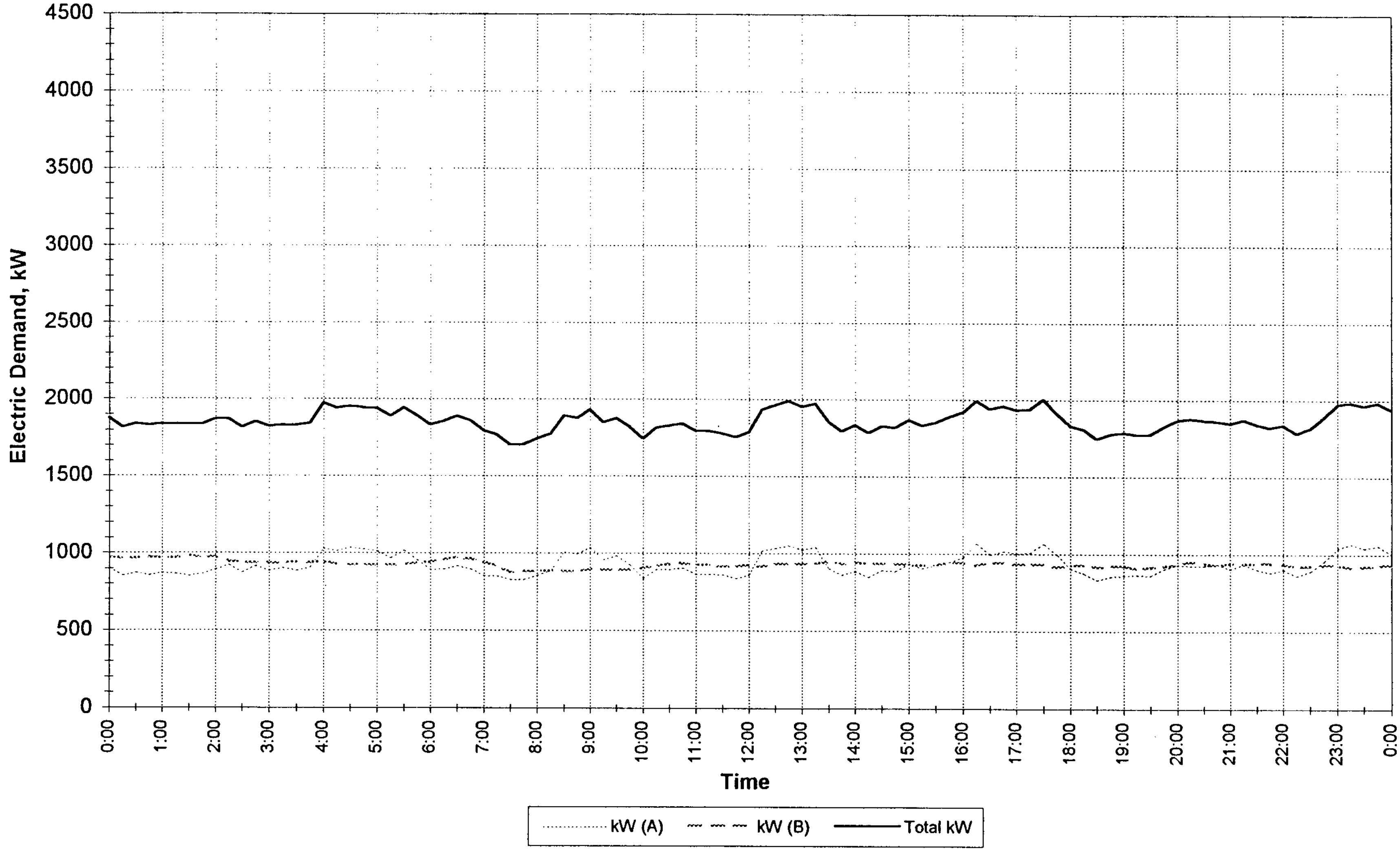


Figure 2.5-8
PBA Demand Data, Wednesday 6/28/95

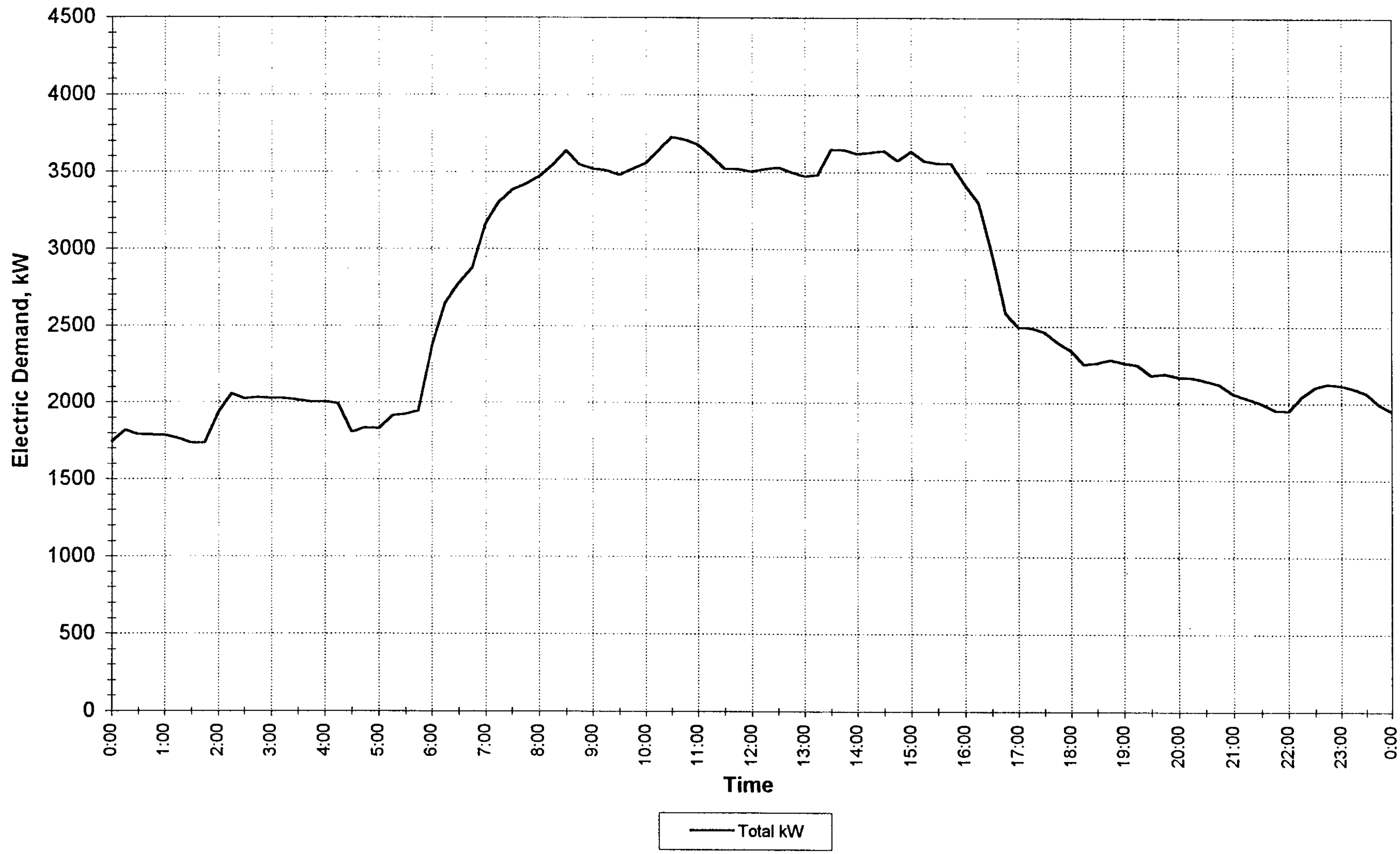


Figure 2.5-9
PBA Demand Data, Sunday 6/25/95

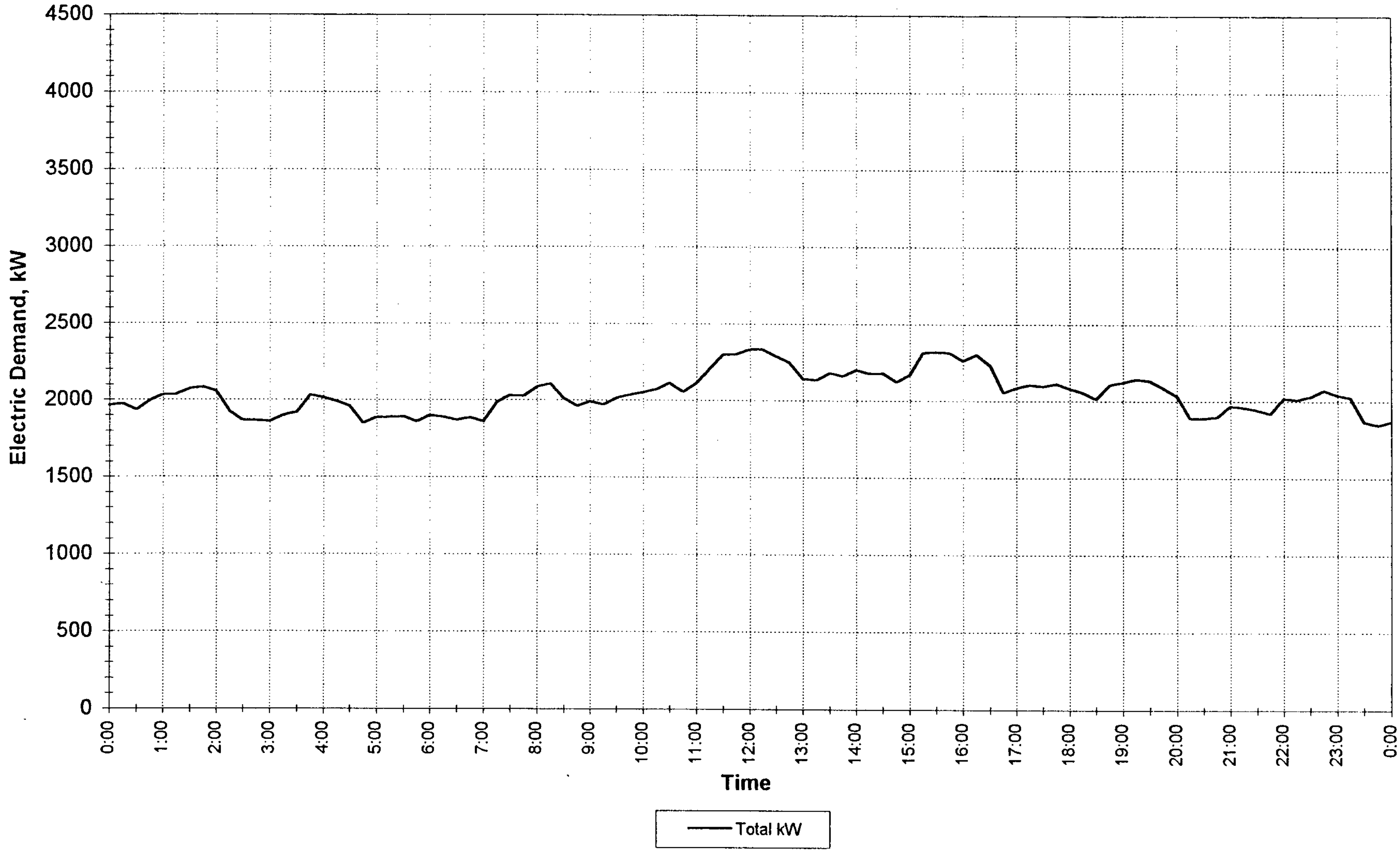
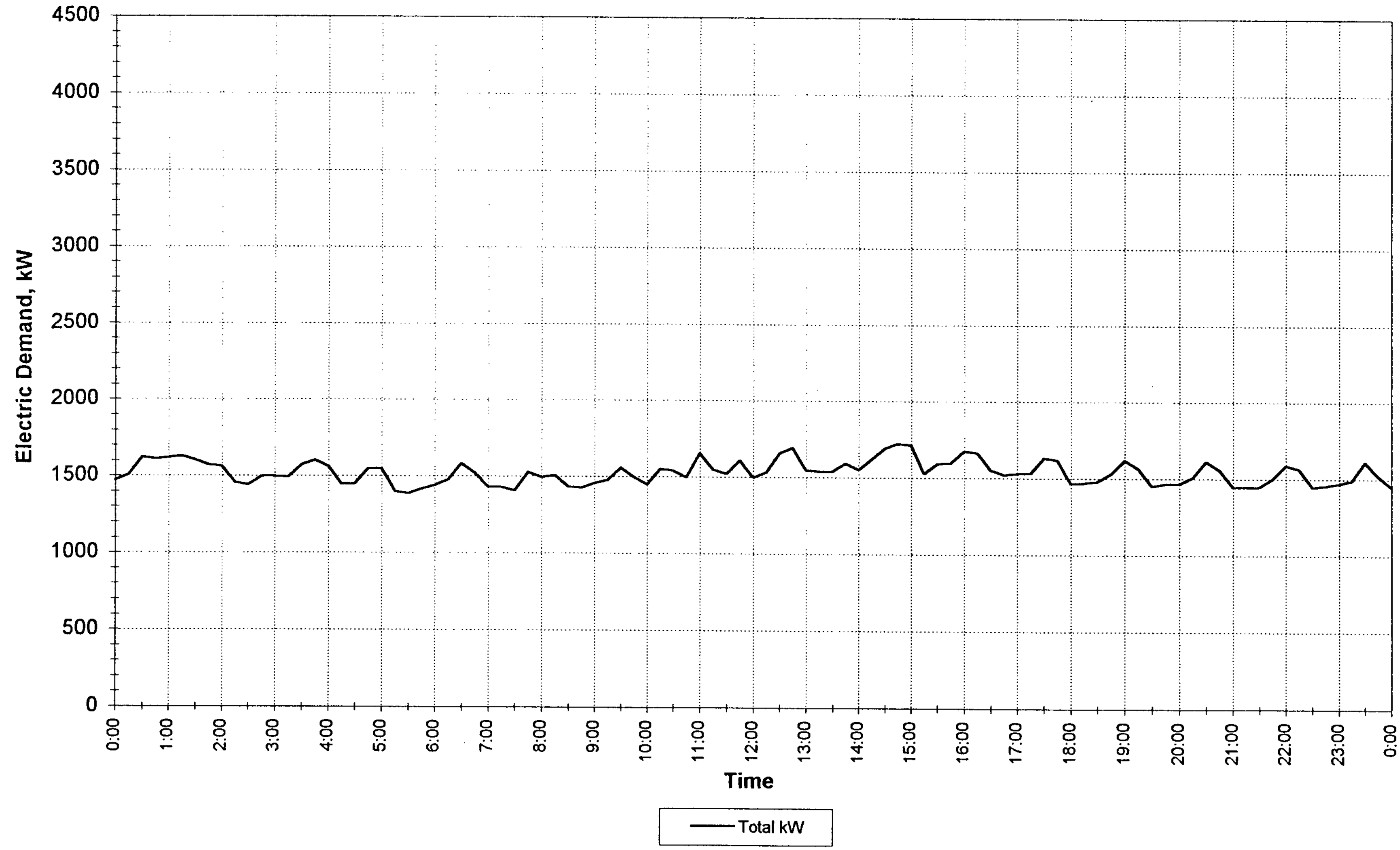


Figure 2.5-10
PBA Demand Data, Wednesday 10/4/95

Figure 2.5-11
PBA Demand Data, Sunday 10/1/95



3.0 METHODOLOGY

3.1 PROJECT APPROACH

The original ECO's to be evaluated involve improving the efficiency of the boilers, air compressors and large electric motors. Two field investigations were conducted to obtain all data required to properly analyze the ECO's. Boiler efficiency measurements were performed for various operating capacities. Boiler logs were copied and used to determine the boiler load factors and how many boilers were operating on a daily basis. Electric motor energy use was measured and annual operating hours were determined from maintenance logs and discussions with the operating personnel. Name plate data were taken from the operating and surplus air compressors. Copies of utility bills, production schedules and previous studies were also obtained.

Many steam and condensate leaks were observed during the initial field surveys. After the initial field surveys a preliminary analysis of the boiler loading and energy consumption data was performed. This analysis indicated a large amount of natural gas was being wasted due to steam leaks from the steam distribution system in production areas 31, 32, 33 and 34. A no-cost modification to the Scope of Work was requested and approved to include analysis of a project to repair or replace the existing steam piping system.

A subsequent field investigation was performed to survey the steam distribution system. Existing distribution system valves were used to isolate each boiler house and one production area, except for the boilers in Building 32-060 which was isolated with areas 31 and 32. With the production areas isolated from each other, the boiler charts and totalizer readings were used to determine the process steam consumption and leaks for each area.

The field survey included a visual inspection of all steam piping from the boilers to the entrance of the end use buildings. Each steam leak was classified as to the type of leak (valve packing, pipe fitting, steam trap, pipe failure, etc.) and the steam flow was quantified based on a scale of one to ten. A steam flow rating of "one" was just a very light flow and a steam flow rating of "ten" was a one-quarter inch to one-half inch opening with steam flowing freely. Copies of the steam distribution system drawings and plans for the addition of a new boiler plant for the white phosphorous area were also obtained.

3.2 ESTIMATE OF ENERGY LOSS FROM STEAM LEAKS

The energy losses due to steam leaks within Production Areas 31, 32, 33 and 34 were estimated by performing a monthly natural gas balance for the entire Arsenal for calendar year 1995. This involved subtracting all identified steam consumption and steam losses from the total natural gas consumption for the Arsenal. Steam consumption at PBA includes process heating, process humidification and comfort heating. Steam losses include condensate leaks, thermal losses due to conduction and convection, system (boiler) efficiency and steam leaks. The methods used for identifying and calculating the natural gas consumption for all of the identified users and losses are described in the following paragraphs. The calculations, assumptions and back-up data for estimating the energy loss due to steam leaks are contained in Appendix A.4.

All of the identified steam leaks are located in production areas 31, 32, 33, and 34. The steam system in area 44 is very small and any leaks associated with this system are negligible. The natural gas used in these areas is equal to the total natural gas energy supplied to the arsenal less the sum of the natural gas consumed by all other buildings within the Arsenal. The following equation was used to determine the natural gas consumption by the steam systems in Production Areas 31, 32, 33, 34, and 44:

$$\sum SS_P = NG_B - \sum IB_M \qquad (1)$$

Where:

$\sum SS_P$ = The monthly natural gas consumption for the steam systems (production and distribution) in Areas 31, 32, 33, 34 and 44.

NG_B = Total monthly facility natural gas consumption as shown on the monthly bills from the supplier.

$\sum IB_M$ = Sum of the monthly natural gas use for the 71 individual buildings with working natural gas meters.

The natural gas supply for PBA is provided through a single supply line and main meter. The monthly readings from the main meter are the basis for determining the total monthly natural gas consumption (NG_B) at PBA and the monthly billing by the natural gas supplier. The natural gas is then distributed to approximately 75 buildings within the Arsenal. These facilities are equipped with properly functioning gas flow meters that are read by the DPW staff on the 25th of every month.

Ideally, the total natural gas consumption at PBA (as shown on the monthly bill) would be equal to the sum of the natural gas use for the 75 individually metered buildings. However, the meters for the boiler houses in Areas 32, 33, 34, & 44 have reportedly been broken for some time and no readings are taken for these buildings. The natural gas consumption for all of the other 71 buildings with working meters (including the laundry and incinerator) was calculated from the meter readings. The natural gas consumption of these facilities was totaled on an monthly basis. The calculations and results are contained in Appendix A.4. These monthly totals are used as IB_M in the natural gas balance equations.

The natural gas consumed by the steam systems in the production areas is divided into three main groups: process steam use, comfort heating, and steam production and distribution system losses. This is described by the following equation.

$$\Sigma SS_P = PE_P + CH_P + SL_P \qquad (2)$$

Where:

PE_P = Process steam used for process heating and humidification.

CH_P = Energy used for comfort (space) heating.

SL_P = System losses from the steam production and distribution system.

Process steam energy is defined as steam heating or humidification utilized for the direct manufacture of a product. The steam demand for process heating/humidification and for comfort heating for each building within the production areas is defined in Exhibit F of the Contingency Master Planning Program Steam and Compressed Air Utility Study prepared by CDG in October 1994 (CDG Utility Study). Steam demand values given in the CDG Utility Study were checked and updated by the Production staff. Total energy consumption for the steam systems in the production areas is therefore equal to the summation of the energy requirements for each area.

$$PE_P = PS_{31} + PS_{32} + PS_{33} + PS_{34} + PS_{44} \qquad (3)$$

Where:

PS_{31} = Process steam consumption in production area 31.

PS_{32} = Process steam consumption in production area 32.

PS_{33} = Process steam consumption in production area 33.

PS_{34} = Process steam consumption in production area 34.

PS_{44} = Process steam consumption in production area 44.

The steam energy used for comfort heating (CH_P) was calculated by a bin temperature method. There are 93 buildings in the production areas that utilize steam for comfort heating and four of them are currently in layaway. Space heating loads for the 89 active buildings were obtained from the CDG Utility Study and updated based on information from the PBA production staff. The percent of heating required for each bin temperature range was determined by assuming full heating load will occur at the 99 percent winter design temperature and no space heating is required when the outside air temperature is 65 degrees F or higher. Bin temperature data were obtained from Engineering Weather Data, TM 5-785. The calculations, assumptions and results are contained in Appendix A.4.

System losses (SL_P) from the steam production and distribution system include conversion losses from changing the chemical energy of the natural gas to steam energy (boiler efficiency), thermal losses due to convection and conduction from the distribution system piping, condensate return losses and distribution system piping leaks.

$$SL_P = CL_P + TL_P + LEAKS_P \qquad (4)$$

Where:

CL_P = Energy losses from condensate system leaks.

TL_P = Thermal energy losses through the pipe insulation.

$LEAKS_P$ = Leaks from the steam distribution system.

Boiler efficiency measurements and calculations indicated that the 70 percent efficiency used by the PBA staff was a fairly accurate average. The conversion efficiency losses are taken into account by dividing all of the calculated steam consumption values (in MBtu of steam) for areas 31, 32, 33 and 34 by 0.7 to obtain MBtu of natural gas. The calculated steam consumption values (in MBtu of steam) for area 44 were divided by 0.8 to obtain MBtu of natural gas. Since boiler efficiency is accounted for by the calculations in Equations 1 through 4, a separate term for conversion losses was not included in the system losses equation.

The condensate return system at PBA is in very poor condition and is scheduled for replacement in the near future. Calculations of the natural gas energy losses due to the poor condition of the condensate system assumed that approximately 10 percent of the available condensate is currently being returned, that the condensate temperature is approximately 120 degrees F and that the make-up water temperature is about 68 degrees F.

Thermal losses (TL_P) from the steam supply piping due to conduction and convection were calculated for each month of the year. The amount of these losses is influenced by the temperature of the pipe and the outside air temperature. Thirty year averages were used for monthly temperatures in these calculations.

By combining and rearranging equations 1, 2 and 4, the following expression was derived for calculating natural gas use due to steam leaks in the production areas:

$$LEAKS_P = NG_B - IB_M - PE_P - CH_P - CL_P - TL_P \qquad (5)$$

The results of the estimated natural gas balance achieved by utilizing Equation 5 are shown in Table 3.2-1. The calculations, assumptions and back-up data for estimating these values are contained in Appendix A.4.

Table 3.2-1 PBA Natural Gas Balance for 1995

Natural Gas Component	Estimated Monthly Natural Gas Consumption (MBtu)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1. Natural Gas Bills (NG_B)	72,425	65,166	58,220	47,855	37,697	38,392	37,838	34,199	35,284	41,937	58,597	77,672
2. Bldgs w/ Meters (IB_M)	9,187	10,282	7,633	5,274	2,505	3,814	5,233	5,277	4,505	6,079	6,715	9,367
3. Process Heat (PE_P)	10,181	10,647	12,176	10,759	10,907	11,848	12,357	10,362	10,034	10,181	9,853	10,544
4. Comfort Heat (CH_P)	35,117	27,788	20,787	6,854	2,517	271	73	137	1,322	7,812	18,317	30,387
5. Condensate Loss (CL_P)	4,228	3,669	3,382	2,847	2,353	2,312	2,180	1,934	2,058	2,397	3,469	4,567
6. Conduction Loss (TL_P)	4,564	4,080	4,392	4,116	4,138	3,890	3,971	3,984	3,947	4,234	4,266	4,530
7. Steam Leaks ($LEAKS_P$)	9,148	8,700	9,849	18,005	15,277	16,257	14,024	12,505	13,417	11,234	15,977	18,278
Steam Leaks (7) = (1) - (2) - (3) - (4) - (5) - (6)												

Results of the natural gas balance listed in Table 3.2-1 are presented graphically by Figures 3.2-1, 3.2-2 and 3.2-3. Figure 3.2-1 shows the results in bar graph format to illustrate how the values of each natural gas-consuming component add up to the total natural gas use. The bars at the bottom of this figure depict the estimated amount of natural gas wasted due to steam leaks. The estimated amount of the steam leaks ranges from about 9,000 MBtu per month to 18,000 MBtu per month.

Figure 3.2-2 is a line graph that shows how the values of the total natural gas use at PBA and all of the components vary on a monthly basis. This figure indicates the estimated losses due to steam leaks are lower during the winter months of January, February and March. Regardless of how and where the steam leaks occur, the driving force for steam leaks is the system operating pressure. Since the boilers and distribution system pressure are kept fairly constant throughout the year, the steam leaks should also remain constant throughout the year. This indicates that the actual winter conditions during 1995 were probably milder than the average bin data that was used to calculate the energy use for space heating. Therefore, if the calculated energy use for space heating was decreased to match the actual 1995 energy consumption for space heating, the estimated steam leaks would increase during these winter months.

The estimated energy use for comfort heating during the summer months is negligible. Therefore, the steam leak estimates for these months should more accurately reflect the average value of the actual steam leaks. The average estimated loss due to steam leaks during June, July and August is 14,260 MBtu per month. Based on this value, the economic analyses assume that the steam leaks remain constant at 14,000 MBtu per month throughout the year. Therefore, the total annual estimated energy loss due to steam leaks at the Arsenal is about 168,000 MBtu per year. Using \$2.81 per MBtu as the average cost of natural gas, the cost of steam leaks at PBA is approximately \$472,000 per year.

Figure 3.2-1
PBA Natural Gas Balance, 1995

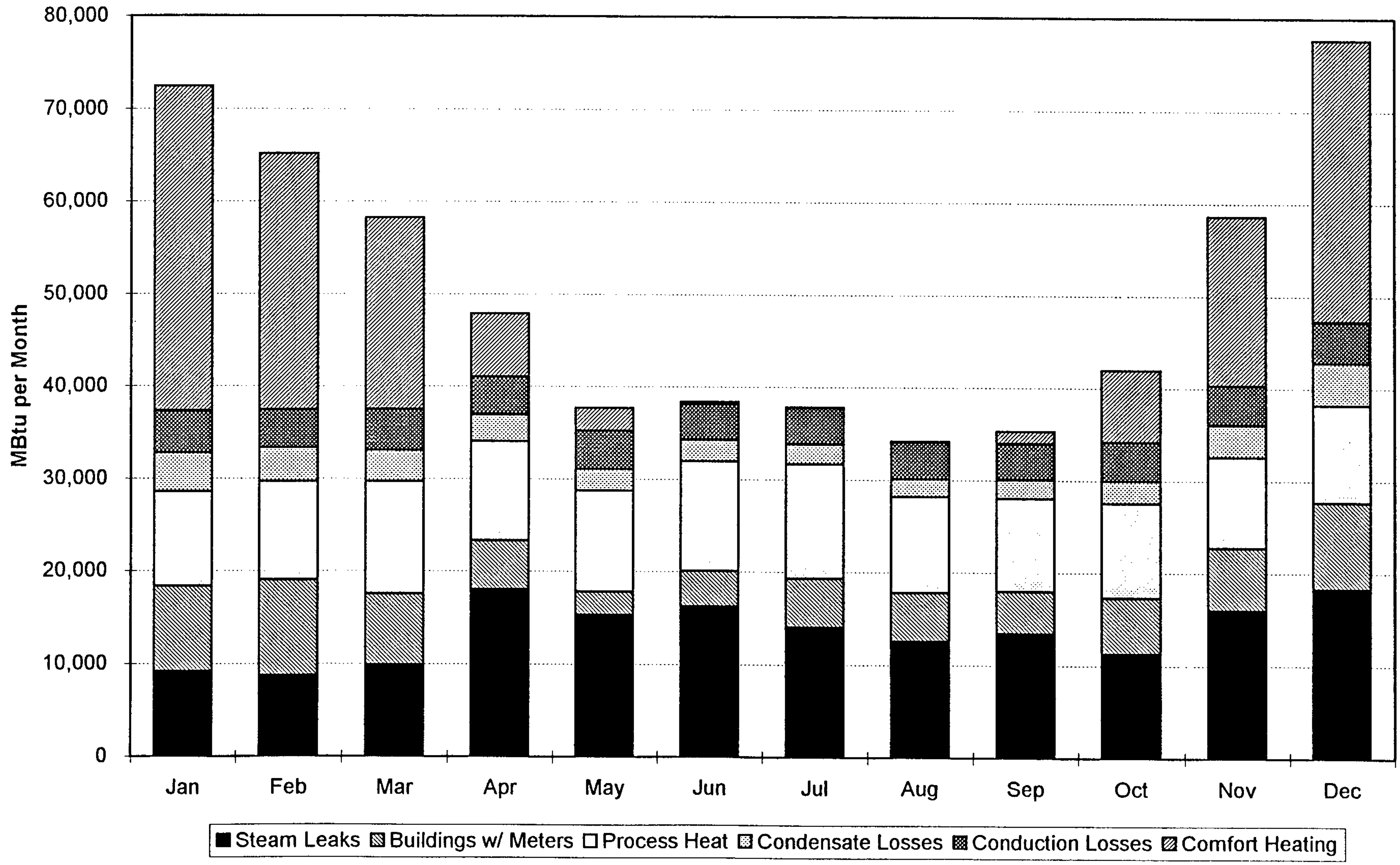


Figure 3.2-2
PBA Natural Gas Balance, 1995

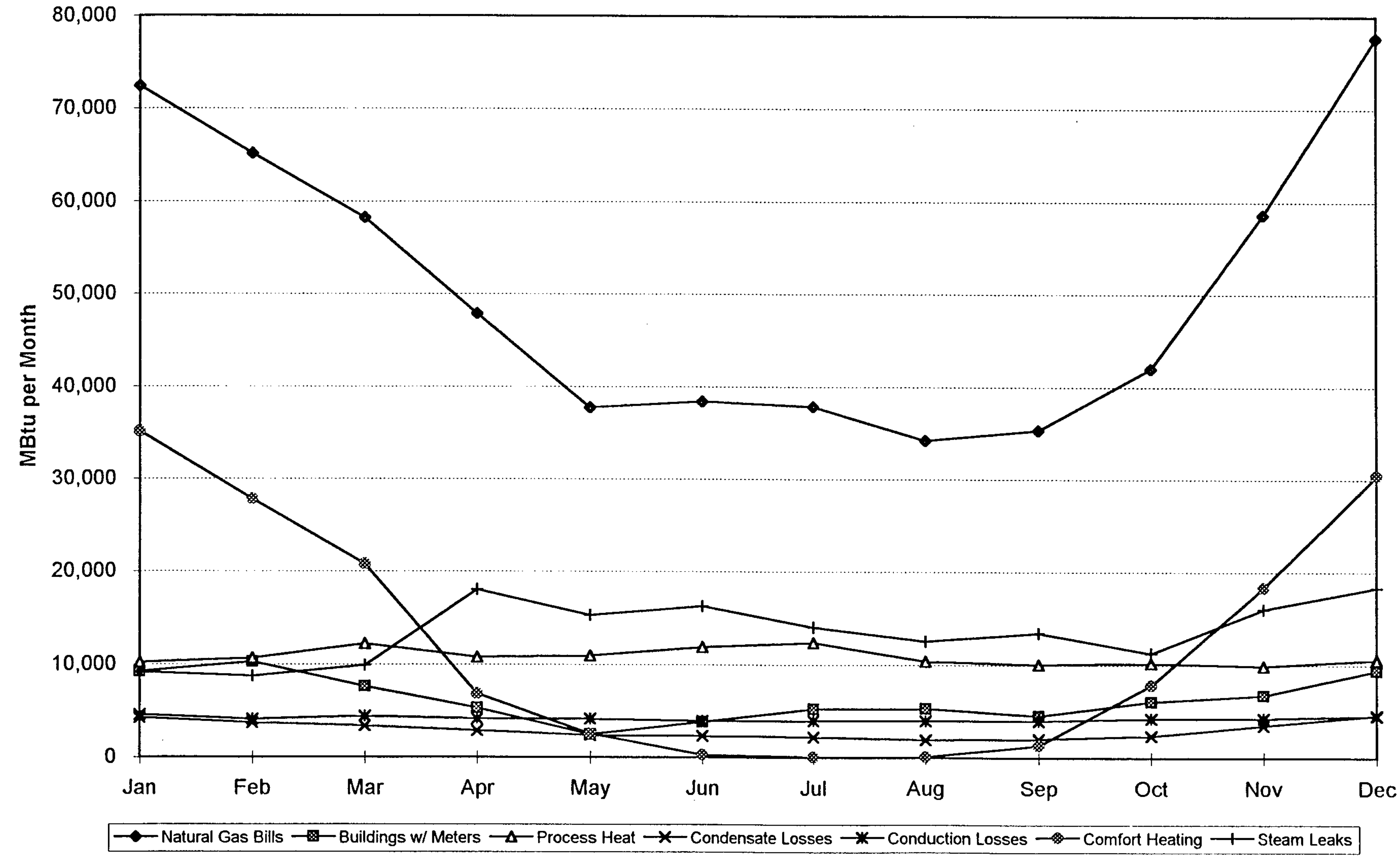


Figure 3.2-3 shows the annual natural gas energy distribution at PBA for 1995. Steam leaks in Areas 31, 32, 33, and 34 represent approximately 27 percent of the natural gas consumption and cost for 1995. Steam leaks are the single largest energy consumer at PBA.

To ensure that all of the natural gas consumed at PBA was accounted for, an additional calculation was performed using the consumption data from the boiler logs. The PBA staff estimates the monthly natural gas use for the boiler houses by taking the steam totalizer readings and dividing by an assumed boiler efficiency of 70 percent. RS&H boiler efficiency measurements and calculations indicate that the boilers in areas 32, 33 and 34 operate at an average efficiency of about 70 percent and the boiler in area 44 operates at an efficiency of about 80 percent.

The total natural gas consumption at PBA should equal the estimated natural gas use for the boilers in areas 32, 33 and 34 plus the total natural gas use for the 71 metered buildings plus the calculated natural gas use for the boiler in area 44. Figure 3.2-4 compares the natural gas use calculated by using the PBA staff estimates with the actual billed natural gas use. The estimated natural gas use is a little higher than the actual for the first three months and lower than the actual for the remainder of the year. The annual total of the estimated natural gas use is within about five percent of the actual natural gas use.

Figure 3.2-3
PBA Estimated Annual Natural Gas Use, 1995

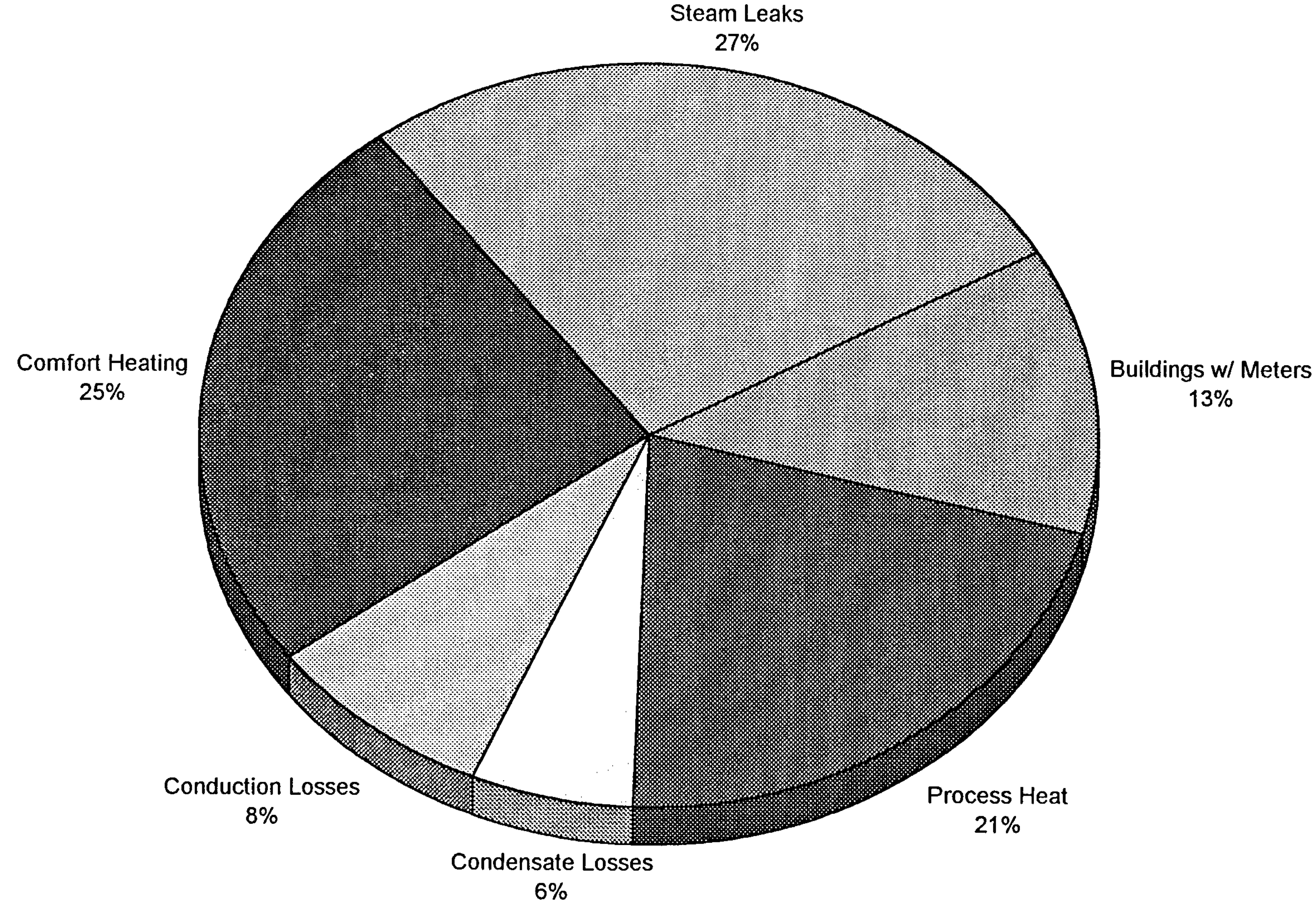
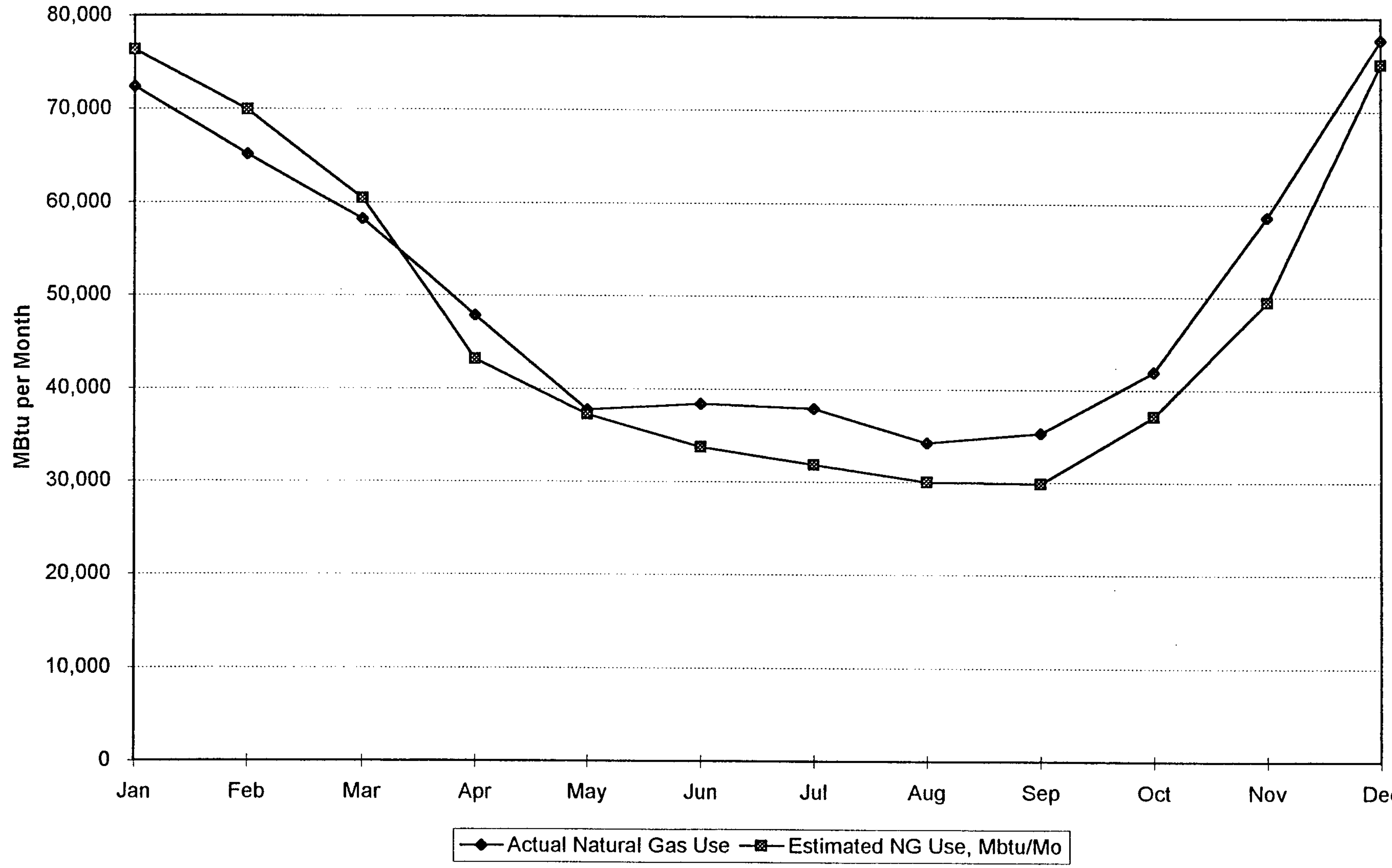


Figure 3.2-4
PBA Actual vs Estimated Natural Gas Use, 1995



3.3 FIELD INVESTIGATION EQUIPMENT

Boiler efficiency was tested using a Model Fyrite II, hand-held microprocessor-based combustion efficiency analyzer manufactured by Bacharach, Incorporated. The Fyrite II reads and stores percent oxygen, stack temperature and primary air temperature and uses this data to calculate percent stack loss, percent carbon dioxide, percent excess air and combustion efficiency.

To determine the average annual boiler efficiency, stack gas analysis data were taken at five different boiler loads. The five load points ranged between the boiler's published 100% and 200% capacity because the boilers typically operate in that range. A curve was then drawn through the data points. A monthly load factor was calculated from boiler operating logs. An annual average load factor was calculated from the monthly data and used to provide an indication of the average boiler operating load during the year. The annual average load factors were then used with the efficiency curves to determine the annual average boiler efficiency.

Electric motor energy use was measured using a Harmonic/Power Analyzer Model HA-2000 manufactured by Amprobe Instrument. Measurements were taken by clamping a current transducer around the phase wire to be tested and connecting the voltage leads from phase to phase or phase to neutral depending on the circuit configuration. Readings were made and recorded for root-mean-square (RMS) volts, RMS amps, kilowatts (kW) working power, volt-amps reactive (VAR) power, kilovolt-amps (kVA) apparent power and power factor (PF).

3.4 ANALYSIS TOOLS

Two types of computer software are used during the energy and ECO analysis phase of this project. These are:

- Microsoft Excel, Version 5.0c
- LCCID Version 1.0, Level 92

Microsoft Excel is a spreadsheet computer program. RS&H uses this program for statistical analysis of energy data, calculating average utility rates, computing boiler efficiency and calculating the energy savings for some of the ECOs. Excel was also utilized to generate the charts and graphs that are presented in this report.

Life Cycle Cost in Design (LCCID) is a computer program developed by the Construction Engineering Research Laboratory (CERL) for performing life cycle cost analysis of Department of Defense (DoD) energy savings projects in accordance with the Energy Conservation Investment

Program (ECIP) guidelines. The Level 92 version contains the latest discount factors and fuel escalation rates provided by the Department of Energy (DOE).

3.5 UTILITY RATES

The utility rates for electricity and natural gas that were used in the energy cost savings calculations and the economic analyses are presented in Table 3.5-1. The source that provided the utility cost information is also listed in the table.

Table 3.5-1. Pine Bluff Arsenal Utility Rates

Utility	Rate	Source
Natural Gas - Annual Average	$2.81/MBtu	Natural Gas Bills
Electricity - Overall Average	$0.057/kWh, $16.79/MBtu	Electric Bills
Energy - Annual Average	$0.029/kWh, $8.58/MBtu	Calc. from 12 months of data
Energy - Summer	$0.0391/kWh, $11.45/MBtu	Electric Rate Schedule
Energy - Other	$0.0326/kWh, $9.55/MBtu	Electric Rate Schedule
Demand - Annual Average	$12.94/kW	Calc. from 12 months of data
Demand - Summer	$13.73/kW	Electric Rate Schedule
Demand - Other	$12.23/kW	Electric Rate Schedule

Natural gas is provided by a government contract with Falling Tree Enterprises located in Tulsa, Oklahoma. The annual average rate for natural gas was calculated from actual utility bills for the 12 month period beginning February, 1995 and ending January, 1996. Calculations for the average natural gas rate and monthly consumption data are contained in Appendix A.6.

Electricity is provided by the Arkansas Power & Light Company (AP&L). There are three electric substations that provide electric service to PBA. Substation A serves incinerator, water plant and LAP facilities (Areas 42 and 44), Substation B serves the production facilities (Areas 31,32, 33 and 34) and Substation C serves the administration and housing areas of the Arsenal. PBA receives two electric bills each month, one for Substations A and B combined and one for Substation C. The AP&L Large Power Service (LPS) rate applies to the Substations A and B bill and is the rate shown in Table 3.5-1.

The annual average electric energy and demand rates were calculated from actual utility bills for the 12 month period beginning February, 1995 and ending January, 1996. The overall average electricity cost was calculated by summing the total annual cost of electric energy and demand costs and divided that value by the total kWh consumed for the year. Monthly electrical consumption data and calculations used to determine the average rates are contained in Appendix A.6.

The calculated annual average electric energy rate is lower than the rates listed in the rate schedule because the fuel adjustment rate has consistently been a negative value. The summer electric energy and demand rates apply during the months of June, July, August and September.

3.6 COST ESTIMATING

Unless otherwise noted on the estimate forms, material and labor costs for all cost estimates were obtained from the 1996 Means Mechanical Cost Data and 1996 Means Electrical Cost Data books. Adjustment factors that must be applied to the "Bare Cost" values shown in the Means books are listed in Table 3.6-1.

Table 3.6-1. Cost Estimate Adjustments

Adjustment	Material	Labor
City Cost Index (Pine Bluff)	-4.8%	-36.8%
FICA/Insurance	N.A.	20.0% (1)
Overhead	N.A.	15.0% (1)
Performance Bond	N.A.	1.0% (1)
Profit	10.0%	10.0% (1)
Sales Tax	4.5%	N.A.
SIOH	N.A.	6.0%
Design Fees	N.A.	6.0%
Contingency	10.0%	10.0%

(1) The product of these factors yields a total labor increase of 53%.

4.0 ANALYSIS

4.1 EVALUATION OF ENERGY CONSERVATION PROJECTS

The following ECO's were evaluated for their technical and economic feasibility.

Electrical Load Reduction ECO's

ECO-E1 Replace compressor motors in Buildings 32-060, 33-060 and 34-140 with energy efficient motors.

ECO-E2 Replace the white phosphorus pollution abatement system scrubber/exhaust fan motors with energy efficient motors.

ECO-E3 Replace primary water pump motors in Buildings 42-010, 42-020 and 42-030 with energy efficient motors.

ECO-E4 Replace filtered water pump motors in Building 42-210 with energy efficient motors.

ECO-E5 Replace the afterburner scrubber fan motor in the incinerator area with an energy efficient motor.

Steam Production and Distribution System ECO's

ECO-H1 Modifications and improvements to the steam distribution system.

- Option A - Repair existing steam pipe and fittings.
- Option B - Install a new steam distribution piping system.

ECO-H2 Modifications and improvements to boilers in Building 32-060.

- Option A - Install new boilers with turbulators, O_2 trim, economizers, etc.
- Option B - Improve efficiency of existing boilers.
- Option C - Install surplus boilers and add economizers.
- Option D - Install economizers on surplus boilers.

ECO-H3 Modifications and improvements to boilers in Building 33-060.

- Option A - Install new boilers with turbulators, O_2 trim, economizers, etc.
- Option B - Improve efficiency of existing boilers.
- Option C - Install economizers on existing boilers.

ECO-H4 Modifications and improvements to boilers in Building 34-140.

- Option A - Install new boilers with turbulators, O_2 trim, economizers, etc.
- Option B - Improve efficiency of existing boilers.
- Option C - Install economizers on existing boilers.

ECO-H5 Modifications and improvements to boilers in Building 42-960.

- Option A - Install new boilers with turbulators, O_2 trim, economizers, etc.
- Option B - Improve efficiency of existing boilers.

ECO-H6 Modifications and improvements to CB boiler (Unit No. 2) in Building 44-120.

Option A - Install a new boiler with turbulators, O_2 trim, economizers, etc.

Option B - Improve efficiency of existing boiler.

Compressed Air System ECO's

ECO-C1 Utilize the two surplus Gardner-Denver Compressors.

Option A - Replace two existing compressors with the surplus compressors.

Option B - Add the surplus compressors in line with existing compressors.

ECO-C2 Replace the existing compressors with more efficient compressors.

ECO-C3 Modifications and improvements to the compressed air system.

Option A - Install dedicated compressors at the end-use buildings.

Option B - Install new compressed air distribution piping.

Option C - Repair existing compressed air pipe and fittings.

The following pages contain a description of each energy conservation project, a discussion of the analysis performed, results of the life cycle cost analysis and recommendations based on the results. The calculations, cost estimates, Life Cycle Cost Analysis Summary sheets (LCCID output) and back-up data are contained in Appendix A.5.

ECO-E1

Replace the compressor motors with energy efficient motors in Buildings 32-060, 33-060 and 34-140.

Description

There are two Ingersoll-Rand model XLE compressors in each of the boiler houses. This project consists of replacing the existing motors on the six model XLE compressors with new energy efficient motors.

Analysis

The existing motors are 150 horsepower and 173 horsepower, low-speed (600 rpm), synchronous type. Low-speed synchronous motors have a high moment of inertia which helps to smooth out the compressor operation during fluctuating loads. General Electric made the existing motors. However, they no longer manufacture synchronous motors in sizes less than 600 horsepower.

Discussions with the General Electric Service Center, Reliance Electric, Westinghouse Motor Company and MSC Industries indicated standard replacement motors are no longer available in this size range. New motors would have to be custom built and the typical minimum order is 50 units.

Results

A life cycle cost analysis was not performed for this project because replacement motors are not readily available and the cost to have these motors custom built would be astronomical.

Recommendations

Due to their age and the unique nature of these motors, energy efficient replacement motors are not available, therefore, this project is not recommended.

ECO-E2

Replace the white phosphorus pollution abatement system scrubber/exhaust fan motors with energy efficient motors.

Description

The pollution abatement system for white phosphorus production utilizes an 800 horsepower centrifugal fan for the exhaust and scrubber system. There are two fans and motors located outside of building 34-196 that are alternated into service. This project would replace the existing 800 horsepower motors with new energy efficient motors.

Analysis

Only one motor and fan operates at any given time. However, since both motors are alternated, this project will assume both motors will be replaced. The fans and motors are only activated during white phosphorus production and demil (dismantling of munitions) operations. The operating schedule for the white phosphorus area indicated there were only about 550 production hours during calendar year 1995.

The efficiency of the existing motors was estimated to be approximately 90 percent. Annual electric energy consumption and operating cost for these fans are estimated to be 1230 MBtu and $20,700, respectively. Performance and cost data for new high efficiency replacement motors was obtained from the manufacturer of the existing motors. The new 800 horsepower motors have a full load efficiency of about 96 percent. The cost for each new motor is $40,640, which does not include shipping and installation. The results of the life cycle cost analysis are shown in the following table and the calculations are contained in Appendix A.5.

Results

Construction Costs	$117,540
Annual Energy Savings (Increase)	
Electricity (MBtu/Year)	168.9
Natural Gas (MBtu/Year)	0
Total (MBtu/Year)	168.9
Annual Cost Savings (Increase)	
Electricity ($/Year)	$2,840
Natural Gas ($/Year)	$0
Operation & Maintenance ($/Year)	$0
Total Cost Savings ($/Year)	$2,840
Savings to Investment Ratio	0.36
Simple Payback Period (Years)	41.4

Recommendations

Based on the life cycle cost analysis this project is not recommended. These motors are very large and expensive and the current operating hours are too low for this project to be economically justified.

ECO-E3

Replace the primary water pump motors in Buildings 42-010, 42-020 and 42-030 with energy efficient motors.

Description

There are three pumps that pump ground water into a tank where it is stored until processing and distribution. The pumps are driven by 150 horsepower electric induction motors. The pump and motor for Building 42-020 are new. However, it is not the energy efficient type, so this project involves replacing all three of the existing pump motors with new energy efficient motors.

Analysis

The three pump motors are operated on an alternating schedule. The first pump will operate intermittently one day, the second one on the second day, etc. The pump logs indicate that these pumps operated for a total of about 3530 hours during calendar year 1995. The total operating hours represent an average of about 1180 hours per year per motor. The existing motors have an estimated efficiency of 92 to 94 percent. New 150 horsepower premium efficiency motors have an efficiency of about 96 percent. These motors operate at approximately 70 percent of full load. The results of the life cycle cost analysis are shown in the following table and the calculations are contained in Appendix A.5.

Results

Construction Costs	$26,700
Annual Energy Savings (Increase)	
Electricity (MBtu/Year)	122.6
Natural Gas (MBtu/Year)	0
Total (MBtu/Year)	122.6
Annual Cost Savings (Increase)	
Electricity ($/Year)	$2,060
Natural Gas ($/Year)	$0
Operation & Maintenance ($/Year)	$0
Total Cost Savings ($/Year)	$2,060
Savings to Investment Ratio	1.16
Simple Payback Period (Years)	13.0

Recommendations

Based on the life cycle cost analysis this project is not recommended. The operating hours for these pumps is not sufficient to warrant replacing them with new energy efficient motors.

ECO-E4

Replace the filtered water pump motors in Building 42-210 with energy efficient motors.

Description

There are four filtered water pumps that pump the stored ground water from the holding tank through filters and chlorinators and then to the high tanks for distribution to the Arsenal. The pumps are driven by 30 horsepower electric induction motors. This project consists of replacing all four of the existing filtered water pump motors with new energy efficient motors.

Analysis

The four filtered water pump motors are located in Building 42-210. The pumps are operated on an alternating schedule that has two of them running during any given day. A typical schedule for nine days is to run pumps 1 and 2 one day, then 1 and 3 the next day, 1 and 4, 2 and 3, 2 and 4, 2 and 1, 3 and 4, 3 and 1, 3 and 2 and back to pumps 1 and 2 on the tenth day. The pump logs indicate these pumps operated for a total of about 9170 hours during calendar year 1995. The annual operating hours represent an average of approximately 2290 hours per year per motor.

The PBA DPW staff indicated they plan to replace the existing filtered water pumping system including the four pumps, motors and some of the piping. The new pumping system will utilize two larger pumps and motors.

The existing motors are old and have an estimated efficiency of 88 percent. New 30 horsepower premium efficiency motors have an efficiency of about 94 percent. Field measurements of motor kW indicate these motors are operating at approximately 90 percent of full load. The results of the life cycle cost analysis are shown in the following table and the calculations are contained in Appendix A.5.

Results

Construction Costs	$8,320
Annual Energy Savings (Increase)	
Electricity (MBtu/Year)	68.8
Natural Gas (MBtu/Year)	0
Total (MBtu/Year)	68.8
Annual Cost Savings (Increase)	
Electricity ($/Year)	$1,160
Natural Gas ($/Year)	$0
Operation & Maintenance ($/Year)	$0
Total Cost Savings ($/Year)	$1,160
Savings to Investment Ratio	2.09
Simple Payback Period (Years)	7.2

Recommendations

Due to the pending replacement of the filtered water pumping system, the payback for replacing the existing motors may be longer than the motors will be utilized. Therefore, this ECO is recommended only if the new pumping system will not be installed before the end of the 7.2 year payback period. The pump system designer and the procurement staff at PBA should specify energy efficient motors for all new systems that operate at about 80 percent of full load for more than approximately 4000 hours per year.

ECO-E5

Replace the afterburner scrubber fan motor in the incinerator area with an energy efficient motor.

Description

The afterburner scrubber system (Building 42-979) for the incinerator utilizes a centrifugal fan for the exhaust and scrubber system. This fan is driven by a 350 horsepower electric induction motor. This project would replace the existing 350 horsepower motor with new premium efficient motor.

Analysis

The scrubber fan motor is a totally enclosed, fan-cooled type designed for use in severe conditions such as in chemical and processing industries. Our measurements indicate the motor operates at about 45 percent of full load. The incinerator staff estimated the operating time for this motor was approximately 8340 hours for calendar year 1995.

The incinerator operating staff also stated that the entire scrubber system is scheduled to be replaced in about one year. The new system has already been purchased from Anderson 2000. The process flow rate and pressure drop for the new scrubber will be greater so the existing fan and 350 horsepower motor will be removed and replaced by a new fan and two 400 horsepower motors with variable frequency drives.

The efficiency of the existing motor is estimated to be 95 percent. A new 350 horsepower premium efficiency motor will have an efficiency of about 96 percent. The results of the life cycle cost analysis are shown in the following table and the calculations are contained in Appendix A.5.

Results

Construction Costs	$21,230
Annual Energy Savings (Increase)	
Electricity (MBtu/Year)	131.0
Natural Gas (MBtu/Year)	0
Total (MBtu/Year)	131.0
Annual Cost Savings (Increase)	
Electricity ($/Year)	$2,200
Natural Gas ($/Year)	$0
Operation & Maintenance ($/Year)	$0
Total Cost Savings ($/Year)	$2,200
Savings to Investment Ratio	1.56
Simple Payback Period (Years)	9.7

Recommendations

Due to the pending scrubber system replacement project the payback for replacing this motor is longer than the motor will be utilized, therefore, this ECO is not recommended. The scrubber system designer and the procurement staff at PBA should specify energy efficient motors for systems that operate at about 80 percent of full load for more than approximately 4000 hours per year.

ECO-H1

Modifications and improvements to the steam distribution piping system.

Option A - Repair existing steam pipe and fittings.

Option B - Install new steam distribution piping system.

Description - Option A

This project consist of repairing and/or replacing all of the failed valves, fittings and steam traps on the existing steam distribution piping system served by the boilers in Buildings 32-060, 33-060 and 34-140. The work also includes asbestos abatement which will be required during removal of the existing fitting insulation.

Description - Option B

This project consist of installing new steam distribution piping from the boilers in Buildings 32-060, 33-060 and 34-140 to the point of connection to all of the facilities currently served by the existing system. The work also includes asbestos abatement which will be required during removal of the existing pipe and fitting insulation.

Analysis

A field survey was performed to identify all steam leaks from the steam piping located in production areas 31, 32, 33, and 34. The survey involved a visual inspection of all steam piping from the boilers to the entrance of the end use buildings. Observations during the field survey revealed many holes in the condensate return and compressed air distribution piping systems. However, all of the steam leaks found during the survey of the steam distribution system were associated with valves, fittings and steam traps. This indicates the steam distribution piping system has not failed and still has some useful life remaining.

The energy losses due to steam leaks within Production Areas 31, 32, 33 and 34 were estimated by performing a monthly natural gas balance for the entire Arsenal for calendar year 1995. This involved subtracting all identified steam consumption and steam losses from the total natural gas consumption for the Arsenal. Steam consumption at PBA includes process heating, process humidification and comfort heating. Steam losses include condensate leaks, thermal losses due to conduction and convection, system (boiler) efficiency and steam leaks.

A total of 104 steam leaks were identified along the steam distribution piping in Areas 31, 32, 33 and 34 and the heat trace piping for the white phosphorus area. The calculated losses due to steam leaks in these areas is about 14,000 MBtu per month. The total annual energy and cost savings achieved by eliminating the steam leaks is 168,000 MBtu and $472,000, respectively.

The methods used for identifying and calculating the natural gas consumption for all of the identified users and losses are described in Section 3.2. The detailed calculations, assumptions and back-up data for estimating the energy loss due to steam leaks are contained in Appendix A.4. A summary of these calculations along with the cost estimates and back-up data for this ECO are contained in Appendix A.5.

The cost estimate for Option A assumes all 104 leaking valves, fittings and steam traps will be removed and replaced. An additional 24 leaks were assumed for the above ground tanks which were not operating during the survey. Some of the leaks can be eliminated by tightening or repairing the items, however, the cost estimate used replacement equipment to be conservative. The cost estimate also includes removal and disposal of the existing asbestos insulation and installation of new fiberglass insulation.

Option B assumes the existing piping will be removed and the new steam piping will be installed on the same poles. The new piping design calls for the main distribution pipes to run about five feet above the ground. This will allow much better access for maintenance, repairs and valve adjustments. The pipes will be raised to about 15 feet high where they cross roads and railroad tracks. A substantial portion of the cost of the new piping system is for asbestos removal and disposal.

__Results__

	Option A	Option B
Construction Costs	$77,920	$5,647,000
Annual Energy Savings (Increase)		
Electricity (MBtu/Year)	0	0
Natural Gas (MBtu/Year)	168,000	168,000
Total (MBtu/Year)	168,000	168,000
Annual Cost Savings (Increase)		
Electricity ($/Year)	$0	$0
Natural Gas ($/Year)	$472,080	$472,080
Operation & Maintenance ($/Year)	$0	$0
Total Cost Savings ($/Year)	$472,080	$472,080
Savings to Investment Ratio	113	1.55
Simple Payback Period (Years)	0.2	12.0

__Recommendations__

Based on the life cycle cost analysis Option A of this project is recommended.

ECO-H2

Modifications and improvements to boilers in Building 32-060.

Option A - Install new boilers with turbulators, O_2 trim, economizers, etc.

Option B - Improve efficiency of existing boilers.

Option C - Install surplus boilers and add economizers.

Option D - Install economizers on surplus boilers.

Description - Option A

The existing boilers will be removed and two new fire tube boilers of the same capacity and pressure will be installed. The new boilers will be equipped with turbulators, O_2 trim and economizers. The burner controls and combustion controls will be fully automatic and fully modulating to maintain optimum efficiency when operating between ten percent load and full load.

Analysis - Option A

The existing boilers were originally installed in 1942 during the beginning of World War II. The burners were replaced about 20 years ago but were never properly adjusted. The current combustion controls result in high excess air operation and excessive fuel consumption at the typical operating load of the boilers. Field tests at various operating loads indicate the excess air for these boilers ranges from 72 percent to 191 percent. Depending on their load, these boilers are currently operating at efficiencies ranging from 72 percent to 77 percent. The calculated annual average efficiency based on the annual average load factor for these boilers is about 74 percent. The new boilers will be equipped with O_2 trim to optimize the fuel-to-air ratio. These controls will allow the new boilers to operate at an efficiency of about 80 percent.

Economizers will also be included with the new boilers to maintain the exhaust gas temperature at about 250 degrees F over the boiler's entire operating load range. Fire tube boilers typically have exhaust gas temperatures that range between 50 degrees F to 150 degrees F above the saturation temperature corresponding to their operating pressure. PBA operates the boilers at a pressure of about 130 psig. The corresponding saturation temperature would be 355 degrees F, and the exit gas temperature should be between 405 degrees F and 505 degrees F. The economizer can reduce the exhaust gas temperature to 250 degrees F. Boiler efficiency increases about one percent for every 40 degrees F reduction in exhaust gas temperature. Therefore, the boilers will pick up four to six efficiency points by adding an economizer.

Description - Option B

An adjustable cam kit will be purchased and installed on each boiler. The cams are positioned in the connecting link between the burner jack shaft and the forced draft inlet vane. After they are installed, the cams will be set up to provide proper proportioning of the air and fuel over the entire operating load range of the boilers.

Analysis - Option B

The existing connecting links between the burner jack shaft and the forced draft fan do not permit proper adjustment of the air-to-fuel ratio over the operating load range of the boiler. As a result the boilers are currently operating with far too much excess air. Field tests at various operating loads indicate the excess air for these boilers ranges from 72 percent to 191 percent. The normal, and most efficient, operating range is 10 percent to 15 percent excess air. The high excess air amounts are reducing the operating efficiency of these boilers by three to eight percent.

Depending on their load, these boilers are currently operating at efficiencies ranging from 72 percent to 77 percent. The calculated annual average efficiency based on the annual average load factor for these boilers is about 74 percent. Installation of the adjustable cam will maintain the residual stack gas O_2 concentration at about 1.7 percent and the excess air at approximately 10 percent when firing natural gas. This retrofit will allow the boilers to operate at an efficiency of about 80 percent over their entire operating load range.

Description - Option C

This option consist of installing two 600 hp, surplus fire tube boilers, with economizers. A new concrete slab and metal-sided building to house these boilers will be built next to Building 32-060. After the boilers are installed, they will be tied into the main steam header system and the boilers in Building 32-060 will be shut down.

Analysis - Option C

As discussed in Option A, the existing boilers were installed in 1942 and operate at approximately 74 percent efficiency. Field data showed the existing boilers are operating with excess air values well above the recommended range. Excess air values ranging from 72 percent to 191 percent and exit gas temperatures ranging from 394 degrees F to 471 degrees F were observed.

The Arsenal has already purchased, and has on site, two new York Shipley, 600 hp, fire tube boilers, with stacks. The cost estimate for this replacement project includes installation of economizers and all other necessary peripheral equipment.

Proper fuel-to-air proportioning control will allow the surplus boilers to operate at an efficiency of about 80 percent. Adding an economizer and a stack gas temperature control loop to maintain the stack temperature at 250 degrees F will raise the operating efficiency to approximately 86 percent.

Description - Option D

This option consist of installing economizers on the two 600 hp, York-Shipley boilers after they are installed in Building 32-060. The top portion of the stacks will be removed, the economizers and all necessary boiler feedwater piping, valves and controls will be installed to allow the boiler feedwater to be heated by the hot combustion gases. The stacks will be reinstalled and the roof around the stacks will be repaired where required.

Analysis - Option D

During the course of preparing this report, demolition of the existing boilers and preparation for installing the surplus boilers was started. This option was added and analyzed because the current construction contact for the boiler replacement project does not include the purchase and installation of economizers.

The energy savings calculations assume adding an economizer and a stack gas temperature control loop to maintain the stack temperature at 250 degrees F will raise the operating efficiency of the York-Shipley boilers from about 80 percent to approximately 85 percent.

Results

	Option A	Option B	Option C	Option D
Construction Costs	$651,660	$7,140	$298,100	$85,810
Annual Energy Savings (Increase)				
Electricity (MBtu/Year)	0	0	0	0
Natural Gas (MBtu/Year)	12,914	6,457	12,914	5,381
Total (MBtu/Year)	12,914	6,457	12,914	5,381
Annual Cost Savings (Increase)				
Electricity ($/Year)	$0	$0	$0	$0
Natural Gas ($/Year)	$36,290	$18,140	$36,290	$15,120
Operation & Maintenance ($/Year)	$8,320	$0	$8,320	$0
Total Cost Savings ($/Year)	$44,610	$18,140	$44,610	$15,120
Savings to Investment Ratio	1.22	47.2	2.68	3.27
Simple Payback Period (Years)	14.6	0.4	6.7	5.7

Recommendations

Due to progress on the boiler replacement project, the payback period for Option B is longer than the equipment will be utilized and Option C is no longer applicable. Therefore, these options are not recommended. Based on the life cycle cost analysis, Option D is recommended.

ECO-H3

Modifications and improvements to boilers in Building 33-060.

Option A - Install new boilers with turbulators, O_2 trim, economizers, etc.

Option B - Improve efficiency of existing boilers.

Option C - Install economizers on existing boilers.

Description - Option A

The existing boilers will be removed and two new fire tube boilers of the same capacity and pressure will be installed. The new boilers will be equipped with turbulators, O_2 trim and economizers. The burner controls and combustion controls will be fully automatic and fully modulating to maintain optimum efficiency when operating between ten percent load and full load.

Analysis - Option A

These boilers are identical to the boilers in Building 32-060. The existing boilers were originally installed in 1942 during the beginning of World War II. The burners were replaced about 20 years ago but were never properly adjusted. The current combustion controls result in high excess air operation and excessive fuel consumption at the typical operating load of the boilers. Field tests at various operating loads indicate the excess air for these boilers ranges from 72 percent to 191 percent. Depending on their load, these boilers are currently operating at efficiencies ranging from 72 percent to 77 percent. The calculated annual average efficiency based on the annual average load factor for these boilers is about 75 percent. The new boilers will be equipped with O_2 trim to optimize the fuel-to-air ratio. These controls will allow the new boilers to operate at an efficiency of about 80 percent.

Economizers will also be included with the new boilers to maintain the exhaust gas temperature at about 250 degrees F over the boiler's entire operating load range. Fire tube boilers typically have exhaust gas temperatures that range between 50 degrees F to 150 degrees F above the saturation temperature corresponding to their operating pressure. PBA operates the boilers at a pressure of about 130 psig. The corresponding saturation temperature would be 355 degrees F, and the exit gas temperature should be between 405 degrees F and 505 degrees F. The economizer can reduce the exhaust gas temperature to 250 degrees F. Boiler efficiency increases about one percent for every 40 degrees F reduction in exhaust gas temperature. Therefore, the boilers will pick up four to six efficiency points by adding an economizer.

Description - Option B

An adjustable cam kit will be purchased and installed on each boiler. The cams are positioned in the connecting link between the burner jack shaft and the forced draft inlet vane. After they are installed, the cams will be set up to provide proper proportioning of the air and fuel over the entire operating load range of the boilers.

Analysis - Option B

The existing connecting links between the burner jack shaft and the forced draft fan do not permit proper adjustment of the air-to-fuel ratio over the operating load range of the boiler. As a result the boilers are currently operating with far too much excess air. Field tests at various operating loads indicate the excess air for these boilers ranges from 72 percent to 191 percent. The normal, and most efficient, operating range is 10 percent to 15 percent excess air.

The high excess air amounts are reducing the operating efficiency of these boilers by three to eight percent. Depending on their load, these boilers are currently operating at efficiencies ranging from 72 percent to 77 percent. The calculated annual average efficiency based on the average annual load factor for these boilers is about 75 percent. Installation of the adjustable cam will maintain the residual stack gas O_2 concentration at about 1.7 percent and the excess air at approximately 10 percent when firing natural gas. This retrofit will allow the boilers to operate at an efficiency of about 80 percent over their entire operating load range.

Description - Option C

This project consists of retrofitting the existing boilers with economizers. The ductwork from each boilers and the plenum will be removed. Some asbestos abatement will be required during this effort. New individual stacks, economizers, piping, valves and controls will be installed for each boiler. The boiler house roof will be repaired after construction of the new stacks is completed.

Analysis - Option C

Installing economizers with the existing configuration (a common plenum and separate stacks) would require a new larger plenum to reduce pressure drop, local roof reinforcement and the addition of isolation dampers at the plenum penetration point from each boiler for gas side maintenance including the economizer. A more desirable configuration is to keep the gas streams from the boilers separate from each other by installing a individual stack for each boiler.

The energy savings calculations assume adding an economizer and a stack gas temperature control loop to maintain the stack temperature at 250 degrees F will raise the operating efficiency of the existing boilers from about 80 percent to approximately 85 percent.

Results

	Option A	Option B	Option C
Construction Costs	$651,660	$7,140	$132,070
Annual Energy Savings (Increase)			
Electricity (MBtu/Year)	0	0	0
Natural Gas (MBtu/Year)	9,074	4,125	3,919
Total (MBtu/Year)	9,074	4,125	3,919
Annual Cost Savings (Increase)			
Electricity ($/Year)	$0	$0	$0
Natural Gas ($/Year)	$25,500	$11,590	$11,010
Operation & Maintenance ($/Year)	$8,320	$0	$0
Total Cost Savings ($/Year)	$33,820	$11,590	$11,010
Savings to Investment Ratio	0.92	30.2	1.55
Simple Payback Period (Years)	19.3	0.6	12.0

Recommendations

Based on the life cycle cost analysis, Option B of this project is recommended.

ECO-H4

Modifications and improvements to boilers in Building 34-140.

Option A - Install new boilers with turbulators, O_2 trim, economizers, etc.

Option B - Improve efficiency of existing boilers.

Option C - Install economizers on existing boilers.

Description - Option A

The existing boilers will be removed and three new fire tube boilers of the same capacity and pressure will be installed. The new boilers will be equipped with turbulators, O_2 trim and economizers. The burner controls and combustion controls will be fully automatic and fully modulating to maintain optimum efficiency when operating between ten percent load and full load.

Analysis - Option A

The existing boilers were originally installed in 1942 during the beginning of World War II. The burners have been replaced but were never properly adjusted. The current combustion controls result in high excess air operation and excessive fuel consumption at the typical operating load of the boilers. Field tests at various operating loads indicate the excess air for these boilers ranges from 34 percent to 226 percent. Depending on their load, these boilers are currently operating at efficiencies ranging from 59 percent to 73 percent. The calculated annual average efficiency based on the annual average load factor for these boilers is about 72 percent. The new boilers will be equipped with O_2 trim to optimize the fuel-to-air ratio. These controls will allow the new boilers to operate at an efficiency of about 80 percent.

Economizers will also be included with the new boilers to maintain the exhaust gas temperature at about 250 degrees F over the boiler's entire operating load range. Fire tube boilers typically have exhaust gas temperatures that range between 50 degrees F to 150 degrees F above the saturation temperature corresponding to their operating pressure. PBA operates the boilers at a pressure of about 130 psig. The corresponding saturation temperature would be 355 degrees F, and the exit gas temperature should be between 405 degrees F and 505 degrees F. The economizer can reduce the exhaust gas temperature to 250 degrees F. Boiler efficiency increases about one percent for every 40 degrees F reduction in exhaust gas temperature. Therefore, the boilers will pick up four to six efficiency points by adding an economizer.

Description - Option B

This project consists of installing air-fuel controls and a deaerator for the boilers in Building 34-140. An adjustable cam kit will be purchased and installed on each boiler. The cams are positioned in the connecting link between the burner jack shaft and the forced draft inlet vane. After they are installed, the cams will be set up to provide proper proportioning of the air and fuel over the entire operating load range of the boilers. This project also includes installing a 900 gallon deaerator mounted on a ten-foot tall stand. The existing feed water heat exchanger will be removed, including asbestos abatement, and the new deaerator will be connected to the existing boilers.

Analysis - Option B

The existing connecting links between the burner jack shaft and the forced draft fan do not permit proper adjustment of the air-to-fuel ratio over the operating load range of the boiler. As a result the boilers are currently operating with far too much excess air. Field tests at various operating loads indicate the excess air for these boilers ranges from 34 percent to 226 percent. The normal, and most efficient, operating range is 10 percent to 15 percent excess air. The high excess air amounts are reducing the operating efficiency of these boilers by seven to 21 percent. Depending on their load, these boilers are currently operating at efficiencies ranging from 59 percent to 73 percent. The calculated annual average efficiency based on the average annual load factor for these boilers is about 72 percent. Installation of the adjustable cam will maintain the residual stack gas O_2 concentration at about 1.7 percent and the excess air at approximately 10 percent when firing natural gas. This retrofit will allow the boilers to operate at an efficiency of about 80 percent over their entire operating load range.

The existing feed water heater was designed to recover heat from the steam exhausted from the boiler feed pump turbines. When the turbine driven boiler feed pumps are operating they consume approximately 725 pounds of steam per hour. The exhaust steam, if completely condensed, would raise the feed water temperature from 65 degrees F to 77.5 degrees F. The turbine driven feed water pumps are not operating, so steam is admitted directly to the heater to warm the feed water. The control system tries to maintain the feed water temperature at about 230 degrees F which requires up to 10,130 pounds of steam per hour. Under these conditions the heater is well overloaded resulting in continual water hammer and steam venting.

The steam vents to the atmosphere continuously and represents a major energy loss from the feed water heating process. No direct measurements of the venting steam could be made. Based on observations, the steam velocity from the 6 inch diameter heater vent pipe was estimated to be about five feet per second. Calculations indicate installing a deaerator will provide a natural gas savings of approximately 1,936 MBtu per year.

Description - Option C

This project consists of retrofitting the existing boilers with economizers. The ductwork from each boilers and the plenum will be removed. Some asbestos abatement will be required during this effort. New individual stacks, economizers, piping, valves and controls will be installed for each boiler. The boiler house roof will be repaired after construction of the new stacks is completed.

Analysis - Option C

Installing economizers with the existing configuration (a common plenum and separate stacks) would require a new larger plenum to reduce pressure drop, local roof reinforcement and the addition of isolation dampers at the plenum penetration point from each boiler for gas side maintenance including the economizer. A more desirable configuration is to keep the gas streams from the boilers separate from each other by installing a individual stack for each boiler.

The energy savings calculations assume adding an economizer and a stack gas temperature control loop to maintain the stack temperature at 250 degrees F will raise the operating efficiency of the existing boilers from about 80 percent to approximately 85 percent.

Results

	Option A	Option B	Option C
Construction Costs	$846,850	$72,470	$195,550
Annual Energy Savings (Increase)			
Electricity (MBtu/Year)	0	0	0
Natural Gas (MBtu/Year)	18,761	12,657	6,164
Total (MBtu/Year)	18,761	12,657	6,164
Annual Cost Savings (Increase)			
Electricity ($/Year)	$0	$0	$0
Natural Gas ($/Year)	$52,720	$35,570	$17,320
Operation & Maintenance ($/Year)	$8,320	$0	$0
Total Cost Savings ($/Year)	$61,040	$35,570	$17,320
Savings to Investment Ratio	1.30	9.12	1.65
Simple Payback Period (Years)	13.9	2.0	11.3

Recommendations

Based on the life cycle cost analysis, Option B is recommended. An ECIP project is pending that will provide a new building and new boilers for the white phosphorus area. If the new boiler project will not be completed within the next few years, Option B should still be implemented. A deaerator should be also be included in the pending boiler replacement project.

ECO-H5

Modifications and improvements to boilers in Building 42-960.

Option A - Install new boilers with turbulators, O_2 trim, economizers, etc.

Option B - Improve efficiency of existing boilers.

Description

The Scope of Work listed the above ECO project options for these boilers. Based on the discussion in the following paragraph, these projects were not considered for further evaluation.

Analysis

The existing boilers are about 18 years old. Field measurements indicate they are operating at about nine percent excess air and the calculated operating efficiency is approximately 79 percent. Adding an economizer to the existing boilers or installing new boilers with an economizer would improve the efficiency slightly. However, these boilers are only operated to provide space heating for the buildings in the incinerator area and a slight improvement in boiler efficiency would not produce much energy savings.

Results

A life cycle cost analysis was not performed for this ECO.

Recommendations

The existing boilers are in good condition and operating efficiently, therefore, Option A and Option B are not recommended.

ECO-H6

Modifications and improvements to CB boiler (Unit No. 2) in Building 44-120.

Option A - Install new boiler with turbulators, O_2 trim, economizers, etc.

Option B - Improve efficiency of existing boiler.

Description

The Scope of Work listed the above ECO project options for this boiler. Based on the discussion in the following paragraph, these projects were not considered for further evaluation.

Analysis

The calculated natural gas consumption and cost for this boiler are about 4,330 MBtu per year and $12,200 per year, respectively. Field measurements indicate this boiler is operating at about 29 percent excess air and the calculated efficiency was about 84 percent. Adding an economizer or a new boiler with an economizer might improve the efficiency slightly. However, operating this boiler at an efficiency of 85 percent would only save about 50 MBtu and $140 per year.

Results

A life cycle cost analysis was not performed for this ECO.

Recommendations

The existing boiler is only about seven years old, in good condition and operating efficiently, therefore, Option A and Option B are not recommended.

ECO-C1

Utilize the two surplus Gardner-Denver air compressors.

Option A - Replace two existing compressors with the surplus compressors.

Option B - Add the surplus compressors in line with the existing compressors.

Description - Option A

This project consist of removing two of the existing compressors that are located in Buildings 32-060, 33-060 and 34-140, installing the two new surplus compressors that have already been purchased, and connecting them to the main compressed air distribution system.

Description - Option B

This project consist of installing the two new surplus compressors in addition to the existing compressors that are located in Buildings 32-060, 33-060 and 34-140, and connecting the new compressors to the main compressed air distribution system.

Analysis

There are currently two Ingersoll-Rand model XLE air compressors in each of the three boiler houses. These compressors are designed to supply 825 cubic feet of air per minute (CFM) at a pressure of 130 pounds per square inch gage (psig). The motors are 150 horsepower and 173 horsepower, low-speed (600 rpm), synchronous type.

PBA has already purchased two model MCYMH air compressors manufactured by Gardner-Denver. Each of these compressors utilizes a 150 horsepower, 1800 rpm, high efficiency induction motor and is designed to supply air at a flow rate of 600 CFM. Option A, which calls for replacing two of the existing compressors, would reduce the compressed air production capacity of the central system by approximately 450 CFM. Option B, which would add the surplus compressors to the existing compressors, would increase the compressed air production capacity of the central system by about 1200 CFM.

Electric demand kW was calculated for the Gardner-Denver and Ingersoll-Rand compressors. The demand kW for each compressor was then divided by that compressors rated air output to determine their electric energy requirements per CFM of compressed air supplied. The existing Ingersoll-Rand model XLE compressors have a calculated electric energy demand of 0.18 kW per CFM. The new Gardner-Denver model MCYMH compressors have a calculated electric energy demand of 0.20 kW per CFM. These values show that for a given compressed air supply requirement, the energy use would increase if the new surplus air compressors were installed and operated.

Results

The calculated energy requirements of the new Gardner-Denver model MCYMH air compressors are higher than those of the existing Ingersoll-Rand model XLE compressors. Assuming the surplus compressors were installed and only operated during production hours, the estimated annual increase in energy consumption is 107.4 MBtu per year. The increase in energy cost would be about $2,860 per year.

The estimated annual maintenance savings would be about $1,040 per compressor or a total of $2,080 per year. Based on these preliminary calculations there would be a net increase in annual operating cost if the surplus compressors were installed and operated, so a life cycle cost analysis was not performed.

Recommendations

The annual operating cost for producing compressed air would increase if the new surplus air compressors were installed and operated, therefore, Option A and Option B of this project are not recommended.

ECO-C2

Replace the existing air compressors with more efficient compressors.

Description

This project involves removing the existing compressors that are located in Buildings 32-060, 33-060 and 34-140, installing new more efficient compressors, and connecting the new compressors to the main compressed air distribution system.

Analysis

There are currently two Ingersoll-Rand model XLE, double acting, reciprocating air compressors in each of the three boiler houses. These compressors are designed to supply 825 cubic feet of air per minute (CFM) at a pressure of 130 pounds per square inch gage (psig). The motors are 150 horsepower and 173 horsepower, low-speed (600 rpm), synchronous type. According to an air compressor sales and service company, the model XLE is the most efficient compressor ever made for air supply rates of less than 3,000 CFM.

Data contained in Compressed Air Systems - A Guidebook on Energy and Cost Savings, by E. M. Talbott, indicate that double acting, reciprocating compressors in the 100 to 200 horsepower range use less energy per CFM than other types of compressors within the same size range. The existing model XLE compressors were compared to a new model MCYMH air compressor manufactured by Gardner-Denver. The model MCYMH is a reciprocating type compressor that utilizes a 150 horsepower, 1800 rpm, high-efficiency induction motor and is designed to supply air at a flow rate of 600 CFM.

Full load electric demand kW was calculated for the new Gardner-Denver compressors using motor data obtained from PBA. The full load electric demand kW was calculated for existing Ingersoll-Rand compressors using information obtained from the motor nameplate. The calculated full load demand kW for each compressor was then divided by that compressor's rated air output to determine its relative efficiency.

Results

The estimated efficiency of the existing Ingersoll-Rand model XLE air compressors is greater than the calculated efficiency of the new Gardner-Denver model MCYMH compressors. The existing Ingersoll-Rand model XLE compressors (with 173 horsepower motors) have a calculated efficiency of 0.18 kW per CFM. The new Gardner-Denver model MCYMH compressors have a calculated efficiency of 0.20 kW per CFM. These efficiency values show that for a given compressed air flow rate, the energy use would increase if new air compressors were installed and operated.

Recommendations

Information from a compressor service representative, a book on compressed air systems and the comparison of calculated efficiencies show the energy efficiency of the existing compressors is as good or better than other available compressors. Therefore, this project is not recommended.

ECO-C3

Modifications and improvements to the compressed air system.

Option A - Install dedicated air compressors at the end use buildings.

Option B - Install new compressed air distribution piping.

Option C - Repair existing compressed air pipe and fittings.

Description - Option A

This project consists of installing 19 new air compressor packages (including the two new surplus compressor packages that have already been purchased) next to the buildings that require compressed air. The compressed air packages include compressor; motor; v-belt drive; solid state programmable controls; temperature gages; regulator; aftercooler; inlet filter/silencer; outlet filter and dryer; connections for air, electricity and water; and a small shed on a concrete slab. The existing compressors located in Buildings 32-060, 33-060 and 34-140 and the main compressed air distribution system will remain in place and be utilized for emergency and maintenance back-up purposes.

Analysis - Option A

According to the CDG Utility Study, a total of 17 buildings use compressed air for process requirements. Three of these buildings are in layaway and three others only require 10 CFM. Multiple compressors are required at some of the remaining 11 buildings so a total of 19 new compressors must be installed to eliminate the need for the existing compressors and main compressed air distribution system. PBA has already purchased two 600 CFM air compressors manufactured by Gardner-Denver. These will be utilized along with eight new 600 CFM, six new 200 CFM and three new 100 CFM compressor packages.

Installing individual compressors at each building that requires compressed air would eliminate the losses due to compressed air leaks, provide better quality supply air and offer greater flexibility to accommodate changing production schedules. Due to the age of the existing compressors, the economic analysis assumes the additional maintenance costs for having more new compressors will be offset by the cost of maintaining the existing old compressors over the next 20 years.

The electric energy consumption required to produce a given amount of compressed air increases with the new air compressors. However, the reduction in air requirements and operating time due to the elimination of compressed air leaks would provide an overall energy savings of approximately $85,000 per year.

Description - Option B

This project consist of installing new compressed air distribution piping from the compressors in Buildings 32-060, 33-060 and 34-140 to the point of connection to all of the facilities currently served by the existing system. The new piping will be utilize the existing pipe supports. The work also includes demolition of the existing compressed air piping system.

Analysis - Option B

There are currently two Ingersoll-Rand model XLE air compressors in each of the three boiler houses. These compressors supply about 825 cubic feet of air per minute (CFM) at a pressure of 120 pounds per square inch gage (psig). With all six of the existing compressors operational, the total compressed air supply capacity is approximately 4950 CFM.

Discussions with the air compressor operating staff indicated between two and three compressors operate during non-production times and between four and six of the compressors will operate during production times. Since very little process air is required during non-production hours, the analysis assumes one compressor operates at full load and one compressor operates at half load during this time to supply leaks in the distribution system. Energy and cost savings are based on reduced compressor air supply requirements due to elimination of the leaks in the distribution system.

Description - Option C

This project consist of repairing and/or replacing all of the failed valves, fittings and pipe sections on the existing air distribution piping system served by the compressors in Buildings 32-060, 33-060 and 34-140.

Analysis - Option C

The energy and cost savings analysis for this option are the same as described for Option B. A comprehensive survey of the compressed air lines was not included in the Scope of Work for this study, however, many compressed air leaks were observed during the survey of the steam distribution system. The analysis uses the air flow from a 1/16 inch diameter leak to calculate the number of leaks in the system. The project construction cost was then calculated based on the calculated number of leaks.

Results

	Option A	Option B	Option C
Construction Costs	$1,478,710	$1,389,140	$83,680
Annual Energy Savings (Increase)			
Electricity (MBtu/Year)	5060.9	5847.3	5847.3
Natural Gas (MBtu/Year)	0	0	0
Total (MBtu/Year)	5060.9	5847.3	5847.3
Annual Cost Savings (Increase)			
Electricity ($/Year)	$84,970	$98,180	$98,180
Natural Gas ($/Year)	$0	$0	$0
Operation & Maintenance ($/Year)	$0	$0	$0
Total Cost Savings ($/Year)	$84,970	$98,180	$98,180
Savings to Investment Ratio	0.87	1.07	17.7
Simple Payback Period (Years)	17.4	14.2	0.9

Recommendations

Based on the life cycle cost analysis, Option C of this project is recommended. In the future, if the production staff decides some of the buildings do not need as much compressed air as indicated in the CDG Utility Study, Option A should be evaluated again.

5.0 RESULTS AND RECOMMENDATIONS

5.1 SUMMARY OF ECO'S

The purpose of this study is to conduct a detailed analysis of the boilers, air compressors and large electric motors in the production areas of PBA and develop projects to improve the efficiency of these systems. Table 5.1-1 lists all ECO's that were considered for this study. All of the ECO's that were eliminated from consideration prior to performing life cycle cost evaluations are indicated in this table along with the reasons for their elimination.

Table 5.1-1 Summary of Energy Conservation Opportunities

ECO No.	Description of ECO	Evaluated	Comments
Electrical Load Reduction			
E1	Replace synchronous motors for compressors.	No	Efficient sync. motors not available. See p. 4-3
E2	Replace WP scrubber/exhaust motors.	Yes	
E3	Replace primary water pump motors.	Yes	
E4	Replace filtered water pump motors.	Yes	
E5	Replace incinerator scrubber fan motor.	Yes	
E6	Reduce Contracted Demand Limit	No	Electric rate does not have a demand limit.
Steam Production and Distribution System			
H1-A	Repair existing steam pipe and fittings.	Yes	
H1-B	Install new steam distribution piping system.	Yes	
H2-A	Bldg. 32-060 - Install new boilers.	Yes	
H2-B	Bldg. 32-060 - Improve efficiency of existing boilers.	Yes	
H2-C	Bldg. 32-060 - Install surplus boilers.	Yes	
H2-D	Bldg. 32-060 - Install economizers on surplus boilers.	Yes	
H3-A	Bldg. 33-060 - Install new boilers.	Yes	
H3-B	Bldg. 33-060 - Improve efficiency of existing boilers.	Yes	
H3-C	Bldg. 33-060 - Install economizers on existing boilers.	Yes	
H4-A	Bldg. 34-140 - Install new boilers.	Yes	
H4-B	Bldg. 34-140 - Improve efficiency of existing boilers.	Yes	
H4-C	Bldg. 34-140 - Install economizers on existing boilers.	Yes	
H5-A	Bldg. 42-960 - Install new boilers.	No	Boilers are operating efficiently. See p. 4-23
H5-B	Bldg. 42-960 - Improve efficiency of existing boilers.	No	Boilers are operating efficiently. See p. 4-23
H6-A	Bldg. 44-120 - Install new boiler.	No	Boiler is operating efficiently. See p. 4-24
H6-B	Bldg. 44-120 - Improve efficiency of existing boiler.	No	Boiler is operating efficiently. See p. 4-24
Compressed Air System			
C1-A	Replace existing compressors with surplus units.	No	Surplus units use more energy. See p. 4-25
C1-B	Add surplus compressors to existing compressors.	No	Surplus units use more energy. See p. 4-25
C2	Replace exist. compressors with more efficient units.	No	Existing units are very efficient. See p. 4-27
C3-A	Install dedicated compressors at the buildings.	Yes	
C3-B	Install new compressed air distribution piping system.	Yes	
C3-C	Repair existing compressed air pipe and fittings.	Yes	

5.2 RESULTS OF ECO EVALUATIONS

The ECO evaluations included energy and labor savings calculations, cost estimates and economic analyses. Table 5.2-1 provides a summary of the results for all of the ECO evaluations. This table lists the evaluated ECO's in order of ECO Number.

Table 5.2-1 Summary of Results of ECO Evaluations

ECO No.	Total Project Cost $	SIR	Simple Payback Years	N. Gas Savings MBtu/Yr	Electric Savings MBtu/Yr	Total Savings MBtu/Yr	N. Gas Savings $/Year	Electric Savings $/Year	O & M Savings $/Year	Total Savings $/Year
E2	117,540	0.36	41.4	0	168.9	169	0	2,840	0	2,840
E3	26,700	1.16	13.0	0	122.6	123	0	2,060	0	2,060
E4	8,320	2.09	7.2	0	68.8	69	0	1,160	0	1,160
E5	21,230	1.56	9.7	0	131.0	131	0	2,200	0	2,200
H1-A	77,920	113	0.2	168,000	0	168,000	472,080	0	0	472,080
H1-B	5,647,000	1.55	12.0	168,000	0	168,000	472,080	0	0	472,080
H2-A	651,660	1.22	14.6	12,914	0	12,914	36,290	0	8,320	44,610
H2-B	7,140	47.2	0.4	6,457	0	6,457	18,140	0	0	18,140
H2-C	298,100	2.68	6.7	12,914	0	12,914	36,290	0	8,320	44,610
H2-D	85,810	3.27	5.7	5,381	0	5,381	15,120	0	0	15,120
H3-A	651,660	0.92	19.3	9,074	0	9,074	25,500	0	8,320	33,820
H3-B	7,140	30.2	0.6	4,125	0	4,125	11,590	0	0	11,590
H3-C	132,070	1.55	12.0	3,919	0	3,919	11,010	0	0	11,010
H4-A	846,850	1.30	13.9	18,761	0	18,761	52,720	0	8,320	61,040
H4-B	72,470	9.12	2.0	12,657	0	12,657	35,570	0	0	35,570
H4-C	195,550	1.65	11.3	6,164	0	6,164	17,320	0	0	17,320
C3-A	1,478,710	0.87	17.4	0	5060.9	5,061	0	84,970	0	84,970
C3-B	1,389,140	1.07	14.2	0	5847.3	5,847	0	98,180	0	98,180
C3-C	83,680	17.7	0.9	0	5847.3	5,847	0	98,180	0	98,180

5.3 RECOMMENDED ECO'S

ECO project funding criteria requires a savings to investment ratio (SIR) greater than 1.25 and a simple payback of less than 10 years. Based on this criteria, the results of the ECO evaluations were used to recommend projects for the heating system, compressed air system and some of the large electric motors at PBA. Table 5.3-1 lists all of the ECO's that meet the energy project funding criteria. The ECO's are listed in order of descending SIR along with the summary information from the ECO analyses.

Table 5.3-1 Summary of Recommended ECO's

ECO No.	Total Project Cost $	SIR	Simple Payback Years	N. Gas Savings MBtu/Yr	Electric Savings MBtu/Yr	Total Savings MBtu/Yr	N. Gas Savings $/Year	Electric Savings $/Year	O & M Savings $/Year	Total Savings $/Year
H1-A	77,920	113	0.2	168,000	0	168,000	472,080	0	0	472,080
H3-B	7,140	30.2	0.6	4,125	0	4,125	11,590	0	0	11,590
C3-C	83,680	17.7	0.9	0	5847.3	5,847	0	98,180	0	98,180
H4-B	72,470	9.12	2.0	12,657	0	12,657	35,570	0	0	35,570
H2-D	85,810	3.27	5.7	5,381	0	5,381	15,120	0	0	15,120
E4	8,320	2.09	7.2	0	68.8	69	0	1,160	0	1,160

These ECO's were recommended based on the results of the life cycle cost analyses. All of these ECO's have SIR's greater than 1.25 and simple paybacks of less than 10 years. The SIR and simple payback period for ECO-E5, ECO-H2B and ECO-H2C meet the requirements for recommended projects, however, the equipment for all of these ECO's will be abandoned before the payback period.

To qualify for funding under the Energy Conservation Investment Program (ECIP) the construction cost of a project must be greater than or equal to $300,000. There are no individual ECO's that meet the ECIP requirements for construction cost. A list of all recommended ECO's that qualify for non-ECIP funding is presented in Table 5.3-2.

Table 5.3-2 Summary of Non-ECIP Projects

ECO No.	Total Project Cost $	SIR	Simple Payback Years	N. Gas Savings MBtu/Yr	Electric Savings MBtu/Yr	Total Savings MBtu/Yr	N. Gas Savings $/Year	Electric Savings $/Year	O & M Savings $/Year	Total Savings $/Year
H1-A	77,920	113	0.2	168,000	0	168,000	472,080	0	0	472,080
H3-B	7,140	30.2	0.6	4,125	0	4,125	11,590	0	0	11,590
C3-C	83,680	17.7	0.9	0	5847.3	5,847	0	98,180	0	98,180
H4-B	72,470	9.12	2.0	12,657	0	12,657	35,570	0	0	35,570
H2-D	85,810	3.27	5.7	5,381	0	5,381	15,120	0	0	15,120
E4	8,320	2.09	7.2	0	68.8	69	0	1,160	0	1,160
Totals	335,340	NA	0.5	190,163	5916.1	196,079	534,360	99,340	0	633,700

The sum of the energy savings for all of the recommended ECO's provide a total natural gas savings of 190,163 MBtu per year and a total electric savings of 5,916 MBtu per year. If the projects that improve boiler efficiency (H2-D, H3-B AND H4-B) are completed before the steam leaks are fixed, the natural gas savings obtained by repairing the leaks in the steam distribution system (H1-A) will be reduced by approximately 15 percent.

Figures 5.3-1 and 5.3-2 compare the 1995 annual energy consumption and cost with the projected energy consumption and cost after the recommended ECO's are implemented. The natural gas energy consumption and cost are reduced by about 31 percent and the electric energy use and cost will be lowered by approximately 10 percent. The total annual energy consumption will be reduced from 670,983 MBtu to 474,904 MBtu. The total annual energy cost will be reduced from $2,698,530 to $2,064,430. The result is a total savings of about 196,079 MBtu per year and $633,700 per year or 29 percent of the current energy use and cost at PBA.

Based on direction from PBA, documentation for funding under the Federal Energy Management Program (FEMP) was prepared for the following projects:

1. ECO-H1A; Repair existing steam distribution system pipe and fittings.
2. ECO-H2D; Install economizers on surplus boilers in Building 32-060 combined with ECO-H3B; Improve efficiency of existing boilers in Building 33-060.
3. ECO-C3C; Repair existing compressed air system pipe and fittings.
4. ECO-E4; Replace filtered water pump motors in Building 42-210 with energy efficient motors.

The programming documentation for these projects is located in Volume IV of this report.

Figure 5.3-1

PBA Annual Energy Use Before and After ECO's

Electric Use is for Substations A & B Only

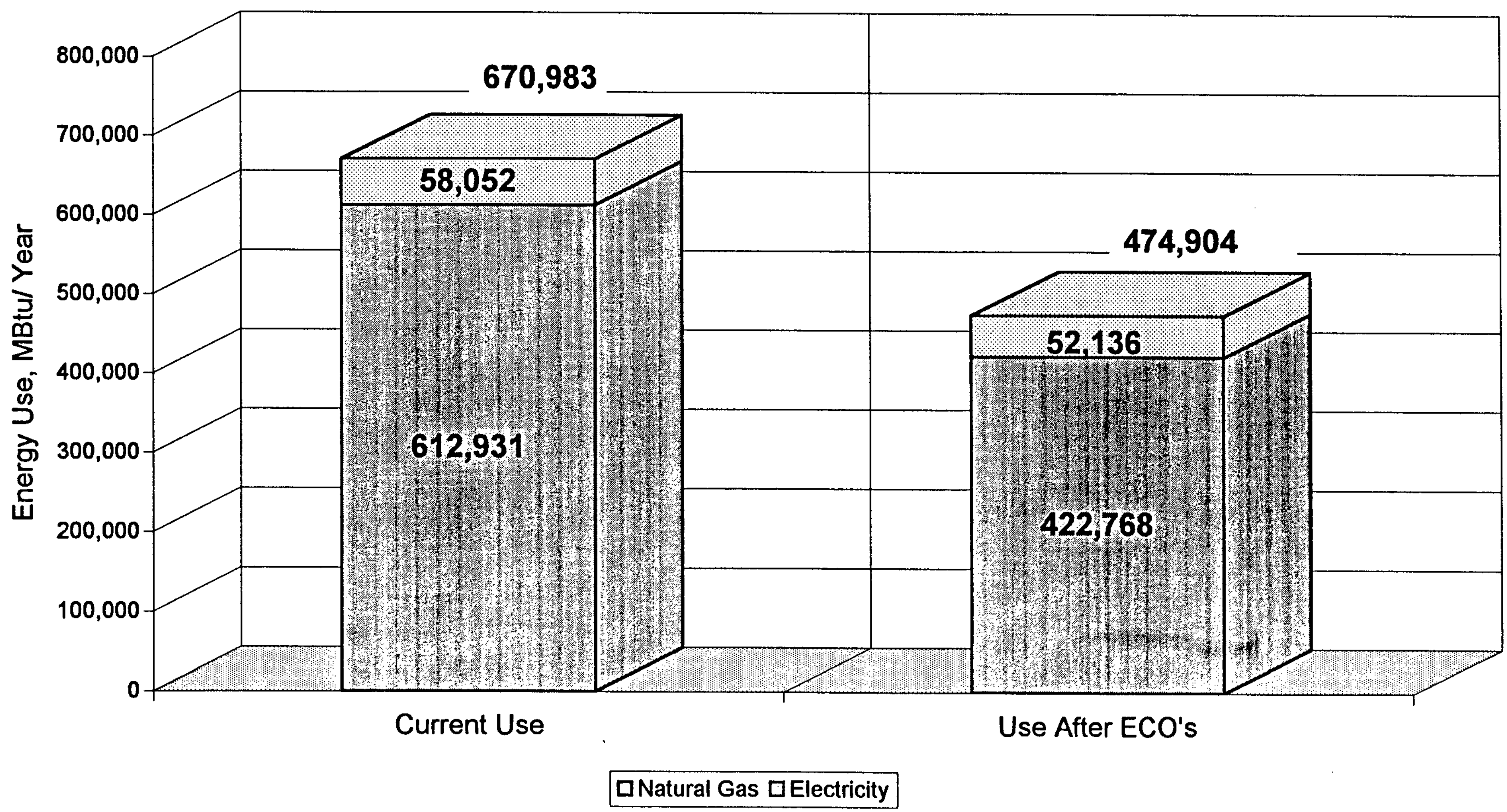
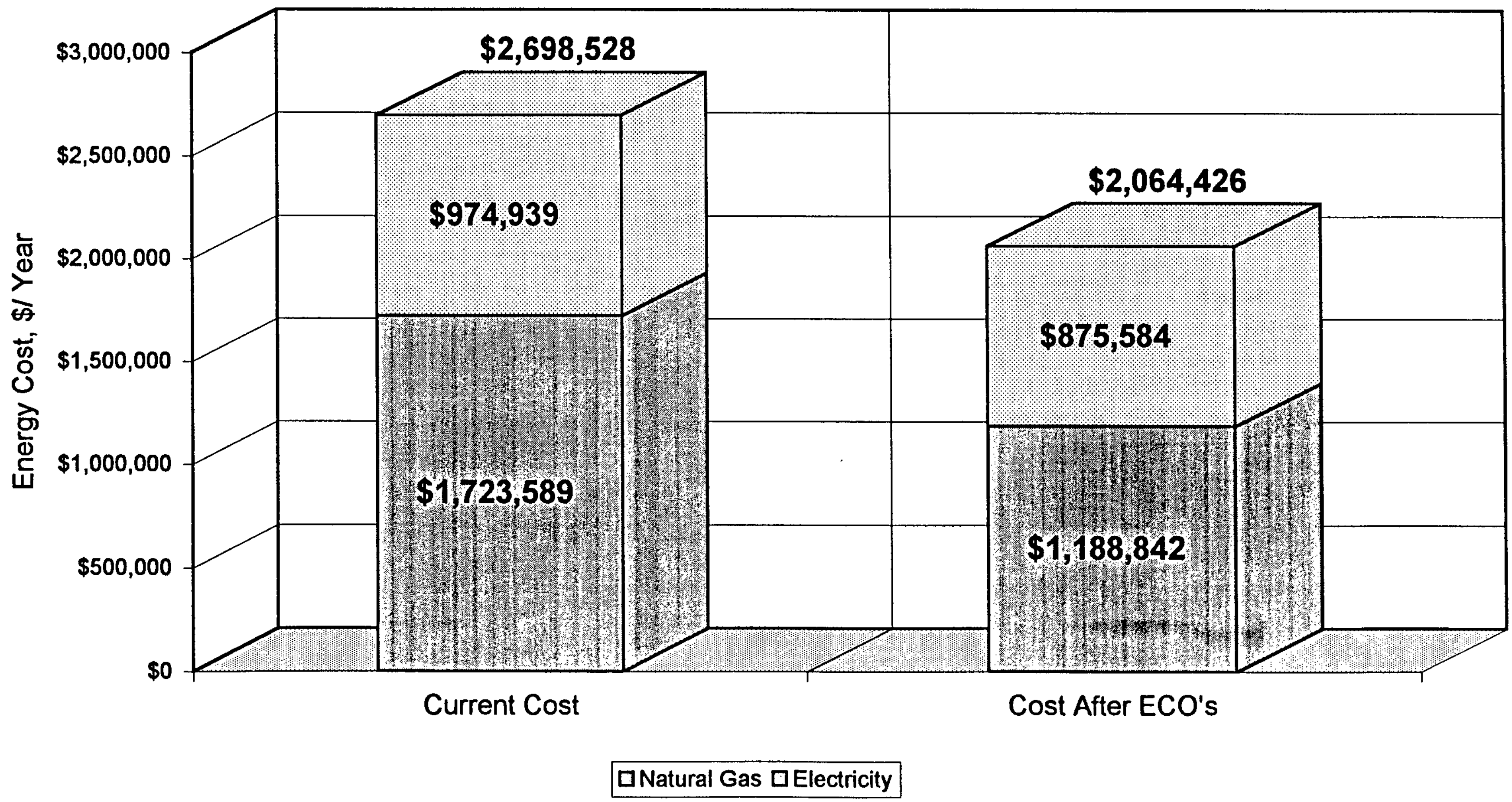


Figure 5.3-2
PBA Annual Energy Cost Before and After ECO's
Electricity Use is for Substations A & B Only



5.4 OPERATION AND MAINTENANCE RECOMMENDATIONS

Boiler Operations

1. Proper operation of the boilers at PBA has been neglected for some time. Communication and coordination between boiler operators and the production staff appears to be virtually non-existent. The steam consumers are unconcerned about their steam use because there is no penalty for squandering steam energy. No one appears to know exactly what system pressure should be maintained to meet the process equipment requirements. The entire system is currently being operated at 120 psig. Operation at 120 psig may not be necessary at all or it may only be required in order to service only one or two buildings. The lowest steam pressure that will produce successful Arsenal performance for winter and summer operations should be determined immediately. All energy losses due to conduction and leaks can be reduced by operation at lower pressures.

2. Repair or replace the stack gas O_2 meters. All of the boilers in buildings 32-060, 33-060, and 34-060 are equipped with stack O_2 measuring devices that indicate on the control panels residual O_2 concentrations in the stack. Unfortunately, none of the instruments are working properly. There is no single reading more important to the efficient operation of the boilers than stack gas O_2. All O_2 instruments should be refurbished and maintained in good working order. Boiler operators should be encouraged to operate with about 1.7 percent residual O_2 in the stack. All of the fuel will not be burned when operating below 1.7 percent. In addition to wasting costly fuel, operating with excess accumulations of unburned fuel in the boiler can cause boiler explosions. When operating above 1.7 percent O_2, the boiler efficiency suffers and energy and money are wasted. Approximately $70,000 was wasted in 1995 because the boilers are operating with too much air. If the operator cannot operate the boilers at the proper O_2 level the cause should be addressed immediately. The cost of natural gas for operating these boilers at full load is approximately $1000 per day.

3. Repair or replace the fuel flow meters. All of the natural gas meters serving buildings 32-060, 33-060, and 34-060 are broken. These meters should be restored to proper service as soon as possible. Each individual boiler should also be equipped with a fuel flow meter. These meters are invaluable in diagnosing problems, cross-checking the steam flow meters and allowing equal share participation of all boilers.

4. Install steam flow meters on all buildings that utilize process steam. The costs of producing a particular product should be known. Process energy is certainly a component of the cost of each product. The Arsenal has about 70 natural gas meters that are read and recorded

monthly. The fact that some energy is delivered in the form of steam does not negate the need to meter amount of energy consumed. Steam flow meters should be installed at every process building so that the proper energy costs may be readily attributed to the products produced. A method of billing or allocating energy costs should be determined and applied to all building occupants. This would provide some incentive for the Production Division to consolidate and conserve whenever possible.

Steam Distribution

1. Repair all steam leaks. Over $470,000 per year is being wasted due to about 128 steam leaks. These leaks are visible to everyone, especially during the winter. All visible or audible steam leaks, no matter how small, should be repaired as soon as possible. In addition to the steam leaks in the distribution lines the leaks in the individual buildings and mechanical equipment rooms should be repaired. Steam leaks were noted in Buildings 34-140 and 32-720.

2. Turn off the steam supply to the WP area whenever possible. Personnel in charge of WP production should keep the boiler operators informed of their production plans. Steam should never be turned on to the WP area without notifying the boiler operators about eight hours in advance and again about 30 minutes prior to opening the valves. This common courtesy will allow the boiler operators time to anticipate the increase in steam demand by putting another boiler into service.

3. The steam heat tracing in the pollution abatement area, at the in-ground storage tanks, and in the above-ground storage area should be analyzed. These lines currently operate at system pressures of over 100 psig. Since the condensate from the steam heat tracing can not be brought back to the steam plant for safety reasons, then perhaps the lines could be operated at a substantially lower pressure. Steam at 10 psig has a temperature of about 240 degrees F.

Compressed Air Distribution

1. Repair all compressed air leaks. Approximately $85,000 per year is being wasted due to compressed air leaks. Many of these leaks are audible with out amplification, or a leak detector can be rented for about $200 per month. All audible compressed air leaks, no matter how small, should be repaired as soon as possible. The following compressed air leaks were noted during the survey of the steam distribution system;

    Leak from air line near Building 31-820.
    Valve from air line open at Avenue 321A and 322 Street.
    Air leak at pipe union next to Building S32-270.

Valve from air line was fully open at Building 33-670.

Leak from air line at Building 34-130.

Two leaks in air line at Building 34-650.

Electric Motors

1. The procurement staff and the departments requesting new motors for PBA facilities should specify premium efficient motors. A very simple spreadsheet computer program could be set up to determine if the additional cost of purchasing a new premium efficient motor would provide an acceptable payback.