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Energy Supply Alternatives for Picatinny Arsenal, NJ

by
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This report documents a study to determine the most economic methods of supplying thermal and electrical energy to Picatinny Arsenal, NJ. Based on energy use patterns and the condition of existing equipment, 10 major potential energy supply alternatives were identified and evaluated. Most of the alternatives contain additional options for various fuels and electrical generation. Each alternative was evaluated on the basis of (1) availability of funds, (2) initial capital costs, and (3) annual O & M costs.

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FOREWORD

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The work was performed by the Energy and Utility Systems Division (FE), of the Infrastructure Laboratory (FL), of the U.S. Army Construction Engineering Research Laboratories (USACERL). Dr. David M. Joncich is Division Chief, CECER-FE, and Dr. Michael J. O'Connor is Laboratory Chief, CECER-FL. The USACERL technical editor was Gloria J. Wienke, Information Management Office.

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COL Daniel Waldo, Jr., is Commander and Director of USACERL, and Dr. L.R. Shaffer is Technical Director.

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1 INTRODUCTION

Background

The Picatinny Arsenal, NJ central power plant (CPP) consists of three oil-fired boilers. Two of these have been converted from pulverized coal boilers rated at 160,000 lb* of steam per hour each. The third is a packaged, oil-fired boiler rated at 50,000 lb of steam per hour. Besides producing part of the electricity for the facility, these boilers provide heating and process steam via approximately 18 miles of steam line to approximately 300 buildings spread over the more than 2,000 acres of the installation. The boilers do not have a condensate return system, so steam is produced using 100 percent makeup water taken from a lake on site.

The boilers produce superheated steam at 430 psig and 700 °F that originally was passed through three condensing steam turbine generators to produce up to 7.5 MW of electricity before being used for heating and process saturated steam loads. These generators are not currently in use because of mechanical failure. This failure has allowed superheated steam at 60 psig and 700 °F to be sent out to a distribution system designed for saturated steam at 125 psig and 300 °F resulting in damage to piping and increased thermal losses. Automatic combustion controls are for the most part either inadequate or not functional.

Due to the poor condition of equipment in the power plant, a large amount of energy is being wasted. Additionally, many potential safety hazards exist at the facility. Picatinny Arsenal requested that the U.S. Army Construction Engineering Research Laboratory (USACERL) perform a study to determine the most practical options available to improve the energy supply situation. This project provided an opportunity to test concepts developed under three ongoing Research, Development, Test, and Evalution (RDT&E) projects: Modernization Technologies for Central Heating Plants, Advanced Electrical Supply Systems, and Advanced Steam Supply Techniques.

Objective

The objective of this research is to provide recommendations on the most cost effective techniques for producing thermal and electrical energy to meet the current and future demands of Picatinny Arsenal.

Approach

To the extent possible, this study has used information available from numerous previous studies of Picatinny's energy supply and consumption. It was necessary to use the earlier studies because (1) this study was not conducted during the heating season and (2) major CPP equipment was inoperable. It was also prudent to use the past studies to avoid duplication of effort and unnecessary costs. Reports documenting past studies were gathered during site visits to Picatinny. Pertinent information was reviewed, analyzed, and verified, as needed, during other site visits. If information was not available from

*A metric conversion table is provided on page 135.

past studies or onsite investigation, or could not be obtained from Picatinny personnel, researchers provided assumptions based on standard engineering practices and experience.

A major task of this study was to evaluate the existing thermal and electrical supply systems. Previous studies did not adequately address the condition and potential of these systems, particularly the CPP. Site visits were made to evaluate the current condition and maintenance status of both steam and electrical generating and distribution equipment.

Steam and electrical supply and consumption patterns were developed from historical records maintained at the CPP. These patterns provided input for computer models that estimated the size and cost for new energy supply equipment. A computer model of the steam supply system was also developed to estimate steam demand and identify distribution problems. Future energy needs were projected based on new building construction plans supplied by Picatinny Master Planning section.

Based on energy use patterns and the condition of existing equipment, 10 major potential energy supply alternatives were identified. Most of the alternatives contain additional options for various fuels and electrical generation. Each alternative was evaluated on the basis of cost (including initial capital cost, and annual operating and recurring maintenance costs), the impact on real property inventory and power plant personnel, availability of funds, and reliability of supplying the required energy. The alternatives are:

Alternative I: Abandon CPP after 5 years/satellite plants (base case).

Alternative II: Upgrade existing CPP.
- II-a,b. 100 percent electric purchase - natural gas (NG)/No. 6 oil
- II-c,d. Cogenerate - back pressure Turbine Generator (TG) - NG/oil
- II-e,f. Cogenerate - back pressure TG and reciprocating generators - NG/oil
- II-g,h. Cogenerate - Allison gas turbine - NG/oil
- II-i,j. Cogenerate - Allison gas turbine/Cheng cycle - NG/oil
- II-k,l. Cogenerate - Solar gas turbine/Heat Recovery Steam Generator (HRSG) - NG/oil

Alternative III: Reconversion to pulverized coal
- III-a. 100 percent electric purchase
- III-b. Cogenerate with back pressure TG

Alternative IV: New plant, bubbling fluidized bed
- IV-a. 100 percent electric purchase - anthracite coal
- IV-b. 100 percent electric purchase - bituminous coal
- IV-c. Cogeneration - anthracite coal
- IV-d. Cogeneration - bituminous coal

Alternative V: New plant, traveling grate spreader stoker
- V-a. 100 percent electric purchase - bituminous coal
- V-b. Cogeneration - bituminous coal

Alternative VI: New plant traveling grate overfeed stoker
- VI-a. 100 percent electric purchase - anthracite coal
- VI-b. 100 percent electric purchase - bituminous coal
- VI-c. Cogeneration - anthracite coal
- VI-d. Cogeneration - bituminous coal

Alternative VII: New dual fuel oil/gas-fired boiler plant

- VII-a and b. Electric purchase
- VII-c and d. Cogeneration

Alternative VIII: Satellite steam plants

- VIII-a. 100 percent electric purchase - natural gas
- VIII-b. 100 percent electric purchase - No. 6 oil
- VIII-c. 100 percent electric purchase - bituminous coal

Alternative IX: Individual building boiler units

- IX-a. 100 percent electric purchase - natural gas
- IX-b. 100 percent electric purchase - No. 2 oil
- IX-c. 100 percent electric purchase - natural gas

Alternative X: Municipal refuse incinerator

Scope

The evaluation methods developed for the analysis and assessment of thermal and electrical requirements at Picatinny will be useful to many other installations, particularly those with central heating or power plants. The energy technology screening and cost estimating procedures for new plant alternatives also will be helpful in evaluating third party finance opportunities.

Mode of Technology Transfer

It is recommended that the evaluation methods used in this report be incorporated into an Engineering Technical Letter on planning and designing central heating and power plants.

2 CONDITION OF EXISTING ENERGY SUPPLY SYSTEMS

Like many military facilities, Picatinny Arsenal has experienced greatly fluctuating funding levels due to proposed mission changes and spending cutbacks. At the same time, Picatinny has also experienced a high turnover in personnel. Both factors have been detrimental to the maintenance and operating condition of the thermal and electrical supply systems.

Picatinny has also undergone a mission change from production to research and development that has radically changed thermal and electrical needs. Add to this the influence of 30 years of aging and obsolete equipment and Picatinny is left with a very challenging modernization and maintenance management problem. Although this situation appears bleak for the existing system, industry has had surprising success in repowering older plants resulting in considerable savings.

This chapter provides condition and capacity estimates for the existing energy supply systems at Picatinny. The central power plant, satellite steam plants on the distribution system, steam distribution system, electrical distribution system, and chillers are discussed. To establish the condition and capacity of the existing energy supply equipment, several site visits were made to Picatinny Arsenal to evaluate equipment condition, observe operation, and gather data. Additionally, previous engineering studies (see **References**) and maintenance records were reviewed to gain a historical perspective on the equipment. Based on this evaluation, recommendations are given on changes in capacity requirements, reliability, safety, and efficiency improvements for the existing energy supply equipment.

With respect to the CPP equipment, recommendations are presented in three scenarios based on the direction Picatinny may take to improve their energy supply situation. The first scenario is a "status quo" or 5-year recommendation. Under this scenario, the various major functional subsystems were evaluated to determine the types of work that would have to be done to reasonably ensure safe and efficient operation for 1 to 5 years. The second scenario is a consideration of equipment upgrades for a 20-year life. The third scenario considers abandoning the existing CPP and constructing a new facility. Capital, operation, maintenance, and life cycle costs for these scenarios are provided in Chapter 5.

Central Power Plant

The central power plant has the capability to supply steam and electricity for the arsenal. The arsenal is comprised of 6491 acres, including lakes and ponds. The CPP, Building 506, is located on the south side of Lake Picatinny. This enclosed building houses all equipment necessary to produce steam and electricity. The plant has three boilers (numbered 4, 5, and 6).

Boiler 4 is a Riley Stoker packaged, 50,000 lb/h steam oil-fired unit, installed in 1971. It operates at 430 psig and 700 °F superheated steam and burns No. 6 oil. Boilers 5 and 6 are Combustion Engineering (CE) units, originally designed to fire pulverized coal, now firing No. 6 oil. Both units are rated at 160,000 lb of steam per hour, with the boiler outlet condition of 430 psig and 700 °F superheated steam. Boiler 5 was installed in 1952; boiler 6 in 1954.

Three partially dismantled steam turbine generators and associated auxiliary equipment are located east of the boilers in the turbine room area on the second floor. The steam turbines are located on the turbine room operating floor next to the main electrical control room. The turbine room first floor is occupied by the surface condensers, boiler feed pumps, air compressors, condensate pumps, bowser oil filters, electrical switchgear, and other miscellaneous auxiliary equipment.

The complete turbine generators are numbered 4 and 5. Turbine 4 is 16-stage and turbine 5 is 14-stage; both are single flow, double extraction, condensing machines, manufactured by General Electric Corporation. The steam turbine generators are type ATB, 2-pole, 3-phase, 60 hertz, 3600 rpm generators. Turbine 4 is rated at 3000 kW and turbine 5 is rated at 3500 kW.

Since April 1988, the plant has not been able to generate electrical power due to the loss of the last operating turbine-generator (No. 5). All process and heating steam has been supplied by pressure-reducing the steam directly from the boilers' main 430 psig superheated steam header system. The steam is still superheated, but is at a lower pressure.

Circulating water is taken in through intake screens on the west side of the plant near the lake (see Figure 1). The circulating and service pumps are located in a pumphouse adjacent to Lake Picatinny. This pumphouse is connected to the basement of the CPP by a tunnel. Circulating water pipes are routed through tunnels and pipe trenches to the turbine room first floor where the condensers receive the water, discharging it back to the lake. Service water is routed to the plant through tunnels and trenches. Service water is used to cool auxiliary equipment.

The No. 6 fuel oil storage tanks (two 424,500-gal and one 846,000-gal) are located aboveground on a hill east of the power plant; the fuel oil is trucked in and stored. The fuel oil is gravity fed to fuel oil service pumps in the southeast corner of the boiler room first floor. The fuel oil heaters and all associated equipment for transferring fuel oil to the burners are located in this area. Appendix A contains nameplate data on CPP equipment.

Boilers

Boiler 4 is a packaged, water-tube boiler with a single burner designed to burn No. 6 oil. The stamping on the boiler exhibits the information listed in Table 1.

Boilers 5 and 6 are welded, four-drum, bent-tube, water-tube, field-erected boilers constructed in accordance with the 1940 edition of the American Society of Mechanical Engineers (ASME) Code Section I for Power Boilers. Figure 2 shows a typical CE four-drum boiler. The stampings on the boilers exhibit the information listed in Table 2. The maintenance history of the boilers is listed below.

1952 to 1954. The Combustion Engineering pulverized coal boilers (5 and 6) were relocated to Picatinny Arsenal from Gopher Ordnance Works in Rosemount, MN. They were 10 years old. Plant personnel believed that new superheaters were installed during the relocation.

1971. Boiler 4 was installed. This boiler is a Riley Stoker Corporation "package" unit designed to fire No. 6 oil and produce 50,000 lb/h of 430 psig and 700 °F steam with a feedwater inlet temperature of 230 °F.

1972 and 1973. Boilers 5 and 6 were converted to burn No. 6 oil. Due to the conversion, the boilers were derated to 160,000 lb/h of 430 psig and 700 °F steam, each with a feedwater inlet temperature of 230 °F. Senior plant personnel believe new superheaters were installed at this time.

1973 to 1975. New air heaters were installed in boilers 5 and 6.

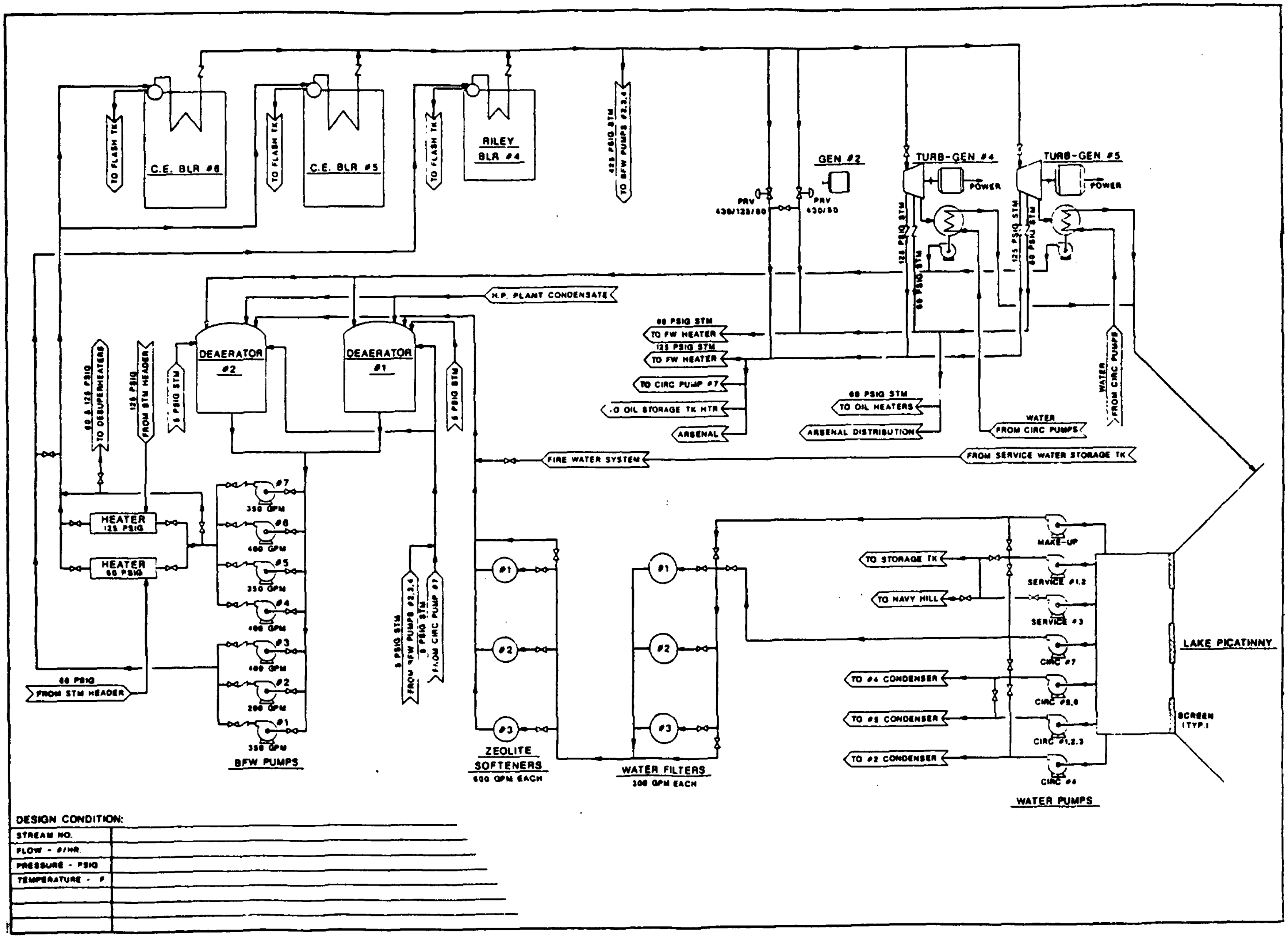

Figure 1. Steam/water flow diagram.

Table 1

Data for Boiler 4

Manufacturer	Riley Stoker Corporation
Year Built	1971
National Board No.	2395
Design Pressure (psig)	525
Working Pressure (psig)	450
Capacity Rating (lb steam/h)	50,000

1982 and 1983. Many front wall tubes and a few generation tubes were replaced in boilers 5 and 6 as recommended by Hartford Boiler Inspection Reports dated 1982.[1]

1984. New superheaters (64-tube banks) were installed in boilers 5 and 6.

1988. The water tubes of boilers 5 and 6 were cleaned on the fireside by high-pressure water jets.

1989. Boilers 5 and 6 were retrofitted with Todd burners that enable propane or natural gas startup and firing.

During field inspection of the CPP, only boiler 5 was available for internal inspection. Boiler 6 was sealed for asbestos removal and boiler 4 was in operation. Inspection of boiler 5 revealed the following:

Main Steam Drum (54 in.). The drum surface had a buildup of approximately 12 mils of iron oxide and undissolved solids. This may be caused by the zeolite softeners or boiler phosphate treatment. The buildup prevented an accurate assessment of cracks, pitting, or other irregularities on the drum shell. The upper several feet of the inside of the tubes was coated with an unknown scale approximately 1/4-in. thick. A sample was forwarded to CE's laboratory for analysis and a recommendation on the type of acid cleaning necessary for removal. The rolled ends of the tubes showed some evidence of thinning and oxidation, however, no corrective action was recommended. No plugged tubes were observed. The continuous blowdown piping was severely plugged with the same residue found on the drum surface and the inside of the tubes. The dryer screens were corroded and partially plugged with the same substance. No evidence of cracking was observed. The baffle plates and pans, although severely coated (approximately 1/4 to 3/8 in.) appeared in good condition. The drum manway weld attachments were in good condition. Chemical feed lines were in good condition. The external surface of the drum is covered with pulverized coal dust and oxidation, preventing an accurate assessment.

[1]Hartford Steam Boiler Inspection and Insurance Company, *A Boiler Condition and Useful Life Study Report, Boiler NB2919* (U.S. Army Research and Development Command, Picatinny Arsenal, 1982).

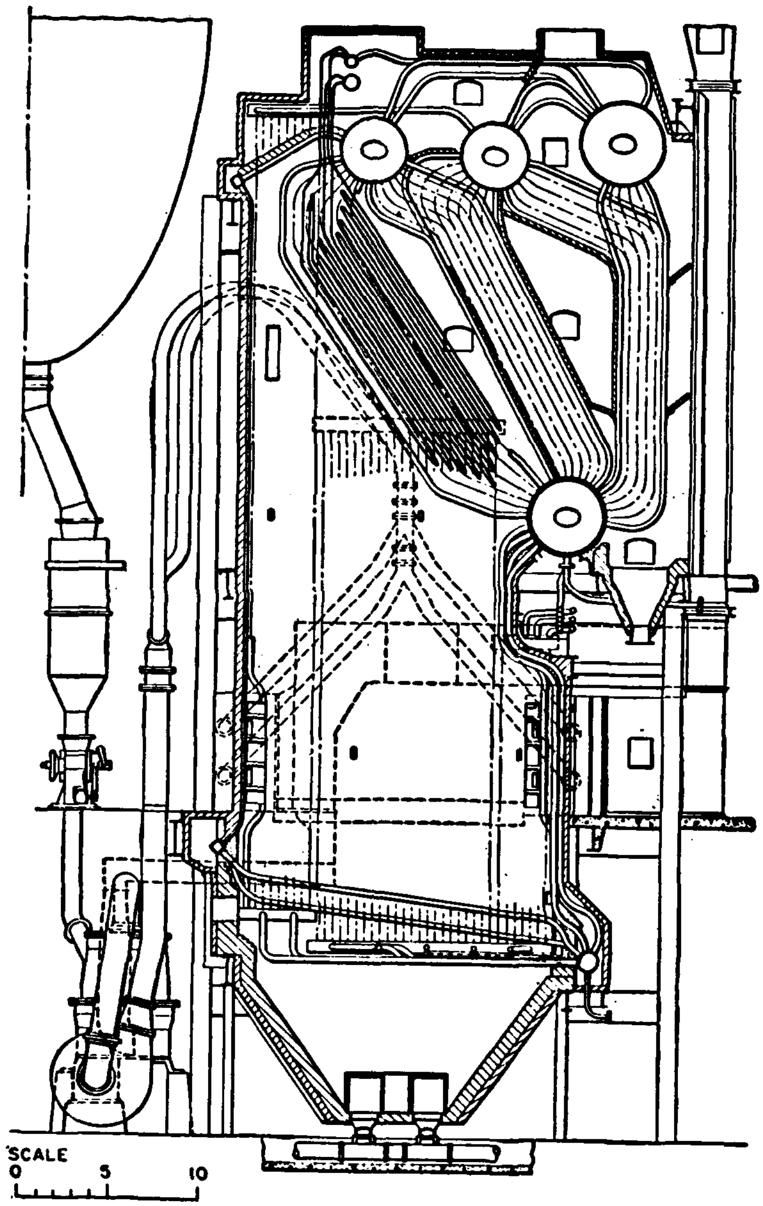

Figure 2. A typical CE four-drum boiler.

Table 2

Data for Boilers 5 and 6

	5	6
Manufacturer	CE	CE
Year Built	1943	1943
National Board No.	2921	2919
HSB No.	10510	10500
Max. Allowable Working Pressure	502	502

Crossover Drums (1 and 2, 42 in.). Both crossover drums were found in approximately the same condition as the main drum. Buildup on the inside of the tubes was similar.

Mud Drum (42 in.). With the exception of the buildup on the inside tube diameters, this drum appeared to be in good condition.

Tubular Air Heater. The air heater was examined on the cold end (air side) from the forced draft fan outlet, through each of the passes, and was found to be in excellent condition. The tube sheet was examined at each level and was also in good condition. The hot end (gas side) showed minimal corrosion at the interface of the tube and the tube sheet. During the most recent tube replacement, several areas of the tube sheet were inaccurately cut to assist installation of the new tubes. The tube sheet can be reworked to reduce potential bypassing. The gas inlet side showed a coating of oil deposits and what appeared to be acid corrosion typical of heavy-oil-fired units that may have acid condensing in the air heater at low steam loads. Plant personnel indicated the tubes are washed with water annually. No severe plugging was noted.

Windboxes. The windboxes were in excellent condition. All expansion joints were in good condition. Installation of new fiberglass insulation was in progress. Although the units are fitted with RO type burners, sometime in the past they had been modified by Southern Technologies Engineering to fire No. 6 oil. During the inspection, the burners were being modified again to include propane ignition. The dampers have been modified from mechanical operation to piston operation that is tied into a new combustion control system. Operation of the inlet dampers to both the upper and lower burners on the right side was successful. Internal inspection revealed that the dampers suffered minor warping from overheating sometime in the past; leakage from the warpage is minimal. According to operating personnel, the air registers at the burner front have not operated for many years. Lubricants applied to the lower left burner mechanism freed the registers in less than an hour. All the internal linkages appeared in good condition; therefore, it is anticipated that applying the appropriate lubricants properly on the rest of the register drives will reinstate proper operation.

Burner Throats. Inspection of the refractory at the burner throats disclosed severe cracking completely around the interface of the refractory and the parent metal. This could be caused by an improper ignition point, lack of sufficient airflow behind the fuel, misalignment of the oil gun tip with the windbox configuration, partially plugged oil gun tips, improperly sized oil gun tips, or improper operation.

Combustion Control System. With the boilers offline, the combustion control system could not be operationally evaluated. However, operating personnel provided some insight into problems. To place a burner in service, the operator must manually open the oil inlet valve slowly, following delayed piston operation of the windbox air inlet damper. If the oil inlet valve is operated too quickly, the combustion control automatically trips the fuel supply. The burner has ignition before the windbox air damper opens. There is no oil supply regulator to maintain a constant oil pressure to the burner front. The operators suggested that if the manual oil supply valve is opened too quickly, the system will trip on low oil pressure. (This is not meant to condemn the present combustion control system, but to state the operator's comments.)

Firebox. An inspection of the firebox (waterwall and superheater tubes) was performed, which indicated substantial external accumulation of fly ash and unburned oil residue on most of the tubes. It was apparent that an improved soot blowing program is needed. The superheater appeared to be in excellent condition. Alignment of all the assemblies was very good. No blistering or bulging was observed. The floor tubes and rear wall tubes at the target area showed a heavier coating of unburned oil residue. The left waterwall tubes at the lower left burner appeared to be covered with a larger amount of unburned fuel than the other walls. (A partially plugged oil gun tip may have been the cause.) It was not possible to assess the caustic embrittlement of the tubes.

Superheater. A penthouse inspection of the superheater tubes was performed, paying particular attention to blistering or bulges. No irregularities were noted. Alignment across the penthouse was good. No tubes were missing or short circuited. Oxidation on the header was noted and the refractory on the adjacent walls and floor needs repair. These repairs are considered routine.

Back Pass. The baffles in the back pass were in excellent condition. All hanger attachments were in good alignment and the block was in good condition. The rear upper baffle support brickwork has deteriorated over the years, allowing bypassing of the hot gases. A 1-ft hole exists in the brick at both the right and left sides at the upper tube penetrations. The brickwork should be repaired before light-off. The bypassing adversely affects the unit's efficiency and if left unrepaired, could burn through the back wall of the unit. It should be noted that the multiclones are still present. Unless conversion to coal is a future consideration, the multiclones should be removed because they reduce fan capacity and increase electrical costs.

Boiler Feedwater System

The boiler feedwater system starts at the pumphouse screened inlets on the east shore of Lake Picatinny and proceeds through pumps and a tunnel to the northeast end of the boilerhouse. There it rises vertically through pressure filters (on the second level) and softeners (on the third level), and into deaerating heaters. It then mixes with pumped condensate returned from various points in the house.

Feedwater pump suctions are manifolded to connect the deaerator discharge to seven pumps located in two separate areas of the building. Feedwater pumps 1 (electric drive), 2, and 3 (turbine drives) are located on the first floor next to a hydraulic pump behind boiler 4. Pumps 4 (turbine drive), 5, 6, and 7 (electric drives) were placed on the same level but behind the pulverizer when the Combustion Engineering units were added.

Feedwater Pumps. Table 3 lists the capacity data for the feedwater pumps at 3500 rpm. A visual examination did not reveal any apparent difficulties or excess wear related to neglect. On the contrary, the installation reflected diligent care and maintenance. The installed capacity of 2450 gpm (1,225,000 lb of steam per hour) is sufficient as shown above. However, the uniform size of all units reflected a design weakness; that is, the inability to cover "low loads." In the summer, the average low load is about 20,000 lb steam/hr (40 gpm). Feedwater pump 2 at 200 gpm and 1400 ft TDH (total developed head) would be the most likely selection for use with low loads. With the boiler operating at reduced pressure (approximately 300 psig), the system wastes energy.

Unless a pump has a variable speed drive (VSD), lower flows generally do not result in horsepower reduction but discharge head increases. Although the turbine drive governor changes speed, the changes are insignificant compared to a VSD. Therefore, steam is being used to provide excessive energy (horsepower). Additionally, a higher discharge head into the control valve results in excessive inlet pressure which increases the differential pressure. Finally, the turbine exhaust steam is probably not usable (within the plant heat balance) and is vented to the atmosphere. All of these factors contribute to wasted energy.

For an anticipated useful life of 5 additional years, the required work on the feedwater pumps consists of normal preventative maintenance (PM) and inspection as has been practiced in the past. It may be necessary to perform minor repair such as replacing the packing.

For an anticipated useful life of 20 additional years, a somewhat more extensive and costly upgrade is anticipated. Each unit should have the entire rotating assembly replaced. The casing should be inspected for signs of stress cracks and a nondestructive test on the upper half at the packing surfaces and bearing mounts adjacent to the turbine drive should be performed. This may indicate the need to repair or replace the pumps.

Makeup Pumps. The single vertical turbine pump is not advisable for this critical system. Another pump should be added as soon as possible.

Pressure Filters. The pressure filters act as the primary filters for removing suspended matter. Three 9 ft - 0 in. diameter by 7 ft - 3 in. high vessels contain a bed of anthracite coal layered by size (from fine at top to coarse at bottom). Each vessel is parallel-piped into a manifold equipped with hydraulically operated control valves that automatically place units "online" (filtering) or "backwashing" (flushing). These valves are sequenced through solenoids (in the hydraulic signal tubing) wired via an electrical status panel containing relays, indicating lights, selector switches, and other functional devices.

Good engineering practice of 2 to 5 gpm/sq ft of media enables capacity between 125 and 300 gpm, or, with one unit backwashing, the system can handle 600 gpm. Note that the 600 gpm includes regeneration flow for softeners (between 100 and 170 gpm), which reduces the total to 430 or 500 gpm during a 30- to 40-minute time period.

Blowdown System. Boilers 4, 5, and 6 are connected to a common system containing a 5-psig flash tank and an atmospheric tank. The flash tank recovers steam flashing from the high-pressure feedwater being drawn from the steam drum to control total dissolved solids (TDS). It discharges through a level control valve into the blowdown tank, which also receives high-pressure feedwater being drawn from the mud drum for sludge control. This mixture is cooled by flashing and venting steam to the atmosphere; the temperature of the resulting liquid is 212 °F. Additional cooling of the liquid takes place when it is mixed with other effluents or by adding cooling water. This system is being modified to allow monitoring and control of the effluent released into Lake Picatinny.

Table 3

Feedwater Pump Capacity

Pump No.	Capacity (gal/min)	Driver
1	350 at unknown	electric
2	200 at 1400 ft TDH	turbine
3	400 at 1270 ft TDH	turbine
4	400 at 1270 ft TDH	turbine
5	350 at 1160 ft TDH	electric
6	400 at 1490 ft TDH	turbine
7	350 at 1150 ft TDH	electric

If an anticipated useful life of 5 additional years were required, the normal valve packing and other PM measures would suffice.

If an anticipated useful life of 20 additional years were required, an extensive and costly upgrade would be necessary. The upgrade would include replacing all piping and valves from the boiler drums through the "rate set" valves to the flash and blowdown tanks. Tank replacement may not be required. Replacement of the level controller and valve on the 5-psig unit should be considered. During repiping, the original tank and transfer pump set in the basement should be abandoned.

Zeolite Softeners. The softener system is comprised of three 6 ft - 0 in. diameter by 8 ft - 0 in. tall high-pressure vessels, each containing a bed of zeolite resin and an underdrain system. The zeolite removes hardness via an ion exchange mechanism in which undesirable ions are absorbed into the resin, which subsequently releases sodium ions. Each vessel is parallel-piped into a manifold equipped with hydraulic control valves that automatically place units in service (removing hardness from filtered water) or regeneration (reversing the ion exchange by putting sodium ions back into the resin). These valves are sequenced through solenoids (in the hydraulic signal tubing) wired via an electrical status panel containing relays, indicating lights, selector switches, and other functional devices.

Good engineering practice of 8 to 11 gpm/sq ft of resin enables capacity between 225 and 310 gpm; one regenerating system can handle 600 gpm.

The filtered water inlet to each unit passes through a meter (equipped with a manual reset auxiliary contact) that records throughput. When a preset amount of fluid passes through the meter, the alarm contacts initiate the regeneration cycle. All valve manipulation is controlled automatically from devices mounted in a panel.

Piping and Control Tubing. A visual inspection of the filter and softener externals, piping manifolds, valving, control tubing, and accessories did not reveal any omissions or damage that could adversely affect operation. However, a few things were observed which could be changed or should have been installed.

A water meter with contacts similar to those used for the zeolite softeners should be installed in place of the present clock to initiate the backwash cycle on the pressure filters.

The plastic hydraulic signal tubing for the control valves should be replaced. Original installation did not route tubing along a common path and bundle them for common protection and support. The existing installation is susceptible to mechanical failure from fatigue/vibration or accidental cutting, and to chemical/environmental attack.

Reports from plant personnel indicate that raw water piping is plugging from hardness and needs replacement. No observations to the contrary were made. However, while inspecting softeners, a "tee" marked "saran lined" was found. If the piping is in fact saran lined, it is highly unlikely that plugging would occur. The extent of saran lining should be determined before beginning a project to replace piping.

Deaerator

The makeup water station for deaerating heater 1 is not equipped with a manual bypass. It is suspected that the various alternate water tie-ins were made at the expense of this bypass. Although lack of a manual bypass valve does not present a major problem because deaerator 2 is installed, the bypass should be replaced.

Turbine Generators

The CPP has lost the ability to generate electrical power due to a series of equipment breakdowns over the past 9 years. Turbine generators 4 and 5 are the most complete units, although the lower turbine casing of unit 4 is setting on blocks. The turbine from another turbine generator set that was not evaluated in this study, turbine generator 2, was removed from the powerhouse in mid-1981 and analyzed for rebuilding by Bethlehem Steel Corporation. Based on the evaluation, Picatinny believes repairing this machine is not economically justifiable. A 1500-kW skid-mounted, back pressure unit was being considered as a replacement. Currently, the turbine is not in the powerhouse, nor has a replacement been installed. Tables 4 and 5 list the nameplate data for turbine generators 4 and 5. The maintenance history of the turbine generators is listed on p 23.

Table 4

Nameplate Data for Turbine Generator 4

TURBINE

S/N: 48218 FORM: LL	KW: 3000 SPEED: 3600
STEAM PRES: 425 LBS	TEMP: 600 DEGREES F
EXHAUST PRES: 2" ABS	16 STAGES
GEI-12262	

GENERATOR

S/N: --	TYPE: AIR COOLED ATB	
POLES: 2	CYCLES: 60	PHASE: 3
DELTA / WYE CONNECTED FOR 2400 VOLTS		
RATING 3750 KVA AT 0.8 PF	EXCITER 125 VOLTS	
ARMATURE -- FILED --		
GEI- --		

EXCITER

MODEL: 51A507	FRAME: 83	TYPE: EDF
VOLTS: 125	WINDING: SHUNT	S/N: 1796506
SPEED: 3600	KW: 25	AMP: 200

Table 5

Nameplate Data for Turbine Generator 5

TURBINE

S/N: 109115	KW: 3750 MAX	SPEED: 3600
STEAM PRES: 425 LBS	TEMP: 750 DEGREES F	
EXHAUST PRES: 2" ABS	14 STAGES	

GENERATOR

S/N: 6978247	TYPE: AIR COOLED ATB	
POLES: 2	CYCLES: 60	PHASE: 3
DELTA / WYE CONNECTED FOR 2400/4160 VOLTS		
RATING 3750 KVA AT 0.8 PF	EXCITER 125 VOLTS	
ARMATURE 902/520 AMP	FILED 151 AMP	
GEI-41155		

EXCITER

MODEL: 51A342	FRAME: 83	TYPE: EDF
VOLTS: 125	WINDING: SHUNT	
SPEED: 3600	KW: 25	AMP: 200
SERVICE FACTOR: 1.15 AT RATED VOLTS DUTY CONT.		
40 DEGREE C RISE	ENCLOSURE T.E. E.V.	
S/N 7133340-RK		

1983 to 1987. Turbine generator 4 was last in service in May 1983. The unit was offline due to problems with the lube oil pump/system.

1988. Personnel attempted to operate turbine 5 but encountered problems. The turbine casing was opened and the upper half removed. The rotor/shaft blades, seals, and diaphragms are "rusted" and require extensive repair. The top casing was placed and blocked on top of the bottom casing.

Mid-1988. Turbine generator 5 was last in service in mid-1988. The unit was taken offline due to significant wear grooves in the generator collector rings.

January 1989. The unit was inspected by G.E. service personnel. G.E. stated that the unit should not be returned to service until the recommended repairs were accomplished.

An additional inspection of turbine generators 4 and 5 was conducted during this study. Additional information on the status of these units was obtained from previous General Electric reports. A summary of the G.E. Inspection Report is provided below.

Turbine Generator 4. Upon initial inspection, it was observed that the turbine horizontal joint bolting was removed; the upper turbine casing was separated from the lower by approximately 4 in.

The steam path was partially visible from the opening at the horizontal joint. All visible internals were heavily rusted, heaps of flaked rust were observed on the lower diaphragm horizontal joints. Steam sealing surfaces were unprotected and were also heavily rusted.

The only accessible interstage packing was the high pressure (HP) packing box. This row was rusted and heavily worn. The ring was also "frozen." It could not be moved away from the rotor on its spring.

Examination of the left side of the HP end revealed water droplets forming on the upper half nozzle block and dripping down into the lower half casing. The water source was identified as a leaking trip throttle valve (TTV). The escaping steam was condensing in the valve chest, forming a pool of water. This water was then leaking through one or more control valves and dripping into the machine. All control and extraction valves were found to be resting on their respective seats.

The steam regulator was found to be heavily rusted. The rust prevented freedom of movement of the regulator components. The condition of the regulator internals could not be determined because the regulator was not disassembled.

Valve gear assemblies were apparently serviceable; however, no means was available to cycle the valves to assure freedom of movement. All valves rested on their respective seats.

Governor assemblies, both speed- and pressure-regulating, were covered with dirt and oil. The governor internals, oil pump, and sump were not disassembled for inspection.

The generator was inspected externally only, as both end shields were intact. The collector rings were rusted and did not contain any spiral grooves as required. Both brush assemblies were intact and all the brushes were riding on the rings.

Turbine Generator 5. Upon initial inspection, all horizontal joint bolting was assembled, which prevented even a limited internal inspection of the turbine.

The steam seal regulator was very dirty. The internal condition could not be determined because the unit was not disassembled.

Valve gear assemblies were apparently serviceable; however, no means was available to cycle the valves to assure freedom of movement. All valves rested on their respective seats.

Governor assemblies, both speed- and pressure-regulating, were dirty and oily. The governor internals, oil pump, and sump were not disassembled for inspection.

The generator was inspected externally only, as both end shields were intact. The collector rings were deeply grooved and rusted. Both brush assemblies were missing.

Without a complete disassembly and thorough inspection of both turbine generator units, no definitive recommendations or assessments can be made. Based on a limited visual inspection, it is believed that unit 4 would require extensive repair and replacement of the steam path components to make the unit serviceable. Should Picatinny decide to refurbish only one of the units, it is recommended that further inspection or repair to unit 5 be pursued. The higher cost of repairs for unit 4 would yield a higher cost per kilowatt.

Electrical Service Distribution (440 Volt)

A visual inspection was made of the entire CPP 440-volt electrical distribution system, including the secondary side of the incoming 2400-volt transformers, distribution panels and panel boards, miscellaneous combination starters and disconnect switches, pull boxes, lighting systems, and grounding. The CPP was constructed in 1954. Most of the major pieces of distribution equipment, control devices, and lighting fixtures are from the original installation.

Primary 440-Volt Distribution Panels. These principal panels are responsible for distributing electrical service throughout the boiler plant as well as the remote pumphouse and abandoned coal handling equipment. All panels are serviced by the secondary section of 2400/440-volt transformers with a total capacity of 2400 kVA located on the exterior of the east wall.

The cables connected to the secondary terminals of the transformers show sign of fatigue and will have to be replaced within the next 5 years.

Panels A and E are General Electric units with AK 1-25 and AK 2-15 breakers. Panel B was manufactured by Federal Pacific Electric Products and fitted with DMB-25 breakers. In both cases, replacement parts are no longer manufactured.

Since this equipment has no moving parts during normal operation and the loads are fairly constant, it will probably last at least 5 more years. However, an extended 20-year life for this plant must include total replacement of all three distribution panels.

Local 440-Volt Panel Boards. Panel boards B-12, D, X, D5, and an unlabeled panel in the pumphouse service the 440-volt needs of motors surrounding the general area of each panel.

Panel boards D and D5 are in very good condition and will not require replacement for 15 years.

Panel boards B-12, X, and the unlabeled board in the pumphouse are from the original boiler installation. They are old, dirty, and in need of new gaskets and replacement cover anchor screws. These panels should be scheduled for replacement in the near future.

Lighting and Receptacle 120/240-Volt Panel Boards. Panel boards labeled C, R, T, V, Pipe Shop, Pumphouse, and an unlabeled panel board on the north wall next to the abandoned hydraulic oil vertical-mounted vessel furnish the needs of all lighting, receptacles, controls, and fractional horsepower motors located throughout the plant.

1. The unlabeled panel board on the north wall is from the latest expansion period but is dirty, covered with salt brine, and contains no spare circuit breakers. This panel will probably last for another 5 years, but will have to be replaced to meet a 20-year future profile.

2. Panel boards C, R, T, V, along with the panel boards in the pipe shop and pumphouse are old, dirty, and without spare circuit breakers or replacement parts. These panel boards should be replaced within the next 5 years.

440 to 120/240-Volt Transformers. These transformers service the need for voltage transformation for the 120/240-volt panel boards described previously. They are from the original construction period. Even though transformers of this small size seldom fail under normal design load operation, replacement is recommended for the 20-year future profile.

125-Volt DC Panel Board. This direct current (dc) panel board is located next to panel board "T" in the basement. The panel board is old but does not need immediate replacement. It will require replacement for the 20-year profile.

Miscellaneous Starters and Disconnect Switches. Many motors throughout the plant and pumphouse are furnished with locally-mounted combination starters or disconnect switches. The starters and switch enclosures are old, dirty, and in many cases corroded. The coil contacts and heaters in the starters are becoming difficult to replace due to lack of stored parts.

Some motors located throughout the plant and the roof ventilators are not furnished with local disconnect switches. This condition is a violation of the National Electric Code.

Some disconnect switches and combination starters in the plant and the pumphouse are no longer in use and should be removed.

Wireways and Pull Boxes. Wireways are used as a distribution method for combination starters, starters, and disconnect switches in both the plant and pumphouse. These wireways require regasketing and replacement of missing hold-down screws.

Pull boxes are located throughout the facility. Some are overloaded with wiring, and some do not have covers or proper locknuts on conduit entry.

There are a few locations where a conduit fitting was used to splice wiring. This condition is a violation of the National Electric Code.

Wiring. There has been an attempt to generate a rewiring program to replace all of the old fiber-insulated wiring with state-of-the-art insulated wiring. The program is progressing slowly. It is imperative that all the old original wiring be replaced as soon as possible with new, correctly-sized wiring in order to maintain a safe electrical system.

Conduit. Most conduit throughout the plant is in good condition but needs to be thoroughly cleaned. The only critical location where conduit should be replaced and resupported is in the total ash pit area. Some motors serviced by flexible conduit have broken conduit at the entrance box fitting (e.g., 40-horsepower vertical air compressor in the northwest corner of the basement under boiler 5).

Grounding. All major pieces of electrical distribution equipment have been grounded. Some, but not all, of the motors have exterior grounding logs. In most cases, ground wires are not routed into the conduit feeders to the motors. The building columns show no ground connections. The stack for boiler 4 is grounded. The stacks for boilers 5 and 6 could not be verified for grounding because the area was encapsulated for asbestos removal.

Lighting. Most of the facility is now illuminated by 200-watt incandescent, 48-in. and 96-in. fluorescent fixtures fitted with two, three, or four lamps. The life expectancy of an incandescent lamp is approximately 750 hours; for a fluorescent lamp it is 18,000 hours. Table 6 lists the general fixture descriptions for the plant and pumphouse.

The existing lighting level throughout the plant is acceptable in most areas, too high in some areas, and spotty only in a very few basement areas. No changes have to be made for the 5-year profile except that all the lighting fixtures in the ash pit area and the tunnel between the plant and pumphouse must be replaced as soon as possible with proper 100 watt vapor-tight high-pressure sodium (HPS) fixtures. The existing fixtures in these areas are broken, without lenses, corroded, and not securely supported.

Exterior lighting fixtures are not mounted above any door leading out to the roof at any level. There are no exterior lighting fixtures mounted on the south, west, or north walls above any doors. The east wall has two small incandescent fixtures that should be replaced with wide-spread wall-pac HPS fixtures.

By summing the number of fixtures in Table 6 and comparing that total to the lamp characteristics listed in Table 7, it is easy to understand why it is highly recommended that all existing incandescent and fluorescent fixtures be replaced by a much smaller number of high-pressure sodium fixtures of smaller wattages for the 20-year program.

The constant maintenance problems of changing incandescent lamps and cleaning fluorescent lamps to obtain the maximum lumen output for the dollars expended would be minimized. Approximately 25 200-W fixtures throughout the plant presently have burned out lamps. Replacing the lighting fixtures would result in a much smaller fixture count and nearly a 55 percent energy savings related to lighting service.

In summary, all existing equipment, except for some general wiring and all devices located in the ash pit and tunnel, has the potential to remain in operational condition for another 5 years. But a 20-year operation scenario would demand that all existing equipment be replaced.

Table 6

CPP and Pumphouse Lighting Fixtures

Ash Pit: 13 200-W IF*

Tunnel: 4 150-W IF

Pumphouse: 2 200-W IF and 5 2-lamp 96 in. FF

Circulation Pump Room: 2 200-W IF

New House Water Treatment Area: 400-W metal halide and 2-lamp 96-in. FF

Mechanics Room: 3 96-in. FF

Supply Room: 3 96-in. FF

Electrical Room: 3 96-in. FF

Lunch Room: 6 48-in. FF

Bath and Laundry Room: 1 48-in. FF

Solvent Store Room: 3 48-in. FF

Water Softener Platform: 3 2-lamp 96-in. FF

Zeolite Platform: 2 2-lamp 96-in. FF

Roof Level Water Treatment Bldg.: 8 200-W IF

Hydraulic Pump and Welding Area: 2- and 4-lamp 48-in. plus 2-lamp 96-in. FF and 200-W IF

Old Basement Condensor Area: 4-lamp 48-in. FF and 200-W IF

Old Basement Under Boilers 5 and 6: 200-W IF

Generator Room Floor: 400-W metal halide fixtures

Electrical Control Room: 2x4 layin 4-lamp FF, 2-lamp 48-in. FF with crate reflector, and over-panel-mounted 2-lamp 48-in. FF with lenses

Mezzanine Above Control Room: 11 200-W IF

Landing Between Basement and Operator Floor: 4 200-W IF

Operator Level: boiler front, 3 2-lamp 96-in. FF and 3 200-W IF; between boilers, 4 200-W IF; wall behind boilers, 6 200-W IF; north and south walls, 5 200-W IF; water test bench, 2-lamp FF and 1 200-W IF

Intermediate Level Above Operator Floor: 2 200-W IF

Steam Drum Level: between boilers, 4 200-W IF; back wall of boilers, 6 200-W IF; north and south walls, 5 200-W IF; top rear of boilers, 6 200-W IF; stairwell up to high roof, 5 200-W IF

Intermediate Level Under Induced Draft (I.D.) Fan Platform: between boilers, 3 200-W IF; back wall of boiler, 7 200-W IF; north and south walls, 5 200-W IF

I.D. Fan Platform: 8 200-W IF around each boiler; intermediate platform above boiler 4, 2 200-W IF and 1 high-pressure sodium fixture

Over Bunker Area: 200-W bare lamp IF

Locker Room: 10 3-lamp and 2 2-lamp 48-in. FF

Toilet Room: 3 2-lamp 48-in. FF and 2 200-W (vapor tight) IF

Corridor To Toilet and Office: 5 2-lamp 48-in. FF

Office: 6 2-lamp 96-in. and 1 2-lamp 48-in. FF

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*IF = incandescent fixture, FF = fluorescent fixture

Satellite Steam Plants

Picatinny maintains several satellite steam plants. Some service buildings are off the steam distribution system and some provide backup to the CPP during outages. Currently, there is only one operational satellite plant (Building 3013) on the distribution system and another (Building 99) soon to be connected to the system. Although the satellite plants do not affect the CPP thermal load, the plant equipment, location, and condition is discussed below. A group of buildings (630, 631, 632, 633, 636) located at a remote location on the arsenal will be discussed because of their potential for use as a centralized satellite plant.

Building 3013

Built in 1890 by the Navy as the "Powerhouse," this building is of masonry construction with steel roof trusses and wood decking. It presently houses a packaged, 50,000 lb/h Bigelow "A" type boiler firing No. 6 oil. Table 8 lists the boiler stamp data. Ancillary equipment consists of a zeolite salt saturator, a spray deaerator heater, a flash tank, a blowdown heat exchanger, two feedwater pumps (electric and turbine drive), and two makeup water booster pumps.

According to Picatinny personnel, the boiler was "used" and has been relocated several times. Neglect and abuse were apparent from missing or replaced lagging, rust on structural steel from leaks at the drum/tube seam and access doors, and poor replacement of the burner and controls.

Table 7

Lamp Characteristics

	Lamp Lumen Output	Hours of Lamp Life
Existing		
200-W incandescent	3700	750
40-W 48-in. fluorescent	3200	18,000
75-W 96-in. fluorescent	4500	18,000
Replacements		
70-W high-pressure sodium	6400	24,000
100-W high-pressure sodium	9500	24,000
150-W high-pressure sodium	16,000	24,000
250-W high-pressure sodium	27,500	24,000
400-W high-pressure sodium	50,000	24,000

Table 8

Building 3013 Boiler Stamp Data

MFG By: The Bigelow Co.	National Board No.: 2480
Order No.: 9901	Serial No.: 1370
ASME Stamp: S-6414	Net MBH: 8035
Heating Surface: 4916	Date: 1970
W.W. Heating Surface: 1398	Capacity: 50,000 lbs steam/hr
Maximum Working Pressure: 250	

Ancillary equipment in Building 3013 was not in use, since the steam demand is seasonal. Based on visual inspection, however, it was apparent that this equipment is marginally operational. If this equipment had been operating at the time of the inspection and if the internals had been examined, a more definitive evaluation could have been made. However, based on the limited examination, it is possible to make the following recommendations for immediate consideration.

1. Repair all drum access hatch leaks.

2. Install a closed chemical-circulating system to increase the effectiveness of storing chemicals during the summer or other nonuse periods.

3. Further evaluate the aesthetic/historical value of the 1890 structure.

For Building 3013 to continue to be useful, the following recommendations are necessary:

1. Architecturally renovate the structure—refurbish the roof and eliminate or replace windows.

2. Examine access/egress per code.

3. Examine the masonry stacks for either removal or renovation.

4. Chemically evaluate the ancillary equipment to determine capacity based on projected load. Results could lead to total replacement, at one extreme or refurbishing the rotating assemblies, softening resins and sprays, at the other extreme.

Building 99

The boiler in this building has only recently been installed and has not been test fired. Table 9 lists the boiler stamp data. Ancillary equipment, such as water treatment equipment and pumps, is also new. According to Picatinny personnel, this boiler was installed to alleviate low steam pressure problems in the area.

Buildings 630, 631, 632, 633, 636

These five buildings are located on a remote ridge and are supplied steam for both heating and production processes from the main distribution system. Buildings 630, 631, 633, and 636 have individual boilers that have never been fired. Boiler stamp data for these buildings are listed in Table 10. All boilers

Table 9

Building 99 Boiler Stamp Data

Federal Boiler Company, Inc.	National Board No.: 5312
Model: AST 2-300	Serial No.: 680008
MFG By: The Beth Corp	Steam sq. ft.:32489
Heating Surface: 1500 FS, 1614 WS	Net MBH: 8035
Input: 12554 MBH, 90 gph	Date: 1987
Gross: 10043 MBH, 300 hp	
Maximum Working Pressure: 150 lb steam	

Table 10

Boiler Stamp Data for Remote Buildings

Building No.	630	631	633	636
Steam (psig)	15	15	15	15
Output (kBtu)	115	118.3	170	250
Input (gal/hr)	1.00	2.40	2.00	2.25
Burner MFG	Utica	Utica	H.B Smith	

were designed to burn No. 2 fuel oil. Building 632 also has a forced air furnace designed to burn No. 2 fuel oil that has never been fired. This group of buildings should be considered as a site for a satellite plant because of its remote location.

Steam Distribution

An inspection of the steam distribution system was made primarily to document the number of buildings serviced by the CPP. This was necessary to estimate the maximum hourly steam demand and calibrate computer models used in the analysis of energy supply alternatives (see Chapter 3). During the inspection, however, researchers observed a number of locations where repairs could reduce steam distribution line and end-use losses.

Failed Desuperheaters

The CPP is currently producing 300 psig, 600 °F superheated steam that is reduced through a pressure-reducing valve to about 60 psig before entering the distribution system. Without desuperheaters, the 60 psig steam will also be superheated at a temperature of about 566 °F. The problem with operating under these conditions is that the equipment using the steam was only designed for about 300 °F. The high temperature presents a potential safety problem, reduces equipment operation efficiency and lifespan, and increases distribution losses.

Distribution losses will be higher because of higher conductive heat losses caused by higher temperature differentials, but more importantly, the losses will be higher because of the inability of existing end-use heat exchange equipment to use the high temperature steam. Heat exchangers are designed for a specific temperature differential between the heating and working fluid. They cannot remove any more energy than the design allows. This means that the additional energy from the superheat cannot be removed and is lost through failed steam traps and valves.

Based on the difference in actual and design steam temperature, the additional losses from high temperature operation may be between 10 and 15 percent of the fuel consumption. Using 1988 fuel consumption data, the loss would Picatinny cost between $402,000 and $602,000 per year. Installing desuperheaters will reduce this loss by providing more usable steam to the end-user heat exchange equipment (steam at lower temperatures).

Unused Lines

A pressure-flow-thermal efficiency model called the Steam Heat Distribution Program (SHDP) was used in this study to model steam distribution system losses. To use this model, the complete system was mapped out as shown in Figure 3. The steam lines and buildings are coded to identify seasonal and discontinued service (see Appendix B).

While surveying the steam lines, researchers noted that steam was distributed to several lines and buildings that should be isolated with valves, at least during the summer. Many of the buildings were warehouses or abandoned production facilities. Supplying steam to these buildings wastes energy though heat loss, condensate loss, and steam leaks.

It is recommended that personnel at Picatinny review this map and perform a thorough in-house survey of steam requirements to identify buildings that should be completely isolated from the distribution system or isolated during the summer. This will be particularly important if the CPP continues to operate during the summer.

Damaged Insulation

Overall, the steam lines appeared to be well insulated due to a recent program to upgrade the condition of the distribution lines. There were, however, still several hundred feet of bare line as well as lines with damaged insulation. Insulation on several sections of line had been damaged by falling trees. Other sections had been damaged by lying in surface water. Damaged and water-soaked insulation will not be effective in reducing heat losses.

Steam Leaks

Because much of Picatinny's distribution system is above ground and does not have a condensate return system, it was relatively easy to identify leaking steam traps and valves. Condensate from steam traps will flash to steam when it comes into contact with the atmosphere. This will appear as a lazy white vapor discharged either intermittently or continuously, depending on the type of trap. This steam loss is unavoidable. However, the presence of a continuous live steam discharge is a problem. Live steam appears as a high-temperature, high-velocity discharge and usually leaves the discharge pipe in a clear flow before it condenses to a visible cloud of steam. Because of the high velocity, live steam discharges are often noisy.

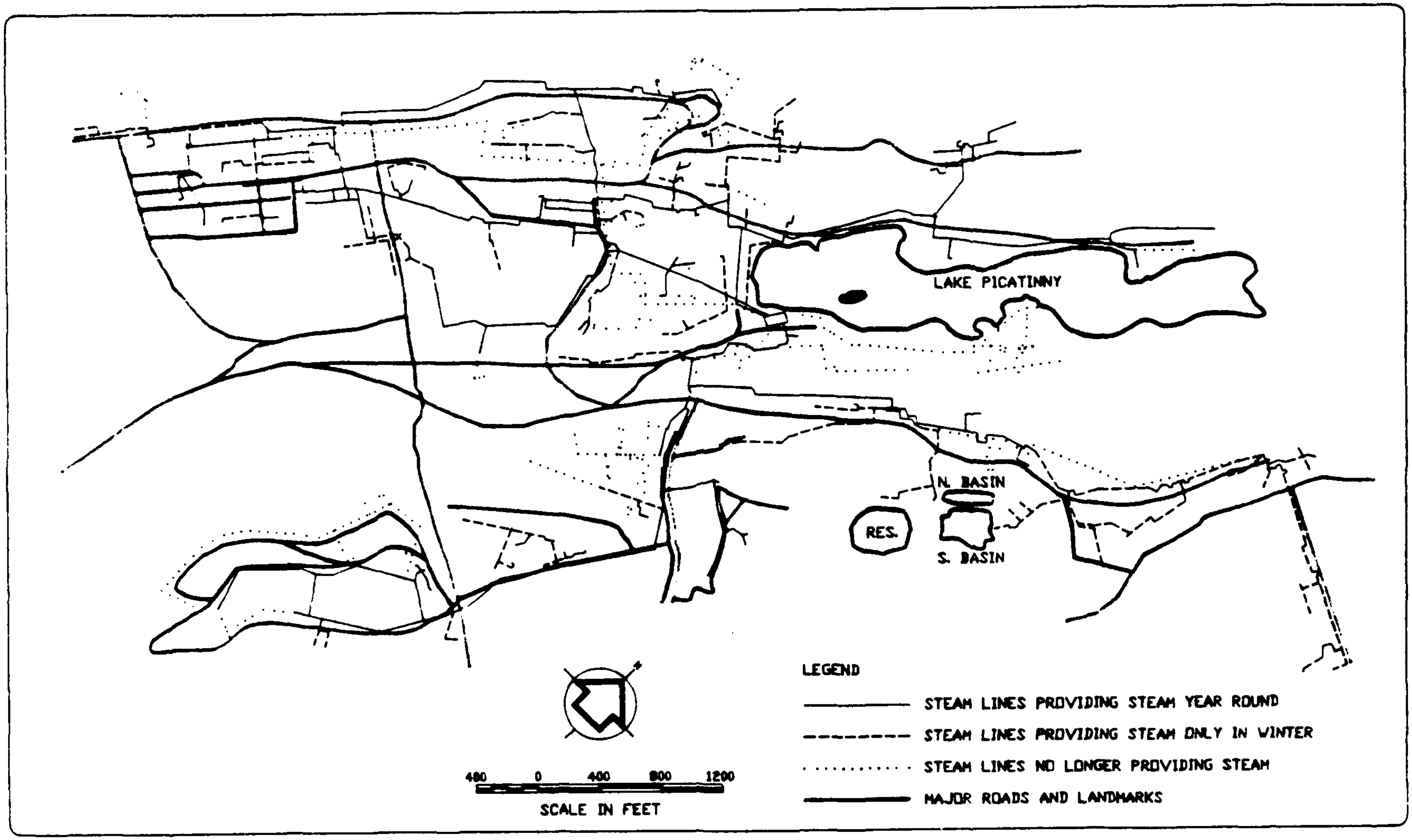

Figure 3. Steam distribution map.

About 30 percent of the steam traps in the portions of the distribution system surveyed during this study were discharging live steam. These leaks can be very costly. For example, assuming a cost of \$5/million British thermal units (MBtu) steam, or about \$5/1000 lb steam, and a leak at 50 psig with a 1/2-in. discharge opening, the losses will be about \$1.46 per hour or \$12,790 per year in fuel costs. Even a 1/8-in. discharge will waste \$1305 annually.

These costs make it easy to justify the cost of an aggressive preventive maintenance program. The highest cost of such a program is in locating the existing steam traps. This effort can also be very labor intensive. Vendors are available to perform baseline steam trap inventory, mapping, and operational status. Costs for these services vary from \$15 to \$50 per steam trap, depending on the level of detail requested.

Condensate Return

Presently, Picatinny does not have any condensate return from outside the CPP. A partial condensate return system was initiated as an ECIP project in 1976. According to correspondence between ARDEC, Picatinny Arsenal, NJ and AMC I&SA, Rock Island, IL, the system was plagued with problems that were never resolved. The final cost of this nonfunctional system was about \$2.5 million dollars.

Condensate losses during the study period accounted for about 11 percent of the total steam output or 67,124 MBtu/yr. The fuel cost benefit of a condensate return system, assuming 90 percent condensate recovery and \$5/MBtu cost of steam, would be about \$302,000/yr. A rough estimate of the maximum capital cost for a condensate return system is about \$183/linear ft of pipe (Schmidt Associates, Inc.). At an estimated 95,000 linear ft (approximate length of the steam distribution system), the capital costs would be \$17,400,000. However, condensate recovery may still be cost effective if evaluated only for the high usage areas of the arsenal. This is a reasonable assumption considering the 1976 ECIP project mentioned above was approved as cost effective.

Distribution System Design

Another capability of the SHDP is to analyze the steam distribution system design. When SHDP was run for Picatinny's distribution system, it identified a "choke point" in the main line servicing the 3400 area and a secondary line serving building 3028. A choke point is defined as a point where the capacity of the distribution line has been reached before the heating load has been satisfied.

The SHDP analysis showed that the existing 6-in. diameter distribution line running from building 3013 to building 3405 is too small. Complaints about poor heating seem to confirm this. To meet the heating loads of the buildings serviced by this section, the line should have an 8-in. diameter. However, changing this line to 8 in. reduced the steam flow in the line from building 3405 to building 1517. The SHDP analysis requires this section (from building 3405 to building 1517) to be upgraded to 6 inches diameter. To correct this problem, the existing lines would have to be replaced with about 4850 ft of 8-in. line and 750 ft of 6-in. line. Cost factors from Means[2] are \$61.00/ft of 8-in. pipe, \$47.00/ft for 6-in. pipe, \$8.65/ft to insulate 8-in. pipe and \$7.25 to insulate 6-in. pipe, yielding a total cost of \$378,500, including labor and materials.

An alternative to replacing the line from building 3013 to building 3405 is to replace or repair an abandoned 10-in. line near building 3024 to near building 3357. This would require buying and installing approximately 3700 ft of 10-in. diameter insulated steam line. It would not have a detrimental effect on the steam flow in other connecting lines. The Means cost factors for this option are \$82/ft for 10-in. pipe

[2] *Means Building Construction Cost Data* (R.S. Means Company, Inc.,1989).

and $9.85/ft to insulate 10-in. pipe. The total cost would be $339,800, including labor and materials. The cost of this option may be substantially less if the line can be repaired. A more detailed analysis of the line condition would be required to provide an accurate estimate.

The other choke point was identified in a secondary line servicing only building 3028. This line is about 300 ft long with a 2-in. diameter. The maximum winter steam load for building 3028 was estimated at 2921 lb steam per hour. SHDP analysis required a 4-in. line to accommodate the heating load. The Means cost factors for this option are $23/ft for 4-in. pipe and $6.35/ft to insulate 4-in. pipe. This gives a cost of $8800, including labor and materials. Because there have been no complaints about poor heating in this building, it is possible that this line was incorrectly labeled on the map, which could mean there is no problem. The line size should be confirmed by field inspection.

Electrical Power Distribution

Like the CPP, the electrical power distribution system is more than 40 years old and the 2400-volt distribution system is outdated; replacement parts are no longer available. Picatinny's electric demand has been growing and currently peaks at about 12 MW, which exceeds the 10-MW meter capacity in the CPP. The Jersey City Power and Light (JCP&L) transmission line is at its limit and JCP&L may have reached their power production limits. Now that the CPP has lost the capability to produce electricity, the electrical supply situation is reaching a critical stage for Picatinny. The electrical infrastructure must be improved and upgraded to provide reliable electrical power to the arsenal.

Because of this situation, Picatinny contracted with a consultant, Aquidneck Management Associates, Ltd., to prepare a Power Modernization Study in 1988.[3] The study report provided information on the status of the existing equipment, recommendations for improvement, and a conceptual modernization plan. As part of the Energy Supply Alternatives study, USACERL and the U.S. Engineering Housing and Support Center (USAEHSC) reviewed the Aquidneck report and also performed an inspection and analysis of the electrical distribution system.

The following is a brief problem history, system description and analysis, and recommendations for improvement of the electrical distribution system. This includes recommendations for improving the Power Modernization Study's conceptual modernization plan.

Problem History

During the past several years, the electrical loads connected to the utility grid have significantly increased. The utility feeder that supplies power to Picatinny Arsenal has reached its maximum electrical capacity. This is a result of not only increased electrical loads at the Arsenal, but also increased commercial loads that are also connected to the Arsenal main feeder.

In the past, the Arsenal generated a large portion of its own electrical power. Since approximately April 1988, electrical power is no longer generated.

The electrical distribution system is old and repair parts (especially for 2400-volt feeder circuit breakers) are no longer commercially available for many items.

Certain building areas experienced low voltage during 1980.

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[3] *Picatinny Arsenal Power Modernization Study* (Aquidneck Management Associates, Ltd., 1989).

The above items were considered and evaluated during a site trip. Conclusions and recommendations are based on inspection, consultation with site personnel, and analysis of information obtained.

Existing Power Distribution System

The Picatinny Arsenal receives its electrical power from the JCP&L Wharton Substation. The power is supplied via a 34.5-kV transmission line to the Picatinny switching station (Picatinny personnel refer to it as the main substation).

Main Switching Station. The switching station consists of three oil circuit breakers (OCB); the main OCB fed from the Wharton substation, and the east and west OCB supplying power to their respective areas throughout the installation. Table 11 lists the nameplate data for the circuit breakers and their respective protective devices.

Observations made at the main switching station are listed below.

1. Lightning arrestors are installed on each line.

2. The relays have no calibration stickers. Lack of calibration is an unsafe condition. In the event of a line fault, the circuit breakers may not operate properly, resulting in serious damage to the system. The relays should be calibrated as soon as possible and should have calibration stickers attached.

3. The west feeder has dried liquid around the pothead. This condition should be investigated.

4. Since the equipment is almost 35 years old, a plan should be implemented to replace circuit breakers and protective devices within 5 years.

Transmission Lines. The installation is supplied power from the main switching station via the 34.5-kV transmission line. The system is divided into the west and east feeders. Site personnel indicated the feeders are radial type. This indicates that in the event of a fault or problem on the 34.5-kV feeders there is no way to backfeed loads.

The 34.5-kV line is currently maintained by contract personnel. In the past the lines were maintained by electric shop personnel. Picatinny still has in-house capability to maintain and repair these lines. Some of the in-house electricians were previously employed by JCP&L.

The 34.5-kV transmission line supplies electrical power to 17 substations located throughout the installation. Most of the substations are 34.5-kV to 2400-volts with transformer capacities ranging from 750 to 5000 kVA. Most of the substation equipment is outdated and replacement parts are no longer available through the manufacturer.

The secondary distribution system consists of a 2400-volt ungrounded system. This is an older type of distribution system and is no longer used. If a ground fault should occur, it is difficult to detect the fault. Because there are no grounding lights associated with this system, a ground fault would go unnoticed until a second fault occurs on a different phase. When a ground fault does occur, equipment rated at line-to-phase voltages will be subject to line-to-line voltages (the grounded feeder will raise the ground potential). A second ground fault (on a different phase) will cause more damage than a normal ground fault on a grounded system.

Table 11

Electric Circuit Data

Main Oil Circuit Breaker:	Type JE-37-E, serial # 12161, 34.5 kV rated, 38 kV max. design, Interrupting MVA-1000 MVA, Rated Impulse 200 kV, 1200 A rating, July 55, Federal Pacific Electric
	168 Amperes were metered at main OCB at 10:14 AM, 15 May 1989
Protective Relays:	Overcurrent (3), Westinghouse Inverted, Style 1545029
	CR Directional Overcurrent (3)
	CO Inverse (Residual), tap 1, time dial 2
West Oil Circuit Breaker:	Same OCB as main, listed above
	100 amperes metered at 10:19, 15 May 1989
Protective Relays:	CO inverse overcurrent relays (3), Westinghouse Style 1545029, tap 6, time dial 1
	CO inverse, style 1545027-A, tap .8, time dial 1, Westinghouse
East Oil Circuit Breaker:	Same as main OCB, listed above
	50 amperes metered at 10:20 AM, 15 May 1989
Protective Relays:	CO inverse over current(3), style 1545029, tap 6, time dial 2, range 2- 12 A Westinghouse
	Type CO adjustable inverse(1), style 1545027- A, tap .8, time dial 2, Westinghouse

Electrical personnel indicated that although there is no ground fault detection system installed, they periodically check the 2400-volt system for ground faults. This does not seem realistic since there are only seven slots for high voltage electricians.

Substations. Personnel indicated that the substations have adequate capacity to supply existing electrical loads. Several substations were inspected for capacity and condition of equipment as noted below.

Substation B

1. Substation B consists of a 2000-kVA, 34.5 kV-to-2400 volt, delta-to-delta transformer and two feeder circuit breakers.

2. Spot current measurements taken on circuit breaker 1 showed values of 90, 90, and 80 amperes on phases A, B, and C, respectively. This calculates to a load of 375 kVA on feeder 1.

3. Spot current measurements taken on circuit breaker 2 showed values of 185, 200, and 200 amperes on phases A, B, and C, respectively. This calculates to a load of 830 kVA on feeder 2.

4. The total load on the transformer is 1205 kVA. This is well below the capacity of the 2000-kVA substation.

5. The circuit breakers are rated for 1200 amperes with a momentary rating of 20,000 amperes. For a transformer impedance value of 6.4 percent, and assuming an infinite bus, the fault current available at the secondary 2400-volt side is 7526 amperes (2000 kVA divided by [1.73 X 2400 X .064]). This is within the momentary rating of the circuit breakers.

6. The relays were last calibrated in September 1983. The circuit breakers probably have not been checked since then.

7. The current transformers on both breakers are 400/5. Each circuit breaker has CO Westinghouse overcurrent relays. Breaker 1 is set at tap 6, time dial 3; this equates to the relay operating when a current value of 480 amperes has been reached. Breaker 2 is set at tap 6, time dial 4; this equates to the relay operating when a current value of 480 amperes has been reached.

8. Substation B has lightning arrestors on the primary side of the substation. The high voltage bus appears to be in good condition. The insulators are not chipped. Maintenance is not done regularly. The substation should be checked out with an IR camera to determine if hot spots exist.

Substation A

1. Substation A consists of a 2000-kVA, 34.5 kV-to-2400 volt delta-to-delta transformer and two feeder circuit breakers.

2. Spot current measurements on circuit breaker 1 showed values of 150, 165, and 165 amperes on phases A, B, and C, respectively. This calculates to a load value of approximately 685 kVA.

3. No load was measured on circuit breaker 2.

4. The total load on the transformer is well below the transformer capacity of 2000 kVA.

5. The circuit breaker characteristics are the same as those listed above for substation B.

6. The relays were last calibrated in August 1983 for breaker 1 and August 1984 for breaker 2. The circuit breakers probably have not been checked since then.

Transformer Bank at Building 350.

1. This transformer bank consists of a three 100-kVA, 2400-208/120 volt system.

2. The insulation on the high voltage and low voltage cables has deteriorated and should be inspected with a megger.

3. The transformer bank should be inspected with an IR scan to determine hot spots on transformers and connections.

4. There did not appear to be an adequate system ground at the wye point of the transformer secondary side. If the system is not grounded correctly, the resulting unstable voltages could affect areas where computer equipment is operated.

Transformer Bank at Building 350A.

1. This substation consists of three banks of 2400-208/120 volt transformers. The transformers look very old.

2. The middle transformer does not appear to have a system ground. If the system is not grounded correctly, unstable voltages will result.

3. An IR scan should be performed on the transformers and connections to determine if hot spots exist.

JCP&L Electric Utility Supply

Between the JCP&L Wharton Substation and Picatinny Arsenal, electrical power is tapped off the I711 transmission line to supply the surrounding commercial and residential areas. This has been the normal mode of operation for many years.

In the past year, the availability of electrical power has become critical due to the increased commercial demand and the inability of Picatinny Arsenal to generate a portion of its required power. The electrical capacity for the I711 transmission line is 40 megawatts. This capacity was reached in July 1988.

Since the limiting factor for the power available at Picatinny Arsenal is the capacity of the I711 transmission line, power must be generated within the Arsenal or JCP&L must increase the transmission line capacity.

Personnel at Picatinny Master Planning indicated an additional feeder from the Wharton Substation to the Picatinny utility grid is planned for installation and operation in 1989. The new transmission line (I747) will have a capacity of 60 megawatts. This will solve Picatinny's immediate requirement for power, but is a short term fix because it only addresses Picatinny's immediate need for power, and not the need for a more reliable electrical power system.

Power System Upgrade

Discussions with Picatinny personnel indicate that they are well aware of the deficiencies in existing equipment. A Military Construction, Army (MCA) project has continually been resubmitted and changed since 1982 for the Improved Power Distribution and Alternate Feeder (DD 1391).

An electric power distribution system modernization plan[4] was submitted to Picatinny Arsenal Master Planning. As part of the plan, a single line diagram was submitted. This plan recommended a single substation (34.5 to 12.47-kV transformation) to supply distribution voltage to the entire system. Comments on this plan are listed below:

1. If the proposed main transformer, primary circuit breaker, or main secondary circuit breaker become inoperative, a power outage to the entire installation will result.

2. Maintenance cannot be performed on the main transformer, primary circuit breaker, or main secondary circuit breaker without a power interruption to the entire installation.

3. The proposed single line diagram shows a position for a future substation transformer. Although this gives redundancy to the system, in this era of "concern for terrorism," one bomb detonated at this substation would cause an outage to the entire post. An equipment malfunction resulting in an explosion or fire could also shutdown the entire substation.

4. The proposed single line diagram shows substations 1, 2, and 3. These are only switching stations and not substations. A voltage transformer is normally required at a substation.

5. The existing system has a single point failure at the main switching station (the main circuit breaker). This means that if the main circuit breaker malfunctioned, this would cause a complete electrical outage. This affects how the reliability of the installation is determined. While the existing system has one single point failure, the proposed system can have at least three (at substation 1: primary and secondary circuit breakers and main transformer). More than one substation located throughout the post would be recommended.

6. The comment addressed in point 5 above was addressed to the proponents of the proposed upgrade (Planning Personnel). They indicated that they agreed with one substation concept, but this is only a "proposed document" that would more than likely be changed before approval. Sometimes the best intentions or plans are put aside or forgotten. It is imperative that this proposed single line diagram concept be changed before implementation. If not, it is possible that the reliability of the proposed system will be less than that of the existing one.

Other Considerations

A new 5000-kVA transformer was installed in Area 700, Building 717. This is a research area. The normal mode of operation is to operate this facility during off-peak hours. This must remain the normal mode of operation. Operation of the facility at peak hours could result in 34.5-kV feeder interruption.

A short circuit and protection coordination study has not been prepared for Picatinny Arsenal in recent years. A study should be performed to ascertain that protective devices will safely interrupt fault currents and the operation of protective devices will result in the minimal amount of power interruption.

[4] *Picatinny Arsenal Power Modernization Study.*

There has been much discussion in recent years about the limited availability of electrical power in the North East. In the next few years, the North East may be very susceptible to brown outs and even black outs. Since this possibility exists, it should be considered when analyzing in-house power generation.

During the site trip a single line diagram for the installation was not available. The first step in analyzing an electrical system is to prepare an up-to-date single line diagram that indicates the distribution system down to the building feeder level.

There does not appear to be a problem with voltage at the utilization levels (208/120 voltage). The electric shop personnel indicated that there were isolated problems with voltage drops for certain areas/equipment, but after supplying different feeders and installing line conditioners for more sensitive equipment, the problems were resolved.

The incoming feeder from JCP&L has an overhead static wire for lightning protection. This static wire is discontinued when the feeder reaches Picatinny Arsenal property. It is recommended that this form of lightning protection be installed during upgrade of transmission lines on the Arsenal.

3 STEAM SUPPLY AND CONSUMPTION

Current Steam Consumption

The period from 1 July 1988 through 30 June 1989 was selected to develop baseline steam consumption primarily because the data was the most current and the CPP turbine-generators were out of service. Since the last turbine-generator went out of service in April 1988, all steam produced is sent to the distribution system. This simplified interpretation of the steam supply and fuel consumption data, because there were no artificial steam loads created by electrical demands.

Another effect of not operating the turbine-generators was that from April to June 1988, the boiler steam pressure fluctuated between 300 and 430 psig. This condition was stabilized to about 300 psig by the end of June. Because the turbine-generators were out of service, the pressure reduction was a necessary safety precaution. Large pressure variations would have made the conversion of steam output (in pounds of steam/hr) to consistent units of MBtu difficult because of differences in steam heat content (enthalpy) at those pressures.

Central Power Plant Steam Load

Hourly steam flow data was obtained from the CPP daily logs. The steam flow readings required correction because the steam flow orifices were not calibrated at the current operating pressure. The relationship between the steam flow for an orifice that is reading a steam flow different than design is as follows:

corrected steam flow = recorded steam flow x correction factor

where correction factor = $(\text{design } v \,/\, \text{actual } v)^{1/2}$

v = specific volume of steam

The two CE boilers were designed to supply steam to the turbine-generators at about 430 psig and 700 °F; the Riley boiler was designed for 450 psig and 700 °F. During the study, the boilers operated at about 300 psig and 600 °F. Based on these values, the correction factors for the CE and Riley boilers are 0.90 and 0.85, respectively. Because the CE boilers were operated more frequently, and to reduce the complexity of calculations, the correction factor of 0.90 was used. The steam flow was also converted to consistent units of MBtu to develop and compare load profiles. The steam enthalpy, based on operating conditions, was 1314 Btu/lb.

Table 12 summarizes the steam flow data by month, showing the uncorrected average hourly load (in 1000 lb steam/hr), corrected average hourly load (in 1000 lb steam/hr) and corrected average hourly load (in MBtu/hr). Table 13 shows the average hourly seasonal steam flows.

Because of the potential inaccuracies in measurement, it is important to cross check steam output readings against other methods of measurement. Some of the methods typically available are feedwater flow, fuel use, and combustion gas analysis. At the time of this study, only fuel consumption data was available. The No. 6 fuel oil use is estimated from visual tank level readings and recorded monthly for Picatinny's Defense Energy Information System (DEIS). The DEIS fuel oil consumption data is summarized in Table 14. The heating value from the DEIS report for No. 6 oil was 149,690 Btu/gal.[5]

[5] *Installation Energy Use Summaries/DEIS Report.*

Table 12

CPP Average Monthly Steam Loads

Month	Steam Flow (in 1000 lb/hr)	Corrected Steam Flow (in 1000 lb/hr)	Corrected Steam Flow (in MBtu/hr)
Jul	32.73	29.31	38.52
Aug	28.55	25.57	33.61
Sep	30.33	27.16	35.70
Oct	79.29	71.01	93.33
Nov	90.26	80.83	106.24
Dec	120.90	108.27	142.30
Jan	135.08	120.96	158.99
Feb	139.11	124.57	163.74
Mar	130.20	116.60	153.26
Apr	106.87	95.70	125.79
May	70.10	62.78	82.51
Jun	30.83	27.61	36.29

Table 13

CPP Average Seasonal Steam Loads

Season	Steam Load (MBtu/hr)
Winter (Dec,Jan,Feb)	154.72
Spring (Mar,Apr,May)	120.46
Fall (Sep,Oct,Nov)	78.59
Summer (Jun,Jul,Aug)	36.14

Table 14

Fuel Oil Consumption

Month	(BBL)	(MBtu)	(MBtu/hr)
Jul	3496.80	21984.38	29.55
Aug	4224.70	26560.70	35.70
Sep	4520.50	28420.40	39.47
Oct	13959.80	87765.26	117.96
Nov	14737.00	92651.52	128.68
Dec	17964.60	112943.44	151.81
Jan	21753.00	136763.00	183.82
Feb	17845.00	112192.00	166.95
Mar	20672.00	129969.00	174.69
Apr	14671.90	92242.00	128.11
May	10714.00	67359.00	90.54
Jun	4438.50	27905.00	38.76
Annual	148,997.80	936,755.70	107.17

The steam flow and fuel consumption from Tables 12 and 14 are plotted by month in Figure 4. Dividing the total steam produced by the fuel input gives an annual plant efficiency of about 94 percent. Although this is obviously too high. The overall shape of the curves is reasonably close considering the potential for measurement inaccuracies.

A more informative look at the load profiles is given in Figure 5, which shows a plot of the minimum and maximum hourly steam flow (MBtu/hr). This plot indicates load variations throughout the year. Of particular interest to this study is the minimum hourly load. This is typically called the "no-load" load. The no-load load is the amount of steam required just to keep the steam lines filled, satisfying heat losses and leaks. It indicates the thermal losses in the distribution system. For the study period, this value was recorded at 20,000 lb steam/hr or about 23.5 MBtu/hr (corrected). This value will vary according to outside temperature and, in Picatinny's case, when the winter lines are opened and closed. Determining the no-load load is not as easy for winter months because of the variation in heat load. The no-load load will be higher in the winter months because of increased heat losses from additional lines on the system and greater temperature differences.

Another important value, obtained from Figure 5, is the maximum steam flow. The maximum steam load for this period was about 170,000 lb steam/hr or about 201 MBtu/hr (corrected). The maximum steam flow is an important design factor for sizing boilers for new plant alternatives. A high load in one year is not accurate enough to predict the maximum design load for an installation. A modeling technique for estimating the maximum load will be described in the following sections.

Figure 6 shows a graph of the same steam load data normalized based on heating degrees. A heating degree is the temperature difference between 65 °F and the ambient temperature. The upper graph is the average daily temperature. From this figure, the average winter heat load is about 4,200 lb steam/hr per heating degree or 5.0 Mbtu/hr (corrected) per heating degree. This value can help predict plant output

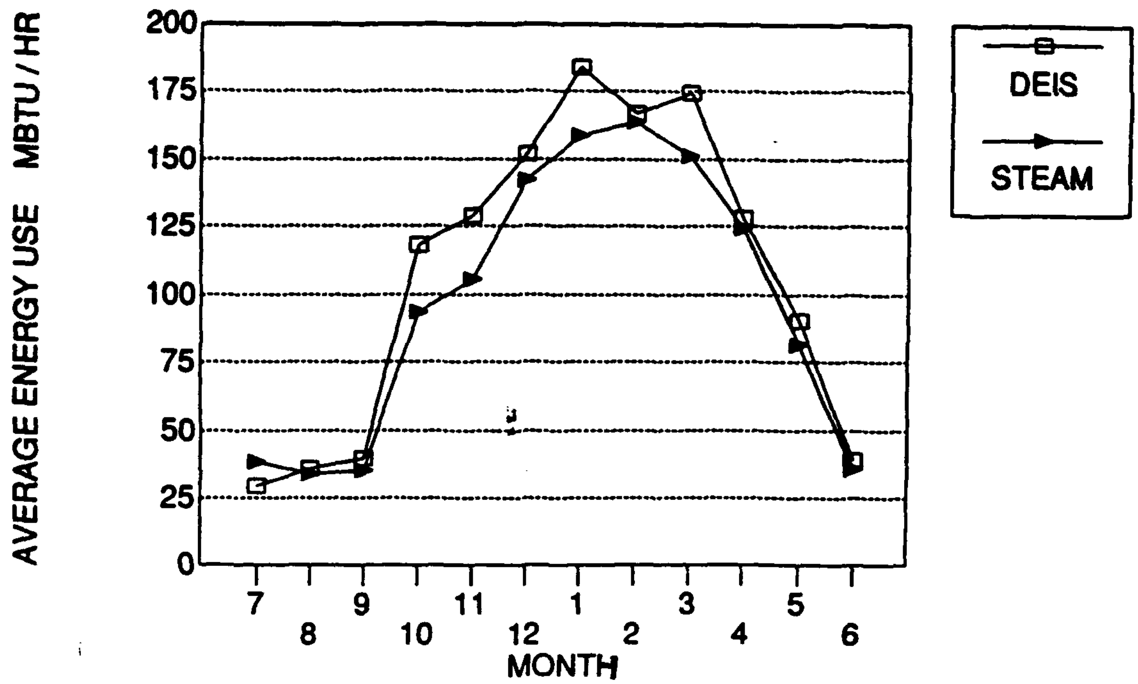

Figure 4. DEIS oil use vs actual steam output.

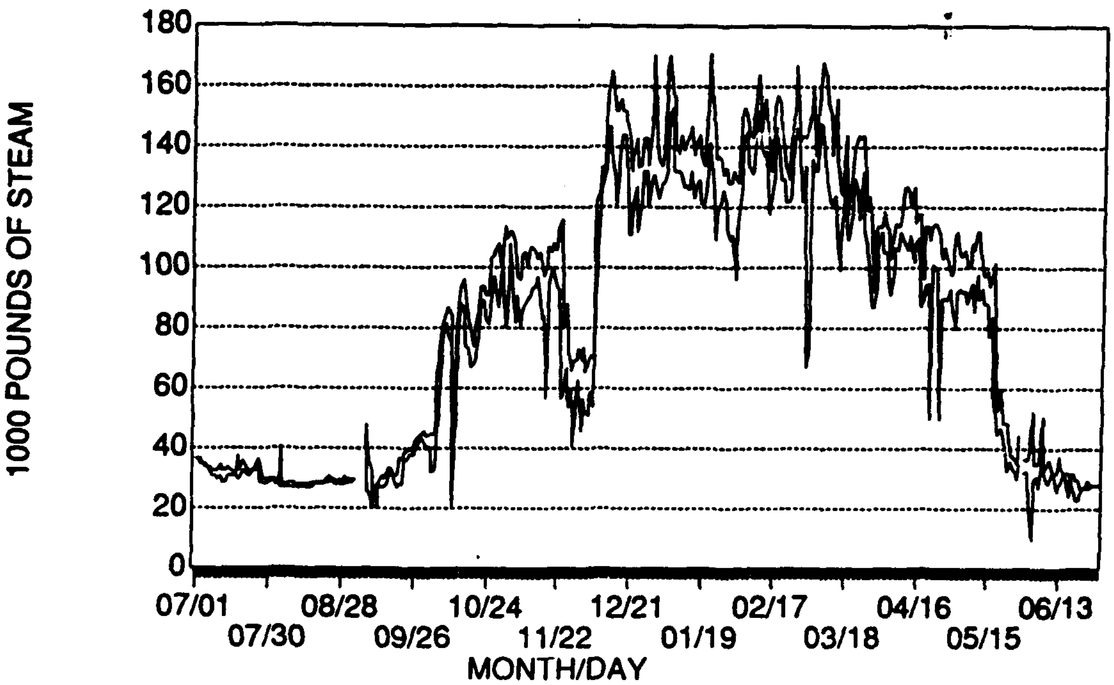

Figure 5. Maximum and minimum steam output.

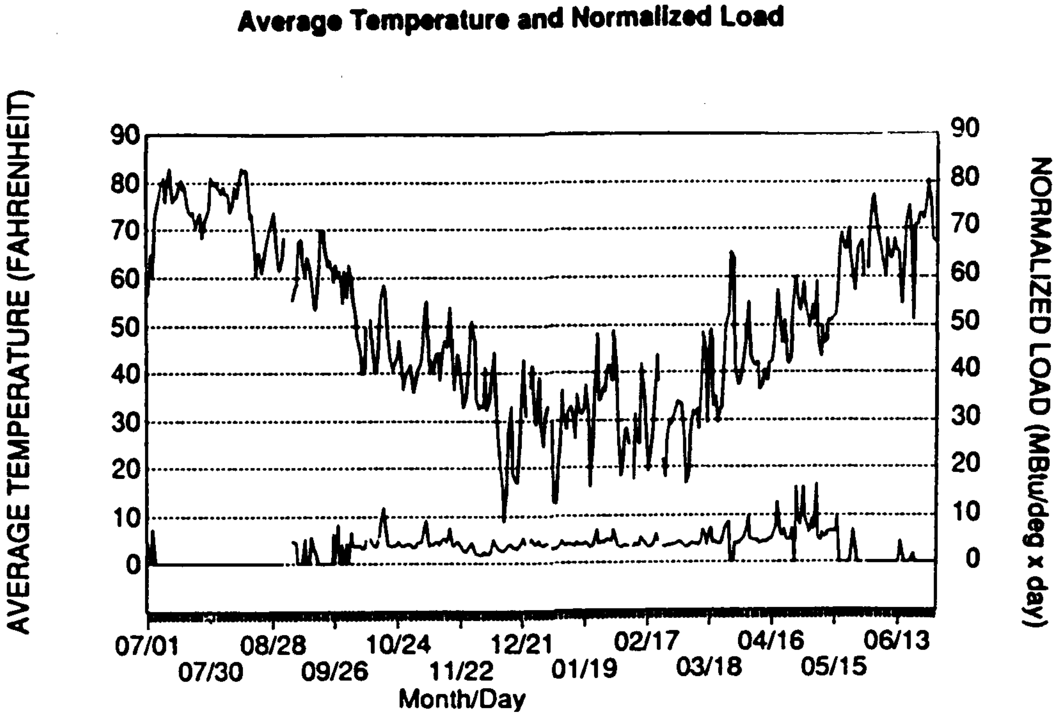

Figure 6. Normalized steam output and ambient temperature.

requirements and determine whether another boiler should be brought on line for the next day, by using local weather forecasts. For example, if the temperature is predicted to be 30 °F, the plant should be ready to produce:

$$5.0 \text{ MBtu/hr per degree } (65 - 30) = 175.5 \text{ MBtu/hr}$$

This method can be further refined by adding variables for cloud cover and day of the week to provide a more accurate prediction.

Steam Cost Estimate

An estimate for the cost of steam can be developed from three major cost elements: fuel, labor, and other operation and maintenance (O&M) costs. Other O&M costs include utilities, minor repairs, and water treatment chemicals. Annual fuel costs for the study period were about $2.82 million dollars. Labor costs were about $0.89 million dollars. Other O&M costs were estimated at $0.80 million dollars, based on an average cost of $0.939/MBtu (quote from Schmidt Associates, Inc.). This gives a total cost of $4.51 million dollars/year to produce steam. Dividing this cost by the amount of steam produced (854,000 MBtu) gives a cost of $5.28/MBtu. This number is probably low because actual O&M costs were not available.

Steam End-Use

In addition to historical records, steam loads can be estimated by summing the heat requirements of the end-users. This includes heating, cooling, and process steam. Picatinny has no significant steam process or cooling loads, according ... Ebasco[6] study and Picatinny personnel. Once the end-user load is obtained, distribution system losses must also be estimated. The estimated steam load equals the end-user loads plus the distribution system losses.

To estimate the end-user load, researchers used an analytic method developed by USACERL,[7] that was further developed into a computer model called HEATLOAD. In this method, typical Army buildings are grouped into the categories listed in Table 15. Each building has a corresponding daily heating energy consumption equation in the following form:

$$E_h = a_1 + (b_1 \times HDD_d) \qquad \text{[Eq 1]}$$

where a_1 and b_1 = regression parameters as listed in Table 15
HDD_d = daily heating degree day.

The regression parameter a_1 is a constant that represents energy use that occurs for zero HDD and reflects nonheating loads such as hot water and cooking.

Building categories and area (sq ft) were obtained from the Building Information Schedule (BIS) for Picatinny Arsenal. A site visit was made to confirm the number of buildings on the system because of discrepancies among the BIS data, previous studies, and information provided by Picatinny personnel. The site visit confirmed that 321 of Picatinny's 1059 buildings are connected to the distribution system.

Table 15

Building Categories and Energy Consumption Equations

Category	Equation
Troop housing barracks	E_h* = 130.50 + (15.99 x HDD_d)**
Troop housing barracks (after 1966)	E_h = 81.91 + (7.40 x HDD_d)
Troop housing barracks (modular)	E_h = 295.90 + (34.21 x HDD_d)
Dining facilities	E_h = 231.80 + (12.42 x HDD_d)
Family housing	E_h = 105.6 + (20.02 x HDD_d)
Administration/Training	E_h = 76.71 + (18.97 x HDD_d)
Medical/Dental	E_h = 254.40 + (24.31 x HDD_d)
Storage	E_h = 35.70 + (36.10 x HDD_d)
Production/Maintenance	E_h = 138.40 + (35.73 x HDD_d)
Fieldhouses/Gymnasiums	E_h = 73.69 + (32.40 x HDD_d)

* E_h = daily heating energy consumption (Btu/sq ft/day).
**HDD_d = daily heating degree day.

[6] Ebasco Services Inc., *Total Energy Study for Picatinny Arsenal, Dover New Jersey* (U.S. Army Corps of Engineers New York District Contract No. DACA51-84-C-0076, 1984).
[7] B.L. Sliwinski, et al., *Fixed Facilities Energy Consumption Investigation-Data Analysis*, USACERL Interim Report E-143/ADA066513 (USACERL, February 1979).

Initially, the HDD data required for HEATLOAD were obtained from Army Technical Manual (TM)[8] 5-785 and from an unofficial reporting station located at Budd Lake, NJ. Picatinny maintains data from the Budd Lake station because the station is close and the data is current and readily available. TM 5-785 provided only a one-line summary for Picatinny Arsenal that included a yearly average HDD and the 99- and 97.5-percent design temperatures. The Budd Lake and the U.S. Air Force Environmental Technical Applications Center (ETAC) annual heating degree days were 6270 (17-yr normal) and 6304, respectively. The ETAC 97.5-percent design temperature of 6 °F seemed low compared to the Budd Lake minimum temperatures. These discrepancies indicated that the TM 5-785 design temperature may not be representative of Picatinny Arsenal.

The ETAC at Scott Air Force Base (AFB), IL was contacted to determine if TM 5-785 has been updated to include more complete information on Picatinny. ETAC had not updated the manual but was able to provide climatological data from a more representative station at St. Paul's Abbey, Newton, NJ. The new official design temperature for Picatinny, based on St. Paul's Abbey, is 4 °F (97.5 percentile). The design temperature is based on 14 years of local temperature data. ETAC also provided monthly temperature data, including the monthly average HDD for the 1988-89 study period and 14-yr normal listed in Table 16. The Budd Lake data was not used in this study, because local data was available from ETAC, which is considered the official source of heating and cooling design data.

The HEATLOAD program was run using both the ETAC 1988-89 and 14-yr normal climate data. Figure 7 compares the HEATLOAD load profiles for the two time periods. This comparison demonstrates the need for modeling thermal supply using long-term average temperature data. It is quite apparent from the low load for January that Picatinny experienced a much warmer winter than normal. Using the 1988-89 study period as a baseline would have underestimated projected winter loads.

Table 16

Monthly Average HDD

Month	1988-89	14-yr normal
JUL	20	8
AUG	24	12
SEP	187	134
OCT	604	450
NOV	712	738
DEC	1142	1113
JAN	1114	1256
FEB	1052	1086
MAR	930	899
APR	618	516
MAY	257	246
JUN	36	46
Average	6696	6504

[8]Technical Manual (TM) 5-785, *Engineering Weather Data* (Departments of the Air Force, the Army, and the Navy, 1 July 1978).

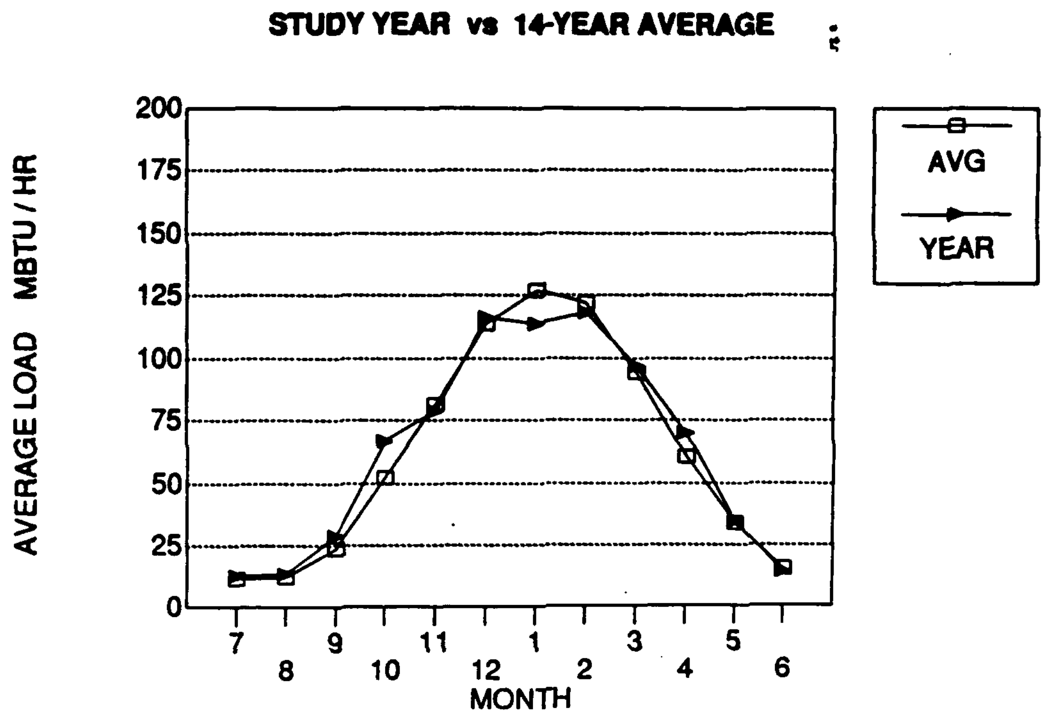

Figure 7. HEATLOAD 1988-89 and 14-yr monthly load profiles.

Figure 8 is an example of the HEATLOAD analysis report for the study period. The energy usage report shows the maximum and average monthly heat load estimates, maximum load requirement, total thermal energy demand, and the total area for each building category. The monthly maximum heat load is based on the average extreme minimum temperature; the average heat load is based on the average HDD.

The CPP average monthly steam output and HEATLOAD profiles are compared graphically in Figure 9. Although the shape of the profiles is close, the HEATLOAD profile is lower because it does not include distribution system losses. This difference indicates the magnitude of distribution losses which are estimated in the following section.

Distribution System Losses

Distribution losses can account for a large percentage of heat plant capacity. As discussed earlier, the no-load load indicates the distribution losses. The recorded summer no-load load was about 23.5 MBtu/hr. Determining the lowest summer load by analyzing steam load data is a good method to estimate distribution losses, but is not a very rigorous method. To better quantify these losses, researchers used the SHDP to estimate distribution losses.

SHDP is a pressure-flow-thermal efficiency computer program for modeling steam district heating systems. The program has several capabilities including design and economic evaluation of manhole renovation and modifications or additions to existing distribution systems, and economic evaluation of operating at lower pressures and improved maintenance of steam traps. In this study, SHDP was used to estimate distribution losses, evaluate satellite plant locations, and identify distribution design problems. A more detailed description of SHDP output information is given in Appendix D.

HEATLOAD
Energy Usage Report

Date: 12/18/1989 Climate Region: PICATINNY STUDY 1988-1989 2
Title : PICATINNY - CURRENT BUILDING CONFIGURATION

Month	Maximum (MBtu/hr)	Average (MBtu/hr)	Building Type	Building Area sq.ft.
Jan	207.294	102.778	Family Housing......	60181
Feb	207.294	107.423	Barracks, pre-1966..	49661
Mar	164.406	85.756	Barracks, post-1966.	0
Apr	121.517	58.895	Barracks, modular...	0
May	107.221	23.692	Admin/Training Facil	1078905
Jun	78.629	3.433	Fieldhs & Gymnasiums	49279
Jul	64.333	1.847	Dining Fac, Commisar	21532
Aug	64.333	2.221	Production/Maint Fac	1137388
Sep	92.925	17.811	Medical/Dental Facil	0
Oct	121.517	55.702	Storage Buildings...	101185
Nov	135.813	67.861	Other No.1..........	0
Dec	178.702	105.319	Other No.2..........	0

Design Maximum Load = 174.413 (MBtu/hr) at 4 degrees F

Parasitic Load = 11.052 (MBtu/hr)

Heating Load (MBtu/yr)	Parasitic (MBtu/yr)	Total (MBtu/yr)
459470.30	96815.74	556286.04

Total heating degree days for the year = 6696

Note: The above table of maximum and average heating loads does not include parasitic loads.

Figure 8. HEATLOAD energy report for 1988-89.

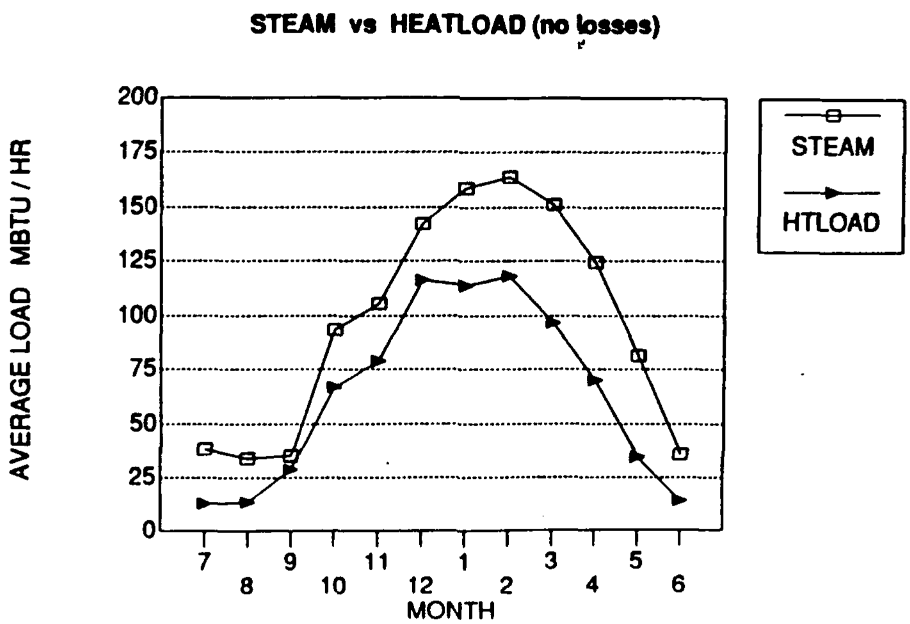

Figure 9. HEATLOAD 1988-89 and CPP monthly load profiles.

To use SHDP, the entire Picatinny steam distribution system was mapped. A site survey was conducted to confirm summer, winter, and unused lines, that are shown in Figure 3. The map is coded to identify the seasonal and unused lines. The survey identified about 150 buildings that were receiving steam, although Picatinny had estimated only 50 buildings had a summer requirement for steam. The survey also showed that about one-third of the steam traps had failed.

SHDP is designed to estimate the total heat load to the heating plant with a breakdown of the distribution losses. This requires entering distribution line nodes, line diameters and lengths, CPP supply pressure, and individual building loads. SHDP was set up to estimate only the distribution losses by setting each building load to zero, instead of entering several hundred values. This configuration described the output of the CPP required to supply just enough steam to fulfill the demand caused by the steam distribution system losses.

This procedure was performed for both a summer and a winter no-load scenario to account for steam lines closed during the summer months. These scenarios were extrapolated to develop monthly average no-load loads based on the average monthly ambient temperature, because conductive losses are dependent on the outside temperature. Table 17 lists the average monthly, seasonal, and annual no-load loads.

The monthly no-load loads from Table 17 are shown graphically in Figure 10. The sharp increase that occurs from September to October and the decrease that occurs from May to June show the significance of opening and closing the winter-only steam lines. This same pattern is also shown in Figure 5. The minor fluctuations in Figure 10 are caused by changes in the outside temperature. The no-load profile shows that it pays to delay the opening and speed the closing of the winter-only steam lines.

This concept can be expanded to closing unneeded summer lines. As discussed earlier in this chapter, a site survey showed about 100 buildings receiving steam that did not require steam during the summer. Although these buildings may not actually use the steam, the lines going to those buildings will lose energy through conduction and failed steam traps. The no-load load could be reduced by one-third, based on the fact that only 50 of 150 buildings need steam. One-third of 17.8 MBtu/hr is about 5.9 MBtu/hr. Assuming summer operation for 122 days (4 months), 24 hours per day, and a typical cost of steam energy at $5/MBtu, the cost of the wasted energy is about $86,000 annually. Overall, the no-load load could be reduced by half with better line and trap maintenance and improved steam supply management. A 50 percent reduction would save $390,000 annually.

Although the SHDP summer no-load estimate (17.8 MBtu/hr) is lower than the CPP no-load estimate (23.5 MBtu/hr), the values are close enough to consider the SHDP model a reasonably accurate method for estimating distribution losses. The difference in these values may be caused by unidentified user loads, a low estimate of trap loss (33 percent trap failure was assumed, based on field survey), or inaccuracies in the CPP steam flow measurements. A more detailed study of the steam distribution system and CPP data could provide more accurate values.

One important loss that has not been accounted for is the loss of condensate from the steam distribution lines. This loss is particularly important for Picatinny because they do not return any condensate from the distribution system to the CPP. The energy available in the condensate was estimated based on 180 °F condensate and 50 °F makeup water. The difference in enthalpy (148 Btu/lb - 18 Btu/lb) gives the available energy in the condensate at 130 Btu/lb. A percentage loss was estimated as a ratio of the energy in the condensate over the energy in the steam supplied to the user. The energy in the end-user

Table 17

Distribution Loss Estimates

Time Period	Losses (MBtu/hr)
JUL	17.6
AUG	17.7
SEP	17.9
OCT	28.6
NOV	29.2
DEC	31.8
JAN	31.4
FEB	32.0
MAR	30.4
APR	28.4
MAY	26.2
JUN	17.7
Winter (Oct-May)	29.7
Summer (Jun-Sep)	17.7
Annual	25.8

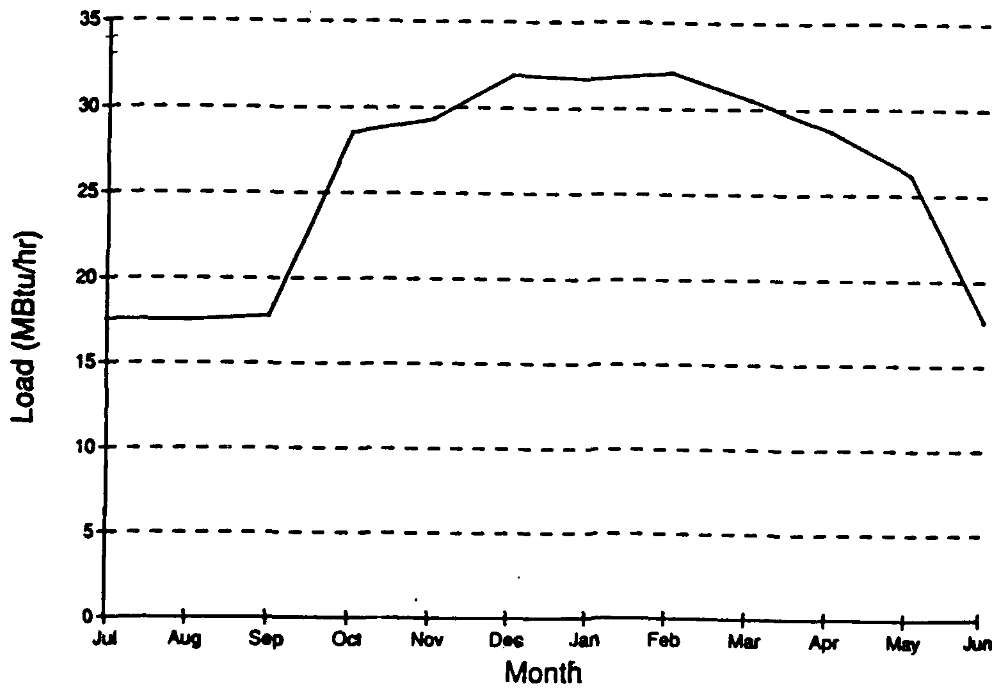

Figure 10. Monthly no-load profile.

steam was assumed at 1177 Btu/lb (60 psig saturated steam). This makes the estimated loss 11 percent of the total load without the distribution losses from leaking steam traps and pipe conduction or about 12.4 percent of the HEATLOAD estimate.

Figure 11 compares the CPP steam load profile and the HEATLOAD load profile for the 1988-89 study period, including distribution losses from Table 17 and condensate losses. Because the estimated profile compares favorably to the CPP steam load profile, the above procedure can also model projected steam requirements.

Projected Steam Consumption

A listing of proposed new and modified facilities through 1998 was provided by the Picatinny Master Planning office. Table 18 lists the facilities that will affect the winter heat load. It shows the project form number, project name, building occupation date (BOD), building area, military category code, approximate location, and HEATLOAD building category. The proposed and modified facilities did not indicate any process steam demands. Facilities with self-contained heating systems also were not included in this list.

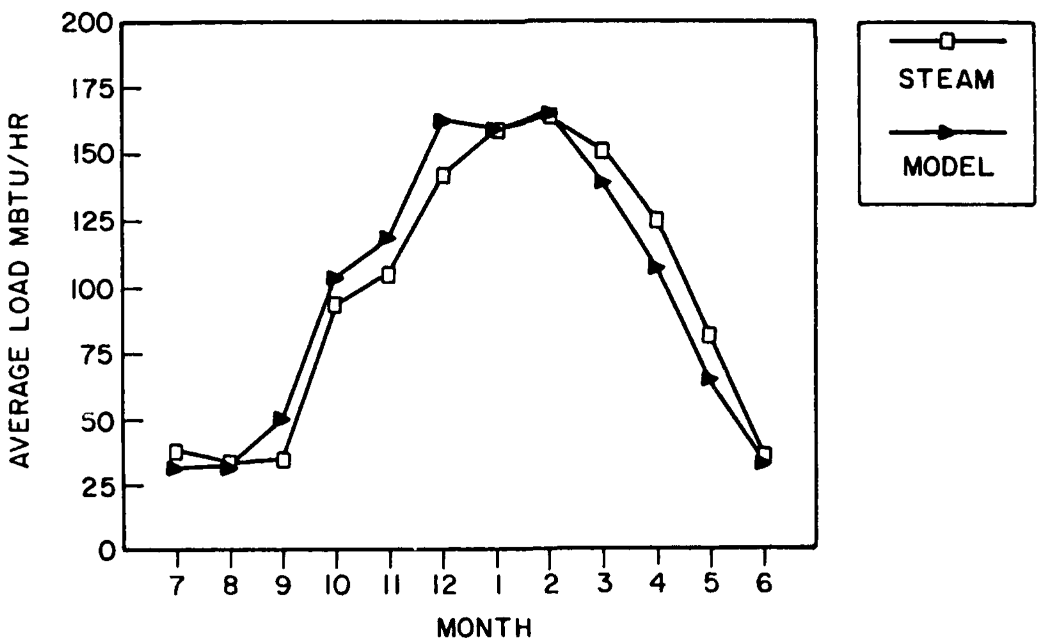

Figure 11. Steam and model load profiles.

Table 18

Projected Steam End-Use

Form No.	Project Name	BOD	Area (sf)	Cat. Code	Location	Cat.
613	BOQ	1995	16000	72410	By 3223	3
29645	ARMAMENT SOFT FAC	1991	178304	31790	1100 Area	5
16183	NEW SECURITY HQ	1997	12500	73016	175 Area	5
12232*	MUNITIONS DEV LAB	1998	142000	31690	31	5
333	ARMAMENT TECH LAB	1990	52500	31590	By 53	8
12101	AMCCOM TMDE LAB	1994	47000	None	Unknown	8
319	EXPLOSIVES LAB	1995	13660	31030	3024	8
621	VEH MAINT FAC	1996	20000	21410	By 223	8
16388	HYPERVEL SYST LAB	1996	16500	31020	1400 Area	8
648	ROTARY WING HANGER	1997	14400	21110	By 3801	8
12232*	MUNITIONS DEV LAB	1998	-87000	31690	31	8
649	CENT STORAGE WARE.	1996	46400	44220	By Bldg T90	10

* Building function is changing from administrative to production.

The HEATLOAD program was run with the current and proposed buildings and the ETAC 14-yr temperature data. Figure 12 shows the results of the HEATLOAD analysis for the projected facility growth. The condensate and distribution losses must be added to HEATLOAD to obtain the total steam demand. Condensate losses were estimated according to the same procedure described earlier. Distribution losses were estimated from the SHDP no-load load using the ETAC 14-yr temperature data. Figure 13 shows the average monthly future load profile, including condensate and distribution losses.

The design maximum load is the sum of HEATLOAD load at the ETAC design temperature of 4 °F (shown in Figure 12), condensate losses, distribution losses, and a 5 percent margin of error. Table 19 summarizes the design maximum load elements. The design maximum load for the projected thermal demands is 294 MBtu/hr or about 250,000 lb/hr (150 psig saturated steam). This is the design steam load assumed for all energy supply alternatives developed during this research.

```
****************************************************************************
**                           H E A T L O A D 2                            **
**                          Energy Usage Report                           **
**                                                                        **
**  Date: 10/16/1989       Climate Region: PICATINNY - NEWTON             **
**  Title : PICATINNY - CURRENT PLUS FUTURE BUILDINGS                     **
****************************************************************************
```

Month	Maximum (MBtu/hr)	Average (MBtu/hr)	Building Type	Building Area sq.ft.
Jan	254.195	147.647	Family Housing......	60181
Feb	254.195	141.922	Barracks, pre-1966..	49667
Mar	204.241	109.298	Barracks, post-1966.	16000
Apr	154.286	70.024	Barracks, modular...	0
May	137.635	39.176	Admin/Training Facil	1427349
Jun	104.332	17.846	Fieldhs & Gymnasiums	49278
Jul	87.680	13.618	Dining Fac, Commisar	21532
Aug	87.680	14.029	Production/Maint Fac	1216398
Sep	120.983	27.613	Medical/Dental Facil	0
Oct	154.286	61.054	Storage Buildings...	149783
Nov	170.938	94.690	Other No.1..........	0
Dec	220.892	132.330	Other No.2..........	0

Design Maximum Load = 215.897 (MBtu/hr) at 4 degrees F

Total (MBtu/yr)

631458.07

Total heating degree days for the year = 6503

Figure 12. HEATLOAD projected loads.

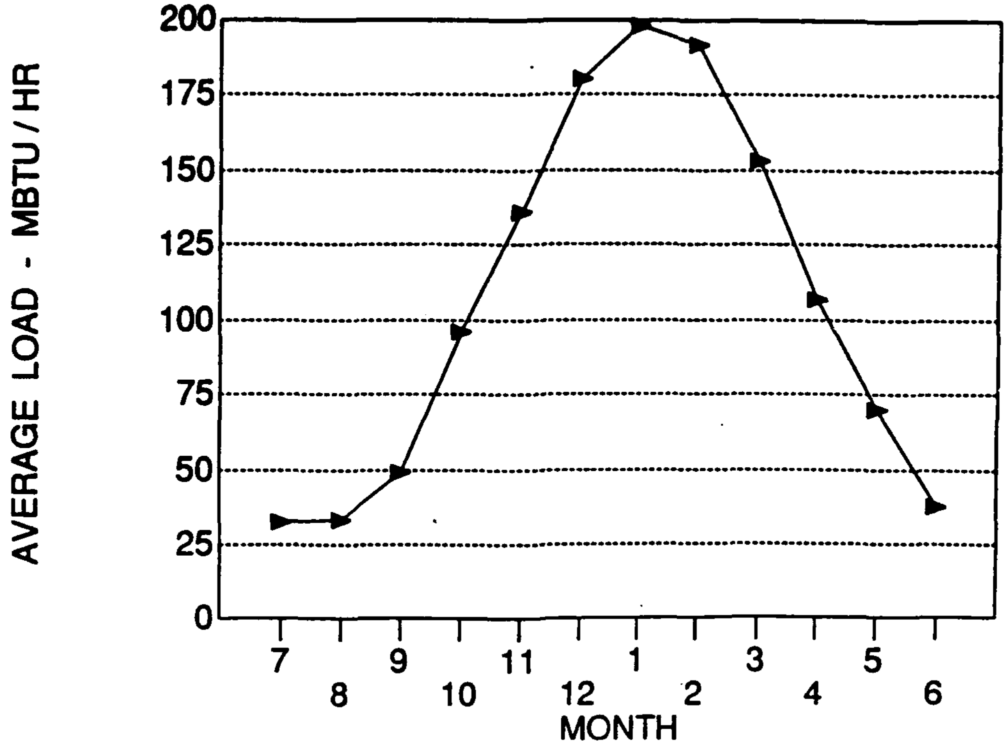

Figure 13. Projected load profile.

Table 19

Maximum Design Heat Load Factors

Factor	Load (MBtu/hr)
End-user load	216
Condensate loss	27
Distribution loss	37
5 percent margin	14
Maximum design load	294

4 ELECTRICAL POWER CONSUMPTION

Current Electrical Consumption

The 1 July 1988 through 30 June 1989 time period was selected to develop baseline electric power consumption. As with the steam supply analysis, this time period was chosen because the CPP turbine-generators were out of service. This simplified the data analysis because all electric power for this time period was purchased from JCP&L.

Information on purchased electrical power was obtained from two sources: (1) the Picatinny DEIS report and (2) CPP daily operating logs. The DEIS report information originates from the JCP&L power bills. The CPP data is read from a meter inside the plant. This meter is not the one that JCP&L uses to compute Picatinny's power bills.

CPP personnel record the instantaneous peak demand (MW) once each hour and the electric use (kW and kVA) at the beginning of each shift. USACERL compiled this data for 1 year to study daily variations and provide a cross check to the JCP&L data. Figure 14 is a graph of the maximum and minimum daily peak demands. The cyclic nature of the electric demand between weekday and weekend is readily apparent. The minimum peak is between 4.5 and 5 MW. The maximum rating of the CPP meter is apparent by the plateaus occurring at 10 MW. According to JCP&L, the peak demand for Picatinny is actually about 12 MW.

JCP&L also provide daily and hourly demand curves for one week in December 1988 and one day in December 1988 (Figures 15 and 16). Figure 15 shows a daily cyclic pattern similar to the weekend/weekday cycle shown in Figure 14. The occurrence of the demand peaks is important for determining the benefits of cogeneration and other peak shaving and peak shifting techniques. Figure 16 shows the electric demand at 15-minute intervals for a 24-hour period for a workday. This curve emphasizes the rapid increase in electric demand between 6 and 7 a.m.

The electric consumption data from the CPP and JCP&L are compared in Table 20. This comparison shows that the DEIS report and the CPP operating log are not consistent. The discrepancy could be caused by (1) different reporting periods, (2) poor calibration of the CPP meter, (3) power factor influence, or (4) transportation errors in data collection. Analysis of energy supply alternatives will be based on the JCP&L total annual electric demand. Because JCP&L routinely calibrates their meters, their electrical use data will be used as the baseline for projecting future needs.

An attempt was made to check the power factor for purchased power at Picatinny using the CPP log data for kW and kVA. The power factor obtained was very inconsistent, ranging from about 0.3 to over 2.0. Because power factors over 1.0 are not possible, the CPP data could not be used for power factor calculations. However, the JCP&L data for the first three quarters of fiscal year 1989 (FY89) showed power factors ranging from 0.76 to 0.79. This resulted in power factor adjustment costs ranging from $1471 to $2169 per month. This cost was less than 1 percent of the total electrical bills. This implies that power factor correction at Picatinny Arsenal is not a major problem.

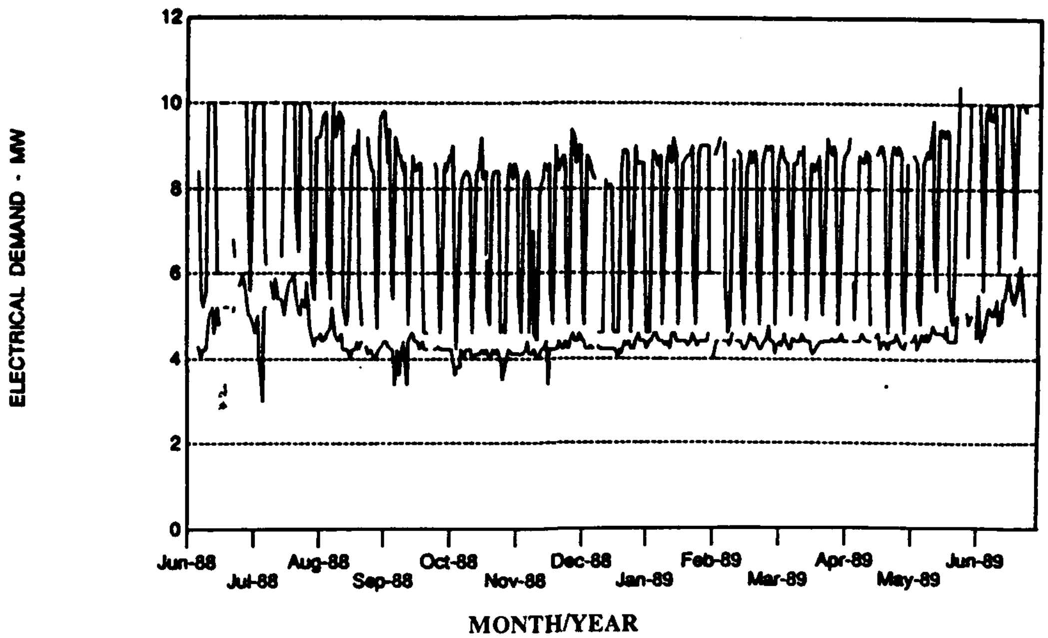

Figure 14. Maximum and minimum electric demands.

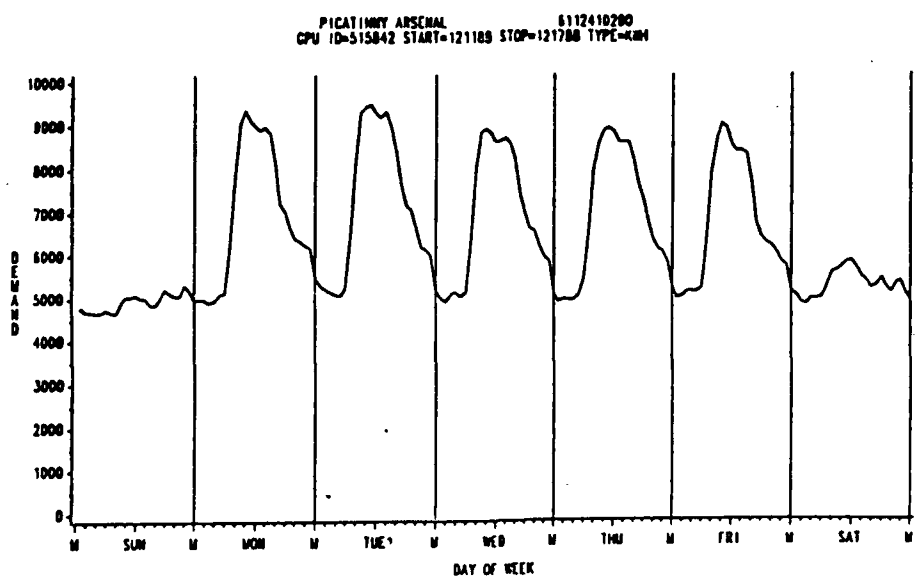

Figure 15. JCP&L daily demand profile.

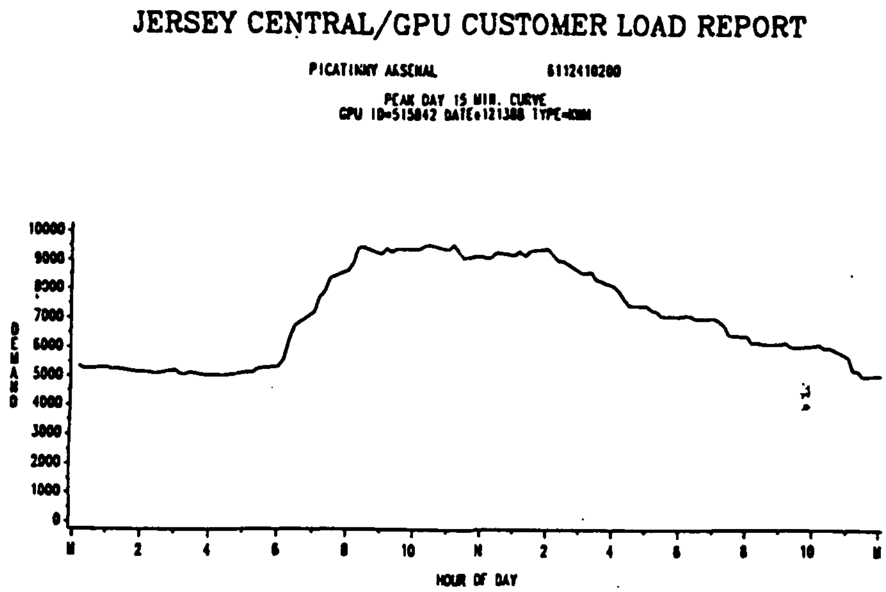

Figure 16. JCP&L hourly demand profile.

Table 20

Comparison of JCP&L and CPP Electric Meters

Month	JCP&L (MWh)	CPP (MWh)	Difference (%)
Jul 1988	5259	5029	4.4
Aug 1988	5227	5189	0.7
Sep 1988	4802	4248	11.5
Oct 1988	4313	3954	4.0
Nov 1988	4240	3954	6.8
Dec 1988	4596	4094	10.9
Jan 1989	4396	4301	2.2
Feb 1989	5011	4180	16.6
Mar 1989	4586	4812	4.7
Apr 1989	4464	4244	-4.9
May 1989	5074	4524	10.8
Jun 1989	5458	5158	5.5
TOTAL	57,426	53,874	

Electrical Costs

The Picatinny electric bill is composed of five charge rates: (1) a flat customer charge, (2) a base rate energy charge, (3) a demand charge, (4) a kilovolt-ampere charge, and (5) an energy adjustment charge. Appendix C contains selected sections of the rate contract for Picatinny. The customer charge is a flat fee of $436.00/month, independent of electrical use. The base rate energy charge has two components, on-peak and off-peak. The on-peak period is between 8 a.m. and 8 p.m., the remaining time is off-peak. The on-peak charge is $0.06371/kWh and the off-peak charge is $0.04918/kWh. The demand charge is based on the maximum 15-minute integrated kilowatt demand during the on-peak period. The demand charge is $9.89/kW during the months of June through September and $8.91/kW for the months of October through May. The kilowatt-ampere is determined by dividing the maximum demnad by the average power and off-peak periods. The last part of the bill is an energy adjustment to compensate for changes in fuel prices and can be a debit or a credit to the electric bill.

Of these costs, the most significant are the base rate energy charge and the demand charge. (The energy adjustment can be significant, however, it is not controlled by the consumer.) Figure 17 compares the costs for the on-peak and off-peak base rate energy charge and the demand charge. On-peak accounts for 38 percent, off-peak accounts for 35 percent and the demand charge accounts for about 27 percent of the anual electric bill, excluding the energy adjustment. Note that the demand charge is really a penalty for using a large amount of electricity during the on-peak period. This charge can be reduced by several methods that are discussed in Chapter 5.

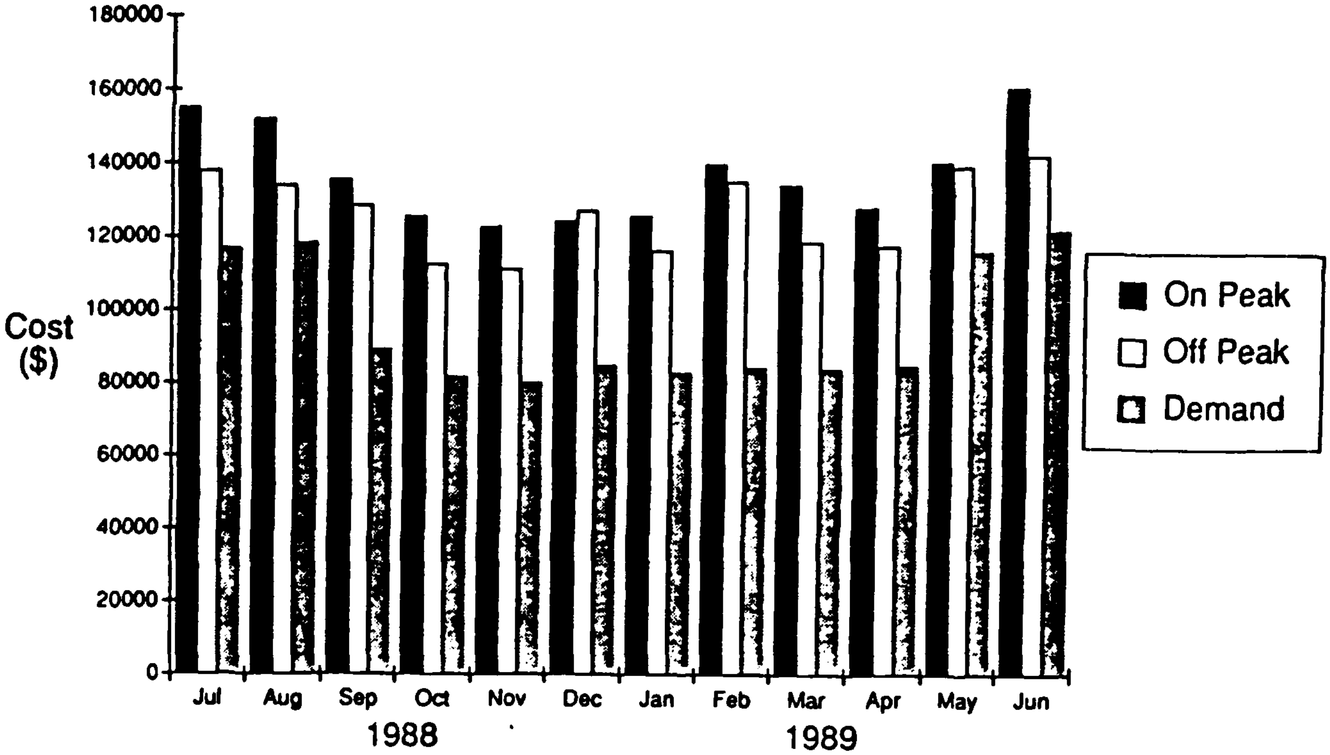

Figure 17. Electrical rate charges.

Projected Electric Consumption

The study period electrical energy use of 57,426 MWh/yr must be escalated to account for new facilities. A growth trend, shown in Table 21, summarizes the annual electric consumption based on the DEIS report for FY83 to FY88. Although electric use has increased significantly since 1983, there has been little growth from 1987 to 1988.

A straight line projection could be made on this data, but it would have little meaning since electric consumption is not directly related to time. Electric consumption depends on a variety of factors, including total building area, building use, occupancy rates, power costs, and outside temperature.

To better account for these factors, an approach similar to the HEATLOAD analysis was made to estimate electrical consumption. Sliwinski[9] developed electric consumption estimates for building categories based on the building area and cooling degree days instead of heating degree days.

Table 22 lists each building and the corresponding daily electrical consumption equation in the form of $E_e = a_1 + (b_1 \times CDD_d)$. Where a_1 and b_1 are regression parameters, as listed in Table 22. Fourteen-year normal cooling degree days were obtained from ETAC and are listed in Table 23. Most categories, however, were unaffected by cooling degree days and were found to correlate well to the summer/fall and winter/spring seasons.

These equations were applied to the building categories and area (sq ft) listed in Table 18 to obtain the additional electric use required of the projected new and renovated buildings. The additional electric use was 10,181 MWh/yr or about an 18 percent increase in electrical consumption. Adding this to the current annual consumption of 57,426, gives a total projected electrical demand of 67,607 MWh/yr.

Table 21

Summary of DEIS Electrical Data

FY	MWh Purch	MWh Gen	Total MWh Demand
1983	34,671	13,060	47,731
1984	39,414	12,470	51,884
1985	34,372	19,461	53,833
1986	34,427	20,376	54,813
1987	34,654	22,047	56,701
1988	44,306	12,994	57,300

[9]B.L. Sliwinski, et al.

Table 22

Building Categories and Electrical Consumption Equations

Category	Equation
Troop Housing Barracks	E_e* = .01516 + (.001275 x CDD_d)
Family Housing	E_e = .01447 + (.001683 x CDD_d)
Administration/Training (May-Sep)	E_e = .0512
Administration/Training (Oct-Apr)	E_e = .0215
Medical/Dental (May-Sep)	E_e = .0557
Medical/Dental (Oct-Apr)	E_e = .0353
Storage (May-Sep)	E_e = .0146
Storage (Oct-Apr)	E_e = .0133
Production/Maintenance (May-Sep)	E_e = .0235
Production/Maintenance (Oct-Apr)	E_e = .0293
Community Facilities (May-Sep)	E_e = .0684
Community Facilities (Oct-Apr)	E_e = .0662

*E_e = daily electrical energy consumption (kWh/sq ft/day) and CDD_d = daily cooling degree day.

Table 23

Cooling Degree Days

Month	CDD
Jan	0
Feb	0
Mar	0
Apr	0
May	14
Jun	91
Jul	197
Aug	145
Sep	35
Oct	0
Nov	0
Dec	0
TOTAL	482

5 ANALYSIS

The preliminary investigation of Picatinny's thermal and electric power needs indicated that several alternatives for supplying thermal and electrical energy for Picatinny Arsenal were technically and economically feasible. In particular, it appeared that several variations of renovating the existing CPP and cogeneration were practical. This chapter summarizes the analytic procedures and assumptions used to determine the costs of these alternatives.

Renovation or New Construction

The utility industry has been concerned about renovation or "life extension" since the Clean Air Act was promulgated in 1972. At that time, life extension was a means of avoiding the high cost of air pollution control equipment required for new energy supply facilities. Now, however, the high cost of constructing new plants has made the concept of life extension important regardless of pollution control requirements. For an industrial-sized facility, a savings of $21,000,000 (based on present worth life cycle costs) could result from a life extension of 25 to 30 years.

The average age of Army central heating plants is about 30 years. Most plants are nearing the end of their expected useful lives. As expected, many plants are experiencing poor combustion efficiency and reliability. However, the actual causes of these problems are often overlooked because of equipment age and appearance. This has resulted in a tendency to simply construct new facilities without first conducting a thorough evaluation.

Aggressive tuneup procedures and preventive maintenance programs can considerably improve efficiency and allow operation of central heating plants past their expected useful life. Tuneups and maintenance, along with the modernization of specific equipment, can substantially extend the expected life of older heating plants.

Electrical Energy Supply Considerations

Industrial energy users have also been very concerned about the high costs of electrical energy. The United States uses about twice as much energy as Japan or West Germany per gross national product (GNP). To compete with imported goods, U.S. industry has taken a hard look at methods to reduce electrical costs, including improving energy efficiency, optimizing cost of purchased electricity, and cogeneration.

Installations have several ways to obtain electricity. The first, and probably the easiest, method is to purchase all the electricity needed from the local utility. The main advantage of this option is convenience. The utility has full responsibility for supplying electricity to the installation at a rate that is usually set by local regulatory boards. The installation then distributes the electricity from a central point to individual users. While this option is convenient, it may not be the cheapest method of obtaining electricity and problems may arise if the utility has overloaded transmission lines or if temporary failures occur in the transmission lines or generating plants.

The other extreme is for an installation to generate all the electricity it uses. The advantage of this option is self-sufficience. This option requires the installation to install sufficient generation capacity to meet peak demands. Usually, total generation of electric power is more expensive than total purchase from the utility and involves a large capital cost. Additionally, unless there is duplication of generation units, power outages will occur due to equipment failures and maintenance downtime.

Between the two extremes is the option of producing part of the electricity used by the installation and purchasing the remainder. This may be done using either cogeneration units producing both electricity and steam or by peaking generators that produce only electricity.

The electrical bill at an installation typically consists of several elements. The first part of course is the energy charge or cost per kilowatt-hour of electricity used. This may be a flat fee or it may be based on the amount used when it is used. The next part of the bill for industrial users is a demand charge. This is a charge for the maximum amount of energy supplied to the installation during a predetermined period. There are also other miscellaneous charges such as a connection fee, a power factor charge, a capacity charge, or other charges as determined by the utility rate schedule. At Picatinny Arsenal the energy charge is about 65 to 69 percent of the total monthly bill, the demand charge is 25 to 30 percent and the other charges are from 1 to 5 percent of the bill.

The bill can be reduced by either reducing the energy charge or reducing the demand charge. The energy charge can be reduced by reducing electrical use or in some cases by shifting the use from periods of high electrical rates to periods with lower rates. Reducing the electrical use is accomplished by energy conservation programs. Shifting use from high-cost periods to low-cost periods is part of load shifting. As an example, the current energy charge at Picatinny Arsenal is $0.06371/kWh between 8 a.m. and 8 p.m. on weekdays and $0.04918/kWh at other times. This is about a 23 percent reduction in energy costs for all use that is shifted to off-peak times. The demand charge can be reduced by load shifting or by peaking generators that produce electricity during peak demand periods at the installation. The peaking generator is turned on either at fixed times or when the electrical demand exceeds a predetermined value.

The advantage of cogeneration is that all of the electricity and thermal energy produced can be used by the installation. Electric utilities typically use only the electrical portion of the energy produced, which limits plant efficiency to about 33 percent. The low efficiency is caused by the inability to use the steam or water byproducts from the turbine-generators. Most of this energy is thrown away in a heat sink such as a cooling tower or a body of water. Transformers and miles of transmission lines reduce utility plant efficiency another 3 to 4 percent. In a cogeneration unit, the byproduct thermal energy can supply a portion of the installation heating requirements. The overall efficiency of a cogeneration unit is typically between 60 and 70 percent. Cogeneration reduces both the energy costs and the peak demand charges for electricity purchases.

Cogeneration systems are typically one of the following types:

1. A heating plant producing steam that is used either by a condensing turbine or a back pressure turbine,
2. An industrial type gas turbine driving a generator set with a heat recovery boiler on the hot gas exhaust,
3. A combined-cycle gas turbine that produces both electricity and steam, or
4. An internal combustion reciprocating engine with a heat recovery boiler. Cogeneration usually has the best return on investment (ROI) when used to supply the base-load electrical and steam demand of an installation.

Peak shaving is another technique used to reduce the cost of electrical energy at an installation. Peak shaving reduces costs by reducing the peak demand and the associated demand charges. Peak shaving can be done either by reducing the demand at peak periods of electrical use or by generating electricity at the installation during the peak demand periods. Peaking generators are usually driven by internal combustion gasoline or diesel engines.

Another way to reduce electrical energy costs is by peak shifting. In this method, electrical loads are either shifted in time to reduce peaks or are shifted to other energy sources. Two examples of time shifting are: (1) use of EMCS to control loads such as air conditioning units so they are on at different times, and (2) shifting tests that have high electrical demand to off-peak times. At Picatinny, shifting a test that uses 3 MW of electricity for a few hours at a time from an on-peak period to an off-peak period will save about $13,000 on the monthly power bill. The $13,000 could be used to pay for the overtime or shift differential pay needed to conduct the test. Probably the best example of shifting electrical loads to other forms of energy would be replacing electrically driven centrifugal chillers with steam adsorption chillers for large air conditioning requirements.

Alternatives Analyzed

For this study, researchers analyzed several different combinations of existing plant renovation, cogeneration, and new thermal supply systems. The following chapters discuss these alternatives. The new thermal systems considered were a new central plant, new satellite plants, and individual building boiler units. These alternatives (Table 24) have been grouped by old or new thermal systems and by 100 percent purchased electricity or cogeneration. Although not shown in Table 24, some of the alternatives consider more than one fuel type and technology. For example, each of the new central plant alternatives that burn coal consider both bituminous and anthracite coal. Individual building boiler units consider No. 2 fuel oil, natural gas, and electric boilers.

Life Cycle Cost Analysis

The life cycle cost for each alternative was analyzed using a computer program developed by USACERL in conjunction with U.S. Army Corps of Engineers Missouri River Division. The program is called Life Cycle Cost in Design (LCCID). LCCID is an economic analysis computer program tailored to the needs of the Department of Defense (DOD). It is intended to be used as a tool in evaluating and ranking design alternatives for new and existing facilities.

LCCID calculates the life cycle costs and other economic parameters for a variety of energy conservation initiatives in DOD construction. It also has many general purpose uses not related to economic analysis of energy. It allows the user limited freedom to create economic criteria for non-DOD applications.

LCCID incorporates the economic criteria of the Army, Navy, and Air Force for design studies and operates in a manner that requires little knowledge of this criteria by the program user.

The basic algorithms and reports in LCCID are recognized as a standard in DOD. Since the DOD, and therefore LCCID, uses the economic criteria of the Department of Energy (DOE) and the Office of Management and Budget (OMB) in these studies, the user may be able to use the program for economic studies for several other Federal agencies. A detailed description of LCCID is contained in Appendix C.

LCC Criteria

In addition to the fixed criteria required by DOD, the project-specific criteria listed in Table 25 were selected as the basis for the life cycle cost analysis of all energy supply alternatives.

Other user-selected criteria dependent on the specific energy supply technology, such as midpoint of construction, are given in the analysis sections of the following chapters for each alternative.

Table 24

Energy Supply Alternatives

Alternative I - Abandon CPP after 5 years/satellite plants (base case)

Alternative II - Upgrade existing CPP
- II-a,b. 100% electric purchase - natural gas/No. 6 oil
- II-c,d. cogenerate - back pressure TG - NG/oil
- II-e,f. cogenerate - back pressure TG and reciprocating generators - NG/oil
- II-g,h. cogenerate - allison gas turbine - NG/oil
- II-i,j. cogenerate - allison GT/cheng cycle - NG/oil
- II-k,l. cogenerate - solar gas turbine/HRSG - NG/oil

Alternative III - reconversion to pulverized coal
- III-a. 100% electric purchase
- III-b. cogenerate with back pressure TG

Alternative IV - new plant bubbling fluidized bed
- IV-a. 100% electric purchase - anthracite coal
- IV-b. 100% electric purchase - bituminous coal
- IV-c. cogeneration - anthracite coal
- IV-d. cogeneration - bituminous coal

Alternative V - new plant traveling grate spreader stoker
- V-a. 100% electric purchase - bituminous coal
- V-b. cogeneration - bituminous coal

Alternative VI - new plant traveling grate overfeed stoker
- VI-a. 100% electric purchase - anthracite coal
- VI-b. 100% electric purchase - bituminous coal
- VI-c. cogeneration - anthracite coal
- VI-d. cogeneration - bituminous coal

Alternative VII - new plant traveling grate overfeed stoker
- VII-a,b. electric purchase
- VII-c,d. cogeneration

Alternative VIII - satellite steam plants
- VIII-a. 100% electric purchase - natural gas
- VIII-b. 100% electric purchase - No. 6 oil
- VIII-c. 100% electric purchase - bituminous coal

Alternative IX - individual building boiler units
- IX-a. 100% electric purchase - natural gas
- IX-b. 100% electric purchase - No. 2 oil
- IX-c. 100% electric purchase - natural gas

Alternative X - municipal refuse incinerator

Fuel and Electricity Costs

Table 26 lists the fuel cost assumptions used for each energy supply alternative. Fuel oil and coal costs are based on prices obtained from the Defense Fuels Supply Center. Electricity use cost ($/kWh) is based on the average monthly bills for Picatinny from July 1988 through June 1989. The electrical use cost listed in Table 26 does not include the monthly fuel cost adjustment which depends on the cost of fuel for a specific time period and would not be representative of any other time period. LCCID will also automatically escalate all fuel and electricity costs based on DOE guidelines. The current off-peak and on-peak use rates and the off-peak and on-peak demand charge rates are also shown in Table 26. A copy of Picatinny's current electrical service contract is provided in Appendix C.

Natural gas is currently unavailable at Picatinny Arsenal. Three potential sources of natural gas were investigated for this study. The first source investigated was a new pipeline from Quebec, Canada currently under construction. The line is being financed by a consortium of utility companies including Brooklyn Union, Mohawk Power and Light, and Consolidated Edison. At first this option appeared to result in the lowest cost. However, research by the Institute of Gas Technology (IGT) found that this pipeline has already committed its full capacity to local distribution companies. Therefore, it cannot be considered a practical option.

The second source investigated was the major natural gas pipeline companies in Newark, NJ. The four potential suppliers are Algonquin Gas Transmission Co., Columbia-Gulf Transmission Co., Texas Eastern Transmission Corp., and Transcontinental Gas Pipeline Co. According to IGT, a price of about $2.00/MBtu could be obtained from any of these companies. However, this option would require building a 40-mile supply pipeline from Newark to Picatinny Arsenal. Construction cost for a 4-in. pipeline is about $27/linear ft (estimate from Means) for a total of about $5,700,000. This cost does not include right-of-way costs or costs of any compressor stations that might be required. Additionally, it would take from 6 to 10 years or more to acquire the right-of-way and build the supply pipeline. Because of the high capital cost, long lead time, and low probability, this option was dropped from future consideration.

Table 25

Life Cycle Cost Criteria

DOE Region 2, New Jersey
Present worth calculation criteria = MCA
Discount Rate = 10 percent
Energy is significant
Date of study = Aug 1989
Beneficial Occupancy Date (BOD) = Jan 1993
Economic Life = 25 years
Energy use units are MBtu

Table 26

Fuel and Electricity Costs Assumptions

Fuel	Cost ($/unit)	Cost ($/MBtu)
Anthracite coal	74/ton	3.29
Bituminous coal	54/ton	2.40
No. 2 oil (fuel oil)	0.51/gal	3.68
No. 6 oil (1% sulfur)	0.45/gal	3.01
No. 6 oil (3% sulfur)	0.42/gal	2.80
Natural gas	------	2.904
Uninterruptible	------	6.00
Electricity	0.0759/KWh	22.25
On-peak use	0.06371/KWh	-----
Off-peak use	0.04918/KWh	-----
On-peak demand	9.98/KW	-----
Off-peak demand	8.91/KW	-----
Uninterruptible demand	4.45/KW	-----

The third source investigated was the local supplier, New Jersey Natural Gas Company (NJNG). Picatinny has been negotiating with NJNG on tapping into a feeder line just outside the installation boundary. The NJNG proposal involves constructing a 1.9 mile, 8-in. pipeline from an existing regulating station to the CPP, at NJNG's expense. The delivered price for an interruptible supply was quoted at $2.904/MBtu for September 1989. The proposal calls for a 5-yr contract with fuel costs tied to the barge price of oil in New York City. Since this was the most probable source of natural gas, $2.904/MBtu was selected as the natural gas fuel cost for this study. Because this is an interruptible supply, the cogeneration alternatives considered in this study, which use natural gas as the primary fuel, assume No. 2 oil as the backup fuel.

An uninterruptible supply is necessary for considering individual building heating units because they are not designed with dual fuel capabilities. Unfortunately, NJNG could not provide a price for an uninterruptible supply at the time of this study, so a typical value of $6.00/MBtu was assumed.

The following chapters provide a brief description of the energy supply alternatives listed in Table 24, including a system overview, capital equipment, annual system requirements, major recurring repairs, and a summary of the expected costs. Appendix E contains supplementary documentation on assumptions and cost analysis.

6 ALTERNATIVE I: CONTINUE PRESENT SYSTEM/NEW SATELLITE PLANTS

System Overview

This alternative considers operating the existing CPP without major repairs until it can no longer function reliably. This alternative has been labeled the "do nothing" approach because the CPP is left in its present condition with only minor improvements for safety. The improvements are the minimum required to keep the plant in operating condition for 5 years, at which time the plant equipment would become unreliable and require major capital investments. The 5-year life was determined based on the current operation and maintenance condition of the plant. At the end of 5 years, the CPP would be abandoned and new satellite plants would begin operation (Alternative VIII).

The following sections describe the major cost elements for this alternative categorized by capital cost, annual system requirements, and major recurring repairs. Table 27 summarizes these costs and provides the present value life cycle costs.

Capital Cost

All existing operable CPP equipment including the 50,000 lb/hr Riley and two 160,000 lb/hr CE boilers are required for this alternative. The efficiency of the boilers was assumed at 80 percent, burning No. 6 oil. No. 6 oil was chosen for the base case because it is the current operating fuel. This alternative also requires the purchase of 100 percent of the installation's electrical demand because the turbine-generators are out of commission.

The only capital investment required for this alternative pertains to the minor improvements to keep the plant operating safely for 5 years. These improvements include: (1) the installation of a desuperheater station, (2) minor electrical service upgrades, and (3) feedwater system upgrades.

The desuperheater station converts superheated steam to saturated steam to protect steam distribution equipment when steam turbines are out of service. A typical desuperheater station is shown in Figure 18. This type of desuperheater reduces and controls the temperature of superheated steam by direct contact with water. The water absorbs heat from the steam which lowers the steam temperature to produce saturated steam. This desuperheater also acts as a pressure-reducing station.

The minor electrical service upgrades include replacement of general wiring and electrical devices located in the older sections of the plant, including the ash pit and the pump house tunnel. The remaining wiring and electrical equipment will last 5 years without major repairs.

The feedwater system upgrades include adding a second makeup pump and rerouting plumbing to provide the makeup water capacity needed to prevent a dry steam explosion in the boiler.

After 5 years, when the CPP is abandoned, four new satellite plants will begin operation as described in Alternative VIII.

Table 27

Cost Summary Alternative I

Capital Investment	$10,795,100
Annual Costs	
Fuel	$ 3,309,100
Operation & Maintenance	
1st 5 Years	$ 1,905,500
After Satellites	$ 1,626,100
Purchased Electricity	$ 5,132,800
Present Value Costs	
Capital Investment	$ 7,669,000
Annual Fuel	$34,303,000
Annual O&M	$12,088,000
Major Recurring Repairs	$ 1,733,000
Annual Purchased Electricity	$34,758,000
TOTAL LIFE CYCLE COST	$90,551,000

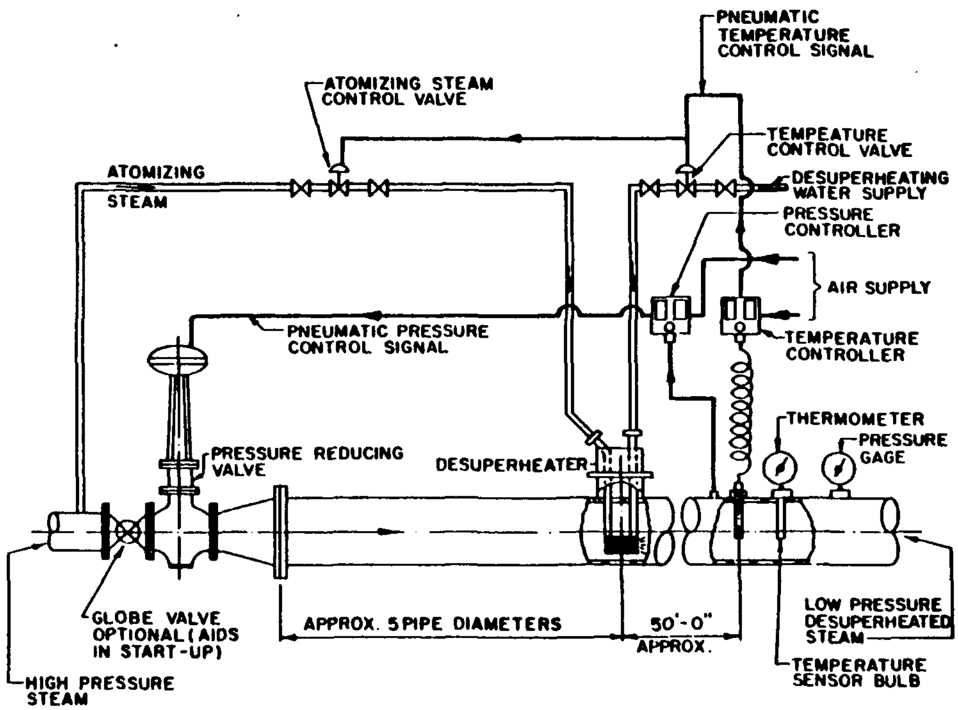

Figure 18. Typical desuperheater station.

Annual System Requirements

The annual fuel costs for the first 5 years are based on the annual projected thermal energy requirements of 934,636 MBtu divided by the plant efficiency. This equates to about 7,814,595 gal/yr of No. 6 oil. Electricity costs are based on 100 percent purchase of the projected electrical requirements of 67,607 MWh/yr.

The current plant operation and maintenance staff consists of 28 persons for an annual labor cost of $1,028,328/yr. This amount was based on an average annual salary of $30,605 and 20 percent overtime. The staff requirements are listed below.

Supervisors:	2
Shift Foremen:	4
Maintenance:	5
Boiler Operators:	14
Cleaner:	1
Welder:	1
Electrician:	1
Total	28

Operation and maintenance costs other than fuel and labor were estimated based on typical industrial plant costs because accurate costs were not available from Picatinny. Schmidt and Associates, Inc. provided an estimate of $0.939/MBtu plant output.

Annual system requirements for the new satellite plant portion of this alternative are described in the chapter for Alternative VIII.

Major Recurring Repairs

The major recurring repairs for the new satellite plants are the same as those described in Alternative VIII.

7 ALTERNATIVE II: UPGRADE EXISTING CPP

This alternative considers repairing and upgrading the existing CPP to extend its useful life to 25 years. Six major options are considered; each has suboptions for natural gas and No. 6 oil as the boiler fuel. The options are:

II-a and b: 100 percent electric purchase

II-c and d: cogenerate with back pressure turbine-generators

II-e and f: cogenerate with back pressure turbine-generators and reciprocating generators

II-g and h: cogenerate with Allison gas turbines,

II-i and j: cogenerate with Allison gas turbine/Cheng cycle, and

II-k and l: cogenerate with solar gas turbine/heat recovery steam generator (HRSG).

Alternatives II-a and b, Electric Purchase

System Overview

These suboptions require upgrading the existing CPP to the degree that it will remain operable for at least 25 years. They require major renovations to one of the existing 160,000 lb/h CE boilers and the 50,000 lb/h Riley package boiler. The remaining CE boiler would be laid up in a wet state so it could be brought on line if necessary. The power plant would supply all of the necessary steam demand for the base, but would not generate any electricity. Electrical requirements would be met by a 100 percent purchase.

Capital Equipment

The capital equipment for this alternative contains the same CPP upgrade items required for Alternative I (desuperheater, minor electrical service upgrades, and feedwater system upgrades). To extend the CPP life 25 years, the following additional major upgrades are required: (1) rebuild the feedwater pump and blowdown system, (2) consolidate the control system, (3) install high efficiency/low NO_x burners, (4) layup system for one CE boiler, and (5) completely upgrade the electrical system.

In addition to the minor upgrades to the feedwater system required for Alternative I, the entire rotating assembly of the existing feedwater pumps should be replaced. The pumps should be inspected for stress cracks. A vibration analysis should be performed. The common boiler blowdown system must be completely replumbed from the boiler drums to the flash and blowdown tanks.

The Riley and one CE boiler will be cleaned (fireside and waterside), inspected, and tested to ensure proper operation and maintenance condition. The control system will be upgraded to a direct digital control system to provide feedback control, automatic control, and system performance tracking. The new control system will also support the operation of new high efficiency/low NOx burners.

These new burners (shown in Figure 19) and the control system will allow the existing CE boiler capacity to increase to about 190,000 lb/h. The Riley boiler capacity may increase, but not substantially, because it lacks the surface area for heat transfer. The high efficiency burners provide a means for thoroughly mixing oil or gaseous fuels with combustion air to obtain maximum combustion efficiency. They are available in a wide variety of types and sizes, but all use the principle of controlling the swirl of combustion air flow to maximize mixing of the fuel with the combustion air. This allows for a stable, wide turndown over a large firing range. Other advantages of these burners are their ability to reduce NO_x emissions though flue gas recirculation or fuel/air staging techniques and their ability to burn more than one type of fuel.

A recent specification for a COEN 4-burner system on a 200,000 lb/h boiler was guaranteed to operate under the performance criteria listed in Table 28. This burner is well suited to the high space heat release and narrow furnaces associated with package boilers, like the Riley Boiler, because of its ability to tailor the flame shape to furnace conditions. It is not uncommon to see this type of single burner operating up to 250 MBtu/h in a boiler furnace width of less than 8 ft. The burner is equally adaptable for large, multiple-fired boilers, like the CE boiler. The register louvers are fully adjustable to meet a wide variety of furnace configurations and shapes of the furnace refractory throat exit.

Extending the rated capacity of one CE boiler means that the plant will be able to operate with only one CE boiler and the Riley boiler. The other CE boiler will not be upgraded because it will be needed only temporarily. It will be layed up in standby condition, ready for operation should the other CE boiler require shutdown.

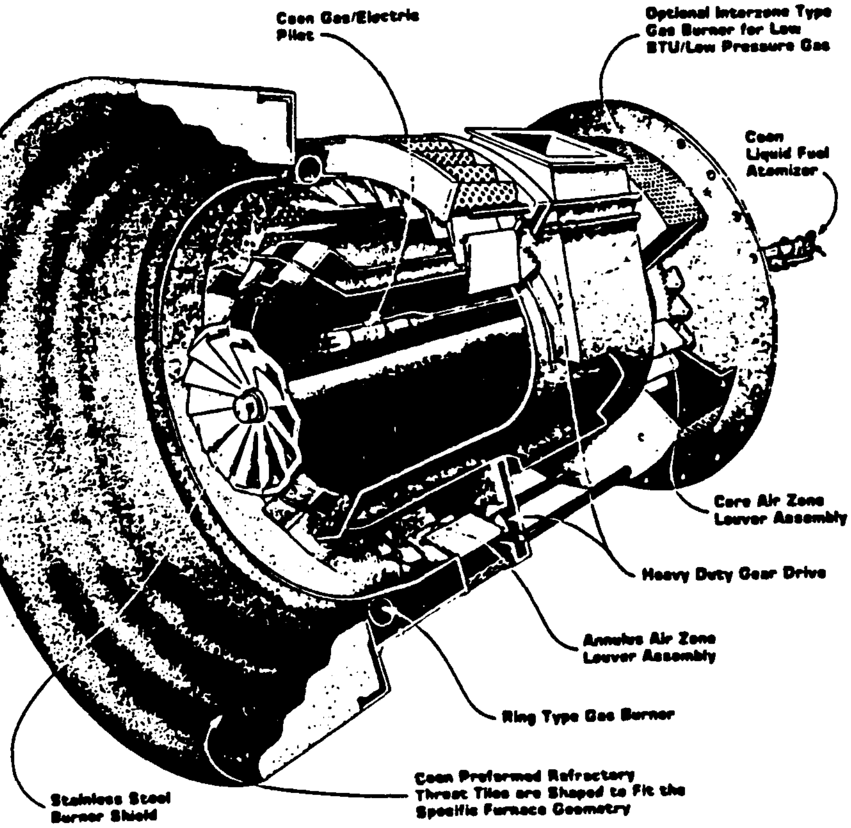

Figure 19. COEN high efficiency burner.

Table 28

High Efficiency Burner Performance Criteria

Excess Air	Maximum	1.0% O_2, 40% to 100% MCR 1.5% O_2, 20% to 40% MCR 2.0% O_2, below 20% MCR
Carbon Monoxide	Maximum 250 ppm 20% to 100% MCR	
Opacity	Less than 10% 20% to 100% MCR	
NO_x	Maximum 0.3 lb/MBtu fired when burning No. 6 oil containing less than .35% Nitrogen, 20% to 100% MCR	

MCR is 200,000 pph steam flow

The upgrade of the electrical service includes bringing the 480-volt system up to standard, installing new motor starters, completely rewiring the plant, and installing new low maintenance lighting fixtures. This upgrade is important to reduce the current costly reactive maintenance and to ensure long term reliability.

Annual System Requirements

The annual fuel costs are based on the annual projected thermal energy requirements of 934,636 MBtu divided by the plant efficiency. This equates to about 1,099,375 MBtu of natural gas or 7,353,598 gal of No. 6 oil/yr. Electricity costs are based on 100 percent purchase of the projected electrical requirements of 67,607 MWh/yr.

The current plant operation and maintenance staff consists of 15 persons for an annual labor cost of $459,075/yr. This amount was based on an average annual salary of $30,605. This staff size is considered adequate for the renovated CPP because the equipment will be more reliable (less maintenance) and the boilers will not require manual operation except for startup and shutdown. The staff requirements are listed below.

Plant Manager:	1
Plant Engineer:	1
Plant Operators:	8
Plant Janitor:	1
Operations Laborer:	1
Maintenance Mechanic:	2
Maintenance Electrician:	1
Total	15

Operation and maintenance costs other than fuel and labor were estimated based on typical industrial plant costs because accurate costs were not available from Picatinny. Schmidt and Associates, Inc. provided an estimate of $0.939/MBtu plant output for the 934,636 MBtu projected annual output.

Operation and maintenance costs other than fuel and labor were estimated based on typical industrial plant costs because accurate costs were not available from Picatinny. Schmidt and Associates, Inc. provided an estimate of $0.939/MBtu plant output for the 934,636 MBtu projected annual output.

Major Recurring Repairs

The major recurring repair for this alternative is a 10-year boiler maintenance and repair that will occur twice during the project life: at 10 and 20 years. The repair includes refractory and tube repairs, and inspection, cleaning, and testing of the repaired boilers. This work is only required for the operating CE boiler and the Riley boiler.

Table 29 summarizes the major costs and provides the present value life cycle costs.

Table 29

Cost Summary Alternative II With Electric Purchase

	Natural Gas	No. 6 Oil
Capital Investment	$ 3,444,300	$ 3,444,300
Annual Costs		
Fuel	$ 3,192,600	$ 3,309,100
Operation & Maintenance	$ 1,336,000	$ 1,336,000
Purchased Electricity	$ 5,132,500	$ 5,132,500
Present Value Costs		
Capital Investment	$ 2,736,000	$ 2,736,000
Annual Fuel	$30,990,000	$34,303,000
Annual O&M	$ 9,184,000	$ 9,184,000
Major Recurring Repairs	$ 319,000	$ 319,000
Annual Purchased Electricity	$34,758,000	$34,758,000
TOTAL LIFE CYCLE COST	$77,986,000	$81,300,000

Alternatives II-c and d, Cogenerate With Back Pressure Steam Turbines

System Overview

These alternatives consider operating the existing CPP in a cogeneration mode. They require the replacement of two nonfunctioning turbine-generator sets. The new equipment will be backpressure steam turbines (BPST) sized for the installation steam demand. This generating equipment will not produce all of the electricity needed, but it will reduce the amount of purchased electricity by reducing the peak demand. As before, the boiler plant will produce all of the necessary steam for the base. These suboptions also require the CPP to be repaired to the level indicated in Alternative II-a.

Capital Equipment

The capital equipment for this option is the same as that for Alternative II-a, with the additional cost of the two backpressure turbines (Figure 20) for cogeneration. The turbine-generators are sized to provide 4.5 MW of generating capacity. The capacity will be provided by a 3 MW-unit and a 1.5-MW unit. This configuration is based on the minimum electrical demands and the steam requirements for the winter and summer seasons. The minimum electric demand is about 4.7 MW all year, regardless of season or day of the week. So, both units could operate at 100 percent capacity as long as there is a need for the 110,000 lb/h steam from the turbines. According to CPP records, this much steam is needed 67 percent of the time during the winter months (October through April). This means the units will have a 67 percent capacity factor during the winter months. During the summer months, only the 1.5 MW unit is needed, based on steam requirements, and could operate at a 100 percent capacity factor.

The turbine-generator controls will be consolidated with boiler controls to allow the operators to monitor both systems. Operators will be trained to operate both systems as is typically done in private industry. This will allow the staff requirements to remain at the same level as Alternative II-a.

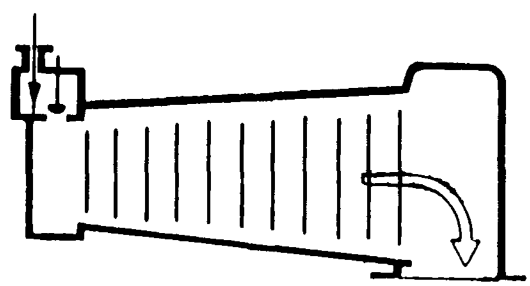

Figure 20. Back pressure turbine.

Annual System Requirements

Annual fuel costs are based on the projected annual steam requirements plus the fuel required to cogenerate electricity divided by the efficiency. This will require about 8,668,332 gal of No. 6 oil or 1,295,930 MBtu of natural gas per year.

Electricity costs are based on 58.6 percent purchase of the projected electrical requirements or 39,618 MWh/yr. The remainder of the required electricity is generated at the boiler plant.

The operation and maintenance staff remains the same as Alternative II-a with a crew of 15. This will be accomplished by cross-training the operators.

Operation and maintenance costs, other than fuel and labor, are based on an estimated cost of $0.939/MBtu steam for 1,101,540 MBtu output.

Major Recurring Repairs

The major recurring repair for this alternative is a 10-year maintenance overhaul of the plant. This maintenance occurs twice (at 10 and 20 years) in the expected life of the plant and includes necessary rebuilds and inspection, cleaning, and testing of the refurbished CE boiler and the Riley boiler.

Table 30 summarizes the major costs and provides the present value life cycle costs.

Table 30

Cost Summary Alternative II With Back Pressure Turbines

	Natural Gas	**No. 6 Oil**
Capital Investment	$ 6,527,700	$ 6,527,700
Annual Costs		
Fuel	$ 3,763,400	$ 3,900,700
Operation & Maintenance	$ 1,439,400	$ 1,439,400
Purchased Electricity	$ 3,008,400	$ 3,008,400
Present Value Costs		
Capital Investment	$ 5,185,000	$ 5,185,000
Annual Fuel	$36,530,000	$40,436,000
Annual O&M	$10,266,000	$10,266,000
Major Recurring Repairs	$ 319,000	$ 319,000
Annual Purchased Electricity	$20,373,000	$20,373,000
TOTAL LIFE CYCLE COST	$72,673,000	$76,578,000

Alternatives II-e and f, Cogenerate With BPST and Reciprocating Generators

System Overview

These suboptions consider operating the existing CPP in a cogeneration mode and peaking generator mode. In addition to the 4.5 MW backpressure units in Alternative II-c, it requires the installation of 5 MW of capacity from reciprocating diesel generators. The additional generating capacity, which is not dependent on the steam demand, will allow the CPP to provide enough electricity so the installation can switch to an interruptible power rate. The reciprocating generators are used as peaking units to reduce the peak demand and the cost of the peak demand (from $9.89-$8.91 to $4.45/kW). When buying interruptible power, the cost for the peak demand decreases. Again, this suboption would not produce 100 percent of the electricity needed year round, but it would produce enough in the summer during peak periods to merit the interruptible power supply. In the case of the electrical service being interrupted, the generators would supply enough electricity to keep the base operational.

Capital Equipment

The capital equipment for this option is the same as that for Alternative II-c, with the additional purchase of the 5-MW diesel generator capacity. The diesel generator capacity will be provided by two 2.5-MW units to provide redundancy. The method of generating electricity will change during peak months. For the months of May through September, the 1.5-MW backpressure turbine would generate electricity constantly, while the 2 peaking generators would be run only during peak electrical periods (0800 until 2000) on weekdays. For the other 7 months of the year, the two backpressure turbines would be run in combination to produce as much electricity as needed. It would not be economically feasible to operate the diesel generator during these 7 months; it will be inactivated.

Annual System Requirements

The annual fuel costs are based on the projected annual steam requirements divided by the efficiency of the boilers burning No. 6 fuel oil and natural gas. An average efficiency of 85 percent was assumed. The quantity of natural gas or No. 6 oil is the same as for the previous alternative. There is an additional cost for distillate oil for operating the reciprocating generator. This cost is based on the consumption of 839,545 gal/yr.

Electricity costs are based on 50.4 percent purchase of the projected electrical requirements or 34,088 MBtu of electricity. The rest of the required electricity will be generated at the boiler plant by the backpressure turbines and the reciprocating diesel generator.

Operation and maintenance costs are based on an estimated cost of $0.939/MBtu steam output and revised staff configuration of 16 persons. An additional person was added to operate the reciprocating generators.

Major Recurring Repairs

The only major recurring repair is the 10-year maintenance of the plant that will occur twice during the expected life of the plant. This maintenance includes necessary rebuilds and inspection, cleaning, and testing of the refurbished CE boiler and the Riley boiler.

Table 31 summarizes the major costs and provides the present value life cycle costs.

Table 31

Cost Summary Alternative II With BPST and Reciprocating Generators

	Natural Gas	No. 6 Oil
Capital Investment	$ 9,869,900	$ 9,869,900
Annual Costs		
Fuel	$ 4,191,600	$ 4,328,900
Operation & Maintenance	$ 1,524,000	$ 1,524,000
Purchased Electricity	$ 2,190,100	$ 2,190,100
Present Value Costs		
Capital Investment	$ 7,839,000	$ 7,839,000
Annual Fuel	$40,865,000	$44,771,000
Annual O&M	$10,476,000	$10,476,000
Major Recurring Repairs	$ 319,000	$ 319,000
Annual Purchased Electricity	$14,831,000	$14,831,000
TOTAL LIFE CYCLE COST	$74,330,000	$78,236,000

Alternatives II-g and h, Cogenerate With Allison Gas Turbine

System Overview

These suboptions require upgrading the CPP ancillary equipment and one CE boiler. In addition, a new Allison gas turbine cogeneration unit will be retrofitted for electrical and thermal energy generation. The cogeneration unit can be installed in the existing CPP or just outside in a Butler type building. The other CE boiler and the Riley boiler will be inactivated.

The Allison cogeneration unit will supply power to the existing main electrical substation, with the saturated steam fed into the existing steam distribution network. The unit will operate in steam demand following mode like a backpressure turbine. Sized at 4.0 MW, the unit can meet the base electrical demand during the heating season. During the summer season, however, it will only be able to meet about 50 percent of the base load because there is no use for the steam produced from the turbine. The remaining electrical demand would be satisfied by purchasing power from the local utility. The Allison unit can supply all the summer steam demand, so the CE boiler can be shut down for the entire summer.

A schematic of the Allison system is shown in Figure 21. The unit consists of the following components: (1) a control and switchgear module, (2) a gas turbine-generator set, (3) a steam diverter valve, and (4) a waste heat recovery boiler with auxiliary burner. The system is designed for installation on four skids, with an optional skid for controlling multiple units. Typical module sizes are given in Table 32. After the unit is set up, it is connected to existing steam lines and fuel supply lines. The system is designed to operate on natural gas with No. 2 fuel oil as a backup.

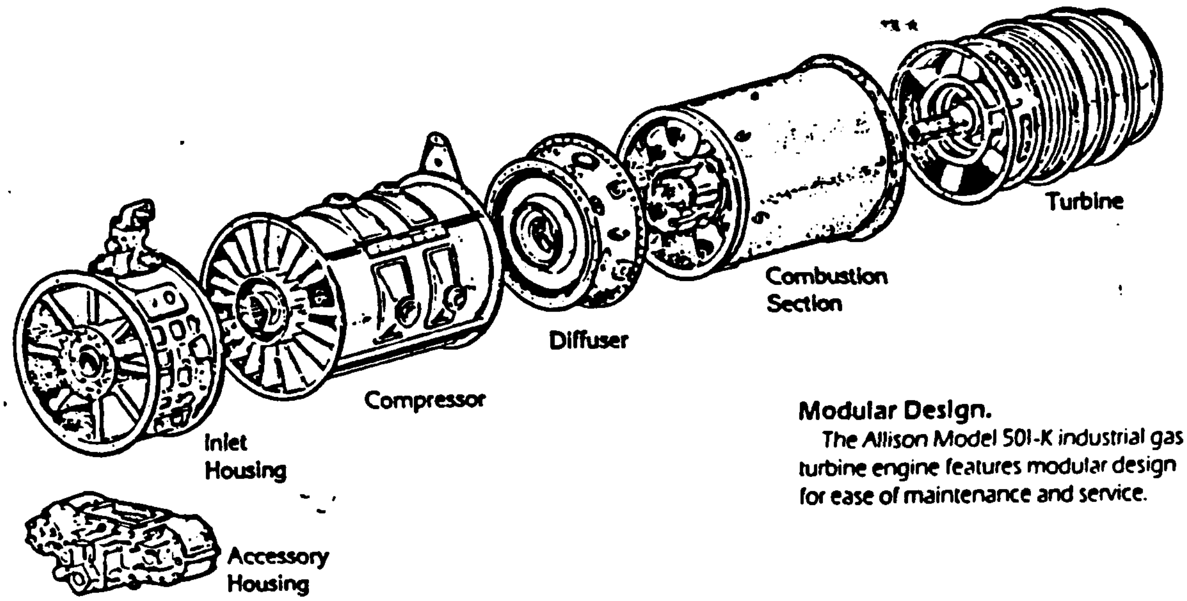

Figure 21. Allison gas turbine system.

Table 32

Typical System Module Sizes

Module	Weights, lb	Dimensions, ft
*Control Module	15,000	15L X 15W X 8H
G.T. Generator Set	50,000	30L X 8W X 20H
Diverter Skid	12,000	8L X 6W X 30H
Boiler & Burner	100,000	45L X 12W X 30H
Control & Switch	25,000	10L X 8W X 8H

*For multiple unit control.

The waste heat recovery boiler with auxiliary burner provides an important advantage over a conventional backpressure turbine-generator system. The waste heat boiler produces steam from the gas turbine combustion gases with the auxiliary burner operating when more steam is needed. Overall, the Allison unit can produce a maximum of about 45,500 lb steam/h at 100 psig while supplying 3.945 MW of electricity. The unit can provide for short duration peaks up to 4 MW. The Allison thermal output plus the upgraded output of the CE boiler provide just enough steam to meet the projected thermal requirements.

Capital Equipment

The Allison gas turbine cogeneration unit is an off-the-shelf unit with standard modular design. It has proven high reliability. The particular model selected for this alternative is a model 501-KB5/4-MW unit with dual fuel capability. The unit can switch from natural gas to No. 2 fuel oil and back without interrupting operation.

The turbine section modules are shown in Figure 22. The Allison turbine is nearly identical to the gas turbines used in many Army helicopters. The maintenance skills required for both are almost identical. As with helicopters, the modular design provides relatively easy and quick maintenance. Any module can be replaced in 2 to 4 hours.

The controls will be consolidated and integrated with the new direct digital control system for the existing boilers in a single control room.

An existing No. 6 oil tank with a capacity of at least 25,000 gal must be converted to No. 2 fuel oil to provide a 3-day backup fuel supply.

Table 33 summarizes the major costs and provides the present value life cycle costs.

Annual System Requirements

Because the Allison units are designed for remote operation and are typically unmanned, boiler operators will be cross-trained to operate the cogeneration unit. Repair and replacement of the unit modules will be done under a maintenance contract for $135,000/yr. This includes repair as needed on a 24-hour basis and routine maintenance by replacing modules on a scheduled basis. Routine maintenance consists of about 1/2-hour of visual inspection and fluid level checks per shift. The staff requirements are the same as those in the previous alternative.

Major Recurring Repairs

The major recurring repairs required are the same 10-and 20-year repairs as described earlier. The Allison turbine generator system major maintenance would be covered under the annual maintenance contract described above.

Alternatives II-i and j, Cogenerate With Allison Gas Turbine/Cheng Cycle

System Overview

These suboptions require upgrading the CPP to the same level as the previous suboptions for the Allison gas turbine. However, the Allison gas turbine system has been enhanced with a Cheng cycle.

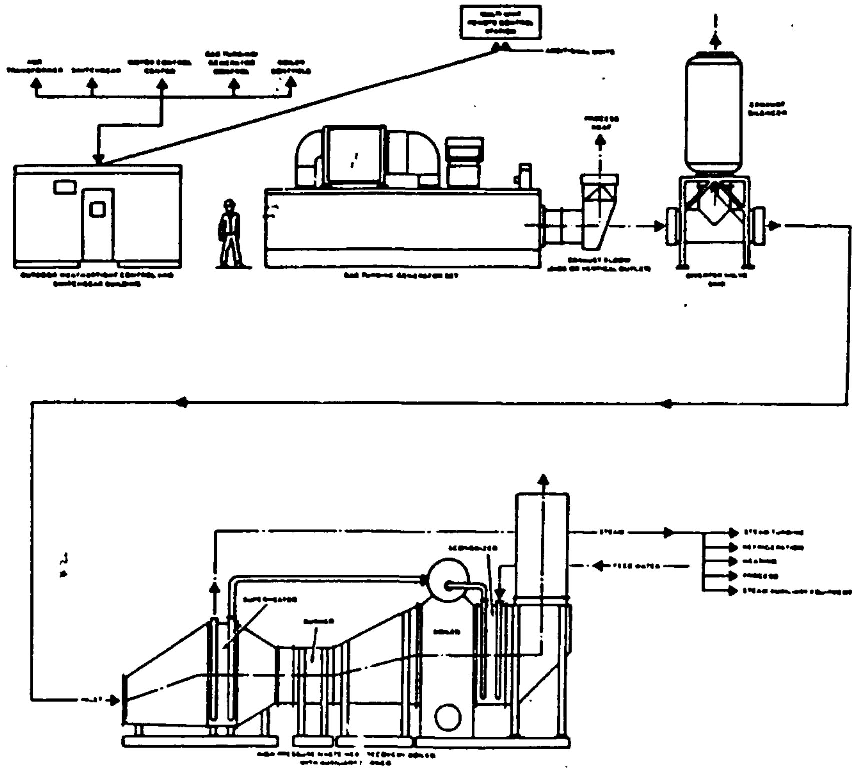

Figure 22. Gas turbine modules.

Table 33

Cost Summary Alternative II With Allison Gas Turbine

	Natural Gas	No. 6 Oil *
Capital Investment	$ 7,812,000	$ 7,812,000
Annual Costs		
Fuel	$ 3,779,800	$ 3,865,200
O & M	$ 1,471,000	$ 1,471,000
Purchase Electricity	$ 3,300,700	$ 3,300,700
Present Value costs		
Capital Investment	$ 6,205,000	$ 6,205,000
Annual Fuel	$38,174,000	$39,059,000
Annual O&M	$10,112,000	$10,112,000
Major Recurring Repairs	$ 221,000	$ 221,000
Annual Purchased Electricity	$22,450,000	$22,450,000
TOTAL LIFE CYCLE COST	$77,162,000	$78,047,000

* Fuel options are for the CE boiler unit. The Allison unit primary fuel is natural gas with No. 2 oil backup.

The Cheng cycle allows up to 23,000 lbs steam/h from the waste heat boiler to be reinjected into the gasturbine and produce more electricity. The advantage to this mode of operation is the ability to produce additional electricity to reduce peak demands.

The Allison/Cheng unit has a broad range of operating modes for both electricity and thermal production. The 5.6-MW unit selected for this study can produce about 5.4 MW with no thermal output. It can also produce about 45,500 lbs steam/h while still generating 3.5 MW. This unit can easily meet summer steam demands, allowing the CE boiler, needed for winter and spring heating requirements, to be layed up for the summer and fall months. Although the unit requires a slightly larger reserve tank for fuel oil, a 3-day reserve is still less than 25,000 gal.

Capital Equipment

The Allison with Cheng cycle is an off-the-shelf, standard modular unit with proven high reliability. The particular model selected for this alternative is a model 501-KH/5.6 MW with dual fuel capability. The unit can switch from natural gas to No. 2 fuel oil and back without interruption of operation. The cost of this unit, installed, is $4,500,000, based on a quote from Allison Turbine Division.

The Allison control system will be consolidated and integrated with the new direct digital control system for the existing boilers in a single control room.

An existing No. 6 oil tank with a capacity of at least 25,000 gal must be converted to No. 2 fuel oil to provide a 3-day backup fuel supply.

Annual System Requirements

The staff and operation and maintenance costs are the same as the previous alternative for the Allison gas turbine system.

Major Recurring Repairs

The major recurring repairs required are the same as the previous alternative for the Allison gas turbine system.

Table 34 summarizes the major costs and provides the present value life cycle costs.

Alternatives II-k and l, Cogeneration with Solar Gas Turbine/HRSG

System Overview

These suboptions require upgrading the CPP to the same level as the previous suboptions for the Allison gas turbine system. In addition, a new Solar Turbine Advanced Combined Cycle (STAC) cogeneration system will be retrofitted for electrical and thermal energy production.

The STAC cogeneration system consists primarily of a Centaur Type H gas turbine generation set, a once-through HRSG, and a high performance, backpressure steam turbine. The physical layout of the STAC is shown in Figure 23. Like the Allison system, it is mounted on skids for installation and can be installed indoors or outdoors. The entire system occupies an area about 50 x 50 sq ft.

A schematic drawing of the system is shown in Figure 24. The STAC operates efficiently over a wide range of varying steam and electricity outputs. The combined electrical output from the gas turbine

Table 34

Cost Summary Alternative II With Allison Gas Turbine/Cheng Cycle

	Natural Gas	No. 6 Oil *
Capital Investment	$9,464,000	$9,464,000
Annual Costs		
Fuel	$3,804,600	$3,890,200
O&M	$1,546,000	$1,546,000
Purchased Electricity	$2,960,100	$2,960,100
Present Value Costs		
Capital Investment	$7,517,000	$7,517,000
Annual Fuel	$38,418,000	$39,305,000
Annual O&M	$10,627,000	$10,627,000
Major Recur. Repair	$ 221,000	$ 221,000
Annual Purch. Elect	$20,137,000	$20,137,000
TOTAL LIFE CYCLE COST	$76,920,000	$77,807,000

*Fuel options are for the CE boiler unit. The Allison unit primary fuel is natural gas with No. 2 oil backup.

and the steam turbine generator sets is 7.7 MW. The steam turbine exhaust is desuperheated to give 73,000 lb/h of saturated steam at 150 psig. The gas turbine exhaust gas is supplementally fired to 2500 °F before entering the HRSG. The HRSG is sized to produce steam at 1500 °F and 1500 psig at the backpressure steam turbine inlet. When the electrical demand exceeds 7.7 MW, the additional electricity will be purchased from the local utility.

The system can operate in several different modes to provide the operational coverage needed. The modes are: (1) gas turbine only (no supplemental firing), (2) gas turbine with supplemental firing, (3) gas turbine with supplemental firing and steam turbine as follows: (a) partial steam bypass around steam turbine with more steam flow to process than through the steam turbine, (b) full steam flow through the steam turbine with the same steam flow to process as through the steam turbine, and (c) partial steam bypass around process with less steam flow to process than through the steam turbine. A diagram of the operating range is shown in Figure 25.

Capital Equipment

The estimated installed cost of the STAC system is $7,200,000 based on a quote from Solar Turbines, Inc. The STAC operates on natural gas or No. 2 fuel oil.

Annual System Requirements

Operation and maintenance staff is the same as for the previous alternative. Solar Turbine, Inc. estimates that additional maintenance costs for equipment repair and tertiary water treatment will cost about $512,000/yr.

Major Recurring Repairs

The major recurring repairs required are the same as for the previous alternative. The Solar turbine generator system major maintenance is covered under the annual maintenance contract described above.

Table 35 summarizes the major costs and provides the present value life cycle costs.

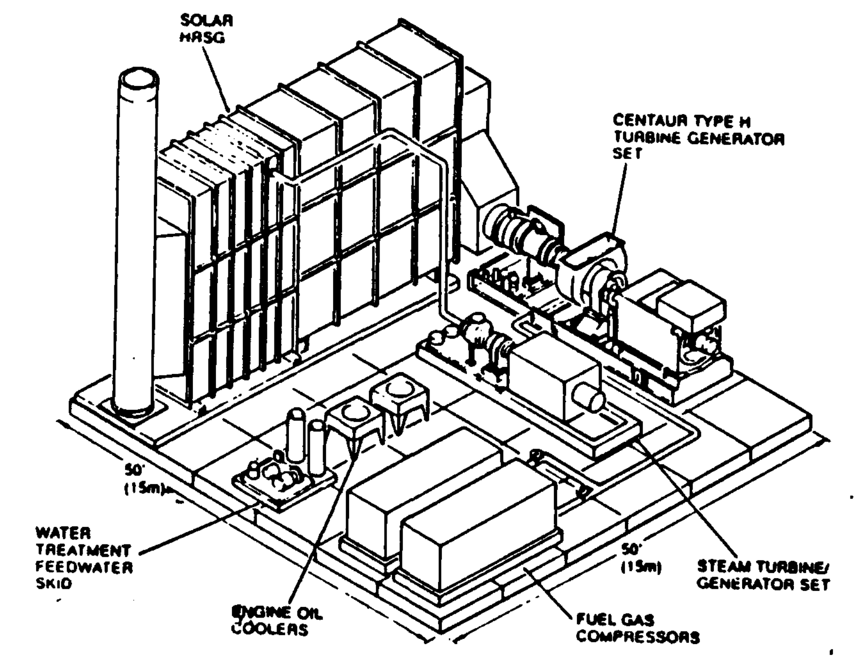

Figure 23. Combined-cycle system layout.

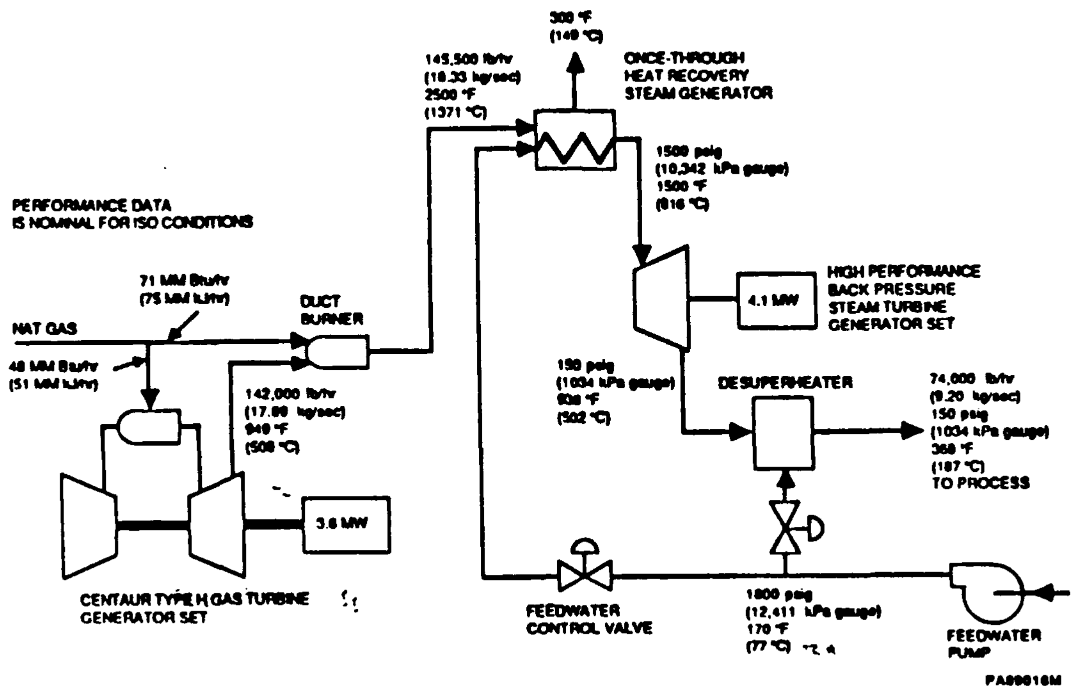

Figure 24. Combined-cycle cogeneration system schematic.

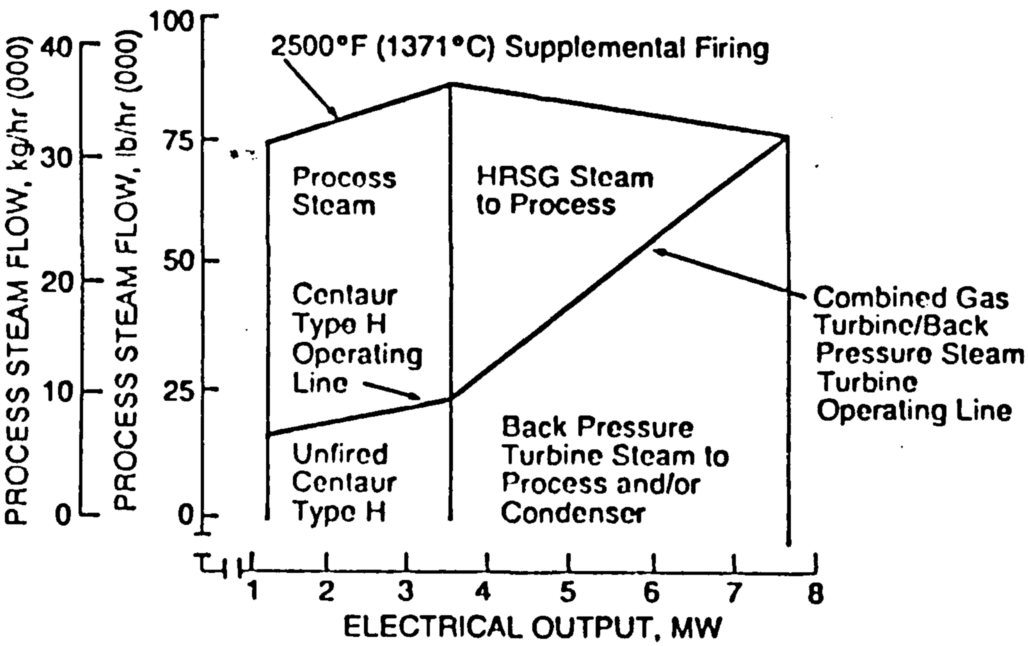

Figure 25. Combined-cycle system operating range.

Table 35

Cost Summary Alternative II With Solar Gas Turbines/HRSG

	Natural Gas	No. 6 Oil *
Capital Investment	$12,340,000	$12,340,000
Annual Costs		
Fuel	$ 3,952,500	$4,001,700
O&M.	$ 1,568,000	$1,568,000
Purchased Electricity	$ 912,500	$912,500
Present Value Costs		
Capital Investment	$ 9,801,000	$9,801,000
Annual Fuel	$39,222,000	$39,733,000
Annual O&M	$10,779,000	$10,779,000
Major Recur. Repair	$ 221,000	$ 221,000
Annual Purch. Elect	$ 6,231,000	$6,231,000
TOTAL LIFE CYCLE COST	$66,253,000	$66,764,000

* Fuel options are for the CE boiler unit. The Allison unit primary fuel is natural gas with No. 2 oil backup.

8 ALTERNATIVE III: RECONVERSION TO PULVERIZED COAL

This alternative considers converting the existing two pulverized coal boilers to pulverized coal firing. Suboptions III-a and III-b consider 100 percent electric purchase and cogeneration, respectively, for bituminous coal only.

Alternative III-a, Electric Purchase

System Overview

Evaluation of this suboption relied on a previous study by EBASCO in 1984 because a detailed investigation was not within the scope of this project. This suboption consists of reconverting the two boilers to pulverized coal firing and repairing/replacing ancillary equipment.

Capital Equipment

The major capital cost items for this option are:

- Steam generators
- Air quality control system
- Other mechanical equipment
- Coal and ash handling equipment
- Piping and insulation
- Electrical wiring and instrumentation
- Foundations
- Structural steel and chimney
- Buildings
- Allowance for demolition
- Relocation and removal.

Specific areas requiring rennovation or upgrade, as reported by EBASCO, were:

- Sootblowers
- Coal scales
- Bottom ash hoppers
- Station air system
- Coal conveying system
- Car thawing shed
- Auxiliary electrical system.

Specific areas requiring new equipment, as reported by EBASCO, were:

- Burners
- Air pollution control equipment
- Induced draft (ID) fan and motor
- Common stack
- Bottom and flyash handling system
- Boiler instrumentation and control
- Associated electrical equipment.

The air pollution control equipment would service both boilers and consists of a spray dryer followed by a fabric filter.

Annual System Requirements

The operation and maintenance labor cost reported by EBASCO was escalated to 1989 dollars giving a cost of $1,146,432. The estimated annual consumption of coal is 41,474 tons (dry) based on the annual requirement of 934,469 MBtu of steam. Electricity costs for the installation are based on 100 percent purchase of the projected electrical requirements of 67,607 MWh/yr.

Major Recurring Repairs

Major repair and replacement costs are based on USACERL estimates according to the following schedule:

Major boiler maintenance:	every 5 years
Coal handling system maintenance:	every 10 years
Ash handling system maintenance:	every 7 years
Scrubber-lime system maintenance:	every 5 years
Major bag house maintenance:	every 3 years
Major ID fan maintenance:	every 20 years
Water treatment system maintenance:	every 10 years
Major deaerator maintenance:	every 20 years
Feedwater pump maintenance:	every 12 years
Major pump maintenance:	every 18 years
Major stack maintenance:	every 20 years
Major building maintenance:	every 20 years
Periodic EPA permit testing/renewal:	every 3 years

Table 36 provides a summary of the initial costs and the present worth life cycle costs.

Alternative III-b, Cogeneration

System Overview

This system is the same as Alternative III-a with the addition of the ability to cogenerate electricity.

Capital Equipment

In addition to the capital cost items in Alternative III-a, new backpressure turbine generators are required. The turbine generator cost estimate from the EBASCO report was updated using the estimate from Alternative II-c because the existing turbine generators are no longer operable.

Annual System Requirements

The operation and maintenance labor cost reported by EBASCO was escalated to 1989 dollars giving a cost of $1,146,432.

The estimated annual consumption of coal is 52,603 tons (dry) based on the annual requirement of 934,469 MBtu of steam plus the generation of 27,977 MWh.

Table 36

Cost Summary Alternative III With Electric Purchase

Capital Investment:	$25,902,000
Annual Costs:	
Fuel:	$ 2,215,200
O&M:	$ 3,132,400
Purchased Electricity:	$ 5,158,200
Present Value Costs:	
Capital Investment:	$20,573,000
Annual Fuel:	$17,851,000
Annual O&M:	$21,532,000
Major Recurring Repairs:	$ 916,000
Annual Purchased Electricity:	$34,932,000
TOTAL LIFE CYCLE COST:	$95,804,000

Electricity costs for the installation are based on purchasing the remaining 39,630 MWh to meet the projected electrical requirements of 67,607 MWh/yr.

Major Recurring Repairs

Major repair and replacement costs are based on USACERL estimates according to the following schedule:

Major cooling tower maintenance:	every 15 years
Major turbine-generator maintenance:	every 5 years
Major boiler maintenance:	every 5 years
Coal handling system maintenance:	every 10 years
Ash handling system maintenance:	every 7 years
Scrubber-lime system maintenance:	every 5 years
Major bag house maintenance:	every 3 years
Major ID fan maintenance:	every 20 years
Water treatment system maintenance:	every 10 years
Major deaerator maintenance:	every 20 years
Feedwater pump maintenance:	every 12 years
Major pump maintenance:	every 18 years
Major stack maintenance:	every 20 years
Major building maintenance:	every 20 years
Periodic EPA permit testing/renewal:	every 3 years

Table 37 provides a cost summary of the initial costs and the present worth life cycle costs.

Table 37

Cost Summary Alternative III With Cogeneration

Capital Investment:	$29,011,600
Annual Costs:	
Fuel:	$ 2,444,300
O&M:	$ 3,132,400
Purchased Electricity:	$ 3,023,800
Present Value Costs:	
Capital Investment:	$23,043,000
Annual Fuel:	$19,698,000
Annual O&M:	$21,532,000
Major Recurring Repairs:	$ 1,028,000
Annual Purchased Electricity:	$20,478,000
TOTAL LIFE CYCLE COST:	$85,779,000

9 ALTERNATIVE IV: NEW BUBBLING FLUIDIZED BED PLANT

This alternative considers abandoning the existing CPP and constructing a new bubbling fluidized bed plant. Suboptions IV-a and IV-b consider 100 percent electric purchase for anthracite and bituminous coal, respectively. Suboptions IV-c and IV-d consider cogeneration for anthracite and bituminous coal, respectively.

Alternative IV-a, Electric Purchase - Anthracite Coal

System Overview

This suboption consists of building a new coal-fired central heating plant next to the existing heating plant. The plant is designed to produce 150 psig saturated steam at a maximum continuous rating of 250,000 lb steam/h. It will consist of four bubbling fluidized bed boilers sized as follows:

1 unit at 46,000 lb steam/h
1 unit at 91,000 lb steam/h
2 units at 116,000 lb steam/h

The building will be approximately 16,170 sq ft and the stack will be about 180 ft tall. The area required for the 90-day long term coal storage pile and the 3-day short term coal storage pile is approximately 5.0 acres. The coal pile runoff pond is sized at 0.4 acres. The coal will be delivered by rail and approximately 820 ft of new rail line are needed for coal receiving and handling. Ash disposal will be at a landfill on the installation.

The design coal for this plant is from Pennsylvania and has the following properties:

Rank:	Anthracite
Moisture:	5.7 percent
Volatile Matter (dry):	4.9 percent
Fixed Carbon (dry):	85.7 percent
Ash (dry):	9.4 percent
Ash Fusion Temperature:	2700 °F
Heat Content (dry):	12,683 Btu/lb

Capital Equipment

Each bubbling fluidized bed boiler includes an economizer. The boiler control system is a conventional digital control system linking each boiler for total plant control. Each boiler control is configured for single-loop integrity and has a single control panel for operations overview, with dedicated annunciator windows, motor controls, and status indicators.

The coal handling system will include a stock/reclaim system and a coal storage silo sufficient for 3 days operation. The coal handling equipment is sized to handle up to 125 tons/h.

The ash handling system is sized to collect up to 52 tons of ash per day. The ash storage silo is sized at 209 tons. Ash discharged for transport to the landfill will contain 10 percent moisture for dust suppression and to improve handling characteristics.

The water treatment system will include zeolite softeners, dealkalizers, a chemical injection skid, and a deaerator. A water lab for testing the water quality is also included.

Air pollution control equipment for each boiler consists of direct injection of limestone into the fluidized bed, a settling chamber, a mechanical collector, and a bag house. A 14-day silo is provided for limestone storage. A continuous emission monitoring system is included for SOx, NOx and opacity.

Physical plant equipment includes the following: air compressor, fire protection system, HVAC system, elevator, electrical substation, mobile equipment, specialty tools and maintenance equipment, locker and shower rooms, office furniture, and plant communications equipment. A 1300-kW diesel generator is provided for emergency backup electrical service.

Annual System Requirements

Operation and maintenance staff consists of 30 people for an annual labor cost of $1,211,423. The staff requirements are:

Plant Manager:	1
Plant Engineer:	2
Plant Technician:	1
Plant Clerk:	1
Plant Secretary:	1
Plant Janitor:	1
Plant Operator:	6
Plant Assistant Operator:	4
Operations Laborer:	2
Fuel Storage Equipment Operator:	1
Fuel Storage Assistant Operator:	1
Fuel Storage Laborer:	2
Maintenance Mechanic:	3
Maintenance Electrician:	3
Maintenance Laborer:	1
Total Staff	30

The estimated annual consumption of coal is 41,474 tons (dry) yielding an annual facility output of 782,712,000 lb of steam. The plant is designed to operate with 0 percent condensate return and 50 °F makeup water.

Electricity costs for the installation are based on 100 percent purchase of the projected electrical requirements. The electrical consumption of the heating plant is estimated at 3,146,000 kWh. Annual diesel/light oil use for heavy equipment and emergency generator operation is estimated at 18,506 gal.

Spare parts are estimated at $81,715 for the first year of operation and then $463,051 annually.

Heat plant water requirements are estimated at 525 gal/min; it is assumed this is available.

Major Recurring Repairs

Major repair and replacement costs are based on the following schedule:

Major boiler maintenance:	every 5 years
Coal handling system maintenance:	every 10 years
Ash handling system maintenance:	every 7 years
Scrubber-lime system maintenance:	every 5 years
Major bag house maintenance:	every 3 years
Major ID fan maintenance:	every 20 years
Water treatment system maintenance:	every 10 years
Major deaerator maintenance:	every 20 years
Feedwater pump maintenance:	every 12 years
Major pump maintenance:	every 18 years
Major stack maintenance:	every 20 years
Major building maintenance:	every 20 years
Periodic EPA permit testing/renewal:	every 3 years

Table 38 summarizes the costs.

Table 38

Cost Summary Alternative IV-a With Electric Purchase - Anthracite

Capital Investment:	$67,827,100
Annual Costs:	
Fuel:	$ 3,460,100
O&M First Year:	$ 2,396,200
O&M After First Year:	$ 2,777,600
Purchased Electricity:	$ 5,132,800
Present Value Costs:	
Capital Investment:	$50,959,000
Annual Fuel:	$29,776,000
Annual O&M:	$17,331,000
Major Recurring Repairs:	$ 1,350,000
Annual Purchased Electricity:	$34,760,000
TOTAL LIFE CYCLE COST:	$134,177,000

Alternative IV-b, Electric Purchase - Bituminous Coal

System Overview

This suboption consists of the same system as suboption IV-a with the exception of the type of coal. The design coal for this plant is from West Virginia and has the following properties:

Rank:	Bituminous
Moisture:	6.8 percent
Volatile Matter (dry):	35.7 percent
Fixed Carbon (dry):	48.8 percent
Ash (dry):	15.5 percent
Ash Fusion Temperature:	2804 °F
Heat Content (dry):	11,880 Btu/lb

Capital Equipment Overview

The capital equipment is the same as for Alternative IV-a.

The physical plant equipment differs only in that a 1500 kW diesel generator is provided for emergency backup electrical service.

Annual System Requirements

Operation and maintenance staff is the same as Alternative IV-a.

The estimated annual consumption of coal is 45,528 tons (dry) yielding an annual facility output of 782,712,000 lb of steam. The plant is designed to operate with 0 percent condensate return and 50 °F makeup water.

Electricity costs for the installation are based on 100 percent purchase of the projected electrical requirements. The electrical consumption of the heating plant is estimated at 3,146,000 kWh. Annual diesel/light oil use for heavy equipment and emergency generator operation is estimated at 18,506 gal.

Spare parts are estimated at $83,229 for the first year of operation and then $471,634 annually.

Heat plant water requirements are estimated at 525 gal/min; and it is assumed this is available.

Major Recurring Repairs

Major repair and replacement costs are the same as for suboption IV-a.

Table 39 summarizes the costs.

Table 39

Cost Summary Alternative IV-b With Electric Purchase - Bituminous

Capital Investment:	$69,807,800
Annual Costs:	
Fuel:	$ 2,596,200
O&M First Year:	$ 2,643,500
O&M After First Year:	$ 3,032,000
Purchased Electricity:	$ 5,132,800
Present Value Costs:	
Capital Investment:	$52,448,000
Annual Fuel:	$22,990,000
Annual O&M:	$19,036,000
Major Recurring Repairs:	$ 1,376,000
Annual Purchased Electricity:	$34,760,000
TOTAL LIFE CYCLE COST:	$130,610,000

Alternative IV-c, Cogeneration - Anthracite Coal

System Overview

This suboption consists of building a new coal-fired central heating plant with cogeneration next to the existing heating plant. The plant is designed to produce 600 psig 750 °F super heated steam at a maximum continuous rating of 250,000 lb steam/h. The installation's steam distribution system will be supplied with 150 psig saturated steam. The plant will consist of four bubbling fluidized bed boilers sized as follows:

1 unit at 46,000 lb steam/h
1 unit at 91,000 lb steam/h
2 units at 116,000 lb steam/h

The facility uses a 4.5-MW single extraction-condensation turbine generator for electric generation.

The building will be approximately 18,835 sq ft and the stack will be about 180 ft tall. The area required for the 90-day long term coal storage pile and the 3-day short term coal storage pile is approximately 5.7 acres. The coal pile runoff pond is sized at 0.5 acres. The coal will be delivered by rail and approximately 946 ft of new rail line are needed for coal receiving and handling. Ash disposal will be at a landfill on the installation.

The design coal for this plant is from Pennsylvania and has the following properties:

Rank:	Anthracite
Moisture:	5.7 percent
Volatile Matter (dry):	4.9 percent
Fixed Carbon (dry):	85.7 percent
Ash (dry):	9.4 percent
Ash Fusion Temperature:	2700 °F
Heat Content (dry):	12,683 Btu/lb

Capital Equipment

Each bubbling fluidized bed boiler includes an economizer. The boiler control system is a conventional digital control system linking each boiler for total plant control. Each boiler control is configured for single-loop integrity and has a single control panel for operations overview, with dedicated annunciator windows, motor controls, and status indicators.

The turbine is designed as a 4.5-MW single extraction-condensation unit. The generator is a 3-phase, 60 cycle, synchronous, air-cooled type with brushless exciters. The generator's voltage is 13.8 kV and rated at 150 MVA with a 0.85 Power Factor. Included with the turbine-generator are all necessary support equipment such as the condenser, cooling tower, circulating pumps, and control system. Lake Picatinny may be used as a heat sink in lieu of the cooling tower if the environmental impact on the lake is minimal. Lake cooling would reduce the initial capital cost by approximately $400,000.

The coal handling system will include a stock/reclaim system and a coal storage silo sufficient for 3 days operation. The coal handling equipment is sized to handle up to 150 tons per/h.

The ash handling system is sized to collect up to 61 tons of ash per day. The ash storage silo is sized at 244 tons. Ash discharged for transport to the landfill will contain 10 percent moisture for dust suppression and to improve handling characteristics.

The water treatment system will include demineralizers with degasification, a chemical injection skid and a deaerator. A water lab for testing the water quality is also included.

Air pollution control equipment for each boiler consists of direct injection of limestone into the fluidized bed, a settling chamber, a mechanical collector, and a bag house. A 14-day silo is provided for limestone storage. A continuous emission monitoring system is included for SOx, NOx and opacity.

Physical plant equipment includes the following: air compressor, fire protection system, HVAC system, elevator, electrical substation, mobile equipment, specialty tools and maintenance equipment, locker and shower rooms, office furniture, and plant communications equipment. A 1500-kW diesel generator is provided for emergency backup electrical service.

Annual System Requirements

Operation and maintenance staff consists of 33 people for an annual labor cost of $1,331,423. The staff requirements are:

Plant Manager:	1
Plant Engineer:	2
Plant Technician:	1
Plant Secretary:	1
Plant Janitor:	1
Plant Operator:	6
Plant Assistant Operator:	4
Operations Laborer:	2
Generator Operator:	4
Fuel Storage Equipment Operator:	1
Fuel Storage Assistant Operator:	1
Fuel Storage Laborer:	2
Maintenance Mechanic:	3
Maintenance Electrician:	3
Maintenance Laborer:	1
Total Staff	33

The estimated annual consumption of coal is 47,919 tons (dry) yielding an annual facility thermal output of 934,636 MBtu and an electric output of 27,977 MWh. The plant is designed to operate with 0 percent condensate return and 50 °F makeup water.

Electricity costs for the installation are based on the purchase of 39,630 MWh of electricity. The electrical consumption of the heating plant is estimated at 3,544,000 kWh. Annual diesel/light oil use for heavy equipment and emergency generator operation is estimated at 18,506 gal.

Spare parts are estimated at $102,143 for the first year of operation and then $578,813 annually.

Plant water requirements are estimated at 600 gal/min; it is assumed this is available.

Major Recurring Repairs

Major repair and replacement costs are based on the following schedule:

Major cooling tower maintenance:	every 15 years
Major turbine-generator maintenance:	every 5 years
Major boiler maintenance:	every 5 years
Coal handling system maintenance:	every 10 years
Ash handling system maintenance:	every 7 years
Scrubber-lime system maintenance:	every 5 years
Major bag house maintenance:	every 3 years
Major ID fan maintenance:	every 20 years
Water treatment system maintenance:	every 10 years
Major deaerator maintenance:	every 20 years
Feedwater pump maintenance:	every 12 years
Major pump maintenance:	every 18 years
Circulating pump maintenance:	every 25 years
Major stack maintenance:	every 20 years
Major building maintenance:	every 20 years
Periodic EPA permit testing/renewal:	every 3 years

Table 40 summarizes the costs.

The coal handling system will include a stock/reclaim system and a coal storage silo sufficient for 3 days operation. The coal handling equipment is sized to handle up to 200 tons/h.

The ash handling system is sized to collect up to 104 tons of ash per day. The ash storage silo is sized at 651 tons. Ash discharged for transport to the landfill will contain 10 percent moisture for dust suppression and to improve handling characteristics.

Annual System Requirements

Operation and maintenance staff is the same as for Alternative IV-c.

The estimated annual consumption of coal is 52,603 tons (dry) yielding an annual facility thermal output of 934,636 MBtu and an electric output of 27,977 MWh. The plant is designed to operate with 0 percent condensate return and 50 °F makeup water.

Spare parts are estimated at $104,036 for the first year of operation and then $589,542 annually.

Major Recurring Repairs

Major repair and replacement costs are the same as Alternate IV-c.

Table 41 summarizes the costs.

Table 41

Cost Summary Alternative IV-d With Cogeneration - Bituminous

Capital Investment:	$75,807,800
Annual Costs:	
Fuel:	$ 2,999,600
O&M First Year:	$ 3,089,800
O&M After First Year:	$ 3,575,300
Purchased Electricity:	$ 3,008,600
Present Value Costs:	
Capital Investment:	$63,654,000
Annual Fuel:	$24,173,000
Annual O&M:	$21,843,000
Major Recurring Repairs:	$ 1,503,000
Annual Purchased Electricity:	$20,374,000
TOTAL LIFE CYCLE COST:	$131,547,000

10 ALTERNATIVE V: NEW TRAVELING GRATE SPREADER STOKER PLANT

This alternative considers abandoning the existing CPP and constructing a new traveling grate spreader stoker plant. Suboptions V-a and V-b consider 100 percent electric purchase and cogeneration, respectively, for bituminous coal only.

Alternative V-a, Electric Purchase - Bituminous Coal

System Overview

This suboption consists of building a new coal-fired central heating plant next to the existing heating plant. The plant is designed to produce 150 psig saturated steam at a maximum continuous rating of 250,000 lb steam/h. It will consist of three traveling grate spreader stoker boilers sized as follows:

1 unit at 57,000 lb steam/h
2 units at 126,000 lb steam/h

The building will be approximately 12,500 sq ft and the stack will be about 191 ft tall. The area required for the 90-day long term coal storage pile and the 3-day short term coal storage pile is approximately 5.5 acres. The coal pile runoff pond is sized at 0.5 acres. The coal will be delivered by rail and approximately 900 ft of new rail line are needed for coal receiving and handling. Ash disposal will be at a landfill on the installation.

The design coal for this plant is from Kentucky and has the following properties:

Rank:	Bituminous
Moisture:	5.3 percent
Volatile Matter (dry):	33.1 percent
Fixed Carbon (dry):	50.8 percent
Ash (dry):	16.1 percent
Ash Fusion Temperature:	2804 °F
Heat Content (dry):	11,930 Btu/lb

Capital Equipment

The boilers are traveling grate, spreader stokers with fly ash reinjection. Each boiler includes an overfire air system and an economizer. The boiler control system is a conventional digital control system linking each boiler for total plant control. Each boiler control is configured for single-loop integrity and has a single control panel for operations overview, with dedicated annunciator windows, motor controls, and status indicators.

The coal handling system will include a stock/reclaim system and a coal storage silo sufficient for 3 days operation. The coal handling equipment is sized to handle up to 150 tons/h.

The ash handling system is sized to collect up to 79 tons of ash per day. The ash storage silo is sized at 315 tons. Ash discharged for transport to the landfill will contain 10 percent moisture for dust suppression and to improve handling characteristics.

The water treatment system will include zeolite softeners, dealkalizers, a chemical injection skid, and a deaerator. A water lab for testing the water quality is also included.

Air pollution control equipment for each boiler consists of a settling chamber, a mechanical collector, a dry scrubber for sulfur reduction, and a bag house. A 14-day silo is provided for lime storage. A continuous emission monitoring system is included for SOx, NOx, and opacity.

Physical plant equipment includes the following: air compressor, fire protection system, HVAC system, elevator, electrical substation, mobile equipment, specialty tools and maintenance equipment, locker and shower rooms, office furniture, and plant communications equipment. A 500-kW diesel generator is provided for emergency backup electrical service.

Annual System Requirements

Operation and maintenance staff consists of 25 people for an annual labor cost of $1,026,573. The staff requirements are:

Plant Manager:	1
Plant Engineer:	2
Plant Technician:	1
Plant Clerk:	1
Plant Secretary:	1
Plant Janitor:	1
Plant Operator:	4
Plant Assistant Operator:	4
Operations Laborer:	1
Fuel Storage Equipment Operator:	1
Fuel Storage Assistant Operator:	1
Fuel Storage Laborer:	2
Maintenance Mechanic:	3
Maintenance Electrician:	2
Total Staff	25

The estimated annual consumption of coal is 46,152 tons (dry) yielding an annual facility output of 782,712,000 lb of steam. The plant is designed to operate with zero percent condensate return and 50 °F makeup water.

Electricity costs for the installation are based on 100 percent purchase of the projected electrical requirements. The electrical consumption of the heating plant is estimated at 3,146,000 kWh. Annual diesel/light oil use for heavy equipment and emergency generator operation is estimated at 17,000 gal.

Spare parts are estimated at $69,895 for the first year of operation and then $396,074 annually.

Heat plant water requirements are estimated at 525 gal/min; it is assumed this is available.

Major Recurring Repairs

Major repair and replacement costs are based on the following schedule:

Major boiler maintenance:	every 8 years
Coal handling system maintenance:	every 10 years
Ash handling system maintenance:	every 7 years
Scrubber-lime system maintenance:	every 5 years
Major bag house maintenance:	every 3 years
Major ID fan maintenance:	every 20 years
Water treatment system maintenance:	every 10 years
Major deaerator maintenance:	every 20 years
Feedwater pump maintenance:	every 12 years
Major pump maintenance:	every 18 years
Major stack maintenance:	every 20 years
Major building maintenance:	every 20 years
Periodic EPA permit testing/renewal:	every 3 years

Table 42 summarizes the costs.

Table 42

Cost Summary Alternative V-a With Electric Purchase - Bituminous

Capital Investment:	$62,136,500
Annual Costs:	
Fuel:	$ 2,642,800
O&M First Year:	$ 2,280,900
O&M After First Year:	$ 2,607,100
Purchased Electricity:	$ 5,132,800
Present Value Costs:	
Capital Investment:	$46,684,000
Annual Fuel:	$21,351,000
Annual O&M:	$16,601,000
Major Recurring Repairs:	$ 956,000
Annual Purchased Electricity:	$34,760,000
TOTAL LIFE CYCLE COST:	$120,352,000

Alternative V-b, Cogeneration - Bituminous Coal

System Overview

This suboption consists of building a new coal-fired central heating plant with cogeneration. The plant is designed to produce 600 psig, 750 °F super heated steam at a maximum continuous rating of 250,000 lb steam/h. The installation's steam distribution system will be supplied with 150 psig saturated steam. The plant will consist of three traveling grate spreader stoker boilers sized as follows:

1 unit at 57,000 lb steam/h
2 units at 126,000 lb steam/h

The facility utilizes a 4.5-MW single extraction-condensation turbine generator for electric generation.

The building will be approximately 15,200 sq ft and the stack will be about 191 ft tall. The area required for the 90-day long term coal storage pile and the 3-day short term coal storage area is approximately 6.2 acres. The coal pile runoff pond is sized at 0.5 acres. The coal will be delivered by rail and approximately 1040 ft of new rail line are needed for coal receiving and handling. Ash disposal will be at a landfill on the installation.

The design coal for this suboption is the same as for Alternate V-a.

Capital Equipment

The boilers are traveling grate, spreader stokers with fly ash reinjection. Each boiler includes an overfire air system and an economizer. The boiler control system is a conventional digital control system linking each boiler for total plant control. Each boiler control is configured for single-loop integrity and has a single control panel for operations overview, with dedicated annunciator windows, motor controls, and status indicators.

The turbine is designed as a 4.5-MW single extraction- condensation unit. The generator is a 3-phase, 60 cycle, synchronous, air-cooled type with brushless exciters. The generator's voltage is 13.8 kV and rated at 150 MVA with a 0.85 Power Factor. Included with the turbine-generator are all necessary support equipment such as the condenser, cooling tower, circulating pumps, and control system. Lake Picatinny may be used as a heat sink in lieu of the cooling tower if the environmental impact on the lake is minimal. Lake cooling would reduce the initial capital cost by approximately $400,000.

The coal handling system will include a stock/reclaim system and a coal storage silo sufficient for 3 days operation. The coal handling equipment is sized to handle up to 200 tons/h.

The ash handling system is sized to collect up to 92 tons of ash per day. The ash storage silo is sized at 366 tons. Ash discharged for transport to the land fill will contain 10 percent moisture for dust suppression and to improve handling characteristics.

The water treatment system will include demineralizers with degasification, a chemical injection skid, and a deaerator. A water lab for testing the water quality is also included.

Air pollution control equipment for each boiler consists of a settling chamber, a mechanical collector, a dry scrubber for sulfur reduction, and a bag house. A 14-day silo is provided for lime storage. A continuous emission monitoring system is included for SOx, NOx, and opacity.

Physical plant equipment includes the following: air compressor, fire protection system, HVAC system, elevator, electrical substation, mobile equipment, specialty tools and maintenance equipment, locker and shower rooms, office furniture, and plant communications equipment. A 500-kW diesel generator is provided for emergency backup electrical service.

Annual System Requirements

Operation and maintenance staff consists of 28 people for an annual labor cost of $1,146,573. The staff requirements are:

Plant Manager:	1
Plant Engineer:	2
Plant Technician:	1
Plant Secretary:	1
Plant Janitor:	1
Plant Operator:	4
Plant Assistant Operator:	4
Operations Laborer:	1
Generator Operator:	4
Fuel Storage Equipment Operator:	1
Fuel Storage Assistant Operator:	1
Fuel Storage Laborer:	2
Maintenance Mechanic:	3
Maintenance Electrician:	2
Total Staff	28

The estimated annual consumption of coal is 53,324 tons (dry) yielding an annual facility thermal output of 934,636 MBtu and an electric output of 27,977 MWh. The plant is designed to operate with 0 percent condensate return and 50 °F makeup water.

Electricity costs for the installation are based on the purchase of 39,630 MWh of electricity. The electrical consumption of the heating plant is estimated at 3,545,000 kWh. Annual diesel/light oil use for heavy equipment and emergency generator operation is estimated at 17,000 gal.

Spare parts are estimated at $87,368 for the first year of operation and then $495,092 annually.

Plant water requirements are estimated at 600 gal/min; it is assumed this is available.

Major Recurring Repairs

Major repair and replacement costs are based on the following schedule:

Major cooling tower maintenance:	every 15 years
Major turbine-generator maintenance:	every 5 years
Major boiler maintenance:	every 8 years
Coal handling system maintenance:	every 10 years
Ash handling system maintenance:	every 7 years

Scrubber-lime system maintenance:	every 5 years
Major bag house maintenance:	every 3 years
Major ID fan maintenance:	every 20 years
Water treatment system maintenance:	every 10 years
Major deaerator maintenance:	every 20 years
Feedwater pump maintenance:	every 12 years
Major pump maintenance:	every 18 years
Circulating pump maintenance:	every 25 years
Majoı stack maintenance:	every 20 years
Major building maintenance:	every 20 years
Periodic EPA permit testing/renewal:	every 3 years

Table 43 summarizes the costs.

Table 43

Cost Summary Alternative V-b With Cogeneration - Bituminous

Capital Investment:	$68,136,500
Annual Costs:	
Fuel:	$ 3,053,500
O&M First Year:	$ 2,693,600
O&M After First Year:	$ 3,101,400
Purchased Electricity:	$ 3,008,600
Present Value Costs:	
Capital Investment:	$57,213,000
Annual Fuel:	$24,607,000
Annual O&M:	$19,199,000
Major Recurring Repairs:	$ 1,053,000
Annual Purchased Electricity:	$20,374,000
TOTAL LIFE CYCLE COST:	$122,446,000

11 ALTERNATIVE VI: NEW TRAVELING GRATE OVERFEED STOKER PLANT

This alternative considers abandoning the existing CPP and constructing a new traveling grate stoker plant. Suboptions VI-a and VI-b consider 100 percent electric purchase for anthracite and bituminous coal, respectively. Options VI-c and VI-d consider cogeneration for anthracite and bituminous coal, respectively.

Alternative VI-a, Electric Purchase - Anthracite Coal

System Overview

These suboptions consist of building a new coal-fired central heating plant next to the existing heating plant. The plant is designed to produce 150 psig saturated steam at a maximum continuous rating of 250,000 lb steam/h. It will consist of three traveling grate stoker boilers sized as follows:

1 unit at 57,000 lb steam/h
2 units at 126,000 lb steam/h

The building will be approximately 12,500 sq ft and the stack will be about 191 ft tall. The area required for the 90-day long term coal storage pile and the 3-day short term coal storage pile is approximately 4.8 acres. The coal pile runoff pond is sized at 0.4 acres. The coal will be delivered by rail and approximately 780 ft of new rail line are needed for coal receiving and handling. Ash disposal will be at a landfill on the installation.

The design coal for this plant is from Pennsylvania and has the following properties:

Rank:	Anthracite
Moisture:	4.0 percent
Volatile Matter (dry):	6.0 percent
Fixed Carbon (dry):	84.0 percent
Ash (dry):	10.0 percent
Ash Fusion Temperature:	2700 °F
Heat Content (dry):	13,505 Btu/lb

Capital Equipment

Each traveling grate overfeed stoker boiler includes an overfire air system and an economizer. The boiler control system is a conventional digital control system linking each boiler for total plant control. Each boiler control is configured for single-loop integrity and has a single control panel for operations overview, with dedicated annunciator windows, motor controls, and status indicators.

The coal handling system will include a stock/reclaim system and a coal storage silo sufficient for 3 days operation. The coal handling equipment is sized to handle up to 125 tons/h.

The ash handling system is sized to collect up to 44 tons of ash per day. The ash storage silo is sized at 178 tons. Ash discharged for transport to the landfill will contain 10 percent moisture for dust suppression and to improve handling characteristics.

The water treatment system will include zeolite softeners, dealkalizers, a chemical injection skid and a deaerator. A lab for testing the water quality is also included.

Air pollution control equipment for each boiler consists of a settling chamber, a mechanical collector, a dry scrubber for sulfur reduction, and a bag house. A 14-day silo is provided for lime storage. A continuous emission monitoring system is included for SOx, NOx, and opacity.

Physical plant equipment includes the following: air compressor, fire protection system, HVAC system, elevator, electrical substation, mobile equipment, specialty tools and maintenance equipment, locker and shower rooms, office furniture, and plant communications equipment. A 500-kW diesel generator is provided for emergency backup electrical service.

Annual System Requirements

Operation and maintenance staff consists of 25 people for an annual labor cost of $1,026,573. The staff requirements are:

Plant Manager:	1
Plant Engineer:	2
Plant Technician:	1
Plant Clerk:	1
Plant Secretary:	1
Plant Janitor:	1
Plant Operator:	4
Plant Assistant Operator:	4
Operations Laborer:	1
Fuel Storage Equipment Operator:	1
Fuel Storage Assistant Operator:	1
Fuel Storage Laborer:	2
Maintenance Mechanic:	3
Maintenance Electrician:	2
Total Staff	25

The estimated annual consumption of coal is 39,292 tons (dry) yielding an annual facility output of 782,712,000 lb of steam. The plant is designed to operate with 0 percent condensate return and 50 °F makeup water.

Electricity costs for the installation are based on 100 percent purchase of the projected electrical requirements. The electrical consumption of the heating plant is estimated at 3,146,000 kWh. Annual diesel/light oil use for heavy equipment and emergency generator operation is estimated at 17,000 gal.

Spare parts are estimated at $68,520 for the first year of operation and then $388,278 annually.

Heat plant water requirements are estimated at 525 gal/min; it is assumed this is available.

Major Recurring Repairs

Major repair and replacement costs are based on the following schedule:

Major boiler maintenance:	every 8 years
Coal handling system maintenance:	every 10 years
Ash handling system maintenance:	every 7 years
Scrubber-lime system maintenance:	every 5 years
Major bag house maintenance:	every 3 years
Major ID fan maintenance:	every 20 years
Water treatment system maintenance:	every 10 years
Major deaerator maintenance:	every 20 years
Feedwater pump maintenance:	every 12 years
Major pump maintenance:	every 18 years
Major stack maintenance:	every 20 years
Major building maintenance:	every 20 years
Periodic EPA permit testing/renewal:	every 3 years

Table 44 summarizes the costs.

Table 44

Cost Summary Alternative VI-a With Electric Purchase - Anthracite

Capital Investment:	$60,328,800
Annual Costs:	
Fuel.	$ 3,490,500
O&M First Year:	$ 1,831,900
O&M After First Year:	$ 2,151,600
Purchased Electricity:	$ 5,132,800
Present Value Costs:	
Capital Investment:	$45,326,000
Annual Fuel:	$29,561,000
Annual O&M:	$13,530,000
Major Recurring Repairs:	$ 926,000
Annual Purchased Electricity:	$34,760,000
TOTAL LIFE CYCLE COST:	$124,103,000

Alternative VI-b, Electric Purchase - Bituminous Coal

System Overview

This suboption consists of the same system as suboption VI-a with the exception of the type of coal.

The area required for the 90-day long term coal storage pile and the 3-day short term coal storage area is approximately 5.2 acres. The coal pile runoff pond is sized at 0.5 acres. The coal will be delivered by rail and approximately 860 ft of new rail line are needed for coal receiving and handling. Ash disposal will be at a landfill on the installation.

The design coal for this plant is from Kentucky and has the following properties:

Rank:	Bituminous
Moisture:	5.8 percent
Volatile Matter (dry):	37.2 percent
Fixed Carbon (dry):	50.4 percent
Ash (dry):	12.4 percent
Ash Fusion Temperature:	2354 °F
Heat Content (dry):	12,460 Btu/lb

Capital Equipment

The capital equipment is the same as for Alternative VI-a.

The coal handling system will include a stock/reclaim system and a coal storage silo sufficient for 3 days operation. The coal handling equipment is sized to handle up to 150 tons/h.

The ash handling system is sized to collect up to 59 tons of ash per day. The ash storage silo is sized at 236 tons. Ash discharged for transport to the landfill will contain 10 percent moisture for dust suppression and to improve handling characteristics.

The water treatment system will include zeolite softeners, dealkalizers, a chemical injection skid, and a deaerator. A water lab for testing the water quality is also included.

Air pollution control equipment for each boiler consists of a settling chamber, a mechanical collector, a dry scrubber for sulfur reduction, and a bag house. A-14 day silo is provided for lime storage. A continuous emission monitoring system is included for SOx, NOx, and opacity.

Physical plant equipment is the same as for Alternative VI-a. A 500-kW diesel generator is provided for emergency backup electrical service.

Annual System Requirements

Operation and maintenance staff is the same as for Alternative VI-a.

The estimated annual consumption of coal is 43,969 tons (dry) yielding an annual facility output of 782,712,000 lb of steam. The plant is designed to operate with 0 percent condensate return and 50 °F makeup water.

Electricity costs for the installation are based on 100 percent purchase of the projected electrical requirements. The electrical consumption of the heating plant is estimated at 3,146,000 kWh. Annual diesel/light oil use for heavy equipment and emergency generator operation is estimated at 17,000 gal.

Spare parts are estimated at $69,521 for the first year of operation and then $393,955 annually.

Heat plant water requirements are estimated at 525 gal/min; it is assumed this is available.

Major Recurring Repairs

Major repair and replacement costs are the same as for Altemative VI-a.

Table 45 summarizes the costs.

Table 45

Cost Summary Alternative VI-b With Electric Purchase - Bituminous

Capital Investment:	$61,194,000
Annual Costs:	
Fuel:	$ 2,629,700
O&M First Year:	$ 1,912,400
O&M After First Year:	$ 2,236,800
Purchased Electricity:	$ 5,132,800
Present Value Costs:	
Capital Investment:	$45,976,000
Annual Fuel:	$21,346,000
Annual O&M:	$14,091,000
Major Recurring Repairs:	$ 942,000
Annual Purchased Electricity:	$34,760,000
TOTAL LIFE CYCLE COST:	$117,115,000

Alternative VI-c, Cogeneration - Anthracite Coal

System Overview

This suboption consists of building a new coal-fired central heating plant with cogeneration next to the existing heating plant.

The plant is designed to produce 600 psig, 750 °F super heated steam at a maximum continuous rating of 250,000 lb steam/h. The installation's steam distribution system will be supplied with 150 psig saturated steam. The plant will consist of three traveling grate stoker boilers sized as follows:

1 unit at 57,000 lb steam/h
2 units at 126,000 lb steam/h

The facility uses a 4.5-MW single extraction-condensation turbine generator for electric generation.

The building will be approximately 15,200 sq ft and the stack will be about 191 ft tall. The area required for the 90-day long term coal storage pile and the 3-day short term coal storage pile is approximately 5.5 acres. The coal pile runoff pond is sized at 0.5 acres. The coal will be delivered by rail and approximately 900 ft of new rail line are needed for coal receiving and handling. Ash disposal will be at a landfill on the installation.

The design coal for this plant is from Pennsylvania and has the following properties:

Rank:	Anthracite
Moisture:	4.0 percent
Volatile Matter (dry):	6.0 percent
Fixed Carbon (dry):	84.0 percent
Ash (dry):	10.0 percent
Ash Fusion Temperature:	2700 °F
Heat Content (dry):	13,505 Btu/lb

Capital Equipment

Each traveling grate overfeed stoker boiler includes an overfire air system and an economizer. The boiler control system is a conventional digital control system linking each boiler for total plant control. Each boiler control is configured for single-loop integrity and has a single control panel for operations overview, with dedicated annunciator windows, motor controls, and status indicators.

The turbine is designed as a 4.5-MW single extraction-condensation unit. The generator is a 3-phase, 60 cycle, synchronous, air-cooled type with brushless exciters. The generator's voltage is 13.8 kV and rated at 150 MVA with a 0.85 Power Factor. Included with the turbine-generator are all necessary support equipment such as the condenser, cooling tower, circulating pumps, and control system. Lake Picatinny may be used as a heat sink in lieu of the cooling tower if the environmental impact on the lake is minimal. Lake cooling would reduce the initial capital cost by approximately $400,000.

The coal handling system will include a stock/reclaim system and a coal storage silo sufficient for 3 days operation. The coal handling equipment is sized to handle up to 150 tons/h.

The ash handling system is sized to collect up to 52 tons of ash per day. The ash storage silo is sized at 207 tons. Ash discharged for transport to the landfill will contain 10 percent moisture for dust suppression and to improve handling characteristics.

The water treatment system will include demineralizers with degasification, a chemical injection skid and a deaerator. A water lab for testing the water quality is also included.

Air pollution control equipment for each boiler consists of a settling chamber, a mechanical collector, a dry scrubber for sulfur reduction, and a bag house. A 14-day silo is provided for lime storage. A continuous emission monitoring system is included for SOx, NOx, and opacity.

Physical plant equipment includes the following: air compressor, fire protection system, HVAC system, elevator, electrical substation, mobile equipment, specialty tools and maintenance equipment, locker and shower rooms, office furniture, and plant communications equipment. A 500-kW diesel generator is provided for emergency backup electrical service.

Annual System Requirements

Operation and maintenance staff consists of 28 people for an annual labor cost of $1,146,573. The staff requirements are:

Plant Manager:	1
Plant Engineer:	2
Plant Technician:	1
Plant Secretary:	1
Plant Janitor:	1
Plant Operator:	4
Plant Assistant Operator:	4
Operations Laborer:	1
Generator Operator:	4
Fuel Storage Equipment Operator:	1
Fuel Storage Assistant Operator:	1
Fuel Storage Laborer:	2
Maintenance Mechanic:	3
Maintenance Electrician:	2
Total Staff	28

The estimated annual consumption of coal is 45,398 tons (dry) yielding an annual facility thermal output of 934,636 MMBtu and an electric output of 27,977 MWh. The plant is designed to operate with 0 percent condensate return and 50 °F makeup water.

Electricity costs for the installation are based on the purchase of 39,630 MWh of electricity. The electrical consumption of the heating plant is estimated at 3,544,000 kWh. Annual diesel/light oil use for heavy equipment and emergency generator operation is estimated at 17,000 gal.

Spare parts are estimated at $85,650 for the first year of operation and then $485,347 annually.

Plant water requirements are estimated at 600 gal/min; it is assumed this is available.

Major Recurring Repairs

Major repair and replacement costs are based on the following schedule:

Major cooling tower maintenance:	every 15 years
Major turbine-generator maintenance:	every 5 years
Major boiler maintenance:	every 8 years
Coal handling system maintenance:	every 10 years
Ash handling system maintenance:	every 7 years
Scrubber-lime system maintenance:	every 5 years
Major bag house maintenance:	every 3 years
Major ID fan maintenance:	every 20 years
Water treatment system maintenance:	every 10 years
Major deaerator maintenance:	every 20 years
Feedwater pump maintenance:	every 12 years
Major pump maintenance:	every 18 years
Circulating pump maintenance:	every 25 years
Major stack maintenance:	every 20 years
Major building maintenance:	every 20 years
Periodic EPA permit testing/renewal:	every 3 years

Table 46 summarize the costs.

Table 46

Cost Summary Alternative VI-c With Cogeneration - Anthracite

Capital Investment:	$66,328,800
Annual Costs:	
Fuel:	$ 4,033,000
O&M First Year:	$ 2,143,400
O&M After First Year:	$ 2,543,100
Purchased Electricity:	$ 3,008,600
Present Value Costs:	
Capital Investment:	$55,695,000
Annual Fuel:	$32,510,000
Annual O&M:	$15,480,000
Major Recurring Repairs:	$ 1,090,000
Annual Purchased Electricity:	$20,374,000
TOTAL LIFE CYCLE COST:	$125,149,000

Alternative VI-d, Cogeneration - Bituminous Coal

System Overview

This alternative consists of the same system as suboption VI-c with the exception of the type of coal.

The coal will be delivered by rail and approximately 994 ft of new rail line are needed for coal receiving and handling. Ash disposal will be at a landfill on the installation.

The design coal for this plant is from Kentucky and has the following properties:

Rank:	Bituminous
Moisture:	5.8 percent
Volatile Matter (dry):	37.2 percent
Fixed Carbon (dry):	50.4 percent
Ash (dry):	12.4 percent
Ash Fusion Temperature:	2354 °F
Heat Content (dry):	12,460 Btu/lb

Capital Equipment

The capital equipment is the same as for Alternate VI-c.

The coal handling system will include a stock/reclaim system and a coal storage silo sufficient for 3 days operation. The coal handling equipment is sized to handle up to 200 tons/h.

The ash handling system is sized to collect up to 69 tons of ash per day. The ash storage silo is sized at 275 tons. Ash discharged for transport to the landfill will contain 10 percent moisture for dust suppression and to improve handling characteristics.

The water treatment system will include demineralizers with degasification, a chemical injection skid and a deaerator. A water lab for testing the water quality is also included.

Air pollution control equipment for each boiler is the same as for Alternative VI-c.

The physical plant equipment is the same as for Alternate VI-c.

Annual System Requirements

Operation and maintenance staff is the same as for Alternate VI-c.

The estimated annual consumption of coal is 50,802 tons (dry) yielding an annual facility thermal output of 934,636 MMBtu and an electric output of 27,977 MWh. The plant is designed to operate with 0 percent condensate return and 50 °F makeup water.

Electricity costs for the installation are based on the purchase of 39,630 MWh of electricity. The electrical consumption of the heating plant is estimated at 3,545,000 kWh. Annual diesel/light oil use for heavy equipment and emergency generator operation is estimated at 17,000 gal.

Spare parts are estimated at $86,901 for the first year of operation and then $492,443 annually.

Plant water requirements are estimated at 600 gal/min; it is assumed this is available.

Major Recurring Repairs

Major repair and replacement costs are the same as for Alternate VI-c.

Table 47 summarizes the costs.

Table 47

Cost Summary Alternate VI-d With Cogeneration - Bituminous

Capital Investment:	$67,194,000
Annual Costs:	
Fuel:	$ 3,038,400
O&M First Year:	$ 2,235,600
O&M After First Year:	$ 2,641,200
Purchased Electricity:	$ 3,008,600
Present Value Costs:	
Capital Investment:	$56,421,000
Annual Fuel:	$24,485,000
Annual O&M:	$16,160,000
Major Recurring Repairs:	$ 1,053,000
Annual Purchased Electricity:	$20,374,000
TOTAL LIFE CYCLE COST:	$118,493,000

12 ALTERNATIVE VII - NEW DUAL FUEL OIL/GAS-FIRED BOILER PLANT

This alternative considers abandoning the existing CPP and constructing a new dual fuel oil/gas-fired plant. Suboptions VII-a and VII-b consider 100 percent electric purchase for natural gas as the primary fuel and No. 6 oil as the primary fuel, respectively. Suboptions VII-c and VII-d consider cogeneration for natural gas as the primary fuel and No. 6 oil as the primary fuel, respectively.

Alternatives VII-a and b, Electric Purchase

System Overview

The suboptions consist of building a new oil/gas-fired central heating plant next to the existing heating plant. The plant is designed to produce 150 psig saturated steam at a maximum continuous rating of 250,000 lb steam/h. It will consist of three oil/gas-fired boilers sized as follows:

1 unit at 40,000 lb steam/h
2 units at 125,000 lb steam/h

The building will be approximately 11,000 sq ft and the stack will be about 80 ft tall. The area required for the plant and oil storage tanks is approximately 2.5 acres. The No. 6 oil will be delivered by tanker truck and the natural gas will be delivered by pipeline. For this study, it is assumed that the gas supply company will be responsible for installing any gas pipeline required.

Capital Equipment

The boilers are packaged, dual fuel, oil/gas-fired. Each boiler includes an economizer. The boiler control system is a conventional digital control system linking each boiler for total plant control. Each boiler control is configured for single-loop integrity and has a single control panel for operations overview, with dedicated annunciator windows, motor controls, and status indicators.

The long term fuel storage facility is designed for 30 days of No. 6 oil storage. The oil is provided by two unloading pumps at 500 gal/min each. The day tank for providing oil to the boilers is 65,000 gal. The two boiler fuel pumps are rated at 20 gal/min each.

The water treatment system will include zeolite softeners, dealkalizers, a chemical injection skid and a deaerator. A water lab for testing the water quality is also included.

Low sulfur No. 6 oil is to be used thereby eliminating the need for an emissions control system. However, a continuous emission monitoring system is included for SOx, NOx, and opacity.

Physical plant equipment includes the following: air compressor, fire protection system, HVAC system, elevator, electrical substation, mobile equipment, specialty tools and maintenance equipment, locker and shower rooms, office furniture, and plant communications equipment. A 360-kW diesel generator is provided for emergency backup electrical service.

Annual System Requirements

Operation and maintenance staff consists of 16 people for an annual labor cost of $671,269. The staff requirements are:

Plant Manager:	1
Plant Engineer:	1
Plant Secretary:	1
Plant Janitor:	1
Plant Operator:	4
Plant Assistant Operator:	4
Operations Laborer:	1
Maintenance Mechanic:	2
Maintenance Electrician:	1
Total Staff	16

The estimated annual facility output is 782,712,000 lb of steam. The plant is designed to operate with 0 percent condensate return and 50 °F makeup water.

Annual fuel consumption with No. 6 oil as the primary fuel is 7,355,000 gal and 1,099 MM SCF with gas as the primary fuel.

Electricity costs for the installation are based on 100 percent purchase of the projected electrical requirements. The electrical consumption of the heating plant is estimated at 3,146,000 kWh.

Spare parts are estimated at $40,201 for the first year of operation and then $227,808 annually.

Heat plant water requirements are estimated at 525 gal/min; it is assumed that this is available.

Major Recurring Repairs

Major repair and replacement costs are based on the following schedule:

Major boiler maintenance costs:	every 15 years
Water treatment system maintenance:	every 10 years
Feedwater pump maintenance:	every 12 years
Major pump maintenance:	every 18 years
Major stack maintenance:	every 20 years
Major building maintenance:	every 20 years
Periodic EPA permit testing/renewal:	every 3 years

Table 48 summarizes the cost.

Table 48

Cost Summary Alternative VII With Electric Purchase

	Natural Gas	No. 6 Oil
Capital Investment:	$26,905,100	$26,905,100
Annual Costs:		
Fuel:	$ 3,193,200	$ 3,309,700
O&M First Year:	$ 1,069,600	$ 1,069,600
O&M After First Year:	$ 1,257,200	$ 1,257,200
Purchased Electricity:	$ 5,132,800	$ 5,132,800
Present Value Costs:		
Capital Investment:	$22,592,000	$22,592,000
Annual Fuel:	$30,995,000	$34,309,000
Annual O&M:	$ 7,887,000	$ 7,887,000
Major Recurring Repairs:	$ 304,000	$ 304,000
Annual Purchased Electricity:	$34,760,000	$34,760,000
TOTAL LIFE CYCLE COST:	$96,538,000	$99,852,000

Alternatives VII-c and d, Cogeneration

System Overview

These suboptions consist of building a new oil/gas-fired central heating plant with cogeneration next to the existing heating plant. The plant is designed to produce 600 psig, 750 °F super heated steam at a maximum continuous rating of 250,000 lb steam/h. The installation's steam distribution system will be supplied with 150 psig saturated steam. The plant will consist of three oil/gas-fired boilers sized as follows:

1 unit at 40,000 lb steam/h
2 units at 125,000 lb steam/h

The facility uses a 4.5-MW single extraction-condensation turbine generator for electric generation.

The building will be approximately 12,000 sq ft and the stack will be about 80 ft tall. The area required for the plant and oil storage tanks is approximately 2.5 acres. The No. 6 oil will be delivered by tanker truck and the natural gas will be delivered by pipeline. For this study, it is assumed that the gas supply company will be responsible for installing any gas pipeline required.

Capital Equipment

The boilers are the same as for Alternatives VII-a and b.

The turbine is designed as a 4.5-MW single extraction-condensation unit. The generator is a 3-phase, 60 cycle, synchronous, air cooled type with brushless exciters. The generator's voltage is 13.8 kV and rated at 150 MVA with a 0.85 Power Factor. Included with the turbine-generator are all necessary support equipment - such as the condenser, cooling tower, circulating pumps, and control system. Lake Picatinny may be used as a heat sink in lieu of the cooling tower if the environmental impact on the lake is minimal. Lake cooling would reduce the initial capital cost by approximately $400,000.

The long term fuel storage facility is designed for 30 days of No. 6 oil storage. The oil is provided by two unloading pumps at 500 gal/min each. The day tank for providing oil to the boilers is 75,000 gal. The two boiler fuel pumps are rated at 20 gal/min each.

The water treatment system will include demineralizers with degasification, a chemical injection skid, and a deaerator. A water lab for testing the water quality is also included.

Low sulfur No. 6 oil is to be used thereby eliminating the need for an emissions control system. However, a continuous emission monitoring system is included for SOx, NOx, and opacity.

Physical plant equipment is the same as for Alternatives VII-a and b.

Annual System Requirements

Operation and maintenance staff consists of 19 people for an annual labor cost of $778,856. The staff requirements are:

Plant Manager:	1
Plant Engineer:	1
Plant Secretary:	1
Plant Janitor:	1
Plant Operator:	4
Plant Assistant Operator:	4
Generator Operator:	4
Maintenance Mechanic:	2
Maintenance Electrician:	1
Total Staff	19

The estimated annual facility thermal output is 934,636 MMBtu with an electric output of 27,977 MWh. The plant is designed to operate with 0 percent condensate return and 50 °F makeup water.

Annual fuel consumption with No. 6 oil as the primary fuel is 8,498,000 gal and 1270 MM SCF with gas as the primary fuel.

Purchased electricity costs for the installation are based on the purchase of 39,630 MWh of electricity. The electrical consumption of the heating plant is estimated at 3,545,000 kWh.

Spare parts are estimated at $50,250 for the first year of operation and then $284,760 annually.

Heat plant water requirements are estimated at 600 gal/min; it is assumed that this is available.

Major Recurring Repairs

Major repair and replacement costs are based on the following schedule:

Major cooling tower maintenance:	every 15 years
Turbine-generator maintenance:	every 5 years
Major boiler maintenance costs:	every 15 years
Water treatment system maintenance:	every 10 years
Feedwater pump maintenance:	every 12 years
Major pump maintenance:	every 18 years
Circulating pump maintenance:	every 25 years
Major stack maintenance:	every 20 years
Major building maintenance:	every 20 years
Periodic EPA permit testing/renewal:	every 3 years

Table 49 summarizes the costs.

Table 49

Cost Summary Alternative VII With Cogeneration

	Natural Gas	No. 6 Oil
Capital Investment:	$32,905,100	$32,905,100
Annual Costs:		
Fuel:	$ 3,689,400	$ 3,824,000
O&M First Year:	$ 1,283,600	$ 1,283,600
O&M After First Year:	$ 1,518,100	$ 1,518,100
Purchased Electricity:	$ 3,008,600	$ 3,008,600
Present Value Costs:		
Capital Investment:	$27,630,000	$27,630,000
Annual Fuel:	$35,812,000	$39,641,000
Annual O&M:	$ 9,461,000	$ 9,461,000
Major Recurring Repairs:	$ 427,000	$ 427,000
Annual Purchased Electricity:	$20,374,000	$20,374,000
TOTAL LIFE CYCLE COST:	$93,704,000	$97,533,000

13 ALTERNATIVE VIII - SATELLITE STEAM PLANTS

This alternative considers abandoning the existing CPP and constructing new satellite boiler plants. Cogeneration was not considered in this alternative because the costs of individual generating units and electrical switching systems would be prohibitive. Suboptions VIII-a, VIII-b, and VIII-c consider boilers heated by natural gas, No. 6 oil, and coal, respectively.

Alternative VIII-a, Natural Gas

System Overview

The location of each satellite plant was based on existing buildings that serve as auxiliary heating plants. These buildings are 99, 506, and 3013. The significance of these buildings is that they already have a sufficient pipe size to accommodate the increased steam flow from the new boilers. Other building choices would require substantial upgrade. An additional boiler was selected for the 600 area buildings to decrease steam losses from transporting steam up to the higher elevation of these buildings.

The yearly loads for each satellite network were determined by using the HEATLOAD program to calculate the load for each building served. These loads were then used in the Steam Heat Distribution Program (SHDP) to determine the buildings to be served by each plant and the maximum load for each of the satellite plants. Maps showing the steam distribution zones for each of the satellite boilers are in Appendix E.

In the case of the boiler in the 600 series buildings, the unit is too small to be fired by coal, therefore the technologies considered for this suboption were No. 2 oil, natural gas, and electricity.

The boiler configurations for each satellite plant are:

Building 506	Three 28.07 MBtu/h boilers
Building 99	Three 48.69 MBtu/h boilers
Building 3013	Three 30.56 MBtu/h boilers
600 Series Buildings	One 1.4 MBtu/h boiler.

Capital Equipment

The capital costs are divided into two categories. The first component is purchased equipment, which includes the boiler, all auxiliary equipment, controls, and installation costs. The second component of the capital cost is the balance of the plant, which includes the cost of the building and supporting equipment.

The capital cost calculations were performed with an order of magnitude algorithm that estimates costs based on the size of the plant in million British thermal units.

Annual System Requirements

Annual system requirements are the operating and maintenance cost and the boiler fuel cost. Each satellite plant was modeled as an independent facility with its own operators and supervisors. The total labor costs are $627,432 per year and the total O&M costs are $996,750 per year. The annual fuel consumption for all four plants is 1,206,746 MBtu.

The cost of purchased electricity is $5,132,800, which is based on 100 percent purchase of the projected requirement.

The efficiency of the boilers was assumed to be 78 percent.

Major Recurring Repairs

Major repair and replacement costs are based on the following schedule:

Major boiler maintenance costs:	every 15 years
Water treatment system maintenance:	every 10 years
Feedwater pump maintenance:	every 12 years
Major pump maintenance:	every 18 years
Major stack maintenance:	every 20 years
Major building maintenance:	every 20 years
Periodic EPA permit testing/renewal:	every 3 years

Tables 50 and 51 summarize the costs.

Table 50

Cost Summary Alternative VIII-a With Natural Gas*

Capital Investment:	$10,616,000
Annual Costs:	
Fuel:	$ 3,504,400
O&M:	$ 1,624,200
Purchased Electricity:	$ 5,132,800
Present Value Costs	
Capital Investment:	$ 7,527,000
Annual Fuel:	$34,017,000
Annual O&M:	$ 9,788,000
Major Recurring Repairs:	$ 1,377,000
Annual Purchased Electricity:	$34,760,000
TOTAL LIFE CYCLE COST:	$87,469,000

*For the boilers in buildings 99, 506, and 3013 only.

Table 51

Cost Summary Alternative VIII-a for 600-Area Buildings

	Natural Gas	No. 2 Oil	Electricity
Capital Investment:	$ 196,000	$ 110,100	$ 131,000
Annual Costs:			
Fuel:	$ 36,300	$ 49,200	$ 208,400
O&M:	$ 1,400	$ 1,900	$ 2,100
Present Value Costs			
Capital Investment:	$ 156,000	$ 87,000	$ 104,000
Annual Fuel:	$ 352,000	$ 499,000	$ 1,412,000
Annual O&M:	$ 8,800	$ 11,400	$ 12,300
Major Recurring Repairs:	$ 1,200	$ 1,600	$ 1,700
Annual Purchased Electricity:	NA	NA	NA
TOTAL LIFE CYCLE COST:	$ 518,000	$ 599,000	$ 1,530,000

Alternative VIII-b, No. 6 Oil

System Overview

The system overview for this alternative is the same as that for Alternative VIII-a, except that this case involves the burning of No. 6 fuel oil instead of natural gas.

Capital Equipment

The capital equipment is the same as that for Alternative VIII-a since the prices depicted are based on the purchase of low sulfur oil. This makes it possible to not have to purchase air pollution control equipment.

Annual System Requirements

The total labor costs are $ 627,432 per year and the operating and maintenance costs are $ 996,749 per year. The annual fuel consumption is 1,176,575 MBtu.

The efficiency for the No. 6 oil-fired alternative was assumed to be 80 percent.

Major Recurring Repairs

The major recurring repairs are the same as for Alternative VIII-a.

Table 52 summarizes the costs.

Table 52

Cost Summary Alternative VIII-b With No. 6 Oil*

Capital Investment:	$10,616,000
Annual Costs:	
Fuel:	$ 3,541,500
O&M:	$ 1,624,200
Purchased Electricity:	$ 5,132,800
Present Value Costs	
Capital Investment:	$ 7,527,000
Annual Fuel:	$36,712,000
Annual O&M:	$ 9,788,000
Major Recurring Repairs:	$ 1,377,000
Annual Purchased Electricity:	$34,760,000
TOTAL LIFE CYCLE COST:	$90,164,000

*For the boilers in buildings 99, 506, and 3013 only.

Alternative VIII-c, Coal

System Overview

Each coal-fired satellite will be self supporting with its own coal fields and coal handling machinery. Contracting for coal will be combined among the satellite plants so the unit costs will be equal among the plants.

Capital Equipment

The boiler configuration for this alternative is the same as that for Alternative VIII-a. The efficiency for the coal-fired alternative was assumed to be 75 percent.

Annual System Requirements

The labor costs are $ 1,092,624 per year and the operating and maintenance costs are $ 3,691,267 per year. The annual fuel consumption is 1,255,016 MBtu.

It is important to note that only the coal option requires limestone and ash disposal costs because the costs are related to the need for air pollution controls.

Major Recurring Repairs

Major repair and replacement costs are based on the following schedule:

Major boiler maintenance:	every 8 years
Coal handling system maintenance:	every 10 years

Ash handling system maintenance:	every 7 years
Scrubber-lime system maintenance:	every 5 years
Major bag house maintenance:	every 3 years
Major ID fan maintenance:	every 20 years
Water treatment system maintenance:	every 10 years
Major deaerator maintenance:	every 20 years
Feedwater pump maintenance:	every 12 years
Major pump maintenance:	every 18 years
Major stack maintenance:	every 20 years
Major building maintenance:	every 20 years
Periodic EPA permit testing/renewal:	every 3 years

Tables 53 and 54 summarize the costs.

Table 53

Cost Summary Alternative VIII-c With Coal*

Capital Investment:	$ 38,717,600
Annual Costs:	
Fuel:	$ 3,012,000
O&M:	$ 4,783,900
Purchased Electricity:	$ 5,132,800
Present Value Costs:	
Capital Investment:	$ 27,454,000
Annual Fuel:	$ 24,272,000
Annual O&M:	$ 28,829,000
Major Recurring Repairs:	$ 4,057,000
Annual Purchased Electricity:	$ 34,760,000
TOTAL LIFE CYCLE COST:	$119,372,000

*For the boilers in buildings 99, 506, and 3013 only.

Table 54

Total Cost Summary Alternative VIII-c*

	Natural Gas	No. 6 Oil	Coal
Capital Investment:	$10,726,100	$10,726,100	$ 38,827,700
Annual Costs:			
Fuel:	$ 3,553,600	$ 3,590,700	$ 3,061,300
O&M:	$ 1,626,100	$ 1,626,100	$ 4,785,800
Purchased Electricity:	$ 5,132,800	$ 5,132,800	$ 5,132,800
Present Value Costs:			
Capital Investment:	$ 7,614,000	$ 7,614,000	$ 27,541,000
Annual Fuel:	$34,516,000	$37,211,000	$ 24,771,000
Annual O&M:	$11,174,000	$11,174,000	$ 32,895,000
Major Recurring Repairs:	$ 1,379,000	$ 1,379,000	$ 4,058,000
Annual Purchased Electricity:	$34,760,000	$34,760,000	$ 34,760,000
TOTAL LIFE CYCLE COST:	$89,443,000	$92,138,000	$124,025,000

*Each case includes costs associated with a No. 2 oil-fired boiler for the 600-area buildings.

14 ALTERNATIVE IX - INDIVIDUAL BOILERS IN EVERY BUILDING

This alternative considers abandoning the existing CPP and installing individual boilers in every building. Suboptions IX-a, IX-b, and IX-c consider using No. 2 oil, natural gas, and electrically operated boilers, respectively.

System Overview

In developing costing models for this option, certain methods were used for the calculations. For calculating a heating load and maximum load for each building, USACERL Interim Report E-143[10] provided the procedures and information necessary. A computer program was developed (named HEATLOAD) for implementing these calculations. The actual costing information was taken from Means Mechanical Cost Data 1989 manual. Costs were verified with some of the local heating system distributors. The costs also compared well with the *1989 National Construction Estimator* by Craftsman.[11]

The boilers to be installed in each building are standard package, steam type boilers. The size range of the boilers evaluated was 100,000 Btu/h up to 7 MBtu/h. Each boiler was categorized into one of 28 different size groups for costing.

The entire system includes 318 buildings and does not consider the buildings already heated by individual furnaces or boilers. The current steam heating system in each building will be used for heating the buildings. Installation of a condensate return system is included in the cost for each building.

Capital Equipment

Alternative IX-a: No. 6 Oil

The costing for the oil-fired boilers included an outside oil tank, piping, breaching, condensate return system, and a feedwater pump. The oil tank was sized to hold at least 1 month's supply of oil required to heat a building. A minimum tank size of 550 gal was used for the smaller buildings. Tanks larger than 1000 gal were considered to be buried underground. Oil-fired boilers were estimated to operate at 70 percent efficiency for those rated under 5 MBtu/h to 75 percent efficiency for those larger then 5 MBtu/h.

Alternative IX-b: Natural Gas

For this option, uninterruptible gas at a cost of $6.00/MBtu was used to ensure system reliability. Natural gas-fired boilers require a gas distribution system. The system required was estimated to be nearly 100,000 ft long. The piping was estimated to be 4 in. diameter buried 4 ft underground. The cost of the piping was estimated at $26.72/ft based on information from *Means Mechanical Cost Data*. Other costs were similar to the oil-fired case. Gas boilers were estimated to operate at 75 percent efficiency.

Alternative IX-c: Electric

The costing for electrically operated boilers included the same equipment as the oil-fired case except for the oil tank system. The electric option assumes that the electric distribution system is adequate to

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[10] B.L. Sliwinski, et al.

[11] *1989 National Construction Estimator* (Craftsman).

carry the increased loads. This must be verified before further consideration of the electric option. Electric boilers operate at 100 percent efficiency.

Annual System Requirements

In calculating a yearly operating and maintenance cost, labor and parts had to be considered. For the labor costs, the U.S. Army Corps of Engineers has guidelines for operating boilers based on their size.[12]

1. Boiler capacity under 0.36 MBtu/h needs 3 visits by an operator per year.

2. Boiler capacities from 0.36 MBtu/h to 1.7 MBtu/h require one visit every month.

3. Boiler capacities from 1.7 MBtu/h to 5 MBtu/h require an operator to visit the boiler every day.

4. Boilers over 5 MBtu/h require an operator to visit the boiler once every shift. Four shifts were assumed per day.

Based on the above constraints, and assuming that a visit constitutes about 2 hours for the smaller two categories and 1 hour for the larger two categories, the number of hours required per year was calculated. A grade/scale of WG 10 was taken as the standard pay scale for the operators; this is about $31,700/yr. The actual number of hours worked per individual - per year was taken to be 1800, which took into consideration leave time and holidays. This translated into a total of 16 people necessary to operate all of the installed boilers. Two persons were added as supervisors. This came to a total cost of $570,600/yr.

For calculating maintenance costs for labor, the following staff was assumed:

1	Pipe Fitter
1	Electrician/Instrument Technicians
1	Foreman
1	Equipment Mechanic
1	Apprentice
2	Other
7	Total

These positions were also given a salary of $31,700/yr for a total labor maintenance cost of $221,900 annually.

Operating materials and maintenance material costs were assumed to be 2 percent of the installed cost.

Fuel costs were based on the total energy required to heat each building for the year and the efficiency of each boiler type.

[12]Army Regulation (AR) 420-49, *Heating, Energy Selection and Fuel Storage, Distribution and Dispensing Systems* (Headquarters, Department of the Army, 18 November 1976).

Major Recurring Repairs

Major repair and replacement costs for all the options were estimated to begin 10 years after initial installation, and are estimated at 5 percent of the total installed equipment cost, per year.

Tables 55 through 57 summarize the costs for this alternative.

Table 55

Cost Summary Alternative IX With No. 2 Oil

Capital Investment:	$11,282,000
Annual Costs:	
Fuel:	$ 3,272,000
O&M:	$ 853,000
Purchased Electricity:	$ 5,132,800
Present Value Costs:	
Capital Investment:	$ 8,961,000
Annual Fuel:	$33,419,000
Annual O&M:	$ 5,867,000
Major Recurring Repairs:	$ 743,000
Annual Purchased Electricity:	$34,760,000
TOTAL LIFE CYCLE COST:	$83,750,000

Table 56

Cost Summary Alternative IX With Gas

Capital Investment:	$12,309,000
Annual Costs:	
Fuel:	$ 5,052,000
O&M:	$ 823,000
Purchased Electricity:	$ 5,132,800
Present Value Costs:	
Capital Investment:	$ 9,777,000
Annual Fuel:	$49,035,000
Annual O&M:	$ 5,654,000
Major Recurring Repairs:	$ 765,000
Annual Purchased Electricity:	$34,760,000
TOTAL LIFE CYCLE COST:	$99,991,000

Table 57

Cost Summary Alternative IX With Electric

Capital Investment:	$10.904,000
Annual Costs:	
Fuel (Electricity):	$14,050,000
O&M:	$ 847,000
Purchased Electricity:	$ 5,132,800
Present Value Costs:	
Capital Investment:	$ 8,661,000
Annual Fuel (Electricity):	$95,148,000
Annual O&M:	$ 5,820,000
Major Recurring Repairs:	$ 819,000
Annual Purchased Electricity:	$34,760,000
TOTAL LIFE CYCLE COST:	$145,208,000

15 ALTERNATIVE X - MUNICIPAL REFUSE INCINERATOR

Landfill capacity is a growing problem in New Jersey. As landfill space becomes limited, the price of disposal escalates. Many landfills in New Jersey and New York are currently charging tipping fees of $120/ton and some waste is being shipped as far away as Indiana, Kentucky, and Illinois. Being aware of this problem, Picatinny has considered the possibility of a third party financed (TPF) heat recovery incineration (HRI) plant to reduce the volume of wastes and ultimately the costs of disposal. The TPF plant would burn waste from Picatinny and surrounding communities, generate steam to sell to Picatinny, and produce electricity to sell to the local utility. This type of plant would most probably be a pit-and-crane arrangement using excess air grate technology as illustrated in Figure 26. These plants normally require air pollution control of some type. In most states, this is usually for particulate (fine fly ash) control, and is accomplished with either an electrostatic precipitator or a baghouse. However, New Jersey, several other states, and proposed federal guidelines would require acid gas scrubbers to be also furnished.

Another technology that would be typical of small community or industrial operations is illustrated in Figure 27. This system involves a modular, dual chamber incinerator with the first, or primary chamber, operating under substoichiometric (starved air) conditions. The secondary chamber operates under excess air conditions, completes the combustion of the gases from the primary chamber, and destroys most potential pollutants. Waste is fed to the incinerator by a front loader from a tipping floor. Under the current regulations in most states, no additional air pollution control equipment would be needed. However, the same regulations noted above would require additional equipment, primarily an acid gas scrubber.

Countywide System

Morris County, NJ has developed specific plans for the construction of a 1348 ton per day (TPD) capacity plant approximately 10 miles southeast of Picatinny.* The plant should have enough capacity to dispose of all of the county's waste with two 670 TPD units. The estimated constructed capital cost including startup is $142,000,000. This does not include financing expenses. The plant is expected to be operational in July 1993, charge a tipping fee of $100/ton, and produce 40 MW of electricity. It should be noted, however, that projects dealing with sensitive environmental, legal, and political issues are often delayed or canceled. If the Morris County plant is constructed as planned, an additional TPF plant for Picatinny would not be economically feasible due to the lack of available waste. At the planned site, the county plant is located too far from the Picatinny Arsenal main building area to transport steam.

If future developments warrant a TPF HRI project at Picatinny, many factors must be considered. Picatinny's steam requirements must be well defined since any "third party" will require a "take or pay" minimum steam purchase. There will be significant associated truck traffic that may be a problem for Picatinny's roads and security may be a problem if the plant is built on the base. It is recommended that any such plant be built just off the base perimeter near the northwest corner where a 10-in. line and a significant steam load exists. Electricity is not normally purchased directly by the Army from any type of cogeneration plant. There would not be a direct benefit to Picatinny from the electrical production, or a direct effect on Picatinny's electrical distribution system. The presence of such a plant will improve the electric utility's reliability to supply the installation.

*Information provided by Glen Schweizer of Morris County at (201) 285-8390.

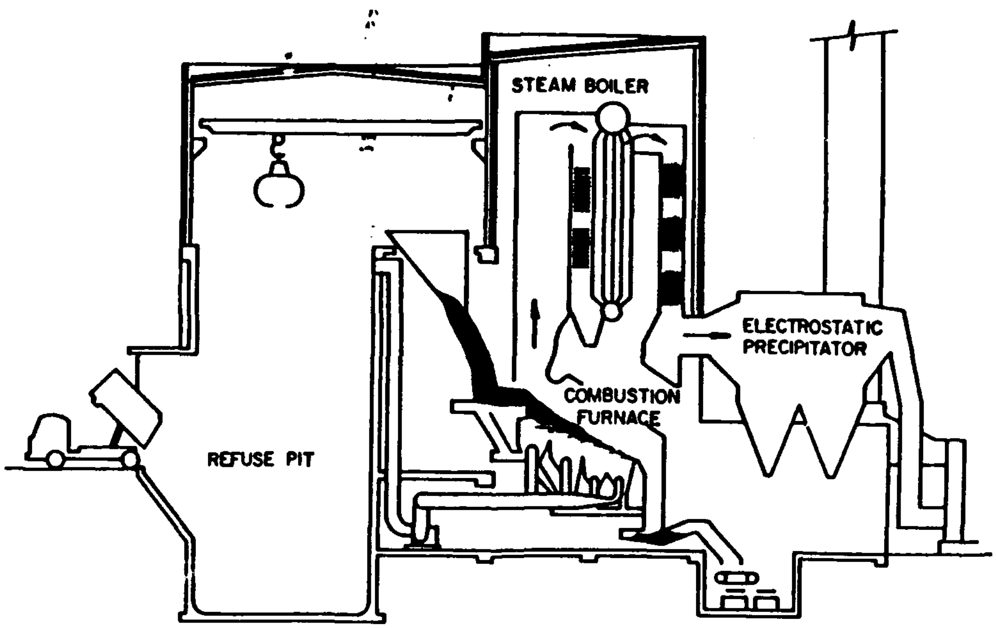

Figure 26. Pit-and-crane incinerator system.

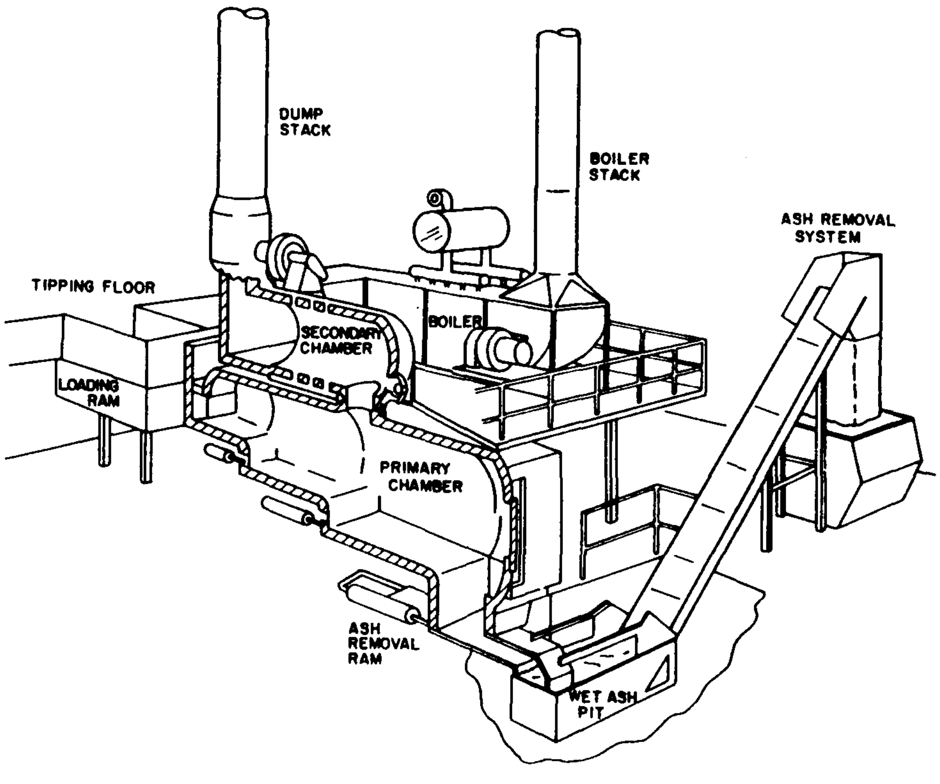

Figure 27. Modular starved air incinerator system.

Local HRI System

An HRI for handling waste only from Picatinny may be feasible if the Morris County disposal costs are around $100/ton or more. The economics of HRI projects depend both on the fuel savings and reduced disposal costs. Several of the alternatives in this study consider converting the CPP from No. 6 oil to natural gas. This will reduce the economic feasibility of an HRI. The steam from an HRI will be displacing steam produced by a lower cost fuel and reduce the energy related economic benefit. However, an HRI for Picatinny may be justified primarily on the basis of disposal cost savings, if the Morris County disposal costs are an indication of what the near-term future will bring.

USACERL has developed a computer based economic model to determine heat recovery incineration feasibility (HRIFEAS). A preliminary HRIFEAS economic analysis was made for Picatinny based on two broad assumptions: (1) disposal costs of $100/ton and (2) waste generation of 0.91 tons/yr/person. The waste generation rate is a U.S. Environmental Protection Agency (USEPA) national average. During a study conducted by USACERL in 1987[11], the amount of waste generated at Picatinny was reported as 130,000 tons/yr which amounts to 19.8 tons/yr/person based on the effective installation population. HRI feasibility is extremely sensitive to these two factors. To obtain an accurate analysis, a complete waste survey must be performed to determine the actual waste generation rate, the cost of disposal, and the potential for recycling and other waste reduction measures. The following analysis is only a screening model to determine if further analysis is warranted.

The HRIFEAS program used to analyze the data is being developed as part of USACERL's HRI standard design package. The program prompts for the required waste disposal and energy information, provides default values if the information is not known, flags values that seem unreasonable, provides technical design and cost information, and interfaces with the LCCID program. The HRIFEAS program determines the optimum economic size of the plant, including the number of incinerator units based on the waste generation rate, and an assumed 7 day per week operating schedule. The information passed to the LCCID program includes an estimate of the plant capital construction cost, the plant O&M cost, amount and cost of auxiliary fuel used, amount and cost of electricity consumed, amount and cost of fuel displaced assuming full use of the steam produced, and an estimate of the landfill O&M cost savings. The economic evaluation is based upon a 15-yr life as specified by the Office of the Chief of Engineers (OCE).

The cost estimates and economic evaluation noted above are based on a typical modular starved-air incinerator arrangement. The results are the life cycle costs of each alternative (in this case, commercial disposal versus an HRI plant), the savings to investment ratio (SIR), and the discounted payback period (DPP). The output from the two programs can be used to prepare the Project Development Brochure and the 1391.

Detailed information on the analysis can be found in Appendix F. The annual amount of waste to be disposed of was taken as 5976 tons/yr based on an effective population of 6567 people. This results in 115 tons/week or 16.4 tons/day (7 days/week) to be incinerated. This would require two 10-TPD units to dispose of this waste with minimal redundancy to accommodate for maintenance outages. This plant size was analyzed both with and without acid gas scrubbers, and displacing either oil at $3.01/MBtu or natural gas at $2.90/MBtu. The results show that the plant would have a reasonable SIR and payback regardless of whether oil or gas is displaced and no scrubber is required. However, the New Jersey Department of Environmental Protection (DEP) has indicated that they probably would require acid gas scrubbing on units this small. In that case, the plant would just barely qualify (SIR=1.0 and payback of

[11]USACERL unpublished study.

14 years) when displacing oil, and not qualify when displacing gas. If Picatinny has significantly more waste available, as confirmed by weighings and a waste characterization study, the results of this analysis could change.

Table 58 compares the cost of this alternative to commercial disposal.

Table 58

HRI Versus Commercial Disposal

	Capital Cost	Landfill Savings	Fuel Savings	SIR	DPP
Oil & No Scrubber	$1,417,701	$358,560	$81,179	1.8	6
Oil & Scrubber	$1,890,903	$286,250	$81,179	1.0	15
Gas & No Scrubber	$1,417,701	$358,560	$58,367	1.6	7
Gas & Scrubber	$1,890,903	$286,250	$58,367	0.9	25

16 CONCLUSIONS AND RECOMMENDATIONS

The results of this study and economic analysis indicate that Alternative II-c is the most practical alternative for Picatinny Arsenal. Alternative II-c considers repairing the existing Central Power Plant and replacing the inoperable electrical generating equipment with a combination of backpressure turbine-generators and reciprocating engines.

It is recommended that this alternative be implemented in a phased approach over a 5-year period. This approach will allow specific cost-effective improvements to be made that are within the budget constraints of the arsenal. Table 59 shows a prioritized list of the specific areas of improvement. The estimated costs for each area are shown in the anticipated fiscal year of project funding.

Table 59 also shows the expected cost savings from implementing each activity. The savings are shown starting the year following project completion. Cost savings for the improvements after Year 1 are from (1) a reduction in overtime required to work on boiler equipment failures, (2) a reduction in the "no-load" load by isolating unneeded steam lines, and (3) a reduction in steam line losses by reducing the enthalpy of the steam with desuperheaters. The cost savings after Year 2 are from (1) a reduction in overtime required to work on electrical equipment failures and (2) a staff reduction made feasible by the consolidation of controls.

The cost savings after Year 3 are from the reduction in electric demand and base rate energy charges from the generation of electricity using backpressure turbine-generators. The cost savings after Year 4 are from the reduction in electric demand and base rate energy charges from the generation of electricity using backpressure turbine-generators and reciprocating generators. About one-third of the cost savings is from the ability to change to an interruptible electric rate, which was made possible by the reciprocating generators. The cost savings after Year 5 are from an increase in efficiency from the installation of high efficiency burners.

METRIC CONVERSION TABLE

1 acre	=	0.4047 hectare
1 ft	=	0.305 m
1 gal	=	3.78 L
1 in	=	25.4 mm
1 lb	=	0.453 kg
1 mil	=	0.00254 cm
1 mile	=	1.61 km
1 psi	=	6.89 kPa
1 ton	=	1016 kg
°C	=	0.55 (°F-32)

Table 59

Central Power Plant Activity Plan

Planned Activity	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Recondition Plant						
Repair Desuperheater	$18,000					
Acid Clean Boilers	$80,000					
Boiler System Inspection	$82,500					
Boiler Repairs	$82,500					
Boiler System Testing	$30,000					
Extra Boiler Layup	$20,000					
Repair Feedwater System	$83,000					
Repair Electrical System						
Replace Old Equip & Wire	$133,000					
Replace 480 Volt Service		$835,000				
Replace Lights With HPS		$45,000				
Redesign Plant Controls		$175,000				
Renovate 1 Turbine-Gen Set						
Repair 1.0 MW BP Turbine			$715,000			
Repair 3.4 MW BP Turbine			$1,430,000			
Replace 5.2 MW IC-Gen				$2,325,000		
Repair Burner System						
Replace Riley Burner					$162,000	
Replace One CE Burner					$650,000	
Annual Total (w/o overheads)	$529,000	$1,055,000	$2,145,000	$2,325,000	$812,000	$0
Annual Total (w/ overheads)	$669,185	$1,334,575	$2,713,425	$2,941,125	$1,027,180	$0
Cummulative Total Expenses	$669,185	$2,003,760	$4,717,185	$7,658,310	$8,685,490	$8,685,490
New Annual Savings		$762,000	$368,000	$1,299,000	$622,000	$165,000
Annual Total Savings		$762,000	$1,130,000	$2,429,000	$3,051,000	$3,216,000
Cummulative Total Savings		$762,000	$1,892,000	$4,321,000	$7,372,000	$10,588,000
Additional Annual Funds	$669,185	$572,575	$1,583,425	$512,125	($2,023,820)	($3,216,000)
Cummulative Additional Funds	$669,185	$1,241,760	$2,825,185	$3,337,310	$1,313,490	($1,902,510)

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APPENDIX A: CPP EQUIPMENT DATA

TURBINE - GENERATORS

Generator No. 2 is a G.E. 3600 RPM, 60 Hz generator rated at 1875 KVA. The serial number of the generator is 5434538. The original service date was August 22, 1938.

The original turbine serial number was 43194 rated at 1500 KW A.C. with inlet steam conditions of 425 psig & 600°F. The Appendix contains two (2) reports in regards to this turbine. The reports are dated 16 February 1982 and April 1, 1981.

Turbine-Generator No. 4 - is a G.E. direct connected 3600 RPM, 16 stage, extraction-condensing unit. The turbine is designed for 425 psig & 600oF steam with two (2) extractions, 125 and 60 psig, and a condenser back pressure of 2" HgA. The turbine/condenser is designed for full throttle flow condensing. The turbine's nameplate data is:

S/N: 48218	Form: LL	KW: 3000	Speed: 3600 RPM
Steam Pressure:	425 Lbs	Temp: 600°F	
Exhaust Pressure:	2" ABS	16 Stages	
GEI - 12262			

The generator is an air-cooled unit rated at 3000 KW A.C. at 2400 volts. The nameplate data of the generator is:

S/N: 48218	Form: LL
Cycle: 60	Phase: 3
KW: 3000:	Speed: 3600 RPM
Type: Air-Cooled	
Y Connected for 2400 Volts	

The nameplate data on the exciter is:

Model: 51A507	Frame: 83	Type: EDF
Volts: 125	Winding: Shunt	
Speed: 3600	KW: 25	AMP: 200
S/N: 1796506		

Turbine-Generator No. 5 is a G.E. direct connected 3600 RPM, 14 stage, extraction-condensing unit. Turbine is designed for 425 psig and 600oF steam with two (2) extractions, 125 and 60 psig, and a condenser back pressure of 2" HgA. The turbine/condenser is designed for full throttle flow condensing. The nameplate data on the turbine is:

SN: 109115	KW: 3750	Speed: 3600 RPM
Steam Pres: 425 Lbs	Temp: 600°F	
Exhaust Pres: 2"ABS	14 Stages	

The generator is an air-cooled unit rated at 3750 KVA with a Power Factor (P.F.) of 0.8 at 2400/4160 volts. The nameplate data on the generator is:

SN: 6978247	Type: Air-Cooled ATB	
Poles: 2	Cycle: 60	Phase: 3
Delta/Wye Connected for 2400/4160 Volts		
Rating: 3750 KVA @ 0.8 P.F.		
Exciter: 125 Volts		
Armature: 902/520 Amp	Field: 151 Amp	
GEI - 41155		

The nameplate data on the exciter is:

Model: 51A342	Frame: 83	Type: EDF
Volts: 125	Winding: Shunt	
Speed: 3600 RPM	KW: 25	Amp: 200
Service Factor: 1.15 @ Rated Volts		
Duty Continuous		
40°C Rise	Enclosure: T.E.E.V.	
S/N: 7133340-RK		

BOILER FEEDWATER SYSTEM

This system starts at the Pumphouse screened inlets on east shore of Picatinny Lake, proceeds through pumps and a tunnel to northeast end of the Boilerhouse. There it rises vertically (thru pressure filters on 2nd level), zeolites (on 3rd level) and into deaerating heaters and mixes with pumped condensate return from various points in house. Feedwater pump suctions are manifolded to connect the deaerator discharge to seven (7) pumps located in two (2) separate areas of the building. Feedwater Pumps No. 1 (electric drive) and Nos. 2 & 3 (turbine drives) are located on the first floor next to a hydraulic pump behind Boiler No. 4, while Pumps No. 4 (turbine drive) and Nos. 5, 6, & 7 (electric drives) were placed on same level but behind No. 5 pulverizer during addition of the Combustion Engineering units.

A. Feedwater System

Seven boiler feed pumps are arranged to operate in parallel taking suction from the deaerating heaters and pumping the feedwater through two feedwater heaters to the boiler feedwater regulators. Feedwater heater No. 1 receives steam from the 125 lb. steam header and feedwater heater No. 2 receives steam from the 60 lb. steam header.

Feedwater heater level is maintained by a level control valve on the heater outlet drain to condensate tank where the condensate is pumped to the deaerator. Pressure gauges and thermometers in the feedwater inlet and outlet piping measure feedwater pressure and temperature. The shell side of the heaters are equipped with high and low level alarms, pressure gauge and thermometer.

There are four motor driven and three turbine driven pumps. All pumps are equipped with suction and discharge pressure gauges. The turbine driven pumps have turbine inlet and exhaust pressure gauges. The pumps are protected by minimum flow orifices that are connected into a pump recirculation header that discharges into the deaerator.

Boiler Feed Pumps

Pump #1

Manufacturer	Worthington
Model	2-1/2 - UNO - 10
Capacity	350 GPM
Drive	Motor
Rating	460 V., 60 Hz, 3 phase
150 HP	

Pump #2

Manufacturer	Worthington
Model	2-1/2 - UNO - 11
Capacity	200 GPM
Serial Number	83TS81019-1
Head	1400 ft @ 3550 RPM
Drive	Turbine
Mfg.	Coppus
Serial Number	83T6279
Type	RL-20L
HP/RPM131/3550	

Pump #3

Manufacturer	Ingersoll Rand
Capacity	400 GPM
Model	2-1/2 CNTA-6
Serial Number	C413225
Head	270 ft. @ 3500 RPM
Drive	Turbine
Mfg.	Terry
Serial Number	36773-A
Type	ZS-1
HP/RPM/Trip	250/3500/4310
Inlet Press/Temp	425 psig/750oF
Outlet Press	10 psig
Governor	Leslie CTHSM-1

Pump #4

Manufacturer	Ingersoll Rand
Capacity	400 GPM
Model	2-1/2 CNTA-6
Serial Number	C67-2R9
Head	1270 ft. @ 3500 RPM
Drive	Turbine
Mfg.	Terry
Serial Number	T36773-A
Type	ZS-1
HP/RPM	250/3600
Inlet Press/Temp.	125 psig/750°F
Outlet Press.	10 psig
Governor	Leslie CTHSM-1

Pump #5	
Manufacturer	Worthington
Capacity	350 GPM
Model	2-1/2 UNO-10
Serial Number	1614937
Head	1160 ft. @ 3550 RPM
Drive	Motor
Mfg.	G.E.
Serial Number	HO 32815
Motor	150 HP, 440 V., 60 Hz,
3 phase	
Pump #6	
Manufacturer	Ingersoll Rand
Capacity	400 GPM
Model	2-1/2 CNTA-6
Serial Number	0869-154
Head	1490 ft. @ 3550 RPM
Drive	Motor
Mfg.	Elliot
Serial Number	CV30111
Motor	2300 V., 60 Hz
3 phase	
250 HP	
Pump #7	
Manufacturer	Worthington
Model	2-1/2 - UNO - 11
Serial Number	83TS81020-1
Capacity	350
Head	1150 ft. @ 3550 RPM
Driver	HP 200
Motor	
Manufacturer	Westinghouse
HP	200
Phase	3
Cycles	60
RPM	3550
Ser. Factor	1.15
Volts	460
AMP	230

B. Condensate-Feedwater System

The condensate-feedwater system condenses steam used in the steam turbines to condensate, pumps it to the deaerator with makeup water, heats it, deaerates it, and feeds it to the boilers at the required flow rate, temperature and pressure. A secondary function is to supply deaerated water to the various desuperheaters for steam temperature control.

The condensate system consists of two main surface condensers, four condensate pumps, two deaerators, condensate storage tank, two preheat exchangers and all interconnecting piping, valves and controls.

The feedwater system consists of seven boiler feed pumps, two feedwater heaters and all interconnecting piping, valves and controls from the outlet of the deaerators to the boiler inlets. The system also includes all piping, valves and controls associates with desuperheaters spray water supply.

Exhaust steam from each steam turbine condenses in its respective main condenser and collects in the condenser hot well. The condensate flows through a header to two 100 percent capacity, motor driven, centrifugal condensate pumps.

The condensate pumps discharge to a common header which supplies water through the tube side of the holding ejector inter-after condenser.

A bypass line containing a level control valve is provided downstream of the holding ejector inter-after condenser. The control valve will close upon a low condenser hot well level signal for the level to return the water level in the condenser back to normal. This bypass is open to provide minimum flow protection for the condensate pumps and provides adequate condensate flow through the air ejector, by means of another valve which is opened to return the condensate back to the condenser. The outlet valve and return valve are normally adjusted to maintain hot well level.

There is no makeup to the condenser. All makeup is into the deaerator. Deaerator level is maintained by an automatic level control valve and automatic dump valve. Makeup is from the treated water system. Deaerator dump is by gravity to the condensate storage tank.

Normal operation of the condensate system is with one condensate pump per steam turbine air ejector, makeup preheat exchanger and one deaerator in operation.

During start-up, the condensate and makeup systems are filled to normal operating levels and all high point vents are opened and maintained in an open position until venting is accomplished. Condensate pump start is initiated by operator action from the local hand switch. Condensate pump discharge flow will be recirculated back to the main condenser through air ejectors until hot well level rises as increased steam flow is admitted to the turbine, return valve closed and condensate pump discharge control valve maintaining main condenser hot well level.

C. Circulating Water System

The circulating water system supplies cooling water from Lake Picatinny ot the main condensers, with back-up cross connect service to steam turbine lube oil coolers, gland steam spray chamber, generator air cooler makeup to deaerator through booster pumps, air compressors, aftercoolers and miscellaneous items requiring cooling.

Six various size vertical mixed flow, wet pit type, circulating pumps are located in a sump beneath the pumphouse. Each pump is installed in an intake channel and is protected by traveling screens. There are three intake structures and three sets of traveling screens to protect the various pumps. Each pump takes suction from the sump and discharges into a common water distribution system. Individual parallel branch lines supply water to each of the components described above. Water leaving the equipment flows through individual branch lines to a 24-inch discharge header. The discharge header returns the heated water to Lake Picatinny some distance from the intake.

Each main condenser supply line is provided with a manual valve and expansion joint. All other branch supply and return lines are provided with manual isolation valves.

The main surface condensers are single shell, two pass, single pressure units with divided water boxes. A two-stage priming ejector, with inter-after condenser, is provided for each condenser. No. 4 turbine-generator has a hogging ejector which assists the holding ejector in removing air and non-condensable gases from the main condenser during start-up. The holding ejector maintains the condenser design pressure during normal operation.

Normal operation of the circulating water system is with the number of circulating water pumps required due to temperature of lake and number of units of line, the holding ejector in operating and all operating equipment cooling water inlet and outlet valves open.

D. Traveling Water Screens

Lake Picatinny may contain aquatic life or debris which could foul up the condenser tubes or the circulating water pumps. Therefore, the water must be screened to remove such material. There are three Link Belt traveling screens in intake structure, one at each of the three inlet chambers to circulating and service water pumps. The screens are made of #304SS wire cloth, 16 W&M gauge wire with .104 sq. openings. Each is capable of screening at least 3250 gallons of water per minute at a maximum water velocity of 2.23 feet per second through 100% clean screen at low water level of 4-10". Each screen unit is a self-contained system driven by its own electric motor drive through a speed reducer and contains a two-inch spray header and nozzle system, totally enclosed splash-proof electric motor and drive housings. Each screen has a built-in washdown system that uses plant service water to remove debris from screen. A solenoid valve controls the water flow to each screen. The washdown interval and duration is controlled by a local timer which can be adjusted for the desired washdown interval. Traveling Screen Data gives information about the screens and motors.

Traveling Screen Data

<u>SCREENS</u>:	
Manufacturer	Link Belt
Capacity per Screen	3250 GPM
Water Velocity	2.23 ft./sec.
Basket Velocity	Approx. 10 ft./min.
Low Water Elevation	4 ft. 10 in.
Spray Nozzle Discharge: 62 psi	68 GPM
<u>MOTORS</u>:	
Manufacturer	Westinghouse
HP	3/4
RPM	1150
Voltage	230/460
Phase	3
Hz	60
Power Source	480 V. Switchgear

E. Circulating Water Pumps

The circulating water pumps are motor driven, single stage, vertical, mixed flow, wet pit type pumps mounted in a sump beneath the pumphouse. Supply water is from Lake Picatinny adjacent to the pumphouse.

Each pump consists of an electric motor, discharge head, column pipe and pumps bowl assembly. The discharge head supports the pump and driver on the foundation and contains an above ground discharge port which connects with the discharge piping. A stuffing box seals the pump top shaft to prevent excessive leakage while allowing some leakage to lubricate the shaft packing. The column pipe extends from the underside of the pump head down to the pump bowl assembly. It carries the pumped fluids and supports the lineshaft bearings. Water rising through the column pipe lubricates the lineshaft bearings. The pump bowl assembly contains the impeller which is connected to the pump shaft. The upper portion of the bowl contains vanes which direct the fluid from the impeller out of the bowl. The vanes also support the bowl bearing housing. The bowl bearing is lubricated by the pumped fluid. The inlet of the pump bowl assembly is fitted with a strainer to prevent internal pump damage due to the intake of foreign objects. A pressure gauge on each pump discharge indicates the output pressure to the distribution system.

The circulating water system consists of four vertical and two horizontal pumps of various sizes and the interconnecting piping and valves for supplying water to plant equipment requiring circulating water. The pumping system is arranged so that any of the pumps, or combination of pumps, through manual valving, can pump water into the circulating water distribution system. The discharge piping is routed through a walkway tunnel to the powerhouse. Start and stop switches are provided on the local motor control center in the pumphouse.

Circulating Water Pumps

<u>**Pump # 1**</u>	
Manufacturer	Ingersoll Rand
Serial Number	0666-12
Size	5 CFV
Capacity	1000 GPM
RPM	1750
Head	58 feet
Motor	
Manufacturer	Electro Dynamic
Serial Number	2643690
Frame	AJ364
Type	KNX
Rating	220/440 V., 48/24 A, 20 HP 1750 RPM, 60 Hz, 3 Phase
<u>**Pump # 2**</u>	
Manufacturer	Worthington
Serial Number	A1446771
Size	12QHOI
Capacity	1500 GPM
RPM	1800
Head	58 feet
Motor	
Manufacturer	U.S. Electric
Serial Number	2344427
Frame	365
Type	CFU
Rating	220/440 V., 74/37 A, 30 HP 1800 RPM, 60 Hz, 3 Phase
<u>**Pump # 3**</u>	
Manufacturer	Worthington
Serial Number	1446772
Size	12QHOI
Capacity	1500 GPM
RPM	1800
Head	58 feet
Motor	
Manufacturer	U.S. Electric
Serial Number	2344425
Frame	365
Rating	220/440 V., 74/37 A, 30 HP 1800 RPM, 60 Hz, 3 Phase

Pump # 4

Manufacturer	Worthington
Serial Number	P-40168
Size	12HH165
Capacity	1200 GPM
RPM	1755
Head	58 feet
Motor	
Manufacturer	General Electric
Serial Number	BLJ-219335
Frame	B284TP16
Rating	220/440 V., 63.4/31.7 A, 25 HP, 1755 RPM, 60 Hz, 3 Phase

Pump # 5

Manufacturer	Ingersoll Rand
Serial Number	0666-11
Size	50 FV
Capacity	1000 GPM
RPM	1750
Head	58 feet
Motor	
Manufacturer	Electro Dynamic Works
Serial Number	57463
Frame	KNX
Rating	20 HP

Pump # 6

Manufacturer	Warren Steam Pump Co.
Serial Number	8827
Size	10 DM 12
Capacity	3180 GPM
RPM	1150
Head	45.8 feet
Motor	
Manufacturer	General Electric
Serial Number	5532897
Frame	504
Type	KF
Rating	220/440 V., 126/63 A, 1175 RPM, 50 HP, 60 Hz, 3 Phase

F. Makeup Water Treatment System

The function of the makeup water treatment system is to keep those constituents from the makeup water of raw water from the Lake which would from a scale deposit that would interfere with heat transfer and lead to boiler tube failure. Makeup water (that portion of the total feedwater not returned to the boilers as condensate) receives treatment by two major processess.

1) Pressure Filters

The pressure filters serve to remove suspended solids from the raw make-up water. The pressure filters consist of three, 9'-0" diameter by approximately 7'-3" high units that operate in a parallel arrangement. Each unit contains graded, anthracite media.

The pressure filters have a cyclic operational sequence. The modes which comprise this cycle are the following:

a) Service - Raw water enters top of unit, moves down through the media, and filtered water exits bottom of unit.

b) Backwash - Raw water enters bottom of unit and moves up through and fluidizes the media loosening and removing entrapped solids, and exits the top of the unit. The backwash rate is approximately 760 GPM. The backwash time is approximately 10 minutes.

c) Rinse - Raw water enters top of unit, moves down through media to reconsolidate it and exits bottom of unit. The rinse rate is approximately 160 GPM. Rinse time is approximately 5 minutes.

2) Sodium Softeners

The sodium softeners serve to remove the scale-forming calcium and magnesium ions from the effluent water of the pressure filters. This removal mechanism is by ion exchange in which the undesireable ions are absorbed into a resin with the subsequent release of sodium ions to the water moving through the resin bed. This replacement or exchange of calcium and magnesium ions for sodium ions is called sodium softening. There are three softener units, each being 6'-0" in diameter by approximately 8'-0" high. Each unit contains 70 ft3 of ion exchange resin. The units operate in parallel. The softeners have a cyclic operational sequence. The individual modes of this sequence can be described as follows:

a) Service - Water enters top of unit, moves down through the resin bed and softened water exits bottom of unit. The volume of water passing through an individual softener unit during the service cycle is 700,000 gallons based upon an inlet water hardness of 2 grains/gallon or 34 mg/1 total hardness as $CaCO_3$. When the water softening capacity of the softener unit is exhausted, it is taken out of service and regenerated.

b) Backwash - This is the first step of the regeneration process. Water enters the bottom of the unit at approximately 170 GPM. This upward flow of water loosens and regrades the resin bed and removes any debris which may have collected in the bed during the service run. Backwash time is approximately 10 minutes.

c) Brining - During this mode, a brine solution is educted into the top of the unit and flows down through the resin bed. Approximately 187 gallons of saturated brine (462 lbs. salt) is introduced slowly over a 15 minute period.

d) Rinse - Water is introduced into the top of the unit at approximately 100 GPM. This water displaces the brine within the resin bed. Rinse time is approximately 30 minutes.

3) Condensate Storage Facilities

The plant is currently operating in a near 100 percent makeup mode with makeup being supplied through the filters and softeners. The only condensate returning is from within the plant, primarily from the steam turbine generators. Condensate is collected and stored in the condensate storage tank which holds approximately 8600 gallons. Water is used for feedwater to the deaerators along with the makeup water. Condensate is transferred from the storage tank to the deaerators by two (2) condensate transfer pumps. Most of the feedwater is supplied through the Power Plant water treatment system.

4) Boiler Blowdown

The water in the boiler system circulates within the system. From the steam drum the water flows through the "unheated" or "partially heated" downcomers to a header (mud drum) located at the bottom of the furnace, and back to the steam drum through vertical "risers," which form the furnace "waterwalls." The drum, downcomers, header, and risers form loops, or circuits, for the water.

The difference in density between the colder water of the downcomers, and the boiling mixture of steam bubbles and water in the heated risers, causes the water to circulate in the system. In the steam drum, steam bubbles rise to the water's surface, releasing steam. The remaining water recirculates and together with the feedwater entering from the feedwater heaters causes an increase in concentration of solids in the water in the mud drum and the lower part of the tubing system. Blowdown of water from the mud drum is used to reduce the solids build-up. A continuous blowdown system offers the best means of controlling the concentration of soluble salts in the boiler water, because it maintains a relatively constant concentration. Continuous blowdown does not interfere with the boiler circulation.

The continuous blowdown system can be controlled to pass 2 to 5 percent of the feedwater flow. Amount of blowdown depends on quantity of steam generated and analysis of both feedwater and boiler water. Care must be exercised to maintain the boiler water level under control throughout the operation.

Intermittent blowdown from the boiler bottom header should be made after the steaming load is reduced, or after the boiler is out of service, as overheating of some portions of the equipment may occur because of low water. Immediately after blowdown bring water back to normal level in gauge glasses. When blowing down, open the quick- opening inner valve first, followed by the outer shut-off valve.

The blowdown flow is directed to a flash tank which is under deaerator pressure. Part of the blowdown will flash to steam and flow to the deaerator. The remaining water passes through a makeup water heat exchanger and discharges to the plant drain disposal system.

5) Chemical Feed Systems

The function of the chemical feed systems is to provide for the internal treatment of boiler water that will prevent the formation of scale and sludge deposits on heat transfer surfaces that retard heat transfer and may cause tube failures. Internal treatment also provides corrosion protection from the effects of dissolved oxygen and low pH. Four chemical feeds are used to provide a system of internal boiler water treatment. These chemicals are caustic soda, phosphate, and sludge conditioner. Two additional chemical feeds are used to provide sodium sulfite treatment to the boiler feedwater in the deaerator.

a) Caustic Soda

Caustic soda is added to boiler water in order to maintain a mimimum pH of 10.5. Maintenance of this pH level will minimize the corrosive attack of the boiler water on steel surfaces.

b) Sulfite

Oxygen corrosion can be a serious problem within a boiler. Sodium sulfite is used for the chemical removal of dissolved oxygen in the boiler feedwater. Sulfite is fed to and supplements the mechanical deaeration that takes place within the deaerating heater. The reaction of sodium sulfite with oxygen can be represented by the following reaction:

$$2\ Na2SO3 \ \text{->}\ O2 = 2\ Na2SO4$$

In order to achieve complete oxygen removal, a continuous feed of sulfite is required into the deaerator, to maintain a residual concentration of sulfite in the boiler water. Sulfite is fed to the storage section of the deaerating heater to assure complete removal of dissolved oxygen in the deaerator.

c) Phosphate

Phosphate is added to the boilers in order to precipitate any residual calcium or magnesium that may pass through the softeners and cause a scale to form on boiler heating surfaces. Since scale formation retards heat transfer, causes reduced boiler efficiencies and causes local overheating of heating surfaces that may result in tube failures, control of scale formation cannot be overemphasized.

d) Sludge Conditioner

It is necessary to maintain the precipitates formed by the addition of phosphate in a fluid or flocculent form so that the precipitates or sludge can be removed by blowdown. If this sludge were to adhere to the boiler heating surfaces, a scale would form resulting in problems previously discussed.

A sludge conditioner is added to the boiler to provide a "coating" on the precipitated sludge to prevent its adherence to boiler surfaces.

6) Plant Service Water System

The service water pumps draw water from Lake Picatinny and pump it to an above ground storage tank for distribution to various users throughout the arsenal, to Navy Hill, and to the service water header for in plant use.

There are three motor driven and one steam driven service water pumps and one motor driven emergency service water pump. Each pump has a discharge valve for isolating the pump. The pumps can be operated in any combination and discharge into a common service water header.

Pump #1	
Manufacturer	Ingersoll Rand
Model	6ALV
Serial Number	0666-10
Size	1500 GPM
Motor	
Manufacturer	General Electric
Model	EK447AK237
Serial Number	GB321004
Rating	2400 V., 150 HP, 35.5 A, 1785 RPM

Pump #2	
Manufacturer	Ingersoll Rand
Model	6ALV
Serial Number	0538144
Size	1500 GPM
Motor	
Manufacturer	Continental
Model	N5855
Serial Number	593044
Rating	2300 V., 150 HP, 33.5 A, 1780 RPM
Pump #3	
Manufacturer	
Model	
Serial Number	1607407
Size	2500 GPM
Motor	
Manufacturer	General Electric
Model	5K81-845C5
Serial Number	HA8356794
Rating	2400 V, 250 HP, 1780 RPM
Emergency Pump #4	
Manufacturer	Ingersoll Rand
Model	ESP
Serial Number	1279/3412
Size	1000 GPM
Motor	
Manufacturer	General Electric
Model	5K6324XL02033
Rating	25 HP
Pump #5	
Manufacturer	Ingersoll Rand
Model	6SE
Serial Number	
Size	
Turbine	
Manufacturer	Worthington
Serial Number	30593
Inlet Pressure	125 psi
Inlet Temperature	550°F
Rating	250 HP
Speed	1890 RPM, Trip 2173 RPM

7) Service Water System

The service water header loops the plant and provides water for the following services:

a) Cooling water for No. 1 and No. 2 air compressors.

b) Cooling water for the turbine oil coolers.

c) Cooling water for the boiler feed pump bearings.

d) Cooling water for fuel oil pump bearings.

e) Cooling water for the I.D. and F.D. fan bearings.

f) Cooling water for the generator air coolers.

In addition, service wate is used in the plant water conditioning system to backwash the filters and through cross connection can supply water directly to the softeners for makeup to the boilers.

APPENDIX B:

PICATINNY BUILDING INVENTORY

Bldg # = Building number
Descrip = Building Description
Area = Area in square feet
Type = Building Type used to classify building for HEATLOAD analysis
Catcode = Category Code for building- corresponds with description.
Year = Year Building was built
JRBTotal = JRB Study results for yearly load (MBtu/yr) for each building
HLTotal = HEATLOAD results for yearly load (MBtu/yr)
HLMax = HEATLOAD maximum load encountered during year (MBtu/hr)
Line = Steam Line status of building
Codes = Boiler, Fuel type, and Cooling information

Line : X=not on steam lines, Y=On line but turned off, B=Winter use only, P=Year-round use
Codes: M=Heated by Main Plant, D=Space Heater, H=Satellite Plant, O=Oil, Z=Electricity, A=Absorption Chiller,
V=Mechanical Ventilation, U=Direct Expansion Air Conditioning
Type : 1=Family Housing, 2=Barracks Pre-1966, 3=Barracks Post-1966, 4=Barracks Modular, 5=Admin/Training Fac.,
6=Field Houses & Gymnasiums, 7=Dining Fac./Commisary, 8=Production/Maint. Fac., 9=Medical/Dental Fac., 10=Storage

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
ADD1	BOQ	16000	3	72410	1995	0.00	1248.28	0.3555	X		ADD1
ADD2	ARMAMENT SOFT FAC	178304	5	31790	1991	0.00	26988.92	9.1669	X		ADD2
ADD3	NEW SECURITY HQ	12500	5	73016	1997	0.00	1892.47	0.6427	X		ADD3
ADD4	MUNITIONS DEV LAB	142000	5	31690	1998	0.00	21494.09	7.3005	X		ADD4
ADD5	ARMAMENT TECH LAB	52500	8	31590	1990	0.00	14851.40	5.0705	X		ADD5
ADD6	AMCCOM TMDE LAB	47000	8		1994	0.00	13294.85	4.5392	X		ADD6
ADD7	EXPLOSIVES LAB	13660	8	31030	1995	0.00	3864.32	1.3193	X		ADD7
ADD8	VEH MAINT FAC	20000	8	21410	1996	0.00	5657.22	1.9316	X		ADD8
ADD9	HYPERVEL SYST LAB	16500	8	31020	1996	0.00	4667.01	1.5935	X		ADD9
ADD10	ROTARY WING HANGER	14400	8	21110	1997	0.00	4073.05	1.3907	X		ADD10
ADD11	MUNITIONS DEV LAB	87000	8	31690	1996	0.00	24610.15	8.4025	X		ADD11
ADD12	CENT STORAGE WARE.	46400	10	44220	1996	0.00	11497.56	4.3264	X		ADD12
1	POST HQ BLDG	159000	5	61011	1982	0.00	24066.98	8.1745	B	M O A	1
2	MUSEUM	5700	6	76010	1918	825.06	1354.31	0.4849	B	M O U	2
3	ADMIN GEN PURP	4500	5	61050	1918	828.20	681.29	0.2314	B	M O	3
4	ELCTRON EQP FAC	4500	8	31740	1918	587.53	1273.38	0.4347	X	U	4
5	OPS GEN PURP	980	5	14131	1918	180.36	148.06	0.0504	B	M O V	5
6	ENGR ADM BLDG	15535	5	61021	1955	2192.38	2351.86	0.7987	B	M O	6
9	ADMIN GEN PURP	15776	5	61050	1942	2226.39	2387.72	0.8110	B	M O V	9
10	ADMIN GEN PURP	15505	5	61050	1941	2188.14	2347.29	0.7972	B	M O	10
10A	WAITING SHELTER	57	11	73055	1951	0.00	0.00	0.0000	X		10A
11	FE MAINT SHOP	17634	8	21910	1941	4676.10	4988.31	1.7031	B	M O	11
12	ADP BUILDING	33800	5	61031	1979	3267.24	5115.84	1.7377	P	M O A	12
13	OPS GEN PURP	13400	5	14131	1930	3553.34	2028.03	0.6889	B	M O	13
17	FLAM MAT STHS	3150	11	44240	1918	0.00	0.00	0.0000	X		17
18	LAB GEN PURP	18900	8	31920	1918	3727.59	5346.43	1.8254	P	M O	18
19	ELCTRON EQP FAC	3150	8	31740	1918	579.74	891.36	0.3043	P	M O	19

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
19A	SENTRY STATION	36	5	87230	1960	0.00	5.32	0.0018	X	D Z	19A
20	ADMIN BLDG R&D	3150	5	61060	1918	579.74	477.08	0.1620	B		20
21	GEN INST BLDG	3150	5	17120	1918	579.74	477.08	0.1620	B	M O	21
22	PREC MACH SHOP	4220	8	32110	1918	550.97	1193.43	0.4075	B	M O	22
22C	GEN STOREHOUSE	1700	10	44270	1944	438.30	421.00	0.1585	Y	M O	22C
23	GEN STOREHOUSE	582	10	44270	1939	0.00	144.51	0.0543	B	M O	23
24	PREC MACH SHOP	26104	8	32110	1942	6776.81	7383.89	2.5211	P	M O	24
30	ADMIN GEN PURP	26950	5	61050	1918	2281.80	4078.95	1.3855	P	M O	30
31	PREC MACH SHOP	87074	8	32110	1943	29968.87	24630.86	8.4096	P	M O	31
31A	MNT SH GEN PURP	1500	8	21885	1942	373.88	423.88	0.1448	P	M O	31A
31C	FLAM MAT STHS	502	10	44240	1940	0.00	123.98	0.0468	P	M O	31C
31E	FLAM MAT STHS	234	11	44240	1940	0.00	0.00	0.0000	X		31E
33	VEH MNT SH GS	23460	8	21430	1933	6090.40	6636.38	2.2658	B	M O	33
33B	FLAT MAT STHS	36	11	44240	1938	0.00	0.00	0.0000	X		33B
33C	WAITING SHELTER	120	11	73055	1960	0.00	0.00	0.0000	X		33C
34	ADMIN GEN PURP	25342	5	61050	1940	3430.85	3835.89	1.3029	P	M O U	34
36	GEN PURPSE WHSE	3150	10	44220	1918	0.00	780.68	0.2937	X		36
39	FE MAINT SHOP	3150	8	21910	1918	785.15	891.36	0.3043	X	D Z	39
40	GEN PURPSE WHSE	3150	10	44220	1918	0.00	780.68	0.2937	X		40
41	GEN PURPSE WHSE	3150	10	44220	1918	0.00	780.68	0.2937	X		41
45	GEN PURPSE WHSE	4500	10	44220	1918	887.52	1115.13	0.4196	X	D Z	45
46	GEN STOREHOUSE	4180	10	44270	1940	0.00	1035.63	0.3897	X		46
47	GEN STOREHOUSE	4180	10	44270	1940	0.00	1035.63	0.3897	X		47
48	GEN STOREHOUSE	4180	10	44270	1940	0.00	1035.63	0.3897	X		48
49	GEN STOREHOUSE	4180	10	44270	1940	0.00	1035.63	0.3897	X		49
50	GEN STOREHOUSE	4180	10	44270	1940	0.00	1035.63	0.3897	X		50
51	GEN STOREHOUSE	4180	10	44270	1940	0.00	1035.63	0.3897	X		51

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
52	GEN STOREHOUSE	4180	10	44270	1941	0.00	1035.63	0.3897	X		52
52A	WAITING SHELTER	119	11	73055	1942	0.00	0.00	0.0000	X		52A
53	GEN STOREHOUSE	4180	10	44270	1941	0.00	1035.63	0.3897	X		53
54	GEN STOREHOUSE	4180	10	44270	1941	0.00	1035.63	0.3897	X		54
55	GEN STOREHOUSE	4180	10	44270	1941	0.00	1035.63	0.3897	X		55
56	GEN STOREHOUSE	4180	10	44270	1941	0.00	1035.63	0.3897	X		56
57	SHIP & REC	4180	10	14133	1941	824.41	1035.63	0.3897	X	D Z	57
58	OPS GEN PURP	19200	5	14131	1937	5091.36	2906.48	0.9871	B	M O U	58
58A	GEN STOREHOUSE	36	10	44270	1944	0.00	9.33	0.0034	X		58A
59	LIBRARY MAIN	19700	5	74041	1937	4875.77	2982.18	1.0128	P	M O	59
60	LAB GEN PURP	28646	8	31920	1942	7938.06	8103.32	2.7667	P	M O V	60
60A	FLAM MAT STHS	78	11	44240	1970	0.00	0.00	0.0000	X		60A
61	ORD ADM BLDG	39987	5	61022	1941	6614.33	6052.55	2.0558	P	M O Y	61
62	ORD ADM BLDG	45804	5	61022	1941	7576.53	6933.10	2.3549	B	M O V	62
63	LUM & P SHED FE	44000	10	44261	1942	0.00	10903.46	4.1027	Y		63
64	ORD FACILITY	10897	8	31510	1942	1958.86	3082.15	1.0524	B	M O U	64
65	ADMIN BLDG R&D	65950	5	61060	1942	10771.15	9982.58	3.3906	B	M O V	65
65A	SENTRY STATION	225	5	87230	1962	0.00	33.89	0.0115	X	D Z	65A
66	GEN STOREHOUSE	9000	10	44270	1944	0.00	2230.27	0.8392	X		66
67	FLAM MAT STHS	9860	10	44240	1956	1944.66	2443.56	0.9194	Y	M O	67
68	ORD FACILITY	6272	8	31510	1951	1335.65	1774.47	0.6058	B	M O	68
70	ARMS BUILDING	1927	10	44223	1948	0.00	477.79	0.1797	X		70
71	APMS BUILDING	1927	10	44223	1948	0.00	477.79	0.1797	Y		71
72	SAFE HOUSE	135	5	14181	1962	0.00	20.15	0.0069	X		72
73	SCALE HOUSE	100	5	14180	1955	0.00	14.97	0.0051	X	D Z	73
74	SENTRY HOUSE	97	5	87230	1987	0.00	14.60	0.0050	X	D Z U	74
79	FE MAINT SHOP	2124	8	21910	1948	307.44	600.40	0.2051	X	D Z U	79

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	MLTotal	MLMax	Line	Codes	Bldg #
80	SEW/TRMT PL PRI	22405	8	83110	1948	0.00	6337.80	2.1639	X		80
80A	SEWAGE PUMP	88	8	83230	1942	0.00	24.83	0.0085	X	H Z	80A
80B	SEW/W TR PL BDG	248	8	83114	1942	0.00	69.89	0.0239	X	H Z	80B
80D	SEW/W TR PL BDG	188	8	83114	1962	0.00	53.32	0.0182	X	D Z	80D
81	ENVIRN TEST FAC	36	8	89015	1975	0.00	10.11	0.0035	X	D Z	81
84	GEN PURPSE WHSE	3000	10	44220	1944	0.00	743.72	0.2798	X		84
90	STG SHED G PURP	4000	10	44222	1950	0.00	991.62	0.3730	X		90
91	GEN STOREHOUSE	60105	10	44270	1942	9816.53	14893.72	5.6043	X	H D	91
91A	FLAM MAT STHS	100	11	44240	1948	0.00	0.00	0.0000	X		91A
91B	FLAM MAT STHS	153	11	44240	1949	0.00	0.00	0.0000	X		91B
91C	FLAM MAT STHS	36	11	44240	1948	0.00	0.00	0.0000	X		91C
91D	FLAM MAT STHS	36	11	44240	1948	0.00	0.00	0.0000	X		91D
91E	FLAM MAT STHS	36	11	44240	1948	0.00	0.00	0.0000	X		91E
91F	FLAM MAT STHS	153	11	44240	1949	0.00	0.00	0.0000	X		91F
91G	FLAM MAT STHS	100	11	44240	1948	0.00	0.00	0.0000	X		91G
92	QUAL ASSUR FAC	35370	8	21652	1964	9182.33	10005.59	3.4161	P	M D P	92
92A	SEWAGE PUMP	153	8	83230	1964	0.00	43.43	0.0148	X		92A
94	ADMIN BLDG R&D	53338	5	61060	1967	8711.32	8073.66	2.7422	P	M D A	94
95	PHYSICS LAB	83180	8	31920	1961	16239.90	23529.82	8.0336	P	M D Y	95
97	SEWAGE PUMP	88	8	83230	1955	0.00	24.83	0.0085	X		97
98	SENTRY STATION	35	5	87230	1947	0.00	5.20	0.0018	X	D Z	98
99	HIPR BL+3.5M CL	2875	8	82111	1943	416.15	813.45	0.2777	P	M D	99
100	FH COL	2546	1	71112	1939	311.04	429.58	0.1408	B	M D	100
101	FH LC & MJ	2056	1	71113	1937	251.18	346.52	0.1136	B	M D	101
101A	DETACH GARAGES	252	11	71410	1944	0.00	0.00	0.0000	X		101A
102	FH COL	2546	1	71112	1939	311.04	429.58	0.1408	B	M D	102
104	FH COL	2546	1	71112	1938	311.04	429.58	0.1408	B	M D	104

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
104A	WAITING SHELTER	60	5	73055	1942	0.00	9.15	0.0031	X		104A
105	FH LC & MJ	1897	1	71113	1880	231.76	319.69	0.1048	B	M O	105
106		1898	0			231.88	0.00	0.0000	S		106
108	FH LC & MJ	2710	1	71113	1936	331.08	457.07	0.1498	B	M O	108
109	FH COL	2546	0	71112	1939	311.04	0.00	0.0000	S	M O	109
110	OFF QTRS MIL	3786	0	72410	1882	462.54	0.00	0.0000	S	M O	110
111	GREENHOUSE	361	8	74029	1928	0.00	102.28	0.0349	X		111
112	FH GEN	6763	1	71111	1909	826.24	1141.55	0.3739	B	M O	112
113	FH COL	5038	1	71112	1909	615.49	850.39	0.2786	B	M O	113
114	FH COL	3790	1	71112	1939	463.02	639.73	0.2096	B	M O	114
114A	DETACH GARAGES	736	10	71410	1937	0.00	182.43	0.0686	B	M O	114A
115	FH COL	3572	1	71112	1937	436.39	602.58	0.1975	B	M O	115
115A	DETACH GARAGES	480	10	71410	1943	0.00	118.82	0.0447	B	M O	115A
115B	WAITING SHELTER	67	11	73055	1942	0.00	0.00	0.0000	X		115B
116A	WAITING SHELTER	112	11	73055	1942	0.00	0.00	0.0000	X		116A
117	FH LC & MJ	8404	1	71113	1937	1026.72	1418.27	0.4646	B	M O	117
118	HL/DEN CL W BDS	8523	9	55040	1958	1580.93	2138.45	0.6169	X	M O	118
119	FH LC & MJ	8596	1	71113	1936	1050.17	1450.28	0.4752	X	M O	119
120	CIV PERS BLDG	1800	5	61040	1918	331.28	272.87	0.0926	X	M O	120
121	OPEN DIN OFF	15024	7	74048	1958	[illegible]7.11	2484.56	0.6[illegible]94	X	M O V	121
121A	GOLF COURSE MNT	944	8	74031	1944	0.00	266.65	0.0911	X	D Z	121A
121B	GOLF COURSE MNT	1048	8	74031	1968	0.00	296.07	0.1012	X		121B
121C	BATH HOUSE	1350	6	74007	1972	195.41	320.37	0.1153	X	V	121C
123	DETACH GARAGES	1041	10	71410	1944	0.00	257.53	0.0970	B	M O	123
124	DETACH GARAGES	1722	10	71410	1936	0.00	427.05	0.1606	B	M O	124
126	FH COL	2546	1	71112	1939	311.04	429.58	0.1408	B	M O	126
127	FH COL	2546	1	71112	1939	311.04	429.58	0.1408	B	M O	127

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
128	DETACH GARAGES	1041	10	71410	1939	0.00	257.53	0.0970	B	M O	128
129	WATER WELL W/PS	224	10	84131	1948	0.00	55.22	0.0209	B	M O	129
130	WATER WELL W/PS	224	8	84131	1948	0.00	63.44	0.0216	X	H O	130
131	VACANT	13492	8	31510	1952	0.00	3816.52	1.3031	X	M O	131
151	FIN ADMIN BLDG	49974	5	61027	1942	7332.83	7564.05	2.5692	P	M O U	151
151A	COMB AC HT BLDG	448	8	89046	1983	0.00	126.88	0.0433	B	M O	151A
154	CHEMISTRY LAB	256	8	31010	1943	0.00	72.62	0.0247	B	M O	154
161	GEN STOREHOUSE	408	10	44270	1942	0.00	101.04	0.0380	X	H Z	161
162	APPL INST BLDG	24512	5	17130	1942	4107.16	3709.85	1.2602	B	M O Y	162
162A	SEWAGE PUMP	32	8	83230	1980	0.00	9.19	0.0031	X		162A
163	SIG PHOTO LAB	5994	5	14130	1942	1077.49	907.64	0.3082	P	M O	163
164	LAB GEN PURP	776	8	31920	1930	0.00	219.73	0.0750	B	M O	164
164B	HIGH EXPLO MAG	115	11	42215	1943	0.00	0.00	0.0000	S	M O	164B
166	LAB GEN PURP	2565	8	31920	1942	334.89	725.65	0.2477	B	M O	166
167	CHEMISTRY LAB	3418	8	31010	1942	446.26	966.77	0.3301	B	M O	167
168	LAB GEN PURP	432	8	31920	1930	0.00	122.28	0.0417	B	M O	168
171	ADMIN BLDG R&D	68950	5	61060	1948	11261.12	10436.77	3.5449	P	M O R	171
172	ENGR ADM BLDG	15650	5	61050	1942	2208.61	2368.67	0.8046	B	M O	172
173	COMM CENTER	22535	5	13120	1942	5850.27	3410.77	1.1585	X	M O U	173
174	CIV PERS BLDG	2508	5	61040	1948	461.58	379.48	0.1289	X	M O	174
175		7327	0			749.63	0.00	0.0000	X		175
176	ADMIN GEN PURP	3412	5	61050	1946	627.96	516.40	0.1754	B	M O U	176
178	PHYSICS LAB	2067	8	31040	1938	0.00	584.53	0.1996	P	M O	178
179	EVIRN TEST FAC	36	8	89015	1978	0.00	10.11	0.0035	X	D Z	179
183	NONMET MAT FAC	19641	8	31910	1945	3290.99	5556.28	1.8970	P	M O V	183
197	LAB GEN PURP	2565	8	31920	1942	334.89	725.65	0.2477	P	M O	197
200	WAITING SHELTER	63	11	73055	1943	0.00	0.00	0.0000	X		200

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
209	VACANT	900	10	44270	1941	0.00	222.68	0.0839	B	M O	209
210	VACANT	19648	8	31510	1918	5210.16	5557.91	1.8976	Y	M O U	210
210E	VACANT	192	10	42235	1941	0.00	47.70	0.0179	X		210E
210F	VACANT	36	10	42235	1938	0.00	9.33	0.0034	X		210F
213	ORD FACILITY	915	8	31510	1916	0.00	259.04	0.0884	B	M O	213
214	CHANGE HOUSE	1870	6	73076	1941	466.10	443.95	0.1597	P	M O	214
215	ORD FACILITY	2244	8	31510	1948	292.98	634.41	0.2167	B	M O	215
215A	GEN STOREHOUSE	36	10	44270	1966	0.00	9.33	0.0034	X		215A
216	CHANGE HOUSE	4874	6	73076	1941	1214.86	1158.37	0.4164	B	M O	216
218		1200	8			156.67	339.27	0.1159	X		218
221	ORD FACILITY	1185	8	31510	1941	154.72	334.92	0.1144	P	M O	221
221A	GEN STOREHOUSE	648	10	44270	1959	0.00	160.89	0.0605	X		221A
222	WAITING SHELTER	126	11	73055	1957	0.00	0.00	0.0000	X		222
223	SENTRY STATION	36	5	87230	1960	0.00	5.32	0.0018	X	D Z	223
224	ELCTRON EQP FAC	300	8	31740	1962	0.00	84.60	0.0289	B	M O	224
225	ORD FACILITY	5636	8	31510	1948	1013.13	1594.28	0.5443	B	M O U	225
230	ORD FACILITY	900	8	31510	1918	0.00	254.67	0.0869	P	M O V	230
230A	HIGH EXPLO MAG	114	11	42215	1944	0.00	0.00	0.0000	S	M O	230A
230B	HIGH EXPLO MAG	88	11	42215	1944	0.00	0.00	0.0000	S	M O	230B
230F	GEN STOREHOUSE	200	10	44270	1941	0.00	49.58	0.0187	P	M O	230F
230G	ORD FACILITY	888	8	31510	1944	0.00	251.02	0.0857	X	D Z	230G
231	ELCTRON EQP FAC	582	8	31740	1959	0.00	165.01	0.0563	Y	M O	231
232	ORD FACILITY	1125	8	31510	1918	146.88	318.34	0.1087	P	M O V	232
232A	FLAM AMT STHS	139	11	44240	1962	0.00	0.00	0.0000	X		232A
232C	AC PLANT	192	8	82610	1943	0.00	54.25	0.0185	X	D O	232C
234	METALLURGY LAB	1378	8	31020	1959	179.91	389.39	0.1330	Y	M O V	234
235	ORD FACILITY	1410	8	31510	1918	184.09	398.59	0.1361	B	M O U	235

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
236	ORD FACILITY	2864	8	31510	1959	373.93	810.02	0.2766	Y	M O	236
237	VACANT	2706	8	31510	1959	353.30	765.42	0.2613	Y	M O	237
238	VACANT	2432	8	31510	1959	317.53	687.74	0.2349	Y	M O	238
240	DISPATCH BLDG	7360	5	87235	1942	1365.21	1113.83	0.3784	B	M O	240
240A	SENTRY STATION	48	5	87230	1957	0.00	7.67	0.0025	X		240A
241	FE MAINT SHOP	21744	8	21910	1942	5765.97	6150.92	2.1001	B	M O	241
241E	VACANT	900	10	44270	1918	0.00	222.68	0.0839	X		241E
242	WASH FAC CEN	1500	8	21456	1984	0.00	423.88	0.1448	X	D L	242
247	ORD FACILITY	2771	8	31510	1962	590.10	784.03	0.2676	Y	M O	247
252	ORD FACILITY	8518	8	31510	1943	2258.76	2409.36	0.8227	B	M O	252
252A	FLAM MAT STHS	54	11	44240	1942	0.00	0.00	0.0000	X		252A
252C	READY MAGAZINE	210	11	42235	1920	0.00	0.00	0.0000	Y	M O	252C
252F	READY MAGAZINE	900	10	42235	1943	0.00	222.68	0.0839	X		252F
256	ORD FACILITY	20910	8	31510	1892	5428.40	5915.09	2.0195	Y	M O	256
256D	VACANT	36	10	42210	1938	0.00	9.33	0.0034	Y	M O	256D
266	LAB GEN PURP	11770	8	31920	1903	2115.79	3329.67	1.1368	B	M O	266
266A	FLAM MAT STHS	36	11	44240	1938	0.00	0.00	0.0000	X		266A
267	ORD FACILITY	1350	8	31510	1941	0.00	382.02	0.1304	Y	M O	267
268	ADMIN GEN PURP	4095	5	61050	1941	1020.69	619.94	0.2105	Y	M O	268
268A	VACANT	64	10	42235	1941	0.00	15.90	0.0060	Y	M O	268A
271	VACANT	8404	8	31510	1905	2228.53	2377.61	0.8117	Y	M O U	271
271A	VACANT	1140	8	31510	1941	284.15	322.71	0.1101	Y	M O	271A
271C	VACANT	33	10	42235	1921	0.00	7.75	0.0030	Y	M O	271C
271D	VACANT	293	8	31510	1920	0.00	82.97	0.0283	Y		271D
271E	VACANT	120	8	31510	1941	0.00	34.01	0.0116	Y	M O	271E
271F	VACANT	224	5	61050	1943	0.00	33.76	0.0115	X	M O	271F
271G	VACANT	120	10	42283	1941	0.00	29.92	0.0112	Y	M O	271G

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
271H	VACANT	220	8	22640	1942	0.00	62.51	0.0213	Y	M O	271H
271I	VACANT	1040	8	31510	1941	259.22	294.21	0.1004	Y	M O	271I
271J	VACANT	156	8	31510	1941	0.00	44.13	0.0151	Y	M O	271J
271K	VACANT	216	8	31510	1941	0.00	60.70	0.0208	Y	M O	271K
271L	VACANT	225	8	31510	1941	0.00	63.67	0.0217	Y	M O	271L
271M	VACANT	185	8	31510	1948	0.00	52.63	0.0179	Y	M O	271M
271N	VACANT	185	8	31510	1948	0.00	52.63	0.0179	X		271N
271S	VACANT	156	8	31510	1945	0.00	44.13	0.0151	Y	M O	271S
281	ADMIN BLDG R&D	5764	5	61060	1921	1036.14	872.26	0.2963	B	M O	281
281A	VACANT	36	10	42283	1942	0.00	9.33	0.0034	X		281A
282	ORD FACILITY	4346	8	31510	1942	925.50	1229.71	0.4198	B	M O U	282
282A	HIGH EXPLO MAG	480	11	42215	1947	0.00	0.00	0.0000	Y	M O	282A
282B	HIGH EXPLO MAG	36	11	42215	1942	0.00	0.00	0.0000	Y	M O	282B
282C	FUSE DET MAG	36	11	42210	1942	0.00	0.00	0.0000	Y	M O	282C
282D	GEN PURPSE WHSE	36	10	44220	1938	0.00	9.33	0.0034	X		282D
290	SENTRY STATION	36	5	87230	1943	0.00	5.32	0.0018	X	O Z	290
295	VACANT	639	8	22635	1941	0.00	180.89	0.0617	Y	M O	295
296	VACANT	1046	8	22680	1941	0.00	295.61	0.1010	Y	M O U	296
300	SENTRY STATION	38	5	87230	1971	0.00	5.57	0.0019	X	O Z	300
301	FE STOREHOUSE	1280	10	44275	1943	147.13	317.14	0.1193	B	M O	301
301A	FE STOREHOUSE	408	10	44275	1943	0.00	101.04	0.0380	B	M O	301A
302	FE MAINT SHOP	37757	8	21910	1905	9802.02	10680.24	3.6466	B	M O	302
302B	SEWAGE PUMP	144	8	83230	1943	0.00	40.47	0.0139	B	M O	302B
302C	FE STOREHOUSE	390	10	44275	1939	0.00	96.82	0.0364	X		302C
302D	WELL WP W/PS	223	8	84470	1921	0.00	63.21	0.0216	B	M O	302D
302E	FE STOREHOUSE	158	10	44275	1944	0.00	38.84	0.0147	B	M O	302E
302F	FE STOREHOUSE	1500	10	44275	1956	0.00	371.42	0.1398	X		302F

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
303	FE MAINT SHOP	4526	8	21910	1940	1128.12	1280.30	0.4371	B	M O	303
304	FE STOREHOUSE	450	10	44275	1941	0.00	111.77	0.0420	B	M O	304
305	FE STOREHOUSE	3840	10	44275	1948	441.38	951.43	0.3580	B	M O	305
306	STG SHED G PURP	5281	10	44222	1980	0.00	1309.00	0.4925	X		306
307	FE MAINT SHOP	21402	8	21910	1880	5556.13	6053.93	2.0670	P	M O	307
308	FE STOREHOUSE	1300	10	44275	1922	256.40	321.84	0.1212	X		308
308A	SEWAGE PUMP	349	8	83230	1943	0.00	98.61	0.0337	B	M O	308A
308B	SEWAGE PUMP	181	8	83230	1922	0.00	50.82	0.0174	B	M O	308B
309	STG SHED G PURP	5281	10	44222	1984	0.00	1309.00	0.4925	X		309
311	GAS STA BLDG	64	5	12310	1941	0.00	9.65	0.0033	X	D Z	311
312	RADASTOR WHSE	1950	10	44160	1986	0.00	483.19	0.1818	Y	M O	312
314C	SALV & SUR PROP	2080	8	44285	1943	239.08	588.43	0.2009	X	H Z	314C
314	SALV & SUR PROP	10433	8	44285	1942	0.00	2951.55	1.0077	B	M O	314
314B	SALV & SUR PROP	3234	8	44285	1957	0.00	914.39	0.3123	X		314B
314D	SALV & SUR PROP	12000	8	44285	1971	0.00	3394.50	1.1590	X		314D
314E	SALV & SUR PROP	10800	8	44285	1971	0.00	3055.23	1.0431	X		314E
315	METALLURGY LAB	5003	8	31020	1907	1247.01	1415.65	0.4832	B	M O	315
316	METALLURGY LAB	5003	8	31020	1907	899.34	1415.65	0.4832	B	M O	316
318	METALLURGY LAB	5006	8	31020	1907	928.56	1416.35	0.4835	B	M O	318
319	ADMIN GEN PURP	5565	5	61050	1906	0.00	842.46	0.2861	B	M O	319
320	PHYSICS LAB	2360	8	31040	1947	0.00	667.51	0.2279	B	M O	320
321	ADMIN BLDG R&D	11406	5	61060	1902	2050.35	1726.85	0.5864	B	M O V	321
321D	GEN STOREHOUSE	1414	10	44270	1941	278.88	350.36	0.1318	Y	M O	321D
322	ADMIN BLDG R&D	5558	5	61060	1906	999.11	841.60	0.2858	B	M O	322
323	LAB GEN PURP	5553	8	31920	1906	998.21	1570.61	0.5363	B	M O U	323
323D	TERM EQP BLDG	600	5	13181	1942	0.00	90.66	0.0308	P	M O	323D
324	GEN STOREHOUSE	5543	10	44270	1906	1093.23	1373.14	0.5168	Y	M O	324

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLmax	Line	Codes	Bldg #
324A	SEWAGE PUMP	121	8	83230	1943	0.00	34.25	0.0117	Y	M O	324A
326	FE MAINT SHOP	5398	8	21910	1918	1431.41	1526.72	0.5213	Y	M O	326
329	PROP SYS FAC	12783	8	31820	1941	3389.73	3615.86	1.2346	B	M O	329
332	CHANGE HOUSE	5560	6	73076	1942	1474.37	1321.31	0.4750	B	M O	332
333	HUMAN ENGR LAB	2338	8	31050	1902	305.25	661.52	0.2258	B	M O	333
337	RECREATION BLDG	2947	6	74069	1928	301.51	699.78	0.2517	B	M O	337
338	RECREATION BLDG	126	6	74069	1980	0.00	30.05	0.0108	X		338
342	SEWAGE PUMP	88	8	83230	1942	0.00	24.83	0.0085	B	M O	342
350	ENGR ADM BLDG	26925	5	61021	1938	3550.33	4075.86	1.3843	P	M O U	350
351	ADP BUILDING	42352	5	61031	1938	5976.93	6410.88	2.1774	P	M O U	351
352	ENGR ADM BLDG	24800	8	31920	1939	3270.13	7015.19	2.3952	P	M O Y	352
353	PHYSICS LAB	22730	8	31040	1938	2271.67	6444.21	2.2001	P	M O Y	353
354	ENGR ADM BLDG	24800	5	61021	1940	3499.90	3754.14	1.2750	P	M O U	354
355	METALLURGY LAB	24800	8	31020	1960	3270.13	7015.19	2.3952	P	M O	355
382	ADMIN GEN PURP	10650	5	61050	1942	2438.02	1611.68	0.5475	B	M O	382
403	LAB GEN PURP	5591	8	31920	1906	1005.04	1581.19	0.5399	B	M O	403
403A	GEN STOREHOUSE	720	10	44270	1947	0.00	178.67	0.0672	Y	M O	403A
403C	FLAM MAT STHS	36	11	44240	1957	0.00	0.00	0.0000	X		403C
404	CHEMISTRY LAB	5731	8	31010	1906	1030.21	1620.73	0.5535	B	M O U	404
405	LAB GEN PURP	9441	8	31920	1920	1697.12	2670.24	0.9118	Y	M O	405
406	FE MAINT SHOP	624	8	21920	1960	0.00	176.53	0.0603	B	M O	406
407	LAB GEN PURP	21026	8	31920	1942	2772.49	5947.30	2.0306	B	M O	407
407A	PREC MACH SHOP	960	8	32110	1942	0.00	271.24	0.0927	B	M O	407A
407B	FLAM MAT STHS	160	11	44240	1954	0.00	0.00	0.0000	S	M O	407B
407F	FLAM MAT STHS	56	11	44240	1975	0.00	0.00	0.0000	X		407F
408	VACANT	6157	8	31920	1920	1106.79	1741.62	0.5946	Y	M O	408
410	WELL MP W/PS	224	8	84470	1943	0.00	63.44	0.0216	X	H I	410

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
410A	GEN STOREHOUSE	64	10	44270	1943	0.00	15.90	0.0060	X		410A
424	ORD.FACILITY	3749	8	31510	1904	489.48	1060.34	0.3621	P	M O	424
424B	GEN PURP MAG	36	10	42283	1938	0.00	9.33	0.0034	X		424B
424C	HIGH EXPLO MAG	100	11	42215	1941	0.00	0.00	0.0000	Y	M O	424C
424D	HIGH EXPLO MAG	100	11	42215	1924	0.00	0.00	0.0000	Y	M O	424D
427	ORD FACILITY	6285	8	31510	1938	1666.62	1777.49	0.6070	P	M O	427
427A	FLAM MAT STHS	200	11	44240	1949	0.00	0.00	0.0000	X		427A
427B	ORD FACILITY	960	8	31510	1939	0.00	271.24	0.0927	Y	M O	427B
427C	VACANT	192	10	44270	1921	0.00	47.70	0.0179	X		427C
429	PROP SYS FAC	891	8	31820	1942	163.98	251.71	0.0860	B	M O R	429
429A	HIGH EXPLO MAG	30	11	42215	1954	0.00	0.00	0.0000	S	M O	429A
430	PROP SYS FAC	1692	8	31820	1922	220.91	479.00	0.1635	Y	M O	430
430A	WELL NP W/PS	195	8	84470	1943	0.00	54.95	0.0188	X	H Z	430A
430B	HIGH EXPLO MAG	42	11	42215	1941	0.00	0.00	0.0000	Y	M O	430B
435	VACANT	432	8	31510	1918	0.00	122.28	0.0417	P	M O	435
436	PROP SYS FAC	958	8	31820	1948	0.00	270.78	0.0925	P	M O	436
437	GEN PURP MAG	80	11	42283	1918	0.00	0.00	0.0000	Y	M O	437
438	BOATHOUSE	104	11	74009	1942	0.00	0.00	0.0000	X		438
439	CHANGE HOUSE	1922	6	73076	1948	479.06	456.65	0.1642	B	M O	439
445	PHYSICS LAB	4795	8	31040	1930	1195.17	1356.81	0.4632	Y	M O	445
445A	IGLOO STORAGE	126	10	42280	1918	0.00	31.33	0.0118	X		445A
445D	VACANT	480	10	44270	1930	0.00	118.82	0.0447	X		445D
445E	VACANT	189	8	22690	1930	0.00	53.56	0.0183	Y	M O	445E
445F	SM ARM PYRO MAG	900	11	42230	1942	0.00	0.00	0.0000	Y	M O	445F
448	ORD FACILITY	3980	8	31510	1930	992.03	1126.27	0.3844	Y	M O	448
448A	FIXED AMMO MAG	352	11	42240	1930	0.00	0.00	0.0000	Y	M O	448A
448B	FIXED AMMO MAG	144	11	42240	1948	0.00	0.00	0.0000	X		448B

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
448C	GEN STOREHOUSE	980	10	44270	1942	0.00	243.21	0.0914	Y	M O	448C
448D	VACANT	144	10	42283	1930	0.00	35.56	0.0134	Y	M O	448D
452	VACANT	2610	8	31510	1942	650.55	738.74	0.2521	Y	M O	452
452A	VACANT	144	10	44270	1930	0.00	35.56	0.0134	X		452A
452B	GEN PURP MAG	96	11	42283	1930	0.00	0.00	0.0000	X		452B
454	ORD FACILITY	22320	8	31510	1941	5794.45	6313.67	2.1557	Y	M O	454
454A	VACANT	100	10	42283	1941	0.00	24.36	0.0093	X		454A
454B	VACANT	1024	10	42283	1942	0.00	253.54	0.0955	Y	M O	454B
455	ENGR ADM BLDG	17110	5	61021	1930	2414.65	2589.96	0.8797	B	M O	455
456	ENGR ADM BLDG	775	5	61021	1931	0.00	117.51	0.0399	B	M O	456
456B	SENTRY STATION	81	5	87230	1941	0.00	12.62	0.0042	X	D Z	456B
457	VACANT	324	8	31510	1941	0.00	91.92	0.0313	Y	M O	457
462	CHEMISTRY LAB	7143	8	31010	1942	0.00	2020.65	0.6899	B	M O	462
462A	GEN PURP MAG	680	11	42283	1941	0.00	0.00	0.0000	Y	M O	462A
462B	GEN PURP MAG	900	11	42283	1942	0.00	0.00	0.0000	Y	M O	462B
462C	GEN STOREHOUSE	100	10	44270	1942	0.00	24.36	0.0093	B	M O	462C
462D	GEN STOREHOUSE	100	10	44270	1942	0.00	24.36	0.0093	B	M O	462D
462E	GEN PURP MAG	16	11	42283	1943	0.00	0.00	0.0000	X		462E
471	ADMIN GEN PURP	1152	5	61050	1965	491.37	174.53	0.0592	P	M O	471
471B	FLAM MAT STHS	36	11	44240	1962	0.00	0.00	0.0000	X		471B
471A	FLAM MAT STHS	36	11	44240	1962	0.00	0.00	0.0000	X		471A
472	CHANGE HOUSE	2000	6	73076	1957	498.51	474.85	0.1708	B	M O	472
476	ENVIRN TEST FAC	36	8	89015	1978	0.00	10.11	0.0035	X	D Z	476
477	ORD FACILITY	5032	8	31510	1945	1334.36	1423.27	0.4860	B	M O U	477
477E	VACANT	36	10	42283	1945	0.00	9.33	0.0034	X		477E
477F	GEN PURP MAG	36	11	42283	1945	0.00	0.00	0.0000	X		477F
497	VACANT	2044	8	31510	1956	0.00	578.31	0.1974	B	M O	497

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
501	FE MAINT SHOP	2446	8	21910	1948	609.67	691.87	0.2362	B	M O	501
506	HIPR BL +3.50L	38893	8	82121	1957	0.00	11002.02	3.7563	P	M O	506
506A	WATER PUMP NP	2325	8	84520	1939	0.00	657.62	0.2245	B	M O	506A
506C	SCALE HOUSE	124	5	14180	1957	0.00	18.80	0.0064	I		506C
506D	SCALE HOUSE	242	5	14180	1967	0.00	36.86	0.0125	I		506D
507	RR ENGINE SHOP	3840	8	21860	1929	957.13	1085.86	0.3708	B	M O	507
507A	STH SPARE PARTS	739	8	21870	1941	0.00	209.38	0.0714	Y	M O	507A
507B	STH SPARE PARTS	224	8	21870	1942	0.00	63.44	0.0216	Y	M O	507B
509	VACANT	1724	10	44270	1930	340.02	427.52	0.1608	Y	M O	509
509A	VACANT	1820	10	44270	1942	358.95	450.92	0.1697	Y	M O	509A
510	VACANT	1886	10	44270	1930	371.97	467.30	0.1758	Y	M O	510
512B	PUMP STA AG	16	8	12530	1956	0.00	4.60	0.0016	I		512B
513	SENTRY STATION	38	5	NONE	1962	0.00	5.57	0.0019	I	D Z	513
514	LAB GEN PURP	5261	8	31920	1930	945.72	1487.87	0.5081	Y	M O	514
519	VACANT	9679	8	31510	1908	0.00	2737.82	0.9348	Y	M O	519
519A	VACANT	445	10	44222	1941	0.00	110.60	0.0415	I		519A
521	VACANT	1542	8	22680	1909	0.00	436.26	0.1489	Y	M O	521
523	VACANT	2087	8	31510	1938	0.00	590.05	0.2015	Y	M O	523
524	CHANGE HOUSE	2285	6	73076	1956	569.54	542.78	0.1952	Y	M O	524
525	ELCTRON EQP FAC	2416	8	31740	1930	315.44	683.14	0.2333	Y	M O U	525
525A	CHEMISTRY LAB	264	8	31010	1930	0.00	74.48	0.0255	Y	M O	525A
527	VACANT	10397	8	31510	1929	0.00	2941.44	1.0042	Y	M O	527
527A	VACANT	120	10	84520	1942	0.00	29.92	0.0112	Y	M O	527A
533	VACANT	3930	8	31510	1941	0.00	1112.02	0.3796	Y	M O	533
534	VACANT	5178	8	31510	1930	0.00	1465.08	0.5001	Y	M O	534
535	VACANT	349	8	22680	1910	0.00	98.61	0.0337	Y	M O	535
537	VACANT	2574	10	44270	1918	507.66	637.58	0.2400	Y	M O	537

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
537A	FLAM MAT STHS	36	11	44240	1938	0.00	0.00	0.0000	X		537A
539	VACANT	3784	8	31510	1930	0.00	1070.22	0.3654	Y	M 0	539
542B	OTHER	405	10	73076	1930	0.00	100.34	0.0378	Y	M 0	542B
550	GEN STOREHOUSE	4500	10	44270	1918	887.52	1115.13	0.4196	Y	M 0	550
550A	AIR RAID SHLTR	353	10	73050	1921	0.00	87.25	0.0329	Y	M 0	550A
553	VACANT	4737	10	44240	1942	0.00	1173.40	0.4416	X		553
555	VACANT	1110	8	31510	1930	0.00	313.98	0.1072	Y	M 0	555
562	VACANT	504	8	31510	1956	0.00	142.51	0.0487	Y	M 0	562
563	ORD FACILITY	750	8	31510	1956	0.00	211.94	0.0724	Y	M 0	563
566	ORD FACILITY	750	8	31510	1956	0.00	211.94	0.0724	Y	M 0	566
567	ORD FACILITY	3492	8	31510	1956	0.00	987.48	0.3372	Y	M 0	567
600	CHANGE HOUSE	6300	6	73067	1942	1670.60	1496.50	0.5381	Y	M 0	600
602	VACANT	343	10	NONE	1935	0.00	84.90	0.0320	Y	M 0	602
602A	VACANT	36	10	42283	1938	0.00	9.33	0.0034	X		602A
602B	VACANT	421	10	42283	1934	0.00	104.10	0.0392	X		602B
602C	CHANGE HOUSE	640	6	73076	1967	0.00	152.37	0.0547	B	M 0	602C
603	VACANT	447	8	31510	1941	0.00	126.64	0.0432	Y	M 0	603
603A	ORD FACILITY	445	8	31510	1941	0.00	126.18	0.0430	Y	M 0	603A
603F	VACANT	261	10	42283	1923	0.00	64.77	0.0243	X		603F
603J	GEN STOREHOUSE	36	10	44270	1944	0.00	9.33	0.0034	X		603J
604	ORD FACILITY	2331	8	31510	1928	304.34	659.01	0.2251	B	M 0	604
604A	ORD FACILITY	213	8	31510	1928	0.00	60.00	0.0205	X		604A
604B	ORD FACILITY	233	8	31510	1931	0.00	65.53	0.0225	X		604B
604C	ORD FACILITY	374	8	31510	1928	0.00	106.17	0.0362	B	M 0	604C
604E	ORD FACILITY	768	8	31510	1942	0.00	216.99	0.0741	B	M 0	604E
604H	ORD FACILITY	864	8	31510	1963	0.00	244.56	0.0835	B	M 0	604H
604I	SENTRY STATION	100	5	87230	1963	0.00	14.97	0.0051	X	D Z	604I

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
605	ORD FACILITY	880	8	31510	1924	0.00	249.16	0.0850	Y	M O	605
606	ORD FACILITY	4748	8	31510	1960	619.91	1343.26	0.4586	B	M O	606
606A	STG SHED & PURP	70	10	44222	1980	0.00	17.31	0.0065	X		606A
606B	STG SHED & PURP	35	10	44222	1980	0.00	9.10	0.0033	X		606B
607	ORD FACILITY	1558	8	31510	1941	203.42	440.86	0.1505	B	M O	607
607A	ORD FACILITY	313	8	31510	1938	0.00	88.50	0.0302	B	M O	607A
608	OTHER	96	8	31090	1980	0.00	27.57	0.0093	X		608
609	HIGH EXPLO MAG	106	11	42215	1928	0.00	0.00	0.0000	X		609
610	HGIH EXPLO MAG	106	11	42215	1928	0.00	0.00	0.0000	X		610
611	ORD FACILITY	7638	8	31510	1965	1373.01	2160.20	0.7376	B	M O	611
611A	HIGH EXPLO MAG	80	11	42215	1965	0.00	0.00	0.0000	X		611A
611C	ORD FACILITY	160	8	31510	1934	0.00	45.06	0.0154	X		611C
612	HIGH EXPLO MAG	64	11	42215	1958	0.00	0.00	0.0000	X		612
613	ORD FACILITY	450	8	31510	1928	0.00	127.34	0.0435	B	M O	613
614	GEN PURPSE WHSE	210	10	44220	1958	0.00	51.93	0.0196	X		614
615	ORD FACILITY	100	8	31510	1958	0.00	28.50	0.0097	X	H Z	615
617	ADMIN BLDG R&D	3723	5	61060	1928	685.20	563.53	0.1914	B	M O	617
617G	ORD FACILITY	1080	8	31510	1938	141.01	305.26	0.1043	B	M O	617G
617A	HIGH EXPLO MAG	271	11	42215	1928	0.00	0.00	0.0000	Y	M O	617A
617B	GEN STOREHOUSE	106	10	44270	1928	0.00	26.64	0.0099	X		617B
617E	FLAM MAT STHS	22	11	44240	1928	0.00	0.00	0.0000	X		617E
617F	FUSE DET MAG	106	11	42210	1928	0.00	0.00	0.0000	X		617F
619	HIGH EXPLO MAG	400	11	42215	1966	0.00	0.00	0.0000	X	D Z	619
620	ORD FACILITY	6818	8	31510	1941	1225.61	1928.50	0.6585	B	M O	620
620A	ORD FACILITY	498	8	31510	1947	0.00	141.11	0.0481	X		620A
621	ORD FACILITY	1638	8	31510	1942	348.82	462.94	0.1582	B	M O	621
621A	SM ARM PYRO MAG	54	11	42230	1947	0.00	0.00	0.0000	X		621A

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
621B	ORD FACILITY	152	8	31510	1914	0.00	43.20	0.0147	X		621B
622	ORD FACILITY	825	8	31510	1964	0.00	233.75	0.0797	B	M O	622
623F	WATER PUMP NP	36	8	84520	1957	0.00	10.11	0.0035	X	D Z	623F
625	AMMO HUT	139	10	42281	1942	0.00	34.38	0.0130	X	D Z	625
627	HIGH EXPLO MAG	140	11	42215	1958	0.00	0.00	0.0000	X	H Z	627
629	HIGH EXPLO MAG	432	11	42215	1942	0.00	0.00	0.0000	X		629
630	ADMIN BLDG R&D	2268	5	61060	1957	417.41	342.86	0.1166	B	M O	630
631	ORD FACILITY	3855	8	31510	1957	1168.86	1090.22	0.3723	B	M O	631
631A	ELECT MNT SHOP	460	8	21710	1962	0.00	130.54	0.0445	B	M O	631A
632	CHEMISTRY LAB	437	8	31010	1957	44.71	123.44	0.0422	B	M O U	632
633	ORD FACILITY	2041	8	31510	1957	480.99	577.62	0.1972	B	M O	633
635	STG SHED G PURP	567	10	44222	1943	150.35	140.12	0.0528	X		635
635A	ORD FACILITY	1920	8	31510	1980	0.00	543.37	0.1855	X		635A
636	ORD FACILITY	1404	8	31510	1957	425.70	397.19	0.1356	B	M O	636
636A	FLAM MAT STHS	106	11	44240	1928	0.00	0.00	0.0000	X		636A
636B	STG SHED G PURP	128	10	44222	1980	0.00	31.80	0.0119	X		636B
636C	ORD FACILITY	640	8	31510	1985	0.00	181.12	0.0618	X	D Z U	636C
639A	WATER PUMP NP	70	8	84520	1965	0.00	19.77	0.0068	X		639A
640	ELCTRON EQP FAC	663	8	31740	1957	0.00	187.34	0.0640	X	H Z	640
641B	ORD FACILITY	25	8	31510	1963	0.00	6.69	0.0024	X	H Z	641B
642	ELCTRON EQP FAC	64	10	42215	1957	0.00	15.90	0.0060	X		642
642B	GEN PURP MAG	104	11	42283	1945	0.00	0.00	0.0000	X		642B
642C	VACANT	256	10	44222	1970	0.00	63.60	0.0239	X		642C
642D	GEN STOREHOUSE	320	10	44270	1977	0.00	79.50	0.0299	X		642D
642E	ORD FACILITY	130	8	31510	1980	0.00	36.34	0.0125	X		642E
642F	ORD FACILITY	320	8	31510	1980	0.00	90.12	0.0309	X		642F
644	HIGH EXPLO MAG	240	11	42215	1964	0.00	0.00	0.0000	X		644

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
645A	LAB GEN PURP	640	8	31920	1962	0.00	181.12	0.0618	X	H Z U	645A
645B	GEN PURP MAG	94	10	42283	1980	0.00	22.95	0.0087	X		645B
647	ELCTRON EQP FAC	203	8	31740	1957	0.00	57.68	0.0196	X	H Z	647
654	ORD FACILITY	420	8	31510	1963	0.00	118.61	0.0405	X	H Z	654
656	ELEC EQP FAC	100	8	31730	1980	0.00	28.50	0.0097	X		656
657	GEN PURPSE WHSE	156	10	44220	1963	0.00	38.37	0.0145	X		657
670	ELCTRON EQP FAC	677	8	31740	1958	0.00	191.47	0.0654	X	H Z V	670
671	GEN PURP MAG	72	11	42283	1958	0.00	0.00	0.0000	X	H Z	671
672	GEN STOREHOUSE	200	10	44270	1956	0.00	49.58	0.0187	X	H Z	672
673	ELCTRON EQP FAC	214	8	31740	1961	0.00	60.23	0.0206	X	H Z	673
717	ORD FACILITY	16437	8	31510	1939	4358.68	4649.74	1.5875	B	M O U	717
717A	ORD FACILITY	1206	8	31510	1941	0.00	341.55	0.1165	B	M O	717A
717B	GEN STOREHOUSE	900	10	44270	1941	0.00	222.68	0.0839	B	M O	717B
717C	GEN PURP MAG	202	11	42283	1948	0.00	0.00	0.0000	Y	M O	717C
717D	CHEMISTRY LAB	600	8	31010	1928	0.00	170.08	0.0580	Y	M O	717D
717G	VACANT	64	10	42283	1941	0.00	15.90	0.0060	X		717G
717I	VACANT	36	10	42283	1943	0.00	9.33	0.0034	Y	M O	717I
717J	VACANT	110	10	42283	1917	0.00	27.57	0.0103	Y	M O	717J
717L	GEN PURP MAG	36	11	42283	1956	0.00	0.00	0.0000	Y	M O	717L
722	PHYSICS LAB	3643	8	31040	1920	475.64	1030.45	0.3518	P	M O U	722
727	SEWAGE PUMP	144	8	83230	1929	0.00	40.47	0.0139	Y	M O	727
732	ORD FACILITY	9077	8	31510	1938	2406.99	2567.28	0.8766	B	M O	732
732A	GEN STOREHOUSE	900	10	44270	1942	0.00	222.68	0.0839	Y	M O	732A
732B	VACANT	36	10	42230	1938	0.00	9.33	0.0034	X		732B
732C	VACANT	72	10	44240	1942	0.00	17.78	0.0067	X		732C
732D	VACANT	64	10	44270	1944	0.00	15.90	0.0060	X		732D
732E	VACANT	36	10	42230	1938	0.00	9.33	0.0034	X		732E

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
732F	VACANT	705	10	42230	1942	0.00	174.27	0.0657	Y	M O U	732F
732G	VACANT	226	10	44240	1943	0.00	55.69	0.0210	Y	M O	732G
732H	HIGH EXPLO MAG	276	11	42215	1943	0.00	0.00	0.0000	Y	M O	732H
735	VACANT	1826	8	31510	1943	455.14	516.27	0.1763	Y	M O	735
735A	VACANT	480	10	82610	1969	0.00	118.82	0.0447	Y	M O	735A
800	VACANT	2072	8	21630	1957	516.45	585.69	0.2001	P	M O	800
803	ORD FACILITY	900	8	31510	1942	0.00	254.67	0.0869	P	M O	803
805	WTR PUMP STA BD	56	8	84142	1985	0.00	15.64	0.0054	P	M O	805
806	CHANGE HOUSE	6024	8	73076	1930	1597.41	1703.70	0.5818	Y	M O	806
807	ORD FACILITY	5010	8	31510	1930	1328.53	1417.28	0.4839	P	M O	807
807B	VACANT	162	8	31510	1941	0.00	45.52	0.0156	P	M O	807B
807C	SENTRY STATION	150	10	87230	1958	0.00	36.96	0.0140	X	D Z	807C
809	ORD FACILITY	4037	8	31510	1948	0.00	1142.14	0.3899	P	M O	809
810	VACANT	22144	8	31510	1948	0.00	6264.02	2.1387	P	M O	810
810A	VACANT	144	8	31510	1944	0.00	40.47	0.0139	X		810A
813	VACANT	4599	8	31510	1948	0.00	1300.76	0.4442	P	M O	813
813A	VACANT	112	10	42283	1941	0.00	28.04	0.0105	X		813A
813C	VACANT	36	10	42283	1938	0.00	9.33	0.0034	X		813C
813D	VACANT	248	8	31510	1948	0.00	69.89	0.0239	X		813D
813E	VACANT	105	10	44270	1948	0.00	26.40	0.0098	P	M O	813E
816	VACANT	8381	8	31510	1930	0.00	2370.51	0.8094	Y	M O	816
816A	VACANT	144	8	31510	1944	0.00	40.47	0.0139	X		816A
816B	VACANT	164	8	31510	1941	0.00	45.99	0.0158	X		816B
816C	VACANT	144	10	42283	1930	0.00	35.56	0.0134	X		816C
816D	VACANT	176	10	42283	1930	0.00	43.95	0.0164	X		816D
820	VACANT	5053	8	31510	1930	0.00	1429.03	0.4880	Y	M O	820
820A	VACANT	38	10	44240	1930	0.00	9.80	0.0036	X		820A

Bldg #	Descrip	Area	Type	Catcode	Year	GRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
820C	VACANT	312	10	42283	1941	0.00	77.63	0.0291	X		820C
822	VACANT	264	10	42283	1930	0.00	65.48	0.0246	X		822
823	VACANT	2200	8	31510	1930	0.00	622.44	0.2125	B	M O	823
824	VAC[illegible]T	718	8	31510	1930	0.00	202.75	0.0693	P	M O	824
824A	VACANT	64	8	31510	1938	0.00	18.37	0.0062	X		824A
825	VACANT	264	10	42283	1930	0.00	65.48	0.0246	X		825
900	LAB GEN PURP	900	8	31920	1950	0.00	254.67	0.0869	P	M O	900
901		1900	8			248.07	537.84	0.1835	X		901
902	LAB GEN PURP	900	8	31920	1950	0.00	254.67	0.0869	Y		902
903	LAB GEN PURP	900	8	31920	1950	0.00	254.67	0.0869	Y	M O	903
904	GEN PURP MAG	900	11	42283	1918	0.00	0.00	0.0000	X		904
905	SP WEAPONS MAG	900	11	42250	1927	0.00	0.00	0.0000	X		905
906	FIXED AMMO MAG	900	11	42240	1918	0.00	0.00	0.0000	X		906
907	GEN PURP MAG	900	11	42283	1918	0.00	0.00	0.0000	X		907
908	PHYSICS LAB	23203	8	31040	1918	4170.99	6563.52	2.2410	P	M O	908
908A	SEWAGE PUMP	84	8	83230	1975	0.00	23.90	0.0081	X		908A
909	GEN STOREHOUSE	900	10	44270	1918	0.00	222.68	0.0839	X		909
910	LAB GEN PURP	1156	8	31920	1950	150.93	327.30	0.1117	Y	M O	910
911	GEN PURP MAG	900	11	42283	1918	0.00	0.00	0.0000	X		911
911A	STG SHED G PURP	70	10	44222	1980	0.00	17.31	0.0065	X		911A
912	FIXED AMMO MAG	900	11	42240	1918	0.00	0.00	0.0000	X		912
913	GEN PURP MAG	900	11	42283	1941	0.00	0.00	0.0000	X		913
914	HIGH EXPLO MAG	900	11	42215	1918	0.00	0.00	0.0000	X		914
915	GEN PURP MAG	900	11	42283	1918	0.00	0.00	0.0000	X		915
916	FUSE DET MAG	900	11	42210	1918	0.00	0.00	0.0000	X		916
917	FUSE DET MAG	900	11	42210	1918	0.00	0.00	0.0000	X		917
918	GEN PURP MAG	900	11	42283	1918	0.00	0.00	0.0000	X		918

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
919	GEN PURP MAG	900	11	42283	1918	0.00	0.00	0.0000	X		919
920	FIXED AMMO MAG	900	11	44240	1918	0.00	0.00	0.0000	X		920
921	GEN PURP MAG	900	11	42283	1918	0.00	0.00	0.0000	X		921
922	FUSE DET MAG	900	11	42210	1918	0.00	0.00	0.0000	X		922
923	FUSE DET MAG	900	11	42210	1918	0.00	0.00	0.0000	X		923
924	FUSE DET MAG	900	11	42210	1941	0.00	0.00	0.0000	X		924
925	GEN PURP MAG	900	11	42283	1941	0.00	0.00	0.0000	X		925
926	VACANT	144	10	42215	1922	0.00	35.56	0.0134	X		926
927	FLAM MAT STHS	78	11	44240	1943	0.00	0.00	0.0000	X		927
928	FIXED AMMO MAG	3150	11	42240	1918	0.00	0.00	0.0000	X		928
929	GEN PURP MAG	3150	11	42283	1918	0.00	0.00	0.0000	X		929
930	FUSE DET MAG	900	11	42210	1918	0.00	0.00	0.0000	X		930
931	GEN PURP MAG	900	11	42283	1918	0.00	0.00	0.0000	X		931
932	FIXED AMMO MAG	900	11	42240	1918	0.00	0.00	0.0000	X		932
933	FUSE DET MAG	900	11	42210	1918	0.00	0.00	0.0000	X		933
934	FIXED AMMO MAG	900	11	44240	1948	0.00	0.00	0.0000	X		934
935	AIR RAID SHLTR	264	6	73050	1941	0.00	62.64	0.0225	X	H Z	935
936	SMOKEDRUM STHS	900	10	42225	1918	0.00	222.68	0.0839	X		936
937	FIXED AMMO MAG	900	11	42240	1918	0.00	0.00	0.0000	X		937
938	GEN PURP MAG	900	11	42283	1918	0.00	0.00	0.0000	X		938
939	GEN PURP MAG	900	11	42283	1918	0.00	0.00	0.0000	X		939
941	GEN PURP MAG	4500	11	42283	1918	0.00	0.00	0.0000	X		941
942	FUSE DET MAG	4500	11	42210	1918	0.00	0.00	0.0000	X		942
943	FUSE DET MAG	4500	11	42210	1918	0.00	0.00	0.0000	X		943
944	FIXED AMMO MAG	4500	11	42240	1918	0.00	0.00	0.0000	X		944
945	GEN PURP MAG	4500	11	42283	1918	0.00	0.00	0.0000	X		945
946	FIXED AMMO MAG	3150	11	42240	1918	0.00	0.00	0.0000	X		946

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
948	GEN PURP MAG	3150	11	42283	1918	0.00	0.00	0.0000	X		948
949	FIXED AMMO MAG	3150	11	42240	1918	0.00	0.00	0.0000	X		949
950	GEN PURP MAG	3150	11	42283	1918	0.00	0.00	0.0000	X		950
951	FUSE DET MAG	3150	11	42210	1918	0.00	0.00	0.0000	X		951
952	FIXED AMMO MAG	1800	11	42240	1918	0.00	0.00	0.0000	X		952
953	GEN PURP MAG	3150	11	42283	1918	0.00	0.00	0.0000	X		953
966	ENVIRN TEST FAC	36	8	89015	1978	0.00	10.11	0.0035	X	D Z	966
975	SUP SVC ADM BLD	1800	5	61023	1942	331.28	272.87	0.0926	X	H Z	975
975A	GEN STOREHOUSE	289	10	44270	1950	0.00	71.35	0.0269	X		975A
1029	ORD FACILITY	2388	8	31510	1974	311.78	675.76	0.2307	B	M I U	1029
1029W	IND WST TNT	70	11	83140	1974	0.00	0.00	0.0000	X		1029W
1030	VACANT	70	10	42290	1952	0.00	17.31	0.0065	X		1030
1031	VACANT	13492	8	31510	1952	3577.74	3816.52	1.3031	Y	M O	1031
1033	VACANT	10464	8	31510	1952	2774.79	2959.64	1.0106	Y	M O U	1033
1033A	ORD FACILITY	96	8	31510	1969	0.00	27.57	0.0093	Y	M O	1033A
1036B	VACANT	338	8	31510	1957	0.00	95.18	0.0326	Y	M O	1036B
1037	VACANT	2312	10	42290	1957	576.27	572.56	0.2155	Y	M O	1037
1038	FLAM MAT STHS	590	11	44240	1956	0.00	0.00	0.0000	X		1038
1052A	VACANT	350	10	42215	1941	0.00	86.55	0.0326	Y	M O	1052A
1053	FE MAINT SHOP	1335	8	21910	1931	245.70	377.65	0.1289	B	M Z	1053
1053A	SENTRY STATION	62	5	87230	1943	0.00	9.40	0.0032	Y	M O	1053A
1061	WATER PUMP P	221	8	84220	1941	0.00	62.74	0.0214	Y	M O	1061
1071	ORD FACILITY	3579	8	31510	1942	0.00	1012.07	0.3456	Y	M O	1071
1071C	VACANT	150	10	44240	1943	0.00	36.96	0.0140	X		1071C
1071D	ORD FACILITY	387	8	31510	1941	0.00	109.19	0.0373	Y	M O	1071D
1071G	VACANT	387	8	31510	1941	0.00	109.19	0.0373	Y	M O	1071G
1090	LAB GEN PURP	9862	8	31920	1948	2615.16	2789.97	0.9525	Y	M O	1090

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
1093	CHLORINATOR BDG	900	8	84150	1942	0.00	254.67	0.0869	Y	M O	1093
1094	FLAM MAT STHS	480	11	44240	1942	0.00	0.00	0.0000	S	M O	1094
1095	COMMUNITY CTR	4248	6	74033	1943	1058.83	1008.95	0.3628	B	M O	1095
1096	SENTRY STATION	16	5	87230	1943	0.00	2.85	0.0009	X	D Z	1096
1101	RECREATION BLDG	119	6	74069	1965	0.00	28.57	0.0102	X		1101
1101A	WAITING SHELTER	121	11	73055	1966	0.00	0.00	0.0000	X		1101A
1101B	PUBLIC TOILET	25	8	73075	1963	0.00	6.69	0.0024	X		1101B
1102	GOLF COURSE MNT	900	8	74031	1960	0.00	254.67	0.0869	X		1102
1103	GOLF COURSE MNT	1312	8	74031	1942	0.00	371.44	0.1267	X		1103
1104	FH NCO & ENL	1320	1	71115	1941	129.92	222.67	0.0730	X	H O	1104
1104A	DETACHED GARAGES	420	11	71410	1941	0.00	0.00	0.0000	X		1104A
1105	FH COL	2806	1	71112	1941	342.81	473.07	0.1551	X	H O	1105
1106	DETACH GARAGES	451	11	71410	1941	0.00	0.00	0.0000	X		1106
1107		1315	0			129.43	0.00	0.0000	X		1107
1109	FH CG & WO	1140	1	71114	1941	112.20	192.22	0.0630	X	H O	1109
1109A	DETACHED GARAGES	258	11	71410	1941	0.00	0.00	0.0000	X		1109A
1110	SEWAGE PUMP	25	8	83230	1979	0.00	6.69	0.0024	X		1110
1111	FH LC & MJ	1581	1	71113	1941	155.61	267.16	0.0974	X	H O	1111
1112	DETACH GARAGES	210	11	71410	1941	0.00	0.00	0.0000	X		1112
1113	OFF QTRS MIL	1580	1	72410	1941	155.51	267.03	0.0874	X	H O	1113
1114	DETACH GARAGES	240	11	71410	1941	0.00	0.00	0.0000	X		1114
1116	DETACH GARAGES	570	11	71410	1941	0.00	0.00	0.0000	X		1116
1117	FH COL	1784	1	71112	1941	217.95	300.60	0.0986	X	H O	1117
1118	OFF QTRS MIL	648	1	72410	1941	63.78	109.77	0.0359	X	H O	1118
1120	DETACH GARAGES	400	11	71410	1941	00	0.00	0.0000	X		1120
1123	FH LC & MJ	2465	1	71113	1941	301.15	415.54	0.1362	X	H O	1123
1123B	CHANGE HOUSE	96	6	73076	1983	0.00	22.86	0.0082	X		1123B

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
1124	DETACH GARAGES	600	11	71410	1941	0.00	0.00	0.0000	X		1124
1125	FH COL	2513	1	71112	1941	307.01	424.42	0.1390	X	H O	1125
1126	DETACH GARAGES	1100	11	71410	1941	0.00	0.00	0.0000	X		1126
1127	FH LC & MJ	2098	1	71113	1941	206.49	353.74	0.1160	X	H O	1127
1130	FH LC & MJ	1977	1	71113	1941	194.58	333.60	0.1093	X	H O	1130
1131	DETACH GARAGES	189	11	71410	1941	0.00	0.00	0.0000	X		1131
1132	FH LC & MJ	2307	1	71113	1941	227.06	389.71	0.1276	X	H O	1132
1134	CREDIT UNION	67	5	74023	1988	0.00	10.02	0.0034	X	H Z U	1134
1136	INFO STAND	1190	5	73078	1956	172.25	180.10	0.0612	X	H O	1136
1137	SENTRY STATION	104	5	87230	1984	0.00	15.46	0.0053	X	D Z	1137
1137A	WAITING SHELTER	66	11	73055	1942	0.00	0.00	0.0000	X		1137A
1138	FH LC & MJ	1893	1	71113	1941	186.31	319.17	0.1046	X	H O	1138
1139	DETACH GARAGES	495	11	71410	1941	0.00	0.00	0.0000	X		1139
1140	FH CG & WO	1323	1	71114	1941	130.21	223.06	0.073[illegible]	X	H O	1140
1140A	DETACHED GARAGES	300	11	71410	1952	0.00	0.00	0.0000	X		1140A
1141	DETACH GARAGES	260	11	71410	1941	0.00	0.00	0.0000	X		1141
1142	FH NCO & ENL	2018	1	71115	1941	198.62	340.69	0.1116	X	H O	1142
1144	FH CG & WO	1394	1	71114	1941	137.20	234.93	0.0770	X	H O	1144
1144A	WAITING SHELTER	63	11	73055	1951	0.00	0.00	0.0000	X		1144A
1145	DETACH GARAGES	357	11	71410	1941	0.00	0.00	0.0000	X		1145
1146	FH CG & WO	1365	1	71114	1941	134.35	230.27	0.0755	X	H O	1146
1147	FH CG & WO	1177	1	71114	1941	115.84	198.79	0.0651	X	H O	1147
1148	DETACH GARAGES	398	11	71410	1941	0.00	0.00	0.0000	X		1148
1149	FH NCO & ENL	1421	1	71115	1941	139.86	240.20	0.0786	X	H O	1149
1175	ENVIRN TEST FAC	36	8	89015	1978	0.00	10.11	0.0035	X	D Z	1175
1176	SNACK BAR	280	7	74062	1944	0.00	46.27	0.0115	X		1176
1178	CHANGE HOUSE	460	6	73076	1961	0.00	109.18	0.0393	X	H O	1178

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
1179	ADMIN GEN PURP	242	5	61050	1958	0.00	36.86	0.0125	X	H Z	1179
1179A	PUBLIC TOILET	19	8	73075	1948	0.00	5.29	0.0018	X		1179A
1179C	AMMO DEMOL FAC	216	8	21630	1948	0.00	60.70	0.0208	X		1179C
1179D	AMMO DEMOL FAC	496	8	21630	1950	0.00	140.65	0.0479	X		1179D
1181	RECREATION BLDG	43	6	74069	1956	0.00	9.94	0.0036	X		1181
1187	RECREATION BLDG	114	6	74069	1956	0.00	27.52	0.0098	X		1187
1200	BL & BAND FAC	616	5	14160	1944	0.00	93.51	0.0317	X	D Z	1200
1200A	VEHICLE STORAGE	200	11	44262	1944	0.00	0.00	0.0000	X		1200A
1201	IGLOO STORAGE	1927	10	42280	1948	0.00	477.79	0.1797	X		1201
1202	IGLOO STORAGE	1927	10	42280	1943	0.00	477.79	0.1797	X		1202
1203	IGLOO STORAGE	1927	10	42280	1942	0.00	477.79	0.1797	X		1203
1204	IGLOO STORAGE	1927	10	42280	1943	0.00	477.79	0.1797	X		1204
1205	IGLOO STORAGE	1927	10	42280	1943	0.00	477.79	0.1797	X		1205
1206	IGLOO STORA[illegible]	1927	10	42280	1943	0.00	477.79	0.1797	X		1206
1207	IGLOO STORAGE	1927	10	42280	1943	0.00	477.79	0.1797	X		1207
1208	IGLOO STORAGE	1927	10	42280	1944	0.00	477.79	0.1797	X		1208
1209	IGLOO STORAGE	1927	10	42280	1944	0.00	477.79	0.1797	X		1209
1210	IGLOO STORAGE	1927	10	42280	1943	0.00	477.79	0.1797	X		1210
1211	IGLOO STORAGE	1927	10	42280	1943	0.00	477.79	0.1797	X		1211
1212	IGLOO STORAGE	1927	10	42280	1943	0.00	477.79	0.1797	X		1212
1213	IGLOO STORAGE	1927	10	42280	1943	0.00	477.79	0.1797	X		1213
1214	IGLOO STORAGE	1927	10	42280	1943	0.00	477.79	0.1797	X		1214
1217	GEN PURP MAG	2214	11	42283	1944	0.00	0.00	0.0000	X		1217
1217B	STG SHED G PURP	70	10	44222	1980	0.00	17.31	0.0065	X		1217B
1219	WATER PUMP WP	632	8	84520	1953	0.00	178.39	0.0610	X	D Z	1219
1221	AMMO DEMOL FAC	50	11	21630	1952	0.00	0.00	0.0000	X	D Z	1221
1221A	GEN PURP MAG	36	11	42283	1954	0.00	0.00	0.0000	X		1221A

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
1222	AMMO DEMOL FAC	384	11	21630	1946	0.00	0.00	0.0000	X	D Z	1222
1222A	ORD FACILITY	656	8	31510	1956	0.00	185.72	0.0634	X		1222A
1222B	PUBLIC TOILET	36	8	73075	1944	0.00	10.11	0.0035	X		1222B
1222D	GEN PURP MAG	36	11	42283	1944	0.00	0.00	0.0000	X		1222D
1222F	ORD FACILITY	184	8	31510	1980	0.00	52.39	0.0178	X	H Z	1222F
1222G	VACANT	50	5	14181	1948	0.00	7.92	0.0026	X	H Z	1222G
1222K	VACANT	120	10	42283	1977	0.00	29.92	0.0112	X		1222K
1227	RECREATION BLDG	392	6	74069	1941	0.00	93.11	0.0335	X		1227
1227A	WATER WELL W/PS	70	8	84131	1968	0.00	19.77	0.0068	X		1227A
1229A	SNACK BAR	98	7	74162	1983	0.00	15.80	0.0040	X		1229A
1240	ORD FACILITY	120	8	31510	1964	0.00	34.01	0.0116	X	H Z	1240
1301	ORD FACILITY	31060	8	31510	1945	8063.42	8786.00	2.9998	P	M O	1301
1302	GEN PURP MAG	900	11	42283	1945	0.00	0.00	0.0000	S	M O	1302
1303	ADMIN GEN PURP	752	5	61050	1945	0.00	113.79	0.0387	B	M O	1303
1304	VACANT	240	8	31510	1945	0.00	68.03	0.0232	Y	M O	1304
1305	ORD FACILITY	300	8	31510	1945	0.00	84.60	0.0289	B	M O	1305
1306	ORD FACILITY	300	8	31510	1945	0.00	84.60	0.0289	B	M O	1306
1307	CHANGE HOUSE	3810	6	73076	1945	701.21	905.27	0.3255	P	M O	1307
1308	VACANT	1843	8	31510	1948	0.00	521.10	0.1780	Y	M O	1308
1309	VACANT	900	8	31510	1945	0.00	254.67	0.0869	Y	M O	1309
1350	VACANT	1563	8	31510	1948	0.00	442.02	0.1509	Y	M O	1350
1351	HIGH EXPLO MAG	660	11	42215	1948	0.00	0.00	0.0000	Y	M O	1351
1352	VACANT	544	8	31510	1945	0.00	153.56	0.0525	Y	M O	1352
1352A	VACANT	124	8	31510	1948	0.00	34.94	0.0120	Y	M O	1352A
1354	VACANT	936	8	31510	1948	0.00	264.79	0.0904	B	M O	1354
1354A	VACANT	169	8	31510	1945	0.00	48.03	0.0163	B	M O	1354A
1357	VACANT	904	8	31510	1948	0.00	255.60	0.0873	B	M O	1357

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
1357A	ORD FACILITY	169	8	31510	1945	0.00	48.03	0.0163	B	M 0	1357A
1359	ORD FACILITY	936	8	31510	1948	0.00	264.79	0.0904	B	M 0	1359
1359A	ORD FACILITY	169	8	31510	1945	0.00	48.03	0.0163	B	M 0	1359A
1361	VACANT	1114	8	31510	1948	0.00	314.91	0.1076	B	M 0	1361
1361A	VACANT	120	8	31510	1947	0.00	34.01	0.0116	B	M 0	1361A
1362	ORD FACILITY	950	8	31510	1970	0.00	268.92	0.0918	X	H 0	1362
1363	ORD FACILITY	853	8	31510	1945	0.00	241.12	0.0824	B	M 0	1363
1363A	ORD FACILITY	140	8	31510	1945	0.00	39.54	0.0135	B	M 0	1363A
1364	ORD FACILITY	290	8	31510	1970	0.00	82.27	0.0280	X	H 0	1364
1365	VACANT	520	10	44240	1945	0.00	129.09	0.0485	B	M 0	1365
1366	VACANT	120	8	31510	1945	0.00	34.01	0.0116	Y	M 0	1366
1368	VACANT	120	8	31510	1945	0.00	34.01	0.0116	X		1368
1369	VACANT	642	8	31510	1948	0.00	181.58	0.0620	Y	M 0	1369
1370	GEN STOREHOUSE	627	10	44270	1947	0.00	155.08	0.0584	X		1370
1372	CHANGE HOUSE	1704	6	73076	1948	424.73	404.59	0.1455	P	M 0	1372
1373	ORD FACILITY	2831	8	31510	1948	0.00	800.60	0.2734	B	M 0	1373
1374	VACANT	1820	8	31510	1948	0.00	514.87	0.1758	Y	M 0	1374
1375	VACANT	1391	10	44240	1948	274.34	344.96	0.1297	Y	M 0	1375
1377	VACANT	2752	8	31510	1948	0.00	778.73	0.2658	Y	M 0	1377
1380	VACANT	122	8	31510	1949	0.00	34.48	0.0118	Y	M 0	1380
1381A	WATER PUMP F	225	8	84220	1948	0.00	63.67	0.0217	X	H Z	1381A
1392	FH NCO & ENL	1128	1	71115	1957	111.02	190.66	0.0624	X	H 0	1392
1392A	DETACH GARAGES	1794	11	71410	1957	0.00	0.00	0.0000	X		1392A
1393	FH NCO & ENL	1413	1	71115	1957	139.07	238.27	0.0781	X	H 0	1393
1393A	DETACH GARAGES	440	11	71410	1957	0.00	0.00	0.0000	X		1393A
1397	WAITING SHELTER	67	11	73055	1956	0.00	0.00	0.0000	X		1397
1398	FH LC & MJ	1929	1	71113	1941	235.67	325.60	0.1067	B	M 0	1398

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
1398A	DETACH GARAGES	461	11	71410	1941	0.00	0.00	0.0000	X		1398A
1399	SENTRY STATION	97	5	87230	1987	0.00	14.60	0.0050	X	D Z U	1399
1400	VACANT	4704	8	31510	1948	0.00	1330.42	0.4543	B	M D	1400
1402	ORD FACILITY	1388	8	31510	1948	0.00	392.59	0.1340	B	M D	1402
1402A	VACANT	480	8	31510	1942	0.00	136.06	0.0464	P	M D	1402A
1403	ORD FACILITY	5600	8	31510	1948	0.00	1584.16	0.5409	P	M D	1403
1404	ORD FACILITY	520	8	31510	1948	0.00	147.11	0.0502	P	M D	1404
1405	VACANT	216	8	31510	1948	0.00	60.70	0.0208	B	M D	1405
1406	ORD FACILITY	3000	8	31510	1948	0.00	848.63	0.2897	B	M D	1406
1407	CHANGE HOUSE	2000	6	73076	1967	498.51	474.85	0.1708	P	M D Y	1407
1408	ORD FACILITY	1056	8	31510	1948	263.21	298.81	0.1020	P	M D U	1408
1408A	HIGH EXPLO MAG	600	11	42215	1948	0.00	0.00	0.0000	S	M D	1408A
1408B	ORD FACILITY	520	8	31510	1944	0.00	147.11	0.0502	B	M D	1408B
1408C	ORD FACILITY	447	8	31510	1948	0.00	126.64	0.0432	B	M D	1408C
1409	ORD FACILITY	3191	8	31510	1956	0.00	902.64	0.3082	Y	M D	1409
1410	ORD FACILITY	1600	8	31510	1948	0.00	452.36	0.1545	X		1410
1411	ORD FACILITY	1820	8	31510	1948	0.00	514.87	0.1758	B	M D	1411
1411A	ORD FACILITY	45	8	31510	1975	0.00	13.09	0.0044	B	M D	1411A
1412	ORD FACILITY	245	8	31510	1948	0.00	69.19	0.0236	P	M D	1412
1412A	ORD FACILITY	180	8	31510	1942	0.00	50.58	0.0173	P	M D	1412A
1413	ORD FACILITY	245	8	31510	1948	0.00	69.19	0.0236	P	M D	1413
1414	VACANT	245	8	31510	1948	0.00	69.19	0.0236	Y	M D	1414
1414A	VACANT	180	8	31510	1942	0.00	50.58	0.0173	Y	M D	1414A
1415	VACANT	245	8	31510	1948	0.00	69.19	0.0236	Y	M D	1415
1416	VACANT	480	8	31510	1948	0.00	136.06	0.0464	B	M D	1416
1417	VACANT	960	8	31510	1948	239.28	271.24	0.0927	B	M D U	1417
1418	ORD FACILITY	480	8	31510	1942	119.64	136.06	0.0464	P	M D	1418

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
1425	VACANT	261	8	31510	1956	0.00	73.79	0.0252	Y	M O	1425
1426	VACANT	261	8	31510	1956	0.00	73.79	0.0252	Y	M C	1426
1428	VACANT	720	8	31510	1954	0.00	204.09	0.0696	Y	M O	1428
1429	VACANT	476	8	31510	1956	62.15	134.25	0.0459	Y	M O U	1429
1430	VACANT	1146	8	31510	1964	0.00	324.10	0.1107	Y	M O	1430
1431	VACANT	524	8	31510	1954	0.00	148.04	0.0506	Y	M O	1431
1435	VACANT	436	8	31510	1954	0.00	123.21	0.0421	Y	M O	1435
1436	VACANT	1080	8	31510	1952	0.00	305.26	0.1043	Y	M O	1436
1437	VACANT	466	8	31510	1956	0.00	131.93	0.0450	Y	M O	1437
1461	VACANT	1074	8	31510	1966	267.70	303.86	0.1037	Y	M O	1461
1462	VACANT	819	8	31510	1974	106.93	231.47	0.0791	Y	M O	1462
1462A	ORD FACILITY	112	8	31510	1974	0.00	31.28	0.0108	X		1462A
1463	VACANT	3826	8	31510	1974	953.64	1082.61	0.3696	Y	M O	1463
1464	SHIP & REC	454	10	14133	1978	0.00	112.71	0.0424	X		1464
1501	ADMIN BLDG R&D	4567	5	61060	1948	596.28	691.31	0.2348	B	M O	1501
1502	AC PLANT	1623	8	82610	1948	211.90	459.46	0.1568	B	M O	1502
1503	ORD FACILITY	2430	8	31510	1948	317.27	687.27	0.2347	B	M O	1503
1504	STG SHED G PURP	704	10	44222	1954	0.00	174.03	0.0656	B	M O	1504
1504A	STD SHED G PURP	108	10	44222	1948	0.00	27.10	0.0101	Y	M O	1504A
1505	ORD FACILITY	288	8	510	1948	0.00	81.81	0.0279	B	M O	1505
1505G	STD SHED G PURP	88	11	44222	1980	0.00	0.00	0.0000	X		1505G
1505H	STD SHED G PURP	88	11	44222	1980	0.00	0.00	0.0000	X		1505H
1505J	STD SHED G PURP	88	11	44222	1980	0.00	0.00	0.0000	X		1505J
1505K	STD SHED G PURP	88	11	44222	1980	0.00	0.00	0.0000	X		1505K
1506	ORD FACILITY	448	8	31510	1954	0.00	126.88	0.0433	B	M O	1506
1507	GEN PURP MAG	608	11	42283	1946	0.00	0.00	0.0000	X		1507
1507B	GEN PURP MAG	118	11	42283	1959	0.00	0.00	0.0000	X		1507B

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
1508	GEN STOREHOUSE	80	11	44270	1955	0.00	0.00	0.0000	X		1508
1509	ORD FACILITY	5911	8	31510	1950	1062.57	1672.20	0.5709	B	M O U	1509
1509A	STD SHED G PURP	452	11	44222	1950	0.00	0.00	0.0000	X		1509A
1510	ADMIN BLDG R&D	6062	5	61060	1950	1124.44	917.78	0.3117	B	M O	1510
1510A	GEN STOREHOUSE	240	11	44270	1947	0.00	0.00	0.0000	X		1510A
1510B	GEN STOREHOUSE	216	11	44270	1948	0.00	0.00	0.0000	X		1510B
1511	VACANT	280	10	44270	1952	0.00	69.23	0.0261	Y	M O	1511
1512	PHYSICS LAB	2203	8	31040	1952	287.63	623.14	0.2128	B	M O	1512
1512A	FLAM MAT STHS	36	11	44240	1958	0.00	0.00	0.0000	X		1512A
1512B	HIGH EXPLO MAG	36	11	42215	1960	0.00	0.00	0.0000	X		1512B
1513	GEN PURP MAG	1150	11	42283	1968	0.00	0.00	0.0000	S	M O	1513
1514	GEN STOREHOUSE	2590	10	44270	1968	510.82	642.20	0.2415	B	M O	1514
1515	PHYSICS LAB	9074	8	31040	1961	1631.15	2566.58	0.8763	B	M O	1515
1516	OTH HEAT PL BLD	72	8	82180	1956	0.00	20.23	0.0069	X		1516
1517	LAB GEN PURP	1865	8	31920	1956	397.16	527.96	0.1802	B	M O	1517
1517A	ELCTRON EQP FAC	336	8	31740	1963	0.00	94.71	0.0324	B	M O	1517A
1518	LAB GEN PURP	1729	8	31920	1956	368.20	489.35	0.1670	B	M O	1518
1519	READY MAGAZINE	36	11	42235	1956	0.00	0.00	0.0000	X		1519
1520	READY MAGAZINE	36	11	42235	1956	0.00	0.00	0.0000	X		1520
1521	ORD FACILITY	36	8	31510	1960	0.00	10.11	0.0035	X		1521
1522	ORD FACILITY	72	8	31510	1970	0.00	20.23	0.0069	X		1522
1528	FLAM MAT STHS	48	11	44240	1960	0.00	0.00	0.0000	X		1528
1529	GEN PURPSE WHSE	73	11	44220	1946	0.00	0.00	0.0000	X		1529
1530	METALLURGY LAB	10500	5	31020	1982	0.00	1589.68	0.5399	X	M O U	1530
1601	LAB GEN PURP	400	8	31920	1949	0.00	113.09	0.0386	B	M O	1601
1602	GEN PURP MAG	36	11	42283	1944	0.00	0.00	0.0000	X		1602
1604	ORD FACILITY	8519	8	31510	1942	2259.03	2409.59	0.8227	B	M O U	1604

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
1608A	FLAM MAT STHS	100	11	44240	1942	0.00	0.00	0.0000	S	M O	1608A
1609	ORD FACILITY	7635	8	31510	1942	2024.61	2159.50	0.7374	B	M O	1609
1609A	VACANT	100	10	44275	1963	0.00	24.36	0.0093	B	M O	1609A
1610	ADMIN GEN PURP	5709	5	61050	1942	1058.96	863.72	0.2935	B	M O	1610
1611	LAB GEN PURP	1401	8	31920	1957	182.92	396.50	0.1353	B	M O U	1611
1612	LEB GEN PURP	1208	8	31920	1957	157.72	342.01	0.1167	B	M O	1612
1615	VACANT	272	10	42210	1941	0.00	67.36	0.0254	Y	M O U	1615
1616	ORD FACILITY	327	8	31510	1942	0.00	92.62	0.0316	Y	M O U	1616
1617	ORD FACILITY	180	8	31510	1943	0.00	50.58	0.0173	Y	M O	1617
1618	GEN PURP MAG	36	11	42283	1942	0.00	0.00	0.0000	Y	M O	1618
1619	LEB GEN PURP	750	8	31920	1942	0.00	211.94	0.0724	Y	M O	1619
1622		0	0			0.00	0.00	0.0000	Y		1622
1626		3526	8			750.88	997.13	0.3405	X		1626
2710	VACANT	225	10	42283	1918	0.00	55.45	0.0209	Y	M O	2710
3002	ENGR ADM BLDG	11200	5	61021	1934	2563.93	1695.31	0.5758	B	M O V	3002
3005	VEH MNT SH DS	3333	8	21420	1941	830.76	942.64	0.3219	B	M O	3005
3006	GEN PURPSE WHSE	12600	10	44220	1953	3061.90	3121.86	1.1748	B	M O	3006
3007	FLAM MAT STHS	400	11	44240	1940	0.00	0.00	0.0000	X		3007
3008	ADMIN GEN PURP	4149	5	61050	1945	763.60	628.35	0.2133	B	M O U	3008
3010	ENGR ADM BLDG	1536	5	61021	1950	282.69	232.41	0.0790	B	M O	3010
3011	SAFE HOUSE	180	5	14181	1940	0.00	27.47	0.0093	X		3011
3012	FLAM MAT STHS	42	11	44240	1905	0.00	0.00	0.0000	X		3012
3013	HIPR BL +3.50L	7403	8	82121	1900	0.00	2094.21	0.7150	P	M O	3013
3018	IGLOO STORAGE	300	10	42280	1918	0.00	73.93	0.0279	X		3018
3021		10682	8			1920.21	3021.68	1.0317	X		3021
3022	PHYSICS LAB	53329	8	31040	1978	8821.26	15085.19	5.1505	P	M O U	3022
3023	SEWAGE PUMP	90	8	83230	1981	0.00	25.29	0.0087	X		3023

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
3024		10149	8			1824.39	2870.67	0.9802	P		3024
3025		1960	0			0.00	0.00	0.0000	X		3025
3028	CHEMISTRY LAB	29564	8	31010	1900	0.00	8363.05	2.8553	P	M O A	3028
3029	GEN PURPSE WHSE	10149	10	44220	1917	0.00	2514.92	0.9463	X		3029
3030	IGLOO STORAGE	300	10	42280	1918	0.00	73.93	0.0279	X		3030
3032	IGLOO STORAGE	300	10	42280	1918	0.00	73.93	0.0279	X		3032
3033	IGLOO STORAGE	300	10	42280	1918	0.00	73.93	0.0279	X		3033
3035	IGLOO STORAGE	300	10	42280	1918	0.00	73.93	0.0279	X		3035
3036	IGLOO STORAGE	300	10	42280	1918	0.00	73.93	0.0279	X		3036
3038	IGLOO STORAGE	300	10	42280	1918	0.00	73.93	0.0279	X		3038
3039	IGLOO STORAGE	300	10	42280	1918	0.00	73.93	0.0279	X		3039
3041	IGLOO STORAGE	300	10	42280	1918	0.00	73.93	0.0279	X		3041
3042	IGLOO STORAGE	300	10	42280	1918	0.00	73.93	0.0279	X		3042
3043	GEN STOREHOUSE	140	11	44270	1951	0.00	0.00	0.0000	X		3043
3045	IGLOO STORAGE	300	10	42280	1918	0.00	73.93	0.0279	X		3045
3047	IGLOO STORAGE	300	10	42280	1918	0.00	73.93	0.0279	X		3047
3049	VACANT	72	10	44240	1918	0.00	17.78	0.0067	Y	M O	3049
3050	ENL BK W/O DIN	31458	2	72111	1943	3312.87	4770.04	1.4496	P	M O	3050
3052	SKILL DEV CEN	1960	6	74022	1926	283.70	465.54	0.1674	B	M O	3052
3054	RANGE HOUSE	64	5	17122	1951	0.00	9.65	0.0033	X		3054
3055	RANGE HOUSE	35	5	17122	1978	0.00	5.20	0.0018	X		3055
3058	PUBLIC TOILET	36	8	73075	1963	0.00	10.11	0.0035	X		3058
3100	FLAM MAT STHS	5384	10	44240	1942	967.83	1334.06	0.5020	B	M O	3100
3100B	HIGH EXPLO MAG	64	11	42215	1966	0.00	0.00	0.0000	X		3100B
3106	ORD FACILITY	3559	8	31510	1934	639.77	1006.55	0.3437	B	M O	3106
3106A	HIGH EXPLO MAG	64	11	42215	1966	0.00	0.00	0.0000	X		3106A
3109	ORD FACILITY	21150	8	31510	1943	2788.84	5983.12	2.0427	P	M O	3109

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
3111	ORD FACILITY	5458	8	31510	1943	981.14	1544.16	0.5272	B	M O	3111
3111A	VACANT	64	10	42215	1965	0.00	15.90	0.0060	X		3111A
3114	FLAM MAT STHS	5559	11	44240	1934	0.00	0.00	0.0000	X		3114
3116	READY MAGAZINE	312	11	42235	1943	0.00	0.00	0.0000	X		3116
3117	SENTRY STATION	100	5	87230	1965	0.00	14.97	0.0051	X	D Z	3117
3119	FH LC & MJ	2602	1	71113	1956	317.89	438.62	0.1438	X	H O	3119
3119A	WAITING SHELTER	37	11	73055	1956	0.00	0.00	0.0000	X		3119A
3124	ADMIN BLDG R&D	7590	5	61060	1918	1407.87	1149.22	0.3903	B	M O	3124
3128	FLAM MAT STHS	10149	11	44240	1929	0.00	0.00	0.0000	X		3128
3132	VACANT	36	5	14181	1950	0.00	5.32	0.0018	X	H Z	3132
3136	SUP MAINT WHSE	5151	10	44226	1944	0.00	1276.73	0.4803	X		3136
3137	FLAM MAT STHS	5080	11	1934	1934	0.00	0.00	0.0000	X		3137
3140	FE STOREHOUSE	5450	10	44275	1934	0.00	1350.43	0.5082	X		3140
3144A	SAFE HOUSE	36	5	14181	1965	0.00	5.32	0.0018	X		3144A
3145	ORD FACILITY	1686	8	31510	1965	220.13	476.73	0.1628	P	M O	3145
3145A	HIGH EXPLO MAG	120	11	42215	1965	0.00	0.00	0.0000	X		3145A
3150	PREC MACH SHOP	125696	8	32110	1942	40756.93	35555.89	12.1397	X	H O U	3150
3152	HT PL +3.5M OL	1200	8	82122	1982	0.00	339.27	0.1159	X	H O	3152
3155	GEN PURPSE WHSE	5450	10	44220	1929	0.00	1350.43	0.5082	X		3155
3157	FE STOREHOUSE	752	10	44275	1896	0.00	186.18	0.0701	X	D Z	3157
3159	ADMIN BLDG R&D	13610	5	61060	1930	3115.63	2060.07	0.6997	B	M O	3159
3162	FLAM MAT STHS	700	11	44240	1942	0.00	0.00	0.0000	X		3162
3164	IGLOO STORAGE	300	10	42280	1918	0.00	73.93	0.0279	X		3164
3166	GEN PURPSE WHSE	10149	10	44220	1929	0.00	2514.92	0.9463	X		3166
3172	IGLOO STORAGE	300	10	42280	1918	0.00	73.93	0.0279	X		3172
3173	LAB GEN PURP	1804	8	31920	1902	235.53	510.28	0.1742	B	M O	3173
3176	PREC MACH SHOP	960	8	32110	1902	0.00	271.24	0.0927	B	M O	3176

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
3177	ELCTRON EQP FAC	1248	8	31740	1914	0.00	353.05	0.1205	B		3177
3178	FLAM MAT STHS	99	11	44240	1905	0.00	0.00	0.0000	X		3178
3180	IGLOO STORAGE	300	10	42280	1918	0.00	73.93	0.0279	X		3180
3200	FE STOREHOUSE	798	10	44275	1945	0.00	197.85	0.0744	B	M O	3200
3201	WATER TRMT PL	1360	8	84110	1934	196.86	384.34	0.1313	B	M O	3201
3202	SNACK BAR	98	7	74062	1985	0.00	15.80	0.0040	X		3202
3203	GEN PURPSE WHSE	5450	10	44220	1930	0.00	1350.43	0.5082	X		3203
3206	GEN STOREHOUSE	420	10	44270	1936	0.00	103.86	0.0391	X		3206
3208	ELCTRON EQP FAC	5450	8	31740	1929	979.70	1541.42	0.5263	X	H O	3208
3208A	ELCTRON EQP FAC	460	8	31740	1962	0.00	130.54	0.0445	X	M O	3208A
3211	GEN PURPSE WHSE	5450	10	44220	1929	0.00	1350.43	0.5082	X		3211
3213	FLAM MAT STHS	5500	11	44240	1942	0.00	0.00	0.0000	X		3213
3215	FH LC & MJ	4398	1	71113	1951	537.30	742.53	0.2432	Y	M O	3215
3217	FH CG & WO	2950	1	71114	1951	360.40	497.95	0.1631	Y	M O	3217
3219	SNACK BAR	288	7	74062	1928	0.00	47.79	0.0119	X		3219
3219A	CHLORINATOR BDG	36	8	84150	1938	0.00	10.11	0.0035	X		3219A
3220	OFF QTRS MIL	18209	2	72410	1945	1917.61	2760.72	0.8390	B	M O	3220
3221	POST CHAPEL	3000	6	73017	1911	434.24	712.70	0.2562	B	M O	3221
3223	GEN STOREHOUSE	312	10	44270	1911	0.00	77.63	0.0291	X		3223
3225	OPEN DIN NCO	4150	7	74047	1982	0.00	686.47	0.1711	X	H L U	3225
3227	OPEN DIN NCO	290	7	44222	1950	0.00	47.95	0.0120	B	M O	3227
3228	OPEN DIN NCO	9242	7	74047	1932	1337.75	1528.74	0.3810	B	M O U	3228
3230	OTHER	1029	8	21910	1942	0.00	290.78	0.0993	B	M O	3230
3231	FH CG & WO	1879	1	71114	1944	184.94	317.34	0.1039	B	M O	3231
3236	FLAM MAT STHS	5450	11	44240	1930	0.00	0.00	0.0000	X		3236
3237	WAITING SHELTER	144	10	73055	1985	0.00	35.56	0.0134	X		3237
3238	FH CO & WO	5470	1	71114	1984	0.00	923.28	0.3024	X	H Z U	3238

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
3238G	DETACH GARAGES	1248	11	71410	1984	0.00	0.00	0.0000	X		3238G
3238K	DETACH STR BDG	65	11	71420	1984	0.00	0.00	0.0000	X		3238K
3238L	DETACH STR BDG	65	11	71420	1984	0.00	0.00	0.0000	X		3238L
3239	FH CG & WO	5470	1	71114	1984	0.00	923.28	0.3024	X	H Z U	3239
3239G	DETACH GARAGES	1248	11	71410	1984	0.00	0.00	0.0000	X		3239G
3239K	DETACH STR BDG	65	11	71420	1984	0.00	0.00	0.0000	X		3239K
3239L	DETACH STR BDG	65	11	71420	1984	0.00	0.00	0.0000	X		3239L
3240	FH NCO & ENL	5470	1	71115	1984	0.00	923.28	0.3024	X	H Z U	3240
3240G	DETACH GARAGES	1248	11	71410	1984	0.00	0.00	0.0000	X		3240G
3240K	DETACH STR BLDG	65	11	71420	1984	0.00	0.00	0.0000	X		3240K
3240L	DETACH STR BLDG	65	11	71420	1984	0.00	0.00	0.0000	X		3240L
3241	FH NCO & ENL	6630	1	71115	1984	0.00	1118.98	0.3666	X	H Z U	3241
3241K	DETACH STR BLDG	65	11	71420	1984	0.00	0.00	0.0000	X		3241K
3242	GEN PURPSE WHSE	10149	10	44220	1919	0.00	2514.92	0.9463	X		3242
3243	WAITING SHELTER	96	10	73055	1986	0.00	23.42	0.0089	X		3243
3244	FH COL	5328	1	71112	1945	650.92	898.65	0.2945	X	H O	3244
3246	DETACH GARAGES	441	11	71410	1935	0.00	0.00	0.0000	X		3246
3247	FH NCO & ENL	7220	1	71115	1984	0.00	1218.57	0.3992	X	H Z U	3247
3247G	DETACH GARAGES	936	11	71410	1984	0.00	0.00	0.0000	X		3247G
3247K	DETACH STR BLDG	65	11	71420	1984	0.00	0.00	0.0000	X		3247K
3247L	DETACH STR BLDG	65	11	71420	1984	0.00	0.00	0.0000	X		3247L
3247M	DETACH STR BLDG	65	11	71420	1984	0.00	0.00	0.0000	X		3247M
3248	FH NCO & ENL	7340	1	71115	1984	0.00	1238.57	0.4058	X	H Z U	3248
3248G	DETACH GARAGES	936	11	71410	1984	0.00	0.00	0.0000	X		3248G
3248K	DETACH STR BLDG	65	11	71420	1984	0.00	0.00	0.0000	X		3248K
3248L	DETACH STR BLDG	65	11	71420	1984	0.00	0.00	0.0000	X		3248L
3250	FH COL	7901	1	71112	1945	832.06	1333.51	0.4368	B	H O	3250

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
3251	WAITING SHELTER	60	11	73055	1980	0.00	0.00	0.0000	X		3251
3253	WAITING SHELTER	116	11	73055	1985	0.00	0.00	0.0000	X		3253
3256	FH NCO & ENL	4852	1	71115	1964	340.79	818.29	0.2682	X	H O	3256
3257	FH NCO & ENL	4852	1	71115	1964	340.79	818.29	0.2682	X	H O	3257
3258	FH NCO & ENL	5113	1	71115	1964	359.12	862.78	0.2827	X	H O	3258
3259	FH NCO & ENL	5113	1	71115	1964	359.12	862.78	0.2827	X	H O	3259
3259A	WAITING SHELTER	126	11	73055	1942	0.00	0.00	0.0000	X		3259A
3260	FH NCO & ENL	5113	1	71115	1964	359.12	862.78	0.2827	X	H O	3260
3261	FH CG & WO	5113	1	71114	1964	359.12	862.78	0.2827	X	H O	3261
3262	FH CG & WO	5113	1	71114	1964	359.12	862.78	0.2827	X	H O	3262
3263	FH CG & WO	5113	1	71114	1964	359.12	862.78	0.2827	X	H O	3263
3264	FH CG & WO	5113	1	71114	1964	359.12	862.78	0.2827	X	H O	3264
3265	FH CG & WO	5113	1	71114	1964	359.12	862.78	0.2827	X	H O	3265
3300	IGLOO STORAGE	300	10	42280	1918	0.00	73.93	0.0279	X		3300
3303	IGLOO STORAGE	300	10	42280	1918	0.00	73.93	0.0279	X		3303
3305	ADMIN BLDG R&D	12000	5	61060	1939	2747.06	1816.77	0.6170	B	M O	3305
3306	ARMY RES CENTER	12000	5	17140	1956	2747.06	1816.77	0.6170	B	M O	3306
3308	GEN PURPSE WHSE	12000	10	44220	1939	0.00	2973.99	1.1190	B	M O	3308
3310	ARMY RES CENTER	12000	5	17140	1939	2747.06	1816.77	0.6170	B	M O	3310
3311	GEN PURPSE WHSE	12000	10	44220	1939	0.00	2973.99	1.1190	X		3311
3312	SUP SVC ADM BLD	18900	5	61023	1951	2667.26	2860.71	0.9717	B	M O	3312
3314	GEN STOREHOUSE	210	10	44270	1940	0.00	51.93	0.0196	B	M O	3314
3315	TNG AIDS CTR	3840	5	17160	1931	706.73	581.47	0.1974	B	M O	3315
3316	FIRE STATION	7043	6	73010	1953	1019.45	1673.21	0.6016	B	M O	3316
3317	GREENHOUSE	527	8	74029	1940	0.00	148.73	0.0509	B	M O	3317
3320	GEN STOREHOUSE	12000	10	44270	1939	0.00	2973.99	1.1190	X		3320
3321	SELF SV SUP CTR	12000	7	74081	1939	0.00	1984.52	0.4947	X		3321

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
3322	SENTRY STATION	97	5	87230	1987	0.00	14.60	0.0050	X	D Z U	3322
3324	EXCHANGE BRANCH	12000	5	74050	1951	1624.58	1816.77	0.6170	X		3324
3325	COMMISSARY	12000	7	74021	1953	0.00	1984.52	0.4947	B	M O	3325
3326	DETACH GARAGES	240	11	71410	1935	0.00	0.00	0.0000	X		3326
3327	FH NCO & ENL	1512	1	71115	1933	148.82	255.54	0.0836	B	M O	3327
3328	CALIBRATION FAC	12383	8	21650	1939	0.00	3502.77	1.1959	B	M O	3328
3329	EXCH WAREHOUSE	12000	10	74055	1939	2157.13	2973.99	1.1190	B	M O	3329
3330	GEN PURPSE WHSE	12000	10	44220	1939	0.00	2973.99	1.1190	X		3330
3331	GEN PURPSE WHSE	12000	10	44220	1939	0.00	2973.99	1.1190	X		3331
3334	GEN PURPSE WHSE	12000	10	44220	1939	0.00	2973.99	1.1190	X		3334
3337	GEN PURPSE WHSE	12000	10	44220	1939	0.00	2973.99	1.1190	X		3337
3338	GEN STOREHOUSE	12000	10	44270	1939	0.00	2973.99	1.1190	X		3338
3339	GEN STOREHOUSE	12000	10	44270	1939	0.00	2973.99	1.1190	X		3339
3340	GEN STOREHOUSE	12000	10	44270	1939	0.00	2973.99	1.1190	X		3340
3341	GEN STORAGE FH	12000	10	44271	1939	1188.79	2973.99	1.1190	B	M O	3341
3342	ORD ADM BLDG	12000	5	61022	1939	2747.06	1816.77	0.6170	B	M O	3342
3344	GEN STOREHOUSE	12000	10	44270	1939	0.00	2973.99	1.1190	B		3344
3345	GEN STOREHOUSE	12000	10	44270	1939	0.00	2973.99	1.1190	X		3345
3349	GEN PURPSE WHSE	12000	10	44220	1939	0.00	2973.99	1.1190	X		3349
3350	GEN PURPSE WHSE	12000	10	44220	1939	0.00	2973.99	1.1190	X		3350
3352	GEN PURPSE WHSE	12000	10	44220	1939	0.00	2973.99	1.1190	X		3352
3353	GEN PURPSE WHSE	12000	10	44220	1939	0.00	2973.99	1.1190	X		3353
3354	GEN PURPSE WHSE	12000	10	44220	1939	0.00	2973.99	1.1190	X		3354
3357	GEN STOREHOUSE	12000	10	44270	1939	1188.79	2973.99	1.1190	B	M O	3357
3359	ADMIN GEN PURP	12000	5	61050	1949	2747.06	1816.77	0.6170	B	M O	3359
3401	ADMIN GEN PURP	3136	5	61050	1944	577.17	474.47	0.1612	B	M O	3401
3402	GEN PURPSE WHSE	3508	10	44220	1944	458.01	869.11	0.3271	B	M O V	3402

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
3403	LAB GEN PURP	2258	8	31920	1951	562.81	638.55	0.2181	B	M O V	3403
3404	ADM & SUP BLDG	1625	5	72330	1952	405.04	246.02	0.0836	B	M O V	3404
3405	VACANT	3412	10	82111	1944	493.88	845.70	0.3182	Y	M O	3405
3408	VACANT	15508	5	61021	1944	2188.57	2347.66	0.7973	B	M O	3408
3409A	VACANT	1764	5	61027	1944	0.00	266.68	0.0907	X		3409A
3409	VACANT	16172	5	61027	1944	2907.09	2447.96	0.8314	B	M O	3409
3410	BN ADMIN & CLRM	8982	5	17151	1944	1666.07	1359.48	0.4618	B	M O	3410
3412	STG SHED G PURP	70	10	44222	1980	0.00	17.31	0.0065	X		3412
3413		4066	8			865.87	1149.75	0.3926	X		3413
3416	VACANT	85	10	83110	1946	0.00	20.84	0.0079	X		3416
3420	SEWAGE PUMP	128	8	83230	1978	0.00	35.87	0.0123	X	D Z V	3420
3500	DET DAY ROOM	1328	5	72360	1946	0.00	200.62	0.0682	S	M O	3500
3501	BN STORAGE BLDG	315	10	72335	1946	0.00	78.33	0.0294	X		3501
3502	VACANT	1401	8	31820	1952	0.00	396.50	0.1353	S	M O	3502
3510	BN STORAGE BLDG	500	10	72335	1946	0.00	123.51	0.0466	S	M O	3510
3511	BN STORAGE BLDG	1029	10	72335	1946	0.00	254.71	0.0959	S	M O	3511
3513	BN STORAGE BLDG	1029	10	72335	1946	0.00	254.71	0.0959	S	M O	3513
3514	BN STORAGE BLDG	1029	10	72335	1948	0.00	254.71	0.0959	X		3514
3515	VEH MNT SH GS	2520	8	21430	1954	0.00	712.57	0.2434	X	H O	3515
3517	VACANT	190	11	72335	1948	0.00	0.00	0.0000	X		3517
3518	BN ADMIN & CLRM	3327	5	17151	1954	612.32	503.30	0.1710	X		3518
3521	GEN STOREHOUSE	537	10	44270	1948	0.00	133.08	0.0501	X		3521
3525	VACANT	1224	10	82123	1949	177.17	303.12	0.1141	S	M O	3525
3533	SEWAGE PUMP	99	8	83230	1975	0.00	28.26	0.0096	X		3533
3537	VACANT	496	8	31820	1949	0.00	140.65	0.0479	X	H Z	3537
3598	GEN STOREHOUSE	48	10	44270	1964	0.00	12.15	0.0045	X	H Z	3598
3600		88	5			16.20	13.49	0.0045	X		3600

Bldg #	Descrip	Area	Type	Catcode	Year	JRBTotal	HLTotal	HLMax	Line	Codes	Bldg #
3602	DETECT EQP FAC	221	8	31720	1952	0.00	62.74	0.0214	X		3602
3603	VACANT	1400	8	31510	1950	182.79	396.26	0.1352	X	H O	3603
3604	ORD FACILITY	196	8	31510	1953	0.00	55.18	0.0189	X	D O	3604
3605	VACANT	322	8	31740	1956	0.00	91.46	0.0311	X	H O	3605
3606	GEN STOREHOUSE	168	10	44270	1964	0.00	41.19	0.0156	X	H Z	3606
3607	ELEC EQP FAC	3097	8	31730	1950	404.35	876.42	0.2992	X	H O	3607
3608	VACANT	100	10	82124	1959	0.00	24.36	0.0093	X		3608
3609	VACANT	776	10	44270	1959	0.00	192.69	0.0724	X		3609
3610	DETECT EQP FAC	221	8	31720	1952	0.00	62.74	0.0214	X		3610
3611	VACANT	1247	8	31920	1957	162.81	352.82	0.1204	X	H O	3611
3612	VACANT	2460	8	31510	1953	321.18	695.99	0.2376	X	H O	3612
3613	VACANT	288	8	31730	1960	0.00	81.81	0.0279	X	H Z	3613
3615	ELEC EQP FAC	285	8	31730	1960	0.00	80.24	0.0275	X	H Z	3615
3616	VACANT	867	8	31720	1959	0.00	245.26	0.0837	X	H Z	3616
3617	VACANT	4177	8	31820	1953	545.36	1181.68	0.4034	X	H O	3617
3618	VACANT	8677	8	31820	1953	1559.79	2454.18	0.8380	X	H O	3618
3623	VACANT	239	10	82123	1962	0.00	59.61	0.0223	X	H O	3623
3625	VACANT	300	8	31820	1961	0.00	84.60	0.0289	S	H O	3625
3700	GEN INST BLDG	1152	5	17120	1965	174.76	174.53	0.0592	X	H O	3700
3701	REC BILLET FAC	768	5	74036	1978	0.00	116.64	0.0395	X	H L U	3701
3702	REC BILLET FAC	768	5	74036	1978	0.00	116.64	0.0395	X	H L U	3702
3703	REC BILLET FAC	768	5	74036	1978	0.00	116.64	0.0395	X	H L U	3703
3704	REC BILLET FAC	768	5	74036	1978	0.00	116.64	0.0395	X	H L U	3704
3705	REC BILLET FAC	768	5	74036	1978	0.00	116.64	0.0395	X	H L U	3705
3706	REC BILLET FAC	768	5	74036	1978	0.00	116.64	0.0395	X	H L U	3706
3707	REC BILLET FAC	768	5	74036	1978	0.00	116.64	0.0395	X	H L U	3707
3708	REC BILLET FAC	768	5	74036	1978	0.00	116.64	0.0395	X	H L U	3708

Bldg #	Descrip	Area	Type	Catcode	Year	JPBTotal	HLTotal	HLMax	Line	Codes	Bldg #
3709	REC BILLET FAC	600	5	74036	1978	0.00	90.66	0.0308	X	H L U	3709
3710	RECREATION BLDG	460	6	74079	1978	0.00	109.18	0.0393	X	H L U	3710
3800	RECREATION BLDG	1250	6	74069	1975	0.00	296.67	0.1067	X		3800
3801	AVN OPS BLDG	21681	5	14112	1978	0.00	3281.76	1.1147	X	H O R	3801
3820	WATER WELL W/PS	118	8	84131	1975	0.00	33.55	0.0114	X		3820
5700		16172	0			0.00	0.00	0.0000	X		5700

APPENDIX C:

SELECTED SECTIONS OF ELECTRIC RATE CONTRACT

SERVICE CLASSIFICATION GT - GENERAL SERVICE TRANSMISSION

APPLICABLE TO USE OF SERVICE FOR:
General service purposes at transmission voltage.

CHARACTER OF SERVICE:
Three phase service at transmission voltage.

RATE PER MONTH (Except when exceeded by MINIMUM CHARGE PER MONTH):

(a) Customer Charge: **$436.00**

(b) Demand Charge (See DETERMINATION OF DEMAND):
$9.89 per on-peak kw (Billing Months June through September)
$8.91 per on-peak KW (Billing Months October through May)

(c) Kilovolt-Ampere Charge:
$0.58 per kVa in excess of the maximum demand created during the on-peak and off-peak hours. Such kVa shall be determined by dividing the maximum demand by the average power factor for the month.

(d) BASE RATE ENERGY CHARGE (See DEFINITION OF ON-PEAK AND OFF-PEAK HOURS):
6.371 cents per on-peak kWh
4.918 cents per off-peak kWh

(e) Energy Adjustment Charge:
All kWh supplied under this service classification are subject to the Energy Adjustment Clause (Rider EAC).

MINIMUM CHARGE PER MONTH:
Monthly bills computed under this service classification shall not be rendered for less than the sum of the current month's: Customer Charge, Energy Charge, Energy Adjustment Charge and Kilovolt-Ampere Charge; all as determined above, plus $2.94 per kW for the highest on-peak or off-peak demand created in the current and preceding eleven months (but not less than the Contract Demand). When the maximum on-peak demand created in the current and preceding eleven months has not exceeded 3% of the maximum off-peak demand created in the current and preceding eleven months, however, the charge per kW specified above shall be reduced by $1.22.

DETERMINATION OF DEMAND:
The on-peak demand shall be the maximum 15 minute integrated kilowatt demand created during the on-peak hours of 8 a.m. to 8 p.m. prevailing time, Monday through Friday each billing month. The off-peak demand shall be the maximum demand created during the remaining hours. The Contract Demand shall be the demand specified in the customer's Application and Agreement for Electric Service when required for line extension minimum revenue purposes.

(continued)

SERVICE CLASSIFICATION GT-GENERAL SERVICE TRANSMISSION(CONTINUED)

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS:
The hours to be considered as on-peak are from 8 a.m. to 8 p.m. prevailing time Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The off-peak hours will not be less than 12 hours daily.

TERM OF CONTRACT:
None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied, contracts of one year or more may be required.

TERMS OF PAYMENT:
Bills are due when rendered and become overdue when payment is not received by the company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

SERVICE CHARGE:
A service charge of **$14.00** is made for initiating service to a customer under this service classification (see Part II, Section 2.01). A **$14.00** service charge is also applicable to service reconnected after a discontinuance requested by the customer or because of a default by the customer, when required between 8 a.m. and 11 p.m. Monday through Saturday. The Service charge for such reconnections required during all other hours shall be **$34.00** (see part II, Section 8.04). A **$34.00** Service Charge shall be applicable for final bill readings required outside of regular business hours. (See part II, Section 3.13)

RECONNECTIONS WITHIN 12 MONTH PERIOD:
Customers which request a disconnection and reconnection of service at the same location within a 12 month period shall not be relieved of minimum charges resulting from demands created during the preceding eleven months, even though occurring prior to such disconnection.

Customers which request more the one disconnection and reconnection of service at the same location within a 12 month period shall be subject to the conditions specified above for the first such period of disconnection. In addition, for subsequent periods of disconnection, the customer shall be required to pay a reconnect charge equivalent to the sum of the minimum monthly charges determined in accordance with the conditions specified in the preceding paragraph.

(continued)

SERVICE CLASSIFICATION GT - GENERAL SERVICE TRANSMISSION (continued)

SPECIAL PROVISIONS (Such provisions shall modify the RATE PER MONTH or MINIMUM CHARGE PER MONTH as specified):

(a) Commuter Rail Service: Where service is used for traction power to a commuter rail system the hours to be considered on-peak for the DETERMINATION OF DEMAND shall be 10:00 a.m. to 5:00 p.m. prevailing time, Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to Change the on-peak hours from time to time as the on-peak periods of the supply system change.

MODIFYING RIDERS:

This service classification may also be modified for Curtailable Service (Rider CUR), Public Utility Exemption from Gross Receipts and Franchise Tax Collection (Rider TXE), Cogeneration and Small Power Production Service (Rider QFS) and Standby Service (Rider STB).

STANDARD TERMS AND CONDITIONS:

This service classification is subject to the Standard Terms and Conditions of this Tariff for Electric Service.

SECTION 5 - CUSTOMER'S INSTALLATIONS (continued)

5.12 Curtailable Service Communication Facilities: A monthly charge of 1-1/2 percent of the original cost of all the Company's communication facilities provided for customer's sole use, for the purpose of facilitating customer's performance of its curtailable obligation, shall be made. Customer shall also be charged for the actual cost to the Company of maintenance and repair thereof, in addition to all other charges for service under this subsection, together with out-of-pocket operating expenses such as rental or tolls for communication circuits. The company will inform the customer in advance of the magnitude of the charges proposed to be made, pursuant to the first sentence of this paragraph. (See Rider CUR)

5.13 Capacity Offset Investments: Eligible Customers who elect to participate in the Company's "Capacity Offset Investments" Program to achieve conservation and to defer loads to off-peak periods shall be qualified for the applicable time-of-day rates. However, during the initial time period specified in the rate schedule, customers served at the location benefitting from the Program shall be billed at a rate equivalent to the non-time-of-day base rate billing amount, where such difference is a positive amount, shall be calculated by the Company and accumulated for each location benefiting from the program. The period during which such a customer shall remain in the program will be specified in the applicable rate schedule. When the accumulated difference equals the payment made by the Company to the customer prior to the expiration of the specified time period, the customer shall automatically revert to and be billed the appropriate time-of-day rate. Succession customers at locations participating in the Company's Capacity Offset Investment Program will be notified by the Company that they have the right to either obtain service under the non-time-of-day rate or the time-of-day rate. However, when electric service is in the name of a builder/developer during the construction of a residential dwelling which is otherwise eligible for participation in the Company's Capacity Offset Investment Program, the builder/developer will be entitled to have the residential dwelling participate in the Capacity Offset Investment Program provided that the builder/developer agrees to provide the company with a signed agreement in which the succession customer agrees to continue to participate in the Capacity Offset Investment Program. Such agreement may be included in the sales contract or lease for the residential dwelling or in a separate agreement.

RIDER EAC - ENERGY ADJUSTMENT CLAUSE
(APPLICABLE to Service Classification RT, RS, GS, GST, GP, GT, OL, MVL, and ISL)

ENERGY ADJUSTMENT CHARGE OR CREDIT:

1. A charge or credit will be made when the Company's estimated twelve-month average cost per kilowatt-hour of electric energy expected to be produced, purchased, and received as interchange, other than the test generation and generation from new units expected to be placed in service during the twelve-month period, (less estimated receipts for the cost of electric energy expected to be sold or delivered as interchange to other electric utilities) as reflected in Accounts 501, 518, 547, and the energy-related portion of Account 555, less any waste heat revenues received, arising from co-generation, which are to be reflected in Account 456, and sold by the Company is **0.001** mills per kilowatt-hour above or below **30.784** mills per kilowatt-hour. The estimated twelve month average cost shall be redetermined annually (or, more frequently, if required by Sections 2 and 3 of this rider). The estimated twelve-month average cost for all succeeding periods will be adjusted to amortize, as a part of such estimated average cost, any under or over-recovery which may have occurred during the prior period. Such under or over-recovery shall be charged or credited to a separate deferred energy account maintained by the Company. To the extent permitted, the excess value of test generation over the cost of fuel consumed for that generation shall be credited to a separate deferred test energy account maintained by the Company to be amortized to the customers when the costs of the unit from which it was produced have been reflected in base rates. Any credit balance in the separate deferred energy account and the separate deferred test energy account shall be credited with interest, monthly, at an annual rate the same as most recent overall rate of return authorized by the Board for the Company. Such interest shall become a part of the balance in the separate deferred energy accounts. The debit balance in the separate deferred energy accounts, as such debit balance shall exist from time to time, shall constitute assets of the Company to be realized from its customers by amortization as set forth above. Any credit balance which shall exist from time to time shall constitute a liability of the Company to its customers to be amortized as set forth above.

2. Whenever a new generating facility is expected to be placed in commercial service within the next 45 days, a new determination shall be made of the Company's estimated twelve-month average cost of energy which reflects the expected impact of the availability of energy from such facility on the Company's cost of energy during the twelve-month period after such facility is placed in commercial service including amortization over such period of any credit or debit balance in the separate deferred energy account. The data when such new generating facility is placed in commercial service shall be treated as the beginning of a new twelve-month period.

3. In the event that (a) a major change in the Company's twelve-month average cost occurs or (b) the debit balance in the separate deferred energy expense account exceeds **$40 million** or the credit balance in such separate account exceeds **$20 million**, a new estimated twelve month average cost may be determined and filed which provides for the amortization over such period of the debit or credit balance in the separate deferred energy expense account. The date when such new estimated twelve-month average cost shall be placed in effect shall be treated as the beginning of a new twelve month period.

(continued)

RIDER EAC - ENERGY ADJUSTMENT CLAUSE (continued)

4. The net charge or net credit will be the adjusted differential cost (determined in accordance with Sections 1 through 3) per kilowatt-hour sold by the Company above or below **30.784** mills per kilowatt-hour, multiplied by a factor to reflect taxes related to revenues from the sales electricity. Any net charge or credit will apply to each kilowatt-hour billed (or to each estimated kilowatt-hour consumed by non-metered customers) each month.

5. When a change in the net charge or credit determined pursuant to Section 1 or Section 3(a) to be placed in effect, the Company shall file with the BPU, not later than 30 days preceding effective date, a schedule setting forth the amount of such net charge or credit and the first when such changed net charge shall be applied, together with the data showing details of the calculation of such net charge or credit. Notice of such filing will be given such manner as shall be prescribed by the BPU and an opportunity for public review and comment on such filing will be afforded on the fifteenth day following such filing, or, if such day shall be a a day on which the BPU is open for the conduct of its business, then on the next succeeding business day of the BPU. Notwithstanding the filing of any comments thereof, such changed charge or credit shall be placed in effect on the date specified in such schedule. However, if directed by the BPU, amounts received by the company pursuant to such schedule may be subject to possible refund by adjustment from the deferred energy account (with interest at a rate to be specified by the BPU), but no refund shall be directed of any amount billed by the Company more than 90 days prior to the entry of an order of the BPU directing such a refund.

6. The energy adjustment clause will reflect the voltage at which service is taken by multiplying the computed composite adjustment factor by factors which reflect energy losses at secondary, primary, and transmission levels. These factors will be revised and filled with the BPU as changes in the basis of their calculations warrant.

7. When a change in the net charge or credit determined pursuant to Section 3(b) is to be placed in effect, the Company shall file with the BPU, not later than 15 days preceding the effective date, a schedule setting forth the amount of such net charge or credit and the first day when such changed net charge or credit shall be applied, together with the data showing the details of calculations of such net charge or credit.. Such changed net charge or credit shall be placed in effect, subject to possible refund by the adjustment from the deferred energy account (with interest at a rate to be specified by the BPU) on how the date specified in such schedule, but no refund should be directed of any amounts billed by the Company more than 90 days prior to the entry of an order of the BPU directing such refund. Notice of a filing pursuant to this will be given in such manner as shall be prescribed by the BPU and an opportunity for public review and comment on such a filing will be afforded on the day set by the BPU.

8. The Company will make quarterly filings to the BPU of its experience under the clause.

(continued)

RIDER EAC - ENERGY ADJUSTMENT CLAUSE (continued)

CALCULATION OF THE ENERGY ADJUSTMENT CHARGE:

1) By Using the Following Formulas:

SEAC = SVA)
PEAC = PVA) x EAC = (Cost - Base + Amort) x Tax Factor
TEAC = TVA)

2) Where the Terms are Defined as Follows:

EAC = Composite Energy Adjustment Charge (Mills per kWh)
SEAC = Secondary Energy Adjustment Charge
PEAC = Primary Energy Adjustment Charge
TEAC = Transmission energy Adjustment Charge

SVA = Secondary Voltage Adjustment of **1.0151**
PVA = Primary Voltage Adjustment of **.9706**
TVA = Transmission Voltage Adjustment of **.9515**

Cost = Estimated Average Cost of Energy as Defined in Paragraph 1 of Rider EAC, including the Capacity Charges Associated with Purchased Power Agreements Related to Replacement Energy Costs Associated with the TMI incident to be recovered through 2/28/90 = **23.694** mills per kWh

Base = Energy Cost included in Base Rates of **30.784** mills per kWh
Amort = Adjustment Resulting from Amortization of Previous EAC or Collections (or Over Collections) of (**.321**) mills per kWh

Tax Factor = 1/(1-Revenue Taxes Rate of 11.93%) or **1.1355**

3) Results in the Following Energy Adjustment Charges:

EAC = (23.694 - 30.784 + (0.321)) x 1.1355 = (8.415) Mills per kWh

SEAC = (1.0151) **(8.542)** mills per kWh
PEAC = (0.9706) x (8.415) = **(8.168)** mills per kWh
TEAC = (0.9515) **(8.007)** mills per kWh

(.008542) cents per kWh for Service Classifications
RT, RS, GS, GST, OL, SVL, MVL, & ISL
(.008168) cents per kWh for Service Classification GP
(.008007) cents per kWh for Service Classification GT

(continued)

RIDER CUR - CURTAILABLE SERVICE
(Applicable to Service Classifications GS, GST, GP, and GT)

AVAILABILITY:
Customers who have 500 kilowatts or more of curtailable load and apply for service under this rider, shall contract to curtail load to a 'predetermined level' upon prior notice by the Company. Such prior notice will be given either 30 minutes or 2 hours before curtailment is required, depending upon which option is contracted for. Such curtailable load may be comprised of separate service locations, but curtailment notification, credit and/or penalty shall be on a group basis to a single service location. No individual location, however, may have less than 200 KW of curtailable load.

PREDETERMINED LEVEL:
The 'predetermined level' of load shall be equal to the Customer's noncurtailable service requirements and shall be set by the Customer upon approval by the Company and may be revised with Company approval as changes in the customer's load conditions warrant. (Also see part II, Section 5.12)

CURTAILMENTS REQUESTED:
Twenty curtailments shall be requested by the Company for a total of 150 hours per year, beginning with the customers applicable meter reading date. Such curtailments will occur between the hours of 8 a.m. and 10 p.m., Monday through Friday.

Customers may optionally elect to take curtailable service for a period of six consecutive months beginning with their May meter reading. Under this option, ten curtailments shall be requested by the Company for a total of 75 hours. Such curtailments will occur between the hours of 8 a.m. and 10 p.m., Monday through Friday.

TERMINATION NOTICE:
Service under this rider requires the Customer to give no less than three years' notice of termination. This requirement shall not be applicable, however, until, until the conclusion of the customers initial period of curtailable service. termination during the initial period, shall cause the customer to incur a penalty equal to the net curtailable credit balance up to the date of termination.

CURTAILABLE CREDIT:
A credit for the difference between the customer's maximum on-peak demand of each billing month and the customer's 'predetermined level' shall be credited each month as determined as follows regardless of the number of curtailments requested and regardless of whether the customer has failed to curtail. This credit may serve to reduce the customer's bill below the minimum charge of the applicable service classification.

(continued)

RIDER CUR - CURTAILABLE SERVICE (continued)

CURTAILABLE CREDIT:
Upon compliance with the Company's request to curtail load, a credit for the difference between the customer's maximum 15 minute integrated demand between 8 a.m. and 8 p.m. prevailing time, Monday through Friday of each billing month and the customer's "predetermined level" shall be determined as follows, but shall not serve to reduce the customer's bill below the minimum charge of the applicable service classification.

SERVICE VOLTAGE	Amount of Prior Notice Contracted For	
	30 Minutes	2 Hours
Secondary	**$4.75/kW**	**$4.55/kW**
Primary	**$4.65/kW**	**$4.45/kW**
Transmission	**$4.45/kW**	**$4.25/kW**

PENALTY FOR FAILURE TO CURTAIL:
A customer shall be deemed to have to have failed to curtail when the customer's maximum 15-minute integrated demand in each period of curtailment has not been reduced to the "predetermined level." For each kilowatt of demand by which the Customer's demand during a period of curtailment exceeds the Customer's "predetermined level," the credit shall not, be granted and a penalty of 3 times the monthly credit per kilowatt shall be added to the monthly charges for service during the billing month in which the failure to curtail occurred. When more than one curtailment has been requested during the billing month, an average of the differences between the Customer's 15-minute integrated demand and the Customer's "predetermined level" shall be used to determine the penalty.

LONG-TERM CONTRACTS: (No longer available - Restricted to current contracts)
Customers who contracted for a 10 year period (and agreed to give no less than five-years notice of cancellation) shall have the curtailable credit increased **$0.80/kW**. Upon receipt of cancellation notice the prevailing credit for short term curtailable service will be in effect for the duration of the term customer receives service under this provision; and cancellation notice of less than five years will invoke a penalty equal to 113% of the difference between the credit for short term and long term curtailable service applied to the previous year curtailed kW multiplied by the number of years deficiency in the notice period, but in no event shall the penalty exceed 113% of the difference between the credit for short term and long term curtailable service actually received by the customer.

RIDER-STB STAND SERVICE

(Applicable to Service Classifications GS, GST and GT)

AVAILABILITY:

Customers with qualifying cogeneration or small power production facilities may obtain Standby Service when such facilities are used to meet the customer's load requirements. (Also see Part II, Section 10 and Rider QFS)

The terms of this Rider shall not be available in any month when the customer's Generation Availability for the current and preceding five months does not exceed 50%.

MODIFICATION OF DETERMINATION OF DEMAND:

This Rider modifies the Determination of Demand of the applicable service classification, such that the demand used for Demand Charge purposes shall be changed to the difference between the Average Demand and 19% of the Standby Service Requirement, but no less than the difference between the maximum demand in the current and preceding five months, and the Standby Service Requirement.

STANDBY SERVICE CHARGE:

This Rider waives the Minimum Charge per Month and correspondingly imposes a Standby Service Charge of **$2.92**, **$2.19** and **$1.10** per kW, respectively for customers served under Service Classifications GS, GP and GT. Such charge is applicable to the difference between the maximum demand created in the current and preceding five months, and the demand used for the Demand Charge purposes.

DETERMINATION OF AVERAGE DEMAND:

The Average Demand shall be determined by dividing the difference between the on-peak energy used in the current and preceding five months, and any on-peak energy used during mutually agreed upon customer's scheduled maintenance if occurring within that six-month period, by the difference between 1560 hours, and the amount of on-peak hours of any such scheduled maintenance.

DETERMINATION OF STANDBY SERVICE REQUIREMENT:

The Standby Service Requirement shall be equal to the maximum demand that the Company may be required to furnish in the succeeding six months, but no less than the maximum demand created in the current and preceding five months, nor more than the customer's normally available generation capacity. Such Standby Service requirements may be revised with company approval as changes in the customer's load conditions warrant.

DETERMINATION OF GENERATION AVAILABILITY:

Generation Availability shall be determined by dividing the difference between the maximum demand created in the current and preceding five months, and the Average Demand, by the Standby Service Requirement.

INITIAL APPLICATION:

During the initial five months application of this Rider, all calculations based upon data of the current and preceding five months, shall be based upon data of the current month and the number of months of experience since its initial application.

Issued: April 7, 1989
Effective: April 7, 1989

Issued by Dennis Baldassari, Vice President-Rates and Treasurer
Madison Avenue at Punch Bowl Road, Morristown, N. J.
Filed pursuant to order of Board of Public Utilities
in Docket No. 836-590 & 841-55 dated April 7, 1989

APPENDIX D:

ENERGY SUPPLY MODELING TECHNIQUES

Life Cycle Cost in Design

Life Cycle Cost in Design (LCCID, pronounced 'El Sid') is an economic analysis computer program tailored to the needs of the Department of Defense (DOD). LCCID was developed by the U.S. Army Corps of Engineers Construction Engineering Research Laboratory (USACERL) in conjunction with U.S. Army Corps of Engineers Missouri River Division. It is intended to be used as a tool in evaluation and ranking design alternatives for new and existing buildings.

LCCID will calculate the life cycle costs, and other economic parameters for a variety of energy conservation initiatives in DOD construction. It also has many general purpose non-energy economic analysis applications in DOD work. It provides the user some limited freedom to create their own economic criteria for non-DOD applications.

LCCID incorporates the economic criteria of the Army, Navy, and Air Force for design studies and operates in a manner that requires little knowledge of this criteria by the program user.

The basic algorithms and reports in LCCID are recognized as a standard in DOD. Since the DOD, and therefore LCCID, uses the economic criteria of the Department of Energy (DOE) and the Office Management and Budget (OMB) in these studies, the user may be able to use the program for economic studies for several other federal agencies.

LCCID is a menu driven, interactive program which can operate on several types of computer hardware. There are extensive on-line helps to assist the first time and infrequent users. LCCID is a public domain computer program available to any requestor. LCCID is the root computer program for other economic analysis computer programs being developed and offered by others.

Economic Basis for LCCID

The specific criteria and other guidance embodied in LCCID are:

1. Office of Management and Budget (OMB) Circular A-94, March 27, 1972.

2. Code of Federal Regulations, 10 CFR 436A, 1987 edition (including Energy Escalation Rate Projections updates of June 1987).

3. Architect/Engineering Instructions, (Department of the Army, March 16, 1987).

4. Department of the Navy Economic Criteria, NAVFAC Publication P-442, "Economic Analysis Handbook", July 1980.

5. Air Force Regulation 88-15 (Draft), 16 January 1986.

6. Department of the Air Force, ETL 84-2, "Computer Energy Analysis" 27 March 1984, Change 1, 16 May 1984. Augmented by multiple address letter form LEEEU (1 Apr 85).

7. Army Technical Manual 5-802-1, "Economic Studies for Military Construction Design -- Applications", 31 December 1986.

8. DOD Energy Conservation Investment Program (ECIP) Guidance.

Algorithms and Terms

This section describes the algorithms and terms used by the program. A brief review of the economic criteria that governs the calculations is included. LCCID is based upon two economic analysis methodologies; Federal Energy Management Program (FEMP) and Office of Management and the Budget (OMB) Circular A-94. The DOD uses both of these methods in its economic studies depending on the type of analysis being performed.

Brief Discussion of Criteria. Both FEMP and OMB A-94 methods use present worth economic analysis approaches. Comparisons are made between the total discounted costs and benefits over the life cycle of each alternative. The methods differ in the timing of costs and benefits, discount rate and the use of investment credits. The FEMP criteria favors energy conservation alternatives. OMB A-94 is the standard economic criteria for the federal sector for general types of analysis. No special treatment is given energy under A-94. The differences between the FEMP and OMB A-94 methods is summarized in Table 1.

PW Discount Rate. Future costs and benefits are reduced to their present value equivalents by discounting. The rapidity at which this discounting occurs is called the discount rate. The larger the discount rate the smaller the present value of a given future cost or benefit. The discount rate may be thought of as the return expected for a given investment. FEMP uses a 7%, and OMB A-94, a 10% discount rate.

Analysis Base Date (ABD). The ABD is the date to which all costs and benefits for each alternative are discounted and then compared. OMB A-94, as executed by the Army and Air Force, uses the date of study (DOS) which is usually today's date, as the ABD. the Navy uses the midpoint of construction as the ABD in its A-94 studies. FEMP criteria uses the date of the DOE fuel escalation values as the ABD. LCCID discounts to the appropriate ABD based upon the user's input under the criteria selection menu.

Table D1
Key Provisions of Principal Criteria Packages Used
for Determining Life Cycle Costs in MILCON Design Applications

	Basic Source of Criteria Package	
	FEDS[a]:OMB A-94	FEMP[b]:10CFR 436A
Standard PW discounting	10%	7%
Analysis Base Date (ABD)	Air Force & Army: Date of Study Navy: Mid-Construction	Artificial Standard Date
Analysis Period	Economic Life or 25 years[c]	Economic Life or 25 years[c]
Constant Dollars	ABD	ABD
Energy Escalation Rates	Per DOE	Per DOE
Cash Flow Basis[d]	Mid-year	End of year
Investment Credits	0%	10%
Nonenergy Escalation Rates	User Option	0%

[a]Federal Standard (FEDS)
[b]Federal Energy Management Program (FEMP)
[c]Whichever is less, measured from Beneficial Occupancy Date (BOD)
[d]Time of Cost for lumping frequently occurring costs (more than once per year)

Analysis Period. The time period covered by the economic analyses in both FEMP and OMB A-94 studies is equal to the economic life expectancy of the project or alternative or 25 years which ever is less. All costs and benefits occurring within this period should be considered in the analysis.

Constant Dollars. All costs and benefits used in FEMP and A-94 studies should be entered in dollar values at the Analysis Base Date. For Army and Air Force A-94 studies these costs/benefits should be entered in today's dollars even though they may occur sometime in the future. A-94 studies conducted for the Navy require the user to input all costs and benefits in the midpoint of construction constant dollars. The user may elect to have LCCID escalate the costs/benefits for Navy A-94 studies by entering a non-fuel escalation schedule and reference this schedule for each cost/benefit.

Costs/benefits for FEMP studies should be entered in dollars as of the date of the DOE fuel escalation tables (7/81, 7/84, or 7/85 etc.). However, when the date of the study (DOS) approximates the date of the tables, only small errors will be introduced if today's dollars are used.

Energy Escalation Rates. Fuel costs are escalated by LCCID according to the differential escalation rates published by DOE for both FEMP and A-94 studies. The DOE tables, which are updated periodically, are arranged by geographic region and sector (residential, commercial, and industrial). The user selects the appropriate geographic region by entering the state for the project (see Chapter 3). LCCID automatically selects the industrial sector for all DOD studies. Non-DOD studies may use residential or commercial sector values in addition to industrial. Fuel prices in each case are entered by the user based upon local pricing information.

Cash Flow Basis. The cash flow basis determines the timing of costs/benefits within a certain year. A-94 treats all frequently recurring costs/benefits in a given year as a lump sum at the mid- point of that year. FEMP criteria places these cost/benefits at the end of the year.

Investment Credits. FEMP criteria provides a 10% investment credit for energy conservation. This credit has the effect of reducing the first cost of the alternative to 90% of its estimated value. LCCID will automatically apply this credit. The user enters the full cost of the investment. A-94 criteria provides for no investment credit.

Non-energy Escalation Rates. Costs/benefits other than energy may be differentially escalated with justification under OMB A-94 criteria. The user performs this escalation by entering a non-fuel escalation schedule and referencing same when entering the cost/benefit (see Chapter 3, Input). No non-fuel escalation is permitted under FEMP criteria.

Criteria Selection. LCCID selects the FEMP or OMB A-94 methodologies in accordance with the economic criteria of DOD and its services. The criteria selection is accomplished by user responses to a series of questions in the Select Study Parameters Menu.

LCCID will first ask the user if the study is for the Army, Air Force, Navy or non-DOD. Non-DOD selection will permit the user to select his/her own criteria. An Army or Air Force selection tells LCCID to use the DOS as the ABD on all A-94 studies. A Navy selection tells the user to use the mid-point of construction as the ABD on A-94 studies.

The second selection in the Select Study Parameters menu asks if energy is SIGNIFICANT (alternatives under consideration are predominantly energy consuming design features or the study is being driven by energy considerations), INCIDENTAL (alternatives being studied have some features that affect energy costs, but the study is being undertaken to consider many other non-energy design features as well) or inconsequential (NONE) to the overall study. This response is key to the criteria selection. LCCID will automatically select OMB A-94 criteria if the response given here is INCIDENTAL or NONE. Additionally, a NONE selection will cause LCCID to bypass the energy input menu items. A response of SIGNIFICANT will prompt LCCID to ask a few more questions before deciding which criteria to follow.

The criteria selection is complete if INCIDENTAL or NONE is entered. A SIGNIFICANT entry prompts LCCID to next ask the user to enter the primary study objective. The choices are: CONVENTIONAL, SPECIAL DIRECTED, and ECIP.

CONVENTIONAL should be entered if the study objective is to select the best conventional energy alternative. Examples of conventional alternatives are VAV vs. Multizone air handlers or fluorescent vs. incandescent lighting fixtures. CONVENTIONAL entry prompts LCCID to select the OMB A-94 criteria for all three DOD services.

When the study objective is governed by congressional statute or involves some extraordinary energy conservation measures, such as active solar or heat recovery chillers, a SPECIAL DIRECTED entry is required. SPECIAL DIRECTED tells LCCID to select the FEMP criteria and prompts another set of questions related to the output reports.

If the study object is to analyze retrofit options according to the Energy Conservation Investment Program the user enters ECIP. ECIP causes LCCID to select the FEMP economic criteria as modified for the ECIP funding program. It also causes LCCID to select the standard DOD ECIP Life Cycle Cost Analysis Summary as the output of the program.

CONVENTIONAL or ECIP entries will end the criteria selection routines. A SPECIAL DIRECTED entry causes the program to ask for the Special Directed Study Type. Selections are SOLAR and NON-SOLAR. Enter SOLAR if the study involves analyzing active or unique passive solar alternatives. SOLAR causes LCCID to automatically report the SIR and DPP in any comparison output reports since these values are required by the solar economic evaluation criteria. NON-SOLAR is selected when the study objective is to evaluated extraordinary non- solar energy conservation measures such as triple paned glazing or high efficiency furnaces. The NON-SOLAR selection, like the SOLAR selection, causes LCCID to select the FEMP criteria but does not automatically generate in the SIR and DPP in the output. The user may select to have these values reported, though, anyway, when selecting the types or reports under the Calculate & Report Life Cycle Costs menu.

With the SOLAR or NON-SOLAR entries the criteria selection of LCCID is complete.

Present Worth Equations. The present worth equations incorporated in LCCID's algorithms are straightforward economic analysis routines following the rules of Table 1.

The present worth, PW_1, of a one time cost/benefit is calculated using the following equation:

$$PW_1 = [CB/(1+d)^m \qquad \text{(Eq. 1)}$$

where: CB is the cost/benefit expressed in ABD dollars,
d is the annual discount rate
m is the number of years from the ABD to the occurrence of the cost or benefit.

The present worth, PW_2, of an annually recurring, constant (non- escalating) cost/benefit is calculated by:

$$PW_2=CB\ S_{j=1}^{n} 1/(1+d)^j \qquad \text{(Eq. 2)}$$

where: n is the number of years of economic life.

The present worth, PW_3, of an annually recurring, constantly escalating, cost/benefit, such as fuel costs is calculated by:

$$PW_3=CB\ S_{j=1}^{n} v^j \qquad \text{(Eq. 3)}$$

where: $v=(1+e)/(1+d)$
e=the constant differential escalation rate expressed in decimal form.

The present worth, PW_4, of an annually recurring constant cost/benefit, CB, which undergos a non-uniform differential escalation is calculated by:

$$PW_4 = CB\ S_{j=1}^{n1}\ v1^j + v1^{n1}\ S_{j=1}^{n2} v2^j + v1^{n1}\ v2^{n2}\ S_{j=1}^{n3}\ v3^J$$

$$+ \ldots + v1^{n1} * v2^{n2} * v3^{n3} \cdots vk\text{-}1^{nk\text{-}1}\ S_{j=1}^{nk} vk^j \qquad \text{(Eq. 4)}$$

where: k is the number of periods with different escalation rates,

n_m is the number of years in the mth period

$v_m = (1+e_m)/(1+d)$

e_m is the differential escalation rate during the mth period.

The total life cycle cost, LCC, is then the sum of the present worths of the cost/benefits calculated as above:

$$LCC= S_{j=1}^{m1} PW_1 + S_{j=1}^{m2} PW_2 + Sm3_{j=1} PW_3 + S_{j=1}^{m4} PW_4 \qquad \text{(Eq. 5)}$$

where: m_1 is the number of one-time cost/benefit items
m_2 is the number of annually recurring, non-escalating cost/benefit items
m_3 is the number of annually recurring, constantly escalating cost/benefit items
m_4 is the number of annually recurring, variable escalating cost/benefit items

Equivalent Uniform Differential Escalation Rate. This term is found on the individual output summary reports. The equivalent uniform differential escalation rate for any given annually recurring cost series (or one-time cost) is that constant rate of differential escalation that would yield the same present worth equivalent value for the cost series (or one-time cost) as would the actual projected differential escalation rate(s). If the LCCID program cannot calculate this value, the output field will appear as all asterisks (*).

Savings to Investment Ratio (SIR). This term is found on the comparison summary reports. The savings to investment ratio (SIR) is calculated by comparing two alternatives. Usually, this calculation is performed between an energy saving investment alternative and an existing or non-energy saving alternative (considered baseline). The SIR is automatically calculated for SOLAR studies; for nonsolar studies, the user may optionally choose to see the SIR. The formula used in the LCCID program is consistent with the formula in the Federal Energy Management Program (FEMP):

SIR = (D[Energy]-D[M&R]+D[Other])/(D[Investment]-D[Salvage]) (Eq. 6)

where Δ [Energy] is the present worth amount of reduction in energy costs (i.e., Considered Baseline Alternative, or CBA, Energy minus Energy Savings Alternative Energy, or ESA);

Δ [M&R] is the present worth amount of Non-fuel Operation and Maintenance Costs (i.e., M&R of ESA minus M&R of CBA). In LCCID, these are the MR costs - Maintenance and Repair and Custodial Costs;

Δ [Investment] is the amount of differential investment (i.e., Investment of ESA minus Investment of CBA). In LCCID, these are the II, PB, and RR costs - Initial Investment, Pre-BOD, and Major Repair/Replacement Costs;

Δ [Salvage] is the amount of differential salvage (i.e., Salvage of ESA minus Salvage of CBA). In LCCID, these are the DI - Net Disposal Costs;

Δ [Other] is the amount of differential operations and maintenance other costs and/or benefits (i.e., Costs of ESA minus Costs of CBA). In LCCID, these are the OT - Other O & M Cost and Monetary Benefits.

Discounted Payback Period. The term discounted payback period (DPP) is found on the Comparison Summary Reports. Similar to SIR, DPP is calculated between a baseline alternative (typically Existing or Non-energy) and an investment alternative (typically Energy Savings). The discounted payback period is defined as the number of years required to recoup an investment through the net savings it provides, with the time value of money and future price level changes taken into account. This number of years is measured from the BOD and, if used for the analysis period of the LCC calculations, would result in an SIR of 1.0.

The DPP is automatically calculated for all SOLAR studies; for nonsolar studies, the user may optionally choose to calculate DPP. Since the user may choose a different baseline from the one LCCID chooses automatically, LCCID can also display DPP for the user's choice of baseline alternatives.

The LCCID calculations for DPP follow the step by step procedure outlined in TM 5-802-1. This procedure is an iterative technique for calculating DPP and follows this approach:

1. A trial analysis period is selected (initially, the economic life entered for the study) and an SIR is computed for this period.

2. If the new SIR is not sufficiently close to 1.0, a new trial analysis period is calculated and a new SIR found.

These steps are repeated until an SIR of 1.0 is obtained or until the LCCID program determines that the investment will not pay back within the economic life of the study. Limitations in the computerization of the procedure also force LCCID to analyze several conditions that would not be attempted in manual use of the procedure. These conditions (illustrating the operating costs differences and investment costs differences between two alternatives) are outlined in Table 2.

In addition to these cases, several other conditions during the step by step procedure calculations should be noted. The procedure can technically allow a negative economic life period to be used as the next potential step in the iterations. Since this could cause unpredictable results in the calculations, the LCCID algorithmic translation will substitute a zero economic life when this condition occurs.

Likewise, if the steps in the procedure are not converging (that is, potential payback periods are going back and forth between two values), LCCID will only allow a certain number (15) of the steps to occur before it calls a halt to the iterations.

Table D2

LCCID Analyses

Case	Δ Operating Costs (Numerator)	Δ Investments (Denominator)	DPP
1.	positive	positive	step by step
2.	negative	negative	???
3.	negative	positive	***
4.	positive	negative	<1
5.	zero	positive	***
6.	zero	negative	???
7.	positive	zero	???
8.	negative	zero	***
9.	zero	zero	***

<u>Case 1</u>: Normal conditions, normal step by step procedure is followed. DPP value will be based on actual calculations.

<u>Case 2</u>: Inverse of normal conditions (may be caused choosing a different baseline). A false, positive SIR is produced so calculations should not proceed. DPP cannot be calculated with the step by step procedure (because of this false SIR), though may be positive. (??? is printed.)

Case 3: SIR is less than zero. Operating costs of baseline are less than alternative, alternative investment is greater than baseline. DPP is probably infinite, though technically invalid to calculate. (*** is printed.)

Case 4: SIR is less than zero. Operating costs of baseline are greater than alternative, alternative investment is less than baseline. DPP is infinitesimal, though technically invalid to calculate. (<1 is printed.)

Case 5: Operating costs between the alternatives is equal. Alternative investment is greater than baseline. DPP is probably infinite but cannot be calculated. (*** is printed.)

Case 6: Operating costs between the alternatives is equal. Alternative investment is less than baseline. DPP is probably infinitesimal but cannot be calculated. (??? is printed.)

Case 7: Investments costs between the alternatives is equal. Baseline operating costs are greater than alternative. DPP is probably infinitesimal but cannot be calculated. (??? is printed.)

Case 8: Investments costs between the alternatives is equal. Baseline operating costs are less than alternative. DPP is probably infinite but cannot be calculated. (*** is printed.)

Case 9: Investment and operating costs between the two alternatives is equal. Other ranking criteria than DPP and SIR should be used for selection. (*** is printed.)

Baseline Alternative. Baseline alternative is the term used by the LCCID program to represent the alternative for comparisons as described above. The user is required to choose a baseline alternative before comparison reports may be viewed. In the comparison reports, the alternative with the least investment cost is chosen as the baseline for comparisons. However, the user may optionally choose to see these comparisons with the user-selected baseline.

Steam Heat Distribution Program

The Steam Heat Distribution Program (SHDP) is a pressure-flow- thermal efficiency computer program for modeling steam district heating systems. The program has several capabilities: it can evaluate benefits of various steam distribution system modifications; it can predict energy savings results from changes in operating strategies; it can show savings that would result from enhanced maintenance; and it can be used as a design tool in changing or expanding a steam distribution system. The model can be used to help evaluate renovation of manholes, replacement of entire sections of systems, the benefits of operating at lower pressures, and enhanced maintenance of steam traps. The model can also be used to evaluate the capacity of the system for adding new buildings or other loads.

Model Description

A steam distribution system will typically consist of pipes, regulators, valves, traps, and vaults. Steam enters the system at the steam plant, passes through pipes, vaults, and regulators, and is delivered to and leaves the system at the buildings (the loads). The steam loses heat through pipe walls by conduction. Steam pressure drops as the steam passes through the pipes, regulators, and valves. Condensate forms in the pipes and is removed from the system at the traps.

SHDP is able to calculate many properties that describe the steady state operation of the steam system. These properties can be divided into two categories. The first category we will call system parameters and the second category we will call steam and heat flow quantities. Before the system parameters and flow quantities can be discussed, it is necessary to understand what a 'node' is.

Nodes. A node is defined as a point in a steam distribution system. It is a point where sections of pipe or regulators meet. It is also a place where steam enters and leaves the system. Steam enters the system at the plant node and leaves the system at the building nodes. The amount of steam entering or leaving the system at a particular node is referred to as 'node flow.' When steam enters the system at a node, the node flow is positive at that node; the node flow is negative for steam leaving the system. Steam condensate is removed from the system at all nodes. This means that SHDP assumes a trap is located at every node Nodes are also the spots where pressures are defined in the system.

From continuity of steam flow, the steam that enters a node must equal the steam that leaves a node. (Steam that enters or leaves a node includes the node flow as well as the pipe and regulator flow.) Continuity of steam flow at a node is the means by which SHDP solves a steam flow problem.

Solution Determination. Assuming the same sign convention as node flow, the sum of all flows into and out of a node must be equal to zero. Using this fact, we can write a steam flow equation for each node. The terms of each equation will consist of pipe and regulator flow with all adjacent nodes, the node flow, and the pipe condensate that leaves the system at the node. If there are N nodes in the system, there will be N simultaneous equations. For a unique solution to exist, there must also be N unknowns.

The set of N equations which make up the system are non-linear; therefore, an interative technique is used to obtain a solution. The technique used is the n-dimensional Newton-Raphson method. This method determines correction terms for the unknowns so that the system of equations is brought into closer balance at each successive iteration. This balanced system is one where the sum of all flows into and out of each node is zero. The unknowns in the system are referred to as the system parameters.

System Parameters. There are four kinds of system parameters. These are node pressures, node flows, pipe diameters, and regulator sizing coefficients. System parameters are the independent variables in the set of simultaneous equations discussed above. For an N node system, any N system parameters can be unknown with two exceptions. At least one pressure must be specified so that the system has a pressure reference. Also, at least one node flow must be unknown.

Calculated Steam and Heat Flow Quantities. SHDP calculates many steam and heat flow quantities. These quantities are dependent variables in the system. Their values cannot be fixed and are always calculated in the problem. Calculated steam flow quantities include steam flow through pipes and regulators, steam condensed in the pipes and vaults, and steam lost at faulty traps. Heat loss calculations include pipe conduction losses, heat lost by not returning condensate, and the heat loss associated with faulty trap steam losses. System thermal efficiency is also calculated. This is done by summing all heat losses and dividing the total by the heat input to the system at the plant. The result is then subtracted from 1.0 to give the thermal efficiency.

Steam Flow and Condensate Formation in Pipes. SHDP calculates steam flow and condensate formation in pipes based on saturated steam conditions. Steam flows in a pipe due to a pressure difference between the two nodes it connects. The mass flow rate of steam in a pipe, Q, is calculated as follows:

$$Q = 21.11\ D^{2.5}\ \text{sq. root}\ (P_1 1.946 - P_2 1.946/fL) \qquad (1)$$

where

Q is the mass flow rate in lbm/hr,
D is the pipe diameter in inches,
P_1 and P_2 are the node pressures in psia,
L is the pipe length in feet, and
f is the Darcy friction factor given by

$$f = 0.0055\ [1 + \{20000.0\ E/D + 10^6/Re\}^{1/3}], \qquad (2)$$

where

E is the surface roughness in inches, and
Re is the Reynolds number given by

$$Re = (4Q/pDm). \qquad (3)$$

Mu is the steam viscosity and is equal to 1.37×10^{-5} lbm/ft-sec. This is equivalent to 4.11×10^{-3} lbm/in-hr.

Saturated steam condenses in a pipe as the result of heat loss by conduction through the pipe walls. Figure 6.1 shows a pipe with inlet steam mass flow rate of m_i lbm/hr at enthalpy h_i, and a total pipe heat loss of H Btu/hr. From mass and energy balance consideration, it can be shown that the rate of condensate formation is given by

$$m_c = m_i\,[(h_o - h_i + H/m_i)/h_o - h_c]. \qquad (4)$$

m_i: inlet mass flow, lbm/hr
m_o: outlet mass flow, lbm/hr
m_c: condensate formation, lbm/hr
h_i: inlet steam enthalpy, Btu/lbm
h_o: outlet steam enthalpy, Btu/lbm
h_c: condensate enthalpy, Btu/lbm
H: pipe heat loss, Btu/hr

Pipe heat loss is calculated as follows:

$$H = UL\,(T_s - T_e), \qquad (5)$$

where
U is the pipe heat transfer coefficient, Btu/hr-ft-F,
L is the pipe length, ft,
T_s is the average steam temperature in the pipe, and
T_e is the environment temperature.

The average steam temperature in the pipe is determined from the average steam pressure. The average steam pressure, PAV, is given by

$$PAV = 2/3\,[P_1 + P_2 - P_1 \times P_2 / P_1 + P_2]. \qquad (6)$$

Saturated steam temperature, as a function of pressure, is then calculated by the empirical relation:

$$T = 79.2768 + 156.305\,X - 28.9973X^2 + 21.5383X^3 - 0.1768X^4, \qquad (7)$$

where: $X = \ln(P)/3.0$.

Saturated steam enthalpy, HG, and saturated liquid enthalpy, HF, are calculated as a function of temperature using the following empirical relations:

$$HG = 1003.5585 + 0.94553T - 1.37336X10^{-3}T^2 + 0.60614X10^{-6}T^3 \qquad (8)$$

$$HF = -39.9815 + 1.08876T - 0.37021X10^{-3}T^2 + 0.60614X10^{-6}T^3 \qquad (9)$$

6.6 Steam Flow in Regulators and Valves

A regulator sets the downstream pressure of the steam flowing through it. A valve restricts the flow of steam through it. The steam flow, Q, through both regulators and valves is calculated using the following Fisher regulator equation:

$$Q = C_sP_1 \sin [59.64/C_1(P_1\text{-}P_2/P_1)^{1/2}], \tag{10}$$

where:
Q is the steam flow in lbm/hr,
P_1 is the upstream pressure in psia,
P_2 is the downstream pressure in psia,
C_s is the sizing coefficient, and
C_1 is the configuration constant.

When this equation is used to model a regulator in SHDP, P_2 is set and C_s and P_1 are generally unknowns. When it is used to model a value, C_s is set and P_1 and P2 are unknowns.

Traps. Traps are devices which allow condensate to leave the system without letting steam escape. In SHDP, a trap is put at every node, and pipe condensate leaves the system at the nearest node. Provision is made in SHDP to account for the steam and heat losses due to a faulty trap. A faulty trap is one which allows live steam to escape. There are two ways for the user to specify faulty traps. One way is to give a percentage of all traps that are faulty at any one time. The second method is to specify particular traps which are faulty. In both cases, the valve equation is used to calculate steam loss through the faulty trap.

Vaults. Vaults, also known as steam pits and manholes, are sections of buried pipe system that are left exposed to allow for access. Often the insulation on pipes in vaults is in poor condition, wet, or nonexistent. To model the greater heat loss and steam condensation resulting from these situations, provision is made in SHDP to calculate additional heat loss in vaults.

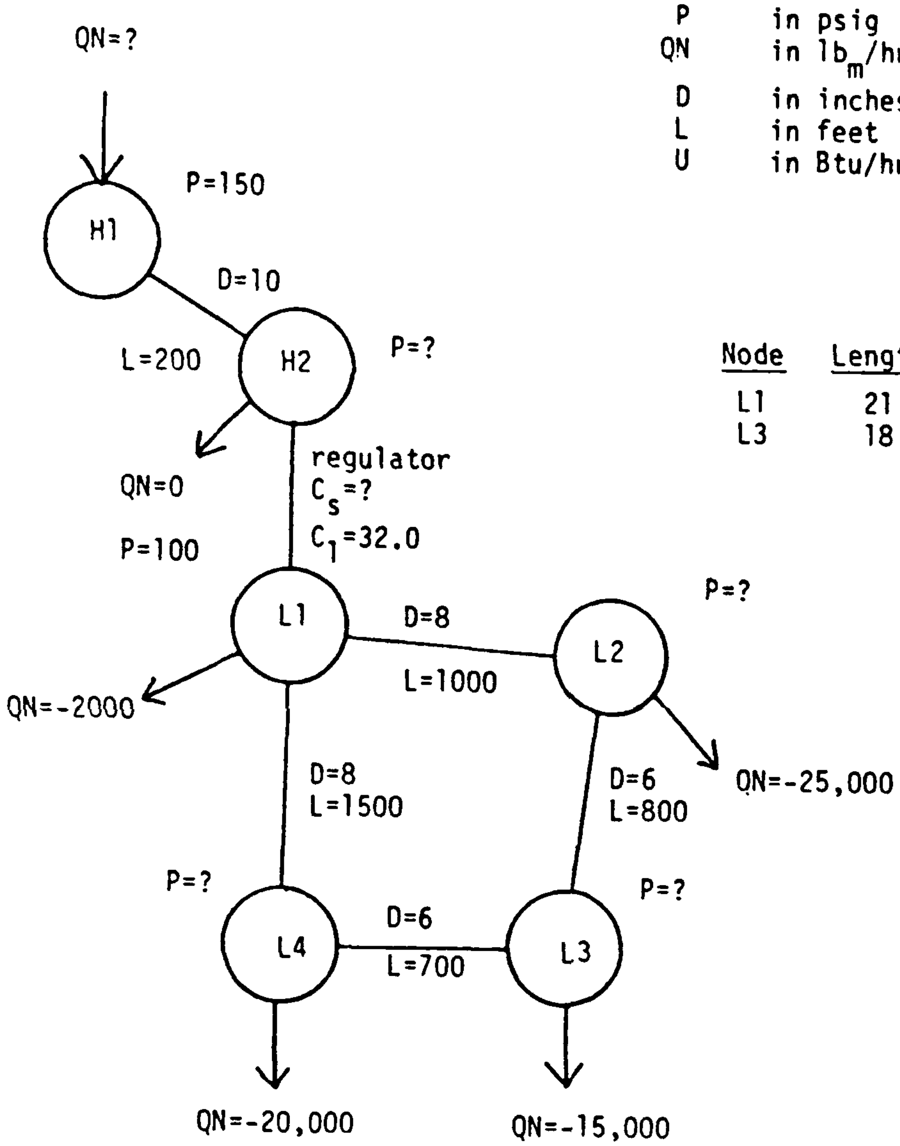
Sample Steam Distribution System

Figure D1 is a schematic of how SHDP analyzes a small steam distribution system. The circles represent nodes. A node is a place where pipes or regulators are joined. Also, nodes are places where steam enters or leaves the system (such as at the steam plant and building loads). The lines connecting the nodes are either pipes or regulators. There is one regulator in the system connecting nodes H2 and L1 The rest of the lines connecting the nodes represent pipes.

The steam plant is at node H1. The pressure at the steam plant is set at 150 psig. In this system, a solution would be sought for the 'node flow', QN, at H1. 'Node flow' refers to the steam that enters or leaves the system at a node. A '?' next to QN indicates that the node flow is unknown. After leaving the steam plant, steam passes through a short pipe, then through the regulator. The regulator sets the downstream pressure at node L1 to 100 psig. The regulator sizing coefficient, Cs, is unknown and would be calculated by SHDP.

Nodes L1 to L4 represent building loads. The building steam loads are represented as node flows at nodes L1 to L4. These flow as given in Figure D1. Notice that the node flow at the building nodes is negative. Steam that leaves the system is a negative flow; steam entering the system is a positive flow. Pressures at nodes L2 to L4 and H2 are unknown and would be calculated by SHDP.

P	in psig
QN	in lb_m/hr
D	in inches
L	in feet
U	in Btu/hr-ft-°F



Node	Vaults Length	Vaults U	Diameter
L1	21	3.1	8
L3	18	2.3	6

Traps

2% of traps are faulty

Ground temperature at 50°F.
No pipe condensation returned.
50% of all load condensate returned.
Load flow condensate at 150°F.
Pipe roughness of 0.0025 inches.

Pipe Heat Transfer Coefficients

Diameter (inches)	U (Btu/hr-ft-°F)
6	0.4
8	0.6
10	0.8

Figure D1. Sample steam distribution system.

CENTRAL HEATING PLANT ECONOMICS

The Central Heating Plant Economics (CHPECON) computer model was developed by USACERL and the Institute of Gas Technology through a program funded by the Department of Defense (DOD). This program was in response to the 1986 Appropriation Act (PL-99-190) Section 8110 that directed the DOD to increase coal use for government facility energy supply. CHPECON is designed to screen candidates for potential new and retrofit steam/power generation facilities. The CHPECON evaluation techniques provide a consistent approach in evaluating competing technologies. The program produces screening criteria that are used in the preliminary stages of evaluation. After passing the preliminary screening, CHPECON provides detailed conceptual facility design information, budgetary facility costs and economic measures of project acceptability including total life cycle costs and levelized cost of service. The program provides sufficient flexibility to vary critical design and operating parameters in order to determine project sensitivity and parametric evaluation.

The plant sizes examined in the model ranged between 60,000 to 500,000 lb/hr with individual boiler sizes from 20,000 to 200,000 lb/hr of steam or HTHW plants. The program is divided into two parts: the screening models and the detailed cost model. The screening models are used to initially evaluate each plant site and boiler technology option to produce a list of the promising locations and technology options. The current version of CHPECON's screening models contain two distinct sections for evaluating new heating plants and cogeneration facilities. Two additional sections for evaluating retrofit heating plants and consolation of existing multiple boiler plants are under development. The addition of these two sections will complete the screening models.

The new heating plant screening model is used to determine if a new coal fired heating plant can be built to replace an existing steam plant (250 psig saturated steam or equivalent hot water). The boiler technology options include: stoker, bubbling fluidized bed, circulating fluidized bed, coal/water slurry and coal/oil slurry boilers.

The cogeneration screening model is used to determine if a new cogeneration steam plant is a feasible alternative for a military base heating plant. Medium pressure (600 psig and 750°F) or high pressure (1300 psig, 1000°F) plants can be analyzed. The boiler types considered here are stoker, coal/oil, coal/water and fluidized bed boilers.

The retrofit screening model is used to determine if the existing boilers can be retrofitted into coal fired boilers or low-Btu gas fired boilers supplied from a gasifier. The boiler options include: coal-water slurry, coal-oil slurry, micronized coal, slagging coal, fluidized bed and stoker boilers, as well as gasification.

The consolidation screening model is used to determine if the military base should consolidate several individual heating plants into one main heating plant. This section assesses whether the steam distribution density is sufficient to consider consolation as a viable option.

After the screening model has been executed, the user has the option to quit or to restart another screening model (for another option) or to continue to obtain a cost estimate for the selected facility. The cost model contains sections for a new heating plant, retrofit heating plant, cogeneration facility and consolidated facility.

The detailed costing model provides conceptual facility design, capital installed costs of the conceptual facility, operational and maintenance costs over the life of the conceptual facility and life cycle costs.

Screening Models

The screening models are menu driven, prompting the user to supply necessary information describing the facility's characteristics and energy needs. Based on the information supplied and internal data base information, the program lists the relevant plant parameters. In addition to the calculated outputs such as the peak boiler house loads, a subjective weighted analysis output is provided. The output provides information for the comparison of the potential sites with available technologies.

New Heating Plant Screening Model

The New Heating Plant Screening Model can be used to determine the feasibility of constructing a new coal fired heating plant at an existing base (150 psig saturated steam or equivalent hot water). The boiler plant options include: stoker, bubbling fluidized bed, circulating fluidized bed, coal-water slurry and coal-oil slurry boilers. The program prompts the user to supply necessary information describing the user's requirements and resources available to the new heating plant. Based on the information supplied and internal program information, the program output gives conceptual area requirements, steam heating load predictions, plant performance estimates, fuel storage area requirements, location site information, boiler coal specifications, coal analysis, boiler sizes, allowed emissions, calculated emissions and water requirements. In addition, a weighted analysis is provided for the subjective factors considered when deciding to build a new heating plant.

The screening model has three basic sections; the program interactive query section, internal data bases, and engineering calculations. The computer prompts the user for required information concerning the installation. The program then determines the feasibility of a new facility using the supplied information, data bases and calculations.

The New Plant Screening Model is divided into eight sections. Each of the sections focuses on a specific aspect of building a new heating plant. For each of these sections, user inputs are required to evaluate the relevant criteria. The following discussion reviews each section including the inputs required as well as the computer logic and actions.

<u>Plant Site Information</u>. This section requires the user to enter the location (State) of the new heating plant. Upon entering the State, the military bases in the specified State are automatically listed on the screen. The user has the option to choose one of the military bases or add a new base. If a site is added, the base name, state, latitude, longitude, monthly degree days, monthly ambient air temperatures, and air quality attainment status must be input. The screen then presents the specific military base information. Any military base information can be temporarily changed at any time. If the chosen military base plant site is located in a non-attainment air quality area, the program makes note of this fact on the display.

<u>Boiler Technology</u>. In this section of the screening model the type of boiler plant to be analyzed is selected. The choices are listed below:

1. Spreader Stoker with Traveling Grates
2. Dump Grate Spreader Stoker

3. Spreader Stoker with Vibrating Grate
4. Spreader Stoker with Reciprocating Grate
5. Chain Grate Stoker
6. Traveling Grate Stoker
7. Bubbling Fluidized Bed Combustor (BFBC)
8. Circulating Fluidized Bed Combustor (CFBC)
* 9. Coal-Water Slurry (CWS) Boiler
* 10. Coal-Oil Slurry (COS) Boiler

* not available in current version

Fuel Search. The fuel search requires the user to enter the radius in miles from the base for the fuel search. For the stoker and FBC types of boilers the program searches the COALFIELD data base for coal deposits within the specified radius and compares the required coal specs of the chosen boiler type to each coal deposit to determine which coal can be used. The coal deposits are sorted according to coal type (lignites, bituminous, anthracite) and arranged by the heating value. For the chosen coal deposit, the coal type, heating value and proximate analysis are displayed. At this point, the user has the option of choosing the fuel for analysis, changing the radius of the fuel search, or further eliminating coal mines by specifying a maximum percent sulfur limit.

If a coal-oil slurry or coal-water slurry boiler is selected, the program asks the user if a coal slurry production plant is located in the area. The user should be aware that only one coal slurry production site is presently in operation, and that future sites most likely will be located near large electric utility load areas of the country. The fuel composition for coal-oil and coal-water slurries are fixed. Table 8 shows typical slurry compositions which are required to determine the plant emissions and plant/boiler performance.

Heating Plant Load Predictions. The heating plant load demand calculation requires the following information: the type of boiler plant to be built (steam or hot water), the average hourly steam demand for each month - lb/hr (hot water - MBtu/hr), the process steam demand for each month - lb/hr (hot water - MBtu/hr), the number of hours per month the process steam (hot water) is used, and whether the process load is located adjacent or remote to the boiler plant.

The steam load prediction formulas based on climatological data calculate the plant maximum continuous rating (PMCR steam flow) in pounds per hour. If the PMCR is outside of the plant limit size of the model, 60,000 lb/hr to 500,000 lb/hr (60 MBtu/hr to 500 MBtu/hr), the program will alert the user to this fact and allow the user to quit or change the plant demand. The program also calculates the minimum and maximum steam or hot water flows for heating facilities.

Conceptual Boiler Sizing. This section allows the user to select a conceptual plant with 3, 4, or 5 boilers. Along with the number of boilers, the equations require the plant design PMCR to be entered as input, where PMCR is derived from the Plant Steam Load Predictions. The user's selection are then used to determine the correct size for each of the plant's boilers in pounds per hour outlet flow. If the boiler sizes are outside the feasible size range for the chosen technology or for the program limits of 20,000 lb/hr to 200,000 lb/hr (20 MMBtu/hr to 200 MMBtu/hr), the program will alert the user to the problem and allow the user to quit, change the number of boilers or change the plant demand. Stoker boiler size ranges are shown below:

Dump Grate Spreader Stoker - 20,000 -- 200,000 lb/hr
Spreader Stoker with Vibrating Grate -- 20,000 - 125,000 lb/hr
Spreader Stoker with Reciprocating Grate -- 20,000 - 125,000 lb/hr
Spreader Stoker with Traveling Grate -- 75,000 - 200,000 lb/hr
Traveling Grate Stoker -- 20,000 - 150,000 lb/hr
Chain Grate Stoker -- 20,000 - 150,000 lb/hr

The 3-boiler sizing method provides for the plant to generate 72.5% of the PMCR with one large boiler out of service. The 4-boiler plant will be able to generate 100% of the PMCR with one large boiler out of service. The 5-boiler plant will also be able to generate 100% of the PMCR with one large boiler out of service.

Plant/Boiler Performance Estimates. This section calculates the heat and mass balance for either a single boiler or a total boiler plant. The single or multiple boiler balance difference depends on the quantity of steam flow input into the program, with the presumption that the boilers are the same. This presumption is valid for the conceptual design stage and with the boiler sizing methods in this study.

The program begins with the key boiler data inputs. The boiler sections calculate the ASME boiler efficiency, the air requirements and flow, the products of combustion and flow, and the flue gas specific heats.

There are three basic versions of the screening model program: one for a stoker plant, one for FBC boiler plants, and one for coal slurry plants. The stoker plant program includes a dry scrubber balance which calculates the dry scrubber lime and water requirements, flue gas flows and several flue gas specific heats. These are calculated from the inlet of the scrubber through the baghouse and into the stack. The boiler section includes the boiler superheater, economizer and/or air heater and all associated fans, pipes, and controls needed to introduce air and fuel into the system. The scrubber and baghouse section includes the necessary equipment required to introduce air, water, and lime into the system.

The FBC boiler plant program calculates and displays boiler information required for sizing a FBC boiler plant equipped with a baghouse. The boiler section includes the furnace, boiler, superheater, economizer and/or air heater and all associated fans, pipes and controls needed to introduce air, fuel, and limestone into the system.

The slurry boiler plant program calculates and displays boiler information required for sizing a boiler plant with a baghouse. The boiler section includes the boiler superheater, economizer and/or air heater and all associated fans, pipes and controls needed to introduce air and fuel into the system. (not available in current version)

Plant Emissions. In order to determine if the proposed plant will meet emission standards, this plant emissions section calculates the emissions plant and compares it to the EMISSION data base. In order to compare the calculated emissions with the EMISSION data base, the user must choose a region of a state if requested to do so while running the program.

To calculate the particulate, SOx and NOx (lbs/ton of coal burned) out of the boiler, factors were determined for each boiler type and coal type.

Plant Area Requirements. To determine whether sufficient area is available to build a new boiler plant, the program calculates the plant area, coal storage rain runoff pond area, and coal storage areas.

The sum of these areas is the total area required to build a new plant. Furthermore, the program calculates the required rail track length. Plant height, stack height and building size are also calculated.

Cogeneration Screening Model

The Cogeneration Plant Screening Model is divided into eight sections similar to those in the New Plant Screening Model. Each of the sections focuses on a specific aspect of building a new cogeneration plant. For each of these sections, user inputs are required to evaluate certain criteria. The following 2 sections describe some of the additional assumptions made for cogeneration.

Cogeneration Plant Load Prediction. The cogeneration plant load demand calculations are based upon the Plant Maximum Continuous Rating (PMCR) required for heating. The plant will operate at maximum capacity at all times. Power is assumed to be generated from turbines operating at steam inlet pressures of 600 or 1300 psig and outlet pressures of 150 psig. Additional power can be generated in the summer by the steam not used for heating. A minimum amount of steam equal to 20% of PMCR is required to be routed through the turbine to condensing. If this minimum amount does not exist, the turbine cannot operate and generate electricity.

Conceptual Boiler Sizing. (see New Heating Plant Screening Model) For each of the boiler technologies, the 3-boiler plant is the default method. With this sizing, the plant will be able to cogenerate electricity throughout the year and, if the turbine is not in use, will be sufficient to meet the minimum heating summer loads using only the small boiler.

Detailed Cost Model

The detailed cost model provides conceptual facility design information, budgetary facility costs, and economic measures of project acceptability including total life cycle costs and levelized cost of service. The following sections describe the major cost areas for capital, operation and maintenance costs.

New Facility Capital Construction Cost

Major equipment costs are broken into modules. The cost of the boiler plant equipment is determined by calling the equipment modules. These modules have different costs for each of the boiler technologies. The lists below indicate the modules each of the boiler technologies require. Also the additional modules are indicated for cogeneration and consolidation.

Major Facility Equipment Cost Modules (stokers)

Boiler
Coal Handling
Ash Handling
Mechanical Collector
Dry Scrubber & Lime System
Baghouse & ID Fan
Boiler Water Treatment
Tanks
Pumps

Air Compressors
Wastewater Treatment
Piping
Instrumentation
Electrical
Building & Services
Site Development
Spare parts, tools, mobile equipment

ADDITIONAL MODULES FOR COGEN

Condenser
Cooling Tower
Feed Water Heater
Turbine Generator

Example Equipment Breakdown for Boiler Water Treatment

- Sodium Zeolite Softening with Brine Tank
- Brine Wastewater Tank
- Demineralizer with Degasification
- Neutralization Tank
- Acid and Caustic Tank
- Demineralizer with Degasification and Mixed Bed
- Demineralizer
- Mixed Bed Demineralizer
- Dealkalizer

Once the equipment costs are determined, these costs are added with the other direct costs of freight costs and installation cost. These costs are further discussed after the discussion of each of the equipment costing modules.

Facility Operations Cost

This section was developed to provide budgetary operations and maintenance cost estimates for new steam production and co-generation power plants. These estimated costs are divided into two parts: operational cost and major maintenance cost. The operational cost components include day to day costs of operating and maintaining a steam or cogeneration facility. Cost for the major equipment rebuilds; i.e., turbine rebuilds, baghouse rebagging, major boiler outages, boiler feedwater pump rebuilds, water treating resin replacement, etc., are included in the major maintenance cost. After calculating the aforementioned, the program sums the costs to estimate the total yearly costs for each year of operation. These yearly costs are developed by the program by estimating monthly costs and totaling them for yearly estimated costs. Cost algorithms are based on fourth quarter 1988 dollars and are escalated yearly for the development of future costs. The operating and maintenance costs are then used with the capital costs to determine the total life cycle cost of the conceptual new facility being evaluated. The costs components included in this category estimate the "day-to-day" costs of operating and maintaining a steam or co-generation facility. The costs included in this category are discussed below:

Labor. The labor cost category is divided into six classifications; Management, Operations and Maintenance, Yard or Fuel Storage, and Steam System.

Management includes the personnel required to manage and direct the total operations of the facility. Included in this category are the Plant Manager, Assistant Plant Manager, Plant Engineers, Plant Secretary, Clerks, Janitor and Instrumentation Technician positions. These personnel are responsible for the total facility. Their duties include the overall operations, maintenance and planning of the facility; payroll and accounting functions; receptionist and secretarial responsibilities; maintenance parts inventory control, restocking and ordering for major maintenance; cost control, etc.

Operations include the personnel required to operate the facility. Included in this category are the Shift Supervisor, Operators, Assistant Operators, and Laborers. These positions are also responsible for minor maintenance or some preventive maintenance; painting, seal repacking, greasing, oiling, etc., when not required for maintaining the operations of the plant.

Fuel Storage personnel are responsible for the long-term fuel storage area operation. This includes fuel stocking, reclaim along with unloading operations.

Maintenance includes the personnel required to perform plant maintenance. Included in this category are the Mechanical and Electrical Maintenance positions and laborers. These positions are mainly responsible for plant maintenance; rebuilding or replacing pumps, small fans, soot blower repairs, nominal boiler repairs, air compressors, instrumentation, plant electrical system maintenance, etc. When required, these personnel are also responsible to assist plant operations; i.e., coal unloading and handling, ash handling, etc. Steam system labor includes the personnel required to maintain the steam distribution system.

Default values for each type of labor as well as the default wages are provided, if not known. The estimated cost of labor was developed as a function of plant size, number of boilers, whether the facility is a heating or co-generation facility, fuel type, personnel salary and productivity level. The user can specify the salary level, % fringe benefit multiplier and % overtime for each type of personnel. The program will then compute the salary cost in dollars per year.

Fuel. This category is broken into two components, the primary and secondary fuel. Primary fuel is the fuel used to produce steam. Secondary fuel is the fuel used for starting the boilers, car thawing for coal receiving, plant vehicles, diesel generators, etc. Primary fuel cost is calculated by multiplying the amount of fuel utilized per year times the cost of the fuel.

Heating facility primary fuel use is estimated by using the average steam load per month divided by the maximum steam load times the fuel utilization rate at the maximum steam flow. This can also be calculated by using the Performance Estimate program to calculate the fuel consumption rate. The fuel consumption rate in lbs/hr is then multiplied by 24 hrs/day and the number of days per month for the monthly fuel rate. To calculate the 1988 yearly fuel cost, sum the monthly fuel rates and multiply by the fuel cost. For future costs, the 1988 cost is increased by the escalation rate.

Co-generation facility primary fuel use is estimated by using the fuel utilization rate (lbs/hr) at PMCR then multiplying this by 24 hours/day times 365 days/year times 0.85 (the power production factor developed from partial and total load loss due to boiler and turbine outages planned and forced).

Lime or Limestone. The cost of these components are calculated similar to the primary fuel cost. The lime or limestone monthly use rate is calculated for each month of the year; the yearly use is determined by summing the monthly rates. For co-generation the yearly usage is estimated by multiplying the yearly rate times 0.96. The 1988 costs are then determined by multiplying lime use times cost per quantity. Future costs are then computed by escalating the 1988 costs.

Water. The water cost estimate is determined by the amount of water consumed by the facility times the cost of water. The amount of water consumed is estimated by the following system uses. Condensate makeup is determined by using the average monthly steam flow times the user input % makeup rate or one minus % condensate return divided by 100 times 24 hours per day times days per month. Sum the monthly rates and convert to gallons. Blowdown makeup is determined similarly to condensate makeup using the user input % blowdown. This is also determined in gallons per year. Dry scrubber water use is estimated with the Stoker Facility/Boiler Estimate program. Using the gallons per minute at PMCR times the monthly average steam rate divided by PMCR times 24 hours per day times day per month determines the gallons per month. Summing the monthly rates determines the yearly consumption.

Plant water usage includes ash conditioning and facility washdown. Ash conditioning is estimated as 10% to 40% by weight of the ash generated. Again, using the Facility/Boiler Performance Estimate program, determine the amount of ash produced. Multiply this value with the average monthly steam flow divided by the PMCR and then multiply by 24 hours per day and days per month to get an estimate of the monthly ash flow. Multiply this value by the user selected % water in ash (default being 10%) divided by 100 and convert amount of water to gallons.

Facility washdown and miscellaneous water use is estimated as 25 gallons per minute times 60 minutes per hour times 3 hours per day times 7 days per week times 52 weeks per year, or 780,000 gallons per year. Personnel water usage is estimated as 8,750 gallons per year per employee. Cooling Tower usage is estimated by Circulating Cooling Water Makeup multiplied by 60 minutes per hour times 24 hours per day times 365 days per year times 0.77. Water treatment wastewater estimate is dependent on the type of water treatment system.

Sanitary Sewer. The estimated cost of the sanitary sewer is a direct function of the amount of waste sent to the sewer. The sewer flow is estimated by adding (half of the blowdown water makeup) plus (Facility washdown and miscellaneous water) plus (Personnel water use) plus (Cooling Tower Blowdown) and multiplying by the sewer cost. Note: The water rate estimate must be in the same units as the sewer cost rate; i.e., if cost is $/gpm,; then water rate must be gpm.

Ash Disposal. The estimated cost of the disposal of ash is a direct function of the amount or weight of waste (ash or residue plus moisture content) produced by the facility. The amount of waste per month is estimated by multiplying the amount of waste generated (See Plant/Boiler Performance Estimate) times 24 hours per day times the average monthly steam load divided by PMCR, the quantity times number of days per month times the quantity of one plus % water added for ash conditioning divided by 100. Summing each monthly waste generation provides an estimate of the amount of waste generated per year. Multiplying this times the cost of waste disposal provides the estimate cost of waste disposal at the location of the disposal site. (Note: The amount of yearly waste must be in the same units as the cost of waste disposal; i.e., tons per year times $ per ton). The program should include an estimated freight cost if the cost of waste disposal does not include this factor.

Electricity Consumption. The cost of electricity is divided into three categories; Process Usage, General Facility Usage and Utility Equipment and Standby Charges. Process charge is the cost of the electricity to operate the facility steam/power generation system. This cost is determined monthly and then the monthly costs are summed for the yearly estimated cost. Each monthly charge is estimated by summing the total system motor KW/hr; i.e., pump motors, fan motors, conveyor systems, etc., then multiplying the KW times 24 hours per day times days per month times the quantity of the Average Steam Load of the month divided by PMCR times the cost of the electricity. Summing the monthly costs provides the yearly process electrical load costs. The General Facility electricity cost is estimated mainly as the facility lighting load. This is divided into the plant or building and the facility area lighting.

Utility Equipment and Standby Charges are the cost of renting the facility substation, power lines into the facility and the cost of the standby demand charge. These costs are usually only for co-generation facilities and are totally dependent on the location of the facility. The user must input these costs, where and if applicable. The total Facility Electrical Yearly Cost is then estimated by summing the Process usage yearly cost, General Facility usage yearly costs and Utility Equipment and Standby Charges yearly costs.

Facility Chemicals. The facility chemical usage is divided into three main areas of use; Boiler, Water Treating, and Cooling Tower. All three are dependent on the steam load of the facility. Boiler chemical usage is dependent on boiler water quality and blowdown rate. Usually the higher the water quality and/or blowdown rate, the less amount of boiler chemicals required. For the design estimate, all boilers will utilize a coordinated phosphate treatment; this being a mixture of 60% by weight trisodium phosphate and 40% by weight disodium phosphate.

The boiler chemical cost is estimated by summing the monthly chemical usage and multiplying times the cost of the chemicals. Treating Chemical usage is divided into two categories; Water Treatment System and Deaerator or Oxygen Scavenger System.

Maintenance Parts. Maintenance parts are estimated as a function of plant size. The yearly spare parts cost is estimated as 85% of the spare part capital cost escalated. During the first year of operation, this cost is estimated as 15% of spare parts.

Facility Consumables. Consumable Costs estimate is the same as that calculated in the Capital Costs. During the first year of operation this cost is estimated as 20% of Consumable Costs.

Facility Grounds Maintenance. This category is for the area or grounds maintenance which includes such things as cutting the grass, road repair, railroad track maintenance, etc.

Mobile Equipment. This category is for maintaining the facility's mobile equipment. The cost is estimated as 8% of the mobile equipment capital cost escalated.

Stack. The stack cost is for an outside contractor to maintain the lights, FAA and beacon, and for an annual inspection.

Facility Maintenance Cost

This category is for major equipment rebuilds; i.e., turbine, boiler, baghouse rebagging, water treatment resin replacement, etc. Also included are the permit renewal fees/tests. The major maintenance costs included are as follows:

Boilers. Each boiler will have yearly outages to perform maintenance. These costs should be escalated yearly as appropriate. In addition to the yearly outages, the boilers will experience extended outages periodically to replace/repair the boilers; i.e., superheater replacement, grate replacement, economizer repairs, safety valve repair, fan repairs, etc.

Turbine-Generator. The small, gear type, turbine-generator is estimated to have an outage every 8 years at a cost of 8% of the turbine-generator's capital cost escalated. The large, 600 psig and 750 °F direct drive type, turbine-generator is estimated to have an outage every 5 years at a cost of 10.5% of the turbine-generator's capital cost escalated. The large, 1300 psig and 1000 °F direct drive type, turbine-generator is estimated to have an outage every 5 years at a cost of 12% of the turbine-generator's capital cost escalated.

Baghouse. The baghouse is estimated to have an outage every 3 years. This is mainly for bag replacement. The estimated cost is 5% of the capital cost of the baghouse escalated. Every 12 years the estimated cost is 7% of the capital cost escalated.

Cooling Tower Maintenance. The cooling tower is estimated to have an outage every 15 years for wood replacement, fan repairs and fill replacement/cleaning. The cost of this is estimated as 10% of the capital cost of the cooling tower escalated.

General Facility Maintenance. General facility maintenance costs are based on the following component maintenance costs.

a. Pumps:

1) Boiler Feedwater Pumps - Motor Driven: These pumps are estimated to be rebuilt every 15 years at an estimated cost of 40% of the pump's capital cost escalated.

2) Boiler Feedwater Pumps - Turbine Driven: These pumps and turbines are estimated to be rebuilt every 12 years at an estimated cost of 60% of the pump's capital cost escalated.

3) Coal Slurry Pumps - These pumps are estimated to be rebuilt every 3 years at an estimated cost of 45% of the capital cost escalated. These pumps are to be replaced every 12 years at the estimated capital cost escalated.

4) Other Centrifugal Pumps - These pumps are estimated to be rebuilt every 18 years at an estimated cost of 40% of the capital cost escalated.

5) Sump Pumps - These pumps are estimated to be rebuilt every 20 years at an estimated cost of 35% of the capital cost escalated.

6) Circulation Water Pumps - These pumps are estimated to be rebuilt every 25 years at an estimated cost of 25% of the capital cost escalated.

b. Deaerator:

The deaerator is estimated to have a major outage for internal parts replacement every 20 years. The estimated cost is 25% of the capital cost escalated.

c. Conveyor Systems:

1) Coal - The coal system is estimated to have the following equipment rebuilt at the time periods provided:

- Bucket Elevators — Every 8 Years
- Coal Crusher — Every 10 Years
- Conveyor Belts — Every 15 Years

2) Limestone or Lime - The limestone or lime systems are estimated to be 3% of the Capital Cost escalated every 5 years.

3) Ash System - The ash system is estimated to have the system rebuilt every 7 years at a cost of 22% of the capital cost escalated.

d. Water Treatment System:

The system is estimated to have a major outage every 10 years for valve repairs, tank relining and resin replacement. The estimated cost is 45% of the capital cost escalated.

e. Stack:

The stack is estimated to require major repair; i.e., top of stack repairs, every 20 years. The estimated cost is 1.0% of capital cost escalated.

f. Air Heater:

This is for coal-water only. The air heater is estimated to have an outage every 15 years for basket replacement. The estimated cost is 35% of the capital cost escalated.

g. Scrubber - Lime System:

This equipment is estimated to require major repairs; i.e., atomizer rebuilds, slaker rebuilds, lime pump rebuilds, etc., every 5 years. The estimated cost is 6% of the capital cost of the dry scrubber-lime system escalated.

h. Building:

The building is estimated to require a new roof, painting, etc., every 20 years. The estimated cost is 15% of the capital cost escalated.

i. Fans:

This estimated cost is for the I.D. fans only. Other fans repairs/rebuilds costs are included with the component which the fans were originally obtained; i.e., F.D. fans are included in the boiler estimated repair costs, building vent fans are included in the building estimated repair costs. The I.D. fans are estimated to be overhauled every 20 years. The cost estimate is 38% of the capital cost escalated.

j. Permits:

This category is to estimate the required periodic EPA permit testing and renewal costs. The cost is estimated to be $30,000 in 1988 dollars every 3 years.

APPENDIX E:

SATELLITE PLANT ZONES

BUILDING INVENTORY FOR PLANT IN BUILDING 506

101	216	404	604 C
113	221	406	604 E
114	224	407	604 H
114 A	225	407 A	606
115	230	407 B	607
115 A	230 A	424	607 A
123	230 B	427	611
151	230 F	429	613
151 A	232	429 A	617
154	235	435	617 B
162	240	436	620
163	241	439	621
164	252	455	717
164 B	266	456	717 A
166	281	462	717 B
167	282	462 C	722
168	321	462 D	732
171	322	471	800
172	323	472	803
176	323 D	477	805
178	329	479	807
183	332	501	807 B
197	333	506	809
209	337	506 A	810
213	342	507	813
214	382	602 C	813 E
215	403	604	823
824	900	ADD3	ADD6
ADD8	ADD17		

BUILDING TYPE	BUILDING AREA (Ft^2)
Family Housing	14,456
Admin/training Facil.	260,730
Fields & Gymnasiums	19,813
Production/Maint Fac	412,937
Storage Buildings	4,562
TOTAL	712,498 Ft^2

BUILDING INVENTORY FOR PLANT IN BUILDING 99

1	31	102	302 D
2	31 A	104	302 E
3	31 C	105	303
5	33	106	304
6	34	108	305
9	58	109	307
10	59	110	308 A
11	60	112	308 B
12	61	124	314
13	62	126	315
18	64	127	316
19	65	128	318
20	68	129	319
21	92	301	320
22	94	301 A	350
23	95	302	351
24	99	302 B	352
30	100	354	353
355	ADD4	ADD5	ADD12
ADD18			

BUILDING TYPE	BUILDING AREA (Ft2)
Family Housing	32,504
Admin/Training Fac.	808,418
Fields & Gymnasiums	5,700
Production/Maint Fac	498,712
Storage Buildings	58,907
TOTAL	1,404,241 Ft^2

BUILDING INVENTORY FOR PLANT IN BUILDING 3013

1029	1053	1094	1095
1301	1302	1303	1305
1306	1307	1354	1354 A
1357	1357 A	1359	1359A
1361	1361 A	1363	1363 A
1365	1372	1373	1398
1400	1402	1402 A	1403
1404	1405	1406	1407
1408	1408 A	1408 B	1408 C
1411	1411 A	1412	1412 A
1413	1416	1417	1418
3002	3005	3006	3008
3010	3013	3022	3024
3028	3050	3052	3100
3106	3109	3111	3124
3145	3159	3173	3176
3177	3200	3201	3220
3221	3227	3228	3230
3231	3250	3305	3306
3308	3310	3312	3314
3315	3316	3317	3325
3327	1501	1502	1503
1505	1506	1509	1510
1512	1513	1514	1515
1517	1517 A	1518	3328
3329	3341	3342	3344
3357	3359	3401	3402
3403	3404	3408	3409
3410	1504	ADD1	ADD2
ADD7	ADD9	ADD10	ADD16

BUILDING TYPE	BUILDING AREA (Ft2)
Family Housing	13,221
Barracks , pre-1966	49,667
Barracks , post-1966	16,000
Admin/Training Fac.	355,933
Fields & Gymnasiums	23,765
Dining Fac , Commisar	21,532
Production/Maint Fac	295,727
Storage Buildings	86,314
TOTAL	862,159 Ft^2

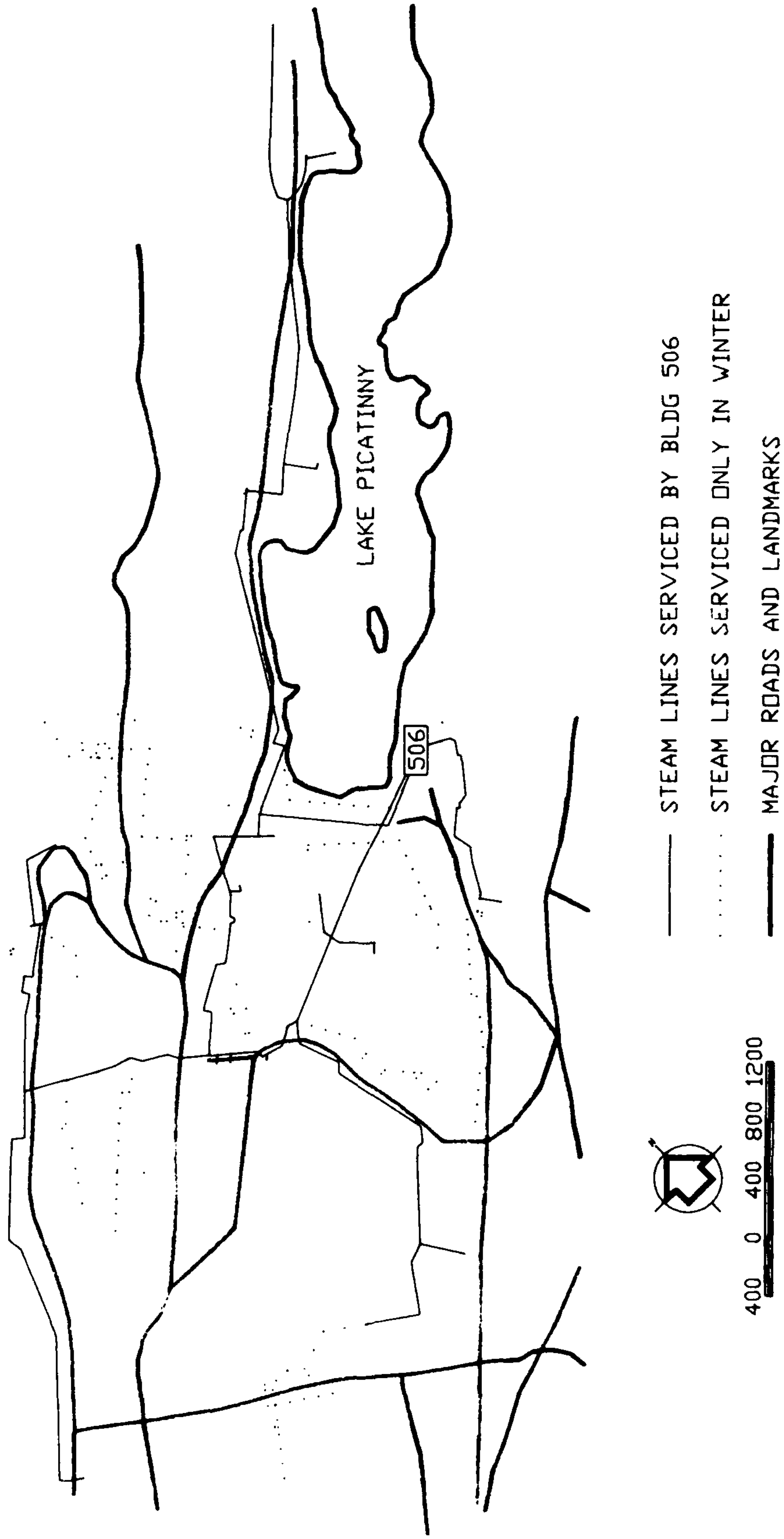
BUILDING INVENTORY FOR PLANT IN 600 SERIES BUILDINGS

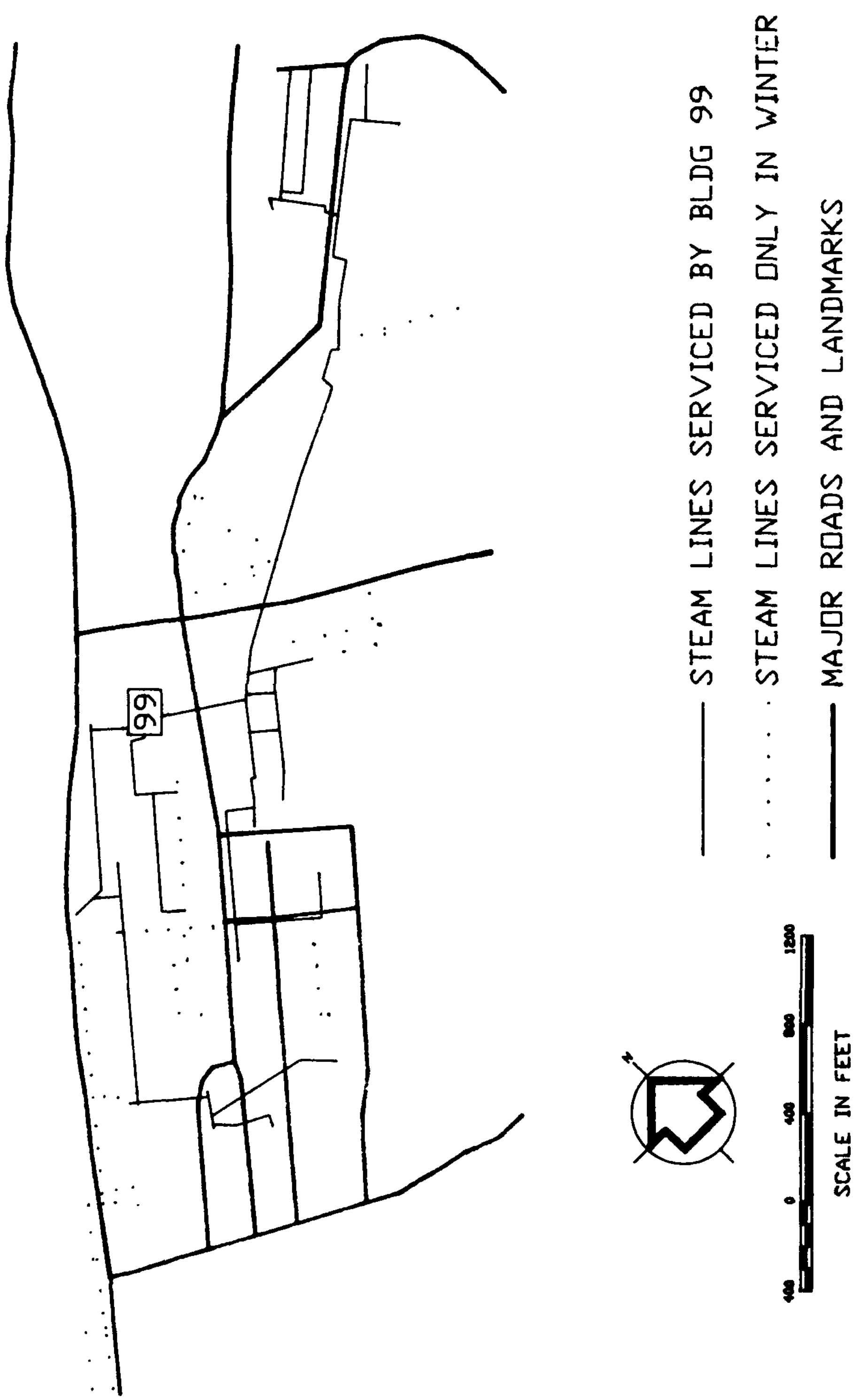
622	630	631	631 A
632	633	636	

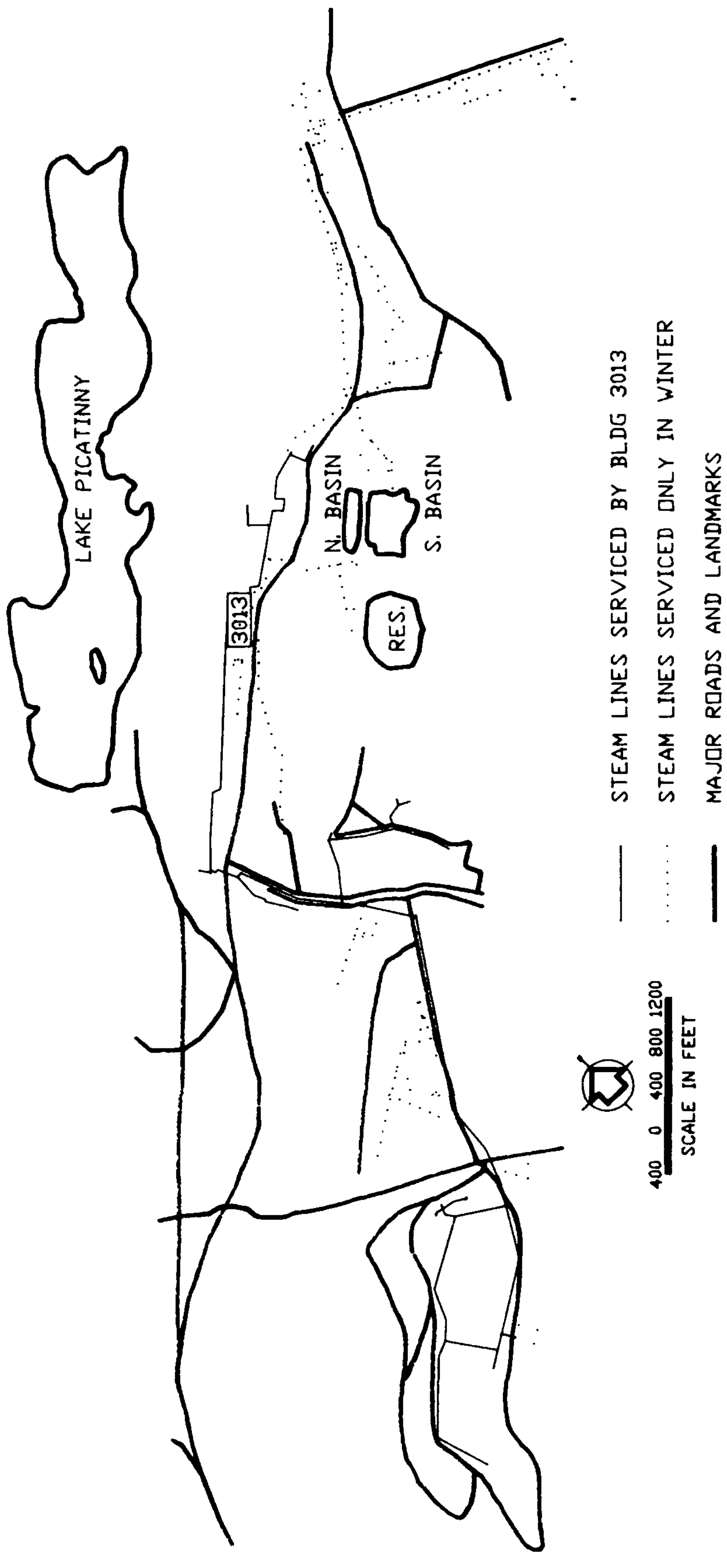
BUILDING TYPE	BUILDING AREA (Ft2)
Admin/Training Fac.	2,268
Production/Maint Fac	9,022
TOTAL	11,290 Ft^2

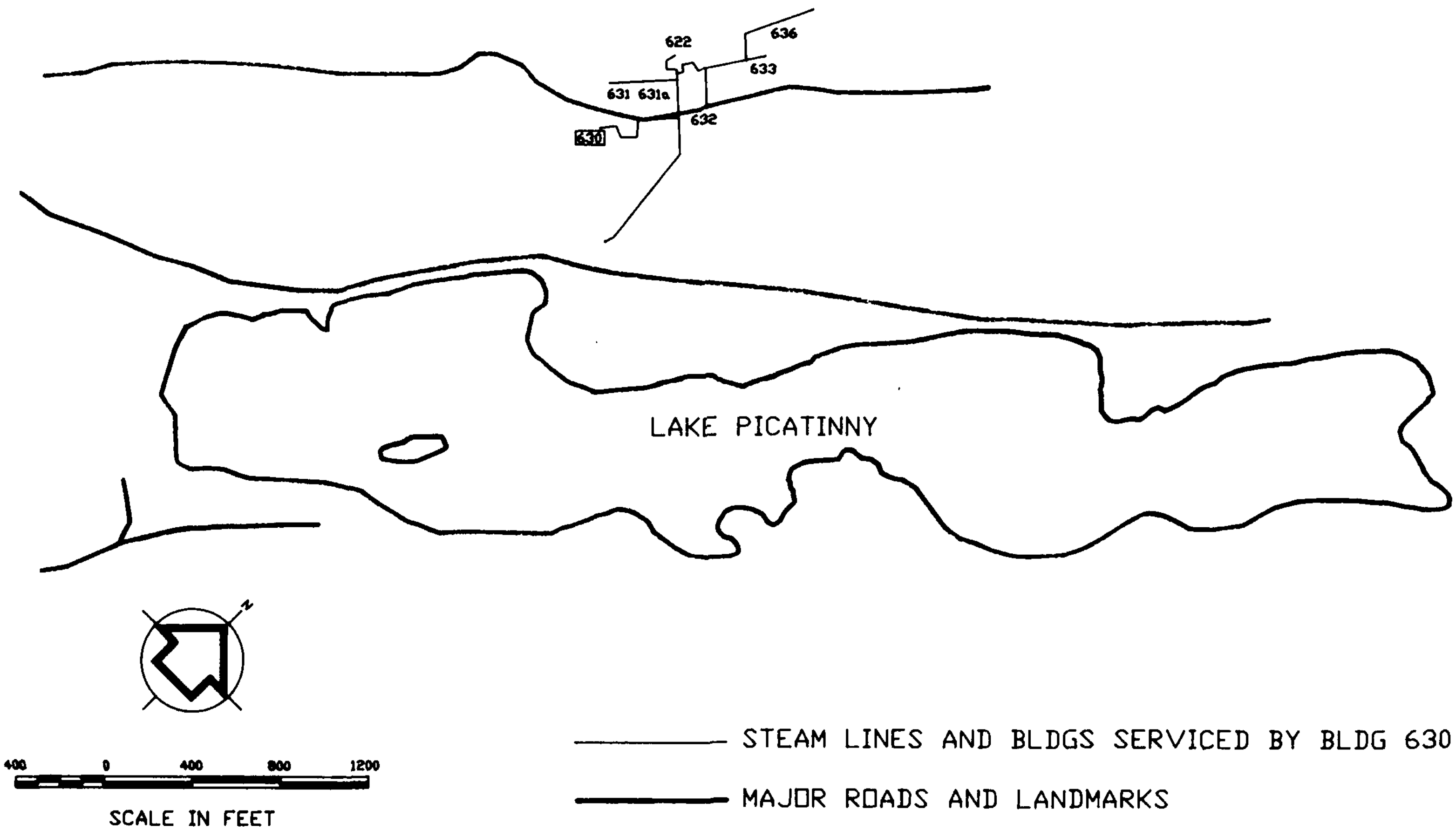
PICATINNY FUTURE BUILDINGS

Building	Name	Area	Form #	BOD
ADD1	40 PERSON BOQ	16000	613	1995
ADD2	ARMAMENR SOFT FAC	178304	29645	1991
ADD3	SECURITY HQ	12500	16183	1997
ADD4	MUNITIONS LAB - BLDG 31	142000	12232	1998
ADD5	ARMAMENT LAB	52500	333	1990
ADD6	AMCCOM TMDE LAB	47000	12101	1994
ADD7	EXPLOSIVES LAB	13660	319	1995
ADD8	VEHICLE MAINTENANCE	20000	621	1996
ADD9	SDI RESEARCH LAB	16500	16388	1996
ADD10	ROTARY WING HANGER	14400	648	1997
ADD12	WAREHOUSE	46400	649	1996
ADD16	ORDINANCE FACILITY	1950	Bldg 3111	-
ADD17	SAFETY OFFICE	15640	Bldg 320	-
ADD18	STORAGE WAREHOUSE	2200	Bldg 312	-


LAKE PICATINNY
506
STEAM LINES SERVICED BY BLDG 506
STEAM LINES SERVICED ONLY IN WINTER
MAJOR ROADS AND LANDMARKS
400 0 400 800 1200
SCALE IN FEET


99
STEAM LINES SERVICED BY BLDG 99
STEAM LINES SERVICED ONLY IN WINTER
MAJOR ROADS AND LANDMARKS
400
0
400
800
1200
SCALE IN FEET


LAKE PICATINNY
3013
N. BASIN
S. BASIN
RES.
400 0 400 800 1200
SCALE IN FEET
STEAM LINES SERVICED BY BLDG 3013
STEAM LINES SERVICED ONLY IN WINTER
MAJOR ROADS AND LANDMARKS



636
622
633
631 631a
632
630
LAKE PICATINNY
N
400
0
400
800
1200
SCALE IN FEET
STEAM LINES AND BLDGS SERVICED BY BLDG 630
MAJOR ROADS AND LANDMARKS

APPENDIX F:

HRI ECONOMIC ANALYSIS

Session Number: 1

SUMMARY OF INPUTS	
INSTALLATION NAME:	Picatinny Arsenal
REGION:	2
WASTE TYPE:	2
HEAT CONTENT:	4500
*WASTE QUANTITY:	5976 tpy
DAYS/WEEK:	7
SHIFTS/DAY:	3
LANDFILL LIFE:	15 years
LANDFILL REPLACEMENT COST:	$0
*LANDFILL COSTS:	$100.00 /ton
FUEL TYPE:	residual oil
FUEL COSTS:	$3.01/MBtu
AUXILIARY FUEL TYPE:	distillate oil
AUXILIARY FUEL COSTS:	$3.68/MBtu
*ELECTRICITY COSTS:	7.6 ¢/KWh

* Value given differs significantly from the table value.
** NOTE: MBtu means MILLIONS of Btu's.

SUMMARY OF OUTPUTS	
TONS PER 7 DAY WEEK OF WASTE:	115 tons/week
INDIVIDUAL INCINERATOR CAPACITY:	10 tons
NUMBER OF INCINERATORS REQUIRED:	2
TOTAL FACILITY CAPACITY:	20 tons/day
CAPITAL COSTS:	$62,834/ton
APC CAPITAL COST:	$0/ton
HRI CONSTRUCTION COSTS:	$1,256,680
O&M COSTS:	$25/ton
HRI O&M COSTS:	$149,400/year
LANDFILL SAVINGS:	$358,560/year
HEAT PRODUCTION:	27,635 MBtu/yr
FUEL COSTS:	$3.01/MBtu
AUXILIARY FUEL COST:	$3.68/MBtu
ELECTRICITY COST:	$22.27/MBtu
ENERGY RECOVERY FACTOR:	80.0%
NUMBER OF HOURS OPERATIONAL:	168 hours/week
NUMBER OF MBtu OF FUEL NEEDED PER TON OF WASTE BURNED:	0.249 MBtu/ton
GROSS FUEL SAVINGS:	$103,978.32/yr
YEARLY AUXILIARY FUEL COSTS:	$5,471.67/yr
YEARLY AUXILIARY FUEL QUANTITY:	1,487 MBtu/yr
YEARLY ELECTRICITY COSTS:	$17,259.64/yr
YEARLY ELECTRICITY QUANTITY:	775 MBtu/yr
NET FUEL SAVINGS:	$81,247/yr

** NOTE: MBtu means MILLIONS of Btu's.

STEAM SUPPLY SUMMARY

Total Amount of Steam Produced:	27,635 MBtu/year
Yearly Amount of Steam Produced:	27,635,434 lb/year
Daily Amount of Steam Produced:	75,922 lb/day
Hourly Amount of Steam Produced:	3,163 lb/hour

AUXILIARY FUEL REQUIREMENTS

Auxiliary Fuel Type:	distillate oil
Fuel Requirements:	1,487 MBtu/year
Yearly:	11,376 gallons/year
Daily:	31.25 gallons/day
Hourly:	1.30 gallons/hour

OPERATING SCHEDULE SUMMARY

Incinerator Operation:	7 days/week
	3 shifts/day
Daily Operation:	24 hours/day
Weekly Operation:	168 hours/week
Yearly Operation:	8736 hours/year
Effective Steaming Time:	24 hours/day

REFUSE DISPOSAL SUMMARY

Total Weight Disposed:	5,976 tons/year
	115 tons/week
	16 tons/day
Total Volume Disposed:	25,295 cuy/year

DISPLACED FUEL SUMMARY

Displaced Fuel Type:	residual oil
Amount Displaced:	34,544 MBtu/year
	230,772 gallons/year
	634 gallons/day
	26.42 gallons/hour

** NOTE: MBtu means MILLIONS of Btu's.

Session Number: 2

SUMMARY OF INPUTS	
INSTALLATION NAME:	Picatinny Arsenal
REGION:	2
WASTE TYPE:	2
HEAT CONTENT:	4500
*WASTE QUANTITY:	5976 tpy
DAYS/WEEK:	7
SHIFTS/DAY:	3
LANDFILL LIFE:	15 years
LANDFILL REPLACEMENT COST:	$0
*LANDFILL COSTS:	$100.00 /ton
FUEL TYPE:	residual oil
FUEL COSTS:	$3.01/MBtu
AUXILIARY FUEL TYPE:	distillate oil
AUXILIARY FUEL COSTS:	$3.68/MBtu
*ELECTRICITY COSTS:	7.6 ¢/KWh

* Value given differs significantly from the table value.
** NOTE: MBtu means MILLIONS of Btu's.

SUMMARY OF OUTPUTS	
TONS PER 7 DAY WEEK OF WASTE:	115 tons/week
INDIVIDUAL INCINERATOR CAPACITY:	10 tons
NUMBER OF INCINERATORS REQUIRED:	2
TOTAL FACILITY CAPACITY:	20 tons/day
CAPITAL COSTS:	$62,834/ton
APC CAPITAL COST:	$14,281/ton
HRI CONSTRUCTION COSTS:	$1,542,300
O&M COSTS:	$30/ton
HRI O&M COSTS:	$181,747/year
LANDFILL SAVINGS:	$286,250/year
HEAT PRODUCTION:	27,635 MBtu/yr
FUEL COSTS:	$3.01/MBtu
AUXILIARY FUEL COST:	$3.68/MBtu
ELECTRICITY COST:	$22.27/MBtu
ENERGY RECOVERY FACTOR:	80.0%
NUMBER OF HOURS OPERATIONAL:	168 hours/week
NUMBER OF MBtu OF FUEL NEEDED PER TON OF WASTE BURNED:	0.249 MBtu/ton
GROSS FUEL SAVINGS:	$103,978.32/yr
YEARLY AUXILIARY FUEL COSTS:	$5,471.67/yr
YEARLY AUXILIARY FUEL QUANTITY:	1,487 MBtu/yr
YEARLY ELECTRICITY COSTS:	$36,007.54/yr
YEARLY ELECTRICITY QUANTITY:	1,617 MBtu/yr
NET FUEL SAVINGS:	$62,499/yr

** NOTE: MBtu means MILLIONS of Btu's.

STEAM SUPPLY SUMMARY	
Total Amount of Steam Produced:	27,635 MBtu/year
Yearly Amount of Steam Produced:	27,635,434 lb/year
Daily Amount of Steam Produced:	75,922 lb/day
Hourly Amount of Steam Produced:	3,163 lb/hour

AUXILIARY FUEL REQUIREMENTS	
Auxiliary Fuel Type:	distillate oil
Fuel Requirements:	1,487 MBtu/year
Yearly:	11,376 gallons/year
Daily:	31.25 gallons/day
Hourly:	1.30 gallons/hour

OPERATING SCHEDULE SUMMARY	
Incinerator Operation:	7 days/week
	3 shifts/day
Daily Operation:	24 hours/day
Weekly Operation:	168 hours/week
Yearly Operation:	8736 hours/year
Effective Steaming Time:	24 hours/day

REFUSE DISPOSAL SUMMARY	
Total Weight Disposed:	5,976 tons/year
	115 tons/week
	16 tons/day
Total Volume Disposed:	25,295 cuy/year

DISPLACED FUEL SUMMARY	
Displaced Fuel Type:	residual oil
Amount Displaced:	34,544 MBtu/year
	230,772 gallons/year
	634 gallons/day
	26.42 gallons/hour

** NOTE: MBtu means MILLIONS of Btu's.

Session Number: 1

SUMMARY OF INPUTS	
INSTALLATION NAME:	Picatinny Arsenal
REGION:	2
WASTE TYPE:	2
HEAT CONTENT:	4500
*WASTE QUANTITY:	5976 tpy
DAYS/WEEK:	7
SHIFTS/DAY:	3
LANDFILL LIFE:	15 years
LANDFILL REPLACEMENT COST:	$0
*LANDFILL COSTS:	$100.00 /ton
FUEL TYPE:	natural gas
*FUEL COSTS:	$2.90/MBtu
AUXILIARY FUEL TYPE:	natural gas
*AUXILIARY FUEL COSTS:	$2.90/MBtu
*ELECTRICITY COSTS:	7.6 ¢/KWh

* Value given differs significantly from the table value.
** NOTE: MBtu means MILLIONS of Btu's.

SUMMARY OF OUTPUTS	
TONS PER 7 DAY WEEK OF WASTE:	115 tons/week
INDIVIDUAL INCINERATOR CAPACITY:	10 tons
NUMBER OF INCINERATORS REQUIRED:	2
TOTAL FACILITY CAPACITY:	20 tons/day
CAPITAL COSTS:	$62,834/ton
APC CAPITAL COST:	$0/ton
HRI CONSTRUCTION COSTS:	$1,256,680
O&M COSTS:	$25/ton
HRI O&M COSTS:	$149,400/year
LANDFILL SAVINGS:	$358,560/year
HEAT PRODUCTION:	27,635 MBtu/yr
FUEL COSTS:	$2.90/MBtu
AUXILIARY FUEL COST:	$2.90/MBtu
ELECTRICITY COST:	$22.27/MBtu
ENERGY RECOVERY FACTOR:	87.0%
NUMBER OF HOURS OPERATIONAL:	168 hours/week
NUMBER OF MBtu OF FUEL NEEDED PER TON OF WASTE BURNED:	0.249 MBtu/ton
GROSS FUEL SAVINGS:	$92,118.12/yr
YEARLY AUXILIARY FUEL COSTS:	$4,311.91/yr
YEARLY AUXILIARY FUEL QUANTITY:	1,487 MBtu/yr
YEARLY ELECTRICITY COSTS:	$17,259.64/yr
YEARLY ELECTRICITY QUANTITY:	775 MBtu/yr
NET FUEL SAVINGS:	$70,547/yr

** NOTE: MBtu means MILLIONS of Btu's.

STEAM SUPPLY SUMMARY

Total Amount of Steam Produced:	27,635 MBtu/year
Yearly Amount of Steam Produced:	27,635,434 lb/year
Daily Amount of Steam Produced:	75,922 lb/day
Hourly Amount of Steam Produced:	3,163 lb/hour

AUXILIARY FUEL REQUIREMENTS

Auxiliary Fuel Type:	natural gas
Fuel Requirements:	1,487 MBtu/year
Yearly:	1,442 Kcuft/year
Daily:	3.96 Kcuft/day
Hourly:	0.17 Kcuft/hour

OPERATING SCHEDULE SUMMARY

Incinerator Operation:	7 days/week
	3 shifts/day
Daily Operation:	24 hours/day
Weekly Operation:	168 hours/week
Yearly Operation:	8736 hours/year
Effective Steaming Time:	24 hours/day

REFUSE DISPOSAL SUMMARY

Total Weight Disposed:	5,976 tons/year
	115 tons/week
	16 tons/day
Total Volume Disposed:	25,295 cuy/year

DISPLACED FUEL SUMMARY

Displaced Fuel Type:	natural gas
Amount Displaced:	31,765 MBtu/year
	30,810 Kcuft/year
	85 Kcuft/day
	3.53 Kcuft/hour

** NOTE: MBtu means MILLIONS of Btu's.

Session Number: 4

SUMMARY OF INPUTS	
INSTALLATION NAME:	Picatinny Arsenal
REGION:	2
WASTE TYPE:	2
HEAT CONTENT:	4500
*WASTE QUANTITY:	5976 tpy
DAYS/WEEK:	7
SHIFTS/DAY:	3
LANDFILL LIFE:	15 years
LANDFILL REPLACEMENT COST:	$0
*LANDFILL COSTS:	$100.00 /ton
FUEL TYPE:	natural gas
*FUEL COSTS:	$2.90/MBtu
AUXILIARY FUEL TYPE:	natural gas
*AUXILIARY FUEL COSTS:	$2.90/MBtu
*ELECTRICITY COSTS:	7.6 ¢/KWh

* Value given differs significantly from the table value.
** NOTE: MBtu means MILLIONS of Btu's.

SUMMARY OF OUTPUTS	
TONS PER 7 DAY WEEK OF WASTE:	115 tons/week
INDIVIDUAL INCINERATOR CAPACITY:	10 tons
NUMBER OF INCINERATORS REQUIRED:	2
TOTAL FACILITY CAPACITY:	20 tons/day
CAPITAL COSTS:	$62,834/ton
APC CAPITAL COST:	$14,281/ton
HRI CONSTRUCTION COSTS:	$1,542,300
O&M COSTS:	$30/ton
HRI O&M COSTS:	$181,747/year
LANDFILL SAVINGS:	$286,250/year
HEAT PRODUCTION:	27,635 MBtu/yr
FUEL COSTS:	$2.90/MBtu
AUXILIARY FUEL COST:	$2.90/MBtu
ELECTRICITY COST:	$22.27/MBtu
ENERGY RECOVERY FACTOR:	87.0%
NUMBER OF HOURS OPERATIONAL:	168 hours/week
NUMBER OF MBtu OF FUEL NEEDED PER TON OF WASTE BURNED:	0.249 MBtu/ton
GROSS FUEL SAVINGS:	$92,118.12/yr
YEARLY AUXILIARY FUEL COSTS:	$4,311.91/yr
YEARLY AUXILIARY FUEL QUANTITY:	1,487 MBtu/yr
YEARLY ELECTRICITY COSTS:	$36,007.54/yr
YEARLY ELECTRICITY QUANTITY:	1,617 MBtu/yr
NET FUEL SAVINGS:	$51,799/yr

** NOTE: MBtu means MILLIONS of Btu's.

STEAM SUPPLY SUMMARY

Total Amount of Steam Produced:	27,635 MBtu/year
Yearly Amount of Steam Produced:	27,635,434 lb/year
Daily Amount of Steam Produced:	75,922 lb/day
Hourly Amount of Steam Produced:	3,163 lb/hour

AUXILIARY FUEL REQUIREMENTS

Auxiliary Fuel Type:	natural gas
Fuel Requirements:	1,487 MBtu/year
Yearly:	1,442 Kcuft/year
Daily:	3.96 Kcuft/day
Hourly:	0.17 Kcuft/hour

OPERATING SCHEDULE SUMMARY

Incinerator Operation:	7 days/week
	3 shifts/day
Daily Operation:	24 hours/day
Weekly Operation:	168 hours/week
Yearly Operation:	8736 hours/year
Effective Steaming Time:	24 hours/day

REFUSE DISPOSAL SUMMARY

Total Weight Disposed:	5,976 tons/year
	115 tons/week
	16 tons/day
Total Volume Disposed:	25,295 cuy/year

DISPLACED FUEL SUMMARY

Displaced Fuel Type:	natural gas
Amount Displaced:	31,765 MBtu/year
	30,810 Kcuft/year
	85 Kcuft/day
	3.53 Kcuft/hour

** NOTE: MBtu means MILLIONS of Btu's.

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