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PERFORMANCE ANALYSIS OF THE JERSEY CITY TOTAL ENERGY SITE: FINAL REPORT

U.S. DEPARTMENT OF COMMERCE
National Bureau of Standards
National Engineering Laboratory
Center for Building Technology
Washington, DC 20234

hudmius

MODULAR INTEGRATED UTILITY SYSTEMS
improving community utility services — supplying electricity, heating, cooling, and water/ processing liquid and solid wastes/ conserving energy and natural resources/ minimizing environmental impact

Prepared for:
Department of Housing and Urban Development
Building Technology Division
Office of Policy Development and Research
Washington, DC 20410

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U.S. DEPARTMENT OF COMMERCE, Malcolm Baldrige, ***Secretary***
NATIONAL BUREAU OF STANDARDS, Ernest Ambler, ***Director***

ABSTRACT

Under the sponsorship of the Department of Housing and Urban Development (HUD), the National Bureau of Standards (NBS) gathered engineering, economic, environmental, and reliability data from a 486 unit apartment/commercial complex located on a 6.35 acre (2.6 hectare) site in Jersey City, New Jersey. The complex consists of four medium to high rise apartment buildings, a 46,000 ft^2 (4300 m^2) commercial building, a school (kindergarten through third grade), a swimming pool, and a central equipment building.

The construction of the complex was started in 1971, and a decision was made by HUD to design the central equipment building to meet both the thermal and electrical energy demands of the site. The necessary equipment was installed to recover the waste heat from diesel engines driving the generators making the central equipment building a total energy (TE) plant. Absorption type chillers were also installed in the central equipment building. This TE plant has been serving the complex since January 1974.

The National Bureau of Standards was responsible for designing and installing the instrumentation and a data acquisition system (DAS) to determine fundamental engineering data from the plant and site buildings. The DAS was put on line in April 1975. The raw data from the DAS was processed by a minicomputer at NBS to obtain a broad spectrum of engineering results. This report describes these systems and presents the appropriate data and a performance analysis of the plant and site. The analysis of the data indicates a significant savings in fuel is possible by minor modifications in plant procedures.

This report also includes the results of an analysis of the quality of utility services supplied to the consumers on the site and an analysis of a series of environmental tests made for the effects of the plant on air quality and noise. In general, these analyses reflected favorable results for the total energy plant.

Economic and energy analyses are presented for the plant as operated during the period of the study and on a comparative basis with twelve alternative system designs applicable for providing the tenants on the site with equivalent utility services. In general, although those systems utilizing the total energy concept showed a significant savings in fuel, such systems do not represent attractive investments compared to conventional systems, with fuel costs of 1977.

Key Words: Absorption chiller; boiler performance; diesel engine performance; engine-generator efficiency; integrated utility system; total energy systems-economic and engineering analysis; waste heat recovery.

DISCLAIMER

Certain commercial equipment, names, and instrumentation are identified by name in this report in order to adequately describe the capabilities and technical features of hardware use in this project. In no case does such identification imply recommendation or endorsement by the National Bureau of Standards, nor does it imply that the material or equipment identified is necessarily the best available for the purpose.

SI CONVERSIONS

In view of the presently accepted practice of the building industry in the United States and the structure of the computer software used in this project, common U.S. units of measurement have been used in this report. In recognition of the United States as a signatory to the General Conference of Weights and Measures, which gave official status to the SI system of units in 1960, appropriate conversion factors have been provided in the table below. The reader interested in making further use of the coherent system of SI units is referred to: NBS SP330, 1972 Edition, "The International System of Units," or E380-72, ASTM Metric Practice Guide (American National Standard Z210.1).

Metric Conversion Factors

Length	1 inch (in) = 25.4 millimeters (mm) 1 foot (ft) = 0.3048 meter (m)
Area	1 ft^2 = 0.092903 m^2
Volume	1 ft^3 = 0.028317 m^3
Temperature	F = 9/5 C + 32
Temperature Interval	1 F = 5/9 C or K
Mass	1 pound (lb) = 0.453592 kilogram (kg)
Mass Per Unit Volume	1 lb/ft^3 = 16.0185 kg/m^3
Energy	1 Btu = 1.05506 kilojoules (kJ)
Specific Heat	1 Btu/[(lb)(°F)] = 4.1868 kJ/[(kg)(K)]
Gallon	1 gallon = 0.0037854 m^3

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1. INTRODUCTION

The thermal energy normally wasted in the generation of electrical power and the potential for the recovery and use of this energy for heating and cooling are widely recognized. In the most efficient electrical generation systems, only 40 percent or less of the energy in the coal, oil, or gas is converted into electrical energy. The remaining 60 percent or more of the input is usually rejected into the environment as waste heat.

In the total energy (TE) concept, efforts are made to recover this normally wasted heat and utilize it for space heating, domestic hot water, and space cooling using absorption-type chillers. The use of this normally wasted heat conserves the additional conventional energy normally required to meet these needs. Since the total energy concept requires the generation of electrical power to be near the area of the utilization of the waste heat, the application of on-site electrical generation systems is encouraged.

1.1 TOTAL ENERGY DEVELOPMENT IN THE UNITED STATES

The general history of the TE concept in the United States is fairly well known. The decade 1962 through 1971 saw the installation of approximately 500 TE plants. Intense promotion by natural-gas utilities was a major factor in this development. Many of the early TE installations were in gas company facilities to familiarize gas utility engineers with the equipment and to "demonstrate" the concept. As late as 1969, one-quarter of all TE installations were still in buildings and plants owned by gas utilities. Gas industry interest was spurred by the need to equalize the seasonal demand for gas by creating a year-round load. Also it was hoped that TE would provide an effective means of combating promotion of the all-electric building concept by the electric utilities.

Since 1972, little promotion of TE has occurred by the gas industry primarily due to growing concern about unavailability of natural gas supplies. The petroleum industry had not mounted a strong TE market development effort in part because natural gas held a significant economic advantage over oil in most areas. Equipment manufacturers likewise had not developed a strong promotional force for TE largely because TE represented a small part of their business and/or the conventional (non-TE) equipment could also be supplied by the same manufacturers. In the last ten years then, private-sector promotion and development of the TE concept has largely waned. The 'energy crisis' and increased interest in energy conservation has again spurred interest in Total Energy - this time largely as part of the Federal R&D activities.

It is of interest to recap the experience of TE development as it stood in 1971-72. TE plants were typically small - by 1972, 40 percent of all installations were under 600 kW total capacity although larger plants were increasingly becoming the norm. Counting the "captive" gas company installations, three-quarters of all TE installations served industrial or commercial facilities. Residential applications accounted for less than 10 percent of the total.

Natural gas was the principal fuel for TE and was used in over 90 percent of all installations in 1972 [1-2]*.

Although the number of plants installed in the promotional days of TE is impressive, there has been little unbiased feedback in terms of actual operating experience. In particular, there is little identification of the types of problems and their extent so that R&D plans could be formulated. There is, however, some general agreement as to the recurring reasons for TE system problems and failures and the major unanswered technical questions regarding TE:

- maintenance requirements and costs
- viability of unattended or semi-attended operation
- inflexibility to meet changes in level of demand (i.e., expansion of facilities or last-minute changes)
- adequacy of controls and auxiliary equipment reliability

1.2 HUD ROLE IN TOTAL ENERGY

One of the purposes of the U.S. Department of Housing and Urban Development (HUD) is to assist sound development of the Nation's communities and metropolitan areas. The goals are decent housing and a suitable living environment at reasonable cost. Space heating and cooling, domestic water heating, and power for lighting and home appliances are elements of decent housing. Clean air and water and the reduction or elimination of pollution contribute to a suitable living environment. Housing at a reasonable cost demands economy of effort, better use of resources, and correction of wasteful and expensive practices [1-3].

These considerations led HUD in 1969 to sponsor studies of the use of waste heat from central power plants for heating and cooling large cities. This work, conducted by the Oak Ridge National Laboratory, indicated that significant economies could be achieved in this manner if cities were built to conform to the requirements of the power plant and thermal distribution system. Unfortunately, community development does not occur in this way.

The question then is, if cities are not developed to meet power plant requirements, can power plants be developed to match urban growth and still make the most efficient use of energy.

This question led to the examination by HUD of the total energy concept. The interest in the total energy concept by HUD is two-fold. First, on-site power generation (with or without heat recovery) affords the potential to add needed generating capacity at a rate consistent with residential development. Secondly, with heat recovery, i.e., the total energy approach, significant savings in primary fuel consumption can be realized.

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* Numbers in brackets refer to references at the end of each section.

HUD's evaluation of the TE concept could have focused on one or more of the existing 500 TE plants in operation. In 1971 there were 28 separate installations of total energy plants serving residential facilities [1-4]. Four of these were combined residential and shopping center or office building complexes. Of the 24 purely residential installations, nine were luxury rental developments in the Kansas City, Kansas, metropolitan area. A HUD/NBS team visited these plants, the developer, and a maintenance contractor in 1970. Instrumentation of these plants was found to be minimal. Hard data on total capital cost, reliability, energy utilization, operating costs, and maintenance costs were not available. The same was also generally true for the nineteen other plants serving residential facilities.

An alternative to collecting and analyzing spare and suspect data from actual existing plants was the building and operating of a total energy plant for a residential development. By taking such a step, under HUD control and direction, the plant could be fully documented as to cost and problems, from initial concept through long-term operation.

This approach was selected by HUD after careful consideration of all factors involved.

1.3 HISTORY OF JCTE DEMONSTRATION

At the time of HUD's growing interest in TE and the recognition of a need for a full-scale TE demonstration, there was a large-scale program underway at HUD to demonstrate industrialized housing, called OPERATION BREAKTHROUGH. This program had identified eleven sites around the country for potential development and demonstration.

The BREAKTHROUGH sites were owned by HUD and were to be developed under contracts with developers and industrialized housing producers.

The existence of the BREAKTHROUGH program provided an excellent opportunity for HUD to demonstrate Total Energy with a minimum of risk and delay by using one of the BREAKTHROUGH sites. The sites were eventually to be sold by HUD to private sector owners so that operation of the TE plant would be in the overall context of a viable commercial venture.

NBS was deeply involved in the housing technology aspects of BREAKTHROUGH, and, under contract to HUD, was brought into the TE demonstration effort. In April 1970, NBS initiated investigations of the technical aspects of residential TE and the selection of one of the BREAKTHROUGH sites for the HUD demonstration. Two feasibility studies were prepared by NBS evaluating and comparing Total Energy and the conventional systems for six of the BREAKTHROUGH sites [1-5, 1-6].

Based on the results of these studies and other factors, HUD chose the Jersey City BREAKTHROUGH site as the location of the TE Demonstration. The Jersey City site was recommended by NBS partly because it had the largest number of dwelling units of the available sites, high spatial density, and a large amount of commercial space.

Jersey City was also preferred because its relative standing among the available sites improved greatly if oil was considered as the fuel to be used. Also the Jersey City site developer was interested in the use of Total Energy.

HUD sponsored the design of the TE plant at Jersey City. A contract was awarded to Gamze-Korobkin-Caloger (GKC) for complete design and preliminary analysis. NBS prepared a performance specification [1-7] which was referenced in the contract documents for the design. This specification addressed the areas of design equipment, selection, reliability, economics, stability of electrical service, maintenance requirements, noise and vibration control, air pollution control, plant space conditioning, aesthetics, safety, future expansion and quality assurance.

Construction at the Jersey City site started in November 1971 and the TE plant began operations in December 1973 - January 1974. A description of the site and plant are presented in section 2 of this report.

In parallel with site activities, NBS designed and built an instrumentation and data acquisition system and developed the methods and procedures to be used in the evaluation of the demonstration. Preliminary drafts of an evaluation plan were prepared in June 1973 and used to elicit comments from people knowledgeable in research and engineering/design fields related to Total Energy. This included the American Society of Heating, Refrigerating and Air Conditioning Engineers (ASHRAE) task force on Total Energy Systems.

The entire site (TE plant and apartment/commercial buildings) is owned by a private real estate corporation, Starrett Housing Corporation. The site is now known as Summit Plaza. This name will be used throughout this report to designate the entire site, including the energy conversion equipment.

1.4 REFERENCES - SECTION 1

1-1. Echols, H. M., "Problems of Total Energy Systems," Actual Specifying Engineer, pp. 60-63, November 1970.

1-2. Federal Council on Science and Technology, "Total Energy Systems, Urban Energy Systems, Residential Energy Consumption," NTIS #PB-221 374, October 1972.

1-3. U.S. Department of Housing and Urban Development, "Total Energy System," HUD-381-PDR, p. 8, December 1974.

1-4. "Total Energy's Plant Directory," Total Energy, Vol. 9, No. 1, pp. 34-61, January 1972.

1-5. Achenbach, P. R., Coble, J. B., Cadoff, B. C., and Kusuda, T., "A Feasibility Study of Total Energy Systems for BREAKTHROUGH Housing Sites," National Bureau of Standards Report 10402, August 12, 1971.

, J. B. and Achenbach, P. R., "Site Analysis and Field rumentation for an Apartment Application of a Total Energy Plant," ional Bureau of Standards Report NBSIR 75-711, May 1975.

chenbach, P. R. and Coble, J. B. "A Performance Specification for a Total Energy Plant at the Jersey City BREAKTHROUGH I Site," National Bureau of Standards Report 10313, December 28, 1970.

2. SITE DESCRIPTION

2.1 PHYSICAL DESCRIPTION OF THE SITE BUILDINGS

The Summit Plaza site occupies an area of 6.35 acres (2.6 hectares) and contains a central equipment building (CEB), four apartment buildings, an elementary school, a swimming pool, a commerical building, and parking space for the tenants. Figure 2.1 is an aerial view of the site and its surroundings and figure 2.2 is the plan layout of the individual buildings contained on the site.

The commercial building, figure 2.3, is brick-faced, three stories in height, and contains approximately 46,000 ft^2 (4,274 m^2) of rentable area; consisting of 25,500 ft^2 (2369 m^2) of office space and 20,500 ft^2 (1905 m^2) of store space. All commercial store front space is on the first (ground) floor and office space is located on the third floor. The second floor contains a 72-space parking garage which is accessable by a ramp. The main mechanical equipment rooms are located on the first floor. The structure was designed by Beyer, Blinder, and Belle (architects and planners) in collaboration with Langer, Polise (consulting engineers); Zoldas, Silman (Structural Engineers); and Howard Branstan (Lighting Consultant).

The Camci Building, figure 2.3, is 16 stories in height, of modular construction, and contains 150 dwellings units consisting of one and two-bedroom apartments. All dwelling units are located on the second through fifteenth floors.

The first floor (ground level) contains, in addition to the mechanical and electrical equipment rooms, a laundry and entrance lobby. The mail room and additional utility and storage rooms are also located on the ground level. Camci, Inc. and Modular Communities, Inc. were the Building Manufacturer and General Contractor, respectively; utilizing the services of Skidmore, Ownings and Merrill (architects); I.B.S. Industrial Buildings, Inc. (Systems Consultants); Paul Weidlinger (Structural Engineer); and Cosentini Associates (Mechanical Engineers).

The Descon building (figures 2.3 and 2.4) is L-shaped, contains a total of 122 dwelling units, and consists of three distinct sections:

1. The first section (figure 2.3) has six two-floor apartments over a parking area. The upper floor is three floors above ground level.

2. The second section (figure 2.3) has 12 two-floor apartments built above a parking area, automobile drive through passage, and the mechanical and pump room which services all three sections of the Descon building. The upper floor is six floors above ground level.

3. The third section (figure 2.4) is an eleven-story high-rise containing 104 dwelling units (20 of these have 1-1/2 times as much floor area as the other units and 4 have between 2 and 3 times as much floor area).

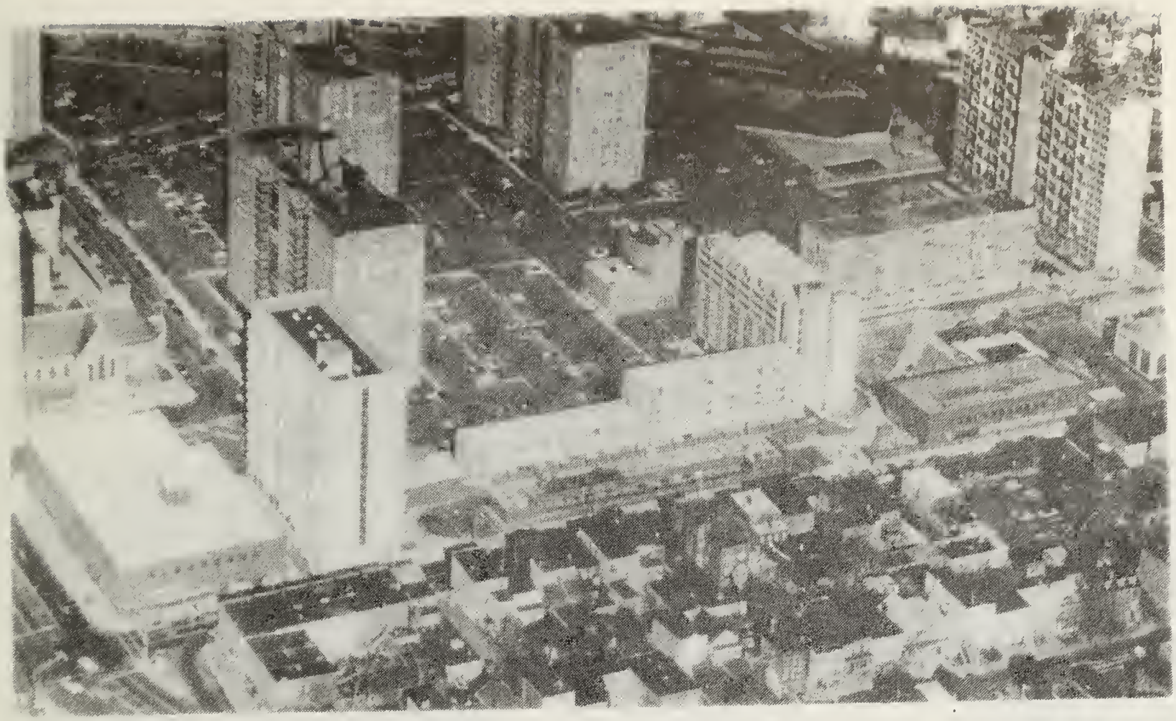

Figure 2.1 Overall view of total energy site

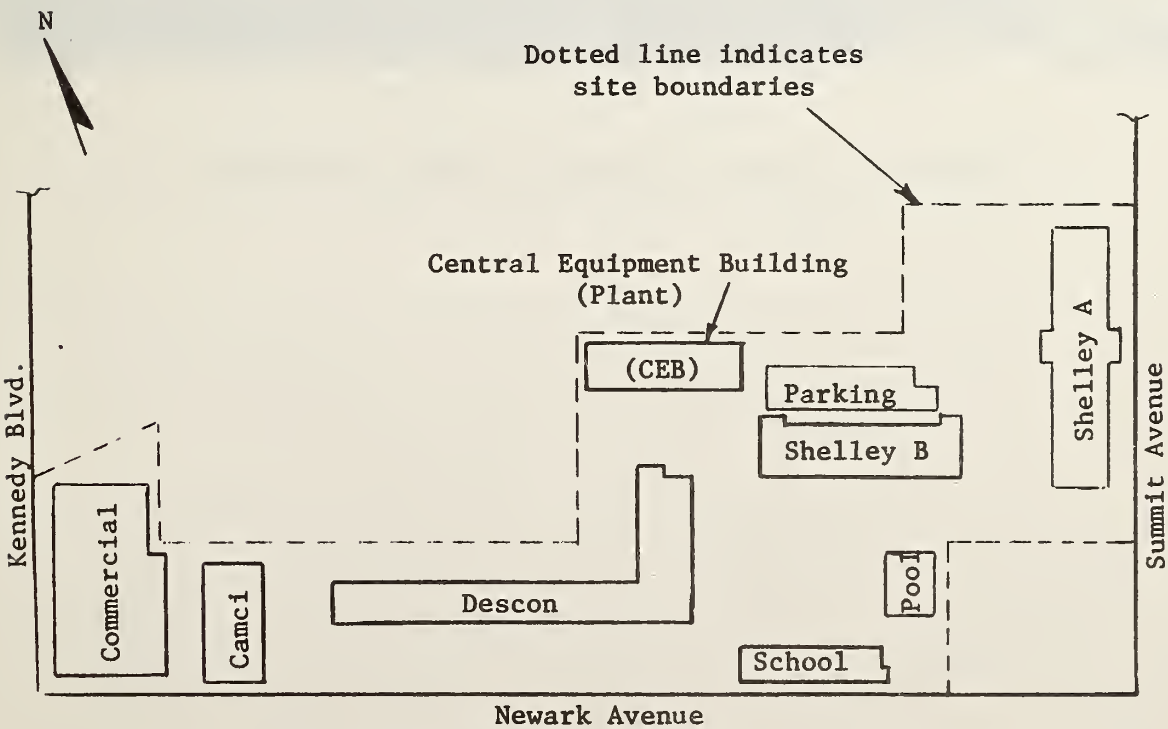

Figure 2.2 Relative location of individual buildings at the Jersey City total energy site

Figure 2.3 Commercial, Camci, and Descon buildings

Figure 2.4 Descon building (11-story section)

This section contains two elevators, a laundry room (on the ground floor), a main electrical equipment room, and an entrance lobby.

The building general contractor was Descon/Concordia Systems, Ltd. with George E. Buchanan, Jr. as architect. Gamze-Korobkin-Caloger and Storch Engineers served as engineering consultants.

The elementary school (figures 2.5 and 2.6) (Preschool through Grade 3) is a brick-faced, two-story structure and contains a small playground adjacent to the building. The building contains approximately 15,700 ft^2 (4790 m^2).

The first floor consists of an auditorium (multi-purpose room), administrative offices, and the mechanical and electrical equipment rooms. The second floor consists of one large open area with movable room dividers which extend to the ceiling. Several offices as well as a kitchen are also located on the second floor. Beyer, Blinder, and Bess served as architects for the building.

The outdoor swimming pool and pavilion (figure 2.6) were designed by Beyer, Blinder, and Bell (architects and planners) with Langes, Polise acting as consulting engineers and Zoldos, Silman as structural engineers.

The swimming pool is 25 ft. wide by 45 ft. long (7.6 m by 14 m) and contains a diving board. The pavilion contains two locker rooms, an instructor's office, storage room, and a mechanical and electrical equipment room. The entire pool is surrounded by either the pavilion, a brick-faced fence, or a metal-type fence.

Shelley B (figure 2.7) is nine stories in height with eight floors above ground and one below. The building contains 40 two-story dwelling units and four levels of lighted parking area. All dwelling units are located on the fourth through the ninth floors. The mechanical and electrical equipment rooms are on the second and third floors. The second floor (ground level) contains an entrance foyer and access to the elevator. Shelley B is of modular construction and was designed by Shelley Systems, Inc.

Shelley A (figure 2.7) contains 18 stories above ground and has 152 dwelling units, a laundry, entry foyer, and space for up to 14 store-front offices. A basement area contains the mechanical and electrical equipment necessary to service the building. This building is the tallest (and largest) building on the site and is served by two elevators. The Shelley A building is of modular construction and was designed by Shelley Systems, Inc.

The three-story central equipment building (CEB) (figure 2.8) contains all of the equipment necessary to produce and control the electrical and thermal energy required by the Summit Plaza site. In addition, the CEB contains facilities for collecting and processing site refuse. An office and rest room area is located on an upper level of the building. The details of the various systems and components contained in the CEB are described in the following section.

Figure 2.5 Elementary school

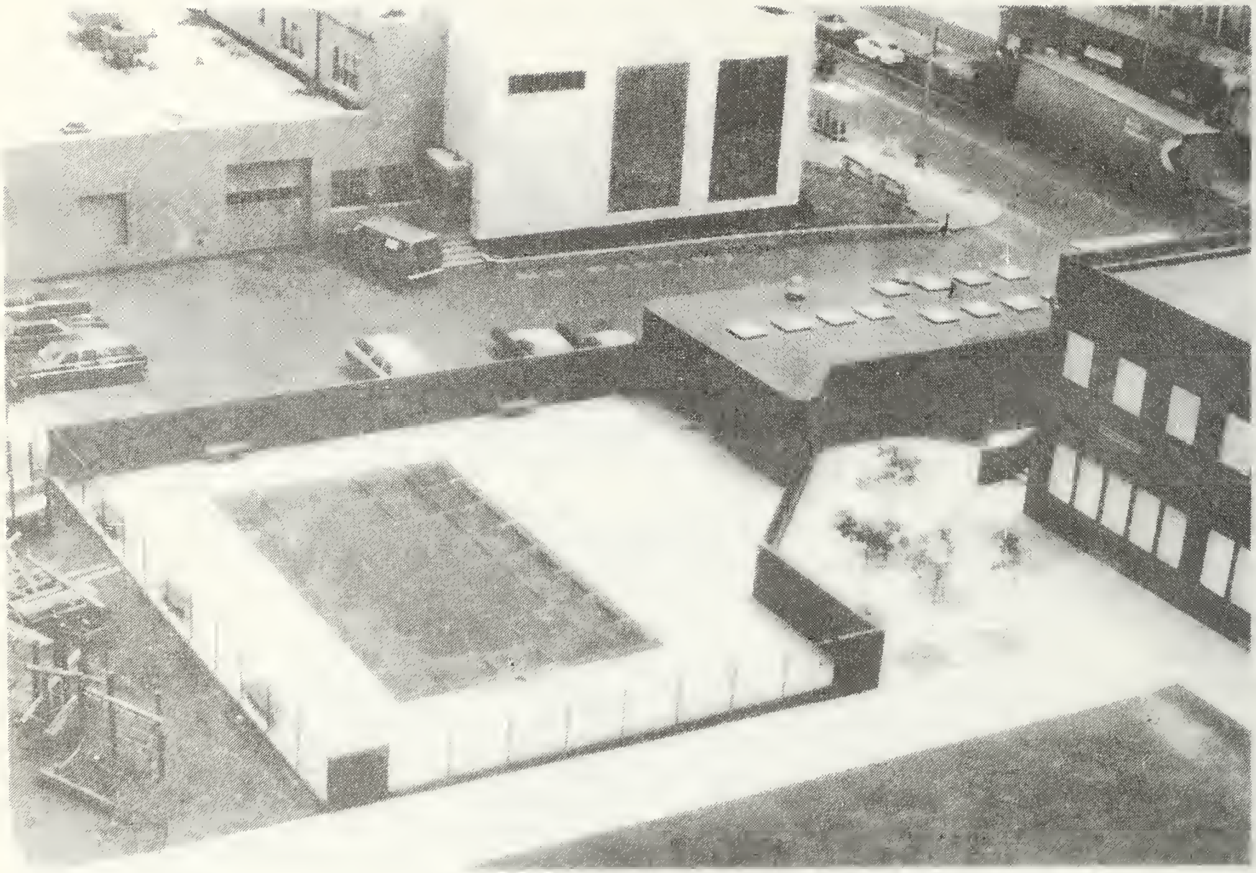

Figure 2.6 Elementary school, swimming pool, and pavilion

Figure 2.7 Shelley "A" and Shelley "B" buildings

Figure 2.8 Central equipment building

2.2 PHYSICAL DESCRIPTION OF THE PLANT

The Total Energy plant is housed in the three-story central equipment building (figure 2.8). Electrical power is generated by five Caterpillar 600 kW diesel engine-generators (figures 2.9 and 2.10). Thermal energy for space heating and domestic hot water production is recovered from both the water jackets of the engines and from their exhausts. Supplementary thermal energy is supplied by two Cleaver-Brooks 1.34 MBtu per hour (4.0 MW) hot-water boilers (figure 2.11). During the air-conditioning season, the thermal energy is also used by two Trane 546 ton (6.6 MBtu per hour) (1.9 MW) absorption chillers (figure 2.12) to produce chilled water. The engines and boilers both burn No. 2 fuel oil which is stored in three 25,000 gallon (95 m^3) underground tanks. The total energy plant was designed to be completely automatic, allowing for unattended overnight and weekend operation. Figures 2.13 and 2.14 show the CEB control room and the master control panel, respectively. During the period of this study, the plant was operated by Gamze-Korobkin-Caloger, Inc., Chicago, Illinois, under contract to HUD. Figure 2.15 illustrates the physical relationship of the various mechanical and electrical components making up the CEB.

Heat is recovered from the engine-generators and utilized in a primary hot water (PHW) loop (figure 2.16). Primary hot water at a temperature ranging from 180°F to 230°F (82°C to 110°C) is pumped at a rate of approximately 11,000 pounds (5000 kg) per minute, transferring heat from the engines and boilers to the chillers and site hot water system. From the engines, the PHW passes through two 25 hp (19 kW) circulation pumps and then through the boilers where additional heat can be added if necessary. During the summer the PHW is routed through the two 546 ton (1.9 MW) absorption chillers which provide 45°F (7°C) chilled water for the site. The PHW then passes through two water-to-water heat exchangers transferring heat to the site secondary hot water system. When both heating and cooling demands are extremely low, a forced-circulation, dry-surface heat exchanger (dry coolers) (figure 2.17) releases the excess PHW heat to the atmosphere to control the upper limit of the PHW temperature. An emergency water-to-water heat exchanger can also release excess PHW heat.

Electricity, hot water, and chilled water are delivered to the site via underground conduits. Two sets of 480-volt, three-phase feeders (one normal and one essential bus) are used for electric power distribution to each site building. In the event of a complete total energy plant electrical outage, power is automatically supplied from the local utility only to the essential bus network to preserve operation of emergency lighting, fire protection systems, and at least one elevator in each building. Hot and chilled water are circulated by a four-pipe system (hot water supply and return, and chilled water supply and return). Heat exchangers in the buildings transfer heat to and from building loops designed for space heating and cooling and domestic hot water production. A more complete description of the plant is provided in reference [2.1].

Figure 2.9 All five of the 600 kW engine-generators

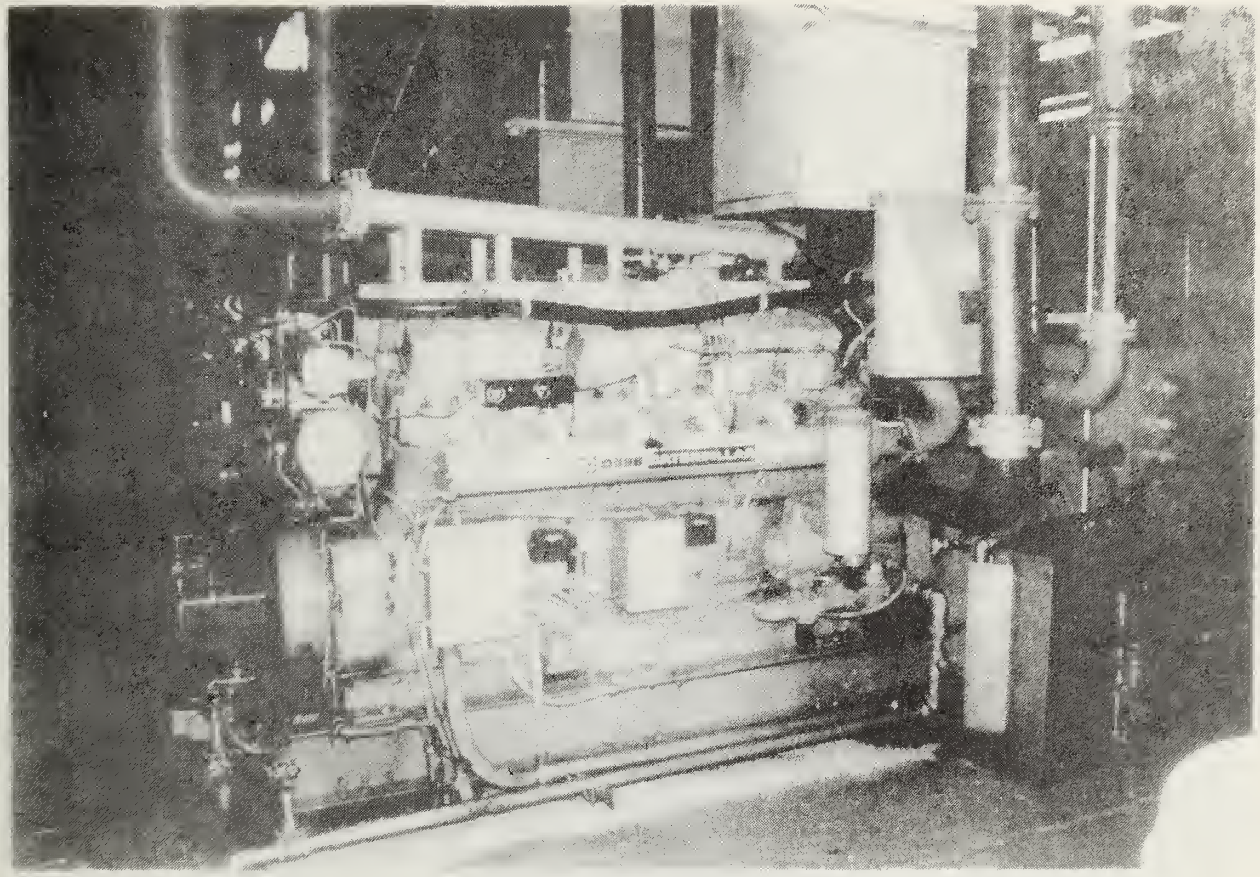

Figure 2.10 One of the five 600 kW engine-generators

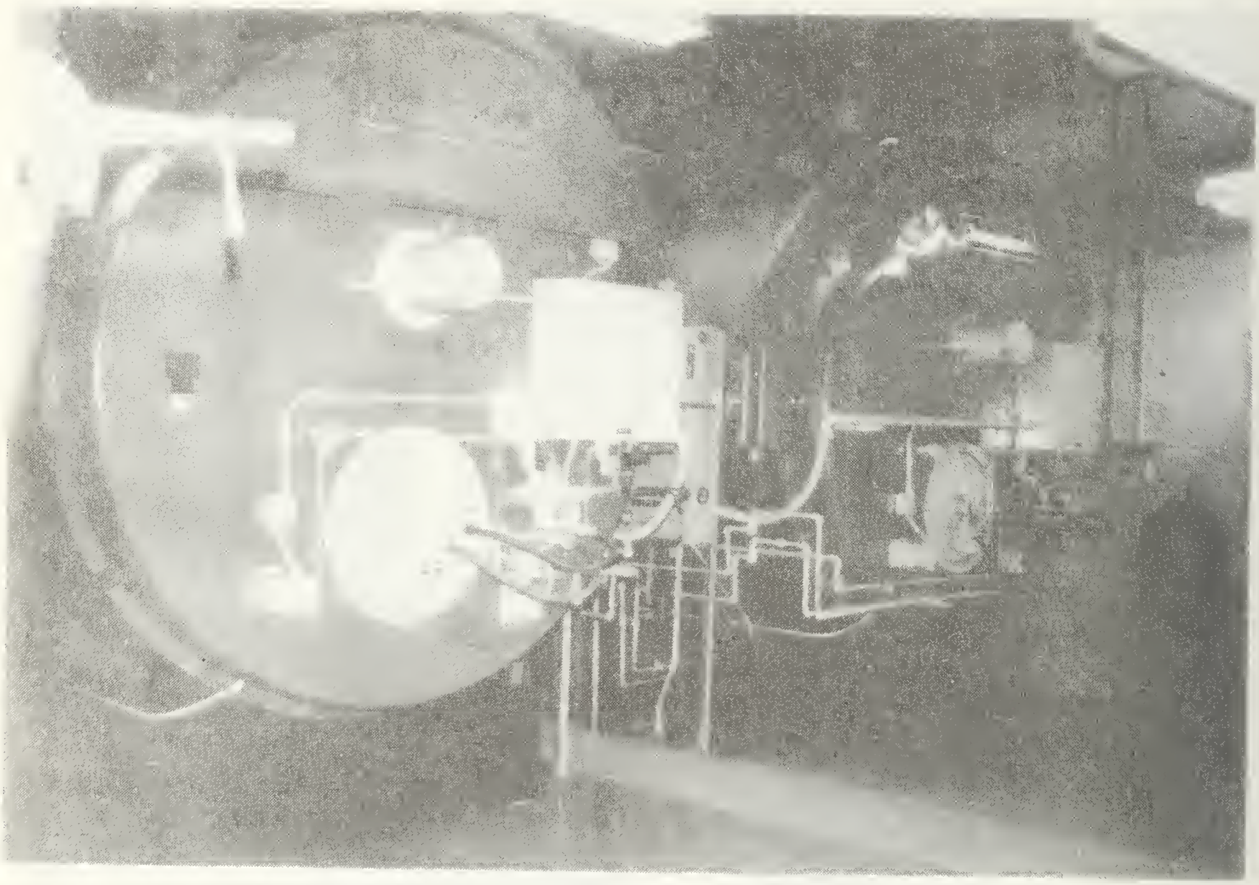

Figure 2.11 Two 13.4 MBtu per hour (4.0 MW) fire-tube hot water boilers

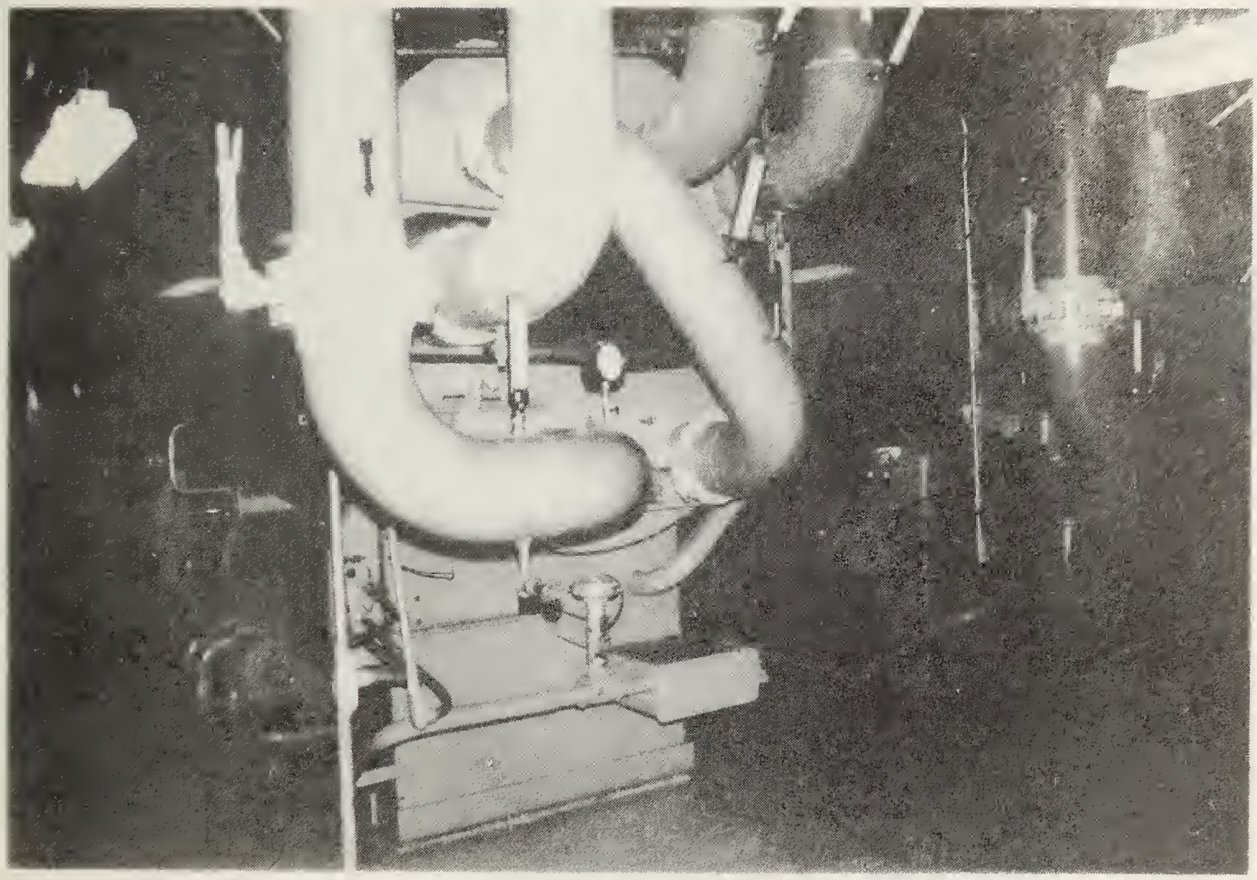

Figure 2.12 Two 546-ton (1.9 MW) absorption-type chillers

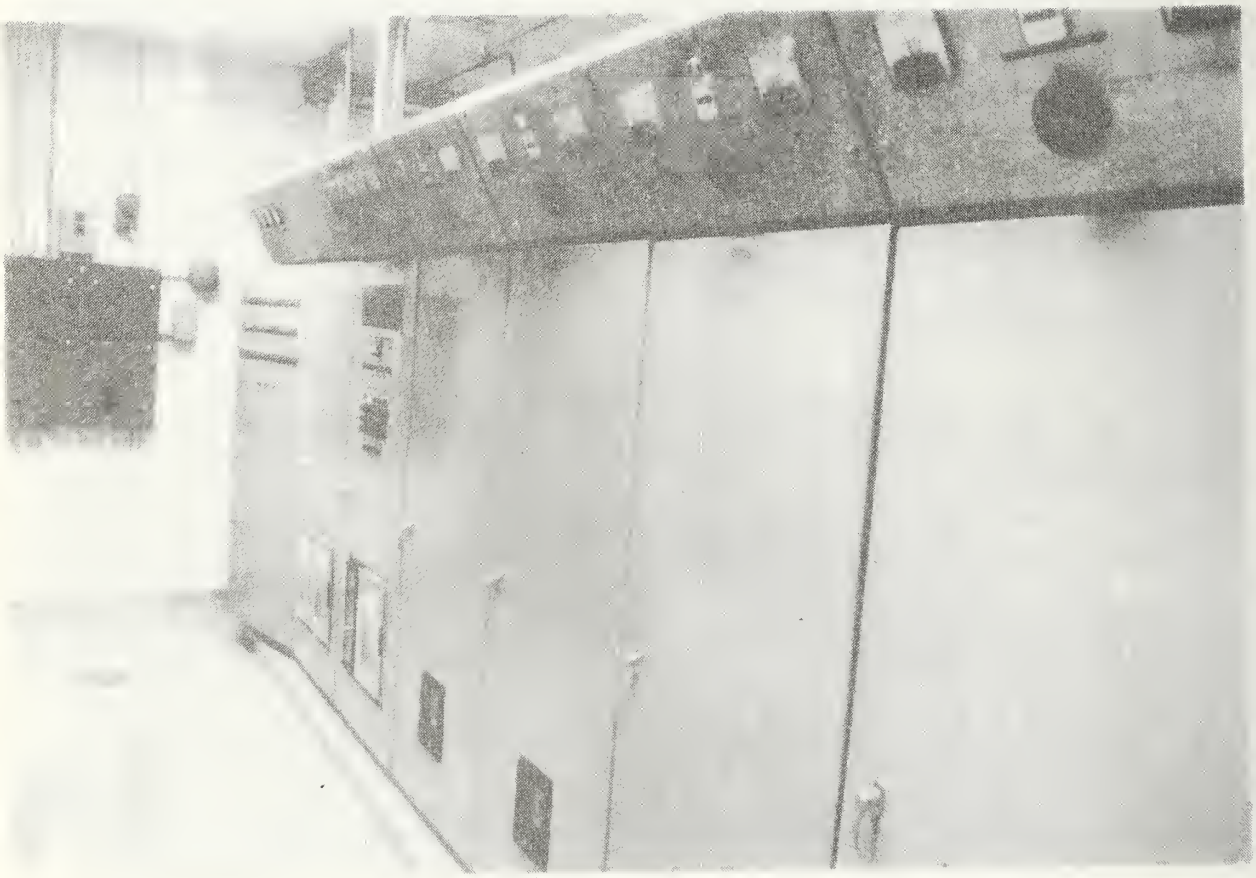

Figure 2.13 Central equipment building control room

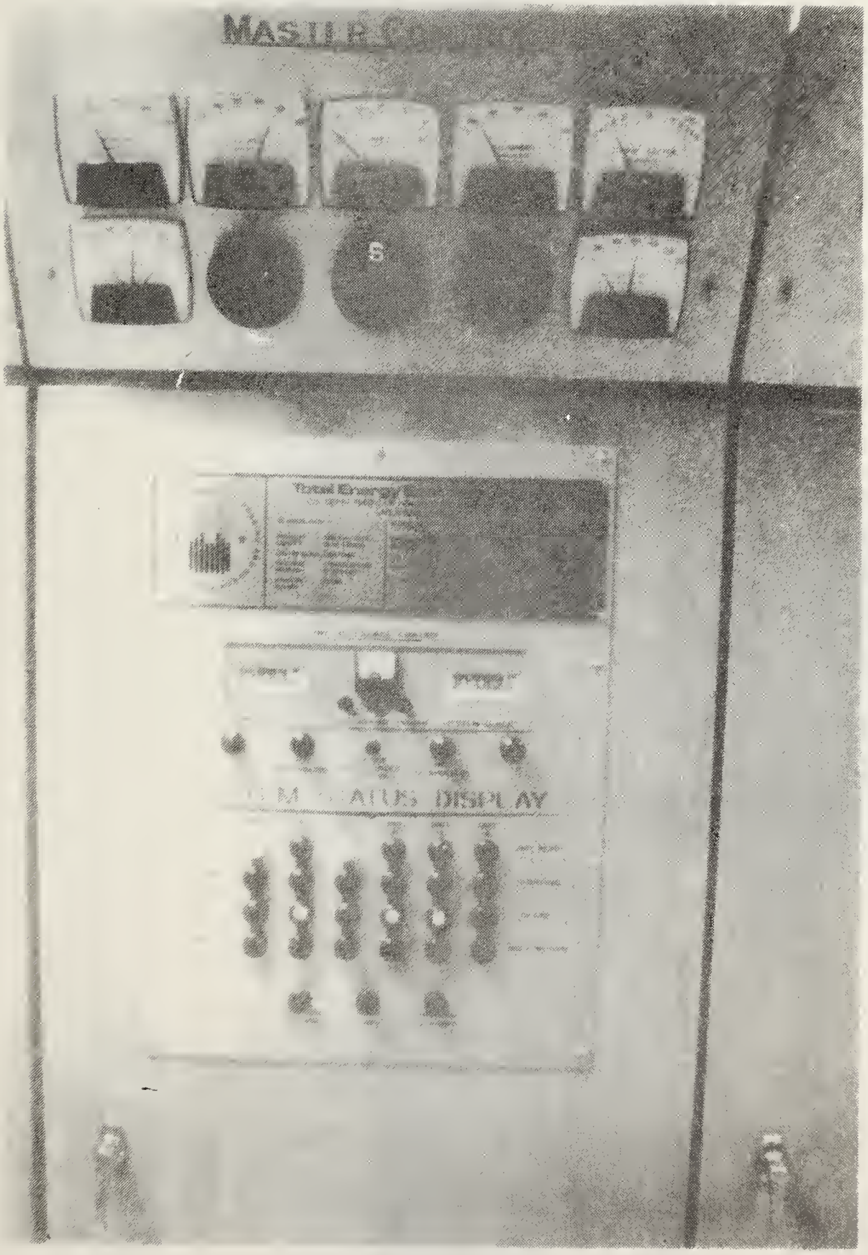

Figure 2.14 Master control panel

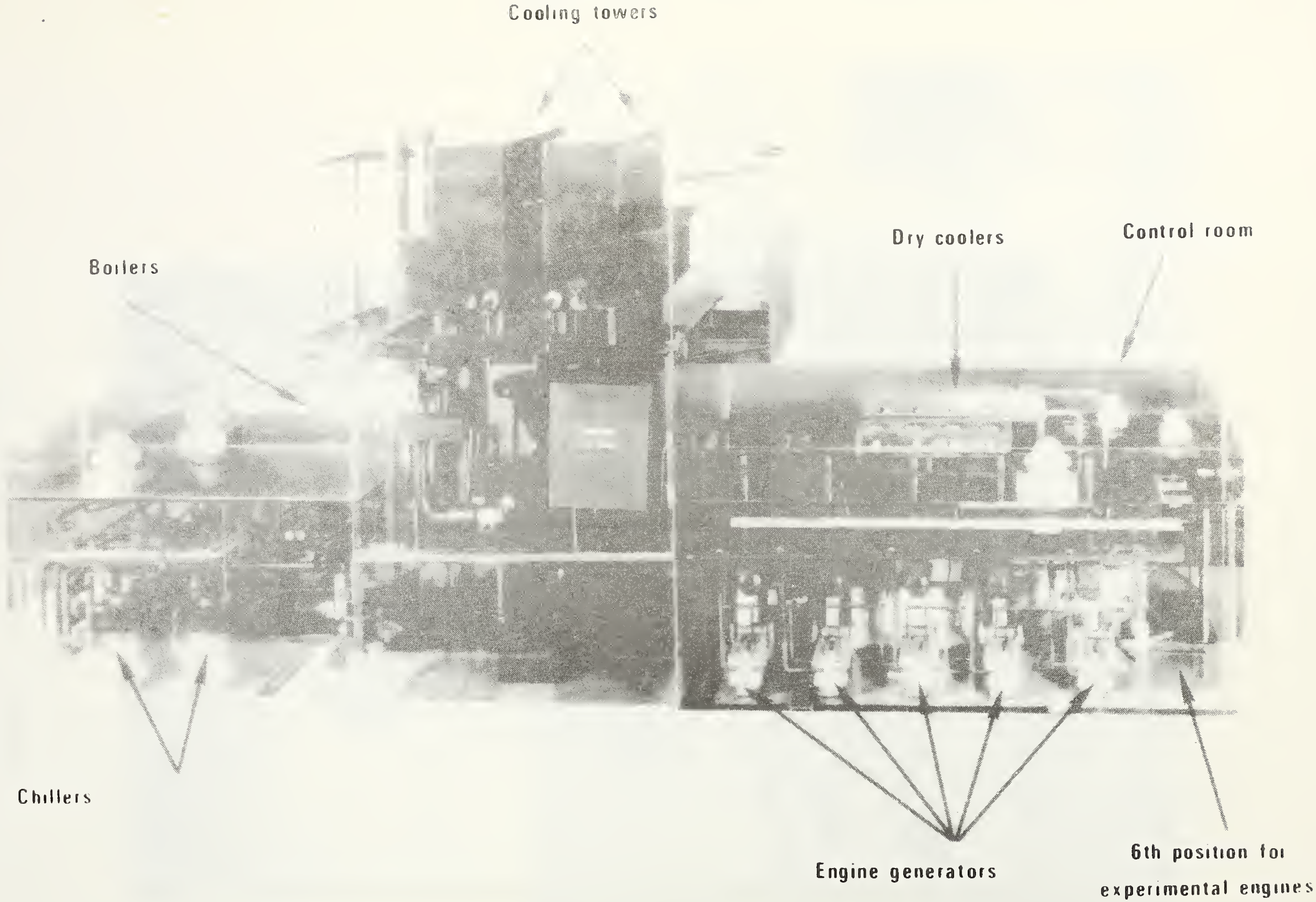

Figure 2.15 Scale model of the central equipment building

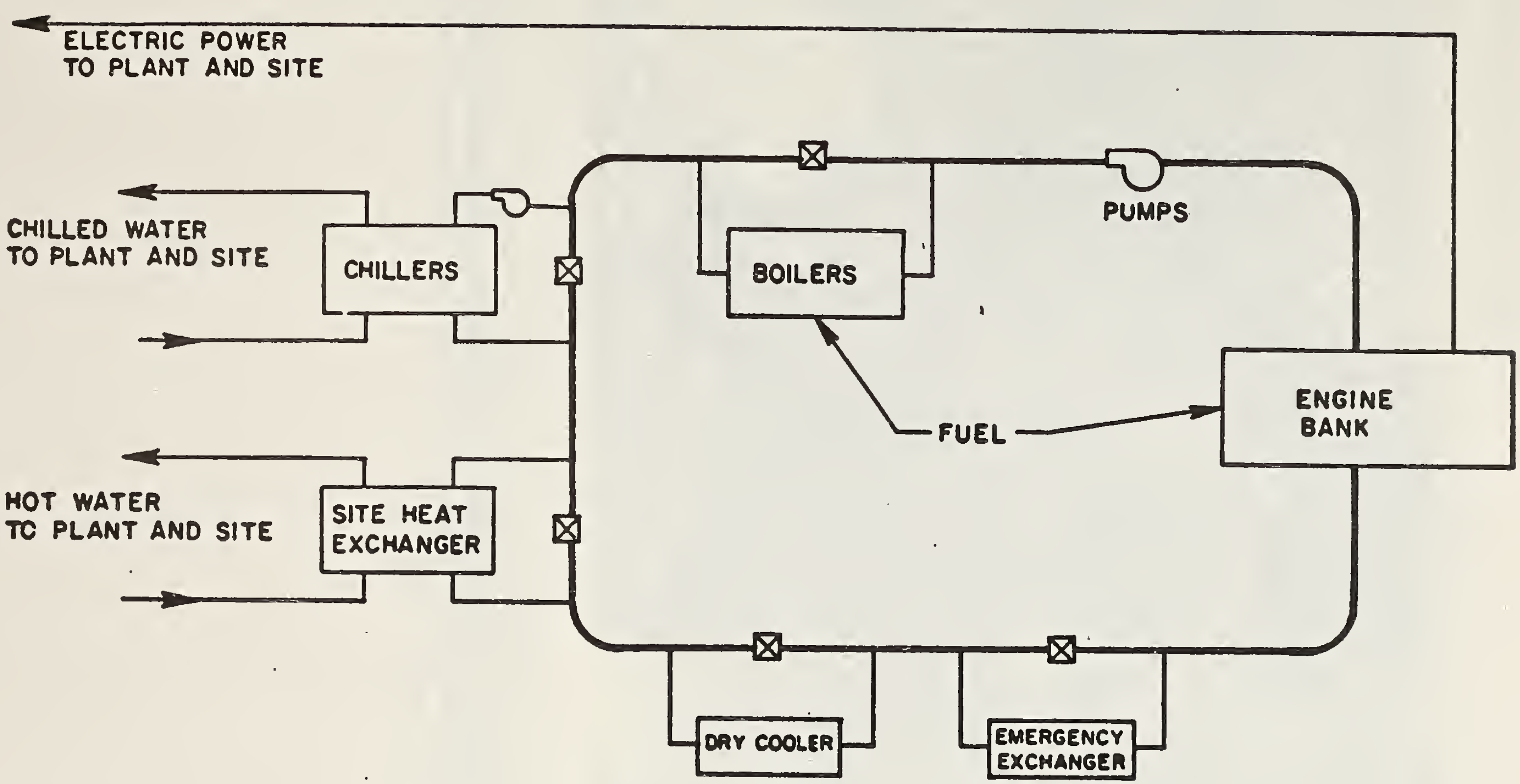

Figure 2.16 Schematic of the primary hot water loop

Figure 2.17 The central equipment building roof showing the cooling towers and the dry coolers for control of PHW and engine lubricating oil temperatures

2.3 PNEUMATIC TRASH COLLECTION SYSTEM

The site is equipped with a pneumatic trash collection system (PTC) which pulls trash from the site buildings into a single, compactor-type receptacle located in the central equipment building. This system consists of a collector chute in each building which holds accumulated refuse until such time that the controls (located in the CEB) (figure 2.18) are actuated to transfer the trash to the CEB. Once the request (automatic or manual) for transfer is made, one of two 150 hp (112 kW) exhausters (figure 2.19) is started. This motor is only started if sufficient on-line reserve electrical power exists in the electrical plant. If sufficient power does not exist, an additional engine-generator is automatically started and put on-line before the exhauster is started.

Trash is transferred in sequential order from the individual buildings through a tube to a holding hopper in the CEB. This transfer takes place through the movement of air (caused by a partical vacuum on the CEB end) created by the exhauster in the transfer pipe. Figure 2.20 shows the end of the trash holding hopper in the CEB. When the trash transfer is complete, the exhauster is automatically turned off and the electrical generating plant returns to its normal reserve condition.

The next stage of the trash sequence consists of its compaction into specially designed containers for subsequent transfer off of the site. These containers are mounted on tracks to facilitate positioning.

Figure 2.21 shows the trash compactor (which is located in the CEB below the hopper) and figure 2.22 shows the CEB loading dock with the containers ready for pickup.

2.4 REFERENCES - SECTION 2

2-1. Gamze-Korobkin-Caloger, Inc., "Final Report, Design and Installation, Total Energy Plant - Central Equipment Building, Summit Plaza Apartments, Operation BREAKTHROUGH Site, Jersey City, New Jersey," HUD Utilities Demonstration Series, Vol. 12, February 1977.

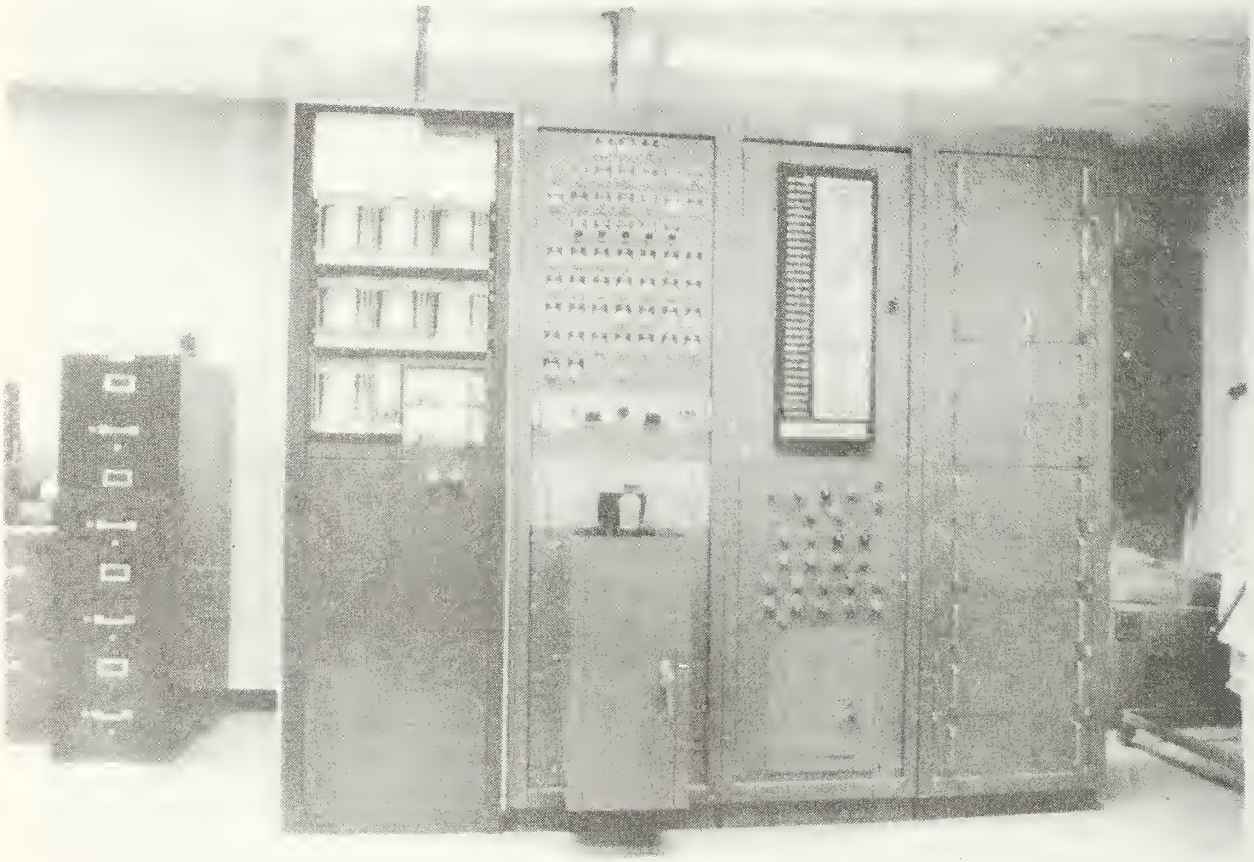

Figure 2.18 Pneumatic Trash Collection master control panel

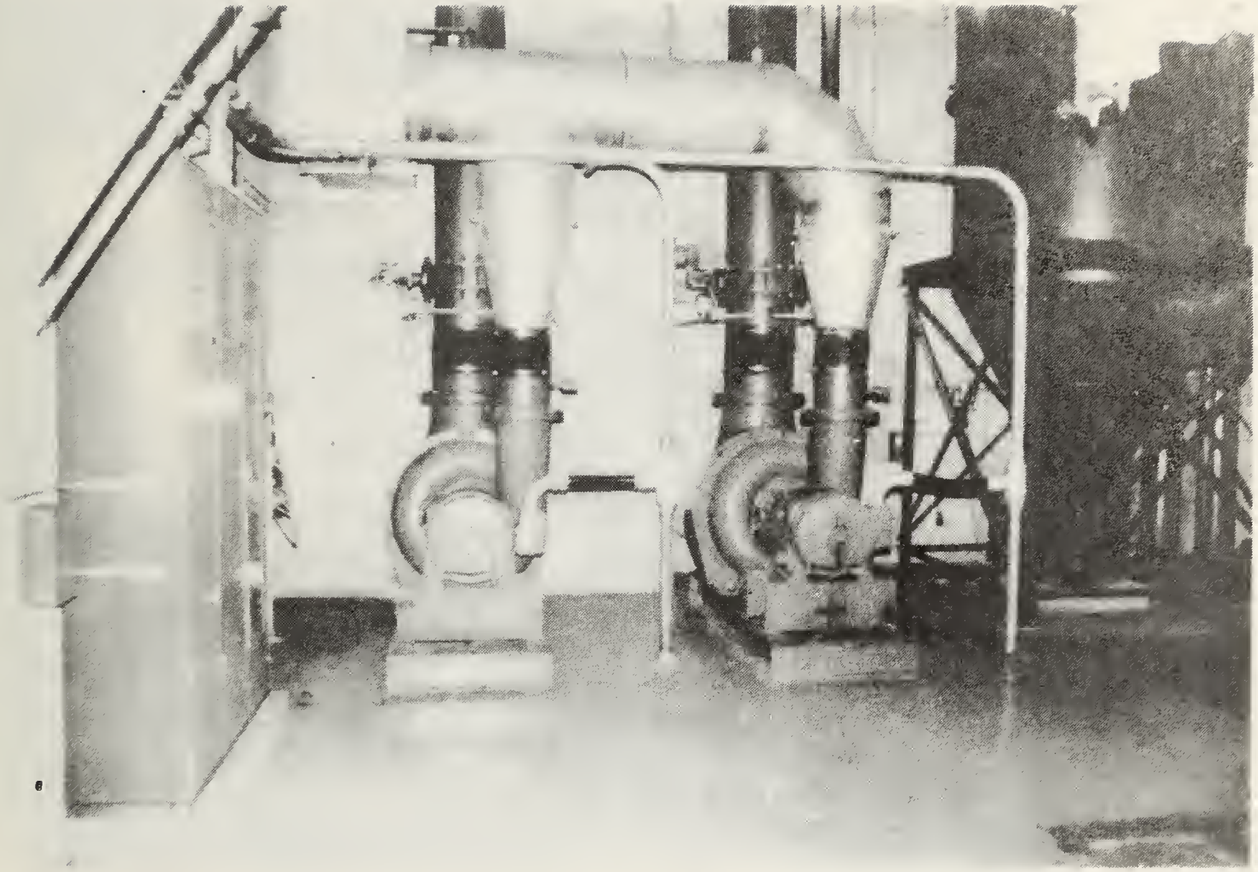

Figure 2.19 Two Pneumatic Trash Collection 150 hp (112 kW) exhausters

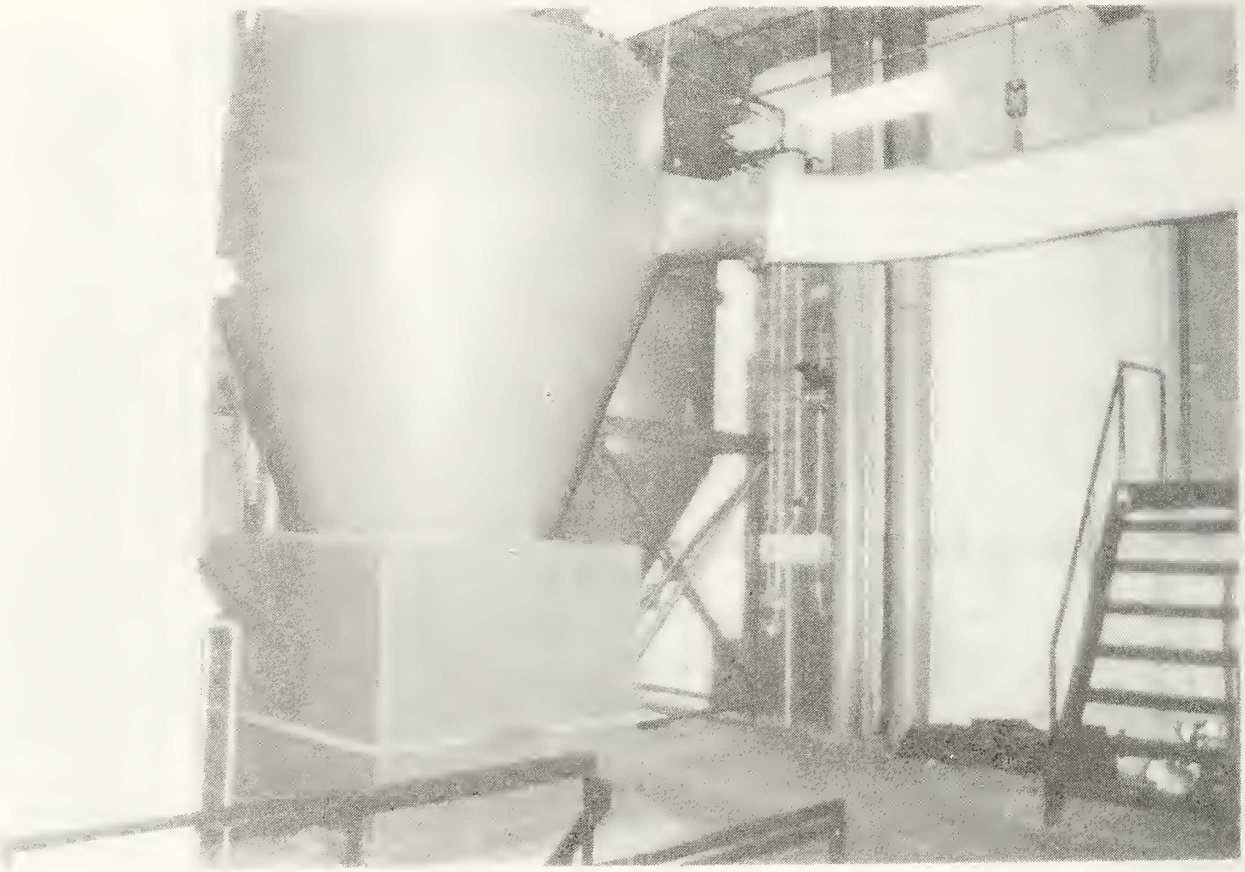

Figure 2.20 Air separator and trash holding hopper in the central equipment building

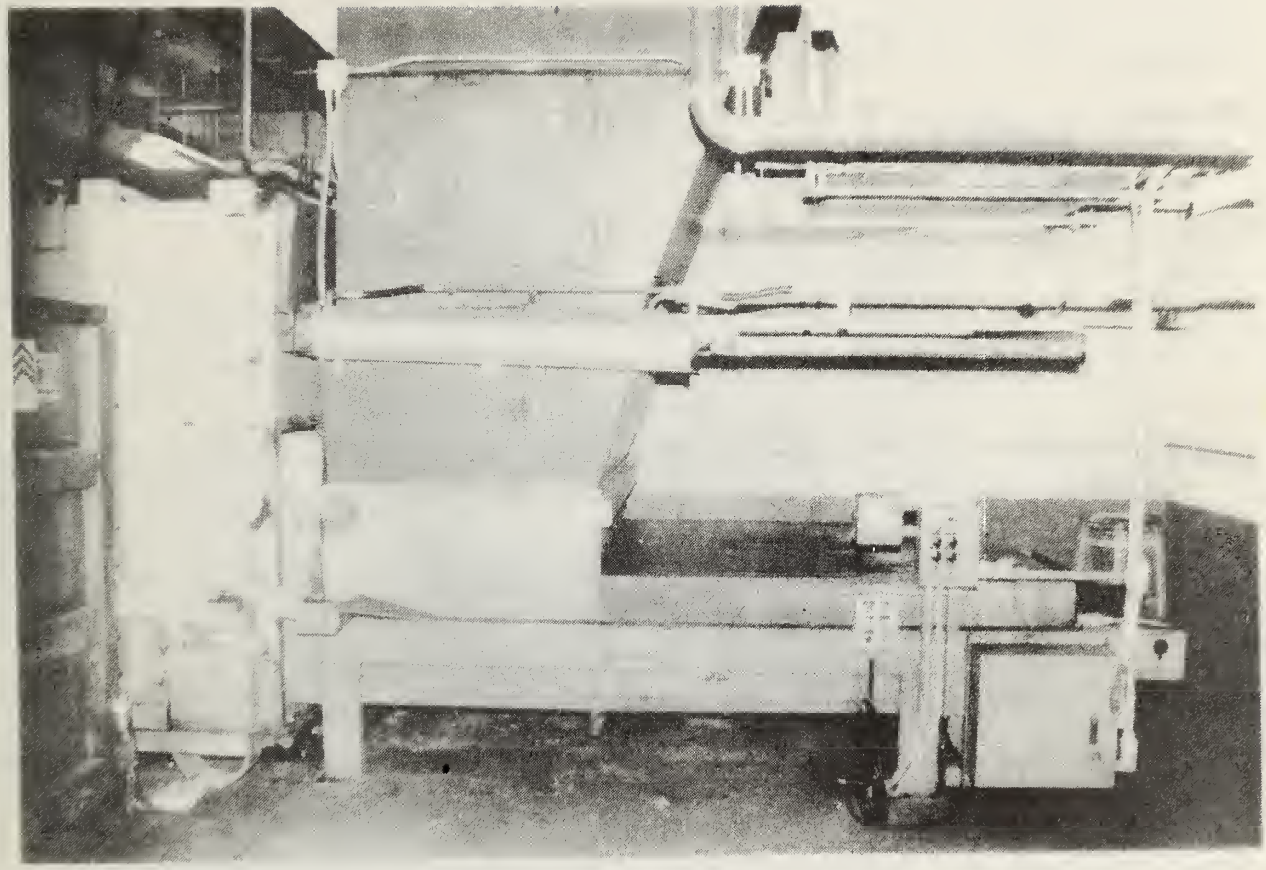

Figure 2.21 The trash hopper and compactor located in the central equipment building

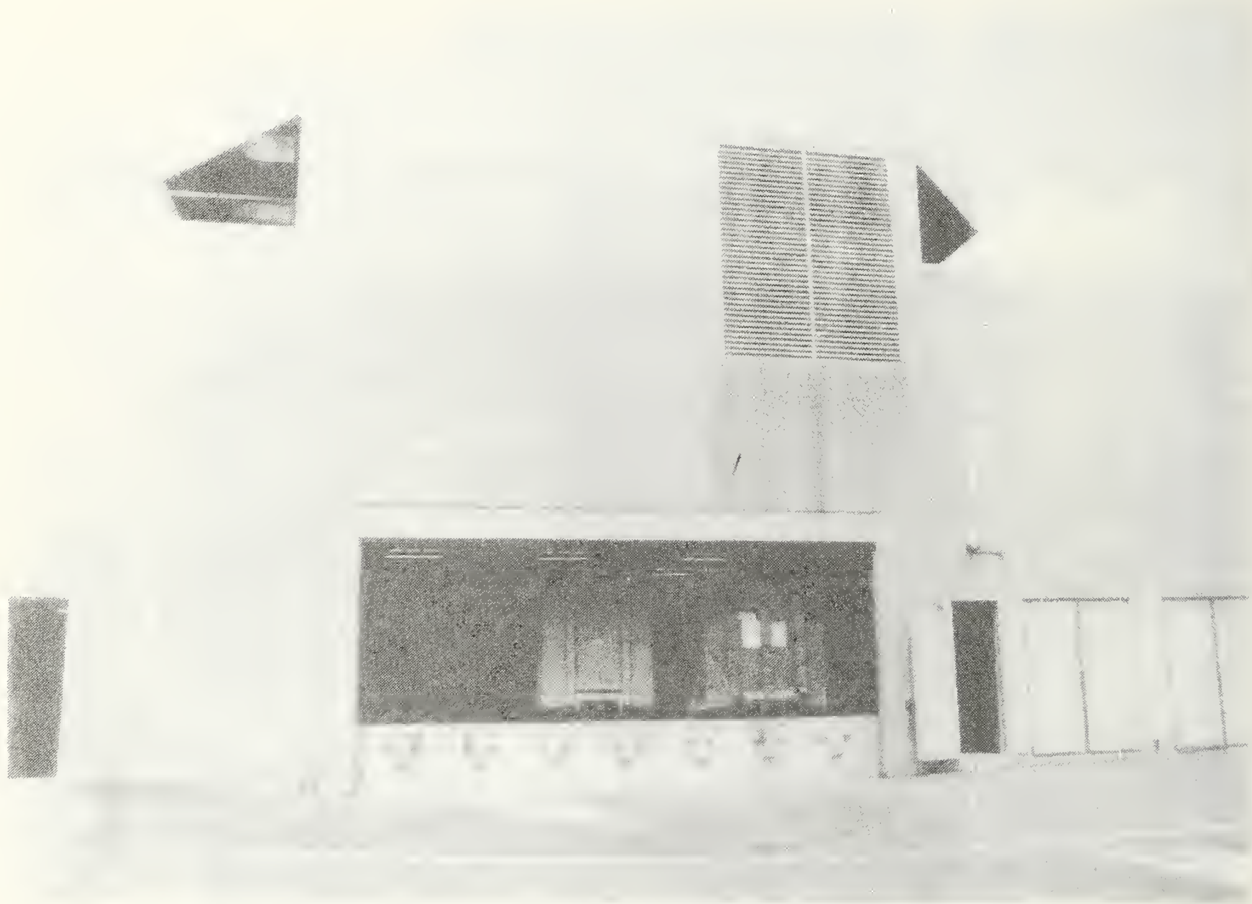

Figure 2.22 Front view of the central equipment building showing the loading dock with the trash containers

3. PLANT AND SITE MEASUREMENTS

Plant analysis and evaluation required collection of actual operational data from the plant. Beginning with plant start-up in January 1974 and continuing through December 1977, several types of data were collected for HUD. These data included:

- continuous thermal/electrical measurements of 225 plant and site variables beginning in April 1975
- economic data (operation and maintenance expenses) from the time of plant start-up
- environmental data during three separate data collection periods in 1977

These data supported economic, environmental, and reliability analyses as well as being the foundation for thermal performance and energy analysis efforts. Additionally, these measurements provided the data for monthly reports of plant performance to the sponsor and provided hourly, daily, and monthly data as requested to aid the plant operator in his efforts to maximize the plant's effectiveness.

The system used to collect and process the site engineering data contained approximately 225 transducers in the plant and site buildings, a data acquisition system (DAS) which sampled and recorded signals from the transducers at five-minute intervals, and a digital computer which processed the site data.

This section describes the system used by NBS to collect JCTE engineering data and discusses the accuracy of the data collection system.

3.1 MEASUREMENT OBJECTIVES

The engineering measurements performed at the site, their frequency, their accuracy, and the duration of the monitoring were determined by the data requirements of the JCTE evaluation activities. These activities included plant and site energy use studies, plant component performance evaluations, and an assessment of the quality of the utility services supplied to the site buildings.

The energy study plan sought to account for all energies supplied to the plant, the energy used by the plant for its operation, the energy supplied to the site, and that energy discarded from the plant as waste energy. These data were used to calculate an overall plant energy effectiveness as a function of time. The data required for this study included:

- fuel consumed by the engine-generators and boilers
- electrical energy generated
- heat recovered from the engines and boilers
- heat used by the absorption chillers
- chilled water produced

- electrical energy, hot water, and chilled water supplied to the site, and that lost in the site distribution systems
- electrical energy and chilled water used in the plant
- heat discarded by the plant

The measurement of energy used by the site required continuous monitoring of the electrical energy, heating, cooling, and domestic hot water demands of each of the site buildings, as well as complete weather information. These measurements were used to establish a data base of demands and demand profiles of urban residential and commercial buildings. This information is valuable for future TE system design. The reliability and quality of the utilities produced by the JCTE plant could be determined from these measurements.

The plant component performance evaluation activity focused on measuring the seasonal operating performance of the major plant components. These components included the engine-generators, the boilers, the chillers, the water-to-water heat exchangers located in the plant, and the water-to-air heat exchangers (dry cooling) located on the roof of the plant. These measurements involved continuous monitoring of the applicable input, output, and parasitic energy requirements of the components.

Details of the plant data and site data are presented in section 4 of this report.

3.2 DESCRIPTION OF THE INSTRUMENTATION AND DATA ACQUISITION SYSTEM

The instrumentation and data acquisition system monitored approximately 225 plant and site variables at five-minute intervals on a continuous year-round basis. The system stored these data on magnetic tape for shipment to NBS for processing. Data could also be transmitted to NBS in real-time by a modem link over a telephone line from the DAS at the Summit Plaza site to the computer at NBS.

The data recorded by the DAS originated from monitoring transducers located in the plant and site buildings. These transducers did not affect plant operation and were completely separate from the operational instrumentation used by the plant operator. The monitoring transducers included turbine and nutating-disk flowmeters and venturies with differential-pressure cells to measure fuel and water flow rates, copper/constantan and iron/constantan thermocouples with ice-point references to measure temperatures, multi-junction thermopiles to measure temperature differences, Hall-effect meters to measure instantaneous electrical power, pressure cells for pressure measurements, and seven types of weather instrumentation. Signal conditioning circuitry was used where necessary to scale voltage levels and to shape pulse signals. Integration was required to convert instantaneous electrical power signals (kilowatts) to electrical energy signals (kilowatt-hours) and to provide analog signals from the pulsatile-output signals from the turbine flow-meters. Signals were also taken from the engine-generators' malfunction transducers. Unlike the previously mentioned instrumentation, the engine-generator malfunction transducers were part of the operational plant equipment. Recording of these signals by the DAS did not affect the operation of the plant.

Signals from the instrumentation were sampled and recorded by the data acquisition system (figure 3.1). The central station of the DAS was located in the central equipment building and was connected by shielded cables to approximately 135 pieces of plant instrumentation and to eight remote DAS stations located in the site buildings (figure 3.2).

Each of the remote DAS stations was controlled by the central DAS so that the five to thirteen transducers connected to each remote station could be sequentially recorded by the central DAS. The central DAS sampled, digitized, and recorded all instrumentation signals once every five minutes. This process required approximately thirty seconds. Data were recorded on reels of magnetic tape which could store up to two weeks of data. At aproximately weekly intervals the reel of tape was changed and sent to NBS in Gaithersburg, Md. for computer processing.

Two modes of real-time data output were available from the instrumentation and data acquisition system. The first mode was a line printer located in the plant control room (figure 3.3). This printer could print out a list of all realtime signals from the instrumentation in millivolts. This listing capability was valuable for instrumentation maintenance, calibration, or repair. The second real-time output mode was a modem link between the DAS and the NBS data processing computer. This mode allowed complete scans to be sent over a telephone line to the NBS computer where raw millivolt instrumentation data were converted into engineering data and printed out for a five-minute period. The modem capability was used to routinely check on the functioning of the instrumentation and DAS, and to provide the plant operator with very recent plant data as requested. For example, during the summer of 1977 extensive adjustments were performed on the absorption chillers to improve their performance. After these adjustments were made, chiller COP was checked daily using the modem link. Erratic operation of the chillers could be quickly detected and the plant operator informed by telephone. As a result of this cooperative effort, some chiller malfunctions were detected and repaired.

A detailed description of the instrumentation and DAS can be found in reference [3-1].

3.3 DESCRIPTION OF THE DATA PROCESSING

Magnetic tapes containing data from the DAS were sent periodically from the site to NBS for computer processing. Processing began by converting the raw millivolt data stored on the tape into engineering units, using transducer and instrumentation calibration data. Then, all five-minute engineering data recorded for each channel during each one-hour period were accumulated to create a single hourly data point for each channel. These hourly values were stored on monthly computer disks. Data requiring information from several channels for calculation, call derived variables (as for example, heat transfer is equal to flow rate times temperature difference), were also stored on the disk. Thus, the end results of computer processing were the conversion of five-minute millivolt data stored on magnetic tape into hourly engineering data stored on monthly disks. Daily and monthly average values were also stored on each

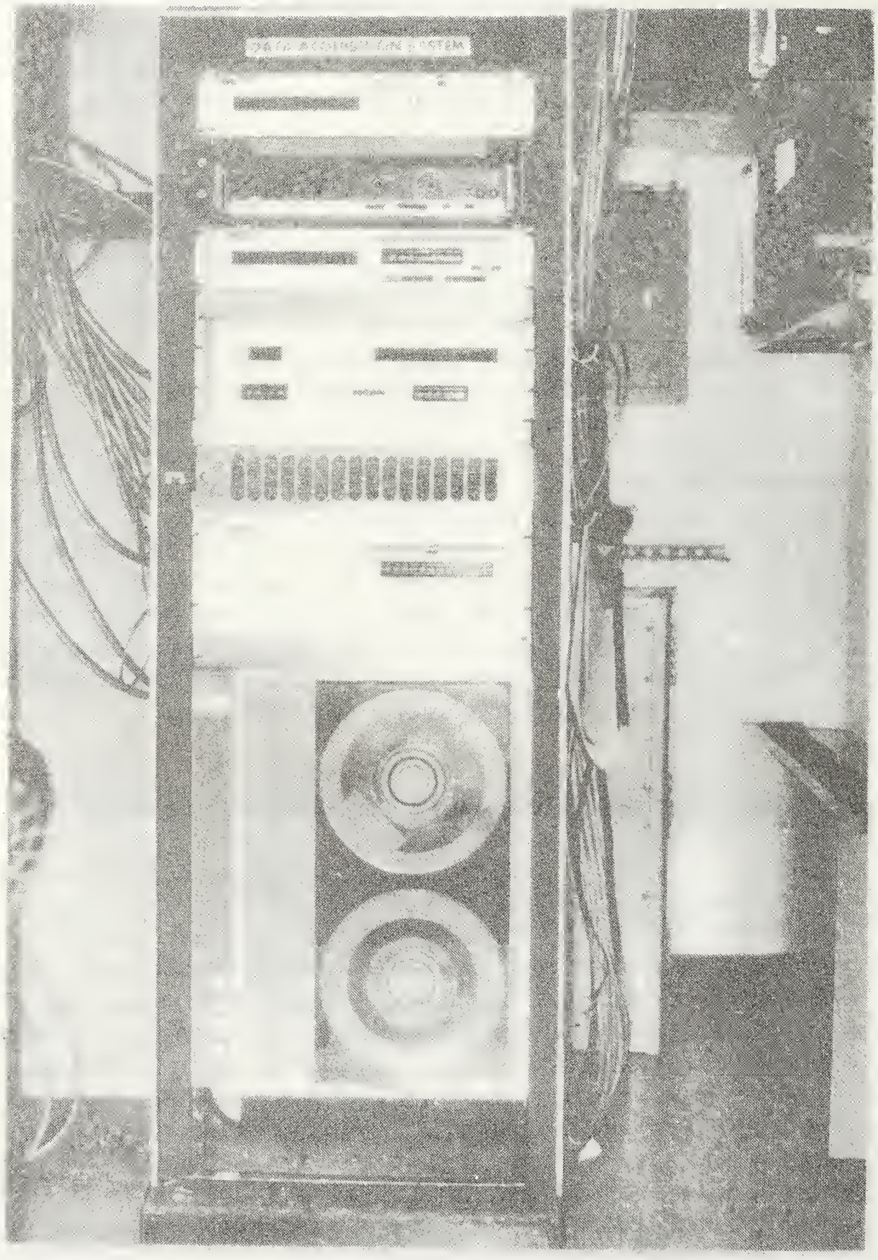

Figure 3.1 Data acquisition system located in the plant

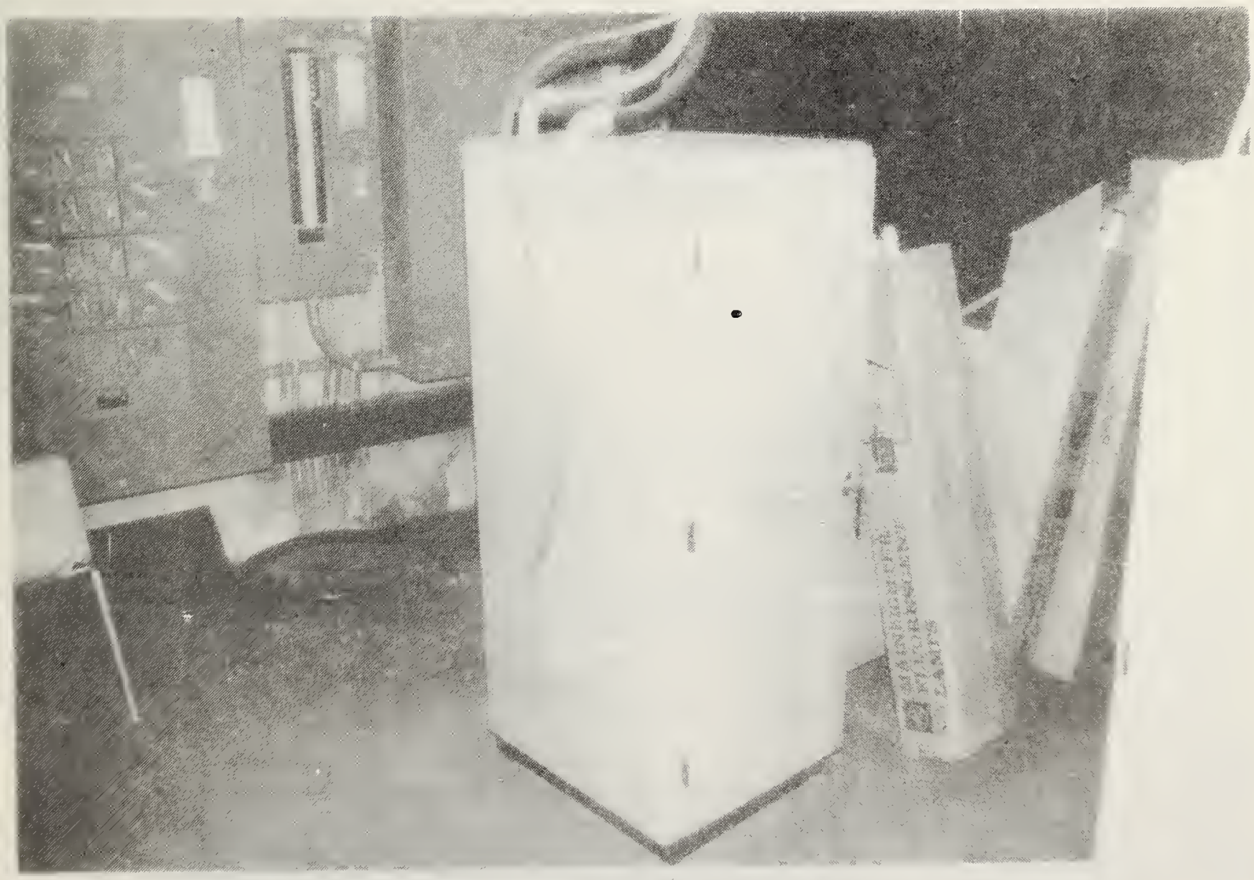

Figure 3.2 One of the eight remote DAS stations located in the site buildings

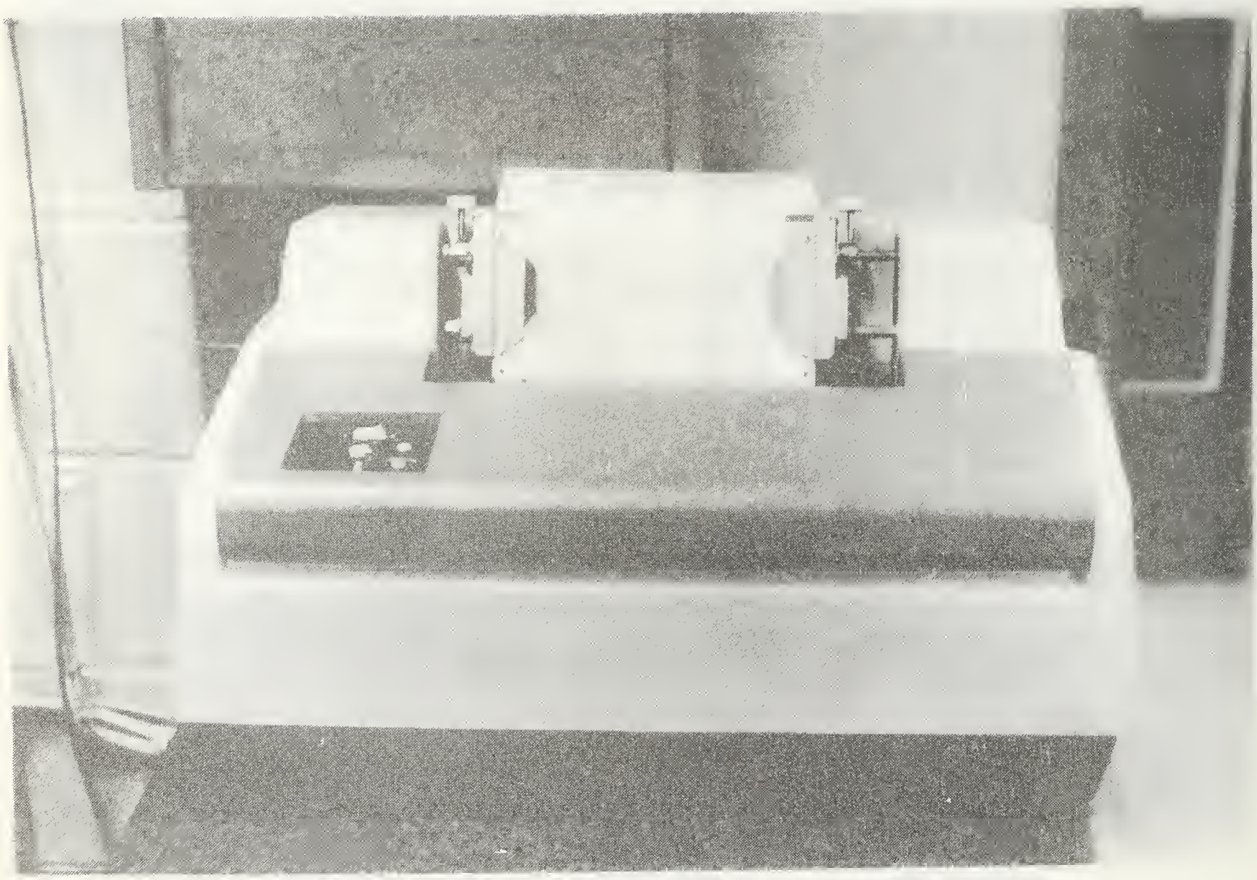

Figure 3.3 Impact printer for registering real-time data

month's disk. Examples of hourly, daily, and monthly data output from the computer disks are included in appendix A. In addition, all daily values were stored on a separate disk for up to a twenty-month period to facilitate the analysis of seasonal trends.

Versatile data output software permitted easy access and analysis of data stored on the monthly and yearly disks. This software permitted hourly, daily, or monthly data to be presented in tabular or graphical form. The graphical output capability allowed plotting of up to five variables over any time scale from one day to an entire month or year. Examples of the graphical outputs are shown in section 4. A simplified flow diagram of the data processing is shown in figure 3.4.

Detailed descriptions of the data processing software and facilities are contained in reference [3-2].

3.4 ACCURACY OF DATA

The accuracy of data presented in this report is primarily dependent upon the accuracy of the measurement instrumentation. For data dependent upon only one measurement (for example, gross electrical power), measurement accuracy depends on only one piece of instrumentation. For data which were calculated from several measurements (for example, thermal energy recovered from the engines), accuracy depends on the combined accuracies of the several pieces of measurement instrumentation.

The accuracies for the various types of monitoring instrumentation, and the accuracies of derived engineering values obtained from more than one data channel are presented in appendix B of this report. All engineering data presented in this report are subject to uncertainities. This should be kept in mind when using the data presented in this report for comparative purposes or when extrapolating the data for applications beyond the limits imposed by the JCTE plant and site.

3.5 REFERENCES - SECTION 3

3-1. Bulik, C., Rippey, W., Hurley, C., and Rorrer, D., "Description of the Data Acquisition and Instrumentation Systems: Jersey City Total Energy Project," National Bureau of Standards Report NBSIR 79-1709, March 1979.

3-2. Rorrer, D. E., Rippey, W., and Chang, Y., "Data Reduction Processes for the Jersey City Total Energy Project", National Bureau of Standards Report NBSIR 79-1757, May 1979.

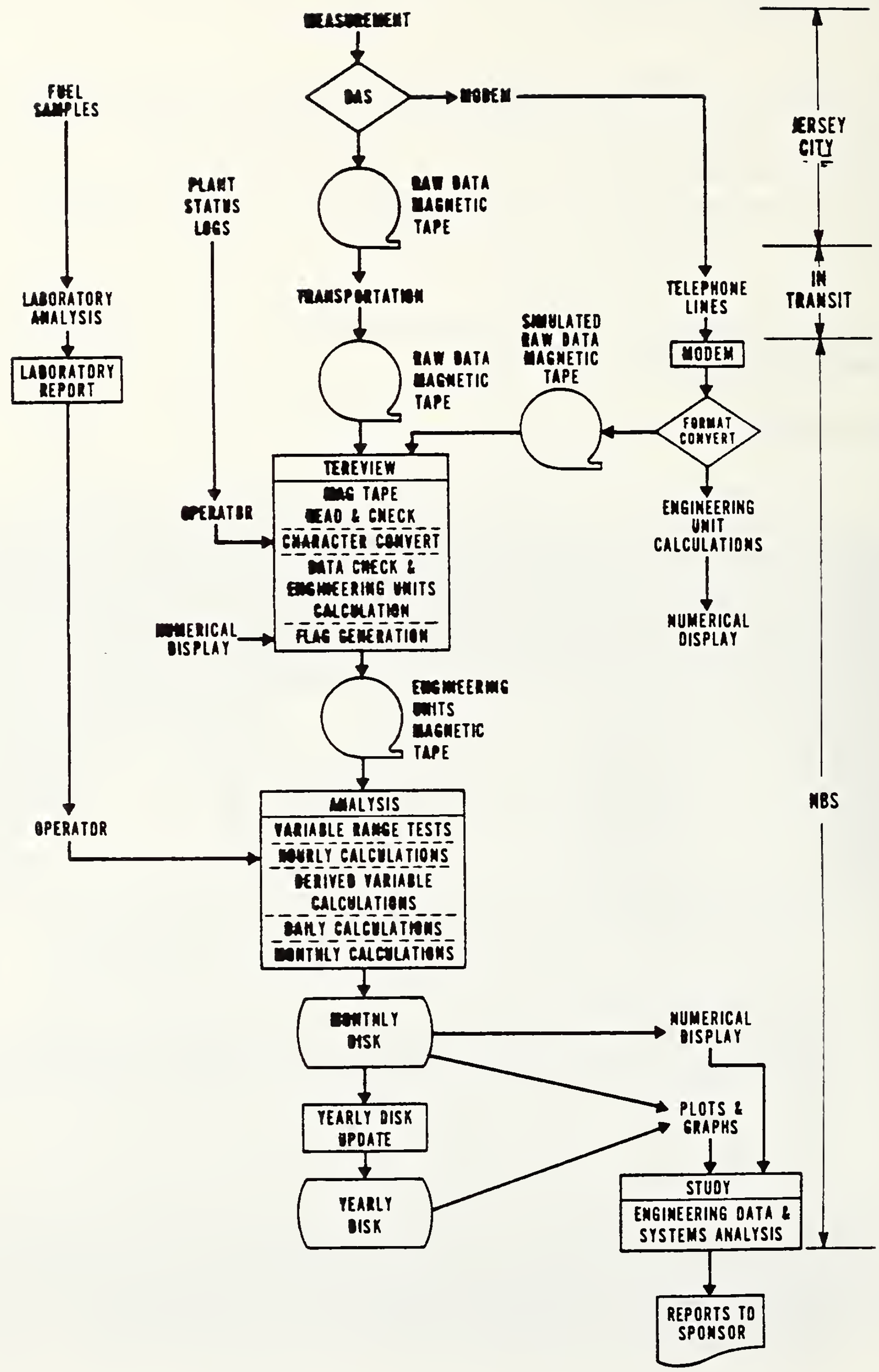

Figure 3.4 Simplified flow diagram of data processing. For further details see reference [3-2].

4. ENGINEERING DATA - PLANT AND SITE BUILDINGS

This section reports the monthly DAS accumulated engineering measurements collected in the plant and in the individual site buildings. For the 33-month period covered by continuous data collection (April 1975-December 1977), the results of calculated energy flow in the forms of electricity, space heating, space cooling, domestic hot water, fuel, etc., are tabulated in monthly increments. The performance of the major components of the plant and the loads of the individual site buildings are also tabulated. In general, all engineering values listed were taken directly from the output of the data processing system with no adjustment. Performance data were calculated directly from these values. In several cases when adequate data were not available from the DAS, projected values are tabulated. Each such value is clearly noted in the tables. The accuracy of the reported values is briefly discussed in section 3.4 and a more comprehensive accuracy analysis is given in appendix B. The data presented in this section are analyzed in section 5.

4.1 THERMAL AND ELECTRICAL MEASUREMENTS FROM THE PLANT

4.1.1 Thermal Energy Input and Output of the Plant

A schematic design showing the relative position of the major components in the plant with respect to a primary hot water loop is presented in figure 4.1. The broad line represents the primary hot water (PHW) loop. This is a closed loop with the pumps continually circulating approximately 11,000 pounds (5000 kg) of water per minute around the loop. The water passes through one or two boilers in series, depending upon how many boilers the plant engineer has on line. The valving of the boilers is such that one or two boilers can be put on line with either boiler in the leading position.

The balance cock shown on the schematic diagram adjacent to the boilers is in a normally-closed position thereby forcing all water through the boilers.

When the chillers are on line, water from the PHW loop is pumped through the absorption chillers. The chillers are connected to the PHW loop in a parallel fashion designed with balance cocks to allow thermal energy to be extracted from the loop at equal rates when both chillers are on line. The site heat exchanger shown on the schematic actually consists of two independent heat exchangers. They are connected in the loop using balance cocks which essentially allow equal rates of flow through each exchanger.

The PHW loop then continues through a balance cock which diverts a portion of the PHW to flow through the forced convection water-to-air heat exchangers shown as the dry cooler. The dry cooler has four pairs of fans which are automatically energized in sequential order in the event that the temperature of the water in the loop reaches a high enough level to activate the controls. This temperature level is usually preset to about 230°F which approaches the maximum recommended operating temperature of the diesel engines. The emergency heat exchanger which follows in the loop is a water-to-water heat exchanger. If a condition should exist where the dry cooler could not shed the excess thermal energy from the loop, valves on a 4-inch (10-cm) city water line are

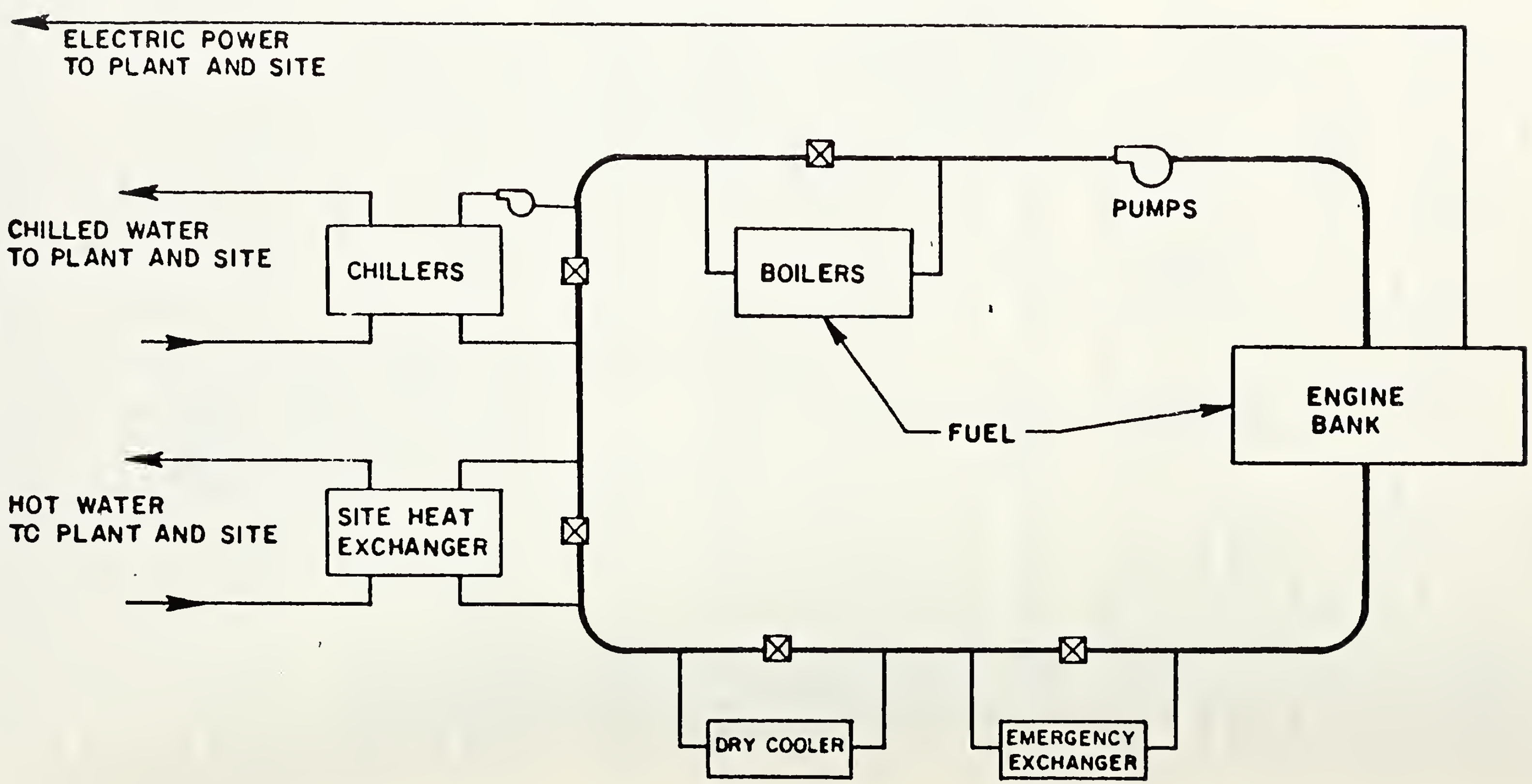

Figure 4.1 Plant primary hot water loop

automatically opened and the thermal energy is released from the PHW to city water passing through this water-to-water heat exchanger. This heat exchanger is located inside the plant and is well-insulated. In general, negligible amounts of thermal energy are lost in the emergency heat exchanger. The losses in the dry cooler are discussed in detail in section 5.

The PHW loop then passes through the jackets of all five engines in parallel. A portion of the water passing through each engine jacket is routed through its respective exhaust gas heat exchanger. The quantities of water passing through the exhaust gas heat exchangers are controlled by balance cocks. From these heat exchangers, the PHW returns to the common loop.

Table 4.1 lists the accumulated monthly values of the thermal energy outputs and inputs of the major components of the plant. Figure 4.2 shows the energy flow in the primary hot water loop and between the major components of the plant. This schematic diagram has been simplified to indicate the basic thermal energy inputs and outputs of the plant. A review of this diagram will assist the reader in understanding the relative significance of the accumulated monthly values listed in table 4.1 and are defined as follows:

Heat recovered from engines is the accumulated monthly net thermal energy recovered by the PHW loop from the jackets and exhaust heat exchangers of the diesel engines. The term "net" is used in this definition because the thermal losses from the idle engines reduce the available thermal gain from the engine bank.

Heat recovered from boilers is the net thermal energy added to the PHW loop by the boilers. This variable was calculated using the DAS measurements of the PHW flow rate through the boilers and the difference in temperature across the boilers. Since this is an accumulated monthly value, the losses through the idle boiler(s) were automatically subtracted.

PHW heat to chillers is the accumulated monthly value of thermal energy removed from the PHW loop by the absorption chillers.

PHW heat to secondary hot water exchangers is the accumulated monthly value of thermal energy removed from the PHW loop by the water-to-water heat exchangers transferring thermal energy to the two secondary hot water loops which circulate from the plant to the site buildings. The values reported were calculated using the DAS measurements of the PHW flow rate and the temperature difference in the PHW across the exchangers.

PHW dry cooler and piping losses is the difference between the accumulated monthly value of the thermal energy supplied to the PHW loop by the boilers and engines and the heat removed by the hot water heat exchangers and the absorption chillers.

Plant cooling load is the accumulated monthly value of the thermal energy absorbed by the large chilled-water fan-coil unit controlling the temperature in the engine room plus the thermal energy absorbed by the small fan-coil units in the office and control room areas of the plant. The large unit controlling

Table 4.1 Monthly Thermal Values (millions of Btu)

All values taken from DAS monthly printouts unless otherwise noted

Month	Recovered from engines	Recovered from boilers	PHW heat to chillers	PWH heat to secondary HW exchangers	PHW dry cooler and piping losses	cooling load plant	cooling load site
1975							
April	1728	3075	Ø	4096	707	Ø	Ø
May[1]	1744	1471	760	1884	571	Ø	100
June	2198	3891	3488	904	1697[2]	336	1000
July[3]	2428	2631	4020	800	239	356	1804
August	2556	3888	5357	802	285	468	2133
September	1839	1087	783	1003	1140[2]	84	128
October	1751	1062	Ø	2266	547	Ø	Ø
November	1863	1986	Ø	3362	487	Ø	Ø
December	2028	4144	Ø	5544	628	Ø	Ø
1976							
January	1753	5635	Ø	6904	484	Ø	Ø
February	1797	3825	Ø	5158	464	Ø	Ø
March	1922	2897	Ø	4421	398	Ø	Ø
April	1930	1252	Ø	2867	315	Ø	Ø
May	1994	559	396	1766	391	1	87
June	2433	4622	5233	1155	667[2]	297	1864
July	2592	4469	5760	1084	217	396	2294
August	2641	5666	6937	1091	279	412	2334
September	2613	3575	4763	1130	395	268	1285
October	2011	1724	313	2957	465	33	140
November	1981	3229	Ø	4737	473	Ø	Ø
December	2001	5032	Ø	6520	513	Ø	Ø
Total 1976	25668	42485	23402	39790	5061	1407	8004
1977							
January	2184	6038	Ø	7630	592	Ø	Ø
February	1798	4023	Ø	5391	430	Ø	Ø
March	1935	2566	Ø	4128	373	Ø	Ø
April	1920	1301	Ø	2891	330	Ø	Ø
May	2096	1540	1606	1765	265	101	490
June	2234	2394	3264	1138	226	254	1366
July	2656	3856	5378	890	244	398	2679
August[4]	2524	3855	5210	985	184	460	2452
September	2216	3747	4525	1144	294	350	1263
October	1953	1536	314	2744	431	38	83
November	1867	2865	Ø	4236	496	Ø	Ø
December	2066	4925	Ø	6453	538	Ø	Ø
Total 1977	25449	38646	20297	39395	4403	1601	8333

1. Data calculated from daily DAS data because of fragmentation of DAS operation and short duration of chiller operation.
2. Excessive losses confirmed in other related data. Apparent malfunction of dry cooler/boiler controls.
3. Only 5.6 days of DAS data available; however, DAS data was found to be representative for entire month.
4. DAS data adjusted to account for DAS downtime during changing weather.

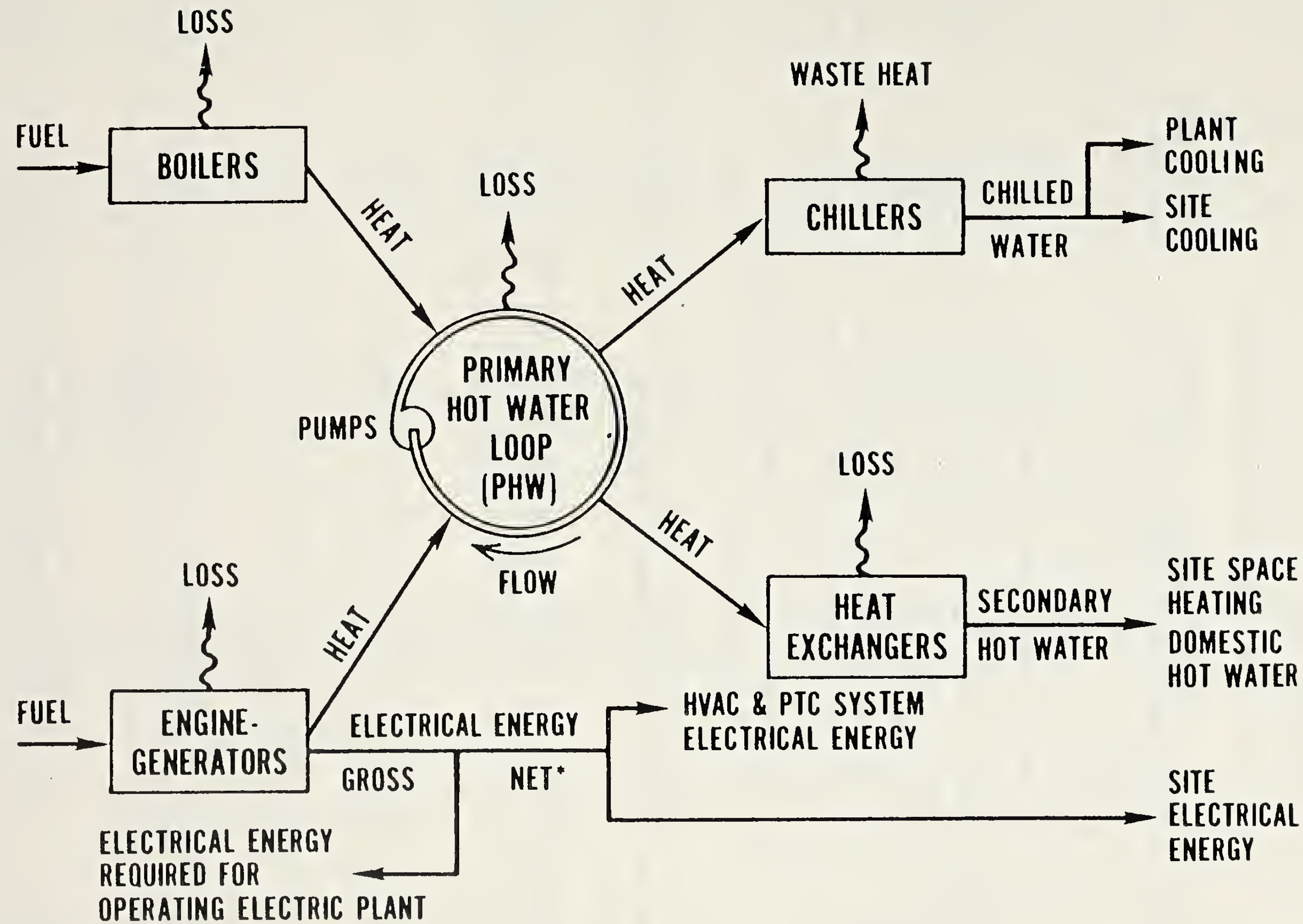

Figure 4.2 Major energy flow diagram for the plant

* Electrical energy required if purchased from the local utility

the temperature in the engine room represents approximately 90 percent of the plant cooling load.

Site cooling load is the accumulated monthly value of the thermal energy absorbed by the two secondary chilled-water loops supplying the site buildings. These quantities were calculated using DAS measurements of water flow rates and temperature differences.

4.1.2 Electrical Energy Values for the Plant

The electrical energy consumed by the site and various plant subsystems are presented in this section. The majority of the loads of the various plant subsystems were computed since they were not directly monitored. The rationale used in the calculations is different for the fixed and variable loads. Fixed loads were derived from manual measurements of the electrical energy consumed by each of the major plant subsystems (boilers, chillers, fan-coil units, etc.) when they were in operation. Variable loads were determined on the basis of manual measurements and calculations of the percentage of the electrical energy consumed by each of the motor control centers (DAS monitored) for supplying the energy for the major plant subsystems (electrical operations, cooling, and heating). During the processing of the data, the various instrumented plant parameters such as the status (ON/OFF) of each of the major components in the plant was determined. Once the status of the overall plant was known, the electrical energy consumed by the heating components, the cooling components, and that used in the generation of electrical energy was computed.

Table 4.2 contains the accumulated monthly values of electrical energy directly measured or calculated as described above. The column headings are defined as follows:

Gross generated is the monthly accumulated electrical energy produced by the generators. A kilowatt-hour meter connected to the main bus bars from the generators was used to confirm the DAS data and to supply data during DAS downtime.

Allocated to heating is the monthly accumulated electrical energy consumed by the heating components of the plant.

Allocated to cooling is the monthly accumulated electrical energy consumed by the cooling components of the plant including the cooling towers.

Total Allocated to HVAC in plant is the sum of the two previous columns and represents the total electrical energy consumed by the plant each month for the operation of the boilers, chillers, and their auxiliary equipment.

PTC load is the monthly accumulated electrical energy consumed by the PTC exhausters. The electrical energy consumed by the compactor and other auxiliary PTC equipment was not directly monitored. The additional electrical energy for this auxiliary equipment has been calculated and found to be less than 10 percent of the values listed for the exhausters.

Table 4.2 Monthly Accumulated Electrical Values (Megawatt-hours)

All values taken from DAS monthly printouts unless otherwise noted

Month	Gross generated	Allocated to heating	Allocated to cooling	Allocated to HVAC in plant	PTC[1] load	Site load	Net generated
1975							
April	531.5	55.7	Ø	55.7	6.7	403.2	465.6
May	542.2	43.8	14.3	58.1	3.8	416.3	478.2
June	638.5	26.0	150.3	176.3	3.5	459.8	640.4
July[2]	740.3	27.5	175.6	203.1	3.2[3]	487.1	693.4
August	758.0	28.7	179.1	207.7	3.2[3]	498.1	709.0
September[4]	637.4	41.8	42.4	84.4	3.8	466.9	555.1
October	576.9	46.5	Ø	46.5	3.1	465.0	514.6
November	593.5	52.2	Ø	52.2	2.5	495.2	550.9
December	652.1	55.4	Ø	55.4	2.7	541.2	599.3
1976							
January	674.9	57.8	Ø	57.8	2.9	557.0	617.8
February	621.2	52.2	Ø	52.2	2.4	506.6	561.2
March	650.6	56.6	Ø	56.6	6.1	523.2	585.9
April	607.0	47.3	Ø	47.3	7.6	478.4	533.3
May	634.0	39.0	22.8	61.8	8.4	482.1	552.2
June	790.7	28.2	152.6	180.8	4.9	542.4	728.4
July	822.8	29.3	179.2	208.5	3.5	565.8	776.8
August	850.2	31.0	200.6	231.6	3.0	567.5	802.1
September	809.5	29.0	182.3	211.3	3.1	544.4	758.8
October	662.4	49.3	15.2	64.4	3.1	530.2	597.7
November	639.3	56.2	0	56.2	3.4	523.2	582.7
December	676.4	56.9	0	56.9	3.9	558.1	618.9
Total 1976	8439.0	532.8	752.7	1285.4	52.3	6378.9	7715.8
1977							
January	689.8	55.6	0	55.6	3.1	574.6	633.3
February	607.8	48.9	0	48.9	2.8	501.9	553.6
March	641.1	53.4	0	53.4	3.3	520.8	577.5
April	617.2	46.7	0	46.7	3.2	499.0	548.9
May	664.4	35.8	63.9	99.6	4.0	494.3	597.9
June	723.9	26.6	134.4	161.0	3.4	510.3	674.7
July	834.6	30.8	178.1	208.9	3.4	570.0	782.2
August	821.7	29.5	156.5	186.0	3.7	580.5	770.2
September	739.3	25.5	140.9	166.3	3.3	522.3	691.9
October	630.4	44.6	19.4	64.9	4.0	499.8	568.7
November	606.2	55.1	0	55.1	4.5	498.3	555.0
December	662.7	56.8	0	56.8	3.5	547.9	608.2
Total 1977	8239.1	509.3	693.2	1203.2	42.2	6319.7	7562.1

1. The values listed represent the DAS recorded values for the exhauster only. The compactor and other PTC accessories are less than 10 percent of the exhauster values listed.
2. Insuffficent DAS data, values adjusted to equate with manual kWh meter reading.
3. Insufficient DAS data, average values for 1975 inserted.
4. Insufficient DAS data, values adjusted to equate with manual kWh reading; PTC values not adjusted.

Site load is the accumulated monthly electrical energy leaving the plant for site consumption. The site load was not directly monitored. It was computed by subtracting all measured plant loads and the PTC exhauster loads from the gross electrical energy generated.

Net generated is the accumulated monthly net electrical energy required by the site, PTC, and HVAC equipment in the plant. It is the electrical energy which would have to be purchased from the grid if the engine-generators were not used.

4.1.3 Fuel Consumption

The monthly values of the fuel consumption are listed in table 4.3. Four fuel variables are reported: fuel consumed by engines, fuel consumed by boilers, total fuel consumed, and higher heating values of the fuel. With minor exceptions, the quantities reported for the engines and the total are measured quantities since May 1976. The values reported for months prior to that date and for the month of October 1976, were determined from models using the measured outputs of the engine-generators and boilers. The engine-generator model assumes an efficiency of 32 percent for the gross electrical energy for the month. The boiler model is described in detail in appendix C of this report.

The measured quantities were taken from two manually-read nutating disc meters mounted on the input lines to the "day tanks." One meter registers the total input to the 1000 gallon (3.8 m^3) day tanks supplying fuel to the boilers and the engines. The second meter registers the input to the tank supplying the engines only. The fuel consumed by the boilers was calculated by substracting the engine fuel consumption from the total consumption. During normal operation of the plant, these day tanks were automatically filled from 3 to 5 times each hour to maintain a constant level within $\pm$ 30 gallons ($\pm$ 0.1 m^3).

The meters were calibrated prior to installation in the fuel lines. A correction factor was used for each meter as determined during calibration. Although these meters were found to have an uncertainty less than 1 percent, the uncertainty of the values reported for the boilers depends upon the relative consumption of the engines and boilers. For months during which the consumption of the boilers and engines were equal, the maximum probable error for the boiler values is 2 percent. However, for months of mild weather when the consumption of the boilers was less than that of the engines, this probable error increases. For example, during mild weather when the boiler consumption was one-quarter to one-tenth of the engine consumption, the theoretical probable uncertainty of the boiler consumption becomes 6 percent to 15 percent, respectively.

In correlating the measured (after April 1976) and the calculated (April 1976 and earlier) total fuel consumption with the total fuel deliveries and storage tank records for the 33-month period covered in this report, the difference was less than 0.2 percent. This correlation and the consistency of the engine and boiler performances increase confidence in the monthly values reported for components.

Table 4.3 Monthly Fuel Values

Month	Consumed by engines (gallons)	Consumed by boilers (gallons)	Total fuel consumed (gallons)	Higher heating value (Btu per gallon)	No. of boilers on-line	Degree Days[2] Heating °F·day	Degree Days[2] Cooling °F·day
1975							
April*	40,652	27,490	68,142	139,400	2	524	Ø
May*	41,470	13,833	55,303	139,400	2	84	117
June*	52,061	34,316	86,378	139,580	2	6	211
July*	56,143	23,537	79,680	140,600	2	Ø	375
August*	57,485	34,180	91,665	140,600	2	1	321
September*	48,335	10,423	58,758	140,600	2	59	46
October*	44,352	10,392	54,744	138,703	2	195	20
November*	45,786	18,348	64,134	138,200	2	400	10
December*	49,938	36,706	86,644	139,226	2	913	Ø
1976							
January*	51,623	49,394	101,017	139,400	2	1170	Ø
February*	47,369	33,752	81,121	139,824	2	738	Ø
March*	49,552	25,900	75,451	140,000	2	645	Ø
April*	46,227	11,871	58,098	140,000	2	338	50
May	48,361	5,455	53,816	138,970	1.5	141	30
June	60,267	41,505	101,772	138,440	1	17	281
July	62,824	36,794	99,618	138,665	1	Ø	317
August	64,586	47,618	112,204	138,890	1	4	305
September	61,906	29,450	91,356	138,967	1	56	110
October[1]	50,749	15,384	66,133	139,168	1	381	6
November	49,532	25,937	75,469	139,665	1	745	Ø
December	51,927	40,835	92,762	139,500	1.7	1107	Ø
Total 1976	644,923	363,895	1,008,817			5342	1099
1977							
January	52,010	50,531	102,541	139,060	2	1361	Ø
February	46,220	32,923	79,143	139,096	2	895	Ø
March	49,807	20,722	70,529	139,000	2	563	6
April	47,788	10,816	58,604	139,400	2	352	18
May	51,407	13,663	65,070	138,935	1.3	89	111
June	54,703	20,022	74,726	138,320	1	24	191
July	63,171	34,623	97,794	139,355	1	Ø	414
August	62,463	33,506	95,969	139,640	1	Ø	321
September	56,745	30,830	87,575	139,640	1.5	50	146
October	47,791	14,836	62,627	139,640	2	319	1
November	46,936	26,367	73,303	139,000	2	527	Ø
December	50,653	43,530	94,183	139,000	2	975	Ø
Total 1977	629,694	332,369	962,064			5155	1208

* Fuel consumption data based on 32 percent engine-generator efficiency and boiler model.

1. Meters inadvertantly by-passed by plant personnel. Models used to generate fuel data.
2. Values taken from National Oceanic and Atmospheric Administration summary of local climatological data from the weather station located at the Newark, N.J. International Airport (approximately 6 miles from site).

The higher heating values listed were determined from averaging the values determined by laboratory testing of fuel samples normally taken from the twice each month. ASTM test procedures D1552, D874, D95, and D287 were used.

The average number of boilers on-line for each month are listed in table 4.3. The heating and cooling degree-days are also listed for each month. These quantities as well as the thermal outputs of the various components in the plant are of interest in analyzing the fuel consumption. The degree-day data are also of interest in analyzing the site data. The values listed were taken from the local climatological data for the weather station of the National Oceanic and Atmospheric Administration (NOAA) located at the Newark, N.J. International Airport (approximately 6 miles from the site) and are based on 65°F.

Several weather station transducers at the site were put on line late in the data reporting period. The data were only used for occasional comparison with the Newark NOAA data and are not included in this report.

4.1.4 Component and Plant Performance

Table 4.4 lists the performance of the major components of the plant and the overall performance of the plant. The efficiency values reported for the engine-generators and boilers prior to May 1976 and for October 1976 are based upon the output/input models for these components as previously mentioned. The chiller/COP values are computed directly from measured thermal values for the entire 33-month period. The terms used in table 4.4 are defined as follows:

Engine gross electrical efficiency values were computed by dividing the gross electrical energy output of the engine-generators by the thermal energy of the fuel consumed by the engines using the same units (i.e., the kilowatt-hour values were multiplied by 3412 to convert the kWh to Btu). The monthly higher heating values listed for the fuel were used in computing these values.

Engine gross electrical plus thermal efficiency values were computed by dividing the gross electrical energy output plus the thermal energy recovered from the engine jackets and exhaust gas heat exchangers by the thermal energy of the fuel consumed by the engines (again all terms had the same units).

Boiler efficiency values were computed by dividing the net thermal energy recovered from the boilers by the thermal energy of the fuel consumed by the boilers.

Chiller COP values were computed by dividing the thermal energy absorbed in the chilled water output of the chillers by the thermal energy extracted from the PHW loop. These values do not include the electrical energy required for the operation of the absorption chillers, cooling tower fan and pump motors, etc.

Engine generator heat rate (Btu per net kWh) is a measure of the net efficiency of the engine-generators and is expressed by dividing the thermal energy of fuel consumed by the engines by the net electrical energy generated by the plant.

Table 4.4 Monthly Component and Plant Performance

Month	Engine gross electrical efficiency %	Engine gross electrical plus thermal efficiency %	Boiler efficiency %	Chiller COP	Engine-generator heat rate (Btu per net kWh)	Plant energy effectiveness
1975						
April*	32.0%	62.5%	80.2%	-	12,170	57.6%
May*	32.0%	62.2%	76.3%	.132	12,090	44.2%
June*	32.0%	62.3%	81.2%	.383	11,347	28.8%
July*	32.0%	62.8%	79.5%	.537	11,383	38.1%
August*	32.0%	63.6%	80.9%	.486	11,399	36.1%
September*	32.0%	59.1%	74.2%	.271	12,243	33.0%
October*	32.0%	60.5%	73.7%	-	11,954	50.7%
November*	32.0%	61.4%	78.3%	-	11,487	57.0%
December*	32.0%	61.2%	81.1%	-	11,602	61.3%
1976						
January*	32.0%	56.4%	81.8%	-	11,649	62.6%
February*	32.0%	59.1%	81.0%	-	11,803	60.8%
March*	32.0%	59.7%	79.9%	-	11,841	58.6%
April*	32.0%	61.8%	75.3%	-	12,136	55.3%
May	32.2%	61.9%	73.7%	.245	12,171	46.6%
June	32.3%	60.3%	80.4%	.413	11,454	34.5%
July	32.2%	62.0%	87.6%	.467	11,214	38.4%
August	32.3%	61.8%	85.7%	.396	11,184	34.6%
September	32.1%	62.5%	87.4%	.326	11,338	33.6%
October*	32.0%	60.5%	80.5%	.553	11,816	53.3%
November	31.5%	60.2%	89.1%	-	11,372	61.9%
December	31.8%	59.5%	88.3%	-	11,703	65.1%
1977						
January	32.5%	62.7%	85.9%	-	11,420	67.2%
February	32.3%	60.2%	87.8%	-	12,048	64.5%
March	31.6%	59.5%	89.1%	-	11,988	60.2%
April	31.7%	60.4%	86.3%	-	12,136	56.2%
May	31.7%	61.1%	81.1%	.368	11,945	43.6%
June	32.6%	62.2%	86.4%	.496	11,214	41.1%
July	32.3%	62.5%	79.9%	.572	11,254	40.5%
August[1]	32.1%	61.1%	82.4%	.559	11,325	40.4%
September	31.8%	59.8%	87.0%	.356	11,452	34.3%
October	32.2%	61.5%	74.1%	.385	11,734	51.3%
November	31.7%	60.3%	78.2%	-	11,755	60.2%
December	32.1%	61.5%	81.4%	-	11,576	63.6%

* Fuel consumption based on 32.0 percent engine-generator efficiency and boiler model in appendix C.

1. DAS data adjusted to account for DAS downtime during changing weather.

Plant energy effectiveness is a measure of net efficiency of the plant in supplying the needs of the site. The values listed in table 4.4 were calculated by dividing the sum of the energy demands of the site (site electrical energy, site hot water, and site chilled water) by the energy content of the fuel consumed by the plant. The reported values were based on measurements made at the plant and therefore include losses in the distribution systems between the plant and site buildings. It should be noted that a specific definition for the energy effectiveness of a total energy system has not been universally adopted to date.

4.1.5 Thermal Energy - Primary Hot Water Loop

Table 4.5 lists the individually-measured thermal inputs and outputs of the PHW loop for the calendar years 1976 and 1977. Although some of the basic data listed in this table are also listed in table 4.1, table 4.5 is presented for the convenience of the reader interested in comparing input/output values for a heat balance or for a comparison with other measured values used in this report. The thermal energy values listed in table 4.5 are based upon the flow measurements using the venturi in the PHW loop and the appropriate thermopiles and thermocouples in the loop. All data listed in table 4.5 were taken directly from the monthly computer printout of the processed data recorded by the DAS.

The accumulated monthly values listed in table 4.5 are defined in section 4.1.1 with the following exceptions:

Total thermal input is the sum of the heat recovered from the engines and the heat recovered from the boilers.

PHW dry cooler losses are the losses from the dry cooler in the PHW loop. These values do not include any other losses from the PHW loop.

Total thermal output is the sum of the measured outputs from the PHW loop. These outputs include the PHW dry cooler losses, the thermal energy removed by the secondary hot water heat exchangers, and the thermal energy removed by the absorption chillers.

4.1.6 Profiles of Plant Loads

Figures 4.3 through 4.11 present a series of profiles describing the thermal and electrical outputs of the plant during 1977. Figure 4.3 shows the daily outputs of the boiler and the daily thermal energy recovered from the engines for the year 1977. The increase in the thermal energy recovered from the engines during the summer months when the electrical energy demand is increased by the loads imposed by the absorption chiller system is worthy of note. Also the drop in boiler demand during the spring and fall seasons indicate the capability of the thermal energy recovered from the engines in meeting the demands of the site during limited periods. Gaps or breaks in any profile shown in this report represented periods during which one or more of the channels in the DAS was not capable of producing the data to calculate the values.

Table 4.5 1976, 1977 Monthly Thermal Values for the PHW Loop (millions of Btu)

All values taken from DAS monthly printouts

Month	PHW dry cooler losses	PHW heat to chillers	PHW heat to secondary HW exchangers	Total thermal output	Total(1) thermal input
1976					
January	NA	∅	6904	NA	7388
February	NA	∅	5158	NA	5619
March	NA	∅	4421	NA	4819
April	225	∅	2867	3092	3182
May	264	396	1766	2426	2553
June	591	5233	1155	6979	7055
July	241	5760	1085	7086	7060
August	299	6937	1071	8327	8307
September	259	4763	1130	6152	6188
October	345	313	2956	3614	3735
November	371	∅	4736	5107	5210
December	443	∅	6520	6863	7033
1977					
January	500	∅	7630	8130	8222
February	372	∅	5391	5763	5821
March	348	∅	4128	4476	4501
April	281	∅	2891	3172	3221
May	262	1606	1765	3633	3636
June	239	3264	1138	4641	4628
July	237	5378	890	6505	6512
August	258	4300	985	5543	5469
September	334	4525	1144	6003	5963
October	374	314	2744	3432	3489
November	399	∅	4236	4635	4731
December	428	∅	6453	6881	6991

Note: NA = Not available

1. Sum of the thermal energy recovered from the engines and the boilers shown in table 4.1.

PHW loop input and output values were determined from independent data channel measurements. Comparison of the input and output totals demonstrates the consistency of the measured data. See appendix B for an explantation of those months when the thermal output slightly exceeds the thermal input. Note the correlation of the small and negative differences with the low demands from the secondary HW exchangers.

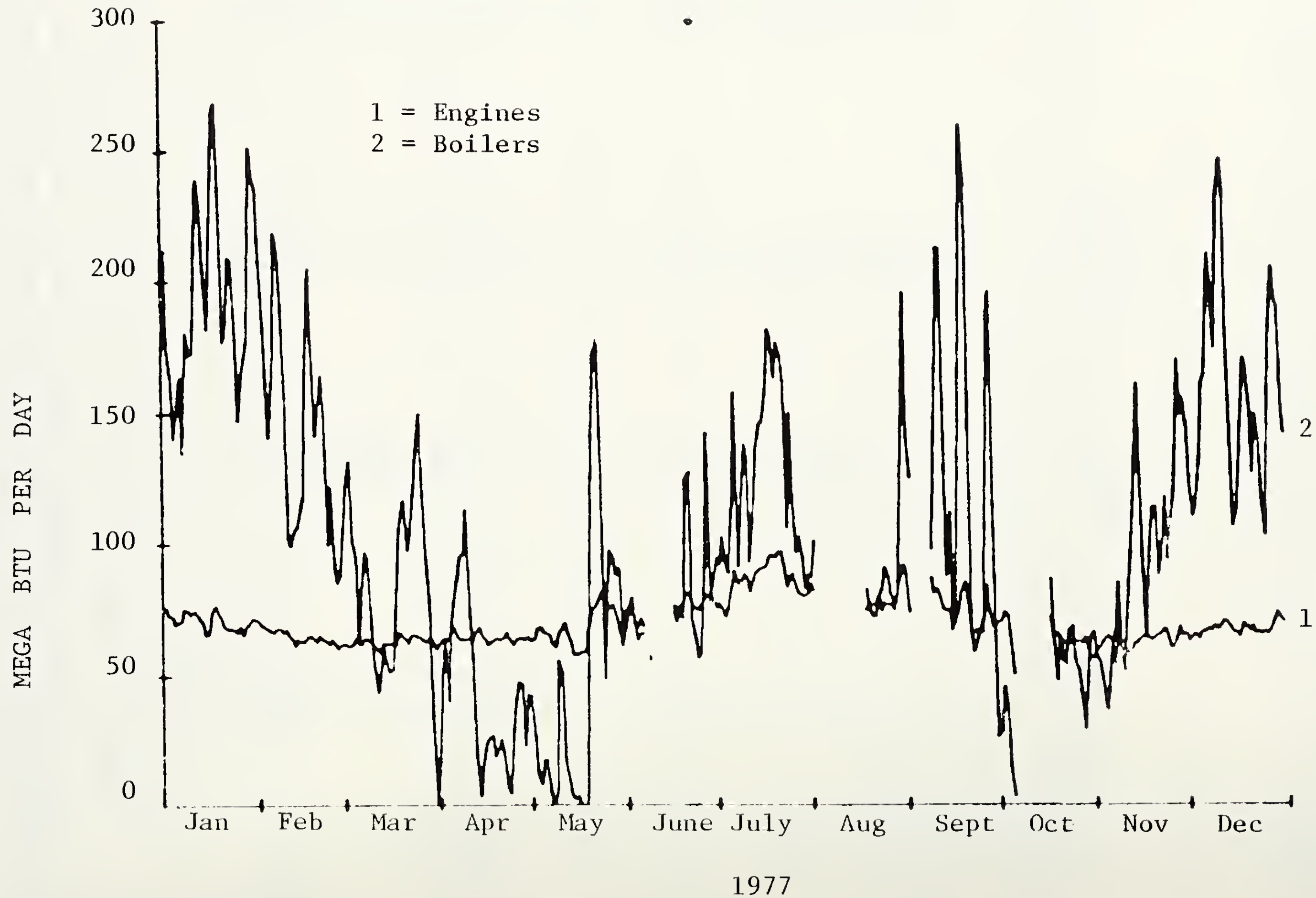

Figure 4.3 Thermal energy recovered from the engines and boilers

Figure 4.4 is a profile of the daily output of the chillers during the 1977 season. It should be noted that the chillers are put in service about the middle of May each year and taken off line during the early part of October.

Figure 4.5 is a profile showing the thermal energy leaving the plant in the form of secondary hot water. The seasonal periods are indicated and the continuing demand of the site for hot water throughout the summer months can be noted.

Figure 4.6 presents profiles of 4 days from each of the four seasons of the year 1977, showing the of the hourly demand of the plant for site hot water, the thermal recovery from the engines and the thermal demand of the chillers from the primary hot water (PHW) loop. During the spring season, the thermal output of the engines often slightly exceeds the demand from the site. However, line losses in the site distribution systems (see section 5) consume this excess thermal output. Figure 4.7 presents the profiles for one of the four days shown in figure 4.6 for each of the four seasons. It is interesting to note that only the diurnal pattern of the heat recovered from the engines follow any similarity from day to day or season to season.

Figure 4.8 shows the thermal output of the boilers for the month of January 1977. This month was chosen because it is one of the colder months of record, dating back to the year 1938. The 1361 heating degree-days at the site during January 1977 were 31 percent higher than the normal heating degree-days reported for the month of January. The Cleaver-Brooks boilers at this plant are rated at 13.39 MBtu per hour (3.9 MW) at altitudes up to 3,000 feet (900 m) with water operating temperatures up to 250°F (120°C). The profiles in figure 4.8 indicate that the leading boiler controls were set to limit the output of the boiler to about 10 MBtu per hour (2.9 MW). The profiles in figure 4.8 further indicate that either one of the boilers alone operating within rated capacity could have met the demands of the plant during the extreme weather conditions of January 1977.

Figure 4.9 presents the daily profiles of the gross and net electrical energy during the year 1977. The typical lower site demands in the spring and fall seasons are indicated as well as the higher loads in the summer months required to operate the auxiliary absorption chiller equipment.

Figure 4.10 shows the hourly electrical energy demands of the site and plant for four days of each of the four seasons of the year. The lower demands of the site in the spring and fall seasons are again reflected. However, the increase in demand of the plant during the summer season is the more significant change and is reflected in the gross generated profile. Figure 4.11 presents the profiles for one of the four days in each season in figure 4.10. Unlike the thermal diurnal profiles, the electrical profiles show a general similarity, the slight differences denoting the shorter days of the winter months and the longer days of the spring season.

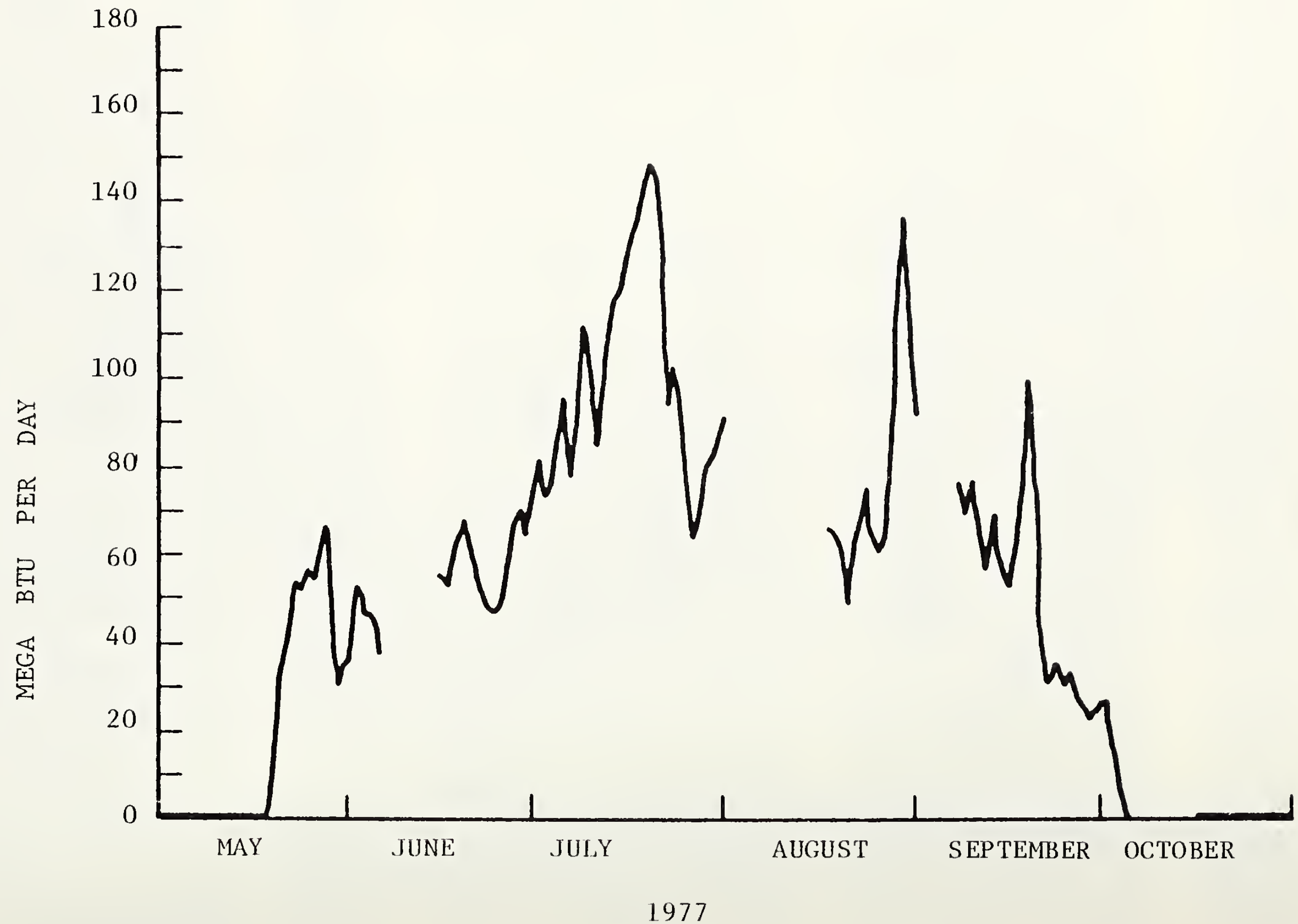

Figure 4.4 Output of the absorption chillers at the plant

Figure 4.5 Thermal energy leaving the plant for the site in the form of secondary hot water

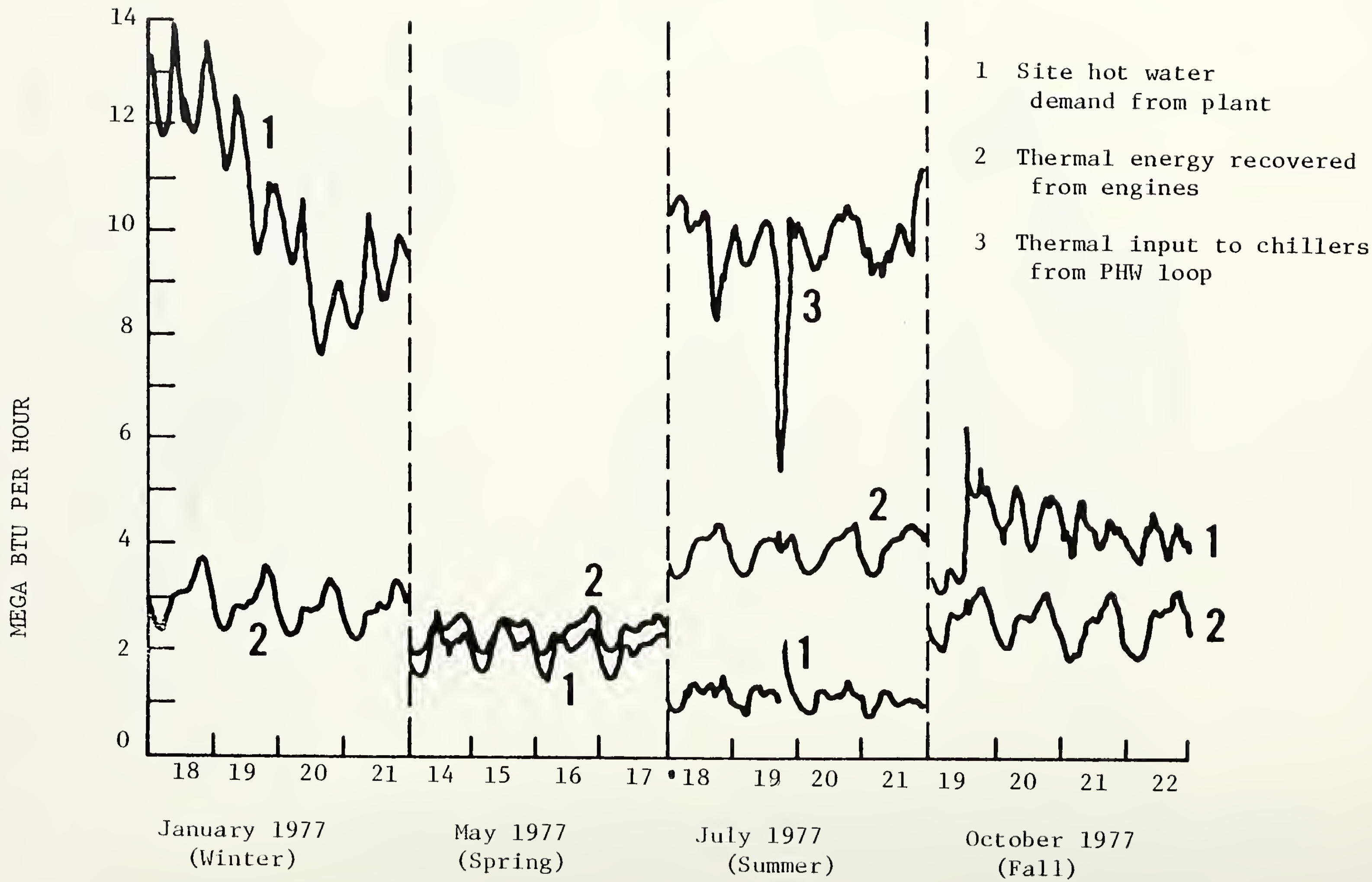

Figure 4.6 Seasonal profiles of site hot water demand, thermal energy recovered from the engines, and chiller input from the primary hot water loop. These profiles denote the thermal demands of the plant relative to the thermal energy recovered from the engines.

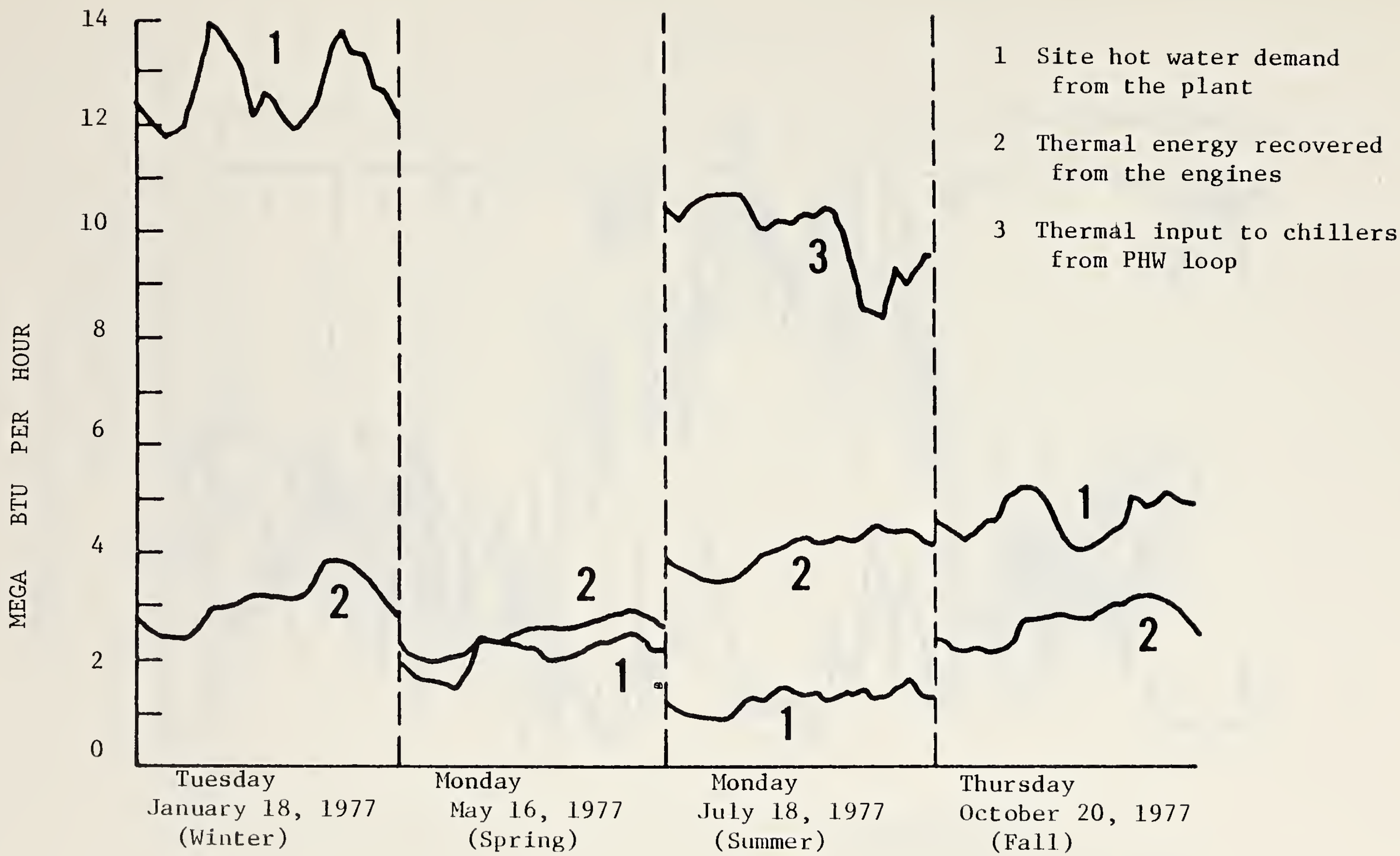

Figure 4.7 Profiles of site hot water demand, thermal energy recovered from the engines, and chiller input from the primary hot water loop for one day of each of the four seasons of the year

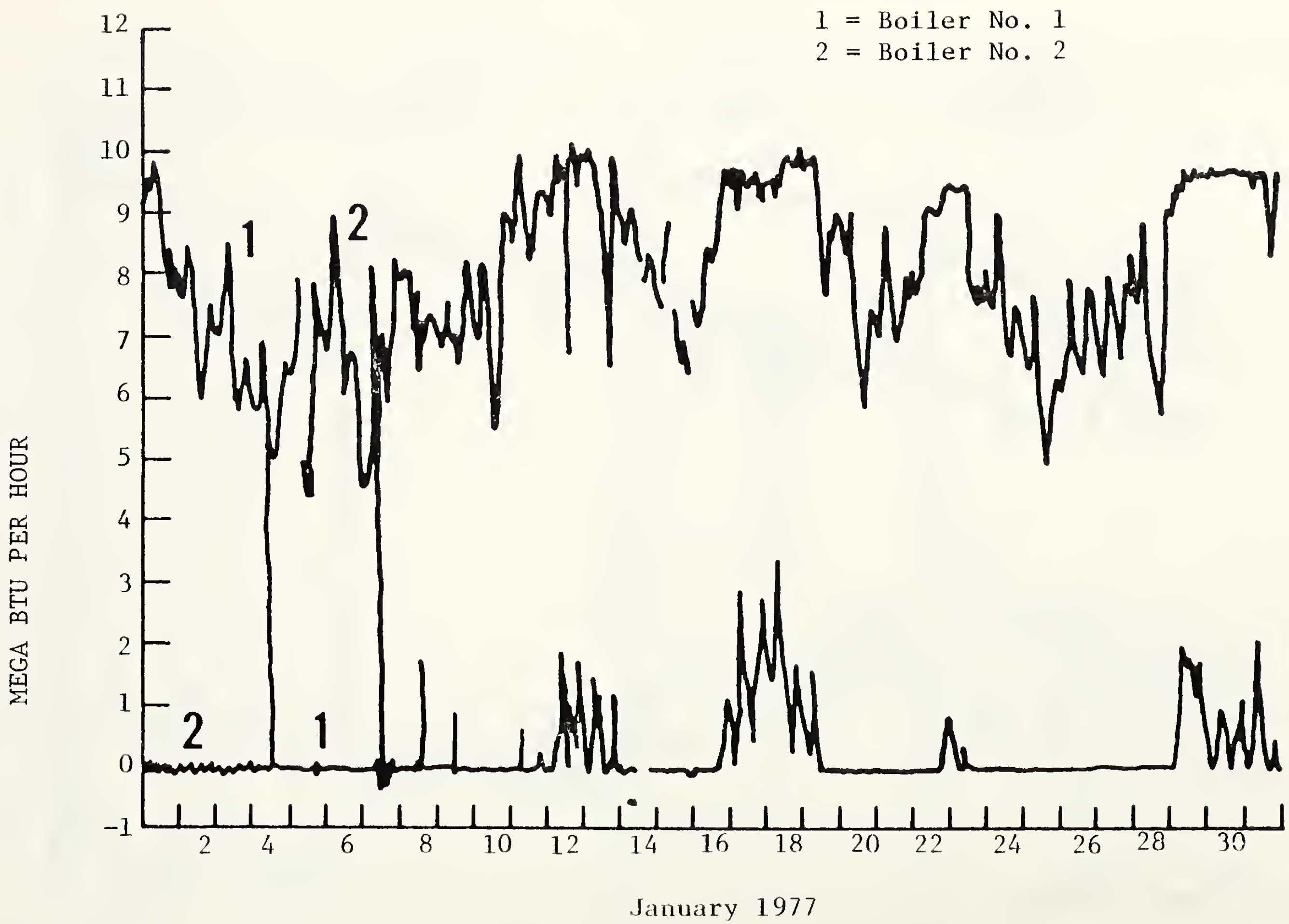

Figure 4.8 Thermal energy recovered from each of the boilers during one of the colder months of record. The boilers are rated at 13.4 MBtu per hour (3.9MW). However, the controls apparently limited the output to 10 MBtu per hour (2.9 MW).

Note: Boiler No. 1 was changed from lagging to leading position January 4, 1977

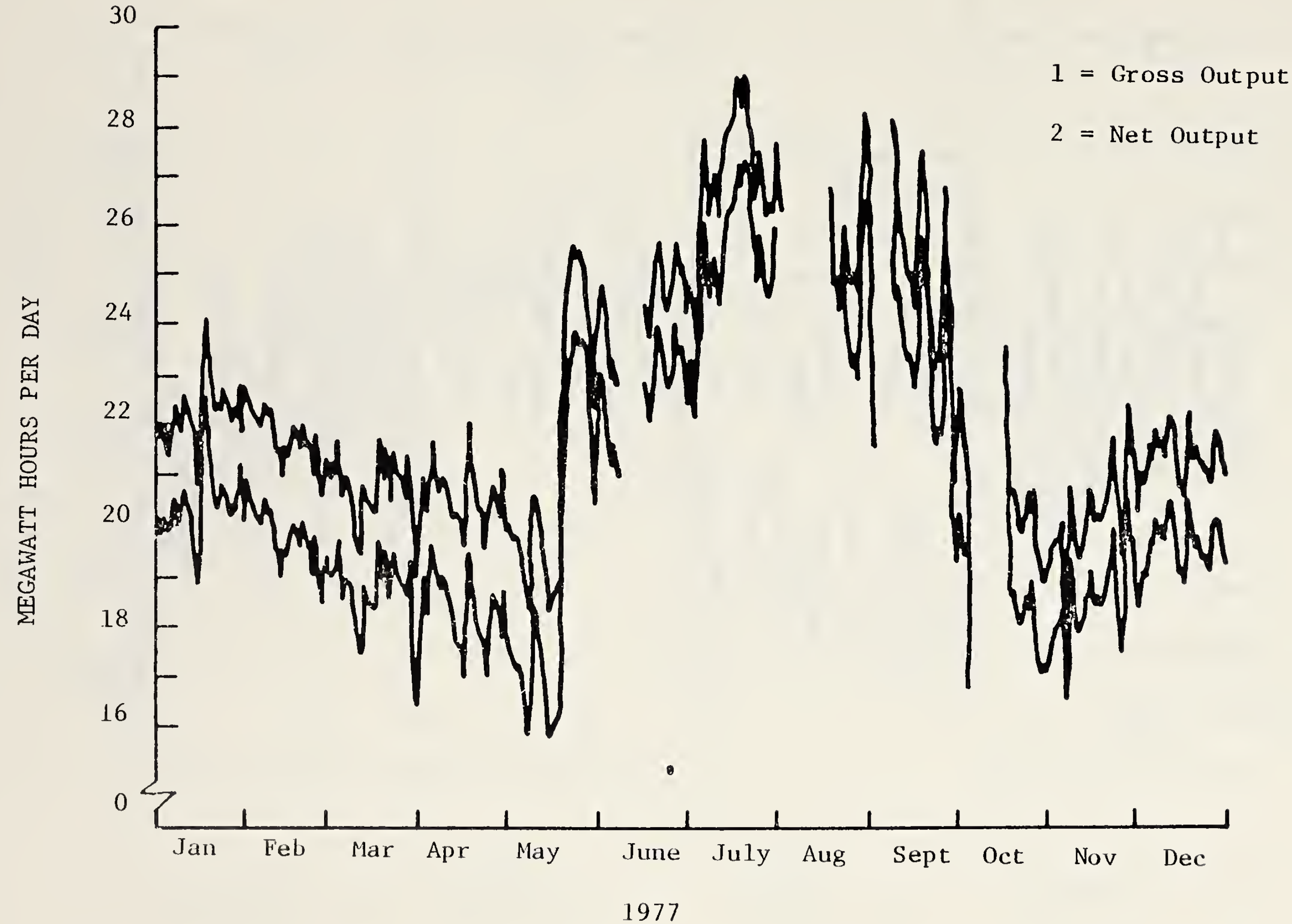

Figure 4.9 Gross and net output of the engine-generators during 1977. The net output is calculated as being representative of the electrical energy that would be purchased from the grid if the plant were not generating electrical power

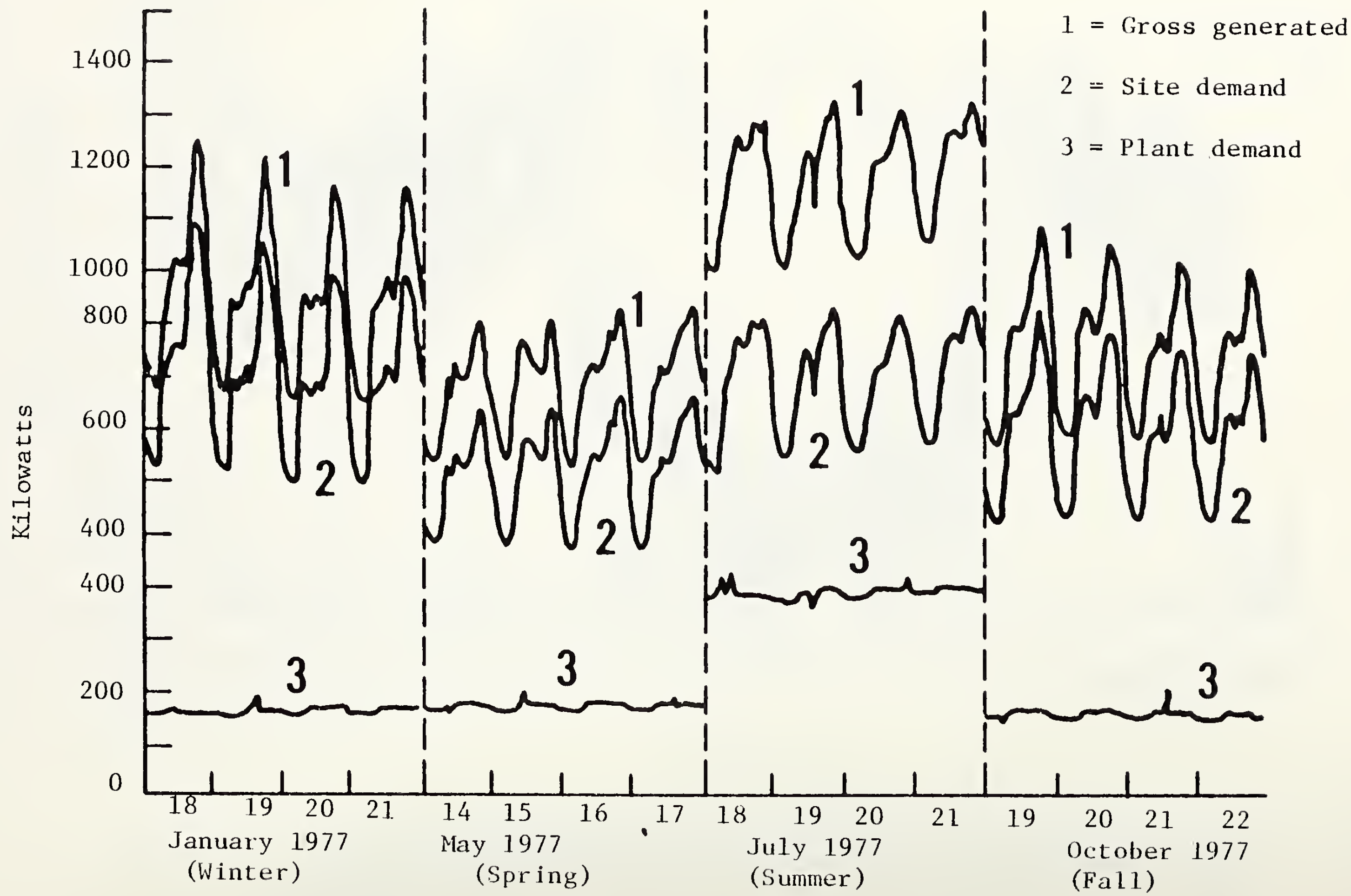

Figure 4.10 Hourly electrical energy demands of the site and plant for four days during each of the four seasons of the year

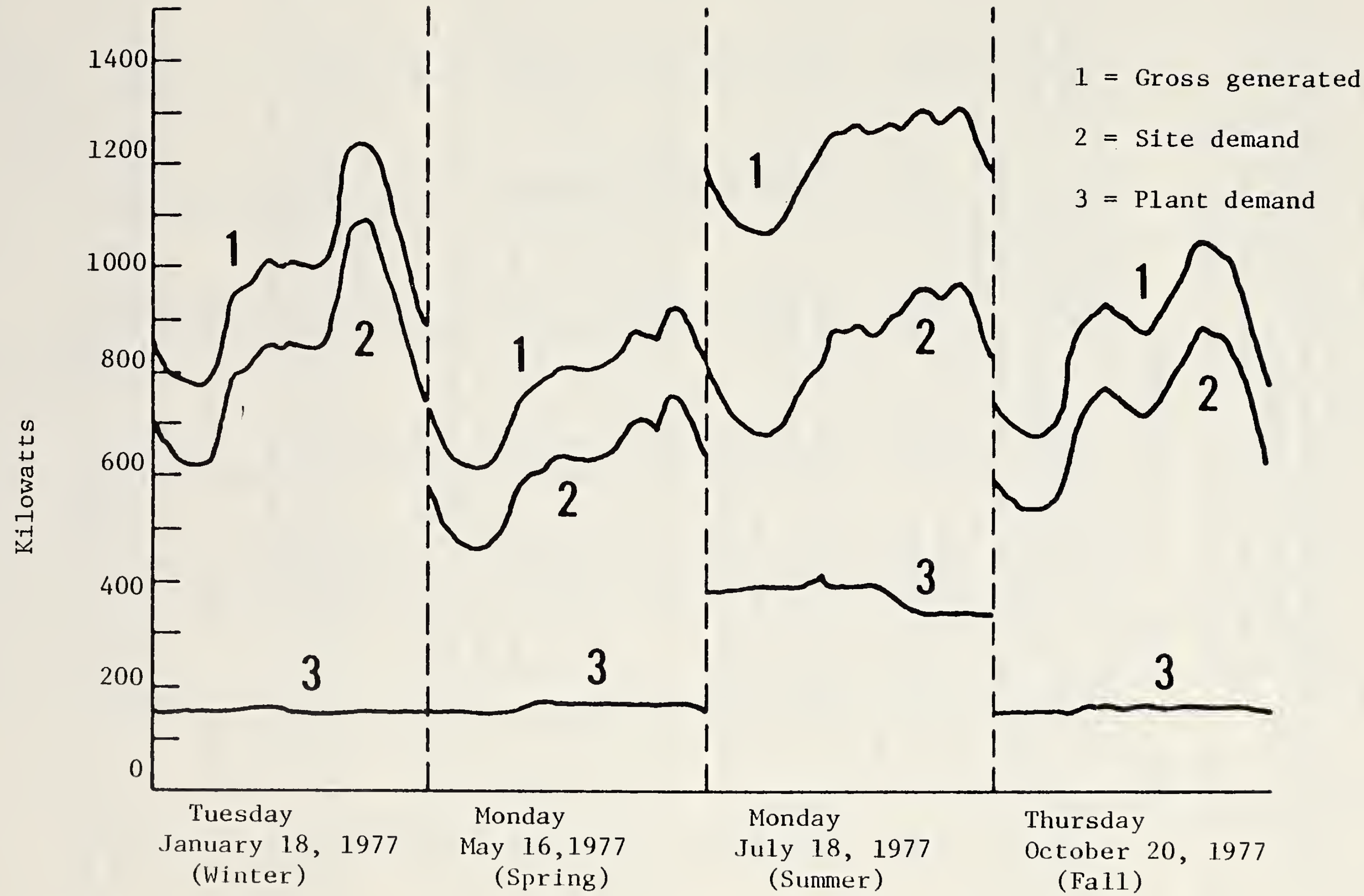

Figure 4.11 Profiles of hourly electrical energy demands of the site for one day of each of the four seasons of the year

4.2 THERMAL AND ELECTRICAL LOAD DATA FOR THE SITE BUILDINGS

Another task of the Summit Plaza total energy project was to collect data describing the individual site building demands for electrical energy and for the thermal energy for space heating, space cooling, and domestic hot water. These data establish a body of information which is useful to future designers and planners of total energy sites as well as providing data for the assessment of the present system and the building loads predicted by various methods prior to erection. The DAS recording the plant data was put in service April 1975. The remote DAS units were put in service November 1975.

4.2.1 Thermal Loads of Site Buildings

The four-pipe hot and chilled water circulation loops contain valved "bridge circuits" enclosed in pits outside the buildings. These valved bridge circuits prevent changes in plant line pressures from significantly affecting the balancing of flow within the several remote buildings. Also the bridge circuits allow the flow in the site distribution systems to be independent of the flow in the distribution systems within the buildings. A valved bridge circuit is simply a restricted bypass or "short circuit" between the plant supply and return lines with a balance cock installed to limit the flow in the bypass. The supply and return lines for the hot and chilled water for each building are connected to their representative bypasses on a manifold located on the higher pressure (plant supply line) side of the balance cock. In general, separate bypasses with a balance cock are installed in the hot water and chilled water loops to supply each building.

Tables 4.6 and 4.7 list the thermal energy consumed by the site buildings on the east and west distribution loops, respectively. Table 4.8 lists the thermal energy released to the chilled water loops by the site buildings. Problems with the venturis measuring the flow of space heating and cooling water invalidated much of the data for the Shelley A building. Unscheduled changes in capacities of other building circulation pumps and subsequent delay in the delivery of replacement differential pressure cells to accommodate the flow increase or decrease through the venturis were the primary cause for the excessive loss of other valid data.

The values for the swimming pool are not listed in the tables because the environment at the pool did not permit the instrumentation (thermal and electrical) to be satisfactorily maintained without undue effort. However, only minute quantities of thermal and electrical energy were required by the pool.

4.2.2 Electrical Loads of Site Buildings

The electrical loads of Shelley B and the commercial building are listed in table 4.9. Seasonal profiles of the electrical loads for Shelley "B" and the commercial building are shown in figures 4.12 and 4.13. The tabular data and the profiles are comprised of two parts; i.e., the electrical energy consumed from the normal bus and that consumed by the essential bus. The essential bus serves hall and stairway lighting, water pumps, the operation one elevator, and any other items necessary in the event of a failure of the site power plant.

Table 4.6 Monthly Hot Water Energy Use for the Site Buildings on the East Secondary Hot Water Loop (millions of Btu)

	Shelley "A"			Shelley "B"			School		
Month	Domestic hot water	Space heating	Total	Domestic hot water	Space heating	Total	Domestic hot water	Space heating	Total
1975									
November	363	555	918	100	368	468	NA	NA	NA
December	NA	NA	NA	107	458	567	NA	NA	NA
1976									
January	470	1290	1760	127	670	689	NA	NA	NA
February	419	873	1292	104	328	432	NA	NA	NA
March	404	740	1154	88	327	415	NA	NA	NA
April	314	653	967	57	184	241	NA	NA	NA
May	349	376	725	98	NA	NA	NA	NA	NA
June	322	Ø	322	90	Ø	90	.5	Ø	.5
July	277	Ø	277	88	Ø	88	.5	Ø	.5
August	260	Ø	260	87	Ø	87	.5	Ø	.5
September	257	Ø	257	80	Ø	80	.6	Ø	.6
October	288	NA	NA	82	237	319	.6	80	80.6
November	375	NA	NA	101	401	502	.6	160	161
December	448	NA	NA	113	NA	NA	.6	222	223
1977									
January	421	1492	1913	120	527	647	.6	234	235
February	345	NA	NA	112	NA	NA	.6	197	178
March	394	NA	NA	124	705	829	.6	104	105
April	322	NA	NA	117	247	364	.6	62	63
May	330	NA	NA	106	61	167	.6	11	12
June	305	Ø	305	91	Ø	91	.5	Ø	.5
July	327	Ø	237	75	Ø	75	.5	Ø	.5
August	NA	Ø	NA	NA	Ø	NA	.5	Ø	.5
September	132	Ø	132	NA	Ø	NA	.5	Ø	.5
October	NA	NA	NA	129	173	302	NA	NA	NA
November	268	853	1139	112	284	396	NA	NA	NA
December	354	1410	1764	121	492	613	NA	NA	NA

NA = Data not available. See text.

Table 4.7 Monthly Hot Water Energy Use for the Site Buildings on the West Secondary Hot Water Loop (millions of Btu)

	Descon			Camci			Commercial Building		
Month	Domestic hot water	Space heating	Total	Domestic hot water	Space heating	Total	Domestic hot water	Space heating	Total
1975									
November	156	364	520	219	454	673	NA	NA	NA
December	185	700	885	213	786	999	NA	NA	NA
1976									
January	204	745	949	248	1173	1421	NA	NA	NA
February	179	523	702	225	648	873	1	537	538
March	172	455	627	233	576	809	1	475	476
April	163	271	434	240	339	579	1	247	248
May	178	126	304	193	97	290	1	NA	NA
June	169	Ø	169	158	Ø	158	1	Ø	1
July	112	Ø	112	158	Ø	158	1	Ø	1
August	138	Ø	138	110	Ø	110	1	Ø	1
September	111	Ø	111	139	Ø	139	1	Ø	1
October	132	323	455	181	397	578	1	270	271
November	152	487	639	239	648	887	1	445	445
December	159	643	802	299	905	1204	1	564	565
1977									
January	175	780	955	268	1220	1488	1	623	624
February	148	722	870	240	NA	NA	1	NA	NA
March	161	576	737	272	437	709	1	322	323
April	139	292	431	253	291	544	1	225	226
May	123	69	192	266	53	319	1	173	174
June	109	NA	109	253	Ø	253	1	Ø	1
July	102	NA	102	251	Ø	251	1	Ø	1
August	NA	NA	NA	NA	Ø	NA	1	Ø	1
September	165	NA	165	NA	Ø	NA	1	Ø	1
October	120	350	470	NA	NA	NA	1	142	143
November	103	602	705	173	730	903	1	298	299
December	153	1061	1214	233	233	1359	NA	NA	NA

NA = Data not available. See text.

Table 4.8 Monthly Chilled Water Energy Use for the Site Buildings on Chilled Water Loops and the Plant (millions of Btu)

Month	Shelley A[1]	Shelley B	School	Plant Cooling coil	Plant Fan coil units	Descon	Camci	Commerical building
1976								
May	NA	NA	NA	10	Ø	NA	NA	NA
June	NA	161	NA	297	Ø	233	925	NA
July	NA	199	NA	396	Ø	260	358	107
August	NA	206	NA	401	11	308	373	417
September	NA	65	50	232	30	129	116	340
October	NA	9	NA	29	4	NA	NA	NA
1977								
May	NA	NA	NA	NA	NA	NA	NA	NA
June	NA	142	46	219	36	191	249	308
July	NA	251	60	358	40	313	577	383
August	NA	NA	NA	346	34	NA	NA	NA
September	NA	NA	NA	317	33	976	NA	NA
October	NA	NA	NA	32	6	NA	NA	NA

NA = Data not available. See text.

[1] Flow rate measurements problems in Shelley A mechanical room negated all Shelley A data.

Table 4.9 Monthly Electrical Energy Consumption for the Shelley B and Commercial Building (kilowatt - hours)

Month	Shelley B PE	Shelley B PN	Shelley B Total	Commercial Building PE	Commercial Building PN	Commercial Building Total
1975						
November	5145	51185	56330	NA	NA	NA
December	5320	58084	63404	NA	NA	NA
1976						
January	5748	60186	65734	2399	43261	45660
February	5386	54711	60097	2157	42739	44896
March	5318	55178	60496	2256	47787	50043
April	4117	50557	55674	2228	48235	47937
May	5152	56397	55549	2272	45889	50463
June	5003	52662	57665	2272	53572	48161
July	5239	53492	58731	2203	52758	55784
August	5244	50807	56051	2203	51131	54961
September	NA	NA	NA	2390	58770	53338
October	5188	55279	50467	2378	46525	51160
November	5231	52081	62081	2248	56744	48903
December	6608	62623	69231	2145	47713	49192
1977						
January	6263	63785	70048	2010	44997	50058
February	5442	57213	62655	2363	47365	47007
March	5614	58083	63697	2360	48726	49725
April	5258	53178	58436	2380	52064	51106
May	5189	49428	54617	2455	52064	54519
June	4807	48874	53681	1911	52167	54078
July	4931	41099	46030	1904	55491	57395
August	NA	NA	NA	NA	NA	NA
September	NA	NA	NA	NA	NA	NA
October	5422	51040	56462	1777	47418	51195
November	5108	53231	58339	1625	48055	49680
December	5528	58364	63892	NA	NA	NA

NA = Data not available
PN = Normal bus
PE = Essential bus

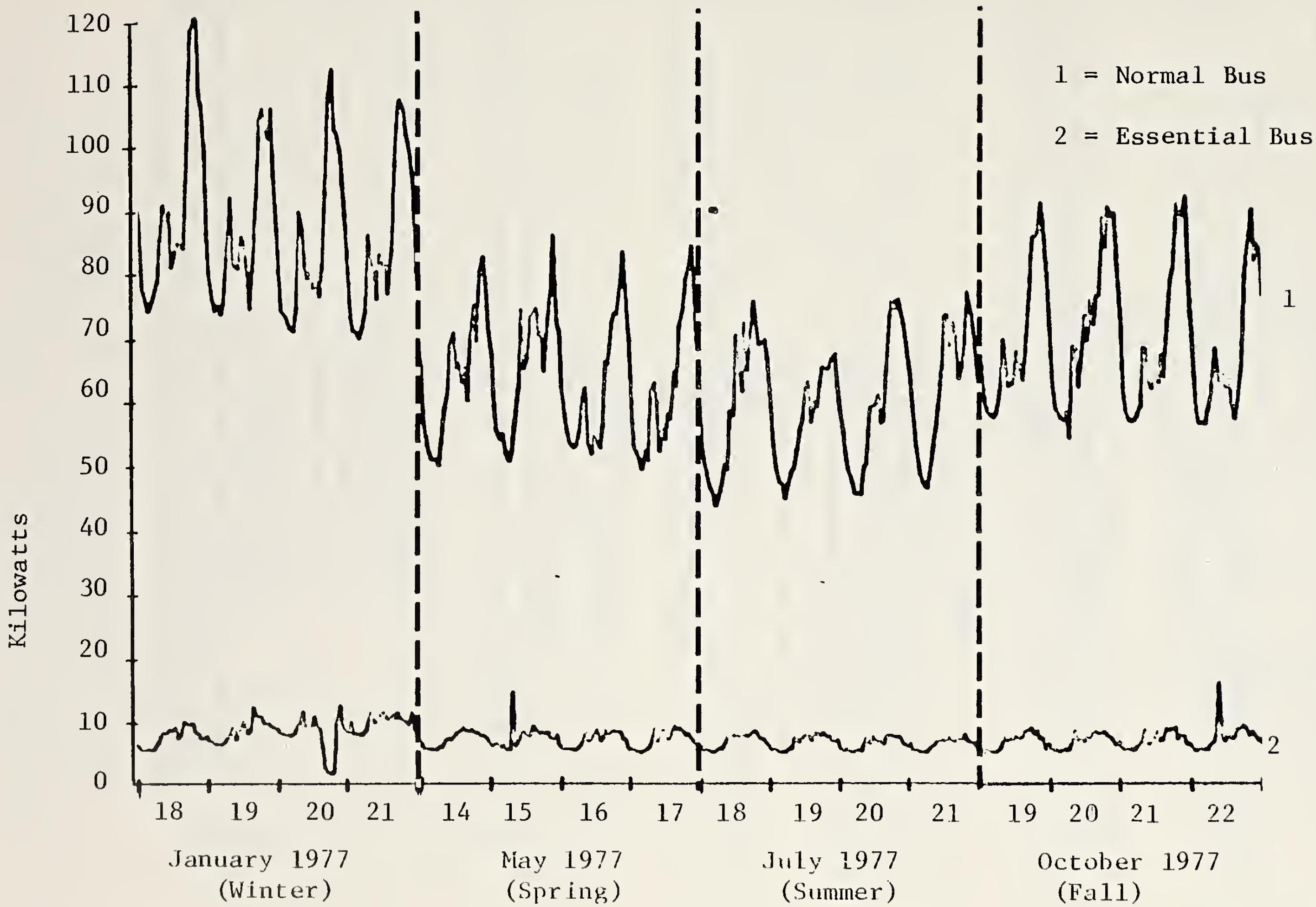

Figure 4.12 Seasonal profiles of electrical loads for the Shelley B residential building

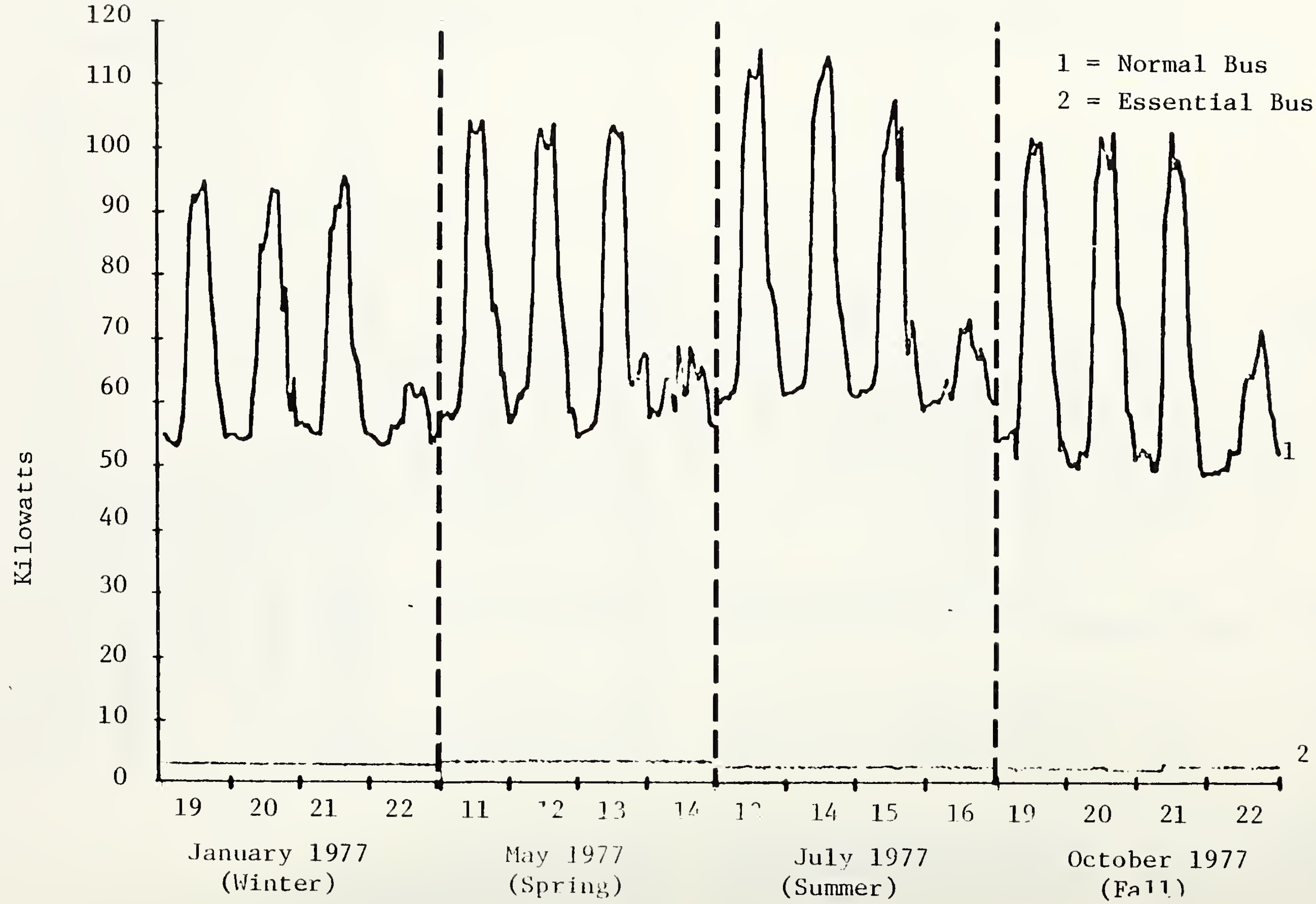

Figure 4.13 Seasonal profiles of electrical loads for the commercial building

During such an event, the essential circuits in the site buildings and the necessary power panels in the plant required to put the plant back on normal operation are automatically switched over to the local utility lines. When the plant is put back in service, the essential bus is switched back on the plant's power system. The normal bus is designed to carry all other circuits.

The seasonal profiles of the electrical loads indicate a diurnal pattern on the normal bus. These profiles are of special interest for the comparison of seasonal loads and because they show the relatively high load factors for the residential and commercial buildings. The high load factors of the normal bus in the residential buildings as well as the commercial building indicate that the essential bus is carrying only a small portion of the electrical energy normally consumed during typical plant operation.

The Shelley "B" building during the year 1977 had four levels of parking areas illuminated 24 hours each day. However, these lamps represent slightly less than 7 kW (8 percent) of the load. Following the monitoring period covered by this report, a timing switch was put on these lights and they no longer function 24 hours each day.

The most significant factor accounting for the high load factor in Shelley B is the load of the pumps, fans, etc. in the mechanical room and other areas of the building. Reference [4-1] lists a design load of 60 kW for this equipment with a total of 80 kW connected. The seasonal diurnal profiles shown in figure 4.12 reflects this reference value.

Another feature of interest is the weekly pattern for the commercial building. Each of the four seasonal profiles shown in figure 4.13 are for Wednesday, Thursday, Friday, and Saturday.

The electrical loads for the remote buildings are presented in a limited form in this section. Diagrams of the electrical system are shown in detail in reference [4-2]. The instrumentation for the electrical systems is also discussed in detail in this reference. Only three of the six site buildings (Shelley B, Commercial, and School) were properly instrumented because of misinformation about the electrical design when the instrumentation was being developed and installed. The entire site, including the plant, operates on a three-phase, four-wire "Y" configuration and requires monitoring of all three phases for unbalanced loads. An incorrect specification issued during the construction phase of the Summit Plaza project resulted in instrumentation in several buildings having only two of the three phases monitored with resultant erroneous data. Monitoring only two phases of a three-phase, 4-wire system is accurate only for balance phase loads (reference [5-8]). In March 1977, the loads on the phases of the lines in the various buildings were periodically monitored using portable test equipment. Some of the measurements indicated that the ratio of the loads on the individual phases varied as much as 2 to 1.

Although the electrical supply to the school was monitored on each of the three phases, the data is limited because of an unavoidable delay in getting the school remote DAS station on-line with the recording DAS. The data available from the school indicated that less than 3 percent of the electrical energy consumed by the site buildings was consumed by the school. For these reasons, the data presented in table 4.9 are limited to the Shelley B and the commercial buildings.

4.3 REFERENCES - SECTION 4

4-1. H.D. Nottingham and Associates, Inc., "Design, Cost and Operating Data for Alternative Energy Systems for the Summit Plaza Complex, Jersey City, N.J.," National Bureau of Standards Report GCR 79-164, May 1979.

4-2. Bulik, C., Rippey, W., Hurley, C., and Rorrer, D., "Description of the Data Acquisition and Instrumentation System; Jersey City Total Energy Project," National Bureau of Standards Report NBSIR 79-1709, March 1979.

5. ENGINEERING ANALYSIS - PLANT COMPONENTS, SUBSYSTEMS, AND SYSTEM

This section presents analyses of the flow of energy through the Summit Plaza Total Energy System and its major components and subsystems for the 33-month period covered by the DAS data. Descriptions of energy flows in the system are presented in such a manner that the effect of present and modified system operation on energy use can be more readily understood.

This section also presents information on the engineering performance of the major plant components and subsystems from an energy point of view. Analyses of mean efficiencies and losses are reported for the engine-generators, boilers, chillers, primary hot water loop, and the site distribution systems. Operational considerations relevant to the energy usage of the components and subsystems are also discussed.

5.1 OVERALL ENERGY BALANCE FOR THE PLANT

The overall energy effectiveness of the plant in meeting the demands of site, including site distribution losses, can be expressed by dividing the total energy leaving the plant (electrical and the thermal) by the total energy of the fuel oil consumed by the plant (using the higher heating value of the fuel oil). The monthly values of this quotient are listed as percentages in table 4.4. The profile of these values for the 33-month period is presented in figure 5.1. It should be noted that the seasonal demands of the site and the performance of the plant components are reflected in figure 5.1. During the colder months, the relatively high efficiency of the boilers together with the thermal energy recovered from the engines result in the higher peaks of the plant energy effectiveness profile. However, during the warmer months the COP of the absorption chillers and the additional electrical energy required to operate the chillers result in lower values for the plant energy effectiveness.

More detailed analyses of the performance of the individual components and subsystems follow in this section. The overall plant energy effectiveness profile is presented here to assist the reader in correlating the relative significance of the component and subsystem performance with the overall energy balance profile for the plant.

5.2 PERFORMANCE ANALYSIS OF PLANT COMPONENTS

5.2.1 Engine Generator Performance

The electrical and thermal efficiencies of the engine-generators of a total energy plant are crucial to the energy efficiency and the economic well-being of the plant. At the Summit Plaza site, five 600-kW diesel engine-generator units are installed to supply all of the electrical energy for the site. Three of these units are capable of supplying the total load at any one time. Five units were installed at the time of construction to allow one unit to be available as a standby while a second unit was being serviced.

These Caterpillar Tractor Co. model D-398, V-12 diesel engines with the generators attached were purchased by the plant designer. The units were

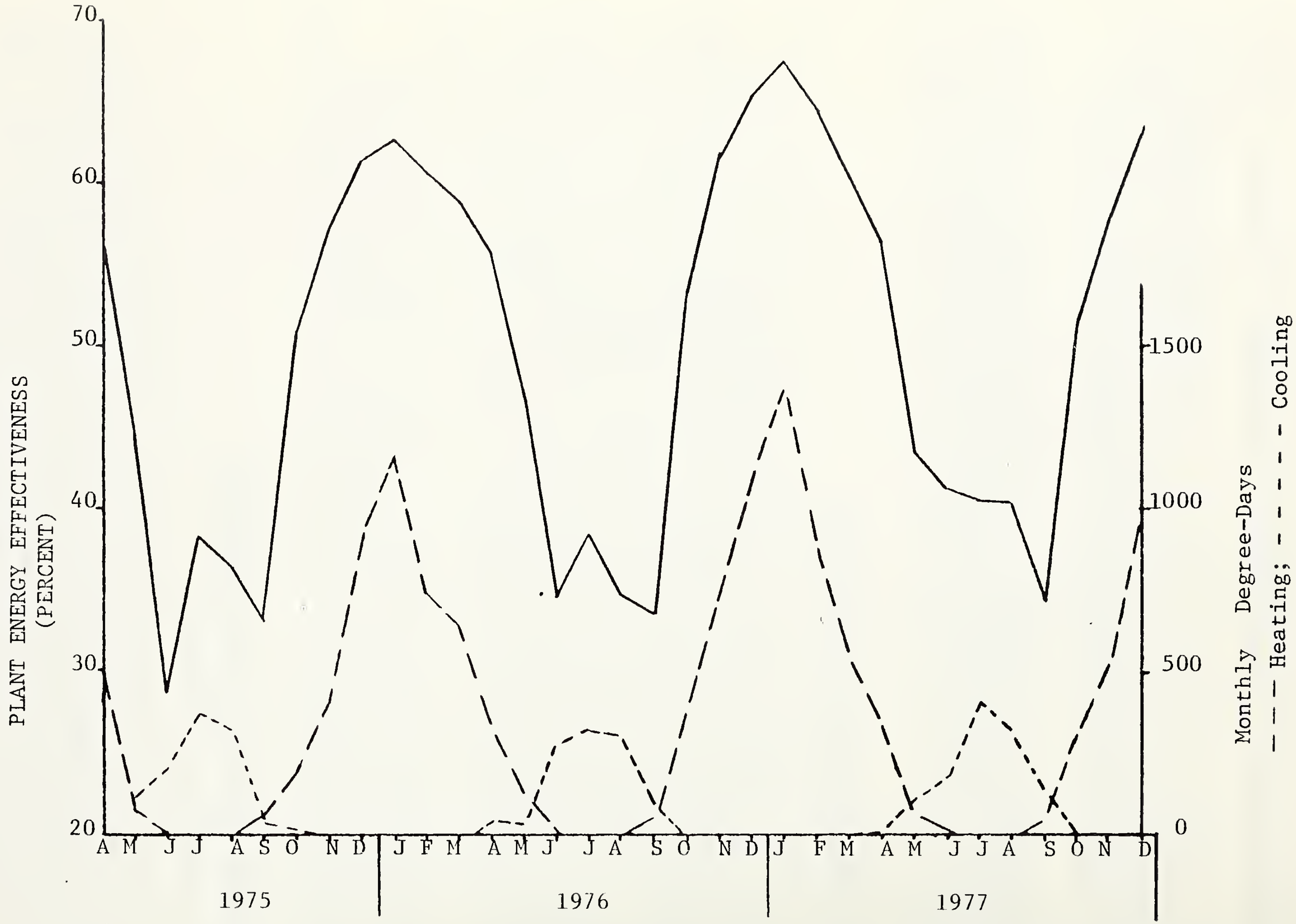

Figure 5.1 Profile of monthly plant energy effectiveness (see section 4.4 for definition) and heating and cooling degree-days

factory-tested simulating anticipated plant conditions under the direction of NBS prior to installation at the Summit Plaza plant. The results of these tests are given in detail in references [5-1] and [5-2]. The four-stroke cycle engines are designed to operate at 1200 RPM and are equipped with turbochargers and aftercoolers. The electrical generators are designed to deliver 600 kW at 480 volts, threephase, and 60 hertz for normal industrial use. For energy service using higher temperature cooling water, the manufacturer rates these engine-generator units at 475 kW.

The average monthly electrical efficiency of the engine-generators for 1977, as shown in table 4.4, was 32.1 percent which is slightly higher than the value of 31.2 percent reported in the factory tests of the units prior to installation. In addition to good electrical efficiency, one of the major features determining the success of a total energy installation is the recovery and use of the thermal energy normally rejected by the engines driving the generators. At the Summit Plaza plant, the five engines are connected in parallel in the primary hot water loop with approximately equal rates of hot water flowing through each engine. The primary hot water flows in series through the water jacket and exhaust heat exchanger of each engine. The thermal energy values listed in table 4.1 as "recovered from the engines" represent the net thermal energy gained by the primary hot water (PHW) loop from the entire bank of five engines. This net value includes the thermal losses from the engines both on and off line. Note that water flows continuously through all engine regardless of whether they are on or off line. A series of electrical load profiles are presented in section 4 (figures 4.9 through 4-11) which are representative of the electrical energy produced in the plant.

Figure 5.2 presents the gross electrical output and the net thermal energy recovered from the bank of the five engines during one of the lower electrical energy demand days and one of the higher electrical energy demand days during the year 1977. These profiles indicate that the net thermal energy recovered from the bank of engines tends to follow the gross electrical output; the recovered thermal energy being slightly less than the gross electrical output for the condition of the exhaust gas heat exchangers on the days shown. The accumulated values of the electrical energy and recovered thermal energy are listed in figure 5.2 for each of the two days.

Analysis of the data indicated three major areas in which energy losses in the engine-generators could be avoided or significantly reduced:

(1) thermal losses from idle engines,
(2) reduced heat recovery caused by the accumulation of deposits in the exhaust heat exchangers on each engine, and
(3) operation of the engines at low loads.

Each of these three areas is discussed in following subsections.

5.2.1.1 Thermal Losses from Idle Engines

Figure 5.3 presents the thermal energy recovered (or lost from engine number 2 under the three basic modes of operation: (1) the engine on line producing

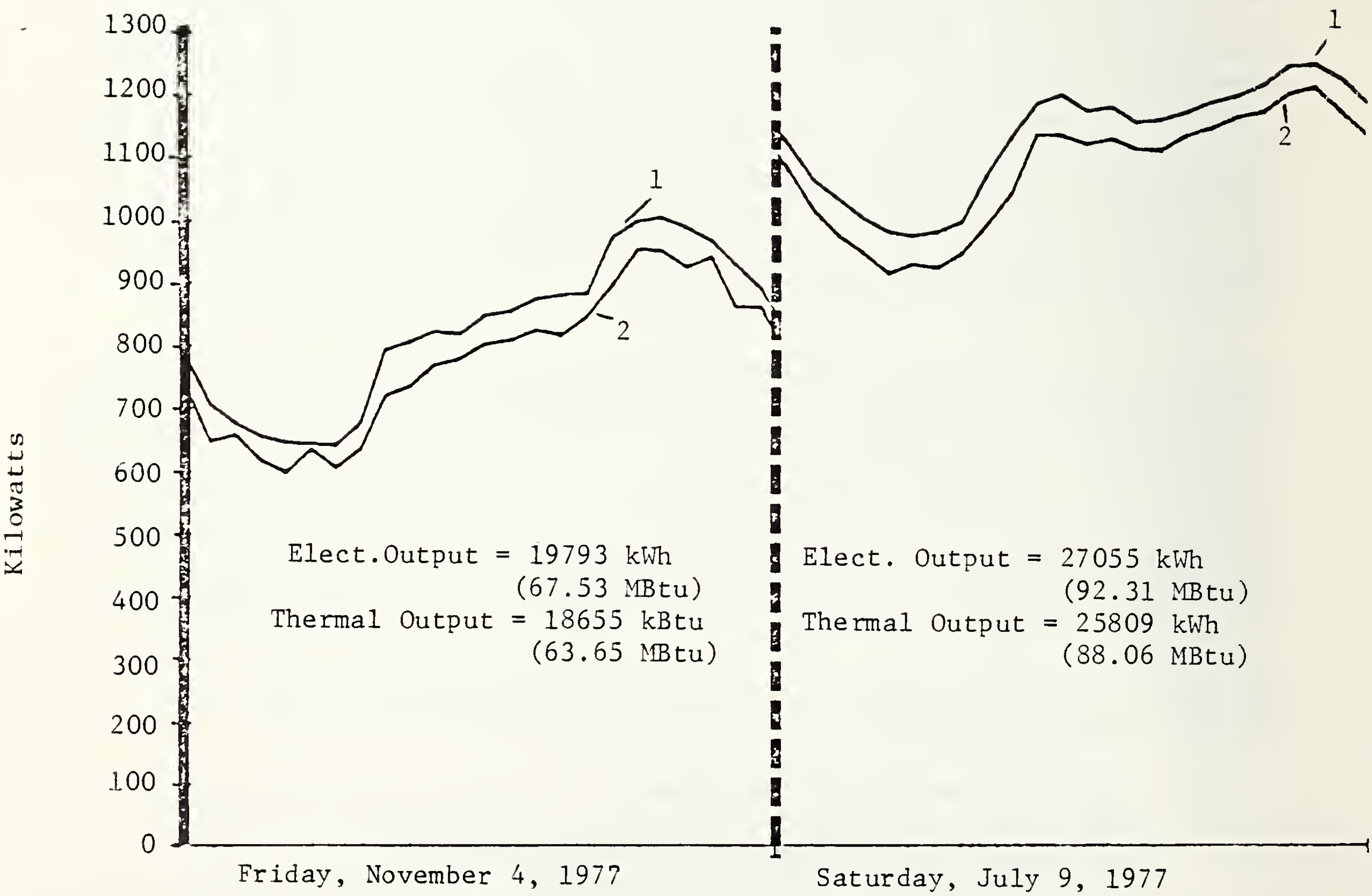

Figure 5.2 Profiles of the gross electrical output and the net thermal energy recovered from the engines. Two days are shown: November 4, 1977 is representative of one of the lower electrical energy demand days of the plant while July 9, 1977 represents one of the higher electrical demand days of the plant. In both cases, the exhaust heat exchangers had not been cleaned for a period of over 30 days.

electrical and thermal energy; (2) the engine not running but remaining in the PHW loop in parallel with the other four engines; and (3) the engine valved out of the PHW loop for minor repairs. Figures 5.3 indicates that engine number 2 was taken off line on May 12, 1977 and put back on line on May 19, 1977. It was valved out of the PHW loop on May 16, 1977. While the engine was valved out of the PHW loop, the thermal output of the engine was zero. However, when the engine was not running and the PHW was flowing through the jacket and exhaust gas heat exchanger, there were thermal energy losses from these idle components. Using the daily values accumulated by the DAS for engine number 2 on May 15, 1977, the loss from the exhaust gas heat exchanger was 964.5 kBtu (1017 MJ) per day. The loss from the jacket was 1431 kBtu (1510 MJ) per day making the total loss 2396 kBtu (2528 MJ) per day or 874.6 MBtu (922.7 GJ) per year for each idle engine in the PHW loop.

Over 7,600 gallons (28.8 m^3) of fuel oil are required per year by the boilers to make up the thermal losses from each idle engine, assuming a boiler efficiency of 83.3 percent and a HHV of 139,000 Btu per gallon for number 2 fuel oil.

Since the maximum plant load requires only three engines, the fourth engine could remain in the PHW loop as a stand-by while the fifth engine is valved out of the PHW loop. Aspects other than fuel savings must be considered in the decision to bypass one or more of the idle engines. The primary concern would be that a valve failure could cause damage to the engine. The reliability and costs of a control system to accommodate this concern must be considered in the cost/benefit analysis for this retrofit. A second concern would be the time required to bring a "cold" engine up to the required temperature before putting the unit on line.

An optional concept in reducing the losses from the idle engines is by-passing the exhaust gas heat exchangers on all idle engines. This technique could be accomplished by automatic valving and still allow the jackets of all idle engines to remain in the PHW loop at all times. Since over 40 percent of the total losses from the idle engines are from the exhaust gas heat exchangers, over 6,000 gallons (22.7 m^3) of fuel oil could be saved annually. This concept reduces the costs and risks involved in valving off an entire engine. Installation of automatic by-pass valves appears to present minimal risk.

5.2.1.2 Thermal Losses from Deposits in the Exhaust Heat Exchangers

The second major area of energy loss identified in the analysis of the enginegenerator thermal data was the rapid decrease in thermal energy recovered from the two-pass fire-tube exhaust heat exchangers in relatively few days after the tubes were cleaned. Figures 5.4 and 5.5 are representative of a typical cycle.

Engine 2 was taken off line on January 3, 1978, and after the tubes were cleaned, put back on line the following day. Figure 5.4 indicates a relatively consistent diurnal pattern for the temperature of the exhaust gases entering the heat exchanger. However, the temperature of the outlet gases from the heat exchangers show a rapid increase with operating time after the tubes were cleaned.

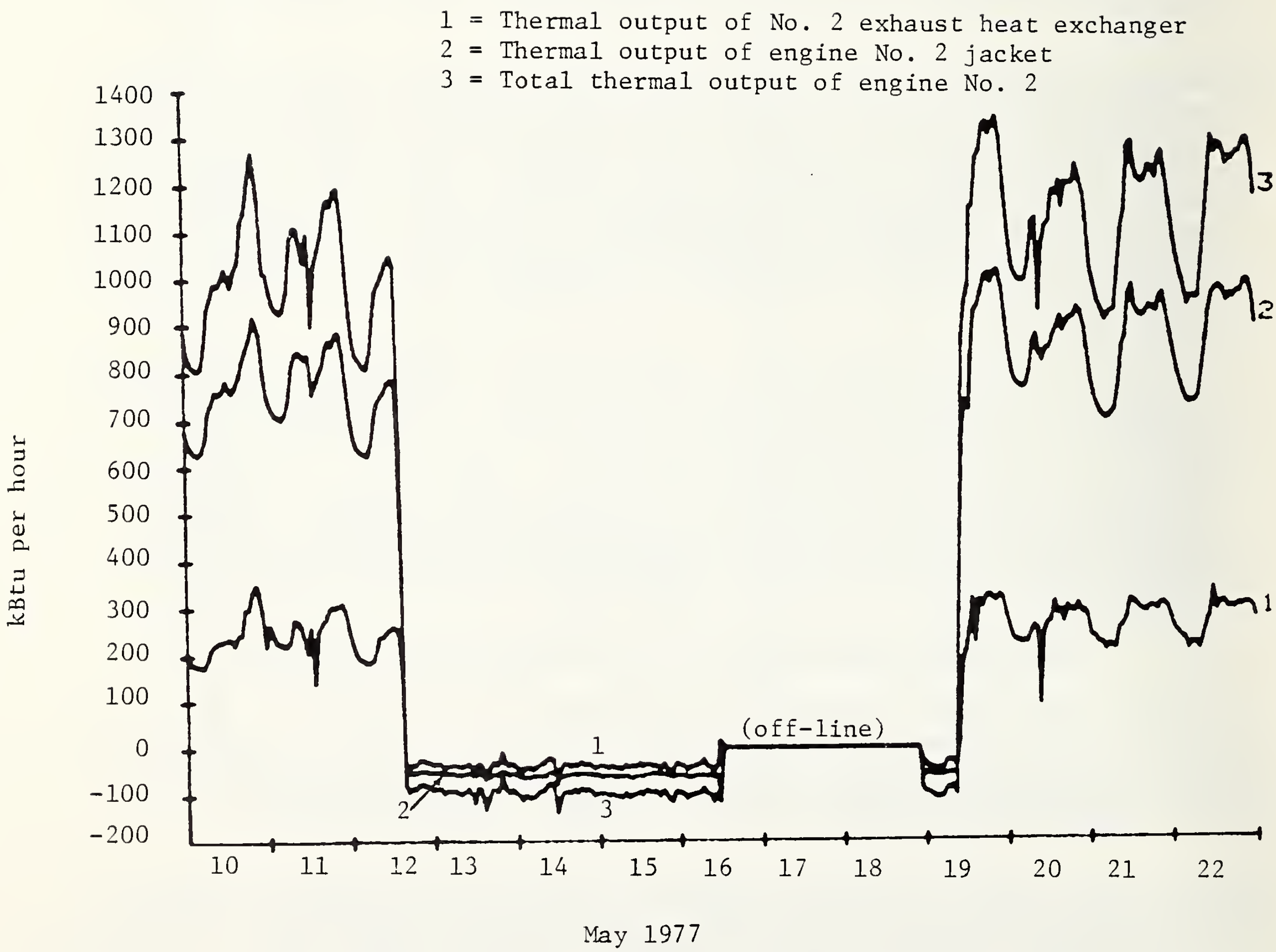

Figure 5.3 The thermal energy recovered (or lost) from engine No. 2 under three modes of operation: on line, off line and valved out of the PHW loop. See text for details.

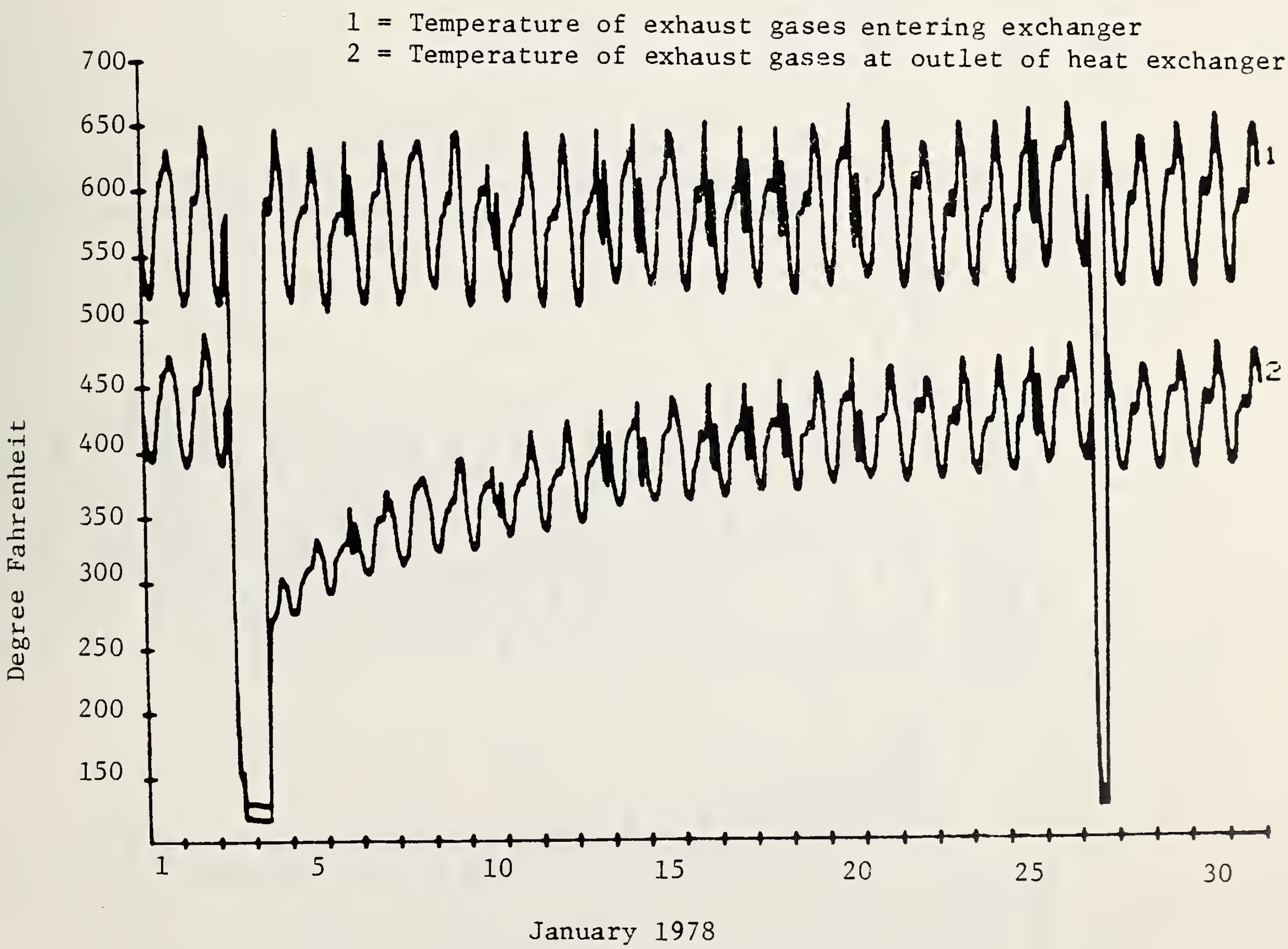

Figure 5.4 Temperature of exhaust gases from engine No. 2 entering and leaving the exhaust gas heat exchanger. The unit was taken off line January 3, 1978, the exchanger cleaned and the unit put back on line January 4, 1978. The rapid accumulation of deposits in the tubes of the exchanger are indicated by the increase in the outlet temperature.

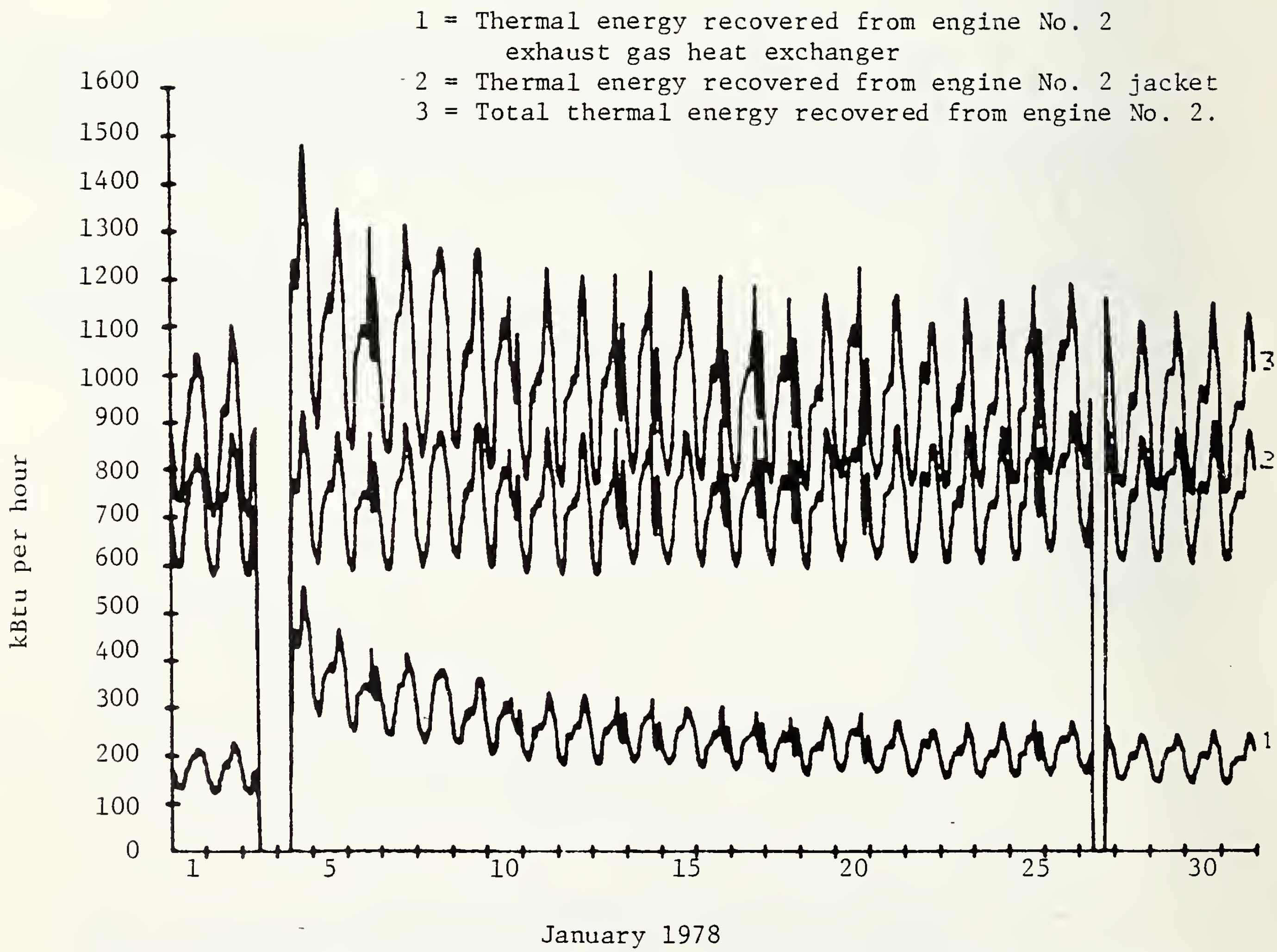

Figure 5.5 Thermal energy recovered from engine No. 2. The accumulation of deposits in the tubes of the exhaust heat exchanger is reflected in curves 1 and 3.

Figure 5.5 presents the thermal outputs of engine no. 2 during the same period as shown in figure 5.4. While the diurnal pattern of the thermal output of the engine jacket remains at a relatively constant level, the output of the exhaust heat exchanger reflects the changes indicated in the temperature profiles shown in figure 5.4. An analysis of the daily thermal values from the DAS for engine no. 2 is shown in table 5.1.

Table 5.1 Output of Engine No. 2, January 1978

Date	Electrical output gross	Thermal Output Exhaust heat exchanger	Jacket	Total
2	6790 kWh	4.121 MBtu	17.13 MBtu	21.25 MBtu
5	7133 kWh	8.924 MBtu	17.74 MBtu	26.67 MBtu
15	7132 kWh	6.795 MBtu	17.72 MBtu	23.52 MBtu
31	6939 kWh	4.535 MBtu	17.68 MBtu	22.22 MBtu

The thermal output of the engine no. 2 exhaust heat exchanger was increased by a factor of 2.2 by the cleaning of the unit on January 4. However, within 26 days the thermal output dropped to 52 percent of the output of the clean unit. These values indicate over 25 percent increase in the total thermal output of engine no. 2 after cleaning the exhaust heat exchanger and, after 25 days, a drop of over 16 percent in the total thermal output.

The net effects of cleaning all of the exhaust gas heat exchangers are shown in figure 5.6 where the daily values from the DAS of the gross electrical energy generated by the three on-line engine-generators are plotted together with the daily values of the net thermal energy recovered from the entire bank of engine jackets and exhaust heat exchangers. The thermal profiles reflect the thermal losses from the idle engines as well as the effects of accumulation of matter in the tubes of the exhaust gas heat exchangers.

Using the same DAS values used to produce the profiles in figure 5.6, the net thermal energy recovered from the engines was calculated to be approximately 7.6 percent greater than the electrical energy on January 5. On that day, the system was operating with three exhaust heat exchangers having two days or less of service after cleaning. During the period January 25 to January 27, the on-line engines were changed and consequently an increase in thermal energy recovery from exhaust gas heat exchangers is indicated. On January 31, the heat exchangers on the bank of five engines had from 8 to 27 days of service after cleaning. The three engines on line on that date had from 13 to 27 days of service after cleaning. However, the net thermal energy recovered from the bank of engines had fallen approximately from 7.6 percent greater than the electrical output to 8.6 percent less than the electrical output. Figure 5.7 shows the gross electrical output of the three on-line units and net thermal output of the entire bank of engines on January 5 and January 31, 1978.

Since many parameters affect the net thermal output of the engines (e.g., the PHW loop temperature, the ambient temperature of the engine room, the individual

Figure 5.6 Gross electrical output of the three on-line units and net thermal energy recovered from the entire bank of engines. The exhaust gas heat exchangers were cleaned during the period December 26, 1977 through January 3, 1978. On the January 25 and 26, the on-line engines were changed. Two engines with less deposits in their exhaust gas heat exchanger were put on line and consequently a rise in the net thermal energy recovered from the engines is indicated. The overall effects of the deposits in the exhaust gas heat exchangers are reflected in these curves. The jackets and exhaust gas heat exchangers of all five engines were in the PHW loop during the period shown.

electrical/thermal characteristics of the on-line engines, the number of doors open in the engine room during periods of repair, etc.), the quantative daily values of thermal energy shown in figures 5.2 and 5.7 should not be used for a rigorous comparative analysis. If such an analysis is desired, the hourly data should be examined for the period of interest. From an analysis of data for the month of January 1978, an estimate of the annual fuel savings can be projected based on the known parameters for this month. Such parameters include the recorded dates of the cleaning of the exhaust gas heat exchangers and the on- and off-line periods of the engines.

Using the month of January 1978 as a model and computing savings for each month of 1977, using the appropriate electrical output, boiler efficiency, and high heating value (HHV) of the fuel oil, an annual savings of over 37,000 gallons (140 m^3) are indicated by operating engines with four or less days of service after the exhaust gas heat exchangers have been cleaned.

In general, these savings can be accomplished by cleaning three exhaust gas heat exchangers every four days, or less than one per day if a simple schedule is followed based upon the number of hours an engine has been on line since the last date of cleaning. Considering the present design of the exhaust gas heat exchangers at the Summit Plaza plant, minor modifications would be required to facilitate this procedure. For example, a fast and simple method of opening and closing the access doors to the units (such as used on an autoclave) and a vacuum/brush combination or other type of abrasive cleaning device with a vacuum unit to collect the ash deposits could be utilized in the procedure (such units are now commercially available). These items would minimize the labor required for brushing operations and cleanup, and reduce the cost to accomplish the cleaning.

If the shorter interval of regular cleaning were accomplished, additional benefits would be obtained. For example, the porous nature of excessive deposits in the tubes of the exchangers have other negative effects such as allowing the flue gas to come in contact with the metal under somewhat static conditions. This gas is cooled below the dew-point temperature by the water on the other side of the tubes. The resulting moisture in combination with the acid ash promotes rapid corrosion under the coating even though the temperature of the gas leaving the exchanger may be at an elevated temperature [5-3]. This known action is an additional incentive for keeping the exhaust heat exchangers clean. A second example is the reduction in each cleaning effort due to the smaller quantity of deposits.

5.2.1.3 Variations in Engine-Generator Efficiency with Load

With the exception of a short period (less than 2 months) during the 33 months of data collection covered by this report, the plant was operated using three engine-generators on line 24 hours each day. During the short period the plant was operated part time using two engine-generators, the third unit was taken off line after the last cycle of the pneumatic trash collector (PTC) (which at that time was at midnight) and put back on line the next morning before the first PTC cycle. Using their rated capacity of 600 kW, it will be noted from figures 5.2 and 5.7 that two engines are capable of operating the plant the vast majority of the time. Figure 5.2 indicates that for only one or two hours on exceptionally high demand days did the load slightly exceed 1200 kW. However, the plant was operated using a maximum level of 480 kW per generator, leaving "120 kW per generator to handle transient loads" [5-4].

Several problems were involved in determining the most practical method of analyzing the engine-generator operation. First were the concerns of the plant operator relative to adequate reserve for "transient loads" typical of a site such as Summit Plaza [5-4]. Second were the transient loads of the PTC system which automatically starts and runs a 150 hp (112 kW) motor 15 to 17 times each day for a five-minute period each hour from 7:00 a.m. to 11:00 p.m. (The scheduling for this automatic operation has been varied from time to time.) Probably the most significant of these items is the PTC transient load which is the largest and can usually be predicted, except when problems occur in the PTC system and manual operation is necessary.

Using the 480 kW value as a maximum steady-state rating for the units established in reference [5-4], and observing figures 4.9 and 4.10, it can be seen that the plant could have been operated part time during the winter and fall season and throughout the spring season on two units. The additional electrical loads of the absorption chiller system during the summer months require three units, using 480 kW as the steady-state maximum.

During those periods when the electrical load is low enough to be carried by two units but three units are on line, the efficiency/load curve shown in figure 5.8 and the diurnal profile of the efficiency of engine-generator unit no. 2 shown in figure 5.9 clearly indicate a reduction in the efficiency as the units are operated at the lighter loads. These numbers are further confirmed by the pre-installation tests at the factory reported in reference [5-1].

In analyzing these data, one month was selected for each of the four seasons of the year 1977. Each hour of the selected month was scanned for electrical loads, using 960 kW (2 x 480 kW) as the maximum steady-state load between the hours of 7:00 a.m. and midnight, and 848 kW (960 kW - 112 kW to operate the PTC) as the maximum steady-state load been midnight and 7:00 a.m. Approximately 7300 gallons (27.6 m^3) of fuel could have been saved in 1977 by taking the third engine-generator off line when the maximum steady-state load fell below the established values within the given time frames. These fuel savings are considered to be conservative since the PTC load is a short-term load (5 minutes each hour) (in addition to its starting load) and could be divided between two engine-generators units operating at 480 kW or less without damage, still allowing reserve up to 600 kW for transients (including the starting transient of the PTC itself).

In addition to the conservation of fuel oil, the total engine running hours would be reduced by approximately 2200 engine-hours per year. This reduction would reduce maintenance costs and extend the life of the engines. In general, for 8 months of the year the plant can be operated with an average of 9 hours per day with two engines and an average of 15 hours per day with three engines.

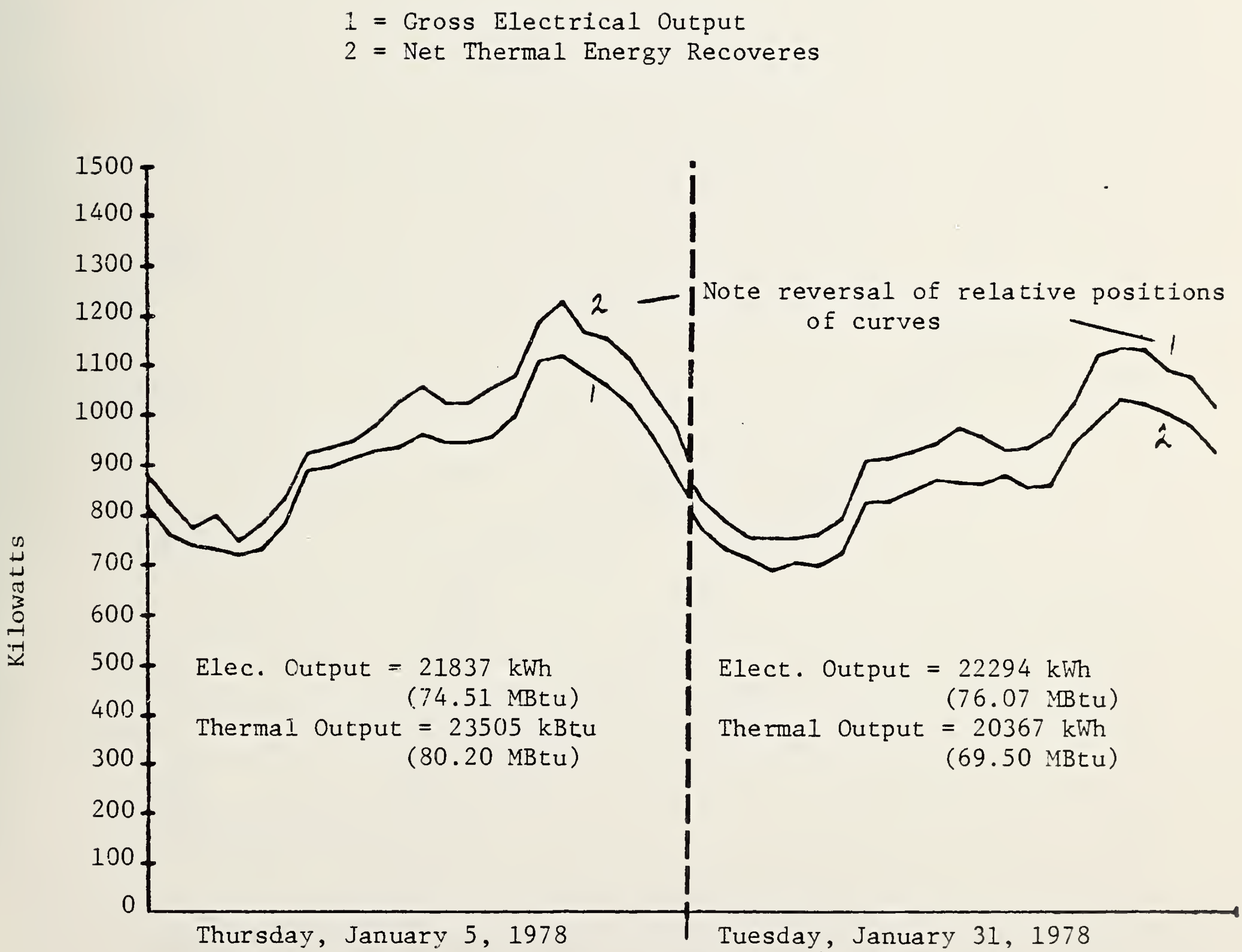

Figure 5.7 Gross electrical and net thermal output of all engines. On January 5, 1978, the electrical system was operating with three exhaust heat exchangers with two days or less of service after cleaning. On January 3, 1978, the system was operating with exchangers having from 13 to 27 days of service after cleaning. The jackets and exhaust gas heat exchangers of all five engines were in the PHW loop for the two days shown.

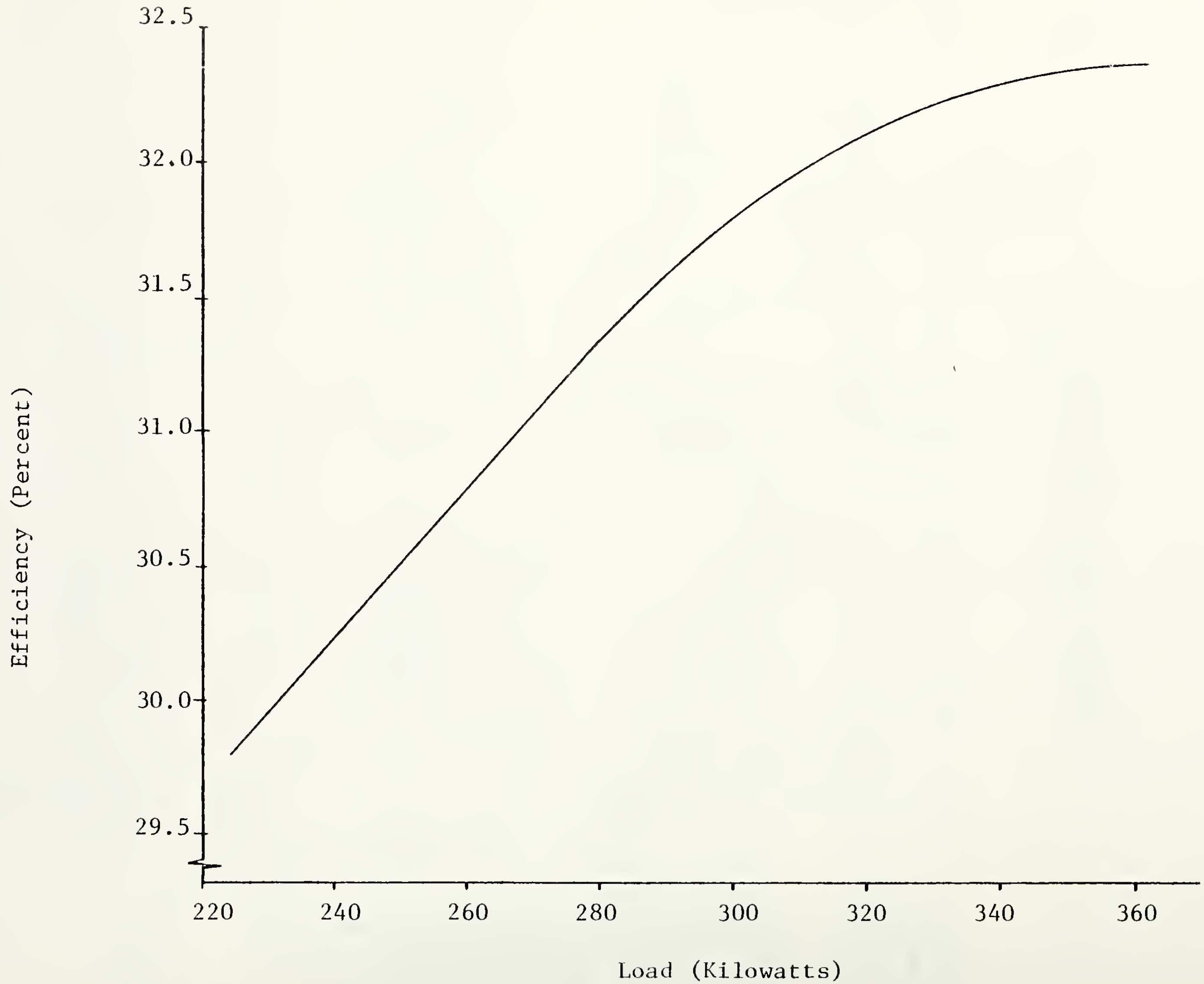

Figure 5.8 Efficiency-load curve for engine generator No. 2. This curve reflects data taken on an hourly basis during a 24-hour period in January 1978.

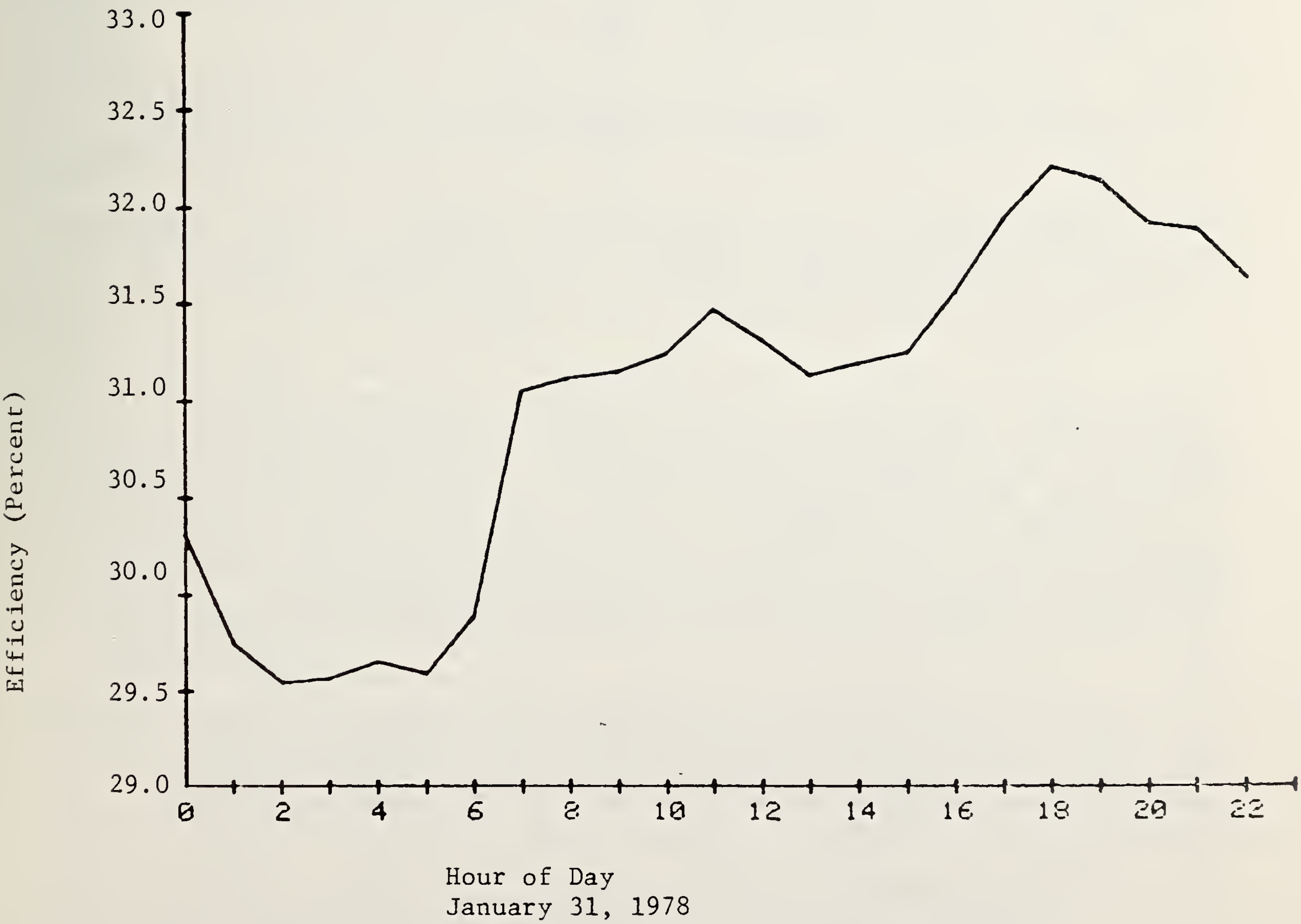

Figure 5.9 Diurnal profile of electrical efficiency of engine-generator No. 2. This curve reflects data taken on a hourly basis during a 24-hour period in January 1978.

The remaining 4 months of the year (June, July, August, and September) would not require the continuous operation of 3 engines. However, the average time per day the plant could operate on 2 engines is very low (0 to 4 hours) and the complications relative to excessive starting, wear on the starting motors, controls, etc., would not justify the shorter periods of 2-engine operation.

5.2.2 Boiler Performance

The Summit Plaza Total Energy Plant is equipped with two Cleaver-Brooks 13.4 MBtu (3.9MW) oil-fired, hot water boilers capable of meeting the thermal demands of the PHW loop even without the thermal energy recovered from the engines. The two boilers are piped and valved so both, either, or neither boiler is in the PHW loop. When both boilers are in use they are connected in series in the PHW loop. The valving and controls are so arranged that either boiler can put in the lead position using the lagging boiler to operate only when the lead boiler cannot meet the load. This happens only at extreme conditions such as those shown in figure 4.8 for the month of January 1977, one of the coldest months on record for this area.

DAS data indicated that an idle boiler continually losses an average of 100 kBtu per hour (29 kW) of primary loop thermal energy to the surrounding environment in the plant. When both boilers are connected to the PHW loop, the losses of the idle boiler must be made up by the operating boiler. At the boiler firing efficiency of 84 percent (see appendix C), the operating boiler would consume approximately an additional 7500 gallons (28.4 m^3) of fuel oil each year if the lagging boiler is left on line during months when it is possible that peak demands can be met by a single boiler.

Valving a boiler in and out of the PHW loop in the present design of the plant requires manual intervention. An analysis of the DAS data performed after 1976 indicated that the output of a single boiler could meet the demand of the site even under the most severe weather conditions. The profiles shown in figure 4.8 indicate that the controls on the leading boiler did not allow the output of the leading boiler to exceed approximately 75 percent of its rated capacity before firing the lagging boiler. During the severe weather conditions of 1976/1977, it was probably advisable to have both boilers on line in case of malfunction. However, for the 33-month period, the DAS data indicated that both boilers were on line for a total of 22 months, only 4 months of which appear to warrant having the two boilers on line (see table 4.3). With the exception of those months when it is advisable to have both boilers on line in case the leading boiler should malfunction, the ease of valving off a boiler and the fuel saved make it advisable to keep only one boiler on line. It should be noted that detailed data analysis was performed too late for immediate system correction.

5.2.3 Chiller Performance

During the 33-month period covered by this report, the two Trane 546-ton, single-stage, absorption chillers did not meet the expected COP of 0.60 which is normally experienced in building installations and is in accordance with the manufacturer's specifications. The COP of these chillers is defined for this report as the total thermal energy removed from the chilled water divided by the PHW thermal energy consumed by the chillers. The electrical energy for chilled-water pump motors, condensate pump motors, and cooling tower fan motors is not included. During the cooling season, the chiller PHW heat demands are larger than that recovered from the engines and relatively large outputs from the boiler are required to meet these demands. The efficient operation of the chillers is vital in maintaining an acceptable level of plant energy effectiveness.

For three cooling seasons in the 33-month period covered by the DAS data (1975, 1976, and 1977), the measured seasonal thermal COP's of the chiller system were 0.401, 0.402, and 0.489, respectively. An analysis of the DAS data and the daily plant logs for these three cooling seasons indicated initial problems in the seasonal and routine servicing and adjustments, most of which were performed under contract. For example, at the end of the 1975 cooling season it was discovered that several large gaskets in the chillers had been improperly installed during routine contractor servicing at the end of the previous cooling season. Fragments of these shredded gaskets may have restricted flows inside the chillers. During the 1976 cooling season, the chillers appeared to operate in a somewhat erratic manner indicating faulty control and/or adjustment. Periods of extremely low COP's (0.2 to 0.3) were experienced for several days which were followed by short periods of higher COP (0.50) which were still below the expected levels.

On September 21, 1976, a factory representative restored the chillers to "normal" operation by making several adjustments in the controls. Figure 5.10 shows the profiles of the PHW thermal input to the chillers and the thermal output from the chillers for the month of September 1976. The results of the adjustments are clearly indicated.

The 1977 cooling season yielded higher COP's during the months of June, July and August (0.496, 0.572, and 0.559, respectively) than previously experienced. These higher values are reflected in the monthly plant energy effectiveness profile shown in figure 5.1. In August 1977, it was discovered that the nozzles in the cooling towers were clogging from matter within the cooling water (appeared to be scaling from the inside of pipes) and the nozzles were removed for cleaning. This action improved the effectiveness of the towers. However, the COP of the chillers dropped to 0.356 due to the reasons given in the following paragraph.

Analysis of the 1977 cooling data revealed excessive delays in turning off the respective cooling tower pumps when the second chilling unit was taken off line. It was also noted that the second chiller was taken off line several times prior to the reduction in the site cooling load. Apparently the second unit was taken off line as the weather changed and not as the demand for chilled water was reduced. Taking the second unit off line prior to the reduction in the chilled water thermal demand resulted in a rise in the temperature of the chilled water and a drop in the thermal COP of the chiller system.

The seasonal COP of the chillers for 1977 was 0.489. Fuel savings of over 32,000 gallons (121 m^3) would have been experienced in 1977 if the chillers

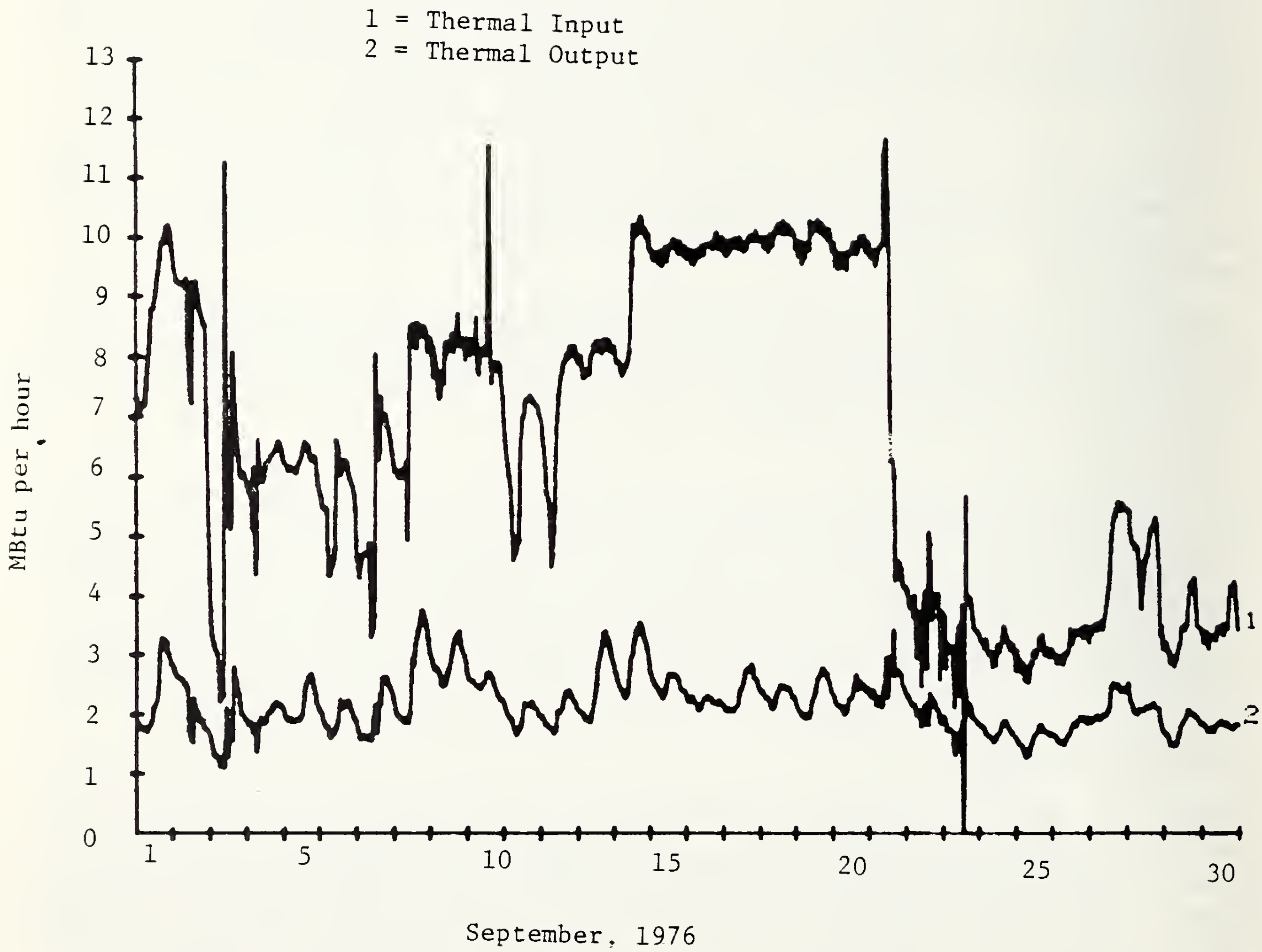

Figure 5.10 Profiles of thermal input and output of the chillers in September 1976. The erratic functioning of the chillers is indicated during the first half of the month. On September 21, 1976, a factory representative restored the units to "normal" operation.

had been functioning at the expected COP of 0.6. Occasional periods of operation with COP values in excess of 0.6 were experienced during the 1978 season when this report was being prepared, indicating that the system can meet the manufacturer's specifications with proper operation, maintenance, and adjustment. The estimate for the 1977 fuel savings resulting from proper chiller performance would be supplemented by additional savings in the reduction of the electrical energy required to operate the chiller system pumps and fans.

An analysis of the data presented in table 4.1 of this report indicates that about 16 percent of the total cooling load was that imposed by plant cooling. Further analysis of the data indicated that the majority of this portion of the cooling load was attributed to the cooling coils in the ventilation system serving the engine-generator and other component areas of the plant. Several conditions existed at the time of the design of the plant which prompted the decision to provide cooling for the plant machinery areas. These conditions included the necessity to "seal" the engine room to reduce the noise level outside the plant, to minimize ventilation air filtering, and to make the plant more comfortable for the maintenance personnel and for the numerous groups of visitors expected to visit and tour the plant. If the machinery areas were not cooled, an estimated annual savings of 23,000 gallons (87 m^3) of fuel oil could be realized, assuming operation of the chillers at a COP of 0.60. If cooling were not provided, modification of the plant ventilation system would be required.

5.2.4 Dry Cooler Losses

The dry cooler (water-to-air heat exchanger) shown in the PHW loop in figure 4.1 is located on the roof of the plant. The eight-fan unit shown in the foreground on figure 2.17 is the dry cooler. The second unit shown in the background of figure 2.17 is used primarily to control the temperature of the lubricating oil in the engines. The dry cooler in the PHW loop functions to release thermal energy whenever the temperature of the water in the PHW loop exceeds a preset limit. This limit is set at a value to prevent overheating of the engines. When the PHW exceeds the preset value, the dry cooler fans are activated and forced air convection transfers thermal energy from the PHW passing through the finned coils of the dry cooler to the atmosphere. Under normal conditions the fans would operate only infrequently during the spring or fall seasons when the thermal recovery from the engines exceeds the site demands.

Incorrect settings and malfunctions of the dry cooler fan controllers have, on occasion, caused large quantities of thermal energy to be released to the atmosphere which had to be made up by the boiler. Table 4.1 indicates the periods during which these conditions existed. During 1977, the data do not indicate any malfunctioning of the dry cooler fan controllers.

The dry cooler also continually lost thermal energy to the atmosphere via natural convection. During the 33-month period covered by DAS data, a draft was induced by the continuous high temperature of the finned coils causing the ambient air to flow from below the units and out the top ducts. Analysis of the DAS data indicates that from 237 MBtu to 500 MBtu (250 GJ to 530 GJ) were lost each month in 1977 from the PHW loop through the dry coolers (see table 4.5).

An experiment was performed on October 19, 1976 to determine the potential for reducing PHW dry cooler losses by restricting the natural convection across the finned coils. In this experiment, the dry cooler air outlets were covered with 3.5 inch (9 cm) glass fiber mats to simulate louvers installed in the dry cooler. Figure 5.11 shows the outlets being covered with the glass fiber mats. Figure 5.12, using DAS data, indicates that the PHW dry cooler losses were reduced by more than 50 percent during the test when the outlets were covered.

Louvers were installed during the period this report was being prepared. The louvers were designed to open from the force generated by the fans. When the fans are not activated, the louvers close by gravity. The thermal energy transferred to the louvers from the finned coils of the dry coolers prevent ice and snow from obstructing the action of the louvers.

A profile of the PHW dry cooler losses for the month of February 1978, is shown in figure 5.13 as recorded by the DAS. The profile clearly shows the day the louvers were installed. An analysis of the available data from the DAS before and after the installation of the louvers indicates a possible annual savings of 11,000 gallons (41.6 m^3) of fuel oil.

Although the DAS data did not indicate any extensive losses caused by malfunctioning dry cooler fan controls during the year 1977, it can be noted from figure 5.13 that one or more pair of the fans were apparently activated during the month of February 1978, after the installation of the louvers. On several occasions, it has been necessary for the plant operator to manually active the dry cooler fans to remove heat from the PHW loop while repairs were being made in the secondary systems. The periods of possible fan operation after February 16, 1978, as shown on figure 5.13, may represent such conditions. The calculation of the 11,000 gallons (41.6 m^3) of annual fuel oil savings was based on actual losses from the dry coolers before and after the installation of the louvers and includes any short service-oriented periods of fan activation. However, excessive losses from malfunctioning controls such as shown in table 4.2 for the months of June and September 1975, and May 1976, were <u>not</u> included in the calculation.

Other approaches could be considered in the reduction of dry cooler losses. For example, if the dry coolers could be completely valved out of the PHW loop, the savings would exceed 30,000 gallons (114 m^3) of fuel oil annually. However, the valving must be fail-safe and activated so PHW would flow through the finned coils only when the release of excess thermal energy is necessary. This approach would require measures to prevent the water from freezing in the coils while they are valved out of the PHW loop. Such measures are feasible if the design of the two dry cooling units were coordinated to allow the thermal energy at the lower temperatures being released from the dry cooling unit in the raw water loop to be used for this purpose. The primary objective of the raw water loop is to remove heat from the engine lubrication oil and aftercoolers.

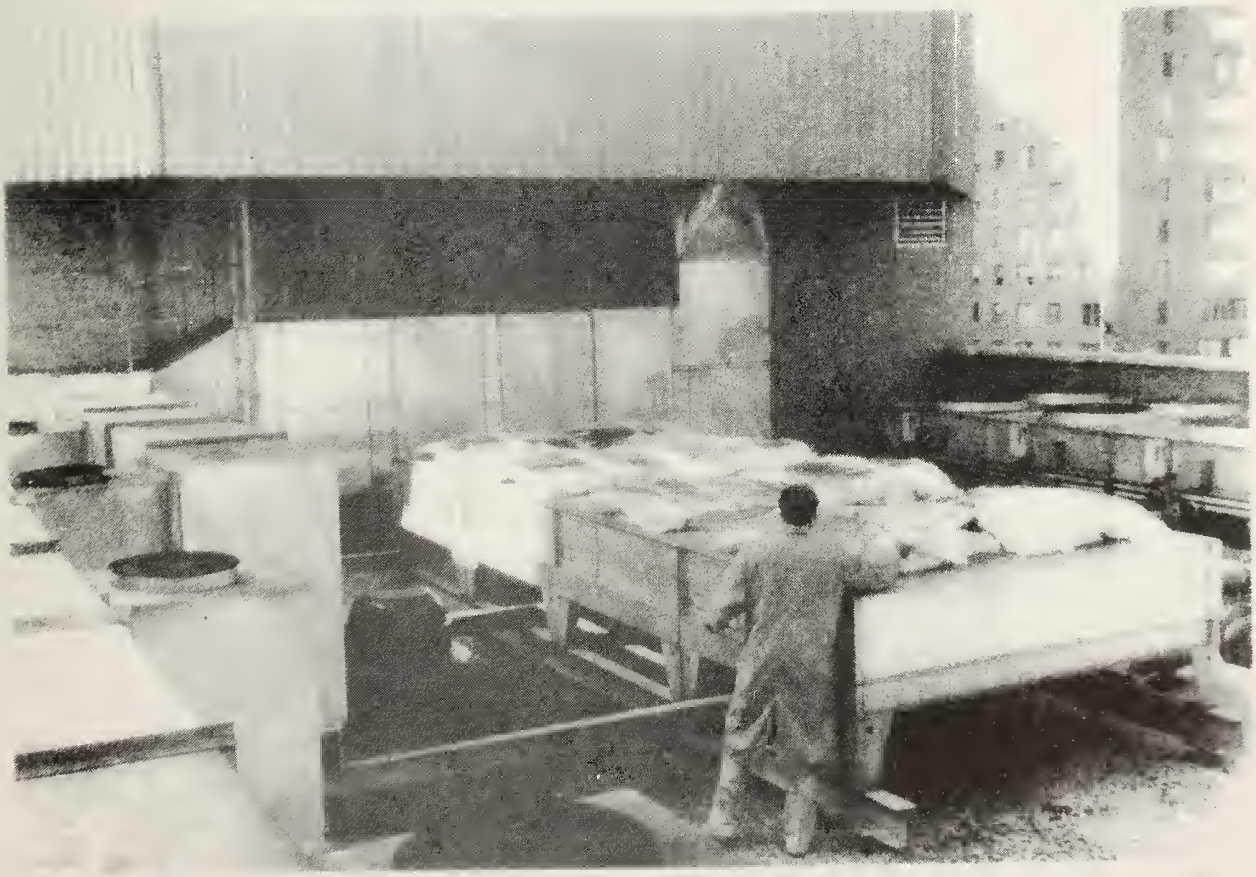

Figure 5.11 Dry cooler convective heat loss experiment performed October 19, 1976. The natural convective flow through the ducts was restricted using glass fiber mats. The results are shown in figure 5.12.

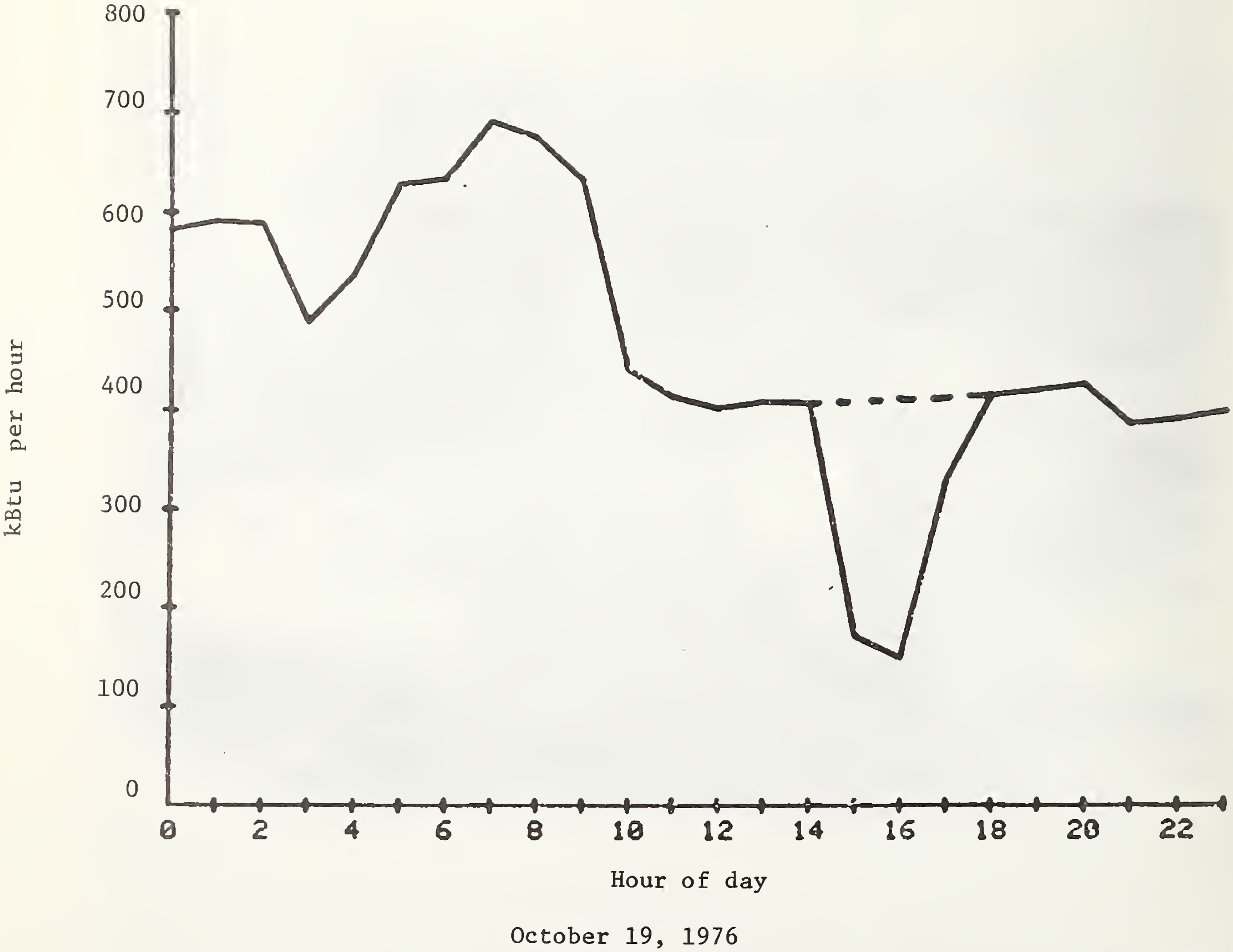

Figure 5.12 Results of dry cooler natural convective heat loss experiment. The dry cooler outlets were fully covered at hour 16. The dotted line indicates loss expected if the outlets were uncovered.

Figure 5.13 Louvers, designed to open from force generated by the fans in the dry coolers, were installed February 16, 1978. When the fans are not activated, the louvers close by gravity. One or more pair of fans were apparently manually activated on February 18, 19, 21, 22, 1978 to release excess heat while repairs were being made in the secondary loops. The profile represents the thermal energy removed from the PHW by the dry coolers.

5.3 SITE DISTRIBUTION LOSSES

In this report, distribution losses are defined as the differences between the thermal and electrical energy outputs of the plant and the thermal and electrical energy used by the buildings. The data for the thermal and electrical outputs of the plant are based upon measurements made at the plant. The data for the energy used by the site buildings are based upon the measurements made at each building.

5.3.1 Site Thermal Losses

The thermal energy consumed by each of the site buildings for space heating, cooling, and for domestic hot water were computed from the raw data collected by the DAS from transducers located in the individual buildings. The collection of raw data via the DAS to produce the tables listed in section 4 of this report began in November 1975. After processing two or three months of remote data (data from the site buildings), it was observed that the summations of the thermal energy being consumed by the site buildings were considerably lower than those leaving the plant. Considerable effort over a period of several months was undertaken to determine whether or not the data were correct. The results verified that the instrumentation and software were correct, that the data reflected real losses, and that the thermal distribution system itself was the cause of these losses.

An investigation of the site distribution system showed that, with one exception, the underground distribution pits outside the buildings were found to have water standing in them high enough to cover all pipes, butterfly valves, and balance cocks located in each pit. Samples of water from each pit were analyzed and found to be free of ethylene glycol (used in the site water loop), indicating that the water came from surface or ground sources. While examining the pits, the temperature of water in the pits was found to be from 126°F to 153°F (52°C to 67°C), while the ambient temperature was 33°F (1°C). The higher water temperatures were found in the pits outside the Shelley A and Descon buildings. The distribution pit serving the Camci and commercial buildings was not accumulating water at the time of this inspection. The samples of water appeared to be relatively clear. All manholes on the site were located in areas with adequate drainage of surface water. These findings and numerous reports of water in the pits noted in the plant engineer's log, indicated that ground water was entering the pits from the top, bottom, or sides of the pits. The fact that the pits had been pumped out several times in the past further confirmed this indication.

On July 15, 1977 portable sump pumps were delivered to the site by the plant operator. On July 22, 1977, the distribution pits on the west secondary system were pumped out by site maintenance personnel. Figure 5.14 shows the results of this action. Using the daily computer values of the thermal energy leaving the plant via the secondary hot water (SHW) to the west zone and the summation of the thermal energy consumed by the west SHW loop for the period July 19-28, 1977, table 5.2 was produced.

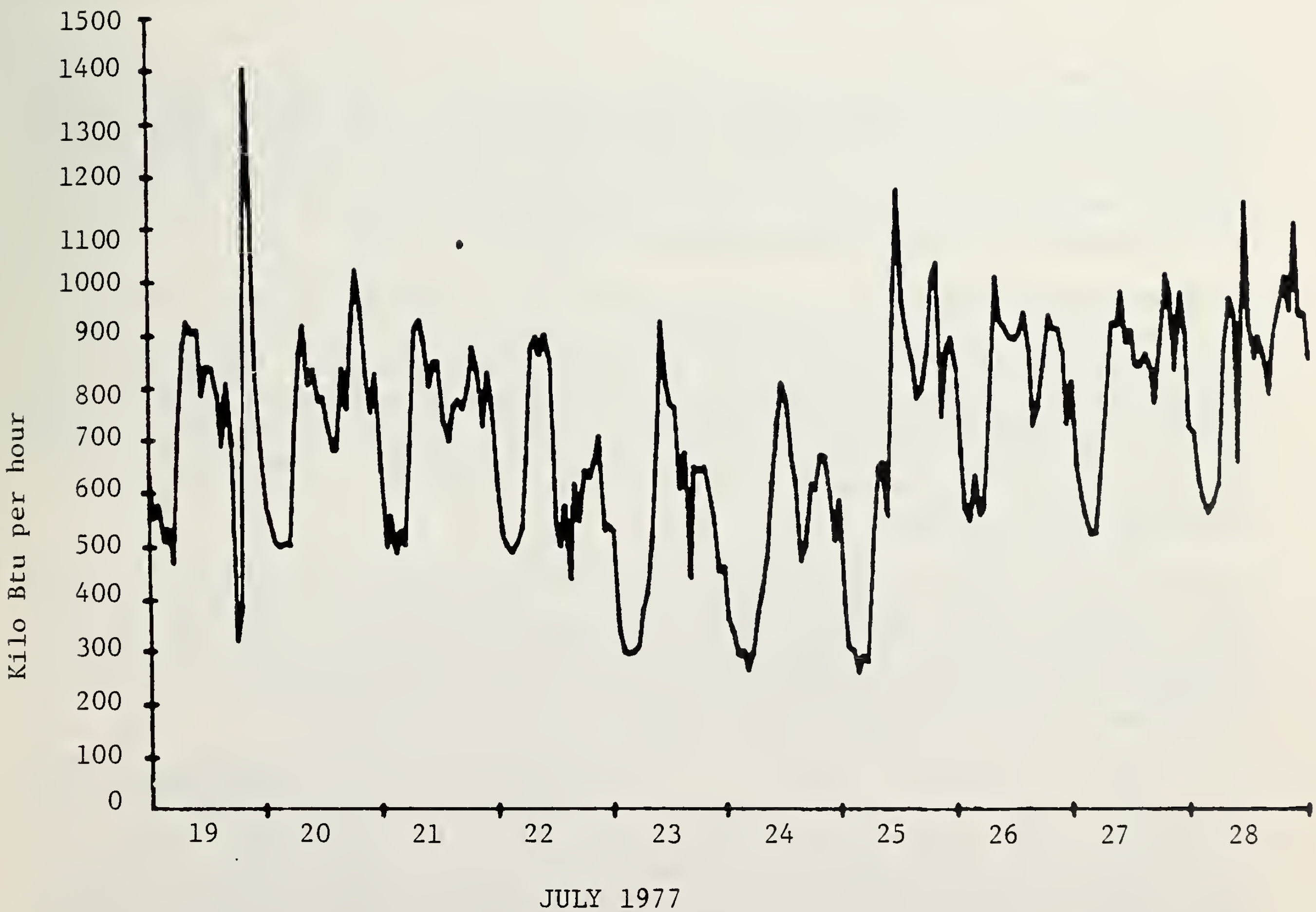

Figure 5.14 Hourly profile of thermal energy from the plant to the west site second hot water loop. Ground water was pumped out of distribution pits on July 22, 1977.

Table 5.2 SHW Thermal Energy to the West Zone in July 1977

Day of month	19	20	21	22	23	24	25	26	27	28
Plant output to west loop (MBtu/day)	17.8	17.8	17.8	15.2	13.1	12.5	16.7	19.2	19.3	20.3
Consumption by West buildings (MBtu/day)	10.9	11.0	11.4	11.0	11.9	11.4	11.3	11.3	11.3	11.1
Loss (MBtu/day)	6.9	6.8	6.4	4.2	1.2	1.1	5.4	8.1	8.0	9.2
Percent loss	39.8	38.2	35.9	27.6	9.2	8.8	32.3	42.2	41.4	45.3

Table 5.2 and the information received from the plant engineer indicated that the pits were filling rapidly after being pumped out. The higher losses indicated for the period July 25-28 should be noted. By this time, ground water had reentered the pits and covered the pipes and valves. Site maintenance was taking place in two of the east site buildings at this time and prevented obtaining similar data for the east secondary loop.

The distribution losses in the chilled water loop serving the west side buildings were also reflected in the daily energy data for this same period. The cooling demand of the buildings is related to the cooling degree days for each day and, because the weather changed during the period after the pits were pumped out, less energy was required for cooling. Table 5.3 was obtained using the cooling degree days for the area, the daily computer values for the plant chilled water output to the west chilled water loop, and the chilled water demand by the buildings.

Table 5.3 and figure 5.15 reflect the distribution losses in the chilled water loop serving the west buildings. The losses affected by the water in the pits are indicated by the reduction in the percentage loss during the period immediately following the removal of ground water from the pits on July 22. The effect of the rapid refilling of pits is also indicated.

With respect to tables 5.2 and 5.3, it was important to note the number of pits on the east and the west loops. The distribution loop supplying the buildings on the east side of the site includes three pits, all of which had water at a level which covered the pipes when inspected in March 1977. The distribution loop supplying the buildings on the west side of the site has two pits, only one of which had water covering the pipes. Therefore, the losses shown for the west loop in tables 5.2 and 5.3 are a small portion of the total losses caused by water in pits.

Table 5.3 Chilled Water Thermal Energy to the West Zone in July 1977

Day of month	19	20	21	22	23	24	25	26	27	28
Cooling degree-days (65°F base)	24	18	25	13	8	14	9	6	3	4
Plant output to west loop (MBtu/day)	75.1	75.9	75.4	64.1	46.8	50.0	44.6	38.5	33.9	35.9
Consumption by West buildings (MBtu/day)	58.1	61.4	58.5	53.7	38.2	40.4	35.0	28.9	24.9	26.6
Loss (MBtu/day)	17.0	14.5	15.9	10.4	6.6	9.6	9.6	9.6	9.0	9.3
Percent loss	22.6	19.1	22.4	16.2	14.1	19.2	21.5	24.9	26.5	25.9

The weather reports from the National Weather Service office at the Newark International Airport for the time period of these observations indicate only a "trace" of precipitation at midnight on July 25, 1977. The lack of traces of ethylene glycol in the pit water, the local weather reports, and a review of the plant log of the minimal quantities of water put into the secondary systems during this period, lead to the conclusion that the pits refilled from leakage of ground water through the pit walls.

At New Brunswick, N.J., earth temperatures of 44°F (7°C), 47°F (8°C), 63°F (17°C), and 61°F (16°C) have been reported for the winter, spring, summer and autumn seasons, respectively [5-5]. An annual average value of 54°F (12°C) is reported. These values are in considerable contrast to the measured temperatures of the water in the pits.

By reviewing the tables in section 4 of this report, it is apparent that relatively large quantities of thermal energy were lost in the distribution system during the winter seasons. However, the ratio of the losses to the thermal output of the plant increased during the periods of less demand. For example, in January 1977, the losses in the secondary hot water loops (east and west) were 1435 MBtu (1514 GJ) or 19.6 percent of the plant output. Figure 5.16 shows the profiles of the daily values of the thermal energy leaving the plant via the SHW system and the summation of the thermal energy consumed by the site buildings in January 1977.

In May 1977, the losses in the west secondary hot water loop were 322 MBtu (340 GJ) or 32.0 percent of the plant output to the west loop. In July 1977, the losses in both east and west secondary hot water loops were 266 MBtu (281 GJ) or 28.6 percent of the plant output. The losses in the west chilled water circulation loop for July 1977 were 351 MBtu (370 GJ) or 21.7 percent of the CEB output to the west loop.

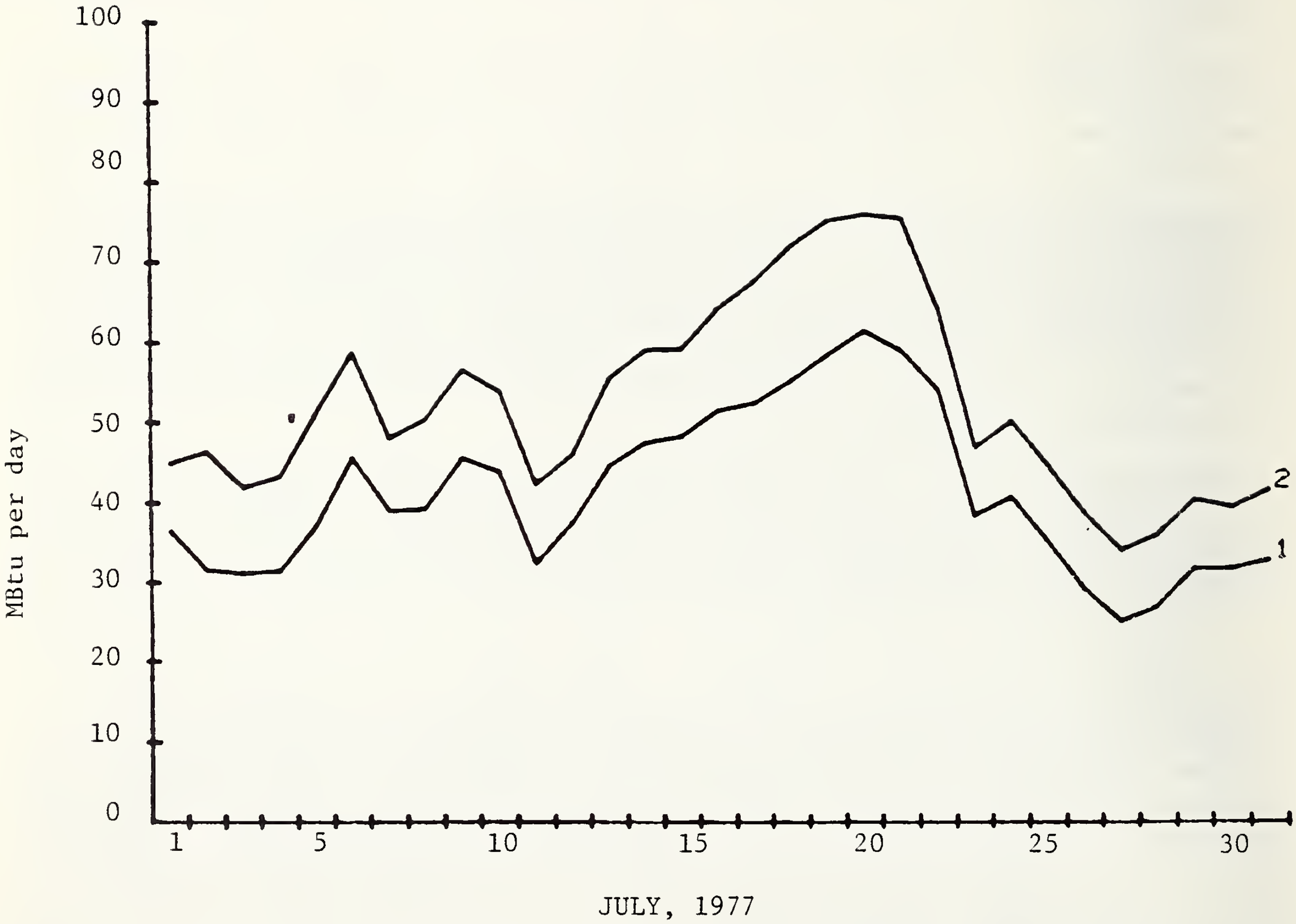

Figure 5.15 Thermal energy in the chilled water in west site distribution loop. Profile number 1 is the summation of thermal energy consumed by the individual buildings on the west loop. Profile number 2 is the thermal energy produced by the plant for the west loop. Ground water was pumped out of distribution pits July 22, 1977.

The 1977 annual distribution losses were calculated using existing valid monthly values from the DAS for the east and west loops and buildings and inserting estimated values for those periods for which valid data were not available. The estimated values were based upon extrapolation of existing valid monthly data. The annual distribution losses in the SHW system were estimated to be 8400 MBtu (8862 GJ) for 1977.

Using the factors and techniques given in reference [5-5], nominal or expected losses were calculated for the underground distribution system at the Summit Plaza site. The data used were the average values for the size of the pipes, thickness and type of insulation, and the length of each size of pipe. The nominal loss for the SHW system was calculated to be 815 MBtu (860 GJ) per year. Substracting this computed nominal value from the estimated annual losses results in an annual excessive loss of 7585 MBtu (8002 GJ). Using the average higher heating value for the fuel and the average boiler efficiency for the year 1977, the annual estimated fuel savings that would be possible if these excessive losses were eliminated in the SHW system is:

$$\frac{7585 \times 10^6 \text{ Btu}}{139174 \text{ Btu/gal} \times .833} = 65{,}426 \text{ gallons of fuel oil.}$$

The same basic procedure was followed for the chilled water distribution system. The lengths of the various sizes of pipe, the average temperature of the chilled water, and the annual time period were adjusted to fit the actual conditions at the Summit Plaza site. The total seasonal losses for 1977 were estimated to be 1554 MBtu (1640 GJ). The computation of the nominal losses for the chilled water system using the techniques given in reference [5-5] resulted in a value of 47 MBtu (50 GJ) for the 1977 season, leaving an excess seasonal loss of 1507 MBtu (1590 GJ). Using the same basic equation to determine the possible fuel savings:

$$\frac{1507 \times 10^6 \text{ Btu}}{139{,}239 \times .839 \times .489} = 26{,}380 \text{ gallons fuel oil,}$$

The higher heating value of the fuel and the boiler efficiency were adjusted to reflect summer performance. The COP of the chillers for the 1977 cooling season was used in the equation.

The above equation only addresses the thermal energy required by the boiler/chiller system to compensate for the excess cooling losses in the chilled water distribution system. Auxiliary electrical energy is required for the boiler/chiller system operation. This energy was not considered in the equation because of its sensitivity to the mode of plant operation. Therefore, the possible fuel savings shown are considered to be conservative.

In general, the excessive distribution losses in the SHW and chilled water systems for the year 1977 are conservatively estimated to be equivalent to approximately 91,000 gallons (345 m^3) of fuel oil. It must be emphasized that all of these excessive losses were not necessarily directly related to the ground water in the distribution pits. City water added to the SHW and cooling water distribution systems (excessive at times), reported breaks in

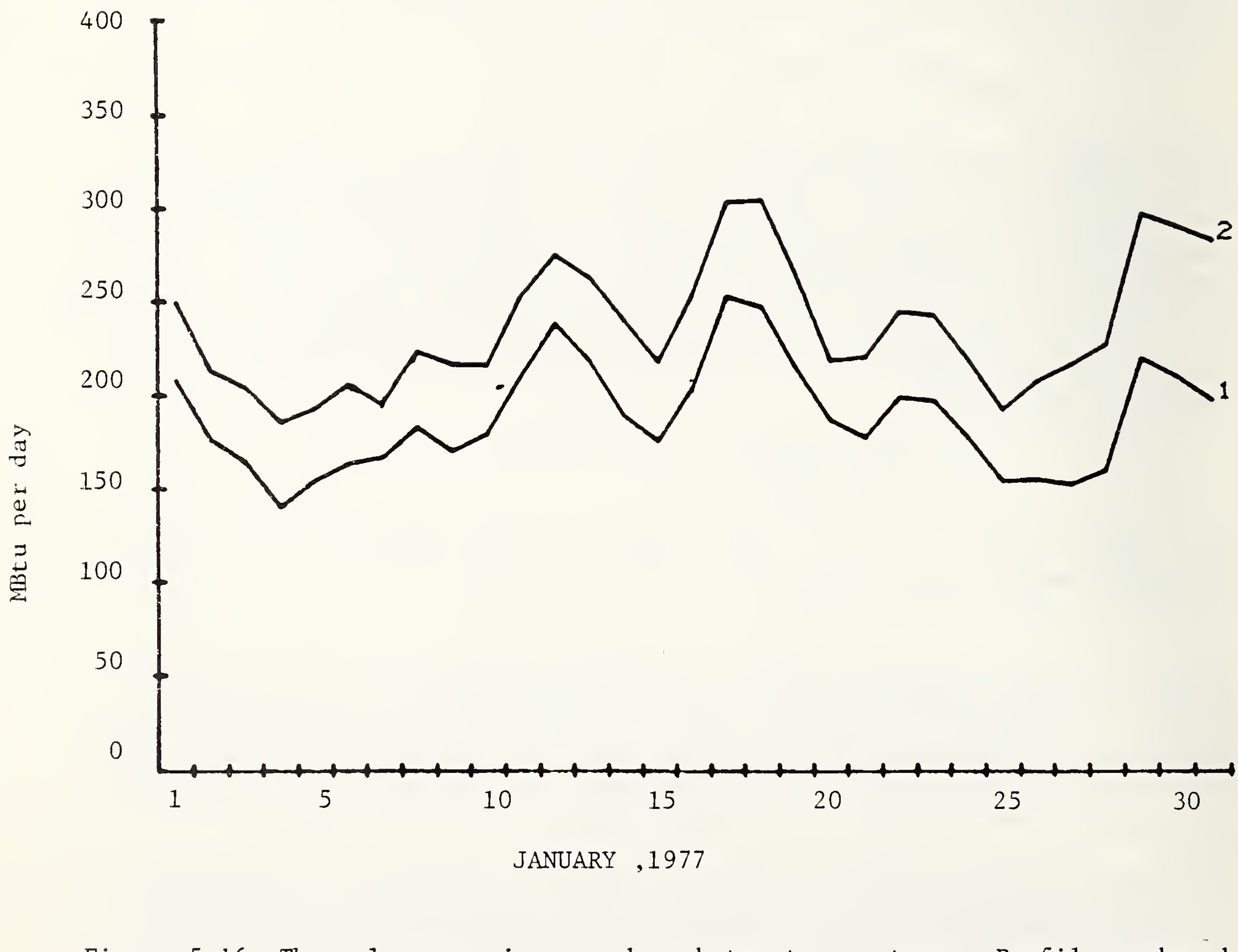

Figure 5.16 Thermal energy in secondary hot water systems. Profile number 1 is the summation of the thermal energy consumed by the site buildings. Profile number 2 represents the total thermal energy leaving the plant in the secondary hot water system.

the systems, extremely wet soil adjacent to the distribution pits, etc., must <u>all</u> be considered as contributing factors. However, when the thermal data listed in section 4 were compared to the losses and calculations were made using the equations developed in reference [5-6], it is felt obvious that the majority of the losses were <u>directly related</u> to the water conditions found in the pits.

5.3.2 Site Electrical Losses

Determination of the electrical losses from measured values was not possible because of the problems of inadequate monitoring of the building loads as stated in section 4. Monitoring only two phases of a three-phase, 4-wire system is accurate only for balanced phase loads (reference [5-8]). In March 1977, the loads on the phases of the lines in the various buildings were periodically monitored using portable test equipment. Some of the measurements indicated that the ratio of the loads on the individual phases varied as much as 2 to 1.

5.4 SUMMARY

Section 5 of this report covers a broad spectrum of system and component performance including some of the operational and maintenance procedures used for the plant and site. Although the analysis of several areas indicate fuel savings by minor modifications in operation and/or maintenance procedures, the fuel savings for all of the individual areas are not necessarily additive due to the interaction of plant components. For example, if the large distribution losses were reduced to the nominal value, the thermal load on the chillers would be reduced. Operating at a reduced level, the fuel savings from the improvement of the chiller operation would also be reduced proportionally. Several other examples will become apparent by reviewing the list in table 5.4.

Although the fuel savings from several areas covered in this section are not directly additive, it will be noted that the calculations for all fuel savings were based upon the plant and site loads for the calendar year 1977. If an estimate of a total annual fuel savings is desired, the loads on the various systems and components must be adjusted to values based on the seasonal weather conditions and, most important, any changes or improvements made in the system, components, operation, and/or maintenance procedures.

5.5 REFERENCES - SECTION 5

5-1. Coble, J. B., Kuklewicz, M. E., Hebrank, J. H., "Performance of the Engine - Generators Used in the Jersey City Total Energy Plant," National Bureau of Standards Report NBSIR 77-1207, October 1976.

5-2. Kitson, C. E., et al., "Exhaust Emission Evaluation of Three Caterpillar Tractor D-398 Diesel-Electric Sets," National Bureau of Standards Report GCR 77-104, November 1977.

5-3. de Lorenzi, O., "Combustion Engineering," Combustion Engineering-Superheater, Inc., The Riverside Press, Cambridge, Massachusetts, 1950.

Table 5.4 Summary of Estimated Annual Fuel Savings Which Would Result from Selected Individual Changes in Equipment, Operation, and/or Maintenance of Plant and Site

Item	Possible Savings Gallons of Fuel Oil
1. Bypass one idle engine	7,500
Alternate - bypass two idle exhaust heat exchangers	(6,000)
2. More frequent cleaning of exhaust heat exchangers	37,000
3. Use of minimum practical number of engine-generators (Additional savings of 2200 engine-hours per year)	7,300
4. Bypassing idle boiler	7,500
5. Improved chiller operation and maintenance	32,000
6. Eliminate use of chilled water to cool plant ventilation air	23,000*
7. Install louvers on PHW dry cooler	11,000 (Note: This has been accomplished)
Alternate - Valve dry coolers out of PHW loop	(30,000)
8. Correct site conditions causing excessive distribution losses	
Secondary hot water	65,000
Chilled water	26,000

* Assumes chiller COP of 0.6

Values shown in parenthesis indicate savings if the "alternate" action is taken.

5-4. Gamze-Korobkin-Caloger, Inc., "Final Report, Design and Installation, Total Energy Plant-Central Equipment Building, Summit Plaza Apartments, Operation BREAKTHROUGH Site, Jersey City, New Jersey," HUD Utilities Demonstration Series, Volume 12, February 1977.

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5-7. Bulik, C., Rippey, W., Hurley, C., and Rorrer, D., "Description of the Data Acquisition and Instrumentation Systems: Jersey City Total Energy Project," National Bureau of Standards Report NBSIR 79-1709, March 1979.

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6. ALTERNATIVE SYSTEMS FOR ENERGY SUPPLY

6.1 INTRODUCTION

As part of this demonstration project at the Jersey City Summit Plaza, a series of comparative analyses were completed. These analyses examined the differences in energy, economic, environmental, and reliability performance between the existing JCTE plant and a number of other ways of providing equivalent energy services to the Summit Plaza buildings.

To develop the data necessary to carry out the comparative evaluations, substantial effort was directed toward the selection, design, and analysis of alternatives energy systems which could be used at Summit Plaza. The analysis not only considered the energy conversion equipment installed at the site but also the utility systems which would supply electricity from remote locations to the site for the use of non-TE (i.e., "conventional") systems.

This section provides the rationale for selecting the alternative systems, describes the on-site systems, and provides basic data for an electric utility system. More detailed data regarding the predicted performance and operation of the alternative systems is discussed in section 7.

6.2 SELECTION OF ALTERNATIVE SYSTEMS

Twelve different designs of energy systems were postulated for the Summit Plaza site. The systems were chosen as being within a representative range of technical options for the buildings at Summit Plaza. In the case of conventional systems, the selections were based on the following criteria:

- construction trends at the time the HVAC systems for Summit Plaza were being designed (1971-1972),

- construction trends at the time of the completion of the project (1977-1978),

- optimum systems based on energy use and economics, irrespective of HVAC construction practice.

A brief investigation was conducted in early 1977 by Mathtech, Inc., under contract to HUD, to identify typical HVAC systems being installed in new construction at the time Summit Plaza was built. Mathtech used data prepared by the U.S. Bureau of the Census and presented in their 1973 Annual Housing Survey. Numerous contacts with local A/E firms, equipment suppliers, building code officials, and utilities were also made. Although the sample size for the northeast census region was admittedly small, the following conclusions concerning mid- to high-rise residential buildings were drawn [6-1]:

- heating would likely be provided by a gas or oil-fired boiler distributing hot water or steam within the building.

- cooling would be provided by individual room units for mid-rise buildings (7-15 stories) while a central system with absorption or perhaps centrifugal chillers would predominate in buildings over 12 stories. A large percentage of buildings would have no air conditioning installed by the builder but probably would have provisions for individual room air conditioners.

- central forced-air systems would not likely be used in the northeast.

It was felt that conventional systems which were probable candidates at the completion of the project (1978) should also be included in the study to give a proper "then vs now" perspective to the case study. Trends in recent years have been to wider use of all-electric systems. Data on the use of electricity for space heating in single-family dwellings are shown in figure 6.1 for the nation as a whole and for the northeast census region. Available data on multi-family dwellings show even greater proportions of electric space heating [6-2]. The actual JCTE design was selected as one of the 12 systems and used for validation as well as a hypothetical alternative design.

6.3 DESCRIPTION OF ALTERNATIVE SYSTEMS

Each of the twelve energy systems examined for Summit Plaza are briefly described below. Figures 6.2 and 6.3 show a schematic representation of the energy flows for each of the systems and table 6.1 provides a summary of the systems and types of equipment installed in each system. Additional conceptual design information is contained in appendix D, including narrative discussions and example schematics. This information is obtained from reference [6.3].

Total Energy Systems

System No.

1. The existing Total Energy plant at Jersey City including: Caterpillar diesel engine-generators, oil-fired boilers, and absorption chillers.

2. The existing JCTE plant with utility interconnection to allow selling of power to Public Services Electric and Gas Co. (PSE&G), the local electrical utility at the site.

3. Same as system 1 except using medium-speed, high-efficiency diesel engines instead of the existing high-speed Caterpillar units.

4. Same as system 1 except using both absorption and compression chillers; the absorption chillers being powered with recovered heat.

Conventional Central Systems

5. A central plant similar to system 1 without on-site power generation and with electrically-driven compression chillers. Electrical energy would be purchased.

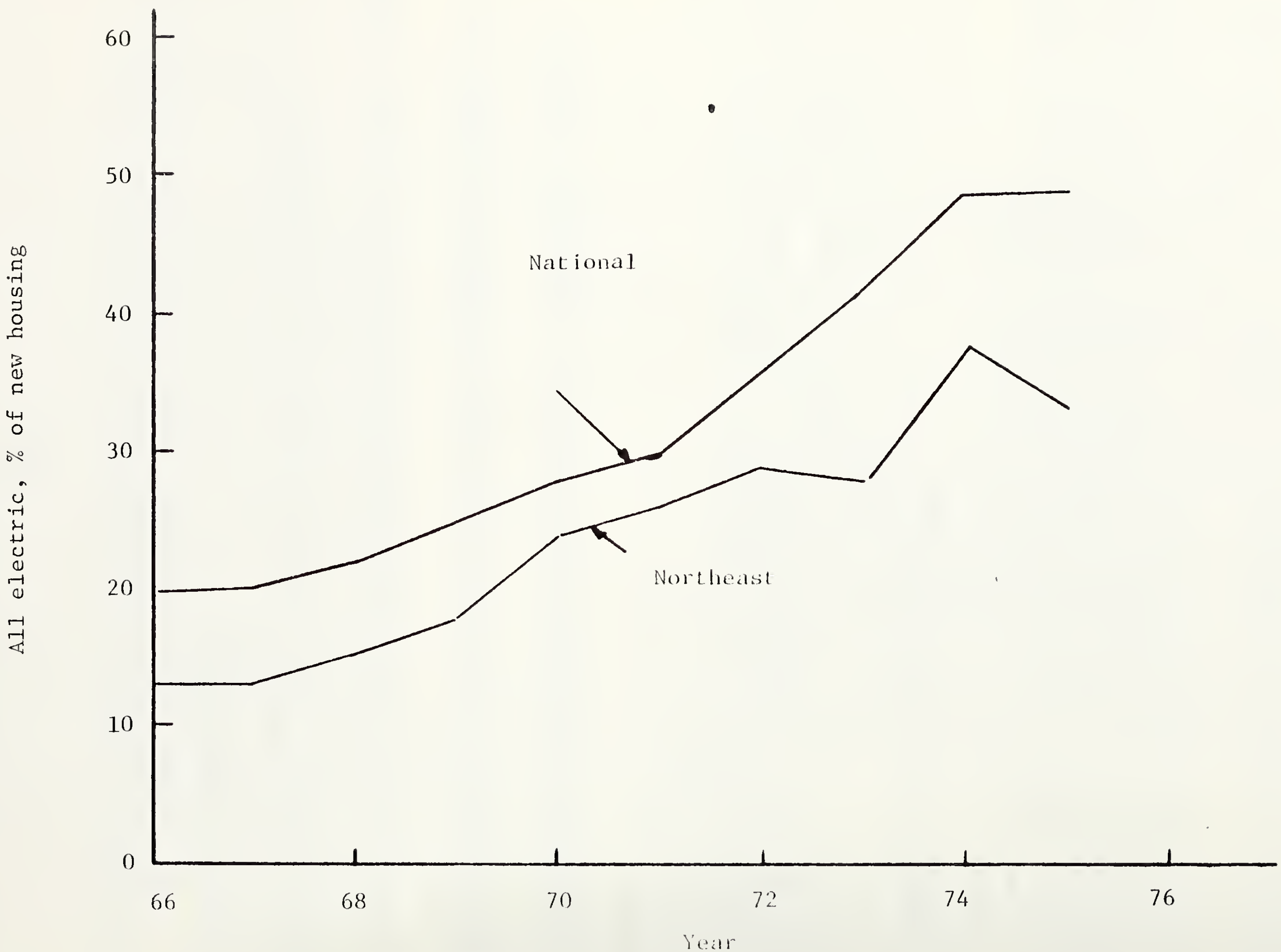
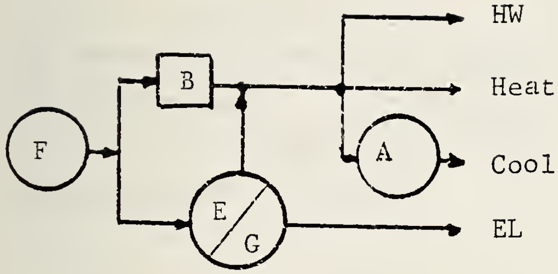
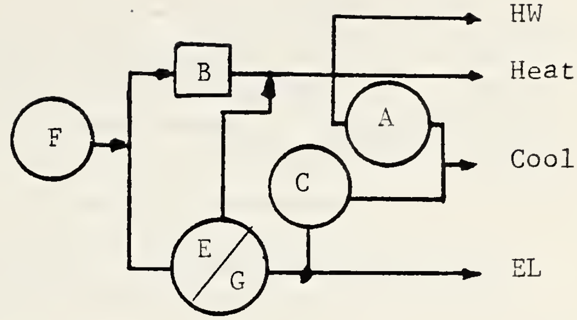


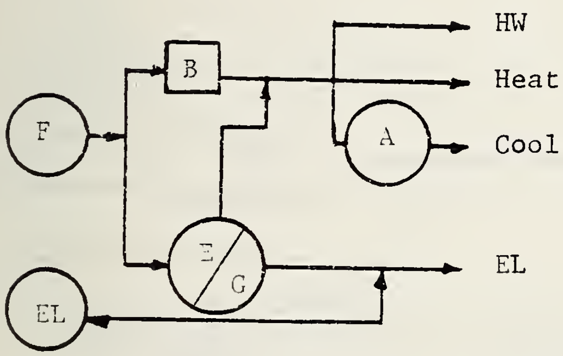
Figure 6.1 Trend to the use of electric space heating in single-family homes



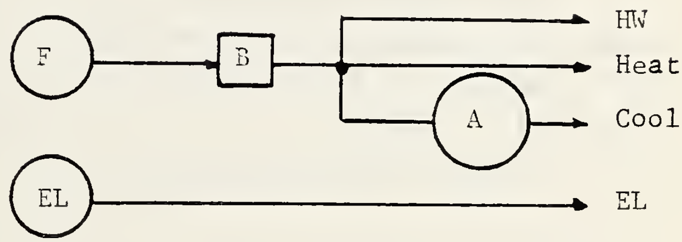
1 & 3 Total energy: Absorption cooling



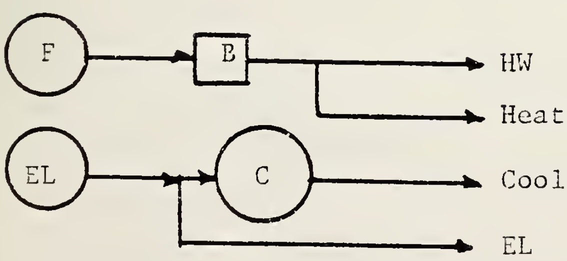
4 Total energy: Centrifugal and absorption cooling



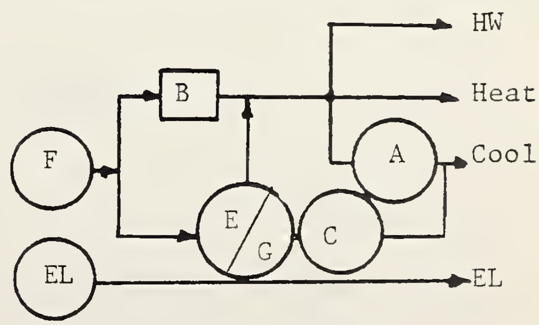
2 Total energy: Absorption cooling



5 Central conventional fuel-fired heating and absorption cooling

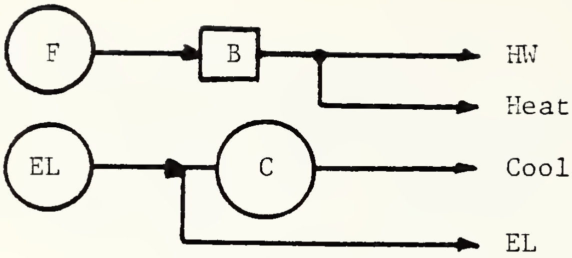


6 Central conventional: Fuel-fired heating, compressive cooling

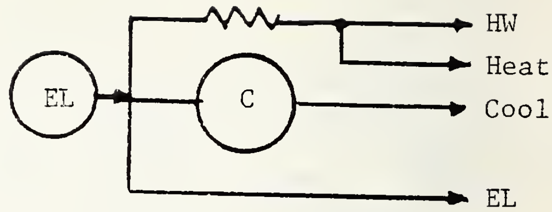


7 Central conventional: diesel-driven compressive plus absorption cooling

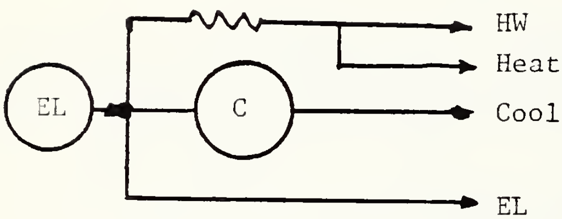
Figure 6.2 Alternative energy systems - TE and conventional central systems
Note: See legend on figure 6.3



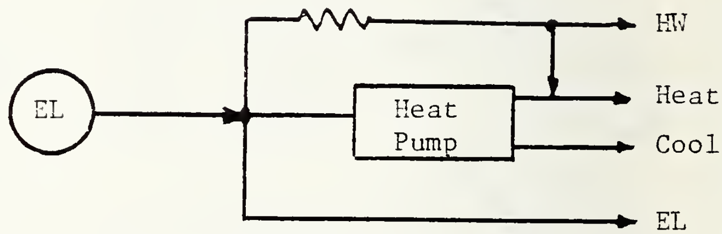
8 Building conventional: fuel fired heating, compressive cooling



9 Building conventional: resistance heating and compressive cooling (all electric)



10 & 12 Dwelling unit: resistance heating and compressive cooling (all electric)



11 Dwelling unit: heat pump with supplement resistance heating (all electric)

Legend - Figures 6-2 & 6-3

F - fuel

B - boiler

E/G - engine - generator

A - absorption chiller

HW - domestic hot water

Heat - space heating

Cool - space cooling

EL - electricity

C - motor-driven compressive chiller

Figure 6.3 Alternative energy systems - conventional building and individual unit systems

Table 6.1 Summary of Alternative Energy Systems and Their Components

System Number	1	2	3	4	5	6	7	8	9	10	11	12
System type:												
TE	x	x	x	x								
Conventional central					x	x	x					
Conventional building								x	x			
Individual unit										x	x	x
Electricity:												
On-site generation	x	x	x	x								
Purchased					x	x	x	x	x	x	x	x
Diesel engines	x	x	x	x			x					
Cooling Equipment:												
Absorption chillers	x	x	x	x	x		x					
Compression chillers				x		x	x	x	x			
Individual air conditioners										x		x
Heat pumps											x	
Heating equipment:												
Oil-fired boilers	x	x	x	x	x	x	x	x				
Electric boilers									x			
Individual resistance heaters										x		
Resistance furnaces												x
Heat pumps											x	
Domestic hot water												
Building heat exchanger	x	x	x	x	x	x	x	x				
Electric water heaters									x	x	x	x

6. Similar to system 5 except using absorption chillers instead of compression chillers.

7. Similar to systems 5 and 6 except using diesel-driven compression chillers and absorption chillers driven by recovered heat.

Conventional Building Systems

8. An individual system for each building using electrically-driven chillers, oil-fired boilers, and hydronic distribution.

9. Similar to system 8 except using electric boilers.

Individual Unit Systems

10. Self-contained through-the-wall terminal air conditioners with electric resistance heat for each apartment.

11. A single heat pump for each apartment with forced-air distribution.

12. A single, split-system air conditioner and resistance heater for each apartment with forced air distribution.

6.4 UTILITY POWER PLANT CHARACTERISTICS

In order to make proper comparisons between alternative systems, the characteristics of the electric utility system must be included along with the on-site equipment for those alternatives using purchased power. These characteristics include energy, economic, reliability, and environmental factors for both the central station generating plants as well as for the utility system as a whole. This section will present energy and environmental characteristics to be used in the comparisons.

Several approaches are possible for doing such an analysis depending on assumptions made regarding power plant operations. It could be based on a case study, regional, or national data. For the case study approach, the characteristics of the PSE&G power plants and systems would be used. The other approaches would use aggregated average data on a regional or notational basis. Although emphasis will be placed on presenting detailed PSE&G data in this section to support the case study analysis of sections 7 and 8.4, regional and national data are also provided for comparative purposes.

Various assumptions are also possible regarding how the Summit Plaza load is served and which plant capacity and/or energy production capability is displaced by the TE plant. The analysis could be based on the displacement of marginal new plant capacity, average system facilities, or facilities displaced because of high operating costs. Data are provided in this section for the several possible approaches. This is done for comparison purposes even though all approaches were not utilized in analysis described in sections 7 and 8.4 of this report.

6.4.1 Marginal New Plants and Displaced Plants

The PSE&G plants whose service dates are nearest to the service date for the TE plant (January 1974) are listed in table 6.2 [6-4]. Actual design and operating data for these plants were used as the characteristics of the displaced marginal new plant capacity in the case study.

Table 6.2 PSE&G New Power Plant Characteristics

Generating Station	Unit no.	Type	Summer Capacity, MW: PSE&G share[a]	Summer Capacity, MW: Unit capacity	Fuel type	Location	Service date
Conemaugh	1	Steam	191	820	Coal	W. Wheatfield Township, Pa.	5/21/70
	2	Steam	191	820	Coal	W. Wheatfield Township, Pa.	5/27/71
- - - - JCTE service data - - - -							1/10/74
Peach Bottom	2	Nuclear	446	1065	Nuclear	Peach Bottom, Pa.	7/05/74
	3	Nuclear	440	1065	Nuclear	Peach Bottom, Pa.	12/23/74

a) Jointly-owned plants

An analysis was also made to identify the specific PSE&G plants whose energy production the TE plant would logically displace in a plant-displacing situation. First, four typical days from 1976 and 1977 where chosen based on weather conditions to represent each of the four seasons. Data were obtained from PSE&G on the hourly output for every generating plant for these four days in order to identify those plants in an intermediate and peaking mode. This assessment was further corroborated by data on the relative ranking of these plants in terms of production expenses as provided in reference [6-5]. The plants identified were largely older steam plants with higher heat rates, using oil as fuel and therefore having higher production expenses. These plants are identified in table 6.3, along with data supporting their selection.

A determination of marginal new and displaced plant characteristics for a national and/or regional analysis was not made. It was felt that the PSE&G marginal new plant capacity could serve as a good proxy for marginal new plants in such an analysis. The displaced plant analysis is considerably less useful unless an effort is made to identify such plants over a particular region of interest. Such an effort would be a substantial undertaking and was considered outside the scope of the JCTE evaluation.

Table 6.3 Displaced Plant Characteristics

Plant name	Type	Fuel	Installed capacity	1977 Operating Data Connected to load	Capacity factor	Production expenses
			MW	Hrs	%	mills/kWh
Essex	Steam	Oil	117	3481	19.8	48.0
Kearny	Steam	Oil	314	7966	30.2	35.1
Burlngton	Steam	Oil	455	8674	27.0	32.6

6.4.2 Power Plant Efficiency

The efficiency of power supply from utility sources is determined by the efficiency of generation plus consideration of distribution losses. The generation efficiency for the PSE&G marginal, system average, and displaced power plant capacity is shown in terms of heat rate in table 6.4 [6-5, 6-6, and 6-7]. Data are also presented for the average distribution loss which is defined as the difference between energy produced (including net interchanged energy) and energy sales. The average delivered heat rate for the various approaches is also shown. Several years of data were used to calculate the heat rates so that anomalous conditions in the specific plants would not distort the value.

On a national scale, average heat rates at the power plant were virtually constant for the 1970's at about 10,410 Btu/kWh. For Federal Power Commission (FPC) Region 1 (which includes New Jersey), the 1975 average heat rate was 10,446, somewhat lower than in prior years. The average heat rates for the eight FPC regions in 1975 varied from 10,155 to 11,241 [6-6, table 9].

An analysis was made of FPC data in reference [6-8] showing relatively stable and uniform values for losses, which in 1975 were about 7.2 percent nationally and 8.0 percent in FPC Region 1, (excluding Maine, New Hampshire and Vermont). As was the case for the specific PSE&G analysis, these losses must be included in the plant heat rates above to obtain energy consumption per kWh delivered to the customer. Therefore, the appropriate average heat rate for use in comparative evaluations are 11,160 Btu/kWh on a national basis and 11,280 Btu/kWh for regional analyses. These values are shown in table 6.5 along with the values for the PSE&G case study plants from table 6.4.

6.4.3 Fuel Utilization

Section 6.4.2 provided data on the efficiency of utility power plant stations, in terms of Btu of source energy consumption per kW delivered to the costomers. It is of importance to further define what specific types of fuel resources are actually cunsumed since comparisons between on-site TE plants and utility-supplied electricity will invaribly involve different types of fuel. There

Table 6.4 Heat Rate of Utility-Supplied Power from Reference [6-5, 6-6 and 6-7]

Type of analysis and plant	1974-1977 Average heat rate	
	Generated	Delivered
	Btu/kWh	Btu/kWh
Marginal new plant		
Conemaugh	9,972	--
Peach Bottom	11,045	--
Average[a]	10,675	11,530
System average	10,657	11,515
Displaced plant		
Essex	15,053	--
Kearny	12,040	--
Burlington	11,575	--
Average[a]	12,080	13,050
% Losses	8.05	

a) Weighted by kWh produced.

Table 6.5 Utility Heat Rates for Use in Overall Evaluation

Type of Analysis	Evaluation Scope: Case study (PSE&G)	Regional	National
	Btu/kWh c)	Btu/kWh c)	Btu/kWh c)
Marginal new plant	11,350	a)	a)
System average	11,515	11,280	11,160
Displaced plant	13,927	b)	b)

a) assumed to be the same as the case study approach
b) not determined
c) all values are for delivered heat reates, including transmission & distribution losses.

should be a distinction between scarce (oil and gas) and non-scarce fuels (coal, nuclear and hydro).

Actual and projected data were obtained from PSE&G in terms of the percentage electrical energy generated by fuel type. Ignoring minor differences in transmission losses and plant efficiency for the various fuels, these data can be used for fuel resource consumption at the power plant. References [6-9 through 6-11] provided actual data through 1978, estimated data for 1979, and official projections (made in 1978) from 1980 through 1994. (The projected data represent 1978 PSE&G data, including the effect of an early 1979 decision not to construct off-shore nuclear power plants.) Figure 6.4 displays the data.

As can be seen from figure 6.4, PSE&G's extensive use of gas and oil in 1974 (totaling 57 percent) is expected to significantly decline in future years through the increased use of nuclear power, which will rise to more than 50 percent of the total used for generation by 1986. In terms of a twenty-year average (1974 through 1993, equivalent to the expected life of the JCTE plant) the total fuel consumption was projected as follows:

Nuclear	39.6	percent
Coal	30.5	percent
Oil	28.9	percent
Gas	1.0	percent

The above data were appropriate for a "System Average" analysis made in 1978. An analysis based on displacement of marginal new plant capacity for the plants

Figure 6.4 Forecasted PSE&G fuel use based on a study made in 1978

shown in table 6.2, weighted by PSE&G share, would show twenty-year data as follows:

Nuclear 70 percent
Oil 30 percent

An analysis based on actual plant capacity displaced would require forecasting, for each year over the twenty-year period, the mix of generation capacity and the plants operating at the least margin of profit. However, in 1978 it was clear that these plants would likely be nearly 100 percent oil-fired.

In terms of a national analysis, it is useful to compare the PSE&G fuel share values with actual and projected national data. National average data are compared with PSE&G data in table 6.6 [6-12, 6-13] based on studies made in 1977.

Table 6.6 PSE&G and National Average Electrical Generation by Fuel Type

Fuel type	1975 National	1975 PSE&G	1986 National	1986 PSE&G
	%	%	%	%
Non-scarce (coal, nuclear, hydro)	69.3	55.1	82.6	81.5
Scarce (gas & oil)	30.7	44.9	17.4	18.5

Table 6.6 clearly shows that, while the nation as a whole used significantly greater portions of non-scarce fuels to generate electricity in 1975, PSE&G appeared in 1978 to be rapidly nearing the national average. If analyses were conducted for only the scarce and non-scarce categories, the national analysis and case study analysis would be virtually the same beyond 1986 using the statistical values available in 1978. If specific fuels were to be examined, significant difference would remain.

6.5 REFERENCES - SECTION 6

6-1. Mathtech, Inc., "Alternative Energy System Configurations to the Jersey City Total Energy Demonstration Project," unpublished report submitted to HUD, March 21, 1977.

6-2. U.S. Bureau of Census, "Characteristics of New Housing," Construction Reports C25-75-13, 1975.

6-3. H.D. Nottingham and Associates, Inc., "Design, Cost and Operating Data for Alternative Energy Systems for the Summit Plaza Complex, Jersey City, N.J.," National Bureau of Standards Report GCR 79-164, May 1979.

6-4. Public Service Electric and Gas Co., "Public Service Electric and Gas Co. Electric System Generator Statistics," Exhibit P-4, Schedule 35 of Docket No. 761-8, March 1, 1976.

6-5. Public Service Electric and Gas Co., "Annual Report of Public Service Electric and Gas Co. to the Federal Regulatory Commission for the Year Ended December 31, 1977," F.P.C. Form No. 1.

6-6. Energy Information Administration, "Steam-Electric Plant Construction Cost and Annual Production Expenses, 1975," U.S. Dept of Energy, DoE/EIA-0033/1, January 1978.

6-7. Public Service Electric and Gas Company, "1977 Annual Report," Report to Stockholders.

6-8. Federal Power Commission, "Statistics of Privately Owned Electric Utilities in the United States, 1975," F.P.C. Report S-260.

6-9. Public Service Electric and Gas Co., "PSE&G Forecaster Generation by Fuel Type," Fuel data for 1980 through 1994 obtained through private communication with PSE&G, 1979.

6-10. Public Service Electric and Gas Co., "Financial & Statistical Review, 1965-1975", 1976.

6-11. Private Communication with PSE&G, Fuel data for the years 1976 through 1979.

6-12. Federal Power Commission, "Annual Summary of the Cost and Quality of Electric Utility Plant Fuels, 1976," Bureau of Power, May 1977.

6-13. National Electric Reliability Council, "Fossil and Nuclear Fuel for Electric Utility Generation, Requirements and Constraints, 1977-1986," August 1977.

7. ENERGY ANALYSIS OF ALTERNATIVE SYSTEMS

7.1 INTRODUCTION

The energy consumption of each of the alternative systems described in Section 6.2 is presented and compared in this section. Energy consumption, in terms of both fuel and electricity consumed on-site, was predicted using a commercially-available computer program. The program simulated in detail the performance and operation of each of the alternative systems in response to diurnal site load variations.

The energy consumption data are basic not only to the energy analysis but also to the economic and environmental impact analyses. These analyses, described later in the report, depended heavily on the energy consumption data produced by the simulation program.

This section describes the simulation program methodology, a program validation effort based on actual JCTE data, and the results.

7.2 SIMULATION PROGRAM DESCRIPTION

7.2.1 Selection

Of the 19 computer programs available for HVAC energy analysis, at least 8 were strong candidates for the JCTE alternative systems' simulation effort. The contractor for the simulation effort chose one of these, the Trane Air Conditioning Economics (TRACE) program, with which he was familiar.

The following section describes the TRACE program and its major features. A subsequent section describes the rationale used in selecting and utilizing TRACE.

7.2.2 TRACE Program

This section provides a brief description of the TRACE program in terms of its general approach, its unique features, and its suitability for the JCTE systems analysis. A more complete narrative and schematic description of the program is given in appendix E, while full documentation can be found in reference [7-1], available to qualified users from the Trane Company.

The general TRACE program structure consists of five parts which correspond to the analytical steps performed in a complete energy/economic analysis of HVAC systems for buildings. This approach was typical of other state-of-the-art simulation programs in 1978. The five parts are: Load, Design, System Simulation, Equipment Simulation, Economic Analysis.

In the Load phase, a unique feature of TRACE is its use of 864 hours of load data to represent an entire year. The 864 hours are based on three typical days per month; a weekday, a Saturday, and a Sunday. These days all have the same weather for a given month but differ in internal loads (lighting, people, etc.). This approach has been shown by the Trane Company to be as accurate as a simulation based on a full 8760-hour year in a case study for a selected building and HVAC system [7-1]. Whether this is true for a wide range of configurations and climates including complex TE systems has not been determined. This approach is also used in the ESOP program developed by NASA for the HUD-MIUS program.

The key to the TRACE 864 hour simulation is the use of a weather reduction subroutine which accepts 8760 hour data from weather tapes and reduces this data analytically into 12 typical 24-hour days, one for each month.

The Design and System Simulation phases contain subroutines for 20 different types of air-side systems. These "systems" (not to be confused with the Alternative Energy Systems) represent most of the possible configurations for air handling and control within a building. These can be applied individually to different zones within the building.

The TRACE program contains a comprehensive file of equipment characteristics to simulate almost any conceivable item of equipment. Full-load and part-load performance data are available for each piece of equipment in this file and the subroutines simulate their operating characteristics as well as those of the necessary auxiliary equipment. The list below shows the approximate number of different items of equipment which are available for use [7-3]:

primary cooling equipment - 58 items
primary heting equipment - 19 items
total energy equipment - 27 items
primary air handling equipment - 13 items
accessory/auxiliary equipment - 43 items

7.2.3 Selection of TRACE

Six criteria for selecting a simulation program were established. These were: methodology, flexibility, adaptability, availabilty, cost, and stature. The possible trade-offs considered when selecting the TRACE program are stated below for each of the criteria:

Methodology - The use of an 864-hour analysis is probably not as desirable for simulating TE systems as an 8760-hour analysis. Until conclusively proven otherwise, it must be assumed that some accuracy is lost in using this type of analysis. On the positive side, the TRACE program has extensive models for air-side systems and primary conversion equipment.

Flexibility - The program can simulate all the conventional systems, including the diesel-driven compressive/absorption system under consideration in this study. As with most other programs, simulation of the more complex TE systems (combined absorption-compression chilling and grid interconnection) requires program modifications. Modifications also are required for specifying equipment performance which is different than that available in the equipment file.

Adaptability - Modifications have to be made by the Trane Company in LaCrosse, Wisconsin and cannot be made by the user.

Availability - The source program is not available to the user and must be input (due to modifications) at the Trane Company in LaCrosse, Wisconsin.

Cost - The cost of running is comparable to other programs.

Stature - The program is widely-used by leading HVAC A/E firms across the country. It is probably not as widely-used as other simulation programs when doing detailed TE studies.

7.3 PROGRAM VALIDATION

The availability of actual measured data from the JCTE site afforded the opportunity to "fine-tune" the computer simulation to accurately model the existing plant (i.e., alternative system no. 1). Obtaining an accurate model of system 1 also improved the accuracy of modelling the other alternative systems since the site loads and many system components are common to the other alternative systems.

The validation process could have been conducted so as to model the JCTE performance as actually operated. This approach would have required modeling several anomalous situations described in section 5 in order to obtain a close match. This approach was not undertaken due to the difficulty and time required in program modification and data analysis.

The validation was conducted using nominal component performances and site loads for system 1 consistent with those indicated in section 5 under non-anomalous conditions.

The logic of the validation process is shown schematically in figure 7.1. The process included selecting periods of actual JCTE data for comparison and adjusting the simulation model so that plant loads and component performance closely approximated the actual/nominal levels for the JCTE plant.

The validation was actually carried out by a comparison of computer predicted vs. actual fuel consumption. Final adjustments to fuel consumption results were made to account for any small residual discrepancies in loads or component performance levels.

7.3.1 Data Periods for Comparison

Since building space conditioning loads are in part determined by the weather, this had to be a consideration in selecting the specific months from the 33 months of measured data. DAS availability also affected in the selection of specific months.

The degree-days were calculated for the reduced "typical" day used by TRACE as a proxy for an entire month's weather. This was then compared to actual degree-days determined at Newark Airport by the National Oceanic & Atmospheric Administration (NOAA) for each corresponding month available from the 33. The degree-days considered to be "normal" for Newark did not enter into the comparison for validation purposes.

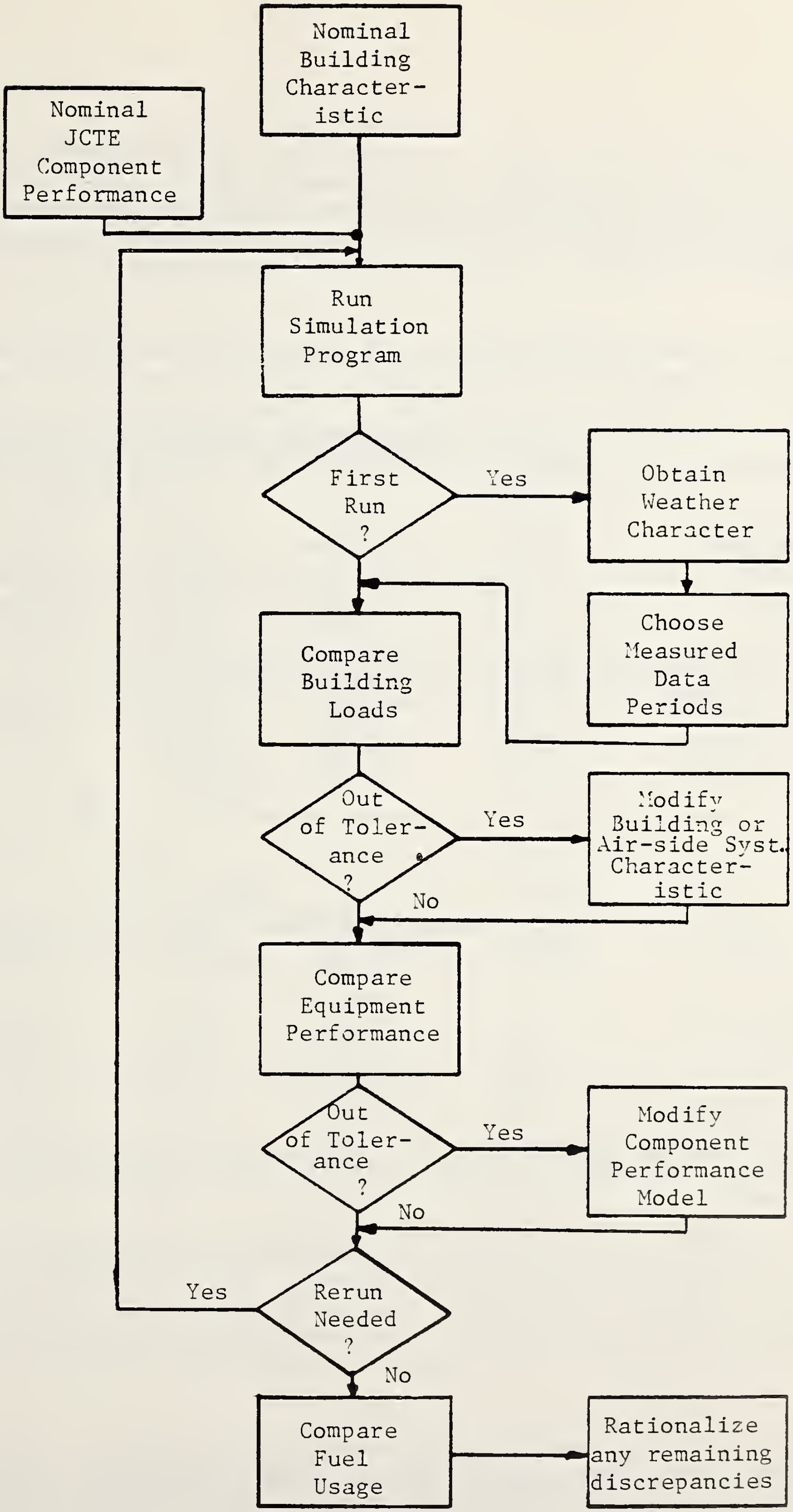


Figure 7.1 Program validation logic

The availability of the DAS (on-line time) was considered important as a determinant of the accuracy of the measured data. DAS availability data were combined with the degree-day comparison to identify the appropriate month on which to base the comparison. The results of this process are shown in table 7.1.

Table 7.1 Selection of Month for Comparison of Simulation Results and JCTE Data

Month	TRACE	Heating degree days/DAS availability (%) NOAA:1975	1976	1977	
January	1097	864/0	1177/95	1361/89	
February	907	832/0	738/93	894/99	
March	753	775/0	645/79	563/94	
April	529	524/86	338/77	352/99	
May	217	84/33	141/92	89/100	
September	55	59/47	56/95	50/70	
October	318	195/75	381/99	319/51[a]	
November	501	400/87	745/96	527/88	
December	911	913/98	1107/57	975/98	
Total	5288	4646	5328	5131	5259[b]

Month	TRACE	Cooling degree days/DAS availability (%) NOAA:1975	1976	1977	
May	6	117/33	30/92	111/100	
June	261	211/98	281/77	191/63	
July	430	375/18	317/23	414/99	
August	324	321/72[a]	305/91	321/44[a]	
September	83	46/47	110/95	146/70	
Total	1104	1070	1043	1183	1140[b]

[a] Month with closet degree days but rejected because of low DAS availability.
[b] Season total for selected months.

7.3.2 Comparison of Loads

Loads for secondary hot water, chilled water, site electricity, and plant electricity for the specific months chosen in section 7.3.1 were obtained from tables 4.1 through 4.4. These actual measured data were compared to loads calculated by the TRACE program.

Differences were expected in the heating and cooling loads due to the large site distribution losses, the magnitude of which was not known accurately at the time the computer program was run. The results of the analysis in section 5 in this report determined the approximate magnitude of the losses and these values were used to normalize the actual JCTE data as shown in table 7.2 to provide a proper comparison.

Table 7.2 Comparison of Heating and Cooling Loads for Program Validation

	Heating and DHW Load		Annual Cooling Load	
	JCTE	Trace	JCTE	Trace
	10^6Btu	10^6Btu	10^6Btu	10^6Btu
Measured value	39,100		9760	
Adjusted for losses	-7,580		-1510	
Nominal/ calculated	31,520	27,916	8250	10,180
% difference	--	-11.4%	--	+23%

Direct monthly comparisons were not made for heating and cooling loads due to the difficulty in determining accurate monthly values for the distribution system losses.

Electrical load comparisons were undertaken for the site load, the plant auxiliary load, and the total load. These load components are shown on an annual basis in figure 7.2 for both the actual measured data (for the selected months) and for the computer-calculated values. The site load at the JCTE was 6240 MWh while the computer calculated value was 5,610, a difference of 10 percent.

Differences in plant auxiliaries are also evident. Chiller auxiliary load determined by computer calculation was 8.2 percent lower than actual measured values. About half of this difference was due to the computer simulation not calling for cooling during May or October. The computer analysis was not capable of calculations for periods of less than 1 month.

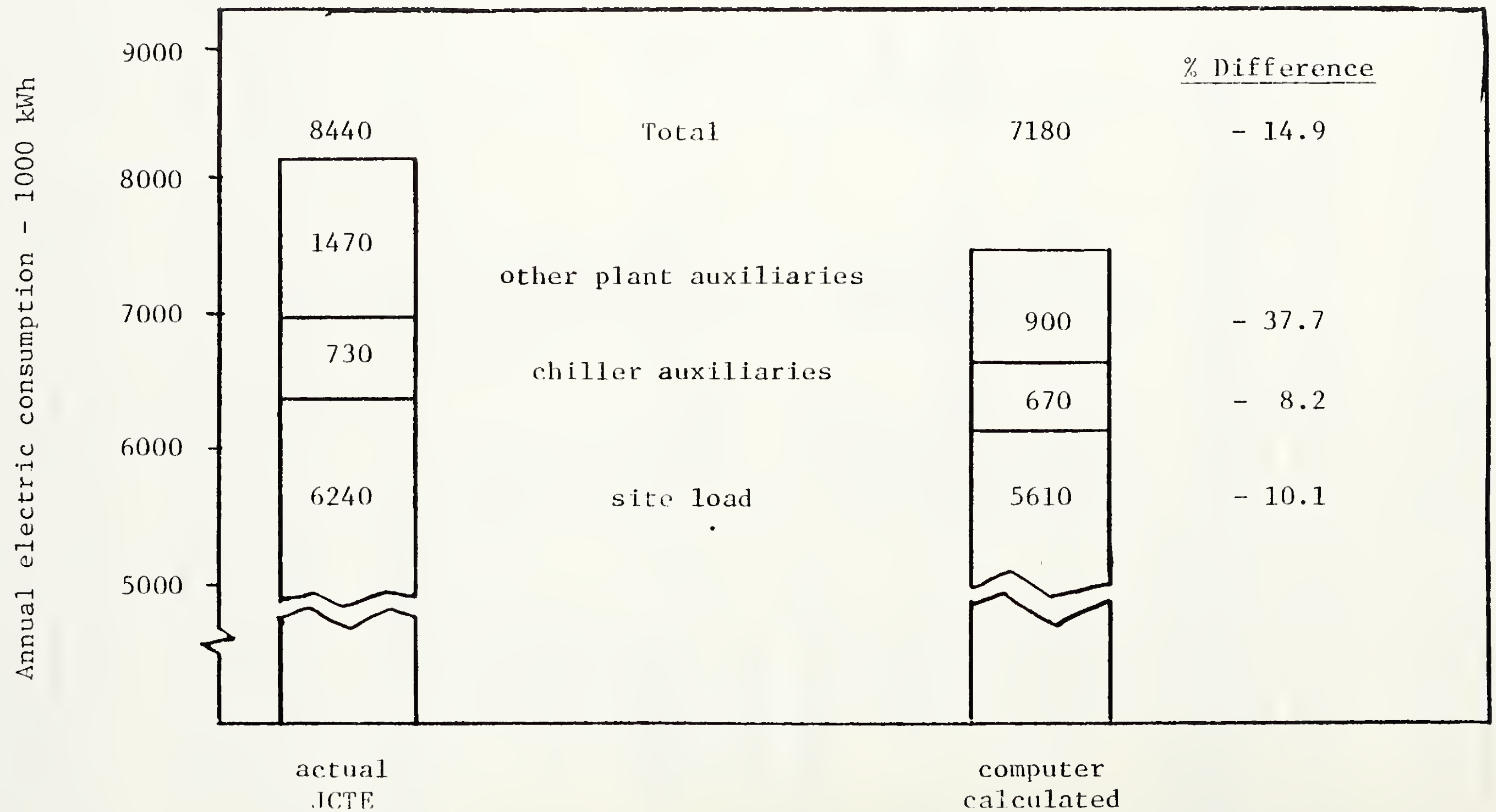


Figure 7.2 Comparison of electrical loads for program validation

Differences in other plant auxiliaries are significant on a percentage basis, the computer predictions being more than 35 percent less than actual measured values. This may be partly because the model of the TE plant was based on an ebulliently-cooled engine-generator configuration.

Due to the above discrepancies in site load and auxiliary load, the total plant electrical load by computer simulation was about 15 percent too low, as shown in figure 7.2.

Additional adjustments to the computer simulation could perhaps have reduced the size of the load discrepancies.

7.3.3 Comparison of Equipment Performance

Since the equipment performance for major components in the TE plant was used in the computer simulation, only minor differences between the computer and actual values resulted for the engine-generator and boilers. The differences in seasonal performance for these components were due to part load effects and differences in equipment loads as described above. Large difference existed for the heat recovery from the engines and COP of the the chillers. These are due to the "typical" performance approach taken in the computer simulation and the fact that conditions encountered in actual operation at JCTE were much different as described in section 5.

7.3.4 Comparison of Fuel Consumption

The differences between computer-predicted and actual loads described above need to be accounted for when comparing results. Also, when determining the fuel consumption of all alternative systems, these differences should be taken into account. The validation should also account for differences in component performance due to "typical" versus "anomalous" operating conditions.

The computer-calculated results for System 1 showed a total annual fuel consumption of 715,000 gallons (2706 m^3) . The necessary adjustment to account for the load discrepancies noted above is an increase of 75,000 gallons (284 m^3), bringing the total adjusted value to 790,000 gallons (2990 m^3).

Actual measured fuel consumption at JCTE for the selected 12 months totaled 987,000 gallons (3740 m^3). The calculated adjustments for anomalous conditions from table 5.1 totalled 215,000 gallons (814 m^3) which were subtracted from the measured data for comparison with the computer results. The resultant corrected annual fuel consumption at JCTE (under normal operation) was 772,000 gallons (2922 m^3) (see section 5.4). The adjusted computer-calculated value of 790,000 gallons (2990 m^3) was only 2.3 percent greater. The results of these calculations are shown in figure 7.3.

From the preceding results, it is readily apparent that the computer predictions (as adjusted) agree very closely with the actual measured JCTE data (as adjusted for anomalous conditions). This level of agreement is well within the uncertainty of the calculations. Thus, the computer-calculated results (as adjusted) serve as an excellent basis for determining the relative fuel consumption and costs for all alternative systems.

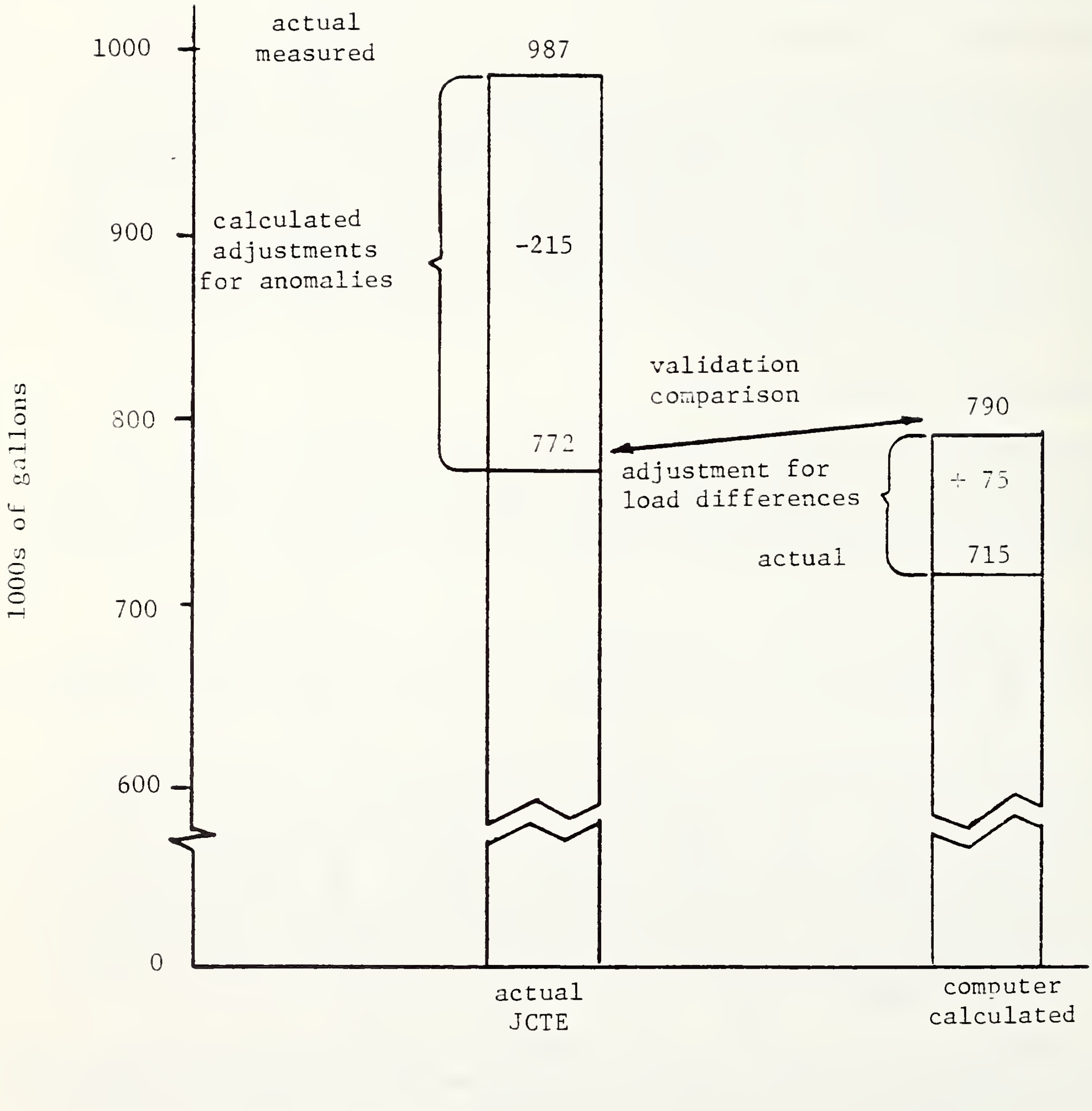


Figure 7.3 Comparison of fuel consumption for program validation

7.4 SIMULATION OF ALTERNATIVE SYSTEMS

7.4.1 Equipment Performance Input Data

The assumptions for equipment performance for all systems were formulated from a number of data sources:

- actual measured JCTE data
- measured JCTE data adjusted for anomalous conditions
- manufacturer's data
- TRACE equipment files

Table 7.3 provides the significant equipment performance assumptions used in the system simulations. Additional details on equipment performance are provided in appendix E of reference [7-4].

7.5 ENERGY CONSUMPTION RESULTS

This section presents a comparison of the total estimated annual energy consumption of the 12 alernative systems described in section 6.

The validated computer program described in section 7.2 was used to calculate energy consumption (fuel & electricity) for each system. A baseline was developed for comparison from adjusted computer-calculated results. This comparison includes the fuel consumption of any on-site fuel-burning equipment plus the equivalent energy consumption at the off-site utility power plant due to consumption of utility-supplied power. The sensitivity of these results to variations in the efficiency of the utility power plant are then examined. Finally, the results are translated into equivalent fuel resource consumption in section 7.5.3 and further comparisons are made.

7.5.1 Baseline Simulation Data

The computer simulations were undertaken to determine energy and operational data for the alternative systems (including the existing TE system) on an equivalent basis. For energy consumption comparisons, equivalency means that typical component performance and typical loads were assumed the same for every system. The results of the simulations which are contained in reference [7-4] were used as the basis for the energy comparison with one exception described below.

Because of inaccuracies in the simulation unique to the combined compression/absorption chiller TE system (System 4), the fuel consumption of this system had to be estimated by adjustments to the simulation results for System 1. Appendix F gives the methodology and calculations for the adjustment procedure. The results for System 4 are felt to be as accurate as for the other simulations, partly because the adjustment affected only a small part of the results (i.e., that portion of the chiller load met by boiler-produced heat in System 1).

The TRACE program calculates the fuel energy consumption for on-site combustion equipment. Such equipment is included in Systems 1 through 8. The program also calculates the energy used in the form of electricity, but does not

Table 7.3 Equipment Performance of Alternative Energy Systems

Equipment	Performance measure	Full load	Seasonal average
600 hp diesel engine-generator	electrical efficiency, %	31.4	30.5
	heat recovery, Btu/kWh	4860	4280
	overal efficiency, %	76.2	67.5
400 hp boiler	thermal efficiency, %	81	80
500 T absorption chiller	COP	0.641[d)]	0.74[d)]
615 hp high-efficiency diesel engine-generator	electrical efficiency, %	39.0	35.6
	heat recovery, Btu/kWh	2900	3070
	overall efficiency, %	72.3	67.6
400T diesel-centrifugal and absorption chiller	COP	n/a	1.49
500T centrifugal chiller	COP	4.83	5.10
building centrifugal chiller (85-238T)	COP	4.83	4.61
2T air-air heat pump[a)b)]	$COP_{cooling}$	1.95	1.89
	$COP_{heating}$	2.58	1.40
2T incremental[b)c)] cooling unit	$COP_{cooling}$	1.75	1.89
	$COP_{heating}$	1.00	0.88

a) Full load performance is for ambient temperatures as follows: 95°F (35°C) for cooling and 45°F (7°C) and 20°F (-7°C) for heating.

b) Seasonal performance includes indoor and outdoor fans and supplementary resistance heat (for the heat pump).

c) Full load cooling performance is for 95°F (35°C) ambient.

d) Values taken from manufacturer publications.

calculate the fuel energy needed at the central power station. Electricity is used in all conventional systems (i.e., Systems 5 through 12). For these systems, data on power plant efficiency from section 6.3 were used to convert the electricity consumption of reference [7-4] to fuel energy consumption. For the baseline analysis in this section, the PSE&G system average heat rate (11,515 Btu/kWh) was used for the conversion. Other heat rates are included for purposes of a sensitivity analysis in the following section.

The TRACE program calculated loads which vary from those determined to be typical for the Summit Plaza site (since 1978). The computer results of reference [7-4] required some adjustment in order to account for this difference. These adjustments are described below.

7.5.2 Adjustments to Baseline Data

In section 7.3.4, the adjustments made to the fuel consumption results for the System 1 simulation to account for differences between predicted and actual plant loads were described. By means of the adjustments, computer-predicted fuel consumption results were shown to closely agree with typical JCTE operational results. To carry out the comparison of all alternative systems on the same basis, similar load adjustments were made to the computer-predicted energy consumption results for all alternative systems.

The adjustments in the hot and chilled water loads were made on the basis of the percentage load differences shown in table 7.2 and were the same for all systems. The adjustments for electrical load were also made on the basis of the data of figure 7.2. In this case, the total energy alternative systems were adjusted for the total 14.9 percent difference shown in figure 7.2 while conventional plants were adjusted for differences in the site load (10.1 percent). The different adjustments for TE and conventional systems had the effect of increasing energy consumption for TE systems more than conventional systems.

The magnitude of the adjustment was determined separately for each system by manual calculations. Consideration was given to the basic conversion equipment involved and its seasonal efficiency from the computer simulations (as modified by part-load shifts, heat recovery effects, etc.). The uncertainty of the adjustments is judged to be ± 10 percent.

These calculated adjustments (for both on-site fuel consumption and purchased electrical energy) were added to the computer-calculated results from reference [7-4] as shown in table 7.4. The adjustments varied from +3 percent to +15 percent for fuel oil consumption and from + 7 percent to +10 percent for electrical energy consumption, depending on the system.

7.5.3 Comparisons of Energy Consumption

Total fuel energy consumption data are shown in table 7.4. Electrical energy consumption is also shown so that the effect of different central station efficiencies can be examined separately. Monthly energy consumption data for each system are provided in appendix G (from the computer simulations, and hence without adjustments for load discrepancies).

As shown in table 7.5 and also in figure 7.4, the lower energy consumption of the TE systems is substantial and attractive. The figure also indicates the relative contributions of the on-site combustion equipment (diesel engines and boilers) and the off-site electric power generating station.

Figure 7.4 shows that the 12 systems can be placed into 3 distinct groups according to energy consumption. The first group is comprised of the TE systems (Systems 1 through 4) and have total energy consumptions averaging 96.2 x 10^9 Btu/year (101.5 GJ/year). The second group is comprised of the conventional central systems (Systems 5 through 7) and the building plant using oil-fired boilers (System 8). This group's fuel consumption averages 128.4 x 10^9 Btu/year (135.5 GJ/year). The third group is comprised of the all-electric systems (Systems 9, 10, and 12) with fuel consumptions averaging 187.8 x 10^9 Btu/year (198.1 GJ/year). System 11, using individual apartment heat pumps, falls between the second and third groups with an annual consumption of 164.5 x 10^9 Btu/year (173.6 GJ/year).

Figure 7.5 shows the relative energy savings of various systems using the existing TE plant as a baseline. Conventional systems use from 24 percent to 88 percent more energy than the existing plant. Only the more optimal TE plant designs save energy over the existing TE plant - by up to 10 percent. This figure also shows the three energy consumption groups more distinctly.

Viewing TE as a generic concept for comparison, the most energy efficient TE system could be used as a baseline. In this case, the conventional systems use from 39 percent to 110 percent more energy than TE (i.e., System 3).

7.5.4 Comparison of Fuel Use

The previous section showed that the TE alternative systems saved significant amounts of energy compared with conventional alternatives. It is also important to examine the types of fuel resources used by each system.

The data of section 6.4.3 enable the electric power plant portion of the source energy consumption for each system to be broken down by fuel types. For a life-cycle analysis of the TE plant, the average PSE&G fuel share data was applied to the energy data of table 7.5. The fuel used on site, whether in a TE plant or by a conventional alternative system, was considered to be oil. This analysis produced the data of table 7.6.

It should also be noted that the oil used at central power plant stations (i.e., residual oil) is quite different than that being used at JCTE (No. 2 distillate). However this distinction is not of major importance because market forces continually change the relative availability of these fuels and because residual oil could be used in on-site combustion systems if necessary.

Most concern is expressed over the consumption of the scarce fuel resources, oil and natural gas. The advantage of systems which use less these fuel resources would seem to partly offset any attendant higher total energy consumption. Table 7.7 and figure 7.6 compare both the relative scarce fuel consumption of the representative systems and their overall energy resource consumption relative to System 1.

Table 7.4 Annual Energy Consumption Adjustments for Load Discrepancies

System No.	Computer - calculated		Adjustments		Final value	
	Fuel	Electricity	Fuel	Electricity	Fuel	Electricity
	1000 gal	MWh	1000 gal	MWh	1000 gal	MWh
1	715.3	0	74.8	0	790.1	0
2	1164.1	(7,016)[a]	18.0	1253	1182.1	(5763)[a]
3	658.8	0	68.7	0	727.5	0
4	676.5	0	86.8	0	763.3	0
5	248.2	7,744	36.0	526	284.2	8,270
6	363.1	7,319	12.6	636	375.7	7,955
7	296.9	7,333	26.7	636	323.6	7,969
8	248.2	8,013	36.0	514	284.2	8,527
9	0	16,200	0	1690	0	17,890
10	0	16,240	0	1550	0	17,790
11	0	14,210	0	970	0	15,180
12	0	16,240	0	1550	0	17,790

a) Electricity transferred to Utility.

Table 7.5 Annual Energy Consumption of Alternative Systems

System No.	Fuel oil[a] consumed	Energy content[b] of fuel oil	Electricity[a] purchased	Source energy[c] consumed
	1000 gal	10^9 Btu	10^3 kWh	10^9 Btu
1	790.1	109.8	0	109.8
2	1182.1	164.3	(5,763)[d]	97.4
3	727.5	101.1	0	101.1
4	763.3	106.1	0	106.1
5	284.2	39.5	8,270	134.7
6	375.7	52.22	7,955	143.8
7	323.6	44.98	7,969	136.7
8	284.2	39.50	8,527	137.7
9	0	0	17,890	206.0
10	0	0	17,790	204.9
11	0	0	15,180	174.8
12	0	0	17,790	204.9

a) From table 7.4, "Final value".

b) Converted at 139,000 Btu/gallon.

c) Electrical energy converted at 11,515 Btu/kWh (29.6 percent efficiency).

d) Electricity sold to Utility; counted as energy credit at power plant.

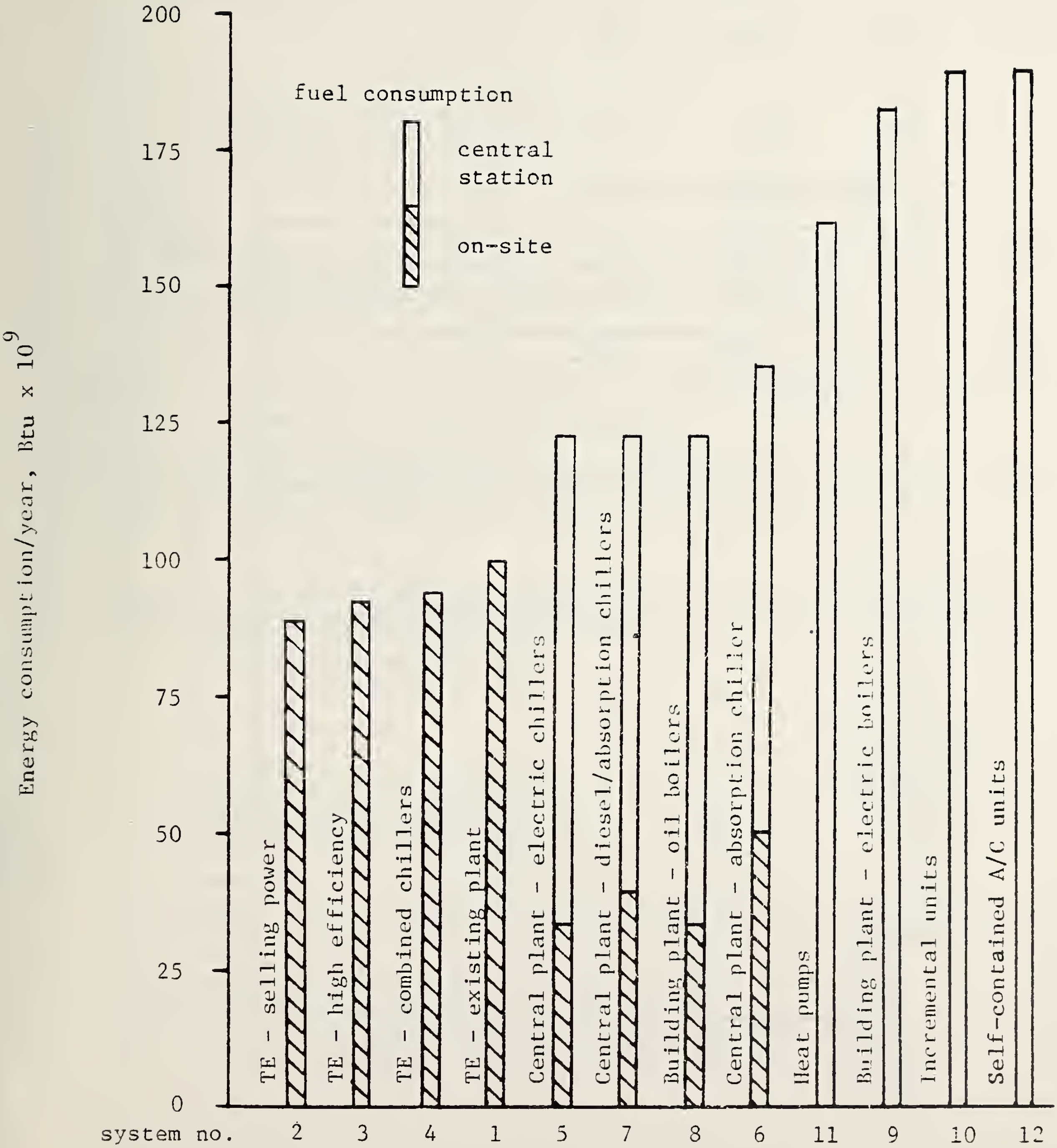


Figure 7.4 Comparison of annual energy consumption for twelve alternative systems. These data include the adjustments of table 7.4.

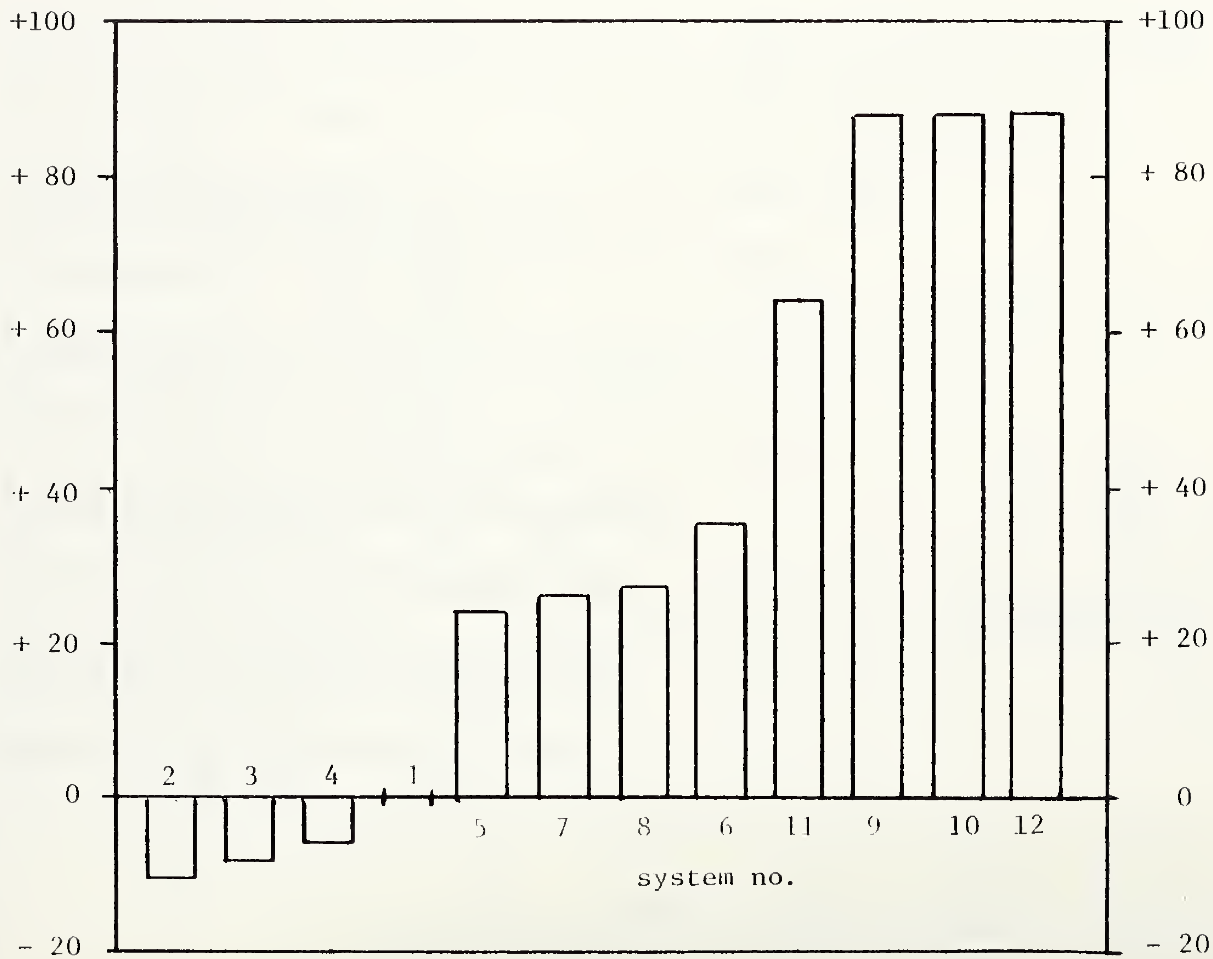


Figure 7.5 Relative energy consumption of twelve alternative systems compared to System 1

Table 7.6 Source Energy Consumption of Alternative Systems

Fuel Type	System No. 1	3	8	11	12
	10^9Btu	10^9Btu	10^9Btu	10^9Btu	10^9Btu
Oil					
on-site	109.8	101.1	39.5	0	0
power station	0	0	28.4	50.5	59.2
Coal	0	0	29.9	53.3	62.5
Gas	0	0	1.0	1.8	2.1
Nuclear	0	0	38.9	69.2	81.1
Total	109.8	101.1	137.7	174.8	204.9

Table 7.7 Relative Source Energy Consumption of Alternative Systems

System No.	Scarce Fuel Consumption Relative to System 1	Total Energy Resource Consumption Relative to System 1
	%	%
3	-7.9	-7.9
8	-37.2	+25.4
11	-52.4	+59.2
12	-44.2	+86.2

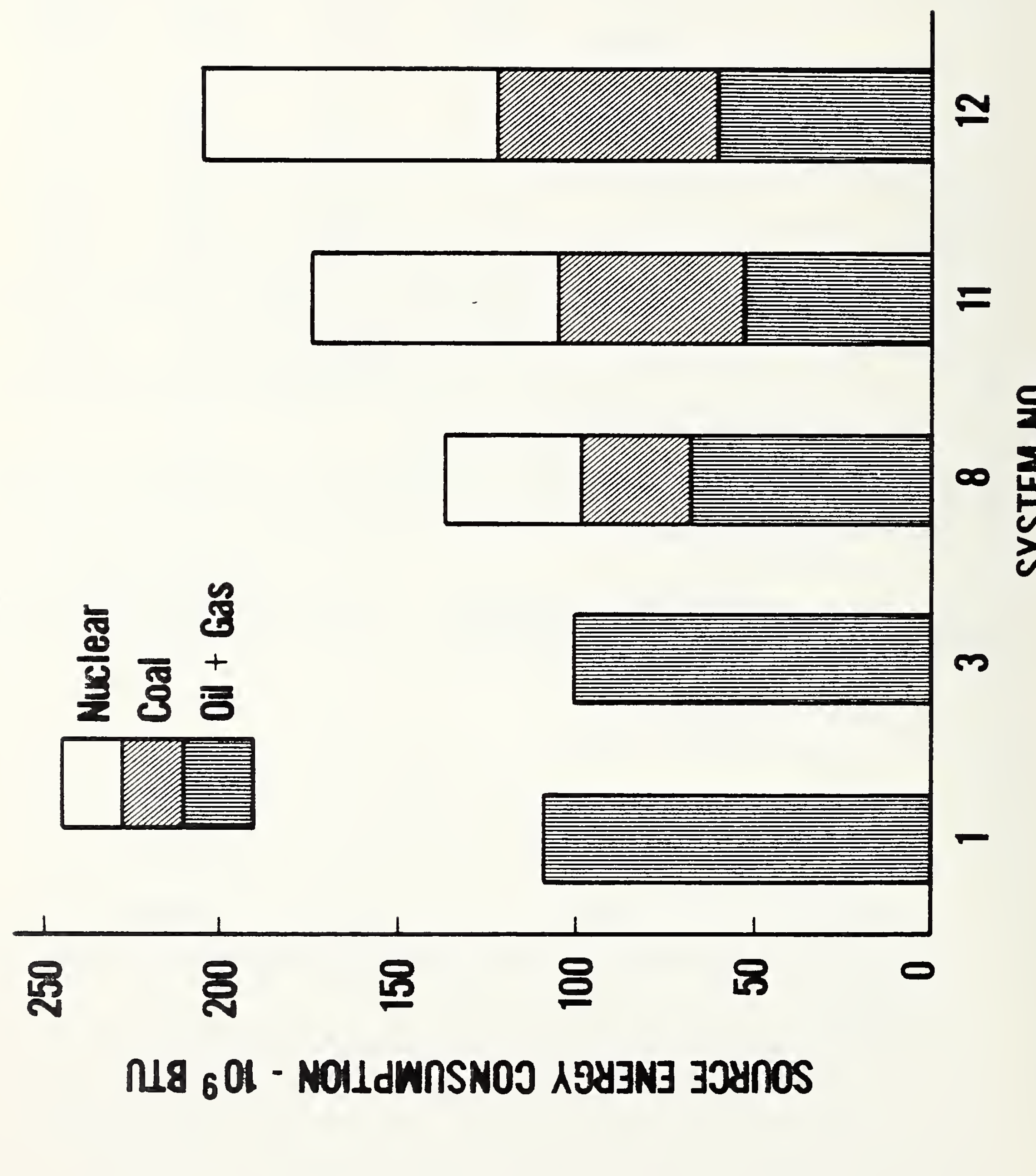


Figure 7.6 Relative source energy consumption for alternative systems

As table 7.7 shows, the conventional systems use significantly less scarce fuels than do the TE systems, while at the same time using considerably more total fuel resources.

7.6 SENSITIVITY TO CENTRAL POWER STATION EFFICIENCY

As discussed in section 6.3, a range of power plant efficiencies can be used in making valid analyses of the comparative energy consumption of the alternative systems. Table 6.5 gives the approximate range of efficiencies (in terms of heat rate) which should be considered.

A sensitivity analysis was conducted over the range of possible heat rates for selected conventional alternative systems. Since the conventional systems seemed to fall largely into two distinct groups in terms of energy consumption, one representative from each group was selected as the basis of the sensitivity analysis. In addition, the heat pump system (System 11) was also selected since it fell between the two major groupings.

The results of the sensitivity analysis are shown in table 7.8 in terms of energy consumption for the specific heat rates representative of the values given in Section 6.4. Figure 7.7 shows how the variation in utility power plant heat rate for the various conventional systems would affect the relative energy savings of the existing TE system (System 1). These data show that the savings can vary between 22.6 percent and 112 percent depending on the type of conventional system chosen for comparison and analytical approach.

Table 7.8 Energy Consumption Variations with Utility Power Plant Heat Rate

	Annual energy consumption, 10^6Btu		
	Utility power plant heat rate, Btu/kWh[a]		
Alternative system no.	11,160	11,515[b]	13,050
8	134,700	137,700	150,800
11	169,400	174,000	198,100
12	198,500	204,900	232,200

a) On a delivered basis; including transmission and distribution losses.
b) Average for PSE&G systems.

The utility power plant heat rate can vary with regions of the country and many other factors. Figure 7.7 however, can be used to determine the relative energy savings results with any typical heat rate.

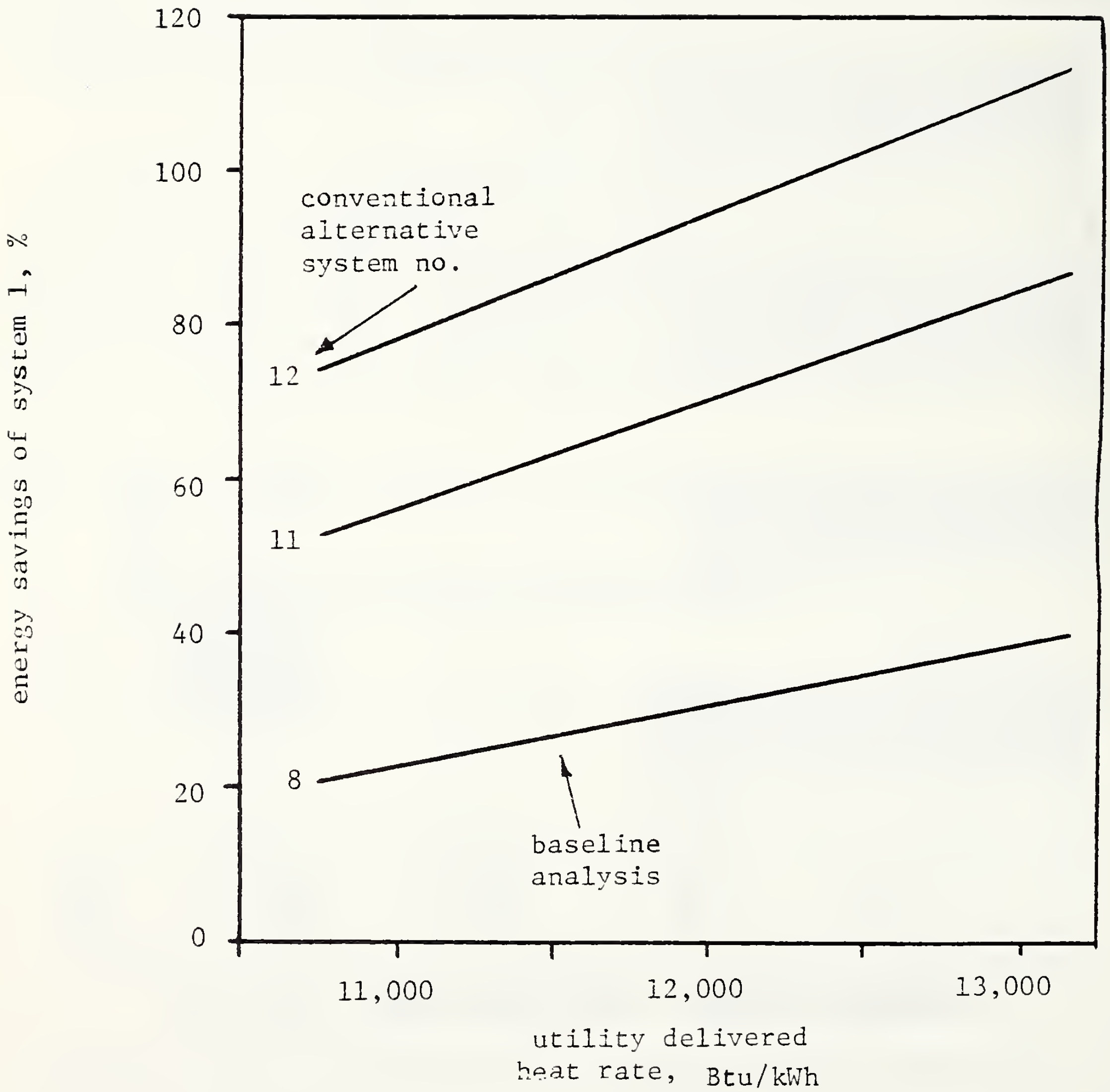


Figure 7.7 Effect of utility power station heat rate on relative energy savings. System 8 is representative of System 5 through System 8; System 12 is representative of Systems 9, 10, and 12.

7.7 REFERENCES - SECTION 7

7-1. The Trane Company, "TRACE Documentation Manual", 1976.

7-2. Patterson, N.R., "TRACE Weather Reduction Accuracy," Internal Memo, A.P.O #1431-249, The Trane Company, April 23, 1975.

7-3. The Trane Company, "TRACE Program Input Version 200," TRACE 2, included as part of reference 7-1, December 1976.

7-4. H.D. Nottingham and Associates, Inc., "Design, Cost and Operating Data for Alternate Energy Systems for the Summit Plaza Complex, Jersey City, N.J.," National Bureau of Standards Report GCR 79-164, May 1979.

8. JCTE COST DATA AND ANALYSIS

8.1 INTRODUCTION

The actual economic data collected for the Summit Plaza TE plant are presented and analyzed in this section in order to develop data for use in the system comparisons described in section 9. Other possible uses for the data include input for evaluating other projects for which specific economic data may not otherwise be available.

This section also presents an analysis of the effect of anomalous conditions at JCTE on the economic data. Anomolous conditions include equipment performance problems, improper or non-optimum operating and maintenance practices, unique institutional factors, etc. A forecast of costs is presented for a "typical" (i.e. non-anomalous) TE situation. Unit costs were also developed, based on the actual "raw" cost data, as a convenient means of presenting the data and as an aid in making direct comparisons with known data from other plants.

This section presents all the actual costs that have been incurred as a result of designing, constructing, owning, and operating the total energy plant at Summit Plaza. The following types of costs were considered:

1. Operation and Maintenance (O&M) costs from initial plant start-up in January 1974 through November 1977.

2. Initial capital costs incurred beginning in late 1971 and capital improvements since plant start-up.

3. Owning costs other than capital investment (i.e., property insurance and taxes).

Indirect revenues from providing utilities to tenants and income tax effects were not considered.

The analysis includes both direct and indirect costs. Direct costs are the costs associated with goods, services, or capital equipment for which actual payment is made to a supplier. These direct costs are separated into components for the electrical, heating, cooling, and PTC subsystems. Indirect costs are the costs associated with transfers of energy between subsystems within the TE plant and for which no actual monetary transaction is made. Indirect costs are a means of further allocating direct costs to the subsystems so that unit costs can be calculated. This further allocation of costs is discussed in appendix I of this report.

8.2 OPERATION AND MAINTENANCE COSTS

8.2.1 Cost Collection Methodology

The firm of Gamze-Korobkin-Caloger, Inc. of Chicago, Illinois (GKC) had the responsibility for operating, maintaining, and improving the JCTE plant for the entire period covered by this report. GKC employees operated and maintained the plant, made fuel and materials purchases, and obtained contract labor services. Even incidential items such as telephone service, remote monitoring by security service, standby electric service, etc., were purchased by GKC. In short, all plant operating expenses, with the exception of one minor O&M cost item discussed below, were incurred by GKC. Owning costs were incurred by the site owner, not GKC.

Cost data were submitted to NBS by GKC on a monthly basis in the form of records of individual disbursements to other companies and of charges made by themselves for operating the plant. These data were also reported to HUD by GKC in accordance with GKC/HUD accounting procedures. NBS had full access to GKC disbursement records (including internal labor, overhead (OH), and assessed fee) as well as cost reports sent to HUD for reimbursement.

Payment to GKC for these operating and maintenance expenses was shared by HUD and Starrett Housing Corporation (SHC) (owner of the entire Summit Plaza site, including the Total Energy Plant). The cost sharing was based on a formula in which SHC's share of the expenses increased year-by-year until no support was to be provided by HUD after 8 years.

The flow of money through the various organizations to pay for O&M expenses is shown in figure 8.1. This figure emphasizes the fact that even though HUD and SHC were sharing O&M costs for the project, this did not in any way influence the cost data being collected by NBS. This was due to the fact that NBS collected total disbursement data from GKC, the plant operator, and not from HUD or SHC. GKC, a private consulting mechanical engineering firm, did not subsidize plant operation, expected to get fully reimbursed for its disbursements, and in fact intended to collect a fee for carrying out its responsibilities.

Only one O&M cost item was not directly reported by GKC. This is the cost of water consumed by the plant. Water was supplied to the entire Summit Plaza site by the City of Jersey City and invoices rendered to the site owner did not separately show the water consumption of the plant. A portion of the water for the plant was separately metered by the plant operator for the water consumed. The water was primarily for make-up in the cooling tower, the heat transfer circuits within the plant, and losses in the site distribution systems. For this report, the total monthly water consumption based on measurements and calculations was used along with the appropriate city water rate (1978) to develop monthly O&M cost data for this item. The annual cost for this item was quite small, 2.4 percent of the total O&M costs excluding fuel costs.

The monthly cost data include all expenditures as they occurred since January 1974. With the four exceptions treated in the next section, this report includes data on individual expenditures directly in terms of magnitude of expenditure and the actual time of occurrence during the year.

8.2.2 Cost Accounting Procedure

Cost data were collected monthly and the raw data were kept in a monthly data base for reduction and analysis. Prior to utilizing the raw data in any way,

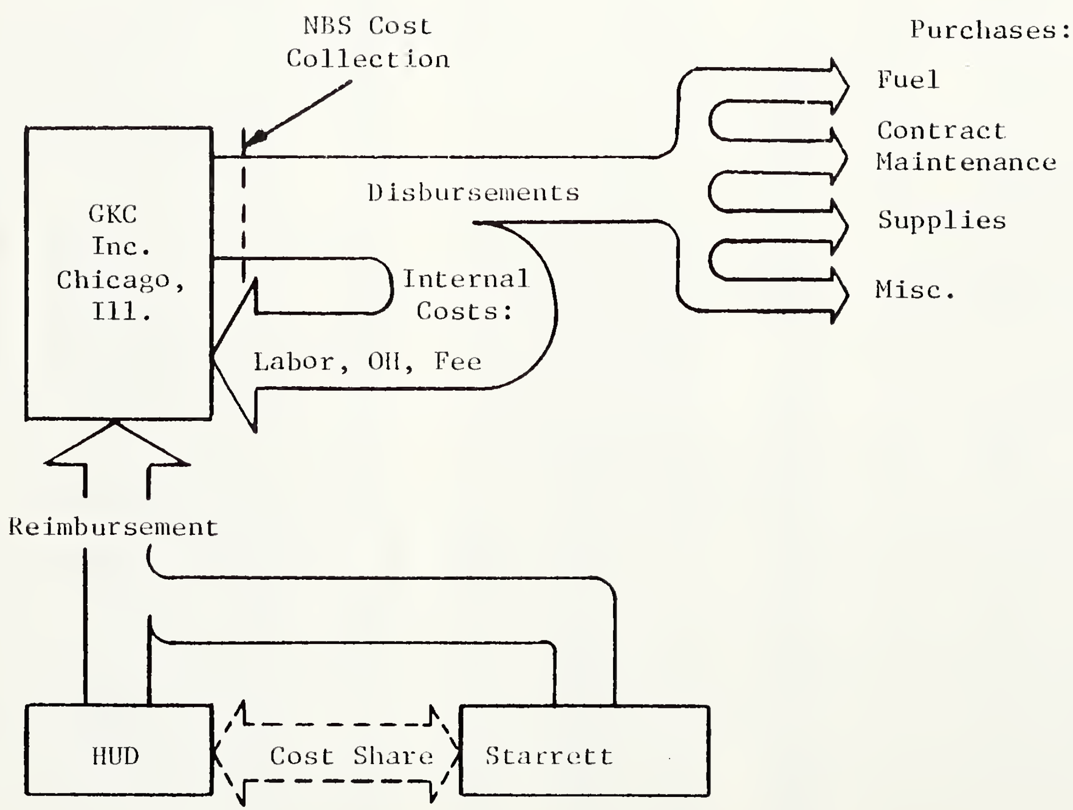


Figure 8.1 Organizational cash flow for the operation of the Jersey City Total Energy site

several adjustments were made to the raw data to improve accuracy or to facilitate comparisons. First, adjustments were made to prorate expenses to more accurately reflect the magnitude and time occurrence of four individual cost items. Second, individual disbursement items were allocated to the various subsystems within the plant and aggregated into seasonal periods in order to calculate unit costs. In all but one case, these adjustments did not change the total yearly cost in any way, but improved the accuracy of the unit cost and seasonal data presentations. The adjustments are described in the following subsections.

8.2.2.1 Prorated Expenses

Four large expenditure items occurred in such a way as to substantially distort month-to-month costs if they were used directly in terms of time of occurrence. One of these items (engine overhauls) was spread over a multi-year time period and appropriate monthly costs were assessed (based on 1979 forecasts). Two of these expenditures (lube oil and insurance) were prorated so that, for each month, a cost was incurred which is equivalent to one-twelfth of the appropriate annual cost. The expenditure for fuel oil was based on actual monthly fuel use, which varied from month to month. By means of these adjustments, the monthly and trimester cost data in this report more accurately reflect the actual level of plant production and maintenance in each period. The engine overhaul and fuel cost prorating schemes are further described below:

Engine overhauls - The overhaul schedule which was projected at the time of plant start-up consisted of three overhauls, two minor and one major, for each engine during the running time of 36,000 hours. When initial minor overhauls on two engines were conducted in January and August 1976 (at 11,800 and 19,900 hours of operation, respectively), the condition of the engines indicated that an extended overhaul schedule should be put into practice. This new schedule called for two overhauls, one minor and one major over a 50,000 hour cycle. The validity of this schedule was confirmed by an inspection performed on an additional engine in December 1977. This approach to overhauls was applied to each individual engine to predict the engine running time and elapsed time at which overhauls would be experienced. Based on this forecast, it was expected to take an average of 116 months (9.6 years) for an engine to complete the first overhaul cycle.

The costs actually incurred during the 47 months of operation through November 1977 did not include any major overhauls because none were performed. (The maximum running time for a single engine at the time was 21,900 hours.) If only actual incurred costs were reported, the cost data would not reflect the true cost of operation. Therefore, the total cost for the projected (revised) overhaul cycle was estimated based on the actual cost of minor overhauls performed through November 1977 and the estimated cost of a future major overhaul provided by the overhaul contractor in 1978. The individual cost items shown here were not escalated for inflation nor discounted. To develop monthly engine cost data, this total estimated cost was divided by the number of months it was expected to take an engine to reach major overhaul.

The actual cost of overhauls experienced during the 47-month period was \$32,300, or \$687 per month. This was for the minor overhauls and inspections described earlier. This monthly cost for overhauls was increased to \$1505 to properly reflect the projected costs for the entire 50,000 hour overhaul cycle. This is approximately half of the projected monthly costs under the original 36,000 hour overhaul cycle. This change is the only case in which data ajdustments changed the actual total yearly costs of the TE plant.

Fuel Oil. Expenditures for fuel were made monthly but fuel deliveries and invoicing were somewhat irregular. For example, a substantial delivery could be made/billed on the last day of a month for fuel which would be used in the following month. Since fuel cost is a significant single item (56 percent of the total O&M costs), a more accurate representation of monthly fuel costs was desired. Therefore, monthly cost data for this report were developed from the fuel actually consumed by the plant during the month (as determined by measurements) and the average unit cost of fuel for the month. Checks were made to insure that the total cost of fuel for a year calculated in this way very nearly equaled the total actual disbursement.

8.2.2.2 Subsystem Cost Separation

Each direct cost item was assigned to the subsystem to which it pertained, except when a single item pertained to two or more subsystems. For these items, the cost was divided between the subsystems either by estimation or by use of secondary data. In some cases, the cost was divided between subsystems according to an estimated fixed percentage. These percentages were estimated by the plant operator and reviewed by NBS. In other cases, secondary data allowed accurate division of cost items between subsystems.

For example, the direct expenditure for fuel oil was charged to the electrical and heating subsystems according to the actual fuel consumption of each, as registered by the NBS data acquisition system.

8.2.2.3 O&M Cost Categories

After the individual monthly expenditures were assigned to the subsystems to which they were attributable, they were condensed into the following categories:

1. Fuel
2. Contract maintenance
3. Direct labor and overhead
4. Plant burden
5. Direct material
6. Miscellaneous

The plant burden category includes those services which are incidential to plant operation and generally not associated with a particular subsystem. Examples are: telephone service, insurance, standby power, and GKC operating fee.

Direct material includes non-capital operation and maintenance items not provided by contract maintenance services. Examples are: chemicals for water treatment, lubrication oil, tools, and spare parts.

8.2.3 Actual O&M Cost Data

The basic O&M data were collected on a monthly basis and the adjustments described above were carried out on the monthly data. For presentation and analysis purposes, it is more convenient to deal with longer periods.

The O&M costs for each of the four subsystems (electrical, heating, cooling, and PTC) for each of the six cost categories are given in table 8.1 for the period March through November 1974, and in tables 8.2 through 8.4 for the three "years" (December-November) of 1975, 1976, and 1977. These 12-month periods were chosen to be consistent with the seasonal periods for which unit costs were calculated (i.e., a "year" commences at the beginning of a winter season on December 1).

8.3 CAPITAL COSTS

8.3.1 Capital Costs for Equipment

Capital equipment costs represent the initial investment as well as capital improvements and replacements during the life of the plant. The initial investment was for all energy and PTC equipment external to the buildings and is reported in the following cost categories:

- engine-generators
- mechanical system
- electrical system
- distribution
- central equipment building
- design fee

These initial costs are presented in table 8.5. These costs were incurred during plant construction which took place from November 1971 through mid-1974. The cost of land occupied by the CEB is not included.

8.3.2 Subsystem Cost Separation

In table 8.5, the capital costs are assigned to the four subsystems on the basis of the function of each piece of equipment. Costs for equipment shared between two or more subsystems were apportioned by relevant indices. For example, fuel storage costs were apportioned by annual average boiler and engine fuel consumption and CEB envelope costs were proportioned by square feet of floor area.

8.4 OWNING COSTS

Owning costs other than capital financing consist of expenditures for property taxes and property insurance by the site owner, Starrett Housing Corporation. Invoices for these items are based on the entire Summit Plaza complex and do not separately include the TE plant.

Table 8.1 Direct O&M Costs - 1974 Summary (March 1974 - November 1974)

Cost Category	Subsystem									
	Electrical		Heating		Cooling		PTC		Plant Total	
	$	%	$	%	$	%	$	%	$	%
1. Fuel	89,454	56.7	42,100	63.4	0	0.0	0	0.0	131,554	53.9
2. Contract maintenance	18,862	12.0	135	0.2	970	6.2	0	0.0	19,967	8.2
3. Direct labor and overhead	25,417	16.1	13,690	20.6	9,186	58.3	2,541	61.9	50,834	20.8
4. Plant burden	11,357	7.2	5,561	8.4	3,247	20.6	932	22.7	21,097	8.7
5. Direct material	12,295	7.8	4,836	7.3	2,180	13.8	609	14.8	19,920	8.2
6. Miscellaneous	250	0.2	50	0.1	175	1.1	25	0.6	500	0.2
Total	157,635	100.0	66,372	100.0	15,758	100.0	4,107	100.0	243,872	100.0

Table 8.2 Direct O&M Costs - 1975 Summary (December 1974 - November 1975)

Cost Category	Subsystem									
	Electrical		Heating		Cooling		PTC		Plant Total	
	$	%	$	%	$	%	$	%	$	%
1. Fuel	189,477	60.0	99,903	70.1	0	0.0	0	0.0	289,380	59.9
2. Contract maintenance	58,612	18.5	7,065	5.0	3,059	15.9	202	3.7	68,938	14.3
3. Direct labor and overhead	38,204	12.1	23,698	16.6	10,686	55.6	3,820	69.1	76,409	15.8
4. Plant burden	17,406	5.5	8,233	5.8	2,330	12.1	1,112	20.1	29,081	6.0
5. Direct material	11,821	3.7	3,216	2.3	3,006	15.6	342	6.1	18,386	3.8
6. Miscellaneous	529	0.2	339	0.2	138	0.7	53	1.1	1,058	0.2
Total	316,048	100.0	142,454	100.0	19,219	100.0	5,530	100.0	483,252	100.0

Table 8.3 Direct O&M Costs - 1976 Summary (December 1975 - November 1977)

Cost Category	Subsystem								Plant Total	
	Electrical		Heating		Cooling		PTC			
	$	%	$	%	$	%	$	%	$	%
1. Fuel	222,107	59.9	124,322	66.9	0	0.0	0	0.0	346,429	58.0
2. Contract maintenance	47,732	12.9	3,933	2.1	7,272	22.8	0	0.0	58,937	9.9
3. Direct labor and overhead	55,397	15.0	36,791	19.9	13,067	40.9	5,540	66.7	110,795	18.6
4. Plant burden	26,863	7.2	12,690	6.8	4,100	12.8	1,753	21.1	45,406	7.6
5. Direct material	17,294	4.7	7,036	3.8	7,304	22.9	889	10.7	32,524	5.5
6. Miscellaneous	1,250	0.3	927	0.5	198	0.6	125	1.5	2,500	0.4
Total	370,644	100.0	185,699	100.0	31,941	100.0	8,307	100.0	596,591	100.0

Table 8.4 Direct O&M Costs - 1977 Summary (December 1976 - November 1977)

Cost Category	Subsystem									
	Electrical		Heating		Cooling		PTC		Plant Total	
	$	%	$	%	$	%	$	%	$	%
1. Fuel	245,407	63.4	127,684	65.7	0	0.0	0	0.0	373,091	59.1
2. Contract maintenance	37,672	9.7	11,288	5.8	9,213	24.6	3,317	27.9	61,490	9.7
3. Direct labor and overhead	52,090	13.4	32,962	16.9	13,919	37.3	5,209	43.7	104,180	16.7
4. Plant burden	37,026	9.5	17,123	8.8	7,647	20.5	2,643	22.2	64,438	10.2
5. Direct material	14,821	3.8	4,878	2.5	6,270	16.8	642	5.4	26,611	4.2
6. Miscellaneous	962	0.2	553	0.3	314	0.8	96	0.8	1,925	0.3
Total	387,978	100.0	194,487	100.0	37,362	100.0	11,907	100.0	631,735	100.0

Table 8.5 Capital Cost Summary

Actual construction costs including overhead and profit

Thousands of Dollars

Cost category	Subsystem: Electrical	Heating	Cooling	PTC	Total
Engine-generator	$ 316	—	--	--	$ 316
Mechanical	132	553	714	85	1,484
Electrical	213	—	--	--	213
Distribution	214	86	110	713	1,123
CEB envelope	208	130	148	109	595
Design fee	52	39	49	Included above	140
Totals	$ 1,135	$ 808	$ 1,021	$ 907	$ 3,871

Real estate for the Summit Plaza complex is paid pursuant to New Jersey statutes, NJSA 55.14 J-1, et. seq., as set forth in an agreement with the City of Jersey City. This agreement provides that the real estate taxes payable for the complex will be 15 percent of annual "shelter rent" of the complex. This means of paying real estate taxes is very common in the New York City and adjacent New Jersey areas. Therefore, the actual expenditures for real estate taxes do not directly depend on the value of equipment used for providing utility services. In presenting the actual costs as experienced for the JCTE plant, this report includes no portion of the total Summit Plaza cost for real estate taxes.

8.5 UNIT ENERGY COSTS

Unit costs for each of the energy commodities provided by the plant were calculated using the actual O&M and capital cost data of sections 8.2 and 8.3. The unit costs are reported as follows:

electricity	¢/kWh
hot water	$\$/10^6$Btu
chiller water	$\$/10^6$Btu or ¢/Ton-hr

The energy quantity used in the denominator is the energy delivered to the site.

Unit costs for JCTE are provided here primarily as a convenient, widely-understood means of presenting the actual cost data. These data can be used for:

- comparing the cost of supplying utility services to the Summit Plaza Complex with different means of supplying the same services

- comparing the cost with actual data from similar existing plant complexes

Either of the above comparisons is not considered a method for comprehensive economic evaluation. Nevertheless, such comparisons may prove useful in some circumstances provided that a cautious approach is employed. Some items of particular concern are cited below. If comparisons are to be made using JCTE unit costs, care must be excercised to insure that:

- all relevant costs are included or that similar physical/cost accounting boundaries are drawn so that comparable cost items are included

- the building complexes being compared have somewhat similar load patterns

- anomalous conditions are considered including differences in the current costs and economic forecasts compared with those of 1978/1979.

If comparisons with other published data is considered, then the limitations of those data should be recognized. In general:

- most published cost data do not completely separate HVAC and electrical system costs from other operating costs for the buildings as was done here.

- there are usually inherent variations among the sampled buildings in terms of size, age, type of HVAC system, usage, etc.

- there are a variety of ways costs are reported (even within a fairly rigid accounting system) which can lead to significant differences in reported costs.

- there may be small sample sizes for some cost items

Because of the significant variations in subsystem loads with the season, it is appropriate to present unit costs on other than annual basis. The time periods chosen here were based on plant operating conditions. Specifically, a year was divided into three unequal periods as follows:

Summer - included all days for which the chiller was operating (generally the last week of May through the first week of October).

Winter - the three months of December, January and February.

Spring/Fall - all other days of the year.

This approach allowed expenses for the chiller to be confined to a single period. It further allowed costs during the periods of low thermal loads in Spring and Fall to be separated from periods of higher loads. The differences in plant loads for these periods were significant. In qualitative terms, plant load differences were as shown in table 8.6.

Monthly O&M costs aggregated into seasons for the purpose of calculating unit costs. These data also provide a more detailed look at the actual data, previously shown as yearly aggregations in tables 8.1 through 8.4. The seasonal data can be found in appendix H.

The seasonal data and the unit costs include a capital cost component in addition to O&M costs. In order to combine these two types of costs the initial capital costs of table 8.5 were converted to an equivalent annual basis. To accomplish this conversion, the initial capital costs were multiplied by an appropriate uniform capital recovery (UCR) factor. The UCR factor depends on the interest rate and the assumed life of the plant which are developed and described in appendix H.

The methodology used to calculate unit costs accounts for the energy transfers between subsystems internal to the plant. This is necessary because of the significant indirect costs associated with these energy transfers. The need to include these energy transfers and their costs in the calculation of unit costs resulted in development of a fairly complex calculation methodology. This methodology is fully discussed in appendix J.

Table 8.6 Qualitative Seasonal Load Variations

Load	Summer	Spring/ Fall	Winter
1. Gross electrical output	high	moderate	moderate
2. Boiler output	high	low	high
3. Site hot water consumption	low	moderate	high
4. Plant auxiliary electrical consumption	high	moderate	moderate
5. Site electrical consumption	moderate	moderate	moderate

The unit costs results are shown in table 8.7 as an aggregated 3-year summary of subsystem unit costs. Year-by-year data do not vary significantly from the aggregated values. More detailed yearly and seasonal data are contained in appendix H. In all cases, the cost components of fuel, other O&M, and capital recovery are provided to facilitate comparisons with other data which may not include capital recovery or which may be based on different unit costs for fuel.

The unit cost data clearly show a very high cost for chilled water and moderately high unit costs for electricity and hot water. The high cost for chilled water is due in large part to the high capital recovery associated with a system which operates only four months of the year. For example, in an office building, with a year-round need for chilled water, the capital recovery portion alone could be cut from nearly $\$19/10^6$Btu to approximately $\$10/10^6$Btu.

8.6 DISCUSSION OF DATA AND ASSESSMENT OF TYPICALITY

The purpose of this section is to discuss the cost data of section 8.2, to identify the major variables which affected actual plant costs, to conduct an assessment of the typicality of the cost data, and to provide adjustments so that the costs can be considered typical.

The assessment typicality of is vital if this demonstration is to provide an understanding of TE plant economics beyond the particular case study which has been completed at Summit Plaza. The typicality of JCTE economic data should be a consideration in analyses which directly use JCTE overall economic results for comparison or which use the JCTE individual cost component data to estimate costs for other TE plants.

The data of tables 8.1 through 8.4 gives O&M costs by component. Figure 8.2 shows the relative contribution of these components during the 1975-1977 period. The analysis of these cost data will be by component as indicated in figure 8.2 by emphasizing effects of fuel costs with slightly less emphasis on direct labor and maintenance and only cursory analysis of the significant elements of the other cost components. The first five parts of the discussion (sections 8.6.1 through 8.6.5) deal exclusively with O&M costs; capital costs are discussed in section 8.6.6.

Table 8.7 Unit Cost of Site Thermal and Electrical Energy
March 1, 1974 through November 30, 1977

Cost category	Electricity	Hot water	Chilled water
	¢kWh	$/MBtu	$/MBtu
Fuel	1.92	3.90	10.08
Other O&M	1.22	2.60	6.80
Capital recovery	1.02	2.87	18.86
Totals	4.16	9.37	35.74
Site energy delivered, MWh or MBtu	18,210	112,000	21,540

8.6.1 Inflation and Other Temporal Effects

The total O&M cost of JCTE has continuously increased since January 1974, as shown for fuel and non-fuel components in figure 8.3. Fuel cost increases have resulted from both increased fuel usage and from rising unit costs for fuel (see figure 8.4). Fuel usage is largely affected by site/plant loads, discussed in section 8.6.2, and by equipment performance, discussed in section 8.6.3.

For non-fuel O&M costs, general increases in costs for on-site labor, contract maintenance, and material costs have been experienced since January 1974.

The combined cost for on-site labor and contract maintenance has also changed over time as the various O&M tasks have been performed either by in-house or by contract personnel and by the number of plant personnel employed. This is discussed further in section 8.6.4.

8.6.2 Plant Loads

The magnitude of the thermal and electrical loads imposed on the plant has a major influence on costs. When these loads increase, total costs rise largely because more fuel is burned, while unit costs (e.g., ¢/kWh) are reduced because fixed costs remain constant.

JCTE cost data can be compared directly with other systems which serve similar loads, irrespective of the type of facility being served or the climate. This approach usually results in the most accurate comparisons. It may also be desired to make comparisons between JCTE costs and costs for services to other similar complexes for which load data are not available. (Similar complexes means approximately the same number of apartments, and/or the same conditioned area, the same building types, the same climates, etc.) In this latter case, it is important to know whether the JCTE loads are typical for this general type of application. TE plant loads are primarily influenced by the following:

Total O & M Costs:	
1975	$483 K
1976	$597 K
1977	$632 K

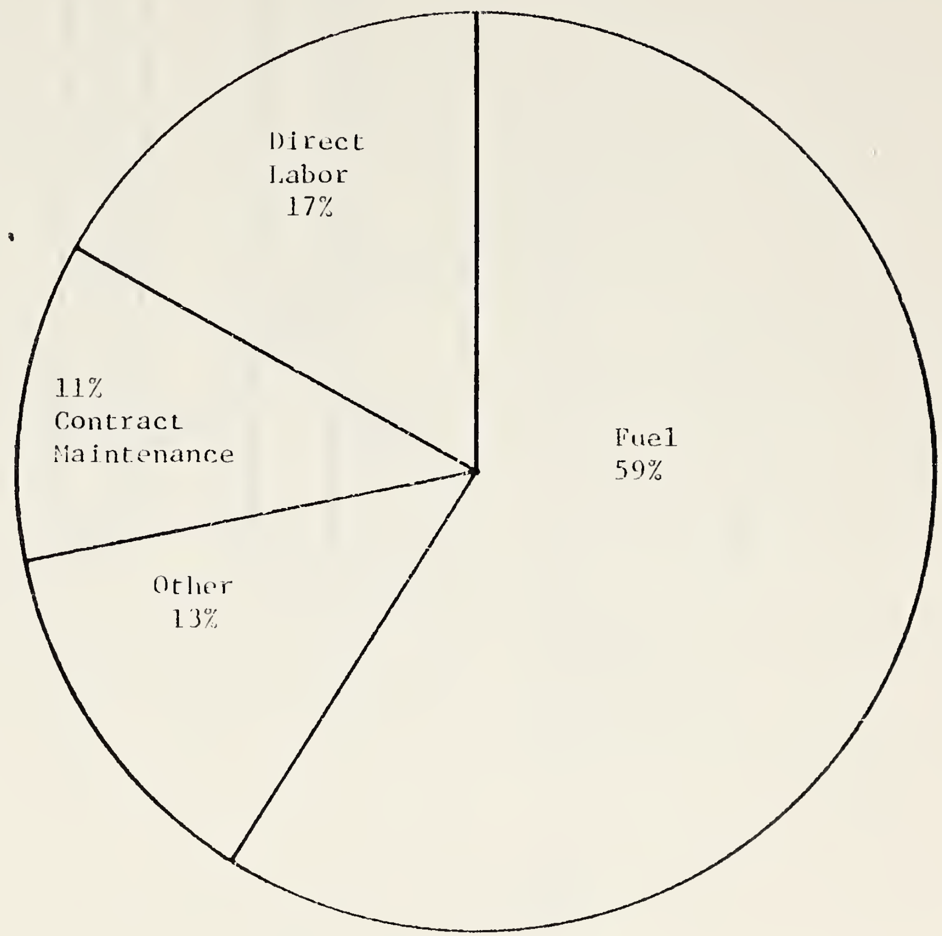


Figure 8.2 Major components of the O&M cost

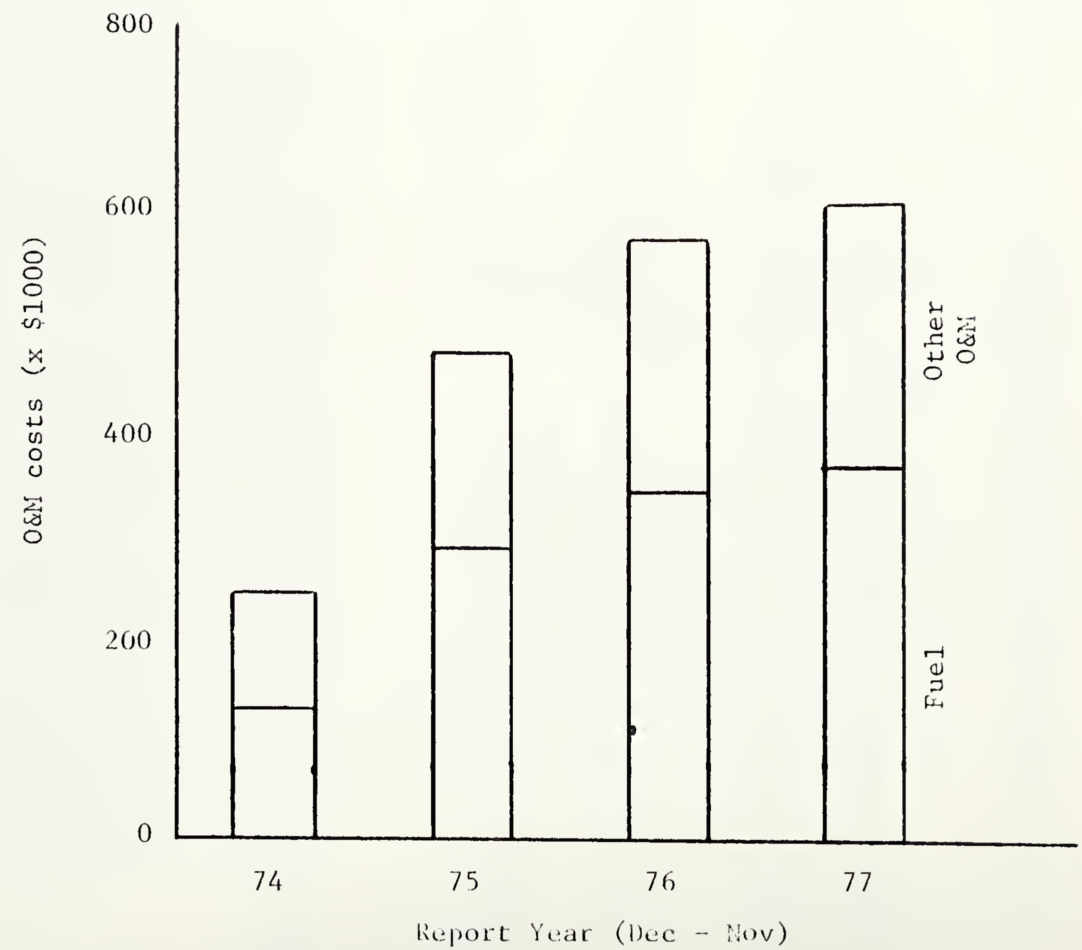


Figure 8.3 Total annual O&M costs

Figure 8.4 Unit cost of fuel oil delivered, 1974 - 1977

- percent site occupancy
- distribution system performance
- weather
- occupant conservation efforts
- building characteristics

The following paragraphs discuss each of these items in turn.

The apartment buildings reached full occupancy in September 1974. The school had its first session beginning in September 1976. However, the commercial building was only partially occupied during the period covered by this report. The hot water, chilled water, and electrical loads at the TE plant would be increased only slightly (less than 5 percent) by a fully occupied commercial building.

The thermal distribution system has been a source of very significant energy
The thermal distribution system has been a source of very significant energy losses, as discussed in section 5.3.1, and has therefore increased plant hot water and chilled water loads accordingly. The excess in hot water load due to the inefficient distribution system was estimated to be 19.6 percent in January 1977 and 28.6 percent in July 1977. Section 5.3.1 also contains an estimate of the annual reduction in fuel oil consumption which would result if the excess losses were eliminated in both hot and chilled water circuits: 91,000 gallon (344 m^3) which is equivalent to a cost savings of $32,300 at the 1976 average fuel cost. This should be taken into account in use of this data for comparisons.

Peak loads, also affected by the losses, have an effect on boiler capacity and capital costs as discussed in sectin 8.6.6.

Weather patterns exert a direct and significant effect on building space conditioning loads, and therefore an evaluation of the typicality of the weather during the four years covered by this report was performed. Data obtained from the National Oceanic and Atmospheric Administration (NOAA) shows both the actual and normal degreedays for heating and cooling. These data are shown in table 8.8 for the Newark Airport weather station which is 6 miles from Summit Plaza [8-1]. These data show that heating loads were somewhat higher than normal during the first 2-1/2 years of operation and somewhat less than normal during the last 1-1/2 years. Cooling loads were consistently higher (7 percent to 18 percent) than normal during the entire 4-year period. For this report it was not considered necessary to develop O&M cost adjustments to account for these relatively minor deviations from typical weather patterns in view of the large distribution system losses. The larger cooling loads due to the weather was somewhat offset by the low commercial building load.

Occupant conservation efforts are very difficult to assess and depend at least in part on the degree of economic incentive. The site contains no individual metering of either electrical or thermal commodities for the purpose of directly billing to the tenants. Under this "master-metered" situation, no significant occupant conservation efforts are likely. Insofar as cost comparisons are concerned where specific load data are not available, Summit Plaza TE costs should be compared only with costs of other complexes which are also "master-metered".

Table 8.8 Actual Weather Patterns, 1974-1977

Heating			Cooling		
Season	Degree-days[a)]	% Dev.[b)]	Year	Degree-days[a)]	% Dev.[b)]
1974[c)]	2903	-11	1974	1125	+10
1974-75	4811	- 4	1975	1100	+ 7
1975-76	4624	- 8	1976	1099	+ 7
1976-77	5577	+11	1977	1208	+18
1977[d)]	1871	+ 5			
Normal season	5304		Normal year	1024	

a) base = 65°F

b) $\% \text{ Dev.} = \frac{\text{actual-normal}}{\text{normal}} \times 100$

c) January through June only, normal = 3252 degree-days

d) September through December only, normal = 1787 degree-days

Building characteristics at Summit Plaza are somewhat atypical. All apartment buildings are of modular construction. The school and commercial buildings, however, generally have typical construction characteristics. The impact of modular construction on apartment building space heating and cooling loads is not known and was not part of this TE demonstration evaluation. All apartment buildings except Decson have double-glazed windows which is somewhat atypical for buildings designed in 1972. In general, it is felt that the building characteristics should not be a factor in comparisons of data.

8.6.3 Equipment Performance

Section 5.2 identified a number of conditions at the site which caused increased fuel usage. The increased fuel use can be translated directly to increase costs. Of the six items listed in section 5.2, all but one appears to be atypical in the sense that either equipment did not function as it does in most plants, or that the conditions could have been easily and inexpensively rectified.

Table 5.1 provided the possible annual fuel savings for the conditions had they been rectified. Taking the more conservative fuel saving values from this table when more than one approach to improvement is provided, the fuel and cost savings for rectifying the five atypical conditions are shown in table 8.9.

The exhaust heat exchangers and dry coolers would possibly require some added investment to realize the above cost savings. However, it is felt that any such costs would be rapidly repaid through the fuel savings, thereby justifying the inclusions of these improvements. For example in February 1978, louvers were actually installed on the dry coolers at a cost of $91,000. Unit fuel costs for the first five months of 1978 averaged 39.27¢/gal. At this fuel cost and the annual fuel savings indicated in table 8.9, the investment in dry cooler louvers had a payback period of 2.1 years.

Table 8.9 Cost Impacts of Improved Equipment Performance

Item	Annual Fuel Savings	Annual Cost Savings[a)]
	gallon	$
Exhaust heat exchangers	37,000	12,720
Engine-generator operation	7,300	2,510
Idle boiler bypass	7,500	2,580
Chiller performance	32,000	11,000
Dry cooler losses	11,000	3,780
Total	94,800	32,590

a) Based on 1976 average fuel cost of 34.37 ¢/gal.

Optimizing the engine-generator schedule reduced fuel costs because the engine-generators were allowed to operate at a higher part-load condition where efficiency is somewhat greater. As discussed in section 5.2.1.3, another benefit was also obtained: a savings of 2200 engine-hours per year. In terms of the overhauling the engine-generator alone, this saves an addition $1500 per year.

8.6.4 Operation and Maintenance

The operating approach envisioned in the design of the plant was carried out and was not changed during the first four years. That approach calls for an operator to be at the plant on a one-shift, 40-hour per week basis. In the evening and on weekends, the plant is completely unattended. A second operator was added during the daytime primarily to assist with maintenance tasks and to provide a back-up to the principal operator in case of sickness or emergency calls.

The single-shift operating approach obviously reduces cost to a minimum. On the negative side are some added costs due to running excessive engines and some loss of reliability. Whether a generic plant should incorporate greater operator attendance cannot be clearly stated on economic grounds. The amount of cost increase for a generic plant with two-shift or three-shift attendance is uncertain since the Summit Plaza plant has added controls which would not be needed in a fully-attended plant. For a small plant like this one, the unattended approach is viable and likely the most cost effective; therefore, no atypicality appears to be present in this area.

The maintenance approach has evolved through three distinct phases. The first phase, from plant start-up through mid-1975, was oriented toward plant shake-down, familiarizing the principal operator with the plant, establishing procedures, etc. In this phase, maintenance functions were almost completely performed by outside contractors (i.e., those firms which had supplied equipment and who also affected contract maintenance services). This was to allow the operator to give proper attention to operational shake-down rather than be burdened with maintenance chores. Equipment warranty provisions also made it advisable to have maintenance well-documented and performed by recognized, qualified service personnel.

A second maintenance phase from mid-1975 through 1976, was based on a transition from contracted maintenance to in-house maintenance. It was felt that cost reductions could be affected by the in-house approach. During the transition phase, two additional plant O&M personnel were added (for a total of three) and an effort at maintenance development and on-the-job training was undertaken. Contract maintenance was retained during the transition period at nearly the same level as if no additional in-house personnel were available. Obviously there were substantial added costs during the transition period for having both contract maintenance and in-house personnel.

The approach during the third phase was to gradually take over the previously-contracted maintenance task with the added in-house personnel and to terminate many of the maintenance contracts. Contract maintenance support was still called upon for major maintenance operations.

Figure 8.5 shows the total labor-related O&M costs for the three maintenance phases. During the first phase, direct labor was relatively constant while contract maintenance steadily increased as maintenance needs developed for the new equipment. The second phase saw a significant increase in labor costs and a slackening in the increase in contract maintenance costs.

Labor costs as a percentage of total labor + contract maintenance costs remained nearly constant at 50 percent in the second phase. During the third phase, in-house labor costs did not increase greatly.

In-house labor costs as a percentage of total labor-related O&M costs was 84 percent in the first phase, 56 percent in the second phase, and 78 percent in the third phase.

The magnitude of cost savings with in-house maintenance versus contractor-performed maintenance was difficult to quantify. However, the total cost trend shown in figure 8.5 clearly shows the three phases. The added cost of the second phase is quite obvious and appears to have been about $14,000 per year.

The overall maintenance approach implemented in the three phases appears to be very reasonable and a viable approach for any TE plant. No atypical factors were noted in the general approach. The maintenance costs for the third phase should be considered most representative of a typical plant.

Specific maintenance situations did exist, however, which resulted in atypical equipment performance. The most significant was the lack of monitoring and maintenance of the cooling tower and chillers which did lead to poor chiller COP's. Proper maintenance of these items would not have increased the O&M costs in any significant way.

O&M costs for labor were also influenced by the high local wage rates (high relative to the national average). This effect is more fully described in section 8.6.6. The cost impact for a 9.2 percent labor premium in the Jersey City area considering in-house labor only was $9,000. It would have been even higher including contract maintenance which is very labor-intensive.

8.6.5 Management and Institutional Factors

From a management and institutional standpoint, the design, construction, and operation of the TE plant in the context of the Summit Plaza development was unique in a number of significant ways. Those management and institutional factors which had an impact on O&M costs are as follows:

- the multiplicity of organizations involved in management, design, construction, and operation of the TE plant and site buildings
- operation of the TE plant under a HUD contract by an engineering firm independent of the site owner
- HUD financial support to the developer for operating the TE plant
- HUD requirements for accounting and reporting costs for the TE plant and for public relations support by the operating firm.

These non-technical aspects and their impact on costs are discussed in the following paragraphs.

The multiplicity of organizations involved in the design and construction of the site was necessitated by the nature of the HUD objectives under the Operation BREAKTHROUGH program. Four different firms had lead responsibility for the various site buildings while the site distribution, the PTC, and the TE plant each were the responsibility of separate firms. This situation is described in more detailed in reference [8-3]. The impact of this situation was difficult to determine, but it appears that it may have been the basic cause of other technical problems such as discrepancies between actual and predicted loads, early operating problems with electrical service, etc.

The TE plant was operated by Gamze-Korobkin-Caloger, under a contract with HUD who, in turn, billed the site owners for part of this cost. The site owners had responsibility for all electrical and mechanical equipment outside the TE buildings, including site distribution and in-building HVAC equipment. This three-party responsibility probably led to the following atypical conditions:

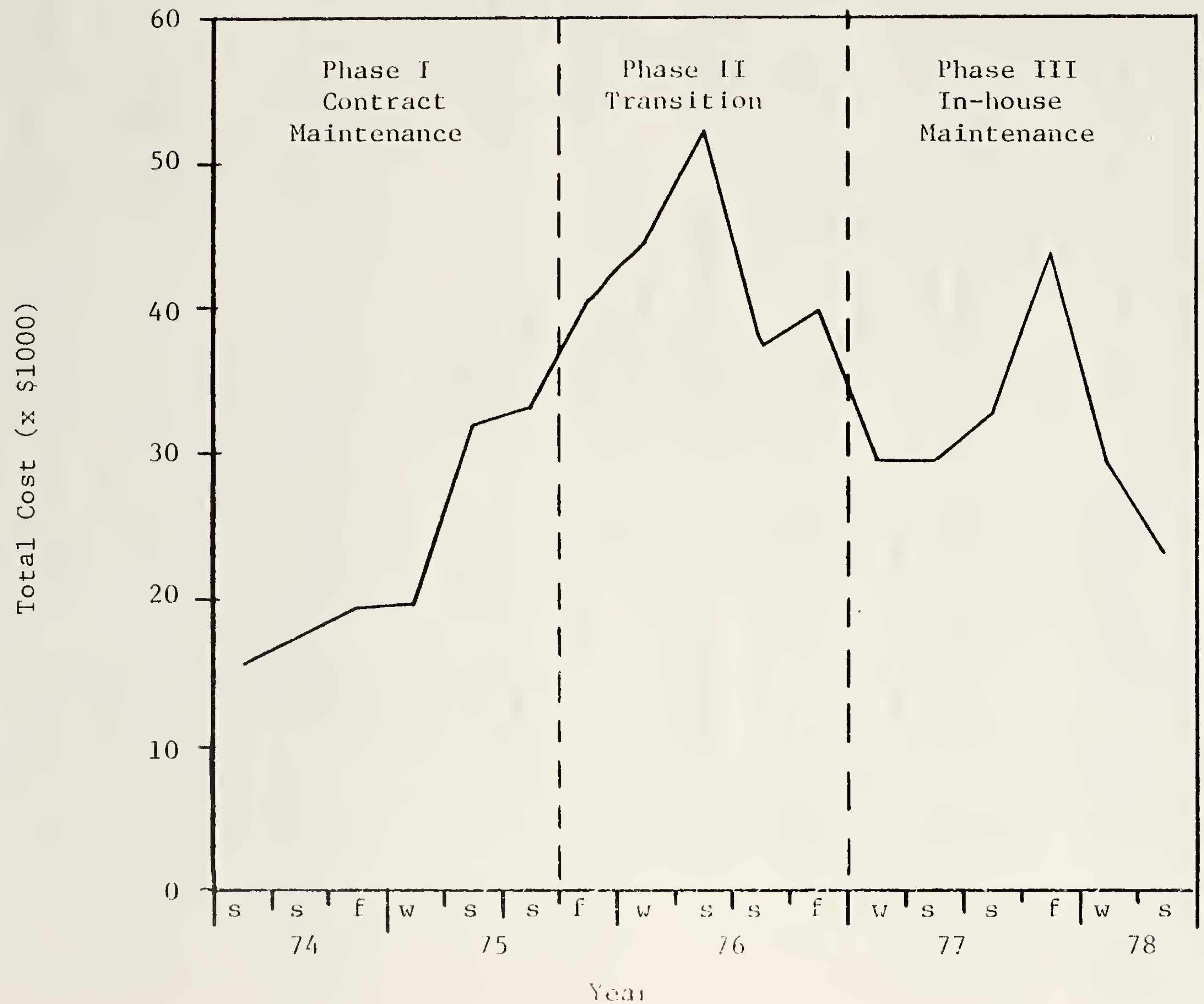


Figure 8.5 Total labor-related O&M costs

- maintenance and operation of site hydronic equipment without full appreciation for impacts on the TE plant

- lack of direct impacts of plant/site O&M practices on costs to the site owner, since HUD assumed plant costs above a certain limit

- lack of direct cost accountability between the site owner and the TE plant operator.

Specific technical problems with a major cost impact can be traced to this management situation, including site distribution losses, chiller performance, and other obvious and correctible plant problems.

Aside from the issue of cost consciousness and having only indirect responsibility, the approach of having an engineering firm based in Chicago operating a single plant in New Jersey would appear to incur added overhead costs for accounting, engineering, travel, etc., in addition to possible difficulties in technical monitoring.

An examination of actual JCTE labor costs is indicative in this respect, as shown in table 8.10. These data for January through June 1977, show that 34.9 percent of total labor costs were incurred in Chicago, at the engineering firm's office. Contributing to this high percentage was the fact that Chicago home-office overhead rates were over twice the overhead for plant personnel.

Table 8.10 Labor Costs by Category, January through June 1977

Location	Labor category	Total Cost (with OH)
Jersey City, N.J.	Plant operator	$ 10,703
	Ass't operators	19,700
		$ 30,403
Chicago, Illinois	Principal	8,716
	Engineer	5,572
	Clerical	1,993
		$ 16,281

Whether this level of management and engineering effort was warranted or not depends on many factors and was not determined in this analysis. The cost impact, however, is reflected in the data.

Two quantifiable atypical costs resulting from management and institutional factors were travel and profit. Travel would not have been incurred if the plant had been operated by local firms or by the site owners. Profit likewise would not have been included if site owners had operated the plant.

Cost data on these two elements are shown in table 8.11. These atypical cost elements are small but noteworthy impacts on costs and should be considered when using the JCTE data. An average value of $20,000 reduction is recommended for this adjustment.

8.6.6 Capital Costs - Design Factors

Capital costs are influenced by the basic design approach, by government-imposed plant design requirements, by local construction practices, and by institutional factors such as general construction/procurement requirements for government-funded projects.

The basic design approach was quite typical of the TE design practices in use in 1970-72. Several specific design decisions can be identified which may have influenced costs relative to other viable design approaches. In the design stage, combined absorption and compression chillers were identified as having lower life-cycle costs but were rejected primarily because of expected reliability problems with engine-driven centrifugal chillers and, secondarily because of limited experience with this design approach [8-3].

Table 8.11 Atypical Costs: Travel and Profit

Year[a)]	Cost element: Travel	Cost element: Profit	Total	% of total yearly[b)] non-fuel O&M
1974	3,113	5,310	8,423	7.5
1975	5,211	5,853	11,064	5.7
1976	6,734	13,578	20,312	8.1
1977	4,245	14,826	19,071	7.4
	19,303	39,567	58,870	7.2

a) December through November
b) Yearly cost from tables 7.1 through 7.4, excluding fuel

It does not appear that electric-driven centrifugal chillers were considered as part of combined chiller scheme. This approach, while sacrificing some thermal efficiency compared to direct drive, seems attractive when a standby-generator is considered for the chiller drive thereby obviating any added generator units. This approach is equivalent to alternative system 4, described in section 6. The cost impact of this approach will be described in section 9.

A second major design decision was the use of hot water cooling of engine jackets instead of the more widely-used ebullient cooling. The choice between these modes of cooling is a complex issue involving engine tolerance for ebullient cooling, water treatment requirements, pumping power, and ease of control. Although there has been a measurable cost impact due to added auxiliary power usage with hot water cooling at Summit Plaza, it cannot be stated definitely that ebullient cooling would result in lower costs when all factors are considered.

A third design decision was to use chilled water to cool the ventilation air for the equipment areas in the plant instead of using larger quantities of outside ambient air without mechanical cooling. The reasons for this decision were atypical and not economically justified. The capital cost of this approach was small because no added chilled capacity was installed to meet this load. However, the operating cost impacts have been significant. As indicated in section 5.2.3, 23,000 gallons (87 m^3) of fuel oil (valued at $8,200) could be saved annually. This savings would be slightly offset by the added electrical energy for distributing larger quantities of ventilation air.

In making adjustments so that the data represents a typical situation, it is recommended that the fuel oil reduction be included and that capital cost reductions due to elimination of the heating and cooling coils be considered to be offset by larger fans and ducts.

The HUD demonstration imposed several significant design requirements on the plant which are definitely atypical. These requirements were:

- a parallel HUD demonstration at Summit Plaza of pneumatic trash collection (PTC) as described in section 2.3

- to minimize possible future government liability in case the TE "experiment" failed, the non-TE components were designed so that the engine-generators could be shut down and the remainder of the plant operate as a conventional central HVAC system

- to permit future experimentation with novel electrical generation equipment, spare room was left in the plant to install a generating unit of the size of the existing units.

The impact of each of these three items is discussed in the following paragraphs.

From table 4.1, the PTC's electrical energy consumption totaled about 45,000 kWh annually, which can be ignored as having any significant effect on plant economics. The PTC has, however, been a major factor in determining engine-generator operational practices (i.e., "three-engine" operation) as described in section 5 and reference [8-3]. Elimination of the PTC would further increase the time two-engine operation would be valid and might allow consideration of a plant with only four engines installed. A four-engine plant with space for adding a fifth engine would have reduced costs by at least $63,200 for the engines alone, not including savings for heat recovery unit, controls, and piping.

In a typical TE plant design, the capital cost of the PTC would not be incurred. From table 8.5, the capital cost allocated to the PTC is $907,000. The architectural/structural design of the CEB was also heavily influenced by the requirements of the PTC and although the data of table 8.5 includes the PTC share of these capital costs, it is possible that a more efficient overall plant design would have been executed without the PTC, thereby reducing capital costs below the allocated costs shown. The magnitude of any such capital cost reduction could not be determined without added study and therefore no specific costs adjustments for a typical design are recommended in this report.

The required design approach to leave extant a self-sufficient central conventional HVAC plant in the event of termination of the electric generation required that the boiler capacity be determined without regard for available engine heat [8-3]. As shown in figure 4.8 and discussed in section 5.2.2, the capacity of just one boiler can handle the entire thermal load. The excessive boiler capacity should be considered in using the capital cost data.

Table 1 of reference [8-3] provides the total peak heat demand (12.1x10^6Btu/h (12.8 GJ/h)) of the buildings with no diversity. With no consideration of engine heat, a two-boiler design would require 253 boiler hp (2480 kW) for each unit [8-4]. Figure 15 of reference [2-3] provides the predicted minimum engine heat output on a typical winter day - approximately 2.6 x 10^6Btu/h (2.7 GJ/h). This heat output can be considered 100 percent available because of back-up engine generator units. Therefore in determining boiler capacity, this output should be subtracted from the load rather than counted as a boiler unit of equivalent capacity. To meet the resulting maximum expected boiler load (9.5 x 10^6Btu/h (10 GJ/h)), two boilers of at least 200 hp (1960 kW) or three boilers of at least 100 hp (980 kW), would be required [8-4].

Thus consideration of engine heat can achieve an equivalent maximum reduction in boiler capacity (each of two boilers) of 21 percent. An approximate estimate of the total cost savings from reference [8-5] is $5,500. (This "redesign" analysis ignores two (atypical) occurrences which were unforseen in the actual design of the TE plant; excessive distribution losses and poor exhaust heat exchanger performance.)

The overcapacity in the existing plant is not solely due to ignoring engine heat. Two 400 hp (3920 kW) units are installed compared to a required capacity of 253 hp (2480 kW) when no consideration is given to engine heat. A significant cost savings would result from use of 200 hp (1960 kW) boilers. This approach is valid according to the sizing procedures of reference [8-4] (which include excess capacity for contingencies when (1) consideration is given to engine heat and (2) when site distribution heat losses are minimized by proper maintenance). Such an approach would reduce capital costs by $11,000.

The extra space in the CEB for an additional engine-generator was a requirement of HUD for future experimentation. This situation appears atypical although such extra space is often provided in TE plant design for commercial-only applications where large load increases can be imposed on the system by a change in tenants. For a primarily residential site like Summit Plaza and in view of the excess electrical capacity provided in the basic design, extra space appears unwarranted. A reduction in CEB floor space of about 6.1 percent and a reduction $33,376 in total capital costs would result from elimination of the extra bay.

Local construction practices and wage rates also influenced the capital costs of the TE plant. Reference [8-6] indicates that the average skilled trade wage rate in Jersey City in 1974 was 9.2 percent greater than an average of 30 major U.S. cities. This factor should be taken into account when utilizing the JCTE data. Labor costs were 22.6 percent of total JCTE plant construction costs [8-7]. Therefore, generic data should reflect a 2.1 percent decrease in capital costs for wage rates, or $62,200.

8.7 TYPICAL COSTS

This section gives typical costs for an optimum design approach, typical weather, and typical equipment performance in a plant built, owned and operated by a typical private organization. This is based on accounting for the atypical features identified in section 8.6. Table 8.12 lists all atypical features identified in section 8.6 along with the recommended cost reductions, if any. In terms of capital costs, the cost of the plant exclusive of the PTC was $2,964,000. This should be reduced by $169,900 (5.7 percent) to reflect the atypicalities present in the existing design. Thus construction cost for a typical plant like that at Summit Plaza which would have begun operation in January 1974, would have been $2,794,000.

In terms of O&M costs, the recommended cost adjustments for all factors in table 8.12 totals $94,800, or about 16 percent of total O&M costs for 1976. Therefore a typical plant operating at Summit Plaza in 1976 would have incurred O&M costs of $501,800 for the year.

Table 8.12 Summary of Recommended Cost Adjustments for Atypicalities

O&M Cost Impacts	Recommended Cost Adjustments
1. Plant loads	
1.1 Occupancy	+$23,700
1.2 Distribution system	-$32,300
1.3 Weather	None
1.4 Occupant conservation	None
1.5 Building characteristics	None
2. Equipment performance	
2.1 Fuel costs (see table 8.9)	-$32,600
2.3 Engine-generator overhauls	- 1,500
3. Operation and maintenance factors	
3.1 Maintenance evolution	- $ -$14,000a)
3.2 Labor wage rates	-$9,900
4. Management and institutional factors	
4.1 Multiplicity of organizations	None
4.2 HUD/operator/ownership relations	None
4.3 HUD requirements of operator	None
4.4 Remote, contracted operation	-$20,000
5. Design factors	
5.1 Plant cooling	-$8,200
5.2 PTC electrical load	None
O&M total	-$94,800

(Continued next page)

Table 8.12 Summary of Recommended Cost Adjustments for Atypicalities (continued)

Capital Cost Impacts			
1.	PTC		-$907,000
2.	Miscellaneous		-$169,900
	2.1 Spare engine bay	-$33,400	
	2.2 Boiler capacity	-$11,100	
	2.3 Labor wages rates	-$62,200	
	2.4 Four engines only	-$63,200	
		Capital total	- $1,076,900

a) adjustment to 1976 costs only

8.8 REFERENCES - SECTION 8

8-1. National Oceanic and Atmospheric Administration, "Local Climatological Data, Annual Summary with Comparative Data - 1977, Newark, New Jersey."

8-2. Kennedy, D., et. al., "Alternative Strategies of Naval Bases, Volume III: Assessment of Total Energy Systems Applications at Naval Facilities," NTIS Report No. AD/A-003 590, November 20, 1974.

8-3. Gamze-Korobkin-Caloger, Inc., "Final Report, Design and Installation, Total Energy Plant - Central Equipment Building, Summit Plaza Apartments, Operation BREAKTHROUGH Site, Jersey City, New Jersey," HUD Utilities Demonstration Series, Vol. 12, February 1977.

8-4. U.S. Department of Housing and Urban Development, "HUD Minimum Property Standards - Multifamily Housing," HUD Publication 4910, 1973.

8-5. Richardson Engineering Services, Inc., "Commercial-Industrial Construction Estimating and Engineering Standards," Vol. 2, Sect. 15100-20, 1974.

8-6. R. S. Means Co., Inc., "1976 Labor Rates for the Construction Industry," 1976.

8-7. H. D. Nottingham and Associates, Inc., "Design, Cost and Operating Data for Alternative Energy Systems for the Summit Plaza Complex, Jersey City, N.J.," National Bureau of Standards Report GCR 79-164, December 1974.

8-8. Hebrank, J., Hurley, C. W., Ryan, J., Obright, W., and Rippey, W., "Performance Analysis of the Jersey City Total Energy Site," National Bureau of Standards Report NBSIR 77-1243, July 1977.

9. ECONOMIC EVALUATION OF ALTERNATIVE SYSTEMS

The relative economics of the Summit Plaza TE plant are presented here by comparing its costs with the estimated costs for the twelve alternative systems described in section 6. The capital cost of each of these systems was estimated from quantity take-offs from a preliminary design. Operation and maintenance costs were estimated using JCTE data for operating labor and plant burden and from cost quotations from vendors on service contracts for major pieces of equipment. Fuel and electricity costs were based on results of the computer simulations described in section 7.

The capital cost and maintenance cost data along with basic fuel and electricity consumption data for the evaluation were taken directly from references [9-1] and [9-2]. Unit energy costs, operating labor requirements and costs, taxes, and insurance costs were estimated by NBS.

The evaluation was carried out using an engineering-economic approach utilizing discounted cash flow techniques. Several evaluation criteria were used including return-on-investment and payback period. The baseline analysis considered the project to be solely financed from equity while the effect of debt financing is shown in a sensitivity analysis.

A sensitivity analysis was also conducted to determine the variability of the comparative results to changes in assumptions in the economic analysis, energy price levels, and escalating rates.

9.1 BASIC ECONOMIC DATA

9.1.1 Capital Costs

The capital costs of each alternative system were estimated in reference [9-1] based on a detailed quantity take-off from the preliminary design. Each piece of mechanical and electrical equipment in the plant was identified as to type, size, and quantity and was costed from estimating handbooks and manufacturer's data. These data were based on the cost levels current as of January 1, 1976.

A summary of the capital cost data is provided in table 9.1. Appendix K provides additional cost detail for each of the systems. These data clearly show that the twelve systems fall into four groups which are equivalent to the four basic design approaches. The categories and their approximate initial capital costs are:

total energy system - approximately $7.3 million
conventional central systems - approximately $5.9 million
individual building systems - approximately $5.0 million
individual apartment systems - approximately $4.1 million

The capital costs of table 9.1 include all elements of the Summit Plaza site which change with changes in energy systems. In the case of the central systems the data include costs for all relevant mechanical and electrical equipment within the buildings as well as within the CEB itself. Therefore the cost of

Table 9.1 Summary of Capital Costs

System No.	Description	Cost, 1975 Dollars
Initial Investment		$ 1000s
1	Total energy - existing	$ 7,331
2	Total energy - existing-selling power	$ 7,331
3	Total energy - high efficiency engines	$ 7,948
4	Total energy - diesel and absorption chillers	$ 7,318
5	Central plant - electric chiller-oil burner	$ 5,836
6	Central plant - absorption chiller-oil burner	$ 5,861
7	Central plant - diesel and electric chillers	$ 6,621
8	Building plant - electric chiller-oil burner	$ 5,027
9	Building plant - electric chiller and boiler	$ 4,963
10	Individual apartment - through-the-wall air conditioners with electric resistance heat	$ 4,120
11	Individual apartment - central heat pump	$ 4,197
12	Individual apartment - central air conditioner and electric resistance heat	$ 3,989
Replacement Cost		
10	Individual apartment - through-the-wall air conditioners with electric resistance heat	$ 1,294
11	Individual apartment - central heat pump	$ 1,125
12	Individual apartment - central air conditioner and electric resistance heat	$ 919

System 1 in table 9.1 is not just the cost of the "total energy system" and cannot be directly compared to the actual TE cost data of table 8.5.

An effort was made to validate the initial capital cost estimates for all systems. This was accomplished by first validating the costs of System 1 and secondly, by validating the cost relationship between the other systems and System 1.

The actual cost of the TE plant was compared to the estimated cost of System 1. Reference [9-2] shows an estimated total cost of $3,638,000 (in January 1976) for the CEB, the CEB equipment, and the site distribution system. The equivalent cost (less the PTC allocation and design fee) of the TE plant from table 8.5, is $2,824,000 which can be considered to have occurred in January 1973. The 1976 cost shows a 29 percent increase over the 1973 cost, or an average annual escalation of 8.83 percent. This escalation rate appears reasonable for the 1973-1976 time period, thereby serving to validate the estimated costs as a good measure of actual 1976 construction costs.

A cost comparison between a limited number of conventional system configurations and the TE plant was made in December 1972 for HUD [9-3]. The cost estimate for the TE plant in that comparison is used here to validate the general accuracy of estimated costs without having to consider the effect of annual escalation. The December 1972 cost estimate for the TE system exclusive of the CEB building envelope was $2,133,000 [9-4]. The equivalent actual cost from table 8.5 is $2,338,000. The 8.8 percent difference in these values shows very close agreement in view of the uncertainties involved in allocating common costs to the PTC subsystem (in the case of the actual data).

A second cost comparison was conducted to validate the cost relationship of the alternative systems to the actual TE plant. Cost estimates for alternative Systems 5 and 6 were compared to the cost estimates for equivalent systems used in the December 1972 design studies. (Systems equivalent to 5 and 6 were the only conventional systems studied in reference [9-3] which could be directly compared to the alternative systems of reference [9-1]). This comparison, in table 9.2, shows that Systems 5 and 6 have very nearly the same relationship to System 1 as the equivalent systems had to the early estimate of TE plant costs. The fact that two independent cost estimates of hypothetical alternatives conducted five years apart show similar results serves to validate the relationship of costs between the systems.

In reviewing the results of the above validation effort, it appears that the initial capital costs are within 8-10 percent of actual construction costs and that the relative costs between systems is likely to be within 5 percent. The higher accuracy for the relative costs is partly because many of the alternative systems contain a great deal of identical equipment.

An important factor in economic analyses is equipment life. Large differences in the life of major equipment items should be accounted for either by means of replacement cost during the time span of the analysis or by considering salvage values for equipment items which outlast the study period. Replacements of

Table 9.2 Comparison of Initial Cost Estimates with Actual Costs

Cost source	TE system	Conventional central systems			
		Absorption chiller		Compression chiller	
	$ 1000	$ 1000	% of TE	$ 1000	% of TE
GKC[a)]	2132	1279	60.0	1236	58.0
HDN&A[b)]	3036	1832	60.3	1806	59.5

a) Gamze-Korobkin-Caloger; January 1973 cost estimates, reference [9-3].
b) H.D. Nottingham and Associates; January 1976 cost estimates, reference [9-1], from appendix K.

minor equipment (pumps, valves, etc.) can be viewed as routine maintenance and accounted for accordingly.

The three individual apartment systems (Systems 10, 11, and 12) were the only systems in which major equipment items were judged to have lives grealty different from the others [9-1]. The relatively small through-the-wall incremental heating and cooling units in System 10, heat pump units in System 11, and self-contained heating and cooling units in System 12 were considered to have equipment lives of approximately 10 years compared to the 20-year life of the large, industrial-oriented equipment in the other systems [9-4, 9-5]. The replacement costs for this equipment was estimated in reference [9-1]. These costs were included by means of the equivalent first-year costs.

9.1.2 Operational and Maintenance Costs

Estimates of maintenance costs for each alternative systems were developed and are described in appendix H of reference [9-1]. These estimates were based on quotations provided by maintenance service contractors for the specific major equipment items used in each of the alternative systems. For each system, all equipment was considered in developing the maintenance costs including the building distribution and terminal units for the central systems. These data are an excellent source of relative costs between alternative systems. These data do not include onsite operating labor, labor overhead, and plant burden. The costs for these items were estimated from actual JCTE data and added separately as discussed later in this section.

The estimated maintenance costs were validated by comparing equivalent costs from the System 1 estimate with actual JCTE costs. Equivalent costs are those related to CEB equipment for strictly maintenance tasks. For the System 1 estimate of reference [9-1], the maintenance costs for site distribution, site building equipment, and overhead were subtracted from the total for the comparison.[1] The actual JCTE cost data for the validation comparison do not include plant burden, fuel, operating labor, labor overhead, or any of the PTC-allocated costs.

Taken as whole, the equivalent data for System 1 in reference [9-1] agree closely with actual cost data from Summit Plaza. For example, in 1976 the actual maintenance costs totaled $93,000. The equivalent estimated cost from reference [9-1] is $91,000. The total maintenance cost estimate for System 1 also includes $33,100 for maintenance of site building and distribution equipment, for a total of 124,200. This value and the comparable costs for all systems are shown in the first column of table 9.3.

The values for maintenance cost shown in table 9.3 were taken directly from appendix H of reference [9-1] with two exceptions. First, appendix H of the reference included an "overhead" item which is deleted from the value of table 9.3, since all overheads are separately included (based on actual JCTE data) in either the "labor" or "plant burden" categories, depending on the nature of the overhead cost. The second exception was for System 2. The maintenance costs for the engine-generators was reduced for two reasons: 1) the near-doubling of these costs over those of System 1 was felt to be excessive and 2) the amount of extra electrical production for export to the utility was reduced over that calculated in reference [9-1] because of electrical load adjustments to all systems as explained in section 7.3. The engine-generator maintenance cost for System 2 was reduced from $78,900 (196 percent of System 1 cost) to $61,000 (152 percent of System 1 cost).

Relevant maintenance cost differences between systems includes plant burden in addition to strictly maintenance costs. Plant burden, as reported in section 8.2 includes standby power, travel, GKC operating fee, liability insurance, and other non-maintenance costs. With the exception of travel and fee, these items should be included in total O&M costs in a typical scenario. Table 8.3 shows a total of $43,650 for plant burden exclusive of the PTC in 1976. Travel and fee (from table 8.1) totaled $20,310 for the year, while standby power was $11,040. Thus, the total estimated maintenance cost from reference [9-1] should be increased by approximately $23,300 (i.e., $43,650 - $20,310) for TE systems and increased by $12,300 (i.e., 23,320 - $11,040) for conventional systems to account for plant burden. Plant burden for each system is shown in the second column of table 9.3. It is important to note that the difference between the systems for plant burden is due to the cost for standby power. The absolute level is not as important as the relative differences. The absolute level could vary considerably depending on which of the "plant burden" costs were assumed to be repeated in a typical owning/operating scenario.

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1) The first two items were not included since they are not a part of the GKC data base. Site building maintenance personnel handle these tasks. The overhead item was likewise deleted since this was separately accounted for either in labor overhead or plant burden, which were separately developed from actual JCTE costs.

Table 9.3 Estimated Annual Operation and Maintenance Costs for Alternative Systems

System number	Maintenance[a)] cost $ 1,000	Plant[b)] burden $ 1,000	Operating[c)] labor cost $ 1,000	Miscellaneous[d)] $ 1,000	Total O&M cost, less fuel and electricity $ 1,000
1	124.2	23.3	85.0	18.6	251.1
2	145.0	23.3	85.0	21.1	274.5
3	124.2	23.3	85.0	19.0	251.5
4	124.2	23.3	85.0	17.7	250.2
5	80.6	12.3	73.9	12.4	179.2
6	80.6	12.3	73.9	14.6	181.4
7	87.4	12.3	73.9	15.4	189.0
8	83.7	12.3	55.4	11.1	162.5
9	82.4	12.3	55.4	10.1	160.2
10	80.0	12.3	18.5	8.5	119.3
11	70.4	12.3	18.5	8.1	109.3
12	68.1	12.3	18.5	7.8	106.7

a) From appendix H of reference [9-1] less "overhead", which is included either in plant burden or operating labor.

b) Based on JCTE data.

c) Including labor overhead, based on JCTE data and trends.

d) Consists of property insurance and plant water use.

The maintenance cost data of reference [9-1] did not include "operating labor" which is defined as any in-house labor required for equipment operation and surveillance and/or for minor housekeeping and maintenance not provided by the outside service contracts. Staffing requirements and skill levels were considered in developing such costs for each alternative system. The cost for System 1 was developed from the actual cost data and staffing levels, adjusted to reflect a typical balance between in-house and contract maintenance services. Data from tables 8.2, 8.3, and 8.4 with consideration of the factors stated in section 8.6.4 and figure 8.7, indicated a cost of $85,000 would be appropriate for System 1. The simpler central, building, and individual systems were assessed proportionately less operating labor costs. The operating labor data are shown in the third column of table 9.3.

Two additional O&M cost items were included in each alternative system. First, property insurance for physical damage to the facilities were included based on the costs paid by Summit Plaza owners for the entire plant. It was assumed that premiums would vary in direct proportion to the total value of the site, including the energy systems. The annual premium being paid by the site owners is 1.7 percent of the total value of the Summit Plaza property. This percentage was applied to the initial capital costs of each of the energy systems. The second item is the cost of water consumed by the energy systems. The cost of water for each system was based on the computercalculated water consumption data in reference [9-1] and the local New Jersey water rate. The combined cost for property insurance and water is shown in table 9.3, column four.

9.1.3 Fuel and Energy Costs

The quantity of fuel and electrical energy consumed by the alternative systems was previously presented in section 7.5. These data, when combined with unit energy costs ($\$/10^6$Btu or ¢/kWh), give the total annual energy costs for each of the alternative systems.

Baseline unit energy cost for the No. 2 distillate fuel used in on-site combustion equipment (System 1 through 8) was based on the actual unit cost of fuel used by the TE plant. For calendar year 1975 and half of 1976, the average delivered cost was very stable at about $\$2.40/10^6$Btu (2.27/GJ) (see figure 8.2). This value was used for the unescalated fuel costs.

Significant regional differences in the cost of oil can exist and should be considered when analyzing systems for other parts of the nation. In 1976 for example, the national average cost of fuel oil which utilities purchased for combustion turbine and internal combustion power generation (i.e., distillate fuel similar to the fuel used at JCTE) was $\$2.37/10^6$Btu ($2.25/GJ). Regional averages varied from $\$2.24/10^6$Btu ($2.12/GJ) to $\$2.56/10^6$Btu ($2.43/GJ) (a 14.6 percent variation) over nine geographic regions comprising the 48 contiguous states. At the same time, the state-by-state averages varied from $2.14 ($2.03) to $\$2.69/10^6$Btu ($2.55/GJ) (a 25.6 percent variation) [9-6]. Such variations will be accounted for in section 9.5 in the sensitivity analysis.

For the baseline analysis using a case study approach and system average costs, the unit cost of electricity was based on PSE&G rate schedules in effect on

January 1, 1976. The rate schedule used was the Large Power & Lighting (LPL) schedule and a single service entry and meter for the entire site was assumed. This afforded the lowest-cost energy available from PSE&G (except for High-Tension service) for the site. This schedule was chosen for two reasons. First, the site is currently supplied with standby service under the LPL rate. Second, the LPL rate would provide the lowest-cost energy to the site and thus would be preferred by a site owner when utilities are included in the monthly rent. The site appears to qualify for the LPL rate as restrictions on its applicability are rather minimal.

Within the context of the case study/average cost approach, there can be significant variations in electric energy unit cost. Use of other than LPL rate or use of individual building metering or individual apartment metering can be valid under various institutional assumptions within the PSE&G system. On a broader scale, the regional average unit costs for large-user service can vary from 6.0¢/kWh to 2.46 ¢/kWh, with the national average being 3.44 ¢/kWh [9-7]. The effect of variations in the unit cost of electricity are examined in section 9.5 in the sensitivity analysis.

Use of the PSE&G LPL rate for the conventional alternative systems entailed not only incorporation of the usual demand, consumption, and energy adjustment components which are different for each system, but also consideration of summer and winter differences, night-use adjustments, and building heating service adjustments for systems using electric heating equipment. In addition, the purchase of standby ("Breakdown") service capacity had to be included for the TE systems. A computer program was developed to account for all these factors in calculating the cost of electricity for each system.

Energy cost data for the baseline analysis are shown in table 9.4. The fuel oil and electricity energy cost components are shown separately as well as the total cost. As also shown in the table, the average annual unit cost for electricity for the conventional systems varied from 3.2 to 3.5 ¢/kWh. (Such differences are due to the factors mentioned in the previous paragraph.) The unit cost for fuel oil was the same for all systems, 2.40 $/Btu ($2.27/GJ), or about 33.6 ¢/gallon (8.9 ¢/liter). The energy consumption quantities used to calculate these costs are those of table 7.5 and appendix G.

9.1.4 Comparison of Actual Costs to System 1 Costs

A comparison of actual 1976 JCTE costs with the estimated costs for the System 1 is shown in figure 9.1. As shown, adjustments of both fuel and 1976 JCTE O&M costs had to be made for an equivalent comparison with System 1. Fuel costs were adjusted for anomalous conditions and for slight differences in fuel quantity (by selecting months from several years for comparison) and fuel costs (1976 average = 34.4 ¢/gallon (9.1 ¢/liter) while System 1 (January 1976) = 33.6 ¢/gallon (8.9 ¢/liter)). After these fuel adjustments, very close agreement between JCTE and System 1 was obtained. This result is not surprising in view of the close agreement in fuel quantities shown in figure 7.3.

Table 9.4 Energy Cost for Alternative Systems

System No.	On-site fuel cost[a]	Utility electricity cost	Unit cost of electricity	Total energy cost
	$ 1,000	$ 1,000	¢/kWh	$ 1,000
1	263.5	-0-	n/a	263.5
2	394.3	145.3[b]	2.52[b]	249.0
3	242.6	-0-	n/a	242.6
4	254.6	-0-	n/a	254.6
5	94.8	289.9	3.51	384.7
6	125.3	277.4	3.49	402.7
7	107.9	277.9	3.49	385.8
8	94.8	297.1	3.48	391.9
9	-0-	572.2	3.20	572.2
10	-0-	574.2	3.23	574.2
11	-0-	497.1	3.27	497.1
12	-0-	574.2	3.23	574.2

a) Unit cost of on-site fuel is the same for all systems, $2.40/10^6$Btu ($2.27/GJ).

b) Credit for electrical energy sales; "Unit cost of electricity" is the sales price.

fuel

other O&M

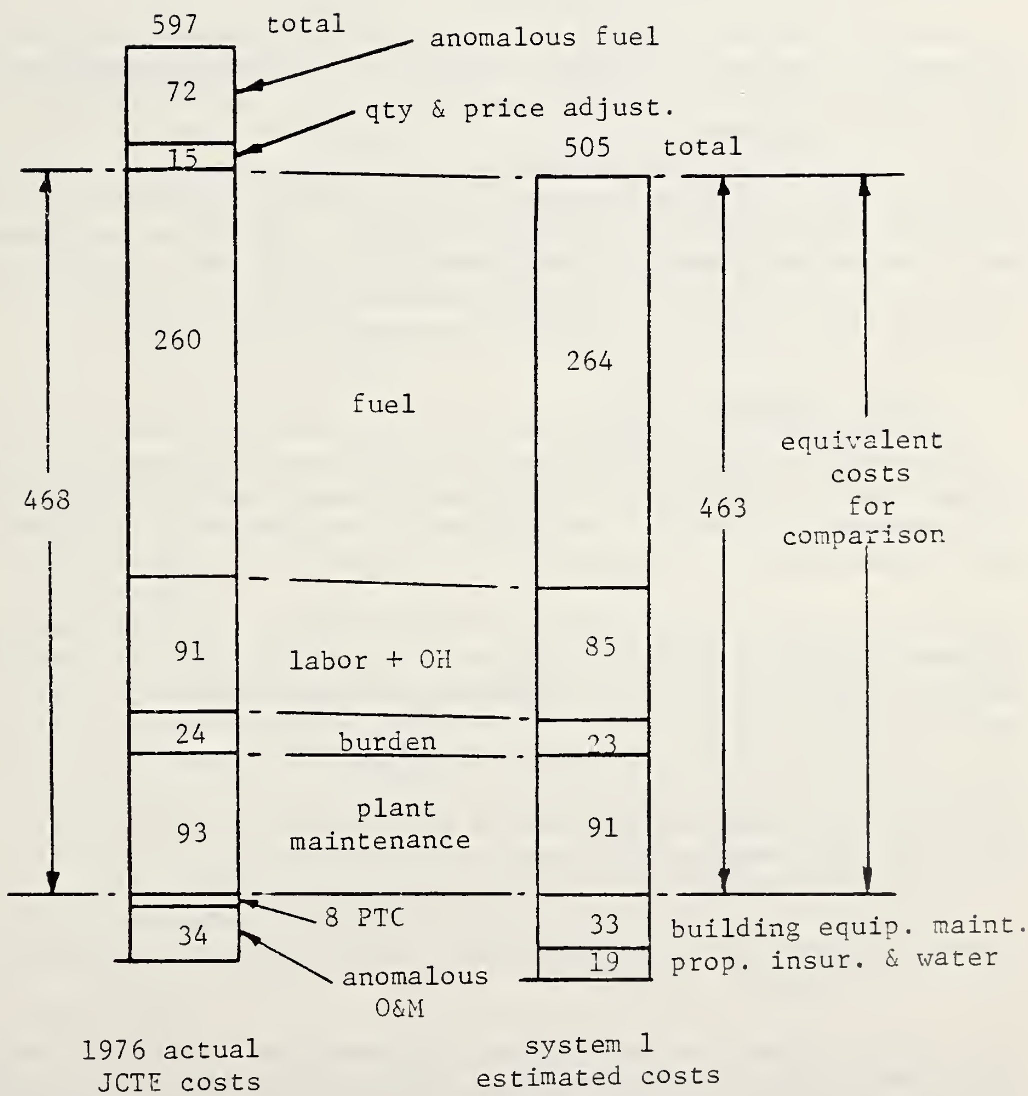

Figure 9.1 Comparison of total costs: JCTE actual vs. estimated for System 1. Note that all costs are in $1000's

O&M costs for JCTE were adjusted for the PTC (not included in System 1), and those previously-identified anomalous O&M cost items except local wage rates which were included in the alternative systems. Systems 1 costs also had to be adjusted to delete the costs for site building maintenance, property insurance and water (not included in actual JCTE costs). These adjustments are clearly shown in figure 9.1.

As described earlier, the estimated maintenance cost for System 1 from reference [9-1] agrees very closely with actual costs, as shown in figure 9.1. Plant burden for System 1 was developed directly from JCTE data and agrees nearly exactly. Labor and overhead for System 1 is $20,000 less than the actual measured data for JCTE due to adjustments for "typical-year" data, supported by JCTE data trends through mid-1978.

In summary, the actual 1976 JCTE total annual costs on an equivalent basis for comparison purposes, including both fuel and O&M, was $482,000. The System 1 costs total was $463,000 (or 4 percent lower), the difference being in the labor cost category.

The labor cost difference could also have been deleted from the JCTE data on the basis of anomalous conditions. However, the labor cost trends are somewhat less well-defined compared to the rather clear anomalies in equipment performance and operating conditions which led to the deletion of $72,000 in anomalous fuel costs and $20,000 in anomalous O&M costs.

9.2 OTHER ESTIMATED COSTS

In addition to the amount of capital, O&M, and fuel costs, the amount of property taxes, insurance costs, income taxes, and debt financing costs should be considered for each of the systems. The method of calculation of each of these items will be discussed in this section.

Federal and state income taxes were included as expenses for each system. The relevant Federal income tax rate was 48 percent and the state rate was 7.5 percent. The combined rate was computed as follows:

$$c = s + (1-s)\, f$$

where c = the combined tax rate
f = the federal tax rate
s = the state tax rate

For the federal tax rates given above, the combined federal plus state tax rate was 51.9 percent.

The taxable income for each system was comprised of the net income less depreciation and interest expense. Depreciation was based on the double-rate declining-balance method while the baseline analysis was conducted on a 100 percent equity basis, so that no deductions for interest were possible.

The sensitivity analysis considered the effect of financing methods wherein debt expenses were equal annual payments made up of both principal amortization and interest expenses.

The Federal investment tax credit cannot be applied to equipment which is a part of a building or otherwise appurtenanced to a non-industrial building. In the case where the owner of the site building at Summit Plaza also owns the TE plant, the investment tax credit cannot be applied. However under a hypothetical scenario whereby a utility company would own a central TE plant or hot and chilled water plant, the investment tax credit may be applicable, but only to the central plant equipment, not the in-building equipment. For the purpose of this study, no investment tax credit was taken, but the effect of the credit under utility ownership was addressed in the sensitivity analysis.

9.3 EVALUATION METHODOLOGY

The economic evaluation was carried out by first calculating the value of several measures of economic viability for each alternative system. The comparative values for each measure were then compared relative to threshold criteria for project acceptance. These criteria were based in part on criteria commonly used in actual practice. The basic data are provided however, so that any criteria could be utilized in the comparison.

9.3.1 Investment Viability Measures

Four measures of investment viability were considered in conducting the comparative economic evaluation:

- Initial Investment Premium
- Simple Payback Period
- Return on Investment
- Present Worth

The first of these, initial investment premium, was not used by itself to evaluate viability, but was subjectively combined with one of the other measures. It should be noted that the first two measures are not based on discounted cash flow analysis. Both Return on Investment (ROI) and Present Worth (PW) use a discounted cash flow analysis and consider the year-by-year cash flow stream over the entire period of analysis. While these latter two measures are most theoretically correct in evaluating alternatives, the initial investment premium and simple payback period are useful and widely-used measures.

9.3.2 Cash Flow Streams

In order to utilize the rate of return and payback measures for evaluating alternative utility systems where there is no revenue from sales, the cash flow streams have to be formatted on an incremental basis. This means that the system with the lowest first cost is taken as a baseline from which the first cost and annual cost for all other systems are compared. This enables the calculation of those measures which require that an annual income be realized for every investment. When formatted on an incremental basis this "income" is the reduction in the annual disbursements for the higher first cost systems.

The basic cash flow data consists of capital investment costs and annual costs for each of the alternative systems. These data are shown in table 9.5. Capital investment costs in this table are based on the data of table 9.1 and include the present worth of the replacement cost for Systems 10, 11 and 12. Annual costs in table 9.5 are the sum of total O&M costs (less fuel and electricity) from table 9.3 and energy costs from table 9.4.

The capital investment costs and annual costs are shown on an incremental basis in table 9.6. Both tables 9.5 and 9.6 show O&M costs in the first year of operation. Income tax payments and/or effects of financing are excluded from the tables. The effect of inflation on annual costs in future years is also excluded.

Calculations for the ROI and PW measures were based on all costs over the period of evaluation. These measures therefore required that the annual costs be forecasted over the entire period for each alternative system.

This forecast was made by two different methods. In the first, the life cycle cash flow streams consisted of equal annual before-tax income amounts expressed in terms of constant (year zero) dollars. Because income taxes were calculated using other than a straight-line depreciation schedule, the total after-tax income amounts vary from year to year. An example of this type of cash flow stream showing the year-by-year method of income tax calculation is shown in table 9.7. Appendix L contains the yearly unescalated cash flows for each of the systems. The ROI calculated using these cash flow streams is called the <u>real</u> ROI.

The second cash flow forecast consisted of annual values of current year dollars which included a constant annual inflation rate over the entire period. Energy costs (both fuel and electricity) were inflated at a 12 percent annual rate while all other O&M were inflated at an 8 percent rate. Income taxes were again based on an accelerated depreciation schedule. An example of this type of cash flow stream with the tax calculations is shown in table 9.8. Appendix L contains a similar set of data for each of the alternative systems. The ROI calculated using these cash flow streams is called the <u>nominal</u> ROI.

The cash flow streams were calculated by an economic analysis computer program which also directly calculated the investment viability measures for the comparative evaluation. This program was developed by the Alabama Power Company and is called Financial Analysis for Capital Expenditures. The computer program is based in part on the Edison Electric Institute's (EEI) AXCESS energy/economic analysis manual developed for the EEI by Price, Waterhouse and Co. and later used as the basis for the financial analysis portion of the AXCESS energy analysis computer program.

Table 9.5 Actual Cash Flow Data for Alternative Systems

System No.	Capital investments[a)]	Annual cost before taxes[b)]
	$ 1,000	$ 1,000
1	7,331	514.6
2	7,331	542.2
3	7,947	494.1
4	7,318	504.8
5	5,836	563.9
6	5,861	584.1
7	6,621	574.8
8	5,027	554.4
9	4,963	732.4
10	5,414	693.5
11	5,321	606.4
12	4,908	680.9

a) Values for Systems 10 through 12 include the value of capital replacements in year 10.

b) First year cost; from tables 9.3 and 9.4.

Table 9.6 Incremental Cash Flow Data for Alternative Systems

System No.	Incremental capital investment[a)b)] $ 1,000	Incremental annual income before taxes[b)c)] $ 1,000
1	2,423	166.3
2	2,423	138.7
3	3,039	186.8
4	2,410	176.1
5	927.8	117.0
6	953.2	96.8
7	1,713	106.1
8	118.9	126.5
9	55.1	-51.6
10	505.8	-12.7
11	413.2	74.5
12	0	0

a) Includes the present worth of capital replacements in year 10 for systems 10, 11, and 12.

b) Baseline system is System 12.

c) First year incremental cost.

Table 9.7 Example of an Incremental Constant - Dollar Cash Flow Stream for an Alternative System

This cash flow stream is for System 1 with an initial incremental investment of $2,423,000.

o Income tax rate = 51.9 percent
o Double-declining balance depreciation with change to straight-line at the break-even point.

Year	Annual income	Tax depreciation	Taxable income	Income tax	Cash flow[a]
	$ 1000s	$ 1000s	$ 1000s	$ 1000s	$ 1000s
1	168.6	242.3	-73.7	-38.2	206.9
2	168.6	218.1	-49.5	-25.7	194.3
3	168.6	196.3	-27.6	-14.3	183.0
4	168.6	176.7	-8.0	-4.2	172.8
5	168.6	159.0	9.6	5.0	163.6
6	168.6	143.1	25.5	13.3	155.4
7	168.6	128.8	39.9	20.7	148.0
8	168.6	115.9	52.7	27.4	141.3
9	168.6	104.3	64.3	33.4	135.3
10	168.6	93.9	74.8	38.8	129.8
11	168.6	84.5	84.1	43.7	125.0
12	168.6	84.5	84.1	43.7	125.0
13	168.6	84.5	84.1	43.7	125.0
14	168.6	84.5	84.1	43.7	125.0
15	168.6	84.5	84.1	43.7	125.0
16	168.6	84.5	84.1	43.7	125.0
17	168.6	84.5	84.1	43.7	125.0
18	168.6	84.5	84.1	43.7	125.0
19	168.6	84.5	84.1	43.7	125.0
20	168.6	84.5	84.1	43.7	125.0

a) Cash flow = annual income - income tax.

Table 9.8 Example of an Incremental Cash Flow Stream for an Alternative System in Current-Year (Inflated) Dollars.

This cash flow stream is for System 1 with an initial incremental investment of $2,423,000.

o Income tax rate = 51.9 percent
o Double declining balance depreciation with change to straight-line at break-even point
o Inflation rates: 12 percent for energy costs, 8 percent for other costs.

Year	Annual Income	Tax Depreciation	Taxable Income	Income Tax	Cash flow[a]
	$ 1000s	$ 1000s	$ 1000s	$ 1000s	$ 1000s
1	168.6	242.3	-73.7	-38.2	206.9
2	194.6	218.1	-23.5	-12.2	206.8
3	224.0	196.3	27.8	14.4	209.6
4	257.6	176.7	80.9	42.0	215.6
5	295.6	158.9	136.6	70.9	224.7
6	338.8	143.1	195.7	101.6	237.2
7	387.8	128.8	259.0	134.4	253.4
8	443.4	115.9	327.5	170.0	273.4
9	506.3	104.3	402.0	208.6	297.7
10	577.6	93.9	483.7	251.1	326.6
11	658.3	84.5	573.8	297.8	360.5
12	749.5	84.5	665.1	345.2	404.4
13	852.7	84.5	768.2	398.7	454.0
14	969.4	84.5	884.9	459.3	510.1
15	1101.2	84.5	1016.7	527.6	573.5
16	1249.9	84.5	1165.5	604.9	645.1
17	1418.0	84.5	1333.5	692.1	725.9
18	1607.6	84.5	1523.1	790.5	817.1
19	1821.6	84.5	1737.1	901.5	920.0
20	2062.9	84.5	1978.4	1026.8	1036.1

a) Cash flow = annual income - income tax

9.4 EVALUATION RESULTS

Results of the calculation of the three primary investment measures are shown in table 9.9. These results will be compared to general investment criteria in this section to determine the viability of the incremental investments for the alternative systems.

Table 9.9 Comparison of Alternative Systems Using Several Incremental Investment Measures

System No.	Initital investment premium	Simple[a] payback period	Discounted Return-on-Investment[b] Real ROI[c]	Nominal ROI[d]
	%	years	%	%
1	49.4	14.6	1.9	11.8
2	49.4	17.5	0.1	10.3
3	61.9	16.3	1.2	10.6
4	49.1	13.7	2.3	12.2
5	18.9	7.9	6.5	17.2
6	19.4	9.8	4.7	15.3
7	34.9	16.2	1.2	10.7
8	2.4	0.9	56.0	68.8
9	1.1	--	--	--
10	10.3	--	--	--
11	8.4	5.5	10.0	19.9
12	0	--	--	--

a) Before income taxes
b) Including income taxes
c) Without inflation
d) With inflation

9.4.1 Simple Payback and Initial Investment Premium

Preliminary evaluation criteria for these investment measures are based on commonly-used criteria tailored so as not to exclude any potentially viable systems. These criteria are:

	Payback Period	Investment Premium
attractive	0-5 years	0-20 percent
marginally attractive	5-10 years	20-50 percent
unattractive	over 10 years	over 50 percent

The investment premium criteria are used as a secondary guideline only; payback period is the primary evaluation measure.

The data of table 9.9 clearly show that in terms of simple payback and initial investment premium, the alternative systems fall into four distinct groups:

- System 8, which has a very low investment premium compared to System 12 and a very attractive payback period of 0.9 years.

- Systems 11, 5, and 6, which have low to moderate investment premiums compared to System 12 and marginally attractive payback periods of 5.5, 7.9, and 9.8 years, respectively.

- Systems 4, 1, 7, 3, and 2, which have high investment premiums compared to System 12 and somewhat unattractive payback periods of 13.7 to 17.5 years.

- Systems 9 and 10, which are definitely inferior investments since both investment cost and annual operating cost is higher than that of System 12.

The best of the total energy systems, System 4, has an investment premium of 49.1 percent and a payback period of 13.7 years. This is unattractive in almost any business enterprise, whether it be a regulated public utility, private utility, or developer.

System 8, using fuel-oil boilers for space heating and domestic hot water production and electric-driven centrifugal chillers, is clearly an attractive investment. The added investments for System 11 (individual heat pumps), System 5 (central plant - electric chiller and oil boiler) can be attractive under certain business conditions.

The sensitivity analysis of section 9.5 will show how the assumptions and conditions have influenced these results and will show that other conclusions are possible under various other assumptions.

Initial investment premiums range from 1.1 percent to 61.9 percent of the baseline energy system (System 12). It may also be useful to express investment premium as a percentage of the total cost for the entire Summit Plaza complex. This was calculated by using a 1976 value of $10,350,000 for total Summit Plaza costs, including all site buildings and the baseline energy system. In this approach, investment premiums for the energy systems range from 0.3 percent to 15.7 percent.

9.4.2 Return on Investment

Investment criteria for real and nominal ROI are not as well established as the criteria for payback period. Attractive values for real ROI can be as low as 2 percent or in excess of 10 percent. A general inflation rate of 8 percent was used in developing the current-dollar for the alternative systems.

Referring to table 9.9, an arbitrary criterion of 3 to 4 percent real ROI is met or exceeded by only four of the alternative systems: System 8, with an ROI of 56 percent, System 11 (ROI = 10 percent), System 5 (ROI = 6.5 percent) and System 6 (ROI = 4.7 percent).

A nominal ROI criterion of 11 to 12 percent is met by System 4 (ROI = 12.2 percent) and System 1 (ROI = 11.8 percent) in addition to the same systems which met the real ROI criterion.

The ROI criteria appear less restrictive than the payback criteria in that they include up to six systems as being acceptable investments. However it is clear from the ROI data of table 9.9 that the TE systems represent marginally attractive investments at best.

9.5 SENSITIVITY ANALYSIS

The sensitivity of the results of section 9.4 are examined here in relation to several important factors/assumptions. These factors are:

- investment tax credit
- changes in the relative cost of fuel oil and electricity
- consideration of debt financing in the economic analysis
- improved utilization of TE plant equipment.

9.5.1 Investment Tax Credit

In section 9.2, it was indicated that under certain circumstances the Federal investment tax credit could be applied to the central facilities. This would be true under any scenario where a separate organization owned the central facilities and supplied services to Summit Plaza as its principle business activity. There may also be other cost differences involved in such the ownership in an actual case. For example, property taxes would be directly applied to the central plant equipment.

Consideration of the tax credit would only be applicable to the separate central facilities and distribution systems for Systems 1 through 7. The in-building equipment would not be eligible for the credit. The credit would amount to 10 percent (for the 1975-76 tax years) and would be applied in the analysis as a reduction to the capital cost.

Appendix K includes the cost of the central equipment building and distribution systems for each of the seven systems. These facilities to which the credit would apply average 43 percent of the total cost of the TE systems (Systems 1 through 4) and 33 percent of the total cost of the conventional central systems (Systems 5 through 7).

Table 9.10 compares the initial investment premium and payback periods with and without the investment tax credit. As the data show, no significant differences in the system-to-system comparisons result from including the investment tax credit in the analysis. With the credit, the best of the total energy systems obtain a 12.0 year payback, which is still unattractive. The best of the

Table 9.10 Effect of Investment Tax Credit on Investment Premium and Payback Period

System no.	Initial Investment Premium		Simple Payback Period	
	Without credit	With credit	Without credit	With credit
	%	%	years	years
1	49.4	43.2	14.6	12.7
2	49.4	43.2	17.5	15.3
3	61.9	54.5	16.3	14.3
4	49.1	42.9	13.7	12.0
5	18.9	15.2	7.9	6.4
6	19.4	15.7	9.8	8.0
7	34.9	29.9	16.2	13.8
8	2.4	n/a	0.9	n/a
9	1.1	n/a	--	--
10	10.3	n/a	--	--
11	8.4	n/a	5.5	n/a
12	--	--	--	--

conventional central systems, System 5, achieves a 6.4 year payback and a 15.2 percent investment premium with the credit which allows it to approach the "attractive" range.

9.5.2 Relative Cost of Fuel Oil and Electricity

Section 9.1.3 briefly introduced several factors influencing fuel oil and electricity costs. One of these factors was the particular electric rate chosen for the analysis. The appropriate rate depends on the type of system and the ownership scenario. It is clear that the central TE and conventional systems (Systems 1 through 7) would be most likely applied to a site owned and operated as a single entity as in the actual Summit Plaza case. In this case, the Large Power and Lighting (LPL) rate is appropriate as was used in the analyses of section 9.1.3.

In cases where the individual buildings or apartments are owned/operated separately and the energy system are likewise decentralized (i.e., Systems 8 through 12) other rates could be applied. Other available rates are the Residential Services (RS), General Lighting and Power (GLP), and Residential Heating Service (RHS) rates.

For residential buildings as individual customers of electric power, the LPL electric rates would still be available although residential rates, adjusted for multi-family occupancy, could also be applied. These PSE&G residential rates are the RS or RHS rates. For the commercial and school buildings, the GLP rate could be applied instead of the LPL rates. The LPL rate would offer lower cost electric service than either RS, RHS, or GLP service, providing it were available for this class of customers.

The individual apartment systems (Systems 10, 11 and 12) also allow metering to be applied to each separate apartment using the RHS rate. This would result in the same rate structure as applying the RHS rate to the entire building as an entity since in the latter case, the rate would be adjusted in direct proportion to the number of apartments in the building [9-8]. However, the possibility would exist for conservation efforts to reduce the consumption levels because the customer would be billed and pay directly for service. The magnitude of this reduction has been estimated to be as much as 30 percent [9-9].

An analysis was conducted for three of the conventional alternative systems using the various rate schedule/owernship scenarios described above. Only Systems 8, 11, and 12 were included in the analysis since the energy consumption patterns for Systems 9, 10 and 12 were nearly identical. Table 9.11 shows the applied rate schedule and average annual unit of electricity for each scenario.

Table 9.11 Unit Cost of Electricity for Several Ownership/Rate Schedule Scenarios

Scenario		System number 8	11	12
Whole site	Rate schedule unit cost[a) (¢/kWh)	LPL 3.48	LPL 3.27	LPL 3.23
Individual buildings	Rate schedule unit cost (¢/kWh)	LPL 3.74	LPL 3.60	LPL 3.55
Individual buildings	Rate schedule unit cost (¢/kWh)	RS/GLP 5.05	RHS/GLP 4.41	RHS/GLP 4.19
Individual apartments[b)	Rate schedule unit cost (¢/kWh)	RS/GLP 5.10	RHS/GLP 4.49	RHS/GLP 4.26

a) Same as table 9.4

b) Includes effect of 20 percent reduction in consumption for apartments.

As shown in the table, significant differences in average unit cost (and therefore total annual electricity cost), result when different approaches are taken to metering and ownership. It should be noted that the individual building approach using the residential small-user rates would produce nearly the same cost results as an individual apartment metering scenario without occupant conservation efforts. As a means of validation, the rates of table 9.11 were compared to the average rate in 1976 for three classes of PSE&G customers. These rates were as follows: residential - 5.74 ¢/kWh, commercial - 4.99 ¢/kWh, industrial - 3.5 ¢/kWh [9-11].

The impact of the hypothetical scenario on the comparative economic viability of the alternative systems was also determined. Table 9.12 shows the effect on the simple payback period.

Table 9.12 Effect of Onwership/Rate Schedule Scenarios on Simple Payback of Alternative Systems

Scenario description	Whole site[a]	Individual buildings	Individual buildings[b]	Individual apartments
Rate schedule(s)	LPL	LPL	RS/RHS/GLP	RS/RHS/GLP
	years	years	years	years
System 1	14.6	10.8	7.2	10.7
System 4	13.7	10.3	6.9	10.2
System 8	0.9	0.7	0.7	1.0
System 11	5.5	5.0	5.6	6.8

a) Results from table 9.9.

b) Results equivalent to individual apartments without occupant conservation.

Not unexpectedly, dramatic changes in payback periods would be produced from changes in the ownership/operating approach. It must be emphasized that these changes would not be produced by temporal changes in electric rates (inflation), nor changes in the utility, but rather institutional changes in how electric rates would be applied and the type of ownership inherent in the facility being served.

Obviously, a large number of electric and fuel-oil rates are possible once the analysis is broadened beyond the PSE&G Summit Plaza. Rather than try to treat these possibilities directly, a set of data have been developed which displays the effect of the relative cost of electricity and fuel oil on the payback period of the TE system, System 1. This relationship is shown in figure 9.2. It is important here to highlight the set of electricity/fuel-oil rates of 1977/1978 which would have made the TE investment "marginally attractive," and "attractive", thus the payback periods of 5 years and 10 years have been shown in figure 9.2.

As shown in the figure, the attractiveness of Total Energy is highly dependent on the relative costs of electricity. The 5 and 10-year payback lines in the figure have a slope of approximately 22.5. This means that the cost of fuel-oil must increase approximately 2.25 times as fast as the cost of electricity in order to maintain a constant payback (i.e., a constant level of investment attractiveness).

9.6 REFERENCES - SECTION 9

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3. Gamze-Korobkin-Caloger, Inc. "Estimated Owning, Operating and Maintenance Cost for a Conventional Central Equipment Building at Operation BREAKTHROUGH Jersey City, New Jersey Site," Unpublished report, 1973.

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9. Midwest Research Institute, "Energy Conservation Implications of Master Metering," Vol. I and Vol. II, NTIS Nos. PB 254 322 and PB 254 323, October 1975.

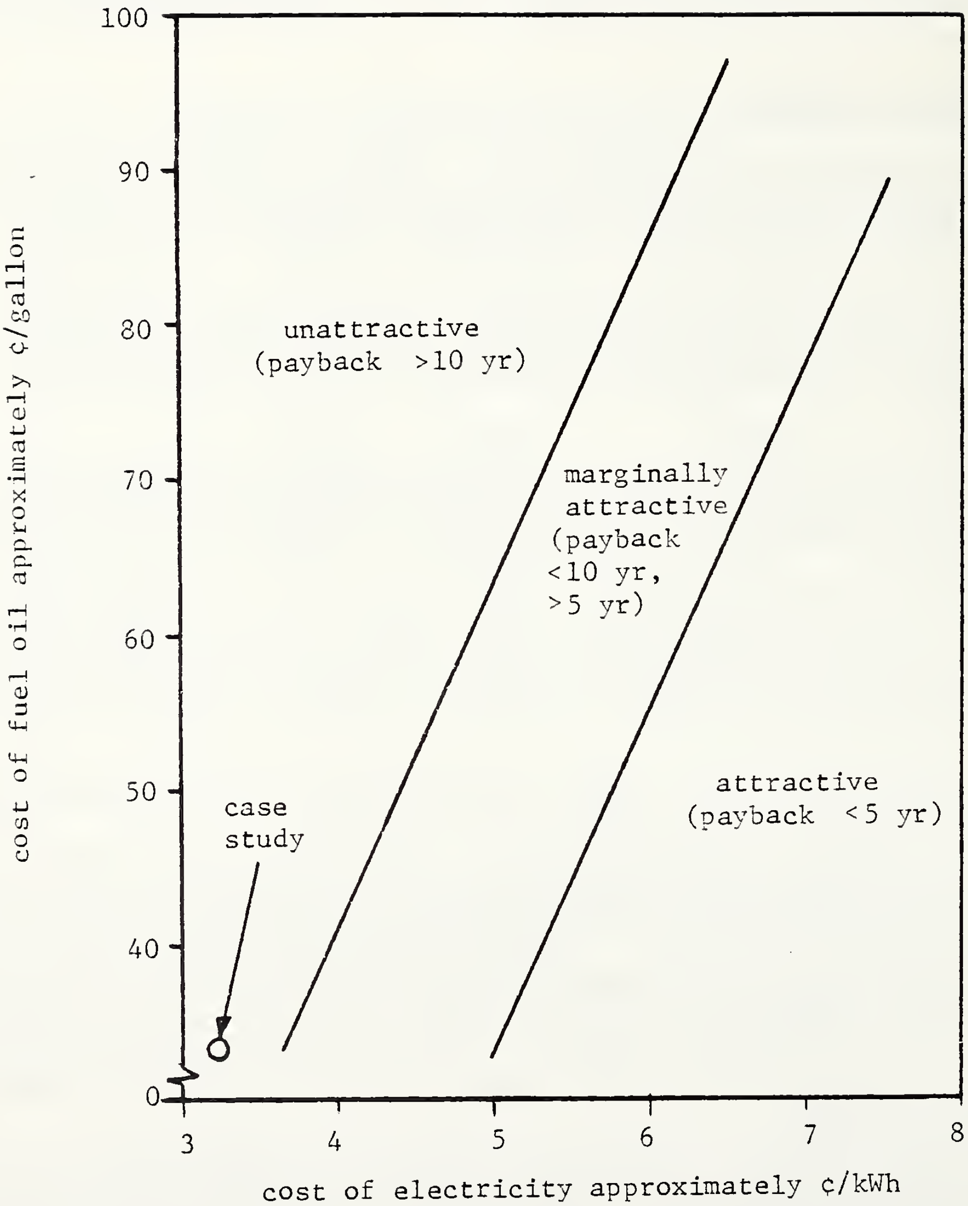

Figure 9.2 Effect of electricity and fuel-oil unit costs on investment attractiveness of a Total Energy System

10. Public Service Electric and Gas Company, "1976 Annual Report," February 10, 1977.

10. RESULTS OF ENVIRONMENTAL TESTS

This section presents a summary of environmental data and an impact analysis of the Total Energy plant on air quality, noise and as a result of cooling tower emissions. In addition to environmental data collected during plant operations, two types of data were collected prior to plant start-up: combustion emissions from the diesel engine-generators and baseline noise data for the site prior to construction. On-site measurements after the start of plant operations were conducted during calendar year 1977 by the Oak Ridge National Laboratory (ORNL) and its subcontractors, the University of Tennessee (Knoxville) for air quality and noise and the Environmental Systems Corporation for cooling tower emissions (see reference [10-1]).

Environmental data were not collected on a continuous basis as were the thermal/electrical data presented in sections 4 and 5. The capability to do so was not designed into the automatic DAS. It was felt that short-duration field measurements at Summit Plaza could adequately characterize basic equipment emissions and site dispersion characteristics and that the continuous load and weather data from the DAS would enable annual weather data to be produced, if desired.

Summit Plaza is located in a heavily-developed commercial, high density residential sector of Jersey City, New Jersey. The demonstration site, shown in the aerial view in figure 10.1, is bounded on the three sides by Summit Avenue, Kennedy Blvd. and Newark Avenue, carrying a high rate of automobile, bus, and truck traffic. In addition to the immediate traffic activity adjacent to the site, the general urban environment of Jersey City includes heavy traffic activity, large industrial manufacturing and petrochemical plants, and coal and oil-fired electrical generating plants. From an environmental standpoint, the Jersey City environs represent high background levels of atmospheric pollutants and noise. These background conditions must be recognized in assessing the environmental impact of the operation of the TE plant.

10.1 AIR QUALITY ASSESSMENT

10.1.1 Scope of Study

The scope of the air quality effort was to measure and characterize the combustion emissions from the TE plant, to determine the general behavior of plume dispersion from the TE plant, and to determine the effect of the plant combustion emissions on local air quality within 350 ft. (107 m) of the TE plant.

Background information on the diesel engine and auxiliary boiler loads coupled with general engine emission characteristics indicated that the diesel engines would be the dominant source of combustion emissions. Therefore, the major effort in emission measurements were related to the diesel engine exhaust.

The Central Equipment Building (CEB) is located among taller apartment buildings which affect the wind flow and hence the dispersion characteristics of the exhaust plumes from the TE plant (see figure 10.1). With low wind speeds, the

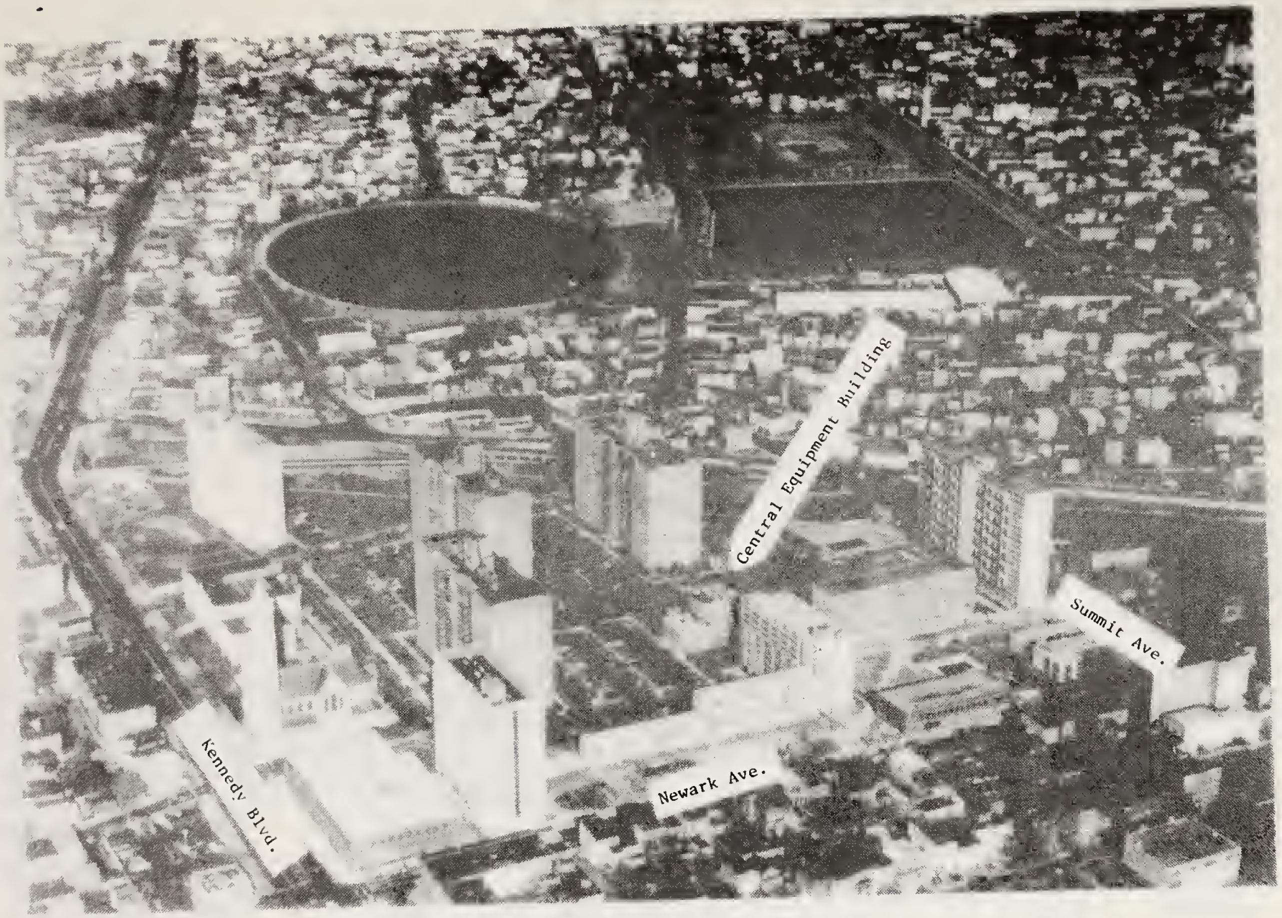

Figure 10.1 Summit Plaza site. This shows the TE plant surrounded by taller buildings.

exhaust plume can rise and escape the building downwash influence in the wake of the CEB and other up-stream buildings. With a completely undisturbed plume rise, calculations showed that the exhaust plume from the TE plant could travel more than a kilometer before reaching ground level, and that ground level pollutant concentrations from the CEB at that point would be indistinguishable from background concentrations [10-1]. Therefore, the on-site effort concentrated on determining the local wind conditions and resulting dispersion conditions from the exhaust plumes.

The pollutants of interest were those for which Federal air quality standards have been promgulated: particulates, sulfur oxides (SO_2), carbon monoxide (CO), hydrocarbons (HC) and nitrogen oxides (NO_x) [10-2]. The NO_x pollutant was further characterized by the separate constituents NO, NO_2 as well as the total NO_x.

The air quality measurements included three periods of on-site data collection. The first period, June 13-18, 1977, was a short-term study to perform initial measurements of wind, emission rates, and ground-level air quality. Two long-term periods of measurements of six weeks each were conducted from July 5 to August 19, 1977, and from November 6, 1977 to January 3, 1978. The latter periods were to obtain data during summer and winter conditions.

10.1.2 Plant Combustion Exhaust System

The exhaust gases from the operating diesel engines are collected in an exhaust duct and discharged through a common stack. The 4.0 ft (1.22 m) diameter stack extends 3.0 ft (0.91 m) above the top of the 60 ft (18.3 m) tall CEB. The diesel engine exhaust is diluted with air in a ratio of about 3 to 1 and given additional momentum by a 75 hp (56 kW) stack dilution fan. The total air plus engine exhaust flow downstream of the dilution fan is 29,000 cfm (13.7 m^3/s) yielding an average velocity of 38.2 ft/s (11.7 m/s) at the stack discharge.

The two boilers each have a 2.0 ft (0.61 m) inside diameter stack extending 3.0 ft (0.91 m) above the top of the CEB. No dilution of the boiler exhaust occurs before it is discharged to the atmosphere. The combustion exhaust system is shown in figure 10.2.

10.1.3 Combustion Emissions

Substantial data were collected to characterize the diesel engine and boiler exhaust emissions. This was done to provide basic data on component performance as a direct contribution to available data and also to support the further analysis of ground level air quality impacts from the TE plant.

10.1.3.1 Engine Emissions

Combustion emissions first received attention during the testing of the diesel engine-generators at the factory in June 1972. In this series of test, three of the engine-generators were instrumented for exhaust emissions. Data were collected on CO, NO_x, HC, and particulates over the full load range of the engines; zero to 660 kW (110 percent load) output. One or two sets of these

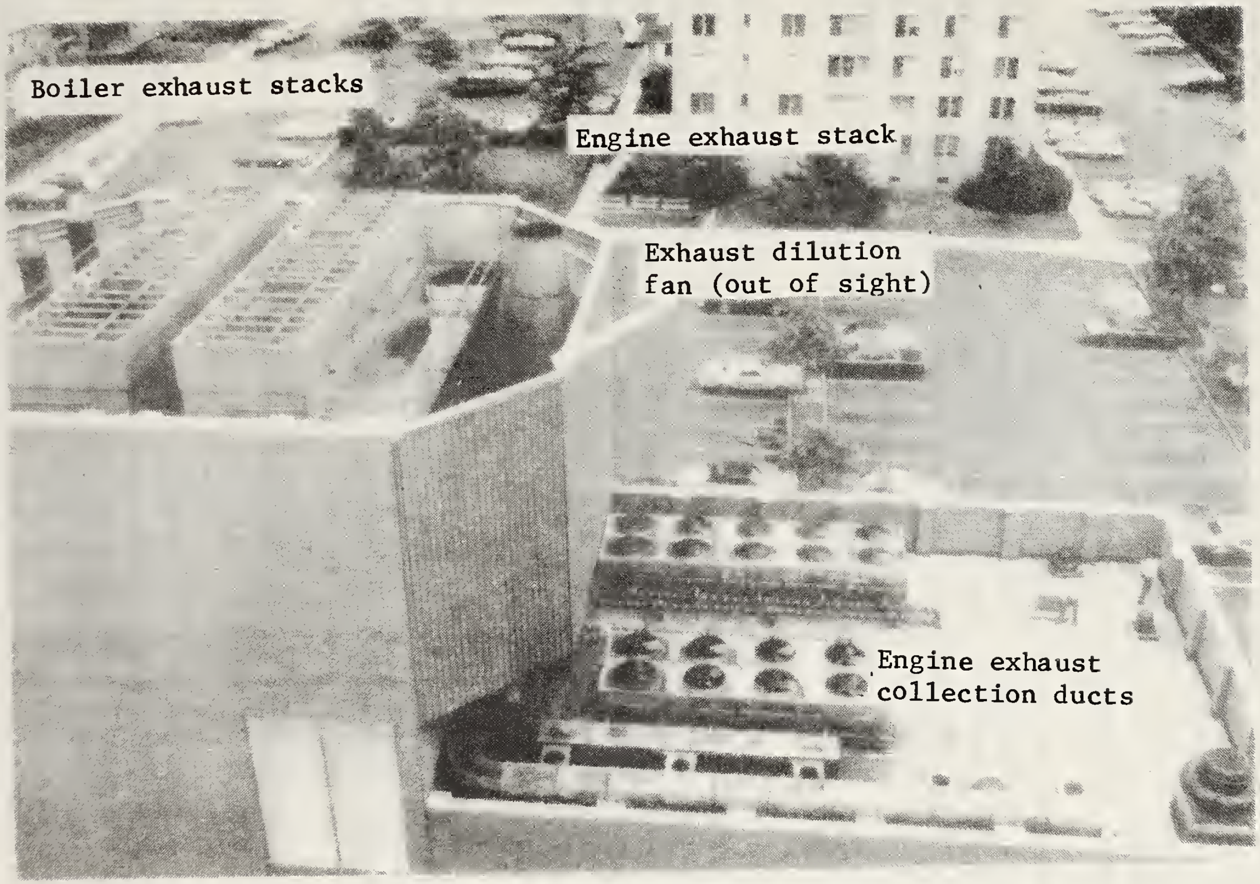

Figure 10.2 Roof area of the TE plant. This shows the various components of the combustion exhaust system.

measurements were made on each engine at each load. Except in the case of CO, these tests utilized measurement methods in accordance with reference [10-3] with minor deviations necessitated by the physical conditions of the test stand. CO was measured by detector tubes in order to obtain the required sensitivity at the low concentrations encountered. The full results of the emissions testing on the test stand are published in reference [10-4].

On-site measurements at Summit Plaza of NO_x, SO_2, CO, total hydrocarbons (THC), and particulates were made on individual engine stacks downstream of the exhaust heat exchanger and just prior to discharge into the common intake duct for the exhaust gas dilution fan. The measurement method used for particulates was the recommended method of reference [10-3]. For all other pollutants, analyses were made by automatic analyzer equipment.

On-site measurements were made while the engines were operating normally in response to load variations. Therefore the range of engine loads was much less than for the factory tests. However, in the field tests many more sets of measurements were taken for each engine over the narrower range of loads. Engine loads ranged from 215 to 390 kW, or 36 to 65 percent of full rated load of 600 kW/engine. This range of engine loads nearly covers the entire normal operating range for the plant (i.e., three engines meeting electrical loads from 650 to 1,170 kW) [10-1].

Both the factory tests and field tests showed significant engine-to-engine variations in emissions. For the factory test, these variations largely occurred only in extremes of the engines' load range. In comparing the test stand and field results, the field test data showed an increase of 14 percent in exhaust gas flow rate over the test stand data. For equivalent concentrations (ppm) of pollutants in the exhaust streams, the higher flow rate produced comparatively greater mass emission rates (gms/h) for the field tests. The reason for the difference in flow rate was not clear.

With this basic difference in mind, comparisons of test stand and field results for total emissions showed fairly close agreement in the case of CO and NO_x, as shown in figures 10.3 and 10.4. The results for THC and particulates in figures 10.5 and 10.6 show significant discrepancies. The reasons for these discrepancies could not be fully identified.

SO_2, which was not measured on the test stand, had a concentration of 45 ppm at 50 percent load with 0.24 weight % sulfur in the fuel.

The results for particulates are noteworthy. The average level of particulate mass emissions in the field was twice that of the factory tests. In addition, the field results showed a much greater variation between tests than did the factory tests. This variation could have been caused by the presence of an exhaust gas heat exchanger which normally removes condensible hydrocarbons but which also can release bursts of particulate material leading to highly variable particulate emission rates [10-1]. Reasons for the higher overall level of particulates were not given in reference [10-1] but one possible cause was wear or improper adjustment of the engines, particularly the diesel fuel injection system.

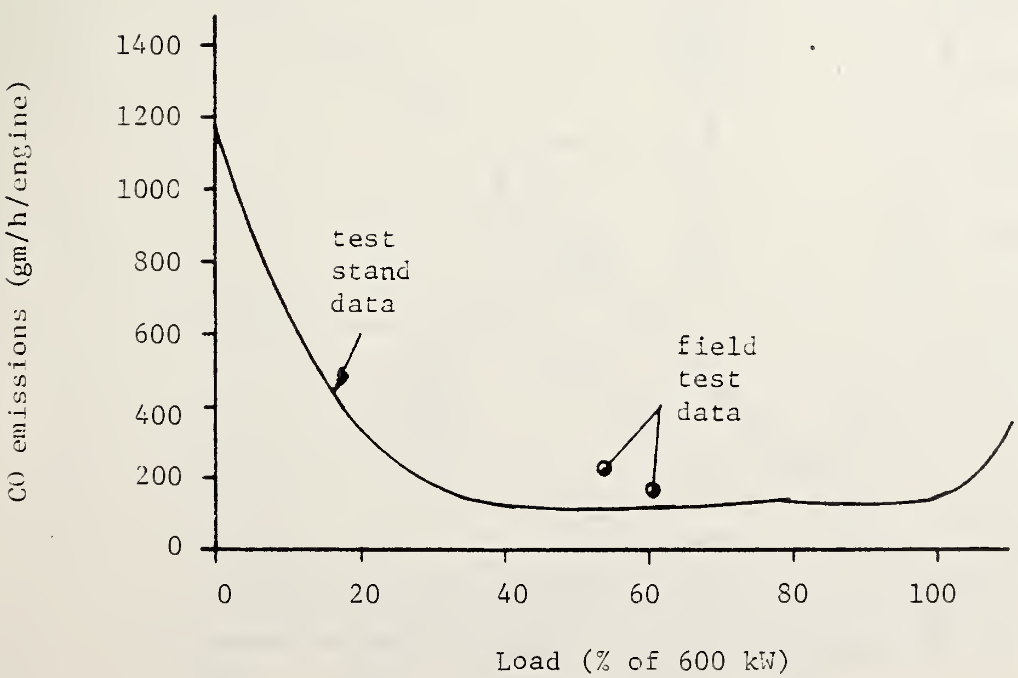

Figure 10.3 Engine-generator carbon monoxide emission rates

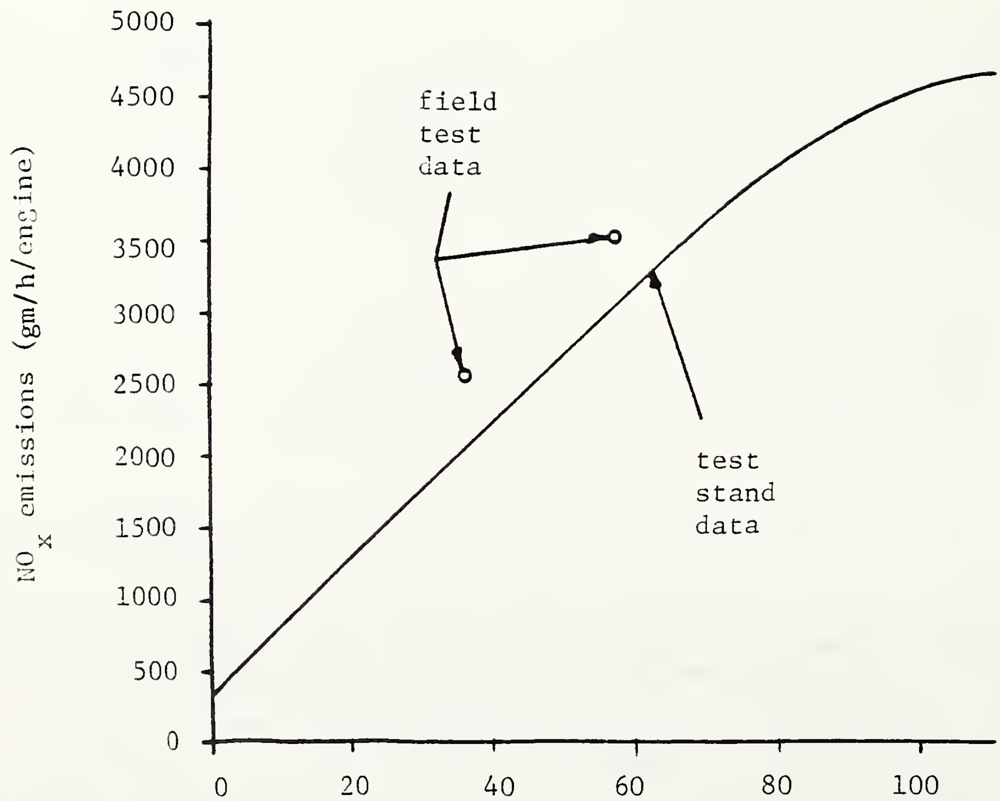

Figure 10.4 Engine-generator nitrogen oxides emission rates

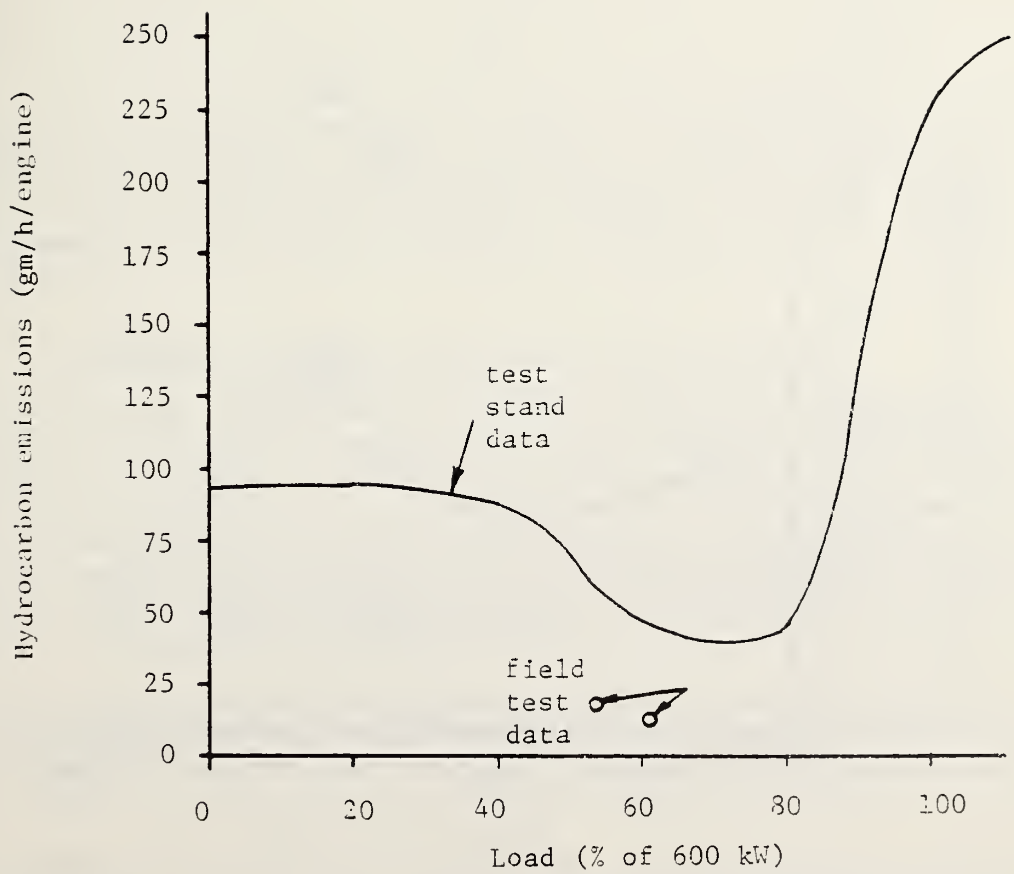

Figure 10.5 Engine-generator hydrocarbon emission rates

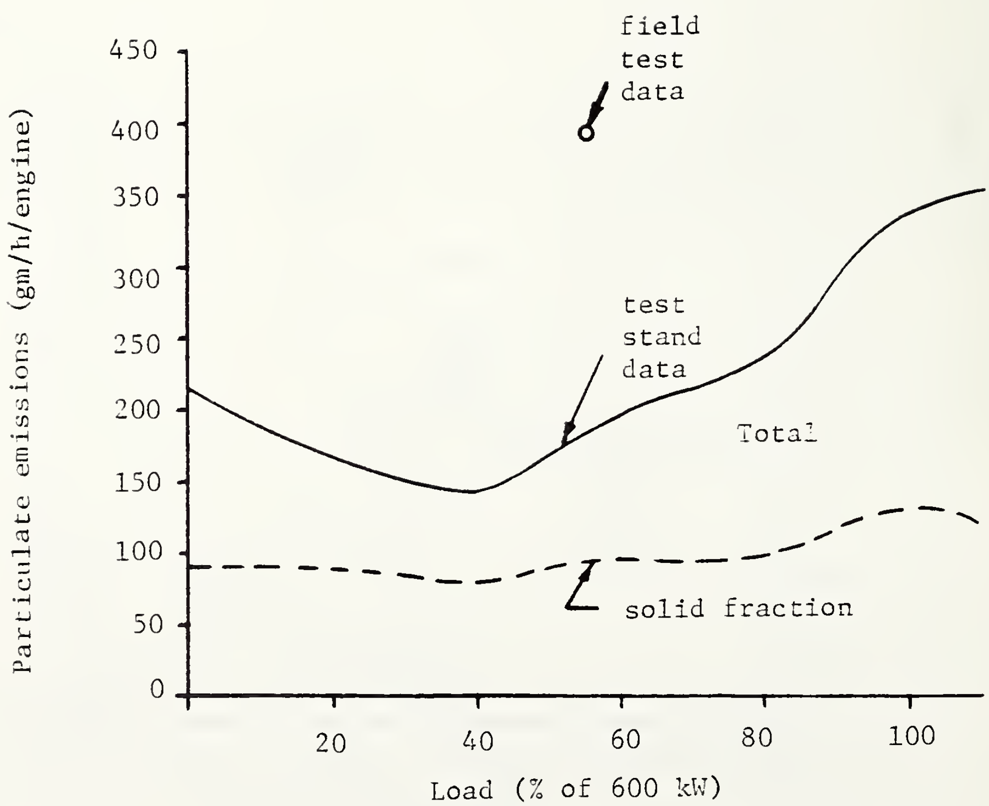

Figure 10.6 Engine-generator particulate emission rates

10.1.3.2 Boiler Emissions

The boilers were not subject to performance or emission tests prior to their installation at Summit Plaza as was the case for the diesel engine-generators. Therefore, comparisons between field and test stand emissions are not made.

Only one set of exhaust emission measurements was made on the boilers in the field. Emissions of SO_2, CO, and NO_x were measured at a heat output rate of 2.3 x 10^6Btu/h (674 kW), or approximately 17 percent of the rated boiler output. The volume concentrations and mass emission rates for this part load condition are presented in table 10.1.

Table 10.1 Boiler Exhaust Concentrations and Emission Rates at 17 percent of Full Load

Pollutant	Exhaust Concentration	Mass Emission Rate
	ppm	gm/h
NO_x	74	604
SO_2	27	307
CO	18	89

Particulate and hydrocarbon emissions were not measured. However, from generic data on oil-fired boiler emissions in reference [10-5], the total hydrocarbons emission rates is estimated to be about the same as that for CO, and the particulate emission rate is about one sixth of the NO_x rate, or approximately 100 gm/h [10-1].

10.1.3.3 Comparison of Engine and Boiler Emission Rates

The emission rates for the diesel engines (figures 10.3 through 10.6) and for the boilers (table 10.2) allow a comparison of emission rates and a determination made of the total combined pollutant emissions for a typical year. The basis for the comparison is an electric load of 1,000 kW provided by three engines operating at 55 percent of full load and a boiler load of 4.6 x 10^6Btu/h (1347 kW) thermal output provided by one boiler operating at 34 percent of rated capacity. These loads are approximately the average annual loads for these components (see tables 4.1 and 4.2).

In order to obtain values for boiler emissions at an output of 4.6 x 10^6Btu/h (1347 kW) a change in boiler mass emissions directly proportional to changes in load was assumed and this was applied to the measured emissions at the 17 percent load.

Engine emission rates were based on figure 10.3 through 10.6. Both test stand and field results were used for THC and particulates, where significant unresolved discrepancies existed.

Results of the comparison are shown in table 10.2 and indicate that only in the case of SO_2 and THC are the boiler emissions significant relative to the engine emissions. However, in the peak winter months, the monthly average boiler load can be as much as twice the annual average with no significant change in engine load. Under these conditions, again assuming proportionality between boiler emissions and load, the boiler emission rates for all pollutants, except possibly NO_x, are significant relative to engine emission rates.

Table 10.2 Engine and Boiler Emission Rates at an Annual Average Load Level

	Emission Rate (gms/h)	
Pollutant	Engines	Boiler
NO_x	10,000	1200
SO_2	800	600
CO	500	180
THC	50 (150)[a]	180[b]
Particulates	1,200 (550)[a]	200[b]

a) Numbers in parentheses are test stand results.

b) Estimated values.

The relative importance of each of these pollutants which respect to ground level air quality is discussed in section 10.1.5.

10.1.4 Site Dispersion Characteristics

One element of the ground-level air quality analysis was to characterize the exhaust gas plume behavior in the vicinity of the CEB with respect to the conditions under which aerodynamic downwash of the plume occurs. The methodology employed (1) photographing of smoke-traced diesel engine exhaust plumes and (2) collecting wind data at the exhaust stack. The wind data provide the key interpretive tool for evaluating the plume observations and the effect of the TE plant operation on local air quality. This section, which describes the plume analysis, is based entirely on material in reference [10-1].

10.1.4.1 Local Wind

The local wind speed* and direction were monitored with a Climatronics Mark III wind sensor located 15 ft (4.5 m) above the top of the CEB. Figures 10.7 and 10.8 represent wind roses for the summer and winter monitoring periods of 1977. The summer period had a high frequency of southerly and westerly winds; whereas the winter period has a more uniform distribution with high wind frequencies from the east-northeast and north directions. Wind speeds were generally lower during the summer period ranging up to 12 mph (5.4 m/s) compared to winter period wind speeds that ranged to more than 25 mph (11.2 m/s).

Hourly wind speed and direction data from the sensor above the CEB were obtained to correlate with ground level air quality data. In addition, the local horizontal plume dispersion condition was estimated from the range of the lateral wind direction over time intervals between 15 minutes to one hour. The range of the lateral wind direction was translated to an equivalent Pasquill atmospheric stability category to aid in correlating short-term, ground-level air quality results.

10.1.4.2 Engine Exhaust Plume Observations

Visual plume observations were obtained by injecting white smoke bombs into the engine exhaust duct and photographing the visible plume. The objectives of these observations were to determine the wind speed* conditions at which incipient building downwash occurred and the character of the plume rise and dispersion in the downwash condition. The engine exhaust was chosen for this observation as the engines are the dominant source of emissions, primarily NO_x, from the TE plant.

The majority of the plume observations were made with southerly and westerly winds as these winds dominated the summer period when these observations were made. The main result of these observations was that no evidence of plume downwash existed with an average wind speed less than about 3-4 mph (1.3 - 1.8 m/s). Such plume behavior is shown in figure 10.9 with a southerly 2-4 mph (0.9 - 1.8 m/s) wind. As the wind speed increased to 3-8 mph (1.3 - 3.6 m/s), the plume rise was limited to 20-30 ft (6-9 m) and the plume partly dispersed into the wake of the CEB. Figure 10.10 shows this condition for a southerly wind. With a 9-12 mph (4.0 - 5.4 m/s) wind speed, the plume was significatly dispered in the CEB wake. Figure 10.11 shows this wind condition for a southerly wind. In general, the observations with southerly winds indicated that as the wind speed increased above the threshold for downwash, the plume rise was reduced and an increasing fraction of the plume was pulled into the CEB wake.

The most systematic plume observations were made with southerly winds, and the same type of plume rise behavior occurred with winds from other directions as

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* The "wind speed" refers to the measured wind condition 15 ft (4.5 m) from the CEB, not the wind speed at higher altitudes unaffected by the building topography.

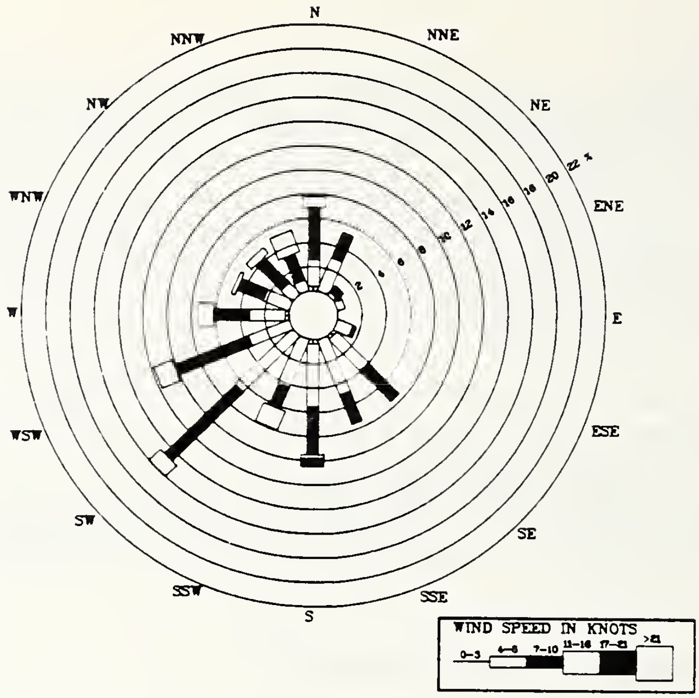

Figure 10.7 Wind rose: Summer monitoring period, 1977

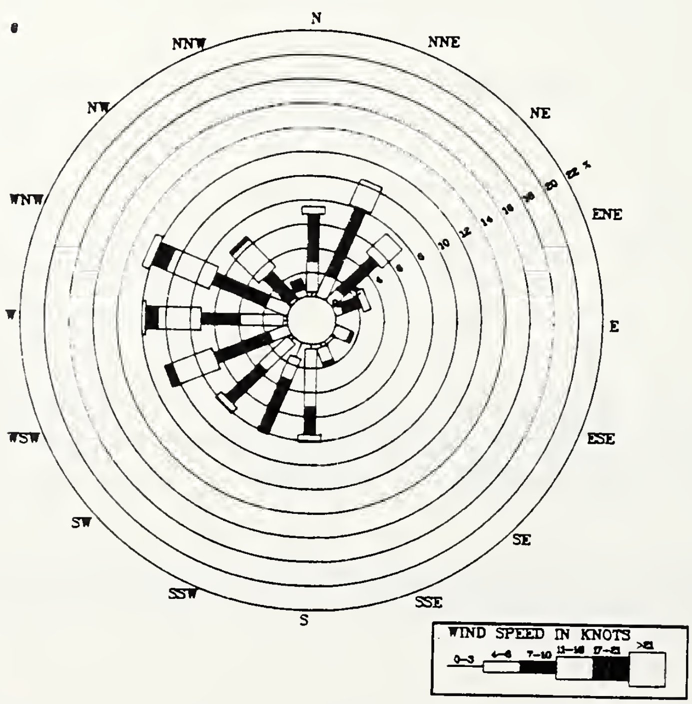

Figure 10.8 Wind rose: winter monitoring period, 1977

Figure 10.9 Diesel engine exhaust plume with 2-4 mph (0.9 - 1.8 m/s) southerly wind. Visibility of the plume was enhanced by means of a smoke bomb dropped into the stack.

Figure 10.10 Diesel engine exhaust plume with 3-8 mph (1.3 - 3.6 m/s) southerly wind. Visibility of the plume was enhanced by means of a smoke bomb dropped into the stack.

Figure 10.11 Diesel engine exhaust plume with 9-12 mph (4.0-5.4 m/s) southerly wind. Visability of the plume was enhanced by means of a smoke bomb dropped into the stack.

above the threshold for downwash, the plume rise was reduced and an increasing fraction of the plume was pulled into the CEB wake.

The most systematic plume observations were made with southerly winds, and the same type of plume rise behavior occurred with winds from other directions as with southerly winds. However, the amount of the plume down-wash into the building cavity (i.e., brought to ground-level directly behind the CEB) appeared qualitatively to be higher for northerly and westerly winds of 8-12 mph (3.6-5.4 m/s) than for southerly winds.

The plume observations fulfilled the primary objectives of determining that the threshold wind speed for the inception of plume downwash was approximately 3.4 mph (1.5 m/s). Analysis of the wind data of figures 10.7 and 10.8 show that wind speeds above this threshold occurred 40 percent and 60 percent of the time during the summer and winter monitoring periods, respectively.

In addition, the observations indicated that the transition of plume downwash from the building wake to the building cavity* occurred with wind speed above 8-12 mph (3.6-5.4 m/s).

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* The "building cavity" is the area directly behind the building which contains recirculating air currents and which exhibits the greatest potential for significant pollutant concentrations should the exhaust plume become entrained in this area.

10.1.5 Ground-Level Air Quality

The purpose of the ground level air quality monitoring was to measure and separate the TE plant source ground level contribution from the background contribution for specific pollutants. In addition to monitoring of pollutants both in exhaust gases and at the ground level, sulfur hexafluoride (SF_6) was utilized as a tracer in the exhaust in short term tests to support and validate the separation of source contribution from the background contribution to air quality. This section, which describes the ground level air quality data and analysis, is based entirely on material in reference [10-1].

10.1.5.1 Data Collection/Monitoring Approach

The monitoring began with a one week period to determine whether typical engine emissions could be detected at ground level by air quality monitoring instruments. This exploratory effort served to direct the primary monitoring effort which consisted of a six-week period in the summer and again in the winter. Based on the results of the preliminary one-week monitoring period, it was concluded that it was not necessary to monitor all pollutants at all times. Emission data and ambient air quality NO_x data taken during the preliminary period indicated that the maximum NO_x emission rate from each diesel engine would be less than 3600 grams/hour while the maximum incremental ground-level concentrations of NO_x during the one-week period was 0.06 ppm (112 $\mu g/m^3$) above background. Based on this observed dilution for NO_x, the maximum hourly concentrations expected for other pollutants were estimated as follows: CO < 0.001 ppm; SO_2 < 0.001 ppm; and THC < 0.0001 ppm. The maximum 24-hour concentration of particulates was estimated to be 12 $\mu g/m^3$.

When these maximum concentrations from the TE plant were compared with the capabilities of standard air monitoring instrumentation, it was concluded that the TE plant contribution for CO, SO_2, THC, and particulates could not be detected even with a zero background concentration and that the sensitivity of the instrumentation was not sufficient to delineate between the general background and the contribution from the CEB. Thus, monitoring for CO, SO_2, and THC was conducted only at the continuously monitoring van 224 ft (68 m) to the east of the CEB (see figure 10.12) to obtain general area air quality data. NO, NO_2, and NO_x were also monitored at the van. At 6 other locations on the site from 30 to 260 ft (9 to 80 m) from the CEB, air samples were taken and later analyzed at the van for NO, NO_2, and NO_x. These 6 other locations are shown in figure 10.12.

10.1.5.2 Statistical Summary of Air Quality Data

Cumulative frequency distributions of one-hour average concentrations were prepared for ground-level concentrations of NO, NO_2, and NO_x for each location for the two monitoring periods. Distributions of SO_2, CO, and THC* were also prepared (summer period, van only). Total pollutant concentrations are presented in tables 10.3 and 10.4 in terms of (1) C_{50}, the 50 percentile value, (2) $C_{99.989}$, the projected 99.989 percentile value, equivalent to the annual one-hour peak value, (3) $\overline{C}$, the arithmetic average value of all measurements, and (4) C_{max}, the maximum observed value.

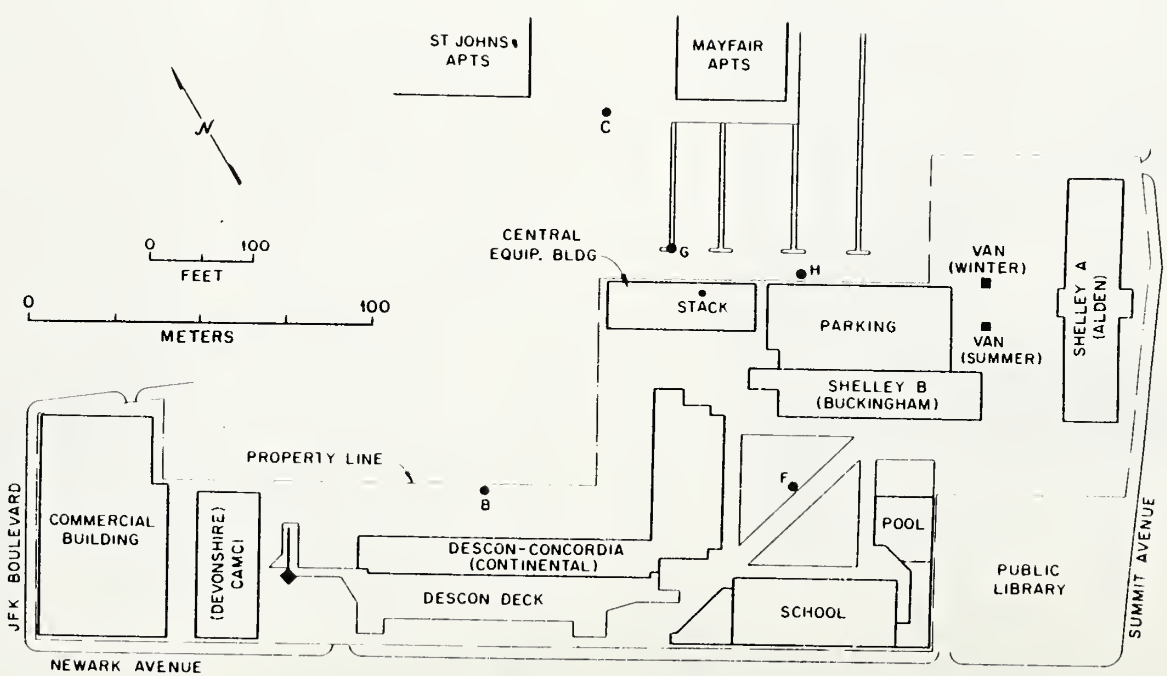

Figure 10.12 Air quality monitoring station locations

In addition to the concentrations for the entire sampling period, total and above-background nitrogen oxide concentrations were determined at several sample locations when they were downwind of the TE plant. The results of this sub-set of data from the total summer and winter sampling periods are presented in table 10.5.

The NO_2 concentrations relative to NO concentrations in tables 10.3 through 10.5 are probably higher than actually occurred for all locations except the east (van) samples because NO can partially convert to NO_2 in the sampling bags prior to analysis. This conversion would tend to lead to higher NO_2 results for the samplers. The data show the opposite, with uniformly lower relative NO_2 values at the samplers than at the van. This dichotomy is not resolved in reference [10-1]. For the air quality analysis using Federal Air Quality Standards, only the van data will be used.

The measured concentrations in tables 10.3 through 10.5 form the basis for assessing the overall air quality during the summer and winter monitoring periods of 1977.

10.1.5.3 Evaluation of General Site Air Quality

It has already been concluded that the contributions of the TE plant to ambient concentrations of CO, THC, and SO_2 were below the lower detectable limit of the monitoring instruments utilized. Thus, contributions of CO, THC, and SO_2 from the TE plant are insignificant even with a zero ambient concentration from other sources.

Concentrations for CO, THC, and SO_2 at the Summit Plaza site can be assessed by comparing concentrations in table 10.3 with allowable concentrations from the Federal Air Quality Standards in table 10.6. For CO, the highest measured and highest projected hourly concentrations of 9.2 and 12.5 ppm are well under the maximum one-hour allowable concentration of 35 ppm. For THC, the arithmetic average concentration, $\overline{C}$, of 1.90 ppm exceeds the maximum three-hour (6 to 9 a.m.) allowable concentration for non-methane hydrocarbons by a factor of 8. The allowable concentration for non-methane hydrocarbons could therefore be exceeded if methane contributed less than ~ 88 percent of the THC concentration, which is likely. For SO_2, the $\overline{C}$ of 0.042 ppm exceeds the allowable annual arithmetic average (secondary) by about a factor of 2. Therefore, for CO, THC, and SO_2, only CO ambient concentrations at the Jersey City site are clearly within allowable limits in accordance with the Federal Air Quality Standards based on the data obtained during the summer of 1977.

For nitrogen oxides, NO, and NO_2, the average concentrations for the two monitoring periods at the monitoring sites 200 to 260 ft (60 to 80 m) from the CEB are shown in comparison with the allowable annual arithmetic average for NO_2 in figure 10.13. Average NO_2 concentrations exceeded the allowable concentration of 0.05 ppm only in the east direction from the TE plant.

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* THC = total hydrocarbons as methane.

Table 10.3 Summary of Measured Air Quality Data-Summer Period

Monitoring site	Pollutant	C_{50} ppm	$C_{99.989}$ ppm	$\bar{C}$ ppm	C_{max} ppm
Van (east)	NO	.0228	1.1	0.0384	.53
	NO_2	.0538	0.27	0.0556	.19
	NO_x	.0810	0.72	0.0939	.63
Van (east)	SO_2	.037	0.34	0.0420	.18
	CO	2.700	12.50	2.100	9.20
	THC	1.500	13.20	1.900	7.60
Station C (north)	NO	.045	0.51	0.0580	0.34
	NO_2	0.0160	0.061	0.0166	0.064
	NO_x	0.061	0.540	0.0749	0.360
Station B (west)	NO	0.0154	0.490	0.0263	0.198
	NO_2	0.012	0.033	0.0132	0.023
	NO_x	0.0307	0.560	0.0395	0.153
Station F (south)	NO	0.0354	0.640	0.0624	0.329
	NO_2	0.018	0.162	0.0191	0.124
	NO_x	0.055	0.550	0.0803	0.348

Table 10.4 Summary of Measured Air Quality Data-Winter Period

Monitoring site	Pollutant	C_{50} ppm	$C_{99.989}$ ppm	$\bar{C}$ ppm	C_{max} ppm
Van (east)	NO	0.055	0.9	0.082	0.54
	NO_2	0.069	0.36	0.079	0.33
	NO_x	0.133	0.91	0.162	0.70
Station C (north)	NO	0.06	0.82	0.085	0.43
	NO_2	0.023	0.98	0.022	0.05
	NO_x	0.085	1.10	0.110	0.46
Station B	NO	0.064	1.20	0.100	0.54
	NO_2	0.020	0.08	0.021	0.50
	NO_x	0.089	1.30	0.121	0.62
Station G (north-close in)	NO	0.064	0.40	0.074	0.22
	NO_2	0.0175	0.041	0.018	0.035
	NO_x	0.074	0.400	0.093	0.240
Station H (east-close in)	NO	0.081	0.950	0.110	0.48
	NO_2	0.025	0.062	0.026	0.043
	NO_x	0.106	0.950	0.137	0.510

Table 10.5 Summary of Downwind Nitrogen Oxides (NO_x) Concentrations

Monitoring site	C_{50} ppm	$C_{99.989}$ ppm	$C_{99.989,AB}$[a] ppm	$\bar{C}$ ppm	$\bar{C}_{AB}$ ppm	C_{MAX} ppm	$C_{MAX,AB}$ ppm
Van (east) summer	0.089	0.28	0.136	0.096	0.036	0.142	0.104
Van (east) winter	0.120	0.39		0.139	0.039	0.385	0.080
C (north) summer	0.053	0.30	0.15	0.061	0.031	0.133	0.096
C (north) winter	0.09	0.78		0.114	0.034	0.277	0.095
G (north-close in) winter	0.115	0.44	0.36	0.125	0.049	0.242	0.140
B (west) winter	0.160			0.212	0.059	0.624	0.15

a) Subscript "AB" denotes "above background."

Table 10.6 Federal Air Quality Standards

	Primary Enforcement by summer 1975	Secondary No time limit on enforcement
	μg/m³ (ppm)	μg/m³ (ppm)
Particulates		
Annual geometric mean	75	60
Maximum 24-hr concentration[a]	260	150
Sulfur oxides		
Annual arithmetic average	80 (0.03)	60 (0.02)
Maximum 24-hr concentration[a]	365 (0.14)	260 (0.1)
Maximum 3-hr concentration[a]	[b]	1300 (0.5)
Carbon monoxide[c]		
Maximum 8-hr concentration[a]	10 (9)	10 (9)
Maximum 1-hr concentration[a]	40 (35)	50 (35)
Photochemical oxidants		
Maximum 3-hr concentration[a]	160 (0.08)	160 (0.08)
Hydrocarbons		
Maximum 3-hr concentration[a] (6-9 am)	160 (0.24)	160 (0.24)
Nitrogen oxides		
Annual arithmetic average	100 (0.05)	100 (0.05)
Maximum 24-hr average	[b]	[b]

[a] Not to be exceeded more than once a year.

[b] No standard proposed.

[c] Values for CO are in mg/m^3.

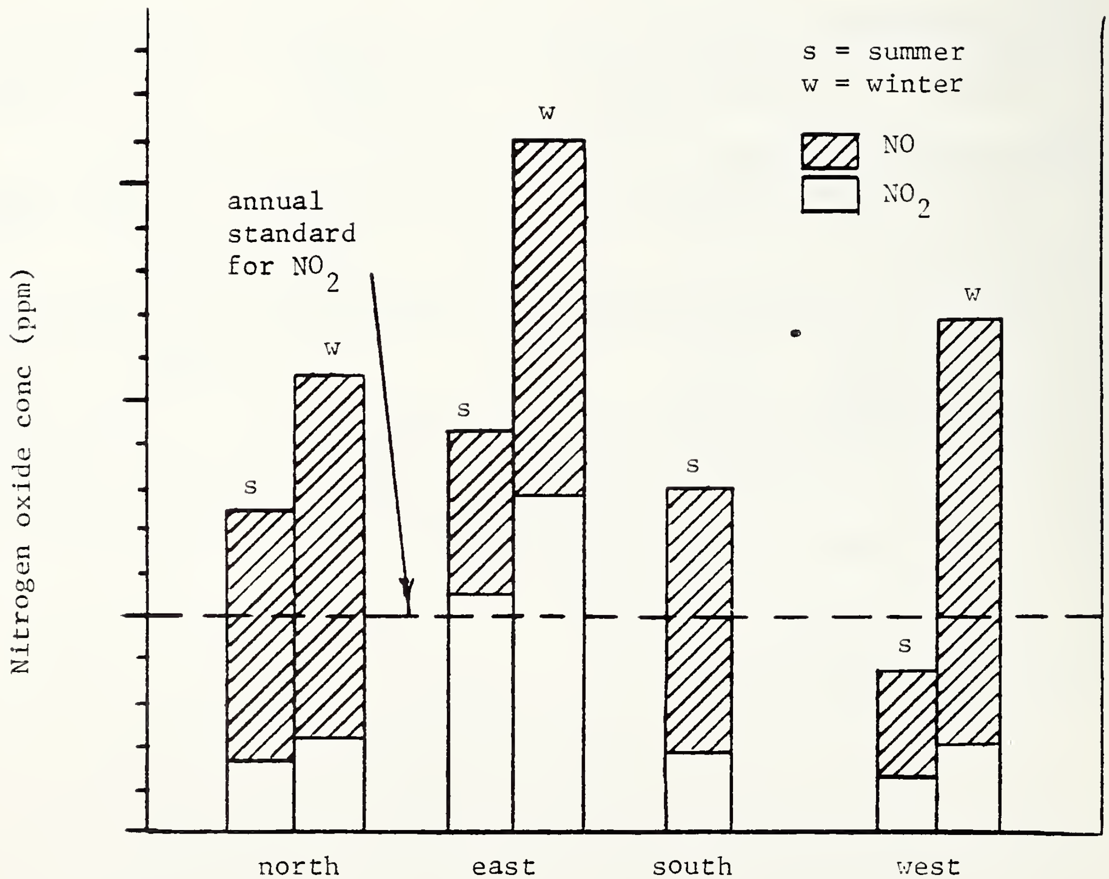

Figure 10.13 Average nitrogen oxide concentrations ~210 ft (65 m) from the TE plant

This is particularly significant in view of the greater accuracy of the east (continuously-monitoring van) NO_2 data. Total nitrogen oxide concentration (NO + NO_2) exceeded the allowable levels in all directions except the west during the summer period. Therefore, with eventual conversion of NO to NO_2, the potential existed for NO_2 concentrations to exceed the allowable annual arithmetic average concentration of 0.05 ppm to the north and south directions during the summer period plus the west direction during the winter period.

10.1.5.4 Contribution of TE Plant to NO_x Concentration

During the summer period, the 0.04 ppm NO_x concentration in the west direction (see table 10.3) serves as an estimate of the average background concentration since the frequency of easterly winds was almost zero (see figure 10.7). Assuming a 0.04 ppm average background concentration, the average NO_x contribution from the TE plant ranged from 0.035 to 0.055 ppm according to the data of table 10.3.

An additional estimate of the TE plant contribution to NO_x concentrations can be made from the results for sampling periods when the wind generally blew toward a stationary sampler. The average NO_x concentration results from table 10.4 are shown graphically in figure 10.14 for the north, east, and west directions from the TE plant. The TE plant contribution to the average NO_x concentration were similar for the summer and winter periods in the north and east directions. However, in the west direction, the TE plant NO_x contribution was greater for the winter period as the summer period contribution was essentially zero. The TE contribution to the average NO_x concentration when the wind blew toward a sampler ranged from 0.03 to 0.06 ppm, similar to the range estimated using the summer period data.

Figures 10.13 and 10.14 show that the average NO_x concentrations during the winter period were significantly higher than during the summer period. The main reason for the higher winter NO_x concentrations is that the background concentrations in the winter period were 0.04 to 0.05 ppm higher than in the summer period at the north and east samplers and reached 0.15 ppm at the west sampler during the winter period (see figure 10.14).

Maximum one-hour nitrogen oxide concentrations observed (C_{max}) and statistically projected "once per year" ($C_{99.989}$) in tables 10.3 through 10.5 show that observed NO_x concentrations range up to 0.63 and 0.70 ppm in the summer and winter periods, respectively, while the corresponding values for projected one-hour concentrations range up to 0.72 and 1.1 ppm. Tables 10.3 and 10.4 show that in most cases, maximum NO_2 concentrations were low compared with the maximum NO or NO_x concentrations with the exception of the north samplers during the winter period.

Finally, it is important to address the question of whether the TE plant NO_x is the main cause of the maximum short-term concentrations of NO_x. The maximum observed NO_x concentrations in table 10.5 range from 0.16 to 0.62 ppm, while the corresponding above-background concentrations were 0.07 to 0.15 ppm. The projected values for the "once per year" concentration above background in table 10.5 are less reliable (hence were not estimated at most samplers) than

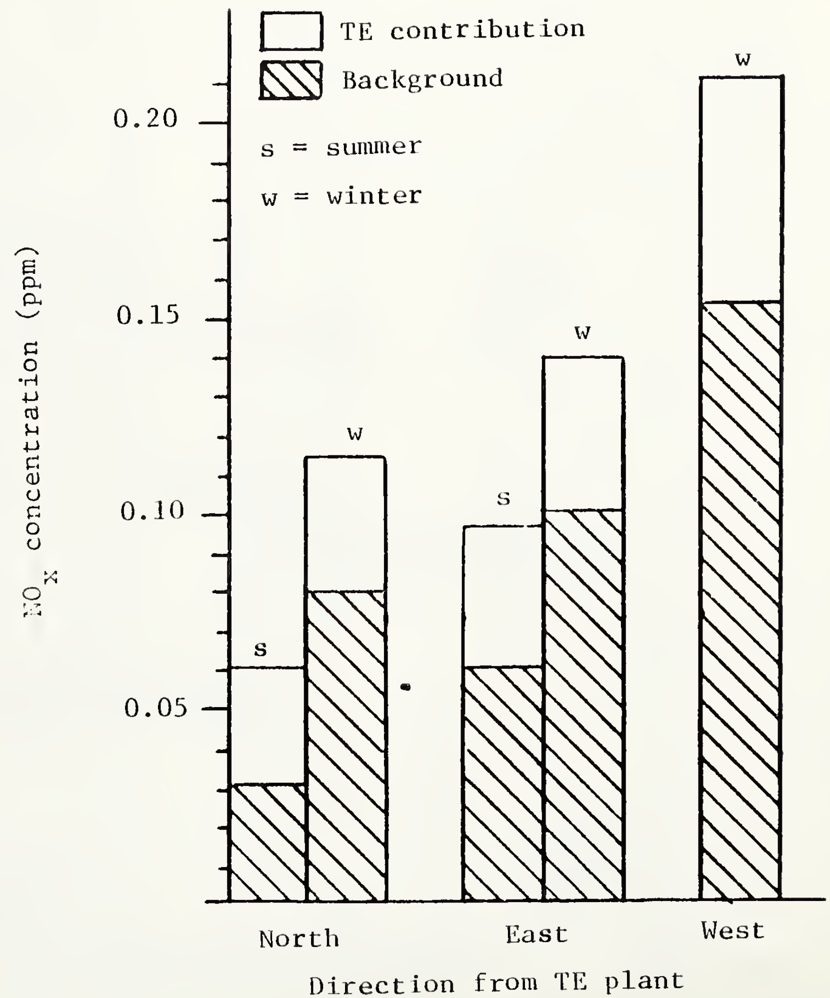

Figure 10.14 TE plant and background average NO_x concentrations when wind blew toward a stationary sampler

the projected total concentration, $C_{99.989}$, in tables 10.3 and 10.4 since data in table 10.5 are based on a relatively small sample size. Hence the question of whether or not the TE plant or the background causes the maximum projected NO_x concentration cannot be directly answered. However, several pieces of evidence lead to the conclusion that the background is the major cause of the maximum NO_x concentrations. First, the maximum observed NO_x concentration of 0.4 to 0.6 ppm were caused by winter background concentrations of 0.3 to 0.45 ppm (see table 10.5); secondly the $C_{99.989}$ value for the west sampler in the summer, a backgrond station, was essentially the same as for the north and south samplers; finally the higher $C_{99.989}$ in the winter than in the summer is consistent with the significantly higher average background concentration in the winter than in the summer (see figure 10.14).

10.1.5.5 Ground-Level Concentration Distribution

Ground-level concentration studies were conducted to describe the variation in above-background NO_x concentrations from the TE plant in the general path of downwash plumes from the plant. The main technique used was a horizontal profile consisting of a 30 to 60 minute run - an array of 12 to 16 portable air bag samples positioned from 50 to 300 ft (15 to 100 m) from the plant stacks. The horizontal profile data was supplemented by above-background NO_x data from the stationary samplers; NO_x data from these samplers were correlated with wind speed data and engine rates estimated from the engine load. In addition to determining the concentration of NO_x above background for a given wind condition, the stack-to-ground dilution was characterized in terms of $\frac{\mu\chi}{Q}$ values, where x = ground-level mass concentration, micrograms/m^3, Q = mass emission rate, gm/s, and m = mean wind speed, m/s. The reason the parameter $\frac{\mu\chi}{Q}$ is used to characterize plume dilution rather than the specific concentration, $\frac{\chi}{Q}$, is that the first order "ventilating" dilution effect of wind speed is removed leaving mechanical and atmospheric turbulence as the dominant mechanisms of plume dilution. The $\frac{\mu\chi}{Q}$ data were calculated from NO_x emission and ground-level concentration data using the estimated NO_x emission rate for the engine load and for some profiles using the SF_6 tracer gas technique.

The horizontal profile results typically showed widely-scattered data and patterns of multiple concentration peaks as opposed to any clearly discernable or uniform concentration pattern. Such non-uniform ground-level concentrations apparently result from the random eddy motion in the downwashed plumes that exposes specific locations to different peak concentrations over a sampling period as short as 60 minutes. Because of the scattered nature of the basic horizontal profile data, little confidence can be placed in results based on calculated $\frac{\mu\chi}{Q}$ and therefore strong conclusions about the site dispersion characteristics could not be developed in reference [10-1].

10.1.6 Summary and Conclusion

The results of the air quality assessment of the Jersey City Total Energy Site can be presented at two levels. The first level of results deals with the general characteristics of pollutant dispersion from this distillate oil-fueled, diesel-combustion process emitting 3-5 kg/h of gaseous pollutants, predominantly nitrogen oxides, from exhaust stacks lower than the height of surrounding buildings. The general characteristics of interest are (1) the degree of plume downwash, (2) the TE plant pollutants that contribute significantly to ground level concentrations, and (3) the general level of background pollutants and TE plant contributions at 200 - 260 ft (60-80 m) from the TE plant. The second level of results deals with the micro-scale behavior of the exhaust plume in the complicated building topography surrounding the TE plant. All the results are based on two six-week monitoring periods in 1977, one summer and one winter. As such the results are limited by the range of wind conditions, controlling the dispersion of exhaust emissions, that occurred during the two monitoring periods.

The general results are summarized as follows:

1. Plume downwash begins with average wind speeds of 3.5 mph (1.6 m/s), and an increasing fraction of the plume is drawn into the wake of the CEB with increasing wind speed. Local wind speeds above the 3.5 mph (1.6 m/s) threshold occurred about 50 percent of the time.

2. Of all the combustion pollutants, only nitrogen oxides, NO_x, were detectable at ground level. The diesel engines were the major contributor, greater than 90 percent of the NO_x emissions during a winter month.

3. Concentration of NO_x from the TE plant at ground level averaged from 0.03 to 0.05 ppm at distances of about 230 ft (70 m) from the CEB. These concentrations represent from 60 to 100 percent of the allowable annual average concentration, 0.05 ppm, for NO_2 in accordance with the Federal Air Quality Standards (FAQS). In addition, background levels of NO_x ranged from about 0.04 ppm during the summer to about 0.08 ppm during the winter. The combination of the TE plant emission and the local background creates the potential for the average NO_2 concentration to exceed the allowable NO_2 concentration of 0.05 ppm in the air within about 210 ft (65 m) of the CEB. Maximum one-hour NO_x concentrations projected for once per year reach about 1 ppm.

4. The background levels of SO_2 exceeded the allowable annual average FAQS values by 100 percent during the summer period. The maximum CO level was well below the applicable one-hour allowable FAQS value. The average hydrocarbon concentration was at the allowable maximum three-hour concentration (6-9 a.m.) if methane is less than 88 percent of the total hydrocarbon concentration.

The combination of exhaust plume observations and horizontal profile measurements of ground-level pollutant distribution indicate the following relative dispersion behavior in the area of 33 to 295 ft (10 to 90 m) from the CEB:

1. For moderate wind speeds 6 mph (2.7 m/s) dilution is lowest to the south of the CEB - in the area bounded by Shelley B, Descon-Corcondia, and the school - and highest to the north of the CEB.

2. Except for the area to the south of the CEB, specific concentrations decrease significantly with distance at intermediate wind speeds of 3.5 to 8 mph (1.6 to 3.6 m/s) in the area of 195 to 295 ft (60 to 90 m) from the CEB.

3. The TE plant exhaust plumes do contribute detectable NO_x concentrations up to 33 ft (10 m) from the CEB even at low wind speeds of 3.5 mph (1.6 m/s). The behavior is caused by part of the plume being caught in random eddies generated by the wind flow around the CEB and other up-wind buildings. This random wind behavior persists for winds up to 12 mph (5.4 m/s) as opposed to complete trapping of the exhaust plume into the cavity of the CEB.

As a result of the air quality monitoring and assessment at the Jersey City Total Energy Site, several general conclusions are drawn that pertain to the siting of diesel engine TE plants in urban areas:

1. The general level of NO_x and total oxidants in the background is important in assessing the potential air quality impact of a TE plant.

2. For a TE plant with exhaust discharged at a height comparable to surrounding buildings, the average NO_x concentration increase within 295 ft (90 m) of the TE plant can be a significant fraction of the allowable annual arithmetic average concentration for NO_2 of 0.05 ppm. Since the allowable concentration for NO_2 is based on limiting the formation of photo-chemical smog, the observed NO_x levels are of concern only during periods of high background levels of non-methane hydrocarbons and ozone to catalize the smog formation reaction.

10.2 NOISE LEVEL ASSESSMENT

10.2.1 Scope of Study

The purpose of the noise assessment was to determine the general impact of normal TE plant activities on the Summit Plaza site and adjacent areas. Five diesel-engine generators, a stack dilution fan, the solid waste disposal system (truck transfer), and the cooling towers were the main sources of noise from the CEB. All these activities are continuous in nature except the transfer of solid waste from the site which was done by diesel truck approximately twice a week. No noise survey data were obtained during this operation.

10.2.2 Data Collection

10.2.2.1 Pre-Construction Period

Noise data were collected in September 1970, prior to any construction activity on the Summit Plaza site. This pre-construction noise survey consisted of around-the clock, sequential measurements at seven locations on the vacant site. Data were collected in the form of three-minute tape recordings and subsequently subjected to statistical analysis by digital computer. A complete description of the methods and results of these tests are contained in reference [10-6].

The pre-construction noise survey provides valid data on background traffic noise levels near the streets bordering the Summit Plaza site. Assuming no significant change in traffic density or patterns, these 1970 data are applicable during the operating period. The pre-construction survey also provided data interior to the site, but since the site itself substantially changed with the new buildings, the applicability of these data as measures of background noise levels in the absence of the TE plant is somewhat limited.

10.2.2.2 Operational Period

Noise data were also collected during July and August of 1977 in five one-hour sampling periods between 8:00 a.m. and 9:00 p.m. During these tests, three engines were operating at electrical loads between 1075 and 1275 kW. Wind varied in direction and speed; however, average wind speeds during all surveys were no greater than 8 mph (3.5 m/s). The stack dilution fan and the cooling tower fans were operating during all surveys [10-1].

The south wall of the CEB has five pairs of doors, one opposite each engine, that provide access during minor and major overhaul. These doors are opened occasionally during routine maintenance in hot weather to improve the comfort of maintenance personnel. It was anticipated that this would cause a significant increase in sound levels in the area south of the CEB and therefore, a survey was performed with two doors open. The frequency with which one or more doors are opened in actual practice is less than once per week, i.e., less frequently than the solid waste pickup. Thus this condition is somewhat anomalous and is trated as such in the noice impact evaluation.

Sound level measurements were made with a hand-held, "A" weighted frequency response Gen. Rad. 1981-B Precision Sound-Level Meter yielding sound levels in dB(A). Measurements were made four feet (1.22 m) above the ground in the areas generally to the north and south of the CEB. Recorded sound level values excluded transient contributions from individual trucks, planes, or humans.

10.2.3 Results

Each of five surveys during the operating period showed essentially similar results. Figure 10.15, taken from reference [10-1] shows typical estimated sound level isopleths in the area within 200 ft (61 m) of the CEB.

As one might expect, the engine-generators are the major source of noise from the TE plant operation. The maximum sound levels on the south face of the CEB directly opposite the operating engines were 74-75 dB(A) with the engine doors closed and up to 85 dB(A) with a pair of doors open opposite one of the three operating engines. The open doors also raised the sound level from 8-10 db(A) in the area between the north end of the Descon-Concordia building and the west end of the Shelley B building [10-1].

Figure 10.5 shows that the site is dominated by two noise sources, the CEB (engine-generators) at 74-75 dB(A) and the Newark Avenue street traffic at 70 dB(A). Prior to site construction, traffic generated noise was measured at an average value of 61 dB(A) for the daytime and an average 57 dB(A) for the night. At the time, peak traffic noise values of at least 65 dB(A) during the daytime and 60(A) at night were experienced 10 percent of the time [10-6]. Thus the TE plant could potentially have a greater impact on site noise levels than the traffic on Newark Avenue.

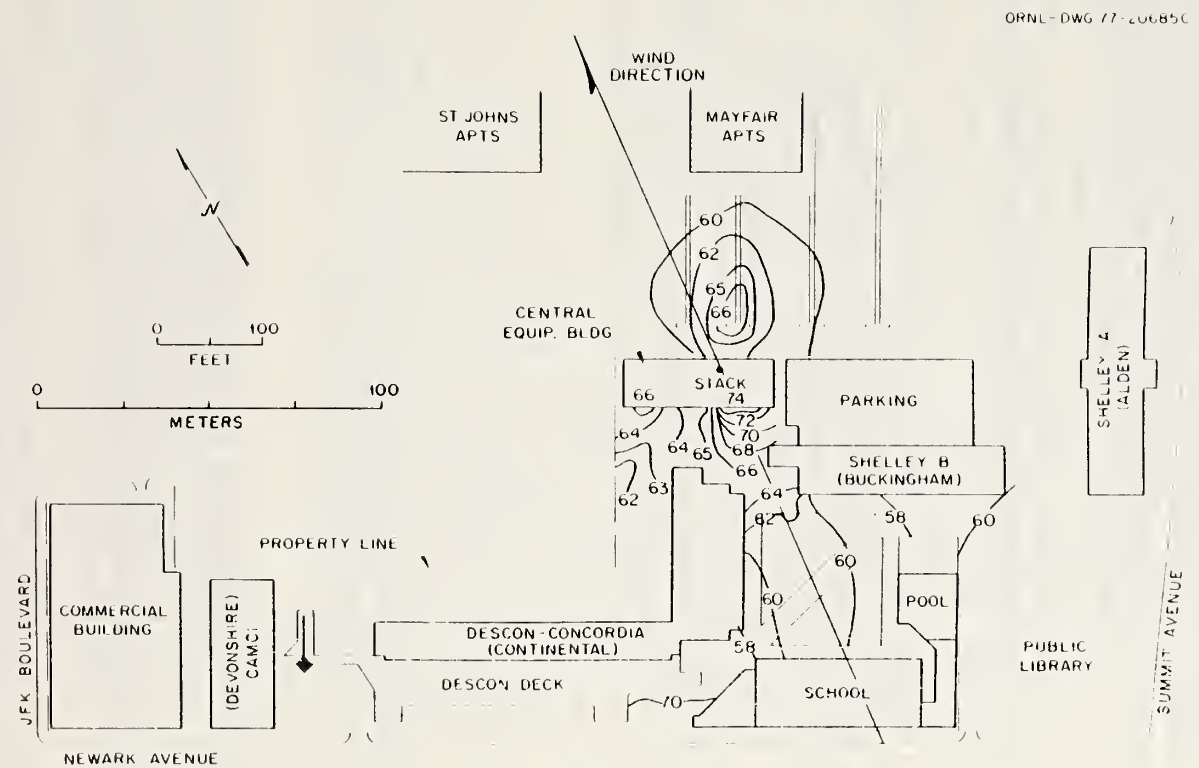

Figure 10.15 Noise levels in dB(A) around the Central Equipment Building during 8–9 a.m., August 4, 1977

A given increment in noise above background levels would be most acutely sensed in the courtyard area of Summit Plaza where people recreate and where the windows and balconies of the Shelley B and Descon apartment buildings face. An examination of the noise levels in the courtyard (bounded by Shelley B, Descon, the school, and the pool) as shown in figure 10.15 indicates a maximum noise contribution from the CEB of about 4 dB(A) since the noise levels continuously decrease from 62 to 58 dB(A) with increasing distance from the CEB.

Other detectable noise sources from the CEB are the absorption chillers in the east end of the CEB and the exhaust stack dilution fan mounted below the engine exhaust stack. The chillers cause an approximate 66 dB(A) peak on the south wall, west end, of the CEB while the dilution fan causes approximately a 66 dB(A) peak sound level in the parking lot north of the CEB (see figure 10.15). However, the dilution fan contribution blends into the background at the near proximity of the Mayfair and St. John's Apartments, resulting in rather minimal impact on outdoor recreational areas and no impacts on the interior building environment.

Careful examination of figure 10.15 and similar data in reference [10-1] indicates that the positioning of the TE plant on the site in relation to the other buildings has minimized overall noise impacts. The close proximity of the Shelley B and Descon buildings permit a relatively narrow path for transmission of CEB noise into the Summit Plaza courtyard. In addition, the end walls of these two apartment buildings facing the CEB are windowless except for corridor windows in Shelley B. Thus the noise levels of 64 to 66 dB(A) at these walls should have minimal impact on interior noise levels. Also the siting of the TE plant adjacent to the open parking lot allows peak noise levels on the north side of the plant to be dissipated before reaching the Mayfair Apartments as previously stated.

10.2.4 Comparison with Local Standards

In 1978, a noise control code was established for certain municipalities in Hudson County, which includes Jersey City. The sound level limit in the code is 65 dB(A) for residential, public space, or open space between 7:00 a.m. and 10:00 p.m. Between 1:00 p.m. and 7:00 a.m., the limit is 50 dB(A). For commercial or business land-use categories, the sound level limit is 65 dB(A) at all times [10-7].

The results of the surveys with all doors on the CEB south wall closed show the daytime 65 dB(A) limit is exceeded from the TE plant only in the limited area within about 75 ft (23 m) south of the CEB. It should also be noted that the 65 dB(A) daytime limit was also exceeded on the south side of the Summit Plaza site from traffic activity on Newark Avenue (see figure 10.15).

With regard to the nighttime residential limit of 50 dB(A), no data during the operational period was taken past 9:00 p.m. However, the operational data taken in the early evening (8:00 p.m.) and the nighttime pre-construction data indicate that the background noise from traffic far exceeds this level and that the sound level in the courtyard at Summit Plaza also exceeded this level by up to 5 dB(A). At the time the data was taken, the incremental impact of the TE plant appeared to be a maximum of about 4 dB(A) in the courtyard [10-1].

10.2.5 Summary and Conclusions

This brief study of noise levels at the Summit Plaza mainly addressed the contribution of continuous operations of the Central Equipment Building (CEB) and the urban surroundings. The major findings of this study are summarized as follows:

1. Of the continuous operations, the engine-generators cause the highest noise levels, predominantly to the south of the CEB. The second highest noise level source is the engine exhaust fan motor causing increasing noise levels predominantly to the north of the CEB. Traffic-generated noise is intermediate between the two major CEB sources.

2. During normal operation, with all doors closed on the south wall of the CEB, the maximum noise level is 74-75 dB(A) at the south wall of the CEB regardless of which engines operate or the total engine load. The maximum noise level increased to 85 dB(A) with two doors open on the south wall opposite the engines.

3. The area exposed to noise levels greater than 65 dB(A), the daytime limit of the local noise ordinance, is limited to about 75 ft (23 m) south of the CEB.

4. The nighttime background noise level in the interior of Summit Plaza from surrounding urban activities is approximately 55 dB(A).

The major conclusions of this study are as follows:

1. The noise contribution from the CEB does not exceed the 65 dB(A) daytime limit of the local noise ordinance at the exterior walls of any adjacent residential buildings under normal operating conditions (with the doors of the CEB closed).

2. The nighttime noise level limit of 50 dB(A) for residential space is probably exceeded at Summit Plaza from the surrounding urban activities alone.

3. The TE plant appears to increase noise levels in the courtyard of the Summit Plaza site by a maximum of 4 dB(A) and in the parking lot of the adjacent Mayfield Apartments by a maximum of 6-8 dB(A).

4. If the TE plant had been constructed on Newark Avenue (i.e., on the part of the site with the highest background noise concentration), its impact may have been lessened.

5. Overall site design including the juxtaposition of the CEB, Shelley B, and Descon buildings and the location of the CEB adjacent to a parking lot combined to minimize its noise impact on Summit Plaza recreational areas and building interior noise levels.

10.3 COOLING TOWER ASSESSMENT

10.3.1 Scope of Study

Two wet cooling towers are used in the TE plant for heat rejection from the absorption chillers during the summer cooling season. The types of potential environmental effects from the cooling towers are chemical toxicity and aesthetic in nature -- plume visibility and nuisance effects of drift deposition. Since the cooling tower water is treated with a chemically benign additive and the plume is rarely visible during the warm summer season, the main consideration became the aesthetic nuisance effects of drift transport deposition. Therefore, the drift emission characteristics of the cooling towers was measured as a prerequisite for the possible calculation of drift transport and deposition. Also, field measurements of drift deposition and concentration were made in the area within 200 ft (60 m) of the CEB.

Subsequent to cooling tower emission measurements, the combustion emission study results showed that the complicated wind flow in the area of the CEB would require a significantly greater effort than was planned for modeling drift transport by the cooling tower plume during building downwash conditions. Since the nuisance effects from the drift deposition were fairly obvious during the on-site monitoring period, a drift transport modeling effort for this unique cooling tower installation was not justified. The remainder of this section presents a summary of the results of drift emission measurements obtained between August 2-12, 1979. The nusiance effects of the observed drift conditions are also discussed. The material in this section is derived exclusively from reference [10-1].

10.3.2 Cooling Tower Operation

10.3.2.1 Description

The towers under investigation are two Baltimore Aircoil Co., Inc., Model No. VST-1050S counter flow, forced draft cooling towers with three cells each and a design circulation water flowrate for the total system of 4440 gpm (0.28 m^3/s). The towers employ three-break galvanized steel drift eliminator blades with hooked trailing edges. In addition, sound attenuation panels are located above in the plane of the drift eliminators.

The towers are located next to one another atop the CEB and are separated by approximately 3.5 ft (1.1 m). The updraft air exit plane of the towers is located approximately 23 ft (7 m) above the central roof section of the CEB. A top view schematic of the two towers is shown in figure 10.16 with the individual cell designations included. The lines in each cell represent the structural members supporting the sound attenuation panels.

10.3.2.2 Operating Conditions

Each cell has a constant speed fan mounted underneath the tower creating a vertical flow of air to remove heat from the tower water. During the period of the drift measurements, the fans for all cells except cell no. 6 were on continuously.

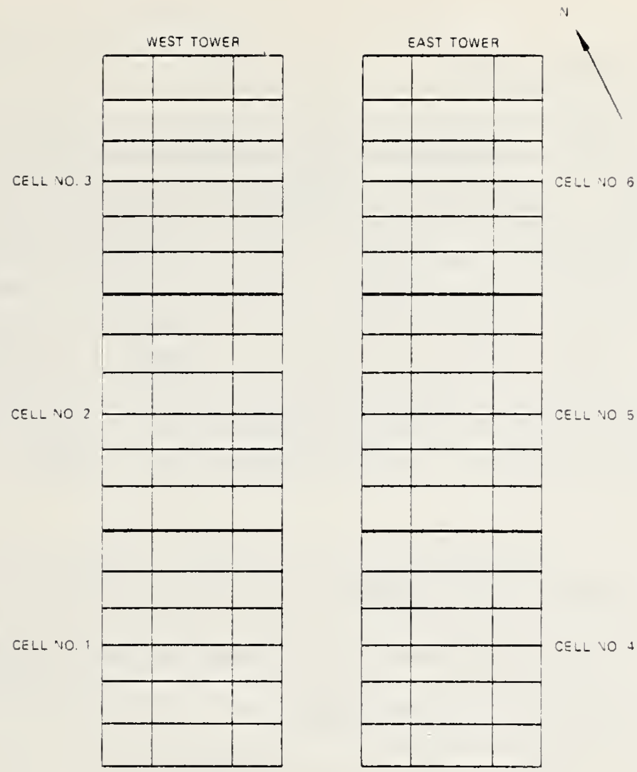

Figure 10.16 Cell designation for TE plant cooling tower

Prior to the measurement period, excessive drift of large droplets had been noted particularly from the west cells, nos. 1, 2, and 3. The plant operating staff determined that debris had accumulated in the distribution headers and in the nozzles that normally direct the water flow downward against the air flow. In some cases, the nozzles had plugged and been forced out of the distribution headers. The water flow then discharged horizontally, resulting in much larger droplet size distribution and much greater drift loss from each cell. During the period of the drift measurements, the plant operating staff removed the debris from the distribution headers and replaced most of the plugged or restricted nozzles with new nozzles. This action returned the water distribution in the headers to normal; however, the drift loss was still abnormally high in certain locations where replacement nozzles were not available.

As a result of the cleaning maintenance performed on the cooling towers, drift measurements were made before and after the maintenance allowing a comparison of drift characteristics to be made.

10.3.2.3 Chemical Treatment

Metallic cooling towers require addition of a chemical to prevent corrosion and mineral scale deposition on the metal surfaces of the tower. The treatment chemical used at the TE plant is a proprietary Calgon Corporation product, designated "CLD-709," which contains the organic phosphonate, amino methyalene phospanate (AMD). The chemical is bicdegradable and low in toxicity, containing no chromates and used in the ph range of 7.0 to 8.2.

10.3.2.4 Heat Rejection Load

The heat rejection load of the cooling tower is coupled to the operation of the absorption chillers that provided chilling water for space cooling from May to September. The space cooling load and heat rejected to the cooling tower varies diurnally with the mean ambient temperature. The heat rejection rate of the cooling towers was normally monitored by the NBS Data Acquisition System (DAS). Because of an outage of the DAS during the drift measurement period, direct measurement of the tower heat rejection rate was not available. However, an estimate was made based on other periods of similar maximum and average ambient temperatures of 85-90°F and 79-82°F, respectively. The heat rejection rate was estimated to be from 14 to 18 x 10^6Btu/h (4.1 to 5.3 MW) during the late morning to afternoon when drift measurements were made.

10.3.3 Measurements

10.3.3.1 Cooling Tower Drift Source

The objective of the cooling tower drift source measurements was to characterize the cooling tower drift effluent at or near the fan stack exit plane with acquisition of the following parameters:

1. the rate of liquid drift mass emission
2. drift liquid mass emission rate as a function of droplet diameter
3. drift mineral mass emission rate
4. updraft air speed, and
5. updraft air temperature.

In addition, samples of circulating water were required for determination of its mineral concentration.

In order to meet this objective, the following instruments were employed:

1. ESC* PILLS II (Particulate Instrumentation by Laser Light Scattering) electro-optical monitor for determination of the rate of liquid drift mass emission and its distribution over the droplet diameters.

2. ESC Sensitive Paper (SP) System for determination of the rate of liquid drift mass emission and its distribution over the droplet diameters (a technique complementary to the PILLS System).

3. ESC Heated Glass Bead Isokinetic (IK) Sampling System for determination of the drift mineral mass emission rate.

4. Propeller anemometer for measurement of updraft air velocity.

5. An electronic psychrometer for determination of the wet and dry-bulb temperatures of the updraft air.

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* ESC = Environmental Systems Corporation.

10.3.3.2 <u>Ground-Level Measurements</u>

The objective of these measurements was to characterize the cooling tower drift deposition characteristics at ground level from plume transported drift rather than the largest drift droplets that were transported by exit momentum from the tower. The rationale for this measurement strategy was that the high drift fallout close to the CEB was a temporary situation that would be remedied by cooling tower maintenance work. This strategy was verified by observing a significant reduction in drift fallout close to the CEB after the maintenance work was concluded.

In order to characterize the drift transported away from the cooling towers, five mobile ground-level data acquisition stations were employed. These stations were located from 65 to 100 ft (20 to 30 m) from the cooling towers. Each station was capable of acquiring the following parameters:

1. airborne droplet mass concentration as a function of droplet size,
2. airborne drift mineral mass concentration,
3. droplet mass deposition flux as a function of droplet size, and,
4. drift mineral mass deposition flux.

The measurements of mineral mass were directed at suitable elements present in the cooling tower circulating water (N_a in the form of salts, and Z_n in the form of oxides of zinc) just as with the mineral mass emission at the tower exit plane.

Concentration measurements were acquired by using ESC Airborne Particle Sampler (APS) units. The APS unit consists of motor-driven arms which sweep sampling elements through the air, collecting droplets and minerals through inertial impaction. A meter counts arm revolutions to determine air volume sampled and a fan assures fresh air input even under calm conditions.

Deposition flux measurements of water and minerals were made by two separate techniques. Droplet mass deposition flux and droplet size was determined by a sensitive paper (SP) technique. Mineral deposition was measured by sample collection on a clear surface with a subsequent distilled water wash and final analysis by flame emission spectophotometry.

10.3.4 Results

This section presents the major results of the measurements performed to characterize the cooling tower drift source and the drift deposition characteristics. The major conclusions with regard to the nuisance effects from the cooling tower operation are also presented.

10.3.4.1 <u>Cooling Tower Drift Source Results</u>

Average updraft air velocity measurements on the tower were quite consistent from cell to cell varying only $\pm$ 0.3 ft/s ($\pm$ 0.1 m/s), about an average value of 14.4 ft/s (4.4 m/s). The total volumetric air flow rate of the tower was calculated to be 6957 ft^3/s (197 m^3/s), a value within 4 percent of the design air flow rate of 6712 ft^3/s (190.1 m^3/s).

In general, most wet and dry-bulb updraft air temperature readings were the same (within the uncertainty of the instruments) indicating saturated air. Wide variation was exhibited in the air temperature from point to point within cells with maximum differences between points in a cell varying from 39°F to 48°F (3.7°C to 9.2°C). The average temperature difference between cells, was in general, less than the variation in temperature observed within a cell.

Liquid drift measurements performed on five cells showed individual cell emission values ranging from 2.30 gm/s (#3 "before") to 0.0466 gm/s (#5 "after") corresponding to drift fractions of .00493 percent and .0000956 percent, respectively, of the design circulating water flow rate. Mass median diameters of the droplet emissions varied from 484 μm to 758 μm and were two or three times the values commonly measured on induced drift cooling towers. The concurrent maintenance of the cooling tower water distribution headers afforded the opportunity for "before" and "after" measurements on cell #3 with the "after" measurements showing an improvement (decrease) in drift emission of over one twentieth of the "before" value. Total tower emissions characteristic of conditions after maintenance were calculated to be 1.63 gm/s; however, it is believed that substantial improvement could be made in this figure with a combination of the maintenance work which was ongoing during the measurements and some work on sealing gaps between the drift eliminator panels.

Analysis of the cooling tower basin water for sodium and zinc showed the sodium concentration during the test period varying between 408 and 545 ppm while the zinc concentration steadily decreased from 5.45 to 1.28 ppm. Measurements of mineral mass emission of the individual cells show sodium emissions varying from 1776 μg/sec (cell #3, 8/5-6/77) to 205 μg/sec (cell #4, 8/8/77). Total mineral emission for the tower was calculated to be 1804 μg/s for Na and 190 μg/s for Zn. Again, the sodium was in the form of salts and the zinc in the form of oxides of zinc.

10.3.4.2 Drift Deposition Results

Measurements of the airborne mineral concentrations (Na and Zn) varied across all station locations only within ± 15 percent of the average daily concentration for each day's run. On August 5, a much larger average sodium concentration (1.33 $\mu g/^3$) was observed than on other days (0.115 to 0.224 $\mu g/m^3$), which may be due to the fluctuating ambient sodium concentration. The range of measured values over all runs ranged from 0.095 to 1.53 $\mu g/m^3$ for sodium and from 0.012 to 0.22 $\mu g/m^3$ for zinc.

Unlike the mineral mass concentration measurements, droplet mass concentrations varied as much as 2 to 3 orders of magnitude between all stations of a single day's run. Measured concentrations over all runs ranged from 0.023 to 132.6 $\mu g/m^3$, and mass median droplet diameters ranged from 41 to 840 μm.

Of the mineral mass deposition measurements, 32 percent of the sodium and 20 percent of the zinc samples were less than the average background. Averaged over all samples, the collected amounts were about twice the respective average backgrounds. Sodium deposits fluxes ranged from 8.78 to 250 kg/km^2.mo over all runs, and zinc deposition fluxes ranged from 0.104 to 17.1 kg/km^2.mo.

Droplet mass deposition flux measurements vary up to 3 orders of magnitude across all stations for a day's run. Measured values over all runs ranged from 114 to 426,000 kg/km^2.mo, and mass median droplet diameters range from 117 to 613 μm.

Two quantitative measurements of drift transport from individual time periods were compared at upwind and downwind sampler stations. These comparisons indicated that in general no significant amount of cooling tower drift material was detectable above the background concentrations or deposition fluxes.

In contrast to the inconsequential quantitative results from the Airborne Particle Samplers and deposition collectors, the qualitative observation of drift fallout within about 50 ft (15 m) was equivalent to a light drizzling rain before the maintenance work was performed on the cooling tower. The dramatic, although not complete, reduction in drift loss, after the cleaning of the distribution headers and nozzles, resulted in a reduction in drift fallout to the point that the fallout was barely detectable to a person downwind of the towers. Additionally, the reduction in drift deposition also eliminated the noticable accumulation of a residue on cars parked within about 50 ft north of the CEB when southerly winds prevailed. This deposition on cars belonging to residents of the adjacent St. John's apartment complex was the most significant nuisance effect of the degraded CEB cooling tower performance.

10.3.5 Conclusions

The major conclusions of this study of the cooling tower operation at the Jersey City Total Energy Plant are as follows:

1. The cooling towers require occasional maintenance to preserve good flow distribution and drift loss characteristics.

2. The drift loss obtained with these cooling towers can be a very acceptable level of 1×10^{-4} percent when properly cleaned and drift eliminators are positioned correctly.

3. Drift deposition from transport by the coolng tower plume was indistinguishable from ambient concentrations of moisture and minerals (Na and Zn).

4. The major nuisance effect from the abnormally high drift loss, prior to the maintenance work on the cooling towers, was from a spotty deposition on parked cars to the north of the CEB. This situation, which is preventable by proper maintenance, could result in significant ill-feelings towards the owner/operator of the TE plant. Therefore, adequate justification exists for periodic inspection and maintenance procedures to be developed and followed to keep the cooling tower drift loss characteristics within acceptable limits.

10.4 REFERENCES - SECTION 10

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10-6. Qunidry, T. L., Fisher, R. L. and Blomquist, D. S., "Noise Survey of the Jersey City Operation BREAKTHROUGH Prototype Site," National Bureau of Standards Report 10219, Revised, October 1972.

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11. RELIABILITY EVALUATION

11.1 SCOPE AND DEFINITION

Two aspects of reliability are considered in this evaluation: "availability" and "quality of service." Availability refers to the continuity of function of service. It can be examined from the standpoint of plant components and/or from a customer service standpoint. The availability of each type of equipment (e.g., boilers, engine-generators) and of each utility service (hot and chilled water and electricity) must be evaluated separately. Major emphasis is placed on electrical reliability in this section since the electrical subsystem is the key subsystem in the TE plant to distinguish it from more conventional systems for supplying the same services to the site.

The major emphasis for the availability analysis was from the customers' standpoint. This "service availability' analysis was carried out by measuring interruptions of utility service to the customer. The performance of individual components within the plant (analyzed by measuring equipment outages) was examined only in a cursory manner.

Quality of service refers to the degree of excellence or acceptability of the service when examined from the customer's standpoint. This investigation is only relevant for periods during which the utility service is fully available. The evaluation of quality of service for Summit Plaza must include hot water, chilled water, and electricity. Again, major emphasis is placed on the quality of electrical service.

Figure 11.1 shows the relative priorities described above for the reliability evaluation.

11.2 ELECTRICAL SERVICE AVAILABILITY

Electrical service availability was evaluated by determining the number, extent and causes of interruptions of customer service. Several types of electrical service interruptions are currently defined (see appendix M) and are applicable to Summit Plaza. However, before the means used to measure service interruptions are discussed, additional information is given on the design of the TE electrical system and the available sources of interruption data.

11.2.1 Electrical System Design Features

Electrical Distribution - The electrical distribution system at Summit Plaza is a configuration specially designed for the use with on-site power generation. Two sets of 480-volt, three-phase feeders are used to every building. One set of feeders supplies "essential" loads within the building such as emergency lighting, fire protection, and one elevator. The other, "normal", feeder supplies all other loads. During normal plant operation, power to both sets of feeders is supplied by the TE plant. When a total plant outage occurs, power to the essential feeder only is supplied by the local utility company.

Investigative Area	Availability	Quality of Utility Service	
View point characterized by	Component (outages)	Interruptions	Quality
<u>Subsystem</u>:			
Electrical	L	H	H
Heating	L	M	M
Cooling	L	M	M

Relative priorities: L = Low, M = Medium, H = High

Figure 11.1 Relative priority of areas for reliability evaluation

Control System - The automatic control system for the engine-generators contains a load shedding capability which can interrupt service to various segments of the load. Need for this can occur during an overload condition or through equipment malfunction whenever a standby engine-generator is not brought on line rapidly enough to provide adequate capacity [11-2].

The site is divided into ten (10) load segments which can be sequentially interrupted after an initial voltage reduction of 10 percent. Load segments include auxiliary loads within the TE plant as well as the individual buildings. The essential load circuit is the last segment to be shed from plant generation. When the essential load is disconnected from the plant supply, it is automatically connected to the utility standby service, thereby receiving virtually uninterrupted service.

11.2.2 Sources of Availability Data

DAS - The DAS began collecting data in April 1975 for the TE plant only. Collection of data for individual buildings began in November 1975. For monitoring of electrical service availability, the DAS provided basic data such as kWh and voltage at various points within the TE plant and at each of the individual buildings. Deviations in gross energy production at the TE plant indicated probable interruption events. The data for individual buildings quantified partial interruptions more fully in terms of specific buildings and magnitude of load loss. Since the DAS recorded data every 5 minutes, the duration of interruptions could be determined within $\pm$ 2.5 minutes.

kW Record - Prior to the start-up of the DAS (and during periods in which the DAS was inoperative) other sources of data had to be utilized. First, a continous-strip chart recording of gross kW production covered the entire period from 1974 to the present. This strip chart was maintained by plant personnel and provided a primary source of data. The strip chart recordings also helped to identify when interruptions had occurred so that the DAS data could be more efficiently accessed. The strip chart could not, however, show the duration of total interruptions since it was not powered from the essential service line.

Narrative Logs - Principal sources of data for identifying the causes of the equipment outages which resulted in service interruptions were found in various narrative log books kept by the plant operator and NBS. Often these also provided some indication of the duration of interruptions in the absence of DAS data.

Utility Bills - As a final cross-reference, the monthly bills from the electric utility were used. In addition to charges for standby service, these bills also registered the quantity and cost of any energy used. This source thereby gave an approximate indication of total interruptions for each month.

11.2.3 Service Availability Methodology

Availability Measures - A number of measures have been developed for evaluating the availability of electric utility systems from the standpoint of customer service [11-3, 11-4]. Four basic measures were selected for this evaluation:

- number of interruptions in a given time period (e.g., year)
- total duration of interruptions in a given time period, minutes
- average duration of interruptions, minutes
- maximum duration of any one interruption, minutes.

These measures quantify the three important aspects of interruptions: frequency, duration, and magnitude. A basic building-block in developing these measures was a "customer interruption."

Accounting Approach - For the Summit Plaza TE plant, two means of accounting for service interruptions were possible depending on how a "customer" was defined, and how partial interruptions (see appendix M) were handled. First, each of the individual buildings could have been considered a single customer. For partial interruptions, an accounting would have been made of those buildings without service. Data would then have been presented using the established measures as if the TE plant were a utility supplying six customers (the four apartment buildings, plus the commercial and school facilities). Three problems were inherent in this approach:

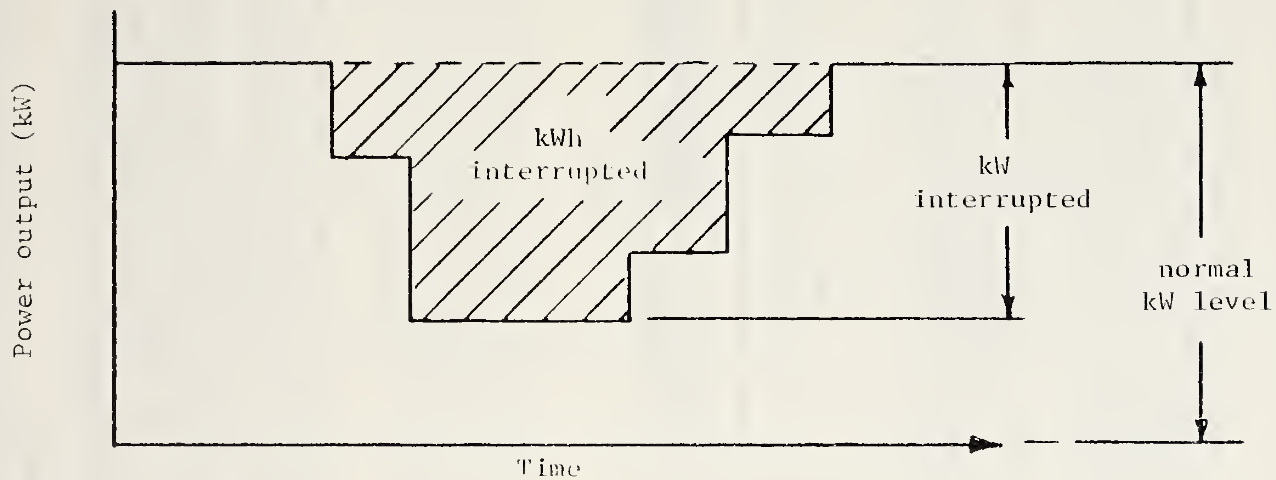
- accounting for partial interruptions which involved only TE plant equipment
- an assumed customer equivalence in terms of load magnitude
- difficulty in identifying the buildings curtailed during partial interruptions prior to November 1975.

These problems were overcome by using a second approach which considered the site as a single customer. Partial interruptions were treated as an "equivalent" total interruption, using plant kW output as the basic measure of service. This accounted for differences in the load demand of the various buildings, including in-plant loads. In generic terms, this was equivalent to the aforementioned approach in the special case where all customers had the same kW demand. This approach is further explained below

Partial Interruptions - Partial interruptions were classified based on coincidence with total interruptions (see appendix M). This was necessary because a partial interruption which was an extension of a total interruption was not counted as an additional interruption event.

In accounting for partial interruptions, the duration and number of individual partial interruptions were adjusted to an equivalent total interruption basis as shown in figure 11.2. The equivalent duration of a partial interruption (both coincident and isolated) was defined as the duration of a total interruption which would have resulted in the same energy curtailment. This calculation entailed determining the energy curtailment of a partial interruption in kW-min and dividing this value by the "normal" or uninterrupted power demand (in kW) of the total site during the interruption.

The equivalent number of isolated partial interruptions was calculated by the actual power demand curtailed as a fraction of the normal power demand. For example, a partial interruption which resulted in an actual load curtailment (in kW) of 50 percent of the normal power demand would be counted as 0.50 interruption.



$$\text{equivalent number} = \frac{\text{kW interrupted}}{\text{normal kW level}}$$

$$\text{equivalent duration} = \frac{\text{kWh interrupted}}{\text{normal kW level}}$$

Figure 11.2 Accounting procedure for partial interruptions

11.2.4 Availability Data Summary

All interruptions occurring during the period from plant start-up in January 1974 through December 1977, were examined. The duration, cause, and type of interruption were noted and the appropriate measures described above calculated. For the period prior to September 1974, some data could not be accurately determined and therefore, some uncertainty exists in the aggregated measures of reliability.

Three interruptions stemming from outages occasioned by NBS actions were deleted from the analysis. These interruptions were assumed to be atypical for commercial TE plants not subject to third party data collection efforts. Momentary interruptions (for a definition, see appendix M) were also not included in the analysis, since these are not normally included in utility system outage data.

Table 11.1 presents yearly aggregated data for electric service availability at the Summit Plaza site. For the year 1976, table 11.1 also includes data considering forced interruptions only since scheduled interruptions (not likely to be repeated in the future) significantly affected overall availability levels in that year.

Table 11.1 Summit Plaza Total Energy Plant
Electrical Service Availability

Year	No. of Interruptions	Interruption Duration, Minutes Total	Average	Maximum
1974	12.8	2474	193	1869
1975	0.6	5	-	-
1976	11.6	992	86	249
1976[a)]	9.6	591	62	135
1977	2.4	116	48	55

a) Forced interruptions only, scheduled interruptions not included.

This table clearly shows that the availability record of the TE plant has varied considerably. Two of the four years (1974 and 1976) had poor availability while two years (1975 and 1977) were considerably better. The year 1975, with its nearly perfect availability record, is particularly noteworthy.

11.2.5 Temporal Trends

It is expected that a TE system will exhibit changing levels of availability with time. Figure 11.3 illustrates a typical life-cycle availability trend which a TE plant might be expected to follow. The trend includes an early debugging phase with higher failure rates and a normal operating phase with a lower failure rate which is nearly constant over a significant portion of the operating life. An effort was made to relate the early interruption pattern of the TE plant to the first two phases of the life-cycle trend.

The causes for the significant unreliability experienced in both 1974 and 1976 are typical of a plant debugging phase. This was indicated by both the causes of the outages resulting in the interruptions and the nature of plant changes undertaken to prevent reocurrence. Unreliable components were identified and replaced. Sytem capabilities and limitations were identified. Operating and maintenance practices were adjusted. Improved record-keeping procedures were instituted. These interruptions also provided a means for the plant operators to "come up the learning curve" regarding equipment and procedures.

The extended interruptions of 1974 are revealing in several respects. First, a number of individual problems combined to cause massive interruptions. Second, there was difficulty in restoring proper plant operation after the interruptions had occurred. Third, there was a high probability that these interruptions were completely preventable, or at the very least, could have been reduced in severity by more rigorous debugging phase procedures.

The data collected indicates that the debugging phase for the electrical subsystem continued at least through the Summer of 1976 when a scheduled interruption was experienced to modify electrical controls to improve availability.

Although only two total interruptions and one isolated partial interruption occurred during 1977, it cannot yet be concluded that the relatively constant reliability level which is characteristic of normal operation (see figure 11.3) had been reached. It is believed that at least another year of availability data were needed to firmly established this trend.

11.2.6 Outage Causes

The causes of equipment outages which resulted in interruptions were identified from operator logs and NBS observations. The outage cause data, shown in table 11.2, clearly shows that the electrical controls were the single major contributing factor. The uncertain outage causes largely stem from the period prior to mid-1974 during which detailed plant logs were not kept.

The electrical control system can be divided into two groups of equipment. One group consists of electrical and mechanical controls for each individual engine-generator and which are physically located thereon. The other group is the automatic control system located in a temperature-controlled room separate from the engine-generators. These two groups of components interact with each other to affect proper operation of the electrical subsystem.

The engine controls group consists of several components including:

- sensors for determining 14 malfunction/alarm conditions
- a governor system, including an actuator for maintaining proper fuel flow to the engine
- generator exciter.

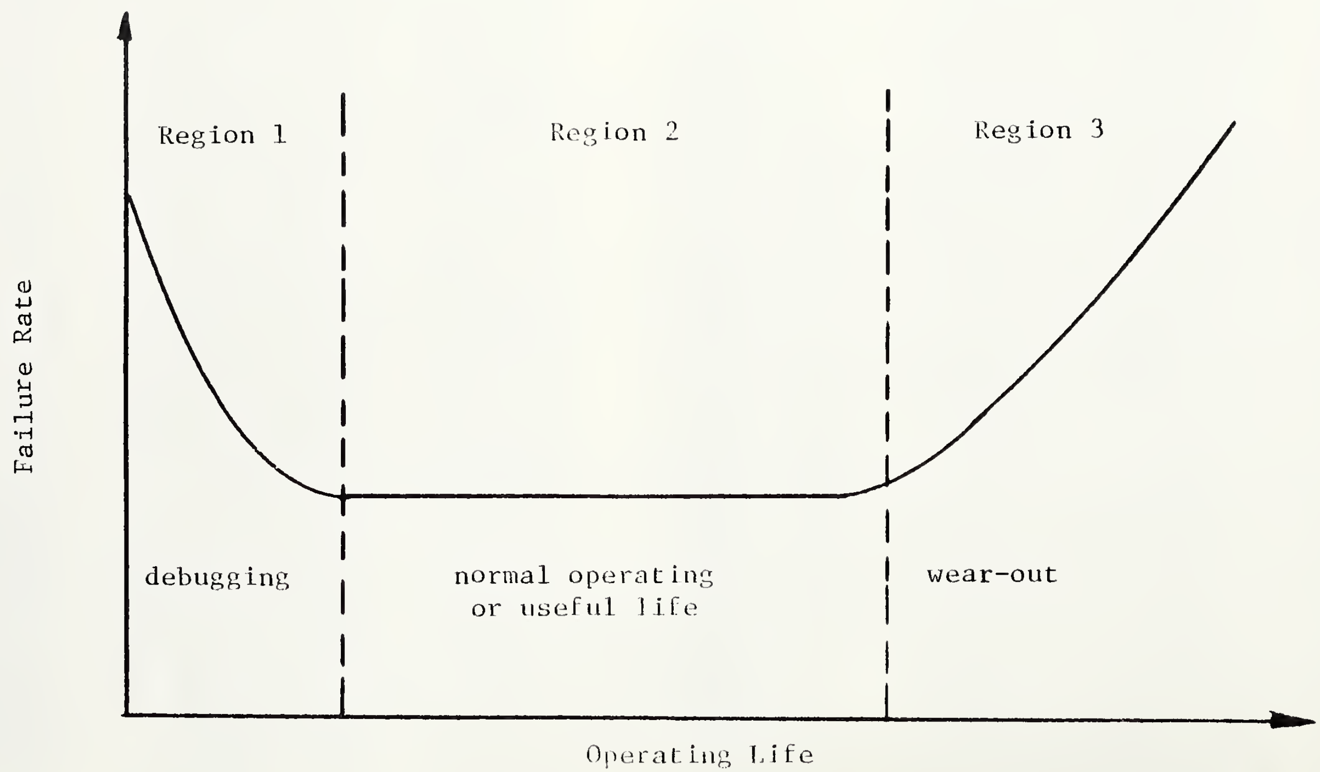


Figure 11.3 Typical failure rate for a TE plant as a function of time

Table 11.2 Number of Interruptions by Outage Cause for the Period 1974 through 1977

Outage cause	Type of interruption: Forced Total	Forced Period	Scheduled (All total)	Total Number
Electrical controls	13	4	2	19
Fuel supply system	2	0	0	2
Operator error	2	0	0	2
Other	0	0	1	1
Uncertain	2	6	0	8
Total	19	10	3	32

The automatic control system group consists of the following functional components:

° engine-generator controls

  speed control (frequency)
  load division
  voltage regulation
  unit start-stop
  alarm indicators

° master control

  unit sequencing
  paralleling
  load shedding
  load demand and capacity matching
  essential load control (utility standby)
  time reference

Components in both groups were the cause of outages resulting in interruptions. The malfunction/alarm sensors and actuators in the engine group and the voltage regulators in the automatic control group were the primary sources of outages.

In a few cases, operator inexperience and maintenance oversights played a contributory role in causing interruptions, particularly in 1974.

The load shedding feature is particularly noteworthy. This system was not originally designed to deal with an unexpected loss of one of the engine-generators. It was mainly intended to cope with lesser electrical imbalances such as load increases which would necessitate an additional engine-generator being brought on-line. Thus the many outages which occurred are not an indictment of the load-shedding feature as designed. Conversely, this feature did not materially assist in achieving high reliability levels.

11.2.7 Sources of Comparative Data

Design Target - The measured availability of the TE plant should be compared first against what was expected or specified in the design phase. In 1970, NBS prepared a performance specification which was used as a basis for system design and component procurement for the Summit Plaza TE plant [11-5]. This specification defined the minimum acceptable levels of performance for the plant. In the area of electrical service availability, these were as follows:

total interruptions time	8 hours per year
total no. of interruptions	12 per year
maximum duration of any one interruption	4 hours

The specification did not distinguish between total and partial interruptions.

Utility Experience - It was desired to make a comparison of the TE plant availability with that of an electric utility. Actual measured data for utility electric service reliability are not readily available. Data are generally not published and in most cases do not have to be reported to regulatory commissions except for large-scale interruptions. Direct contacts with individual utilities, along with a few known sources of published data were utilized to obtain data for the comparisons. Three approaches to these comparisons were developed depending on the source of measured utility data. These approaches and the data sources are described below.

Individual Utility Data - A specific case study approach was taken by using data from the local electric utility company serving the Jersey City area, the Public Service Electric and Gas Co. (PSE&G). These data were obtained directly from PSE&G for 1976 for two cases as follows:

- for the distribution circuit which would have supplied Summit Plaza in any non-TE scheme (the same circuit which has supplied the site with standby service). This circuit is entirely underground and is highly reliable.

- for an average PSE&G customer (as calculated by PSE&G). This includes rural as well as urban/suburban areas.

A somewhat broader approach was also taken in utilizing data from two other utility companies servicing urbanized areas. The Duquesne Light Company (DLC), serving the Pittsburgh area, has published service reliability data on 4-kV and 23-kV circuits for the years 1964 through 1971 [11-6] and for 23-kV circuits only for 1973-1976 [11-7]. These data give a somewhat optimistic picture of the overall DLC system reliability because the published data do not include the unreliability of power supply to the distribution circuits.

Data were also obtained directly from the Boston Edison Co. (BECo) for the years 1974-1977. These were average data for the entire BECo service territory.

National Average Data - A comparison with national average reliability data was also possible by using data collected by the Edison Electric Institute (EEI) [11-8]. The EEI collected such data from 1956 through 1967. These data were gathered on the basis of individual customer interruptions of 5 minutes or more. Therefore, these data were quite different than the data on large-scale electric power disturbances reported to the state regulatory agencies and the Federal Economic Regulatory Commission [11-9].

The EEI data show a nearly constant trend in service reliability over the 12-year period. Therefore, these data were felt to be a good representation of reliability levels.

Generic Targets for Availability - Target values or rules-of-thumb for electrical service availability also were used an an adjunct to measured data. Two sources supplied published data on such generic "national" availability targets [11-10, 11-11].

The actual data obtained from the sources described above are summarized in table 11.4. Generic data and design criteria are shown in table 11.3. There can be a wide range of service availability especially when individual circuits are examined. The 4-kV DLC data, the BECo data, and EEI average data however, are narrowly grouped around the generic or target values. PSE&G appears to have considerably better availability than the average utility.

11.2.8 Evaluation

Comparison of Data - A comparison was made between the availability of the Summit Plaza TE system (i.e., table 11.1) and the other data described above.

This comparison is shown in table 11.5. The following points should be noted:

- of the 4 years of plant operation, only two years completely met the requirements of the NBS performance specifications.

- both the PSE&G typical system and the circuit serving the adjacent area have a high level of availability which the TE plant has only met in one year.

- the TE plant appears to have exceeded the availability record of the average utility in one year (1975) and has nearly met it in another (1977). In the two remaining years, the availability was much worse than the general utility.

Table 11.3 Summary of Generic Utility Availability Targets

			Unavailability	Frequency
Source	Date	Ref	min./year	interr./year
Generic data:				
Electrical World	1977	[11-10]	$\leq$ 60-90	$\leq$ 1.5
REA	1972	[11-11]	$\leq$ 60 urban $\leq$ 120 suburban	-- --
Design criteria:				
REA	1972	[11-11]	$\leq$ 300	--
DL Co.	1978	[11-7]	< 60	1.5

Table 11.4 Summary of Actual Utility Availability

Source				Availability Measure[a]		
				Unavailability	Frequency	Duration
Co.	Level	Year	Ref	min./year	interr./year	min./interr.
PSE&G	Summit plaza	74-77		0	0	0
PSE&G	System average	74-77		33.2	.489	67.9
BE Co.	4-kV circuits	74-77		93.0	.983	94.7
DL Co.	4-kV circuits	67-71	[11-6]	79.9[c]	-	-
	23-kV circuits	67-71	[11-6]	182[c]	-	-
	23-kV circuits	73-76	[11-7]	210	2.88	72.9
EEI	National survey	66-67	[11-8]	71.5	-	-

a) Unavailability = 525,600 x Service Unavailability Index[b]
Frequency = System Interruption Frequency Index[b]
Duration = Customer Interruption Duration Index[b]

b) Indices are defined per IEEE paper A75 588-4

c) Does not include unreliability of power supply to distribution circuits; other data includes all system components.

Table 11.5 TE Plant vs. Utility Availability

	TE Plant		Actual Utility Data[a]		
			PSE & G		
	1975	1977	Summit Plaza	Typical	Other
Total interruption duration (minutes/year)	5	116	0	33	60-90
Number of interruptions per year	0.5	2.4	0	0.5	1.5

[a] annual average

Unattended Operation - The plant was specifically designed for partly-attended operation to minimize operation labor costs. In actual practice, the plant has been staffed with two people on a single-shift, 40-hour per week basis.

It is obvious that restoration of service will take longer if an interruption occurs during a period when the plant is unattended than when it is attended. Data on individual interruptions were analyzed to determine the impact of this difference in restoration time.

Only total, forced interruption events were considered. The extended interruptions of August 1974 were not considered because they are anomalous situations and would distort the data. Four early 1974 interruptions were also not considered because of uncertainties in duration and operator attendance.

Table 11.6 shows the results of this analysis and indicates a significant effect of unattended operation. Particularly significant is the minimum equivalent durations: 10 minutes for attended operation (achieved on 2 occasions) and 54 minutes for unattended operation. It is also noteworthy that the total number of interruptions did not vary between attended and unattended operation periods even though the plant was in an unattended mode 76 percent of the time. Perhaps this is because the lower electrical load levels during the night resulted in more plant flexibility to adjust to outage conditions.

Whether labor attendance on greater than a one-shift basis would be warranted depends on the economic costs of additional operators weighed agains the benefits of increased availability.

11.2.9 Conclusions

The measured data show that the TE plant has the capability of being highly reliable and within the availability targets set, and achieved, by many electric utility companies.

Table 11.6 Effect of Unattended Operation on Duration of Total Interruptions

	Plant Status	
	Attended	Unattended
No. of Interruptions[a]	7	6
Interruption Duration (minutes)		
minimum	10	54
maximum	86	135
average	27	83

a) Interruptions include those from plant start-up through December 1977, for which attendance data were available.

The Summit Plaza TE plant did not appear as of 1977, from the measured data, to be fully out of the debugging phase of plant operation. Thus, "normal" availability levels were then not yet attained.

The electrical control system was the principal source of equipment outages which produced service interruptions. To the extent that the Summit Plaza TE plant serves as a model for TE technology, it appears that electrical controls are a fruitful area for R&D and/or product improvements.

The partly-attended operating status of the plant had an adverse affect on availability, to the extent of a three-fold increase in average interruption duration.

11.3 ELECTRICAL SERVICE QUALITY

Service quality measures relevant to supply systems consist primarily of voltage and frequency. Power factor and phase-to-phase voltage unbalance are largely load-dependent and are therefore of less importance.

11.3.1 TE Plant Data

The Summit Plaza demonstration was instrumented for the following parameters:

Plant	Site
Power factor of CEB bus	Voltage of Shelley A normal bus
Frequency of CEB bus	Voltage of Shelley B normal bus
Voltage of CEB bus	Voltage of School normal bus
Voltage of PSE&G feeder	Voltage of Descon A3 normal bus

Voltage of Descon A1 and A2 normal bus
Voltage of Camci normal bus
Voltage of Commercial normal bus

In this case the main interest was directed to the performance of the TE plant and not the site distribution system, individual building equipment, or load characteristics. Therefore, the two TE plant parameters of voltage and frequency was the basis of electrical service quality evaluations. The PSE&G feeder voltage was also valuable as a basis for comparison.

Nominal values for these parameters are 480 volts and 60 hertz. The DAS data could be scanned on either an hourly or, if necessary, a 5-minute basis to determine variations from the nominal values. The distribution of the values about nominal or mean values were then used to completely describe the quality levels. It is useful to first identify existing criteria or comparative data for voltage and frequency as a means of directly determining from the DAS how well the TE plant service quality compared with conventional service.

11.3.2 Sources of Comparative Criteria and Data

As with the service interruption evaluation, several sources of service quality data were examined to develop data for comparisons. These sources and data are described in the following paragraphs.

The NBS Performance Specification [11-5] and the GKC Design Report [11-2] provide criteria for allowable voltage and frequency variations. Although the latter report contains some apparent inconsistences, the intent of these reports was to establish limits on voltage of about ± 1 percent under steady load conditions at the plant bus. Frequency limits were ± 0.25 percent (± 0.15 hertz) at steady-load conditions. The plant was designed with the capability to meet these levels of service quality.

The Public Service Electric & Gas Co. (PSE&G) has developed criteria for voltage and frequency variations but no data are available on actual system performance. PSE&G strives to maintain frequency at 60 Hz ± 0.02 Hz under normal conditions. This variation may increase under "unusual or emergency" conditions. When the system nominal frequency drops 0.7 Hz, automatic load shedding relays will initiate load shedding. This situation is clearly an emergency condition, not likely to be experienced. No data are available to indicate how often variations up to 0.7 Hz occur.

PSE&G maintains standards for voltage variations at their customer's meters. These standards vary with the type of circuit and customer. For service to Summit Plaza, the standards are + 4 percent, -3 percent of nominal voltage. Again, these limits are applicable under normal operating conditions.

The New Jersey Department of Public Utilities administers a regulation pertaining to voltage and frequency variations. A maximum variation of ± 4 percent for a period greater than 5 minutes is specified, although this only pertains to service supplied at 150 volts or below. (Service to Summit Plaza would be at 480 volts.) No quantitative limits on frequency are specified in the regulation [11-12].

An analysis of data collected by the National Association of Regulatory Utility Commissioners (NARUC) indicates that 29 local regulatory agencies (State public utility commissions or equivalent) utilize numercial limits on voltage variations. Twenty-one of these use $\pm$ 6 percent or less as a limit, with eleven using $\pm$ 5 percent [11-13]. These data include some cases in which the limits apply only to residential and lighting loads; limits for industrial and non-lighting loads (when they are specified separately) are generally less restrictive.

The NARUC does not summarize regulations applying to frequency limits. As indicated by the New Jersey regulations (and as corroborated by review of several other states' regulations), frequency variations are generally not the subject of quantitative criteria.

Perhaps the most detailed voltage criteria are promgulated by the American National Standards Institute (ANSI). The relevant standard recognizes that there is a distribution characteristic for voltage which is likely to be Guassian, that the voltage variation depends on what point in the electric system is being considered, and that the variations depend on whether "desirable"/"allowable" levels or "normal/short-term" conditions are being considered [11-14].

The ANSI Standard provides the following voltage variation for 480-volt nominal supply:

allowable	+28v.,	-40 v.
desirable	+24v.,	-24 v.

(The terms "allowable" and "desirable" are not in the ANSI Standard and have been coined for use in this report as descriptors for the two voltage ranges in the Standard.)

The voltage and frequency criteria described above are summarized in table 11.7. The PSE&G and ANSI voltage criteria were chosen as the basis of comparison with the TE plant data. These criteria are appropriate for specific and generic comparisons, respectively. Clearly, the NBS-GKC design specification voltage limits are much too restrictive. The New Jersey limits are very nearly the same as PSE&G is while the NARUC limits are between the PSE&G and ANSI limits and therefore attainment can be estimated by interpolation.

For frequency comparison with the TE plant data, the PSE&G "normal" level of $\pm$0.02 Hz, the NBS/GKC design target of $\pm$0.15 Hz and an intermediate level of $\pm$0.10 Hz were chosen as appropriate.

11.3.3 Comparison of Results

Because of the rapid fluctuation of frequency and voltage, it was desirable that service quality evaluations be carried out using the 5-minute DAS data. Special software routines were developed to access and reduce the 5-minute data.

The general objective was to determine the total duration that the parameter was outside the criteria established in the preceeding section.

Table 11.7 Comparative Data for Electrical Service Quality

Source	Reference	Voltage Limits	Frequency Limits
NBS	11-5	±1%	±0.15 Hz[b]
GKC	11-2	±1%	±0.15 Hz[b]
PSE&G		+4%, -3%[a]	±0.02 Hz[b]
N.J.	11-12	±4%	-
NARUC	11-13	± 6% or less	-
ANSI	11-14	allowable +6%, -8%[a] desirable +5%, -5%[a]	-

a) Voltage levels chosen for comparative analysis
b) Frequency levels chosen for comparative analysis.

One major factor which influenced results of this study was the adequacy of sensor calibration for the parameters. Throughout the data collection effort, the thermal and electrical measurements relating to energy flows were given a higher priority for instrumentation maintenance than those relating to quality of service. The result was that the average recorded values for some of the parameters were substantially different from the nominal value (i.e., 480 v or 60 Hz).

The analysis of frequency variation shows a fairly stable electrical supply from the TE plant. The frequency exceeded PSE&G limits 11.0 percent of the time and exceeded design specification limits 0.9 percent of the time.

The analysis of voltage variation for the TE plant shows that the stability was excellent. Out of the 15 months for which voltage data were available, only in three months was there any occurrence of voltage excursions beyond either the PSE&G or ANSI limits. These excursions were limited in duration to less than 2 percent of the time in the month.

Similarly, the monitoring of PSE&G voltage at the plant essential bus showed excellent stability. In only two months was there any occurrence of voltage variation. These excursions were of negligible duration.

11.4 HOT WATER AND CHILLED WATER AVAILABILITY AND QUALITY

The reliability of thermal energy supply can either include or exclude the distribution system. As described in section 5.3, the thermal losses of the distribution system were excessively high. Aside from questions regarding energy efficiency and economics, the capability of the energy system to adequately heat and cool the buildings may have been adversely impacted by these losses. Since this situation is clearly atypical, it is considered more useful to evaluate the performance of the TE plant itself in this regard. The availability of hot and chilled water supply was evaluated by examining 5-minute DAS data for periods of zero flow in the four secondary flow loops.

- SHW flow in site East zone
- SHW flow in site West zone
- CHW flow in site East zone
- CHW flow in site West zone.

For all data examined, there were no periods of zero flow in the flow loops.

Service quality of the hot water and chilled water was measured by the temperature of the supply leaving the plant. For chilled water, two quality levels were established, at temperatures of 45°F (72°C) and 50°F (10°C). The design chilled water supply temperature was 45°F (72°C) [11-2]. For hot water, upper and lower limits were established. The lower limit of 180°F (82.2°C) was felt to be the minimum to adequately meet space heating needs, although this limit could vary during the year. The upper limit of 200°F (93.3°C) was established by the designer [11-2].

Analysis of the 5-minute DAS data by means of special computer routines produced the data of table 11.8 for hot and chilled water service quality. As can be seen, chilled water service quality was relatively poor. Chilled water supply temperature leaving the plant exceeded 45°F 59.5 percent of the time and exceeded 50°F 26.4 percent of the time. This is not unexpected in view of the operational problems of the chillers as discussed in section 5.2.3. Hot water service quality, was excellent, with negligible excursions beyond the temperature limits.

Table 11.8 Hot and Chilled Water Service Quality

	Year			Total
Chilled Water	1975	1976	1977	Period
% time > 45°F	53	65	59	59
% time > 50°F	27	26	26	26
Hot Water				
% time < 180°F	0	0	.10	.04
% time > 200°F	.01	0	.02	.01

11.5 REFERENCES - SECTION 11

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11-8. Edison Electric Institute, "The Reliability of Electric Service," EEI Publication 68-52, June 1968. This document is the only published record of the reliability data collected by EEI. Additional (unpublished) details beyond that provided in this reference was obtained directly from EEI for this report.

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APPENDIX A

Examples of Hourly, Daily, and Monthly Printouts from Computer Disks

HOURLY SUMMARY FOR MAY 2, 1977, 700- 800 PAGE 1

TOTAL DATA TIME: 60 MINUTES, ACTUAL TIME: 122 7: 0

NBS LOC	VALUE	UNITS	TIME	DEP	VALUE	UNITS	TIME
10	57.773	PSI	60	1010	-.006	MINUTES	60
11	.749	PSI	60	1011	.000	MINUTES	60
12	1.467	PSI	60	1012	.000	MINUTES	60
13	-.020	PSI	60	1013	823.466	KWH(INS)	60
14	-.019	PSI	60	1014	.000	KWH(INS)	60
15	11908.242	LB/MIN	60	1015	.000	KWH(INS)	60
16	2558.168	LB/MIN	60	1016	823.466	KWH(INS)	60
17	2436.610	LB/MIN	60	1018	.000	KWH(INS)	60
18	.000	LB/MIN	60	1019	14.609	KWH(INS)	60
19	7155.236	LB/MIN	60	1020	106.483	KWH(INS)	60
20	6057.763	LB/MIN	60	1021	36.658	KWH(INS)	60
21	.000	LB/MIN	60	1022	.000	KWH(INS)	60
22	.000	LB/MIN	60	1023	.000	KWH(INS)	60
23	.000	LB/MIN	60	1025	832.553	KWH(AVG)	60
24	.000	LB/MIN	60	1026	.000	KWH(AVG)	60
25	.000	LB/MIN	60	1027	.000	KWH(AVG)	60
26	2879.925	LB/MIN	60	1028	832.253	KWH(AVG)	60
27	.000	LB/MIN	60	1030	.000	KWH(AVG)	60
28	.000	LB/MIN	60	1031	14.985	KWH(AVG)	60
29	.000	LB/MIN	60	1032	113.035	KWH(AVG)	60
30	.000	GPM (AV)	60	1033	35.471	KWH(AVG)	60
31	5.763	GPM (AV)	60	1034	.000	KWH(AVG)	60
32	5.436	GPM (AV)	60	1035	.000	KWH(AVG)	60
33	.000	GPM (AV)	60	1036	16.947	KWH(AVG)	60
34	.000	GPM (AV)	60	1037	129.273	KWH(AVG)	60
35	.000	GPM (AV)	60	1038	146.221	KWH(AVG)	60
36	.000	GPM (AV)	60	1039	7.236	KWH(AVG)	60
37	.000	GPM (AV)	60	1040	65.399	KWH(AVG)	60
38	.000	GPM (AV)	60	1041	72.636	KWH(AVG)	60

HOURLY SUMMARY FOR MAY 2, 1977, 700- 800 PAGE 2

NBS LOC	VALUE	UNITS	TIME	DER.	VALUE	UNITS	TIME
39	.000	GPM (AV)	60	1042	.000	KWH(AVG)	60
40	.000	GPM (AV)	60	1043	2.568	KWH(AVG)	60
41	823.466	KW (INS)	60	1044	28.017	KWH(AVG)	60
42	.000	KW (INS)	60	1045	30.584	KWH(AVG)	60
43	.000	KW (INS)	60	1046	.000	KWH(AVG)	0
44	.000	KW (INS)	60	1047	33.895	KWH(AVG)	60
45	14.609	KW (INS)	60	1048	.000	KWH(AVG)	0
46	106.483	KW (INS)	60	1049	33.126	KWH(AVG)	60
47	36.658	KW (INS)	60	1050	.000	KWH(AVG)	0
48	.000	KW (INS)	60	1051	33.658	KWH(AVG)	60
49	.000	KW (INS)	60	1052	85.683	KWH(AVG)	60
50	175.360	DEG F	60	1053	119.341	KWH(AVG)	60
51	175.030	DEG F.	60	1054	3.300	KWH(AVG)	60
52	174.996	DEG.F.	60	1055	62.300	KWH(AVG)	60
53	173.429	DEG F	60	1056	65.600	KWH(AVG)	60
54	172.684	DEG F.	60	1059	163.491	KWH(AVG)	60
55	181.498	DEG F.	60	1060	46.000	KWH(AVG)	60
56	181.319	DEG F.	60	1061	75.178	KWH(AVG)	60
57	175.689	DEG.F.	60	1062	.000	KWH(AVG)	60
58	179.181	DEG.F.	60	1063	88.313	KWH(AVG)	60
59	175.293	DEG F.	60	1064	75.178	KWH(AVG)	60
60	175.446	DEG F.	60	1065	.000	KWH(AVG)	60
61	89.480	DEG.F.	60	1066	669.361	KWH(AVG)	60
62	88.635	DEG F	60	1067	744.539	KWH(AVG)	60
63	90.129	DEG F.	60	1073	70.853	KWH(AVG)	60
64	98.286	DEG F.	60	1074	26.751	KWH(AVG)	60
65	74.274	DEG.F	60	1075	97.605	KWH(AVG)	60
66	82.353	DEG F.	60	1076	147.983	KWH(AVG)	60
67	81.106	DEG F.	60	1077	.000	KWH(AVG)	0
68	74.090	DEG F.	60	1078	28.017	KWH(AVG)	60

HOURLY SUMMARY FOR MAY 2, 1977, 700- 800 PAGE 3

NBS LOC	VALUE	UNITS	TIME	DER	VALUE	UNITS	TIME
69	74.046	DEG.F	60	1079	65.399	KWH(AVG)	60
70	79.558	DEG.F.	60	1080	129.273	KWH(AVG)	60
71	74.090	DEG.F	60	1081	.000	KWH(AVG)	0
72	72.129	DEG.F.	60	1082	.000	KWH(AVG)	0
73	108.716	DEG.F	60	1087	.000	B.T.U	60
74	81.541	DEG.F.	60	1088	.000	B.T.U	60
75	81.183	DEG.F.	60	1089	.000	B.T.U.	60
76	88.104	DEG.F.	60	1090	-38986.672	B.T.U.	60
77	89.716	DEG.F.	60	1091	.000	B.T.U.	60
78	85.723	DEG.F.	60	1092	38986.672	B.T.U	60
79	86.195	DEG.F.	60	1093	38986.672	B.T.U	60
80	156.146	DEG.F.	60	1100	.000	B.T.U	0
81	177.407	DEG.F.	60	1101	-113576.944	B.T.U	60
82	115.619	DEG.F	60	1102	-113576.844	B.T.U.	60
83	120.797	DEG.F.	60	1103	.000	B.T.U.	0
84	119.941	DEG.F.	60	1104	-43135.148	B.T.U.	60
85	119.839	DEG.F.	60	1105	-43135.148	B.T.U.	60
86	-.379	DL DEG.F	60	1106	-50626.234	B.T.U	60
87	-.381	DL DEG.F	60	1107	-58164.977	B.T.U.	60
88	1.052	DL DEG.F	60	1108	-58164.977	B.T.U.	60
89	3.636	DL DEG.F	60	1109	-53092.633	B.T.U.	60
90	-1.119	DL DEG.F	60	1110	-55759.531	B.T.U	60
91	-.676	DL DEG.F	60	1111	-55759.531	B.T.U.	60
92	2.424	DL DEG.F	60	1112	.000	B.T.U.	0
93	.409	DL DEG.F	60	1113	-171741.812	B.T.U.	60
94	5.500	DL DEG.F	60	1114	-171741.912	B.T.U.	60
95	.109	DL DEG.F	60	1115	.000	B.T.U	0
96	-2.988	DL DEG.F	60	1116	-98894.687	B.T.U.	60
97	2.331	DL DEG.F	60	1117	-98894.687	B.T.U.	60
98	3.109	DL DEG.F	60	1118	.000	B.T.U	0

HOURLY SUMMARY FOR MAY 2 1977: 700- 800 PAGE 4

NBS LOC	VALUE	UNITS	TIME	DER	VALUE	UNITS	TIME
99	7.106	DL DEG.F	60	1119	2868515.000	B.T.U	60
100	.947	DL DEG.F	60	1120	2868515.000	B.T.U.	60
101	.000	DL DEG.F	60	1121	2597879.000	B.T.U.	60
102	.000	DL DEG.F	60	1122	-66104.515	B.T.U	60
103	.000	DL DEG.F	60	1123	-75903.750	B.T.U.	60
104	-1.842	DL DEG.F	60	1124	-66104.500	B.T.U.	60
105	.000	DL DEG.F	60	1125	-66104.500	B.T.U.	60
106	-.320	DL DEG.F	60	1126	1731748.000	B.T.U	60
107	5.160	DL DEG.F	60	1127	1655844.250	B.T.U.	60
108	.081	DL DEG.F	60	1128	1665643.500	B.T.U.	60
109	-.000	DL DEG.F	60	1129	1665643.500	B.T.U.	60
110	832.853	KW (AVG)	60	1130	.000	B.T.U.	60
111	.000	KW (AVG)	60	1131	.000	B.T.U	60
112	.000	KW (AVG)	60	1132	.000	B.T.U.	60
113	.000	KW (AVG)	60	1133	4022542.000	B.T.U.	60
114	14.985	KW (AVG)	60	1134	3929768.500	B.T.U.	60
115	113.035	KW (AVG)	60	1135	3929768.500	B.T.U.	60
116	35.471	KW (AVG)	60	1136	283264.062	B.T.U.	60
117	.000	KW (AVG)	60	1137	292514.687	B.T.U.	60
118	.000	KW (AVG)	60	1138	292514.687	B.T.U.	60
120	202.250	ON/OFF	60	1139	-47599.531	B.T.U	60
121	202.917	ON/OFF	60	1140	-132201.531	B.T.U	60
122	203.000	ON/OFF	60	1141	4121521.000	B.T.U.	60
123	203.333	ON/OFF	60	1142	4131320.000	B.T.U.	60
124	203.417	ON/OFF	60	1143	4131320.000	B.T.U.	60
125	203.667	ON/OFF	60	1144	4258206.000	B.T.U.	60
126	203.917	ON/OFF	60	1145	4174683.000	B.T.U.	60
127	204.083	ON/OFF	60	1146	4174683.000	B.T.U.	60
128	204.333	ON/OFF	60	1147	-136685.000	B.T.U.	60
129	204.333	ON/OFF	60	1148	-43363.000	B.T.U.	60

HOURLY SUMMARY FOR MAY 2, 1977. 700- 800 PAGE 5

NBS LOC	VALUE	UNITS	TIME	DER	VALUE	UNITS	TIME
140	.422	GPM (AV)	0	1149	-43363.000	B.T.U.	60
141	.425	GPM (AV)	0	1155	3939752.000	B.T.U.	60
142	.411	GPM (AV)	0	1156	.000	B.T.U.	60
143	.418	GPM (AV)	0	1157	.000	B.T.U.	60
144	.366	GPM (AV)	0	1158	2582812.500	B.T.U.	60
145	.979	GPM (AV)	0	1159	1356939.750	B.T.U.	60
146	.947	GPM (AV)	0	1160	1356939.750	B.T.U.	60
160	497.750	VOLTS	60	1161	82790.000	B.T.U.	60
163	468.500	VOLTS	60	1162	-9983.500	B.T.U.	60
172	4.990	MINUTES	60	1163	-9983.500	B.T.U.	60
173	.000	MINUTES	60	1170	.000	B.T.U.	60
174	.000	MINUTES	60	1171	.000	B.T.U.	60
177	.698	PWR.FACT	60	1172	.000	B.T.U.	60
178	59.994	HERTZ	60	1173	.000	B.T.U.	60
179	7.536	DL DEG F	60	1174	.000	B.T.U.	60
180	.000	LB/MIN	60	1175	.000	B.T.U.	60
183	5.239	KW (AVG)	60	1176	.000	B.T.U.	60
187	267.253	DEG F.	60	1177	.000	B.T.U.	60
193	58.680	DL DEG F	60	1178	.000	B.T.U.	60
194	.000	LB/MIN	60	1179	.000	B.T.U.	60
195	-.148	DL DEG.F	60	1180	.000	B.T.U.	60
196	.000	LB/MIN	60	1181	.000	B.T.U	60
197	12.458	DL DEG.F	60	1182	.000	B.T.U.	60
198	.000	GPM (AV)	60	1183	.000	B.T.U.	60
199	28.017	KW (AVG)	60	1184	.000	B.T.U.	60
200	2.568	KW (AVG)	60	1185	.000	B.T.U.	60
201	280.475	VOLTS	60	1191	-7643.381	B.T.U.	60
202	40.133	DEG.F.	60	1192	-.549	B.T.U.	60
203	130.922	DEG F.	60	1193	-.549	B.T.U.	60
204	132.855	DEG.F.	60	1194	7638.108	B.T.U	60

HOURLY SUMMARY FOR MAY 2, 1977, 700- 800 PAGE 6

NBS LOC	VALUE	UNITS	TIME	DER	VALUE	UNITS	TIME
207	4.805	DL DEG.F	60	1195	944676.000	B.T.U.	60
208	901.075	LB/MIN	60	1196	944670.750	B.T.U.	60
209	-13.103	DL DEG.F	60	1197	944670.500	B.T.U	60
210	.000	LB/MIN	60	1198	952313.375	B.T.U	60
211	3.355	DL DEG.F	60	1199	952313.375	B.T.U.	60
212	4.806	GPM (AV)	60	1200	14047.689	B.T.U	60
213	62.300	KW (AVG)	60	1201	38986.672	B.T.U.	60
214	3.300	KW (AVG)	60	1202	-55236.328	B.T.U	60
215	192.238	VOLTS	60	1203	236988.281	B.T.U	60
217	95.197	DEG.F.	60	1204	709882.250	B.T.U.	60
218	167.725	DEG.F.	60	1205	889434.375	B.T.U	60
219	165.035	DEG.F	60	1206	889434.125	B.T.U	60
221	2.190	C/CM2/MN	60	1207	897077.000	B.T.U.	60
222	2.036	C/CM2/MN	60	1208	897077.000	B.T.U	60
223	.000	DEGREES	60	1209	889434.125	B.T.U.	60
224	151.000	MILES/HR	60	1210	897077.000	B.T.U.	60
225	31.000	IN.HG.	60	1211	897077.000	B.T.U.	60
226	199.990	DEG.F.	60	1212	999904.875	B.T.U	60
227	100.000	PER-CENT	60	1213	-110470.500	B.T.U.	60
228	150.580	DEG.F.	60	1214	-110470.750	B.T.U.	60
235	7.595	DL DEG.F	60	1215	-102827.875	B.T.U.	60
236	87.958	LB/MIN	60	1216	-102827.875	B.T.U	60
237	.735	DL DEG.F	60	1217	-110470.750	B.T.U.	60
238	.000	LB/MIN	60	1218	-102827.875	B.T.U.	60
239	5.580	DL DEG.F	60	1219	-102927.875	B.T.U	60
240	583.667	LB/MIN	60	1225	.000	B.T.U.	0
241	65.399	KW (AVG)	60	1226	.000	B.T.U	0
242	7.236	KW (AVG)	60	1227	.000	B.T.U	0
243	120.417	VOLTS	60	1228	.000	B.T.U.	0
244	85.734	DEG.F.	60	1229	.000	B.T.U.	0

HOURLY SUMMARY FOR MAY 2, 1977, 700- 800 PAGE 7

NBS LOC	VALUE	UNITS	TIME	DER.	VALUE	UNITS	TIME
245	172.360	DEG F	60	1230	.000	B T.U.	0
246	173.169	DEG.F	60	1231	.000	B T.U.	0
249	21.899	DL DEG.F	60	1232	000	B T U.	0
250	570.000	LB/MIN	60	1233	326405.187	B T.U.	60
251	-3 199	DL DEG.F	60	1234	422557.062	B.T.U.	60
252	1279 313	LB/MIN	60	1235	748962 250	B.T.U	60
253	9.491	DL DEG.F	60	1236	195426 094	B.T.U.	60
254	573.196	LB/MIN	60	1237	110625.344	B T.U.	60
255	129 273	KW (AVG)	60	1238	306051 437	B T.U.	60
256	16 947	KW (AVG)	60	1241	000	B.T U	60
257	497 713	VOLTS	60	1242	000	B.T.U.	60
258	96 876	DEG F	60	1243	000	B.T U	0
260	175 140	DEG F	60	1244	000	B T.U	0
261	174 630	DEG.F.	60	1245	.000	B T U	0
263	14 682	DL DEG.F	60	1246	000	B.T.U.	0
264	979 609	LB/MIN	60	1247	000	B T.U.	0
265	-4 598	DL DEG F	60	1248	331847 625	B T U.	60
266	.000	LB/MIN	60	1249	466503.500	B.T.U.	60
267	13.792	DL DEG.F	60	1250	798351 125	B.T U	60
268	642.759	LB/MIN	60	1251	531909.375	B T.U.	60
269	85.683	KW (AVG)	60	1252	331054.000	B T.U.	60
270	33.658	KW (AVG)	60	1253	862963.375	B T U	60
271	478.460	VOLTS	60	1254	967 300	B.T U	60
273	99.206	DEG F	60	1255	258793.312	B.T.U.	60
274	174.093	DEG F.	60	1256	259760.625	B.T.U.	60
275	173.509	DEG.F.	60	1257	1921075.000	B.T.U.	60
277	1 526	DL DEG.F	60	1258	561737.500	B.T.U.	60
278	5094.198	LB/MIN	60	1259	.000	B T.U.	0
279	3.228	DL DEG.F	60	1260	.000	B T U.	0
280	1713.415	LB/MIN	60	1261	.000	B.T.U.	0

HOURLY SUMMARY FOR MAY 2 1977: 700- 800 PAGE 8

NBS LOC	VALUE	UNITS	TIME	DER	VALUE	UNITS	TIME
281	.000	KW (AUG)	0	1262	.000	B.T.U.	0
282	33.895	KW (AUG)	60	1263	.000	B.T.U.	0
283	33.126	KW (AUG)	60	1264	.000	B.T.U.	0
284	497.520	VOLTS	60	1265	.000	B.T.U.	0
285	129.635	VOLTS	60	1266	.000	B.T.U.	60
286	164.321	DEG.F.	60	1267	.000	B.T.U.	60
287	175.446	DEG.F	60	1268	.000	B.T.U.	60
288	.000	SUM/WINT	60	1269	.000	B.T.U	60
289	.000	SUM/WINT	60	1270	.000	B.T.U.	60
315	46.000	KW (AUG)	60	1271	.000	B.T.U.	60
316	2.000	SUM/WINT	60	1272	.000	B.T.U.	60
317	.500	PER-CENT	60	1273	.000	B.T.U.	60
318	1.000	EFF	60	1274	.000	B.T.U.	60
319	35.000	DEG.API	60	1275	.000	B.T.U	60
320	139480.000	BTU/GAL	60	1276	.000	B.T.U	60
				1277	.000	B.T.U	60
				1278	.000	B.T.U.	60
				1279	.000	B.T.U.	60
				1285	.000	B.T.U.	0
				1286	.000	B.T.U	0
				1287	.000	B.T.U.	0
				1288	.000	B.T.U.	0
				1289	.000	B.T.U.	0
				1290	.000	B.T.U	0
				1291	.000	B.T.U.	0
				1292	.000	B.T.U.	0
				1294	.000	GALLONS	0
				1295	.000	GALLONS	0
				1296	.000	GALLONS	0
				1298	.000	GALLONS	0

HOURLY SUMMARY FOR MAY 3, 1977; 700- 800 PAGE 9

NBS LOC	VALUE	UNITS	TIME	DER	VALUE	UNITS	TIME
				1299	.000	GALLONS	0
				1300	.000	GALLONS	0
				1301	.000	GALLONS	0
				1302	.000	GALLONS	0
				1303	.000	GALLONS	0
				1304	.000	GALLONS	0
				1305	.000	GALLONS	0
				1307	.000	GALLONS	0
				1308	.000	GALLONS	0
				1309	.000	GALLONS	0
				1310	.000	GALLONS	0
				1311	.000	GALLONS	0
				1312	.000	GALLONS	0
				1313	.000	GALLONS	0
				1315	46.000	KW (AVG)	60
				1316	2.000	SUM/WINT	60
				1317	.500	PER-CENT	60
				1318	1.000	EFF	60
				1319	35.000	DEG API	60
				1320	139480.000	BTU/GAL	60

ENTER COMMAND

DAILY SUMMARY FOR MAY 2, 1977 PAGE 1

TOTAL DATA TIME: 1420 MINUTES, ACTUAL TIME: 122 0: 0

NBS LOC	VALUE	UNITS	TIME	DER	VALUE	UNITS	TIME
10	59.648	PSI	1420	1010	.221	MINUTES	1420
11	.000	PSI	1440	1011	6.057	MINUTES	1420
12	35.917	PSI	1440	1012	156.701	MINUTES	1420
13	.001	PSI	1420	1013	19615.324	KWH(INS)	1420
14	.092	PSI	1440	1014	22.259	KWH(INS)	1420
15	11931.836	LB/MIN	1420	1015	4222.692	KWH(INS)	1420
16	2556.083	LB/MIN	1420	1016	15370.377	KWH(INS)	1420
17	2423.839	LB/MIN	1420	1018	.000	KWH(INS)	1420
18	.000	LB/MIN	1440	1019	370.510	KWH(INS)	1420
19	7164.501	LB/MIN	1420	1020	2474.698	KWH(INS)	1420
20	5870.330	LB/MIN	1420	1021	875.432	KWH(INS)	1420
21	.000	LB/MIN	1440	1022	.000	KWH(INS)	1420
22	.000	LB/MIN	1440	1023	132.315	KWH(INS)	1420
23	.000	LB/MIN	1440	1025	19922.572	KWH(AVG)	1420
24	.000	LB/MIN	1440	1026	12.115	KWH(AVG)	1420
25	.000	LB/MIN	1440	1027	4238.705	KWH(AVG)	1420
26	2874.046	LB/MIN	1420	1028	15671.854	KWH(AVG)	1420
27	.000	LB/MIN	1440	1030	.000	KWH(AVG)	1420
28	.000	LB/MIN	1440	1031	378.981	KWH(AVG)	1420
29	.000	LB/MIN	1440	1032	2633.189	KWH(AVG)	1420
30	.000	GPM (AV)	1440	1033	847.874	KWH(AVG)	1420
31	.000	GPM (AV)	0	1034	.000	KWH(AVG)	1420
32	.000	GPM (AV)	0	1035	152.517	KWH(AVG)	1420
33	.000	GPM (AV)	0	1036	385.968	KWH(AVG)	1420
34	.000	GPM (AV)	0	1037	3250.010	KWH(AVG)	1420
35	.000	GPM (AV)	0	1038	3635.977	KWH(AVG)	1420
36	.000	GPM (AV)	0	1039	168.086	KWH(AVG)	1420
37	.000	GPM (AV)	0	1040	1584.561	KWH(AVG)	1420
38	.000	GPM (AV)	0	1041	1752.647	KWH(AVG)	1420

DAILY SUMMARY FOR MAY 2, 1977 PAGE 2

NBS LOC	VALUE	UNITS	TIME	DER	VALUE	UNITS	TIME
39	.000	GPM (AV)	0	1042	.000	KWH(AVG)	1440
40	.000	GPM (AV)	0	1043	52.823	KWH(AVG)	1420
41	817.305	KW (INS)	1420	1044	308.598	KWH(AVG)	1420
42	32.925	KW (INS)	40	1045	361.421	KWH(AVG)	1420
43	277.603	KW (INS)	900	1046	.000	KWH(AVG)	0
44	.000	KW (INS)	0	1047	593.999	KWH(AVG)	1420
45	15.438	KW (INS)	1420	1048	.000	KWH(AVG)	0
46	103.112	KW (INS)	1420	1049	690.653	KWH(AVG)	1420
47	36.476	KW (INS)	1420	1050	.000	KWH(AVG)	0
48	.000	KW (INS)	0	1051	819.377	KWH(AVG)	1420
49	8.896	KW (INS)	880	1052	2140.108	KWH(AVG)	1420
50	175.664	DEG.F.	1420	1053	2959.485	KWH(AVG)	1420
51	175.293	DEG.F.	1420	1054	79.200	KWH(AVG)	1440
52	178.731	DEG.F.	1420	1055	1725.855	KWH(AVG)	1420
53	173.747	DEG.F.	1420	1056	1805.055	KWH(AVG)	1420
54	181.663	DEG.F.	1420	1059	4012.560	KWH(AVG)	1420
55	180.373	DEG.F.	1420	1060	1104.000	KWH(AVG)	1440
56	180.221	DEG.F.	1420	1061	1330.219	KWH(AVG)	1420
57	175.963	DEG.F.	1420	1062	.000	KWH(AVG)	1440
58	179.759	DEG.F.	1420	1063	2529.824	KWH(AVG)	1420
59	175.566	DEG.F.	1420	1064	1330.219	KWH(AVG)	1420
60	175.770	DEG.F.	1420	1065	152.517	KWH(AVG)	1420
61	92.265	DEG.F.	1420	1066	15910.109	KWH(AVG)	1420
62	92.977	DEG.F.	1420	1067	17392.844	KWH(AVG)	1420
63	93.901	DEG.F.	1420	1073	1492.575	KWH(AVG)	1420
64	92.739	DEG.F.	1420	1074	606.877	KWH(AVG)	1420
65	74.834	DEG.F.	1420	1075	2099.453	KWH(AVG)	1420
66	83.746	DEG.F.	1420	1076	3865.963	KWH(AVG)	1420
67	84.801	DEG.F.	1420	1077	.000	KWH(AVG)	0
68	77.705	DEG.F.	1420	1079	308.598	KWH(AVG)	1420

DAILY SUMMARY FOR MAY 2, 1977 PAGE 3

NBS LOC	VALUE	UNITS	TIME	DER	VALUE	UNITS	TIME
69	77.676	DEG F.	1420	1079	1584.561	KWH(AVG)	1420
70	83.240	DEG F.	1420	1080	3250.010	KWH(AVG)	1420
71	77.873	DEG F	1420	1081	.000	KWH(AVG)	0
72	125.704	DEG F.	60	1082	.000	KWH(AVG)	0
73	153.528	DEG F	1420	1087	.000	B.T.U.	1440
74	84.791	DEG.F.	1420	1088	.000	B.T.U.	1440
75	84.258	DEG F.	1420	1089	.000	B.T.U.	1440
76	89.484	DEG.F.	1420	1090	-297568.062	B.T.U.	1420
77	91.207	DEG.F	1420	1091	.000	B.T.U	1420
78	87.164	DEG.F	1420	1092	297568.062	B.T.U.	1420
79	87.642	DEG F	1420	1093	297568.062	B.T.U.	1420
80	157.379	DEG.F.	1420	1100	.000	B.T.U	0
81	165.457	DEG F.	1420	1101	-2621914.500	B.T.U	1420
82	123.447	DEG.F	1420	1102	-2621914.500	B.T.U	1420
83	390.432	DEG F	1420	1103	.000	B.T.U.	0
84	131.984	DEG F	1420	1104	4766707.000	B.T.U	1420
85	213.151	DEG F.	1420	1105	4766707.000	B.T.U.	1420
86	-.373	DL DEG.F	1420	1106	-1365100.000	B.T.U.	1420
87	3.066	DL DEG.F	1420	1107	-1373768.500	B.T.U.	1420
88	.722	DL DEG F	1420	1108	-1373768.500	B.T.U	1420
89	3.913	DL DEG.F	1420	1109	10685568.000	B.T.U	1420
90	-1.086	DL DEG.F	1420	1110	10683472.000	B.T.U	1420
91	4.435	DL DEG.F	1420	1111	10683472.000	B.T.U.	1420
92	.712	DL DEG.F	1420	1112	.000	B.T.U.	0
93	.395	DL DEG.F	1420	1113	-3995684.000	B.T.U.	1420
94	4.124	DL DEG F	1420	1114	-3995684.000	B.T.U.	1420
95	.000	DL DEG F	1440	1115	.000	B.T.U.	0
96	-2.938	DL DEG.F	1420	1116	15450180.000	B.T.U.	1420
97	.644	DL DEG.F	1420	1117	15450180.000	B.T.U.	1420
98	2.742	DL DEG.F	1420	1118	.000	B.T.U.	0

DAILY SUMMARY FOR MAY 3, 1977 PAGE 4

NBS LOC	VALUE	UNITS	TIME	DEP	VALUE	UNITS	TIME
99	4.892	DL DEG.F	1420	1119	55782384.000	B.T.U.	1420
100	.000	DL DEG.F	1440	1120	55782384.000	B.T.U.	1420
101	.000	DL DEG.F	1440	1121	67236896.000	B.T.U.	1420
102	.000	DL DEG.F	1440	1122	-1162823.250	B.T.U.	1420
103	.000	DL DEG.F	1440	1123	-1673950.750	B.T.U.	1420
104	-4.265	DL DEG.F	1420	1124	-1162822.500	B.T.U.	1420
105	.000	DL DEG.F	1440	1125	-1162822.500	B.T.U.	1420
106	-.319	DL DEG.F	1420	1126	12230464.000	B.T.U.	1420
107	5.330	DL DEG.F	1420	1127	10556514.000	B.T.U.	1420
108	.133	DL DEG.F	1420	1128	11067636.000	B.T.U.	1420
109	.002	DL DEG.F	1420	1129	11067636.000	B.T.U.	1420
110	830.111	KW (AVG)	1420	1130	.000	B.T.U.	1440
111	17.920	KW (AVG)	40	1131	.000	B.T.U.	1440
112	278.656	KW (AVG)	900	1132	.000	B.T.U.	1440
113	.000	KW (AVG)	0	1133	73165152.000	B.T.U.	1420
114	15.791	KW (AVG)	1420	1134	70852448.000	B.T.U.	1420
115	109.716	KW (AVG)	1420	1135	70852448.000	B.T.U.	1420
116	35.328	KW (AVG)	1420	1136	6815565.000	B.T.U.	1420
117	.000	KW (AVG)	0	1137	6786811.000	B.T.U.	1420
118	10.254	KW (AVG)	880	1138	6786811.000	B.T.U.	1420
120	.000	ON/OFF	0	1139	-1685045.500	B.T.U.	1420
121	.000	ON/OFF	0	1140	-3113629.000	B.T.U.	1420
122	.000	ON/OFF	0	1141	74679744.000	B.T.U.	1420
123	.000	ON/OFF	0	1142	75190880.000	B.T.U.	1420
124	.000	ON/OFF	0	1143	75190880.000	B.T.U.	1420
125	.000	ON/OFF	0	1144	78295648.000	B.T.U.	1420
126	.000	ON/OFF	0	1145	75954224.000	B.T.U.	1420
127	.000	ON/OFF	0	1146	75954224.000	B.T.U.	1420
128	.000	ON/OFF	0	1147	-3615894.000	B.T.U.	1420
129	.000	ON/OFF	0	1148	-763325.375	B.T.U.	1420

DAILY SUMMARY FOR MAY 3, 1977

NBS LOC	VALUE	UNITS	TIME	DER	VALUE	UNITS	TIME
140	.000	GPM (AV)	0	1149	-763325.375	B.T.U	1420
141	.452	GPM (AV)	780	1155	70127232.000	B.T.U.	1420
142	.000	GPM (AV)	0	1156	.000	B.T.U.	1440
143	.000	GPM (AV)	0	1157	.000	B.T.U.	1440
144	.000	GPM (AV)	0	1158	41361392.000	B.T.U.	1420
145	.000	GPM (AV)	0	1159	28765816.000	B.T.U.	1420
146	.000	GPM (AV)	0	1160	28765816.000	B.T.U.	1420
160	495.731	VOLTS	1420	1161	3037937.000	B.T.U.	1420
163	471.678	VOLTS	1420	1162	725250.750	B.T.U.	1420
172	5.000	MINUTES	1420	1163	725250.750	B.T.U	1420
173	.747	MINUTES	40	1170	.000	B.T.U.	1440
174	.858	MINUTES	900	1171	.000	B.T.U	1440
177	.700	PWR FACT	1420	1172	.000	B.T.U	1440
178	60.009	HERTZ	1420	1173	.000	B.T.U.	1440
179	.000	DL DEG.F	1440	1174	.000	B.T.U	1440
180	.000	LB/MIN	1440	1175	.000	B.T.U	1440
183	.000	KW (AVG)	1440	1176	.000	B.T.U	1440
187	.000	DEG.F	0	1177	.000	B.T.U	1440
193	.000	DL DEG.F	0	1178	.000	B.T.U.	1440
194	6.437	LB/MIN	940	1179	.000	B.T.U.	1440
195	.000	DL DEG.F	1440	1180	.000	B.T.U.	1440
196	.000	LB/MIN	1440	1181	.000	B.T.U	1440
197	8.170	DL DEG.F	1120	1182	.000	B.T.U.	1440
198	.000	GPM (AV)	0	1183	.000	B.T.U.	1440
199	12.858	KW (AVG)	1420	1184	.000	B.T.U.	1440
200	2.201	KW (AVG)	1420	1185	.000	B.T.U.	1440
201	281.351	VOLTS	1420	1191	-118918.750	B.T.U.	1420
202	37.513	DEG.F.	880	1192	9231.066	B.T.U.	1420
203	.000	DEG.F.	0	1193	9231.066	B.T.U.	1420
204	.000	DEG.F.	0	1194	813845.625	B.T.U.	1420

DAILY SUMMARY FOR MAY 2, 1977

NBS LOC	VALUE	UNITS	TIME	DER	VALUE	UNITS	TIME
207	3.995	DL DEG.F	1420	1195	22209504.000	B.T.U	1420
208	897.529	LB/MIN	1420	1196	22904436.000	B.T.U.	1420
209	.000	DL DEG.F	1440	1197	22904436.000	B.T.U.	1420
210	.000	LB/MIN	1440	1198	23032580.000	B.T.U	1420
211	3.545	DL DEG.F	1420	1199	23032580.000	B.T.U	1420
212	2.319	GPM (AV)	1180	1200	548937.750	B.T.U	1420
213	71.911	KW (AVG)	1420	1201	297568.062	B.T.U.	1420
214	3.300	KW (AVG)	1440	1202	-1319970.250	B.T.U	1420
215	191.243	VOLTS	1420	1203	4709023.000	B.T.U.	1420
217	95.711	DEG.F.	1420	1204	19068848.000	B.T.U	1420
218	169.008	DEG.F.	1420	1205	21584468.000	B.T.U	1420
219	166.202	DEG.F.	1420	1206	21584460.000	B.T.U	1420
221	.000	C/CM2/MN	0	1207	21712616.000	B.T.U.	1420
222	.000	C/CM2/MN	0	1208	21712616.000	B.T.U.	1420
223	.000	DEGREES	0	1209	21584460.000	B.T.U	1420
224	.000	MILES/HR	0	1210	21712616.000	B.T.U	1420
225	31.000	IN.HG.	1420	1211	21712616.000	B.T.U.	1420
226	.000	DEG.F.	0	1212	24224364.000	B.T.U.	1420
227	.000	PER-CENT	0	1213	-2639907.500	B.T.U	1420
228	.000	DEG.F.	0	1214	-2639910.500	B.T.U.	1420
235	6.695	DL DEG.F	1420	1215	-2511761.000	B.T.U.	1420
236	46.674	LB/MIN	1000	1216	-2511761.000	B.T.U	1420
237	.000	DL DEG.F	1440	1217	-2639910.500	B.T.U	1420
238	.000	LB/MIN	1440	1218	-2511761.000	B.T.U.	1420
239	3.817	DL DEG.F	1420	1219	-2511761.000	B.T.U	1420
240	588.859	LB/MIN	1420	1225	.000	B.T.U.	0
241	66.023	KW (AVG)	1420	1226	.000	B.T.U	0
242	7.004	KW (AVG)	1420	1227	.000	B.T.U	0
243	119.919	VOLTS	1420	1228	.000	B.T.U.	900
244	86.182	DEG.F.	1420	1229	89517280.000	B.T.U	780

NBS LOC	VALUE	UNITS	TIME	DER	VALUE	UNITS	TIME
245	172.906	DEG.F.	1420	1230	.000	B.T.U.	0
246	173.717	DEG.F.	1420	1231	.000	B.T.U.	0
249	20.136	DL DEG.F	1420	1232	.000	B.T.U.	0
250	570.000	LB/MIN	1440	1233	7352575.000	B.T.U.	1420
251	.000	DL DEG.F	1440	1234	9175156.000	B.T.U.	1420
252	.000	LB/MIN	1440	1235	16527732.000	B.T.U.	1420
253	8.918	DL DEG.F	1420	1236	3265221.500	B.T.U.	1420
254	572.550	LB/MIN	1420	1237	2928907.500	B.T.U.	1000
255	135.417	KW (AVG)	1420	1238	6163338.000	B.T.U.	1000
256	16.082	KW (AVG)	1420	1241	.000	B.T.U.	1440
257	495.254	VOLTS	1420	1242	.000	B.T.U.	1120
259	97.311	DEG.F.	1420	1243	.000	B.T.U.	0
260	175.483	DEG.F.	1420	1244	.000	B.T.U.	0
261	174.961	DEG.F.	1420	1245	.000	B.T.U.	0
263	11.240	DL DEG.F	1420	1246	.000	B.T.U.	0
264	909.406	LB/MIN	1420	1247	.000	B.T.U.	0
265	.000	DL DEG.F	1440	1248	4340226.000	B.T.U.	1420
266	.000	LB/MIN	1440	1249	10293382.000	B.T.U.	700
267	7.835	DL DEG.F	1420	1250	14056880.000	B.T.U.	700
268	648.348	LB/MIN	1420	1251	7324324.000	B.T.U.	1420
269	89.171	KW (AVG)	1420	1252	7235313.000	B.T.U.	1420
270	34.141	KW (AVG)	1420	1253	14559638.000	B.T.U.	1420
271	476.327	VOLTS	1420	1254	9675.264	B.T.U.	1420
273	99.133	DEG.F.	1420	1255	5157580.000	B.T.U.	1420
274	174.249	DEG.F.	1420	1256	5167256.000	B.T.U.	1420
275	174.032	DEG.F.	1420	1257	33342420.000	B.T.U.	700
277	1.637	DL DEG.F	700	1258	10319856.000	B.T.U.	700
278	4833.720	LB/MIN	700	1259	.000	B.T.U.	0
279	1.762	DL DEG.F	1420	1260	.000	B.T.U.	0
280	1712.053	LB/MIN	1420	1261	.000	B.T.U.	0

NBS LOC	VALUE	UNITS	TIME	DER	VALUE	UNITS	TIME
281	.000	KW (AVG)	0	1262	.000	B.T.U.	0
282	24.750	KW (AVG)	1420	1263	.000	B.T.U.	540
283	28.777	KW (AVG)	1420	1264	.000	B.T.U.	0
284	495.815	VOLTS	1420	1265	.000	B.T.U.	0
285	143 146	VOLTS	1240	1266	.000	B.T.U.	1440
286	164 980	DEG F.	1420	1267	.000	B.T.U.	1440
287	175.782	DEG.F	1420	1268	.000	B.T.U.	1440
288	.000	SUM/WINT	0	1269	.000	B.T.U.	1440
289	.000	SUM/WINT	0	1270	.000	B.T.U.	1440
315	45.000	KW (AVG)	1440	1271	.000	B.T.U.	1440
316	2 000	SUM/WINT	1440	1272	.000	B.T.U.	1440
317	.500	PER-CENT	1440	1273	.000	B.T.U.	1440
318	1.000	EFF	1440	1274	.000	B.T.U.	1440
319	35.000	DEG API	1440	1275	.000	B.T.U.	1440
320	139480.000	BTU/GAL	1440	1276	.000	B.T.U.	1440
				1277	.000	B.T.U.	1440
				1278	.000	B.T.U.	1440
				1279	.000	B.T.U.	1440
				1285	.000	B.T.U.	0
				1286	.000	B.T.U.	0
				1287	.000	B.T.U.	0
				1288	.000	B.T.U.	0
				1289	.000	B.T.U.	0
				1290	.000	B.T.U.	0
				1291	.000	B.T.U.	0
				1292	.000	B.T.U.	0
				1294	.000	GALLONS	0
				1295	.000	GALLONS	540
				1296	.000	GALLONS	0
				1298	.000	GALLONS	0

DAILY SUMMARY FOR MAY 2, 1977

NBS LOC	VALUE	UNITS	TIME	DER.	VALUE	UNITS	TIME
				1299	.000	GALLONS	0
				1300	.000	GALLONS	0
				1301	.000	GALLONS	0
				1302	000	GALLONS	0
				1303	.000	GALLONS	0
				1304	.000	GALLONS	0
				1305	.000	GALLONS	0
				1307	.000	GALLONS	900
				1308	641.793	GALLONS	780
				1309	000	GALLONS	0
				1310	000	GALLONS	0
				1311	000	GALLONS	0
				1312	000	GALLONS	0
				1313	.000	GALLONS	0
				1315	1104 000	KW (AVG)	1440
				1316	2 000	SUM/WINT	1440
				1317	.500	PER-CENT	1440
				1318	1 000	EFF.	1440
				1319	35 000	DEG.API	1440
				1320	139480.000	BTU/GAL	1440

ENTER COMMAND

MONTHLY SUMMARY FOR MAY 1977 PAGE 1

TOTAL DATA TIME: 44465 MINUTES, ACTUAL TIME: 121 0: 0

NBS LOC	VALUE	UNITS	TIME	DEF	VALUE	UNITS	TIME
10	64.369	PSI	43145	1010	3.037	MINUTES	44465
11	.242	PSI	44580	1011	1322.031	MINUTES	44445
12	43.193	PSI	44505	1012	5915.030	MINUTES	44445
13	.001	PSI	44560	1013	654820.125	KWH(INS)	44465
14	.158	PSI	44505	1014	874.304	KWH(INS)	44465
15	11769.934	LB/MIN	44465	1015	169707.687	KWH(INS)	44465
16	2575.360	LB/MIN	44465	1016	484238.312	KWH(INS)	44465
17	2353.363	LB/MIN	41825	1018	.000	KWH(INS)	44465
18	1893.077	LB/MIN	44475	1019	11637.805	KWH(INS)	44465
19	7103.840	LB/MIN	44465	1020	77346.141	KWH(INS)	44465
20	5816.373	LB/MIN	44465	1021	34779.437	KWH(INS)	44465
21	5622.183	LB/MIN	40340	1022	37552.812	KWH(INS)	44465
22	7107.913	LB/MIN	44415	1023	3462.938	KWH(INS)	44465
23	297.295	LB/MIN	44295	1025	664365.375	KWH(AVG)	44445
24	4949.562	LB/MIN	44415	1026	989.285	KWH(AVG)	44445
25	2190.357	LB/MIN	43040	1027	170667.969	KWH(AVG)	44445
26	2864.914	LB/MIN	44465	1028	492708.250	KWH(AVG)	44445
27	189.376	LB/MIN	38730	1030	.000	KWH(AVG)	44445
28	2380.696	LB/MIN	44415	1031	11888.436	KWH(AVG)	44445
29	2662.541	LB/MIN	44475	1032	82023.578	KWH(AVG)	44445
30	.000	GPM (AV)	26640	1033	34042.273	KWH(AVG)	44445
31	.000	GPM (AV)	0	1034	38149.070	KWH(AVG)	44500
32	.000	GPM (AV)	0	1035	3956.219	KWH(AVG)	44445
33	.000	GPM (AV)	0	1036	11987.637	KWH(AVG)	44445
34	.000	GPM (AV)	0	1037	87434.406	KWH(AVG)	44445
35	.000	GPM (AV)	0	1038	99422.031	KWH(AVG)	44445
36	.000	GPM (AV)	0	1039	5189.187	KWH(AVG)	44445
37	.000	GPM (AV)	0	1040	49428.492	KWH(AVG)	44445
38	.000	GPM (AV)	0	1041	54617.703	KWH(AVG)	44445

NBS LOC	VALUE	UNITS	TIME	DER	VALUE	UNITS	TIME
39	.000	GPM (AV)	0	1042	1247.812	KWH(AVG)	44525
40	.000	GPM (AV)	0	1043	1697.578	KWH(AVG)	44445
41	880.007	KW (INS)	44465	1044	8508.443	KWH(AVG)	44445
42	153.712	KW (INS)	340	1045	10206.018	KWH(AVG)	44445
43	308.977	KW (INS)	32805	1046	35279.570	KWH(AVG)	650
44	.000	KW (INS)	0	1047	18562.859	KWH(AVG)	44445
45	15.642	KW (INS)	44465	1048	59060.930	KWH(AVG)	650
46	103.958	KW (INS)	44465	1049	22163.023	KWH(AVG)	44445
47	46.739	KW (INS)	44465	1050	77391.141	KWH(AVG)	650
48	124.807	KW (INS)	17955	1051	25217.855	KWH(AVG)	44445
49	8.587	KW (INS)	24090	1052	67989.437	KWH(AVG)	44445
50	187.116	DEG F	44465	1053	93207.250	KWH(AVG)	44445
51	186.736	DEG F.	44465	1054	2455.300	KWH(AVG)	44570
52	189.686	DEG.F.	42125	1055	52064.234	KWH(AVG)	44445
53	185.252	DEG F.	44465	1056	54519.523	KWH(AVG)	44445
54	191.735	DEG F.	44465	1059	170049.875	KWH(AVG)	44445
55	194.191	DEG.F.	44465	1060	34224.000	KWH(AVG)	44580
56	191.022	DEG.F.	44465	1061	35793.172	KWH(AVG)	44445
57	187.519	DEG.F.	44465	1062	63851.367	KWH(AVG)	44525
58	191.273	DEG.F.	44465	1063	66416.125	KWH(AVG)	44445
59	187.018	DEG F.	44465	1064	99644.500	KWH(AVG)	44445
60	187.405	DEG.F.	44465	1065	3956.219	KWH(AVG)	44445
61	74.927	DEG.F	44465	1066	494315.625	KWH(AVG)	44445
62	72.880	DEG.F	44465	1067	597916.125	KWH(AVG)	44445
63	79.006	DEG F.	44405	1073	46236.016	KWH(AVG)	44445
64	71.426	DEG.F.	44465	1074	18874.398	KWH(AVG)	44445
65	70.124	DEG F.	33930	1075	65110.422	KWH(AVG)	44445
66	85.274	DEG.F.	44465	1076	120053.672	KWH(AVG)	44445
67	85.183	DEG.F.	44465	1077	53609.805	KWH(AVG)	650
68	81.132	DEG.F	44465	1078	9756.256	KWH(AVG)	44445

NBS LOC	VALUE	UNITS	TIME	DEP.	VALUE	UNITS	TIME
69	81.103	DEG.F.	44465	1079	49428.492	KWH(AVG)	44445
70	87.153	DEG.F.	44465	1080	87434.406	KWH(AVG)	44445
71	81.358	DEG.F.	44465	1081	290569.562	KWH(AVG)	650
72	122.853	DEG.F	12390	1082	359521.625	KWH(AVG)	650
73	163.014	DEG.F.	44465	1087	468406080.000	B.T.U.	41720
74	89.182	DEG.F.	44465	1088	1853891328.000	B.T.U.	44475
75	88.425	DEG.F.	44465	1089	2377310208.000	B.T.U.	41730
76	93.189	DEG.F.	44465	1090	2140728832.000	B.T.U.	29795
77	94.993	DEG.F.	44465	1091	304411584.000	B.T.U.	33750
78	89.929	DEG.F.	44465	1092	4262780.000	B.T.U.	43085
79	90.443	DEG.F.	44465	1093	2778556928.000	B.T.U	29795
80	191.031	DEG.F	44465	1100	.000	B.T.U.	0
81	172.823	DEG.F	44465	1101	-82601424.000	B.T.U	44465
82	128.811	DEG.F	44465	1102	-82801424.000	B.T.U.	44465
83	464.102	DEG.F.	44465	1103	.000	B.T.U.	0
84	134.681	DEG.F.	44465	1104	137728768.000	B.T.U.	40925
85	310.851	DEG.F.	44465	1105	137728768.000	B.T.U.	40925
86	-.384	DL DEG.F	44465	1106	-43563416.000	B.T.U.	44465
87	4.379	DL DEG.F	40985	1107	-44014568.000	B.T.U.	44465
88	.776	DL DEG.F	44465	1108	-44014568.000	B.T.U.	44465
89	3.990	DL DEG.F	44465	1109	432080960.000	B.T.U.	42005
90	-1.106	DL DEG.F	44465	1110	444419328.000	B.T.U.	40925
91	5.718	DL DEG.F	41105	1111	431681920.000	B.T.U.	42005
92	.765	DL DEG.F	44465	1112	.000	B.T.U.	0
93	.497	DL DEG.F	44465	1113	-126816000.000	B.T.U.	44465
94	3.352	DL DEG.F	44465	1114	-126816000.000	B.T.U.	44465
95	2.557	DL DEG.F	44535	1115	.000	B.T.U.	0
96	-3.629	DL DEG.F	44465	1116	582534272.000	B.T.U.	41045
97	2.940	DL DEG.F	44465	1117	582534272.000	B.T.U	41045
98	2.371	DL DEG.F	44465	1118	.000	B.T.U.	0

NBS LOC	VALUE	UNITS	TIME	OER	VALUE	UNITS	TIME
99	3.872	DL DEG.F	44465	1119	1644241152.000	B.T.U.	41045
100	-.778	DL DEG.F	35070	1120	1644241152.000	B.T.U.	41045
101	.191	DL DEG.F	32735	1121	2095551232.000	B.T.U.	44465
102	1.566	DL DEG.F	44475	1122	1134382592.000	B.T.U.	44465
103	3.681	DL DEG.F	39510	1123	1122771200.000	B.T.U.	44465
104	-1.037	DL DEG.F	41830	1124	1134382592.000	B.T.U.	44465
105	2.347	DL DEG.F	44475	1125	1134382592.000	B.T.U.	44465
106	-.328	DL DEG.F	44465	1126	406043776.000	B.T.U.	44465
107	5.788	DL DEG.F	43145	1127	1528815104.000	B.T.U.	44465
108	.198	DL DEG.F	43085	1128	1540426240.000	B.T.U.	44465
109	.006	DL DEG.F	44465	1129	1540426240.000	B.T.U.	44465
110	892.814	KW (AVG)	44445	1130	428171136.000	B.T.U.	44475
111	173.816	KW (AVG)	340	1131	1175254272.000	B.T.U.	44475
112	310.716	KW (AVG)	32790	1132	1606307328.000	B.T.U.	44535
113	.000	KW (AVG)	0	1133	1844242176.000	B.T.U.	44465
114	15.979	KW (AVG)	44445	1134	1765290496.000	B.T.U.	44465
115	110.244	KW (AVG)	44445	1135	1765290496.000	B.T.U.	44465
116	45.747	KW (AVG)	44445	1136	263617856.000	B.T.U.	44465
117	127.626	KW (AVG)	17880	1137	261507104.000	B.T.U.	44465
118	9.533	KW (AVG)	24785	1138	261507104.000	B.T.U.	44465
120	.000	ON/OFF	0	1139	-51520264.000	B.T.U.	44465
121	.000	ON/OFF	0	1140	-88291872.000	B.T.U.	44465
122	.000	ON/OFF	0	1141	3536074240.000	B.T.U.	44465
123	.000	ON/OFF	0	1142	3547685376.000	B.T.U.	44465
124	.000	ON/OFF	0	1143	3547685376.000	B.T.U.	44465
125	.000	ON/OFF	0	1144	3662645248.000	B.T.U.	44465
126	.000	ON/OFF	0	1145	3581584384.000	B.T.U.	44465
127	.000	ON/OFF	0	1146	3581584384.000	B.T.U.	44465
128	.000	ON/OFF	0	1147	-126571936.000	B.T.U.	44465
129	.000	ON/OFF	0	1148	-33898632.000	B.T.U.	44465

NBS LOC	VALUE	UNITS	TIME	DEF	VALUE	UNITS	TIME
140	.008	GPM (AV)	8400	1149	-33898632.000	B.T.U.	44465
141	.394	GPM (AV)	38190	1155	1758941824.000	B.T.U.	44465
142	.478	GPM (AV)	7005	1156	.000	B.T.U.	44580
143	.457	GPM (AV)	1560	1157	.000	B.T.U.	44580
144	.456	GPM (AV)	7305	1158	1007241216.000	B.T.U.	44465
145	.539	GPM (AV)	7565	1159	761700864.000	B.T.U.	44465
146	.000	GPM (AV)	0	1160	761700864.000	B.T.U.	44465
160	496.128	VOLTS	44465	1161	75300240.000	B.T.U.	44465
163	450.949	VOLTS	44465	1162	-3651082.000	B.T.U.	44465
172	5.000	MINUTES	44445	1163	-3651082.000	B.T.U.	44465
173	2.414	MINUTES	2725	1170	2328966.000	B.T.U.	43040
174	.896	MINUTES	32850	1171	608866560.000	B.T.U.	43040
177	.697	PWR FACT	44465	1172	611695744.000	B.T.U.	43040
178	60.004	HERTZ	44465	1173	93642880.000	B.T.U.	39570
179	2.699	DL DEG F	44535	1174	6630605.000	B.T.U.	35910
180	1.899	LB/MIN	26880	1175	.000	B.T.U.	26640
183	1.572	KW (AVG)	44525	1176	453199744.000	B.T.U.	44535
187	.000	DEG.F.	0	1177	453199744.000	B.T.U.	44535
193	1.092	DL DEG.F	21775	1178	-36337720.000	B.T.U.	30710
194	64.703	LB/MIN	28500	1179	60553416.000	B.T.U.	32735
195	.475	DL DEG F	38850	1180	.000	B.T.U.	26640
196	266.549	LB/MIN	40215	1181	488665344.000	B.T.U.	32735
197	8.111	DL DEG.F	37330	1182	488665344.000	B.T.U.	32735
198	1.022	GPM (AV)	22915	1183	.000	B.T.U.	26640
199	11.428	KW (AVG)	44445	1184	144939744.000	B.T.U.	32195
200	2.282	KW (AVG)	44445	1185	144939744.000	B.T.U.	32195
201	281.250	VOLTS	44465	1191	-3698765.000	B.T.U.	44465
202	49.963	DEG.F.	19975	1192	830746.375	B.T.U.	44465
203	150.266	DEG.F.	13345	1193	830746.375	B.T.U.	44465
204	150.872	DEG.F.	13165	1194	32601008.000	B.T.U.	44465

NBS LOC	VALUE	UNITS	TIME	DER	VALUE	UNITS	TIME
207	4.586	DL DEG.F	41115	1195	740877312.000	B.T.U.	44465
208	832.372	LB/MIN	44465	1196	769779456.000	B.T.U.	44465
209	1.103	DL DEG.F	44175	1197	769779456.000	B.T.U.	44465
210	898.019	LB/MIN	44475	1198	774308864.000	B.T.U.	44465
211	3.257	DL DEG.F	41235	1199	774308864.000	B.T.U.	44465
212	2.543	GPM (AV)	39885	1200	38261212.000	B.T.U.	43085
213	69.969	KW (AVG)	44445	1201	4262780.000	B.T.U.	43085
214	3.300	KW (AVG)	44570	1202	-41897784.000	B.T.U.	44465
215	191.348	VOLTS	44465	1203	141218848.000	B.T.U.	44465
217	82.049	DEG.F.	44285	1204	631634688.000	B.T.U.	43145
218	178.556	DEG.F	38660	1205	727881600.000	B.T.U.	44465
219	175.337	DEG.F	38300	1206	727881472.000	B.T.U.	44465
221	.000	C/CM2/MN	0	1207	732411008.000	B.T.U.	44465
222	.000	C/CM2/MN	0	1208	732411008.000	B.T.U.	44465
223	.000	DEGREES	0	1209	727719296.000	B.T.U.	44295
224	.000	MILES/HR	0	1210	732250880.000	B.T.U.	44295
225	31.000	IN HG.	44465	1211	732250880.000	B.T.U.	44295
226	.000	DEG.F	0	1212	809107712.000	B.T.U.	42915
227	.000	PER-CENT	0	1213	-83337648.000	B.T.U.	42915
228	.000	DEG.F.	0	1214	-83337760.000	B.T.U.	42915
235	5.242	DL DEG.F	44465	1215	-78950864.000	B.T.U.	42915
236	167.346	LB/MIN	36850	1216	-78950864.000	B.T.U.	42915
237	.829	DL DEG.F	39930	1217	-83337760.000	B.T.U.	42915
238	522.937	LB/MIN	37055	1218	-78950864.000	B.T.U.	42915
239	4.540	DL DEG.F	44465	1219	-78950864.000	B.T.U.	42915
240	558.371	LB/MIN	44000	1225	.000	B.T.U.	0
241	66.440	KW (AVG)	44445	1226	.000	B.T.U.	0
242	6.975	KW (AVG)	44445	1227	.000	B.T.U.	0
243	119.915	VOLTS	44465	1228	9797914.000	B.T.U.	42600
244	78.957	DEG.F.	44465	1229	2175918592.000	B.T.U.	42390

NBS LOC	VALUE	UNITS	TIME	DEP	VALUE	UNITS	TIME
245	193.988	DEG F.	43505	1230	1058193920.000	B.T.U	17745
246	184.569	DEG.F.	43565	1231	235603520.000	B.T.U.	17520
249	14.652	DL DEG.F	37700	1232	698858752.000	B.T.U	24705
250	559.267	LB/MIN	44580	1233	233245504.000	B.T.U.	43985
251	.042	DL DEG F	31055	1234	139045664.000	B.T.U.	37700
252	366.430	LB/MIN	44535	1235	363286656.000	B.T.U.	38000
253	9.389	DL DEG.F	43985	1236	106159648.000	B.T.U.	44465
254	559.867	LB/MIN	44465	1237	60315664.000	B.T.U.	36805
255	117.530	KW (AVG)	44445	1238	167441888.000	B.T.U	36805
256	16.113	KW (AVG)	44445	1241	354398.562	B.T.U.	44475
257	494.745	VOLTS	44465	1242	133205.437	B.T.U.	37315
259	97.148	DEG F.	43630	1243	26782988.000	B.T.U	21775
260	197.388	DEG F	44225	1244	11090530.000	B.T.U	15425
261	126.125	DEG.F	44105	1245	430811712.000	B.T.U	12450
263	11.291	DL DEG F	44345	1246	430811712.000	B.T.U	12450
264	701.427	LB/MIN	43445	1247	255979808.000	B.T.U.	12450
265	.710	DL DEG.F	42980	1248	136255232.000	B.T.U.	37705
266	1055.297	LB/MIN	42975	1249	144456672.000	B.T.U	26955
267	12.275	DL DEG.F	43865	1250	285184832.000	B.T.U	20150
268	529.254	LB/MIN	44465	1251	265661600.000	B.T.U.	43865
269	91.384	KW (AVG)	44445	1252	51649208.000	B.T.U	43745
270	33.896	KW (AVG)	44445	1253	319068160.000	B.T.U.	44345
271	475.263	VOLTS	44465	1254	307361.625	B.T.U	41215
273	82.966	DEG.F.	44285	1255	171723616.000	B.T.U.	40375
274	185.287	DEG F.	44165	1256	173816256.000	B.T.U.	41115
275	185.122	DEG F.	44105	1257	795336576.000	B.T.U.	18650
277	-.297	DL DEG.F	26010	1258	262579040.000	B.T.U.	18650
278	4705.649	LB/MIN	22715	1259	1068222208.000	B.T.U.	7565
279	3.012	DL DEG.F	37705	1260	502696320.000	B.T.U.	7665
280	1296.597	LB/MIN	38895	1261	3859614720.000	B.T.U.	17385

NBS LOC	VALUE	UNITS	TIME	DEP	VALUE	UNITS	TIME
281	47.419	KW (AVG)	650	1262	1420280320.000	B.T U.	10785
282	24 941	KW (AVG)	44445	1263	000	B.T U.	28560
283	29 799	KW (AVG)	44445	1264	1420280320 000	B.T.U.	10725
284	494 950	VOLTS	44465	1265	5279894528 000	B.T U.	10725
285	137.961	VOLTS	31220	1266	2362969 500	B T U	31055
286	122 166	DEG F.	44110	1267	28269492.000	B.T U	39930
287	187 269	DEG F	44345	1268	.000	B.T U.	44580
288	000	SUM/WINT	0	1269	16582646 000	B T U.	43110
289	000	SUM/WINT	0	1270	000	B T.U.	26640
315	46 000	KW (AVG)	44640	1271	000	B.T U.	26640
316	1 597	SUM/WINT	44640	1272	000	B.T U	26640
317	500	PER-CENT	44640	1273	65956760 000	B.T U	43635
318	1 000	EFF	44640	1274	89985504 000	B.T.U.	42980
319	34 698	DEG.API	44640	1275	112475280.000	B T U.	44175
320	138935.125	BTU/GAL	44640	1276	268572416.000	B.T.U.	42380
				1277	200312352 000	B.T.U	42380
				1278	.000	B T.U.	26640
				1279	.000	B.T.U.	26640
				1285	.000	B T U	0
				1286	.000	B T U	0
				1287	.000	B.T.U.	0
				1288	.000	B T U	0
				1289	000	B.T.U.	0
				1290	.000	B.T.U.	0
				1291	.000	B.T.U	0
				1292	000	B T.U.	0
				1294	10267 406	GALLONS	10785
				1295	.000	GALLONS	28560
				1296	10267.406	GALLONS	10725
				1298	.000	GALLONS	0

NBS LOC	VALUE	UNITS	TIME	DER	VALUE	UNITS	TIME
				1299	.000	GALLONS	0
				1300	.000	GALLONS	0
				1301	.000	GALLONS	0
				1302	.000	GALLONS	0
				1303	.000	GALLONS	0
				1304	.000	GALLONS	0
				1305	.000	GALLONS	0
				1307	70.246	GALLONS	42600
				1308	15668.543	GALLONS	42390
				1309	7649.834	GALLONS	17745
				1310	1703.211	GALLONS	17520
				1311	5052.148	GALLONS	24705
				1312	27901.793	GALLONS	17385
				1313	38159.109	GALLONS	10725
				1315	34224.000	KW (AVG)	44640
				1316	1.597	SUM/WINT	44640
				1317	.500	PER-CENT	44640
				1318	1.000	EFF.	44640
				1319	34.698	DEG.API	44640
				1320	138935.125	BTU/GAL	44640

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APPENDIX B

UNCERTAINTY OF CALCULATED VALUES

B.1 INTRODUCTION

Instrumentation for the JCTE project was selected to provide maximum measurement accuracy and a high degree of reliability. Because the program required long-term monitoring in a field environment, laboratory instrumentation and instruments requiring frequent calibration or maintenance were avoided. To meet these requirements, thermocouples were selected for temperature measurements; venturis and turbine flowmeters were selected for flow measurements; and Hall-effect meters were selected for electrical power measurements. The measurement accuracies of these instruments as they were connected to the DAS are given in detail in reference [B-1].

B.2 UNCERTAINTY OF MULTI-MEASUREMENT VALUES

The uncertainty of multi-measurement data can be calculated using the root mean square (RMS) technique, also called the statistical bounds technique. The RMS technique states that a given variable, s, is calculated from several measurements (say x, y, and z) according to the equation:

$$s = f(x,y,z) \qquad \text{(B-1)}$$

The RMS uncertainty, ds, of the calculated variable, s, is:

$$ds = [(\frac{\partial f}{\partial x}\cdot dx)^2 \quad (\frac{\partial f}{\partial y}\cdot dy)^2 + (\frac{\partial f}{dz}\cdot dz)^2]^{1/2}$$

For the case of a plant component in the primary hot water loop, thermal energy values were calculated from flow rate, temperature difference, and specific heat according to the following equation:

$$E = F\cdot\Delta T\cdot C_p \qquad \text{(B-3)}$$

where:

E is the rate of thermal energy input or output of the component of interest,

F is the water flow rate,

ΔT is the difference in temperature of the water entering and leaving the component of interest, and

C_p is the specific heat of the water in the loop.

The uncertainty of the calculated energy, dE, is expressed by:

$$dE = [(dF \cdot \Delta T \cdot C_p)^2 + (d\Delta T \cdot F \cdot C_p)^2 + (dC_p \cdot F \cdot \Delta T)^2]^{1/2} \qquad \text{(B-4)}$$

where:

dE is the uncertainty in the thermal energy
dF is the uncertainty in the rate of flow
$d\Delta T$ is the uncertainty in the temperature difference, and
dC_p is the uncertainty in the specific heat.

By dividing equation (B-4) throughout by the thermal energy, E, or equation (B-3):

$$\frac{dE}{E} = \left[\frac{(dF \cdot \Delta T \cdot C_p)^2}{(F \cdot \Delta T \cdot C_p)^2} + \frac{(d\Delta T \cdot F \cdot C_p)^2}{(F \cdot \Delta T \cdot C_p)^2} + \frac{(dC_p \cdot F \cdot \Delta T)^2}{(F \cdot \Delta T \cdot C_p)^2}\right]^{1/2}$$

which reduces to:

$$\frac{dE}{E} = \left[\frac{dF}{F}^2 + \frac{d\Delta T}{\Delta T}^2 + \frac{dC_p}{Cp}^2\right]^{1/2} \qquad \text{(B-5)}$$

where:

$\frac{dE}{E}$ is the ratio of the uncertainty of E with respect to the computed value of the thermal energy, E;

$\frac{dF}{F}$ is the ratio of the uncertainty of F with respect to the measured value of F;

$\frac{d\Delta T}{\Delta T}$ is the ratio of the uncertainty of ΔT, with respect to the measured value of ΔT; and

$\frac{dC_p}{C_p}$ is the ratio of the uncertainty of C_p with respect to the assumed value of C_p.

Reducing equation (B-5) to a simplified form:

$$R_p = r_F^2 + r_{\Delta T}^2 + r_{C_p}^2 \qquad \text{(B-6)}$$

Inserting typical instrumentation uncertainties from reference [B-1], where an uncertainty of the flow rates in the CEB was 1.1 percent ($r_F = .011$), the uncertainty in the ΔT measurement was 0.2°F (0.1°C) ($r_{\Delta T} = \frac{0.2}{\Delta T}$), and the uncertainty in the assumed value of the specific heat was 1 percent ($r_{C_p} = .01$); the uncertainty in the thermal energy is (for a typical value of ΔT of 5°F (0.3°C) for a component in the primary hot water loop):

$$R_p = \sqrt{.011^2 + (\cdot\frac{2}{5})^2 + .01^2}$$

$$R_p = .0427 \text{ or } 4.27\%$$

Assuming typical conditions for a component in the primary hot water loop when the rate of flow of water was 11,000 pounds per minute (83.2 kg/s), the ΔT was 5°F (3°C), and a 1 percent uncertainty in the assumed specific heat, the R_p of 4.27 percent is equivalent to 2,348 Btu per minute (41.26 kW) or 104.8 MBtu (110.6 GJ) per month.

The data sometime indicated slightly higher output values of the insulated hot water heat exchangers in the primary loop than the input, (see table 4.5) which of course is impossible. In these calculations, the thermal outputs of the two secondary heating loops were often directly compared with the thermal input from the primary hot water loop. Neglecting losses, the following equation applies:

$$E_{s1} + E_{s2} - E_p = 0 \qquad \text{(B-7)}$$

where:

E_p is the thermal energy removed from the primary hot water loop,

E_{s1} is the thermal output of one secondary loop, and

E_{s2} is the thermal output of the other secondary loop.

Each of the three energy values noted in equation (B-7) were be calculated using three independent sets of variables similar to those described above. Using the same derivation used to obtain equations (B-5) and (B-6), the total uncertainty is equal to the RMS of the uncertainties of each variable involved:

$$R_T = \sqrt{R_p^2 + R_{s1}^2 + R_{s2}^2} \qquad \text{(B-8)}$$

where:

R_T is the uncertainty in the sum of the values in equation (B-7)

R_p is the uncertainty in the thermal energy input from the primary hot water loop obtained from equation (B-6),

R_{s1} is the uncertainty of the thermal energy output from one secondary output loop, and

R_{s2} is the uncertainty of the thermal energy output from the second secondary loop.

Using the same value of ΔT for the calculation of R_{s1} and R_{s2} that was used in calculating R_p, equation (B-8) becomes:

$$R_T = \sqrt{.0427^2 + .0427^2 + .0427^2}$$

$$R_T = .074 \text{ or } \pm 7.4\%.$$

In this example, the uncertainty would be $\pm$ 7.4 percent of the sum of the three quantities, E_{s1}, E_{s2} and E_p. Because the losses from the heat exchanger were quite small in comparison with the average thermal exchange, the uncertainty occasionally caused the data to indicate an impossible value.

B.3 SPECIAL FACTORS IN COMPUTING UNCERTAINTIES

Two variables involved in the above examples should be given special attention when calculating of an uncertainty for a specific case. First, the value of ΔT was set to 5°F (3°C) for all calculations. In reality, these values varied from 0.7°F (0.4°C) to 10°F (6°C) on both sides of the exchanger depending upon the thermal demands of the secondary loops. In randomly observing actual ΔT readings for the primary and the two secondary loops, they were found to be 1.8°F (1°C), 0.7°F (0.4°C), and 2.6°F (1.4°C) respectively, for a five-minute period during the month of July, 1977 and 9.0°F (5.0°C), 6.0°F (3.3°C) and 10°F (6°C) respectively, for a similar period during the month of February, 1978. Since the uncertainty of the ΔT was given as a tolerance instead of a ratio, the vast differences in the value of $r_{\Delta T}$ in equation (B-6) will significantly affect the uncertainties found by using equations (B-6) and (B-7).

The second variable that should be noted is the assumed value of the specific heat of the fluid in the loops. It is noted in reference [B-3] that the specific <u>weight</u> of the fluids were computed for each venturi in the primary and secondary loops for every five-minute period. However, the specific <u>heat</u> of the fluid was considered to be unity in the thermal energy calculations made in the existing software. An uncertainty of 1 percent for the specific heat, C_p, was introduced in the calculation of the uncertainty of thermal energy because of the known <u>increase</u> in specific heat of water as the temperature increases, and the known <u>decrease</u> in the specific heat of the fluid as ethylene glycol and other additives are introduced (see reference [B-4]). Since the additives in each loop were introduced in a somewhat random fashion to slightly reduce the freezing point of the fluid and to prevent internal corrosion of the pipes, the specific <u>heat</u> of the fluid was decreased by an unknown factor. Information obtained from the plant engineer and from laboratory tests of samples of the fluids indicated a 1 percent to 3 percent <u>decrease</u> in the specific heat at ambient temperatures. Based upon these factors the ratio of .01 or 1 percent was established for the specific heat.

B.4 AVAILABILITY OF DAS DATA

The accuracy of <u>monthly</u> data is affected by the percentage of time data were recorded by the DAS for a given month. Data for those months during which less than 60 percent of the total data were recorded should be used with caution. The two months during the year when the chillers were put on-line or taken off-line by the plant engineer, denotes a change in the mode of operation of the plant from winter to summer or from summer to winter, respectively. Data for these two months (usually May and October) are presented in this report and should used keeping the date of the change in mode of operation in mind. The plant thermal energy data for May, 1975, are an excellent example. The monthly plant data listed for May 1975, were based on calculations from DAS daily summaries due to the fragmented data and the short chiller on-time.

The accuracy of the daily data is not necessarily affected by the percentage of time data were recorded for the month in which a given day appears. However, before using the daily data, the total time of data collection during the day of interest should be observed. If one or more hours were absent from the data channel or derived variable of interest, it is advisable to select another day. This same philosphy applies to the use of the hourly data. In the monthly, daily, and hourly printouts from the computer, the time of recorded valid data are shown in a column adjacent to the engineering units for each DAS channel and each derived variable. Typical examples of monthly, daily, and hourly data are shown in appendix A.

B.4.1 Problems Affecting DAS On-Line Time

Table B.1 shows the percentage of DAS on-line time for each of the 33 months covered by this study. Figure B.1 is a bar graph of the values listed in this table. Routine monitoring and preventive maintenance minimized DAS malfunctions that would have otherwise resulted in the loss of large banks of data. However, problems were experienced which reflected on the DAS on-line time. Lighting was the apparent cause of severe damage to the DAS in July 1975 and in August 1977. Restoration of the DAS operation on each of these occasions involved the replacement of more than 60 integrated circuit chips in the DAS, all specially-designed operational amplifiers, many of the power supplies, and several integrated circuit chips in the remote DAS units. The required replacement of the operational amplifiers in the remote DAS stations necessitated extended periods of off-line time for the remote data. The long time delay experienced in obtaining manufacturer's repair and/or supply of new operational amplifiers occasioned redesign of these units in an attempt to minimize this problem in the future.

A mechanical failure of the cooling units in the DAS room in July 1976 allowed the system to become overheated and record data erraticly. An additional air conditioner was installed as a standby to the two existing cooling units to avoid future problems of this type.

One additional problem was experienced which reflected on the availability of data. The tape recording system malfunctioned several times causing the loss of as much as 12 days of data at one time. Although the recorder was cleaned, rebuilt, and realigned after over 2-1/2 years of continuous satisfactory service, occasional mechanical and electrical problems continued to create DAS tapes or sections of DAS tapes that could not be processed.

B.5 REFERENCES - APPENDIX B

B-1. Bulik, C., Rippey, W., Hurley, C, and Rorrer, D., "Description of the Data Acquisition and Instrumentation Systems: Jersey City Total Energy Project", National Bureau of Standards Report NBSIR 79-1709, March 1979.

B-2. Crumpler, T. B. and Yoe, J. H., "Chemical Computations and Errors", John Wiley and Sons, Inc., New York, New York, Chapter 10, 1940.

B-3. Rorrer, D. E., Rippey, W., and Chang, Y., "Data Reduction Processes for the Jersey City Total Energy Project", National Bureau of Standards Report NBSIR 79-1759, May 1979.

B-4. Baumeister, T., "Marks Standard Handbook for Mechanical Engineers", Seventh Edition, McGraw-Hill Book Company, New York, New York.

Table B.1 DAS On-Line Time*

	1975	1976	1977
January	--	94.8%	89.0%
February	--	92.8%	98.6%
March	--	79.0%	94.4%
April	85.7%	77.1%	98.8%
May	32.7%	91.8%	99.6%
June	97.8%	77.4%	63.1%
July	18.0%	22.9%	99.0%
August	72.4%	91.2%	43.6%
September	46.8%	95.0%	69.5%
October	74.5%	98.9%	51.0%
November	86.9%	96.1%	87.5%
December	97.9%	57.1%	98.0%

*Represents percentage of time data were recorded by the DAS for each month. Individual channel time may be less than the DAS on-line time.

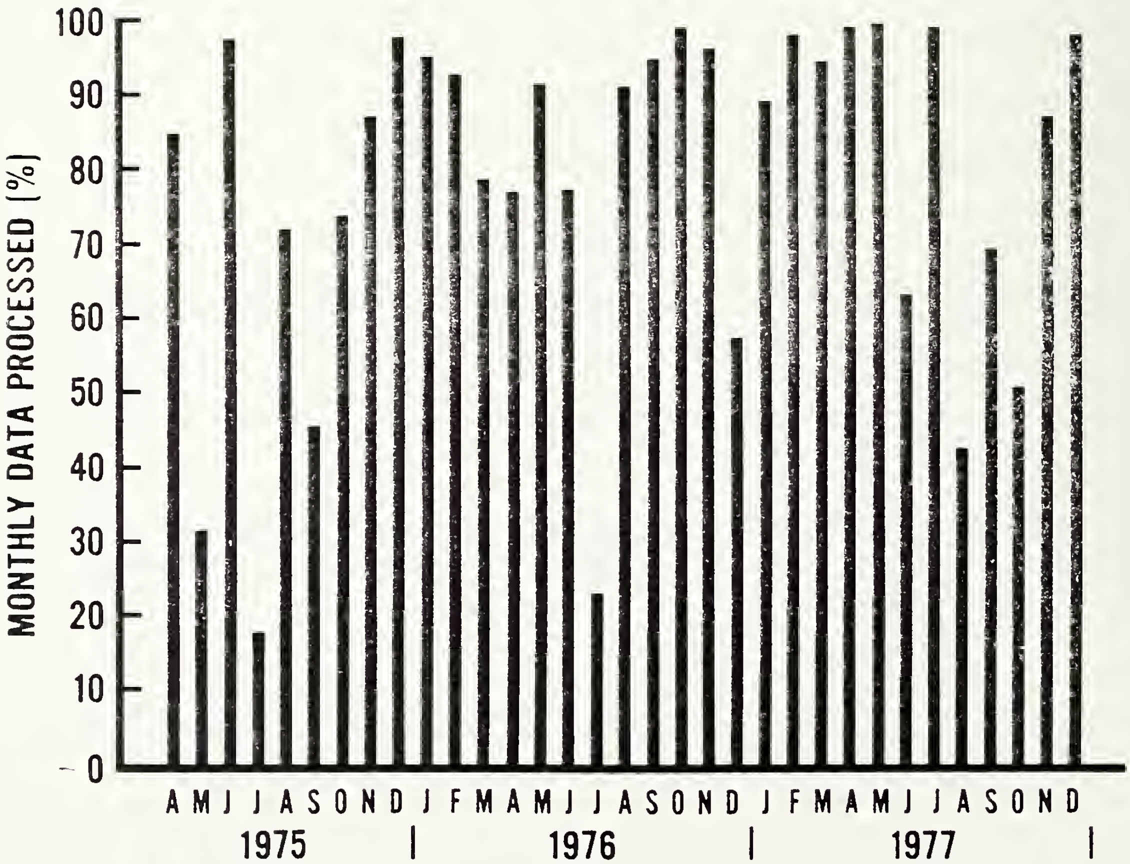

Figure B.1 Percentage of monthly data recorded and processed by NBS

APPENDIX C - BOILER FUEL CONSUMPTION MODEL

A mathematical boiler model was used to determine the boiler fuel consumption for months when fuel data was unavailable. This model predicted the fuel consumed by the boiler(s) from monthly DAS measurements of the total boiler(s) output.

The boilers at the JCTE site are fire-tube, hot-water boilers having a rated full-load capacity of 13.4 MBtu per hour (3.9 MW). Unless a boiler is bypassed, primary hot water continuously flows through it. The construction of a fire-tube boiler is such that the boiler shell inner walls are maintained at the temperature of the boiler water while the endplates are heated by the combustion gases.

The mathematical boiler model is described by two terms. The first term accounts for a fixed percentage of the combusted fuel's heat content being transferred to the boiler mechanisms which carefully regulates the fuel/air mixture and due to boiler controls which only allows firing at rates greater than 30 percent full-load. The second term accounts for the heat losses from the boiler's shell. The shell is held at a relatively constant temperature by the primary hot water flowing through the boiler. The boiler model is expressed by the equation:

$$BO = (m_f)(HV)(F) - (L)(T)(N) \qquad \text{(C-1)}$$

where:

BO is the DAS measurement of boiler output for the time period T,
m_f is the constant boiler firing efficiency,
HV is the higher heating value of one gallon of fuel oil,
F is the gallons of fuel oil consumed in the time period T,
L is the constant boiler loss rate, and
N is the number of boilers connected into the primary loop during time interval T.

Note that the boiler firing efficiency is different from the boiler operating efficiency which includes shell losses.

Numerical values for the two terms of the boiler model were determined from DAS measurements and boiler fuel measurements. From DAS measurements of idle boiler PHW heat, the constant loss term was found to be approximately 100 kBtu per hour (29.3 kW). Using a regression analysis based on equation (C-1) and specific periods of boiler output and boiler fuel data when data were available, the average firing efficiency was determined to be 84 percent.

The manufacturer's data sheet which describes boiler part-load operating efficiency is in agreement with this model. The model predicts operating efficiencies of 83.3 percent at 100 percent load and 82.0 percent at 30 percent steady-state load. These values are within 1 percent of the performance data given by the manufacturer.

Computation of boiler fuel consumption using the model required only data for the total boiler output and the duration that the boiler(s) were valved into the primary loop (generally this was all or none of a month). To compute fuel consumption, the boiler(s) loss rate was multiplied by the duration of time that each boiler was "valved in" and added to the measured total boiler(s) output. This quantity was divided by the boiler <u>firing efficiency</u> and the fuel's heat content. This computation is represented by the following rearrangement of equation (C-1):

$$F = \frac{BO + (L)(T)(N)}{(HV)(\eta_f)}, \text{ or}$$

$$F(\text{gallons}) = \frac{BO(\text{Btu}) + [100\ \text{kBtu/h}][T(\text{hours})][N]}{[.84][HV(\text{Btu/gallon})]}$$

The <u>operating efficiencies</u> of the boiler(s) were determined by dividing the measured boiler output by the fuel consumption times the fuel heat content. Measured fuel consumption data were used when available; however, when measured data were not available, the boiler model was used to determine fuel data. Due the constant loss term, the monthly <u>operating efficiency</u> of the boiler(s) dropped below 80 percent during low output months.

APPENDIX D - DETAILED DESCRIPTION OF ALTERNATIVE ENERGY SYSTEMS

D.1 INTRODUCTION

This appendix describes in detail each of the twelve alternative systems which were used in the comparative systems analysis. Each of the twelve is described in terms of major equipment, functional relationships, design parameters, and operating approach. Where individual buildings differ in equipment type and/or size, this is clearly indicated along with key design parameters for each building.

Table D.1 provides a summary description of the alternatives systems in terms of basic equipment and system type. It should be noted that none of the alternative energy systems include the pneumatic trash collection system.

D.2 SYSTEM 1 - TOTAL ENERGY SYSTEM

The total energy system is based on the on-site generation of electrical power by five diesel-electric sets rated at 640 kW in conventional form, derated to 475 kW for high temperature jacket water conditions. These generators are located in the Central Equipment Building (CEB). Waste heat is recovered by the primary hot water system which consists of engine jacket cooling and water-cooled exhaust gas mufflers. When required by site demand, additional heat is provided to the primary hot water system by two 400 horsepower (3.9 MW) oil-fired boilers. Fuel for both the generators and boilers is No. 2 fuel oil with a higher heating value of 140,000 Btu per gallon (560 GJ/m^3). The generators feed a main switchboard bus rated at 4000A, three-phase, which serves the CEB and radial feeders to the site. The average load is handled by three of the generators which are alternated in their use.

During the cooling season, the primary hot water system provides heat to two 546 ton (1.9 MW) absorption chillers. The chillers may be operated independently or in parallel, depending on site demand. The chilled water system provides 44°F (6.7°C) water to the site buildings for cooling purposes. The chiller condenser water systems consist of two roof-mounted cooling towers, each having the capacity to provide 2,220 gpm (8.40 m^3/min) of water at 85°F (29°C) to the chiller condensers.

During the heating season, the primary hot water system provides heat to the building heating hot water system through two water-to-water heat exchangers, each with the capacity to exchange 16 x 10^6 Btu per hour (16.9 GJ/h). Building heating hot water at approximately 200°F (93°C) is pumped to the individual buildings by three 500 gpm (1.9 m^3/min) pumps through the site distribution system.

Some buildings' heating hot water is used throughout the year for generation of domestic hot water at each building.

Table D-1. Summary of System Components

	System Number											
Component Description	1	2	3	4	5	6	7	8	9	10	11	12
Energy System:												
Central System	X	X	X	X	X	X	X					
Individual Building								X	X			
Individual Apartment										X	X	X
Electricity:												
Diesel Generators	X	X	X	X								
Sell Electricity		X										
Purchase Electricity					X	X	X	X	X	X	X	X
Cooling:												
Absorption Chillers	X	X	X	X		X	X					
Electric Motor Chillers				X	X			X	X			
Incremental Thru-the-Wall Units											X	
Heat Pump Units											X	
Diesel Driven Chillers							X					
Self-Contained Cooling Units												X
Heating:												
Oil-Fired Boilers	X	X	X	X	X	X	X	X				
Electric Boilers									X			
Incremental Thru-the-Wall Units											X	
Heat Pump Units											X	
Electric Resistance Furnace												X
Domestic Hot Water:												
Oil-Fired Boilers	X	X	X	X	X	X	X	X				
Electric HW Heaters									X	X	X	X

The primary hot water passes through a dry cooler to reject any excess heat and to maintain its temperature to approximately 190°F (88°C) before returning to the diesel engine.

Additional engine heat is recovered by the lube oil cooling system. Heat is collected from the engine oil coolers and aftercoolers, and is used to provide heat to the air handling unit and the fan coil units in the CEB. Unused lube oil cooling system heat is discharged through a roof-mounted roof cooler.

Intake air for the diesel engines is provided by a 40,000 cfm (19 m^3/s) air handling unit in the CEB. The unit is provided with a heating coil supplied from the lub oil cooling water system and a cooling coil supplied from the chiller water system. The unit also provides air for general air conditioning of the CEB. Fan coil units provide heating and cooling for the CEB office and control room.

Hot water, chilled water, and electricity are provided to the site buildings by the site distribution systems. The chilled water and hot water systems consist of underground piping runs connected to each building's hot water and chilled water supply. Valve pits are provided to insulate any building from the system. The electrical distribution is via underground duct banks to an electrical equipment room at each building.

Each of the four apartment buildings is provided with a mechanical room which contains pumps, an air handler, and a domestic hot water generator. Individual apartments are heated and cooled by two-pipe fan coil units. Hot water or chilled water (depending on season) from the site distribution system is pumped to the fan coil units from mechanical rooms. The fan coil units are individually controlled in each apartment. Conditioned air is supplied to corridors, lobbies, and other central areas of each building by air handling units which are supplied with hot water and chilled water for temperature control. Ventilation is provided by individual apartment kitchen and bathroom exhaust fans and by a centralized corridor exhaust system. Hot water from the site distribution system also provides the heating medium for the domestic hot water heaters located in each building mechanical room. City water for domestic use is supplied to each building from the city mains.

Each building (except the swimming pool) receives one normal power feeder (PN) and one essential power feeder (PE). The essential feeder is tied to the public utility (Public Service Electrical and Gas Company) and is for loads such as exit lights, elevators, and fire pumps. The essential feeder receives power from the generator bus and usually functions as a normal feeder, and is transferred to the utility source only when there is a generator bus outage. The electrical room at each building houses all of the major equipment for the normal and essential service, for transforming to 480/272V or 208/120V, and distribution throughout the building.

The commercial building consists of two occupied floors separated by a parking level. The upper floor office area is heated and cooled by a central air handling unit and four-pipe fan coil units located on the perimeter. The lower floor is designed for retail shops and is provided with hot water and chilled water supply taps for tenant connections. Hot water and chilled water for the building is supplied from the site distribution system. The hot water supplied is used for both building heating and domestic hot water generation.

The school building is heated and cooled by four-pipe fan coil units located throughout the building, again served from the site distribution system. The hot water is used for domestic hot water generation, as well. The swimming pool bath house uses hot water from the site distribution system to generate domestic hot water only.

D.3 SYSTEM 2 - TOTAL ENERGY SYSTEM SELLING POWER

All equipment for System 2 is identical to that used for System 1; however, the operation of System 2 differs from that of System 1. While the generators in System 1 are operated to match the site electrical power demand, in System 2 the generators are operated such that the total site heat requirement is matched by the heat rejected from the diesel engines and any excess electrical power generated in this operating mode is sold to the local power company. This operating mode minimizes the auxiliary heat energy input by the oil-fired boilers into the primary hot water loop, since auxiliary heat is required only when the site heat energy requirement is greater than the capacity of the diesel engine heat recovery system (approximately 660 hours per year).

The local power company, Public Service Electric and Gas Company, indicated that it would accept all of the electrical power that the Jersey City Total Energy Plant could produce during the utility system's peak load hours, 8:00 a.m. and 10:00 p.m. During the hours between 10:00 p.m. and 8:00 a.m., System 2 will be operated in a manner identical to System 1.

D.4 SYSTEM 3 - TOTAL ENERGY SYSTEM WITH HIGH EFFICIENCY ENGINE-GENERATORS

System 3 utilizes large, medium-speed, high-efficiency, engine-generators in the total energy system. Except for the substitution of these engine-generators for the standard units used in System 1, all equipment and operating modes are identical to System 1.

D.5 SYSTEM 4 - TOTAL ENERGY SYSTEM WITH ELECTRIC-DRIVEN CENTRIFUGAL CHILLERS AND ABSORPTION CHILLERS

System 4 is a total energy system utilizing absorption water chillers and electric-driven compression water chillers. In this system, the site chilled water demand is met first by an absorption water chiller fueled by hot water recovered from the diesel-generators. Increases in the chilled water demand greater than the output of the absorption machine at this heat input rate are met by the electric-driven centrifugal water chiller. Starting the electric-driven centrifugal chiller results in additional heat recovery from the diesel-generator sets. This additional heat recovery is used by the absorption machine to increase its output. Approximately one ton of additional cooling is generated at the absorption machine for each four tons of cooling generated by the electric-driven centrifugal chiller. This system minimizes the firing of the boiler to meet chilled water demand as is required in System 1.

Relative to System 1, this system substitutes a 550 ton (1.9 MW) compression water chiller and its associated electrical service in place of one of the absorption units and substitutes a smaller cooling tower for one of the System 1 units. All other equipment and operating modes are identical to System 1.

D.6 SYSTEM 5 - CENTRAL PLANT WITH ELECTRIC CHILLER AND OIL BOILER

System 5 is based on the central utility plant concept without total energy capability. The CEB, in this scheme, provides hot water for heating and chilled water for cooling to the buildings on the site. Electrical power is purchased from the local utility and is distributed to the site buildings from the CEB.

Hot water and chilled water are supplied to the buildings on the site by an underground distribution system as in System 1. The hot water heating system contains two 210 hp (2.1 MW) oil-fired boilers, and hot water heating pumps. The hot water, as in System 1, is used during the winter for space heating and throughout the year for domestic hot water generation. The chilled water system consists of two 550-ton (1.9 MW) electric motor-driven centrifugal chillers delivering chilled water to the buildings on the site. The chillers are cooled by a condenser water system containing two 660-ton (2.3 MW) cooling towers located on the roof of the CEB.

As in System 1, the primary heating and cooling of the site buildings is done by fan coil units. The description of the System 1 includes a detailed description of the site buildings' mechanical and electrical systems which are unchanged for System 5.

The normal electrical power is purchased from the local utility company at 480V, three-phase. There is one incoming service to the main stitchgear in the CEB where it is then distributed to the two 620 HP (460 kW) chillers, the CEB, and the buildings on the site via a radial distribution system.

The site distribution, the site building loads, and the internal building distribution is similar to System 1.

Emergency power for the essential circuit is provided by a diesel engine-driven generator located in the CEB, which is interconnected to the main switchboard and the site feeders in the same manner as it was in System 1. The only difference is the physical location of the emergency supply is at the CEB rather than Descon-Concordia.

D.7 SYSTEM 6 - CENTRAL PLANT WITH ABSORPTION CHILLER AND OIL BOILER

System 6 is a central utility plant without total energy capability and is similar to System 5. In System 6, two 550 ton (1.9 MW) absorption water chillers are substituted for the electric-driven centrifugal water chillers used in System 5. The electrical distribution in the CEB is similar to System 5 although it differs in that there is no requirement to feed electric motor-driven chillers as in System 5. All other equipment and operating modes are identical to that of System 5.

D.8 SYSTEM 7 - CENTRAL PLANT WITH DIESEL-DRIVEN ABSORPTION CHILLERS AND OIL BOILERS

System 7 is based on the central utility plant concept without total energy capability similar to System 5 and System 6.

Chilled water in this system is produced by an engine-driven centrifugal and absorption chiller arrangement. Two 400-ton (1.4 MW) centrifugal chillers are driven by diesel engines having a waste heat recovery system consisting of engine jacket cooling and exhaust gas cooling. The waste heat from these engines is recovered by the primary hot water system and is used to drive two 150-ton (0.5 MW) absorption chillers to produce additional chilled water. When required by the absorption chillers, supplemental heat is provided to the system by the hot water heating system through a water-to-water heat exchanger. The system is designed to provide up to 1000 tons (3.5 MW) of cooling without the addition of supplemental heat. At part load conditions, the system is designed to be balanced so that the heat demand of the absorption chillers is equal to the heat recovered from the diesel engines. At cooling loads from 1000 tons (3.5 MW) to the design load of 1100 tons (3.8 MW), supplemental heat is required for the absorption chillers The diesel engines are rated at 415 bhp (310 kW) at 1200 rpm. At peak operating conditions, fuel consumption per engine is 25.1 gallons per hour (0.095 m^3/h) of No. 2 fuel oil with a heating value of 140,000 Btu per gallon (560 GJ/m^3).

The centrifugal chillers operate at 3600 rpm thereby requiring the use of 3:1 speed increasing gears between the engines and chillers.

All other equipment and operating modes are similar to System 6.

D.9 SYSTEM 8 - INDIVIDUAL PLANT WITH ELECTRIC CHILLERS AND OIL BOILERS

In System 8, each site building is provided with its own independent heating and cooling system. There is no central utility plant as in the previous systems. Each building has an enlarged mechanical room housing the equipment required to generate hot water and chilled water for the heating, cooling, and domestic hot water requirements of the building. Electrical service is purchased from the local utility and is supplied to each building. The use of the hot water, chilled water, and electrical service within each building under System 8 is the same as in System 1; heating and cooling for the conditioned spaces is provided by fan-coil units and central area handling units.

Shelley A, Camci, and Descon-Concordia each contain electric motor-driven centrifugal water chillers, roof-mounted cooling towers, and oil-fired boilers. (Equipment sizes are shown in table D.2). Hot water and chilled water is circulated through the buildings as in previous systems. The condenser water is pumped from the mechanical room to the roof-mounted cooling tower. Fuel oil is stored in underground storage tanks located adjacent to each building.

Shelley B contains an electric motor-driven reciprocating chiller, a roof-mounted cooling tower, and an oil-fired boiler.

The commercial building uses an electric motor-driven centrifugal chiller, roof-mounted cooling tower, and an electric hot water heating boiler.

The school building has an air-cooled roof-mounted reciprocating water chiller and an electric hot water boiler. Both the commercial building and the school have 15 kW electric domestic hot water heaters.

Space for the additional air conditioning and heating equipment is obtained by converting portions of the parking areas to mechanical rooms in Shelley B, Descon-Concordia, and the commercial building. New floor space must be provided in Shelley A and Camci. The roof of the school is utilized for the location of the added equipment.

Table D.2 Equipment sizes for System 8

	Chiller size	Condenser water pump heat	Boiler size	Circulating pump head
	ton	ft		ft
Shelley A	350	170	130 hp	45
Shelley B	96	70	40 hp	85
Camci	225	150	100 hp	45
Descon-Concordia	238	110	110 hp	95
Commercial	136	35	400 kW	60
School	85	-	170 kW	50

The 480V, three-phase, electrical service could be metered separately at each building or master-metered for the entire site. All buildings have sufficient demand to qualify for the Large Power and Lighting (LPL) Schedule of PSE&G.

Additional electrical equipment has been installed for the cooling systems, but the remainder of the internal building distribution is the same as System 1.

Diesel engine-driven emergency generators and transfer switches have been added at each building. These have small day tanks that are filled from the underground fuel tanks. The generators are mounted in the electrical rooms or on outside pads.

D.10 SYSTEM 9 - INDIVIDUAL PLANT WITH ELECTRIC CHILLERS AND ELECTRIC BOILERS

System 9 involves independent building systems as did System 8 except that heating is provided by electric hot water boilers. Each building generates its own hot water and chilled water and purchases electrical service. The occupied areas are heated and cooled in the same manner as in Systems 1 through 8, by the use of fan coil units and central air handling units.

Shelley A, Camci, and Descon-Concordia are provided with electric motor-driven centrifugal chillers and Shelley B is provided with an electric motor-driven reciprocating chiller. All four buildings have roof-mounted cooling towers, electric hot water boilers for heating, and electric domestic hot water heaters. Equipment sizes are shown in table D.3. The commercial building and the school have the same systems as used in System 8.

The 480V, three-phase, electrical service could be metered separately at each building. All buildings have a large enough demand to qualify for the LPL rate schedule.

Additional electrical equipment has been installed for the heating, cooling and domestic hot water systems, but the remainder of the internal building distribution is the same as System 1. Although the electrical equipment would be slightly larger, additional floor space requirements would be minimal, and space as provided in System 1 is sufficient.

Diesel engine-driven emergency generators and transfer switches have been added at each building. These have underground fuel oil tanks located outside the building. The generators would be mounted in the electrical rooms or on outside pads.

Table D.3 Equipment sizes for System 9

	Chiller size	Condenser pump head	Boiler size	Circulating pump head	Domestic hot water heater
	ton	ft	kW	ft	kW
Shelley A	350	170	1300	45	190
Shelley B	96	70	300	85	50
Camci	225	150	720	45	190
Descon-Concordia	238	110	880	95	170
Commercial	136	35	400	60	15
School	85	-	170	50	15

D.11 SYSTEM 10 - INDIVIDUAL AIR-COOLED HEATING AND COOLING UNITS

In System 10, the building hydronic heating and cooling concept is eliminated. The system is based on the use of numerous all-electric, thru-the-wall air conditioning units. Each unit provides approximately 9,000 Btu/h (9.5 MJ/h) of heating and cooling. Units are located in each apartment and throughout the commercial building and school. Central zones in the apartment buildings and the commercial building are heated and cooled by all-electric rooftop air conditioning units. Table D.4 indicates the quantity of the thru-the-wall units required for each building. In addition, each apartment is provided with an electric domestic hot water heater with sizes ranging from three kW to nine kW. The commercial building and the school each have electric domestic hot water heaters. The cooling capacities of the rooftop air conditioning units for the central area are 20 tons (70 kW) in Shelley B, 30 tons (105 kW) in Shelley A, Camci, and Descon-Concordia, and 70 tons (246 kW) in the commercial building. Building ventilation for the school is accomplished by use of rooftop exhaust fans. The thru-the-wall units in the school are larger than in the other buildings, each providing 12,000 Btu/h (12.7 MJ/h) of heating and cooling. All rooftop units in the other buildings, as well as all thru-the-wall units, contain electric resistance heating elements. The capacity of the heating elements in the rooftop units are 100 kW in Shelley A, Camci, and Descon-Concordia, 40 kW in Shelley B, and 200 kW in the commercial building.

Table D.4 Number of individual air conditioning units per building

Building	No. of Units
Camci	368
Commercial	87
Descon-Concordia	404
School	70
Shelley A	576
Shelley B	180
Total	1,685

Electrical service is 480V, three-phase, from the public utility company and is metered separately at each building. All buildings have sufficient demand to qualify for the LPL rate schedule, and qualify under that rate's provisions for space heating service for a reduced demand charge during the months of November through May.

Additional electrical equipment is required to accomodate the individual heating-cooling units and domestic water heaters. This consists mainly of circuit breakers, feeders, panelboards, and increased transformer sizes where required. The remainder of the building distribution is the same as System 1.

Deisel engine-driven emergency generators and transfer switches are provided at each building as in System 9.

Although there is additional electrical equipment, the electrical room floor space for this system will be no greater than in System 1.

D.12 SYSTEM 11 - INDIVIDUAL AIR-COOLED HEAT PUMP UNITS

System 11 provides heating and cooling by use of self-contained packaged heat pump units. Apartment units have a cooling capacity of approximately 25,000 Btu/h (26 MJ/h) each and each unit contains 5.3 kW of supplemental electric resistance heat which is required for heating when the outside temperature falls below 28°F (-2°C). The air-to-air units are completely self-contained and are connected to ducted air distribution systems in each apartment. The units are located on the balconies (where available) inside utility closets. Where no balcony exists, the units are mounted in the exterior wall and the utility closet is located inside the apartment. The return air systems consist of return grills mounted in each utility closet wall. Common areas of the apartment buildings are heated and cooled by rooftop air conditioning units, as in System 10. The rooftop unit capacities in Shelley A, Camci, and Descon-Concordia are 30-tons (105 kW) each and in Shelley B are 20-tons (70 kW). The heating capacities are 100 kW in Shelley A, Camci, and Descon-Concordia and 60 kW in Shelley B. Each apartment contains an electric domestic hot water heater as in System 10.

The commercial building is heated and cooled by similar self-contained heat pump units and a 50-ton (175 kW) rooftop air conditioning unit (200 kW heating capacity). The heat pumps provide all the heating and cooling for the first floor and for the perimeter of the third floor. The heat pump capacities are 54,000 Btu/h (57 MJ/h) on the first floor and 25,000 Btu/h (26 MJ/h) on the third floor. The building is provided with one 15 kW electric domestic hot water heater.

The school is heated and cooled by 60,000 Btu/h (63.3 MJ/h) heat pumps located on the perimeter of the first floor and on the roof. There is no central rooftop air conditioning unit for the school. These units contain 10.6 kW of supplemental resistance heat, which is required when the outdoor temperature falls below 25°F (4°C).

The number of units in each building is given in table D.4. The floor space used for mechanical rooms in previous systems is used for additional storage or parking in this system.

Table D.5 Number of heat pump units per building

Building	No. of Units
Camci	153
Commercial	24
Descon-Concordia	141
School	12
Shelley A	152
Shelley B	140
Total	522

Electrical service is 480V, three-phase, from the public utility company and is metered separately at each building. All buildings have sufficient demand to qualify for the LPL rate schedule, and as in system 10, they receive a reduced demand rate during the months of November through May.

Additional electrical equipment is required to accommodate the heat pump units and domestic water heaters. This consists mainly of circuit breakers, feeders, panel boards, and increased transformer sizes where required. The remainder of the building distribution is the same as System 1.

Diesel engine-driven emergency generators and transfer switches have been added at each building as in System 9.

Although there is additional electrical equipment, the electrical room floor space for this System will be no greater than System 1.

D.13 SYSTEM 12 - INDIVIDUAL AIR-COOLED SELF-CONTAINED AIR CONDITIONING UNITS WITH ELECTRIC FURNACES

System 12 substitutes individual air-cooled self-contained air conditioning units and electric furnaces for the individual heat pumps used in System 11. The System 12 units are physically similar to the heat pumps of System 11 except that they have no heating capability. Heating is provided solely be electric resistance heaters located within the unit discharge ductwork.

All other equipment and operating modes are similar to System 11. The performance of the system is assumed equal to System 10, the only difference being initial capital costs.

APPENDIX E - TRACE PROGRAM DESCRIPTION

E.1 PROGRAM ORGANIZATION (See figure E.1)

The TRACE program has five major parts or phases, each with a specific function that must be performed to provide a complete energy and economic analysis. The names of these phases are load, design, system simulation, equipment simulation, and economic analysis.

The building heating/cooling load calculation procedures, used in the load phase of the program, are of sufficient detail to permit the evaluation of the effect of variables such as building orientation, size, shape and mass, as well as hourly climatic data. The calculation procedures used to simulate the operation of the building and its systems through a full year are of sufficient detail to permit the evaluation of the effect of system design and mechanical equipment operating characteristics on annual energy use. Manufacturers' data are used in the program for the simulation of all systems and equipment. These procedures use techniques recommended in appropriate ASHRAE publications or produce results which are consistent with the recommended techniques.

The documentation in the TRACE manual shows that the calculation procedures in the program explicitly account for the following items:

- Climatic data, including coincident hourly data for temperature, solar radiation, wind, and humidity of typical days of the year, representing seasonal variations. In total, the TRACE program calculates building heat gains and losses, by zone, for 864 hours of the year.

- Building orientation, size, shape, mass, and heat transfer characteristics.

- Building operational characteristics, accounting for changes in interior temperature, humidity, ventilation, illumination, and control modes for occupied and unoccupied hours.

- Mechanical operational characteristics, taking into account capacity under design conditions, part load performance, and effects of ambient dry bulb and wet bulb temperature on equipment performance.

- Internal heat generation from illumination, equipment, and the number of people in occupied spaces during both occupied and unoccupied hours.

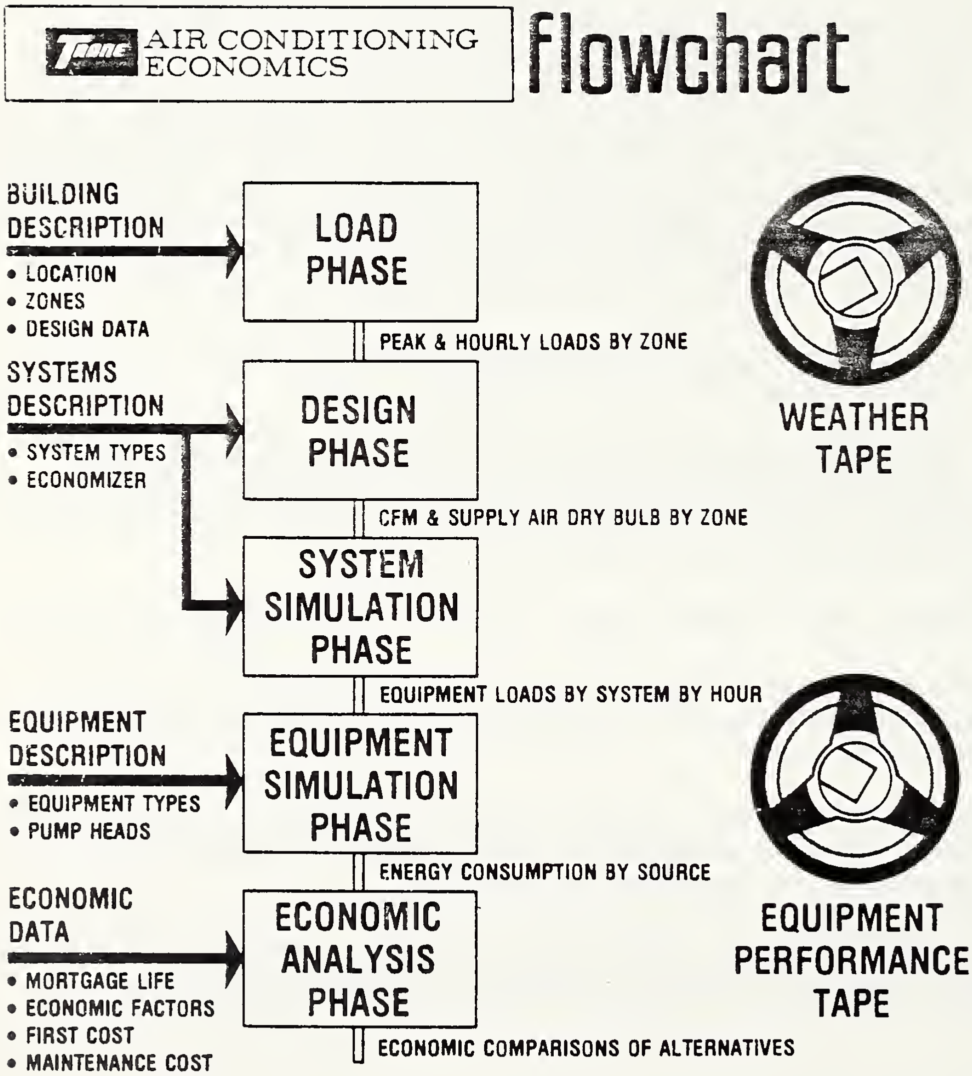

Figure E.1 TRACE flowchart

E.2 <u>LOAD PHASE</u> (See figure E.2)

In the load phase of the program, conventional load data describing building construction, orientation, and location are required input. In addition, the use profile of the building, including lighting schedules, occupancy schedules, and miscellaneous load schedules are required.

From the building location, the program automatically selects a full year of weather for the city closest to the building location. Building loads are then calculated by zone, by hour.

E.3 <u>DESIGN PHASE</u> (See figure E.3)

The second major phase of the program is the design phase. The purpose of this phase is to establish the building design load. The type of mechanical system to be used is required input as well as the relationship between the roof, wall, and lights and the return air. In addition, the outside air quantities under design conditions are required.

The program then determines design cooling load, heating load, outside air quantity, total air quantity, and the supply air dry bulb temperature. The air quantities and supply air dry bulb temperature in the cooling mode are determined psychrometrically using standard procedures outlined in the ASHRAE Handbook of Fundamentals. Design loads determined in this phase are based on 100 percent of design input values, even though the coincident design values of weather affected loads may not actually occur during the weather year. The aforementioned design values are determined for both the perimeter and interior systems.

E.4 <u>AIR SIDE SYSTEM SIMULATION PHASE</u> (See figure E.4)

The next major phase of the program is the air-side system simulation phase. Its key function in the program is to translate building heating and cooling loads on an hourly basis into equipment loads, by system, utilizing all of the hourly building variables that affect the system operation. In this phase, the program tracks the air around the complete air-side system loop, picking up and cancelling gains and losses along the path of each system.

The output from the system simulation phase is the equipment load, by system, by hour. This phase of the program is perhaps the most complicated. Complications arise from the fact that each major system or system combination must utilize separate individual system subroutines to reflect the actual operation and control of that system. The program contains subroutines for 20 different system types that form innumerable combinations of perimeter and interior systems to handle the building comfort requirements.

E.5 <u>EQUIPMENT SIMULATION</u> (See figure E.5)

The equipment loads, by system, by hour, are then provided to the equipment simulation phase, along with a description of the equipment to be used in the system. The previously described weather information is input to this phase

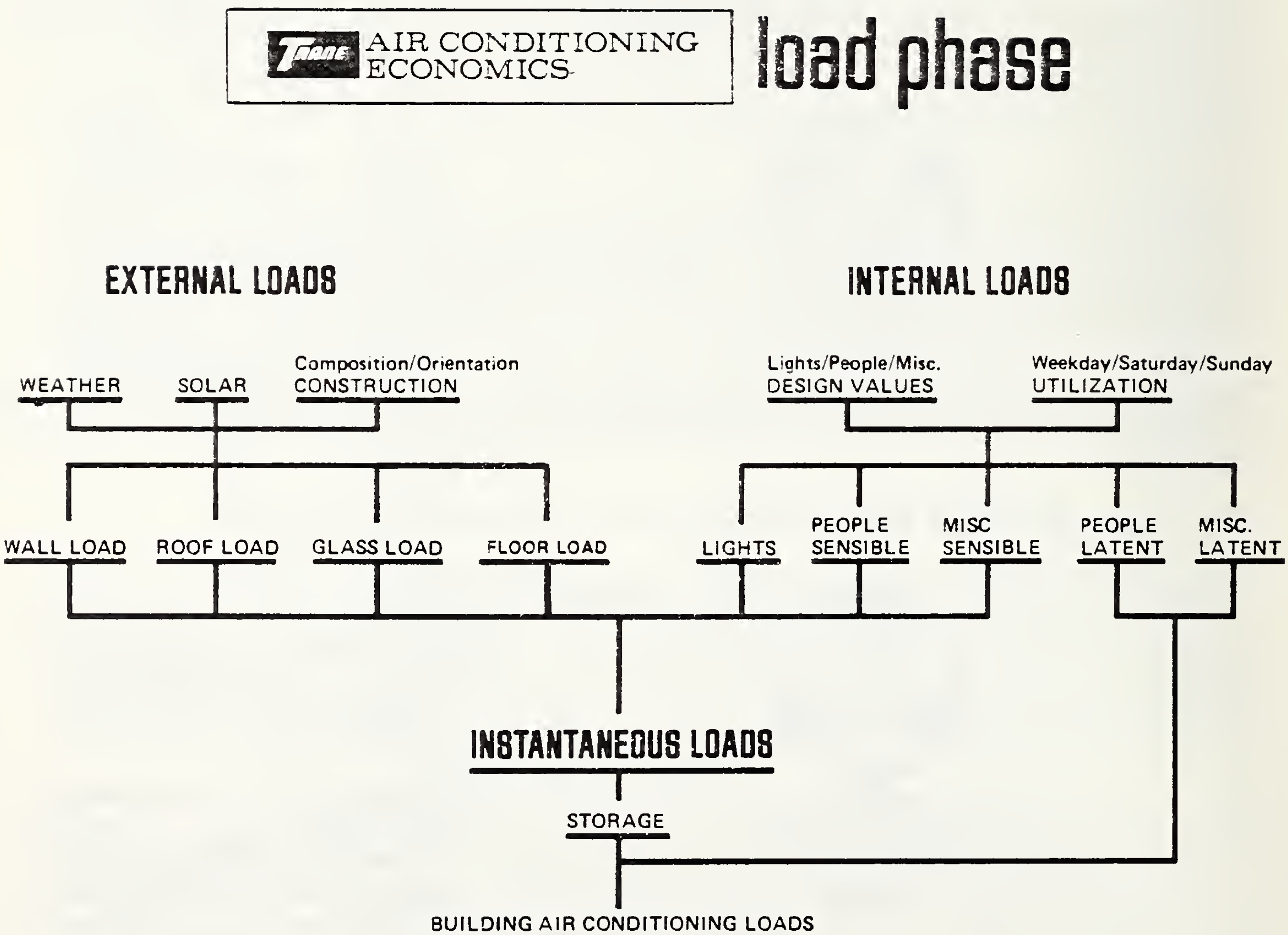

Figure E.2 Load phase

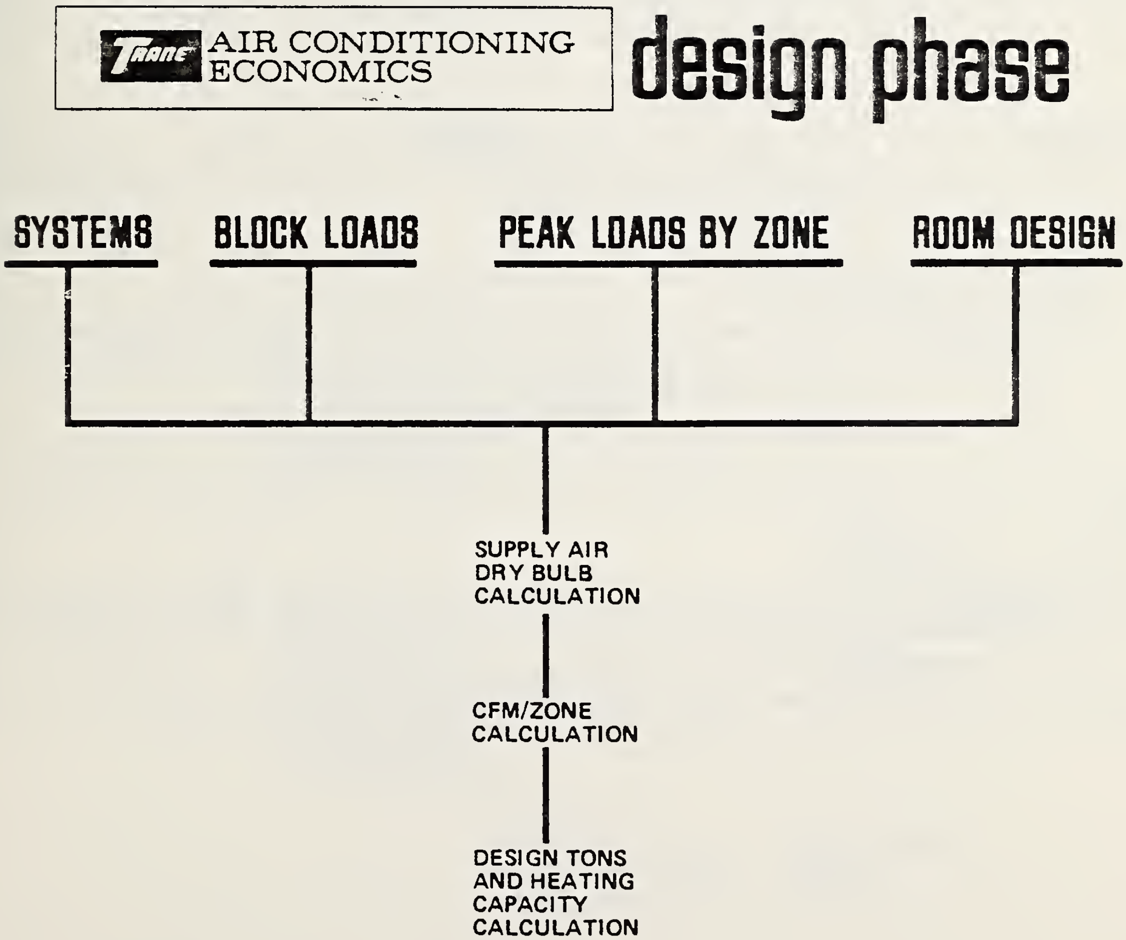

Figure E.3 Design phase

also. Regardless of whether the equipment has air-cooled or water-cooled condensing, the weather affects the overall part-load efficiencies of equipment performance.

The essential function of the equipment simulation phase is to translate equipment loads, by system, by hour, into energy consumption by source. The loads are translated into kilowatt hours of electricity, therms of gas, oil, district hot water or district chilled water; even to the extent of calculating the total gallons of make-up water required by a cooling tower or the energy consumed by the crackcase heaters of a reciprocating compressor. The input requirements for this phase consist only of the equipment types for heating, cooling, and air moving as well as pump heads and pump motor efficiencies for each system where hydronic pumping is involved. These data are utilized within the program to call the performance information for the various pieces of equipment from the equipment library. This information is used to convert system loads into energy consumption for subsequent processing in the economic analysis phase.

It is important to note that it is not necessary for the user to input the part-load performance of equipment accessories into the program. They are already contained in the separate equipment library.

E.6 <u>ECONOMIC ANALYSIS PHASE</u> (See figure E.6)

The final major phase of the program is the economic analysis phase. This phase utilizes user input such as the utility rates and system installed cost data along with other economic information such as mortgage life, cost of capital, etc., to compute annual owing and operating costs. It also calculates the various financial measurements of an investment such as cash flow effect, profit and loss effect, payout period, and return on additional investment between alternatives.

In very simple terms, the program determines how much it costs to operate one system compared with another. It then computes the present worth of the savings and the incremental return on the additional investment. It is keyed to provide information that the owner needs to make his final economic decision, including monthly and yearly utility costs over the life of the building.

AIR CONDITIONING ECONOMICS

system simulation phase

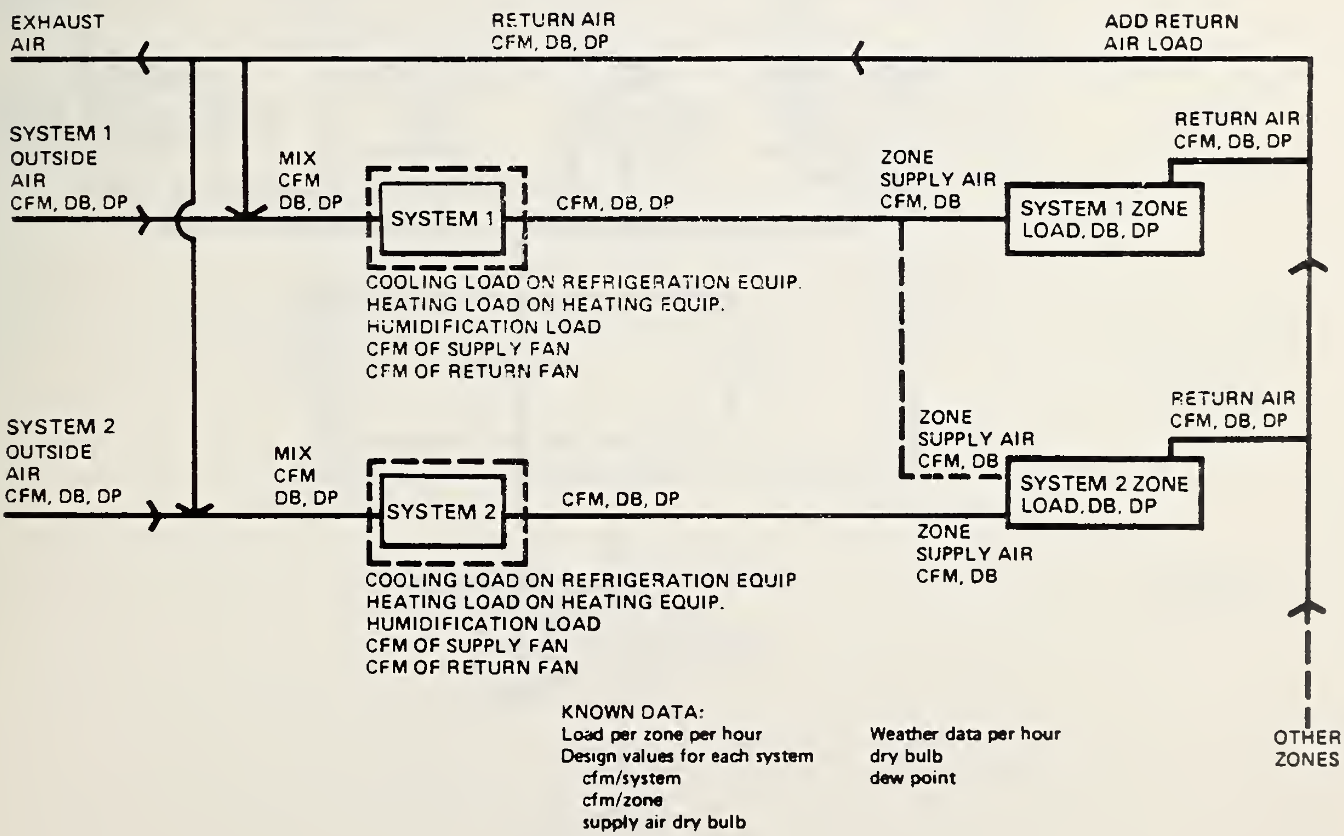

Figure E.4 System simulation phase

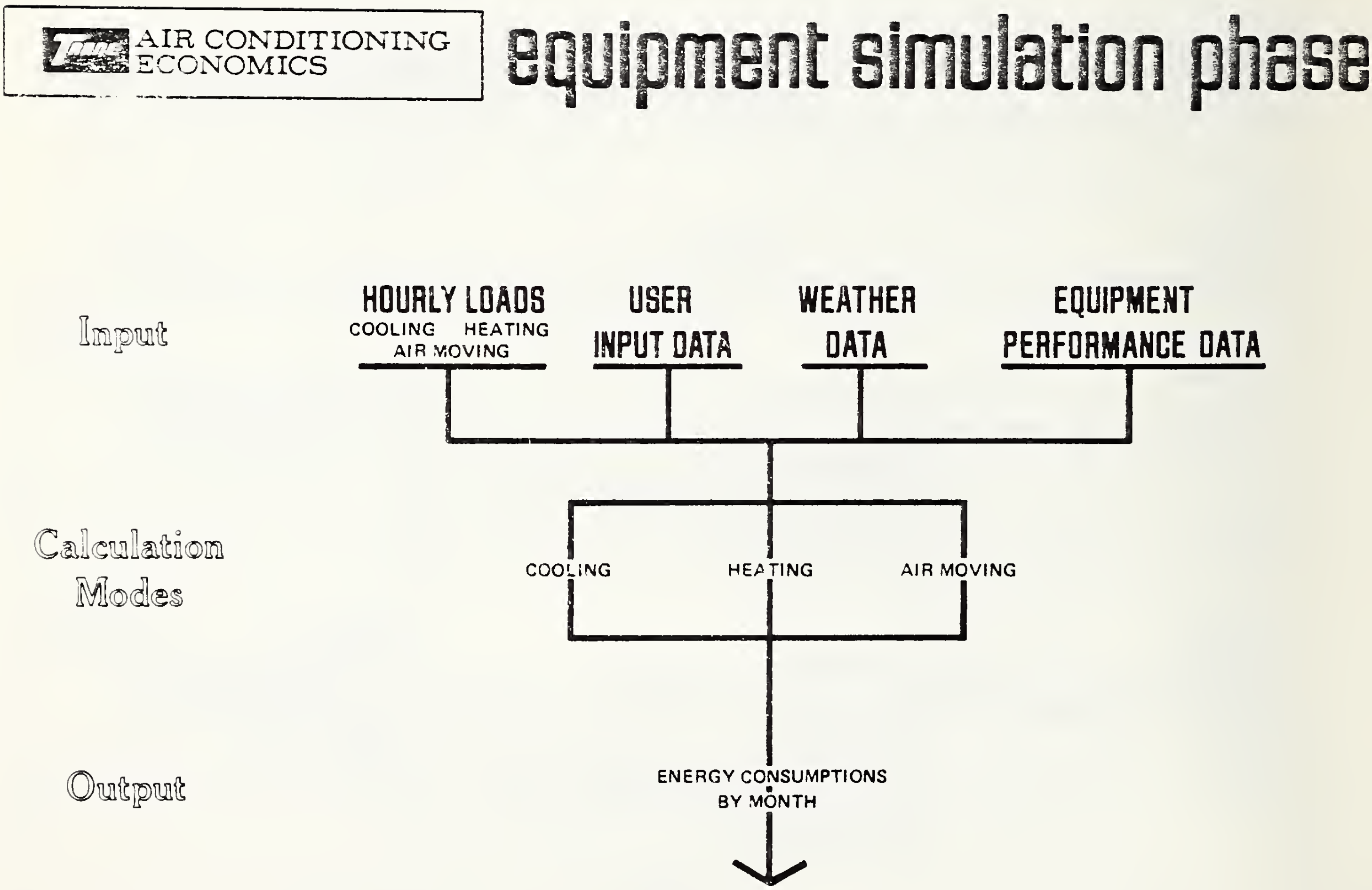

Figure E.5 Equipment simulation phase

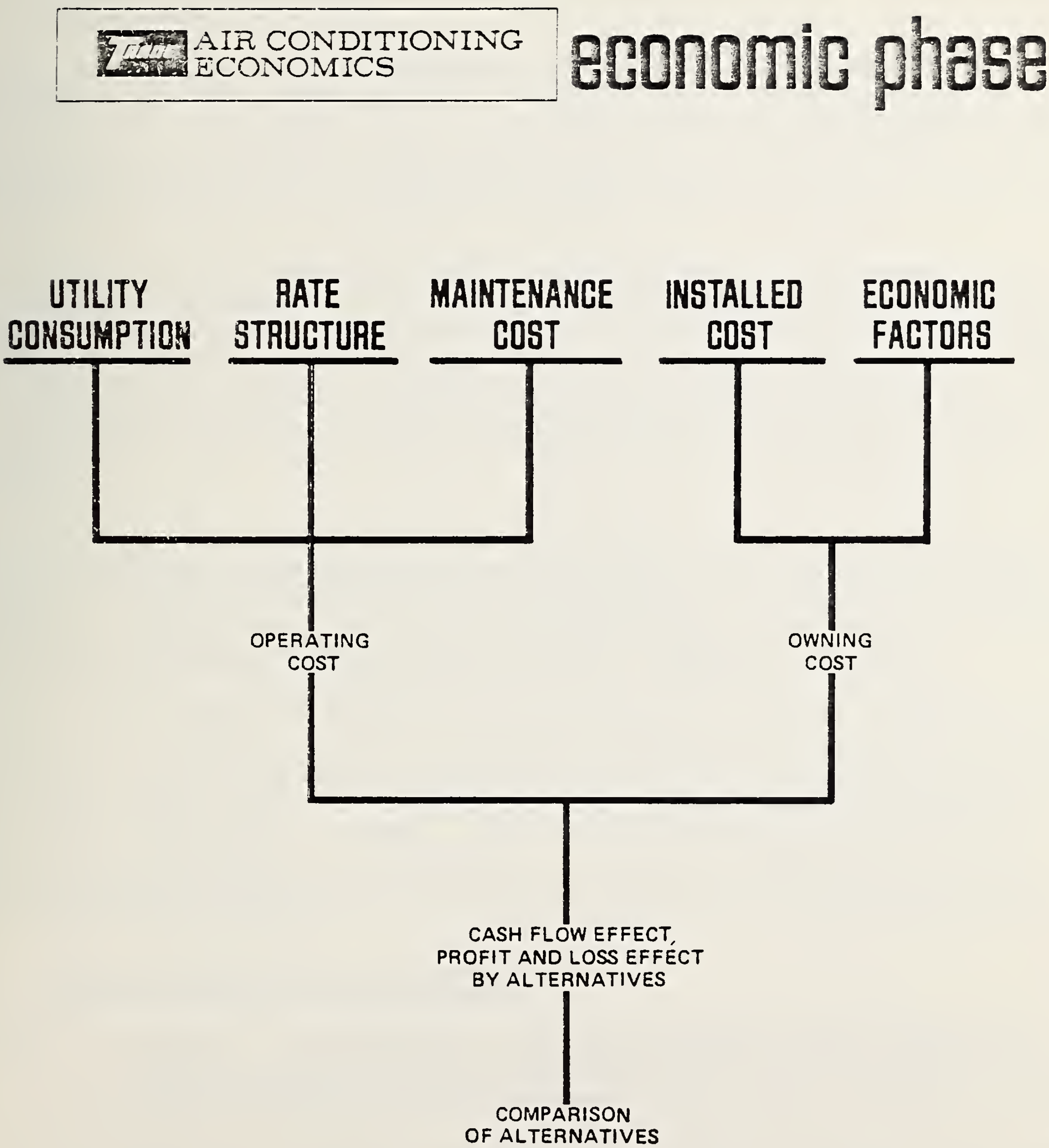

Figure E.6 Economic phase

APPENDIX F - FUEL ADJUSTMENT FOR COMBINED CHILLER OPERATION

F.1 PROBLEM IDENTIFICATION

System 4 of the alternative systems consists of a combined compression/absorption chilling system, whereby recovered heat from site electrical generation is used. This system could not be handled by the TRACE program without special internal modifications. These modifications were attempted, but subsequent analysis showed that simulation results were incorrect or at the very least corresponded to an unoptimized system.

Table F.1 shows a comparison of the chiller auxiliaries for System 1 and 4 from computer printouts in appendix I of reference [F-1]. The data show considerably more electrical energy consumption for the chilled water and condenser pumps for System 4. This is clearly not possible since these pumps are exactly the same for both systems. Likewise, the larger electrical consumption for the cooling tower fan in System 4 is not probable in a properly optimized system because the cooling towers are smaller and reject less heat than in System 1.

Since only the chiller system is changed between System 1 and System 4, the other components should perform identically during the non-cooling months. As table F.2 illustrates, the boiler fuel consumption for System 4 is considerably different (+13.6 percent) in the non-cooling months. Differences during the non-cooling months can also be seen for other components as well.

Clearly, the attempt to simulate this system with the TRACE program was not successful. With additional efforts, the program could probably be correctly modified to produce an accurate simulation of such a system in the future. For the Summit Plaza study, it was desirable that an approximate calculation of the performance of System 4 be made. This would be based on System 1, with appropriate adjustments to account for the combined chiller approach. The following sections describe the equations used for the adjustment and give the fuel adjustment results.

F.2 GENERAL EQUATIONS FOR ADJUSTMENTS

Given:

1) System 1 - all-absorption system using waste heat from engine generators and additional boiler-produced heat to produce chilled water for plant and site purposes.

2) System 4 - combined compression/absorption system using waste heat from engine-generators in absorption chillers and motor-driven centrifugal chillers to produce chilled water. Boiler-produced heat is not used for input to the chillers.

3) Total chilled water load and the base absorption chiller load in System 1 is known from appendix I of reference [F-1].

Table F.1 Comparison of energy use for chiller auxiliaries, System 1 vs System 4

Combining Chilling (System 4)

a)		Absorption (550T)	Compression (550T)	Total
5501	Chilled water pump	134,685 kWh	131,118 kWh	165,803 kWh
5012	Condenser pump	103,105 kWh	157,901 kWh	361,006 kWh
5102	Cooling tower fan	206,785 kWh	115,281 kWh	322,066 kWh
5301	Controls	16,425 kWh	8,760 kWh	25,185 kWh
5050	~~Soln.~~ Solution pumps	29,900 kWh	--	29,900 kWh
		590,900 kWh	413,060 kWh	1,003,960 kWh
5401	Make-up water	2,962,020 gal	1,971,396 gal	4,933,416 gal

Absorption Chilling only (System 1)

		Unit #1 (550T)	Unit #1 (550T)	Total
5001	Chilled water pump	134,685 kWh	12,445 kWh	156,140 kWh
5012	Condenser pump	203,105 kWh	32,356 kWh	235,461 kWh
5102	Cooling tower fan	206,785 kWh	32,942 kWh	239,727 kWh
5301	Controls	16,425 kWh	3,285 kWh	19,710 kWh
5050	Solution pumps	29,900 kWh	4,761 kWh	34,661 kWh
		590,900 kWh	94,799 kWh	695,699 kWh
540	Make-up water	6,682,087 gal	222,682 gal	6,904,769 gal

a) Numbers refer to TRACE equipment identification numbers in the computer printouts of appendix B of reference [F-1]

Table F.2 Boiler fuel oil consumption, System 1 vs. System 4, from Appendix I of reference [F-1]

	System 1 "B" gallons	System 4 gallons
J	35,868	39,598
F	25,517	28,606
M	15,794	18,087
A	8,603	10,016
M	2,010	2,753
J	17,532	122
J	25,513	0
A	21,422	0
S	3,941	1,168
O	4,372	5,482
N	9,900	11,556
D	26,503	30,022
TOTAL	196,975	147,400
non-cooling		
TOTAL	128,567	146,110

Objective: Determine the fuel consumption of System 4.

Approach: Convert the boiler fuel consumption in June through September into chilled water load. Calculate the incremental engine-generator fuel necessary to meet this load in a combined chiller scheme. Calculate changes in chiller auxiliary electric consumption.

Step 1. Calculate the thermal chiller load generated from boiler-produced heat in System 1. (see Nomenclature in Section F.4 of this Appendix)

$$\Delta H_{abs,in} = H_{abs,b} = F_b \cdot \mu_b$$

$$\Delta H_{abs,out} = \Delta H_{abs,in} \cdot COP_{abs}$$

therefore:

$$\Delta H_{abs,out} = F_b \cdot \mu_b \cdot COP_{abs} \tag{F-1}$$

Step 2. Calculate the incremental chiller load in a combined chiller system (System 4) in terms of engine fuel.

The incremental electrical output is used solely by the centrifugal chiller:

$$H_{cent,out} = \Delta F_e \cdot \mu_e \cdot COP_{cent}$$

The incremental absorption chiller load in system 4 is met by incremental recovered heat:

$$\Delta H_{abs,out} = \Delta F_e \cdot \mu_{recov} \cdot COP_{abs}$$

The total incremental chiller load is:

$$\begin{aligned} \Delta H_{c,out} &= H_{cent,out} + H_{abs,out} \\ \Delta H_{c,out} &= \Delta F_e \cdot \mu_e \cdot COP_{cent} + \Delta F_e \cdot \mu_{recov} \cdot COP_{abs} \end{aligned} \tag{F-2}$$

Step 3. Calculate the incremental engine-generator fuel necessary to meet the chiller load in System 1.

Equate $\Delta H_{abs,out}$ for System 1 (equation F-1) and $\Delta H_{c,out}$ for System 4 (equation F-2) and solve for ΔF_e:

$$\Delta F = \frac{F_b \cdot \mu_b \cdot COP_{abs}}{\mu_e \cdot COP_{cent} + \mu_{recov} \cdot COP_{abs}} \tag{F-3}$$

Appropriate values for all parameters (based on non-anomalous plant conditions) were well-established at JCTE and were incorporated into the TRACE computer analysis. On an annual average basis these values are as follows [F-1]:

$\mu_b = 0.80$, $COP_{abs} = 0.74$, $\mu_{recov} = 0.35$,

$\mu_3 = 0.31$, $COP_{cent} = 5.1$

Using the above values, equation (F-3) becomes:

$$\Delta F_e = 0.322 F_b \qquad \text{(F-4)}$$

Step 4. Calculate the differences in cooling tower heat rejection, the resultant change in electric load for cooling tower auxiliaries, and the change in engine fuel (ΔF_e).

The total heat rejection in System 1 is:

$$H_{rej,total} = H_{abs,in} (1 + COP_{abs}) \qquad \text{(F-5)}$$

The base heat rejection due to base absorption chiller load (met by recovered heat from site electric generation) is:

$$H_{rej,base} = H_{rej,total} - H_{rej,boiler}$$

$$= H_{abs,in} (1 + COP_{abs}) = F_b \cdot \mu_b (1 + COP_{abs})$$

$$= (1 + COP_{abs}) (H_{abs,in} - F_b \cdot \mu_b)$$

The incremental heat rejection from the combined chiller system:

$$\Delta H_{rej,c} = H_{cent,in} + H_{cent,out} + \Delta H_{abs,in} + \Delta H_{abs,out}$$

$$= H_{cent,in} (1 + COP_{cent}) + \Delta H_{abs,in} (1 + COP_{abs})$$

$$= \Delta F_e \cdot \mu_e (1 + COP_{cent}) + \Delta F_e \cdot \mu_{recov} (1 + COP_{abs})$$

The total heat rejection in System 4 is:

$$H_{rej} = H_{rej,base} + \Delta H_{rej,c}$$

$$= (1 + COP_{abs}) (H_{abs,in} - F_b \cdot \mu_b) + \Delta F_e \cdot \mu_e (1 + COP_{cent}) +$$

$$\Delta F_e \cdot \mu_{recov} (1 + COP_{abs})$$

$$= (1 + COP_{abs}) (H_{abs,in} - F_b \cdot \mu_b + \Delta F_b \cdot \mu_{recov}) +$$

$$(1 + COP_{cent}) \Delta F_e \cdot \mu_e \qquad \text{(F-6)}$$

The fractional difference in heat rejection in System 4 relative to System 1 is:

$$\frac{\Delta H_{rej,syst\ 4}}{H_{rej,syst}} = \frac{\text{equation (F-5) - equation (F-6)}}{\text{equation (F-5)}}$$

Substituting previous values from reference [F-1], and COP and μ, and expressing ΔF_e in terms of F_b from equation (F-4):

$$\frac{\Delta H_{rej,syst\ 4}}{H_{rej,syst\ 1}} = \frac{0.609F_h}{1.71\ H_{abs,in}}$$

$$= \frac{0.356F_h}{H_{abs,in}} \qquad \text{(F-7)}$$

This indicates that in System 1, 1.71 of the boiler heat produced to operate the chillers is rejected in the cooling tower, whereas in System 4, only .967 (i.e., $1.71- \frac{.609}{\mu_b}$) of this amount of heat is rejected; the base heat rejection remaining constant.

The change in total auxiliary load can be assumed to be approximately a linear change in tower auxiliaries as a function of heat rejection. Therefore:

$$\Delta E_{aux} = \frac{E_{ct}\ \Delta H_{rej,syst\ 4}}{H_{rej,syst\ 1}}$$

$$\Delta F_e' = \frac{\Delta E_{aux}}{\mu_e} = \frac{E_{ct}\ 0.356F_b}{\mu_e\ H_{abs,in}} \qquad \text{(F-8)}$$

Step 5. It is also necessary to consider the effect of the decrease in E_{aux} on the base heat rejection from the engine and the added engine fuel ($\Delta F_e'$) needed to make up the resultant loss in base chiller production.

$$\Delta H_{abs,base,out} = \Delta F_e' \cdot \mu_{recov} \cdot COP_{abs}$$

$$\Delta\Delta H_{c,out} = \Delta H_{abs,base,out}$$

$$= \Delta\Delta F_e \cdot \mu_e \cdot COP_{cent} + \Delta\Delta F_e \cdot \mu_{recov} \cdot COP_{abs}$$

$$\Delta F_e'' = \frac{\Delta F_e\ \mu_{recov}\ COP_{abs}}{\mu_e\ COP_{cent} + \mu_{recov}\ COP_{abs}}$$

$$\Delta F_e'' = \frac{\mu_{recov}\ \ COP_{abs}}{\mu_e\ COP_{cent} + \mu_{recov}\ COP_{abs}} \qquad \text{(F-9)}$$

Using values from reference [F-1] as listed under Step 3:

$$\frac{\Delta F_e''}{\Delta F_e'} = 0.133 \qquad \text{(F-10)}$$

Step 6. The total change in fuel consumption can be found from the various components F_b, ΔF_e, $\Delta F_e'$ and $\Delta F_e''$

$$\Delta Fuel = -F_b + \Delta F_e - \Delta F_e' + \Delta F_e''$$

For a general case

$$\Delta Fuel = -F_b + \text{equation (F-3)} - \frac{E_{ct} \cdot \text{equation (F-7)}}{\mu_e \cdot \text{equation (F-5)}} \quad (1 - \text{equation (F-9)}) \qquad \text{(F-11)}$$

For the values in reference [F-1]

$$\Delta Fuel = -F_b + \text{equation (F-4)} - \text{equation (F-8)} \; [1 - \text{equation (F-10)}]$$

$$= -F_b + 0.326 F_b - \frac{E_{ct} \; 0.356 F_b}{\mu_e \; H_{abs,in}} (1-0.133)$$

$$= F_b \left(-0.674 - \frac{0.305}{H_{abs,in}}\right) \qquad \text{(F-12)}$$

F.3 ADJUSTMENT OF SYSTEM 1 RESULTS FOR SYSTEM 4 OPERATION

Using equation (F-12), only three values from the System 1 simulation are needed: F_b, the boiler fuel used solely to generate hot water for the chiller; $H_{abs,in}$, the total heat (boiler and engine) used as input to the chiller and E_{ct}, the cooling tower auxiliary electrical energy.

F_b can be found from the data in the table F.2:

total System 1 output	68,408 therms
less that needed for space heating	1,290 therms
	67,118 therms = F_b

$H_{abs,in}$ = 137, 443 therms (from appendix I of reference [F-1])

E_{tc} = condenser pump and c.t. fan

= 235,461 + 239,727 kWh (from appendix I of reference [F-1])

= 16,218 therms

Substituting into each of terms of equation (F-12),

1) Boiler fuel eliminated = F_b

= -67,118 therms

2) Added engine fuel for combined chiller load = 0.326 F_b

= 0.326 (67,118) = 21,880 therms

3) change in c.t. auxiliaries

$$= \frac{E_{ct}}{\mu_e} \quad \frac{0.356\ F_b}{H_{abs,in}}$$

$$= \frac{-16,218}{0.31} \quad \frac{0.356\ (67,118)}{137,443}$$

$$= -9,095 \text{ therms}$$

4) Added fuel for reduced base electrical load

$$= +0.133\ (9095)$$

$$= +1210 \text{ therms}$$

5) Total ΔFuel = -67,118

+21,880

-9,095

+1,210

-53,123 therms = $-5,312 \times 10^6$ Btu

This is the total annual difference in fuel consumption between System 1 and System 4. At 139,000 Btu/gal, the total fuel consumption for System 4 is 38,216 gallons less than System 1.

F.4 NOMENCLATURE

COP Coefficient of performance of chiller system

E Electrical consumption, kWh

F Fuel input, Btu

H Heat energy (enthalpy), Btu

μ Efficiency

Δ Indicates an incremental value for a component which is already carrying a base load in System 1

Subscripts

abs absorption chiller

adj adjustment

aux auxiliary

b	boiler
base	base consumption where rejected heat from electrical production for plant and site uses is used to generate chilled water
c	chiller system (abs + cent)
cent	centrifugal chiller
e	electrical
in	into component (input)
out	out of component (output)
recov	recovered
rej	rejected
ct	cooling tower

F.5 REFERENCES - APPENDIX F

F-1. H.D. Nottingham and Associates, Inc., "Design, Cost and Operating Data for Alternative Energy Systems for the Summit Plaza Complex, Jersey City, N.J." National Bureau of Standards Report GCR 79-164, May 1979.

APPENDIX G - MONTHLY ENERGY CONSUMPTION DATA FOR ALTERNATIVE SYSTEMS

G.1 INTRODUCTION

The data provided in tables G.1 through G.12 is taken directly from reference [G-1]. These tables consist of monthly energy purchases (fuel oil and electricity), energy consumption (Btu), electrical demand (kW), and make-up water requirements (gallons) for all 12 alternative systems. Tables G.10 and G.12 (for Systems 10 and 12, respectively) are identical since the performance of these systems was assumed to be the same.

The energy content of the fuel oil was determined in these tables by assuming a higher heating value (HHV) of 140,000 Btu/gal. The conversion of electrical energy to source energy consumption was accomplished by assuming a power plant delivered heat rate of 11,570 Btu/kWh or 29.5 percent overall thermal efficiency. The total source energy consumed is the sum of the energy content of the fuel oil and the equivalent source energy consumption for the production of electric energy. The conversion factors used in the tables of this appendix are slightly different from those used in the body of the report (i.e., 11,515 Btu/kWh and 139,000 Btu/gal).

Table G.1 Energy consumption for System 1

Month	Fuel Oil Consumed gallons	Energy Content of Fuel Oil 10^6 Btu	Electricity Purchased kWh	Electrical Demand kW	Total Source Energy Consumed 10^6 Btu	Make-Up Water 1000 gal
January	70,648	9,890	-0-	-0-	9,890	1
February	58,684	8,215	-0-	-0-	8,215	10
March	55,838	7,817	-0-	-0-	7,817	67
April	49,075	6,870	-0-	-0-	6,870	179
May	45,606	6,384	-0-	-0-	6,384	293
June	66,682	9,335	-0-	-0-	9,335	1,737
July	79,805	11,172	-0-	-0-	11,172	2,367
August	74,695	10,457	-0-	-0-	10,457	2,043
September	53,895	7,545	-0-	-0-	7,545	979
October	47,312	6,632	-0-	-0-	6,623	248
November	49,872	6,982	-0-	-0-	6,982	134
December	63,233	8,852	-0-	-0-	8,852	5
Annual Totals	715,349	100,149	-0-	-0-	100,149	8,062

Source energy consumed per conditioned square foot (573,780 ft^2) = 174,500 Btu per year per square foot

Table G.2 Energy consumption System 2

Month	Fuel Oil Consumed gallons	Energy Content of Fuel Oil 10^6 Btu	Electricity Purchased kWh	Electrical Demand kW	Total Source Energy Consumed 10^6 Btu	Make-Up Water 1000 gal
January	113,550	15,898	(628,367)	-0-	8,626	353
February	100,040	14,006	(566,278)	-0-	7,454	416
March	105,030	14,705	(631,546)	-0-	7,396	648
April	97,760	13,687	(617,406)	-0-	6,542	786
May	95,840	13,417	(638,829)	-0-	6,026	923
June	96,900	13,567	(513,889)	-0-	7,621	1,869
July	107,160	15,003	(500,544)	-0-	9,212	2,428
August	104,060	14,569	(509,752)	-0-	8,671	2,147
September	93,380	13,074	(524,314)	-0-	7,007	1,387
October	97,600	13,665	(637,820)	-0-	6,285	876
November	98,030	13,725	(615,758)	-0-	6,601	720
December	110,560	15,479	(631,246)	-0-	8,176	493
Annual Totals	1,219,980	170,798	(7,015,745)	-0-	89,627	13,046

Source energy consumed per conditioned square foot (573,780 ft^2) = 156,200 Btu per year per square foot

Table G-3. Energy consumption for System 3

Month	Fuel Oil Consumed gallons	Energy Content of Fuel Oil 10^6 Btu	Electricity Purchased kWh	Electrical Demand kW	Total Source Energy Consumed 10^6 Btu	Make-Up Water 1000 gal
January	69,370	9,711	-0-	-0-	9,711	-0-
February	57,062	7,988	-0-	-0-	7,988	-0-
March	51,632	7,228	-0-	-0-	7,228	-0-
April	40,647	5,690	-0-	-0-	5,690	-0-
May	37,537	5,255	-0-	-0-	5,255	90
June	61,876	8,662	-0-	-0-	8,662	1,685
July	78,449	10,982	-0-	-0-	10,982	2,337
August	70,807	9,913	-0-	-0-	9,913	1,994
September	47,984	6,717	-0-	-0-	6,717	887
October	38,597	5,403	-0-	-0-	5,403	49
November	43,057	6,028	-0-	-0-	6,028	-0-
December	61,746	8,644	-0-	-0-	8,644	-0-
Annual Totals	658,769	92,227	-0-	-0-	92,288	7,042

Source energy consumed per conditioned square foot (573,780 ft^2) = 160,700 Btu per year per square foot

Table G.4 Energy consumption for System 4

	Month	Fuel Oil Consumed gallons	Energy Content of Fuel Oil 10^6 Btu	Electricity Purchased kWh	Electrical Demand kW	Total Source Energy Consumed 10^6 Btu	Make-Up Water 1000 gal
a	January	70,648	9,890	-0-	-0-	9,890	1
a	February	58,684	8,215	-0-	-0-	8,215	10
a	March	55,838	7,817	-0-	-0-	7,817	67
a	April	49,075	6,870	-0-	-0-	6,870	179
a	May	45,606	6,384	-0-	-0-	6,384	293
b	June	236,263	33,077	-0-	-0-	33,077	n/a
b	July			-0-	-0-		n/a
b	August			-0-	-0-		n/a
b	September			-0-	-0-		n/a
a	October	47,312	6,623	-0-	-0-	6,623	248
a	November	49,872	6,982	-0-	-0-	6,982	134
a	December	63,233	8,852	-0-	-0-	8,852	5
	Annual Totals	676,535	94,715	-0-	-0-	94,615	n/a

Source energy consumed per conditioned square foot (573,780 ft^2) = 164,900 Btu per year per square foot

a. Same as System 1

b. Calculated by adjustment to System 1 per Appendix F

Table G.5 Energy consumption System 5

Month	Fuel Oil Consumed gallons	Energy Content of Fuel Oil 10^6 Btu	Electricity Purchased kWh	Electrical Demand kW	Total Source Energy Consumed 10^6 Btu	Make-Up Water 1000 gal
January	46,359	6,490	596,120	989	13,389	-0-
February	36,494	5,109	532,442	979	11,271	-0-
March	29,218	4,090	572,425	966	10,715	-0-
April	19,460	2,724	540,433	954	8,978	-0-
May	11,454	1,603	545,557	954	7,917	-0-
June	7,074	990	787,922	1,782	10,108	843
July	6,522	913	929,483	1,912	11,669	1,169
August	6,599	923	876,734	1,880	11,070	997
September	9,233	1,292	684,678	1,405	9,216	443
October	14,693	2,057	550,567	954	8,428	-0-
November	21,875	3,062	542,636	958	9,342	-0-
December	39,174	5,484	584,808	984	12,252	-0-
Annual Totals	248,162	34,742	7,743,801	1,912 MAX	124,360	3,452

Source energy consumed per conditioned square foot (573,780 ft^2) = 216,700 Btu per year per square foot

Table G.6 Energy consumption System 6

Month	Fuel Oil Consumed gallons	Energy Content of Fuel Oil 10^6 Btu	Electricity Purchased kWh	Electrical Demand kW	Total Source Energy Consumed 10^6 Btu	Make-Up Water 1000 gal
January	46,357	6,490	595,190	988	13,378	-0-
February	36,494	5,109	531,602	978	11,261	-0-
March	29,218	4,090	571,495	964	10,704	-0-
April	19,460	2,724	539,533	953	8,968	-0-
May	11,455	1,603	544,627	953	7,906	-0-
June	35,432	4,960	686,018	1,466	12,899	1,686
July	45,206	6,328	781,234	1,488	15,370	2,338
August	40,673	5,694	752,132	1,479	14,398	1,994
September	23,015	3,222	642,221	1,223	10,654	887
October	14,693	2,057	549,637	953	8,418	-0-
November	21,875	3,062	541,736	957	9,332	-0-
December	39,174	5,484	583,878	983	12,241	-0-
Annual Totals	363,059	50,828	7,319,300	1,488 MAX	135,533	6,905

Source energy consumed per conditioned square foot (573,780 ft^2) = 236,200 Btu per year per square foot

Table G.7 Energy consumption for system 7

Month	Fuel Oil Consumed gallons	Energy Content of Fuel Oil 10^6 Btu	Electricity Purchased kWh	Electrical Demand kW	Total Source Energy Consumed 10^6 Btu	Make-Up Water 1000 gal
January	46,359	6,490	596,120	989	13,386	-0-
February	36,494	5,109	532,442	979	11,269	-0-
March	29,218	4,090	572,425	966	10,713	-0-
April	19,460	2,724	540,433	954	8,977	-0-
May	11,454	1,603	545,557	954	7,516	-0-
June	17,660	2,472	687,481	1,469	10,426	1,475
July	23,661	3,312	783,018	1,491	12,372	2,046
August	21,186	2,966	753,881	1,482	11,687	1,745
September	15,618	2,186	643,552	1,225	9,632	776
October	14,693	2,057	550,567	954	8,426	-0-
November	21,875	3,062	542,636	958	9,340	-0-
December	39,174	5,484	584,808	984	12,250	-0-
Annual Totals	296,860	41,560	7,332,848	1,491 MAX	126,391	6,042

Source energy consumed per conditioned square foot (573,780 ft^2) = 220,300 Btu per year per square foot

Table G.8 Energy consumption for System 8

Month	Fuel Oil Consumed gallons	Energy Content of Fuel Oil 10^6 Btu	Electricity Purchased kWh	Electrical Demand kW	Total Source Energy Consumed 10^6 Btu	Make-Up Water 1000 gal
January	46,354	6,490	581,234	969	13,214	-0-
February	36,494	5,109	581,996	959	11,112	-0-
March	29,218	4,090	557,539	946	10,504	-0-
April	19,460	2,724	526,026	934	8,809	-0-
May	11,454	1,603	530,671	934	7,742	-0-
June	7,074	990	883,983	1,777	11,217	843
July	6,522	913	1,029,081	1,913	12,818	1,169
August	6,599	923	977,989	1,867	12,238	997
September	9,233	1,292	773,550	1,598	10,241	443
October	14,693	2,057	535,680	934	8,253	-0-
November	21,875	3,062	528,231	938	9,173	-0-
December	39,174	5,484	569,922	964	12,077	-0-
Annual Totals	248,162	34,742	8,012,900	1,913 MAX	127,440	3,452

Source energy consumed per conditioned square foot (573,780 Ft^2) = 222,200 Btu per year per square foot

Table G.9 Energy consumption for System 9

Month	Fuel Oil Consumed gallons	Energy Content of Fuel Oil 10^6 Btu	Electricity Purchased kWh	Electrical Demand kW	Total Source Energy Consumed 10^6 Btu	Make-Up Water 1000 gal
January	-0-	-0-	2,127,165	3,565	24,617	-0-
February	-0-	-0-	1,734,457	3,320	20,072	-0-
March	-0-	-0-	1,527,142	2,828	17,673	-0-
April	-0-	-0-	1,167,955	2,320	13,516	-0-
May	-0-	-0-	903,016	1,650	10,450	-0-
June	-0-	-0-	1,109,460	2,052	12,839	843
July	-0-	-0-	1,235,590	2,189	14,299	1,169
August	-0-	-0-	1,187,053	2,143	13,737	997
September	-0-	-0-	1,071,601	1,873	12,401	443
October	-0-	-0-	1,016,896	1,969	11,768	-0-
November	-0-	-0-	1,251,363	2,441	14,481	-0-
December	-0-	-0-	1,874,254	3,072	21,690	-0-
Annual Totals	-0-	-0-	16,205,950	3,565 MAX	187,549	3,452

Source energy consumed per conditioned square foot (573,780 ft^2) = 326,866 Btu per year per square foot

Table G.10 Energy consumption for System 10

Month	Fuel Oil Consumed gallons	Energy Content of Fuel Oil 10^6 Btu	Electricity Purchased kWh	Electrical Demand kW	Total Source Energy Consumed 10^6 Btu	Make-Up Water 1000 gal
January	-0-	-0-	2,180,121	3,683	25,230	-0-
February	-0-	-0-	1,770,355	3,422	20,488	-0-
March	-0-	-0-	1,539,073	2,906	17,811	-0-
April	-0-	-0-	1,160,409	2,371	13,429	-0-
May	-0-	-0-	874,317	1,654	10,118	-0-
June	-0-	-0-	1,110,799	2,397	12,855	-0-
July	-0-	-0-	1,288,758	2,768	14,914	-0-
August	-0-	-0-	1,184,867	2,585	13,712	-0-
September	-0-	-0-	976,004	1,880	11,295	-0-
October	-0-	-0-	996,109	1,991	11,527	-0-
November	-0-	-0-	1,247,088	2,481	14,432	-0-
December	-0-	-0-	1,909,553	3,169	22,099	-0-
Annual Totals	-0-	-0-	16,237,452	3,683 MAX	187,914	-0-

Source energy consumed per conditioned square foot (573,780 ft^2) = 327,502 Btu per year per square foot

Table G.11 Energy consumption for System 11

Month	Fuel Oil Consumed gallons	Energy Content of Fuel Oil 10^6 Btu	Electricity Purchased kWh	Electrical Demand kW	Total Source Energy Consumed 10^6 Btu	Make-Up Water 1000 gal
January	-0-	-0-	1,986,657	3,882	22,991	-0-
February	-0-	-0-	1,552,308	3,603	17,964	-0-
March	-0-	-0-	1,171,402	1,989	13,566	-0-
April	-0-	-0-	935,711	1,623	10,828	-0-
May	-0-	-0-	791,289	1,234	9,157	-0-
June	-0-	-0-	1,100,047	2,397	12,730	-0-
July	-0-	-0-	1,288,759	2,768	14,914	-0-
August	-0-	-0-	1,184,867	2,585	13,712	-0-
September	-0-	-0-	927,921	1,880	10,738	-0-
October	-0-	-0-	855,756	1,456	9,903	-0-
November	-0-	-0-	998,160	1,806	11,551	-0-
December	-0-	-0-	1,422,494	3,319	16,462	-0-
Annual Totals	-0-	-0-	14,215,386	3,882 MAX	164,512	-0-

Source energy consumed per conditioned square foot (573,780 ft^2) = 286,717 Btu per year per square foot

Table G.12 Energy consumption for System 12

Month	Fuel Oil Consumed gallons	Energy Content of Fuel Oil 10^6 Btu	Electricity Purchased kWh	Electrical Demand kW	Total Source Energy Consumed 10^6 Btu	Make-Up Water 1000 gal
January	-0-	-0-	2,180,121	3,683	25,230	-0-
February	-0-	-0-	1,770,355	3,422	20,488	-0-
March	-0-	-0-	1,539,073	2,906	17,811	-0-
April	-0-	-0-	1,160,409	2,371	13,429	-0-
May	-0-	-0-	874,317	1,654	10,118	-0-
June	-0-	-0-	1,110,799	2,397	12,855	-0-
July	-0-	-0-	1,288,758	2,768	14,914	-0-
August	-0-	-0-	1,184,867	2,585	13,712	-0-
September	-0-	-0-	976,004	1,880	11,295	-0-
October	-0-	-0-	996,109	1,991	11,527	-0-
November	-0-	-0-	1,247,088	2,481	14,432	-0-
December	-0-	-0-	1,909,553	3,169	22,099	-0-
Annual Totals	-0-	-0-	16,237,452	3,683 MAX	187,914	-0-

Source energy consumed per conditioned square foot (573,780 ft^2) = 327,502 Btu per year per square foot

G.2 REFERENCES - APPENDIX G

G-1. H.D. Nottingham and Associates, Inc., "Design, Cost and Operating Data for Alternative Energy Systems for the Summit Plaza Complex, Jersey City, N.J." National Bureau of Standards Report GCR 79-164, May 1979.

APPENDIX H - SEASONAL DIRECT COST AND DETAILED UNIT COST DATA

H.1 SEASONAL DIRECT COST DATA

Economic data collected at JCTE on a monthly basis were aggregated into seasonal periods so that unit costs could be calculated on a similar basis. The seasonal data include the effect of prorating annual expenses as described in section 8.2.2.1. One other aspect of prorating, not described previously, also had to be applied to the seasonal data. Costs for chiller maintenance were prorated over the period of chiller operation regardless of the time-occurrence of the maintenance. This was necessary since some chiller maintenance was performed in the winter but could only be meaningfully applied to the period in which the chiller operated.

As briefly mentioned in section 8.5, capital costs are included in the unit cost data. The capital costs had to be converted to an equivalent annual basis so that they could be combined with the annual unit cost data. This conversion was done by means of the Uniform Capital Recovery (UCR) factor, which depends on the interest rate and the life of the plant (or other appropriate time period for study).

When dealing with actual cost data for several years following a capital investment, the interest rate should be the nominal rate (i.e. including inflation). This approach puts the capital recovery costs on the same basis as the actual annual costs (which, by nature, include inflation). Since O & M costs are expected to increase with inflation each year while capital recovery is fixed, the relationship between capital and O & M costs can be expected to change each year. The unit costs provided in this report are thus unique to the particular years being presented and in fact, capital recovery is a somewhat greater proportion of total unit costs than would be the case in later years.

The interest rate for determining the UCR factor was based on financing the plant with 100 percent debt at a nominal interest rate which was typical of early 1973 when the present owner purchased the entire Summit Plaza site. At that time, industrial and public utility A-rated bond yields were approximately 7.3 percent and 7.8 percent, respectively representing a lower limit for interest rates [H-1]. Major insurance company financing of income-producing multi-family and non-residential mortgages in the same time period averaged 8.6 percent [H-2]. Housing developers, however, when financing a partly subsidized housing project such as Summit Plaza usually obtained federally-guaranteed loans at an interest rate less than they could obtain under normal circumstances. For this report, an interest rate of 8.0 percent was used in determining the UCR factor.

The time period for determining the UCR factor was based on the expected lifetime of the equipment installed at JCTE. Electric utilities generally use a service life of 30 years in estimating capital recovery of conventional large steam generating equipment [H-3]. This equipment should outlast a diesel TE facility and therefore represents an upper limit for equipment life. The minimum useful life of chillers, boilers and engines for depreciation purposes is generally estimated at 20 years [H-4]. Therefore the life span of the JCTE plant for capital recovery purposes was conservatively assumed to be 20 years.

Applying a life of 20 years and the interest rate of 8.0 percent, UCR factor was calculated as follows [H-5]:

$$(\mathrm{UCR}, i, n) = \frac{i(1+i)^n}{(1+i)^{n-1}}$$

where: i = interest rate
n = time period for capital recovery
= equipment life

$$(\mathrm{UCR}, 0.08, 20) = 0.10185$$

This is equivalent to an annual fixed charge rate of 10.185% of the initial capital costs. Monthly costs for capital recovery are one-twelfth of the annual costs.

Certain equipment replacement and improvement items, which occurred during the first three years of operation were considered to be capital expenses and were thus included in the reported capital recovery cost entries. These capital expense items were individually reported by GKC as they occurred. Examples of such expenses were: pump replacement, control system modifications, etc. The capital cost entries were determined in the same manner as for initial capital costs. They were based on the year in which the expense was incurred, the remaining life of the plant, and the same interest rates as for the initial capital investment. For example, capital improvement items occurring in the second year of plant operation (1975) were annualized by a UCR factor corresponding to 8.0 percent and an 18-year life.

This analysis did did not include a forecast of future replacement or improvement items. Also, in assuming that the prior replacement/improvement items were capitalized in the year in which the expense occurred and have useful lives equal to the remaining plant life, the data in this report have a slightly lower level of capital recovery during the years prior to the incurring of such costs.

Seasonal cost data are presented in tables H-1 through H-9. These data are consistent with the annual cost data of tables 8-2 through 8-4. The "Other O & M" category in tables H-1 through H-9 is the total of the five non-fuel categories of section 8. The Capital Recovery category is a linear prorating of the annualized capital recovery amount (i.e. the capital recovery of a 3-month lized capital recovery amount (i.e. the capital recovery of a 3-month period is one-fourth of the annualized capital recovery determined by the UCR factor).

H.2 DETAILED UNIT COST DATA

The data of tables H.1 through H.9 were used as input to the unit cost calculation methodology described in appendix I. The results of these calculations are shown in tables H.10 through H.13.

Table H.1 Total Direct Costs - Season Summary
Winter, 1975 (December 1974 - February 1975)

Cost Category	Subsystem Electric	Heating	Cooling	PTC	Plant Total
	$	$	$	$	$
Fuel	41,904	32,924	-	0	74,828
Other O & M	28,476	11,048	-	1,026	40,550
Capital recovery	29,431	20,948	-	23,095	73,474
TOTALS	99,811	64,920	-	24,121	188,852

Table H.2 Total Direct Costs - Season Summary
Summer-Fall, 1975 (March 1 - May 28 & September 28 - November 30)

Cost Category	Subsystem Electric	Heating	Cooling	PTC	Plant Total
	$	$	$	$	$
Fuel	74,828	31,865	-	0	106,693
Other O & M	54,472	25,782	-	2,364	82,618
Capital recovery	49,054	39,911	-	38,491	122,456
TOTALS	178,354	92,588	-	40,855	311,767

Table H.3 Total Direct Costs - Season Summary
Summer, 1975 (May 29 - September 27)

Cost Category	Subsystem Electric	Heating	Cooling	PTC	Plant Total
	$	$	$	$	$
Fuel	72,745	35,114	0	0	107,859
Other O & M	43,624	5,721	19,216	2,140	70,701
Capital recovery	39,244	27,931	105,580	30,792	203,547
TOTALS	155,613	68,766	124,796	32,932	382,107

Table H.4 Total Direct Costs - Season Summary
Winter, 1976 (December 1975 - February 1976)

Cost Category	Subsystem Electric	Heating	Cooling	PTC	Plant Total
	$	$	$	$	$
Fuel	51,424	41,375	-	0	92,799
Other O & M	42,014	18,577	-	1,987	62,578
Capital recovery	29,431	20,948	-	23,095	73,474
TOTALS	122,869	80,900	-	25,082	228,851

Table H.5 Total Direct Costs - Season Summary
Spring - Fall, 1976 (March 1 - May 25 & October 3 - November 30)

Cost Category	Subsystem Electric	Heating	Cooling	PTC	Plant Total
	$	$	$	$	$
Fuel	79,484	28,443	-	0	107,927
Other O & M	61,606	34,829	-	3,544	99,979
Capital recovery	46,111	32,817	-	36,181	115,109
TOTALS	187,201	96,089	-	39,725	323,015

Table H.6 Total Direct Costs - Season Summary
Summer, 1976 (May 26 - October 2)

Cost Category	Subsystem Electric	Heating	Cooling	PTC	Plant Total
	$	$	$	$	$
Fuel	91,199	54,504	0	0	145,703
Other O & M	44,917	7,970	31,941	2,777	87,605
Capital recovery	42,187	30,026	105,580	33,102	210,895
TOTALS	178,303	92,500	137,521	35,879	444,203

Table H.7 Total Direct Costs - Season Summary
Winter, 1977 (December 1976 - February 1977)

Cost Category	Subsystem Electric	Heating	Cooling	PTC	Plant Total
	$	$	$	$	$
Fuel	56,281	46,564	-	0	102,845
Other O & M	31,109	19,493	-	5,010	55,612
Capital recovery	29,431	20,947	-	23,095	73,473
TOTALS	116,821	87,004	-	28,105	231,930

Table H.8 Total Direct Costs - Season Summary
Spring - Fall, 1977 (March 1 - May 18 & October 4 - November 30)

Cost Category	Subsystem Electric	Heating	Cooling	PTC	Plant Total
	$	$	$	$	$
Fuel	85,411	31,324	-	0	116,735
Other O & M	51,384	34,966	-	3,295	89,645
Capital recovery	44,149	31,421	-	34,641	110,211
TOTALS	180,944	97,711	-	37,936	316,591

Table H.9 Total Direct Costs - Season Summary
Summer, 1977 (May 19 - October 3)

Cost Category	Subsystem Electric	Heating	Cooling	PTC	Plant Total
	$	$	$	$	$
Fuel	103,715	49,796	0	0	153,511
Other O & M	60,078	12,344	37,362	3,602	113,386
Capital recovery	44,149	31,422	105,580	34,642	215,793
TOTALS	207,942	93,562	142,942	38,244	482,690

Table H.10 Cost of Site Thermal and Electrical Energy
March 1, 1974 through November 30, 1977

Cost Category	Electricity ¢/kWh			Hot Water $/MBtu			Chilled Water $/MBtu		
	1975	1976	1977	1975	1976	1977	1975	1976	1977
Fuel	1.79	1.87	2.07	3.91	3.73	4.07	10.99	10.08	9.52
Other O & M	1.39	1.31	1.19	2.24	2.77	2.73	6.69	6.17	7.48
Capital recovery	1.14	0.98	0.97	3.24	2.73	2.68	25.61	16.94	16.52
TOTALS	4.32	4.16	4.23	9.39	9.23	9.48	43.29	33.19	33.52
Site energy delivered, MWh or MBtu	5,520	6,362	6,330	33,760	38,780	39,460	5,160	8,044	8,333

Table H.11 Cost of Site Electrical Energy

Cost Category	Electrical energy ¢/kWh								
	1975			1976			1977		
	Wtr.	Spg. Fall	Sum.	Wtr.	Spg. Fall	Sum.	Wtr.	Spg. Fall	Sum.
Fuel	1.80	1.70	1.89	1.87	1.79	1.95	2.02	1.99	2.18
Other O & M	1.53	1.15	1.58	1.86	0.95	1.31	1.25	0.64	1.65
Capital recovery	1.43	0.86	1.27	1.22	0.65	1.15	1.22	0.68	1.08
TOTALS	4.76	3.71	4.74	4.95	3.39	4.41	4.49	3.31	4.91
Site Energy Delivered, MWh	1,359	2,269	1,891	1,605	2,383	2,374	1,635	2,257	2,439

Table H.12 Cost of Site Hot Water Energy

Cost Category	Hot Water, $/MBtu								
	1975			1976			1977		
	Wtr.	Spg. Fall	Sum.	Wtr.	Spg. Fall	Sum.	Wtr.	Spg. Fall	Sum.
Fuel	3.43	4.35	3.97	3.56	4.05	3.31	3.56	4.84	3.77
Other O & M	1.27	3.46	0.92	1.73	4.60	0.63	1.54	4.88	1.44
Capital recovery	2.11	4.14	3.96	1.74	3.94	2.38	1.55	4.08	2.93
TOTALS	6.81	11.95	8.85	7.03	12.59	6.32	6.65	13.80	7.84
Site Energy Delivered, MWh	14,650	15,570	3,545	17,620	16,030	5,140	19,540	14,740	5,179

Table H.13 Cost of Site Chilled Water Energy

Cost Category	Chilled Water, $/MBtu		
	Summer 1975	Summer 1976	Summer 1977
Fuel	10.99	10.08	9.52
Other O & M	6.69	6.17	7.48
Capital Recovery	25.61	16.94	16.52
TOTALS	43.29	33.19	33.52
Site Energy Delivered, MWh	5,163	8,044	8,333

Tables H-10 shows yearly values for the unit costs for each of the energy commodities as well as the site energy delivered. Tables H.11 and H.12 provide data on a seasonal basis.

H.3 REFERENCES - APPENDIX H

H-1. "Industrial Bond Yields", Public Utilities Fortnightly, Vol. 98, No. 4, pg. 41, August 12, 1976, and "Public Utility Bond Yields", Public Utilities Fortnightly, Vol. 98, No. 6, p. 33, September 9, 1976.

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H-3. Federal Power Commission, "The 1970 National Power Survey," p. I-19-6, December 1971.

H-4. American Society of Heating, Refrigeration and Air Conditioning Engineers, Inc., "ASHRAE Handbook and Product Directory - 1976 Systems," Chapter 44, 1976.

H-5. Grant, E.L., Ireson, W.G., and Leavenworth, R.S., "Principles of Engineering Economy," 6th ed., p. 34, Ronald Press Co., 1976.

APPENDIX I - UNIT COST CALCULATION METHODOLOGY

I.1 INTRODUCTION

The quantity of utility services supplied to the site is not the same as that produced by the subsystems due to energy flows internal to the plant between subsystems. In order to calculate unit costs of utility services supplied to the site, direct subsystem costs had to be allocated between subsystems to account for these internal energy flows. Energy flows requiring consideration are as follows:

- thermal energy recovered from engines and used in the heating and cooling subsystems,
- electrical energy used for the heating, cooling, and PTC subsystems,
- heat used by the chillers for production of chilled water,
- chilled water used to cool plant office and equipment areas, and
- supplementary heating for plant office area.

The recovered heat from the engine generators is provided entirely to the heating subsystem, even though in the summer the vast majority of all heat, including recovered heat, is utilized by the cooling subsystem. For bookkeeping purposes only, the heating subsystem was considered to be responsible for all PHW heat production, recovery, and losses. This helped to streamline the cost separation formulations.

For the most part, allocating costs between subsystems was relatively straightforward once basic ground rules were established. However, in the case of the recovered heat from the diesel engines, the allocation process was conceptually complex.

I.2 HEAT RECOVERY FROM ENGINES

A number of techniques can be devised for electrical/thermal cost separation. There appears to be no concensus among engineers and economists regarding cost separation from dual-purpose diesel energy systems.

At least two general approaches are possible:

1) from the viewpoint of the electrical subsystem: determine total heat and electrical energy output from the electrical subsystem and allocate electrical subsystem costs, in part or in whole, based on the thermodynamic equivalence of the two commodities, or

2) from the viewpoint of the heating subsystem: determine the cost of a unit of boiler-produced heat and apply this unit cost to the quantity of by-product heat to determine allocated cost.

Cost allocation formulas for both of these approaches are given in this appendix. The approach from the electrical subsystem viewpoint is called the "Cost Separation" approach and is analyzed first. The heating subsystem viewpoint is called the "Heat Value" approach and is dealt with later in this appendix.

Significant thermal and economic accounting questions bearing on the implementation of either of these approaches are:

- ° What heat commodity will be used as a basis for cost transfer: potentially available heat, recovered heat, utilized heat, or the equivalent energy input to the boilers necessary to produce the utilized heat? How should heat losses be accounted for?

- ° Which cost elements are separable? Should fixed and variable costs be treated differently?

The following two sections will address these questions in turn.

I.2.1 Heat Accounting

The economics of total energy are based on efficient recovery of by-product heat from the diesel exhaust. Difficiencies in design, operation, or maintenance of either the diesel engines or the heat recovery units may be a source of inefficiency. Considering the heat recovery units as part of the heating subsystem, it is not immediately clear whether capture of less than the maximum potential exhaust heat should be a penalty to the heating subsystem or to the electrical subsystem. Baseline data in this report is presented using actual heat recovered, while the maximum potential heat recovery case is analyzed on the basis of a sensitivity analysis. The baseline data therefore, are somewhat in favor of low heat unit costs at the expense of higher electrical unit costs.

After heat is added to the PHW system, certain losses occur before the heat is utilized. These losses are either inadvertent (and undesired) or deliberate. Inadvertent losses include convection heat loss from piping and heat rejection units. Deliberate losses consists of operation of heat rejection equipment during periods of low heat demand for site use.

Inadvertent losses occur entirely within the heating subsystem and, therefore, should influence the unit cost of heat but not the unit cost of electricity. Deliberate heat losses should be partly reflected in the unit cost of electricity since it is the basic inflexibility of this subsystem that causes diurnal mismatches between heat and electricity demands.

The majority of the heat losses at JCTE during the period for which thermal data are available were the inadvertent type. Therefore, no adjustment of the recovered heat was made to account for the heat losses.

A further question is how to properly measure thermodynamic equivalence of heat and electricity: on the basis of energy or availability. For this report, availability measures were used.

I.2.2 Cost Accounting

The Cost Separation approach is based on electrical subsystem costs while the Heat Value approach uses heating subsystem costs to develop allocated cost.

Particularly with regard to capital costs, it is not clear which of the subsystem costs to include when determining the allocated cost by either approach. For example, it may seem that only fuel-related costs should be included instead of total fixed and variable costs. In a system where an integrated design has resulted in a capital cost reduction for boilers on the basis of the heat producing capacity of the engine-generators, it is appropriate to include capital costs in the allocated cost in both approaches. This is especially true in a system which has an operating mode which virtually assures an uninterrupted supply of recovered heat.

For this report, both fixed and variable costs for the relevant subsystem were included in determining the cost of recovered heat whether using the Heat Value approach or the Cost Separation approach. Any other costs accounting method (e.g. one based on variable costs only) would result in lower costs for recovered heat.

In the JCTE case, boiler capacity was determined based on a condition where no heat was available from the engine generators [I-1]. The added capital costs are reflected in higher heat costs, but were not considered a basis for neglecting capital costs in determining the value of recovered heat.

I.3 OTHER INTERSUBSYSTEM ENERGY TRANSFERS

In developing an approach for cost separation for other than recovered heat, a basic assumption is that the unit cost of a particular energy product at the producing subsystem is the same regardless whether it is used by another subsystem or transported to site buildings. Thus, all uses of an energy product share proportionately in the fixed and variable expenses of the producing subsystem. Allocating fixed costs (i.e., capital recovery) to energy commodities used within the plant also arises from the fact that these energy outputs are not optional outputs bearing only incremental production costs. This approach is consistent with that of the recovered heat energy transfer.

The cost of energy commodities as provided to the site buildings is the relevant unit cost. In cost accounting for the intersubsystem energy transfers, site distribution costs were not included in plant subsystem direct costs. Site costs were applied only to the energy quantities delivered to the site. This was done because distribution costs are a significant portion (approximately 10 percent) of the costs of their respective subsystems but only relate to energy products delivered to the site. For this reason, the unit cost of each energy product as delivered to the site is slightly higher than the plant unit cost used for cost accounting between subsystems.

The following two major sections develop the methodology for determining first the unit costs at the plant and second, the unit costs at the site buildings.

I.4 FORMULATION OF PLANT UNIT COSTS

In formulating the cost separation, the following basic equation was used:

$$\text{Direct cost} + \text{indirect cost of energy from other subsystems} = \text{cost of products} \qquad \text{(I-1)}$$

The direct cost is that cost already described in section 7, i.e., the reported costs before cost separation. Applying this equation to each subsystem resulted in a set of equations which were solved simultaneously. This provided a basis for solving the cost separation problem. In applying equation (I-1) the following notation was used:

C_i' = total direct cost of subsystem i, less distribution costs. This item is primed to indicate "as reported" costs, before cost separation.

$E_{i,j}$ = quantity of product energy transferred from subsystem i to subsystem j.

$\bar{c}_i$ = unit cost of energy produced at plant subsystem i.

for i: e = electrical; h = heating; c = cooling;
p = pneumatic trash collection

I.4.1 Equations for the Cost Separation Approach

For the electrical subsystem, the net cost of energy from other subsystems consists of the added cost of the chilled water energy used to cool the plant electrical area and the reduction in cost due to heat recovery. The reduction in cost due to recovered thermal energy is the total electrical subsystem cost (including the cost of chilled water energy) multiplied by a heat recovery factor, (denoted by "χ"). Thus, for the electrical subsystem, equation (I-1) becomes:

$$C_e' + E_{c,e} \cdot \bar{c}_c - \chi(C_e' + E_{c,e} \cdot \bar{c}_c) = E_{e,n} \cdot \bar{c}_e$$

or

$$(1-\chi)\,(C_e' + E_{c,e} \cdot \bar{c}_c) = E_{e,n} \cdot \bar{c}_e \qquad \text{(I-2)}$$

where: $E_{e,n} = E_{e,s} + E_{e,c} + E_{e,h} + E_{e,p}$

The heat recovery factor can be formulated in several ways; however, section I.2.1 provides the approach for this report which results in the following:

$$\chi = \frac{A_r}{A_r + A_e} \quad \text{for the baseline case, and}$$

$$\chi = \frac{A_p}{A_p + A_e} \quad \text{for the sensitivity analysis.}$$

where: A_r = availability of actual recovered heat

A_e = availability of elecricity produced, and

A_p = availability of potential recovered heat

This formulation differs for that in the first report on this project which was based solely on energy equivalence [I-2].

For the heating subsystem, the net cost of energy from other subsystems consists of the added cost of recovered heat plus the added cost due to electric energy consumption by the heating subsystem plus the added cost of chilled water used to cool the boiler area. Thus, for the heating subsystem, equation (I-1) becomes:

$$C_h' + \chi\,(C_e' + E_{c,e} \cdot \bar{c}_c) + E_{e,h} \cdot \bar{c}_e + E_{c,h} \cdot \bar{c}_c = E_{h,n} \cdot \bar{c}_h \qquad \text{(I-3)}$$

where: $E_{h,n} = E_{h,s} + E_{h,c}$

For the cooling subsystem, the cost of energy from other subsystems consists of the added cost due to use of hot water energy in the absorption chillers plus the added cost due to electric energy consumption.

Equation (I-1) for the cooling subsystem becomes:

$$C_c' + E_{h,c} \cdot \bar{c}_h + E_{e,c} \cdot \bar{c}_e = E_{c,n} \cdot \bar{c}_c \qquad \text{(I-4)}$$

where: $E_{c,n} = E_{c,s} + E_{c,e} + E_{c,h} + E_{c,p}$

For the pneumatic trash collection system, the cost of electric energy and space cooling are the elements to be considered in addition to the direct costs. Equation (I-1) becomes:

$$C_p' + E_{e,p} \cdot \bar{c}_e + E_{c,p} \cdot \bar{c}_c = C_p$$

Equations (I-2) through (I-4) represent a system of three equations in three unknowns for the Cost Separation approach. The unknowns are the unit costs $\bar{c}_e$, $\bar{c}_h$ and $\bar{c}_c$. Assuming consistency and independence of this set of equations, the solution is a straightforward matter. Moreover, negative unit costs or other anomalous solutions are unlikely because costs are separated in proportion to energy flows which are reasonable and consistent.

The Cost Separation approach was used earlier in JCTE unit cost calculations with the heat recovery factor calculated in terms of the energy equivalence of heat and electricity rather than availability equivalence [I-2]. This resulted in a heat recovery factor equal to 0.47. This value is subject to some variation depending on the exact thermal assumptions made in response to the first question in section J.2. The magnitude of the variation for JCTE was approximately 0.41 to 0.57.

When evaluating the equivalence of heat and electricity by availability measures, significantly greater variation than that expressed above is possible. This occurs because significant quantities of availability are consumed by each of the components in question (diesel engine, heat recovery unit, and boiler) relative to their availability output. The magnitude of the variation in the heat recovery factor for JCTE in this case was approximately 0.21 to 0.43. The variation in this case was large enough to cause concern about using the Cost Separation approach to produce meaningful results. In any case, it is necessary to display unit cost results parametrically, for a range of values of the heat recovery factor, thus diminishing the usefulness of the unit cost data.

I.4.2 Equations for the Heat Value Approach

Following the approach taken in the previous section for the unit cost electricity, the net cost of energy from other subsystems includes the heat energy recovered valued at the unit cost of boiler-produced heat. The unit cost of boiler-produced heat is not the same as the unit cost of heating subsystem heat. Equation (I-1) becomes:

$$C'_e - E_r \cdot \bar{c}_b + E_{c,e} \cdot \bar{c}_c = E_{e,n} \cdot \bar{c}_e \qquad \text{(I-5)}$$

where: E_r = energy recovered

$\bar{c}_b$ = unit cost of boiler-produced heat

$$= \frac{C'_h + E_{e,h} \cdot \bar{c}_e + E_{c,h} \cdot \bar{c}_c}{E_b}$$

$$E_b = E_{h,n} + E_{losses} - E_r$$

For the heating subsystem, the net cost of energy must include the cost of recovered heat which was subtracted from electrical subsystem costs. Thus, equation (I-1) becomes:

$$C'_h + E_r \cdot \bar{c}_b + E_{e,h} \cdot \bar{c}_e + E_{c,h} \cdot \bar{c}_c = E_{h,n} \cdot \bar{c}_h \qquad \text{(I-6)}$$

For the cooling subsystem, the approach is unchanged from the Cost Separation Approach and equation (I-4) is appropriate.

Equations (I-4), (I-5) and (I-6) represent the series of simultaneous equations for solving the cost separation problem for the Heat Value approach. These equations were used to produce the unit cost data of section 8 in this report.

I.4.3 Unit Cost Components

Since published data often provide only O & M costs for comparison purposes, it was felt desirable to provide site unit costs for the JCTE plant showing O & M and capital recovery components separately. For the Heat Value approach, the set of equations (I-4) through (I-6) were used three times to calculate the three unit cost components: fuel, other O & M, and capital. By this process, each of the direct cost components of a particular subsystem was allocated to other subsystems in proportion to the amount of energy utilized. This procedure also guaranteed that the cost structure of a particular energy commodity was the same whether used as a final site product or as an input to another subsystem. Taking the fuel cost component as an example, equation (I-4) for the cooling subsytem becomes:

$$C'_{c,f} + E_{h,c} \cdot \bar{c}_{h,f} + E_{e,c} \cdot \bar{c}_f = E_{c,n} \cdot \bar{c}_{c,f}$$

$C'_{c,f}$, the direct fuel cost for the cooling subsystem, is zero (see for example table 8-8) since the chillers consume no fuel directly. However, the electric energy and hot water energy used by the cooling subsystem have fuel cost components associated with them and thus the fully allocated unit cost for cooling contains a fuel component. This is $\bar{c}_{c,f}$.

The data for these equations are readily available from the direct cost data of section 8 and from production quantities reported in section 4.

I.5 UNIT COST SITE ENERGY

By combining the direct costs for site distribution with the unit costs of energy products at the plant, the unit cost for energy products delivered to the site buildings were calculated.

Conceivably, the site distribution costs could include both capital recovery and O & M components. The reported data of section 8 does not separately show O & M costs for site distribution. The plant operator's responsibility theoretically ends at the TE plant building wall and maintenance of distribution equipment on the site grounds and inside site buildings is the responsibility of the site owner/operator. This division of responsibility has not always been adhered to, resulting in some plant labor being expended on site distribution O & M activities. These activities were minor except for the PTC subsystem and only a small percentage of plant labor has been involved. Thus an assumption of zero O & M costs for site distribution of energy products up to the site building wall was made.

Equations were developed for the cost of site energy commodities using the following basic equation:

$$\text{site unit cost} = \text{plant unit cost} + \text{site distribution unit cost} \quad \text{(I-7)}$$

In applying equation (I-7), the following notation was used:

$\bar{c}_{i,k,j}$ = the cost for subsystem energy product i, of cost component k provided to j.

$C'_{i,k}$ = direct cost for subsystem i of cost component k (plant cost only)

$C'_{i,k,j}$ = as above except denotes added direct cost for j

for i: subsystem e, h, c are defined as before
for k: f = fuel cost; o = other O & M; d = capital recovery
for j: s = site; p = plant

and other notations as before.

Since there are no reported O & M costs for site distribution, both the fuel and O & M site unit costs components are the same as the plant. Therefore, equation (I-7) for fuel and O & M unit costs for each site energy commodity becomes the following:

electrical

$$\bar{c}_{e,f,s} = \bar{c}_{e,f,p} \tag{I-8}$$

$$\bar{c}_{e,o,s} = \bar{c}_{e,o,p} \tag{I-9}$$

heating

$$\bar{c}_{h,f,s} = \bar{c}_{h,f,p} \tag{I-10}$$

$$\bar{c}_{h,o,s} = \bar{c}_{h,o,p} \tag{I-11}$$

cooling

$$\bar{c}_{c,f,s} = \bar{c}_{c,f,p} \tag{I-12}$$

$$\bar{c}_{c,o,s} = \bar{c}_{c,o,p} \tag{I-13}$$

The capital costs for site distribution are separately reported in section 7 of this report. Equation (I-7) for capital recovery unit costs for each site energy commodity becomes:

electrical

$$\bar{c}_{e,d,s} = \bar{c}_{e,d,p} + C'_{e,d,s}/E_{e,s} \tag{I-14}$$

heating

$$\bar{c}_{h,d,s} = \bar{c}_{h,d,p} + C'_{h,d,s}/E_{h,s} \tag{I-15}$$

cooling

$$\bar{c}_{c,d,s} = \bar{c}_{c,d,p} + C'_{c,d,s}/E_{c,s} \tag{I-16}$$

In addition to yearly unit cost data, seasonal unit costs were developed to provide additional insight into the effects of plant operation. It should be noted, however, that it was not possible to produce the yearly unit costs by any simple weighted averaging of seasonal unit costs. Due to the form of the cost separation equations, the allocation of total costs to the site energy commodities depends on whether the cost separation is done monthly, quarterly, or yearly. The total allocated cost data presented were based on applying the cost separation equation to 12-month periods. Legitimate differences of up to 10 percent between seasonal and yearly values can be obtained by summing seasonal costs obtained by applying the equations seasonally.

I.6 REFERENCES - APPENDIX I

I-1 Gamze-Korobkin-Caloger, Inc., "Final Report, Design and Installation, Total Energy Plant-Central Equipment Building, Summit Plaza Apartments, Operation BREAKTHROUGH Site, Jersey City, New Jersey", HUD Utilities Demonstration Series, Vol. 12, February, 1977.

I-2 Hebrank, J., Hurley, C. W., Ryan, J., Obright, W., and Rippey, W., "Performance Analysis of the Jersey City Total Energy Site," National Bureau of Standards Report NBSIR 77-1243, July 1977.

APPENDIX J - DETAILED INITIAL COST DATA FOR ALTERNATIVE SYSTEMS

J.1 INTRODUCTION

This appendix presents detailed capital cost data for each of the alternative energy systems. For each system, the data are subdivided by each site building, the distribution system, and by mechanical and electrical elements. The cost of the floor space occupied by each system was also assessed as a cost element because substantial difference between systems was expected in this area. The initial cost data were obtained from reference [J-1].

Table J.1 Summary cost estimate for Systems 1 and 2

Item	Mechanical Cost	Electrical Cost	Total Cost
Central Equipment Building	$2,335,802	$ 203,164	$2,538,966
Site Distribution System	303,344	194,237	497,581
Camci	414,602	475,673	890,275
Commercial Building	260,065	80,207	340,272
Descon-Concordia	415,021	450,115	865,136
School	77,857	69,975	147,832
Shelley A	490,508	499,400	989,908
Shelley B	147,013	151,498	298,511
Building floor space	---	---	762,810
TOTAL	$4,444,212	$2,124,269	$7,331,291

Note: Unit Cost = $7,331,291 ÷ 573,780 ft^2 = $12.77/ft^2

Table J.2 Summary cost estimate for System 3

Item	Mechanical Cost	Electrical Cost	Total Cost
Central Equipment Building	$2,952,006	$ 203,164*	$3,155,170
Site Distribution System	303,344*	194,237*	497,581*
Camci	414,602*	475,673*	890,275*
Commercial Building	260,065*	80,207*	340,272*
Descon-Concordia	415,021*	450,115*	865,136*
School	77,857*	69,975*	147,832*
Shelley A	490,508*	499,400*	989,908*
Shelley B	147,013*	151,498*	298,511*
Building floor space	---	---	762,810*
TOTAL	$5,060,416	$2,124,269	$7,947,495

Note: Unit Cost = $7,947,495 ÷ 573,780 ft^2 = $13.85/ft^2

* Cost identical to System 1

Table J.3 Summary cost estimate for System 4

Item	Mechanical Cost	Electrical Cost	Total Cost
Central Equipment Building	$2,318,991	$ 206,889	$2,525,880
Site Distributing System	303,344*	194,237*	497,581*
Camci	414,602*	475,673*	890,275*
Commercial Building	260,065*	80,207*	340,272*
Descon-Concordia	415,021*	450,115*	865,136*
School	77,857*	69,975*	147,832*
Shelley A	490,508*	499,400*	989,908*
Shelley B	147,013*	151,498*	298,511*
Building floor space	---	---	762,810*
TOTAL	$4,427,401	$2,127,994	$7,318,205

Note: Unit Cost = $7,318,205 ÷ 573,780 ft^2 = $12.75/$ft^2$

* Cost identical to System 1

Table J.4 Summary cost estimate for System 5

Item	Mechanical Cost	Electrical Cost	Total Cost
Central Equipment Building	$1,028,420	$ 280,442	$1,308,862
Site Distribution System	303,344*	194,237*	497,581*
Camci	414,602*	475,673*	890,275*
Commercial Building	260,065*	80,207*	340,272*
Descon-Concordia	415,021*	446,306	861,327
School	77,857*	69,975*	147,832*
Shelley A	490,508*	499,400*	989,908*
Shelley B	147,013*	151,498*	298,511*
Building floor space	---	---	501,310
TOTAL	$3,136,830	$2,197,738	$5,835,878

Note: Unit Cost = $5,835,878 ÷ 573,780 ft^2 = $10.17/$ft^2$

* Cost identical to System 1

Table J.5 Summary cost estimate for System 6

Item	Mechanical Cost	Electrical Cost	Total Cost
Central Equipment Building	$1,063,309	$ 270,933	$1,334,242
Site Distribution System	303,344*	194,237*	497,581*
Camci	414,602*	475,673*	890,275*
Commercial Building	260,065*	80,207*	340,272*
Descon-Concordia	415,021*	446,306**	861,327
School	77,857*	69,975*	147,832*
Shelley A	490,508*	499,400*	989,908*
Shelley B	147,013*	151,498*	298,511*
Building floor space	---	---	501,310
TOTAL	$3,171,719	$2,188,229	$5,861,258

Note: Unit Cost = $5,851,258 ÷ 573,780 ft^2 = $10.22/$ft^2$

* Cost identical to System 1

** Cost identical to System 1 unless emergency switchboard

Table J.6 Summary cost estimate for System 7

Item	Mechanical Cost	Electrical Cost	Total Cost
Central Equipment Building	$1,673,353	$ 270,933	$1,944,286
Site Distribution System	303,344*	194,237*	497,581*
Camci	414,602*	475,673*	890,275*
Commercial Building	260,065*	80,207*	340,272*
Descon-Concordia	415,021*	446,306	861,327
School	77,857*	69,975*	147,832*
Shelley A	490,508*	499,400*	989,908*
Shelley B	147,013*	151,498*	298,511*
Building floor space	---	---	651,310
TOTAL	$3,781,763	$2,188,229	$6,621,302

Note: Unit Cost = $6,621,302 ÷ 573,780 ft^2 = $11.54/$ft^2$

* Cost identical to System 1

Table J.7 Summary cost estimate for System 8

Item	Mechanical Cost	Electrical Cost	Total Cost
Site Distribution System	---	$ 194,237	$ 194,237
Camci	$ 606,842	513,024	1,119,866
Commercial Building	339,806	95,038	434,844
Descon-Concordia	616,305	484,511	1,100,816
School	128,040	78,875	206,915
Shelley A	712,563	534,701	1,247,264
Shelley B	247,909	174,879	422,788
Building floor space	---	---	300,260
TOTAL	$2,651,465	$2,075,265	$5,026,990

Note: Unit Cost = $5,026,990 ÷ 573,780 ft^2 = $8.76/ft^2

Table J.8 Summary cost estimate for System 9

Item	Mechanical Cost	Electrical Cost	Total Cost
Site Distribution System	---	$ 194,237	$ 194,237
Camci	$ 580,128	527,272	1,107,400
Commercial Building	339,806	95,038	434,844
Descon-Concordia	582,726	495,647	1,078,373
School	128,040	78,875	206,915
Shelley A	678,988	545,340	1,224,328
Shelley B	237,511	179,309	416,820
Building floor space	---	---	300,260
TOTAL	$2,547,199	$2,115,718	$4,963,177

Note: Unit Cost = $4,963,177 ÷ 573,780 ft^2 = $8.65/ft^2

Table J.9 Summary cost estimate for System 10

Item	Mechanical Cost	Electrical Cost	Total Cost
Site Distribution System	---	$ 194,237	$ 194,237
Camci	$ 349,441	591,234	940,675
Commercial Building	119,934	104,734	224,668
Descon-Concordia	358,756	614,062	972,818
School	45,067	85,789	130,856
Shelley A	501,123	678,898	1,180,021
Shelley B	161,282	229,902	391,184
Building floor space	---	---	85,080
TOTAL	$1,535,603	$2,498,856	$4,119,539

Note: Unit Cost = $4,119,539 ÷ 573,780 ft^2 = $7.18/ft^2

Table J.10 Summary cost estimate for System 11

Item	Mechanical Cost	Electrical Cost	Total Cost
Site Distribution System	---	$ 194,237	$ 194,237
Camci	$ 361,613	623,859	985,472
Commercial Building	138,757	99,832	238,589
Descon-Concordia	463,384	604,082	1,067,466
School	60,745	81,763	142,508
Shelley A	498,893	643,327	1,142,220
Shelley B	145,870	195,066	340,936
Building floor space	---	---	85,080
TOTAL	$1,669,262	$2,442,166	$4,196,508

Note: Unit Cost = $4,196,508 ÷ 573,780 ft^2 = $7.31/ft^2

Table J.11 Summary cost estimate for System 12

Item	Mechanical Cost	Electrical Cost	Total Cost
Site Distribution System	---	$ 194,240	$ 194,240
Camci	$ 318,390	623,860	942,250
Commercial Building	128,590	99,830	228,420
Descon-Concordia	392,440	604,080	996,520
School	55,660	81,760	137,423
Shelley A	437,870	643,330	1,081,200
Shelley B	128,920	195,070	323,990
Building floor space	---	---	85,080
TOTAL	$1,461,870	$2,442,170	$3,989,120

Note: Unit Cost = $3,989,120 ÷ 573,780 ft^2 = $6.95/$ft^2$

J.2 REFERENCES - APPENDIX J

J-1 H.D. Nottingham and Associates, Inc., "Detailed Initial Cost Data for Alternative Energy Systems for the Summit Plaza Complex, Jersey City, N.J." National Bureau of Standards Report GCR 79-165, May 1979.

APPENDIX K - ANNUAL CASH FLOW STREAMS FOR ALTERNATIVE SYSTEMS

K.1 INTRODUCTION AND ASSUMPTIONS

Use of Rate-of-Return (ROI) and Present Worth analysis to judge the economic viability of the incremental investments for the alternative energy systems required that cash flow streams be formulated for each of the alternative systems over the entire period of analysis. These cash flow streams take the form of a total net incremental cash flow for each year during the 20-year analysis period. The net cash flows were based on a number of assumptions in the area of plant operation, non-recurring capital replacement costs, depreciation for tax purposes, income tax rate, and debt financing.

Total annual disbursements before taxes consist of plant operation expenses and capital replacement expenses. Annual disbursements for plant operation (i.e. before taxes) in constant dollars are expected to remain constant throughout the period. This is based on the assumption that a typical year was used in the computer energy analysis and the results would not, on the average, change from year-to-year. The constant capital disbursements were based on two simplifications: (1) Systems 10, 11, and 12, which incur large non-recurring capital replacement costs in year 10, could be adequately modelled by including the present value of these replacements in the initial cost and (2) all Systems incur minor capital replacement and improvement costs nearly every year and these could be adequately handled by including a constant (real dollar) amount in the annual disbursements for plant operation.

Depreciation for tax purposes represents an allowable deduction from annual incremental income in order to determine the income on which taxes are computed. The depreciation schedule used for all systems is a combination of the double-declining balance and straight line methods. The double-declining balance method was used for the initial years of the period up to the point where the depreciation deduction was less than that which would result from using the straight line method for the remaining undepreciated balance over the remaining analysis period. This combined approach is allowable under Federal income tax laws and results in full depreciation of the initial incremental investment with no salvage value (undepreciated balance) at the end of the period.

Because of the high depreciation deduction incurred in the first few years when using the double-declining balance method, negative income taxes are shown in the cash flow stream. It was assumed that these could be applied to other taxable income by the owner of the Summit Plaza site/plant and therefore were legitimate as additions to the total net income. The alternative means of analysis (based on carry-forward of the negative tax) would have produced very nearly the same results.

Because other than a simple straight-line depreciation schedule was used, the cash flows after taxes, in constant dollars, are not constant from year-to-year even though the incremental income is constant. This variation in cash flow every year virtually requires a computerized analysis to determine discounted cash flow measures such as ROI and Present Worth.

The income tax rate used in determining the cash flow streams was based on the combined Federal and State tax rates applicable to large business enterprises. The tax rate is uniform for all systems and all years in the analysis at 51.9 percent of taxable income. The income tax amount was subtracted from annual operating income before taxes to determine total net income taxes (i.e. annual "cash flows").

Debt financing was not considered in the baseline analysis, but was briefly examined in sensitivity analyses. Appropriate debt financing calculations were based on the percent of the investment which is debt financed and the interest rate for the debt. In order to formulate cash flows, the total debt/mortgage payments had to be separated into principle and interest amounts so that interest effects could be included in yearly tax calculations. This complex series of calculations was made with the computer program used by NBS for the sensitivity analysis. No cash flow data is provided in this appendix for the debt financing analysis because it was felt these data and general evaluation approach was not particularly relevant to investment decisions.

Two sets of cash flow streams were generated for the economic analysis, one based on constant dollars and one based on consideration of inflation. These two approaches and the cash flow data are discussed in the following two sections.

K.2 CASH FLOW STREAMS WITHOUT INFLATION

Tables K.1 through K.9 provide the incremental cash flow streams for Systems 1 through 8 and System 11. Cash flow streams for Systems 9 and 10 wère not calculated because all values would be negative (i.e. these systems had both an increase in first cost and an increase in operating cost compared to the baseline system. System 12, the baseline system, was not included in the cash flow streams since all values would be zero.

All data in tables K.1 through K.9 are in terms of constant (1976) dollars. This is a common approach to economic analysis but does contain one discrepancy: depreciation amounts were calculated on a constant investment expressed in 1976 dollars. However, since depreciation deductions are actually taken in later years, they are, in their basic form, in current-year (i.e. inflated) dollars. This could be accounted for by including an annual de-escalator to depreciation deductions so that they also would be in terms of constant dollars.

K.3 CASH FLOW STREAMS INCLUDING INFLATION

The data in tables K.10 through K.18 are cash flows in current dollar (1976) terms. These inflated values were based on an 8 percent nominal inflation rate for all disbursements other than energy and a 12 percent nominal inflation rate for energy purchases (i.e. fuel oil and electricity).

While the data in tables K.10 through K.18 solve the problem of depreciation deductions which was inherent in the data of tables K.1 through K.9, it raises a potentially more difficult problem. This problem concerns the proper inflation rate to use in developing the cash flow streams. The inflation rates chosen were based on the need to investigate what was felt to be a maximum (average) inflation rate above the general level of inflation for energy commodities to compare with the constant-dollar data in tables K.1 through K.9 wherein energy commodities are expected to increase only at the same rate as the general level of inflation.

Other assumptions concerning inflation rates can be made by formulating new cash flows streams for analysis or by interpolating betwen the two sets of results produced from using uninflated and inflated cash flow data.

SCHEDULE OF CASH FLOWS
FOR
PROJECT NAME -SYSTEM 1
LOCATION -FINAN 0 DEPR.CODE 4

TOTAL INITIAL INVESTMENT OR ADDED INITIAL INVESTMENT .... $	2423249.	COMPUTED SALVAGE VALUE ....$	0.
AVG ANNUAL INCOME OR SAVINGS RESULTING FROM ADDED INVESTMENT $	794278.	INCOME TAX RATE	51.90 PCT
PERCENT OF INVESTMENT TO BE DEBT FINANCED	.0 PCT	INTEREST RATE ON DEBT FINANCING	8.000 PCT
INVESTMENT TAX CREDIT (PCT. OF INVESTMENT-FIRST YEAR ONLY)	.0 PCT	ESTIMATED LIFE OF ASSET	20YRS

DOUBLE DECLINING BALANCE DEPRECIATION
WITH CHANGE TO STRAIGHT LINE AT BREAK EVEN POINT

PRESENT WORTH OF ANNUAL CASH FLOW AFTER DEPRECIATION AND TAXES

YR	ANNUAL INCOME $	TAX DEPRECIATION $	INTEREST CHARGES $	TAXABLE INCOME $	INCOME TAX $	AMORTIZATION PAYMENT $	CASH FLOW TO EQUITY %	TOTAL CASH FLOW %	PRES WORTH EQUITY FLOW %	PRES WORTH TOTAL FLOW %
1	168635.	242325.	0.	-73690.	-38245.	0.	206880.	206880.	185113.	185113.
2	194554.	218092.	0.	-23538.	-12216.	0.	206770.	206770.	165549.	165549.
3	224038.	196283.	0.	27755.	14405.	0.	209633.	209633.	150182.	150182.
4	257551.	176655.	0.	80896.	41985.	0.	215566.	215866.	138184.	138184.
5	295616.	158989.	0.	136627.	70909.	0.	224707.	224707.	128888.	128888.
6	338821.	143090.	0.	195731.	101584.	0.	237237.	237237.	121758.	121758.
7	387829.	128781.	0.	259048.	134446.	0.	253383.	253383.	116363.	116363.
8	443386.	115903.	0.	327483.	169964.	0.	273422.	273422.	112354.	112354.
9	506331.	104313.	0.	402018.	208647.	0.	297684.	297684.	109453.	109453.
10	577609.	93882.	0.	483727.	251055.	0.	326554.	326554.	107436.	107436.
11	658281.	84493.	0.	573788.	297796.	0.	360485.	360485.	106121.	106121.
12	749543.	84493.	0.	665050.	345161.	0.	404382.	404382.	106518.	106518.
13	852737.	84493.	0.	768244.	398718.	0.	454019.	454019.	107010.	107010.
14	969376.	84493.	0.	884883.	459254.	0.	510122.	510122.	107583.	107583.
15	1101156.	84493.	0.	1016663.	527648.	0.	573508.	573508.	108225.	108225.
16	1249985.	84493.	0.	1165492.	604890.	0.	645095.	645095.	108926.	108926.
17	1418010.	84493.	0.	1333517.	692095.	0.	725915.	725915.	109677.	109677.
18	1607640.	84493.	0.	1523147.	790513.	0.	817127.	817127.	110468.	110468.
19	1821581.	84493.	0.	1737088.	901548.	0.	920033.	920033.	111294.	111294.
20	2062879.	84493.	0.	1978386.	1026782.	0.	1036097.	1036097.	112147.	112147.

PRES WORTH CASH FLOW TO EQUITY= 2423249. RETURN ON EQUITY INVESTMENT= 11.759%

PRES WORTH TOTAL CASH FLOW = 2423249. RETURN ON TOTAL INVESTMENT = 11.759%

Table K.1

SCHEDULE OF CASH FLOWS
FOR
PROJECT NAME -SYSTEM 2
LOCATION -FINAN 0 DEPR.CODE 4

TOTAL INITIAL INVESTMENT OR ADDED INITIAL INVESTMENT .... $ 2423249.		COMPUTED SALVAGE VALUE ....$	0.
AVG ANNUAL INCOME OR SAVINGS RESULTING FROM ADDED INVESTMENT $	685114.	INCOME TAX RATE	51.90 PCT
PERCENT OF INVESTMENT TO BE DEBT FINANCED	.0 PCT	INTEREST RATE ON DEBT FINANCING	8.000 PCT
INVESTMENT TAX CREDIT (PCT. OF INVESTMENT-FIRST YEAR ONLY)	.0 PCT	ESTIMATED LIFE OF ASSET	20YRS

DOUBLE DECLINING BALANCE DEPRECIATION
WITH CHANGE TO STRAIGHT LINE AT BREAK EVEN POINT

PRESENT WORTH OF ANNUAL CASH FLOW AFTER DEPRECIATION AND TAXES

YR	ANNUAL INCOME $	TAX DEPRECIATION $	INTEREST CHARGES $	TAXABLE INCOME $	INCOME TAX $	AMORTIZATION PAYMENT $	CASH FLOW TO EQUITY $	TOTAL CASH FLOW $	PRES WORTH EQUITY FLOW $	PRES WORTH TOTAL FLOW $
1	123337.	242325.	0.	-118988.	-61755.	0.	185092.	185092.	167801.	167801.
2	145464.	218092.	0.	-72628.	-37694.	0.	183158.	183158.	150536.	150536.
3	170833.	196283.	0.	-25450.	-13209.	0.	184042.	184042.	137131.	137131.
4	199879.	176655.	0.	23224.	12053.	0.	187826.	187826.	126877.	126877.
5	233094.	158789.	0.	74105.	38460.	0.	194634.	194634.	119193.	119193.
6	271033.	143090.	0.	127943.	66402.	0.	204631.	204631.	113609.	113609.
7	314322.	128781.	0.	185541.	96296.	0.	218026.	218026.	109738.	109738.
8	363468.	115703.	0.	247765.	128590.	0.	235078.	235078.	107267.	107267.
9	419864.	104313.	0.	315551.	163771.	0.	256093.	256093.	105940.	105940.
10	483809.	93882.	0.	389927.	202372.	0.	281437.	281437.	105548.	105548.
11	556512.	84493.	0.	472019.	244978.	0.	311534.	311534.	105921.	105921.
12	639111.	84493.	0.	554618.	287846.	0.	351265.	351265.	108272.	108272.
13	732887.	84493.	0.	648394.	336516.	0.	396371.	396371.	110762.	110762.
14	839282.	84493.	0.	754789.	391735.	0.	447547.	447547.	113379.	113379.
15	959922.	84493.	0.	875429.	454347.	0.	505575.	505575.	116115.	116115.
16	1096632.	84493.	0.	1012139.	525300.	0.	571332.	571332.	118959.	118959.
17	1251469.	84493.	0.	1166976.	605660.	0.	645809.	645809.	121905.	121905.
18	1426746.	84493.	0.	1342253.	696629.	0.	730117.	730117.	124944.	124944.
19	1625062.	84493.	0.	1540569.	799555.	0.	825507.	825507.	128071.	128071.
20	1849346.	84493.	0.	1764853.	915958.	0.	933388.	933388.	131280.	131280.

PRES WORTH CASH FLOW TO EQUITY= 2423249. RETURN ON EQUITY INVESTMENT= 10.304%

PRES WORTH TOTAL CASH FLOW = 2423249. RETURN ON TOTAL INVESTMENT = 10.304%

Table K.2

SCHEDULE OF CASH FLOWS
FOR

PROJECT NAME -SYSTEM 3
LOCATION -FINAN 0 DEPR.CODE 4

TOTAL INITIAL INVESTMENT OR ADDED INITIAL INVESTMENT .... $	3039453.	COMPUTED SALVAGE VALUE ....$	0.
AVG ANNUAL INCOME OR SAVINGS RESULTING FROM ADDED INVESTMENT $	868330.	INCOME TAX RATE	51.90 PCT
PERCENT OF INVESTMENT TO BE DEBT FINANCED	.0 PCT	INTEREST RATE ON DEBT FINANCING	8.000 PCT
INVESTMENT TAX CREDIT (PCT. OF INVESTMENT-FIRST YEAR ONLY)	.0 PCT	ESTIMATED LIFE OF ASSET	20YRS

DOUBLE DECLINING BALANCE DEPRECIATION
WITH CHANGE TO STRAIGHT LINE AT BREAK EVEN POINT

PRESENT WORTH OF ANNUAL CASH FLOW AFTER DEPRECIATION AND TAXES

YR	ANNUAL INCOME $	TAX DEPRECIATION $	INTEREST CHARGES $	TAXABLE INCOME $	INCOME TAX $	AMORTIZATION PAYMENT $	CASH FLOW TO EQUITY $	TOTAL CASH FLOW $	PRES WORTH EQUITY FLOW $	PRES WORTH TOTAL FLOW $
1	188992.	303945.	0.	-114953.	-59661.	0.	248653.	248653.	224753.	224753.
2	217376.	273551.	0.	-56175.	-29155.	0.	246531.	246531.	201417.	201417.
3	249622.	246196.	0.	3426.	1778.	0.	247844.	247844.	183027.	183027.
4	286230.	221576.	0.	64654.	33555.	0.	252675.	252675.	168660.	168660.
5	327763.	199419.	0.	128344.	66611.	0.	261152.	261152.	157564.	157564.
6	374855.	179477.	0.	195378.	101401.	0.	273454.	273454.	149128.	149128.
7	428219.	161529.	0.	266690.	138412.	0.	289807.	289807.	142856.	142856.
8	488658.	145376.	0.	343282.	178163.	0.	310495.	310495.	138342.	138342.
9	557072.	130838.	0.	426234.	221215.	0.	335857.	335857.	135260.	135260.
10	634480.	117755.	0.	516725.	268180.	0.	366300.	366300.	133341.	133341.
11	722020.	105979.	0.	616041.	319725.	0.	402295.	402295.	132368.	132368.
12	820978.	105979.	0.	714999.	371084.	0.	449894.	449894.	133802.	133802.
13	932796.	105979.	0.	826817.	429118.	0.	503678.	503678.	135400.	135400.
14	1059096.	105979.	0.	953117.	494668.	0.	564428.	564428.	137147.	137147.
15	1201702.	105979.	0.	1095723.	568680.	0.	633022.	633022.	139030.	139030.
16	1362660.	105979.	0.	1256681.	652217.	0.	710443.	710443.	141036.	141036.
17	1544275.	105979.	0.	1438296.	746476.	0.	797799.	797799.	143156.	143156.
18	1749131.	105979.	0.	1643152.	852796.	0.	896335.	896335.	145378.	145378.
19	1980131.	105979.	0.	1874152.	972685.	0.	1007446.	1007446.	147694.	147694.
20	2240542.	105979.	0.	2134563.	1107838.	0.	1132704.	1132704.	150096.	150096.

PRES WORTH CASH FLOW TO EQUITY= 3039453. RETURN ON EQUITY INVESTMENT= 10.634%

PRES WORTH TOTAL CASH FLOW = 3039453. RETURN ON TOTAL INVESTMENT = 10.634%

Table K.3

SCHEDULE OF CASH FLOWS
FOR
PROJECT NAME -SYSTEM 4
LOCATION -FINAN 0   DEPR.CODE 4

TOTAL INITIAL INVESTMENT OR ADDED INITIAL INVESTMENT .... $ 2410163.		COMPUTED SALVAGE VALUE ....$	0.
AVG ANNUAL INCOME OR SAVINGS RESULTING FROM ADDED INVESTMENT $	828983.	INCOME TAX RATE	51.90 PCT
PERCENT OF INVESTMENT TO BE DEBT FINANCED	.0 PCT	INTEREST RATE ON DEBT FINANCING	8.000 PCT
INVESTMENT TAX CREDIT (PCT. OF INVESTMENT-FIRST YEAR ONLY)	.0 PCT	ESTIMATED LIFE OF ASSET	20YRS

DOUBLE DECLINING BALANCE DEPRECIATION
WITH CHANGE TO STRAIGHT LINE AT BREAK EVEN POINT

PRESENT WORTH OF ANNUAL CASH FLOW AFTER DEPRECIATION AND TAXES

YR	ANNUAL INCOME $	TAX DEPRECIATION $	INTEREST CHARGES $	TAXABLE INCOME $	INCOME TAX $	AMORTIZATION PAYMENT $	CASH FLOW TO EQUITY $	TOTAL CASH FLOW $	PRES WORTH EQUITY FLOW $	PRES WORTH TOTAL FLOW $
1	178490.	241016.	0.	-62526.	-32347.	0.	211037.	211037.	188079.	188079.
2	205769.	216915.	0.	-11146.	-5785.	0.	211554.	211554.	168027.	168027.
3	236548.	195223.	0.	41325.	21448.	0.	215100.	215100.	152258.	152258.
4	271508.	175701.	0.	95807.	49724.	0.	221784.	221784.	139910.	139910.
5	311189.	158131.	0.	153058.	79437.	0.	231752.	231752.	130293.	130293.
6	356200.	142318.	0.	213882.	111005.	0.	245195.	245195.	122855.	122855.
7	407227.	128086.	0.	279141.	144874.	0.	262353.	262353.	117151.	117151.
8	465040.	115277.	0.	349763.	181527.	0.	283513.	283513.	112827.	112827.
9	530504.	103750.	0.	426754.	221486.	0.	309018.	309018.	109598.	109598.
10	604597.	93375.	0.	511222.	265324.	0.	339273.	339273.	107238.	107238.
11	688416.	84037.	0.	604379.	313673.	0.	374743.	374743.	105563.	105563.
12	783194.	84037.	0.	699157.	362862.	0.	420332.	420332.	105524.	105524.
13	890320.	84037.	0.	806283.	418461.	0.	471859.	471859.	105573.	105573.
14	1011352.	84037.	0.	927315.	481276.	0.	530076.	530076.	105696.	105696.
15	1148044.	84037.	0.	1064007.	552220.	0.	595824.	595824.	105881.	105881.
16	1302364.	84037.	0.	1218327.	632312.	0.	670052.	670052.	106118.	106118.
17	1476528.	84037.	0.	1392491.	722703.	0.	753825.	753825.	106397.	106397.
18	1673022.	84037.	0.	1588985.	824683.	0.	848339.	848339.	106711.	106711.
19	1894638.	84037.	0.	1810601.	939702.	0.	954936.	954936.	107051.	107051.
20	2144518.	84037.	0.	2060481.	1069390.	0.	1075128.	1075128.	107413.	107413.

PRES WORTH CASH FLOW TO EQUITY= 2410163. RETURN ON EQUITY INVESTMENT= 12.207%

PRES WORTH TOTAL CASH FLOW = 2410163. RETURN ON TOTAL INVESTMENT = 12.207%

Table K.4

SCHEDULE OF CASH FLOWS
FOR
PROJECT NAME -SYSTEM 5
LOCATION -FINAN 0 DEPR.CODE 4

TOTAL INITIAL INVESTMENT OR ADDED INITIAL INVESTMENT .... $	927836.	COMPUTED SALVAGE VALUE ....$	0.
AVG ANNUAL INCOME OR SAVINGS RESULTING FROM ADDED INVESTMENT $	519128.	INCOME TAX RATE	51.90 PCT
PERCENT OF INVESTMENT TO BE DEBT FINANCED	.0 PCT	INTEREST RATE ON DEBT FINANCING	8.000 PCT
INVESTMENT TAX CREDIT (PCT. OF INVESTMENT-FIRST YEAR ONLY)	.0 PCT	ESTIMATED LIFE OF ASSET	20YRS

DOUBLE DECLINING BALANCE DEPRECIATION
WITH CHANGE TO STRAIGHT LINE AT BREAK EVEN POINT

PRESENT WORTH OF ANNUAL CASH FLOW AFTER DEPRECIATION AND TAXES

YR	ANNUAL INCOME $	TAX DEPRECIATION $	INTEREST CHARGES $	TAXABLE INCOME $	INCOME TAX $	AMORTIZATION PAYMENT $	CASH FLOW TO EQUITY $	TOTAL CASH FLOW $	PRES WORTH EQUITY FLOW $	PRES WORTH TOTAL FLOW $
1	118012.	92784.	0.	25228.	13094.	0.	104918.	104918.	89553.	89553.
2	135033.	83505.	0.	51528.	26743.	0.	108290.	108290.	78893.	78893.
3	154325.	75155.	0.	79170.	41089.	0.	113236.	113236.	70414.	70414.
4	176179.	67639.	0.	108540.	56332.	0.	119847.	119847.	63611.	63611.
5	200922.	60875.	0.	140047.	72634.	0.	128238.	128238.	58096.	58096.
6	228924.	54788.	0.	174136.	90377.	0.	138547.	138547.	53574.	53574.
7	260597.	49309.	0.	211288.	109658.	0.	150939.	150939.	49818.	49818.
8	296407.	44378.	0.	252029.	130803.	0.	165604.	165604.	46653.	46653.
9	336876.	39940.	0.	296936.	154110.	0.	182766.	182766.	43947.	43947.
10	382595.	35946.	0.	346649.	179911.	0.	202684.	202684.	41599.	41599.
11	434223.	32352.	0.	401871.	208571.	0.	225652.	225652.	39530.	39530.
12	492503.	32352.	0.	460151.	238819.	0.	253684.	253684.	37932.	37932.
13	558271.	32352.	0.	525919.	272952.	0.	285319.	285319.	36414.	36414.
14	632464.	32352.	0.	600112.	311458.	0.	321006.	321006.	34968.	34968.
15	716138.	32352.	0.	683785.	354885.	0.	361253.	361253.	33589.	33589.
16	810474.	32352.	0.	778122.	403846.	0.	406628.	406628.	32271.	32271.
17	916802.	32352.	0.	884450.	459030.	0.	457772.	457772.	31009.	31009.
18	1036615.	32352.	0.	1004263.	521213.	0.	515402.	515402.	29800.	29800.
19	1171588.	32352.	0.	1139236.	591264.	0.	580324.	580324.	28639.	28639.
20	1323606.	32352.	0.	1291254.	670161.	0.	653445.	653445.	27525.	27525.

PRES WORTH CASH FLOW TO EQUITY= 927836. RETURN ON EQUITY INVESTMENT= 17.159%

PRES WORTH TOTAL CASH FLOW = 927836. RETURN ON TOTAL INVESTMENT = 17.159%

Table K.5

SCHEDULE OF CASH FLOWS
FOR
PROJECT NAME -SYSTEM 6
LOCATION -FINAN 0   DEPR.CODE 4

TOTAL INITIAL INVESTMENT OR ADDED INITIAL INVESTMENT .... $ 953216.   COMPUTED SALVAGE VALUE ....$ 0.
AVG ANNUAL INCOME OR SAVINGS RESULTING FROM ADDED INVESTMENT $ 456765.   INCOME TAX RATE .... 51.90 PCT
PERCENT OF INVESTMENT TO BE DEBT FINANCED .... .0 PCT   INTEREST RATE ON DEBT FINANCING 8.000 PCT
INVESTMENT TAX CREDIT (PCT. OF INVESTMENT-FIRST YEAR ONLY) .0 PCT   ESTIMATED LIFE OF ASSET 20YRS

DOUBLE DECLINING BALANCE DEPRECIATION
WITH CHANGE TO STRAIGHT LINE AT BREAK EVEN POINT

PRESENT WORTH OF ANNUAL CASH FLOW AFTER DEPRECIATION AND TAXES

YR	ANNUAL INCOME $	TAX DEPRECIATION $	INTEREST CHARGES $	TAXABLE INCOME $	INCOME TAX $	AMORTIZATION PAYMENT $	CASH FLOW TO EQUITY $	TOTAL CASH FLOW $	PRES WORTH EQUITY FLOW $	PRES WORTH TOTAL FLOW $
1	98224.	95322.	0.	2902.	1506.	0.	96718.	96718.	83849.	83849.
2	113142.	85789.	0.	27353.	14196.	0.	98946.	98946.	74368.	74368.
3	130101.	77210.	0.	52891.	27450.	0.	102651.	102651.	66887.	66887.
4	149366.	69489.	0.	79877.	41456.	0.	107910.	107910.	60958.	60958.
5	171234.	62541.	0.	108693.	56412.	0.	114822.	114822.	56233.	56233.
6	196042.	56286.	0.	139756.	72533.	0.	123509.	123509.	52439.	52439.
7	224168.	50658.	0.	173510.	90052.	0.	134116.	134116.	49366.	49366.
8	256037.	45592.	0.	210445.	109221.	0.	146816.	146816.	46851.	46851.
9	292128.	41033.	0.	251095.	130318.	0.	161810.	161810.	44765.	44765.
10	332979.	36930.	0.	296049.	153650.	0.	179329.	179329.	43011.	43011.
11	379195.	33237.	0.	345958.	179552.	0.	199643.	199643.	41512.	41512.
12	431458.	33237.	0.	398221.	206677.	0.	224781.	224781.	40521.	40521.
13	490533.	33237.	0.	457296.	237337.	0.	253196.	253196.	39570.	39570.
14	557281.	33237.	0.	524044.	271979.	0.	285302.	285302.	38655.	38655.
15	632671.	33237.	0.	599434.	311106.	0.	321565.	321565.	37771.	37771.
16	717788.	33237.	0.	684551.	355282.	0.	362506.	362506.	36915.	36915.
17	813855.	33237.	0.	780618.	405141.	0.	408714.	408714.	36083.	36083.
18	922245.	33237.	0.	889008.	461395.	0.	460850.	460850.	35272.	35272.
19	1044498.	33237.	0.	1011261.	525845.	0.	519653.	519653.	34481.	34481.
20	1182350.	33237.	0.	1149113.	596390.	0.	585960.	585960.	33708.	33708.

PRES WORTH CASH FLOW TO EQUITY=   953216. RETURN ON EQUITY INVESTMENT= 15.347%

PRES WORTH TOTAL CASH FLOW   =   953216. RETURN ON TOTAL INVESTMENT = 15.347%

Table K.6

SCHEDULE OF CASH FLOWS
FOR
PROJECT NAME -SYSTEM 7
LOCATION -FINAN 0 DEPR.CODE 4

TOTAL INITIAL INVESTMENT OR ADDED INITIAL INVESTMENT .... $ 1713260. COMPUTED SALVAGE VALUE ....$ 0.
AVG ANNUAL INCOME OR SAVINGS RESULTING FROM ADDED INVESTMENT $ 493392. INCOME TAX RATE .... 51.90 PCT
PERCENT OF INVESTMENT TO BE DEBT FINANCED .... .0 PCT INTEREST RATE ON DEBT FINANCING 8.000 PCT
INVESTMENT TAX CREDIT (PCT. OF INVESTMENT-FIRST YEAR ONLY) .0 PCT ESTIMATED LIFE OF ASSET 20YRS

DOUBLE DECLINING BALANCE DEPRECIATION
WITH CHANGE TO STRAIGHT LINE AT BREAK EVEN POINT

PRESENT WORTH OF ANNUAL CASH FLOW AFTER DEPRECIATION AND TAXES

YR	ANNUAL INCOME $	TAX DEPRECIATION $	INTEREST CHARGES $	TAXABLE INCOME $	INCOME TAX $	AMORTIZATION PAYMENT $	CASH FLOW TO EQUITY $	TOTAL CASH FLOW $	PRES WORTH EQUITY FLOW $	PRES WORTH TOTAL FLOW $
1	107396.	171326.	0.	-63930.	-33180.	0.	140576.	140576.	126988.	126988.
2	123524.	154193.	0.	-30669.	-15917.	0.	139441.	139441.	113788.	113788.
3	141846.	138774.	0.	3072.	1594.	0.	140252.	140252.	103386.	103386.
4	162647.	124897.	0.	37750.	19592.	0.	143055.	143055.	95260.	95260.
5	186246.	112407.	0.	73839.	38322.	0.	147924.	147924.	88981.	88981.
6	213004.	101166.	0.	111838.	58044.	0.	154960.	154960.	84204.	84204.
7	243325.	91050.	0.	152275.	79031.	0.	164294.	164294.	80646.	80646.
8	277667.	81945.	0.	195722.	101580.	0.	176087.	176087.	78080.	78080.
9	316540.	73750.	0.	242790.	126008.	0.	190532.	190532.	76319.	76319.
10	360523.	66375.	0.	294148.	152663.	0.	207860.	207860.	75212.	75212.
11	410263.	59738.	0.	350525.	181923.	0.	228340.	228340.	74637.	74637.
12	466490.	59738.	0.	406752.	211104.	0.	255386.	255386.	75408.	75408.
13	530024.	59738.	0.	470286.	244079.	0.	285945.	285945.	76270.	76270.
14	601786.	59738.	0.	542048.	281323.	0.	320463.	320463.	77215.	77215.
15	682813.	59738.	0.	623075.	323376.	0.	359437.	359437.	78235.	78235.
16	774268.	59738.	0.	714530.	370841.	0.	403427.	403427.	79322.	79322.
17	877458.	59738.	0.	817720.	424397.	0.	453061.	453061.	80471.	80471.
18	993854.	59738.	0.	934116.	484806.	0.	509048.	509048.	81675.	81675.
19	1125104.	59738.	0.	1065366.	552925.	0.	572179.	572179.	82931.	82931.
20	1273065.	59738.	0.	1213327.	629717.	0.	643348.	643348.	84233.	84233.

PRES WORTH CASH FLOW TO EQUITY= 1713260. RETURN ON EQUITY INVESTMENT= 10.700%

PRES WORTH TOTAL CASH FLOW = 1713260. RETURN ON TOTAL INVESTMENT = 10.700%

Table K.7

SCHEDULE OF CASH FLOWS
FOR
PROJECT NAME -SYSTEM B
LOCATION -FINAN 0 DEPR.CODE 4

TOTAL INITIAL INVESTMENT OR ADDED INITIAL INVESTMENT .... $ 118948. COMPUTED SALVAGE VALUE ....$ 0.
AVG ANNUAL INCOME OR SAVINGS RESULTING FROM ADDED INVESTMENT $ 531575. INCOME TAX RATE .... 51.90 PCT
PERCENT OF INVESTMENT TO BE DEBT FINANCED .... .0 PCT INTEREST RATE ON DEBT FINANCING 8.000 PCT
INVESTMENT TAX CREDIT (PCT. OF INVESTMENT-FIRST YEAR ONLY) .0 PCT ESTIMATED LIFE OF ASSET 20YRS

DOUBLE DECLINING BALANCE DEPRECIATION
WITH CHANGE TO STRAIGHT LINE AT BREAK EVEN POINT

PRESENT WORTH OF ANNUAL CASH FLOW AFTER DEPRECIATION AND TAXES

YR	ANNUAL INCOME $	TAX DEPRECIATION $	INTEREST CHARGES $	TAXABLE INCOME $	INCOME TAX $	AMORTIZATION PAYMENT $	CASH FLOW TO EQUITY $	TOTAL CASH FLOW $	PRES WORTH EQUITY FLOW $	PRES WORTH TOTAL FLOW $
1	127587.	11895.	0.	115692.	60044.	0.	67543.	67543.	40020.	40020.
2	145086.	10705.	0.	134381.	69744.	0.	75342.	75342.	26450.	26450.
3	164860.	9635.	0.	155225.	80562.	0.	84298.	84298.	17535.	17535.
4	187197.	8671.	0.	178526.	92655.	0.	94542.	94542.	11652.	11652.
5	212418.	7804.	0.	204613.	106195.	0.	106223.	106223.	7757.	7757.
6	240886.	7024.	0.	233862.	121375.	0.	119511.	119511.	5171.	5171.
7	273008.	6321.	0.	266687.	138410.	0.	134598.	134598.	3451.	3451.
8	309243.	5689.	0.	303554.	157544.	0.	151699.	151699.	2304.	2304.
9	350103.	5120.	0.	344983.	179046.	0.	171057.	171057.	1540.	1540.
10	396166.	4608.	0.	391558.	203218.	0.	192948.	192948.	1029.	1029.
11	448081.	4147.	0.	443934.	230402.	0.	217679.	217679.	688.	688.
12	506575.	4147.	0.	502428.	260760.	0.	245815.	245815.	460.	460.
13	572466.	4147.	0.	568319.	294957.	0.	277509.	277509.	308.	308.
14	646673.	4147.	0.	642526.	333471.	0.	313202.	313202.	206.	206.
15	730226.	4147.	0.	726079.	376835.	0.	353391.	353391.	138.	138.
16	824281.	4147.	0.	820134.	425649.	0.	398632.	398632.	92.	92.
17	930137.	4147.	0.	925990.	480589.	0.	449548.	449548.	61.	61.
18	1049251.	4147.	0.	1045104.	542409.	0.	506842.	506842.	41.	41.
19	1183258.	4147.	0.	1179111.	611958.	0.	571300.	571300.	27.	27.
20	1333994.	4147.	0.	1329847.	690190.	0.	643804.	643804.	18.	18.

PRES WORTH CASH FLOW TO EQUITY= 118948. RETURN ON EQUITY INVESTMENT= 68.774%

PRES WORTH TOTAL CASH FLOW = 118948. RETURN ON TOTAL INVESTMENT = 68.774%

Table K.8

SCHEDULE OF CASH FLOWS
FOR
PROJECT NAME -SYSTEM II
LOCATION -FINAN 0 DEPR.CODE 4

TOTAL INITIAL INVESTMENT OR ADDED INITIAL INVESTMENT .... $ 413171.
AVG ANNUAL INCOME OR SAVINGS RESULTING FROM ADDED INVESTMENT $ 271163.
PERCENT OF INVESTMENT TO BE DEBT FINANCED .... .0 PCT
INVESTMENT TAX CREDIT (PCT. OF INVESTMENT-FIRST YEAR ONLY) .0 PCT

COMPUTED SALVAGE VALUE ....$ 0.
INCOME TAX RATE .... 51.90 PCT
INTEREST RATE ON DEBT FINANCING 8.000 PCT
ESTIMATED LIFE OF ASSET 20YRS

DOUBLE DECLINING BALANCE DEPRECIATION
WITH CHANGE TO STRAIGHT LINE AT BREAK EVEN POINT

PRESENT WORTH OF ANNUAL CASH FLOW AFTER DEPRECIATION AND TAXES

YR	ANNUAL INCOME	TAX DEPRECIATION	INTEREST CHARGES	TAXABLE INCOME	INCOME TAX	AMORTIZATION PAYMENT	CASH FLOW TO EQUITY	TOTAL CASH FLOW	PRES WORTH EQUITY FLOW	PRES WORTH TOTAL FLOW
	$	$	$	$	$	$	$	$	$	$
1	74214.	41317.	0.	32897.	17073.	0.	57141.	57141.	47676.	47676.
2	83235.	37185.	0.	46050.	23900.	0.	59335.	59335.	41308.	41308.
3	93348.	33467.	0.	59881.	31078.	0.	62270.	62270.	36171.	36171.
4	104685.	30120.	0.	74565.	38699.	0.	65986.	65986.	31981.	31981.
5	117393.	27108.	0.	90285.	46858.	0.	70535.	70535.	28524.	28524.
6	131637.	24397.	0.	107240.	55657.	0.	75980.	75980.	25636.	25636.
7	147604.	21958.	0.	125646.	65210.	0.	82394.	82394.	23196.	23196.
8	165500.	19762.	0.	145738.	75638.	0.	89862.	89862.	21108.	21108.
9	185557.	17786.	0.	167771.	87073.	0.	98484.	98484.	19302.	19302.
10	208038.	16007.	0.	192031.	99664.	0.	108374.	108374.	17722.	17722.
11	233233.	14406.	0.	218827.	113571.	0.	119662.	119662.	16327.	16327.
12	261470.	14406.	0.	247064.	128226.	0.	133244.	133244.	15169.	15169.
13	293116.	14406.	0.	278710.	144650.	0.	148466.	148466.	14103.	14103.
14	328581.	14406.	0.	314175.	163057.	0.	165524.	165524.	13119.	13119.
15	368326.	14406.	0.	353920.	183684.	0.	184642.	184642.	12210.	12210.
16	412864.	14406.	0.	398458.	206800.	0.	206064.	206064.	11370.	11370.
17	462774.	14406.	0.	448368.	232703.	0.	230071.	230071.	10592.	10592.
18	518703.	14406.	0.	504297.	261730.	0.	256973.	256973.	9871.	9871.
19	581374.	14406.	0.	566968.	294256.	0.	287118.	287118.	9202.	9202.
20	651600.	14406.	0.	637194.	330703.	0.	320897.	320897.	8582.	8562.

PRES WORTH CASH FLOW TO EQUITY= 413171. RETURN ON EQUITY INVESTMENT= 19.851%

PRES WORTH TOTAL CASH FLOW = 413171. RETURN ON TOTAL INVESTMENT = 19.851%

Table K.9

SCHEDULE OF CASH FLOWS
FOR
PROJECT NAME -SYSTEM I
LOCATION -FINAN 0 DEPR.CODE 4

TOTAL INITIAL INVESTMENT OR ADDED INITIAL INVESTMENT .... $ 2423249. COMPUTED SALVAGE VALUE ....$ 0.
AVG ANNUAL INCOME OR SAVINGS RESULTING FROM ADDED INVESTMENT $ 168635. INCOME TAX RATE .... 51.90 PCT
PERCENT OF INVESTMENT TO BE DEBT FINANCED .... .0 PCT INTEREST RATE ON DEBT FINANCING 8.000 PCT
INVESTMENT TAX CREDIT (PCT. OF INVESTMENT-FIRST YEAR ONLY) .0 PCT ESTIMATED LIFE OF ASSET 20YRS

DOUBLE DECLINING BALANCE DEPRECIATION
WITH CHANGE TO STRAIGHT LINE AT BREAK EVEN POINT

PRESENT WORTH OF ANNUAL CASH FLOW AFTER DEPRECIATION AND TAXES

YR	ANNUAL INCOME $	TAX DEPRECIATION $	INTEREST CHARGES $	TAXABLE INCOME $	INCOME TAX $	AMORTIZATION PAYMENT $	CASH FLOW $	TOTAL CASH FLOW $	PRES WORTH EQUITY FLOW $	PRES WORTH TOTAL FLOW $
1	168635.	242325.	0.	-73690.	-38245.	0.	206880.	206880.	203064.	203064.
2	168635.	218092.	0.	-49457.	-25668.	0.	194303.	194303.	187201.	187201.
3	168635.	196283.	0.	-27648.	-14349.	0.	182984.	182984.	173044.	173044.
4	168635.	176655.	0.	-8020.	-4162.	0.	172797.	172797.	160396.	160396.
5	168635.	158989.	0.	9646.	5006.	0.	163629.	163629.	149084.	149084.
6	168635.	143090.	0.	25545.	13258.	0.	155377.	155377.	138955.	138955.
7	168635.	128781.	0.	39854.	20684.	0.	147951.	147951.	129873.	129873.
8	168635.	115903.	0.	52732.	27368.	0.	141267.	141267.	121719.	121719.
9	168635.	104313.	0.	64322.	33383.	0.	135252.	135252.	114386.	114386.
10	168635.	93882.	0.	74753.	38797.	0.	129838.	129838.	107782.	107782.
11	168635.	84493.	0.	84142.	43669.	0.	124966.	124966.	101824.	101824.
12	168635.	84493.	0.	84142.	43669.	0.	124966.	124966.	99945.	99945.
13	168635.	84493.	0.	84142.	43669.	0.	124966.	124966.	98102.	98102.
14	168635.	84493.	0.	84142.	43669.	0.	124966.	124966.	96292.	96292.
15	168635.	84493.	0.	84142.	43669.	0.	124966.	124966.	94516.	94516.
16	168635.	84493.	0.	84142.	43669.	0.	124966.	124966.	92773.	92773.
17	168635.	84493.	0.	84142.	43669.	0.	124966.	124966.	91062.	91062.
18	168635.	84493.	0.	84142.	43669.	0.	124966.	124966.	89382.	89382.
19	168635.	84493.	0.	84142.	43669.	0.	124966.	124966.	87733.	87733.
20	168635.	84493.	0.	84142.	43669.	0.	124966.	124966.	86115.	86115.

PRES WORTH CASH FLOW TO EQUITY= 2423249. RETURN ON EQUITY INVESTMENT= 1.879%

PRES WORTH TOTAL CASH FLOW = 2423249. RETURN ON TOTAL INVESTMENT = 1.879%

Table K.10

SCHEDULE OF CASH FLOWS
FOR

PROJECT NAME -SYSTEM 2
LOCATION -FINAN 0 DEPR,CODE 4

TOTAL INITIAL INVESTMENT OR ADDED INITIAL INVESTMENT .... $ 2423249.
AVG ANNUAL INCOME OR SAVINGS RESULTING FROM ADDED INVESTMENT $ 123337.
PERCENT OF INVESTMENT TO BE DEBT FINANCED .... .0 PCT
INVESTMENT TAX CREDIT (PCT. OF INVESTMENT-FIRST YEAR ONLY) .0 PCT

COMPUTED SALVAGE VALUE ....$ 0.
INCOME TAX RATE .... 51.90 PCT
INTEREST RATE ON DEBT FINANCING 8.000 PCT
ESTIMATED LIFE OF ASSET 20YRS

DOUBLE DECLINING BALANCE DEPRECIATION
WITH CHANGE TO STRAIGHT LINE AT BREAK EVEN POINT

PRESENT WORTH OF ANNUAL CASH FLOW AFTER DEPRECIATION AND TAXES

YR	ANNUAL INCOME $	TAX DEPRECIATION $	INTEREST CHARGES $	TAXABLE INCOME $	INCOME TAX $	AMORTIZATION PAYMENT $	CASH FLOW TO EQUITY $	TOTAL CASH FLOW $	PRES WORTH EQUITY FLOW $	PRES WORTH TOTAL FLOW $
1	123337.	242325.	0.	-118988.	-61755.	0.	185092.	185092.	184923.	184923.
2	123337.	218092.	0.	-94755.	-49178.	0.	172515.	172515.	172200.	172200.
3	123337.	196283.	0.	-72946.	-37859.	0.	161196.	161196.	160755.	160755.
4	123337.	176655.	0.	-53318.	-27672.	0.	151009.	151009.	150459.	150459.
5	123337.	158989.	0.	-35652.	-18504.	0.	141841.	141841.	141195.	141195.
6	123337.	143090.	0.	-19753.	-10252.	0.	133589.	133589.	132860.	132860.
7	123337.	128781.	0.	-5444.	-2826.	0.	126163.	126163.	125359.	125359.
8	123337.	115903.	0.	7434.	3858.	0.	119479.	119479.	118610.	118610.
9	123337.	104313.	0.	19024.	9873.	0.	113464.	113464.	112535.	112535.
10	123337.	93882.	0.	29455.	15287.	0.	108050.	108050.	107068.	107068.
11	123337.	84493.	0.	38844.	20160.	0.	103177.	103177.	102147.	102147.
12	123337.	84493.	0.	38844.	20160.	0.	103177.	103177.	102054.	102054.
13	123337.	84493.	0.	38844.	20160.	0.	103177.	103177.	101960.	101960.
14	123337.	84493.	0.	38844.	20160.	0.	103177.	103177.	101867.	101867.
15	123337.	84493.	0.	38844.	20160.	0.	103177.	103177.	101774.	101774.
16	123337.	84493.	0.	38844.	20160.	0.	103177.	103177.	101682.	101682.
17	123337.	84493.	0.	38844.	20160.	0.	103177.	103177.	101589.	101589.
18	123337.	84493.	0.	38844.	20160.	0.	103177.	103177.	101496.	101496.
19	123337.	84493.	0.	38844.	20160.	0.	103177.	103177.	101404.	101404.
20	123337.	84493.	0.	38844.	20160.	0.	103177.	103177.	101311.	101311.

PRES WORTH CASH FLOW TO EQUITY= 2423249. RETURN ON EQUITY INVESTMENT= .091%

PRES WORTH TOTAL CASH FLOW = 2423249. RETURN ON TOTAL INVESTMENT = .091%

Table K.11

SCHEDULE OF CASH FLOWS
FOR
PROJECT NAME -SYSTEM 3
LOCATION -FINAN 0 DEPR.CODE 4

TOTAL INITIAL INVESTMENT OR ADDED INITIAL INVESTMENT .... $ 3039453.
AVG ANNUAL INCOME OR SAVINGS RESULTING FROM ADDED INVESTMENT $ 188992.
PERCENT OF INVESTMENT TO BE DEBT FINANCED .... .0 PCT
INVESTMENT TAX CREDIT (PCT. OF INVESTMENT-FIRST YEAR ONLY) .0 PCT

COMPUTED SALVAGE VALUE ....$ 0.
INCOME TAX RATE .... 51.90 PCT
INTEREST RATE ON DEBT FINANCING 8.000 PCT
ESTIMATED LIFE OF ASSET 20YRS

DOUBLE DECLINING BALANCE DEPRECIATION
WITH CHANGE TO STRAIGHT LINE AT BREAK EVEN POINT

PRESENT WORTH OF ANNUAL CASH FLOW AFTER DEPRECIATION AND TAXES

YR	ANNUAL INCOME $	TAX DEPRECIATION $	INTEREST CHARGES $	TAXABLE INCOME $	INCOME TAX $	AMORTIZATION PAYMENT $	CASH FLOW TO EQUITY $	TOTAL CASH FLOW $	PRES WORTH EQUITY FLOW $	PRES WORTH TOTAL FLOW $
1	188992.	303945.	0.	-114953.	-59661.	0.	248653.	248653.	245718.	245718.
2	188992.	273551.	0.	-84559.	-43886.	0.	232878.	232878.	227413.	227413.
3	188992.	246196.	0.	-57204.	-29689.	0.	218681.	218681.	211029.	211029.
4	188992.	221576.	0.	-32584.	-16911.	0.	205903.	205903.	196353.	196353.
5	188992.	199419.	0.	-10427.	-5411.	0.	194403.	194403.	183199.	183199.
6	188992.	179477.	0.	9515.	4938.	0.	184054.	184054.	171398.	171398.
7	188992.	161529.	0.	27463.	14253.	0.	174739.	174739.	160804.	160804.
8	188992.	145376.	0.	43616.	22637.	0.	166355.	166355.	151282.	151282.
9	188992.	130838.	0.	58154.	30182.	0.	158810.	158810.	142716.	142716.
10	188992.	117755.	0.	71237.	36972.	0.	152020.	152020.	135001.	135001.
11	188992.	105979.	0.	83013.	43084.	0.	145908.	145908.	128045.	128045.
12	188992.	105979.	0.	83013.	43084.	0.	145908.	145908.	126534.	126534.
13	188992.	105979.	0.	83013.	43084.	0.	145908.	145908.	125040.	125040.
14	188992.	105979.	0.	83013.	43084.	0.	145908.	145908.	123564.	123564.
15	188992.	105979.	0.	83013.	43084.	0.	145908.	145908.	122106.	122106.
16	188992.	105979.	0.	83013.	43084.	0.	145908.	145908.	120665.	120665.
17	188992.	105979.	0.	83013.	43084.	0.	145908.	145908.	119241.	119241.
18	188992.	105979.	0.	83013.	43084.	0.	145908.	145908.	117833.	117833.
19	188992.	105979.	0.	83013.	43084.	0.	145908.	145908.	116443.	116443.
20	188992.	105979.	0.	83013.	43084.	0.	145908.	145908.	115068.	115068.

PRES WORTH CASH FLOW TO EQUITY= 3039453. RETURN ON EQUITY INVESTMENT= 1.194%

PRES WORTH TOTAL CASH FLOW = 3039453. RETURN ON TOTAL INVESTMENT = 1.194%

Table K.12

SCHEDULE OF CASH FLOWS
FOR
PROJECT NAME -SYSTEM 4
LOCATION -FINAN 0 DEPR.CODE 4

TOTAL INITIAL INVESTMENT OR ADDED INITIAL INVESTMENT .... $ 2410163.
AVG ANNUAL INCOME OR SAVINGS RESULTING FROM ADDED INVESTMENT $ 178690.
PERCENT OF INVESTMENT TO BE DEBT FINANCED .... .0 PCT
INVESTMENT TAX CREDIT (PCT. OF INVESTMENT-FIRST YEAR ONLY) .0 PCT

COMPUTED SALVAGE VALUE ....$ 0.
INCOME TAX RATE .... 51.90 PCT
INTEREST RATE ON DEBT FINANCING 8.000 PCT
ESTIMATED LIFE OF ASSET 20YRS

DOUBLE DECLINING BALANCE DEPRECIATION
WITH CHANGE TO STRAIGHT LINE AT BREAK EVEN POINT

PRESENT WORTH OF ANNUAL CASH FLOW AFTER DEPRECIATION AND TAXES

YR	ANNUAL INCOME $	TAX DEPRECIATION $	INTEREST CHARGES $	TAXABLE INCOME $	INCOME TAX $	AMORTIZATION PAYMENT $	CASH FLOW TO EQUITY $	TOTAL CASH FLOW $	PRES WORTH EQUITY FLOW $	PRES WORTH TOTAL FLOW $
1	178690.	241016.	0.	-62326.	-32347.	0.	211037.	211037.	206320.	206320.
2	178690.	216915.	0.	-38225.	-19839.	0.	198529.	198529.	189753.	189753
3	178690.	195223.	0.	-16533.	-8581.	0.	187271.	187271.	174992.	174992
4	178690.	175701.	0.	2989.	1551.	0.	177139.	177139.	161824.	161824
5	178690.	158131.	0.	20559.	10670.	0.	168020.	168020.	150063.	150063
6	178690.	142318.	0.	36372.	18877.	0.	159813.	159813.	139543.	139543
7	178690.	128086.	0.	50604.	26264.	0.	152426.	152426.	130119.	130119
8	178690.	115277.	0.	63413.	32911.	0.	145779.	145779.	121662.	121662
9	178690.	103750.	0.	74940.	38894.	0.	139796.	139796.	114061.	114061
10	178690.	93375.	0.	85315.	44279.	0.	134411.	134411.	107217.	107217
11	178690.	84037.	0.	94653.	49125.	0.	129565.	129565.	101041.	101041
12	178690.	84037.	0.	94653.	49125.	0.	129565.	129565.	98783.	98783
13	178690.	84037.	0.	94653.	49125.	0.	129565.	129565.	96575.	96575
14	178690.	84037.	0.	94653.	49125.	0.	129565.	129565.	94416.	94416
15	178690.	84037.	0.	94653.	49125.	0.	129565.	129565.	92306.	92306
16	178690.	84037.	0.	94653.	49125.	0.	129565.	129565.	90243.	90243
17	178690.	84037.	0.	94653.	49125.	0.	129565.	129565.	88226.	88226
18	178690.	84037.	0.	94653.	49125.	0.	129565.	129565.	86254.	86254
19	178690.	84037.	0.	94653.	49125.	0.	129565.	129565.	84326.	84326
20	178690.	84037.	0.	94653.	49125.	0.	129565.	129565.	82441.	82441

PRES WORTH CASH FLOW TO EQUITY= 2410163. RETURN ON EQUITY INVESTMENT= 2.286%

PRES WORTH TOTAL CASH FLOW = 2410163. RETURN ON TOTAL INVESTMENT = 2.286%

Table K.13

SCHEDULE OF CASH FLOWS
FOR

PROJECT NAME -SYSTEM 5
LOCATION -FINAN 0 DEPR.CODE 4

TOTAL INITIAL INVESTMENT OR ADDED INITIAL INVESTMENT .... $	927836.	COMPUTED SALVAGE VALUE ....$	0.
AVG ANNUAL INCOME OR SAVINGS RESULTING FROM ADDED INVESTMENT $	118012.	INCOME TAX RATE	51.90 PCT
PERCENT OF INVESTMENT TO BE DEBT FINANCED	.0 PCT	INTEREST RATE ON DEBT FINANCING	8.000 PCT
INVESTMENT TAX CREDIT (PCT. OF INVESTMENT-FIRST YEAR ONLY)	.0 PCT	ESTIMATED LIFE OF ASSET	20YRS

DOUBLE DECLINING BALANCE DEPRECIATION
WITH CHANGE TO STRAIGHT LINE AT BREAK EVEN POINT

PRESENT WORTH OF ANNUAL CASH FLOW AFTER DEPRECIATION AND TAXES

YR	ANNUAL INCOME $	TAX DEPRECIATION $	INTEREST CHARGES $	TAXABLE INCOME $	INCOME TAX $	AMORTIZATION PAYMENT $	CASH FLOW TO EQUITY $	TOTAL CASH FLOW $	PRES WORTH EQUITY FLOW $	PRES WORTH TOTAL FLOW $
1	118012.	92784.	0.	25228.	13094.	0.	104918.	104918.	98521.	98521.
2	118012.	83505.	0.	34507.	17909.	0.	100103.	100103.	88268.	88268.
3	118012.	75155.	0.	42857.	22243.	0.	95769.	95769.	79297.	79297.
4	118012.	67639.	0.	50373.	26143.	0.	91869.	91869.	71429.	71429.
5	118012.	60875.	0.	57137.	29654.	0.	88358.	88358.	64511.	64511.
6	118012.	54788.	0.	63224.	32813.	0.	85199.	85199.	58411.	58411.
7	118012.	49309.	0.	68703.	35657.	0.	82355.	82355.	53019.	53019.
8	118012.	44378.	0.	73634.	38216.	0.	79796.	79796.	48239.	48239.
9	118012.	39940.	0.	78072.	40519.	0.	77493.	77493.	43990.	43990.
10	118012.	35946.	0.	82066.	42592.	0.	75420.	75420.	40203.	40203.
11	118012.	32352.	0.	85660.	44458.	0.	73554.	73554.	36818.	36818.
12	118012.	32352.	0.	85660.	44458.	0.	73554.	73554.	34573.	34573.
13	118012.	32352.	0.	85660.	44458.	0.	73554.	73554.	32465.	32465.
14	118012.	32352.	0.	85660.	44458.	0.	73554.	73554.	30485.	30485.
15	118012.	32352.	0.	85660.	44458.	0.	73554.	73554.	28626.	28626.
16	118012.	32352.	0.	85660.	44458.	0.	73554.	73554.	26881.	26881.
17	118012.	32352.	0.	85660.	44458.	0.	73554.	73554.	25242.	25242.
18	118012.	32352.	0.	85660.	44458.	0.	73554.	73554.	23703.	23703.
19	118012.	32352.	0.	85660.	44458.	0.	73554.	73554.	22257.	22257.
20	118012.	32352.	0.	85660.	44458.	0.	73554.	73554.	20900.	20900.

PRES WORTH CASH FLOW TO EQUITY= 927836. RETURN ON EQUITY INVESTMENT= 6.493%

PRES WORTH TOTAL CASH FLOW = 927836. RETURN ON TOTAL INVESTMENT = 6.493%

Table K.14

SCHEDULE OF CASH FLOWS
FOR
PROJECT NAME -SYSTEM 6
LOCATION -FINAN 0   DEPR.CODE 4

TOTAL INITIAL INVESTMENT OR ADDED INITIAL INVESTMENT .... $	953216.	COMPUTED SALVAGE VALUE ....$	0.
AVG ANNUAL INCOME OR SAVINGS RESULTING FROM ADDED INVESTMENT $	98224.	INCOME TAX RATE	51.90 PCT
PERCENT OF INVESTMENT TO BE DEBT FINANCED	.0 PCT	INTEREST RATE ON DEBT FINANCING	8.000 PCT
INVESTMENT TAX CREDIT (PCT. OF INVESTMENT-FIRST YEAR ONLY)	.0 PCT	ESTIMATED LIFE OF ASSET	20YRS

DOUBLE DECLINING BALANCE DEPRECIATION
WITH CHANGE TO STRAIGHT LINE AT BREAK EVEN POINT

PRESENT WORTH OF ANNUAL CASH FLOW AFTER DEPRECIATION AND TAXES

YR	ANNUAL INCOME $	TAX DEPRECIATION $	INTEREST CHARGES $	TAXABLE INCOME $	INCOME TAX $	AMORTIZATION PAYMENT $	CASH FLOW TO EQUITY $	TOTAL CASH FLOW $	PRES WORTH EQUITY FLOW $	PRES WORTH TOTAL FLOW $
1	98224.	95322.	0.	2902.	1506.	0.	96718.	96718.	92392.	92392.
2	98224.	85789.	0.	12435.	6454.	0.	91770.	91770.	83745.	83745.
3	98224.	77210.	0.	21014.	10906.	0.	87318.	87318.	76118.	76118.
4	98224.	69489.	0.	28735.	14913.	0.	83311.	83311.	69377.	69377.
5	98224.	62541.	0.	35683.	18520.	0.	79704.	79704.	63405.	63405.
6	98224.	56286.	0.	41938.	21766.	0.	76458.	76458.	58103.	58103.
7	98224.	50658.	0.	47566.	24687.	0.	73537.	73537.	53383.	53383.
8	98224.	45592.	0.	52632.	27316.	0.	70908.	70908.	49173.	49173.
9	98224.	41033.	0.	57191.	29682.	0.	68542.	68542.	45406.	45406.
10	98224.	36930.	0.	61294.	31812.	0.	66412.	66412.	42027.	42027.
11	98224.	33237.	0.	64987.	33728.	0.	64496.	64496.	38989.	38989.
12	98224.	33237.	0.	64987.	33728.	0.	64496.	64496.	37245.	37245.
13	98224.	33237.	0.	64987.	33728.	0.	64496.	64496.	35580.	35580.
14	98224.	33237.	0.	64987.	33728.	0.	64496.	64496.	33988.	33988.
15	98224.	33237.	0.	64987.	33728.	0.	64496.	64496.	32468.	32468.
16	98224.	33237.	0.	64987.	33728.	0.	64496.	64496.	31016.	31016.
17	98224.	33237.	0.	64987.	33728.	0.	64496.	64496.	29629.	29629.
18	98224.	33237.	0.	64987.	33728.	0.	64496.	64496.	28304.	28304.
19	98224.	33237.	0.	64987.	33728.	0.	64496.	64496.	27038.	27038.
20	98224.	33237.	0.	64987.	33728.	0.	64496.	64496.	25829.	25829.

PRES WORTH CASH FLOW TO EQUITY= 953216. RETURN ON EQUITY INVESTMENT= 4.682%

PRES WORTH TOTAL CASH FLOW = 953216. RETURN ON TOTAL INVESTMENT = 4.682%

Table K.15

SCHEDULE OF CASH FLOWS
FOR
PROJECT NAME -SYSTEM 7
LOCATION -FINAN 0 DEPR.CODE 4

TOTAL INITIAL INVESTMENT OR ADDED INITIAL INVESTMENT .... $ 1713260. COMPUTED SALVAGE VALUE ....$ 0.
AVG ANNUAL INCOME OR SAVINGS RESULTING FROM ADDED INVESTMENT $ 107396. INCOME TAX RATE .... 51.90 PCT
PERCENT OF INVESTMENT TO BE DEBT FINANCED .... .0 PCT INTEREST RATE ON DEBT FINANCING 8.000 PCT
INVESTMENT TAX CREDIT (PCT. OF INVESTMENT-FIRST YEAR ONLY) .0 PCT ESTIMATED LIFE OF ASSET 20YRS

DOUBLE DECLINING BALANCE DEPRECIATION
WITH CHANGE TO STRAIGHT LINE AT BREAK EVEN POINT

PRESENT WORTH OF ANNUAL CASH FLOW AFTER DEPRECIATION AND TAXES

YR	ANNUAL INCOME $	TAX DEPRECIATION $	INTEREST CHARGES $	TAXABLE INCOME $	INCOME TAX $	AMORTIZATION PAYMENT $	CASH FLOW TO EQUITY $	TOTAL CASH FLOW $	PRES WORTH EQUITY FLOW $	PRES WORTH TOTAL FLOW $
1	107396.	171326.	0.	-63930.	-33180.	0.	140576.	140576.	138851.	138851.
2	107396.	154193.	0.	-46797.	-24288.	0.	131684.	131684.	128473.	128473.
3	107396.	138774.	0.	-31378.	-16285.	0.	123681.	123681.	119185.	119185.
4	107396.	124897.	0.	-17501.	-9083.	0.	116479.	116479.	110868.	110868.
5	107396.	112407.	0.	-5011.	-2601.	0.	109997.	109997.	103413.	103413.
6	107396.	101166.	0.	6230.	3233.	0.	104163.	104163.	96727.	96727.
7	107396.	91050.	0.	16346.	8484.	0.	98912.	98912.	90725.	90725.
8	107396.	81945.	0.	25451.	13209.	0.	94187.	94187.	85331.	85331.
9	107396.	73750.	0.	33646.	17462.	0.	89934.	89934.	80478.	80478.
10	107396.	66375.	0.	41021.	21290.	0.	86106.	86106.	76108.	76108.
11	107396.	59738.	0.	47658.	24735.	0.	82661.	82661.	72166.	72166.
12	107396.	59738.	0.	47658.	24735.	0.	82661.	82661.	71281.	71281.
13	107396.	59738.	0.	47658.	24735.	0.	82661.	82661.	70407.	70407.
14	107396.	59738.	0.	47658.	24735.	0.	82661.	82661.	69543.	69543.
15	107396.	59738.	0.	47658.	24735.	0.	82661.	82661.	68690.	68690.
16	107396.	59738.	0.	47658.	24735.	0.	82661.	82661.	67847.	67847.
17	107396.	59738.	0.	47658.	24735.	0.	82661.	82661.	67015.	67015.
18	107396.	59738.	0.	47658.	24735.	0.	82661.	82661.	66193.	66193.
19	107396.	59738.	0.	47658.	24735.	0.	82661.	82661.	65381.	65381.
20	107396.	59738.	0.	47658.	24735.	0.	82661.	82661.	64579.	64579.

PRES WORTH CASH FLOW TO EQUITY= 1713260. RETURN ON EQUITY INVESTMENT= 1.242%

PRES WORTH TOTAL CASH FLOW = 1713260. RETURN ON TOTAL INVESTMENT = 1.242%

Table K.16

SCHEDULE OF CASH FLOWS
FOR
PROJECT NAME -SYSTEM 8
LOCATION -FINAN 0 DEPR.CODE 4

TOTAL INITIAL INVESTMENT OR ADDED INITIAL INVESTMENT .... $	118948.	COMPUTED SALVAGE VALUE ....$	0.
AVG ANNUAL INCOME OR SAVINGS RESULTING FROM ADDED INVESTMENT $	127587.	INCOME TAX RATE	51.90 PCT
PERCENT OF INVESTMENT TO BE DEBT FINANCED	.0 PCT	INTEREST RATE ON DEBT FINANCING	8.000 PCT
INVESTMENT TAX CREDIT (PCT. OF INVESTMENT-FIRST YEAR ONLY)	.0 PCT	ESTIMATED LIFE OF ASSET	20YRS

DOUBLE DECLINING BALANCE DEPRECIATION
WITH CHANGE TO STRAIGHT LINE AT BREAK EVEN POINT

PRESENT WORTH OF ANNUAL CASH FLOW AFTER DEPRECIATION AND TAXES

YR	ANNUAL INCOME $	TAX DEPRECIATION $	INTEREST CHARGES $	TAXABLE INCOME $	INCOME TAX $	AMORTIZATION PAYMENT $	CASH FLOW TO EQUITY $	TOTAL CASH FLOW $	PRES WORTH EQUITY FLOW $	PRES WOR TOTAL FLC $
1	127587.	11895.	0.	115692.	60044.	0.	67543.	67543.	43299.	43299.
2	127587.	10705.	0.	116882.	60662.	0.	66925.	66925.	27503.	27503.
3	127587.	9635.	0.	117952.	61217.	0.	66370.	66370.	17485.	17485.
4	127587.	8671.	0.	118916.	61717.	0.	65870.	65870.	11124.	11124.
5	127587.	7804.	0.	119783.	62167.	0.	65420.	65420.	7082.	7082.
6	127587.	7024.	0.	120563.	62572.	0.	65015.	65015.	4512.	4512.
7	127587.	6321.	0.	121266.	62937.	0.	64650.	64650.	2876.	2876
8	127587.	5689.	0.	121898.	63265.	0.	64322.	64322.	1835.	1835
9	127587.	5120.	0.	122467.	63560.	0.	64027.	64027.	1171.	1171
10	127587.	4608.	0.	122979.	63826.	0.	63761.	63761.	747.	747
11	127587.	4147.	0.	123440.	64065.	0.	63522.	63522.	477.	477
12	127587.	4147.	0.	123440.	64065.	0.	63522.	63522.	306.	306
13	127587.	4147.	0.	123440.	64065.	0.	63522.	63522.	196.	196
14	127587.	4147.	0.	123440.	64065.	0.	63522.	63522.	126.	126
15	127587.	4147.	0.	123440.	64065.	0.	63522.	63522.	81.	81
16	127587.	4147.	0.	123440.	64065.	0.	63522.	63522.	52.	52
17	127587.	4147.	0.	123440.	64065.	0.	63522.	63522.	33.	33
18	127587.	4147.	0.	123440.	64065.	0.	63522.	63522.	21.	21
19	127587.	4147.	0.	123440.	64065.	0.	63522.	63522.	14.	14
20	127587.	4147.	0.	123440.	64065.	0.	63522.	63522.	9.	9

PRES WORTH CASH FLOW TO EQUITY= 118948. RETURN ON EQUITY INVESTMENT= 55.993%

PRES WORTH TOTAL CASH FLOW = 118948. RETURN ON TOTAL INVESTMENT = 55.993%

Table K.17

SCHEDULE OF CASH FLOWS
FOR
PROJECT NAME -SYSTEM I
LOCATION -FINAN 0   DEPR.CODE 4

TOTAL INITIAL INVESTMENT OR ADDED INITIAL INVESTMENT .... $	413171.	COMPUTED SALVAGE VALUE ....$	0.
AVG ANNUAL INCOME OR SAVINGS RESULTING FROM ADDED INVESTMENT $	74214.	INCOME TAX RATE	51.90 PCT
PERCENT OF INVESTMENT TO BE DEBT FINANCED	.0 PCT	INTEREST RATE ON DEBT FINANCING	8.000 PCT
INVESTMENT TAX CREDIT (PCT. OF INVESTMENT-FIRST YEAR ONLY)	.0 PCT	ESTIMATED LIFE OF ASSET	20YRS

DOUBLE DECLINING BALANCE DEPRECIATION
WITH CHANGE TO STRAIGHT LINE AT BREAK EVEN POINT

PRESENT WORTH OF ANNUAL CASH FLOW AFTER DEPRECIATION AND TAXES

YR	ANNUAL INCOME $	TAX DEPRECIATION $	INTEREST CHARGES $	TAXABLE INCOME $	INCOME TAX $	AMORTIZATION PAYMENT $	CASH FLOW TO EQUITY $	TOTAL CASH FLOW $	PRES WORTH EQUITY FLOW $	PRES W TOTAL F $
1	74214.	41317.	0.	32897.	17073.	0.	57141.	57141.	51923.	5192
2	74214.	37185.	0.	37029.	19218.	0.	54996.	54996.	45412.	4541
3	74214.	33467.	0.	40747.	21148.	0.	53066.	53066.	39818.	3981
4	74214.	30120.	0.	44094.	22885.	0.	51329.	51329.	34998.	3499
5	74214.	27108.	0.	47106.	24448.	0.	49766.	49766.	30834.	3083
6	74214.	24397.	0.	49817.	25855.	0.	48359.	48359.	27227.	2722
7	74214.	21958.	0.	52256.	27121.	0.	47093.	47093.	24093.	2409
8	74214.	19762.	0.	54452.	28261.	0.	45953.	45953.	21364.	2136
9	74214.	17786.	0.	56428.	29286.	0.	44928.	44928.	18980.	1898
10	74214.	16007.	0.	58207.	30209.	0.	44005.	44005.	16893.	1689
11	74214.	14406.	0.	59808.	31040.	0.	43174.	43174.	15060.	1506
12	74214.	14406.	0.	59808.	31040.	0.	43174.	43174.	13685.	1368
13	74214.	14406.	0.	59808.	31040.	0.	43174.	43174.	12436.	1243
14	74214.	14406.	0.	59808.	31040.	0.	43174.	43174.	11300.	1130
15	74214.	14406.	0.	59808.	31040.	0.	43174.	43174.	10269.	1026
16	74214.	14406.	0.	59808.	31040.	0.	43174.	43174.	9331.	933
17	74214.	14406.	0.	59808.	31040.	0.	43174.	43174.	8479.	847
18	74214.	14406.	0.	59808.	31040.	0.	43174.	43174.	7705.	770
19	74214.	14406.	0.	59808.	31040.	0.	43174.	43174.	7002.	700
20	74214.	14406.	0.	59808.	31040.	0.	43174.	43174.	6362.	636

PRES WORTH CASH FLOW TO EQUITY=   413171.   RETURN ON EQUITY INVESTMENT=   10.048%

PRES WORTH TOTAL CASH FLOW   =   413171.   RETURN ON TOTAL INVESTMENT =   10.048%

WFIN   NIF0

Table K.18

APPENDIX L - DEFINITION OF TERMS FOR ELECTRICAL SERVICE RELIABILITY

The definitions below are standard definitions developed by the Institute of Electrical and Electronics Engineers (IEEE).

- Interruption -- an interruption is the loss of service to one or more consumers and is the result of one or more component outages.

- Interruption duration - the period from the initiation of an interruption to a consumer until service has been restored to that consumer.

Classification of interruption by type of outage:

- Forced interruption - an interruption caused by an outage that results from energy conditions directly associated with a component requiring that it be taken out of service immediately or an outage caused by improper operation of equipment or human error.

- Scheduled interruption - an interruption caused by an outage that results when a component is deliberately taken out of service at a selected time, usually for purposes of construction, preventative maintenance, or repair.

Classification of interruptions by duration:

- Momentary interruption - an interruption of duration limited to the period required to restore service by automatic or supervisory controlled switching operations or by manual switching at locations where an operator is immediately available. Note: such switching operations must be completed.

- Sustained interruption - an interruption not classified as a momentary interruption.

The definitions below were developed specially for the TE evaluation to facilitate calculations of reliability indices:

Classification of interruptions by portion of site curtailed:

- Total interruption - an interruption affecting the entire Summit Plaza site wherein the plant is not generating any electrical energy and the buildings are served by only the essential load circuit from the utility connection.

- Partial interruption - an interruption affecting one or more buildings on the Summit Plaza site, but less than the entire site. This includes situations in which only the auxiliary loads within the plant were interrupted.

Classification of partial interruptions by coincidence with a total interruption:

- coincident partial interruption - a partial interruption occurring at the beginning or end of a total interruption and due to the same cause as the total interruption. A typical example of such an interruption is shown in figure L.1.

- isolated partial interruption - a partial interruption which does not immediately precede or follow a total interruption. This class of interruption is immediately preceded and followed by periods of normal operation. An example of such an interruption is shown in figure L.2.

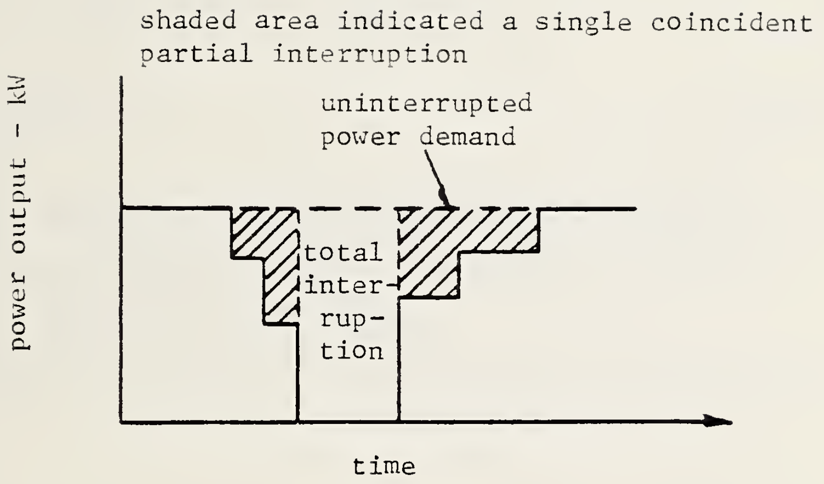

Figure L.1 Coincident partial interruption

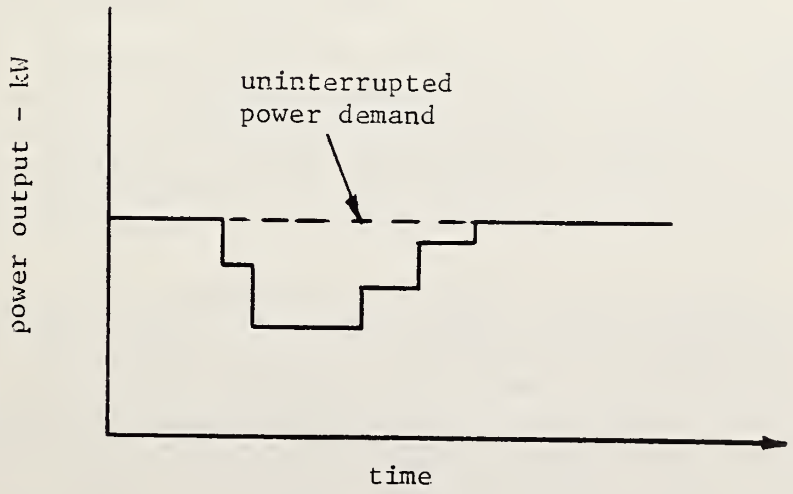

Figure L.2 Isolated partial interruption

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10. SUPPLEMENTARY NOTES

☐ Document describes a computer program; SF-185, FIPS Software Summary, is attached.

11. ABSTRACT (A 200-word or less factual summary of most significant information. If document includes a significant bibliography or literature survey, mention it here)

Under the sponsorship of the Department of Housing and Urban Development (HUD), the National Bureau of Standards (NBS) gathered engineering, economic, environmental, and reliability data from a 486 unit apartment/commercial complex located on a 6.35 acre (2.6 hectare) site in Jersey City, New Jersey. The complex consists of four medium to high rise apartment buildings, a 46,000 ft^2 (4300 m^2) commercial building, a school (kindergarten through third grade), a swimming pool, and a central equipment building.

The construction of the complex was started in 1971, and a decision was made by HUD to design the central equipment building to meet both the thermal and electrical energy demands of the site. The necessary equipment was installed to recover the waste heat from diesel engines driving the generators making the central equipment building a total energy (TE) plant. Absorption type chillers were also installed in the central equipment building. This TE plant has been serving the complex since January 1974.

The National Bureau of Standards was responsible for designing and installing the instrumentation and a data acquisition system (DAS) to determine fundamental engineering data from the plant and site buildings. The DAS was put on line in April 1975. The raw data from the DAS was processed by a minicomputer at NBS to obtain a broad spectrum of engineering results. This report describes these (contd.)

12. KEY WORDS (Six to twelve entries; alphabetical order; capitalize only proper names; and separate key words by semicolons)

Absorption chillers; boiler performance; central utility plant; diesel engine performance; engine-generator efficiency; environmental impact; heat recovery; total energy system.

13. AVAILABILITY

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systems and presents the appropriate data and a performance analysis of the plant and site. The analysis of the data indicates a significant savings in fuel is possible by minor modifications in plant procedures.

This report also includes the results of an analysis of the quality of utility services supplied to the consumers on the site and an analysis of a series of environmental tests made for the effects of the plant on air quality and noise. In general, these analyses reflected favorable results for the total energy plant.

Economic and energy analyses are presented for the plant as operated during the period of the study and on a comparative basis with twelve alternative system designs applicable for providing the tenants on the site with equivalent utility services. In general, although those systems utilizing the total energy concept showed a significant savings in fuel, such systems do not represent attractive investments compared to conventional systems, with fuel costs of 1977.