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U.S. DEPARTMENT OF ENERGY
CONTRACT NO. EC-77-C-02-4488.A003
PHASE III, STAGE I

MASTER

GEORGETOWN UNIVERSITY
INTEGRATED COMMUNITY ENERGY SYSTEM
FEASIBILITY ANALYSIS

FINAL REPORT

OCTOBER 1980

VOLUME 1 OF 2

POPE, EVANS AND ROBBINS INCORPORATED
CONSULTING ENGINEERS

DISCLAIMER

GEORGETOWN UNIVERSITY

INTEGRATED COMMUNITY ENERGY SYSTEM

(GU-ICES)

PHASE III, STAGE I

FEASIBILITY ANALYSIS

FINAL REPORT

OCTOBER 1980

VOLUME 1 OF 2

GEORGETOWN UNIVERSITY

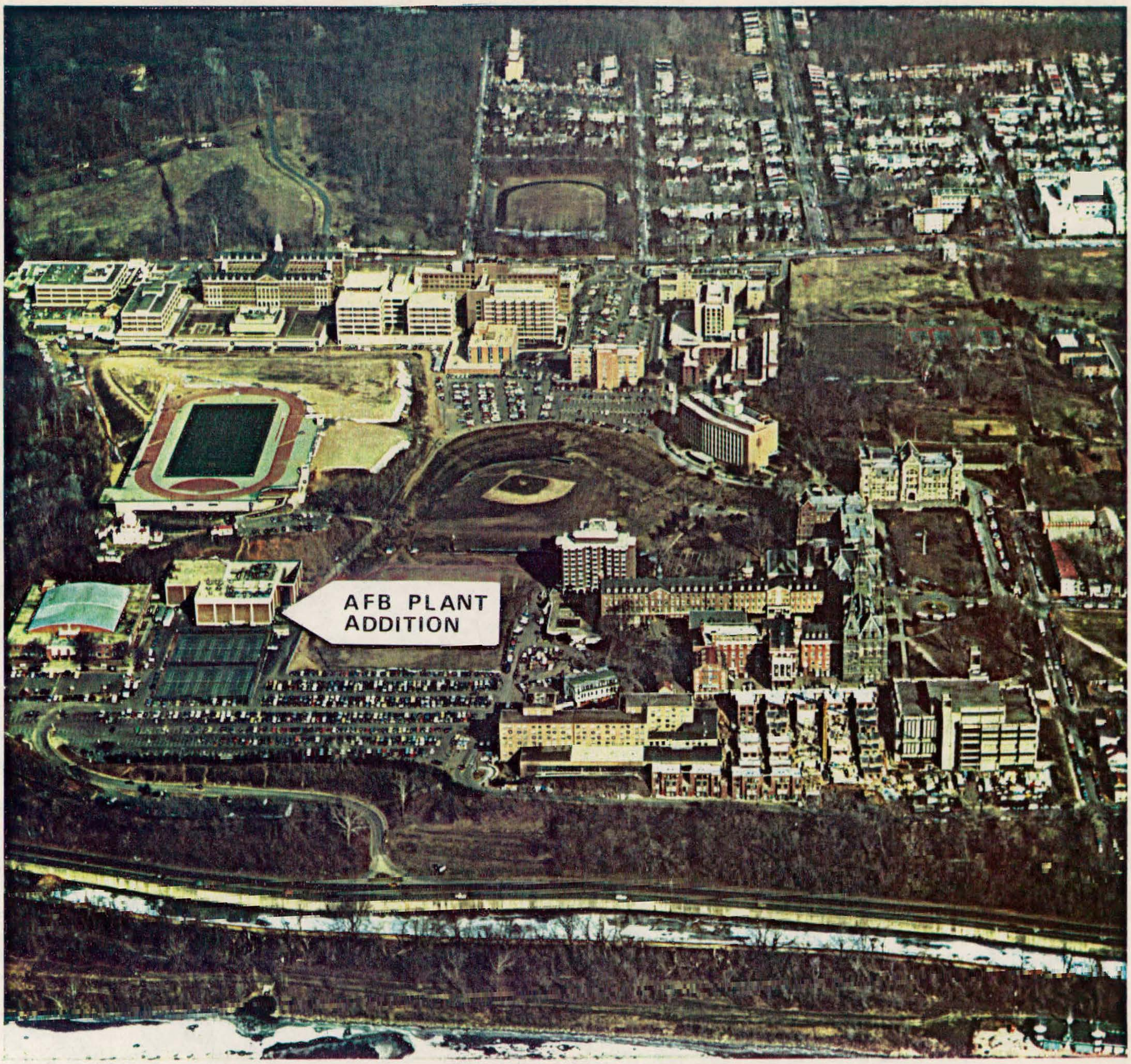
37th & O STREET, N.W.

WASHINGTON, D.C. 20057

Prepared for the

U.S. DEPARTMENT OF ENERGY
Office of the Assistant Administrator
for Conservation and Solar Applications
Division of Buildings and Community Systems

Contract No. EC-77-C-02-4488 A003



AERIAL VIEW
GEORGETOWN UNIVERSITY
WASHINGTON, D. C.

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INTEGRATED COMMUNITY ENERGY SYSTEM
FEASIBILITY ANALYSIS

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APPENDIX

SUMMARY

GEORGETOWN UNIVERSITY
INTEGRATED COMMUNITY ENERGY SYSTEMS (ICES)
PHASE III, STAGE I - FEASIBILITY ANALYSES

EXECUTIVE SUMMARY

General

The Georgetown University ICES program is intended to optimize the operation of the newly constructed coal-fired, atmospheric fluidized bed boiler (AFB) and, if determined to be cost effective, to complement the AFB by the addition of cogeneration, thermal storage, heat pumps and absorption refrigeration to reduce Georgetown University's energy consumption and dependence upon natural gas and fuel oil.

The AFB plant, which started operational testing in July 1979, has a rated output of 100,000 lb/hr of steam at a pressure of either 275 or 625 psig. The former pressure level will satisfy existing campus steam requirements and match the output rating of two natural gas/No. 6 fuel oil fired boilers whereas the 625 psig capability was designed into the boiler to permit future cogeneration.

The AFB is designed to burn high sulfur ($\pm$ 3%S) bituminous coal in a fluidized bed of limestone at a relatively low bed temperature of 1550°F. Sulfur dioxide emissions are controlled by sulfur caputre in the limestone bed. Nitrogen oxide emissions are inhibited by the low bed temperature. Particulate emissions are controlled by passing all flue gases through a baghouse. Coal fuel and limestone sorbent are supplied to the boiler and spent bed material and flyash are removed from the site.

Scope of Feasibility Analysis

The scope of this feasibility analysis evaluates five distinct applications, namely:

- Cogeneration in parallel with utility
- Added storage of coal, limestone, and ash
- Hot and cold thermal storage
- Absorption refrigeration
- Heat pumps

The analyses consider the technical and cost considerations, as well as community acceptance, compliance with applicable codes and regulations and environmental impact. Alternate schemes considered are subjected to life cycle cost analyses, conceptual design, and scheduling for implementation.

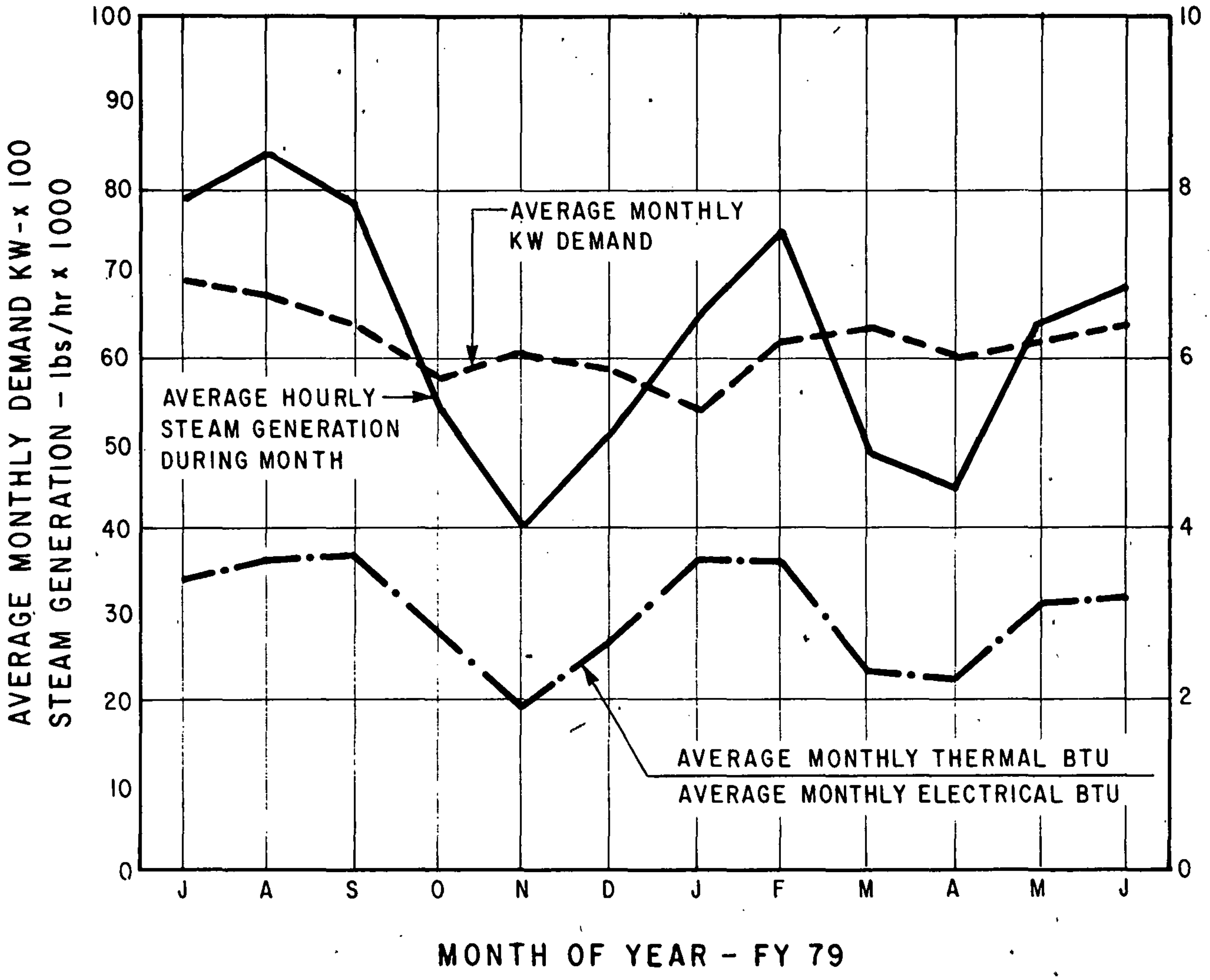
The analyses were based upon load data obtained for the University operation. A convenient representation of the steam and electric data appears on Exhibit 1. We include for reference purposes, the ratio of campus thermal to electric demand.

Exhibit 2 indicates the on-campus locations for the alternate subsystems considered in this report.

Cogeneration of Electricity

A total of six cogeneration schemes were given detailed consideration. All schemes involved the installation of one of more back pressure steam turbine driven generators operating from the 625 psig saturated steam from the AFB and discharging at a lower pressure(s) for further use in supplying campus energy requirements. At present, there is a summer requirement for 275 psig steam for operating turbine driven central chillers; a year-round requirement for 90 psig steam for

MONTHLY STEAM AND ELECTRICAL USAGE



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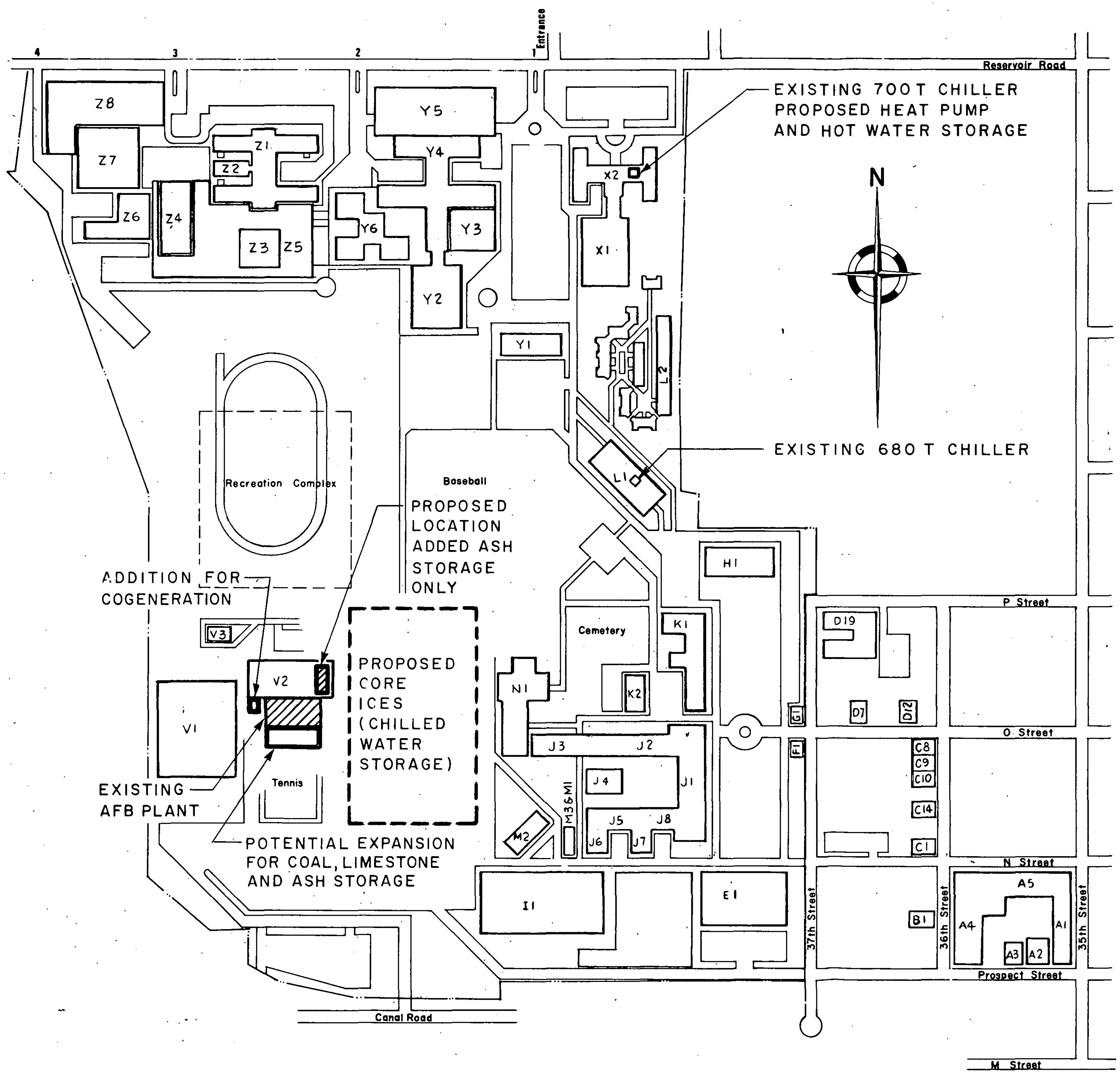


GEORGETOWN UNIVERSITY

A1	Loyola Hall
A2	Xavier Hall
A3	Ryder Hall
A4	Walsh Building
A5	Coleman Nevils Building
B1	Office Of Economics
C1	Bookstore
C8-10	Alumni House
C14	Placement Office
D1-2	American Language Institute
D7	Black Student Alliance
D19	Poulton Hall
E1	Lauinger Library
F1	S. Gatehouse
G1	N. Gatehouse
H1	White - Gravenor
I1	New South Building
J1	Healy Building
J2	Old North Building
J3	New North Building
J4	Dahlgren Chapel
J5	Mulledy Hall
J6	Gervase Hall
J7	Ryan Hall
J8	Maguire Hall
K1	Copley Hall
K2	Ryan Administration Building
L1	Reiss Science Building
L2	Student Housing
M1	Garage
M2	O'Gara Building
M3	Mc Sherry Building
N1	Harbin Hall
V1	Mc Donough Gymnasium
V2	Heating & Cooling Plant
V3	Observatory
X1	Darnall Hall
X2	St. Mary's Hall
Y1	Kober Cogan Building
Y2	Gorman Building
Y3	Bles Building
Y4	Georgetown Hospital
Y5	Hospital Parking Garage (Deck 1)
Y6	Concentrated Care Center
Z1	Medical-Dental Bldg.
Z2	Medical-Dental Annex
Z3	Dalgren Library
Z4	Basic Science Building
Z5	Preclinical Science Building
Z6	Medical Center Vivarium
Z7	Dental Clinic
Z8	Hospital Parking Garage (Deck II)

EXHIBIT 2

LOCATION PLAN

POPE, EVANS AND ROBBINS

export to campus buildings for space heating, production of domestic hot water, and similar uses; and at 10 psig for space heating and preheating boiler feedwater within the boiler plant.

The six schemes analyzed are indicated in Exhibits 3 and 4.

An extraction-condensing cycle was also investigated; because of load conditions and steam requirements, it was not found to be a feasible alternative.

A comparison of the six cogeneration schemes is tabulated below:

Scheme	Initital Cost Invested (S x 10^3)	Discounted Payback Yrs (10% Discount)	Annual Energy Savings (10^9 Btu)	Annual Energy Savings Equiv. Barrels of Oil	10^3 Btu $ Invested
A	1,180	3.97	64.1	10,300	54
B	1,348	4.05	69.7	11,200	52
C	1,669	5.59	66.0	10,700	40
D	1,578	6.70	56.3	9,100	35
E	3,361	5.35	46.4	7,500	14
F	6,179	5.87	(16.0)	-	-

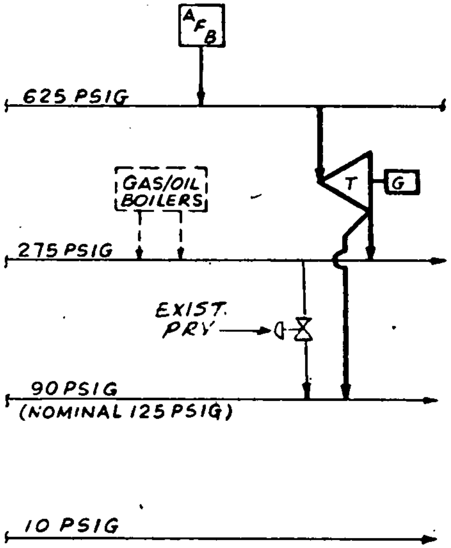
Scheme A is recommended for immediate implementation.

Added Storage of Coal and Limestone (Not Recommended)

Space limitations, environmental and institutional requirements at GU precluded provision of storage capacity normally

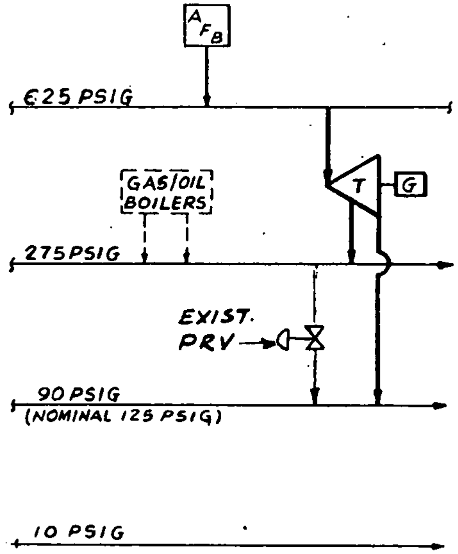
[redacted]

COGENERATION SCHEMES A, B & C



MAXIMUM STEAM FLOW (LB/HR) & K.W. PRODUCED	
SUMMER	WINTER
1045 KW	2270KW
100,000	0
0	100,000
0	0

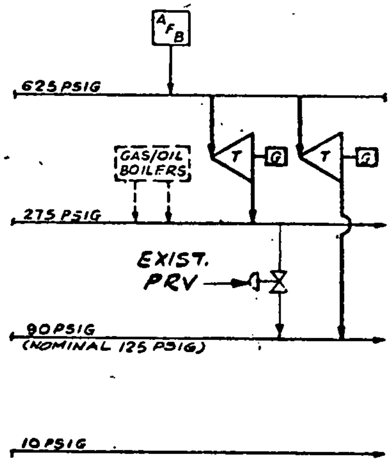
FLOW DIAGRAM
SCHEME A



MAXIMUM STEAM FLOW (LB/HR) & K.W. PRODUCED	
SUMMER	WINTER
1140 KW	2475 KW
93,000	0
7,000	100,000
0	0

FLOW DIAGRAM
SCHEME B

ES-6



MAXIMUM STEAM FLOW (LB/HR) & K.W. PRODUCED	
SUMMER	WINTER
1000KW	2475 KW
100,000	0
0	100,000
0	0

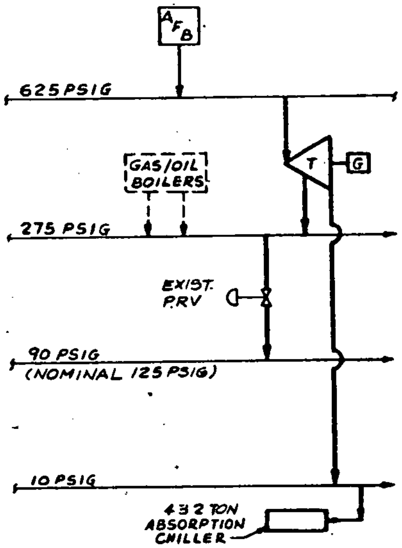
EXHIBIT 3

FLOW DIAGRAM
SCHEME C

POPE, EVANS AND ROBBINS

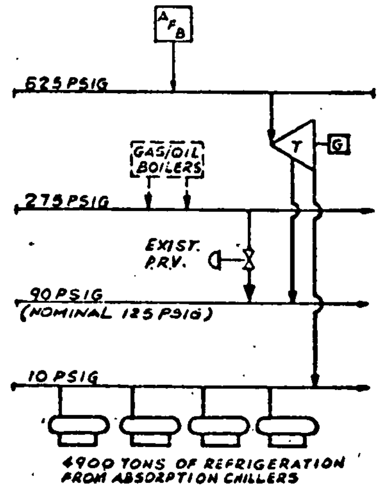
[redacted]

COGENERATION SCHEMES D, E & F



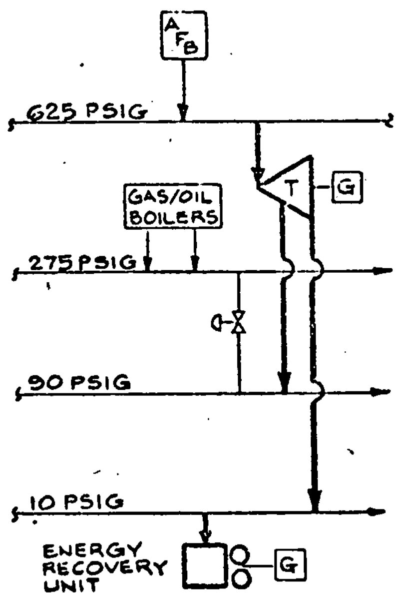
MAXIMUM STEAM FLOW (LB/HR) & K.W. PRODUCED	
SUMMER	WINTER
1306KW	1306KW
93,000	90,000
0	0
7,000	10,000

FLOW DIAGRAM
SCHEME D



MAXIMUM STEAM FLOW (LB/HR) & K.W. PRODUCED	
SUMMER	WINTER
3300KW	2390KW
0	0
0	90000
100,000	10,000

FLOW DIAGRAM
SCHEME E



MAXIMUM STEAM FLOW (LB/HR) & K.W. PRODUCED	
SUMMER	WINTER
3300 + 2500 = 5800KW	2390KW
	0
0	100,000
100,000	0

FLOW DIAGRAM
SCHEME F

POPE, EVANS AND ROBBINS

EXHIBIT 4

associated with a coal fired plant. Outdoor storage was not feasible on campus and all bunkers and silos were constructed within the confines of the AFB plant extension. Present storage capacity, based on 80 percent boiler output while burning high sulfur coal with 12 percent ash is:

Coal	-	12 days
Limestone	-	14 days
Spent Bed Material	-	3.5 days
Flyash	-	2.3 days

Coal fired plants are sensitive to emergencies created primarily by strikes of coal miners and truckers. Additional storage capacity would render Georgetown University less vulnerable to emergencies. It would further alleviate truck scheduling problems relating to continuing removal of spent bed material and flyash. The objective was established of providing 30 days storage of coal and limestone, and 12 to 14 days storage for bed material and flyash. Storage of the latter by-products for more than 14 days is undesirable because both materials are highly hygroscopic and tend to form cementitious materials in storage.

The above objectives can best be realized by constructing an extension to the AFB plant as shown on Exhibit 1. This would minimize rework of existing plant handling systems and restrict truck traffic to the surfaces presently devoted to this purpose. The initial cost of implementing this approach is estimated at $2,700,000.

<u>Added Storage of Ash</u> (Recommended)

As an alternative to the above costly extension, storage capacity for spent bed material and flyash alone could be increased to eleven or more days by installing additional storage silos within the existing Heating and Cooling Plant cooling tower enclosure, a location which is also depicted on Exhibit 1. While this approach would retain the present

12 to 14 days limitation on coal and limestone storage, it would increase the storage capacity of spent bed material and flyash to a comparable period of time. This would alleviate the present ash storage restrictions and render the plant insensitive to short delays in removing ash products from the plant. The estimated construction cost for this scheme is $675,000.

Hot Thermal Storage (Not Recommended)

Central storage of either pressurized or unpressurized hot water is not presently feasible at Georgetown University which now has a campus steam distribution system. However, local domestic hot water storage in the hospital complex is feasible if coupled with a heat pump installation. This item is discussed further under the topic, "heat pumps".

Cold Thermal Storage (Recommended)

Central cold water storage does offer potential advantages. The projected 1984 peak cooling load is 6,700 tons. This compares with an existing 6,000 tons of central chiller capacity in the Heating and Cooling Plant which supplies the campus chilled water distribution system. There are, in addition, several remote electrically driven chillers on campus which normally operate only during periods when the central plant is not in operation. Two of these are located in or near the hospital area and are also interconnected to the campus chilled water distribution system.

It is proposed to operate the two cited electrical chillers at night to take advantage of the utility company's low cost off-peak rates and avoid additional demand charges. Chilled water, thus produced in excess of that which is actually required, would be centrally stored in the lower portion of the Core ICES structure shown on Exhibit 1 for use during daytime in supplyilng particularly the chilled water requirements in excess of that which the central chillers can produce. Total storage is in excess of 11,000 ton-hours.*

The life cycle cost analysis indicates a cost of $1,113,000 to build this into the Core ICES. This is offset by reductions in the cost of electricity used at night. The discounted payback period for this scheme is 12 years.

The project would benefit the utility company in shifting a block of electrical demand from daytime hours to off-peak nighttime hours when they can generate from their more efficient base load machines.

It would further provide the university with the benefit, aside from electrical energy cost savings, of effectively increasing their central plant capacity without adding to their installed equipment.

Absorption Refrigeration

Two absorption refrigeration schemes were considered in conjunction with cogeneration as required by scope. Neither proved to be feasible.

Heat Pumps (Recommended only in conjunction with Cold Storage)

At Georgetown University, the potential exists for applying heat pumps in the condenser water return lines between electrically driven chillers and their local cooling towers for the purpose of extracting sufficient waste heat for producing domestic hot water. In locations where the chillers are operated only for about 2000 hours per year, it was determined that this application would not be economically feasible. A heat pump is feasible when considered in conjunction with the chiller in the hospital and coupled with central chilled water storage previously discussed, and with local domestic hot water storage.

*One ton-hour = 12,000 Btu.

The proposed arrangement would call for a heat pump and 15,000 gallons of hot water storage capacity to be installed in the hospital. Space is available for this installation. The heat pump would operate at night on low off-peak electric rates concurrently with the chiller. Hot water thus produced would be stored and drawn upon during the daytime hours.

The initial cost of this proposal is $82,000 and the discounted payback period is 11.7 years. Annual energy savings are 4.2 x 10^6 Btu, or the equivalent of 680 barrels of oil annually.

Recognizing that this is feasible only if chilled water storage and nighttime operation of the hospital chiller is also implemented, the two projects should be considered as one having an initial cost of $1,195,000 and a discounted payback period of 12 years.

Implementation of the cold storage heat pump scheme is recommended.

Heat Exchangers (Recommended for New South and Darnall Halls)

As a result of the heat pump investigation, it was determined that in lieu of heat pumps, heat exchangers could be installed in some electric chiller condenser water return lines from which energy could be extracted to preheat domestic hot water. Heat exchangers involve a low first cost and little maintenance. Applications were evaluated for five locations of which four offer the greatest potential as follows:

PROPOSED HEAT EXCHANGER INSTALLATIONS

Location	Initial Cost	Domestic Hot Water GPD	Discounted Payback (10%)	Annual Energy Savings 10^6 Btu	10^3 Btu/$ Invested
New South Hall (Recommended)	$ 7,500	24,000	4.4 yrs	960	128
Darnall Hall (Recommended)	10,500	18,000	12.3 yrs.	720	69
Harbin Hall (Not Recommended)	7,700	6,000	Over 25 yrs.	240	31
Henle Village (Not Recommended)	4,700	6,000	18.6 yrs.	240	51

For New South Hall and Darnall Hall, both of which include cafeterias, the installation of heat exchangers as described above will lead to significant energy savings and are recommended for implementation by the university as part of their on-going energy conservation program.

Life Cycle Cost Analysis

The life cycle cost analyses discussed above were calculated to determine discounted payback periods assuming 10 percent discount and a 25 year life. Long-term differential escalation rates for fuel and energy are those which are applied by the Department of Defense (DOD). The analyses assume that a project would be completed by July 1982. Costs of construction are estimated at January 1980 costs, then escalated to midpoint of construction using DOD established short-term escalation rates. Recurring costs (e.g., maintenance and operation labor and materials) that start with operation in July 1982 are calculated in terms of the present worth of their 25 year life cycle costs at zero differential escalation and 10% discount as of July 1982.

Institutional Assessment

The programs considered herein would not adversely affect local area groups or reviewing agencies. Georgetown University, as a matter of practice, conducts periodic meetings with local area groups to review their long range plans. Some of the ICES concepts have been reviewed with local groups within the context of GU long range planning. As selected programs move into preliminary design, the normal procedures for obtaining approval by interested community groups and of reviewing agencies will be instituted.

None of the proposed programs involve unusual construction or building requirements. The DC Building Department was consulted at the outset of this Feasibility Analysis at which time all areas of study were discussed. The opinion of both the Building Department and the University is that there are no elements of the proposed programs that pose any problem in complying with applicable rules and regulations.

Environmental Impact Assessment

The programs proposed herein are either extensions of existing facilities previously approved, or introduce no new elements that affect the environment. The assessment contained in this report concludes that the proposed programs have no adverse environmental impact.

Long Term Recommendation of Conservation Extraction/Condensation and Hot Water Distribution

Georgetown University master planning for the next decade should include their thermal and electric generation, purchase and distribution on the assumption that their on-going energy conservation program will reduce their requirements to the lowest acceptable levels. The objective of the plan would be to reduce the source energy requirements, especially of non-renewable and imported fuels, and to reduce the cost of energy to the University. The existing steam heating distribution system will require major replacement costs in this coming decade, further supporting consideration of an optimum heat generation and distribution system.

Modern thermal-electric systems used in Europe employ coal-burning steam generation with steam turbine electric generators in which steam is both extracted and condensed. The major difference between this arrangement and other utility systems is that the condenser water is distributed for heating the buildings linked to the system. This results in electric generation with less than half the source energy of the average public utility and programming electric generation during peak rate periods for maximum cost savings. The hot water distribution systems possess many advantages for which they are known, i.e., longer life, lower first cost, reduced losses, large thermal inertia, adaptability to storage systems, expansion capability, flexibility for matching thermal and electric loads for cost reduction and relieving the public utility during peak periods. Such a system can also generate chilled water by steam turbine driven or steam absorption chillers with steam supplied from the cogenerator steam turbine extraction points.

Under this system, it would appear that the University would purchase 2 to 3 MW of power from PEPCO and generate 7 to 8 MW by cogeneration with a heat rate of about 5,200 Btu/kWh at a cost of about 1.1 cents per kWh. This compares with purchased power comparable values of 11,600 Btu/kWh and more than 4 cents per kWh.

This system warrants further investigation as part of GU's master planning of thermal and electric energy generation, distribution and use.

SCOPE OF REPORT

This report constitutes the Final Report for Phase III, Stage I, Feasibility Analysis under Contract No. EC-77-C-02-4488.A003. The complete scope of work is included in Appendix A; an abstract is included below.

Stage I, Feasibility Analysis, consists of essentially seven elements, all of which are included in this report. These elements are:

Task 1 - Institutional Assessment
Task 2 - Environmental Impact Assessment
Task 3 - Generation of Energy Demand Profiles
Task 4 - Alternative Subsystems Analyses

- Cogeneration of Electricity
- Added Coal, Limestone and Ash Storage and Handling
- Hot and Cold Thermal Storage
- Absorption Chillers
- Heat Pumps

Task 5 - Life Cycle Cost Analyses
Task 6 - Incremental Savings and Optimization
Task 7 - Conceptual Designs

Stage II, Preliminary Design, is not included herein. This is a follow-on stage dependent on the recommendations envolving from Stage I.

A brief description of the seven respective Tasks covered by this report follows.

Task 1, Institutional Assessment, includes the assessment of the impact of D.C. and Federal Government requirements, the report on community interactions and their tentative resolutions, the report on the electrical utility requirements relating to cogeneration and the report on project financing opportunities and restraints.

Task 2, Environmental Impact Assessment, requires the preparation of a draft environmental impact assessment report on all of the candidate alternative subsystems.

Task 3, Generation of Energy Demand Profiles, requires that baseline load data be developed for the steam, chilled water, electrical and fuel produced or consumed at Georgetown University together with projections through 1984 to cover GU Master Plan campus additions and the effect of on-going GU energy conservation measures.

Task 4, Alternative Subsystems Analysis, requires in-depth consideration of five separate items as further described below.

- Cogeneration of Electricity: The report includes an evaluation of six alternate schemes for turbine driven electric generation with the turbine operating at an inlet pressure of 625 psig.

- Added Coal, Limestone and Ash Storage and Handling: The report includes an evaluation of rail delivery of coal; and of schemes providing increased AFB coal and limestone storage from 10 to about 30 days, and increased bed material and flyash storage from 2-1/2 to about 10 days.

- Hot and Cold Thermal Storage: The report includes a review of current thermal storage applications, and an evaluation of schemes for applying thermal storage at GU in a manner which is beneficial from the standpoint of reduced costs and energy consumption.

- Absorption Chillers: The report contains the evaluations related to adding central system absorption chillers operating either from the exhaust of a cogenerating turbine, or from the exhaust of the turbines driving the existing centrifugal chillers.

- Heat Pumps: The report contains evaluations of potential applications of heat pumps at selected locations containing cooling towers for the generation of domestic hot water.

Task 5, Life Cycle Cost Analyses, requires that life cycle cost estimates be prepared for each of the alternative energy subsystems considered for further evaluation.

Task 6, Incremental Savings and Optimization, requires that an evaluation be performed on the incremental energy and cost savings for each subsystem; that the candidate subsystems be ranked on the basis of payback periods; and that annual and cumulative budget profiles be prepared.

Task 7, Conceptual Design, requires the preparation of conceptual designs for viable alternative subsystems; capital cost estimates; schedules for design and construction; and priorities for action.

ARRANGEMENT OF REPORT

This Feasibility Analysis covers a wide range of studies and evaluations. The following review is intended to enhance understanding of the arrangement of the report so that items of interest may be located more expeditiously.

The Report is divided into five parts, namely:

SECTION	1	- Institutional Assessment
SECTIONS	2 through 7	- Technical Report
SECTION	8	- Appendix

Section 1 contains all material relating to the Institutional Assessment including consideration of the requirements and position of the Potomac Electric Company as they relate to cogeneration at Georgetown in parallel with the utility (Task 1).

Sections 2 through 7 contain all technical information relating to the Alternative Subsystems Analysis (Task 4). This includes the energy demand profiles upon which the evaluations were based (Task 3). It further includes the results of the Life Cycle Cost Analyses (Task 5) which are developed in detail in the Appendix for evaluation in the Technical Report. Also included is the material relating to Incremental Savings and Optimization (Task 6) and the Conceptual Design for candidate alternate subsystems (Task 7).

Section 8 contains all material relating to the Environmental Impact Assessment (Task 2).

The Appendix contains supplementary material including the budget cost estimates used in the life cycle cost analyses, the basic assumptions upon which the life cycle analyses were developed, and the detailed life cycle cost analysis for each subsystem considered in detail.

SECTION 1

1.0 INSTITUTIONAL ASSESSMENT

1.1 Impact Of Statutes, Codes and Regulations

The proposed GU - ICES facilities would essentially be constructed adjacent to the Central Heating and Cooling Plant which supplies steam and chilled water to the Georgetown University Hospital Complex and Main Campus.

The design-concept of the cogenerator is to house the equipment in an addition to the Heating-Cooling Plant. This facility would be the same architectually as the atmospheric fluidized bed boiler (AFB) unit which is separated from the Heating-Cooling Plant by a wall. The building that would house the cogenerator requires Board of Zoning Adjustments (BZA) and Fine Arts Commission Approvals in addition to compliance with District of Columbia Building and Fire Codes. Representatives from the Physical Plant at Georgetown and Pope, Evans and Robbins reviewed code requirements with the D.C. Building Department officials and determined that the proposed construction would comply with local regulations. The proposed construction must be submitted to the BZA and Fine Arts Commission when the preliminary plans are developed in sufficient detail that the proposed structure can be reviewed for height restrictions and conformance to the approved master plan. There are no problems anticipated in either this review or compliance with D.C. code.

The design concept of storage coal, limestone and ash is to house the required bunkers in a new structure south of the AFB. This structure would be the same architectually as the AFB building. It would require BZA and Fine Arts Commission approvals in addition to compliance with District of Columbia Building and Fire Codes. Based on the preliminary review of the facility with D.C. Building Officials, compliance with applicable codes and regulations appears to offer no problems.

When preliminary plans are developed, the proposed structure can be submitted to Fine Arts and BZA for conformance with aesthetics considerations and the approved master plan. In the event that it is determined that provisions for only ash storage, which is most critical to operations, is selected, it is proposed to locate those ash storage bunkers in the existing cooling tower area. No code problems are foreseen for this alternate.

The design concept of cold thermal storage is to construct this volumn below grade, integrated with the foundation at the planned Core ICES parking garage. This facility would not be visible to the public and would not require Fine Arts Commission approval. The parking garage would require approval by that agency, the BZA, Department of Transportation (DOT) and other regulatory authorities. Preliminary discussions have been held with DOT and the Georgetown Citizens Association which have expressed their interest in the garage proposal. No adverse comments have been received. The D.C. Building representatives could see no problem in the Code Compliance in storing cold water.

The design concept for installing heat pumps for domestic hot water heating does not present any code or any institutional problem. The installation of the units could be authorized by building permit issued by the District of Columbia. Any units installed under the ICES Program would be shielded from public view.

1.2 Political Interaction With Existing Community

The Vice President for Planning and Physical Plant and the Director of Planning for Georgetown University addressed the membership of the Citizens Association of Georgetown January 14, 1980 on current development plans of the University. They were informed on the status of the AFB operation to date and the ICES Program at Georgetown University. The presentation was well received by the Citizens Group who indicated that they were interested in the Georgetown University construction projects and wanted to participate as the program progressed.

In 1979 the Georgetown Business Association was briefed on the Fluidized Bed Boiler Project, the Solar Inter-Cultural Building and the ICES Program from an environmental and energy savings perspective. The effect of energy savings for the Georgetown area was pointed out and the environmental improvements caused by the Core ICES Program was explained. During the question and answer period all areas of concern were addressed to the satisfaction of the entire group. It was clearly evident at the completion of this meeting that approval and enthusiasm permeated the entire group.

1.3 Requirements of Potomac Electric Power Company (PEPCO)

1.3.1 Introduction

One of the primary concepts considered in this Feasibility Analysis is that of cogeneration of electricity. The economic effectiveness of cogeneration is dependent to a large extent upon its acceptance by the electric utility company which presently supplies electrical energy to Georgetown University.

From the outset of the study, the Potomac Electric Power Company has cooperated fully with the university and its consultants as evidenced by their letter of February 21, 1980 which appears as Exhibit 1-1. The GU cogenerator is the first to be discussed with PEPCO, and hence the utility policy had to be developed during the course of the study. For this purpose a series of three meetings were held with utility representatives, the first meeting addressing primarily the technical aspects of a grid-connected tie, and the latter two addressing the matter of applicable utility credit for cogenerated electricity.

PEPCO has agreed to accept grid-connected cogenerators as a matter of company policy. This would apply not only to the GU cogenerators, but to others that may follow. The technical requirements for such a tie have been prepared in preliminary form and were made known to the university. Acceptance by PEPCO's management is reportedly assured with little, if any, change.

PEPCO's policy on the rate structure applying to cogeneration installations is still evolving and may not appear in final form until the Fall of 1980. The utility and the university have reached agreement on a probable rate structure that

POTOMAC ELECTRIC POWER COMPANY 1900 PENNSYLVANIA AVENUE, N.W., WASHINGTON, D.C. 20068
(202) 872-2000

VICE PRESIDENT FOR
PLANNING & PHYSICAL PLANT

FEB 26 1980

RECEIVED

February 21, 1980

Mr. John B. Anderson
Director, Physical Plant
Georgetown University
Washington, D. C. 20057

Dear John:

As the cogeneration feasibility study of your GU/ICES program draws to a close, it is useful to review some of the issues that have been discussed.

First, as stated before, Pepco is very much interested in cogeneration since it represents a possible way of generating commercial quantities of electric energy. If such forms of generation prove someday to become economical, Pepco would quite naturally be interested in cogeneration as a possible alternative to central station generation. Additional Pepco interest stems from the fact that the National Energy Act addresses cogeneration and because of local interest in cogeneration experiments, particularly the Georgetown University effort. Coal based experiments are of particular interest.

Second, although hindered by the unsettled state of the proposed FERC regulations, we have discussed some basic rate assumptions that will allow your economic analysis to proceed. The final FERC regulations are being issued this week and a firm determination of applicable rates will be made in the near term.

Third, we have discussed many aspects of the technical design, the key aspect being the protection requirements for connection to the Pepco distribution system. These protection requirements are the product of a considerable engineering effort. Although still subject to internal review, we don't anticipate any significant changes for your application.

We look forward to continued cooperation and participation in the remaining phases of your GU/ICES program.

Sincerely,

V. Cushing

Vincent J. Cushing
Manager, Corporate Planning

should serve as a conservative basis for the economic evaluation required for a GU cogenerator.

The basis upon which the Feasibility Analysis of the GU cogenerator schemes was performed appears in the succeeding subsections.

1.3.2 Federal Rulemaking on Cogeneration

The Federal Energy Regulatory Commission has adopted regulations implementing Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA). Prior to the enactment of PURPA, a cogenerator or small power producer seeking to establish interconnected operation with a utility faced three major obstacles. First, a utility was not generally willing to purchase electricity or was not willing to pay an appropriate rate. Secondly, some utilities charged discriminatorily high rates for back-up service to cogenerators and small power producers. Thirdly, a cogenerator providing electricity to utility's grid was subject to extensive State and Federal Regulation.

Sections 201 and 210 of PURPA are designed to remove these obstacles. Rules implementing Sections 201 and 210 of PURPA have been prescribed in Docket Numbers RM 79-54 and RM 79-55 respectively. Section 201 sets forth criteria and procedures by which small power producers and cogeneration facilities can obtain qualifying status to receive the rate benefits and exemptions set forth in the Commission's rules implementing Section 210 of PURPA.

Under Section 201 of PURPA, cogeneration facilities and small power production facilities which meet certain prescribed standards and which are not owned by persons primarily engaged in the generation or sale of electric power can become qualifying facilities and thus become eligible for the rates and exemptions set forth under Section 210 of PURPA.

Section 210 prescribes rules designed to encourage cogeneration by requiring utilities to purchase available electric energy from qualifying cogeneration facilities and, to offer to sell electric energy to such facilities.

The rules also provide guidelines for the interconnection arrangements between qualifying facilities and electric utilities. This document constitutes an important step leading to policies that would result in better utilization of available energy resources. To the individual establishment where cogeneration is viable, it offers fiscal benefits along with energy conservation. A summary of the documents follows.

The rules provide that electric utilities must purchase electric energy and capacity made available by qualifying cogenerators and small power producers at a rate reflecting the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources, rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers (i.e., allowing cogeneration facilities to base the rates they charge utilities upon the cost to the utilities for producing, or purchasing from other utilities, the same amount of electricity). To enable potential cogenerators and small power producers to be able to estimate these avoided costs, the rules require electric utilities to furnish data concerning present and future costs of energy and capacity on their systems.

These rules also provide that electric utilities must furnish electric energy to qualifying facilities on a nondiscriminatory basis, at a rate that is just and reasonable and in the public interest, and must provide certain types of service which may be requested by qualifying facilities to supplement or back-up those facilities' own generation.

The rule exempts all qualifying congeneration facilities and certain qualifying small power production facilities from certain provisions of the Federal Power Act, from all the provisions of the Public Utility Holding Company Act of 1935 related to electric utilities, and from State laws regulating electric utility rates and financial organization.

The implementation of these rules is reserved to the state regulatory authorities and non-regulated electric utilities. Within one year of the issuance of the Commission's rules, each state regulatory authority or non-regulated utility must implement these rules. That implementation may be accomplished by the issuance of regulations, on a case-by-case basis, or by any other means reasonably designed to give effect to the Commission's rules.

The Commission observes that this rulemaking represents an effort to evolve concepts in a newly developing area within rigid statutory constraints. The Commission is attempting to afford broad discretion to the state regulatory authorities and non-regulated electric utilities in recognition of the variety of institutional, economic and local circumstances which may be affected by this rulemaking.

1.3.3 PEPCO Position on Compliance

Potomac Electric Power Company's stated position is to permit any customer to operate his generating equipment in parallel with their electric system whenever this can be done without adverse effects to their other customers, or to their equipment or personnel.

Since Georgetown University's cogeneration will be the first one operating in parallel with their system, PEPCO has no precedence or experience to call upon and certain precautions on their part are expected. PEPCO's mere acceptance of the University's desire to cogenerate in parallel with their system is not enough to guarantee the viability of the scheme. Economics of cogeneration will be determined, among others, to a large extent by the demand charges in the utility's rate structure. PEPCO has not yet established any policy on this for facilities operating in parallel with the utility. This does not allow the calculation of exact cost benefits to the university.

Present understanding of PEPCO's position follows:

- Georgetown University will be credited with cogenerated electricity by calculating the monthly purchased power on the basis of the reduced PEPCO monthly input to the University. The difference between this amount, and the charges that would prevail if all electrical energy were purchased from PEPCO constitutes the savings potential.

- Unscheduled shutdown of the cogenerator could increase the demand on PEPCO service and lead to an increased demand charge during the month. If this increased demand also becomes the peak for the year, then by terms of a newly proposed rate schedule GU would pay a monthly demand charge for this new peak for the succeeding 11 months. PEPCO is considering the University's request to relax this requirement. Alternatively, the University is considering means of dropping an equivalent amount of campus load during such an outage.

- PEPCO is presently also evaluating the so-called "capacity" credit which would be offered to GU and other cogenerators for installing generation capacity that will enable PEPCO to defer a portion of its planned expansion. This credit is not known as of this date.

1.3.4 Grid Connection of On-Site Generation

Connection of the university's cogeneration to the distribution system on the campus, in order for it to operate in parallel with the power company, will be done under the guidelines issued by PEPCO which are summarized below:

- Certain protective devices, including an intertie circuit breaker and protective relays, will be specified by PEPCO and must be installed at any location where a customer desires to operate generation in parallel with the power company. This protection is intended to isolate the customer from the PEPCO system in the event of a scheduled or unscheduled outage at any part of the system.

- PEPCO will not assume any responsibility for protection of the customer's generator, or any other portion of the customer's electrical equipment. The customer is fully responsible for protecting his equipment in such a manner that faults or other disturbances on the PEPCO system or on the customer's system do not cause damage to his equipment.

- The customer will bear that portion of the costs resulting from the additional equipment that must be installed on the PEPCO system to allow for parallel operation. The customer contribution for the modifications to PEPCO's system required by the customers equipment will be negotiated concurrently with the service contract, as provided by current PEPCO policy.

- All customer installations shall adhere to the applicable national and local codes, rules and regulations.

1.3.5 Rate Structure

PEPCO is in the process of instituting "time-of-day" metering which will impose significantly higher charges for energy consumption during certain times of the day, particularly during the months of June through September. An extract of the proposed rate structure based on the time-of-day demand is shown in Appendix B. Energy charge varies with the time of the day by the classifications of "on-peak", "intermediate" and "off-peak" charges. On-peak charges are applied on weekdays between Noon and 8 PM; intermediate charges are applied on weekdays between 8 AM and Noon; and from 8 PM to Midnight, and off-peak charges are applied from Midnight to 8 AM on weekdays and all day during weekends and holidays. Exhibit 1-2 illustrates the proposed rate structure. On-peak and intermediate charges are substantially greater than present charges. Cogeneration during these summer periods could produce significant cost reductions to GU, particularly because of a reduction in demand imposed on the power company.

PROPOSED PEPCO RATE SCHEDULE GT
ENERGY CHARGE SCHEDULE

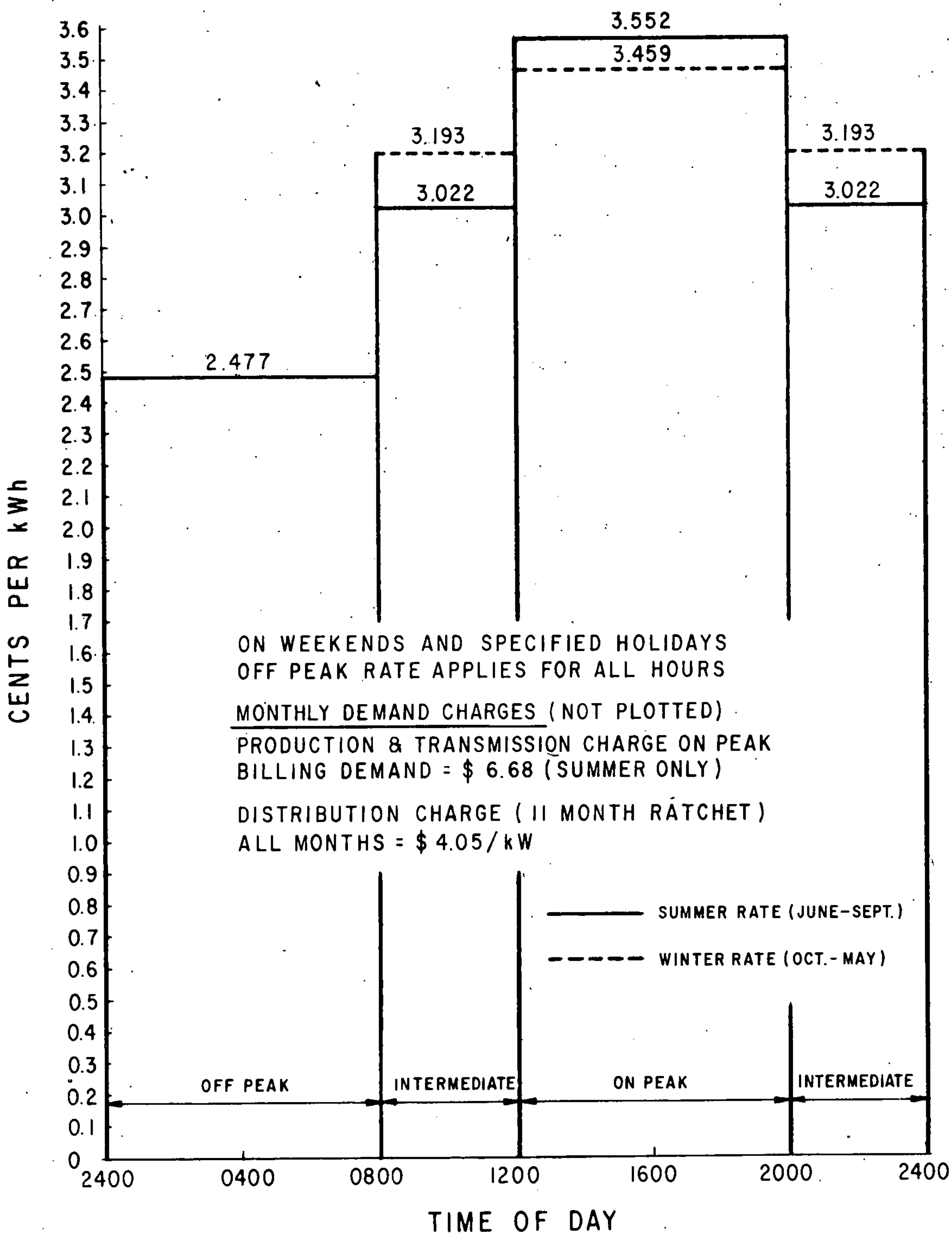


EXHIBIT 1-2

Another significant feature of the new rates is the elimination of declining block-type energy rates. The new rates are designed in such a manner that each customer who elects to accept the new rate schedule provides the same percentage of the power company's total revenue requirements as it does under existing rates. Thus if the university were to maintain its present load-time characteristics, the new rate structure will not result in any cost increase, except for the customary periodic increases granted to the utility. The new rates provide incentive for consumers to shift their loads to off-peak hours.

In addition to energy charge, there are other charges which are based on demand. There is a production and transmission charge, applicable only during the summer months, on the billing demand which shall be the maximum 30 minute demand recorded during the on-peak period of the billing month. In addition, there is a distribution charge which is applied to the maximum 30 minute demand recorded during the billing month, but shall not be less than the highest such demand established during the previous eleven months. Summer months, for the purposes of application of this rate schedule, are the billing months of June through September, and winter months are the billing months of January through May, plus October through December. Total charges for the month shall be composed of the energy charges, production and transmission charges when applicable, distribution charges and fuel adjustment charge. Since a base fuel adjustment charge is already factored into the time-of-day rates, only minor adjustments would initially result from the fuel adjustment charge.

In addition to the energy and demand charges, the rate structure stipulates a base customer charge of $165 per month. Monthly billings to GU are obtained after considering

5% discount for high voltage (13.2 kV) service and adjusting for fuel charge.

Based on this rate structure, the monthly purchase costs from utility may be represented by the general equation:

$$P = 0.95\ (e + \frac{a}{100} AK + \frac{b}{100} BK + \frac{c}{100} CK$$

$$+ DP + \hat{D}d) + \frac{K}{100} (FA - 1.53823)\ L \qquad \text{(A-1)}$$

where

- P = Cost of purchased electricity in a month.
- K = Energy consumption in one month in kWh.
- A = Fraction of total kWh used in "on-peak" period.
- B = Fraction of total kWh used in "intermediate" period.
- C = Fraction of total kWh used in "off-peak" period.
- D = On-peak period peak kW demand of the month.
- $\hat{D}$ = Greater of the peak demand recorded during the billing month and the highest demand established during the preceeding 11 months.
- a = Energy Cost in cents/kWh, on-peak period.
- b = Energy Cost in cents/kWh, intermediate period.
- c = Energy Cost in cents/kWh, off-peak period.
- p = Production and Transmission charge in dollars per kW.
- d = Distribution Charge in dollars per kW.
- e = Customer Charge.
- FA = Fuel Adjustment charge developed in step (c) of the PEPCO Fuel Adjustment Charge Rider FA.
- L = Transmission and Distribution Efficiency Compensation factor.

Substituting C = 1-A-B, Equation (A-1) becomes:

$$P = 0.95\ [e + \frac{K}{100}\ aA + bB + c\ (1-A-B)$$

$$+ Dp + \hat{D}d] + \frac{K}{100} (FA - 1.53823) L$$

Substituting the appropriate numerical values in the above equation and saving the factor representing the fuel adjustment cost, the electricity cost (less fuel adjustment cost) during a summer month is:

$$P_{summer} = 0.95\ (165 + \frac{3.552}{100}\ AK + \frac{3.022}{100}\ BK + \frac{2.477}{100}\ CK + 6.68\ D + 4.05\ \hat{D}) \qquad (A-2)$$

and during a winter month is:

$$P_{winter} = 0.95\ (165 + \frac{3.459}{100}\ AK + \frac{3.193}{100}\ BK + \frac{2.477}{100}\ CK + 4.05\ \hat{D}) \qquad (A-3)$$

Here certain approximations, that will simplify the analysis but will not affect the accuracy of the results when calculated over a period of 12 months, can be made.

For the Fiscal Year 1979, the average values for the fraction of energy used during various times of the day classifications have been found to be:

A = 0.28 ("on-peak")
B = 0.25 ("intermediate")
C = 0.47 ("off-peak")

Further, the factor $4.05\hat{D}$ represents the monthly distribution charge which totalled $462,910 during the Fiscal Year 1979.

Sum total of the monthly peak demands recorded for FY 1979

= 108,550 kW

Average distribution charge per kW of peak demand

$$= \frac{462,910}{108,550}$$

= 4.26

Replacing the factor $4.05\hat{D}$ in the cost model by 4.26D will simplify analysis while maintaining the accuracy of the cost model. Equations (A-2) and (A-3) are simplified to:

$$P_{summer} = 156.75 + 0.02768K + 10.39D$$
$$P_{winter} = 156.75 + 0.02784K + 4.047D$$

The results derived using the above equations for typical values of K and D are shown graphically in Exhibit 1-3. Also shown on this exhibit are electricity costs under the present rate schedule GS.

PEPCO RATE SCHEDULE GT

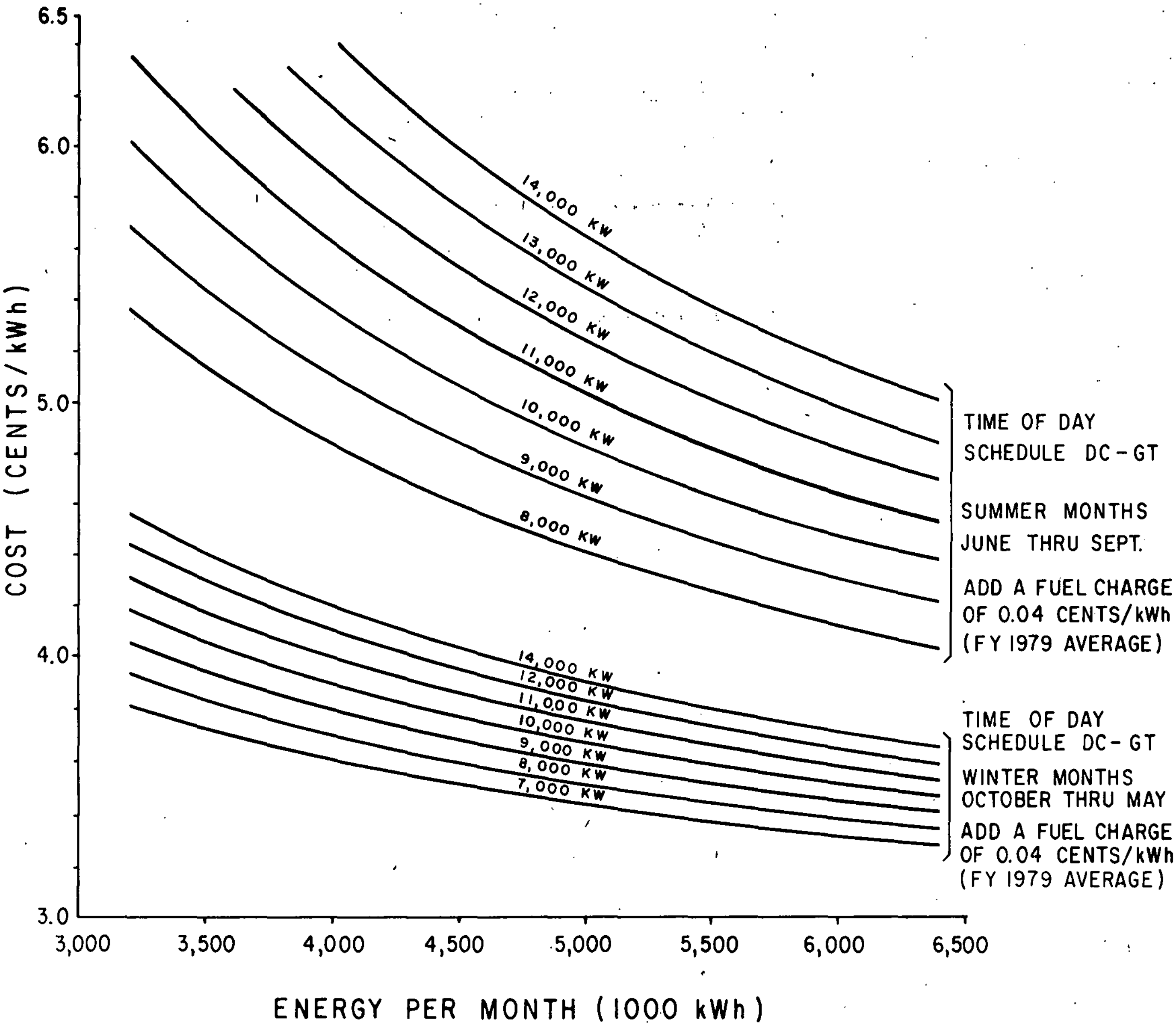


EXHIBIT 1-3

1.4 Financing Opportunities and Constraints

The following is a summary of funding required to implement the selected subsystems which comprise the GU-ICES along with the respective payback periods of each subsystem:

Subsystem	Capital Cost	Discounted Payback
Cogeneration (Scheme A)	$ 1,180,000	3.97
Additional Ash Storage	675,000	-
Cold Thermal Storage	1,113,000	12.3
Heat Pumps	82,500	11.7
Heat Exchanger, New South	7,500	4.4
Heat Exchanger, Darnall	10,500	12.3
	$ 3,068,500	

In order for a capital project to receive serious consideration for funding by the university, the payback period of the project should in general be less than five years. In addition, the risk involved in undertaking the project should be relatively low. Of those subsystems of the GU-ICES offering an attractive payback period, the cogenerator and the heat exchangers in New South qualify as serious candidates for funding by the university. Success of the cogenerator is totally dependent on the reliability of the new fluidized combustion facility. While operating experience on the unit to date is very encouraging, a true picture of the reliability of the new technology will emerge as operating experience is gained over the next three years. Under terms of the DOE/GU contract, the university has already made a substantial commitment regarding the FBC unit. The unit must be operated as the primary steam generator at the university with the cost of operating being assumed by the university.

In view of this commitment, the university will seek Government assistance to implement the GU-ICES Program. The use of tax-free bond issues to fund the GU-ICES subsystems are not considered feasible in view of the impact of current record high level inflation and short-term interest rates on the bond market. In addition, the District of Columbia has not, as yet, developed and implemented the mechanism through which Georgetown University can utilize tax-free bonds.

From the University's point of view, the most feasible and logical approach to funding the GU-ICES is through federal loans or grants. Federal assistance is warranted from the fact that implementation of the GU-ICES will considerably enhance the contribution of the Fluidized Combustion project as a national exemplar demonstration model. Considerable national attention is being focused on the Fluidized Combustion unit at Georgetown. Information to the public regarding the innovative application of the GU-ICES program can be readily disseminated to the public, thereby contributing significantly to the furtherance of DOE and national energy objectives.

SECTION 2

2.0 ENERGY DEMAND PROFILES

2.1 General

Georgetown University (GU) supplies its campus heating, domestic hot water, cooling and electrical requirements by the combustion of natural gas, fuel oil and coal in centrally located steam generators, and the purchase of electricity from the public utility. In the near future, this will be supplemented to a limited extent by solar energy as new construction which incorporates solar panels is implemented.

Building heating and domestic hot water requirements are supplied from the steam distribution system originating at the central Heating and Cooling Plant. This system operates at a range from 80 to 100 psig steam pressure. Steam for this and other purposes is generated by two 100,000 lb/hr gas or oil fired boilers which began operation in 1968. A third 100,000 lb/hr atmospheric fluidized-bed boiler (AFB) fueled by high sulfur coal was recently constructed and placed in operation in December 1979.

Building air conditioning requirements are met essentially by a central chilled water system which also originates at the Heating and Cooling Plant. This system is supplied by two 3000 ton condensing steam turbine driven chillers, normally operating from early or mid May to mid or late October. Buildings on campus not connected to the central chillers and those located beyond the main campus are served by local chillers which are either electrically driven or steam absorption units. Of these, two electrically driven chillers, located in buildings on the main campus, provide back up sources of chilled water during the cooling season, and supply off-season cooling needs when the central plant is shut down.

Campus electrical requirements are supplied by power purchased from the Potomac Electric Power Company (PEPCO). About 90 percent of all electrical energy consumed is distributed by a GU-owned 13.2 kV distribution system supplied by PEPCO from conjunctively billed services at two locations. Remaining electrical energy requirements are supplied by PEPCO through separately metered, low voltage services.

Baseline data for energy demand profiles was taken from an analysis of available GU data for their Fiscal Years 1978 and 1979. The GU fiscal year extends from July of the preceding calendar year through June of the referenced year. During this period, the outside energy sources to the university consisted of natural gas, No. 6 fuel oil and electricity.

Natural gas is supplied by the Washington Gas Light Company on an interruptible basis. In the two years analyzed for baseline data, natural gas fuel was used for generating from 98 to 99 percent of the annual boiler steam output. The natural gas has an average heat content of 1030 Btu per cubic foot.

Fuel oil is used only at such time that natural gas is interrupted. The oil is No. 6 oil with a heating value of about 147,500 Btu/gal.

Purchased electricity is assumed to require a source fuel energy input by the utility of 11,600 Btu per kWh delivered to GU. This value includes energy required for generation and distribution losses in the utility system.

Based on the above assumptions, and excluding natural gas energy obtained at small separately metered services, the annual non-renewable energy input to Georgetown University for their Fiscal Years 1978 and 1979 was as follows:

TABLE 2-1

ANNUAL GU ENERGY CONSUMPTION
(SOURCE FUEL)

Energy Source	GU FY '78 Quantity Used	GU FY '78 Total Btu x 10^6	GU FY '79 Quantity Used	GU FY '79 Total Btu x 10^6
Natural Gas	660.7 x 10^6cf	680,000	621.1 x 10^6cf	640,000
No. 6 Fuel Oil	125,244 gal	18,000	63,510 gal	9,000
Electricity:				
Main Service	53.2 x 10^6KWh	617,100	54.5 x 10^6KWh	632,000
Separately Metered Services	8.1 x 10^6KWh	94,000	7.6 x 10^6KWh	88,000
TOTAL		1,409,000		1,369,000

These represent an annual consumption equivalent to about one-quarter of a million barrels of oil.

The further development of the baseline energy demand data used in this Feasibility Analysis follows in subsequent subsections.

In order to project meaningful future demand profiles, which are necessary to accomplish the present scope of work, it is essential that complete, realistic and reliable energy demand profiles for the present campus load are available for computational purposes. The available data was examined for accuracy, completness and reliability. Load and energy demand profiles for the existing campus were generated from the data. Corrections were applied where necessary (i.e., see 2.2.2) and, when hard data was either lacking or reported to be inaccurate to an extent that corrections could not be applied, estimates were made based on standard reference material and good engineering judgement.

The corrected baseline data was then used as a basis for projecting future, 1984, load and energy demand profiles by accounting for increased requirements of each energy stream to satisfy the additional demands of planned new construction. The total energy profiles thus determined were then used to evaluate specific requirements and benefits derivable from the incorporation of energy conserving and dollar saving systems into the Georgetown University's Master Plan.

2.2 Sources of Data

Energy demand profiles were developed from data available either directly from GU and the electrical utility, from field observations, or from calculations. Where existing data was found to be of questionable accuracy, it was refined to greater accuracy by appropriate means. The procedure followed in each case is outlined within respective sections of the report.

2.2.1 Fuels for Steam Generation

During GU Fiscal Years 1978 and 1979, for which the energy demand data was developed, the university generated 98% of its steam from natural gas fuel, supplemented by fuel oil during short periods when gas was interrupted.

Natural gas, provided by the Washington Gas Light Company, is metered by a utility-owned meter which is assumed to be accurate. Data on the daily and monthly usage and steam generation was obtained from the monthly reporting forms prepared by GU personnel in the Heating and Cooling Plant.

Fuel oil used in steam generation is separately metered. Data on daily and monthly usage was obtained from the same monthly reporting forms prepared in the Heating and Cooling Plant.

Coal consumption required for operation of the newly installed atmospheric fluidized bed boiler does not appear in the cited data as the AFB was not operational at that time. Consumption rates used in subsequent analyses were estimated from information developed during startup of this plant.

2.2.2 Steam Generation Data

Exhibit 2-1 shows a schematic flow diagram of the steam system within the GU Heating and Cooling Plant. This exhibit clearly indicates the three 100,000 lb/hr steam boilers, the steam lines at 625, 275, 125 and 10 psig, various turbines, condensers, pumps, tanks, export lines and other pertinent information.

Steam flow (lb/hr) from each gas/oil fired boiler is metered with respective steam flow meters. This data is recorded regularly and entered upon the monthly reporting forms previously mentioned for tabulated total daily production. In reviewing the boiler fuel consumption and steam generation data contained on these forms, the calculated monthly steam generation thermal efficiency was found to vary from 80 to 96 percent. This compares with the boiler manufacturer's predicted efficiency of about 83 percent. Apparently, the steam generation data is not accurate for the months in which the calculated thermal efficiencies significantly exceed 83 percent. This was confirmed by plant personnel who indicated that a difference of as much as 10% in the indications of steam production was observed when boiler switch-over was carried out during constant load periods. This could result from the meters being out of calibration, from meters reading higher than actual flow in winter months when the boiler drum pressure is often dropped to values below the summer operating pressure of 270 psig, to varying boiler operating conditions, and other reasons. For purposes of this study, it was decided that a more accurate indication of steam generation would be obtained by assuming that the fuel flow was accurate and deriving steam flow by applying the boiler manufacturers predicted efficiency of 83 percent to the fuel flow. Actual steam generation for GU FY '78 and '79 was derived in this manner and applied in projecting future steam generation requirements as discussed later in Subsection 2.3.

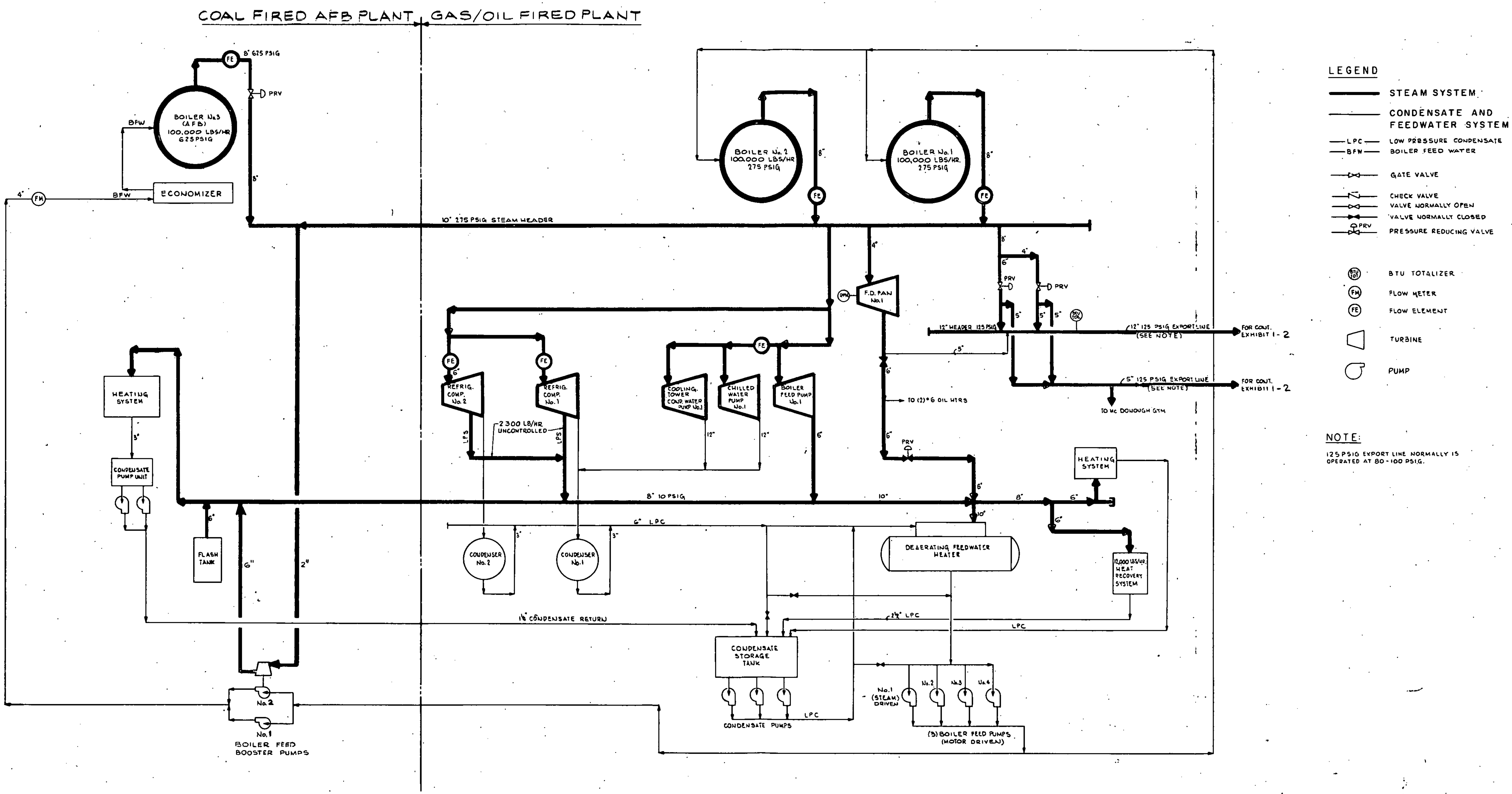


EXHIBIT 2-1

HEATING AND COOLING PLANT STEAM FLOW DIAGRAM

POPE, EVANS AND ROBBINS

2.2.3 Steam Flow to Plant Auxiliaries

Several pieces of auxiliary equipment within the Heating and Cooling Plant require plant produced steam. These include several steam turbine driven equipment items, a deaerater and an oil preheater. The steam turbine driven devices, which operate at a pressure of 270 psig, are a forced draft fan rated at 100 hp (this fan also has the capability of being powered by a separate electric drive motor which was in use at the time of survey due to turbine problems), and three pumps rated at a total of about 660 hp using a maximum of about 10,000 lb/hr of steam as reported by the Heating and Cooling Plant personnel. The three turbine driven pumps are the Cooling Tower Condenser Water Pump No. 1 rated at about 270 hp; Chilled Water Pump No. 1 rated at about 300 hp; and Boiler Feed Pump No. 1 rated at 90 hp. Although there are steam flow elements or meters present in some of the supply lines, as shown in Exhibit 2-1, none of these provide reliable data, either because they are not connected to read out devices or because they are out of calibration. As a consequence, the steam flow to the plant auxiliaries had to be estimated. In addition, bottom and surface blowdown and gland leakage consume some of the steam value in terms of losses. Based on the above information, a value of 10 percent of the total produced steam in the Heating and Cooling Plant was attributed to plant auxiliaries and internal plant losses. This was allocated as 12 percent during the cooling season and 8 percent during the heating season.

2.2.4 Steam Flow to Turbine Driven Central Chillers

Two turbine driven chillers, each rated at 3000 tons of refrigeration, require 270 psig saturated steam for their operation. Although individual steam flow meters are installed in the respective turbine inlet supply lines as shown on Exhibit 2-1, these are reportedly inaccurate and were not relied upon for data acquisition. Since directly read steam consumption data was not available, chiller plant Btu output was reconstructed from chiller plant output flow rate in gallons per minute and the temperature differential of supply versus return, both of which are recorded on circular charts. The steam consumption coincident with the chilled water production thus was deduced by establishing an equivalence relationship between the two. This was accomplished by using turbine performance data as discussed in Section 2.4.

2.2.5 Export Steam Flow

Export steam is that which leaves the Heating and Cooling Plant via an underground distribution to supply steam to buildings on campus. End uses for export steam include:

- Space heating, either by steam or hot water radiation,
- Domestic hot water production,
- Process, e.g., sterilizers, and
- Equipment washdown.

Some export steam is also required to overcome losses in the distribution system and in the heat exchange equipment.

As indicated on Exhibit 2-1, there are no existing steam flow meters on the two export steam lines leaving the GU Heating and Cooling Plant to serve campus needs. A Btu meter and transducer has recently been added to the 12-inch export line reporting back to the GU JC-80 energy master control system. This meter was not calibrated nor operating during the two year period for which data was taken. Lacking direct data on export steam flow, this information was derived by subtracting calculated values of steam flow to the turbine driven chillers and to plant auxiliaries from the Heating and Cooling Plant steam production.

2.2.6 Campus Electricity Use

Energy and demand data were derived from the power company monthly billings. To establish an annual load profile, information more detailed than is provided by the monthly bills, such as daily demand profiles, was required. As a prelude to implementation of its proposed time-of-day rate structure, PEPCO had recorded detailed statistics on the university's electricity consumption. This data, called Fifteen Minute Pulse Reports, was made available to PER for use in the present study.

Data acquired from the power company is regarded as highly reliable for the present study. However, certain discrepancies were observed in the peak demands in the Pulse Reports when checked against the peak demands in the utility bills, with some values in the latter in some cases being considerably lower. Extreme values of demand data in the Pulse Reports were ignored as anomalous.

Major buildings on the campus have energy meters but no records are maintained of their energy use.

2.3 Steam Distribution and Production

2.3.1 Steam Distribution System

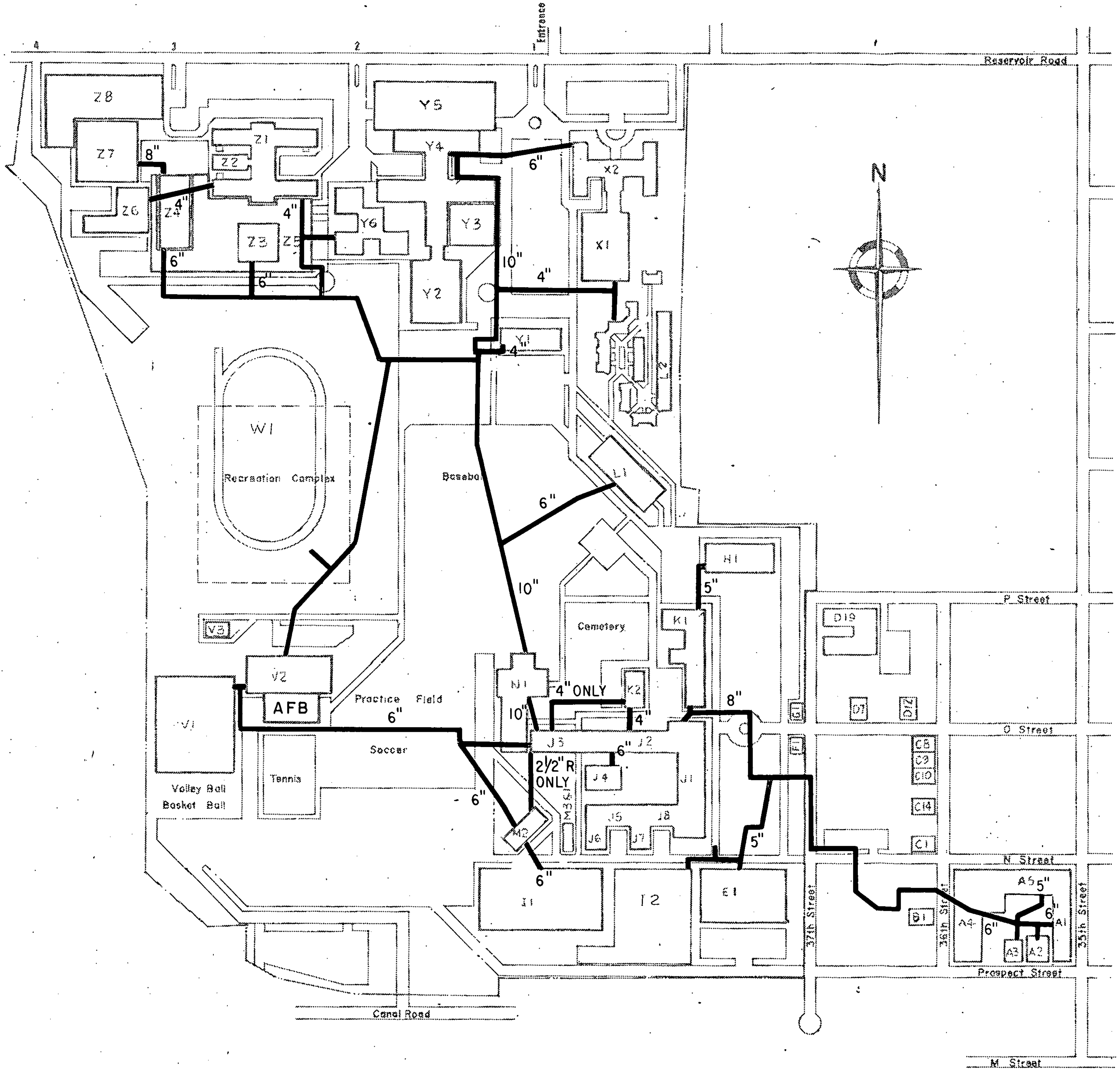
The GU Heating and Cooling Plant was introduced in preceding Sections 2.1 and 2.2.2 with respect to steam generation and the availability of source data. A brief description of the plant was presented with reference to Exhibit 2-1 which is a schematic flow diagram of the steam system within the GU Heating and Cooling Plant. Exhibit 2-2 is a representation of the routing of the underground steam distribution system. A more informative steam distribution diagram is shown in Exhibit 2-3 which is a schematic representation of the campus buildings and the distribution system. Details of information shown on this diagram will be identified and discussed as particular items are addressed. Buildings presently connected to the steam distribution system are shown connected. All buildings shown alone without connection to the line schematic are not presently served by the steam distribution system. Proposed structures are not shown connected even if plans call for them to be connected to the distribution system.

2.3.2 Steam Production Baseline Data

Raw data of FY '78 and '79 monthly steam production and coincident fuel consumption as recorded by GU Heating and Cooling Plant personnel appears on Table 2-2. This data, coupled with daily steam flow charts, represents the basic data available for steam production.

Approximated boiler thermal efficiencies were calculated from this data in the following manner:

$$\eta_b = \frac{h\text{ (steam output/lb - feedwater/lb) x monthly steam production (lb)}}{\text{monthly fuel consumption x Btu/unit of fuel}}$$



GEORGETOWN UNIVERSITY

A1	Loyola Hall
A2	Xavier Hall
A3	Ryder Hall
A4	Walsh Building
A5	Coleman Nevils Building
B1	Office Of Economics
C1	Bookstore
C8-10	Alumni House
C14	Placement Office
D1-2	American Language Institute
D7	Black Student Alliance
D19	Poulton Hall
E1	Lauinger Library
F1	S. Gatehouse
G1	N. Gatehouse
H1	White - Gravenor
I1	New South Building
J1	Healy Building
J2	Old North Building
J3	New North Building
J4	Dahlgren Chapel
J5	Mulledy Hall
J6	Gervase Hall
J7	Ryan Hall
J8	Maguire Hall
K1	Copley Hall
K2	Ryan Administration Building
L1	Reiss Science Building
L2	Student Housing
M1	Garage
M2	O'Gara Building
M3	Mc Sherry Building
N1	Harbin Hall
V1	Mc Donough Gymnasium
V2	Heating & Cooling Plant
V3	Observatory
X1	Darnall Hall
X2	St. Mary's Hall
Y1	Kober Cogan Building
Y2	Gorman Building
Y3	Bles Building
Y4	Georgetown Hospital
Y5	Hospital Parking Garage (Deck I)
Y6	Concentrated Care Center
Z1	Medical-Dental Bldg.
Z2	Medical-Dental Annex
Z3	Dalgren Library
Z4	Basic Science Building
Z5	Preclinical Science Building
Z6	Medical Center Vivarium
Z7	Dental Clinic
Z8	Hospital Parking Garage (Deck II)

NOTES

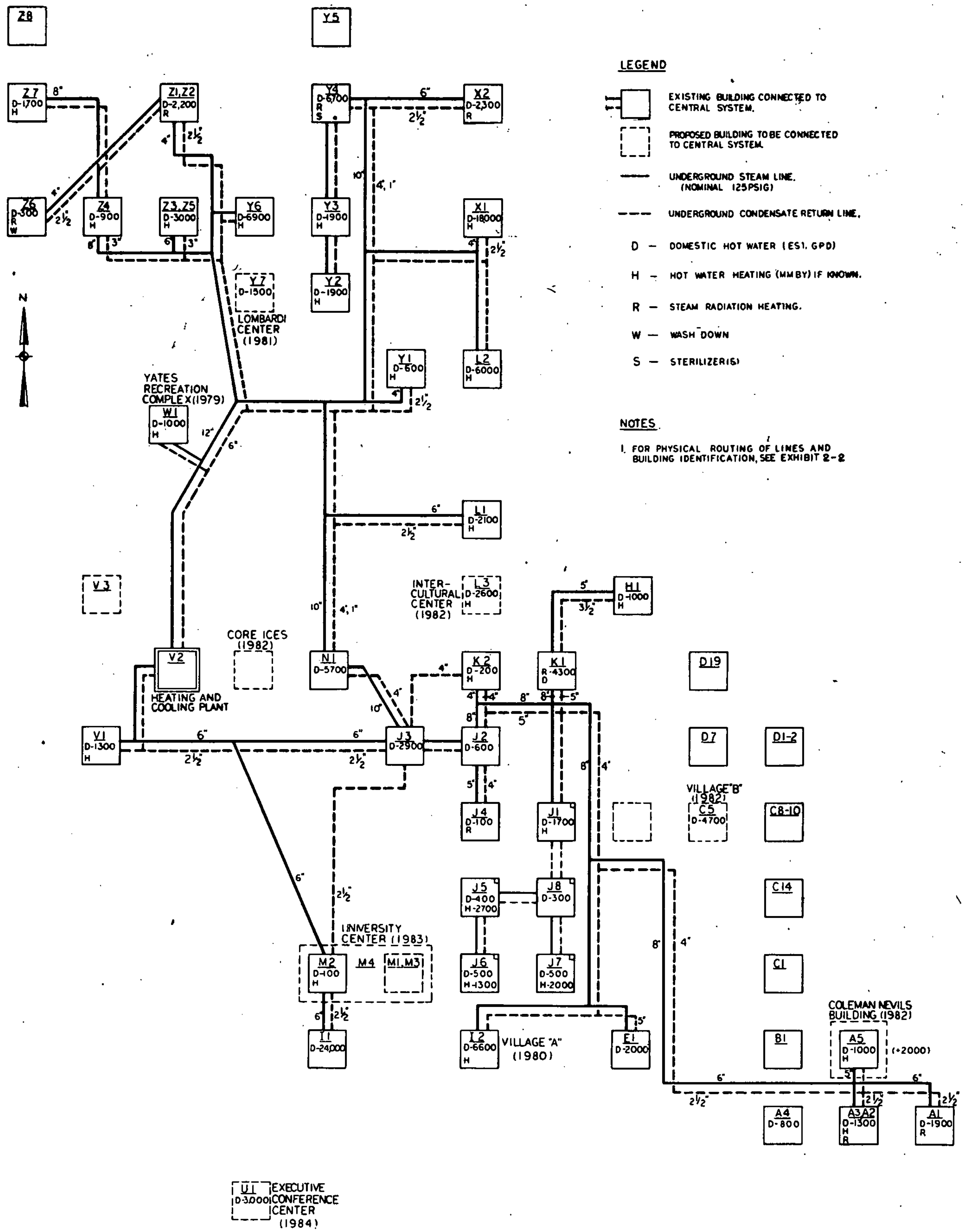
1. ROUTING SHOWN IS FOR STEAM AND CONDENSATE RETURN UNLESS OTHERWISE NOTED.
2. FOR FLOW DIAGRAM OF STEAM AND CONDENSATE RETURNS, SEE EXHIBIT 2-3

EXHIBIT 2-2

STEAM DISTRIBUTION SYSTEM

POPE, EVANS AND ROBBINS

STEAM DISTRIBUTION SYSTEM SCHEMATIC



LEGEND

EXISTING BUILDING CONNECTED TO CENTRAL SYSTEM.

PROPOSED BUILDING TO BE CONNECTED TO CENTRAL SYSTEM.

UNDERGROUND STEAM LINE. (NOMINAL 125PSIG)

UNDERGROUND CONDENSATE RETURN LINE.

D — DOMESTIC HOT WATER (EST. GPD)

H — HOT WATER HEATING (MMBY) IF KNOWN.

R — STEAM RADIATION HEATING.

W — WASH DOWN

S — STERILIZER(S)

NOTES

1. FOR PHYSICAL ROUTING OF LINES AND BUILDING IDENTIFICATION, SEE EXHIBIT 2-2

TABLE 2-2

GEORGETOWN UNIVERSITY STEAM PRODUCTION DATA - FY78 AND FY79

	TOTAL STEAM 10^3 LB/MO		FUEL CONSUMED		CALCULATED EFFICIENCY	
	BY GAS	BY OIL	GAS (10^4 CF)	OIL(Gal)	GAS FIRED	OIL FIRED
FY78:						
July '77	70,600	-	7,834	-	88.3	-
Aug.	74,056	-	8,170	-	88.8	-
Sept.	67,446	-	7,493	-	88.2	-
Oct.	56,758	-	6,165	-	90.2	-
Nov.	35,456	-	3,949	-	88.0	-
Dec.	45,534	-	4,860	-	91.8	-
Jan. '78	48,792	3,844	5,089	29,821	94.0	87.8
Feb.	44,882	6,388	4,660	49,359	94.4	88.2
Mar.	35,944	5,832	3,845	46,064	91.6	86.3
Apr.	26,521	-	2,921	-	89.0	-
May	39,294	-	4,529	-	85.0	-
June	54,708	-	6,558	-	89.2	-
TOTAL	599,991	16,064	66,073	125,244	89.0	87.4
FY79:						
July '78	58,298	-	6,958		82.1	
Aug.	62,890	-	7,560		81.5	
Sept.	55,874	-	6,666		82.2	
Oct.	40,270	-	4,715		83.7	
Nov.	28,868	-	3,602		78.5	
Dec.	37,818	-	4,349		85.2	
Jan. '79	48,045	2,991	5,198	24,974	90.6	81.6
Feb.	49,974	4,791	5,124	38,536	95.6	84.7
Mar.	36,685	-	3,937		91.3	
Apr.	32,256	-	3,330		94.9	
May	47,454	-	5,297		87.8	
June	48,678	-	5,372		88.8	
TOTAL	547,110	7,782	62,108	63,510	86.3	83.5

The enthalpy of saturated steam at 275 psig is 1202.6 Btu/lb, and of boiler feedwater @ 227°F is 195.2 Btu/lb for a net differential of 1007.4 Btu/lb. Heating value of natural gas was taken at 1030 Btu/cf and of fuel oil 147,500 Btu/gal. Thermal efficiencies calculated in this manner are also shown on Table 2-2. It becomes obvious from the high efficiencies (>85 percent) calculated for some months, that the raw data is not entirely accurate and merits correction. Referring to boiler performance specifications for the gas/oil fired boilers, it was found that the predicted boiler efficiency from 25 to 100 percent load is about 83 percent. Since natural gas accounted for 98 to 99 percent of the annual steam production during the base years evaluated, and since gas is metered by a utility owned meter, it was assumed that fuel flow was accurate. Actual steam production, therefore, was corrected assuming an 83 percent thermal efficiency applied to the fuel consumed.

A further correction was made to the FY '78 and '79 steam production figures to correct the values for the respective months to mean heating and cooling degree days rather than actual.

The results of the above corrections appear in the plot for Exhibit 2-4. For each month of the two year period, there are plotted three separate values, namely:

- Steam generation as recorded,
- Steam generation as corrected for 83 percent boiler efficiency, and
- Steam generation as further corrected for monthly heating and cooling degree days.

The final step in establishing annual steam generation baseline data consisted of averaging the corrected month-to-

[redacted]

MONTHLY STEAM GENERATION

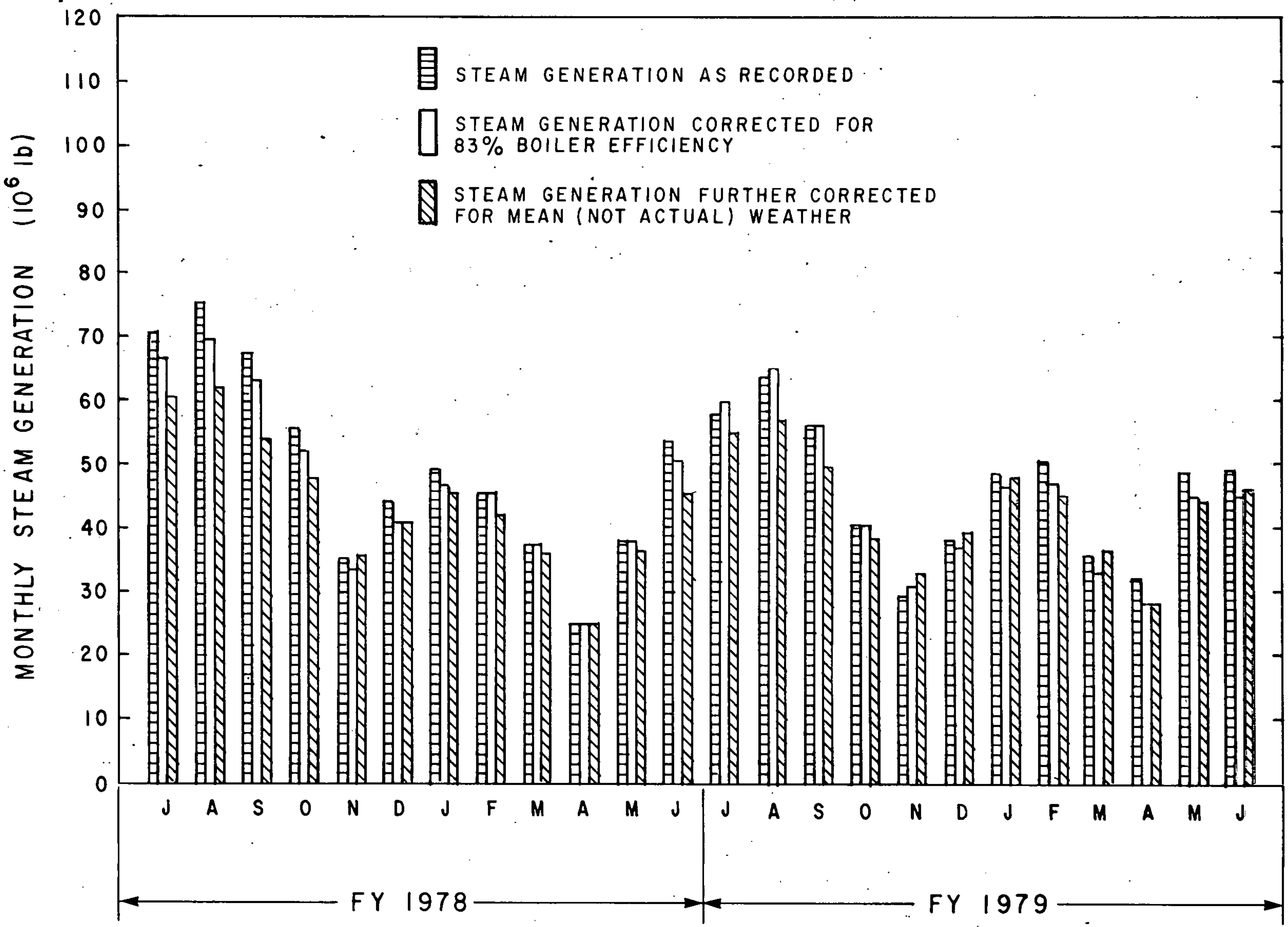


EXHIBIT 2-4

month generation figures for the two years to arrive at the averaged monthly steam generation profile shown in Exhibit 2-5.

The resulting monthly load distribution profile revealed a symmetry about the end of July and the end of January. As a result, the year was folded about July 31/August 1 and corresponding months were averaged to obtain six characteristic periods during which steam consumption was distinct during an average year. Averaged distinct steam production during these six periods (July/August, June/September, May/October, April/November, March/December and January/February) are shown in Exhibit 2-6 and Exhibit 2-7 for the existing campus. Exhibit 2-6 presents average monthly steam generation for the six characteristic periods while Exhibit 2-7 presents the same data converted to average hourly steam generation. Each of these corrected baseline profile loads is subdivided to reflect the equivalent proportional steam allocations for plant auxiliaries, domestic hot water, space heating and chilled water production.

Export steam is used predominantly in building space heating, either by direct radiation or conversion to hot water; for building domestic hot water generation; for reheat in building air conditioning systems; for building cooling by steam absorption chillers in one existing building*; and to a small extent for miscellaneous applications such as hospital sterilizers, washdown in the Vivarium, etc. None of the local users are metered and recorded and, therefore, accurate determination of the division of steam load based on recorded data is not possible.

*Future construction plans indicate the probable use of one additional absorption chiller in Village "B", a dormitory town house complex to be completed in 1982.

EXISTING AND PROJECTED 1984 AVERAGE MONTHLY STEAM GENERATION

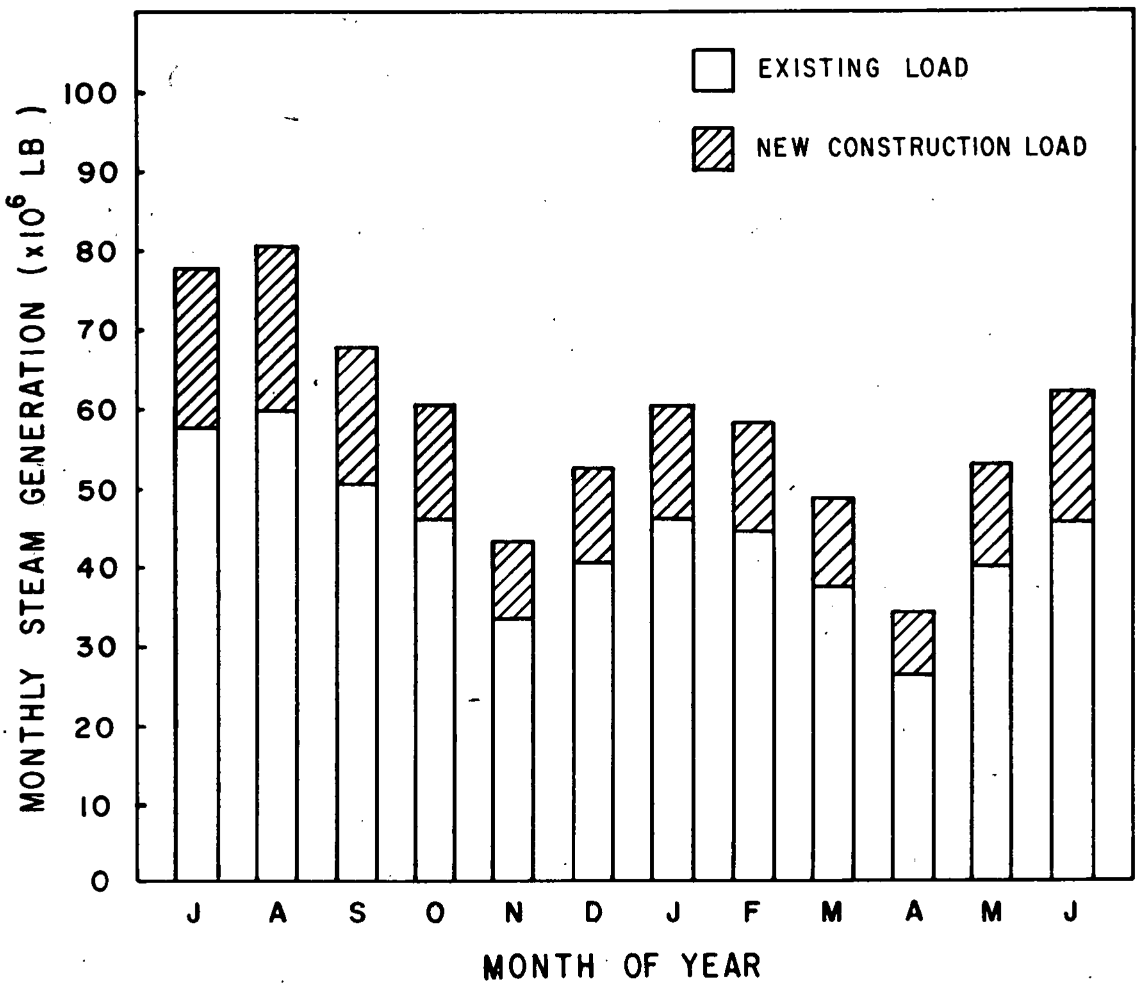


EXHIBIT 2-5

EXISTING AVERAGE MONTHLY STEAM GENERATION AND CONSUMPTION ALLOCATION

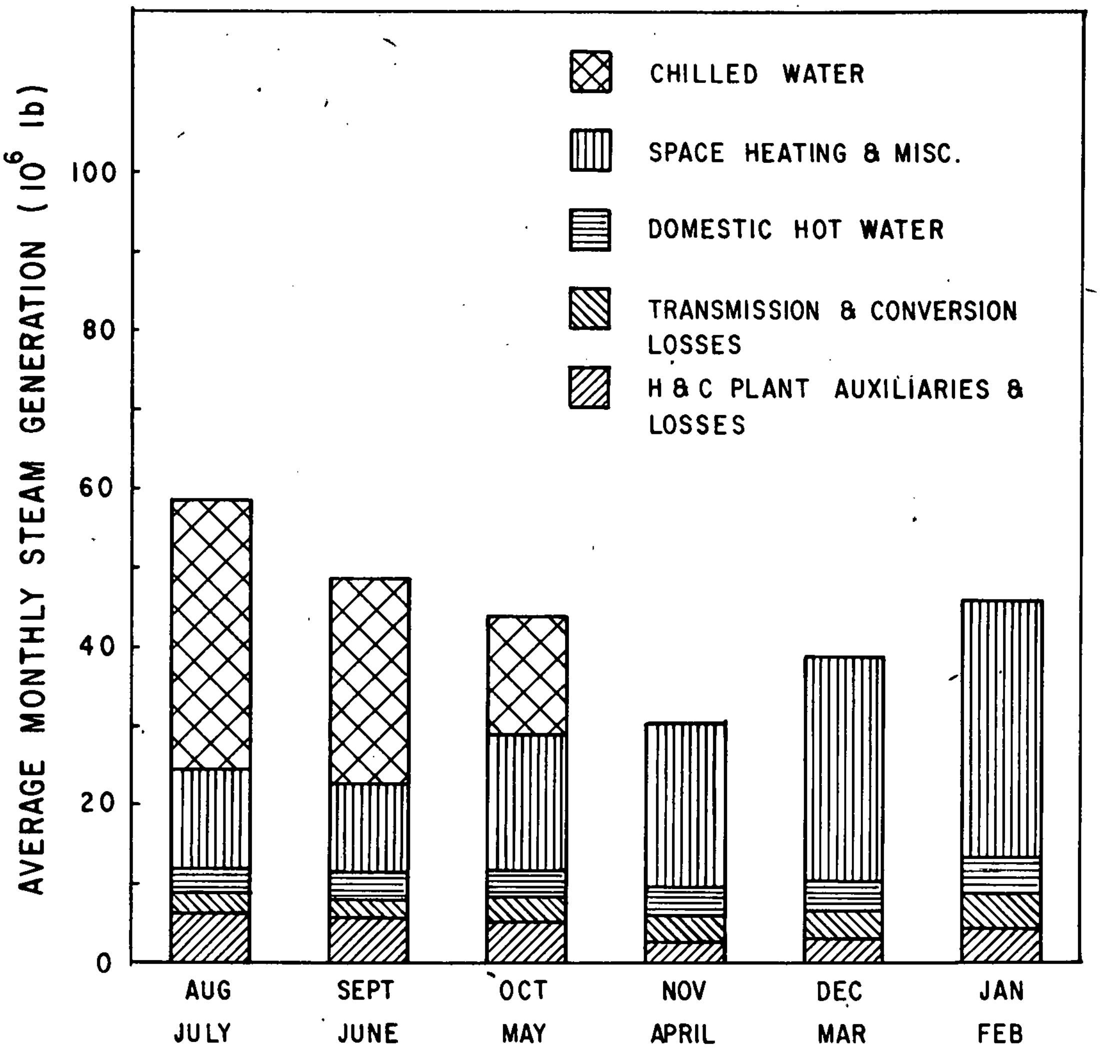


EXHIBIT 2-6

EXISTING AVERAGE HOURLY STEAM PRODUCTION AND CONSUMPTION ALLOCATION

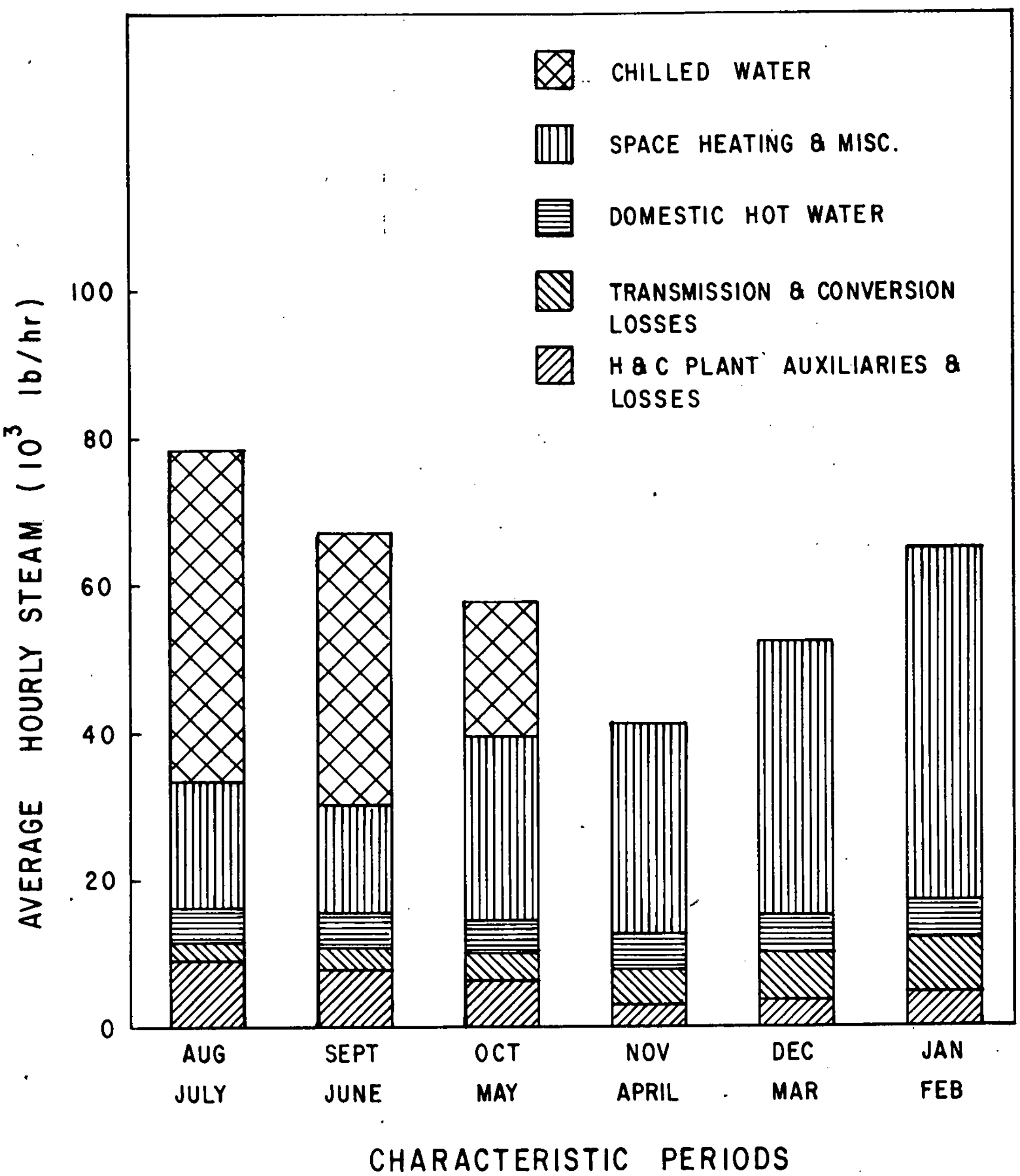


EXHIBIT 2-7

Instead, the equivalent proportional steam allocations were determined as a result of estimates and calculations described within the respective sections dealing with individual topics. Details can be found in both Section 2.2 where sources of data are discussed as well as Sections 2.3 through 2.6 where production and distribution of individual energy streams are discussed.

There are several observations worth noting. July and August represent peak steam demand periods during the year, reflecting cooling demands. Maximum total steam demand during the summer exceeds maximum total steam demand during the winter. November and April have minimum total steam demand since heating demands are low and the chillers are not on-line.

The campus loads as observed are affected by some special load influences unique to Georgetown University and are stated here to complete the load profile.

There are two two-week periods during which most of the campus is inactive due to vacations. These are the end of December - beginning of January, Christmas vacation and the spring vacation around Easter. In addition, there is a four to six week period centered approximately about the middle of August when the medical and dental school students are not on campus and the medical and dental areas allegedly are shut down. It is not certain, however, to what degree services are curtailed to affected areas during these periods.

In order to perform specific tasks within the scope of work, representative daily, weekly, monthly, seasonal and annual data had to be derived from available and estimated source data.

Typical continuous steam load data as read from GU circular charts for two representative periods are shown in Exhibits 2-8 and 2-9. Total steam production as well as the portion of equivalent chiller plant steam consumption are shown on these exhibits. The determination of the steam consumption by the chiller plant is described in Section 2.4. A portion of these results is included here to provide a better insight into the steam production and utilization picture. The period April 22 through April 28, 1979 shown in Exhibit 2-8 was selected since it revealed a typical load history when main plant chiller operations were turned on, in this case, early Monday morning April 23, 1979. This is an unusually early startup of this chiller plant and is indicative of flexibility in general system utilizations. The other period, July 7 through July 9, 1977, shown in Exhibit 2-9, was selected to portray a peak summer steam demand utilization.

By using such representative daily data during the two-year analysis period, load duration curves for steam were produced for certain seasonal and annual periods.

Exhibit 2-10 shows steam load duration curves for the summer months cooling season May through October; for winter months heating season December through March; and for the minimum demand months, April and November. Addition of these load durations yield the annual load duration curve shown in Exhibit 2-11.

Representative days from throughout the two fiscal year analysis periods were also used to obtain average hourly steam load and chilled water load profiles for weekdays and weekend days for the six characteristic periods. The daily data used was in the form shown in Exhibits 2-8 and 2-9.

STEAM GENERATION AT START OF COOLING SEASON

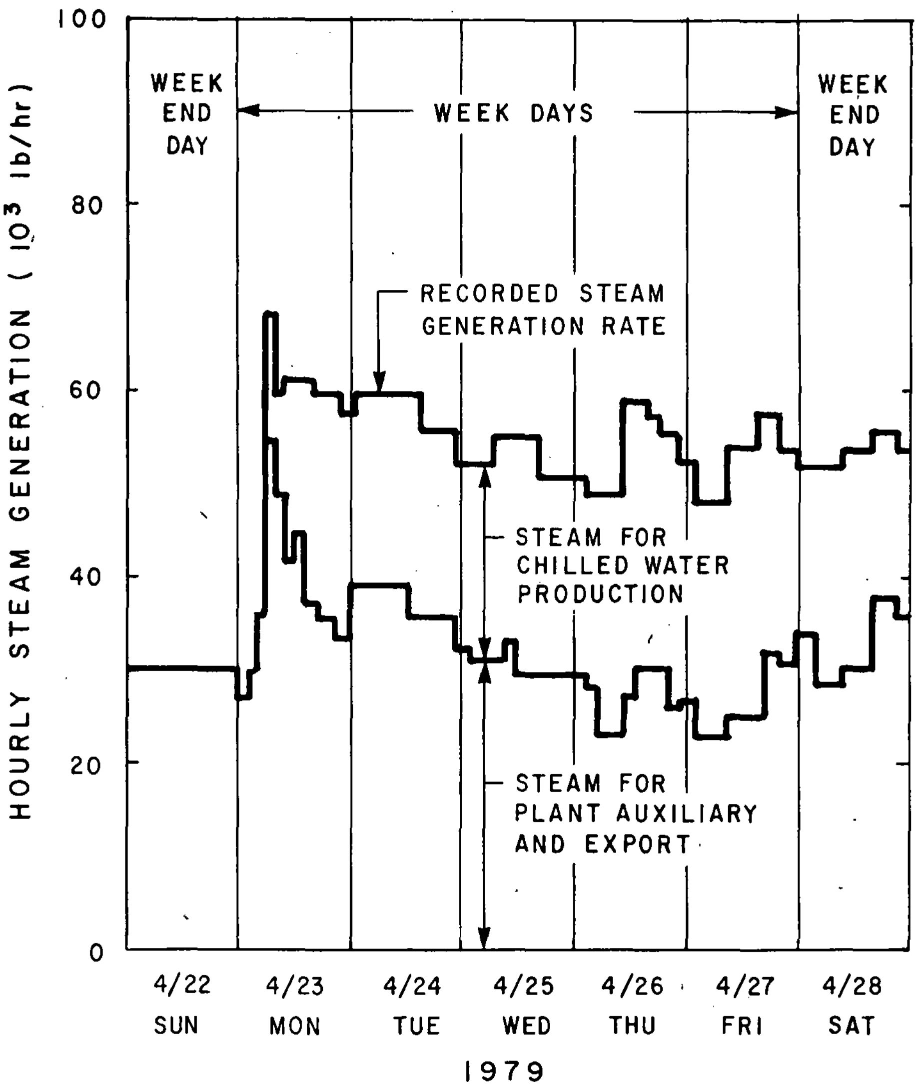


EXHIBIT 2-8

STEAM GENERATION DURING MIDDLE OF COOLING SEASON

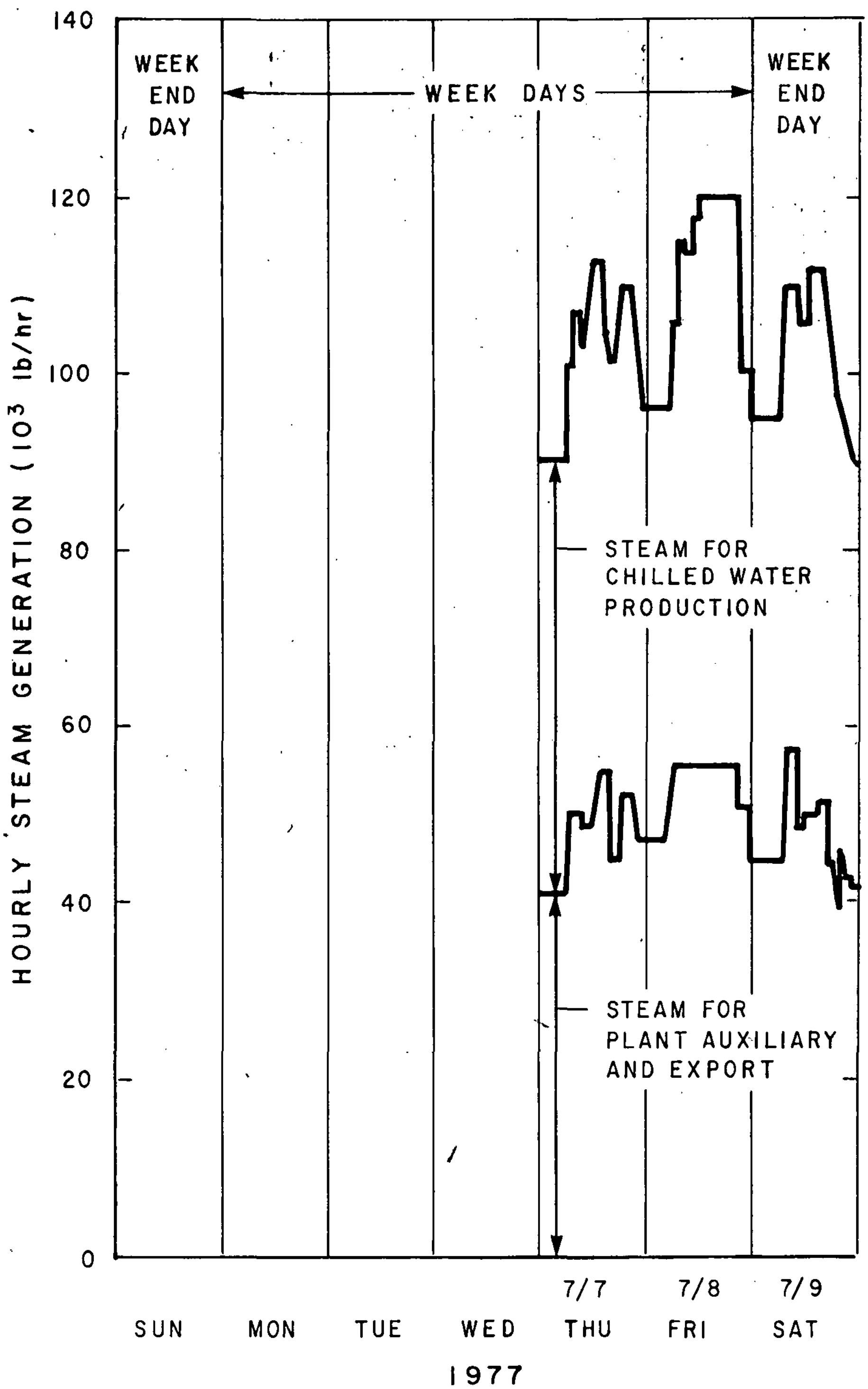


EXHIBIT 2-9

EXISTING
SEASONAL STEAM LOAD DURATION CURVES

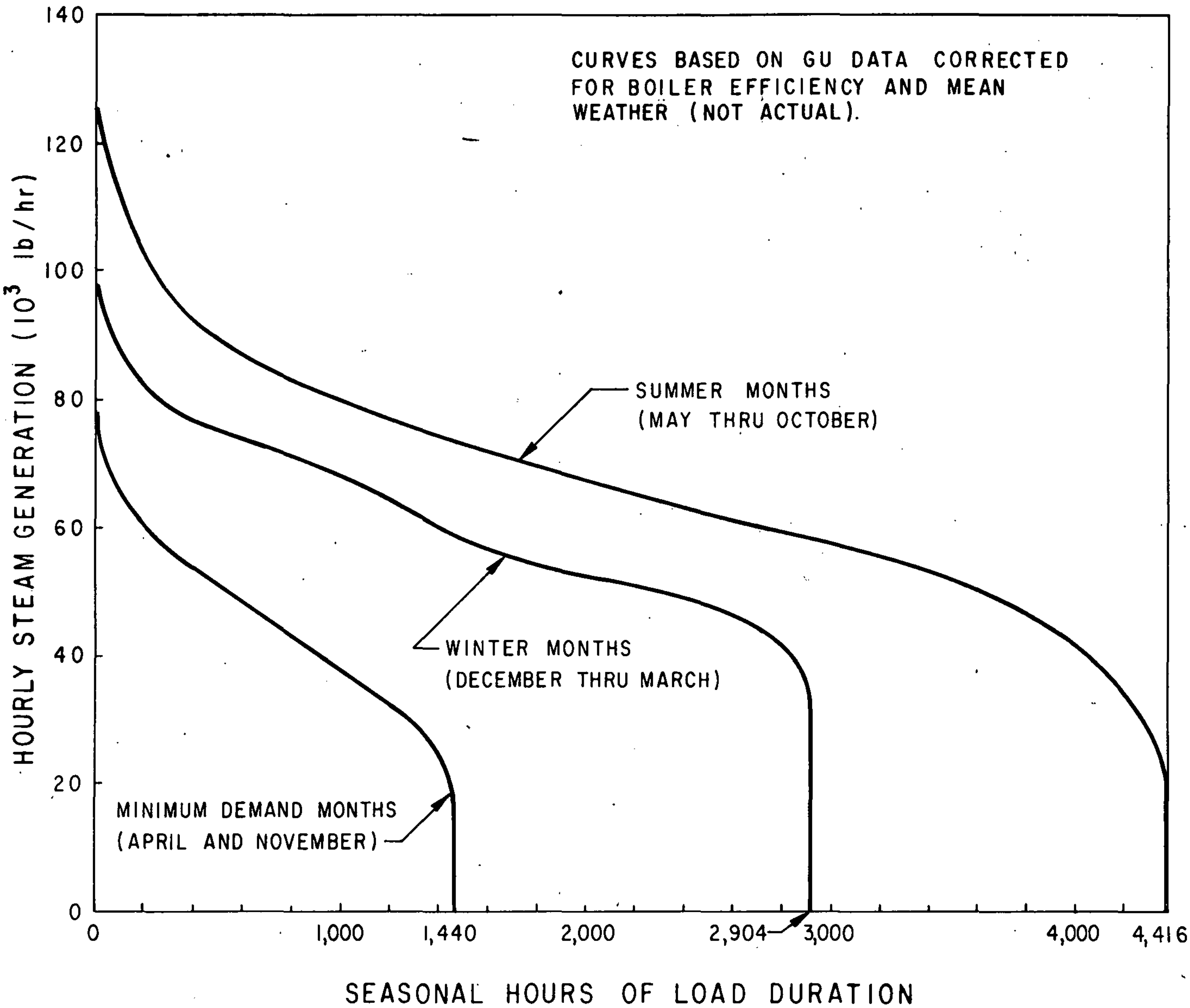


EXHIBIT 2-10

EXISTING
ANNUAL STEAM LOAD DURATION CURVE

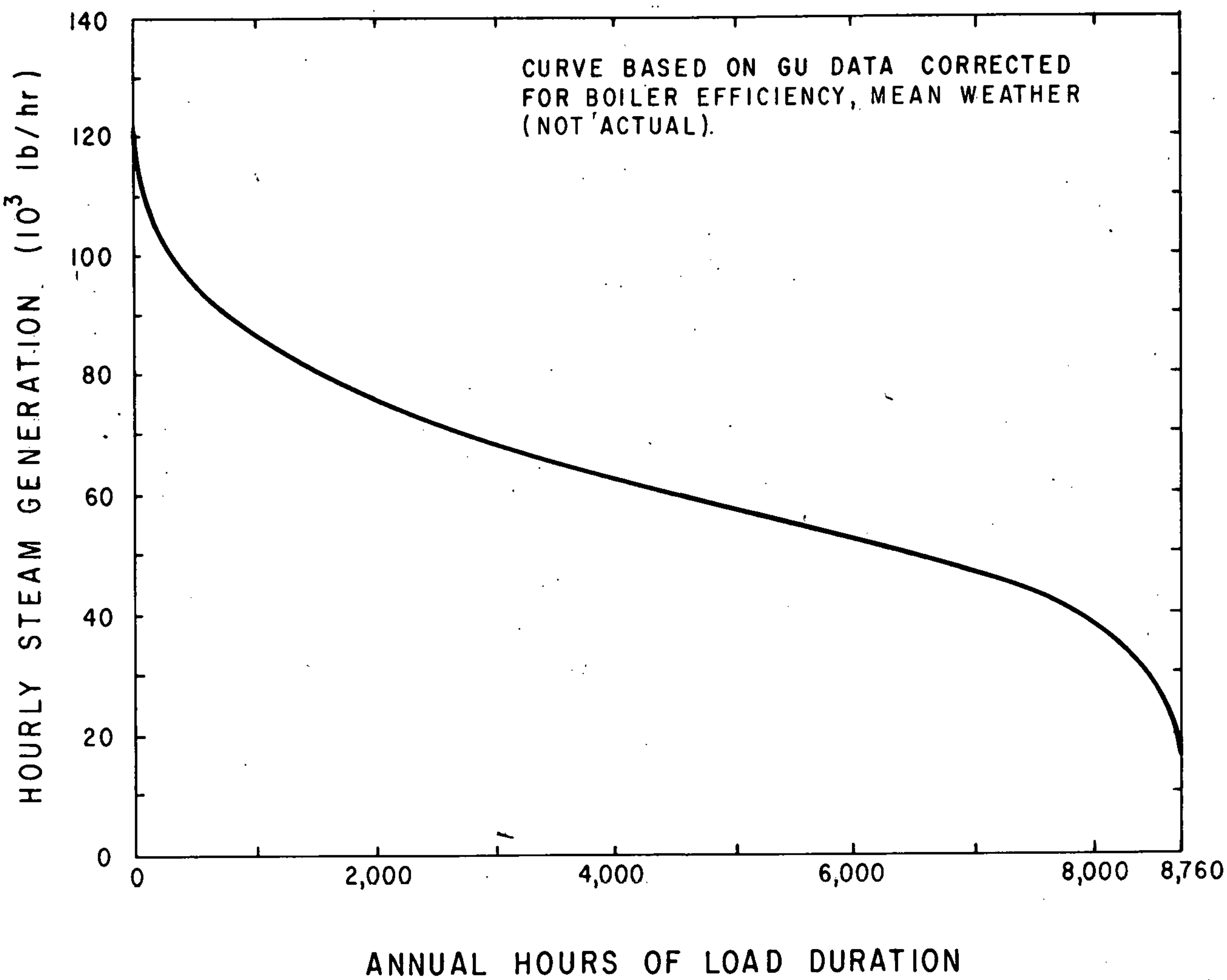


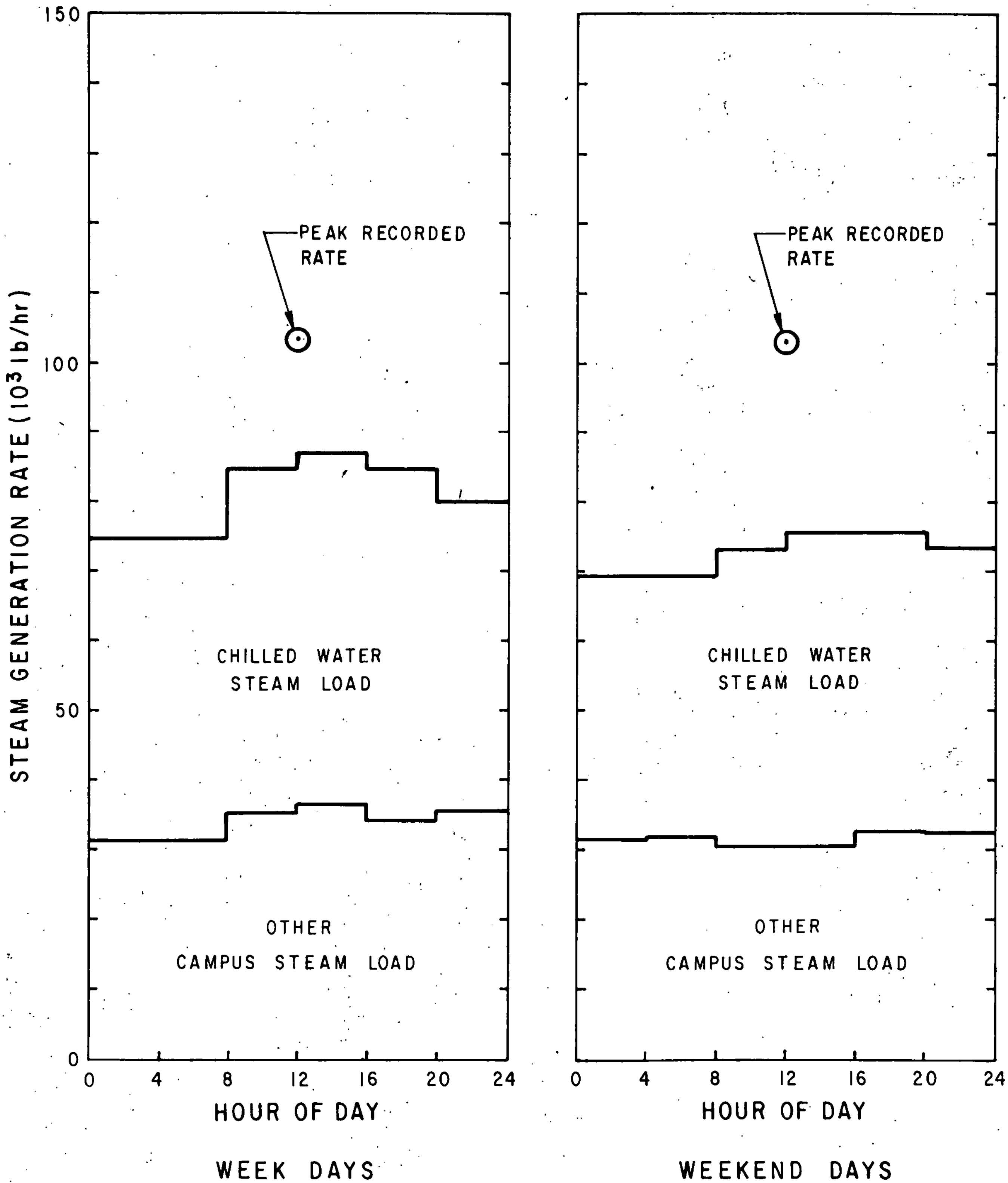
EXHIBIT 2-11

Consumption values for corresponding hours for all data within each characteristic period were added and divided by the number of data points used in order to arrive at an average consumption value for each hour during a typical characteristic period week day or weekend day. These hourly consumption data points were plotted and averaged over multi-hour segments in a 24 hour period. These multi-hour segments were chosen to coincide with the new proposed time-of-day electric metering rate schedule discussed in Section 1.3.5. In order to allow for a better load variation distribution picture, the peak period was split in two. The additional partition of the electric rate schedule segmentation is at 4 PM in the middle of the on-peak period. The time intervals selected thus were Midnight to 8 AM, 8 AM to 12 Noon, 12 Noon to 4 PM, 4 PM to 8 PM and 8 PM to Midnight.

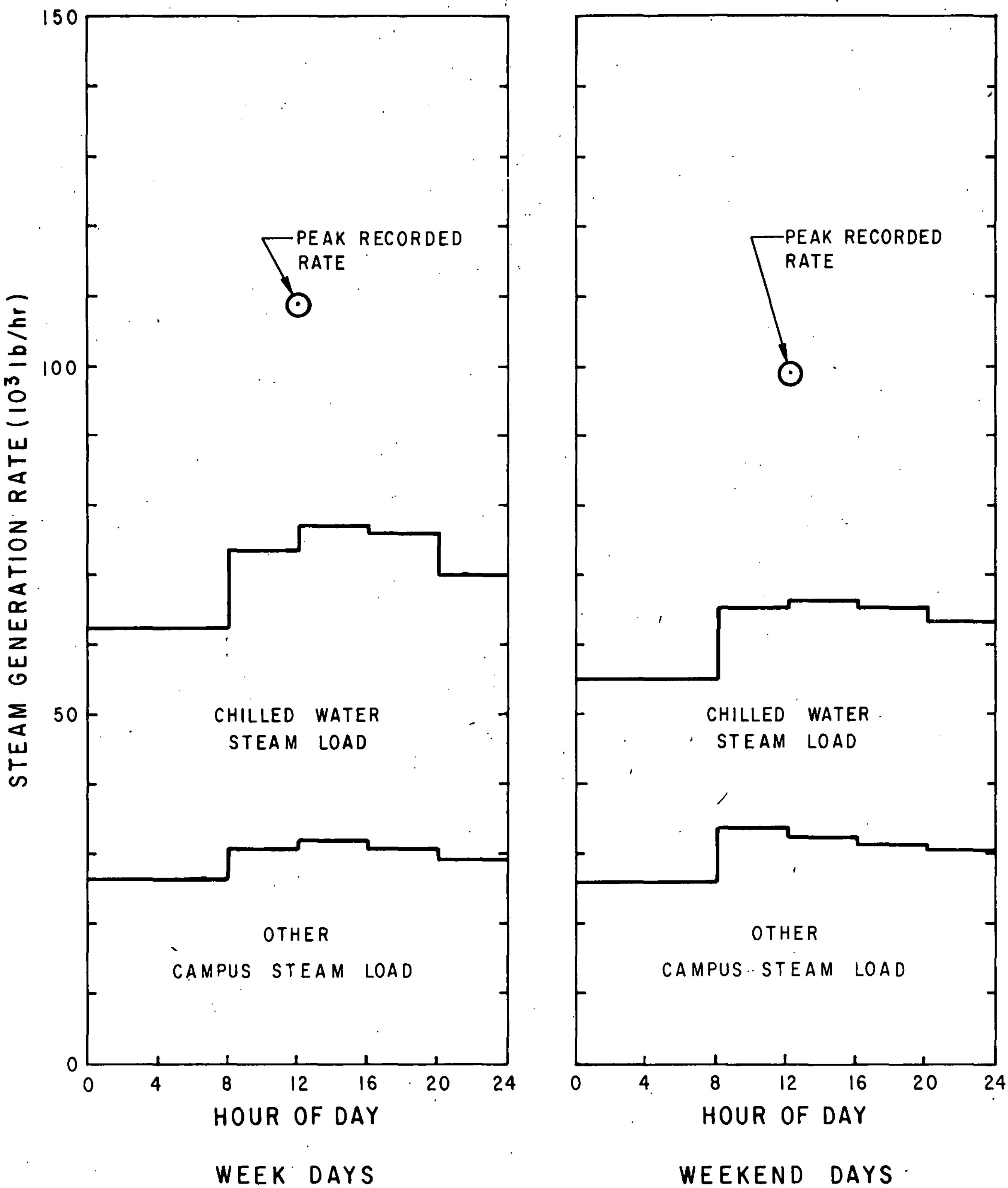
All of the corrections previously discussed were applied and the data was normalized to yield the same total annual consumption of the respective energy streams, namely total steam and chilled water.

The steam profile data for all characteristic periods for the existing campus, showing also the contribution of chilled water equivalent steam during the cooling season, are presented in Exhibits 2-12 through 2-17. Peaks are also indicated for each type of day in each period. New construction impacts are discussed later and corresponding exhibits will be presented there.

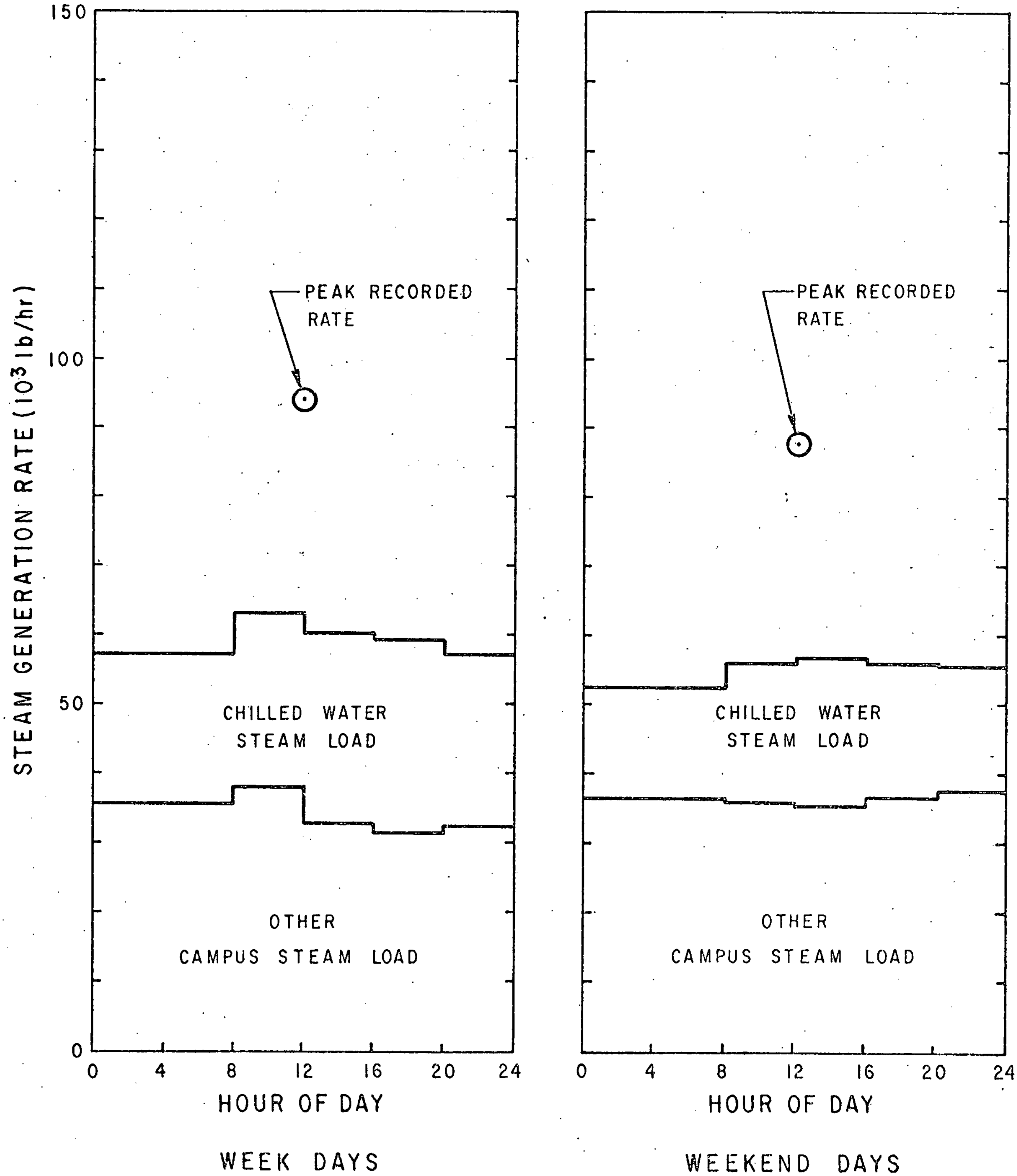
EXISTING AVERAGE DAILY STEAM PRODUCTION JULY AND AUGUST



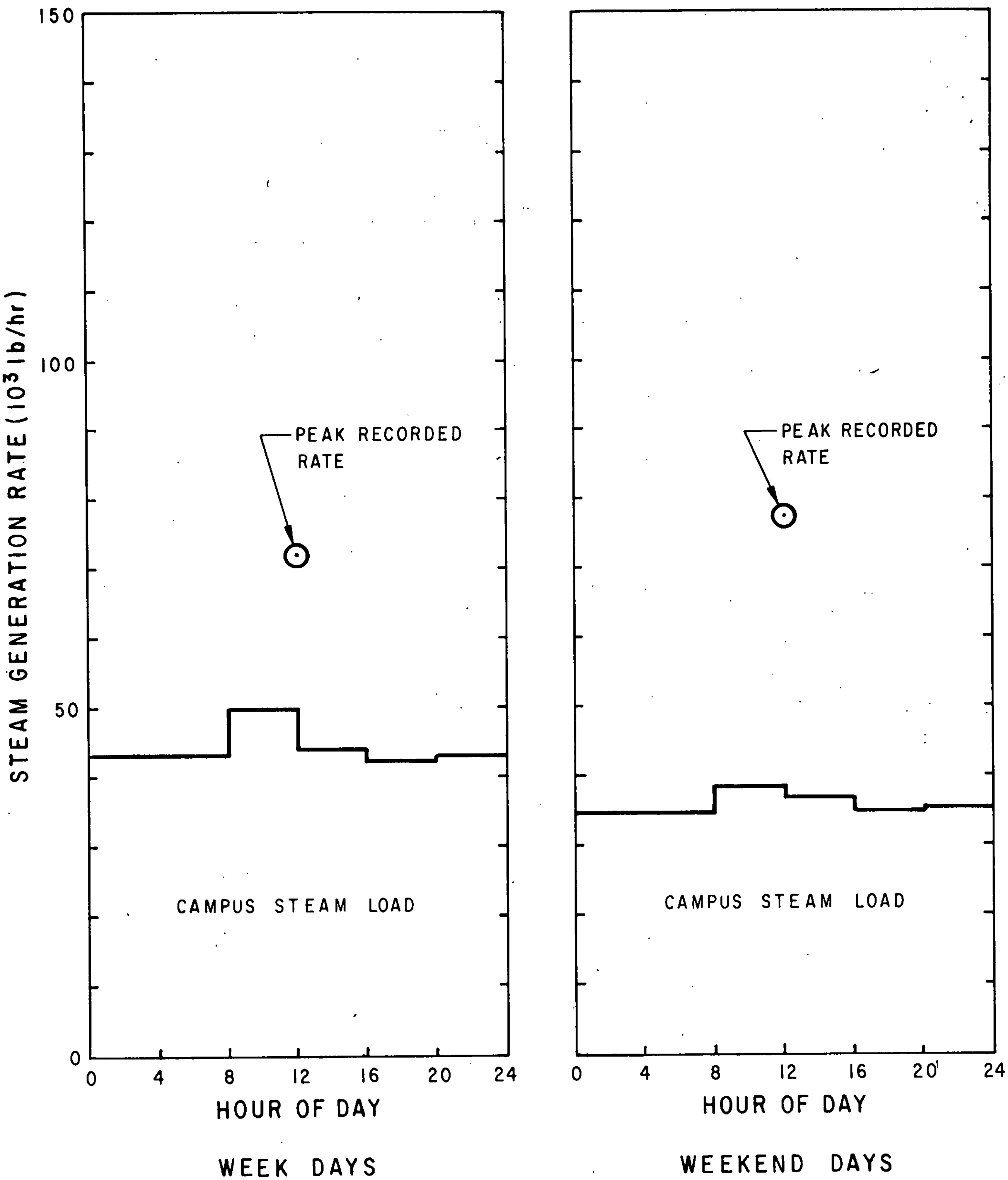
EXISTING AVERAGE DAILY STEAM PRODUCTION
JUNE AND SEPTEMBER



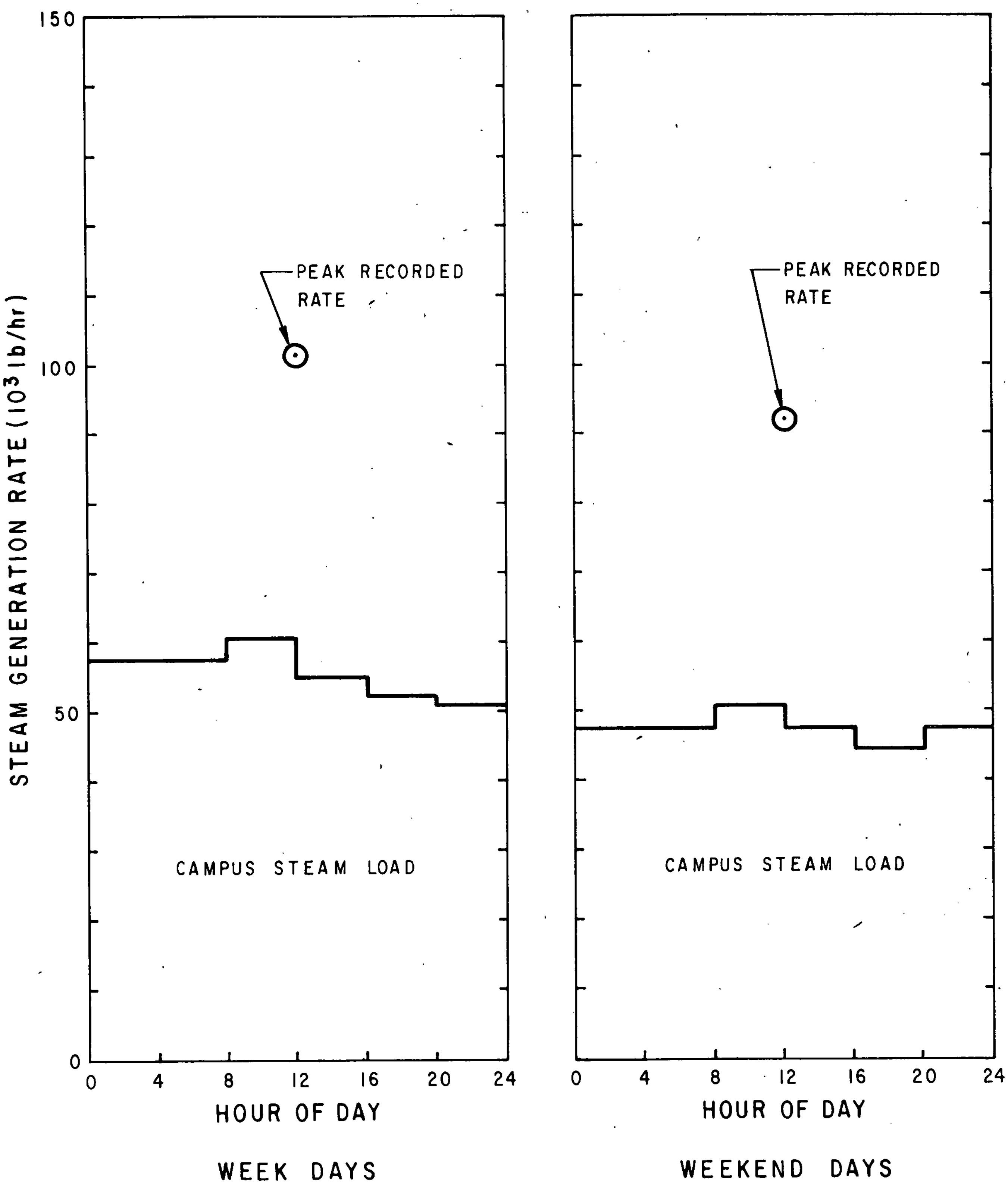
EXISTING AVERAGE DAILY STEAM PRODUCTION
MAY AND OCTOBER



EXISTING AVERAGE DAILY STEAM PRODUCTION
APRIL AND NOVEMBER



EXISTING AVERAGE DAILY STEAM PRODUCTION
MARCH AND DECEMBER



EXISTING AVERAGE DAILY STEAM PRODUCTION
JANUARY AND FEBRUARY

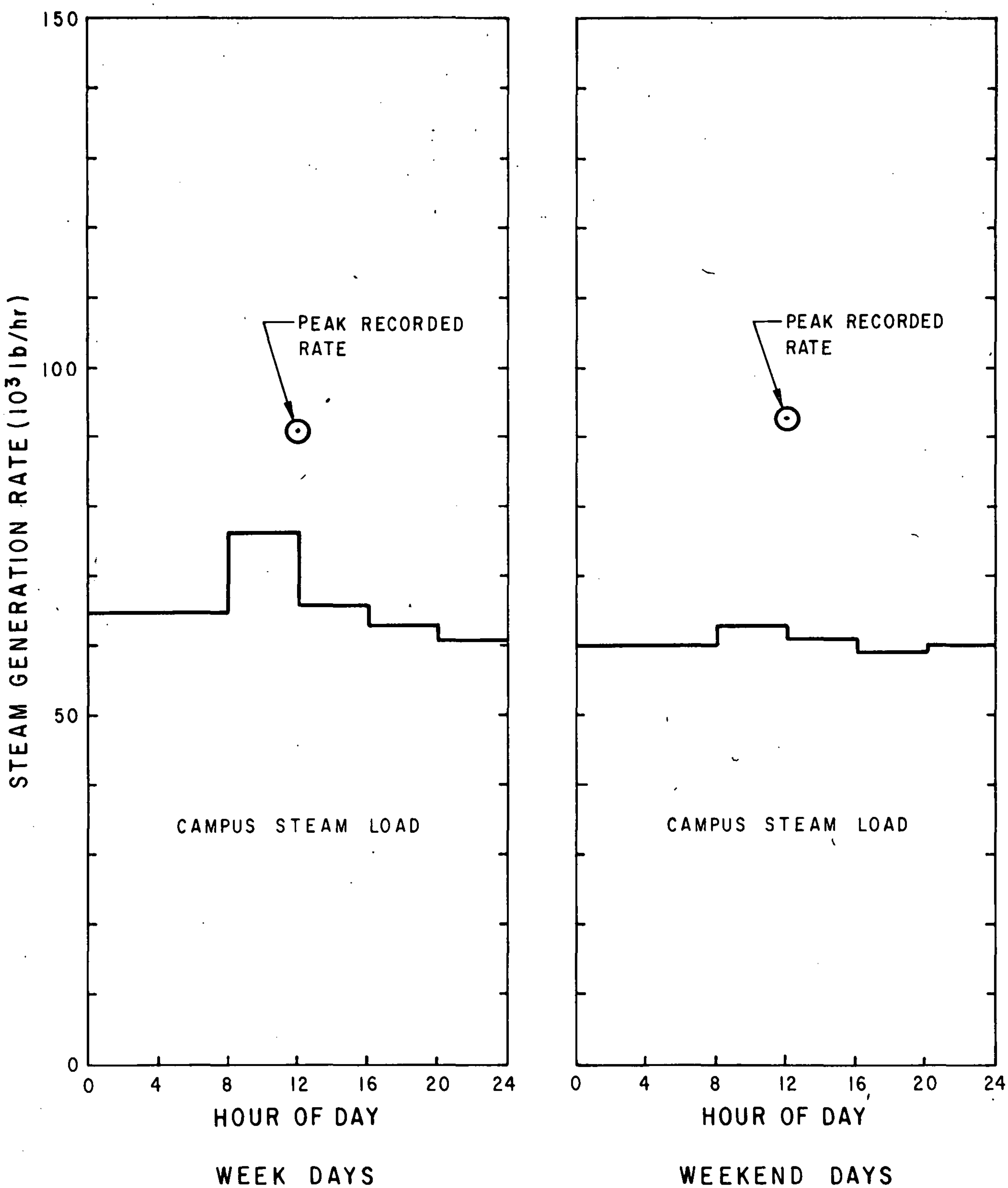


EXHIBIT 2-17

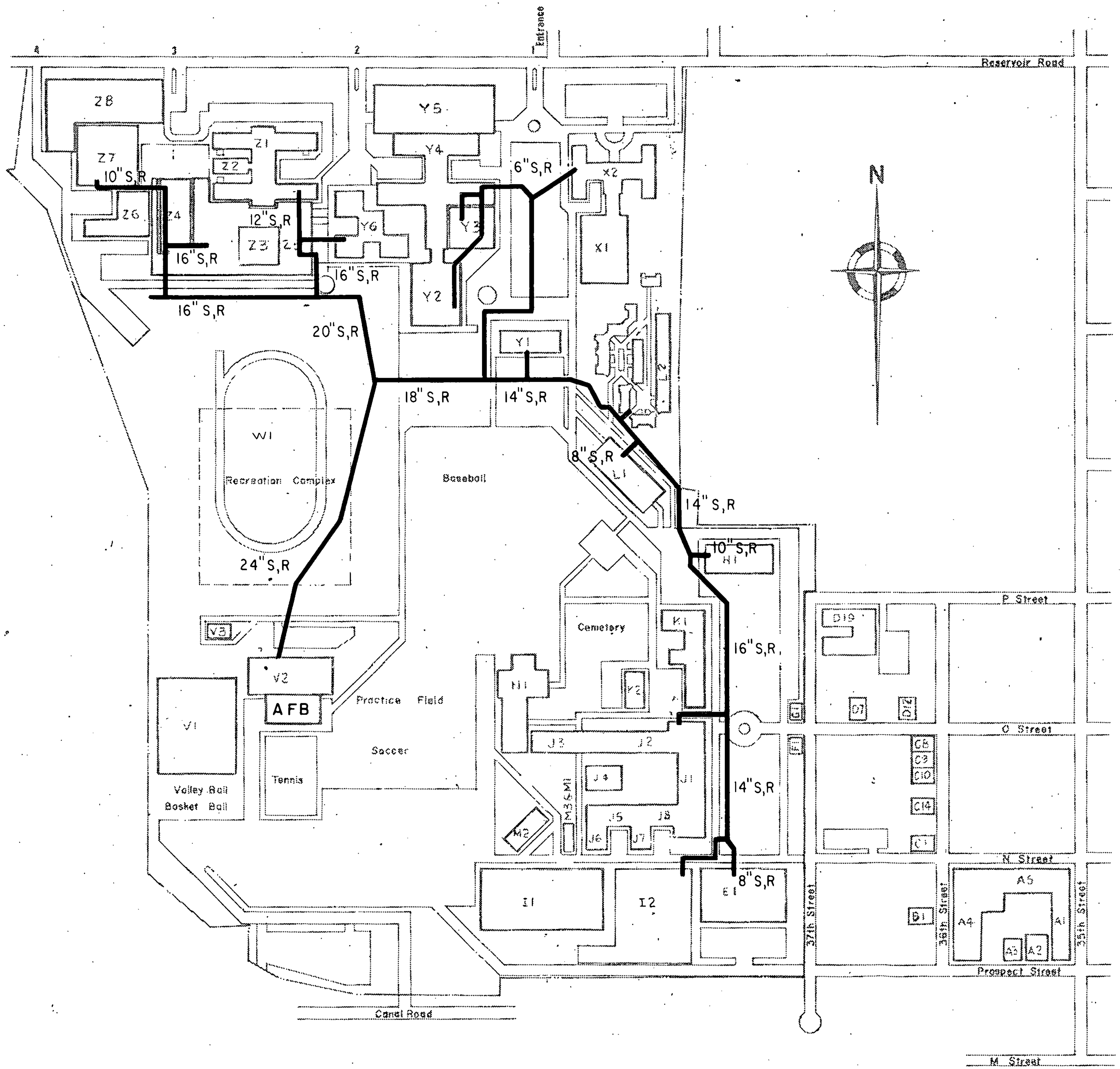
2.4 Central Chilled Water Production and Distribution

2.4.1 Chilled Water Distribution System

Central chilled water is produced in one or both of the two 3000-ton rated steam turbine-driven chillers located in the Heating and Cooling Plant. The chiller turbines operate between 270 psig saturated steam and condensing at 4 inches of mercury with an uncontrolled extraction of 2300 lb/hr at 10 psig. The condensing load is handled by the same cooling water circuit that discharges the refrigeration system waste heat. Chilled water is distributed throughout the campus by means of a distribution network which supplies about 64 percent of the campus occupied floor area with cooling requirements. This network is shown in Exhibit 2-18 with the connected load labelled. An additional 18 percent of the campus is cooled by local electric refrigeration units varying in size from 7 to 460 tons. The locations of these secondary systems are shown in Exhibit 2-19 and are labelled with the letter L as shown in the legend. The remainder or about 18 percent is either uncooled or supplied by local window units. The extent of the latter was not evaluated.

The central chilled water system is operated for the entire cooling season which lasts up to about 6 months from May to October. At the time the central plant is shut down, there is still a cooling demand by the hospital complex consisting of the GU Hospital, the Gorman Building, the Bles Building and the Concentrated Care Center. This load is supplied by a 700 ton chiller recently installed and located in the GU Hospital and if this capacity cannot adequately supply the demands, a second 680 ton chiller located in the Reiss Science Building can be used to supplement the demand. The connection is through the existing main chilled water network. The Reiss Science chiller is also used to handle a local computer generated load within the Reiss Science Building

GEORGETOWN UNIVERSITY



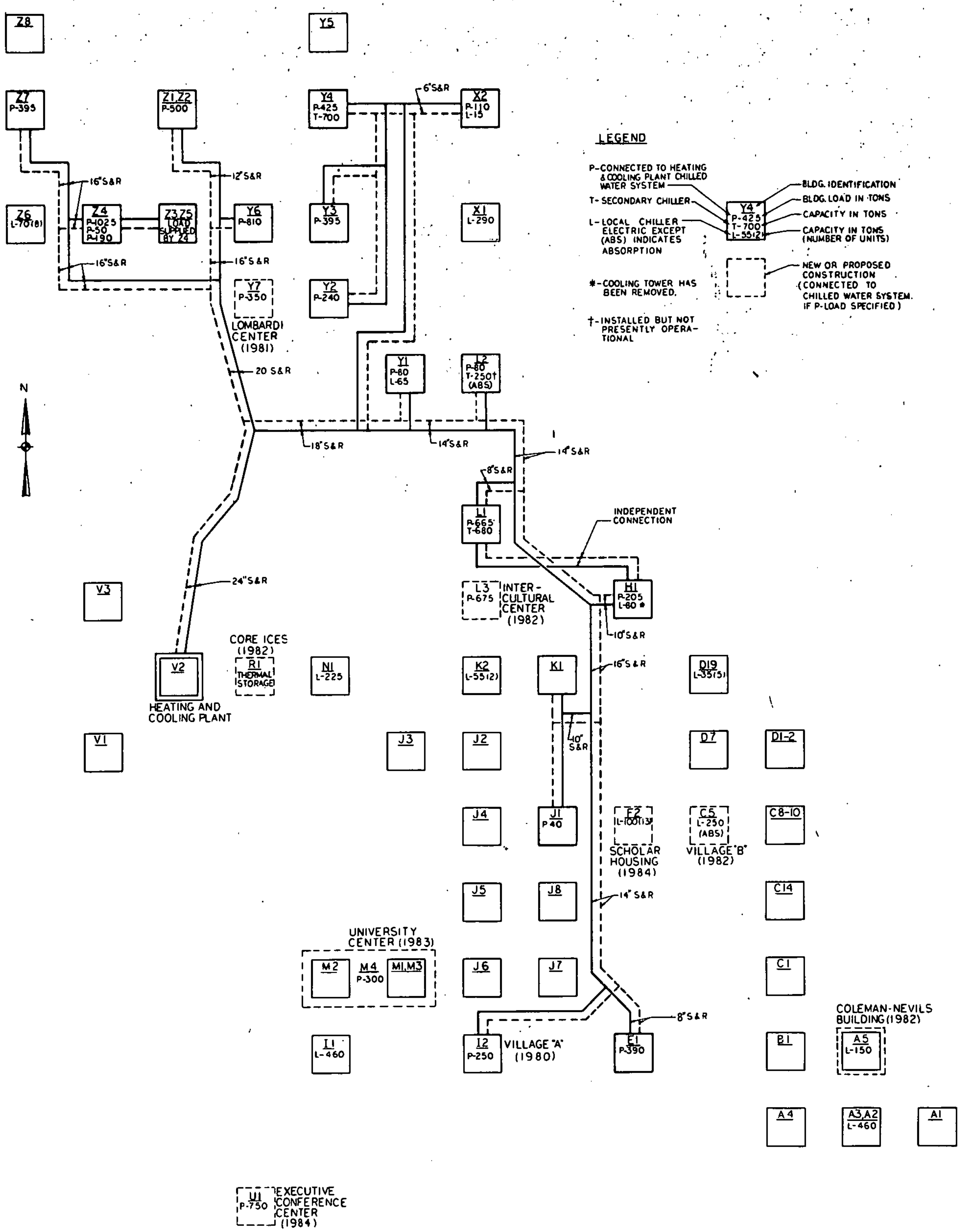
A1	Loyola Hall
A2	Xavier Hall
A3	Ryder Hall
A4	Walsh Building
A5	Coleman Nevils Building
B1	Office Of Economics
C1	Bookstore
C8-10	Alumni House
C14	Placement Office
D1-2	American Language Institute
D7	Black Student Alliance
D19	Poulton Hall
E1	Lauinger Library
F1	S. Gatehouse
G1	N. Gatehouse
H1	White-Gravenor
I1	New South Building
J1	Healy Building
J2	Old North Building
J3	New North Building
J4	Dahlgren Chapel
J5	Mulledy Hall
J6	Gervase Hall
J7	Ryan Hall
J8	Maguire Hall
K1	Copley Hall
K2	Ryan Administration Building
L1	Reiss Science Building
L2	Student Housing
M1	Garage
M2	O'Gara Building
M3	Mc Sherry Building
N1	Harbin Hall
V1	Mc Donough Gymnasium
V2	Heating & Cooling Plant
V3	Observatory
X1	Darnall Hall
X2	St. Mary's Hall
Y1	Kober Cogan Building
Y2	Gorman Building
Y3	Bles Building
Y4	Georgetown Hospital
Y5	Hospital Parking Garage (Deck 1)
Y6	Concentrated Care Center
Z1	Medical-Dental Bldg.
Z2	Medical-Dental Annex
Z3	Dalgren Library
Z4	Basic Science Building
Z5	Preclinical Science Building
Z6	Medical Center Vivarium
Z7	Dental Clinic
Z8	Hospital Parking Garage (Deck II)

EXHIBIT 2-18

CHILLED WATER DISTRIBUTION SYSTEM

POPE, EVANS AND ROBBINS

CHILLED WATER
DISTRIBUTION SYSTEM SCHEMATIC



and the White-Gravenor Building. There is an independent chilled water connection joining these two structures. These two chillers are labelled T to distinguish them from the local units labelled L since the former can be interconnected into the main chiller distribution network whereas the latter cannot.

The recent connection to Village "A", a construction project in the completion stages and partially occupied, is shown connected although it is considered new construction in the context of this report.

2.4.2 Chilled Water Production

Whereas steam flow meters are installed in the turbine inlet steam supply lines as shown on Exhibit 2-1, these are reportedly inaccurate and are not relied upon to indicate chilled water production coincident steam consumption. Chilled water production itself was the only source of data available to determine the coincident steam consumption. Chilled water production for GU FY '78 and '79 was derived from chiller daily circular recorder charts on which were recorded the flow rate in gpm and the temperature differential, ΔT, between supply and return water. This data was used to determine the refrigeration delivered in Btu/hr according to the relationship:

$$\text{Btu/hr of refrigeration} = Q\ \Delta T$$

where Q = lb/hr of chilled water obtained by multiplying gpm x lb/gal x 60 min/hr

or

$$\text{Btu/hr of refrigeration} \simeq 500 \times \text{gpm} \times \Delta T$$

The equivalent tons of refrigeration is this number divided by 12,000 Btu/ton hr. Typical evaluated results for the week* of April 22 to April 28, 1979 are presented in Exhibit 2-20.

*This is the same week as that in Exhibit 2-8.

HOURLY CHILLED WATER GENERATION AT START OF COOLING SEASON

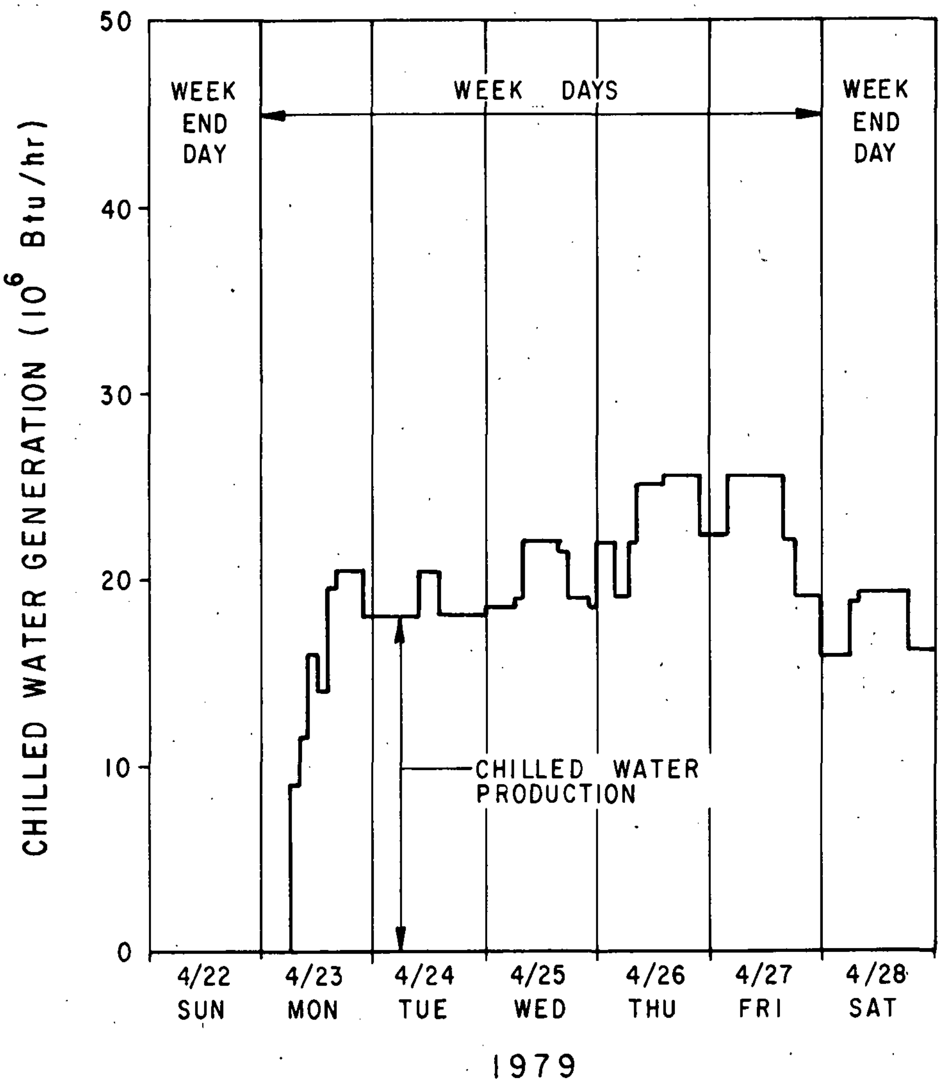


EXHIBIT 2-20

Existing performance test data on the chiller turbines was not available. Consequently, no direct evaluation of the chilled water equivalent steam consumption was possible. The original turbine performance curves included in Appendix H were used to establish this equivalence as described herewith.

At the guarantee point, the turbines have a rating of 3150 hp at 4300 rpm with a steam rate of 12.15 lb/hr/hp without extraction. This would require a steam rate of about 12.8 lb/hr/ton of refrigeration or a maximum steam consumption of about 38,300 lb/hr per machine. This value is not an accurate overall representation due to the fact that:

a) the chillers are not operated at the guarantee point (primarily speed control is used), which increases average steam consumption by about 0.4 lb/hr/ton.

b) there is an uncontrolled extraction of about 2300 lb/hr at about 10 psig which increases steam consumption by about 1.0 lb/hr/ton.

c) the efficiency of the turbine and compressor have decreased over the life of the system. An increase in consumption of about 0.2 lb/hr/ton is assumed to account for this.

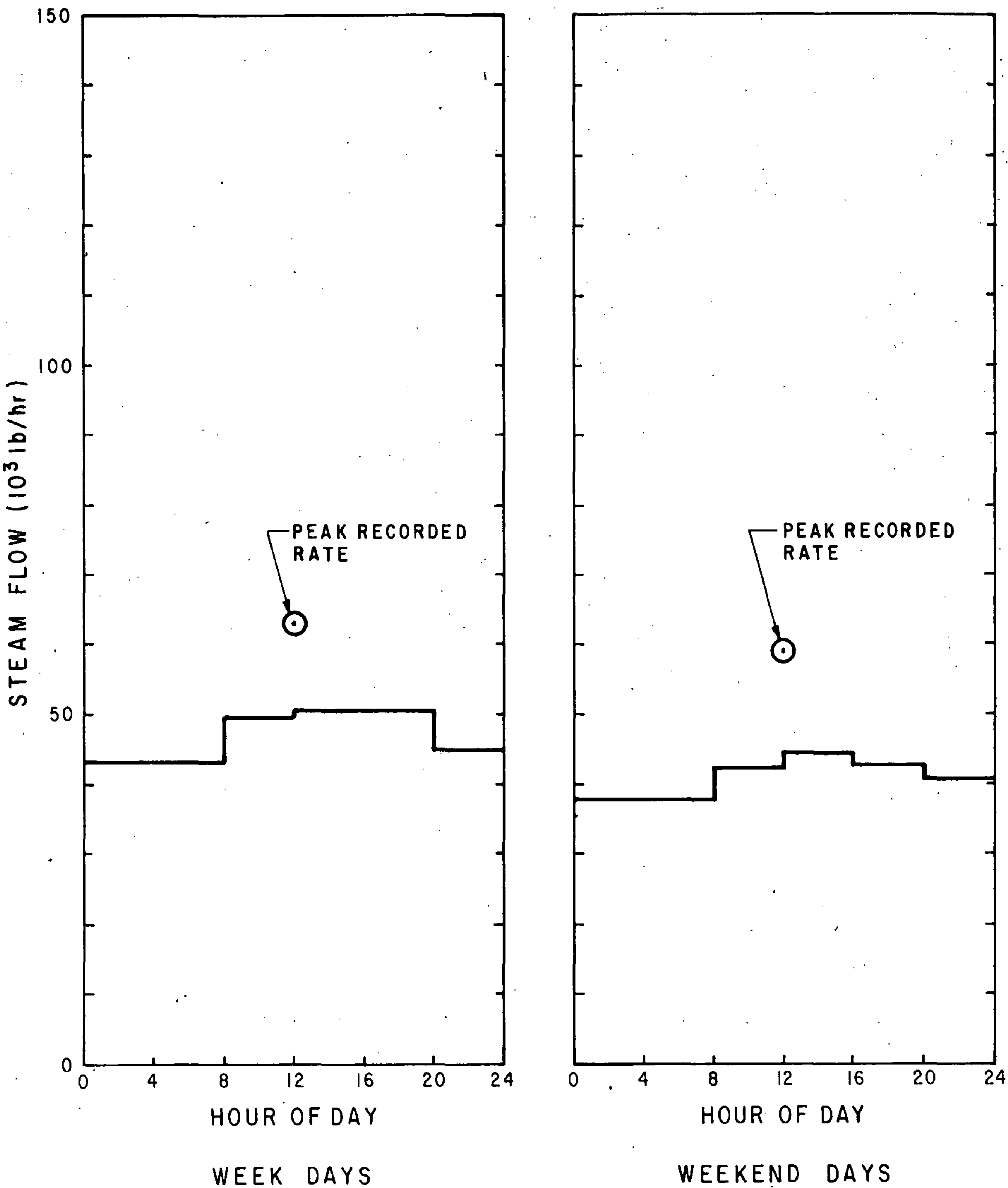
The combination of items a) through c) totals 1.6 lb/hr/ton and thus lead to the conclusion that a better representative value for the steam rate is 14.4 lb/hr/ton of refrigeration. This value was used to develop chilled water coincident steam consumption data.

Exhibits 2-8 and 2-9 typically show these values deducted from the total steam production to allow determination of steam production for purposes other than chilled water as described in the corresponding text.

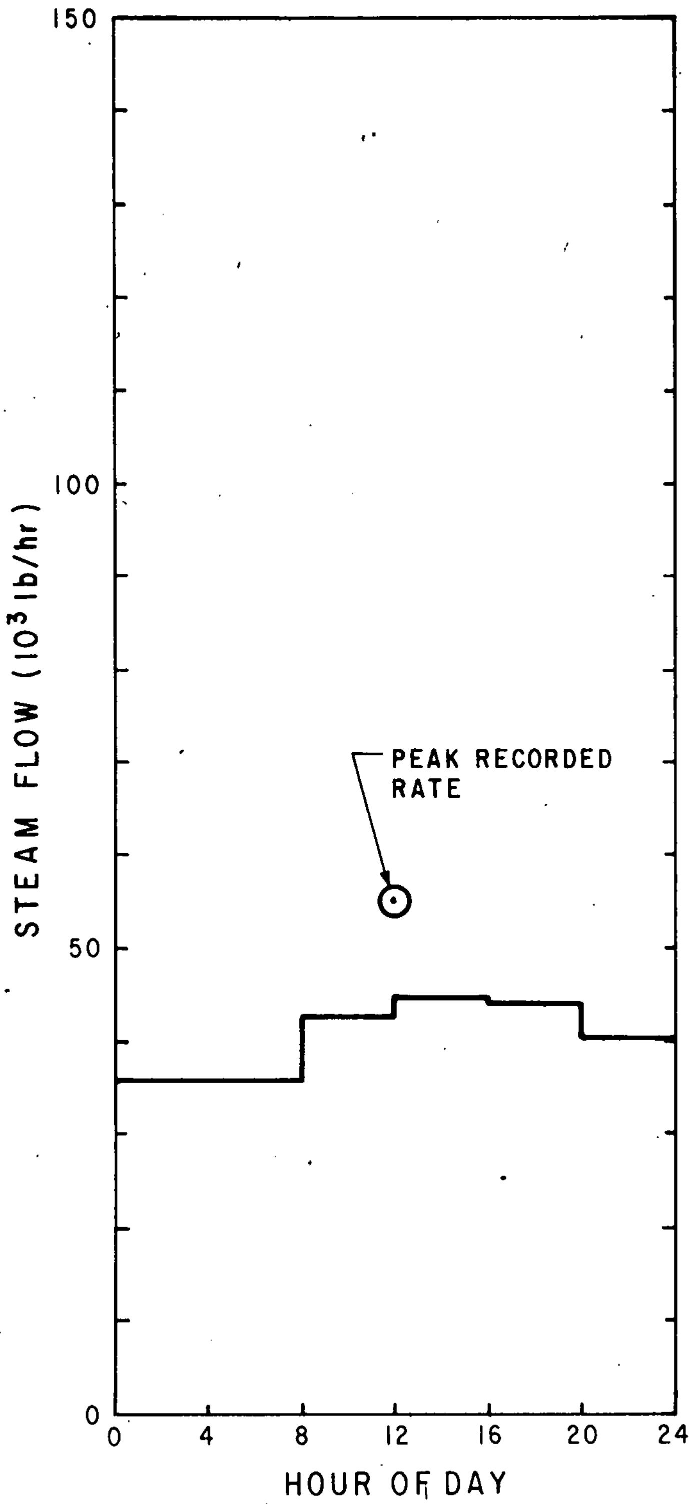
The chilled water coincident steam load hourly variation data described earlier with reference to Exhibit 2-20 was used to determine average chilled water coincident steam load data for weekdays and weekend days for characteristic periods in the same way as was done for the steam data described earlier in Section 2.3. The results of this computation are presented in Exhibits 2-21 through 2-23 for the existing campus and were used to determine the "other" campus steam demands by simple subtraction from the total steam load. The consideration of the impact of new construction will be deferred to Sections 2.7 and 2.8.

This data was developed to get a better idea of the GU campus loads, their variations, possible effect on electric demands during the various rate periods and to have a data base from which thermal storage evaluation would be meaningful. Furthermore, the impact of new construction on chiller requirements can better be appreciated and evaluated with this type of information. The role of the 700 ton and 680 ton electric chillers in the GU Hospital Building and the Reiss Science Building, in context with an expanding campus, are also better considered with a complete data display.

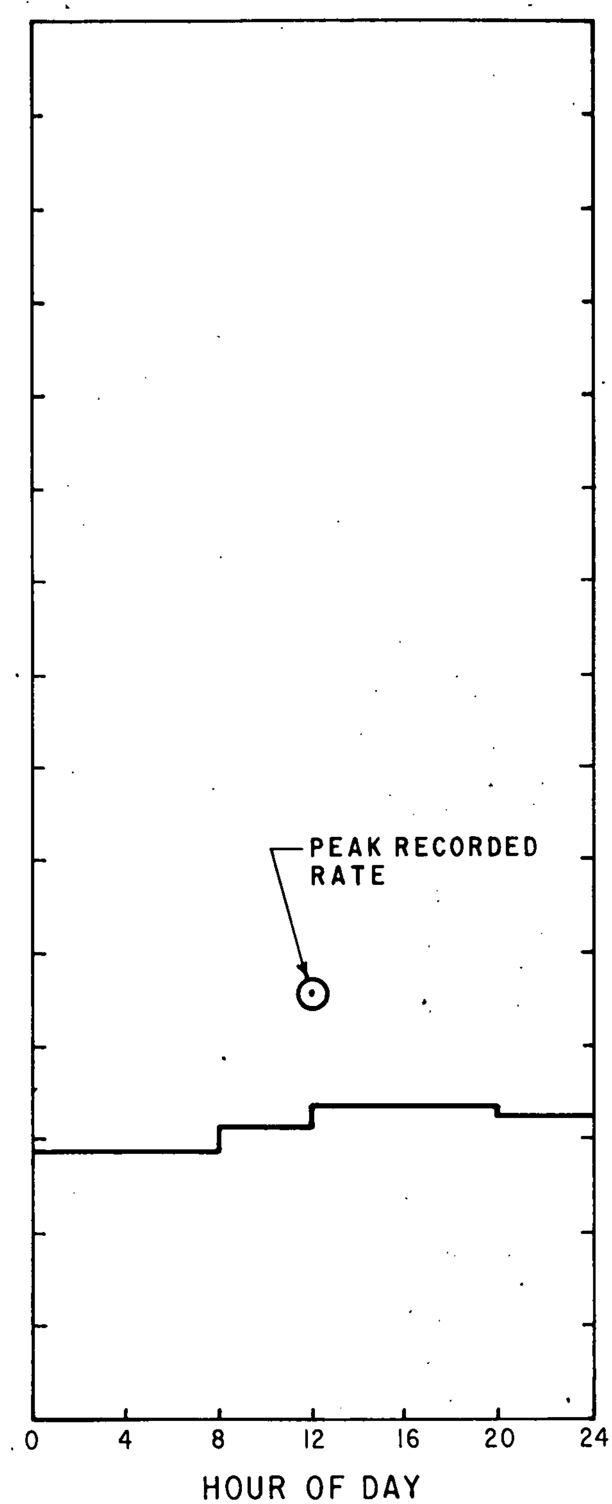
EXIST. AVERAGE STEAM FLOW FOR CHILLED WATER PRODUCTION JULY AND AUGUST



EXIST. AVERAGE STEAM FLOW FOR CHILLED WATER PRODUCTION
JUNE AND SEPTEMBER

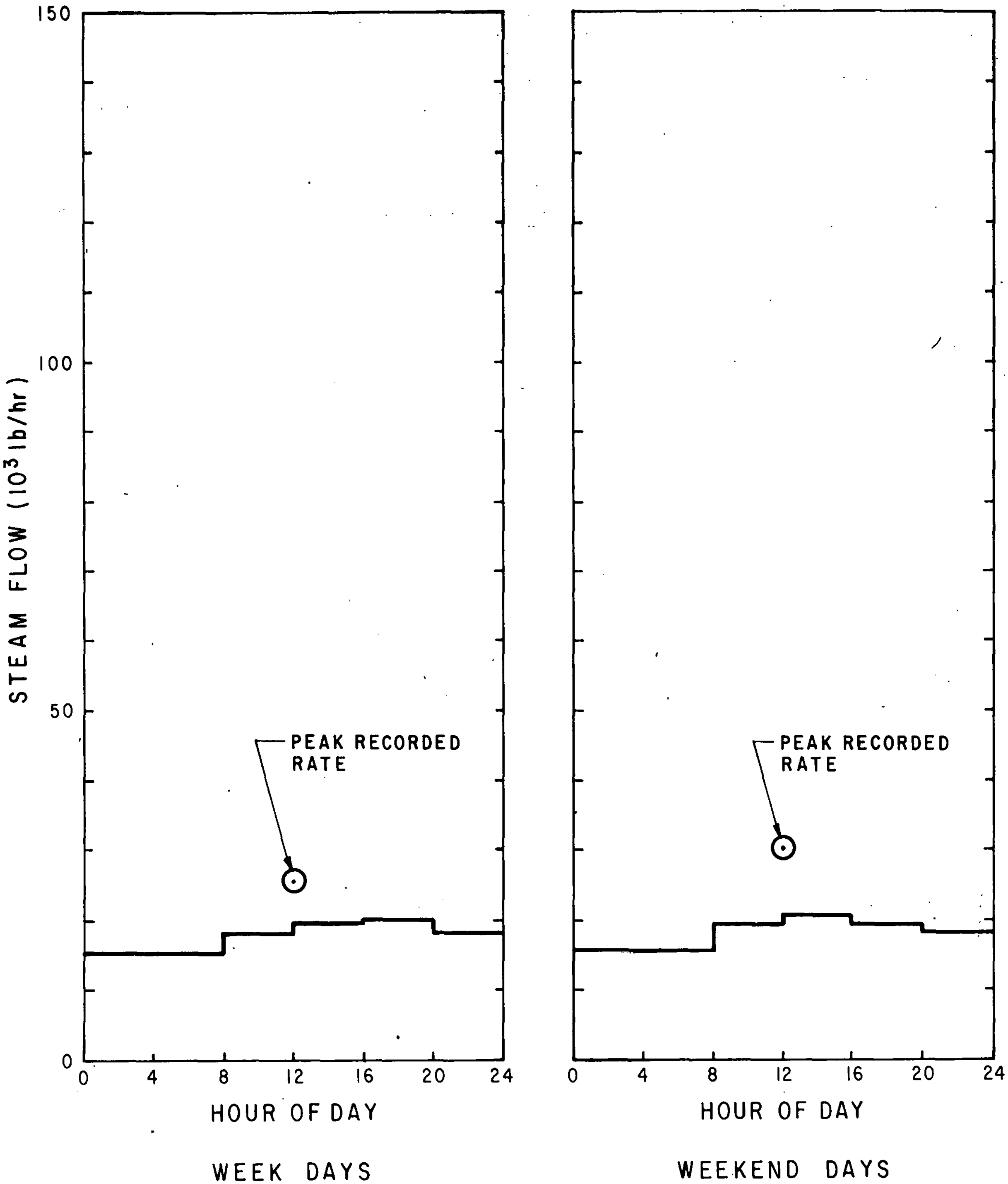


WEEK DAYS



WEEKEND DAYS

EXIST. AVERAGE STEAM FLOW FOR CHILLED WATER PRODUCTION
MAY AND OCTOBER



2.5 Domestic Hot Water Production and Distribution

2.5.1 Domestic Hot Water City Water Source

As a basis for discussing the energy load consisting of domestic hot water along with its generation and distribution, it is essential to summarize the city water supplied to the GU campus. Table 2-3 lists the water consumption in millions of cubic feet for the campus as a whole and for the hospital separately during the indicated time intervals.

TABLE 2-3

CITY WATER SUPPLY IN 10^6 CUBIC FEET

FY	Time Interval	Hospital Complex	Campus Total
1975	1/29/76 - 7/26/76	5.5364	35.0831
1976	7/26/76 - 2/5/77	2.0089	36.9392
1977	2/5/77 - 1/5/78	3.2344	42.4500
1978	1/5/78 - 6/30/78	1.2098	40.6949
1979	7/1/78 - 6/30/79	Not Available	42.9966

The wide fluctuation and variation of supplied city water is a result of several factors. The two most important influences were water main breaks and construction programs. These two factors periodically shifted and exaggerated recorded water consumption among the various meters on campus. Since the city water supply does not represent a significant energy supply stream to the campus and is relevant only in terms of being the water sources for the domestic hot water supply and make up water, little effort was expended in trying to evaluate the exact nature and listing of this utility. It is worthwhile only to determine whether the reported consumption rates are realistic.

From the data presented in Table 2-3, an average consumption for the campus would be represented by about 57.8×10^6 cu ft/year. This would be about $.158 \times 10^6$ cu ft/day or about 1.2×10^6 gal/day. Considering an average of about 10,000 students per day, this would indicate an average consumption rate of about 108 gal/person/day. By similar computation, the hospital complex shows a consumption of about 4.94×10^6 cu ft/year or about 100,000 gal/day. With 500 active beds, this becomes about 200 gal/bed/day.

General "rules of thumb"[1,2,3,4] indicate that general institutions such as the campus as a whole should consume city water in a range of from 50 to 150 gal/person/day, while hospitals should be rated at 100 to 250 gal/bed/day. Comparing these ranges to the above derived values, it is seen that GU is reasonably representative in its city water consumption with values being in the middle of the range of so called "rules of thumb" criteria.

2.5.2 Domestic Hot Water Distribution

There is no central domestic hot water (DHW) distribution system. Instead each building or group of buildings have local heat exchangers within which city water is heated by steam from the main steam distribution system. All but three of the buildings use storage tanks with continuous hot water circulation while the Concentrated Care Center and Darnall Hall and White-Gravenor have instantaneous heaters without storage tanks to meet the DHW demands. GU as a whole has begun to attend to all of the controls for DHW to limit its temperature to between 120 and 125°F, except for Darnall Hall and New South Hall where cafeteria dishwashing requirements require a higher level of about 140°F so that the local boosters can raise the DHW to the proper dishwasher temperature. The DHW in these two instances is controlled by mixing valves. During December of 1979 specific temperature readings of the various DHW systems were observed and it was noted that the temperature reduction program was generally effective, except for a few locations with special problems that had not yet been resolved. Specific data pertaining to DHW is available in tabulated form in the Appendix.

2.5.3 Domestic Hot Water Production

The total domestic hot water consumption for the entire GU campus was estimated to be about 110,000 gallons per day. This includes an estimated 18,000 gallons per day for the hospital complex. A listing of the estimated domestic hot water consumption of the various buildings evaluated by reference to standard published criteria is contained in the previously referenced tabulation included in Appendix H. The steam demand requirements for this load are included in the data presented in Exhibits 2-6 and 2-7. For lack of more specific data, it was assumed that this average daily DHW steam demand was constant throughout the year.

2.6 Electrical Consumption and Distribution

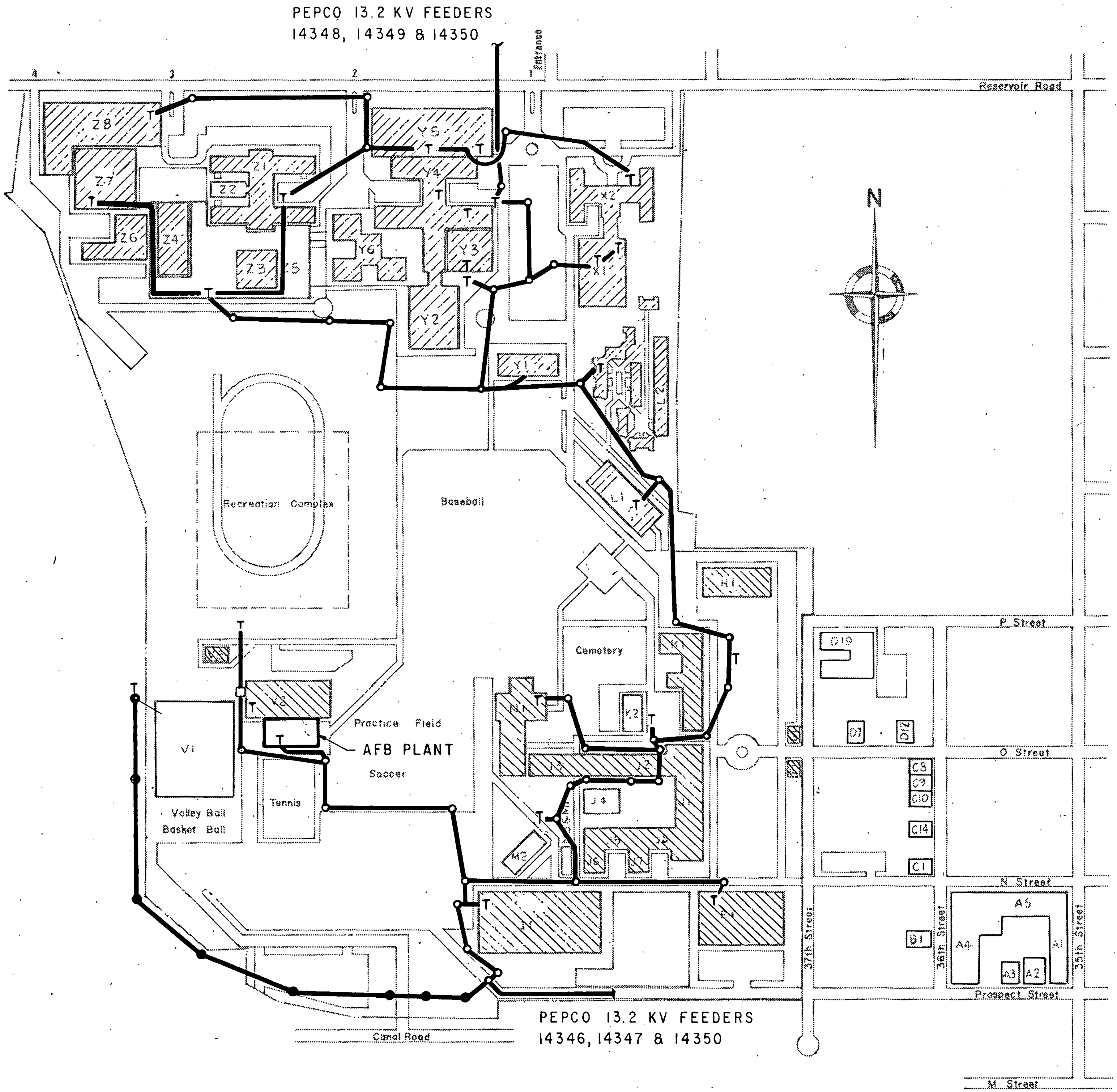
2.6.1 Electrical Distribution

The Potomac Electric Power Company, PEPCO, provides Georgetown University with six 13.2 kV feeders. The utility company has provided two metering stations located at two ends of the campus. Feeders 14348, 14349 and 14350 serve the north half of the campus through the North Substation located in the University Hospital. Feeders 14346, 14347 and 14350 furnish power to the south half of the campus through the South Substation located in the New South Hall. Demand on the six feeders which provide a major portion of the campus electrical energy is conjunctively metered. In addition, there are nine other buildings with services separately metered by PEPCO. The Heating and Cooling Plant is served by feeders 14346, 14347 and 14350 from the South Substation. Feeders 14346 and 14350 furnish power to the old gas-fired boiler plant, and Feeders 14346 and 14347 serve the new AFB plant. Since Feeder 14346 is common to both boiler plants, the cogenerator, discussed in Section 2.0 will, therefore, be tied to this circuit.

On-campus distribution is at 13.2 kV via underground ducts. The distribution network is arranged in such a way, that an outage on any one incoming feeder will cause the transfer of loads from the affected feeder to the remaining two still in service. Exhibit 2-24 shows the routing of the underground distribution.

2.6.2 Electrical Consumption

As of June 1979 the peak demand on the system has not exceeded 9400 kW. A profile of monthly demand and load factor is shown in Exhibit 2-25. Table 2-4 presents monthly energy consumption data for FY 1979 segregated into on-peak, intermediate and off-peak periods. Note that energy division



GEORGETOWN UNIVERSITY

A1	Loyola Hall
A2	Xavier Hall
A3	Ryder Hall
A4	Walsh Building
A5	Coleman Nevils Building
B1	Office Of Economics
C1	Bookstore
C8-10	Alumni' House
C14	Placement Office
D1-2	American Language Institute
D7	Black Student Alliance
D19	Poulton Hall
E1	Lauinger Library
F1	S. Gatehouse
G1	N. Gatehouse
H1	White - Gravenor
I1	New South Building
J1	Healy Building
J2	Old North Building
J3	New North Building
J4	Dahlgren Chapel
J5	Mulledy Hall
J6	Gervase Hall
J7	Ryan Hall
J8	Maguire Hall
K1	Copley Hall
K2	Ryan Administration Building
L1	Reiss Science Building
L2	Student Housing
M1	Garage
M2	O'Gara Building
M3	Mc Sherry Building
N1	Harbin Hall
V1	Mc Donough Gymnasium
V2	Heating & Cooling Plant
V3	Observatory
X1	Darnall Hall
X2	St. Mary's Hall
Y1	Kober Cogan Building
Y2	Gorman Building
Y3	Bles Building
Y4	Georgetown Hospital
Y5	Hospital Parking Garage (Deck 1)
Y6	Concentrated Care Center
Z1	Medical-Dental Bldg.
Z2	Medical-Dental Annex
Z3	Dalgren Library
Z4	Basic Science Building
Z5	Preclinical Science Building
Z6	Medical Center Vivarium
Z7	Dental Clinic
Z8	Hospital Parking Garage (Deck II)

LEGEND

T - TRANSFORMER LOCATION

- MANHOLE

- POLE

- SUPPLIED FROM PEPCO SERVICE TO HOSPITAL AREA

- SUPPLIED FROM PEPCO SERVICE TO NEW SOUTH HALL

- SERVED BY SEPARATELY METERED SERVICES

NOTE

PEPCO SERVICES TO HOSPITAL AREA AND NEW SOUTH HALL ARE CONJUNCTIVELY BILLED.

EXHIBIT 2-24

ELECTRICAL DISTRIBUTION SYSTEM

POPE, EVANS AND ROBBINS

MONTHLY ELECTRICAL DEMAND AND LOAD PROFILES (JULY 1978 - JUNE 1979)

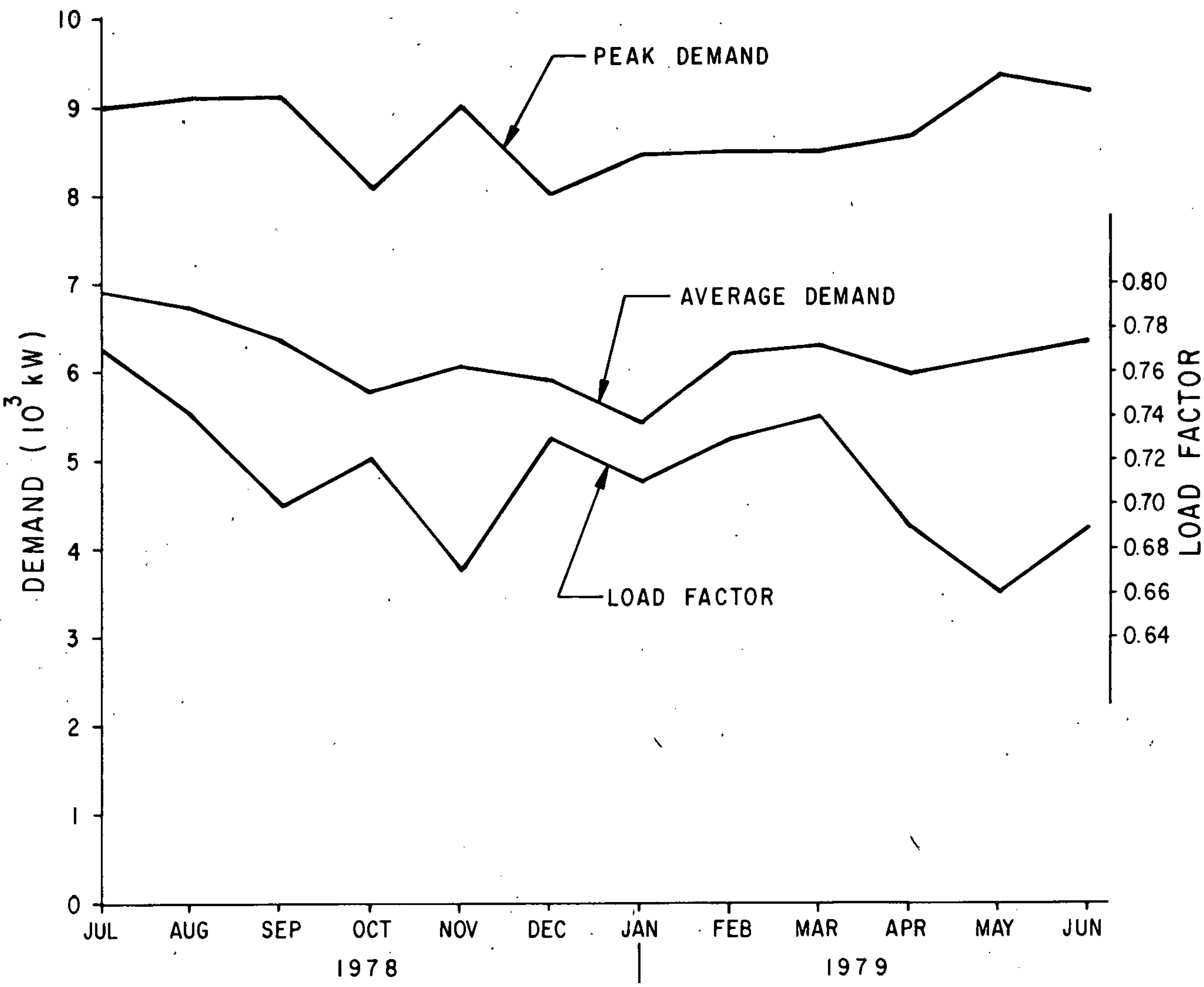


EXHIBIT 2-25

[redacted] [redacted]

TABLE 2-4

ELECTRICITY CONSUMPTION
BY TIME OF DAY

FY 1979

Billing Period	ON-PEAK		INTERMEDIATE		OFF-PEAK		
	10^3 KWH	Fraction of Total	10^3 KWH	Fraction of Total	10^3 KWH	Fraction of Total	Total 10^3 KWH
7/11/78 - 8/9/78	1,286	0.28	1,194	0.26	2,111	0.46	4,591
8/9/78 - 9/8/78	1,347	0.28	1,226	0.25	2,272	0.47	4,845
9/8/78 - 10/9/78	1,300	0.27	1,170	0.25	2,273	0.48	4,743
10/9/78 - 11/7/78	1,079	0.27	990	0.25	1,945	0.48	4,014
11/7/78 - 12/7/78	1,219	0.28	1,088	0.25	2,045	0.47	4,352
12/7/78 - 1/11/79	1,157	0.26	1,046	0.24	2,205	0.50	4,408
1/11/79 - 2/8/79	1,204	0.29	1,082	0.26	1,878	0.45	4,164
2/8/79 - 3/13/79	1,328	0.27	1,207	0.24	2,396	0.49	4,931
3/13/79 - 4/11/79	1,271	0.29	1,174	0.27	1,935	0.44	4,380
4/11/79 - 5/10/79	1,199	0.29	1,088	0.26	1,875	0.45	4,162
5/10/79 - 6/12/79	1,280	0.26	1,183	0.24	2,405	0.50	4,868
6/12/79 - 7/12/79	1,294	0.28	1,182	0.26	2,091	0.47	4,567
TOTAL	14,964	0.28	13,630	0.25	25,431	0.47	54,025

between on-peak, intermediate and off-peak periods for various months follows approximately a fixed pattern. On an average, approximately 28 percent of total electricity is consumed in the on-peak period, 25 percent in the intermediate period and the remaining 47 percent in the off-peak period. This generalization of energy consumption between the three periods resulted in a considerable simplification of the electricity cost model as derived in Section 1.3.5.

Off-peak hours are about half the total hours in a year and during this period, about half of the total electric energy is consumed. This condition warrants further investigation for potential energy conservation during a period when loads should be lower. It should also be noted that unless a facility operates with three full shifts, a high load factor is not desirable in that it shows that load has not been reduced during off-peak hour periods.

Exhibit 2-26 is a graph showing the GU electric load profile on several selected days as noted. Selected days such as this, from the supplied PEPCO computer data, were used to generate a load duration curve shown in Exhibit 2-27 and were averaged analogous to the steam and chilled water data, previously discussed, to obtain weekday and weekend day electric profiles for the six characteristic periods there identified. The results of this evaluation for the existing campus are shown in Exhibits 2-28 through 2-33 and were prepared for use in conjunction with future construction program impacts, cogeneration and thermal storage evaluations.

ELECTRICAL LOAD PROFILE FOR SELECTED DAYS

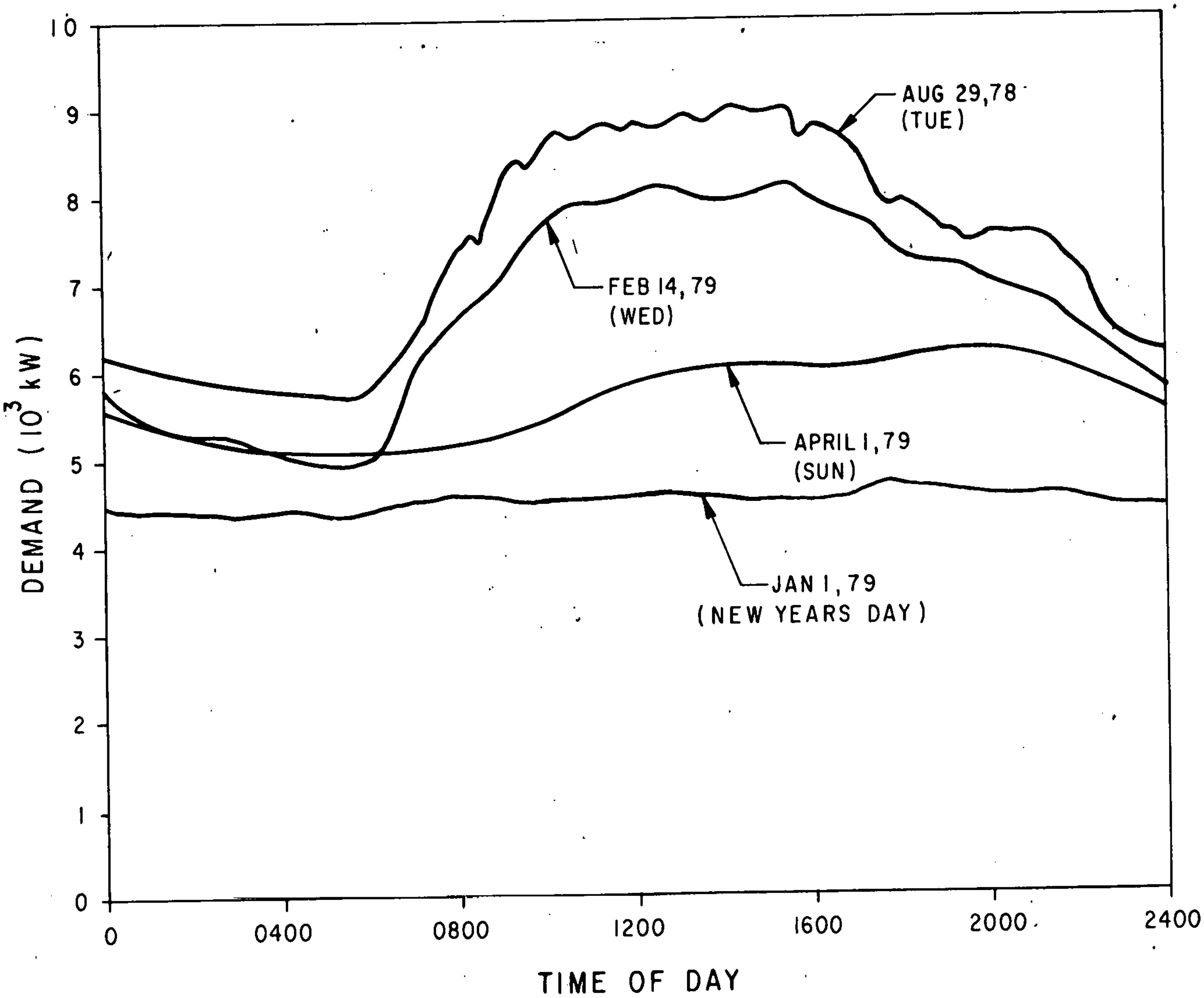


EXHIBIT 2-26

FY 79 ELECTRICAL LOAD DURATION CURVE

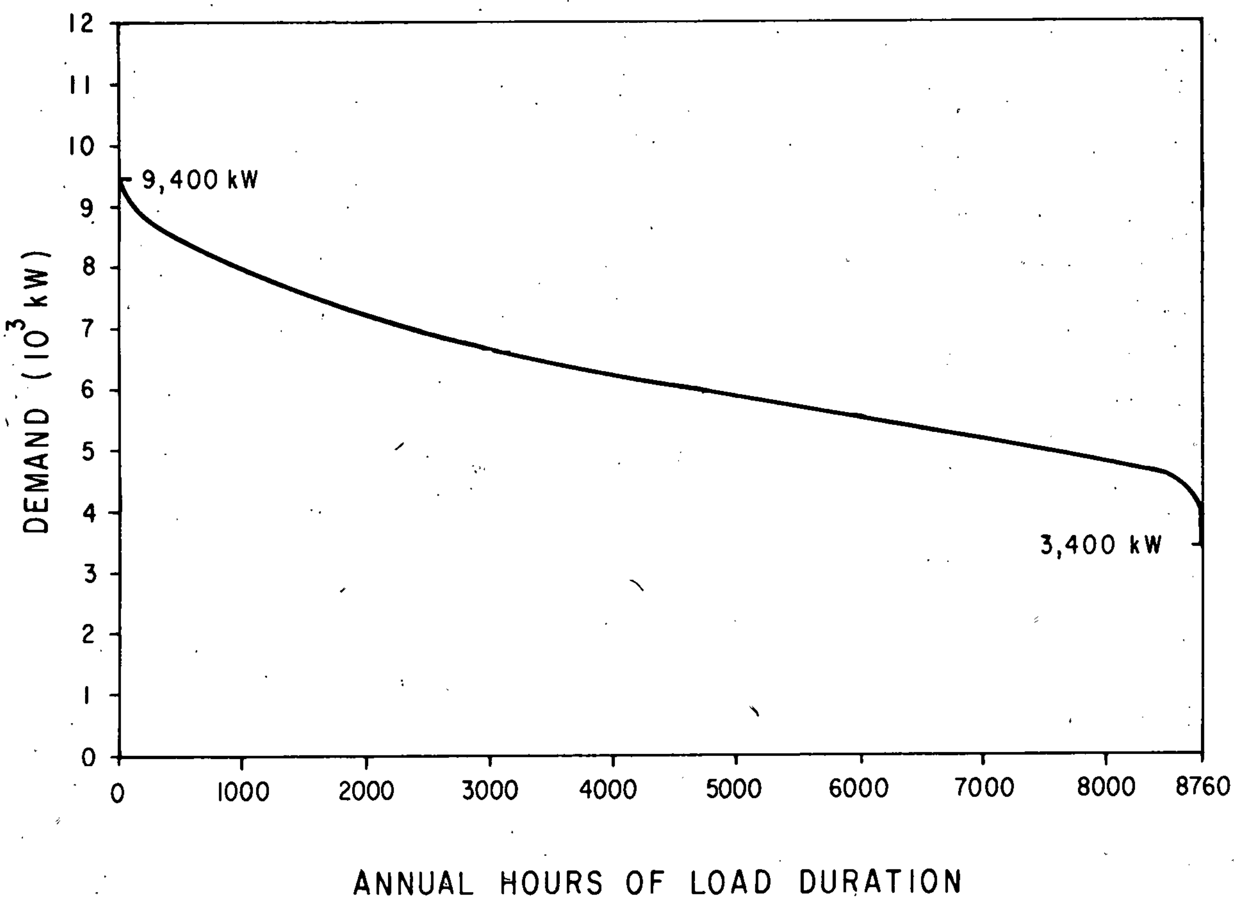
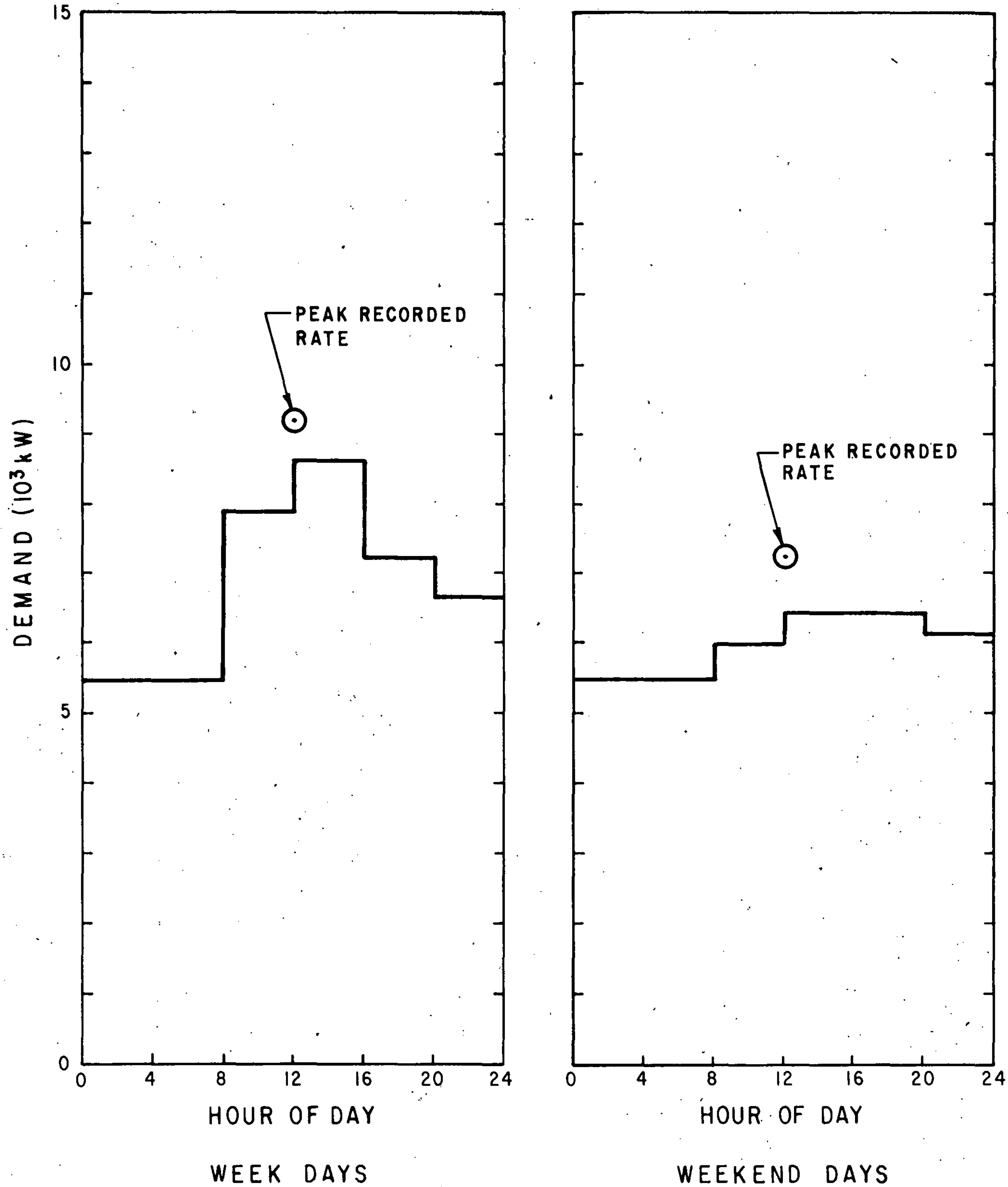
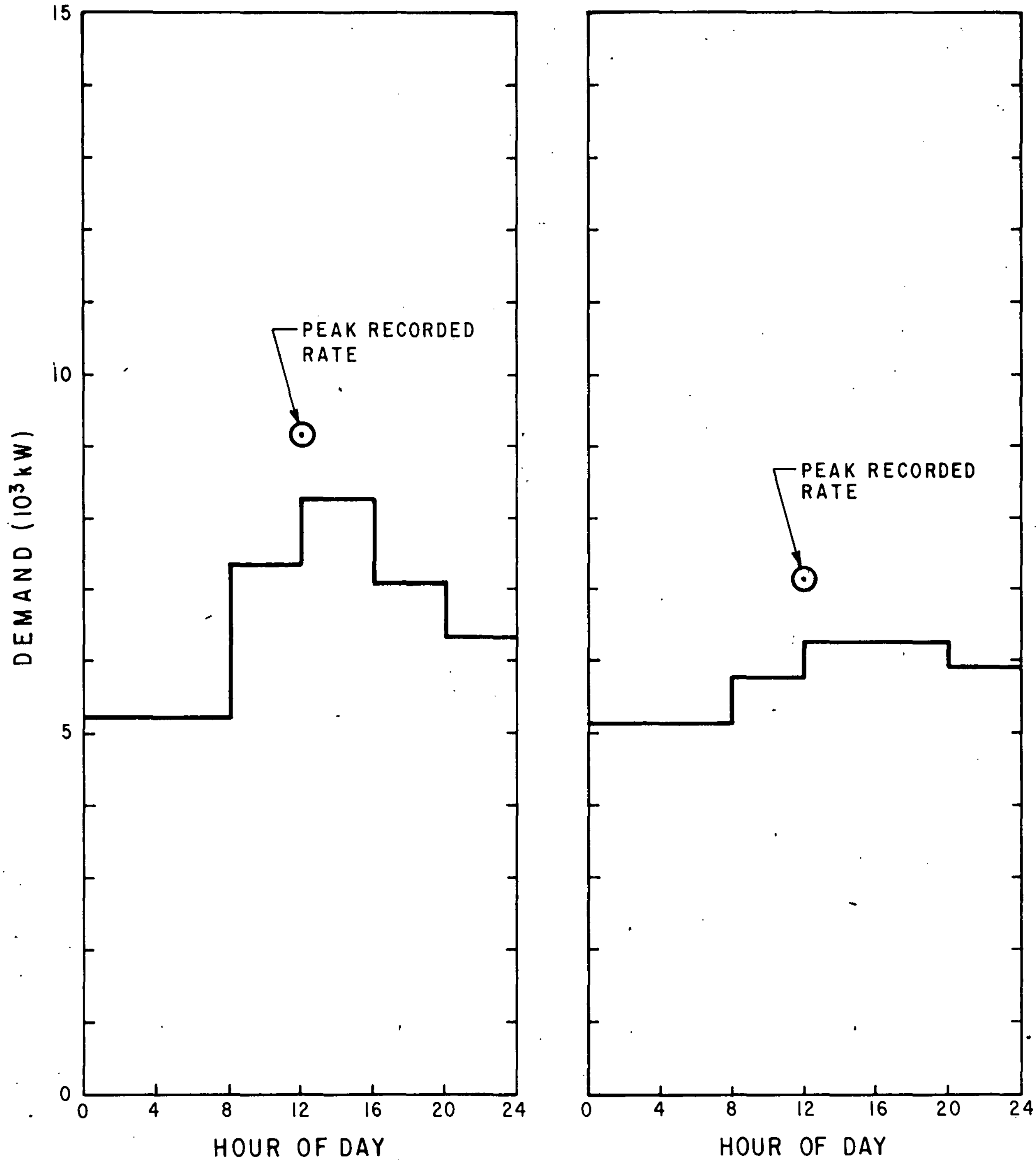


EXHIBIT 2 – 27

EXISTING AVERAGE DAILY ELECTRICAL DEMAND JULY AND AUGUST



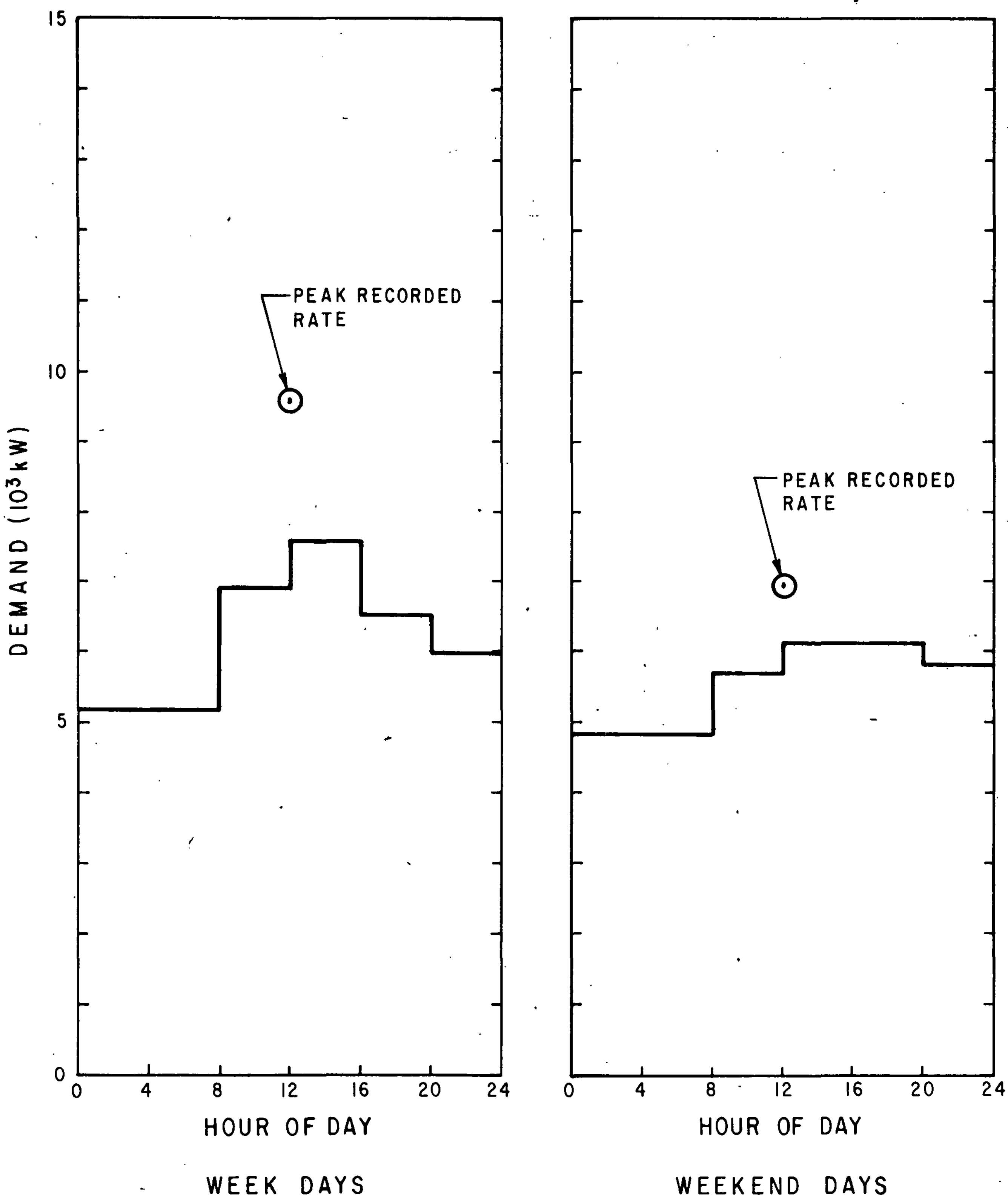
EXISTING AVERAGE DAILY ELECTRICAL DEMAND
JUNE AND SEPTEMBER



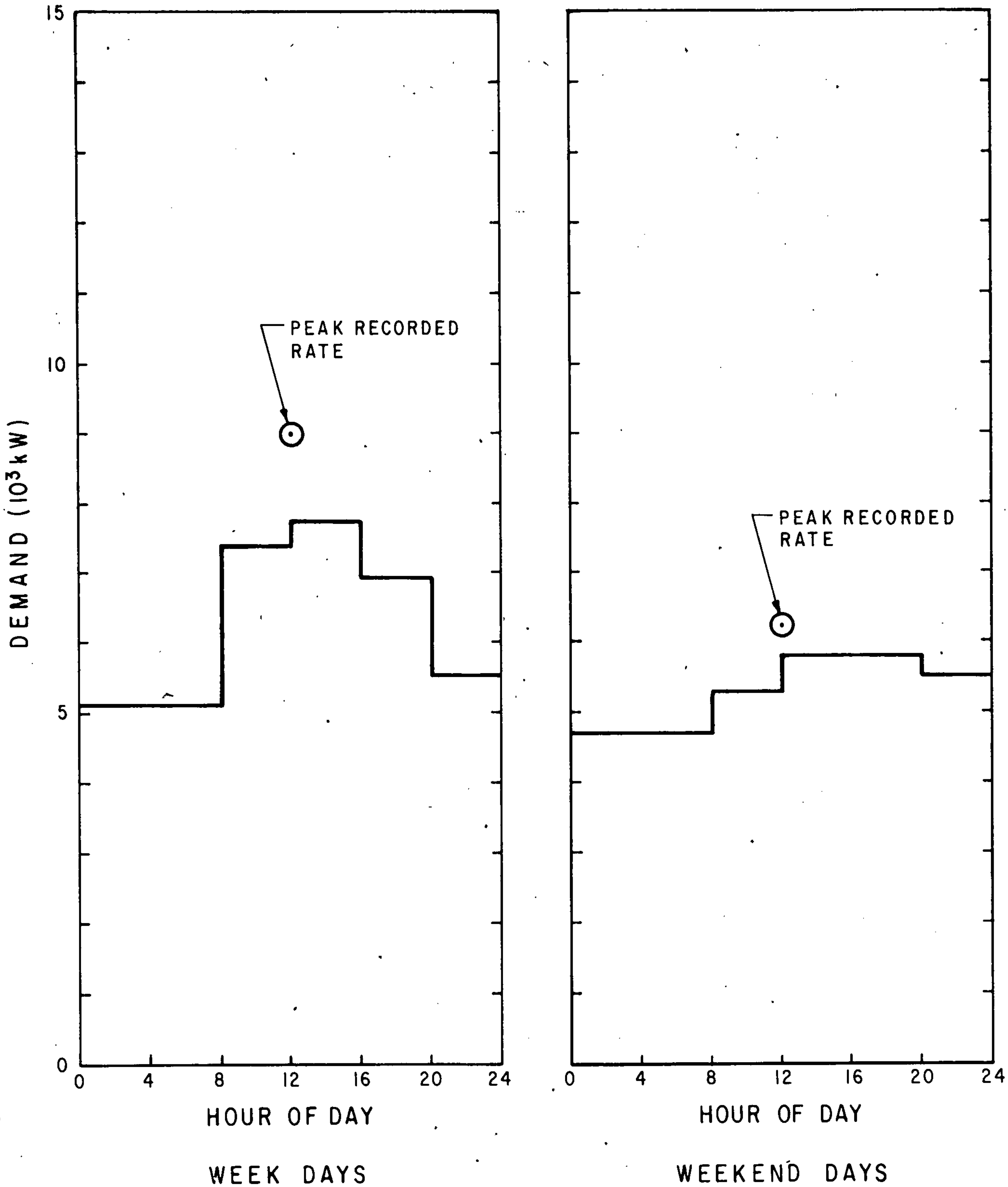
WEEK DAYS

WEEKEND DAYS

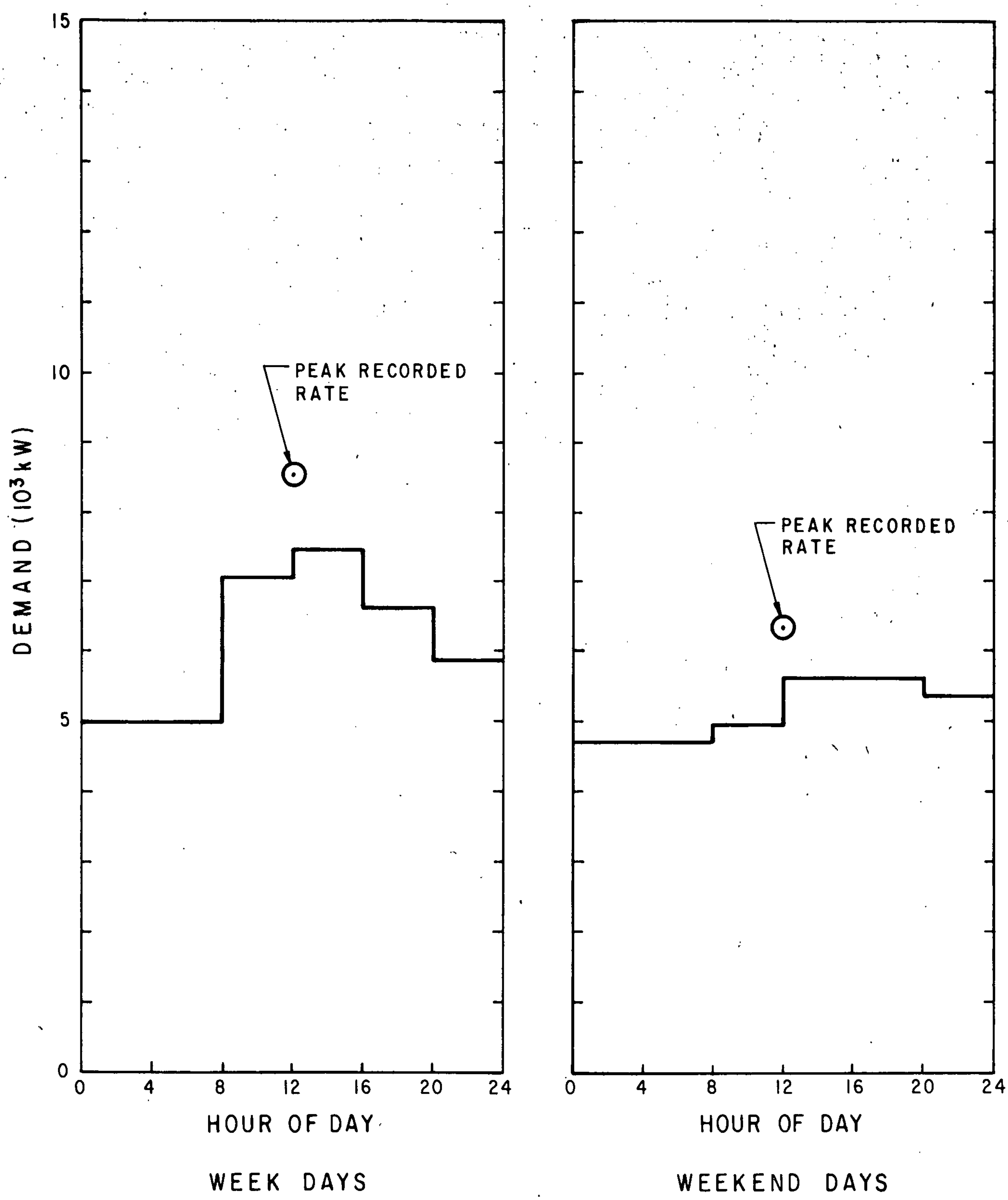
EXISTING AVERAGE DAILY ELECTRICAL DEMAND
MAY AND OCTOBER



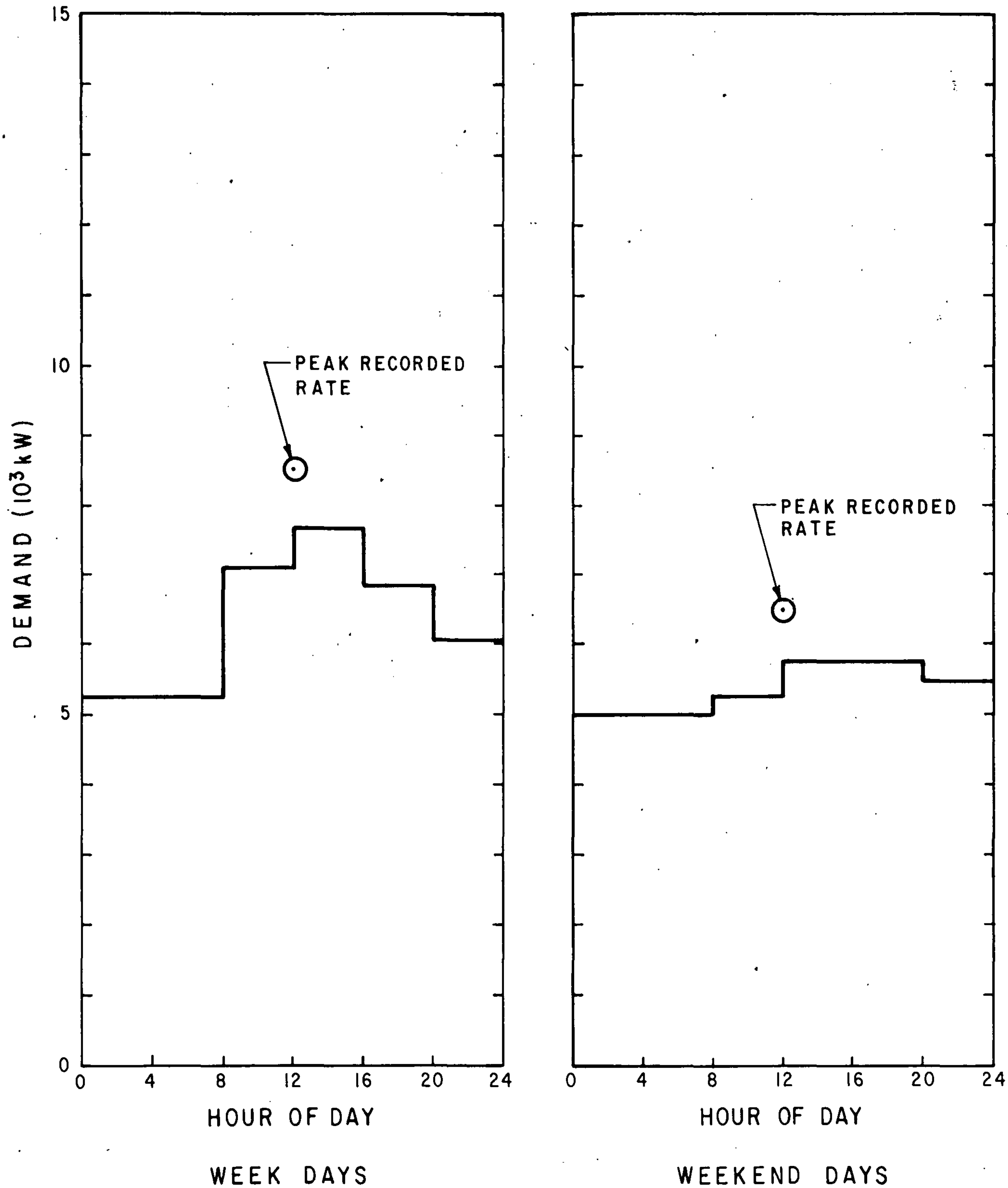
EXISTING AVERAGE DAILY ELECTRICAL DEMAND
APRIL AND NOVEMBER



EXISTING AVERAGE DAILY ELECTRICAL DEMAND
MARCH AND DECEMBER



EXISTING AVERAGE DAILY ELECTRICAL DEMAND
JANUARY AND FEBRUARY



2.7 Impact of Master Plan Construction Program

2.7.1 Components of Master Plan

Georgetown University is presently implementing a Master Plan construction program which will add approximately one million square feet of building area by 1984. The additional building floor space represents an increase of 32 percent over that which now exists. Table 2-5 summarizes the essential data relating to the expansion program based on discussions with the university's planners and as derived from additional information as it became available.

The new construction project locations are shown on Exhibit 2-3, a schematic of the steam distribution system, and Exhibit 2-19, a schematic of the chilled water distribution system. They can be identified by the name of the project next to the schematic representation of the proposed structure.

This new construction falls into two categories:

- Construction completed to date in FY '80, or due to be completed before early 1980; this includes the recently completed Yates Recreation Complex (143,000 sq ft), Wl, representing only a small heating and cooling load due to its underground construction; and Village "A", I2, (123,000 sq ft) a new town house style student residence complex in the south of the campus. It is presently partially occupied and is connected to the campus chilled water steam and electrical networks. Accommodation for 510 students will be available.

TABLE 2-5

MASTER PLAN CONSTRUCTION THROUGH 1984

Proposed Construction	Completion Date	Building Data: Area sq.ft.	Roof	Floors* Above	Floors* Below	Occupancy	Utility Requirements: Electric (kW)	Ch.Water (Tons)	Htg. & DHW (Btu/sf/yr)
Yates Recreation Center	1979	134,000	Flat Astro Turf Football Field	0	1 & 2	Athletics and Recreation	Not Available	-	Not Available
Village "A"	1980	123,000	Flat Staggered	2-3	0-1	Residence for~510	300	250	150,000
Lombardi Center	1981	100,000	Flat	2	3	Cancer Research, Labs, Offices, Classrooms	500	350	200,000
Intercultural Center	1982	176,000	Sloped, Solar Panels	2-3**	1-2	Offices, Classrooms, Auditoriums	600	650	55,000
Coleman-Nevils Renovation	1982	73,000	Flat	4	1	Offices, Residence for~200	Assumed as Existing	-	200,000
Core-ICES	1982		Flat, Grass Soccer Fields	3**	1	Parking, Thermal Storage	200	-	-
Village "B"	1982	120,000	Flat Staggered	2-3	0-1	Residence for~360	300	250 (ABS)	150,000
University Center	1983	110,000	Flat	2	1	Student Union, Offices, Ballroom, Conf. Rooms, Restaurant	400	300	200,000
Scholar Housing	1984	26,000	Sloped, Solar Panels	2		13 Houses	100	-	Good Insulation
Executive Conference Center	1984	200,000	Flat Observ. Deck	5**	1	Conference Rooms, Offices, Personnel, Security	750	750	150,000

* Above and below refers to grade level.
**Above ground on south side of building; below ground on north side of building.

- Construction not yet begun; this includes all of the other planned construction and renovation programs listed and discussed below.

The Lombardi Center (100,000 sq ft), Y7, a medical/educational facility with an emphasis on cancer research is about to enter construction. Consisting of five stories, with three below ground and two above, there is not planned to be a 65°F temperature restriction on the structure due to the nature of its use. This building will be connected to the main campus electric, steam and chilled water distribution systems. It is scheduled for completion in the Fall of 1981.

The Intercultural Center (176,000 sq ft), L3, is a unique structure partly above ground and partly below ground with the entire sloped roof covered with photovoltaic solar panels capable of producing up to 600 kW of electric power, sufficient to meet its own needs at peak production. Electrical interconnection to the main campus grid is planned. In addition, the building design hopes to achieve an energy consumption load limited to 55,000 Btu/sf annually. Primary occupancy will be classrooms, auditoria and offices. Connection to the main plant steam and chilled water systems are planned. Completion date is anticipated prior to the Spring of 1982.

The Coleman-Nevils Renovation (73,000 sq ft), A5, involves refurbishment of an existing off-campus structure currently being used for offices and classroom space into a combined classroom and apartment unit, capable of housing slightly over 200 students. It will remain connected to the present steam distribution system and will continue to have separate electrical metering. There are no plans to extend the chilled water system to this location. Completion is projected for the Fall of 1982.

Core ICES, R1, is the name given to the multipurpose structure to be located at the heart of the campus. This structure will primarily be viewed as a large, three-story parking facility with space for about 2200 cars, covered with a green athletic field devoted to the sport of soccer. Within its foundations and supporting structure will be housed compartments for thermal storage designed to incorporate this present state-of-the-art energy concept into the integrated community energy production and distribution systems. This construction program is also slated for a Fall 1982 completion.

Village "B" (122,000 sq ft), C5, is to be comparable to Village "A" and will consist of 72 town house units housing about 360 students. The reduced population density of "B" as compared to "A" is in part due to the fact that about 50% of this complex is aimed at accommodating handicapped individuals in suitably supervised quarters. This complex will be off the main campus, just outside the main gate, and connection to the main plant steam distribution network is planned. Other services will be separately supplied and metered. Completion is scheduled for the Fall of 1982.

The University Center (110,000 sq ft), M4, housing a student union, ballrooms, resturants, game rooms, offices and other miscellaneous student functions is planned for construction on or around the site of the first GU erected structure, the McSherry Building. It is intended to be connected to all three campus energy systems, the steam, chilled water and electric distribution systems. Completion by 1983 is anticipated.

Scholar Housing (26,000 sq ft), F2, an estimated 13 houses just inside the main gate for visiting scholars, is a project being considered. An electric tie-in to the main campus system for these all electric houses is intended. Provisions for solar application by using sloped roofs are contemplated. Heat pump application is also being considered. Completion would be sometime in 1983 or 1984.

An Executive Conference Center/New South Entrance (200,000 sq ft), V1, with a new total three-way traffic interchange at the present Canal Street entrance is planned to provide the campus with easier access. A potential Metro terminal as a result of using an existing right-of-way is a strong possibility. All central services, namely steam, chilled water and electricity are planned for this proposed facility. Completion in 1984 is planned.

2.7.2 Impact of New Construction

The increased occupied floor space of nearly one million square feet will represent an additional burden on the campus energy systems which presently service a little over three million square feet. The nature of the construction and use and the heating and cooling requirements of the new space require the following increases in distribution of energy:

- A 30 percent increase in space heating is estimated using the increase of occupiable floor area directly.

- A 40 percent increase in cooling is estimated based on the ratio of additional conditioned floor area due to new construction to the floor area now conditioned by the main plant.

- A 25 percent increase in electrical consumption is estimated based on an 80 percent diversity factor applied to the maximum additional kilowatt rating of each new structure. This factor was felt adequate due to the heavy reliance for cooling on the main plant chilled water system.

2.8 Bases for Evaluation of Alternate Subsystems

2.8.1 General

The source data for the existing GU campus and its reduction to usable form has been presented in Sections 2.1 through 2.6. The impact of new construction, according to the GU master plan, was addressed in Section 2.7. Application of the adjustment factor results of Section 2.7 to the findings of the other sections will yield data upon which evaluations for the 1984 campus can be based. Since chilled water loads increased by about 40 percent and heating demands increased by about 30 percent, the resulting total steam production was adjusted by a factor which varies from about 1.36 in the summer to 1.3 in the winter. The electric load is simply related by the factor of 1.25 reflecting the 25 percent diversified increase expected. Any cogeneration or photovoltaic generation when active, will reduce the PEPCO purchase requirement and was not included in the presentation of 1984 loads. Further electrical savings can be realized by avoiding on-peak consumption as much as possible or shifting it to off-peak periods. Photovoltaic generation, cogeneration and thermal storage are vehicles which can be used to achieve this result.

Average results are predicted when applying the adjustment factors of Section 2.7.2. Since National Weather Bureau data indicates up to ± 10 percent variations about means, the maximum conditions to be considered must be increased by 10 percent. FY 1978 was close to one of those +10 percent deviation years from mean data. The results presented in the remainder of this section are representative for mean weather data.

2.8.2 Steam Data

The 1984 adjusted average steam consumption profile for the six characteristic periods previously defined in Section 2.3 is shown in Exhibits 2-34 and 2-35. Exhibit 2-34 shows average monthly steam generation while Exhibit 2-35 shows this same data expressed as hourly steam generation. The subdivision to show corresponding steam utilization by chilled water production, space heating, domestic hot water, etc., is analogous to that presented in Section 2.3. Exhibit 2.5 showed the individual average monthly steam generation data prior to the formation of the six characteristic periods and the expected additional steam generation for each individual month is also included there for completeness.

Exhibits 2-36 and 2-37 show the seasonal and annual steam load duration curves used for 1984 campus evaluations. These exhibits follow the same format as those presented in Section 2.3.2. These data were used in cogeneration analyses.

Daily average steam profile data for the 1984 campus for the six characteristic periods is presented in Exhibits 2-38 through 2-43. This data was used in the evaluation of cogeneration and benefits of thermal storage by minimizing gas/oil boiler operation and operating electric chillers at off-peak hours.

2.8.3 Chilled Water Data

The 1984 adjusted chilled water consumption maximum value based on results of Sections 2.4.2 and 2.7 is expected to be about 6750 tons of refrigeration. This value is obtained by dividing the maximum 1984 projected chilled water steam flow of 88.2 x 10 lb/hr by 14.4 lb/hr/ton of refrigeration and increasing this by 10 percent. The 10 percent increase is in accordance with National weather Bureau data which shows weather data to vary ± 10 percent

1984 AVERAGE MONTHLY STEAM PRODUCTION AND CONSUMPTION ALLOCATION

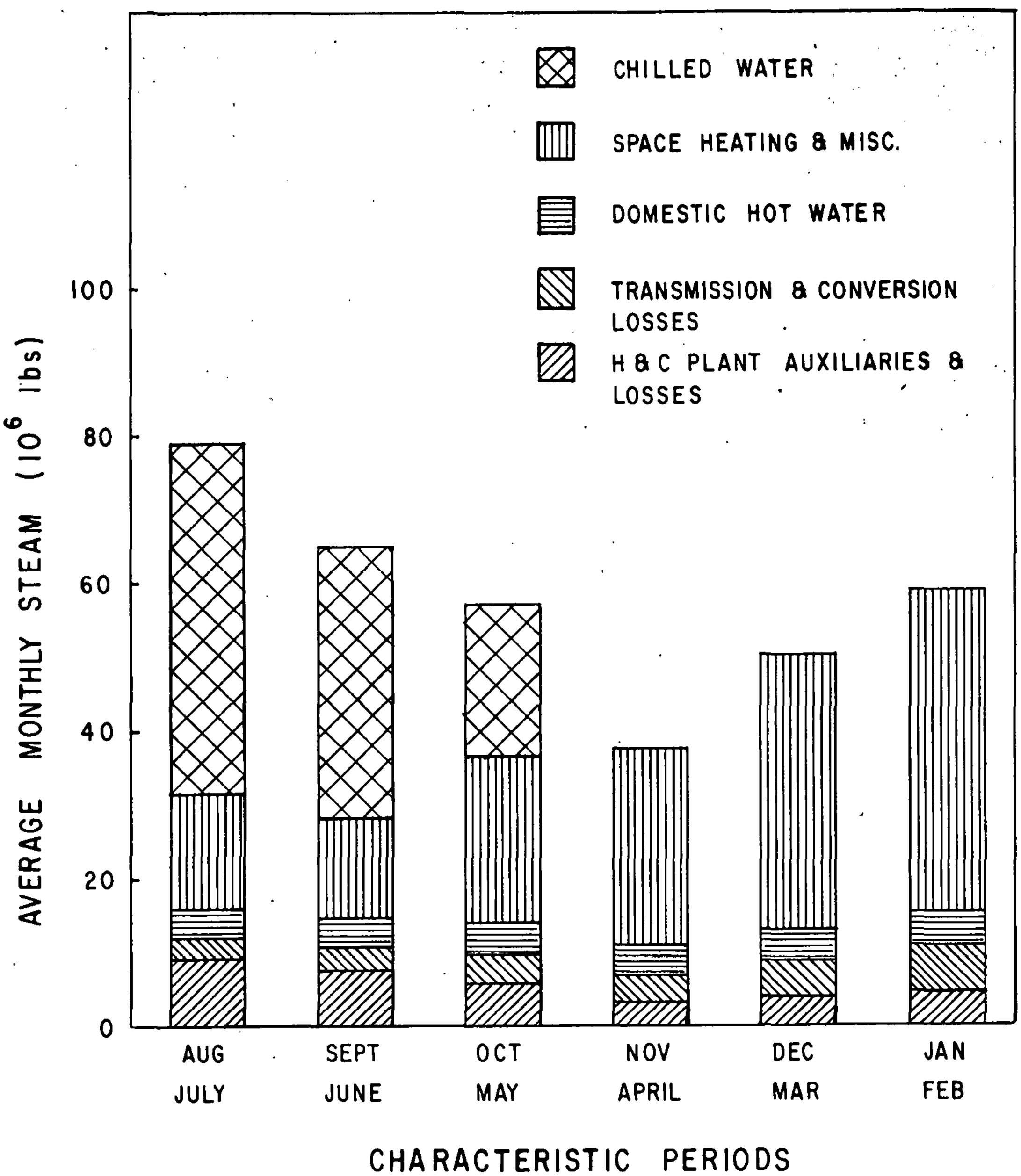
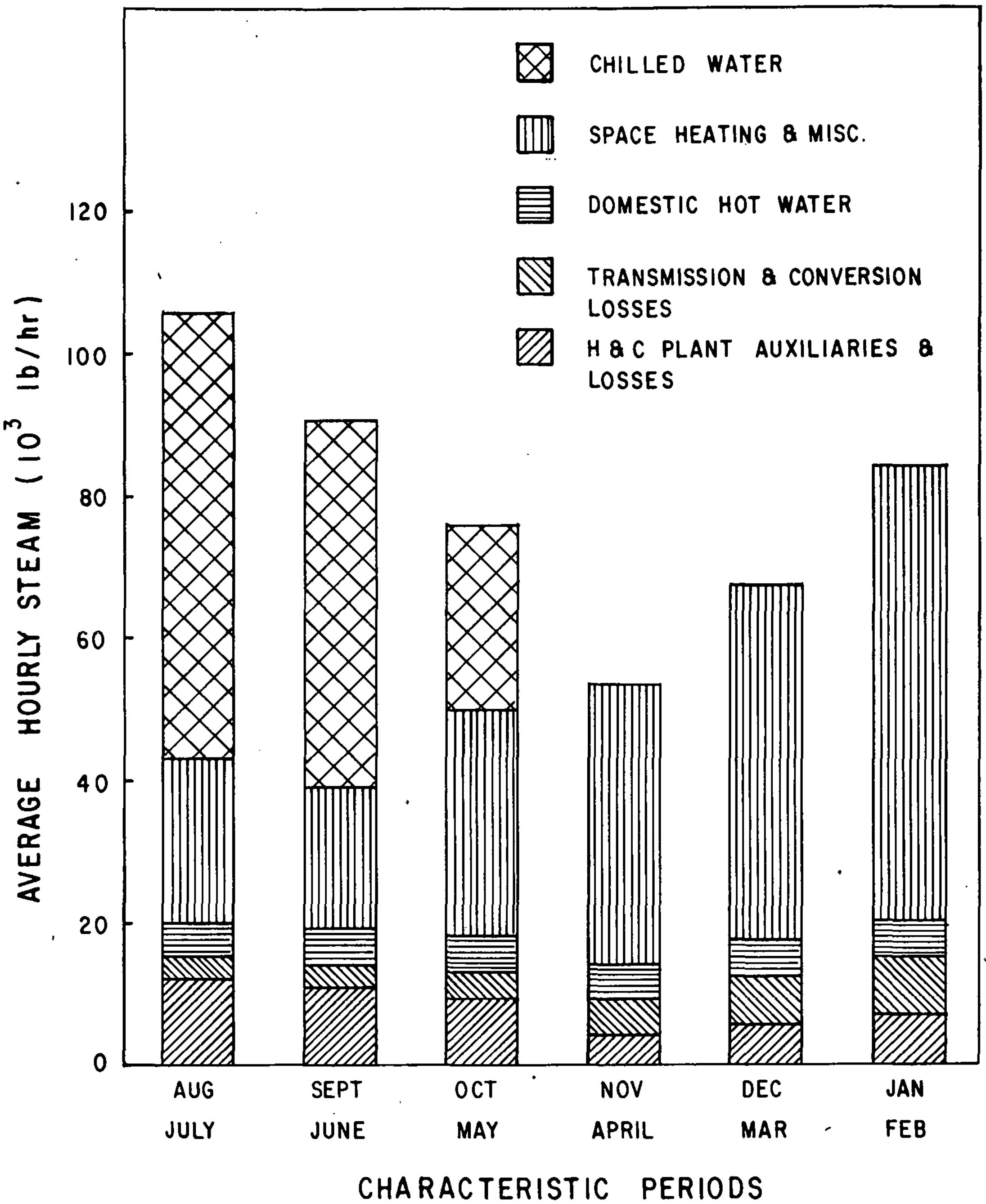


EXHIBIT 2-34

1984 AVERAGE HOURLY STEAM PRODUCTION AND CONSUMPTION ALLOCATION



PROJECTED 1984
SEASONAL STEAM LOAD DURATION CURVES

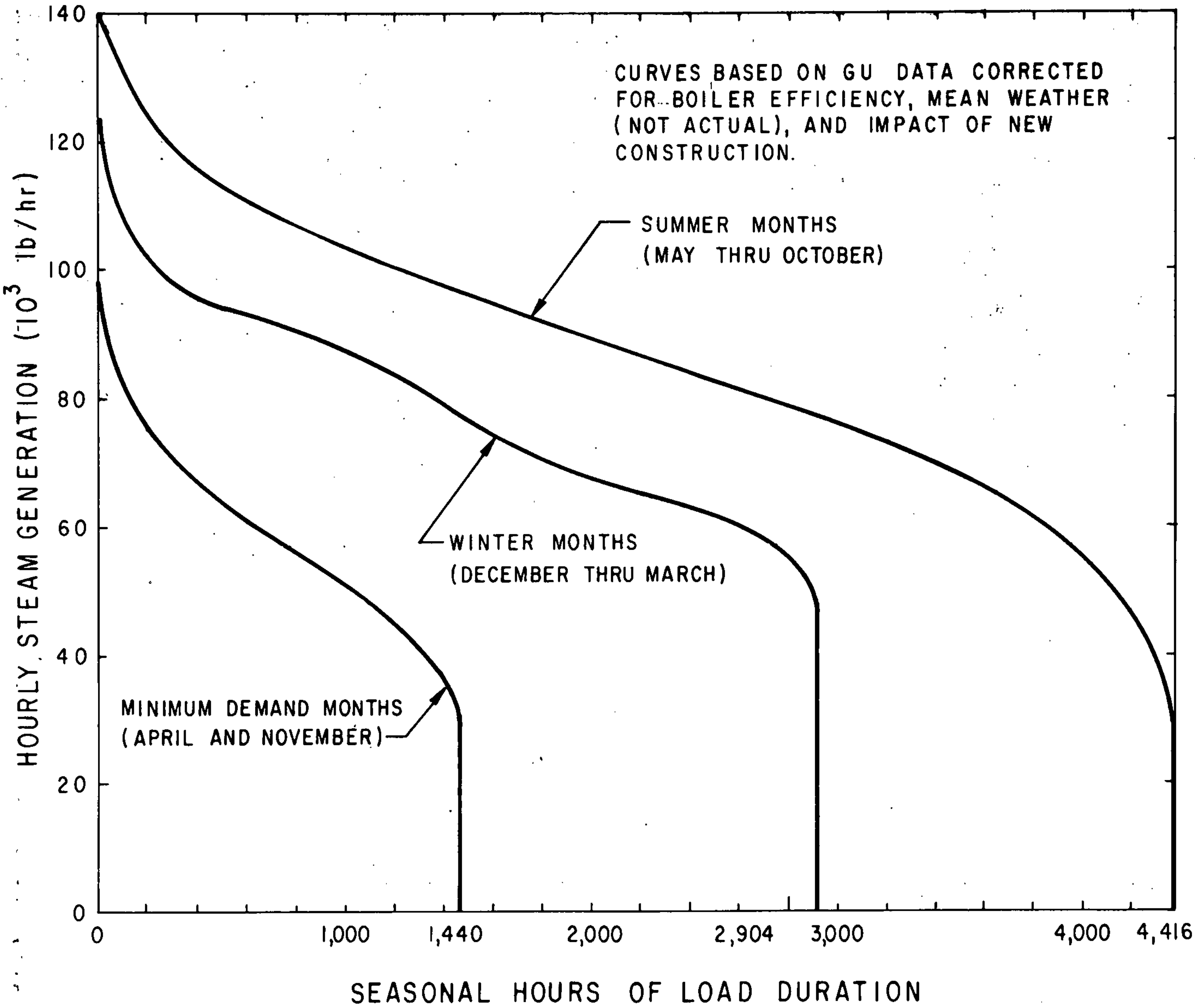


EXHIBIT 2-36

PROJECTED 1984
ANNUAL STEAM LOAD DURATION CURVE

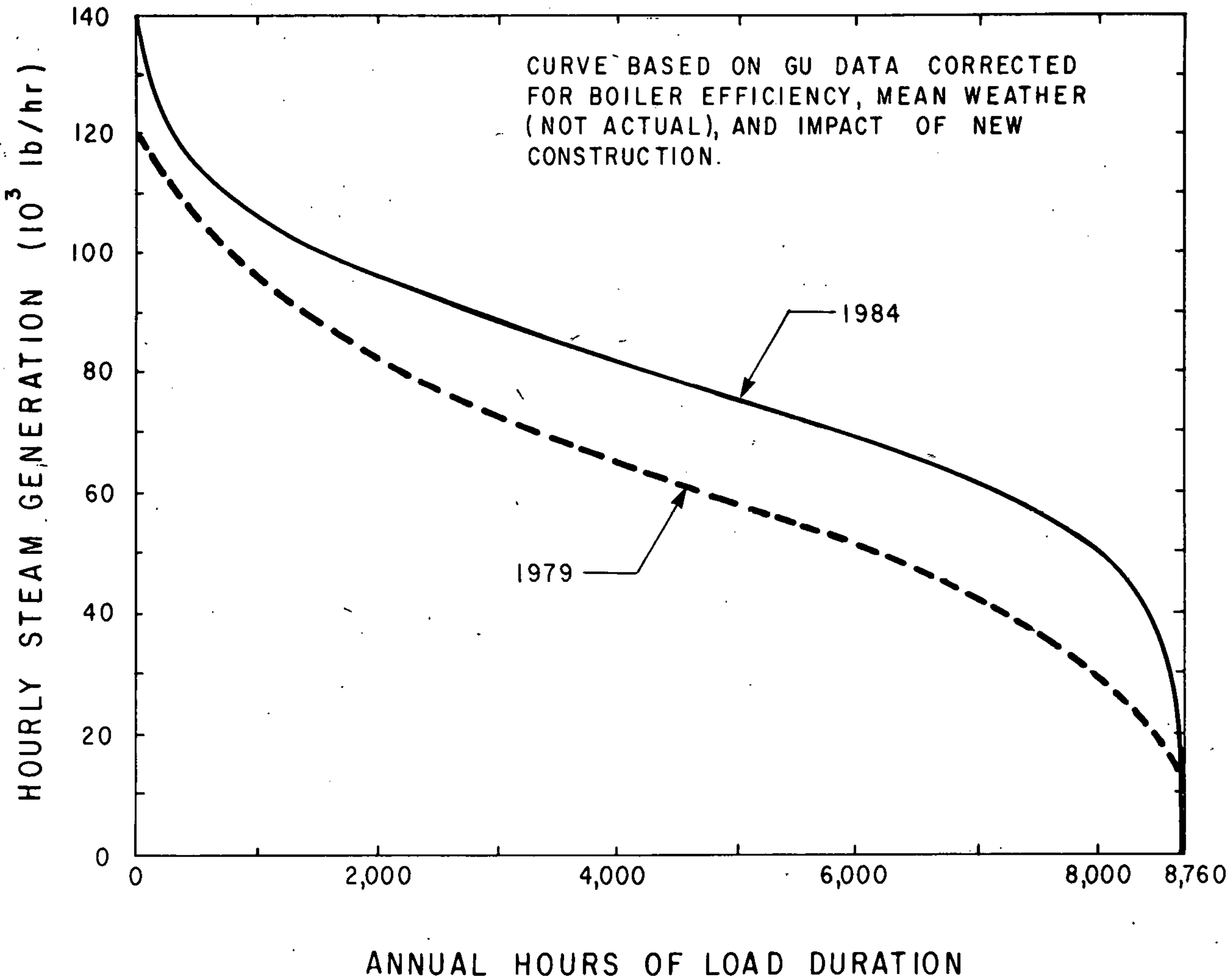
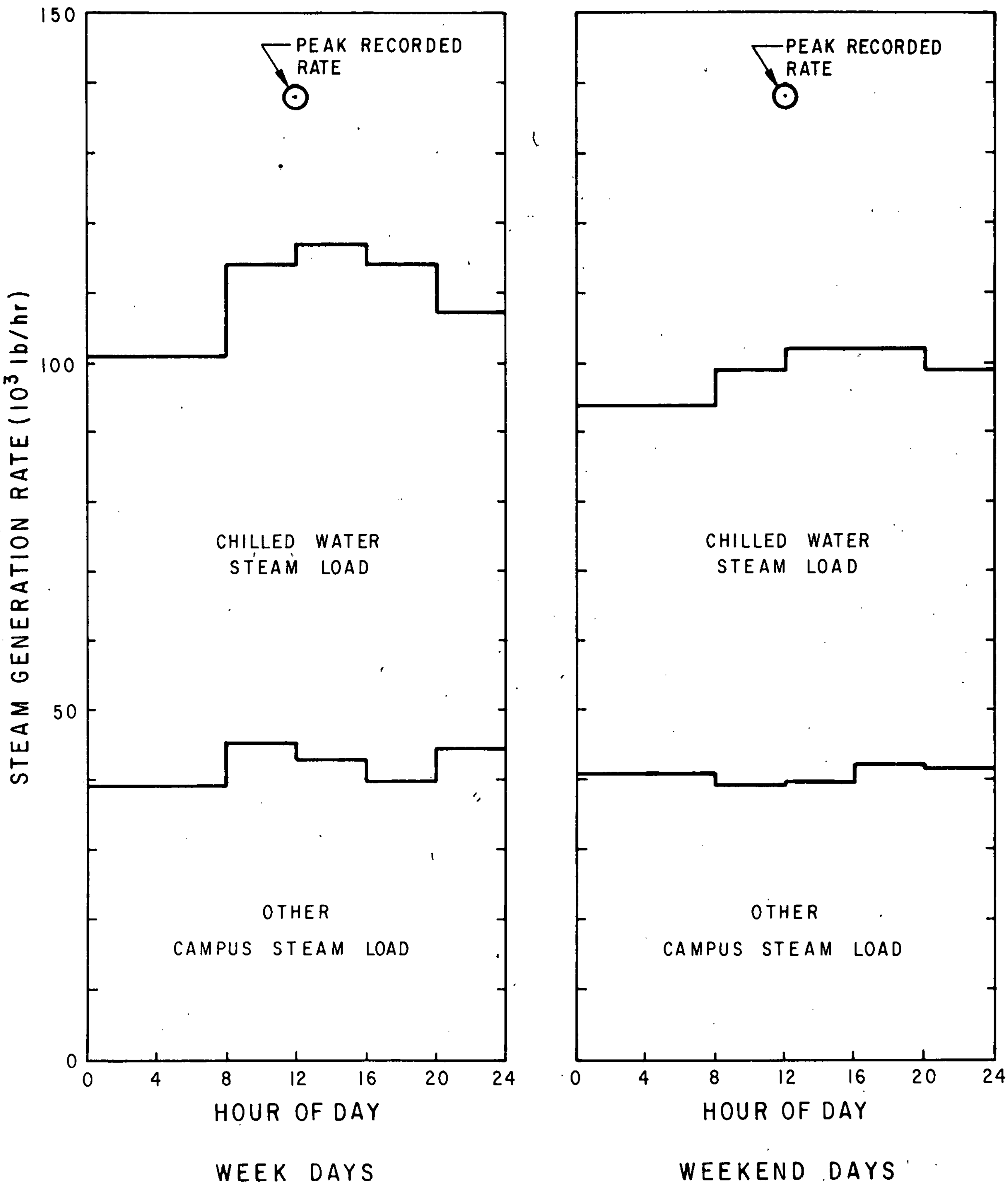
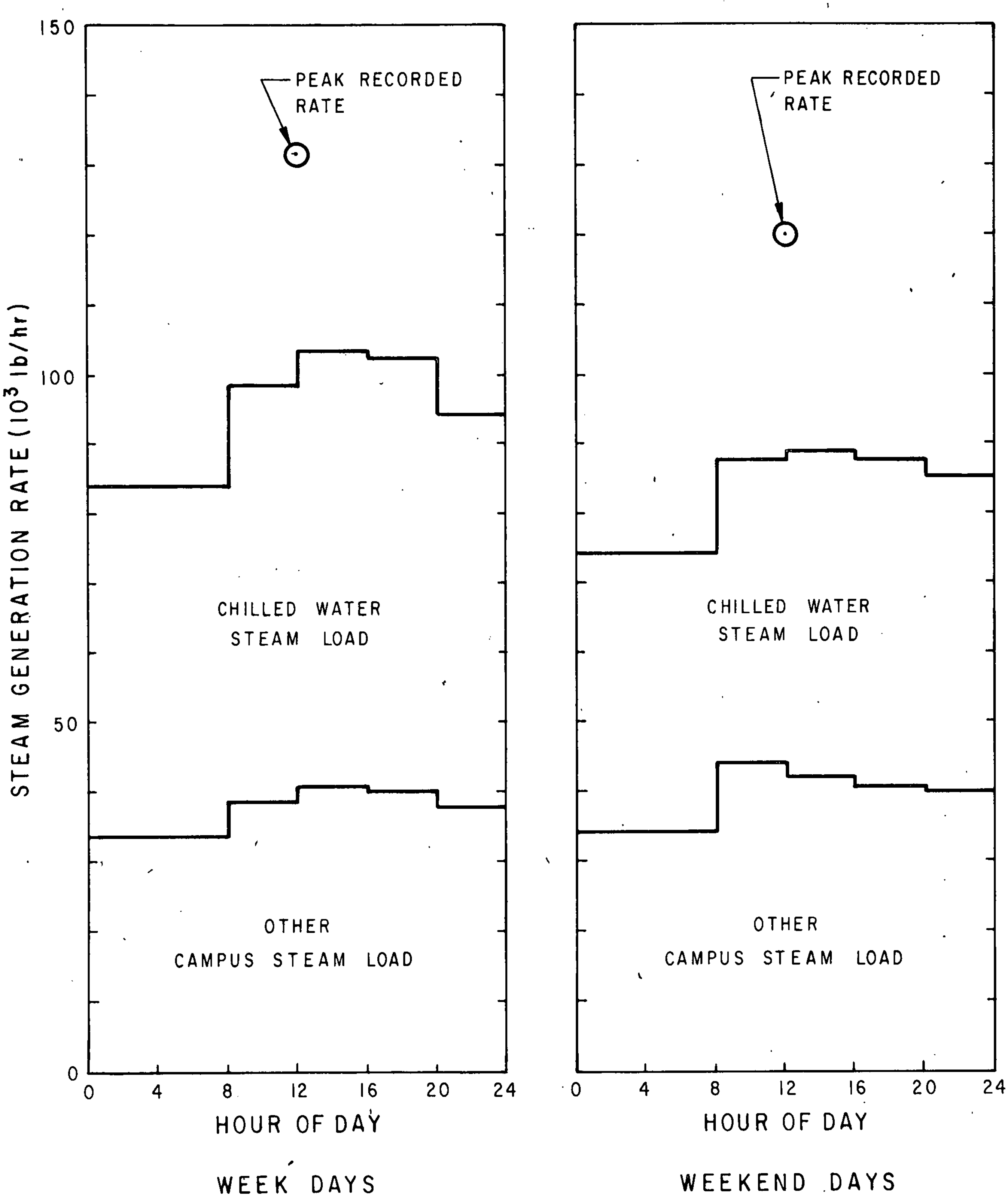


EXHIBIT 2-37

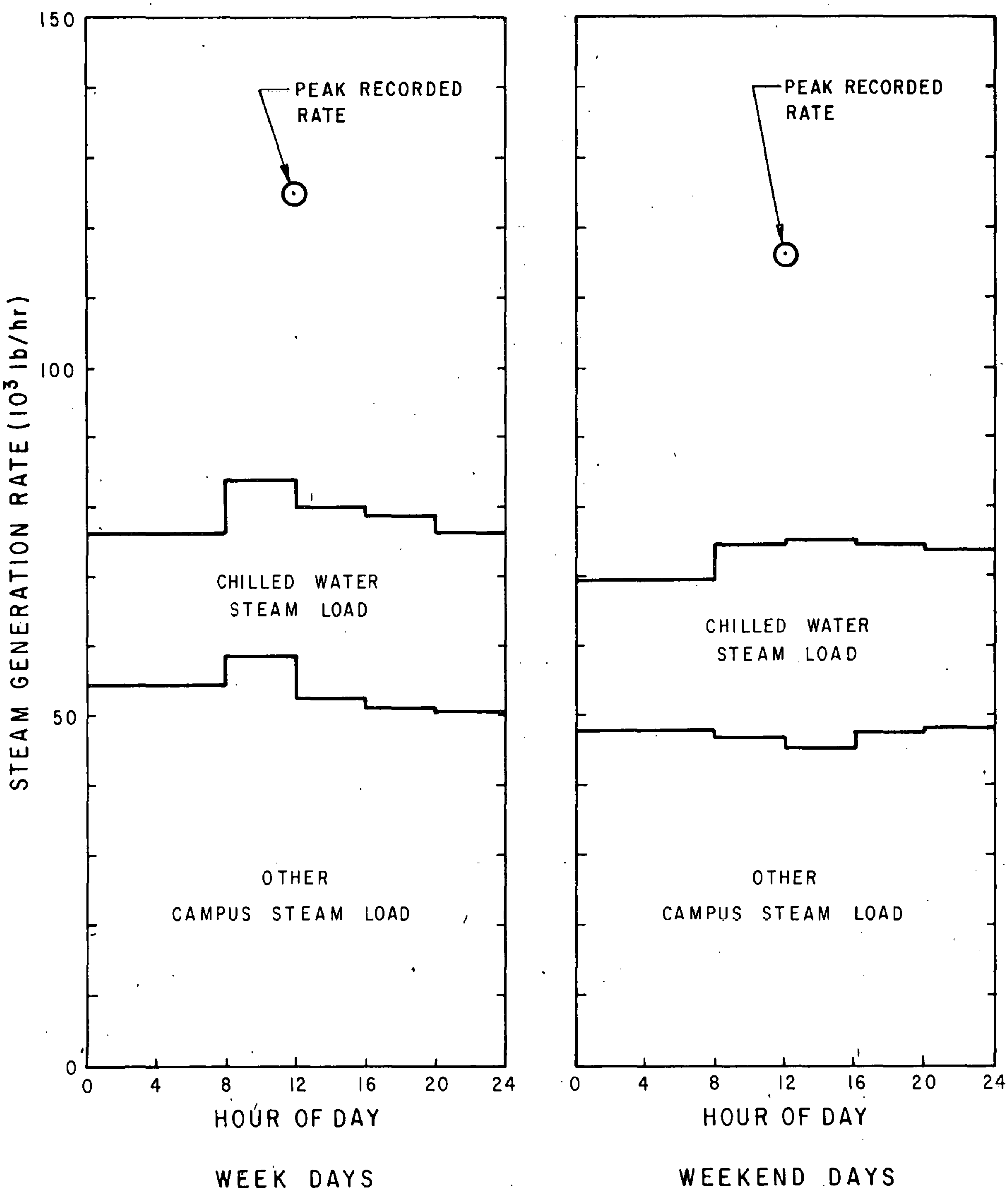
1984 AVERAGE DAILY STEAM PRODUCTION
JULY AND AUGUST



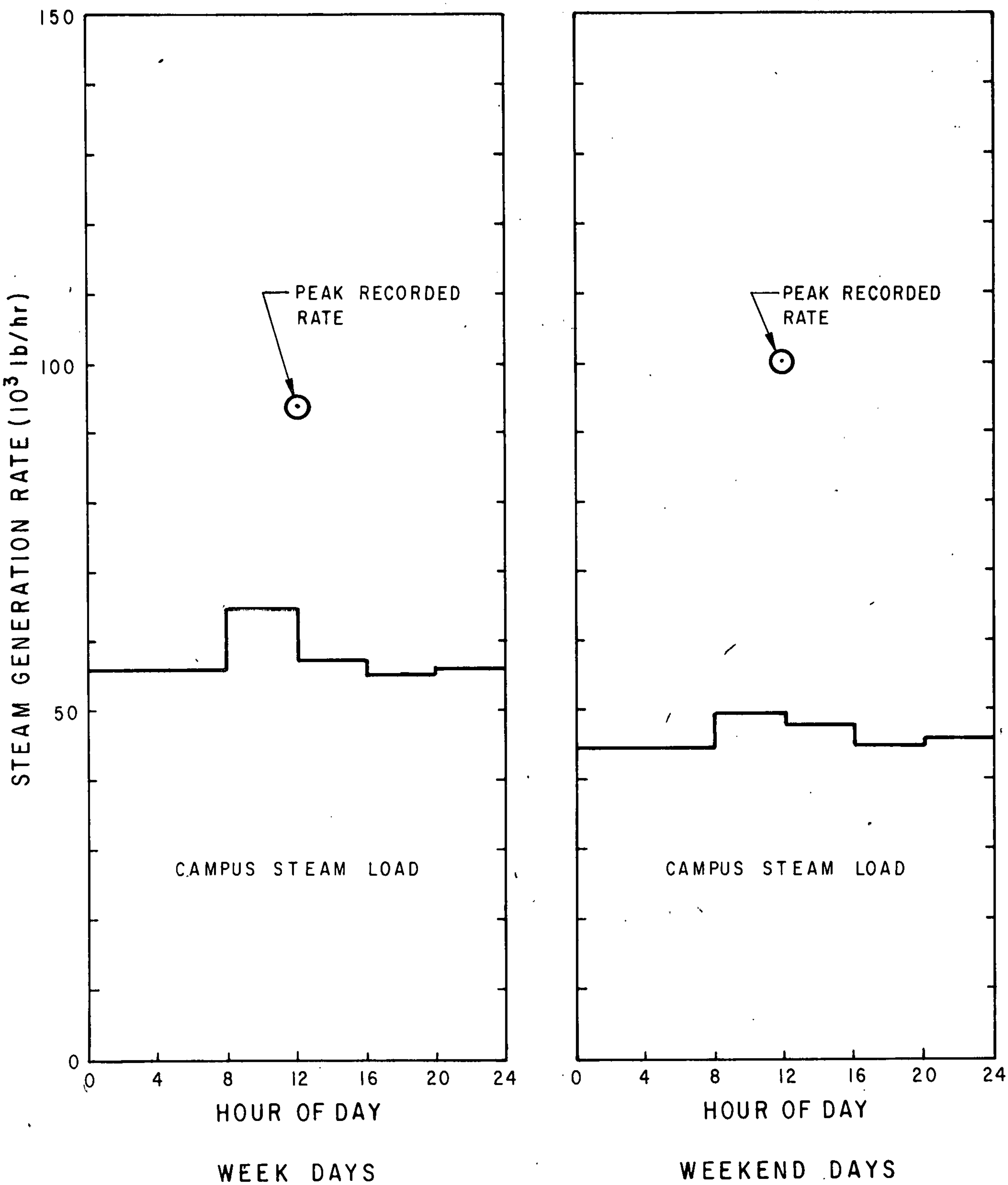
1984 AVERAGE DAILY STEAM PRODUCTION JUNE AND SEPTEMBER



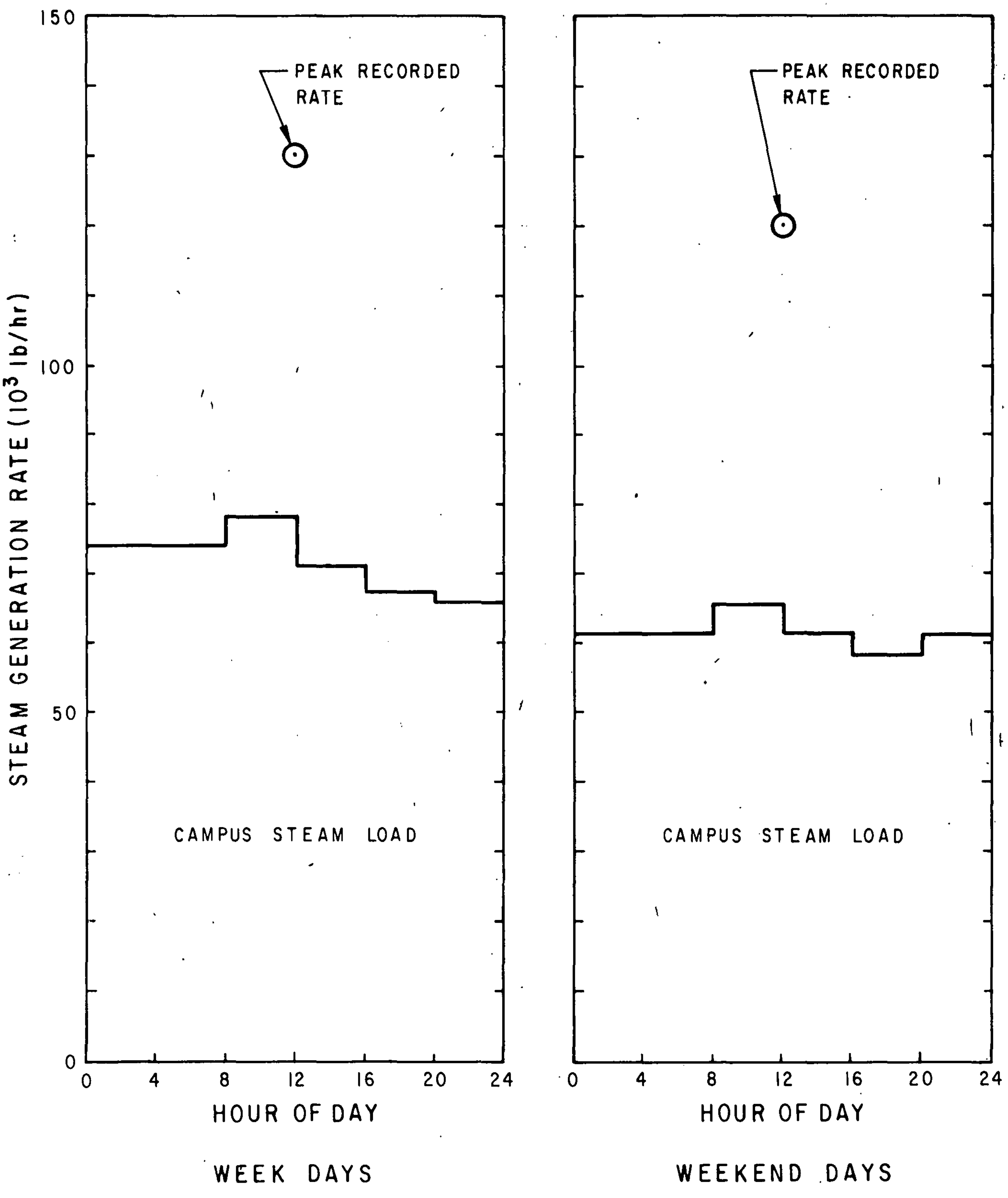
1984 AVERAGE DAILY STEAM PRODUCTION
MAY AND OCTOBER



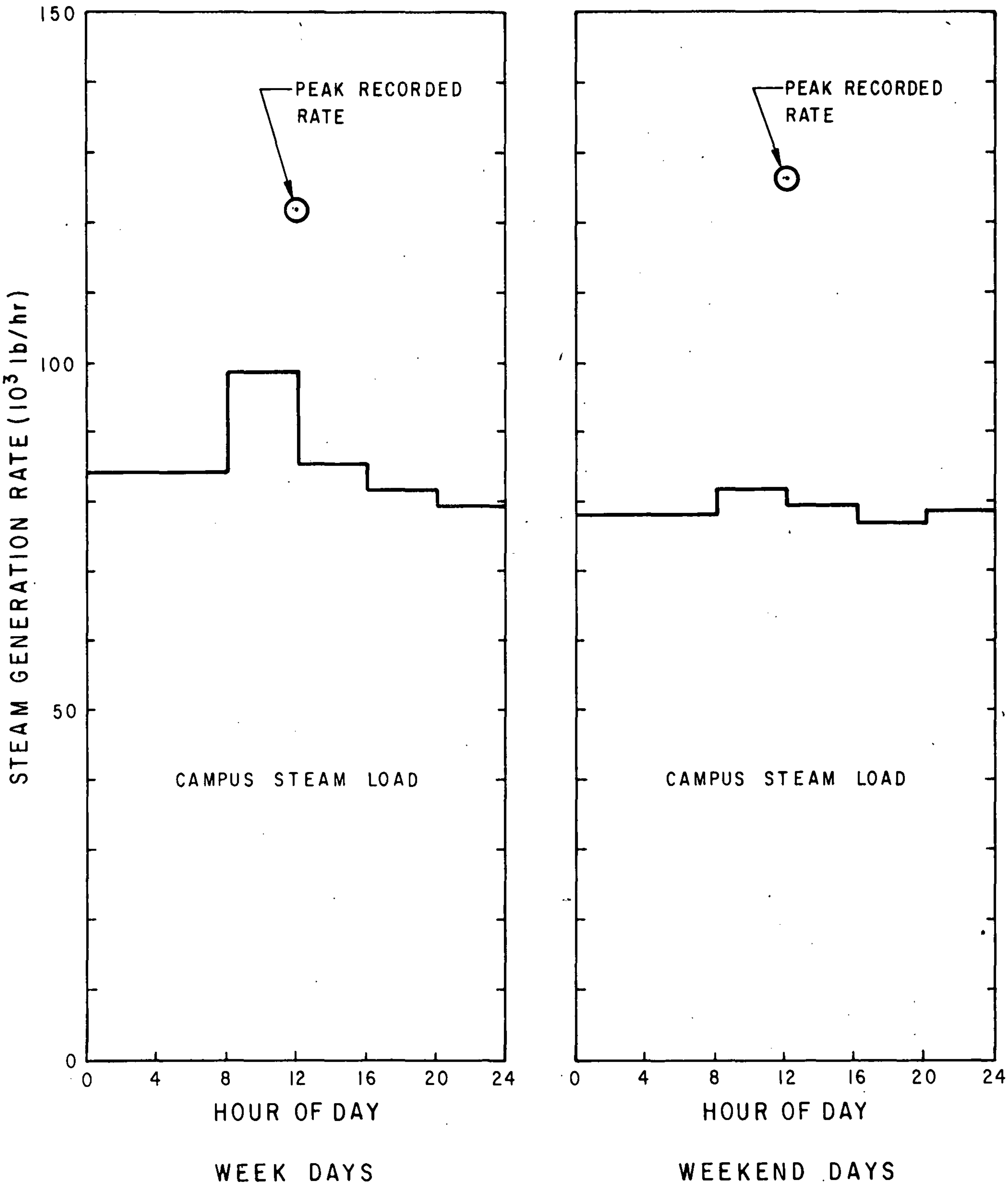
1984 AVERAGE DAILY STEAM PRODUCTION
APRIL AND NOVEMBER



1984 AVERAGE DAILY STEAM PRODUCTION
MARCH AND DECEMBER



1984 AVERAGE DAILY STEAM PRODUCTION
JANUARY AND FEBRUARY



about mean values. The 6750 tons represents a diversity of about 86 percent which implies a corresponding value of 7850 without diversity. This is close to the 7630 tons total capacity of all chillers that could be tied into the chilled water distribution network, namely the central plant at 6000 tons, the electric driven hospital chiller at 700 tons, the electric driven Reiss Science Building chiller at 680 tons and the Henle Village absorption chiller at 250 tons. The three additional local chillers can be viewed as supplementary units. Therefore, the peak load could be handled.

Average chilled water production equivalent steam flow was evaluated for the 1984 proposed campus. The results of these evaluations are presented in Exhibits 2-44 through 2-46. These curves were used in the evaluation of thermal storage and minimization of non-coal fired steam generation and use of the electric chillers at off-peak hours.

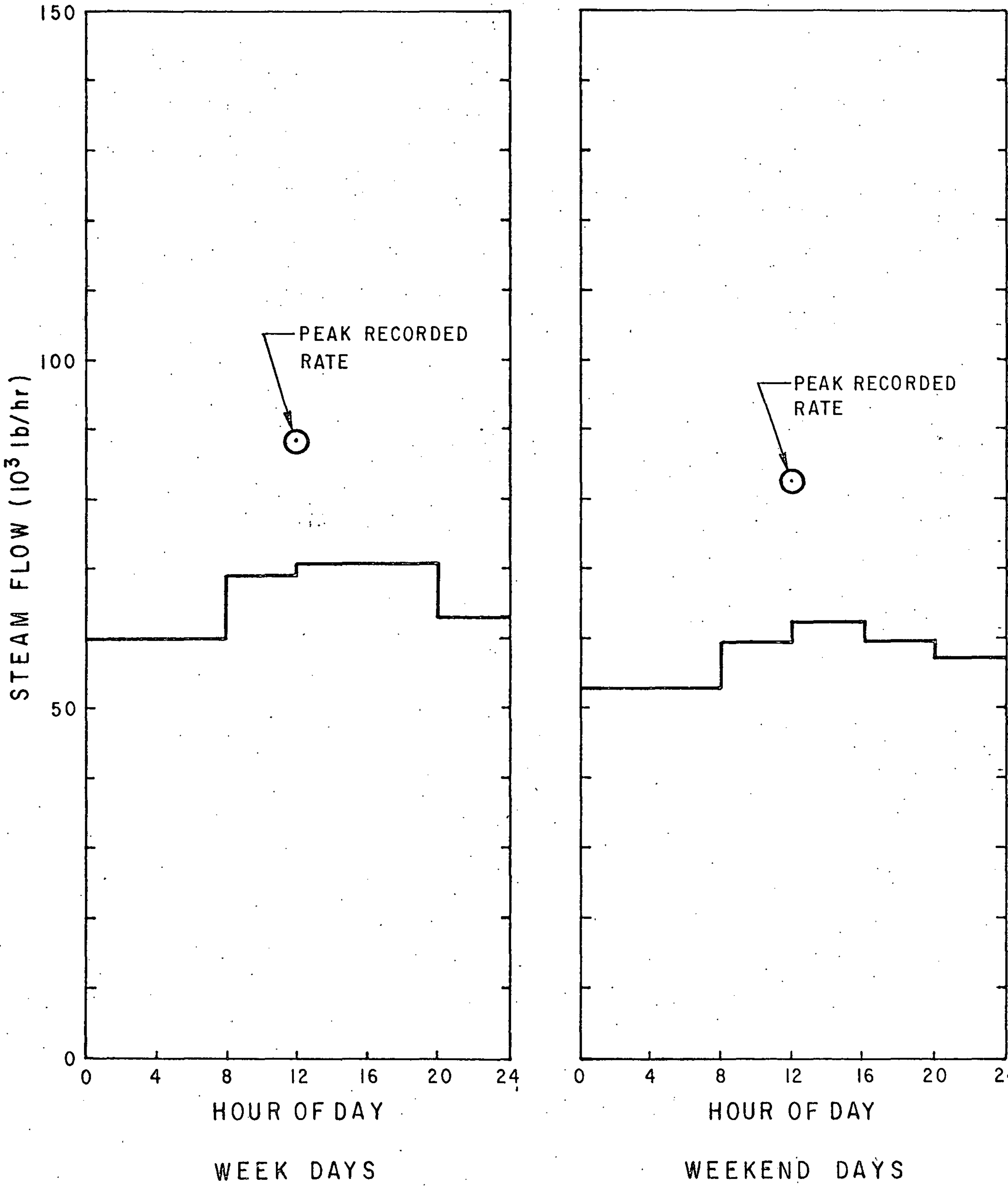
2.8.4 Domestic Hot Water

The increased DHW consumption for the 1984 campus was incorporated into the increase of other than chilled water steam requirements and was thus increased by a factor of 1.3. Estimates of specific contributions to DHW consumption is included in the DHW calculation sheet in Appendix H. The increase evaluated there was close to 25 percent, however, since the DHW is a small portion of the total steam load, using the factor of 1.3 was considered to be of sufficient accuracy.

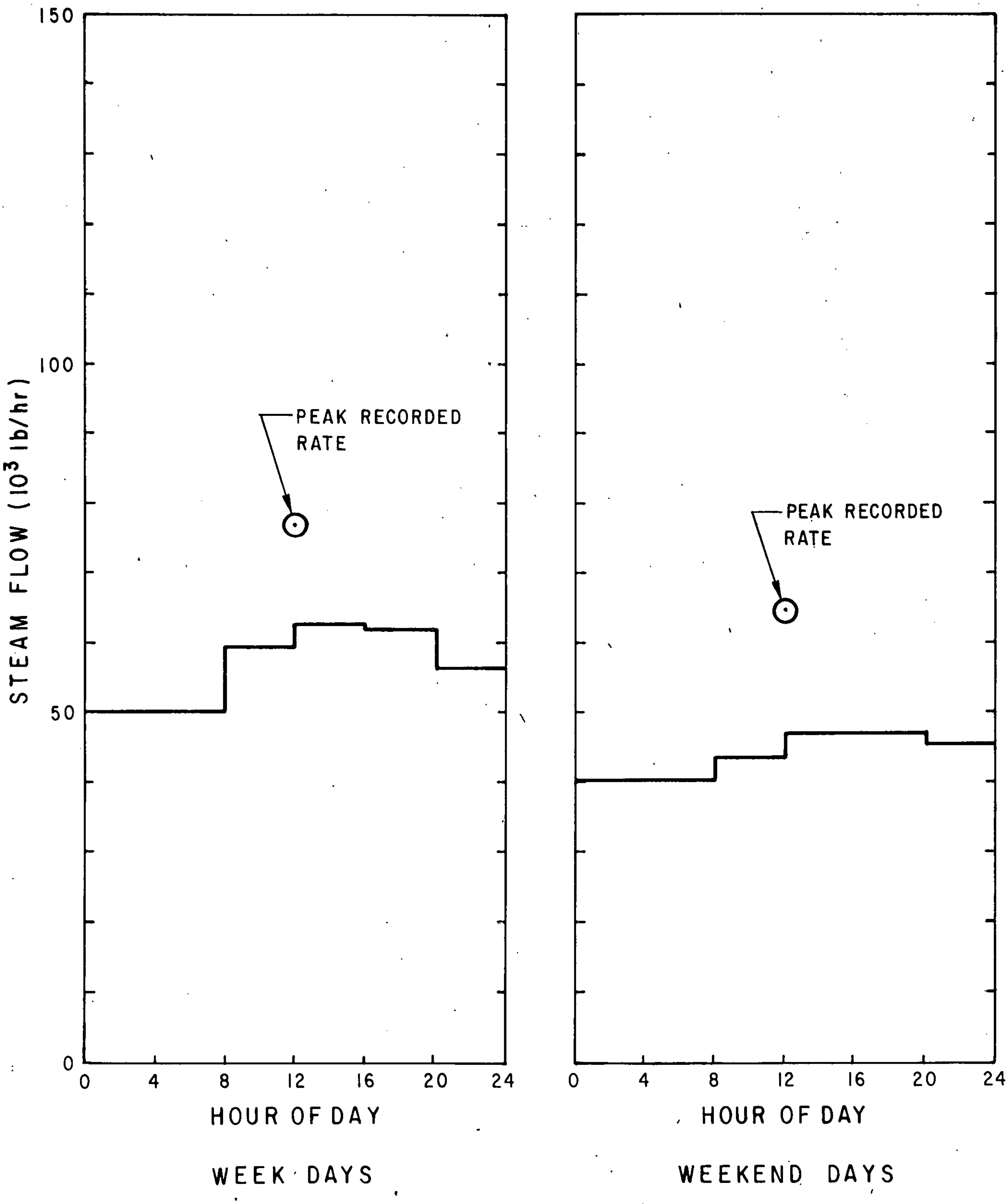
2.8.5 Electrical Data

The projected peak demand for the 1984 GU load is expected to be 11,750 kW as shown in Exhibit 2-47, which is the 1984 electrical load duration curve. The minimum demand shown is 4250 kW. These results are obtained by multiplying the findings of Section 2.6.2, shown in Exhibit 2-27, by

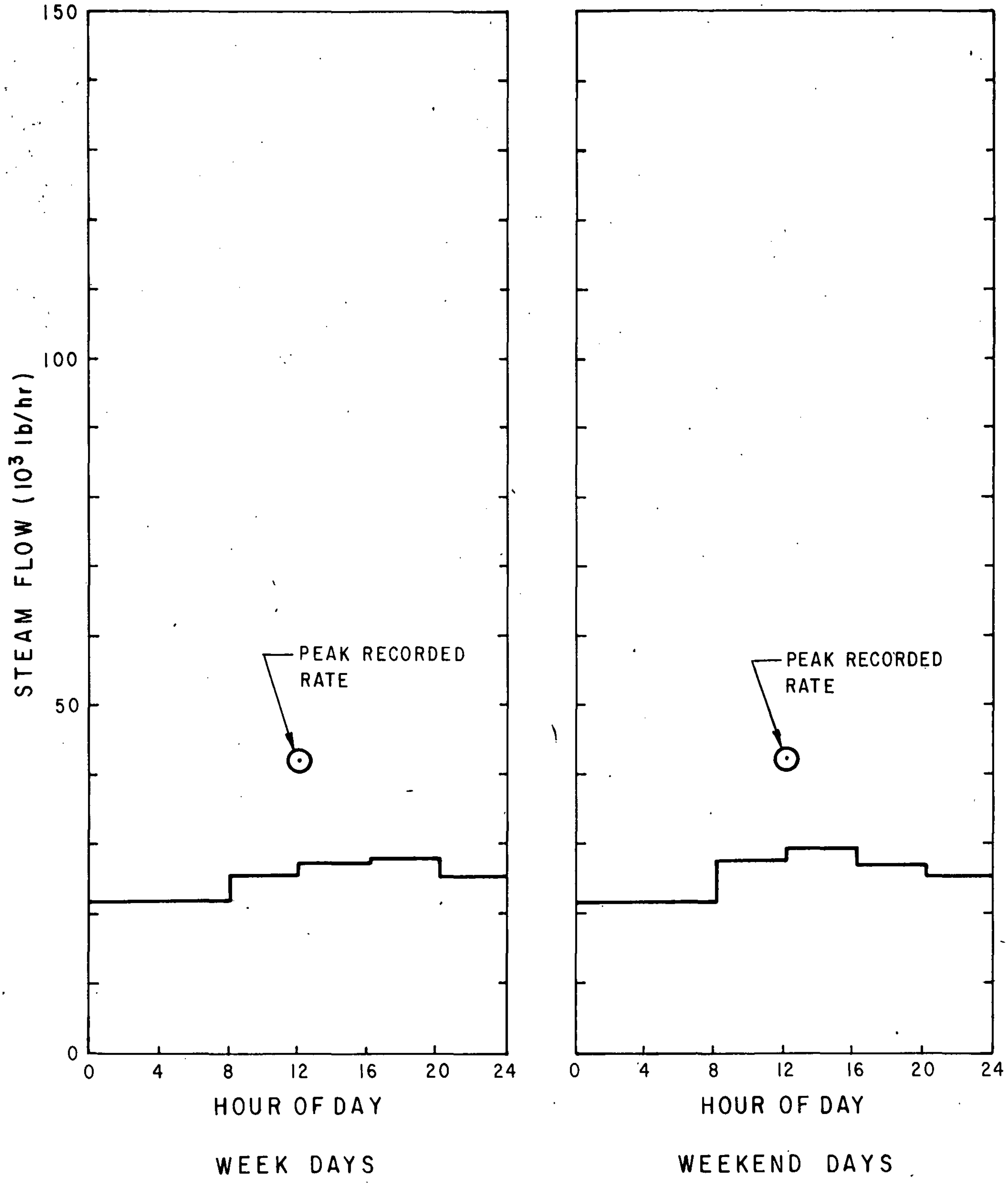
1984 AVERAGE STEAM FLOW FOR CHILLED WATER PRODUCTION JULY AND AUGUST



1984 AVERAGE STEAM FLOW FOR CHILLED WATER PRODUCTION JUNE AND SEPTEMBER



1984 AVERAGE STEAM FLOW FOR CHILLED WATER PRODUCTION
MAY AND OCTOBER



1984 ELECTRICAL LOAD DURATION CURVE

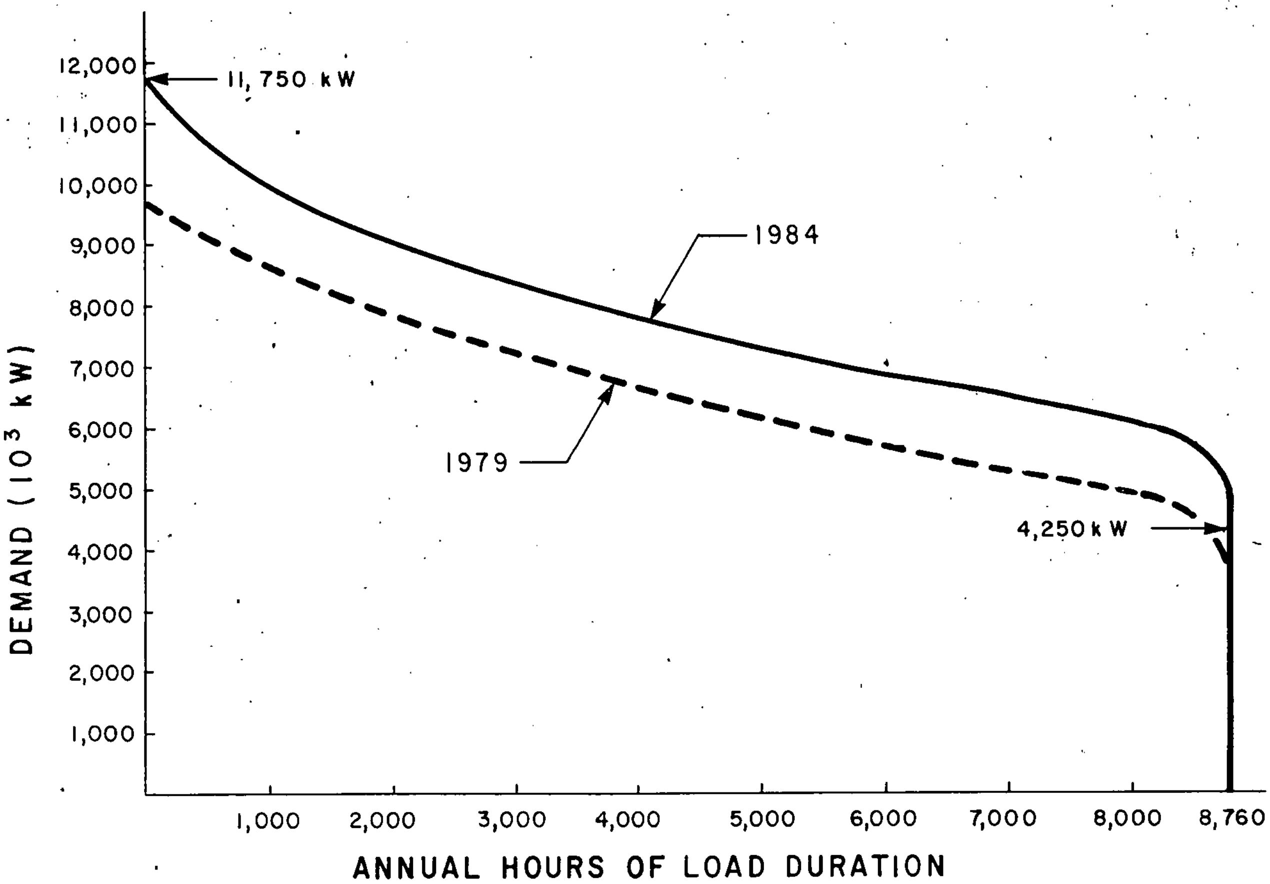
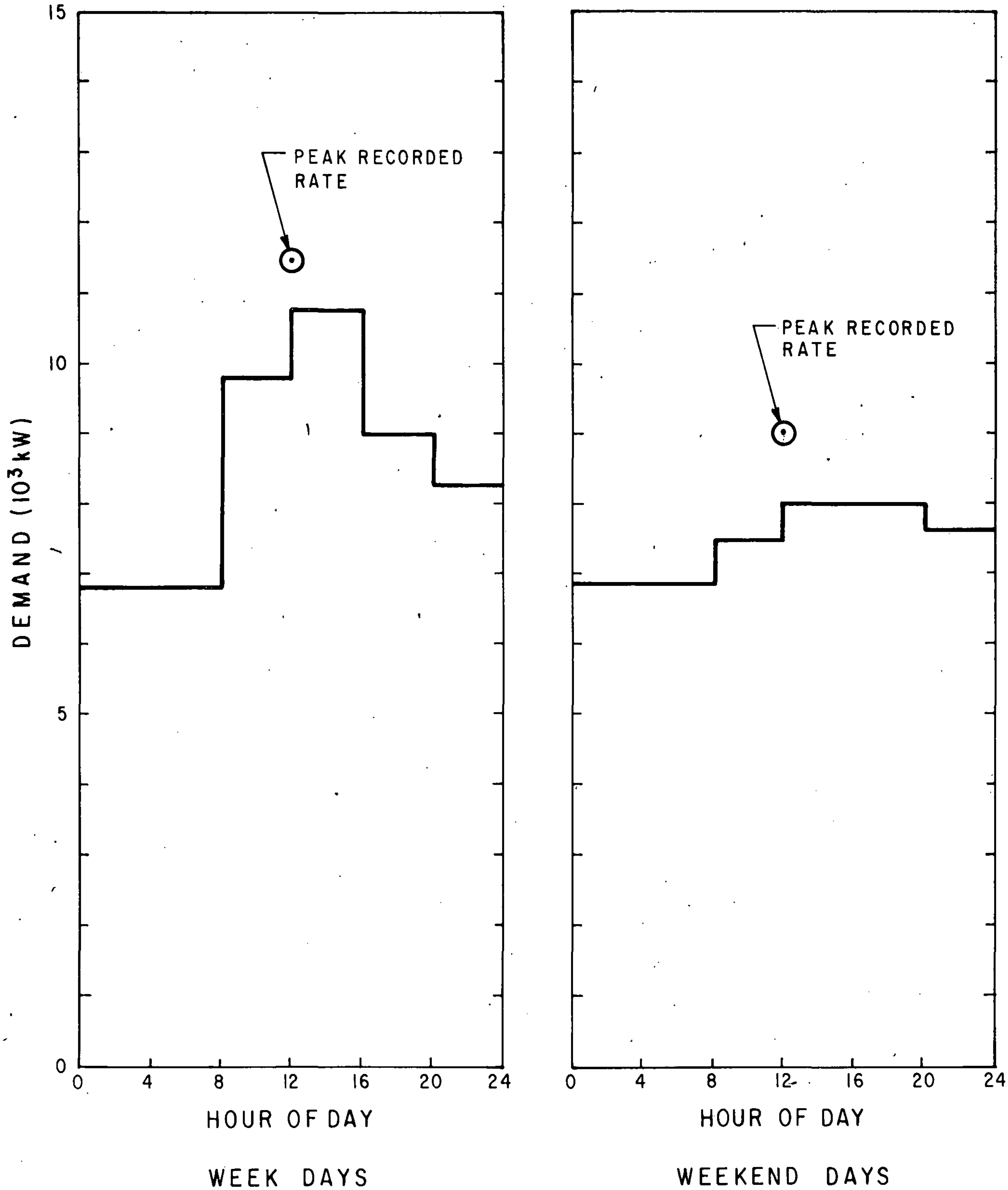


EXHIBIT 2-47

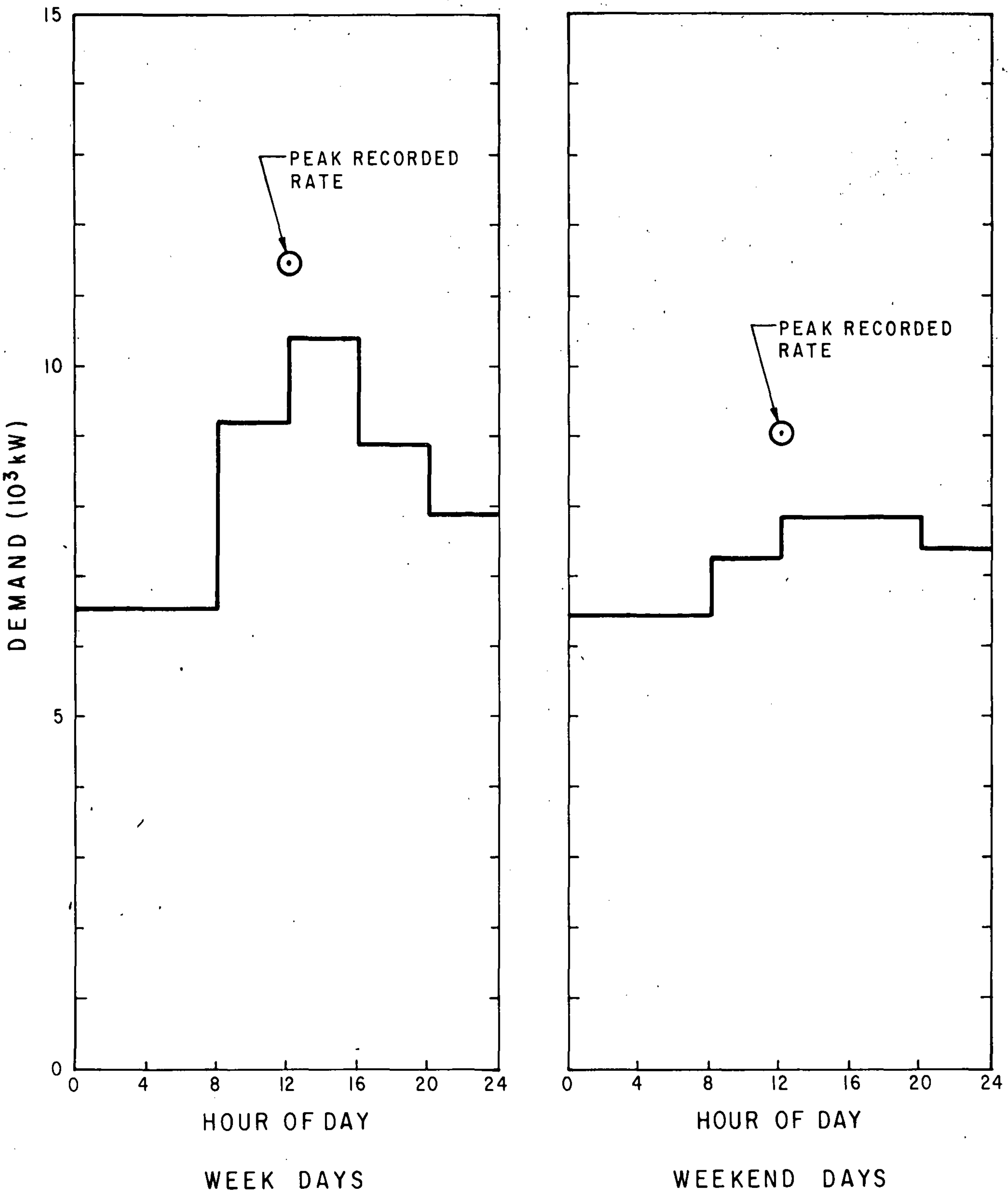
1.25 which is the adjustment factor described in Section 2.7.2.

This same factor was applied to the results shown in Exhibits 2-28 through 2-33 to obtain the 1984 average daily electrical consumption during the six characteristic periods. These 1984 results are presented in Exhibits 2-48 through 2-53. Peak anticipated demand values are also shown. These were evaluated by using the peak values found during FY '79 and applying to them the same factor of 1.25. Consequently, these values are only as accurate as FY '79 was representative of the GU campus as a whole.

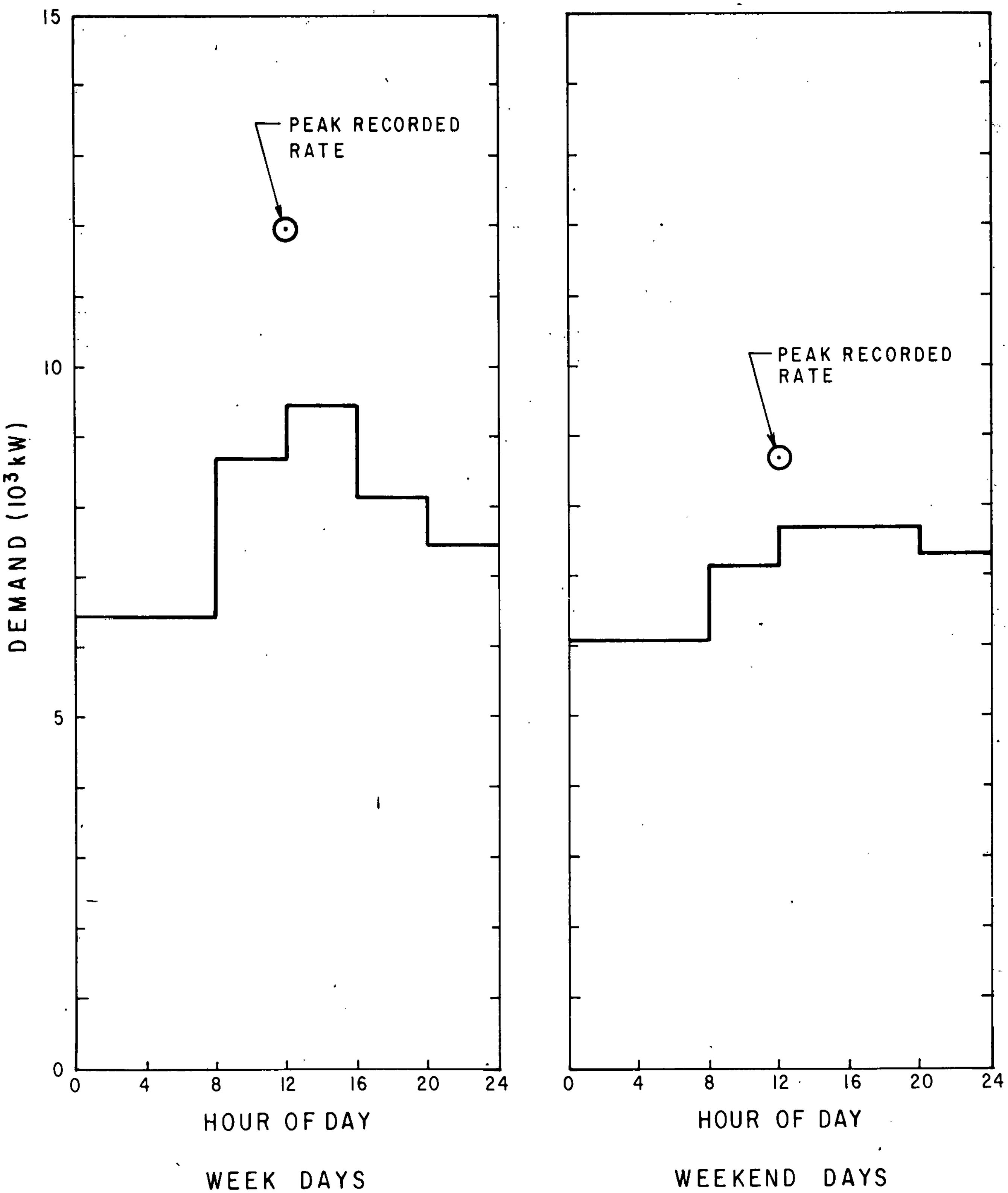
1984 AVERAGE DAILY ELECTRICAL DEMAND
JULY AND AUGUST



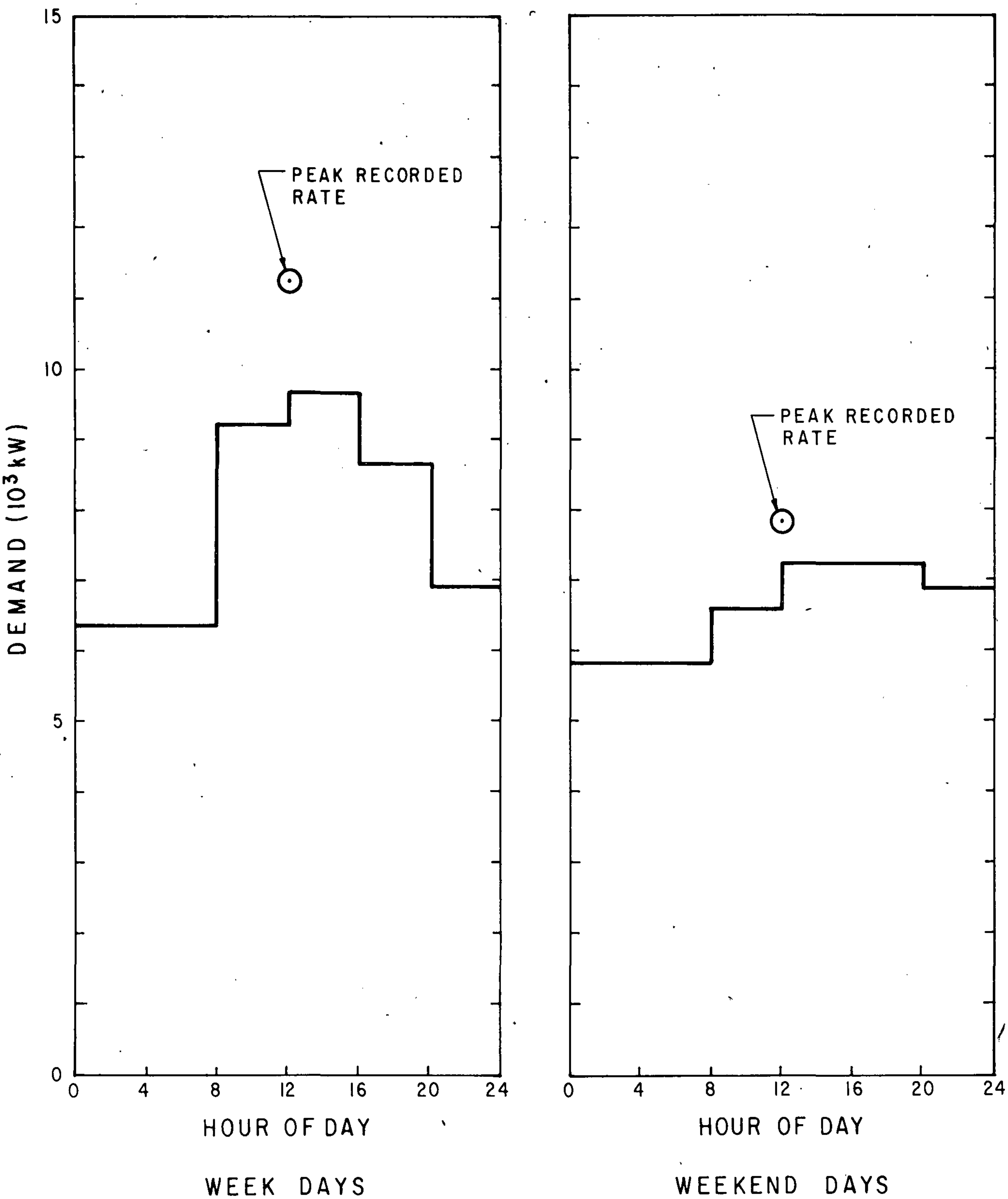
1984 AVERAGE DAILY ELECTRICAL DEMAND
JUNE AND SEPTEMBER



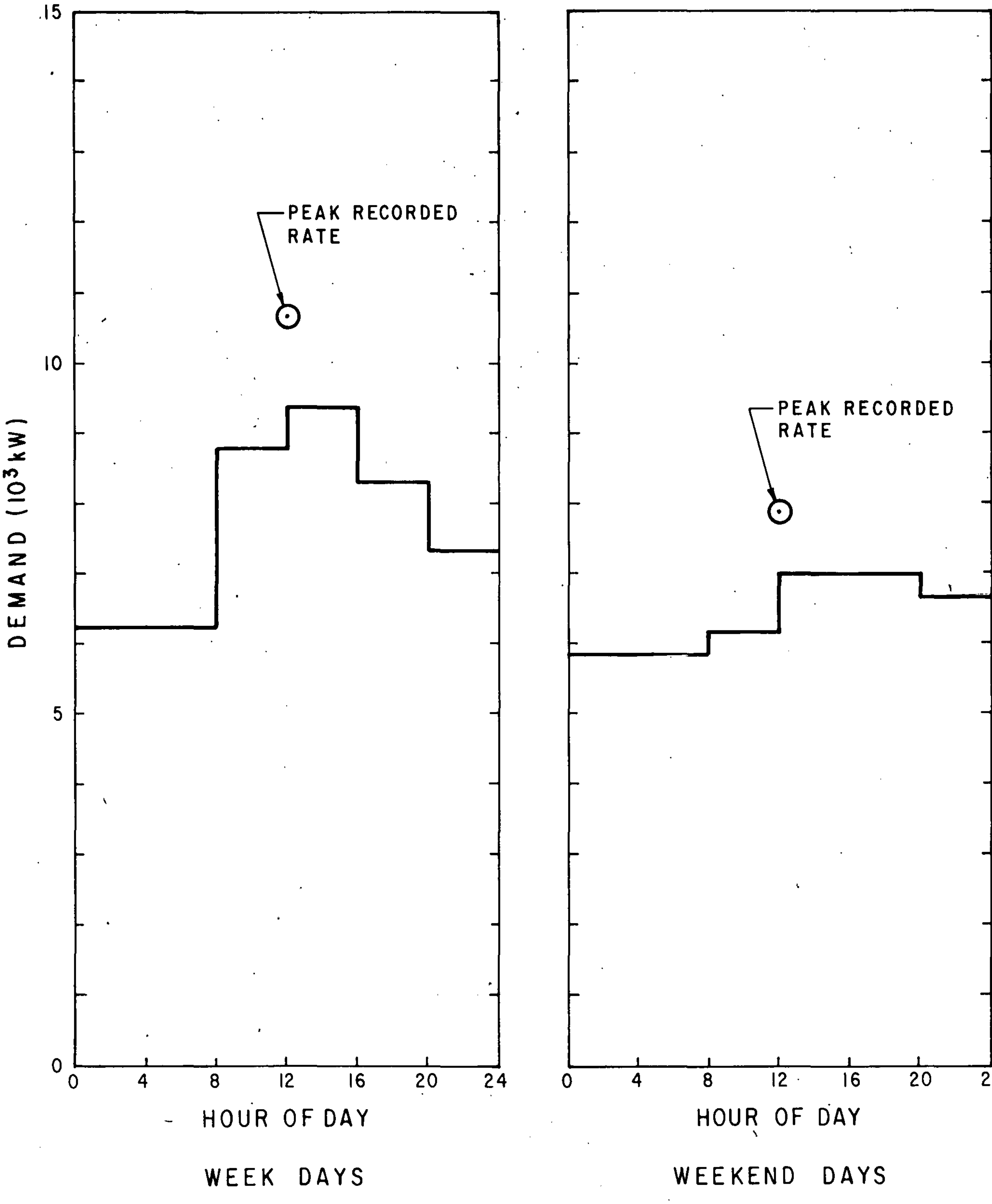
1984 AVERAGE DAILY ELECTRICAL DEMAND
MAY AND OCTOBER



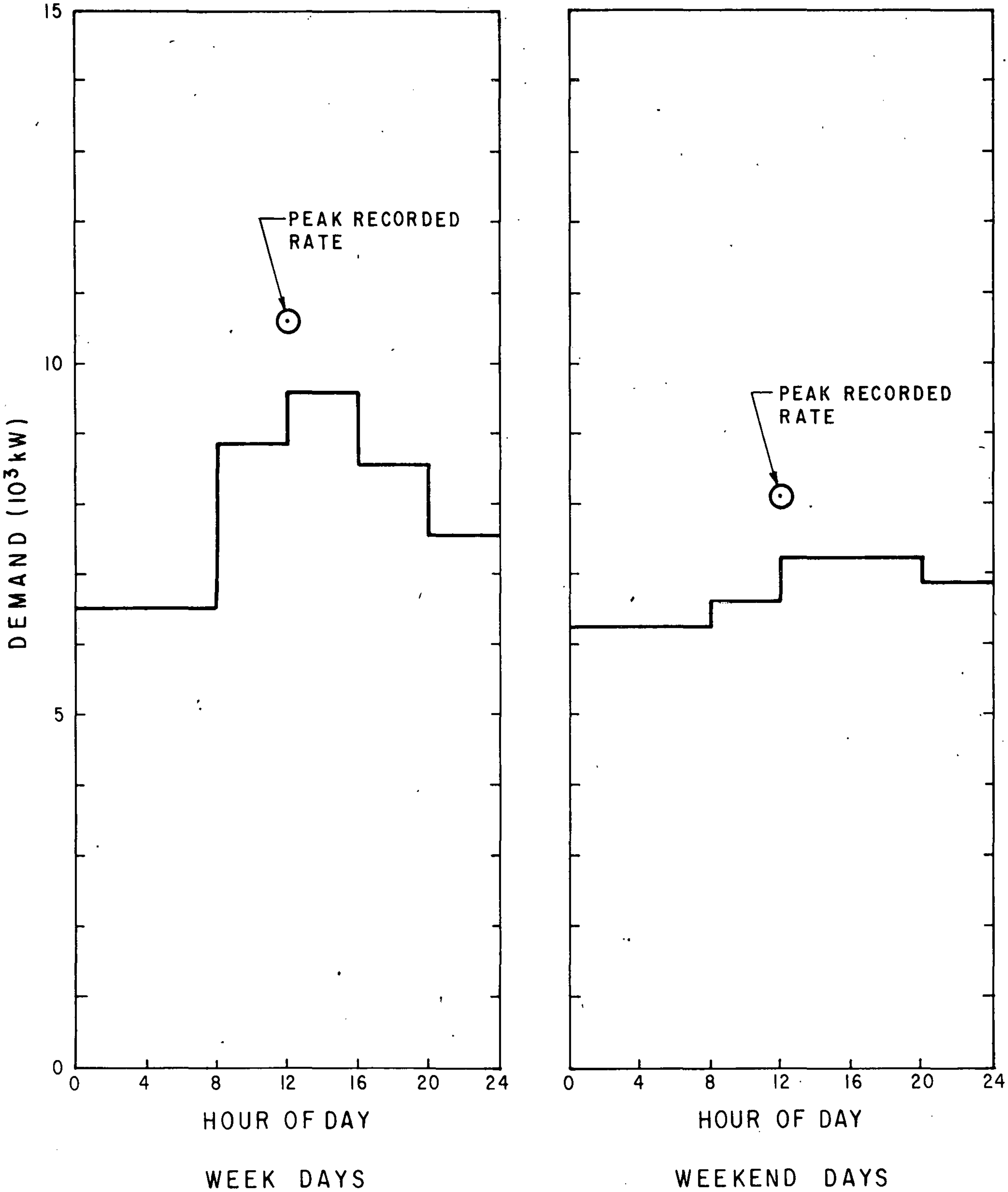
1984 AVERAGE DAILY ELECTRICAL DEMAND
APRIL AND NOVEMBER



1984 AVERAGE DAILY ELECTRICAL DEMAND
MARCH AND DECEMBER



1984 AVERAGE DAILY ELECTRICAL DEMAND
JANUARY AND FEBRUARY



2.8.6 Evaluation of Alternate Subsystems

Six different cogeneration schemes as shown in Table 3-2 were considered.

As shown in Section 1.3.5, the cost of PEPCO electricity for any one month of summer (June through September) is:

$$P_{summer} = 156.75 + 0.02768K + 10.39D$$

And, the cost of PEPCO electricity for any one month of winter (October through May) is:

$$P_{winter} = 156.75 + 0.02784K + 4.047D$$

Now, if amount of purchased electricity and demand are reduced by ΔK and ΔD respectively because of cogeneration, the resulting PEPCO charges avoided ΔP are:

$$\Delta P_{summer} = 0.02768 \quad K + 10.39 \; \Delta D$$
$$\Delta P_{winter} = 0.02784 \quad K + 4.047 \; \Delta D$$

With a knowledge of the electricity that can be produced as a by-product from the steam generated during various periods of the year, the cost that would have to be paid to PEPCO if this electricity was purchased instead, is determined using the relationships arrived above. These results are summarized in Table on pages APP-C-25 through 30 of Appendix C.

2.9 References for Section 2.0

1. Metcalf and Eddy, Inc., Wastewater Engineering, McGraw Hill.

2. Department of the Army, Water Supply-General Consideration, Army Technical Manual TM 5-813-1, also Air Force Manual, AFM 88-10, Ch. 1. July 1965.

3. ASHRAE Handbook and Product Directory, 1976 Systems, Ch. 37.

4. R.S. Means Company, Inc., Building Construction Cost Data, 1980.

SECTION 3

3.0 COGENERATION OF ELECTRICITY

3.1 General

The "Statement of Work" for this Feasibility Analysis contains the following directive:

> "Evaluate the available alternate schemes for introducing turbine-driven electric generators operating between the AFB combustor pressure of 625 psig and the campus usage pressure of 275 psig in summer and 125 psig in winter".

Cogeneration can be defined as an incrementally small addition of energy input into a system to obtain electricity at a better heat rate than that obtained by the utility company. Electricity is obtained as a by-product of the steam that is being generated primarily for heating, cooling and process. Heat rate is the unit source energy input for obtaining a unit of electricity output. In the English system of units this is generally measured as British thermal units per kilowatt hour (Btu/kWh). A typical large utility company generates electricity with condensing turbine generators at a rate of 9,000 to 12,000 Btu/kWh. It is generally a function of boiler and plant efficiency, turbine cycle efficiency and condensing water temperature. The condensing water temperature determines the energy level at which heat is removed from the system; lower temperatures improve the heat rate. Recognizing that every utility experiences further energy losses in its distribution system, the Department of Energy (DOE) has established an average heat rate of 11,600 Btu/kWh delivered to a customer.

3.1.1 Cogeneration Turbine Generators

Steam turbines for driving electric generators fall into either of two general categories - condensing or backpressure, with intermediate extraction points available for both types.

Condensing turbines are machines which use steam at elevated pressure and temperature and exhaust to a condenser. Electric utilities use large machines of this type, coupled with large boilers delivering high pressure superheated steam to turbines and rated upwards to one million kW of output capacity. The steam is used in driving the turbine condensed and returned to the boiler for subsequent steam generation.

Backpressure turbine generators differ from condensing units in that they serve as a pressure reducing station (PRV) in exhausting steam at a pressure substantially lower than the inlet pressure, yet suitable for further use at the reduced pressure. A turbine of this type extracts a small percentage of the available potential energy in the steam and electric energy can be produced at heat rates approaching the theoretical 3413 Btu per kWh. Backpressure turbines operate at a much lower heat rate than condensing turbines. In large commercial and industrial installations where a need already exists for significant amounts of steam for heating, cooling or process requirements, cogeneration by backpressure turbine generators may prove economically feasible at a significant reduction in Btu input per kWh generated.

Both condensing and backpressure turbines can be modified by providing one or more extraction points from which steam may be withdrawn at a pressure below the inlet pressure, but greater than the outlet or exhaust pressure. Turbines modified in this manner may prove beneficial in locations where steam is required at some intermediate pressure level. The heat rate for a turbine generator with extraction is less than that of a condensing unit but greater than the heat rate of a backpressure unit.

Condensing turbine generators of a size which can be supported by the typical large industrial or commercial boiler plant are small by comparison with utility sized machines and operate at a much higher heat rate. Their application in locations such as Georgetown University would require more Btu/kWh than purchased energy and can be justified economically only in rare instances wherein peak shaving generation proves to be economically profitable. Another possibility is to consider an extraction-condensing turbine. Here the features of both the above cycle are combined. This system is particularly appropriate* when

- the utility offers to purchase excess power generated and so help offset the condensing cycle costs;

- the need for electric energy far exceeds the need for thermal energy;

- the utility rate structure is such that peak shaving can be economically justified;

- when the facility has excess steam capacity available (for GU this would mean that the AFB is not used to its maximum).

These situations do not exist at GU and condensing turbine generators are not considered herein.

3.1.2 Conditions for Cogeneration at Georgetown University

Steam plant production and steam usage at Georgetown University is discussed in Section 2 and summarized in Table 3-1 below:

TABLE 3-1

GU STEAM PRODUCTION AND USAGE SUMMARY

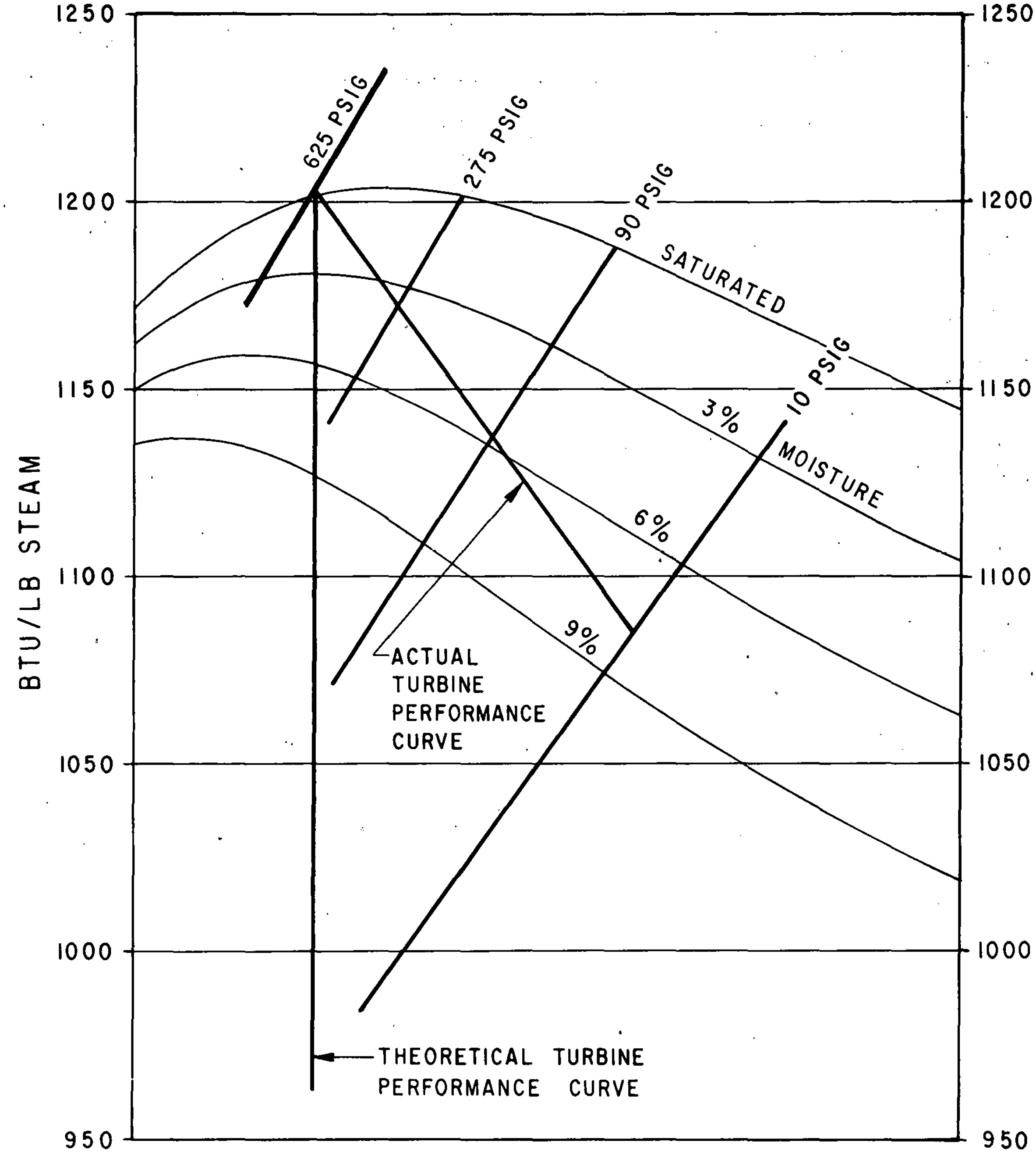
	Steam Production Capacity		Use Pressure Steam (PSIG)		
	Pressure (psig)	Rating (lb/hr)	275	125	10
AFB Boiler Plant	625/275	100,000			
Auxiliary Turbines	-	-	X		
Heating/Cooling Plant	275	(2)-100,000			
Auxiliary Turbine			X		
Turbine Driven Chillers			X		
Deaerator					X
Space Heating					X
Campus Distribution					
Space Heating				X	
Hot Water Generation				X	
Process				X	

The AFB boiler was intentionally designed to be capable of generating 625 psig saturated steam to permit cogeneration at some future date. Space limitations precluded designing the boiler with a superheater to further enhance cogeneration. This condition remains, as it is not feasible to add a superheater to the AFB boiler.

With 625 psig steam available from the AFB boiler, and terminal steam using equipment operating at pressures of 275 and a nominal 125 psig respectively, backpressure turbine generation is technically feasible. It must be recognized, however, that the level of electric cogeneration will vary directly with the heating, cooling and process steam requirements. Further, steam entering the turbine generator is in a saturated condition, and as its pressure decreases during the passage through the turbine, it leaves in a less than saturated state. This means that a portion of the steam has condensed and is not available for further use. This amounts to 3 to 8 percent, the greater percentage associated with the lower pressure discharge. Exhibit 3-1 is a Mollier diagram indicating the moisture at the turbine discharge and the energy available for cogeneration at the various exhaust pressure levels.

As shown in Table 3-1, Georgetown University's existing plant operates at three pressure levels. The highest level is 275 psig for the turbine driven refrigeration chillers in the Heating and Cooling Plant which produce chilled water for the central cooling system during the summer. The original plant's gas/oil fired boilers produce steam at this level. The outlying buildings connected to the export steam system require less pressure to satisfy their requirements. The hospital complex needs steam at a minimum of 90 psig to function and this is the present export line pressure. It was originally operated at 125 psig, but was reduced as an economy measure. The reduced pressure is obtained through a pressure reducing station (PRV) from the 275 psig line. The third level of pressure is 10 psig, needed for feedwater heating and space heating in the boiler plant. Steam at 10 psig is produced by use of backpressure turbines for boiler feedwater, chilled water and cooling water pumps, flash steam from a blowdown system and PRV make-up as required.

TURBINE PERFORMANCE CURVE



MOLLIER DIAGRAM

EXHIBIT 3-1

3.1.3 Georgetown University Steam Load

Hourly steam generation rates at GU for Fiscal Year '79 is shown on Exhibit 3-2 below. Steam load peaks during the summer months of July and August when most of the steam produced is supplied to turbine driven chillers supplying chilled water distribution to most of the campus buildings. Steam production also peaks during January and February at which time export steam is supplied principally for building heating. The months of November and April typically require minimum production in that neither cooling nor heating requirements of any magnitude occur during these months.

MONTHLY STEAM GENERATION RATES

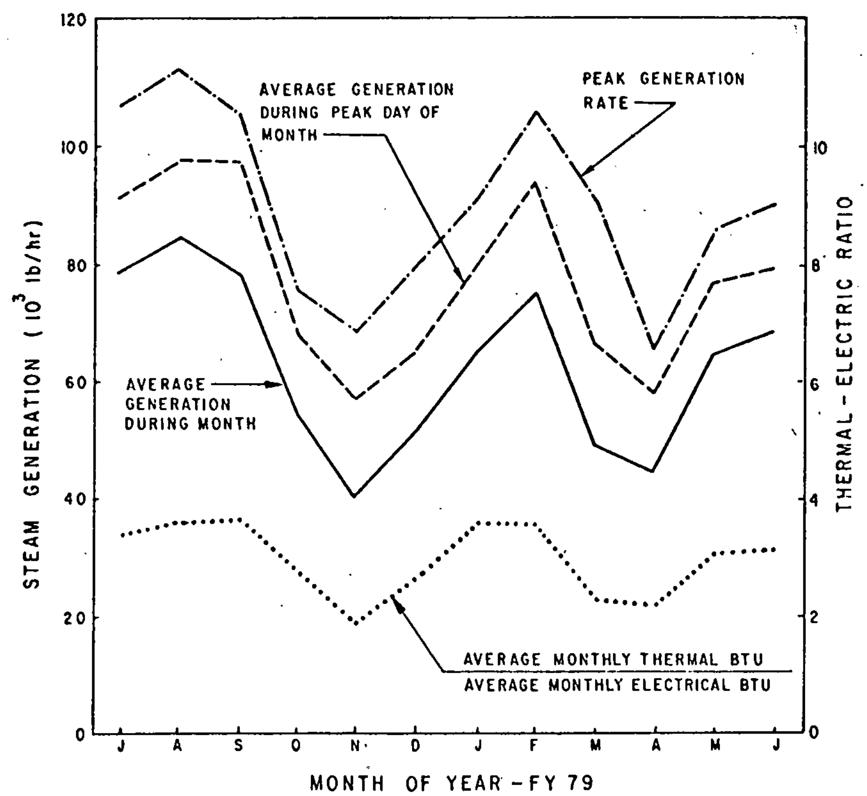


EXHIBIT 3-2

For the evaluation of alternate generation schemes, it was recognized that the university's building program will add substantial load to the system in the immediate future. The projected steam load for 1984 is developed in Section 2.0. This projection is broken down into typical day hourly steam generation rates corresponding to the hours of the day and week representing the utility's hours of off-peak, intermediate, and on-peak billing. This, then, is the steam load used in the economic evaluation of alternate cogeneration schemes.

Further consideration was given to the fact that it is impossible to operate the AFB plant for the 8760 hours in a year. Since the cogenerators can operate only on the 625 psig steam output of the AFB boiler, some concession must be made to this fact. For these evaluations, therefore, it was assumed that the AFB plant would be shut down for maintenance during the low steam demand months of November and April, and that unscheduled outages would limit its operation to 95 percent of the available hours during the remaining 10 months of each year. Annual hours of cogeneration operation is taken as a conservative assumption of 6,950.

3.1.4 Summary of Alternate Schemes Evaluated

A total of six alternate schemes for cogeneration of electricity were evaluated as summarized in Table 3-2. In all six schemes, inlet steam is at 625 psig saturated and 100,000 lb/hr maximum flow. Of the six, Scheme F is not a true cogeneration cycle because all of the steam input is used for electrical generation.

TABLE 3-2

ALTERNATE SCHEMES FOR COGENERATION

Scheme	No. of TG's	Extraction Steam Psig	Extraction Steam Use	Exhaust Steam Psig	Exhaust Steam Use	Generator Output KW Summer	Generator Output KW Winter
A	1	-		275-S	Chillers Export	1045	-
				90-W	Export	-	2270
B	1	275-S	Chillers	90-S/W	Export	1140	2475
C	2			275-S	Chillers Export	1000	-
				90-W	Export	-	2475
D	1	275-S	Chillers	10-S	Abs. Chillers	1306	1306
E	1	90-S/W	Export	10-S	Abs. Chillers	3300	2390
F	1	-	-	10-S	Energy Recovery Unit	5800	
				90-W	Export		

S - Summer; W - Winter

Scheme F is not a true cogeneration cycle because all steam is delivered to electrical generation and none remains for export. Hence, implementation of this scheme will be feasible only if it can be proven that by this method the university can generate electricity more economically than the utility.

3.1.5 Other Considerations

In all cogeneration schemes considered, the generator will operate in parallel with the electric utility, the Potomac Electric Power Company (PEPCO), an arrangement which has been accepted by all parties. Frequency control is therefore provided by the utility system. Once the machine speed is fixed by the utility frequency and the inlet and outlet steam pressures are determined, the steam flow will determine the level of cogeneration.

The requirements for a hot tie to the PEPCO system have been established by PEPCO and are shown in Exhibit 3-3.

Turbine generator prices were solicited from eleven manufacturers of whom five responded with cost and power output estimates. Cost and output estimates used in this report correspond to those provided by the low bidder.

TASK 4a – PROPOSED COGENERATION TIE TO PEPCO

LEGEND

25 – SYNCHRONIZING RELAY
26 – GENERATOR THERMAL DEVICE
32 – DIRECTIONAL POWER RELAY
50/51N – NEUTRAL OVERCURRENT RELAY
51V – OVERCURRENT RELAY, VOLTAGE RESTRAINT
59 – OVERVOLTAGE RELAY
67 – DIRECTIONAL OVERCURRENT RELAY
87G – GENERATOR DIFFERENTIAL RELAY
87T – TRANSFORMER DIFFERENTIAL RELAY

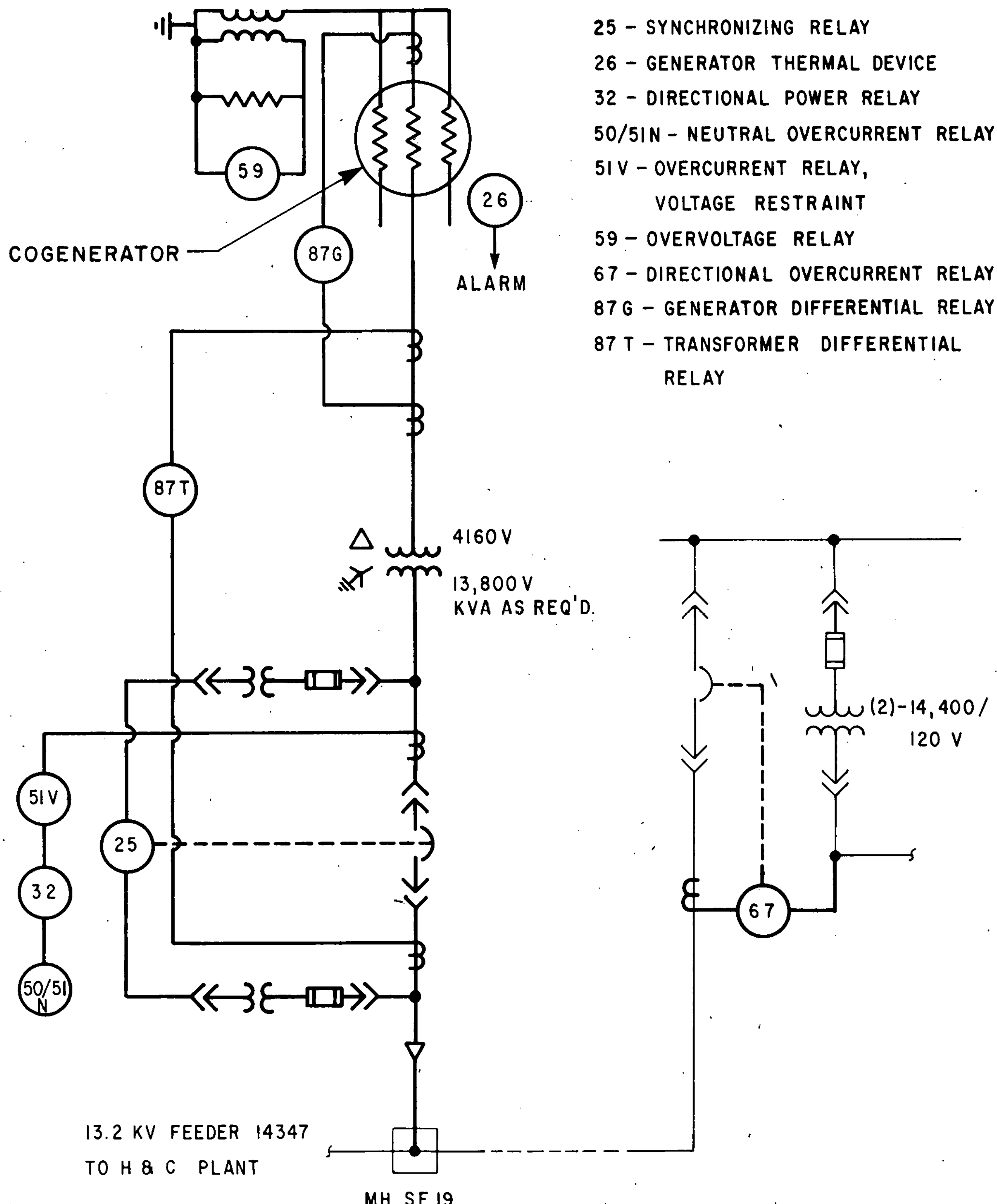


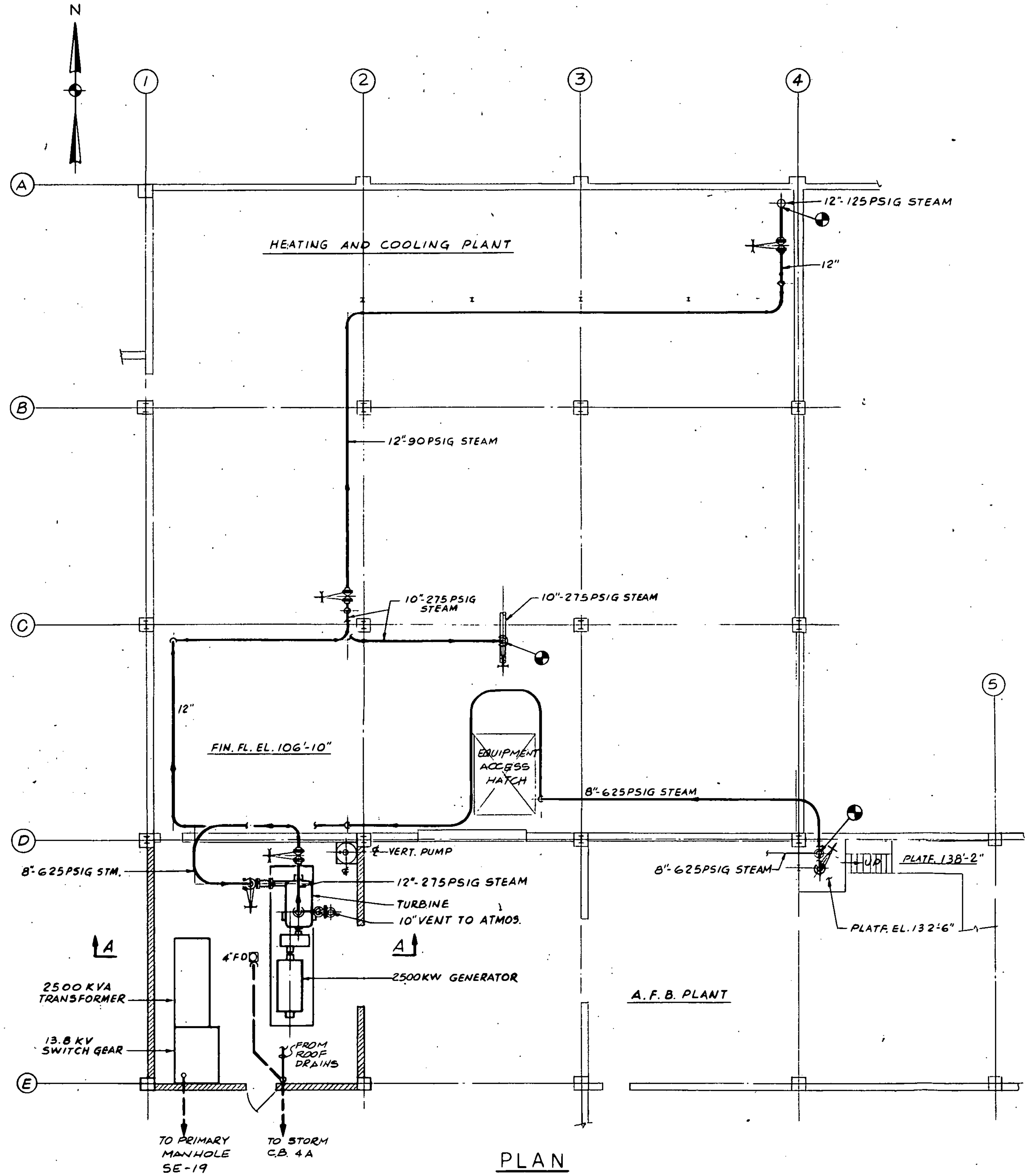
EXHIBIT 3-3

3.2 Alternate Scheme A

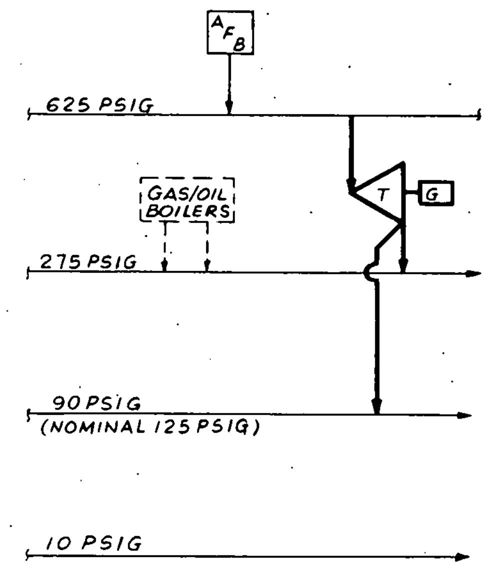
Scheme A, shown on Exhibit 3-4, consists of a single 2500 kW backpressure turbine generator. During summer operation, the turbine exhausts into the 275 psig header to provide steam to the existing turbine driven chillers and, through a pressure reducing valve (PRV), to the 90 psig export steam line. During operation in non-cooling months, the turbine exhausts directly into the 90 psig header to provide export steam for campus heating and similar uses. Pressure sensors in each of the two headers will signal individually to the turbine governor. The sensors will be mutually exclusive, thus the turbine will tend to pass only sufficient steam to maintain the desired exhaust pressure of 275 psig in the summer months and 90 psig in the winter.

Generator output, with full load 100,000 lb/hr steam at 625 psig entering the turbine, is 1045 kW with 275 psig summer months backpressure, and 2270 kW with 90 psig winter months backpressure. Allowing for steam condensed in the turbine, exhaust steam flow will be about 96 percent of inlet steam flow when exhausting at 275 psig and about 94 percent when exhausting at 90 psig. During periods when total steam flow requirements exceed 96,000 lb/hr in summer months and 94,000 lb/hr in winter months, the additional steam would be supplied by the gas/oil fired boilers.

Space does not exist within the Heating and Cooling Plant or the AFB plant for housing the turbine generator and its associated switchgear. An extension on the southwest corner of the Heating and Cooling Plant is proposed as shown on Exhibit 3-4 and Exhibit 3-5. This would be a one-story, one-bay addition with exterior wall treatment to match the adjoining structure.

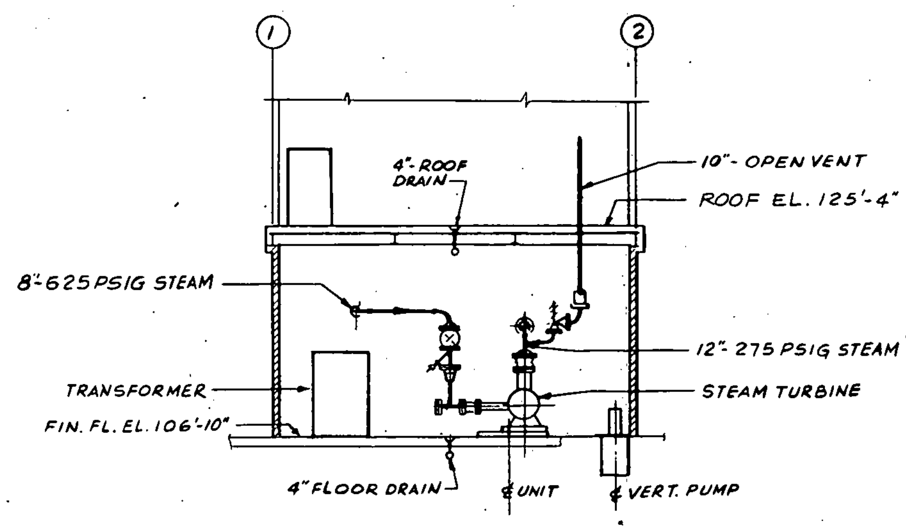


PLAN



MAXIMUM STEAM FLOW (LB/HR) & K.W. PRODUCED	
SUMMER	WINTER
1045 KW	2270KW
100,000	0
0	100,000

FLOW DIAGRAM



SECTION A-A

GRAPHIC SCALE

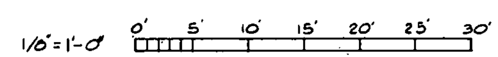
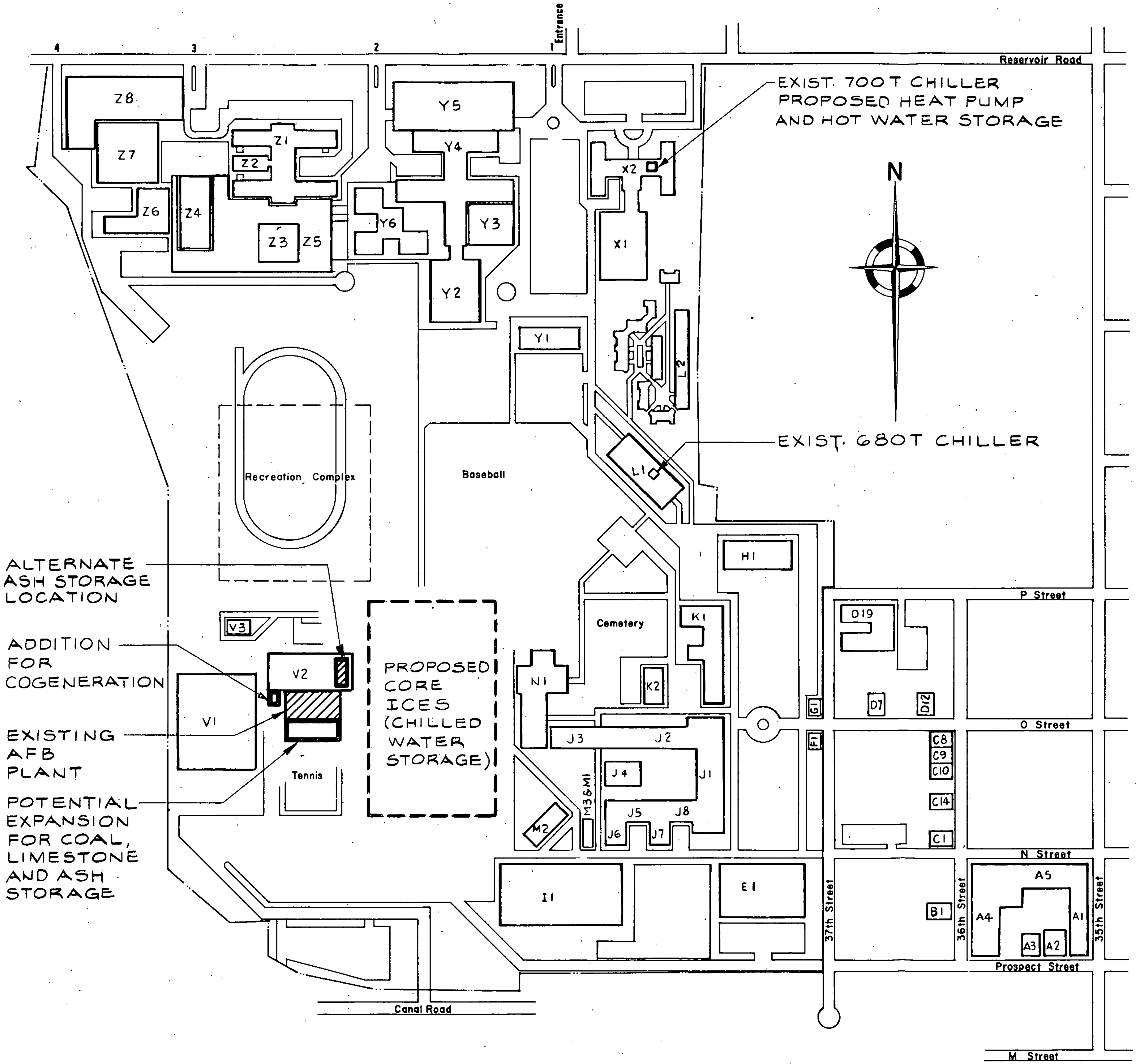


EXHIBIT 3-4

COGENERATION SCHEME A

POPE, EVANS AND ROBBINS



GEORGETOWN UNIVERSITY

A1 Loyola Hall
A2 Xavier Hall
A3 Ryder Hall
A4 Walsh Building
A5 Coleman Nevils Building
B1 Office Of Economics
C1 Bookstore
C8-10 Alumni House
C14 Placement Office
D1-2 American Language Institute
D7 Black Student Alliance
D19 Poulton Hall
E1 Lauinger Library
F1 S. Gatehouse
G1 N. Gatehouse
H1 White - Gravenor
I1 New South Building
J1 Healy Building
J2 Old North Building
J3 New North Building
J4 Dahlgren Chapel
J5 Mulledy Hall
J6 Gervase Hall
J7 Ryan Hall
J8 Maguire Hall
K1 Copley Hall
K2 Ryan Administration Building
L1 Reiss Science Building
L2 Student Housing
M1 Garage
M2 O'Gara Building
M3 Mc Sherry Building
N1 Harbin Hall
V1 Mc Donough Gymnasium
V2 Heating & Cooling Plant
V3 Observatory
X1 Darnall Hall
X2 St. Mary's Hall
Y1 Kober Cogan Building
Y2 Gorman Building
Y3 Bles Building
Y4 Georgetown Hospital
Y5 Hospital Parking Garage (Deck 1)
Y6 Concentrated Care Center
Z1 Medical-Dental Bldg.
Z2 Medical-Dental Annex
Z3 Dalgren Library
Z4 Basic Science Building
Z5 Preclinical Science Building
Z6 Medical Center Vivarium
Z7 Dental Clinic
Z8 Hospital Parking Garage (Deck II)

EXHIBIT 3-5

LOCATION PLAN

POPE, EVANS AND ROBBINS

The projected annual energy saving by this scheme is 64.1 x 10^9 Btu for an 9,100,600 annual kWh of generation when compared with the equivalent generation by a utility at an energy input of 11,600 Btu/kWh.

This scheme offers the following advantages:

a. Initial investment is lowest.

b. Electrical generation increases with steam flow. Since both electrical and steam use peak during on-peak summer month hours, this results in maximum generation and cost savings during the on-peak hours of utility service.

c. Building expansion requirements are a minimum.

Disadvantages associated with the scheme are:

a. Lower electrical output during summer cooling months when campus electrical demand peaks. This is due to electricity being generated from the smaller summer steam pressure differential of 625 to 275 psig compared to the larger winter differential of 625 to 90 psig.

3.3 Alternate Scheme B

Scheme B, shown on Exhibit 3-6, again consists of a single turbine generator. It differs from Scheme A in that the turbine drive is a 90 psig backpressure unit with a 275 psig extraction point. Thus, this unit can simultaneously supply summer chiller requirements at 275 psig and concurrent export steam requirements at 90 psig. Extraction will automatically respond to the 275 psig header requirements. During winter months operation, the extraction port will be valved closed and the entire steam flow through the turbine will be exhausted at 90 psig.

At full load, 100,000 lb/hr turbine inlet steam flow, the peak generator output will be about 1140 kW during summer months and 2475 during winter months.

Space requirements are the same as for Scheme A, namely a one-story, one-bay addition to the southwest corner of the Heating and Cooling Plant.

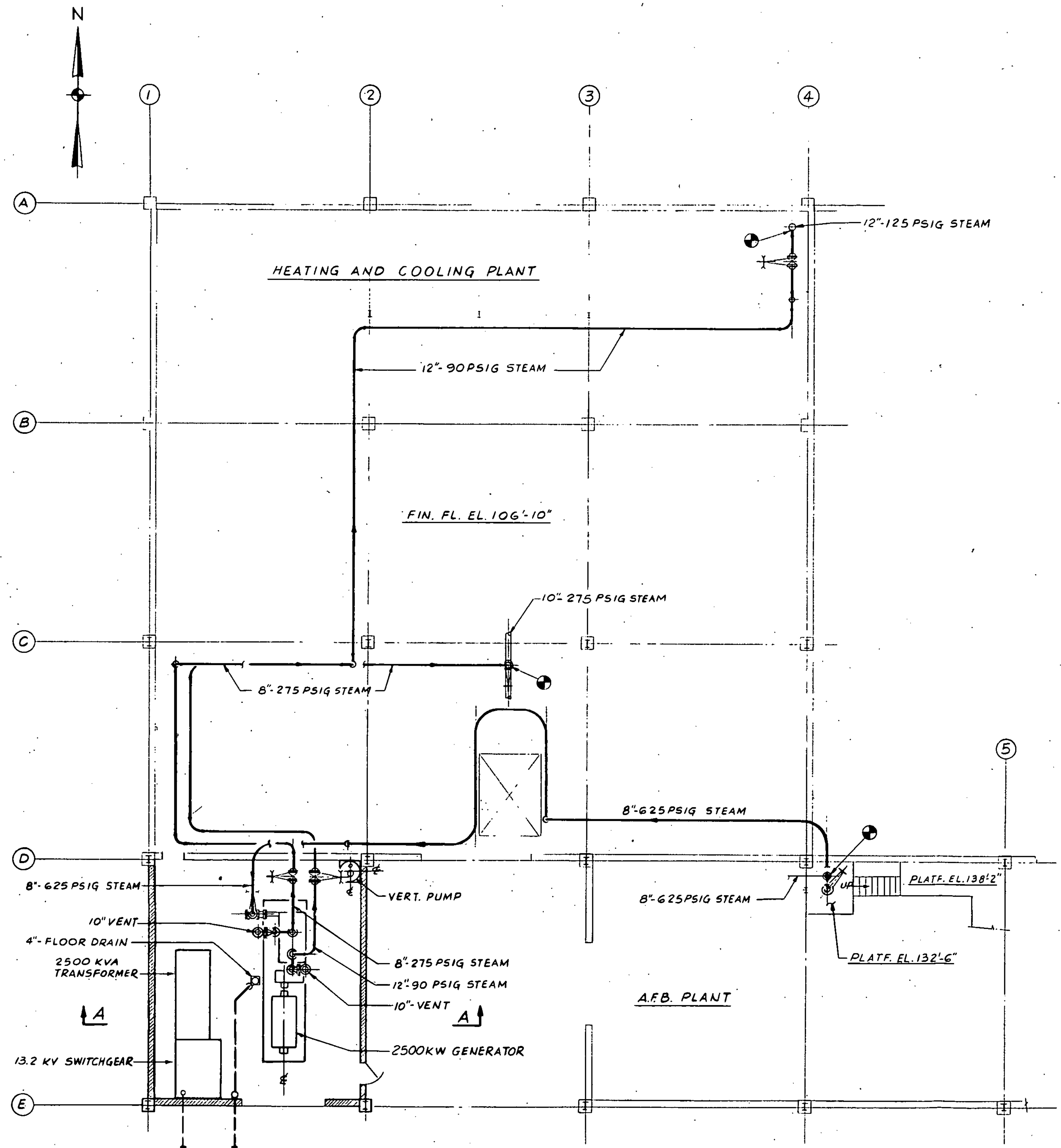
For the same projected steam load conditions as in Scheme A, the annual kWh of generation are increased to 9,900,000. Thus, the projected annual energy saving by this scheme is 69.7×10^9 Btu.

The principal advantages of this scheme are:

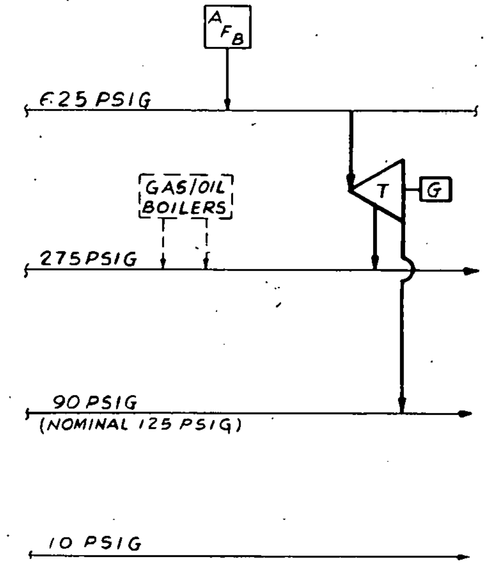
a. Relatively low first cost.

b. Summer electrical generation varies directly with steam flow, both of which are larger during on-peak hours of the summer months.

c. Building expansion requirements are a minimum.

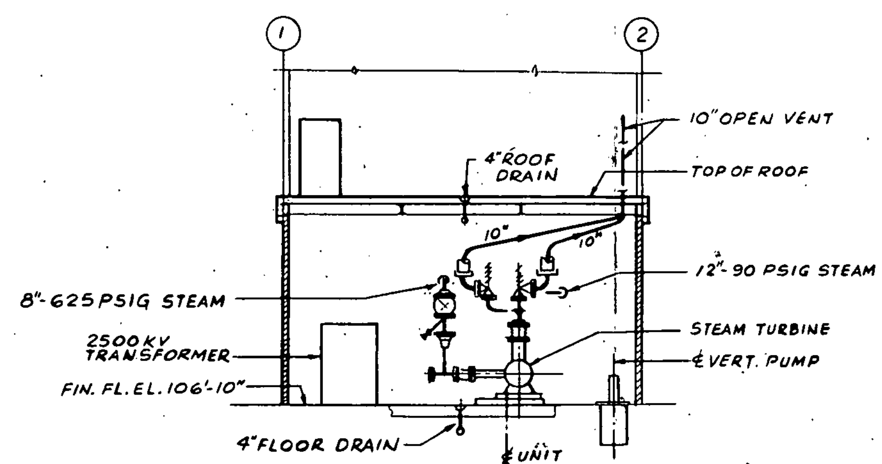


PLAN



MAXIMUM STEAM FLOW (LB/HR) & K.W. PRODUCED	
SUMMER	WINTER
1140 KW	2475 KW
93,000	0
7,000	100,000

FLOW DIAGRAM



SECTION A-A

GRAPHIC SCALE

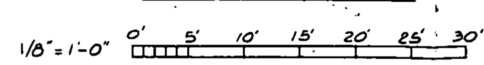


EXHIBIT 3-6

COGENERATION SCHEME B

POPE, EVANS AND ROBBINS

d. During summer month periods of generation when it is not necessary to extract maximum steam flow from the turbine at 275 psig, the steam flow to the 90 psig exhaust assures greater kWh generation than can be attained under Scheme A. A minimum of 7,000 lb/hr of 90 psig steam is required for turbine low pressure stage cooling.

Disadvantages of this scheme are:

a. Relatively low electrical output during summer cooling months when campus electrical load peaks.

3.4 Alternate Scheme C

Scheme C, shown on Exhibit 3-7, provides for the installation of two backpressure turbine generators, each separately controlled by line pressure in the 275 psig and 90 psig header respectively. During winter months, the 275 psig backpressure unit would be secured. Both units could operate concurrently during some periods of summer operation when the chillers do not require all available steam from the AFB unit. During peak periods of summer cooling, the 90 psig backpressure unit would be shut down.

At full load, 100,000 lb/hr turbine inlet steam flow, peak generator output will be about 1000 kW during summer months when all steam flow would pass through the 275 psig backpressure unit, and 2475 kW during winter months.

Space requirements are minimally larger than for Schemes A and B.

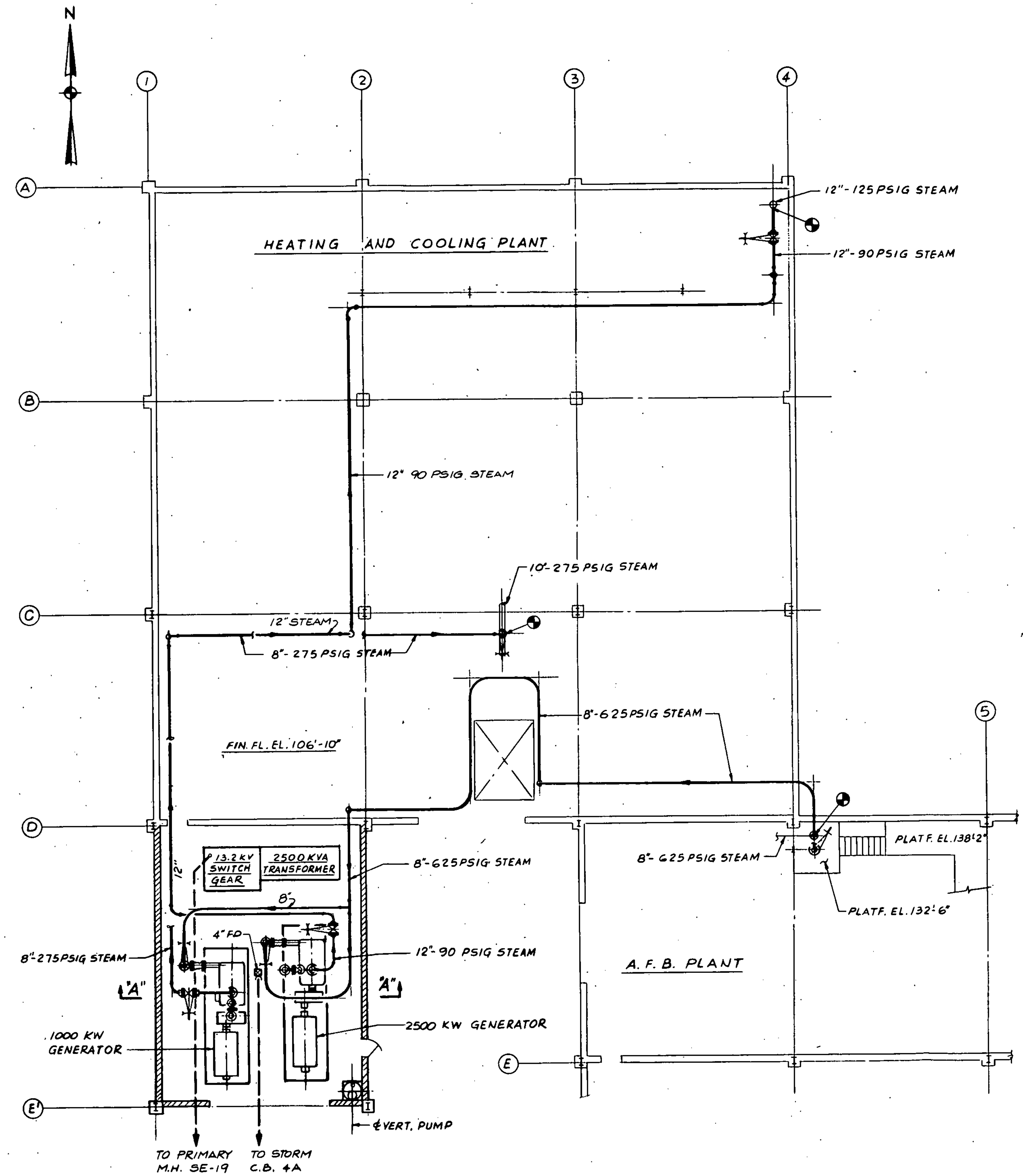
The projected annual generation for the two units combined is 9,376,500 kWh. Projected annual energy savings, when compared with the purchase of equivalent kWh, is 66.0×10^9 Btu.

The principal advantages of Scheme C are:

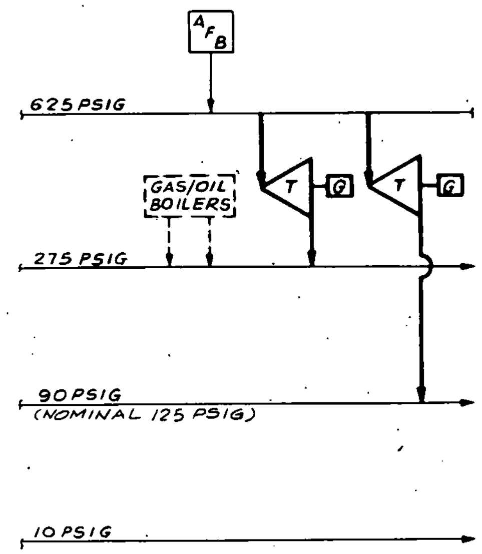
a. Summer electrical generation varies directly with steam flow, both of which peak during on-peak hours of the summer months.

b. Building expansion requirements are a minimum.

c. Unscheduled outages on one turbine generator can be partially offset by operating second unit.

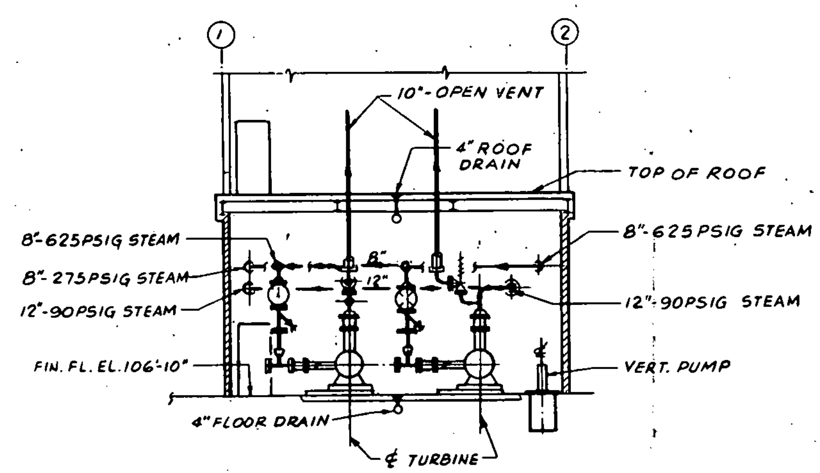


PLAN



MAXIMUM STEAM FLOW (LB/HR) & K.W. PRODUCED	
SUMMER	WINTER
1000 KW	2475 KW
100,000	0
0	100,000

FLOW DIAGRAM



SECTION A-A

GRAPHIC SCALE

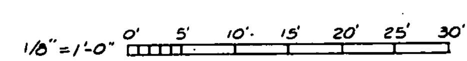


EXHIBIT 3-7

COGENERATION SCHEME C

POPE, EVANS AND ROBBINS

Disadvantages of this scheme are:

a. Relatively low electrical output during summer cooling months when electrical load peaks.

3.5 Alternate Scheme D

Scheme D, shown on Exhibit 3-8, provides a single backpressure turbine generator exhausting to the 10 psig headers, but with a 275 psig extraction port. Minimum steam flow must be maintained at the discharge. This is about 7000 lb/hr and thus the turbine would, in summer, discharge to the 275 psig header for use in the chiller turbines or in the campus distribution system through existing PRV's; additional steam would pass through to a 432 ton absorption refrigeration machine. In winter, steam would enter the 275 psig header for distribution through the PRV's and would also pass through to the 10 psig header for boiler plant feedwater and space heating.

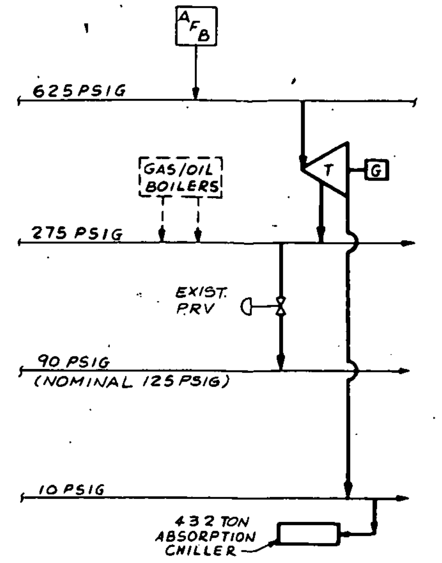
At full load, 100,000 lb/hr turbine inlet steam flow, the peak generator output would be about 1300 kW summer and winter.

Space requirements increase over those for Schemes A, B and C to the extent that an upper level is required above the turbine generator bay to house the absorption chiller associated with this scheme. There should be sufficient thermal capacity in the existing cooling tower for this chiller. Additional pumps are provided for both chilled water and cooling water.

For the same projected steam load conditions as in Scheme A, the annual kWh of generation are increased in summer, but decreased in winter for a total of 7,998,000 kWh of annual generation. Thus the projected annual energy saving by this scheme is 56.3×10^9 Btu.

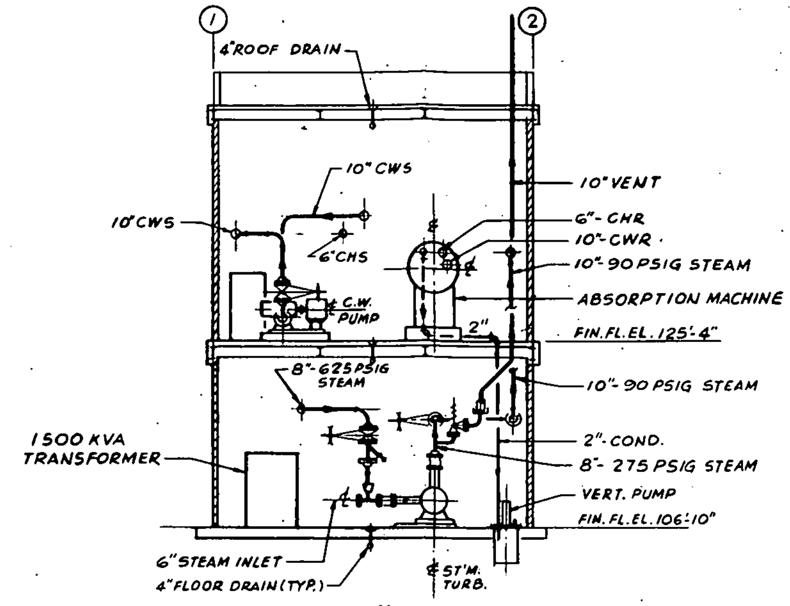
The principal advantages of this scheme are:

a. A small quantity of chiller capacity provides for light loads during part of

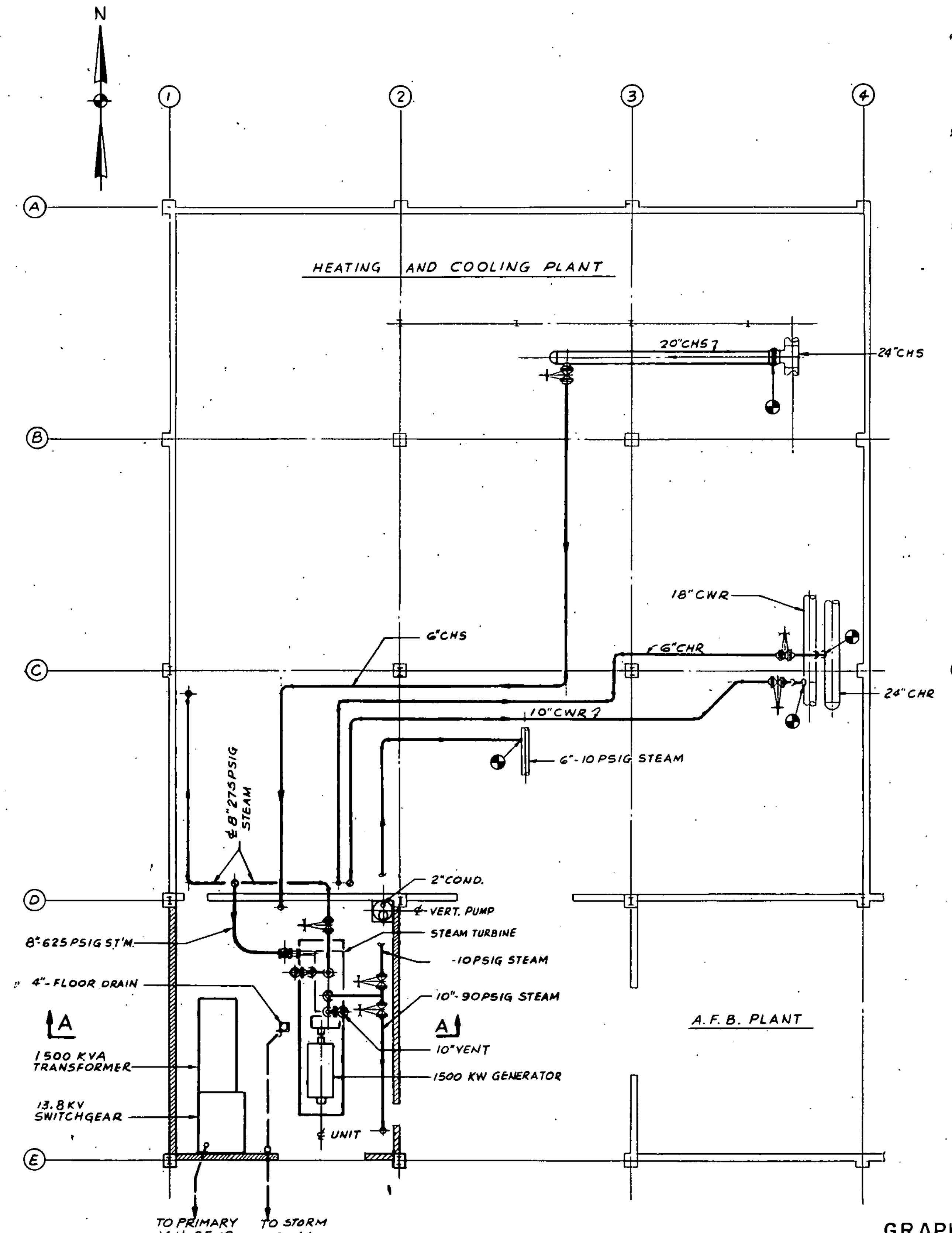


MAXIMUM STEAM FLOW (LB/HR) & K.W. PRODUCED	
SUMMER	WINTER
1306KW	1306KW
93,000	90,000
0	0
7,000	10,000

FLOW DIAGRAM



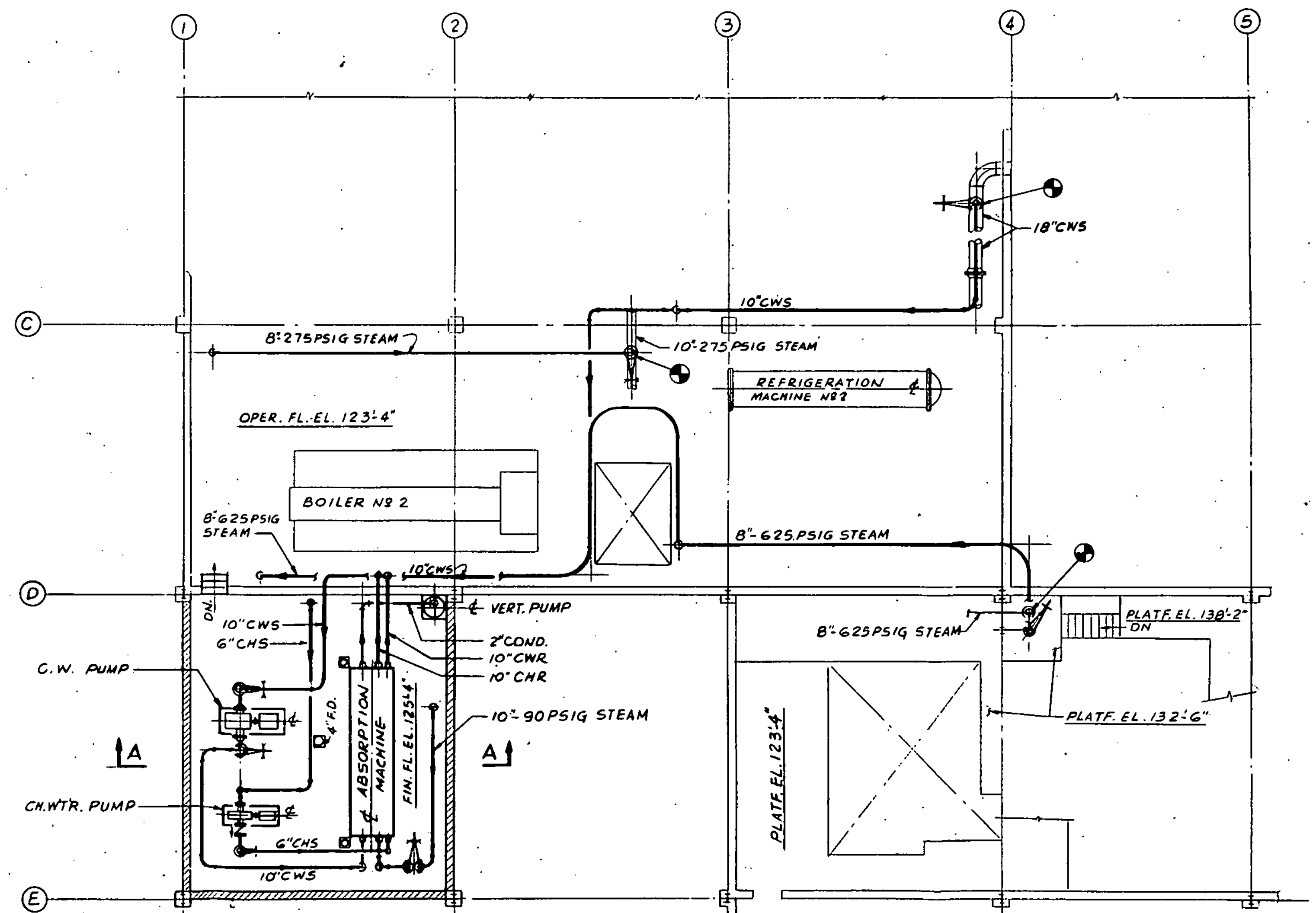
SECTION A-A



PLAN - EL. 106'-10"

GRAPHIC SCALE

1/8" = 1'-0" 0' 5' 10' 15' 20' 25' 30'



PLAN EL. 125'-0"

EXHIBIT 3-8

COGENERATION SCHEME D

POPE, EVANS AND ROBBINS

the year, thus there is more likelihood of cogeneration during the entire year.

Offsetting disadvantages are:

a. A full story must be added to the one-bay structure to house the absorption machine and associated equipment.

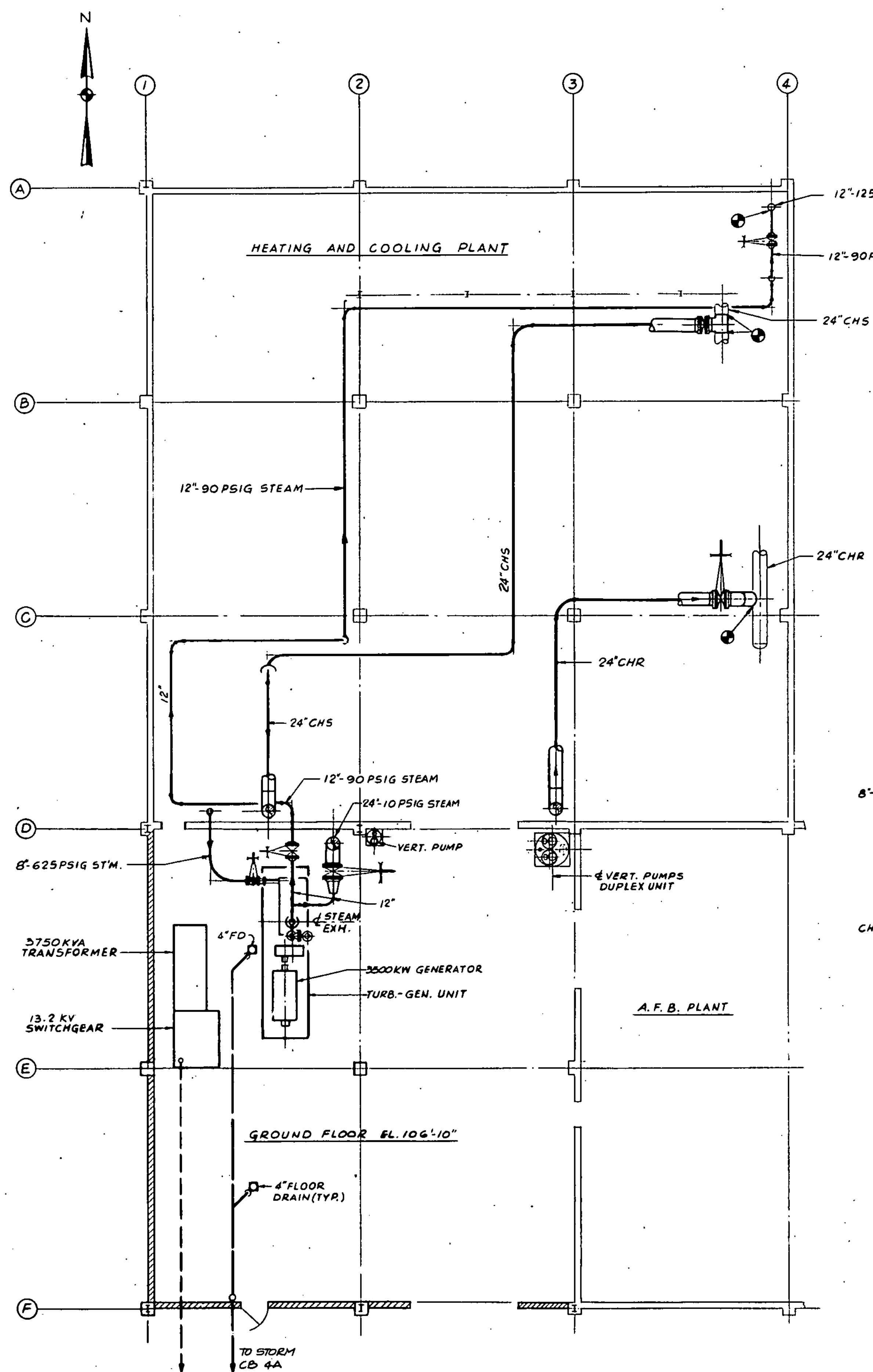
b. Absorption machines use more steam per ton of refrigeration than high pressure, turbine driven centrifugal machines.

c. Relatively low electrical output during summer cooling when campus electrical load peaks.

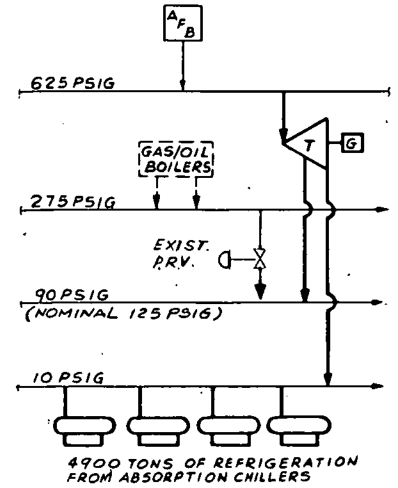
3.6 Alternate Scheme E

Scheme E, shown on Exhibit 3-9, is one in which maximum electrical generation is attained during summer months to offset the higher costs of electrical energy purchased under the provisions of time-of-day metering. The turbine generator would backpressure at 10 psig and be provided with a 90 psig extraction point. This scheme is not true cogeneration since its function is to generate maximum electricity rather than only that which is a by-product of campus steam requirements.

In summer operation, the full 100,000 lb/hr turbine inlet steam flow would be exhausted at 10 psig. There is no requirement for this amount of low pressure steam in the existing plant. For this scheme to have a practical application, it must be coupled with 4900 tons of new absorption refrigeration equipment which would supplant most of the existing 6000 tons of existing centrifugal chiller capacity as the primary central chiller plant. During peak cooling periods of the summer, the entire steam flow would pass through the turbine to the absorption chillers, thus producing maximum electrical energy coincident with the periods of maximum cooling. In this scheme, one of the existing gas/oil fired boilers must be on line to supply 275 psig steam to one of the existing centrifugal chillers to make up cooling capacity required in excess of the 4900 tons provided by the absorption chillers, and to provide 90 psig steam for export. In winter operation the 10 psig exhaust steam flow would be reduced to the minimum necessary to cool the turbine blades in the last stage and would be further used for feedwater heating. In winter months most of the turbine steam flow would be extracted at 90 psig to satisfy campus heating loads.

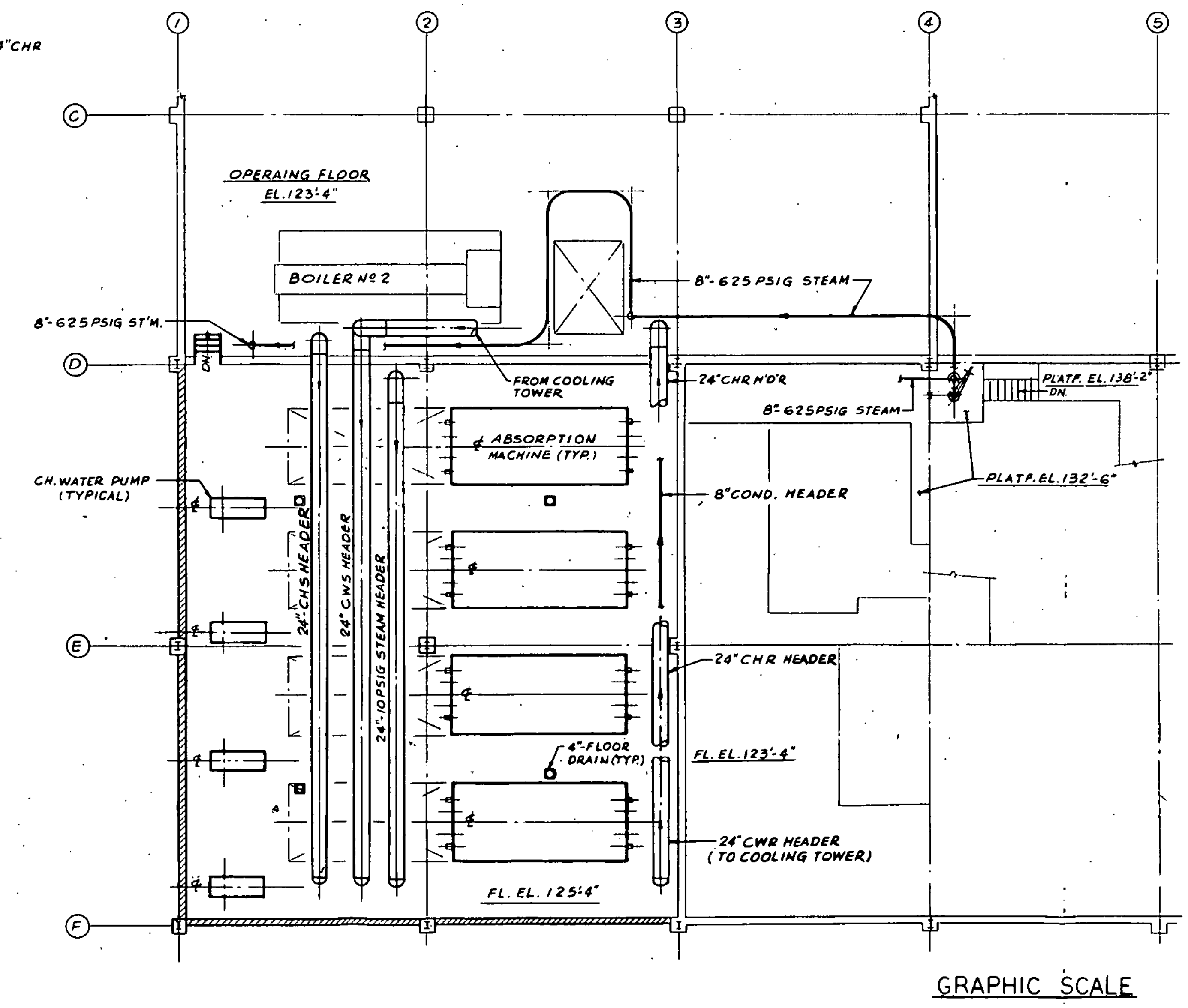


PLAN EL. 106'-10"



MAXIMUM STEAM FLOW (LB/HR) & K.W. PRODUCED	
SUMMER	WINTER
3300KW	2390KW
	90,000
100,000	10,000

FLOW DIAGRAM



PLAN EL. 123'-4"

EXHIBIT 3-9

COGENERATION SCHEME E

POPE, EVANS AND ROBBINS

With 100,000 lb/hr turbine inlet steam flow, the turbine generator would provide a maximum of 3300 kW in summer months and 2390 kW in winter months.

Space requirements are considerably increased, however. A two-level, four-bay extension will be required as shown on Exhibit 3-9.

Whereas this scheme provides for maximum electrical generation during summer months to offset the high cost time-of-day charges for purchased electricity, these savings will be offset to some extent by the higher operating costs of the less efficient absorption chillers. The centrifugal chillers require about 14 pounds of steam per ton of refrigeration. The less efficient absorption machines will require about 19 pounds per ton. These factors are considered in the life cycle cost analysis.

Projected annual generation for this scheme is 18,203,000 kWh for an annual energy savings of 128.2×10^9 Btu when compared to the equivalent utility generation at 11,600 Btu/kWh. The offsetting increased Btu requirement for absorption refrigeration is an annual 81.8×10^9 Btu, leaving a net annual energy savings of 46.4×10^9 Btu.

Advantages of this scheme include:

a. Increased summer electrical generation with attendant increased savings in purchased electrical costs.

b. Additional chiller capacity becomes available for meeting the university's chilled water demands. The limitations on central chiller capacity is the cooling tower which is rated at about 6000 tons.

Hence the fact that installed chiller capacity is increased to about 10,900 tons does not allow the plant to operate above the capacity of the cooling tower. It should be noted that there are relatively inexpensive means of increasing cooling tower performance to permit some additional thermal loading of the existing tower.

Disadvantages include:

a. Building expansion to accommodate this scheme is much greater than in preceeding schemes.

b. Existing gas/oil fired boilers must be operated for greater periods of the year than in preceeding schemes.

c. If the AFB boiler or the turbine generator were to go out of service during summer months when campus electrical demand is peaking, it would be extremely difficult for the university to reduce electrical load equivalent to the level of on-site generation affected. Therefore, a new monthly peak billing demand is likely to be charged to the university.

3.7 Alternate Scheme F

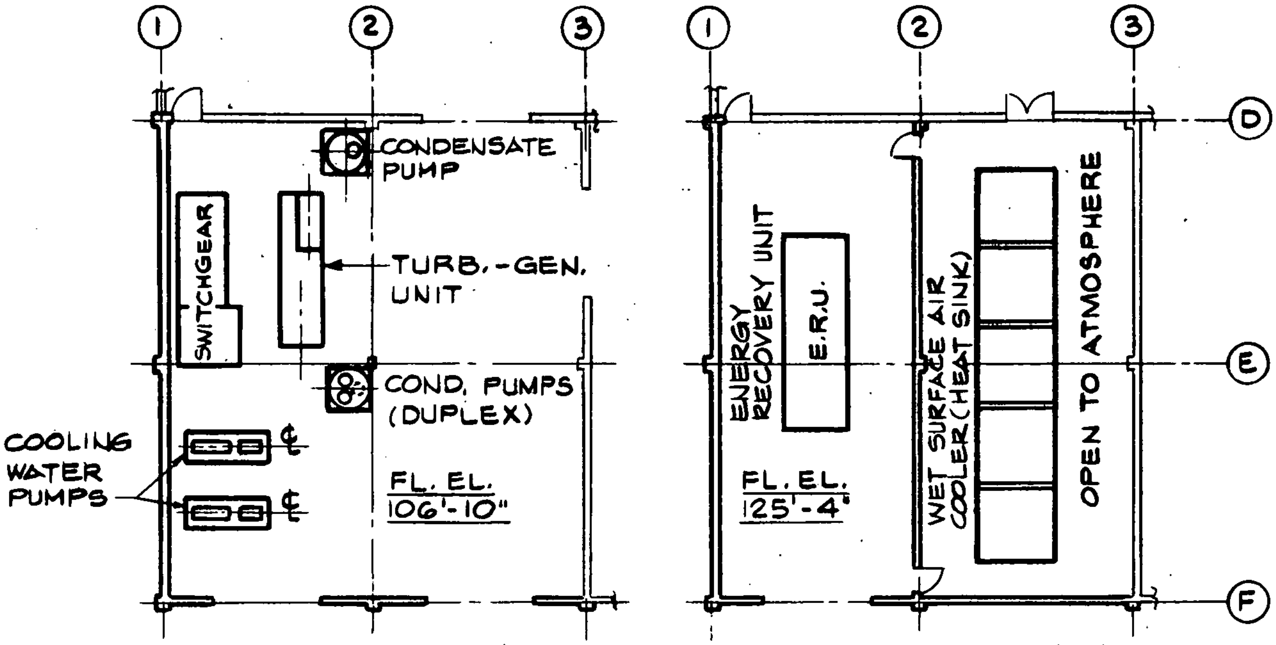
In Alternate Scheme F, a 3500 kW turbine generator is combined with an energy recovery unit (ERU) to achieve maximum on-site electrical generation during summer. A flow diagram and plan view for this scheme is shown on Exhibit 3-10. The turbine generator is identical with that considered in Scheme E. In place of the absorption refrigeration machines operating from the 10 psig turbine exhaust, an ERU operating on the Rankine cycle is used to produce additional electrical energy during summer months when purchased electricity carries a premium charge.

Scheme F is not a true cogeneration scheme because the summer steam flow from the AFB unit is used exclusively for generation of electrical energy. Thus, this scheme is in direct competition with the utility. If the 10 psig steam is a true waste product, then the competition would favor self-generation. This would be the case where a process exhaust is discharged to atmosphere as a non-recoverable product. In the case of GU, the 10 psig steam is condensed for reuse in the boiler and thus does not qualify as a waste stream. Scheme F also necessitates operating an oil/gas fired boiler to produce steam during summer months for the central turbine driven chillers and to supply export steam requirements.

As the Rankine cycle requires a heat sink, in the manner as the refrigeration cycle, a series of wetted surface gas to air heat exchangers would be placed on the roof, concealed behind a wall at the south of the building. The process would thus require a two-story, four-bay extension to the existing plant.

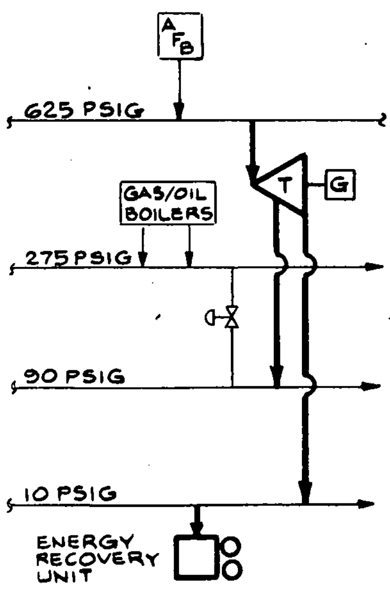
Projected annual generation for this scheme is 28,000,000 kWh for an annual savings of 197 x 10^9 Btu. There is an

COGENERATION SCHEME F



PLAN AT EL. 106'-10"   PLAN AT EL. 125'-4"

0' 5' 10' 20' 30'
GRAPHIC SCALE



MAXIMUM STEAM FLOW (LB/HR) & K.W. PRODUCED	
SUMMER	WINTER
3300 + 2500 = 5800KW	2390KW
	100,000
100,000	

FLOW DIAGRAM

EXHIBIT 3-10

offsetting increase energy use of 213 x 10^9 Btu in operating the gas/oil fired boilers in the summer giving net annual deficit of about 16 x 10^9 Btu.

Advantages of this scheme include:

a. Increased summer electrical generation with attendent increased savings in purchased electrical costs.

Disadvantages of this scheme are:

a. Building extension to house this scheme is costly.

b. Existing gas/oil fired boilers must be operated during the summer to produce chilled water and deliver 90 psig steam to the campus.

c. If the ERU is unavailable, only small quantities of electricity could be generated in the summer as the need for 90 psig and 10 psig steam is small.

As this scheme produces an energy loss, it is not given further consideration.

3.8 Life Cycle Cost Analyses

The derivation of life cycle cost analyses of the six cogeneration schemes considered appears in the Appendix of this report and results are summarized in Table 3-3 below.

TABLE 3-3

LIFE CYCLE COST ANALYSES FOR COGENERATION SCHEMES

Scheme	Initial Cost ($\$ \times 10^3$)	Annual Electrical Generation (10^3 kWh)	Discounted Payback Period (Yrs) @ 10% Discount Rate	@ 3% Discount Rate
A	1,180	9,100	3.97	3.61
B	1,348	9,900	4.05	3.67
C	1,669	9,375	5.59	4.82
D	1,578	7,998	6.70	5.63
E	3,361	18,203	5.35	4.65
F	6,179	28,000	5.87	5.06

3.9 Incremental Savings and Optimization

Energy savings under each of the alternate schemes considered is tabulated in Table 3-4 below.

TABLE 3-4

ENERGY SAVINGS FOR ALTERNATE COGENERATION SCHEMES

Scheme	Initial Cost ($\$ \times 10^3$)	Discounted Payback Years (@ 10% Discount)	Annual Energy Savings: Energy** (10^9 Btu)	Equiv. Barrels Oil*	Energy/ Investment (10^3 Btu/$)
A	1,180	3.97	64.1	10,300	54
B	1,348	4.05	69.7	11,200	52
C	1,669	5.59	66.0	10,700	40
D	1,578	6.70	56.3	9,100	35
E	3,361	5.35	46.4	7,500	14
F	6,179	5.87	(16)***	-	-

Schemes A and B offer comparable discounted payback periods and Btu savings per dollar of investment. Scheme B provides 9 percent greater energy reduction than Scheme A at a cost differential of 14 percent. Implementation of either scheme is recommended.

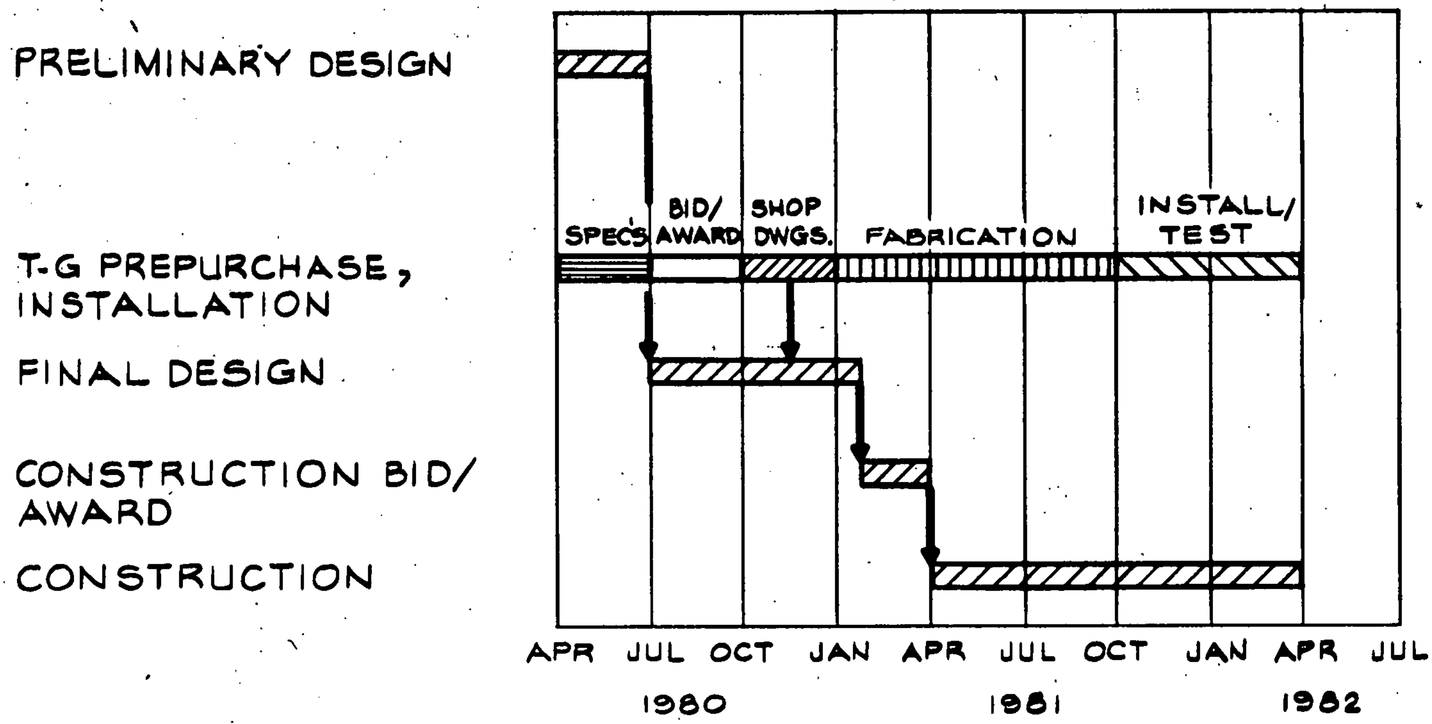
Capital investment requirements are developed for Scheme A in the time schedule shown on the next page. Requirements for Scheme B would be similar with minor modifications.

*42 gals/barrel x 148,000 Btu/gal = 6.2×10^6 Btu/barrel.

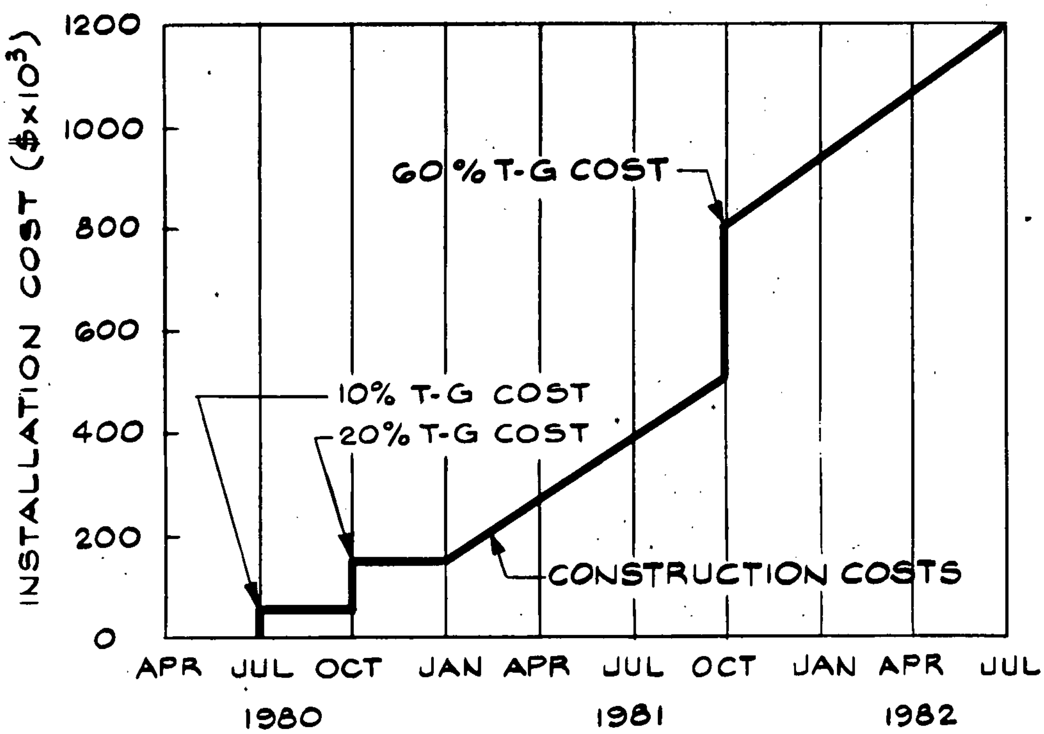
**Based on a turbine heat rate of 3413 Btu/kWh and associated efficiencies of 83% for the boiler, 95% for the generator and 95% for electrical distribution, for a net heat rate of 4556, Btu/kWh. This is comparable to a utility company heat rate of 11,600 Btu/kWh.

***Energy loss, therefore, no savings.

SCHEME A- COGENERATION



CONSTRUCTION SCHEDULE



INVESTMENT CASH FLOW (UNDISCOUNTED)

3.10 Conceptual Design

Conceptual designs were developed for each of Schemes A through F and a tentative design for Scheme F. These appear in Exhibits 3-4, 3-6, 3-7, 3-8, 3-9 and 3-10 respectively. Simplified flow diagrams for each scheme appear on the above exhibits.

For Scheme A, which is the lowest capital cost and most cost effective energy reduction scheme, the proposed schedule is developed in Subsection 3.9 preceding.

Considering the early payback for Scheme A, it is recommended that the preliminary design phase be authorized immediately concurrent with authorization to prepare prepurchase specifications for the turbine generator. The proposed project schedule assumes that the turbine generator and associated equipment will be prepurchased and that the final design will be formulated on the basis of the actual equipment to be installed. This procedure will insure the earliest completion of installation and eliminates the potential need to redesign the cogeneration facility for a turbine generator other than the unit for which the initial design was based.

SECTION 4

4.0 ADDED COAL, LIMESTONE AND ASH STORAGE AND HANDLING

4.1 General

The central element in the Georgetown University ICES is the newly constructed, coal fired, atmospheric fludized-bed boiler plant. Rated at 100,000 lb/hr output, this unit has the capacity to supply the bulk of the university's steam requirement. Coal fuel is substantially more economical than natural gas and fuel oil as noted in the following comparison of December 1979 approximate cost figures:

	$ Per Unit	Btu Content	$ Per Million Btu
Coal	± 40/T	12,750/lb	1.57
Interruptible Gas	3.38/cf	1,030/cf	3.48
No. 5 Fuel Oil	0.78/gal	147,500/gal	5.29
Electricity	0.037/kWh	3,413/kWh	10.84

Assuming that the cost of coal will not escalate as rapidly as natural gas or fuel oil, the fuel cost factor will increasingly favor coal and, therefore, enhance the economic benefits to Georgetown University that can be realized by maximum steam generation from the AFB unit.

This factor was recognized in the statement of work for this Feasibility Analysis, which contains the following directive:

"Evaluate alternate means of:

- Delivering coal and limestone to GU storage.
- Enlarging on-site storage capability for coal, limestone and ash.
- Interconnecting present storage bunkers and silos in the AFB plant with additional storage as may be proposed."

As originally constructed, the AFB plant was limited in space available for storage of coal, limestone and ash by the restraints imposed by the building envelope. Exhibit 4-1 shows the present truck entry area, coal and limestone storage bunkers, and ash silos in plan view. It will be noted that three bunkers are available for coal storage, one bunker for limestone storage, and one silo each for bed material and flyash respectively. Ash silos are suspended above the truck entry. Trucks are used for transport of coal and limestone to the plant, and for removal of spent bed material and flyash. The truck entry area provides space within the building for unloading coal and limestone, and for loading ash. Additional provisions are included for unloading limestone from a point outside the plant to minimize truck waiting time.

Storage capacity built into the existing AFB plant is summarized in Table 4-1 below.

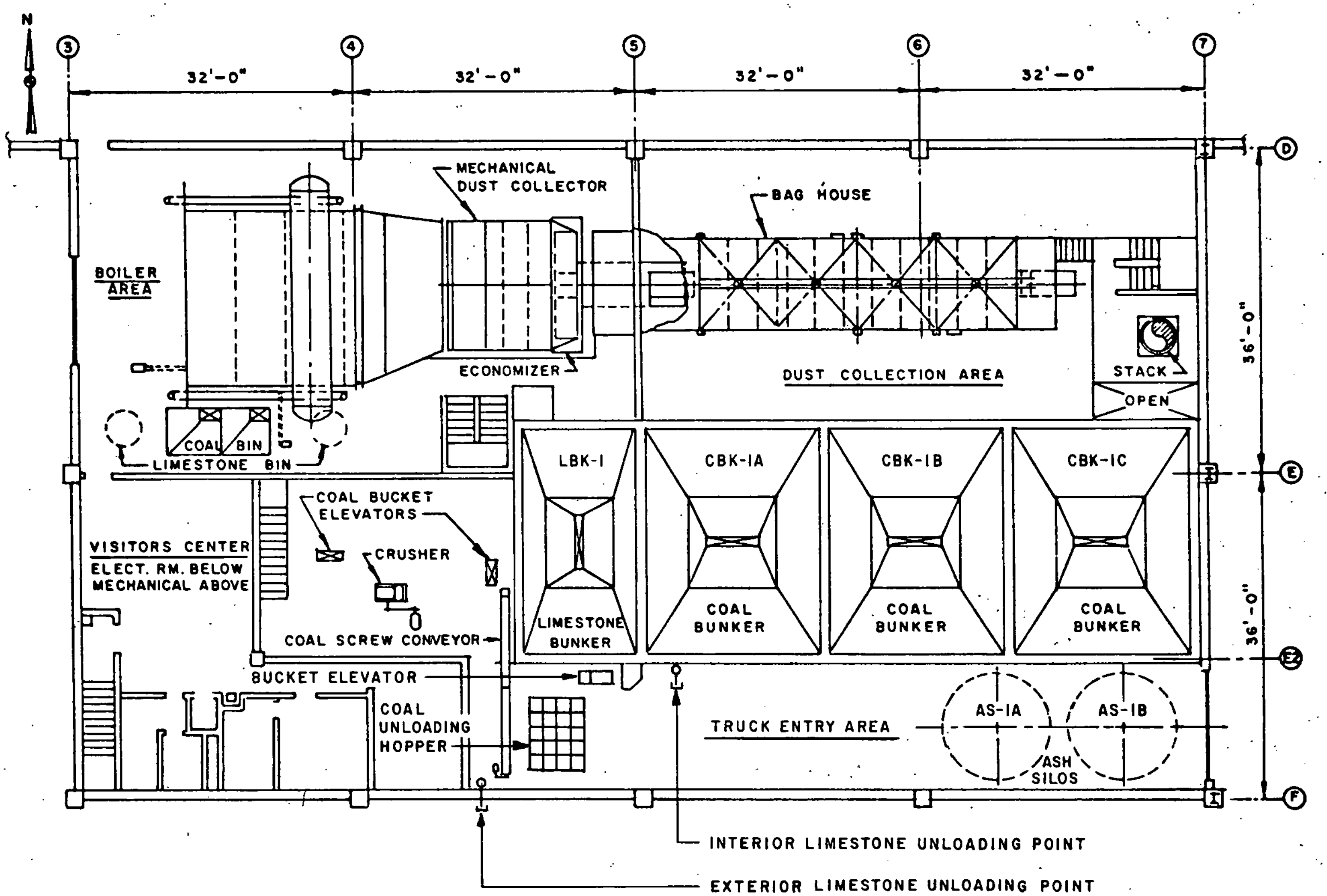
TABLE 4-1

AFB PLANT COAL, LIMESTONE AND ASH STORAGE CAPACITY

MATERIAL	BULK DENSITY (lb/ft^3)	STORAGE CAPACITY ft^3	STORAGE CAPACITY Tons	DAYS STORAGE At 80% Load
Coal	50	42,900	1,080	12
Limestone	90	9,740	440	14*
Bed Material	67	2,480	80	3.5
Flyash	34	2,480	42	2.3

*Limestone storage based upon burning 3.3%S coal

AFB PLANT
PLAN VIEW



POPE, EVANS AND ROBBINS

EXHIBIT 4-1

Trucks delivering coal and limestone, or removing ash from the plant enter the campus through the Gymnasium parking lot located immediately adjacent to the plant. At full load operation, the following numbers of trucks are required:

Material Hauled	T/Day	T/Truck	No. Trucks/Day
Coal	115	25	4.6
Limestone	39	25	1.6
Bed Material	29	20	1.5
Flyash	23	15	1.5
Total			9.2

Converting the above number of daily trucks to the equivalent number that would be required if trucks are limited to 5 days per week, continuous full load operation of the boiler will require 13 trucks per day.

4.2 Alternate Delivery Means for Coal and Limestone

4.2.1 Background

Georgetown University is located in close proximity to the Potomac River and to a Chessie system railroad siding alongside the river. Potentially, either barge or rail delivery could serve as an alternate delivery means for coal and limestone.

At present, high sulfur coal is obtained from a coal supplier located in Western Maryland, drawing upon high sulfur seams in both Western Maryland and Southwestern Pennsylvania. Delivery from the supplier is by covered truck, a one-way distance of approximately 140 miles.

Limestone is obtained from a quarry and processing plant located in Stevensville, Virginia, about 15 miles south of Winchester. Delivery from the plant is by fully enclosed bulk material transporter with truck mounted blower for unloading. Total one-way distance to GU is approximately 75 miles.

4.2.2 Barge Delivery

Barge delivery is not practical. No facilities exist for barge tie-up and unloading in the vicinity of GU, nor are the coal and limestone sources located such that barge transportation could be considered.

4.2.3 Rail Delivery Considerations

Rail delivery, particularly of coal, was evaluated in depth. Coal unloading facilities for rail delivered coal that once existed within Washington, D.C. have been abandoned with the exception that GSA's Central and West Heating Plants, which currently receive low sulfur coal by rail. Of these two plants, the GSA West Plant is located about one mile from the GU AFB plant. Coal delivered by rail to this GSA plant would still require transhipment by truck to GU.

A meeting was held at GU on November 7, 1979 with a representative of the Chessie System to discuss the potential for rail delivery of coal to a siding located between the Potomac River and the Chesapeake and Ohio Canal immediately west of the GU campus. This is the same siding over which the railroad now moves 5 to 6 coal cars daily to the GSA West Plant and additionally transports lumber to a lumber yard nearby. Exhibit 4-2 indicates the location of the siding and the railroad-owned land upon which coal delivery facilities could be built.

In order to leave the main siding clear for daily rail traffic, an unloading siding would be required. Since land on both sides of the Chessie right-of-way is owned by the National Capitol Park Service (NCPS), all unloading facilities would have to be on railroad property. All costs for constructing the siding, car unloading facility, and transportation to the GU AFB would be at GU expense.

The following items were considered in the evaluation:

- 300 foot siding.
- Enclosed dump facility to accommodate four 65T dump cars.
- Car puller, car shaker and bottom dump hopper.
- Exhaust facility including fugitive dust collection.

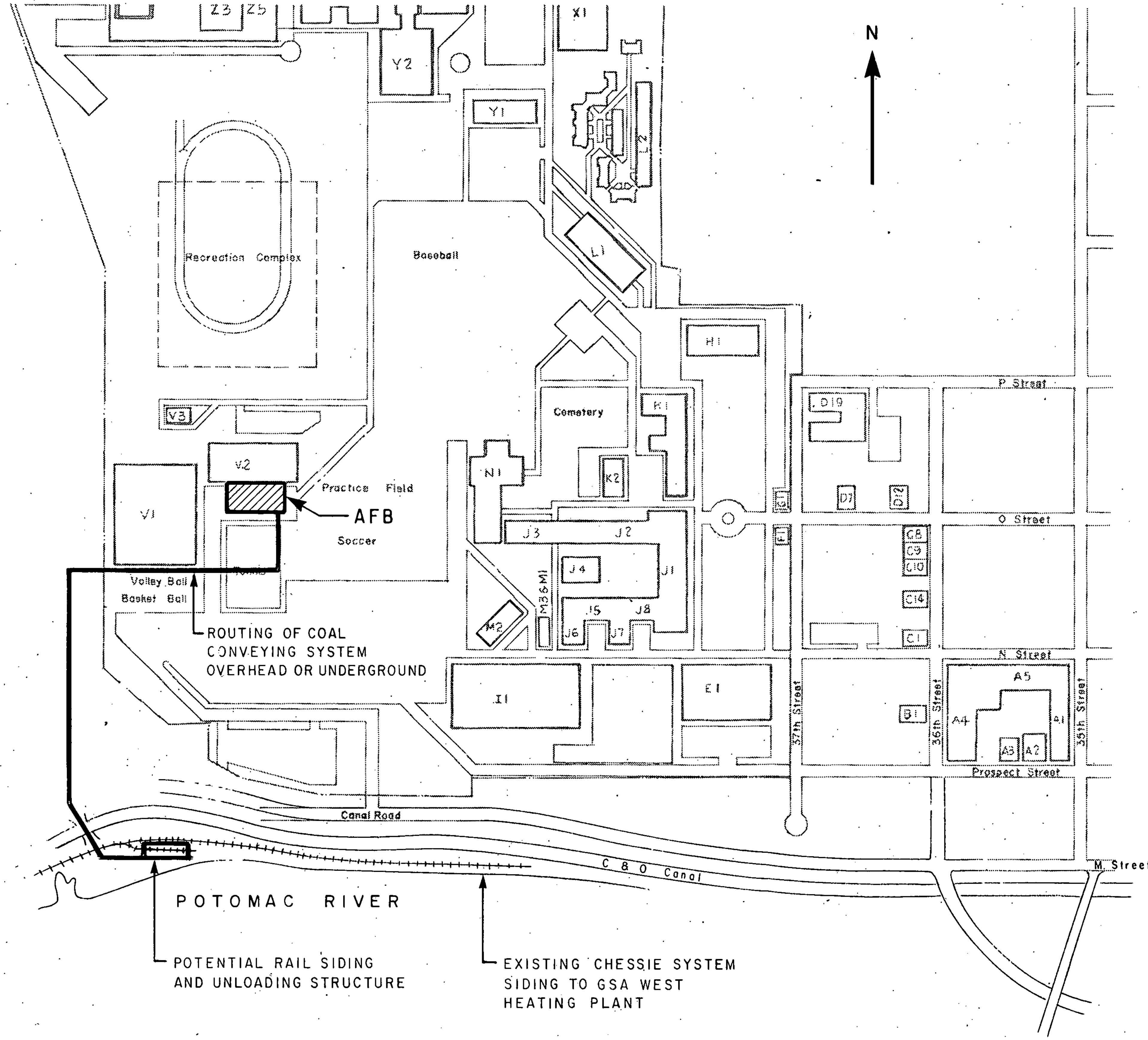


EXHIBIT 4-2

COAL DELIVERY BY RAIL

POPE, EVANS AND ROBBINS

- Conveyor from dump facility up to GU AFB, either in tunnel underground, or overhead in enclosed gallery. Total length of conveyor would be 1650 feet and the rise in elevation from the dump facility to the AFB would be 100 feet. The conveyor best suited for this purpose, whether overhead or underground, appeared to be the "SERPENTIX" conveyor which can negotiate turns without transferring from one belt to another.

- Tunnel conveyor would require escape hatches every 300 feet, lighting and ventilation.

- Conveyor would, of necessity, be routed partially over NCPS property whose approval would be required beforehand.

- Manpower requirements were assumed to be two men assigned to the unloading facility, and a conveyor mechanic for half time, a total of 2-1/2 men.

4.2.4 Rail Delivery Costs

Costs quoted on November 7, 1979 for carload coal deliveries by the B&O Division of the Chessie System are:

- From western Maryland and southwestern Pennsylvania - $13.71/net ton

- From Pittsburgh and most of West Virginia - 14.40/net ton

In the three year period from October 1976 through October 1979, rail delivery costs have increased by 53 percent to the above levels. The current rail charges per ton are within a dollar or two of trucking costs.

4.2.5 Rail Delivery Cost Effectiveness

In this Feasibility Analysis, it is assumed that the GU AFB is operated at 95 percent availability for 10 months per year, a total of 6950 hours per year. If it is further assumed that the average steam generation rate during this period is 75,000 lb/hr, the annual coal consumption becomes 5T/hr x 6950 hr x 0.75 = 26,000 tons.

For purposes of evaluation, it is further assumed that rail delivery of coal to a siding in Washington, D.C. compared with truck delivery direct to the GU AFB plant, represents a cost differential of $5 less per ton by rail.

Potential annual savings = 26,000 x $5 =		$130,000
Operating & Maintenance labor:		
2-1/2 men x $26,000/yr =	$65,000	
Maintenance Costs	15,000	
		80,000
Net Annual Savings		$ 50,000

There is no assurance that a $5 per ton differential exists now, or would continue in the future.

The capital investment required for implementing this approach, including siding, unloading facility, and conveyor up to the AFB, is estimated to cost $3,250,000 if a predominantly overhead conveying system would prove acceptable from the RR siding to the AFB and $10,000,000 if it were required to place the conveyor completely within an underground tunnel.

This scheme is not cost effective and by agreement with GU, it was dropped from further consideration.

4.3 Additional Storage Requirements

Table 4-1 listed the capacity of the existing coal, limestone, spent bed material and flyash storage bunkers and silos in terms of equivalent days operation at 80 percent capacity. Coal and limestone storage is sufficient for upwards of two weeks of boiler operation. Bed material and flyash silos, however, are more limited in their capacity and, for long periods of boiler operation, require frequent trucking for material removal.

Industrial and utility size coal fired boiler plants normally have provisions for storing sufficient coal for 60 to 90 days of operation. The primary reason for on-site storage is to provide sufficient coal to sustain plant operation through emergencies such as inclement weather or strikes by coal miners, railroad employees, or truck drivers. Industrials and utilities are usually not subject to the severe space limitations which prevail at GU. Outdoor coal storage is not uncommon, nor is ponding or other storage facilities for flyash. These options do not exist at GU and hence the continuing operation of the AFB is heavily dependent upon uninterrupted deliveries of coal and limestone, and of truck removals of ash.

To lessen this vulnerability to interruption in service, a stated task of the Statement of Work for this Feasibility Analysis is that of evaluating means of enlarging on-site storage capacity for coal, limestone and ash, and for interconnecting present storage bunkers and silos with additional storage as may be proposed.

Labor disputes often persist for a significant period, but the amount of additional storage that should be considered for GU is tempered by two principal factors:

- Cost of providing additional storage within aesthetically acceptable enclosures, and
- Space limitations.

There are other factors, such as the potential for spontaneous combustion in coal stored for prolonged periods, and hygroscopic action of limestone and ash which creates handling problems. For coal and limestone, storage capacity for the present and proposed storage combined of about 30 days was arrived at as the most feasible target.

Spent bed material and flyash are greatly affected by hygroscopic action. These ash products of fluidized-bed combustion contain a significant percentage of calcium oxide, an extremely hygroscopic chemical that draws moisture from the air and forms a cementitious material. For these materials, a combined storage capacity of about two weeks with present and proposed silos would be the maximum that can be accommodated without risking handling problems that would offset the benefits of a greater storage capacity.

Existing coal handling facilities consist of combinations of screw conveyors, bucket elevators and mass conveyors as shown on Exhibit 4-3. In the alternate schemes considered, provisions were included for interconnecting proposed storage spaces with the present plant coal handling system.

The existing limestone handling system is pneumatic throughout as shown on Exhibit 4-3. In the alternate storage schemes evaluated, consideration was given to interconnecting the proposed storage to the present AFB plant handling system.

Bed material and flyash are also handled pneumatically in the present AFB plant as shown on Exhibit 4-3. Provisions are included in the alternate storage schemes for extending pneumatic handling to the proposed added storage cells.

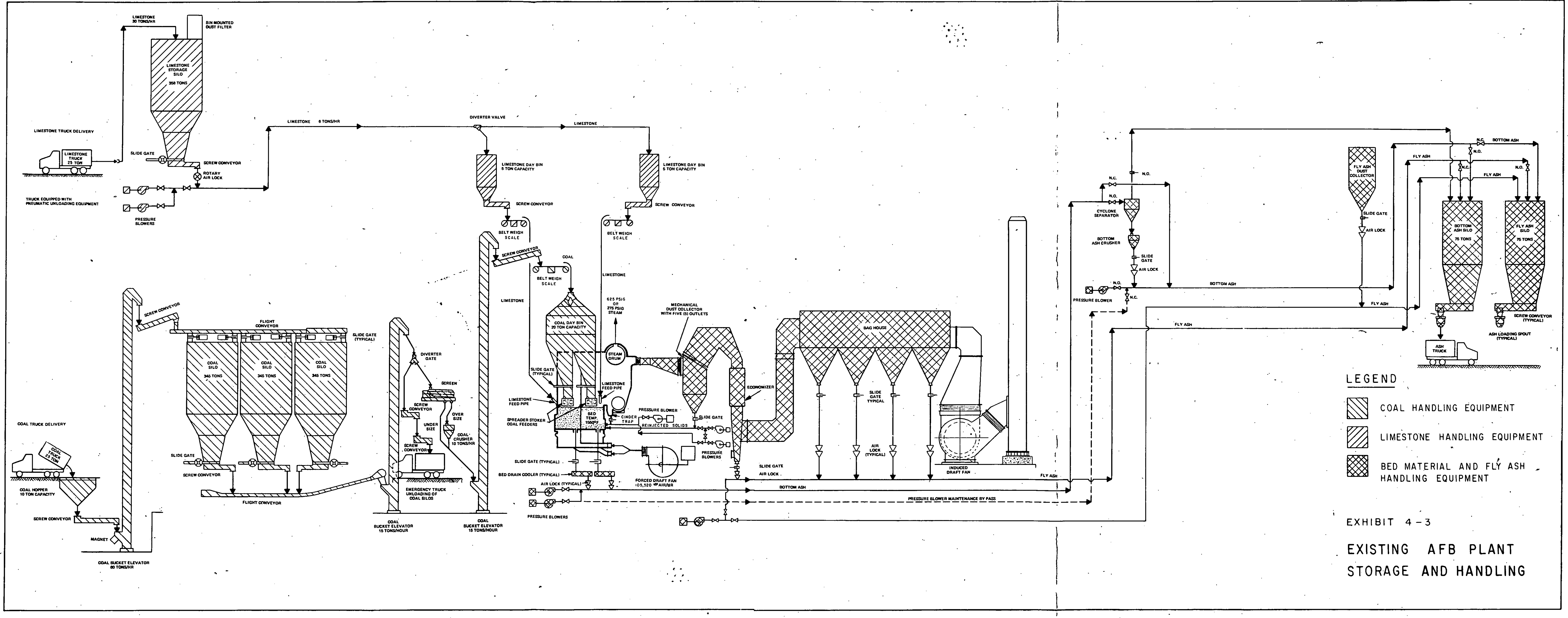


EXHIBIT 4-3

EXISTING AFB PLANT STORAGE AND HANDLING

4.4 Scheme A - Added Storage in Core ICES

The proposed Harbin parking structure - or Core ICES - is to be located immediately east of the AFB plant. This is intended to be a three level parking structure with athletic field above. Its close proximity to the AFB plant appeared to offer high potential for incorporating additional coal, limestone and ash storage into this structure.

A total of five alternative methods were analyzed in which existing AFB storage capacity would be supplemented by additional storage in the Core ICES. Table 4-2 sets forth the apportionment of storage between existing and proposed for each method, and the combined storage resulting therefrom. The material bulk densities upon which the respective capacities were evaluated are as follows:

Coal	-	50 lb/cf
Limestone	-	90 lb/cf
Flyash	-	34 lb/cf
Bed Material	-	67 lb/cf

Consideration of schemes in which existing coal bunkers would be converted to storing the heavier limestone presuppose that the structural strength of the coal bunkers is adequate. The coal bunker design was based on an 800 ton load, well in excess of any loading considered herein. However, the steel hoppers below the coal bunkers will require additional stiffeners if a material more dense than coal is stored therein.

The five methods evaluated are summarized briefly below. For flow diagrams pertaining to each method, reference should be made to Appendix D.

TABLE 4-2

EXPANDED STORAGE IN CORE ICES

	METHOD 1	2	3	4	5
EXISTING AFB PLANT:					
Bunker LBK-1	438T-L*	438T-L	438T-L	326T-B	438T-L
Bunker CBK-1A	360T-C*	643T-L	643T-L	360T-C	321T-L/ 239T-B
Bunker CBK-1B	479T-B*	360T-C	360T-C	643T-L	360T-C
Bunker CBK-1C	243T-F*	360T-C	479T-B	243T-F	360T-C
Silo AS-1A	83T-B	83T-B	83T-B	83T-B	83T-B
Silo AS-1B	42T-F	83T-B	83T-B	42T-F	83T-B
CORE ICES					
Coal Bunkers	2340T	1980T	2340T	2340T	1980T
Limestone Bunkers	512T	0	0	0	0
Flyash Storage	0	128T	320T	0	320T
Bed Material	0	0	0	0	0
COMBINED STORAGE					
Tons of Coal	2700	2700	2700	2700	2700
Days Operation @ 80%	30	30	30	30	30
Tons of Limestone	950	1081	1081	643	759
Days Operation @ 80%	30	34	34	20	24
Tons of Flyash	285	128	320	285	320
Days Operation @ 80%	16	7	18	16	18
Tons of Bed Material	562	166	562	409	405
Days Operation @ 80%	24	7	24	18	18

Tons/day @ 80% Load: Coal - 90T Flyash - 18T
Limestone - 32T Bed Material - 23T

*Legend: C - Coal B - Bed Material
L - Limestone F - Flyash

4.4.1 Method 1

Method 1 proposes to provide a combined total of 30 days storage for coal and limestone; 16 and 24 days respectively for flyash and bed material. Within the existing AFB plant, two of three coal bunkers would be diverted to other usage. One bunker would be used for storing flyash and the other for storing bed material. New storage in the Core ICES would be provided to supplement coal and limestone storage. New truck unloading facilities would be required in the Core ICES to accept coal and limestone deliveries. A common underground conveyor would be required to transport coal and limestone from Core ICES storage to the existing AFB plant. Conveying systems in the existing AFB plant would require revision to accommodate the revised usage of the two converted coal bunkers. A sketch of this arrangement appears on Exhibit 4-4.

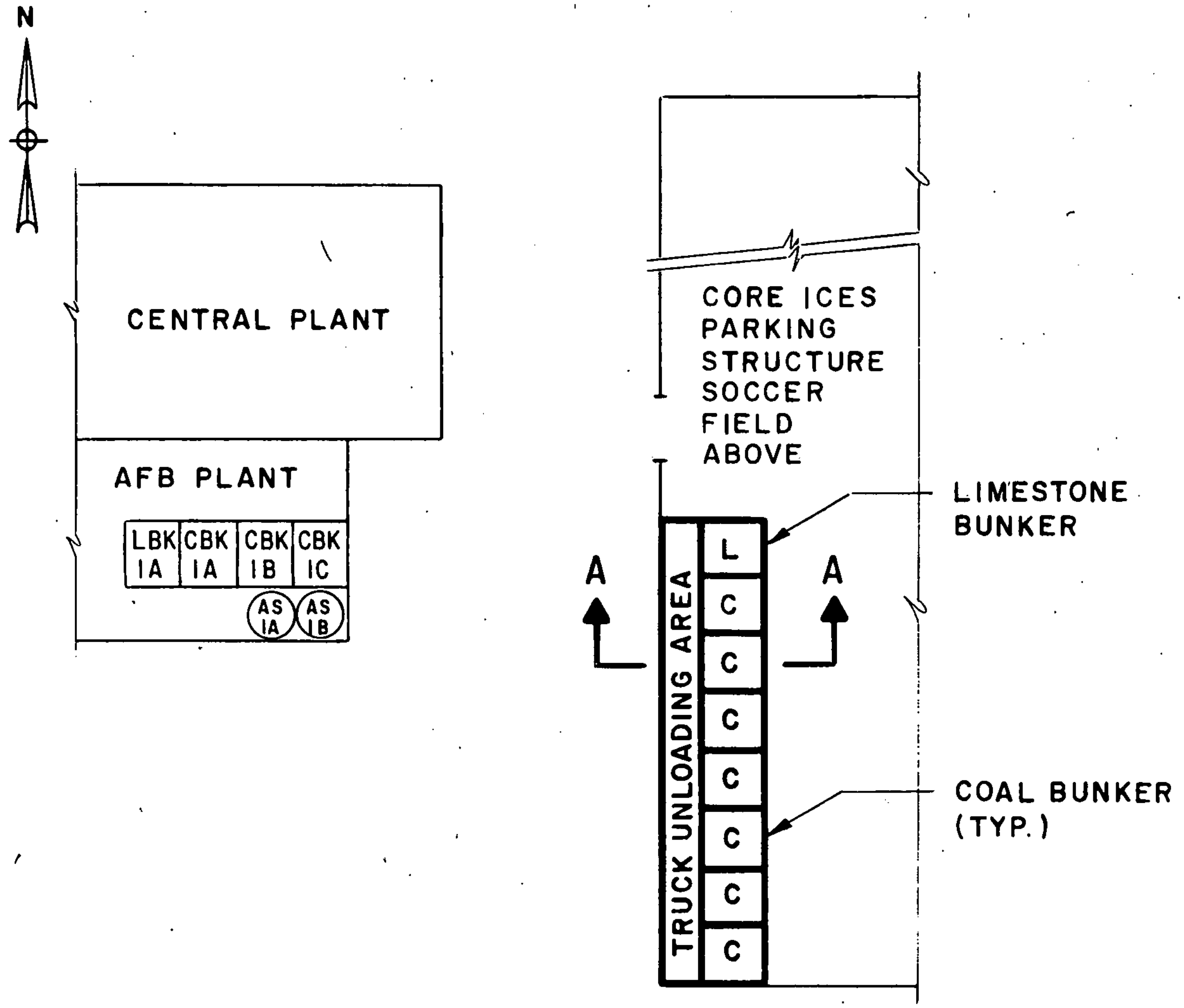
The advantages of this method are:

- Flyash and bed material storage would remain in the existing plant, eliminating problems associated with conveying these materials.
- Multiple plant infeed sites would be available for limestone as well as coal.
- The majority of coal deliveries will be made at the new site, eliminating possible interference with ash removal.

The disadvantages are:

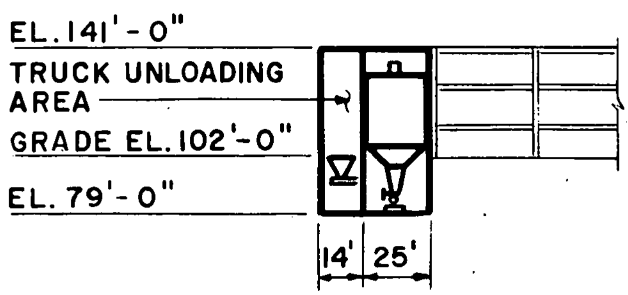
- AFB plant "in house" coal supply is limited to four days.
- Limestone conveyance from the new facility to the AFB will require the purchase of at least one high horsepower pressure blower.

SCHEME A
ADDED STORAGE IN CORE ICES



PLAN

SCALE: 1" = 60' – 0"



SECTION A - A

SCALE: 1" = 60' - 0"

EXHIBIT 4-4

4.4.2 Method 2

Under Method 2, combined storage capability would total 30 days for coal, 34 days for limestone, but is reduced to 7 days each for flyash and bed material.

In this configuration, one of the two AFB plant coal bunkers is converted to limestone storage thus placing all limestone storage within the AFB. Both ash silos are dedicated to bed material storage. Additional storage is provided in the Core ICES for coal and flyash.

As with Method 1, additional conveying facilities are required between the AFB and the Core ICES, and further modifications are required in the existing plant.

Space requirements within the Core ICES are similar to that shown on Exhibit 4-4 for Method 1.

The advantages of this method are:

- Flyash can be unloaded independently from plant operations.
- Flyash is easily transported due to its size and bulk density, requiring little power.
- The majority of coal deliveries will be made at the new site, eliminating possible interference with ash removal.
- Bed material storage remains in the existing plant.
- Limestone storage remains in the existing plant, eliminating costly conveyance.

- "In house" coal supply is 8 days rather than 4 days.

Offsetting disadvantages are:

- Flyash loading facility will be required at the new site.

- Available solid wastes storage imposes a limitation of 7 equivalent operating days.

4.4.3 Method 3

Method 3 involves converting one of the three coal bunkers in the AFB plant to limestone and one to bed material leaving only one bunker at that location for coal storage. Both ash silos would be used for bed material storage. Combined storage, including proposed facilities in the Core ICES would again be 30 days for coal, and 34 days for limestone, but flyash and bed material storage capacity would be increased to 18 and 24 days respectively. All limestone and bed material storage would be in the AFB plant; all flyash storage in the Core ICES, and coal predominantly stored in the Core ICES with only one bunker remaining at the AFB plant.

Space requirements within the Core ICES are similar to that required for Method 1.

The advantages of this method are:

- Flyash can be unloaded independently from plant operations.

- Flyash is easily transported due to its size and bulk density.

- The majority of coal deliveries will be unloaded at the new site, eliminating possible interference with ash removal.
- Bed material storage remains in the existing plant.
- Limestone storage remains in the existing plant, eliminating costly conveying.

Disadvantages are:

- Flyash loading facility will be required at the new site.
- "In house" coal supply is limited to 4 days.

4.4.4 Method 4

In Method 4, the present AFB plant limestone bunker is dedicated to bed material storage which, when coupled with the existing bed material silo, provides 18 days of storage capacity. The first coal bunker in the AFB plant remains committed for that purpose and is supplemented by additional coal storage in the Core ICES for a total of 30 days capacity. The middle coal bunker is converted to limestone storage with 20 days capacity. The third coal bunker is converted to flyash storage which, when coupled with the existing flyash storage, provides 16 days of storage capacity. The Core ICES, in this arrangement, provides only for additional coal storage.

Space requirements within the Core ICES are similar to the requirements under Method 1.

Advantages of this method are:

- All solid waste and limestone storage remains in the existing plant, eliminating problems associated with conveying these materials.

- 16 to 18 total equivalent operating days of solid waste storage will be created.

The disadvantages are:

- A limitation of 20 days storage capacity of limestone is imposed.

- AFB plant "in house" coal supply is limited to 4 days.

- Considerable rework of AFB plant internal materials handling systems is required.

4.4.5 Method 5

In Method 5, the limestone bunker and two coal bunkers remain dedicated as before. One coal bunker would be converted to a dual bunker containing bed material and additional limestone. Both ash silos would be dedicated to bed material storage. Added storage placed in the Core ICES would accommodate additional coal and flyash storage.

Storage capacities by this method are 30 days for coal, 24 days for limestone, and 18 days for both bed material and flyash.

- Flyash can be unloaded independently from plant operations.

- Flyash is easily transported due to its size and bulk density.

- The majority of coal deliveries will be unloaded at the new site, eliminating possible interference with ash removal.

- Bed material and limestone storage remain in existing plant, eliminating costly conveying.

Disadvantages:

- Flyash loading facility will be required at new facility.

- Problems associated with CBK-1A Bunker Division must be considered in detail.

4.4.6 Conclusions

As a result of the above evaluations, it became apparent that incorporating additional coal, limestone and/or ash storage into the Core ICES introduced problems which detracted materially from any potential advantages.

For added storage in the Core ICES to be practical, it must utilize the full height of that structure, as shown on Exhibit 4-4, in order to provide means of bringing trucks in for unloading, and for removing stored materials from bunkers or silos. This requirement seriously restricts the use of the Core ICES as a parking structure.

A more serious consideration is that of accommodating trucks in and out of the structure without impeding auto traffic, or requiring changes in grade that are incompatible with the development of the Core ICES and access thereto.

The above, coupled with the necessity of providing means for conveying materials back and forth between the AFB plant and the Core ICES storage area led to a decision by Georgetown midway into the Feasibility Analysis to abandon this approach.

In its place, the decision was made to evaluate the creation of additional storage in an addition to the AFB plant to the south. This location offers several advantages over those discussed above and are addressed in Subsection 4.5 following.

4.5 Scheme B - Added Storage in Extension to AFB Plant

Providing additional storage in an extension to the AFB plant offers several advantages, of which the following are of greatest importance:

a. Restrict truck traffic to vicinity of existing plant.

b. Minimize plant operating problems.

c. Minimize alterations to existing plant storage.

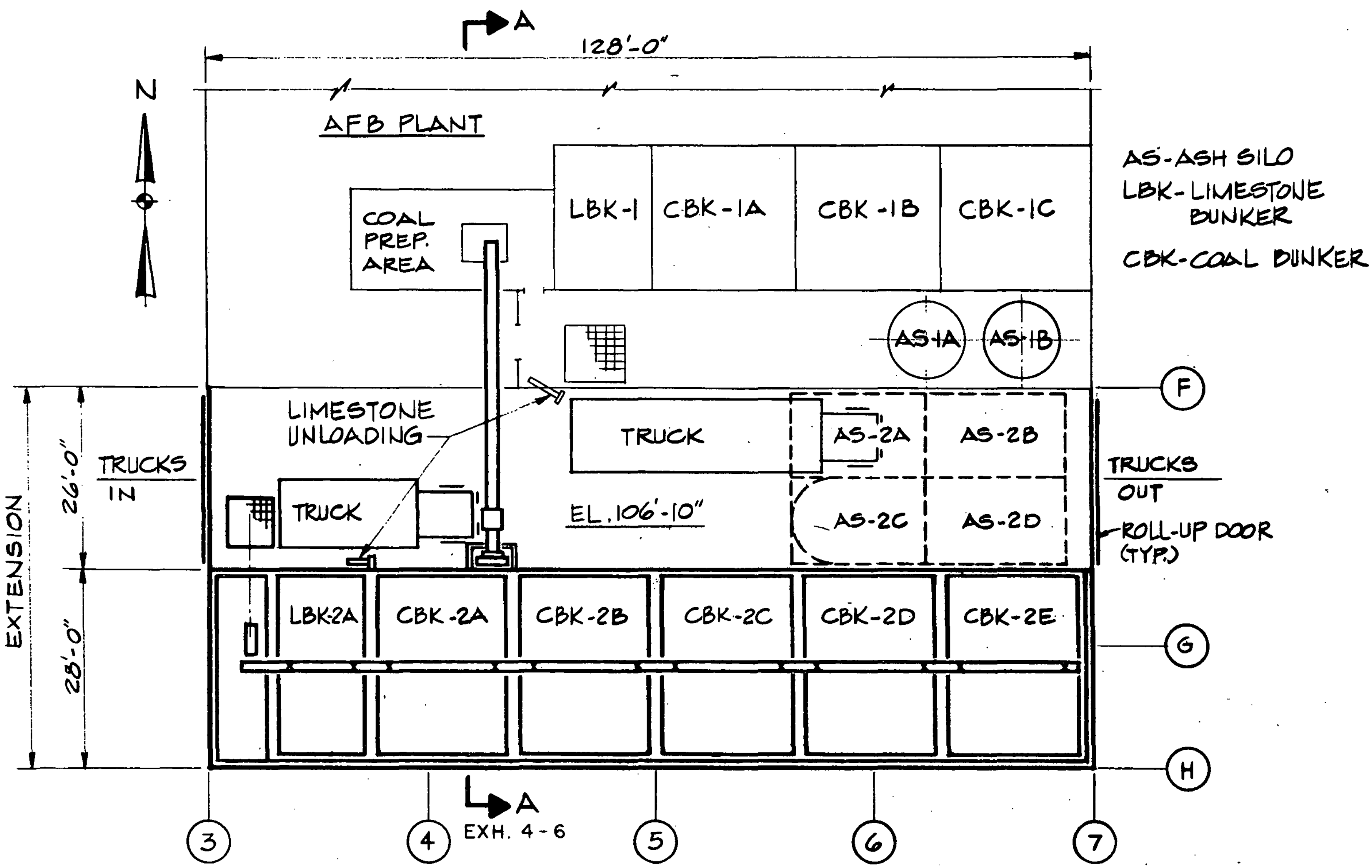
Plant expansion for this purpose is feasible only to the south. Expansions to the east would encroach upon GU plans for the Core ICES structure, whereas expansion to the west is not feasible for lack of adequate space for this purpose, and encroachment upon access to the existing Heating and Cooling Plant.

Expansion to the south entails removal of three tennis courts. GU is creating additional tennis courts elsewhere and has agreed to this approach, if storage at this location is decided upon.

The physical arrangement for Scheme B was developed in cooperation with the GU architect such that its relationship to the Core ICES parking structure was compatible with the Master Plan for development in this area. The pattern for incoming and exiting truck traffic is diverted from the parking structure and confined to the vicinity of the AFB plant.

In plan, the plant extension for the additional storage would appear as shown on Exhibits 4-5 and 4-6. The accompanying flow diagrams are shown on Exhibits 4-7, 4-8 and 4-9 for the proposed coal, limestone and solids removal systems respectively. Storage space for the three materials would

ADDED STORAGE IN EXTENSION TO AFB PLANT

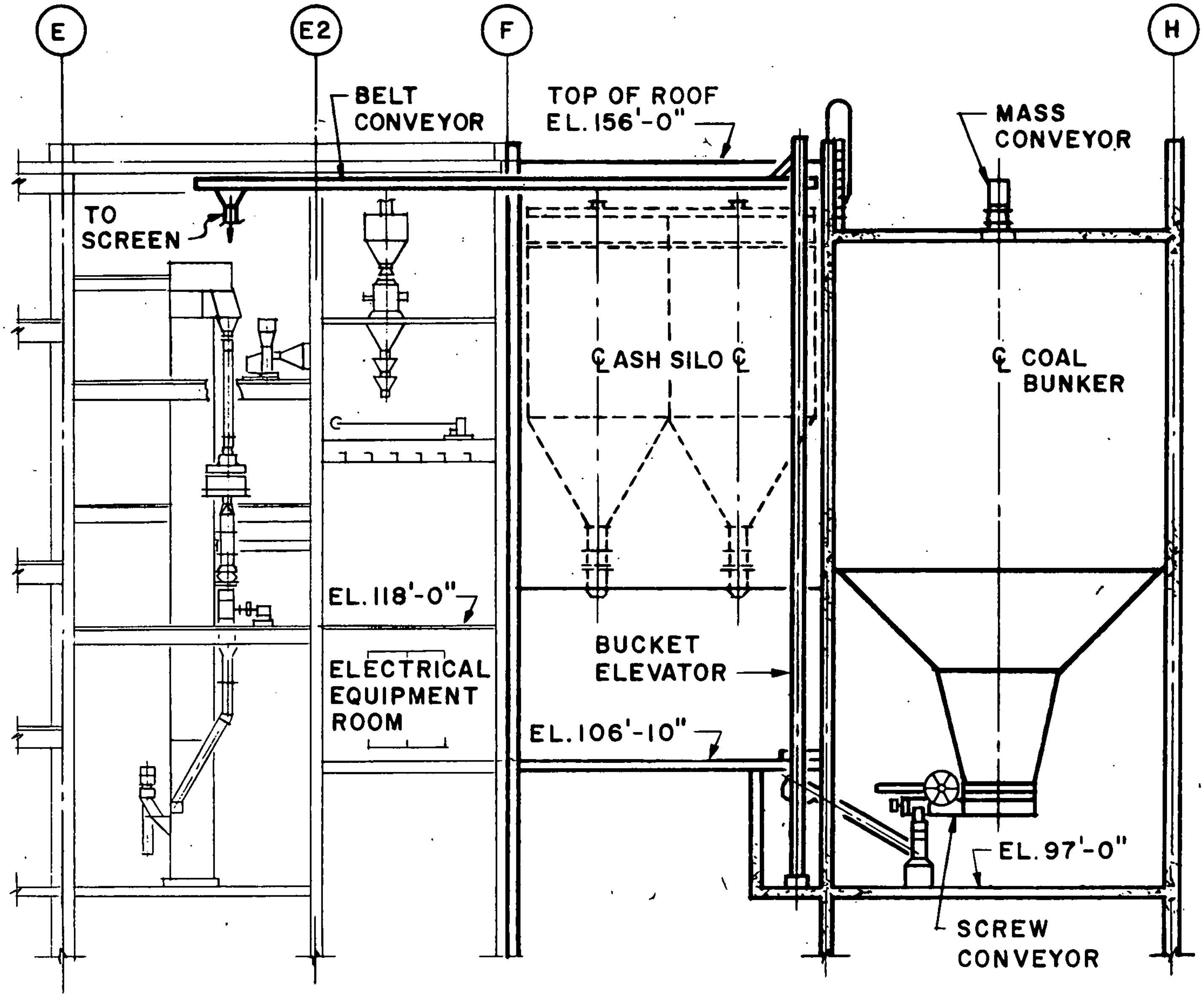


PLAN

POPE, EVANS AND ROBBINS

EXHIBIT 4-5

ADDED STORAGE IN EXTENSION TO AFB PLANT



SECTION A-A

FLOW DIAGRAM
ADDED COAL STORAGE AND HANDLING

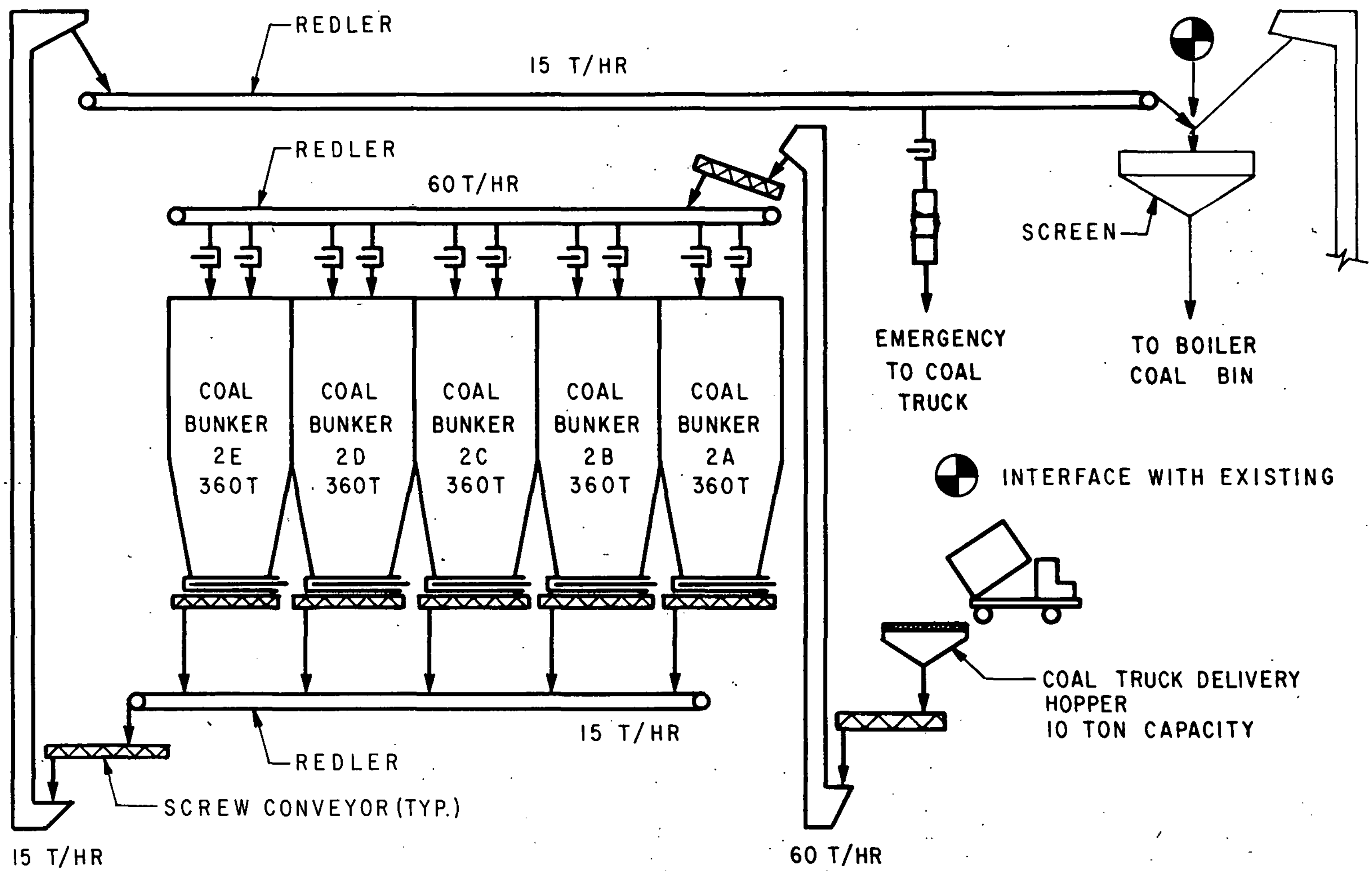


EXHIBIT 4-7

FLOW DIAGRAM
ADDED LIMESTONE STORAGE AND HANDLING

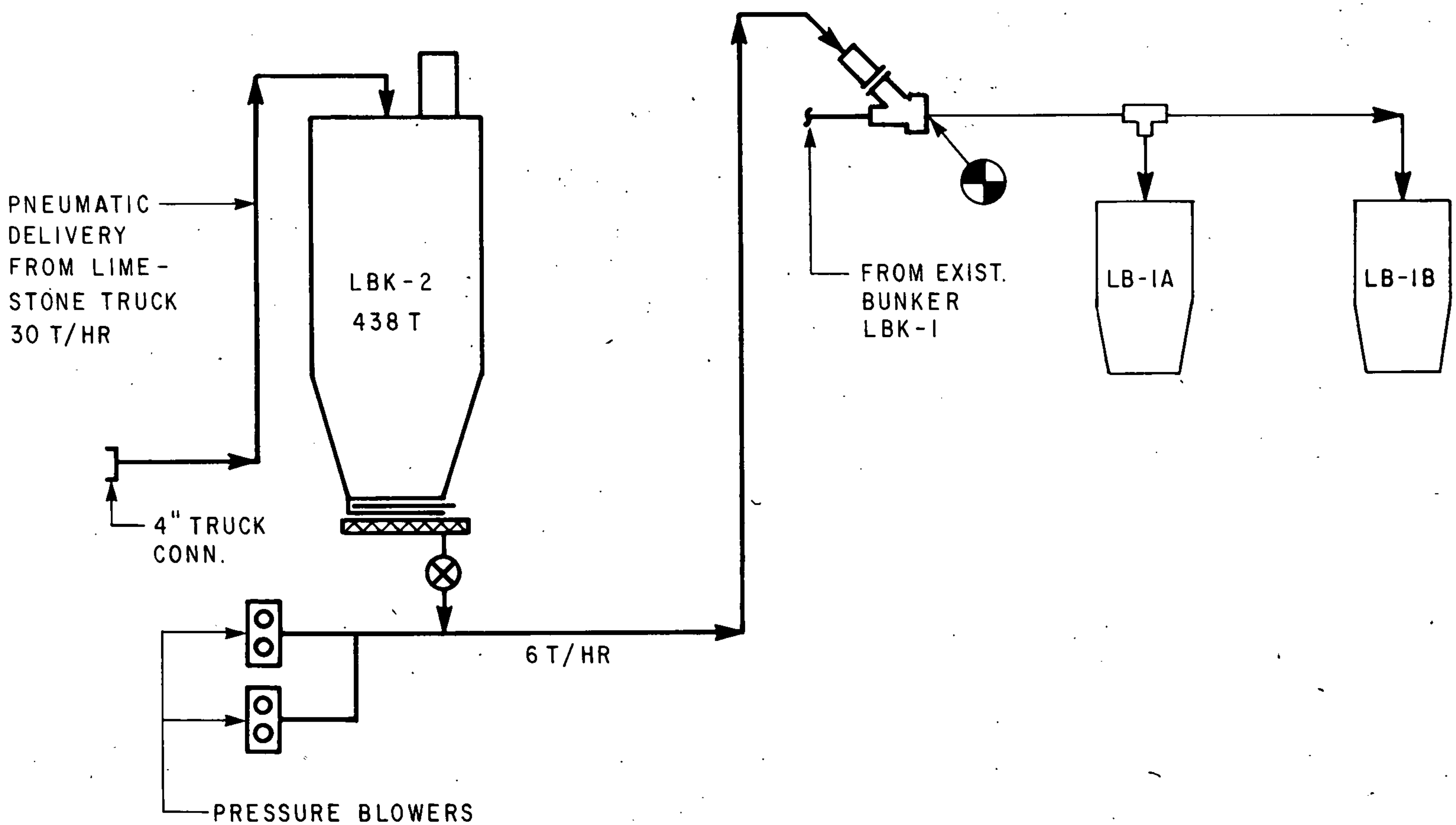
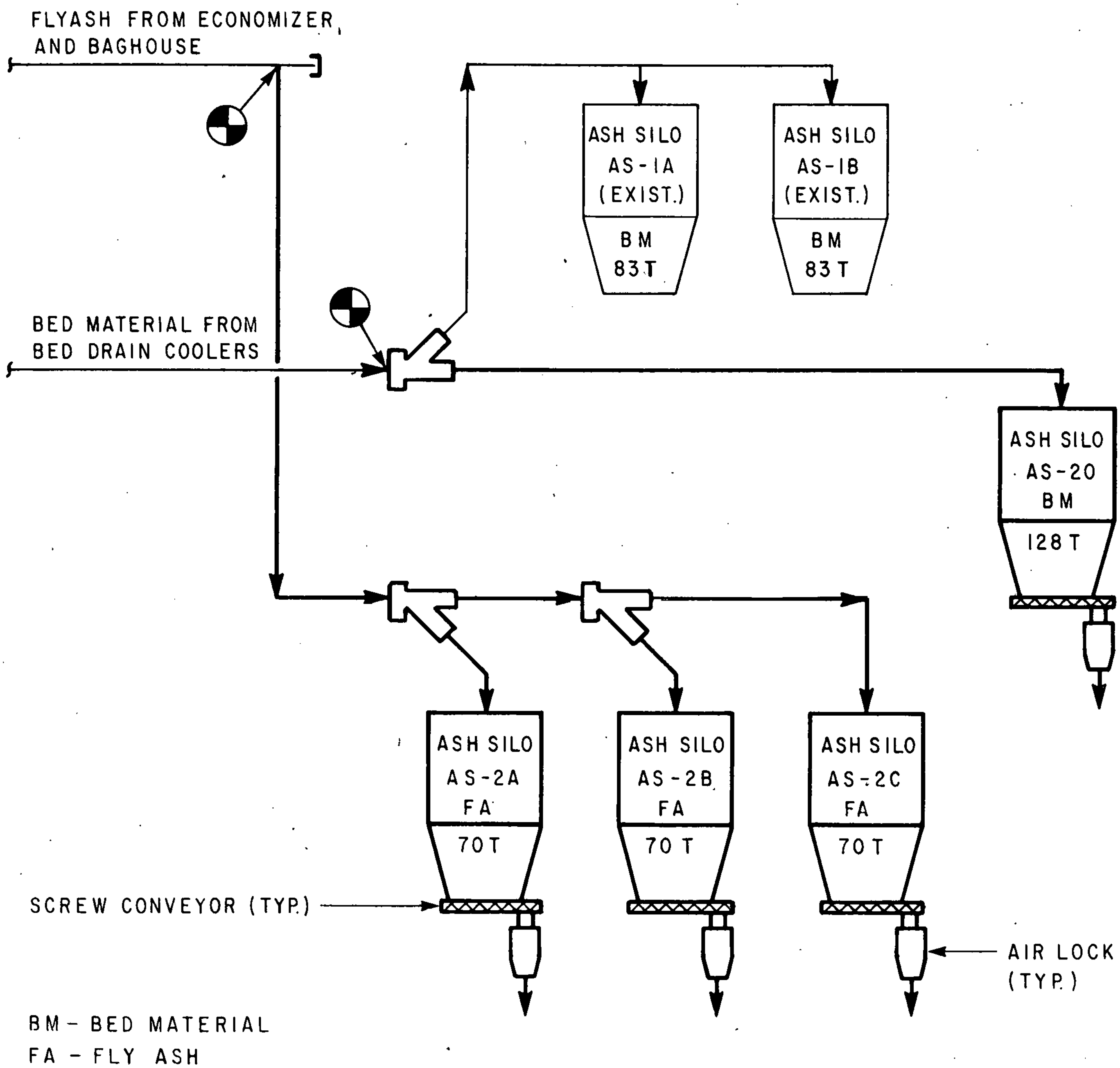


EXHIBIT 4-8

FLOW DIAGRAM
ADDED ASH STORAGE AND HANDLING



be expanded to a new combined total of the existing AFB plant and proposed extension as shown in Table 4-3.

TABLE 4-3

EXPANDED STORAGE IN AFB PLANT EXTENSION

	Coal		Limestone		Bed Material		Flyash	
	Tons	Days	Tons	Days	Tons	Days	Tons	Days
EXISTING PLANT								
Bunker LBK-1	-	-	438	14.0	-	-	-	-
Bunker CBK-1A	360	4	-	-	-	-	-	-
Bunker CBK-1B	360	4	-	-	-	-	-	-
Bunker CBK-1C	360	4	-	-	-	-	-	-
Silo AS-1A	-	-	-	-	83	3.5	-	-
Silo AS-1B	-	-	-	-	83	3.5	-	-
PROPOSED EXTENSION								
Bunker LBK-2	-	-	438	14.0	-	-	-	-
Bunker CBK-2A	360	4	-	-	-	-	-	-
Bunker CBK-2B	360	4	-	-	-	-	-	-
Bunker CBK-2C	360	4	-	-	-	-	-	-
Bunker CBK-2D	360	4	-	-	-	-	-	-
Bunker CBK-2E	360	4	-	-	-	-	-	-
Silo AS-2A	-	-	-	-	-	-	70	3.8
Silo AS-2B	-	-	-	-	-	-	70	3.8
Silo AS-2C	-	-	-	-	-	-	70	3.8
Silo AS-2D	-	-	-	-	160	6.9	-	-
TOTAL	2880	32	876	28	326	13.9	210	11.4

Refer to Table 3-2 for production rate of above material @ 80% load.

In the proposed storage scheme, therefore, additional storage is provided such that the combined capacity for each material, as compared with existing capacity is as follows:

	Existing	Proposed
Coal	12 days	32 days
Limestone	14 days	28 days
Bed Material	3.5 days	12.5 days
Flyash	2.3 days	9.3 days

The number of day's storage is based upon burning coal with about 3 percent sulfur content, containing 12 percent ash, and having a Btu value per pound of 12,750.

Limestone storage in days can be extended significantly by burning coal with a lower sulfur content than 3 percent. Reducing the sulfur content to 2.5 percent will increase limestone storage capacity from 28 days to about 32, or equivalent to coal storage. A slight increase in bed material and flyash storage capacity in days can be achieved by purchasing coal with an ash content of less than 12 percent. Emergencies such as strikes by miners or truckers usually carry an early warning which may enable GU to order coal with lower sulfur and ash content for storage prior to such a strike and thereby prolong the available storage. Storage can also be extended during emergencies by operating the boiler at less than the 80 percent load and making up the remaining demand with the existing gas/oil fired boilers.

In this scheme, existing storage facilities would be retained with no change in handling systems other than to accommodate the interface with the proposed handling systems. New handling equipment would be of the same type as existing, thereby minimizing spare parts requirements and ease of maintenance. A further major benefit of the proposed storage is that the AFB plant can be operated with either the existing or proposed storage, thus permitting one or the other to be shut down for maintenance without affecting plant operation.

With reference to bed material and flyash storage, Table 4-3 indicates that these total 12.5 and 9.3 days respectively, considerably less than the 28 to 32 days storage available for limestone and coal respectively. In Subsection 4.3 preceeding, it is pointed out that the hygroscopic characteristic of both bed material and flyash is such that lengthy storage entails a high risk of agglomerating the loose material in cementitious form which then causes plugging within the storage silos. The stored material would require excessive manual attention to remove it.

Assuming that the regularly employed disposal contractor is not available, any enclosed truck could be used on a short-term basis for transporting reject material to a local landfill.

The estimated cost of implementing this scheme is $2,700,000.

4.6 Scheme C - Increased Ash Storage Only

As an alternative to Scheme B in which coal and limestone storage is increased to about 30 days, and that of bed material ash and flyash to about 12 days, the potential exists for providing increased bed material and flyash storage only within the present Heating and Cooling Plant cooling tower enclosure.

Exhibit 4-10 indicates the location of this space. Clear space adjacent to the cooling tower would permit construction of ash silos supported by a steel structure at an elevation that will permit a truck to pass below the silos for unloading.

Construction of additional ash storage at this location would entail the following work:

a. Replace existing 12 foot high by 16 foot wide rollup door with a 16 foot high motor-operated door. Rework metal panel above as required.

b. Construct footings for structural steel supports.

c. Construct structural steel silo support framing.

d. Construct silos and lift into place by crane.

e. Construct asphalt truck surface below silos with drain to existing storm system.

ADDED ASH STORAGE IN COOLING TOWER ENCLOSURE

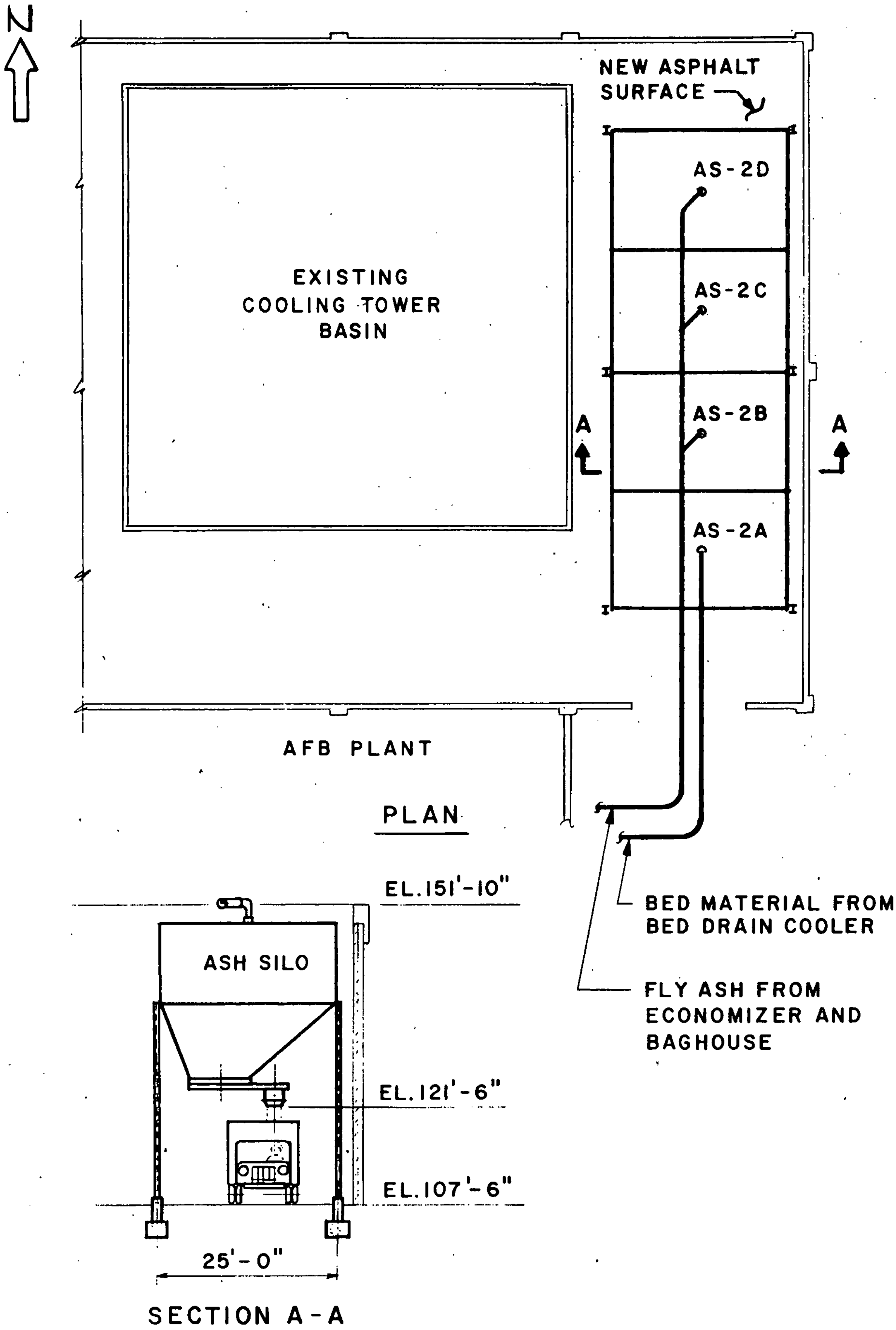


EXHIBIT 4-10

f. Extend and modify solids removal control panel (SRCP) to incorporate controls for expanded storage.

g. The two existing ash silos would be reserved for bed material storage. This requires no piping changes, only the setting of a diverter gate.

The flow diagram for this arrangement is the same as for Scheme B and appears on Exhibit 4-9.

Scheme C does not relieve the AFB plant coal and limestone storage limitations. It does, however, at no increase in total plant area, alleviate the now critical ash storage limitations. By providing this storage within the present cooling tower enclosure, the silos would be located contiguous to the existing plant in a truck accessible space such that construction would entail minimum modifications to the present ash removal systems. Total AFB plant storage capacity would then be as shown on Table 4-4.

TABLE 4-4

EXPANDED STORAGE WITHIN COOLING TOWER ENCLOSURE

	Coal		Limestone		Bed Material		Flyash	
	Tons	Days	Tons	Days	Tons	Days	Tons	Days
EXISTING PLANT								
Bunker LBK-1	-	-	438	14	-	-	-	-
Bunker CBK-1A	360	4	-	-	-	-	-	-
Bunker CBK-1B	360	4	-	-	-	-	-	-
Bunker CBK-1C	360	4	-	-	-	-	-	-
Silo AS-1A	-	-	-	-	83	3.5	-	-
Silo AS-1B	-	-	-	-	83	3.5	-	-

TABLE 4-4 (Con'd)

		Coal		Limestone		Bed Material		Flyash	
		Tons	Days	Tons	Days	Tons	Days	Tons	Days
COOLING TOWER									
Silo	AS-2A	-	-	-	-	160	6.9	-	-
Silo	AS-2B	-	-	-	-	-	-	70	3.8
Silo	AS-2C	-	-	-	-	-	-	70	3.8
Silo	AS-2D	-	-	-	-	-	-	70	3.8
TOTAL		1080	12	438	14	326	13.9	210	11.4

The estimated cost of implementing this scheme is $675,000. It provides the much needed additional ash storage at 25 percent of the cost of the previous scheme.

4.7 Life Cycle Cost Analysis

The provision of additional storage capability does not provide an energy saving, nor yield direct cost reductions that permit a conventional life cycle cost analysis. It will, however, enhance continuous AFB plant operation on coal fuel and decreases the university's dependence upon regular deliveries of coal and limestone, and regular truck arrivals for removal of bed material and flyash.

A coal fired plant situated in a less restrictive location than Georgetown University would normally be provided with further storage capacity that would provide assurance that the plant could continue in operation for extended periods if faced with an emergency such as a coal miner's or truck driver's strike. This tends to assure that low cost coal fuel will be burned in place of higher cost natural gas fuel; that the benefits of low cost cogeneration of electricity will be continued; and that coal fuel will substitute for gas and oil for a longer period of time.

In terms of real savings, the ability to store an additional 20 days of coal and limestone could be expected to produce the following savings in the event of a coal or truck strike:

Assuming 20 days additional operation at 80 percent boiler input on coal vs. comparable output from gas fuel, then the comparable fuel costs for this period are as follows:

Coal (including limestone and ash removal) @ $58.00/ton
= $2.30 per million Btu
Gas fuel = $3.50 per million Btu

Coal required for 20 days operation at 80 percent output is:

80,000 lb/hr steam x (1202.6 - 309 Btu/lb) ÷ 0.83 efficiency x 24 hr/day x 20 days = 41,340 x 10^6 Btu.
At $2.30 per million Btu, coal fuel cost becomes $95,080.

The gas fired boiler has no economizer. The gas fuel required for 20 days operation at 80 percent is:

80,000 lb/hr steam x (1202.6 - 196.2 Btu/lb) ÷ 0.83 efficiency x 24 hr/day x 20 days = 46,560 x 10^6 Btu.

At $3.50 per million Btu, gas fuel cost becomes $162,970.

The fuel cost differential during a 20 day emergency favors coal by $162,970 - $95,080 = $68,890.

Added to this is the additional savings achieved by concurrent cogeneration during the 20 day extended period of operation by the AFB plant. At 80 percent output, the winter generation rate is about 1900 kW. Cogeneration in winter months will result in electrical energy savings over purchased of about 1-1/2 cents per kWh.

Cogeneration savings during this 20 day period of extended operation then becomes 20 days x 24 hours/day x 1900 kW/hr x $0.015¢/kWh = $13,680.

Combined fuel energy and electrical cost savings during each 20 day emergency would then become at least $68,890 + $13,680 = $82,570.

If in the future, gas fuel is charged at the same cost per million Btu as fuel oil, a proposal now under consideration, then the fuel cost savings by continued use of coal would substantially increase.

The above is insufficient for effecting an acceptable life cycle cost analysis. The determination of the value of additional storage facilities must be predicted upon other factors such as the importance of maximizing coal usage in preference to other fuels, continued demonstration of the AFB plant in prolonged operations, and similar factors.

4.8 Incremental Savings and Optimization

Of the two schemes retained for consideration, Scheme B provides for increasing storage capacity for coal, limestone and ash products in an appendage to the AFB plant, whereas, Scheme C provides for increasing ash storage only within the confines of the present cooling tower enclosure of the Heating and Cooling Plant. The capital costs associated with the two schemes are $2,700,000 for Scheme B and $675,000 for Scheme C.

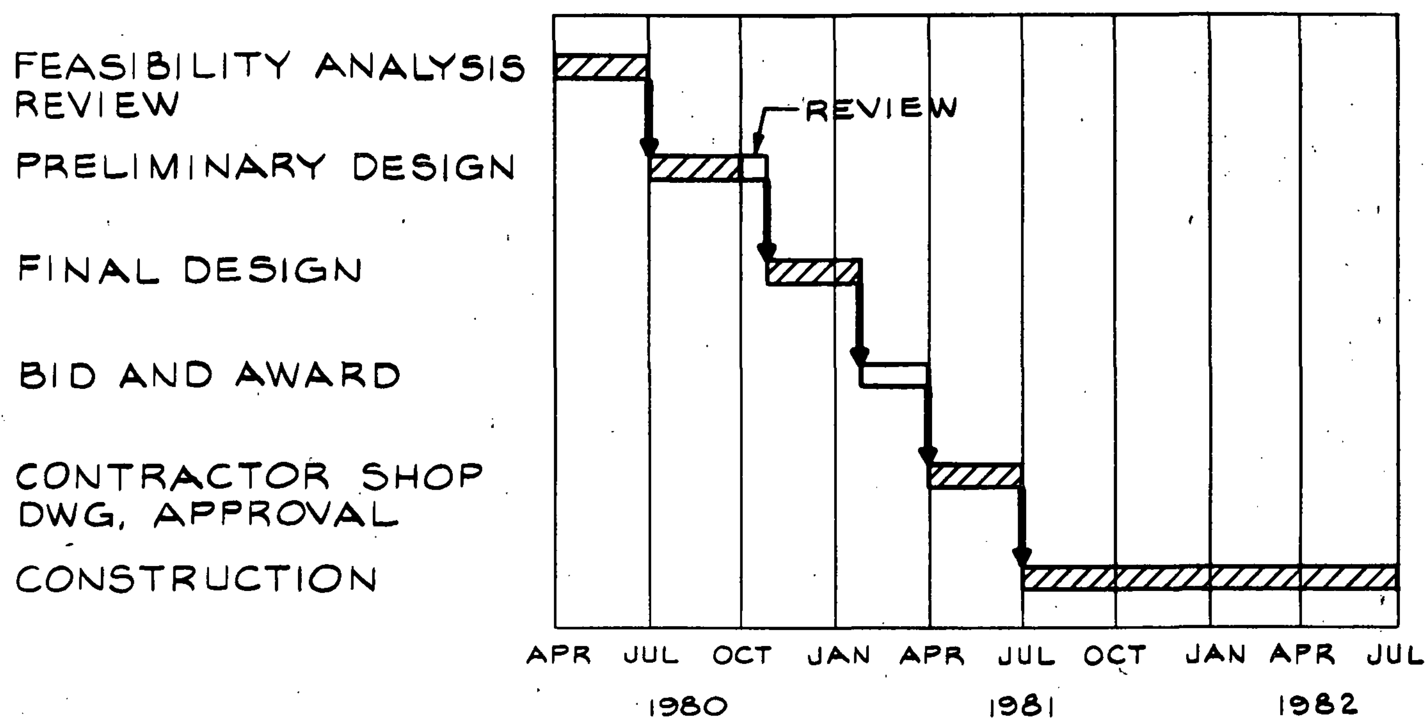
It would be desirable from the standpoint of maintaining continuous plant operation through emergencies to implement Scheme B. If this is not feasible, then as a minimum, Scheme C should be adopted. This would serve to increase ash storage capability to the same period of time as the existing coal and limestone storage, namely about 12 days at 80 percent boiler output. Scheme C will facilitate truck scheduling for removal of ash, and eliminate the problem, whereby continued AFB plant operation through a weekend is dependent upon ash removals on Friday afternoon followed by additional ash removal on the following Monday morning.

4.9 Conceptual Design

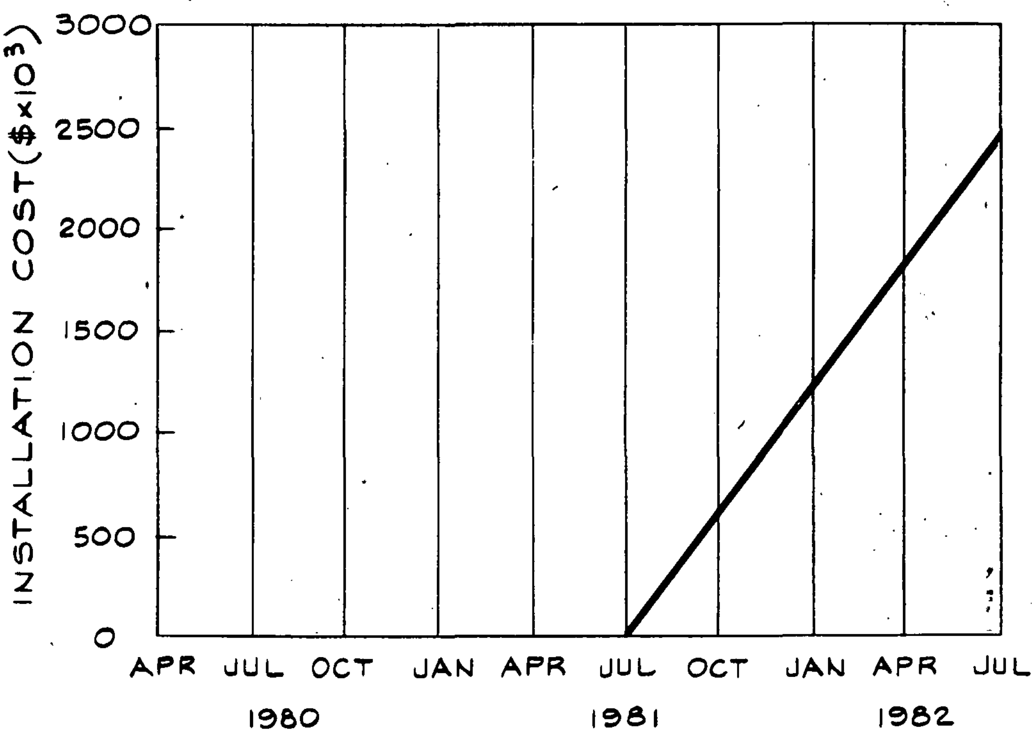
Conceptual designs were prepared for both Schemes B and C. These appear on Exhibits 4-5 through 4-10.

Schedules for implementing both schemes follow.

SCHEME B - ADDED STORAGE IN AFB PLANT ADDITION

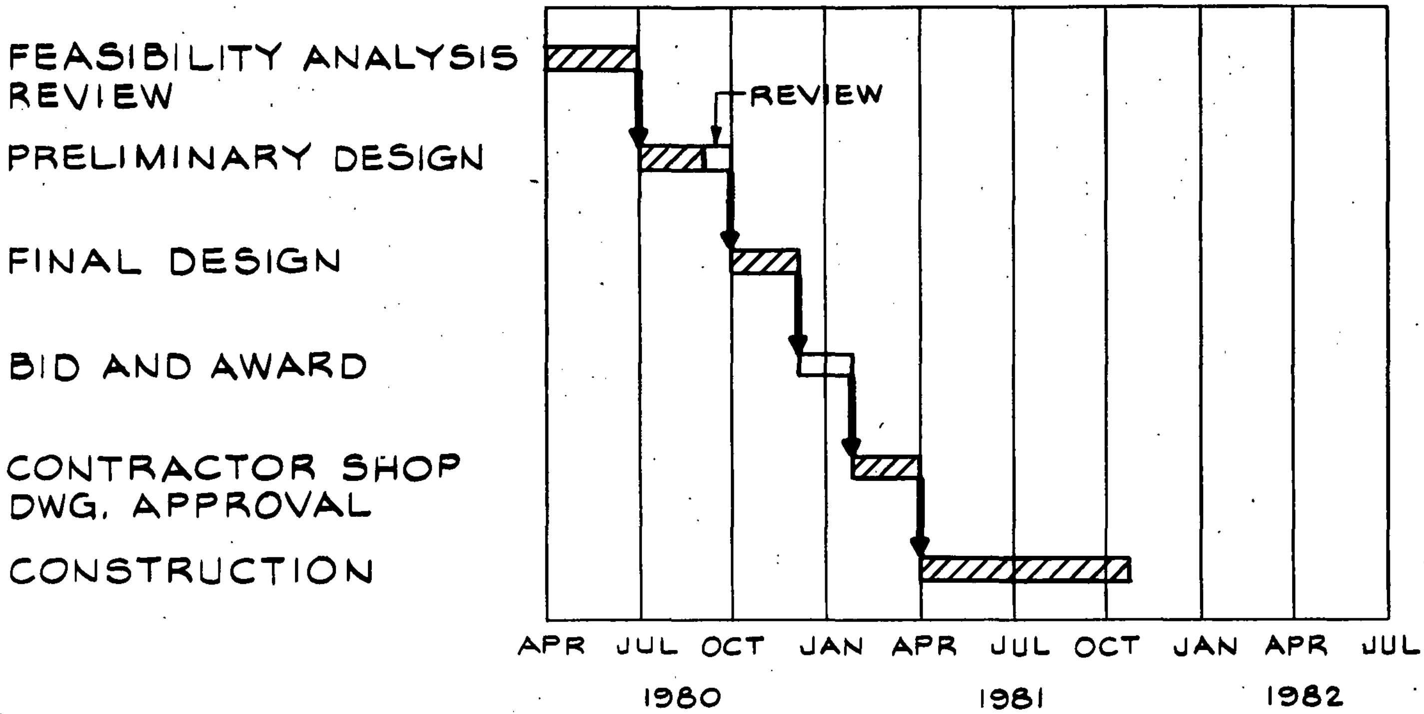


CONSTRUCTION SCHEDULE

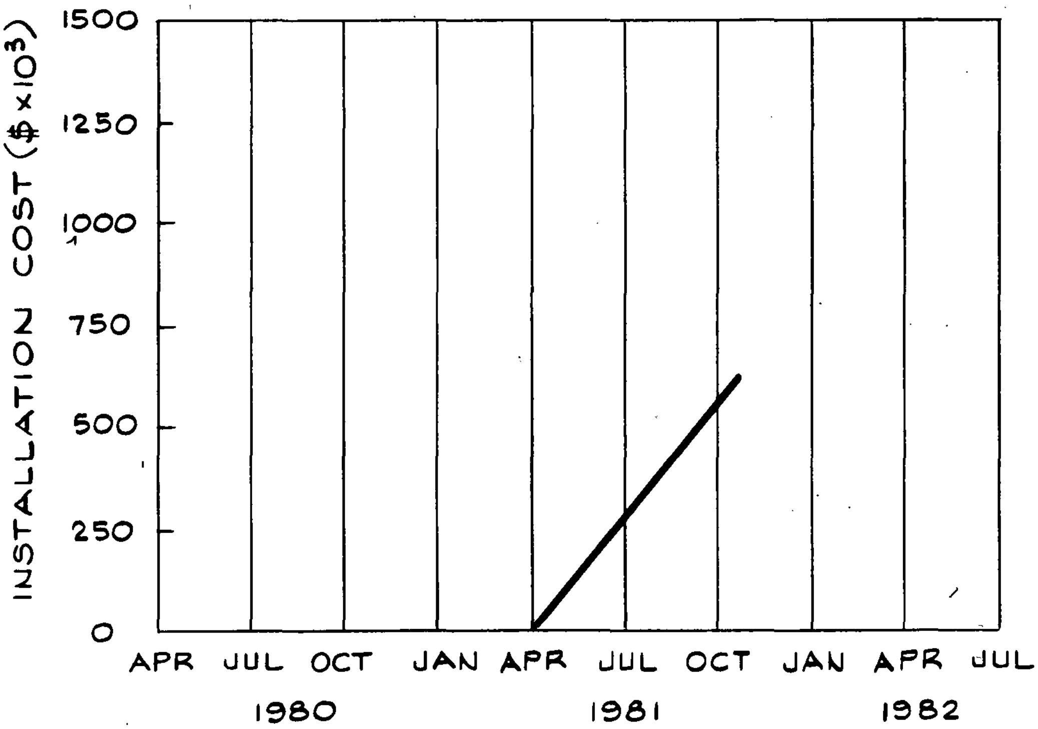


INVESTMENT CASH FLOW (UNDISCOUNTED)

SCHEME C- ADDED ASH STORAGE ONLY



CONSTRUCTION SCHEDULE



INVESTMENT CASH FLOW (UNDISCOUNTED)

SECTION 5

5.0 HOT AND COLD THERMAL STORAGE

5.1 State-Of-The-Art

5.1.1 General

Thermal storage was described as "A Sleeping Giant"[1] by R.T. Tamblyn in his prize winning article published in the June 1977 issue of ASHRAE Journal. This title implies that this form of energy has not yet been tapped to its fullest extent. On our planet, natural storage examples are the molten core with its associated hot springs, polar ice caps, gigantic glaciers as well as warm, cold and stratified oceans representing vast sources of stored natural energy that could be tapped. Some of these sources are being explored and experimented with today. Within our solar system the sun is the single largest source of stored energy which is responsible for our existence and may prove to be our energy salvation. Capturing the benefit of this stored form of energy falls into the category of solar energy. A most important component of the solar energy system, is the hot and/or cold thermal storage subsystem.

The above forms of stored energy, namely those of the first kind, are classified as "free" sources of direct thermal energy (usable in the context of the first law of thermodynamics) requiring no complex mechanical interactions, nor chemical or nuclear reactions. Only physical reactions, phase change, mass and energy transport and transfer and other simple mechanical processes are necessary to take advantage of these energy forms. Use of these resources will result in savings of fossil fuel Btu's and, usually dollars.

There are in addition, the man-made or artificial systems for thermal energy storage which can also save Btu's and dollars. We can label these as thermal storage of the second kind. It is in our national interest to conserve Btu's. This is evidenced by the number of energy conservation full and shared grants programs, such as the "Solar Energy for Domestic Hot Water Heating Grants Program" and the "50 Percent Shared Grants Energy Conservation Program for Schools and Hospitals", recently and presently being funded by the Federal Government through DOE. These programs are an incentive to become energy (BTU) conservation conscious by imposing monetary rewards when disinterest, laziness or even certain reimbursement programs would tend to minimize attention to this awareness.

Energy Btu's are saved by using the free forms of energy such as solar and geothermal whenever possible; maximizing recovery from waste streams such as condensate, solid waste and processes; and minimizing heat transfer losses. These energy savings simultaneously reflect dollar savings although implementation and installation costs determine the payback. At Georgetown University, under the GU ICES program, a five to ten year payback is sought.

Aside from direct energy related savings previously discussed, additional dollar savings can be realized by use of thermal storage systems of the second kind. This is achieved by shifting electric loads to off peak periods when energy and demand charges are reduced, and allowing excess generation and storage during low use periods to supplement high use or load periods. This saves both in terms of peak shaving as well as reduced equipment costs by being able to use smaller sized equipment. Again, only potentially cost effective measures will usually be implemented.

Thermal storage of the second kind, or man made storage, to effect energy conservation or saving of Btus is a practical reality today. One of the earliest of this form of thermal storage device was the historic ice house, located at the edge of a pond or lake, where blocks of ice cut from these frozen bodies of water during the winter were stored, insulated with sawdust and used later that summer in ice boxes for food preservation.

Many thermal storage systems have been studied and some have been put to practical use. A review of the literature was conducted to establish the current state of the art of thermal storage and to develop criteria for its applicability, feasibility and economy. In addition, plant engineering personnel, at existing thermal storage locations, were contacted to elicit their comments regarding operation, maintenance and performance.

The review of the current state of the art of thermal storage indicates a variety of storage methods. Fifteen different methods or systems were identified in a recent NASA study.[2] They are listed here and in reasonable order of practicality:

- Water tank storage
- Ice storage (as part of "annual cycle energy storage" (ACES Systems)
- Thermal wells
- Organic compounds (oils)
- Paraffins
- Rocks and similar solids
- Reversible chemical reactions
- Liquid metals
- Heat of vaporization
- Absorbent systems
- Inorganic salts
- Several forms of hydrates
- Metal hydrides and molten semiconductors.

In January of 1979, Oak Ridge National Laboratory[3] (ORNL) published a summary of research, development and demonstration programs related to Low Temperature Thermal Energy Storage (LTTES) programs in this country. Later in July 1979, the Solar Energy Research Institute[4] (SERI) published "Low Temperature Thermal Energy Storage", a state-of-the-art survey within the U.S. and abroad.

Many of these storage methods are still conceptual, experimental and/or not available for practical use. To be effective and economical, storage media must have good specific heat values and/or large values for heats of fusion or vaporization. The majority of systems currently in operation or being designed incorporate water storage tanks and/or ice storage such as ACES systems.

General thermal storage systems include two categories: hot thermal storage systems (for domestic hot water or space heating) and cold thermal storage systems (to provide space cooling and/or process cooling, such as milk processing). Application of storage subsystems to overall energy conservation systems usually involve other subsystems as well. The ACES system is a good example of a typical energy conservation system with several components, including thermal storage. Basically, the subsystems consist of:

a) a heat pump to provide partial heat (see c for the other part) for additional space heating (during the heating season) while extracting

b) heat of fusion from a water/ice storage tank system which can continuously refreeze due to heat pump operation as in a) after intermediate melting

c) from excess solar panel energy not delivered directly to space heating (supplemented by the heat pump, see a) or delivered to

d) hot thermal storage for later space heating or to

e) domestic hot water storage tanks.

It can be seen in this example that thermal storage is not entirely independent of other energy subsystems. The scope of work for this feasibility analysis precludes solar energy for consideration with the thermal storage systems. This eliminates ACES type of systems from consideration unless the solar portion can be replaced with an existing comparable waste heat stream. Such a waste heat stream is not available at GU, except possibly as a by-product of cogeneration which is addressed in Section 3. As a consequence, hot and cold thermal storage systems will be treated in separate sections following. It must be pointed out, however, that there are circumstances under which the individual subsystems being considered may ultimately result in what, when viewed as a whole, could be considered a combined hot/cold storage system. An example (considered later in Section 7), would be the following application:

A heat pump is used to extract waste heat from cooling tower water of an air conditioning system with the heat pump discharge energy being used to heat domestic hot water. This would provide all or supplemental domestic hot water whenever the chiller plant is running to handle an air conditioning load and the heat pump is operated simultaneously. If the mode of this operation is now changed so that the chiller plant is operated at off-peak electric rates and the resulting chilled water and simultaneously generated domestic hot water are stored in their respective storage tanks, a combined hot/cold storage system is realized.

There are basically two types of storage systems classified as either open or closed.[5] The primary distinctions are as described herewith.

A closed system consists of a group of interconnected sealed and possibly pressurized tanks without exposure to air. The tanks are usually connected in series to minimize mixing of different temperature fluids. Valving is minimized and control is simple. Charging is in one direction and discharging is in the opposite. Piping is arranged to by-pass tanks for repair or other reasons.

An open system consists of a group of individual or interconnected tanks exposed to atmosphere and not pressurized. Transfer of stored water can be done by the empty tank method which minimizes mixing or by the labyrith method where complex routing of the flow pattern is used to reduce mixing. The empty tank method requires more controls while the labyrinth approach is operated in series like the closed system. Since the tanks are exposed to the atmosphere, corrosion and contamination precautions must be incorporated.

Other methods to reduce or eliminate mixing of supply and return water have been studies.[6] Some of these are rigid removable partitions, flexible membranes and nozzle matrix arrangements.

The concepts discussed are applicable to both low temperature hot storage as well as cold storage. Higher temperature hot storage becomes more complicated due to the low boiling point of water and, therefore, pressurized systems must be used. Lower temperature cold storage systems are of the ice variety and have the advantages of less space requirement due to the latent heat of fusion. However, disadvantages are the expansion of ice upon freezing and the reduced conductivity of ice relative to water. Specific applications of the various concepts are presented in the following sections where state-of-the-art hot and cold thermal storage are separately addressed.

5.1.2 Hot Thermal Storage

The most common use for hot storage is in solar energy heating and cooling systems. The storage media can be the transport fluid itself, such as oil or water, or a fluid other than the transport fluid or rocks with either air, water or oil as the transport fluid.

An interesting example of a solar energy system using oil and rocks as the storage media is at one of Honeywell's general office buildings in Minneapolis, Minnesota.[7] The building is eight stories high, 100,000 SF in area and is served by solar collectors located atop of an adjacent five story parking ramp. The system has 20,250 square feet of trough type concentrating collectors, which use an oil as the primary energy transport fluid. The secondary flow loop uses another transport fluid to transport solar energy to the building solar heating and cooling and hot water systems and the high temperature thermal storage subsystem. The storage system consists of two 18,000 gallon underground steel cylindrical tanks containing a mixture of 40% transfer fluid and 60% small rocks (0.375-1.0 in.). The tanks are insulated with 4-inch thick foam-glass and are moisture sealed. The solar energy is stored in these underground tanks at 300°F whenever the building's heating-cooling or hot water load is not great enough to use all the collected solar energy. The cooling system is served by two 100 ton Rankine cycle water chillers.

Hot thermal storage can be applied to systems other than solar energy systems for conservation and economy. Building heating, ventilating and air conditioning systems where waste heat is substantial during the heating season can benefit from hot thermal storage. A good example of a waste heat thermal energy storage system is found at the A.O. Smith Corporate Data Center Building in Milwaukee, Wisconsin.[8]

The building is a one-story building and has an area of 20,500 square feet. This system uses a heat reclaim system of two 125 ton heat pumps as a source for simultaneous heating and cooling for the office and computer areas of the building. Chilled water for cooling is produced at the heat pumps evaporator and hot water is produced at the heat pumps condenser. This system employs a 1000 gallon storage tank which stores hot water. This stored energy is in effect waste building heat from computers, lights, people and machinery. When the daytime cooling load in winter exceeds the building heat loss, the excess hot water generated at the condenser is stored for later use. There are electric heating coils in the storage tank to supplement the hot water heating system but thus far their use has not been required. A comparison of the heat pump, heat recovery and storage system with a conventional boiler and chiller arrangement showed that the first cost and the operating cost for the boiler system would be greater than for the heat reclaim system.

There are other building heating ventilating and air conditioning systems where waste heat hot thermal storage has been applied for energy conservation. The West Bend High School in West Bend, Wisconsin and the Presto Products Company building in Appleton, Wisconsin,[9] and the City Hall in Rochester, New York.[10]

The system of storing waste heat from refrigeration processes can work with conventional refrigeration cycles as well as heat pumps. Buildings with large interior core areas requiring cooling during the heating season are the prime candidates for this application. When the perimeter heating demand is less than the heat rejected from refrigeration, condenser water is stored for later use. A full discussion on this application for hot water storage is given in "Heat Storage With Use of Centrifugal Refrigeration Machines and Evaporative Coolers", by Foster E. Filson.[11]

Thermal energy storage may be used to store waste heat from sources other than building or plant heating, ventilating and air conditioning systems.[12] For example, during the heating season in total energy plants or cogeneration plants when the electric demand is high and the heating load is low, there will be an excess of high grade thermal energy. This energy, which would be wasted, could be stored for later use. The use of thermal storage in this case would save the heat that would otherwise have to be supplied by an auxiliary boiler.

The Monroe County Government building in Stroudsburg, Pennsylvania has been retrofitted with a new integrated HVAC system with diesel cogeneration facilities.[13]

In heating, or domestic hot water systems where hot water is generated by electric boilers, hot water storage tanks can also be used beneficially. The realized benefits are economic rather than energy conserving. Where electric demand charges vary widely with the time of day, it becomes economical for the user to generate hot water during off-peak hours of the day. In order to satisfy daily heating loads, hot water storage is necessary. An example of a system similar to this is the Catholic Medical Center in Manchester, New Hampshire.[14]

Hot thermal storage in thermal wells of waste heat from electric power generation plants is being assessed in Denmark on a seasonal basis.[15] Denmark has, in the past, been dependent on imports for almost all (98.8%) of her energy needs. This dependence could be reduced significantly by more efficient utilization of primary energy sources. One possibility for achieving this is by storage of thermal energy. The idea of large scale storage of waste heat has given rise to research in the area of thermal wells or aquifers. Recently, Louisiana State University has conducted experiments on the technology and use of storage of heated water in aquifers.[16] However, "the need for well instrumented field tests of injection/storage/production (I/S/P) projects involving heated water is at least as acute as the need for theoretical studies". Examination of the use of thermal wells for energy storage have also been conducted by Meyer and Todd.[17,18]

Research to develop natural geological systems for thermal energy storage is being carried on by the United States Government as well. The United States Geological Survey is cooperating with USDOE in this activity. These activities involve: (1) categorizing and selecting suitable sites (2) establishing thermal cycle efficiencies (3) establishing charge and discharge characteristics (4) determining environmental impact potential and (5) performing system analyses.

5.1.3 Cold Storage

Cold thermal storage is most commonly based on chilled water or ice. Chilled water is primarily used for short term storage requirements such as for on-peak/off-peak or day/night charging/discharging operations. Ice, on the other hand, plays its role more for seasonal charging/discharging operations. There are some applications where ice is used even for on-peak/off-peak operations. The typical benefit of ice or chilled water storage is threefold:

- achieving energy conservation
- peak shaving (reducing demand charges)
- reducing installed chiller capacity (reducing capital outlays)

Many cold storage schemes either in operation or under design will achieve some or all of these goals. Several designs or concepts were identified during the course of this study. Brief descriptions of some of the more interesting systems are presented.

The Gilbane Building in Providence, Rhode Island is a 104,000 square foot, five-story building with four floors of office space and an enclosed parking ground floor. The building's HVAC systems were designed with the latest in energy conservation features. As part of this design, three two-compartment 20,000 gallon storage tanks were installed to store chilled water. The inclusion of 60,000 gallons of chilled water storage reduced the installed electric centrifugal chiller capacity from 225 tons to 150 tons with auxiliary equipment correspondingly smaller.

The Development Lab and Manufacturing Facility,[19] general products division of IBM in Tuscon, Arizona contains approximately three million square feet of floor space in nineteen free standing structures. These structures are served by a single central plant which provides, among other utilities, chilled and hot water for space conditioning. The chilled water system uses nine, 300,000 gallon steel storage tanks of the open type to store chilled water. Chilled water is generated during off-peak, unoccupied hours by either steam turbine-driven or electric motor chillers depending upon relative operating costs. This operating procedure reduces demand charges due to time-of-day rates when the centrigual chillers are operating.

The Veterans Administration Hospital in Wilmington, Delaware[20,21] is the first commercial ACES installed in the United States. The basis of an ACES is to store energy from one season to another. This system is a modified ACES system, in that it does not have adequate storage capacity for a full season's thermal energy requirements and also uses several sources of heat supply. The system is called the "energy bank" and it employs the following equipment for its operation:

- solar collectors
- two compressors
- a double-bundle condenser
- a water chiller
- a brine cooler
- an evaporator/condenser (outdoor unit)
- an ice tank with coils
- an automatic control system

During winter, the system heats by extracting heat from either the outdoor unit (when outside ambient is above 40°F) or the brine cooler (when outside ambient is below 40°F).

During summer, when cooling is required, air conditioning is accomplished by drawing on the charged ice tank. This operation continues until mid to late July when all the stored ice is melted. Then, during the latter portion of the summer, the refrigeration equipment is run during off-peak hours to store ice for the following day. This takes advantage of time-of-day electricity rates so that dollars are conserved.

The refrigeration package was designed to provide 75 tons of peak cooling and 800 MBtuh of heating to the building.

The ice tank is of concrete and is 50 feet long by 40 feet wide by 11 feet deep. The inside of the tank is coated with an elastomeric compound of asphalt and urethane. It forms the basement of the building.

A cold storage ACES scheme similar to the one implemented at the VA Hospital is found at the Madison Area Technical College System, Vocational and Technical Adult Education building in Reedsburg, Wisconsin.[22] The ACES here stores sufficient ice in late winter and spring to provide all the summer cooling load, with some additional ice generated during the summer to meet domestic hot water requirements. This system provides for hot water storage as well as ice storage.

Research on ice-maker heat pumps was conducted at Oak Ridge National Laboratories in 1976.[23] It concluded that a cubic foot of ice storage can accommodate the equivalent of about 1/2 ton-hour. Also compared were operating cost per unit of heat delivered by various methods. These results are summarized in the table below:

TABLE 5-1

1976 OPERATING COST PER UNIT OF HEAT DELIVERED AT THE REGISTER (SOURCE: REFERENCE 23)

Assumed cost of electricity, ¢/kWh	4.00
Assumed cost of oil, ¢/gal	40.00
Assumed cost of gas, $/1,000 ft^3	3.00
Assumed cost of water, $/1,000 gal at 60°F	1.00
Operating cost for heat delivery: $/10^6 Btu	
Ice-maker heat pump, (COP = 2.78)	4.65
Air-to-air heat pump, (Seasonal COP = 2.0)	5.86
Oil-fired furnace	6.30
Gas-fired furnace	6.26
Resistance electric heat	11.72

The conclusion for the overall economics of ice maker heat pumps was: "seasonal storage of ice may be marginally justified in the case of new building construction where bin costs can be reduced by integration with the building design".[24]

The State Office Building in Sacremento, California[25] is an unusual structure because it consumes only 21,100 Btu/sq ft/yr. The building is approximately 250,000 gross square feet with an office area of 185,000 square feet. The design utilizes underground architecture which incorporates active and passive systems to achieve such low energy usage.

Another ACES given a different label by its author is the Dual Phase Annual Cycle, DPAC.[26] This is a hybrid system for heating and cooling buildings. The DPAC system would have the following characteristics:

- Two large seasonal storage systems (1 hot, 1 cold) are charged and depleted 6 months out of phase.

- The hot storage tank is heated by solar collectors all year. The majority of the heat is collected in the summer. This supplies domestic hot water and winter heating.

- Water in the cold tank is frozen by a heat exchanger with the winter air. This is not a solar process. A brine loop in the ice provides chilled water for summer air conditioning.

- Economy of scale applies to the storage system.
- DPAC is most practical in hot summer-cold winter climates.
- A conventional 4 pipe HVAC system distributes heating and cooling to the building.

5.1.4 Commentary

There are considerably more articles on thermal storage that could be discussed. Additional references are provided in Appendix E. The primary conclusion however, is that for the GU application, thermal storage practically applied should be based on water. Hot water storage for domestic and/or space heating and chilled water and/or possibly ice storage for air conditioning purposes should be considered. This was done according to the statement of work and the evaluations of the respective systems are discussed subsequently in separate sections.

It also must be pointed out that many thermal storage systems incorporate both hot and cold thermal storage simultaneously and that individual considerations or isolation of one system from the other is not always possible. Many thermal storage concepts require the inclusion of both for maximum effectiveness in energy as well as cost savings.

5.2 GU Application

5.2.1 Hot Thermal Storage

The state-of-the-art review revealed that hot thermal storage is effective only under certain circumstances. The requirements for effective utilization of hot thermal storage necessitates some or all of the following items. A usable hot thermal waste stream that does not coincide with thermal requirements is a prime candidate for storage consideration. This type of waste stream is often associated with industrial processes. Solar thermal energy can be viewed as a similar stream since it is not continuous nor entirely reliable during specific demand intervals. The former does not exist on the GU campus while the latter has thus far been addressed as photovoltaic electric generation only, being excluded from study for heating applications.

In addition to the availability of the energy source streams indicated above, it is essential that there exists a suitable thermal distribution system to convey the waste and stored heat energy to the user location. The GU campus presently has a steam distribution network rather than a hot water distribution network so the second component of the requirements for benefits of hot thermal storage is not available. The cost of installing such a distribution network merely to introduce hot thermal storage, when neither solar thermal energy nor thermal waste stream are available, is not justified. Thermal storage of this nature is, therefore, ruled out for the GU campus.

One other consideration of applicability of hot thermal storage (and for cold thermal storage) occurs in use of dual purpose energy systems, that is, systems which are designed to provide simultaneous heating and cooling. These systems* are usually classified as heat recovery or heat reclaim

*Refer to Section 5.1.1 for a discussion of these systems.

systems and incorporate refrigeration machines and/or heat pumps.

These systems are usually incorporated during design of new construction or major renovations and thermal storage is employed when the cooling and heating loads do not coincide and/or off-peak energy rates are to be taken advantage of. There is no application of this concept to GU Core ICES.

Table 5-2 is a summary of the hot thermal storage considerations for GU Core ICES. The purposes, applications, requirements and possible benefits related to the feasibility of hot thermal storage are listed there.

Hot thermal storage is practical and required as a result of a favorable evaluation of the application of heat pumps to air conditioning system cooling towers. This application is more fully discussed in Section 7-2, Heat Pumps, and Section 5.2.2, Cold Thermal Storage.

Note that, should a hot water distribution system for GU be considered as a replacement for the existing steam distribution system, hot and cold thermal storage, heat pumps, and solar energy systems should be reevaluated. Considerable additional benefits could be derived from less restrictive guidelines.

5.2.2 Cold Thermal Storage

The impact of new construction led to the determination of the bases for evaluation of alternate subsystems for the 1984 campus configuration. It was determined that either or both of the auxiliary electric driven chillers are required to meet peak chilled water demands. These peak demands usually occur during peak electric rate periods.* Cold thermal storage of chilled water generated at other

*According to the proposed PEPCO rate structure discussed in Section 1.3.5.

TABLE 5-2

THERMAL STORAGE AT GU CORE ICES

Purpose	Application	Requirements	Benefits	Negatives
Save Energy	Summer Domestic hot water and reheat	Usable waste stream	IF waste stream energy and $ will be saved	NO usable waste stream, existing or considered for 1984 expansion
Save Dollars	Winter Domestic hot water and space heating	Dual purpose energy system i.e. simultaneous heating and cooling	IF dual purpose energy system, energy and $ will be saved	NO dual purpose energy energy system existing or considered for 1984 expansion
		"FREE" energy source e.g. solar	IF "FREE" energy system, energy and $ will be saved	NO "FREE" energy (i.e. solar) system existing or considered for 1984 expansion
		Distribution system for space heating and domestic hot water	Future heating distribution system may be hot water (ultimately existing steam must be replaced)	NO; cost of new DHW or heating distribution system very high. Good only if new is required
		Incorporate in original design OR renovation when new system is required	Lower installation costs when preplanned and not retrofit	Energy loss due to heat transfer 2-5%/day, Btu's and $ lost

times affords the opportunity to reduce these costs. The application of cold thermal storage within the GU Core ICES program is shown schematically in Exhibit 5-1. Cold thermal storage would be located within Core ICES, the substructure of the proposed parking garage. When the campus demand is low, such as at night, excess chilled water generated by the adjacent central chillers is stored in the cold thermal storage vessels.* Later, during the day, when the central chiller is unable to handle the full load, the stored chilled water supplements the chilled water supply to meet the demand, thus averting the need for turning on the auxiliary chillers during peak electric rate periods.

Initially, it was the intent to apply one of a variety of computer programs, including some available through the auspices of the DOE, to optimize this thermal storage application. Further investigation disclosed that none of the programs under consideration were applicable to, or in a form usable for, the specific task at hand. In addition, the development of baseline data revealed certain constraints, unique to GU, which allowed for a less complex thermal storage evaluation without a computer program. Some of these constraints were:

- the capacities of the central and the auxiliary chillers.
- the difference between maximum and minimum average daytime and nighttime loads.
- the duration of the average daytime and nighttime loads.
- the magnitude and timing of corresponding other campus loads.
- the maximum capacity of the AFB plant.

*The hospital and other supplementary chillers could be operating simultaneously, satisfying part of the campus load while central chiller output is stored.

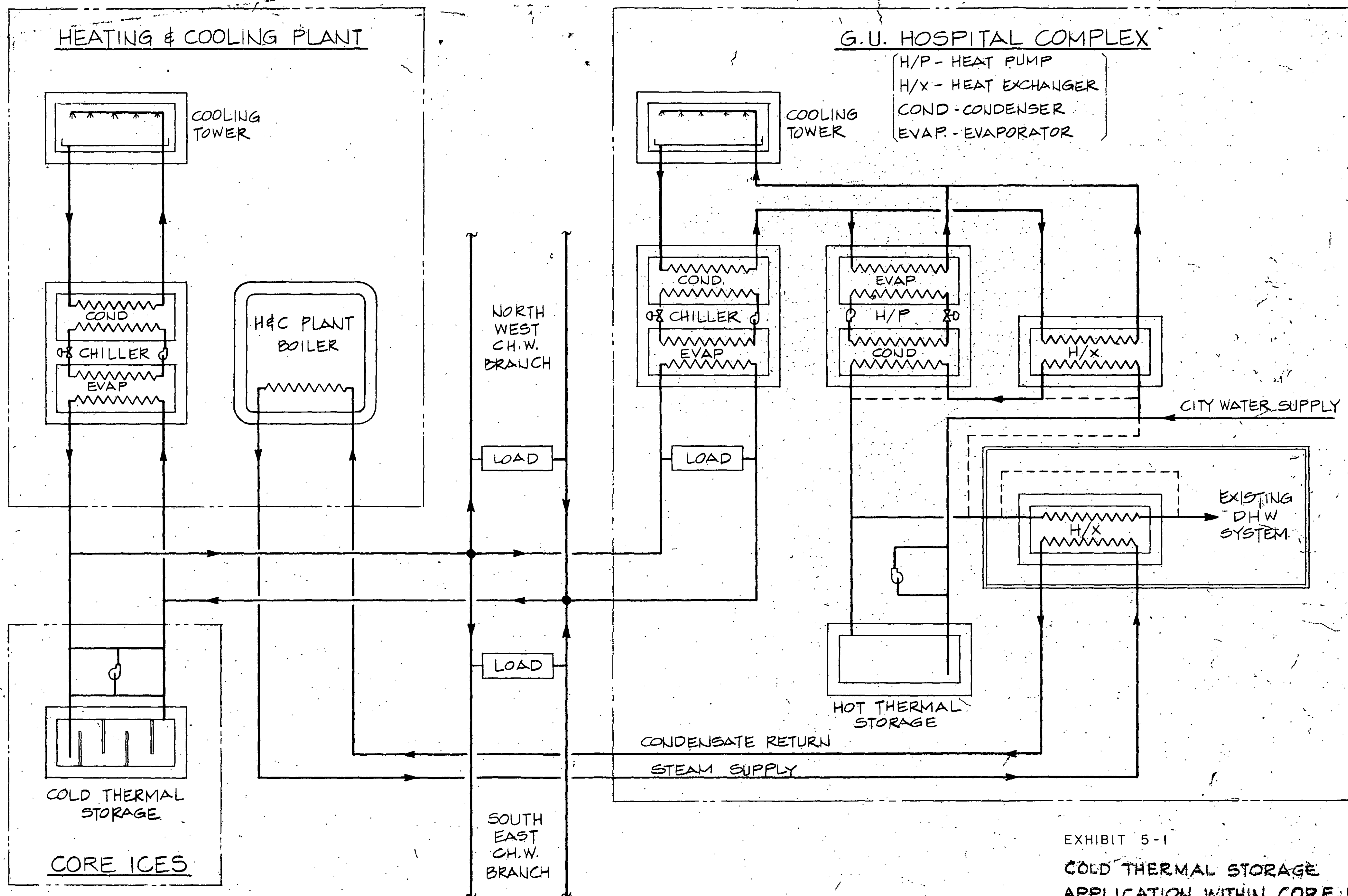


EXHIBIT 5-1

COLD THERMAL STORAGE APPLICATION WITHIN CORE ICES

POPE, EVANS AND ROBBINS

All possible alternatives were finally narrowed down to analyses of thermal storage capacity requirements for the following considerations:

1. Balancing chilled water load on average July and August days to maximize AFB output in order to
   a) minimize or eliminate gas/oil fired boiler operation.
   b) maximize cogeneration.

2. Balancing chilled water load on maximum July and August days for both a) and b) of Item 1 above.

3. Increase May, June, September and October AFB output during the day to maximize cogeneration during peak periods.

4. Eliminate operation of total of 1380 tons of electric driven chillers during peak electric rate and demand charge periods and operating them off-peak instead.

5. Possibility of installing and operating a 3000 ton electric driven chiller at off-peak electric rates or periods.

Details of these considerations are included in Appendix E. The primary result, coincidentally, showed that the difference between maximum average daytime and maximum average nighttime chilled water load is roughly equivalent to the 1380 ton capacity of the two electric driven auxiliary chillers. Operation of these at off-peak rates and avoidance of demand charges is the most significant savings of all five considerations, amounting to about $92,000 annually.

Aside from the demand and energy charge savings just discussed, Items 1 through 4 represent what can be classified as AFB optimization schemes in conjunction with cold thermal storage. They represent additional savings that can be realized as a result of increasing coal versus gas or oil produced steam, using electrical energy when its cost is lower and maximizing cogeneration during periods when electrical costs are at a maximum. While taking advantage of chilled water storage capacity in Core ICES.

Items 1, 2 and 4 add at most another $5000 with Item 3 producing a negative effect due to thermal losses.

In view of the results indicating the significant savings by using off-peak with the 1380 tons of electric refrigeration, the chilled water storage tank was sized to hold capacity equal to operating this tonnage for a period of eight hours, or about 11,000 ton-hours. The resulting storage value, allowing 25% increase for mixing and losses, amounts to 1.3×10^6 gallons of chilled water storage. For this value, a temperature difference of 15°F (namely an operating range of 40°F to 55°F) was chosen. The preliminary construction cost for this size storage, piping and pumps is estimated to be about one million dollars. Additional components of these evaluations are contained in Appendix E.

There is no single best cold storage vessel design of either the closed or open type. The least expensive and most easily constructed tank system for the GU ICES application appears to be an open system constructed of concrete as a part of the supporting structure of the proposed parking garage. Given the choice of mixing reduction techniques, the least complex in components and control, with the highest degree of stratification, appears to be the labyrinth method. The conceptual design for this configuration is presented in Section 4.5.

As a by-product of the thermal storage benefits, an analysis was made to evaluate the cost effectiveness of direct central plant electrical chilling at off-peak electric rate hours as opposed to coal generated steam driven chilling. A large size unit of 3000 tons, equivalent to one of the steam driven units, was considered for this purpose. Equipment cost at about $120 per ton of refrigeration with an additional 75% for installation results in a cost for such a unit of about 630 thousand dollars. A structure to house such a unit would have a value of about 75,000 cu ft and would cost an additional 250 thousand dollars for a total of about 880 thousand dollars.

The savings realizable would correspond to the difference between equivalent electric and coal generated chilling of $0.0204/ton hour and $0.0394/ton hour, respectively. Decreasing this savings would be the loss of cogeneration valued at $0.0047/ton hour. For the cooling season, at 3000 tons, operating 8 hours per day for 4 months, and 1500 tons operating 6 hours per day for 2 months, the maximum savings would be:

$$[(3000 \times 8 \times 4) + (1500 \times 6 \times 2)] \times 30.5 \text{ days/month} \times (\$0.0047/\text{ton hour difference}) = \$49,771$$

or about $50,000 per year

Considering the poor payback and additionally the reduction in cogeneration, making that payback worse, a large size electric chiller to replace an existing steam unit is not practical. As an added unit, with coincident thermal storage capacity to meet additional loads, such an alternative could prove economically feasible. It appears, however, that the existing steam and electric driven chillers will be able to handle the 1984 loads, hence further evaluation of this scheme was not carried out.

5.3 Life Cycle Cost Analysis

5.3.1 Hot Thermal Storage

The hot thermal storage consists of a 15,000 gallon hot water storage tank as a component of the heat pump application. The life cycle cost analysis for it is included in that analysis for the heat pump application in Section 6.4.

5.3.2 Cold Thermal Storage

The cold thermal storage, consisting of a 1.3 million gallon multi-compartment storage tank with adjacent pump room will cost an estimated $1 million to incorporate into the Core ICES parking structure shown in Exhibit 3-5. Two alternatives were evaluated, one with and the other without AFB and cogeneration optimization as discussed in Section 4.2.2. The discounted payback periods for the two alternatives evaluated are as listed in Table 5-3 below.

TABLE 5-3

LIFE CYCLE COST ANALYSIS FOR THERMAL STORAGE

Alternative	Initial Cost ($ x 10^3)	Discounted Payback Period (Yrs)	
		10% Discount Rate	3% Discount Rate
No AFB Optimization	1113	12.3	9.1
AFB Optimization	1113	12.0	8.9

5.4 Incremental Savings and Optimization

5.4.1 Hot Thermal Storage

Incremental savings and optimization for hot thermal storage are included in the discussion on heat pumps in Section 7.5.

5.4.2 Cold Thermal Storage

There are no energy savings for cold thermal storage by itself. The energy savings are a result of the operation of the heat pump to generate DHW simultaneously with the operation of the electric driven chiller while chilled water is stored. The energy savings are, therefore, discussed under Heat Pumps in Section 7.5.

Cost savings are achieved by operating electric driven chillers (up to 1380 ton capacity) at off-peak electric rate hours. These savings can amount to $92,000 annually since the electrical load corresponding to 1380 tons of electric driven chilling is not added to the other peak campus demand during the months when demand charges are maximum but occurs at off-peak hours when no demand charges exist.

Additional savings are realized by optimizing the coal fired steam production and minimizing the gas or oil generated steam. This additional annual saving is approximately $6,500.

Exhibit 5-2 shows these savings as a function of storage capacity. It is seen that storage capacity in excess of 1.3 x 10^6 gallcns* for 1380 tons of electrical chilling does not increase these savings. The knee in the curve is not arbitrary but corresponds to the storage required to store the number of ton-hours generated by the referenced tonnage over a period of 8 hours and increased by 25% to account for mixing and heat transfer losses.

*The corresponding storage value for 700 tons of refrigeration is 0.65 x 10^6 gallons.

CHILLED WATER STORAGE

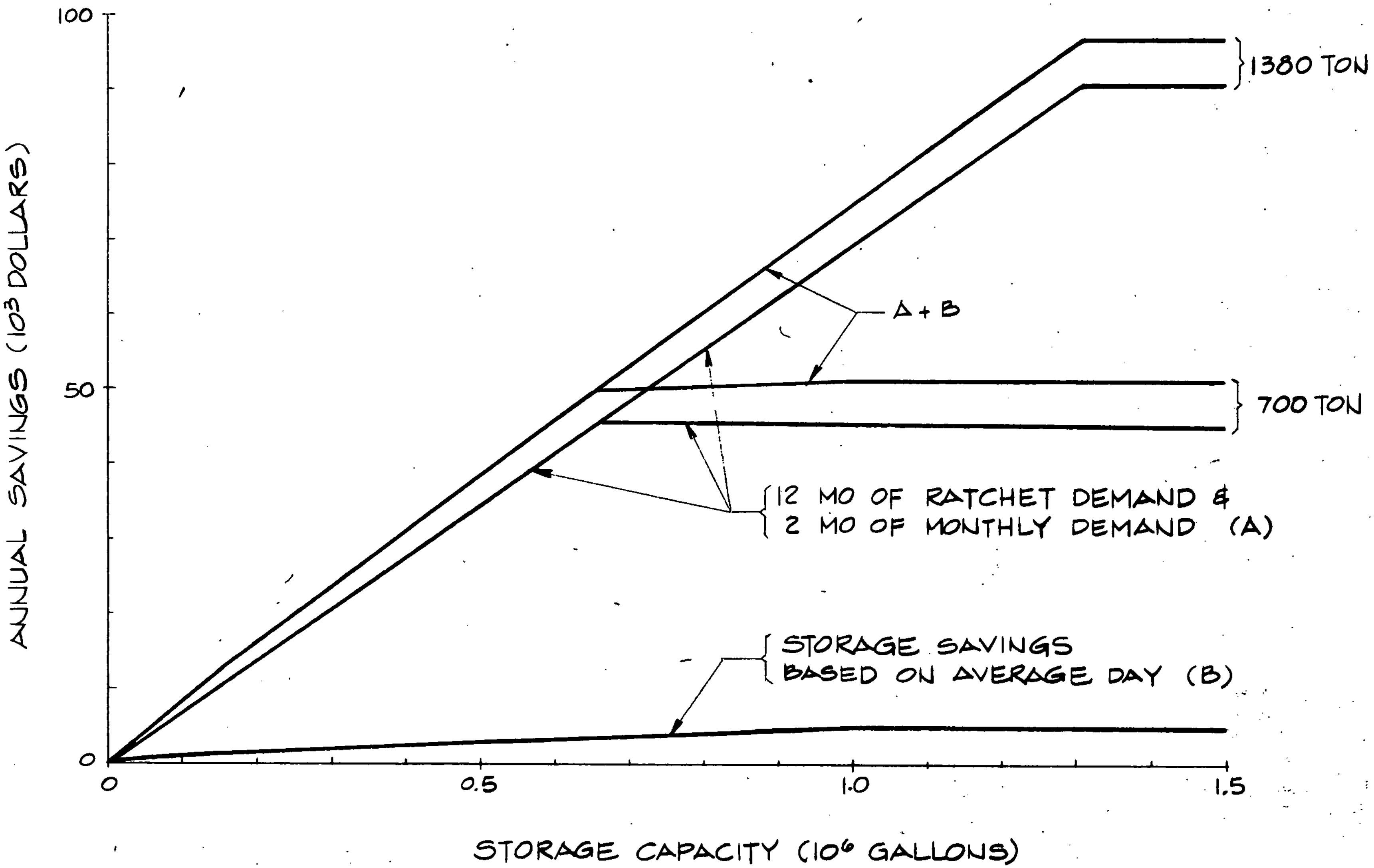


EXHIBIT 5-2

5.5 Conceptual Design

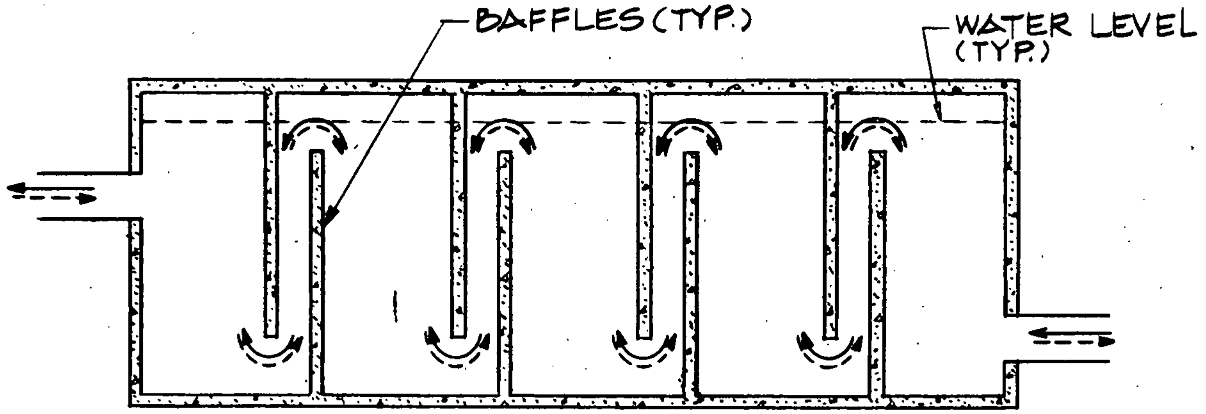
Since hot thermal storage is incorporated into the heat pump analysis, only cold thermal storage will be discussed.

Any thermal storage tank system must be designed to minimize mixing and heat transfer losses. The latter is achieved by suitable insulation whereas the former is attained by partitioning of the storage vessel into compartments with connection between the compartments arranged to take advantage of buoyancy and stratification effects due to thermal gradients. In effect, this results in the generation of a form of labyrinth.

The individual tanks and connecting surfaces will be insulated on the interior with foam insulation which will be waterproofed. By insulating the interior surfaces, hysteresis due to concrete temperature lags, as the fluid temperature changes within a tank, will be eliminated.

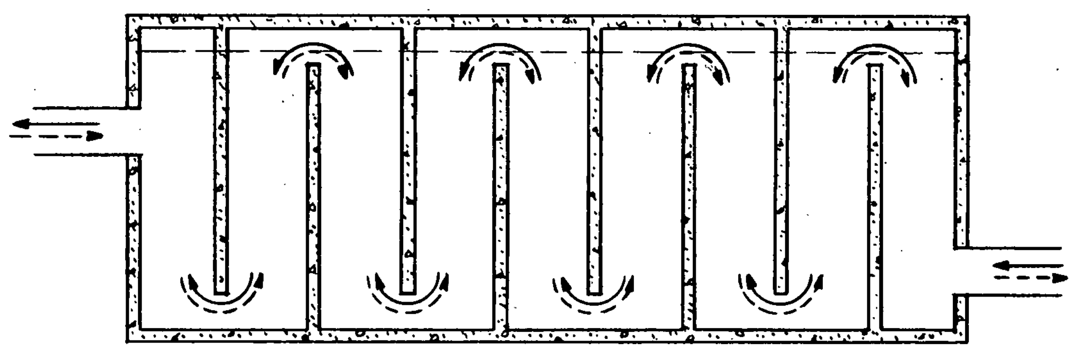
The partitioning can be done in one of two ways. One way is to separate adjacent tanks by baffle walls with alternate top and bottom weirs, a concept used in Japan, and shown in Exhibit 5-3, Scheme 2. The other is to separate adjacent tanks by parallel wall baffles with connection from one tank to the next arranged so that cold fluid always flows out of the bottom of one tank into the top of the adjacent one, or warm fluid always flows out of the top of one tank into the bottom of the adjacent one. This concept was also used in Japan and is shown in section in Exhibit 5-3, Scheme 1, and isometrically in Exhibit 5-4a. Instead of the parallel wall fluid path, equivalent connection from one tank to the next can be achieved by pipe as shown in Exhibit 5-4b. The advantage of the double eall partition to the single alternate top/bottom partition is a considerable reduction in the amount of mixing. For the same degree of mixing, four to

STORAGE CONCEPTS TO MINIMIZE BLENDING OF WATER



SECTION

a) SCHEME 1 LABYRINTH



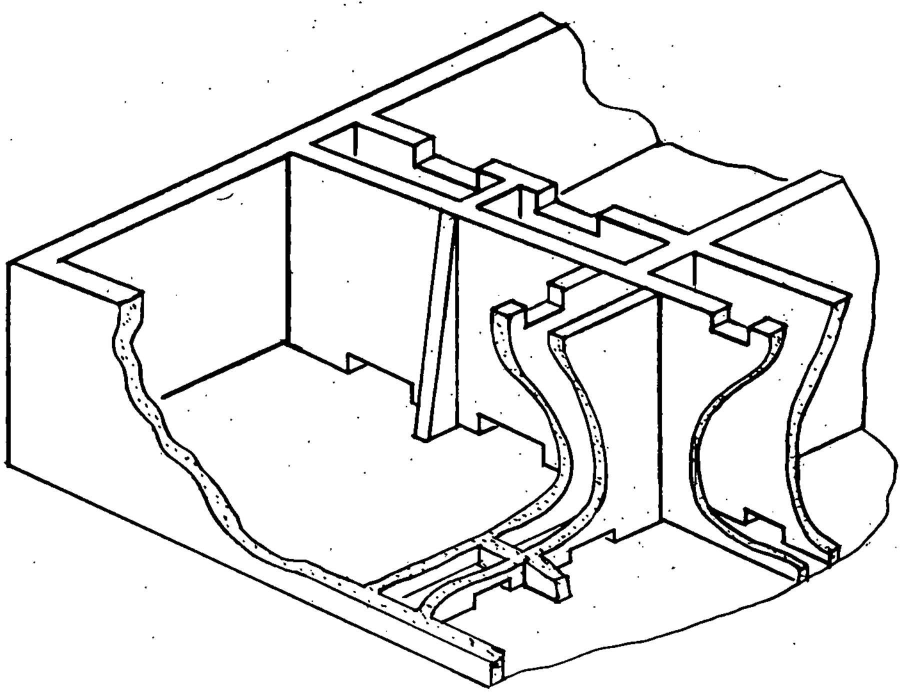
SECTION

b) SCHEME 2 LABYRINTH
(4-8 TIMES AS MANY COMPARTMENTS NEEDED FOR SAME BLENDING AS SCHEME 1)

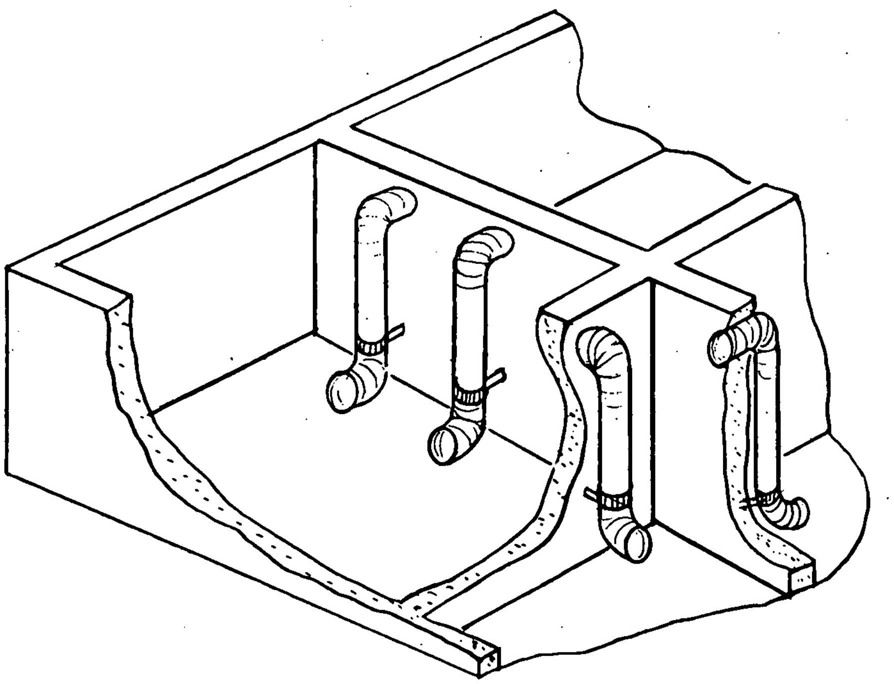
←—— CHARGING WITH CH. W.

- - - → DISCHARGING (SUPPLYING CH. W.)

CHILLED WATER STORAGE TANK CONFIGURATION FOR CORE ICES



a) CONCRETE WEIR WATER LINK



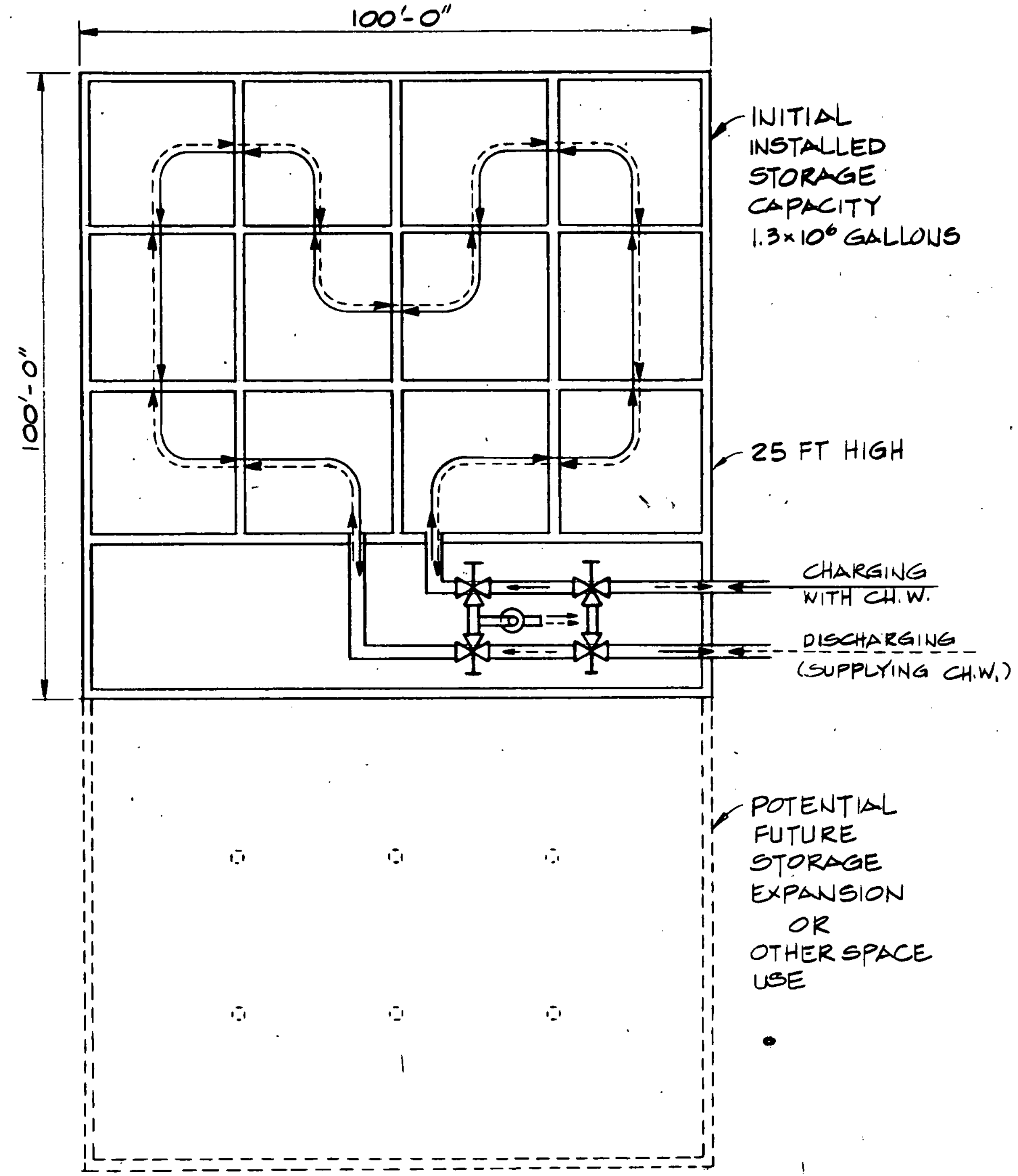
b) STEEL PIPE WATER LINK

eight times less compartments are required for the double wall concept. This would reduce the number of partitions by a factor of at least two. In addition, the double wall concept could result in a reduction in the thickness of the partition baffles since they could be used to reinforce each other as shown in Exhibit 5-4a. The pipe connection would require the same thickness wall, however, only one quarter as many. The cost estimate was carried out for the more expensive alternate, top and bottom weir baffling, to obtain a conservative estimate. Preliminary design will determine the final choice.

Exhibit 5-5 is a plan view of a typical partitioning with adjacent pump room. Also shown by dashed lines is a duplication of the total storage space on the opposite side of the pump room for possible future cold or hot thermal storage expansion or other space utilization. The merits of this warrants further investigation.

The scheduling of the cold thermal storage component as part of the parking garage structure must be integrated into the overall construction program. The design and construction schedule and investment cash flow projections of the chilled water storage portion of the project are presented on the next page.

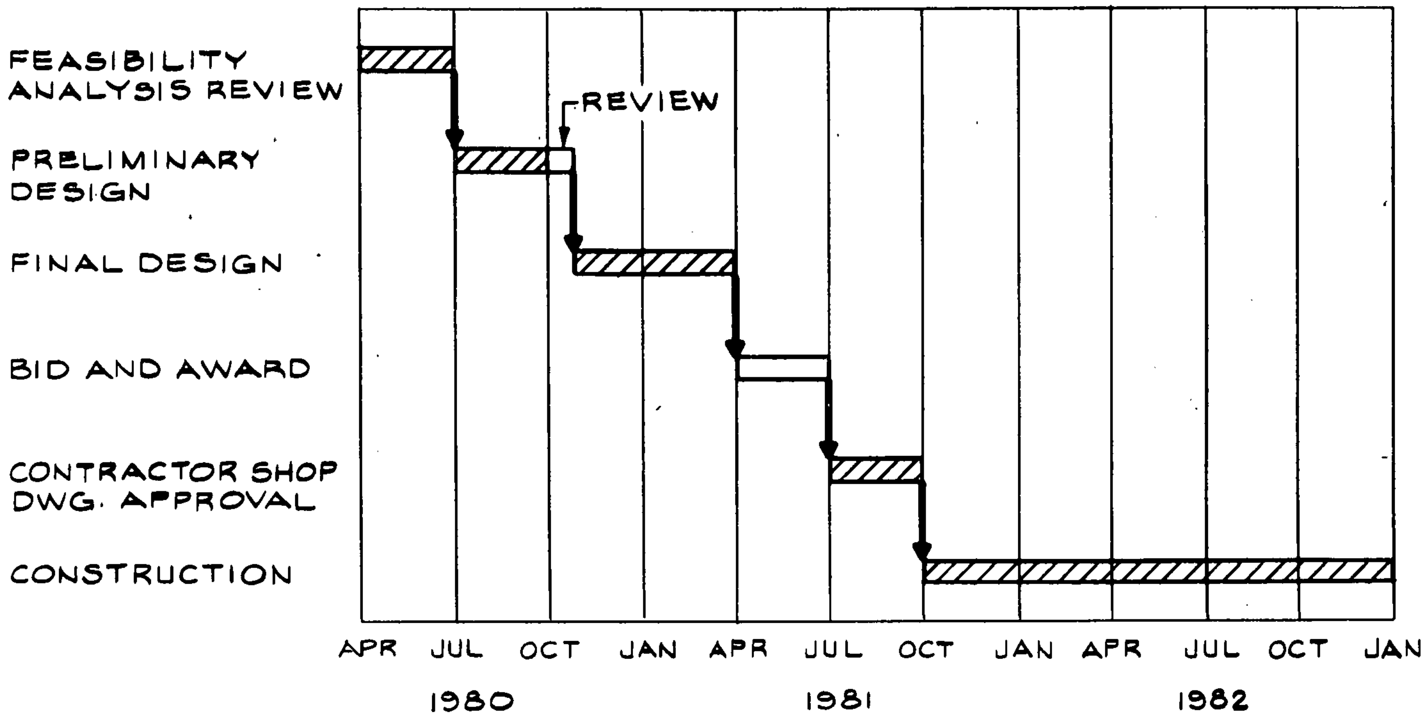
PLAN ARRANGEMENT OF STORAGE COMPARTMENTS AND STORAGE PUMP SYSTEM



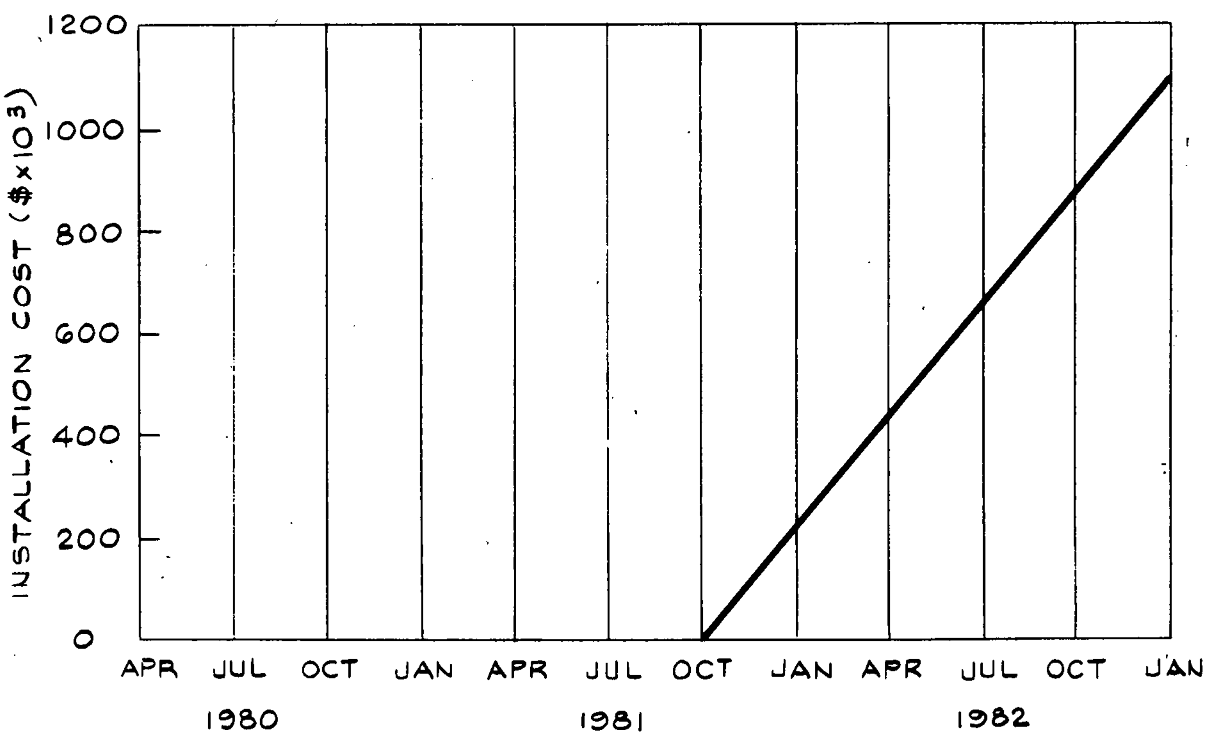
STORAGE-12 COMPARTMENTS, 22 FT. CUBES

EXHIBIT 5-5

CHILLED WATER STORAGE WITHIN CORE ICES



CONSTRUCTION SCHEDULE



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SECTION 6

6.0 ABSORPTION CHILLERS

6.1 General

The scope of work includes evaluating the feasibility of using absorption chillers operating as a central chiller either from the exhaust of a cogenerating turbine or from the exhaust of the turbines driving the existing centrifugal chillers. Absorption chillers are included in the analysis of the schemes for cogeneration in Section 2. Low pressure absorption chillers use about 19 lb/hr (19,000 Btu/hr) of steam to produce one ton of refrigeration as compared to about 14 lb/hr for turbine drives. Turbine drives require high pressure steam to be efficient, such as those already existing at GU. Absorption units operate at an energy disadvantage, but fill a need in that they can produce chilled water using low pressure steam in a plant that would otherwise have to waste this steam. There is an absorption chiller that uses 125 psig steam and has a conversion rate of about 15 pounds per hour of steam per ton of refrigeration. This equipment is made by only one manufacturer, costs more and has other disadvantages. It also would not satisfy the scope requirement for using low pressure exhaust steam.

Steam turbine driven chillers use steam at high pressure to expand through the turbine and exchange heat energy for mechanical energy. The absorption machine uses heat to drive off water vapor and change the ability of a chemical solution to absorb moisture and through this action, produce a cooling effect. Absorption refrigeration fills the need where cooling is required and steam is available. It permits the steam to act as the prime mover while producing only a minor increase in electric demand. An electric motor driven chiller uses about one horsepower per ton which is about 3500 Btu per ton versus 19,000 Btu for an absorption unit and 14,000 Btu for a steam turbine driven unit. On a source energy basis, the 3500 would become 11,600 Btu and the 19,000 and 14,000 would become about 25,000 and 19,000 Btu respectively.

Steam use for turbine is a direct function of the inlet and outlet pressures as well as their rotational speed, with higher speed machines being more efficient in converting heat energy to mechanical energy. At GU, the turbines are rated at 14.4 lb/ton, using the 275 psig inlet pressure and 85°F water available for condensing service. If a new boiler and turbine arrangement were selected, it would be possible to reduce the steam required to 12 lb/ton, but that would entail a high capital cost.

6.2 Cogenerating Turbine Exhaust

Two cogeneration schemes incorporated absorption refrigeration as a means of improving the overall efficiency of the plant. In Scheme D, one 490 ton unit was added to the system as a means of using 10 psig steam. This promoted the generation of electricity by increasing the pressure range of the turbine generator. The added benefit did not offset the costs as shown in the life cycle cost analysis for Scheme D.

In Scheme E there are four machines located in a new extension to the boiler plant. New chilled water pumps and condenser water booster pumps, to work in conjunction with the machines, would also be required. It is assumed that existing cooling tower would have sufficient thermal capacity to incorporate the 4900 tons of refrigeration, despite the fact that absorption machines reject more heat than do the turbine drives. No extension would be made to the tower, however, new fill could be installed and other maintenance would be done to increase its performance. This cogeneration scheme also did not prove to be cost effective or space efficient as shown in the life cycle cost analysis.

6.3 Turbine Driven Chillers Exhaust

The steam turbine driven chillers each have an uncontrolled extraction of about 2300 lb/hr at 10 psig. This could theoretically generate 120 tons of refrigeration. Based on the first cost, low thermal efficiency of the equipment and total anticipated hours of operation, this system would not be energy or cost effective.

6.4 Life Cycle Cost Analyses

The absorption chiller applications that had some possibility of being feasible are those associated with cogeneration Schemes D and E. They are a subsystem of the cogeneration schemes and their cost analysis is included with the schemes.

6.5 Incremental Savings and Optimization

See the cogeneration Schemes D and E for the absorption chillers subsystem analysis.

6.6 Conceptual Design

The absorption chiller conceptual design is included with the cogeneration Schemes D and E.

SECTION 7

7.0 HEAT PUMPS

7.1 General

The statement of work calls for the evaluation of the potential for energy savings by applying heat pumps for domestic hot water (DHW) heating, including consideration of heat pumps in conjunction with existing cooling towers. The feasibility of a particular application is dependent on the temperature levels of the waste heat source and the DHW temperature to be achieved. Practical application is obtained only if this temperature difference is not too large.

The role of the heat pump as a component of the GU ICES can best be understood by a description of its operation and function. This analysis is begun by reference to a heat engine which is a device that extracts an amount of energy q_H from a high temperature reservoir or source at temperature T_H and discharges an amount of energy q_L to a low temperature reservoir at temperature T_L, while performing some work w equal to the difference between the energy extracted and energy discharged. That is:

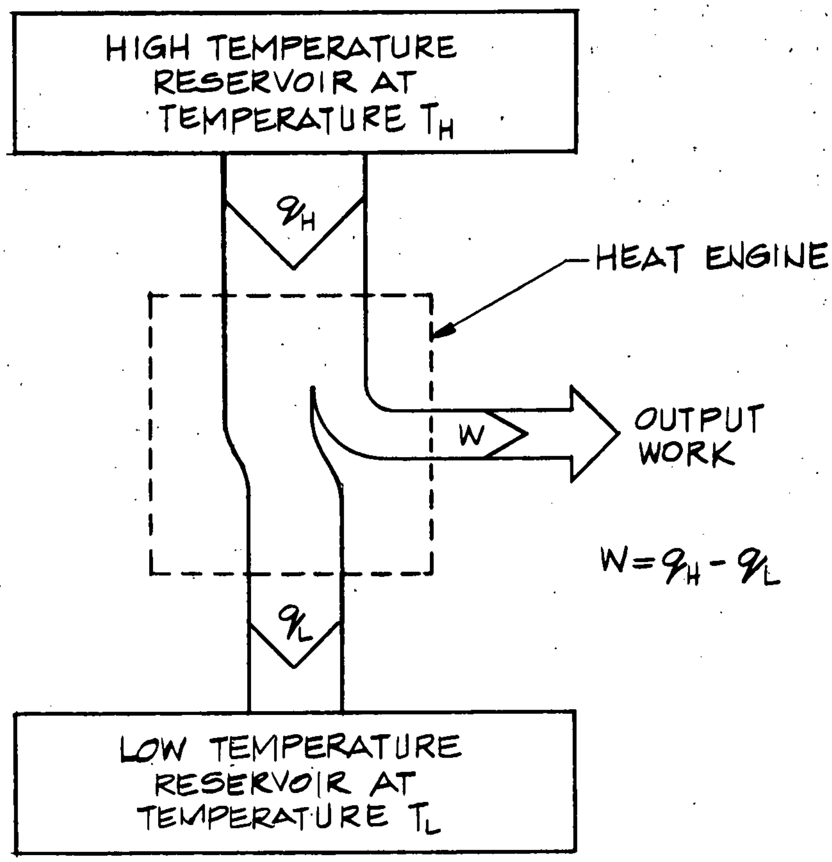
$$w = q_H - q_L$$

A schematic diagram of such a device and the corresponding cycle, on a temperature-entropy (T-S) diagram, are shown in Exhibit 7-1 a) and b). Such a cycle is called a Carnot cycle and would be duplicated by an ideal steam turbine/ compressor set operating entirely in the wet region (under the saturation curve - shown as a dashed line in Exhibit 7-1 b)). The efficiency of such a work producing cycle is:

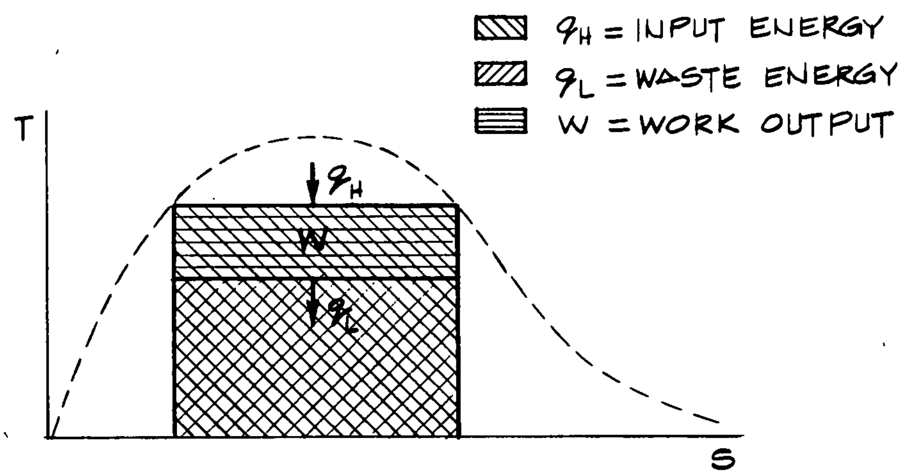
$$\eta = \frac{\text{output}}{\text{input}} = \frac{\text{useful effect}}{\text{expenditure}} = \frac{w}{q_H} = \frac{q_H - q_L}{q_H} = 1 - \frac{q_L}{q_H} = 1 - \frac{T_L}{T_H}$$

and is always less than 1. The ratio $q_L/q_H = T_L/T_H$ for ideal reversible cycles.

HEAT ENGINE CYCLE



a) HEAT ENGINE SCHEMATIC



b) HEAT ENGINE CYCLE
TEMPERATURE-ENTROPY DIAGRAM

The heat engine cycle can be reversed by causing the system fluid to flow in the opposite direction through the device. This would require the turbine to act as a compressor and the compressor to act as a turbine. The result is a refrigeration cycle and is portrayed for comparison in Exhibit 7-2 a) and b).

The refrigeration cycle, in contrast to the heat engine cycle, consists of extracting an amount of heat q_L from the space to be conditioned*, expending work w** and discharging the waste heat q_H***. In the ideal reversed cycle, shown in Exhibit 7-2 b), there is a balance between q_H, q_L and w according to

$$q_H = q_L + w$$

so that the horizontally crosshatched area representing the work w is in fact equal to the difference between the two areas which are crosshatched in opposite diagonal directions. This equivalence exists since the area on a T-S diagram represents an amount of heat energy.

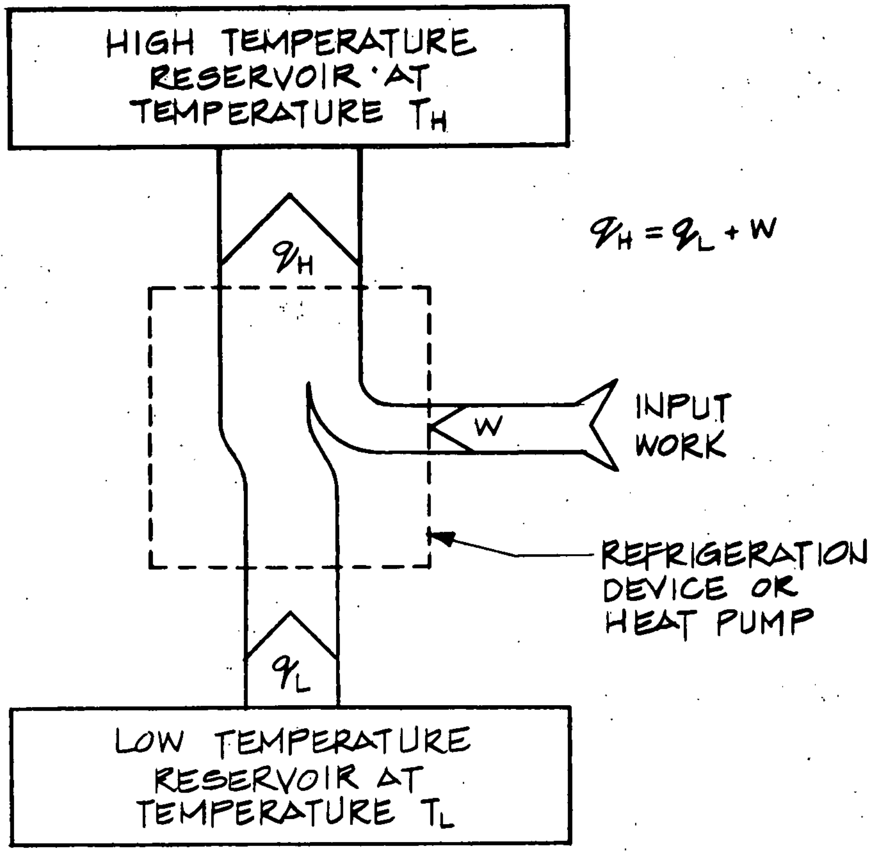
In actual refrigeration cycles the turbine is replaced with an expansion valve or throttling device which achieves a result similar to a turbine but at a significant cost savings. There is a penalty to be paid, however, by using the throttling device. This penalty is demonstrated in Exhibit 7-2 c) by comparison to 7-2 b). Since a throttling device is a constant enthalpy process whereas the turbine extracts energy from a flow process, less heat can be absorbed at the low temperature for the same amount of heat discharged, implying a greater amount of work for the same amount of heat absorbed. This extra work corresponds to the turbine work not being recovered when a throttling valve is used. If the device were to be used strictly for heating, the turbine could be

*The interior of a refrigerator or building being air conditioned, namely the low temperature reservoir.

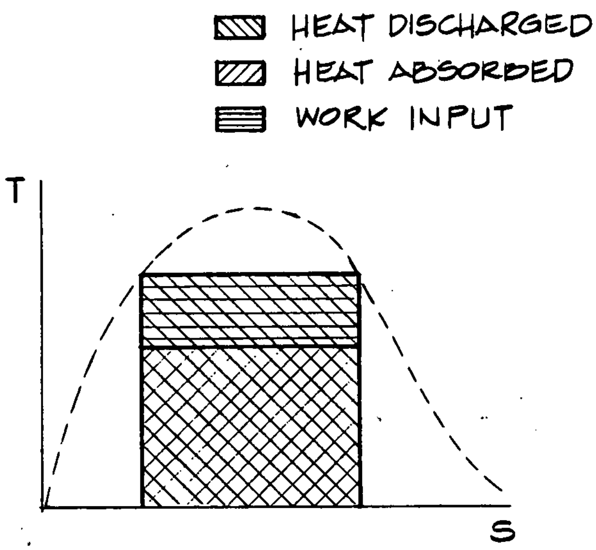
**Electric motor or turbine or reciprocating engine power.

***Via cooling coils or a cooling tower to be the ambient which by comparison is the high temperature reservoir.

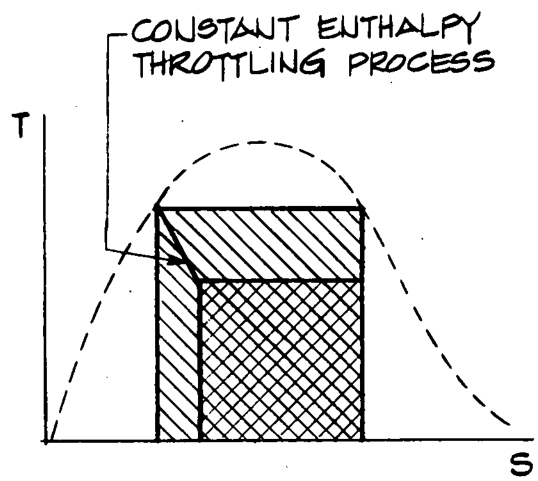
REFRIGERATION OR HEAT PUMP CYCLE



a) REFRIGERATION OR HEAT PUMP SCHEDULE



b) REVERSE HEAT ENGINE CYCLE



c) REFRIGERATION OR HEAT PUMP CYCLE

desirable, however, the resulting increased cost is not warranted.

The reverse heat engine cycle according to classical thermodynamics is one of two things, either

a) it is a refrigeration device where the useful effect is the removal of an amount of low temperature energy q_L while expending work w, or

b) it is a heat pump whose useful effect is the supplying of an amount of high (relatively speaking) temperature energy q_H while expending work w.

It is useful to have a measure of the performance of these devices for comparison purposes similar to the efficiency of a work producing engine discussed earlier. This performance measure again is the ratio of

$$\frac{\text{output}}{\text{input}} = \frac{\text{useful effect}}{\text{expenditure}}$$

For the refrigeration device, the useful effect was stated to be q_L, the low temperature energy extracted, while the expenditure is obviously, w, the work required. This ratio can be greater than one, hence instead of using the term efficiency, which is always less than one, the term coefficient of performance (COP) was coined. For a refrigeration device this value is:

$$COP_{ref} = \frac{q_L}{w} = \frac{q_L}{q_H - q_L} = \frac{1}{\frac{q_H}{q_L} - 1} = \frac{1}{\frac{T_H}{T_L} - 1}$$

and it is seen that it can be greater than unit, if the demoninator is less than one.

For a heat pump, on the other hand, the useful effect is q_H, the high temperature energy delivered at T_H, and the expenditure again is the work w. The Coefficient of Performance of the heat pump is:

$$COP_{H/P} = \frac{q_H}{w} = \frac{q_H}{q_H - q_L} = \frac{1}{1 - \frac{q_L}{q_H}} = \frac{1}{1 - \frac{T_L}{T_H}}$$

and this value is always greater than one. The relationship between the two COP's, using the same device for either purpose is:

$$COP_{H/P} = COP_{ref} + 1$$

It is thus seen that the same device can be used as either a refrigeration machine or as a heat pump, depending on what the useful effect of the application is intended to be. In other words, this device can either heat or cool, or, for that matter, it can do both. The more traditional applications of this device have been as refrigeration machines or chillers used for air conditioners and refrigerators since that was the most economical method, and sometimes the only one, for generating cooling. Furthermore, fuel costs were low and performances of devices were not very good so the heating application lagged that of the cooling mode. As fuel costs rose and as a result of improved technology, the concept of using the reverse heat engine, i.e., the refrigeration cycle, not only as a refrigeration machine, but also as a heating device, became practical. The direct result was the marketing of refrigeration machines, not only for cooling, but also for heating and more interestingly, for the dual function of heating and cooling. If a single device is used to satisfy simulataneous heating and cooling load then two useful effects are obtained simultaneously for the same expenditure of work (or energy). The COP of such an application is therefore:

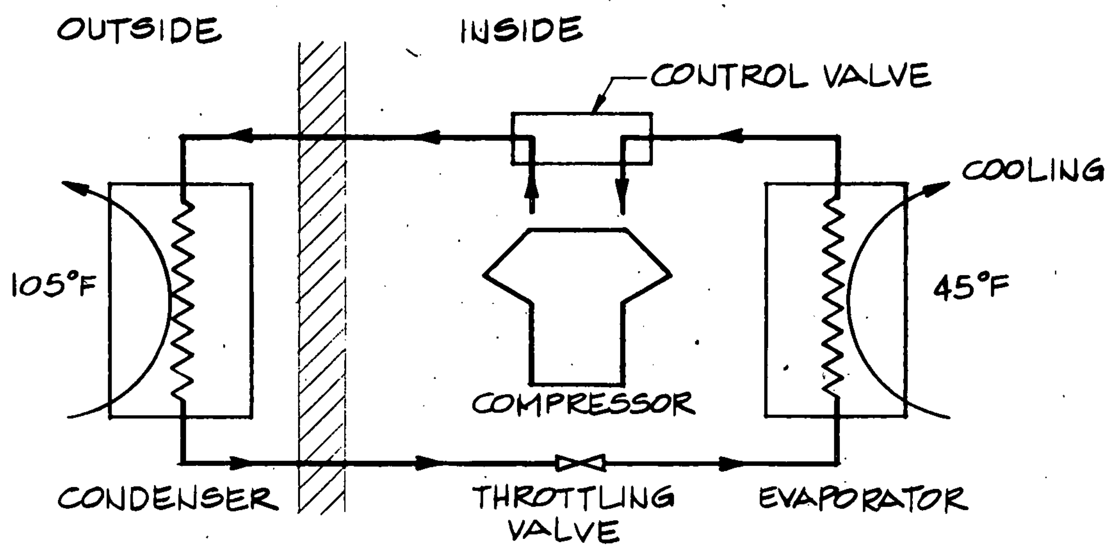
$$COP_{dual} = \frac{q_H + q_L}{w} = \frac{q_H}{w} + \frac{q_L}{w} = COP_{ref} + COP_{H/P}$$

This implies an extremely energy conserving and cost reduced method of simultaneous heating and cooling. If at least one of the COP's (either COP_{ref} or $COP_{H/P}$) is greater than 3.4 (the ratio of source to site energy in Btu/kWh namely 11,600 ÷ 3413), the other benefit from an energy standpoint is entirely free. This point is clarified later with a specific example.

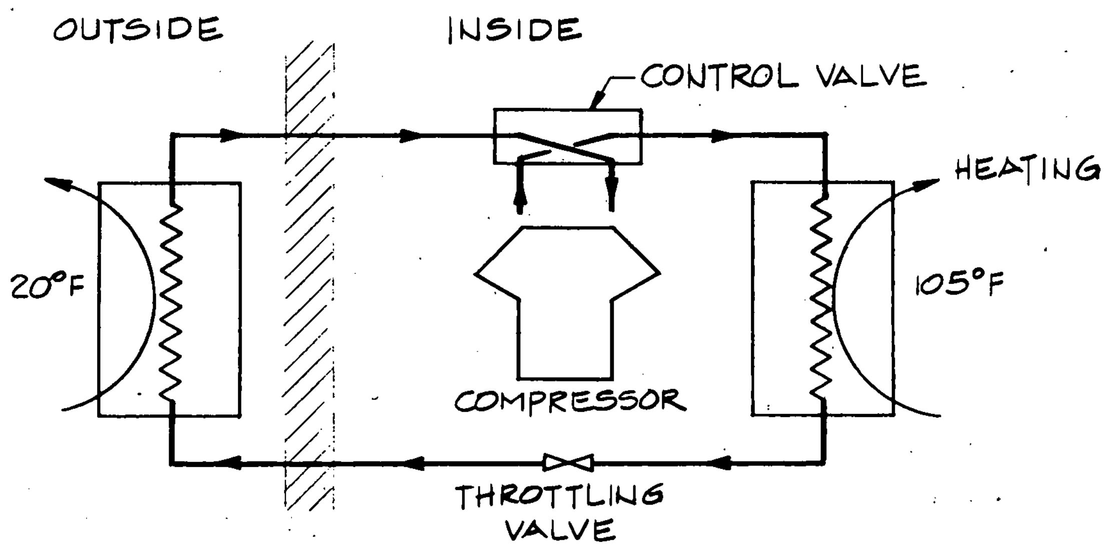
It is at this point that nomenclature must be clarified. In the classical sense, the refrigeration machine used for heating purposes was called a heat pump. Today, the multipurpose unit which is used to cool in the summer and heat in the winter is called a heat pump. Although some technical literature refers to such a device as one in which there is a reversal of the refrigeration cycle, this is only partially correct. The cycle remains the same, however, the functions of the evaporator (heat absorber) and condenser (heat discharger) are interchanged by suitable valve controls thus allowing the heat exchanger in the interior of the space to receive the benefit which provides either cooling (as the evaporator) or heating (as the condenser) while the compressor and throttling valve still act exactly as before. This difference is shown in Exhibit 7-3.

The other multipurpose use of the refrigeration machine is in the dual role of performing cooling and heating simultaneously. In the strict sense of the word, the device performs both as a refrigeration device (cooling of some energy stream) and as a heat pump (heating of some other energy stream). Carrier calls this mode of operation "Heat Reclaim".[1] A practical illustration of heat reclaim is in a building which requires simultaneous heating and cooling such as an interior computer space being cooled in the winter while the perimeter offices need to be heated to offset losses through the walls and windows.

HEAT PUMP APPLICATION FOR HEATING AND COOLING



a) SUMMER OPERATION



b) WINTER OPERATION

For new construction and major renovations, in appropriate geographical locations and with compatible heating and cooling loads, the application of this concept must be given serious consideration regardless of whether it is labelled a refrigeration machine, heat pump or heat reclaim device. For consistency within the present statement of work, the term heat pump will be used whenever the application of a refrigeration device is specifically intended to generate a usable higher temperature energy stream by extracting energy from any source stream. The source stream in the present application is a waste stream, the condenser water return going to the cooling tower.

There are many modern systems taking advantage of the benefit of the heat pump. To understand the advantages of the heat pump, it is necessary to refer to the COP of a heat pump. A typical heat pump will usually have a coefficient of performance of somewhere between 3 and 7. This means that for every Btu or kWh of energy supplied, 3 to 7 times as much energy in the form of heat is delivered at the heat pump output. Alternatively, 3 to 7 times less energy is consumed for the same amount of heat delivered. In general, the higher the COP the more heat delivered per unit work or the less work required per unit heat delivered.

Furthermore, as long as the COP exceeds 3.4 (the ratio of source energy equivalent 11,600 Btu/kW to local energy equivalent 3413 Btu/kW) the system is more energy efficient than utility supplied power. In addition, the dollar expenditure per Btu (or kWh) of energy delivered is now the instantaneous electric rate divided by the COP. As a comparison, direct electric heating would be 3 to 7 times more expensive than heating by heat pumps. If the heat pump is now used in the role of simultaneous heating and cooling, this benefit is compounded. One way to look at it is to consider that cooling is required anyway so the heating is entirely free. The other way to view it is to recall that $COP_{ref} = COP_{H/P} - 1$, so for a $COP_{H/P} = 7$, $COP_{ref} = 6$ and the overall energy benefit is 6 + 7 = 13 for the expenditure of 1 unit of energy. This becomes a system to be installed wherever possible (even at a $COP_{H/P} = 3$, the overall benefit is 5, still in excess of the 3.4 energy ratio).

Some of the modern systems which incorporate heat pumps have already been discussed in the sections on hot or cold thermal storage. This comes about since the maximum benefit from heat pumps can be realized by operating them at off-peak electric rate hours (where and when they are in effect) and incorporating cold and hot thermal storage to provide these requirements for the other times. Subsystems typically combined with heat pumps into overall energy systems are solar panels, waste energy streams, ice storage, chilled water storage, heating hot water storage, domestic hot water storage and direct use of heat pump output (hot, cold or both).

The specific application of the heat pump within the present scope of work is the use of a heat pump to extract waste heat energy from the condenser water or return stream of existing local chiller systems and to deliver the reclaimed heat to a city water stream to produce domestic hot water at about 120°F wherever practical. This application is also called cascade heat pumps.[2]

7.2 GU Heat Pump Application

Application of heat pumps at GU was specifically directed to the generation of domestic hot water heating in conjunction with existing cooling towers. One benefit of this specific application is the use of a low temperature thermal waste stream for energy reclamation and for the generation of a useful higher temperature thermal energy stream, namely domestic hot water (DHW). Other benefits are a reduction of water vapor and thermal pollution of the atmosphere from the cooling tower and a reduction of emissions from the Heating and Cooling Plant boilers corresponding to reduced boiler output requirements.

Condenser return water at about 95°F is cooled by a cooling tower to about 85°F. This cooling results in wasting of all of the chilling energy plus the work of refrigeration. An equivalent cooling can be achieved for all or part of this condenser return water by reclaiming this heat, or some part of it, by any other economically competitive means. The heat pump meets this criterion best due to its cooling effect resulting in a simultaneous heating effect, as described in Section 7.1. There are other conditions that are necessary for an effective and economic system to be implemented:

- Sufficient hours of chiller operation.
- Sufficient domestic hot water demand.
- Concurrent chiller operation and DHW demand.
- Sufficient space for housing heat pump.
- Proximity of heat pump space to chiller, to minimize piping costs.

Additional considerations to allow off-peak electric rate utilization:

- Chilled water storage to allow off-peak, chilller operation.

- Space to house DHW storage tank used to store off-peak heat pump generated DHW.

- Proximity of storage tank space to heat pump location to minimize piping costs.

The additional factors that will determine the feasibility are:

- Implementation must be cost effective.
- Energy must be conserved and cost reduced.

The last factor can be answered rather rapidly by a positive response as long as the COP of the heat pump exceeds 3.4, whereas the other factors are interelated or subject to site conditions.

The criteria listed above were applied to specific buildings on the GU campus. Table 7-1 is a summary of the findings. One of the primary considerations is the ability to operate the heat pump at off-peak electric rate hours in order to improve the economics. This requires simultaneous off-peak chiller operation which is only feasible with chillers connected to the main chilled water distribution network so that storage, previously discussed in Section 5.2.2 can be used. In addition, the number of operating hours must be large enough to allow sufficient savings to be realized so that a reasonable payback period is obtained.

The application of the heat pump in the condenser water return circuit led to the idea of preheating the city water being supplied to the heat pump by means of a standard water to water heat exchanger to reduce the size of the heat pump required. The resulting typical system is shown in Exhibit 7-4. The heat pump and heat exchanger are operated in parallel in the condenser water loop to extract the maximum waste heat.

TABLE 7-1

HEAT PUMP/DHW CONSIDERATIONS

BUILDING NAME	CHILLER			DHW		SPACE AVAILABILITY			PIPING	APPLICATION
	Tons Refrig.	Yearly Hours	Storage Tie In	Consumpt. GPD	Adequate Yes/No	Heat Pump	Storage Tank	Heat Exchange	Length To H/P or H/X	Recommendations
GU Hospital Complex	700	3,600	Yes	18,000	Yes	Yes	Yes	Yes	H/P & H/X Long	H/P & H/X
Reiss Science Building	680	1,500	Yes	2,000	No	No	No	Yes	—	—
Darnall Hall	290	2,000	No	18,000	Yes	No	No	Yes	H/X Long	H/X
New South Building	460	2,000	No	24,000	Yes	No	No	Yes	H/X Short	H/X
Harbin Hall	225	2,000	No	6,000	Marginal	Yes	No	Yes	H/X Long	—
Henle Village	250 (ABS)	2,000	Possibly	6,000	Marginal	No	No	Yes	H/X Short	—
Ryder* Hall	460	2,000	No	600	No	No	No	Yes	—	—

*East Campus Building

HEAT PUMP APPLICATION IN TYPICAL BUILDING WITH LOCAL CHILLER

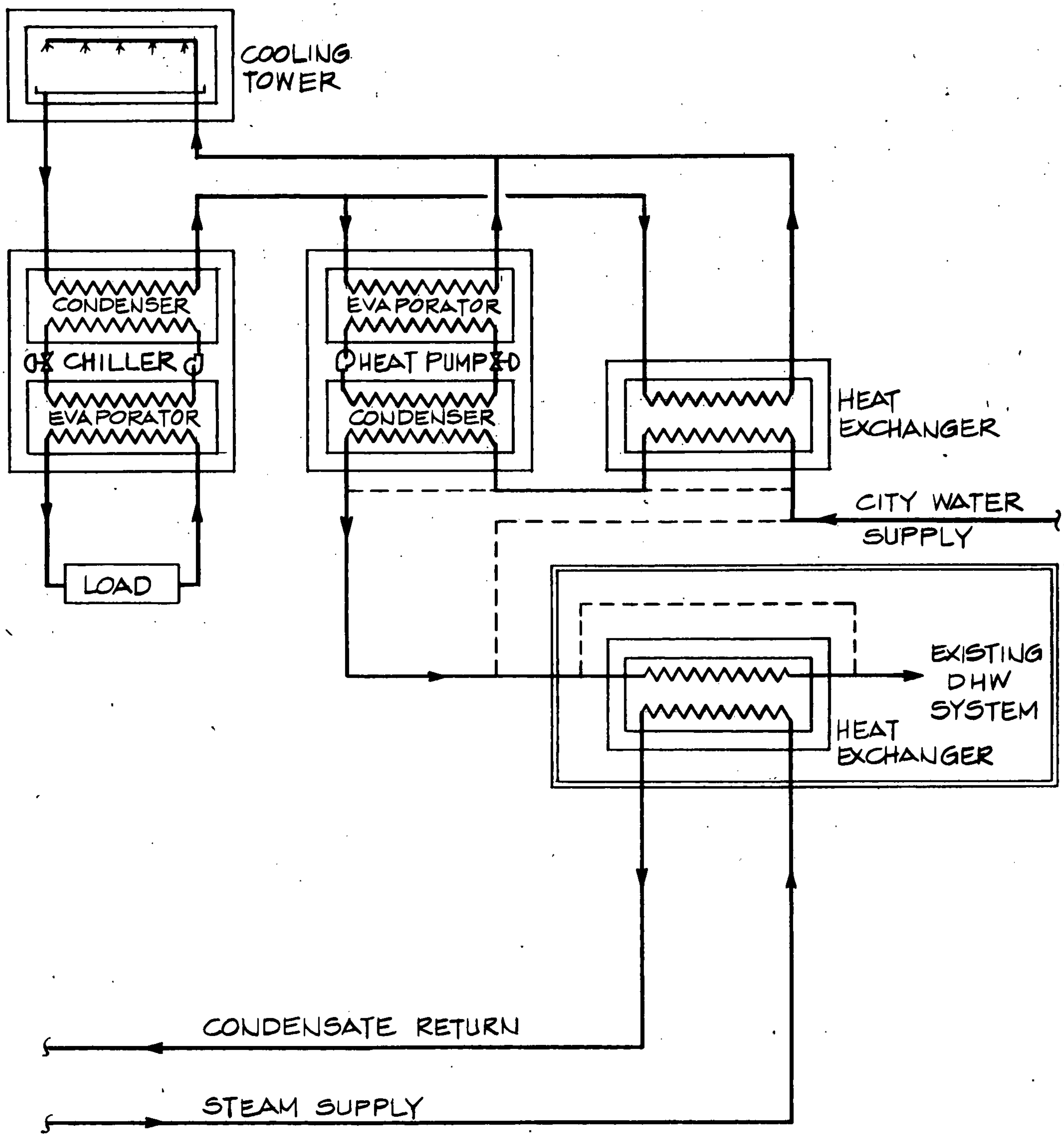


EXHIBIT 7-4

A summary of the heat pump and heat exchanger evaluations including energy as well as cost savings for various operating modes is included in Appendix G.

The previously discussed limitations restrict the heat pump application to the hospital complex since winter operation of that local chiller is a regular occurrence. By also using this chiller during the regular cooling season, while taking advantage of cold thermal storage, the number of operating hours can be increased to 3000 to 4500. 3600 hours were used for evaluation. Exhibit 7-5 shows this system within the GU Hospital complex and how it relates to the Heating and Cooling Plant as well as cold thermal storage in Core ICES.

City water enters the hospital and is preheated in the heat exchanger. It is raised to its design temperature by the heat pump whence it is stored in the hot thermal storage vessel for subsequent use. In the event of problems with any portion of the heat pump system or if inadequate temperature levels are obtained, the existing DHW system automatically provides the required heating.

The DHW storage tank can be charged if there is excess production while demand is being fulfilled. During this phase, the circulating pump in the storage loop would be on. If there is excess demand over production, regulating valves would allow for partial demand being supplied from storage and if there is no supply at all from the heat pump, the full demand would be met by storage. Should storage be depleted and/or the heat pump or chiller not operational, the existing DHW system would carry the whole load similar to the way it would occur if there were a problem as mentioned earlier. In this way, the existing DHW system is not shut down but acts as a supplementary and backup system.

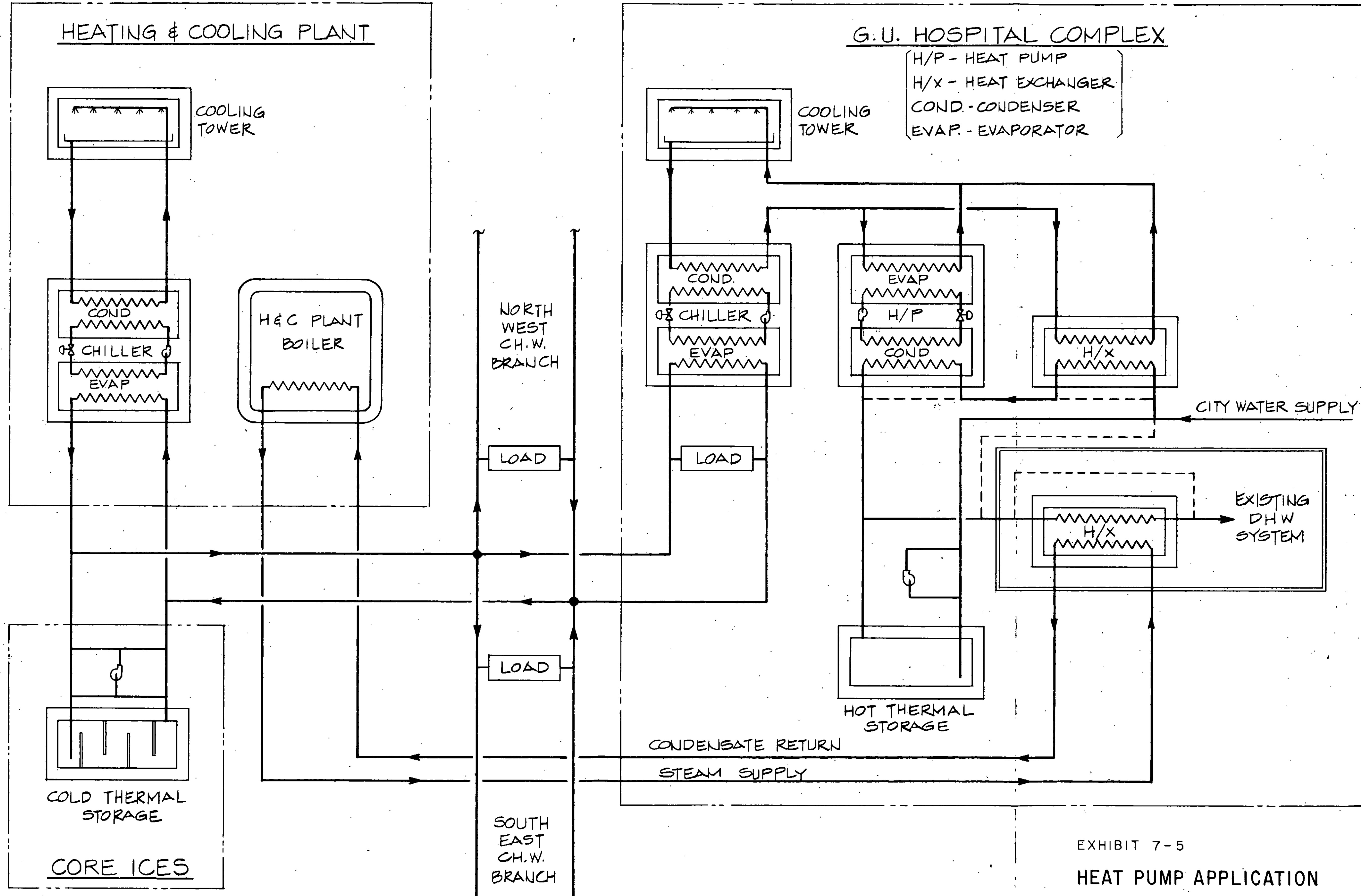


EXHIBIT 7-5

HEAT PUMP APPLICATION WITHIN HOSPITAL COMPLEX

POPE, EVANS AND ROBBINS

Application of the heat pump to all other independently cooled buildings was ruled out as indicated in the summary table, Table 7-1. The idea of the preheat heat exchanger, however, led to a separate evaluation of its consideration for those buildings where the heat pump proved unacceptable. It is obvious that energy can be saved by extracting any amount of waste energy from the condenser water return stream. This application is addressed in the following subsection, Section 7.3.

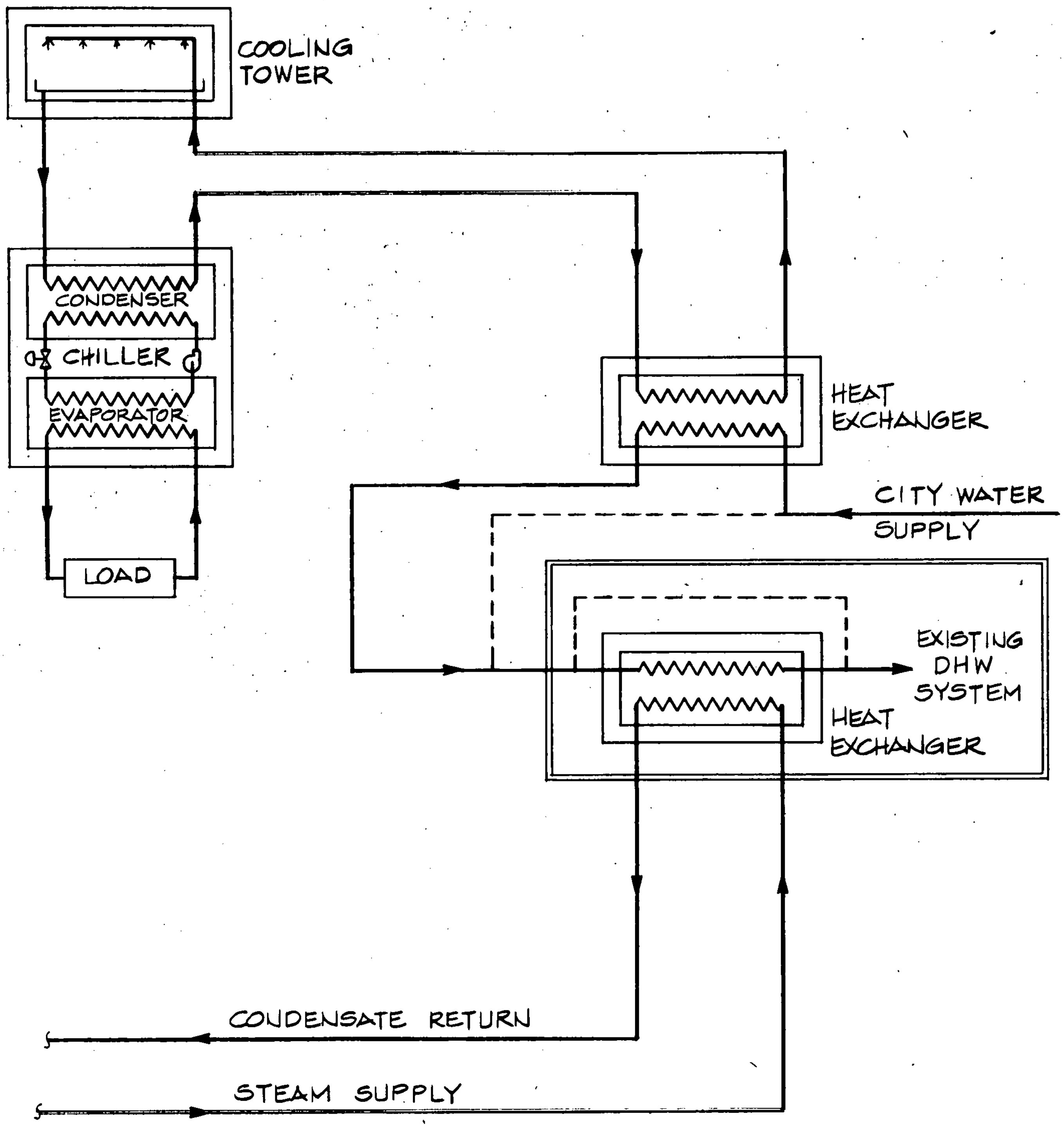
7.3 GU Heat Exchanger Application

Consideration of only a heat exchanger to preheat city water prior to entering the existing DHW system is a by-product of the heat pump analysis and is shown for a typical application in Exhibit 7-6. No storage tank is required in this system since chiller operation is generally coincident with DHW consumption.

Based on the preliminary findings of the heat pump application, heat exchanger evaluations were restricted to the New South Building and Darnall Hall which each have large DHW consumption rates due to their large cafeterias, and Harbin Hall and Henle Village which have marginal DHW consumption. New South Building and Henle Village have short piping run requirements, but Henle Village's absorption chiller has not been used to date which would exclude the latter from further consideration. However, if this unit is used and since it is within a building tied to the main chilled water distribution system, significant hours of operation of this absorption chiller could change this picture. Darnall and Harbin Halls both require long piping runs, however, Darnall's large DHW consumption would appear to offset this drawback. Consequently, Harbin Hall would appear to have less merit.

All four buildings were evaluated technically for heat exchanger application. The life cycle cost analysis presented in Section 7.4 was used to determine that only New South Building and Darnall Hall would benefit from heat exchanger application.

HEAT EXCHANGER APPLICATION IN TYPICAL BUILDING WITH LOCAL CHILLER



7.4 Life Cycle Cost Analysis

Both the heat pump application and the separate heat exchanger application are addressed here since the latter is a by-product of the former. Details of the life cycle cost analysis are found in the Appendix.

Results show that investment and discounted payback periods for the heat pump and heat exchanger applications are as shown in Table 7-2.

TABLE 7-2

LIFE CYCLE COST ANALYSIS FOR HEAT PUMPS AND HEAT EXCHANGERS

Building Name	Intitial Cost ($\$ \times 10^3$)	Discounted Payback Period (Yrs)	
		10% Discount Rate	3% Discount Rate
Hospital	82.5	11.7	8.4
New South	7.5	4.4	3.9
Darnall	10.5	12.3	8.4
Henle	4.7	18.6	12.0
Harbin	7.7	> 25	22.0

Installation of the heat pump in the hospital complex is recommended as is the installation of the heat exchangers in New South and Darnall Hall. Despite the excessive discounted payback period for the heat pump application, this would be an exemplar installation and, therefore, is warranted. Installation of heat exchangers in Henle Village and Harbin Hall is not recommended.

7.5 Incremental Savings and Optimization

Application of the heat pump and the heat exchanger save both energy and costs. Energy is saved due to waste heat recovery and costs are reduced due to two factors. First, fuel costs corresponding to energy saved are realized. Second, costs by generating DHW at off-peak electric rates are reduced. Table 7-3 summarizes the energy and cost savings of the individual application.

TABLE 7-3

ENERGY AND COST SAVINGS DUE TO HEAT PUMPS AND HEAT EXCHANGERS

Building Name	Annual Cost Savings ($ x 10^3)	Annual Energy Savings 10^6 Btu/yr	10^3 Gal of Oil/Yr	Barrels of Oil/Yr
Hospital	10.0	4200	28.5	680
New South	2.0	960	6.7	160
Darnall	1.5	720	5.0	120
Henle	.5	240	1.7	40
Harbin	.5	240	1.7	40

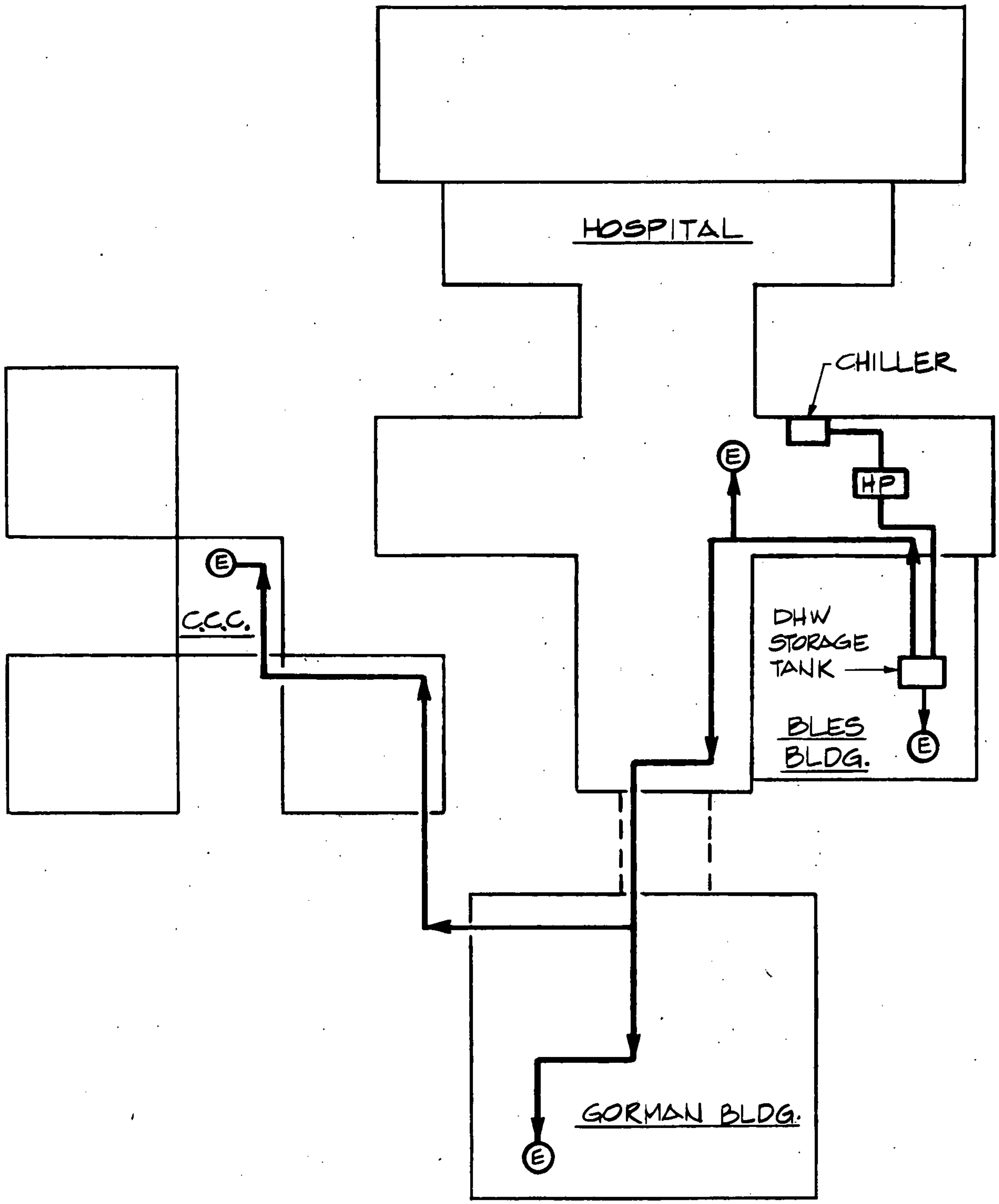
7.6 Conceptual Design

The heat pump and storage tank installation in the Hospital Complex is relatively easy since there is adequate space within the hospital and adjacent Bles Building to house them in close proximity to the 700 ton hospital chiller. This makes it simple to connect to the condenser water return line leading to the cooling tower. The connection from the DHW storage tank to the existing DHW systems within the Hospital and Bles Buildings is also easy. The remaining portion of the piping system, connecting the storage tank to the existing DHW systems within the Gorman Building and the Concentrated Care Center, is more complex due to the additional length of pipe required to reach the mechanical rooms within those structures. Exhibit 7-7 indicates the general location of system components within the respective structures.

Incorporation of the heat exchangers into the respective buildings for which they have been recommended is a relatively easy procedure. Only a small space within an existing mechanical room is required for the heat exchangers which will be installed within the New South Building and Darnall Hall. Piping connections to the condenser water return line to the cooling tower is simple and direct and is indicated in Exhibit 7-3. Similarly DHW piping connections, also shown schematically in Exhibit 7-3, are simple and direct, although somewhat longer for Darnalll Hall since the chiller mechanical room is on the sixth floor and the DHW mechanical room is in the basement. This leads to a greater initial cost for the latter.

Estimated piping requirements for all systems are included in Appendix G.

HEAT PUMP GENERATED DHW DISTRIBUTION SYSTEM



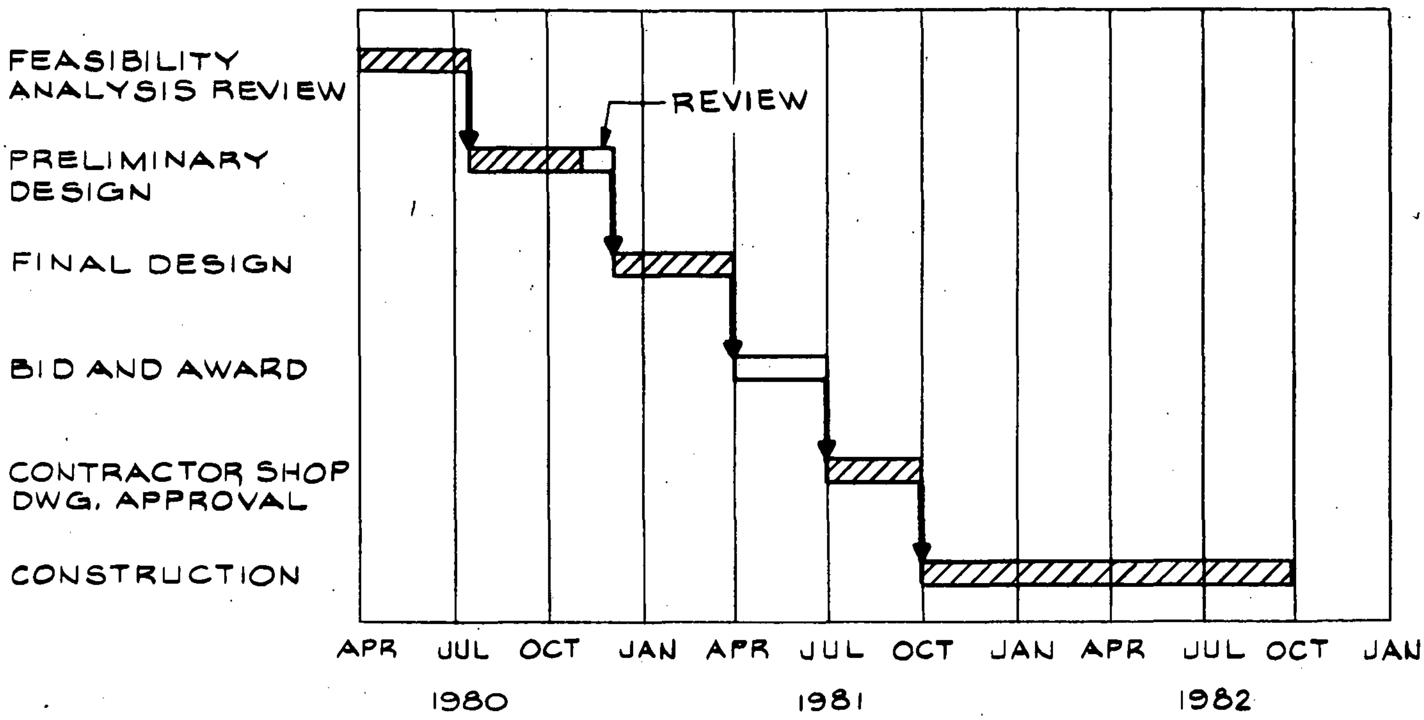
Ⓔ EXISTING DHW SYSTEM

The scheduling of the heat exchanger application to the New South Building and Darnall Hall are independent of any construction schedule associated with the GU master plan. These recommendations also fall into the category of energy conservation opportunities (ECO) and should possibly be weighed with other identified ECOs. However, the benefits to be achieved make early implementation desirable.

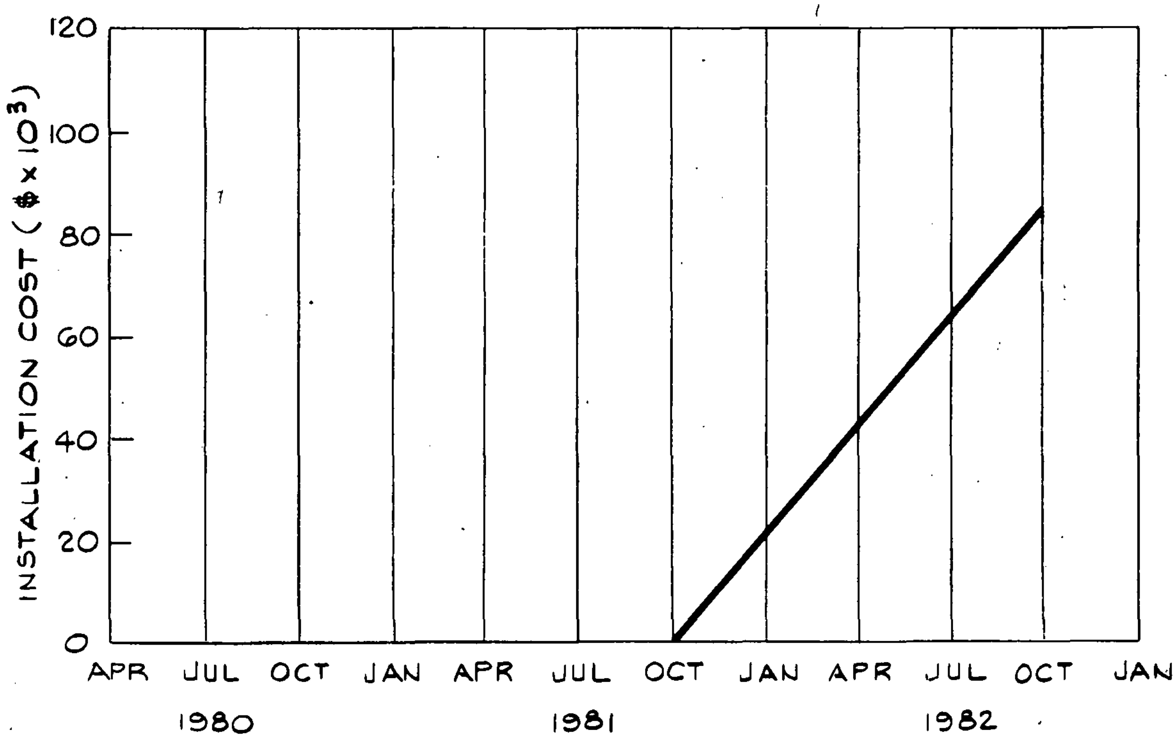
The heat pump application can be implemented in the hospital at any time since it will be coupled to the local chiller. For effective savings to be achieved, however, chilled water storage implementation is necessary. The schedule for the completion of the heat pump installation therefore does not precede the completion of the chilled water installation.

The design and construction schedule and investment cash flow projectives for the projects are presented on the following pages.

HEAT PUMP FOR DHW GENERATION IN HOSPITAL

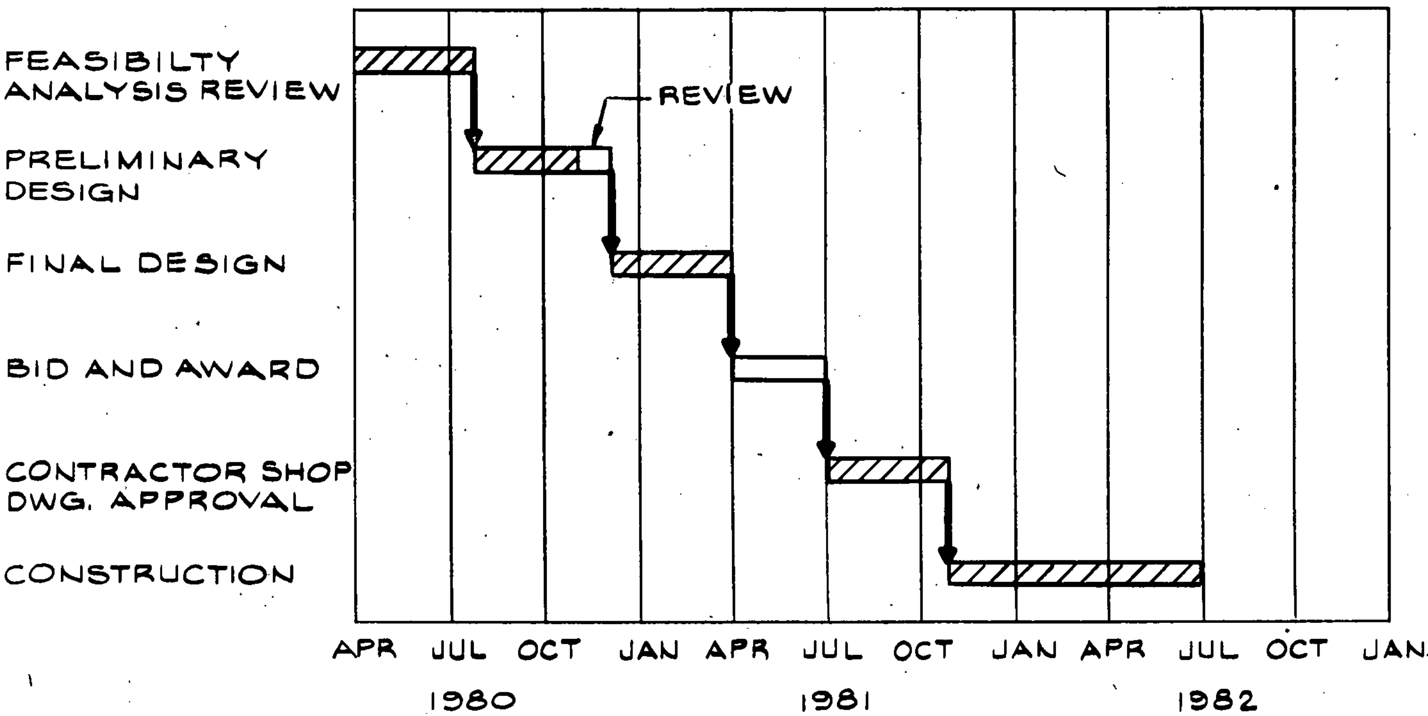


CONSTRUCTION SCHEDULE

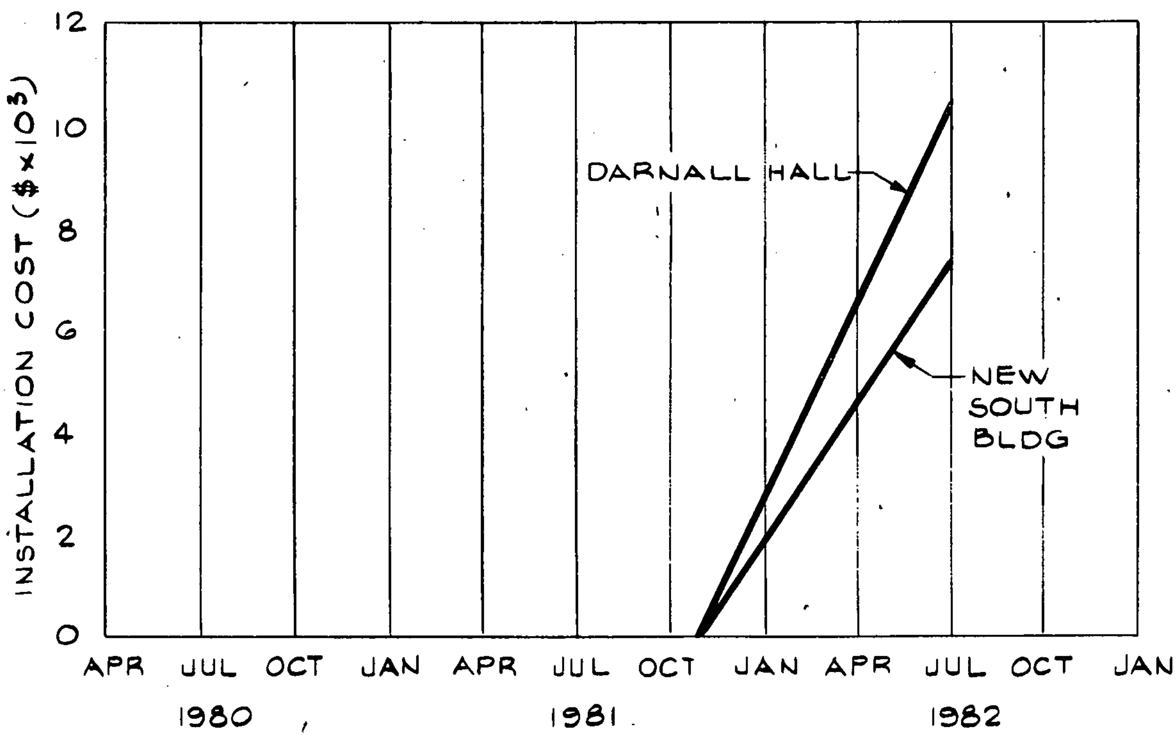


INVESTMENT CASH FLOW (UNDISCOUNTED)

HEAT EXCHANGER FOR DHW PREHEATING IN NEW SOUTH BLDG. AND DARNALL HALL



CONSTRUCTION SCHEDULE



INVESTMENT CASH FLOW (UNDISCOUNTED)

REFERENCES

1. Carrier Equipment Corporation, Engineering Guide for Reciprocating Chiller Heat Reclaim Systems, 1977, Catelog 592 026.

2. Carrier Equipment Corporation, Engineering Guide to Cascade Heat Pump Systems, 1969, Catalog 592 006.

SECTION 8

8.0 ENVIRONMENTAL IMPACT ASSESSMENT

8.1 Introduction

Federal policy for protection of the environment is established by the National Environmental Policy Act (NEPA). The Council on Environmental Quality (CEQ), established by NEPA, requires that federal agencies evaluate environmental aspects of proposed actions in order to minimize adverse environmental effects.

The objective of this project phase is to evaluate the cost and energy savings of integrating alternative energy subsystems into the atmospheric fluidized bed (AFB) combustor. Various schemes of the following energy subsystems are evaluated in other sections of this report:

Cogeneration of Electricity
Added Coal and Limestone Storage and Handling
Hot and Cold Thermal Storage
Absorption Chillers
Heat Pumps

The following candidate energy subsystems have demonstrated technical and economic feasibility or warrant further consideration:

1. Cogeneration of Electricity - Scheme A
2. Added Coal, Limestone and Ash Storage - Two Schemes
3. Cold Thermal Storage
4. Heat Pumps

This section presents the environmental impact assessment (EIA) of each candidate energy subsystem. Various EIA formats have been suggested by the different federal agencies. Typical formats include:

1. Description of proposed action

2. Description of existing environment

3. Environmental impact of the proposed action

4. Adverse impacts which cannot be avoided should the proposal be implemented

5. Relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity

6. Irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented

7. Alternatives to the proposed action

The proposed actions and alternatives are described in detail in other sections of this report. This EIA, therefore, includes format topics 2 through 6.

8.2 Existing Environment

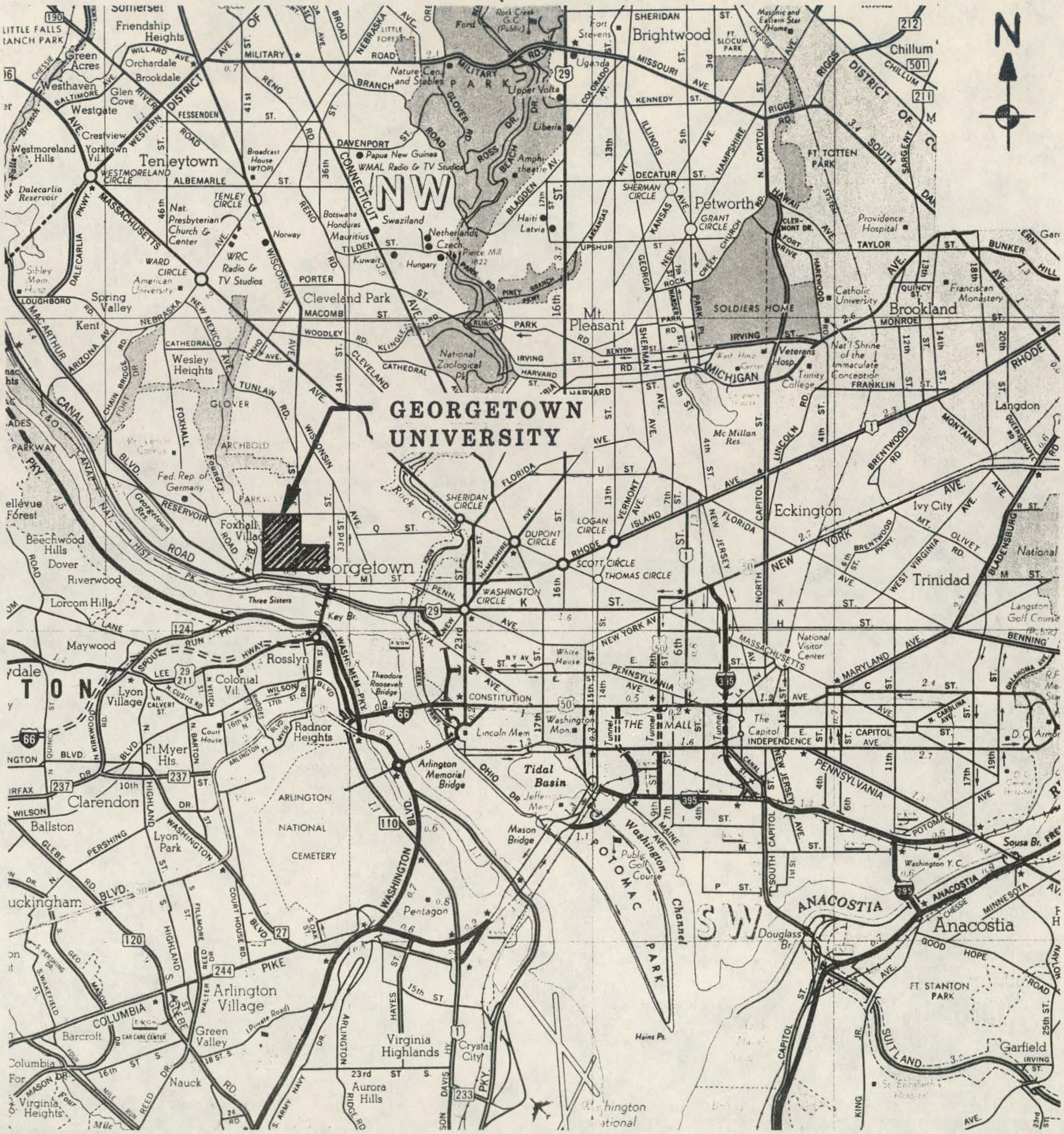
8.2.1 Existing Campus

The campus of Georgetown University (GU) is located in northwest Washington, D.C. in the Georgetown section. A location map is presented in Exhibit 8-1. The campus consists of over 50 buildings on a 101 acre area. Site borders are: to the north, Reservoir Road N.W.; to the west, Glover Archbold Park; to the south, Prospect Street; and to the east, 35th Street, N Street N.W., 36th Street, P Street N.W. and the property of the Sisters of the Visitation. The campus overlooks the Potomac River and is separated from it by Canal Road and the Chesapeake and Ohio Canals and railroad tracks. Canal Road is a major access road to central Washington, D.C. and bridges over the Potomac River.

Georgetown, to the north and east of the campus, is a historic residential section of tree-lined streets and restored houses. The area immediately adjacent to the campus is an urban mix of high and low density uses many of which are non-conforming under existing zoning regulations. Land use of adjacent properties includes residential, institutional and commercial.

Founded in 1789, the university has continuously occupied the present site. A number of buildings have been designated historic buildings for preservation as part of our national heritage. A restoration program of several buildings has been undertaken to upgrade their facilities while retaining their historical architecture. Design criteria for new facilities stress renovation and preservation of historical architectural harmony.

LOCATION MAP



GU is divided into three major areas. Medical Center buildings are located in the north, academic and mixed occupancy buildings in the east and recreation and service buildings in the west. Parking areas are scattered throughout the campus.

The Heating and Cooling Plant is located in the west part of the campus. The plant consists of steam generating boilers and chillers to supply steam and chilled water to most of the other campus buildings through underground distribution systems. To the west of the plant is McDonough Gymnasium. To the south and east are parking areas, volley ball, basketball and tennis courts, and soccer and baseball fields. To the north is a recreation complex. It is an underground recreational facility with Kehoe Field for spectator sports reconstructed on the roof.

University related traffic has had an impact on the surrounding community. The main entrance to the Medical Center is from Reservoir Road. Other entrances to campus are from O Street, Prospect Street and Canal Road. Much commuter traffic therefore uses the streets of Georgetown. Truck traffic to the Central Heating and Cooling Plant uses the Canal Road entrance and does not impact Georgetown. The University has undertaken several programs to discourage single occupant automobile use by increasing parking fees, and improving alternate forms of transportation.

8.2.2 Future Development

Georgetown University's planning is centered on the continued providing of quality higher education. Planning goals seek to provide personalized instruction in a residential living/learning environment. Green spaces, natural beauty and the availability of recreation improve the external living concept. Housing enabling small groups of scholars to live and study together enhances the residential living concept. Planning objectives also seek to reduce on-campus traffic and improve traffic flow around the campus. Future development must conform to the historic character of the Georgetown District.

The land use plan of GU, presented in Exhibit 8-2, continues present land use practices. Maximum proposed site development is presented in Exhibit 8-3. The impact of GU on the community will be minimized by turning the campus inward. The plan provides for transition from the community by concentrating intensive use areas in the central portion of the campus. Traffic access to the campus will be limited to the northern and southern border. Once on campus, traffic is directed to below surface parking and loading areas and away from institutional use areas.

The location of the Heating and Cooling Plant, in a service designated area, conforms to land use. Core ICES, a multi-purpose parking and energy systems facility, is proposed for the area east of the Heating and Cooling Plant.

New construction is subject in varying degrees to the requirements of several agencies of the District of Columbia Government, National Capital Planning Commission, National Park Service, Washington Metropolitan Area Council of Governments, Fine Arts Commission and Citizens Associations. In particular, the Old Georgetown Act of September 22, 1950 administrated by the Fine Arts Commission affects new construction subject to public view from a public street and establishes height restrictions.

The Campus Development Plan has been approved by the District of Columbia Board of Zoning Adjustments. The Georgetown Citizen's Association has filed against approval. The prime

LAND USE PLAN

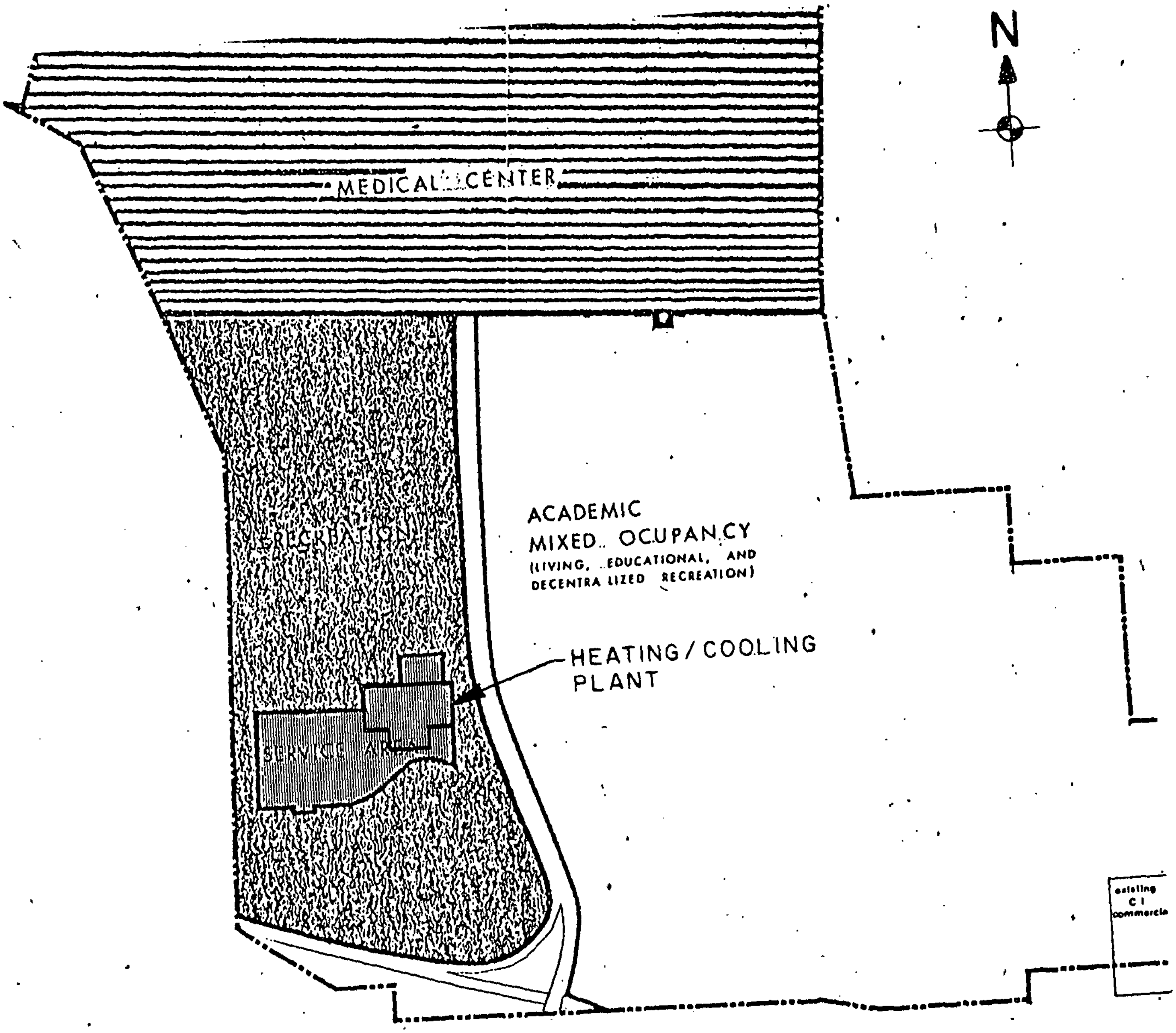
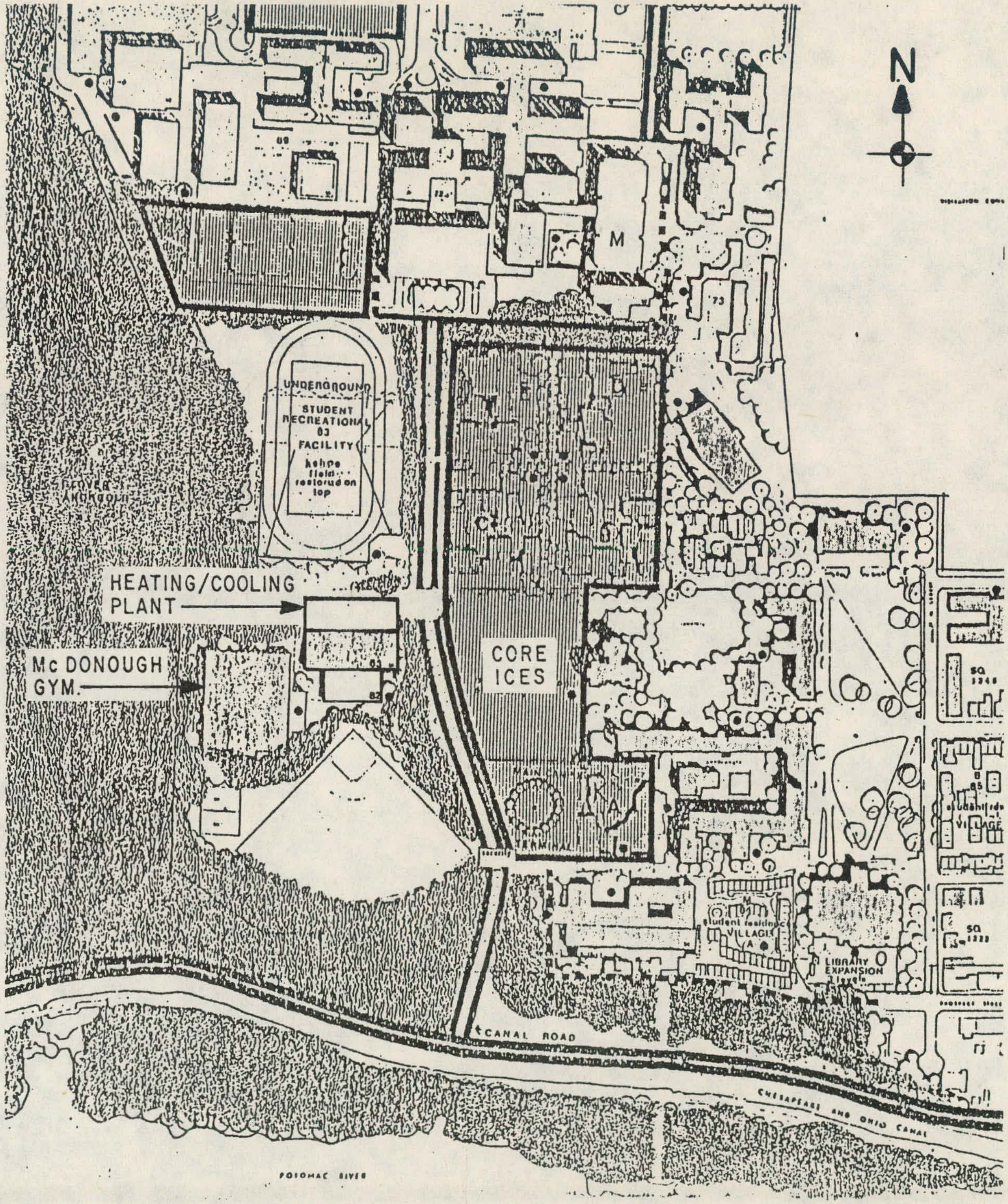


EXHIBIT 8-2

POPE, EVANS AND ROBBINS

FUTURE DEVELOPMENT PLAN



conflict is utilization of land bordering Georgetown for use as student residences and is not applicable to the balance of the plan.

8.2.3 Heating and Cooling Plant

The Heating and Cooling Plant consists of:

2 Keystone oil/gas fired boilers of 100,000 lb/hr steam capacity each at 275 psig.

1 coal fired atmospheric fluidized bed (AFB) boiler of 100,000 lb/hr steam capacity at 625 psig.

2 Worthington turbine driven centrifugal refrigeration compressors of 3000 ton capacity each with Bahco condensers and one two-cell Pitchard cooling tower.

Presently, steam is produced at 275 psig. During the summer cooling seasons, most of the steam is used by the turbine-driven centrifugal compressors to supply chilled water to the chilled water distribution system. A smaller amount of steam is supplied through a pressure reducing valve (PRV) at 90 psig to the steam distribution system. During the intermediate and winter heating season, all steam is supplied through the PRV valve to the steam distribution system. A small portion of the steam is supplied to steam plant auxiliaries.

The Heating and Cooling Plant was constructed in two stages. In 1970 the oil/gas fired boilers and chillers were commissioned. The boilers were initially fired with natural gas, shifting to oil when gas supplies were curtailed. Recently as oil has sharply increased in price, natural gas firing was resumed. The AFB boiler was constructed in 1979 as a plant addition. This boiler is a development project, funded by the U.S. Energy Research and Development Administration, now the Department of Energy, to demonstrate atmospheric fluidized bed combustion of low quality high sulfur coal in compliance with atmospheric emission limitations. The boiler is undergoing a start-up and demonstration phase. In the future, it is planned that the boiler will supply the plant base load and be supplemented by the oil/gas fired boilers during periods when the steam demand is above 100,000 lb/hr and during maintenance downtimes.

In 1984, during the six month summer cooling period, from May through October, the AFB boiler is expected to operate for 4392 hours, operating at full capacity for 1300 hours. The oil/gas-fired boilers will operate at part load for 1300 hours to meet peak steam demands. During the four month winter heating season, the AFB boiler will operate for 2904 hours, operating at full capacity for 350 hours. The oil/gas fired boilers will operate at part load for 350 hours to meet peak steam demand. During the intermediate months of November and April, the AFB boiler will be down for maintenance and all steam will be supplied by the oil/gas fired boilers. Steam production and operating hours of each boiler are summarized as follows:

	AFB	Oil/Gas Boilers
Steam production, 10^6 lbs		
Summer	370	15
Winter	234	3
Intermediate	-	88
Total	604	106

	AFB	Oil/Gas Boilers
Operating Hours		
Actual	7,296	3,090
Summer		
At full load	1,300	-
EFL at part load*	2,400	150
Winter		
At full load	350	-
EFL at part load*	1,990	30
Intermediate	-	880
Total EFL*	6,040	1,060

*EFL = Equivalent Full Load Hours.

Estimated fuel consumption, atmospheric emissions and solid waste generation by the boilers of the Heating and Cooling Plant using present operations in 1984 are presented in Table 8-1. The AFB boiler will burn coal with a heat content of 12,750 Btu/lb and 3.3 percent sulfur. Limestone, injected into the boiler to control sulfur oxide emissions will contain 94 percent calcium carbonate. Particulate emissions from the boiler are controlled by cyclones and baghouse filtration. Solid waste, consisting of bed material from the boiler and flyash captured by particulate emission control equipment, is composed of calcium oxide, calcium sulfate, limestone inerts, unburned fuel carbon and coal ash. The oil/gas fired boiler will burn natural gas with a heat content of 1030 Btu/cu ft.

The Heating and Cooling Plant operates in compliance with the District of Columbia Air Quality Control Regulations. Ambient air quality standards are specified by the Federal Environmental Protection Agency (EPA) Regulations on National Primary and Secondary Ambient Air Quality Standards (40 CFR 50). Ambient air quality in the vicinity of GU has been classified by the EPA as follows:

TABLE 8-1

HEATING AND COOLING PLANT
BOILER MATERIAL BALANCE
1984
UNDER PRESENT OPERATIONS

	AFB Boiler at 275 psig		Oil/Gas Fired Boiler Burning Gas	
EFL Hours (1)	6,040		1,060	
Fuel Consumption	9,515 lb/hr (2)	28,700 ton/yr	118,000 cu ft/hr (3)	
Limestone Consumption	3,117 lb/hr (2)	9,410 ton/yr	-	
Atmospheric Emissions				
Sulfur Oxides	85 lb/hr (4)	257 ton/yr	.6 $lb/10^6$ cu ft (5)	.04 ton/yr
Particulates	4 lb/hr (4)	12 ton/yr	15 $lb/10^6$ cu ft (5)	.94 ton/yr
Nitrogen Oxides	40 lb/hr (4)	121 ton/yr	230 $lb/10^6$ cu ft (5)	14.4 ton/yr
Solid Waste				
Bed Material	2,400 lb/hr	7,250 ton/yr	-	
Flyash	1,900 lb/hr	5,700 ton/yr	-	

(1) EFL = Equivalent Full Load Hours.

(2) Foster Wheeler Energy Corporation performance data.

(3) $\dfrac{100{,}000\text{ lb/hr} \times 1007.4\text{ Btu/lb}}{.83\text{ efficiency} \times 1030\text{ Btu/cu ft}}$

(4) Fluidized Bed Combustion Industrial Application, Georgetown University, Environmental Impact Assessment by Pope, Evans and Robbins, Inc., August 1976.

(5) Compilation of Air Pollutant Emission Factors, Second Edition, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, March 1975.

Particulates	Does not meet standards.
Sulfur Dioxide	Better than standards.
Nitrogen Dioxide	Cannot be classified as better than standards.

The critical ambient air quality parameter is particulates. The boilers emit this pollutant in the lowest quantity and do not significantly contribute to the existing air quality deterioration with respect to this pollutant.

Coal, limestone and solid waste is transported by truck using the entrance from Canal Road. Truck traffic is summarized as follows:

Haul	Truck Capacity (Tons)	Number of Trucks: Per Day At Full Load*	Number of Trucks: Annually
Coal	25	6.4	1,148
Limestone	25	2.1	376
Bed Material	20	2.0	363
Flyash	15	2.1	380
Total		12.6	2,267

*Five days per week delivery.

8.3 Probable Environmental Impact

The environmental impact matrix presented in Table 8-2 identifies potential impacts which may result from each candidate energy subsystem. Other than the impacts identified there will be no impacts on the ecological, physical, chemical and cultural systems.

8.3.1 Cogeneration of Electricity

Under this alternative, the AFB boiler is operated at 625 psig feeding steam to back pressure turbine generators. Steam enters the turbine in a saturated condition, reduces in pressure during passage through the turbine, leaves in a less than saturated condition and is supplied to downstream consumers. Condensate is recovered from the turbine at the leaving pressure and is used for feedwater heating, thereby reducing the quantity of steam required for this purpose. Electrical energy generated is theoretically equal to the enthalpy difference between the entering steam and sum of leaving steam and condensate.

AFB boiler production will increase as compared to present operations since turbine condensation must be satisfied in addition to downstream consumption. With less AFB boiler capacity available to satisfy downstream consumption, the oil/gas fired boilers must be operated for correspondingly longer periods. During the intermediate season months of April and November, when the AFB boiler will be down for maintenance, no electricity will be generated and the oil/gas fired boilers will satisfy steam demands in the same way as at present.

It is assumed that the operation of the AFB boilers at partial load and operation of the oil/gas fired boilers during the summer cooling and winter heating season will increase in direct proportion to turbine condensation. This

TABLE 8-2

CANDIDATE ENERGY SYSTEM

Impact	Cogeneration of Electricity	Additional Coal, Limestone, Ash Storage	Thermal Storage	Heat Pumps
Land Use and Aesthetics	Negligible	Scheme 1 Not Significant Scheme 2 None	None	None
Atmospheric Emissions	Max. 4 Percent Increase	No Change	Max. 1 Percent Increase	Max. 1 Percent Reduction
Solid Waste	4 Percent Increase	No Change	Max. 1 Percent Increase	Max. 1 Percent Reduction
Truck Traffic	4 Percent Increase	No Change	Max. 1 Percent Increase	Max. 1 Percent Reduction
Noise	Negligible Increase	No Change	No Change	No Change
Wastewater	No Change	No Change	No Change	Slight Reduction

is conservative since steam savings achieved by turbine condensate recovery is not considered.

The various schemes under this alternative differ in that steam is extracted and discharged from turbine generators at different pressures for downstream use. Turbine condensate formation as a percent of entering steam for the various leaving pressures are as follows:

Leaving Pressure (psig)	Condensate (%)
275	4
90	6
10	8

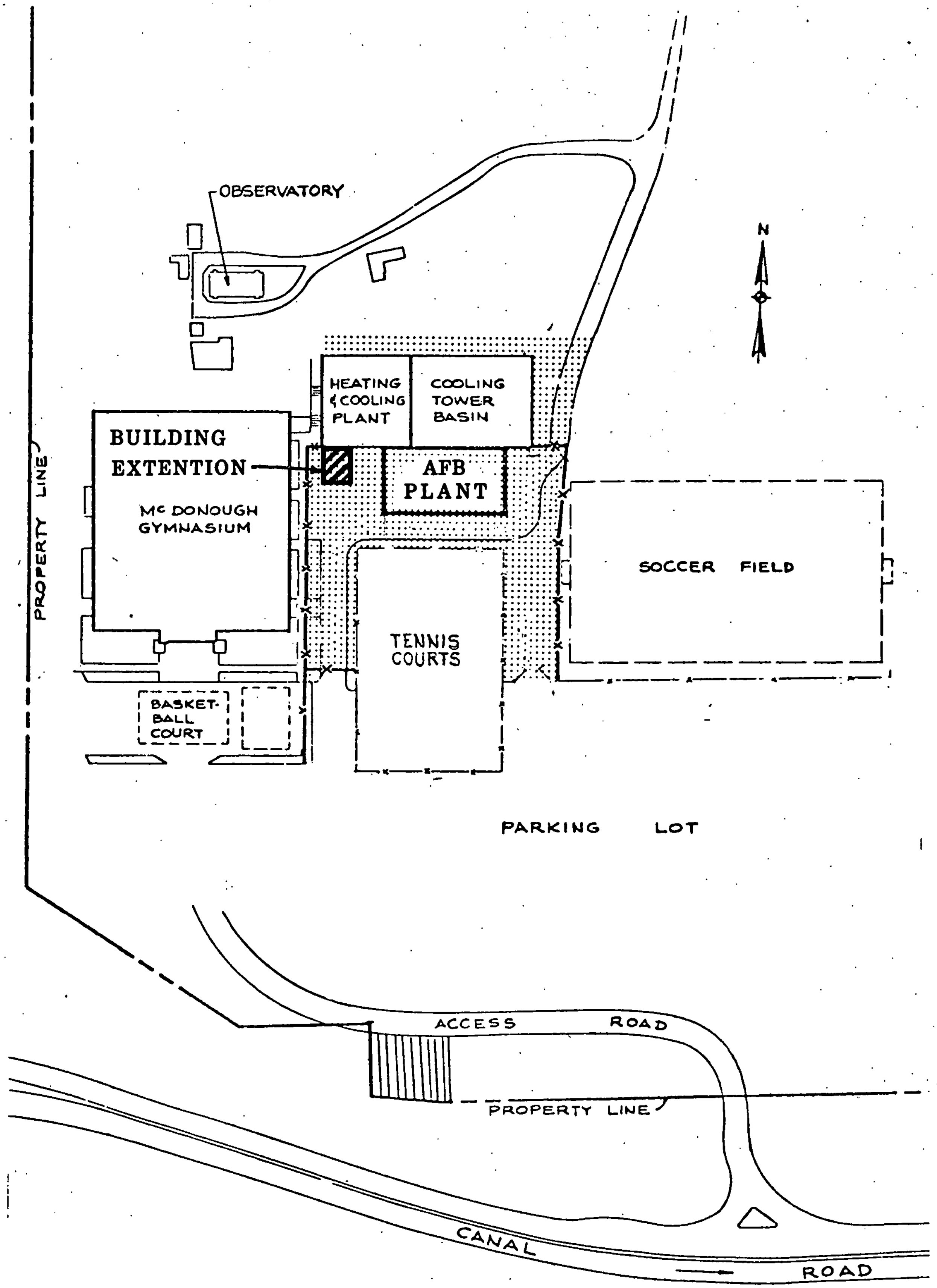
Scheme A of this alternative is the recommended scheme. During the summer cooling season, the turbine exhausts steam at 275 psig to supply the turbine driven chillers and through a PRV to supply the distribution system. During the winter heating season, the turbine exhausts steam at 90 psig to supply the distribution system. Increased boiler operation is estimated as 4 percent of AFB operation in the summer and 6 percent of AFB operation in the winter.

An extension to the existing Heating and Cooling Plant is required to house the additional equipment required. Potential environmental impacts of this alternative include increased atmospheric emissions, solid waste, traffic, noise and wastewater.

- <u>Land Use and Aesthetics</u>

A one bay, 32 foot long, one-story extension to the Heating and Cooling Plant is required. The proposed extension is presented in Exhibit 8-4. The area is presently an access driveway. Access to the west end of the AFB plant will be maintained. The required extensions will be shielded

SITE PLAN
COGENERATION OF ELECTRICITY



on all sides by the plant building itself, McDonough Gymnasium and future screen plantings to the south. The extension will be integrated with existing architecture, will not project above the existing roof line nor change the scale of the plant. The extension will not visually impact either the campus or surrounding areas.

- Atmospheric Emissions

Atmospheric emissions resulting from the proposed scheme is summarized as follows:

	Present Operation	Cogeneration of Electricity
Equivalent Full Load Hours		
AFB	6,040	6,255
Oil/Gas Fired Boilers	1,060	1,133
Atmospheric Emissions, ton/yr		
Sulfur Oxides	257	266
Particulates	13	13.5
Nitrogen Oxides	135	140

The limestone to coal ratio is assumed constant. The annual sulfur oxide emission rate could be reduced to the present levels by increasing the limestone feed rate. Solid waste generation and truck traffic to haul limestone and solid waste could increase slightly however. Particulate and nitrogen oxide emissions are controlled by the best available control technology and will increase in proportion to boiler operation.

Emissions will increase by not more than four percent. The critical ambient air quality parameter is particulates. Emissions of this pollutant show the lowest increase in magnitude. The increased atmospheric emissions will not cause a significant deterioration of ambient air quality.

- Solid Waste

At the higher operating pressure of 625 psig, the AFB boiler will consume coal at a slightly higher rate than under present operating conditions. The increased coal feed rate will require a concurrent increase in limestone feed rate. Solid waste as a result of the increased coal ash and limestone injection and increased boiler operation will, therefore, increase. Table 8-3 presents coal and limestone consumption and solid waste generation for cogeneration of electricity and present operations. With cogeneration, solid waste increases by about four percent compared to present operations. This increase will not significantly shorten disposal facility life.

- Traffic

Traffic due to coal, limestone and solid waste hauling with cogeneration of electricity and under present operation is as follows:

		Annual Number of Trucks	
Haul	Truck Capacity (tons)	Cogeneration of Electricity	Present Operation
Coal	25	1,196	1,148
Limestone	25	392	376
Bed Material	20	377	363
Flyash	15	400	380
Total		2,365	2,267

Annual traffic volume increases only four percent. Peak daily traffic will not change. This increase in traffic volume will not significantly impact access roads or the GU campus.

- Noise

All noise emitting equipment will be located inside the Heating and Cooling Plant extension which limits

TABLE 8-3

HEATING AND COOLING PLANT
AFB BOILER MATERIAL BALANCE
1984
COGENERATION OF ELECTRICITY

	Cogeneration of Electricity		Under Present Operation
EFL Hours(1)	6,255		6,040
Coal Consumption	9,565 lb/hr	29,900 ton/yr	28,700 ton/yr
Limestone Consumption	3,133 lb/hr	9,800 ton/yr	9,410 ton/yr
Solid Waste			
Bed Material	2,410 lb/hr	7,540 ton/yr	7,250 ton/yr
Flyash	1,910 lb/hr	6,000 ton/yr	5,700 ton/yr
Total		13,540 ton/yr	13,000 ton/yr

(1) EFL = equivalent full load hours.

the transmission of noise to the outside. Equipment installation, vibration isolation and sound absorbent enclosures will ensure that interior noise levels conform to OSHA standards. Outside noise levels will not be noticeably increased.

- Wastewater

Two sources of wastewater are make-up water treatment and boiler blowdown. Make-up water is required to compensate for steam and condensate losses. Since turbine condensate will be recovered, cogeneration would not normally introduce new losses. The quantity of make-up water to be treated and the resulting wastewater will therefore remain the same.

Boiler blowdown is required to maintain an acceptable dissolved solids concentration in the boiler water. Dissolved solids are introduced by the make-up water. Since make-up water flow will not change, boiler blowdown will not change.

8.3.2 Added Coal, Limestone and Ash Storage and Handling

Presently, coal and limestone storage is sufficient for about two weeks of AFB operation. Bed material and flyash storage is sufficient for only a few days operation. In the event of extended emergencies, such as inclement weather or a strike, operation of the AFB boiler would have to be curtailed. Two schemes for increased storage are considered feasible. The first scheme provides for additional storage of all materials in an extension to the Heating and Cooling Plant. The second scheme provides for additional bed material and flyash storage only, within the existing cooling tower enclosure of the Heating and Cooling Plant.

- <u>Added Storage in Extension to AFB Plant</u>

Under this scheme, a 54 foot wide extension to the AFB boiler plant would enclose additional bunkers for coal and limestone storage and silos for bed material and flyash storage. Coal and limestone storage would be increased to about one month of AFB operation. Bed material and flyash storage would be increased to 9 to 12 days of AFB operation. The new material handling equipment would be of the same type and integrated with the existing equipment to permit interchangeable operation of existing and new storage facilities. All material handling operations including truck loading and unloading, will continue to be performed inside the AFB plant. From the receiving hopper coal would be conveyed by enclosed bucket and redler conveyors to any one of the existing and new bunkers. Similar equipment would convey coal from any of the bunkers to the boiler feed preparation system. Limestone, bed material and flyash will be pneumatically conveyed.

AFB operation will not be increased as a result of this scheme, except for increased operational capability during emergencies. Atmospheric emissions, solid waste and wastewater from the AFB will not be increased. Truck traffic will not be increased, except as required for the initial filling of the additional coal and limestone bunkers. Since material handling operations will not increase, fugitive dust and noise will also not be increased. Fugitive dust from the new enclosed handling systems will be minimal and confined inside the building. Interior ventilation will ensure compliance with OSHA dust concentration standards. Fugitive dust emissions to the outside will be controlled by filtering exhaust air and providing vent filters on all new bunkers and silos. Noise generated by the additional material handling equipment will be the same as present operations and will conform to OSHA standards. The building extension limits noise transmission to the outside.

The only environmental impact of this alternative is upon aesthetics. The required Heating and Cooling Plant extension is presented in Exhibit 8-5. The extension would require relocation of the tennis courts which is in accordance with future development plans. The extension will be integrated with existing architecture and will not project above the existing roof line. It will be shielded from view on three sides by McDonough Gymnasium, the plant itself, and future screen plantings. Although the plant area will be increased, the extension, being a continuation of the present building outline, will not substantially change the building scale nor significantly increase visual impact of the building on either the campus or surrounding areas.

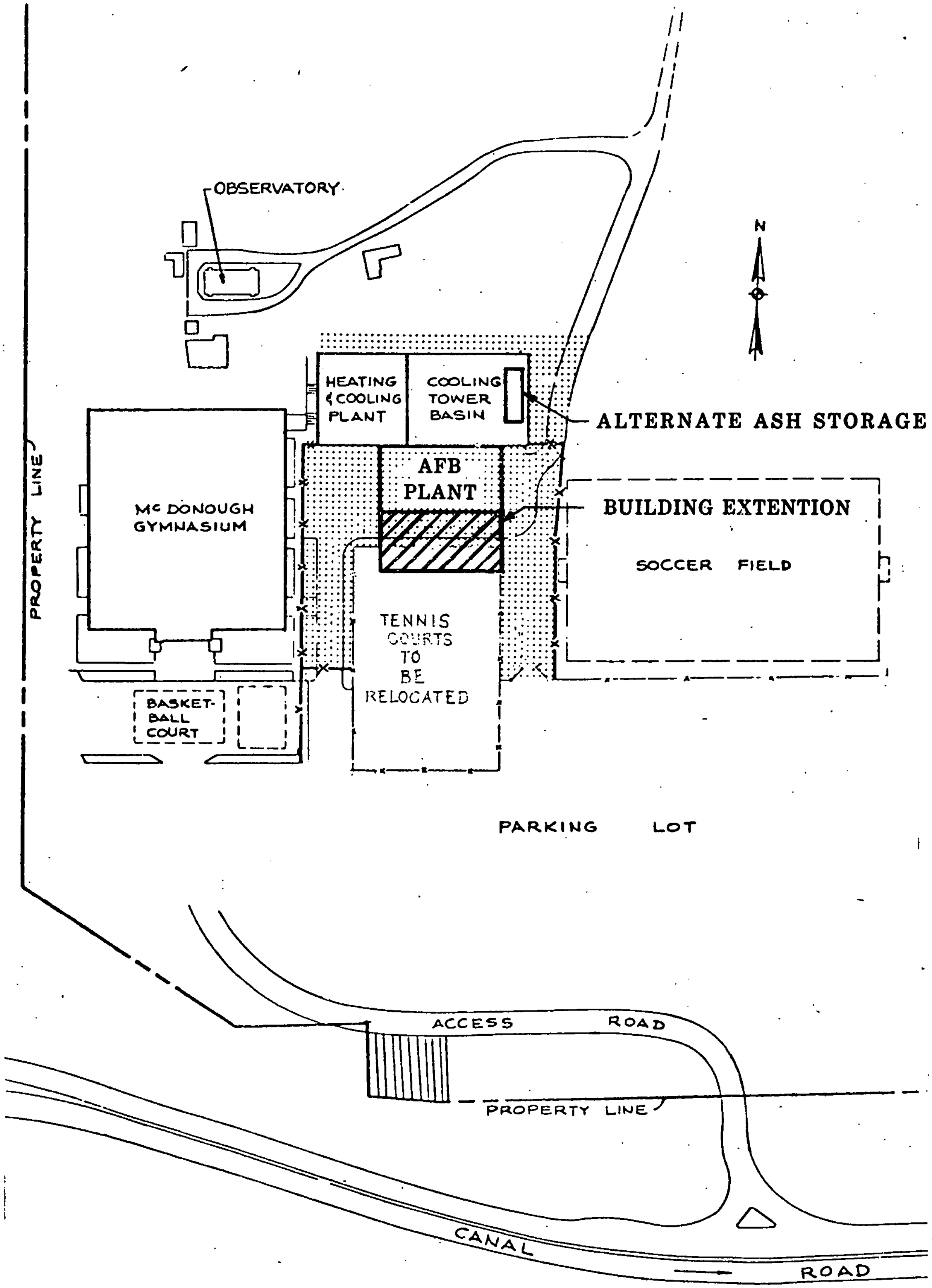
- Increased Ash Storage

Additional silos for bed material and flyash storage can be installed in the clear space of the cooling tower enclosure. Storage capability for these materials would be increased to about two weeks of AFB operation corresponding to the existing coal and limestone storage capability. Materials would be pneumatically conveyed into storage. The bins would be provided with vent filters to prevent fugitive dust emissions. The enclosure wall would be modified to permit truck access. Silos would be unloaded through drop chutes into the enclosed trucks.

There will be no environmental impacts to to this scheme. Material handling systems are enclosed, preventing fugitive dust emissions. Any possible emissions would be mostly contained by the enclosure walls. Material handling system noise is insignificant compared to the adjacent cooling towers. The top of the silos, being below the roof line, would not be visible from outside the enclosure.

SITE PLAN

ADDED STORAGE IN EXTENSION TO AFB PLANT



8.3.3 Cold Thermal Storage

Under present operations, peak chilled water demands will be satisfied by operating two auxiliary electric driven chillers located in the GU hospital and Reiss Science Building in addition to the Heating and Cooling Plant chillers. Peak demand periods usually occur during the daytime and coincide with peak electric rate periods. This energy subsystem provides for operation of the electric driven chillers at night, when the chilled water demand is low, and storage of chilled water production for use during subsequent daytime high demand periods. Significant electrical cost savings are achieved by reduction of demand charges and shifting energy consumption from high to low energy cost periods. Electrical energy consumption increases slightly due to increased chilled water pumping into and out of storage. The cold thermal storage would consist of a 1.3 million gallon multi-compartment storage tank and adjacent pump room located in a new sub-basement of the proposed Core ICES parking structure.

The storage tank can also be used to optimize AFB operation and permit a reduction in operation of the oil/gas fired boilers. During the daytime, both steam and chilled water demands are highest, often necessitating the operation of both the AFB and oil/gas fired boilers. At night, the steam and chilled water demand are reduced below the AFB and turbine driven chiller capacity. Nighttime AFB and turbine driven chiller production could, therefore, be increased and excess chilled water production can be stored for use during the subsequent day. With reduced daytime chiller steam demand, more of the AFB production is available for distribution, and operation of the oil/gas fired boiler can be reduced. It is estimated that approximately 7.1 million cubic feet of gas, approximately five percent of the 1984 gas consumption, can be saved. AFB operation would increase by about one percent. However, implementation of the heat pump energy subsystem will reduce AFB operation by the same amount.

There will be no impact on land use or aesthetics caused by this energy subsystem. The thermal storage reservoir would be constructed in a new sub-basement of the proposed Core ICES Building. There will be no new visible structures. The new sub-basement will not displace any existing or proposed activities. Construction will require an additional 6500 cubic yards of excavation and concrete work. This will not significantly increase the environmental impact due to construction of the Core ICES Building. Disposal of excavated material will not be a problem.

Atmospheric emissions from the AFB will increase by about one percent. The increase in particulate and nitrogen oxide emissions will be partially offset by reduced emissions from the oil/gas fired boilers. Coal and limestone consumption will increase by about 300 ton/yr and 100 ton/yr respectively. Ash generation will increase by about 135 ton/yr. Truck traffic will consequently increase by about one percent. The small increase in ash quantities will not significantly shorten disposal facility life. Noise and wastewater generation will not be changed as compared to existing operations.

8.3.4 Heat Pumps

Under present operations, condenser water leaves the electric driven chillers at 95°F, is cooled to about 85°F by cooling towers, and returned to the condenser. This energy subsystem provides for heat recovery from the condenser water by heat exchangers and heat pumps to generate domestic hot water. The subsystem can be most feasibly applied to the GU hospital chiller. This chiller operates all year and, with the implementation of chilled water storage, will operate only at night when electric rates are lowest. Heat pumps would, therefore, also operate during the night when electric rates are lowest. The hospital hot water demand is high and thus offers a convenient consumer of hot water production.

Heat exchangers can be installed to recover heat from the condenser water of the independent electric chillers located in New South Hall and Darnall Hall by preheating city water before it enters the domestic hot water system. Both buildings have substantial hot water demands which coincide with chilled water demand.

This scheme will reduce the quantity of steam required to produce domestic hot water. The reduced steam demand will primarily reduce AFB production although some reduction in the operation of the oil/gas fired boilers may also be achieved. AFB operation would decrease by about one percent.

Equipment required to implement this subsystem will be installed inside existing structures and there will be no impact on land use or aesthetics. There is sufficient room available in the GU hospital mechanical equipment room to install the heat pump in close proximity to the chillers. The room will contain any additional noise generated by the heat pumps. The hot water storage tank can be installed in the mechanical equipment room of the Bles Building. The heat exchangers require minimal space in the mechanical equipment rooms of the New South Hall and Darnall Hall.

The reduced environmental impact due to reduced AFB operation will be about the same as the increased impact due to the cold thermal storage energy subsystem. Make-up water requirements, chemical treatment and blowdown by the cooling towers will be reduced slightly due to the lower temperature of condenser water to be cooled.

8.4 Unavoidable Adverse Environmental Impacts

There are no significant unavoidable adverse environmental impacts. New structures, required to implement two of the candidate energy subsystems, are small extensions of an existing Heating and Cooling Plant. The plant has BZA approval and conforms to approved GU land use plans. The extensions will conform to the requirements of the Old Georgetown Act and there will be no aesthetic impact on historic Georgetown. The other two candidate energy subsystems do not require new visible structures.

There will be a small increase in boiler operation under two candidate subsystems. The increase is within allowable operating permit conditions. Atmospheric emissions will increase slightly. Existing ambient air quality for sulfur dioxide and nitrogen dioxide are in compliance with ambient air quality standards and the slight increase in emissions will not cause contravention of these standards. Existing ambient air concentration of particulates exceeds standards. The slight increase in particulate emissions will not significantly further deteriorate ambient air quality. Coal and limestone consumption and ash generation also increase slightly under these subsystems. Increased truck traffic will not, however, be significant. Implementation of the heat pump subsystem will, on the other hand, reduce boiler operation and offset the slightly increased environmental impacts of other subsystems.

8.5 Relationship Between Local Short-Term Use of Man's Environment and Maintenance and Enhancement of Long-Term Productivity

This section presents the justification for and discusses the cumulative long-term effects and foreclosure of future options by implementing the proposed actions. United States energy policy recognizes the limited availability of inexpensively priced gas and fuel oil upon which much of our economic activity presently depends. The National Energy Act provides a policy framework to encourage energy conservation and increase the use of domestic coal reserves. The cost of utilities is consuming an increasing portion of the Georgetown University budget. In an effort to limit this increase, reduce education cost and insure funding availability for development plans, GU is constantly striving to reduce energy consumption and its associated costs.

8.5.1 Cogeneration of Electricity

The annual electric generation under this system would be 9,100,600 kWh, reducing by approximately 13.5 percent the total 1984 GU purchased electrical energy. Additional energy input for electric generation is:

Coal: $1{,}200 \text{ ton/yr} \times 25.5 \times 10^6 \text{ Btu/ton} = 30.6 \times 10^9 \text{ Btu/yr}$

Gas: $8.6 \times 10^6 \text{ cf/yr} \times 1030 \text{ Btu/cu ft} = 8.9 \times 10^9 \text{ Btu/yr}$

Total 39.5×10^9 Btu/yr

Most of the additional energy required is supplied by coal. This compares to an energy input of 104.5×10^9 Btu/yr required by a utility system to generate the same amount of electricity.

A net reduction in energy consumption and shift to coal usage is achieved. For a present investment cost of about $1.2 million, GU will achieve a present value net savings of $216,000/yr. The discounted payback period is four years.

The only long-term effect of this alternative is a minimal increase in the ambient air pollutant concentration at Georgetown during the operating life of the plant. This increase will be more than offset by the improvement in air quality resulting from a corresponding decrease in electrical generation to be achieved at the site of utility power plants supplying the energy to be saved. Since utilities require higher energy input to generate the same amount of electricity, emissions from the utility plant would be correspondingly higher. Consequently efficient cogeneration results in improved air quality.

This alternative conforms to the national energy policy for reducing energy consumption and increasing reliance on domestic coal without serious long-term effects. The boilers will operate at higher load factors, improved efficiency and reduced emissions. Utility system capacity would be made available to allow reduced operation of plants using less desirable fuels or to satisfy new consumers without constructing additional plant capacity.

8.5.2 Added Coal, Limestone and Ash Storage and Handling

In the event of an extended emergency in which coal and limestone could not be delivered for more than two weeks or ash could not be removed for more than a few days, operation of the AFB boiler must be curtailed. The necessary steam and cooling water could still be provided, however, by operating the oil/gas fired boilers. Electricity, under the cogeneration alternative, could not be generated. This alternative provides for additional coal, limestone and ash storage facilities to increase the emergency operating capability of the AFB.

The requirement for extended emergency operating capability must be evaluated with respect to the frequency of duration of emergencies. Considering the volatility of coal mining labor relations and the relatively mild weather, extended emergencies are not likely to occur more than once every three years.

The project offers a minimal energy conservation opportunity during the additional operating period of the AFB. Electrical energy would continue to be generated on-site at a high energy conversion rate. In addition, the project permits a minimal increase in the utilization of abundant domestic coal instead of critical supplies of gas and/or oil. Cost savings are low in comparison to capital costs and the payback period is long.

There are no significant short or long term environmental impacts due to this alternative. Implementation of this alternative will not foreclose future options.

8.5.3 Cold Thermal Storage

This subsystem achieves a present value electrical energy cost savings of $92,000/yr by shifting electric chiller operation from peak electric rate periods to off-peak electric rate periods. Additionally, optimization of AFB operation will achieve a 5 percent reduction in gas consumption. While this subsystem does not achieve a reduction in energy consumption, significant cost savings are achieved and coal consumption is increased in favor of gas. For present value investment cost of about $1.1 million, GU will achieve a present value net annual savings of $70,500. The discounted payback period is 12 years. The only long term effect of this alternative is a very minimal increase in atmospheric emissions.

This alternative conforms to the national energy policy of increasing reliance on domestic coal and to GU goals of reducing utility costs. Electrical consumption would be shifted from peak demand periods, thereby reducing the need for future utility capacity expansion.

8.5.4 Heat Pumps

This subsystem provides for heat recovery from chiller condenser water using heat exchangers and heat pumps to generate domestic hot water. Steam demand for this purpose is thereby reduced. AFB operation will be reduced by about one percent accompanied by a slight increase in the consumption of electricity during nighttime off-peak electric rate periods. A net reduction in annual energy consumption of 5.88×10^9 Btu is achieved. For a present value investment cost of about $100,000, GU will achieve present value net annual savings of $10,200. The discounted payback period is less than 12 years. This subsystem results in a net long-term improvement in the Georgetown environment. A corresponding small increase in environmental impact would result at the site of the utility power plant supplying the additional electrical energy required.

This alternative conforms to the national energy policy of reducing energy consumption. While electrical consumption increases, the increase would occur at night when electrical demand is low and would not reduce utility capability to meet peak demands.

8.6 Irreversible and Irretrievable Commitments of Resources

This section describes the extent to which the proposed energy alternatives irreversibly curtail the range of potential uses of the environment. None of the energy alternatives would require a significant irreversible commitment of resources for construction. Each of the energy alternatives variably impact the patterns of non-renewable energy consumption as follows:

	Changes in Annual Consumption			
	Puchased Electricity (10^3 kWh)	Coal (ton/yr)	Gas (10^6cu ft/yr)	Energy (10^9Btu/yr)
Cogeneration of Electricity	- 9,100	+ 1,200	+ 8.6	- 65
Additional Coal, Limestone and Ash Storage	-	-	-	-
Thermal Storage	-	+ 300	- 7.1	+ 0.3 (1)
Heat Pumps	+ 137	- 300	-	- 6
Net Result	- 9,000	+ 1,200	+ 1.5	- 71

(1) Energy loss during storage.

These alternatives achieve a net reduction in purchased electricity representing a reduction of non-renewable fuels consumed by the utility. Coal and gas consumption is increased slightly. The alternatives thus achieve a net reduction in the consumption of non-renewable fuel resources.