AN ENGINEERING AND ECONOMIC ANALYSIS AND A TEN YEAR PLAN FOR EXPANSION OF A UNIVERSITY POWER PLANT

by

DONALD CONWAY GRAY II

B. S., Kansas State University, 1973

A MASTER'S THESIS

submitted in partial fulfillment of the

requirements for the degree

MASTER OF SCIENCE

Department of Mechanical Engineering

KANSAS STATE UNIVERSITY
Manhattan, Kansas

1974

Approved by:

Robert E Crank
Co-Major Professor

Robert L. Gorton
Co-Major Professor

THIS BOOK CONTAINS NUMEROUS PAGES WITH THE ORIGINAL PRINTING BEING SKEWED DIFFERENTLY FROM THE TOP OF THE PAGE TO THE BOTTOM.

THIS IS AS RECEIVED FROM THE CUSTOMER.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

CHAPTER I

INTRODUCTION

A university power plant is often charged with the diversified responsibility of supplying heat, chilled water for air conditioning, and electricity to the campus. This task is made more difficult by the relatively unstable growth in both absolute and relative terms of a university's area and population, as well as by the unique blend of buildings and activities that are inherent in a collegiate educational institution. Any study attempting to develop the most attractive, long-range proposal to satisfy the total demands of a campus must recognize and evaluate the complete problem rather than addressing the individual requirements of a particular facility independently of the total campus demand. The current emphasis on aesthetics, environmental concerns and energy conservation produces additional parameters that must be considered.

To date, little attention has been directed toward this composite demand analysis resulting in a somewhat arbitrary collection of equipment and operating schemes on many college campuses. Kansas State University will be the subject of this evaluation but the techniques may be applied elsewhere. It is probable that the general trends and characteristics of campus demands found here are not unlike those of similar universities.

The existing power plant will be examined and its operational characteristics defined. Projections of the heating, cooling and electrical loads of Kansas State University through the year 1984 will be generated and various schemes to meet these demands shall be proposed. The most attractive proposal will then be selected as a result of an economic analysis of the alternatives with due consideration for the attendant concerns mentioned above.

CHAPTER II

A DESCRIPTION OF THE EXISTING POWER PLANT AND ITS OPERATION

The Kansas State University Power Plant is the central source of utility services on campus. Operating with a primary fuel of natural gas and No. 6 fuel oil as backup, it produces all of the steam required for heat, process use and absorption water chilling, as well as some for electrical generation. This plant, which serves 3,913,774 square feet of the campus shown in Figure 1, consists principally of six operational water tube boilers, three steam turbine-generator, two steam absorption water chillers, one electrically driven centrifugal water chiller and the normal array of supporting auxiliaries. As might be expected of a plant that has developed over a 46 year period, there is a minimum of instrumentation. A flow diagram of the major plant equipment as of July 1973 is given in Figure 2.

Virtually all of the campus is heated by steam provided by the six boilers with a combined capacity of 331,000 lb/hr except those areas with environmental constraints requiring other methods. Absorption refrigeration machines, operating on a lithium bromide cycle, with a total nominal capacity of 4159 tons cool 1,289,813 square feet while 2376 tons of electric centrifugal units serve 1,033,712 square

THIS BOOK CONTAINS NUMEROUS PAGES WITH THE ORIGINAL PRINTING BEING SKEWED DIFFERENTLY FROM THE TOP OF THE PAGE TO THE BOTTOM.

THIS IS AS RECEIVED FROM THE CUSTOMER.

THE FOLLOWING THREE IMAGES HAVE THE SAME PAGE AND FIGURE NUMBER AT THE BOTTOM DUE TO THE PAMPHLET BEING GLUED TO A PIECE OF PAPER.

THIS IS AS RECEIVED FROM THE CUSTOMER.

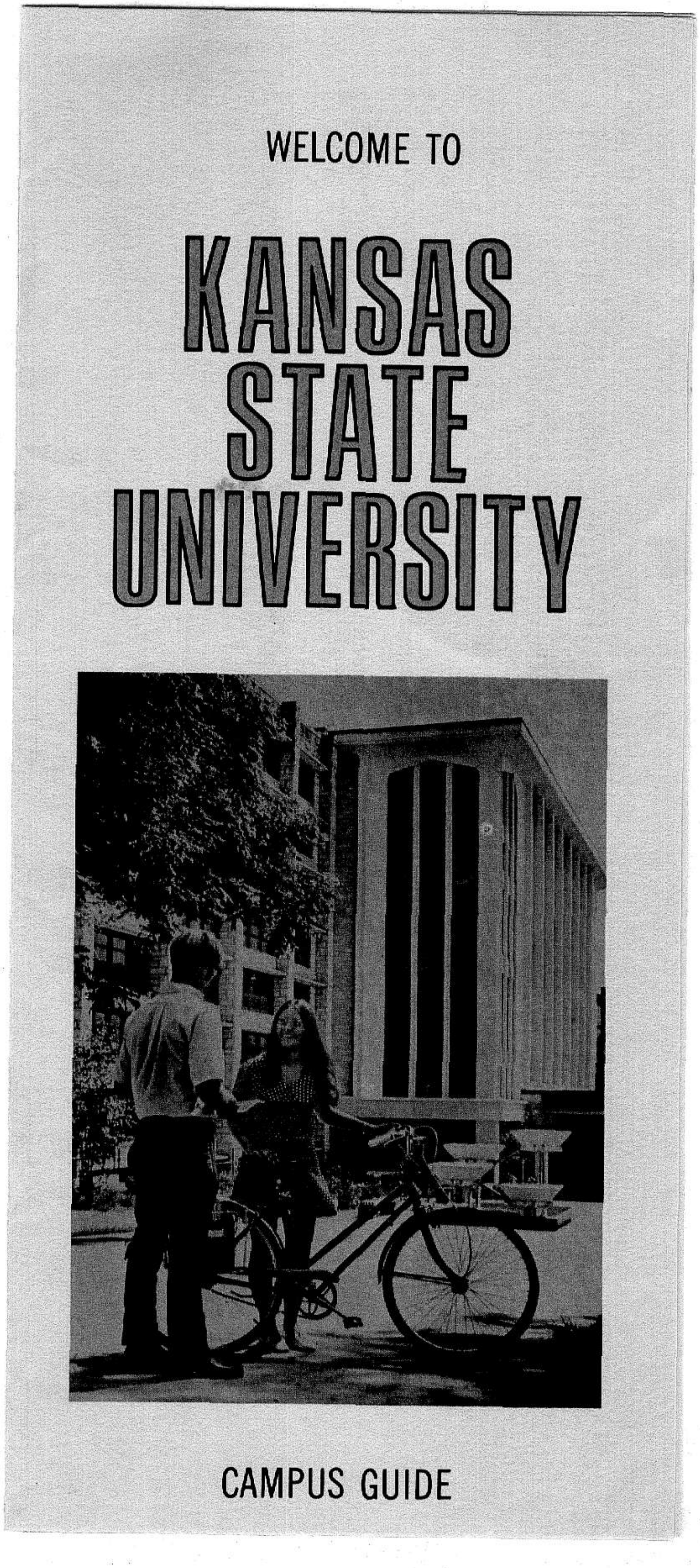


Figure 1. A Map of Kansas State University

	Bldg. Number	Map Location
Ackert Hall	23	D-7
Aeronautics Lab	41	D-8
Ahearn Field House	6	E-4
Anderson Hall	16	G-6
Art Annex	19	E-6
Athletic Dormitory	75	B-11
Bessie West Hall	60	F-13
Boyd Hall	59	G-13
Burt Hall	38	E-8
Bushnell Hall	46	E-9
Call Hall	67	D-12
Calvin Hall	9	H-4
Cardwell Hall	39	E-8
Chemical Engineering	32	G-8
Comparative Medical Sciences	72	C-11
Conservatory	30	H-9
Dairy Barn	69	C-9
Danforth and Memorial Chapel	13	I-6
Denison Hall	34	G-7
Derby Food Center	61	F-14
Dickens Hall	31	G-9
Dykstra Veterinary Hospital	45	D-9
East Stadium	3	F-2
Eisenhower Hall	28	G-7
Engineering Shops	26	F-6
Environmental Research Lab	18	F-6
Extension Forestry	82	A-3
Fairchild Hall	15	H-5
Farrell Library	35	F-8
Feed Technology	49	F-10
Ford Hall	62	G-15
Frank Meyers Field	78	A-7
Goodnow Hall	20	D-6
Greenhouses	53	G-10
Greenhouses	55	H-11
Haymaker Hall	63	F-15
Hollis Alumni-Endowment House	42	D-8
Holton Hall	33	G-8
Holtz Hall	27	G-6
Home Management Houses	54	G-11
Housing Maintenance	70	C-10
Jardine Terrace	76	B-9
Justin Hall	56	H-10
Kansas Artificial Breeding Service Unit	81	B-4
K-State Union	7	F-4
KSU Auditorium	14	I-5
KSU Stadium	77	A-9
Kedzie Hall	8	G-5
King Hall	52	F-10
Kramer Food Center	21	D-5
Lafene Student Health Center	36	F-7
Leasure Hall	37	F-8
Marlatt Hall	22	C-5
Men's Gymnasium	5	E-4
Military Science	40	*E-8*
Moore Hall	64	F-14
Multi-Disciplinary Teaching	73	C-11
Natatorium	4	E-4
Nichols Gym	11	H-3
Pittman Building	71	D-10
Power Plant	25	E-7
President's Residence	29	I-8
Putnam Hall	57	H-13
Seaton Hall	17	F-5
Shellenberger Hall	50	F-10
Surgery Teaching	44	D-9
Tennis and Handball Courts	74	B-11
Thompson Hall	12	J-4
Track and Field Facility	79	A-7
Trailers A, B, C, R, S	10	H-3
Umberger Hall	68	D-10
University Inn Complex	1	H-1
University Terrace	80	B-4
Van Zile Hall	58	G-13
Vehicle Maintenance Shop	43	D-9
Ward Hall	24	E-7
Waters Hall	47	F-9
Waters Hall Annex	*48*	*F-10*
Weber Hall	66	E-13
West Stadium	2	F-2
Willard Hall	51	F-9
Wind Erosion Lab	65	E-15

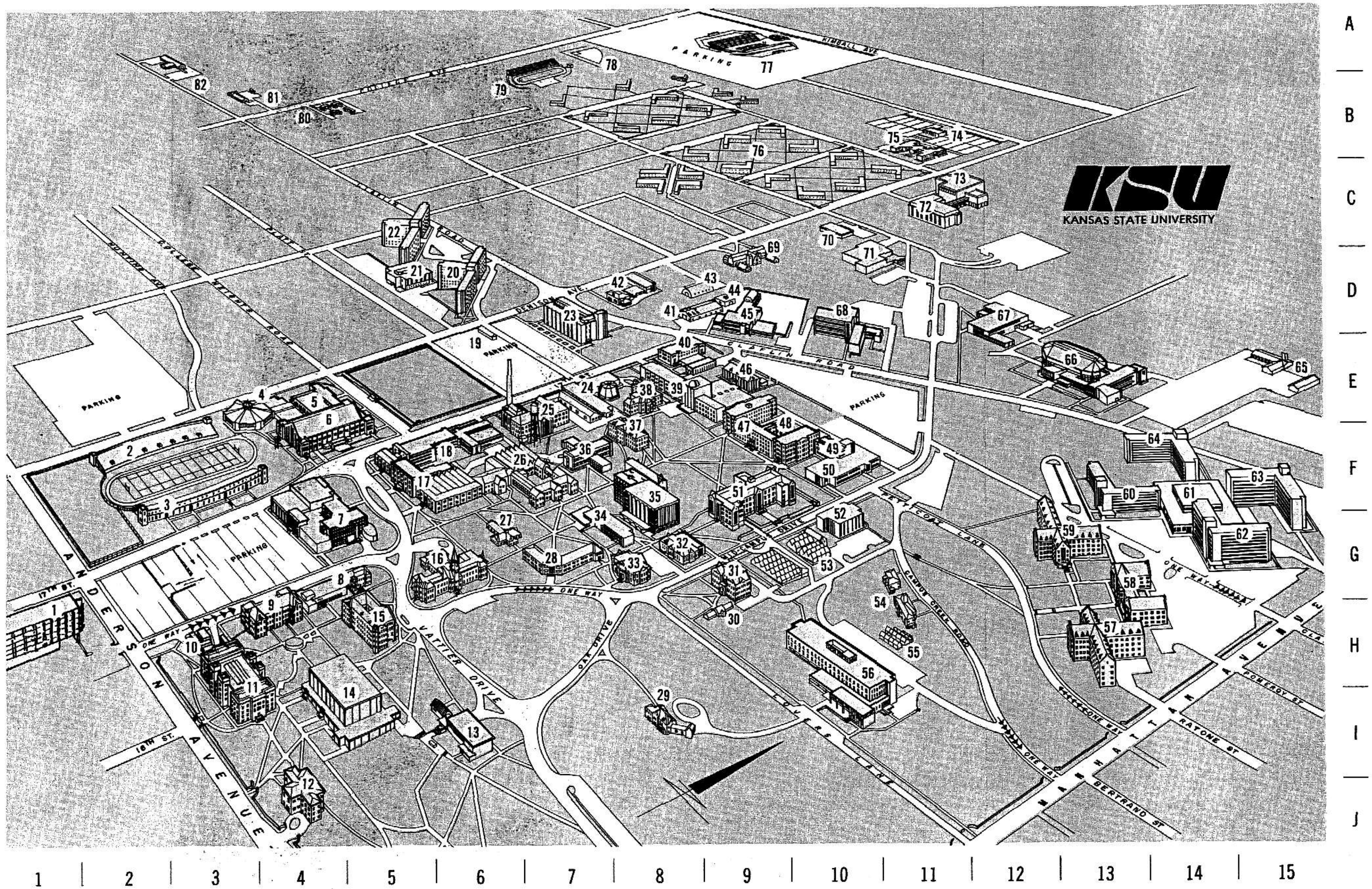


Figure 1. A Map of Kansas State University

KANSAS STATE UNIVERSITY

Founded in 1863 as the first of the nation's land-grant universities, Kansas State University has an enrollment of about 15,000 students and a teaching and research faculty of about 1,400. KSU offers strong academic programs through its eight Colleges and Graduate School. The Colleges include Agriculture, Architecture and Design, Arts and Sciences, Business Administration, Education, Engineering, Home Economics, and Veterinary Medicine.

Figure 1. A Map of Kansas State University

THIS BOOK CONTAINS NUMEROUS PAGES WITH DIAGRAMS THAT ARE CROOKED COMPARED TO THE REST OF THE INFORMATION ON THE PAGE.

THIS IS AS RECEIVED FROM CUSTOMER.

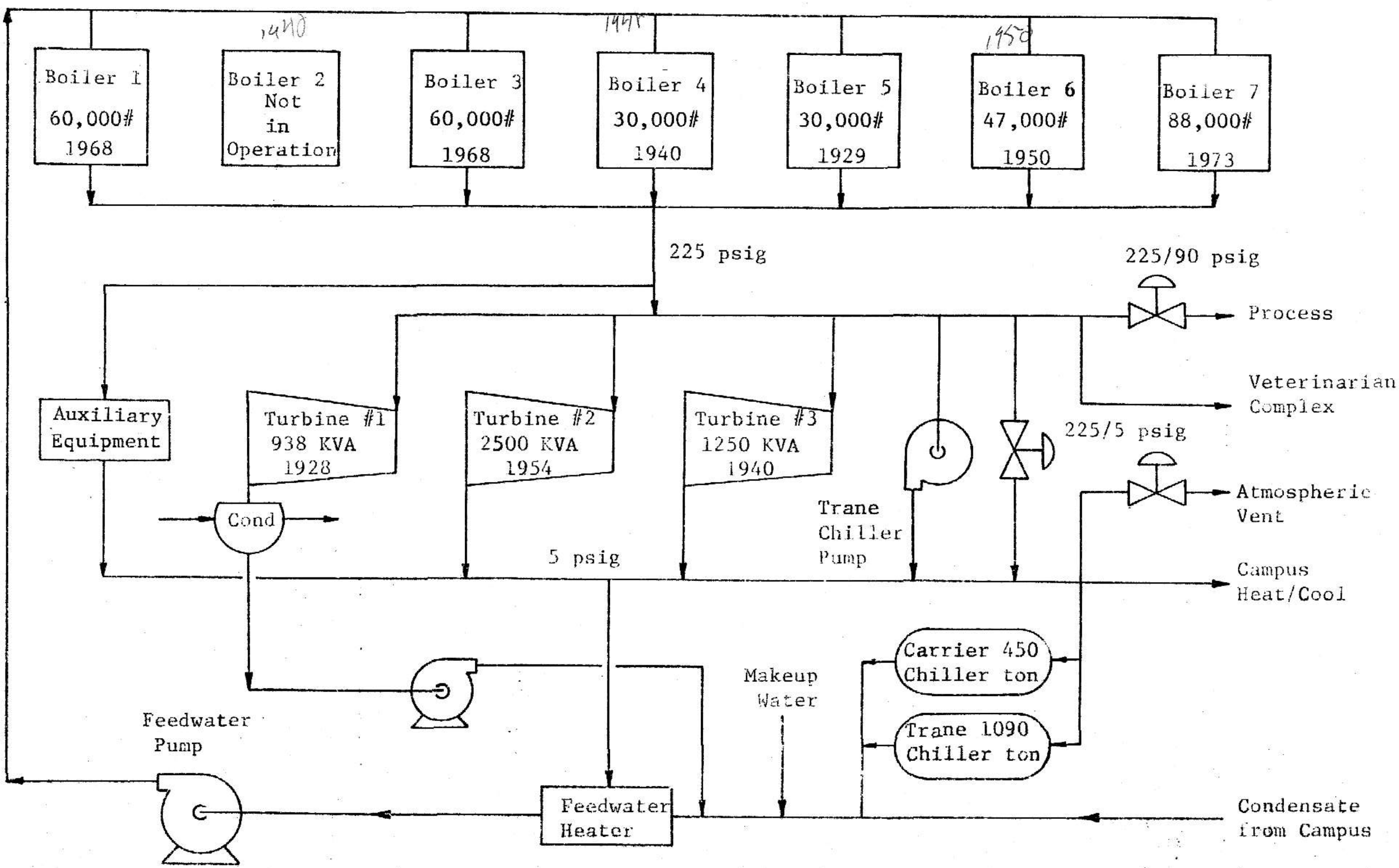


Figure 2. Flow Diagram of Major Plant Equipment - July 1973.

feet. Of this chilling capacity, the power plant houses 1543 tons and 450 tons of absorption and centrifugal equipment respectively. The balance of the equipment is distributed throughout the campus as exemplified by the machines located at the Derby complex and the Student Union. These air conditioning figures do not include the multitude of small scale units located on campus.

Process steam is supplied to the campus at approximately 90 psig and 500°F for laboratory use, cooking and domestic water heating. Auxiliary steam, approximately 225 psig and 500°F, is utilized within the plant itself, principally to drive three boiler feed pump turbines and, when natural gas service is interrupted, to heat fuel oil and to power fuel oil pump turbines. Heating steam for most of the campus is at about 5 psig and 230°F after passing through a reducing valve or being expanded through a turbine. This flow can be supplemented by bleeding steam into the heating lines from the process steam distribution system via three electrically operated valves in Seaton Hall, the Horticulture Greenhouse and Ahearn Fieldhouse. Unlike the other buildings, the veterinary complex is supplied with 225 psig, 500°F steam directly off the main header which also supplies the three turbine-generators. One of the turbines is a condensing unit with a 27 inch vacuum exhaust pressure while the other two are non-condensing units with approximately 5 psig exhaust. The Trane pump circulates chilled water from the central absorption machines within the main distribution loop that serves the campus. The exhaust steam from the auxiliary equipment, the Trane pump drive turbine and the non-condensing turbines flows into a low pressure header that distributes the steam for final use in absorption machines (both in and out of the plant), building heating systems and, in some structures, domestic hot water heaters. On those occasions when the low pressure flow demand exceeds the exhaust flow plus the additional steam provided from the process lines, the 225/5 psig reducing valve is opened to supplement the low pressure supply. If the load imbalance is reversed, an atmospheric vent releases the excess low pressure steam to the atmosphere. It should be noted that (due to absorption machine requirements) the secondary header is maintained at 7 psig while chillers are operating.

An extensive water treatment system exists in the power plant basement since not all of the steam distributed to the campus returns as condensate. Partially softened city water is passed through three zeolite softeners. After this treatment, the water is placed in one of two large storage tanks until required by the boilers. Several chemical agents are also added intermittently to both the boiler and chiller water systems.

Cooling towers are located immediately south of the power plant building. There are five towers, one for each of the central chillers, as well as one for both the condensing turbine and the auxiliary equipment. Inhibiting agents are added to the untreated city water that circulates in these towers.

The electrical energy requirements of the campus are satisfied by Kansas Power and Light Company substations and the campus generators. Electricity generated in the power plant is radially distributed to the central campus at 4160 volts. There are two KP&L 7500 KVA substations located in the southwest and northeast corners of the campus that are connected by 12,500 volt lines along the north and west sides of the central campus. These feeder lines supply power to peripheral buildings such as the Derby and veterinary complexes. Since most of these peripheral buildings are not interconnected with the central campus radial distribution system, they are totally dependent upon KP&L for power. The southwest substation also feeds power directly into the power plant bus, via a 5000 KVA transformer located immediately east of the plant, to supplement the capacity of the central campus system.

Prior to 1966, the campus turbines generated the majority of the electricity consumed by Kansas State. However, with the advent of substantially greater loads, Kansas Power and Light Company became the major source of electrical energy. The growth of this load and the transition of suppliers can be observed by referring to Figure 3. The present operational philosophy of the power plant personnel is to generate

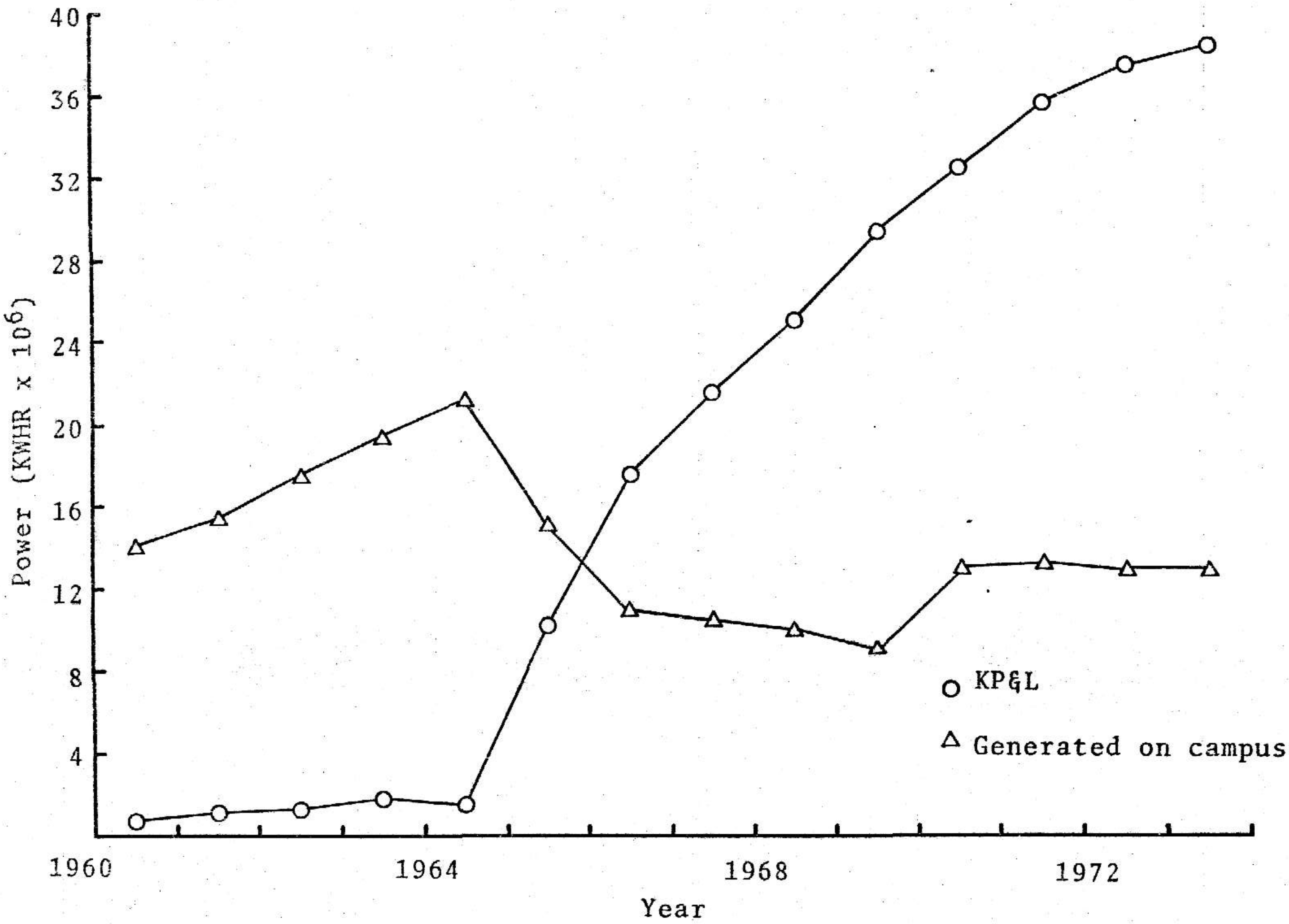
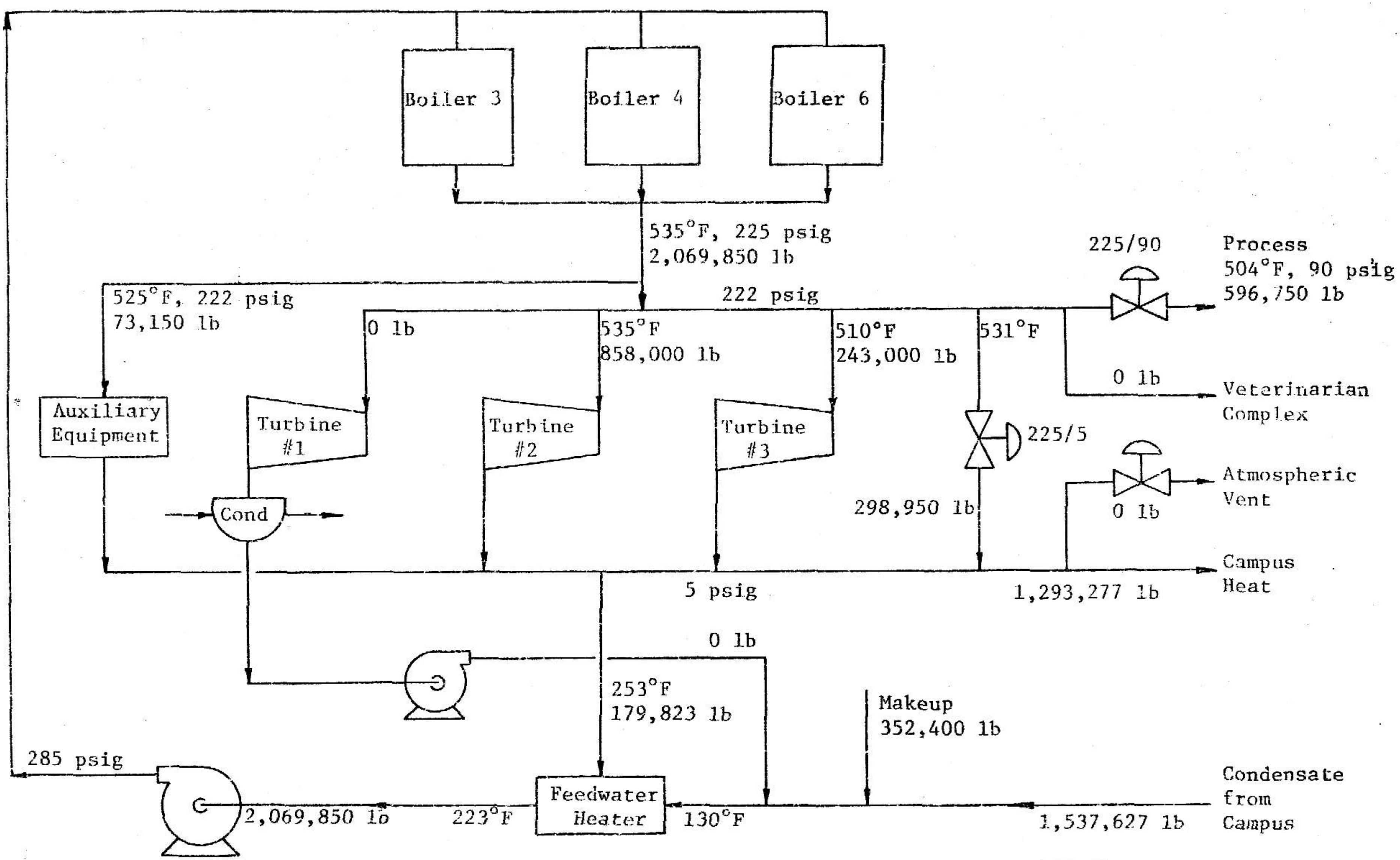


Figure 3. Electrical Energy Consumption According to Source

the peaks of electrical demand while satisfying campus steam requirements, and to buy the base electrical supply in an effort to take advantage of the LP-64 schedule contract with KP&L (see Appendix A). Accordingly, the plant carries a greater load during the day by operating various combinations of the three generators as dictated by electrical and steam demands. The higher loads of a summer day would typically result in all three units functioning during the day, supplying both electricity and exhaust steam, while unit 2 would run alone at night. Winter days normally see unit 2 and/or 3 operating continuously while unit 1 might occasionally operate during the day. Herein lies the greatest merit of the plant's operational capability - the same steam may be used in a prime mover to drive a generator and as an energy source for building environmental control. In a sense, electricity is a by-product of heating and cooling the campus.

After a study of the plant's functional history, four days were selected to represent the various ambient conditions under which the power plant operates. This particcular technique of defining the plant's operational characteristics is justified by its history of operating with a dual function: heating or cooling the campus. There is relatively little fluctuation, for example, in the heating situation of November 18 versus that of February 18 due to the great diversity of demand and the lack of precise building heating controls. Therefore, a carefully chosen "typical" winter day can accurately represent the average operating conditions for approximately six months while a "typical" summer day would describe the average conditions for the remaining six months. For this reason, subsequent analysis will be based upon the assumed continuous existence of the "typical" situations with due consideration accorded to the existence of extremely atypical circumstances as indicated by "worst case" data. On the pages that follow, there are tables and figures that depict plant operational characteristics and the campus demands it strives to satisfy on both "typical" and "worst case" summer and winter days.

Figures 4 and 5 illustrate the operating equipment, conditions and steam flows in the plant on a twenty-four hour basis for January 22, 1973, and July 23, 1973, the typical days. Table 1 contains additional operational data as well as thermodynamic and cost figures for the two "typical" days and also the two "worst case" situations. It should be noted that the lack of instrumentation precludes a more detailed specification of performance and required that some data be extrapolated or calculated rather than established from plant records. The meters that are in use are rarely calibrated and thus their accuracy is questionable. Finally, demand characteristic curves for total steam production and for electricity consumption may be found in Figures 6 and 7 respectively. The electrical demands depicted in Figure 7 are not those of the entire campus, but rather those of the



All flows are
24 hour totals

Figure 4. Flow Diagram and Operating Data for January 22, 1973.

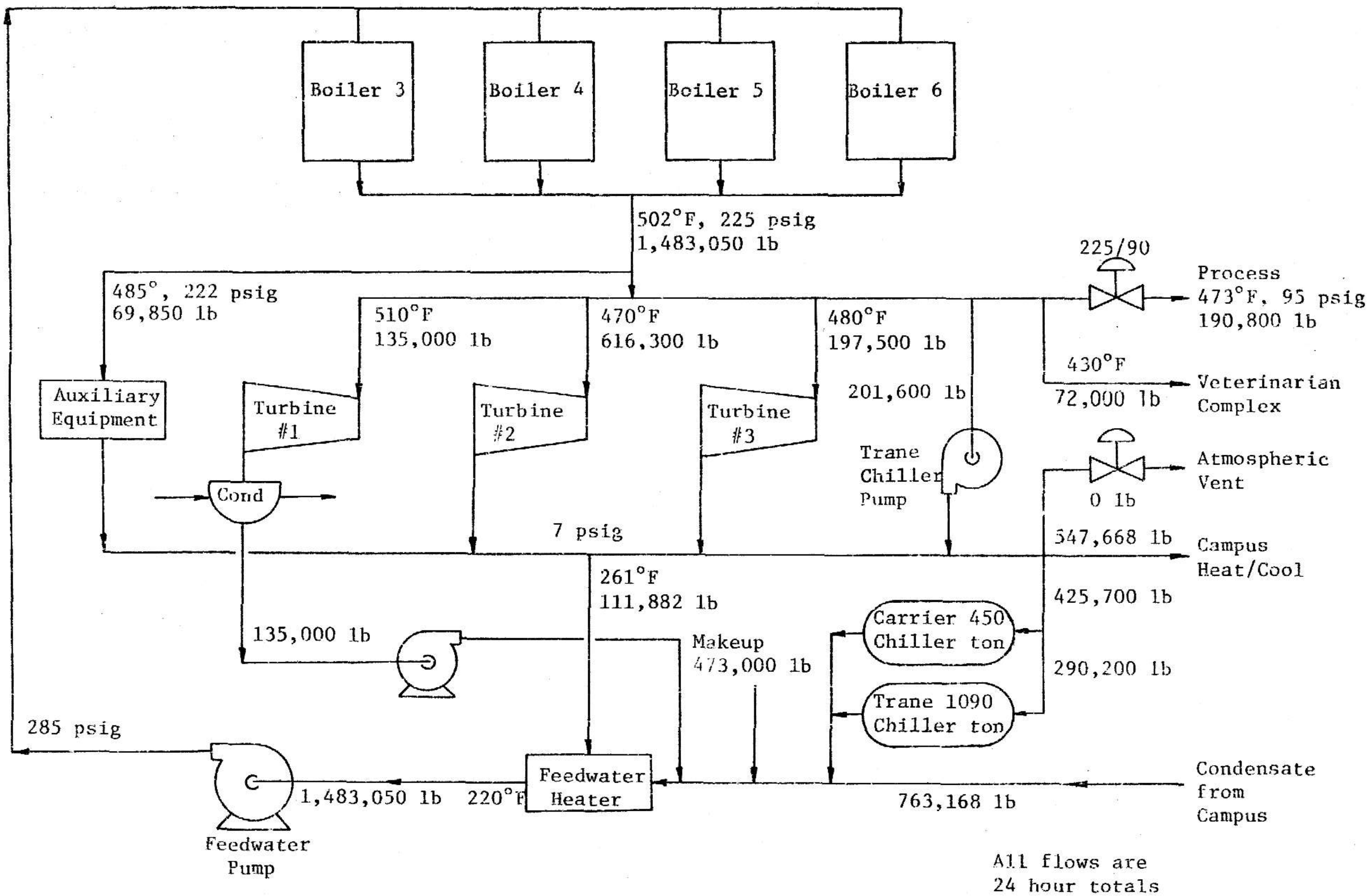


Figure 5. Flow Diagram and Operating Data for July 23, 1973.

TABLE 1

OPERATIONAL AND COST DATA FOR THE POWER PLANT ON FOUR SELECTED DAYS

	Worst Winter Day Monday January 8, 1973	Typical Winter Day Monday January 23, 1973	Worst Summer Day Monday July 2, 1973	Typical Summer Day Monday July 23, 1973
Ambient Temperature Range (°F)	-1 → 9	24 → 37	70 → 98	69 → 85
Atmospheric Pressure (in. Hg)	29.25	28.40	29.85	28.67
Boilers Used	3-4-5-6	3-4-6	3-4-5-6	3-4-5-6
Total Steam Produced (lb/24 hr)	3,018,000	2,069,850	1,870,000	1,461,050
Peak Steam Production (lb/hr)	132,000	100,000	117,000	89,000
Steam Distribution (lb/24 hr)				
#1 turbine	0	0	137,000	135,000
#2 turbine	1,024,000	858,000	960,000	616,300
#3 turbine	0	243,000	239,000	197,500
Atmospheric vent	94,800	0	294,900	0
Auxiliary steam	164,000	73,150	65,000	69,850
Campus Distribution - low pressure	2,174,000	1,293,277	602,729	547,668
Chiller-Carrier 435 ton	0	0	132,400	135,500
Chiller-Trane 1090 ton	0	0	296,000	290,200
Process steam (corrected)	581,000 (249,000)	596,750 (228,000)	188,000	190,800
Reducing valve 225/5 psig	1,581,000	298,950	0	0
Trane pump	0	0	209,600	201,600
Veterinary complex	0	0	72,000	72,000
Power Plant Btu Gas (f^3)	708,900	3,143,600	2,903,000	2,330,500
Average Btu/f^3	975	966	967	973
Gas Cost ($)	232.02	1,028.90	946.69	759.98
Power Plant Oil (gal)	22,363	0	0	0
Btu/gallon [11]	143,925	-	-	-
Oil Cost ($)	2,169.21	-	-	-
Total Fuel Cost	2,401.23	1,028.90	946.69	759.98
Cost/1,000,000 Btu ($)	0.6146	0.3388	0.3372	0.3352
KWHR Produced				
#1 turbine	0	0	6,100	5,800
#2 turbine	36,700	34,300	34,300	21,800
#3 turbine	0	8,800	9,000	6,500
KP&L Purchased (kwhr)	32,200	35,600	87,700	84,000
Total Power Consumer (kwhr)	68,900	78,700	137,100	116,100
KP&L Power Expense ($)	357.42	434.32	947.16	940.80
KP&L Expense (¢)	1.11	1.22	1.08	1.12
Energy Cost Allocations* ($)				
Campus heating/cooling	-	755.40	-	416.67
Power generation (¢/kwhr)				
#1 turbine	-	0	-	1.2857
#2 & #3 turbine	-	0.2107	-	0.2206
Miscellaneous	-	59.49	-	61.05
Process	-	123.28	-	105.39
Cost/useful Btu** (¢x10^{-8})	-	4,563	-	4,770

* See Appendix B for development and definition of these costs.

** Btu available for useful application on something other than power plant auxiliaries.

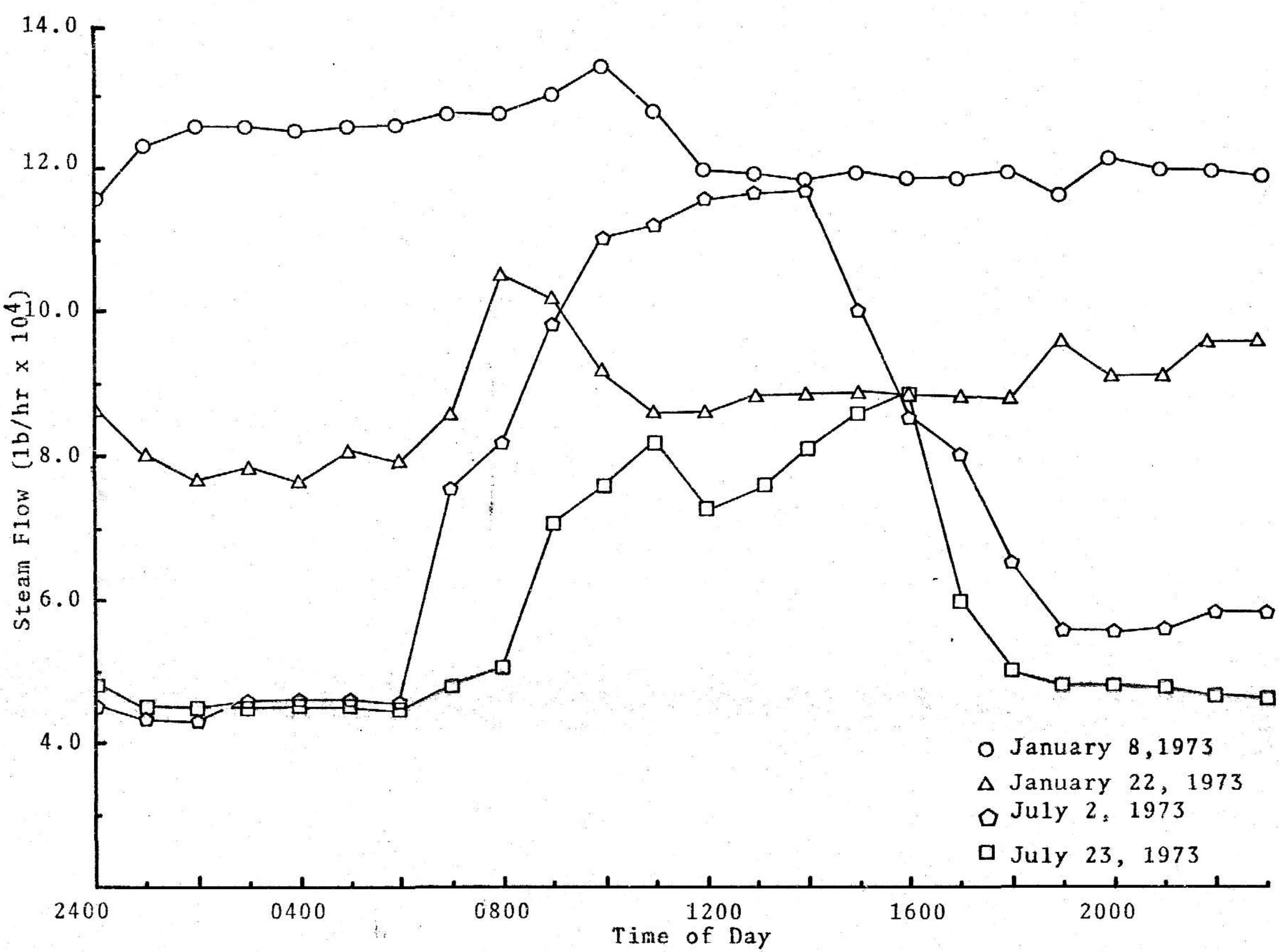


Figure 6. Total Steam Demand Characteristics

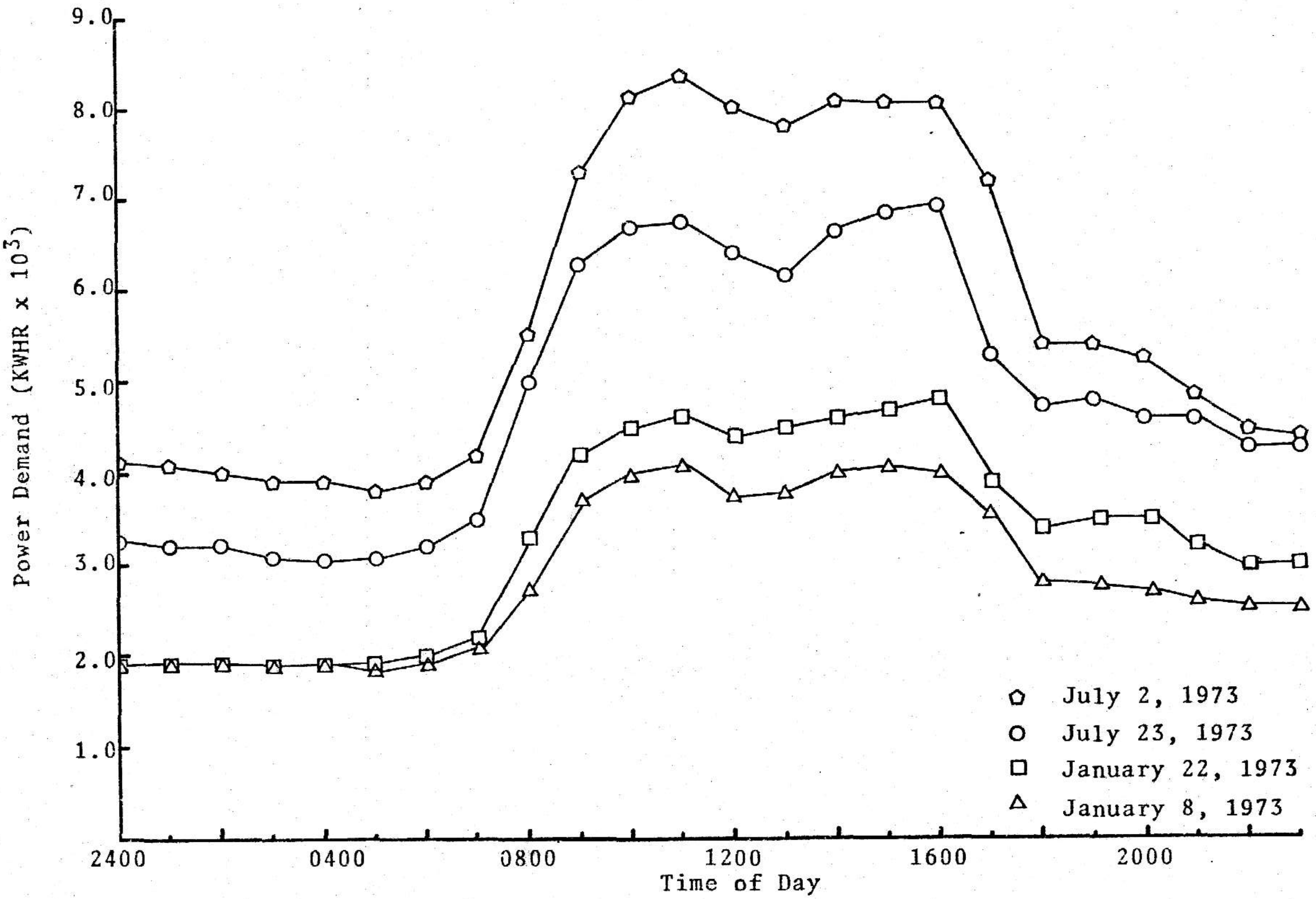


Figure 7. Central Campus Electricity Demand Characteristic

area served by the radial distribution system originating in the power plant. The lack of adequate records prevents the inclusion of that power consumed by the veterinary complex, the Derby complex, Ackert Hall, King Hall, and Farrell Library in Figure 7. However, the characteristics of their demands should not differ significantly from those that are known, and it is possible to determine total campus consumption from billing statements.

Referring to Figure 6, some conclusions can be drawn about steam demand although limited significance should be attributed to any given data point due to the questionable reliability of the metering and recording devices. For each operating condition, there is a base load that is relatively constant between 7:00 p.m. and 6:00 a.m. At approximately 6:00 a.m., steam flow increases. During the summer months this load is principally due to absorption chillers, the condensing turbine and, to an extent, process steam used for cooking and water heating. The load builds gradually all day as building temperatures increase. It declines rapidly in the evening as the atmospheric temperature and people load decline, and as unit 1 is shut down due to a diminished electrical demand. It can be readily observed that air conditioning is becoming the determining factor in boiler capacity requirements.

Winter day steam flow has characteristics similar to those of a summer day. There is a sharp increase in steam flow around 7:00 a.m. as building temperatures are elevated to normal comfort levels and as cooking begins. After this is achieved, the demand lessens and remains relatively constant throughout the day. There is another upward trend in the evening as outdoor temperatures decline and as the dormitories demand steam for food services and water heating. As would be expected, this aspect of the demand is more prevalent during the winter months when more dormitories are in use. The worst case winter day exhibits a more constant demand than the other days, but this is not unexpected since January 8 occurred during the semester recess and thus, the load is more nearly one of heating only.

Characteristics of the electrical energy demands can be determined from Figure 7. Again there is a base load for each condition, the summer base being approximately twice that of the winter, and a large demand peak that begins to develop around 7:00 a.m. This peak has developed completely by 10:00 a.m. and remains essentially constant until 4:00 p.m. except for a slight decline in the vicinity of noon. This peak demand is, for the most part, past by 6:00 p.m. with a gradual demand reduction thereafter as people retire from their daily activities. Having explored the current operational characteristics of the power plant and its loads, the demands of years to come must be addressed and identified.

CHAPTER III

THE PROJECTION OF CAMPUS DEMANDS FOR STEAM AND ELECTRICITY

The two most basic parameters to be considered in the projection of Kansas State University's demand for heating steam, electricity, and chilled water are student enrollment and the total square footage of campus buildings. More specifically, the types of buildings, their locations and the nature of the activities they house, the presence or lack of air conditioning, and the housing preferences of students become salient factors in forecasting the utility demands of the campus.

The physical plant expansion projection found in Figure 8 was based upon the "Capital Improvements Program for Kansas State University" as submitted by Dr. Paul M. Young, Vice President for University Development in a July 17, 1973, letter to the Kansas Board of Regents. This data base was selected not only for its knowledgeable and official source, but also because, as a state institution, building programs are created to replace antiquated facilities and to satisfy existing requirements rather than to maintain a given service level in view of expected growth.

Student enrollment projections through the 1983-84 academic year can be found in Figure 9. It should be noted that

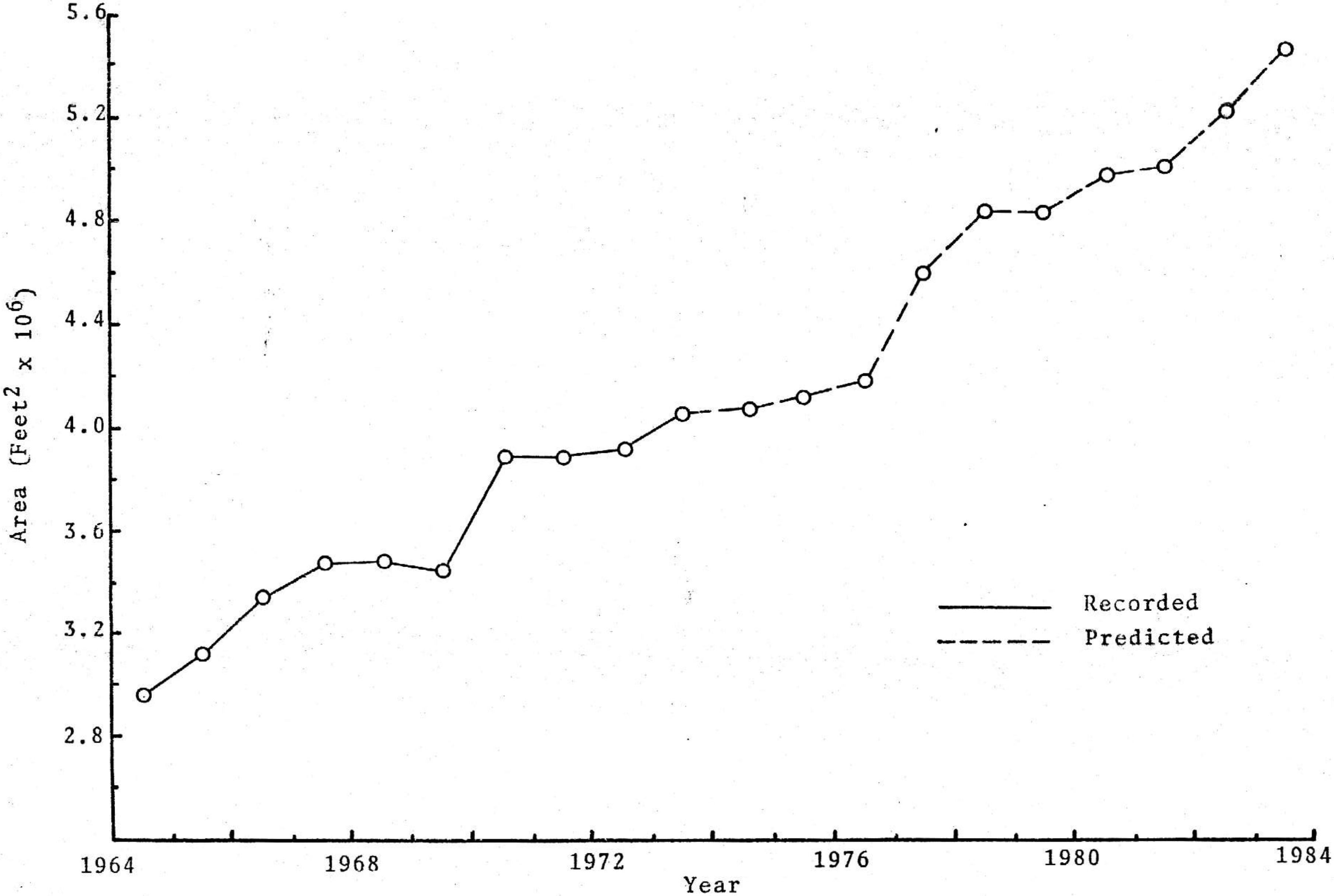


Figure 8. Area of Campus Buildings

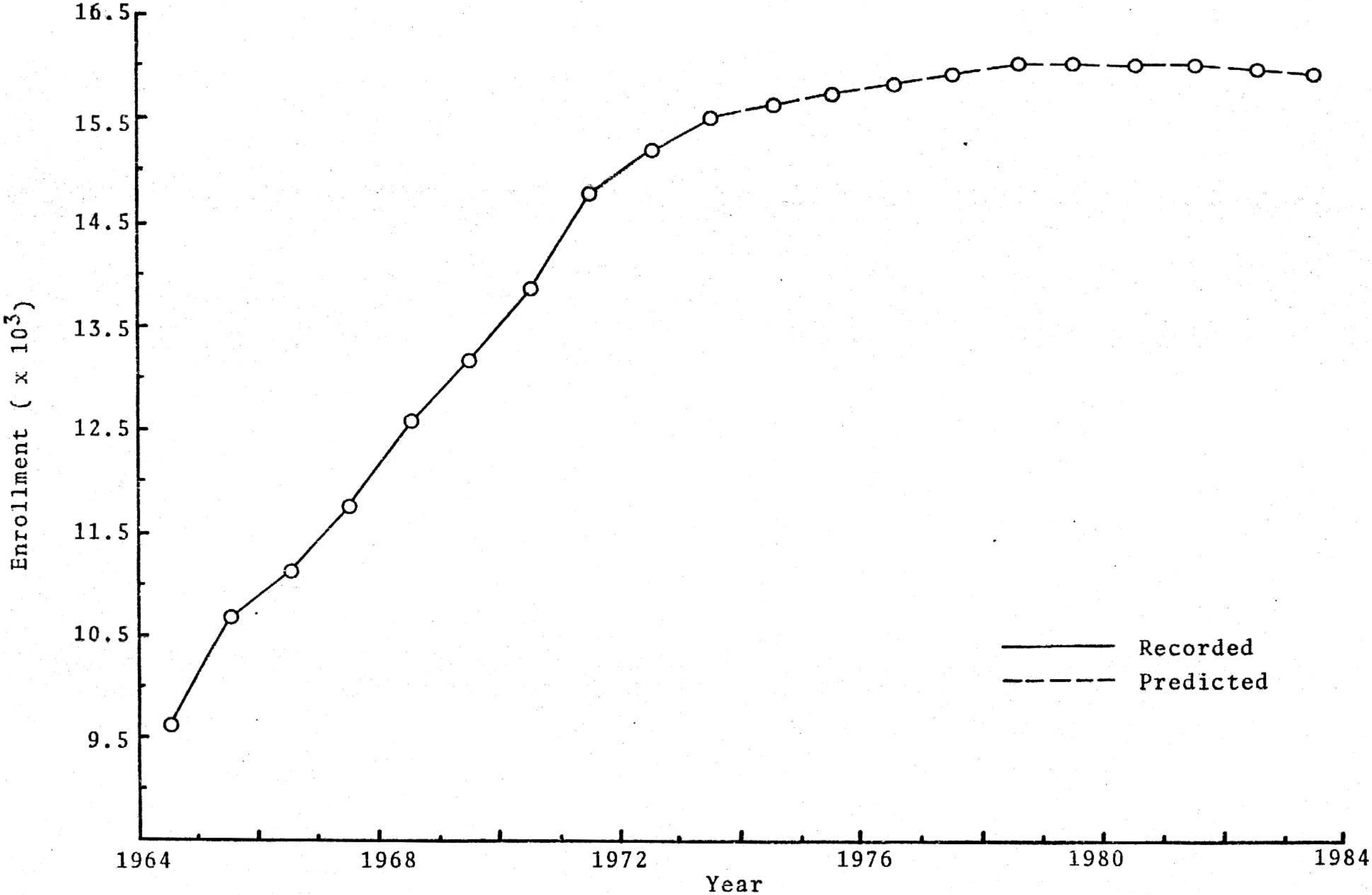


Figure 9. Student Enrollment

future enrollment will become increasingly more stable than that of the past ten years as the student body reaches a maximum of 16,000 in 1978 [7]. This forecast was based upon many factors which included the following considerations:

1. There are no plans to alter the cost of attending Kansas State relative to the purchasing power of the dollar [7].
2. There is no sign of significant industrial expansion in Kansas to increase the population of the State.
3. The draft laws and veterans' educational benefits appear to be static.

The slower growth rate of, and the eventual decline in, enrollment is partially the result of the tremendous increase in junior college and vocational school opportunities in recent years. There has been a steady decline from 60% to 54% of Kansas high school graduates entering college as freshmen during the past few years [7]. The absence of a military draft is no doubt a contributing factor in the decline. Kansas has also been experiencing reduced birth rates since 1965 (coincidentally, the year birth control pills were widely introduced) and this phenomenon will manifest itself at the university level in the 1982-83 academic year. While the primary grades one through four are currently sustaining enrollment reductions, the effect on Kansas State should be minimal due to the addition of vocational-technical programs on campus to serve the Manhattan area. It is also probable that a higher proportion of a given age group will attend college in the 1980's due to better family financial positions resulting from fewer children to support.

The occupancy rate of the dormitories also influences the demands placed on the power plant. Currently, the occupancy rate is 99% and it promises to remain stable since there are no indications of a change in university housing requirements for freshmen. Moreover, on-campus housing has become an increasingly attractive alternative for upperclassmen as a result of rapidly rising costs for off-campus housing and the liberalization of dormitory regulations. With these projections as a working premise, the future demands for steam and electricity must be determined.

A survey of current forecasting literature [12, 21] was helpful in the assimilation of various forecasting techniques, limitations and concerns, but fruitless in terms of identifying a particular method suitable for long-range utility demand projections. As such, the reasonable approach was to identify historic trends and characteristics of the demands and to apply these trends to expected future conditions when more specific information was unavailable. In other situations, there were indications that future developments would exhibit characteristics unlike those currently in existence and consequently, those new traits were investigated and defined. The final forecast must then be a composite of those factors that can be expressed analytically and of engineering judgments on those factors that cannot be so described.

Figure 10 indicates the past and projected annual steam requirements of the power plant's auxiliary equipment. Historically, there appears to be no correlation between the total amount of steam produced and that required by the boiler feed pumps. This is counter to engineering principles and, since no explanation for this unexpected performance could be discovered, it is reasonable to predict a moderate, constant increase in this annual flow as total steam production expands. The figure, in this case, is 450,000 lb/year with the assumption that existing equipment has sufficient capacity to operate without additions through 1984.

The projected annual process steam requirements can be discerned from Figure 11. These figures represent only that steam employed in laboratory use, domestic water heating or cooking; steam used for building heat by way of the 90/5 reducing valves has been deleted from these forecasts. Process steam demand has been closely related to total campus area over the last ten years. Consumption has averaged 23.32 $lb/f^2/year$. In so much as food services and dormitories affect process demand and since there are no plans for significant expansion of these facilities, process demand can be expected to be reduced in new buildings. Accordingly, 22.0 $lb/f^2/year$ was selected and utilized in the process steam demand forecast for all proposed construction.

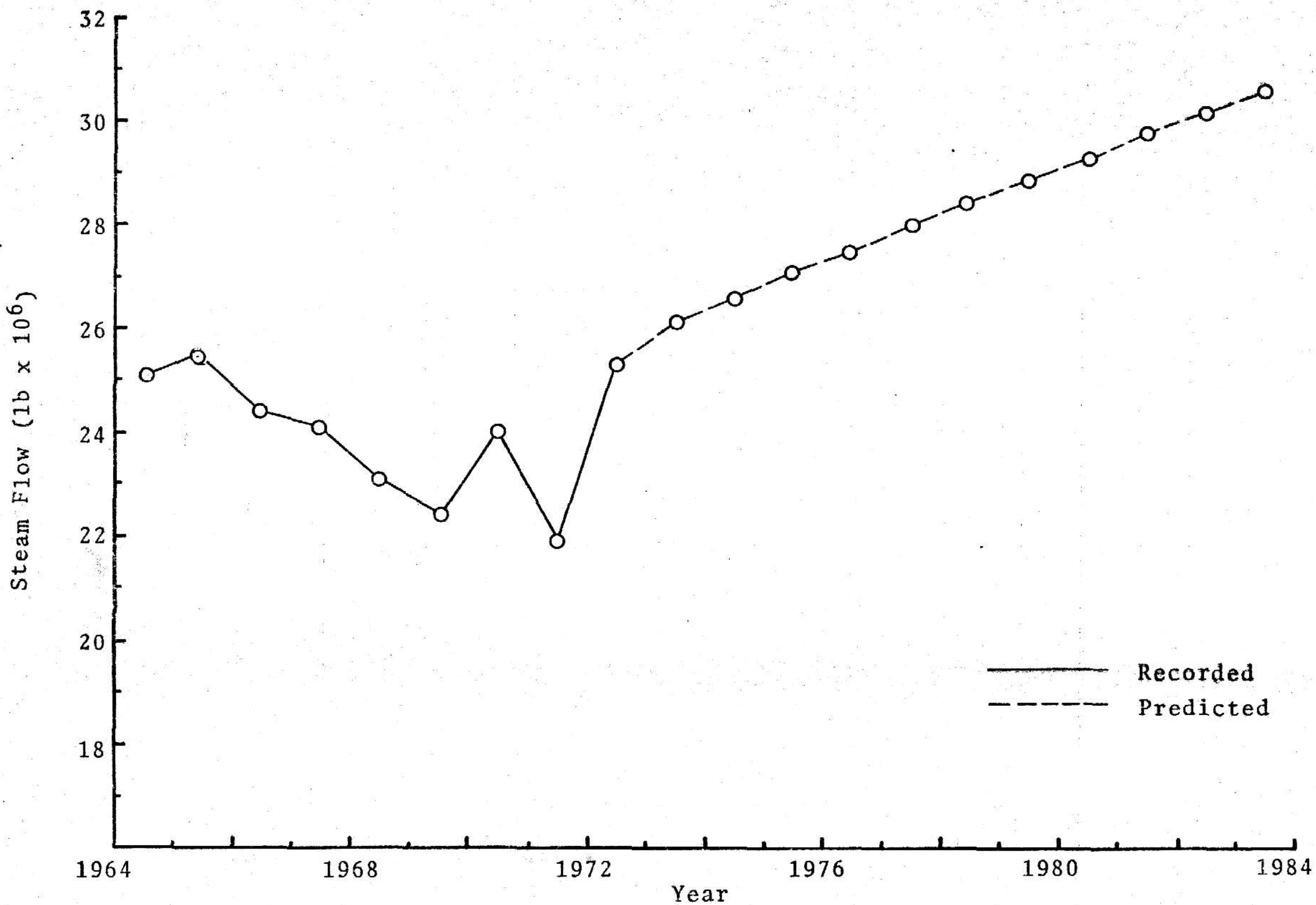


Figure 10. Annual Auxiliary Steam Requirements

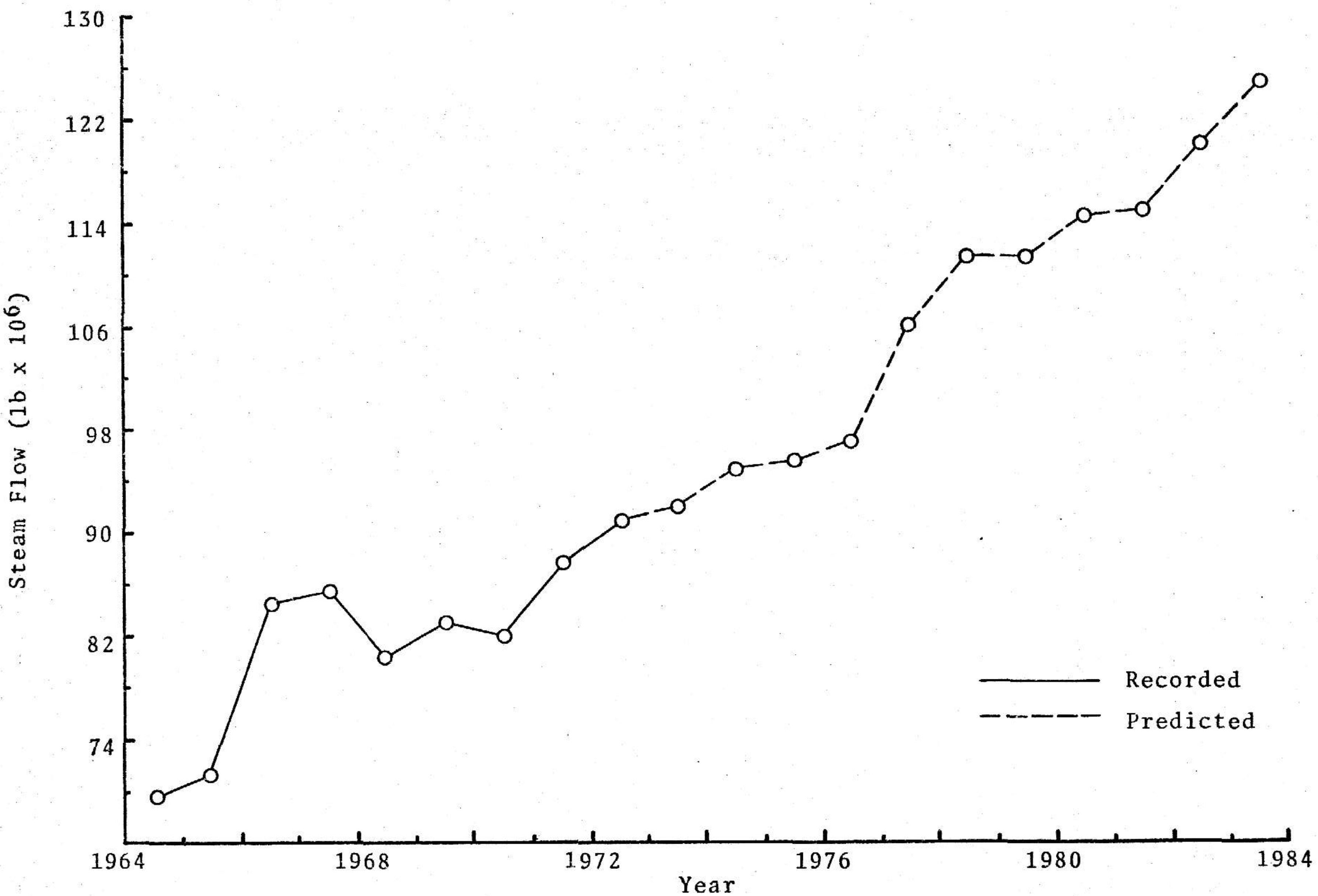


Figure 11. Annual Process Steam Requirements

Steam is vented to the atmosphere as a result of an unequal supply of, and demand for, low pressure steam. Referring to Figure 12, it is apparent that substantial progress has been made in reducing this loss. Due to a change in the administration's electricity generation philosophy, the campus turbine-generators are no longer constantly operated to capacity, but rather to utilize the steam required for other uses. Consequently, the steam imbalance is less frequent and less severe than in past years. It is reasonable to expect further loss reductions with the addition of new steam absorption chillers, greater areas to heat and, due to vastly increased water costs, a more vigilant conservation effort on the part of the operating personnel, although some loss will always occur due to load fluctuations.

Heating steam is that steam which performs a heating function within a building regardless of the path it follows in route to the heat exchanging element from the boiler. Furthermore, this definition is operative during the fourth quarter of October through the first quarter of April inclusive. There exists a reasonably constant relationship between the heating steam requirements and the amount of area being served. An examination of this relationship over the last ten years yields a figure of 66.5 lb/f^2/year as the flow required to heat currently existing buildings. After investigating the design criterion for the heating facilities in Durland Hall, the Veterinary Medicine Clinic and Hospital and the auditorium

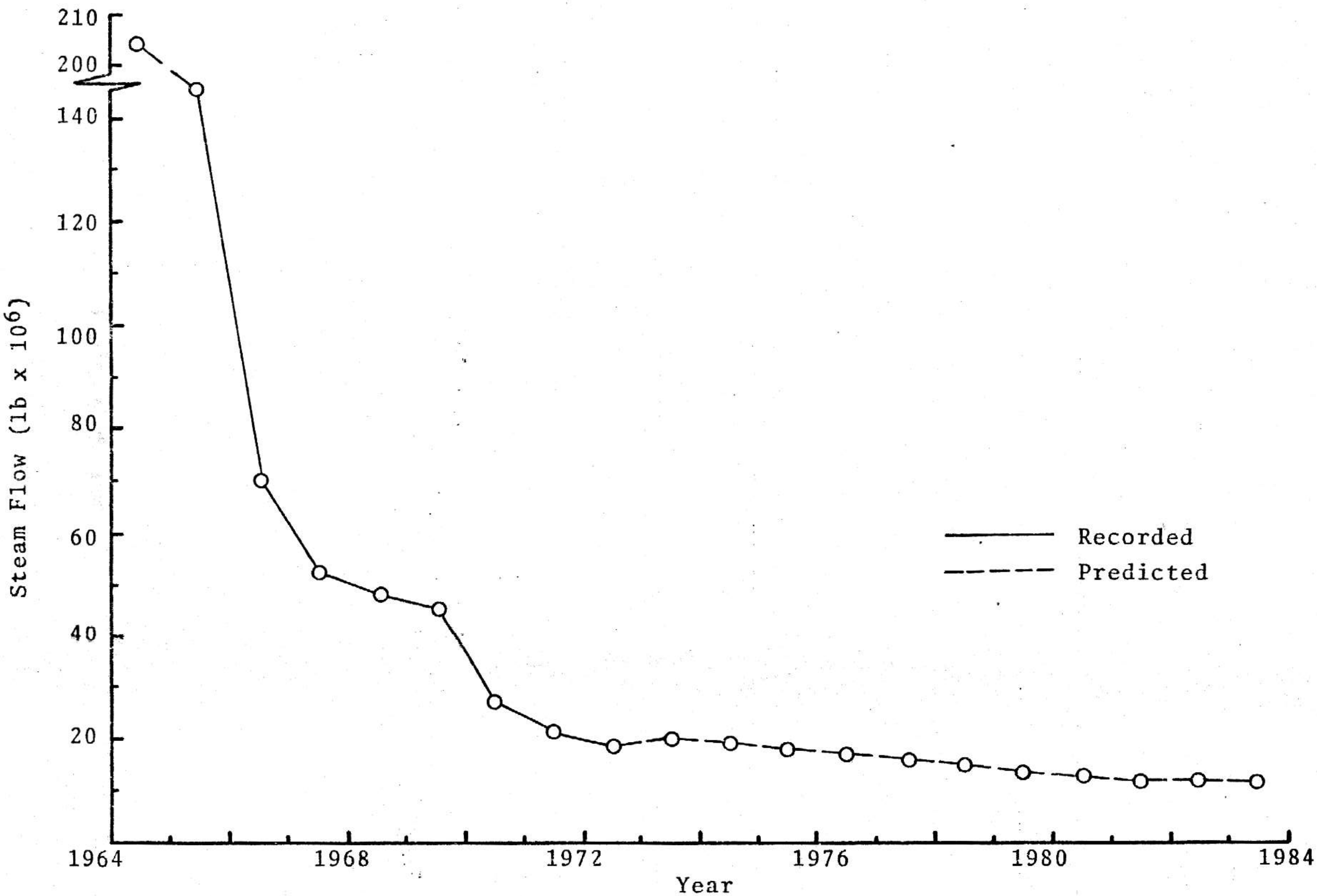


Figure 12. Annual Steam Vented to the Atmosphere

addition, 60.0 lb/f^2/year was found to be a typical new building heating steam requirement. This reduction in demand would be expected in view of the greater efficiency, reliability and better control systems inherent with modern heating systems. With this data base and the assumption that all new facilities will be steam heated, the heating steam projections through 1984 are presented in Figure 13.

Cooling steam is defined in the same manner as heating steam. Any steam used in the power plant chillers or distributed to the campus in the low pressure lines for chiller use during the second quarter of April through the third quarter of October inclusive, is designated as cooling steam. Existing instrumentation allows this flow to be divided into two categories: in-plant chiller steam flow and out-of-plant chiller steam flow. The measurement of the latter flow is significantly less reliable because the final flow figure is empirically derived after the initial readings are compensated for the additional functions the low pressure steam performs on campus. Using the definition above and the operating records of the power plant, it can be determined that absorption chillers require 106.54 lb/f^2/year and 153.37 lb/f^2/year for in- and out-of-plant units respectively, to air condition buildings. Although the difference in unit requirements is large, it is not unreasonable in view of the exterior machines' increased steam flow needs due to lower supply pressure, more frequent start-up and distribution system leaks. Therefore,

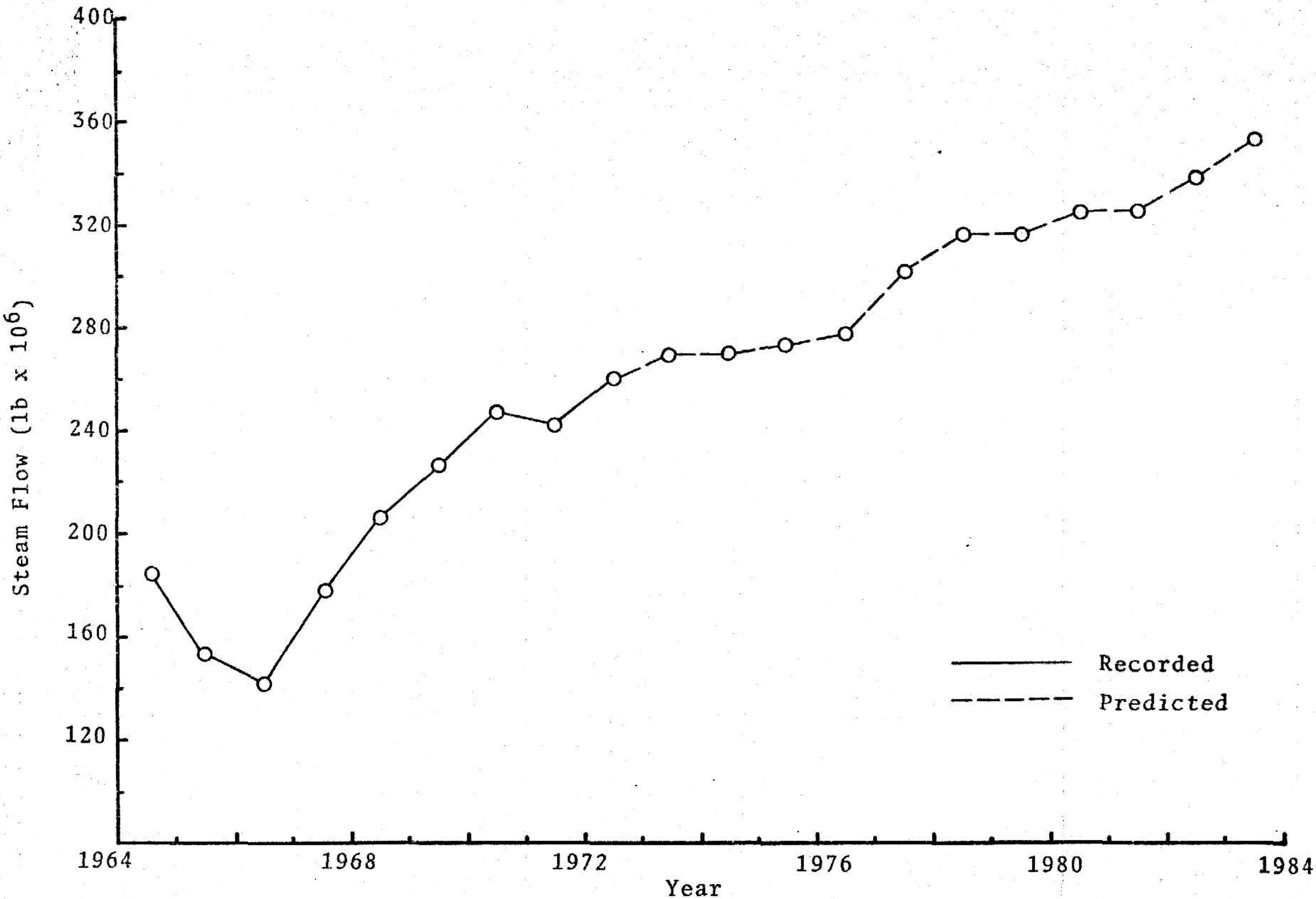


Figure 13. Annual Heating Steam Requirements

107.0 lb/f^2/year was selected as the steam necessary to cool additional campus buildings, not only because of the figure's greater reliability but also because the "Status Report to the Kansas Board of Regents - Long-Range Campus Planning"[9] indicates that future additions to the campus, excluding the veterinary complex, will be located in the central campus area. Therefore, the required chillers could and should be located in the power plant. For the purposes of the cooling steam forecast found in Figure 14, it was assumed that all future facilities would be totally air conditioned by central steam absorption units and that existing areas without such provisions would remain unserviced.

A forecast of the steam requirements for the open feed-water heater and the chilled water distribution loop pump may be found in Figure 15. Feedwater heater steam is an estimated function of total steam flow that is dependent upon many factors, primarily the amount of make-up water added to the system. In so much as feedwater steam flow is not recorded, analytical means were required to determine a current average flow as well as an estimate of past and future performance. A derived factor of 0.1 was employed to generate the estimates prior to 1973 while 0.09 was used thereafter. The feedwater estimate was the result of multiplying the proper factor times the total annual flow, lacking the feedwater quantity. While atmospheric vent losses were reduced significantly through 1970, proportionately greater condensate losses due to

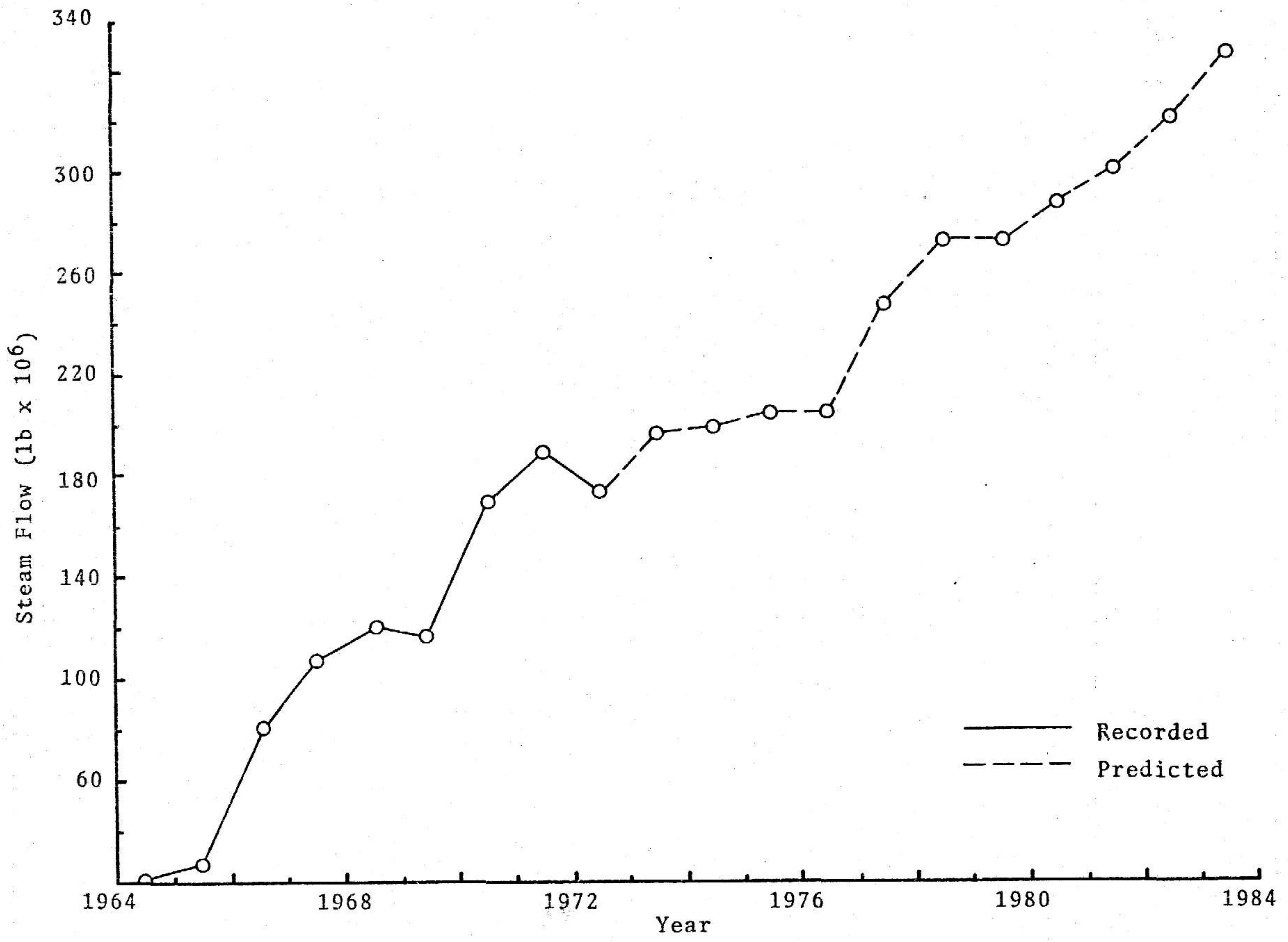


Figure 14. Annual Chiller Steam Requirements

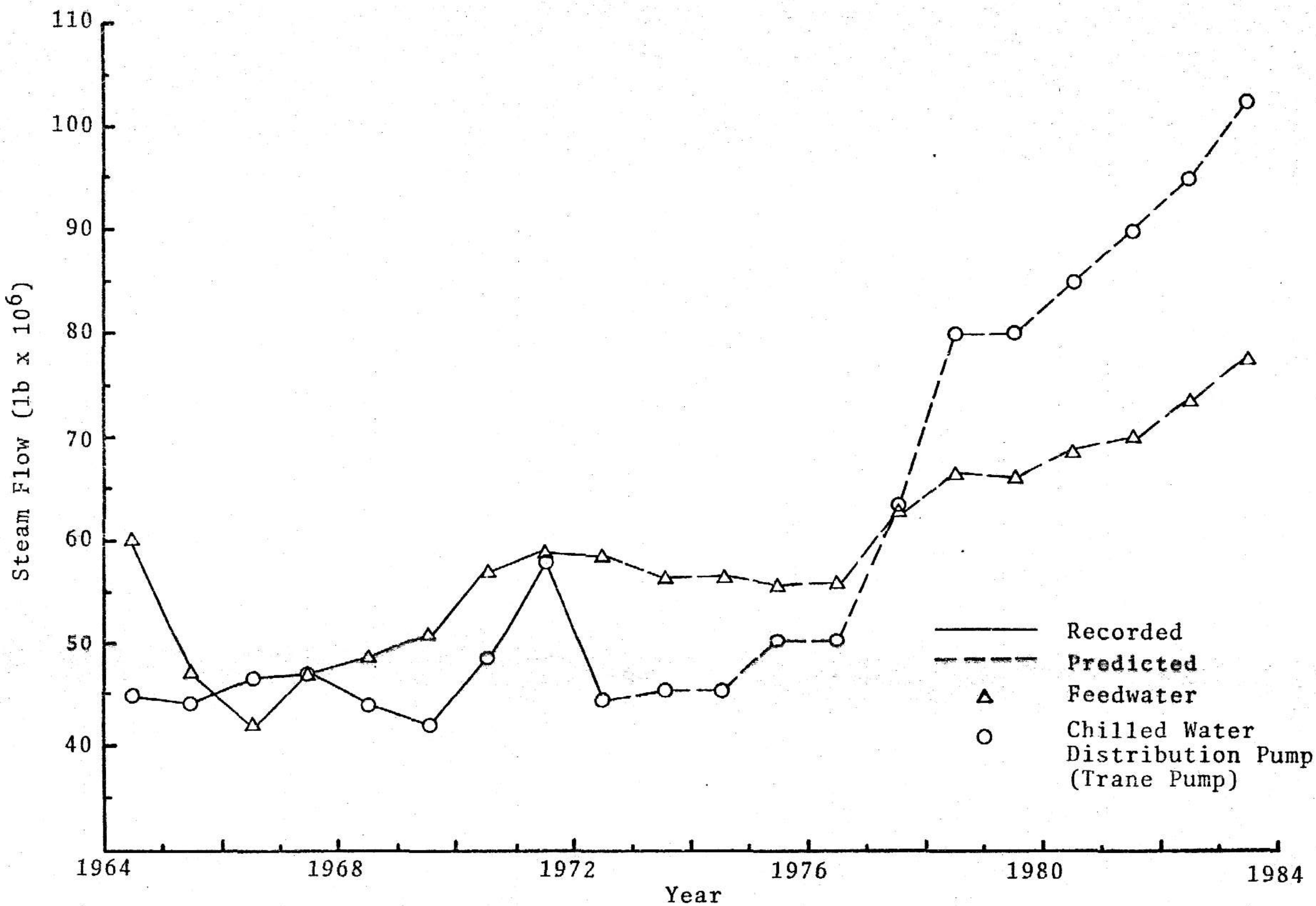


Figure 15. Annual Feedwater Heater Steam and Annual Chilled Water Distribution Pump Steam Requirements

curtailed operation of the condensing turbine offset much of this gain in terms of diminished feedwater heater steam requirements. Another major chilled water distribution loop will be necessary as new buildings are added to the campus. It was assumed that only one such loop will be installed and that it will be sized and located to serve all future additions to the central campus. The steam requirements of such a pump are determined by augmenting the current pump flow in approximate proportion to the air conditioning load additions.

With these individual steam demand forecasts, the total annual flows as exhibited in Figure 16 can be developed. The dramatic increase of 1977 indicates that boiler capacity should be investigated to assure sufficient steam generation capability will exist to satisfy the greater demand. The enlarged cooling load also indicates that the steam load duration curve will become progressively more nearly horizontal, implying that firm capacity requirements will become increasingly important. A tabulation of the various steam application requirements for 1964-84 may be found on Table 2. It should be noted that steam flow is categorized by use and, since some steam is utilized in more than one function, total steam produced is not the sum of the rows in that table.

The final consideration in defining future steam loads is that of peak flow demand. There can be found an historical correlation between the peak demand and the area served by

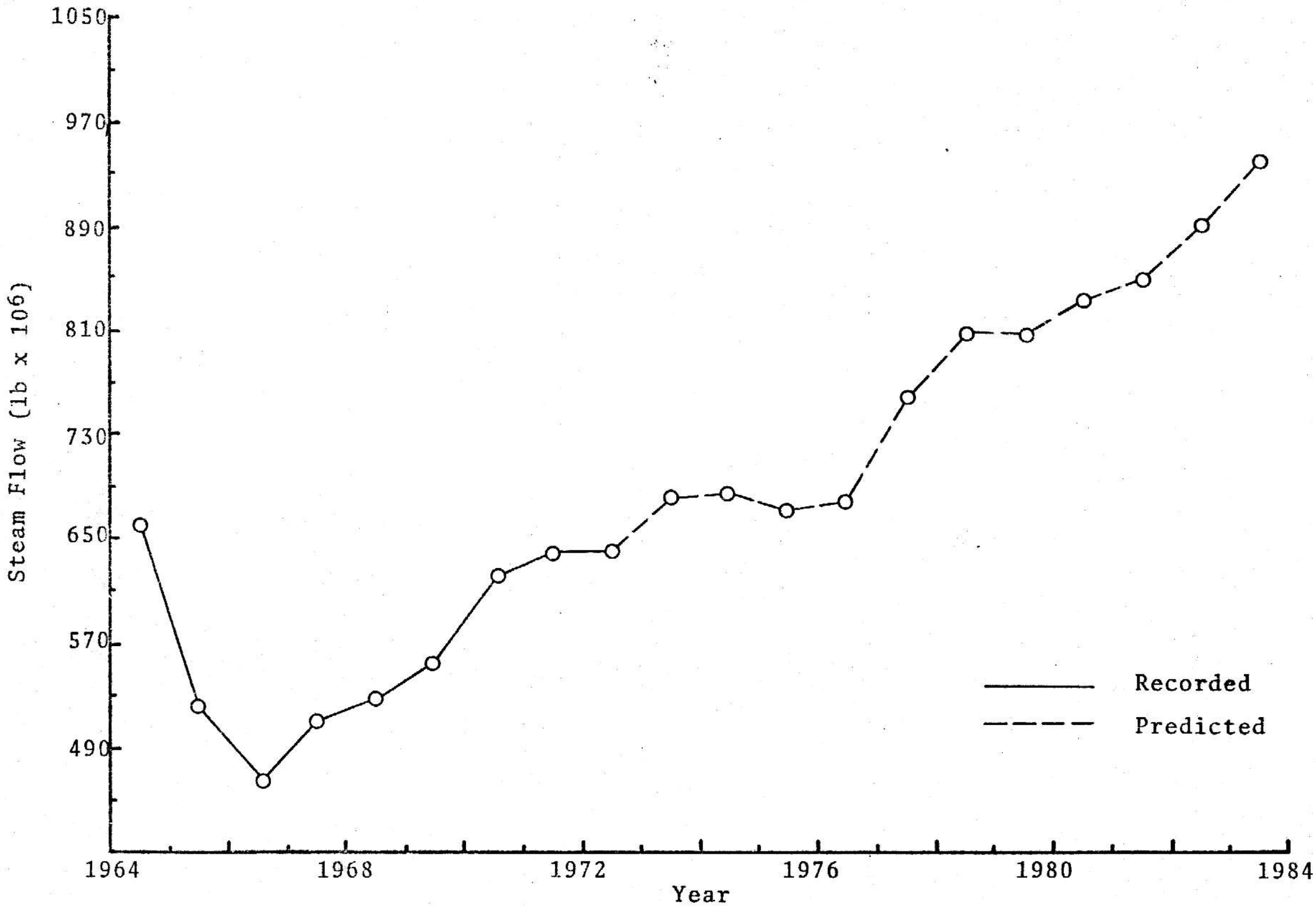


Figure 16. Annual Total Steam Production

TABLE 2

ANNUAL FUNCTIONAL STEAM FLOWS

All values are lb_m of steam x 10^6

	Process	Aux.	Feed-water	Unit #1	Trane Pump	Misc†	Heating	Cooling	Vent	Calculated†† Total	Recorded Total	Per Cent††† Difference
1964-65	69.41	25.08	60.05	102.75	45.00	20	184.70	19.51	204.1	660.51	671.7	-1.69%
1965-66	71.23	25.46	47.24	53.28	44.88	20	153.75	27.85	146.3	519.62	523.5	-0.75%
1966-67	84.69	24.42	42.45	24.38	46.34	20	143.81	81.40	70.2	466.95	477.0	-2.15%
1967-68	85.61	24.08	46.76	19.55	46.87	21	178.96	109.86	52.6	514.33	519.7	-1.04%
1968-69	80.50	23.12	48.41	15.39	43.94	23	206.39	120.21	38.6	532.50	546.3	-2.59%
1969-70	83.01	22.39	50.83	14.42	42.29	22	227.03	116.21	45.6	559.09	560.8	-0.30%
1970-71	81.97	24.04	57.11	21.78	48.48	24	247.23	169.04	27.1	628.23	623.7	0.70%
1971-72	87.47	21.91	58.78	19.93	55.82	26	242.87	189.96	21.6	646.61	640.0	1.01%
1972-73	90.76	25.29	58.75	19.51	44.68	25	260.49	173.11	18.6	646.22	639.6	1.02%
1973-74	92.99	26.13	56.13	20.23	45.12	25	269.29	196.12	20.0	679.76		
1974-75	94.86	26.56	56.42	20.00	45.50	25	270.23	197.79	19.0	683.30		
1975-76	95.52	27.03	55.42	0.00	50.50	25	273.21	204.81	18.0	671.37		
1976-77	96.98	27.48	55.89	0.00	50.50	25	277.21	204.81	18.0	676.89		
1977-78	105.99	27.93	62.62	0.00	65.50	25	301.81	247.01	16.0	758.43		
1978-79	111.28	28.38	66.62	0.00	80.00	25	316.21	272.69	15.0	806.80		
1979-80	111.28	28.83	66.53	0.00	80.00	25	316.21	272.69	14.0	805.71		
1980-81	114.25	29.28	68.73	0.00	85.00	25	324.31	287.14	13.0	832.43		
1981-82	114.99	29.73	70.04	0.00	90.00	25	325.74	300.51	12.0	848.28		
1982-83	119.83	30.18	73.49	0.00	95.00	25	338.94	320.84	12.0	890.10		
1983-84	125.06	30.63	77.54	0.00	105.00	25	353.19	346.25	12.0	939.04		

† This figure indicates that quantity of steam distributed in the low pressure lines while chillers are in operation that is not used by an absorption machine.

†† Calculated Total = Process + *Feedwater* + *#1* + *Miscellaneous* + *Heating* + *Cooling* + *Vent*

††† Per Cent Difference = $\frac{\text{Calculated-Recorded}}{\text{Calculated}}$

the power plant. This correlation, represented by a factor of 0.04404, is fundamentally another version of what is commonly known as the diversity factor. It should continue to be a reliable indicator of peak demand since heating and cooling will remain as the major steam loads. As was found in the total annual flow requirements, there is a sharp upward trend in the peak steam flow shown in Figure 17 commencing in 1977, directing one to examine the existing boilers' ability to fulfill this demand.

If campus demand for electricity is to be met, it too must be predicted and analyzed on a long term basis so that adequate arrangements for service can be made. To this end, electrical energy demand was forecast on a per unit area per year basis. This approach is justified by the fact that electricity consumption is relatively dependent upon area while, to a degree, independent of student population. It was assumed that all future construction would include central air conditioning of the steam absorption type and, for the most part, any existing areas lacking cooling systems would remain uncontrolled. Accordingly, the curve of Figure 18 was developed. A distinct trend toward a less rapid growth rate in electrical energy consumption appears in 1970. It is reasonable to expect this reduced growth rate to continue because, while increased services and new facilities will require higher energy levels, the primary element of past increases, the addition of air conditioners, should be unimportant. Consequently,

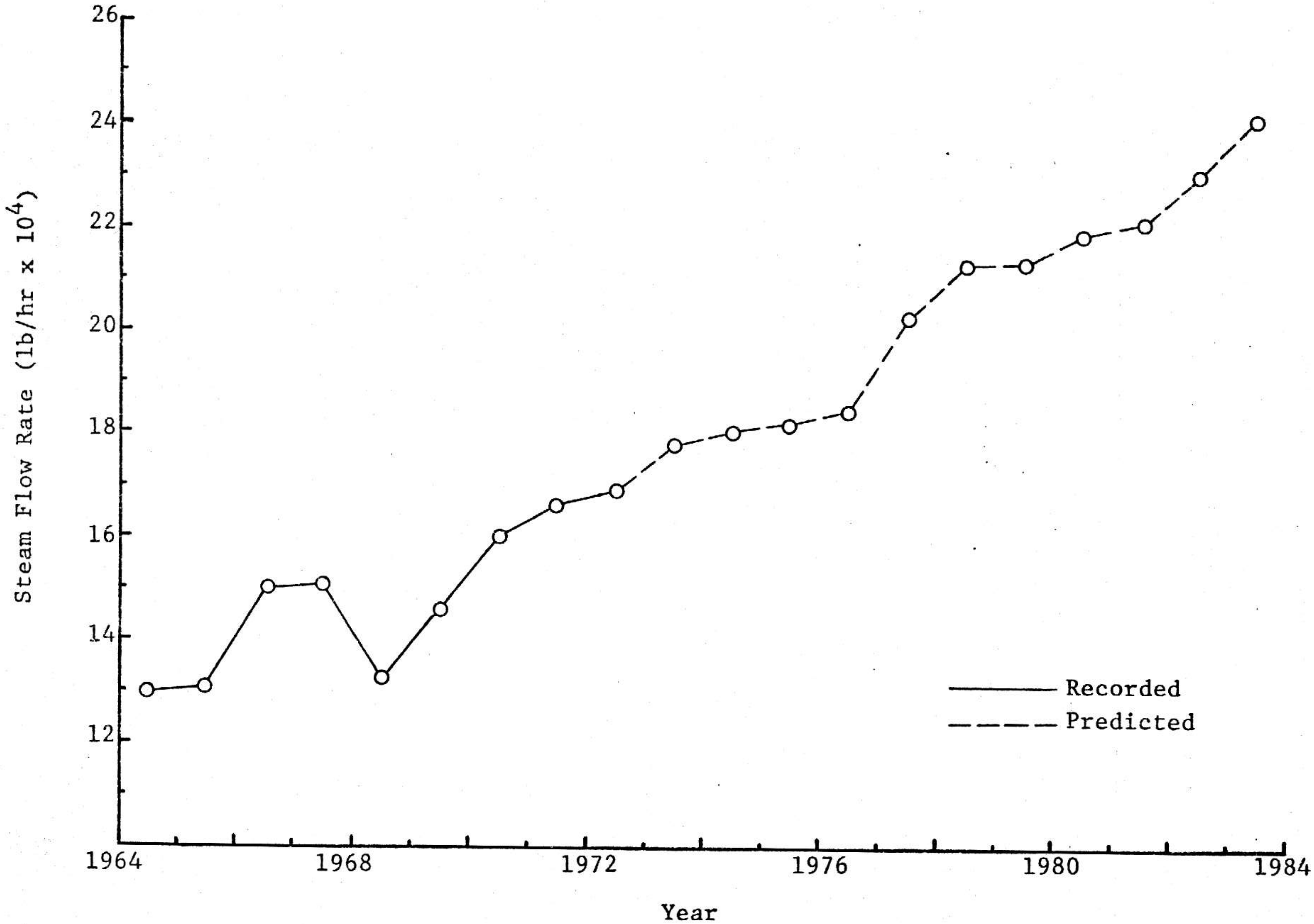


Figure 17. Annual Peak Steam Flow

THIS BOOK CONTAINS NUMEROUS PAGES WITH ILLEGIBLE PAGE NUMBERS THAT ARE CUT OFF, MISSING OR OF POOR QUALITY TEXT.

THIS IS AS RECEIVED FROM THE CUSTOMER.

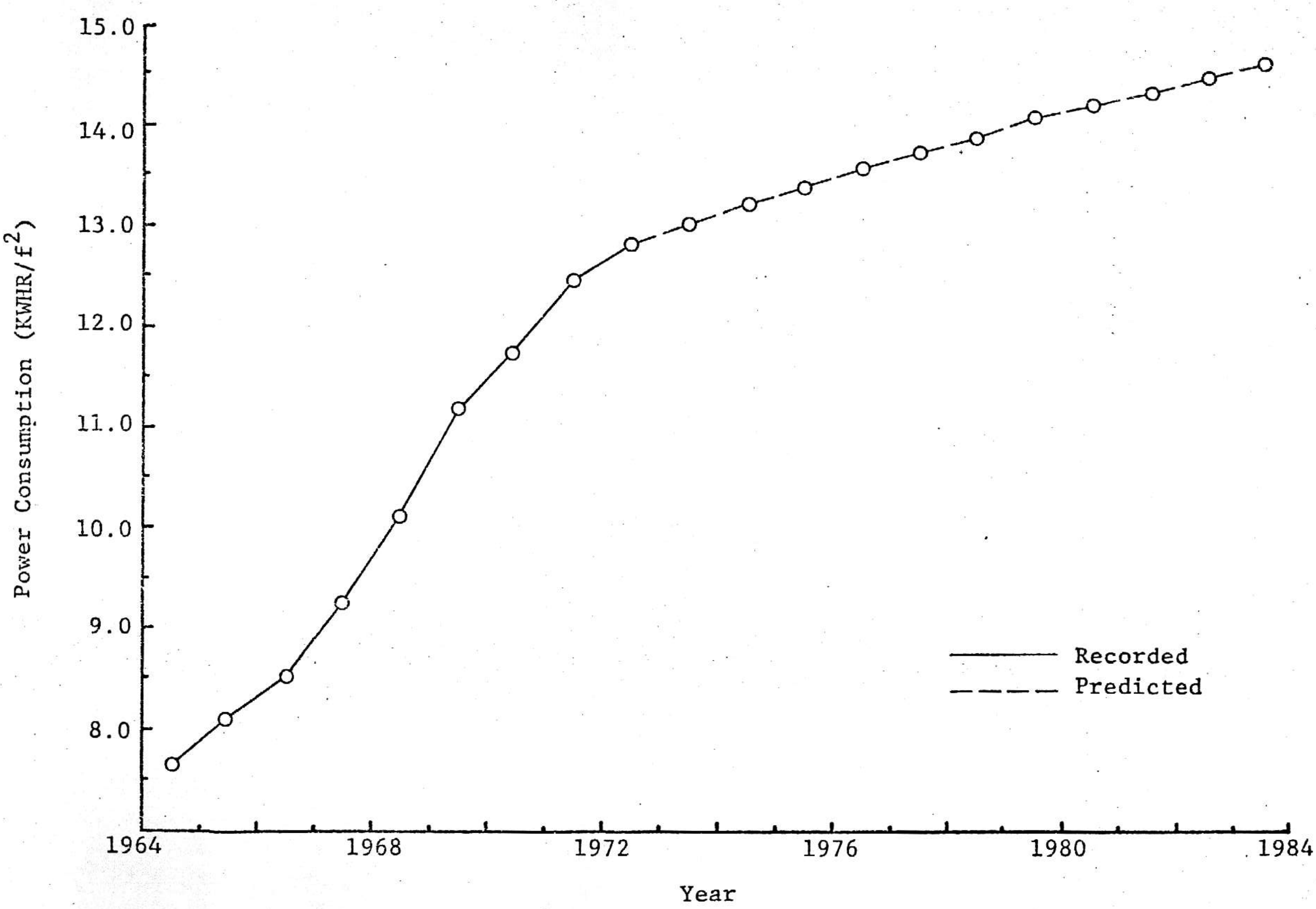


Figure 18. Annual Electricity Consumption on a Per Unit Area Basis

this new growth rate was extrapolated into the 1980's. With Figure 18 as a data base, Figures 19 and 20 were developed to depict electricity consumption per student per year and the total annual electricity consumption of the campus respectively.

Surprisingly, and of no direct importance to this study, both of these curves can be accurately represented by linear equations as indicated by statistical correlation coefficients of 0.9878 and 0.9941 respectively.

The determination of peak electrical demand is also a pertinent factor in the definition of future energy requirements. Not only must commitments to meet this demand be secured, but the demand characteristics must also be identified if the most economical arrangements are to be made because peak demands greatly influence electrical billing rates. Historically, Kansas State's annual electrical peak demand and total annual electricity consumption have been related by a factor that was empirically determined to be 0.0002565. It was this factor, in conjunction with the total annual use data of Figure 20, that was used in the development of Figure 21. Again, 1977 brings a stronger upward trend in the peak electrical demand just as it brought greater peak and annual steam flows.

With these forecasts to indicate the anticipated steam and electrical demands to be placed upon the power plant through mid-1984, various alternatives to satisfy these

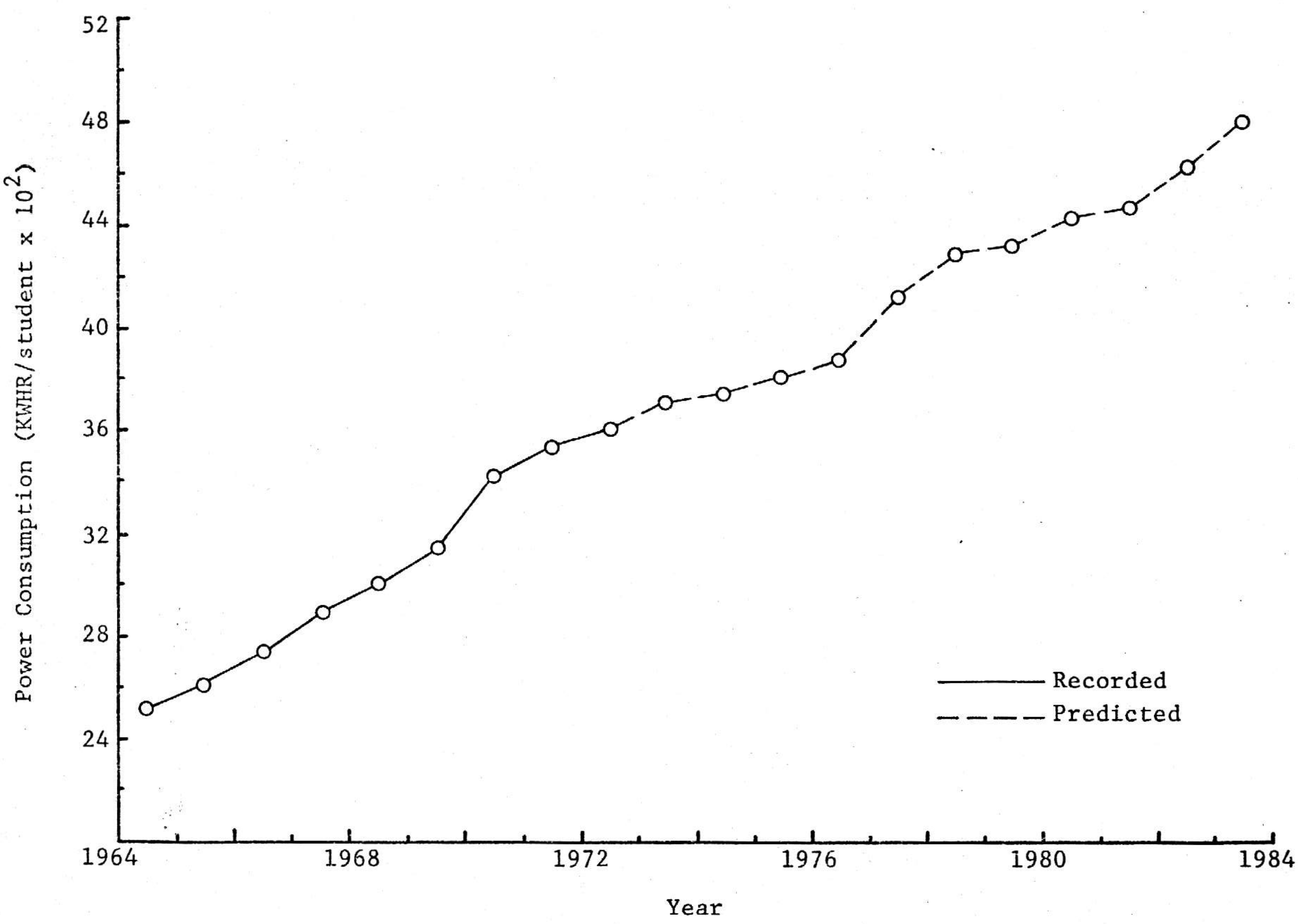


Figure 19. Annual Electricity Consumption on a Per Student Basis

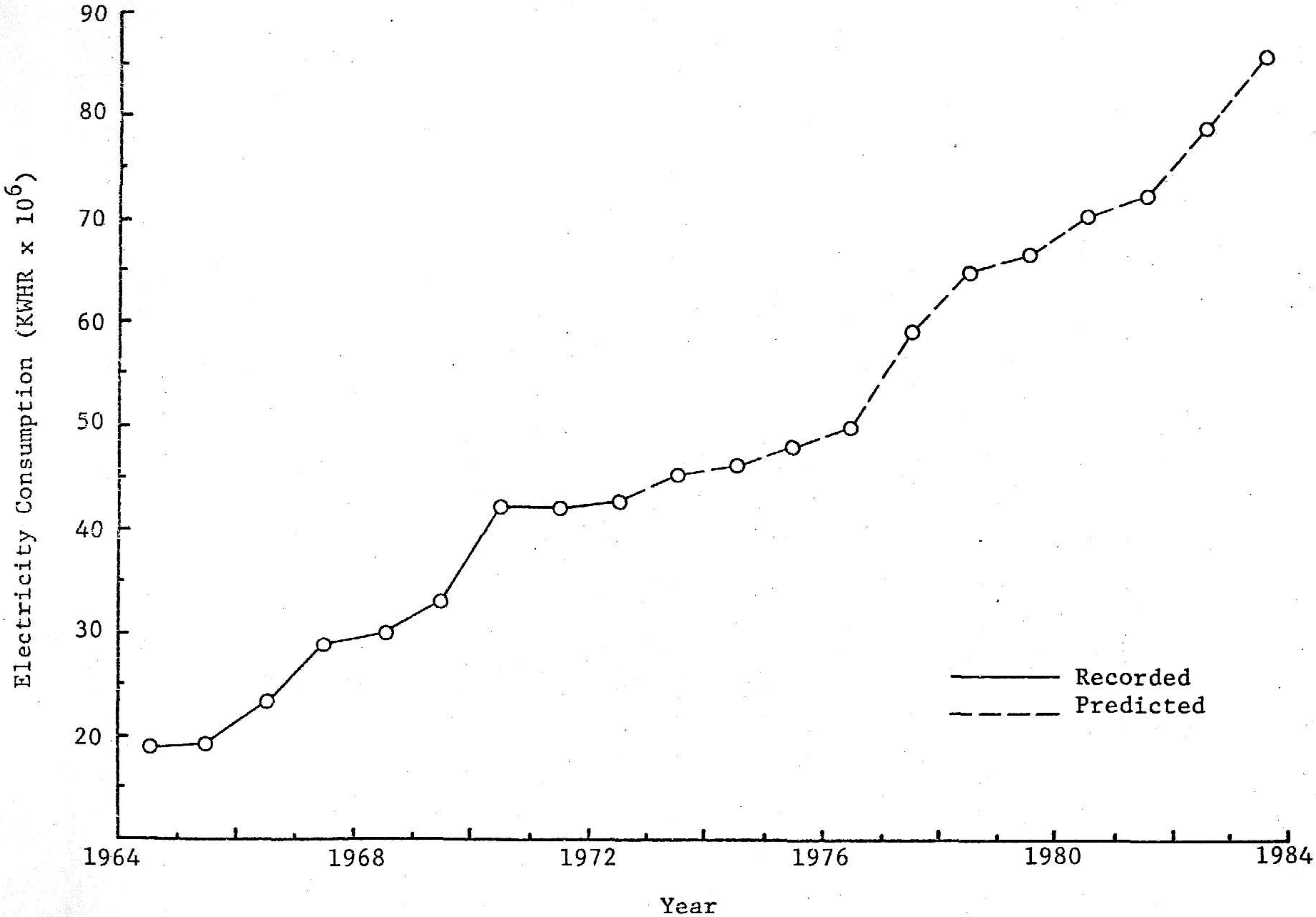


Figure 20. Annual Total Electricity Consumption

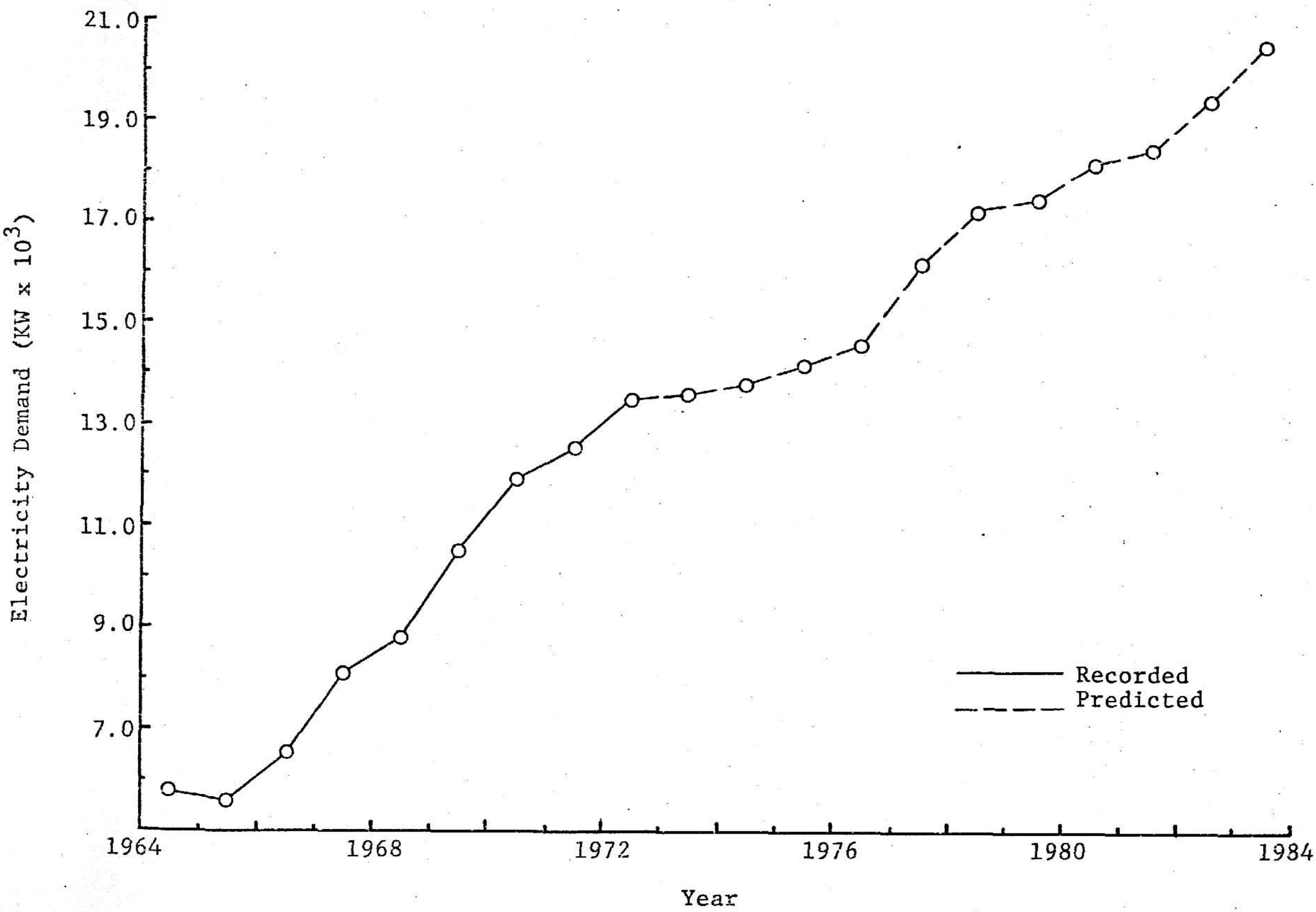


Figure 21. Annual Peak Electrical Energy Demand

requirements must be generated.

CHAPTER IV

THE PROPOSAL OF ALTERNATIVES

Kansas State University is committed to a central steam heating system. The existing investment in the production and distribution facilities precludes the serious consideration of other alternatives even if a more economical method existed. Therefore, the wise approach is to seek maximum utilization of those steam production resources by having steam perform a variety of services. This is currently accomplished by operating turbine-generators, air conditioning water chillers and power plant auxiliary equipment with steam, as well as heating the campus. The heat requirements for laboratories and food services are also satisfied with steam.

The following proposals are designed to meet the utility requirements of the campus through the 1983-84 academic year. The dates indicated within the proposals are those on which the units should be operational, the sizes listed are nominal capacities and the listed prices, in 1974 dollars, are for the equipment only unless otherwise noted. The General Electric Company, The Marley Company and The Trane Company are the manufacturers of the various units suggested and it was assumed that their cost and operational data was representative of the respective industries. There was no attempt made to evaluate the desirability of a particular manufacturer's product versus that of another, only an identification of the most satisfactory type of equipment to be incorporated in an expansion of the power plant.

The air conditioning proposals recognize the two principal types of commerical water chilling units: steam absorption and electric centrifugal. The absorption refrigeration approach certainly is in keeping with a greater utilization of the steam production facilities but, in view of the energy crisis and the attendant increases in fuel costs, it is prudent to also examine the centrifugal machine.

The proposals are designed to serve the central campus or the isolated veterinary complex and they are labeled accordingly. The central campus units will all be located in the power plant building and will be supplied with low pressure steam or electricity as a primary energy source. The units for the veterinary complex are on location and, since high pressure steam is available, two-stage steam absorption machines may be considered as well as the single stage absorption units that are proposed elsewhere. It was assumed that chillers have an operational life in excess of thirty years and thus, replacement of existing units was not contemplated. An annual listing of the new areas to be cooled and the required chiller capacity may be found in Appendix C.

PROPOSAL AAA

Central Campus
Single Stage, Steam Absorption

June 1, 1975	256 ton	$ 32,800
June 1, 1977	520 ton	52,000
June 1, 1978	852 ton	76,000
June 1, 1980	420 ton	44,800
June 1, 1981	420 ton	44,800
June 1, 1982	750 ton	70,000
June 1, 1983	852 ton	76,000

PROPOSAL AAB

Central Campus
Single Stage, Steam Absorption

June 1, 1975	750 ton	$ 70,000
June 1, 1978	852 ton	76,000
June 1, 1980	852 ton	76,000
June 1, 1982	1660 ton	148,700

PROPOSAL AAC

Central Campus
Single Stage, Steam Absorption

June 1, 1975	1660 ton	$148,700
June 1, 1980	1465 ton	126,000
June 1, 1983	955 ton	81,000

PROPOSAL AAD

Veterinary Complex
Single Stage, Steam Absorption

June 1, 1977	852 ton	$ 76,000

PROPOSAL AAE

Veterinary Complex
Two-Stage, Steam Absorption

June 1, 1977	852 ton	$120,000

PROPOSAL ABA

Central Campus
Two-Stage, Electric Centrifugal

June 1, 1975	250 ton	214 kw	$ 28,500
June 1, 1977	511 ton	419 kw	43,000
June 1, 1978	820 ton	645 kw	64,000
June 1, 1980	448 ton	362 kw	41,000
June 1, 1981	448 ton	362 kw	41,000
June 1, 1982	765 ton	602 kw	62,000
June 1, 1983	820 ton	645 kw	64,000

PROPOSAL ABB

Central Campus
Two-Stage, Electric Centrifugal

June 1, 1975	765 ton	602 kw	$ 62,000
June 1, 1978	820 ton	645 kw	64,000
June 1, 1980	1290 ton	1005 kw	99,000
June 1, 1982	1290 ton	1005 kw	99,000

PROPOSAL ABC

Veterinary Complex
Two-Stage, Electric Centrifugal

June 1, 1977	906 ton	668 kw	$ 74,000

The costs of the cooling towers required by the various chiller proposals may be found in Appendix D.

As has been mentioned previously, the ability of the existing boilers to meet the increasing steam demands of the campus is suspect. A further examination yields the conclusion that additional boiler capacity is indeed required. Assuming a thirty-five year operational life [19], boilers #4 and #5 should be operating on a back-up basis at present and #6 will reach this status in 1985. The current firm capacity of existing boilers is 227,000 lb/hr (assuming all units are operational except #2) and the projected peak demand of 1977-78 is 203,000 lb/hr. Being cognizant of the expansion of the power plant building in 1976 and the increased demands of 1977, the following proposal was created.

PROPOSAL BAA

225 psig, 150°F Superheat, Packaged Water-Tube Boiler
Gas/Oil Fired, Basic Controls Package

June 1, 1977	90,000 lb/hr	$156,000

It is beyond the scope of this study to determine the most economical boiler capacity. Therefore, the only other option would be to alter the installation date. Considering the decreasing reliability of the existing units and the expanded steam requirements of 1977, it appears that June 1977 is the most reasonable time for installation and thus, no additional boiler proposals were generated.

There are many schemes that could be proposed to satisfy the electrical energy requirements of Kansas State University.

However, the limitations of this study prevent the consideration of all but the most immediately applicable methods of power acquisition. This eliminates schemes involving solar energy conversion, gas turbines with exhaust gases producing steam, diesel engines and other methods of questionable suitability to the unique characteristics of the University's operation. Additional condensing turbines are not reasonable because neither the operational efficiency nor the economy of scale factor of an on-site station can compare favorably with those of a commerical utility. The more practical goal of selecting the most economical sizes of the equipment obviously suited for campus use is greatly curbed by the unavailability of the necessary evaluatory information. Therefore, two basic proposals were created. One involves an additional non-condensing unit to supplement the existing non-condensing turbines, whose continued operation is assumed, while the other suggests an automatic extraction turbine sized to utilize the entire available steam flow, with units #2 and #3 serving in a back-up capacity. In either case, campus demand for low pressure steam would be the primary factor in determining the steam flow available for use in the turbine(s) and, that demand will be satisfied at all times.

The alternative to securing additional generating capacity for the power plant is to operate the existing turbines to lessen the quantity of electrical energy that must be purchased until they fail. As the units do fail, the University will become totally dependent upon the Kansas Power and Light Company for electrical energy. It can be noted in Table 2 that the condensing unit should be retired at the conclusion of the 1974-75 academic year but, if KP&L can provide the power necessary to allow the turbine's withdrawal from service at an earlier date, it should be done. The cost of electricity produced by this unit currently exceeds the cost of purchased power (see Table 1).

The turbine sizes were selected such that the annual low pressure steam requirements of the campus could be met well in excess of 90% of the time by turbine exhaust alone, through January of 1984. This requires that the turbine(s) be capable of expanding 110,000 lb/hr for low pressure consumption. Therefore, an additional non-condensing turbine must have a throttle flow capacity of 38,000 lb/hr and the automatic extraction turbine capacity would be 115,000 lb/hr. The additional 5,000 lb/hr of flow in the extraction turbine is necessitated by the turbine's low pressure end, minimum allowable cooling flow requirements [17].

PROPOSAL CAA

Non-condensing Turbine-Generator
38,000 lb/hr throttle flow
225 psig   525°F   5 psig exhaust
2250 KVA Generator

Turbine-generator	$360,000
Installation	75,000

PROPOSAL CAB

Automatic, Single Extraction, Condensing Turbine-Generator
115,000 lb/hr throttle flow
Extraction: 35,000 lb/hr minimum; 110,000 lb/hr maximum
225 psig   525°F   5 psig extraction   3" Hg exhaust
7400 KVA Generator

Turbine-generator	\$700,000
Installation	100,000
Condenser	60,000
Cooling tower	12,000

CHAPTER V

AN ECONOMIC ANALYSIS OF THE PROPOSALS

The various proposals presented in the preceding chapter require the commitment of substantial amounts of capital to the power plant. Therefore, it is reasonable, particularly in a university where funds are difficult to acquire, to identify the manner in which these funds can be most effectively and/or efficiently utilized. For this reason, an economic analysis of the alternatives shall be performed. The analysis is intended to determine the comparative costs of the alternatives through 1983, but not the absolute costs.

The cost of energy is of paramount importance in this evaluation. The extreme instability of the energy market today requires that some basic assumptions be made. It shall be assumed that coal, oil and natural gas will be sold at an equal price to all consumers. The price for 1,000,000 Btu of heating value will be 35.07¢ on January 1, 1975, and it will increase by 5% (compounded annually) on January 1 of each year thereafter throughout the period under study, assuming an inflation rate of zero.

The costs associated with the chiller proposals can be broken into two major areas: fixed costs and operational expense. The fixed costs are defined as depreciation on, and supply and maintenance expense for, chillers, cooling towers and their auxiliary equipment (pumps, piping). The operational expense consists of the cost of energy required to operate the machines. The following assumptions were employed in the development of the cost figures used in the economic analysis.

1. Capital is available at 7% interest.
2. Equipment costs, in 1974 constant dollars, will remain static.
3. Cooling towers, absorption chillers and centrifugal chillers have an operational life expectancy of 30 years and no net salvage value.
4. Boilers have an operational life of 35 years and no net salvage value. Annual maintenance and supply expenses equal 8% of the unit price for both the boilers and the chillers.
5. Transportation and installation expense for a chiller is an additional 20% of the machine cost. This is also true for a boiler.
6. Auxiliary equipment cost for an absorption chiller cooling tower or a centrifugal chiller cooling tower is an additional 25% and 30% of the tower cost respectively.
7. A motor starting unit for centrifugal chiller costs an additional 10% of the machine price.

8. Annual maintenance and supply (including water and water treatment) expense for the cooling tower required by an absorption or a centrifugal machine is 8% and 10% of the tower's cost respectively.

The predicted energy costs for the single stage absorption machines may be based upon one of two steam consumption schemes. One utilized the chillers nominal steam rate and its load-steam rate relationship [1] in conjunction with the cooling load demand characteristics that are discussed on page 56. The other method relies on the 107.0 lb/f^2/year figure developed previously. Of the two methods, the latter one yields the greatest energy consumption figure and thus, it will be used to ensure the adequacy of the energy estimate. The product of the area served by a proposal at a given time and 107.0 lb/f^2/year equals the total chiller steam required by that proposal to operate for one cooling season. This product is then multiplied by the change in steam enthalpy per pound across a chiller (see Appendix B for development, this figure is assumed to be constant) and times the cost of a "useful Btu" (see Appendix B) at the time in question. The cost of a "useful Btu" as found on Table 1 is first updated to reflect the greater fuel prices of January 1, 1975, and then escalated in accordance with the 5% factor described earlier. It follows that:

Annual Energy Cost = (Area served by the proposal) x (107.0 lb/f^2/year) x (1025 Btu/lb) x (cost/useful Btu)

The energy requirements of the two-stage absorption machine in Proposal AAE are 35% less and the required heat rejection capabilities of its cooling tower are 20% less than those of a comparably sized single stage absorption unit [18]. Therefore, the 107.0 lb/f^2/year figure is reduced to 70.0 lb/f^2/year. With this modification, energy costs for Proposal AAE are calculated in the same manner as for the other steam absorption cold generators.

The method required to evaluate the energy expense of centrifugal chillers is more complex than that necessitated by the absorption machines. Not only must the total power consumption be determined, but the peaks of power demand must also be identified. This information is reduced to monthly energy requirements and then the cost of electricity is computed according to the billing procedures specified in the Kansas Power and Light Company's LP-64 schedule contract (see Appendix A).

Initially, it is necessary to determine the total power required by the centrifugal chillers for a given cooling season. To this end, it was determined by heuristic means that a base cooling load, a normal high load and a peak load would exist on the chillers for 60%, 30% and 10% of the 4776 hour-long cooling season respectively. With the peak cooling load taken to be 100%, the two lower loads are 70% and 44% of the peak. The peak cooling load incurred by a group of chillers in a given air conditioning season is equal to the chilling capacity (nominal tons) of the proposed machines for that given year times the appropriate capacity factor. The capacity factor is the ratio of the chiller capacity necessary to serve the existing new area (see Appendix C) to the proposal capacity existing at that same time. For example, the 1980 capacity of Proposal AAC is 3125 tons. The required capacity is 2015.7 tons and thus, the capacity factor is 0.645. Assuming a power factor of 1.0 for the chiller motor and capitalizing on the virtually linear relationship between chiller load and chiller electricity requirements [4], total annual energy requirements of a proposal's machines can be calculated as follows:

Annual Energy Consumed (kwhr) = Capacity factor x [477.6 hr x 1.00 x peak power (kw) + 1432.8 hr x 0.70 x peak power (kw) + 2865.6 hr x 0.44 x peak power (kw)]

The peak power requirements of the various individual centrifugal chillers can be found in the proposal presentations of Chapter IV [4]. Having identified the annual electrical power characteristics of the centrifugal chillers, the monthly consumption characteristics must be determined. Both the monthly air conditioning loads and the associated chiller power requirements are described in terms of their annual characteristics in Table 3.

TABLE 3

MONTHLY AIR CONDITIONING LOAD CHARACTERISTICS

	Apr	May	June	July	Aug	Sept	Oct
% of peak load [16]	13	17	50	100	83	50	33
% of peak power [4]	23	25	50	100	83	50	35
% of total load [16]	1	5	15	30	25	15	9
% of total power	1	5	15	30	25	15	9

The monthly power consumption of a proposal shall be defined as the product of the percentage figure in the last row of Table 3 and the annual electricity consumption term described previously. The monthly peak power of the chillers can be determined by again capitalizing on the load-power relationship of centrifugal chillers [4]. This monthly peak is the product of the capacity factor, the peak power percentage found in Table 3 and the power rating of the chosen proposal as listed in Chapter IV for a given year. Applying these definitions and relationships to the various proposals' yearly energy needs will resolve those requirements in such a fashion that the annual electricity cost can be calculated. It is assumed that the chillers are on a separate billing circuit from the remainder of the campus and that the LP-64 contract described in Appendix A will remain operative without modification.

In contrast to the energy costs that vary each year, the fixed costs remain unchanged for a given machine. The purchase price of the chiller, the cooling tower and all the associated equipment is combined with the cost of transporting and installing the machine. This total first cost is then depreciated by using a sinking fund factor for 7% interest and thirty years. To this annual depreciation expense, the estimated annual cost of supplies and maintenance is added, resulting in an annual fixed expense figure for each individual unit contained in each proposal. Another expense included in the analysis of the steam absorption chiller proposals after January 1, 1977, is the fixed cost associated with the proposed boiler addition. It was decided to charge the central campus proposals with 35% and 12% of the new boiler's depreciation expense (also calculated using a sinking fund) and supply expenditures respectively. The veterinary complex proposals were charged with 12% and 3% of the same two respective expenses. The total proportion of the boiler supply expense charged to air conditioning (15%) is low because makeup requirements in the cooling mode of operation are much less than those of the heating mode.

The economic analysis, using 1974 constant dollars, was performed with a base point of January 1, 1975. All expenses were treated as annual ones with no adjustment as to the time of year when they were incurred. All costs were determined on a calendar year basis resulting in a slight overstatement of costs in some instances. For example, in calculating the energy expense of 1975, the months of April and May are included in the energy consumption and cost computations when, in fact, the proposals indicate that the units are not operational until June 1. However, the magnitude of this error is very slight since these are the low load months. In any event, the same error is present in all of the computations and, because this analysis is comparative rather than absolute, it is trivial. The total annual costs of the various chiller proposals are presented in Table 4. It should be noted that these figures are in future dollars except where present worth is indicated. After examining the tabulated data, it is apparent that the steam absorption chiller proposals are less costly through 1983 than the corresponding proposals involving centrifugal machines, despite their greater first cost. The two-stage absorption machine is also less costly over time than a single stage unit of equal capacity.

The economic analysis of the power generation proposals will be directed toward the determination of generated electricity expense versus purchased electricity expense. This evaluation will recognize the investment costs of the turbine-generators but not the cost of steam generation facilities because the turbines will, in essence, use only that steam which would already exist to perform other functions. The cost of energy used by the turbines will be considered, as will the estimated maintenance and supply expenses. The

TABLE 4

TOTAL ANNUAL DOLLAR COSTS FOR CHILLER PROPOSALS

Proposal	Year	Chillers and Cooling Towers*	Energy	Boiler #8*	Present Worth of Costs
AAA	1975	$ 3,914.39	$ 3,559.45	$ 0.00	$ 7,473.84
AAA	1976	3,914.39	3,737.67	0.00	7,151.62
AAA	1977	10,103.44	13,017.08	1,969.33	21,913.47
AAA	1978	19,631.49	28,521.67	1,969.33	40,914.99
AAA	1979	19,631.49	30,325.54	1,969.33	39,614.22
AAA	1980	25,122.87	41,274.03	1,969.33	48,745.12
AAA	1981	30,614.25	52,505.41	1,969.33	56,694.79
AAA	1982	39,283.95	69,763.55	1,969.33	69,130.18
AAA	1983	48,812.00	92,459.99	1,969.33	83,366.45
				Total	$375,005.08
AAB	1975	$ 8,669.93	$ 3,559.45	$ 0.00	$ 12,229.38
AAB	1976	8,669.93	3,737.67	0.00	11,596.14
AAB	1977	8,669.93	13,017.67	1,969.33	20,661.96
AAB	1978	18,197.98	28,521.67	1,969.33	39,744.81
AAB	1979	18,197.98	30,325.54	1,969.33	40,035.78
AAB	1980	27,726.03	41,274.03	1,969.33	50,601.17
AAB	1981	27,726.03	52,505.41	1,969.33	54,770.37
AAB	1982	46,178.80	69,763.55	1,969.33	73,423.60
AAB	1983	46,178.80	92,459.99	1,969.33	81,833.92
				Total	$384,897.13

*This cost includes depreciation, supply and maintenance expense

-continued-

Proposal	Year	Chillers and Cooling Towers*	Energy	Boiler #8*	Present Worth of Costs
AAC	1975	$18,452.77	$ 3,559.45	$ 0.00	$ 21,012.22
AAC	1976	18,452.77	3,737.67	0.00	20,739.18
AAC	1977	18,452.77	13,017.08	1,969.33	29,205.78
AAC	1978	18,452.77	20,521.67	1,969.33	39,952.80
AAC	1979	18,452.77	30,325.54	1,969.33	39,715.37
AAC	1980	34,290.40	41,274.03	1,969.33	55,281.57
AAC	1981	34,290.40	52,505.41	1,969.33	59,144.20
AAC	1982	34,290.40	69,763.55	1,969.33	66,020.70
AAC	1983	44,562.00	92,459.99	1,969.33	80,892.95
				Total	$411,964.78
AAD	1977	$ 9,528.05	$15,697.78	$ 442.09	$ 22,418.36
AAD	1987	9,528.05	16,276.65	442.09	21,425.25
AAD	1979	9,528.05	17,306.06	442.09	20,809.01
AAD	1980	9,528.05	18,170.76	442.09	20,064.46
AAD	1981	9,528.05	19,076.87	442.09	19,354.02
AAD	1982	9,528.05	20,029.29	442.09	18,680.64
AAD	1983	9,528.05	21,030.18	442.09	18,022.19
				Total	$140,793.93
AAE	1977	$10,905.93	$10,269.58	$ 442.09	$ 18,880.81
AAE	1978	10,905.93	10,648.27	442.09	17,955.57
AAE	1979	10,905.93	11,321.72	442.09	17,294.74
AAE	1980	10,905.93	11,886.97	442.09	16,566.55
AAE	1981	10,905.93	12,480.19	442.09	15,876.74
AAE	1982	10,905.93	13,103.27	442.09	16,289.50
AAE	1983	10,905.93	13,758.06	442.09	14,611.74
				Total	$117,475.65

-continued-

Proposal	Year	Chillers and Cooling Towers*	Energy	Boiler #8*	Present Worth of Costs
ABA	1975	$ 3,719.01	$ 6,275.68	$ 0.00	$ 9,994.69
ABA	1976	3,719.01	6,375.53	0.00	9,434.36
ABA	1977	8,988.20	18,242.80	0.00	23,783.56
ABA	1978	16,831.83	37,081.28	0.00	44,009.35
ABA	1979	16,831.83	37,873.32	0.00	41,734.56
ABA	1980	21,618.50	49,887.15	0.00	50,983.53
ABA	1981	26,405.17	61,592.18	0.00	58,632.63
ABA	1982	33,920.04	81,593.39	0.00	71,930.21
ABA	1983	41,763.67	104,219.45	0.00	84,962.18
				Total	$395,465.07
ABB	1975	$ 7,514.87	6,070.09	0.00	$ 13,584.96
ABB	1976	7,514.87	6,161.95	0.00	12,782.36
ABB	1977	7,514.87	17,295.88	0.00	21,669.71
ABB	1978	15,358.50	36,482.90	0.00	42,318.13
ABB	1979	15,358.50	37,259.19	0.00	40,142.04
ABB	1980	27,331.64	48,554.52	0.00	54,106.83
ABB	1981	27,331,64	60,505.43	0.00	58,525.84
ABB	1982	39,304.78	80,100.72	0.00	74,353.80
ABB	1983	39,304.78	102,290.78	0.00	82,408.62
				Total	$399,892.29
ABC	1977	$ 8,888.39	$ 19,295.14	0.00	$ 24,615.49
ABC	1978	8,888.39	19,685.58	0.00	23,324.93
ABC	1979	8,888.39	20,073.77	0.00	22,095.23
ABC	1980	8,888.39	20,537.54	0.00	20,980.62
ABC	1981	8,888.39	20,998.88	0.00	19,913.89
ABC	1982	8,888.39	21,460.31	0.00	18,898.14
ABC	1983	8,888.39	21,974.98	0.00	17,962.48
				Total	$147,790.78

turbine-generators of Proposals CAA and CAB shall have an overall efficiency of 80%, regardless of the steam flow rate [17]. The turbine expansion curves, as plotted on a Mollier diagram, are assumed to be straight lines. It is also assumed that both of the proposed turbines will have an operational life of 30 years and that their respective maintenance and supply expenses are \$8,000 and \$10,000.

It is assumed that the non-condensing turbine of Proposal CAA will be operated on a continuous, fully loaded basis. The existing non-condensing turbines will be operated when low pressure steam requirements significantly exceed 38,000 lb/hr. With 100% throttle flow, the turbine-generator can produce, at a heat rate of 4266 Btu/kwhr, 1700 kw during the summer months and 1790 kw when the plant is in the heating mode of operation. The reduced electricity production of the turbine-generator during the summer is due to the difference in the power provided by the prime mover to the generator, which is the result of changing the turbine exhaust pressure from 5 psig to 7 psig. For the expected annual generation of 15,250,560 kwhr, the investment cost is \$249.87/kw. Using the heat rate above and the "useful Btu" cost for 1975, the energy cost charged to the turbine would be \$32,483.90 for the 1975-76 academic year. The total annual cost of the turbine-generator would be the sum of the fixed costs and the operating expenses, \$45,094.90. Assuming this entire amount of electricity could be purchased from the Kansas Power and Light Company at the lowest energy cost of $.006/kwhr, the energy charge would be $114,531.70 after compensating the energy billing rate for the greater fuel costs of 1975. It follows that Proposal AAC represents a potential savings of $69,436.80, and a return on investment of 15.96%.

The automatic extraction turbine-generator of Proposal CAB essentially has two heat rates: one for the steam that is extracted for distribution in the low pressure header, and another for that steam which flows completely through the turbine and into the condenser. Those two heat rates are 4266 Btu/kwhr and 14,071 Btu/kwhr respectively. Therefore, the extracted flow should be maximized and the "back-end" flow should be minimized. Accordingly, the analysis will be developed assuming that the throttle flow will be such that the low pressure steam requirements are fulfilled by the extraction steam and that the "back-end" flow will be maintained at the lowest allowable level of 5000 lb/hr. Using the annual air conditioning load characteristics discussed previously (assuming steam absorption chillers are in use), the annual heating load characteristics (a heuristic determination: 100% of the peak load, 5% of the heating season; 63% of the peak load, 70% of the heating season; 52% of the peak load, 25% of the heating season), the projected heating and cooling loads of the 1975-76 academic year, and the operating philosophy explained above, the extraction turbine-generator will produce 28,082,022 kwhr.

$$KWHR = \frac{(EF \times h_1) + (CF \times h_2)}{3413 \text{ Btu/kwhr}}$$

where EF = Extraction flow, lb
CF = Condenser flow, lb

Summer: $h_1 = 152.56$ Btu/lb $h_2 = 254.82$ Btu/lb

Winter: $h_1 = 160.65$ Btu/lb $h_2 = 254.82$ Btu/lb

This electricity will be produced with a weighted average heat rate of 5625.6 Btu/kwhr. With this heat rate and the 1975 cost of a "useful Btu", the energy cost for operating the turbine is $78,878.48. The total annual cost of the turbine-generator is $98,121.68 for the academic year 1975-76. If the 28,082,022 kwhr of power were purchased, the minimum possible energy charge under the LP-64 contract schedule would be $210,895.98. The resultant savings of Proposal CAB would be $112,774.38, yielding a return on the investment of 12.93%. It must be recognized that this financial data presents the proposal in its least favorable light because, as the low pressure steam demand grows each year and the generation of electricity consequently increases, the weighted average heat rate will decline and the return on investment factor will increase substantially.

CHAPTER VI

RECOMMENDATIONS AND CONCLUSIONS

Having determined the financial aspects of the various proposals to meet the heating, cooling and electricity requirements of the campus, the results of the analysis must be evaluated. Futhermore, those characteristics of the proposals that do not readily lend themselves to quantification or are not acknowledged by the economic analysis of Chapter V must also be recognized and their significance as to the overall desirability of a particular proposal appraised. In brief, engineering judgment must be exercised before any given proposal can be labeled as the recommended one.

It was suggested in Chapter IV (in Proposal BAA) that a new boiler be added to the power plant to augment the existing steam generation capacity. Steam production is a vital operation on this campus and, as was noted previously, the capacity and reliability of the current units become increasingly suspect with the passage of time. Therefore, it would be the recommendation of this report that Proposal BAA be accepted.

An evaluation of the chiller proposals is a more complex task. The economic analysis of Chapter V indicates that the total costs of absorption machines are less than those of comparable centrifugal machines through 1983. It should be noted that this total expense difference will increase for evaluation periods beyond 1983 because the annual expense of absorption chillers becomes progressively smaller relative to the annual costs of centrifugal machines. This fact further enhances the initial desirability attributed to the absorption chillers because they utilize the same facilities (boilers, etc.) that are necessary to heat the campus rather than requiring the addition of substantial amounts of electrical equipment. Therefore, it is suggested that absorption refrigeration chillers be purchased to satisfy the air conditioning needs of future campus buildings.

Concluding that the electrically driven centrifugal machine is the less attractive alternative for Kansas State's applications, the problem becomes one of selecting a specific absorption proposal. Designating Proposal AAA (the small, single stage absorption machines that are added frequently) as the most desirable one on the basis of its lowest cost, as shown on Table 4, would not be justified. Although Proposal AAA is the least expensive alternative through 1983, Table 4 does not indicate which proposal is the least costly over the 30 year life of the equipment. The lesser fixed cost expense of Proposal AAB will negate the $9,892.05 advantage of Proposal AAA during the year 1992. Thereafter, Proposal AAB will have a lower total cost (life to date) than Proposal AAA. The largest, single stage absorption machines (Proposal AAC) have fixed costs that are substantially less than those of

Proposal AAA. Consequently, of the \$36,959.70 difference in cost as stated in Table 4, all but \$9,599.82 will have been amortized by the conclusion of the expected operational machine life. Because the financial characteristics of the various absorption proposals are actually not as divergent as they initially appear to be, the qualitative aspects of proposal evaluation become more salient.

From an operational standpoint, it is easier to properly control and balance the load between two or three chillers versus six or seven. The probability of equipment failures, and thus the associated expense and inconvenience of repairs, increases with the number of machines operating. It is also probable that with fewer machines to service, the quality of maintenance on a given unit would be higher than that which would exist if more machines were in the plant. It is very possible that the installation expense for chillers was underestimated and that this cost, on a dollar per unit of chiller capacity basis, would be substantially less for large units. This would reduce the relative computed cost of the large unit proposals to the small machine proposal. The administrative expense of not only operating the lesser number of units, but also of petitioning the Board of Regents and the State Legislature for funding less frequently favors Proposal AAC. And finally, aesthetic considerations support the installation of as few chillers and cooling towers as possible, for construction invariably destroys (temporarily, at least) the natural beauty of the campus as well as disrupting normal collegiate activities. Therefore, it is recommended that Proposal AAC be adopted to provide the chiller capacity to air condition the additional central campus buildings through 1983.

The economic analysis of the veterinary complex proposals does provide the basis for a decision. Proposal AAE, the two-stage absorption cold generator, should be accepted, for it is distinctly less costly to operate. It follows that the two-stage machine would also be the most desirable equipment for central campus cooling if the operation of turbine-generators was no longer possible.

It is the recommendation of this study that Proposal CAB, the automatic extraction turbine-generator, be adopted. The analysis of Chapter V indicates conclusively that campus power generation is less costly than purchasing electricity, even if it could all be bought at the lowest energy rate, which is unlikely. The decision to recommend Proposal CAB in preference to the non-condensing turbine was multifaceted. If additional generation capacity is to be incorporated in the power plant, the magnitude of such an addition should be great enough to carry a large part of the campus load. The economy of scale factor certainly favors the automatic extraction unit for its investment cost is $157 per kw (at maximum production) while the non-condensing turbine requires nearly $250 per kw. As was mentioned in Chapter V, the larger turbine-generator will have a greater annual return on investment as time progresses (23.5% in 1983) while Proposal CAA will exhibit a constant rate of return. Another significant benefit from the operation of the condensing, automatic extraction turbine would be the virtual elimination of venting steam to the atmosphere. This reduction of heat and water waste would realize substantial savings for the power plant. Finally, Proposal CAA assumes that the two existing non-condensing turbines will continue to operate into the 1980's. In view of their age, this assumption is questionable.

The economic feasibility of an on-site power generation facility has been demonstrated. The potential educational value to students of a complete, small-scale power plant is noteworthy in the age of the energy crisis. The University's ability to function without total dependence on a commerical utility is laudable, as the local power outage of December 4 and 5, 1973, demonstrated. Although additional study is required to precisely determine the most desirable type of equipment, the possibility of expanding the power generation capabilities of Kansas State University should be actively pursued.

APPENDIX A

The billing procedures associated with a Kansas Power and Light Company Contract - Schedule LP-64 are as described below:

Capacity Charge:

$1.40 per KVA for the first 175 KVA of the billing capacity.
$1.10 per KVA for the next 425 KVA of the billing capacity.
$0.90 per KVA for all additional KVA of the billing capacity.

Energy Charge:

1.25¢ per KWHR for the first 50 KWHR per KVA of billing capacity.
0.90¢ per KWHR for the next 100 KWHR per KVA of billing capacity.
0.70¢ per KWHR for the next 250 KWHR per KVA of billing capacity.
0.60¢ per KWHR for all additional KWHR.

Fuel Adjustment:

For each 0.1¢ by which the weighted average cost of fuel, and associated costs, burned by the Company's generating stations during the second calendar month preceding the billing month exceeds or is less than 22¢/1,000,000 Btu, the energy charge shall be increased or decreased by the product of .000001 and the weighted average efficiency of the stations in said calendar month expressed in Btu input/KWHR of net generation.

Billing Capacity:

It is the customer's average KVA load during the 30 minute period of maximum use during the month provided that the capacity shall be in no case less than 175 KVA.

$$\text{Billing Capacity (KVA)} = \frac{\text{Maximum capacity (KW)}}{\text{Power factor}}$$

Appendix B

For the purpose of allocating energy consumption and subsequent costs among the various functions performed by the power plant, the systems can be visualized as shown in Figure 22. The power plant is represented as a closed system with heat values attributed to each of the externally beneficial operations of the plant - i.e., operations that occur to support the power plant itself are assigned a value of zero. The heat that is consumed in these externally beneficial operations shall be labeled "useful Btu's".

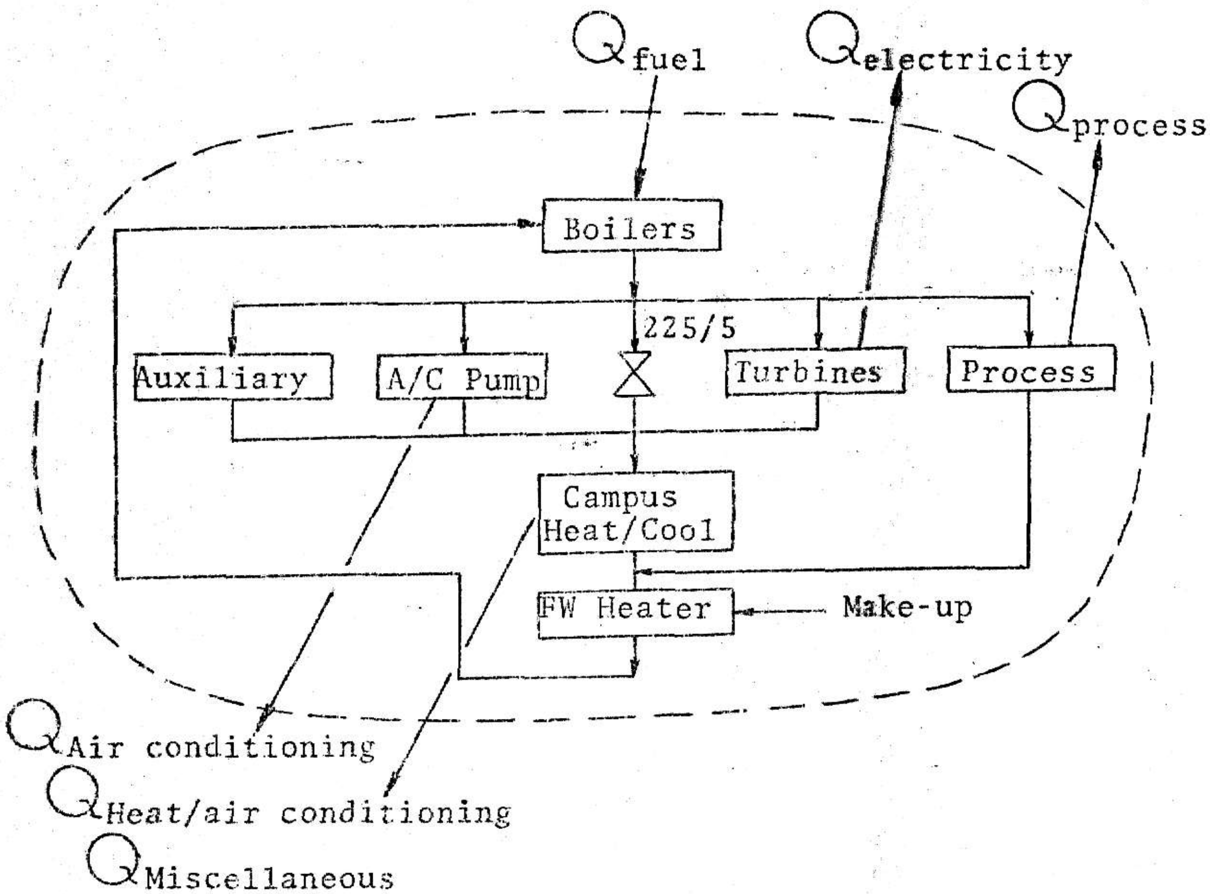


FIGURE 22.
A Thermodynamic System Representation of the Power Plant

The dotted line represents the system boundaries and the arrows indicate the various externally beneficial operations, as well as the addition of fuel to the system. Energy consumption of the various operations is calculated by multiplying the steam flow rate of that operation by the change in specific enthalpy of the steam across that operation. The total steam enthalpy change is the product of total steam production and the specific enthalpy difference of steam entering and leaving the boilers. The sum of the heat values of the operations shown on Figure 22 will be less than the total enthalpy increase of working fluid in the boiler because energy consumption of internal power plant operations (auxiliary steam to operate the boiler feedpumps) is not recognized. The heat content of fuel added to the system exceeds the enthalpy added to the system by the boilers because the boilers are only 75-80% thermally efficient, at best [13].

Prior to the development of cost figures, the enthalpy change incurred during the various functions must be determined. The developments that follow are based upon 24 hour operational data found on Table 1 of Chapter I.

A. Turbine-Generator:

$$\Delta h\ (\text{Btu/lb}_m) = \frac{(3413\ \text{Btu/kwhr}) \times \text{KWHR produced}}{\text{Steam flow } (\text{lb}_m) \times \text{Turbine efficiency}}$$

Assume generator efficiency is 100%.

Turbine efficiencies [2]:

Unit #1	68%
Unit #2	75%
Unit #3	70%

The following Δh (Btu/lb_m) values can be determined:

	1/8/73	1/22/73	7/2/73	7/23/73
Δh_1	--	--	223.48	215.64
Δh_2	163.09	181.92	162.59	215.64
Δh_3	--	176.57	183.60	160.47

B. Auxiliary Steam (Boiler Feedpump)

Where: $v_{f_1} = 0.0168\ f^3/lb_m$ @ 222°F, $\Delta p = 285$ psi

$$\text{Pump work} = v_{f_1} \Delta p$$

$$= 0.8862\ Btu/lb_m$$

Pump efficiency [11] = 50%
Turbine efficiency [2] = 32%
Overall efficiency = 16%

In an effort to minimize the apparently random variations in steam flow to the boiler feedpump driving turbines, the flow data for 1/22/73, 7/2/73 and 7/23/73 was combined. The data for 1/8/73 was deleted because oil was burned that day and thus the auxiliary steam requirements were affected.

It follows that:

$$\Delta h = \frac{0.8862\ Btu/lb_m \times \text{Steam Production } (lb_m/24\ hr)}{0.16 \times \text{Auxiliary Steam Flow } (lb_m/24\ hr)}$$

$$= 144.35\ Btu/lb_m$$

C. The Trane Pump

Where: $v_{f_1} = 0.01602\ f^3/lb_m$ @ 50°F, $\Delta p = 10$ psi

$$\text{Pump work} = v_{f_1} \Delta p$$

$$= 0.02966\ Btu/lb_m$$

$$= 928{,}780.4\ Btu/24\ hr$$

(Assuming a constant 2620 gpm is circulated in the chilled water dirtirbution loop)

Pump efficiency [11] = 83%
Turbine efficiency [2] = 23%
Overall efficiency = 19%

Substituting the sum of the two summer days' data into:

$$\Delta h = \frac{2(928{,}780.4 \text{ Btu}/24 \text{ hr})}{\text{Pump turbine steam flow } (\text{lb}_m/24 \text{ hr}) \times \text{overall efficiency}}$$

$$= 23.78 \text{ Btu}/\text{lb}_m$$

D. The 225/5 psig reducing valve is assumed to be a perfect throttling device.

E. The 90/5 psig reducing valve is assumed to be a perfect throttling device.

The enthalpy of the steam in the low pressure header can be calculated by using a single mass-energy balance. The enthalpy of the steam is known as it leaves the boilers, and the enthalpy changes of the steam through the various paths to the low pressure header have been identified above. Therefore, the enthalpies of the various flows into the low pressure header are known. The result of such an energy balance, the low pressure header steam enthalpy, is:

January 08, 1973	$h = 1201$ Btu/lb_m
January 22, 1973	$h = 1141$ Btu/lb_m
July 02, 1973	$h = 1125$ Btu/lb_m
July 23, 1973	$h = 1132$ Btu/lb_m

The specific enthalpy change for steam in process use and in heating or air conditioning systems can be determined if the enthalpy of the condensate returning to the plant is known.

	Condensate h_f	Heat/Cool Δh	Process Δh
1/08/73	97 Btu/lb_m	1104 Btu/lb_m	1173 Btu/lb_m
1/22/73	98 Btu/lb_m	1043 Btu/lb_m	1185 Btu/lb_m
7/08/73	108 Btu/lb_m	1017 Btu/lb_m	1162 Btu/lb_m
7/23/73	108 Btu/lb_m	1024 Btu/lb_m	1158 Btu/lb_m

There is an additional aspect of campus steam use that has not been recognized by the preceding comments. It will be recalled that some of the low pressure steam distributed to campus is not employed in building environmental control. An estimated figure 125,000 lb_m/day was used to compensate the cooling figures for these extraneous uses and it shall be termed miscellaneous flow.

In Table 5 that follows, the daily energy consumption and the daily cost of the various power plant functions are tabulated for the two "typical" operating days. The energy consumption term is calculated by taking the product of the steam flow through a process and the specific enthalpy change of steam across that process. Costs are determined by multiplying the energy consumption term by the ratio of total daily fuel costs to the sum of the heat values of the externally beneficial power plant operations.

TABLE 5

COSTS AND ENERGY CONSUMPTION OF INDIVIDUAL FUNCTIONS

	January 22, 1973		July 23, 1973	
	Energy used (Btu x 10^8)	Cost (Dollars)	Energy used (Btu x 10^8)	Cost (Dollars)
#1 Turbine	0	$ 0	1.5633	$ 74.57
#2 Turbine	1.5609	71.22	0.9921	47.32
#3 Turbine	0.4290	19.58	0.3169	15.12
Absorption chillers	0	0	8.6873	414.38
Heating	16.5348	755.40	0	0
Miscellaneous	1.3038	59.49	1.2800	61.05
Process	2.7018	123.28	2.2095	105.39
Trane pump	0	0	0.0479	2.29
Veterinary complex	0	0	0.8338	39.77
Total	22.5503	1,028.97	15.9308	759.89
Fuel	30.3672	1,028.90	22.6758	759.98

APPENDIX C

The addition of new buildings to the campus requires that more chiller capacity be obtained. It was found that 293 square feet are currently cooled by one ton of chiller capacity. This same relationship, 293 f^2/ton, was applied to the projected campus area increases to determine the necessary additional chiller capacity.

TABLE 6

A TABULATION OF NEW BUILDING AREA AND THE REQUIRED CHILLER CAPACITY

	Total Additional Area After 1974 (f^2)		Total Required Capacity (tons)	
Year	Central Campus	Vet Complex	Central Campus	Vet Complex
1975	65,600	0	223.9	0
1976	65,600	0	223.9	0
1977	215,600	260,000	735.8	887.4
1978	455,600	260,000	1,554.9	887.4
1979	455,600	260,000	1,554.9	887.4
1980	590,600	260,000	2,015.7	887.4
1981	715,600	260,000	2,442.3	887.4
1982	905,600	260,000	3,193.2	887.4
1983	1,143,100	260,000	4,003.8	887.4

APPENDIX D

The costs of delivered and erected cooling towers required for the various proposals contained in Chapter IV may be found below. The first stated price is that of the cooling tower itself and the second cost listed is that of the required concrete basin. All prices are in 1974 constant dollars.

Proposal AAA

June 1, 1975	$ 9,000 + 3,200
June 1, 1977	14,200 + 4,100
June 1, 1978	25,700 + 8,000
June 1, 1980	13,900 + 3,900
June 1, 1981	13,900 + 3,900
June 1, 1982	22,600 + 6,800
June 1, 1983	25,700 + 8,000

Proposal AAB

June 1, 1975	$ 22,600 + 6,800
June 1, 1978	25,700 + 8,000
June 1, 1980	25,700 + 8,000
June 1, 1982	48,200 + 16,100

Proposal AAC

June 1, 1975	$ 48,200 + 16,100
June 1, 1980	43,000 + 13,700
June 1, 1983	28,600 + 8,700

Proposal AAD

June 1, 1977	$ 25,700 + 8,000

Proposal ABA

June 1, 1975	$	6,000 + 1,800
June 1, 1977		10,500 + 3,600
June 1, 1978		15,700 + 4,700
June 1, 1980		8,000 + 2,700
June 1, 1981		8,000 + 2,700
June 1, 1982		14,500 + 4,300
June 1, 1983		15,700 + 4,700

Proposal ABB

June 1, 1975	$	14,500 + 4,300
June 1, 1978		15,700 + 4,700
June 1, 1980		22,900 + 7,100
June 1, 1982		22,900 + 7,100

Proposal ABC

June 1, 1977	$	16,600 + 5,100

LIST OF REFERENCES

1. "Absorption Cold Generators", Technical Data Publication No. DS-ABS1, The Trane Company, La Crosse, Wisconsin.

2. Church, Edwin F., "Turbine Performance". Steam Turbines, 3rd Edition. McGraw-Hill Book Company, Inc., New York, 1950, 458-459.

3. DeGarmo, E. P., Engineering Economy, 4th Edition. The MacMillan Company, Toronto, Ontario, 1969.

4. "Direct Drive CenTraVac", Technical Data Publication No. DS-CTV-1, The Trane Company, La Crosse, Wisconsin.

5. Elgard, O. I., Electric Energy Systems Theory, McGraw-Hill Book Company, Inc., New York, 1971.

6. Furner, Blair O., "Campus Utility Costs". Heating, Piping, Air Conditioning, November, 1973.

7. Gerritz, Ellsworth M., Dean of Admissions and Records, Kansas State University, A private conversation with the author, October 1, 1973.

8. Jordan, Richard C. and Gayle B. Priester, "Absorption Refrigeration and Chemical Dehumidification", Refrigeration and Air Conditioning, Prentice-Hall, Inc., New York, 1948, 337-355.

9. Kansas State University Planning Staff, William Hale Associates and Oblinger-Smith Corporation, "Status Report to the Kansas Board of Regents - Long-Range Campus Planning", Kansas State University, Fall, 1973.

10. Kansas Power and Light Company Electricity Contract, Schedule LP-64.

11. Mechanical Engineers Handbook, Lionel S. Marks, editor, 50th Edition. McGraw-Hill Book Company, Inc., New York, 1951, 458-459, 773, 1853.

12. Mullick, Satinder K., John C. Chambers and Donald D. Smith, "How to Choose the Right Forecasting Technique". Harvard Business Review, July-August, 1971, 45-74.

13. "Packaged Water Tube Boilers", Technical Data Publication No. SP-BLR1, The Trane Company, La Crosse, Wisconsin.

14. Skrotzki, B. G. A. and William A. Vopat, Applied Energy Conversion, McGraw-Hill Book Company, Inc., New York, 1945.

15. Solberg, Harry L., Orville C. Cromer and Albert R. Spalding, Elementary Heat Power, John Wiley and Sons, Inc., New York, 1946.

16. Stoecker, W. F., "Absorption Refrigeration". Refrigeration and Air Conditioning, McGraw-Hill Book Company, Inc., New York, 1958, 172-184.

17. Studniarz, J. J., Power Generation Sales Engineer, The General Electric Company, Kansas City, A private conversation with the author, March 7, 1974.

18. "Two-Stage Absorption Cold Generator", Technical Data Publication No. TS-ABS2, The Trane Company, La Crosse, Wisconsin.

19. Wallace, Douglass S., Registered Professional Engineer, Burgess, Latimer and Miller Engineers, Topeka, A private conversation with the author, December 7, 1973.

20. Wark, Kenneth, Thermodynamics, McGraw-Hill Book Company, Inc., New York, 1966.

21. Wheelwright, Steven C. and Spyros Makridakis, Forecasting Methods for Management, John Wiley and Sons, Inc., New York, 1973.

ACKNOWLEDGEMENTS

The author wishes to express his sincerest appreciation to his co-major advisors, Dr. Robert L. Gorton and Professor Robert E. Crank, both of the Mechanical Engineering Department. Their continuous guidance and encouragement was of tremendous assistance to the author. Sincere gratitude is also extended to Professor Jacob J. Smaltz of the Industrial Engineering Department for serving on the advisory committee.

VITA

Donald Conway Gray II

Candidate for the Degree of

Master of Science

Thesis: AN ENGINEERING AND ECONOMIC ANALYSIS AND A TEN YEAR PLAN FOR EXPANSION OF A UNIVERSITY POWER PLANT

Major Field: Mechanical Engineering

Biographical Data:

Personal: Born on July 26, 1951, in Kansas City, Missouri; the son of Donald C. and Jean M. Gray.

Educational: Graduated from Shawnee Mission South High School in June of 1969; awarded the degree Bachelor of Science in Mechanical Engineering, Magna Cum Laude, by Kansas State University on May 11, 1973; completed the requirements for a Master of Science degree in May 1974.

Professional: Phi Kappa Phi, Tau Beta Pi, Pi Tau Sigma, Sigma Tau, Phi Eta Kappa, American Society of Mechanical Engineers; employed by the Power Division of Black and Veatch Consulting Engineers for the summers of 1971 through 1973.

AN ENGINEERING AND ECONOMIC ANALYSIS AND A TEN YEAR PLAN FOR EXPANSION OF A UNIVERSITY POWER PLANT

by

DONALD CONWAY GRAY II

B. S., Kansas State University, 1973

AN ABSTRACT OF A MASTER'S THESIS

submitted in partial fulfillment of the

requirements for the degree

MASTER OF SCIENCE

Department of Mechanical Engineering

KANSAS STATE UNIVERSITY
Manhattan, Kansas

1974

ABSTRACT

This thesis is concerned with an examination and analysis of the existing Kansas State University Power Plant and the functions it performs for this campus. The campus utility demand characteristics were identified as well as the plant's working characteristics for both the cooling and heating modes of operation.

The heating, cooling and electrical demands of the campus and their effects on the power plant were forecast through the 1983-1984 academic year by means of identifying historical trends of and correlations between the demands themselves and between influencing parameters such as student enrollment and campus area. Subsequent to the prediction of the indicated campus needs, several alternatives were suggested as viable methods to satisfy those demands. The various proposals were subjected to an engineering economic analysis and, after an evaluation of those results and additional qualitative evaluatory parameters, specific recommendations for the expansion of the power plant's capacity were presented.