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USE OF STEAM-ELECTRIC POWER PLANTS TO PROVIDE THERMAL ENERGY TO URBAN AREAS

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CIVIL DEFENSE RESEARCH PROJECT

U.S. DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

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Contributions to this study of the urban use of waste heat from electric generating plants were made by some 25 members of the staff of the Oak Ridge National Laboratory, several people from other installations in Oak Ridge, and a few consultants. The program coordinator spent most of his time on the study for two years; several other staff members gave large fractions of their time to the program, and the expertise of more than 20 other people was brought to bear on the study for occasional periods.

The impetus to investigate the city as a consumer of heat from the power plants came from S. E. Beall, who continued thereafter to provide advice and to make suggestions regarding the content of this report. Many most helpful suggestions and opinions were received during the course of the study from J. W. Megley of the International District Heating Association and the Boston Edison Company. Much appreciated assistance in evaluating the performance of absorption air-conditioning equipment was provided by S. E. Johnson of the Carrier Air Conditioning Company. P. L. Geiringer of Paul L. Geiringer and Associates reviewed a draft of the report and provided us with a detailed and most informative critique. Many valuable comments were offered by members of the staff of the Philadelphia Electric Company based on their review of a draft. Most contributors to the study are specifically identified in the body of the report. Among those whose contributions are not so designated and to whom acknowledgment is due are G. W. Renfro, I. K. Namba, R. K. Sood, G. Morris, F. T. Snyder, G. A. Cristy, and W. J. Muenzer.

ABSTRACT

This study has shown that with coordinated planning of energy centers and new cities, it would be feasible to provide thermal energy from steam-electric power plants to urban areas. With nuclear plants the siting with respect to nearby populations could be in accordance with present-day practice.

An analysis was made of a 1980 reference city of 389,000 people with a climate similar to that of Philadelphia. Thermal energy extracted from the turbines of a generating plant that employed light-water reactors would be used for providing space heat, hot water, and air conditioning for the commercial buildings and the two-thirds of the city's inhabitants who lived in three-story apartment buildings. The apartment areas were considered to have an average population density of 21,500 people per square mile in one arrangement and 14,333 people per square mile in an alternate layout. Heat would also be supplied for manufacturing processes and desalting sewage plant effluent for reuse. The use of heat in the reference city would reduce the average heat rejected to the plant's cooling water to about 63% of that which would be rejected from a single-purpose plant, and this heat rejection would be reduced to 21% of that from a single-purpose plant during the period of maximum heat consumption in the summer.

The cost of distributed hot water in the reference city was estimated to be 142.5¢/MBtu, which is competitive for most U.S. cities. The estimate was based on current (1968-1970) costs escalated 4% per year during a five-year period of construction, a 14% annual fixed-charge rate, and a charge to the consumers for electricity equal to that which would have been incurred from building a single-purpose plant that produced the same amount of electricity as the energy center. With the charge for hot water for absorption air conditioning set at 79¢/MBtu, in order to equal the energy cost for compression systems supplied with 16 mills/kwhr electricity, the cost for space heating and domestic hot water would be 198¢/MBtu. If the plant cooling water were used to heat and air condition greenhouses, the cooling towers would be eliminated, and with no charge at all for greenhouse heat, the cost of heat for the city would be slightly reduced.

With a city of 194,500 people sited closer to its energy center, the cost of space heat would be reduced from 198¢/MBtu to 181¢/MBtu. The cost of space heating in the northern states would be about 170¢/MBtu and rather insensitive to air-conditioning charges. In southern cities the space- and water-heating costs would be higher and more sensitive to the changes in the air-conditioning charge. In the very southern portions of the country the system appeared to be competitive only in those areas that had electricity costs for air conditioning of 20 mills/kwhr or higher.

It was also determined that heat from the generating plants might be used for urban vehicle propulsion and snow melting.

This study convincingly shows the feasibility of serving new cities with heat from a central atomic power station thus reducing air and water pollution. In consideration of the urgency of the present pollution and conservation problems, it is believed that it would be worthwhile at this point to select an existing city for a similar conceptual design study that would determine specific applications and uses of thermal energy, develop an implementation plan, and carry out an economic analysis.

It is concluded that there should be a national effort to determine specifically where new power plants could be sited to provide low-cost thermal energy, as well as electricity to new cities and existing urban areas.

SUMMARY

Objectives

The purpose of this study for the Department of Housing and Urban Development was to determine the feasibility of providing thermal energy, as well as electricity, to urban areas from steam-electric power plants. The economic feasibility is based simply on electricity and heat costs; no cost credits were taken for reductions in environmental pollution.

Since the conversion of heat to work is never complete, part of the energy supplied to the power plant turbine, often as much as two-thirds, must be rejected to the power plant cooling water as heat rather than being converted into electricity. There are strong incentives to beneficially use this large amount of heat that is normally wasted at less than 100°F and also to use heat extracted from the turbine at somewhat higher temperatures. For many heat-consuming processes the use of rejected or extracted heat would conserve all or part of the fossil-fuel that would otherwise have to be burned in order to provide the heat. Such uses of heat would eliminate the atmospheric pollution from gases and particulates caused by the additional combustion process and also avoid the accompanying heat addition to the biosphere. Large amounts of heat can be used for absorption air conditioning. Although there would be little effect on the total heat release to the biosphere (as compared to using electric-compressive systems), the heat release would be spread to many buildings where air-conditioning equipment was in operation. Thus the amount of heat thrown away at the steam-electric plant would be greatly reduced. These considerations of resource conservation and environmental improvement are principal elements in this study of the use of thermal energy from steam-electric power plants.

Heat-electric systems, their efficiencies, and heat rejection characteristics are examined first. The consumption of heat in several applications is then discussed in some depth. Information is presented on the siting of nuclear stations, their reliability, and costs. Finally, all this information is integrated in a highly conceptual "new city" with light-water reactors in an "energy center" supplying heat and electricity

for the city's needs. A conceptual new city was chosen rather than an existing city to avoid the problems of renovating an existing city. The resulting new city information is directly applicable to planned expansions of existing cities and also provides baseline data with which to approach more complex problems. Since there was time to deal with only one or the other, the new city was the reasonable choice. Light-water reactors were used to avoid dealing with the problems of atmospheric pollutants from a fossil-fueled plant. However, the information on heat consumers, their requirements, and the conclusions on the uses for heat generally apply to any other heat generator, regardless of its source of energy.

Heat-Electric Systems

There are two modes of making use of the heat from the steam electric plant — at normal cooling-water temperatures in the region of 95°F for functions such as greenhouse heating, or by extraction of steam from the turbine at higher temperatures (after it has made some electricity) in order, for example, to provide manufacturing process heat or for heating and cooling buildings. Figure I is a schematic diagram of a heat-electric system illustrating applications considered in a reference city study.

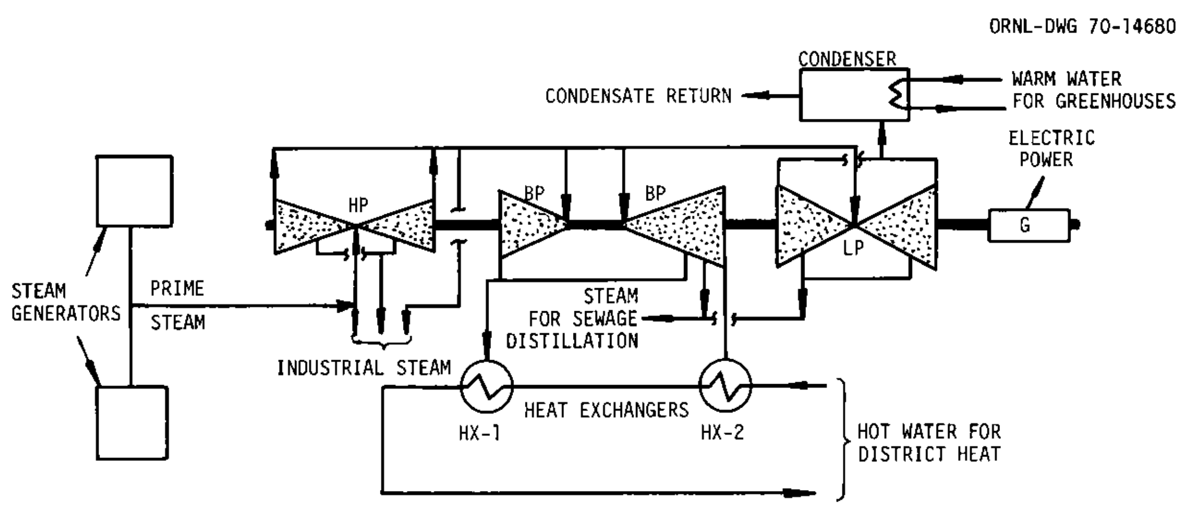

Fig. I. Schematic Arrangement of a Heat-Electric System.

Steam extraction is a typical heat-electric operation that is employed in some of the country's larger district heating systems. Withdrawal of high-temperature steam does, of course, reduce the electrical efficiency of the plant, but of greater importance is the fact that it increases the overall efficiency of energy utilization. The heat rejections at the condenser from single-purpose installations employing the best large fossil-fueled plants (FFP), advanced nuclear reactors under development (AR),* and light-water reactors (LWR) are approximately 53, 53, and 66%, respectively, of the energy input in the turbine. Figure II illustrates the reductions in thermal rejection at the condenser achieved by the use of heat-electric systems with these power plants. It can be seen that the thermal rejection at the condenser is eliminated when the steam allocation ratio is 1 and the temperature of the withdrawn steam is the normal condensation temperature of 95°F (i.e., complete beneficial use of waste heat). Figure III mainly illustrates how the thermal rejections at the condenser are eliminated by withdrawing all the steam from the turbine at temperatures higher than 95°F (i.e., back-pressuring) and employing steam allocation ratios greater than 1.

Energy Utilization Studies

The general studies on energy utilization reviewed surveys and projections of energy consumption in the United States and evaluated possible applications for thermal energy from the steam-electric power plants. The evaluation of how heat from the plants might be used rather than wasted constituted a major portion of the study. Its results are equally relevant to nuclear and fossil-fueled plants.

Building Services

Figure IV illustrates the importance of providing heat for building services by comparing the nation's total rate of electricity consumption for all purposes with the rate of energy consumption for solely space

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*Advanced nuclear reactors under development include the liquid-metal fast breeders, fast gas-cooled breeders, high-temperature gas-cooled reactors, and the molten-salt thermal breeders.

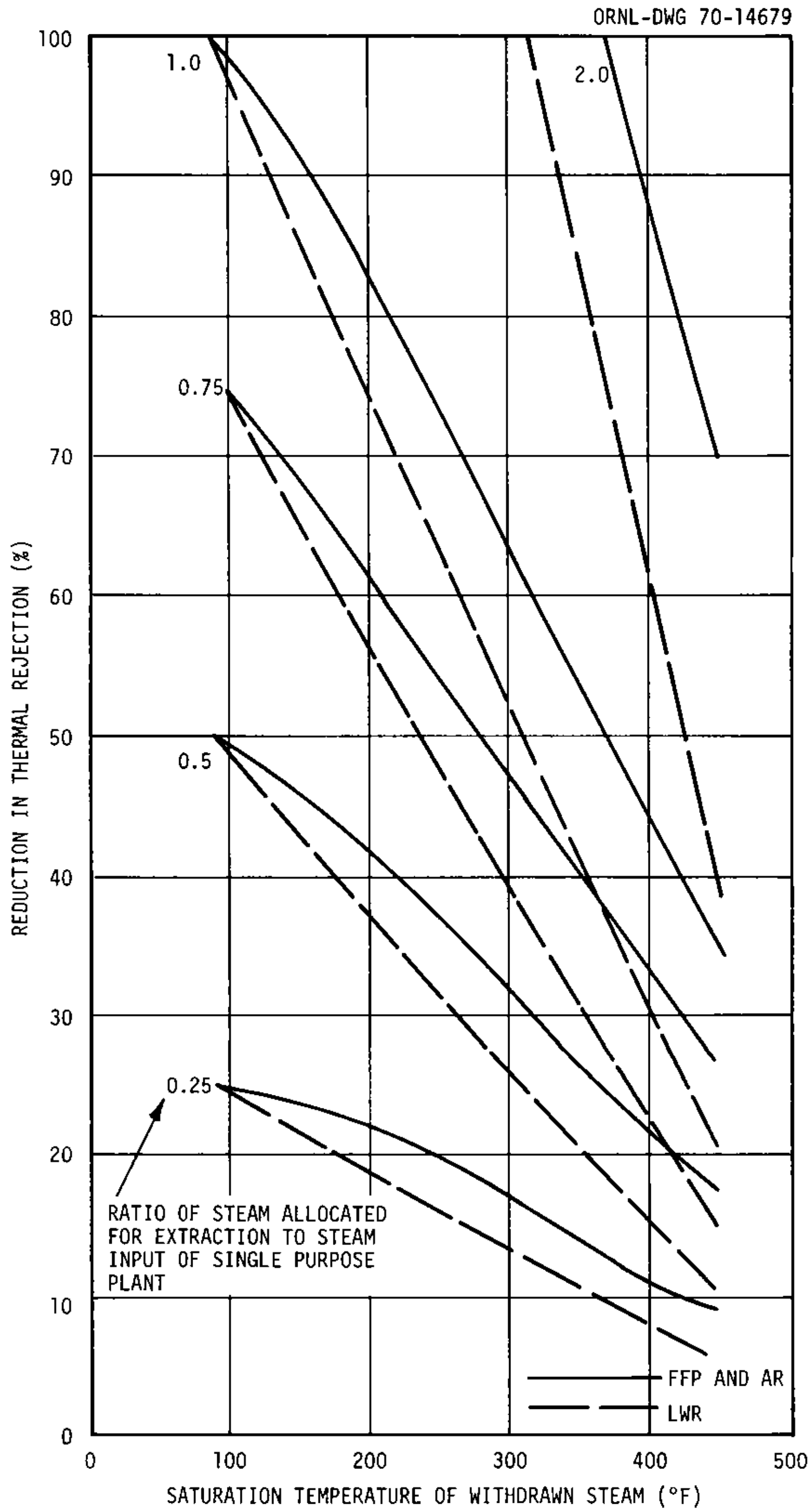

Fig. II. Reductions in Thermal Rejection at Condenser Based on Constant Electric Generation.

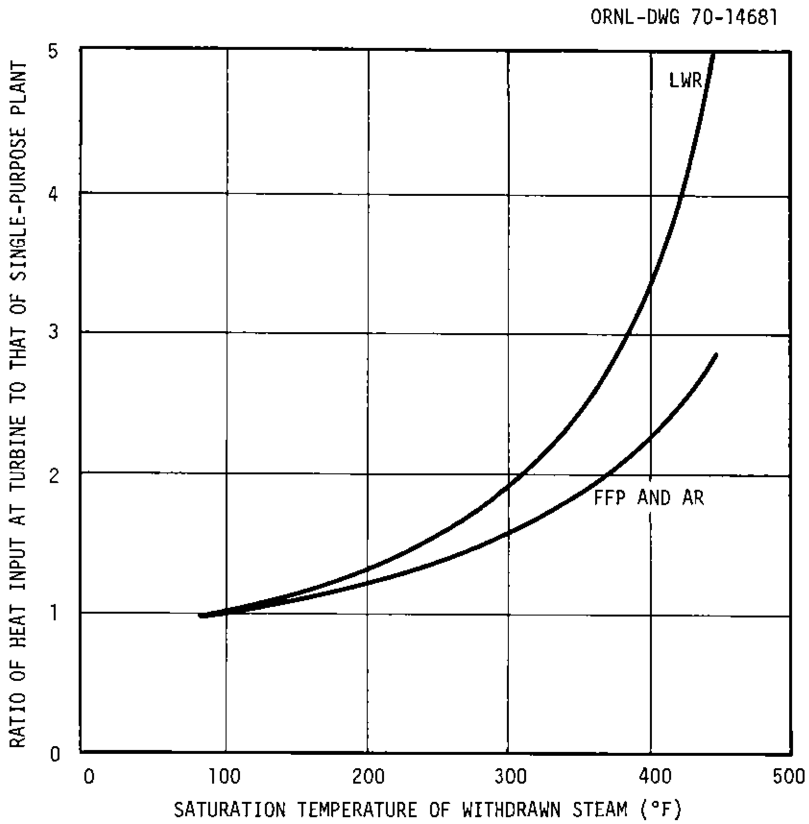

Fig. III. Effect of Withdrawal Conditions for 100% Reduction in Thermal Rejection at Condensers Based on Constant Electrical Generation.

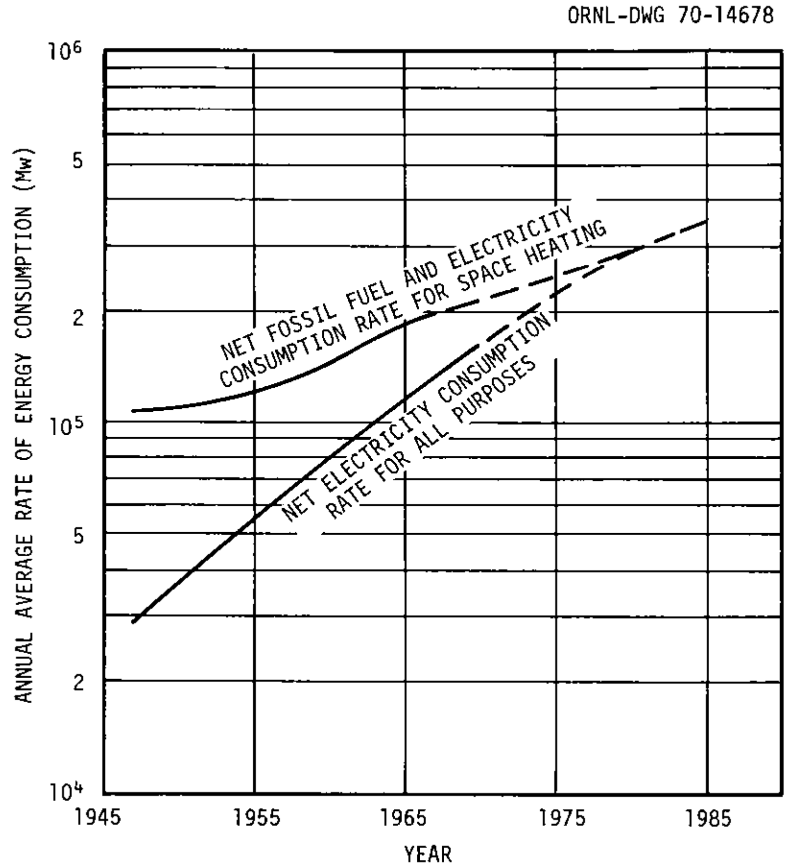

Fig. IV. U.S. Annual Average Rate of Electricity Consumption for All Purposes and Energy Consumption for Space Heating from 1947 to 1985.

heating the country's buildings. It can be seen that for 1980, the total rate of energy consumption as electricity and the rate of energy consumption for space heating are projected to be about equal at approximately 3×10^5 Mw. However, when domestic water heating and heat for air conditioning are also included, the heat consumption of the buildings becomes even greater.

The temperature of water provided for building services should effect a reasonable compromise between low heat distribution cost and reduced heat emission to the condenser at the energy center. Hot water at 300°F was chosen as the heat-transfer fluid to deliver the heat from the power plant to the reference city. With 300°F water used in a heat exchanger to furnish 240°F water for 2-psig lithium bromide absorption air-conditioning equipment and returned to the energy center at 210°F, the resulting thermal emission to the biosphere from the air-conditioning process is only slightly more than from conventional electric air-conditioning practice. However, with the absorption system the entire heat release would occur at many sites within the city and relieve the problem of a large heat emission from electricity production at the power plant.

The emission for 1 ton-hr of compressive air conditioning with electricity from an LWR would be approximately 8800 Btu, comprised of 2900 Btu from the electricity and 5900 Btu of heat emitted at the steam-electric generating plant. A lithium bromide absorption system would use and release approximately 17,200 Btu of heat from the district hot water system. If the absorption system described above utilized 300°F water from a center employing an LWR, the 17,200 Btu would be obtained from 7250 Btu of the heat that was already being emitted from electrical generation at the plant (for purposes other than the ton-hr of air conditioning under consideration) and 9950 Btu additional heat required from the reactor. The requirement of additional heat from the reactor is also indicative of a lowering of the electrical generating efficiency of the plant to provide 17,200 Btu of heat at 300°F for the district system. The thermal emission to the biosphere caused by the ton-hr of 2-psig absorption air conditioning in that case would be the 9950 Btu as compared with 8800 Btu for the electric-compressive system. The use of cooler water from the energy center would have a smaller effect on electricity generation and lead to a thermal emission of less than 9950 Btu.

The capital cost of absorption air-conditioning equipment is currently greater than electric-compressive equipment, but it is believed that with quantity production this difference would be eliminated.

Sewage Distillation

Steam at about 32 psig could be used to desalt sewage plant effluent to make the water reusable and to eliminate stream pollution. The cost of water from a 150-Mgd system which combined 34.5 Mgd distilled water from tertiary effluent with 50-Mgd purified natural water and 65.5-Mgd tertiary sewage plant effluent would be approximately 26¢/kgal compared to 14¢/kgal for normal water and sewage treatments. No credit was assumed for eliminating stream pollution from the sewage plant.

Manufacturing Process Heat

It was estimated that in 1980 industrial steam consumption in the United States (aside from steam generated with internally produced fuel) would be approximately 67.6×10^{14} Btu, which is equivalent to an annual average energy consumption rate of 2.3×10^{5} Mw. The principal steam consumers were chemical industries, petroleum refineries, paper mills, and food processing plants, which utilized respectively 39, 22, 18, and 13% of the total. Approximately 40% of the steam could be delivered at a pressure of 100 psig or less and 12% at 50 psig or less. However, due to pressure drops in steam distribution mains, the major steam extractions for industry would probably have to be made at pressures of 200 psig or greater.

Transportation

The performance of a city bus powered with superheated steam from 300°F water would compare well with one using a diesel engine except that the operating range between refills would be only 10 miles. Tankage for a 16,000-lb bus would comprise 30% of the gross weight. With 400°F water the tankage weight would be reduced to 20% of the gross and the range increased to 20 miles.

Snow Melting

Systems for melting snow from sidewalks by using ethylene glycol solution heated with district heat would require initial investments in the range of 30 to 60¢/ft^2 and would appear to be worthwhile only in cases where usage was heavy, such as near public places or high-rise buildings. Systems under heavily loaded roadways or runways would be considerably more expensive, and the feasibility of their use would again relate to the nature of the traffic and the benefits assumed for preventing accidents, delays, highway deterioration, etc. The hauling of snow from the city to melt it with the warm water discharge at the plant would be worthwhile under some circumstances.

Greenhouse Heating and Cooling

The normally discharged heat from a 1000-Mw(e) reactor is sufficient to heat 750 to 1500 acres of greenhouses or other enclosed environment structures, depending on location. In the summer the warm water can be used for evaporative cooling to maintain cool temperatures within the houses. In the winter, heat is transferred to warm the air of the houses. The greenhouses would perform as horizontal cooling towers. At the climate of Philadelphia the amount of heat that can be rejected through a greenhouse is approximately seven times its peak winter heat requirement. Assuming no income to the steam electric plant from greenhouse use, the net cost of modifying a standard greenhouse installation for power station heat rejection in summer and winter would be no greater than the cost of building a cooling tower.

Conclusions from Utilization Studies

The thermal energy utilization studies demonstrated that the amount of heat required for building services such as heating, air conditioning, and hot-water supply is appreciable by comparison with the quantities of heat released from plants generating electricity. The extraction of heat for such purposes from the turbines would result in significant reductions in waste heat emissions from steam-electric plants. Major amounts of steam are also needed for industrial processing. It would be most advantageous to establish a large concentration of low-temperature steam-consuming industry in close proximity to the energy center. The seasonal and diurnal variations in the requirements of the citys' buildings and in the industrial steam consumption would cause important variations in the extracted heat load. The desalting of sewage plant effluent by distillation to provide potable water appears most attractive, but the process needs additional development. Snow melting operations could also be carried out with heat from the energy center when large benefits would accrue in terms of heavy vehicle or pedestrian traffic usage, prevention of accidents, and a lessening of highway deterioration. The adoption of steam from superheated water for propulsion of urban vehicles is believed to be worthwhile but not generally applicable to the 1980 reference period chosen for the major portion of the study. A particularly important conclusion is that steam-electric plant cooling water can be piped to nearby greenhouses, which would utilize variable amounts of the heat for space heating or evaporative cooling and also serve as horizontal cooling towers to dissipate the remainder.

Energy Center Studies

Siting

A study of siting practice showed that there are now many people living within a few miles of some nuclear steam-electric plants and that the largest populations within specified radii from a plant in the United States are in the area surrounding the Indian Point station in New York State. For a 1980 reference city study, the population within any radial distance from its energy center should be no more than that projected for the Indian Point station in 1980.

Reliability

Energy centers were assumed to be base loaded, tied into an electrical grid, but not to a thermal energy grid. Excess electricity above the city's needs could be furnished to the grid during periods of low demand or small heat extraction.

The performance information on existing nuclear reactors and fossil-fueled boilers indicated that under such circumstances the use of two steam generators at an energy center should provide an adequately reliable source of heat for a district system. An outage of longer than 10-hr duration could be expected about every ten years, on the average. Additional reliability at small cost could be obtained with a low-temperature fossil-fueled standby heating plant.

Costs

The capital and operating costs of the energy center were considered to be in two categories — the cost of electricity production and the cost of heat production. The former included costs for steam production for electricity and electricity generation; the latter consisted of costs for heat production for nonelectrical purposes. The total cost of electricity production at the energy center was almost always taken to be the same as that of a single-purpose plant generating the same annual average amount of electricity as the center. All additional cost at the center was assumed to be heat production costs. The energy center was sized to produce the annual amount of electricity required by the city it served. These ground rules led to electricity production cost increases as the city and energy center became smaller. This use of small plants near each city rather than a regional plant serving several small cities would result in shorter heat transmission distances but higher electricity production costs. There would be some reduction in electrical transmission losses to each city, as compared with those from a regional plant, and in some arrangements the use of smaller plants would also lower the capital cost of electrical transmission.

The capital costs of the energy center, including the capital cost of heat production, were based on 1968 prices escalated 4%/year during a five-year period of construction and a 14% annual fixed-charge rate.

The total cost of heat production varied only slightly with the type of nuclear reactor and somewhat more with the range of prices assumed for fossil fuels. Average heat production costs were generally in the 30 to 40¢/MBtu range for 400 to 1000-Mw(e) plants. Adjustments in cost were made between various types of heat extractions as, for example, to compensate for the greater thermodynamic value of high-temperature industrial steam as compared with the costs for water pumps, heat accumulators, standby heat plants, etc. that could be used for a district heating system based on distributing hot water.

Reference City Study

General Design

The purpose of studying a reference city and variations in its parameters was simply to demonstrate the ideas discussed in the report. Therefore its design was only conceptual and provided just enough information to define a reasonable arrangement for analysis. There was no need or attempt to design a city per se.

The city is imagined as a new one with 389,000 people located in a geographical area having the climate of Philadelphia, Pennsylvania. The energy center is designed to produce the average amount of electricity forecast for a city of 389,000 people in 1980, except for a small reduction to compensate for the use of district heat for air conditioning and domestic hot-water production. The heat source consists of two light-water reactors. The industrial consumers of low-temperature process heat are located in close proximity to the energy center, and their process heat consumption conforms to the projected country average for a population of the chosen size in 1980. Extraction pressures are raised to compensate for pressure drops in the supply mains. Since the effect of "country average" industrial consumers on feasibility is small compared with that of providing building services, their nature is unspecified, and the industrial load factor is assumed to be unity. The role of the building heat consumption was accentuated by sizing the sewage distillation plant at the energy center at about two-thirds the size that could be justified by the sewage study.

The residential and commercial areas of the city are all situated at a distance greater than five miles from the energy center, as illustrated in Fig. V. The population at any distance from the energy center is less

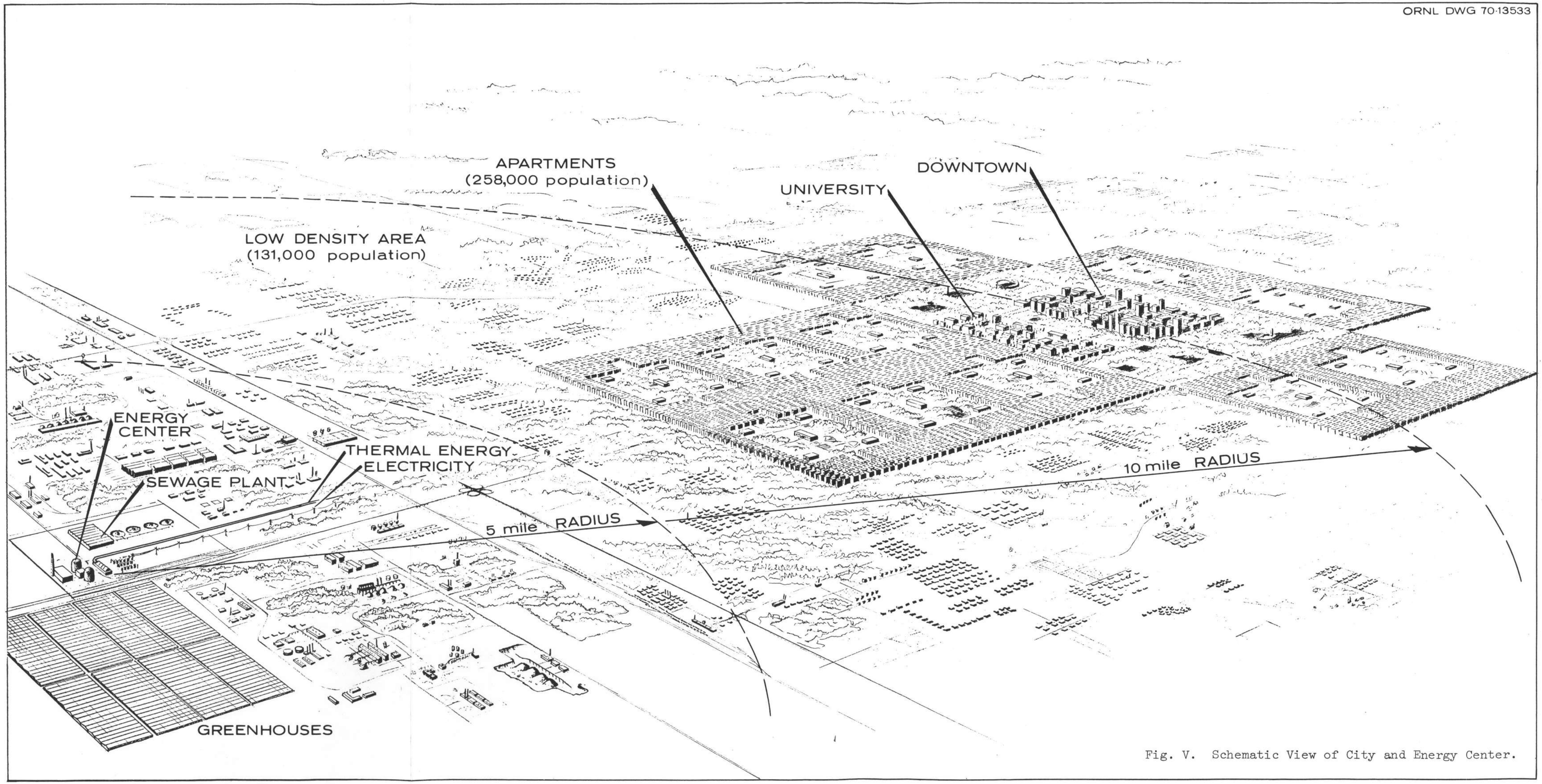

Fig. V. Schematic View of City and Energy Center.

than that for the area surrounding the Indian Point reactor in 1980. The downtown area and an apartment house area are in one sector between 6 and 12 miles from the center, and they received 300°F water for building services. (With a less remote energy center, water at a temperature less than 300°F would be transmitted and distributed at the same cost as the 300°F water in this reference case.) This section of the city that is supplied with district heat has a total area of 16 square miles. All heat transmission, distribution, and cooled-water return lines are buried 6 ft below ground surface. Of the 389,000 people who live in the city, 258,000 of them reside in 12 square miles of apartment area. The downtown area is located in the remaining 4 square miles. The other 131,000 people live outside the 16-square-mile area at unspecified locations within the 5- to 12-mile annulus. All 389,000 people are supplied with electrical energy from the center. The general city statistics are listed in Table I. The 222,000 people shown in Table I as being in the five- to ten-mile annulus of the reference city are to be compared with 300,000 within a ten-mile radius projected for Indian Point in 1980, and the total population of 389,000 within the 12-mile radius is to be compared with 400,000 projected for Indian Point.

The portion of the city supplied with thermal energy from the center is laid out in a fashion that allowed it to be characterized with relatively few parameters. After an economic analysis was made of its energy

Table I. Reference City Statistics

Population served by energy center	389,000
Population distribution relative to energy center	
5- to 10-mile annulus	222,000
10- to 12-mile annulus	167,000
Population served by district heating system	
5- to 10-mile annulus	172,000
10- to 12-mile annulus	86,000
Area served by district heating system, square miles	16

system, the effects of changing important parameters, such as population density, total population, dwelling space per person, and distance from the energy center, were readily estimated. A major simplification was achieved for purpose of analysis by the use of uniform building structures and a repetitive mile-square layout of the apartment area that houses a large fraction of the population. This led to answers regarding the cost of services to uniform consumers that are useful in obtaining those for mixed sizes and other more desirable arrays of consumers.

The apartment buildings were assumed to be uniform and three stories high with 300 ft^2 of net usable enclosed space per person, including entrances, hallways, and stairways. Two-story apartments could just as well have been used, along with somewhat higher heating and air-conditioning requirements. City block sizes could also have been varied with little effect on the analysis. The resulting population density in the apartment area is 21,500 people per residential square mile. It is to be noted, however, that almost all inhabitants could leave the apartment area by traveling less than one-half mile. The schools and commercial facilities were sized to serve only the residents of each residential mile. In an alternate arrangement of apartment buildings that resulted in the same district heating cost, the 21,500 people were spread over a 1 1/2-mile area giving a population density of 14,333 per square mile in the apartment areas.

Heat Requirements

A summary of energy production and consumption estimates is given in Table II.

It may be seen that the heat rejection to the condenser cooling water during the hottest summer hour is very small. Even this could be used beneficially in approximately 200 acres of greenhouses (or in poultry houses, swine houses, or fish ponds) located at the energy center. Furthermore, the maximum heat disposal capacity of 200 acres of greenhouses is sufficient to dispose of the entire 1180 Mw(t) at any time of the year. Thus no cooling towers or warm water discharge would be required if greenhouses were provided.

Table II. Energy Production and Loads for Reference City

Production capacity of heat source	2268 Mw(t)
Annual average thermal power production	2041 Mw(t)
Annual average net electrical power production	463 Mw(e)
Annual average internal power consumption	29 Mw(e)
Annual average district heating load	457 Mw(t)
Peak summer district heating load	1144 Mw(t)
Peak winter district heating load	1088 Mw(t)
Minimum district heat load	0 Mw(t)
Industrial steam load at 965 psig	43 Mw(t)
Industrial steam load at 450 psig	251 Mw(t)
Industrial steam load at 207 psig	74 Mw(t)
Sewage distillation steam at 32 psig	90 Mw(t)
Annual average heat to condenser	634 Mw(t)
Maximum heat to condenser	1180 Mw(t)
Heat to condenser at hottest summer hour	230 Mw(t)

Cost of Heat

The cost of heat production at the energy center for the reference city is shown in Table III.

The cost of distributing heat to the city is 106¢/MBtu. The capital cost of district heat distribution was based on 1969 prices escalated 4% per year during five years of construction and a 14% annual fixed-charge rate. The annual operating and maintenance costs of the distribution system, including allowances for heat losses and pumping power, were estimated to be 3% of the capital cost of the system.

The sum of the heat production and distribution costs add up to the total cost of district heat for the buildings of the city. This is in the region of 106¢/MBtu for distribution plus 36¢/MBtu for heat production or approximately 142¢/MBtu in 1973-74. This is equal to the average cost of 142¢/MBtu for district heat in 43 cities of the United States in 1968. The cost in the nation's largest system was 152¢/MBtu; in the second to tenth

Table III. Unit Heat Production Costs for Reference City

	Heat Costs at Power Plant (¢/MBtu)	
	With Cooling Tower	With Greenhouses[a]
Industrial steam		
Prime (965 psig)	50.4	46.3
450 psig	43.8	40.3
207 psig	37.5	34.5
32 psig	24.3	22.3
District heat	36.5	34.6

[a]Assuming no thermal energy charge to greenhouses.

largest systems the average was 133¢/MBtu with a range of 119-154¢/MBtu. A study of reports from many apartment building owners indicated that in 1968 their average heat production cost was 142¢/MBtu. Space heating, domestic hot water heating, and air conditioning these buildings in the reference city affects the major portion of the reduction in heat emission to the energy center cooling water. The cost of providing this heat from the energy center as compared to other methods of serving the buildings is the dominant factor in assessing the economic feasibility of using heat from the steam-electric power plants for urban applications. No cost credit is taken for reducing thermal emissions or conserving fossil fuels.

The cost of energy for air conditioning with 300°F water and 2-psig absorption air-conditioning equipment would be equivalent to a cost of 28.5 mills/kwhr for electricity for an electric-compressive system. With a charge of 79¢/MBtu for air-conditioning heat the energy cost would be equivalent to 16 mills/kwhr for electricity for a compressive system. At the latter price the charge for heat for space heating and domestic hot water heating would have to be increased from approximately 142 to 198¢/MBtu. The air-conditioning charge would be defraying the cost of 300°F heat production plus somewhat more than the incremental distribution cost of heat for air conditioning. Several large district heating systems have special summer or air-conditioning rates. The relationships between space heating and hot water costs and charges for air conditioning and also greenhouse winter heating charges are shown in Fig. VI.

Variations in the reference city design that reduce the space per person down to as low as 200 ft^2 or halved the population and moved it closer to a smaller energy center made changes in the heat cost that were not large enough to have a major influence on assessing the feasibility of using heat as well as electricity from the energy center. This was also the effect of most changes in the assumed reference city's climate. In the portions of the country with close to zero degree days of heating, a charge of 235¢/MBtu for hot water heating led to an air-conditioning energy charge equal to that incurred with electricity at 20 mills/kwhr for compressive systems. Lowering the population density in the apartment areas

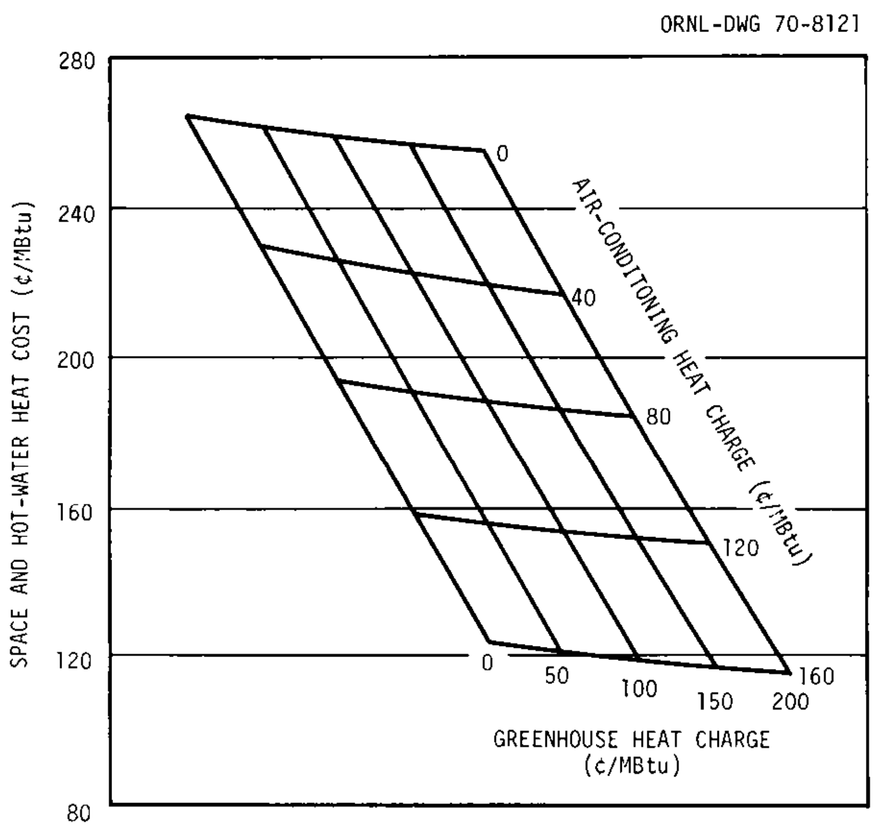

Fig. VI. Cost of District Heat Supplied from an Energy Center with Greenhouses and No Cooling Towers to the Reference City.

of the reference city to 8600 people per square mile, while holding the number of apartment dwellers to 258,000, increased the cost of thermal energy from approximately 142¢/MBtu to 186¢/MBtu. The differential cost of providing space heat to single-family dwellings adjacent to the apartment areas was high and depended strongly on the arrangement. It was also shown that small cities with as few as 3000 people in apartment areas could be provided economically with thermal energy as well as electricity from a nearby large regional or large industrial nuclear steam-electric plant.

Conclusions and Recommendations

The use of thermal energy from steam-electric plants would result in significant reductions in thermal emissions and air pollution and aid in the conservation of fossil-fuel resources. Its use for several purposes in new cities, particularly those in the 200,000–400,000 population range, appears to be economically attractive. It is recommended that a program be established to determine specifically where new power plants could be sited in conjunction with the development of new cities so that low-cost thermal energy, as well as electricity, could be provided for agricultural, industrial, commercial, and residential needs.

Whether it would be feasible to provide thermal energy to presently existing cities from electric power plants would require a separate study of particular cities. In consideration of the urgency of the present pollution and conservation problems, it would be worthwhile to select an existing city for a conceptual design study that would determine the application and uses of thermal energy, develop an implementation plan, and carry out an economic analysis. The results would not only apply to the chosen city but they would also aid in making estimates of feasibility for other cases.

1. INTRODUCTION

Most electricity in this country is generated in large power plants by using the energy released from the oxidation of coal, gas, or oil or the fissioning of atoms to produce high-pressure steam for driving a turbine-generator. As always, the conversion of heat to work is not complete, and in this case about all the unused heat is usually removed by condensing the steam after it leaves the turbine with a stream of cool water. The cooling-water is usually taken from rivers or ocean estuaries and returned to them at temperatures as high as 95°F. In fossil-fueled plants heat is also emitted to the air from the combustion-chamber stack.

The heat emitted from the generating plants in this country currently amounts to about twice as much as that converted to electricity. The fraction of the heat emitted at generating plants that have light-water-moderated and -cooled reactors is about the same as the U.S. average. Higher efficiencies resulting in emissions that amount to only one and one-half times the energy converted to electricity occur with modern, large fossil-fueled plants. This higher efficiency will also be obtained with plants that employ the nuclear reactors now being developed.

Beneficial use of this large amount of low-temperature heat or of heat removed from the turbine even at somewhat higher temperatures would result in conservation of energy resources, reduction in thermal pollution of the waters and the biosphere, and reduction in releases to the atmosphere of particulates and gaseous pollutants from such processes as space heating and industrial process steam production. In addition, it appears that the steam which has already been used to produce electricity can also be an economical source of heat.

These considerations of resource conservation and environmental improvement led to the Oak Ridge National Laboratory (ORNL) study for the Department of Housing and Urban Development (HUD) of the use of thermal energy, as well as electricity, from nuclear power plants located in or near an urban area. The study was made to provide an estimate of the technical, social, and economic feasibility of providing heat from reactors to urban areas. The scope of the study included estimating the feasibility of using present-generation light-water reactors in the 1970–1985 period, the longer range possibilities of using the high-temperature reactors that should be available after 1985, and evaluations of what can be done with fossil-fueled plants.

In the interest of arriving at some useful conclusions as quickly as possible, emphasis was placed on electricity- and heat-generating plants (heat-electric energy centers) that would employ light-water reactors and supply heat and electricity to new cities. The use of nuclear reactors obviates the necessity of presupposing a solution to the atmospheric pollution problem caused by emissions of gases and particulates from fossil-fueled plants. There is copious information available on the light-water reactor plants, and immediate planning for their use could begin. By limiting the study to new cities it was not necessary to deal with the myriad of questions that pertain to the renovation of existing cities. The new city information is directly applicable to planned expansions of existing cities. It is also baseline data with which to approach more complex situations.

Although the emphasis is on reactors, the information on heat consumers and their requirements and the conclusions on the uses for heat constitute a major portion of the study, and the results generally apply to any other heat generator, regardless of its source of energy.

The sections that follow describe methods for obtaining heat from the condenser or the turbine (Sect. 2) and potential uses for heat, such as for space heating, air conditioning, and manufacturing process heat (Sect. 3). Employing this information on heat production and usage, conceptual designs are presented of energy centers, and estimates are made of the cost of heat production as a function of parameters such as center size, type of energy source, and reliability (Sect. 4). Estimates are made of the reductions in heat emissions that accrue to various methods of heat utilization. Information is presented on energy-center siting and (in Sect. 5) heat transmission and distribution costs. Finally, for a reference city, a new city with a climate the same as that of Philadelphia, Pennsylvania, an energy center functioning in 1980 is defined and analyzed, and an assessment is made of feasibility as it relates to city size and population density, costs, and methods of economic analysis (Sect. 6).

Answers are supplied to such questions as whether the thermal energy can be distributed without losing excessive amounts to the ambient, and whether by use of it a significant reduction can be made in uncontrolled emissions. The evaluation of economic feasibility is made simply on the basis of electricity and heat costs. The cost of obtaining services from the energy center for heating, air conditioning, etc., is compared with alternative methods of obtaining them. No cost credit is taken for such savings as accrue from decreased requirements for thermal pollution control, cleaning services[1] or, even more pertinent, the reduction in need for medical care.

2. HEAT-ELECTRIC SYSTEMS

The production of electric power involves the emission of large quantities of heat, and it is often quite advantageous to use the heat in a combined heat-electric system. This is presently being done by some large industries that can economically justify producing part or all of their required electrical power while producing the heat needed for their industrial process. Also, some public utilities provide district heating and electrical power from a combined system. Since the production of electric power in the conventional method results in large quantities of unused, low-temperature heat, which today is largely wasted, the use of a combined heat-electric power system reduces the ratio of unused heat to power.

The principles of heat removal from normal condensers, extraction turbines, and back-pressure turbines are described in this section, particularly with respect to effectiveness in reducing waste heat emissions. The conceptual design of the extraction-turbine system employed in the reference city is included as one of the illustrations.

2.1 Condensing Turbine System

The production of electric power by the usual method of expanding steam through a turbine results in about 60 to 70% of the heat being rejected into cooling water at the condenser. This heat is then released to the environment by the cooling water being returned to the river, lake, etc. from which it came or cooled in a cooling tower. The temperature of the cooling water outflow is normally less than 100°F. Technically the exhaust steam heat can be used for such purposes as warming fish ponds and greenhouses, low-temperature distillation, snow melting, and possibly others.

Of these uses, only the low-temperature distillation would significantly affect the operation of the power plant itself, and it would affect only those plants that normally could be designed to exhaust at less than 109°F. The 109°F temperature is a practical one for operation of a low-temperature distillation plant. Therefore, if the cooling water available would permit designing a power plant to operate at less than 109°F, raising the exhaust temperature to 109°F would result in a slight decrease in the plant's thermal efficiency. For example, the decrease in efficiency that would occur in raising the exhaust temperature from 92 to 109°F would be approximately 1%. However, the decrease in efficiency caused by the 109°F exhaust temperature in the winter could be close to 2% due to the lower exhaust temperature available during that season.

The economics of a particular application and the criteria applicable to it and the power plant are then the controlling factors in determining whether and how the heat in the cooling water will be used or disposed of without use. Furthermore, it is not necessary to use all of it. Any fraction of it can be selected for an economic analysis. However, in the case of an increased exhaust temperature, most of it should be used, or the extraction system described below should be employed.

While uses of this low-temperature heat are rather limited, its low cost at the plant (<1¢/MBtu) makes economic analysis of possible application worthwhile. Figure 1 shows schematically the system discussed

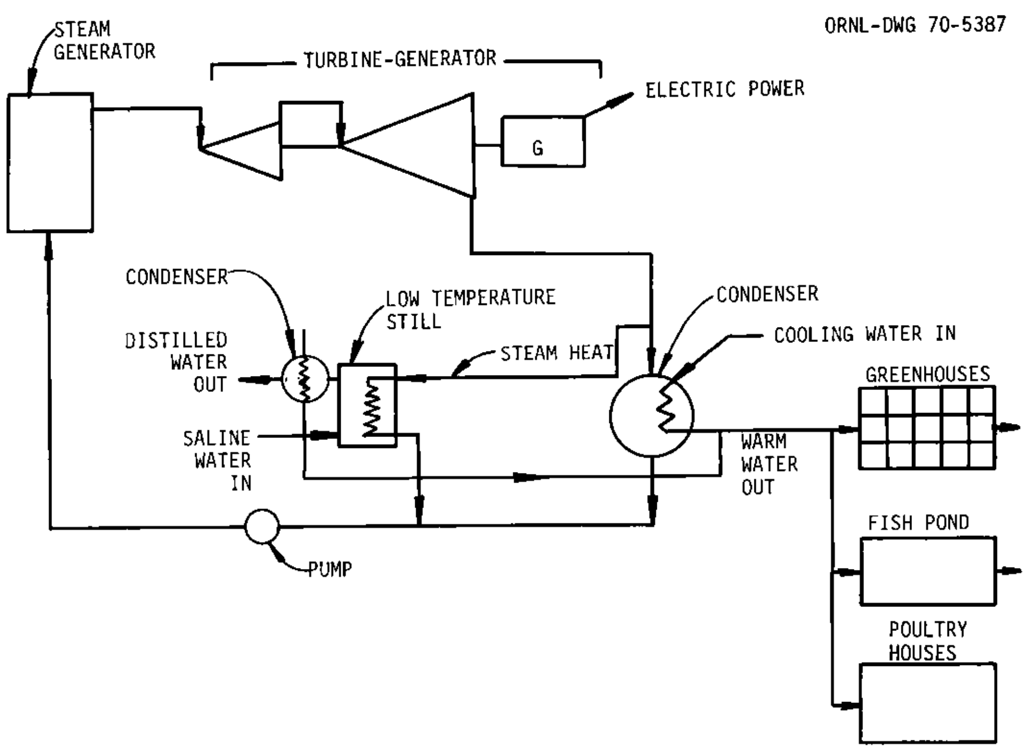

Fig. 1. Condensing Turbine System with Waste Heat Utilization.

here with three possible uses of the low-temperature heat, but any desired number of uses, more or less, than this may be considered.

2.2 Back-Pressure Turbine System

Heat for district heating or industrial purposes at temperatures considerably higher than obtainable from the condensing turbine is desirable for many applications, as discussed in Section 3. This can be produced while producing electric power by two separate methods that use the same steam for heat as was used to produce the power — a back-pressure method and an extraction method. A combination of the two methods may also be used. In general, the prime steam is expanded to the desired lower pressure and temperature in the turbine, and part of its energy is converted to electricity. Steam is then removed from the turbine and its remaining available energy is utilized in the heat system.

If the quantity of the steam required for its heat content is large relative to the desired power production, a back-pressure turbine can be used. Normally, the steam expands through a turbine from its prime-steam condition to about 1.5- to 2.5-in.-Hg abs pressure. The turbine can be designed so that the steam expansion can be terminated at almost any pressure and the steam permitted to exhaust into heat exchangers or a piping system at the desired temperature or pressure for beneficial use. Assuming that all the steam can be used, there would be no waste heat from the turbine exhaust. The equipment arrangement for a back-pressure heat-electric system is shown schematically in Fig. 2.

The value of the exhaust steam is often considered to be a function of its available energy per unit weight for generating electricity. Its value is therefore less than that of prime steam and decreases as the exhaust temperature decreases. Figure 3 is a typical example of the variation in the exhaust steam cost at the turbine as a function of the exhaust temperature for a medium-size (∿1100-Mw thermal), light-water-cooled nuclear steam generator. The cost of the prime steam is determined from the capital cost of the equipment for producing it, the fuel cost, and the operation and maintenance costs. The effects of the capital and fuel cost on the prime steam cost vary considerably with the interest rate and the

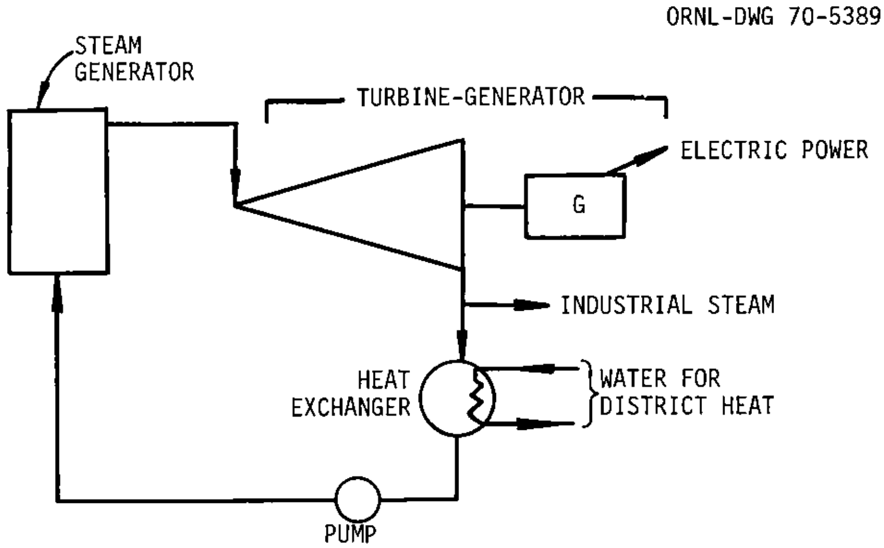

Fig. 2. Back-Pressure Turbine System for Producing Process Steam and Hot Water.

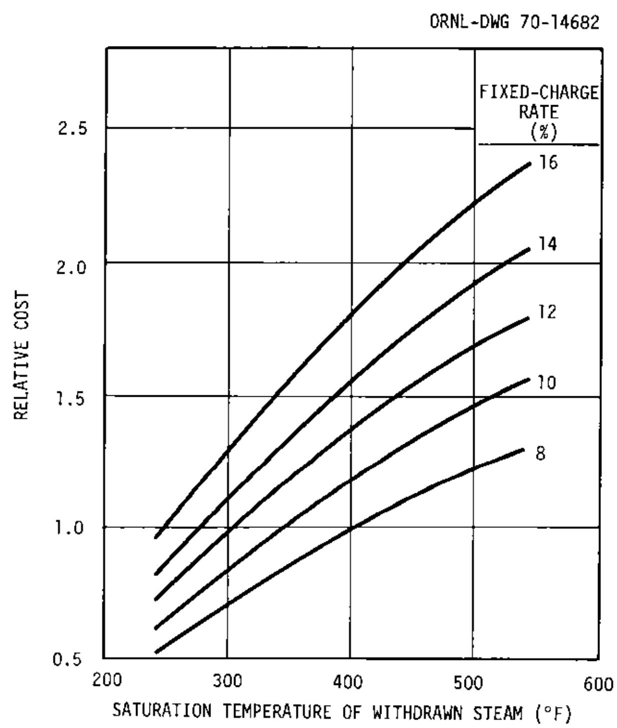

Fig. 3. Relative Costs of Steam at Turbine from Typical Medium-Size Light-Water Reactor.

corresponding annual fixed-charge rate. The effects on exhaust steam cost are shown in Fig. 3 for five fixed-charge rates.

2.3 Extraction Turbine System

When the steam demand is small to moderate, steam may be taken from the turbine through extraction nozzles in much the same manner as for conventional feedwater heating. By providing extraction nozzles at more than one point along the length of the turbine, industrial steam can be furnished at different pressures. This permits power to be generated by the pressure drop through the turbine that would be lost if the steam were extracted at some high pressure and throttled to the desired pressures outside the turbine. This system is shown schematically in Fig. 4. As indicated, steam may be extracted at the crossovers between high-pressure, intermediate-pressure, or low-pressure casings, if desired. This turbine can be designed so that when the heat load is reduced the steam that would have been extracted will continue to expand through the turbine and thus increase electric power production.

Production of electric power by use of this heat-electric system reduces the amount of steam reaching the last stages of the turbine and the amount of waste heat production. The effects of exhaust conditions on the

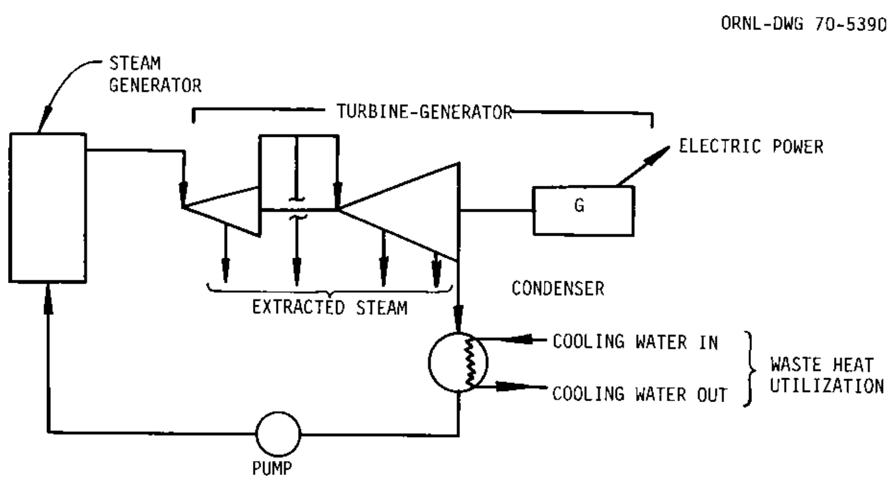

Fig. 4. Extraction Turbine System for Producing Process Steam and Heating Water for Waste Heat Utilization.

gross steam cycle efficiencies of three types of nuclear plant and a fossil-fueled plant are shown in Fig. 5,* and the reduction and elimination of thermal rejections at the condenser by use of the extraction and back-pressure systems are illustrated in Figs. 6 and 7 for these plants.

*Supplied by John Moyers, ORNL.

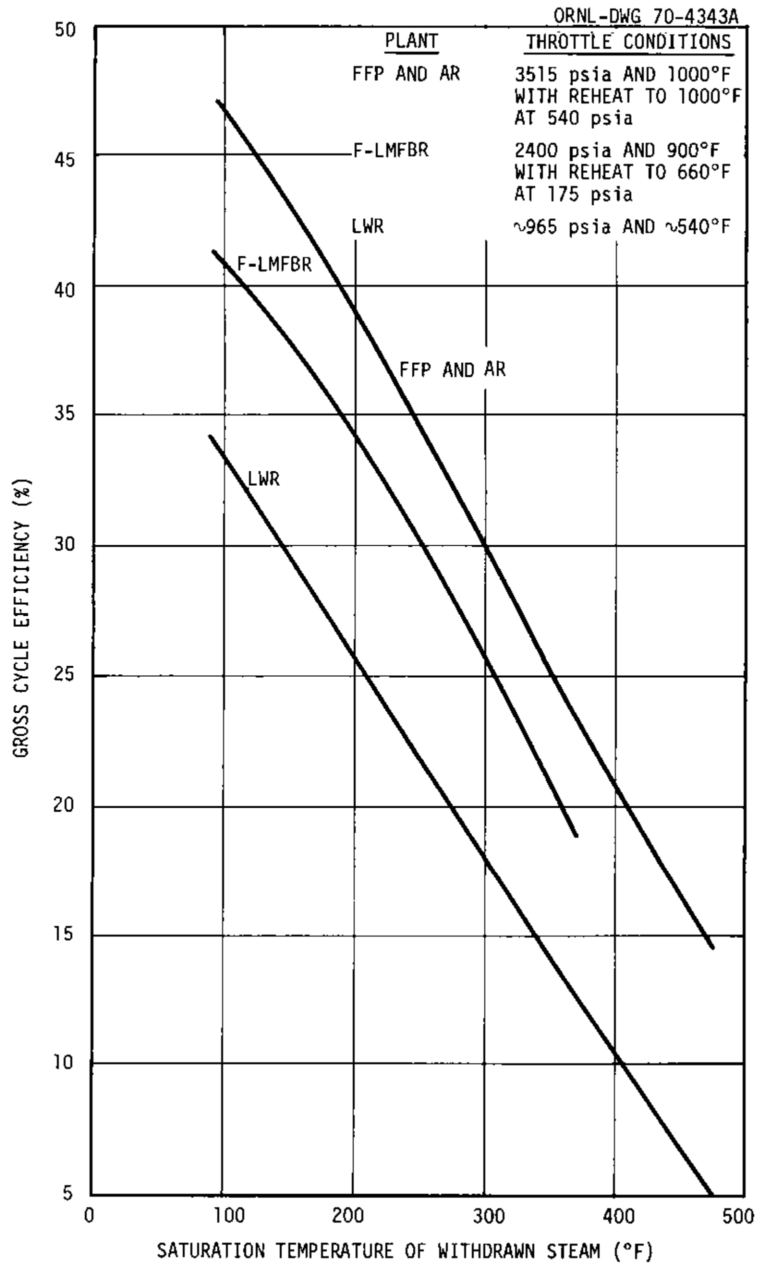

Fig. 5. Effects of Exhaust Conditions on Efficiencies of Various Power Plants.

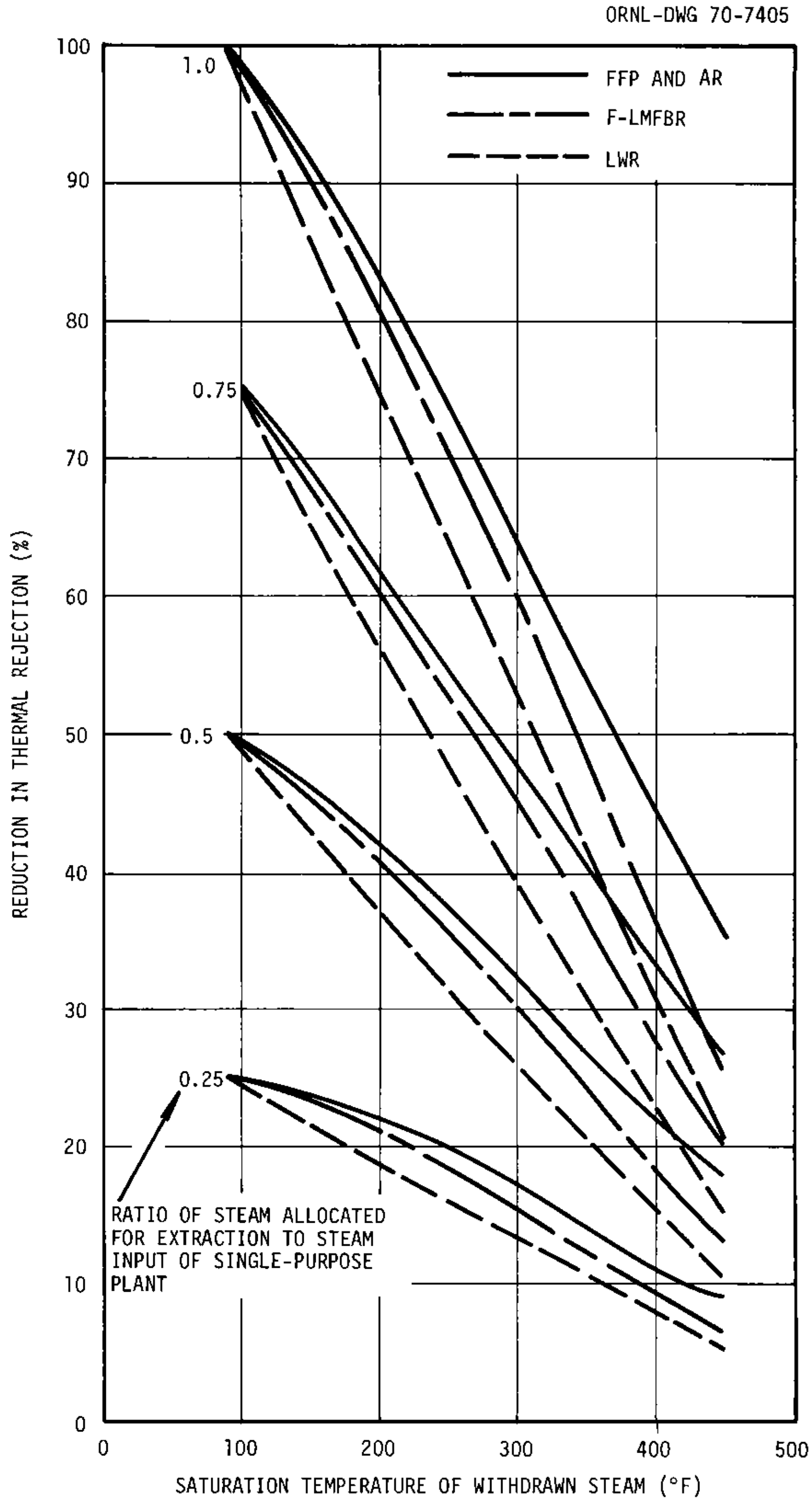

Fig. 6. Reduction in Thermal Rejection at Condenser Based on Constant Electrical Generation.

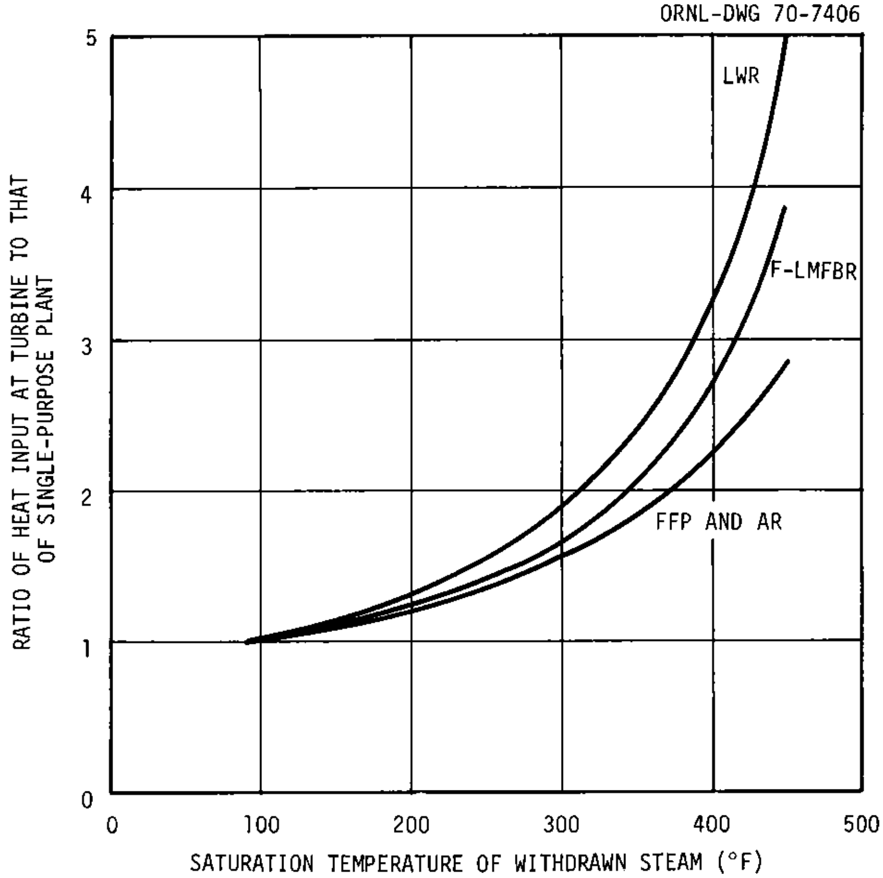

Fig. 7. Effect of Withdrawal Conditions for 100% Reduction in Thermal Rejection at Condensers Based on Constant Electrical Generation.

The data are based on condensate being returned to the boiler at the saturation temperature of the withdrawn steam. The thermal rejection at the condenser is estimated by taking the difference between the heat input from the fuel to the boiler and the gross electricity produced. This neglects minor adjustments for heat from internally used electricity and heat lost directly to the atmosphere. The three cycles are those of the best large fossil-fueled plants (FFP) and advanced nuclear reactors under develoment (AR),* the first generation liquid-metal-cooled fast

*Advanced nuclear reactors under development include the liquid-metal fast breeders, fast gas-cooled breeders, high-temperature gas-cooled reactors, and the molten-salt thermal breeders.

breeder reactor (F-LMFBR), which is also under development, and of light-water reactors (LWR), such as the existing boiling-water or pressurized-water reactors. They also encompass the temperature range of cycles currently used with large fossil-fueled plants. These data illustrate, as might be expected, that the least waste heat is produced by the FFP and AR, followed by the F-LMFBR and the LWR, that extractions of heat at the same temperature have a greater percentagewise effect on reducing the waste heat in the more efficient cycles, and that the heat removals have less effect on the efficiency of electricity production in the high-temperature efficient cycles.

2.4 Conceptual Arrangements

The three turbine systems described above can be combined into a composite arrangement to serve multiple loads and provide great flexibility. Two examples follow which illustrate schematically the turbine-generator and heat exchanger arrangements for large nuclear-fueled light-water-cooled steam generators.

Figure 8 shows the arrangement for a system that can produce an annual average of 1000 Mw(e) at a plant load factor of 90%, 2600 Mw of district heat (water at 200 to 380°F), and industrial steam loads (IS) at 400, 225, and 67 psia totaling 816 Mw. The turbines for this system are mounted on two shafts that drive two generators coupled electrically. There are two double-flow high-pressure (HP) casings on separate shafts, two double-flow low-pressure (LP) casings on the shaft with one HP unit, and a double-flow back-pressure (BP) unit on the shaft with the other HP unit.

The water for district heating is heated in two stages in heat exchangers 1 and 2 (Hx-1 and Hx-2). The steam for this is taken from the crossover line for Hx-1 and from the exhaust of the BP unit for Hx-2. Industrial steam is extracted from the HP units, the crossover line, and the BP exhaust. The district heat load can be varied from 390 to about 2600 Mw without varying the steam generator output. This is accomplished by varying the flows in the LP casings and in the extraction line to Hx-1 and the BP unit to Hx-2.

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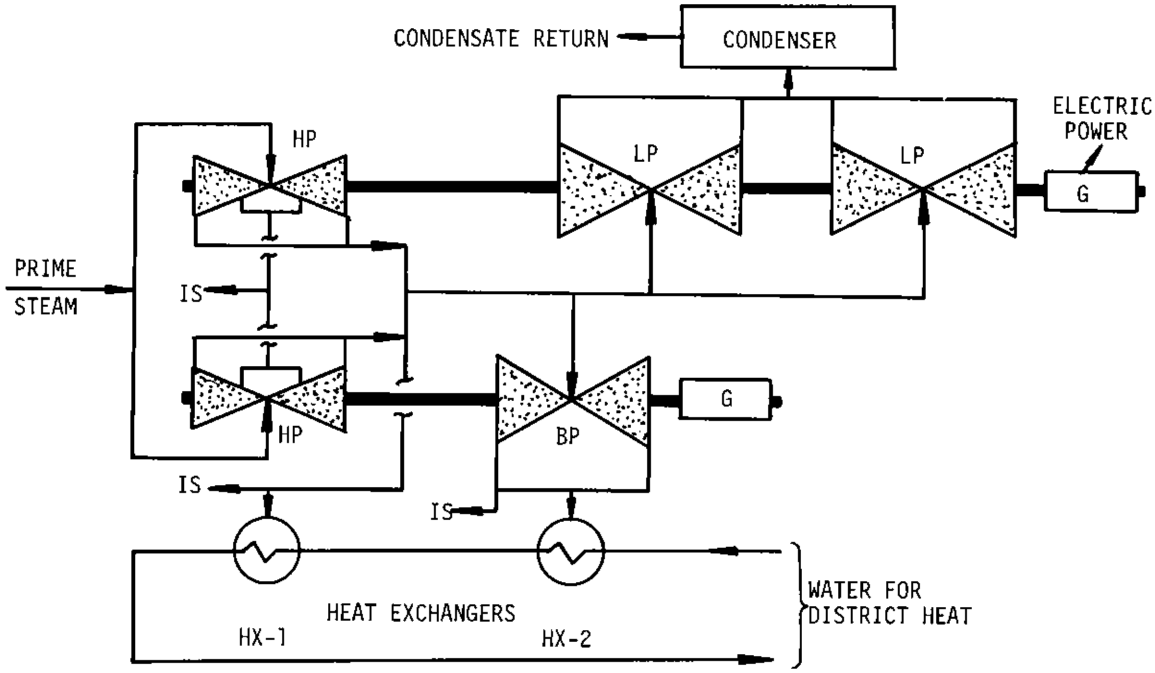

Fig. 8. Turbine-Generator and Heat Exchanger Arrangement for a 1000-Mw(e) Power and Heat System.

The power generation varies as these steam flows vary and is a maximum when the district heat load is at its minimum. The heat discharged at the condenser is a maximum at this condition. Although not shown, beneficial use could be made of some of this waste heat.

A smaller system used in the reference city study in Section 6 is shown in Fig. 9. This arrangement could produce an annual average of 463 Mw(e) at a load factor of 90%; 1144 Mw of heat to provide water at 300°F; 90 Mw of steam at about 270°F for a sewage distillation system (SDS); and 368 Mw of industrial steam (IS) at prime steam conditions (465 and 222 psia).

The turbine-generator equipment is mounted on a single shaft and includes a double-flow HP unit, two single-flow BP units exhausting at different pressures, and one double-flow LP unit. The hot water is heated in two stages by the exhaust steam from the BP units, and the SDS is extracted from one BP unit and the LP unit. Prime steam for industry is

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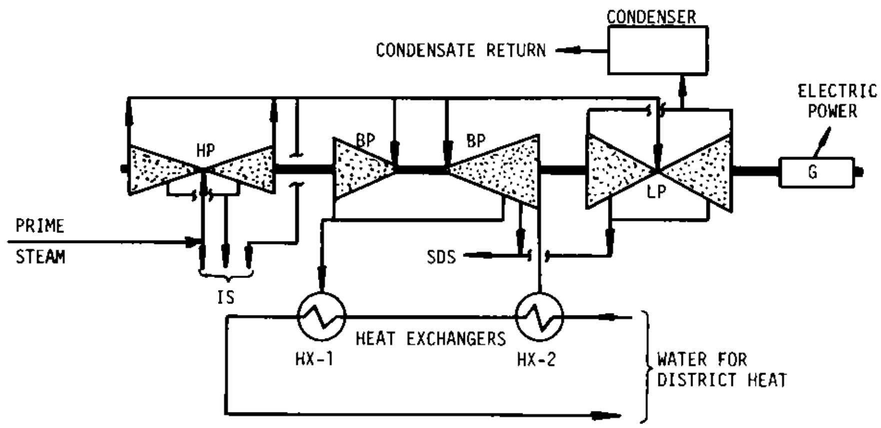

Fig. 9. Turbine-Generator and Heat Exchanger Arrangement for a 500-Mw(e) Power and Heat System.

taken from the steam system ahead of the throttle to the HP unit, and IS is extracted from the HP unit and crossover line.

The hot-water load may vary from approximately 0 to 1144 Mw. This is accomplished by varying the steam flow to the BP units and the LP unit. At the minimum heat load the flow to the LP unit is maximum, the power generation rate is maximum, and so is the waste heat. The steam generator operates at full load regardless of the water heating load.

The sizing of the loads and equipment and the cost calculations for this system are presented in Section 4.3.

2.5 Closed-Cycle Gas-Turbine System

Another heat-electric power system that could be used would employ a turbine driven by a noncondensable gas rather than by steam. For comparison with the steam cycles, this system is shown schematically in Fig. 10, with three stages each of cooling and compression. Other heat exchanger and compressor arrangements can be designed, and both steam and hot water can be produced to serve separate heat loads. In this system the gas is heated to a high temperature in the heat source and expanded

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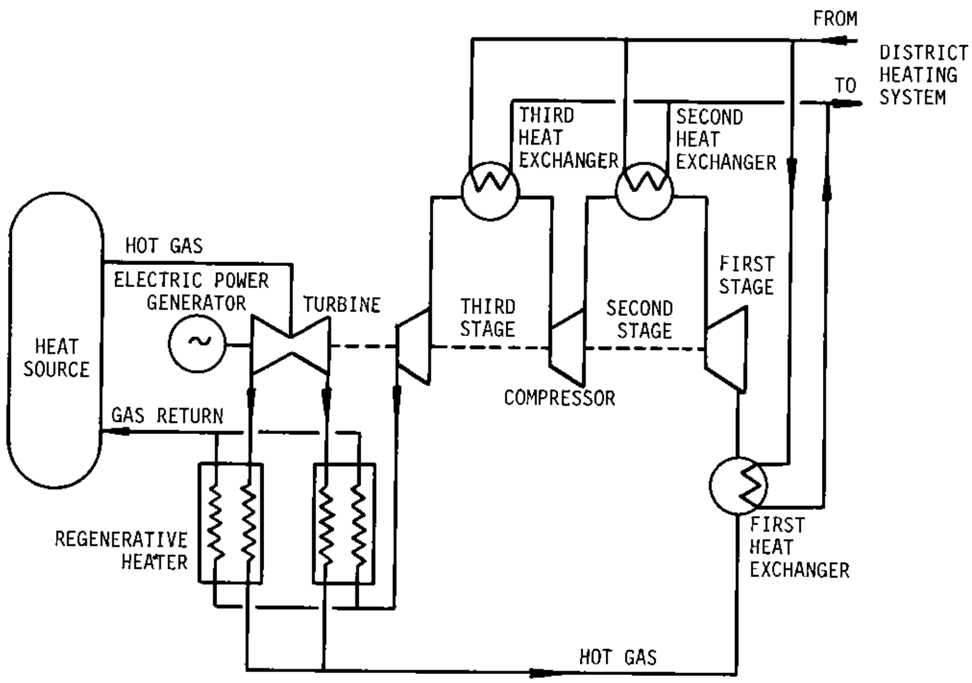

Fig. 10. Gas-Turbine and Compressor Heat-Electric System.

through a turbine. The turbine drives the electric power generator and the gas compressor, which return the gas to the heat source at the design pressure.

The gas exhausting from the turbine into the regenerative heater transfers a part of its heat to the gas returning to the heat source. The remainder of the heat added to the gas in the heat source is transferred to the heat system in the first heat exchanger. The first compression stage drives the gas through the second heat exchanger, where heat energy added by the compression process is transferred to the heat system. This is repeated by the second compression stage and third heat exchanger. The third compression stage returns the gas to the heat source through the regenerative heater. In this particular simplified illustration, there is no cooling water except from the district systems.

3. ENERGY UTILIZATION

A prime requisite for studying heat utilization from plants generating electricity is knowledge of the consumers' patterns of electricity and heat consumption. The patterns require description as they are now, as they project into the future, and as the projections may be altered by innovations. Information describing consumption and means for molding the characteristics of that consumption, as in the reference city analyzed in Section 6, are presented below.

Section 3.1 contains data and projections on the amounts of energy consumed in this country as electricity and as heat. It gives a basis for selection of the per capita electricity consumption in the reference city study, and it indicates the important amount of heat used in residential and commercial buildings. A presentation of information on present-day district heating systems points to an available background in large-scale operations.

Section 3.2 mainly describes the mechanics and economics of the beneficial use and dissipation of waste heat from the condenser cooling water by greenhouses, including those used in the reference city study. Likewise, Section 3.3 includes a description of sewage desalting by distillation for the water-recycle system employed in the reference city.

An analysis of propulsion with steam from hot water stored in mass transit and other urban vehicles for use at sometime beyond 1980 is in Section 3.4. Section 3.5 discusses factors influencing the desirability of using heat from an energy center for snow melting on walkways, highways, airport runways, and other public places. This application of waste heat utilization is not exploited in the reference city.

Statistical data and projections on industrial process steam consumption presented in Section 3.6 deal with the total quantity of process steam used in the United States and a breakdown by industry of the amounts and pressure requirements. Consumption in the reference city is based on these data, and conforms to the projected country average for a population of the chosen size.

Section 3.7 contains experience data and calculational techniques for determining energy consumption and design loads for space heating, water heating, and air-conditioning buildings. There is a detailed discussion of the waste heat dispersal capability of the absorption air-conditioning systems used in the reference city.

The cost of heat transfer systems using steam, hot water, Dowtherm, etc. are compared in Section 3.8. Section 3.9 contains information on the cost of space heating with electricity, individual building steam plants, and present-day commercial district heat to provide a basis for evaluating the economically competitive position of the hot-water district heating system serving many of the buildings in the reference city.

3.1 United States Statistics

3.1.1 Energy Statistics

This section on energy statistics is based on data and projections contained in a study by the Texas Eastern Transmission Corporation.[2] A recent projection of electricity consumption made by the United States Atomic Energy Commission,[3] which was based on data furnished by the Federal Power Commission, gives essentially the same results as the Texas Eastern Study.

The average rate of consumption of energy from fossil fuel, hydro, and nuclear energy sources in the United States in 1965 was 1.75×10^6 Mw(t). Of this total, 3.21×10^5 Mw(t) was used to produce 1.17×10^5 Mw of electrical power. Projected values for these energy-consumption rates to the year 1985 are given in Fig. 11.

The consumers of the energy are listed in Table 1. Commercial consumers consist of stores, office buildings, hotels, laundries, institutions, and government buildings. The energy is composed of all the energy in the fossil fuels and electricity delivered to the consumers. It does not include the waste heat rejected in the process of generating electricity. The energy consumed for residential space heating is based on Texas Eastern data for residential space heating. The commercial space heating was estimated by assuming that the fraction of commercial fossil-fueled energy used in space heating was the same as the fraction of residential fossil-fuel energy used for space heating. It was also assumed that the fraction of commercial space heating that was done electrically was the same as that for residential space heating. It is noteworthy that the Texas Eastern projections showed residential energy usage increasing by a factor of 1.5 during the period 1965–1980, whereas the commercial energy consumption was projected to increase by a factor of 2.5.

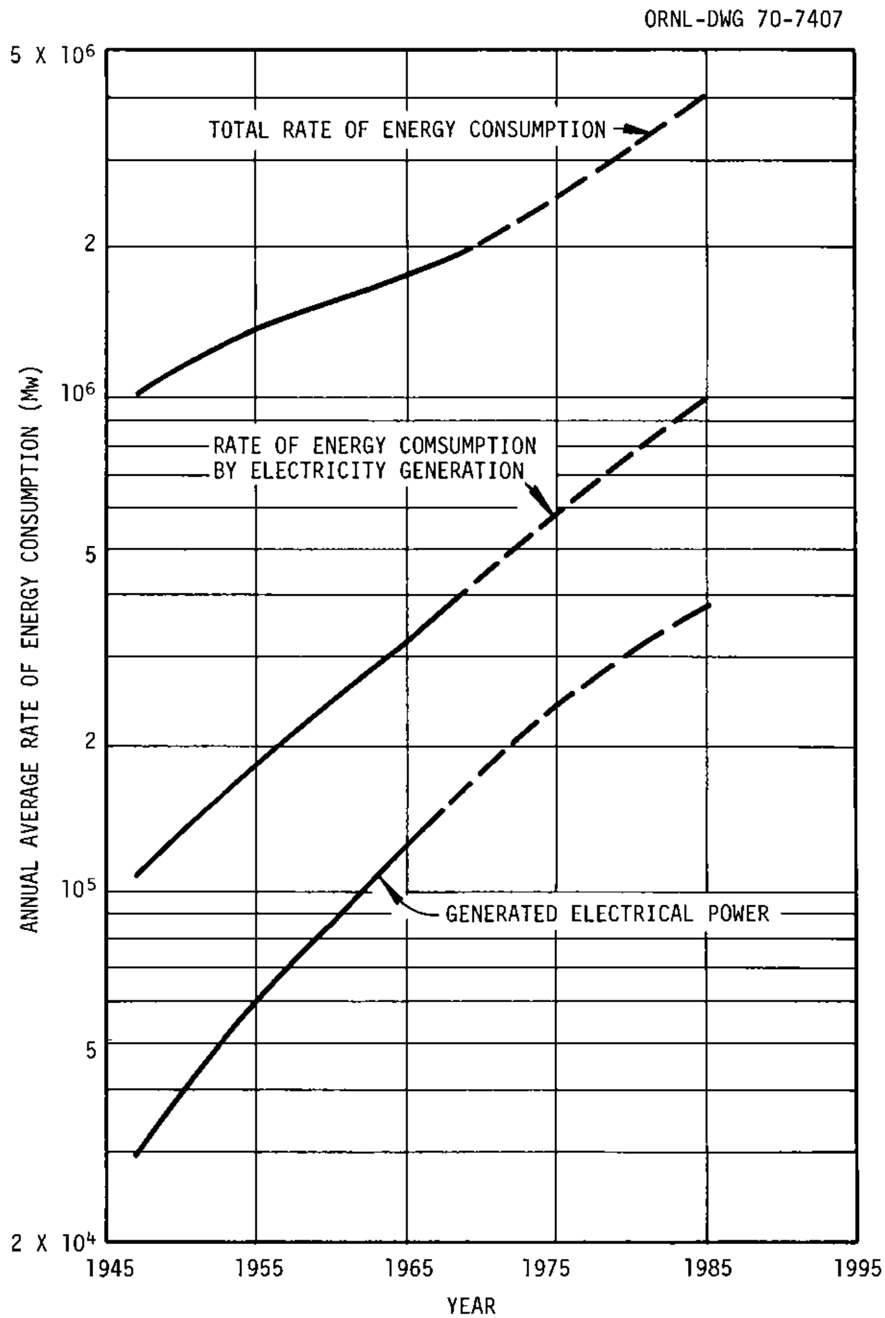

Fig. 11. U.S. Annual Average Rate of Energy Consumption from 1947 to 1985.

Table 1. Average Rate of Energy Delivery[a] to U. S. Consumers

Use	Energy (Mw)	
	1965	1980
Residential heat and power	301,491	454,444
Space heating component	(195,063)	(270,380)
Commercial heat and power	100,073	247,374
Space heating component	(47,150)	(92,983)
Transportation	431,467	734,764
Industrial heat and power	595,457	1,056,624
Total	1,428,488	2,493,206

[a]As fossil fuel and as electricity.

The average rate of consumption of energy in the United States in 1965 for space heating was estimated to be 2.53×10^5 Mw(t). Of this total 1.48×10^5 Mw(t) was used for residential space heating and 3.63×10^4 Mw(t) was used for commercial space heating. The remaining 6.87×10^4 Mw(t) was lost by inefficient combustion, electrical transmission losses, and waste heat rejected in the process of generating electricity. Of these losses, only that for inefficient combustion is included in the rate of energy delivery for space heating in Table 1. Projected values for the energy consumption rates for residential and commercial space heating requirements to the year 1985 are given in Fig. 12.

It may be seen from inspection of Figs. 11 and 12 that by 1980 the average annual rate of energy consumption for residential and commercial space heating is expected to equal approximately the country's average net electrical power production of 3×10^5 Mw in 1980. Space heating alone therefore has the potential for making a significant reduction in the emission of waste heat. Also, using the same heat distribution system, the buildings can be furnished with heat for air conditioning and hot water. Methods for using low-temperature heat for these applications,

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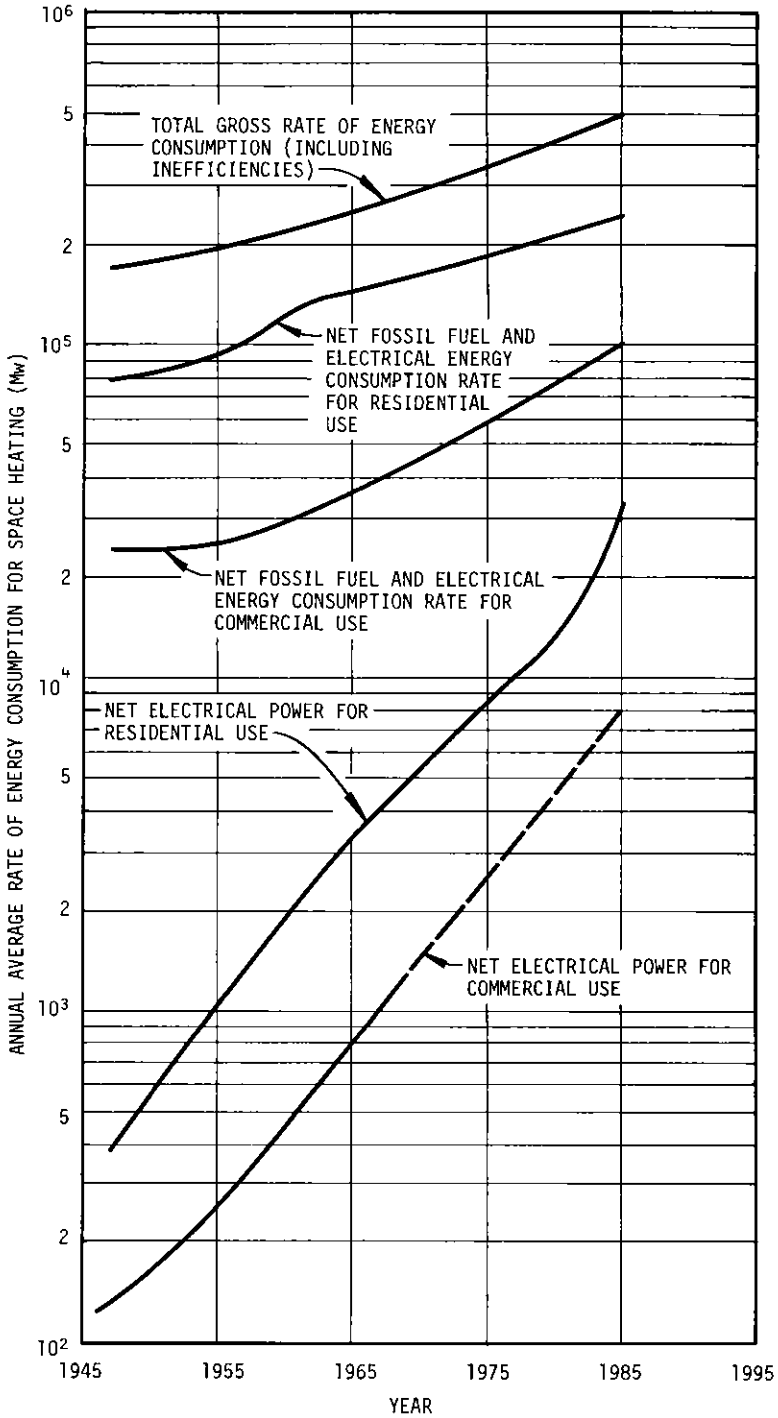

Fig. 12. U.S. Annual Average Rate of Energy Consumption for Space Heating from 1947 to 1985.

and for estimating consumption and variations in consumption for specific buildings, seasons, etc., are discussed in Section 3.7.

It may be seen from Table 1 that the largest user of energy is industry, and the portion that could be manufacturing process steam is estimated in Section 3.6. Since the next largest consumption is for transportation, in Section 3.5 one form of vehicle propulsion is described that utilizes the thermal energy stored in hot water.

3.1.2 Electricity Statistics

From a study by I. T. Dudley of ORNL of the characteristic electrical load curves of typical cities in the United States (based on Federal Power Commission data), three cities, Boston, Massachusetts, Jacksonville, Florida, and Seattle, Washington, were selected as representative of the effects of climate on the annual electrical load curve. Shown in Fig. 13

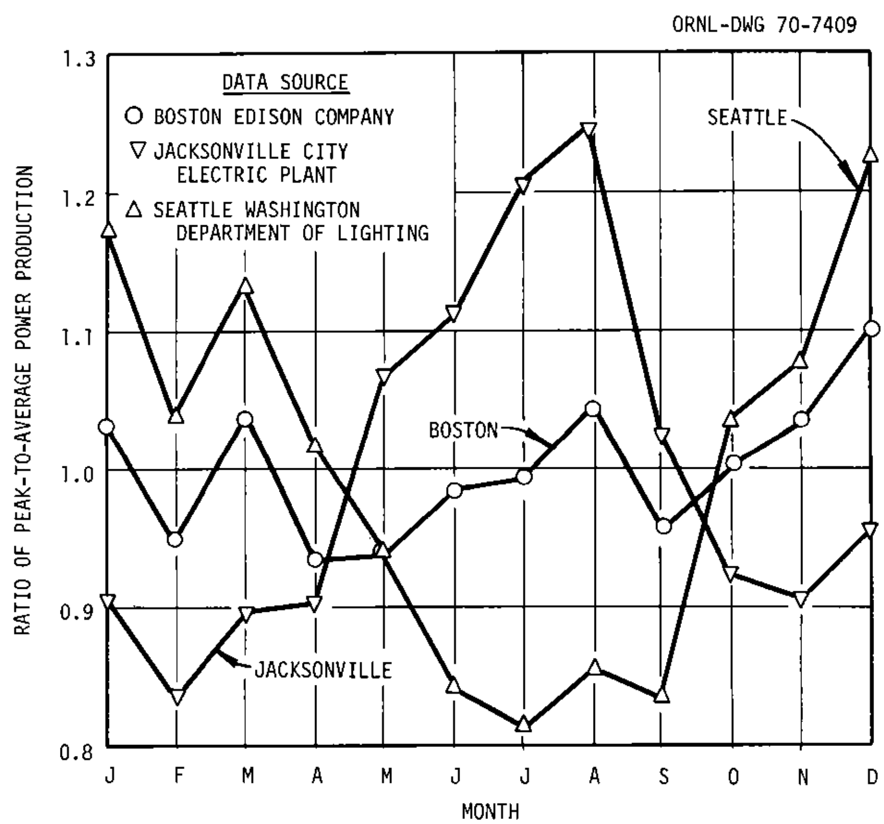

Fig. 13. Monthly Variations in the Electrical Loads of Three Representative Cities in the Year 1967.

are the monthly variations in the electrical requirements of these three cities for the year 1967. The diurnal variations for December 7, 1967, and August 10, 1967, are shown in Figs. 14 and 15, respectively. According to J. W. Megley of the International District Heating Association and the Boston Edison Company, the data on the Boston Edison Company from the Federal Power Commission include significant contract and bulk sales to other utilities; Figs. 14 and 15 include separate data points furnished for the Boston Edison service area.

Specific electrical energy consumptions of 11 utility system areas are presented in Table 2 that were calculated from Federal Power Commission data and information in the 1967 Electrical World Directory of Electrical Utilities. These cities were selected to show the variations in use of electrical power throughout the United States and may be compared with the average per capita consumption in the United States in 1967 of 6200 kwhr. On this basis the use of a projected average per

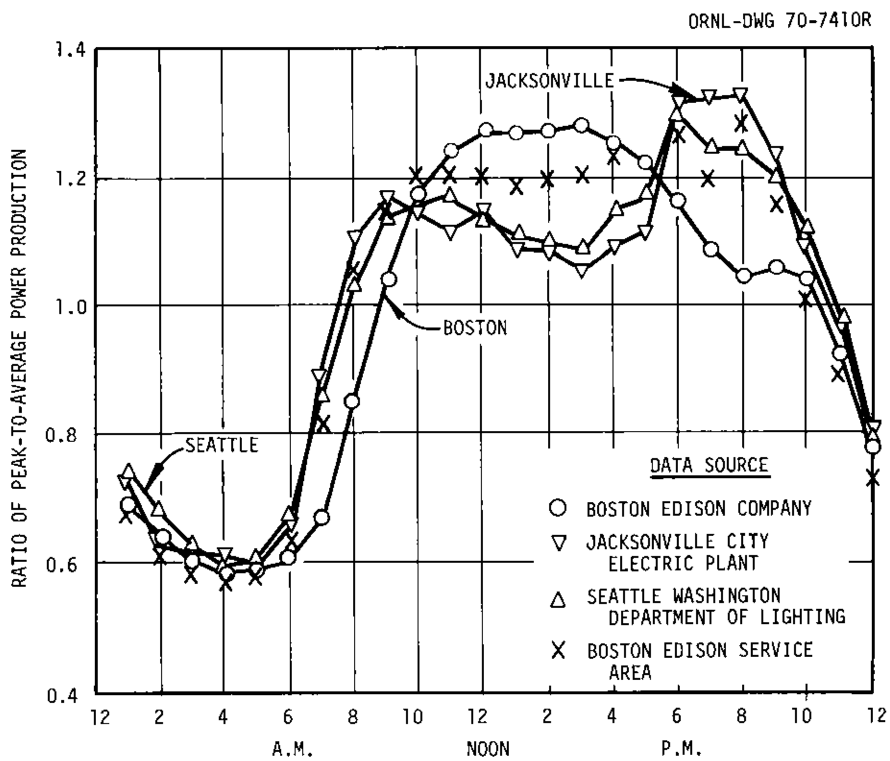

Fig. 14. Variations in the Electrical Loads of the Three Representative Cities on December 7, 1967.

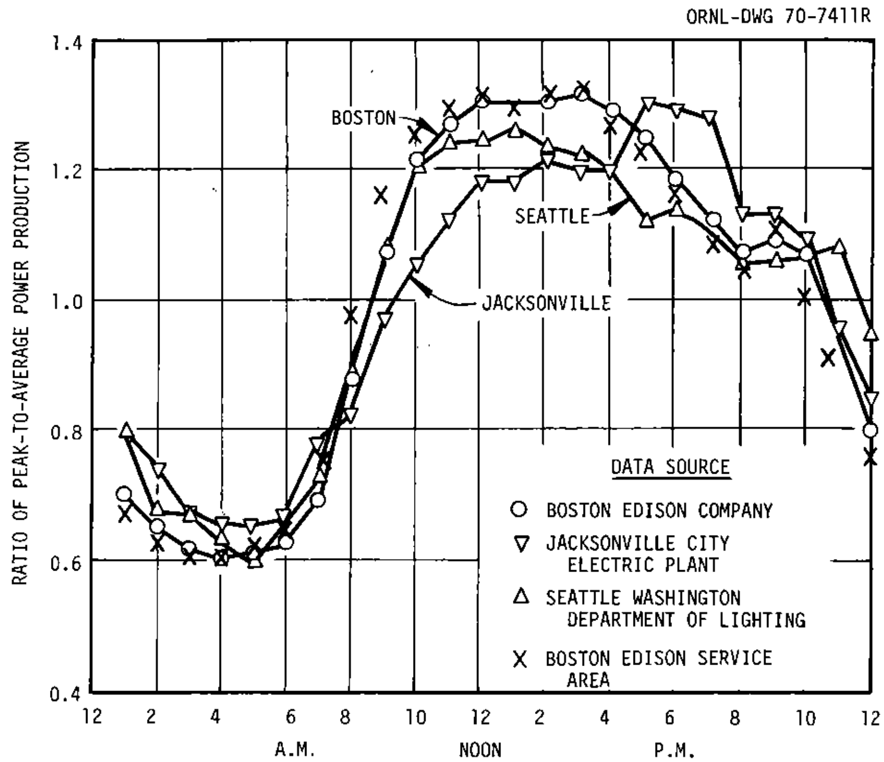

Fig. 15. Variations of the Electrical Loads of the Three Representative Cities on August 10, 1967.

Table 2. 1967 Per Capita Electrical Energy Consumption in Selected Areas in the United States

Area	Utility System	Per Capita Electricity Consumption (kwhr)
Anchorage, Alaska	City of Anchorage, Alaska	3,821
Boston, Mass.	Boston Edison Company	5,252
Dallas, Texas	Dallas Power & Light Company	7,403
Jacksonville, Fla.	City of Jacksonville, Florida	13,959
Kansas City, Kansas	Board of Public Utilities	5,644
Los Angeles, Calif.	City of Los Angeles	4,567
Memphis, Tennessee	Memphis Light, Gas & Water Division	6,896
Phoenix, Arizona	Arizona Public Service Company	8,500
Rochester, Minn.	City Electric Department, Rochester, Minnesota	6,221
Seattle, Wash.	The City of Seattle, Department of Lighting	10,306
Tucson, Arizona	Tucson Gas & Electric Company	6,936

capita consumption in the 1980 reference city discussed in Section 6 appears to be reasonable.

3.1.3 Statistics for District Heating Companies

There is some limited significance in comparisons of existing district heating systems and the reference-city system in Section 6 with respect to size, load factors, minimum load, etc. Forty-four district heating companies in U. S. cities reported data for 1968 on 20 operating and cost characteristics to the Statistics Committee of the International District Heating Association (IDHA).[4] A brief summary of operating characteristics derived from these data is given in Table 3.

Table 3. District Heating System Operating Characteristics for 1968

	44 City Systems	Largest System (New York)	Second to Eleventh Largest Systems
Total steam sold, 10^3 lb	84,245,528	32,702,528	34,862,337
Total steam delivered to system, 10^3 lb	96,672,365	38,469,388	38,806,916
Annual system load factor,[a] %	33	37	34
Number of customers served	14,903	2,514	6,569
Length of distribution system piping, 10^3 ft	3,028	528	1,416

[a]Based on the year's peak hourly delivery and the total steam delivered to the system during the year.

Of interest is the fact that among the 11 large city systems the lowest quantity of steam sold per year per foot of distribution system was 13,900 lb/yr·ft in Indianapolis, Indiana. Only a small amount of the distributed steam was used for air conditioning. The total installed tonnages of air conditioning on the systems were reported to the Sales

Development Committee of IDHA to be the following:[5]

City	Tons
New York	569,945
St. Louis	1,200
Boston	36,532
Philadelphia	13,338
Detroit	20,609
Baltimore	3,610
Rochester, N.Y.	8,240
Denver	8,465
Rochester, Minn.	572
Seattle	90
Grand Rapids	3,450

The estimated composition of the New York district heating system load, as provided to ORNL by the Consolidated Edison Company of New York, Inc., was

Residences	30%
Office buildings	45%
Industries	11%
Institutions	13%

Estimated typical diurnal load curves that were supplied for various seasons are shown in Fig. 16. It may be seen from the summer day curve that there is considerable consumption of steam for air conditioning. The steam curves for the system for calendar years 1966 and 1967 are shown in Fig. 17.

In another example, the Hartford district heating system supplies both steam and chilled water to its customers, who are all commercial, in a four-pipe system. The chilled water is produced at the plant by steam-driven chillers. Snow melting is also done in a large area of walkways. The data on the system loads, given in Table 4, were furnished to ORNL by the Connecticut Natural Gas Corporation. From Table 4 it may be seen that peak steam usage by customers for heating and peak steam usage by the district system for producing chilled water are about equal. The Corporation also stated that the portion of the 1968 steam production that was used for the chillers was approximately 32%. It is estimated on the basis of the above information that the steam consumption by the chillers during 1968 was 17% of that required for a year of operation at the year's

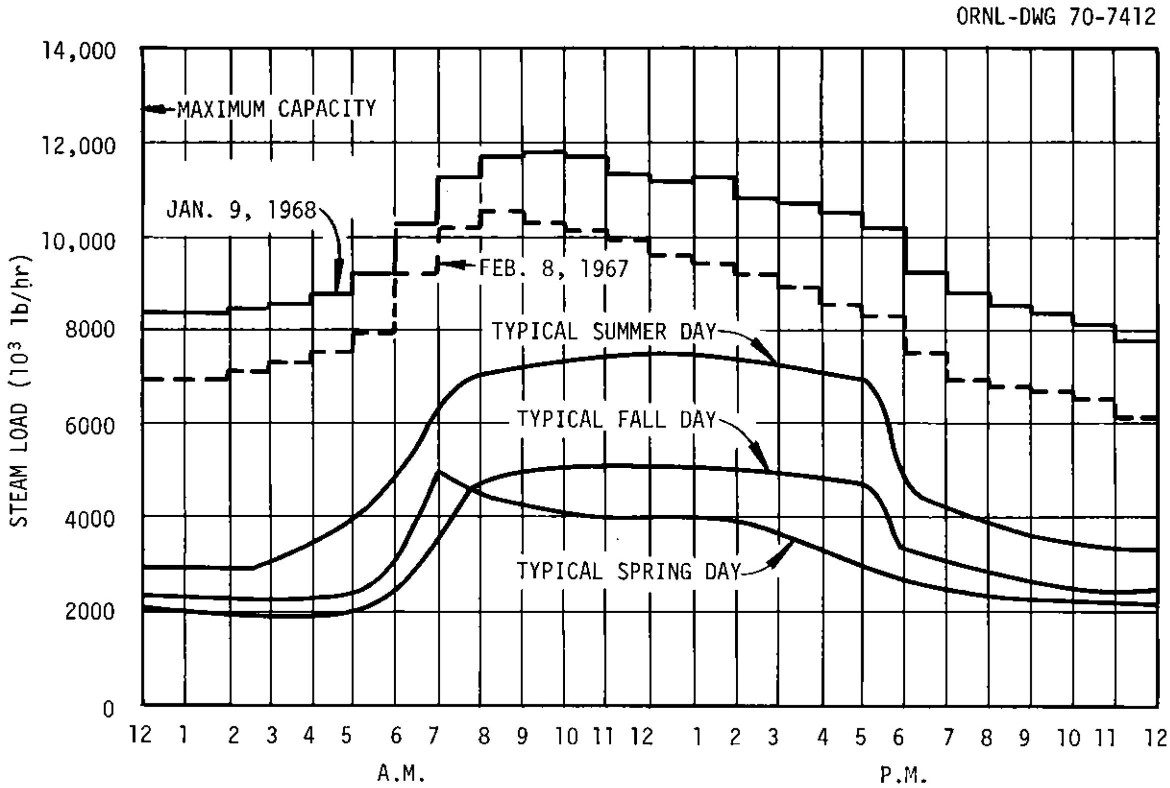

Fig. 16. New York Steam System Load Curves on Typical Days. (Information supplied by Consolidated Edison Company of New York)

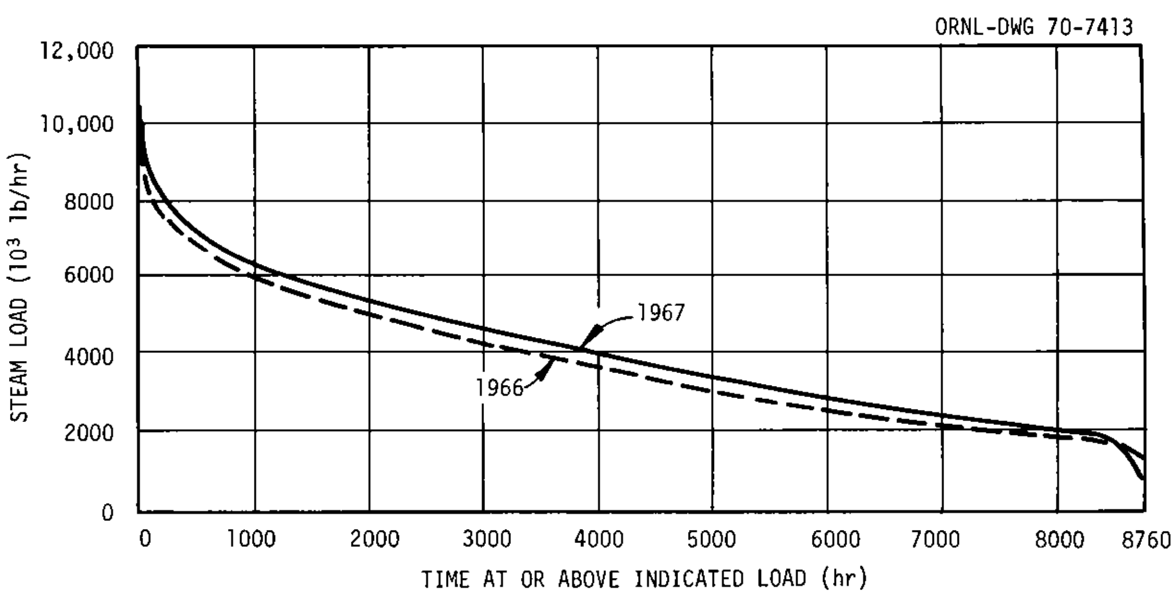

Fig. 17. New York Steam System Loads for Calendar Years 1966 and 1967. (Information supplied by Consolidated Edison Company of New York)

Table 4. Hartford District Heating System Load Data Supplied by Connecticut Natural Gas Corporation

	System Load Data (thousands of pounds)				
	Production	Sales	Plant Use	Refrigeration	Losses
	During 1968 (12 months)				
Maximum days					
1-8-68, A.O.T.[a] 3.2°F	3847.0	3246.0	461.6	93.2	46.2
7-18-68, A.O.T. 81.5°F	3751.6	550.0	378.9	2816.6	6.1
Minimum day, 3-31-68, A.O.T. 56.0°F	920.8	693.0	64.5	160.2	3.1
Maximum hours					
1-2-68, 7 to 8 a.m.	199.0				
7-17-68, 1 to 2 p.m.	215.0				
Minimum hour, 9-1-68, 12 to 1 p.m.	58.0				
Average day (366 days)	2048.2	1171.6	192.3	656.7	27.6
Average hour (8784 hours)	85.3	48.8	8.0	27.4	1.1
	During First Nine Months of 1969				
Maximum days					
1-29-69, A.O.T. 24.0°F	3356.6	2877.0	352.4	98.4	28.8
7-17-69, A.O.T. 80.9°F	4133.0	443.0	530.4	3112.6	47.0
Minimum day, 5-4-69, A.O.T. 62.2°F	1124.4	588.0	134.9	380.5	21.0
Maximum hours					
1-29-69, 8 to 9 a.m.	179.0				
7-17-69, 2 to 3 p.m.	238.0				
Minimum hour, 5-30-69, 8 to 9 a.m.	65.0				
Average day (273 days)	2223.3	1071.7	256.3	844.5	50.8
Average hour (6552 hours)	92.6	44.7	10.7	35.2	2.0

[a]Average outside temperature.

peak hourly demand. It may also be seen from Table 4 that the minimum hourly steam production in 1968 occurred in the fall and amounted to 27% of the year's hourly peak and that the minimum hourly production in the spring of 1969 was also 27% of the year's peak. The average hourly steam production in 1968 was 40% of peak, and for the first nine months in 1969, it was 39%. Monthly production of steam in the Hartford System for all purposes during 1968 was reported to be as follows:

Month	Thousands of Pounds
January	84,715
February	78,296
March	58,847
April	43,288
May	46,896
June	56,153
July	68,553
August	74,506
September	61,807
October	49,709
November	54,824
December	70,872

The Equitable Gas-Energy Company in Pittsburgh supplies steam heat, hot-water heat, and chilled water for air conditioning to a large commercial and residential complex – Allegheny Center.[6] The daily total steam production data for all purposes from July 1, 1968 through June 30, 1969 supplied by the Company to ORNL are plotted in Fig. 18.

A study of a central steam-heating and chilled-water air-conditioning system for an urban district in Nashville was prepared by I. C. Thomasson & Associates. From their data[7] it is estimated that the load factor on the heating system expected for 1980 is 31% and that the annual consumption of chilled water is expected to be 22% of the maximum possible demand of the consumers.

3.2 Waste Heat for Heating and Cooling of Greenhouses and for Other Agricultural Uses*

Low-temperature waste heat is receiving considerable attention in the United States today for application in agriculture and aquaculture. The

*Based on studies by S. E. Beall and G. Samuels of ORNL.

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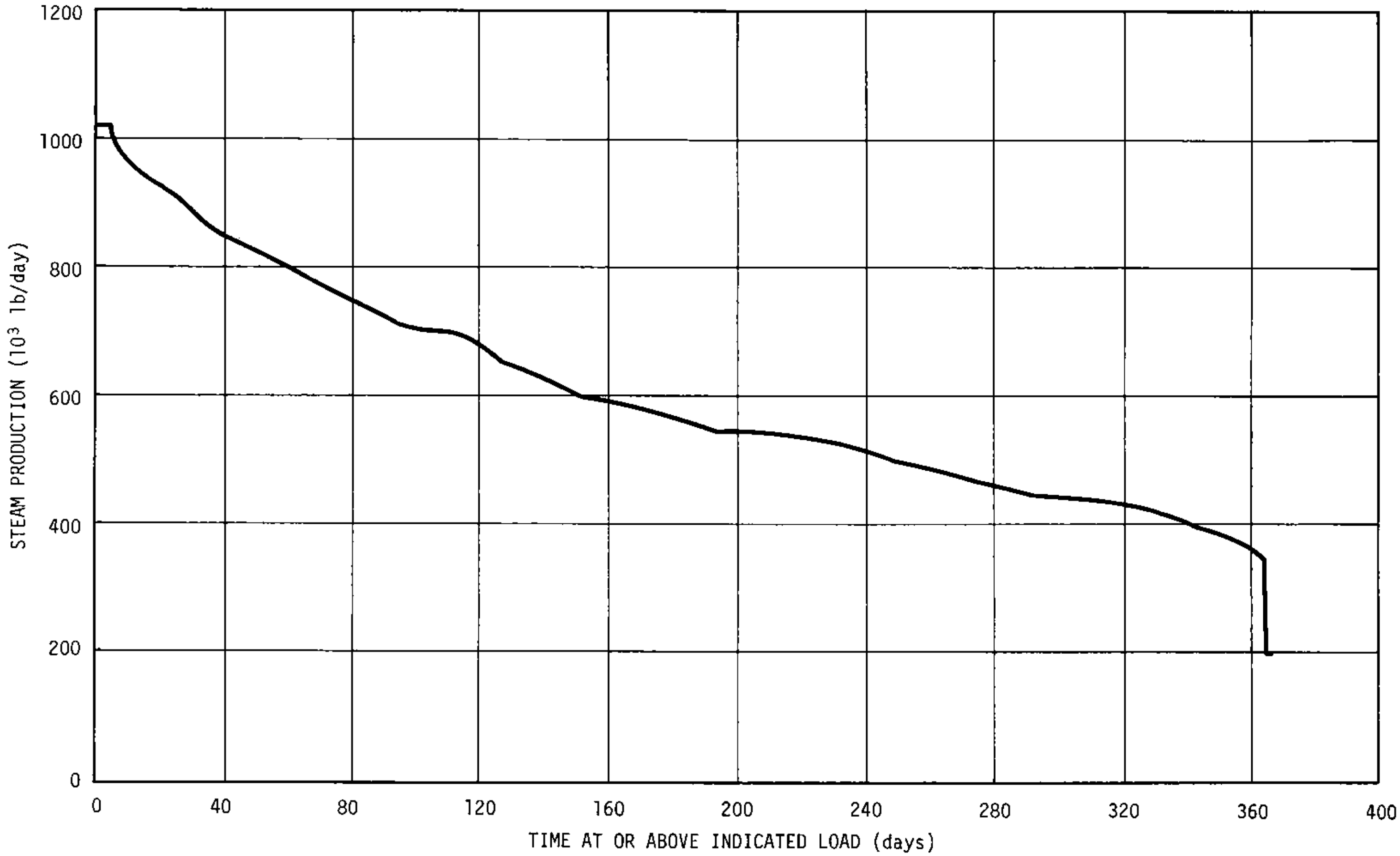

Fig. 18. Allegheny Center Steam System Load for July 1968 Through June 1969.

temperature of heat rejected from many power plants is high enough to be used for heating greenhouses, poultry houses or aquaculture ponds. Even in circumstances where the rejected heat is below 80°F the temperature of the discharge water can be economically raised to a useful range with a small loss in generating efficiency. These applications are most attractive if the food-growing structures can be located in a reactor exclusion area (which is usually 500 or more acres of idle land) so that normal turbine condenser outlet water can be circulated to the houses or ponds.

Also, utilities in the Pacific Northwest and the States of Washington and Oregon have begun regional studies that include other agricultural considerations, and studies of this type should be undertaken elsewhere in the United States. So far, almost all power needs in the northwest have been met with hydrogenerating capacity, but the utilities and the states are looking ahead at the problems, especially thermal pollution, that will accompany the steam power stations that will be needed in the future. The Washington State Research Center is spending $430,000 on a study of possible plant sites and agricultural development along the Columbia River. The Eugene (Oregon) Water and Electric Board is financing several experimental farms (totaling 170 acres) to study irrigation with water as hot as 135°F. Their studies indicate that water at this temperature, sprayed from a height of 8 or 10 ft, will cool to ambient air temperature by the time it reaches the ground and will not damage field crops in hot weather. They have found that the spring and fall growing seasons can be extended past the light-frost periods as a result of warm water sprays. The State of Washington is supporting similar work at Washington State University. At Oregon State University there is an investigation of the effect (on crop growth) of underground pipes heated with condenser discharge water. Depending on the site, the warm water might also be distributed through existing irrigation canals but, of course, much of the heat would be lost prior to spraying onto crops.

3.2.1 Waste Heat Temperature Requirements

There are many large cities in the United States that depend heavily on truck and rail shipments for their fresh vegetable, poultry, and fish supplies. ORNL has studied the food requirements of the city of Denver, Colorado, as an example, and estimated that it would require more than 600 acres of greenhouses to provide the city's consumption of tomatoes, peppers, cucumbers, lettuce, and other fresh vegetables. The normally discarded heat from a 1000-Mw(e) reactor is sufficient to heat 750 to 1500 acres of greenhouses, depending on the location. At Denver, which has low wet-bulb temperatures, it would be possible to replace the cooling tower at the Ft. St. Vrain station of Colorado Public Service Company with cheap evaporative cooler-heaters located in the greenhouses (or poultry houses). The houses could be cooled to at least 75°F in the summer by evaporating 92°F water from the turbine condenser with once-through air. In the winter the evaporative pads could be operated in an air-recirculating mode so that the air temperature would be maintained above 65°F with a zero outside temperature.

3.2.2 Effect of Waste Heat on Agricultural Production

Table 5 indicates how much fresh produce can be grown in a 500-acre greenhouse range. The value of the produce averages $27,000/acre for the indicated mixture of vegetables. The University of Arizona, in cooperation with the University of Sonora, Mexico, has an experiment[8] under way at Puerto Penasco, Sonora, Mexico, to demonstrate how a combined desalting, diesel-electrical generation, and greenhouse-heating operation can be managed. The yields in Table 5 were extrapolated to the much greater acreage on the basis of the experience in Mexico in one winter season of growth. The success of this venture is indicated by the recent announcement that the Sheikh of Abu Dhabi (on the Persian Gulf) has appropriated $3,200,000 for the design and installation of a 20-acre greenhouse complex with desalting and electrical generation for that city of 20,000 people. The expected production of vegetables is 2×10^6 lb per year.

In Iceland, which is blessed with an abundance of geothermal energy, flowers and vegetables are grown commercially in more than 30 acres of geothermally heated glasshouses. In the vicinity of Cleveland, Ohio, more than 500 acres of glasshouses are used for vegetable culture.

Table 5. Possible Mixture of Crops for Controlled-Environment Greenhouse Complex

Crop	Days Required Per Crop	Yield Per Crop-Acre[a]	Crops Per Year	Yield Per Acre-Year	Wholesale Value Per Acre-Year[b]	Acres Assigned	Total Income
Cucumbers	100	144,000 lb	3.6	518,000 lb	$41,440 at 8¢/lb	50	$ 2,072,000
Eggplants	130	24,000 lb	2.7	67,500 lb	$10,100 at 15¢/lb	50	505,000
Lettuce (leaf)	40	84,000 heads	9	756,000 heads	$37,800 at 5¢/head	100	3,780,000
Bell peppers	146	30,000 lb	2.5	75,000 lb	$18,750 at 25¢/lb	50	937,500
Radishes	30	480,000 bunches	12	5,760,000 bunches	$288,000 at 5¢/bunch	5	1,440,000
Squash	105	22,200	3.6	80,000 lb	$12,000 at 15¢/lb	50	600,000
Tomatoes	140	92,000	2.5	230,000	$23,000 at 10¢/lb	100	2,300,000
Flowers	180	40,000 plants	2	80,000	$20,000 at 25¢/plant	50	1,000,000
Strawberries	180	40,000 lb	2	80,000	$20,000 at 25¢/lb	50	1,000,000
						505	$13,634,000
					Projected average income:		$27,230/acre

[a]Winter season, Puerto Penasco Experiment Station, Sonora, Mexico.

[b]1966 wholesale prices, mostly from U.S.D.A. Yearbook for 1967.

Commercial cultivation of tomatoes in greenhouses is profitable with heat from oil-fired heaters at \$1 to \$1.50/MBtu, making the total heat cost as high as \$10,000/acre. Reactor heat at 20¢/MBtu would produce an additional profit of \$4,000 to \$6,000/acre. Just as important would be the increased income to the reactor operator. Selling the heat at 20¢/MBtu to a 500-acre greenhouse range could increase the reactor operating profit by \$500,000 to \$1,000,000 per year. This would be an additional 10 to 15% net profit for a 1000-Mw(e) plant operating 8000 hr per year, which might normally expect a profit of \$6 to \$9 million per year from the sale of electricity.

Admittedly, a 500-acre greenhouse operation would be a big undertaking anywhere in the world, but it is not necessary that all the heat be used for greenhouses. Broiler and egg production and animal husbandry are also potential large consumers of heat, and fowl and animals are normally raised in light, uninsulated structures that could accommodate the evaporative cooling-heating system. The Denver area could support a 200-acre spread of broiler and laying houses.

The evaporative system proposed for these applications requires a constant blowdown of a few percentage of the total flow to avoid a buildup of salts in the circulating water. For a 1000-Mw(e) power plant, the blowdown rate could be as much as 10,000 gpm. If the warm water were discharged either from cooling tower blowdown or by once-through cooling, it could be used to maintain temperatures in pools for algae growing and fish culture. Several studies have shown[9] that a combination of controlled warm temperatures and nutrient supply from animal wastes or city sewage effluent could produce heavy yields of algae — up to 30,000 lb/acre. The algae could be centrifuged, dried, and used as food for fish, fowl, and animals. Several organizations (Nuclear Utilities Services and the University of California) have large-scale experiments in progress.

In recent years the culture of catfish and trout has become commercially feasible. At constant optimum growth temperatures, such as 90°F for catfish, production can be greatly increased compared with growth at ambient temperatures. Yields of 2000 to 4000 lb per acre-year are possible in pond cultivation, and greater than 200,000 lb per acre-year has been demonstrated in flowing raceways supplied with adequate oxygen and food.

With a 5000-gpm blowdown stream, an annual production of 400 to 500,000 lb can be expected.

Depending on the particular reactor site, there are several other possibilities for applying warm-water effluents to aquaculture operations. Higher yields of fish, shellfish, and crustaceans have been demonstrated where optimum growth rates are maintained with regulated water temperatures. The Long Island Lighting Company, at their Northport Long Island plant, is engaged in a cooperative experiment in oyster culture and is planning on commercial-scale operations. The Maine Power and Light Company is supporting an experiment on improving lobster growth rates with warm water. At the University of Miami Marine Laboratory, on Biscayne Bay south of Miami, Florida, experiments are being conducted with shrimp culture in water similar to that to be discharged from the Turkey Point station of the Florida Power and Light Company. At Panama City, Florida, and at Key West, Florida, commercial shrimp farms are being established. It is expected that harvests of 2000 lb or more shrimp per acre will be demonstrated, as has been done in Japan.

3.2.3 Economics of Heating Greenhouses in Denver Area

A study to evaluate the economics of heating greenhouses was made for the Denver, Colorado, area with the Fort St. Vrain nuclear installation as the reference plant. The objectives of this study were to (1) determine the feasibility of using heat rejected from a power plant without increasing the condenser pressure or penalizing the power plant in any manner, (2) determine the relative capital cost of using this heat as compared with conventional heat sources, and (3) estimate the value of the heat.

In order to minimize the cost of the heat exchangers and also to use the greenhouses to reject the plant waste heat in summer, a direct-contact evaporative-pad heat exchanger was selected. Figure 19 shows a section of the type of evaporative pad commonly used to cool greenhouses. The one chosen for this study has aspen fibers or splinters for packing. Normally these units use recycled water at a minimum flow rate of 1/3 to 1 gpm/ft of pad. The recycled water temperature approaches the wet-bulb temperature during operation, and the water in turn cools the air drawn

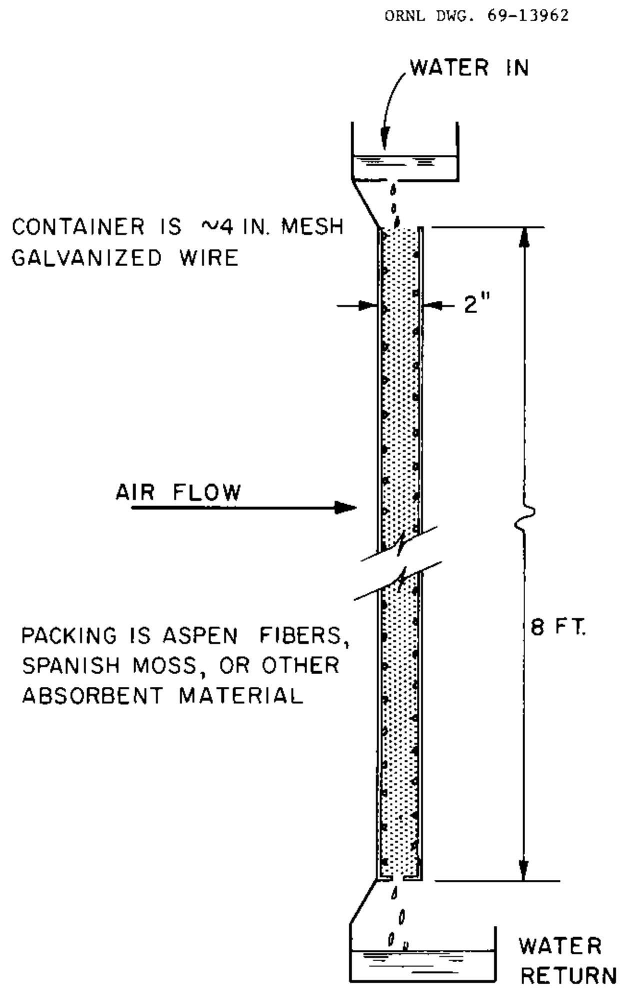

Fig. 19. Cross Section of Evaporative Pad of Type Used to Cool Greenhouses.

through the pad. In warm climates with wet-bulb temperatures below 75°F, summer cooling can be maintained with 92°F water. More important, the pads can be used to heat the greenhouses in the winter and make the power plant cooling towers unnecessary.

Figure 20 shows the greenhouse arrangement used for this application. Except for the plastic sheet, this arrangement is fairly typical of large units that use evaporative pads for summer cooling. The plastic sheet is used to form an attic to serve as a passage for recycling air during cold weather. During the summer the air is drawn through the pads and exhausts at opposite ends. As the outside temperature and thus the

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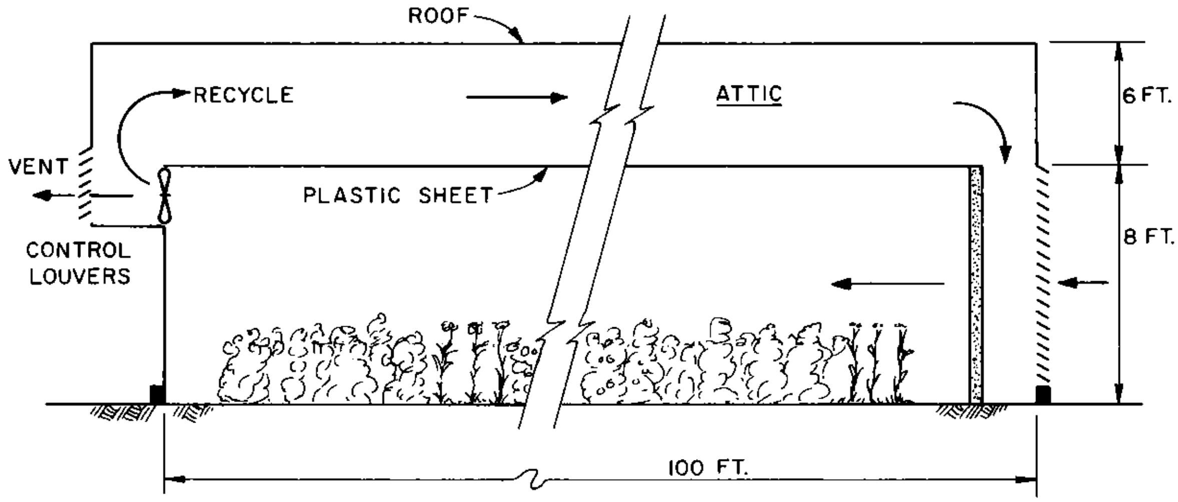

Fig. 20. Typical Greenhouse and Air Flow System.

inside temperature drops, the vent louvers close and force the air to recycle through the pads, where the air is heated by the water. The main difficulty with this system is that during cold nights the humidity of the air leaving the pads is 100%. Since most food-growing operations cannot stand such high humidity, a finned-tube heat exchanger has been designed in series with the pad. To reduce the humidity to 70 to 80% requires that about one-third to one-half the heat be added by the dry heat exchanger and the remainder by the pads.

Table 6 gives the air and water conditions for several summer operating cases with the pads replacing the cooling towers normally employed at the Fort St. Vrain plant. It was assumed that the hot water from the condenser would be pumped directly to the greenhouses without intermediate cooling. The air and water flow rates are for each 50 × 100-ft greenhouse. The first case is for summer design conditions for the Denver area (64°F wet bulb) and for the total plant waste heat of 500 Mw dumped to 100 acres of greenhouses. In all cases the range of the water temperature is 22°F, the same as for the Fort St. Vrain plant, which is designed for 80 to 102°F. It is interesting to note that if the pads had been operated in the normal manner with recycled water, the air temperature from the pads would be 70°F, so the penalty or increase in greenhouse temperature caused

Table 6. Greenhouse Conditions for Summer Operation

Case	Ambient Conditions		Air Flow Rate (lb/hr)	Water Flow Rate (lb/hr)	Range of Conditions in Greenhouse		Range of Water Temperature (°F)
	Dry Bulb Temperature (°F)	Relative Humidity (%)			Temperature (°F)	Relative Humidity (%)	
1[a]	95	16	306,000	88,200	76–86	80–67	67–89
2[b]	50	73	306,000	88,200	~58	~95	51–73
3[b,c]	50	73	153,000	88,200	~67	~100	57–79
4[d]	95	16	306,000	44,100	71–81	85–71	64–86
5[e]	50	73	306,000	44,100	~53	~90	48–70
6[f]	50	73	153,000	44,100	~57	~100	50–72

[a]Summer conditions for Denver (64°F wet bulb) and 500 Mw of waste heat dumped to 100 acres of greenhouses.

[b]Moisture in air assumed to remain same as for day conditions, but dry bulb temperature dropped to 50°F.

[c]Air flow rate reduced by one-half.

[d]Conditions same as in case 1, except that 200 acres of greenhouses were assumed and the water flow rate was reduced by one-half.

[e]Similar to case 2, with 200 acres of greenhouses and water flow rate reduced by one-half.

[f]Similar to case 3, with 200 acres of greenhouses and water flow rate reduced by one-half.

by using the pads to replace the cooling towers is only 6°F. For the second and third cases it was assumed that the amount of moisture in the air remained the same as the day design condition and the dry-bulb temperature dropped to 50°F. For the third case it was assumed that the air flow was reduced by one-half. Cases 4, 5, and 6 are repeats of the first three cases except that it was assumed that there was 200 acres of greenhouses and the water flow rate per greenhouse was cut to one-half. It is also interesting to note that the return water temperature to the condenser is 13 to 16°F colder with the pads than with the present cooling towers. The heat load on the greenhouses was 295 to 300 Btu/hr·ft^2, which is the maximum solar load for latitude 40°. It was assumed that one-half the solar heat evaporated moisture in the greenhouse and the other half appeared as sensible heat. The air flow rates shown in Table 6 were calculated to limit the air temperature rise to 10°F in passing through the greenhouse.

Table 7 gives similar data for winter operating conditions. In addition to the outside temperatures shown here, the wind velocity was assumed to be 15 mph and the sky was assumed to be clear with an effective temperature of -100°F. The water flow rate for the first five cases is for 200 acres, while the rate for the last two cases is for emergency conditions when the plant is shut down and an emergency heater is being used to supply heat at a rate of 1.5 Mw/acre. The table also shows the effect of venting at low rates on the air, water, and roof temperatures. Actually, the heat available from the plant is sufficient to heat 250 to 300 acres.

The cost of the equipment to use the plant waste heat is in the range of the cost for conventional heating systems. The reported costs of conventional systems vary from \$0.50 to \$1.00/ft^2 or \$22,000 to \$44,000 per acre. The cost of the added equipment to use the waste heat (pumps, piping, emergency heater, and plastic liner for the attic) is about \$35,000/acre for 100 acres. Taking credit for eliminating the cooling towers now provided for the Fort St. Vrain plant would reduce this figure to about \$18,000 to \$20,000/acre. For a 200-acre layout, the cost per acre of added equipment would be about \$27,000, and again taking credit for eliminating the cooling tower would reduce this to \$18,000 to \$20,000/acre. If dry heat were needed to reduce the humidity to 70 to

Table 7. Greenhouse Conditions for Winter Operation

Wind velocity: 15 mph
Effective sky temperature: -100°F
Greenhouse area: 200 acres

Outside Air Temperature (°F)	Water Flow Rate (lb/hr)	Air Flow Rate (lb/hr)		Air Temperature (°F)		Range of Water Temperature (°F)	Mean Roof Temperature (°F)
		Recycle	Vent	Over Plants	Through Attic		
-30	44,100	153,000	0	72	72–65	66–88	1
-15	44,100	153,000	0	76	76–69	71–93	15
0	44,100	153,000	0	80	80–74	75–97	26.5
0	44,100	148,400	4,600	72	72–65	66–88	21
0	44,100	141,400	11,600	63	63–56	56–78	15
0[a]	26,500	153,000	0	56	56–50	51–73	12
0[a]	26,500	148,400	4,600	51	51–44	45–67	8.5

[a]Emergency conditions: reactor shut down and an emergency heater being used to supply heat at the rate of 1.5 Mw per acre.

80%, the cost of the heat exchangers would be about \$5,000/acre and the total \$23,000 to \$25,000/acre.

The reported cost of heating greenhouses is in the range \$5,000 to \$10,000/acre per year. For the Denver area, the total heat required per acre will be 5×10^9 to 10×10^9 Btu/year. If the cost or value of the heat is assumed to be only 20¢/MBtu, the yearly total heat cost is \$1,000 to \$2,000/acre and for 200 acres is \$200,000 to \$400,000 per year.

3.2.4 Extrapolation of Economics to Reference City in an Area with the Climate of Philadelphia

No calculations were made specifically for Philadelphia, Pennsylvania, which provided the reference climate data used for the reference city discussed in Section 6. However, the results of the Denver calculations can be extrapolated to estimate the performance of such a system for other climatic conditions. For Philadelphia, the median of the annual extreme winter temperatures is 7°F with an average of 22 hr less than or equal to 11°F and 54 hr less than or equal to 15°F. For these relatively mild winter conditions and the greenhouse heating system described above, the heat required per acre will be somewhat less than 1.5 Mw.

With the power system designed for the reference city study, all the reject heat is needed in the city, except a minimum of 263 Mw in the winter, a maximum of 1180 Mw in the spring or fall, and a maximum of 756 Mw in the summer. The minimum heat-rejection rate of 263 Mw in the winter is sufficient to heat approximately 200 acres of greenhouses, but a 1200-Mw rejection rate (~6 Mw/acre) can be managed at any season, based on Samuels' calculations.

It was assumed that the greenhouse water system could handle all the warm water when necessary and dissipate all the heat (a maximum of 1180 Mw) so that no cooling towers were necessary. The cost of equipment to distribute and utilize the heat from the reactor in the greenhouses is about \$6,750,000. This figure includes the piping, the incremental cost of the pumps, an emergency heat system, the plastic material to form the attics in the greenhouses, and \$1,000,000 for heat exchangers to reduce the humidity on winter nights. The cost of the cooling towers if there had been no greenhouses was assumed to be \$6/kw of heat rejected by natural draft towers, as in Section 4.3, or $7,080,000; the cost of conventional greenhouse heating equipment was taken to be $22,000/acre or $4,730,000 for 200 acres. By use of the greenhouses the cooling tower cost of $7,080,000 was saved. There was an increase of $2,350,000 in the greenhouse heating equipment cost, the "greenhouse heat-dissipation system (differential cost)," borne by the energy center operator in the reference city study. Thus by use of the reactor-greenhouse complex, there was a net savings in equipment costs of $4,730,000, as compared with separate operation of a reactor and heated greenhouses.

The cost of fuel for heating conventional greenhouses in the Philadelphia area, assuming fuel costs of $1/MBtu to $1.5/MBtu, is $5,000 to $7,500/acre. Thus the system described as the second case would reduce the operating cost by more than $1,000,000 per year for 200 acres. The evaporative pad units would also be advantageous for summer operation. First, the water leaving the pads and returning to the power plant condenser would be within a few degrees of the wet-bulb temperature. This is lower than would normally be delivered by a cooling tower and would increase the efficiency of the plant during hot weather. Second, the evaporative pads fed with warm water would cool the air passed over the plants growing in the greenhouses to within 5° of the wet bulb. Without the pads the temperature of the air, at Philadelphia summer design conditions, would enter at 90 to 93°F and exit at 100 to 103°F (daytime). With the pads the corresponding air temperatures would be about 10°F less — that is, 83°F at the pad end and 93°F at the exit end.

As a result of these considerations, the cost of energy in the reference city in Section 6 was computed under several circumstances — with no use of greenhouses, with the use of greenhouses instead of cooling towers and no charge for greenhouse heating, and with several different charge rates for greenhouse heat.

3.3 Desalting of Sewage by Distillation to Obtain Water for Recycle*

Desalting sewage is one of the potential uses of thermal energy from a nuclear-fueled energy center serving an urban area. The increasing

*Adapted from work performed under interagency agreement IAA-H-3-69 and reported in Ref. 10.

problems of properly disposing of sewage and the increasing demands on natural water supplies make this potential application of thermal energy extremely important.

It is now generally recognized that the relatively fixed natural water supply in the United States will not be adequate to supply the water needs of a growing population and expanding industry. Renovation and reuse of water thus becomes an increasing necessity. Envisioned uses range from agricultural and industrial process water to potable water, with the degree of purification required varying according to the specific use.

The effluent streams discharged from the most effectively run conventional treatment plants contain soluble and suspended organic compounds that exert an oxygen demand on the receiving streams. In many locations there is a pressing need to remove such contaminants in order to preserve the quality of surface waters.

City water uses add about 300 mg/liter more minerals than are found in the water supply of the municipality. The materials making up this increment are ammonia, nitrates, and phosphates, which often cause algae blooms in surface waters. The dissolved solids content of the effluents from many cities exceed 500 ppm.

Public Health Service standards recommend that a municipal water supply contain less than 500 ppm minerals. If municipal wastes are reused, each cycle will increase the mineral content. Demineralization of at least a portion of the waste will thus be required to assure quality. The demineralization processes will yield a purified water stream but unfortunately also a concentrated waste stream, and this waste concentrate must be treated, handled, or placed in such a manner that it no longer pollutes the environment.

The distillation process is technically the most developed of the demineralization processes and permits evaporation to dryness. The concentrated solid waste stream can then be incinerated for heat recovery or possibly used as fertilizer. The small volume of salts or ashes from this process would have to be dumped at sea, stored in caverns, or processed to recover minerals. Distillation therefore has two potential roles in municipal waste treatment: (1) a means of demineralization and (2) a step in ultimate disposal.

There are several publications of investigations on this subject that present the results of both experimental and paper studies.[11-16] In general attempts to distill sewage with little or no pretreatment resulted in several problems. There are reported difficulties with fouling of all waste demineralization processes by organics, but little work has been done to define the extent of pretreatment needed to avoid fouling. Tests have indicated that fouling could be avoided by controlling the pH of the secondary effluent fed to an evaporator, but it has not been definitely established that filtered primary effluent can be evaporated satisfactorily.

Difficulty is also anticipated with ammonia and other volatiles in sewage distillation. Again, virtually nothing has been done to investigate whether there are economical solutions to these problems. The solutions may involve feed pretreatments, removal of sidestreams from a distillation plant, or polishing of product with ozonation or adsorption.

If local needs for sewage demineralization are foreseen within the next decade, a more vigorous experimental program to explore these questions is indicated. Such a program should include distillation, as well as other processes. However, it can be concluded that with proper pretreatment, distillation of sewage effluent is technically feasible.

Many distillation plants for demineralizing ocean or brackish inland waters are operating or under construction, and development work is continuing to improve the processes. While the multistage flash process is the one most widely used, a more advanced distillation concept, a combination multieffect vertical-tube evaporator (VTE) and multistage flash (MSF) feed heating, is used for study purposes.[17] The MSF process could also be used for waste-water distillation but would have higher costs.

Development work on the VTE process is currently being actively pursued by the Office of Saline Water (OSW) of the U. S. Department of the Interior. OSW has a 1-Mgd* vertical-tube test-bed desalting plant in operation at Freeport, Texas. Advanced components, including tube bundles that have improved heat transfer surfaces, are being tested in this plant. Also, an advanced five-effect pilot plant is now in operation at the OSW

*Mgd = million gallons per day.

East Coast Seawater Test Station at Wrightsville Beach, North Carolina. This unit is designed to test advanced plant components, including heat transfer tubes, and the use of more complete plant instrumentation under a wide variety of operating conditions and parameters to optimize design features affecting plant operation. A VTE component test vehicle pilot plant is planned for installation at the OSW Clair Engle Test Facility. This unit is designed to test large tube bundles and full-scale equipment of the size required by desalting plants in the 25- to 100-Mgd capacity.

A commercial plant of 1-Mgd capacity that uses the VTE process was recently installed at St. Croix, Virgin Islands, by the Stearns-Roger Corporation. At the present time, there are 92 desalting plants of 25,000-gpd capacity or over in operation in the world with a total capacity of approximately 16.6 Mgd or about 7.5% of the world's total desalting capacity. A conceptual design study of a large-scale VTE (250-Mgd) plant was prepared by ORNL for OSW.[17]

While the development of plant components for large-scale VTE plants is somewhat behind that for MSF process plants, based on current progress in VTE component development it is reasonable to assume that plants in the size range (up to 100 Mgd) considered in this study will be available by the 1980 period.

Although these multiple-effect evaporators are attractive for many applications, a low-temperature single-effect VTE that uses exhaust steam (about 100°F) from a conventional turbine as a heat source is also being studied in the water desalination program at the Oak Ridge National Laboratory,[18] and a preliminary design and cost estimate have been made for a dual-purpose seawater distillation plant. This evaporator would use the full exhaust steam flow from the turbine of a nuclear-fueled light-water-cooled reactor producing 1000-Mw(e) net and operating at a plant load factor of 0.80. It could produce about 20 Mgd of distilled water for an estimated cost of 20 to 25¢/kgal, depending on tube and shell material used.

A patented commercial process, the Carver-Greenfield dehydration system, is being considered for processing of sewage sludge or for evaporation of brines to dryness.[16] The process operates at 250 to 300°F, and therefore steam would be rejected into a conventional VTE distillation system. According to the supplier: "Wet solids are pulverized in a grinder to 1/4 in. particles or smaller. To maintain fluidity at all stages of dryness, the feed is slurried in the fluidizer tank by adding approximately 10 parts of oil to one part solid. Dehydration of the slurry occurs in single or multiple stages of falling film evaporators, in which multiple effect steam economy can be achieved. The dry slurry emerges from the final evaporator with a very low moisture content. The dehydrated solids are separated from the oil in a continuous centrifuge, so that the oil is available for recycle back to the fluidizing tank. Any fluidizing oil remaining in the solids after centrifuging can be removed by pressing or by washing with an extraction oil. The resulting dry solids are a sterile product of uniform consistency, that can be burned as boiler fuel, stored without decomposition, or bagged and marketed."

The usefulness of distillation can be determined only by comparison with other methods of providing the same water supply or the same degree of pollution control. The difficulty of this determination is compounded by some of the following considerations:

1. The Federal Water Quality Administration places the highest priority on more effective removal of organics from waste. Demineralization of waste, including distillation, can probably be deferred until it is desired to reuse waste water.

2. There are uncertainties in the various process requirements and future costs.

3. There are large variations in local water supply costs, ability to dispose of concentrated wastes, and stream standards.

In the ORNL study, a simple model was postulated in which the sewage was evaporated to dryness and the water recycled to supplement the natural water supply. The raw sewage was subjected to primary and secondary treatment, and the effluent was then treated by filtration through activated carbon for removal of organics. About one-third of this filtrate was distilled, and the solids were dehydrated for complete water recovery. The product of this step was treated by ozonation and blended with that which received no treatment after filtration. This water, suitable for household use, would be recycled by blending with the incoming natural water supply. This model is shown in Fig. 21.

Some of the technical and economic parameters used in this model are given in Tables 8 and 9. The estimated costs are given in Tables 10 and 11. No costs are estimated and no credit is taken for heat, salt, and minerals recovered from the solids. The unit costs in Table 11 are based on the entire quantity of water supplied to the users.

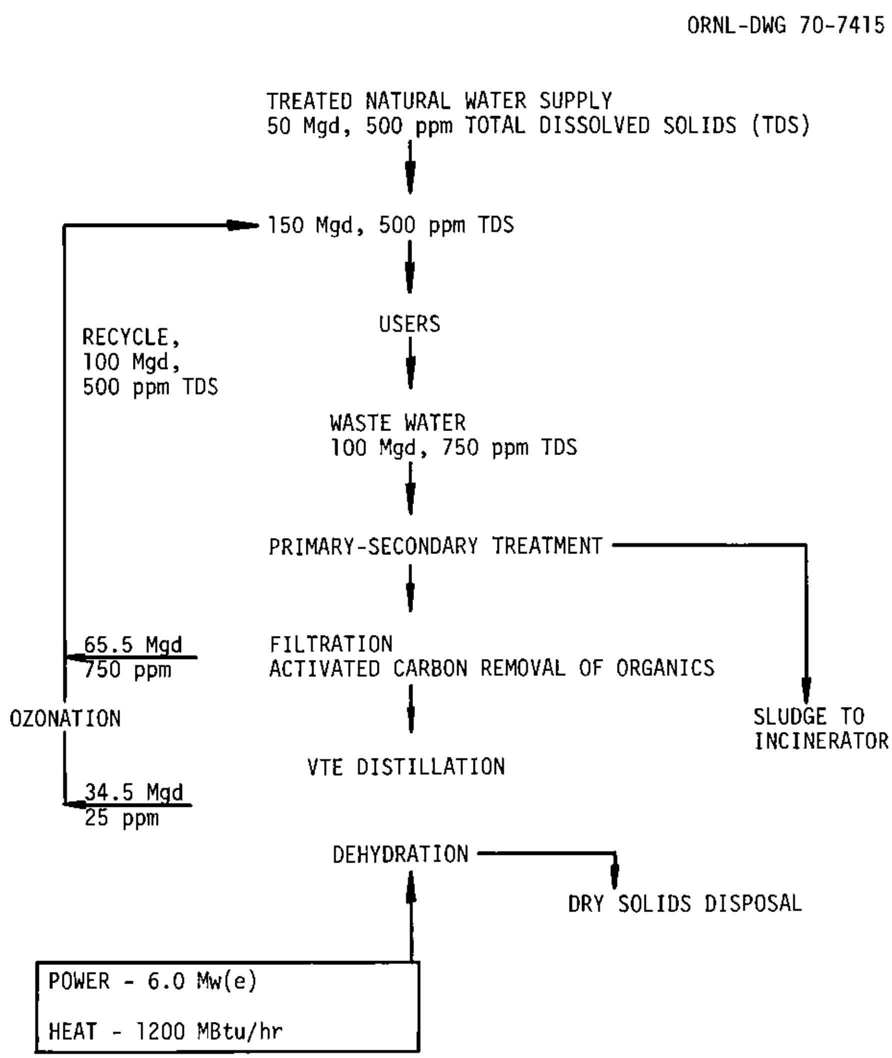

Fig. 21. Water Supply Including Water Reclaimed by Distillation and Distillation to Dryness.

Table 8. Technical and Economic Assumptions for Water Systems Study

Population of city	1 million
Water supply	150 Mgd
Waste supply	100 Mgd
Natural water cost	10¢/kgal
Natural water salinity	0 to 500 ppm TDS[a]
Desired salinity of supply	≤500 ppm
Increase in salinity of waste over supply	250 ppm
Cost of primary treatment	2¢/kgal
Cost of disposal of primary sludge	1¢/kgal
Cost of primary plus secondary treatment	4¢/kgal
Cost of disposal of primary plus secondary sludge	2¢/kgal
Cost of pumping and storage of reclaimed waste water	4¢/kgal

[a]TDS = total dissolved solids.

Two examples of conventional sewage treatment are given in Figs. 22 and 23, and cost estimates are listed in Tables 12 and 13 to serve as a basis of comparison in determining the economic impact of waste water distillation on the overall cost of water and sewage treatment. The costs for the complete recycle system range from 23 to 84% higher than for the conventional systems. If strict antipollution controls must be added to the conventional systems, the cost difference will be reduced significantly. Removal of nutrients, such as nitrates and phosphates, are one of the special problems that face conventional systems. In many urban areas the natural water available is insufficient to meet predicted future demands, and thus these areas would benefit from the recycle system. As natural waters become more mineralized, the cost of the natural water supply will increase. For the models discussed here, the incremental increase of the total unit cost will be a factor of three greater for the conventional system than for the recycle system.

Table 9. Technical and Economic Assumptions for Advanced Waste Treatment Systems

Cost of filtration of secondary effluent	1¢/kgal
Cost of activated carbon treatment	5¢/kgal for treatment of secondary effluent for reuse 2.5¢/kgal for partial treatment of feeds to or from other processes
Cost of ozonation	1¢/kgal
VTE distillation	
Function	Provides product of 25 ppm TDS and blowdown of 70,000 ppm TDS
Maximum operating temperature	260°F
Capital cost of plant in range of 15- to 35-Mgd feed	$0.8 per daily gallon capacity
Power consumption	4 kwhr/kgal feed
Steam consumption	100 Btu/lb feed
Power cost	4 to 6.6 mills/kwhr
Heat cost	15 to 27.4¢/MBtu
Fixed charge rate	6%/year
Plant factor based on 5% over-size plant that is down 5% of the time	100%
Distillation to dryness	
Function	Converts 70,000 ppm feed to water and dry salts
Operating temperature	260 to 300°F
Capital cost	$2 per daily gallon capacity
Steam	Operates as attachment to VTE and does not require significant addition
Power consumption	10 kwhr/kgal feed
Net cost of disposing of dry solids	$10/ton

Table 10. Cost of Distillation of 34.5-Mgd Feed to Dryness for Two Different Costs of Steam and Power

	Case A	Case B
Steam cost, ¢/MBtu	27.4	15
Power cost, mills/kwhr	6.6	4
Annual cost, thousands of dollars		
Amortization (6% of \$27.6 × 10^6 + \$1 × 10^6)	1715	1715
Operation and maintenance	572	572
Acid for feed treatment (2¢/kgal)	251	251
Electric power (6.0 Mw × 8760 hr)	347	209
Heat (1200 MBtu × 8760 hr)	2882	1578
Total	6293	4325
Cost, ¢/kgal feed	49.8	34.3

Table 11. Estimated Cost for Sewage Disposal and Water-Recycle System

	Supply (Mgd)	Costs (¢/kgal)	
		High-Cost Energy	Low-Cost Energy
Natural water	50	3.3	3.3
Primary plus secondary treatment		2.7	2.7
Sludge disposal		1.3	1.3
Filtration and activated carbon treatment	65.5	3.4	3.4
VTE distillation-dehydration	34.5	11.5	7.9
Total	150.0		
Ozonation		0.2	0.2
Recycle pumping and storage		2.7	2.7
Disposal of dry solids		0.7	0.7
Total cost for water supply and sewage disposal		25.8	22.2

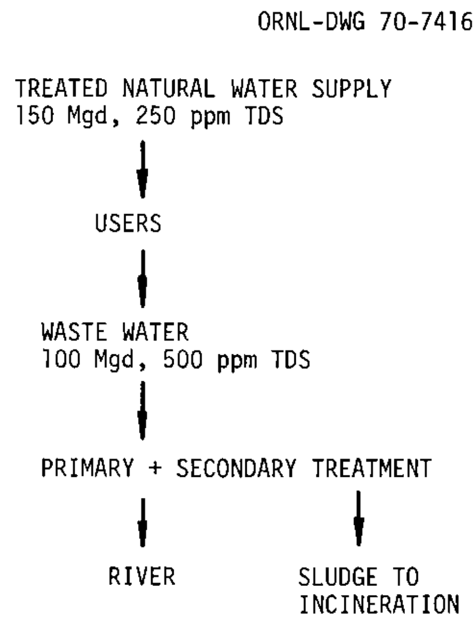

Fig. 22. Conventional Water Supply and Sewage Disposal.

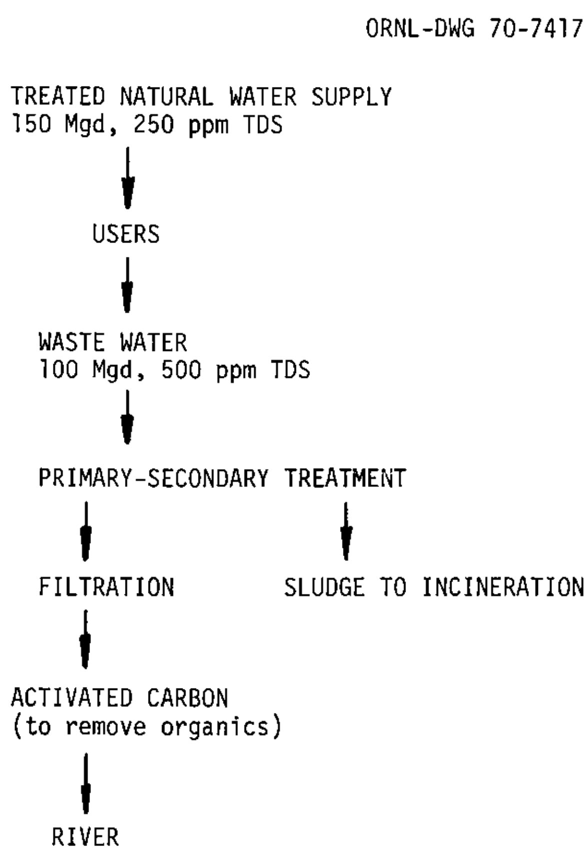

Fig. 23. Conventional Water Supply with Tertiary Treatment of Wastes.

Table 12. Costs of Conventional System with Natural Water Supply and Primary and Secondary Treatment of Sewage

	Costs (¢/kgal)
Natural water	10
Primary plus secondary treatment at 4¢/kgal waste × (100 Mgd waste/150 Mgd supply)	2.7
Sludge disposal at 2¢/kgal waste × (100/150)	1.3
Total for water supply and sewage disposal	14

Table 13. Costs of Conventional Supply and Strict Pollution Standards Requiring More Complete Removal of Organics from Waste

	Costs (¢/kgal)
Natural water	10
Primary plus secondary treatment (as in Table 12)	2.7
Sludge disposal (as in Table 12)	1.3
Filtration plus activated carbon treatment at 6¢/kgal waste × (100 Mgd waste/150 Mgd supply)	4.0
Total for water supply and sewage disposal	18

As illustrated in Fig. 21 and Table 10, this process requires 1200 MBtu/hr or 350 Mw of heat for a city of one million people. Beneficial use is made of the heat, with a corresponding decrease in heat emission from the power plant condenser. However, the distillation process also employs a condenser, which must be located an effective distance from the power plant cooling tower in order to relieve the problem of concentrated thermal energy disposal. Desalting of sewage plant effluent is included in the design of the center for the reference city to the extent of a 90-Mw plant for a city of 389,000 people.

3.4 Urban Vehicle Propulsion with Hot Water

A study by A. P. Fraas of ORNL has shown that the heat distributed through a district heating system can be used to reduce the air pollution by providing stored steam or superheated water for vehicles such as buses and trucks. This arrangement has been used in freight yard locomotives operating in power plants, powder plants, chemical plants, and tobacco warehouses in order to eliminate any possible source of sparks. It also could be applied to urban public transportation vehicles, local trucks, and plant equipment such as lift trucks. To avoid venting steam, a closed-cycle engine could be used.

Sixty years ago the automotive steam power plant was a serious competitor of the internal combustion engine, but the complexity of the heat transfer problems in the boiler and condenser was such that the internal combustion engine forged ahead during World War I and the steam automobile largely dropped from view. The rapidly growing problem of air pollution in urban areas has led to a reexamination of the relative merits of steam and internal combustion engines for automotive service. The assessment of the economic viability of the 1980 reference city is made without assuming use of steam transportation. However, there is a long-range interest in the system, and its description follows.

3.4.1 Analysis of Performance Potential

Although it would be possible to store steam in tanks in much the same way as one stores compressed air, approximately ten times as much useful energy per cubic foot of tank can be stored in superheated water and released by allowing the pressure in the tank to drop slowly to cause steam to be flashed off the water.

The performance potential of stored, superheated water was estimated (see Table 14) to determine the effect of the initial pressure in the superheated water storage tank on the energy available in the steam if the pressure on the superheated water were allowed to drop during operation of the vehicle from the initial pressure shown on the first line of Table 14 to a final pressure of 50 psia. To avoid changes in engine performance in the course of drawing down the energy in the tank of superheated water,

Table 14. Energy Available from the Expansion of Superheated Water

Pressure, psia	1500	1000	700	500	350	250	100	50
Temperature, °F	596.20	544.58	503.08	467.01	431.73	400.97	327.82	281.02
Enthalpy of liquid, Btu/lb	611.7	542.6	491.6	449.5	409.8	376.1	298.5	250.2
Enthalpy of vapor, Btu/lb	1170.1	1192.9	1201.8	1204.7	1204.0	1201.1	1187.2	1174.1
Specific volume of liquid, ft^3/lb	0.02346	0.02159	0.02050	0.01975	0.01912	0.01865	0.01774	0.017274
Specific volume of vapor, ft^3/lb	0.27719	0.44596	0.65556	0.92762	1.32554	1.84317	4.4310	8.5140
Entropy, Btu	1.3373	1.3910	1.4304	1.4639	1.4968	1.5264	1.6027	1.6586
Enthalpy of liquid above 50 psia condition, Btu/lb	361.5	292.4	241.4	199.3	159.6	125.9	48.3	0
Specific volume after 20:1 expansion, ft^3/lb	5.5438	8.9192	13.1112	18.5524	26.5108	36.8634	88.6200	170.2800
Steam pressure after 20:1 expansion, psia	79	47	32.4	21.75	14.85	10.5	4.1	2.0
Enthalpy after 20:1 expansion, Btu/lb	963	972	976	977	976	975	968	963
Enthalpy drop in 20:1 expansion, Btu/lb	207.1	220.9	225.8	227.7	228.0	226.1	219.2	211.1

the steam discharged from the tank would be throttled to 50 psia before supplying it to the engine, irrespective of the pressure in the storage tank. As may be seen, the amount of this energy would be 361.5 Btu/lb for an initial pressure of 1500 psia and would drop to only 48.3 Btu/lb of superheated water if the initial pressure were 100 psia.

The energy available from the expansion of the steam flashed from the superheated water depends on both the expansion ratio in the reciprocating engine employed and the initial steam conditions. The power output from the cylinder of a reciprocating engine is directly proportional to the inlet pressure, but the efficiency with which the energy can be employed with an engine having a fixed expansion ratio is almost independent of the initial pressure. The values in the lower portion of Table 14 show the variation in this energy (i.e., the adiabatic work available) if it is assumed that the engine expansion ratio is 20. As may be seen, the values for the adiabatic work shown in the last line of Table 14 are almost independent of the initial pressure. The values given in Table 14 are summarized in Fig. 24, which shows the initial temperature, the engine steam outlet pressure, the adiabatic work in Btu/lb for an expansion ratio of 20, and the total energy available per pound of superheated water by reducing its pressure to 50 psia, all as a function of the initial pressure in the tank of superheated water.

3.4.2 Comparison with Other Energy Sources

In comparing the data of Table 14 with data for some commonly used sources of energy it was found that the superheated water system is competitive with lead-acid or silver-cadmium batteries.[19] Typical data are tabulated in Table 15 for both the energy stored and for the useful energy delivered to the wheels. As may be seen, electric power in lead-acid storage batteries can be employed with about a 90% motor efficiency, whereas the power from the steam in superheated water would entail large losses inherent in the thermodynamic cycle. (Similar losses occur in a gasoline engine.) The effects of engine efficiency are also shown in Table 15. However, a tank of superheated water could be recharged in a few minutes, whereas a bank of storage batteries would require many hours for recharging.

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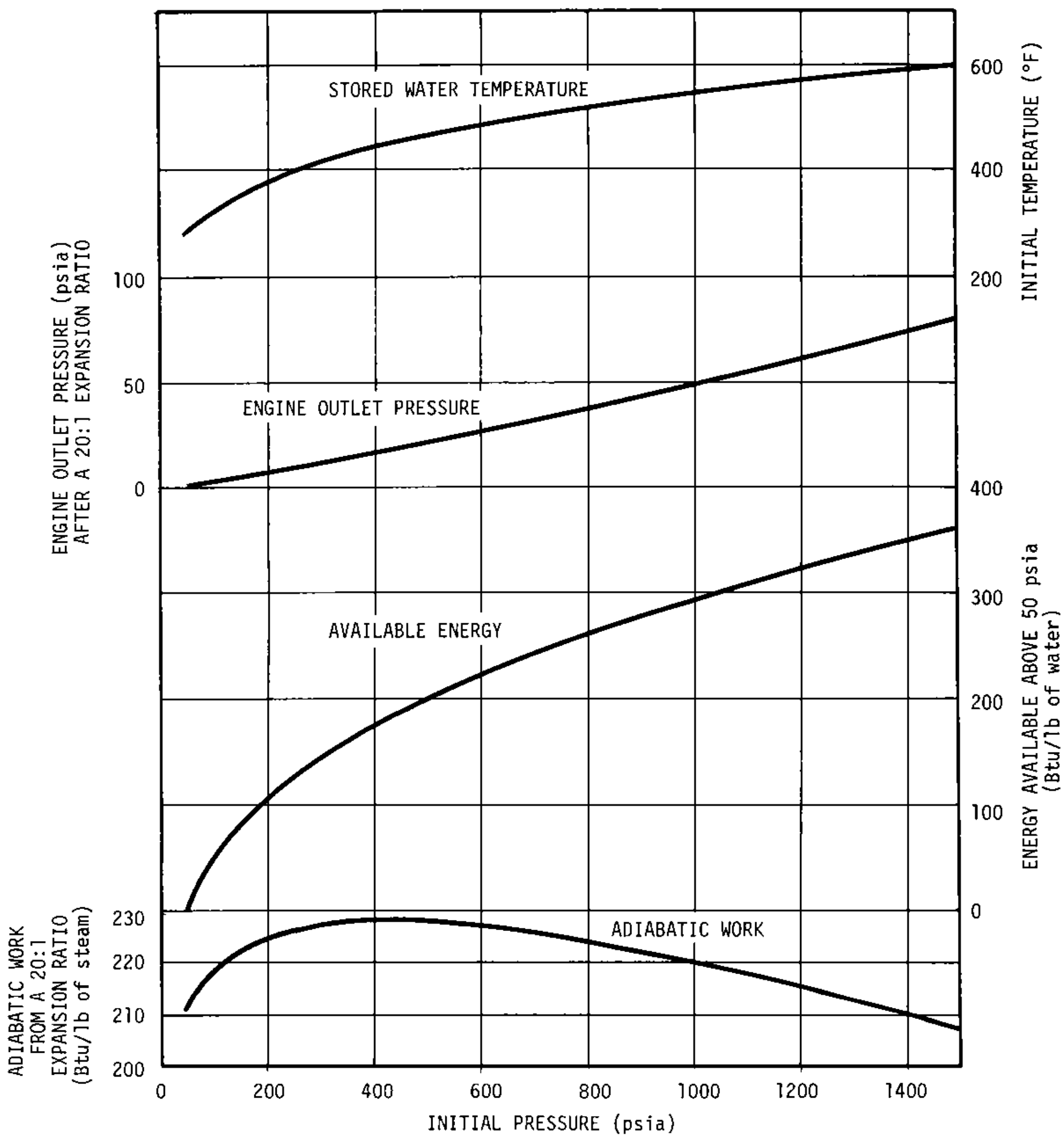

Fig. 24. Effects of Initial Pressure on the Energy Available from Reducing the Pressure of Superheated Water to 50 psia. Curves are also given for the initial temperature, the exhaust pressure, and the adiabatic work for a 20:1 volumetric expansion.

Table 15. Energy Available from Typical Sources for Automobile Propulsion

	Energy Stored [Btu (thermal) per pound]	Useful Energy at Drive Wheels (Btu/lb)
Batteries		
Lead-acid	46[a]	41.5
Nickel-cadmium	39.2[a]	35.2
Silver-cadmium	68.3[a]	61.5
Silver-zinc	136.6[a]	123
Superheated water		
Release from 400 to 280°F (260 to 50 psia)	130	26
Release from 545 to 280°F (1000 to 50 psia)	292	58
Gasoline	18,000	3,600

[a]From Ref. 19.

Implicit in the data of Table 14 is a clear-cut demonstration of the advantage in the use of superheated water compared with steam for energy storage in pressurized tanks. For the 500-psia condition, for example, the specific volume of the vapor is roughly 50 times that of the liquid, while the enthalpy of the liquid is more than one-third that of the vapor. Thus the energy available from the liquid is about 15 times greater than that available from steam stored at the same pressure in the same volume.

3.4.3 Vehicle Performance

Vehicles that use energy storage systems such as lead-acid batteries or superheated water are limited in their range of operation by the space and load capacity available for the energy storage units, the efficiency of energy utilization, and the power requirements of the vehicle. The problem is complicated by the fact that the power demand varies with driving conditions (i.e., acceleration, hill climb, and operating speed). Since the bulk of operation is at a fairly constant speed on level road, this condition is the most important from the fuel economy standpoint. Figure 25 shows a road load curve for a typical large bus that would normally be fitted with an engine having a power capacity of around 200 hp.[20] Most of the time the engine would be operating at part load, and hence the specific fuel consumption under part load conditions would largely determine the gas mileage.

The characteristic curve for specific fuel consumption as a function of load differs greatly for gasoline and diesel engines on the one hand and steam engines on the other. Typical characteristic curves for the three types of engine are shown in Fig. 26 (Refs. 21 and 22). At full power the specific fuel consumption is higher for the steam engine than for the gasoline and diesel engines, but at part load the reverse is the case. This comes about because the nature of the losses in gasoline and diesel engines causes a marked increase in specific fuel consumption if the engine is throttled, whereas this is not the case with steam engines. Good engineering data are not available for the advanced type of steam engine that could be built today, but there is reason to believe that the performance indicated in Fig. 26 is achievable with 400°F steam.[23] It should be noted that there would be no heat losses due to combustion with the energy storage power plant envisioned, and there would be no losses in the transmission because a direct-drive steam engine would give an exceptionally smooth, fast start.

In estimating the operating range readily obtainable for a vehicle powered from 400°F superheated water, it seems reasonable to assume that 20% of the gross vehicle weight could be devoted to tankage and that the weight of the tanks would be 25% that of the contained superheated water. (If titanium vessels similar to those used for hydraulic accumulators in aerospace vehicles were employed, the tankage weight would be about one-eighth the weight of the superheated water.) Data on fleets of city buses indicate that the fuel mileage on diesel-powered buses is commonly about 7 miles/gal (Refs. 24 and 25). Assuming that under representative road load conditions the energy in the fuel consumed by the diesel engine would be equivalent to the energy consumption of the steam engine, it would require 120 lb of superheated water per mile, or about 150 lb of water plus

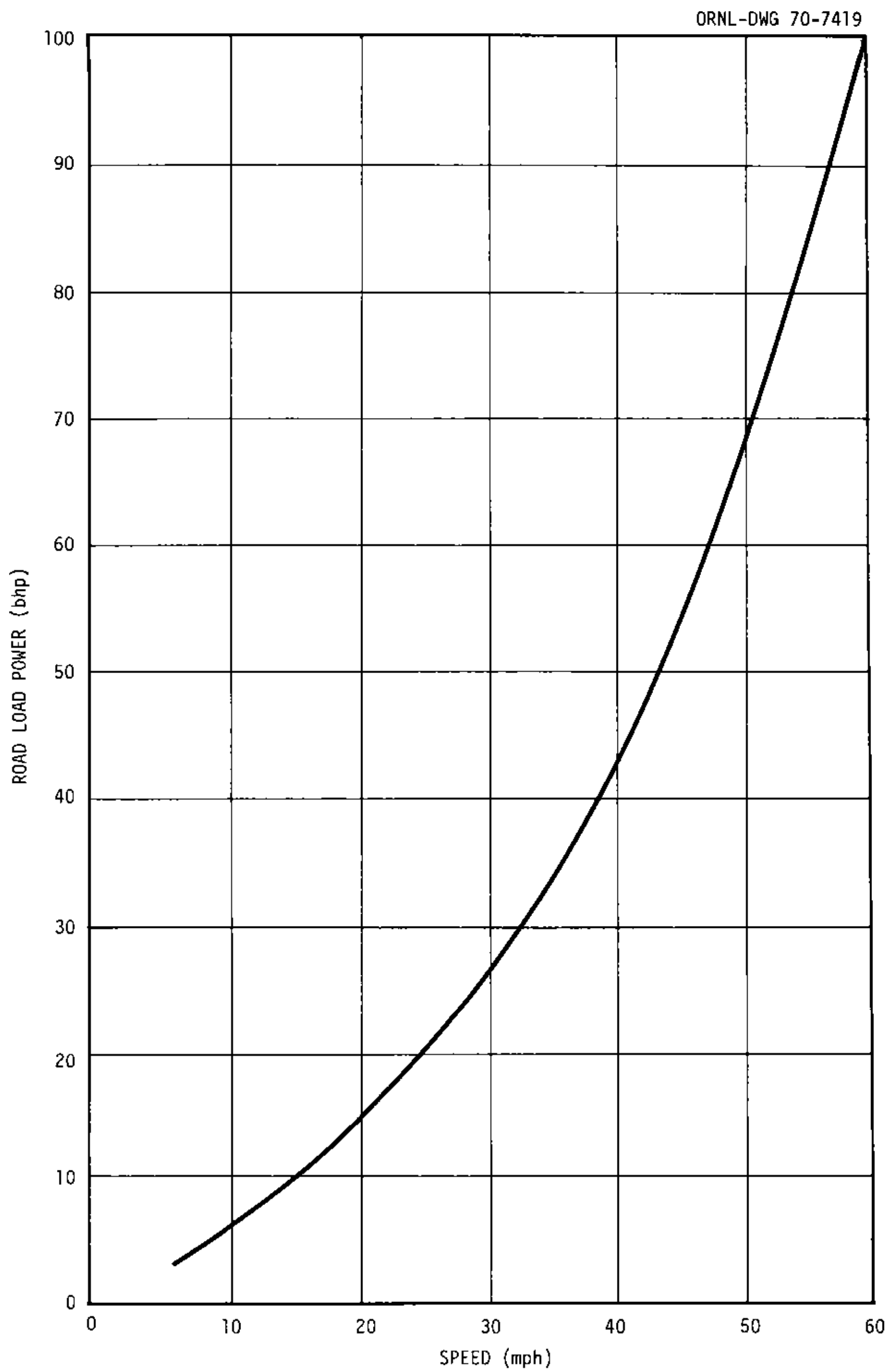

Fig. 25. Road Load Power Requirement of a 16,000-lb Bus.

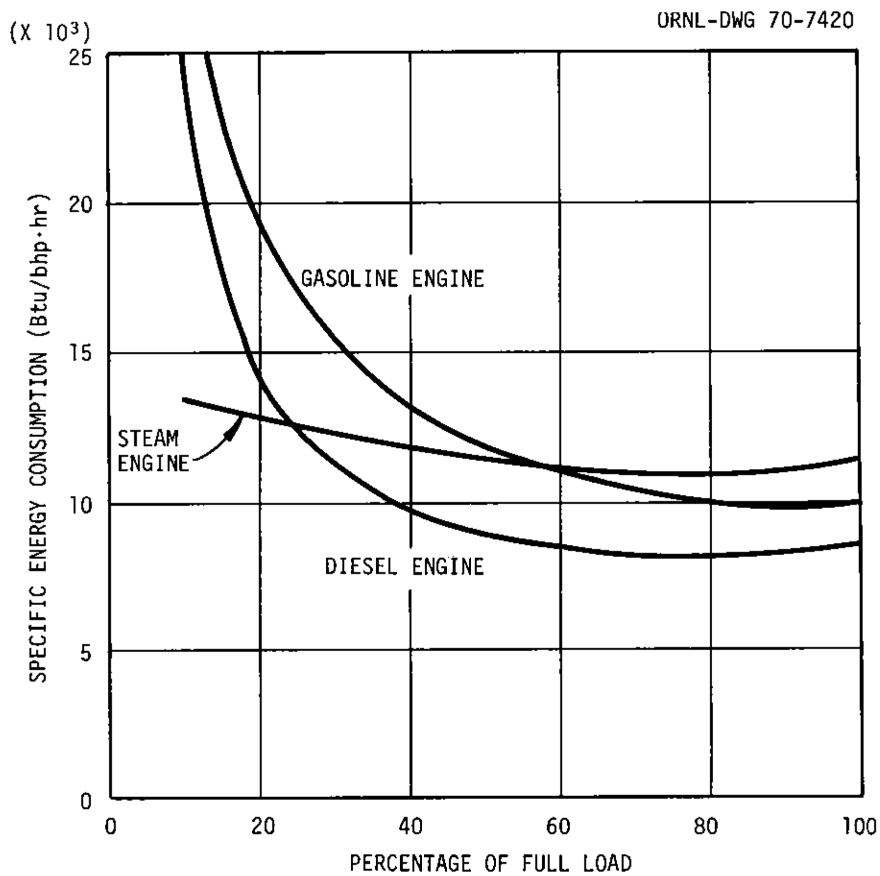

Fig. 26. Effects of Load at Constant Speed on the Specific Fuel Consumption of Typical Gasoline, Diesel, and Steam Engines.

tankage. Thus in a 16,000-lb bus in which 20% of the gross weight was allocated to the energy storage system (i.e., 3200 lb) the range of the vehicle between refills would be approximately 20 miles. If 300°F water were used for power, the operating range would be only about 10 miles, and attainment of this range would require a tankage increase to about 30% of the gross vehicle weight.

3.5 Snow Melting

There are several places where hot water and steam are used for snow melting on sidewalks, relatively short roadways, and airport runways. Discussions of this method of heat utilization date back to 1925 in the Proceedings of the National District Heating Association. Of particular significance is that use of an integral snow-melting system prevents the snow and ice from accumulating. Waste heat can also be used in keeping harbors and shipping lanes open. One study of this application dealt with extending the season of the St. Lawrence Seaway.[26] Of course, the use of heat from an energy center for these purposes is a matter of economics and not technical feasibility.

A design and cost estimate, based on 1969 costs, was prepared by I. T. Dudley of ORNL for heating a typical wide sidewalk of a large multi-story building. He also prepared a cost estimate based on 1969 costs for a more elaborate system installed in Detroit, Michigan, in 1959.[27] This system heats the sidewalks, steps, and arcade of a large 14-story banking building. It receives steam from the same source as the building heating system. The heating pipe layout is complicated somewhat by the steps, building columns through the arcade floor, and tree planters in the sidewalk. The pipe diameter is about three-fourths that of the typical system and it uses twice the length of pipe per unit area as compared with the typical system. The sidewalk heating system is operated in a conservative manner relative to the arcade. It operates only when snow is expected, while the arcade system circulates hot fluid whenever the temperature drops below 40°F. Therefore, the systems are designated as high- and low-cost systems for purposes of discussion here.

The basic design conditions for the low-cost system are the following:

1. Walkway is 20 ft wide and 200 ft long.
2. Walkway is adjacent to building and equipment is located in basement nearby.
3. Hot water is the source of energy.
4. Snow fall rate is 1 in./hr.
5. Snow density is 5.9 lb/ft^3.
6. Air temperature is 26°F.
7. System installation with new sidewalk.

Reported results for a snow melting system show that 107 Btu/hr is required per square foot of walkway if the heating lines are made of 1 1/2-in. sched-40 pipes spaced 20 in. apart and the concrete is 4 in.

thick.[28] The pipes were on a bed of gravel 4 in. thick, and the concrete was poured on top the pipes and gravel. This piping arrangement is shown in Fig. 27. The flow diagram for this system, which uses a circulating fluid of 50% ethylene glycol and 50% water, is shown in Fig. 28. Basically the same type of equipment is used in the high-cost system. The estimated costs are shown in Table 16. The installation cost for the low-cost system includes the capital cost for all equipment shown on the flow sheet. These estimates give a range of costs representing the maximum and minimum that might be expected on a sidewalk installation for the fixed charges and for operation and maintenance. The energy cost is varied ±50% to illustrate the effect of this cost on the total for both the high- and low-cost systems.

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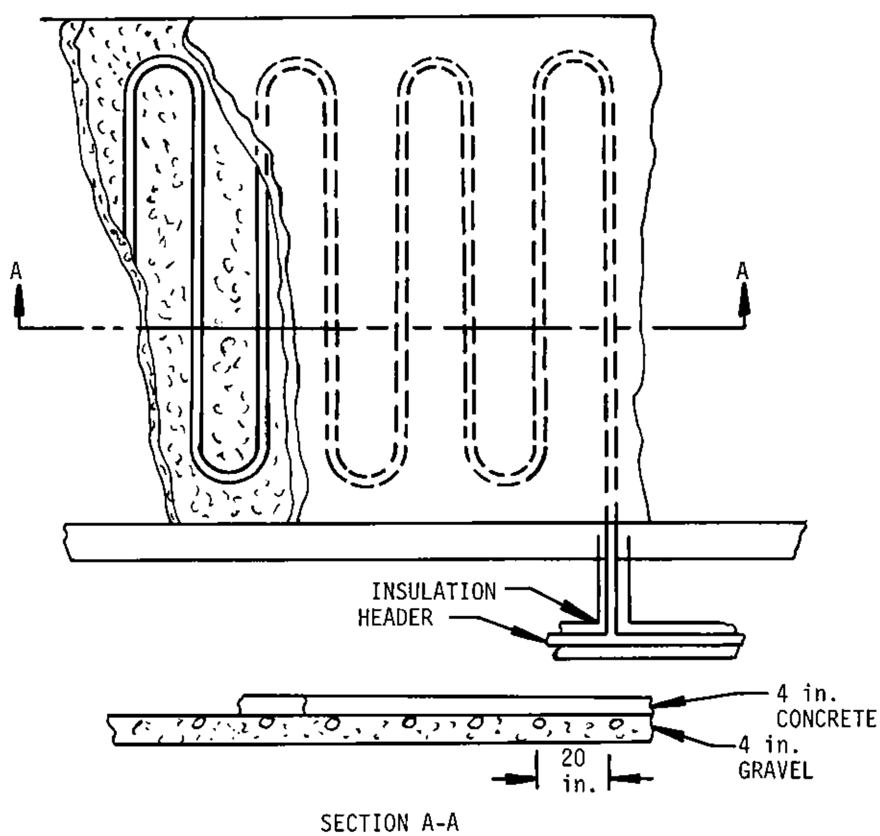

Fig. 27. Snow-Melting Pipe Arrangement in Sidewalk.

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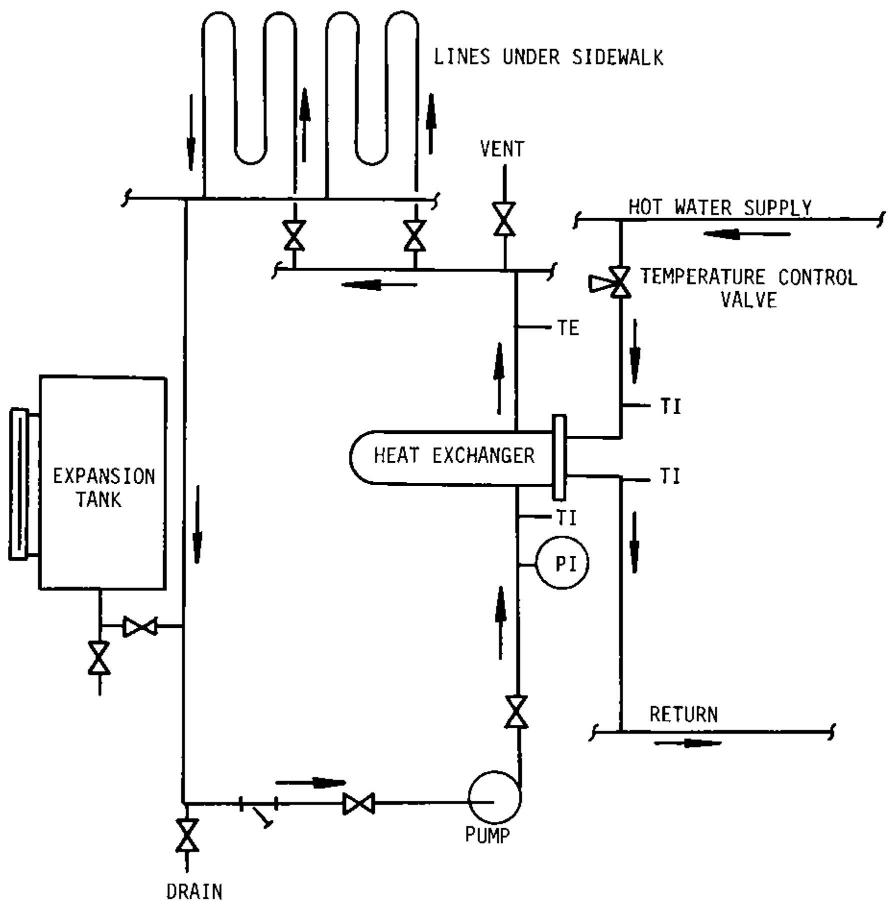

Fig. 28. Flow Diagram for Sidewalk Snow-Melting System.

Since this cost estimate is for a relatively small area, scaling to larger sizes should reduce the fixed charges significantly. An equation of the form

$$A = B(C)^n ,$$

where A is the cost of a given system, B and n are constants, with $n < 1$, and C is the size of the given system, can be used to estimate the effects on cost of scaling to larger sizes. If the area of the system discussed here is increased by a factor of 10 and $n = 0.85$, the unit fixed charge would be 70.8% of that for the smaller systems. This would give $\$0.276/ft^2$ and $\$0.60/ft^2$ for the low- and high-cost systems compared with

Table 16. Cost Estimate for a City Sidewalk Snow-Melting System Based on 1969 Costs

Sidewalk area: 4000 ft²

	Low-Cost System	High-Cost System
Installation (does not include sidewalk)	\$13,620	\$24,900
Annual costs		
Maintenance	\$ 290	\$ 580
Operation	260	260
Fixed charges at 11.5%	1,566	2,866
Subtotal	\$ 2,116	\$ 3,706
Steam at \$1.30/1000 lb	187	988
Power at \$0.14/kwhr	13	56
Total annual cost	\$ 2,316	\$ 4,750
Unit costs		
Unit total annual cost	\$0.58/ft²	\$1.19/ft²
Incremental change for ±50% variation of energy (steam and electricity cost)	\$0.03/ft²	\$0.13/ft²
Unit cost for installation	\$3.40/ft²	\$6.23/ft² (a)
Unit annual cost for fixed charges	\$0.39/ft²	\$0.72/ft²

[a]The installation cost experienced for the Detroit system in 1958 was \$4.11/ft².

\$0.39/ft² and \$0.72/ft². For the high-cost system the annual steam usage was estimated to be 14% of that required for heating only the building, and for the low-cost system it was 2.6%. The fixed charges and operation and maintenance are the major portion of the total cost. Efforts to reduce the cost of these two factors will be the most effective in reducing the total cost.

Installation in roadways with heavy axial loads would be more expensive than in sidewalks. For some applications, initial installation costs as high as \$12.00/ft² were reported in 1948 (Ref. 29). The values of safety, appearance, and public approval should be considered when comparing the cost of a snow-melting system with that of the more conventional method of using plows, sweeper, shovels, and salt. Public approval and economic feasibility are both associated with high-use areas, such as downtown business districts, large apartment buildings, and public transportation terminals. Some perspective on the snow-melting systems might be obtained from considering that a design value of 107 Btu/hr per square foot of pavement amounts to 875 Mw/square mile of paved surface, and the demand would occur during moderate winter temperatures prior to expected storms.

In northern locations where high average snow falls or unusually large snowfalls in a short time create problems in keeping the streets open, it is often necessary to remove the snow to a dumping area. Open fields, bays, and rivers are sometimes used for this purpose. Suitable open spaces are becoming scarce, and if a navigable waterway is used for dumping, clogging it with ice and snow creates another problem. Therefore, show melting at a small dumping area should be given consideration under these circumstances.

The warm water from the condenser of the energy center offers a free heat source for this purpose. If the energy center is located close to the area to be cleared so that bringing the snow to the energy center would not be costly, this is obviously an ideal solution to the problem. However, in an emergency situation, this method of snow melting is worthy of consideration even at a remote center.

Some use of thermal energy for snow melting would obviously be worthwhile in a new city, but in the interest of obtaining easily applied economic reference data, it was not included in the reference city.

3.6 Industrial Process Steam Consumption*

Investigations of future energy consumption in the United States have included studies of the possibilities of using low-temperature heat in industry. It appears that a large amount of extracted heat might be consumed for industrial purposes, and its use would of course reduce the quantity of heat wasted to the environment. The major users would be manufacturers

*Adapted from work performed under interagency agreement IAA-H-3-69 and reported in Ref. 30.

who need process steam for boiling, sterilizing, drying, evaporating, and other similar purposes. For example, the Dow Chemical Company will be supplied with major quantities of heat from Consumer Power Company's nuclear steam-electric plant being built at Midland, Michigan. The major groups of manufacturers who use this type of steam are, as listed by the Bureau of the Budget,[31] food and kindred products, paper and allied products, chemicals and allied products, petroleum refining and related industries, and rubber and miscellaneous plastic products.

For the investigation described here it was assumed that all the fuel consumed by the five major groups of industries listed above would be used to produce process steam in the period 1962 to 1980. The textile mill products industry was added to the group when it was found that 50 to 75% of the process heat used in this industry is process steam.[32] Also, for estimating the country's total consumption, it was assumed that process steam is consumed by only those six industries.

As given by the Census of Manufacturers,[33] the fuel used by the six industries is of two kinds: (1) purchased and (2) generated and consumed internally. All six industries purchase fuels, whereas only one (petroleum refining and related industries) is listed by the Census of Manufactures as generating and internally consuming fuel. The paper and allied products industry is known to produce fuel and consume it internally, but no records of quantities appear to be available.

3.6.1 Estimates of Process Steam Consumption in 1980

Consumption predictions were based on quantities of fuel purchased in 1962, and two methods of estimation were used. One was based on the Texas Eastern Transmission Corporation[34] and the other on the Bureau of the Census data[33] projected with the Texas Eastern projection ratio.

The heating values of the quantities of fuel purchased in 1962 by the six industries of interest are listed in Table 17, as well as projected values for 1985 from the Texas Eastern study. The efficiency of conversion of fuel to heat was assumed to be 100%. By interpolation, the total heating value in 1980 would be 106.2×10^{14} Btu. With a fuel-to-steam heat conversion efficiency of 70%, the heat content of the steam

Table 17. Heating Values of the Quantities of Fuel Purchased by Six Industries in 1962 and Projected Values for 1985

Manufacturing Category	Heating Value of the Quantity of Fuel Purchased (Btu)	
	In 1962	In 1985[a]
	$\times 10^{14}$	$\times 10^{14}$
Food	7.65	13.41
Paper	9.15	23.69
Chemicals	18.48	49.95
Petroleum	11.34	27.35
Rubber	1.39	3.50
Textile	2.42	3.74
Total	50.43	121.64

[a]From Ref. 34, Fig. 49.

produced in 1980 from this quantity of purchased fuel-produced heat is 74.4×10^{14} Btu.

When the heat produced and consumed internally in 1962, 14.3×10^{14} Btu, as estimated by the Bureau of the Census, is added to the total heating value of 50.43×10^{14} Btu given in Table 17, the overall total for 1962 becomes 64.7×10^{14} Btu. Projected to 1980, this overall total value becomes 95.4×10^{14} Btu for a conversion efficiency of 70%.

In comparison, similar calculations based on the Bureau of the Census data for fuel purchased in 1962 by the six industries of interest gave a total heating value of 45.82×10^{14} Btu (see Table 18). Extrapolating to 1980 and assuming a conversion efficiency of 70%, the heat content of the steam produced in 1980 from purchased fuel would be 67.6×10^{14} Btu. With the addition of the heating value of the fuel produced and consumed internally and projection to 1980 by using the Texas Eastern ratio, the 1980 estimate for a conversion efficiency of 70% is 88.7×10^{14} Btu. Thus

Table 18. Types of Fuel Purchased in 1962 by the Six Industries, Equivalent Heat Values, and Total Heat Values[a]

Industry	Coal (Bituminous, Lignite, and Anthracite)		Coke and Breeze		Fuel Oil (Distillate and Residual)		Gas (Natural, Manufactured, etc.)		Other Fuels (Gasoline, LPG, etc.)		Total Equivalent Heat Value (Btu)
	Purchased (short tons)	Equivalent Heat Value (Btu)	Purchased (short tons)	Equivalent Heat Value (Btu)	Purchased (42-gal bbl)	Equivalent Heat Value (Btu)	Purchased (ft^3)	Equivalent Heat Value (Btu)	Purchased (dollars)	Equivalent Heat Value (Btu)	
	$\times 10^3$	$\times 10^{14}$	$\times 10^3$	$\times 10^{14}$	$\times 10^3$	$\times 10^{14}$	$\times 10^6$	$\times 10^{14}$	$\times 10^3$	$\times 10^{14}$	$\times 10^{14}$
Food and kindred products	8,752	2.26	70	0.0182	21,045	1.23	330,274	3.47	45,498	0.371	7.35
Paper and allied products	15,145	3.91	102	0.0265	31,105	1.81	265,118	2.78	14,247	0.116	8.65
Chemicals and allied products	22,600	5.83	383	0.0996	19,866	1.16	782,894	8.22	35,740	0.292	15.60
Petroleum refining and related industries	934	0.241	5	0.00130	9,825	0.573	960,535	10.1	13,690	0.112	11.02
Rubber and miscellaneous plastic products	2,339	0.604	2	0.000520	3,833	0.223	31,047	0.326	4,662	0.038	1.19
Textile mill products	3,051	0.787	Not available		9,945	0.580	53,075	0.558	9,958	0.081	2.01
										Total	45.82

[a]Data from Ref. 33.

the two estimates for 1980 are

Data Source	Steam Consumption in 1980 (Btu)
Texas Eastern Transmission Corporation	95.4×10^{14}
Bureau of Census	88.7×10^{14}

The difference in these two values is attributable to the use of somewhat different heating value factors for converting fuel to heat. The estimated consumption of process steam in 1980 is approximately equivalent to the 92×10^{14} Btu of electrical energy estimated[35] to be required in 1980.

These data indicate that a significant amount of thermal energy from an urban nuclear energy center would be consumed by manufacturing industries if those steam-using industries were located in the urban area in proportion to the population of the area. For example, if internally generated fuel continued to be used, a city of 500,000 people in 1980 would have an average use of 465 Mw of process steam from the energy center. This is based on a projected population[36] of 243,291,000 people in the United States in 1980 and a consumption of 67.6×10^{14} Btu per year.

3.6.2 Estimates of Steam Pressures Required

The textile mill products and rubber and miscellaneous plastic products were dropped from consideration in the steam pressure investigation because of the comparatively small quantities of fuel they use to produce steam. Estimates of steam pressures required by the other four industries in 1980 are listed in Table 19. These data are from Ref. 37. The steam pressures given are end-use pressures. The steam supply would be received by each industrial plant at a higher pressure, of course, and suitable pressure reductions would be made prior to the various end usages.

Under some circumstances a larger than average concentration of low-pressure steam-consuming industry could be located in the vicinity of the energy center. However, for the reference city it was assumed that the amount of steam used by industries surrounding the center was in line with

Table 19. Estimates of Steam Pressures and Pressure Distributions Required in 1980

Industry	Percentage of Total Process Steam Usage[a]	Steam Pressures and Distribution	
		Pressure Range (psig)	Distribution (%)
Chemicals and allied products	39	450–1000	3
		200–450	15
		100–200	53
		≤100	29
Petroleum refining and related industries	22	150–600	20
		≤150	80
Paper and allied products	18	100–200	71
		≤100	29
Food and kindred products	13	50–100	10
		≤50	90
Other industries	8		

[a]Based on 1965 data from Ref. 37.

the city's population as given by data in the previous section and that the pressures corresponded approximately to the profile shown above.

3.7 Space Heating, Water Heating, and Air Conditioning

3.7.1 Thermal Requirements of Air-Conditioning Systems*

The effects of supplying energy for air conditioning on the total thermal energy requirement, the waste heat utilization, and the waste heat disposal of a heat-electric plant were investigated. The energy sources considered employed three steam cycles described in Section 2. One is representative of the best large fossil-fueled plants (FFP) now in operation and the advanced reactors (AR) under development. One is typical of the early low-temperature versions of the liquid-metal-cooled fast-breeder

*Adapted from work performed under interagency agreement IAA-H-3-69 and reported in Ref. 38.

reactor (F-LMFBR), and the other is for light-water reactors (LWR), such as the boiling-water reactor and the pressurized-water reactor. These three steam cycles also encompass the temperature range currently used with large fossil-fueled plants. With the exception of stack losses, the data for reactors are interchangeable with those for fossil-fired plants with comparable steam cycles.

Two basic types of air-conditioning methods were considered. One was the compression type that depends on the expansion of a fluid for the cooling effect and mechanical energy for the compression of the fluid. The other was an absorption system with a two-pressure heat-operated cycle that uses a vaporizable liquid as the refrigerant and a second fluid as the absorbent. For this study, water was chosen as the refrigerant and a solution of lithium bromide as the absorbent.

Two locations of the refrigeration equipment relative to the power plant site were used to determine the effects on the reactor-site waste-heat-disposal requirements. One of the locations considered was at the power plant; in this case, the heat gained from the air conditioning, in addition to the energy required to operate the refrigeration equipment, would be disposed of entirely at the plant site. The other location considered for the refrigeration equipment was at the consumption site; in this location the energy required to operate the refrigeration equipment would have to be exported from the power plant. If the refrigeration equipment were located at the plant site, the consumers would also have to be close by to use presently known coolant-distribution technology. The least expensive systems for distribution of coolant are those that distribute chilled water. Since there is such a small temperature difference between its freezing point and the desirable room temperature, chilled water cannot be exported long distances economically. It is generally distributed to large consumers no farther than one-half mile away from the plant.

An energy center, as considered thus far, is capable of supplying energy to the consumer for various uses. However, to permit a better comparison of air-conditioning methods, it is worthwhile to begin by assuming a plant that provides only electrical energy. Next it is assumed that, in addition to the original electricity, electricity and heat at various temperatures are provided solely for the purpose of air conditioning. This is done so as to emphasize the effects of the air-conditioning load on the total energy produced by the plant. These results and methods can be related to a more complex plant without changing their basic validity.

The steam cycle of each of the energy sources was modified to allow the turbine to exhaust at various back pressures to supply steam to a turbine-driven compressor or to an absorption-type refrigeration system. The modification employed for the study of the compression refrigeration system is shown in Fig. 29. Turbine No. 1 is a conventional condensing turbine that drives an electrical generator. Turbine No. 2 is also a condensing turbine and is used to supply shaft power for a turbine-driven compression-refrigeration system. The steam supply to turbine No. 2 is obtained from the exhaust of turbine No. 3, which is a back-pressure turbine.

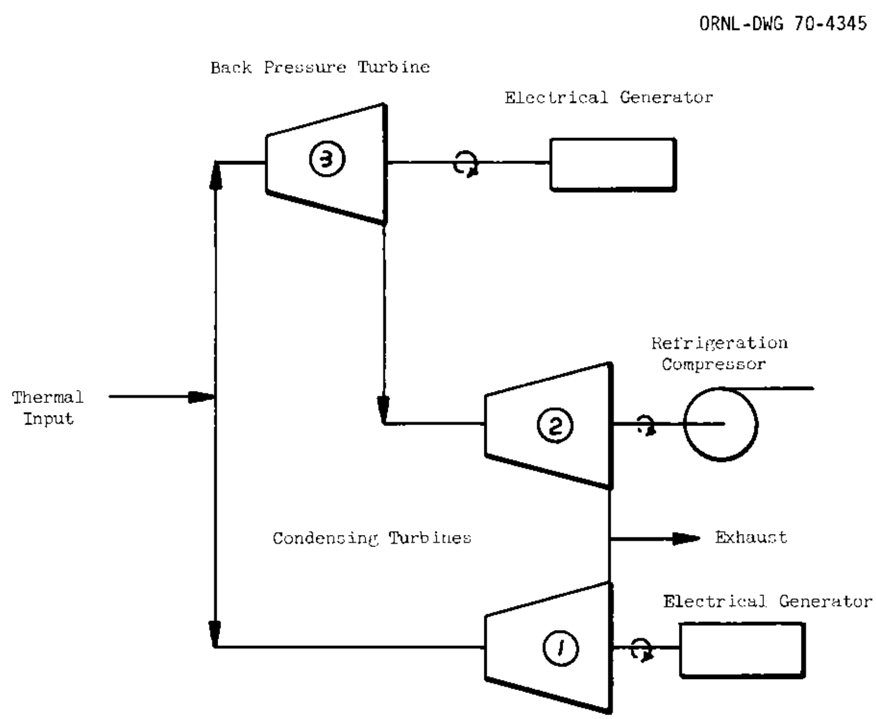

Fig. 29. Combined Plant for Production of Electrical Power and Refrigeration by Compression.

By placing an electric generator and motor between the turbine and the refrigeration compressor, a conventional electric motor-driven refrigeration system would be obtained.

The modification employed for the study of the absorption-refrigeration system is shown in Fig. 30. The plant employs two generator-coupled turbines — one a conventional condensing turbine and the other a back-pressure turbine. The exhaust from the back-pressure turbine is used to supply steam heat to the absorption-refrigeration system. The steam is used to heat the absorption system directly or indirectly through an intermediate hot-water loop.

Figure 31 shows a basic absorption-refrigeration cycle with the addition of a regenerative heat exchanger. In the cycle, the cold refrigerant water is vaporized in the evaporator to supply the cooling load. The water vapor is then absorbed in the lithium bromide solution in the absorber. The dilute salt solution is pumped to the concentrator through

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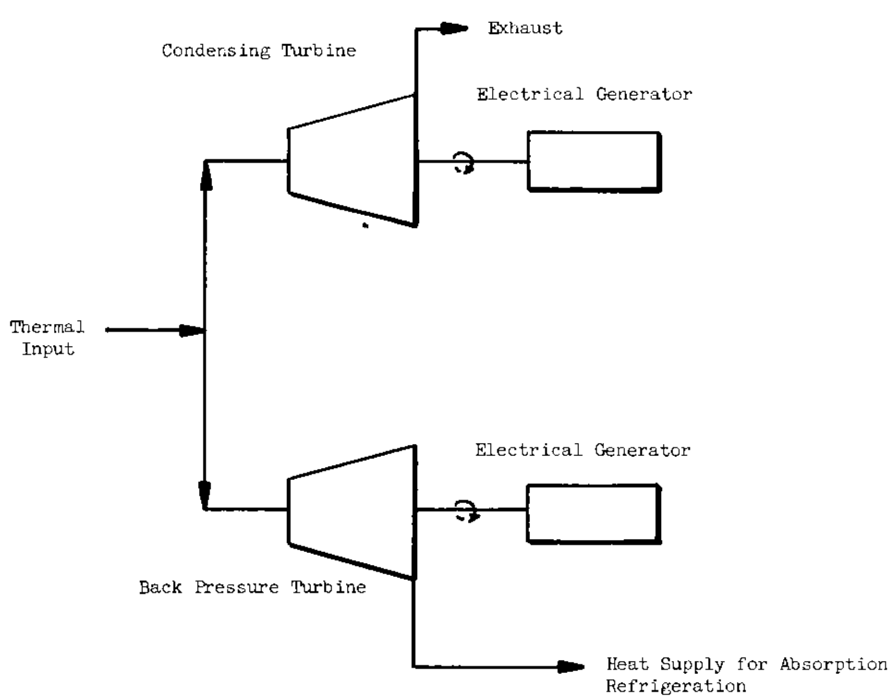

Fig. 30. Combined Plant for Production of Electrical Power and Refrigeration by Absorption.

a regenerative heat exchanger. In the concentrator the water is removed from the salt solution by boiling and condensed in the condenser. The concentrated salt is returned through the regenerative heat exchanger to the absorber. To complete the cycle the water in the condenser is returned to the evaporator through an orifice in which some of the water is flashed off and the temperature of the remainder lowered. The temperatures shown in Fig. 31 are representative of the temperature levels usually associated with a lithium bromide system. Typical hot water and steam supply conditions for the concentrator in commercial equipment are shown in Table 20.

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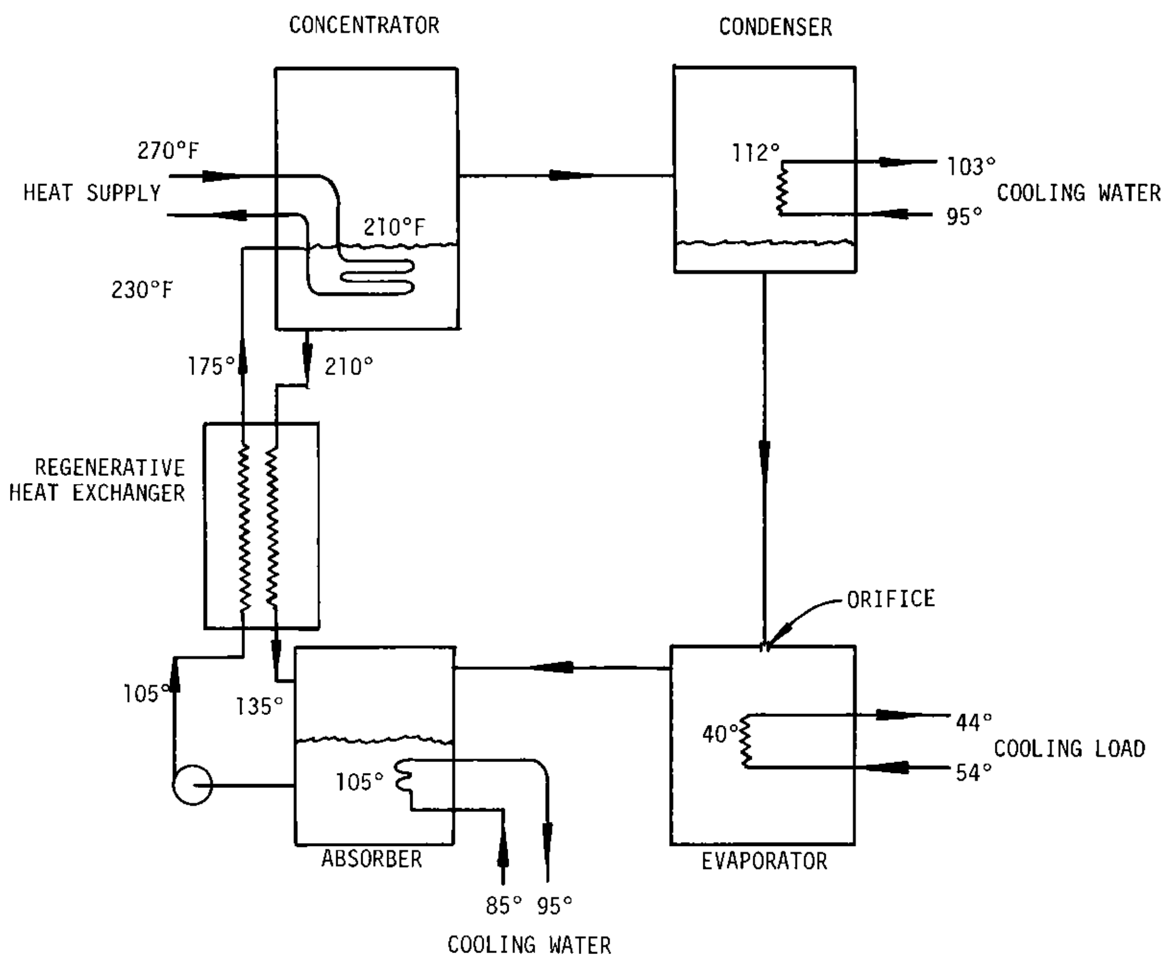

Fig. 31. Basic Absorption Refrigeration Cycle with a Regenerative Heat Exchanger.

Table 20. Equivalent Water Temperatures and Steam Pressures for Commercial Lithium Bromide Absorption Systems

Water with a 40°F Temperature Drop and the Following Supply Temperature (°F)	Equivalent Saturated Steam Supply (psig)
240.0	2
247.3	4
253.8	6
259.8	8
266.0	10
270.0	12

The thermal energy requirement of commercial lithium bromide absorption systems is about 17,200 Btu/ton·hr.

The common electric-motor-driven compression-refrigeration system for producing 44°F chilled water with a 95°F condenser cooling water supply requires only about 2900 Btu of electricity per ton·hr and 2600 Btu/ton·hr in the largest sizes. A value of 2900 Btu is generally used in this study. If refrigeration systems were located at the consumption sites, approximately six times as much energy would have to be transmitted to the absorption systems as compared with electrically driven systems. With all the inefficiencies that occur in steam distribution, the turbine-driven compressive systems would also require about as much thermal energy to be transmitted as do the absorption systems. If the consumption sites were located at long distances from the plants, neither absorption systems nor turbine-driven systems could compete economically with electrically driven compressors if they were charged full steam generation and distribution costs. However, most utilities offer summer heat at enough discount to make absorption refrigeration competitive (see Sect. 3.9). It is also to be noted that, currently, absorption air-conditioning equipment is more expensive than electric compressive systems, but the differential cost would most likely be eliminated with large-volume production.

The effects of exhaust conditions on the gross cycle efficiencies of the three plants considered as power sources are shown in Fig. 5 in Section 2.3. The saturated steam temperature corresponding to the exhaust pressure was used as representative of the exhaust conditions for the plants. The incremental plant energy production per ton hour of air-conditioning service is partly a function of these efficiency values.

The increases in the energy produced at the center resulting from air conditioning with chilled water from compressive and steam heated absorption refrigeration are shown in Fig. 32. In these estimates no allowance was made for pressure drops in steam lines or power losses in electrical transmission systems. The steam supply pressure for the absorption system was allowed to vary from 2 to 12 psig. The energy production required for the compressive refrigeration, including turbine-driven compressive refrigeration, was simply a function of the reactor

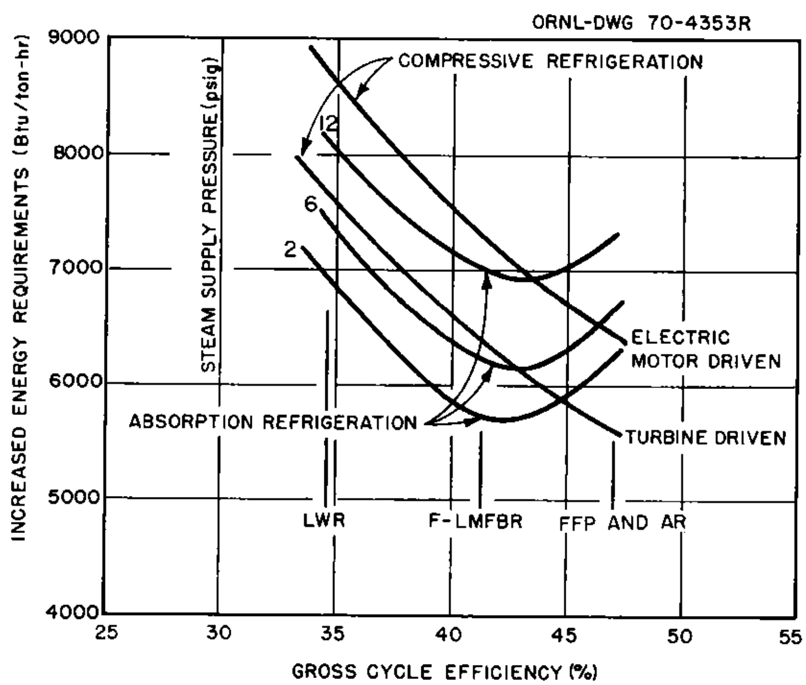

Fig. 32. Increase in Plant Energy Requirements Resulting from Air Conditioning with Compressive and Steam-Heated Absorption Refrigeration.

type. If the refrigeration equipment is located at the energy center, the effects of these air-conditioning methods on the plant energy disposal requirements include the 12,000 Btu/ton·hr brought back to the plant from the air conditioning. This is shown in Fig. 33, where only the 2-psig steam-supply-pressure absorption system was included for comparison with the compressive system. The other steam supply pressures have similar but higher values than the 2-psig system.

The increase in the plant energy requirements resulting from air conditioning with compressive refrigeration and hot-water-heated absorption refrigeration are shown in Fig. 34. The effect of using various water supply temperatures (250 to 280°F) for the absorption system is shown. The water was fed to an intermediate heat exchanger that provided water of desired temperature to the concentrator. The return water temperature was

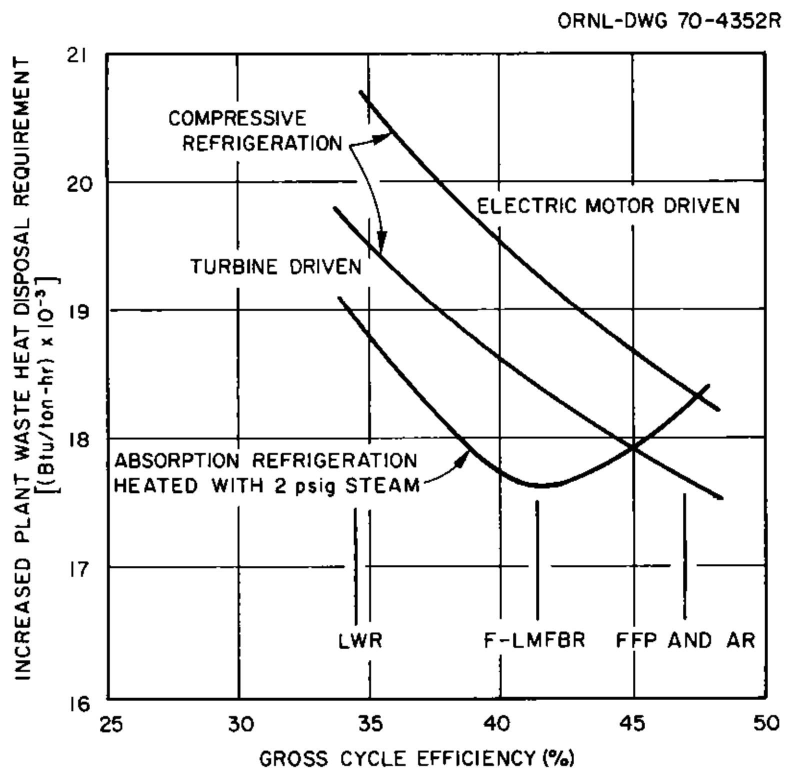

Fig. 33. Increase in the Plant Energy Disposal Requirements Resulting from Air Conditioning with Compressive and Steam-Heated Absorption Refrigeration Located at the Plant Site.

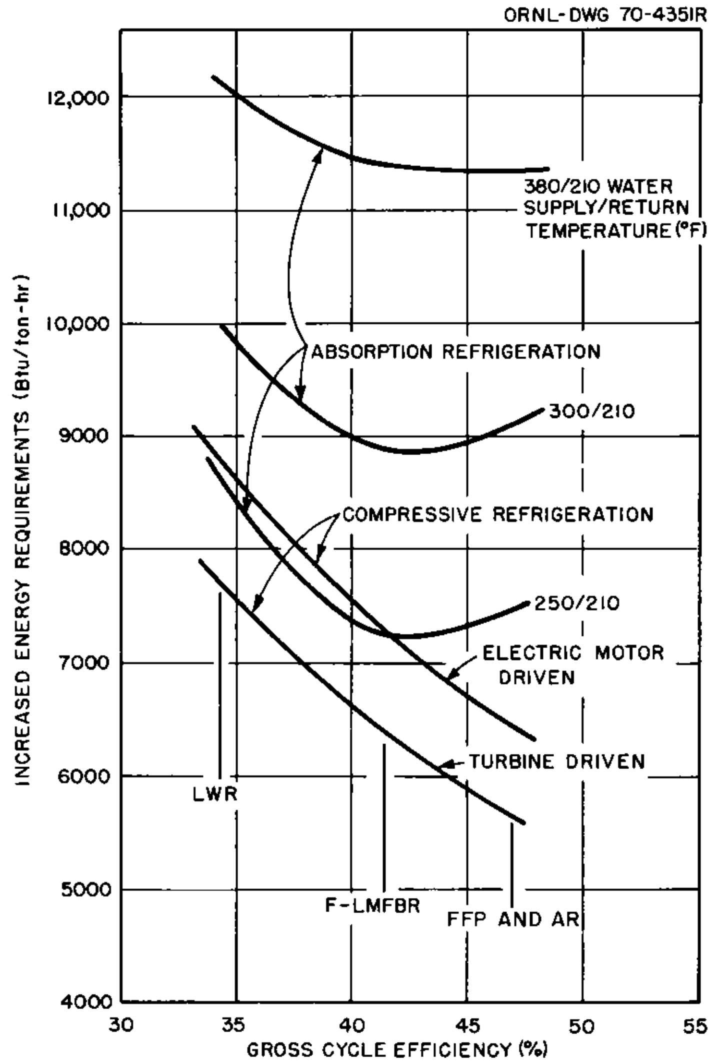

Fig. 34. Increase in the Plant Energy Requirements Resulting from Air Conditioning with Compressive Refrigeration and Hot-Water-Heated Absorption Refrigeration Equivalent to 2-psig Steam.

maintained at a constant value of 210°F. In all cases the absorption systems operated with 240°F water entering the concentrator, and the absorption-refrigeration equipment performed the same as if it were operated with 2-psig steam. With refrigeration equipment at the plant site the effects of these air-conditioning methods on the plant energy disposal requirements are shown in Fig. 35. The energy disposal requirements include the 12,000 Btu/ton·hr obtained from the air conditioning.

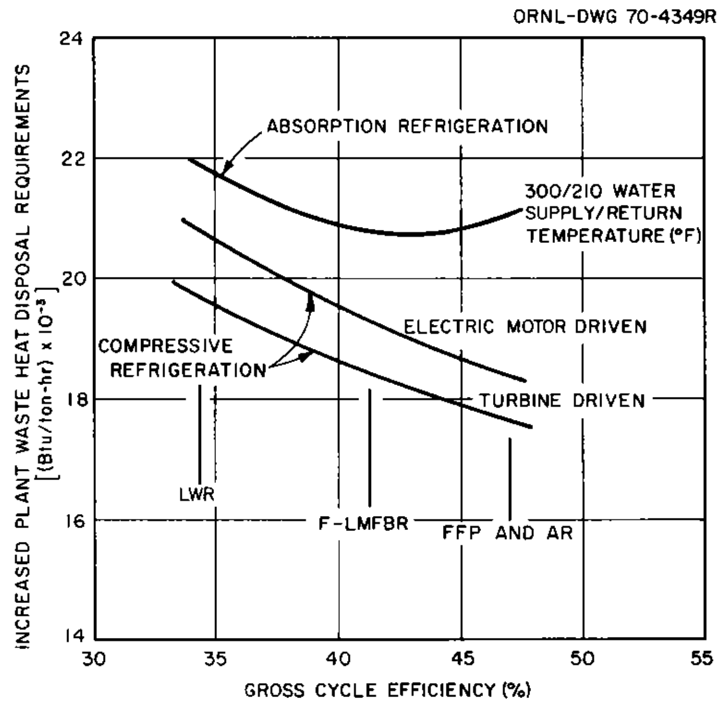

Fig. 35. Increase in the Plant Energy Disposal Requirements Resulting from Air Conditioning with Compressive and Water-Heated Absorption Refrigeration Located at the Plant Site.

Only the 300°F water-supply-temperature absorption system was included for this comparison with the compressive system.

A reduction in the plant-site energy-disposal requirements results when the energy for operating the refrigeration systems is exported from the plant site to the air-conditioning consumption site. Figure 36 shows the plant energy disposal requirements for an electric-motor-driven compressive refrigeration system and an absorption-refrigeration system supplied with 300°F water with both located at the consumption site. The electric system has a positive energy disposal requirement due to disposal of the heat from the electrical generation at the plant site. The absorption system has a negative energy disposal requirement resulting from the exportation of the heat for the system operation to the consumption site. This would also be true for compressive systems driven with steam exported to the consumption site.

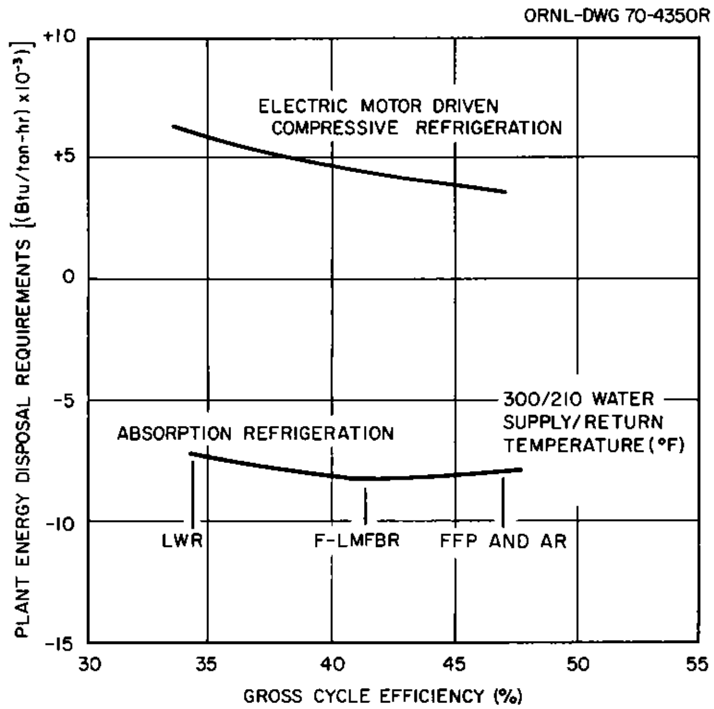

Fig. 36. Plant Energy Disposal Requirements Resulting from Air Conditioning with Compressive and Water-Heated Absorption Refrigeration Located at the Consumption Site.

The effects of producing 500 Mw(e) and 10^5 tons of air conditioning on the total thermal energy distribution of the three types of reactor are given in Table 21. The reactor thermal inputs vary more with reactor types because of the differences in gross cycle efficiencies than with the type of refrigeration system. However, the plant thermal energy disposal requirements are greatly reduced by the use of absorption air conditioning at the consumption site. The effects of producing 500 Mw(e) and air conditioning at the consumption site by absorption until a full back-pressure situation is reached and then by a combination of absorption and electric-motor-driven compressive refrigeration on the total energy distribution of the three types of reactor is shown in Fig. 37. The points corresponding to the minimum plant site disposal requirement occur when the turbines are fully back pressured. Additional air-conditioning load beyond this point is supplied from the combination of back-pressure heat for the absorption system and electricity for the compressive system.

Table 21. Effects on Total Thermal Energy Distribution of Producing 500 Mw(e) and 10^5 Tons of Air Conditioning by Various Methods

Refrigeration Location and Type	Reactor Type	Reactor Thermal Input (Mw)	Plant Site Thermal Energy Disposal Requirements (Mw)
Consumption site, electric-driven compressor	LWR	1814	1229
	F-LMFBR	1503	918
	FFP and AR	1324	739
Plant site, turbine-driven compressor	LWR	1778	1629
	F-LMFBR	1473	1324
	FFP and AR	1297	1149
Plant site, absorption system heated with 2-psig steam	LWR	1756	1608
	F-LMFBR	1452	1304
	FFP and AR	1318	1170
Consumption site, absorption system heated with 300°F water	LWR	1799	794
	F-LMFBR	1496	491
	FFP and AR	1352	347

In summary, the effects on the thermal addition to the biosphere of the various air-conditioning methods studied range from a low value of 5700 Btu/ton·hr for an absorption system supplied with 2-psig back-pressure steam from the F-LMFBR to a high value of 12,700 Btu/ton·hr for an absorption system supplied with 380°F water from a light-water reactor. The compression-type refrigeration systems were competitively within this range.

The major effect on thermal emission of air conditioning with thermal energy would be local, rather than biospheric, and would result from the exportation of heat energy from the plant site to the air-conditioning consumption sites. This exportation of heat energy would relieve the thermal energy disposal problem associated with the concentrated block of heat normally disposed of at the energy-generating facility.

Air conditioning at the consumption sites with 2-psig absorption equipment heated with 300°F water from the energy center would result in

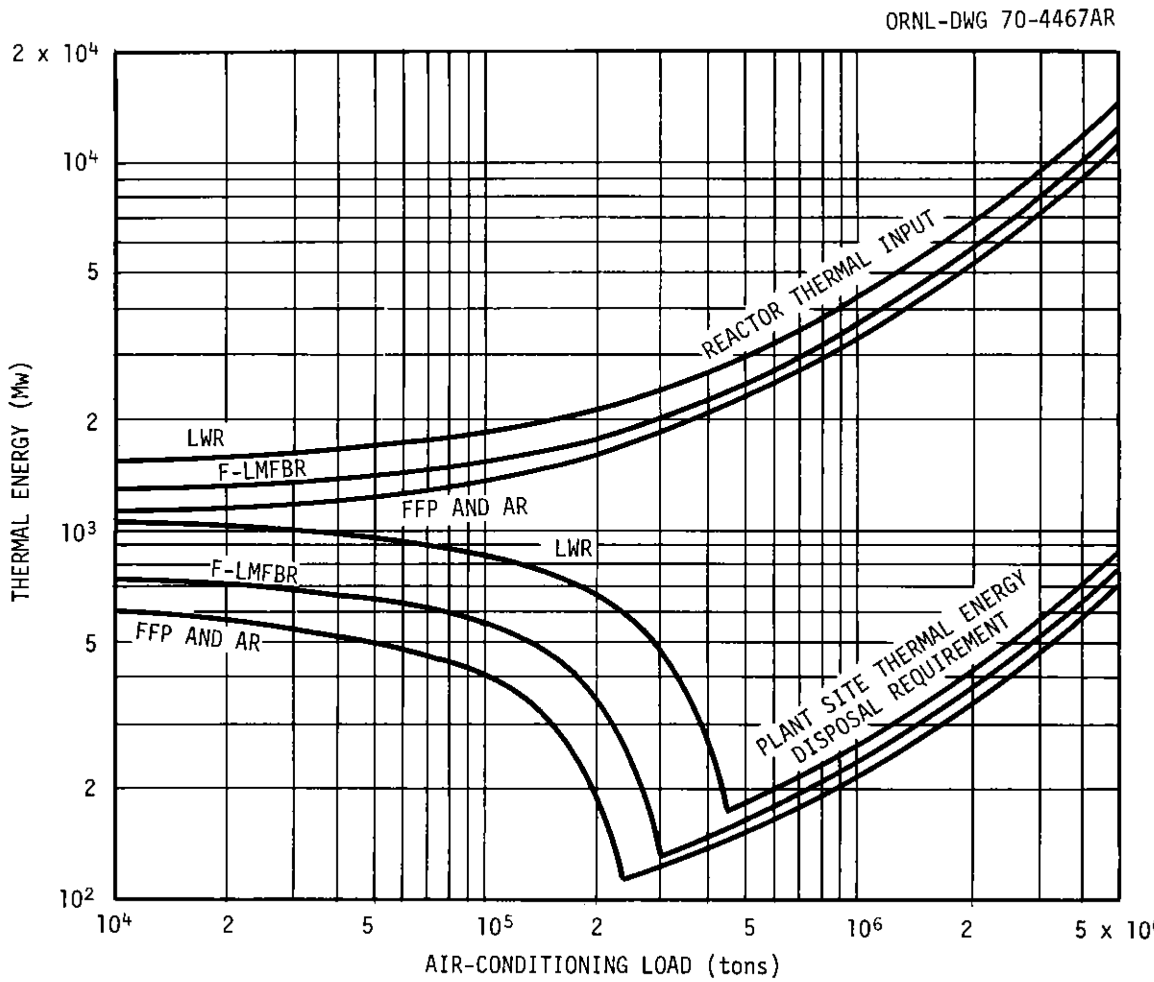

Fig. 37. Total Energy Distribution of a System Producing 500 Mw(e) for Uses Other Than Air Conditioning and Air Conditioning by a Combination of Absorption and Electric-Driven Compressive Refrigeration Located at the Consumption Site. Water supply temperature to absorption system is 300°F.

a thermal emission to the biosphere that would be approximately 12% more than that resulting from conventional electric air-conditioning practice. It would move large quantities of heat from the energy center to many scattered sites within the city. This is the system utilized in the reference city described in Section 6.

3.7.2 Thermal Energy Utilization in Buildings

Space heating, water heating, and air conditioning constitute the major services that can be supplied to buildings with a district heat-distribution system. From Section 3.1, it may be seen that a large amount of energy is involved in space heating and that there are seasonal and diurnal variations in its rate of usage. The same is true for air conditioning and also, with the exception of seasonal variations, for hot-water usage. These variations are sufficiently large that they must be taken into account in order to describe the physical and economic relationships between the city, its energy center, the thermal energy distribution system, and the reduction in waste heat emission.

For the reference city in Section 6, it is necessary to know how much thermal energy is required for each particular kind of building and its peak usage. This is needed in order to estimate how much energy is consumed, how much steam (on the average) must be passing completely through the condensing turbine so its thermal energy will be available for peak heating, and how the building's peak heat usage affects the size of the distribution system required.

Design requirements for heating and cooling buildings are reasonably well known and available. Energy consumption data are relatively scarce, and it is this kind of information in particular that is collected here for later use in the design and analysis of the reference city.

Space Heating. A check on new apartment and office buildings from Tennessee to Massachusetts indicates that they generally have a heat loss of 25 to 35 $Btu/hr \cdot ft^2$ at design conditions — winter days, at time of low internal heat load, high winds, and temperatures ranging from 9°F in Knoxville to -1°F in Boston. The estimation of the energy consumed by the space heating of a particular structure for a specific time period involves the structural design and the weather.

A study[39] of the heating requirement of the Parkview Apartments, located in Winchester, Massachusetts, by J. W. Megley of the International District Heating Association and the Boston Edison Company, shows the effects of variations in the hourly temperature on the space heating load for a day of coldest morning temperature and for a day of coldest afternoon temperature. The temperature variations are shown in Fig. 38, and the estimated heating loads are shown in Fig. 39 for these two cases. Commercial buildings with large numbers of people and intense lighting

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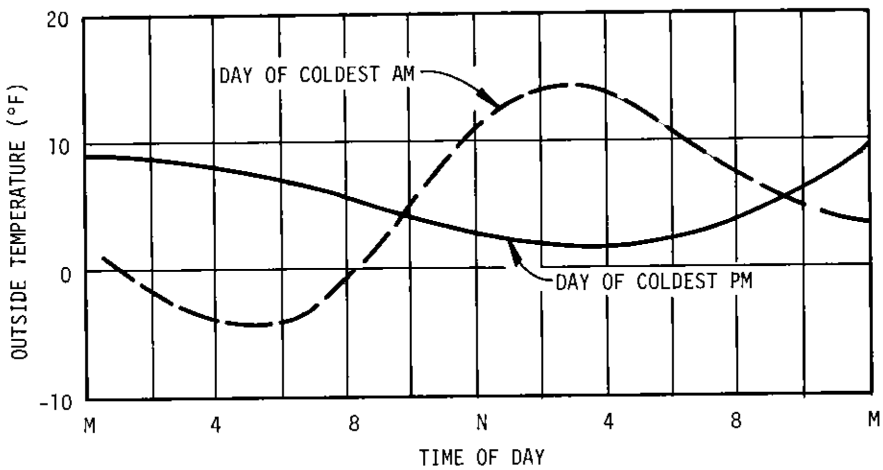

Fig. 38. Hourly Temperatures for Day of Coldest Morning and Day of Coldest Afternoon.

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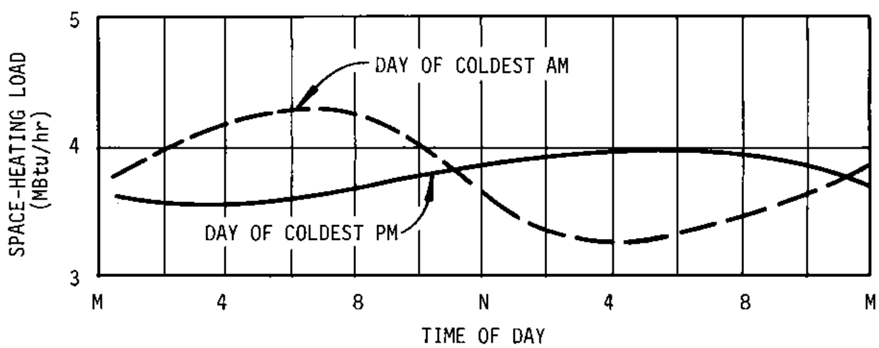

Fig. 39. Gross Space Heating Loads.

and office machinery usage during daytime business hours have very small requirements for space heating during that daytime period.

A computer program based on available weather data was written by M. T. Heath of the Oak Ridge Computing Technology Center so that accurate heat consumption requirements based on past data can be calculated. Hourly data from many of the major stations is available from the U.S. Weather Bureau. Consultation on the program and on the selection of input data was provided by J. W. Megley, A. B. Fuller of ORNL, and M. J. Wilson of I. C. Thomasson & Associates, Inc. (on a subcontract basis).

The overall purpose of the program is to determine the energy demands a given collection of buildings would make on a district heating system. The collection can be a single building or an entire city and can include several different types of buildings whose characteristics are specified by the user. Both thermal and electrical requirements are computed. In addition to input concerning the physical properties of the buildings the program needs weather information, which is available from U.S. Weather Bureau data at the desired location. The terminology, symbols, and formulas used below were taken largely from Ref. 40.

For each kind of building the basic calculation is that of the thermal energy balance during a given hour. This quantity is simply the sum of the heat losses (nominal) and heat gains inside the building, where by convention heat losses are taken to be positive and heat gains negative. The value thus obtained can be thought of as the amount of heat that must be added (or removed) in order to maintain a specified comfort level (temperature and humidity) in the building. The heat losses and gains considered are those due to transmission, ventilation and infiltration, electrical power use, regulation of humidity, solar radiation through glass, and latent and sensible heat of occupants. From the heat balance the actual thermal and electrical demands on the district system can be determined, depending on the kinds of heating and cooling employed. Values for longer time periods are computed by summing over consecutive hours.

The formulas used in computing the various heat gains and losses are given below.

1. Transmission:

$$AU(T_i - T_e)$$

2. Ventilation and infiltration:

$$hNC\rho(T_i - T_o)$$

3. Humidity regulation:

$$hNL\rho(W_i - W_o)$$

4. Electrical power:

$$KFE$$

5. Occupants:

$$D(H_s + H_l)$$

The symbols in these formulas are defined as follows:

A = Ratio of exposed surface to floor area.

U = Coefficient of transmission in Btu/hr·ft^2·°F. This is a composite value averaged over the walls, roof, windows, etc.

T_i = Indoor temperature in °F to be maintained.

T_o = Outdoor air temperature in °F.

T_e = Sol-air temperature of the outdoor air. This is the outdoor air temperature adjusted for the solar effect and a time lag (see p. 489 of Ref. 40).

h = Ceiling height in ft.

N = Number of air changes per hour due to ventilation and infiltration.

C = Specific heat of air in Btu/lb·°F.

L = Latent heat of vapor in Btu/lb of water at temperature T_i.

ρ = Density of air in lb/ft^3 at temperature T_o.

W_i = Humidity ratio to be maintained indoors in lb moisture per lb dry air.

W_o = Humidity ratio of outdoor air in lb moisture per lb dry air.

K = Conversion factor from electrical to heat units (3.413×10^3 Btu/kwhr).

E = Electrical energy in kwhr used per square foot of floor area (nonspace heating).

F = Fraction of electrical energy consumed that actually shows up as a heat gain in the building.

D = Density of population in the building in persons per square foot.

H_s = Sensible heat in Btu/hr due to one person.

H_l = Latent heat in Btu/hr due to one person.

The heat balance is calculated on a per square foot basis for each type of building.

No formula is given for the heat gain due to solar radiation through glass because this calculation is much too complicated to be summarized in a single formula or even a few formulas. The procedure used is essentially that given on p. 479 of Ref. 40. The value depends on the physical properties of the building (window area, kind of glass, shading, etc.) and the solar intensity, which is in turn a function of sun angle, time of day, season, cloud cover, and location of the city. To simplify program input the physical constants for the glass are fixed at those values for standard double-strength glass, and the variation between buildings is then indicated by modulation of the shading coefficient (see Ref. 40, p. 478). The solar intensity value, which is a byproduct of this calculation, is also used in computing the sol-air temperature (see Ref. 40, p. 489).

The values of the variables in the above formulas must be specified for each type of building in a given run of the program. Some of them, such as the surface-area ratio, transmission coefficient, and ceiling height are fixed throughout the time period involved. Others, such as the indoor temperature and humidity, ventilation and infiltration, electrical use, and building occupancy, are allowed to vary with time of day. Further variation is allowed in the day-to-day pattern due to weekends and holidays. All this is accomplished by specifying two 24-hr schedules for such variables. For the solar radiation computation the program requires the latitude and longitude of the city, the fraction of exposed surface area that is wall area, the fraction of wall area that is glass area, the time lags for wall transmission and for radiant solar effect, and a schedule for the shading coefficient. The weather data consist of hourly readings for dry-bulb temperature of outdoor air, absolute humidity of outdoor air, and percentage cloud cover. These data are contained on magnetic tape obtained from the U.S. Weather Bureau for the location in question.

It should be noted that since the program uses real hourly weather data rather than some averaged or idealized values, the program simulates actual operating conditions. This differs from the practice of basing heating and cooling estimates on degree-day figures or other generalized measures of weather conditions over extended periods. Basing the calculations on actual weather and using a comparatively microscopic scale with respect to time and building characteristics should give more accurate estimates for heating and cooling needs. It should also be emphasized that the values computed are what would be required to completely attain the desired comfort level without regard to any limitation that might be imposed by the equipment employed. Since one seldom designs equipment to meet absolute maximum demand and instead settles for somewhat less than optimum comfort on the few worst days of the year, this means that computed values may not agree exactly with past experience, even if all other factors are equal.

Although the program is designed to simulate the demands placed on a district heating system by all its customers over a given period of time, the main testing and use of the program so far has been in estimating the heating and cooling needs of individual buildings over a year's time. Specifically, the numbers wanted were the total heat consumption for a year, the peak hourly heat consumption during the year, the total heat rejection for a year, and the peak hourly heat rejection during the year. A comparison of the results obtained by the use of this method with those of other methods for estimating the energy required for heating and air conditioning the reference city is given in Section 6.

For design purposes the results of a modified degree-day method [see Eq. (2) below] were used for predicting the energy consumption for space heating buildings in the reference city to 70°F. The degree-day method is a commonly used one, and the computations are based on the consumption data of similar systems in operation. The assumption is made that the major fraction of the heat loss from a structure is directly related to the difference between the indoor and outdoor temperatures in terms of degree days. The number of degree days in a day when the mean temperature is below 65°F is defined as the difference between 65°F and the mean daily temperature. It is assumed that internal heat loads raise the indoor temperature from 65°F to 70°F. The average number of degree days per year and their distribution for various areas of the United States have been tabulated and are available in several sources, such as the ASHRAE Guide and Data Book.[41]

The periodic energy consumption can be estimated by the degree-day method from

$$F = BVD \,, \tag{1}$$

where

F = heat consumption for estimated period, Btu,

B = experienced heat requirement, Btu per degree day per 1000 ft^3 of heated space,

V = volume of heated space, 1000 ft^3,

D = number of degree days for period of estimation.

The heat consumptions experienced for typical buildings located in many sections of the United States[41] are given in Table 22.

Estimates can also be made by a modified degree-day method based on building design data by using the equation

$$F = CRVD \,, \tag{2}$$

where F, V, and D are defined as in Eq. (1) above,

R = design heat requirement, Btu per degree day per 1000 ft^3 of heated space under building and weather design conditions,

and

C = factor to compensate for differences between the heat required per degree day under design conditions and the requirements per degree day under other conditions over extended periods of time.

Air Conditioning. The design factors discussed above as affecting space-heating requirements also apply to air conditioning, but the relative importances of the design factors are not the same. As, for example, the sun loading, the internal heat sources, and the requirements for maintaining constant temperatures in special work areas below normal requirements are some of the conditions that have a greater influence on air-conditioning requirements than on space-heating requirements. The requirements are also influenced by human factors such as periodic operation during only the hottest weather, opening of windows during operation, and differences in preferred indoor temperature. Typical factors[42] used

Table 22. Steam Consumption of Buildings with Various Types of Occupancy[a]

Type of Building	Number of Buildings	Average Volume of Heated Space (1000 ft^3)	Steam for Heating (lb per degree day per 1000 ft^3)	Average Time of Occupancy (hr/day)
Office	334	2160	0.685	12.1
Bank	16	806	0.786	11.7
Department store	63	3400	0.385	11.1
Stores	73	310	0.624	10.4
Warehouse	24	2230	0.459	9.4
Hotel and club	73	1795	0.990	22.3
Apartment or residence	51	1425	0.962	21.8
Theater	22	1240	0.482	12.9
Garage	13	1540	0.202	21.4
Factory	19	1350	0.808	9.5
Church	9	656	0.532	7.9
Hospital	4	3306	1.194	22.0
School	8	1115	0.592	11.5
Municipal or federal building	15	3215	0.587	15.6

[a]Data obtained from Ref. 41.

for the estimation of average air-conditioning installed capacity requirements for a small number of commercial facilities are given in Table 23. Part of a more comprehensive and recent coverage[43] of the requirements for commerical, residential, and government facilities is given in Table 24. The cooling load check figures in Table 24 are divided by a diversity factor to obtain installed capacities adequate for meeting design conditions and peak loads. Typical diversity factors for Philadelphia, according to M. J. Wilson, are 0.80 to 0.85 for large apartment buildings and 0.075 for large office buildings.

Table 23. Average Size Factors for Checking and Field Estimating of Air-Conditioning Requirements[a]

Type of Store	Average Floor Area (ft^2/ton)
Camera shop	180
Drug store	150
Grocery	300
Clothing store	200
Jewelry shop	160

[a]Data obtained from Ref. 42.

Several methods have been developed for determining the periodic energy requirements of air-conditioning systems. These methods are similar to those described for determining space-heating requirements, but when hourly Weather Bureau data are available, a computer program such as that previously described could probably give the most accurate results.

Some consumption data for small residential units and commercial establishments obtained before 1959 from utility records in several major cities are given in Tables 25 and 26, respectively.

Table 24. Cooling Load Check Figures[a]

Classification	Refrigeration (ft^2/ton)		
	Low	Average	High
Apartment, high rise	450	400	350
Auditoriums, churches, theaters	400	250	90
Educational facilities, schools, colleges, universities	240	185	150
Factories			
Assembly areas	240	150	90
Light manufacturing	200	150	100
Heavy manufacturing	100	80	60
Hospital patient rooms	275	220	165
Hotels, motels, dormitories	350	300	220
Libraries and museums	340	280	200
Office buildings	360	280	190
Residential			
Large	600	500	380
Medium	700	550	400
Restaurants	135	100	80
Shopping centers, department stores, and specialty shops			
Department stores			
Basement	340	285	225
Main floor	350	245	150
Upper floors	400	340	280
Dress shops	345	280	185
Drug stores	180	135	110
5¢ and 10¢ stores	345	220	120
Malls	365	230	160

[a]Data obtained from Ref. 43.

Table 25. Estimated Annual Hours of Operation for Properly Sized Air-Conditioning Equipment in Typical Cities During Normal Cooling Season[a,b]

City	Operating Time (hr)	City	Operating Time (hr)
Atlanta, Georgia	750	Jacksonville, Fla.	1600
Boston, Mass.	200	Minneapolis, Minn.	350
Chicago, Ill.	400	New Orleans, La.	1500
Cleveland, Ohio	450	New York, N.Y.	350
Dallas, Texas	1400	St. Louis, Mo.	1000
Fresno, Calif.	900	Washington, D.C.	800

[a]Based on average indoor temperature of 80°F.

[b]From Ref. 44.

Table 26. Equivalent Full-Load Operating Hours of Refrigeration Equipment Used for Summer Cooling May 15 to October 15[a]

Application	Hours Open for Business	Full-Load Operating Hours of Refrigeration Equipment Used							
		Atlanta	Boston	Chicago	Los Angeles	New Orleans	Phila-delphia	St. Louis	Wash-ington, D.C.
Department stores	940	840	560	610	580	890	720	750	780
Drug stores	2100	1630	950	1060	980	1790	1330	1420	1530
Offices	1100	1030	660	720	680	1060	880	910	960
Restaurants (long hours)	2100	1510	820	930	850	1690	1210	1300	1400
Specialty shops	1090	800	530	590	560	860	690	720	750
Theaters, neighborhood	900	640	420	450	430	650	520	550	580

[a]From Ref. 45.

The data shown in Table 25 are probably below present requirements due to the increases in use of electrical- and gas-operated appliances since these data were obtained. The data in Table 26 are also probably below present figures due to currently increased lighting, increased use of office machinery, longer business hours, and the present practice of air conditioning many office buildings 24 hr per day.

Some current experience in large apartment buildings and complexes in Philadelphia was supplied by M. J. Wilson. The load factor on air-conditioning equipment is 0.50–0.52 over a cooling period of 5500–5600 hr when installed in accordance with data on Table 24 and a diversity factor of 0.80–0.85. This is equal to an annual load factor of 32%.

With the use of district chilled-water system data supplied by the Connecticut Natural Gas Company, it was estimated (see Sect. 3.1) that the energy consumed for commercial air conditioning in downtown Hartford for the year 1968 was 17% of that required for a year of operation at the yearly peak hour demand. This is considerably higher than the values of 8 and 12% that would be derived from the data in Table 26 for offices in Boston and Atlanta, respectively.

The cooling degree hours above a fixed temperature, say 85°F as a criterion, when available can be used to determine the cooling requirements by methods similar to those using the heating degree days for determining the heating requirements. Approximate values of the cooling degree-hour values for various localities can be obtained from degree-hour maps.[46] A cooling degree-day map based on a discomfort index is also available.[48] The actual local variations for a particular region are required to make accurate determination of the energy requirements.

The peak and periodic consumption of energy by air conditioning in the reference city were estimated for design purposes by use of the data in Table 24 and assumptions regarding diversities and load factors.

Hot Water. The use of energy for heating water represents a sizeable fraction of the domestic energy consumption in the United States. If it is assumed that one-half the nonheating energy expended in 1965 for residential and commercial use was used for water heating, the fraction of the national energy expenditure for water heating would be approximately 4%, which for a 60°F average rise in water temperature represents a daily per capita hot-water consumption of 45 gal. Of this 45 gal, approximately 36 gal was used in residences, and the remaining 9 gal was used by commercial facilities.

The requirements for hot water vary in total volume flow rate, duration of peak load period, and temperature required. Some hot-water demand and load characteristics[47] for various types of buildings and facilities are given in Tables 27, 28, and 29.

The estimated hot-water usage in the previously mentioned Parkview Apartments on a day of maximum usage is shown in Fig. 40.

The future uses of hot water will probably increase with the increase in the per capita income and increased use of dishwashers, washing machines, and other domestic hot-water consuming facilities, such as baths and showers. Due to the ability to store hot water within buildings, the actual load variations placed on an energy source depend considerably on the storage-capacity installed.

Diurnal Variations in the Thermal and Electrical Loads. The diurnal variations in the thermal and electrical loads of an energy system do not coincide. Based on the assumption that residences were the main cause of diurnal heat load variations, an example of noncoincidence in a system is illustrated in Fig. 41. The thermal curves are the normalized curves for the maximum requirement for thermal energy used for hot water and space heating of the Parkview Apartments, Winchester, Massachusetts. The electrical curve is the normalized curve (from Fig. 14 in Sect. 3.1) for the Boston Edison Company service area, Boston, Massachusetts. These two locations are close enough to each other to have similar climatic conditions and permit direct comparison. The summer thermal load variations, which are greatly affected by the large demand for air conditioning in the middle of the day, more nearly coincide with the electrical load requirements.

If heat from the energy center were supplied by a back-pressure turbine system, and the turbine-generator system operation followed the system electrical load, a matching of the heat and electricity loads on the center would have to be affected by such devices as heat accumulators, standby heating plants, bypassing of the turbine, and optional use of

Table 27. Estimated Hot-Water Demand Characteristics for Various Types of Buildings

Type of Building	Hot Water Required Per Person[a] (gpd)	Maximum Hourly Demand in Relation to Day's Use	Duration of Peak Load (hr)
Residences, apartments, hotels, etc.[b]	20–40	1/7	4
Offices	2–3	1/5	2
Factories	5	1/3	1

[a]At 140°F.

[b]Daily hot-water requirements and demand characteristics vary with type of hotel. The better class hotel has a relatively high daily consumption with a low peak load. The commercial hotel has a lower daily consumption but a high peak load.

Table 28. Maximum Daily (24 hr) Requirements for Hot Water in Apartments and Private Houses

Number of Rooms	Hot-Water Usage (gal) Number of Bathrooms			
	1	2	3	4
1	60			
2	70			
3	80			
4	90	120		
5	100	140		
6	120	160	200	
7	140	180	220	
8	160	200	240	250
9	180	220	260	275
10	200	240	280	300

Table 29. Maximum Daily (24 hr) Requirements for Hot Water in Hotels, Office Buildings, and Hospitals

Use	Hot-Water Usage (gal)
Hotels	
Room with bath, transient	50
2 rooms with bath	80
Office Buildings	
White-collar worker (per person)	2–3
Other workers (per person)	4.0
Cleaning per 10,000 ft^2	30.0
Hospitals	
Per bed	80–100

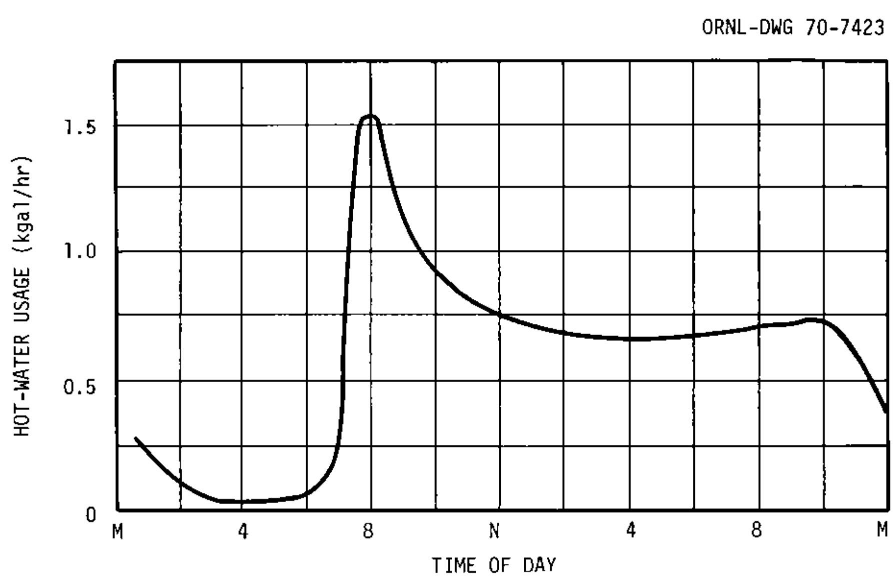

Fig. 40. Domestic Hot-Water Usage for Maximum Day.

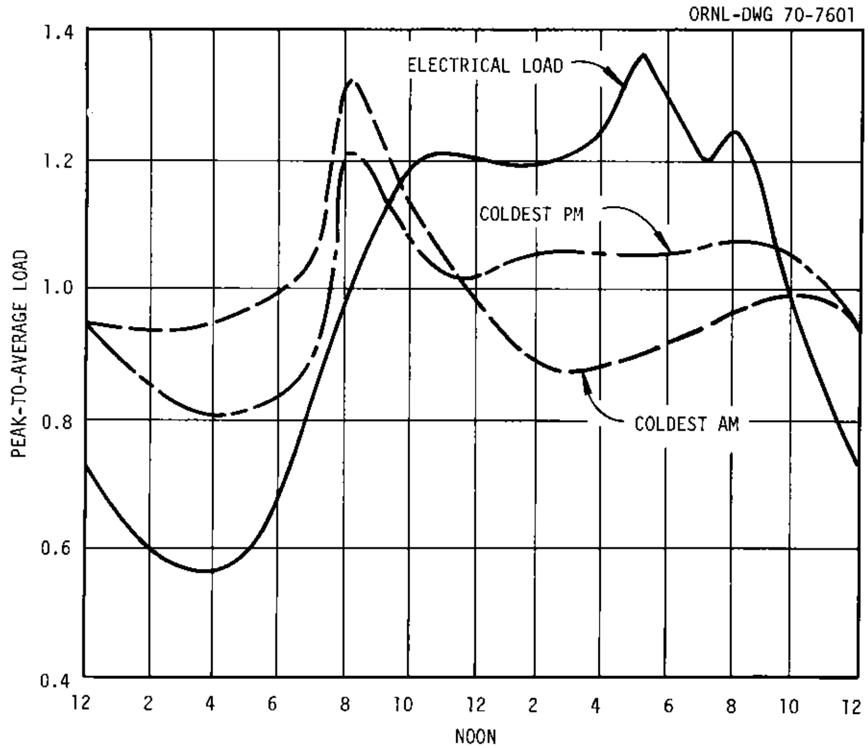

Fig. 41. Variations in the Diurnal Electrical and Heating Load.

electricity or thermal energy for heating in some installations. Electrical load-following energy centers with extraction turbines would be able to vary the ratio of extracted heat to electricity production and at times lessen the matching problem. A base-loaded energy center that always produces as much energy as possible and is connected to a regional electrical grid has additional degrees of freedom.

3.8 Temperature Requirements and Heat Transfer Media

Heat distribution systems utilizing water or steam are less expensive than those using heat transfer fluids such as Dowtherm A or sodium by factors of 2 to 4 when the temperature is in the region of approximately 300 to 500°F. The difference is mostly due to the cost of the inventory of heat transfer fluid and to the superior heat transfer characteristics of water and steam as compared with the other fluids at low temperature. However, at higher temperatures where the pressure of water or steam becomes very high, low-pressure fluids, such as Dowtherm or sodium, and at very high temperatures, other fluids, such as fused fluoride salts, become competitive and even less expensive than water or steam systems. The high-temperature range involves the use of either prime steam or steam from which very little electricity has been made.

However, the utilization of large quantities of heat from electricity generating plants would usually involve building services and industrial processes which, in most cases, require heat at the lower of the two temperature ranges. For large heat distribution systems the choice of fluid would therefore usually be limited to steam or water.

Steam is used to the greatest advantage in industries where high rates of heat transfer through containers and steady high temperatures are required to speed such processes as water evaporation from chemicals and the cooking of foods. In cases where heat can be transferred from the fluid over a range of temperatures as it cools, such as in providing buildings with space heat, absorption refrigeration, and domestic hot water, and in providing low-temperature process heat, hot water is completely adequate. The initial high temperature of the water in the distribution system may be required to supply the temperature requirement of a particular application, or it might be a means of conveying a large amount of heat in a small volume of fluid in small pipes.

The providing of hot water has less effect on lowering the efficiency of the electrical plant than the supplying of steam at the same temperature. Steam must be extracted from the turbines at the initial high temperature required in the steam distribution system, and there is a drop in both temperature and pressure as it flows down the pipeline to the consumer. In contrast, water can be heated at the plant in stages, with only the final increment of heat added at the peak temperature. From the standpoint of waste heat utilization, a decided advantage accrues to the use of water. Water at 300°F was used to provide service to the buildings of the new reference city in Section 6. Higher temperature water would be required to serve existing steam-heating installations in the buildings of an old city.

The pressure and temperature drops that occur in steam lines of various sizes and lengths are illustrated in Fig. 42. It is assumed that the exit velocity of the steam is 250 fps and that heat is removed until the condensate temperature is lowered to 200°F. It may be seen that long-distance conveyance of steam requires high pressure and temperature extractions from the turbine that are not effective in reducing heat emissions at the power plant.

The costs of providing steam and hot water for district heating are sufficiently similar to make cost comparisons dependent on the location of the heat consumers and their consumption pattern and on other design requirements imposed on the system. Under many circumstances hot-water systems have the economic advantage.[48] If condensate must be returned to the energy center because of thermal pollution considerations, estimates indicate that the initial capital cost of a steam distribution system might be very little less than that of a water system. High heat losses and the maintenance of condensate traps in steam systems are likely to more than compensate for the difference.

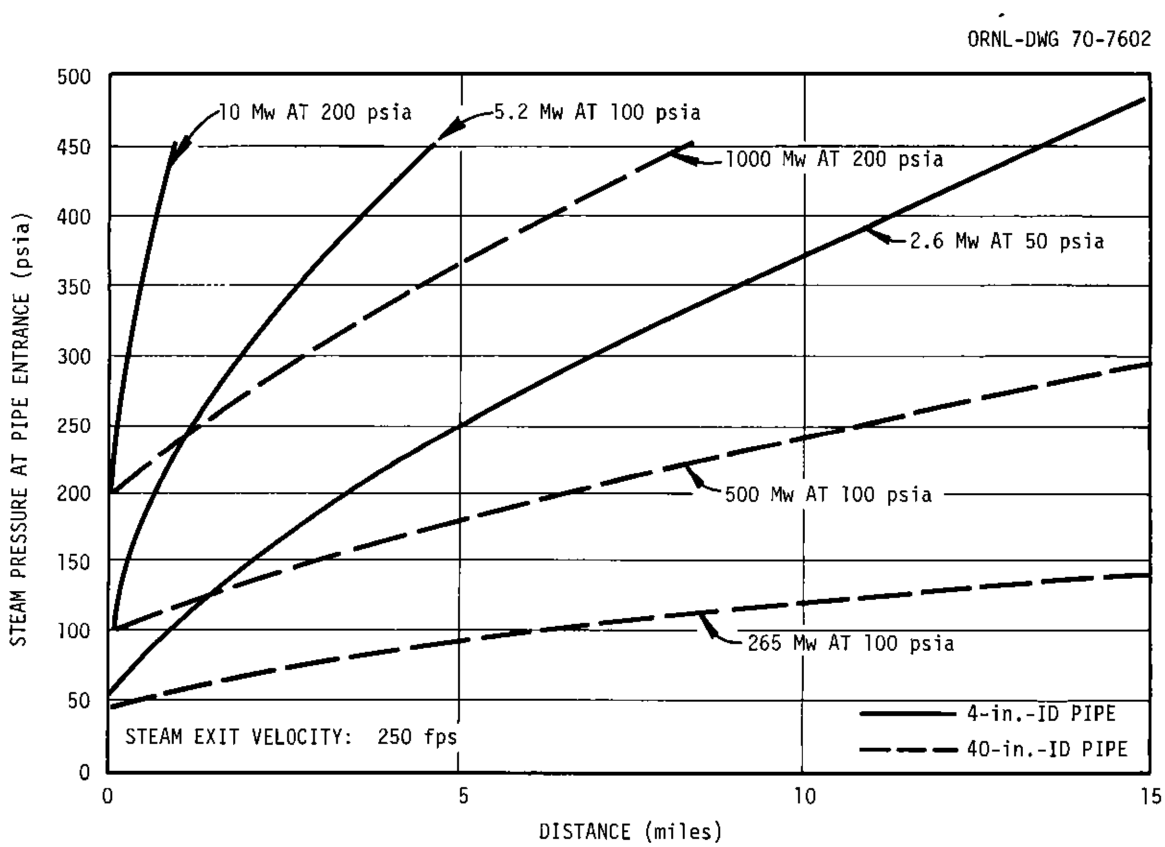

Fig. 42. Transmission of Heat with Steam.

An evaluation of the operational safety of high-temperature hot-water systems and steam systems[48] resulted in the conclusion that at equal temperature, in the event of line breakage, the water systems are less hazardous for the following reasons:

1. From the efflux test of nozzles it is apparent that cool water is ejected at the beginning of the efflux; in this way a short interval for possible escape is provided.

2. The heat transmitted to space by escaping steam during the same time interval is much higher than that transferred from ejected high-temperature water.

3. The steam exit velocity and kinetic energy are about five times those of escaping hot water.

4. Breaks of unattended lines filled with steam can remain undetected for a long time, whereas escaping water is soon noticed.

3.9 Current Heat Costs

The production of prime steam in large nuclear reactors and large modern fossil-fueled plants cost about 30 to 50¢/MBtu, depending on size of the plant, annual fixed-charge rates, and fuel costs. The production of an average of 65 Mw of 235-psig steam in the Y-12 Plant at Oak Ridge costs approximately 73¢/MBtu. From recent data in several reports by large district heating companies, it is estimated that the production cost for high-pressure steam suitable for industrial or space heating purposes averages approximately 70¢/MBtu.

The average revenue received in 1968 from distributed heat by the district heating companies[49] (i.e., the total cost of distributed heat) was as follows, based on 10^6 Btu/10^3 lb of steam:

	Revenue (¢/MBtu)
Average of 43 systems reporting	142
Second to tenth largest systems	133
Range in second to tenth largest systems	119–154
Largest system	152
Smallest system	148
Highest cost system	232
Lowest cost system	73

The average cost of heat production in the United States in office buildings and apartments was estimated for 1968 and projected to 1972 by M. J. Wilson of I. C. Thomasson and Associates, Inc., to be

	Cost of Heat Utilized (¢/MBtu)	
	1968	1972
Office buildings	117	135
Apartment buildings	142	163

These estimates were based on survey data on existing buildings of many types and ages. Among the sources were the 1968 Office Building Experience Exchange Report published by the Building Owners and Managers Association and the Economic Aspects of Incremental Comfort Systems published by the Remington Corporation.

The sales price for district heat often entails seasonal adjustments, particularly where air conditioning is concerned. As an indication of this, the National District Heating Association 1967 Rate Reference Book shows that one system in 1967 had a charge of 92.5¢/10^3 lb of steam for consumption over 10^6 lb from May through October, as compared with charges ranging from 145 to 195¢/10^3 lb from November through April. Another system charged 90¢/10^3 lb for consumption above 200,000 lb in a year for air conditioning, while the general rate for consumption above 200,000 lb ranged from 205 to 135¢/10^3 lb.

The cost of electricity for space heating is usually between 200 and 600¢/MBtu, depending on the region of the country. Although the electricity is expensive, the initial cost of the building heating system and the cost of maintenance is much less for some types of electrical installations and some types of buildings than that of systems distributing steam, hot water, or hot air and often overcomes the considerable differential in heat cost.

4. ENERGY CENTER

How the service requirements described in the previous sections might be provided by energy centers is described in this section, as well as where a center might be located, how reliable the service would be, and what would be the cost of producing electricity and thermal energy. It may be seen from Section 2 on Heat-Electric Systems that if an energy center generates the amount of electricity used by an urban area, there are relatively large quantities of heat that must be utilized in the area to effect a significant reduction in waste heat emission. From Section 3.1 on United States requirements it may be seen that a major portion of this reduction must come from heating and air conditioning the area's buildings unless some disproportionately large segment of the country's process steam-using industries are located in the area. The distribution of heat to buildings, particularly to streets of small buildings, can be expensive, since the piping costs are generally linear with pipe diameter, whereas pipe capacities increase proportionally to the square of the diameter. There is obviously an incentive for low-cost heat and close-in siting of the heat-producing plant, with its attendant low transmission cost, to allow for a high heat distribution cost.

Locating a new large fossil-fueled plant in an urban area would involve questions of fuel supply, cost of eliminating air pollution, and future governmental decisions that are not predictable. Therefore this program is concentrated on light-water nuclear reactors as the heat source for which near-term (1970–1985) siting practice can be assessed, as in Section 4.1. The present significant separation between nuclear energy centers and large populations is expected to decrease as time passes; however, inclusion of this separation distance and the associated cost penalty is appropriate for use in evaluating economic feasibility, as is done in Sections 6 and 7.

Reliability of the heat source is treated in Section 4.2, where it is assumed that the generating plants in different urban areas are connected by means of the usual electricity transmission grid. In contrast it is assumed that heat-electric plants are separated from each other by distances that make heat grids uneconomical. This is a costly assumption, which leads to multireactor or multiboiler centers and the possible need for standby capacity. Reactor and boiler reliability statistics are presented, and the question of the acceptability of the heat-production failure pattern is estimated for two-reactor and two-boiler systems.

Section 4.3 presents conceptual designs of energy centers and estimated reductions in heat emissions and heat production costs, including those for the reference city. The effects of utilizing one reactor, two reactors, two fossil-fueled boilers, three reactors, standby heat sources, distribution of 300 or 380°F water, and other factors are discussed.

4.1 Nuclear Reactor Siting*

The potential of the use of thermal energy from a nuclear reactor to supply heat to cities is greatly contingent on the location of the reactor. The cost of distribution of heat necessarily increases with distance, and accordingly there are limits as to how far the reactor can be from the consumer if it is to supply heat.

The selection of a location for a nuclear reactor requires the approval of the U.S. Atomic Energy Commission, and approval is based on judgment that the reactor built at the particular site will not endanger the health and safety of the public. Many facets of a reactor proposal are analyzed and reviewed in making the safety determination, and in particular it must be established that the reactor has been designed to prevent the release and distribution of harmful fission products to the environment. In addition, although every effort is made to prevent fission-product release, means are required for containing fission products and removing them from the containment atmosphere by trapping or washing. The systems or devices that carry out these functions are termed engineered safety features. Such devices or systems that decrease the likelihood of the release of fission-product activity to the environment enhance the acceptability of a site; and as engineered safety features have become more effective, more reliance has been placed in them for protection of the public.

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*Adapted from work performed under interagency agreement IAA-H-3-69 and reported in Ref. 50.

Siting practice has changed during the 20 years of power reactor experience from distance separation from population centers to distance separation plus engineered safety features. With large research programs and information from operating experience, the AEC is trying to advance the trend toward decreased reliance on distance by increasing reliance on engineered safety features. In 1964, Herbert Kouts, then chairman of the Advisory Committee for Reactor Safeguards, said:[51]

> "It is important to recognize that engineered safeguards are designed to allow the siting of reactors at locations where, without such safeguards protection of the public would not be adequate. The advantages of a remote site cannot be exactly balanced by engineered safeguards. On the other hand, the advantages of a remote site may be temporary, if appreciable increases in population density occur near the reactor. Few sites presently in use are such that some engineered safeguards are not desirable. Thus, the protection of the public ultimately depends on a combination of engineered safeguards and adequate distances. ..."

The population distribution curves for the nuclear power stations at Indian Point, Zion, and Three Mile Island (see Fig. 43) indicate that there is already suburban siting, and it is expected that people will continue to build their homes and businesses close to existing nuclear power plants and thereby cause urban siting to become fact with the passage of time. These developments will no doubt be reflected in changes in siting policy for new reactors. As stated in a report of the Office of Science and Technology, which was released in 1969, "The probable trend toward metropolitan siting of large power reactors requires consideration of measures to minimize the degree of risk in populated areas. The AEC is developing guidance for the selection of sites located in more highly populated regions."[52]

4.1.1 Analysis of United States and Foreign Siting Practices and Trends

Distances to the boundaries of population centers, distances to the centers of metropolitan areas, and the numbers of people in each of those areas are listed in Table 30 for existing nuclear plants, reactors being built, reactors for which construction permit applications are being considered, reactors for which applications were withdrawn, and one reactor

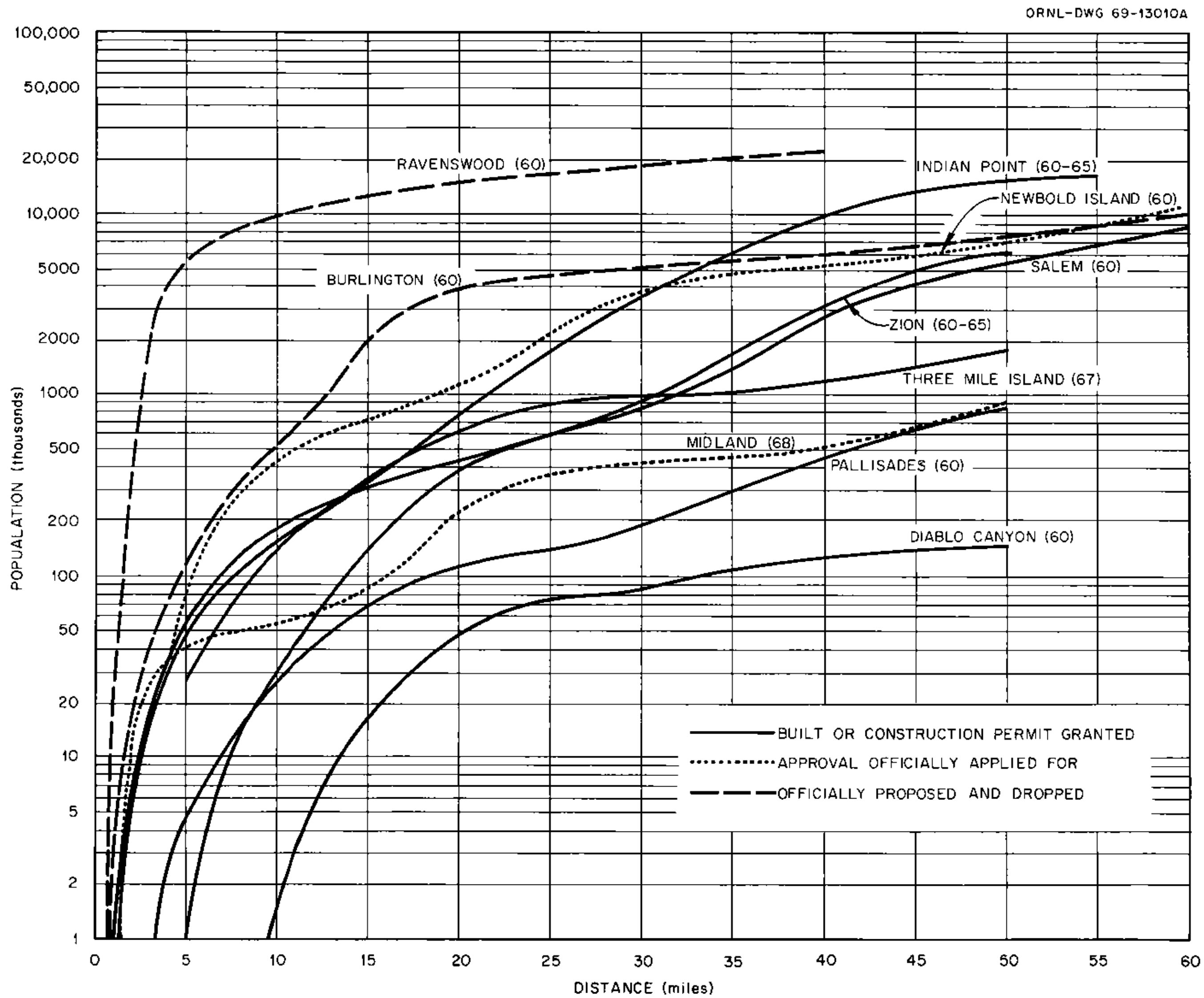

Fig. 43. Cumulative Population as a Function of Distance from Nuclear Plants in the U.S. Numbers in parentheses indicate date of population information.

Table 30. Distances from Light-Water-Cooled Reactor Plants to Population Centers and Metropolitan Areas

Reactor	Population Center			Metropolitan Area		
	Distance to Boundary (miles)	Population	Name	Distance to Center (miles)	Population	Name
			Operating Reactors			
Big Rock Point	45	18,300	Traverse City, Michigan	46	18,300	Traverse City, Michigan
Connecticut Yankee	9.5	33,250	Middletown, Connecticut	22	162,178	Hartford, Connecticut
Dresden	14	67,000	Joliet, Illinois	45	5,000,000	Chicago, Illinois
Ginna	10	493,402	Rochester, New York	15	493,402	Rochester, New York
Humboldt Bay	2.5	28,000	Eureka, California	4	28,000	Eureka, California
Indian Point	2.5	19,000	Peekskill, New York	40	8,000,000	New York City, New York
Oyster Creek	31	61,940	Atlantic City, New Jersey	35	61,940	Atlantic City, New Jersey
Peach Bottom	18.5	61,000	Lancaster, Pennsylvania	20	61,000	Lancaster, Pennsylvania
San Onofre	2.0	40,000	Camp Pendleton, California	51	600,000	San Diego, California
Yankee	9	22,000	North Adams, Massachusetts	40	170,000	Springfield, Massachusetts
			Reactors Being Built			
Browns Ferry	10	29,200	Decatur, Alabama	30	146,200	Huntsville, Alabama
Calvert Cliffs	35	1,000,000	Washington, D.C.	45	1,000,000	Washington, D.C.
Cook	8	31,000	Benton Harbor, Michigan	26	133,000	South Bend, Indiana
Cooper	60	128,000	Lincoln, Nebraska	63	128,000	Lincoln, Nebraska
Crystal River	55	29,700	Gainsville, Florida	88	88,000	Orlando, Florida
Diablo Canyon	12	20,400	San Luis Obispo, California	170	3,000,000	Los Angeles, California
Fort Calhoun	9	500,000	Omaha, Nebraska	20	500,000	Omaha, Nebraska
Kewaunee	17	32,000	Manitowoc, Wisconsin	30	62,888	Green Bay, Wisconsin
Maine Yankee	25	40,000	Lewiston, Maine	35	72,566	Portland, Maine
Millstone Point	3.2	26,000	New London, Connecticut	5.0	50,000	Groton — New London, Conn.
Monticello	22	33,800	St. Cloud, Minnesota	40	1,700,000	St. Paul, Minnesota
Oconne	21	42,000	Anderson, South Carolina	29	66,000	Greenville, South Carolina
Palisades	16	31,000	Benton Harbor, Michigan	45	133,000	South Bend, Indiana
Point Beach	13	32,000	Manitowoc, Wisconsin	27	62,888	Green Bay, Wisconsin
Prairie Island	26	1,700,000	St. Paul, Minnesota	30	1,700,000	St. Paul, Minnesota
Quad Cities	3.2	34,000	Clinton, Illinois	20	240,000	Davenport, Iowa
Rancho Seco	17	25,000	Lodi, California	25	100,000	Sacramento, California
Robinson 2	56	162,000	Columbia, South Carolina	58	162,000	Columbia, South Carolina
Russellville	55	37,000	Hot Springs, Arkansas	57	129,000	Little Rock, Arkansas
Salem	15.5	23,500	Bridgetown, New Jersey	18	95,800	Wilmington, Delaware
Surry	14	113,662	Newport News, Virginia	17	113,662	Newport News, Virginia
Three Mile Island	10	80,000	Harrisburg, Pennsylvania	12	80,000	Harrisburg, Pennsylvania
Turkey Point	10	43,000	Coral Cables, Florida	30	330,000	Miami, Florida
Vermont Yankee	16	17,562	Keene, Vermont	17	17,562	Keene, Vermont
Zion 1&2	4	55,000	Waukegan, Illinois	40	3,000,000	Chicago, Illinois

Table 30 (continued)

Reactor	Population Center			Metropolitan Area		
	Distance to Boundary (miles)	Population	Name	Distance to Center (miles)	Population	Name
			Applications Being Considered			
Arnold	8	92,035	Cedar Rapids, Iowa	10	92,035	Cedar Rapids, Iowa
Beaver Valley	8	22,306	East Liverpool, Pennsylvania	25	604,332	Pittsburgh, Pennsylvania
Bell	12	28,799	Ithaca, New York	40	216,038	Syracuse, New York
Brunswick	17	44,013	Wilmington, North Carolina	20	44,013	Wilmington, North Carolina
Easton	15	67,492	Troy, New York	22	129,726	Albany, New York
Fitzpatrick	7	22,155	Oswego, New York	36	216,038	Syracuse, New York
Hatch	50	21,200	Waycross, Georgia	70	208,000	Savannah, Georgia
Hutchison Island	8	34,000	Ft. Pierce, Florida	90	330,000	Miami, Florida
Malibu	10	3,000,000	Los Angeles, California	30	3,000,000	Los Angeles, California
Midland	1/2	27,779	Midland,[a] Michigan	4	27,779	Midland, Michigan
Pilgrim	25	25,000	Brockton, Massachusetts	36	800,000	Boston, Massachusetts
Sequoyah	12	180,000	Chattanooga, Tennessee	15	180,000	Chattanooga, Tennessee
Shoreham	18	45,000	Stratford, Connecticut	50	8,000,000	New York City, New York
			Applications Withdrawn			
Bodega Bay	21	31,000	Santa Rosa, California	43	1,000,000	San Franciso, California
Bolsa Island	10	344,000	Long Beach, California	30	3,000,000	Los Angeles, California
			Reactor Shutdown			
Pathfinder	3.5	54,282	Sioux Falls, South Dakota	5	54,282	Sioux Falls, South Dakota

[a]Dow Chemical Plant actually lies between the residential city and the plant. This provides an additional 2 1/2 to 3 miles of isolation.

now shut down. Table 31 gives cumulative population figures for each site out to several miles from the plant, including some plants in other countries. Curves showing these data for selected plants are plotted on Fig. 43.

The Indian Point Station, which was granted an operating license early in 1962 was, until applications were filed for Zion 1 and 2 in late 1967, the station nearest to large centers of population. There are 53,000 people living within 5 miles of Indian Point, 155,000 within 10 miles, 327,000 within a 15-mile circle, and the center of the New York metropolitan area is within 40 miles. The projected 1980 census shows 100,000 within 5 miles, 300,000 within 10 miles, and 700,000 within 15 miles. Insofar as the distribution of thermal energy is concerned, these are significant populations, particularly if they are heavily concentrated within their annuli.

As mentioned, Indian Point represented an upper bound on the nearness of large populations until the Zion station, which received a construction permit December 26, 1968, was started. There are 56,000 people within 5 miles and 189,000 within 10 miles; thus the upper-bound population was increased somewhat over that for the Indian Point Station. At this point a combination of the Zion-Indian Point curves describes the upper bound of the siting curve in this country.

For various reasons, some officially proposed and other unofficially considered plants have been dropped. The application for a proposed plant at Bodega Bay in California was withdrawn because of objection to its nearness to the San Andreas earthquake fault zone. The proposed plant at Easton, New York, was dropped because of anticipated adverse thermal effects. The Bell Station near Ithaca, New York, was tabled because of public sentiment against thermally polluting Lake Cayuga. Two plants at Bolsa Island near Long Beach, California, were dropped because financial support was inadequate. The Ravenswood plant application filed on December 10, 1962, for construction in the Borough of Queens in New York City was withdrawn after several weeks of adverse public activity. The population distribution of the Ravenswood site is compared on Fig. 43 with the distribution at other sites. The Boston Edison Company considered some sites near Boston before going out of its service area to purchase

Table 31. Light-Water-Cooled Power Reactors

Reactor Plant	Nearest City	Docket No. and Date	Licensing Condition: Construction Permit	Licensing Condition: Operating License	Thermal Power (Mw)	Reactor Type and Manufacturer[a]	Population (in thousands): 0-1 m	0-5 m	0-10 m	0-20 m	0-30 m	0-40 m	0-50 m	0-60 m	Year of Census
Arnold	Cedar Rapids, Iowa	50-331, 11-68			1670	BWR (GE)	0.015	2.73	75	172	228	343	537		70
Beaver Valley	East Liverpool, Pennsylvania	50-334, 1-69			2660	PWR (W)	0.72	17	174	519	1860	3195	4,233		70
Bell	Ithaca, New York	50-319, 3-68	Tabled		2436	BWR (GE)	0.116	9.64	31	144	419	1081	2,023		60
Big Rock Point	Traverse City, Michigan	50-155	5-60	8-62	240	BWR (GE)	0.005	4.9	9	27		52		135	60
Bodega Bay	Santa Rosa, California	50-205	Withdrawn		1008	BWR (GE)	0	0.5	2.1	48	115 (25 m)				60
Bolsa Island 1	Long Beach, California	50-307	Tabled		3400	(b)	0.59	101	812	3101	5883	7880	8,956	9,375	70
2		-308	Tabled		3400	(b)									
Browns Ferry 1	Decatur, Alabama	50-259	5-67		3293	BWR (GE)	0.32	2.78	22	100	209	412	523	656	60
2		-260	5-67		3293	BWR (GE)									
3		-296	7-68		3293	BWR (GE)									
Brunswick 1	Wilmington, North Carolina	50-324, 7-68			2436	BWR (GE)	0.144	3.51	7.39	73	117	140	182		66
2		-325, 7-68			2436	BWR (GE)									
Burlington	Philadelphia, Pennsylvania		Withdrawn		3250	PWR (W)	4.73	119	536	3905	5067	6062	7,600	9,760	60
Calvert Cliffs 1	Washington, D.C.	50-317, 1-68			2450	PWR (CE)	0.17	11	52	180	372	1033	4,750		65
2		-318, 1-68			2450	PWR (CE)									
Cook 1	Benton Harbor, Michigan	50-315, 12-67			3250	PWR (W)	0.066	7.08	46	157	503	672	1,067	4,669	65
2		-316, 12-67			3250	PWR (W)									
Cooper	Lincoln, Nebraska	50-298, 7-67	6-68		2381	BWR (GE)	0.004	1.18	3.49	27	67	104	178		60
Connecticut Yankee	Middletown, Connecticut	50-213	5-64	6-67	1473	PWR (W)	0.407	7.92	53	368					60
Crystal River 3	Gainsville, Florida	50-302, 8-67	9-68		2452	PWR (BW)	0	0.08	5.18	11	22	87	161		67
4		-303			2452	PWR (BW)									
Davis-Besse	Toledo, Ohio	50-346, 8-69			2633	PWR (BW)	0.808	3.23	15.60	95	617	893	1,815		60
Diablo Canyon 1	San Luis Obispo, California	50-275	4-68		3250	PWR (W)	0	0.01	1.57	49	87	122	149	158	60
2		-323, 6-68			3250	PWR (W)									
Dresden 1	Joliet, Illinois	50-10	5-56	9-62	700	BWR (GE)	0.1	2.3	28	187			5,857		50
2		-237	2-66		2300	BWR (GE)									
3		-249	11-66		2300	BWR (GE)									
Easton	Troy, New York	50-300	Withdrawn		2381	BWR (GE)	0.234	6.66	42	407	655	844			60
Fermi 2	Detroit, Michigan	50-341, 4-69			3293	BWR (GE)	0.137	6.85	50.91	330	2137	3485	4,260		60
Fitzpatrick	Oswego, New York	50-333, 12-68			2436	BWR (GE)	0	1.98	32	76	140	527			60
Fort Calhoun	Omaha, Nebraska	50-285	6-68		1420	PWR (CE)	0.45	13	24	301	708	800			80
Ginna (Brookwood)	Rochester, New York	50-244	4-66		1300	PWR (W)	0.25	7.70	34	629			953		70
Hatch	Waycross, Georgia	50-321, 5-68			2436	BWR (GE)	0.049	0.86	5.09	43	82	140	253		72
Humboldt Bay	Eureka, California	50-133	11-60	8-62	240	BWR (GE)	1.7 (1.5 m)	38	49	81	88 (25 m)				60
Hutchison Island	Ft. Pierce, Florida	50-335, 1-69			2700	PWR (CE)	0.1 (2 m)	1.02	43	87 (25 m)			311		68

[a]GE = General Electric Company; W = Westinghouse Electric Company; CE = Combustion Engineering, Inc.; BW = Babcock & Wilcox Company; AC = Allis-Chalmers Manufacturing Company.

[b]Not known.

Table 31 (continued)

Reactor Plant	Nearest City	Docket No. and Date	Licensing Condition: Construction Permit	Licensing Condition: Operating License	Thermal Power (Mw)	Reactor Type and Manufacturer[a]	Population (in thousands): 0-1 m	0-5 m	0-10 m	0-20 m	0-30 m	0-40 m	0-50 m	0-60 m	Year of Census
Indian Point 1 2 3 4 5	Peekskill, New York	50-3 -247 -286 -342, 6-69 -343, 6-69	5-56 10-66 8-69	3-62	615 2758 3025 3293 3293	PWR (BW) PWR (W) PWR (W) BWR (GE) BWR (GE)	1.08	53	155	327 (15 m)	1720 (25 m)	6344 (35 m)	13,324 (45 m)	16,098 (55 m)	60-65
Kewaunee	Manitowoc, Wisconsin	50-305	8-68		1650	PWR (W)	0.02	1.80	12	89	232	374			65
Limerick 1 2	Philadelphia, Pennsylvania	50-352, 2-70 -353, 2-70			3293 3293	BWR (GE) BWR (GE)	0.498	65.93	129.4	691.6	3497	5282	6,224	6,886	60
Maine Yankee	Lewiston, Maine	50-309	10-68		2440	PWR (CE)	0.54	3.05	26	69	220	417	525		60
Malibu	Los Angeles, California	50-214	Tabled		1473	PWR (W)		6	12	700	3100				60
Midland 1 2	Midland, Michigan	50-329, 1-69 -330, 1-69			2452 2452	PWR (BW) PWR (BW)	0.08	41	55	244	419	530	931		68
Millstone Point 1 2	New London, Connecticut	50-245 -336, 2-69	5-66		2010 2650	BWR (GE) PWR (CE)	0.298	67 (6 m)	96	236					65
Monticello	St. Cloud, Minnesota	50-263	6-67		1469	BWR (GE)	0.023	3.94	9.71	43	190	966			60
Newbold Island 1 2	Philadelphia, Pennsylvania	50-354, 2-70 -355, 2-70			3400 3400	BWR (GE) BWR (GE)	4.9 (2 m)	92	446	1153	3725	5247	6,949	11,979	60
Nine Mile Point	Oswego, New York	50-220	4-65		1538	BWR (GE)	0	1.98	32	76	140	527			60
North Anna 1 2	Fredericksburg, Virginia	50-338, 3-69 -339, 3-69			2652 2652	PWR (W) PWR (W)	0.012	1.04	9.24	44	184.3	573	879		68
Oconee 1 2 3	Anderson, South Carolina	50-269 -270 -287	11-67 11-67 11-67		2452 2452 2452	PWR (BW) PWR (BW) PWR (BW)	0	2.16	36	89	343	514	693		65
Oyster Creek	Atlantic City, New Jersey	50-219	12-64	4-69	1600	BWR (GE)	0.198	4.84	33	136		1153			66
Palisades	Benton Harbor, Michigan	50-255	3-67		2200	PWR (CE)	0.037	4.67	26	116	189	460	870		60
Pathfinder	Sioux Falls, South Dakota	50-130	5-60	3-64	190	BWR (wNSH)[c] (AC)	0.013	8.08	56	60	67	81			
Peach Bottom 2 3	Lancaster, Pennsylvania	50-277 -278	1-68 1-68		3294 3294	BWR (GE) BWR (GE)	0.114	6.15	24	249		2498			60-66
Pilgrim	Brockton, Massachusetts	50-293	8-68		1912	BWR (GE)	0.309	7.70	26	124	672	1952	3,993		65
Point Beach 1 2	Manitowoc, Wisconsin	50-266 -301	7-67 7-68		1396 1396	PWR (W) PWR (W)	0.04	1.24	22	202	386				65
Prairie Island 1 2	St. Paul, Minnesota	50-282 -306	6-68		1650 1650	PWR (W) PWR (W)	0.087	2.43	16	55	244	1272			60
Quad Cities 1 2	Clinton, Illinois	50-254 -265	2-67 2-67		2300 2300	BWR (GE) BWR (GE)	0.06	5.37	39	256	350 (25 m)				60
Rancho Seco	Lodi, California	50-312, 11-67			2452	PWR (BW)	0.012	0.17	4.06	303	908	1052	1,349		65
Ravenswood	New York, New York	50-204	Withdrawn			PWR (W)									
Robinson 2	Columbia, South Carolina	50-261	4-67		2094	PWR (W)	0.417	11	27	76	220	381	615		66
Russellville	Hot Springs, Arkansas	50-313, 11-67			2584	PWR (BW)	0.105	3.74	23	49	77	105	155		67
Salem 1 2	Bridgetown, New Jersey	50-272 -311	9-68 9-68		3250 3250	PWR (W) PWR (W)	0	1.18	28	399	897	2910	5,384	7,528	67

[c] wNSH = with nuclear superheat.

Table 31 (continued)

Reactor Plant	Nearest City	Docket No. and Date	Licensing Condition: Construction Permit	Licensing Condition: Operating License	Thermal Power (Mw)	Reactor Type and Manufacturer[a]	Population (in thousands) 0-1 m	0-5 m	0-10 m	0-20 m	0-30 m	0-40 m	0-50 m	0-60 m	Year of Census
San Onofre	Camp Pendleton, California	50-206		3-67	1347	PWR (W)	0	8.83	22	97			>1,000		60
Seabrook	Portsmouth, New Hampshire	50-340	Tabled		2660	PWR (W)	0.444	37.12	80.20	293	944	2192	3,504		68
Seala 1	Dotham, Alabama	50-348, 10-69			2660	PWR (W)	0.018	2.53	11.08	84	134	237	339		75
Sequoyah 1 2	Chattanooga, Tennessee	50-327, 10-68 -328, 10-68			3423 3423	PWR (W) PWR (W)	0.08	6.11	25	282	383	504	604	758	60
Shoreham	Stratford, Connecticut	50-322, 5-68			1593	BWR (GE)	0.6	7.5	21	168	1403	2462	4,506		60
Surry 1 2	Newport News, Virginia	50-280 -281	6-68 6-68		2441 2441	PWR (W) PWR (W)	0.005	0.79	40	179	506	953	1,240		66
Three Mile Island 1 2	Harrisburg, Pennsylvania	50-289 -320, 4-68	5-68		2452 2468	PWR (BW) PWR (BW)	635	27	137	630	996	1217	1,796		67
Trojan	Portland, Oregon	50-344, 6-69			3423	PWR (W)	0.155	5.10	48.13	79	143	673	942	1,021	60
Turkey Point 3 4	Coral Cables, Florida	50-250 -251	4-67 4-67		2097 2097	PWR (W) PWR (W)	0	0	42	232	818	1204	1,379		66
Vermont Yankee	Keene, Vermont	50-271	12-67		1600	BWR (GE)	0.48	6.41	25	110	137 (25 m)				60
Yankee	North Adams, Massachusetts	50-29		6-61	600	PWR (W)	0.174	2.03	29	104					50
Zion 1 2	Waukegan, Illinois	50-295 -304	12-68 12-68		3391 3391	PWR (W) PWR (W)	1.26	56	189	447	923	3144	6,288		60–65
Pickering	Toronto, Canada		Under construction		1742 1742	PWR(W) PWR(W)	31.6 (4 m)	206 (8 m)	499 (12 m)	1407	2424 (28 m)				68
Hartlepool	Newcastle, United Kingdom		Site being prepared			GCR	0.140	208	508	838	2654	2835	3,071		
Tokai-Mura	Tokyo, Japan		Operating		585	GCR	2	68	459	652	925	2200	2,730	4,100	65
Kahl/Main	Frankfurt, Germany		Operating		60	BWR	11.9 (1.3 m)	190 (6.2 m)	986 (12.4 m)	2923 (24.9 m)			7,422	9,812 (62 m)	
BASF	Mannheim, Germany		Contract being negotiated				7 (1.3 m)	562 (6.2 m)	1114 (12.4 m)	2197 (24.9 m)	2955 (31 m)	5870 (43 m)	7,293	9,925 (62 m)	
Vårtan	Stockholm, Sweden		Proposed		(b)	(b)	21	610	1060	1220	1335				

the Pilgrim site. Since no particular site in the Boston metropolitan area was ever selected, no realistic comparative curve can be drawn, but the population distribution curve would probably have been above that for Indian point, at least out to 10 to 15 miles.

The application for a permit to build a reactor at the Burlington, New Jersey, site on the Delaware River between Philadelphia and Trenton was withdrawn after a considerable public relations effort. The AEC advised the utility to select a site that was less sensitive as far as population distribution was concerned. As shown in Fig. 43, the curve for the Burlington site is clearly beyond that for Indian Point out to more than 30 miles.

The Midland, Michigan, site proposed in October 1968 has been of interest with respect to population distribution. As shown in Fig. 43, the population within less than 4 miles exceeds that at Zion or Indian Point. Because of this the AEC has clearly stated that the plant must have safety features at least equivalent to those of the Zion and Indian Point plants (Indian Point 2, in this case).[53]

It appears therefore that the population distributions of the Zion and Indian Point sites may imply a current limit, since the curves for existing sites and those approved for construction fall below those for Zion and Indian Point. All other proposed sites, except Midland, which is still being considered, were dropped or changed when it became apparent that the population distribution curve was above the combination Zion-Indian Point curve.

A new situation has developed, however, with consideration of the Newbold Island, New Jersey, site. Public Service Gas and Electric Company of New Jersey requested that the ACRS give an opinion on the Newbold Island, New Jersey, site before formal application was made. (This was done at least once previously in November 1962 for the site selected by the City of Los Angeles for a reactor at Malibu, California.) The Newbold Island site is only about 6 miles from the Burlington site mentioned above, which was abandoned in favor of the less sensitive Salem site (see Table 30). The population distribution curve for the Newbold Island site is shown in Fig. 43. On September 10, 1969, the ACRS concluded that the site for the suggested plant was not unacceptable with respect to the health and safety of the public.[54]

The British too have had much experience in reactor siting, and their limited space and large population will force them to use urban sites if nuclear development is to continue in that country. The Ministry of Power has been working toward a formalized siting policy for gas-cooled reactors with prestressed-concrete pressure vessels. The guidelines that now appear most probable are an average population density of 4.2 persons per acre out to 20 miles, but a 30° sector may have an average population density of 20 persons per acre; this would allow siting at the edge of a fairly densely populated area. Additional criteria may be established for control of activities near the plant — plans must be available for evacuating the population within 2/3 miles of the plant, and this requirement could be extended to 2 miles; within 5 miles new construction is controlled. In the United Kingdom the site nearest to dense population is the one at Hartlepool. Presumably selection of this site was based on the above criteria. The population distribution around Hartlepool is shown on Fig. 44.

The Japanese also have major siting problems because of their very heavy population density and the fact that Japan is in one of the most seismically active regions in the world. In 1965 the first power reactor, Tokai-Mura (a British-type gas-cooled reactor), was made critical, and in 1966 construction was started on three light-water-cooled plants. The population density associated with Tokai-Mura is the highest close to the reactor and is shown in Fig. 44. The data for the Tokai-Mura site also show that the population is below the Indian Point curve from about 23 miles out to beyond 70 miles.

The Pickering station for which population figures are plotted in Fig. 44 is being built near Toronto, Canada. This is the closest approach to a population center that has been made in Canada.

The Experimental Power Station at Kahl/Main (VAK), Germany, was first made critical in November 1960. It is still the most sensitive site presently used in Germany; however, approval has been granted to build a large nuclear plant near Ludwigshafen. The population distribution around this plant (BASF) is shown in Fig. 44. As indicated in Table 31

ORNL-DWG 69-13009A

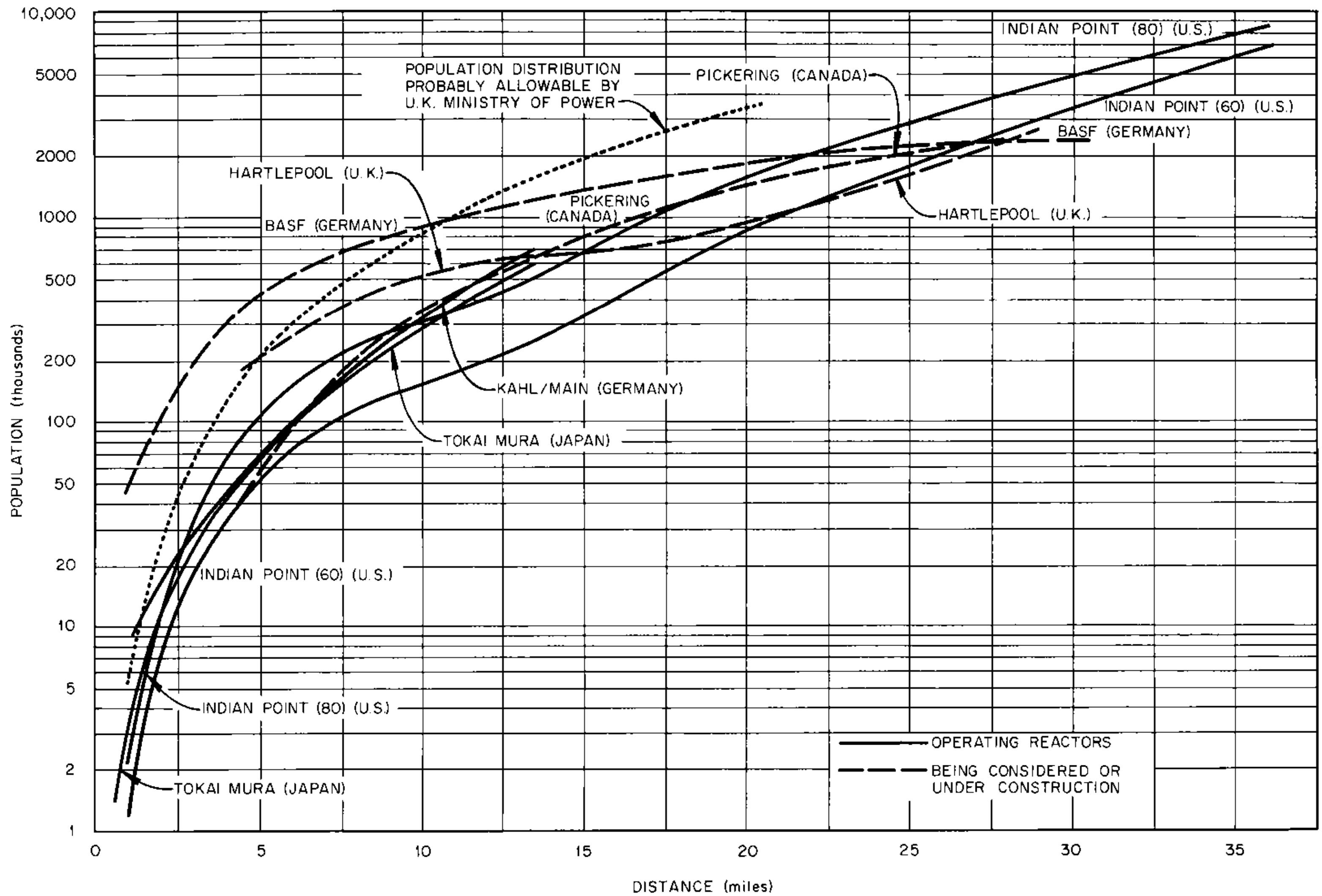

Fig. 44. Cumulative Population as a Function of Distance from Existing and Proposed Nuclear Plants Abroad Compared with Curve for Indian Point. Numbers in parentheses indicate date of population information.

there are 562,000 people within 6.2 miles of the site, 1,114,000 people within 12.4 miles, and 2,197,000 within 25 miles.

The curves of Fig. 44 indicate that even compared with the projected population curve for Indian Point in 1980, there will be significantly higher population densities at Hartlepool in the United Kingdom and at BASF in Germany out to 15 to 22 miles than at any site in the United States.

4.1.2 Possibilities of Underground or Underwater Siting

Some have suggested that in addition to the various engineered safety features, it would be advantageous to place reactor plants either underground or underwater. There has been study of underground siting in Europe and some experience, especially in the Scandinavian countries.[55-58] In the U.S., however, studies have been made which indicate that although the concept may be feasible and may offer potential safety advantages, the technology of deep excavation is not well developed and may present severe engineering problems. The attendant economic penalty appears to be significant.[59-61] Currently, studies in tunneling technology for utility distribution are under way at ORNL for the U.S. Department of Housing and Urban Development, which include attempts to develop more economical tunneling methods.* These developments may prove to be applicable to underground siting of reactors. Some recent studies have also been made of underwater and floating containment systems.[62,63] Proponents of the underwater technique claim 2 to 3 orders of magnitude reduction in fission products available for release under accident conditions.

4.1.3 Effects of New Reactor Concepts on Siting

Until breeder reactors are available, light-water-cooled reactors will probably continue to be the standard choice of the utilities for nuclear power production in the United States, since the approximately 20 years experience with these plants has brought about the resolution of most of the safety and siting problems. Breeder reactors that use either

*Interagency Agreement No. IAA-H-2-69, Systems Analysis of Utility Tunnel Technology.

the plutonium or the thorium fuel cycle are being developed to fully utilize natural resources by converting fertile material into fissile material at a rate greater than that at which fuel is used. It is currently anticipated that breeder reactors will be available for purchase by 1985.

At the present time the breeder concept receiving the most attention in the U.S. is the Liquid Metal Fast Breeder Reactor (LMFBR).[64] Others that show promise are the Molten Salt Breeder Reactor (MSBR) and the Fast Gas-Cooled Breeder Reactor (FGBR). Evaluations of other new concepts, including advanced converters and the high-temperature gas-cooled reactor, have been reported by the AEC.[65]

The breeder reactors, being new concepts, will present safety problems that have not been confronted in the accumulated light-water-cooled reactor experience. However, enough investigation has already been done for the major safety problems to have been outlined for study. Each of the concepts has certain advantages and disadvantages as far as safety is concerned. The introduction of the new reactor types will no doubt influence siting policies.

4.1.4 Siting an Energy Center

The preceding information leads to the conclusion that, for planning the location of an energy center now with light-water reactors to be in operation by 1980, the projected population density in the vicinity of the Indian Point Station can serve as a guide. It would be advisable to have the population surrounding the center at all radii be no greater than that forecast for Indian Point. Since the use of district heat would lead to concentrating some of the population in specific sectors, it would also be of interest to analyze centers having smaller populations at each radius than those predicted for Indian Point. For longer range studies it would appear that relatively close-in siting could be assumed.

4.2 Heat Source Reliability

The most important aspect of reliability of the heat source is the frequency and duration of failures that lead to complete cessation of heating service to the consumers. The heat failures that might occur with light-water reactors were studied by detailed review of operating reports of present-day light-water-reactor generating stations in this country by E. W. Hagen of ORNL. Heating service failures were estimated, particularly for a two-reactor station with no standby heat source. Information on failures in fossil-fueled power plant boilers was obtained from Edison Electric Institute equipment availability data.

The nuclear power stations whose operating histories were reviewed, the reactor type, and the year the reactor was initially made critical are listed below:

Station	Type of Reactor	Year Made Critical
Dresden, Unit 1	BWR	1959
Big Rock Point	BWR	1962
Humboldt Bay, Unit 3	BWR	1963
Shippingport	PWR	1957
Yankee	PWR	1960
Indian Point, Unit 1	PWR	1962
Connecticut Yankee	PWR	1967

Six of the seven reactors achieved criticality between the years 1957 and 1962 and ranged in size from 68.5 Mw(e) for Humboldt Bay to 265 Mw(e) for Indian Point. Connecticut Yankee became operative in 1967 and is rated at 462 Mw(e). From 1966 to 1970 the sizes of the commercial power reactors started up or scheduled for startup averaged about 500 Mw(e). In the early 1970's this size is to increase to 1064.5 Mw(e) at Browns Ferry units 1, 2, and 3. Early operation of Big Rock Point and Shippingport were for generation of test information rather than electricity; Dresden, Indian Point, and Shippingport were load-following plants; and Yankee was base loaded. Connecticut Yankee was also operated as a base-loaded plant on the electric power distribution system. Therefore operating data from the early plants cannot be extrapolated per se to future plants. However, the early plants should be indicative of the growing pains of a new industry, and if the present pattern prevails as the industry matures, the operation of stations will become more efficient, availability will increase, outages for testing and training will not be increased, and the general performance should be better.

The station operating reports from the first six nuclear-powered generating plants were reviewed for the three-year period beginning with January 1966 and ending with December 1968. The seventh plant, Connecticut Yankee, was initially made critical in July 1967, and hence its review period was continued to June 1969. A summary was made of those events that affected the heat available from the reactor; that is, caused the reactor to be shut down. These occurrences were tallied for each of the seven stations to determine a figure for heat unavailability. Each event was placed into one of eight categories of occurrences as being either scheduled or forced, and the date and duration of each outage was recorded. These categories are

1. scheduled refueling,
2. scheduled plant cooldown,
3. scheduled primary heat loop maintenance,
4. scheduled nuclear maintenance,
5. scheduled core maintenance and nuclear measurements,
6. unscheduled reactor core plus controls maintenance of
   a. less than 1 hr,
   b. one to 5 hr,
   c. five to 24 hr,
   d. more than 24 hr,
7. unscheduled primary heat loop maintenance of
   a. less than 1 hr,
   b. one to 5 hr,
   c. five to 24 hr,
   d. more than 24 hr,
8. unscheduled secondary plant (electricity generation) system maintenance of
   a. less than 1 hr,
   b. one to 5 hr,
   c. five to 24 hr,
   d. more than 24 hr.

Categories 6 and 7 comprise failures that result in reactor unavailability and no heat.

From the operating reports and previously published data, reactor availability values were determined for the seven power reactors (Table 32). The availability average for these seven reactors during this review period was 83.4% and the mean value was 86.8%. As may be seen from Table 33 the largest factor affecting availability was the refueling outages, which averaged 40 days, with a mean of 32 days per year, for 15 refueling operations. While in many cases refueling could have been

Table 32. Reactor Availability

Station	Reactor Availability (%)										
	1958	1959	1960	1961	1962	1963	1964	1965	1966	1967	1968
Dresden			58.7	40.2	80.6	80.7	82.7	78.3	95.8	60.1	63.8
Big Rock Point							56	30.7	77	87	80.6
Humboldt Bay							89	79	89.9	91.4	93.8
Shippingport	68	67	50	64	76	81	(a)	71.5	87.6	86.8	86.1
Yankee					65	78	90	74	89.9	91.9	87.9
Indian Point						67	48	64	72.1	87	81
Connecticut Yankee										81	82.1

[a]Plant being modified.

Table 33. Factors Influencing Reactor Availability

Station	Average Avail-ability (%)	Refueling Outage (%)	Nuclear Plant Forced Outage (%)	Electricity Generating Plant Outage (%)
Dresden	73.2	18.1	0.52	2.4
Big Rock Point	81.5	13.3	2.49	2.2
Humboldt Bay	91.1	7.6	0.39	0.41
Shippingport	86.8	None	0.51	0.75
Yankee	89.9	6.7	0.05	1.55
Indian Point	80.0	13.8	0.66	0.64
Connecticut Yankee	81.6	None	0.36	3.0

completed sooner, the fact that much plant maintenance was also scheduled for these times resulted in the outages often being extended. The two stations that did not experience a refueling outage had to schedule more shutdowns for maintenance. Since these reactors are not the primary source of energy for electricity generation on the distribution grid for any of the operating utilities, the economic incentive was not so strong as it might have been to get the reactors back on line. As the second-generation reactor-powered stations become operative, the economies of reducing downtime will become more rewarding. However, major maintenance will still be performed during these outages. The second unit at Dresden, which will have an initial capacity of 715 Mw(e), is expected to need only 15 to 20 days for refueling, and the forced outage rate is predicted to be about 1%; availability should be about 94%. Connecticut Yankee began its first refueling in March 1970. This will provide the first comparison to the earlier and smaller reactor stations. If the initial design of the reactor plants surveyed had emphasized the importance of the repetitive operation of refueling, outage time for this periodic operation could have been reduced.

When the reactor plant is coupled only to a single load, such as the electrical load, operating characteristics of that load directly affect the reactor plant availability. Voltage transients in the distributions system or on the plant tie lines can lead to a reactor scram, and a loss of electric load most assuredly will scram the reactor. Scheduled shutdowns and forced outages due to disturbances in and maintenance on the secondary plant (i.e., the electricity generating and power distributions systems) affected the average power reactor availability 1.56%, or 5.69 days, per reactor per year. These outages are reflected in Tables 32 and 33, but since their effect on heat availability can be eliminated by design changes, they are not reflected in the data in Table 34, which summarize all the forced outages. The number of these occurrences, the duration of the resultant outage, and the percent of the review period are tabulated for the seven power reactors. The average downtime from forced outages causing no heat production was 0.7%. The average duration of all 82 forced outages was 1/82 of 5.0% of 2.9 years or 15 hr. It is interesting to note that human error accounted for 15 of the outages (six alone at Connecticut Yankee); this indicates some of the difficulties to be expected at a new facility during the first few years of operation.

Since at least two reactors are required so that one can supply heat while the other is being refueled or undergoing other planned maintenance,

Table 34. Forced Outages of Nuclear Plant and Heat Loop

Station	Forced Outages							
	Less Than 1 hr		1 to 5 hr		5 to 24 hr		More Than 24 hr	
	No.	%[a]	No.	%	No.	%	No.	%
Dresden	8	0.015	1	0.005	4	0.161	2	0.339
Big Rock Point	2	0.004	1	0.019	2	0.120	3	2.348
Humboldt Bay	0	0	2	0.024	1	0.037	1	0.330
Shippingport	7	0.011	1	0.019	6	0.208	1	0.270
Yankee	0	0	6	0.053	0	0	0	0
Indian Point	4	0.015	9	0.146	3	0.114	2	0.384
Connecticut Yankee	0	0	12	0.126	3	0.116	1	0.120

[a]Percentage of review period.

the reliability of two reactors is pertinent. Estimates of the heat production failures for an energy center with two reactors are given in Table 35. Refueling shutdowns would be scheduled for spring and fall when heat consumption is low and a heat failure of smaller importance than in other seasons. Heat failures of about 5 hr duration can cause major effects in the availability of heat even in large distribution systems. Depending on the time of year, failures of more than 24 hr duration might cause major and undesirable effects on building temperatures. The estimates in Table 35 indicate that with two conventional light-water reactors

Table 35. Estimated Heat Production Failures for an Energy Center with Two Reactors

Energy Center Condition	Average Time per Failure (hr)	Estimated Time Between Failures (years)
One reactor in 40-day annual refueling period and second reactor in forced outage from nuclear or heat-loop failure		
Failures less than 1 hr each	0.5	4
Failures of 1 to 5 hr each	3	3
Failures of 5 to 24 hr each	10	5
Failures of more than 24 hr each	96	9
All failures	15	1
One reactor in 15-day annual refueling period and second reactor in forced outage from nuclear or heat-loop failure		
Failures less than 1 hr each	0.5	12
Failures of 1 to 5 hr each	3	8
Failures of 5 to 24 hr each	10	13
Failures of more than 24 hr each	96	24
All failures	15	3
Both reactors in forced outage from nuclear or heat-loop failure		
Failures less than 1 hr each	0.5	1
Failures of 1 to 5 hr each	3	7
Failures of 5 to 24 hr each	10	26
Failures of more than 24 hr each	96	370
All failures	1	1

and the refueling periods expected in the near future, complete failures in heat service for a significant time would rarely occur.

Information on the availability of fossil-fueled power plant boilers was obtained from the statistics contained in the Analytical Report of Equipment Availability for the Seven-Year Period 1955–1961 published by the Edison Electric Institute.[66] For the 3019 boiler years reported for the period of 1955–1961 the scheduled outage time was only about 6%. This is about the same as predicted for the second nuclear reactor at Dresden. The average percentage of time that the boilers were unavailable due to forced outages was 1.0%. This can be compared with 0.7% for the previously discussed seven nuclear reactors. The average duration of all forced outages for the boilers was 144 hr, which indicates fewer short-duration shutdowns than for the nuclear reactors.

The unavailability due to forced outage of boilers associated with plants generating 200 to 325 Mw of electricity was about 2% — three times as great as for the 50- to 89-Mw plants. Similarly, boilers with throttle temperatures between 900 and 955°F were affected by forced outages only 0.6% of the time, those with temperatures between 1040 and 1060°F were affected 1.6% of the time, and those with a throttle temperature of 1100°F had forced outages ranging from around 8.6% of the time in 1958 to about 3.4% in 1959 and back up to approximately 7.7% in 1961.

A center with two reactors or two fossil-fueled boilers should provide sufficiently reliable heating service on the basis of past experience and forecasts for the future. However, during initial operation of the energy center the service might not be adequately reliable. There are also special facilities, such as hospitals or certain industrial plants, that would require a standby heat source. Normally these facilities would be expected to supply their own emergency heat. However, due to an interest in the above special situations, the cost of a low-temperature standby heat source is estimated for several of the cases in Section 4.3. A standby source is not used in the reference city, but its cost for that case is estimated in Section 6.

4.3 Energy Center Conceptual Designs, Thermal Emission Reduction, and Costs

4.3.1 Designs

Conceptual designs and cost estimates were made by H. R. Payne of ORNL for many versions of energy centers. They were mostly of an exploratory nature to demonstrate the effects on emissions and costs of fossil-fueled systems as compared with present-day reactors and reactors being developed, different standby equipment, fuel cost, heat and electric power load, etc. The final conceptual design was that used in connection with the reference city (Sect. 6).

The electricity produced by an energy center in the conceptual designs is the projected average amount consumed by the urban area it would serve in 1980. Section 3.1 on United States requirements indicates that the urban areas in the United States in 1980 will require on an average about 1000 Mw(e) for 800,000 people, 500 Mw(e) for 400,000 people, etc.

Since the plant in the energy center would be new, it was assumed it would be the most economical plant in the utility's system to operate. It would therefore, be operated as a base-loaded plant to produce all the energy possible. When it produced more electricity than the urban area could consume, the excess would be exported to the grid. When the electricity consumption in the city peaked or the heat consumption depressed the electricity production below the consumption rate, the grid would provide electricity to the urban area.

Since the steam generators would be operated as base-loaded units and the system would follow the heat load, the turbine would never be fully loaded. The condensing sections would be fully loaded only at minimum heat load, and the back-pressure sections would be fully loaded only at maximum heat load. At low heat loads the electricity production would be greater than the annual average. The required generator would be larger than that of a power-only plant producing the same annual power.

The water for district heating was considered to be heated in two stages, with each stage supplying half the heat. Heat exchanger approach temperatures ranged between 2 and 12°F. The maximum heat extraction from the turbine would be that which reduced the steam flow to the condensing section to the minimum. In two cases peak heat service was obtained from low-temperature fossil-fueled boilers rather than from the turbine. Natural-draft wet cooling towers were used for waste heat discharge in all designs and cost estimates in this section. As shown in Section 3.2 and Section 6 on the reference city, cost savings would result if the cooling towers were replaced with greenhouses that would make beneficial use of much of the heat.

A typical arrangement of turbine-generator-heat exchangers, the configuration used for the reference city, is shown in Fig. 45. District heat and three industrial heat loads are supplied. The steam flow varies between the two back-pressure turbine sections, which supply heat exchangers HX-1 and HX-2 with steam, and the condensing section to permit the steam generator to operate as a base-loaded unit. The high-pressure section of the turbine operates at rated load regardless of heat load

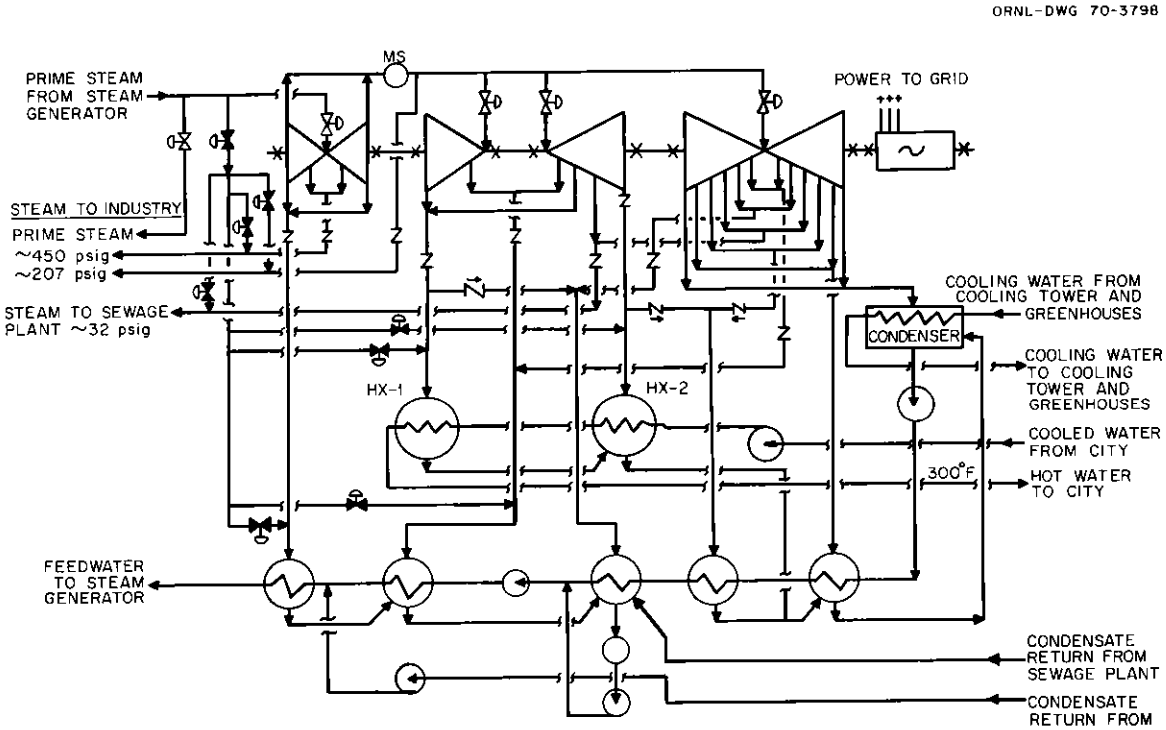

Fig. 45. Schematic Diagram of Arrangement of Turbine-Generator, District Water Heaters, and Process Steam System for Producing 300°F Water for the Reference City.

variation. (Representatives of the General Electric Company's Turbine Division kindly provided some consultation regarding the turbine design.)

The steam generator was assumed to have an availability or operating load factor of 90%. Piping and valve arrangements would permit bypassing the turbine in order to provide heat when the turbine-generator or other electrical equipment was shut down for maintenance. The distance between this heat-electric energy center and other centers in this or other cities was assumed to be so large that it was not feasible to use a heat grid.

Most plants were considered to have two or more reactors or boilers for supplying steam to the turbines and a low-temperature steam-generating fossil-fueled plant for standby heat in case of failures in the high-temperature steam generators. Heat accumulators at the plant were also included in most of the designs to store hot water for district heating. They could supply heat during short shutdowns of the steam generator. They could also help meet demands of high thermal energy rather than having all variation in electrical requirements reflect in the demand from the grid.

When two or more heat sources were used they were connected to a single turbine as in modern high-temperature fossil-fueled plant practice. Although no detailed safety studies were made, it appeared that adequate controls and instrumentation could be provided to also allow at least two nuclear plants to supply steam to a single turbine.

The energy centers in the conceptual designs were separated from large concentrations of population and assigned sufficient acreage so that there was room near the center for an industrial area that was supplied with process steam. Some of this industry could be in the plant exclusion area if a large labor force was not required. Variations in the manufacturing steam load were not taken into account; in fact, the load was taken as being constant in order to simplify the analysis. Hot water for space heating, air conditioning, etc. was transmitted beyond the industrial area to the heat exchangers of some significant fraction of the buildings in the city. A plot plan for an energy center used in connection with the reference city is shown in Fig. 46. The reference city is treated in Section 6 both with and without the greenhouses illustrated in Fig. 46.

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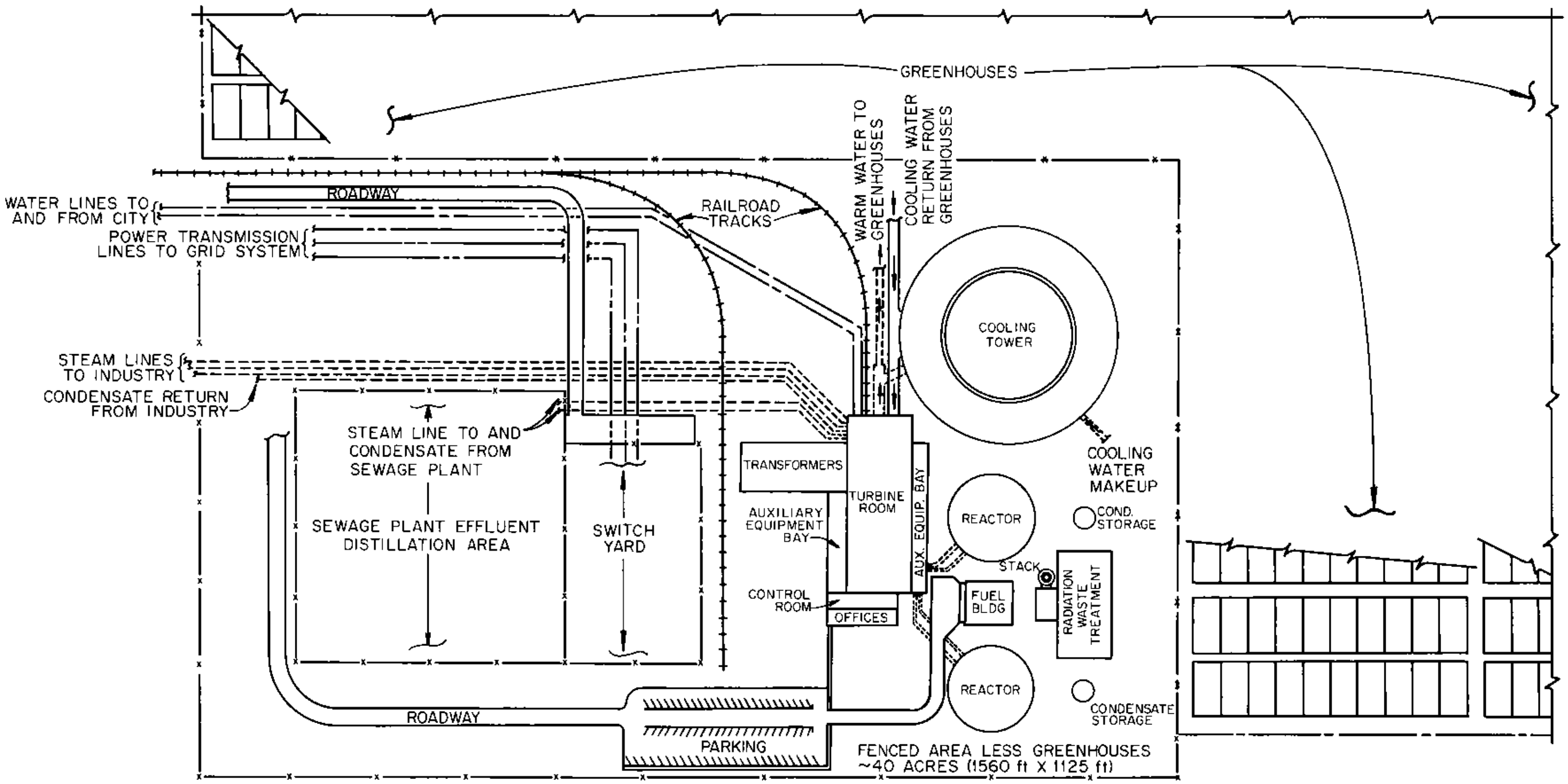

Fig. 46. Energy Center Plot Plan.

In an energy center that used fossil-fueled boilers, some additional area would be required for coal storage or oil and gas storage tanks.

In specifying light-water reactors (LWR's), no real distinction has been made between pressurized-water and boiling-water reactors. However, in the case of boiling-water reactors, the steam extracted from the turbine has passed through the core of the reactor, and if this steam were transmitted directly to industrial consumers within the exclusion area, intermediate heat exchangers would be needed at the plant to protect against possible radioactivity. Also, the water side of the heat exchanger is normally at the higher pressure due to pumping, so any leakage would be toward the steam side. There would then be another barrier provided by the heat exchanger at each building.

Table 36 describes all the cases considered. Case 31 is the basic design of the center for the reference city without use of greenhouses. Some cases, such as 7 to 9, 10 to 12, 17 to 19, and 22 to 24 involve only differences in methods of cost estimating rather than differences in design.

In each case the desired quantity of power was established. The heat loads were then determined from the criteria established for each case. These were primarily the desired temperature of the district heating water supply and industrial steam, the ratio of the normal heat load to the maximum, the ratio of the minimum heat load to the normal heat load and restrictions on the amount of steam that could be withdrawn and still allow a sufficient quantity of steam to pass through the low-pressure end of the turbine. For cases 15 and 20 the normal heat load was the maximum permissible extraction from the turbine-generator system, and the normal power load was that generated under this operating condition. Heat loads greater than normal were considered to be furnished in those cases by oil-fired boilers, which would also serve as the standby heat supply. For cases 5, 13, 17, 18, and 19 a single reactor was assumed, and a low-temperature fossil-fueled steam generator was necessary for supplying heat during planned shutdowns, as well as emergencies. In cases 1 through 21 the industrial steam was taken from the same points in the turbine system as that for the district heat. In cases 22 through 31 the industrial steam conditions were different from those of the district heating steam.

Table 36. Description of Energy Centers[a]

Case No.	Type of Heat Source	Thermal Capacity of Heat Source (Mw)	Number Reactors or Boilers	Annual Net Average Electricity Generation (Mw)	Annual Average District Heat Load (Mw)	Annual Average Industrial Heat Load (Mw)	Peak Heat Load (Mw)	Peak District Heat Load (Mw)	Minimum District Heat Load (Mw)	Ratio of Low-Temperature Standby Boiler Capacity to Peak Heat Load	Cooling-Tower Capacity (Mw)	Annual Average Heat Load to Cooling Tower (Mw)	District Heat Water Temperature (°F)		Industrial Process Steam Pressure at Turbine (psig)
													In	Out	
1	LWR	4856	2	1000	1475	413	3496	3083	1265	0.5	1907	1419	150	380	207, 32[b]
2	LWR	7284[c]	3	1000	1475	413	3496	3083	1265	0	1907	1419	150	380	207, 32[b]
3	LWR	4856	2	1000	1475	413	3496	3083	1265	0.5	1907	1419	150	380	207, 32[b]
4	LWR	4856	3	1000	1475	413	3496	3083	1265	0	1907	1419	150	380	207, 32[b]
5	LWR	1942	1	400	590	165	1398	1233	506	1	763	568	150	380	207, 32[b]
6	LWR	1942	2	400	590	165	1398	1233	506	0.5	763	568	150	380	207, 32[b]
7	FFP	1396	2	400	453	127	970	843	372	0	388	251	150	380	207, 32[b]
8	FFP	1396	2	400	453	127	970	843	372	0	388	251	150	380	207, 32[b]
9	FFP	1396	2	400	453	127	970	843	372	0	388	251	150	380	207, 32[b]
10	FFP	2094[c]	3	400	453	127	970	843	372	0	388	251	150	380	207, 32[b]
11	FFP	2094[c]	3	400	453	127	970	843	372	0	388	251	150	380	207, 32[b]
12	FFP	2094[c]	3	400	453	127	970	843	372	0	388	251	150	380	207, 32[b]
13	LWR	1942	1	400	590	165	1398	1233	506	1	763	568	150	380	207, 32[b]
14	LWR	1942	2	400	590	165	1398	1233	506	0.5	763	568	150	380	207, 32[b]
15	LWR	6300	2	1018	3185	897	7560	6663	2731	0.7[d]	1334	560	150	380	207, 32[b]
16	LWR	4423	2	1009	1267	357	3008	2651	1087	0.5	1737	1293	150	300	72, 11[b]
17	LMFBR	3487	1	1000	986	276	2337	2061	846	0.5	1131	823	150	380	207, 32[b]
18	LMFBR	3487	1	1000	986	276	2337	2061	846	0.5	1131	823	150	380	207, 32[b]
19	LMFBR	3487	1	1000	986	276	2337	2061	846	0.5	1131	823	150	380	207, 32[b]
20	LWR	2913	2	444	1475	413	3497	3084	1265	0.7[d]	617	259	150	380	207, 32[b]
21	LWR	4856	2	1000	1475	413	3496	3083	286	0.5	2675	1419	150	380	207, 32[b]
22	LWR	4850	2	1000	1087	816	3413	2597	390	0.38	2310	1398	200	300	965, 400,[e] 100
23	LWR	4850	2	1000	1087	816	3413	2597	390	0.38	2310	1398	200	300	965, 400,[e] 100
24	LWR	4850	2	1000	1087	816	3413	2597	390	0.38	2310	1398	200	300	965, 400,[e] 100
25	LWR	4556	2	1000	566	816	3214	2398	360	0.37	2135	1655	200	300	965, 400,[e] 100
26	LWR	2425	2	500	544	408	1706	1298	195	0.38	1155	699	200	300	965, 400,[e] 100
27	LWR	4850	3	1000	1087	816	3413	2597	390	0.25	2310	1398	200	300	965, 400,[e] 100
28	LWR	2425	3	500	544	408	1706	1298	195	0.25	1155	699	200	300	965, 400,[e] 100
29	LWR	7275[c]	3	1000	1087	816	3413	2597	390	0	2310	1398	200	300	965, 400,[e] 100
30	LWR	5144	2	1000	1251	816	3778	2962	444	0.39	2460	1499	150	380	965, 400,[e] 100
31	LWR	2268	2	463	457	368 + 90[f]	1602	1144	0	0	1180	634	148 to 202	300	965, 450,[g] 207, 32

[a]All systems, except case 31, have hot-water accumulators with a capacity for storing district heat equivalent to that needed for 1 hr at peak demand.

[b]Equal heat extractions at each of two indicated pressures.

[c]The capacity of each of the three reactors or boilers is one-half the normal load demand; one is considered to be the standby steam source.

[d]The fossil-fueled boilers serve both as a standby heat source and as a peaking plant to operate when the demand is above the normal operating load.

[e]11.6% of heat at 965 psig, 68.4% at 400 psig, and 20.0% at 100 psig.

[f]Sewage treatment load.

[g]9.4% of heat at 965 psig, 54.9% at 450 psig, 16.1% at 207 psig, and 19.6% at 32 psig.

All the centers, except case 31, had hot-water accumulators with a capacity for storing district heat equivalent to that needed for 1 hr at peak demand.

4.3.2 Thermal Emissions

Table 36 also shows the annual average and maximum heat (cooling-tower capacity) emissions to the cooling towers for each case. They are estimated by taking the difference between the heat input from the fuel to the boiler and the gross electricity produced. This neglects minor adjustments for heat from internally used electricity and heat lost directly to the atmosphere. The average emission for most of the centers is appreciably less than that for a single-purpose plant, even though the maximum heat emission in some cases is greater than that of a single-purpose plant. If large heat emissions occurred for only short periods, some consideration could be given to whether it would be more economical to temporarily reduce the operating level and total energy production of the plant or to construct a large cooling tower. In order to illustrate these relationships, steam cycle heat emissions from light-water-reactor and fossil-fueled plants are shown in Figs. 47 and 48, respectively, as functions of the amount of heat utilized. Figures 49 and 50 show the instantaneous heat emissions at various heat loads from energy centers with specified average annual heat loads. It may be seen from these figures that the minimum heat emissions (which would occur at maximum heat withdrawal on very hot or cold days) would be less than 20% of those for single-purpose plants.

4.3.3 Costs

Cost estimates for the energy centers were based on 1968 prices escalated 4% per year during a five-year period of construction. The annual fixed-charge rate was taken as 14%. Some of the sources of information concerning costs were the following:

1. Fuel costs for light-water reactors — Current Status and Future Technical and Economic Potential of Light-Water Reactors, USAEC Report WASH 1082, March 1968.
2. Capital, operating, and maintenance costs of reactor plants — personal communication with M. L. Myers and R. C. Olson of ORNL.

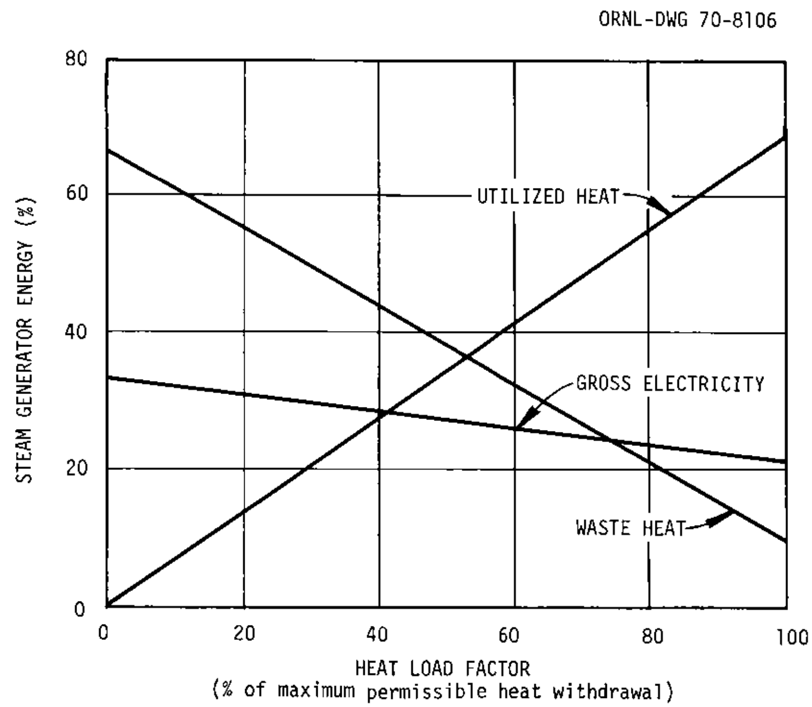

Fig. 47. Heat and Power Production as a Function of the Heat Load Factor for an LWR Plant. District heat provided by water heated from 200 to 300°F.

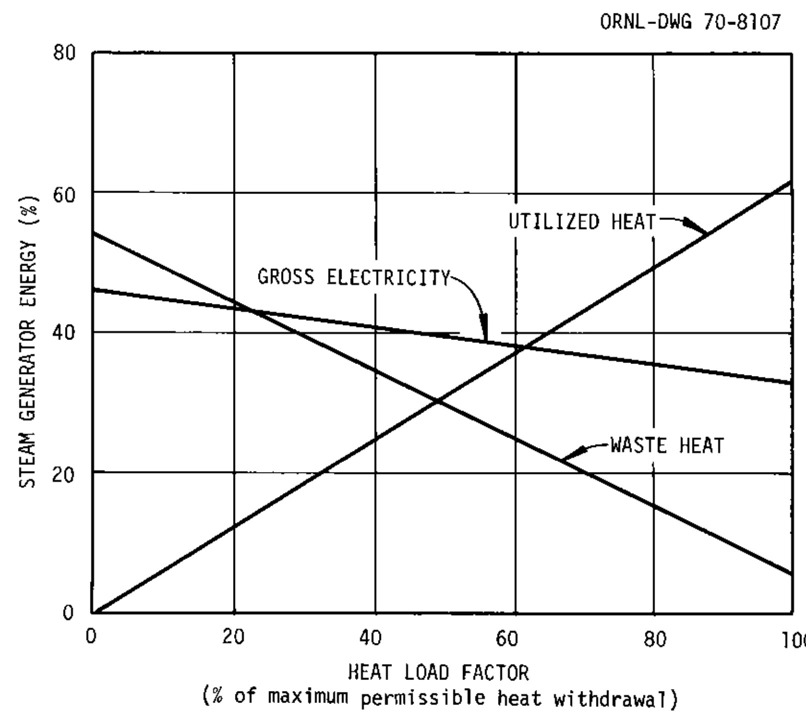

Fig. 48. Heat and Power Production as a Function of the Heat Load Factor for an FFP or AR Plant. District heat provided by water heated from 200 to 300°F.

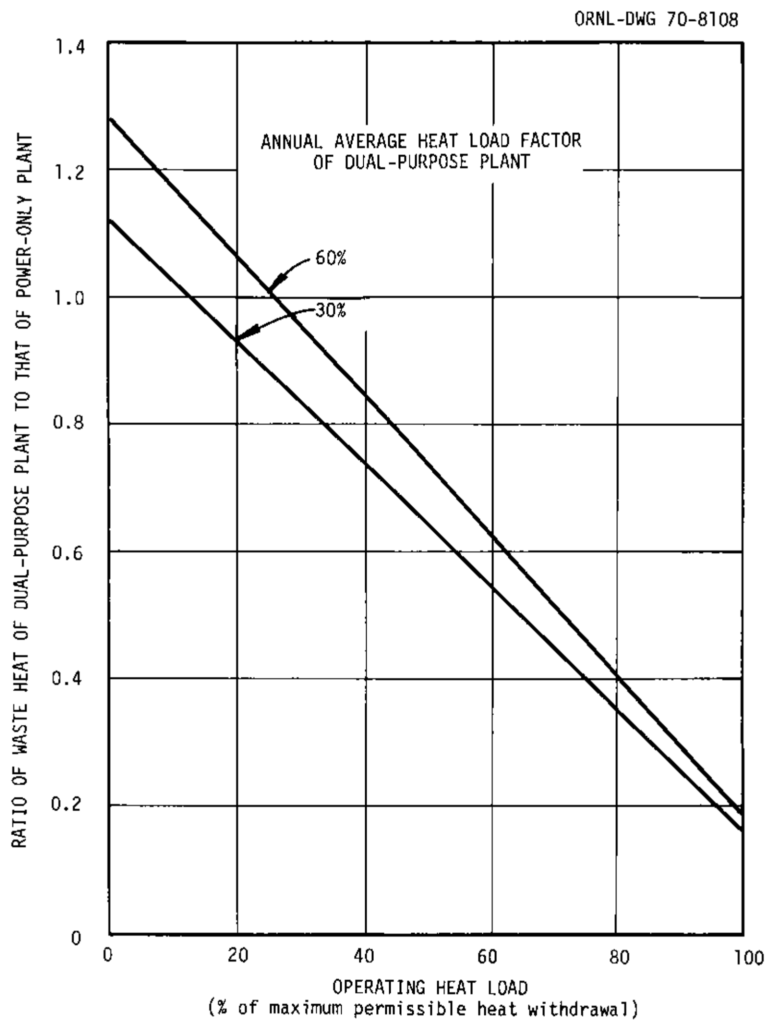

Fig. 49. Comparison of Waste Heat from Single- and Dual-Purpose Plants with Light-Water Reactors. District heat provided by water heated from 200 to 300°F.

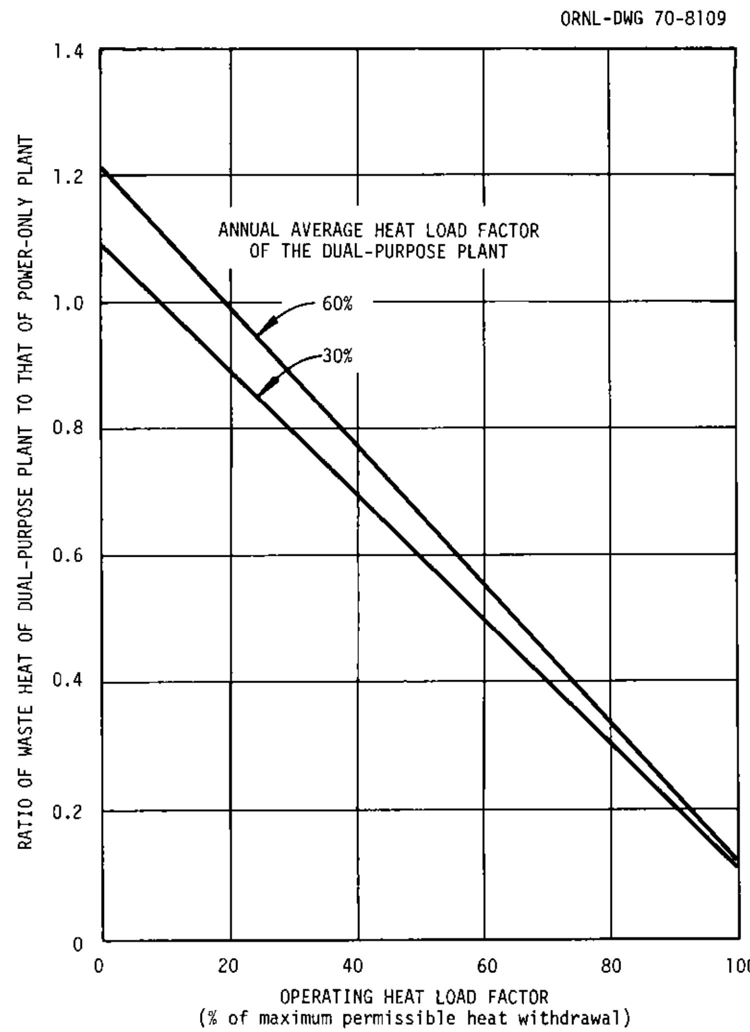

Fig. 50. Comparison of Waste Heat from Single- and Dual-Purpose FFP or AR Plants. District heat provided by water heated from 200 to 300°F.

3. Fuel cost of LMFBR — Conceptual Plant Design, System Description and Costs for a 1000-Mwe Sodium-Cooled Fast Reactor, Task Report of 1000-Mwe LMFBR Follow-on-Work, USAEC Report GEAP-5678, General Electric Company, September 1968.
4. Cost of pumps — J. A. Smith, Pumps for Desalination Plants, USAEC Report K-D-1908, Oak Ridge Gaseous Diffusion Plant, May 26, 1966.
5. Cost of heat exchangers — S. J. Senatore et al., Study of 250-Mgd Multistage Flash Distillation Plant with Two-Level Brine Flow, USAEC Report ORNL-4214, Oak Ridge National Laboratory, January 1969.
6. Cost of standby boilers — Manual of Procedures and Methods for Calculating Comparative Costs of Municipal Water Supply from Saline and Conventional Water Sources in Texas, OSW R & D 257, U.S. Department of the Interior.
7. Cost of accumulators — Chicago Bridge and Iron Company.
8. Cost of oil storage tanks — Pittsburgh-Des Moines Steel Company.

It was necessary to adopt some conventions for allocating costs between thermal energy at various temperatures and electricity. In most instances the total cost of all extracted heat and an average unit cost were determined by a power credit, or a cost difference, method. In this method the cost of electricity at the energy center is fixed as being that from a single-purpose plant with the same average annual production of electricity. The cost of heat calculated in this manner is equal to all the costs incurred beyond those of a single-purpose plant.

In some cases costs were initially allocated to steam in proportion to its thermodynamic value for making electricity according to the method of Burwell and Hammond.[67] By that method the cost of back pressure or extracted steam at the turbine is

$$H = S\left(\frac{\varepsilon - \beta}{\varepsilon}\right)\left(\frac{1}{1 - \beta}\right) - 1.2\left(\frac{\beta}{\varepsilon}\right)\left(\frac{1 - \varepsilon}{1 - \beta}\right) ; \qquad (1)$$

where

H = exhaust steam cost,

S = prime steam cost,

ε = power only (condensing) efficiency,

β = back-pressure turbine efficiency.

The first term relates to the thermodynamic value of the exhaust steam and to the penalty incurred by having to produce additional steam to make electricity. The second term relates to condenser cost savings. Other charges associated with such items as pumps, heat exchangers, hot-water accumulators, standby heat boilers, and excess turbine capacity were then added to obtain the total cost of the heat at the plant. The total cost of heat arrived at by this method is less than that found by the cost difference method when there is more than one heat source at the center. This is due chiefly to considering the cost of prime steam as being the same for both thermal energy usage and electricity generation, even though the cost of prime steam is actually higher than that from a single-purpose one-heat-source plant. A modification of this method is used in connection with the reference city in Section 6 that normalizes the heat cost at each temperature to arrive at the same total cost of heat as that obtained by the cost difference method. With this modification the cost of electricity is the same as from a single-purpose plant.

A third method of computing is to assume that all heat at the turbine has the same cost as prime steam. In this case the cost of heat at the plant also includes the cost of excess turbine capacity, accumulators, standby heat sources, etc. This method leads to very high estimates and was used in only a couple of the exploratory cases.

When the cost of electricity production is assumed to be the same as that from a single-purpose plant with the same average annual production of electricity, electricity production cost increases as the city and energy center become smaller. The use of small plants near each city, rather than a regional plant serving several small cities, results in higher electricity production costs, but there would be some reduction in electrical transmission losses to each city. In some arrangements the use of the smaller plants would also lower the capital costs of electrical transmission.

Table 37 gives the cost summary for the cases described in Table 36. The effect of standby boilers on average heat costs may be seen by comparing the last two columns. This increase appears less significant when the total cost of heat, including distribution to the customers, is considered. Accumulators with a capacity of 1 hr at peak heat load cost

Table 37. Energy Center Cost Summary

Case No.	Type of Heat Source	Thermal Capacity of Heat Source (Mw)	Number Reactors or Boilers	Annual Net Average Electricity Generation (Mw)	Capital Cost (thousands of dollars)	Fuel-Cycle Cost[a] [mills/kwhr(t)]	Annual Average Heat Load (Mw)	Power Value for Cost Allocation (mills/kwhr)	Steam Value for Cost Allocation (¢/MBtu)	Cost Allocation Method	Average Unit Cost of Heat (¢/MBtu)	Unit Cost of Heat Without Standby Heat[b] (¢/MBtu)
1	LWR	4856	2	1000	314,511	0.511	1888	5.23		Power credit	36.4	30.8
2	LWR	7284	3	1000	378,677	0.511	1888	5.23		Power credit	53.2	
3	LWR	4856	2	1000	314,511	0.511	1888		35.4	Prime steam cost	46.1	39.8
4	LWR	4856	3	1000	326,169	0.511	1888	5.23		Power credit	39.6	
5	LWR	1942	1	400	160,890	0.524	755	6.84		Power credit	42.9	
6	LWR	1942	2	400	174,391	0.524	755	6.84		Power credit	47.2	39.8
7	FFP	1396	2	400	86,567	25[c]	580	5.18		Power credit	31.9	
8	FFP	1396	2	400	86,567	30[c]	580	5.62		Power credit	35.0	
9	FFP	1396	2	400	86,567	40[c]	580	6.49		Power credit	41.3	
10	FFP	2094	3	400	110,042	25[c]	580	5.18		Power credit	52.5	
11	FFP	2094	3	400	110,042	30[c]	580	5.62		Power credit	55.6	
12	FFP	2094	3	400	110,042	40[c]	580	6.49		Power credit	61.9	
13	LWR	1942	1	400	160,890	0.511	755	5.23[d]		Power credit	67.8	
14	LWR	1942	2	400	174,391	0.511	755	5.23[d]		Power credit	72.1	64.7
15	LWR	6300	2	1018	386,818	0.511	4082	5.23		Power credit	35.0	
16	LWR	4423	2	1009	304,777	0.511	1624	5.23		Power credit	35.3	28.9
17	LMFBR	3487	1	1000	300,845	0.1	1262	4.24		Power credit	28.0	
18	LMFBR	3487	1	1000	300,845	0.15	1262	4.37		Power credit	28.6	
19	LMFBR	3487	1	1000	300,845	0.25	1262	4.62		Power credit	30.1	
20	LWR	2913	2	444	237,306	0.511	1888	6.84		Power credit	46.3	
21	LWR	4856	2	1000	330,903	0.511	1888	6.84		Power credit	40.9	34.6
22	LWR	4850	2	1000	317,239	0.511	1903	6.84		Power credit	37.0	32.1
23	LWR	4850	2	1000	317,239	0.511	1087[e]		35.5	Prime steam cost	56.2[f]	47.8[f]
24	LWR	4850	2	1000	317,239	0.511	1087[e]		17.4	Exhaust steam cost	38.1[f]	29.7[f]
25	LWR	4556	2	1000	302,669	0.511	1382			Power credit	42.7	36.7
26	LWR	2425	2	500	202,574	0.524	952	6.41		Power credit	44.4	38.9
27	LWR	4850	3	1000	347,357	0.511	1903	5.23		Power credit	44.7	41.0
28	LWR	2425	3	500	219,799	0.524	952	6.41		Power credit	53.3	49.3
29	LWR	7275	3	1000	386,365	0.511	1903	5.23		Power credit	54.5	
30	LWR	5144	2	1000	326,646	0.511	2066	5.23		Power credit	38.2	33.2
31	LWR	2268	2	463	182,669	0.511	915	6.55		Power credit	38.2	

[a] Except as noted under footnote c, fossil fuel for standby or peak heating is assumed to cost 40¢/MBtu.

[b] For cases where a separate low-temperature boiler is used for standby heat only and its cost is included in the previous column.

[c] Fossil fuel cost, ¢/MBtu for entire center.

[d] The low power credit of a large system is used in the allocation to illustrate one aspect of scaling to a small system.

[e] District heat.

[f] Costs are for district heat only.

about 3¢/MBtu. The natural-draft wet cooling towers included in all cases in Tables 36 and 37 cost $6/kw of heat-dissipating capacity.

For orientation, one can examine cases 23 and 24. The cost of prime steam at the turbine is 35.5¢/MBtu. The total cost of heat at the plant for district heat is 38.1¢/MBtu, which is slightly higher than the original cost of prime steam at the turbine. The district heat cost includes 17.4¢/MBtu for the thermodynamic value of steam at the turbine. The standby plant adds 9.4¢/MBtu, and the accumulators add 3¢/MBtu. The pumps and heat exchangers for the district heating add about half and the excess turbine capacity adds approximately the other half of another 8.3¢/MBtu of cost that is incurred.

4.3.4 Comparisons and Conclusions

There are many conclusions that can be reached from comparisons of the design and heat cost information for various centers in Tables 36 and 37. Some examples follow:

The cost of heat, 39.8¢/MBtu, at the LWR plant in case 6 is approximately the same as that at the modern fossil fuel plants in cases 8 and 9 (35.0 and 41.3¢) where the fuel costs are assumed to be 30 and 40¢/MBtu.

Comparison of cases 1 and 31 shows that despite higher power value allocation the estimated cost of heat production increases as the power plant becomes smaller. The power value allocation estimates of 4.24 to 4.62 mills/kwhr for the LMFBR and its low fuel-cycle costs in cases 17, 18, and 19 reflect the assumption that this advanced reactor, which is under development, will produce power more economically than the LWR and heat at about the same cost.

A comparison of cases 22 and 27 shows that the use of three high-temperature steam generators, each producing one-third the required energy, and no standby low-temperature heat plant would be more expensive than using two high-temperature steam sources and a low-temperature fossil-fueled standby plant — 37¢/MBtu versus 41¢/MBtu.

A comparison of case 30, where the heat is extracted to produce 380°F water, with case 22, where the water temperature is 300°F, shows a moderate difference in heat emitted by the cooling tower, but only about 1¢/MBtu difference in heat costs. Cases 15 and 20 demonstrate that when a low-temperature fossil-fueled peaking plant is employed, a large average heat load can be produced by the center. The load variations in the electricity plant would be lessened, the heat rejection to the cooling towers reduced, and the cost of heat would remain about the same as if the high-temperature plant supplied the peak heat. In contrast, occasional very high peaks, much above average, could be handled by a small peaking plant, heat accumulators, or a standby plant serving as an occasional peaking plant.

The general conclusions are that use of energy centers could cause effective reductions in heat emissions and that the cost of heat at the plant would be much less than that now available for district heating from other sources. For an equal cost to the consumer, this would allow a bigger fraction of the heat charges to be spent in the distribution system and permit expanded services as compared with those in existing district heating systems. Less-densely populated and larger customer areas could be served. It has been shown that small increases in distribution system investment per unit of heat can allow for significant decreases in consumption per unit length of distribution main and large increases in the total size of a distribution system.[68]

5. HOT-WATER SYSTEM PIPING DESIGN AND COST

Many types of thermal-expansion devices, heat-insulating materials, and water-barrier systems are used on underground pipes for conveying hot water and steam. The conceptual design of the piping chosen for distributing hot water in the reference city is shown in cross section in Fig. 51.

The design and cost estimates were developed by the Union Carbide Nuclear Division, Y-12 Plant, Engineering Division. Essentially the piping design was patterned after that used in the district heating system recently installed by Allegheny Center, Inc., of Pittsburgh, Pennsylvania.[69] The poured-concrete-envelope structure is designed to protect the piping and thermal insulation from wetting by sealing the system to prevent the entry of any water. The effects of water on many types of distribution systems are given in a report of the Federal Construction Council.[70] The adoption of this particular piping design was recommended by W. L. Griffith of the Y-12 Plant and W. J. Boegly, Jr., of ORNL based on a survey they made of the performances of underground piping installations. There is a basic difference in the system design in that the small Allegheny system uses steam as the heat transfer medium rather than hot water.

Estimates were made of the 1969 cost of the concrete-sealed piping system. The following principal design and cost assumptions were used:

1. pipeline invert 6 ft below road or ground surface in medium grade soil,
2. nominal design pressure of 400 psi,
3. supply line temperature of 300 to 400°F,
4. return line temperature of 140 to 200°F,
5. cost estimates include allowances of 35% for indirect charges, 15% for engineering, and 10% for contingencies,
6. labor cost estimated for Oak Ridge, Tennessee, area, which is approximately country average.

The costs shown in Fig. 52 are the installed costs of one mile of supply line and one mile of return line, with necessary expansion joints. The components of the cost are listed in Table 38. No block or isolation

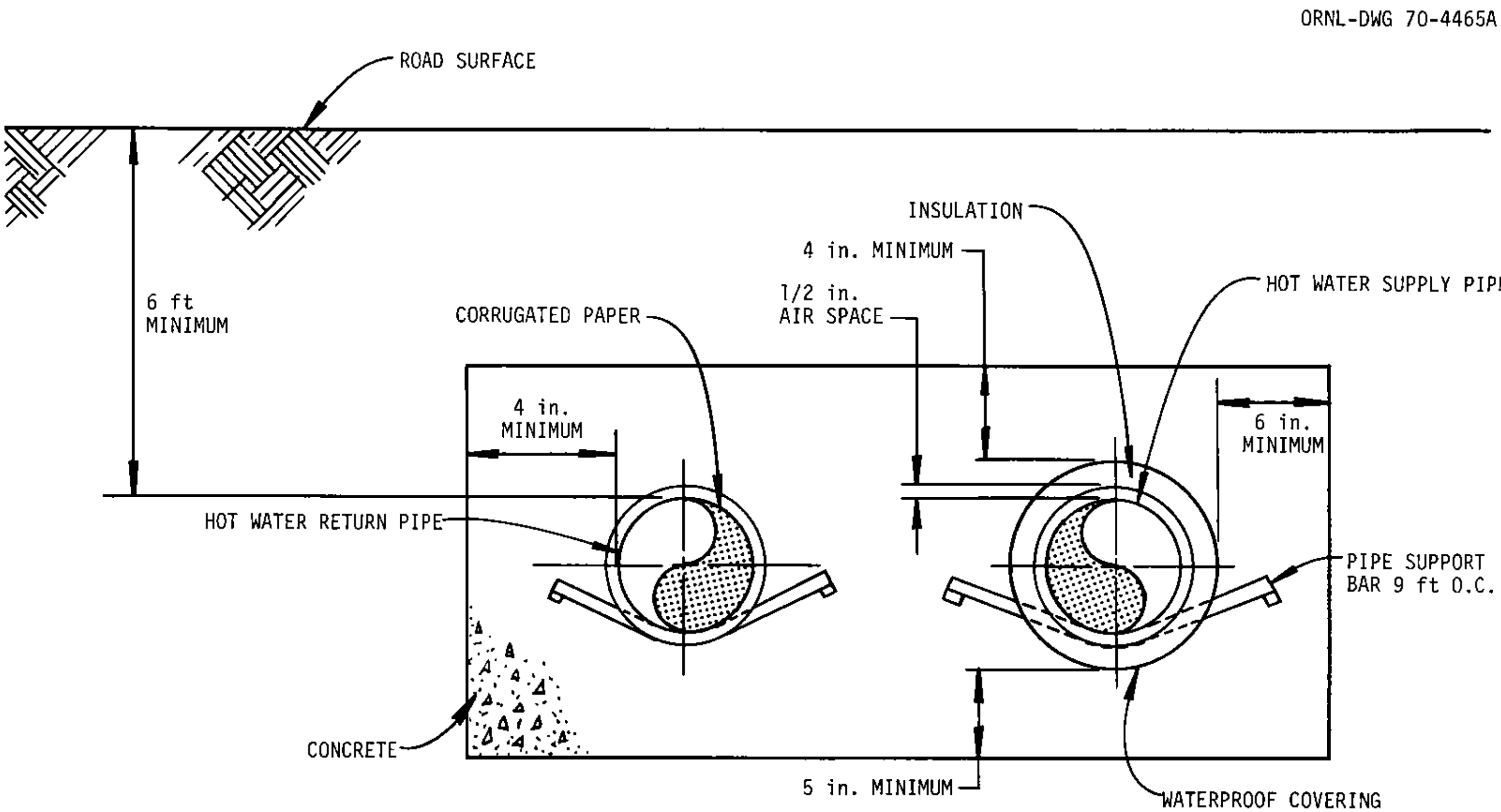

Fig. 51. Poured-Concrete-Sealed Hot-Water Supply and Return Line Installation.

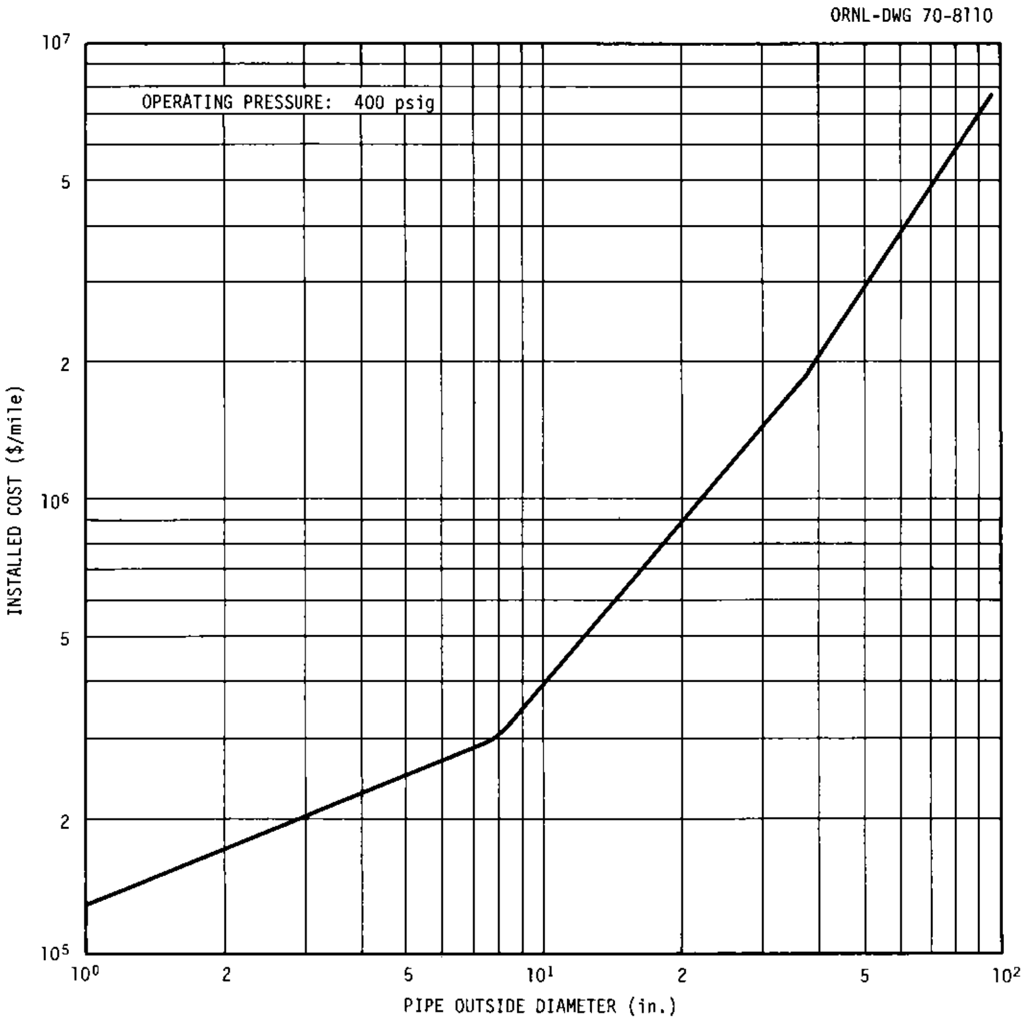

Fig. 52. Installed Cost of Supply and Return Pipe System Sealed with Poured Concrete. Based on 1969 dollars.

Table 38. Percentage of Total Pipe System Cost by Component

Component	Percentage of Total Cost						
	Pipe Diameter (IPS)						
	4 in.	8 in.	12 in.	16 in.	24 in.	30 in.	36 in.
Excavation	19.1	16.3	14.3	12.6	11.3	10.3	9.6
Concrete	29	26.1	24.5	22.4	21.8	20.6	20.2
Pipe	35.5	42.1	44.7	50.1	52.7	54.8	55.7
Insulation	16.4	15.5	16.5	14.9	14.2	14.3	14.5

valves are included in the costs shown in Fig. 52. The installed costs for valves, one in the supply and one in the return line, are shown in Fig. 53. The installed costs of the meters used for the determination of the heat consumption in the buildings of the reference city are shown in Fig. 54. They were based on estimates by manufacturers of cold water

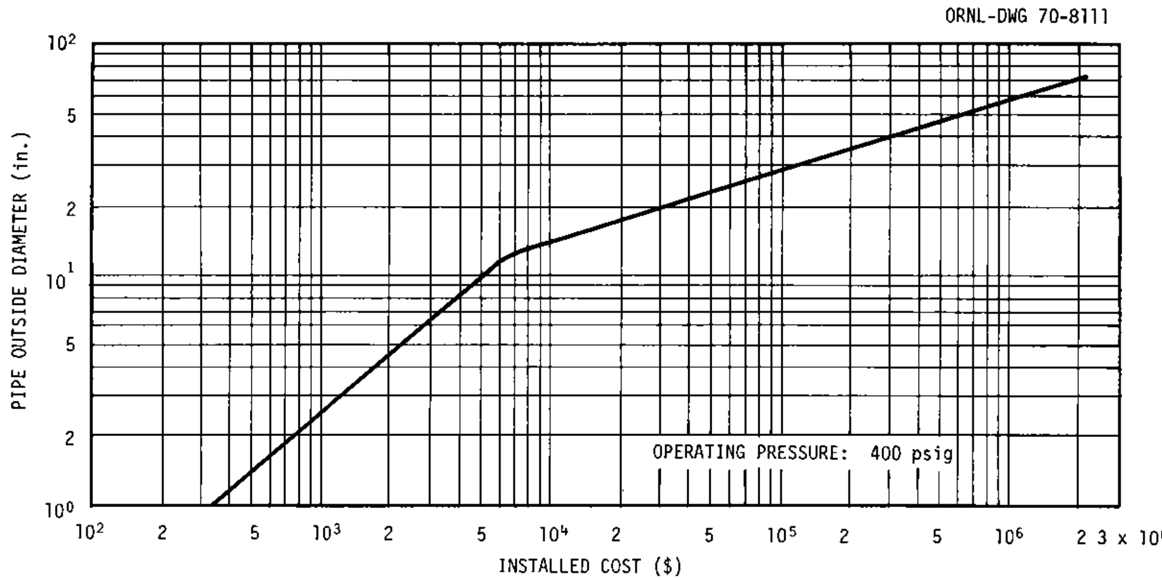

Fig. 53. Cost of Installed Valves — One in Supply Line and One in Return Line. Based on 1969 dollars.

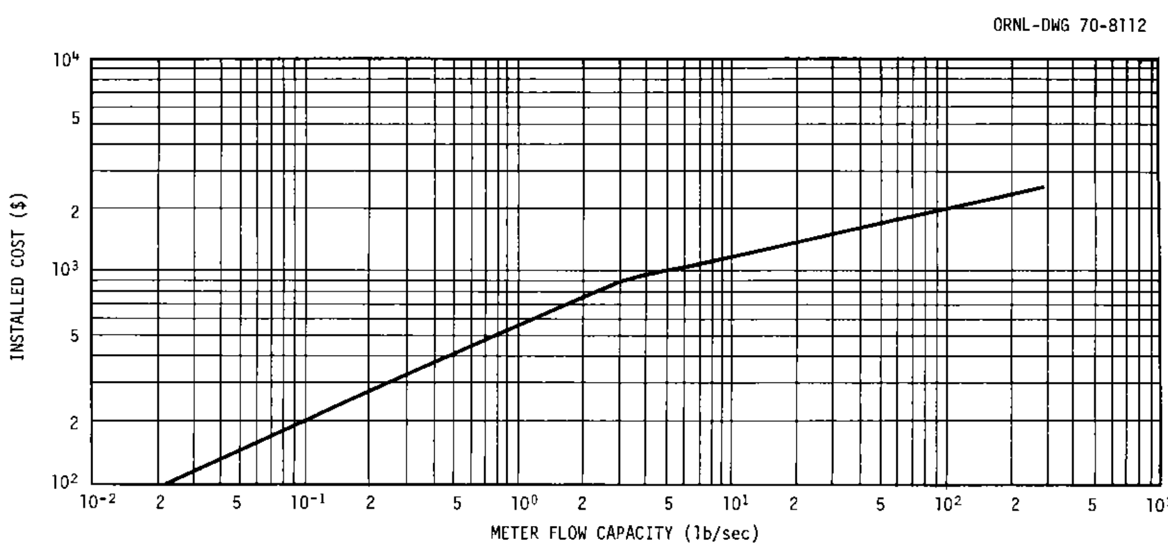

Fig. 54. Installed Cost of Meter in Return Line. Based on 1969 dollars.

meters and included additional costs for increased accuracy and higher temperature.

The heat losses for underground piping were estimated by methods recommended by the National District Heating Association[71] and are shown in Fig. 55. The heat losses in Fig. 55 are those for a single pipe insulated with a 0.5-in. air gap, Carytemp (expanded-silica-type) insulation, and 5 in. of concrete. The thermal conductivity of the Carytemp insulation

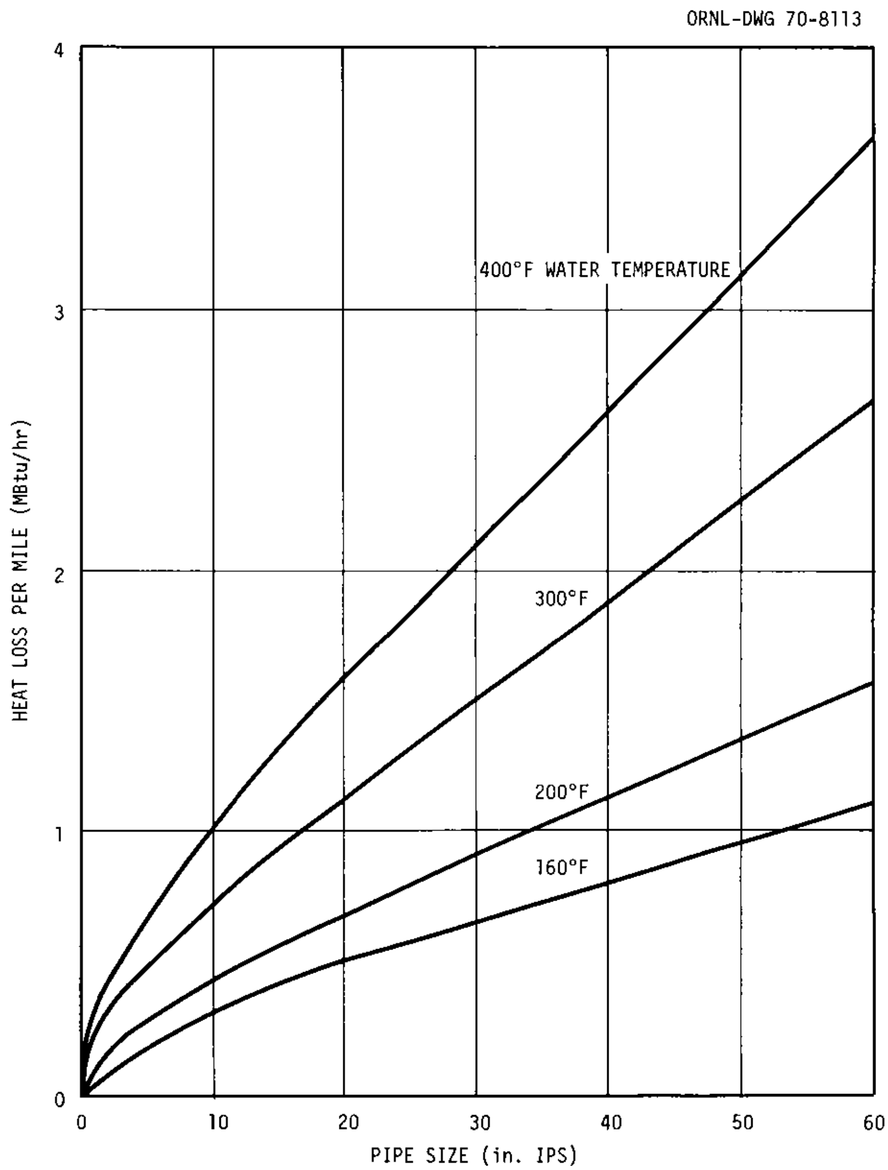

Fig. 55. Heat Loss from a Single Buried Pipe in 50°F Soil.

is 0.42 Btu/hr·ft^2·°F·in. at 300°F. Two inches of this insulation was used for pipe sizes up to 8 in. and 2.5 in. was used for pipe sizes above 8 in. The heat loss is considered as part of the operating and maintenance cost that is applied to an overall system and not to any of the component parts.

Some comparisons can be made between the estimated piping costs for the reference city and the costs for cities in which there are interferences from existing utility lines. Some information supplied by the Boston Edison Company and by the Consolidated Edison Company of New York on steam mains with no condensate return lines can be used for this purpose. In about 1967, in downtown Boston, 11,000 ft of 24-in. steam main was installed at a cost of $210/lin. ft. Eight-thousand feet of 16-in. main was installed outside of the downtown area at a cost of $120/lin. ft. It was estimated that a downtown installation in the latter case would have cost an additional 25%. The cost of dual 24-in. piping (Fig. 52) is $\$1.15 \times 10^6$/mile or $218/lin. ft. Dual valve installations for a new city, according to Fig. 53, would cost $60,000 each. The cost of 16-in. dual piping in Fig. 52 is $\$0.7 \times 10^6$/mile or $132/lin. ft, and dual valves would cost $15,000. An estimate for 542 ft of 8-in. main in an unspecified location in New York City was $180/lin. ft. This last case is in strong contrast to $57/lin. ft, which is the cost shown in Fig. 52 for 8-in. main in a new city.

Another piping design of interest is used in the hot-water district heating system with a thermal design capacity of 340 Mw that is presently being installed in the city of Sapporo, Japan, by the American Hydrotherm Corporation.[72] The underground distribution system is a prefabricated metal-cased type that consists of the hot-water service pipe covered with calcium-silicate pipe insulation installed within a spiral welded steel conduit. The outer surface of the casing is coated to resist corrosion and moisture. The conduit is installed in a trench in a sand cushion for earthquake protection and backfilled to street level.

It may be seen from the above data that the installed cost of underground piping in an existing city would be sensitive to specific interferences with other underground utilities that would have to be determined and evaluated. In contrast the cost of underground piping for new cities can be estimated as a function of pipe sizes, meter sizes, etc., and information regarding the nature of the earth to be trenched.

6. THE REFERENCE CITY

6.1 General Design

The reference city study was carried out by M. E. Lackey and H. R. Payne. The city is imagined as a new one with 389,000 people located in a geographical area having the climate of Philadelphia, Pennsylvania. The purpose of studying a reference city was simply to demonstrate the ideas discussed in the previous five sections. Therefore, its design was only conceptual and provided only enough information to define a reasonable arrangement for analysis. There was no need or attempt to design a city per se. The choice of a new city rather than an existing city was based on the factors described in Section 1; that is, it would not be necessary to treat the problems of renovating an existing city, the new city information would be directly applicable to planned expansions of existing cities, and the new city results would provide baseline data with which to approach more complex problems. Since there was time to deal with only one, the new city was the reasonable choice. The energy center for the reference city is described in detail in Section 4.3. Light-water-cooled reactors were chosen as the energy source to avoid dealing with the problem of atmospheric pollution from a fossil-fueled plant and to impose a transmission distance of thermal energy from the plant to the city within the bounds of current siting practice for nuclear facilities (described in Sect. 4.1).

The center is designed to produce the average amount of electricity forecast in Section 3.1 for a city of 389,000 people in 1980, except for a small reduction to compensate for the use of district heat for air conditioning and domestic hot-water production. The industrial consumers of low-temperature process heat are located in close proximity to the energy center, and their process heat consumption conforms to the projected country average (see Sect. 3.6) for a city of the chosen size in 1980, with extraction pressures raised to compensate for pressure drops in the supply mains. The industrial and sewage-treatment heat loads and steam pressures assumed are those for case 31 in Table 36. The nature of the industrial consumers is unspecified, and the industrial load factor is assumed to be unity. These simplifications could be made because the assumption of national-average composition of industrial heat placed the main burden of heat utilization on the city's buildings. The role of the building heat consumption was further accentuated by sizing the sewage distillation plant at the energy center at about two-thirds the size that could be justified from the data in Section 3.3.

The residential and commercial areas of the city are all situated at a distance greater than five miles from the energy center, as illustrated in Fig. 56. The population at any distance from the energy center is less than that shown in Section 4.1 for the areas surrounding the Indian Point reactor in 1980. The downtown area and an apartment house area are in one sector between 6 and 12 miles from the center, and they received 300°F water for building services. This section of the city that is supplied with district heat has a total area of 16 square miles. Of the 389,000 people who live in the city, 258,000 of them reside in 12 square miles of

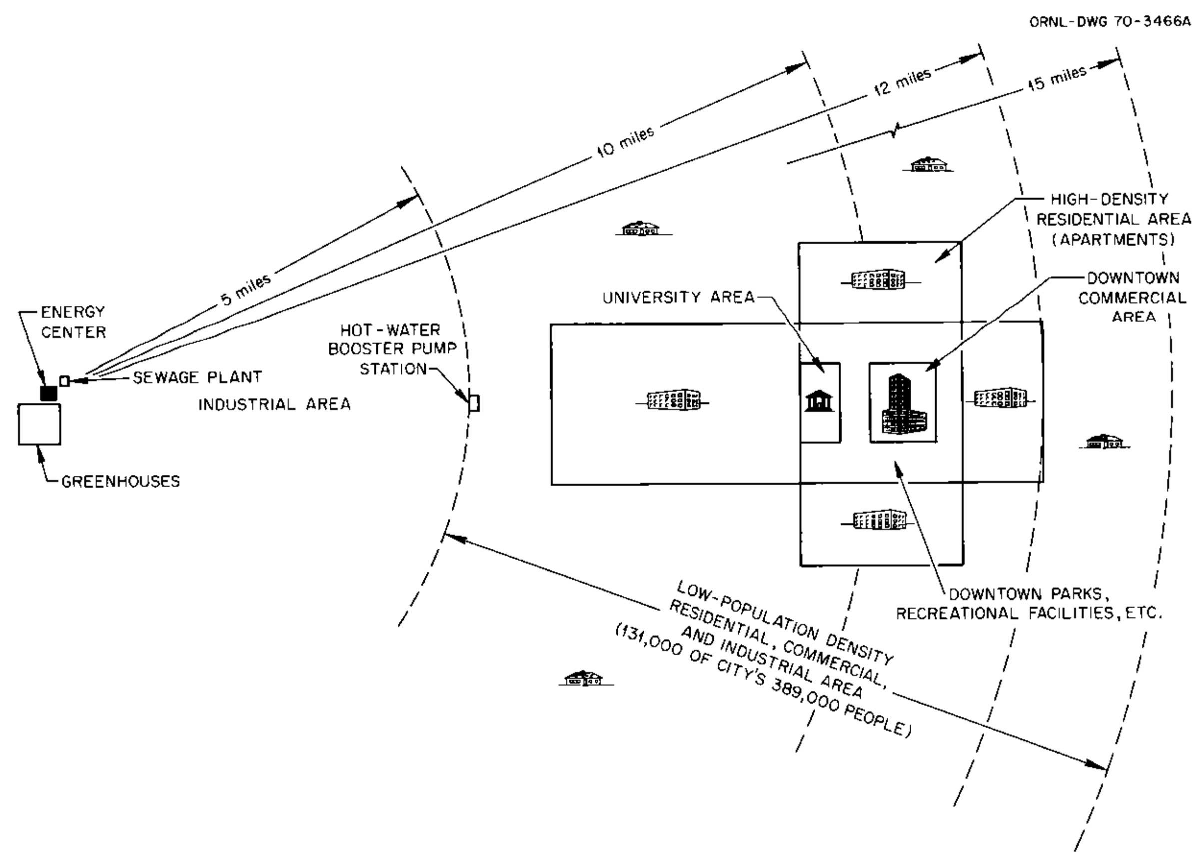

Fig. 56. Plot Plan of a Reference City and Energy Center.

apartment area. The downtown area is located in the remaining 4 square miles. The other 131,000 people live outside the 16-square-mile area at unspecified locations within the 5- to 12-mile annulus. All 389,000 people are supplied with electrical energy from the center. The general city statistics are listed in Table 39. The 222,000 people shown in Table 39 as being in the five- to ten-mile annulus of the reference city are to be compared with 300,000 within a ten-mile radius projected for Indian Point in 1980, and the total population of 389,000 within the 12-mile radius is to be compared with 400,000 projected for Indian Point.

Table 39. Reference City Statistics

Population served by energy center	389,000
Population distribution relative to energy center	
5- to 10-mile annulus	222,000
10- to 12-mile annulus	167,000
Population served by district heating system	
5- to 10-mile annulus	172,000
10- to 12-mile annulus	86,000
Area served by district heating system, square miles	16

The portion of the city supplied with thermal energy from the center is laid out in a fashion that allows it to be characterized with relatively few parameters. After an economic analysis was made of its energy system, the effects of changing important parameters, such as population density, total population, dwelling space per person, and distance from the energy center, were readily estimated. A major simplification was achieved by the use of uniform building structures and a repetitive mile-square layout of the apartment area that houses a large fraction of the population. This led to answers regarding the cost of services to uniform consumers that are translatable to those for mixed sizes and alternative arrays of consumers.

The arrangement of apartments, shopping centers, schools, and open areas for churches, parks, etc. in a typical residential mile is shown in Fig. 57. The arrangement of the apartment buildings on a typical apartment block is shown in Fig. 58. For the purpose of estimating thermal energy requirements, the apartment buildings were assumed to be uniform and three stories high with 300 ft^2 of net usable enclosed space per person, including entrances, hallways, and stairways. Two-story apartments could just as well have been used, along with somewhat higher heating and air-conditioning requirements. City block sizes could also have been varied with little effect on the analysis. The resulting population density is 21,500 people per residential mile. It is to be noted, however, that almost all inhabitants can leave the apartment area by traveling less than

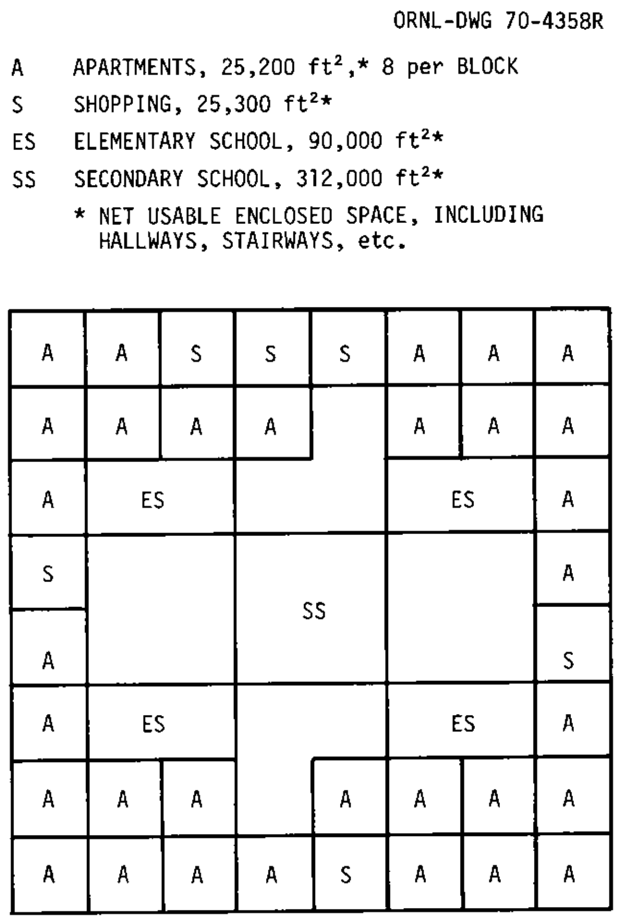

Fig. 57. Typical Residential Mile in Apartment Area.

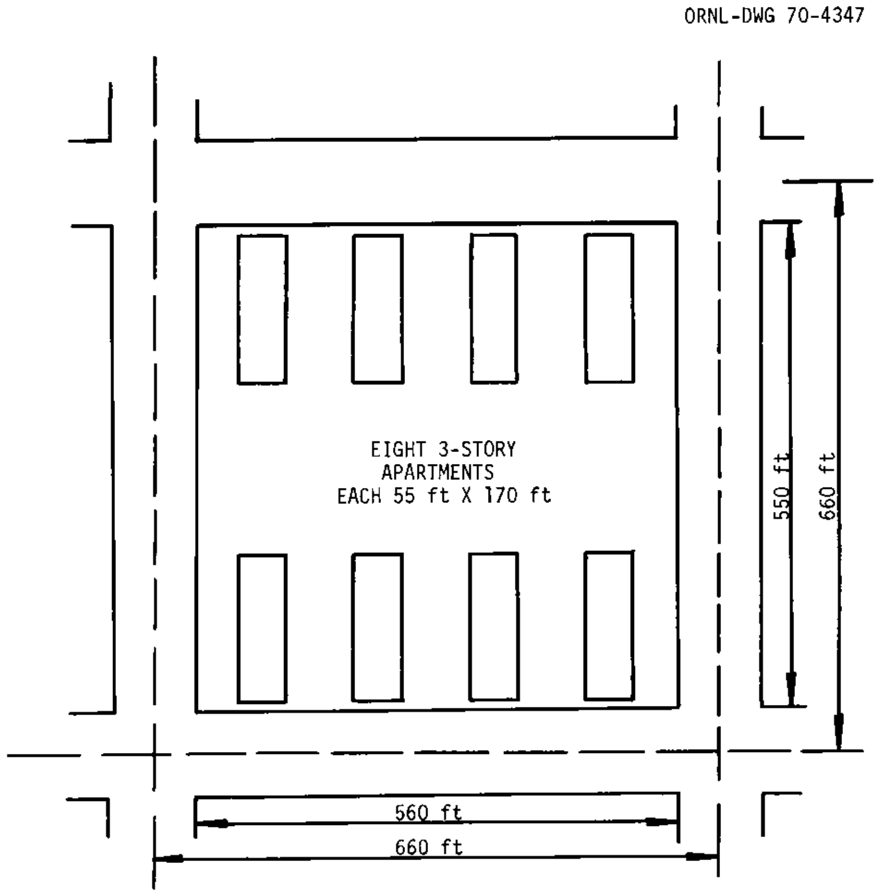

Fig. 58. Typical Apartment Block.

one-half mile. The schools and commercial facilities are sized to serve only the residents of each residential mile.

The commercial facilities, including institutions, located in the downtown region are shown in Fig. 59. Considerable information concerning the size and nature of these facilities was obtained from a description[73] of plans for the new city of Columbia, Maryland, and from examination of facilities in existing cities. The commercial facilities, including institutions, are based on the requirements of a city with 389,000 people in 1970, with no extrapolation to 1980. This tended to enhance the role of the apartment buildings and lead toward assumptions of high population densities. Table 40 gives a compilation of the space available in all the facilities served by the district heating system.

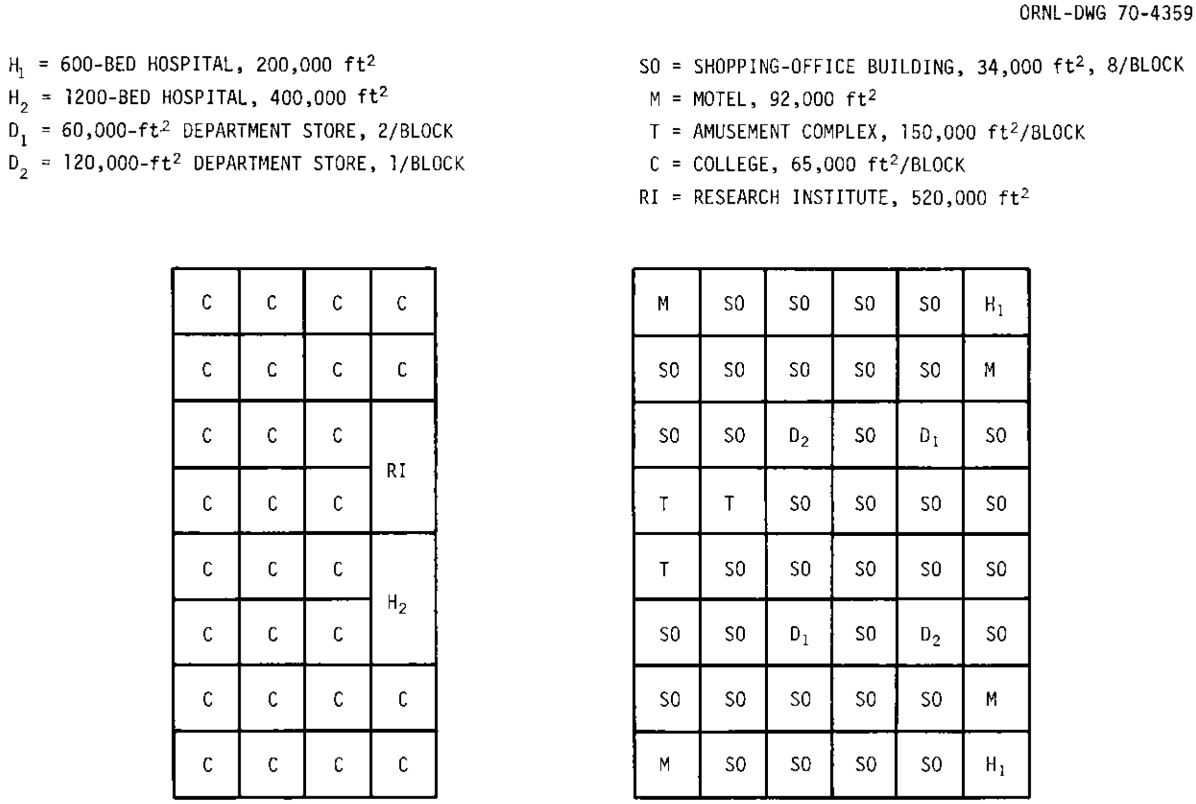

Fig. 59. Downtown Arrangement and Net Usable Space.

6.2 District Heat Consumption

Heat is supplied to the building space shown in Table 40 in sufficient quantity to meet the needs for space heating, air conditioning, and hot water. Design requirements and heat consumptions were estimated by the methods designated in Section 3.7.2. The space-heating and air-conditioning design values used for each building type are listed in Table 41 and the hot-water consumption rate is given in Table 42.

The following assumptions were made to determine the annual heat consumption:

1. The modified degree-day method of determining space heating consumption described in Section 3.7.2 is applicable.

2. Apartment air conditioning is required five months at a load factor of 0.40.

Table 40. Space Available in Facilities Served by District Heating System

Space Type	Area (ft^2)
	$\times 10^6$
Apartment	77.4
Elementary school	4.32
Secondary school	3.74
Shopping	4.43
Office	7.39
College	1.82
Research institute	0.52
Hospital (2400 beds)	0.80
Amusement	0.45
Motel	0.37
Total	101.24

Table 41. Design Values for Heating and Air-Conditioning Installations[a]

Building Type	Area (ft^2)	Heating ($Btu/hr \cdot ft^2$)	Air Conditioning (ft^2/ton)
	$\times 10^6$		
Apartments	77.4	30	440
Schools	8.06	35	385
Local commercial	1.82	25	275
Hospitals	0.80	58	220
Department stores	0.48	30	275
Shops and offices	9.52	30	275
Motels	0.37	35	310
Amusement complex	0.45	46	315
University	1.82	45	385
Research institute	0.52	40	275

[a]Based on data in Table 24 in Sect. 3.7.2 and assumed diversity factors.

Table 42. Estimated Hot-Water Average Consumption Rates[a]

Apartments	40 gallons per day per person
Shops and offices	2 gallons per day per employee
Hospital	100 gallons per day per bed
Hotel	50 gallons per day per room
Public schools and university	35 gallons per week per student
Cleaning	30 gallons per day per 10,000 ft^2

[a]Based on data in Tables 27, 28, and 29 in Sect. 3.7.2.

3. Air conditioning is required for secondary schools five months and for elementary schools two months at a load factor of 0.45.

4. Air conditioning is required for residential and downtown commercial facilities five months at a load factor of 0.45.

5. The cleaning requirement in Table 42 does not apply to apartments. Schools are cleaned five days a week and all other facilities six days a week.

For these assumptions the annual heat supplied by the district heat system is given in Table 43. These values were used for thermal energy consumption and cost estimations for the reference city.

The annual heat consumption for space heating the apartments shown in Table 43 was obtained by taking 0.8 for the value of C in the modified degree-day method equation given in Section 3.7.2. The design temperature was assumed to be 7°F, the median of the annual extremes at the Philadelphia airport, and the number of degree days 4815, the mean value for airport and city weather stations (see Sect. 3.7). Significant agreement was obtained when the estimated apartment usage of thermal energy for heating and air conditioning in Table 43 was compared with the estimates obtained from the computer program and hourly weather bureau data from Philadelphia.

Table 43. Annual Heat Consumption

	Annual Heat Consumption (Btu)		
	For Space Heating	For Air Conditioning[a]	For Hot Water
	$\times 10^{12}$	$\times 10^{12}$	$\times 10^{12}$
Apartments	3.71	4.43	2.5
Schools	0.276	0.402	0.051
Combined downtown and local commercial buildings	0.594	1.58	0.143
Cleaning			0.004
Total	4.58	6.412	2.698

[a]300°F water supplied to 2-psig lithium bromide absorption refrigeration equipment.

For the computer program it was assumed that a temperature of 75°F was maintained in the apartments. The relative humidity was held at 60% while cooling, and there was no humidity regulation during periods of heating. The apartments were assumed to be of conventional design, with ventilation, internal heat loads, etc., that led to design requirements of 30 Btu/hr·ft^2 for heating to 75°F (rather than 70°F as in the degree-day calculation) and 440 ft^2/ton for air conditioning. Hourly Philadelphia airport weather bureau data were used for the years 1955, 1956, 1957, 1959, and 1961 through 1964. A comparison of the results with those from the methods previously used is given below:

	Modified Degree-Day Method Results	Computer Program Results
Average annual heat consumption for heating, Btu	3.7×10^{12}	4.1×10^{12}
Average annual peak hourly heat consumption for heating, Btu/hr	2.3×10^{9}	2.3×10^{9}

	Results Based on Assumed Load Factor	Computer Program Results
Average annual heat consumption for air conditioning, Btu	4.4×10^{12}	3.3×10^{12}
Average annual peak hourly heat consumption for air conditioning, Btu/hr	3.0×10^{9}	3.0×10^{9}

The district heat system capacity was based on the integrated peak hourly requirements of all consumers listed in Table 41. The hot-water consumption was taken to be zero at the time of the peak and that was equivalent to the use of an additional modest diversity factor. The return water temperature from space heating was taken as 160°F, that from air conditioning as 210°F, and that from water heating as 100°F. The mixed mean temperature of the return water was 148°F in the winter and 202°F in the summer. These considerations led to sizing the system to provide a peak flow rate of 12,691 lb/sec of 300°F water to supply the summer peak air-conditioning load. The winter peak load requires a flow rate of 6932 lb/sec.

6.3 District Heating System

6.3.1 Distribution System Design

A schematic flow diagram of the district heating system for the reference city is shown in Fig. 60. Some consultation on the general design of such systems was supplied by Paul L. Geiringer of Paul L. Geiringer Associates. In addition to the piping, the major pieces of equipment in the system are the supply pumps, the heat exchangers, and the pressurizer, which are located at the energy center, and the booster pumps, which are located at the edge of the city. The system is sized to supply the peak flow rate of 12,691 lb/sec of 300°F water.

The booster pumps are located at an elevation of 100 ft relative to the energy center. The maximum elevation of a consumer in the city relative to the booster station is 100 ft. Intermittent elevation changes within the city could be as large as 150 ft without dropping the line pressure below the saturation pressure of the 300°F water.

The various pipe sizes and lengths of dual piping used in the design of the district heating system are listed in Table 44. The location

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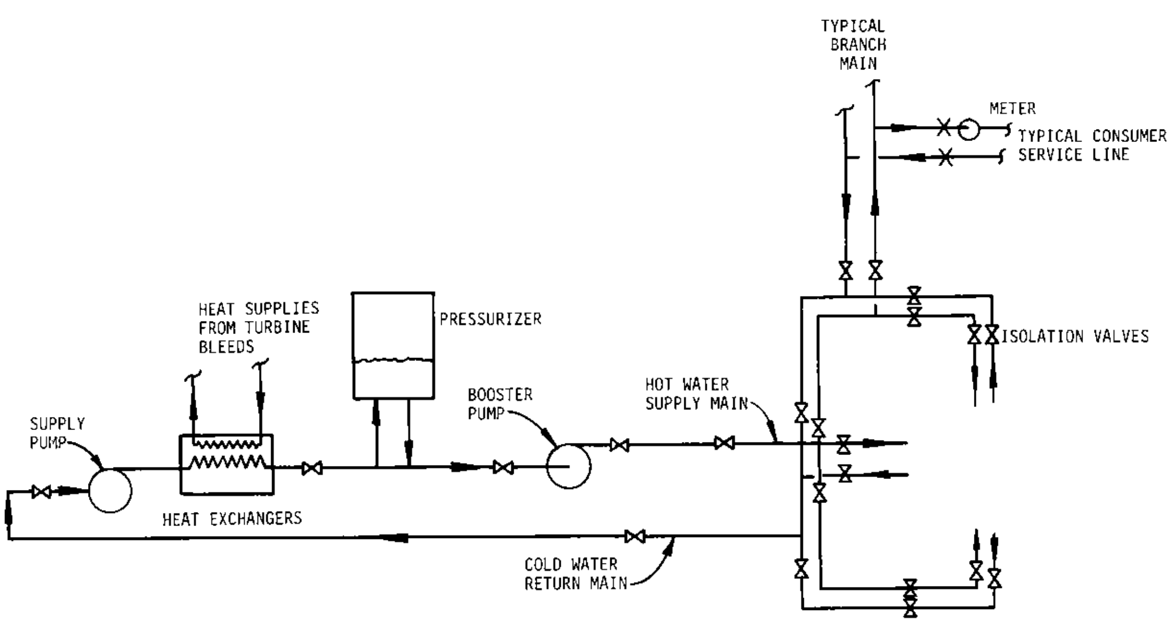

Fig. 60. Schematic Diagram of District Heating System.

and sizes of the branch main piping for the downtown area and for a representative residential mile are shown in Figs. 61 and 62, respectively.

Table 44. Pipe Sizes and Lengths Used in the District Heating System

Pipe Size (in.)	Pipe Length (miles)	Pipe Size (in.)	Pipe Length (miles)
54	6 3/4	8	11
48	2	6	16 5/8
30	3	4	33 5/8
24	2 1/2	3	12 3/4
20	1 5/8	2 1/2	2 1/4
18	1/8	2	6 3/4
16	5/8	1 1/4	3
12	13 1/2	1	32

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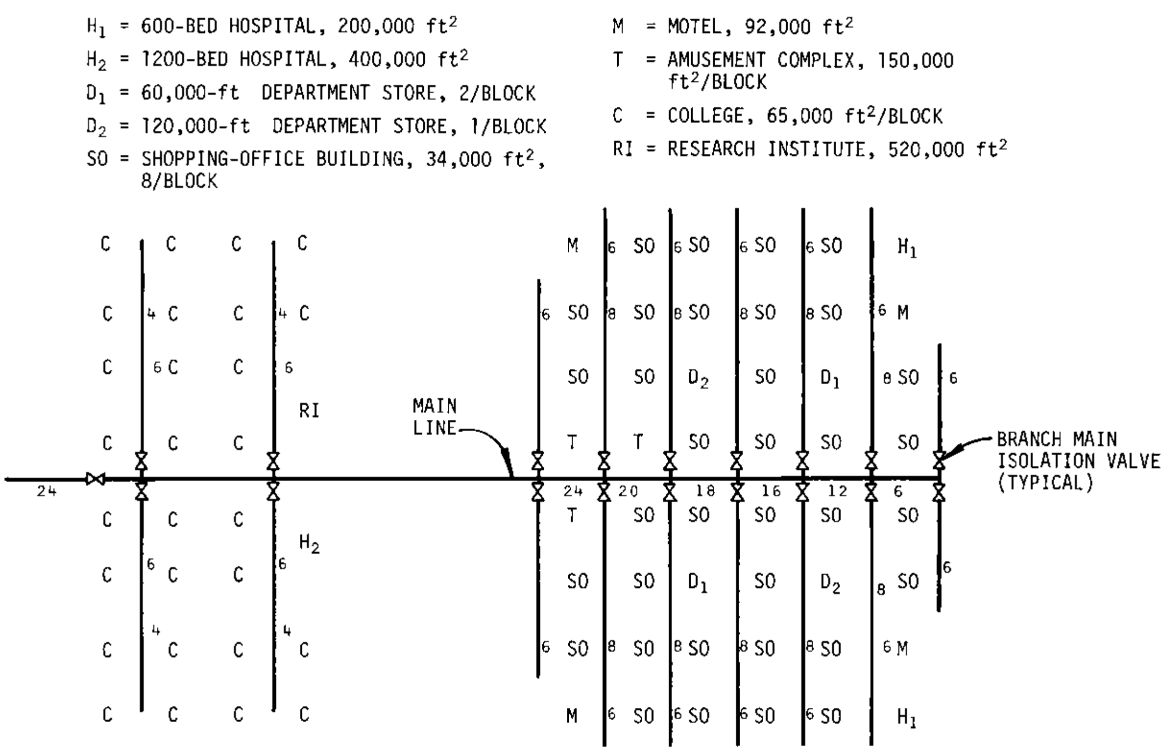

Fig. 61. Branch Main Piping for Downtown Area.

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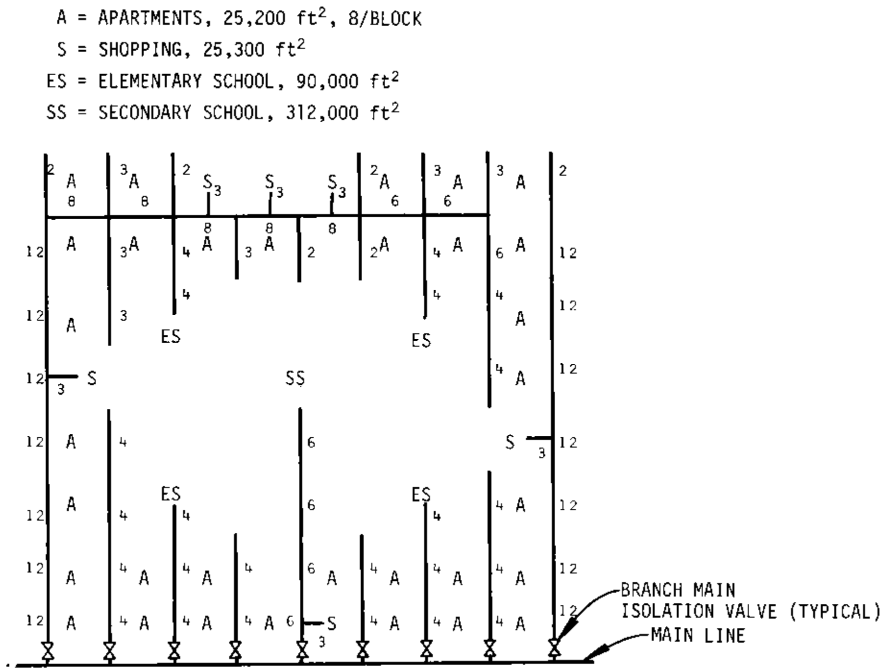

Fig. 62. Branch Main Piping for a Representative Residential Mile.

Pressurizer. The pressurizer is located at the energy center near the discharge of the heat exchangers. It is designed to prevent the line water pressure from dropping at any place in the supply main to a value low enough to allow boiling of the hot water. The 300°F water boils at a pressure of approximately 67 psia. Another requirement of the pressurizer is to prevent cavitation of the booster pumps, and a minimum suction pressure of 90 psia was assumed to be sufficient. In determining the operating pressure of the pressurizer it was assumed that, in addition to the friction pressure loss between the pressurizer and the booster pumps, the booster pumps were located at an elevation of 100 ft above the pressurizer. A third use of the pressurizer is an expansion tank to absorb the changes in the volume of the system inventory that result from changes in the mean operating temperature that result from varying load and varying distribution of the load.

The pressurizer was sized to allow for the expansion of the water in the loop from a mean temperature of 60°F to operating temperature. The maximum expansion in the water volume is 95,550 ft^3 during the heating season and 115,400 ft^3 during the air-conditioning season. The liquid inventory in the pressurizer is maintained at the system operating temperature by allowing approximately 1% of the system flow to bypass through the pressurizer to make up the heat losses from the tank walls. This flow is supplied by a pitot pump that is installed in the main line. The pressurizer is shown in Fig. 63.

The system pressure is maintained by using an overpressure of nitrogen in the pressurizer. The gas volume of the pressurizer was sized to allow for maintaining acceptable system pressures during the heating season in the case of a complete failure of the heat source for 1 hr at the time of maximum heat demand. Under these conditions, it was assumed that no nitrogen would be added to the system. A gas volume of 74,800 ft^3 is sufficient to give a total pressurizer volume of 170,350 ft^3. Three operating conditions of the pressurizer are given in Table 45 that are representative of the range of conditions experienced during system

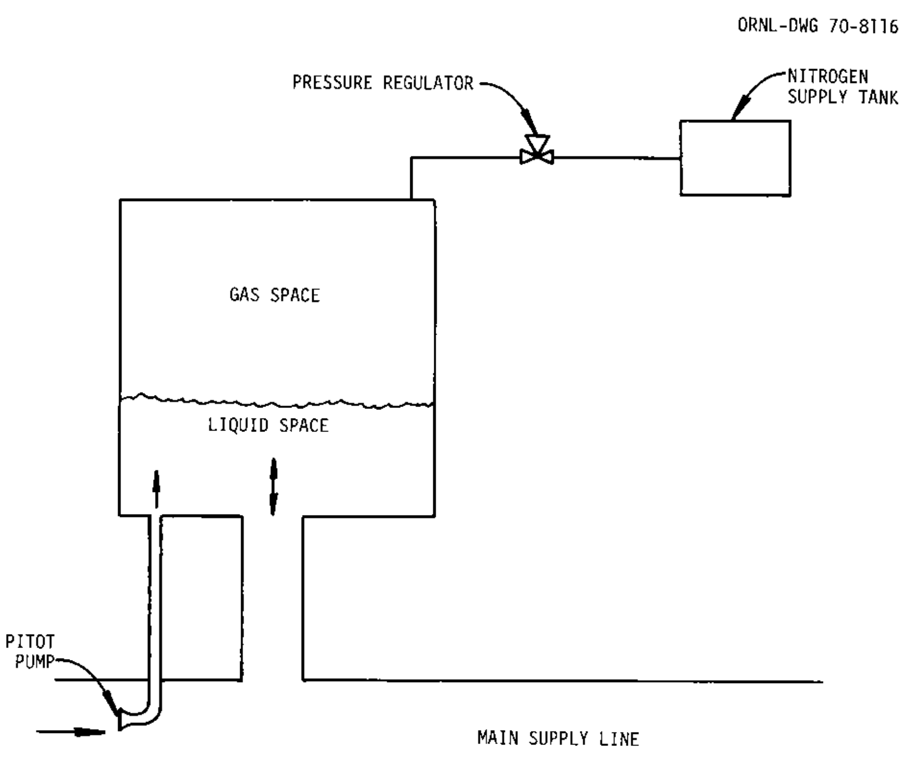

Fig. 63. District Heating System Pressurizer.

Table 45. Pressurizer Operating Conditions

	Pressure (psia)	Temperature (°F)	Gas Volume (ft^3)	Liquid Volume (ft^3)
Initial system filling	100	60	170,350	0
Cooling season peak load	215	300	54,970	115,380
Heating season peak load	221	300	74,800	95,550
Heating season peak load for 1 hr with no heat supply	157.8	286.3	102,850	67,500

operation. (On this large system, pumped pressurization might also be considered.)

Pumping Stations. The designs of the supply and the booster pump stations are the same (Fig. 64). Multiple pumps are used to provide flexibility in operation and to serve as installed spares in case of malfunctions that result in flow disruptions. Each station has a pressure-relief line that bypasses the flow from the supply main to the return main. The line in the booster station serves to limit the discharge pressure of the booster station to 400 psig to prevent the overpressurizing of the supply main that might result from a mismatch of the head-flow characteristics of the booster pumps and the flow requirements determined by the consumer. The relief line in the supply pump station serves to maintain sufficient pressure in the station inlet lines to prevent cavitation of the pumps that might result from a mismatch of the head-flow characteristics of the supply pumps and the flow requirements determined by the consumers.

6.3.2 Distribution System Cost

The capital cost of the district heat distribution system is shown to be $85.4 million in Table 46. The interest on investment during construction is included in the $16 million indirect cost. A breakdown of the capital costs to show the costs of various components of the system is given in Table 47.

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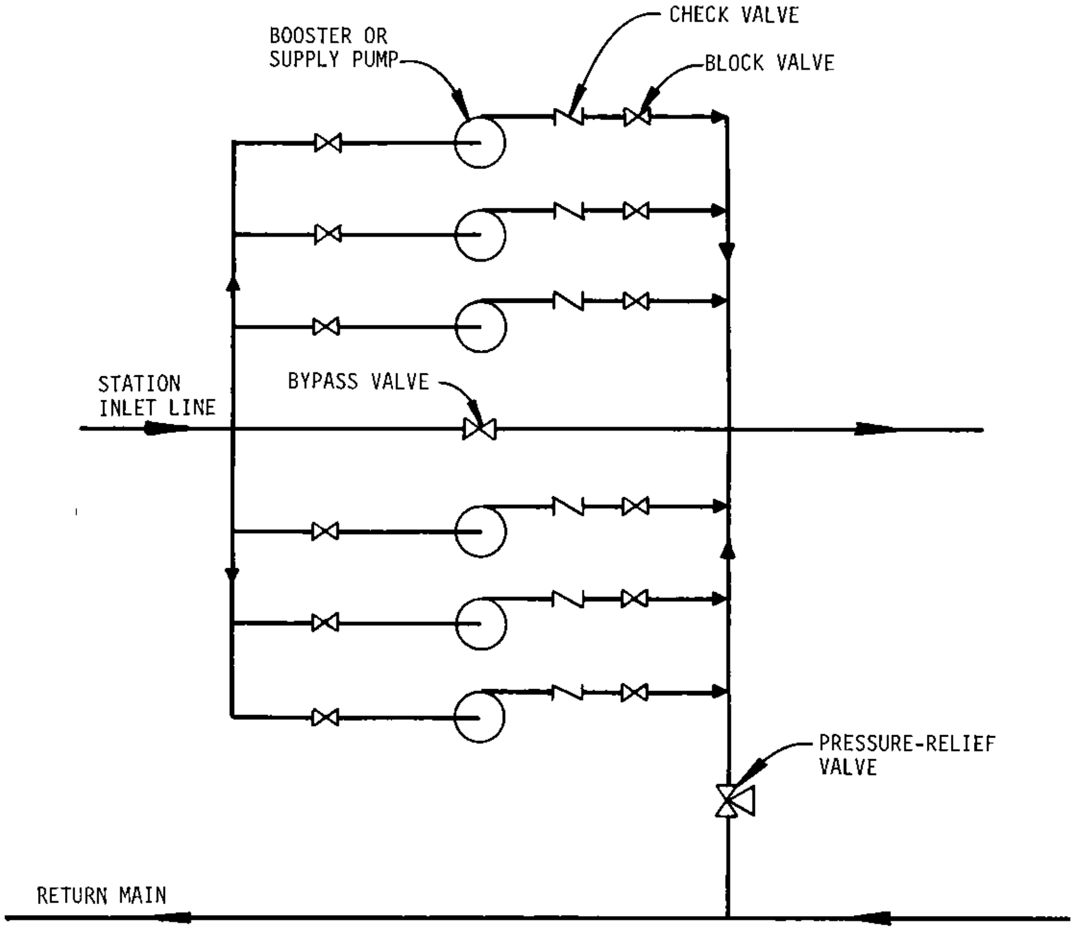

Fig. 64. Schematic Diagram of a District Heating System Pump Station.

Table 46. Capital Cost of District Heat System

Cost Item	Cost (in millions of dollars)
Direct	$45.4
Indirect	16
Engineering (15%)	9.2
Contingency (10%)	7
Escalation (10%)	7.8
Total	$85.4

Table 47. Capital Costs of Various Components of District Heating System

Components	Cost (in millions of dollars)
Mains	
54 in.	\$25
Other	17.6
Branch mains	25.4
Consumer service lines	13.9
Booster pump and pressurizer	3.5
Total	\$85.4
Typical residential mile	\$ 2.8
Downtown commercial area	\$ 5.7

The annual operating and maintenance costs are estimated to be 3% of the capital costs. This includes an annual allowance for the cost of system heat losses of 10^{12} Btu and a smaller allowance for power for pumping. The estimate of 3% is based on operating and maintenance cost information on some large district heating systems, which indicates that the operating and maintenance costs for steam systems range from 5 to 15% of the capital costs. However, many large expenses incurred in steam systems, such as those for maintenance of steam traps and other complex equipment, are not applicable to water systems.

Based on the capital cost of \$85.4 million, an operating and maintenance charge of 3%, an annual capital charge of 14%, and an annual heat consumption of 13.69×10^{12} Btu (from Table 43), the average cost of distribution is \$1.06/MBtu.

6.4 The Energy Center

6.4.1 Design and Loads

The energy center for the reference city is that described as case 31 in Section 4.3. The size of the steam plant (and the maximum summer heat usage by the city) is based on applying an additional 94% diversity factor to the summer peak district load and assuming heat losses that are negligible relative to the plant size. The major equipment required for this system and its load ratings are

Reactors	2 units, 1134 Mw(t) each
Turbine-generator	1 unit, 597 Mw(e) net
Heat exchangers	2 stages in series, 1144 Mw(t)
District heating water pumps	6 units (1 spare), 16,600 gpm each
Cooling towers or greenhouses	1180-Mw(t) heat-dissipating capacity

Figure 45 in Section 4.3 illustrates the arrangement of the turbines, water heaters, and industrial steam piping. Figure 46 of Section 4.3 is a layout of the center both with cooling towers and with greenhouses. In accordance with the data in Section 4.3, the cooling towers could be reduced in size by use of the greenhouses and eliminated entirely by having 200 acres of greenhouses located at the energy center. Cost data are presented in the next section for centers with and without the cooling towers.

An estimation of the city's electrical and district heating system loads based on monthly average data is shown in Fig. 65. The projected average electrical requirement for a city of 389,000 is 500 Mw(e) based on the data of Section 3 and a projected country population of 235,000,000 people.[74] That projection was made for a city that was not mostly served by a district heating system. If it is assumed that 20% of the district system's hot-water requirements and 50% of its air-conditioning load were included in the estimates of the electrical requirements, the electrical power production for the reference city can be reduced to an average value of 463 Mw(e), shown in Fig. 65.

The maximum heat emission to the condenser cooling water was estimated by assuming that the district heating system load at that time would be small enough so that a value of zero could be used for it, along with a value of 458 Mw for the full industrial and sewage plant load. This included the further assumption that in some years the occurrence of the minimum hourly district heat load or some other very small load would be in

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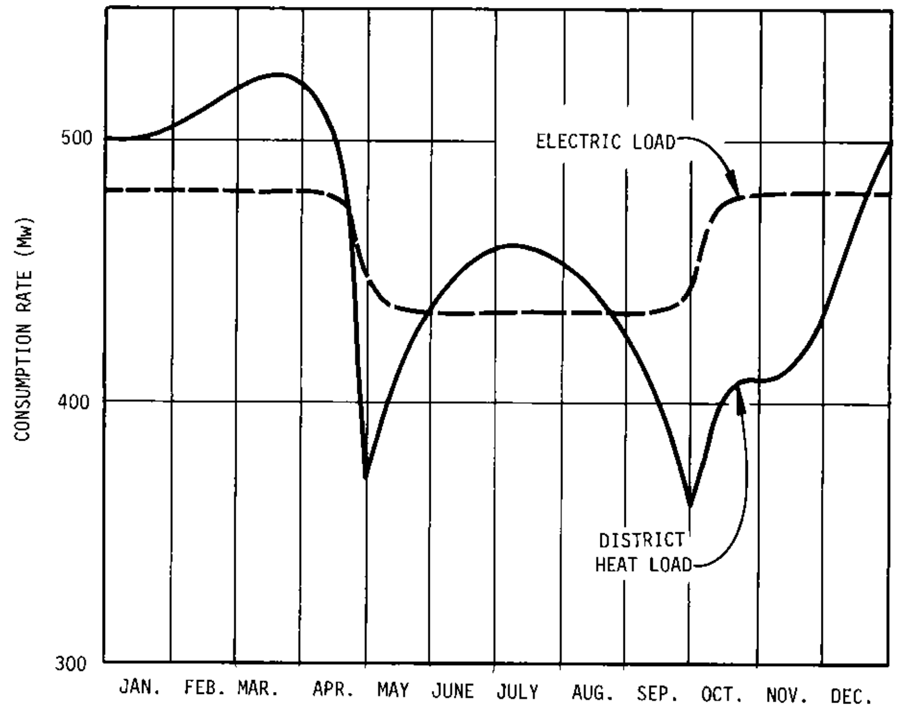

Fig. 65. Annual Electric and District Heating System Loads.

periods other than those during which one reactor was refueled in the spring and the other in the fall. A summary of the energy loads for the center follows:

Capacity of heat source	2268 Mw(t)
Annual average thermal power	2041 Mw(t)
Annual average net electrical power	463 Mw(e)
Annual average internal power consumption	29 Mw(e)
Annual average district heat production	457 Mw(t)
Peak summer district heating load (300–202°F)	1144 Mw(t)
Peak winter district heating load (300–148°F)	1088 Mw(t)
Minimum district heat load	0 Mw(t)
Industrial steam load at 965 psig	43 Mw(t)
Industrial steam load at 450 psig	251 Mw(t)
Industrial steam load at 207 psig	74 Mw(t)
Sewage distillation steam at 32 psig	90 Mw(t)
Annual average steam to condenser	634 Mw(t)

The heat and electric power loads for three heat system operating conditions were determined by using an exhaust pressure of 2.5 in. Hg for the condensing section of the turbine. These loads are listed in Table 48. Compared with a single-purpose LWR plant of 500 Mw(e), which would have a heat emission to the condenser cooling water of approximately 1000 Mw(t), the emissions of approximately 230 Mw(t) to the energy center condenser during the hottest hours of the summer provide a valuable reduction in the waste heat problem. An average emission reduction to 634 Mw is also a significant benefit. The hypothetical maximum emission at the center is shown to be 1181 Mw(t), which is slightly greater than that from the single-purpose plant. Figure 66 illustrates the relationship between the heat emission to the energy center cooling water at various operating conditions and that of a power-only plant that averages 500 Mw(e).

The addition of heat accumulators to the energy center would reduce the variations in demand for heat and changes in turbine operation at the electrical generating plant. The capital cost of accumulators with a capacity of 1 hr at peak winter district heating load would add a few cents per MBtu to the cost of heat production, as indicated in Section 4. The locating of heat accumulators at various points throughout the system could increase the reliability of service. The capital cost of a low-temperature

Table 48. Heat and Power Loads of Energy Center for Reference City

Industrial heat load
Prime steam (965 psig): 43 Mw(t)
Steam at 450 psig: 251 Mw(t)
Steam at 207 psig: 74 Mw(t)
Sewage treatment heat load: 90 Mw(t)

	Net Power Output [Mw(e)]	District Heating Load [Mw(t)]	Total Heat Load [Mw(t)]	Heat to Cooling Water [Mw(t)]
Winter maximum	426	1089	1547	263
Summer maximum	404	1144	1602	230
Minimum	597	0	458	1181

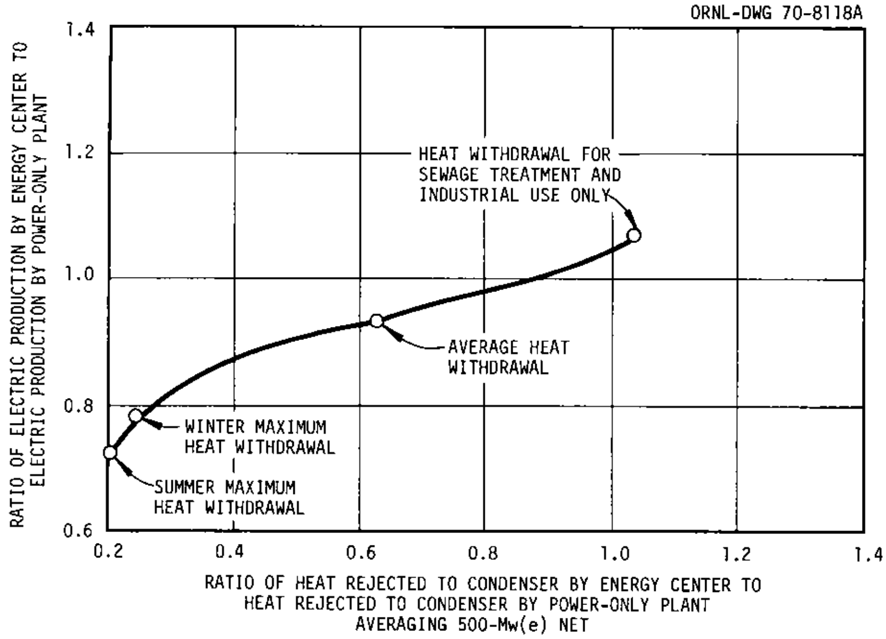

Fig. 66. Heat Rejection to the Cooling Water of the Energy Center Compared with the Rejection of a Power-Only Plant.

fossil-fueled standby heat plant for the energy center with a capacity of one-half the peak district heating load would also add a few cents per MBtu to the heat production cost. The need for such devices in the reference city is not evident. Evaluation of their utility in any actual city would require a very detailed set of information regarding the requirements of the city, and the reactor design performance.

6.4.2 Heat-Production Costs

Energy center and heat-production costs were determined for systems with cooling towers and for systems using greenhouses instead of cooling towers, and production costs were determined by the two cost-allocation methods discussed earlier. A power-only plant with a net electrical rating of 463 Mw was estimated to produce power at a cost of 6.55 mills/kwhr. This value was used to determine the power credit in calculating the average heat costs. The capital costs, the operation, maintenance, and fuel-cycle costs, and the annual costs of the energy center used to determine the heat cost are given in Table 49.

Table 49. Energy Center Costs for Determining Heat Cost

	Costs (in thousands of dollars)	
	With Cooling Tower	Without Cooling Tower
Capital costs		
Steam system (reactors)	114,694	114,694
Power-generating system (turbine-generator)	57,830	57,830
Cooling tower	7,080	
Greenhouse heat-dissipating system[a]		2,350[b]
Heat system (heat exchanger and pumps)	3,065	3,065
Total	182,669	177,939
Annual costs		
Operation and maintenance	2,180	2,140
Fuel-cycle cost at 0.511 mills/kwhr	9,137	9,137
Total	11,317	11,277
Fixed charges at 14%	25,573	24,911
Total	36,890	36,180
Annual power credit	26,543	26,543
Annual heat cost	10,347	9,645

[a]Differential cost.

[b]From Section 3.2.

Average costs of heat production were calculated on the basis of three different assumptions. The first assumption was the use of cooling towers; the other two cases were based on the use of greenhouses. The heat required for space heating the greenhouses is about 33.4 Mw years per year. Their maximum winter requirement is approximately 263 Mw(t). Although the second case was based on utilizing greenhouses, the average heat was determined without the greenhouse heat load being included in the annual heat load. This was equivalent to not charging for greenhouse heat. The final case included the greenhouse heat load, even though it would be at waste heat temperature. The results for the three cases are given below:

Average cost with cooling towers based on district and process heat	38.2¢/MBtu
Average cost without cooling towers based on district and process heat	35.6¢/MBtu
Average cost without cooling towers based on district, process, and greenhouse heat	34.3¢/MBtu

The separate costs for five different loads on the basis of the value of their steam at the turbine follow:

	Cost (¢/MBtu)
Industrial steam at prime steam condition (965 psig)	44
Industrial steam at 450 psig	38.3
Industrial steam at 207 psig	32.8
Sewage treatment steam at 32 psig	21.2
District heat (average for steam from two BP casings at 305 and 244°F)	21.2

Annual costs for these loads would be

	Annual Cost
Industrial steam at prime steam condition	$ 565,700
Industrial steam at 450 psig	2,874,200
Industrial steam at 207 psig	727,700
Sewage treatment steam at 32 psig	513,400
District heat	2,897,900
Total annual steam cost	$7,576,900

The annual cost of $1,677,000 for heat exchangers, pumps, and excess turbine capacity and the operating and maintenance costs for this equipment should apply to only the district heat costs. Subtracting this cost from the two values of total heat cost in Table 49 gives the cost to which the individual heat loads should be normalized. For example,

Total annual heat cost (power credit method), W/CT	$10,347,000
Annual cost for heat exchangers, pumps, and excess turbine capacity	1,677,000
Annual cost of heat to be prorated	8,670,000
Annual cost of industrial steam at prime steam conditions = $(565.7/7576.9) \times 8670 \times 10^3$	$ 647,300

If this is done for each load and the annual cost of $1,677,000 is charged to district heat, the following unit heat costs are obtained:

	Unit Costs (¢/MBtu)
Industrial steam at prime steam conditions (965 psig)	50.4
Industrial steam at 450 psig	43.8
Industrial steam at 207 psig	37.5
Sewage treatment steam at 32 psig	24.3
District heat	36.5

If this procedure is applied, using the annual cost of heat without cooling towers from Table 49, and no charge is made for the 33.4 Mw used by the greenhouses, the following unit costs are obtained:

	Unit Costs (¢/MBtu)
Industrial steam at prime steam conditions (965 psig)	46.3
Industrial steam at 450 psig	40.3
Industrial steam at 207 psig	34.5
Sewage treatment steam at 32 psig	22.3
District heat	34.6

If in addition to being relieved of cooling-tower expense, a charge is made for the annual average of 33.4 Mw used by the greenhouses for space heating, the unit heat costs become a function of the heat charge to the greenhouses, as shown in Fig. 67.

6.5 Cost of District Heat

The cost of the district heat is the sum of the heat production cost at the plant, discussed in Section 6.4.2, and the distribution cost of 106¢/MBtu estimated in Section 6.3.2. The costs of space and hot water heating and air conditioning supplied by the energy center with a cooling tower and no greenhouses are shown in Fig. 68. The costs for heat supplied from the energy center with greenhouses and no cooling towers are shown in Fig. 69.

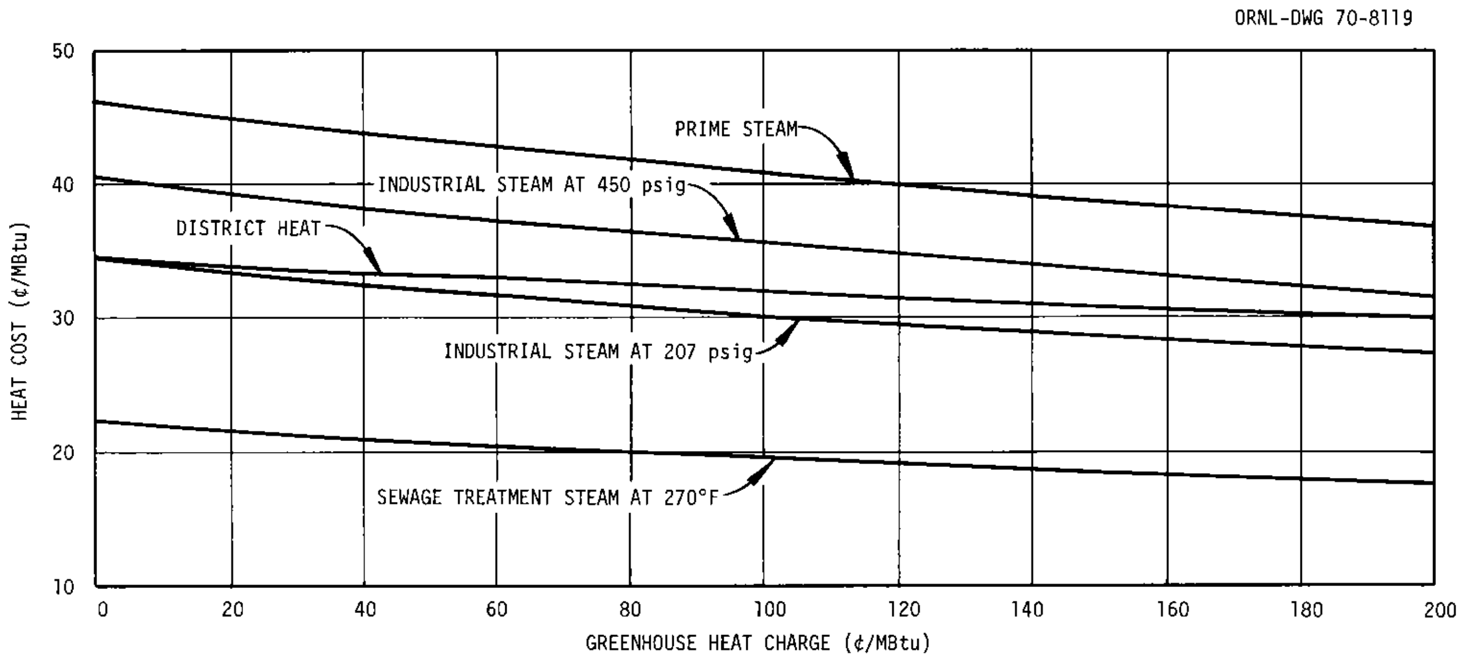

Fig. 67. Effect of Greenhouse Heat Charge on Heat Costs for the Reference City.

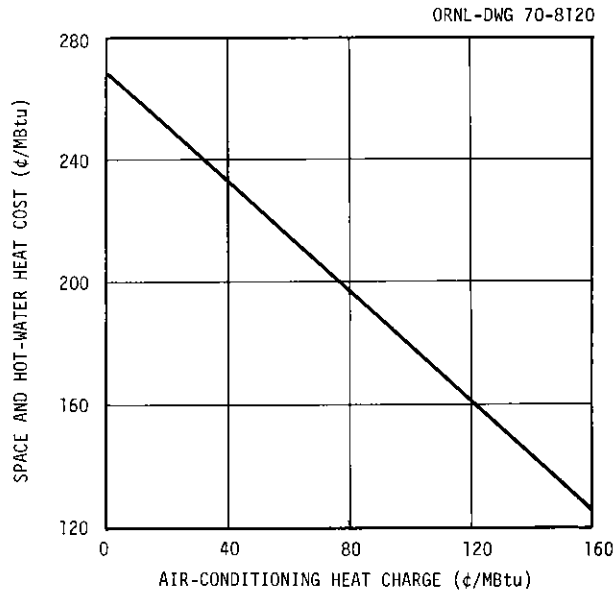

Fig. 68. Cost of District Heat Supplied from an Energy Center with Cooling Towers and No Greenhouses for the Reference City.

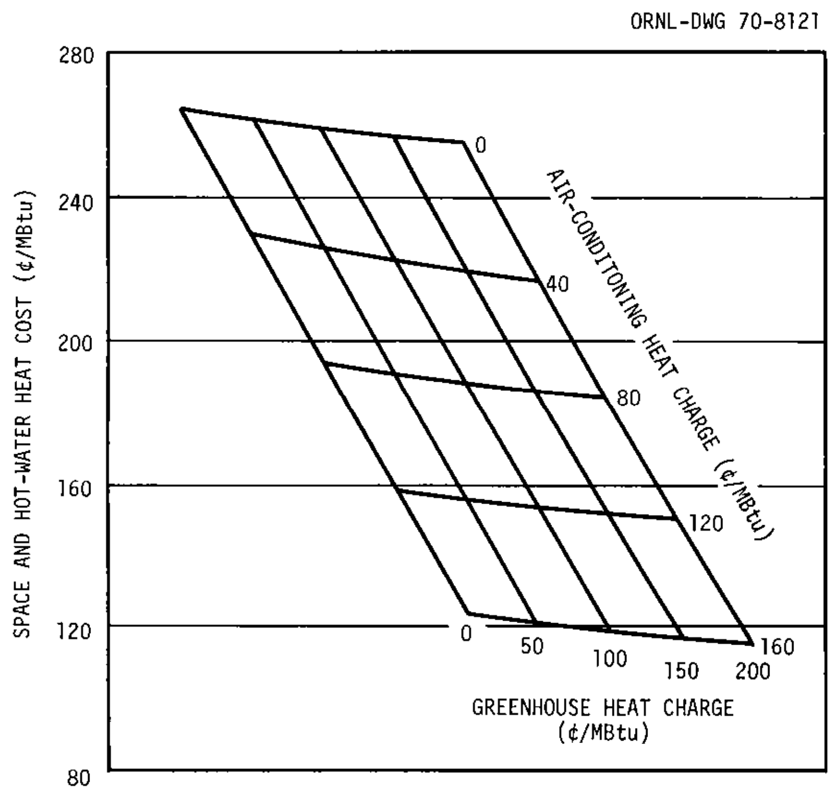

Fig. 69. Cost of District Heat Supplied from an Energy Center with Greenhouses and No Cooling Towers to the Reference City.

The costs in Figs. 68 and 69 are shown as functions of the air-conditioning heat charge. The charge for heat to air condition is usually partly based on the energy cost for air conditioning with electricity. For purposes of comparison, a charge of 79¢/MBtu should be used for heat that is used to air condition with 2-psig absorption equipment in order to have an equal energy cost in an area where the electrical charge is 16 mills/kwhr. The costs in Fig. 69 include the effects of income from the sale of heat to the greenhouses.

As an example of costs it may be seen from Fig. 68 that with no greenhouses and equal unit charge for heating and air conditioning, the cost of district heat is 142.5¢/MBtu. With a 79¢/MBtu charge for air conditioning it becomes 198¢/MBtu. The estimated cost of heat from a district system that provided no air conditioning was approximately 208¢/MBtu, the same as that which accrues from a 68¢/MBtu charge for air conditioning in the reference system; so a 79¢/MBtu charge for air conditioning defrays the cost of air-conditioning heat production and somewhat more than the incremental cost of distributing heat for air conditioning. If the cooling towers are eliminated by the use of greenhouses, the corresponding costs are 140.6¢/MBtu and 195¢/MBtu. If the charge for greenhouse space heating equaled the average heat production cost of 34.3¢/MBtu, the resulting reduction from 195¢/MBtu would be approximately 2¢/MBtu. If the greenhouse charge was 100¢/MBtu, the reduction from 195¢/MBtu would be approximately 5.5¢/MBtu.

When the above costs are compared with the district heating rates and other heat cost figures given in Section 3.9 (such as 142¢/MBtu average cost from U. S. district heating companies in 1968), it becomes evident that the cost of thermal energy from the plant for the reference city is competitive with that from other energy sources and systems of utilization.

6.6 Application of Results to Other Cities

6.6.1 One-Half-Size City

One of the perturbations studied was a one-half-size reference city (194,500 population) of the same general layout as the reference city.

The one-half-size reference city was assumed to be half size in all respects; that is population, facilities, and energy requirements.

The residences were sited in the area lying between three and seven and one-half miles from the energy center rather than starting at a distance of six miles as for the reference city. The general plot plan of the city is shown in Fig. 70. The population at any distance from the energy

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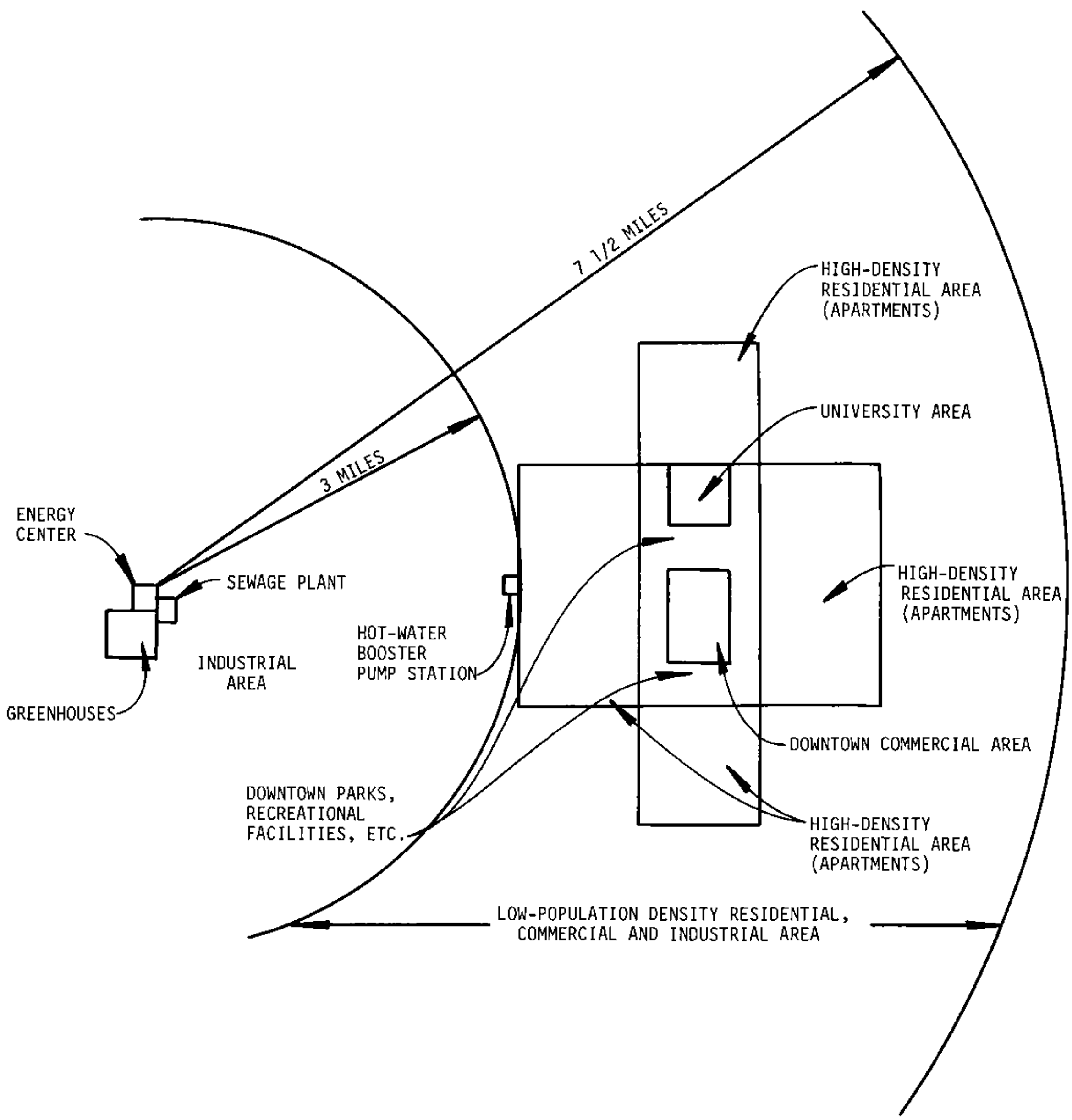

Fig. 70. Plot Plan of a One-Half-Size Reference City and Energy Center.

center is less than that shown in Section 4.1 for the area surrounding the Indian Point Reactor station in 1980.

The branch mains and service piping in the residential mile are unchanged from those for the reference city. The main piping was reduced in diameter to accommodate the decrease in the peak flow requirement of the one-half-size city. The 54-in. main was reduced to a 42-in. main, for example. The reduction in both the size and length of the mains results in a reduction in the average heat distribution cost to 90.1¢/MBtu, as compared with 106¢/MBtu for the full-size city.

From data[75] on the effect of plant size on the cost of nuclear steam generating facilities, it is estimated that the prime steam cost for this one-half-size city would increase approximately 26% compared with that for the reference city. The unit heat production costs for the one-half-size city with and without cooling towers and with no charge for the greenhouse heat are given in Table 50.

The unit heat production costs for the one-half-size city without cooling towers and with a charge for the greenhouse heat are shown in Fig. 71 as a function of the unit heat charge to the greenhouse. The district heating cost is the sum of the cost at the energy center and the distribution cost. The cost of space and hot water heating and the air-conditioning heat supplied to the one-half-size city by an energy center

Table 50. Unit Heat Production Costs for a One-Half-Size Reference City

	Heat Costs (¢/MBtu)	
	With Cooling Tower	Without Cooling Tower
Industrial steam		
Prime (925 psig)	63.5	58.3
450 psig	55.2	50.8
207 psig	47.3	43.5
32 psig	30.6	28.1
District heat	42.8	40.3

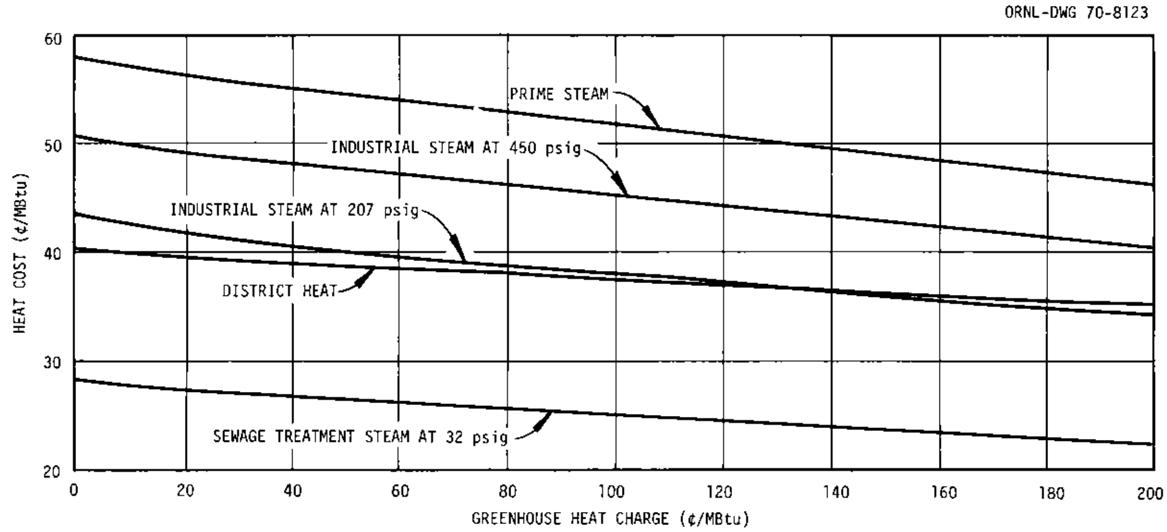

Fig. 71. Effects of Greenhouse Heat Charge on Heat Costs for a One-Half-Size Reference City.

with a cooling tower and no greenhouses is shown in Fig. 72. The costs for heat supplied from an energy center with greenhouses and no cooling towers is shown in Fig. 73.

It may be seen that despite the higher heat production costs shown in Table 50 and Fig. 71, the cost of district heat in the small city is less than in the larger reference city. The cost reduction is due to the smaller transmission distance. For example, with cooling towers and no greenhouse and a charge of 79¢/MBtu for air-conditioning heat, the cost of district heat for space and water heating is 180¢/MBtu, as compared with 198¢/MBtu for the reference city.

6.6.2 The Small City

Heat could be extracted from a large energy center and distributed to a closeby small city or town if proper planning were done with respect to the town's location and concentration of buildings. Although the use of heat from the plant under such circumstances might be economically attractive, little would be gained with respect to reducing waste heat emissions. The inclusion of a large concentration of industry requiring low-temperature process heat, or a large greenhouse area would contribute to the solution of the heat usage problem.

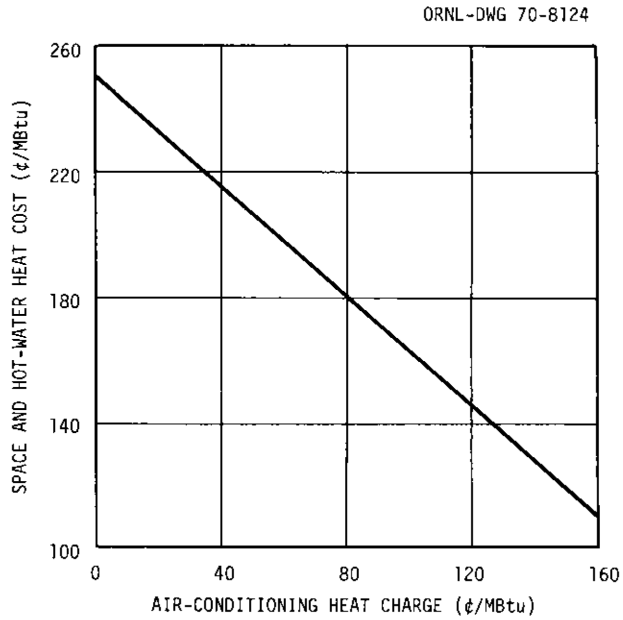

Fig. 72. Cost of District Heat Supplied from an Energy Center with Cooling Towers and No Greenhouses for the One-Half-Size Reference City.

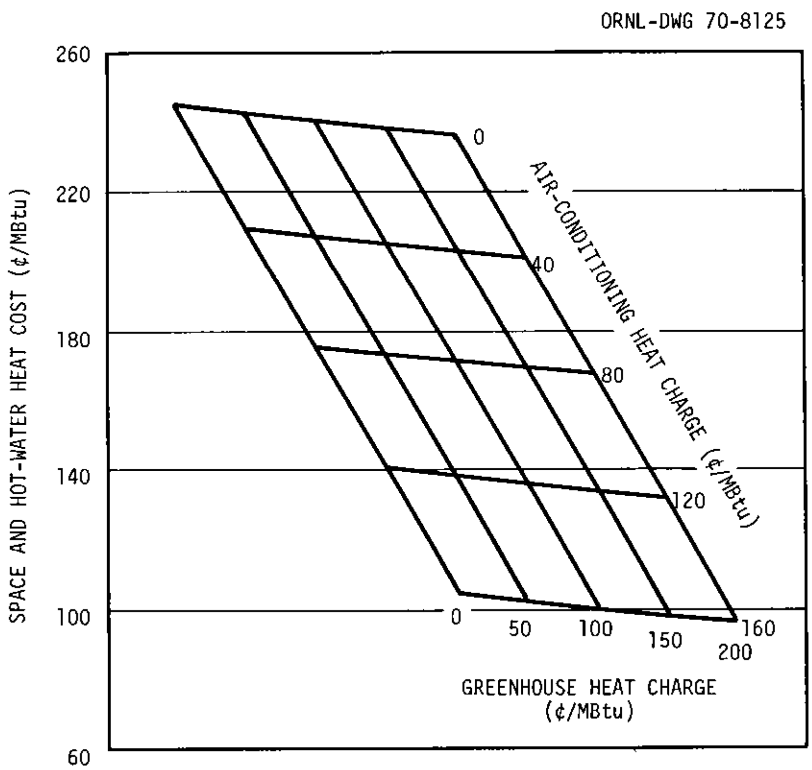

Fig. 73. Cost of District Heat Supplied from an Energy Center with Greenhouses and No Cooling Towers to the One-Half-Size Reference City.

The cost of distributing heat to 1 square mile of apartment house area having various populations within such small cities is shown in Fig. 74. Comparisons should be made with a cost of 106¢/MBtu for the reference city. It is first assumed that no dwellings are closer to the energy center than the apartment area and that its closest boundary to the center is at a distance compatible with the population projections for the Indian Point Station in 1980. This is designated as the Indian Point (80) Limit. Then costs are shown for apartment areas located at distances equal to and greater than that limit. For example, for a square mile apartment area having 5375 people with its closest boundary 1.1 miles from the center, the distribution cost would be 95¢/MBtu and, if the distance of the closest boundary were 2 miles, the cost would be 114¢/MBtu.

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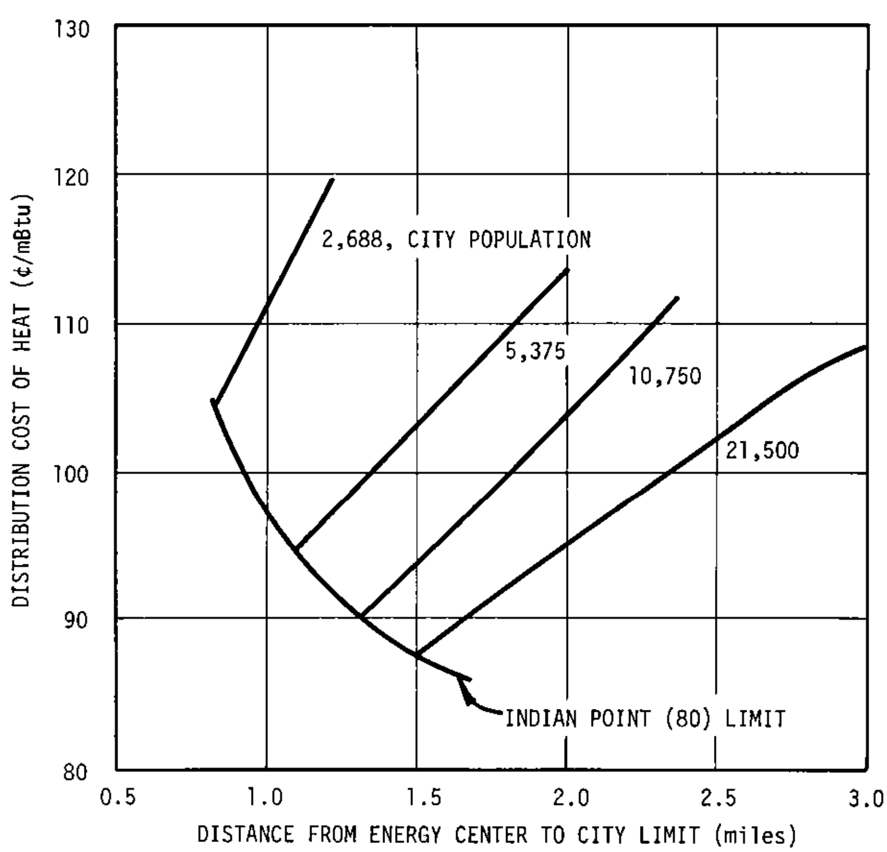

Fig. 74. Cost of Heat Distribution to a Square Mile of Apartment Areas with Various Populations.

6.6.3 The 1975 City

A city of 389,000 people with characteristics in keeping with projections to 1975 would consume 89% of the electricity used by the 1980 reference city. With a correspondingly smaller plant, it would have a smaller waste heat problem and less available thermal energy. If the buildings had the same thermal energy requirements as the 1980 city, the energy center would supply heat to a smaller number of people, and the cost estimate would be carried out as for the half-size city discussed in Section 6.6.1. If the energy center were built by 1975 with a power plant large enough to satisfy the city's requirements in 1980, the excess electricity would have to be sold to the grid until that time.

6.6.4 Cities with Lower Population Density

With minor piping changes, the population of a residential square mile could be placed in an area of approximately 1 1/2 square miles, as shown in Fig. 75, to give an average population density of 14,333 per square mile. Since the piping changes required to make this change would be minor, it is assumed that they would have no effect on the distribution costs. The broken lines in Fig. 75 indicate locations where pipe sizes are lower than those in the original square-mile layout in Fig. 62.

Estimates were made of what the cost of heat would be if the apartment areas in the reference city contained a lower density of apartment buildings and had a correspondingly lower population density, thereby spreading their 258,000 inhabitants over a larger area within the city. Estimates were made for both the original 1-square-mile and 1.5-square-mile street configurations. The results are shown in Table 51. The listed cost of space heat is based on a charge of 79¢/MBtu for air-conditioning heat.

6.6.5 Single-Family Dwellings

The incremental cost of supplying space heat to a single small consumer is shown in Fig. 76. The costs shown are for an energy center with cooling towers and no greenhouses. The incremental cost of heat for space

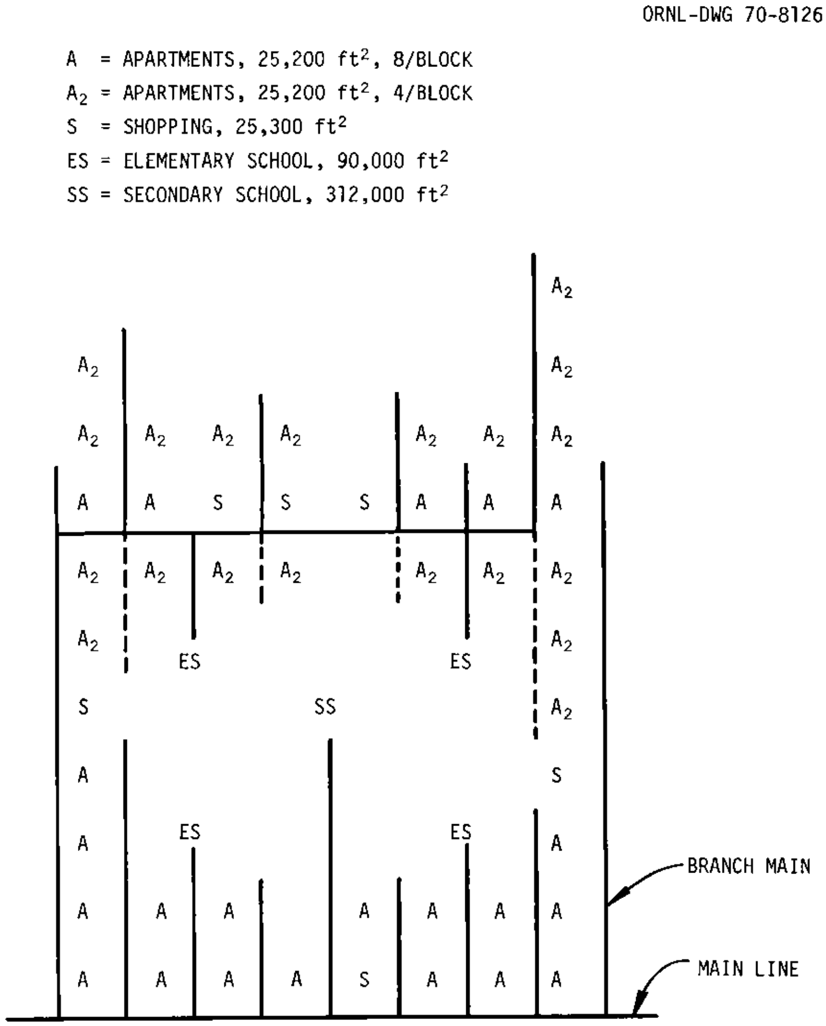

Fig. 75. Arrangement for a Typical Residential Square Mile Expanded to 1 1/2 Square Miles.

Table 51. Heat Costs for Apartment Areas with Various Population Densities

Population Density (people/mi²)	Average Cost of Heat (¢/MBtu)	Cost of Heat for Space Heating (¢/MBtu)
21,500	142.5	198
14,334	142.5	198
10,750	186	280
8,600	186	280
5,375	292	480
4,778	292	480

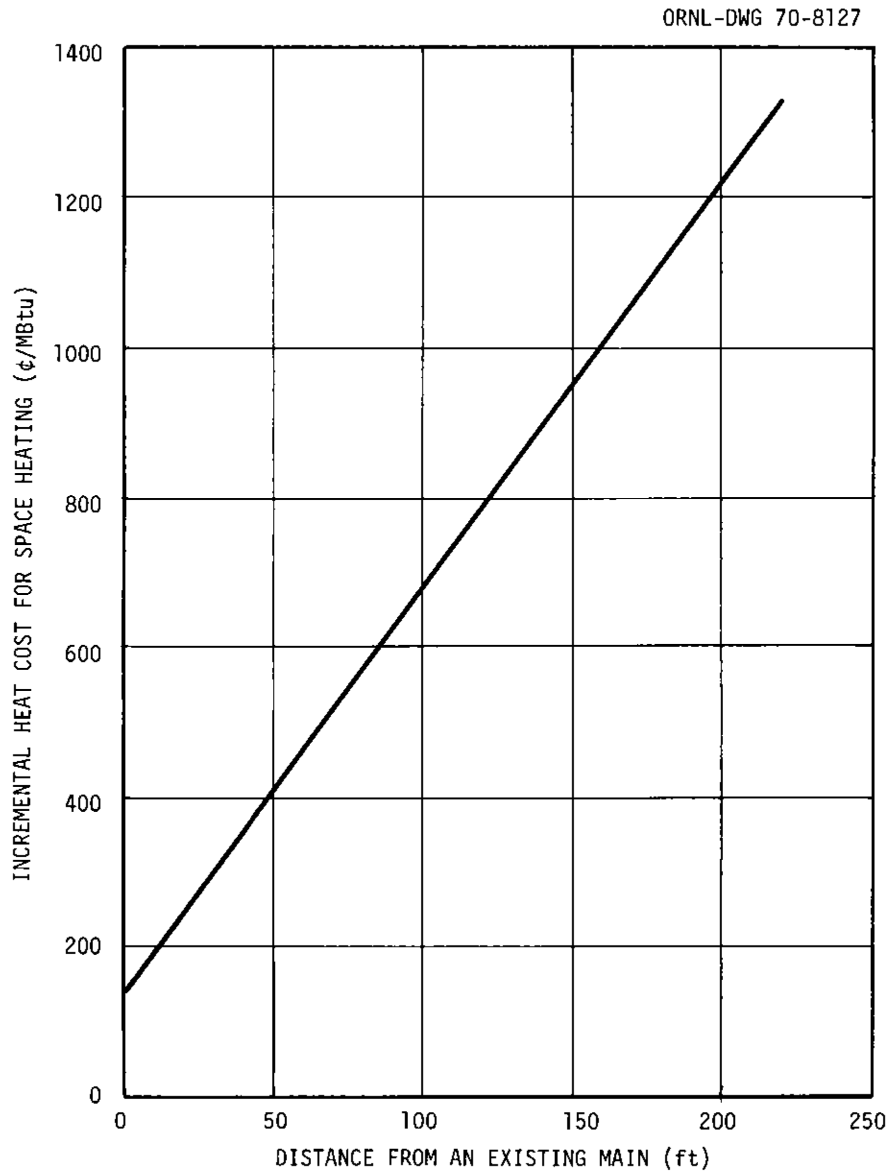

Fig. 76. Incremental Cost of Space Heat Supplied to a Single Consumer with a Peak Demand of 50,000 Btu/hr.

heating for one-fourth mile of small consumers, each of which had a 25-ft service line connection from the branch main, is shown in Fig. 77.

It may be seen that the estimated incremental cost in 1975 for serving fairly large family dwellings on the fringe of the apartment area on 50-ft lots is 510¢/MBtu and 580¢/MBtu on 100-ft lots. Also, if the cost of serving a small number of single-family dwellings were included

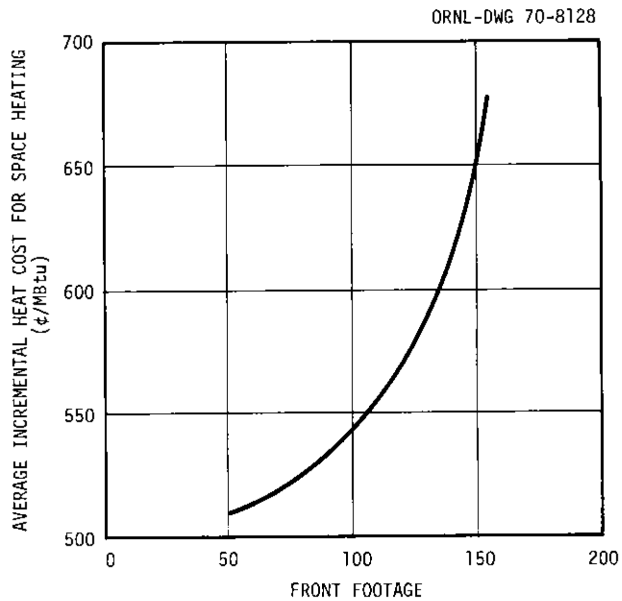

Fig. 77. Average Incremental Cost of Space Heat for a One-Fourth-Mile Line of Consumers with a Peak Demand of 50,000 Btu/hr.

in the average cost of heat to all consumers, the resulting increase in the average cost would be very small.

6.6.6 Residential Living Space

Estimates are shown in Fig. 78 of the effects of the net residential enclosed living space per person at a constant area population density on the heat costs of the reference city. In determining these costs the following assumptions were made:

1. The consumption of heat only for space heating and air conditioning of the residential buildings would be affected by a change in the residential living space.
2. The piping length and pressure distribution would remain constant.
3. The cost of steam at the energy center would remain constant.

The heat supplied annually for district heating, based on these assumptions, is given in Table 52.

It may be seen from Fig. 78 that the cost of heat in the reference city is not a particularly sensitive function of the space allocation in the range of 200 to 350 ft^2 per person. For example, a decrease from the

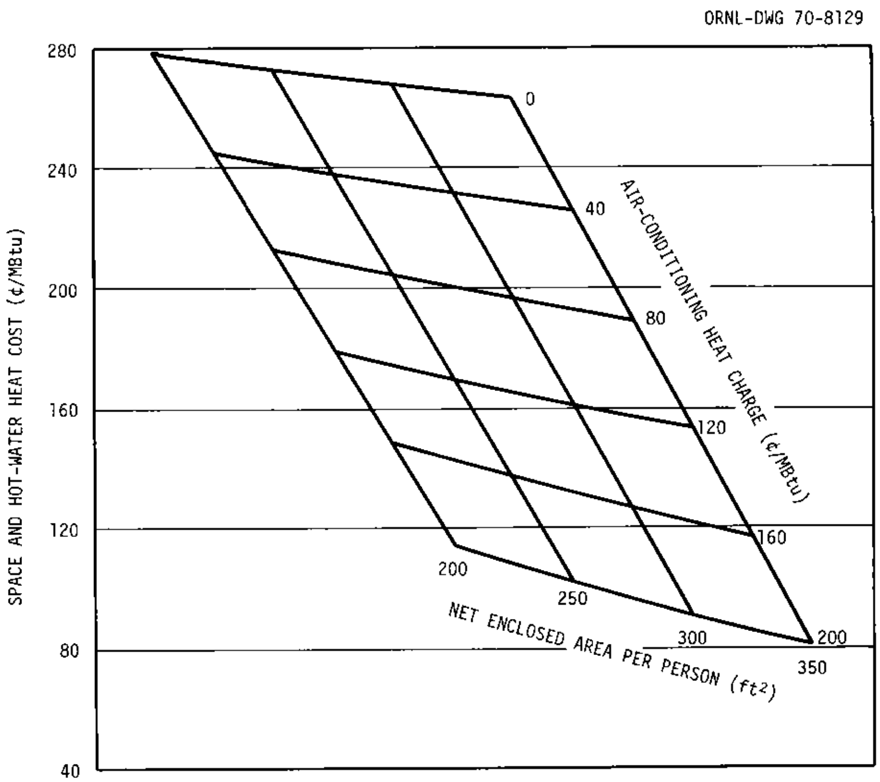

Fig. 78. Effects of Residential Living Space on Cost of District Heat Supplied from an Energy Center with Cooling Towers and No Greenhouses.

Table 52. Variation in Annual Heat Consumption with Residential Living Space Allowance

Living Space (ft^2/person)	Annual Heat Requirement (Btu)			
	For Space Heating	For Air Conditioning	For Water Heating	Total
	$\times 10^{12}$	$\times 10^{12}$	$\times 10^{12}$	$\times 10^{12}$
200	3.34	4.94	2.70	10.98
250	3.96	5.67	2.70	12.33
300	4.58	6.41	2.70	13.69
350	5.20	7.15	2.70	15.05

300 ft^2 per person used in the reference city to 225 ft^2 per person would increase the cost of heat for space and water heating from 198¢/MBtu to only 210¢/MBtu.

6.6.7 Duration of Heating Season

The effects of the length of the heating season on the heat costs of the reference city are shown in Figs. 79 and 80 for climates having

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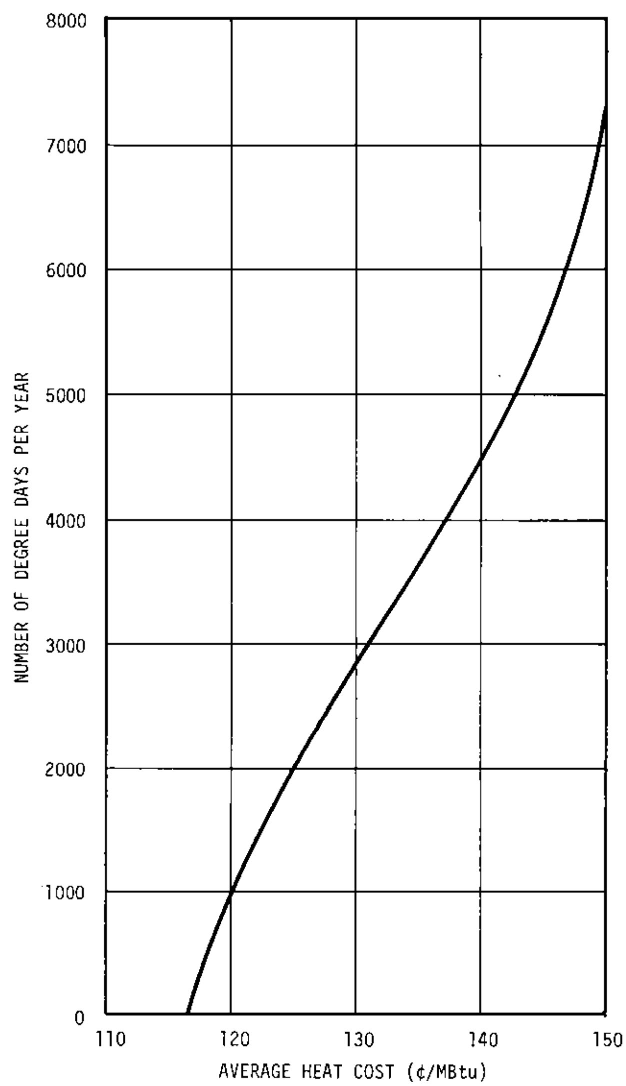

Fig. 79. Effect of Length of Heating Season for Climates Between 0 and 7222 Degree Days on Average Cost of District Heat from an Energy Center with Cooling Towers and No Greenhouses.

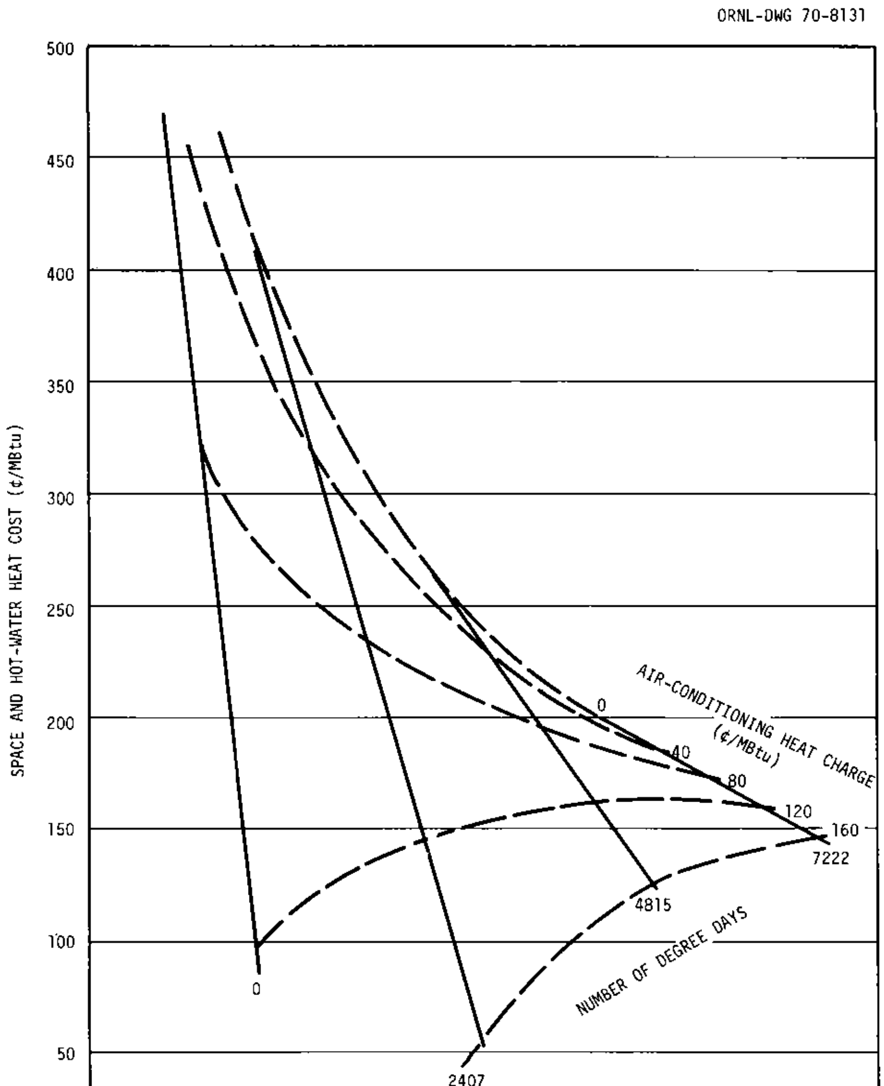

Fig. 80. Effect of Length of Heating Season on Cost of District Heat from an Energy Center with Cooling Towers and No Greenhouses.

between 0 and 7222 degree days. In determining these values it was assumed that the fraction of the year during which the buildings were heated was directly proportional to the number of degree days and that in the remaining part of the year, air conditioning was required. Also the approximation was made that the peak air-conditioning load for the district system did not vary with climate. The annual heat consumption from the district system using this assumed distribution of heating and cooling seasons is shown in Table 53.

Figure 80 shows that the cost of thermal energy, or the average cost of district heat, becomes less if the city is located in warmer climates. However, from Figs. 79 and 80 it may be seen that if the charge for large quantities of heat for air conditioning in places with warmer climates was below the average cost of heat, the cost of heat for space and water heating would be greater than that in the reference city. Figures 79 and 80 also show that with a fixed charge for air-conditioning heat that is less than the average cost of heat, the costs for space heating and water heating in places with colder climates would be less than for the reference city.

For climates with more than about 7222 degree days the peak air-conditioning load would decrease rapidly with increasing number of degree days, distribution systems would become smaller until the peak heating load became the size-determining factor, and the average cost of heat would be in approximately the 140 to 160¢/MBtu range, with the exact cost depending on the particular geographical location.

In a climate with 7222 degree days of heating and a charge of 79¢/MBtu for absorption air-conditioning heat that results in the same energy costs as electricity at 16 mills/kwhr for compressive air conditioning, the cost for space and water heating would be approximately 170¢/MBtu,

Table 53. Variation of Annual Heat Consumption with Length of Heating Season

Degree Days	Annual Heat Consumption (Btu)			
	For Space Heating	For Air Conditioning	For Water Heating	Total
	$\times 10^{12}$	$\times 10^{12}$	$\times 10^{12}$	$\times 10^{12}$
0	0	15.39	2.70	18.09
2407	2.29	10.9	2.70	15.89
4815	4.58	6.41	2.70	13.69
7222	6.87	3.21	2.70	12.78

according to Fig. 80. If the reference city were located in a climate with 2407 degree days of heating and the charge for absorption air-conditioning heat was 79¢/MBtu, the cost of space and water heating would be approximately 235¢/MBtu. The 2407-degree-day climate is similar to that of Atlanta, Georgia, with 2826 degree days, that of Fort Worth, Texas, with 2361 degree days, and that of San Jose, California, with 2410 degree days. However, small increases in the heat charge for air conditioning would lower the cost for other purposes rather rapidly. In an extremely warm climate with zero degree days the average heat cost (from Fig. 79) would be 117¢/MBtu. With the same charge for both water and air-conditioning heat, the air-conditioning energy cost would be equivalent to 23.6 mills/kwhr of electricity for compressive air conditioning. With a charge of 14 mills/kwhr for water heating, the air-conditioning energy cost would be equivalent to 14 mills/kwhr of electricity for compressive systems.

If it is assumed that in the 1975-1980 period, either space or water heating charges higher than 235¢/MBtu or air-conditioning charges higher than the 16 mills/kwhr electrical equivalent would not be desirable, the estimates given above indicate that the economic feasibility of locating the reference city in climates having less than about 2400 degree days of heating is questionable. It also can be seen that if only the 235¢/MBtu limit for water heating were applied to the zero degree day climate, the charge for air-conditioning energy would be equivalent to 20 mills/kwhr of electricity for a compressive system, and it would be feasible to locate the reference city in places in the very southern portion of the country where the electricity cost for air conditioning would be higher than 20 mills/kwhr. A decrease in heat costs and changes in the estimated lower limits for degree days and existing area power costs could be brought about by elimination of most of the transmission main between the energy center and the city, which according to Table 47 costs $25 million out of a total of $84.5 million for the distribution system. This might come about by the use of fossil-fueled plants or future changes in nuclear reactor siting practice.

7. CONCLUSIONS AND RECOMMENDATIONS

It is concluded from this study that with coordinated planning of the cities and power plants, it would be feasible in the 1975-1980 period and beyond to supply low-cost thermal energy from steam-electric power plants to new cities, especially those in the population range of 200,000 to 400,000. With respect to climate the cities could be located anywhere in the continental United States, except perhaps in the most southern portion. In those very southern regions it would be feasible only in those areas that had very high energy costs. The nature of the terrain would also have an important bearing on the feasibility of a location, particularly because of its effect on the cost of trenching for underground piping. An appreciable fraction of the buildings of the city would be concentrated in commercial areas or in low-rise apartment or town-house complexes. If nuclear reactors were the source of energy, their siting with respect to concentrations of people could be in keeping with present-day practice.

The use of thermal energy extracted from the turbines of the generating plants would be economically attractive. For example, in one configuration of a 1980 reference city with a population of 389,000 people and a climate similar to that of Philadelphia, Pennsylvania, the cost of distributed hot water to commercial and low-rise apartment areas was estimated to be 142.5¢/MBtu. If the charge for heat for absorption air conditioning were set at 79¢/MBtu, in order to equal the energy cost for compression systems supplied with 16 mills/kwhr electricity, the charge for space heating and domestic hot water would be 198¢/MBtu. On the average such a system would be competitive in the sense that its use would result in an approximately equal cost as compared with other systems. Whether it would be competitive on this basis in any particular location would depend considerably on the local costs of fossil fuels and electricity and the incentive for reducing air pollution and thermal pollution. The determination of whether it would be economically feasible to provide thermal energy to presently existing cities from electric power plants would require a separate study of the detailed layout and long-range goals of each of them.

The thermal energy could be used mainly for providing buildings with space heat, domestic hot water, and energy for air-conditioning equipment and for manufacturing process heat. There are also other applications, such as the propulsion of urban transportation vehicles, the desalting of sewage plant effluent to provide potable water, the melting of snow, and the heating and cooling of greenhouses. Greenhouses and, in some systems, snow melting, would utilize warm water from the power plant condensers. The greenhouses would also dissipate waste heat that was not required to provide them with heat or evaporative cooling, and a sufficiently large greenhouse installation would eliminate the need for cooling towers.

The utilization of generating plant heat for space heating, hot-water supply, manufacturing process heat, and transportation energy would constitute not only beneficial use of the heat but, in each application, it would usually replace fossil-fuel burning and its accompanying pollution of the atmosphere and thermal additions to the biosphere. No cost credits are taken for reducing air pollution or easing problems associated with thermal emissions. With extracted heat from the generating plant distributed as hot water or steam to air condition the buildings of the urban area by means of absorption refrigeration systems, or with steam distributed to power compressive systems, the thermal energy from the generating plants would be released at numerous sites throughout the area. This would result in easing the problem of concentrated heat release at the generating plant. The total thermal release to the biosphere from absorption air conditioning with extracted heat would be approximately the same as with the generation of electricity and use of motor-driven compressive systems.

In consideration of the urgency of the present pollution and conservation problems, it would be worthwhile to select an existing city for a conceptual design study that would determine the application and uses of thermal energy, develop an implementation plan, and carry out an economic analysis. The results would not only apply to the chosen city but they would also aid in making estimates of feasibility for other cases. It is also recommended that a program be established to determine specifically where new power plants could be sited to provide low-cost thermal energy, as well as electricity, to new cities and existing urban areas.

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