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District Heating/Cogeneration Application Studies for the Minneapolis–St. Paul Area

A Net Energy Analysis of a Cogeneration–District Heating System and Two Conventional Alternatives

John C. Yeoman

OPERATED BY
UNION CARBIDE CORPORATION
FOR THE UNITED STATES
DEPARTMENT OF ENERGY

Printed in the United States of America. Available from
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road, Springfield, Virginia 22161
NTIS price codes—Printed Copy: A03 Microfiche A01

ORNL/TM-6830/P6
Dist. Category UC-95d

Contract No. W-7405-eng-26

ENGINEERING TECHNOLOGY DIVISION

ENERGY DIVISION

DISTRICT HEATING/COGENERATION APPLICATION STUDIES
FOR THE MINNEAPOLIS-ST. PAUL AREA

A NET ENERGY ANALYSIS OF A COGENERATION-DISTRICT HEATING SYSTEM AND TWO CONVENTIONAL ALTERNATIVES

John C. Yeoman

Date Published — October 1979

Research sponsored by the Division of Advanced Nuclear
Systems and Projects, Department of Energy

Prepared by the
OAK RIDGE NATIONAL LABORATORY
Oak Ridge, Tennessee 37830
operated by
UNION CARBIDE CORPORATION
for the
DEPARTMENT OF ENERGY

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ABSTRACT

As part of a series of studies on the institutional and technical aspects of cogeneration and district heating, a net energy analysis has been performed on three systems for providing space heating, space cooling, domestic hot water, and domestic electricity for an idealized community located in a climate similar to that of Minneapolis, Minnesota. The three systems are an all-electric system, a gas-electric system, and a cogeneration-district heating system. The capital and operating energy costs were determined, and a life cycle energy cost analysis was performed. Results of the life cycle energy cost analysis show that the cogeneration-district heating system consumes about half as much primary energy as the all-electric system and four-fifths as much primary energy as the gas-electric system. In the gas-electric and all-electric systems, coal provides 39% and 70%, respectively, of the operating energy. Coal provides 76% of the annual operating energy for the district heating system. Because the district heating system consumes primarily coal rather than scarce and more expensive crude oil and natural gas, it depends less on foreign sources of fossil fuel.

1. INTRODUCTION

1.1 Purpose

This report presents a net energy analysis of three alternative systems for providing space heating, space cooling, domestic hot water, and domestic electricity in an idealized community. The three alternatives are an all-electric system, a gas-electric system, and a cogeneration-district heating system. The costs of both capital and operating energy over the estimated system lifetimes are calculated so that a life cycle energy cost can be determined.

A net energy analysis determines the energy made available to society by energy production processes after the deduction of the energy lost to society as a result of the processes. Advocates of net energy analysis maintain that conventional economic evaluations of energy production processes are inadequate to determine the energy cost of the processes. The principal reason for the alleged deficiencies is that traditional economic theory fails to account for economic subsidies for energy production. These subsidies result primarily from controls on the price of fossil fuels. Price controls distort the market mechanism and therefore misrepresent the true cost of the fossil fuels.[1]

1.2 Community Definition

The idealized community being analyzed is assumed to experience the climate of Minneapolis, Minnesota. The community has a population of 1,175,040 and occupies an area of 544 km^2. The community is composed entirely of two-story garden apartment buildings identical to those studied extensively in ORNL/HUD/MIUS-25.[2] Appendix A gives more-detailed information on the assumed physical characteristics of the buildings.

Each building contains 12 apartments arranged as shown in Fig. 1.1. The apartment buildings are grouped into 60-building clusters as shown in Fig. 1.2. Four clusters are arranged as shown in Fig. 1.3 to cover an area of 2.59 km^2. The total community is comprised of 120 four-cluster units dispersed over the 544-km^2 area. The total number of apartments is 345,600.

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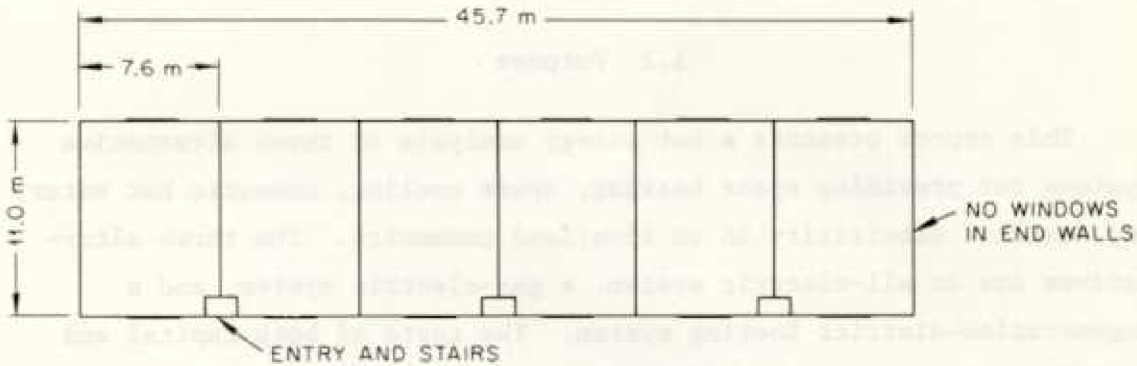

Fig. 1.1. A typical two-story apartment building (12 apartments).

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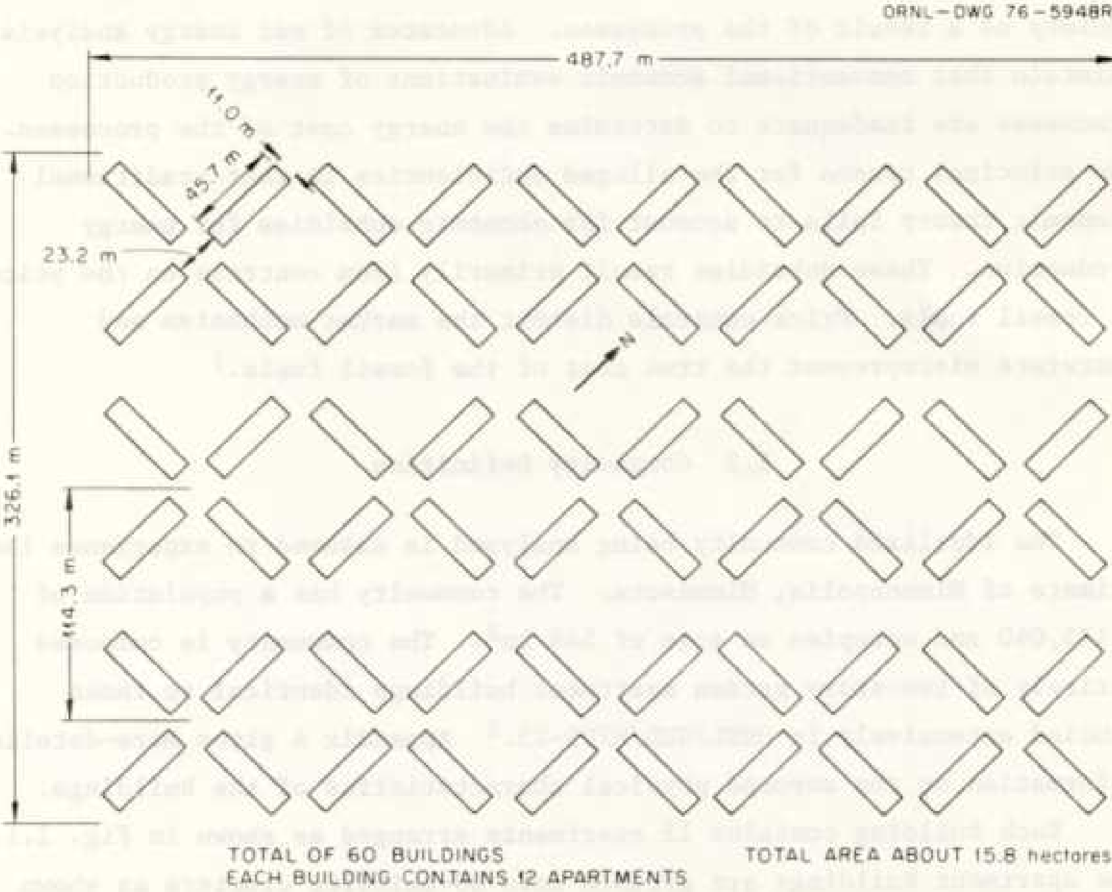

Fig. 1.2. A cluster of 60 apartment buildings (720 apartments).

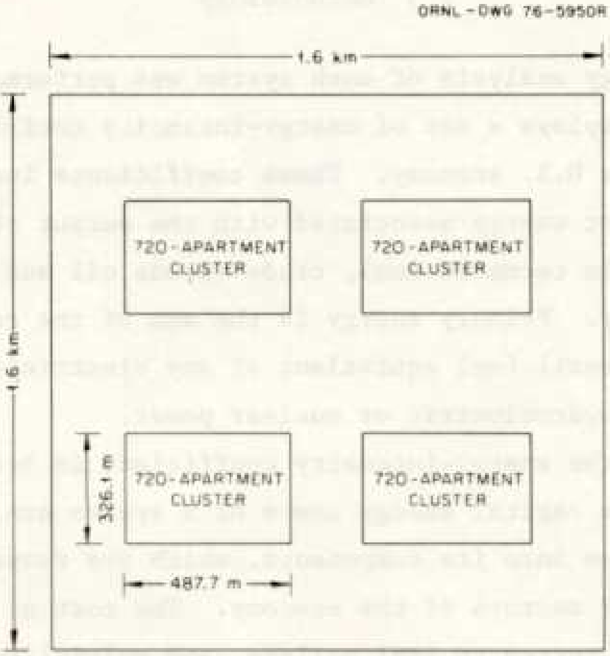

Fig. 1.3. A four-cluster unit (2880 apartments).

The peak heating, cooling, and electrical demands of each apartment are given in Table 1.1. The demands have been calculated on the basis of the climate in Minneapolis. The peak heating demand of the community is 5.4 MW(t)/km^2, which is low compared with that of typical northern cities because the apartment buildings are relatively dispersed. The annual energy usages of each apartment are also given in Table 1.1.

Table 1.1. Peak energy demands and annual usage per apartment

	Peak demand (kW)	Annual usage (kWhr)
Space heating	7.0	10,991
Space cooling	5.0	6,301
Hot water	1.4	5,363
Space heating and hot water	7.9	16,354
Diversified domestic electricity	1.25	6,500

Source: W. R. Mixon et al., *Technology Assessment of Modular Integrated Utility Systems*, ORNL/HUD/MIUS-25 (December 1976).

1.3 Methodology

The net energy analysis of each system was performed by input-output analysis, which employs a set of energy-intensity coefficients for 357 sectors of the U.S. economy. These coefficients include all the direct and indirect energy associated with the output of each sector and are reported in terms of coal, crude (crude oil and natural gas), and primary energy. Primary energy is the sum of the coal and crude energy plus the fossil fuel equivalent of any electricity consumed that was generated by hydroelectric or nuclear power.

The unit of the energy-intensity coefficient is Btu of output per 1967 dollar.[3] The capital energy costs of a system are obtained by breaking the system into its components, which are respectively assigned to each of the 357 sectors of the economy. The cost of each component is determined, converted to 1967 dollars, and multiplied by the appropriate energy-intensity coefficient. The result is the amount of coal, crude, and primary energy that each component of the system requires for manufacture and assembly. The component energy costs are then summed to give the total capital energy cost of the system.

The operating energy cost of a system is determined by calculating the efficiency with which the system converts coal, crude, and primary energy into final products. The total amount of final product (space heating, space cooling, domestic hot water, or domestic electricity) is then divided by the conversion efficiencies to give the total operating energy costs.

Several assumptions were made in this net energy analysis. First, the capital energy cost of apartment equipment common to all three systems was neglected. This equipment includes condensate drain, controls, concrete pads for the outdoor unit, and ducts. The capital energy cost of these items is minor, and since the items are common to the three systems, they will not affect any comparisons.

The capital energy cost of transporting all the components of all three systems was also neglected because the absolute difference between the transportation capital energy cost for different systems was judged to be insignificant. The capital energy cost of the electrical distribution system was also neglected because it is insignificant compared with the other capital costs. The gas-electric and district heating systems have the same electrical distribution system. The electrical distribution system of the all-electric system carries larger loads than the other systems do, but neglecting it does not appreciably affect the capital energy costs of the system.

In all the systems, electrical reserve capacity is assumed to be supplied by the utility grid. In the district heating system, reserve heating capacity is provided for the largest heating unit, the cogeneration power plant. The reserve heating capacity is supplied by extra peak heating plants that are not normally needed to meet the peak heating load.

No attempt was made to discount the energy used over the system lifetime. In this analysis, a unit of energy consumed now is as valuable as a unit of energy consumed at some time in the future. In this sense, a net energy analysis differs considerably from an economic analysis.

2. ALL-ELECTRIC SYSTEM

2.1 System Definition

The all-electric system provides space heating and cooling with a heat pump in each apartment. Domestic hot water is provided by an electric water heater in each apartment. Electricity is provided by coal-fired, base-load power plants and gas turbine, peak-load power plants.

A peak generating capacity of 3018 MW(e) is required by the all-electric system. The system consumes 8854×10^6 kWhr of electricity annually. These figures include transmission and distribution losses of 10% and are based on the apartment load data in Sect. 1.2 and the apartment equipment specifications in Sect. 2.2.

2.2 Capital Energy Costs

The apartment equipment required for the all-electric system consists of a heat pump and an electric water heater. The heat pump, which has a heating capacity of 7.0 kW,[4] is provided with electric resistance heating coils for use when the outdoor temperature drops. It has seasonal heating and cooling coefficients of performance (COP) of 1.5 and 2.1, respectively, in a Minneapolis climate. The heat pump is placed in energy group 5203 (of the 357 energy sectors), refrigeration machinery. The electric water heater has a capacity of 227 liters and is assumed to be 83% efficient.[5] The electric water heater is placed in energy group 4211, fabricated metal products. The capital energy costs of the apartment equipment, given in Table 2.1, are calculated for the entire 30-year life of the system.

Two 600-MW(e) coal-fired power plants provide base-load electric power. Peak-load requirements are satisfied by gas turbine power plants with a total capacity of 1818 MW(e). The capital energy costs per megawatt of electrical generating capacity are derived in Appendix B. Table 2.2 gives the capital energy costs of the generating capacity needed for the all-electric system. The total capital energy costs of the all-electric system are given in Table 2.3.

Table 2.1. Capital energy costs of apartment equipment in an all-electric system

	Cost (1977 dollars)	Lifetime (years)	Number per building	Energy costs (kWhr × 10^6)		
				Coal	Crude	Primary
Heat pump	1,050	10	12	6,221	8,762	16,706
Electric water heater	175	7	12	2,203	2,203	4,634

Table 2.2. Capital energy costs of an all-electric system electrical generation

	Energy costs (kWhr × 10^6)		
	Coal	Crude	Primary
Coal-fired plants	1324	1987	3371
Gas turbine plants	602	903	1572

Table 2.3. Total capital energy costs of the all-electric system

	Energy costs (kWhr × 10^6)		
	Coal	Crude	Primary
Apartment equipment	8,424	10,965	21,340
Electrical generation	1,926	2,890	4,943
Total capital energy cost	10,350	13,855	26,283

2.3 Operating Energy Costs

The operating energy costs of the all-electric system are comprised solely of the operating energy costs of the electric power plants. The operating energy costs of the electric power plants are calculated in Appendix B in terms of units of energy input per unit of energy output.

The assumed load-duration curve for the all-electric system, Fig. 2.1, shows the number of hours per year the electric load is at or below a given load. The area under the curve is equal to the annual electricity consumption, in this case 8854×10^6 kWhr. The load-duration curve allows one to determine what fraction of the total amount of electricity produced is generated by the base-load power plants and what fraction is generated by the peak-load power plants.

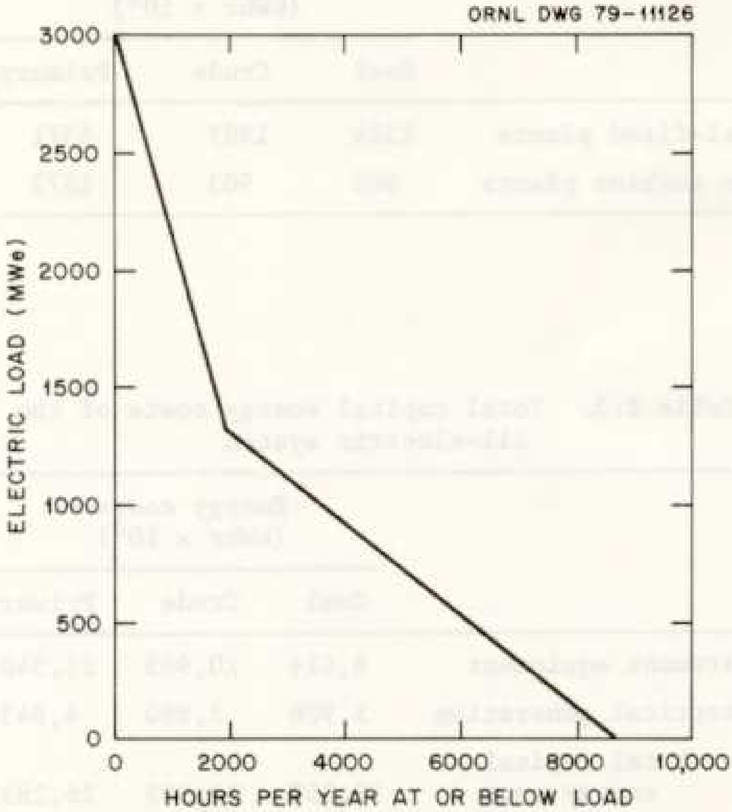

Fig. 2.1. The assumed load-duration curve for the all-electric system.

The coal-fired, base-load power plants generate 6876×10^6 kWhr, or 78% of the electricity consumed annually by the community. The gas turbine, peak-load power plants produce 1978×10^6 kWhr, or 22% of the electricity. The amount of electricity generated by the base-load power plants corresponds to an annual load factor of 65%.

The annual operating energy costs of the all-electric system can be calculated by multiplying the amount of electricity produced by each type of power plant by its operating energy costs, which are given in Appendix B. The resulting energy costs are given in Table 2.4.

Table 2.4. Annual operating energy costs of the all-electric system

	Energy costs (kWhr $\times 10^6$)		
	Coal	Crude	Primary
Coal-fired plants	21,447	619	22,066
Gas turbine plants	158	8,503	8,661
Total annual operating cost	21,605	9,122	30,727

3. GAS-ELECTRIC SYSTEM

3.1 System Definition

In the gas-electric system, space heating is provided by a gas furnace in each apartment. An electric compressive chiller provides space cooling, and a gas water heater provides domestic hot water. Electricity is provided by coal-fired, base-load power plants and gas turbine, peak-load power plants. Gas is provided to each apartment by a gas utility.

A peak electric generating capacity of 1350 MW(e) is required by the gas-electric system. The system consumes 3560×10^6 kWhr of electricity and 8705×10^6 kWhr of gas annually. These figures are based on the apartment load data in Sect. 1.2 and the apartment equipment specifications in Sect. 3.2. Electric transmission and distribution losses of 10% are included.

3.2 Capital Energy Costs

The apartment equipment required for the gas-electric system consists of a gas furnace, a compressive chiller, and a gas water heater. The gas furnace has a heating capacity of 7.0 kW and is assumed to be 65% efficient. It is placed in energy group 4003, nonelectric heating equipment.

The electric compressive chiller has a capacity of 5.3 kW and a seasonal cooling COP of 2.2; it is placed in energy group 5203, refrigeration machinery.[6] The gas water heater has a capacity of 227 liters, and its efficiency is assumed to be 65%. It is placed in energy group 4211, fabricated metal products. The capital energy costs of the apartment equipment, given in Table 3.1, are calculated for the entire 30-year life of the system.

One 470-MW(e) coal-fired power plant provides base-load electric power. Gas turbine power plants with a generating capacity of 880 MW(e) satisfy peak-load requirements. Table 3.2 gives the capital energy costs of the generating capacity needed by the gas-electric system (see Appendix B).

Table 3.1. Capital energy costs of apartment equipment in the gas-electric system

	Cost (1977 dollars)	Lifetime (years)	Number per building	Energy costs ($kWhr \times 10^6$) Coal	Crude	Primary
Gas furnace	243	20	12	1085	1405	2613
Compressive chiller	600	10	12	3705	5225	9437
Gas water heater	200	7	12	2634	2634	5537

Table 3.2. Capital energy costs of electrical generation by the gas-electric system

	Energy costs ($kWhr \times 10^6$)		
	Coal	Crude	Primary
Coal-fired plant	519	778	1355
Gas turbine plants	291	437	761

The capital energy costs of a gas utility are fully derived in Appendix C. The total capital energy costs of the gas-electric system are given in Table 3.3.

Table 3.3. Total capital energy costs of the gas-electric system

	Energy costs ($kWhr \times 10^6$)		
	Coal	Crude	Primary
Apartment equipment	7,424	9,264	17,587
Electrical generation	810	1,215	2,116
Gas utility	658	5,127	5,869
Total capital energy cost	8,892	15,606	25,572

3.3 Operating Energy Costs

The operating energy costs of the gas-electric system consist of those of the electric power plants and the gas utility. The operating energy costs per unit of energy delivered by the gas utility are derived in Appendix C.

The assumed electric load-duration curve for the gas-electric system is shown in Fig. 3.1. The annual electricity consumption of this system is 3560×10^6 kWhr. The coal-fired, base-load power plants generate 2670×10^6 kWhr, or 75% of the electricity consumed by the community. The gas turbine peak-load plants generate 890×10^6 kWhr, or 25% of the electricity. The amount of electricity generated by the base-load power plants corresponds to an annual load factor of 65%. Table 3.4 gives the annual operating energy costs of electrical generation.

The total annual operating energy costs of the gas-electric system are given in Table 3.5.

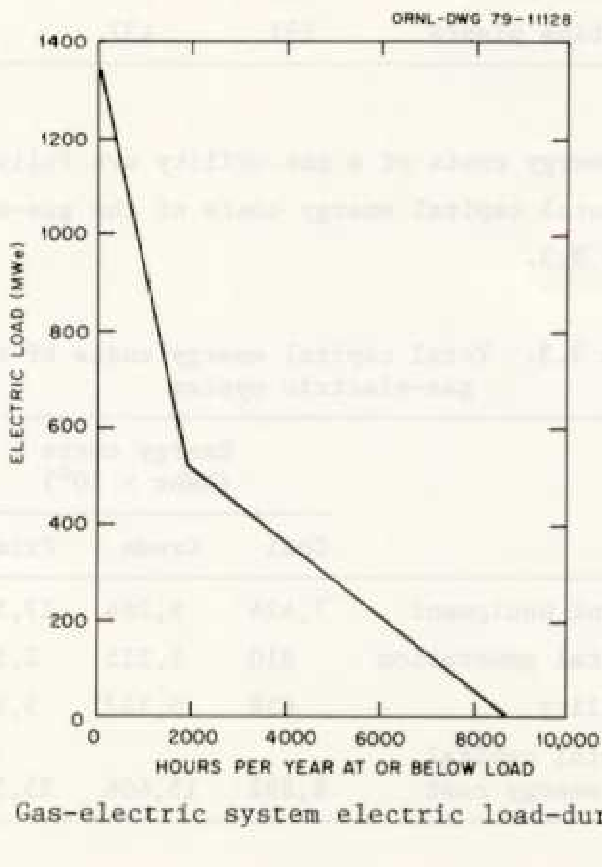

Fig. 3.1. Gas-electric system electric load-duration curve.

Table 3.4. Operating energy costs of electrical generation by the gas-electric system

	Energy costs (kWhr × 10^6)		
	Coal	Crude	Primary
Coal-fired plants	8328	240	8568
Gas turbine plants	71	3826	3897

Table 3.5. Annual operating energy costs of the gas-electric system

	Energy costs (kWhr × 10^6)		
	Coal	Crude	Primary
Electrical generation	8,399	4,066	12,465
Gas utility	76	9,431	9,518
Total annual operating costs	8,475	13,497	21,983

4. DISTRICT HEATING SYSTEM

4.1 System Definition

The district heating system provides space heating and domestic hot water by distributing thermal energy from a coal-fired cogeneration power plant and peak heating plants to each apartment building by means of a 149°C hot water distribution system. Within each apartment building, a secondary thermal distribution system carries heat from a heat exchanger in the basement to a fan-coil heat exchanger unit in each apartment. Space cooling is provided by an electric compressive chiller in each apartment.

The coal-fired cogeneration power plant is assumed to be located 40.3 km from the community. Thermal backup for the plant is provided by extra peak heating plants with a capacity equal to the peak heat production of the cogeneration power plant.

A peak electric generating capacity of 1350 MW(e) and a peak heat production capacity of 2950 MW(t) are required by the system. The system consumes 3560×10^6 kWhr of electricity and 6081×10^6 kWhr of heat annually, including electric transmission and distribution losses of 10% and heat transmission losses of 7.5%. The figures are based on the apartment load data in Sect. 1.2 and the apartment equipment specifications in Sect. 4.2.

4.2 Capital Energy Costs

The equipment required for the district heating system consists of a fan-coil unit, an electric compressive chiller, and a hot water tank and heat exchanger in each apartment. Additionally, each apartment building requires a heat exchanger in the basement, a piping system to distribute thermal energy throughout the building, and pumps.

The fan-coil unit has a heating capacity of 7.0 kW (ref. 2). It is placed in energy group 4211, fabricated metal products. The electric compressive chiller, the same as the one for the gas-electric system, has a capacity of 5.3 kW and a seasonal cooling COP of 2.2. It is placed in energy group 5203, refrigeration machinery. The hot water tank has a capacity of 227 liters and the heat exchanger has a capacity of 1.4 kW. They are placed in energy group 4211, fabricated metal products.[2]

The building heat exchanger has a capacity of 95 kW, and it is placed in energy group 4211, fabricated metal products. The necessary piping is placed in energy group 4208, pipe; the pumps are placed in energy group 4901, pumps.[2] The capital energy costs of the apartment equipment, given in Table 4.1, are calculated for the entire 30-year life of the system.

Table 4.1. District heating system apartment equipment capital energy costs

	Cost (1977 dollars)	Lifetime (years)	Number per building	Energy costs ($kWhr \times 10^6$)		
				Coal	Crude	Primary
Fan-coil unit	245	10	12	2245	2245	4726
Electric compressive chiller	600	10	12	3704	5223	9434
Hot water tank/heat exchanger	150	7	12	1966	1966	4135
Heat exchanger	8970	30	1	1511	1519	3191
Pumps	575	10	1	231	305	557
Piping	575	30	1	84	127	253

A coal-fired cogeneration power plant with a rated capacity of 810 MW(e) provides base-load electric power. At rated capacity, the plant can supply heat at a rate of 1183 MW(t), 1.46 times its electricity production. The power plant has a maximum generation capacity of 890 MW(e) and a heat production rate of 690 MW(t). The complete design and performance characteristics of the plant can be found in ref. 7. The cogeneration power plant was sized to meet approximately half the peak heat demand. Peak-load electricity requirements are satisfied by gas turbine power plants with a capacity of 460 MW(e). Table 4.2 gives

Table 4.2. Capital energy costs of district heating system electrical generation

	Energy costs (kWhr × 10^6)		
	Coal	Crude	Primary
Coal-fired plant	894	1340	2334
Gas turbine plants	152	229	398

the capital energy costs of the electrical generating capacity necessary for the district heating system (Appendix B).

The thermal distribution system can be divided into three distinct parts, the 40.3-km transmission line from the power plant to the community, distribution within the community from the main pipe to each 60-building cluster, and distribution within each 60-building cluster. The community thermal distribution system is shown in Figs. 4.1 and 4.2. Figure 4.3 shows the community thermal distribution system between the

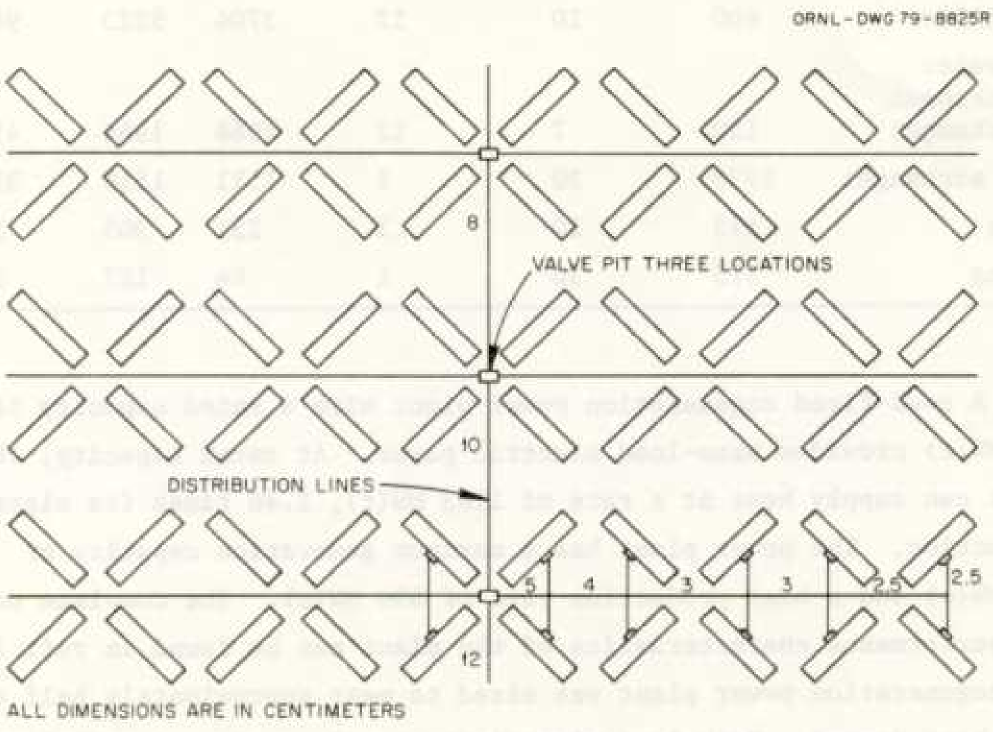

Fig. 4.1. Thermal distribution system for a 60-building cluster. Dimensions pertain to pipe diameters.

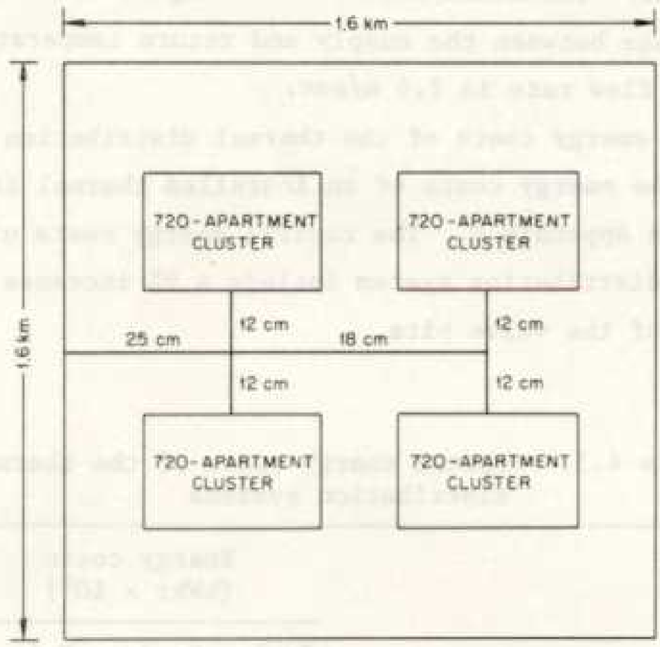

Fig. 4.2. A four-cluster unit with its thermal distribution system. Dimensions pertain to pipe diameters.

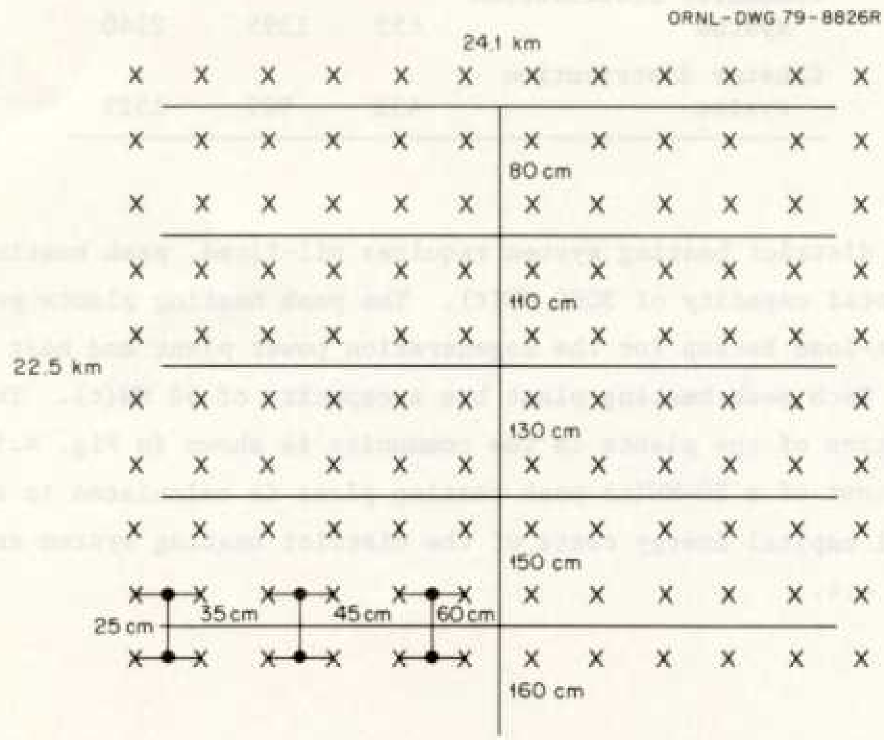

Fig. 4.3. A community thermal distribution system. Each "X" represents a four-cluster unit; each "•" represents a peak heating plant. Dimensions given in centimeters pertain to pipe diameters.

four-cluster units. The assumptions for sizing the distribution lines are that the difference between the supply and return temperatures is 67°C and that the maximum flow rate is 2.4 m/sec.

The capital energy costs of the thermal distribution system are given in Table 4.3. The energy costs of an installed thermal distribution system are calculated in Appendix D. The capital energy costs of the 60-building-cluster thermal distribution system include a 9% increase to account for the energy cost of the valve pits.

Table 4.3. Capital energy costs of the thermal distribution systems

	Energy costs ($kWhr \times 10^6$)		
	Coal	Crude	Primary
Transmission line, 40.3 km	677	1238	2127
Community distribution system	655	1395	2140
Cluster distribution system	431	989	1529

The district heating system requires oil-fired, peak heating plants with a total capacity of 3000 MW(t). The peak heating plants provide both base-load backup for the cogeneration power plant and heat for peak demand. Each peak heating plant has a capacity of 50 MW(t). The distribution of the plants in the community is shown in Fig. 4.3. The capital cost of a 50-MW(t) peak heating plant is calculated in Appendix E. The total capital energy costs of the district heating system are given in Table 4.4.

Table 4.4. Total capital energy costs of the district heating system

	Energy costs ($kWhr \times 10^6$)		
	Coal	Crude	Primary
Apartment equipment	9,741	11,385	22,296
Electrical generation	1,046	1,569	2,732
Thermal distribution system	1,763	3,622	5,796
Peak heating plants	1,038	1,070	2,223
Total capital energy cost	13,588	17,646	33,047

4.3 Operating Energy Costs

The operating energy costs of the district heating system are comprised of those of the cogeneration power plant, the electric peak-load gas turbine plants, and the peak heating plants. The operating energy costs of the peak heating plants are calculated in Appendix E.

The load-duration curve for the district heating system is shown in Fig. 4.4. The cogeneration power plant produces annually 4681×10^6 kWhr, or 77% of the required heat. The peak heating plants produce 1400×10^6 kWhr, or 23% of it. The electric load-duration curve for the district heating system is identical to that of the gas-electric system (Fig. 3.1). The cogeneration power plant generates 3054×10^6 kWhr, or 86% of the electricity required by the community. The gas turbine, peak-load plants generate 506×10^6 kWhr, or 14%.

The cogeneration power plant was sized to meet approximately half the heat load of the community. It is oversized for the electrical needs of the community and thus possesses excess generating capacity. Assuming an annual load factor of 65% and a market for the extra electricity generated, the cogeneration power plant will generate 4612×10^6 kWhr annually. This is 1558×10^6 kWhr more than the

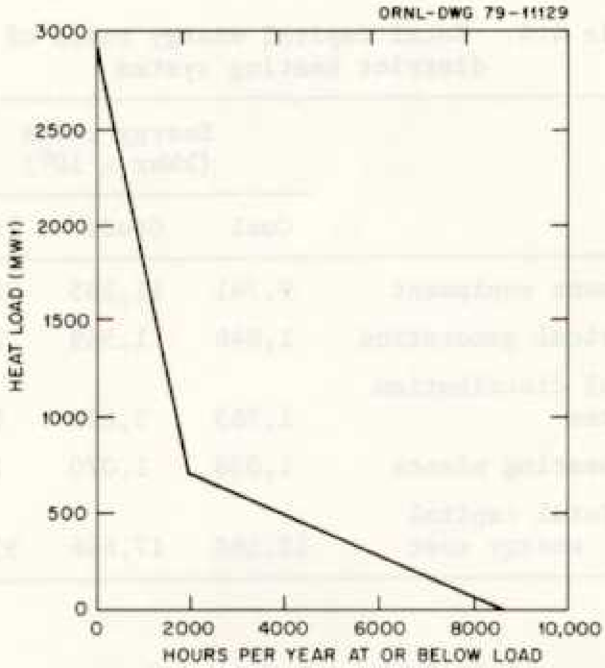

Fig. 4.4. District heating system heat load-duration curve.

3054×10^6 kWhr of electricity required by the community. The electric load-duration curve (Fig. 3.1) shows that the power plant must operate at its maximum electrical capacity of 890 MW(e) for 1100 hr/year. It must also operate at an average electrical output of 850 MW(e) for 250 hr/year. Thus, the cogeneration power plant must generate 3420×10^6 kWhr while operating at its rated capacity of 810 MW(e) and 1183 MW(t). This corresponds to operating at its rated capacity for 4223 hr/year.

The operating energy requirements of the district heating system may be summarized as follows. The peak heating plants must produce 1400×10^6 kWhr of heat; the peak-load gas turbine plants must generate 506×10^6 kWhr of electricity; and the cogeneration power plant must generate 4612×10^6 kWhr of electricity, 1558×10^6 kWhr of which is excess. The cogeneration power plant operates at 890 MW(e) for 1100 hr/year, 850 MW(e) for 250 hr/year, and 810 MW(e) for 4223 hr/year.

The operating energy costs of the district heating system are given in Table 4.5. Because the excess electricity generated can be sold to the utility grid, it is reconverted to its fossil fuel equivalent and

Table 4.5. Annual operating energy costs of the district heating system

	Energy costs (kWhr × 10^6)		
	Coal	Crude	Primary
Cogeneration plant	17,914	93	18,007
Gas turbine plant	40	2,175	2,215
Peak heating plant	15	1,875	1,890
Subtotal: plant operation energy costs	17,969	4,143	22,112
Excess electricity equivalent	-4,860	-140	-5,000
Total operating energy costs	13,109	4,003	17,112

subtracted from the operating energy costs of the district heating system. It is reconverted to its fossil fuel equivalent by using the operating energy costs of the coal-fired, base-load power plant. Appendix B lists these costs.

5. RESULTS AND CONCLUSIONS

5.1 Results

The capital energy costs, annual operating energy costs, and annual life cycle costs of the three systems are given in Tables 5.1, 5.2, and 5.3. The annual life cycle energy cost is defined to be the system lifetime multiplied by the annual operating energy cost summed with the capital energy cost, all divided by the system lifetime.

Table 5.1. Comparison of capital energy costs of three heating systems

	Energy costs ($kWhr \times 10^6$)		
	Coal	Crude	Primary
All-electric system	10,350	13,855	26,283
Gas-electric system	8,892	15,606	25,572
District heating system	13,588	17,646	33,047

Table 5.2. Comparison of annual operating energy costs of three heating systems

	Energy costs ($kWhr \times 10^6$)		
	Coal	Crude	Primary
All-electric system	21,605	9,122	30,727
Gas-electric system	8,475	13,497	21,983
District heating system	13,109	4,003	17,112

Table 5.3. Comparison of annual life cycle energy costs of three heating systems

	Energy costs ($kWhr \times 10^6$)		
	Coal	Crude	Primary
All-electric system	21,950	9,583	31,573
Gas-electric system	8,771	14,017	22,836
District heating system	13,562	4,590	18,213

5.2 Conclusions

This net energy analysis of three alternative systems for providing space heating, space cooling, domestic hot water, and domestic electricity for a large community shows that the cogeneration-district heating system is the most energy efficient. The annual life cycle energy cost analysis shows that the district heating system consumes substantially less energy than either the all-electric system or the gas-electric system. Figure 5.1 shows the cumulative primary energy usage over the lifetimes of the three systems. The district heating system uses 58% as much primary energy as the all-electric system and 80% as much primary energy as the gas-electric system. Figure 5.1 also shows that the operating energy costs dominate the total primary energy consumption of all three systems. The differences in capital energy cost have a negligible effect on the life cycle energy costs.

In the gas-electric and all-electric systems, coal provides 39% and 70%, respectively, of the operating energy. Coal provides 76% of the annual operating energy for the district heating system. Because the district heating system consumes primarily coal rather than scarce and more expensive crude oil and natural gas, it depends less on foreign sources of fossil fuel.

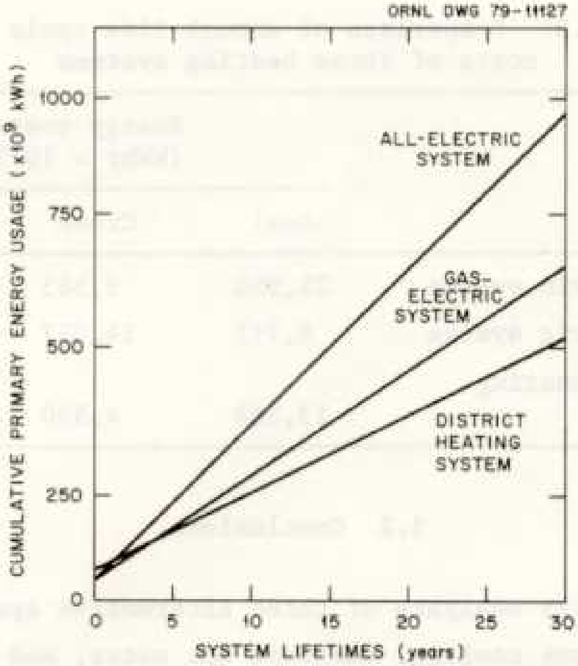

Fig. 5.1. Comparison of cumulative primary energy usage.

Appendix A

APARTMENT CHARACTERISTICS[2]

General data

1. apartment size: 7.6 by 11.0 m (83.6-m^2 floor area);
2. glass area: 8.4 m^2 total (about 4.7 m^2 in front, 3.7 m^2 in rear, shading coefficient of 0.56);
3. window type: double glazed;
4. design ceiling height: 2.4 m;
5. overall heat-transfer coefficients, kWhr m^{-2} °C^{-1}: walls, 6.8×10^{-4}; roof, 2.8×10^{-4}; glass, 34.6×10^{-4};
6. building compass orientation: an equal number of buildings facing north, south, east, and west;
7. air changes for ventilation: 0.057 m^3/sec year-round;
8. indoor design conditions: 23°C dry-bulb temperature with ±1°C temperature band, 50% relative humidity (summer control).

Domestic hot water

1. 65.5°C water;
2. 219 liters/day per apartment.

Domestic electricity

1. 110/220 V supplied to each apartment;
2. peak diversified load per apartment = 1.25 kW;
3. average annual use per apartment = 6500 kWhr.

Heating and air conditioning schedule

1. heating during the months of January, February, March, April, May, September, October, November, and December;
2. cooling during the months of May, June, July, August, September, and October.

Appendix B
ELECTRIC GENERATION ENERGY COSTS

Capital Energy Costs

The capital energy costs of coal-fired, base-load power plants have been derived from the results reported by Pilati in *Total Energy Requirements for Nine Electricity-Generating Systems*.[8] In that report, the author calculates the capital energy costs of electric power plants on the basis of units of energy per unit of electricity produced annually. Since the load factor of a cogeneration power plant will probably be less than that of a conventional power plant, the capital energy costs in Pilati's report have been converted to units of energy per unit of generating capacity. For this conversion, the power plants in Pilati's report were assumed to operate with an annual load factor of 65%. The resulting capital energy costs are given in Table B.1 in terms of millions of kilowatt-hours per megawatt of rated capacity.

Table B.1. Capital energy costs of a coal-fired power plant (10^6 kWhr/MW)

Coal	Crude	Primary
1.104	1.656	2.882

The capital energy costs of the gas turbine, peak-load power plants were calculated from those of the coal-fired, base-load power plants. The calculation compared the cost per unit of generating capacity of one type of facility with that of the other. The capital energy costs of the gas turbine, peak-load power plants were 30% of those of the coal-fired power plants.

Operating Energy Costs

Pilati's report gives the operating energy costs of a conventional coal-fired, base-load power plant. The operating energy costs are given in Table B.2 along with assumed operating energy costs of the gas turbine power plants.

Table B.2. Operating energy costs
(input energy/output energy)

	Coal	Crude	Primary
Conventional plant	3.12	0.09	3.21
Gas turbine plant	0.08	4.30	4.38

The operating energy costs of the cogeneration power plant have been calculated from the performance characteristics given in ref. 7. Table B.3 gives the operating energy costs for several levels of electrical output.

Table B.3. Cogeneration power plant operating energy costs
(input energy/output energy)

Output [MW(e)]	Coal	Crude	Primary
810	3.97	0.02	3.99
850	3.79	0.02	3.68
890	3.61	0.02	3.63

Appendix C
GAS UTILITY ENERGY COSTS

The energy cost of a gas utility, per unit of energy delivered, and the energy cost of gas production, per unit of gas produced, are given in ref. 3 and shown in Table C.1. The difference between these energy costs is equal to the operating and maintenance energy costs plus some fraction of the capital energy cost of the gas utility. The difference is also given in the table. The fraction of the capital energy cost multiplied by the system lifetime equals the total capital energy cost of the gas utility.

Table C.1. Gas utility and production energy costs (input energy/output energy)

	Coal	Crude	Primary
Gas utility	0.0112	1.1037	1.1166
Gas production	0.0049	1.0546	1.0604
Difference	0.0063	0.0491	0.0562

For a gas utility with a 30-year life, assuming that its operation and maintenance energy costs comprise 60% of the difference and that its capital energy costs comprise 40% of the difference, Table C.2 gives the capital energy costs and annual operating energy costs of such a gas utility based on the amount of energy delivered per year. Because the assumed division of the energy costs between maintenance and capital costs affects only whether the costs appear as capital or operating costs, the total lifetime cost will be the same.

Table C.2. Gas utility energy costs (input energy/output energy)

Energy cost	Coal	Crude	Primary
Capital	0.0756	0.5892	0.6744
Operating	0.0087	1.0841	1.0941

Appendix D

ENERGY COSTS OF THERMAL DISTRIBUTION

The thermal distribution system consists of black steel pipe chosen to satisfy the ASA B31.1 Code for Pressure Vessels for the design temperature, 149°C. The pipe is surrounded by a layer of calcium silicate insulation and then by insulating concrete. The insulating concrete encloses both pipes (supply and return) of the dual-pipe system, as shown in Fig. D.1. The pipeline is buried so that the top of the pipe is 2 m below the ground surface. The cost breakdown for the construction of the thermal distribution system is given in Table D.1.[9]

The labor costs include digging the trench, laying the pipe and concrete insulation, and backfilling the trench. The labor energy costs were set equal to those of sector 1103, new construction of public utilities. The costs of concrete and bedding were combined and equated to energy sector 3610, concrete blocks. The respective costs of the pipe and the expansion loops were also combined and equated to sector 4208, pipe. The energy cost of insulation was set equal to sector 3620, mineral wool.

Reducing the costs in Table D.1 to their 1967 equivalents and performing the required calculations result in Figs. D.2 and D.3, which give the energy cost per meter of an installed thermal distribution system as a function of pipe diameter.

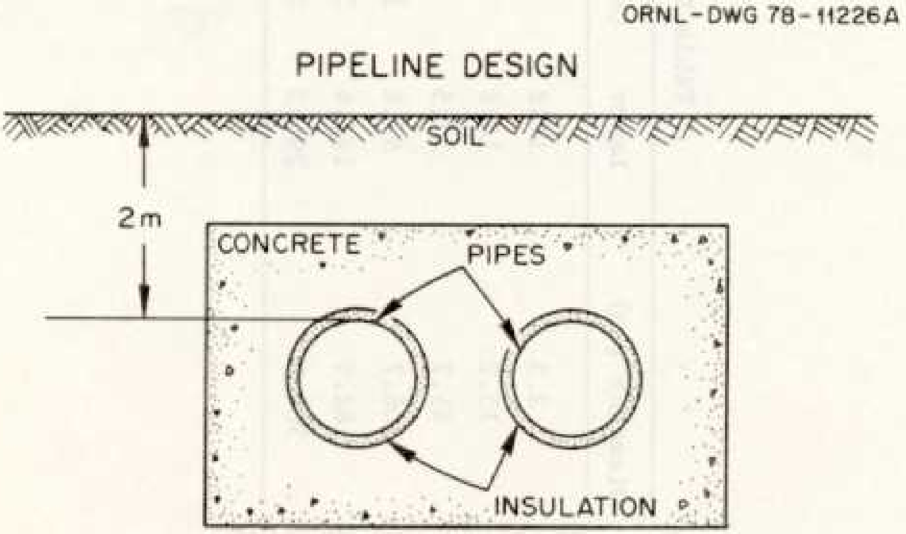

Fig. D.1. The dual-pipe system.

Table D.1. Pipe cost data (1978 dollars per meter)

Diameter (cm)	Labor	Concrete	Bedding	Pipe	Expansion loops	Insulation	Total
2.5	14.8	7.9	3.3	3.6	1.0	14.4	45.0
15.2	14.8	16.1	3.9	24.3	6.9	29.2	95.2
45.7	29.5	46.9	5.6	124.3	37.7	95.5	341.3
106.7	65.6	137.8	8.9	442.9	118.1	291.3	1064.6
182.9	147.6	305.8	12.5	1771.7	403.5	984.3	3625.4
304.8	295.3	721.8	19.0	5150.9	1105.6	2657.5	9950.1

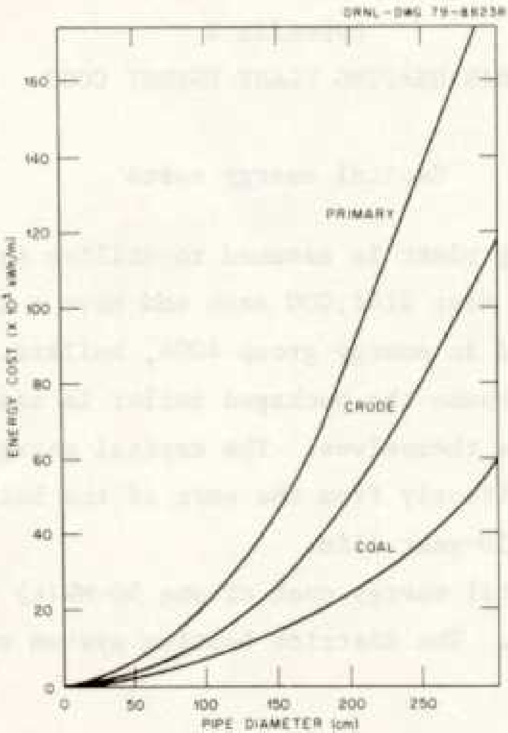

Fig. D.2. Energy cost per meter of an installed thermal distribution system.

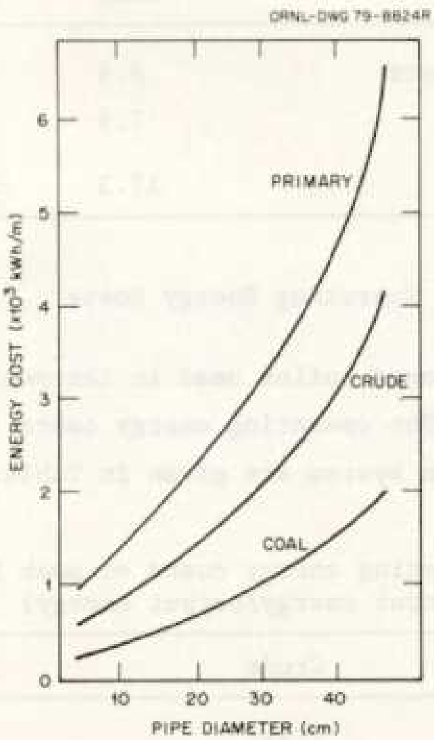

Fig. D.3. Energy cost per meter of an installed thermal distribution system using small pipes.

Appendix E

PEAK HEATING PLANT ENERGY COST

Capital energy costs

Each peak heating plant is assumed to utilize two 25-MW(t), oil-fired packaged boilers that cost $142,000 each and have a 15-year life.[10] The boilers are placed in energy group 4006, boilers.

The building to house the packaged boiler is assumed to cost 1.7 times as much as the boilers themselves. The capital energy cost of the building is derived directly from the cost of the boiler. The building is assumed to have a 30-year life.

The 30-year capital energy cost of one 50-MW(t) peak heating plant is given in Table E.1. The district heating system requires 60 peak heating plants.

Table E.1. Capital energy cost of one 50-MW(t) peak heating plant ($kWhr \times 10^6$)

	Coal	Crude	Primary
Oil-fired packaged boilers	9.4	9.6	20.0
Building	7.9	8.2	17.0
Total	17.3	17.8	37.0

Operating Energy Costs

The oil-fired packaged boiler used in the peak heating plants has an efficiency of 80%. The operating energy costs for heat delivered to the thermal distribution system are given in Table. E.2.

Table E.2. Operating energy costs of peak heating plants (input energy/output energy)

Coal	Crude	Primary
0.01	1.34	1.35

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