MASTER

COSTS OF URBAN AREA RETROFIT TO
DISTRICT HEATING AND COOLING SYSTEMS:
NORTH-CENTRAL CITIES

ARGONNE NATIONAL LABORATORY

ENERGY AND ENVIRONMENTAL SYSTEMS

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

The facilities of Argonne National Laboratory are owned by the United States Government. Under the terms of a contract (W-31-109-Eng-38) between the U. S. Department of Energy, Argonne Universities Association and The University of Chicago, the University employs the staff and operates the Laboratory in accordance with policies and programs formulated, approved and reviewed by the Association.

MEMBERS OF ARGONNE UNIVERSITIES ASSOCIATION

The University of Arizona	Kansas State University	The Ohio State University
Carnegie-Mellon University	The University of Kansas	Ohio University
Case Western Reserve University	Loyola University	The Pennsylvania State University
The University of Chicago	Marquette University	Purdue University
University of Cincinnati	Michigan State University	Saint Louis University
Illinois Institute of Technology	The University of Michigan	Southern Illinois University
University of Illinois	University of Minnesota	The University of Texas at Austin
Indiana University	University of Missouri	Washington University
Iowa State University	Northwestern University	Wayne State University
The University of Iowa	University of Notre Dame	The University of Wisconsin

NOTICE

This report was prepared as an account of work sponsored by the United States Government. Neither the United States nor the United States Department of Energy, nor any of their employees, nor any of their contractors, subcontractors, or their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness or usefulness of any information, apparatus, product or process disclosed, or represents that its use would not infringe privately-owned rights. Mention of commercial products, their manufacturers, or their suppliers in this publication does not imply or connote approval or disapproval of the product by Argonne National Laboratory or the U. S. Department of Energy.

ARGONNE NATIONAL LABORATORY
9700 South Cass Avenue
Argonne, Illinois 60439

COSTS OF URBAN AREA RETROFIT TO
DISTRICT HEATING AND COOLING SYSTEMS:
NORTH-CENTRAL CITIES

by

D.J. Santini
A.A. Davis
S.M. Marder*

Energy and Environmental Systems Division

* ANL Consultant

March 1978

NOTICE
This report was prepared as an account of work sponsored by the United States Government. Neither the United States nor the United States Department of Energy, nor any of their employees, nor any of their contractors, subcontractors, or their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness or usefulness of any information, apparatus, product or process disclosed, or represents that its use would not infringe privately owned rights.

Work sponsored by
U.S. Department of Energy
Assistant Secretary for Conservation and Solar Applications
Buildings and Community Systems Division, Community Systems Branch

This report is available from
National Technical Information Service
5285 Port Royal Road
Springfield, Virginia 22161

TABLE OF CONTENTS

	<u>Page</u>
ABSTRACT.	1
1. OVERVIEW.	1
2. INTRODUCTION.	7
3. SCOPE OF STUDY.	9
3.1 DHCS FEASIBILITY	9
3.2 DHCS FLEXIBILITY	11
4. METHODOLOGY	15
4.1 DEMAND ESTIMATES	15
4.2 ENERGY SUPPLY ANALYSIS	27
4.3 COMPONENT CAPITAL COST ESTIMATES	30
4.4 ANNUALIZED SYSTEM COSTS.	38
5. COMPARISON WITH ALTERNATIVE ENERGY DELIVERY OPTIONS	45
5.1 ALTERNATIVE SYSTEMS.	45
5.1.1 Coal to Electricity to Heat	45
5.1.2 Coal to Gas Via Gasification to Heat.	50
5.1.3 Coal to Oil Via Liquifaction-to-Heat.	51
5.2 COMPARISONS OF ESTIMATES	52
6. ESTIMATES OF SCARCE-FUEL SAVINGS.	55
REFERENCES.	61

LIST OF TABLES

<u>Table No.</u>	<u>Title</u>	<u>Page</u>
1.1	Cost Per Million Btus - Alternate Options (\$).	2
1.2	Fuel Consumption and Scarce-Fuel Savings (Btu x 10 ¹²).	3
3.1	Basic Heat Data on Cities under Study.	10
4.1	City Building Square Footing x 10 ³	17
4.2	Energy Demand Factors (Btu/ft ²).	20
4.3	Results of Existing Retrofit Options	28
4.4	Capital Costs, City/Zone	40
4.5	DHCS-Operation and Maintenance Costs.	41
4.6	Cost per 10 ⁶ Btu @ 20-yr, 8%/20%.	42
5.1	Costs of Coal-Electric Option.	46
5.2	Costs of Coal Gasification Option.	47
5.3	Costs of Coal Liquids Option	48
6.1	Selected Heating/Cooling Characteristics for Residential Units .	57
6.2	Current Fuel Usage-By City	58

LIST OF FIGURES

<u>Figure No.</u>	<u>Title</u>	<u>Page</u>
4.1	Residential Average Day Heating Demand Pattern Illustrated by Computer Graphics for Washington, D.C.	21
4.2	Residential Average Day Heating Demand Pattern Illustrated by Computer Graphics for St. Louis.	22
4.3	Residential Average Day Heating Demand Pattern Illustrated by Computer Graphics for Cleveland.	23
4.4	Residential Average Day Heating Demand Pattern Illustrated by Computer Graphics for Milwaukee.	24
4.5	Residential Average Day Heating Demand Pattern Illustrated by Computer Graphics for Detroit.	25
4.6	Residential Average Day Heating Demand Pattern Illustrated by Computer Graphics for Chicago.	26
4.7	Washington, D.C. - Demand Zones and Supply Lines	31
4.8	St. Louis - Demand Zones and Supply Lines.	32
4.9	Cleveland - Demand Zones and Supply Lines.	33
4.10	Milwaukee - Demand Zones and Supply Lines.	34
4.11	Detroit - Demand Zones and Supply Lines.	35
4.12	Chicago - Demand Zones and Supply Lines.	36

COSTS OF URBAN AREA RETROFIT TO DISTRICT HEATING
AND COOLING SYSTEMS: NORTH-CENTRAL CITIES

ABSTRACT

This study considers the major urbanized areas of six U.S. cities to arrive at reasonably accurate estimates of costs required to retrofit them with district heating and cooling (DHCS) systems. In this study only costs associated with heating and hot water are addressed. Demand estimates and energy supply analyses are made, and component capital costs are estimated to arrive at annualized system costs. Finally, a comparison of alternative energy delivery options is made, and estimates of scarce-fuel savings are derived.

1 OVERVIEW

This study has been undertaken to arrive at reasonably accurate estimates of the costs required to retrofit major portions of six U.S. cities with district heating and cooling (DHCS) systems. Detailed analysis to date has considered district heating. It should be carefully noted by the reader that this study only covers costs of retrofit to a heating and hot water mode. Effects of including cooling will most certainly change the overall cost. Such costs will be the subject of future work. The systems under consideration would primarily involve retrofitting existing electric generating facilities to cogenerate both electric and thermal energy. Secondarily, they would involve existing thermal systems and, in tertiary cases new supplemental boilers would be installed. Costs for district heating and cooling systems in each city were compared against coal-electric, coal gasification, and coal liquefaction options. The results, summarized in Table 1.1, indicate that retrofitting of major metropolitan areas to a district heating mode is within the range of economic feasibility. Furthermore, as costs for energy rise, and as availability of gas and oil decreases, the viability of such a district heating and cooling system increases. This study also estimates potential savings in scarce fuels (oil and gas) created by switching from existing space heat fuel mixes to a cogeneration mode. Results of such estimates are summarized in Table 1.2.

Based on these results, this report generally concludes that President Carter's call for investigation and analysis of a resurgence of cogeneration

Table 1.1. Cost Per Million Btus - Alternate Options (\$)*

City	DES High Est.	DES Low Est.	Coal to Electr.	Coal Gas To Heat	Coal Liquid To Heat
Washington					
8% - 20 yr	11.50	5.22	20.00	6.25	6.51
20% - 20 yr	19.50	8.83	36.43	8.68	9.26
St. Louis					
8% - 20 yr	12.81	5.56	20.13	6.29	6.03
20% - 20 yr	21.65	9.43	36.97	8.72	8.79
Cleveland					
8% - 20 yr	11.54	4.79	16.45	6.29	6.03
20% - 20 yr	19.65	8.30	30.01	8.71	8.79
Milwaukee					
8% - 20 yr	10.16	4.27	14.83	6.30	6.03
20% - 20 yr	17.15	7.28	26.93	8.72	8.78
Detroit					
8% - 20 yr	12.57	5.47	15.31	6.29	6.03
20% - 20 yr	20.95	9.20	27.83	8.72	8.77
Chicago					
8% - 20 yr	9.88	4.56	20.22	6.29	6.03
20% - 20 yr	16.61	7.83	37.11	8.72	8.78

*These represent costs per final Btu of heating services delivered in the building. All conversion steps are included.

Table 1.2. Fuel Consumption and Scarce Fuel Savings (Btu x 10¹²)

	Current Fuel Consumption						Fuel Consumption Co-Generation			Btu Savings		% Scarce Fuel Saved		
	Gas	Oil	Elec.	Coal	Elec.	Oil	Other	Total	Oil/gas	Coal	Total	Total	Oil/Gas*	
Wash.	18.3	20.5	1.4		1.0		5.2	46.4	4.6	17.3	21.9	24.5	35.2	88
St. Louis	31.7	8.6	0.6		0.1		2.2	43.2	4.8	15.9	20.7	22.5	35.6	88
Cleve.	54.4	6.5	1.0		0.1		3.4	65.4	6.5	24.5	31.0	34.4	54.5	89
Mil.	44.3	20.3	1.1		0.1		6.4	72.2	5.6	27.7	33.3	38.9	59.1	91
Detroit	79.1	11.3	1.4		0.3		13.0	105.1	12.5	35.6	48.1	57.0	78.2	86
Chicago	76.3	53.9	2.5		0.6		6.7	140.0	11.0	44.2	55.2	84.8	119.8	92

*Oil/gas savings can be greater than total savings because of substitution of coal for oil and gas as primary fuels.

and district heating was well founded. Additional work will be required, possibly on one target city, to identify more closely the site-specific factors that will determine whether cost estimates will fall within the high or low estimates projected in this study.

Not covered in this report are the myriad of institutional problems that certainly would occur should such an option be chosen. These problems may have more impact than technical or economic considerations. The traditional New York slogan, "Dig We Must," is now often addressed by the question, "Must We Dig?" Economic considerations do not examine the inconvenience factors that arise from closing major traffic arteries for long periods. Retail sales most probably will be affected by traffic diversions, (as well as other segments of the economy). The reaction of state and local officials, as well as the attitude of the public in general, should be assessed.

An equally important factor is that success of the project would require relatively large areas of a city to be retrofitted at once. The option of installing a system and then soliciting users is impractical. Success depends on the availability of a firm user list long before actual construction starts. This implies that there must be a general acceptance by end users, or, alternatively, that government must require the use of such a system. It is most likely that long-term unavailability of fuel will be a gradual occurrence rather than a sharp break. Therefore, use out of necessity will not arise for a large block of potential users at once.

To date, projected shortages of fuels have been met in various ways. Most common have been bans on new gas hookups. For example, in central Illinois new building space owners have the option of electric heat or propane. This new need has been met by gradual increases in electric capacity. This gradual increase in capacity, rather than a large block as would be the case in a DHCS, has mitigated some of the institutional problems. In fact, the potential for the alternatives to DHCS to be phased in slowly through existing, or incrementally expanded, transmission systems, is the strongest argument for their use.

In summary, the DHCS option, which is the object of this study, falls within economic bounds that make it a possible option for the future. Detailed technical analysis and past experience have made it clear that no overruling technical reasons exist to abandon the option. However, institutional problems

need much more detailed study. A possible next step would be to select a city that has the leadership, population attitude, utility company interest, and the potential need for a DHCS and then to begin a detailed evaluation of the applicability of a DHCS for that specific area.

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

2 INTRODUCTION

Previous work has indicated that certain U.S. cities have a fuel saving potential that would warrant a close look at the feasibility of DHCS retrofit.¹ From that list of potential cities, this study considers Washington, D.C., St. Louis, Cleveland, Milwaukee, Detroit, and Chicago. Washington, D.C. has been the subject of a joint study between Argonne National Laboratory and Brookhaven National Laboratory. Those two semi-independent studies have yielded results which, within the scope of techniques used, are relatively close. Such results have prompted Argonne to extrapolate the methodology used in the Washington study to the other cities under consideration.

DHCS, while fraught with institutional problems, can yield significant benefits -- from both an economic and fuel-conservation viewpoint. This study covers, in significantly more detail than past studies, the extent of such benefits. Although it is fairly detailed, this report nevertheless is simply a first step toward potential retrofitting of a major city. For all its sophistication, the study is, in essence, merely a demand-and-supply analysis. Site-specific criteria are utilized in the analysis; however, the criteria are still on a scale that would need significant refinement before a rational design can be made to proceed with a retrofit operation.

The overall purpose of this study is to demonstrate that the concept of DHCS retrofit can hold its own when compared with other options. It should be remembered that there are two events that could foster the serious consideration of a DHCS. This study pre-supposes that either of these two events is possible and, indeed, probable.

The first event possible is that the cost of heat supplied to the type of space considered will accelerate at a rate faster than other items accelerate. Certainly this has been true since 1973 and undoubtedly will continue to be so. For example, the low cost estimate for DHCS retrofit found in Cleveland was \$4.79/10⁶ Btu provided. Should the cost of natural gas or fuel oil reach that level, the DHCS options would be competitive from a purely economic point of view.

A comparison can be made with the cost of home heating fuels now utilized. For example, the cost of residential heating oil in the Midwest in January, 1977 was about 40.75¢/gallon. At approximately 0.14×10^6 Btus/gallon the usable costs (assuming a 67% efficient furnace) would be \$4.34/ 10^6 Btu. Natural gas, at an average price of \$1.91/ 10^6 Btu in a 70%-efficient furnace has an ultimate cost of \$2.72/ 10^6 Btu. This very sophomoric example demonstrates that a projected DHCS cost of \$4.79/ 10^6 is not as out of line as could be assumed at first glance.

The second event that would enhance the practicability of DHCS retrofit involves the possibility that traditional fossil fuels will become unavailable. (at any price) in the quantities needed by the cities. Should this occur, available options for fuel supply must be found. Although many alternatives are available, a DHCS certainly would be one of them. Because the Midwest region is coal rich, this report compares the DHCS options with: (1) a coal-electric system; (2) coal gasification systems; and (3) coal liquefaction systems. By its very nature a DHCS option must be instituted in fairly large blocks; thus, to some extent, it precludes the *phase in* approach that the other alternatives allow.

Decreasing fossil fuel supplies in the aggregate will affect various end-users in different ways. Society, as a whole, must determine which sector will suffer the effects of a shortfall and to what degree. It is logical to assume that those sectors that have the best mechanisms (both technically and economically) to adopt to new energy sources will be the first to be curtailed. Traditionally, large industry is curtailed first. Thus, it is expected that commercial/residential users will be given priority for scarce fuels. Although this does not preclude the eventuality of scarce fuel curtailments to urban cores, it will effectively delay the time at which an alternate energy supply becomes imperative in the urban areas.

The above discussion has been undertaken to alert the reader that economic viability, alone, will not determine the implementation of DHCS. Such a decision will be intimately entwined with a myraid of institutional problems.

3. SCOPE OF STUDY

This study deals with the center cities of six major northern U.S. urbanized areas. In all cases, except Chicago, the proposed DHCS systems would supply heating and hot water requirements to most of the center city. Areas to be serviced by the proposed DHCS were determined by the total supply which could be made available from existing sources and, in some cases, by minor additions of thermal boilers. Chicago presented a case, probably matched only by New York City, in which the demand was so great that available supplies could satisfy only a fraction of the required demand. This fact was further complicated because the Commonwealth Edison Company supplies power to the city proper, in large part, from very distant electric generating facilities.

Table 3.1 details the supply and demand factors for the cities under study. It also relates information on the percentage of the city proper that would fall under the DHCS. The case of Chicago should be kept in mind because here only the most dense demand areas are covered. Because higher density of demand implies lower DHCS costs, the final economic projections then appear to make Chicago the most viable candidate for DHCS. However, the supply network costs have not been specifically studied at the densities found in much of Chicago. Although Chicago's high-demand density generally would yield lower per-Btu costs, such density may be associated with greater costs than estimated for this study. Nevertheless, an independent study or a DHCS concept for a new downtown Chicago residential development project also found the DHCS to be economically viable.²

3.1 DHCS FEASIBILITY

To determine the feasibility of DHCS retrofit, and also to assess the economic viability of such retrofit in relation to varying demand densities, each city was broken down into a workable number of demand zones. City zones were determined by using the principle that areas with the highest demand density would be the first to be retrofitted. This concept was tempered by supply location. For example, an effort was made to bring supply facilities into the city in geographically related clusters. In this manner, main transmission piping could be designed to handle several plants in the same general area. By this zone method, each city could have from three to four independent DHCS systems which eventually can be tied together.

Table 3.1. Basic Heat Data on Cities Under Study

City	Peak Demand MW-Heat	Usable Supply MW-Heat	Total City Area Km ²	Area Covered Km ²	% Covered	Average Demand MW-Heat	Actual Plant Supply MW-Heat
Washington	3174	3348	124	101	82%	868	5116
St. Louis	3426	3357	181	126	70%	907	4975
Cleveland	3989	4042	216	202	94%	1226	5995
Milwaukee	4133	4184	209	193	92%	1326	6270
Detroit	5638	5798	382	374	98%	1842	8592
Chicago	9066	8951	585	137	23%	2525	13,300

Although each zone theoretically could operate independently, the total integrated system is much more efficient for two reasons:

- (1) As additional zones come on line, the transmission lines move closer to a closed loop. When the loop is complete, maximum flexibility for repair and hot water diversion is reached; and
- (2) Increased supply yields increased flexibility. In the closed-loop situation, any supply point from any zone could feed to any demand point within the city area served.

3.2 DHCS FLEXIBILITY

The subject of supply flexibility deserves additional discussion. A comparison between a proposed district heating and cooling system and any other central supply option (e.g., all-electric, all-gas) immediately reveals that the DHCS may not be as flexible as other alternates. In the case of an all-electric system or all-gas system, an existing interconnect system stretches well beyond the city limits. Electric utilities have the option of purchasing additional power from a grid network, and existing gas distribution lines effectively tie the entire nation's gas supply together. In the case of DHCS, however, the overall supply is dictated by the maximum capacity of the local supply facilities. This situation can be mitigated by reserve capacity in the form of standby boilers or by conservative estimates of available supply. The former approach is not considered here, but the latter approach is considered in two ways:

- (1) Supply requirements are based on peak heating and hot water demands. Obviously, such peak demands will be required for only a small fraction of the time. In other instances, the excess capacity can be considered reserve.
- (2) The methods of calculating "available" supply and peak demand were very conservative; thus, a built-in reserve is factored into our calculations.³

Table 3.1 shows the nature of such estimates. Available supply is roughly equivalent to peak demand but is significantly above average demand. Available supply also is only a fraction of actual supply produced at the supply point.

Flexibility and reserve increase in going from a zone concept to a city concept. This was dramatically shown to be the case in Cleveland. Zone III of Cleveland relies on the Davis-Besse Nuclear Power Plant for 100% of its supply. Should Zone III be considered as an independent DHCS, any failure of the Davis-Besse plant would cause a total 100% loss of supply. However, when the entire city is considered on a DHCS system, a failure of the Davis-Besse plant would result only in a 17% loss of total supply. While this loss could be very serious at a peak period, it could be readily absorbed in most cases.

While the DHCS does not have the inherent flexibility of some alternate options, this does not presuppose that an unresolvable problem exists. Certainly, operable systems in Europe and in certain United States installations have proven that sufficient standby capacity and inherent reliability exists to make a DHCS a viable option. It should also be noted that when a generating unit is removed from the line, this does not automatically shut down the DHCS. It is quite possible that the cogenerating unit operation which causes the electric generating capability to be shut down would not interfere with heat production capability.

The DHCS system under consideration here covers only the energy supplied to provide space heating and hot water. Conceptually, a DHCS may provide either heating or cooling. Cooling can be provided by using an absorption chiller. However, such a device is relatively inefficient, and its low expected efficiencies indicate that, in most cases, less energy would be utilized by generating electricity to run compression chillers than by using DHCS to generate heat for an absorption chiller.^{1,4,5} This property of DHCS limited the scope of this study to areas dominated by heating load. Although demand assessments were made for cooling needs, the proposed DHCS does not envision supplying heat for cooling. Thus, the overall economics are based on heat load only.

While on the surface efficiencies would indicate that absorption chillers would not be *extensively* utilized, certain supply components of the DHCS warrant a second look. Specifically, heat generated via reboilers on gas turbines is very low cost in that very little electrical capacity is given up to obtain heat for absorption chillers.^{1,6,7} It is quite conceivable that heat generated in such a manner could prove much more economical than compression chillers. Although not covered in this study, an optimization analysis of the cooling potential of a DHCS warrants serious consideration.

The DHCS in this study utilizes a two pipe system (one feed, one return) for the transmission of the heat exchange medium. In this case, the medium is hot water at about 200°F. The hot water so distributed can be used in a variety of ways which would cause greater or lesser retrofit costs within the end user building. Although the authors recognize that to be totally accurate an assessment of the specific end use heating mechanisms in every building type would be required, such an assessment was beyond the scope of this study. The end use retrofit costs used in this study generally assumes that 200°F water could be used directly as a heat exchange medium once a heat exchanger was retrofitted to existing buildings. These retrofit costs are based on estimates compiled by Burns & Roe for buildings currently using steam or hot water systems.⁸

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

4 METHODOLOGY

This study utilizes an indepth analysis of both the demand and supply components of a DHCS. When both such components are understood, a match is effected so as to design a viable zone-oriented DHCS. The text of this report details how the parameters involved were generated.

4.1 DEMAND ESTIMATES

To determine the demand (either heating or cooling) the following two basic parameters were estimated:

- (1) the number of square feet to be served, and
- (2) the amount of energy needed to satisfy the needs in each square foot.

Obviously, different types of building space will have different energy needs, and thus an assessment of space by various categories must be determined.

Although a very large number of building type breakdowns is theoretically desirable, this study considers only the following four basic building categories:

- (1) low-density residential -- defined as single-family houses, townhouses, and two- to three-story apartment buildings;
- (2) high-density residential -- defined as high-rise apartment houses;
- (3) commercial/institutional buildings -- defined as high-rise office buildings, hospitals, schools, etc; and
- (4) industrial buildings -- defined as urban type multi-story industrial complexes rather than land-intensive industry.

The square footage per building type was estimated by Real Estate Research Corporation by compiling data from various planning and city agencies and disaggregating the data according to square kilometer grid lines corresponding to the Universal Transverse Mercator Grid (km^2) for all cities, except Chicago. The Chicago estimates were based on one square mile grids that have been used in previous Argonne work. Residential square footage generally was gleaned from U.S. Census estimates of dwelling units in census tracts.⁹

Areas of a city that contained more than 75% single-family residences were eliminated. This is consistent with previous data demonstrating the lower economic viability of utilizing DHCS in such areas.¹⁰

Commercial and institutional, as well as industrial data on square footage were not as readily available. Various sources of information were used to estimate the square footage in such buildings. Although the above data were collected for the entire city under study, the zone concept, and the fact that only a percentage of a city was served by our DHCS (see Table 3.1) dictated which square kilometer grid data would be used in our demand estimates. Table 4.1 details the square footage used by building classification in each city under study.

The amount of energy used per square foot in the various categories was somewhat more difficult to assess. However, the distinction among building types allowed analysis in broad categories. For example, the location of high-rise commercial buildings in the central business districts (CBDs) allowed omission in this study of the more energy-consuming shopping center type of retail store. This is allowable because of our knowledge that DHCS will be mostly concentrated in the CBDs.*

Residential energy demand per square foot was based, in large part, on excellent data generated by contacts in the Washington area. Data were provided from actual meter readings of low-density, residential units. Two years of data were available, and a good estimate of daily heating demand was obtained. Actual meter readings, corrected by a furnace efficiency factor (67%), gave an estimate of energy used. The data generated for Washington were compared to previous studies of residential energy use. Findings of $15.06 \text{ Btu/ft}^2 \cdot \text{HDD}$ corresponded well enough with previous efforts ($14.6 \text{ Btu/ft}^2 \cdot \text{HDD}$) that it seemed safe to use an equation relating energy usage with Heating Degree days HDD to estimate energy usage in other cities.^{11,12}

When the average day value is found, and an equation is accepted for other cities, an estimate of peak heat usage was generated by utilizing the ASHRAE 97.5% design temperature. For example, for Washington, D.C., the 97.5%

*The authors recognize that this procedure will underestimate commercial energy demands outside of CBDs.

Table 4.1. City Building Square Footing x 10³

City	Low Density Residential	High Density Residential	Commercial Institutional	Industrial
Washington	*	295,325*	159,916	13,022
St. Louis	*	243,706*	77,243	59,946
Cleveland	259,408	68,667	41,460	78,410
Milwaukee	241,208	57,715	59,044	43,981
Detroit	452,792	36,620	77,714	70,104
Chicago	409,752	120,058	335,475	227,077

* Figures in High Density Resid. Row for Wash. & St. Louis are sum of R-1 and R-2

design temperature was 19°F, and the peak heat load would be $14.6 \text{ Btu/ft}^2 \cdot \text{HDD} \times (65^\circ - 19^\circ) = 671.6 \text{ Btu/ft}^2 \cdot \text{day}$. Because of other factors (e.g., diversity) the use of a 97.5% design temperature is appropriate for use in this study.³

Data for high-rise residential building were less available, so an assumption was made that this classification would behave in essentially the same way as low-density residential as regards seasonal variations of climate. However, the actual usage of energy would be only a fraction of that used in low-density residential. The factor used to correlate high to low density residential was 0.72. This factor was assumed to apply fairly consistently for, not only average heating, but for peak heating and cooling as well. The utilization of this factor in concert with the transfer equation for average heating loads in various cities allows an analysis of peak heat load of residential units in cities under consideration.

Estimates of commercial/institutional (C/I) building heat uses were derived from an outgrowth of earlier work. Analysis of such work indicated that much of this classification was office space and that other types of C/I buildings had amounts of energy usage that straddled office energy usage. Based on such findings, it seemed reasonable to assume that the office building can be used as a good surrogate for the overall energy consumption behavior in central business districts.^{13, 14} An equation that is dependent on heating degree days was formulated to estimate the commercial energy usage per square foot.

Industrial building energy consumption suffers from the same problem that plagues C/I buildings, i.e., a lack of first-hand data. Even with good data, this class of floor space would be difficult to describe generically because it represents a highly variable class of energy consumer. Nevertheless, it is possible to characterize the downtown industrial energy consumer with some degree of confidence. A generalized assumption made was that CBD industry will behave somewhat similar to the C/I classification with the major difference being more usage per day because of shift operations. The only recognized data available (IDHA study) would indicate a ratio of C/I to industrial usage of 1:1.18.¹⁵ Although the lack of validation of this ratio is recognized, it does fit the assumption made above, and thus was used as a transfer function for deriving industrial energy usage as related to C/I usage. Downtown areas, which are likely to be served first by a DHCS, have much much C/I floor space

than industrial facilities. Industry tends to be more dispersed through the city than is commercial activity.

Hot water usage is assumed to be a function of occupancy levels rather than square footage, and thus hot water usage varies by occupancy levels assumed for each building type. Previous works provide insights into residential hot-water usage. After correction, a value of $22 \text{ Bt/ft}^2 \cdot \text{day}$ was generated for low-density, residential hot-water usage. To arrive at hot-water usage in high-density residential, a surrogate comparison of rooms per unit in high-vs. low-density residential was utilized for hot-water consumption. C/I hot-water usage was based on work undertaken by Brookhaven National Laboratory in a companion study;¹⁶ whereas, industrial hot-water usage was scaled up from C/I in the same way heating demand was scaled.

Having both the square footage available, by sq km^2 (or mi^2) in each city and the per square foot energy demands, energy demand can be determined. Table 4.2 depicts the per square foot factors for the total city. The above information allowed estimation of various data on a square-kilometer basis. These data were computerized to permit the design of transmission lines from supply points that would serve clusters of demand. Such information also allowed fairly accurate estimates of local distribution and building retrofit costs.

To summarize each km^2 (or mi^2) is provided with the following information:

- low-density residential square feet
- high-density residential square feet
- commercial/institutional
- industrial
- peak heating demand
- average heating demand
- hot water demand

An example of energy density distribution patterns is shown in Fig. 4.1. Although this particular display applies only to Washington residential heat plus hot water, a similar display is available for each energy category or for appropriate combinations of these categories.* Energy distribution patterns for St. Louis, Detroit, Milwaukee, Cleveland, and Chicago are given in Figs. 4.2 through 4.6, respectively.

*Information of peak and average cooling also was tabulated and is available but was not utilized in this study.

Table 4.2. Energy Demand Factors (Btu/ft²)

City	Low Den. Resid.	High Den. Resid.	Comm./Instit.	Industrial
Washington				
Average Day Heat	168	121	85	95
Peak Day Heat	672	484	339	380
Hot Water	22	15	9	11
St. Louis				
Average Day Heat	190	137	96	113
Peak Day Heat	788	568	398	470
Hot Water	22	15	9	11
Cleveland				
Average Day Heat	246	177	124	147
Peak Day Heat	847	610	427	504
Hot Water	22	15	9	11
Milwaukee				
Average Day Heat	298	215	150	175
Peak Day Heat	978	704	494	583
Hot Water	22	15	9	11
Detroit				
Average Day Heat	257	185	130	153
Peak Day Heat	832	599	420	496
Hot Water	22	15	9	11
Chicago				
Average Day Heat	245	176	124	146
Peak Day Heat	934	673	472	557
Hot Water	22	15	9	11

Fig. 4.1 Residential Average Day Heating Demand Pattern
Illustrated by Computer Graphics for Washington, D.C.

Fig. 4.2 Residential Average Day Heating Demand Pattern
Illustrated by Computer Graphics for St. Louis

Fig. 4.3 Residential Average Day Heating Demand Pattern
Illustrated by Computer Graphics for Cleveland

Fig. 4.4 Residential Average Day Heating Demand Pattern
Illustrated by Computer Graphics for Milwaukee

Fig. 4.5. Residential Average Day Heating Demand Pattern
Illustrated by Computer Graphics for Detroit

Fig. 4.6 Residential Average Day Heating Demand Pattern
Illustrated by Computer Graphics for Chicago

4.2 ENERGY SUPPLY ANALYSIS

Having arrived at estimates for energy *demand*, the next task in this study was to assess energy *supply*. The basic supply criteria followed was to attempt to retrofit a city until available supply was exhausted. These criteria were breached in two cities when new thermal boilers were introduced. This was done to arrive at a rational supply-demand balance. However, in the case of Chicago, an extremely large amount of new capacity would be required to retrofit the entire city. Because of the many problems surrounding the installation of such large capacity, the area to be retrofitted was cut off when supply no longer existed.

In almost all cases, supply was derived from existing electric generating or thermal plants. Close analysis of generic systems (see Refs. 6 and 17-27) revealed that there are five basic ways in which supply may be obtained:

- (1) condensing pressure and extraction volume increase retrofit on existing single-stage turbines (CPEI).
- (2) intermediate cross-over extraction retrofit on existing multi-stage turbines (CO).
- (3) recuperator boiler retrofit on existing gas turbines (RB).
- (4) conversion of existing steam boilers or installation of new hot water boilers (B).
- (5) installation of new specifically manufactured variable turbines.

All of the above options except (5) were utilized at various times in the five North-Central cities during this study. The new turbine option was used in only the methodology development case of Washington, D.C. as a substitute for a planned generating unit.¹

Ideally, the analysis of a specific system would require a detailed evaluation of each unit. However, detailed study of specific generic units and a comparison of those results with installed capacity indicated that individualized study was not required. Generic studies performed resulted in sufficiently accurate thermodynamic estimates such that the results were applied to all units in that classification. Table 4.3 depicts the results of such analysis. The heat and electric megawatt power of various units, as shown in Table 4.3, served as the basis for supply selection. Retrofit of steam turbines results in a

Table 4.3. Results of Existing Retrofit Options

Initial Power & Type Unit-MW	Retrofit Option	Elec. Power After Retro-MW	Heat Power After Retro-MW	Total Power After Retro-MW
30-Turbine	CPEI	14.7	55.8	70.5
60-Turbine	CPEI	31.6	104.6	136.2
100-Turbine	CPEI	64.8	143.4	208.2
60-Turbine	CO	45	75	120
100-Turbine	CO	70	130	200
120-Turbine	CO	90	150	240
200-Turbine	CO	145	255	400
62-Gas Turb	R.B	56	125	181

substantial loss in electric generating capacity, but this loss is more than recovered in heat power. Nevertheless, the electric capacity lost should be made up so that the electric utility will still be able to satisfy its peak demand. Replacement capacity is figured into overall costs as will be explained later.

Retrofit of existing gas turbines reaps large overall increases in power. These increases are due to the fact that the heat energy derived comes from waste heat in the exhaust gas, and not as a result of decreased feed to the turbine. Unfortunately, gas turbines are *peak* units and thus are the last units to be brought on line when operated optimally from the electrical point of view. This study, in generating supply, attempts to keep plant electrical load factors at least proportionate to what they were before retrofit.

Information on specific units of generating facilities was obtained with the assistance of the major utilities in each city's service areas. This information provided the necessary data from which to cluster supply points and, hence, energy demands to be serviced from each point.

When the only total available heat energy was established, corrections were made to account for capacity factors and system losses. Generally, an overall capacity factor of 0.75, and a loss factor of 0.9 were used. Thus, a gross energy supply of 1000 MW would satisfy a net energy demand of 675 MW.

All of the above information allows a match of peak demand and supply by zone. Supply points were picked so as to serve the most dense demand zones first. Each square kilometer was rated with regard to peak heating supply plus hot water. A supply cluster was brought into the city by means of transmission pipes that were designed to carry the hot water gallonage produced by that cluster.²⁸⁻³⁶ Transmission pipes followed major rights-of-ways, and an attempt was made to bring the main track directly into the center city. Some trial and error was necessary to arrive at the exact boundaries of a particular zone; the major criteria being that the demand should not exceed the supply by more than 5%. For example, for St. Louis, the demands of zones one and three exceeded supply by 7.9% and 5.1%, respectively. In zones two and four, supply exceeded demand by 6.1% and 2.8%, respectively. Overall the peak demand exceeded potential supply by only 2.0%.

A secondary consideration in determining demand boundaries was an awareness of local distribution costs. An attempt was made to locate transmission lines so that the local distribution pipeline would not have to extend more than two km in any direction. While this criteria could not be met at all times, it was met in the vast majority of cases.

Figures 4.7 to 4.12 display the results of the zone selection criteria. As can be seen from examination of these figures and Figs. 4.1 to 4.6, zones were added in order of decreasing demand. Zone I covers the main downtown business district while Zones II and III are always adjacent to that district. The area not covered was of lower demand density and remained after supply was exhausted. Figures 4.7 to 4.12 also reveal the basic adherence to the transmission piping loop concept. While individual zone transmission pipes terminate at approximate zone lines, the final piping creates a closed loop. This allows supply from any point to serve any demand sector. The reader should be aware that each transmission line is actually two lines. The DHCS under consideration here is a hot water system and thus supply and return lines are necessary.

4.3 COMPONENT CAPITAL COST ESTIMATES

A knowledge of supply and demand allows for a more detailed analysis of costs involved. Each cost component was analyzed and projected. In all cases, a dual estimation methodology was utilized. The first estimate was a high estimate and utilized conservative costs. The second estimate was less conservative and gave allowance for site-specific conditions as well as less expensive materials of construction. The purpose of this study is to provide a range of costs. Much more detailed analysis will be needed to ascertain actual costs. The following cost components were analyzed:

- *Transmission Pipe:* This item includes the cost of purchasing and installing pipe to connect supply points to demand sectors. Preliminary cost estimates for both initial capital and installation (urban and rural) were prepared by Burns & Roe Corp.⁸ High cost estimates utilized steel pipe and a high percentage of urban costs. Low costs estimates substituted a synthetic pipe and a higher percentage of rural installation.
- *Local Distribution Piping:* This item is the connecting pipes from the transmission bus to the building wall. Detailed analysis of demand in certain northwestern cities was undertaken by the Energy Systems Resource Group for Brookhaven National Laboratory.¹⁶ That work was sufficient to allow the

Fig. 4.7 Washington, D.C. - Demand Zones and Supply Lines

Fig. 4.8 St. Louis - Demand Zones and Supply Lines

Fig. 4.9 Cleveland - Demand Zones and Supply Lines

Fig. 4.10 Milwaukee - Demand Zones and Supply Lines

Fig. 4.11 Detroit - Demand Zones and Supply Lines

Fig. 4.12 Chicago - Demand Zones and Supply Lines

generation of cost/demand equations that were applied to the cities covered in this study. Once again high and low estimates were generated utilizing the same variables as for transmission piping.

- *End Use (Bldg.) Retrofit:* In almost all cases the end user will be required to retrofit this energy delivery system to utilize hot water as the principal energy source. Estimates on retrofit charges per square foot of building space were gleaned from previous work undertaken by Burns & Roe.⁸ Costs are available for various classifications of buildings. The dollar per square foot retrofit costs for high and low estimates were generated by using factors provided for differing classes of buildings. For example, the cost factor for apartment buildings of about 200 units was used city-wide for the high residential estimate ($\$0.32/\text{ft}^2$) and the cost factor for apartment buildings of about 400 units was used for the low residential estimate ($\$0.24/\text{ft}^2$).
- *Plant Retrofit:* This item involves the costs involved in preparing a supply facility to operate in a cogeneration mode. Any of the five previously listed retrofit options were applied as the particular unit dictated. High cost estimates were very conservative and involved costs at 15 percent of the current cost of the power plant, although costs would actually be confined to turbine modification. Costs of recuperative boilers and new thermal boilers were gleaned from the literature. Because of the conservative approach given this item, low costs were simply taken as one-half of high costs.
- *Replacement Capacity:* This item includes: (1) the cost of constructing a new gas-turbine plant to replace the electrical generation lost because of retrofit; and (2) the cost of providing coal-based synthetic fuel to such new plants. This was determined to represent a lower cost than construction of coal-fired power plants as replacement plants.

The need for such new capacity is obvious in that only a small amount of space heating in the studies cities was provided by electric heat. Therefore, because the DHCS would substitute for scarce fuels and not electric heat, the electrical capacity lost as a result of retrofit would still be needed for its original uses. Because of the structure of this study, it is appropriate to assume that the newly constructed capacity would be in the form of peakers, and thus the type of unit envisioned in our cost estimates. Because fuel for gas turbine peakers is becoming increasingly scarce, cost provisions are made assuming coal liquids plants to provide fuel for such new capacity.

Table 4.4 details the individual cost components by both zone and city total. Zone costs will vary widely as can be expected because of site-specific variations and because of some special case situations. For example, Zone II in Washington shows a zero cost for electrical replacement capacity because the supply to that zone was provided by existing thermal boilers. Thus, no loss of electrical generation was suffered (i.e., through thermal retrofit of existing generating units).

4.4 ANNUALIZED SYSTEM COSTS

Annual costs are composed of four components as follows:

- (1) Operation and Maintenance (O&M) Charges for Piping Systems;
- (2) Operation and Maintenance Charges for Portions of Plant Associated with Cogeneration;
- (3) Fuel Costs Associated with Cogeneration; and
- (4) Capital Recovery Charges.

O&M costs for piping systems are derived from the Net Energy Methodology developed for DOE (then ERDA).³⁷ The factors chosen herein were based on similar charges that have been experienced by owner/operators of major pipeline systems. To be consistent with our high-low estimates, factors were chosen at both extremes of reported values. These O&M factors are simply a ratio of dollars expended for annual O&M to initial capital dollars invested, i.e., a simple multiplication of the O&M factor times the sum of capital cost for transmission and local distribution gives us the desired dollar value. O&M for end use retrofit was not considered a proper DHCS charge. This cost traditionally is borne by the end user, so this report follows that procedure.

To assess properly the O&M charges attributable to DHCS plant operation, a general concept of how often a specific plant (or unit) will operate must be found. In this study it is assumed that the relative order of plant loading before DHCS operation will remain after retrofit. Thus, base-load plants would operate first, followed by intermediate plants, followed by peakers. A relative ranking by heat available and load factors allow an estimate of the percentage of time a unit must operate to meet overall zone demand. From this analysis, it is simple to determine the amount of electricity that the subject unit would produce during the period of cogeneration, had the cogeneration mode

been inoperative. Cogeneration is assumed to double the normal O&M costs of the unit during the period of cogeneration. When the normal electrical output during this period is known, the Net Energy Method again provides O&M costs for the different types of electric generating facilities. These factors are related in terms of \$/Btu and can thus be multiplied by the equivalent normal electrical Btus produced by the subject plant to arrive at an estimate of O&M cost due to cogeneration.

Fuel costs obviously are highly dependent on the type of fuel used. Escalated FEA cost estimates adjusted to 1977 for the geographic areas under investigation were utilized in this study. The only exception to this rule is the Chicago area Commonwealth Edison data which were used as a basis for nuclear fuel costs. Total fuel costs (TFC) are calculated by utilizing the following formula:

$$\text{TFC} = \text{Btu provided by plant} \times \text{plant efficiency factor} \times \text{plant heat unit fuel cost}$$

where

$$\text{TFC} = \text{Total Fuel Cost}$$

Table 4.5 displays the individual and composite annual costs by zone and by city. As was the case in Table 4.4, there is wide variation between zones due to site specific criteria. For example in Zone II, Cleveland shows a fuel cost of only $\$1.39 \times 10^6/\text{yr}$. This is because the only plant in that zone is nuclear powered and thus has a low fuel charge.

Capital recovery costs are dependent on interest rates and payback time. In this study two payback scenarios are assessed for both high and low costs. This first scenario projects interest rates of 8% and a project life of 20 years and the second projects interest rates of 20% and a project life of 20 years. From all of the above total annual costs can be derived from the following formula:

$$\text{TAC} = \frac{\text{Capital Costs} \times \text{Cap. Recovery Factor} + \text{O\&M Costs} + \text{Fuel Costs}}{\text{Annual Btu Demand per Zone} \times 10^6}$$

where

$$\text{TAC} = \text{Total Annual Costs in } \$/10^6 \text{ Btu.}$$

The results of such calculations are displayed in Table 4.6. This calculation places all zones on a standard basis so the reader can accurately

Table 4.4 Capital Costs, City/Zone

City	Zone	High Cost - \$x10 ⁶						Low Cost - \$x10 ⁶					
		Trans- mis- sion	Dis- tribu- tion	Bldg. Retro fit	Plant Retro- fit	Re- place MW	Total	Trans- mis- sion	Dis- tribu- tion	Bldg. Retro- fit	Plant Retro- fit	Re- place MW	Total
Washington	I	115	287	136	72	234	844	47	100	82	36	107	382
	II	24	48	17	7	0	96	9	17	10	4	0	40
	III	161	218	47	31	144	599	83	76	31	16	72	278
	IV	168	161	27	18	70	444	86	56	19	9	35	205
	Total	1168	714	227	128	448	1985	225	249	142	65	214	905
St. Louis	I	75	183	40	37	112	447	26	64	27	19	56	192
	II	93	18-	30	26	122	451	47	63	21	13	61	205
	III	192	274	51	71	159	747	55	96	35	36	79	301
	IV	90	167	28	31	134	450	58	59	30	16	67	218
	Total	450	804	149	165	527	2095	186	282	163	84	263	916
Cleveland	I	157	639	129	108	453	1450	53	221	82	54	227	639
	II	237	380	40	48	208	913	111	138	27	24	104	398
	III	74	242	28	29	110	423	33	85	19	15	55	207
	Total	468	1261	197	185	771	2876	197	442	178	93	386	1243
Milwaukee	I	342	501	88	76	302	1309	200	174	56	38	151	620
	II	212	444	97	57	291	1101	57	155	34	29	146	120
	III	8	308	36	133	8	493	3	108	25	67	4	206
	Total	562	1253	221	226	601	2903	260	437	115	134	301	1246
Detroit	I	133	446	63	84	300	1026	47	156	43	42	150	438
	II	517	827	133	104	448	2029	299	299	88	52	224	961
	III	209	240	73	67	264	1553	110	329	47	34	132	652
	Total	859	2213	269	255	1012	4608	456	784	178	128	506	2051
Chicago	I	273	120	253	59	267	972	96	42	137	30	134	439
	II	291	596	173	102	392	1554	204	209	107	51	196	767
	III	378	576	158	108	613	1883	188	202	105	54	307	856
	Total	942	1292	584	269	1272	4259	488	453	349	135	637	2062

4.5. DHCS - Operation & Maintenance Costs

City	Zone	High Estimate \$x10 ⁶				Low Estimate \$x10 ⁶			
		Trans Dist	Plant O&M	Fuel Costs	Total	Trans Dist	Plant O&M	Fuel Costs	Total
Washington	I	16.3	9.9	17.90	44.10	0.98	4.95	17.90	28.53
	II	2.9	0.46	3.11	6.47	0.17	0.23	3.11	3.51
	III	15.4	5.64	6.13	27.17	1.07	2.82	6.13	10.02
	IV	13.4	2.02	2.69	18.11	0.95	1.01	2.89	4.65
	Total	48.0	18.02	29.83	95.85	3.17	9.01	29.83	42.01
St. Louis	I	10.48	3.15	12.21	25.84	0.60	1.58	12.21	14.39
	II	11.09	4.54	4.08	19.71	0.74	2.27	4.08	7.09
	III	18.92	7.10	7.78	33.8	1.01	3.55	7.78	12.34
	IV	10.43	5.07	5.92	21.42	0.78	2.54	5.92	9.24
	Total	50.92	19.86	29.99	100.77	3.13	9.94	27.99	43.06
Cleveland	I	32.32	16.95	20.14	69.41	1.85	8.49	20.44	30.43
	II	25.06	6.89	8.02	39.97	1.63	3.45	8.02	13.10
	III	12.83	7.49	1.39	21.71	0.79	3.74	1.39	5.92
	Total	70.22	31.33	29.55	131.09	4.27	15.68	29.55	49.50
Milwaukee	I	34.23	16.30	10.93	61.46	2.50	8.15	10.83	21.58
	II	26.64	10.59	8.71	45.94	1.42	5.30	8.71	15.43
	III	12.83	3.50	17.40	33.73	0.74	1.75	17.40	18.89
	Total	73.70	30.39	37.04	141.13	4.66	15.20	37.04	56.90
Detroit	I	23.51	12.77	29.32	65.6	1.36	6.38	29.32	32.06
	II	54.58	29.08	25.39	109.25	4.00	14.51	25.39	43.93
	III	46.66	12.90	12.16	71.22	2.94	6.45	12.16	21.55
	Total	124.75	44.75	66.87	246.67	8.30	27.37	66.87	102.54
Chicago	I	15.96	5.73	8.05	29.78	.92	2.87	2.87	11.84
	II	56.02	21.33	26.07	78.32	2.75	10.67	10.67	34.46
	III	20.74	48.22	15.01	102.00	2.61	24.11	24.11	41.76
	Total	90.72	75.28	49.12	215.12	6.29	37.65	37.65	88.06

4.6. Cost per 10⁶ Btu @ 20 yrs 8%/20% (\$)

City	Zone	@ 8% -20 yrs		@ 20% - 20 yrs	
		High	Low	High	Low
Washington	I	9.68	4.67	16.20	7.62
	II	10.13	4.68	16.70	7.13
	III	14.00	6.07	23.80	10.60
	IV	14.10	5.85	24.20	10.50
Total		11.50	5.22	19.50	8.83
St. Louis	I	12.26	5.83	20.20	9.24
	II	12.64	5.37	21.62	9.48
	III	13.27	5.16	22.63	8.91
	IV	12.98	6.07	21.97	10.42
Total		12.81	5.56	21.65	8.43
Cleveland	I	10.26	4.46	17.41	7.54
	II	15.29	6.17	26.15	12.90
	III	10.27	4.10	18.37	7.36
Total		11.54	4.79	19.65	8.30
Milwaukee	I	11.43	4.97	19.38	8.74
	II	12.17	4.48	20.95	7.83
	III	6.47	3.15	10.41	4.80
Total		10.16	4.27	17.15	7.28
Detroit	I	11.54	5.54	18.74	8.62
	II	11.37	5.11	18.93	8.69
	III	15.92	9.55	27.07	10.29
Total		12.57	5.47	20.95	9.20
Chicago	I	17.74	7.79	31.60	14.05
	II	8.90	4.25	14.99	7.24
	III	9.16	4.09	15.18	6.90
Total		9.88	4.56	16.61	7.83

assess the estimated costs of a DHCS. The slight variability within zones is to be expected because of site-specific considerations. However, the most striking aspect of Table 4.6 is the close correlation between overall costs per 10^6 Btu among the various cities. For example, low cost estimates (8% - 20 yr) vary by only \$1.29/ 10^6 Btu (30.2%) from the two extremes of city-wide average costs.

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

5 COMPARISON WITH ALTERNATIVE ENERGY DELIVERY OPTIONS

5.1 ALTERNATIVE SYSTEMS

Having arrived at overall annual costs involved in a DHCS, a consideration is made of alternative energy delivery systems that could be used instead of DHCS. In each analysis, the basic premise is that an energy delivery system must be built so that it can provide enough energy to meet the demands that were utilized in the DHCS analysis.

Three alternate energy systems were analyzed: (1) coal-to-electricity-to-heat; (2) coal-to-gas via gasification-to-heat; (3) coal-to-oil via liquefaction-to-heat. In each case, an amended net energy methodology was utilized as the starting point for cost calculations. The procedure used in arriving at final costs was similar to that employed in the DHCS option. Thus, capital costs, O&M costs, fuel costs, and capital recovery costs were established and utilized to arrive at final $\$/10^6$ Btu estimates.³⁷⁻³⁹ Results of these calculations are shown in Tables 5.1 to 5.3.

5.1.1 Coal to Electricity to Heat

The overall net energy trajectory³⁷ for this option assumed a 65% power plant capacity figure, a 34% power plant efficiency, and a 20-yr lifecycle for all major components. Adjustments have been made to the net energy methodology to make it more consistent with the work undertaken in this study:

- Power plant costs are escalated from $\$445 \times 10^6/1000$ MW to $\$635 \times 10^6/1000$ MW to reflect recent cost estimates.³⁸
- The overall plant capacity utilization (based on load curve analysis) for space heating is approximately .325 which is one half of the original 65% estimate. Although this causes a high electrical cost estimate, it reflects actual costs associated with constructing plant specifically for space heating.
- The overall plant efficiency (based on new unit designs) is estimated at 42% rather than the 34% originally estimated. Such corrections were incorporated.

Table 5.1 Costs of Coal-Electric Option

City	Zone	Avail. MW	Cap. Costs \$x10 ⁶	Tot. Ann. Costs \$x10 ⁶	Fuel Costs \$x10 ⁶ / Btu	8% 20 yr \$x10 ⁶ / Btu	20%-20 yr \$x10 ⁶ / Btu
Washington	I	2141	2145	30.56	20.87	20.15	36.73
	II	284	285	4.06	2.54	21.88	40.00
	III	868	870	12.40	9.81	17.59	31.89
	IV	808	810	11.54	7.10	22.18	40.56
	Total	4101	4110	58.56	40.32	20.00	36.43
St. Louis	I	796	798	11.37	7.36	17.17	31.36
	II	824	826	11.77	6.57	19.72	36.18
	III	1560	1563	22.27	10.53	23.05	42.48
	IV	800	802	11.46	6.55	19.24	35.26
	Total	3980	3989	56.84	30.81	20.13	36.97
Cleveland	I	2768	2774	39.53	27.10	16.27	29.66
	II	1228	1230	17.53	11.00	17.68	32.32
	III	800	802	11.43	8.36	15.42	28.03
	Total	4796	4806	68.49	46.46	16.45	30.01
Milwaukee	I	2216	2220	31.63	21.55	16.39	29.88
	II	1568	1571	22.39	16.42	15.31	22.11
	III	1232	1234	17.58	16.40	12.32	22.17
	Total	5016	5025	71.61	54.37	14.83	26.93
Detroit	I	1844	1848	26.33	18.65	15.82	28.79
	II	3350	3356	47.82	35.13	15.30	27.80
	III	1680	1683	23.98	18.23	14.83	27.95
	Total	6874	6887	98.13	72.01	15.31	27.83
Chicago	I	3005	2409	34.33	9.18	39.80	74.16
	II	4750	3807	54.24	33.65	17.93	32.71
	III	5545	4445	63.34	39.87	17.61	32.23
	Total	13,300	10,661	151.91	82.60	20.22	37.11

Table 5.2 Costs of Coal Gasification Option

City	Zone	Avail. MW	Cap. Costs \$x10 ⁶	Tot. Ann. Costs \$x10 ⁶	Fuel Costs \$x10 ⁶ / Btu	8% 20 yr \$x10 ⁶ / Btu	20%-20 yr \$x10 ⁶ / Btu
Washington	I	13393	314	10.05	41.73	6.25	8.67
	II	1628	38	1.22	5.07	6.24	8.67
	III	6298	148	4.74	19.63	6.25	8.69
	IV	4560	107.0	3.42	14.20	6.25	8.68
	Total	25879	607	19.42	80.63	6.25	8.68
St. Louis	I	5823	137	4.38	18.35	6.29	8.73
	II	5195	122	3.90	16.37	6.29	8.72
	III	8327	195	1.83	25.92	6.24	8.67
	IV	5181	122	1.15	16.33	6.30	8.74
	Total	24526	576	18.43	77.31	6.29	8.72
Cleveland	I	21448	503	16.10	67.61	6.29	8.72
	II	8697	204	6.53	27.42	6.29	8.72
	III	6581	154	4.93	20.74	6.28	8.70
	Total	36726	861	27.55	11.58	6.29	8.71
Milwaukee	I	17037	399	12.77	53.70	6.29	8.67
	II	12985	305	9.76	40.93	6.30	8.72
	III	9441	222	7.10	29.76	6.30	8.73
	Total	39463	926	29.63	124.39	6.30	8.72
Detroit	I	14742	346	11.07	46.47	6.29	8.72
	II	27771	652	20.86	87.54	6.29	8.72
	III	14410	338	10.82	45.42	6.29	8.72
	Total	56923	1336	42.75	179.44	6.29	8.72
Chicago	I	7257	170	5.44	22.88	6.29	8.71
	II	26522	622	19.90	83.60	6.29	8.72
	III	31519	739	23.65	99.35	6.29	8.72
	Total	65298	1532	49.02	205.83	6.29	8.72

Table 5.3 Costs of Coal Liquids Option

City	Zone	Req. Btu/yr $\times 10^9$	Cap. Costs $\$ \times 10^6$	Tot. Ann. Costs $\$ \times 10^6$	Fuel Costs $\$ \times 10^6 /$ Btu	8% 20 yr $\$ \times 10^6 /$ Btu	20%-20 yr $\$ \times 10^6 /$ Btu
Washington	I	13393	356	16.90	34.10	6.51	9.26
	II	1628	43	2.05	4.15	6.50	9.25
	III	6298	167	7.92	16.04	6.50	9.24
	IV	4560	121	5.74	11.61	6.51	9.25
	Total	25879	687	32.61	65.90	6.51	9.26
St. Louis	I	5823	155	7.34	12.03	6.03	8.79
	II	5195	138	6.54	10.74	6.03	8.78
	III	8327	221	10.47	17.21	6.03	8.77
	IV	5181	138	6.54	10.71	6.04	8.80
	Total	24526	652	30.89	50.70	6.03	8.79
Cleveland	I	21448	570	27.01	44.34	6.03	8.79
	II	8679	231	10.94	17.98	6.03	8.78
	III	6581	175	8.29	13.60	6.03	8.79
	Total	36726	976	46.24	75.92	6.03	8.79
Milwaukee	I	17037	452	21.42	35.22	6.03	8.77
	II	12985	345	16.35	26.84	6.03	8.78
	III	9441	251	11.89	19.52	6.03	8.79
	Total	39463	1048	49.65	81.58	6.03	8.78
Detroit	I	14742	391	18.53	30.47	6.03	8.77
	II	27771	737	34.92	57.41	6.03	8.77
	III	14410	383	18.15	29.79	6.03	8.79
	Total	56923	1511	71.59	117.67	6.03	8.77
Chicago	I	7257	193	9.14	15.00	6.04	8.79
	II	26522	704	33.36	54.82	6.03	8.78
	III	31519	837	39.66	65.15	6.03	8.78
	Total	65298	1734	82.16	134.97	6.03	8.78

After correction, the following capital costs³⁷ for the trajectory components were:

	<u>\$ x 10⁻⁶/1000 Btu</u>
Underground Mine =	3,120
Cleaning Plant =	400
Rail Transport =	1,400
Power Plant =	74,440
Transmission =	12,920
Distribution =	25,200
<u>Total =</u>	<u>117,480</u>

Using the above figure, the ratio of total pathway costs to power plant cost is $\$117480/74440 = 1.58$. This ratio is used as the pathway capital multiplier.

The pathway multiplier can be utilized on the amount of electric capacity needed to replace the DHCS capacity. Although the electric system is charged for fuel on the basis of heat pump efficiency, it is sized on the basis of resistance heat backup to the heat pump. Thus, because of the differences in end-use efficiency of hot water systems (some 80%) and electric resistance heating (some 100%), the total capacity required in the electric option is 80% of that required by the DHCS system. Thus, the overall formula to arrive at total electric option capital costs is:

Capital Costs = MW of DHCS x 0.8 x Cost/MW x Pathway Mult. or,
for St. Louis:

$$\text{Capital Costs} = 4975 (.8) (.635 \times 10^6) (1.578) = \$3989 \times 10^6$$

No costs are included for end-use retrofit; this lowers the cost estimates of this option relative to the other options.

Operation and maintenance costs are projected on the basis of the amended net energy procedure, as a multiplier of capital costs. For coal-electric-heat:³⁷

$$\text{O\&M Multiplier} = \frac{\text{Total Annual O\&M Cost}}{\text{Total Cap. Costs}} = \frac{1674}{117480} = 0.01425$$

Fuel costs for the coal-electric-heat option are simply a multiple of the Btus required times the fuel cost per Btu divided by the ratio of useful Btus/input Btus. In all cities, except Washington, coal costs were estimated at $\$0.893/10^6$ Btu; for Washington at $\$1.10/10^6$ Btu.³⁹ The useful-to-input Btu/ratio from the amended net energy methodology is 0.706.³⁷

Detailed breakdowns of all the above calculation results as well as overall annual costs in terms of $\$/10^6$ Btu are given in Table 5.1. These figures can be directly compared to the DHCS option in Tables 4.6 and 1.1.

5.1.2 Coal to Gas Via Gasification to Heat

Coal gasification costs, unlike electrical system costs, can be based on total demand rather than on capacity. Most buildings in the cities under study currently are served by gas. Consequently, the coal gasification option is essentially a *status quo* option, i.e., the existing system will not be revised because high Btu coal gas will merely be substituted for natural gas. No building retrofit will be necessary. The distribution system and storage facilities already exist.

One big advantage of the gas system is its storage capability. Natural gas or coal gas can be readily stored over long periods without losing the energy content. This is not true of thermal or electrical energy. This storage capability allows a coal gasification plant to run at a very high capacity factor and requires much less capital investment per unit output.

The overall net energy trajectory for the coal gas option required modification as follows:

- A major upward escalation in gasification plant cost was necessary to reflect recent estimates. The original estimate of $\$371 \times 10^6/\text{TCF}$ increased to $\$1250 \times 10^6/\text{TCF}$.³⁸
- The cost for distribution systems was deleted on the assumption that existing transmission networks may be utilized.

After correction, the capital costs for the trajectory components are:³⁷

Underground Mine	=	$\$1,200 \times 10^{-6}/1000 \text{ Btu}$
Rail Transport	=	$680 \times 10^{-6}/1000 \text{ Btu}$
Coal Gasification	=	$13,820 \times 10^{-6}/1000 \text{ Btu}$
Total	=	$\$15,720 \times 10^{-6}/1000 \text{ Btu}$

Estimates from Washington Gas and Light Co. project a 67% average efficiency for gas furnaces.¹¹ Utilizing this factor, the overall cost per Btu of final demand is $\$23.463 \times 10^{-6}/\text{Btu}$. This cost, multiplied by demand figures for the various zones, gives an estimate of total capital costs.

Operation and maintenance costs are projected on the basis of the amended net energy procedure as a multiplier of capital costs. For the coal gasification:³⁷

$$\text{O\&M Multiplier} = \frac{\text{Total Annual O\&M Cost}}{\text{Total Cap. Cost}} = \frac{503}{15720} = .03200$$

Fuel costs for the coal gasification option are simply a multiple of the Btus required times the final Btus divided by the ratio of delivered/required Btus. Coal costs are the same as those used in the electric option. The useful-to-input Btu ratio was determined to be 0.353.³⁷

Detailed breakdowns of all the above calculations results, as well as annualized costs, are given in Table 5.2.

5.1.3 Coal to Oil Via Liquefaction to Heat

The coal liquefaction option is treated similarly to the gasification option, except that additional costs for enlarged refinery storage and distribution are included.

The only major change from the original net energy procedure is that the cost of the liquefaction plant is escalated to reflect current dollar estimates. The scale-up is identical to that used for gasification plants.

The capital costs for the trajectory components are:³⁷

		<u>\$ x 10⁻⁶/1000 Btu</u>
Underground Mine	=	980
Rail Transport	=	340
Liquefaction Plant	=	15,500
Refining	=	1,200
Barge System	=	80
Storage	=	240
Distribution	=	380
Total	=	18,720

Our estimates for the efficiency of an oil-fired furnace are 70.5% (advanced oil furnace assumed because replacement would be required), and this factor results in an overall final demand cost of \$25,553 x 10⁻⁶/1000 Btu. This cost, multiplied by demand figures for the various zones, gives the estimate of total capital costs.

Once again, operation and maintenance costs are projected on the basis of the annualized net energy procedure, as a multiplier of capital costs. For

coal liquefaction, the following exists:³⁷

$$\text{O\&M Multiplier} = \frac{\text{Total O\&M Costs}}{\text{Total Cap. Costs}} = \frac{887}{18720} = .04738$$

Fuel costs are calculated in an identical method to that used for gasification. The ratio of delivered to required Btus is 0.432.

Detailed breakdowns of all the costs and annualized estimates are found in Table 5.3.

5.2 COMPARISONS OF ESTIMATES

A review of Table 1.1 reveals the comparisons among the various alternate energy supply options.

In all cases, the low-cost DHCS option at an 8% interest rate over 20 years is the least costly of the options. It is marginally less expensive than coal conversion processes and significantly less expensive than the coal-electric option. That same low-cost option when costed at a 20% interest rate is essentially at parity with coal conversion options, but still very significantly less than the coal-electric option.

The high-cost DES options (at both 8% and 20%) exceed the coal conversion option costs, but still are significantly less than the electric option.

Meaningful comparisons can be drawn only with a clear understanding of the assumptions underlying each option as outlined in the text. For example, the estimate for coal-electric assumes a low plant capacity utilization. If the excess capacity from the plant were utilized elsewhere, the costs per million Btu would drop. However, it would take a load factor well over 65% to make the electric option competitive with the high-cost DHCS option, except in Detroit, where a 58% factor would make the two options equal. When considering coal conversion options, very high load factors are assumed. This assumption is used because of the capabilities of storing these fuels for very long periods after production and before final use.

Another factor not fully considered is the technological constraints on the various options. The coal-electric option is fully proven as a heat source and the DHCS system is fairly well proven. The coal conversion technology must

be considered "undemonstrated" on a large-scale operation. Thus, costs reflected in the coal conversion option are best guess estimates and assume that technical problems can be overcome.

Once again, it is emphasized that, to estimate the costs of a DHCS option more accurately, a much more detailed study of a city should be undertaken. Such a study should emphasize, not only the technical and economic constraints, but also the institutional constraints.

THIS PAGE
WAS THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

6 ESTIMATES OF SCARCE-FUEL SAVINGS

A major advantage of the DHCS over the existing heat supply mechanisms in the study cities is that there is a great potential for offsetting scarce fuels usage. Table 6.1 shows the percentage of heat supplied to residential consumers by energy types in each city studied. Scarce fuels supply more than 85% of the total residential heat load in all six study cities. Table 6.1 allows a direct reading of residential heat supply; however, similar data for the commercial and industrial sectors were not readily available. Estimates for these sectors were based on previous work undertaken by Hittman and Associates.¹³ Data for Baltimore and Denver were used in combination with residential data for these cities to generate linear equations that were then applied to the six study cities, generating the following commercial/industrial heating percentage estimates.

Fuel (by %)	Washington D.C.	St. Louis	Cleveland	Milwaukee	Detroit	Chicago
Utility Gas	13	41	47	29	41	25
Fuel Oil	79	57	51	67	53	72
Electricity	4	0	0	0	0	1
Other	4	2	2	4	6	2

Using these data, knowing the square footage in each category, and the average demand factors (see Tables 4.1 and 4.2) it is possible to calculate total annual Btus required according to fuel and building type by the following formula:

$$\text{Btu used/yr} = (\text{Square Feet}) \left(\frac{\text{Avg. Demand Factor}}{\text{Day}} \right) (365 \frac{\text{Day}}{\text{Yr}}) \left(\frac{\% \text{ Fuel}}{\text{Used}} \right) \div (\text{Efficiency})$$

Efficiencies of the various fuels used were obtained from the net energy methodology and are as follows:

Gas to Heat	=	0.578
Oil to Heat	=	0.554
Electricity to Heat	=	0.562
Other Fuels to Heat	=	0.300

The above equation is calculated for all building types and fuels. By summing results of the four building types for a given fuel one obtains the fuel use estimates presented in the first five columns of Table 1.2. Electricity here is divided into current coal/oil generation proportions.

Table 6.1 details specific heating information about the subject cities; table 6.2 displays the overall results in utilizing the information in Table 6.1, the commercial/industrial data just presented, and building square footage data previously generated.

The above-generated, scarce-fuel usage provides reasonable estimates of the amounts of energy currently used to furnish heat and hot water to the sectors of the cities under consideration. To access the savings attainable by DHCS retrofit, a few basic points must first be emphasized, including:

- The DHCS must provide the same amount of energy to the end use as did the original energy supply.
- The electricity produced by cogeneration is utilized as it was before retrofit took place, i.e., the additional fuel used to generate electricity lost due to cogeneration is not included. Because all auxiliary fuel is assumed to be coal, consideration of this additional fuel would not affect scarce-fuel savings; however, it would slightly raise the overall Btus utilized for total DHCS energy production. The difference is small, and is due only to differences in new peak generating unit efficiency vs. existing unit efficiency.
- Fuel savings are computed on a city-wide basis.
- It is assumed that after retrofit, power plants will continue to use the same fuel mix as had previously been used. It is further assumed that retrofitted plants will be utilized in the same general operating sequence as before retrofit.

To compare the current fuel use estimates with the estimated fuel used by cogeneration under DHCS operation, the useful Btu requirements of the city must be considered. These are listed in Tables 5.2 and 5.3. From these *end use* energy requirements, the amount of energy which must be generated at the plant door can be determined. This is done by utilizing the 75% district heating factor and the 10% line-loss factor previously used in this study. Thus, for each Btu required by the end user, $1.48 (1 \div .75 \div .9)$ Btus of energy must be generated by the plant.

Table 6.1 Selected Heating/Cooling Characteristics for Residential Units

	C h i c a g o	C l e v e l a n d	D e t r o i t	M i l w a t e r	S t . L o u i s	W a s h i n g t o n, D. C.
House Heating						
Fuel Percentages						
Utility Gas	62	94	87	72	87	52
Fuel Oil, Kerosene, Etc.	15	1	4	21	8	35
Electricity	3	2	2	2	2	6
Coal or Coke	17*	1	5	3	1	4
Other Fuels	2	2	2	2	2	3
Heating Equipment						
Percentages						
Steam or Hot Water	56	20	29	24	28	55
Warm Air Furnace	25	66	59	64	50	32
Built-In-Electric	2	1	1	2	1	4
Other	16	13	11	10	20	8
Selected Heating						
Equipment Percentages						
Steam or Hot Water						
Rental Units	65	30	46	33	33	55
Owner Units	38	8	17	14	22	56
Air Conditioning						
Percentages	37	19	22	29	25	52

*Chicago figures have changed dramatically because of new environmental regulations on coal burning. The oil/gas percentages currently are thought to be similar to those of the other cities.

Table 6.2 Current Fuel Usage - By City

	% Gas	% Oil	% Elec.	% Other	10 ⁶ Sq. Foot	Btu Ft ²	% Eff. Gas	% Eff. Oil	% Eff. Elec.	% Eff. Other	Usage Btu x 10 ¹²			
											Gas	Oil	Elec.	Other
Wash., D.C.														
Res.	.52	.35	.06	.07	295	175	57.8	55.4	56.2	30	17.0	11.9	2.0	4.4
C/I	.13	.79	.04	.04	173	95					1.3	8.6	0.4	0.8
St. Louis														
Res.	.87	.08	.02	.03	244	207	57.8	55.4	56.2	30	27.7	2.7	0.7	1.8
C/I	.41	.57	0	.02	137	114					4.0	5.9	0	0.4
Cleveland														
Res.	.94	.01	.02	.03	328	252	57.8	55.4	56.2	30	49.1	0.5	1.1	3.0
C/I	.47	.51	0	.02	120	149					5.3	6.0	0	0.4
Milwaukee														
Res.	.72	.21	.02	.05	299	302	57.8	55.4	56.2	30	41.1	12.5	1.2	5.5
C/I	.29	.67	0	.04	103	171					3.2	7.8	0	0.9
Detroit														
Res.	.87	.04	.02	.07	489	273	57.8	55.4	56.2	30	73.3	3.5	1.7	11.4
C/I	.41	.53	0	.06	148	151					5.8	7.8	0	1.6
Chicago														
Res.	.76	.18	.03	.03	530	250	57.8	55.4	56.2	30	63.6	15.7	2.6	4.8
C/I	.25	.72	.01	.02	563	143					12.7	38.2	0.5	1.9

The next step down the DHCS energy pathway involves the amount of energy input to the plant to allow generation of the required plant output. To generate this number the heat rates of the subject plants can be utilized. Although heat rates will differ somewhat among plants (and indeed individual units) it was determined that the generic numbers generated from previous work on Washington, D.C.¹, would be accurate enough for this study. The heat rate so determined for the thermal component is 1.95 MM Btu/kWh or 0.570 fuel Btu in per thermal Btu out.

At this point, a note of explanation is necessary. The factor 0.570 Btu in/Btu out, may appear on the surface to violate all laws of thermodynamics in that more energy is created than inputed to the system. This rather unique result is due to the nature of cogeneration. In essence, our work revealed that the electric component efficiency (and heat rates) were relatively close before and after cogeneration. However, because of the generation of thermal as well as electric energy after retrofit, the overall efficiency of the system increased by approximately 100%. The electric component losses are small compared to overall thermal gains. When these small losses are considered as Btus sacrificed to gain the large amount of thermal Btus, the accounting framework yields an efficiency credit apparently greater than 100%. This somewhat unique distribution is valid for two major reasons:

- (1) The increase in efficiency is totally resultant from the retrofit operations.
- (2) The thermal output is the energy component which is replacing traditional scarce fuels, and is an added increment to the original electric generating system. It is this comparison of incremented gains and losses that results in high efficiencies.

Using the above logic, an overall energy efficiency factor can be found as follows:

$$\text{Eff.} = \frac{\text{Btu} \times (.75) (.9)}{.5702} = 1.184$$

This efficiency factor can now be used in combination with the city total end use Btus required for each city to obtain an estimate of total Btus of fuel required to run the DHCS. Thus, for Washington, D.C.; 25.9×10^{12} Btu for end use $\div 1.184 = 21.9 \times 10^{12}$ Btu, which is presented in column nine of Table 1.2.

This total Btu requirement for cogeneration is allocated to oil/gas and coal according to the relative capacities and expected operating hours of the respective oil/gas and coal-fired retrofitted generating units.

Results of similar computations for each city are listed in Table 1.2.

Overall Btu and scarce Btu (oil/gas) savings are now simply the result of subtracting fuel consumption after cogeneration from current fuel consumption. Results of these computations are also shown in Table 1.2. Savings of about 90% of scarce-fuel usage are not at all suprising in that coal and nuclear power plants are generally substituted for oil and gas in the primary heat energy source.

REFERENCES

1. Santini, D.J., and A.A. Davis, Argonne National Laboratory, unpublished manuscript (1978).
2. Harrison, W., et al., *District Heating and Cooling Utilizing Temperature Differences of Local Waters. Preliminary Feasibility Study for the Chicago 21 South Loop New Town Project*, Argonne National Laboratory Report ANL/WR-77-1 (May 1977).
3. ASHRAE *Guide Data Books*, Handbook of Fundamentals (1972).
4. Christian, J.E., *Central Cooling - Absorptive Chillers*, Argonne National Laboratory Report ANL/CES/TE 77-8 (August 1977).
5. Uherka, K.H., Argonne National Laboratory, unpublished manuscript (1977).
6. Stodola, A., *Steam and Gas Turbines*, Vol. 1 and 2, Peter Smith, New York (1945).
7. Eudaly, P., Oak Ridge National Laboratory, unpublished manuscript (1978).
8. Olikier, I., *Urban Area District Energy System Study*, draft report #3251-06, Burns & Roe, Inc., Oradell, N.J. (1977).
9. U.S. Department of Commerce, Census of Housing, *1970 Detailed Housing Characteristics*, USGPO, Washington, D.C. (1972).
10. Fulbright, B.E., *MIUS Community Conceptual Design Study*, National Aeronautics and Space Administration Report, NASA TMX-58174 (June 1976).
11. Boyland, R.J., *Seasonal Efficiency for Residential Oil-Fired Central Furnaces and Boilers*, Interdepartmental Communication of the Washington Gas and Light Company (July 1977).
12. Dole, S.H., *Energy Use and Conservation in the Residential Sector: A Regional Analysis*, Rand Report R-1641-NSF (June 1975).
13. Bernstein, H.M., and P.M. McCarthy, *A Study of the Physical Characteristics, Energy Consumption, and Related Institutional Factors in the Commercial Sector*, Hittman Associates, Inc., Report HIT-630 (1975).
14. Salter, R.G., R.L. Petruschell, and K.A. Wolf, *Energy Conservation in Non-residential Buildings*, Rand Report, R-1623-NSF (October 1976).
15. International District Heating Association, *Principles of Economical Heating*, Pittsburgh, Pa. (1973).
16. Bernow, S.S., R.A. Rosen, and J. Karkheck, Brookhaven National Laboratory, unpublished manuscript (1977).

17. Mitroiu, C., *Some Concepts of Choosing Capacities and Flows of Energy for the Warm Side and Cold End, Combined Heat and Power Plants*, Scientific Bulletin, University of Bucharest (1971).
18. Anatol Schelfberg and Alexandru Misu, *An Analysis of the Economic Efficiency of Large Combined Heat and Power Production Systems in Romania*, Scientific Bulletin, University of Bucharest (1971).
19. Colt, G., and I. Grecu, *The Steam Consumption for a District Heating Power Plant*, Energetica Magazine, 10(12), Bucharest (1972).
20. Grecu, I., and A. Ashendorf, *The Increased Condensing Pressure Turbines for District Heating Systems*, Energetica Magazine, 9(1), Bucharest (1969).
21. General Electric Company, *Steam Turbine Generators for Industrial Applications*, Bulletin GEA 8511 A5, General Electric Corp., Lynn, Mass.
22. Worthington Power Recovery Turbines, Washington Large Mechanical-Drive Steam Turbines, Bulletin No. 4875-B1, Worthington, Corp., Wellsville, N.Y.
23. *Turbodyne SST-2 Standard Single-Stage Turbines*, Turbodyne Corp. Bulletin 4805-DGA.
24. Elliot AYR Single-Stage Turbines, Elliot YR Single-Stage Turbines, Elliot Single Valve Multistage Industrial Turbines, Elliot Multivalve Turbines, Bulletin H-31E, Elliot Div., Corner Corp., Jeannette, Pa.
25. Baily, I.G., R.C. Cotton, and R.C. Spencer, *Predicting the Performance of Large Steam Turbine-Generators Operating with Saturated and Low Super-heat Steam Conditions*, American Power Conference, Vol. XXIX, Illinois (1967).
26. Fallah, M.H., Mathtech, Inc., unpublished information (1976).
27. Kearton, W.J., *Steam Turbine Operation*, Sir Isaac Pitman & Sons Ltd., London (1964).
28. Lopatin, B.V., *Thermal Piping Systems*, Technical Publishing Company, Bucharest (1967).
29. Subin, E.P., *The Design of District Heating Piping Systems*, Technical Publishing Company, Bucharest (1964).
30. Johns Manville, *Thermal Tables for Underground Heating and Cooling Systems*, Denver (1975).
31. Iliescu, R., *District Heating Piping Systems*, University of Bucharest Publishing Company (1967).
32. Rose, R.W., *Thermal Insulation for Buried Piping*, District Heating Magazine, IDHA 62(3) (1977).

33. Aamot, H.W.C., and J.J. McFadden, *Utility Distribution Systems in Sweden, Finland, Norway and England*, Corps of Engineers, U.S. Army, Cold Research and Engineering Laboratory, Hanover, N.H. (1976).
34. Aamot, H.W.C., and G. Phetteplace, *Long Distance Heat Transmission with Steam and Hot Water*, presented at International Total Energy Congress, Copenhagen (Oct. 4-8, 1976).
35. *Underground Heat Distribution System*, Report No. BOR-64 for Federation Construction Council by Task Group T-54, Publication 1186, National Academy of Sciences - National Research Council, Washington, D.C. (1964).
36. *Field Investigation of Underground Heat Distribution Systems*, Report No. 47 for the Federal Construction Council by Task Group T-54, Publication 1144, National Academy of Sciences - National Research Council, Washington, D.C. (1963).
37. Development Sciences, Inc., *Using Net Energy Methodology for Energy Planning: Tradeoffs of Supply vs. End Use Technologies, Volume II, Final Report*, Energy Research and Development Administration, FE-77-2443/1, DS 055 (April 1977).
38. Federal Energy Administration, *National Energy Outlook*, Federal Energy Administration Report, FEA-N-75/713 (February 1976).
39. Federal Power Commission, *FPC News*, various issues in 1975-76.