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Economic and Technical Analysis of Retrofit to Cogenerating District Energy Systems: North-Central Cities

by

D. J. Santini, A. A. Davis, and S. M. Marder

**ENERGY AND ENVIRONMENTAL
SYSTEMS DIVISION**

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ECONOMIC AND TECHNICAL ANALYSIS OF RETROFIT TO
COGENERATING DISTRICT ENERGY SYSTEMS: NORTH-CENTRAL CITIES

by

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Energy and Environmental Systems Division

June 1979

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COSTS OF URBAN AREA RETROFIT TO DISTRICT
ENERGY SYSTEMS: NORTH-CENTRAL CITIES

ABSTRACT

Six major U.S. cities have been studied to achieve reasonably accurate estimates of costs required to retrofit them with district energy systems (DES). 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 energy systems (DES). The systems under consideration would involve:

- (1) existing electric generating facilities retrofitted to cogenerate both electric and thermal energy;
- (2) existing thermal systems and, in some cases;
- (3) existing facilities retrofitted with new supplemental boilers.

Costs for district energy systems in each city were compared against those of 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 if availability of gas and oil decreases, the viability of such a district energy system increases. This study also estimates potential savings in scarce fuels (oil and gas) by switching from existing space heat fuel mixes to a cogeneration mode. Results of such estimates are summarized in Table 1.2. Scarce fuel savings would be realized after a long period of time when a DES is made completely operational; however, such savings will not be realized all at once.

Based on these results, this report generally concludes that President Carter's call for investigation and analysis of a resurgence of cogeneration and district heating was well founded. Additional work will be required, possibly on one target city, to identify more closely the site-specific

Table 1.1. Total Costs - \$/10⁶ Btu(a)(b)

City	Discount Rate	DES High Est.	DES Low Est.	Coal to Electr. ^(c)	Coal Gas To Heat	Coal Liquid To Heat
Washington, D.C.	8%	11.52	5.15	19.96	6.26	6.51
	20%	14.46	8.73	36.36	8.69	9.26
St. Louis	8%	12.95	5.61	20.14	5.67	6.03
	20%	21.93	9.53	36.97	8.10	8.78
Cleveland	8%	11.59	4.82	16.45	5.67	6.03
	20%	19.71	8.34	30.01	8.10	8.78
Milwaukee	8%	10.95	4.66	16.05	5.67	6.03
	20%	18.43	7.93	29.23	8.10	8.78
Detroit	8%	12.57	5.47	15.31	5.67	6.03
	20%	20.95	9.20	27.83	8.10	8.78
Chicago	8%	10.14	4.66	20.22	5.67	6.03
	20%	17.08	7.94	37.11	8.10	8.78

(a) Total annualized costs are calculated as follows:

Total Costs =

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

(b) Costs are per final Btu delivered in the building after all conversion losses. Equipment lifetimes are uniformly assumed to be 20 years.

(c) Assumes a 32.5% load factor, plants used only for heating. If plants could be used at 65% load factor, costs would be cut approximately in half.

factors that will determine whether cost estimates will fall within the high or low estimates projected here

Not covered in this study are the numerous institutional problems that certainly would occur should the DES 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 as well as other segments of the economy, most probably would be affected by traffic diversions. The reaction of state and local officials and the attitude of the public, in general, should be assessed.

Table 1.2. Fuel Consumption-Scarce Fuel Savings, 10¹² Btu/yr^(a)

	Current Fuel Consumption						Fuel Consumption Co-Generation			Btu Savings		% Scarce Fuel Saved
	Gas	Oil	Elec. Coal	Elec. Oil	Other	Total	Oil/Gas	Coal-Nuc- lear	Total	Total	Oil/Gas ^(b)	
Wash. D.C.	18.3	20.4	1.5	1.1	5.1	46.4	4.3	16.2	20.5	25.9	35.5	89
St. Louis	31.8	6.7	0.6	0.1	1.8	41.0	4.4	14.7	19.1	21.9	34.2	89
Cleveland	54.4	6.5	1.0	0.1	3.4	65.4	6.1	22.9	29.0	36.4	54.9	90
Milwaukee	44.3	18.3	1.1	0.1	6.4	70.2	5.2	25.8	31.0	39.2	57.5	92
Detroit	79.1	8.4	1.4	0.3	13.0	102.2	11.6	33.2	44.8	57.4	76.2	87
Chicago	78.3	53.9	2.5	0.6	6.7	140.0	12.3	49.1	61.4	78.6	120.5	91

(a) Consumption values consider only the service area served by the cogeneration alternative.

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

An equally important factor for success of the project requires 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 the necessity of general acceptance by end users, or, alternatively, governmental requirement of the use of such a system. It is most likely that long-term unavailability of fuel would be a gradual occurrence rather than a sharp break. Therefore, use out of necessity will not arise immediately for a large block of potential users.

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. Increased options for electric heat have been met by gradual increases in electric capacity. This gradual increase in capacity has mitigated some of the institutional problems. In fact, the ability of the alternatives to DES to be phased in slowly through existing, or incrementally expanded, transmission systems, is a strong obstacle to the rapid introduction of a large district energy system, such as has been assumed in this study.

There may be methods, however, of easing the difficulty of adopting a DES. First, the system can start small by serving the most advantageous areas first and growing incrementally as most utilities currently do. Second, new construction in the planned DES service area could select a temporary oil or gas fired heating, ventilating, air conditioning (HVAC) system that is DES compatible. When DES transmission links are later built, the DES compatible HVAC system could be connected to the DES. These, and other alternatives can be explored in more detailed DES studies than are presented here.

Many of the detailed questions not examined in this report are under consideration in a study of a Minneapolis-St. Paul cogeneration-based district heating system.¹ That particular study arrives at even more optimistic results than this one. That result for Minneapolis-St. Paul is a function of two factors. First, the annual heating demand per square foot of building space is 40 percent greater than for the average of the six cities studied here. Second, the service area, as suggested above, is confined to a more advantageous zone than in this study. Only the central business district (CBD) and limited surrounding high density residential areas are considered

for Minneapolis-St. Paul, while the CBD and large residential areas are examined in this report.

Also under study by Argonne National Laboratory (ANL) are the indirect effects of the DES in terms of employment and secondary capital costs. This study should demonstrate the degree of advantage that a cogeneration DES would have in terms of employment and secondary capital costs (such as induced construction of new housing). The DES should provide more employment in the urban area that it serves than competing heating technologies. This is expected because competing technologies extract and often convert the energy resource in rural areas where housing and employment are not initially available.

In summary, the DES option, which is the object of this study, falls within economic limits which make it a possible option for the future. Detailed technical analysis and past experience [see ref. 1-6] have made it clear that no overruling technical reasons exist to abandon the option. Ongoing and additional studies can resolve some of the economic, environmental, and institutional issues that require more analysis. This, and the Eastern cities study⁷ confirm the existence of a fairly large potential market for the cogeneration-based DES in major northern U.S. cities east of the Mississippi River. If further work proves that this heating system is desirable in one of these cities, it is likely to be desirable in all.

The results of this report can be considered a sound starting point for future work. The significant, but still generalized effort put forth on this analysis of cost components for several cities is a natural complement to the more detailed work done for Minneapolis-St. Paul. Additional work being done on indirect costs should provide an understanding of the total direct and indirect social and capital costs of the DES versus other heating alternatives. It must be admitted, however, that firm conclusions for a given city cannot be based on this study. By necessity, generalized information of technical criteria was used; whereas, specific nuances of a city system may have been overlooked. Previous market analysis³ has revealed that Minneapolis-St. Paul should be the most attractive site in the U.S. for a large cogeneration-based DES. Thus, the detailed analysis of Minneapolis-St. Paul will determine if market penetration of the DES can begin. If the DES is initiated there, then similar detailed study of the cities in this and the Eastern report should be undertaken.

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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 DES retrofit.³ 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. These 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, D.C. study to the other cities under consideration.

District energy systems, although fraught with institutional problems, can yield significant benefits -- from both an economic and a 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 and is, in essence, merely a demand-and-supply analysis. Although site-specific criteria are utilized in the analysis, the criteria are still on a scale that would need significant refinement before an acceptable design can be made to proceed with a retrofit operation.

The overall purpose of this study is to demonstrate that the concept of DES retrofit is, given a range of uncertainty, economically and technically feasible when compared with other options. Two events could foster the serious consideration of a DES, and this study pre-supposes that either of the two is possible and, indeed, probable.

- *The first possible event* 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 DES retrofit found in Cleveland was \$4.97/10⁶ Btu provided. Should the cost of natural gas or fuel oil exceed that level, the DES options would be competitive from a purely economic standpoint. This scenario is true only if the low-cost option is found to be accurate and if 8% financing is possible. The highest cost option for Cleveland (i.e., \$20.12/10⁶ Btu) clearly would not be competitive with traditional fuels.

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¢/gal. At approximately 0.14×10^6 Btu/gal, the usable costs (assuming a 63% efficient furnace)⁹ would be \$4.62/ 10^6 Btu. Natural gas, at an average price of \$1.91/ 10^6 Btu in a 67%-efficient furnace⁹ has an ultimate cost of \$2.84/ 10^6 Btu. This example demonstrates that a projected DES cost of \$4.77-5.72/ 10^6 Btu is not as out of line as could be assumed at first glance. However, this assumes that the low-cost option would prevail.

• *The second possible event* that would enhance the practicability of DES retrofit involves the possibility of traditional fossil fuels becoming unavailable (at any price) in the quantities needed by the cities. Should this occur, available options for fuel supply must be found. Among the many alternatives available, a DES would certainly be included. This report compares the DES options with: (1) a totally electric system; (2) coal gasification systems; and (3) coal liquefaction systems. A DES option, by its very nature, must be instituted in fairly large blocks and, thus, to some extent, precludes the phase in approach that the other alternatives allow. Although the "phase in" problem is real, certain steps can be taken to overcome it. For example, the concept of movable package boilers can be utilized to supplement DES retrofit components until the system attains sufficient flexibility to be viable.

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 extent. It is logical to assume that those sectors that have the best mechanisms (both technically and economically) to adapt 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 commercial 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 DES. Such a decision will be intimately entwined with a myriad of institutional problems.

3. DISTRICT ENERGY SYSTEMS (DES) AND THEIR ALTERNATIVES

In this section, district energy systems are compared to several other methods of providing space heating and water heating in the immediate future. A large range of possible alternatives for providing these functions exists.

Consideration of the properties of district energy systems reveals a distinct market for their application. Because DES are based on the distribution of energy in water, the capital costs for energy distribution are much higher per unit distance than for transmission of electricity. Clusters of buildings and consequent high energy demand density are important to the economic viability of a DES. Such clusters are more frequent and more dense within urban areas.

Within buildings, energy may be distributed by electricity, by air, or by water. Because of lower expenses for gas and oil than for electricity, and because of higher overall efficiency, most heating systems have relied on gas or oil combustion to heat air or water. The selection of water as a distribution medium is more common in multi-floor buildings where the smaller volume occupied by the distribution system allows more floor space available for rent. The more common use of water as an in-building energy distribution medium in high-density urban areas means that new buildings located there probably can be made compatible with a DES at a reasonable cost.

These properties of the DES market restricted this search for applications of DES to large center cities where building and energy demand densities may be expected to be high.

Conceptually, a DES may provide either heating or cooling. Cooling can be provided by using an absorption chiller, a device which uses heat to produce a cooling effect. However, this process is relatively inefficient. A good absorption chiller may have a coefficient of performance (COP) of up to 0.70; whereas, a good compression chiller may have a COP (energy delivered/energy input) of 4.4, because it uses energy to pump (transfer) heat from one location to another. As will be shown later, these COP values mean that, in most cases, less net energy is used by generating electricity to run a compression chiller than by cogenerating heat to run an absorption chiller.

Consequently, from an efficiency point of view, a DES should generally not be used for cooling. There are, however, limited exceptions to this rule for a specific type of cogenerating unit.

This property of the DES market caused us to confine the search for applications of DES to northern cities where the demand for heating relatively dominates the total space-conditioning demand. A further study will be made for cooling in which the present experience is limited.

In addition to confining itself to northern cities, this study is further restricted to only six of these cities, five of which are in the Midwest. The sixth city, Washington, D.C., was initially studied in conjunction with Brookhaven National Laboratory to develop general methods of evaluating district energy systems. Based on the common Washington, D.C. experience, Brookhaven has conducted a study of three Eastern cities; Argonne has conducted this study of five Midwestern cities.

In this report, the Washington, D.C. experience is used to compare district energy systems and their alternatives from various points of view. First, the alternative energy delivery systems to be evaluated will be described. Second, the economies of the systems will be computed and compared. Finally, the relative efficiency of the systems and their potential for offsetting scarce fuel will be evaluated.

Before proceeding, it is necessary to indicate why this study covers only the subject of heating and hot water and excludes cooling. The major reason was the lack of reliable and available data on cooling characteristics of buildings in the cities covered. The inclusion of cooling should reduce the costs of energy delivered, would change the requirements for plant replacement, and would modify design criteria.

3.1 ESTABLISHING THE ALTERNATIVES

This study considers the possibility of substituting a steam-based, district energy system for the current conventional heating methods in the time frame from the early 1980s to the first decade of the 21st century. The

future scenario on which the study is based is one in which natural gas and crude oil supplies to Midwestern cities are gradually constricted, thereby forcing the substitution of alternative energy sources for these fuels.

Some alternative technologies, e.g., solar and geothermal, and alternative locations, e.g., rural and suburban, are eliminated by simple logic. Geothermal energy is not available in the Midwest. Solar energy will more likely penetrate the suburban, single-family housing market before it serves high-density, urban areas. In suburban buildings, the ratio of rooftop surface-area-to-interior heated volume is more favorable to solar heating. The high distribution costs involved in circulating hot water from a central point to single-family homes makes a decentralized solar system with heat generators in each home much more competitive. Thus, even within the cities under study, those areas dominated by single-family housing are eliminated.

The alternatives given prime consideration here are those that substitute coal as an original resource for oil and natural gas. The proximity of the Midwest to vast coal reserves makes this one of the most likely areas for early substitution of coal for oil and gas. Nuclear power also is a likely alternative to oil and gas, but offers a smaller set of possibilities. Nuclear power can be used to generate electricity or thermal energy; however, unlike coal, it cannot be converted to oil or gas. Furthermore, because this study considers the possibility of retrofitting existing power plants, those power plants closest to the source of demand will be the first to be retrofitted. This procedure would reduce costs of distribution systems.

Because of historical patterns of urban growth and electrical generation technology, the older fossil-fuel power plants tend to be closer in than are the nuclear plants. In fact, most nuclear plants are fairly remote from the areas they serve. Thus, although some nuclear plants will be considered for retrofit to a DES, most potential retrofit situations will be for fossil-fueled power plants. Although Washington, D.C., power plants are fired mainly by oil, the Midwestern area's power plants are fired predominantly by coal/nuclear. In fact, the Eastern cities were studied by Brookhaven because of the reliance on coal by the Midwest and on oil by the East.

Considering coal to be the Midwest's fuel of first choice to substitute for oil and gas, the possible transformation pathways are traced for converting coal to end-use heating demand. Four possibilities are examined:

1. coal to heating oil to heat;
2. coal to utility gas to heat;
3. coal to electricity to heat; and
4. coal to cogenerated electric/thermal energy to heat.

3.1.1 Current Heating and Air-Conditioning Methods

As of 1970, well over three quarters of the residential dwelling units in our midwestern study cities used utility gas or petroleum derivatives for heating. Table 3.1 illustrates the percentages by house heating fuel for each city.

Table 3.1. Selected Heating/Cooling Characteristics of Residential Units¹⁰

	Chicago	Cleveland	Detroit	Milwaukee	St. Louis	Washington 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 Furnaces	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 other cities.

Chicago had the lowest overall percentage, i.e., 77%. The 17% figure for direct use of coal or coke in Chicago is negligible now, because Chicago has since adopted a coal ban for environmental reasons. This coal ban illustrates that non-price considerations, such as environmental regulations, can impact dramatically on the selection of fuels. As for new electrical power plants, environmental problems will tend to force siting of new cogenerating plants further away from downtown areas. This, in turn, will increase distribution costs and make coal-fired DES less competitive with conventional systems using cleaner fuels, such as utility gas and low-sulfur oil.

The percentages listed in Table 3.1 show the extreme dependence of midwestern cities on utility gas. The projection to be made in this report is that this dependence cannot continue because supplies of utility gas will not be adequate in the future. The decline in availability of gas to serve new housing is apparent from recent trends in househeating systems installed in new homes. From 1971 to 1975 the percentage of new, single-family homes using utility gas in the north-central region of the U.S. declined from 78% to 49%. At the same time, the percentage using electricity increased from 12% to 38%. In multi-family dwelling units the same trend was observed, but the percentages favored electricity even more. In 1975, there were electrically-based systems in 49% of the new multi-family dwelling units -- up 10% from the previous year. As old gas- and oil-fired housing units are removed from the housing stock, the proportion of homes using electricity clearly will increase. The process is slow, however, because the housing stock is replaced at only about 2% per year. In the Midwest, this substitution of electric heat for gas and oil clearly is desirable from the point of view of shifting to the more abundant fuels (coal and uranium). However, as will be demonstrated later, this shift does not result in the most efficient use of coal. In fact, depending on the final method of electric heating, it could be less efficient than gasifying or liquefying coal for use in conventional gas/oil furnaces. Furthermore, independent of the final method of electric heating, it is less efficient than cogenerating electricity and thermal energy.

Table 3.1 also gives a crude breakdown of the type of heating equipment used in dwelling units of the study cities. From this table, it is seen that steam or hot water systems are more common in the study cities than in the North Central region as a whole. Furthermore, steam or hot water systems are

more prevalent in occupied rental units than in occupied owner units. The residential space inventoried for this study is strongly oriented toward rental dwelling units. First, with the exception of Detroit, all cities studied here have more rental than owner units. Second, the procedure used deletes those zones of the cities in which single-family housing dominates.

These characteristics of the market area covered indicate that water-based systems are more competitive in this market than elsewhere. However, they do not necessarily imply lower retrofit costs. The DES being proposed here uses 200°F hot water. Existing steam systems may use water or steam temperatures from 160°F to 350°F. When the DES temperature is higher than the existing water temperature, retrofit would be a matter of simply inserting a heat exchanger in place of the existing boiler or water heating unit. However, when the existing system uses temperatures above 200°F, then one of two options would have to be selected: (1) the whole heating system would have to be replaced, or (2) the 200°F water from the DES could be used as input or makeup water. Although the latter option would be less expensive, it would have only a limited effect on efficiency; whereas, the former, although costing more, would be more efficient.

The 200°F water could be used also by central warm-air systems by replacing the furnace with a water-to-air heat exchanger. This might actually represent the lowest cost situation as far as retrofit is concerned.

Information on commercial buildings is much harder to obtain than that for residences. However, one study of the heating and cooling systems in the central business districts of Denver and Baltimore can at least provide an indication of typical facilities in downtown areas.¹¹ The central business district (CBD) is of particular interest because it is the most densely developed area of a city. As such, it will be the first area to be linked to a DES. The marketability of steam in the CBD is indicated by the presence of steam systems serving the downtown areas of several major U.S. cities.⁸ This study takes the position that bias in the data should be of the type that will give more accurate estimates of demand in the high-density, downtown areas of our cities. As a result, both commercial and industrial energy demand figures are based on the types of buildings found in and around central business districts. For industry, this means that the estimates should be most accurate for labor-intensive industries housed in older, multi-level buildings typically found downtown near a CBD.

The Baltimore and Denver studies indicate that most building square footage in central business districts is for office buildings. In Baltimore, 60% of the CBD is allocated to office space. In Denver, the figure is 57%. As Table 3.2 shows, most CBD buildings are heated by hot air or steam systems. However, a substantial percentage of hot water heating systems exists in the newer Denver CBD.

In summary, we emphasize two points made in this section: first, that our study cities are currently highly dependent on natural gas and petroleum for heating; second, that although warm-air heating systems are found in most existing central city buildings, the use of water-based heating systems is much more frequent in such buildings than elsewhere.

3.1.2 Alternative Heating Methods

The important characteristics of the midwestern space-conditioning market have been discussed previously. These characteristics have been taken into account to develop our scenario of the future. In this scenario, a decline in supplies of natural gas and oil forces the Midwest to switch to coal as an original energy source for urban space conditioning. Although nuclear and solar energy also are potential alternatives for gas and oil, these appear to be less likely to solve the problems of the center cities of urban areas than does the possible use of coal.

Table 3.2. Selected Heating/Cooling Characteristics of Central Business District Floor Space¹¹

City	Heating System				Cooling			
					% Cooling			
	% Hot Air	% Hot Water	% Steam	% Radiant Heat	Equipment Using			
					% Cooled	Steam	Electric	Gas
Baltimore	55	3	41	1	82	32	68	0
Denver	40	19	40	1	77	28	61	11

Some important characteristics of midwestern central cities supporting this scenario are:

1. heavy dependence on gas and oil for space heating;
2. dependence on coal and nuclear sources for power generation;
3. proximity of power plants to central city areas;
4. a relative shift in new construction from gas and oil-based heating systems to electrical systems;
5. abundance of coal in and near the Midwest.

If the scenario established here is accepted, then the logical question to ask is: How can one most efficiently and economically shift to coal? Four major options exist for the transformation of coal to final space-conditioning services. These are conversion of:

1. coal-to-cogenerated-electric/thermal-energy-to-heat;
2. coal-to-utility-gas-to-heat;
3. coal-to-heating-oil-to-heat; or
4. coal-to-electricity-to-heat.

Because the main thrust of this study centers around option number 1 (coal-to-cogenerated electric/thermal-energy-to-heat), all other alternatives will be based on service to the same area of supply as the cogeneration system. As will be seen later, only a percentage of the subject cities will be supplied by a projected DES. This projected area will serve as the basis of comparison for all options. Before proceeding, it is necessary to undertake a brief review of the technology underlying each of the four alternatives considered.

• *Coal-to-Cogenerated-Electric/Thermal-Energy-to-Heat*

The most complex of the options is that in which coal is used to cogenerate electric and thermal energy. In addition to the possibility of building new cogenerating power plants, there is also an opportunity to retrofit existing plants. Based on the Washington, D.C. experience, two generic types of retrofit situations for fossil-steam power plants are available. First, for the older, single-stage generating turbines, a back-pressure and extraction turbine retrofit system may be used.¹² This system is the least flexible and most costly. It derates the electrical output of the plant permanently and costs up to 10% of the capital cost of the turbine.

The older, single-stage turbine units usually are closer to the downtown area than are the newer multi-stage turbine generators. Consequently, the higher cost of the former units is compensated by the lower costs of a distribution system linked to closer units. Figure 3.1(a) details the methodology employed for steam extraction via this mode.

Second, the multi-stage crossover retrofit has several advantages over the back-pressure retrofit of a single-stage turbine.¹³⁻¹⁶ The first advantage is that the intermediate take-off cross-over results in less derating of the power plant. The second is that the cross-over can be temporarily shut off, allowing the plant to generate at its previous full output level. Third, the retrofit itself is less costly (about 5% of the cost of the turbine). Figure 3.1(b) details the cross-over method of steam extraction.

Of particular importance regarding the above two retrofit options is the cost associated with such an undertaking. Retrofit does not consist merely of a few pipes and valves; rather, it may require major modifications of the turbine itself. As will be seen later, a very conservative approach has been taken regarding such costs. Discussions with turbine vendors have established that such retrofits can be accomplished within the dollar estimates utilized here.

Retrofit will require long down-times on the units retrofitted. In extreme cases this down-time could stretch to twelve months, and this factor must be considered in any future detailed study. The most efficient and least costly method of cogenerating is to design a new extraction turbine specifically to generate both electrical and thermal energy.

Finally, gas turbines may be retrofitted to allow capture of exhaust gas via a recuperator boiler. This technique can produce heat power roughly equivalent to twice the original electrical output of the turbine. The cost of such recovery is relatively low. The use of gas turbines would probably be limited in time of use because these units are peaking electrical units with very low load factors. They are very flexible in the sense that cogeneration can be turned on and off with only a 5% penalty in electrical output. As will be shown later, this is the only retrofit option where the thermal energy gained by retrofit is so high in relation to the electrical output sacrificed that it is clearly more efficient to run absorption chillers after retrofit than to run electrically-driven compression chillers without retrofit. (See Ref. 17 and 18).

Fig. 3.1(a). Methodology Employed for Steam Extraction

Fig. 3.1(b). Steam Extraction Via Crossover Method

After electricity and thermal energy have been created by a cogenerating power plant, several options still remain for final conversion of energy to meet space-conditioning demands. For heating, electricity may be used for resistance heating or heat pumps; hot water may be used directly in a hot water system.

Although steam boilers, themselves, are not cogenerating equipment, they often will be necessary in a cogenerating DES because of peak heating demands. Such boilers would be held on standby for those days in which the weather is worse than the "average peak" design conditions, and also to allow flexibility during initial startup. In Washington, D.C., and other cities, existing district heating systems serve the downtown area. Following construction of a new hot water DES, the existing district steam boilers could be retrofitted to generate hot water for peak demands of the new DES.

- *Coal-to-Utility Gas-to-Heat*

In this option, coal is converted to pipeline quality utility gas (~ 1000 Btu/ft³) via the Lurgi gasification process. The Lurgi technology is considered as a surrogate for all gasification technology, in that it appears to be the most advanced and most likely to be utilized soon. Several projects utilizing the Lurgi technology have been under study¹⁹ and the Department of Energy currently is considering cost sharing a demonstration plant utilizing an advanced Lurgi technology (slagging gasifier).

The advantages of the coal gasification option lie mainly in its direct applicability to existing distribution networks. Such a plant could be considered an input into existing piping systems. The technology itself is fairly well demonstrated and is shown in schematic form in Fig. 3.2.

- *Coal-to-Heating-Oil-to-Heat*

In this option, coal is converted first to a synthetic crude oil, and then refined to produce a heating oil that can provide a direct substitute for present-day oil usage. Unlike the gasification option, no clear leader in the technology race exists; thus, a "generic" technology is postulated. Technologies that offer the most promise for the near-term future include:

Fig. 3.2. Basic Coal Gasification Diagram

solvent refined coal II,
the Exxon donor process, and
the H-coal process.¹⁹

These three processes are all currently being actively developed by both government and private investors. The advantages of this route lie in the direct replacement concept. Distribution piping and local truck and barge delivery systems exist. Although limited retrofit problems occur, the plant could be economically sized so that the portion of the plant's output not needed to supply the study city areas could be utilized elsewhere. Figure 3.3 shows the flow sequence for the H-coal process.

- *Coal-to-Electricity-to-Heat*

This option is straightforward and presently is being utilized in areas where gas curtailments exist. Under this scenario, coal would be burned in a conventional utility boiler and then converted to electricity as shown in Fig. 3.4.

This option does not have the advantages of the gas/oil option in that for existing buildings, substantial retrofit problems exist. Virtually all the existing building stock relies on hot water, steam, or forced-air heat. The electric option requires adaptation of these systems to resistance heaters or heat pumps.

Although this section concerns itself primarily with the use of coal to provide heating, undoubtedly, there will continue to be some oil- and gas-fired electrical generating capacity by most electric utilities. Oil- and gas-driven combustion turbines are used by utilities to meet peak electrical demands and for quick response to surges in demand. Combustion turbines are ideal for this purpose because of their low capital cost per unit of generating capacity and because they have an excellent cycling capability.

This section has introduced a comprehensive (though not exhaustive) set of pathways for converting coal into heating and cooling services. Four major possible pathways have been shown. At the same time, it has been illustrated that several permutations of technologies are possible within these pathways. The most complex pathway to evaluate is that for coal-to-cogenerated-electric/thermal-energy-to-heat.

Fig. 3.3. H-Coal Process

Fig. 3.4. Major Components of a Coal-Electric Plant

3.2 EVALUATING THE ALTERNATIVES

The previous section outlined the potential mechanism for supplying energy to residential, commercial, and industrial facilities. Next, the distribution networks, costs, and the efficiency of the alternatives are analyzed. Various assumptions will be made so that each option is examined on an equal basis. The main assumption is that a specific area of the city under consideration must be supplied with energy by a substitute means. By this is meant that, at a certain time, the heating and hot water energy equivalent, which are supplied by a scarce fuel, must be supplied by another option. As was shown in Table 3.1, each city under consideration relies on from 93 to 98% of its space heating energy from scarce fuels.* Thus we assume that, without scarce fuels, a totally new system would be needed, while with scarce fuels, the existing energy system would be utilized in a business-as-usual mode.

In the case of district heating, when a percentage of plant capacity is diverted to heating needs, that electrical capacity will have to be replaced. The cost of a DES would entail not only retrofit of an existing plant, but also construction of new plants to offset the loss.

For a base case of 1,000 MW of heat power required, the costs of the various options would entail the following three elements:

I. Replacement of 1,000 MW of heat power with a DES

Capital Costs:

- Transmission lines from existing plants and new plants to demand zones
- Local piping distribution systems
- End-use building retrofits
- Power plant retrofit
- Replacement of lost capacity

II. Replacement of 1,000 MW of heat power with new coal-fired electric heating

Capital Costs

- Cost of new plant and ancillary capacity
- Cost of end-use retrofit

*The coal or coke figure for Chicago at 17% has been drastically reduced in recent years.

III. Replacement of 1,000 MW of heat power with a coal gasification or liquefaction plant

Capital Costs:

- Cost of gas/liquids plant and ancillary facilities
- Assume that existing distribution and end-use facilities would be utilized in this option

It is necessary first to select the areas of a major metropolitan area that can be supplied by a DES, and then to calculate costs for alternate energy systems for that same area. The following section describes the procedures utilized to select areas, design DES heating systems, calculate costs, and evaluate alternate energy systems.

3.2.1 Selection of Geographic Areas to be Supplied

The base case for this study is a DES that can provide both peak demands for heating and hot water requirements. The entire area of cities under study cannot be covered. Economics as well as availability of present or proposed potential cogeneration facilities serves to put real-world boundaries on the areas considered.

A comprehensive survey of the six metropolitan areas under consideration was supplied by Real Estate Research Corporation. This survey provided square footage of residential, commercial, and industrial buildings within 1 km² units. Using this square footage information and data on building specific energy demand (peak heat and cooling, average heat and cooling, and hot water) aggregate energy demands were developed by the authors on a 1 km² breakdown. Energy demand was segregated according to four types of building space selected. Table 3.3 details the total square footage of each of the four building types for each city.

Obviously, different types of building space will have different types of energy needs; thus an assessment of space by various categories must be determined. Although breakdowns of many building types theoretically are 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;

Table 3.3. City Building Square Footage x 10³

City	Low-Density Residential	High-Density Residential	Commercial Institutional	Industrial
Wash., D.C.	*	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 the high density resid. row for Wash. and St. Louis are the sum of Low-and High-Density Residential categories.

- (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.

Residential square footage generally was developed from U.S. Census estimates of dwelling units in census tracts. Those 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 DES in such areas.^{1,20}

Commercial/institutional and industrial data on square footage were not as readily available. Various sources of information (see Appendix B) 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 DES (see Table 3.4) dictated which data would be used in our final demand estimates.

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 (CBD) allowed

omission in this study of the more energy-consuming shopping-center-type of retail store. This is allowable because district energy systems will be concentrated mostly in the CBDs.*

Residential energy demand was based largely on excellent data generated by contacts in the Washington, D.C. area.^{9,21,22} Data were provided from actual meter readings by disaggregate customer classes of building. 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.⁹ The data generated for Washington, D.C., were compared with previous studies of residential energy use. The Washington, D.C., estimates of $15.06 \text{ Btu/ft}^2 \cdot \text{HDD}$ corresponded well enough with previous efforts ($14.6 \text{ Btu/ft}^2 \cdot \text{HDD}$)²³ that it seemed safe to use this relationship relating energy usage with Heating Degree Days (HDD) to estimate energy usage in other cities (see Appendix B). The average day and peak day values were obtained by using this relationship for the climate of other cities. The estimate of peak heat usage was generated by utilizing the ASHRAE 97.5% design temperature. For example, for Washington, D.C., the 97.5% design temperature was 10°F ; the peak heat load would be $14.6 \text{ Btu/ft}^2 \cdot \text{HDD}$ ($65^\circ - 19^\circ$) = $671.6 \text{ Btu/ft}^2 \cdot \text{day}$. Because of other factors, e.g., diversity (described in Appendix B) the use of a 97.5% design temperature is appropriate in this study.

Because data for high-rise residential buildings were less available, an assumption was made that this classification would behave in essentially the same way as low-density residential regarding 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 developed from the limited data that did exist, and was found to apply fairly consistently for, not only average heating, but also for peak heating and cooling. Use of this factor in concert with the transfer equation for average heating loads in various cities allows an analysis to be made of peak heat load of residential units in cities under consideration.

*Admittedly, this procedure will underestimate commercial energy demands outside of CBDs.

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.¹¹ Based on such findings, it is reasonable to assume that the office building can be used as a good surrogate for the overall energy consumption behavior in central business districts. A regression equation that is dependent on heating degree days and solar insolation was formulated to estimate the commercial (office building) energy usage per square foot.^{24,25} (See Appendix B.)

A lack of first-hand data precludes an accurate calculation of energy consumption for industrial buildings. 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 similarly 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 1:1.18.²⁶ Although validation of this ratio is lacking, 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. The validity of this function is not critical, since downtown areas, that are likely to be served first by a DES, have far more C/I floor space than industrial facilities. Industry tends to be more dispersed throughout the city than is commercial activity.

Hot-water usage is assumed to be a function of occupancy levels rather than of square footage; thus hot-water usage varies by the occupancy levels per square feet assumed for each building type. Previous work provides insights into residential hot-water usage. After correction, a value of 22 Btu/ft²-day was generated for low-density, residential hot-water usage. To arrive at hot-water usage in high-density residential, a surrogate of rooms per unit was utilized for hot-water consumption. Commercial/industrial hot-water usage was based on work by Brookhaven National Laboratory and the Energy Systems Research Group in a companion study;⁷ whereas, industrial hot-water usage was scaled up from C/I in the same way as was the heating demand.

Having both the square footage available, by km^2 (or mi^2) in each city as well as unit energy demands, energy demand factors can be determined for the total city. Table 3.4 depicts these factors for the six study cities.

The information below allowed estimation of various data on a km^2 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.

Table 3.4. Energy Demand Factors, $\text{Btu}/\text{ft}^2\cdot\text{Day}$

City	Low Den. Resid.	High Den. Resid.	Comm./Inst.	Industrial
Wash., D.C.				
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

To summarize, each km² (or mi²) is provided with the following information:

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

Having arrived at the aggregate demand, plots were prepared to locate visually high-density demand zones. Figure 3.5 (a-f) shows the results of such plots for the six study cities.

Information gathered from utility companies serving the six cities determined the current electric generating facility locations with respect to demand zones, as well as potential capacity available. By an analysis of the demand areas and the supply locations, preliminary "zones" were established for bringing a district heating system on-line. The primary criteria for selecting such zones were based on the ability to:

- serve the highest density areas first;
- minimize distance from the energy source to the demand area; and
- utilize existing facilities before considering new capacity.

With these general criteria in mind, and by a series of trial-and-error modifications of zone boundaries, a fairly good sequence of DES introduction was formulated. Table 3.5 details the supply and demand for the subject cities, and Fig. 3.6 (a-f) displays the zones on the demand maps. Note that heat demand to determine capacity is defined as peak heat demand plus hot water demand.

As was seen in Table 3.5, the supply and demand do not exactly match; in fact, in some cases demand exceeds supply. However, in no case does demand exceed supply by more than 2%. This small overload can be compensated for easily and is certainly within the limits of error of this study. In most cases, the entire city will not be covered by the DES. As explained above, the high-energy-demand areas (most likely cost effective) were covered first. As the study progressed to lower demand areas, if the available supply were

Fig. 3.5(a). Residential Average Day Heating Demand Pattern, Illustrated by Computer Graphics for Washington, D.C.

Fig. 3.5(b). Residential Average Day Heating Demand Pattern,
Illustrated by Computer Graphics for St. Louis

Fig. 3.5(c). Residential Average Day Heating Demand Pattern,
Illustrated by Computer Graphics for Detroit

Fig. 3.5(d). Residential Average Day Heating Demand Pattern,
Illustrated by Computer Graphics for Milwaukee

Fig. 3.5(c). Residential Average Day Heating Demand Pattern,
Illustrated by Computer Graphics for Cleveland

Fig. 3.5(f). Residential Average Day Heating Demand Pattern,
Illustrated by Computer Graphics for Chicago

Fig. 3.6(a). Washington, D.C. -- Demand Zones and Supply Lines

Fig. 3.6(b). St. Louis — Demand Zones and Supply Lines

Fig. 3.6(c). Cleveland -- Demand Zones and Supply Lines

Fig. 3.6(d). Milwaukee -- Demand Zones and Supply Lines

Fig. 3.6(e). Detroit -- Demand Zones and Supply Lines

Fig. 3.6(f). Chicago -- Demand Zones and Supply Lines

Table 3.5. Basic Heat Data on Six Study Cities

City	Peak ^(a) Demand M-W Heat Power	Usable ^(b) Supply MW-Heat Power	Total City Area, km ²	Area Covered km ²	% of City Covered	Average ^(c) Demand MW-Heat Power	Actual ^(d) Plant Supply MW-Heat Power
Wash., D.C.	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	13300

(a) Peak demand is defined as the maximum load which would be required in the covered section of the city during the heating season.

(b) Usable supply is the amount of heat energy which can be relied on to supply the demand after losses.

(c) Average demand is the summation of each day's demand divided by the number of days summed (365).

(d) Actual plant supply is the amount of heat energy generated by the units retrofitted prior to losses.

exhausted, no consideration was given to adding new plants. Thus, in most cases, the cutoff for boundaries of the DES was determined by exhaustion of the available supply.

A considerable amount of effort was expended in determining estimates for heat loading in various types of buildings as well as in the different cities. Such work was the underpinning of this section. A detailed explanation of such background work may be found in Appendix B.

The zones and total areas of the cities covered herein now serve as the basis for comparison of all alternatives. For example, for an energy supply technology option in Detroit, the basic parameter will be to cover 374 km or to provide some cogeneration services to 98% of the sq. km zones of the city (see Table 3.5).

3.2.2 The Coal-to-Cogeneration Option

- *Selection of supply points*

The intent of this section is to provide a brief overview of the methodology used to assess the energy that could be obtained via cogeneration retrofit. A detailed technical description may be found in Appendix A. The methods of retrofit and some brief observations follow.

- *Condensing Pressure and Extraction Volume Increase Retrofit on Existing Turbines.* This type of retrofit is applicable to existing single-stage turbines larger than 20 MW. Turbines with a power under 20 MW have been shown to be an uneconomical retrofit situation and are excluded from consideration. The type of turbine considered has existing steam extractions at specific points.

In keeping with the scope of this study, theoretical thermodynamic formulas were used to obtain heat and work outputs. However, actual steam characteristics were used to determine properties at the various input and outlet points. The general procedure used was to extract steam (at various points) in excess of that used in the existing system. The amount of steam extracted was that needed to provide a given amount of heat energy for the DES.

Table 3.6 shows the results of the generic analysis for 30-, 60-, and 100-MW power units. (Derating varies from 35 to 51% of initial loading.) Conversely, overall power (heat plus electrical) increases by 208% to 235% of the original loading.

Table 3.6. Retrofit Condensing Pressures and Extraction Volume Increases (CPEI) Data

No.	Nominal Turbine Power, MW	Parameters		Electric Power		Heat Power		Total Heat and Electric Power, MW
		PSIA	°F	MW	% of Original	MW	% of Original	
1	30	715	850	14.7	49	55.8	185	70.5
2	60	915	900	31.6	53	104.6	174	136.2
3	100	1515	1000	64.8	65	143.4	144	208.2

- *Intermediate Crossover Extraction Retrofit on Existing Turbines.*

For both the tandem compound and cross compound turbine arrangements, crossover steam extraction was utilized. Because of economic considerations, this method was found preferable to extraction from the turbine itself. The cost of modifying the casing and possibly changing the rotor, if steam were to be extracted from the turbine, would exceed 50% of the original turbine costs. Conversely, crossover extraction, which requires piping modifications and installation of a regulating valve, can be accomplished at a cost of 5-10% of the initial turbine cost.

Five generic units were studied for this methodology: 60, 100, 120, 200, and 320 MW, power.

Table 3.7 details the results of the generic study and shows the expected pattern of decreased electrical output and increased overall power output.

- *Recuperator Retrofit on Existing Gas Turbines.* Much of the heat in the exhaust gas from an open-cycle gas turbine can be recovered to generate heat power. At an inlet temperature of between 500 and 1200°F, a well-designed recuperator can produce heat power of double the initial electrical power produced by the gas turbine. The design and boiler outlet temperature would be 325°F $\pm$ 25° to prevent corrosive effects caused by condensation.

Table 3.7. Retrofit Intermediate Crossover
Extraction (CO) Data

No.	Nominal Turbine Power, MW	Parameters				Electric Power		Heat Power		Total Heat & Electric Power, MW
		PSIA	°F	PSIA	°F	MW	% of Original	MW	% of Original	
1	60	915	900	-	-	45	75	75	125	120
2	100	1515	1000	-	-	70	70	130	130	200
3	120	1515	1000	360	1000	90	75	150	125	240
4	200	2365	1050	441	1000	145	73	255	128	400
5	820	Complex				230	70	350	110	580

Figure 3.7 diagrams the available inlet temperatures to a recuperator (A) and the heat that can be recovered (B) as a function of gas turbine % loading. This figure is for a typical 10-MW gas turbine. The amount of power (heat) available is a direct function of the percent rated load of the turbine.

- *Conversion of Existing Steam Boilers (Installation of New Hot Water Boilers).* In the event that a facility has an existing steam-producing boiler, either for electrical generation or for a steam DES, that boiler can be a likely candidate for conversion to hot water and inclusion in our overall supply matrix. We are assuming that the boiler in question no longer is needed for electrical generation because of retirement of the turbine or for some other reason.

In such a case, this study assumes that the fuel in such a boiler would be the same after retrofit; however, the option to switch fuel always exists, subject to economic and technological considerations. However, for this study, fuel switching was not costed. The conversion from steam to hot water is estimated at approximately 15% of the original boiler cost.

Should a large DES design require more heat power than can be made available from the existing system, installation of new hot water boilers should be considered. For a DES, the ideal type of boiler would be one of large capacity (>100 MW heat power) but which produces low temperature water (200-300°F).

By knowing the above information, potential supply data for each electrical generation unit and boiler can be closely estimated. Table 3.8 (a-f) gives such a detailed breakdown and shows that each plant site is individually analyzed for the effects of retrofit. The column headed "Power before retro MW," is the starting point for available supply. As is explained later in more detail, losses and capacity factor corrections are calculated to result in a loss of some 33% of initially available supply. This correction explains the difference between the columns labeled "Actual Plant Supply MW Heat Power" and "Usable Supply MW Heat Power" in Table 3.5. A much more detailed analysis of each individual unit can be found in Appendix A.

Fig. 3.7. Inlet Temperatures to Recuperator Boiler Vs. Exhaust Heat Recoverable

Table 3.8.(a) Washington Supply Selection Chart

Facility	Type Unit	No. Units	Fuel	Power Before Retro. MW	Power After Retrofit		Loss Elec. Power MW	Retrofit*
					MW Elec.	MW Heat		
Zone I								
Benning Buzzard Pt.	Steam Tur.	7	Oil	685	463	845	222	CPE/CO
Buzzard Pt.	Steam Tur.	5	Oil	230	130	391	100	CPE
Potomac	Comb. Tur.	2	Oil	320	290	640	30	RC
New Thermal	Steam Tur.	5	Coal	455	325	600	130	CO
Boiler		2	Oil/Coal	-	-	200	-	Boiler
Zone II								
Benning	Boiler	1	Oil	-	-	55	-	CB
W. Thermal	Boiler	1	Oil	-	-	100	-	CB
C. Thermal	Boiler	1	Oil	-	-	100	-	CB
New Thermal	Boiler	1	Oil/Coal	-	-	100	-	Boiler
Zone III								
Dickerson	Steam	1	Coal	183	125	210	58	CO
New Dickerson	Steam	1	Coal	800	560	875	240	Ext. Turb.
Zone IV								
Morgan-town	Comb.	6	Oil	290	260	580	30	RC
Dickerson	Steam	2	Coal	366	250	420	116	CO

*CPE = Condensing pressure and extraction volume increase retrofit method

CO = Intermediate crossover extraction retrofit method

CB = Converted existing boiler

RC = Recuperator retrofit on gas turbine

Ext.Turb.= New turbine specifically designed for extraction

Table 3.8.(b) St. Louis Supply Selection Chart

Facility	Type Unit	No. Units	Fuel	Power Before Retro. MW	Power After Retrofit		Loss Elec. Power MW	Retrofit* Method
				MW Elec.	MW Heat			
Zone I								
Ashley	Steam Tur.	4	Oil	70	42	140	28	CPE
Venice	Steam Tur.	6	Oil	500	295	780	205	CPE/CO
Venice	Comb. Tur.	1	Gas	38	34	75	4	RC
Zone II								
Merimac	Steam Tur.	4	Coal/Gas	800	550	910	250	CO
Merimac	Comb. Tur.	1	Oil	60	54	120	6	RC
Zone III								
Labadie	Steam Tur.	4	Coal	2200	1660	1950	540	CO
Zone IV								
Sioux	Steam Tur.	2	Coal	980	700	1000	280	CO

*See Table 3.8(a) for meaning of symbols

Table 3.8.(c) Cleveland Supply Selection Chart

Facility	Type Unit	No. Units	Fuel	Power Before Retro. MW	Power After Retrofit		Loss Elec. Power MW	Retrofit* Method
					MW Elec.	MW Heat		
Zone I								
Ashtabula	Steam Tur.	9	Oil/Coal	745	430	1115	315	CPE/CO
East Lake	Steam Tur.	5	Coal	1175	805	1430	370	CO
Lake Shore	Steam Tur.	5	Coal	480	285	655	195	CPE/CO
Edgewater	Steam Tur.	2	Coal	180	110	260	70	CPE/CO
Zone II								
Avon Lake	Steam Tur.	9	Oil/Coal	1180	750	1535	420	CPE/CO
Zone III								
Davis								
Besse	Nuclear	1	Uran.	910	680	1000	230	CO

*See Table 3.8(a) for meaning of symbols

Table 3.8.(d) Milwaukee Supply Selection Chart

Facility	Type Unit	No. Units	Fuel	Power Before Retro. MW	Power After Retrofit		Loss Elec. Power MW	Retrofit* Method
					MW Elec.	MW Heat		
Zone I								
Port Wash.	Steam Tur.	5	Coal	400	275	500	125	CO
Port Wash.	Comb. Tur.	1	Gas	20	18	40	2	RC
Lakeside	Steam Tur.	11	Oil/Gas	320	160	580	160	CPE
Lakeside	Comb. Tur.	1		40	36	80	4	RC
Point Beach	Steam Tur.	2	Nuc.	1040	780	1220	260	CO
Point Beach	Comb. Tur.	1		20	18	40	2	RC
Valley	Steam Tur.	2	Coal	270	190	310	80	CO
Zone II								
S. Oak Creek	Steam Tur.	4	Coal	1170	820	1260	350	CO
S. Oak Creek	Comb. Tur.	1		20	18	40	2	RC
N. Oak Creek	Steam Tur.	4	Coal	600	340	660	260	CO
Zone III								
Commerce	Steam Tur.	1	Oil/Gas	35	17.5	65	17.5	CO
E. Wells	Boiler	1	Oil/Gas	-	-	15	-	RC
New Thermal	Boiler		Coal/Oi	-	-	1460	-	Boiler

*See Table 3.8(a) for meaning of symbols

Table 3.8.(e) Detroit Supply Selection Chart

Facility	Type Unit	No. Units	Fuel	Power	Power		Loss	Retrofit*
				Before	After	Retrofit	Elec.	
				Retro.	MW	MW	Power	
				MW	Elec.	Heat	MW	Method
Zone I								
Conners Cr.	Steam Tur.	8	Coal/Oil/Gas	540	370	725	170	CPE/CO
Del Ray	Steam Tur.	6	Oil/Gas	375	195	630	180	CPE
River Rouge	Steam Tur.	3	Coal/Oil	900	620	950	280	CO
Zone II								
Trenton	Steam Tur.	3	Coal/Oil	775	570	915	205	CO
Monroe	Steam Tur.	3	Coal	2460	1725	2700	735	CO
Willis/ Beacon	Steam Tur. Thermal	-	Oil/Gas	-	-	572	-	Boilers
Zone III								
St. Clair	Steam Tur.	7	Coal/Oil	1880	1325	2100	555	CO

*See Table 3.8(a) for meaning of symbols

Table 3.8.(b) Chicago Supply Selection Chart

Facility	Type Unit	No. Units	Fuel	Power Before Retro. MW	Power After Retrofit		Loss Elec. Power MW	Retrofit* Method
					MW Elec.	MW Heat		
Zone I								
Crawford	Steam Tur.	2	Coal/Gas	545	380	600	165	CO
Crawford	Comb. Tur.	1		210	190	420	20	RC
Fisk	Steam Tur.	2	Coal	490	340	620	150	CO
Fisk	Comb. Tur.	2		310	279	620	31	RC
Ridgeland	Steam Tur.	4	Oil/Gas	645	450	745	195	CO
Zone II								
Will Cty.	Steam Tur.	4	Coal	1125	810	1280	315	CO
Joliet	Steam Tur.	4	Coal	1605	1175	1950	430	CO
Joliet	Comb. Tur.	2		160	144	320	16	RC
Lombard	Comb. Tur.	1		300	270	600	30	RC
Aurora	Comb. Tur.	1		300	270	600	30	RC
Zone III								
Calumet	Comb. Tur.	1		300	270	600	30	RC
Zion	Steam Tur.	2	Nuclear	2200	2200	2400	660	CO
Stateline	Steam Tur.	4	Coal	960	660	1065	300	CO
Waukegan	Steam Tur.	4	Coal	890	610	1180	280	CO
Waukegan	Comb. Tur.	1		150	135	300	15	RC

*See Table 3.8(a) for meaning of symbols

- *Capital Costs of the Cogeneration Option*

- *Costing of Transmission Lines.* The above knowledge of supply points and demand centers yields the end points for the transmission piping network. Knowledge of the volume of water to be distributed and the transmission distances allows an accurate estimate to be made of transmission pipe sizing. Transmission pipe is defined as the main lines that leave and return to the supply point. Line sizes will be reduced further within the city by a local distribution system. Only the main pipelines are considered in transmission cost. Figure 3.6 (a-f) displayed the proposed transmission loop for each of the five study cities (see pp. 36-41).

Costs of transmission pipe installation vary widely, depending on the area to be served and the materials used. Partial cost estimates were provided by Burns & Roe Corporation.²⁷ Because of the wide cost variables involved, two sets of costs are calculated. This procedure will be followed in many areas of this study. The high-cost estimate emphasizes difficulty in laying pipe in urban areas and extends such high urban costs virtually to the city boundaries. Moreover, the high cost option utilizes steel piping throughout. The low-cost option recognizes that a cost gradient for pipe installation exists from the urban core to the rural supply sites. Thus, a fraction of the "mid-area" pipe is factored in at a reduced cost. The low-cost option also substitutes arimid fiber piping for steel, a materials saving of some 30 percent.

Utilizing the above criteria, Table 3.9 details the transmission costs, by zones, in the various cities.

- *Costing of Local Distribution System.* Having determined the termination points of individual major transmission lines, the next step is to provide a delivery system directly to the end user.

The transmission pipe routes were carefully selected so that, in most cases, no distribution line will have to extend beyond 2 km from the main transmission trunk. By this arrangement, costs projected via detailed work undertaken by Energy Systems of Boston, Mass.,⁷ will be applicable to the present analysis. Energy Systems data can be mathematically expressed by Eq. 3.1 and 3.2.

Table 3.9. Transmission Costs by Zone

Area	High Estimate 10 ⁶ \$	Low Estimate 10 ⁶ \$
<u>Washington, D.C.</u>		
Zone I	115	47
Zone II	24	9
Zone III	161	83
Zone IV	168	86
Total:	468	225
<u>St. Louis</u>		
Zone I	75	26
Zone II	93	47
Zone III	192	55
Zone IV	90	58
Total:	450	186
<u>Cleveland</u>		
Zone I	157	53
Zone II	237	111
Zone III	74	33
Total	468	197
<u>Milwaukee</u>		
Zone I	342	200
Zone II	212	57
Zone III	8	3
Total:	562	260
<u>Detroit</u>		
Zone I	517	299
Zone II	133	47
Zone III	209	110
Total:	859	456
<u>Chicago</u>		
Zone I	273	96
Zone II	291	204
Zone III	378	188
Total:	942	488

$$C = 4.2540 + 0.01094D \quad (3.1)$$

or

$$C = 0.6965 + 0.411 (D^{0.5}) \quad (3.2)$$

where:

C = cost per zone in $10^6\$$

D = Annual demand per km^2 in 10^9 Btu/yr

Equation 3.1 is best applied to lower capacity areas; whereas, Eq. 3.2 is best applied to extremely high demand density areas, such as Chicago. Although the design of our local distribution network is not identical to that assumed by Energy Systems, the application of the above formulas should yield sufficient accuracy for this study.

The results from Eq. 3.1 and 3.2 will be high for the same reasons expressed under the transmission system above (i.e., urban add-on and steel piping). Accordingly, similar adjustments are applied to the distribution costs. Applying the equations to applicable city zones, projected costs are shown in Table 3.10.

- *End-Use Retrofit.* Having established the costs of bringing hot water directly to the end users' building, it is now necessary to consider the costs of retrofitting existing buildings to accommodate the DES. For the scope of this study, only that retrofit necessary to accomplish heating and hot water is considered.

Retrofit costs will vary widely according to the type of building to be retrofitted. Raw data for various types of retrofit operations are derived from work undertaken by Burns & Roe Corp.²⁷ Data are provided for heating retrofit for various building classifications in dollars/ ft^2 of building space. Because of the nature of commercial and industrial buildings in the center city (i.e., high-rise rather than low-level spread), the same cost factor is applied for both building classes. The criteria for residential assumes that most residential retrofits are of the multi-story variety; thus, such factors are used for all residential retrofit costs.

For each factor, the data provided details of two categories that are dependent on the size of the individual building to be retrofitted. This is a reflection of economy of scale. To be consistent with our high/low cost

Table 3.10. Distribution Costs by Zone

Area	High Estimate 10 ⁶ \$	Low Estimate 10 ⁶ \$
<u>Washington, D.C.</u>		
Zone I	287	100
Zone II	48	17
Zone III	218	76
Zone IV	161	56
All Zones:	<u>714</u>	<u>249</u>
<u>St. Louis</u>		
Zone I	183	64
Zone II	180	63
Zone III	274	96
Zone IV	167	59
All Zones:	<u>804</u>	<u>282</u>
<u>Cleveland</u>		
Zone I	639	224
Zone II	380	133
Zone III	242	85
All Zones:	<u>1261</u>	<u>442</u>
<u>Milwaukee</u>		
Zone I	501	174
Zone II	444	155
Zone III	308	108
All Zones:	<u>1253</u>	<u>437</u>
<u>Detroit</u>		
Zone I	446	156
Zone II	827	299
Zone III	940	329
All Zones:	<u>2213</u>	<u>784</u>
<u>Chicago</u>		
Zone I	120	42
Zone II	596	209
Zone III	576	202
All Zones:	<u>1292</u>	<u>453</u>

approach, the factors for larger and smaller buildings will be used to yield the high- and low-cost estimates; these factors are:

High-Cost Commercial/Industrial	= \$0.76/ft ² , (smaller building)
Low-Cost Commercial/Industrial	= \$0.41/ft ² , (larger building)
High-Cost Residential	= \$0.32/ft ² , (smaller building)
Low-Cost Residential	= \$0.24/ft ² , (larger building)

From the disaggregated data provided by Real Estate Research, square footage by building type for each zone can be gathered similar to those in Table 3.3. The equation derived that best expresses the cost of retrofit is then:

$$C = F_{CI}(C+I) + FR_I(R_1) + FR_{II}(R_2) \quad (3.3)$$

where:

- C = cost of retrofit in \$
- F_{CI} = cost factor for C/I buildings in \$/ft²
- C = commercial floor space in ft²
- I = industrial floor space in ft²
- FR_I = cost factor for residential class I space in \$/ft²
- FR_{II} = cost factor for residential class II space in \$/ft²
- R_1 = residential Class I floor space in ft²
- R_2 = residential Class II floor space in ft²

Applying the above equation to the zones in the study cities the results are shown in Table 3.11.

- *Power Plant Retrofit.* An additional cost of a DES is the retrofit cost associated with backfitting electrical or heat-generating systems. As mentioned in Sect. 3.2.2 and more fully detailed in Appendix A, five basic retrofit options are under consideration in this study;

- (1) condensing pressure and extraction volume increase retrofit on existing turbines (CPE);
- (2) intermediate crossover extraction retrofit on existing turbines (CO);
- (3) recuperator retrofit on existing gas turbines (RC);
- (4) installation of new, specifically designed extraction turbines; and
- (5) conversion of existing steam boilers or installation of new hot water boilers (CB).

Table 3.11. End-Use Retrofit by Zone

Area	High Estimate 10 ⁶ \$	Low Estimate 10 ⁶ \$
<u>Washington, D.C.*</u>		
Zone I	136	82
Zone II	17	10
Zone III	47	31
Zone IV	27	19
All Zones:	227	142
<u>St. Louis</u>		
Zone I	49	27
Zone II	37	21
Zone III	62	35
Zone IV	34	30
All Zones:	182	113
<u>Cleveland</u>		
Zone I	129	82
Zone II	40	27
Zone III	28	19
All Zones:	197	128
<u>Milwaukee</u>		
Zone I	84	56
Zone II	56	34
Zone III	34	25
All Zones:	174	115
<u>Detroit</u>		
Zone I	133	88
Zone II	63	43
Zone III	73	47
All Zones:	269	178
<u>Chicago</u>		
Zone I	259	140
Zone II	177	110
Zone III	161	108
All Zones:	597	358

*Wash. and St. Louis residential based on average R_1 and R_2 ft² values; Fraction High = .53, Fraction Low = .37.

With the exception of option (4), every retrofit scheme was utilized at some point during the analysis of available supply. As noted in Appendix A, estimated costs for achieving each retrofit option are as follows:

CPE	- 10% of turbine cost
CO	- 5% of turbine cost
RC	- \$10/kWt
CB (conversion of boiler)	- 15% of new boiler
New Boiler	- \$45.50/kW

Because of the many uncertainties involved with retrofit options (1) and (2), a conservative cost approach will be used, both for the high and low estimates; basic costs will be pegged at a percentage of the total plant costs. The same 10 and 5% figure will be applied, and a cost of 50% of high costs will be used as a low-cost alternative. Moreover, we will assume that all plants to be retrofitted via options (1) and (2) are coal-fired. The costs thus derived will tend to be conservative on this basis, because some of the retrofitted facilities are oil-fired and have a lower overall cost. The base figure of \$635/kW will be used for new coal-fired electrical plant capacity.

To apply the above-estimated cost to the equipment to be retrofitted, a complete analysis of the type of units within each electric generating facility is required. Appendix A covers the details of such analysis. Table 3.12 shows the costs/zone in each city as a result of retrofit costs. The electric power capacities retrofitted are not the same as the thermal supply provided, as shown in Table 3.8. For example, the Labadie plant (St. Louis Zone III) has an original electric power of 2200 MW. All of this will be retrofitted (CO) so as to be available if needed. During cogeneration, 1660 MW of electric power will be available and 1950 MW of thermal power will be available. At the buildings there will be only 1316 MW of actual heat power available after an assumed 10% transmission/distribution energy loss and a 25% capacity loss and reserve necessary during peak generation.

A similar (but importantly different) case exists for recuperator boiler retrofit. Appendix A shows that a gas turbine can provide captured

Table 3.12. Plant Retrofit by Zone

Area	High Estimate 10 ⁶ \$	Low Estimate 10 ⁶ \$
<u>Washington, D.C.*</u>		
Zone I	72	36
Zone II	7	4
Zone III	31	16
Zone IV	18	9
All Zones:	128	65
<u>St. Louis</u>		
Zone I	37	19
Zone II	26	13
Zone III	71	36
Zone IV	31	16
All Zones:	165	84
<u>Cleveland</u>		
Zone I	108	54
Zone II	48	24
Zone III	29	15
All Zones:	185	93
<u>Milwaukee</u>		
Zone I	76	38
Zone II	57	29
Zone III	133	67
All Zones:	266	134
<u>Detroit</u>		
Zone I	104	52
Zone II	84	42
Zone III	67	34
All Zones:	255	128
<u>Chicago</u>		
Zone I	59	30
Zone II	102	51
Zone III	108	54
All Zones:	269	135

heat of about twice the original electrical capacity of the turbine. Thus, the Buzzard Pt. Station, (Washington Zone I) which has 320 MW of gas turbine power, will be retrofitted with a boiler equivalent to 640 MW heat power. This 640 MW power initial supply will translate into about 432 MW of available power supply $[640(.75)(.9)]$.

Plants to be retrofitted were selected on the basis of location as well as of potential for retrofit. In most cases, ample existing supply was available. However, in certain areas (i.e., Washington, D.C. Zone 1, 2) new capacity was required and supplied via new boilers. Table 3.8 details pertinent data on plants retrofitted or constructed by zones. Information on the facilities both before and after retrofit is presented.

- *Replacement of Lost Capacity.* As can be seen from Table 3.8 (column 8, "Loss Elec"), when existing generating facilities are retrofitted to provide heat for a DES, a net loss in electrical capacity results. This is particularly true in cities such as the ones under study in that only an insignificant portion of the heating load is electrically obtained. Thus, any reduction in electric capacity is not offset by the DES. Conversely, the demand for electricity will remain after reduction.

Although factoring in the cost of replacing such capacity is subject to controversy, the authors recognize that the electricity lost to derating is needed only at times of peak demand, and in many cases serves as reserve, rather than as required output. Nevertheless, to portray costs in this study conservatively, we should not prejudge the need for a specific percentage of reserve and will replace such derated capacity on a MW for MW basis. However, because the power reproduced will be of a peaking nature, it was determined that replacement costs will be assumed to be those of oil-fired peakers, i.e., \$186/kW.*

The next problem to be addressed is the availability of fuel to power the replacement capacity. A logical case can be made to substitute part of the oil saved via the DES substitution for this new capacity. However, the most conservative type approach will be used. It is assumed that oil to fire the new peaking units will not be available from traditional sources and will have to be supplied from new coal liquefaction plants. Costs for such

*See Sect. 3.2.6 for sensitivity analysis of this issue.

liquefaction facilities are estimated at \$18.52/10⁶ Btu of energy delivered.* By factoring in the efficiency of a combustion turbine at 28.5%, the cost would be \$221.7/MWh. Assuming that the newly constructed peaking units will run only 15% of the time, this is the amount that would have to be spent to allow a combustion turbine to produce 1 MW of electrical capacity. Table 3.13 details the costs per zone of installing new peak replacement capacity and building auxiliary coal liquids plants.

Only a fraction of a commercially viable coal liquefaction plant is required for the new peaking plants. Therefore, it is assumed here that in the time frame under consideration, liquids plants will be required to supplement existing oil supplies. Thus, there will be capacity from which to draw. Although we recognize that this is speculation, the entire concept of having to use coal liquids rather than traditional oil supplies is extremely conservative.

The costs for construction of substitute capacity are fairly realistic. Because most utilities are considering, or actually building, additional capacity, it is assumed that some derating from the DES will be absorbed in anticipated expansions via specially designed turbines. Hence, a rather arbitrary 50% of the cost of substitute capacity will be used in the low-cost option. As stressed above, it is extremely conservative to assume that liquids plants will be required for all new capacity. Here again, we assume only a 50% need for the low-cost option.

Finally, it should be emphasized that all costs in this study are of a "modular" nature, i.e., if one wanted to assess the costs of a DES absent replacement costs, this could be easily accomplished. This procedure will become clear when the methodology for determining annualized costs is explained later.

- *Summary of Capital Costs for DES.* All of the above information can now be assembled so as to give an overall capital cost estimate of both high and low cost DES. Table 3.14 (a) and (b) presents such data by zones of cities as well as by total cities. The data are displayed as initial capital cost per MBtu of demand satisfied. Although it would seem logical to bring the DES on line by zone order of lowest cost per MBtu; in most instances this

*Using net energy methodology, FE-77-2443-2²⁹

Table 3.13. Replacement Capacity by Zone

Area	High Estimate 10 ⁶ \$	Low Estimate 10 ⁶ \$
<u>Washington, D.C.</u>		
Zone I	234	107
Zone II	0	0
Zone III	144	72
Zone IV	70	35
All Zones:	448	214
<u>St. Louis</u>		
Zone I	112	56
Zone II	122	61
Zone III	159	79
Zone IV	134	67
All Zones:	527	263
<u>Cleveland</u>		
Zone I	453	227
Zone II	208	104
Zone III	110	55
All Zones:	771	386
<u>Milwaukee</u>		
Zone I	302	151
Zone II	291	146
Zone III	8	4
All Zones:	601	301
<u>Detroit</u>		
Zone I	300	150
Zone II	448	224
Zone III	264	132
All Zones:	1012	506
<u>Chicago</u>		
Zone I	267	134
Zone II	392	196
Zone III	613	307
All Zones:	1272	637

Table 3.14.(a) Capital Cost Summary - Low Costs

Area	Zone	Reg. 10 ⁹ Btu/Yr	Trans. Cost 10 ⁶ \$	Local Dist. 10 ⁶ \$	Bldg. Retro. 10 ⁶ \$	Plant Retro. 10 ⁶ \$	Replace Cap. 10 ⁶ \$	Totals	
								10 ⁶ \$	\$/10 ⁶ Btu·Yr
									Avg. Zone Costs
Wash., D.C.	I	13393	47	100	82	36	107	372	27.78
	II	1628	9	17	10	4	0	40	24.57
	III	6298	83	76	31	16	72	273	44.14
	IV	4560	86	56	19	9	35	205	44.96
All Zones:		25879	225	249	142	65	214	895	34.58
St. Louis	I	5823	26	64	27	19	56	192	32.97
	II	5195	47	63	21	13	61	205	39.46
	III	8327	55	96	35	36	79	301	36.15
	IV	5181	58	59	30	16	67	230	44.39
All Zones:		24526	186	282	113	84	263	928	37.84
Cleveland	I	21448	53	221	82	54	227	637	29.70
	II	8697	111	138	27	24	104	404	46.45
	III	6581	33	85	19	15	55	207	31.45
All Zones:		36726	197	444	128	93	386	1248	33.98
Milwaukee	I	17037	200	174	56	38	151	619	36.33
	II	12985	57	155	34	29	146	421	32.42
	III	9441	3	108	25	67	4	207	21.93
All Zones:		39463	260	437	115	134	301	1247	31.60
Detroit	I	27771	299	299	88	52	224	962	34.64
	II	14742	47	156	43	42	150	438	29.71
	III	14410	110	329	47	34	132	652	45.25
All Zones:		56923	456	784	178	128	506	2052	36.05
Chicago	I	7257	96	42	140	30	134	442	60.91
	II	26522	204	209	110	51	196	770	29.03
	III	31519	188	202	108	54	307	859	27.25
All Zones:		65298	488	453	358	135	637	2071	31.72

Table 3.14.(b) Capital Cost Summary - High Costs

Area	Zone	Reg. 10 ⁹ Btu/Yr	Trans. Cost 10 ⁶ \$	Local Dist. 10 ⁶ \$	Bldg. Retro. 10 ⁶ \$	Plant Retro. 10 ⁶ \$	Replace Cap. 10 ⁶ \$	Totals 10 ⁶ \$	Avg. Zone Costs \$/10 ⁶ Btu·Yr
<u>Wash., D.C.</u>	I	13393	115	287	136	72	234	844	63.02
	II	1628	24	48	17	7	0	96	58.97
	III	6298	161	218	47	31	144	601	95.43
	IV	4560	168	161	27	18	70	444	97.37
All Zones:		25879	468	714	227	128	448	1985	76.70
<u>St. Louis</u>	I	5823	75	183	49	37	112	456	78.31
	II	5195	93	180	37	26	122	458	88.16
	III	8327	192	274	62	71	159	758	91.03
	IV	5181	90	167	34	31	134	456	88.01
All Zones:		24526	450	804	182	165	527	2128	86.77
<u>Cleveland</u>	I	21448	157	639	129	108	453	1486	69.28
	II	8697	237	380	40	48	208	913	104.98
	III	6581	74	242	28	29	110	483	73.39
All Zones:		36726	468	1261	197	185	771	2882	78.47
<u>Milwaukee</u>	I	17037	342	501	84	76	302	1305	76.60
	II	12985	212	444	56	57	291	1060	81.63
	III	9441	8	308	34	133	8	491	52.01
All Zones:		39463	562	1253	174	266	601	2856	72.37
<u>Detroit</u>	I	27771	517	827	133	104	448	2029	73.06
	II	14742	133	446	63	84	300	1026	69.60
	III	14410	209	940	73	67	264	1553	107.77
All Zones:		56923	859	2213	269	255	1012	4608	80.95
<u>Chicago</u>	I	7257	273	120	259	59	267	978	134.77
	II	26522	291	596	177	102	392	1558	58.74
	III	31519	378	576	161	108	613	1836	58.25
All Zones:		65298	942	1292	597	269	1272	4372	66.95

cannot be done. In many cases one zone will, by necessity, be overbuilt to compensate for later zones (e.g., transmission lines). In such cases, the lower cost or later-installed zone could not operate unless the earlier zone (more costly) was brought on line first. An example would be Zone III in Cleveland which adds the Davis Besse Station to the DES (see Fig. 3.6[c]). The relatively low cost (\$76.43/10⁶ Btu) as compared to Step II (\$108.07/10⁶ Btu) is a result of transmission lines having been necessarily installed, and oversized to accept Davis Besse in an earlier step. (See Table 3.14(b), High Costs).

• *Operating & Maintenance (O&M) Costs of DES*

The previous section outlined the methodology whereby the capital cost component of a DES was calculated. This component, when factored by an appropriate capital recovery factor, will produce part of the total annual costs. The remaining pieces of annual costs are:

O&M on the piping and transmission systems,

O&M on the retrofitted plants (or newly constructed plants), and incremental fuel charges resultant from operation in a DES mode.

This section will give a brief overview of the methodology utilized to arrive at such annual costs.

- *Transmission and Local Distribution O&M Costs.* The operating costs for a DES piping system are assumed to be fairly equivalent to those of any other extensive pipeline system. Rather than attempt to estimate discrete costs, it is satisfactory in a study this rough to look at experience of other kinds of pipelines and apply those cost factors as expected DES costs. The net energy methodology developed for the former Energy Research & Development Administration (ERDA)²⁸ contains an adequate sampling of such pipeline costs. The following classifications of pipe and annual costs were derived from that source:

$$\text{Gas Distribution} \quad 0.0069 = \frac{\$ \text{ Annual O\&M}}{\$ \text{ Capital Invested}}$$

$$\text{Gas Transmission Pipeline} \quad 0.0244 = \frac{\$ \text{ Annual O\&M}}{\$ \text{ Capital Invested}}$$

$$\text{Oil Pipeline (Product)} \quad 0.04061 = \frac{\$ \text{ Annual O\&M}}{\$ \text{ Capital Invested}}$$

$$\text{Oil Pipeline (Crude)} \quad 0.0163 = \frac{\$ \text{ Annual O\&M}}{\$ \text{ Capital Invested}}$$

To be consistent with our rationale regarding capital costs, both a high cost and a low cost estimate will be selected. In this case, the capital cost multipliers for transmission and distribution systems are taken from the high and low end of the samples calculated above. Thus, capital costs for the combined distribution and transmission components of any one zone are multiplied by 0.0069, to arrive at a low estimate, and by 0.04061 to arrive at a high estimate. Table 3.15 gives the results of such calculations.

- *Plant O&M Charges.* The next major component of annual operation and maintenance charges relates to those costs associated with operation of the supply plants. In most cases, each supply plant will be operating, regardless of whether the DES is functional. However, plants have been assumed to be retrofitted so that they may operate simultaneously in an electrical and heat generation mode.

To estimate plant O&M costs that are attributable to the DES, the fraction of time that the plant is operating in a DES mode must be known. For this study, it is assumed that the relative electric load factors of the various facilities within a given zone will remain proportionately the same after DES operation as before DES operation. In other words, base-load electrical generation plants will be put on line first for a DES; whereas, peakers will be used as demand increases. This technique minimizes the changes in load scheduling as applied by the utility. When the plants have been scheduled in order of electric load factor, the percent of total power that the plant provides in a zone is assumed to be proportional to the percent of time that the unit must provide the DES with thermal supply. As long as the calculated percentage of time that the plant must supply heat is less than the percent of time that the plant ran before installation of a DES, the system can perform normally.* Should the demand for DES heat supply of a specific plant exceed the normal load factor of that plant, load rescheduling will be required.

*Actually, detailed analysis of hourly load profiles is necessary to establish this point, but such analysis was well beyond the scope of this study.

Table 3.15. DES - Annual Fuel Costs and Operation/Maintenance Costs

Area	Zone	High Estimate 10 ⁶ \$/Yr				Low Estimate 10 ⁶ \$/Yr			
		Trans. Dist.	Plant O&M	Fuel Costs	Total	Trans. Dist.	Plant O&M	Fuel Costs	Total
<u>Wash., D.C.</u>	I	16.30	9.90	17.90	44.10	0.98	4.95	17.90	23.83
	II	2.90	0.46	3.11	6.47	0.17	0.23	3.11	3.51
	III	15.40	5.64	6.13	27.17	1.07	2.82	6.13	10.02
	IV	13.40	2.02	2.69	18.11	0.95	1.01	2.69	4.65
All Zones:		48.00	18.02	29.83	95.85	3.17	9.01	29.83	42.01
<u>St. Louis</u>	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	33.80	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
All Zones:		50.92	19.86	29.99	100.77	3.13	9.94	29.99	43.06
<u>Cleveland</u>	I	32.32	18.05	20.14	70.51	1.85	9.03	20.14	31.02
	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
All Zones:		70.21	32.43	29.55	132.19	4.27	16.22	29.55	50.04
<u>Milwaukee</u>	I	34.23	16.30	10.93	61.46	2.50	8.15	10.93	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	19.89
All Zones:		73.70	30.39	37.04	141.13	4.66	15.20	37.04	56.90
<u>Detroit</u>	I	23.51	12.77	29.32	65.60	1.36	6.38	29.32	37.06
	II	54.58	29.08	25.39	109.05	4.00	14.51	25.39	43.90
	III	46.66	12.90	12.16	71.72	2.94	6.45	12.16	21.55
All Zones:		124.75	54.75	66.87	246.37	8.30	27.34	66.87	102.51
<u>Chicago</u>	I	15.96	5.73	8.05	29.74	0.92	2.87	8.05	11.84
	II	56.02	21.33	26.07	103.42	2.76	10.67	26.07	39.50
	III	20.74	48.22	15.01	83.97	2.61	24.11	15.01	41.73
All Zones:		92.72	75.28	49.13	217.13	6.29	37.65	49.13	93.07

Two points should be made clear. First, this analysis is on a zone-by-zone basis; thus each zone is calculated independently. As additional units are introduced, flexibility of scheduling increases. Thus, what may seem to be unreasonable demands on specific units would, in practice, be dampened by increased supply points. A second factor is that the entire exercise conducted in this subsection is not to dictate load scheduling, but rather to determine a reasonable estimate of O&M costs (and next fuel charges). The approach of first using generating units that have least operating costs* is a generally accepted principle. The degree of error introduced by over- or under-stating plant capacity is considered well within the error range of a study of this scope.

When the relative running time ranking of a facility has been determined, its heat requirement/day is established. This is based on its percentage of the yearly heating and hot water demand for a zone. A 28% loss is estimated between the plant and ultimate use. For example, Zone I of Cleveland utilizes the following facilities:

	Heat Power MW	% Heat Capacity Supplied by Plant	% Heat Supplied by Plant
Ashtabula	1115	32.23	27.4
East Lake	1430	41.33	65.6
Lake Shore	655	18.93	6.4
Edge Water	260	7.51	0.6

From proportionate heat loads, it is estimated that the East Lake plant will supply 65.6 of the total seasonal heat demand. It may be thought of as the "base loaded" heat plant. The average annual demand in the subject zone is 21448.5×10^9 Btu/yr. The East Lake plant is responsible for:

$$\frac{21448.5 \times 10^9 \times .656}{.72} = 19542 \times 10^9 \frac{\text{Btu}}{\text{yr}}$$

By knowing the rating of a facility -- both thermal after cogeneration and electrical before cogeneration -- an approximation can be made of how much

*When capital stock is in place, it must be paid for in any case.

electrical power would have been produced had the cogeneration mode been inoperative. Using our sample case:

$$19542 \times 10^9 \frac{\text{Btu}}{\text{yr}} \cdot \frac{1175 \text{ MW Elec.}}{1430 \text{ MW Heat}} = 16057 \times 10^9 \frac{\text{Btu}}{\text{yr}}$$

By knowing the equivalent electrical output, we assign an additional O&M cost to cogeneration, equivalent to standard plant electrical operating O&M cost. The ERDA Net Energy Method Report²⁸ is used as a cost source. O&M costs are estimated as follows:

$$\begin{aligned} \text{Oil Fired Plants} &= \$681 \times 10^{-9}/\text{Btu} \\ \text{Coal Fired Plants} &= \$798 \times 10^{-9}/\text{Btu} \\ \text{Gas Turbines} &= \$879 \times 10^{-9}/\text{Btu} \end{aligned}$$

Boiler operations are estimated at 5% of their capital costs per year or \$2275/MW·yr.

In the sample case, the annual O&M for the East Lake coal-fired plant is calculated at:

$$(16057 \times 10^9 \text{ Btu/yr}) (\$798 \times 10^{-9}/\text{Btu}) = \$12.81 \times 10^6/\text{yr}$$

Costs for the remaining plants in Zone I of Cleveland are: Ashtabula, \$4.03 x 10⁶/yr; Lake Shore, \$1.11 x 10⁶/yr; and Edge Water \$0.10 x 10⁶/yr. Using the same procedure, estimated annual O&M Plant costs were calculated for each zone of each city. A figure of 50% of the high cost was utilized to arrive at the low cost estimates in this area. Table 3.15 shows these results.

- *Fuel Costs.* Fuel costs are a function of type of fuel burned, heat rate of the facility, the time the facility is running, and unit fuel costs.

Unit fuel costs may be extracted from published midwestern fuel averages* and escalated to 1978 values.³¹ Costs used in this study are as follows:

*FEA Monthly Energy Review (September 1976).

Fuel	Midwestern Area \$10 ⁶ Btu	Washington \$10 ⁶ Btu
Coal	0.893	1.10
Residual Oil	2.170	2.00
Gas	1.350	2.50

Nuclear fuel estimates are more difficult to obtain; however, such estimates are significantly lower than those for fossil fuels. This report relies on data provided to the FPC for the Chicago area plants; i.e., \$0.216/10⁶ Btu.

The low estimate for nuclear fuel will show up dramatically in city zones utilizing nuclear power as a DES supply source.

It is assumed that transmission/distribution losses are 10% up to the building face, and that heat energy is converted at an 80% efficiency in the building. Consequently, the plant must produce 1.389 ($= 1.0 \div 0.9 \div 0.8$) units of heat to provide 1.0 unit of heat in a building. The fuel input to the plant per unit of heat output is a function of the heat rate. In the case of cogeneration, the heat input needed for thermal output is simply the fuel required to produce electricity lost during cogeneration. In effect, by creating a small amount of additional electrical capacity, one is able to gain the use of substantial thermal energy previously disposed of as waste heat. Consequently, the cogeneration heat rates have the unusual property that less energy input is required than energy output obtained. Heat rates are normally expressed in terms of MBtu/kWh. To convert this to Btu input per Btu output, one must multiply by the conversion factor for Btu/kWh, which is 0.293×10^{-3} .

To obtain total fuel costs the following formula is applied for each plant in each zone.

$$F = D \times R \times O \times H \times C \times \$$$

where:

F = total fuel costs in \$ x 10⁶

D = total final demand in the zone inside buildings in
Btu x 10⁹

R = ratio of production of plant to service in buildings = 1.389

O = fraction of heat in this zone provided by this plant

H = heat rate in 10^3 Btu/kWh

C = conversion factor equal to 0.293×10^{-3} Btu/kWh

\$ = cost per Btu for this fuel type in $\$/10^6$ Btu

For the East Lake Plant in Zone I of Cleveland this equals:

$$\$10.48 \times 10^6 = (21448.5 \times 10^9) (1.389)(0.672)(2.0 \times 10^3)(0.293 \times 10^{-3})(0.893 \times 10^{-6})$$

Fuel costs for other plants are calculated in a similar manner. Zone fuel costs and city fuel costs are likewise accumulated, and the results are found in Table 3.15.

- *Total Annual Costs*

Two sets of conditions were assumed to calculate total annual costs. It is fairly safe to assume that should a DES be installed, the rates would fall within the extremes postulated in this report.

The first estimate assumes 8% capital cost on a 20-yr life. The second estimate assumes 20% capital costs on a 20-yr life. Knowing these capital recovery figures provides the last piece to the annual costs. The overall annual costs may now be calculated by utilizing the equation:

$$\text{Total Annual Costs} = \text{Capital Costs} \times \text{Capital Recovery Factor} + \text{O\&M Costs} + \text{Fuel Costs}$$

The annual costs divided by the annual heat required per zone will yield a $\$/10^6$ Btu cost. For our sample zone (Zone I, Cleveland), the following is calculated at 8%, 20 years:

$$\frac{\$1530 \times 10^6 (0.10185) + 50.37 \times 10^6 + \$20.14 \times 10^6}{21449 \times 10^9 \text{ Btu}} = \$10.55/10^6 \text{ Btu (High Cost)}$$

$$\frac{\$665 \times 10^6 (.10185) + 10.88 \times 10^6 + \$20.14 \times 10^6}{21449 \times 10^9 \text{ Btu}} = \$4.60/10^6 \text{ Btu (Low Cost)}$$

Table 3.16 details the results in other zones and cities.

Table 3.16. Cost per 10^6 Btu at 20 yrs, 8%/20%

Area	Zone	At 8% - 20 yrs		At 20% - 20 yrs	
		High	Low	High	Low
<u>Wash., D.C.</u>	I	9.71	4.61	16.23	7.48
	II	9.98	4.66	16.08	7.20
	III	14.03	6.09	23.91	10.66
	IV	13.89	5.60	23.97	10.25
	All Zones:	11.52	5.15	19.46	8.73
<u>St. Louis</u>	I	12.41	5.83	20.52	9.24
	II	12.77	5.38	21.90	9.47
	III	13.33	5.16	22.75	8.91
	IV	13.10	6.30	22.21	10.90
	All Zones:	12.95	5.61	21.93	9.53
<u>Cleveland</u>	I	10.34	4.47	17.52	7.55
	II	15.29	6.24	26.15	11.05
	III	10.77	4.10	18.37	7.36
	All Zones:	11.59	4.82	19.71	8.34
<u>Milwaukee</u>	I	11.41	4.97	19.33	8.73
	II	11.85	4.49	20.30	7.85
	III	8.87	4.34	14.25	6.61
	All Zones:	10.95	4.66	18.43	7.93
<u>Detroit</u>	I	11.54	5.54	18.74	8.62
	II	11.37	5.11	18.93	8.69
	III	15.95	6.10	27.11	10.79
	All Zones:	12.57	5.47	20.95	9.20
<u>Chicago</u>	I	17.82	7.83	31.77	14.14
	II	9.88	4.45	15.96	7.45
	III	8.60	4.10	14.63	6.92
	All Zones:	10.14	4.66	17.08	7.94

- *Summary of Total Annual Costs.* As can be seen from a review of Table 3.16, costs within various cities may vary greatly (e.g., Cleveland low estimate, 20%, 20-yr). This fluctuation is to be expected. Individual zone costs are highly dependent on each other because of the type of availability and location of supply plants. Capital costs for transmission and distribution points also will vary greatly.

More important are the overall city comparisons; here surprisingly good parity is found. For example, in the low-cost 8% option, costs per 10^6 Btu vary by only \$0.95/ 10^6 Btu between cities. This close correlation indicates the validity of the original selection of these cities as comparable for cogeneration retrofit. Chicago is found to be least expensive for retrofit in all cases. This is due largely to its unusually high density of buildings for this set of cities. The only comparable city in the U.S. in this respect is New York. Milwaukee is found to be the next most economical in all cases. For Milwaukee, the high seasonal heating demands help to hold down the cost with respect to the other cities. On the whole, however, these cities are fairly comparable in cost. Still, these results cannot be easily extrapolated to less dense or more southern cities.

3.2.3 The Coal-to-Electricity Option

- *Selection of Scope of Area to Be Served.*

To maintain a basis of comparison, the geographical area to be served by any option will remain constant. Thus, the discussion of area selection found in Sect. 3.2.1 applies equally to all other options.

By so doing, the amount of energy that must be supplied by the coal-electric option is identical to that required of the cogeneration option. Differences in initial energy input are caused by differences in efficiencies of the two options.

- *Capital Cost for Coal-to-Electricity Option*

As in the following two cases, this study relies in large part on the net energy methodology for establishing base-line costs.²⁸ The base case consists of a coal mine in West Virginia producing a coal at 13,000 Btu/lb which is washed by conventional methods to some 14,300 Btu/lb. Shipping is estimated at approximately 500 miles and fed to a generic 1000-MW power

plant. Adjustments have been made to a few assumptions utilized in the net energy methodology to make it 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.

- The overall plant capacity utilization (based on load curve analysis) for space heating is approximately .325, which is half the original NEM estimate of 65%. Although this causes a high electrical cost estimate, it reflects actual costs associated with constructing plants specifically for space heating.

- The overall plant efficiency (based on unit study) is estimated at 42%, rather than at the 34% originally estimated. Such corrections were incorporated.

After correction, the following 20-yr costs for the trajectory components were:

		10^{-6} $\$/10^3$ Btu
Underground Mine	=	3,120
Cleaning Plant	=	400
Rail Transport	=	1,400
Power Plant	=	74,440
Transmission	=	12,920
Distribution	=	25,200
Total	=	117,480

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 DES 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 DES system. It is assumed that transmission/distribution losses are identical at 10% in both systems. Thus, the overall formula to arrive at total electric option capital costs is:

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

$$\text{Capital Costs} = 4975 (.8) (.635 \times 10^6) (1.578) = \$3988 \times 10^6.$$

Because no costs are included for end-use retrofit, the cost estimates of this option are lower than actual costs would be.

Before proceeding, two points should be made clear:

The costs of this option will be extremely high, based on:

- (1) the lower overall efficiency of this option vs. the cogeneration option, and
- (2) the very low capacity factor (32.5%) assigned to the plant.

The question of overall efficiency is not subject to much debate. However, the subject of plant capacity does raise an important question; namely: Is it realistic to assume that building an intermediate load power plant for a 0.325 capacity factor will be undertaken to provide heat to cities? Many would argue that the answer is no, or rather that the capacity factor incorporated in this study should be closer to the normal (e.g., 65%).

The use of the .325 capacity factor, however, is necessary if one uses the scenario put forth in this study - namely that the entire service area is served by one technology. Recall from Table 3.1 that the electric heating technology was from two to six percent of the housing stock. We postulate here a 100% penetration of a very large area. This represents such a substantial electrical demand for heating that the utilities serving these cities would become winter peaking utilities, even though they now have excess capacity in the winter. If marginal cost pricing principles are accepted, then all of the capital cost of new capacity for heating should be charged to new heating customers. Even if pricing is not done in this way, marginal cost analysis is useful to determine the true cost of the service to heating customers.

The average heating season's only load factor (based on heat pump²⁹ and heating season characteristics³¹) for our six study cities is 21.5%, substantially less than the 32.5% figure assumed here. Our 32.5% overall load factor for the heating services electrical capacity is equivalent to assuming that

34% of the capacity runs at a 65% load factor and 66% is heating season only capacity running at a 21.5% load factor. The validity of this assumption on a utility- by-utility basis has not been examined, but it must be remembered that the required MW of capacity (Table 3.5) varies from 3174 MW to 9066 MW heat power. Northern utilities simply do not have this kind of excess of summer over winter capacity. For example, in 1975 the U.S. winter to summer peak ratio was 0.91, the difference being .09. Installed capacity in Illinois was 25942 MW. Using the U.S. figure, the excess state capacity is estimated as 2335 MW, which is 26% of the Chicago heating requirements. Using this approach, and including Virginia and Maryland to serve Washington, D.C., the average excess winter capacity is only 34% of the total D.C. area heating service requirements shown in Table 3.5. This approach is surely conservative, since it assigns the estimated excess capacity of entire states to single cities within those states.

The capital costs computed by use of the 0.325 load factor are shown in Table 3.17. These costs are shown by zone and by city.

• *Operating & Maintenance Costs of Coal-Electric Option.*

To arrive at operating and maintenance costs for the coal-electric option, we turn once again to the Net Energy Methodology, in which operating and maintenance costs for the various steps in the process are delineated parallel to the associated capital costs.²⁸ The existing factors found therein were adjusted so as to make them consistent with the adjustments made in capital costs. The following factors were determined:

<u>Process Step</u>	<u>\$ x 10⁻⁹/Btu</u>
Underground Mine	260
Cleaning Plant	15
Rail Transport	112
Power Plant	798
Transmission	166
Distribution	323
Total	<u>1674</u>

Knowing both the capital costs and the operating and maintenance costs, the O&M multiplier is calculated as follows:

Table 3.17. Cost of Coal-Electric Option

Area	Zone	Reg. Btu/Yr $\times 10^9$	Cap. Cost $10^6\$$	Total O&M Cost $10^6\$$	Fuel Cost $10^6\$$	Total Annual Costs	
						$10^6\$$ 8%, 20 yr	$10^6\$$ 20%, 20 yr
<u>Wash., D.C.</u>	I	13393	2145	30.56	20.87	20.15	36.73
	II	1628	285	4.06	2.54	21.88	40.00
	III	6298	870	12.40	9.81	17.59	31.89
	IV	4560	801	11.41	7.10	22.18	40.56
	All Zones:	25879	4101	58.43	40.32	19.96	36.36
<u>St. Louis</u>	I	5823	798	11.37	7.37	17.17	31.36
	II	5195	826	11.77	6.57	19.72	36.18
	III	8327	1563	22.27	10.53	23.05	42.48
	IV	5181	802	11.43	6.55	19.24	35.26
	All Zones:	24526	3989	56.84	31.02	20.14	36.97
<u>Cleveland</u>	I	21448	2774	39.53	27.10	16.27	29.66
	II	8697	1230	17.53	11.00	17.68	32.32
	III	6581	802	11.43	8.36	15.42	28.03
	All Zones:	36726	4806	68.49	46.46	16.45	30.01
<u>Milwaukee</u>	I	17037	2220	31.63	21.55	16.39	29.88
	II	12985	1571	22.39	16.42	15.31	22.11
	III	9441	1234	17.58	11.94	16.44	30.16
	All Zones:	39463	5025	71.60	49.91	16.05	29.23
<u>Detroit</u>	I	27771	3356	47.82	35.13	15.30	27.80
	II	14742	1848	26.33	18.65	15.82	28.79
	III	14410	1683	23.98	18.23	14.83	27.95
	All Zones:	56923	6887	98.13	72.01	15.31	27.83
<u>Chicago</u>	I	7257	2409	34.33	9.18	39.80	74.16
	II	26522	3807	54.25	33.65	17.93	32.71
	III	31519	4445	63.34	39.87	17.61	32.23
	All Zones:	65298	10661	151.92	82.70	20.22	37.11

$$\begin{aligned}
 \text{O\&M Multiplier} &= \frac{\text{Total O\&M Cost}}{\text{Total Capital Cost}} \\
 &= \frac{1674}{117,480} \\
 &= 0.01425
 \end{aligned}$$

This O&M multiplier, when applied to capital costs, then yields an estimate of O&M costs, or for St. Louis:

$$\begin{aligned}
 \text{Annual O\&M Costs} &= \text{O\&M Multiplier} \times \text{Capital Costs} \\
 &= 0.01425 \times \$39.89 \times 10^6 \\
 &= \$56.84 \times 10^6/\text{yr}
 \end{aligned}$$

To estimate the fuel costs for this option, it is necessary to know three factors: (1) the cost of fuel, (2) the number of Btus required, and (3) the efficiency.

Cost of fuel was determined by checking actual coal costs as reported in FPC 12 forms³² and rounding off for areas of the country. In the Midwest, a reasonable estimate for coal is \$0.893/10⁶ Btu; whereas, in Washington, D.C., a cost of \$1.10/10⁶ Btu was utilized.

The number of Btus required was previously determined (see Table 3.14) and is used directly for this calculation.

To determine efficiency, this report assumes a heat pump efficiency with a COP of 2.1. Subsequent analysis with later data has shown this to be optimistic,^{29,30} but we retain the 2.1 value because it is conservative with respect to our conclusions. Use of a heat pump efficiency is considered justifiable for two reasons:

first, it can be assumed that newer additions to the system would use heat pumps as would many retrofit situations;

second, the entire process of generating capital costs has been conservative (i.e., low capacity factors for heating services only)

thus this overstatement of fuel efficiency (i.e., heat pumps instead of resistance heat or electric boilers) is not significant enough to affect the conclusions about the lack of economic viability of electricity for heating.

From the Net Energy Methodology, the following "energy flow" can be established:

<u>Process Step</u>	<u>Btu Leaving Step</u>
Underground Mine	2975
Cleaning Plant	2617
Rail Transport	2617
Power Plant	1099
Transmission	1055
Distribution	1000
Heat Pump COP = 2.1 =	2100

From the above, efficiency is found to be: $2100/2975 = 0.706$. Fuel costs can now be estimated; for example, for St. Louis:

$$\text{Fuel Costs} = \text{Btu req.} \times (\text{Cost/Btu}) \div \text{eff.}$$

$$\text{Fuel Costs} = 24526 \times 10^9 \times 0.893 \times 10^{-6} \div 0.706 = \$31.02 \times 10^6$$

Both O&M and fuel costs for the coal-electric option are shown in Table 3.17.

- *Capital Recovery Charges*

The procedure for calculating capital recovery charges for the coal-electric option is essentially identical to that used in the DES option. The same parameters of 8% or 20% interest over a 20-yr period were applied. Results of these calculations can be found in Table 3.17.

3.2.4 The Coal-to-Gas-to-Heat Option

- *General*

The procedures and rationale for the area served are identical to those used in the coal-electric option.

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 merely will be substituted for natural gas. No building retrofit will be necessary in this case because 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 their 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 (assumed to be 80% in this study) and requires much less capital investment per unit output.

• *Capital Costs of Gasification Option*

The base case for this option consists of using unwashed coal from West Virginia. The coal is shipped some 500 miles to a generic gasification plant in the Northeast. Although this base case is not totally consistent with our case (i.e., a mine mouth plant in the Midwest), it is anticipated that the differences are of minor consequences regarding overall capital costs, given the accuracy of this study.

When the net energy methodology for the coal gasification process was investigated, an extremely low value for the gasification plant itself was detected. This estimate was raised to reflect more recent projections; $\$1250 \times 10^6/\text{TCF}$ was utilized.³² Moreover, it was assumed that the existing gas transportation and distribution piping network would be sufficient to handle the output of the plant. Accordingly, this figure was deleted from capital costs. After adjustments, the following 20-yr costs are seen:

Underground Mine	=	\$ 1220 x 10 ⁻⁹ Btu
Rail Transport	=	680 x 10 ⁻⁹ Btu
Coal Gasification	=	13820 x 10 ⁻⁹ Btu
Total	=	\$15720 x 10 ⁻⁹ Btu

A reasonable estimate for average efficiency of a gas furnace is 67 percent. Applying that factor to the above capital costs, a final cost for energy supplied would be $\$15,720 \times 10^{-9} \text{ Btu} \div 0.67 = \$23463 \times 10^{-9} \text{ Btu}$.

The final cost figure multiplied by the projected demand in each zone will yield estimates of capital costs. For example, in St. Louis:

$$\text{Cap. costs} = \text{Btu demand} \times \text{Cost/Unit}$$

$$\text{Cap. cost} = 24526 \times 10^9 \times \$23463 \times 10^{-9} = \$576 \times 10^6$$

A summary of capital costs by zone and by total city can be found in Table 3.18.

• *Operating & Maintenance Costs of Coal Gasification Option*

The basic parameters for O&M costs for the various process steps are derived from the Net Energy Methodology as follows:

Process Step	\$ x 10 ⁻⁹ /Btu
Underground Mine	203
Rail Transport	115
Gasification	186
Total	504

An O&M multiplier can be calculated from the capital and O&M costs:

$$\text{O\&M Multiplier} = \frac{\text{Total O\&M Costs}}{\text{Total Cap. Costs}} = \frac{503}{157200} = .03200$$

Table 3.18. Costs of Coal Gasification Option
(Total City)

City	Btu Demand (Btu/yr x 10 ⁹)	Cap. Costs (\$ x 10 ⁶)	Total Ann. Costs (\$ x 10 ⁶)	Fuel Costs (\$ x 10 ⁶ /Btu)	8%-20 yr (\$x10 ⁶ Btu)*	20%-2 (\$ x 10 ⁶)
Washington (ANL/ESCOR)	25879	607.2	19.43	80.64	6.26	8.69
St. Louis	24526	575.5	18.42	62.04	5.67	8.10
Cleveland	36726	861.7	27.57	92.91	5.67	8.10
Milwaukee	39463	925.9	29.63	99.83	5.67	8.10
Detroit	56923	1336.0	42.75	144.00	5.67	8.10
Chicago	65298	1532.0	49.02	165.19	5.67	8.10

*Since no transmission/distribution costs are assumed there is no intra- or inter-urban area specific variation in these costs. Capital costs per Btu for the plant are assumed constant. Only fuel charges are varied by region. Thus, the uniform cost values result. More detailed analysis would undoubtedly show substantial variation among the cities and among zones in cities.

This O&M multiplier when applied to capital costs gives an estimate of total O&M costs, or as applied to St. Louis:

$$\text{O\&M Costs} = 575.5 \times 10^6 \times 0.0320 = 18.42 \times 10^6/\text{yr.}$$

Fuel costs are estimated from a typical energy flow. This allows a calculation of energy efficiency:

<u>Process Step</u>	<u>Btu Leaving Step</u>
Underground Mine	1900
Rail Transport	1900
Gasification	1000
67% Eff. of Gas Furnace	670

$$\text{Eff.} = \frac{\text{Useful Btu out}}{\text{Btu in at Mine}} = \frac{670}{1900} = 0.353.$$

By utilizing the same unit fuel cost estimates (i.e., \$0.893/10⁶ Btu for midwestern coal and \$1.10/10⁶ Btu for eastern coal), along with the known demand and calculated overall efficiencies, fuel cost estimates can be calculated as follows:

$$\text{Fuel Cost} = \text{Btu req.} \times (\text{Cost/Btu}) \div \text{Eff.}$$

$$\text{St. Louis} = 24526 \times 10^9 \times 0.893 \times 10^{-6} \div 0.353 = \$62.04 \times 10^6.$$

Both O&M and fuel costs for the coal gasification option are found in Table 3.18.

- *Capital Recovery Charges*

The procedure for calculating capital recovery charges for the coal gasification option is essentially identical to that used in the DES option. The same parameters of 8% or 20% interest over 20 years are applied. Results of these calculations can be found in Table 3.18.

3.2.5 Coal-to-Liquids-to-Heat Option

- *General*

The procedures and rationale for the area served are identical to those used in the coal-electric option.

Costs for coal liquification are similar to those found in the coal gasification section. In view of the low percentage of fuel oil now used in buildings (see Table 3.1), it is assumed that the existing transportation, distribution, and piping systems must be greatly expanded to handle the output of the liquids plant. The liquids option has the same generic advantage as that of the gasification option, i.e., ease of storage. Therefore, it can be run at a very high capacity factor and thereby reduce the plant capital per Btu output.

• *Capital Cost of Liquification Option*

The base case for this option consists of using unwashed coal from West Virginia and shipping it to New Jersey, the site of both the liquids plant and the refinery. Material is then barged or stored for later use. As in the case of gasification, the base case is not what would be expected in the Midwest, but would be more applicable to Washington, D.C. No attempt was made to adjust the figures for a Midwest base because the accuracy of this report did not warrant such corrections.

Investigation of the NEM for coal liquids revealed that the capital costs attributed to the liquid plant were unrealistically low. This number was changed from the reference number by using the same scale-up factor used in the gasification process.³² After this modification, the following 20-yr costs would be:

<u>Process Step</u>	<u>\$ x 10⁻⁹/Btu</u>
Underground Mine =	980
Rail Transport =	340
Liquefaction Plant =	15,500
Refining =	1,200
Barge System =	80
Storage =	240
Distribution =	380
<u>Total</u> =	<u>18,720</u>

A reasonable estimate of the efficiency of new oil-fired furnaces, necessary for retrofit in most cases, would be 70.5%, and this would yield a cost for energy supplied of $18720 \div 0.705 = \$26553 \times 10^{-9}/\text{Btu}$.

The final cost figure multiplied by the demand in each zone will yield estimates of capital costs. For example, in St. Louis:

$$\text{Cap. Cost} = \text{Btu demand} \times (\text{Cost/Unit})$$

$$\text{Cap. Cost} = 24526 \times 10^9 \times 26553 \times 10^{-9} = \$651 \times 10^6.$$

A summary of capital costs by zone and by individual city can be found in Table 3.18.

• *Operating & Maintenance Costs*

As explained in previous cases, the Net Energy Methodology process costs for O&M are as follows:

<u>Process Step</u>	<u>\$ x 10⁻⁹/Btu</u>
Underground Mine =	163
Rail Transport =	54
Liquids Plant =	271
Refining =	362
Barge System =	7
Storage =	12
Distribution =	18
Total =	887

The calculated O&M multiplier then becomes:

$$\text{O\&M Multiplier} = \frac{\text{Total O\&M Costs}}{\text{Total Cap. Costs}} = \frac{887}{18,720} = 0.0474.$$

The multiplier, when applied to capital costs, gives an estimate of total O&M costs. For example, for St. Louis:

$$\text{O\&M Costs} = 651.2 \times 10^6 \times .04738 = \$30.85 \times 10^6/\text{yr.}$$

Fuel costs are estimated from a typical energy flow which allows a calculation of energy efficiency:

<u>Process Step</u>	<u>Btu Leaving Step</u>
Underground Mine =	1631
Rail Transport =	1631
Liquids Plant =	1080
Liquids Refinery =	1010
Barge =	1010
Storage =	1010
Distribution =	1000
Advanced Oil-fired Furnace =	705
Retrofit at 70.5%	

$$\text{Eff.} = \frac{\text{Useful Btus out}}{\text{Btus in at mine}} = \frac{705}{1631} = 0.432$$

By utilizing the same unit fuel costs estimates along with the known demand and calculated overall efficiencies, fuel cost estimates can be calculated as follows:

$$\text{Fuel Cost} = \text{Btu required} \times (\text{Cost/Btu}) \div \text{Eff.}$$

For example, in St. Louis:

$$\text{Fuel Cost} = 24,526 \times 10^9 \times .893 \times 10^{-6} \div 0.432 = \$50.7 \times 10^6.$$

Both operation and maintenance costs as well as fuel costs are found in Table 3.18.

• *Capital Recovery Charges*

The procedures for calculating capital recovery charges for the coal liquefaction option are essentially identical to those used in the DES option. The same parameters of 8% or 20% interest over 20 years were applied. Results can be found in Table 3.19.

3.2.6 Comparison of Economics

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

In all cases, the low-cost DES option -- at an 8% interest rate over 20 years -- is the least costly of the options. It is marginally less expensive

Table 3.19. Costs of Coal Liquids Option
(Total City)

City	Btu Demand (Btu/Yr x 10 ⁹)	Cap. Costs (\$ x 10 ⁶)	Total Ann. Costs (\$ x 10 ⁶)	Fuel Costs (\$ x 10 ⁶ / Btu)	8%-20 Yr (\$x10 ⁶ Btu)*	20%-20 Yr (\$ x 10 ⁶)
Washington (ANL/ESCOR)	25879	687.2	32.56	65.90	6.51	9.26
St. Louis	24526	651.2	30.85	50.70	6.03	8.78
Cleveland	36726	975.2	46.20	75.92	6.03	8.78
Milwaukee	39463	1048.0	49.65	81.58	6.03	8.78
Detroit	56923	1511.0	71.59	117.67	6.03	8.78
Chicago	65298	1734.0	82.16	134.98	6.03	8.78

*See note to Table 3.18.

than coal conversion processes and significantly less expensive than the coal-electric option.

The high-cost DES options (at both 8% and 20%) exceed the costs of the coal conversion options, 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 DES option, except in Detroit, where a 58% factor would make the two options equal. The discussion in Sec. 3.2.3 shows why such load factors are not plausible if electricity provides most of the heat demand for a city. When considering coal conversion options, very high load factors are assumed because of the capabilities of storing these fuels for long periods after production and before final use.

Other factors, not fully considered, are the technological constraints on the various options. The coal-electric option is fully proven as a heat source, and the DES has been fairly well proven in Europe. However, 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 but assume that technical problems can be overcome.

The concept of using a high and low estimate for the DES allows some insights into the possible cost ranges of such a system. However, in all cases specific cost increments are included, but are subject to debate as to the appropriateness of their inclusion. Two incremental costs are of particular concern, and their effect on overall costs will be explored.

- *Plant Replacement.*

This report assumes the necessity of replacing capacity lost because of cogeneration. Although such replacement would maintain the exact same net generation capacity to the utility involved, it is questionable that it is necessary in all cases.

The questions regarding the advisability of building replacement capacity revolve about a number of key issues, including:

(1) What is the reserve capacity of the utility in question? If a utility has a reserve above that normally considered safe, a certain portion of the capacity should not be replaced. Such a design would allow the utility to utilize its overall resources better and to provide cogeneration services at a lower overall cost.

(2) Is the utility a summer or winter peak system? When a utility peaks in the summer (because of the air-conditioning load), large amounts of capacity are idle during the winter months, the time at which the demand is put on a DES. In many cases (i.e., regenerative boilers or extraction turbines) the steam load can be shut off and the system put back on full electric load. Thus, the overall balance may not require replacement capacity to be built. Furthermore, if cooling eventually is introduced, the heat used essentially would be a subtraction from the electricity utilized for such cooling. Here, the need for replacement capacity depends on generating unit characteristics.

(3) New facilities could be specially designed for cogeneration. In cases where new plant capacity is to be added, units could be designed for a cogeneration mode. This option allows the industry to plan ahead and add both energy supplies at the same time. Preliminary calculations considering both cooling demand and cogenerating replacement capacity indicate to us that substantial savings per Btu can be achieved.

Table 3.20 shows the effect of replacement capacity on the total cities in question. A brief review of Table 3.20 indicates that substantial savings in cost per million Btu delivered could be realized if plant replacement capacity were not included in the base price.

- *Building Retrofit Costs.*

This report assumes that building retrofit costs will be a startup charge to the DES. This is a somewhat unique assumption in that traditionally the individual building owner is responsible for costs incurred to install his own heating plant. However, because of the unique nature of this type of system, such costs were included.

The main reason for this decision was to create a "ready market" for the energy. It is anticipated that, if an individual building owner has the option of continuing a present energy system or retrofitting to the DES, the

initial capital outlay will sway the decision to the present system. For a DES to be viable, a large market must be available; therefore, the costs of retrofit were included. Nevertheless, it is important to understand the incremental costs associated with this decision. Table 3.21 details the incremental costs on a capital outlay basis and on a capitalized basis.

Table 3.20. Effect of Plant Replacement on DES Costs

City	Capital Costs, 10 ⁶ \$		Total Costs \$/10 ⁶ Btu		Total Costs % Change
	Overall Cost	Replacement Capacity Cost	Original	w/o Rep. Cap.	
<u>Washington, D.C.</u>					
High 8%	2048	448	11.52	9.76	-15.3
High 20%			19.46	15.90	-18.3
Low 8%	930	214	5.15	4.31	-16.3
Low 20%			8.73	7.03	-19.5
<u>St. Louis</u>					
High 8%	2178	527	12.95	10.76	-16.9
High 20%			21.93	17.52	-20.1
Low 8%	951	263	5.61	4.52	-19.4
Low 20%			9.53	7.33	-23.1
<u>Cleveland</u>					
High 8%	2972	771	11.59	9.45	-18.5
High 20%			19.71	15.40	-21.9
Low 8%	1305	386	4.82	3.75	-22.2
Low 20%			8.34	6.18	-25.9
<u>Milwaukee</u>					
High 8%	2929	601	10.95	9.40	-14.2
High 20%			18.43	15.30	-17.0
Low 8%	1313	301	4.66	3.88	-16.7
Low 20%			7.93	6.36	-19.8
<u>Detroit</u>					
High 8%	4758	1012	12.57	10.76	-14.4
High 20%			20.95	17.30	-17.4
Low 8%	2152	506	5.47	4.56	-16.6
Low 20%			9.20	7.37	-19.9
<u>Chicago</u>					
High 8%	4419	1272	10.14	8.16	-19.5
High 20%			17.08	13.08	-23.4
Low 8%	2195	637	4.66	3.67	-21.2
Low 20%			7.94	5.94	-25.2

Table 3.21. Effect of Building Retrofit on DES Costs

City	Capital Costs 10 ⁶ \$		Total Costs \$/10 ⁶ Btu		Total Costs
	Overall Cost	Building Retro. Costs	Original	w/o Bldg. Retrofit	% Change
<u>Washington, D.C.</u>					
High 8%	2048	227	11.52	10.63	-7.7
High 20%			19.46	17.66	-9.2
Low 8%	930	142	5.15	4.59	-10.9
Low 20%			8.73	7.60	-12.9
<u>St. Louis</u>					
High 8%	2178	182	12.95	12.19	-5.9
High 20%			21.93	20.41	-6.9
Low 8%	951	113	5.61	5.14	-8.4
Low 20%			9.53	8.58	-10.0
<u>Cleveland</u>					
High 8%	2972	197	11.59	11.04	-4.7
High 20%			19.71	18.61	-5.6
Low 8%	1305	128	4.82	4.47	-7.3
Low 20%			8.34	7.62	-8.6
<u>Milwaukee</u>					
High 8%	2929	174	10.95	10.50	-4.1
High 20%			18.43	17.52	-4.9
Low 8%	1313	115	4.66	4.36	-6.4
Low 20%			7.93	7.33	-7.6
<u>Detroit</u>					
High 8%	4758	269	12.57	12.09	-3.8
High 20%			20.95	19.98	-4.6
Low 8%	2152	178	5.47	5.15	-5.9
Low 20%			9.20	8.56	-7.0
<u>Chicago</u>					
High 8%	4419	597	10.14	9.21	-9.2
High 20%			17.08	15.20	-11.0
Low 8%	2195	358	4.66	4.10	-12.0
Low 20%			7.94	6.81	-14.2

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4. ESTIMATES OF SCARCE-FUEL SAVINGS

A major advantage of the DES over the existing heat supply mechanism in the study cities is its great potential for offsetting usage of scarce fuels. Table 3.1 showed 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 3.1 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.¹¹ 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. The following commercial/industrial heating percentage estimates were obtained:

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 and knowing the square footage in each category, and the average demand factors (from Tables 3.3 and 3.4), it is possible to calculate total annual original Btus in the fuel in the ground required according to fuel and building type by using Eq. 4.1:

$$B_f = \sum_{i=1}^4 (F_i \times D_i \times \frac{365 \text{ days}}{\text{yr}} \times P_{fi} \times E_f) \quad (4.1)$$

where: B_f = Btu/yr of given fuel type, f

F_i = square footage of building type i

D_i = average heat demand per day of building type i
in Btu/ft²

P_{fi} = percentage of fuel type f used in building type i

E_f = efficiency from ground to building heat of fuel type f .

Efficiencies (Eq. values) 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

Equation 4.1 is used to calculate all building types and fuels. By summing results of the four building types for a given fuel, the fuel use estimates presented in the first five columns of Table 1.2 are obtained. Electricity here is divided into current coal/oil generation proportions.

Table 3.1 details specific heating information about the six subject cities; Table 4.1 displays the overall results in utilizing the information in Table 3.1, the commercial/industrial data just presented, and building 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 assess the savings attainable by DES retrofit, a few basic points first must be emphasized:

- The DES 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 because of 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 DES energy production. The difference is small and is caused only by differences in new peak generating unit efficiency vs. existing unit efficiency.
- Fuel savings are computed on a citywide basis.
- After retrofit, it is assumed that 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 DES operation, the useful Btu requirements of the city (listed in Tables 3.18 and 3.19) must be considered.

Table 4.1. Current Fuel Usage - by City

	% Gas	% Oil	% Elec.	% Other	10 ⁶		Usage, Btu x 10 ¹² /Yr			
					Sq. Foot	Btu Ft ²	Gas	Oil	Elec.	Other
Wash., D.C.										
Res.	.52	.35	.06	.07	295	175	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	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	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	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	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	63.6	15.7	2.6	4.8
C/I	.25	.72	.01	.02	563	143	12.7	38.2	0.5	1.9

From these end use energy requirements, the amount of energy that must be generated at the plant door can be determined. This is done by utilizing the 80% in building efficiency factor and the 10% line-loss factor previously used in this study. Thus, for each Btu required by the end user, 1.39 ($=1 \div .80 \div .9$) Btus of energy must be generated by the plant.

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

The factor 0.570 Btu in/Btu out, may appear to violate all laws of thermodynamics in that more energy is created than is input to the system. This rather unique situation is caused by the nature of cogeneration. In essence, the electric component efficiency (and heat rates) are held constant in our accounting framework before and after cogeneration. However, because of the generation of thermal, as well as electric, energy after retrofit, the overall efficiency of the system is increased by approximately 100%. Electric component losses are small compared with 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 that is replacing traditional scarce fuels, and is an added increment to the original electric generating system. It is this comparison of incremental gains and losses that results in high efficiencies.

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

$$\text{Eff.} = \frac{\text{Btu} \times (.80) (.9)}{.570} = 1.263 \quad (4.2)$$

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 DES. Thus, for Washington, D.C.: 25.9×10^{12} Btu for end use $\div 1.263 = 20.5 \times 10^{12}$ 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 surprising in that coal and nuclear power plants generally are substituted for oil and gas as the primary heat energy source.

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APPENDIX A
TECHNICAL ATTRIBUTES OF THERMAL DISTRIBUTION SYSTEMS AND ELECTRIC
GENERATING UNITS RETROFITTED TO PROVIDE THERMAL ENERGY

A.1 PURPOSE

The purpose of Appendix A is to provide detailed documentation and technical explanation regarding the methods by which heat energy can be derived from existing and new unit processes. Five generic methodologies are available for obtaining heat energy:

1. condensing pressure and extraction volume increase retrofit on existing turbines;
2. intermediate crossover extraction retrofit on existing turbines;
3. recuperator boiler retrofit on existing gas turbines;
4. installation of new specially manufactured extraction turbines; and
5. conversion of existing steam boiler or installation of new hot water boilers.

Each of the above options has been reviewed to ascertain the effects on the total existing utility system.

Cases 1 and 2 would result in a loss of electrical output as steam is extracted for heat energy. Because of such extractions, the overall energy (heat plus electrical) will increase significantly; however, this increase occurs at the expense of net generating capacity and will incur a retrofit cost to accomplish this conversion.

Case 3 would yield a very small electrical generation loss, but incurs the cost of a recuperator boiler retrofit. Moreover, attention must be given to the present and after retrofit load factors applied to the gas turbines.

Case 4 assumes a new turbine installation specifically designed to produce both electricity and heat energy. This option increases the net generation capacity of the system while providing heat energy for the DES. The costs are roughly comparable to the purchase of a standard extraction turbine without provision for DES heat generation.

Case 5 would not alter electrical generation capacity in that the units considered (existing or new) are heat generators only. Costs will range

from low (for minor installation retrofit) to high for a completely new installation.

Ideally, the analysis of a specific system would entail a detailed look at each unit. This would be a time consuming and potentially unnecessary exercise given the scope of this study. Accordingly, the logical option would be to analyze specific generic units of representative sizes. After this step has been accomplished, the results can be spot-checked against actual field installations to check the validity of the generic study.

A.1.1 Condensing Pressure and Extraction Volume Increase Retrofit on Existing Turbines

This type of retrofit is applicable to existing single-case turbines larger than 20 MW. Turbines with capacities less than 20 MW have been shown to be uneconomical retrofit situations and are thus excluded from consideration. The type of turbine considered here has existing steam extractions at specific points.

The generic units to be considered are 30 MW, 60 MW, and 100 MW. Figure A.1 shows a typical turbine configuration with its associated extraction and feedwater heat system.

In keeping with the scope of this study, theoretical thermodynamic formulas were used to obtain heat and work outputs. However, actual steam characteristics were used to determine properties at the various input and outlet points. Figure A.1 details typical values for such properties.

The general procedure used was to extract steam (at various points) in excess of that used in the existing system. The amount of steam extracted was that needed to provide a given amount of heat energy for the DES.

To calculate the heat extracted, the following equation was used:

$$HE = M:\eta E: (3.413 \times 10^6) \sum \alpha J \cdot \Delta HJ \quad (A.1.1)$$

where:

M = Heat power (MW),
 ηE = lbs/h steam flow,
 3.413×10^6 = Conversion factor MW to Btu/H,

Fig. A.1. One Case 30 MW Turbine CPEI Retrofit

α_J = For J extractions, the ratio of extractions
 $\alpha_J = MJ: \Sigma MJ$, and

ΔH_J = The enthalpy difference after each extraction.

The overall equation for power would be:

$$P = M: \Delta H \cdot \eta_M: (3.413 \times 10^6) \quad (A.1.2)$$

or, for more than one extraction:

$$PE = M \cdot \eta_M: (3.413 \times 10^6) \Sigma (1 - \alpha_J) \cdot \Delta H_J \quad (A.1.3)$$

where:

η_M = mechanical efficiency of the turbine-electric generator.

At this point, one criterion should be stressed: the maximum steam extraction allowed must retain at least 20% of the initial steam to pass through the entire turbine. This provision will be adequate to protect the turbine from superheat and potential damage.

Figure A.2 is a Molier diagram on which the various steam characteristics for a 30-MW electric generating turbine are plotted. By use of this diagram and the associated equations, total work and steam required can be calculated.

Figure A.3 shows diagrammatically the results of steam extractions of various percentages as well as the expected results at various present extractions. As can be seen from the figure, total power (both electric and heat) increases over the initial 30-MW electric output. Moreover, increases in heat output occur during further derating of the turbine.

A similar analysis was undertaken for a generic 60-MW and 100-MW turbine generator system (see Figs. A.4-A.9).

Before proceeding, an analysis was made to determine the effects of varying steam inlet conditions. Steam temperatures were varied between 850°F and 1000°F. Steam pressures were varied between 750 psia and 2365 psia. Figures A.10 and A.11 show the Molier charts for these options and the resultant power output. Although changes are recorded by making such variations, these are not significant; thus, the concept of using generic studies as a substitute for actual "in plant" analysis appears to be valid.

• Results

Table A.1 shows the results of the generic analysis for 30-, 60-, and 100-MW units. Derating varies from 35 to 51% of initial loading. Conversely,

Fig. A.2. Mollier Diagram for Turbine Shown in Fig. A.1

Fig. A.3. Retrofit CPEI Results for Turbine Shown in Fig. A.1

Fig. A.4. One Case 60 MW Turbine CPEI Retrofit

Fig. A.5. Mollier Diagram for Turbine Shown in Fig. A.4

Fig. A.6. Retrofit CPEI Results for Turbine Shown in Fig. A.4

Fig. A.7. One Case 100 MW Turbine CPEI Retrofit

Fig. A.8. Mollier Diagram for Turbine Shown in Fig. A.7

Fig. A.9. Retrofit CPEI Results for Turbine Shown in Fig. A.7

Fig. A.10. Mollier Diagram Showing Influence of Pressures and Temperatures for Steam Supplied to the Turbine

Fig. A.11. Influence of Pressures and Temperatures for Steam Supplied in CPEI Retrofit

Table A.1. Retrofit Condensing Pressure and Extraction Volume Increases (CPEI) Data

No.	Turbine MW	Parameters	Electric	Heat	Total MW
		PSIA °F	MW %	MW %	
1	30	$\frac{715}{850}$	$\frac{14.7}{49}$	$\frac{55.8}{185}$	70.5
2	60	$\frac{915}{900}$	$\frac{31.6}{53}$	$\frac{104.6}{174}$	136.2
3	100	$\frac{1515}{1000}$	$\frac{64.8}{65}$	$\frac{143.4}{144}$	208.2

overall power (heat plus electrical) increases by 208% to 235% of the original loading.

A.1.2 Intermediate Crossover Extraction Retrofit of Existing Turbines

For both the tandem compound and cross compound turbine arrangements, crossover steam extraction was used. Because of economic considerations, this method was found preferable to extraction from the turbine itself. Costs to modify the casing and possibly change the rotor, if steam were to be extracted from the turbine, would exceed 50% of the original turbine costs. Conversely, crossover extraction requires piping modifications, and installation of a regulating valve can be accomplished at a cost of 5-10% of the initial turbine cost.

Although economics dictate the crossover rather than the extraction technique, the result is lower cogeneration efficiency.

Because the mathematics are similar to that used in Sect. A.1.1, the generic analysis methodology was used. Figure A.12 shows a typical turbine arrangement, the associated extraction points, and feedwater heating system. As in the previous case, a minimum of 20% of the input steam was allowed to flow through the system to protect against superheat and resultant damage.

Five generic units were studied -- 60 MW, 100 MW, 120 MW, 200 MW, and 320 MW. The Molier diagram for the 100 MW unit and the associated power output diagrams are shown in Figs. A.13 and A.14. Similar analyses were conducted for the other generic units (Figs. A.15-A.26).

Fig. A.12. Two Cases 60 MW Turbine CO Retrofit

Fig. A.13. Mollier Diagram for Turbine Shown in Fig. A.12

Fig. A.14. Retrofit CO Results for Turbine Shown in Fig. A.12

Fig. A.15. Two Cases 100 MW Turbine CO Retrofit

Fig. A.16. Mollier Diagram for Turbine Shown in Fig. A.15

Fig. A.17. Retrofit CO Results for Turbine Shown in Fig. A.15

Fig. A.18. Three Cases 120 MW Turbine CO Retrofit

Fig. A.19. Molier Diagram for Turbine Shown in Fig. A.18

Fig. A.20. Retrofit CO Results for Turbine Shown in Fig. A.18

Fig. A.21. Three Cases 200 MW Turbine CO Retrofit

Fig. A.22. Mollier Diagram for Turbine Shown in Fig. A.21

Fig. A.23. Retrofit CO Results for Turbine Shown in Fig. A.21

Fig. A.24. Multi Cases 320 MW Turbine CO Retrofit

Fig. A.25. Mollier Diagram for Turbine Shown in Fig. A.24

Fig. A.26.. Retrofit CO Results for Turbine Shown in Fig. A.24.

Table A.2 details the results of the generic study. The same pattern of decreased electrical output and increased overall power output prevails.

A.1.3 Recuperator Boiler Retrofit on Existing Gas Turbines

Much of the heat in the exhaust gas from an open cycle gas turbine can be recovered to generate heat power. At an inlet temperature of between 500 and 1200°F a well-designed recuperator boiler can produce heat power of double the initial electrical power produced by the gas turbine. The design and boiler outlet temperature would be 325°F + 25°F to prevent any corrosive effects of condensation.

Figure A.27(a) diagrams the available inlet temperatures to a recuperator boiler (8A) and the heat that can be recovered (Fig. A.27(b)), as a function of gas turbine percent loading. Figure A.27 is for a typical 10-MW gas turbine and shows that the amount of power (heat) available is a direct function of the percent rated load of the turbine.

Exhaust gas boilers that would be used in this retrofit option should be of the watertube variety. Heat recovery can come exclusively from the turbine exhaust gas or may be supplemented by auxiliary fuel sources. Given the above gas inlet/outlet temperatures, boilers are available that

Table A.2. Retrofit Integer Mediar Crossover Extraction (CO) Data

No.	Turbine MW	Parameters		Electric MW %	Heat MW %	Total MW
		Psia °F	Psia °F			
1	60	915		45	75	120
		900	-	75	125	
2	100	1515		70	130	200
		1000	-	70	130	
3	120	1515	360	90	150	240
		1000	1000	75	125	
4	200	2365	441	145	255	400
		1050	1000	73	128	
5	320	Complex		230	350	580
				70	110

a.

b.

Fig. A.27. Recuperator Boiler (RB) Retrofit Data
a. Temperature
b. Heat

have an efficiency greater than 80%. Costs for such units are estimated at between \$20 and \$50/kW.

A.1.4 Installation of New Extraction Turbines

Retrofitting existing turbines have the significant disadvantage of derating the turbine. However, the overall power produced is significantly higher than the nominal electrical output. Thus, the option exists for design of new extraction turbines that can adequately handle the electrical load demand as well as the heat energy demand for a DES.

This option is viable only in the case where a total energy system is being designed initially or when an existing DES system is being upgraded. In any event, considerable R&D in this area is required.

A.1.5 Conversion of Existing Steam Boilers (Installation of New Hot Water Boilers)

Should a facility have an existing steam-producing boiler, either for electrical generation or a steam DES, that boiler can be a likely candidate for conversion to hot water and inclusion in the overall matrix. This assumes that the boiler in question is no longer needed for electrical generation.

In such a case, this study assumes further that the fuel used in such a boiler would be the same after retrofit; however, the option to switch fuel always exists, subject to economic and technological considerations. For purposes of this study, fuel switching was not costed. The conversion from steam to hot water is estimated at approximately 15% of the original boiler cost.

Should a large DES system design require more heat power than can be made available from the existing system, the installation of new hot water boilers should be considered. For a DES, the ideal type of boiler would be one of large capacity (>100 MW heat) but which produces low temperature water (200°-300°F).

Although R&D in this area may reduce the costs of such boilers, a good estimate for costs would be approximately \$20/kW.

A.1.6 Summary

All of the above suggest possible mechanisms by which heat power can be derived from existing or new power generators. The decision regarding which power source is applicable for a specific DES is extremely complex. A detailed knowledge of the equipment available within a given system, as well as knowledge of the system's present demand are required.

Many required prerequisites for equipment selection will be given only casual attention here. The methodology used and units selected in the next part of this appendix overlook many considerations because the scope of this study requires just a casual look; however, should the study result in continued work, much more detailed justification for the selection process will be required.

A.2 METHODOLOGY FOR PLANT SELECTION PROCESS

The generalized methodology to be used will be established by using the Washington, D.C., data as a guideline. Techniques and conclusions drawn from the previous section (A.1) will be used as the basis for available power from the Washington units.

Before selecting units to be retrofitted/added for the establishment of a DES, an estimate of the total heating and cooling demand of the system must be established. Appendix B details the research that was conducted to obtain energy demands in the Washington, D.C., area.

The following values were established:

$$(H_p) \text{ Peak Value; Heating} = 280,548 \times 10^6 \frac{\text{Btu}}{\text{day}} \approx 3400 \text{ MW}$$

$$(H_a) \text{ Average Heating demand} = 70,378 \times 10^6 \frac{\text{Btu}}{\text{day}} \approx 850 \text{ MW}$$

$$(h_a) \text{ Average Hot Water demand} = 8,706 \times 10^6 \frac{\text{Btu}}{\text{day}} \approx 110 \text{ MW}$$

$$(C_p) \text{ Peak Value; Cooling} = 177,076 \times 10^6 \frac{\text{Btu}}{\text{day}} \approx 2150 \text{ MW}$$

$$(C_a) \text{ Average Cooling demand} = 42,021 \times 10^6 \frac{\text{Btu}}{\text{day}} \approx 510 \text{ MW}$$

Figure A.28 shows the above values plotted as a load duration curve. These figures presuppose that the necessary retrofitting by or for the end users can be accomplished, and therefore that the generated heat loads would be utilized.

The techniques described in A.1 were applied to the specific units within the Washington, D.C., system, and the results are shown in Tables A.3 to A.8. Columns 1-4 are self-explanatory. Column 5 is an outgrowth of the previous technique. Column 6 details the fuel rates in Btu/kWh for both electric and heat power. Figure A.29 shows the statistical methodology used to determine the heat rate for electric power. For this study, it was assumed that the accuracy of Fig. A.29 will suffice. It was further assumed that the difference in electric fuel rate (EFR) was insignificant before and after cogeneration. Given the EFR, the heat fuel rate (HFR) can be calculated by the equation:

$$\text{HFR} = \text{EFR} \frac{[\text{NEP} - \text{CEP}]}{\text{CHP}} \quad (\text{A.1})$$

where:

NEP = Nominal Electric Power (MW)

CEP = Cogeneration Electric Power (MW)

CHP = Cogeneration Heat Power (MW)

From the above, the efficiencies can be calculated, as shown in Column 7 of Tables 3-8.

$$\eta_n = \frac{3.413}{\text{EFR}}$$

$$\eta_c = \frac{[\text{CEP} + \text{CHP}]}{\text{NEP}}$$

η_n = Nominal and/or cogeneration electric power efficiency

η_c = Cogeneration efficiency

3,413 = Ideal conversion kWh/Btu

Before proceeding with the potential availability of energy from an existing system, it is necessary to establish an overall capacity factor. Other literature has suggested a dual-capacity factor comprised of:

Fig. A.28. Washington, D.C. Heating and Cooling Requirements Diagram

a.

b.

Fig. A.29. Heat Rates and Efficiencies for Generic Turbine Retrofit

$$C_1 = 0.65\text{---}0.78,$$

where C_1 is the heat required annually to satisfy base portion of the load duration curve as a percentage of design capability of the extraction system.

$$C_2 = 0.95\text{---}0.99$$

Where C_2 is defined as that percentage of the base portion of the load curve that can be supplied after consideration of the extraction system unreliability.

The combined capacity factor is $C_1 \times C_2$ or $0.62\text{---}0.75$. This report assumes an overall capacity factor of $C = 0.75$.

Table A.9 shows the overall results of the previously mentioned analysis of the Washington, D.C., system. From the table, the following heat energy output can be calculated.

Existing Retrofit Steam Turbine Systems:

Benning	845 MW
Buzzard Point	390 MW
Potomac River	600 MW
Dickerson	630 MW
	$2465 \times 0.75 \approx 1850 \text{ MW}$

Future Steam Turbine Systems:

Dickerson	$875 \times 0.75 \approx 655 \text{ MW}$
-----------	--

Existing Gas Turbine Systems:

Buzzard Point	640
Morgantown	580
	$1220 \times 0.75 \approx 915 \text{ MW}$

Total MWh available = 3420 MW.

One additional factor requires consideration. A certain amount of heat provided to the DES will be lost because of leakage and other piping-associated losses. These losses can be accounted for in a district energy factor (DEF) defined as:

$$DEF = \frac{\text{MW cogeneration}}{\text{MW MAX Demand (1.1)}}$$

in the particular case

$$DEF = \frac{3420}{(1.1)(3510)} = 0.89$$

in which 1.1 indicates that 10% of the heat provided is lost in the DES. Given the above capacity factors, and a maximum heat requirement of 3510 MW, the additional heat necessary to balance the system is:

$$1.1 \times \frac{3510 - 3420}{.75} = 588 \text{ MWh}$$

This additional heat must be provided by existing or new boilers.

Analysis of the Washington, D.C., system reveals that the west thermal plant and the central thermal plant have steam boilers that could be retrofitted as hot water boilers. Additionally, the two boilers at the Benning Station could be utilized:

West & Central	$\frac{2 \times 2 \times 200,000 \times 793}{3.413 \times 10^6}$	- 200 MW
Benning Plant	$\frac{2 \times 150,000 \times 696}{3.413 \times 10^6}$	- $\frac{55 \text{ MW}}{255 \text{ MW}}$

Moreover, the work (heat) produced from pumping in the DES will produce an estimated 24.5 MWh. Using these sources of energy still leaves a net deficit of $588 - 260 - 24.5 \approx 800$ MW.

This approximately 800 MW will have to be provided by new hot water boilers to be centrally located.

The above-mentioned heat energy comes as a result of quality existing and future electrical outputs. Table A.10 details the potential loss of such capacity.

Tables A.11-A.18 detail the characteristics of the Washington, D.C., units and suggested retrofit options. Tables A.19-A.24 detail the equipment that will be required to facilitate the selected options.

A.2.3 Distribution Systems

Having arrived at the potential energy availability at specific needs as well as the types of retrofit that will be necessary to accomplish the goal, the next step is to determine the pumping and piping requirements.

As basic parameters, the outlet temperature from the heat exchanger was selected as 200°F and the return as 140°F. The pump rate then can be determined from the equation:

$$\text{GPM} = \frac{3.413 \times 10^6}{500 \Delta T} \text{ HP} \quad (\text{A.2})$$

in which head pressure (HP) in ft of water is established by the equation:

$$\text{HP} = \Sigma 2 \cdot \text{LJ} \cdot \text{HPLJ} \quad (\text{A.3})$$

in which:

LJ is the single length of pipeline (supply or return)

HPLJ is the unit pressure drop per length of pipe (ft.H₂O/
ft. pipe) at each pipe diameter.

From the above, the power required to drive the pumps is:

$$P = \frac{\text{GPM} \times \text{HP}}{44800 \cdot \eta} \text{ (MW)} \quad (\text{A.4})$$

where:

η is the combined efficiency of the pump.

In the study, $h = 0.75$.

The results of the above equations as applied to the Washington, D.C., area are found in Table A.25.

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6. Commonwealth Edison Company
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WASHINGTON, D.C.

Table 1. Plant's Power Groups' Characteristics

D.E.S. WashingtonState D.C.Plant Benning

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST10*	30	CPEI	15	55	9.68	2.52	0.352	0.781
2	ST11*	30	CPEI	15	55	9.68	2.52	0.352	0.781
3	ST12*	30	CPEI	15	55	9.68	2.52	0.352	0.781
4	ST13	50	CPEI	25	90	9.28	2.54	0.367	0.828
5	ST14	25	CPEI	13	45	10.00	2.22	0.341	0.838
6	ST15	275	CO	190	300	8.02	2.22	0.425	0.760
7	ST16	275	CO	190	300	8.02	2.22	0.425	0.760
	TOTAL ST	685	-	463	845	8.31	2.26	0.410	0.778
	CPEI = Condensing Pressure and Extraction Volume Increase Retrofit								
	CO = Crossover Extraction Retrofit								
	ST = Steam Turbine								

* T are working two from three in same time.

Table 2. Plant's Power Groups' Characteristics

D. E. S. Washington State D.C.Plant Buzzard Point

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal.	Cogen.
1	ST1*	30	CPEI	15.0	55.0	9.68	2.64	0.352	0.867
2	ST2	30	CPEI	15.0	55.0	9.68	2.64	0.352	0.867
3	ST3	50	CPEI	25.0	84.0	9.28	2.74	0.367	0.802
4	ST4	50	CPEI	25.0	84.0	9.28	2.74	0.367	0.802
5	ST5	50	CPEI	25.0	84.0	9.28	2.74	0.367	0.802
6	ST6	50	CPEI	25.0	84.0	9.28	2.74	0.367	0.802
1	GTE	160	RB	145	320	12.00	0.56	0.285	0.828
2	GTW	160	RB	145	320	12.00	0.56	0.285	0.828
	TOTAL ST	230	-	130	391	9.33	2.39	0.365	0.827
	TOTAL GT	320	-	290	640	12.00	0.56	0.285	0.828

*May be reactivated.

GT $\equiv$ Gas TurbineRB $\equiv$ Recovery Boiler

Table 3. Plant's Power Groups' Characteristics

D. E. S. Washington State D.C.Plant Potomac River

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST1	82	CO	60.0	110	8.68	1.74	0.393	0.815
2	ST2	67	CO	50.0	91	9.04	1.69	0.377	0.793
3	ST3	102	CO	71.4	133	8.26	1.90	0.413	0.828
4	ST4	102	CO	71.4	133	8.26	1.90	0.413	0.828
5	ST5	102	CO	71.4	133	8.26	1.90	0.413	0.828
	TOTAL ST	455	-	325	600	8.45	1.83	0.404	0.821

Table 4. Plant's Power Groups' Characteristics

D. E. S. Washington State D.C.Plant Dickerson

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST1	183	CO	125	210	8.00	2.21	0.426	0.800
2	ST2	183	CO	125	210	8.00	2.21	0.426	0.800
3	ST3	183	CO	125	210	8.00	2.21	0.426	0.800
1	ST4 [*]	800	EXTR	560	875	7.85	2.15	0.434	0.800
1	GT	13	BR	12	26	12.00	0.60	0.285	0.702
	TOTAL ST	550	-	375	630	8.00	2.21	0.426	0.800
	TOTAL ST [*]	800	-	560	875	7.85	2.15	0.434	0.800
	TOTAL GT	13	-	12	20	12.00	0.60	0.285	0.702

^{*} Will be installed on 1983, special D.E.S. type.EXTR $\equiv$ Extraction.

Table 5. Plant's Power Groups' Characteristics

D. E. S. Washington State D. C.Plant Morgan Town

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST1	550	CO	390	610	8.00	2.10	0.426	0.775
2	ST2	550	CO	390	610	8.00	2.10	0.426	0.775
1	GT1	20	RB	18	40	12.00	0.60	0.285	0.827
2	GT2	20	RB	18	40	12.00	0.60	0.285	0.827
3	GT3	62	RB	56	125	12.00	0.58	0.285	0.832
4	GT4	62	RB	56	125	12.00	0.58	0.285	0.832
5	GT5	62	RB	56	125	12.00	0.58	0.285	0.832
6	GT6	62	RB	56	125	12.00	0.58	0.285	0.832
	TOTAL ST	1110	-	780	1220	8.00	2.10	0.426	0.775
	TOTAL GT	290	-	260	580	12.00	0.58	0.285	0.831

Table 6. Plant's Power Groups' Characteristics

D. E. S. Washington State D.C.Plant Chalk Point

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST1	330	CO	230	350	8.00	2.29	0.426	0.750
2	ST2	330	CO	230	350	8.00	2.29	0.426	0.750
3	ST3	608	CO	420	655	8.00	2.30	0.426	0.753
1	ST4 *	608	EXTR	420	655	8.00	2.30	0.426	0.753
1	GT1	16	RB	14.4	32	12.00	0.60	0.284	0.824
2	GT2	35	RB	31.6	70	12.00	0.58	0.284	0.824
	TOTAL ST	1268	-	880	1355	8.00	2.29	0.426	0.752
	TOTAL ST *	608	-	420	655	8.00	2.30	0.426	0.753
	TOTAL GT	51	-	46	102	12.00	0.59	0.284	0.824

* Will be installed in 1981.

EXTR $\equiv$ Extraction.

Table 7. Cogeneration D.E.S. System Data

D.E.S. Washington State D.C.

No.	Plant		Benning	Buzzard Point	Potomac River	Dickerson Exist	Dickerson New	Buzzard Point
	Characteristic							
1	Nominal Power	MW	685	230	455	550	800	320
2	Type of Fuel	Work	Oil #6	Oil #6	P. Coal	P. Coal	P. Coal	Oil #2
		Start	Oil #2	Oil #2	Oil #2	Oil #2	Oil #2	Oil #2
3	Type of Turbines		Steam	Steam	Steam	Steam	Steam	Gas
4	Cogeneration Electric Power	MW	455	130	325	375	560	290
5	Cogeneration Heat Power	MW	845	390	600	630	875	640
6	Fuel Rate for Power Plant	Elec.	8.31	9.33	8.45	8.00	7.85	12.00
		Heat	2.26	2.39	1.83	2.21	2.15	0.56
7	Efficiencies η	Nom.	0.410	0.365	0.404	0.426	0.434	0.284
		Cog.	0.778	0.827	0.821	0.800	0.800	0.828

Table 8. Cogeneration D.E.S. System Data (Contd.)

D.E.S. Washington State D.C.

No.	Plant Characteristic		Morgan- Town	Benning Thermal	West Thermal	Central Thermal	New Thermal	
1	Nominal Power	MW	290					
2	Type of Fuel	Work	Distillate Oil					
		Start	Oil #2					
3	Type of Turbines		Gas					
4	Cogeneration Electric Power	MW	260					
5	Cogeneration Heat Power	MW	580	55	100	100	300	
6	Fuel Rate for Power Plant	Elec.	12.00					
		Heat	0.58					
7	Efficiencies η	Nom.	0.284					
		Cog.	0.831					

Table 9. Maximum Electricity Loss through Cogeneration

D.E.S. Washington State D.C.

No	Power Plant	Nominal MW	Cogen. MW	Difference MW
1	Benning	685	455	230
2	Buzzard Point	230	130	100
3	Potomac River	455	325	130
4	Dickerson Exist	550	375	175
5	Dickerson New	800	560	240
6	Buzzard Point - GT	320	290	30
7	Morgan Town - GT	290	260	30
	TOTAL	3330	2395	935

Table 10. Technological Retrofit Selection

D.E.S. Washington State D.C.
 Plant Benning

No.	Power Group	Nom. Pow. Max. MW	Boiler				Turbine			Cond.	Fuel				Retrofit
			Man. Name	Date Inst.	PSIA	°F	Man. Name	Date Inst.	Type	Man. Name	Coal	Oil	Gas	Nucl	
1	ST10	30	F&W	12.27	700	900	GE	8.27	SS	Wort	-	X	-	-	CPEI
2	ST11	30	CE	7.32	1700	1000	GE	6.29	SS	Wort	-	X	-	-	CPEI
3	ST12	30	CE	8.68	1965	950	GE	5.31	SS	Wort	-	X	-	-	CPEI
4	ST13	50	F&W	5.72	1965	950	GE	8.47	SS	Wort	-	X	-	-	CPEI
5	ST14	25	-	-	-	-	GE	7.52	SS	-	-	X	-	-	CPEI
6	ST15	275	-	-	-	-	GE	8.68	TC	West	-	X	-	-	CO
7	ST16	275	-	-	-	-	GE	5.72	TC	West	-	X	-	-	CO

Table 11. Technological Retrofit Selection

D.E.S. Washington

State D.C.

Plant Buzzard Point

No.	Power Group	Nom. Pow. Max. MW	Boiler				Turbine			Cond.	Fuel				Retrofit
			Man. Name	Date Inst.	PSIA	°F	Man. Name	Date Inst.	Type	Man. Name	Coal	Oil	Gas	Nucl	
1	ST1	30	B&W	12.33	650	825	GE	12.33	SS	IR	-	X	-	-	CPEI
2	ST2	30	B&W	5.34	650	825	GE	7.38	SS	IR	-	X	-	-	CPEI
3	ST3	50	CE	11.40	650	900	GE	11.40	SS	WORT	-	X	-	-	CPEI
4	ST4	50	CE	9.41	650	900	GE	7.42	SS	WORT	-	X	-	-	CPEI
5	ST5	50	CE	9.43	650	900	GE	7.43	SS	WORT	-	X	-	-	CPEI
6	ST6	50	CE	9.45	650	900	GE	9.45	SS	WORT	-	X	-	-	CPEI

Table 12 . Technological Retrofit Selection

D.E.S. WashingtonState D.C.Plant Potomac River

No.	Power Group	Nom. Pow. Max. MW	Boiler				Turbine			Cond.	Fuel				Retrofit
			Man. Name	Date Inst.	PSIA	OP	Man. Name	Date Inst.	Type	Man. Name	Coal	Oil	Gas	Nucl	
1	ST1	82	CE	10.49	850	920	GE	10.49	T	WORT	X	X	-	-	CO
2	ST2	67	CE	6.50	850	925	GE	6.50	T	WORT	X	X	-	-	CO
3	ST3	102	CE	7.54	1875	$\frac{1050}{1000}$	GE	7.54	TC	IR	X	X	-	-	CO
4	ST4	102	CE	3.54	1875	$\frac{1050}{1000}$	GE	3.56	TC	IR	X	X	-	-	CO
5	ST5	102	CE	5.57	1875	$\frac{1050}{1000}$	GE	5.57	TC	IR	X	X	-	-	CO

Table 13. Technological Retrofit Selection

D.E.S. Washington State D.C.Plant Dickerson

No.	Power Group	Nom. Pow. Max. MW	Boiler				Turbine			Cond.	Fuel				Retrofit
			Man. Name	Date Inst.	PSIA	°F	Man. Name	Date Inst.	Type	Man. Name	Coal	Oil	Gas	Nucl	
1	ST1	183	CE	7.59	$\frac{2400}{460}$	$\frac{1050}{1000}$	GE	7.59	CC	WORT	X	-	-	-	CO
2	ST2	183	CE	5.60	$\frac{2400}{460}$	$\frac{1050}{1000}$	GE	5.60	CC	WORT	X	-	-	-	CO
3	ST3	183	CE	4.62	$\frac{2400}{460}$	$\frac{1050}{1000}$	GE	4.62	CC	WORT	X	-	-	-	CO
1	ST4*	800													

* New provided for 1983.

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Plant Buzzard Point - Gas Turbines

[illegible]

Table 15. Technological Retrofit Selection

D.E.S. Washington State D.C.Plant Morgan Town - Gas Turbines

No.	Power Group	Nom. Pow. Max. MW	Boiler				Turbine			Cond.	Fuel				Retrofit
			Man. Name	Date Inst.	PSIA	Op	Man. Name	Date Inst.	Type	Man. Name	Coal	Oil	Gas	Nucl	
1	GT1	20	-	-	-	-	GE	12.70	-	-	-	X	-	-	RB
2	GT2	20	-	-	-	-	GE	2.71	-	-	-	X	-	-	RB
3	GT3	62	-	-	-	-	GE	6.73	-	-	-	X	-	-	RB
4	GT4	62	-	-	-	-	GE	6.75	-	-	-	D	-	-	-
5	GT5	62	-	-	-	-	GE	5.73	-	-	-	D	-	-	-
6	GT6	62	-	-	-	-	GE	5.73	-	-	-	D	-	-	-

Table 16. Technological Retrofit Selection

D.E.S. Washington

State D.C.

Plant Central Thermal Plant

[illegible]

Table 17. Technological Retrofit Selection

D.E.S. Washington State D.C.

Plant West Thermal[illegible]

Table 18. New Equipment in Plants

D.E.S. Washington State D.C.Plant Benning

No.	Power Group	Heat Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtu			MW	10 ⁵ MBtu
1	ST1	55	CPEI	1	6,250	46	1.60	-	-	-	-
2	ST2	55	CPEI	1	6,250	46	1.60	-	-	-	-
3	ST3	55	CPEI	1	6,250	46	1.60	-	-	-	-
4	ST4	90	CPEI	1	10,200	75	2.60	-	-	-	-
5	ST5	45	CPEI	1	5,100	37.5	1.30	-	-	-	-
6	ST6	300	CO	1	34,100	300	10.0	-	-	-	-
7	ST7	300	CO	1	34,100	300	10.0	-	-	-	-

Table 19. New Equipment in Plants

D.E.S. Washington State D.C.Plant Buzzard Point

No.	Power Group	Heat Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtu			MW	10 ⁵ MBtu
1	ST1	55	CPEI	1	6,250	46	1.60	-	-	-	-
2	ST2	55	CPEI	1	6,250	46	1.60	-	-	-	-
3	ST3	84	CPEI	1	9,550	70	2.38	-	-	-	-
4	ST4	84	CPEI	1	9,550	70	2.38	-	-	-	-
5	ST5	84	CPEI	1	9,550	70	2.38	-	-	-	-
6	ST6	84	CPEI	1	9,550	70	2.38	-	-	-	-
1	GT1	-	-	-	-	-	-	1	45,467	400	13.64
2	GT2	-	-	-	-	-	-	1	45,467	400	13.64

Table 20. New Equipment in Plants

D.E.S. Washington State D.C.Plant Potomac River

No.	Power Group	Heat Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtu			MW	10 ⁵ MBtu
1	ST1	110	CO	1	12,500	110	3.80	-	-	-	-
2	ST2	91	CO	1	10,400	91	3.10	-	-	-	-
3	ST3	133	CO	1	15,100	133	4.60	-	-	-	-
4	ST4	133	CO	1	15,100	133	4.60	-	-	-	-
5	ST5	133	CO	1	15,100	133	4.60	-	-	-	-

Table 21. New Equipment in Plants

D.E.S. Washington State D.C.Plant Dickerson

No.	Power Group	Heat Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtu			MW	10 ⁵ MBtu
1	ST1	210	CO	1	23,900	210	3.80	-	-	-	-
2	ST2	210	CO	1	23,900	210	3.80	-	-	-	-
3	ST3	210	CO	1	23,900	210	3.80	-	-	-	-
1	ST4	875	EXTR	2	100,000	437.5	15.0	-	-	-	-

Table 22. New Equipment in Plants

D.E.S. Washington State D.C.Plant Morgan Town

No.	Power Group	Heat Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtu			MW	10 ⁵ MBtu
1	GT1	50	RB	-	-	-	-	1	5,700	50	1.70
2	GT2	50	RB	-	-	-	-	1	5,700	50	1.70
3	GT3	155	RB	-	-	-	-	1	17,600	155	5.30
4	GT4	155	RB	-	-	-	-	1	17,600	155	5.30
5	GT5	155	RB	-	-	-	-	1	17,600	155	5.30
6	GT6	155	RB	-	-	-	-	1	17,600	155	5.30

Table 23. New Equipment in Plants

D.E.S. Washington State D.C.

Plant : New Thermal

[illegible]

Table 24. Pump Stations D.E.S. Characteristics Data

D.E.S. Washington State D.C.

No.	Station Name	Heat MW	At Deg. F	GPM	L Mile	H Ft. H ₂ O	P kW	Pumps	Dia φ Inch
1	Benning	845	60	96,000	7.5	950	2.72	4	48
2	Buzzard Point	<u>445</u> 800	60	<u>50,600</u> 91,000	5.0	635	2.68	6	60
3	Potomac River	600	60	68,200	5.0	635	1.29	3	42
4	Dickerson	<u>620</u> 875	60	<u>70,500</u> 100,000	17.5	2220	11.27	6	60
5	Morgantown	720	60	82,000	17.5	2220	5.42	2	48
6	Central	100	60	11,370	5.0	635	0.22	2	24
7	West	100	60	11,370	5.0	635	0.22	2	24
8	New	300	60	34,110	5.0	635	0.66	2	36
						Total	24.48	27	

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CHICAGO, ILLINOIS

Table 1 . Demand Data

D.E.S. Chicago State Illinois

Energy	Peak / Average	10^6 Btu / Day	MW
Heating Demand	Peak (HP)	2,132,098	26,050
	Average (HA)	559,222	6,830
Hot Water	Average (HA)	48,152	590
Cooling Demand	Peak (CP)	814,417	10,000
	Average (CA)	204,617	2,500

Table 2. Plant's Power Groups' Characteristics

D.E.S. ChicagoState IllinoisPlant Crowford

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST7	220	CO	150	250	8.00	2.24	0.426	0.775
2	ST8	325	CO	230	350	8.00	2.17	0.426	0.760
1	12GT	210	RB	190	420	12.00	0.57	0.284	0.825
	TOTAL ST	545	-	380	600	8.00	2.20	0.426	0.766
	TOTAL GT	210	-	190	420	12.00	0.57	0.284	0.825

Table 3. Plant's Power Groups' Characteristics

D.E.S. Chicago
 Plant Will County

State Illinois

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST1	165	CO	115	190	8.00	2.11	0.426	0.788
2	ST2	165	CO	115	190	8.00	2.11	0.426	0.788
3	ST3	275	CO	190	290	8.00	2.35	0.426	0.744
4	ST4	520	CO	390	610	8.00	1.71	0.426	0.819
	TOTAL ST	1125	-	810	1280	8.00	1.97	0.426	0.791

Table 4. Plant's Power Groups' Characteristics

D.E.S. ChicagoState IllinoisPlant State Line

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST1	200	CO	135	225	8.20	2.37	0.416	0.749
2	ST2	200	CO	135	225	8.20	2.37	0.416	0.749
3	ST3	200	CO	135	225	8.20	2.37	0.416	0.749
4	ST4	360	CO	255	390	8.00	2.37	0.426	0.763
	TOTAL ST	960	-	660	1065	8.13	2.29	0.419	0.753

Table 5. Plant's Power Groups' Characteristics

D.E.S. ChicagoState IllinoisPlant Joliet

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST5	120	CO	80	160	8.20	2.05	0.413	0.826
2	ST6	325	CO	225	430	8.00	1.86	0.426	0.858
3	ST7	580	CO	435	680	8.00	1.70	0.426	0.819
4	ST8	580	CO	435	680	8.00	1.70	0.426	0.819
1	5JT	10	RB	9	20	12.00	0.60	0.284	0.824
2	6GT	150	RB	135	300	12.00	0.60	0.284	0.824
	TOTAL ST	1605	-	1175	1950	8.01	1.76	0.425	0.827
	TOTAL GT	160	-	144	320	12.00	0.60	0.284	0.824

Table 6. Plant's Power Groups' Characteristics

D.E.S. ChicagoState IllinoisPlant Waukegan

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST5	120	CO	80	160	8.20	2.05	0.413	0.826
2	ST6	120	CO	80	160	8.20	2.05	0.413	0.826
3	ST7	325	CO	225	430	8.00	1.86	0.426	0.858
4	ST8	325	CO	225	430	8.00	1.86	0.426	0.858
1	4JE	150	RB	135	300	12.00	0.60	0.284	0.824
	TOTAL ST	890	-	610	1180	8.05	1.91	0.423	0.850
	TOTAL GT	150	-	135	300	12.00	0.60	0.284	0.824

Table 7. Plant's Power Groups' Characteristics

D.E.S. Chicago State IllinoisPlant Fisk

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST18	165	CO	115	190	8.00	2.11	0.426	0.788
2	ST19	325	CO	225	430	8.00	1.86	0.426	0.788
1	5IC	10	RB	9	20	12.00	0.60	0.284	0.824
2	8JE	300	RB	270	600	12.00	0.60	0.284	0.824
	TOTAL ST	490	-	340	620	8.00	1.94	0.426	0.835
	TOTAL GT	310	-	279	620	12.00	0.60	0.284	0.824

Table 8. Plant's Power Groups' Characteristics

D.E.S. ChicagoState IllinoisPlant Ridgeland

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST1	150	CO	105	175	8.00	2.06	0.426	0.793
2	ST2	165	CO	115	190	8.00	2.11	0.426	0.788
3	ST3	165	CO	115	190	8.00	2.11	0.426	0.788
4	ST4	165	CO	115	190	8.00	2.11	0.426	0.788
	TOTAL ST	645	-	450	754	8.00	2.09	0.426	0.789

Table 9. Plant's Power Groups' Characteristics

D.E.S. ChicagoState IllinoisPlant Zion - Nuclear

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST1	1100	CO	770	1200	10.42	2.86	0.327	0.586
2	ST2	1100	CO	770	1200	10.42	2.86	0.327	0.586
	TOTAL ST	2200	-	1540	2400	10.42	2.86	0.327	0.586

Table 10. Plant's Power Groups' Characteristics

D.E.S. Chicago

State Illinois

Plant Calumet[illegible]

State Illinois

Plant Lombard

[illegible]

Table 12. Plant's Power Groups' Characteristics.

D.E.S. Chicagc State Illinois

Plant Aurora Electric Junction[illegible]

Table 13. Cogeneration Selection

D.E.S. Chicago State Illinois

	Plant		Heat Available In Plants	MW Heat Usable
1	Crowford	ST GT	600 420	450 315
2	Will County	ST	1280	960
3	State Line	ST	1065	800
4	Joliet	ST CT	1950 300	1465 225
5	Waukegan	ST GT	1180 300	885 225
6	Fisk	ST GT	620 600	465 450
7	Ridgeland	ST	745	560
8	Zion - Nuclear	ST	2400	1800
9	Calumet	GT	600	450
10	Lombard	JE	600	450
11	Aurora	GT	600	450
12	New Power Plants	ST	6240	4680
13	New Thermal Plants	HW	19,500	14,630
	TOTAL		39,000	29,230

MAX TO THE POWER PLANT

$$26,460 \times 1.11 = 29,300 \text{ MW}$$

REQUIRED IN THE POWER PLANT

$$29,300 : 0.75 = 39,000 \text{ MW}$$

Table 14. Cogeneration D.E.S. System Data

D.E.S. Chicago State Illinois

No.	Plant		Crowford		Will County	State Line	Joliet	
	Characteristic							
1	Nominal Power	MW	545	210	1125	960	1605	150
2	Type of Fuel	Work	Coal & Gas	Oil & Gas	Coal & Gas	Coal & Gas	Coal & Gas	Oil
		Start	Gas	Oil & Gas	Gas	Gas	Gas	Oil
3	Type of Turbines		Steam	Gas	Steam	Steam	Steam	Gas
4	Cogeneration Electric Power	MW	380	190	810	660	1175	135
5	Cogeneration Heat Power	MW	600	420	1280	1065	1950	300
6	Fuel Rate for Power Plant	Elec.	8.00	12.00	8.00	8.13	8.01	12.00
		Heat	2.20	0.57	1.97	2.29	1.76	0.60
7	Efficiencies η	Nom.	0.426	0.284	0.426	0.419	0.425	0.284
		Cog.	0.766	0.825	0.791	0.753	0.827	0.824

Table 14. Cogeneration D.E.S. System Data (Cont'd)

D.E.S. Chicago State Illinois

No.	Plant		Calumet	Lombard	Aurora	New Power Plants	New Thermal Plants	
	Characteristic							
1	Nominal Power	MW	300	300	300			
2	Type of Fuel	Work	Oil	Oil & Gas	Oil			
		Start	Oil	Oil & Gas	Oil			
3	Type of Turbines		Gas	Gas	Gas			
4	Cogeneration Electric Power	MW	270	270	270			
5	Cogeneration Heat Power	MW	600	600	600	6240	19,500	
6	Fuel Rate for Power Plant	Elec.	12.00	12.00	12.00			
		Heat	0.60	0.60	0.60			
7	Efficiencies η	Nom.	0.284	0.284	0.284			
		Cog.	0.824	0.824	0.824			

Table 14. Cogeneration D.E.S. System Data (cont'd)

D.E.S. ChicagoState Illinois

No.	Plant		Waukegan		Fisk		Ridgeland	Zion Nuclear
	Characteristic							
1	Nominal Power	MW	890	150	490	300	645	2200
2	Type of Fuel	Work	Coal & Gas	Oil	Coal & Gas	Oil	Oil	Uranium
		Start	Gas	Oil	Gas	Oil	Oil	-
3	Type of Turbines		Steam	Gas	Steam	Gas	Steam	Steam
4	Cogeneration Electric Power	MW	610	135	340	270	450	1540
5	Cogeneration Heat Power	MW	1180	300	620	600	745	2400
6	Fuel Rate for Power Plant	Elec.	8.05	12.00	8.00	12.00	8.00	10.42
		Heat	1.91	0.60	1.94	0.60	2.09	2.86
7	Efficiencies η	Nom.	0.423	0.284	0.426	0.284	0.426	0.327
		Cog.	0.850	0.824	0.835	0.824	0.789	0.586

Table 15 . Maximum Electricity Loss Through Cogeneration

D.E.S. Chicago State Illinois

No.	Power Plant	Nominal MW	Cogen. MW	Difference MW
1	Crowford	755	570	185
2	Will County	1125	810	315
3	State Line	960	660	300
4	Joliet	1755	1310	445
5	Waukegan	1040	745	295
6	Fisk	790	610	180
7	Ridgeland	645	450	195
8	Zion - Nuclear	2200	1540	660
9	Calumet	300	270	30
10	Lombard	300	270	30
11	Aurora	300	270	30
	TOTAL	10,170	7,505	2,665

Table 16. Technological Retrofit Selection

D.E.S. Chicago

State Illinois

Plant Crowford

[illegible]

* Gas Turbines.

Table 17. Technological Retrofit Selection

D.E.S. Chicago State Illinois
 Plant Will County

No.	Power Group	Nom. Pow. Max. MW	Boiler				Turbine			Cond.	Fuel				Retrofit
			Man. Name	Date Inst.	PSIA	°F	Man. Name	Date Inst.	Type	Man. Name	Coal	Oil	Gas	Nucl	
1	ST1	165	-	1955	1900	$\frac{1050}{1010}$	-	1955	CC	-	CY*	-	-	-	CO
2	ST2	165	-	1955	1900	$\frac{1050}{1010}$	-	1955	CC	-	CY	-	-	-	CO
3	ST3	275	-	1957	2100	$\frac{1050}{1050}$	-	1957	CC	-	PC	-	-	-	CO
4	ST4	520	-	1963	2490	$\frac{1000}{1000}$	-	1963	CC	-	PC	-	-	-	CO

* Cyclone = CY

Table 18. Technological Retrofit Selection

D.E.S. Chicago State Illinois

Plant State Line

[illegible]

NO DATA AVAILABLE

Table 19. Technological Retrofit Selection

D.E.S. Chicago State Illinois
 Plant Joliet

No.	Power Group	Nom. Pow. Max. MW	Boiler				Turbine			Cond.	Fuel				Retrofit
			Man. Name	Date Inst.	PSIA	°F	Man. Name	Date Inst.	Type	Man. Name	Coal	Oil	Gas	Nucl	
1	ST5	120	-	1950	1325	1010	-	1950	TC	-	CY	-	X	-	CO
2	ST6	325	-	1959	2100	1050 1000	-	1959	CC	-	CY	-	X	-	CO
3	ST7	580	-	1965	2500	1000	-	1965	CC	-	PC	-	X	-	CO
4	ST8	580	-	1966	2500	1000 1000	-	1966	CC	-	PC	-	X	-	CO
2	6 IC*	150	-	-	-	-	-	1967	2 cycle	-	-	-	-	-	RB

* Internal Combustion.

Table 20. Technological Retrofit Selection.

D.E.S. Chicago State Illinois
 Plant Waukegan

No.	Power Group	Nom. Pow. Max. MW	Boiler				Turbine			Cond.	Fuel				Retrofit
			Man. Name	Date Inst.	FSIA	°F	Man. Name	Date Inst.	Type	Man. Name	Coal	Oil	Gas	Nucl	
1	ST5	120	-	1931	650	$\frac{750}{750}$	-	1931	TC	-	CP	-	X	-	CO
2	ST6	120	-	1952	1850	$\frac{1000}{1000}$	-	1952	TC	-	CY	-	X	-	CO
3	ST7	325	-	1958	2100	$\frac{1050}{1000}$	-	1958	CC	-	CY	-	X	-	CO
4	ST8	325	-	1962	2100	$\frac{1000}{1000}$	-	1962	CC	-	P	-	X	-	CO
	4JE*	150	-	-	-	-	-	1968	OPEN	-	-	-	-	-	RB

* Jet Engine

Table 21. Technological Retrofit Selection

D.E.S. Chicago State Illinois

Plant Fisk

[illegible]

* Jet Engine

Table 22. Technological Retrofit Selection

D.E.S. Chicago State Illinois
Plant Ridgeland

[illegible]

Table 23. Technological Retrofit Selection

D.E.S. Chicago State Illinois
Plant Zion Nuclear

[illegible]

Table 24. Technological Retrofit Selection

D.E.S. Chicago State Illinois

Plant Calumnet

[illegible]

Table 25. Technological Retrofit Selection

D.E.S. Chicago State Illinois

Plant Lombard

[illegible]

* Jet Engine

Table 26. Technological Retrofit Selection.

D.E.S. Chicago State Illinois

Plant Aurora[illegible]

Table 27. New Equipment in Plants.

D.E.S. Chicago State IllinoisPlant Crowford

No.	Power Group	Heat Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtu			MW	10 ⁵ MBtu
1	ST7	220	CO	1	28,417	250	8.52	-	-	-	-
2	ST8	325	CO	1	39,783	350	11.94	-	-	-	-
1	12GT	210	RB	-	-	-	-	12	3,978	35	1.19

Table 28. New Equipment in Plants

D.E.S. Chicago State IllinoisPlant Will County

No.	Power Group	Heat Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtu			MW	10 ⁵ MBtu
1	ST1	165	CO	1	21,597	190	6.48	-	-	-	-
2	ST2	165	CO	1	21,597	190	6.48	-	-	-	-
3	ST3	275	CO	1	32,963	290	4.89	-	-	-	-
4	ST4	520	CO	1	69,337	610	20.80	-	-	-	-

Table 29. New Equipment in Plants

D.E.S. Chicago State IllinoisPlant State Line

No.	Power Group	Heat Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtu			MW	10 ⁵ MBtu
1	ST1	200	CO	1	25,575	225	7.67	-	-	-	-
2	ST2	200	CO	1	25,575	225	7.67	-	-	-	-
3	ST3	200	CO	1	25,575	225	7.67	-	-	-	-
4	ST4	360	CO	1	44,330	390	13.30	-	-	-	-

Table 30. New Equipment in Plants

D.E.S. Chicago State IllinoisPlant Joliet

No.	Power Group	Heat Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtu			MW	10 ⁵ MBtu
1	ST5	120	CO	1	18,187	160	5.46	-	-	-	-
2	ST6	325	CO	1	48,867	430	14.66	-	-	-	-
3	ST7	580	CO	1	77,293	680	23.19	-	-	-	-
4	ST8	580	CO	1	77,293	680	23.19	-	-	-	-
2	6GT	150	RB	-	-	-	-	6	2,558	22.5	0.77

Table 31. New Equipment in Plants

D.E.S. Chicago State IllinoisPlant Waukegan

No.	Power Group	Heat Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtu			MW	10 ⁵ MBtu
1	ST5	120	CO	1	18,187	160	5.46	-	-	-	-
2	ST6	120	CO	1	18,187	160	5.46	-	-	-	-
3	ST7	825	CO	1	48,867	430	14.66	-	-	-	-
4	ST8	325	CO	1	48,867	430	14.66	-	-	-	-
1	4JE	150	RB	-	-	-	-	4	8,525	75	2.56

Table 32. New Equipment in Plants

D.E.S. Chicago State IllinoisPlant Fisk

No.	Power Group	Heat Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtu			MW	10 ⁵ MBtu
1	ST18	165	CO	1	21,567	190	6.47	-	-	-	-
2	ST19	325	CO	1	48,877	430	14.66	-	-	-	-
2	8JE	300	RB	-	-	-	-	8	8,525	75	2.56

Table 33. New Equipment in Plants

D.E.S. Chicago State IllinoisPlant Ridgeland

No.	Power Group	Heat Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtu			MW	10 ⁵ MBtu
1	ST1	150	CO	1	19,892	175	5.97	-	-	-	-
2	ST2	165	CO	1	21,597	190	6.48	-	-	-	-
3	ST3	165	CO	1	21,597	190	6.48	-	-	-	-
4	ST4	165	CO	1	21,597	190	6.48	-	-	-	-

Table 34 . New Equipment in Plants

D.E.S. Chicago State Illinois

Plant Zion - Nuclear

[illegible]

Table 35. New Equipment in Plants

D.E.S. Chicago State Illinois

Plant Calumet

[illegible]

Table 36 . New Equipment in Plants

D.E.S. Chicago State Illinois

Plant Lombard

[illegible]

Table 37. New Equipment in Plants

D.E.S. Chicago State Illinois

Plant Aurora

[illegible]

Table 38 . New Equipment in Plants

D.E.S. Chicago State Illinois

Plant New Power Plants[illegible]

Table 39. New Equipment in Plants

D.E.S. Chicago State Illinois

Plant	New Thermal Plants
1	1
2	2
3	3
4	4
5	5
6	6
7	7
8	8
9	9
10	10
11	11
12	12
13	13
14	14
15	15
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88	88
89	89
90	90
91	91
92	92
93	93
94	94
95	95
96	96
97	97
98	98
99	99
100	100

[illegible]

Table 40. Pump Stations D.E.S. Characteristics Data

D.E.S. Chicago State Illinois

No.	Station Name	Heat MW	Δt °F	GPM	L Mile	H Ft H ₂ O	P MW	Pumps	Dia. ϕ Inch
1	Crowford	600	60	68,200	5.00	635	1.29	4	42
	"	420	60	47,740	5.00	635	0.90	4	36
2	Will County	1280	60	145,490	20.00	2540	11.00	8	60
3	State Line	1065	60	121,055	20.00	2540	9.15	6	54
4	Joliet	1950	60	221,650	25.00	3175	20.94	10	72
	"	300	60	34,100	25.00	3175	3.22	2	36
5	Waukegan	1180	60	134,130	15.00	1905	7.60	6	60
	"	300	60	34,100	15.00	1905	1.93	2	36
6	Fisk	620	60	70,470	5.00	635	1.33	4	48
	"	600	60	68,200	5.00	635	1.29	4	48
7	Ridgeland	745	60	84,680	5.00	635	1.60	4	48
8	Zion-Nuclear	2400	60	272,800	20.00	2540	20.62	16	72
9	Calumet	600	60	68,200	10.00	1270	2.58	4	48

Subtotal 83.45

74

Table 40. Pump Stations D.E.S. Characteristics Data (Cont'd)

D.E.S. Chicago State Illinois

No.	Station Name	Heat MW	Δt °F	GPM	L Mile	H Ft H ₂ O	P MW	Pumps	Dia. φ Inch
						SUBTOTAL	83.45	74	
10	Lombard	600	60	68,200	15.00	1905	3.87	4	42
11	Aurora	600	60	68,200	20.00	2540	5.15	4	42
12	New P.O	6,240	60	709,280	17.50	2220	46.87	20	2 x 72
13	New TP	19,500	60	2,216,500	5.00	635	41.89	40	2 x 76
						TOTAL	181.23	142	

DETROIT, MICHIGAN

Table 1. Demand Data

D.E.S. Detroit State Michigan

Energy	Peak / Average	10^6 Btu / Day	MW
Heating Demand	Peak (HP)	467,169	5,710
	Average (HA)	144,169	1,765
Hot Water	Average (hA)	12,003	150
Cooling Demand	Peak (CP)	197,691	2,415
	Average (CA)	35,039	430

Table 2. Plant's Power Groups' Characteristics

D.E.S. DetroitState MichiganPlant Greenwood

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST 1	817	CO	572	895	8.00	1.82	0.426	0.776
1	ST 2	1342	CO	940	1470	10.42	2.85	0.327	0.587
2	ST 3	1342	CO	940	1470	10.42	2.85	0.327	
	TOTAL ST	817	--	572	895	8.00	1.82	0.426	0.776
	NUCLEAR								
	TOTAL ST	2685	--	1880	2940	10.42	2.85	0.327	0.587

Table 3. Plant's Power Groups' Characteristics

D.E.S. DetroitState MichiganPlant Marysville

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST 6	50	COEI	25	85	9.28	2.74	0.367	0.828
2	ST 7	75	CPEI	40	125	8.68	2.43	0.393	0.864
3	ST 8	75	CPEI	40	125	8.68	2.43	0.393	0.864
	TOTAL ST	200	---	105	335	8.83	2.50	0.386	0.849

Table 4. Plant's Power Groups' Characteristics

D.E.S. DetroitState MichiganPlant St. Clair

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST 1	165	CO	115	190	8.00	2.11	0.426	0.788
2	ST 2	150	CO	105	170	8.00	2.12	0.426	0.781
3	ST 3	150	CO	105	170	8.00	2.12	0.426	0.781
4	ST 4	165	CO	115	190	8.00	2.11	0.426	0.788
5	ST 5	350	CO	240	370	8.00	2.38	0.426	0.743
6	ST 6	350	CO	240	370	8.00	2.38	0.426	0.743
7	ST 7	550	CO	405	640	8.00	1.81	0.426	0.809
1.	GT 11	20	BR	18	40	12.00	0.60	0.284	0.824
2	2 D	5.4	BR	4.9	10.8	12.00	0.60	0.284	0.824
	TOTAL ST	1880	--	1325	2100	8.00	2.11	0.426	0.776
	TOTAL GT	25.4	--	22.9	50.8	12.00	0.60	0.284	0.824

Table 5. Plant's Power Groups' Characteristics

D.E.S. DetroitState MichiganPlant Conners Creek

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST 8	30	CPEI	15	55	9.68	2.52	0.352	0.781
2	ST 9	30	CPEI	15	55	9.68	2.52	0.352	0.781
3	ST 10	30	CPEI	15	55	9.68	2.52	0.352	0.781
4	ST 12	60	CPEI	45	80	9.08	1.70	0.376	0.783
5	ST 13	60	CPEI	45	80	9.08	1.70	0.376	0.783
6	ST 14	60	CPEI	45	80	9.08	1.70	0.376	0.783
7	ST 16	135	CO	95	160	8.00	2.00	0.425	0.803
8	ST 4	135	CO	95	160	8.00	2.00	0.425	0.803
1	2 D	5.4	BR	4.9	10.8	12.00	0.56	0.284	0.826
	TOTAL ST	540	--	370	725	8.75	2.05	0.390	0.791
	TOTAL GT	5.4	--	4.9	10.8	12.00	0.60	0.284	0.824

Table 6. Plant's Power Groups' Characteristics

D.E.S. DetroitState MichiganPlant Delray

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST 11	50	CPEI	25	85	9.28	2.74	0.367	0.828
2	ST 12	50	CPEI	25	85	9.28	2.74	0.367	0.828
3	ST 13	50	CPEI	25	85	9.28	2.74	0.367	0.828
4	ST 14	75	CPEI	40	125	8.68	2.43	0.393	0.864
5	ST 15	75	CPEI	40	125	8.68	2.43	0.393	0.864
6	ST 16	75	CPEI	40	125	8.68	2.43	0.393	0.864
	TOTAL ST	375	--	195	630	8.92	2.55	0.382	0.840

Table 7. Plant's Power Groups' Characteristics

D.E.S. DetroitState MichiganPlant River Rouge

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST 1	275	CO	190	290	8.00	2.35	0.426	0.744
2	ST 2	275	CO	190	290	8.00	2.35	0.426	0.744
3	ST 3	350	CO	240	370	8.00	2.38	0.426	0.743
1	4 D	10.6	BR	9.5	21.2	12.00	0.60	0.284	0.824
	TOTAL ST	900	--	620	950	8.00	2.36	0.426	0.744
	TOTAL GT	10.6	--	9.5	21.2	12.00	0.60	0.284	0.824

Table 8 Plant's Power Groups' Characteristics

D.E.S. DetroitState MichiganPlant Trenton-Channel

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST 7	120	CO	85	160	8.00	1.75	0.426	0.869
2	ST 8	120	CO	85	160	8.00	1.75	0.426	0.869
3	ST 9	535	CO	400	595	8.00	1.82	0.426	0.792
	TOTAL ST	775	--	570	915	8.00	1.79	0.426	0.816

Table 9. Plant's Power Groups' Characteristics

D.E.S. Detroit
 Plant Enrico Fermi

State Michigan

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST 1	150	CO	105	175	8.00	2.06	0.426	0.793
1	NUCLEAR ST 2	1100	CO	825	1200	10.42	2.39	0.327	0.602
1	4 GT	62	BR	56	125	12.00	0.58	0.284	0.829
	TOTAL ST	150	--	105	175	8.00	2.06	0.426	0.793
	NUCLEAR TOTAL ST	1100	--	825	1200	10.42	2.39	0.327	0.602
	TOTAL GT	62	--	56	125	12.00	0.58	0.284	0.829

Table 10. Plant's Power Groups' Characteristics

D.E.S. DetroitState MichiganPlant Monroe

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST 1	820	CO	575	900	8.00	2.18	0.426	0.766
2	ST 2	820	CO	575	900	8.00	2.18	0.426	0.766
3	ST 3	820	CO	575	900	8.00	2.18	0.426	6.766
4	ST 4	820	CO	575	900	8.00	2.18	0.426	0.766
1	5 D	13.5	BR	12	27	12	0.60	0.284	0.824
	TOTAL ST	3280	--	2300	3600	8.00	2.18	0.426	0.824
	TOTAL GT	13.5	--	12	27	12.00	0.60	0.284	0.824

Table 11. Plant's Power Groups' Characteristics

D.E.S. DetroitState MichiganPlant Port Huron

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	2 D	5.4	BR	4.9	10.8	12.0	0.56	0.284	0.826
	TOTAL GT	5.4	--	4.9	10.8	12.0	0.56	0.284	0.826

Table 12. Plant's Power Groups' Characteristics

D.E.S. Detroit State MichiganPlant Willis & Beacon Thermal

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
	ST 1	--	--	21	72	9.28	2.75	0.367	0.825
	BOILERS	--	--	--	500	--	4.55	--	0.750
	TOTAL ST	--	--	21	72	9.28	2.75	0.367	0.825
	TOTAL B	--	--	--	500	--	4.55	--	0.750

Table 13. Plant's Power Groups' Characteristics

D.E.S. Detroit
Plant Persalt

State Michigan

[illegible]

Table 14. Plant's Power Groups' Characteristics.

D.E.S. Detroit
 Plant Harbor Beach

State Michigan

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST 1	110	CO	77	145	8.00	1.82	0.426	0.776
1	2 GT	4.3	BR	3.9	8.60	12.00	0.56	0.284	0.830
	TOTAL ST	110	--	77	145	8.00	1.82	0.426	0.776
	TOTAL GT	4.3	--	3.9	8.60	12.00	0.56	0.284	0.830

Table 15. Cogeneration Selection

D.E.S. Detroit State Michigan

No.	Plant	Heat Available in Plant	MW Heat Usable	
1	St. Clair	2100	1575	
2	Connors Creek	725	540	
3	Delray	630	470	
4	River Rouge	950	710	
5	Trenton Channel	915	685	
6	Monroe	2700	2025	
7	Beacon & Thermal	572	430	
	TOTAL	8592	6435	

MAX TO THE POWER PLANT

$$5760 \times 1.10 = 6335 \text{ MW}$$

REQUIRED IN THE POWER PLANT

$$6335 : 0.75 = 8450 \text{ MW}$$

DISTRICT ENERGY FACTOR

$$(6435 - 430) : 6335 = 0.95$$

Table 16. Cogeneration D.E.S. System Data

D.E.S. DetroitState Michigan

No.	Plant		St. Clair	Conners Creek	Delray	River Rouge	Trenton Channel	Monroe
	Characteristic							
1	Nominal Power	MW	1880	540	375	900	775	2460
2	Type of Fuel	Work	Coal, oil & Gas	Coal, oil & Gas	Oil & Gas	Coal, oil & Gas	Coal, oil & Gas	Coal & oil
		Start	Oil & Gas	Oil & Gas	Oil & Gas	Oil & Gas	Oil & Gas	Oil
3	Type of Turbines		Steam	Steam	Steam	Steam	Steam	Steam
4	Cogeneration Electric Power	MW	1325	370	195	620	570	1725
5	Cogeneration Heat Power	MW	2100	725	630	950	915	2700
6	Fuel Rate for Power Plant	Elec.	8.00	8.75	8.92	8.00	8.00	8.00
		Heat	2.11	2.05	2.55	2.36	1.79	2.18
7	Efficiencies η	Nom.	0.426	0.390	0.385	0.426	0.426	0.426
		Cog.	0.776	0.791	0.840	0.744	0.816	0.824

Table 16. Cogeneration D.E.S. System Data (Contd.)

D.E.S. DetroitState Michigan

No.	Plant		Beacon	Thermal				
	Characteristic							
1	Nominal Power	MW	-	-				
2	Type of Fuel	Work	Coal & Gas	Oil & Gas				
		Start	Gas	Oil & Gas				
3	Type of Turbines		Steam	-				
4	Cogeneration Electric Power	MW	21	-				
5	Cogeneration Heat Power	MW	72	500				
6	Fuel Rate for Power Plant	Elec.	9.28	-				
		Heat	2.75	4.55				
7	Efficiencies η	Nom.	0.367	-				
		Cog.	0.825	0.750				

Table 17 . Maximum Electricity Loss Through Cogeneration

D.E.S. Detroit State Michigan

No.	Power Plant	Nominal MW	Cogen. MW	Difference MW
1	St. Clair	1880	1325	555
2	Conners Creek	540	370	170
3	Delray	375	195	180
4	River Rouge	900	620	280
5	Trenton Channel	775	570	205
6	Monroe	2460	1725	735
7	Beacon	21	21	-
	Sub Total	6951	4826	2125
	TOTAL	2125 x 0.75		1590

Table 18. Technological Retrofit Selection

D.E.S. Detroit State MichiganPlant St. Clair

No.	Power Group	Nom. Pow. Max. MW	Boiler				Turbine			Cond. Man.	Fuel				Retrofit
			Man. Name	Date Inst.	PSIA	°F	Man. Name	Date Inst.	Type		Coal	Oil	Gas	Nucl	
1	ST 1	165	B&W	1953	$\frac{1800}{330}$	$\frac{1000}{1000}$	GE	1953	CC **	-	PC*	-	-	-	CO ****
2	ST 2	150	B&W	1953	$\frac{1800}{330}$	$\frac{1000}{1000}$	AC	1953	CC	-	PC	-	-	-	CO
3	ST 3	150	B&W	1953	$\frac{1800}{330}$	$\frac{1000}{1000}$	AC	1953	CC	-	PC	-	-	-	CO
4	ST 4	165	B&W	1953	$\frac{1800}{330}$	$\frac{1000}{1000}$	GE	1953	CC	-	PC	-	-	-	CO
5	ST 5	350	B&W	1959	$\frac{2400}{495}$	$\frac{1050}{1000}$	GE	1959	CC	-	-	X	-	-	CO
6	ST 6	350	CE	1961	$\frac{2400}{495}$	$\frac{1050}{1000}$	WEST	1961	TC ***	-	PC	-	-	-	CO
7	ST 7	550	CE	1969	$\frac{2520}{521}$	$\frac{1000}{1000}$	WEST	1969	TC	-	PC	-	-	-	CO

* Pulverized Coal = PC ** Cross-Compound = CC *** Tandem-Compound = TC **** Cross-Over = CO.

Table 19. Technological Retrofit Selection

D.E.S. DetroitState MichiganPlant Conners Creek

No.	Power Group	Nom. Pow. Max. MW	Boiler				Turbine			Cond.	Fuel				Retrofit
			Man. Name	Date Inst.	PSIA	°F	Man. Name	Date Inst.	Type	Man. Name	Coal	Oil	Gas	Nucl	
1	ST 8	30	CE	1934	600	825	GE	1934	SC*	-	-	X	X	-	CPEI
2	ST 9	30	CE	1939	600	825	GE	1935	SC	-	-	X	X	-	CPEI
3	ST 10	30	CE	1937	600	825	GE	1935	SC	-	-	X	X	-	CPEI
4	ST 12	60	CE	1937	600	825	GE	1936	SC	-	-	X	X	-	CPEI
5	ST 13	60	CE	1936	600	825	GE	1936	SC	-	-	X	X	-	CPEI
6	ST 14	60	CE	1936	600	825	GE	1939	SC	-	-	X	X	-	CPEI
7	ST 16	135	B&W	1951	1300	950	WEST	1951	TC	-	PC	-	-	-	CO
8	ST 4	135	CE	1936	600	825	GE	1938	SC	-	-	X	X	-	CO

*Single Casing = SC

Table 20. Technological Retrofit Selection

D.E.S. DetroitState MichiganPlant Delray

No.	Power Group	Nom. Pow. Max. MW	Boiler				Turbine			Cond.	Fuel				Retrofit
			Man. Name	Date Inst.	PSIA	°F	Man. Name	Date Inst.	Type	Man. Name	Coal	Oil	Gas	Nucl	
1	ST 11	50	B&W	1941	375	700	GE	1929	SC	-	-	X	X	-	CPEI
2	ST 12	50	B&W	1940	375	700	GE	1929	SC	-	-	X	X	-	CPEI
3	ST 13	50	B&W	1938	375	700	GE	1933	SC	-	-	X	X	-	CPEI
4	ST 14	75	B&W	1939	815	900	GE	1938	SC	-	-	X	X	-	CPEI
5	ST 15	75	B&W	1941	815	900	GE	1943	SC	-	-	X	X	-	CPEI
6	ST 16	75	B&W	1940	815	900	GE	1942	SC	-	-	X	X	-	CPEI

Table 21 . Technological Retrofit Selection

D.E.S. Detroit

State Michigan

Plant River Rouge[illegible]

Table 23. Technological Retrofit Selection

D.E.S. DetroitState MichiganPlant Monroe

No.	Power Group	Nom. Pow. Max. MW	Boiler				Turbine			Cond.	Fuel				Retrofit
			Man. Name	Date Inst.	PSIA	°F	Man. Name	Date Inst.	Type	Man. Name	Coal	Oil	Gas	Nucl	
1	ST 1	820	B&W	1971	<u>3500</u> 740	<u>1000</u> 1000	GE	1971	TC	-	CP	-	-	-	CO
2	ST 2	820	B&W	1973	<u>3500</u> 740	<u>1000</u> 1000	WEST	1973	TC	-	CP	-	-	-	CO
3	ST 3	820	B&W	1973	<u>3500</u> 740	<u>1000</u> 1000	WEST	1973	TC	-	CP	-	-	-	CO

Table 24. Technological Retrofit Selection

D.E.S. Detroit State MichiganPlant Beacon Beacon, Willis & Boulevard - Thermal

No.	Power Group	Nom. Pow. Max. MW	Boiler				Turbine			Cond.	Fuel				Retrofit
			Man. Name	Date Inst.	PSIA	°F	Man. Name	Date Inst.	Type	Man. Name	Coal	Oil	Gas	Nucl	
1	ST 1	21 72	CE	1959	870	700	STAHL	1959	RADIAL	-	-	X	X	-	No Retrofit
1-20	Boilers	25	B&W	-	-	-	-	-	-	-	-	-	-	-	Retrofit To Hot Water

Table 25. New Equipment in Plants

D.E.S. Detroit State MichiganPlant: St. Clair

No.	Power Group	Nominal Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtuh			MW	10 ⁵ MBtuh
1	ST 1	165	CO	1	21,600	190	6.48	-	-	-	-
2	ST 2	150	CO	1	19,324	170	5.80	-	-	-	-
3	ST 3	150	CO	1	19,324	170	5.80	-	-	-	-
4	ST 4	165	CO	1	21,600	190	6.48	-	-	-	-
5	ST 5	350	CO	1	42,000	370	12.61	-	-	-	-
6	ST 6	350	CO	1	42,000	370	12.61	-	-	-	-
7	ST 7	550	CO	1	72,747	640	21.82	-	-	-	-

Table 26. New Equipment in Plants

D.E.S. Detroit State MichiganPlant: Conners Creek

No.	Power Group	Nominal Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtuh			MW	10 ⁵ MBtuh
1	ST 8	30	CPEI	1	6,275	46	1.60	-	-	-	-
2	ST 9	30	CPEI	1	6,275	46	1.60	-	-	-	-
3	ST 10	30	CPEI	1	6,275	46	1.60	-	-	-	-
4	ST 12	60	CPEI	1	9,000	66	2.25	-	-	-	-
5	ST 13	60	CPEI	1	9,000	66	2.25	-	-	-	-
6	ST 14	60	CPEI	1	9,000	66	2.25	-	-	-	-
7	ST 16	135	CO	1	18,187	160	5.45	-	-	-	-
8	ST 4	135	CO	1	18,187	160	5.45	-	-	-	-

Table 27. New Equipment in Plants

D.E.S. Detroit State MichiganPlant: Delray

No.	Power Group	Nominal Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtuh			MW	10 ⁵ MBtuh
1	ST 11	50	CPEI	1	9,660	70	2.39	-	-	-	-
2	ST 12	50	CPEI	1	9,660	70	2.39	-	-	-	-
3	ST 13	50	CPEI	1	9,660	70	2.39	-	-	-	-
4	ST 14	75	CPEI	1	11,367	100	3.41	-	-	-	-
5	ST 15	75	CPEI	1	11,367	100	3.41	-	-	-	-
6	ST 16	75	CPEI	1	11,367	100	3.41	-	-	-	-

Table 28. New Equipment in Plants

D.E.S. Detroit

State Michigan

Plant: River Rouge

[illegible]

Table 29. New Equipment in Plants

D.E.S. Detroit State MichiganPlant: Trenton Channel

No.	Power Group	Nominal Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtuh			MW	10 ⁵ MBtuh
1	ST 7	120	CO	1	18,187	160	5.46	-	-	-	-
2	ST 8	120	CO	1	18,187	160	5.46	-	-	-	-
3	ST 9	535	CO	1	67,632	595	20.30	-	-	-	-

Table 30. New Equipment in Plants

D.E.S. Detroit

State Michigan

Plant: Monroe

[illegible]

Table 31. New Equipment in Plants

D.E.S. Detroit State Michigan

Plant: Beacon, Willis & Boulevard - Thermal

[illegible]

Table 32. Pump Stations D.E.S. Characteristics Data

D.E.S. DetroitState Michigan

No.	Station Name	Heat MW	Δt °F	GPM	L Mile	H Ft H ₂ O	P MW	Pumps	Dia. φ Inch
1	St. Clair	2100	60	238,700	25	3,170	22.5	8	72
2	Conners Creek	725	60	82,410	5	630	1.55	2	48
3	Delray	630	60	71,510	7.5	950	2.02	2	48
4	River Rouge	950	60	107,980	10	1270	3.59	3	54
5	Trenton Channel	915	60	104,050	15	1900	5.88	4	54
6	Monroe	2700	60	306,900	25	3170	29.00	12	2 x 60
7	Beacon	172	60	19,550	5	630	0.37	2	28
8	Willis	200	60	22,730	5	630	0.43	2	32
9	Boulevard	200	60	22,730	5	630	0.43	2	32
						TOTAL	65.77	37	

ST. LOUIS, MISSOURI

Table 1 . Demand Data

D.E.S. St. Louis State Missouri

Energy	Peak / Average	10^6 Btu / Day	MW
Heating Demand	Peak (HP)	316,174	3,865
	Average (HA)	77,739	950
Hot Water	Average (hA)	8,137	100
Cooling Demand	Peak (CP)	157,332	1,925
	Average (CA)	47,176	575

Table 2. Plant's Power Groups' Characteristics

D.E.S. St. LouisState MissouriPlant Ashley

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST1	10	CPEI	6	20	13.75	1.75	0.248	0.645
2	ST7	20	CPEI	12	40	12.00	2.40	0.284	0.738
3	ST8	20	CPEI	12	40	12.00	2.40	0.284	0.738
4	ST9	20	CPEI	12	40	12.00	2.40	0.284	0.738
	TOTAL ST	70	-	42	140	12.25	2.45	0.278	0.723

Table 3. Plant's Power Groups' Characteristics

D.E.S. St. LouisState MissouriPlant Labadie

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST1	555	CO	415	650	7.88	1.70	0.433	0.831
2	ST2	555	CO	415	650	7.88	1.70	0.433	0.831
3	ST3	555	CO	415	650	7.88	1.70	0.433	0.831
4	ST4	555	CO	415	650	7.88	1.70	0.433	0.831
	TOTAL ST	2220	-	1660	2600	7.88	1.70	0.433	0.831

Table 4. Plant's Power Groups' Characteristics

D.E.S. St. LouisState MissouriPlant Maramec

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST1	125	CO	85	165	8.28	2.00	0.412	0.824
2	ST2	125	CO	85	165	8.28	2.00	0.412	0.824
3	ST3	250	CO	175	265	7.64	2.16	0.446	0.785
4	ST4	300	CO	205	315	7.94	2.40	0.429	0.744
1	GT	60	RB	54	120	12.00	0.60	0.284	0.824
	TOTAL ST	800	-	550	910	7.95	2.18	0.429	0.783
	TOTAL GT	60	-	54	120	12.00	0.60	0.284	0.824

Table 5. Plant's Power Groups' Characteristics

D.E.S. St. LouisState MissouriPlant Sioux

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST1	490	CO	350	500	7.41	2.08	0.460	0.800
2	ST2	490	CO	350	500	7.41	2.08	0.460	0.800
	TOTAL ST	980	-	700	1000	7.41	2.08	0.460	0.800

Table 6. Plant's Power Groups' Characteristics

D.E.S. St. LouisState MissouriPlant Venice No. 2

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST1	50	CO	35	65	9.39	2.17	0.363	0.726
2	ST2	50	CO	35	65	9.39	2.17	0.363	0.726
3	ST3	100	CPEI	50	170	9.22	2.71	0.370	0.814
4	ST4	100	CPEI	50	170	9.22	2.71	0.370	0.814
5	ST5	100	CPEI	50	170	9.22	2.71	0.370	0.814
6	ST6	100	CO	75	140	9.26	1.65	0.368	0.791
1	GT	37.5	RB	34	75	12.00	0.60	0.284	0.824
	TOTAL ST	500	-	295	780	9.26	2.43	0.368	0.791
	TOTAL GT	37.5	-	34	75	12.00	0.60	0.284	0.824

Table 7. Cogeneration Selection

D.E.S. St. Louis State Missouri

No.	Plant	Heat Available	MW Heat	Type of Fuel
1	Ashley ST	140	105	
2	Labadie ST	1950	1460	
3	Maramec ST GT	910 120	685 90	
4	Sioux ST	1000	750	
5	Venice No. 2 ST GT	780 75	585 55	
6	New Thermal HW	840	630	
	TOTAL	5815	4360	

MAX TO THE POWER PLANT

$$3965 \times 1.10 = 4360 \text{ MW}$$

REQUIRED IN THE POWER PLANT

$$4360 : 0.75 = 5815 \text{ MW}$$

DISTRICT ENERGY FACTOR

$$(5815 - 840) : 5815 = 0.86$$

Table 8 . Cogeneration D.E.S. System Data

D.E.S. St. Louis State Missouri

No.	Plant		Ashley	Labadie	Maramec		Sioux	New Thermal
	Characteristic							
1	Nominal Power	MW	70	1665	800	60	980	
2	Type of Fuel	Work						
		Start						
3	Type of Turbines		Steam	Steam	Steam	Gas	Steam	
4	Cogeneration Electric Power	MW	42	1245	550	55	700	
5	Cogeneration Heat Power	MW	140	1950	910	120	1000	840
6	Fuel Rate for Power Plant	Elec.	12.25	7.88	7.95	12.00	7.41	
		Heat	2.45	1.70	2.18	0.60	2.08	
7	Efficiencies η	Nom.	0.278	0.433	0.429	0.284	0.460	
		Cog.	0.723	0.831	0.783	0.824	0.800	

Table 8 . Cogeneration D.E.S. System Data (Contd.)

D.E.S. St. Louis State Missouri

No.	Plant		Venice No. 2					
	Characteristic							
1	Nominal Power	MW	500	37.5				
2	Type of Fuel	Work						
		Start						
3	Type of Turbines		Steam	Gas				
4	Cogeneration Electric Power	MW	295	34				
5	Cogeneration Heat Power	MW	780	75				
6	Fuel Rate for Power Plant	Elec.	9.26	12.00				
		Heat	2.43	0.60				
7	Efficiencies η	Nom.	0.368	0.284				
		Cog.	0.791	0.824				

Table 9 . Maximum Electricity Loss Through Cogeneration

D.E.S. St. Louis

State Missouri

[illegible]

Table 10. Technological Retrofit Selection

D.E.S. St. Louis State Missouri

Plant Ashley

[illegible]

Table 11. Technological Retrofit Selection

D.E.S. St. Louis State MissouriPlant Labadie

No.	Power Group	Nom. Pow. Max. MW	Boiler				Turbine			Cond.	Fuel				Retrofit
			Man. Name	Date Inst.	PSIA	°F	Man. Name	Date Inst.	Type	Man. Name	Coal	Oil	Gas	Nucl	
1	ST1	555	CE	1970	2400	$\frac{1000}{1000}$	West	1970	TC	-	PC	-	-	-	CO
2	ST2	555	CE	1971	2400	$\frac{1000}{1000}$	West	1971	TC	-	PC	-	-	-	CO
3	ST3	555	CE	1972	2400	$\frac{1000}{1000}$	GE	1972	TC	-	PC	-	-	-	CO
4	ST4	555	CE	1973	2400	$\frac{1000}{1000}$	GE	1973	TC	-	PC	-	-	-	CO

Table 12. Technological Retrofit Selection

D.E.S. St. LouisState MissouriPlant Maramec

No.	Power Group	Nom. Pow. Max. MW	Boiler				Turbine			Cond.	Fuel				Retrofit
			Man. Name	Date Inst.	PSIA	°F	Man. Name	Date Inst.	Type	Man. Name	Coal	Oil	Gas	Nucl	
1	ST1	125	CE *	1953	1250	$\frac{950}{950}$	WEST	1953	TC	-	PC	-	X	-	CO
2	ST2	125	CE	1954	1250	$\frac{950}{950}$	WEST	1954	TC	-	PC	-	X	-	CO
3	ST3	250	FW **	1959	2000	$\frac{1000}{1000}$	GE	1959	TC	-	PC	-	X	-	CO
4	ST4	300	FW	1961	2000	$\frac{1000}{1000}$	WEST	1961	TC	-	PC	-	X	-	CO
1	GT	60	-	-	-	-	GE	1974	OPEN	-	-	-	-	-	RB

* Combustion Engineers

** Foster Wheeler

Table 13. Technological Retrofit Selection

D.E.S. St. Louis State Missouri

Plant Sioux

[illegible]

Table 14. Technological Retrofit Selection

D.E.S. St. LouisState MissouriPlant Venice No. 2

No.	Power Group	Nom. Pow. Max. MW	Boiler				Turbine			Cond.	Fuel				Retrofit
			Man. Name	Date Inst.	PSIA	°F	Man. Name	Date Inst.	Type	Man. Name	Coal	Oil	Gas	Nucl	
1	ST1	50	CE	1942	850	900	AC *	1942	TC	-	-	X	X	-	CO
2	ST2	50	CE	1942	850	900		1942	TC	-	-	X	X	-	CO
3	ST3	100	Riley	1943	850	900	GE	1943	SC	-	-	X	X	-	CPEI
4	ST4	100	Riley	1943	850	900	GE	1948	SC	-	-	X	X	-	CPEI
5	ST5	100	B&W	1950	850	900	GE	1950	SC	-	-	PC	-	-	CPEI
6	ST6	100	B&W	1950	850	900	WEST	1950	TC	-	-	PC	-	-	CO
1	GT	35	-	-	-	-	WEST	1967	OPEN	-	-	-	X	-	RB

* Allis Chalmers

Table 15. New Equipment in Plants

D.E.S. St. Louis State MissouriPlant: Ashley

No.	Power Group	Nominal Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtuh			MW	10 ⁵ MBtuh
1	ST1	10	CPEI	1	2275	16	0.55	-	-	-	-
2	ST7	20	CPEI	1	4550	32	1.10	-	-	-	-
3	ST8	20	CPEI	1	4550	32	1.10	-	-	-	-
4	ST9	20	CPEI	1	4550	32	1.10	-	-	-	-

Table 16. New Equipment in Plants

D.E.S. St. LouisState MissouriPlant: Labadie

No.	Power Group	Nominal Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtuh			MW	10 ⁵ MBtuh
1	ST1	555	CO	1	73,885	650	22.17	-	-	-	-
2	ST2	555	CO	1	73,885	650	22.17	-	-	-	-
3	ST3	555	CO	1	73,885	650	22.17	-	-	-	-
4	ST4	555	CO	1	73,885	650	22.17	-	-	-	-

Table 17. New Equipment in Plants

D.E.S. St. LouisState MissouriPlant: Maramec

No.	Power Group	Nominal Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtuh			MW	10 ⁵ MBtuh
1	ST1	125	CO	1	18,755	165	5.63	-	-	-	-
2	ST2	125	CO	1	18,755	165	5.63	-	-	-	-
3	ST3	250	CO	1	30,120	265	9.04	-	-	-	-
4	ST4	300	CO	1	35,805	315	10.74	-	-	-	-
1	GT	60	RB	-	-	-	-	1	15,915	140	4.77

Table 18. New Equipment in Plants

D.E.S. St. Louis State Missouri

Plant: Sioux

[illegible]

Table 19. New Equipment in Plants

D.E.S. St. Louis State MissouriPlant: Venice No. 2

No.	Power Group	Nominal Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtuh			MW	10 ⁵ MBtuh
1	ST1	50	CO	1	7,390	65	2.17	-	-	-	-
2	ST2	50	CO	1	7,390	65	2.17	-	-	-	-
3	ST3	100	CPEI	1	19,325	135	4.60	-	-	-	-
4	ST4	100	CPEI	1	19,325	135	4.60	-	-	-	-
5	ST5	100	CPEI	1	19,325	135	4.60	-	-	-	-
6	ST6	100	CO	1	15,915	140	4.77	-	-	-	-
1	GT	37.5	RB	-	-	-	-	1	8,525	75	2.56

Table 20. New Equipment in Plants

D.E.S. St. Louis

State Missouri

Plant: New

[illegible]

Table 21. Pump Stations D.E.S. Characteristics Data

D.E.S. St. LouisState Missouri

Plant _____

No.	Station Name	Heat MW	Δt °F	GPM	L Mile	H Ft H ₂ O	P MW	Pumps	Dia. ϕ Inch
1	Ashley	140	60	15,915	5.00	635	0.30	2	24
2	Labadie	1950	60	221,650	20.00	2540	16.76	8	72
3	Maramec	1030	60	117,080	15.00	1905	6.64	6	54
4	Sioux	1000	60	113,670	15.00	1905	6.44	6	54
5	Venice #2	855	60	97,185	5.00	635	1.83	4	48
6	New Thermal	840	60	95,480	5.00	635	1.80	4	48
	TOTAL						33.77	30	

Table 21. Pump Stations D.E.S. Characteristics Data

D.E.S. St. Louis State Missouri
 Plant _____

No.	Station Name	Heat MW	Δt °F	GPM	L Mile	H Ft H ₂ O	P MW	Pumps	Dia. ϕ Inch
1	Ashley	140	60	15,915	5.00	635	0.30	2	24
2	Labadie	1950	60	221,650	20.00	2540	16.76	8	72
3	Maramec	1030	60	117,080	15.00	1905	6.64	6	54
4	Sioux	1000	60	113,670	15.00	1905	6.44	6	54
5	Venice #2	855	60	97,185	5.00	635	1.33	4	48
6	New Thermal	840	60	95,480	5.00	635	1.30	4	48
	TOTAL						33.77	30	

CLEVELAND, OHIO

Table 1 . Demand Data

D.E.S. ClevelandState Ohio

Energy	Peak / Average	10^6 Btu / Day	MW
Heating Demand	Peak (HP)	328,567	4,015
	Average (HA)	95,464	1,165
Hot Water	Average (hA)	8,221	100
Cooling Demand	Peak (CP)	128,641	1,570
	Average (CA)	25,490	310

Table 2. 'Plant's Power Groups' Characteristics

D. E. S. Cleveland State OhioPlant Avon Lake

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST1	35	CPEI	17.5	65	11.36	3.06	0.300	0.707
2	ST2	35	CPEI	17.5	65	11.36	3.06	0.300	0.707
3	ST3	35	CPEI	17.5	65	11.36	3.06	0.300	0.707
4	ST4	35	CPEI	17.5	65	11.36	3.06	0.300	0.707
5	ST5	50	CPEI	25	85	11.05	3.25	0.310	0.682
6	ST6	75	CPEI	37.5	105	9.17	3.27	0.371	0.704
7	ST7	75	CPEI	37.5	105	9.17	3.27	0.371	0.704
8	ST8	215	CO	145	245	7.68	2.20	0.444	0.805
9	ST9	625	CO	435	735	7.51	1.94	0.454	0.850
1	GT1	30	RB	27	60	12.00	0.60	0.284	0.824
	TOTAL ST	1180	-	750	1535	8.36	2.34	0.408	0.790
	TOTAL GT	30	-	27	60	12.00	0.60	0.284	0.824

Table 3. Plant's Power Groups' Characteristics

D. E. S. Cleveland State OhioPlant East Lake

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST1	120	CO	80	160	8.00	2.00	0.426	0.852
2	ST2	120	CO	80	160	8.00	2.00	0.426	0.852
3	ST3	120	CO	80	160	8.00	2.00	0.426	0.852
4	ST4	215	CO	145	245	7.68	2.20	0.444	0.805
5	ST5	600	CO	420	705	7.58	1.94	0.450	0.844
1	GT1	30	RB	27	60	12.00	0.60	0.284	0.824
	TOTAL ST	1175	-	805	1430	7.73	2.00	0.441	0.839
	TOTAL GT	30	-	27	60	12.00	0.60	0.284	0.824

Table 4. Plant's Power Groups' Characteristics

D. E. S. Cleveland State OhioPlant Lake Shore

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST14	60	CPEI	30	100	9.70	2.91	0.352	0.763
2	ST15	60	CPEI	30	100	9.70	2.91	0.352	0.763
3	ST16	60	CPEI	30	100	9.70	2.91	0.352	0.763
4	ST17	60	CPEI	30	100	9.70	2.91	0.352	0.763
5	ST18	240	CO	165	255	8.08	2.91	0.422	0.739
1	GT	4							
	TOTAL ST	480	-	285	655	8.89	2.65	0.384	0.752

Table 5. Plant's Power Groups' Characteristics

D. E. S. Cleveland State OhioPlant Edge Water

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST2	5	-	-	-	10.50	-	0.324	-
2	ST3	60	CPEI	30	100	9.70	2.91	0.352	0.763
3	ST4	120	CO	80	160	8.20	2.05	0.413	0.826
1	GT	50	RB	45	100	12.00	0.60	0.284	0.824
	TOTAL ST	180	-	110	260	8.70	2.34	0.392	0.806
	TOTAL GT	50	-	45	100	12.00	0.60	0.284	0.824

Table 6. Plant's Power Groups' Characteristics

D. E. S. Cleveland State OhioPlant Niles

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST1	120	CO	80	160	8.20	2.05	0.413	0.826
2	ST2	120	CO	80	160	8.20	2.05	0.413	0.826
1	GT	30	RB	27	60	12.00	0.60	0.284	0.824
	TOTAL ST	240	-	160	320	8.20	2.05	0.413	0.826
	TOTAL GT	30	-	27	60	12.00	0.60	0.284	0.824

Table 7. Plant's Power Groups' Characteristics

D. E. S. Cleveland State OhioPlant Davis - Besse Nuclear

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST4	910	CO	680	1000	10.42	2.40	0.327	0.604
2	ST5	910	CO	680	1000	10.42	2.40	0.327	0.604
	TOTAL ST	1820	-	1360	2000	10.42	2.40	0.327	0.604

Table 8. Cogeneration Selection

D.E.S. Cleveland State Ohio

No.	Plant	Heat Available in Plant	MW Heat Selected	Type of Fuel
1	Asthabula	1115	835	
2	Avon Lake	1535	1150	
3	East Lake	1430	1070	
4	Lake Shore	655	490	
5	Edge Water	260	195	
6	Niles	320	240	
7	Davis-Besse-Nuclear	1000	750	Uranium
	TOTAL	6315	4730	

MAX TO THE POWER PLANT

$$4115 \times 1.10 = 4525 \text{ MW}$$

REQUIRED IN THE POWER PLANT

$$4525 : 0.75 = 6030 \text{ MW}$$

DISTRICT ENERGY FACTOR: 1.00

$$4730 - 4525 = 205 \text{ MW}$$

Table 9 . Cogeneration D.E.S. System Data

D.E.S. ClevelandState Ohio

No.	Plant		Astha- bula	Avon Lake	East Lake	Lake Shore	Edge Water	Niles
	Characteristic							
1	Nominal Power	MW	745	1180	1175	480	180	240
2	Type of Fuel	Work						
		Start						
3	Type of Turbines		Steam	Steam	Steam	Steam	Steam	Steam
4	Cogeneration Electric Power	MW	430	750	805	285	110	160
5	Cogeneration Heat Power	MW	1115	1535	1430	655	260	320
6	Fuel Rate for Power Plant	Elec.	9.93	8.36	7.73	8.89	8.70	8.20
		Heat	2.80	2.34	2.00	2.65	2.34	2.05
7	Efficiencies η	Nom.	0.343	0.408	0.441	0.384	0.392	0.413
		Cog.	0.711	0.790	0.839	0.752	0.806	0.800

Table 9. Cogeneration D.E.S. System Data (Con'd)

D.E.S. Cleveland State Ohio

No.	Plant		Davis-Besse Nuclear					
	Characteristic							
1	Nominal Power	MW	910					
2	Type of Fuel	Work	Uranium					
		Start	-					
3	Type of Turbines		Steam					
4	Cogeneration Electric Power	MW	680					
5	Cogeneration Heat Power	MW	1000					
6	Fuel Rate for Power Plant	Elec.	10.42					
		Heat	2.40					
7	Efficiencies η	Nom.	0.327					
		Cog.	0.604					

Table 10. Maximum Electricity Loss Through Cogeneration

D.E.S. Cleveland State Ohio

No.	Power Plant	Nominal MW	Cogen. MW	Difference MW
1	Asthabula	745	430	315
2	Avon Lake	1180	750	430
3	East Lake	1175	805	370
4	Lake Shore	480	285	195
5	Edge Water	180	110	70
6	Niles	240	160	80
7	Davis-Besse Nuclear	910	680	230
	SUBTOTAL	4910	3220	1690
	TOTAL 1690 x .075			1267

Table 11. Technological Retrofit Selection

D.E.S. ClevelandState OhioPlant Asthabula

No.	Power Group	Nom. Pow. Max. MW	Boiler				Turbine			Cond.	Fuel				Retrofit
			Man. Name	Date Inst.	PSIA	°F	Man. Name	Date Inst.	Type	Man. Name	Coal	Oil	Gas	Nucl	
1	ST1	50	B&W	1930*	375	700	GE	1930	SC	-	-	X	-	-	CPEI
2	ST2	50	B&W	1930*	375	700	GE	1930	SC	-	-	X	-	-	CPEI
3	ST3	50	B&W	1931*	375	700	GE	1931	SC	-	-	X	-	-	CPEI
4	ST4	50	B&W	1938*	375	700	GE	1938	SC	-	-	X	-	-	CPEI
5	ST5	225	CE	1958	2400	$\frac{1050}{1050}$	GE	1958	TC	-	PC	-	-	-	CO
6	ST6	80	B&W	1949	850	900	GE	1949	SC	-	X	-	-	-	CPEI
7	ST7	80	B&W	1949	850	900	GE	1949	SC	-	X	-	-	-	CPEI
8	ST8	80	B&W	1953	850	900	GE	1953	SC	-	X	-	-	-	CPEI
9	ST9	80	B&W	1953	850	900	GE	1953	SC	-	X	-	-	-	CPEI

*Converted to oil in 1972.

Table 12. Technological Retrofit Selection

D.E.S. ClevelandState OhioPlant Avon Lake

No.	Power Group	Nom. Pow. Max. MW	Boiler				Turbine			Cond.	Fuel				Retrofit
			Man. Name	Date Inst.	PSIA	CF	Man. Name	Date Inst.	Type	Man. Name	Coal	Oil	Gas	Nucl	
1	ST1	35	CE	1926*	375	500	GE	1926	SC	-	-	X	-	-	CPEI
2	ST2	35	CE	1926*	375	500	GE	1926	SC	-	-	X	-	-	CPEI
3	ST3	35	CE	1928*	375	500	GE	1928	SC	-	-	X	-	-	CPEI
4	ST4	35	CE	1929*	375	500	GE	1929	SC	-	-	X	-	-	CPEI
5	ST5	50	CE	1943*	375	500	GE	1943	SC	-	-	X	-	-	CPEI
6	ST6	75		1949	850	945	GE	1949	SC	-	X	-	-	-	CPEI
7	ST7	75		1949	850	945	GE	1949	SC	-	X	-	-	-	CPEI
8	ST8	215	CE	1959	3500	$\frac{1100}{1050}$	WEST	1959	TC	-	X	-	-	-	CO
9	ST9	625	CE	1970	3500	$\frac{1000}{1050}$	WEST	1970	TC	-	X	-	-	-	CO

*Converted to Oil in 1972.

Table 13. Technological Retrofit Selection

D.E.S. Cleveland State Ohio

Plant: East Lake

[illegible]

Table 14. Technological Retrofit Selection

D.E.S. ClevelandState OhioPlant Lake Shore

No.	Power Group	Nom. Pow. Max. MW	Boiler				Turbine			Cond.	Fuel				Retrofit
			Man. Name	Date Inst.	PSIA	Op	Man. Name	Date Inst.	Type	Man. Name	Coal	Oil	Gas	Nucl	
1	ST14	60	B&W	1941	850	950	GE	1941	SC	-	X	-	-	-	CPEI
2	ST15	60	B&W	1941	805	950	GE	1942	SC	-	X	-	-	-	CPEI
3	ST16	60	B&W	1951	850	950	GE	1951	SC	-	X	-	-	-	CPEI
4	ST17	60	B&W	1951	850	950	GE	1951	SC	-	X	-	-	-	CPEI
5	ST18	240	CE	1962	2400	$\frac{1000}{1000}$	GE	1962	TC	-	X	-	-	-	CO

Table 15. Technological Retrofit Selection

D.E.S. Cleveland State Ohio
Plant Edge Water

[illegible]

NO DATA AVAILABLE

Table 16. Technological Retrofit Selection

D.E.S. Cleveland

State Ohio

Plant Niles[illegible]

NO DATA AVAILABLE

Table 17. Technological Retrofit Selections

D.E.S. Cleveland State Ohio

Plant Davis-Besse Nuclear

[illegible]

NO DATA AVAILABLE

Table 18. New Equipment in Plants

D.E.S. Cleveland State OhioPlant Asthabula

No.	Power Group	Heat Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtu			MW	10 ⁵ MBtu
1	ST1	50	CPEI	1	9,550	70	2.39	-	-	-	-
2	ST2	50	CPEI	1	9,550	70	2.39	-	-	-	-
3	ST3	50	CPEI	1	9,550	70	2.39	-	-	-	-
4	ST4	50	CPEI	1	9,550	70	2.39	-	-	-	-
5	ST5	225	CO	1	28,985	255	8.70	-	-	-	-
6	ST6	80	CPEI	1	8,870	65	2.22	-	-	-	-
7	ST7	80	CPEI	1	8,870	65	2.22	-	-	-	-
8	ST8	80	CPEI	1	8,870	65	2.22	-	-	-	-
9	ST9	80	CPEI	1	8,870	65	2.22	-	-	-	-

Table 19. New Equipment in Plants

D.E.S. Cleveland State OhioPlant Avon Lake

No.	Power Group	Heat Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtu			MW	10 ⁵ MBtu
1	ST1	35	CPEI	1	6,820	50	1.71	-	-	-	-
2	ST2	35	CPEI	1	6,820	50	1.71	-	-	-	-
3	ST3	35	CPEI	1	6,820	50	1.71	-	-	-	-
4	ST4	35	CPEI	1	6,820	50	1.71	-	-	-	-
5	ST5	50	CPEI	1	5,460	40	1.36	-	-	-	-
6	ST6	75	CPEI	1	8,185	60	2.05	-	-	-	-
7	ST7	75	CPEI	1	8,185	60	2.05	-	-	-	-
8	ST8	215	CO	1	27,850	245	8.35	-	-	-	-
9	ST9	625	CO	1	83,545	735	25.06	-	-	-	-

Table 20, New Equipment in Plants

D.E.S. Cleveland State OhioPlant East Lake

No.	Power Group	Heat Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtu			MW	10 ⁵ MBtu
1	ST1	120	CO	1	18,190	160	5.46	-	-	-	-
2	ST2	120	CO	1	18,190	160	5.46	-	-	-	-
3	ST3	120	CO	1	18,190	160	5.46	-	-	-	-
4	ST4	215	CO	1	27,850	245	8.35	-	-	-	-
5	ST5	600	CO	1	80,135	705	24.04	-	-	-	-

Table 21. New Equipment in Plants

D.E.S. Cleveland State OhioPlant Lake Shore

No.	Power Group	Heat Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtu			MW	10 ⁵ MBtu
1	ST14	60	CPEI	1	11,370	80	2.73	-	-	-	-
2	ST15	60	CPEI	1	11,370	80	2.73	-	-	-	-
3	ST16	60	CPEI	1	11,370	80	2.73	-	-	-	-
4	ST17	60	CPEI	1	11,370	80	2.73	-	-	-	-
5	ST18	240	CO	1	28,985	255	8.70	-	-	-	-

Table 22. New Equipment in Plants

D.E.S. Cleveland State Ohio

Plant Edge Water

[illegible]

Table 23. New Equipment in Plants

D.E.S. Cleveland State Ohio

Plant Niles

[illegible]

Table 24. New Equipment in Plants

D.E.S. Cleveland State Ohio

Plant Davis-Besse-Nuclear

[illegible]

Table 25. Pump Stations D.E.S. Characteristics Data

D.E.S. Cleveland State Ohio

No.	Station Name	Heat MW	Δt °F	GPM	L Mile	H Ft H ₂ O	P MW	Pumps	Dia. ϕ Inch
1	Asthabula	1115	60	126,740	25.00	3175	11.98	6	54
2	Avon Lake	1535	60	174,480	20.00	2540	13.19	8	72
3	East Lake	1430	60	162,545	5.00	635	3.07	8	60
4	Lake Shore	655	60	74,450	5.00	635	1.41	4	48
5	Edge Water	260	60	29,550	5.00	635	0.56	2	32
6	Niles	320	60	36,375	20.00	2540	2.75	2	36
7	Davis-Besse	1000	60	113,670	25.00	3175	10.74	6	54
						TOTAL	43.70	36	

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Table 1 . Demand Data

D.E.S. MilwaukeeState Wisconsin

Energy	Peak / Average	10^6 Btu / Day	MW
Heating Demand	Peak (HP)	341,469	4,170
	Average (HA)	104,014	1,270
Hot Water	Average (hA)	7,407	100
Cooling Demand	Peak (CP)	108,851	1,330
	Average (CA)	25,349	310

Table 2. Plant's Power Groups' Characteristics

D.E.S. MilwaukeeState WisconsinPlant Port Washington

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST 1	80	CO	55	100	8.60	2.15	0.397	0.769
2	ST 2	80	CO	55	100	8.60	2.15	0.397	0.769
3	ST 3	80	CO	55	100	8.60	2.15	0.397	0.769
4	ST 4	80	CO	55	100	8.60	2.15	0.397	0.769
5	ST 5	80	CO	55	100	8.60	2.15	0.397	0.769
1	GT	20	RB	18	40	12.00	0.60	0.284	0.824
	TOTAL ST	400	-	275	500	8.60	2.15	0.397	0.769
	TOTAL GT	20	-	18	40	12.00	0.60	0.284	0.824

Table 3. Plant's Power Groups' Characteristics

D.E.S. MilwaukeeState WisconsinPlant Lake Side

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST 1	20	CPEI	10	35	13.10	3.74	0.260	0.585
2	ST 2	20	CPEI	10	35	13.10	3.74	0.260	0.585
3	ST 3	30	CPEI	15	55	12.60	3.44	0.271	0.632
4	ST 4	30	CPEI	15	55	12.60	3.44	0.271	0.632
5	ST 5	30	CPEI	15	55	12.60	3.44	0.271	0.632
6	ST 6	30	CPEI	15	55	12.60	3.44	0.271	0.632
7	ST 9	60	CPEI	30	110	12.00	3.27	0.284	0.662
8	ST 12	60	CPEI	30	110	12.00	3.27	0.284	0.662
9	ST 7	10	CPEI	5	17.5	12.00	3.43	0.284	0.639
10	ST 8	10	CPEI	5	17.5	12.00	3.43	0.284	0.639
11	ST 10	10	CPEI	5	17.5	12.00	3.43	0.284	0.639
12	ST 11	10	CPEI	5	17.5	12.00	3.43	0.284	0.639
1	GT	40	RB	36	80	12.00	0.60	0.284	0.824
TAL ST		320	-	160	580	12.36	3.40	0.276	0.638
TAL GT		40	-	36	80	12.00	0.60	0.284	0.824

Table 4. Plant's Power Groups' Characteristics

D.E.S. MilwaukeeState WisconsinPlant Oak Creek South

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST 5	275	CO	190	290	7.80	2.29	0.437	0.777
2	ST 6	275	CO	190	290	7.80	2.29	0.437	0.777
3	ST 7	310	CO	220	340	7.66	2.04	0.445	0.804
4	ST 8	310	CO	220	340	7.66	2.04	0.445	0.804
1	GT	20	RB	18	40	12.00	0.60	0.284	0.824
	TOTAL ST	1170	-	820	1260	7.73	2.15	0.441	0.784
	TOTAL GT	20	-	18	40	12.00	0.60	0.284	0.824

Table 5. Plant's Power Groups' Characteristics

D.E.S. MilwaukeeState WisconsinPlant Oak Creek North

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST 1	125	CO	85	165	8.00	1.94	0.426	0.852
2	ST 2	125	CO	85	165	8.00	1.94	0.426	0.852
3	ST 3	125	CO	85	165	8.00	1.94	0.426	0.852
4	ST-4	125	CO	85	165	8.00	1.94	0.426	0.852
	TOTAL ST	600	-	340	660	8.00	1.94	0.426	0.852

Table 6. Plant's Power Groups' Characteristics

D.E.S. Milwaukee

State Wisconsin

Plant Point Beach-Nuclear

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST 1	520	CO	390	610	10.42	2.22	0.327	0.629
2	ST 2	520	CO	390	610	10.42	2.22	0.327	0.629
1	GT	20	RB	18	40	12.00	0.60	0.248	0.824
	TOTAL ST	1040	-	780	1220	10.42	2.22	0.327	0.629
	TOTAL GT	20	-	18	40	12.00	0.60	0.248	0.824

Table 7. Plant's Power Groups' Characteristics.

D.E.S. MilwaukeeState WisconsinPlant Valley

No.	Power Group	Nominal Power MW	Retrofit	Cogeneration Power MW		Fuel Rates MBtu/kWhr		Efficiencies η	
				Electric	Heat	Electric	Heat	Nominal	Cogen.
1	ST 1	135	CO	95	155	10.17	2.76	0.335	0.620
2	ST 2	135	CO	95	155	10.17	2.76	0.335	0.620
		270	-	190	310	10.17	2.76	0.335	0.620

Table 8. Plant's Power Groups' Characteristics

D.E.S. Milwaukee

State Wisconsin

Plant Commerce Street

[illegible]

Table 9. Plant's Power Groups' Characteristics

D.E.S. Milwaukee State Wisconsin

Plant East Wells St. - Thermal[illegible]

Table 10. Cogeneration Selection

D.E.S. MilwaukeeState Wisconsin

No.	Plant	Heat Available in Plant	MW Heat Selected	Type of Fuel
1	Port Washington	ST 500 GT 40	375 30	
2	Lake Side	ST 580 80	435 60	
3	Oak Creek South	ST 1260 GT 40	945 30	
4	Oak Creek North	ST 660	495	
5	Point Beach - Nucl	ST 1220 GT 40	915 30	
6	Valley	ST 310	235	
7	Commerce St.	ST 65	50	
8	East Wells Therm	ST 15	10	
9	New Thermal	HW 1460	1090	
	TOTAL	6270	4700	

MAX TO THE POWER PLANT

$$4270 \times 1.10 = 4700 \text{ MW}$$

REQUIRED IN THE POWER PLANT

$$4700 : 0.75 = 6270 \text{ MW}$$

DISTRICT ENERGY FACTOR

$$(4700 - 1100) : 4700 = 0.77$$

Table 11. Cogeneration D.E.S. System Data

D.E.S. MilwaukeeState Wisconsin

No.	Characteristic	Plant	Port Washington		Lake Side		Oak Creek South	
1	Nominal Power	MW	400	20	320	40	1170	20
2	Type of Fuel	Work						
		Start						
3	Type of Turbines		Steam	Gas	Steam	Gas	Steam	Gas
4	Cogeneration Electric Power	MW	275	18	160	36	820	18
5	Cogeneration Heat Power	MW	500	40	580	80	1260	40
6	Fuel Rate for Power Plant	Elec.	8.60	12.00	12.36	12.00	7.73	12.00
		Heat	2.15	0.60	3.40	0.60	2.15	0.60
7	Efficiencies η	Nom.	0.397	0.284	0.276	0.234	0.441	0.284
		Cog.	0.769	0.824	0.638	0.824	0.784	0.824

Table 11. Cogeneration D.E.S. System Data (Cont'd)

D.E.S. MilwaukeeState Wisconsin

No.	Characteristic	Plant	Oak Creek North	Point Beach Nuclear		Valley	Commerce Street	East Wells Street
1	Nominal Power	MW	600	1040	20	270	35	--
2	Type of Fuel	Work						
		Start						
3	Type of Turbines		Steam	Steam	Gas	Steam	Steam	Boiler Steam
4	Cogeneration Electric Power	MW	340	780	18	190	18	--
5	Cogeneration Heat Power	MW	660	1220	40	310	65	15
6	Fuel Rate for Power Plant	Elec.	8.00	10.42	12.00	10.17	12.50	--
		Heat	1.94	2.22	0.60	2.76	3.37	4.74
7	Efficiencies η	Nom.	0.426	0.327	0.284	0.335	0.273	--
		Cog.	0.852	0.629	0.824	0.620	0.644	0.720

Table 12 . Maximum Electricity Loss Through Cogeneration

D.E.S. MilwaukeeState Wisconsin

No.	Power Plant	Nominal MW	Cogen. MW	Difference MW
1	Port Washington	420	293	127
2	Lake Side	360	196	164
3	Oak Creek South	1190	838	352
4	Oak Creek North	600	340	260
5	Point Beach - Nuclear	1060	798	262
6	Valley	270	190	80
7	Commerce Street	35	18	17
	SUB TOTAL	3935	2673	1262
	TOTAL 1262 x 0.75			945

Table 13 Technological Retrofit Selection

D.E.S. Milwaukee State WisconsinPlant Port Washington

No.	Power Group	Nominal Power MW	BOILER				TURBINE			COND	FUEL				Retrofit
			Man Name	Date Inst	PSIA	O _F	Man Name	Date Inst	Type	Man Name	Coal	Oil	Gas	Nucl	
1	ST 1	80	CE	1935	1230	$\frac{825}{825}$	AC	1935	TC	-	PC	-	-	-	CO
2	ST 2	80	CE	1943	1290	$\frac{850}{850}$	AC	1943	TC	-	PC	-	-	-	CO
3	ST 3	80	CE	1948	1290	$\frac{875}{875}$	AC	1948	TC	-	PC	-	-	-	CO
4	ST 4	80	CE	1949	1380	$\frac{900}{900}$	AC	1949	TC	-	PC	-	-	-	CO
5	ST 5	80	CE	1950	1450	$\frac{950}{950}$	AC	1950	TC	-	PC	-	-	-	CO
1	GT	20	-	-	-	-	-	-	-	-	-	-	-	-	RB

Table 14. Technological Retrofit Selection

D.E.S. Milwaukee State WisconsinPlant Lakeside

No.	Power Group	Nominal Power MW	BOILER				TURBINE			COND	FUEL				Retrofit
			Man Name	Date Inst	PSIA	O _F	Man Name	Date Inst	Type	Man Name	Coal	Oil	Gas	Nucl	
1	ST 1	20	EM	1920	290	700	GE	1920	SC	-	-	X	X	-	CPEI
2	ST 2	20	EM	1920	290	700	GE	1921	SC	-	-	X	X	-	CPEI
3	ST 3	30	EM	1920	290	700	GE	1922	SC	-	-	X	X	-	CPEI
4	ST 4	30	EM	1920	290	700	GE	1924	SC	-	-	X	X	-	CPEI
5	ST 5	30	EM	1920	290	700	GE	1924	SC	-	-	X	X	-	CPEI
6	ST 6	30	EM	1920	290	700	GE	1926	SC	-	-	X	X	-	CPEI
7	ST 9	60	EM	1924	290	700	West	1928	SC	-	-	X	X	-	CPEI
8	ST 12	60	EM	1924	290	700	AC	1930	SC	-	-	X	X	-	CPEI
9	ST 7	10	CE	1926	750	700	GE	1926	SC	-	-	X	X	-	CPEI
10	ST 8	10	CE	1928	750	700	GE	1928	SC	-	-	X	X	-	CPEI
11	ST 10	10	CE	1930	750	700	GE	1930	SC	-	-	X	X	-	CPEI
12	ST 11	10	CE	1930	750	700	GE	1930	SC	-	-	X	X	-	CPEI
1	GT	40	-	-	-	-	GE	1968	OPEN	-	-	X	-	-	RB

Table 15. Technological Retrofit Selection

D.E.S. Milwaukee

State Wisconsin

Plant Oak Creek South

No.	Power Group	Nom. Pow. Max. MW	Boiler				Turbine			Cond.	Fuel				Retrofit
			Man. Name	Date Inst.	PSIA	°F	Man. Name	Date Inst.	Type	Man. Name	Coal	Oil	Gas	Nucl	
1	ST 5	275	FW	1960	2400	$\frac{1050}{1000}$	AC	1960	CC	-	PC	-	-	-	CO
2	ST 6	275	FW	1961	2400	$\frac{1050}{1000}$	AC	1961	CC	-	PC	-	-	-	CO
3	ST 7	310	CE	1965	2520	$\frac{1050}{1000}$	GE	1965	CC	-	PC	-	-	-	CO
4	ST 8	310	CE	1967	2400	$\frac{1050}{1000}$	GE	1967	TC	-	PC	-	-	-	CO
1	GT	20	-	-	-	-	WEST	1968	OPEN	-	-	X	-	-	RB

Table 16. Technological Retrofit Selection

D.E.S. Milwaukee State Wisconsin

Plant Oak Creek North[illegible]

Table 17. Technological Retrofit Selection

D.E.S. Milwaukee State Wisconsin

Plant Point Beach - Nuclear

[illegible]

Table 18. Technological Retrofit Selection

D.E.S. Milwaukee State Wisconsin

Plant Valley

[illegible]

Table 19. Technological Retrofit Selection

D.E.S. Milwaukee

State Wisconsin

Plant Commerce Street

[illegible]

Table 20. Technological Retrofit Selection

D.E.S. Milwaukee

State Wisconsin

Plant East Wells Street

[illegible]

Table 21. New Equipment in Plants

D.E.S. Milwaukee

State Wisconsin

Plant: Port Washington

No.	Power Group	Nominal Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtu			MW	10 ⁵ MBtu
1	ST 1	80	CO	1	11,370	100	3.41	-	-	-	-
2	ST 2	80	CO	1	11,370	100	3.41	-	-	-	-
3	ST 3	80	CO	1	11,370	100	3.41	-	-	-	-
4	ST 4	80	CO	1	11,370	100	3.41	-	-	-	-
5	ST 5	80	CO	1	11,370	100	3.41	-	-	-	-
1	GT	20	BR	-	-	-	-	1	2275	20	0.68

Table 22. New Equipment in Plants

D.E.S. Milwaukee State WisconsinPlant: Lake Side

No.	Power Group	Nominal Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtu			MW	10 ⁵ MBtu
1	ST 1	20	CPEI	1	1135	8	0.27	-	-	-	-
2	ST 2	20	CPEI	1	1135	8	0.27	-	-	-	-
3	ST 3	30	CPEI	1	1705	12	0.41	-	-	-	-
4	ST 4	30	CPEI	1	1705	12	0.41	-	-	-	-
5	ST 5	30	CPEI	1	1705	12	0.41	-	-	-	-
6	ST 6	30	CPEI	1	1705	12	0.41	-	-	-	-
7	ST 9	60	CPEI	1	3410	24	0.82	-	-	-	-
8	ST 12	60	CPEI	1	3410	24	0.82	-	-	-	-
9	ST 7	10	CPEI	1	568	4	0.14	-	-	-	-
10	ST 8	10	CPEI	1	568	4	0.14	-	-	-	-
11	ST 10	10	CPEI	1	568	4	0.14	-	-	-	-

Table 22. New Equipment in Plants (Cont'd)

D.E.S. MilwaukeeState WisconsinPlant: Lake Side

No.	Power Group	Nominal Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtu			MW	10 ⁵ MBtu
12	ST 11	10	CPEI	1	568	4	0.14	-	-	-	-
1	GT	40	RB	-	-	-	-	1	9095	80	2.73

Table 23. New Equipment in Plants

D.E.S. Milwaukee State WisconsinPlant: Oak Creek South

No.	Power Group	Nominal Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtu			MW	10 ⁵ MBtu
1	ST 5	275	CO	1	32,965	290	9.89	-	-	-	-
2	ST 6	275	CO	1	32,965	290	9.89	-	-	-	-
3	ST 7	312	CO	1	38,650	340	11.59	-	-	-	-
4	ST 8	312	CO	1	38,650	340	11.59	-	-	-	-
1	GT	20	BR	-	-	-	-	1	4550	40	1.36

Table 24. New Equipment in Plants

D.E.S. Milwaukee

State Wisconsin

Plant: Oak Creek North

[illegible]

Table 25 . New Equipment in Plants

D.E.S. MilwaukeeState WisconsinPlant: Point Beach - Nuclear

No.	Power Group	Nominal Power MW	Retrofit	Heat Exchangers				Boilers			
				No.	GPM	Power		No.	GPM	Power	
						MW	10 ⁵ MBtu			MW	10 ⁵ MBtu
1	ST 1	520	CO	1	69,335	610	20.80	-	-	-	-
2	ST 2	520	CO	1	69,335	610	20.80	-	-	-	-
1	GT	20	RB	-	-	-	-	1	4550	40	1.36

Table 26 . New Equipment in Plants

D.E.S. Milwaukee

State Wisconsin

Plant: Valley

[illegible]

Table 27. New Equipment in Plants

D.E.S. Milwaukee

State Wisconsin

Plant: Commerce Street

[illegible]

Table 28. New Equipment in Plants

D.E.S. Milwaukee

State Wisconsin . . .

Plant: East Wells Street Thermal

[illegible]

Table 29. New Equipment in Plants

D.E.S. Milwaukee

State Wisconsin

Plant: New

[illegible]

Table 30. Pump Stations D.E.S. Characteristics Data

D.E.S. MilwaukeeState Wisconsin

No.	Station Name	Heat MW	Δt °F	GPM	L Mile	H Ft H ₂ O	P MW	Pumps	Dia. φ Inch
1	Port Washington	540	60	61,380	20.00	2540	4.64	3	42
2	Lake Side	660	60	75,020	5.00	635	1.42	4	48
3	Oak Creek S	1300	60	147,770	10.00	1270	5.59	6	60
4	Oak Creek N	660	60	75,020	10.00	1270	2.84	4	48
5	Point Beach	1260	60	143,220	50.00	6350	27.06	6	60
6	Valley	310	60	35,240	5.00	635	0.67	2	36
7	Commerce St	65	60	7,390	5.00	635	0.14	2	20
8	E. Wells St.	15	60	1,705	5.00	635	0.03	2	16
9	New Therm	1460	60	165,955	5.00	635	3.14	6	60
					TOTAL		45.53	35	

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APPENDIX B
ESTIMATION OF URBAN HEATING AND
COOLING DEMANDS AND SERVICE COSTS

Precise estimation of energy demands in buildings is difficult, even when the design and construction materials for the building are known. These difficulties are compounded in this study because there are no good, comprehensive records of building types, sizes, or locations for U.S. urban areas. Reasonably good information is available only on a very limited basis for specific building types or for specified areas. As a result, the demand estimation methodology used here is based on informed judgment that infers urban energy consumption patterns by indirect means.

Data available to estimate energy consumption include: (1) housing unit data provided by the U.S. Census Bureau, (2) employment data generally developed by metropolitan councils of government or transportation planning agencies, and (3) commercial/industrial floor space studies conducted by city agencies for downtown areas. The first two categories were converted to estimated square feet totals by multiplying by square feet per housing unit or square feet per employee.

Based on patterns of energy consumption, four types of buildings are defined for this study: (1) low-density residential, (2) high-density residential, (3) commercial/institutional, and (4) industrial. A characteristic energy demand per square foot is estimated for each of these four categories and for each city. Energy demands per square foot are adjusted for the number of heating (or cooling) degree days occurring in a particular urban area according to: (1) average daily heating demand, (2) peak day heating demand, (3) average daily hot water demand, (4) average daily cooling demand, and (5) peak day cooling demand.

In addition to estimating the energy demand by building type and function, it is also necessary to estimate demand by location. To this end, it was decided to overlay a square grid on each city being studied. The most convenient grid is that of the Universal Transverse Mercator (UTM) system. This system is based on metric measurement. As a result, the grid system used for all of the study cities except Chicago was a square kilometer grid matching the UTM system. For Chicago, previously obtained square mile data as made it simpler to use a square mile grid.

The combination of all of these steps allows the preparation of demand matrices for square kilometers or for groups of square kilometers as shown in Table B.1 which illustrates the format to be used for data presentation. Only the first three columns of this matrix have been used in this study, but all five columns have been constructed. In fact, this matrix computation is done by computer and has been linked to a graphical output program that can illustrate the urban energy demand pattern for any element or sum of elements of the demand matrix. This capability is illustrated by Figs. B.1 through B.4, which show the average daily total heating demands (heating plus hot water) for the residential (Fig. B.1), the commercial/institutional (Fig. B.2), the industrial (Fig. B.3), and the total (Fig. B.4) categories for the original study city, Washington, D.C.

B.1 BUILDING CHARACTERISTICS

In the process of studying available data and of devising a cost-effective data-acquisition methodology, it became clear that only a limited differentiation of building types would be possible. The distinction was made on the basis of three criteria: (1) building occupancy/use patterns, (2) building design, and (3) frequency of building type.

Table B.1. Urban Zone Energy Demand Factor Matrix

Building Type	Demand x 10 ⁶				
	Average Day Heating	Peak Day Heating	Average Day Hot Water	Average Day Cooling	Peak Day Cooling
Low Density Residential					
High Density Residential					
Commercial/Institutional					
Industrial					
Total

Fig. B.1. Residential Average Day Heating Demand Pattern
Illustrated by Computer Graphics for Washington,
D.C.

Fig. B.2. Commercial/Institutional Average Day Heating Demand Pattern Illustrated by Computer Graphics for Washington, D.C.

Fig. B.3. Industrial Average Day Heating Demand Pattern Illustrated by Computer Graphics for Washington, D.C.

Fig. B.4. Total Average Day Heating Demand Pattern Illustrated by Computer Graphics for Washington, D.C.

The first criterion distinguishes between residential and nonresidential buildings. Residential occupancy rates are highest in the evening and at night, nonresidential occupancy rates are highest during working hours. Among residences, the single-family home may be distinguished from apartment buildings by both occupancy patterns (fewer children in apartments) and by design. Among downtown nonresidential buildings, commercial and institutional buildings may be distinguished from industrial buildings by the average number of 8-hour shifts worked.

The multifloor apartment building may readily be distinguished from the single family home or townhome. Each unit in a typical apartment building will have much less exterior surface area per unit volume than single family homes. This leads to lower heating energy consumption per square foot in the multifloor residential building. This property shows up in Table B.2, which shows results of simulations of heating demand by type of (new, well-insulated) residence conducted for the MIUS Community Design Study.¹¹

As far as the commercial/institutional buildings are concerned, the most frequent building type within the five major midwestern cities is the high rise office building. These buildings differ from high-rise apartment buildings in some important respects. First, they are deeper than apartment buildings because outside lighting is not as important in offices as in homes. Lighting levels generally are much higher in offices than in homes. As a result of these two characteristics, the interior zones of some office buildings require cooling year round. This effect tends to outweigh the high winter heat losses created by the typical glass facade of office

Table B.2. MIUS Estimates of Residential Demand by Building Type

Building Type	Demand per yr. per 1000 ft ²
Single Family	10,600 kWh
Townhome	9,800 kWh
Garden Apartment	7,000 kWh
Mid-rise Apartments (10 floors)	6,600 kWh
High-rise Apartments (20 floors)	5,800 kWh

buildings. The effect also causes almost all office buildings to require cooling, whereas many homes do without cooling. Research has shown that the average heating loads per sq.ft. for office buildings are somewhat less than for residences, but the average cooling loads are often more than twice as high -- even without considering the less-frequent use of air conditioning in residences.

The location of high-rise commercial buildings allows us to neglect the more energy-consuming, shopping-center type of retail store. Because district energy systems will be most economically attractive at high building densities, it is necessary and appropriate to bias energy consumption estimates in favor of those buildings found in densely developed central business districts (CBDs). Although modern retail stores are typically constructed on one or two levels, the older CBD department stores are typically multifloor buildings more similar to office buildings than to contemporary shopping mall stores. Most smaller retail outlets in CBDs are ground floor tenants of high rise buildings. As a result of these properties and study objectives, commercial/institutional building energy demand has been estimated as if all such buildings were office buildings. The effect of this assumption is to underestimate commercial building demands outside the CBD.

Industrial buildings are much less homogeneous in design and energy consumption pattern than are commercial/institutional buildings. However, certain locational patterns among industries exist. Land-intensive industries, such as auto, steel, or chemical manufacturing tend to locate in suburban or low-density areas where land costs are lower than in the central cities. Labor-intensive industries, such as printing and publishing, tend to locate in downtown areas where they can serve the office market. As in the case of downtown department stores, such industries are typically located in multifloor mid- or high-rise buildings. Thus, the industrial buildings of most interest will be somewhat similar to office buildings in their energy-consumption patterns. The differences should arise, in part, from the use of multiple shifts in industrial buildings, resulting in somewhat greater energy consumption.

Having discussed the general logic behind the categorization of building types, the following sections discuss the details of the methodology

used for each building category. The approach used starts with the building itself and attempts to develop per-square-foot energy consumption figures for a building type within a specific climate. Where possible, different sources are compared to validate the results.

B.1.1 Residential

In the process of developing estimates of energy consumption, several different sources were consulted. Some simulation studies of predicted energy consumption by building type are available, and some studies of metered consumption are also available.¹⁹ However, it is difficult to depend on these sources for estimates of average residential consumption. Most simulations are for well-insulated, contemporary building designs. Consumption patterns predicted from these sources would underestimate the energy demands of a housing stock that includes houses over 50 years old. Even those sources based on metered homes generally are biased toward new homes. Typically, the metered data were available from special studies conducted by utility companies to predict demands in new service areas.

Because this study considers the possibility of retrofitting the entire standing stock of buildings, it was necessary to obtain data on system-wide energy consumption. To this end, the help of local utilities was sought in the initial study city, Washington, D.C. Good cooperation was obtained from both Potomac Electric and Washington Gas Light Company. Unfortunately, fuel oil suppliers are numerous, and there is no good record for consumption patterns of fuel-oil customers. However, most residential heating fuel customers depend on gas. In 1970, over 50% of the residential units in Washington, D.C. were heated by utility gas. In midwestern cities, the bias toward utility gas is even greater, with a minimum of 62% and maximum of 94% of residential units heated by gas in 1970. By comparison, fuel oil was used in a maximum of 21% of residential units in midwestern cities, and electricity only 3%. Because of the clear dominance of utility gas as a heating fuel in the midwestern study area, data from Washington Gas Light was used as a basis for estimates of residential energy demand.

● *Low-Rise Residential*

The System Design and Technical Services Division of Washington Gas Light Company (WGL) provided a record of peak day and monthly gas consumption by geographical area by class of customer and by heat and nonheat uses.

The first class of customer identified by WGL is the "domestic" customer which consists of all residential dwelling units which are individually metered. This class of customer is primarily single family homes along with some townhomes and garden apartments. As a consequence, it matches our low density residential class of customer.

The WGL figures provide us with a means of estimating the gas consumption at the meter. By combining this result with an estimate of actual operating furnace efficiency,⁵ an estimate of the final energy demand per average gas heated dwelling unit in Washington, D.C. was obtained. WGL provided data on peak hour demand for the winter of 1976-77 and with monthly demand figures for the winters of 1976-77 and 1975-76.

● *Average Day Demands*

(1) By summing monthly heating consumption in the domestic category for Washington, D.C. and dividing by the number of meters, the annual consumption per domestic meter was obtained. This figure, divided by 365 to obtain the daily consumption, was computed for two 12-month periods and averaged as follows:

3.624 therms/meter/day from July '75 to June '76

4.152 therms/meter/day from July '76 to June '77

7.776 2 = 3.888 therms/meter/day average for D.C.

(2) By multiplying this figure by 10^5 Btu/therm, by an efficiency factor of 0.67 and then dividing by the estimated square footage in single family homes (1500 ft^2), an estimate was obtained of the amount of energy used in a low-density residential unit in Washington, D.C. as follows:

$$3.888 \text{ therms/day} \times 10^5 \text{ Btu/therm} \times 0.67 \frac{\text{Btu out furnace}}{\text{Btu in furnace}} \quad 1500 \text{ ft}^2$$

$$= 173.7 \text{ Btu/ft}^2/\text{day}$$

These consumption figures were found to be from 10-40% higher than for new homes constructed in the Baltimore area and about equal to a new Chicago area

single-family home with "normal" 1974 insulation.¹² The consumption figures used here are based on current consumption patterns and do not consider possible additions to insulation in old urban homes.

(3) To scale the energy demand per day up or down according to climate, it was necessary to develop a formula relating Btu/ft² to heating degree days. An earlier study⁸ had developed several different formulas for annual demands as a function of heating degree day (HDD) requirements, depending upon the design of the home. Washington, D.C. results then were compared to the predicted results using formulas already developed.⁸

From step (2) above, the energy consumption per meter was annualized as follows:

$$173.7 \text{ Btu/ft}^2/\text{day} \times 365 \text{ days/yr} = 63400.5 \text{ Btu/ft}^2/\text{yr}.$$

Because there are 4211 heating degree days for Washington, D.C. according to the 1975 Statistical Abstract,²⁸ 15.06 Btu/ft²/HDD was obtained per domestic metered unit for Washington, D.C.

This value corresponds well to the results of the Rand study's⁸ "House No. 1" simulation results (see Fig. B.5). For this house, with 1-7/8-in. wall insulation and 3-1/2-in. roof insulation, it was estimated that 14.6 Btu/ft²/HDD would be consumed. Because of the close correspondence between this value and the Washington, D.C. value based on WGL figures, it has been decided to use the "House No. 1" formula for the low-density residential class for this study.

The formula, expressed as a factor times the annual heating degree days in the local area, works out to:

$$R_{1ADH} = (0.040 \text{ Btu/ft}^2/\text{HDD}/\text{day})\text{HDD} \quad (1)$$

where:

$$(0.040 \text{ Btu/ft}^2/\text{HDD}/\text{day}) = (14.6 \text{ Btu/ft}^2/\text{HDD}/\text{yr}) \div (365 \text{ days/yr.})$$

R_{1ADH} = low-density residential average daily heating demand in Btu/ft²; and

HDD = annual heating degree days on a 65° base.

The Rand study⁸ also found that the same relationship could be used to predict cooling degree days when the cooling degree days were defined to be equal to the average daily Discomfort Index (DI) exceeding 60. The Discomfort

Fig. B.5. Rand "Residential Sector" House No. 1, walls 1-7/8 inch insulation, ceiling 3-1/2 inch, no storm windows or doors

Index, based on both the dry-bulb temperature and the dew-point temperature, accounts for the effects of relative humidity. As a result, Eq. 1 can be modified to obtain a method of estimating the average daily cooling demand:

$$R_{1ADC} = (0.040 \text{ Btu/ft}^2/\text{CDD/day}) \text{ CDD(DI)} \quad (2)$$

where:

$$DI = 0.55 T_d + 0.2 T_{dp} + 17.5 \quad (2a)$$

R_{1ADC} = low density residential average daily cooling demand in Btu/ft²

CDD(DI) = annual cooling degree days based on the discomfort index in excess of 60.

T_d = dry bulb temperature, °F

T_{dp} = dew point temperature, °F

The CDD(DI) figure was merely interpolated from an isoline map provided in the Rand study⁸ (see Fig. B.6).

Peak Day Demands

Washington Gas Light has monitored the hourly demand, by location, for the peak hour of gas consumption in Washington, D.C. The therms/h/meter value for the 1976-77 D.C. peak hour was 0.662 therms. By dividing the average therms per meter per day figure obtained earlier (3.888 therms) by 24 hours, an estimate of the average hourly consumption rate per meter is determined to be 0.162 therms. The ratio of the peak hour to the average hour figure may be termed the "load factor" for heating for the Washington, D.C. service area of WGL. This load factor equals 0.245.

This WGL load factor is higher than the load factor for a single home because of a phenomenon called "diversity". Diversity of load means that the peak loads of all individual units will not occur simultaneously. WGL has estimated a "diversity factor" for its system of 0.66. This diversity factor is equivalent to the ratio of the load factor for an individual unit to the system load factor. For design purposes of a DES system, this means that the capacity of the system does not have to be so great that it can meet the sum of design day demands for each individual dwelling unit. In this study, the system has been designed to an ASHRAE 97-1/2% design day. This selection

Fig. B.6. Average Annual Total Number of Cooling Degree-Days
(Period: 1953-1957, incl. Base: Discomfort
Index 60)

and have not been multiplied by a diversity factor. Therefore, a system designed to meet the level of demand estimated in this Appendix is capable of providing current levels of service, i.e., public comfort has not been degraded. The capital costs required to design the system to this level thus are conservative in that they do not allow reductions from lower thermostat settings on coldest days.

As for heating, the Rand "Residential Sector" study⁸ has been adapted for design-day cooling needs. The nature of the adaptation is identical to that for heating and is straightforward, and the peak day cooling demand equation is:

$$R_1PDC = 14.6 \times (DI_{2-1/2\%} - 60^\circ) \quad (4)$$

where:

R_1PDC = low density residential peak day cooling demand in Btu/ft²

DI is defined earlier (Eq. 2a) and is based on ASHRAE's 2-1/2% design day.

Having thus estimated the energy demands for low-density residential dwelling units, it is necessary to note that these dwelling units are not likely to be served economically by a District Energy System. In the NASA MIUS Community Conceptual Design Study,¹¹ it was concluded that piping costs to provide thermal energy to single-family homes were excessive. Consequently, the single-family homes were served by heat pumps. A similar approach was developed in Argonne's Fox Valley study¹⁸. As a result of these precedents, and as a consequence of limits to manpower, it was decided that square kilometers devoted primarily to single-family-detached housing would not be included in estimates of residential demand. Square kilometers in which over 75% of the residential dwellings were single-family-detached housing would not be included in estimates of residential demand. Square kilometers in which over 75% of the residential dwellings were single-family, detached housing units, have no estimated residential energy demand. Thus, the demand figures developed here are not actually estimates of total heating/cooling demand within that city's boundary.

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• *High-Rise Residential*

Unfortunately, information provided by WGL on group-metered customers was of no value here because there was no record of the number of dwelling units per meter. The Rand "Residential Sector" study⁸ confined itself to single-family homes in its detailed analysis. Information on multifloor residential buildings is limited and is useful primarily for the comparison of residential building types. Therefore, it was assumed that high-rise residential behavior would be similar to low-rise residential behavior in response to the seasonal variations of climate, but that the energy demands would be only a fraction of those of low-rise buildings. Given this assumption, it was then necessary to decide on the appropriate fraction relating the two classes of buildings.

In Table B.2, comparative heating demand figures for various building types were listed to explain the high rise/low class breakdown. These figures have been used to develop estimates of the class energy consumption patterns in Chicago and Washington, D.C. First, it was assumed that the average consumption in the high-rise class of building is midway between the mid-rise and high-rise buildings. This was done because U.S. Census data do not give a breakdown by building height.

Mid-rise = 6,600 kWh/yr

High-rise = 5,800 kWh/yr

$$12,400 \div 2 = 6,200 \text{ kWh/yr}$$

The remaining types of buildings were matched to Census Bureau classification in the following manner:

<u>Building type</u>	<u>Census breakdown (unit description)</u>
Single family	1, detached 1, attached
Townhome	2 3 and 4 5 or more (owner)
Garden Apartment	5 to 19 (renter) 10 to 19 (renter)

Based on these classifications, the proportion of single family, townhome, and garden apartment dwelling units in Chicago and Washington, D.C., were computed. These proportions were used to compute a weighted average consumption figure from the values listed in Table B.2. This average value for low density, residential was 8650 kWh/yr. A ratio of high-density residential consumption to low-density residential consumption then was computed, i.e., $6200 \text{ kWh}/8650 \text{ kWh} = 0.72$. This factor was assumed to apply uniformly for peak and average heating and cooling values. Thus, any high-density, residential heating or cooling equation is equivalent to the low-density, residential equation multiplied by 0.72, as follows:

$$R_2\text{ADH} = 0.72 R_1\text{ADH} \quad (5)$$

$$R_2\text{PDH} = 0.72 R_1\text{PDH} \quad (6)$$

$$R_2\text{ADC} = 0.72 R_1\text{ADC} \quad (7)$$

$$R_2\text{PDC} = 0.72 R_1\text{PDC} \quad (8)$$

where:

$R_2\text{ADH}$ = high-density residential average daily heating demand
in Btu/ft²

$R_2\text{PDH}$ = high density residential peak daily heating demand
in Btu/ft²

$R_2\text{ADC}$ = high density residential average daily cooling demand
in Btu/ft²

$R_2\text{PDC}$ = high density residential peak daily cooling demand
in Btu/ft²

B.1.2 Commercial/Institutional

In conducting this survey of available data on square footage of buildings, it was found that some of the best data was for the central business districts (CBDs) of major metropolitan areas. Furthermore, the results of a survey of square footage in the Baltimore and Denver CBDs have been published.⁴ The Baltimore survey also identifies energy use patterns by building type. From previous work it is known that high densities are necessary to make a DES economically feasible. Because this effort is a feasibility study that attempts to pinpoint a market for DESs, it was decided that, when possible, any biases in the data should favor the most densely developed areas of the city. This decision meant that, given information on

energy consumption in downtown department stores and suburban shopping centers, the former consumption pattern should be selected for demand estimation methodology.

Figures B.1 to B.4 show that the commercial/institutional category of floor space is heavily concentrated in the downtown area (CBD). Within the CBD itself, office space dominates the total square footage.⁴ Fully 60% of the floor space in Baltimore is office space and in Denver 57% is office space. The International District Heating Association (IDHA) has prepared a survey of buildings, their volume, and their energy consumption per unit volume.¹⁵ This survey was conducted in cooperation with the Building Owners' and Managers' Association, an organization responsible for some of the CBD office space surveys used here. A strong similarity exists in the IDHA survey and the Baltimore/Denver surveys. Relative magnitudes of sample square footage or volume are shown in Table B.3. Note that office space is far ahead of any other single category and, in fact, is ahead of all other categories combined in all studies.

The results shown in Table B.1 indicated that it might be appropriate to use office energy consumption patterns as a surrogate for all CBD buildings' energy consumption behavior. It was possible to check the

Table B.3. Ranking by Area or Volume of Similar Building Categories in Baltimore and Denver CBDs vs. IDHA Survey

Building Type	Sq. Ft. Sampled in Baltimore CBD (10^3ft^2)	Rank	Sq. Ft. Sampled in Denver CBD (10^3ft^2)	Rank	Volume Sampled by IDHA (10^6ft^3)	Rank
Offices	6477	1	14100	1	721	1
Department Stores	1142	2	1029	4	214	2
Hotels/Motels/Clubs	950	3	2900	2	131	3
Warehouses	439	4	2000	3	54	4
Small Stores	383	5	984	5	23	6
Banks	69	6	177	6	13	7
Theaters	52	7	-	-	27	5

validity of this assumption through the building energy use factors already developed.^{4,15} The energy use indexes of buildings, other than office buildings, fall on both sides of the office building energy use indexes as shown in Table B.4. Using the square footage and volume figures of Table B.3, a weighted average energy consumption index was computed for the sets of building types commonly found in CBD's and included in both studies. It was found, in both cases, that the average value was very close to the office building value. For the Baltimore data,⁴ the average exceeded the office value by nine percent; whereas, for the IDHA data,¹⁵ the average was less than the office value by five percent.

Based on the above findings, it seemed reasonable to proceed with the assumption that office buildings can be used as a good surrogate for the overall energy consumption behavior in CBD areas. Proceeding with this assumption, and ignoring the fact that it had not been validated for cooling, the Bernstein and McCarthy study⁴ was used to develop an estimate of cooling consumption of office buildings in Baltimore. This study found that 61% of Baltimore commercial space is cooled by electricity and 39% is cooled by steam. This ratio is assumed to hold for office buildings. From Ref. 24 the estimates of coefficients of performance (COPs) for cooling equipment in

Table B.4. Ranking by Energy Use Index of Similar Building Categories in Baltimore CBD vs. IDHA Survey

Building Type	Baltimore Heat Demand Index(10^3 Btu/Ft ²)	Rank	IDHA Steam Heat Demand Index Lb/Deg-Day/ 10^6 Ft ³	Rank
Hotels/Motels/ Clubs	78	1	.990	1
Banks	67	2	.786	2
Theaters	62	3	.482	5
Small Stores	41	4	.624	4
Offices	34	5	.685	3
Department Stores	23	6	.385	7
Warehouses	17	7	.459	6
Area or Volume Weighted Average	37		.650	

office buildings can be found. These use a COP of 4.4 for electrically-driven compression chillers and 0.64 for steam-driven absorption chillers. Finally, steam-cooled office buildings use 67×10^3 Btu/ft²-yr, and electrically cooled office buildings use 12×10^3 Btu/ft²-yr of energy before conversion by the cooling equipment.⁴ Using these statistics, a final demand for steam is calculated as follows:

$$67 \times 10^3 \text{ Btu/ft}^2\text{-yr} \times 0.64 \frac{\text{Btu out of chiller}}{\text{Btu in chiller}} = 43 \times 10^3 \text{ Btu/ft}^2\text{-yr}$$

and for electricity, a final demand of:

$$12 \times 10^3 \text{ Btu/ft}^2\text{-yr} \times 4.4 \frac{\text{Btu out of chiller}}{\text{Btu in chiller}} = 53 \times 10^3 \text{ Btu/ft}^2\text{-yr}$$

Weighting these two final demand values by their respective proportions of floor space, an average final cooling consumption is estimated for a Baltimore office building of 49×10^3 Btu/ft²-yr.

The total final consumption per square foot per year of a Baltimore office building is estimated to be equal to $49 \times 10^3 + 34 \times 10^3 = 83 \times 10^3$ Btu/ft²-yr. This value (and its breakdown into heating and cooling components) are compared to values obtained in the office building simulations done in the Rand "Nonresidential Buildings" study which did not include Baltimore as a model city in its simulations. However, two individual cities, St. Louis and New York, are fairly similar to Baltimore in terms of heating and cooling needs. It was found that the Rand "half-light, glass curtain wall" office building simulation offered reasonable similarity (for St. Louis and New York) to the Baltimore results (see Table B.5).

	<u>Heating Degree Days</u>	<u>Cooling Degree Days</u>
St. Louis	4750	1500
New York	4848	1000
Baltimore	4729	1200

Table B.5. Office Building Energy Demand Data

Location	Rand Estimate of Heating Demand (Btu/ft ² -yr)	Our Estimate of Heating Demand Based On Baltimore (Btu/ft ² -yr)	Heating Degree Days (Ref. 28)	Rand Estimate of Cooling Demand (Btu/ft ² -yr)	Cooling Degree Days (Ref. 29)	Mean Annual Solar Radiation (Ref. 29)
Miami	3200	1500	206	76900	4200	490
Phoenix	15100	11200	1152	73500	3000	530
Birmingham	23000	NA	NA	56300	2000	390
Los Angeles	13600	13100	1819	47500	1000	460
Dallas	20800	16500	2290	63500	3500	425
Atlanta	26000	22300	3095	50500	1500	390
St. Louis	39100	34200	4750	47700	1500	370
New York	37500	34900	4848	42600	1000	340
Seattle	33100	37300	5185	32000	200	300
Boston	43300	40400	5621	34200	500	330
Denver	44700	43300	6016	41500	500	410
Detroit	48000	46200	6419	36800	700	320
Minneapolis	56200	59700	8310	34200	600	330

NA indicates "not applicable".

The Rand "Nonresidential Buildings" study²⁴ consists largely of simulations of standard office building behavior under various climatic conditions. This study presents the greatest opportunity for developing climate sensitive estimates of commercial/institutional buildings' energy consumption behavior because it includes estimates of consumption in so many different urban locations. Because a range of building design and operating conditions were included in this study, it was possible to select the design and operating mode--i.e., glass curtain walls and reduced light levels - which most closely matched the Baltimore "typical" office building's behavior. By using the behavior of this building type in locations other than Baltimore, it was possible to develop regression models of heating and cooling energy consumption of office buildings as a function of climate. The heating, cooling, and climatic variables used to develop these equations are listed in Table B.5. Also listed in this table is an estimate of annual heating consumption based on the ratio of Baltimore "typical" office building heating consumption to Baltimore heating degree days -- i.e., $34,000 \text{ Btu/ft}^2\text{-yr} \div 4729 \text{ HDD} = 7.19$. Note the close similarity of these demand estimates to the Rand²⁴ estimates. As another check of the validity of the use of the Rand estimates to approximate office building behavior, estimated total consumption for selected cities in the Rand study were compared to regional average office building energy consumption estimates in Ref. 16. These comparisons are shown in Table B.6. Note that the Faucett¹⁶ energy consumption figures are at the building

Table B.6. Selected Office Building Energy Consumption Comparison

Rand Location	Rand Value (Btu/ft ²)	Faucett Location	Faucett Value (Btu/ft ²)	Rand to Faucett Ratio
Minneapolis	90400	West North Central Region	138000	.66
New York	80100	Middle Atlantic Region	118000	.68
Atlanta	76500	South Atlantic Region	130000	.59
Los Angeles	61100	Pacific Region	76100	.80

face before conversion; whereas the Rand figures²⁴ are for energy necessary after conversion. As a result, the ratio of the Rand to Faucett figures will always be less than one. Considerable variability exists in the ratio, but the comparisons still indicate that the Rand values²⁴ are reasonable approximations of reality.

Using the data in Table B.5, we develop the following two annual heating and cooling demand equations. First, for heating, we assume that the Rand annual heating demand value is strictly a function of heating degree days:

$$AH = 7.37 (HDD) \quad R^2 = 0.958 \quad N=12 \quad (9)$$

(t=37.2)

and

AH = annual heating demand in Btu/ft² (Rand Estimate)

HDD = annual heating degree days based on 65°F

For cooling, the equation is considerably more complex. Part of the problem is that much of the cooling load is a result of interior lighting loads rather than external weather loads. There should be some minimum cooling load every day (and year), simply as a result of use of lighting. We include a constant term in our equation to account for this effect. Second, a larger proportion of cooling loads in office buildings occur as a result of solar radiation because of the high proportion of glass in such buildings. A solar radiation term is included in the cooling equation to account for this effect. When cooling degree days are added, we develop the following equation:

$$AC = 6550 + 7.88 (CDD) + 77.2 (ASR) \quad (10)$$

(t=1.29) (t=9.44) (t=5.09)

$$R_2 = .977 \quad N = 13$$

where:

AC = annual cooling demand in Btu/sq.ft

CDD = annual cooling degree days on a 65°F base

ASR = average daily solar radiation in gram calories per sq. cm. (Ref. 29)

Formulas (9) and (10) may be readily translated into average-day and peak-day demands in a manner similar to that used for low-density residential. First, for heating, if the annual values of Eq. 9 are divided by 365 days per

year, the following equation for average day commercial/institutional (office building) consumption per square foot is obtained:

$$\text{CADH} = 0.0202 (\text{HDD}) \quad (11)$$

where:

CADH = commercial/institutional average daily heating demand in Btu/ft²

Because Eq. 9 defines the relationship between demand and heating degree day, it may remain intact for the peak day equation with only a modification to account for the change from annual to peak day heating degree days as follows:

$$\text{CPDH} = 7.37 (65^\circ - \text{T}_{97.5\%}) \quad (12)$$

where:

T_{97.5%} = ASHRAE 97.5% design day temperature

CPDH = commercial institutional peak day heating demand in Btu/ft²

Using Eqs.(11) and (12) and substituting the appropriate values, a value of 85.1 Btu/ft² consumption per average day and a value of 339 Btu/ft² for the peak day in Washington, D.C. are obtained. The ratio of these two figures, the load factor, is equal to 0.251. This figure compares to an estimated load factor (average day to peak day) of 0.331 for the Washington Gas Light Company's (WGL's) commercial and industrial heating customers. This indicates that the magnitude of the peak day heating consumption has been overestimated for this class of customer. The reason for this overestimate is that diversity has not been directly accounted for. Selection of a 97.5% design day instead of 99% has the effect of allowing for diversity to a certain extent. This is illustrated by the fact that multiplication of our peak day value by WGL's 0.66 diversity factor would give us an excessively high load factor of 0.380. As a result, we have chosen to take no further account of diversity in our computations. We repeat our assertion made in the residential discussion that the capacity to which our DES will be designed is more than adequate to provide heat even on coldest days. If anything, our demand estimates err on the side of causing excess capacity of the DES and damaging its economic attractiveness:

To determine cooling, Eq. 6 is divided by 365 days per year as follows:

$$\text{CADC} = 17.9 + 0.0216 (\text{CDD}) + 0.211 (\text{ASR}) \quad (13)$$

where:

CADC = commercial/institutional average daily heating demand in Btu/ft²

For the peak day cooling equation, an approximate July average daily solar radiation figure is used in place of the annual average daily figures. This value is roughly the same for all midwestern cities and was set at a uniform 550 gram calories/cm². The equation is:

$$\text{CPDC} = 17.9 + 7.88 (T_{2.5\%} - 65^\circ) + 0.211 (\text{JSR}) \quad (14)$$

where:

CPDC = commercial/institutional peak daily heating demand in Btu/ft²

T_{2.5%} = ASHRAE 2.5% design day temperature

JSR = average daily solar radiation during July²⁹

B.1.3 Industrial

As was the case for high-rise buildings, the information on industrial consumption patterns is sparse; there is less information on this class of floor space than on any other. Even with good information, this class of floor space would be difficult to describe generically because it represents a highly variable class of energy consumer. However, it is possible to characterize the downtown industrial energy consumer with at least a small amount of confidence. In the CBD location, industries tend to be similar to commerce in the sense that they are likely to be located in multi-floor buildings and are likely to involve many employees/ft² i.e., to be labor intensive. Therefore, it has been assumed that industrial space in the DES's marketable demand areas will behave as commercial/institutional space, except that it will exhibit slightly greater energy consumption because industries will use multiple shifts more frequently than will commerce. The accuracy of this assumption is not critical because the industrial floor space category does not represent much of the downtown floor space. This is illustrated well in Tables B.1 to B.4.

The small amount of information that does exist is in agreement with assumptions here. Reference 15 estimates a value of 0.808 lb/°day/1000 ft³.

ft³. Compared to the value of 0.685 for office buildings, this gives a ratio of industrial-to-office consumption of 1.18. Although this ratio has little inherent merit in the absence of validation, it serves as a rough approximation about the relationships of energy consumption in the two classes of floor space. Thus:

$$IADH = 1.18 \text{ CADH} \quad (15)$$

$$IPDH = 1.18 \text{ CPDH} \quad (16)$$

$$IADC = 1.18 \text{ CADC} \quad (17)$$

$$IPDC = 1.18 \text{ CPDC} \quad (18)$$

where:

$IADH$ = industrial average daily heating demand in Btu/ft²

$IPDH$ = industrial peak daily heating demand in Btu/ft²

$IADC$ = industrial average daily cooling demand in Btu/ft²

$IPDC$ = industrial peak daily cooling demand in Btu/ft²

B.1.4 Hot Water

Hot water demands were assumed to be a function of occupancy patterns of buildings rather than of climate. Consequently, the water heating energy consumption rates vary by class of building, but not by location. A value for single-family house hot water consumption, developed from the Rand "Residential Sector"²⁴ is 22 Btu/ft²/day. This value was used for the low-density residential sector. To adjust this value for high-density residential, we simply used rooms per unit as a surrogate for occupancy rate per dwelling unit. This information was obtained from the Statistical Abstract.²⁸ For owned housing units (a proxy for low-density residential), there was a median value of 5.8 rooms per unit in 1974. For rental units (a proxy for high-density residential), there was a median value of 4.0 rooms per unit. Thus, for high-density residential, it can be estimated:

$$4.0 \text{ rooms per unit} / 5.8 \text{ rooms per unit} \times 22 = 15 \text{ Btu/ft}^2$$

as a daily consumption figure.

For commercial/institutional water heating energy, value estimated by the Energy Systems Research Group of Boston, Mass.³ for their work on this project was used. This value seemed reasonable when compared to residential values because it was substantially less because less bathing and dishwashing per occupant takes place in most commercial and institutional establishments than in residences.

Table B.7. Statistics for Computation of Demand Factors

City	Annual Heating Degree Days	Annual Heating Degree Days per Design Day	Annual Discomfort Index Cooling Degree Days	2.5% ASHRAE Based Discomfort Index Cooling Degree Days per Design Day	Annual Temperature Cooling Degree Days	Average Solar Radiation	2.5% ASHRAE Based Temp. Cooling Deg. Days per Design Day
Chicago	6127	64	1350	22.75	1000	345	26
Cleveland	6154	58	900	21.45	750	325	24
Detroit	6419	57	950	20.90	700	330	23
Milwaukee	7444	67	1200	20.35	450	340	22
St. Louis	4750	54	1950	24.80	1500	370	29
Washington	4211	46	1500	23.50	1050	360	27

Table B.8. Chicago Energy Demand Factors (Btu/ft²)

Building Type	Average Day Heat	Peak Day Heat	Hot Water	Average Day Cooling	Peak Day Cooling
Low Density Residential (R1)	245	934	22	54	332
High Density Residential (R2)	176	673	15	39	239
Commercial/Institutional (C)	124	472	9	112	339
Industrial (I)	146	557	11	132	400

Table B.9. Cleveland Energy Demand Factors (Btu/sq.ft)

Building Type	Average Day Heat	Peak Day Heat	Hot Water	Average Day Cooling	Peak Day Cooling
R1	246	847	22	36	313
R2	177	610	15	26	225
C	124	427	9	103	323
I	147	504	11	121	381

Table B.10. Detroit Energy Demand Factors (Btu/sq.ft)

Building Type	Average Day Heat	Peak Day Heat	Hot Water	Average Day Cooling	Peak Day Cooling
R1	257	832	22	38	305
R2	185	599	15	27	220
C	130	420	9	103	315
I	153	496	11	122	372

Table B.11. Milwaukee Energy Demand Factors (Btu/sq.ft)

Building Type	Average Day Heat	Peak Day Heat	Hot Water	Average Day Cooling	Peak Day Cooling
R1	298	978	22	48	297
R2	215	704	15	35	214
C	150	494	9	99	307
I	177	583	11	117	363

Table B.12. St. Louis Energy Demand Factors (Btu/sq.ft)

Building Type	Average Day Heat	Peak Day Heat	Hot Water	Average Day Cooling	Peak Day Cooling
R1	190	788	22	78	362
R2	137	568	15	56	261
C	96	398	9	128	362
I	113	470	11	151	428
Weighted* Average of R1 and R2	186	770	21	76	354

*For St. Louis, no residential floor space breakdown was made. Weights were based on overall low and high rise units in the city as obtained from Census data.

Table B.13. Washington, D.C. Energy Demand Factors (Btu/sq.ft)

Building Type	Average Day Heat	Peak Day Heat	Hot Water	Average Day Cooling	Peak Day Cooling
R1	168	672	22	60	343
R2	121	484	15	43	247
C	85	339	9	117	347
I	95	380	11	131	409
Weighted* Average of R1 and R2	155	618	20	55	315

*For Washington, no residential floor space breakdown was made. Weights were based on overall low and high rise units in the city as obtained from Census data.

The estimated value is 9 Btu/ft²/day. For industrial water heating, it was assumed that the same relationship held as for space heating when compared to commercial/institutional. Thus, an industrial value of 1.18 times 9, or 11 Btu/ft²/day was developed.

B.1.5 Computation of Energy Demand Factors

Using Eqs. 1 through 8 and 11 through 18 and also using the values developed in the hot water section, a complete matrix of energy demand factors as illustrated in Table B.1 can be developed for each of the study cities. Data that were used in these equations is presented in Table B.7. The demand factor matrices for the six cities of interest are shown in Tables B.8 through B.13.

B.1.6 Square Footage Estimation

Square footage was estimated by the Real Estate Research Corporation. The first stage of the data collection process was to contact planning and city agencies from all of the cities to be included in the studies. Following confirmation of agencies or individuals likely to have good information, a Real Estate Research (RER) employee was sent to each city to compile estimates of building square footages. Each RER data collector carried a set of U.S. Geological Survey Topographical maps on which were drawn grid lines corresponding to the Universal Transverse Mercator Grid (UTM), except in the case of Chicago, which was based on a square mile grid. The data analyst was then asked to estimate the building square footages in each one of the UTM square kilometer grids based on the best available data. In the process of conducting these surveys, the data in some of the proposed study cities was found to be either inadequate or too inaccessible within the budgetary framework of the project. As a result, both Newark and Manhattan were deleted from the study scope.

In general, the U.S. Census estimates of numbers of dwelling units in census tracts provided the best source of information on which to estimate residential square footage. These dwelling unit figures were broken down into categories based on the number of dwelling units per building to facilitate estimates of both high- and low-density residential square footage. The census data were always used to eliminate those residential areas of the city that were over 75% single-family housing.

Commercial/institutional and industrial data were not as readily available. A typical source used for this information was an employment survey by planning districts. Often these employment surveys are conducted as a part of origin-destination studies for transportation planning purposes. The employment figures were converted to square footage estimates by applying a square footage/employee factor developed by Ide Associates of Philadelphia.¹³ In some cases, building square footage surveys were available for certain portions of the city. Generally, these were conducted as office space surveys for the Central Business District. Where these studies were available, they were used either as sources or checks for the zones to which they applied.

No one-to-one comparability of the square footage estimates exists for each city. The data sources available varied greatly in quality and detail. Each data analyst was given instructions on what to expect and how to proceed in studying a city, but they were responsible for using their best judgement concerning the method of estimation. Data availability and quality generally were overriding factors, but time constraints sometimes caused use of lower quality of information than was available. Estimates of the square footage data for each of the site study cities follows:

- Chicago

Chicago is conveniently sectioned into a quarter-square-mile (township) grid system that has been used as the standard for all past data collection. Argonne National laboratory and RER agreed to follow this pattern by examining the land uses within these township sections.

Employment data by place of work were supplied by the Northeastern Illinois Planning Commission (NIPC) and aggregated by Argonne into sixteen employment categories. The data are broken down according to square miles (aggregated from quarter-square mile) following the set rules of the township numbering system.

• *Residential*

To determine the residential square footage within the square mile sections, the thorough land use map of Chicago (1970) was used as the authoritative source. The mapping delineated residential uses into four categories:

1. Low-Density Residential: areas of least intensive residential use with single-family and two family housing predominating. Prevailing density: less than 22 housing units per net acre.
2. Medium-Density Residential: areas where two and three flat apartment buildings predominate. Prevailing density: 22 to 40 housing units per net acre.
3. High-Density Residential (under 5 stories): areas of 3 and 4 story walk-up apartment buildings, frequently of the large court type. Prevailing density; more than 41 housing units per net acre.
4. High-Density Residential (5 stories and more): areas where medium and high rise apartment structures predominate. Prevailing density: more than 41 housing units per net acre.

For purposes of this study, the first three classifications were grouped together and designated R₁; whereas, the fourth category fit within the designation of elevator buildings and was labeled R₂.

With this information, a table was set up to determine the residential square footage. (See Table B.14). The average number of units per acre was set as well as the average square footage of a typical dwelling unit. These two figures were multiplied to estimate the square footage per acre according to the type of residential land use. Because there are 640 acres per square mile, this number was multiplied by the square footage per acre to ascertain square feet per square mile. A percentage of the various residential uses per square mile was decided by visual inspection, and this percentage was multiplied by the preceding column. Finally, the numbers derived for the first

Table B.14. Chicago Residential Square Footage Classifications

Classification	Average # D.U./Acre	Average Sq. Ft./D.U.	Sq. Ft./ Acre	Acre/Sq. Mile	Sq. Ft./ Sq. Mile	% Sq. Mile "Eyeball"	Total Residential Sq. Ft./ Sq. Mile
Low	10	1,500	15,000	640	9,600,000	(Ex.) 20%	(Ex.) 1,920,000*
Medium	31	1,300	40,000	640	25,792,000	(Ex.) 10%	2,579,200
High (5 story)	50	1,300	65,000	640	41,600,000	(Ex.) 5%	2,080,000
High	100	1,300	130,000	640	83,200,000	(Ex.) 0%	0

*Ex. indicates "example."

three categories were totaled and entered on the work sheets as R₁. The fourth category was entered under the R₂ classification.

• *Commercial/Institutional and Industrial*

The commercial square footage data were obtained by determining average number of square feet per employee according to Standard Industrial Codes. The square footage per employee figures used in the commercial category were:

	<u>ft²/employee</u>
Wholesale Trade	682
Retail Trade	525
FIRE and Services	200
Government (Federal, State, and Local combined)	393
Self-employed	200
Institutional (School)	697

These figures were derived from an Ide Associates study, Estimating Land and Labor Area Implicit in Employment Projections.¹³

The number of employees from the employment data printout was multiplied by the corresponding ft²/employee figure and entered on the work sheets. The work sheets list the latitudes and longitudes relevant to the subject area. Each box on that sheet represents the corresponding square mile according to the township numbering system. The sum total represents the amount of square feet of floor space devoted to commercial purposes in that particular square mile.

The same procedure was used to determine the industrial square footage per square mile. Square footage per employee was determined according to the various SIC codes and then multiplied by the number of employees in that category from the NIPC data. The square footage/employee figures also from the Ide study, were:

	<u>ft²/employee</u>
Construction	200
Durable Manufacturing	500
Non-Durable Manufacturing	450
Transportation & Warehousing	1000
Communication & Utilities	210

- Cleveland

Mr. Joe Cole of the Northeast Ohio Area Wide Coordinating Agency, (NOACA) provided commercial and industrial employment statistics broken down by approximately 350 small areas within the city. Residential data were not available in this format. Therefore, census tract data were used for the residential categories.

- *Residential*

Lacking an up-to-date land-use map, census tract data were used to compute R_1 and R_2 square footages. R_1 was defined to include census categories of up to 49 units per building. R_2 includes 50 units or more per building.

- *Commercial/Institutional and Industrial*

Data aggregated by traffic zones (350 zones) were transformed into the km^2 grids. The industrial sector was defined to include NOACA categories of construction, manufacturing, transport, and wholesale. Commercial floor space included retail, finance, business, entertainment, personal services, and professional and public activities. Ide square footage estimates¹³ were defined for each category and were multiplied by the number of employees. These products were summed to obtain sectoral totals. The Ide¹³ multipliers used are listed below:

Commercial/Institutional

retail	525
finance	200
business	200
entertainment	800
personal services	200
professional	200
public	393

Industrial

construction	235
manufacturing	450
transportation	780
wholesale	682

- Detroit

Detroit is the most industrialized city in this study. Because of the heavy emphasis on manufacturing in this city, a separate study of industrial employment for Detroit was available. For commercial uses, however, some of the areas were not well documented and had to be estimated on the basis of a land use map. The highly developed areas did not have separate studies of commercial floor space.

- Residential

The U.S. Census statistics were used to determine the residential square footage in each square kilometer. The first step was to eliminate all those census tracts that had greater than 75 percent single-family residential units. For Detroit, this constituted nearly 30 percent of the total number of census tracts. Moreover, these census tracts were predominantly the larger tracts away from the older central section of Detroit.

For each tract, the number of year-round housing units was broken into the following categories:

Units in StructureNumber of UnitsExample

1	48
2	37
3 and 4	19
5 to 49	129
50 or more	48

For the one-unit structure, 1,500 ft² was used as the average size of that type of dwelling unit. For the rest, 1,300 ft² was used as the standard. These numbers multiplied by the actual number of units produced the square footage totals desired. The products of the first four numbers in the column

were summed and labeled R_1 (Residential I). The product of the last number (in this case 48), equaled our R_2 category.

The census tracts were entered on the U.S.G.S. maps to help determine how each fit into the square kilometer grid system. A percentage of the census tract was allocated to the correct square kilometer. If more than one census tract overlapped into a particular square kilometer, then a sum of the various percentages was necessary.

- *Commercial/Institutional*

The commercial figures that were produced came directly from the land-use map and special studies for particular areas of the city. The CBD data* were accurate, up-to-date, and easily transferable to the square kilometer grid system. The same holds true for the information dealing with the Central Function Area (CFA).

For the outlying areas of the city, the grid system was superimposed on the existing land use map. Therefore within any particular square kilometer, some area may be devoted to commercial purposes. By using the scale on the map, it was determined that, on the average, the commercial strips along the major thoroughfares were 200 ft deep. Within each km^2 , a measurement was made of a proportion of a mile that may be devoted to this purpose. For example, one square may have 2 mi of commercial use; whereas, another may have 2.7 mi. This proportion was multiplied by 5,280, the number of feet in one mile. This computed length of feet was multiplied by the 200 ft to determine the actual amount of square footage of land area for commercial use.

In the Ide study,¹³ land area per employee is given as 3,500 ft^2 /employee for commercial purposes. This number was divided into the square footage to determine the number of employees. As the standard, 525 ft^2 /employee was used. This number was multiplied by the previous quotient to arrive at the square footage of commercial space within each square kilometer.

*(The CBD is defined as that area bounded by U.S. Interstate 75 on the north, the Chrysler Freeway on the east, the Detroit River on the south, and the John C. Lodge Freeway on the west. The CFA is defined as that area bounded by the Edsel Ford Freeway on the north, the Chrysler Freeway on the east, Interstate 75 on the south, and the Lodge Freeway on the west.)

An additional source of information was the "List of Health Care Institutions" which catalogued the number of employees for each hospital within the City of Detroit. These health centers were spot located and the square footage entered into the correct square kilometer.

- *Industrial*

To determine the industrial floor space totals, The Harris Michigan Manufacturers Industrial Directory (1976) was used as the basic source. This document, a compilation of all the industrial plants within the city of Detroit, lists the numbers of employees, SIC number, zip code and actual square footage with varying degrees of completeness for each company.

Two steps were taken to screen some of the entries. First, those zip codes that did not have a large concentration (over 100,000 ft² of industrial space) were eliminated. Those zip codes not included were 482 - 06, 10, 21, 22, 24, and 40. Second, those establishments with less than twenty employees were not tallied unless the square footage of the plant was already given.

If the square footage was not provided, the number of employees was multiplied by the SIC conversion factors found in the Ide study.¹³ This result and the square footage totals already given were summed according to zip code.

After industrial totals had been established by zip code, the land-use map was used to place the industrial concentrations within each zip code. A percentage of the total was allocated to those square kilometers in which industrial areas were predominant. Because of the magnitude of industrial plants in the Detroit area, those sections of the city show up very clearly directly on the U.S.G.S. maps.

- *Milwaukee*

Milwaukee was one of the more organized cities with respect to data availability. The Department of City Development (DCD) was a very useful source of data. In addition to supplying commercial/industrial employment data, it provided a special study on downtown CBD floor space. It also supplied a land-use map indicating the locations of major industrial parks and major electric generating plants.

- *Residential*

Because no thorough or complete residential data were available for Milwaukee, the 1970 census tract data were used. The method used to compute the R_1 and R_2 totals is as follows:

CENSUS TRACT INFORMATION

Units

1	No. of households x 1500 = A	
2	No. of households x 1300 = B	$A + B + C = R_1$
3 & 4	No. of households x 1300 = C	
5 to 49	No. of households x 1300 = D	$D + E = R_2$
50 or more	No. of households x 1300 = E	

The R_2 category includes structures with more than five units. This cut point was chosen in consultation with Richard Kateley of RER and reflected his judgement on the inadequacies of data in the 50 or more¹¹ category and the DCD's view of the best means of distinguishing residential density.

After determining a total R_1 and R_2 figure for each census tract, the totals were prorated dividing each according to the proportion included in the kilometer guide.

- *Commercial/Institutional and Industrial*

These data were obtained from the Milwaukee Department of City Development (DCD) which ran a computer printout of the number of commercial employees and industrial employees in each of some 400 destination traffic zones. Traffic zones were transformed into our km^2 . Next, the multipliers 450 ft^2 for commercial and 500 ft^2 for industrial were used as the average square footage per employee. These numbers were multiplied by the respective numbers in each traffic zone. After deriving the number of sq. ft of space for each zone, the total was prorated to different km^2 according to the previously determined transformation percentages.

- *St. Louis*

To obtain square footage totals for the three categories (residential, commercial, industrial) in each square kilometer area of the City of St. Louis, several mathematical procedures, along with a certain amount of esti-

ming, were required. The following is a step-by-step description of the work involved.

It was necessary to work up square footage figures by traffic zones. The main source of information here was the booklet, Land Use and Socio-economic Projections.

Traffic zones were traced over the square kilometer areas on the U.S.G.S. maps. The percentage of each traffic zone then was estimated for each square kilometer to yield an equation for each square to which the residential, commercial, and industrial figures could be applied. Adjustments were made for factors such as parks, rivers, railroads, etc., that might have considerably distorted the proportions.

In a sense, the CBD was treated as one traffic zone except that it was not necessary to calculate the square footage. Multiplying square feet per traffic zone by percent per square kilometer, adding these figures together (plus the CBD totals, where applicable) gave residential, commercial, and industrial figures for each square kilometer. All numbers were rounded to the nearest 1,000. Because not all square kilometer areas are fully contained within the St. Louis city limits, it was necessary to evaluate density only on the proportion within the boundary line.

● *Residential*

Because the traffic zones listed only dwelling units, no breakdown into the two residential categories, R_1 and R_2 , was undertaken. However, 1970 data were used because no 1980 dwelling unit projections were available. To obtain an average square foot/dwelling unit figure, the 1970 Census of Housing was used; 1,500 ft²/unit was assumed for single-family and 1,300 ft²/unit for multi-family housing. From the census data, Table 43, it was learned that 34.3 % of all structures are single-family (single-family detached, single-family attached, mobile homes or trailers); whereas, 65.7% are multi-family structures (2,3,4,5, or more families). Using a weighted average, a multiplier of 1368.6 rounded to 1370 ft²/dwelling unit was obtained.

- *Commercial and Industrial*

Employment figures projected for 1980 were used for commercial and industrial. Commercial includes public also. Each zone's employment was multiplied by a constant to calculate square footage. The assumed multipliers were 400 sq.ft/employee for commercial and 500 sq.ft/employee for industrial.

- Washington, D.C.

The procedure followed for Washington, D.C. was very similar to that used for St. Louis. As in St. Louis, information was available based on transportation planning districts. Household data and employment data per transportation planning district were obtained from the Washington area Council of Governments. Estimates of square footage per zone were established using these data. Correspondences between the transportation planning zones and the UTM square kilometer grid were established. The square footage estimates were then "transferred" from zones to square kilometers as described for St. Louis.

- *Residential*

The transportation planning zones had information on total households in the zone but did not indicate the type of building in which these households lived. Census data could have been used to obtain this information, but this would have entailed establishing a correspondence between the census tracts and km² in addition to the correspondences between the transportation planning zones and the km² grid. It was decided to aggregate the residential category into just one class (as in St. Louis) to avoid this duplication of effort.

- *Commercial/Institutional and Industrial*

Information on employment in the transportation planning zones was quite detailed. The breakdown was almost identical to that for Chicago where a detailed list of square feet per employee factors was used to develop the commercial/institutional and industrial square footage estimates.

B.2 LOCAL DISTRIBUTION SYSTEM CHARACTERISTICS

The Energy Systems Research Group (ESRG) of Boston, Mass. subcontracted to Brookhaven National Laboratory to design and cost a local distribution system for the distribution of thermal energy from the major transmission lines to the building face. The ESRG conducted a thorough analysis of demand in each of the northeastern cities being studied by Brookhaven. In Argonne's judgement, however, the detailed analysis was necessary only for one city, i.e., Washington, D.C. The detailed Washington, D.C. estimates then could be used to develop an approximate cost function to be applied to the remaining cities. The detailed procedure used by ESRG is explained below along with Argonne's development of an approximate cost function from this work.

B.2.1 District Heating Sections and their Local Distribution Networks

After the design level demand for space heating and hot water heating had been calculated for each grid square of the city, the computer program which does this calculation then ranked the grid squares by design demand. These rankings were printed out in the form of a grid square map of the city. Natural boundaries then were drawn, e.g., rivers and bays, so that grid squares on opposite sides of such boundaries would not be included in the same "distribution section". A "distribution section" was defined as a small section of the city, generally composed of six contiguous grid squares, but ranging from 3 to 10 grid squares, depending on circumstances. The grid squares in distribution sections share a common pipe network for distributing the hot water from main transmission pipelines to the pipes that service individual blocks. All sections were designed to have as much uniformity in demand density as possible within each section because the analysis thereafter would analyze the system at the section level of aggregation. However, sometimes the two criteria of geographical contiguity and rough uniformity of design demand density were not entirely compatible, this occurred when geographical and political boundaries made it difficult to satisfy the uniformity criterion. Fig. B.7 shows the sections defined for Washington, D.C.

After sections were chosen in this way, it was easy to design the piping system generically for different geometrical groupings of grid squares into sections. Additional design parameters that had to be specified were the temperature changes the hot water would undergo at the point of end-use, and

Fig. B.7.. Energy Systems Group Sections for the Local Distribution Cost Study (Washington, D.C)

the outdoor temperature difference (and therefore demand) that are assumed for the design points; included are hot tap water plus design space heating. These are:

1. water temperature into end-use device at design outdoor temperature - 200°F ;
2. water temperature out of end-use device at design outdoor temperature - 110°F ; and
3. Outdoor temperature; monthly average temperature of coldest month relative to 65°F base.

To meet the peak heating requirements, both the hot water input temperature from the power plants and the hot water flowrate in the distribution system can be increased. Similarly, to meet peak cooling requirements, the pressure must be increased temporarily because the maximum useful temperature drop for cooling at the end-use device was assumed to be limited to 25°F , and the maximum coefficient of performance (COP) was assumed to be 0.7. Servicing peak demand for heating and cooling, therefore, requires an increased ratio of pumping energy requirements to district heating or cooling requirements for a small fraction of the year as compared with the pumping energy required to meet design conditions. Of course, this is more than offset by the larger fraction of the year when less hot water flow is required, and, therefore, pumping energy requirements are relatively lower.

For each section, a "1 capacity" flowrate was defined as that flowrate that meets design demand of the average grid square in the section, i.e., total section demand divided by the number of grid squares in the section. All other distribution pipes then were sized by flowrate in integer multiples of the "1 capacity" pipe flowrate. The optimal relationship between flowrate (in gal/min) and pipe diameter (in.) was derived by Burns and Roe, Inc.,²² assuming that the cost of heat from the utility is about \$1/MMBtu and the electricity charge for pumping energy is about \$.05/ kWh; i.e., flowrate (in gal/min) = $14.32D^2$, where D is the pipe diameter (in.). The total length of pipe of each diameter optimally corresponding to the flowrate carried were then assumed for each section. The most common section chosen was rectangular (2 x 3 grid squares). This provides the simplest illustration of the way the distribution pipe system was laid out and sized; see Fig. B.8.

The solid lines in Fig. B.8 are the grid square boundaries, the dotted lines are the pipes, and the X marks the point that the transmission system

Total Pipe Length

2 capacity - 2 km

1 capacity - 6 km

(numbers within the rectangle represent the capacity rating of the pipes-- dotted lines, and the solid lines in the lower left grid square indicate a typical array of street distribution pipes.)

Fig. B.8. Distribution Pipe System for a Standard Six-Grid Section

would connect to the distribution system. The numbers beside each pipe section indicate the capacity equivalent that pipe would carry to meet design demand. In each grid square, many 1/2 km street pipes would come off each "1 capacity" pipe (which runs through the center of each grid square) to service the individual blocks. The design calculation was performed assuming that only streets running in one direction, viz. in the longest block direction, would require pipes. The buildings on the end of the blocks could be served by a pipe running from the corner half-way down the block through the neighboring buildings. This assumption implies that each 1/2 kilometer street pipe must be able to carry a capacity of 1/2 divided by the sectional average number of kilometers of streets per grid square. For example, if the grid squares in a section average 10 kilometers of streets, then the 1/2 kilometer street pipe will be rated at .05 capacity. If pipes were to be laid down each street in both directions, the district heating system would be more expensive.

A more complicated pipe system for a section of 8 grid squares is shown in Fig. B.9.

B.2.2 Costing the Local Distribution Networks

Once the length of pipe vs. capacity for a particular section has been estimated, then it is a simple matter to apply cost per unit length for appropriate capacities to estimate capital cost of the distribution system. These cost computations were computerized by ESRG, based on input of pipe length vs. capacity classification and annual demand per square kilometer. The cost of piping used was based on estimates provided by the consulting firm of Burns and Roe, Inc., (Ref. 22). The Washington, D.C. cost figures are presented in Table B.15.

Table B.15. Piping System Cost Estimate (\$ per foot of Piping System)*
Washington, D.C. Urban Area Poured Concrete Fill Design

Item or Process	Pipe OD (In.)				
	4	8	12	20	30
1. Street Removal - 2 in. Asphalt, 8 in. Concrete (Non-Reinforced)	3.70	4.62	5.54	7.18	9.45
2. Timber Sheeting - Place & Remove	44.50	46.60	48.77	52.96	58.30
3. Excavation - medium Weight soil, 50% by Hand, 50% by machine	9.53	13.12	17.24	25.44	39.52
4. Concrete fill & Reinforcement	8.39	12.43	17.09	25.33	40.35
5. Backfill - Sand Fill, Spread by Hand	4.38	5.47	6.56	8.51	11.18
6. Street Replacement	4.90	6.12	7.34	9.51	12.52
7. Piping					
Material & Equipment					
- Pipes	9.62	23.82	44.88	69.72	82.14
- Insulation & Coating	8.56	13.26	18.70	28.60	43.22
- Fittings, Valves, Expansion Joints & X-Ray Equipment	9.90	15.35	20.99	43.68	80.27
Labor (installatcn & welding)					
- Pipes, insulation & coating	23.25	44.85	58.80	75.06	95.81
- Fittings, valves and expansion joints	2.61	4.13	6.37	8.33	11.22
8. Manholes	4.35	4.35	7.34	9.23	9.23
TOTAL COST PER FOOT OF SYSTEM (\$/FT)	133.69	194.12	259.62	363.55	493.21
ADJUSTED TOTAL FOR URBAN AREA (\$/FT)	260.69	378.52	477.69	734.36	1030.81

*Cost includes one foot of insulated supply pipe and one foot of insulated return pipe.

Total Pipe Length

3 capacity - 2 km

2 capacity - 1 km

1 capacity - 8 km

(numbers within the figure represent the capacity rating of the pipes (dotted lines)).

Fig. B.9. Distribution Pipe System for an Irregularly Shaped Eight-Grid Section

Argonne has decided that the general quality of cost estimates available for other components of the study did not warrant the previously described detailed section-by-section analysis for the five midwestern cities. Chicago would have required that the entire procedure be repeated because the Chicago grid is a mi^2 grid rather than a km^2 . As a result of this logic, it was decided that ESRG would not be employed to generate local distribution cost estimates for the midwestern cities. Instead, the early results of ESRG for Washington, D.C. were used to develop a general cost function. This allowed more effort to be expended on some other important components of the DES. The cost function used by Argonne is based on the ESRG results for the first nine Washington, D.C. zones shown in Fig. B.7. The data for these nine zones are shown in Table B.16. A linear regression equation of cost on demand plus a constant term was estimated. Because of the limited range of densities over which this regression equation extends, it can only be expected to be valid over the range of densities occurring in Washington, D.C. However, all midwestern cities except Chicago, have the same range of annual demand densities as those of Washington, D.C., and the equation is:

$$C = 4.2540 + 0.01094D \quad R^2 = 0.91 \quad N=9 \quad (19)$$

(t = 10.45) (t = 8.34)

where:

C = cost per zone in 10^6 \$

D = annual demand/ km^2 in 10^9 Btu

Table B.16. Energy Systems Research Group
Washington, D.C. Estimates of
Local Distribution Cost Vs
Annual Demand

ESRG Zone No. (See Fig. B.7)	Annual Demand/ km ² (10 ⁹ Btu)	Cost/km ² (\$x10 ⁶)
1	657	10.8
2	405	10.0
3	286	7.31
4	226	6.52
5	161	5.96
6	180	6.48
7	130	5.63
8	204	6.62
9	150	5.21

In the computations presented here, the D value has been an average demand averaged over several sections. Some error results from this procedure.

Note the bottom two lines in Table B.15. As can be seen, Burns and Roe has included an "urban" add-on amounting roughly to a doubling of costs. This urban add-on is applied appropriately in downtown areas but not necessarily in other areas of the city. In this study, both a high and low estimate of local distribution costs are generated. The high estimate makes the unnecessarily harsh assumption that the urban add-on is appropriate for the entire city. This high estimate is based on Eq. 19. The low estimate makes the very optimistic assumption that good piping route selection avoids the urban add-on in every part of the city. This estimate is half the value computed through Eq. 19.

B.2.3 Building Retrofit

Also a part of the local distribution system is the energy conversion equipment in the building itself. In nearly all cases, the building will have to be retrofitted to accept hot water for heating. Burns and Roe has generated some estimates of retrofit costs for office buildings and apartment buildings whose current heating systems use steam or hot water. This seems to

be a reasonable initial choice of conventional system based on current systems in use. According to data obtained from the U.S. Census, 54% of the rental units in the study cities used steam or hot water heat in 1970. According to estimates based on the Bernstein and McCarthy study,⁴ 48% of the Baltimore and Denver CBD's square footage was heated by steam or hot water. These classes of building represent the most likely market for thermal energy from a DES. The above data can be viewed in another way. For example, about half the floor space in the DES market area is based on systems other than steam or hot water (primarily hot air), and the appropriate means of retrofitting these buildings has not yet been studied.

In view of this problem, the actual estimates of cost used here and their breakdown are listed in Table B.17. As in the case of the local piping costs, a high and low cost estimate is generated for building retrofit. Only heating system retrofit costs are used here. For the high-cost estimates, the high apartment heating retrofit value of \$0.32 per square foot was used for all residential floor space. Because residential demand estimates are strongly biased toward multi-family dwelling units, and because downtown areas are of primary interest, this uniform value for all residential seems appropriate. The high office building retrofit value of \$0.76 per square foot was used for all commercial/institutional and industrial buildings. Although some very high retrofit cost estimates have been generated for retail stores, these stores represent suburban types of low-density, auto-oriented shopping malls with rooftop units.²² In downtown areas, retail outlets are on the first floors of office buildings or are in multi-floor buildings themselves. Downtown industry also locates in office-like buildings, so the uniform use of the \$0.76 value throughout the city tends to understate retrofit costs in the more residential areas of the city.

For the low-cost retrofit estimates, the low apartment value of \$0.24 per square foot was used for all residential, and the low office building value of \$0.41 per square foot was used for commercial/institutional and industrial square footage. Retrofit costs were generated simply by multiplying the above cost figures by the square footage of the appropriate building type in the zone.

Table B.17. Building Retrofit Case Study Descriptions and Cost Breakdowns

Item No.	Case No.	Building & System(s) Description	Gross Building Area (Sq. Ft.)	Installed Capacity		Cost (Dollars)			Total Costs	Heating	Air Conditioning	Total	Air Conditioning Cost Per Ton
				Heating BtuH (10 ⁶)	Air Conditioning (Tons)	Heating ^a	Air Conditioning ^b	Street Inter-connection					
1	1.0	Office Building 10 floors Steam absorption, one central fan room Steam/hot water heat	200,00	17.5	520	152,200	73,200	14,000	221,700	0.76	0.37	1.11	141
2	1.1	Office Building 10 floors Steam absorption, one central fan room Steam/hot water heat	400,000	33.0	1,200	164,300	82,600	14,000	246,900	0.41	0.21	0.62	69
3	2.0	Office Building 10 floors Compression chiller One central fan room Steam/hot water heat	200,000	17.5	520	152,200	176,900	14,000	328,900	0.76	0.88	1.64	340
4	2.1	Office Building 10 floors Compression chiller One central fan room Steam/hot water heat	400,000	33.0	1,200	164,300	279,500	14,000	443,800	0.41	0.74	1.11	233
5	3.0	Apartment Building Unitary (window) AC Hot water heat	200,000 200 APTS.	16.5	350	63,600	489,000	14,000	552,500	0.32	2.45	2.76	1,397
6	3.1	Apartment Building Unitary (window) AC Hot water heat	400,000 400 APTS.	30.0	711	97,000	916,100	14,000	1,013,100	0.24	2.29	2.53	1,288
7	4.0	Retail Store Roof top direct expansion AC Hot water heat	1,500	1.0	10	11,500	28,000	5,000	39,500	7.67	18.67	26.33	2,850
8	4.1	Retail Store Roof top direct expansion AC Steam heat	1,500	1.0	10	18,300	28,000	5,000	46,300	12.20	18.67	30.87	4,630
9	4.2	Retail Store Roof top direct expansion AC Gas/air heat	30,000	2.3	100	83,400	125,700	10,000	209,100	2.78	4.19	6.97	1,257

^aHeating costs cover complete installation including street service.^bAir conditioning cost may be added to heating cost, but may not be taken separately.

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