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II.1.

GEOTHERMAL DISTRICT HEATING

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1. DESCRIPTION

Geothermal district heating is defined as the use of one or more production fields as sources of heat to supply thermal energy to a group of buildings. Services available from a district heating system are space heating, domestic water heating, space cooling, and industrial process heat. A district heating system is not limited to a particular type heat source. Heat sources that could be used for a district heating system include co-generating power plants, conventional boilers, municipal incinerators, solar collectors, groundwater heat pumps, industrial waste heat sources, and geothermal fields. Depending on the temperature of geothermal fields, it may be advantageous to develop a hybrid system including, in addition to geothermal, a heat pump and/or conventional boiler for peaking purposes.

A geothermal district heating system comprises three major components, as shown in Figure 1.

The *first part* is *heat production* which includes the geothermal production and recharge fields, conventional fueled peaking station, and wellhead heat exchanger.

The *second part* is the *transmission/distribution system*, which delivers the geothermal fluid or geothermally heated water to the consumers. The *third part* includes *central pumping stations* and *in-building equipment*.

Geothermal fluids may be pumped to a central pumping station/heat exchanger or heat exchangers in each building. Thermal storage tanks may be used to meet variations in demand.

2. ADVANTAGES OF GEOTHERMAL DISTRICT HEATING

Potential advantages of district heating include:

1. *Reduced fossil fuel consumption*. Geothermal district heating nearly eliminates the consumption of oil, coal, or natural gas traditionally used for space and domestic water heating. It may be advantageous to use conventional fuels for peak demand.
2. *Reduced heating costs*. Through the use of geothermal energy and increased efficiency, district heating systems often can offer thermal energy at lower prices than conventional heating systems.
3. *Improved air quality*. By installing a closed system with injection wells, geothermal district heating systems eliminate noxious gases, greenhouse gases (such as CO_2) and particulates that occur in cities with conventional single-building heating systems.
4. *Reduced fire hazard in buildings*. The fire hazard in buildings is reduced because no combustion occurs within individual buildings.
5. *Cogeneration*. Cities located near high-temperature (>150oC) geothermal fields can jointly produce electric power and hot water for district heating at a greater efficiency than generating electric power alone.

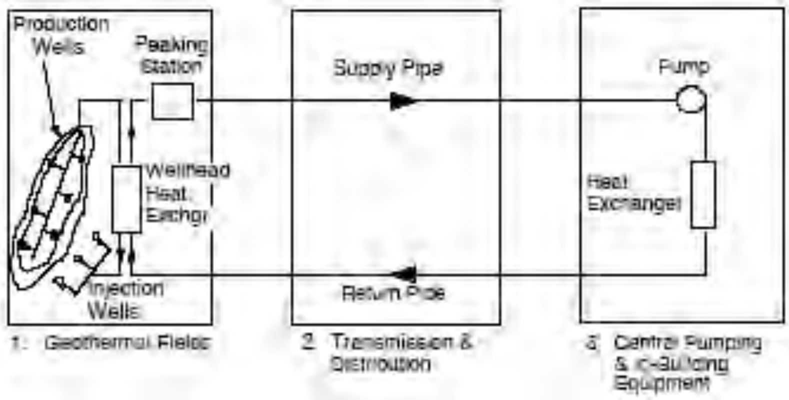

Figure 1. Geothermal district heating system - three major components.

3. EXAMPLES OF DISTRICT HEATING SYSTEMS

Geothermal district heating systems are in operation in at least 12 countries, including: Iceland, France, Poland, Hungary, Turkey, Japan and the U.S. The Warm Springs Avenue project in Boise, Idaho, dating back to 1892 and originally heating more than 400 homes, is the earliest formal project in the U.S. A more in-depth discussion of district heating economics and design can be found in Harrison (1987), Karlsson (1982) and Reisman (1985).

The most famous geothermal district heating project in the world is the Reykjavik municipal heating system (Hitaveita Reykjavikur) started in 1930. Today it serves the entire urban area of 150,000 people. A total of 60 million m3 of geothermal fluid are used annually to supply 35,000 homes with space heating and domestic hot water. The original low-temperature field (Reykir) supplies 89oC water through two 350-mm and one 700-mm diameter pipeline over a 19-km distance. A new field at Nesjavellir, supplies fluid through a 27-km long pipeline that varies between 800 and 900 mm in diameter. It is designed to carry up to 96oC water at a maximum flow of 1,870 l/s. Insulated storage tanks are used to meet peak flows and provide an energy supply in the event of breakdown in the system. A fossil fuel-fired peaking station is used to boost the 80oC home supplied water to 110oC during 15 to 20 of the coldest days of the year. The city is served by a number of pumping stations, distributing fluid through 1180 km of pipelines. The entire system provides 3,000 Gwh per yearwith a peak power demand of 640 MWt (Lund, 1996; Ragnarsson, 1996). Figure 2 is a simplified diagram of the original system without the Nesjavellir project.

At the other end of the geothermal heating spectrum is the mini-district heating system for the Oregon Institute of Technology campus in Klamath Falls, Oregon (Rafferty and Lienau, undated). The 11-building campus has been heated by geothermal hot water since 1964; where, three hot water wells supply all of the heating needs for the 62,000 m2 of floor space. The combined capacity of the well pump is 62 l/s of 89oC water with the average heat utilization rate over 0.53 MWt and the peak at 5.6 Mwt. All are equipped with variable-speed drives to modulate flow to campus needs. In addition to heating, a portion of the campus is also cooled using the geothermal resource. This is accomplished through the use of an absorption chiller. The chiller requires a flow of 38 l/s and produces 541 kW of cooling capacity with 23 l/s of chilled water at 7oC. The hot water distribution system consists of pre-insulated fiberglass piping installed in underground concrete tunnels. Plate heat exchangers have been installed in all buildings to isolate the building systems from exposure to the geothermal fluids. The waste water is delivered to an injection well on the other end of the campus. A simplified diagram of the system is shown in Figure 3.

4. OVERVIEW OF GUIDE PROCEDURES AND LIMITATIONS

This guide to geothermal district heating development is intended to assist in initial evaluation through the following five steps:
Step 1: Analyze Geothermal Heat Production. This step utilizes information on the characteristics of an identified resource to

estimate the heat production from a geothermal fields.
Step 2: Identify District heating Market Areas. This step provides procedures for identifying potential market areas for district heating service. Heating demands in the service area are estimated and several criteria such as the density of thermal loads and distance from production fields are provided as guides in selecting market areas.

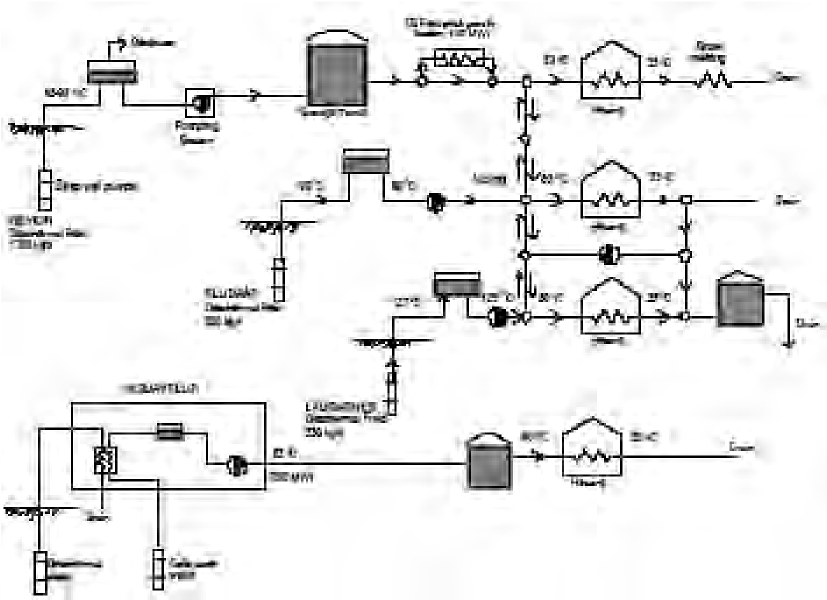

Figure 2. Reykjavik district heating system (prior to the Nesjavellir connection).

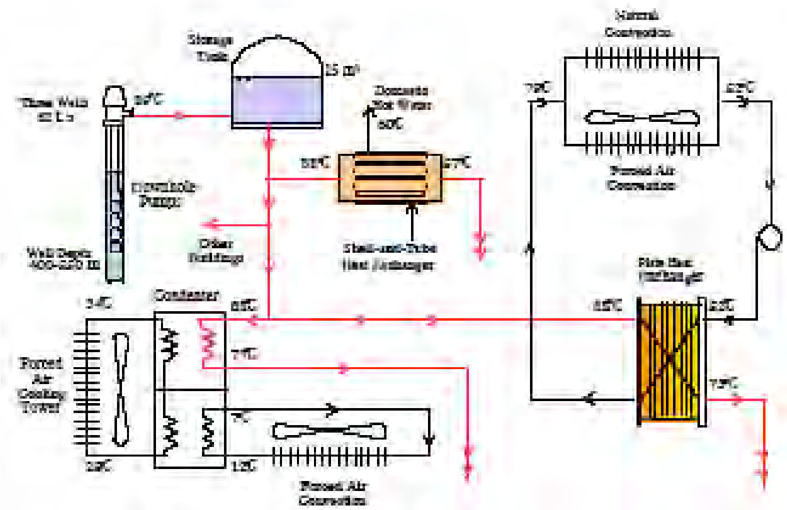

Figure 3. Oregon Institute of Technology heating and cooling system.

Step 3: Preliminary Design of District Network for Selected Zones. This step considers engineering design options available for the geothermal district heating system, which are dependent on resource temperature, quality and depth.
Step 4: Analyze Economic Aspects of District Heating System. This step provides a procedure to estimate capital expenditures, as well as annual operation and maintenance costs. These are then translated into costs per unit of energy for both district heating and conventional systems.
Step 5: Evaluate District Heating Feasibility. This step explains how district heating and conventional costs in Step 3 are compared. Evaluation criteria are suggested to determine whether district heating is appropriate.

A limitation of the guide's analysis is that thermal loads calculated in Step 2 are limited to space heating and domestic water heating. If industrial process loads are known, they can be included. Process loads vary greatly among different industries; however, they definitely improve the load factor for district heating systems.

Space cooling loads were not considered in the guide because construction of a district “cooling” system is usually difficult to justify economically.

District heating is usually economically feasible only in locations with a sufficiently long and cold winter season. It would be difficult to justify a district heating system in a location with less than 2200 heating degree days, Celsius.

The area(s) to be served by a district heating system should have high hourly and annual demands for thermal energy per unit of land area. Typically, an area for which district heating is being considered should be characterized by buildings that have a least several stories and are situated relatively close to each other. A Swedish study (Wahlman, 1978) indicates the thermal load density common to various land uses in Sweden and its suitability for district heating. Although the thermal load densities shown on Table 1 are not universally applicable throughout the world, the subjective ratings for district heating suitability generally are applicable, as they have been checked against USA systems.

Geothermal production fields should be located near the potential district heating service area(s). This condition will reduce both the cost of pipelines and system’s heat losses. Economical transmission distances will vary with temperature of the geothermal resource and size of district heating system. The longest district heating pipeline is 60 km of uninsulated asbestos cement, supplying the Akranes system in Iceland.

STEP 1 : ANALYZE GEOTHERMAL HEAT PRODUCTION

The purpose of Step 1 is to identify geothermal production fields that can be used for the district heating system and estimate the thermal power available from these fields.

Table 1. Desirability of Various Areas for District Heating

Type of Area	Thermal Load Density*		Desirability for
	MW/km^2	10^6Btu/hr Acre	District Heating
Downtown: High Rises	>70	>0.97	Very Favorable
Downtown: Multi-Stored	50-70	0.70-0.97	Favorable
City Core; Commercial Bldgs. and Multi-Family Apartment Bldgs.	20-50	0.28-0.70	Possible
Residential: Two-Family Houses	12-20	0.17-0.28	Questionable
Residential: Single-Family	<12	<0.17	Not Possible*

- However, see Rafferty (1996) for a discussion of the feasibility of heating single-family residences using geothermal district heating.

The cost of transporting heat from production fields to consumers is critical to success of a district heating system. Proximity of the resource to areas of probable use and possible conflict with present land uses must be taken into account. The first step in exploring for the geothermal resource is to define the physical characteristics required for the district heating system; generally, these include temperature, flow rate, and water quality. After a review of the pertinent literature has been completed to estimate potential heat production from identified fields, a decision should be made as to whether or not a given prospect area shows sufficient potential to warrant a detailed site-specific exploration.

Future action would involve various geological, geochemical, and geophysical tools to further define the characteristics of the resource. The application of these tools is beyond the scope of this preliminary analysis. The final verification of a geothermal resource, of course, must be based on drilling.

Task 1 - Determine Production and Recharge Fields Locations and Characteristics

Based on available literature and known surface manifestations, areas near the district heating system have potential as production well sites are identified on a map of the area. Each area should be evaluated as to certain desirable characteristics, which include:

1. Temperature isotherms and depth,
2. Estimated flow rate,
3. Confidence level takes into account probability of drilling success based on estimated temperature and flow information for a typical well,
4. Proximity of district heating system so as to minimize transmission lengths, and
5. Availability of land for development.

The direct use of geothermal waters requires large flows. For example, the Icelandic system requires an average pass through of 1200 l/s of geothermal fluid to heat 16,000 housing units. After the useful heat is extracted from the fluids, surface and subsurface disposal alternatives exist. In some cases, beneficial uses downstream can be considered; however, injecting fluids into the producing reservoir can extend the useful life by mining the heat from the rock.

Task 2 - Prepare Map of Geothermal Production and Injection Field

Production and injection fields are located on a map, as shown in Figure 4, and characteristics listed on Table 2 from which estimates of heat production can be determined.

Task 3 - Estimate Heat Production from the Geothermal Field

The recoverability of energy from a geothermal reservoir ultimately depends on the amount of water that can be produced by wells tapping these reservoirs. To assess the recoverable energy, a development plan that specifies the production period and load factor, the desired flow rate of the wells, and the allowable drawdown needs to be selected. The number of wells that can be placed under this plan and the total production of water will depend on the type of resource and its characteristics, such as transmissivity and storage coefficient.

The flow rate varies with well spacing; as well spacing increases, the flow rate per well also increase until a maximum flow rate is reached. This maximum flow rate corresponds to a spacing at which interference between wells becomes negligible, and it is controlled mainly by the transmissivity of the reservoir (White and Williams, 1975). At a smaller well spacing, well interference causes the flow rate per well to decrease. However, as the well spacing decreases, the number of wells that can be placed in a reservoir increases faster than the rate at which the flow rate per well decreases. Therefore, the total production from the reservoir, that is, the product of the number of wells and their flow rate, also increases with decreasing well spacing.

Data from Table 2 are used for the following sample calculations:

1. Measured or assumed wellhead temperatures and confidence level for Zone 1 are 90oC and 0.75 respectively. The reference (reject) temperature of the geothermal fluid at the heat exchanger is assumed to be 50oC (DT = 40oC),
2. Maximum flow/well of 32 kg/s,
3. Minimum spacing/well of 366 m or six wells/km2, and
4. The geothermal power per well for Zone 1 is then:

qWH / Well = (MWH) (hWH - href)
(confidence level) (Equation 1)
= (32 kg/s) (376.9 - 209.3) kJ/kg (0.75)
= 4.0 MWt
where:
MWH = mass peak flow produced at wellhead
hWH = enthalpy (or heat content) per unit mass of saturated liquid at the wellhead (example = 90oC)
href = enthalpy per unit mass of saturated liquid at the reference temperature (example = 50oC)

The geothermal power from Zone 1 of the production field is then:
= (qWH/Well) (area)(no. wells/unit area)
(Equation 2)
= (4.0 MW/well)(3.3 km2)(6 wells/km2) = 80 MWt

STEP 2 - IDENTIFY DISTRICT HEATING MARKET AREAS

Step 2 identifies geographical areas that can utilize the resources identified in Step 1. In many cases, the most attractive service areas for district heating are dependent on:

1. High-thermal load areas,
2. High-load factor,
3. Close as possible to geothermal production field,
4. New development or redevelopment from the core of the initial service area,
5. Major physical obstacles between production fields and load areas, and
6. Legal, institutional, and environmental issues.

Table 2. Worksheet 1: Geothermal Production Field Characteristics

A	B	C	D	E	F	G	H	I	J
Name Prod. Field	Confid Level	Temp. (°C)	Well Depth (m)	Flow (kg/s Well)	DT (°C)	Thermal Power/ Well MW/Well	Resour-ce Area (km²)	No. Wells/ Area Wells/km²	Wellhead Thermal Power (MW)
Old Fort									
Zone I	0.75	90	1,000	32	40	4.0	3.3	6	80
Zone II	0.50	80	1,000	25	30	1.6	2.0	6	19
Zone III	0.25	70	1,000	16	20	0.34	4.3	6	9
Subtotal									108

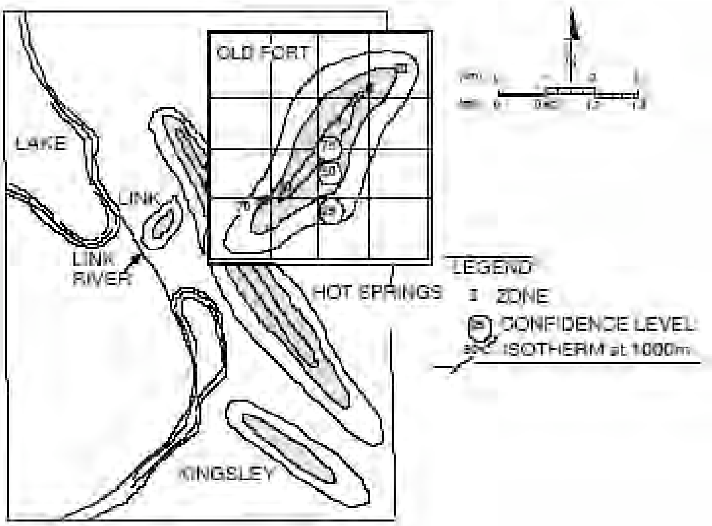

Figure 4. Geothermal production field.

Quantitative estimates of heat load must be made to ensure loads and thermal supplies are adequately matched. Step 2 is an aid in estimating thermal loads and provides assistance in selecting service area boundaries based on the above listed principles. Two major tasks are included in this step: the first is the preparation of a "thermal load map" and accompanying energy use data; the second is the application of this information to "identify potential service areas."

Task 1 - Prepare Thermal Map and Estimate Peak Heating Load (PHL) and Annual Energy use (AEU)

To prepare the thermal map as shown in Figure 5, pumping district boundaries are based on four main criteria: 1) natural topographic features; 2) man-made features; 3) land use, and 4) census tract.

If the heating load data is not available for each building, peak heating load and annual energy use, shown on Table 3, can be estimated. To estimate peak heating load and annual energy use, the floor space of each building type is used to compute peak heating load from space and water heating load factors, Figure 6.

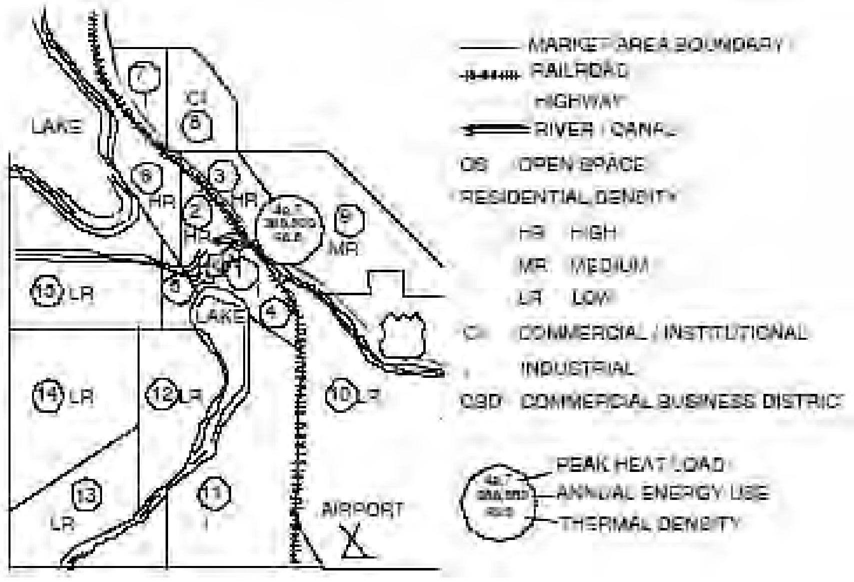

Figure 5. Geothermal city market areas.

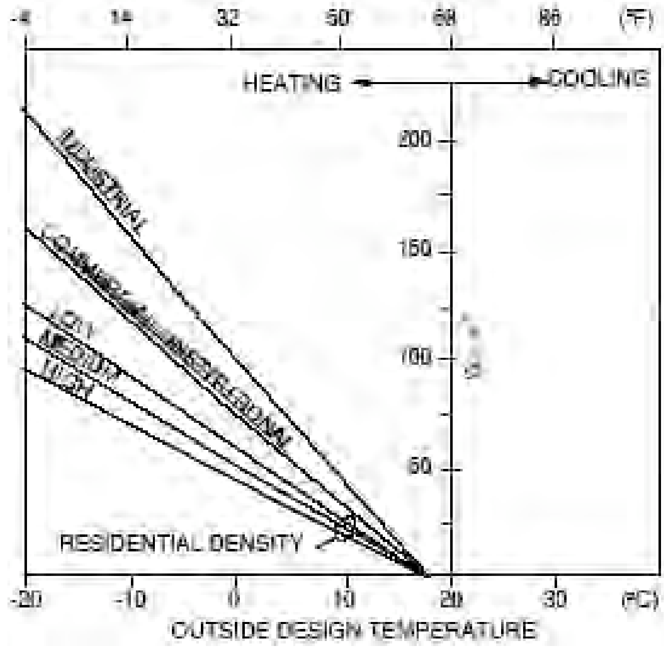

Figure 6. Space and water heating load factor.

Land use categories used include low-density residential (one-story), medium-density residential (four stories or less), high-density residential (more than four stories), comercial/institutional, and industrial. Space and water heating load factors for the land use categories are determined from Figure 6 based on winter design temperature which will be equaled or exceeded 97.5 percent of the total hours from December through January. These heating load factors are typical for the categories of buildings in the USA.

The peak heating load (PHL) for the building type is then:

PHL = (A) (HLF) (Equation 3)
= (3.40 x 105 m2) (132 W/m2)
= 44.9 MW*
where: A = area of floor space
HLF = heating load factor from Figure 6
* PHL is increased to 49.7 MW to compensate for transmission and distribution losses (see Table 3).

The annual energy use (AEU) represents the annual consumption of energy. After estimating the peak heating load, the annual energy use can be calculated by using the interim correction factor (C0) from Figure 6 for heating effect versus degree day.

Table 3. Worksheet 2: District Energy Load Data

Building Type	A Peak Floor Space (m^2)	B Heating Load Factor (HLF) (W/m^2)	C Heating Load (PHL) (MW) A x B	D Annual Energy Use (AEU) (GJ)
Low-Density Residential				
Med-Density Residential				
High-Density Residential				
Commercial/Institutional	3.40×10^5	132	44.0	350,000
Industrial				

	Subtotal Peak	Subtotal Annual
Thermal Density = 98.5 MW/km^2	Heating Load (PHL) = 44.9 MW	Energy Use (AEU) = 350,000 GJ/yr
Load Factor = 0.25	Transmission & Distri-bution losses (11% of PHL) = 4.8 M	Transmission & Distri-bution losses (11% of AEU) = 38,500 GJ/yr
Outside Design Temp = -10^oC	Total Peak Heating Load (PHL) = 49.7 MW	Total Annual Energy Use (AEU) = 388,500 GJ/yr

The annual energy use (AEU) is then:

AEU = (86.4) (PHL) (CD) (HDD)/(18 - WDT) (Equation 4)

= (86.4)(44.9 MW)(0.82) (3080)/(18 + 10)

= 350,000 GJ/yr*

where: PHL = peak heating load (MW/hr)

CD = interim correction factor (example: at -10oC)

HDD = heating degree days (Celsius) from climate data (weather bureau)(example = 3080oC days/yr)

WDT = dry-bulb winter design temperature (oC)

* AEU is increased to 388,500 GJ to compensate for transmission and distribution losses (see Table 3).

Thermal density indicates desirability of areas for district heating and are compared to data in Table 1.

The thermal load density (TLD) for the pumping district (including losses) is then:

TLD = (PHL) / (A) (Equation 5)

= (49.7 MW)/(0.505 km2)

= 98.4 MW/km2

where: PHL = peak heating load

A = land area of pumping district

The load factor indicates the equivalent percentage of the year that the district heating system will be operating at peak heating load or equivalent full load hours. Essentially, the equivalent full-load hours represents the amount of time required for a district system being supplied energy at the peak level rate (PHL) to have the total amount of energy supplied equal that of its annual demand.

The equivalent load hours (ELH) is then:

ELH = (AEU) / (PHL) (Equation 6)

= (388,500 GJ/yr)/[(49.7 MW)(3.60 GJ/MW·hr)]

= 2171 hrs/yr

where: AEU = annual energy use

PHL = peak heating load

The load factor (LF) can be computed by dividing the equivalent load hours by the hours in one year. Typical load factor for district heating systems range from 0.20 to 0.25.

The load factor (LF) is then:

LF = (ELH) / (8760) (Equation 7)

= (2171)/(8760)

= 0.248

where: ELH = equivalent load hours per year

8760 = hours per year

The load factor is used to compute costs of pumping and can be used to determine the annual energy use once the peak heating load is known.

Alternatively, if the annual energy use for a district system was determined from the consumption of fossil fuels, the peak heating load can be determined from the load factor.

The heat load duration curve is prepared from climatic data by plotting the hours per year for a peak year at a given outside temperature versus outside temperature as shown in Figure 8.

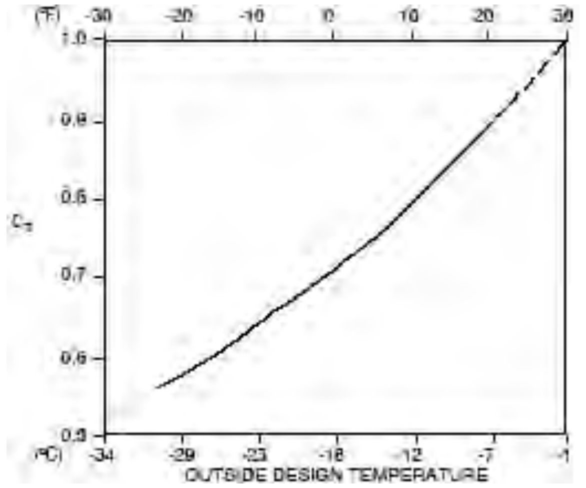

Figure 7. Correction factor for heating effect.

The purpose of the load duration curve is to determine what percentage of the peak heating load could economically be supplied by a peaking boiler boosting the temperature of the geothermal fluids. Since the peak heating load is usually necessary only a few hours per year, the size of installed piping and pumps can be reduced by fossil fueled peaking. For example, designing the geothermal system to supply 50 percent of the peak heating demand (-1oC winter design temperature), the boiler would supply 23,000 GJ of the 388,500 GJ required by the district, or 6.0 percent of the annual energy demand. This is represented by the shaded area shown on Figure 8. The boiler would be used for peaking purposes only 144 hours or 6 days per year.

Task 2 - Identify High-Potential District Heating Areas from Energy Use Data

Several issues to be considered when identifying market areas are summarized below:

1. Area to be serviced should have high-energy load densities,
2. Connected loads should have a high-load

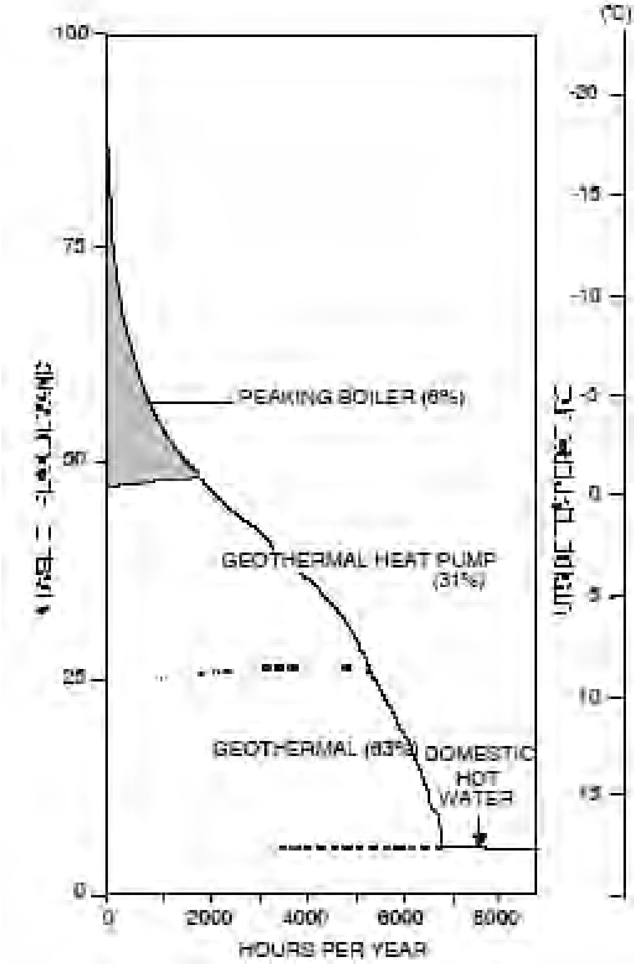

Figure 8. Geothermal city heat load duration curve.

factor, thereby promoting full use of equipment,
3. Market areas should be as close as possible to thermal sources, while simultaneously utilizing all, or nearly all, the available thermal capacity,
4. Areas of new development or redevelopment often are necessary to form the core of the initial service area,
5. Major physical obstacles between heat sources and load areas should be avoided, and
6. Other community objectives should be considered in selecting areas to be served by district heating.

Because the Central Business District (CBD) is usually the largest collection of contiguous energy-intensive zones, it is the most obvious area to be considered for district heating service. However, a sufficiently large, intensive load, other than the CBD, could be located near a thermal source. This suggests two general approaches to identifying potential market areas.

The first approach attempts to identify a separate, sufficiently large and intensive load near each thermal source. The second approach starts with the CBD and incrementally adds adjoining zones. Actual selection of market areas might be made through consideration of both approaches (i.e., the CBD may be served, as well as a few energy-intensive loads located near the geothermal production fields).

The following is a discussion of how the energy load data generated in Table 3 can be used in each of these two approaches.

First Approach. For each geothermal production field, identify the closet set of contiguous pumping districts with adequate thermal demand. Using the map, for each geothermal field identified in Step 1, Figure 2, try to identify a set of contiguous pumping districts that: 1) are as close as possible to the geothermal production field, and 2) provide a peak heating load (PHL) approximately equal to (within 10%) the available supply capacity of the geothermal field identified in Step 1, Task 2.

For a large city, several alternative market areas may be identified for each geothermal production field. If pumping districts with a sufficiently large load cannot be located within 24 km of any geothermal production field, that field will be eliminated from future consideration.

Table 4 shows a comparison between peak heating load for each market area and thermal power from the geothermal field. In this case, a surplus of thermal power existed; so, additional market areas need to be considered.

Table 4. Worksheet 3: Market Area Identification

A	B	C	D	E
Pumping District Name	Thermal Density (MW/km^2)	Peak Heating Load (MW)	Thermal Power of Selected Geothermal Fields	Surplus (+) or Deficit (-) of Thermal Power (Col. E = Col. D - Col. C) (MW)
Old Fort	98.5	49.7	108	+58.3

Second Approach. Allocate available geothermal field heat production to Central Business District (CBD)--Centered Service Area. Usually a city's Central Business District (CBD) represents the largest collection of contiguous energy-intensive areas in the city. Therefore, the CBD always should be investigated for its suitability for district heating. To examine this possibility, the largest collection of contiguous energy-intensive areas including and surrounding the CBD should be delineated, and the total thermal lead of the area determined.

As in the first approach, Table 4 was used to summarize each alternative set of geothermal production fields to serve the CBD and its surrounding areas by using data from Tables 2 and 3.

STEP 3 - PRELIMINARY DESIGN OF DISTRICT HEATING NETWORKS FOR SELECTED PUMPING DISTRICTS (MARKET AREAS)

The purpose of this step is to consider general designs for geothermal district heating systems. Design of a district heating system is site-specific, depending on resource temperature, quality and depth. Retrofit versus new construction of end-use equipment in buildings is also a controlling factor in the design. Design of a distribution network for a selected pumping district involves selection and sizing of: 1) wellhead and circulating pumps, 2) materials for transport of geothermal fluids, 3) material for local distribution network, 4) single-building versus wellhead central heat exchangers, 5) controls, 6) end-use equipment in buildings, and 7) possible augmentation with heat pumps and/or peaking boilers.

Guidelines and options for the selection and sizing of components necessary for the district heating system are discussed in "Equipment Used in Direct Heat Projects" (Ryan, 1981) and U.S. experience is discussed in Rafferty (1989).

The options for the design of a district heating system are: 1) single-pipe flow through with in-building heat exchangers and disposal of geothermal fluid at the end-use site or returned to the production field area for recharge, 2) double-pipe circulation system with a central wellhead heat exchanger, and 3) hybrid of option 2 with augmentation by heat pump and/or peaking boiler.

These three options are schematically illustrated in Figure 9.

Heat pumps and fossil fueled peaking stations lend themselves well to geothermal district heating concepts.

A hybrid system may be desirable in the case of a high-cost resource (deep wells) development and/or low-temperature resources (<60oC). The plan would be to construct the plant so the wells could be fully utilized, thus optimizing expensive parts of the development, drilling wells, and installing piping networks. In this case, the geothermal wellhead heat exchanger would represent only 25 percent of the maximum capacity; however, it will supply over half the annual energy use and be fully utilized. When heat requirements increase in the chilly spring and autumn months, the heat pump will further cool the geothermal fluid coming from the heat exchanger. Thus, it will be only necessary to couple in a boiler during the extreme cold winter periods in order to yield the maximum heating load performance.

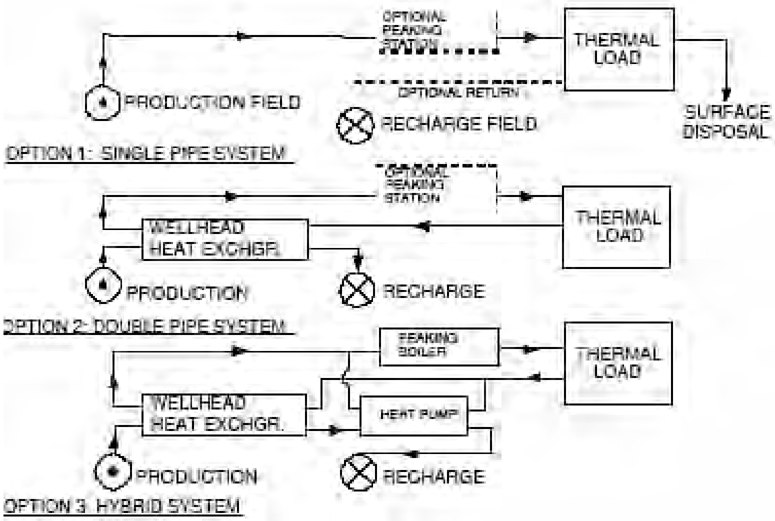

Figure 9. District heating design options.

This temperature boosting of the heated water, possible in all options, will enable a reduction in the size of installed piping and pumps, thus reducing capital expenditures.

The use of heat pumps should, of course, be adapted to the unique nature of each project (i.e., load factor, resource temperature, quality and depth). These systems are sensitive to economic conditions relating to the capital expenditures of the geothermal systems.

The heat load duration curve shown on Figure 8, indicates that if the geothermal wellhead heat exchanger is designed to supply about 25 percent of the peak demand (63 percent of Annual Energy Use and geothermal plus heat pump supplies almost 50 percent of peak demand (94 percent of Annual Energy Use), then the peaking boiler supplies only 6 percent of the annual energy used. It should be noted, the heat pump will require about 10 percent of the 31 percent (about 1/3) of the annual energy supplied from either an electric or diesel source.

The option selected for a site-specific application is highly sensitive, in addition to economic consideration, to resource temperature and quality. Shallow, intermediate temperature (>90oC) resources with high-quality water (< 300 ppm total dissolved solids and <1 ppm non-condensible gas) could consider option 1. However, if the end-use equipment primarily consists of copper alloy material, option 2 (or option 1 with in-building heat exchangers) should be considered since small traces of hydrogen sulfide and ammonia can be corrosive to copper alloy materials.

STEP 4 - ANALYZE ECONOMIC ASPECTS OF GEOTHERMAL DISTRICT HEATING

Step 4 provides "Rules of Thumb" method of determining cost data for comparing geothermal district heating and conventional fossil fuel alternatives.

Previously conducted studies of district heating provide cost data that can be used in the "first-cut" feasibility analysis. Cost data for any city is highly dependent on that city's unique circumstance and data that are specifically derived for local applications should be substituted for guide values when possible. However, one study that applied a consistent evaluation methodology was "Economic and Technical Analysis of Retrofit to Cogenerating District Energy Systems: North Central Cities" (Santini, et al., 1978) by Argonne National Laboratory is used for estimating heating system, exclusive of the geothermal production field development.

The major feasibility test of any energy system is how economically it can compete with its alternatives. One way to evaluate the economics of district heating is to compare to cost per GJ of district heating produced geothermal energy with the cost per GJ of heating produced using fossil fuels: in Step 4, these unit costs are computed by estimating: 1) district heating capital costs, and 2) annual expenses (See Table 7).

Task 1 - Estimate District Heating Capital Costs

Capital costs are estimated for geothermal production field development, peaking station, transmission system, local distribution system, and in-building retrofit equipment.

Estimates of the geothermal production field costs include costs incurred in exploring and developing the field (see Table 5). The number of production wells required to supply the selected market area are determined by dividing the total peak heating load from Table 3 by the thermal power per well, Table 2, Column G. The number of injection wells is 50 percent of the number of production wells as shown on Table 5. Drilling costs are site-specific and the cost/m depends on the depth and temperature which determines the type of drilling rig utilized. Generally, wells up to 1.0 km of depth and less than 120oC can be drilled with domestic water well drilling rigs. Greater depth and temperature wells require oil-well type drilling rigs. Since drilling costs vary greatly depending on local conditions, they should be obtained from local drillers.

Peaking station capital (CPS) costs for an oil-fired hot water boiler can be estimated from Equation 8. CPS = (capital cost/MW)(number of MW) (Equation 8)

Local distribution costs include the pipes and accompanying equipment needed to convey hot water from transmission pipes to street hookups of individual buildings. Because the distribution piping must be sized to service the maximum energy demands, the cost of the distribution system is dependent on the peak heating load, size of the market area, and a factor that takes into account thermal density and type of drilling. The resulting equation from the Argonne Study (Pferdehirt and Kron, 1980), which is based on case studies, is then (updated for 1997):

CDS = (28.43 A + 0.007665 PHL) (f) (Equation 9)

where: CDS = cost of local distribution system, in US$

A = size of market area, in km2

PHL = peak heating load, in MW

f = adjustment factor ranging from 0.70 to 2.00

The adjustment factor is determined according to the following assumptions:

f = 2.0 Service area highly urbanized and steel pipe is used,

f = 1.50 Densely developed city core areas and prefabricated plastic pipe is used,

f = 1.00 Suggested for most applications where prefabricated plastic pipe reduces material and labor costs, and

f = 0.70 New developments where piping can often be laid to prevent some extra urban related expense (e.g., street removal and replacement, and other utility systems).

Transmissions costs depend mainly on: 1) thermal demand density within the market area, and 2) distance between market perimeter or central pumping station and geothermal production field.

An alternative is to express transmission costs as a proportion of local distribution costs.

Equation 10 is a first-cut estimate of installed thermal transmission system.

CTS = (x) (CDS) (Equation 10)

where: CTS = cost of transmission system, in $106

CDS = cost of local distribution system

x = 1.20 - production fields 24 km from market area

= 1.00 - usual value for production fields 16 km from market area

= 0.80 - production fields less than 8 km from market areas

To estimate end-use equipment retrofit costs, the cost factors in Table 6 should be multiplied by the total floor space of the appropriate building type.

Because the average age of structures, building materials and building operating characteristics vary considerably among cities, values from Table 6, which are typical for U.S. buildings in categories listed, should only be used when site-specific data are not available.

Task 2 - Estimate Annual Expenses

The following procedures provide guidance for estimating the annual expense of operating and maintaining the district heating system.

Production well maintenance costs include changing packing, replace bearings at three-year intervals, and overhauling variable-speed drive at fiveyear intervals.

Electrical operating costs are determined from the load factor, rated load (60%) and efficiency (72%). The annual geothermal field O & M costs (AGFC) in millions of dollars is then:

AGFC = [(power/pump) (rated load/efficiency) (Equation 11) (8760 h/yr) (load factor) (cost/kWh) (year) + maintenance costs/pump] (no. wells)

Estimate the annual peaking station fuel cost (APSC) by using the load duration curve (Figure 6) and a 70 percent boiler efficiency, the annual fuel cost is then:

APSC = (AEU) (PF) (1.43) ($/GJ) (Equation 12)

where: APSC = annual peaking station costs

AEU = annual energy use, in GJ

PF = percentage of annual energy use supplied by boiler

1.43 = accounts for boiler efficiency

$/GJ = unit cost of fuel oil (No. 2)

Experience in Denmark and Sweden indicates that O & M costs for transmission and distribution per year are approximately equal to 1 percent of the initial capital costs for these systems (Wahlman, 1978). The annual transmission and distribution cost in million dollars per year is then:

ATDC = (CDS + CTS) (0.01) (Equation 13)

where:

ATDC = annual transmission and distribution O & M costs

CDS = cost of distribution system

CTS = cost of transmission system

Task 3 - Compute Cost Per Unit of Heat from District Heating System

Capital costs are expressed in dollars; whereas, annual expenses are expressed in dollars per year. To convert capital costs into a dollar-per-year figure, the capital recovery factor (CRF) must be specified. The capital recovery factor can be computed using Equation 14.

CRF' *i*(1%*i*)*n*

(1%*i*)*n*&1 (Equation 14)

where: CRF = capital cost recovery factor

i = interest rate

n = assumed life of equipment, in years. A generally accepted value for life of district heating equipment is 20 years.

The capital recovery factor should be multiplied by the total capital expenditure to produce the annual equivalent costs. This cost is added to the annual expense to derive total annual equivalent costs, and thus, the first year costs per unit of energy (Table 7, line 14) for the district heating system.

Task 4 - Compute Costs Per Unit of Heat from Conventional Systems

The cost/GJ of heating with conventional fuels and equipment must be determined to evaluate the relative attractiveness of district heating. The cost that the consumer pays for each unit of end-use heat will depend on the price of fuel used, the heat content of the fuel, and the efficiency of the heating equipment employed. Average values of heat content and equipment efficiencies are listed in Table 8.

Table 5. Worksheet 4: Geothermal Production Field Development Schedule and Cost

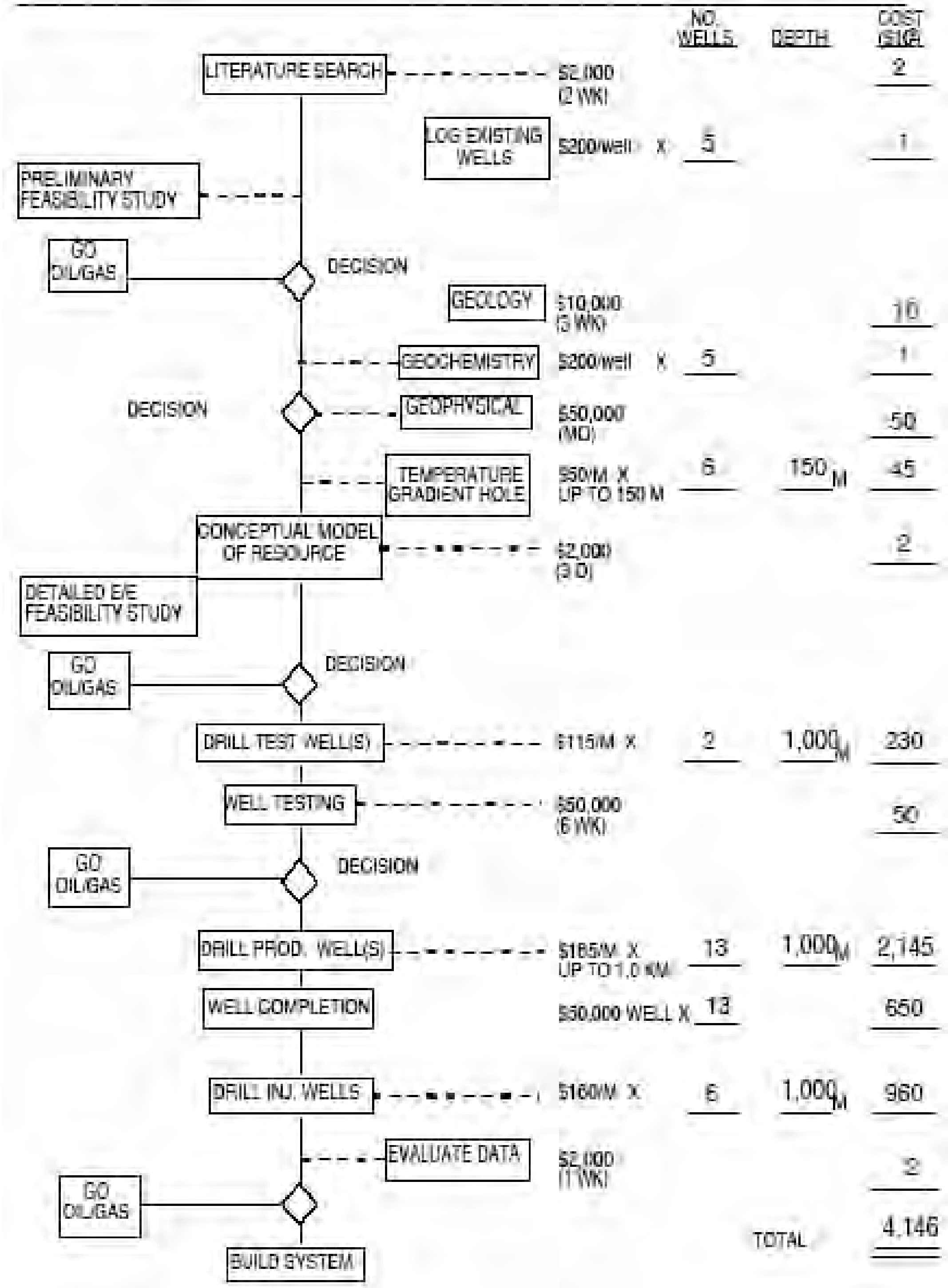

Table 6. End-Use Retrofit Unit Costs

Building Type	Retrofit Cost (USA, 1997) $/m²
Medium Density Residential	13.00
High Density Residential	7.00
Commercial/Industrial/Institutional (Small Buildings)	16.50
Commercial/Industrial/Institutional (Large Buildings)	9.00

Table 7. Worksheet 5: Cost Estimation for District Heating System

Market Area Characteristics

Name of Market Area and Thermal Source(s) CBD 1 / Old Fort
Land Area a) 0.505 km^2
Sum of Annual Energy Uses b) 388,500 GJ
Sum of Total Peak Hourly Energy Loads c) 49.7 MW

Cost Data

	Cost Component		Amount (Millions of Dollars)
1.	a. Geothermal Field Development	1)	4.146
	b. Peaking Station	2)	0.103
	c. Local Distribution System	3)	7.369
	d. Transmission System	4)	2.948
	e. End-Use Equipment Retrofit	5)	2.791
	Total Items 1 through 5	6)	17.357
2.	Annual Expenses		
	a. Geothermal Production Field Operation and Maintenance	7)	0.063
	b. Peaking Plant Fuel	8)	0.214
	c. Transmission and Distribution Operation and Maintenance	9)	0.103
	Total Items 7 through 9	10)	0.380

Unit Cost Computations

11) Capital Recovery Factor 0.1175 (@ 10% for 20 years)
12) Annual Equivalent Capital Costs = (6) + (11) = $2.039
13) Total Annual Costs = (10) + (12) = $ 2.419
14) First-Year Cost Per Unit of Energy in $/GJ $6.23/GJ

Table 8. Average Values of Fuel Heat Rates and Heating Equipment Efficiencies

Heating	Conversion	Fuel Heat Content	Equipment Efficiency
Fuel Oil (No. 2)	Furnace or Boiler	38,971 GJ/L	0.67
Fuel Oil (No. 6)	Furnace or Boiler	41,755 GJ/L	0.67
Natural Gas	Furnace or Boiler	$3{,}728 \times 10^{-2}$ GJ/m^3	0.67
Electric	Resistance Heaters	3,600 GJ/kWh	1.0
Electric	Ground-Source Heat Pump	3,600 GJ/kWh	2.4 - 3.5[a]

a. Heating Coefficient of Performance (COP)

Equation 15 can be used to estimate the cost of heating from various systems.

Cost/GJ = (C) / (H) (E) (Equation 15)

where: C = unit cost of fuel, cost of fuel oil in dollars per liter, cost of natural gas in dollars per m3, and cost of electricity in dollars per kWh
H = heat content of fuel
E = efficiency of conversion equipment

Task 5 - Compute the Average Annual Cost Per Unit of Energy

Since annual costs will inflate at some rate, i - the average annual cost per unit of energy (AAC/GJ) over a period of n years, is then:

AAC/GJ ' FYC [(1%*i*)*n*&1]/*i*
n (Equation 16)

where: AAC/GJ = average annual cost per GJ
FYC = cost of O & M district heating per GJ or cost of fuel per GJ or cost of fuel per GJ in the first year
i = inflation rate
n = life of project in years, usually 20 years

Table 9 gives a summary of conventional versus district heating costs per unit of energy for first-year and twenty-year average annual.

STEP 5 - EVALUATE DISTRICT HEATING FEASIBILITY

Step 5 provides a method of evaluating the comparative costs of district heating and conventional heating to determine the economic feasibility of district heating. Non-economic considerations also are introduced. In Step 4, unit costs were computed for each district heating market area identified in Step 2, as well as for conventional heating systems. Comparison of these unit costs indicates the economic attractiveness of district heating to the retrofit market.

Therefore, heating systems that are economically attractive to the retrofit market will look even better for new development.

Table 9. Worksheet 6: Unit Cost of Conventional Sources vs. District Heating
Name of Market Area and Geothermal Field

A	B	C	D	E	F
Fuel Type Used for Space Heating	Fuel Cost First Yr. ($/GJ)	Fuel Cost 20 Yr. Avg. ($/GJ)	DH Cost First Yr. ($/GJ)	DH Cost 20 Yr. Avg. ($/GJ)	Break Even (Yrs)
Natural Gas	$5.38	$13.76	$6.23	$8.07	1.3
Electric Resistance					
Electric Heat Pump					
Oil (No. 2)					
Oil (No. 6)					

Task 1 - Compare Conventional and District Heating Unit Costs

If columns B and D of Table 9 show that district heating first-year unit costs are less than the costs of conventional systems, serious consideration should be given to a more detailed feasibility study. Such a study could further examine technical considerations, such as the engineering feasibility of system design, in addition to refining the cost estimates. If the comparative heating costs for several district heating market areas indicate that each is economically attractive, each alternative should receive further analysis. Alternatives with the lowest costs should receive the most attention.

Task 2 - Consider District Heating System with First-Year Costs Higher than Conventional Systems

Even if district heating first-year costs are higher than those of a conventional system, a life-cycle cost analysis might still indicate economic feasibility of a district heating system. The 20-year annual average unit cost gives a rough comparison of the effect of fuel escalation and district heating system costs. District heating unit costs are made up largely of capital charges which, after the system is built, do not escalate. Therefore, if the majority of the energy (94%) for the district heating system is supplied by geothermal and the annual cost of conventional fuel for the peaking station is only 6 percent of the
total annual cost, district heating unit costs will escalate at a much lower rate than conventional fuels. To compute the approximate number of years for the cost per unit of energy for conventional fuel to equal (break even) that of district heating, use Table 9, columns B through E, and Equation 17.

Years to Break even = 10(D-B)/(C-B-E+D) (Equation 17)

Therefore, if first-year district heating unit costs are close to breaking even (< 5 year or within 30%) of conventional heating unit costs, a further analysis of district heating might still be warranted, as shown in Table 9, column F. To implement a system in which first-year costs are higher, but life-cycle costs are lower than conventional alternatives, subsides from other sources or from later user fees would probably be required to make early-year customer fees competitive.

Task 3 - Consider Future Action

The following action could be taken given the information provided by the analysis guide:

1. Discontinue Study. The analysis guide

steps may indicate that geothermal district heating is not an economically or socially justifiable conservation method for the study area.

2. Enlist Private or Government Support. Potential users could be approached to determine if they would endorse a detailed analysis of a district heating system. Because of the large investment required for engineering feasibility study and subsequent implementation, a district heating system requires the development of a broad base of support within the community.

3. Build an Element into the Comprehensive Plan. The local comprehensive plan, energy plan, or other documents can influence future civic action. They can help clarify a program, publicize it, and encourage public participation. If district heating proves to be beneficial from a conservation standpoint, it may be wise to begin building a "district heating advisory committee" to verify the system's public acceptability.

4. Perform an Engineering Feasibility Study. If the results of this analysis guide for a district heating system is not more than marginally more expensive than a conventional system, the next step would be to confer with in-house or consultant mechanical engineers to examine system feasibility in greater detail. This would involve a conceptual design of the system, including items such as geothermal exploration (Table 6—proceed through first three decision points) transmission/distribution pipe sizing and routing, specific equipment needed for central plants, and general inbuilding systems. Cost estimates can then be improved, based on this more detailed description of system components. Other issues to be examined in an engineering feasibility study include the following:

a. Drill test wells and perform reservoir engineering,

b. Detailed analysis of thermal loads,

c. Survey of types of heating systems in existing buildings,

d. Coordination between system load growth and capacity construction,

e. Establishment of peaking station thermal supply temperature,

f. Examine the possibility of serving other loads such as airconditioning and industrial process loads, and

g. Examine legal, institutional, and environmental barriers to system implementation.

5. Hire an Engineer and Develop Designs. If the system has excellent economics, utility support, reasonable political support, and if the study team is well funded, a possible action would be to hire a mechanical engineering firm to transform the basic work from this study into engineering drawings, equipment lists, and detailed cost estimates. This engineering work would begin with an analysis similar to the one in Item 4, but would go considerably further and specify detailed equipment types.

Final drafting of the construction drawings, an expensive and potentially time-consuming task, would not be done until most institutional and financing arrangements have been finalized.

Finally, in pursuing any of the preceding steps toward further assessment and possible implementation of district heating, planners should be careful to intertwine increasingly detailed feasibility studies with correspondingly increasing commitments from major decision-makers. These decision-makers must develop a sense of "ownership" over system plans if implementation is to become a reality. Technical staffs of appropriate governmental agencies, the local electric utility, and potential large, industrial customers should be involved significantly in the technical analyses.

Executives of these agencies and corporations must be kept informed of study results and asked to express their approval through public endorsements of study results, allocations of funds and/or personnel for further study (if necessary), and eventually the financial commitments necessary to construct and operate the district heating system.

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