CHAPTER 5

ECONOMICS OF DIRECT-USE DEVELOPMENT

Work Group

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CONTENTS

(Chapter 5, Appendix B, continued)

FIGURES

TABLES

APPENDIX B TABLES

APPENDIX B GRAPHS

INTRODUCTION

This chapter addresses itself to the economic evaluation of direct-use geothermal energy for space heating and for those businesses and industries that are known to be profitable and use conventional forms of energy. In this context, the economic feasibility of direct-use geothermal energy is a matter of determining the reduced costs of this alternative energy system as compared to the capital investment required for the system.

There are several elements which must be considered when determining the feasibility of direct-use geothermal energy:

1. The geologic parameters of the resource.

2. The engineering criteria or the technical viability of the project.

3. The economics of the venture, i.e., will the annual savings provide sufficient return to the investor to justify the capital expenditure?

Many knowledgeable entrepreneurs typically give careful attention to geologic and engineering detail, but fail to give proper consideration to the economic analysis of their project.

Economic evaluation or cost analysis comprises a myriad of variables but can be treated in a relatively simple manner. The analysis should constitute a carefully planned, dispassionate review of all available information to determine the probable value of the proposal. Primary consideration should be given to the cost of finding, developing and utilizing the geothermal resource. Often the preliminary estimates are unreliable due to a lack of historically accurate data. Nevertheless, this cost analysis should be made, since the objective is whether or not the project is worthy of consideration. At its very worst, such an evaluation is better than intuition.

Although there are many approaches to economic evaluation, a rather simple step-by-step procedure is as follows:[1]

1. Collect historical cost of conventional fuel-use data. If there are no historical data available, estimate the heat load and current cost of conventional fuel.

2. Determine inflation rates for energy and operation and maintenance costs.

3. Estimate costs of geothermal equipment and installation.

4. Estimate annual operation and maintenance costs of both conventional and geothermal operation.

5. Consider effect of investment tax credit, depreciation and depletion allowance where applicable.

This chapter presents a hypothetical example of direct-use geothermal energy, modeled closely after an actual case. This example will serve to illustrate the parameters of a comprehensive economic evaluation. The discussion begins with a simple evaluation, progresses in complexity through extensive cost estimates and concludes with a more comprehensive, after-tax evaluation. The cost estimates used in this example are for Klamath Falls, Oregon, in terms of 1979 dollars.

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[1] Assumes that the resource has been discovered.

COLLECTION OF HISTORICAL FUEL-USE DATA

For this hypothetical economic analysis, a city located near a known geothermal resource area (KGRA) wishes to develop a geothermal district-heating system for a ten-block business district. The first step would be to obtain a history of fuel consumption and costs over the previous three to five years. This data collection should include monthly fuel bills, type of fuel used, amount of consumption in Btu's, kilowatt-hours, therms or gallons, etc., and type of existing heating system in each building scheduled to use geothermal.

For this study, let us assume that the entire district uses natural gas at 85% efficiency with an annual heat load of 6.0 x 10^{10} Btu's (6.3 x 10^{10} kJ) and a current cost of $0.35 per therm (1 therm = 10^5 Btu's; $0.33 per 10^5 kJ). Therefore, at 85% efficiency, annual gas consumption for this district is approximately 7.06 x 10^5 therms. At the current rate of $0.35 per therm ($0.33 per 10^5 kJ) for natural gas, the annual cost of heating this district is $247,100. The city plans to finance the geothermal project with an 8% municipal bond maturing in 20 years. Based on current costs, a 20-year life and an 8% cost of capital, we can now estimate the amount of capital the city can afford to invest in order to avoid these annual cash flows of $247,100. For this estimate, we will use the same formula as that used to calculate the pay-off of a loan, given the amount and number of payments remaining: $247,100 per year for 20 years.

Formula: $$PV = a\frac{(1 + i)^n - 1}{i(1 + i)^n}$$

Where PV = present value
a = annual payment
i = interest rate per year
n = number of years of payments

Therefore: $$PV = \$247,100\ \frac{(1 + .08)^{20} - 1}{.08\ (1 + .08)^{20}}$$

$$PV = \$2,426,064$$

This figure represents the total amount of capital investment that could be made today to avoid a series of annual expenses of $247,100 over a 20-year period. Of course, the annual operation and maintenance costs of the geothermal system have not yet been taken into account. Suppose that annual operation and maintenance costs were estimated to be $10,000 per year. Then the annual savings would be $247,100 - $10,000 or $237,100, resulting in PV = $2,327,883, which is the maximum capital investment that could be spent today for the geothermal system.

This cursory analysis could very well indicate that the project is not economically feasible, and a more detailed study, using inflation rates of conventional energy, is required.

DETERMINATION OF INFLATION RATES

In order to reasonably project inflation rates, it is necessary to review the historical data regarding conventional fuel consumption and costs. Our data show that the city was paying $0.175 per therm ($0.166 per 10^5 kJ) for natural gas in 1976 and $0.35 per therm ($0.33 per 10^5 kJ) in 1979. Therefore, we need to consider this rapid escalation of natural gas prices. Using the single-payment compound-amount factor, we can identify $0.175 as present value, $0.35 as a future value and solve for the rate of inflation as follows:

Formula: $FV = PV (1 + i)^n$

Where FV = present rate
PV = past rate
i = inflation rate per year
n = number of years between rate change

Therefore: $.35 = 175 (1 + i)^3$

$$\frac{.35}{.175} = (1 + i)^3$$

$$2 = (1 + i)^3$$

$$\sqrt[3]{2} = 1 + i$$

$$1.2599 = 1 + i$$

$$i = 1.2599 - 1$$
i = .2599 or approx 26% inflation/yr

A word of caution: It would be dangerous to assume that this rate of inflation, based on a three-year study, would continue over the next 20 years. Exaggerated inflation rates will cause projects to appear economically feasible at one date, but the same project might be uneconomical if rates of inflation were lower. Therefore, it is better to use conservative inflation rates in determining the economic feasibility of a project. If actual fossil-fuel inflation rates prove to be higher than those forecast, the geothermal project will have an even larger advantage economically. The following conservative inflation rates for conventional fuels were obtained from the Oregon Department of Energy:

1. Natural gas - 5.2% above the economic inflation rate through 1986;
   1.5% above the economic inflation rate thereafter.

2. Electric power - 2.5% above the economic inflation rate through 1986;
   1.58% above the economic inflation rate thereafter.

The economic inflation rate chosen for this case study is 7% per annum. Therefore, inflation rates for natural gas would be 12.2%, changing to 8.5% in 1987. With this rate of inflation, the 20-year cash flow of natural gas costs would appear as follows in Table 1:

TABLE 1

20-YEAR CASH FLOW OF NATURAL GAS COSTS OF THE KLAMATH FALLS PROJECT

Year	NATURAL GAS Annual Cost $ 247,100.00	PRESENT WORTH (For an 8% cost of capital) 8%
1	277,246.20	256,709.44
2	311,070.24	266,692.59
3	349,020.81	277,063.97
4	391,601.34	287,838.68
5	439,376.71	299,032.40
6	492,980.67	310,661.44
7	553,124.31	322,742.72

(continued on next page)

(Table 1, continued)

Year	Annual Cost $ 247,100.00	PRESENT WORTH (For an 8% cost of capital) 8%
8	600,139.87	324,236.90
9	651,151.76	325,738.00
10	706,499.66	327,246.04
11	766,552.13	328,761.07
12	831,709.06	330,283.11
13	902,404.34	331,812.20
14	979.108.70	333,348.37
15	1,062,332.94	334,891.65
16	1,152,631.24	336,442.07
17	1,250,604.90	337,999.67
18	1,356,906.32	339,564.49
19	1,472,243.35	341,136.55
20	1,597,384.04	342,715.88
Total:	16,144,088.59	6,354,917.24

Accordingly, the city could spend $6,354,917 as compared to the $2,426,064 before considering inflation. Therefore, a project that may have appeared uneconomical initially may be feasible after considering the rapidly rising costs of conventional energy.

ESTIMATION OF COSTS OF GEOTHERMAL EQUIPMENT AND INSTALLATION

At this point, the costs of development of the geothermal resource and the distribution system should be considered. The design of the system and cost estimates should be obtained from a geothermal engineering-consulting firm. Such a firm obtained the following data and completed the feasibility study in the hypothetical model. The system design included: production wells, a primary (main-supply) pipeline, a centralized heat-exchanger system, a secondary (distribution system) pipeline, an injection well and a primary and secondary pumping system. A diagram of the system is shown in Figure 1.

To determine the size of transmission pipelines and the amount of flow required, i.e., the number of wells needed, the data for fuel consumption should be reviewed, paying particular attention to the coldest months of the year, to determine the peak load. This peak should be verified in the engineering design of the system by considering total volume (cubic feet or meters) to be heated, type of buildings, insulation, etc., the minimum outside-design temperature versus the desired inside temperature and the amount of energy that can be extracted from the geothermal resource. Heating systems are normally over-designed by 25 percent. The method of estimating peak load appears in Chapter 4.

Using this approach, the peak load for our ten-block model is estimated to be 27.8×10^6 Btu's per hour (29.3×10^6 kJ/hr = 8.14 MWt). With an assumed well temperature of 200°F (93°C) based on geologic forecasts and tests of existing wells in the area, the heating system will be designed to extract 40°F (22°C; ΔT) from the water pumped from the resource. This would require 1390 gallons per minute (87.7 l/s) flow, calculated as follows:

$$\frac{\text{peak load}}{500\ (\Delta T)} = \text{flow rate} \qquad \frac{(\text{kJ/hr})}{15{,}200\ (\Delta T\ ^\circ C)} = \text{l/s}$$

where 500 is a constant — where 15,200 is a constant

$$\text{therefore: } \frac{27.8 \times 10^6}{500\ (40)} = 1390 \text{ gpm} \qquad \text{therefore: } \frac{29.3 \times 10^6}{15{,}200 \times 22^\circ C} = 87.7 \text{ l/s}$$

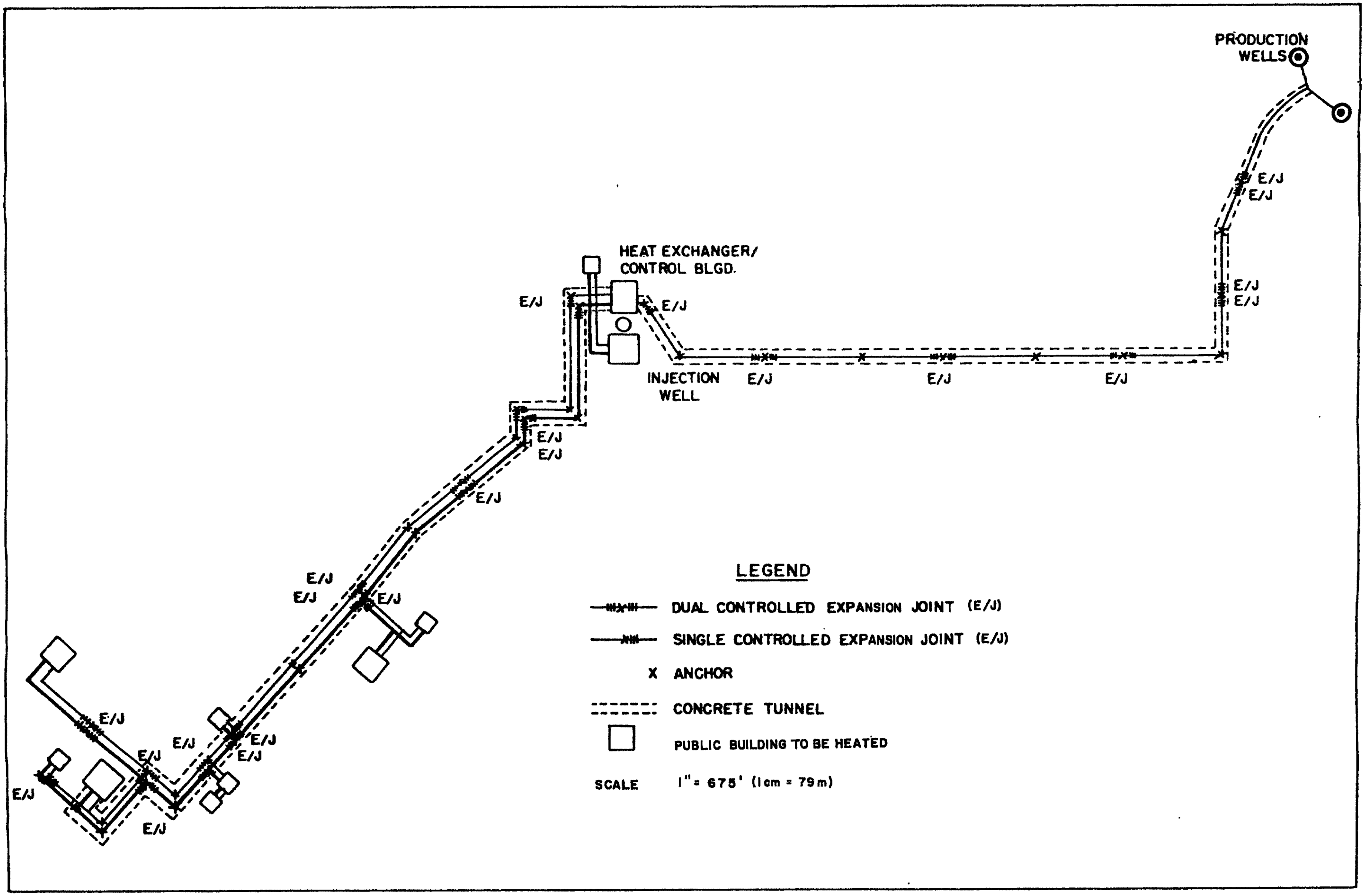

FIGURE 1. Diagram of the Klamath Falls hypothetical city heating system.

To satisfy the peak load, three production wells, each delivering up to 500 gallons per minute (31.5 l/s), would be required. Water would be delivered to the heat-exchange building by an 8-inch (20 cm) primary transmission line.

In many cases, it is not economical to design a system to satisfy the peak load if this peak load occurs infrequently. When retrofitting geothermal systems to existing conventional fuel systems, it is often more economical to design the geothermal system to handle the major portion of the heat load and supply the peak periods with a centralized conventional fuel-fired boiler. Consideration should be given to a conventional fuel that can be stored, such as coal or heating oil. These fuels would be used during the coldest periods of the year when conventional systems would also be demanding peak load and natural gas and electrical power would be in short supply.

For the heating-district model, three 1000-foot (305-m) production wells are to be drilled at a total cost of $116,694. The decision to drill the third well was based on the fact that the peak load would require 80% production from the third well and because future plans for the system include expansion to a 54-block area.

Well-drilling costs (up to 3000 feet/depth, 914 m) in the Klamath Basin, using cable or rotary rigs are as follows:

$1.00 per inch of diameter per foot ($1.29/cm/m) of depth in "soft" rock;
$2.50 per inch of diameter per foot ($3.23/cm/m) of depth in "hard" rock up to 500 feet (150 m) in depth;
Every additional 100-foot (30-m) increment adds $1.00 per foot of depth ($3.28/m, incremental charges).

Casing costs can be estimated at $1.05 per inch of diameter per foot of depth ($1.36/cm/m). Full-depth casing is assumed for all wells. Example:
$1.05 x 10-inch (25.64-cm) casing x 1 foot (.3 m) of depth = $10.50/ft (.3 m).

Using the above costs, which include mobilization and demobilization and which consider drilling conditions in the Klamath Basin (i.e., one-third of drilling in "hard" rock), the following drilling costs were developed:

Average Well Costs[2]

Depth (feet)	100 (30 m)	500 (152 m)	1,000 (305 m)	2,000 (610 m)	3,000 (914 m)
Drilling costs ($)[3]	1,800	9,000	17,000	34,500	51,000
Casing cost ($)	1,050	5,250	9,450	17,850	24,150
Total cost ($)	2,850	14,250	26,450	52,350	75,150

Range of Costs[2]

All "soft" rock ($)	2,200	11,000	20,500	41,000	59,500
All "hard" rock ($)	4,000	20,000	37,000	72,500	103,000

[2] Based on current costs. Costs are expected to rise approximately 10% in the very near future.

[3] Does not include costs for drilling mud, additional air compressors if required, foaming agents, etc.

Based on November 1978 costs and on the relative amounts of "hard" and "soft" drilling that are expected in the drilling area, cost of a 1000-foot (305-m) well would be:

0-350 ft	14-in drill 175' (35.6 cm/53 m)	@ $ 1.00/ft[4] =	$2,450
(0-107 m)	14-in drill 175' (35.6 cm/53 m)	@ $ 2.00/ft[4] =	6,125
	10-in I.D. casing (25.4 cm)	@ $10.50/ft =	3,675
350-1000 ft.	12-in drill 238' (30.4 cm/73 m)	@ $ 1.00/ft[4] =	$ 2,856
(107-305 m)	12-in drill 412' (30.4 cm/126 m)	@ $ 2.50/ft[4] =	12,360
	8-in I.D. casing (20.3 cm)	@ $ 8.55/ft =	5,557
	Incremental depth charges	=	3,000
	One 10-in (25.4 cm) and one 8-in (20.3 cm) casing shoe	=	225
	100 sacks cement @ $10.00/sack	=	1,000
	Standby time @ $350.00/day, 3 days	=	1,050[5]
	Well completion by air @ $125.00/hr	=	600
	TOTAL		$38,898

The production well pumps selected for our model are vertical turbine with variable speed fluid drive. These pumps have proven highly successful at Oregon Institute of Technology and Presbyterian Intercommunity Hospital in Klamath Falls. They are capable of maintaining a constant pressure in the supply lines while flow requirements vary from zero to full-flow. Maintenance costs are minimal. Specifications on the well head pumps and cost data are listed below.

<u>Well head pumps</u>

Vertical turbine with variable speed drive:

Rated flow at 1750 RPM	500 gpm	(31.5 l/s)
Column length	350 ft	(107 m)
Column diameter	8 in	(20.3 cm)
Bowl diameter	9-3/4 in	(24.8 cm)
Shaft diameter	1-1/2 in	(3.8 cm)
Number of bowls	11	
Discharge of pressure	20 psi	(138 kPa)
Motor (electric)	75 hp	
Drive - torque converter type 2% slip at full load. Rated Capacity	75 hp	
Wire to water efficiency	72%	
Current estimated cost	$41,488	
Number required	2 ea	

Pump selection is site specific. In those areas where water quality of the resource is more corrosive, the pump costs and maintenance costs will greatly exceed the costs for the Klamath Falls model.

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[4] Per diameter inch (diameter centimeter).

[5] Standby time accumulated while running logs, 48-hr pump test and miscellaneous delays for testing and logging.

The production well pumps supply fluid to two plate-type heat exchangers, the control system and two circulation pumps housed in a heat-exchanger building. Vertical turbine circulation pumps were chosen over centrifugal pumps due to higher efficiency and lower maintenance costs.

Circulation pumps

Two types of circulation pumps were investigated, vertical turbine and centrifugal. Although initial cost of the centrifugal pumps was lower, the vertical turbine pumps offer the following advantages: better packing life and much less likelihood of air entrainment in the closed-loop system with a resultant decrease in corrosion problems. It is nearly impossible for vertical turbines to allow air in the system since the packing is under positive internal pressure at all times while, under certain low-flow high-speed conditions, centrifugal pump-shaft packings may have negative internal pressure. Vertical turbine pumps also offer higher wire-to-water efficiencies, lower net positive suction-head requirements and flatter operating curves.

Circulation pump comparison:

Vertical turbine	Centrifugal
400 gpm @ 100 psi (25.2 l/s @ 689 kPa)	400 gpm @ 100 psi (25.2 l/s @ 689 kPa)
1750 rpm	3600 rpm
40 hp	40 hp
Wire-to-water efficiency 73%	Wire-to-water efficiency 62%
NPSH[6] 7.2 ft (2.2 m)	NPSH 10.2 ft (3.1 m)
Estimated maintenance cost: $200/yr	Estimated maintenance cost: $250/yr
Present cost: $13,691	Present cost: $12,033

The pumps selected have the following specifications:

Vertical turbine with variable speed drive
Rate flow at 1750 rpm, 100 and 400 gpm (6.3 and 25.2 l/s)

Column length and diameter	none required
Bowl diameter	6-5/8 in (16.8 cm)
Shaft diameter	1 in (2.5 cm)
Number of bowls	4
Discharge pressure	100 psi (689 kPa)
Motor (electric)	40 hp
Drive torque converter type, 2% slip at full load. Rated Capacity	50 hp
Wire-to-water efficiency	75%
Current estimated cost	$13,691
Number required	2 ea

Two plate-type heat exchangers were selected for this application because of their high efficiency, small space requirements and ease of cleaning. The exchangers can operate at the minimum flows required for domestic water heating during summer months and also accept additional plates to handle increased loads while maintaining inlet and outlet temperature as the district is expanded.

The manufacturer based the design of the heat exchangers on engineering specifications for secondary water-flow rate, pressure drop, inlet temperature, outlet temperature, geothermal water-

[6] Net Positive Suction Head

flow rate, pressure drop and inlet temperature. Geothermal water outlet temperature and exchanger cost are iterated to obtain the most economical exchanger with minimum flow rates. Data on the heat exchangers follow:

Plate heat exchanger general specifications:

Type - Single pass with 150 316 stainless steel plates EPDM gaskets
Size - 9'3" long x 1'7" wide x 5' high with maximum platage (2.82 x 0.48 x 1.52 m)

Geothermal side - 219°F (104°C) inlet
176°F (80°C) outlet
4.3 psig (29.6 kPa) pressure drop
350 gpm (22.1 l/s) flow
(1000 gpm [63.1 l/s] maximum flow)

Secondary side - 200°F (93°C) outlet
160°F (71°C) inlet
3.7 psig (25.5 kPa) pressure drop
378 gpm (23.8 l/s) flow
(1000 gpm [63.1 l/s] maximum flow)

Cost - $14,000 ea
Number required - 2

Life of the 316 stainless steel plates is expected to be 30 years or more in the Klamath Falls geothermal water.

Additional plates for future expansion cost $80 each, including gaskets.

The primary pipeline for the system is to be 8-inch (20 cm) steel, schedule 40, 4060 ft (1.24 km) in length, placed in a concrete tunnel. The cost of this line is estimated to be $506,175. This figure includes cost of pipe, expansion joints, fittings, pipe guides, excavation, bedding placement and backfill, a highway undercrossing, a railroad undercrossing, a 42" x 30" (107 x 76 cm) concrete tunnel and six pre-cast expansion vaults.

The costs are based on estimates provided by various suppliers of equipment, City of Klamath Falls recent bid prices and estimates from Means Mechanical Cost Data Guide for 1978. It should be noted that there were large variations in estimates given by suppliers, as much as 2-300% variation. The costs presented below appear to be the most reasonable estimates, including allowance for profit and overhead.

<u>8" (20 cm) Steel Pipe in a Concrete Tunnel</u>

<u>Primary line</u> (8" [20 cm] steel pipe)

4060' (1237 m) @ 8" (20 cm) - Sch 40 @ $10.323/LF[7]	$ 41,911
Install and weld @ 70%	29,338
Fittings	6,433
Install and weld @ 40%	2,573

(continued)

[7] LF = linear foot (.3 m)

Expansion joints	$ 5,303
Install @ 56%	2,970
Pipe guides (79 required)	3,804
Install @ 56%	2,130
Insulation @ $4.59/LF	18,635
Labor @ 123%	22,921
Concrete tunnel 3860' (1177 m) of 42" (108 cm) x 30" (77 cm) @ $46.50/LF (-200' [61 m] canal & highway crossing)	179,490
Excavation, bedding, placement and backfill @ $35/LF	135,100
Highway undercrossing $175 x 120' (37 m)	21,000
RR undercrossing $100 x 250' (76 m)	25,000
6 pre-cast expansion vaults (Model 675 LA) @ $1,063	6,378
Install @ 50%	3,189
Subtotal	$506,175

The secondary distribution line totals an estimated $631,060. A detailed cost summary of the secondary distribution system is as follows:

Secondary line (8" [20 cm], 6" [15 cm] and 3" [8 cm] steel pipe)

2170' (662 m) x 2 @ 8" (20 cm) - Sch 40 @ $10.323/LF	$ 44,801
2250' (686 m) x 2 @ 6" (15 cm) - Sch 40 @ $6.865/LF	30,892
Install and weld @ 70%	52,985
1360' (415 m) x 2 @ 3" (8 cm) - Permapipe (installed, factory insulated) @ $24.13/LF	65,634
Fittings	10,625
Install and weld @ 40%	4,250
Expansion joints	13,174
Install @ 56%	7,377
Pipe guides (368 required).	10,301
Install @ 56%	5,769
Insulation 8" (20 cm) @ $4.59/LF, 6" (15 cm) @ $3.89/LF	37,426
Labor @ 123%	46,034
Concrete tunnel 2170' (662 m) of 42" (108 cm) x 30" (77 cm) @ $46.50/LF	100,905
2250' (686 m) of 38" (94 cm) x 28" (72 cm) @ $40.45/LF	91,013
Savings on concurrent construction of utilities	(49,265)

(continued)

Excavation, bedding, placement and backfill @ $35/LF	154,700
8 Precast expansion vaults (Model 575 LA) @ $737	5,896
1 Precast expansion vault (Model 675 LA) @ $1063	1,063
Labor and equipment @ 50%	3,480
Subtotal	$637,060
TOTAL	$1,143,235

Four different designs for the pipe system were considered:

1. Steel pipe in a concrete tunnel

2. Steel pipe direct buried, insulated and sealed

3. Asbestos cement direct buried

4. Fiberglas reinforced plastic.

Although the steel pipe in a concrete tunnel has the highest initial cost, it was estimated to have nearly twice the life of the other piping systems and reduced annual maintenance costs. One of the vital factors in selecting this system was the fact that both primary and secondary lines will be run in congested areas. Pipelines laid in tunnels beneath sidewalks will provide easy access for maintenance and will melt snow during winter months.

Concrete tunnels for the primary line are oversized to allow for the planned future expansion. Although the oversizing raises the initial cost, it is much more economical than trenching, bedding, placement and backfill at a later date. Nearly all geothermal space-heating systems installed have provided for future expansion.

An 800-foot (244-m) injection well will be drilled at the end of the primary line for $30,000. A total cost summary for the entire system appears below:

Total Cost Summary

Item	Cost
A. Wells and Well Head Equipment	
1. Production well (3) @ $38,898	$ 116,694
2. Production well pumps (3) @ $41,988	125,964
3. Well head buildings (3) @ $3,500	10,500
4. Power hook-up in buildings (3) @ $500	1,500
Subtotal	$ 254,658
B. Distribution Piping Network:	
5. Primary supply pipeline (8" [20 cm] steel in concrete tunnel)	506,175
6. Secondary supply pipeline (8" [20 cm] & 6" [15 cm] steel in concrete tunnel, 3" [8 cm] steel buried)	637,060
Subtotal	$1,143,235

(continued)

C. Heat Exchanger Building:

7.	Plate heat exchangers (2) @ $14,000	$ 28,000
8.	Control System, wiring, etc. (basic)	44,537
9.	Circulation pump (2) @ $13,691	27,382
10.	Expansion/surge tank	5,000
11.	Building, including installation of equipment	90,000
12.	Injection well (includes building)	33,500
13.	Injection well pump	2,587
	Subtotal	$231,006
	Total Equipment and Installation Costs	$1,628,899

D. Overhead Costs:

Engineering @ 10%	162,890
Contingency (inflation @ 5% for 6 mos)	81,445
Total Cost	$1,873,234

ESTIMATING ANNUAL OPERATION AND MAINTENANCE COSTS

To complete the total cost for this project, it is necessary to project annual operation and maintenance costs of the geothermal system. Maintenance costs are limited to materials and labor. Operating costs involve electrical power costs for pumping and wages for personnel involved in operating the system. The maintenance costs of our hypothetical model are as follows:

A. Production-well pump maintenance costs are shown in detail. All pump maintenance costs were calculated in this manner.

1. Change packing and lubricate at 6-mo intervals

material per pump	$ 6
labor per pump	23
Total	$29

Annual cost $29 x 2 = $58

Total for 3 pumps: $58 x 3 = $174

2. Pull pump, inspect & replace bearings at 3-yr intervals

material per pump	$ 700
labor per pump	3,300
Total	$4,000

Annual cost $4,000 ÷ 3 = $1,333

Total for 3 pumps $1,333 x 3 = $4,000

(continued)

3. Overhaul variable speed drive at 5-yr intervals

material per pump	$180
labor per pump	400
Total	$580

Annual cost $580 ÷ 5 = $116

Total for 3 pumps $116 x 3 = $348

Total annual production-pump maintenance costs $4,522

B. Total annual circulation-pump maintenance costs 568

C. Total annual injection-pump maintenance costs 79

D. Total annual primary pipeline maintenance costs 400

E. Total annual secondary pipeline maintenance costs 510

F. Total annual heat-exchanger maintenance costs 1,268

G. Total annual maintenance on 3 well-house buildings and heat-exchanger building 1,200

Total annual maintenance costs $8,547

Electrical operation costs

To determine the annual operating cost of the system, it is necessary to calculate the total electrical power requirements for pumping and the annual load for the system.

The load factor for our hypothetical system is 25%. The load factor is computed by dividing the estimated annual hours of operation by the total hours per year. Estimated annual demand for the system is 2190 hours divided by 24 hrs/day times 365 days/year = 25% load factor.

Three 75 hp production-well pumps operating at 60% of rated load with 72% efficiency:

225 hp x .6 = 135 hp ÷ 72% eff = 187.5 hp input

One 20 hp injection pump operating at 60% of rated load with 71% efficiency:

20 hp x .6 = 12 hp ÷ 71% eff = 17 hp input

Two 40 hp circulating pumps operating at 60% of rated load with 73% efficiency:

80 hp x .6 = 48 hp ÷ 73% eff = 66 hp input

TOTAL = 270.5 hp input

270.5 hp x 2190 hrs = 592,395 hp hours/yr

592,395 hp hrs/yr x .7457 kilowatt hrs/hp hr = 441,749 KW hr/yr

441,749 KW hr/yr at $0.025/KW hr = $11,044/yr electrical power cost

Annual maintenance costs

The maintenance costs are estimated to inflate at 7% annually and the electrical costs are inflated at 9.5% through 1986 and 8.58% thereafter. Table 2 is a 20-year projection of electrical costs and operation and maintenance costs.

TABLE 2

20-YEAR PROJECTION OF ELECTRICAL, OPERATION AND MAINTENANCE COSTS
FOR THE KLAMATH FALLS PROJECT

Year	Geothermal Electrical Annual Cost 11,044.00	Geothermal Operation & Maintenance Annual Cost 8,547.00	Total Cost/Yr.
1	12,093.18	9,145.29	21,238.47
2	13,242.03	9,785.46	23,027.49
3	14,500.03	10,470.44	24,970.47
4	15,877.53	11,203.37	27,080.90
5	17,385.89	11,987.61	29,373.50
6	19,037.55	12,826.74	31,864.29
7	20,846.12	13,724.61	34,570.73
8	22,634.72	14,685.34	37,320.05
9	24,576.78	15,713.31	40,290.09
10	26,685.46	16,813.24	43,498.71
11	28,975.08	17,990.17	46,965.25
12	31,461.14	19,249.48	50,710.62
13	34,160.50	20,596.95	54,757.45
14	37,091.47	22,038.73	59,130.21
15	40,273.92	23,581.44	63,855.37
16	43,729.43	25,232.14	68,961.57
17	47,481.41	26,998.39	74,479.80
18	51,555.31	28,888.28	80,443.60
19	55,978.76	30,910.46	86,889.22
20	60,781.74	33,074.19	93,855.93
		Total	993,283.71

Wages for operation in our hypothetical case were excluded due to the fact that personnel who operate and maintain the existing system will be identical for the geothermal system.

Now we are ready to construct a 20-year cash flow of the costs and savings resulting from converting the district to geothermal energy (Table 3).

The total cost of the proposed geothermal system (from page 14) is $1,873,234. The present worth of the 20-year cash flows at an 8% cost of capital indicates that the city could afford to spend $5,953,737 today to avoid the projected cost of natural gas over the next 20 years.

This completes the economic analysis for a non-profit organization. This example provides the reasons for giving careful attention to the costs of the proposed and existing systems. A precise cost analysis will aid the decision to drill or not to drill.

TABLE 3

20-YEAR CASH FLOW OF THE KLAMATH FALLS PROJECT

Year	Natural Gas Annual Cost 247,100	Geothermal Electrical Annual Cost 11,044	Geothermal Operation & Maintenance Annual Cost 8,547	Annual Savings	Present Worth 8%
1	277,246	12,093	9,145	256,008	237,044
2	311,070	13,242	9,785	288,043	246,950
3	349,021	14,500	10,470	324,050	257,242
4	391,601	15,878	11,203	364,520	267,933
5	439,377	17,386	11,988	410,003	279,041
6	492,981	19,038	12,827	461,116	290,582
7	553,124	20,846	13,725	518,554	302,571
8	600,140	22,635	14,685	562,820	304,074
9	651,152	24,577	15,713	610,862	305,583
10	706,500	26,685	16,813	663,001	307,098
11	766,552	28,975	17,990	719,587	308,618
12	831,709	31,461	19,249	780,998	310,145
13	902,404	34,161	20,597	847,647	311,678
14	979,109	37,091	22,039	919,978	313,217
15	1,062,333	40,274	23,581	998,478	314,762
16	1,152,631	43,729	25,232	1,083,670	316,313
17	1,250,605	47,481	26,998	1,176,125	317,870
18	1,356,906	51,555	28,888	1,276,463	319,434
19	1,472,243	55,979	30,910	1,385,354	321,003
20	1,597,384	60,782	33,074	1,503,528	322,579
			Total	15,150,805	5,953,737

CONSIDERATION OF INVESTMENT TAX CREDIT, DEPRECIATION AND PERCENTAGE DEPLETION ALLOWANCE FOR A TAXABLE CORPORATION

In order to understand thoroughly the economic analysis for a taxable corporation, the reader should be familiar with the National Energy Act (NEA) of 1978, which is discussed beginning on page 22 of this chapter.

To illustrate the economic effect of the NEA, we can modify our hypothetical model with the assumption that the geothermal resource and distribution system are to be developed by a taxable corporation that intends to sell energy to the heating district. With this assumption, we can maintain identical capital investment and annual operating costs to exemplify taxable versus nontaxable cost analysis.

Obviously, there should be an economic incentive for the district to convert from natural gas to geothermal energy. It is doubtful that the corporation could charge the district the price of natural gas, allow this price to increase annually at natural-gas inflation rates and persuade the users within the distribution system to convert to geothermal energy. On the other hand, the corporation must charge some price that will cover its operating costs and provide an acceptable after-tax return on investment. In an attempt to surmount this stumbling block, we can hypothesize that the corporation agrees to sell geothermal energy at the same price as natural gas, inflating this price at the economic inflation rate. This rate would allow the corporation to recover the increasing costs of operation and maintenance and would provide the users with a cheaper source of energy due to the greatly reduced inflation rates. Figure 2 compares geothermal versus natural gas for a 20-year period using this hypothesis.

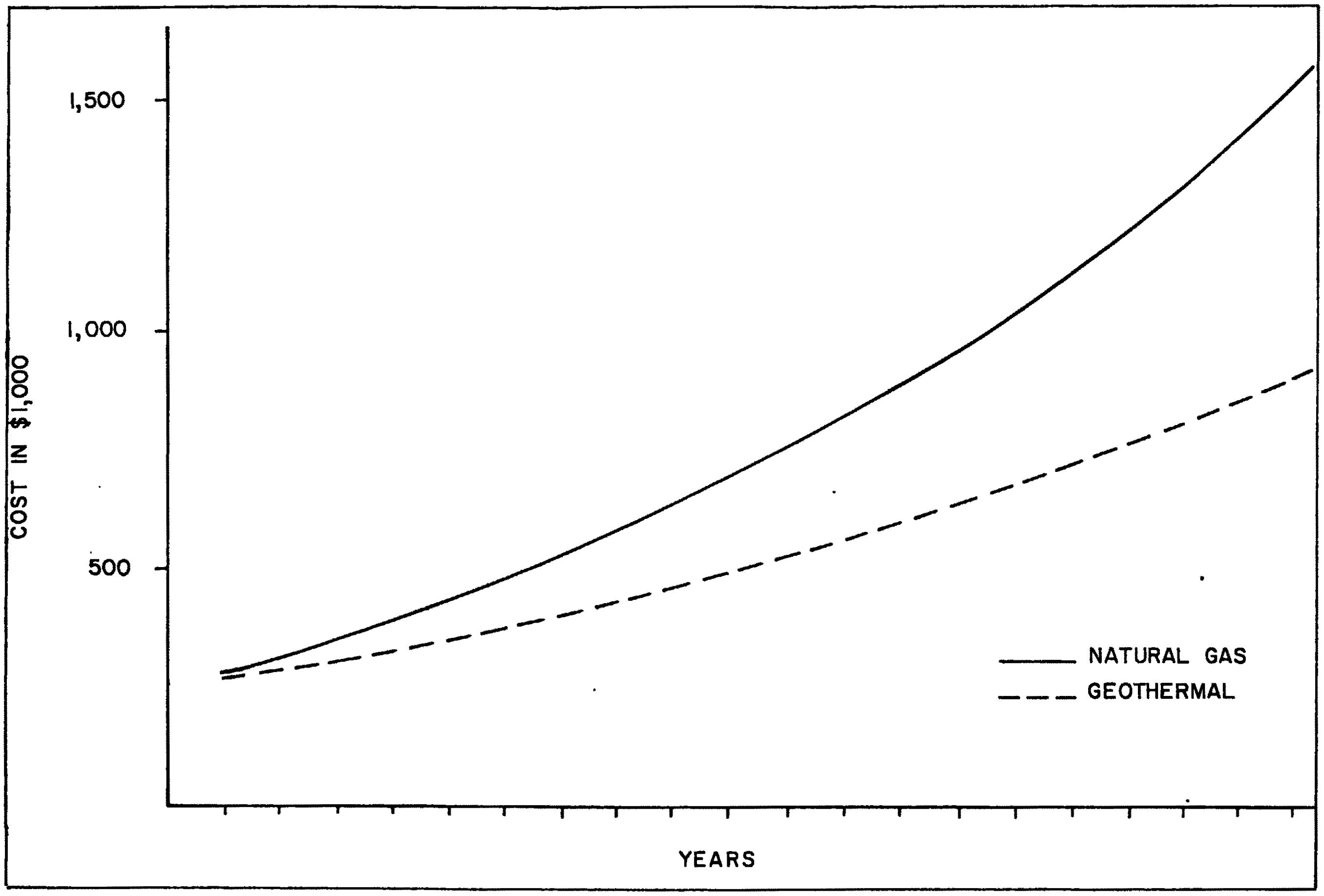

FIGURE 2. Geothermal and natural gas comparison under an inflation rate formula.

Hypothetically, the gross sales for the corporation will start at $264,397 for 1980 and increase at 7% per year over the 20-year period. For simplicity, we will assume that the corporation elects to capitalize its intangible costs and use a ten-year life and straight-line depreciation with a ten percent salvage value.

As indicated in the later discussion on taxes, there are many methods of depreciation and treatments of intangible costs. However, the reader should bear in mind the limits placed on these various methods. The biggest factor is that the corporation must make a profit and owe taxes in order to reap tax benefits.

For example, in the year 1980, the corporation will be eligible for $374,647 investment tax credit, a $58,167 depletion allowance based on 22% of sales and $168,591 depreciation expense which could reduce its total taxes by $601,405. But its gross sales are only $264,397. Therefore, the corporation cannot take full advantage of all the tax credits in the first year but will need to carry these credits forward. A large corporation with other alternative energy income could apply these tax credits against its total tax liability.

Since the depletion allowance cannot exceed 50% of net income before taxes, the depletion allowance will be $37,284 for 1980 and $45,643 for 1981 as indicated in Column B of the pro forma income statement.

The corporation will need to carry the 20% investment tax credit forward through 1988 in order to recover its total investment tax credit. However, the tax law provides only a three-year carry-back and a seven-year carry-forward for investment tax credits. Therefore, 1986 is the last year that the tax credit will be available. The corporation will be able to avoid $268,544 of tax payments in this seven-year period.

A second economic analysis was done using straight-line depreciation with a 15-year life in an effort to recapture the full depletion allowance and a higher amount of investment tax credit. The end result was a slightly lower return on investment after taxes. No accelerated depreciation method was attempted since gross sales in the early years of the project are low and an accelerated depreciation would be of no advantage.

Table 4 presents a pro forma income statement as follows:

Column A (gross sales) is the rate charged to the heating district based on the current cost of natural gas and a 7% inflation rate.

Column B represents the depletion allowance with the first and second years adjusted to be not more than 50% of net income before taxes.

Column C represents a straight-line depreciation based on the amortization of all tangible and intangible costs, a ten-year life and a ten percent salvage value.

Column D represents the electrical power costs required to run the geothermal system inflating at the projected electrical rates.

Column E represents the operating and maintenance costs of the geothermal system inflating at the economic inflation rate.

Column F is net income before taxes.

Column G is the tax liability assuming an effective tax rate of 48%. Actual tax liability would be slightly less if the corporation had no other sources of income. No taxes are paid in the first seven years while the corporation is using up its investment tax credit.

Column H is net income after taxes.

Column I adds the calculated depreciation and depletion allowances to the net income after taxes since these items do not represent out-of-pocket expenses but rather methods used to reduce the tax liability.

Column J shows the after-tax cash inflow to the corporation.

Column K indicates the present worth of these cash flows at 15.49522%, which yields a total net present value of $1,873,234, the cost of the original investment.

The data from our last analysis indicate that the project would be feasible for a corporation that requires an after-tax return on investment of less than 15.5%. The foregoing analysis, which may have seemed exhaustive, supports the advice that a careful study of the economics is as vital as a careful study of the engineering and the geology. The decision to use geothermal energy should be made only after all factors have been examined.

Note: All systems design and costs data were extracted from the Klamath Falls Geothermal District Heating the Commercial District Design, Interim Report for the City of Klamath Falls, PON EG-77-N-03-1553, Feb. 1979.

TABLE 4

PRO FORMA INCOME STATEMENT

	A	B	C	D	E	F	G	H	I	J	K
Year	Gross Sales	Percentage Depletion	Deprecia-tion	Electrical Costs for Geothermal System	Operation & Maintenance Costs for Geothermal System	Net Income Before Taxes	Federal Income Tax	Net Income After Taxes	Plus Depreciation & Depletion	After Tax Cash Flow	Net Present Value
				11,044	8,547						15.49522%
1	264,397	37,284	168,591	12,093	9,145	37,203	0	37,283	205,875	243,159	210,536
2	282,905	45,643	168,591	13,242	9,785	45,643	0	45,643	214,234	259,877	194,823
3	302,708	54,487	168,591	14,500	10,470	54,659	0	54,659	223,079	277,738	180,278
4	323,898	51,824	168,591	15,878	11,203	76,402	0	76,402	220,415	296,817	166,814
5	346,571	51,986	168,591	17,386	11,988	96,620	0	96,620	220,577	317,197	154,351
6	370,830	55,625	168,591	19,038	12,827	114,751	0	114,751	224,216	338,966	142,814
7	396,789	59,518	168,591	20,846	13,725	134,109	0	134,109	228,109	362,218	132,136
8	424,564	63,685	168,591	22,635	14,685	154,968	74,385	80,583	232,276	312,859	98,818
9	454,283	68,142	168,591	24,577	15,713	177,260	85,085	92,175	236,734	328,909	89,950
10	486,083	72,912	168,591	26,685	16,813	201,081	96,519	104,562	241,504	346,066	81,944
11	520,109	78,016		28,975	17,990	395,127	189,661	205,466	78,016	283,483	58,120
12	556,517	83,477		31,461	19,249	422,328	202,718	219,611	83,477	303,088	53,802
13	595,473	89,321		34,161	20,597	451,394	216,669	234,725	89,321	324,046	49,805
14	637,156	95,573		37,091	22,039	482,452	231,577	250,875	95,573	346,449	46,104
15	681,757	102,264		40,274	23,581	515,638	247,506	268,132	102,264	370,395	42,678
16	729,480	109,422		43,729	25,232	551,096	264,526	286,570	109,422	395,992	39,506
17	780,543	117,081		47,481	26,998	588,982	282,711	306,271	117,081	423,352	36,569
18	835,181	125,277		51,555	28,888	629,460	302,141	327,319	125,277	452,597	33,850
19	893,644	134,047		55,979	30,910	672,708	322,900	349,808	134,047	483,855	31,333
20	956,199	143,430		60,782	33,074	718,913	345,078	373,835	143,430	517,265	29,002
										TOTAL -	1,873,233

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APPENDIX A

OVERVIEW OF STATE AND FEDERAL TAXATION

INTRODUCTION

Whenever the issues of taxes, tax credits, tax incentives, depletion allowances and/or intangible deductions are raised, it must be remembered that there are 51 tax systems in this country: one federal and 50 state. State corporate and personal income-tax structures may or may not parallel the federal corporate and personal income-tax structure. Generally, the states have followed the federal government's lead in constructing their own tax systems. However, in the post-Proposition 13 mood of the electorate, it is not clear that states will adopt tax incentives for geothermal resources. Moreover, since the geothermal tax incentives adopted as part of the 1978 Energy Tax Act are so new, there will be some uncertainty as to their application until the IRS promulgates its Treasury Regulations for these new Internal Revenue Code (IRC) sections. Until that time, it is safe to assume that the IRS will follow (with certain exceptions) the Treasury Regulations and court cases that are applied to the oil and gas industry. All the Treasury Regulations cited in the footnotes in the text below were written for the oil and gas industry, but they are generally applicable to geothermal.

THE FEDERAL TAX SYSTEM

Prior to the passage of the Energy Tax Act of 1978,[1] the federal tax treatment of geothermal resources was based mainly on judicial decisions, not statutory authority. In 1969, the 9th Circuit Court of Appeals[2] held that the federal intangible drilling deduction[3] and the percentage depletion allowance[4] applied to the geothermal drilling at The Geysers. To reach this result, the Court held that geothermal steam was "gas" within the meaning of §263(c) and §613(b)(1) of the IRC.

In 1975, the Code was revised to provide a 22% percentage depletion allowance for any geothermal deposit in the U.S. or a U.S. possession that was determined to be a gas.[5] But the IRS refused to follow either the Court decisions or the new Code provision and contested both the intangible drilling deduction and depletion allowance on activities and income from The Geysers. Furthermore, because of the IRS intransigence, the tax treatment of drilling a geothermal deposit that was hot water instead of steam was even less clear.[6]

The Energy Tax Act of 1978 has eliminated most of the uncertainties of tax treatment of geothermal exploration and development. The new provisions can be used to promote capital investment and to generate for the investor certain tax savings which reduce the risk of investment. Furthermore, the definition of geothermal deposits[7] is broad enough to include all the various

[1]P.L. 95-618, §403(b), amending IRC §613A(b).

[2]Arthur E. Reich, 52 T.C. 700 (1969), aff'd, 454 F.2d 1157 (9th Cir. 1972) and George D. Rowan, 28 T.C.M. 797 (1969).

[3]IRC §263(c).

[4]IRC §613.

[5]P.L. 94-455.

[6]In Miller v. United States, 78-1 U.S.T.C. P9127 (D.C.C.D. Cal. 1977) the federal district court denied the intangible drilling deduction to investors who drilled geothermal wells in Nevada in an area of hot water, not steam, reservoirs.

[7]"A geothermal reservoir consisting of natural heat which is stored in rocks or in an aqueous liquid or vapor (whether or not under pressure)."

forms of geothermal energy including dry steam, hot water or dry hot rocks. The Act covers three basic subjects: intangible drilling costs, depletion allowance and tax credits.

Intangible drilling costs

Option to deduct intangible drilling costs. §402 of the Energy Tax Act amends §263(c) of the IRC to allow a taxpayer the option to deduct as expenses intangible drilling costs (called "intangibles" or IDCs).[8] The costs of drilling and completing a geothermal well are divided for tax purposes into two classes: intangible drilling costs and equipment costs. The equipment costs must be capitalized and "recovered" through depreciation or depletion. Intangible drilling costs may be treated in two ways.[9] They may be deducted as expenses (in tax terminology they may be expensed) in the year in which they were incurred or they may be capitalized and deducted over a certain period of time as depreciation or depletion.[10] Allowing a taxpayer to expense (deduct) all the intangibles in the year in which they were incurred gives the taxpayer a kind of "accelerated depreciation."

The taxpayer must make his election to expense or to capitalize intangibles in the first taxable year in which he incurs such costs.[11] Once having done so, the taxpayer must treat such expenditures on all geothermal properties in the same manner for all future years.[12] However, if the taxpayer elects to capitalize his intangibles, he is granted a second election to capitalize or to expense the portion of intangibles attributable to dry or nonproductive wells.[13]

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[8] Intangible drilling costs are defined by U.S. Treasury Regulation §1.612-4(a) as any cost incurred which in itself has no salvage value and which is "incident to and necessary for the drilling of wells and the preparation of wells for the production of oil and gas." Such expenditures expressly include "wages, fuel, repairs, hauling, supplies, etc." that are used (1) in the drilling, shooting and cleaning of wells; (2) in such clearing of ground, draining, road making, surveying and geological works as are necessary in preparation for the drilling of wells; and (3) in the construction of such derricks, tanks, pipelines and other physical structures as are necessary for the drilling of wells and the preparation of wells for the production of oil or gas. The IRS will probably follow this regulation for geothermal deposits, making adjustments for the differences between drilling in the oil and gas industry and the geothermal industry.

[9] Since the geothermal provision for the option to expense intangibles is separate from oil and gas activities, a taxpayer may make one kind of election for his geothermal deposits and a different one for his oil and gas wells. For example, he could decide to expense intangibles for both geothermal and oil and gas properties or he could capitalize oil and gas and expense geothermal intangibles.

[10] U.S. Treasury Regulations §§1.612-4(b)(1), (b)(2) & (b)(3) state that intangibles, if capitalized, are to be separated and recovered as depreciation or depletion. Intangibles not represented by physical property (clearing ground, draining, road making, surveying geological work, excavating, grading and the drilling, shooting and cleaning of wells) are to be recovered through depletion. Intangible expenditures represented by physical properties (wages, fuel, repairs, hauling, supplies, etc.) are to be recovered through depreciation.

[11] A taxpayer must make a clear election either to expense or to capitalize. If he does not, the IRS will hold that he elected to capitalize intangibles. It is best that if a taxpayer desires to expense intangibles, he include with his income-tax return an express statement of election to expense in accordance with the option granted by U.S. Treasury Regulation §1.612-4(a).

[12] U.S. Treasury Regulation §1.611-4(e).

[13] But this second election need not be exercised until the first year in which a dry hole is drilled.

For example, if Taxpayer (T)[14] has spent $50,000 in intangibles in 1978, T may claim as a deduction on his income-tax return the $50,000 of intangible costs. But if T decides to capitalize intangible drilling costs, T will not take a $50,000 deduction for 1978 but instead will deduct this amount over a given period of time as depreciation or depletion.

But a noncorporate taxpayer, a Subchapter S corporation or a personal holding company that decides to expense intangibles instead of capitalizing them, may be subject to one of the following: the minimum tax (see "B"); a limitation on deductions to the amount "at risk" (see "C"); or recapture of intangible deductions if the property is sold at a profit (see "D").

Preference income--minimum tax. Some types of income are given preferential treatment by special provisions of the tax law. A minimum tax applies to a number of items that are considered to be of a tax-preference nature. These types of income include capital gains, stock options and income offset by depletion, amortization and intangible drilling costs. The tax is computed by totaling all the items of tax preference, then reducing this amount by the greater of $10,000 or one-half a taxpayer's regular income tax after reduction by credits. A flat 15% rate is then applied against the balance.[15]

If a taxpayer has "excess intangible drilling costs" that exceed net geothermal income, he will have preference income subject to the minimum tax. Intangible drilling costs are considered to be excessive when the intangible drilling and development costs of a geothermal well allowable for the tax year is greater than the sum of (1) the amount allowable if the costs had been capitalized and straight-line recovery of intangibles had been used and (2) the net income for the tax year from the geothermal property.

Straight-line recovery means the ratable amortization of such intangibles over the 120-month period beginning with the month in which production from the well begins (or, if elected, any method which would be permitted for purposes of determining cost depletion). Net income from geothermal properties means the gross income from all such property reduced by any deductions allocable to the properties, except intangible drilling and development costs in excess of straight-line recovery.

This preference does not apply to taxpayers who elect to capitalize by straight-line recovery their intangibles. Nor does it apply to nonproductive wells.[16]

Special rules apply to corporations in computing their minimum tax.[17] And the IRS will publish rules under which items of tax preference of both individuals and corporations are to be properly adjusted where the tax treatment that gave rise to the preference does not result in a reduction of the taxpayer's income tax for any tax year.

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[14]The owner of the operating rights in a property who has the responsibility to develop the property is granted the option of expensing intangibles. But each taxpayer, regardless of his relationship to another taxpayer, is entitled to a separate election. Thus each partner in a partnership is entitled to a separate election. Trusts as separate taxpayers are entitled to an election regardless of the kind of election made by the beneficiaries.

[15]A taxpayer may be able to claim the unused part of certain credits against his minimum tax. Also if a taxpayer has a net operating loss that remains to be carried forward to a succeeding tax year, the minimum tax otherwise due may be deferred in an amount of up to 15% of the net operating loss to be carried forward to subsequent tax years when the loss is absorbed. In the years when the loss is absorbed, the taxpayer will be liable for the minimum tax deferred in an amount equal to 15% of the net operating loss absorbed in each year. See IRC §57(a)(11).

[16]Nonproductive wells are those which are plugged and abandoned without having produced steam or hot water in commercial quantities for any substantial period of time.

[17]See IRS Publication 542, Corporations and the Federal Income Tax.

In effect, what this provision does is to lessen the benefit of the option to expense intangible drilling costs. Few taxpayers now have geothermal income and if they choose to expense intangibles, they will have preference income (that is, the amount they deduct by expensing intangibles will definitely be greater than the sum of intangibles capitalized and net geothermal income).

Losses limited to amount at risk.[18] The 1976 Tax Reform Act limited the tax benefits available to persons engaging in oil and gas operations. These same limitations with some changes were extended to geothermal operations by the 1978 Energy Tax Act.

Before passage of the 1976 Act, a taxpayer could take deductions up to the amount of his cost (or "basis") in a business or investment venture. But the basis of a taxpayer often included expenditures financed by nonrecourse loans for which the taxpayer had no personal liability (i.e., he had nothing "at risk" because of the way the loan was made to him or to an investment group). Such leveraged nonrecourse loans were often employed by investors to finance drilling and development costs of oil and gas activities. Since a taxpayer could elect to expense intangible drilling costs, he could take deductions far in excess of his own actual investment. This kind of investment was desirable for a high-bracket taxpayer because the large deductions for intangibles could be used to offset income earned from other sources.

The 1976 law added §465 to the IRC and limited the amount of losses[19] deductible by a taxpayer engaged in exploring for and exploiting oil and gas. The taxpayer's deduction cannot exceed the total amount the taxpayer has at risk in the venture. Deductions taken for intangibles are considered losses for purposes of this section.

The Revenue Act of 1978 changed the "at risk" rules for years beginning after December 31, 1978. The most significant change is that previously allowed losses must be recaptured when the taxpayer's "at risk" amount is reduced below zero. But only the excess of the losses previously allowed in a particular "at risk" activity over any amounts previously recaptured will be recaptured under this provision. However, such recaptured losses may be deductible in a later year if the "at risk" is later increased.

The practical effect of these "at risk" provisions is to eliminate the use of nonrecourse financing to increase available deductions.

Recapture of intangible costs expenses as ordinary income on disposition of geothermal property. Probably the most far-reaching change of the 1976 Tax Reform Act affecting corporate and noncorporate taxpayers is the requirement that upon the disposition of oil and gas property, taxpayers are required to recapture all or some part of the intangible costs incurred as ordinary income if the property is disposed of at a gain (a profit). These recapture provisions were extended by the Energy Tax Act of 1978 to intangible drilling costs incurred in connection with geothermal deposits.[20]

This recapture provision applies only to intangibles which the taxpayer elects to expense in the year in which they were incurred and does not apply to intangibles which were capitalized. The amount of intangibles recaptured as ordinary income (instead of capital gains) is the lesser of (1) the intangible costs incurred (reduced by an amount which would have been allowed as cost depletion had such intangibles been capitalized) or (2) the gain realized on the disposition. Or, in other words, the amount recaptured and taxed as ordinary income is the amount that the intangibles deducted exceed that which would have been allowed had the intangibles been capital-

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[18]See IRC §465(c).

[19]A loss is the excess of allowable deductions allocable to a particular activity over the income derived from the activity during a taxable year.

[20]P.L. 95-618, §402(c), amending IRC §1254(a).

ized and amortized on a straight-line basis (120) months from time the property went into production.[21]

Percentage depletion

The IRC provides two methods of computing a depletion allowance: cost depletion and percentage depletion. Cost depletion provides for a deduction for the taxpayer's basis (cost) in the property in relation to the production and sale of minerals from the property. On the other hand, percentage depletion is a statutory concept that provides for a deduction of specified percentages of the gross income from the property. The deduction, however, cannot exceed 50% of the net income from the property. A taxpayer is required to compute depletion both ways and to claim the larger of the two amounts.

A depletion allowance reduces the taxpayer's basis in a property but the total amount taken as a depletion allowance is not restricted to the taxpayer's basis. Even though cost depletion will be zero after the taxpayer's initial basis has been recovered (for example, T deducts $5000 per year for five years for a total of $25,000 - the amount of his original investment), the taxpayer may continue to claim percentage depletion based on income from the property.[22]

§403 of the 1978 Energy Tax Act grants percentage depletion on income from geothermal deposits. The rate through 1980 is 22%. It decreases by 2% yearly until 1983 and thereafter the rate is 15%.

This percentage depletion allowance is much more favorable than the one allowed oil and gas. It is not limited in any way to a specified amount of production. It has no 65% of taxable income limitation nor is it restricted to independent producers. However, the percentage depletion cannot exceed 50% of the taxable income from the property and is subject to the minimum tax-preference income rules.[23]

There is some question about the availability of depletion on minerals which are consumed by the producer of such minerals. Many manufacturers are now exploring and developing their own sources of energy supplies, particularly natural gas reserves and in some areas geothermal. But the depletion allowance is dependent upon the sale of a mineral. Some courts have held that no depletion is allowable for minerals consumed in the operation of the producing energy property. It is not clear, however, if a depletion allowance is precluded with respect to gas used in manufacturing operations. For example, the IRS ruled in 1968 that the value of dry gas manufactured from wet gas and used as fuel for a gasoline absorption plant is includable in determining "gross income from the property" for percentage depletion purposes, but the value of dry gas reinjected into the geological formation is not includable. One way for the corporate taxpayer to avoid the problem is to conduct its exploration and development activities through a wholly owned subsidiary. The subsidiary could sell the gas to the parent at an arm's length price and create depletable gross income.

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[21] It should be noted that there are questions as to the proper method of calculating the reduction of recapturable intangibles under this section.

[22] A depletion allowance on the income derived from production and sale of the minerals from a property is available only to the owner of an economic interest in that property. An owner of an economic interest can be an owner of mineral interests, royalties, working interests, overriding royalties, net profits interests or certain kinds of production payments.

[23] The excess of the depletion deduction over the adjusted basis of the property at the end of the year (determined without regard to the depletion deduction for the year) is what would be preference income.

Tax credits

Residential energy credit. §101 of the 1978 Energy Tax Act provides for a non-refundable tax credit for certain expenditures incurred for equipment which uses geothermal energy in a taxpayer's principal residence in the United States. The equipment must be new and must meet certain performance and quality standards; it must reasonably be expected to remain in production for five years. The credit is as follows: (a) 30% of the expenditure up to $2000, (b) 20% of the expenditure from $2000 to $10,000. The maximum credit is $2200. The credit may be carried over to future years for equipment purchased after April 20, 1977 and before January 1, 1986.

Additional investment tax credit for alternative energy property. A 10% investment-tax credit in addition to the existing investment-tax credit is available for geothermal equipment which qualifies as either "alternative energy property" or "specially defined energy property." Public utilities cannot benefit to the extent of "alternative energy property" but can use the credit for "specially defined energy property."

The business-energy credit is limited to 100% of tax liability, except for solar- or wind-energy property on which the credit is refundable. Until the IRS issues its regulations on this new section, it will not be completely clear what kind of equipment qualifies.

STATE TAX SYSTEMS[24]

Of the fifteen states with known geothermal resources, Nevada, Texas, Washington and Wyoming have no state personal or corporate income tax. Alaska, Colorado, Hawaii, Idaho, Montana and New Mexico apply their income-tax levies to adjusted gross income as calculated for federal income tax. But five states have an independently determined income tax: Arizona, California, Louisiana, Oregon and Utah. Their differences from the federal law are largely due to the state provisions concerning percentage depletion for resources extraction industries.

Two states, California and Arizona, provide two examples of how complex the state tax picture can be. California has a Franchise Tax and a Corporate Income Tax. The franchise tax is for the privilege of exercising a corporate franchise within the state. The tax rate is 9% of net income attributable to California. Insofar as the franchise tax overlaps the corporate income tax, the amount due under the franchise tax is offset against the amount due under the income tax. The computation of income for both the franchise tax and the income tax follows generally the pattern of the federal income tax and interpretations of the federal law by the Treasury Department, with the exception of depletion provisions. The tax rate for the income tax is also 9%.

Prior to 1975, California provisions for depletion allowance for oil and gas and other minerals conformed basically to federal law. However, California did not follow the federal Tax Reduction Act of 1975 which eliminated percentage depletion for oil and gas wells (with a few exceptions). California merely placed a limit on the total amount deductible by each individual taxpayer. These limitations apply only after the total accumulated depletion allowed or allowable exceeds the adjusted cost of the property.

A deduction of 22% of gross income (less rentals and royalties) for the taxable year is allowed for oil and gas properties. This deduction may not exceed 50% of taxable income computed with-

[24]For an extensive analysis of state tax systems, see State Taxation of Geothermal Resources Compared with State Taxation of Other Energy Minerals, Sharon C. Wagner, published by the Geothermal Resources Council, Davis, CA.

out allowance for depletion. In addition, where the deduction exceeds $1.5 million and is greater than the adjusted cost of the taxpayer's interest in the property, the deduction is reduced. The reduction equals 125% of the amount in excess of $1.5 million.[25]

For example, suppose that the 22% depletion is $3.5 million and that this amount exceeds the cost of the taxpayer's interest in the property. The deduction in this case is reduced by 125% of $2 million ($3.5 million minus $1.5 million), which equals $2.5 million. The allowed deduction in this case is $3.5 million minus $2.5 million which equals $1 million. If, instead, the 22% depletion amounts to $7.5 million, then the reduction is 125% of $6 million, which is equivalent to the depletion allowance itself, and no deduction is allowed.[26]

For oil and gas, California follows federal provisions for intangible drilling costs.[27] Exploration expenditures may not be deducted for oil and gas but they may for other minerals. Geothermal exploration, development or percentage-depletion deductions are not specifically allowed, but, in practice, companies at The Geysers have been allowed percentage depletion and deductions for intangible drilling costs.

In 1977, Arizona raised its corporate tax rates and then raised them again in 1978. But Arizona does specifically provide for a depletion allowance and depreciation in computing new income. The depletion allowance is 27-1/2% of gross income, excluding an amount equal to any rents or royalties paid in respect to the property. The allowance cannot exceed 50% of the taxpayer's net income computed without allowance for depletion from the property, except that in no case will the depletion allowance be less than it would be if computed without reference to this provision. Also expenditures paid or incurred during the income-tax year for the development of a geothermal resource well, if paid or incurred after 12/31/53, may be deducted from gross income or charged to the capital account. Amounts up to $75,000 paid or incurred for the purpose of ascertaining the existence, location, extent or quality of any deposit of geothermal resources are allowed as a deduction.

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[25] CAL. REV. & TAX CODE §17686.

[26] Bock, 1978 Guidebook to California Taxes, p. 123.

[27] CAL. REV. & TAX CODE §24423. CAL. ADMIN. REG. 24831(d).

APPENDIX B

PRICING DIRECT-USE GEOTHERMAL ENERGY
(A Pricing Guide)

INTRODUCTION

Geothermal energy is not new. It has been used successfully for centuries. Now, when conventional energy supplied by non-renewable resources is in short supply, and when costs of this energy rapidly escalate, renewed attention is being focused on geothermal and the economics of its use.

This appendix will not provide a magic formula for pricing direct-use geothermal energy; it will introduce the reader to the parameters that ultimately dictate the cost of this energy to the end user.

The price of geothermal energy must relate to the cost of developing and delivering the resource. As in all enterprises, the final analysis reduces to dollars and cents. If the project will make no dollars of profit, then it makes no sense!

Many direct-use geothermal systems supply energy at a fraction of the cost of conventional fuels. Experience indicates, however, that the following major factors significantly influence the cost of geothermal energy:

1. Efficiency
2. Annual load factor
3. Capital investment
   a) Transmission distance
   b) Drilling costs versus confidence level
4. Cost of capital or required return on investment.

Other factors which influence cost to a lesser degree are water quality, site location and pumping depth. As technologies develop to reduce drilling costs and to handle water with corrosive properties, the influence of these factors will change. To simplify the analysis, we will assume pumping depths in the neighborhood of 300 feet (90 meters) and water quality from good to excellent.

EFFICIENCY

Most present-day space-heating systems use hot (200°F, 93°C) water that is piped either to heat exchangers placed in rooms throughout the building or to fan-coil units installed in a duct-work system supplying heated air to individual rooms. Both these systems are typically closed loops and they remove 20°F (11°C) of heat between the supply and the return lines. In other words, the supply water at 200°F (93°C) circulates through the system, then it returns to the boiler at 180°F (82°C), is reheated to 200°F (93°C) and recirculated. The efficiency of these systems is, basically, the efficiency of the heat source. Typical efficiencies are: heating oil - 85%; natural gas - 90%; and electricity - 100%.

With geothermal energy, water is pumped from a production well to a heat exchanger (where energy is withdrawn) and then to an injection well. The total annual operating costs of such a system comprise the pumping, the maintenance and amortization of the capital invested in the system. These costs are unrelated to the efficiency with which heat is removed from the thermal waters supplied by a well.

Suppose System A extracts 10°F (5°C) from a 200°F (93°C) supply and injects the water at 190°F (88°C); System B extracts 100°F (56°C) and injects the water at 100°F (38°C). The cost per MBtu (GJ) for System A would be ten times that of System B. Assume the cost of drilling one production well and one injection well to be $100,000. With an annual cost of capital of 15% and a 20-year well life, the total annual equivalent cost of developing and operating either system would be $26,000. If both systems were operating 100% of the time, System A extracting 10°F (5°C) of heat could deliver 2.19 x 10^4 MBtu (2.31 x 10^4 GJ) annually at a cost of $1.19/MBtu ($1.13/GJ). However, System B extracting 100°F (56°C) could deliver 2.19 x 10^5 MBtu (2.31 x 10^5 GJ) annually at a cost of $0.12/MBtu ($0.11/GJ). Systems designed to extract greater amounts of heat from the geothermal reservoir (increased efficiency) will usually increase the capital investment greatly. Normally, however, the annual savings resulting from this increased efficiency will more than repay the capital investment.

Geothermal systems are capital intensive and the fixed costs (capital recovery) often comprise more than 90% of the total annual cost. Thus drilling one production and one injection well and extracting 100°F (56°C) is more economically feasible than drilling ten production and three injection wells and extracting 10°F (5°C) from each of the producers to satisfy the same heat load. There are space-heating systems which have been successfully designed to extract 75°F (24°C) from a 140°F (60°C) supply. Some systems in use which were direct conversions from fossil fuel extract 80°F (44°C) because the original heating system was so over-designed.

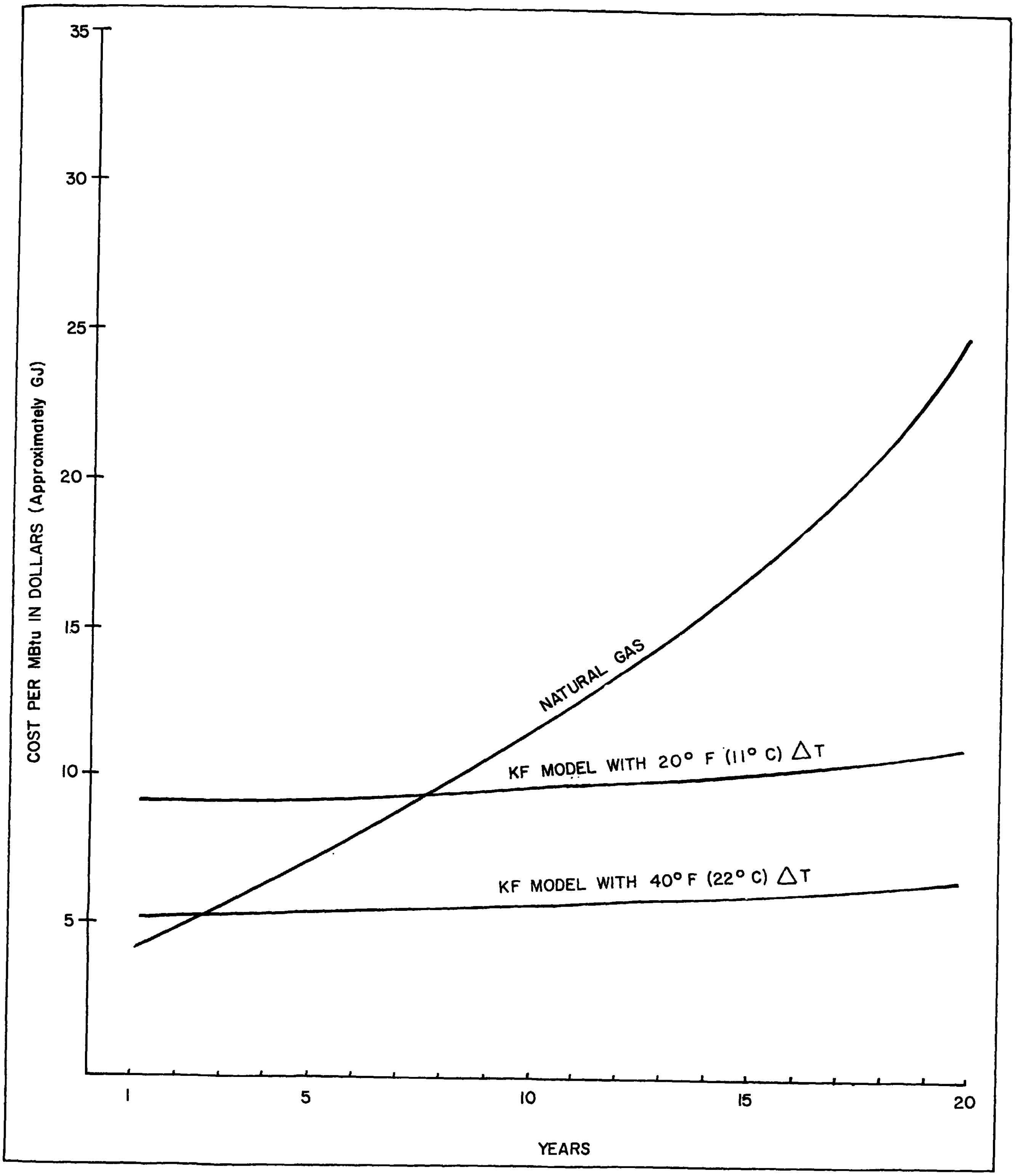
Graph 1 shows the hypothetical Klamath Falls heating-district model described in the economics section of this text. The cost of capital is 15% and the project life is 20 years. The inflation rates are the same as those assumed in the economics section in this chapter. For the remainder of this section, this district-heating model will be referred to as the KF Model. The graph depicts costs of the KF Model when comparing the extraction of 20°F (11°C) versus the extraction of 40°F (22°C) of heat. Retrofit costs for the 20°F (11°C) ΔT (ΔT = amount of heat removed) system were assumed to be minimal or zero, and retrofit costs for the 40°F (22°C) ΔT system were assumed to be $250,000. The yearly costs per MBtu of each of these systems are also compared to the forecast yearly costs of the present system, operating on natural gas.

It should be noted that the capital investment required for the 20°F (11°C) ΔT system is double the capital investment required for the 40°F (22°C) ΔT system, but that the retrofit costs are not required for the 20°F (11°C) ΔT system since the existing heating system is designed for a 20°F (11°C) ΔT. (This graph provides only an approximation since the cost of the secondary distribution line, concrete vaults and the primary supply line would increase by less than 200%.)

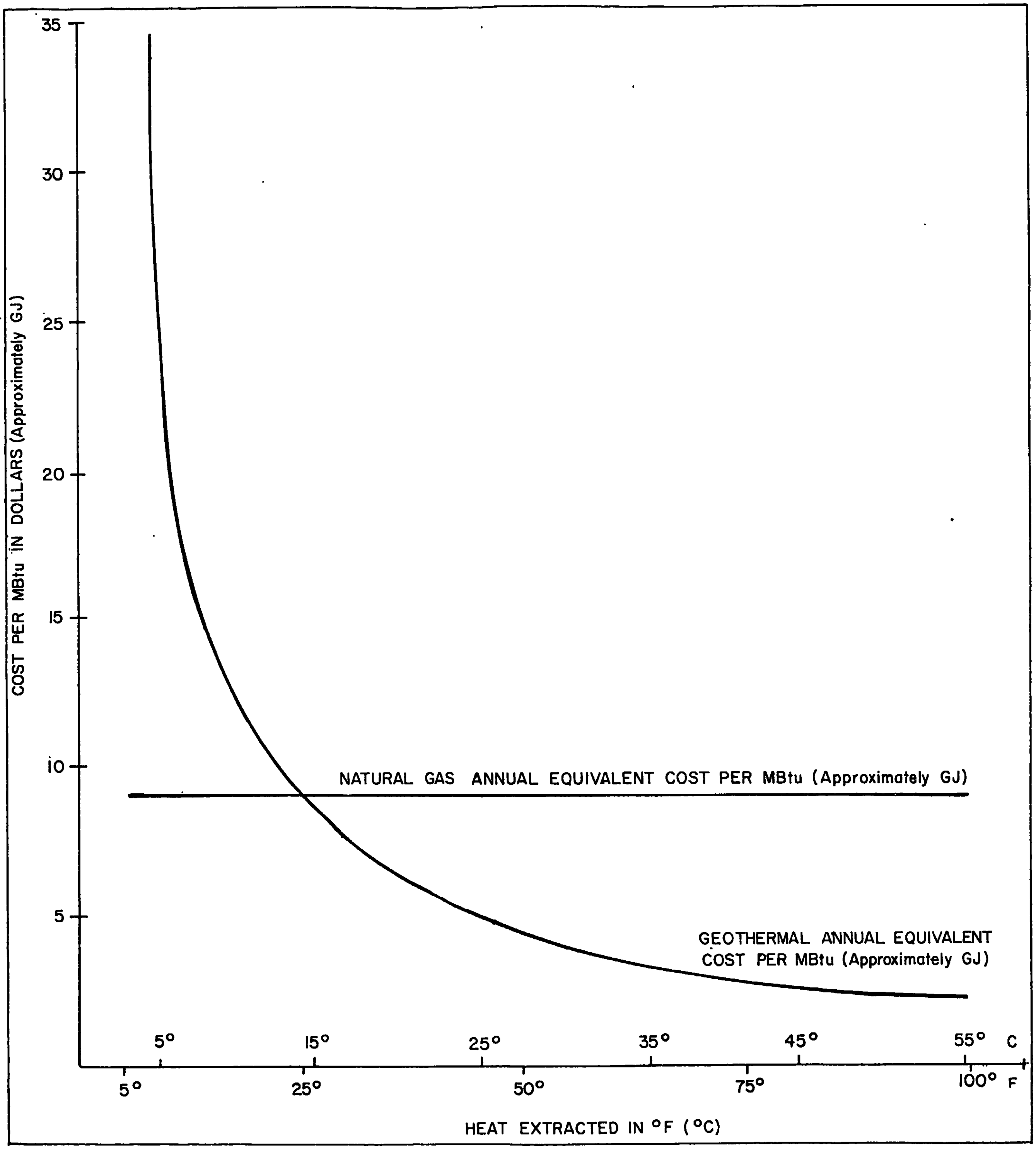
Graph 2 shows the KF Model with an annual load factor of 25%. Capital investment, operating and maintenance costs remain the same. It compares the 20-year annual equivalent cost per MBtu (GJ) resulting from heat extraction that ranges from 5°-100°F (3°-56°C), and the 20-year annual equivalent cost for natural gas. It can be seen that the systems break even at about 25°F (14°C) ΔT. A higher load factor would decrease the break-even ΔT.

ANNUAL LOAD FACTOR

The annual load factor depends upon the annual hours of operation of the system. For an industrial process application operating 24 hours per day, 365 days per year, the annual load factor is 100%. An industry operating 5 days per week would have an annual load factor of 23% per 8-hour shift. The KF Model has an annual load factor of 25% that is based on climatic conditions in Klamath Falls (6300 F degree days or 3500 C degree days).



GRAPH 1. KF Model cost per MBtu (GJ) as ΔT changes from 20°F (11°C) to 40°F (22°C) as compared to the forecast cost for natural gas inflating @ 12.2% through 1986 and at 8.5% thereafter.



GRAPH 2. KF Model with a 25% annual heat load factor showing 20-year annual equivalent costs per MBtu at 15% as the heat extracted varies from 5-100°F (3-56°C).

The annual load factor can be almost as influential on the cost of energy as the efficiency of the system. In the KF heating district, the geothermal system has been designed to supply the peak-load requirements, but the system is used only 25% of the time, based on that peak load. This 25% use reduces annual operation and maintenance costs, but does not make full use of the capital investment. The annual equivalent cost with a 15% cost of capital over a 20-year life for the KF Model is $5.58/MBtu ($5.29/GJ). If additional uses could be found for the available energy to increase the annual load to 100%, these uses would reduce the cost to $1.84/MBtu ($1.74/GJ). Therefore, as the annual load approaches 100%, the cost per MBtu (GJ) is significantly reduced.

Many heating districts have load factors in the range of 20-30%. If additional heat loads can be found to utilize the geothermal heat source during times other than peak heating periods, such uses would measurably improve the economic viability of the projects. One use for heating districts could be the provision of inexpensive air conditioning during the summer months. Absorption-type refrigeration units which can utilize heat from the geothermal system are readily available, but their addition would increase the capital investment required. It is expected, however, that the increased load factor will greatly offset incremental costs and thereby reduce the energy production costs. An industrial load coupled with space heating could also improve the load factor.

Graph 3 shows cost/MBtu (GJ) of the KF Model, holding capital investment constant and varying the annual load factor from 5% to 100%. The electrical pumping costs and the maintenance costs per MBtu vary directly with the annual load factor. On the other hand, the capital investment for the geothermal system is fixed and independent of the annual load factor. Therefore, these costs vary inversely with the annual load factor so that as the annual load factor increases, the annual equivalent cost of the capital investment per MBtu (GJ) decreases.

The graph indicates that there is a marked cost reduction as the load factor increases from 5% to 50%. This cost reduction tapers off and provides a savings of only $0.50/MBtu ($0.47/GJ) as the annual load factor increases from 70% to 100%.

In a plant using the heat for an industrial process, one should note the significant reduction in cost per million Btu's by operating two 8-hour shifts rather than one shift. Vertical lines indicate the annual load factors for an industrial process load operating one, two or three shifts five days per week.

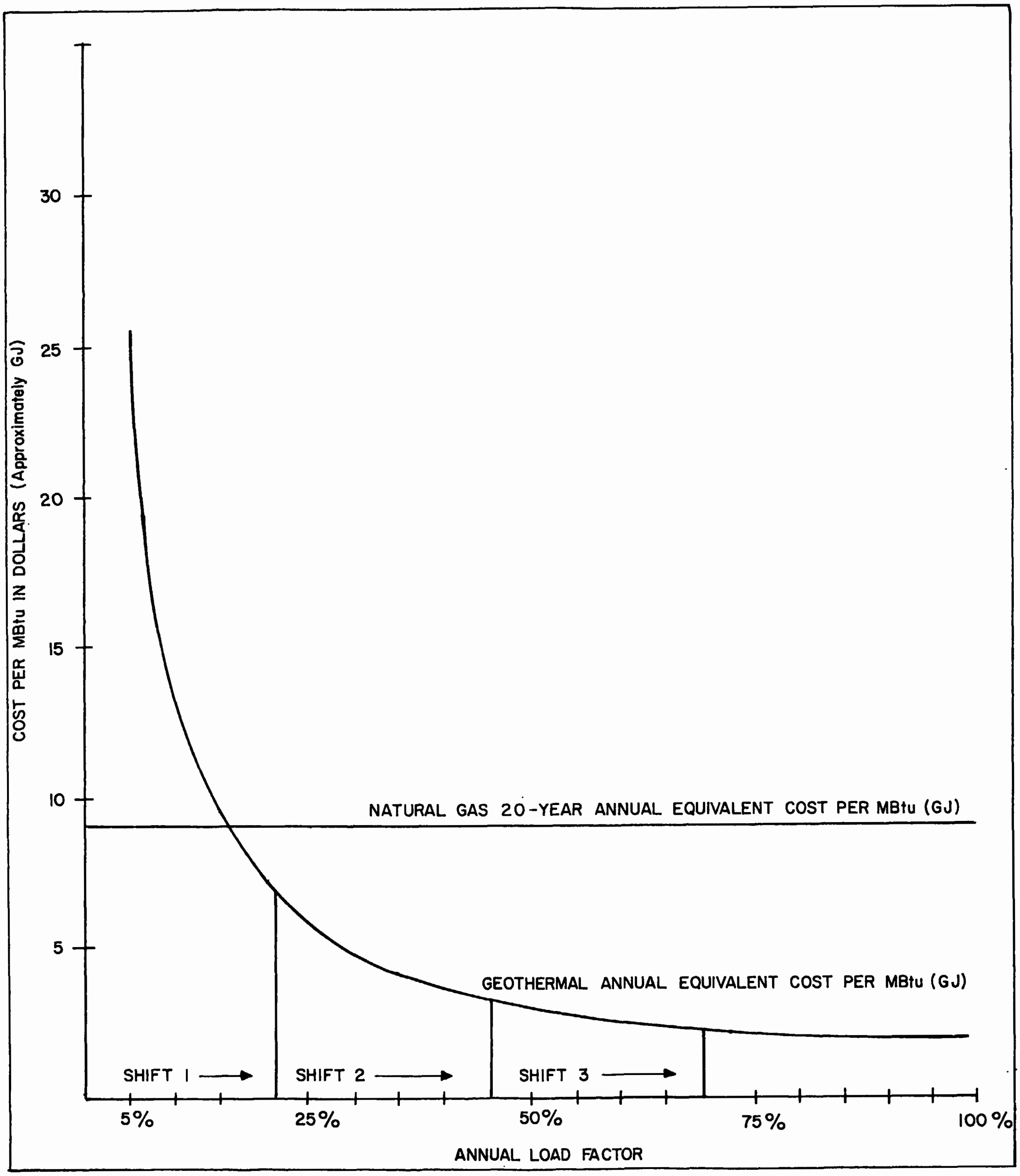
CAPITAL INVESTMENT

Transmission distance

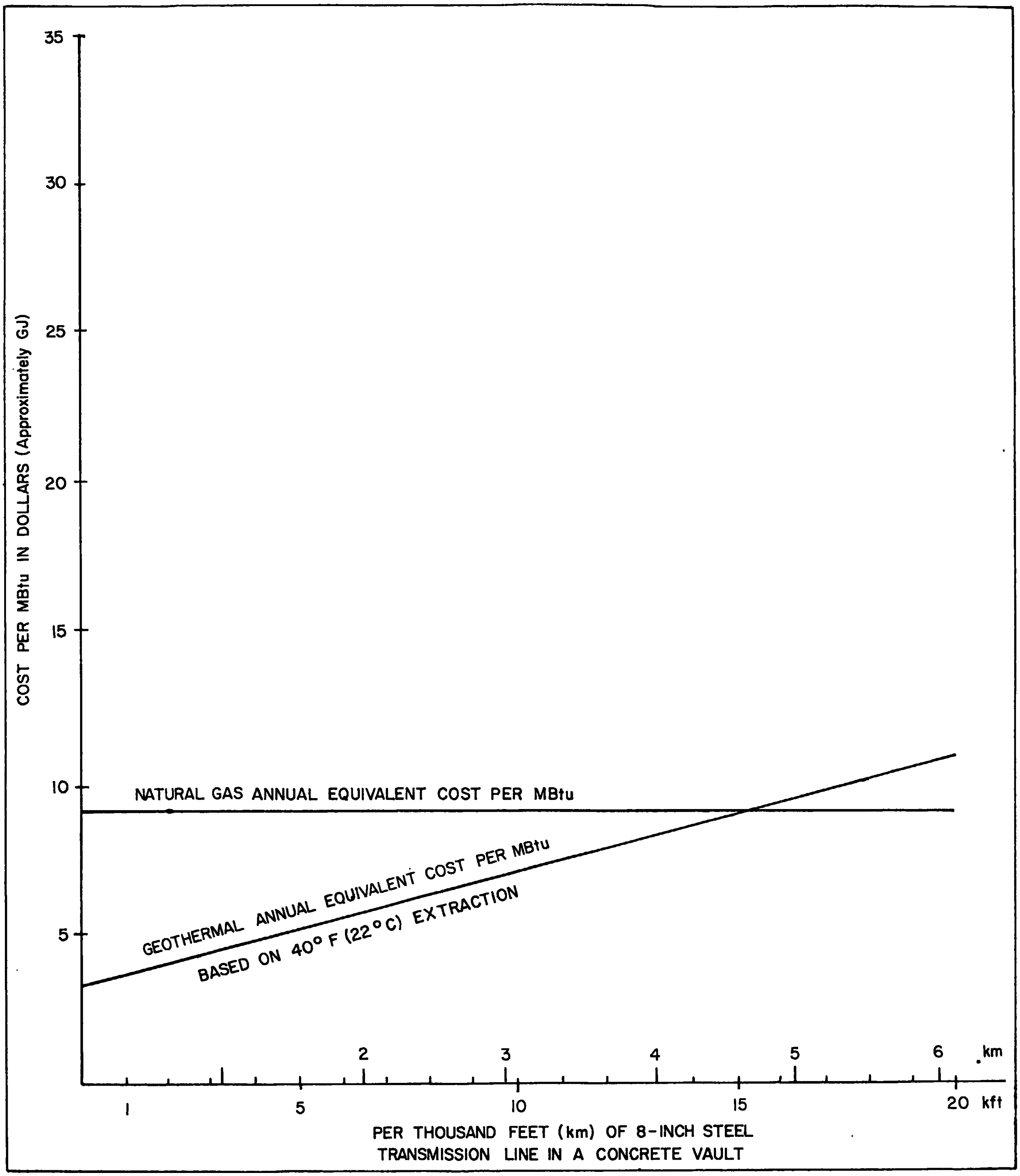
Geothermal pipelines are one of the largest capital investments in a geothermal system. Ideally, the well field and the user should be located close together. It is important that transmission lines be properly installed and insulated to reduce both heat loss and maintenance costs.

In the KF Model, an 8-inch (20-cm) supply line provided a maximum of 1390 gpm (88 l/s) of 200°F (93°C) water to a heat-exchanger building 4060 ft (1.24 km) from the resource. Based on the 25% load factor, the 20-year annual equivalent cost of the primary transmission line, at 15% cost of capital, is $1.55/MBtu ($1.47/GJ) or $0.38/MBtu/1000 ft ($1.18/GJ/km). Note that if the highway and railroad undercrossings were not required, the cost of the primary transmission line would be $0.31/MBtu/1000 ft ($0.96/GJ/km).

Graph 4 shows the cost/MBtu (GJ) of the KF Model extracting 40°F (22°C) from the geothermal fluid with a 25% annual load factor while varying the length of the primary transmission from 0



GRAPH 3. KF Model 20-year annual equivalent cost at 15% cost of capital as the annual load factor varies from 5% to 100%.



GRAPH 4. KF Model 20-year annual equivalent cost per MBtu (GJ) at 15% per thousand feet (km) of 8-inch (20 cm) transmission line in a concrete vault.

to 20,000 ft (0 to 6.1 km). It can been seen that transmission in excess of about 15,000 ft (4.6 km) may well be economically impractical.

Annual maintenance and pumping costs were not included in this graph. The annual maintenance costs for steel pipe in a concrete tunnel, properly installed, are extremely low. Pumping costs for the KF Model are negligible, since there is a slight down grade from the well head to the secondary pipeline. Nevertheless, it is worth considering that maintenance costs and pumping costs, along with temperature loss, would normally increase the costs per MBtu (GJ) slightly more than the graph indicates.

Drilling costs versus confidence level

The cost of drilling into a productive geothermal resource is site specific and highly variable. Drilling costs are directly affected by the geologic conditions, resource depth, site accessibility and the temperature of the resource.

One extreme example is Lava Hot Springs, Idaho, where 140°F (60°C) water is commonly encountered at depths of 6-10 ft (2-3 m). Thus, wells are dug with a back hoe. In contrast, geothermal wells elsewhere have been drilled into high-temperature resources at depths of over 10,000 ft (3 km) requiring expensive oil-well drilling and blowout-protection equipment. It is obvious, therefore, that drilling costs are a major component of the capital investment required for a geothermal heating system.

Drilling for geothermal resources can be risky. Some dry holes have been drilled even in areas known to contain geothermal resources and in areas delineated by state-of-the-art geologic, geophysical and geochemical studies. For example, Klamath Falls, Oregon, has over 500 geothermal wells; the resource is well defined; however, in spite of this, several drilling attempts near "good" wells have been unsuccessful, resulting either in "dry holes" or cold water.

The probability of completing a geothermal well that has the desired temperature and flow rate is referred to as the confidence level. In a known geothermal resource area where geologic studies indicate a 90% confidence level of reaching 200°F (93°C) temperature at 1000 ft (305 m) with a 60% confidence level of striking an aquifer at this depth, then the confidence level is 0.9 x 0.6 = 0.54 or 54%. This means that approximately two wells would have to be drilled in order to obtain one successful well. As one can readily see, drilling costs combined with the confidence level play a major role in determining the feasibility of a project or the value of the resource.

Though the costs of drilling an unsuccessful well are lower than for a successful one, because an unsuccessful well probably requires only surface casing while a successful one requires full casing, etc., even a dry hole can cost up to $75/ft ($80/m)--a very significant sum for a 1000-ft (305-m) well.

The KF Model requires three production wells drilled to 1000 ft (305 m) with drilling costs of $17,000 each. As the confidence level drops from 100% to 80%, the increase in cost is $0.03/MBtu ($0.03/GJ). A confidence level of 50% increases the cost to $0.14/MBtu ($0.13/GJ). By comparison, suppose the anticipated depth of a production well was 5000 ft (1524 m) and the cost of drilling an unsuccessful well increased from $17,000-$200,000. As the confidence level decreases from 100% to 50%, the annual equivalent cost increases by $1.60/MBtu ($1.52/GJ). The above figures are based on a 20-year life and a 15% cost of capital and are calculated as follows:

$$I = \frac{\left(\frac{P}{C} - P\right) d_u \left[\frac{i(1+i)^n}{(1+i)^n - 1}\right]}{L}$$

Where P = The number of production wells required
C = Confidence level (as a decimal number)
d_u = Drilling cost of an unsuccessful well
i = Interest rate (cost of capital or return on investment)
n = Life of the project in years
L = Annual heat load in MBtu (GJ)
I = Incremental annual equivalent cost per MBtu (GJ)

Graph 5 pertains to the KF Model which has an annual heat load of 6.0×10^4 MBtu (5.7×10^4 GJ), a 20-year life and a 15% cost of capital. The graph plots the change in annual equivalent cost per MBtu (GJ) for a $17,000 well and a $200,000 well as the confidence level changes from 100% to 10%. These annual equivalent costs are compared with the 20-year annual equivalent cost of natural gas. The confidence level has little effect on the $17,000 well, but if drilling costs were $200,000 per well, the project would break even with the cost of natural gas at a confidence level of 50%.

COST OF CAPITAL

Graph 6 compares the 20-year annual equivalent cost of geothermal energy to the cost of natural gas for the KF Model as the cost of capital or return on investment (i) varies from 5% to 60%. Three different annual load factors are plotted. The 25% load factor breaks even with natural gas at about i = 28%. The 50% load factor breaks even with natural gas at about i = 38%, and the 75% load factor breaks even with natural gas at about i = 57%.

The Klamath Falls Model is a typical heating district developed by a municipality. The entire system was financed with city, county, state and federal funds. The production wells, transmission and distribution pipelines and injection well were all located on land owned by the city.

In a discussion of pricing of direct-use geothermal energy, it is necessary to consider that the owner of a resource may wish to develop that resource and sell the energy to a user, in this case, a heating district. The price charged by the developer would have to provide an advantage over conventional energies in order to persuade the user to abandon his present heating system and purchase geothermal energy.

Table 1 presents a pro forma income statement projected over a 20-year period, with the following assumptions:

1. The geothermal developer owns the resource.

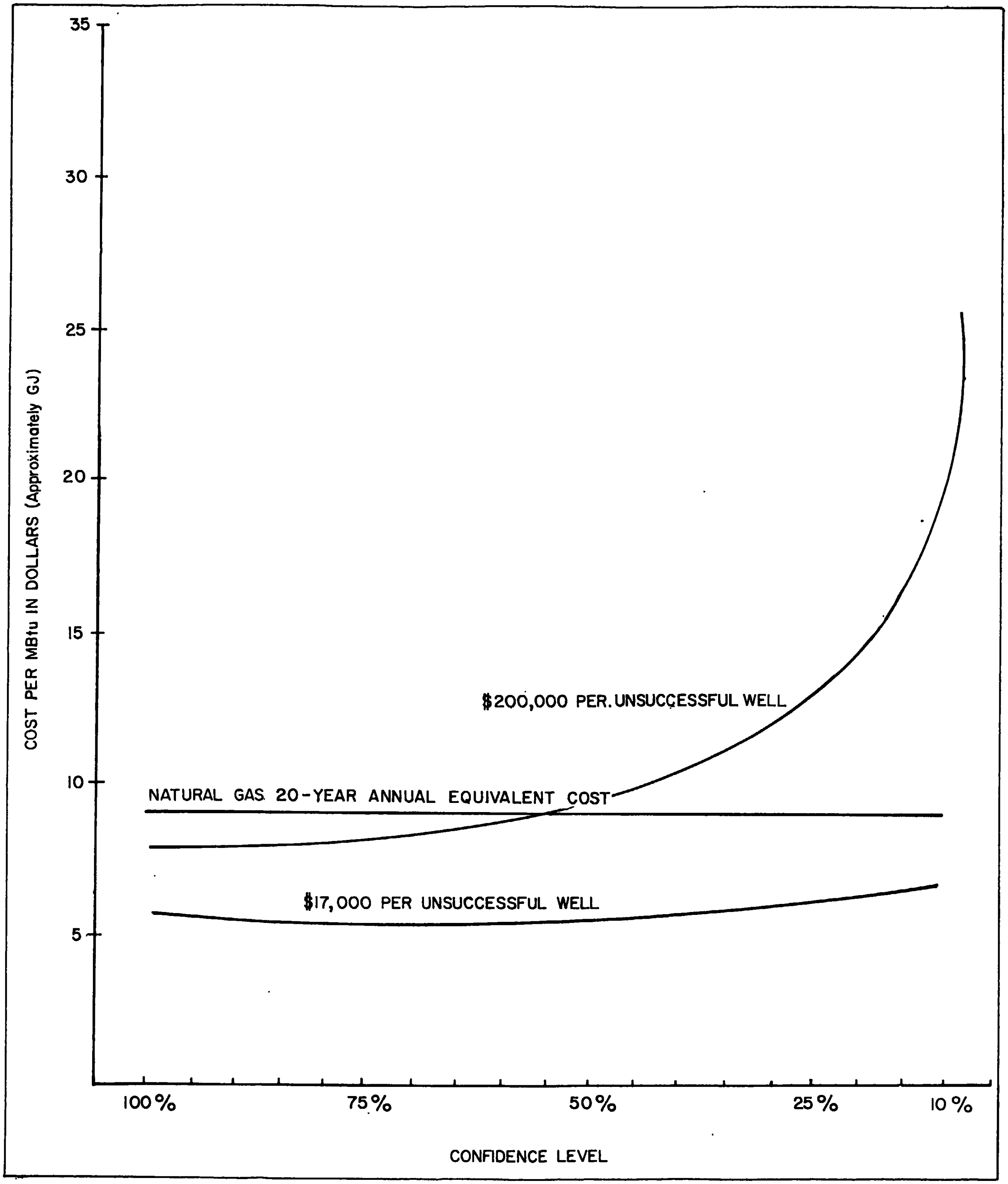
2. The developer will bear the cost of the entire geothermal system including $500,000 retrofit costs for the existing buildings.

3. The developer can borrow money at the prime interest rate of 15% (this would probably be higher).

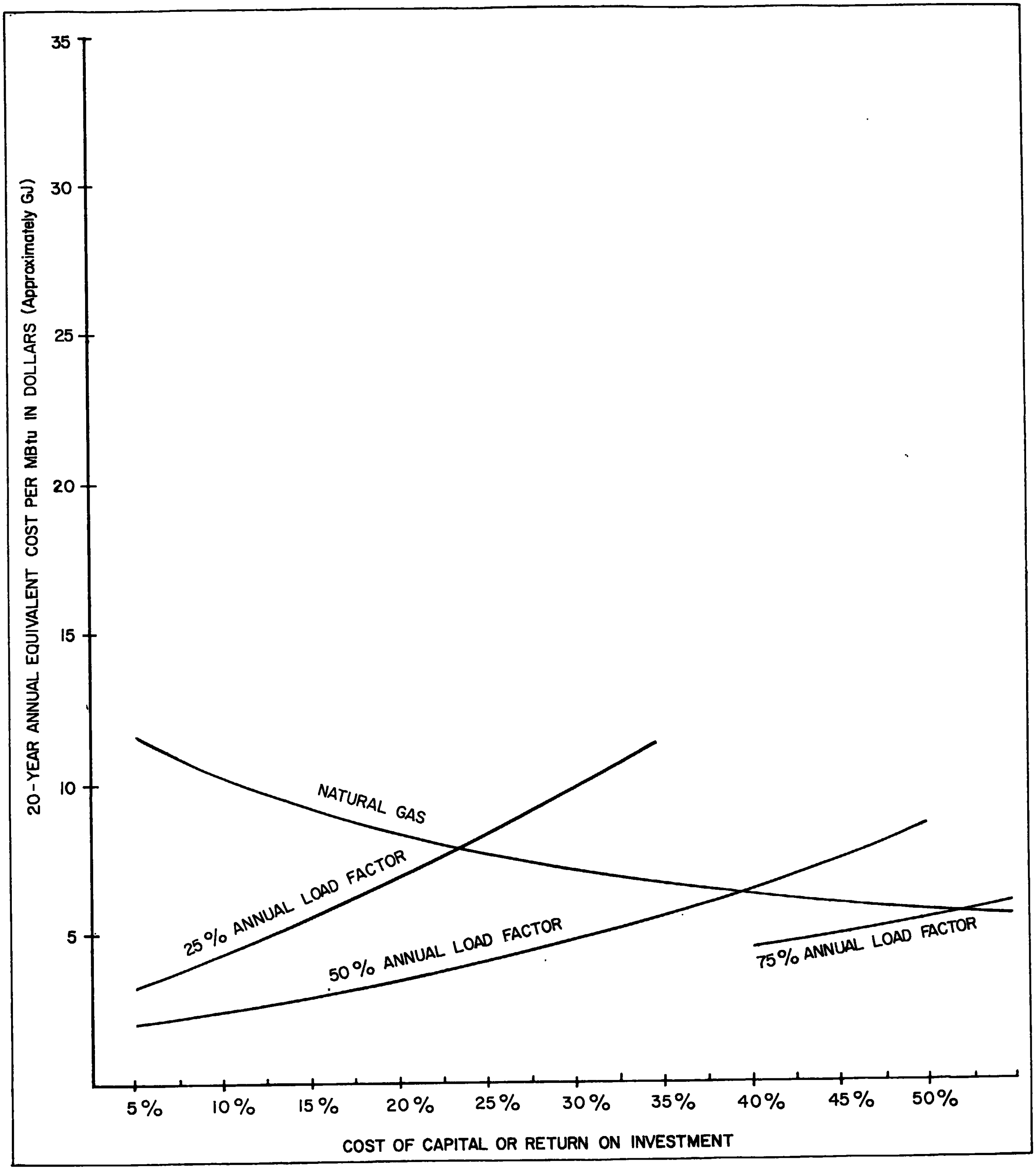
4. The developer agrees to sell energy to the heating district at a rate that is 10% lower than the cost of natural gas.

5. The developer will maintain the system. This cost is estimated to be $8547/year plus $30,000 for salaries.

6. Insurance for the system, excluding reservoir insurance, will cost 0.6%/year of the total capital investment.



GRAPH 5. Confidence level vs. drilling costs.



GRAPH 6. Natural gas vs. cost of capital vs. annual load factors.

TABLE 1

PRO FORMA INCOME STATEMENT
PROJECTED FOR 20 YEARS

(ALL COSTS AND REVENUES ARE STATED IN TERMS OF PER MBtu [APPROXIMATE GJ] PER YEAR)

Year	Gross Sales	Geothermal System Electrical Costs	Geothermal System Maintenance	Geothermal Maintenance Salaries	Geothermal System Insurance	Total Variable Geothermal Costs	Annual Loan Payment	Total Cost	Net Income Before Taxes	Present Worth At 7%
Present Cost	3.71	0.18	0.14	0.50	0.24					
1	4.159	0.202	0.152	0.535	0.242	1.131	6.319	7.450	-3.292	-3.076
2	4.666	0.221	0.163	0.572	0.247	1.203	6.319	7.522	-2.856	-2.495
3	5.235	0.242	0.175	0.613	0.252	1.281	6.319	7.600	-2.364	-1.930
4	5.874	0.265	0.187	0.655	0.257	1.364	6.319	7.683	-1.809	-1.380
5	6.591	0.290	0.200	0.701	0.262	1.453	6.319	7.772	-1.181	-0.842
6	7.395	0.317	0.214	0.750	0.267	1.549	6.319	7.868	-0.473	-0.315
7	8.297	0.347	0.229	0.803	0.273	1.652	6.319	7.971	0.326	0.203
8	9.002	0.377	0.245	0.859	0.278	1.759	6.319	8.078	0.924	0.538
9	9.767	0.410	0.262	0.919	0.284	1.874	6.319	8.194	1.574	0.856
10	10.597	0.445	0.280	0.984	0.289	1.998	6.319	8.317	2.280	1.159
11	11.498	0.483	0.300	1.052	0.295	2.130	6.319	8.449	3.049	1.448
12	12.476	0.524	0.321	1.126	0.301	2.272	6.319	8.591	3.884	1.725
13	13.536	0.569	0.343	1.205	0.307	2.425	6.319	8.744	4.792	1.989
14	14.687	0.618	0.367	1.289	0.313	2.588	6.319	8.907	5.780	2.241
15	15.935	0.671	0.393	1.380	0.319	2.763	6.319	9.082	6.853	2.484
16	17.289	0.729	0.421	1.476	0.326	2.951	6.319	9.270	8.019	2.716
17	18.759	0.791	0.450	1.579	0.332	3.153	6.319	9.472	9.287	2.940
18	20.354	0.859	0.481	1.690	0.339	3.370	6.319	9.689	10.665	3.155
19	22.084	0.933	0.515	1.808	0.346	3.602	6.319	9.921	12.162	3.363
20	23.961	1.013	0.551	1.935	0.353	3.852	6.319	10.171	13.790	3.564
									TOTAL PRESENT WORTH	18.34

The pro forma income statement shows projected cash flows per MBtu (GJ) using the same inflation rates as those in the economics section of this chapter. Salaries were assumed to increase at the economic inflation rate of 7% and insurance costs were projected to increase 2%/year. It should be noted that because of the high capital investment required, the system operates at a loss for the first six years and requires the next six years to recover these losses. With a 7%/year inflation rate, the present worth of the 20-year cash flows to the developer is $18.34/MBtu ($17.38/GJ) before taxes. If a developer were in a 50% effective tax bracket, the present worth would be reduced to $9.17/MBtu ($8.69/GJ).

Table 2 uses the data from Table 1 with the assumption that the developer does not own the resource. The developer pays a royalty of 10% of gross sales to the owner of the resource. Notice that such an arrangement causes the project to operate in the red for the first seven years and requires the next seven and a half years to recover these losses. The present worth of the 20-year cash flow to the developer is $7.78/MBtu ($7.37/GJ) before taxes or $3.89/MBtu ($3.69/GJ) after taxes.

TABLE 2

EXTENSION OF 20-YEAR PRO FORMA INCOME STATEMENT
PAYING 10% OF GROSS SALES ROYALTIES TO THE LANDOWNER

(ALL FIGURES ARE IN TERMS OF PER MBtu [APPROXIMATE GJ])

Year	Less 10% Royalty	Net Income After Royalties	Present Worth At 7%	% of Increase In Variable Costs Due to 10% Royalties
1	0.416	-3.707	-3.465	36.7
2	0.467	-3.323	-2.902	38.8
3	0.524	-2.888	-2.357	40.9
4	0.587	-2.396	-1.828	43.0
5	0.659	-1.840	-1.312	45.3
6	0.739	-1.213	-0.808	47.7
7	0.830	-0.504	-0.314	50.2
8	0.900	0.024	0.014	51.1
9	0.977	0.597	0.325	52.1
10	1.060	1.221	0.621	53.0
11	1.150	1.899	0.902	53.9
12	1.248	2.637	1.171	54.9
13	1.354	3.439	1.427	55.8
14	1.469	4.311	1.672	56.8
15	1.593	5.259	1.906	57.7
16	1.729	6.290	2.131	58.6
17	1.876	7.411	2.346	59.5
18	2.035	8.629	2.553	60.4
19	2.208	9.954	2.752	61.3
20	2.396	11.394	2.944	62.2
		TOTAL PRESENT WORTH	7.78	

Table 3 presents a 20-year cash flow for the resource owner and shows a present worth of $10.57/MBtu ($10.02/GJ) before taxes of $5.29/MBtu ($5.01/GJ) after taxes.

TABLE 3

20-YEAR CASH FLOW OF ROYALTY PAYMENTS
PER MBtu (GJ) TO THE RESOURCE OWNER

Year	Royalty Revenue	Present Worth at 7%
1	0.416	0.389
2	0.467	0.408
3	0.524	0.427
4	0.587	0.448
5	0.659	0.470
6	0.739	0.493
7	0.830	0.517
8	0.900	0.524
9	0.977	0.531
10	1.060	0.539
11	1.150	0.546
12	1.248	0.554
13	1.354	0.562
14	1.469	0.570
15	1.593	0.578
16	1.729	0.586
17	1.876	0.594
18	2.035	0.602
19	2.208	0.611
20	2.396	0.619
	TOTAL PRESENT WORTH	10.57

To summarize these data over the 20-year project life in terms of present worth at 7% per annum:

Developer A develops the resource on his own land and earns \$9.17/MBtu (\$8.69/GJ) after taxes (Table 1).

Developer B leases the resource, paying a royalty of 10% of gross sales to the resource owner and earns \$3.89/MBtu (\$3.69/GJ) after taxes (Table 1 modified by Table 2).

The landowner earns royalties of \$5.29/MBtu (\$5.01/GJ) after taxes.

The assumption of a 10%-of-gross-sales royalty was based on the fact that the federal government currently charges a royalty of 10% of gross energy sales for geothermal energy developed on federal lands. Since the federal government is exempt from taxes, the present worth of the 20-year cash flows of royalty payments would be \$10.57/MBtu (\$10.02/GJ). If the KF Model is a typical example, the federal government would receive a higher present worth per MBtu (GJ) than any other participant. Surface lease costs were not considered in this analysis. Such costs would increase the benefit to the resource owner considerably more than is indicated. The KF Model is not a good investment unless the production wells can be drilled on the city's own property with a cost of capital considerably less than 15%. Table 4 shows the capital investment costs of the KF Model.

In order to provide further perspective on the major factors which influence the value of a geothermal resource, we can examine two actual applications. These will be referred to as Case A and Case B. Both cases occur in well established geothermal resource areas with an established history of production.

TABLE 4

KF MODEL
BREAKDOWN OF SYSTEM COSTS PER MBtu
ASSUMES A 20-YEAR LIFE AND 15% COST OF CAPITAL

TOTAL COST SUMMARY

Item	Cost	Including 10% Contingency Plus 5% Inflation	20-Yr. Annual Equivalent Cost @ 15%	Cost/MBtu (Approx GJ)	% of Total
WELL AND WELL HEAD EQUIPMENT					
Production well	$ 38,898	$ 44,733	$ 7,147	$ .119	
Well pump	41,988	48,286	7,714	.12857	
Well head bldg	3,500	4,025	643	.0107	
Power hook-up	500	575	92	.00153	
Total/1 Well	84,886	97,619	15,596	.2598	
SUBTOTAL/3 WELLS	$254,658	$292,857	$46,788	$ .7794	16%
DISTRIBUTION PIPING NETWORK					
Primary supply	$ 506,175	$ 582,101	$ 92,997	$1.5499	
Secondary supply	637,060	732,619	117,044	1.9507	
SUBTOTAL	$1,143,235	$1,314,720	$210,041	$3.5	70%
HEAT EXCHANGER BUILDING					
Plate H.E.	$ 28,000	$ 32,200	$ 5,144	$ .0857	
Control system	44,537	51,218	8,183	.13638	
Circulation pump	27,382	31,489	5,031	.0838	
Expansion/surge tank	5,000	5,750	919	.0153	
Building and installation	90,000	103,500	16,535	.2756	
Injection well	30,000	34,500	5,512	.0919	
Building and hook-up	3,500	4,025	643	.0107	
Injection pump	2,587	2,975	475	.0079	
SUBTOTAL	$ 231,006	$ 265,657	$ 42,442	$ .7074	14%
TOTAL	$1,628,899	$1,873,234	$299,271	$4.99	

Case A is a 200-bed hospital with an annual heat load of 1.89 x 10^4 MBtu (1.79 x 10^4 GJ). The hospital drilled an on-site geothermal well to a depth of 1582 ft (482 m). The well cost $32,915.00. It produced 400 gpm (25 l/s) of 191°F (88°C) water with a static level of 332 ft (101 m) and a drawdown of 15 ft (4.6 m). A 100-horsepower, 500 gpm (31.5 l/s) deep-well turbine pump was set at 550 ft (168 m). The pump cost $29,100. Total cost to the hospital for pipelines, shell-and-tube heat exhangers and installation was $250,250. These costs were financed by an 8% bond maturing in 20 years. The system reduced the annual heating costs of natural gas and diesel fuel by $31,200 in the first year of operation. The projected 20-year annual equivalent cost using natural gas and diesel fuel is $6.60/MBtu ($6.26/GJ). Actual fuel costs over the past three years indicate that this estimate is ultra conservative. The 20-year annual equivalent cost of the geothermal system is $2.34/MBtu ($2.22/GJ). This includes the interest and the payoff of the bonds issued. The average annual equivalent savings are $80,301 over the 20-year period. Based on the quality of the resource, the actual life of the system is anticipated to be 40 years, an unexpected benefit. Because of the over-design of the hospital heating system and the temperature of the resource, the hospital was able to extract 80°F (44°C) from the geothermal resource.

Case B is a much smaller hospital with an annual heat load of 5.556 x 10^3 MBtu (5.27 x 10^3 GJ). A 1500-ft (457-m) well had been developed 1700 ft (518 m) from the hospital. This well produced 170°F (77°C) water at 240 gpm (15 l/s) with water quality less than that of Case A. Because the resource was known to exist at 1500 ft (457 m), Case B presents an excellent example for a comparison to Case A. The cost to develop a geothermal system was estimated to be identical to Case A ($250,250). With less than 30% of the heat load required for Case A, the need for 400 gpm (25 l/s) did not exist. The existing heating system in this hospital required 180°F (82°C) supply temperature with 160°F (71°C) return fluid (20°F [11°C] ΔT). The water quality of the resource dictated a plate heat exchanger to isolate the geothermal fluid from the hospital heating system. Because a 10°F (5°C) temperature drop would occur from the primary to the secondary fluid, the supply temperature would be only 160°F (71°C), the same temperature as the return fluid in the existing system. Therefore, this hospital heating system would require $25,000 for retrofit in order to extract a 20°F (11°C) ΔT from 160°F (71°C) supply water. At an 8% cost of capital, the 20-year annual equivalent would be $5.04/MBtu ($4.78 GJ). The cost of pumping and $2500 per year maintenance, due to poorer water quality, totals $4.19/MBtu ($3.97/GJ) annually. The total annual equivalent cost for the whole project is $9.23/MBtu ($8.75/GJ) for the geothermal system as compared to a 20-year annual equivalent cost of $6.35/MBtu ($6.02/GJ) for natural gas.

As an alternative, the hospital considered buying 170°F (77°C) water delivered at the site by a geothermal developer at a price of $0.45/100 ft^3 ($0.16/m^3), thus eliminating all but the retrofit costs. The consequences of buying energy at $0.45/100 ft^3 ($0.16/m^3) and extracting only 20°F (11°C) ΔT would result in a 20-year annual equivalent cost of $6.67/MBtu ($6.32/GJ), assuming a 7% per year price escalation rate by the supplier of the geothermal fluid. In the year following this study, the geothermal supplier increased his price by 24%, making the marginal project totally unfeasible. This hospital continues to operate on natural gas.

SUMMARY

When direct-use geothermal applications for space or process heating are evaluated, experience has shown that each study must be site-specific.

A recipe for maximizing the benefit of direct-use geothermal energy is:

1. Develop resources at shallow depths with flow rates and temperatures that are compatible to the user. Good to excellent water quality is important.

2. Keep distances between the production well and the user to an absolute minimum, i.e., short pipelines.

3. Seek or develop uses that will require an annual load factor of at least 25%; 50% or greater is preferred.

4. Obtain low interest loans and be willing to reduce the rate of return on investment in order to reap the long-run benefits.

If prices or royalties are to be charged in situations where the developer and the user are different organizations, then values must be assessed against the annual savings or cost benefit resulting from the geothermal system. This price or royalty must be evaluated for each and every application. Each direct-use geothermal application is unique with supply and demand dedicated to each other.

Consider the two actual applications, Cases A and B, in this chapter. Case A describes a very valuable resource with substantial savings to the user over a 40-year period, while Case B, with a resource only 20°F (11°C) lower in temperature, is of no value to the user.

To establish a price for direct-use geothermal energy, one must study the structures and characteristics of the costs presented in this chapter. One should also keep in mind the aspects and lessons of Case A and Case B. Our case rests.