MIT-EL 90-001

Energy Laboratory

Massachusetts Institute
of Technology

Economic Predictions for Heat Mining: A Review and Analysis of Hot Dry Rock (HDR) Geothermal Energy Technology

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Final Report
for the
U.S. Department of Energy
Geothermal Technology Division

MIT-EL 90-001

July 1990

Acknowledgement

The authors would like to express their appreciation to those individuals who provided important data and comments. Although it would be impossible to name them all, J.N. Albright, H.C.H. Armstead, A.S. Batchelor, D.W. Brown, F. Cochrane, R.E. Cummings, D. Duchane, R.B. Duffield, J. Dunn, D. Entingh, S. Fleming, R. Grieder, C.O. Grigsby, R. Hendron, A. Jelacic, J.E. Livesay, J.E. Mock, G. Morris, H.D. Murphy, C.W. Myers, R. Nicholson, J. Owen, R.M. Potter, J.E. Rannels, F. Roach, B.A. Robinson, I. Smith, M.C. Smith, C. Tosaya, R. Traeger, and J. Whetten were especially helpful. J. Hale is gratefully acknowledged for her help in preparing the report. The Geothermal Technology Division of the U.S. Department of Energy, Sandia National Laboratories and the MIT Energy Laboratory provided partial support for this project. The views and opinions presented in this report are solely those of the authors, and as such, do not necessarily reflect an endorsement by the U.S. Government, its agencies or laboratories.

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1. Objectives and Scope

The HDR geothermal energy resource is associated with accessible regions of hot rock beneath the earth's surface that do not contain sufficient natural porosity or permeability. Energy can be extracted by creating artificial permeability using hydraulic stimulation techniques to propagate and open joints or fractures. The resulting fracture network is connected to a set of injection and production wells where heat is removed by circulating water under pressure from the surface, down one well, through the fractured zone, and up a second well. Electricity and/or process steam would then be generated using the heated water in an appropriately designed power plant. This *heat mining* concept is closed-loop on the geothermal side so there are no effluents, thus minimizing the environmental impact of the HDR "fuel cycle" to site preparation, well drilling, and other land use issues.

Because HDR systems do not require natural, indigenous hot fluids and high permeability, the HDR resource itself can be defined by the accessible thermal energy in the earth's crust above some minimum temperature level. Thus the size of the HDR resource is very large and more widely distributed than natural geothermal systems. For example, in the U.S., to a 10 km depth assuming an average geothermal temperature gradient of 25°C/km and a minimum initial rock temperature of 150°C, the amount of thermal energy in place is about 10 million quads[1] (Tester, Brown, and Potter (1989)). Worldwide the HDR resource base is estimated at over 100 million quads (Armstead and Tester (1987)). Based on the enormous size and ubiquitous distribution of the resource and its positive environmental characteristics, HDR could provide an acceptable alternative to the fossil and nuclear options for meeting a substantial fraction of worldwide electric power and space and process heat demand.

The main objectives of this study were first, to review and analyze several economic assessments of Hot Dry Rock (HDR) geothermal energy systems, and second, to reformulate an economic model for HDR with revised cost components. The economic models reviewed include the following studies sponsored by:

1. Electric Power Research Institute (EPRI)--Cummings and Morris (1979)

2. Los Alamos National Laboratory (LANL)--Murphy, et al. (1982)

3. United Kingdom (UK)--Shock (1986)

4. Japan--Hori, et al. (1986)

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[1] 1 quad = 10^{15} BTU = 1.055×10^{18} J ≈ 180 million barrels of oil equivalent

5. Meridian--Entingh (1987)

6. Bechtel (1988)

A general evaluation of the technical feasibility of HDR technology components was also conducted in view of their importance in establishing drilling and reservoir performance parameters required for any economic assessment (see Sections 2-5). In our review, only economic projections for base load electricity produced from HDR systems were considered. Bases of 1989 dollars ($) were selected to normalize costs.

Following the evaluation of drilling and reservoir performance, power plant choices and cost estimates are discussed in Section 6. In Section 7, the six economic studies cited earlier are reviewed and compared in terms of their key resource, reservoir and plant performance, and cost assumptions. Based on these comparisons, we have estimated parameters for three composite cases. Important parameters include: (1) *resource quality*--average geothermal gradient (°C/km) and well depth, (2) *reservoir performance*--effective productivity, flow impedance, and lifetime (thermal drawdown rate), (3) *cost components*--drilling, reservoir formation, and power plant costs and (4) *economic factors*--discount and interest rates, taxes, etc. In Section 8, composite case conditions were used to reassess economic projections for HDR-produced electricity. In Section 9, a generalized economic model for HDR-produced electricity is presented to show the effects of resource grade, reservoir performance parameters, and other important factors on projected costs. A sensitivity and uncertainty analysis using this model is given in Section 10. Section 11 treats a modification of the economic model for predicting costs for direct, non-electric applications. HDR economic projections for the U.S. are broken down by region in Section 12. In Section 13, we provide recommendations for continued research and development to reduce technical and economic uncertainties relevant to the commercialization of HDR.

2. HDR Resource Quality and Drilling

The development of the HDR resource at a particular location depends largely on being able to gain access to high rock temperatures which will lead to acceptable fluid temperatures for generating electric power. Although some exploration for locating high quality HDR resources is required, the difficulty and costs associated with locating a suitable HDR site are far less than for hydrothermal or fossil fuel resource development. In fact, the more or less ubiquitous nature of the HDR resource suggests that its *grade* in terms of average geothermal gradient will be the single key factor influencing the "commercial-quality" of a particular site. In *Heat Mining*, Armstead and Tester (1987) subdivide the grade of HDR resources in the U.S. into two categories, *thermal* with above average gradients ≥38°C/km and *non-thermal* with gradients of about 20 to 25°C/km. About 16% of the land area in the U.S. can be categorized as a thermal area with a significant fraction existing in hyperthermal regions near or within active hydrothermal systems. A typical range for average gradients in such hyperthermal systems would be from 60 to 80°C/km. Fenton Hill, NM and Roosevelt Hot Springs, UT fall into this latter category.

Therefore, in order to evaluate a range of HDR grades, economic studies frequently examine several gradients or try to parameterize the effect of gradient on costs. Milora and Tester (1976) were the first to do this for generic HDR resources. Their estimates were later updated by Cummings and Morris (1979), Tester (1982), and Armstead and Tester (1987). In other studies, for example, Murphy et al. (1982), Japan (1986), and Bechtel (1988), specific sites were selected to establish resource parameters.

In establishing HDR economic feasibility requirements in this study, we examined a range of gradients within three separate HDR resource grades:

1. *High* (with high gradients $\langle \nabla T \rangle$ = 80°C/km)
2. *Mid* (with above normal gradients $\langle \nabla T \rangle$ = 50°C/km)
3. *Low* (with near-normal gradients $\langle \nabla T \rangle$ = 30°C/km)

The next set of issues has to do with estimating costs for drilling and completing wells to gain access to the HDR resource. Although HDR reservoir temperatures are selected as a design choice, an acceptable range can easily be bracketed for electric power applications. In any situation, one balances the cost of producing the fluid against the cost of converting its thermal energy into electric power. Effectively, this is equivalent to balancing drilling costs against power plant capital costs to reach a minimal total cost corresponding to optimal design temperature or reservoir depth for a particular HDR site. These effects are illustrated in Figure 2.1. Using the dashed line for reference, one can see that reservoir design temperature range from about 140°C for low gradient areas (20°C/km) to about 250°C or more for high gradient areas (>80°C/km) with a fairly flat minimum. Strictly speaking, the actual values of these reservoir design temperature optima depend on the capital costs and system performance assumptions used. (These points are revisited again in Section 9).

Thus, although no absolute quantitative conclusion can be made at this time, a reasonable range for optimal drilling depths for HDR electric power systems can be specified for each resource grade based on earlier studies as shown in Table 2.1 (see Armstead and Tester (1987) Ch. 14 and Tester (1982)):

TABLE 2.1 ESTIMATED OPTIMAL TEMPERATURES AND DEPTHS FOR HDR RESOURCES

HDR resource grade	∇T	Optimal depth range*	Optimal initial reservoir temperature range
	°C/km	km	°C
1. *High* (high gradient)	80	2.9-3.6	250-300
2. *Mid* (above-normal gradient)	50	3.1-4.5	170-240
3. *Low* (near-normal gradient)	30	4.2-6.5	140-210

* an average ambient surface temperature of 15°C was assumed

Consequently, from the table above we are particularly interested in estimating the drilling costs for wells in HDR service over depths ranging from about 2.9 to 6.5 km (9,500 to 21,400 ft).

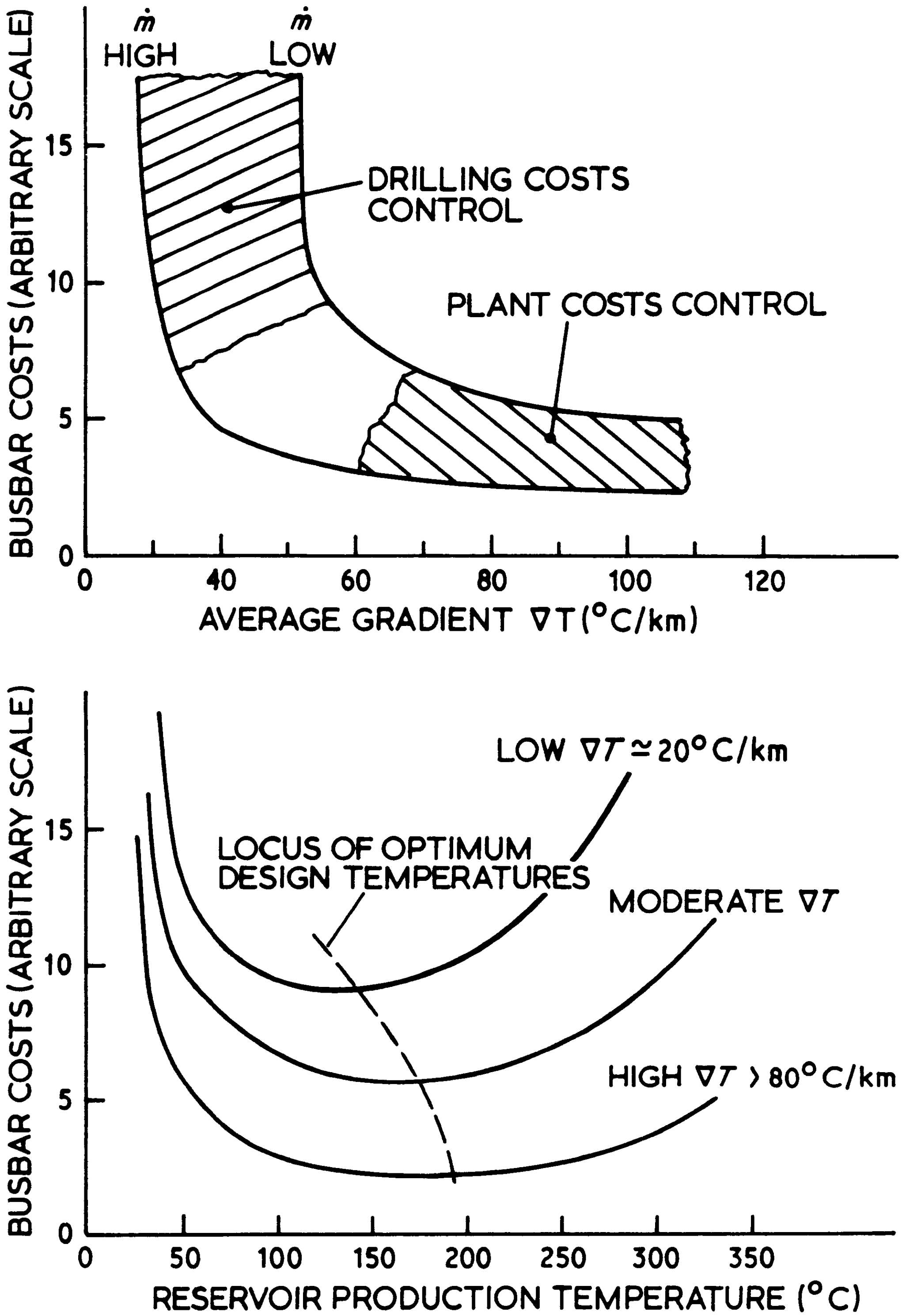


Figure 2.1. Generalized effects of resource quality and reservoir performance on busbar generating costs for HDR-produced electricity (from Armstead and Tester (1987)).

At this stage of HDR development, it is difficult to say what rock types should be considered. Most of the HDR wells drilled to date have been in hard crystalline granitic-type formations for most of their depth with varying amounts of overlying sediments and/or volcanics. Although rock penetration rates are slower in these harder formations, holes tend to be more stable and consequently require only modest mud and casing programs in comparison to typical oil and gas wells in a similar depth range from 2.9 to 6.5 km. Once expansion and contraction effects have been properly accounted for, completion programs for HDR wells are also straightforward in comparison to those required in less stable formations.

To establish base case costs and a cost range for HDR drilling, we reviewed all available drilling and completion cost data for geothermal (hydrothermal and HDR) and oil and gas wells for the period 1972-1988. The geothermal well costs came from a number of sources including Carson and Lin (1981), Entingh (1989), Batchelor (1989), and Armstead and Tester (1987) as well as from the six case studies being examined. Joint Association Survey (JAS) data for drilling and completing oil and gas wells in the continental U.S. in a particular year were used as a reference point to compare actual HDR well costs against.

In order to normalize well costs to a common year dollar, a drilling cost index was established as shown in Table 2.2 and Figure 2.2. To develop this index, JAS average oil and gas well costs based on total footage for depths ranging from 1250 ft (0.38 km) to 20,000 ft (6.1 km) were used from 1977 to 1988. In addition, Energy Information Administration (EIA) costs for 1976 to 1977 (Anderson and Funk (1986)) was used to supplement the JAS data base. For wells drilled before 1976, a 17% annual inflation factor was assumed.

Table 2.3 gives actual and predicted drilling and completion costs for individual wells for HDR and hydrothermal systems. 1988 JAS composite costs for completed oil and gas wells are also included in Table 2.3. Dry well costs were not included in deriving the JAS composite. Costs for average well depths are shown. Figure 2.3 presents a composite of actual and predicted well costs normalized to 1989 $. The collection of individual well cost data from a number of hydrothermal sites in the U.S. compiled by Carson and Lin (1981) was normalized to 1989 $ and plotted in Figure 2.4 with the data listed in Table 2.4. The line plotted in Figures 2.3 and 2.4 corresponds to a least squares fit of the 1988 JAS oil and gas composite well cost data extrapolated to 1989 $. One immediately sees that without exception, all hydrothermal and HDR well costs are higher than a typical, average oil and gas well drilled to the same depth. Furthermore, the *bandwidth* of costs for HDR wells lies somewhat above the scatter of hydrothermal wells.

Following the methodology described earlier by Milora and Tester (1976) and later updated by Armstead and Tester (1987), we chose to establish a range of expected drilling costs for HDR wells drilled to 10 km depths. Figure 2.5 shows the same data as plotted in Figure 2.3 except that an HDR base case curve has been plotted with an upper bound (HDR problem burdened) and a lower bound (HDR commercially mature) shown. These well cost figures will be discussed again when various HDR economic models are compared (Section 7), when the composite cases are presented (Section 8), and when the generalized model is discussed (Sections 9-11).

TABLE 2.2. MIT COMPOSITE COST INDEXES

YEAR	MIT COMPOSITE PLANT COST INDEX	MIT COMPOSITE DRILLING COST INDEX
1965	100.0	-
1966	103.9	-
1967	108.3	-
1968	114.1	-
1969	121.9	-
1970	131.8	-
1971	144.2	-
1972	154.0	53.4
1973	163.4	62.4
1974	183.0	73.1
1975	201.3	85.5
1976	215.1	100.0
1977	229.5	108.7
1978	246.9	130.2
1979	268.4	153.5
1980	292.3	177.5
1981	322.7	223.4
1982	343.7	252.4
1983	356.8	190.5
1984	365.6	167.5
1985	369.8	170.4
1986	373.0	162.7
1987	381.8	139.2
1988	(400)	159.7
1989	(415)	(166)

(xxx) = Projected value.

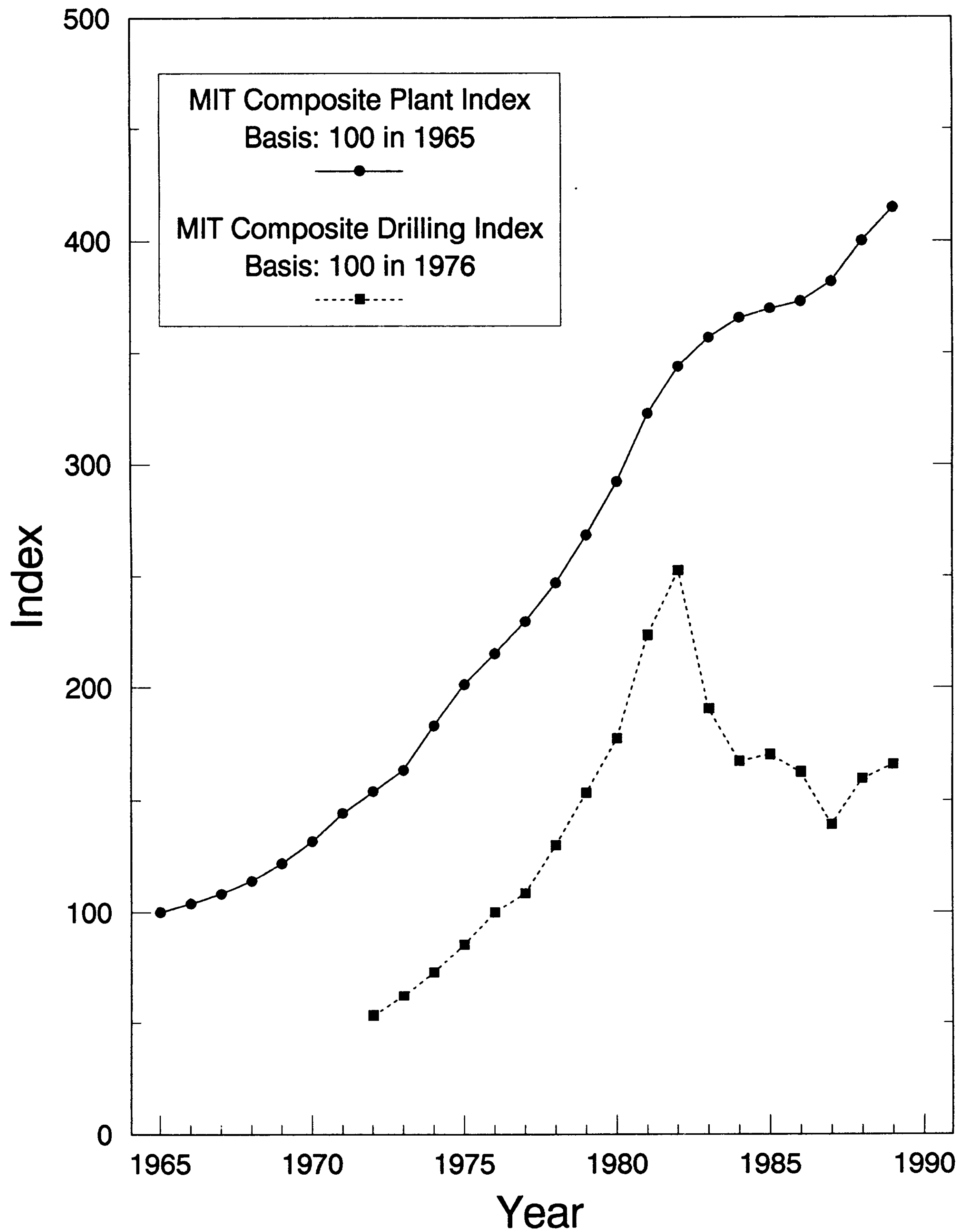


Figure 2.2. Estimated plant construction and drilling cost inflation indexes.

TABLE 2.3. ACTUAL AND PREDICTED DRILLING AND COMPLETION COSTS (1989$)

Plot #	Well ID	Depth Meters	Cost M$	Year Completed	Cost 1989 M$	Comments
1	GT-1	732	0.060	1972	0.187	Fenton Hill Site, New Mexico, USA.
2	GT-2	2,932	1.900	1974	4.315	Actual costs.
3	EE-1	3,064	2.300	1975	4.465	
4	EE-2	4,660	7.300	1980	6.827	
5	EE-3	4,250	11.500	1981	8.545	
6	EE-3A	4,572	5.160	1988	5.364	
7	RH-11 (low)	2,175	1.240	1981	0.921	Rosemanowes Site, Cornwall, UK.
8	RH-11 (high)	2,175	1.984	1981	1.474	Actual costs.
9	RH-12 (low)	2,143	1.240	1981	0.921	Conversion rates:
10	RH-12 (high)	2,143	1.984	1981	1.474	low = $1 per pound.
11	RH-15 (low)	2,652	2.250	1985	2.192	high = $1.6 per pound.
12	RH-15 (high)	2,652	3.600	1985	3.507	as recommended by A.S. Batchelor (1989).
	UK (Shock, 1987)	6,000	8.424	1985	8.206	From Camborne School of Mines ($1 per pound).
	Bechtel (1988)	3,657	3.359	1987	4.006	Predictions for Roosevelt Hot Springs, UT Site.
	Japan (1986)	3,000	6.000	1985	5.845	Predicted costs.
	Meridian (1987) I	3,000	6.900	1984	6.838	Predicted costs based on Heat Mining.
	Meridian (1987) II	3,000	3.800	1984	3.766	
	Meridian (1987) III	3,000	3.000	1984	2.973	
	Heat Mining (1987)	3,000	3.000	1984	2.973	Predicted costs.
13	Geysers	1,800	0.486	1976	0.807	Actual costs cited in Milora and Tester (1976).
14	Geysers	3,048	2.275	1989	2.275	Actual costs from A.S. Batchelor (1989).
15	Other Hydrothermal	1,600	0.165	1976	0.274	Actual costs cited in Milora and Tester (1976).
	IM-GEO IV-FL	1,829	1.123	1986	1.146	Meridian predictions of hydrothermal wells
	IM-GEO IV-BI	2,743	0.956	1986	0.975	from their IM-GEO data base (Entingh, 1989).
	IM-GEO BR-FL	2,438	1.217	1986	1.242	Only base well costs shown.
	IM-GEO BR-BI	914	0.556	1986	0.567	See key below for hole details.
	IM-GEO CS-FL	3,048	2.032	1986	2.073	
	IM-GEO CS-BI	914	0.576	1986	0.588	
	IM-GEO YV-FL	1,524	0.906	1986	0.924	
	IM-GEO YV-BI	152	0.406	1986	0.414	
	IM-GEO GY-DS	3,048	1.155	1986	1.178	
	JAS	954	0.142	1988	0.148	Actual costs for oil and gas wells
	JAS	1,340	0.160	1988	0.166	from Joint Association Survey (1988).
	JAS	1,859	0.263	1988	0.273	
	JAS	2,628	0.528	1988	0.549	
	JAS	3,376	1.111	1988	1.155	
	JAS	4,108	1.682	1988	1.748	
	JAS	4,834	3.019	1988	3.138	
	JAS	5,539	4.236	1988	4.403	

Plot #'s refer to Figures 2.3 and 2.5.

M$ = Millions of US Dollars.

Key:

IV-FL - Imperial Valley Flash, Salton Sea, CA field.
IV-BI - Imperial Valley Binary, Heber, CA field.
BR-FL - Basin and Range Flash, Dixie Valley, NV field.
BR-BI - Basin and Range Binary, generic NV field.
CS-FL - Cascades Flash, Newberry, OR field.
CS-BI - Cascades Binary, generic OR, WA field.
YV-FL - Young Volcanics Flash, Coso, CA field.
YV-BI - Young Volcanics Binary, Mammoth, CA field.
GY-DS - Dry Steam, The Geysers, CA field (Costs from B.J. Livesay).

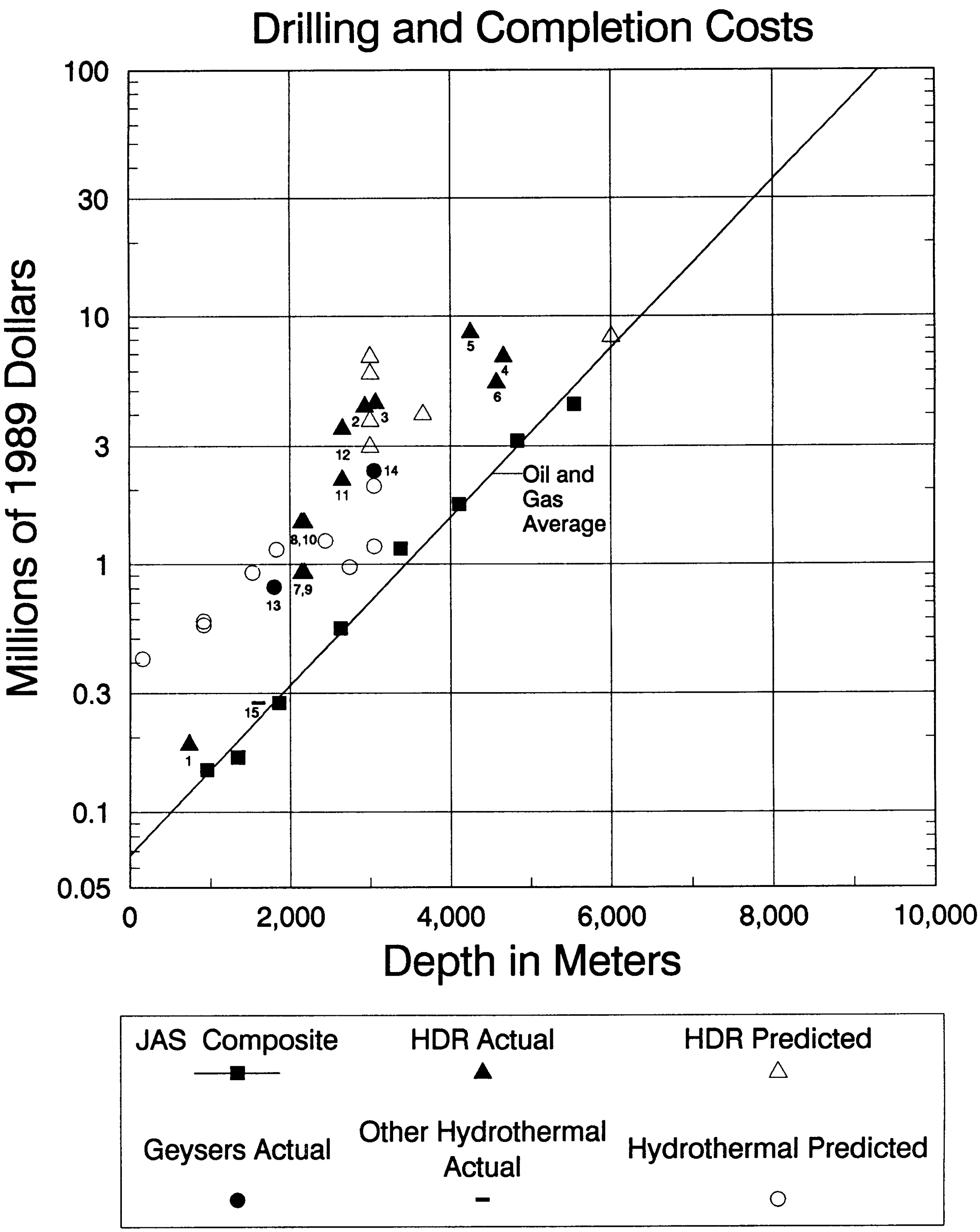


Figure 2.3 Actual and predicted drilling and completion costs
(see Table 2.3 for data and sources).

TABLE 2.4. HYDROTHERMAL WELL COST DATA From Carson and Lin (1981)

WELL DESCRIPTION	DEPTH FT	COST 1979 M$	DEPTH METERS	COST 1989 M$
Direct Use	1,500	0.20	457	0.216
Direct Use	1,550	0.23	472	0.249
Direct Use	1,600	0.25	488	0.270
Direct Use	2,300	0.30	701	0.324
Direct Use	2,200	0.32	671	0.346
Direct Use	4,250	0.31	1,295	0.335
Direct Use	5,100	0.30	1,554	0.324
Direct Use	4,400	0.52	1,341	0.562
Direct Use	10,200	2.30	3,109	2.487
Baca, NM	4,400	0.41	1,341	0.443
Baca, NM	4,900	1.00	1,494	1.081
Baca, NM	5,400	0.90	1,646	0.973
Baca, NM	5,700	1.23	1,737	1.330
Baca, NM	5,700	0.34	1,737	0.368
Baca, NM	6,450	0.97	1,966	1.049
Baca, NM	6,450	2.00	1,966	2.163
Baca, NM	7,000	1.10	2,134	1.190
Baca, NM	7,100	1.50	2,164	1.622
Baca, NM	7,100	1.60	2,164	1.730
Baca, NM	8,400	1.50	2,560	1.622
Baca, NM	9,100	1.65	2,774	1.784
Baca, NM	9,400	1.40	2,865	1.514
Baca, NM	9,500	1.20	2,896	1.298
Baca, NM	6,200	1.70	1,890	1.838
Utah-Nevada	4,100	0.48	1,250	0.519
Utah-Nevada	4,500	0.75	1,372	0.811
Utah-Nevada	5,200	1.45	1,585	1.568
Utah-Nevada	5,250	0.57	1,600	0.616
Utah-Nevada	5,500	0.63	1,676	0.681
Utah-Nevada	6,200	1.05	1,890	1.136
Utah-Nevada	8,000	2.40	2,438	2.595
Northern Nevada	6,100	1.60	1,859	1.730
Northern Nevada	7,200	0.62	2,195	0.670
Northern Nevada	8,250	1.30	2,515	1.406
Northern Nevada	9,250	1.40	2,819	1.514
Northern Nevada	10,100	1.40	3,078	1.514
Northern Nevada	10,100	1.70	3,078	1.838

M$ = Millions of US dollars

TABLE 2.4. HYDROTHERMAL WELL COST DATA Continued

WELL DESCRIPTION	DEPTH FT	COST 1979 M$	DEPTH METERS	COST 1989 M$
Cove Fort, UT	2,650	1.30	808	1.406
Cove Fort, UT	2,700	1.10	823	1.190
Cove Fort, UT	5,500	1.45	1,676	1.568
Cove Fort, UT	5,700	1.50	1,737	1.622
Cove Fort, UT	7,500	2.70	2,286	2.920
Roosevelt Hot Springs	6,350	0.55	1,935	0.595
Roosevelt Hot Springs	6,800	0.66	2,073	0.714
Roosevelt Hot Springs	7,600	1.30	2,316	1.406
Imperial Valley, CA	7,800	0.76	2,377	0.822
The Geysers, CA	8,750	1.40	2,667	1.514
The Geysers, CA	9,350	1.35	2,850	1.460
Other Wells	2,700	0.23	823	0.249
Other Wells	2,950	0.41	899	0.438
Other Wells	3,600	0.30	1,097	0.319
Other Wells	3,900	0.28	1,189	0.303
Other Wells	3,800	0.32	1,158	0.346
Other Wells	4,000	0.38	1,219	0.411
Other Wells	5,450	0.27	1,661	0.292
Other Wells	3,400	1.05	1,036	1.136
Other Wells	4,600	1.60	1,402	1.730
Other Wells	5,100	1.15	1,554	1.244
Other Wells	5,600	0.99	1,707	1.071
Other Wells	6,000	1.05	1,829	1.136
Other Wells	6,750	1.22	2,057	1.319
Other Wells	10,700	2.90	3,261	3.136

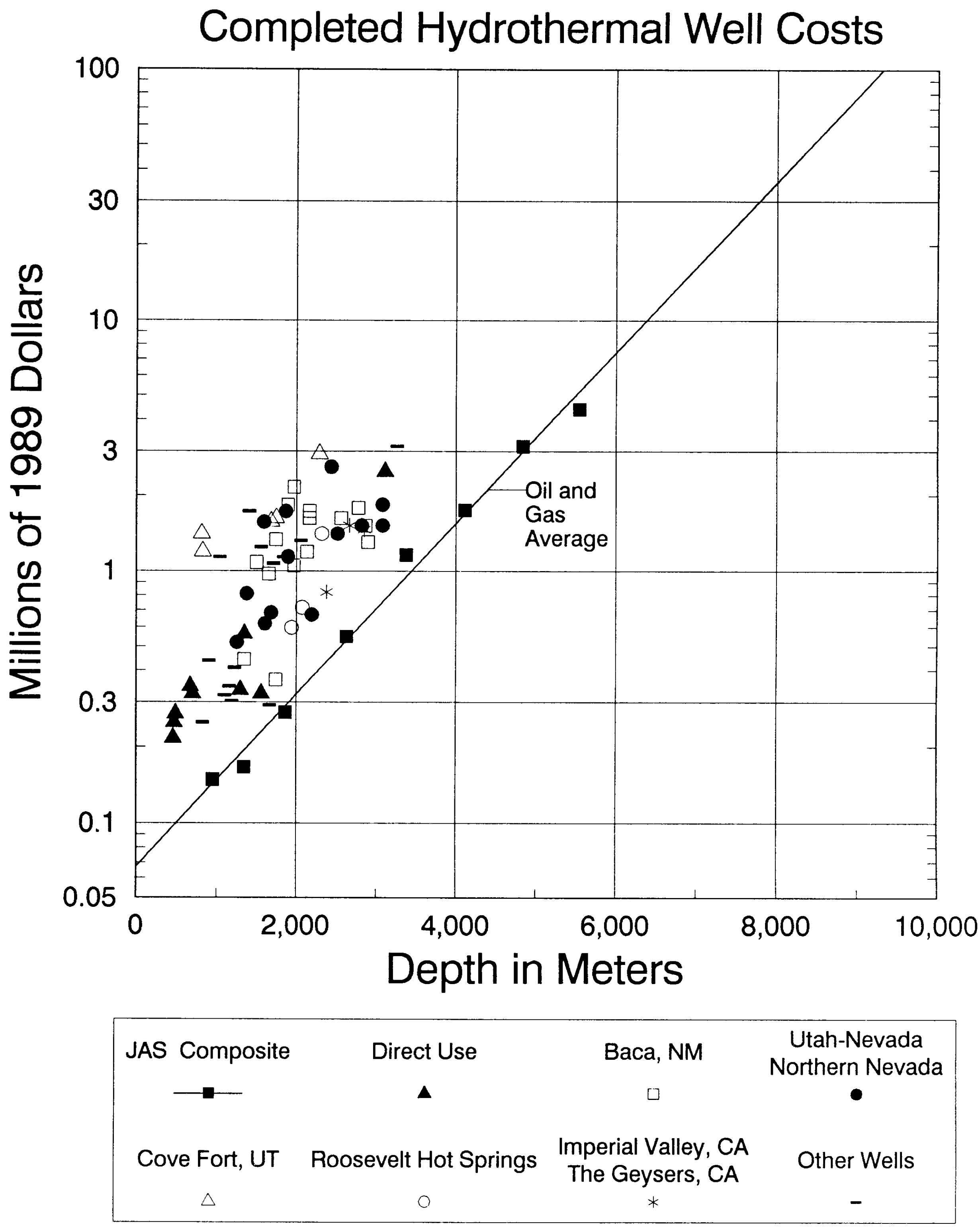


Figure 2.4. Actual hydrothermal completed well costs as a function of depth (adapted from Carson and Lin (1981)).

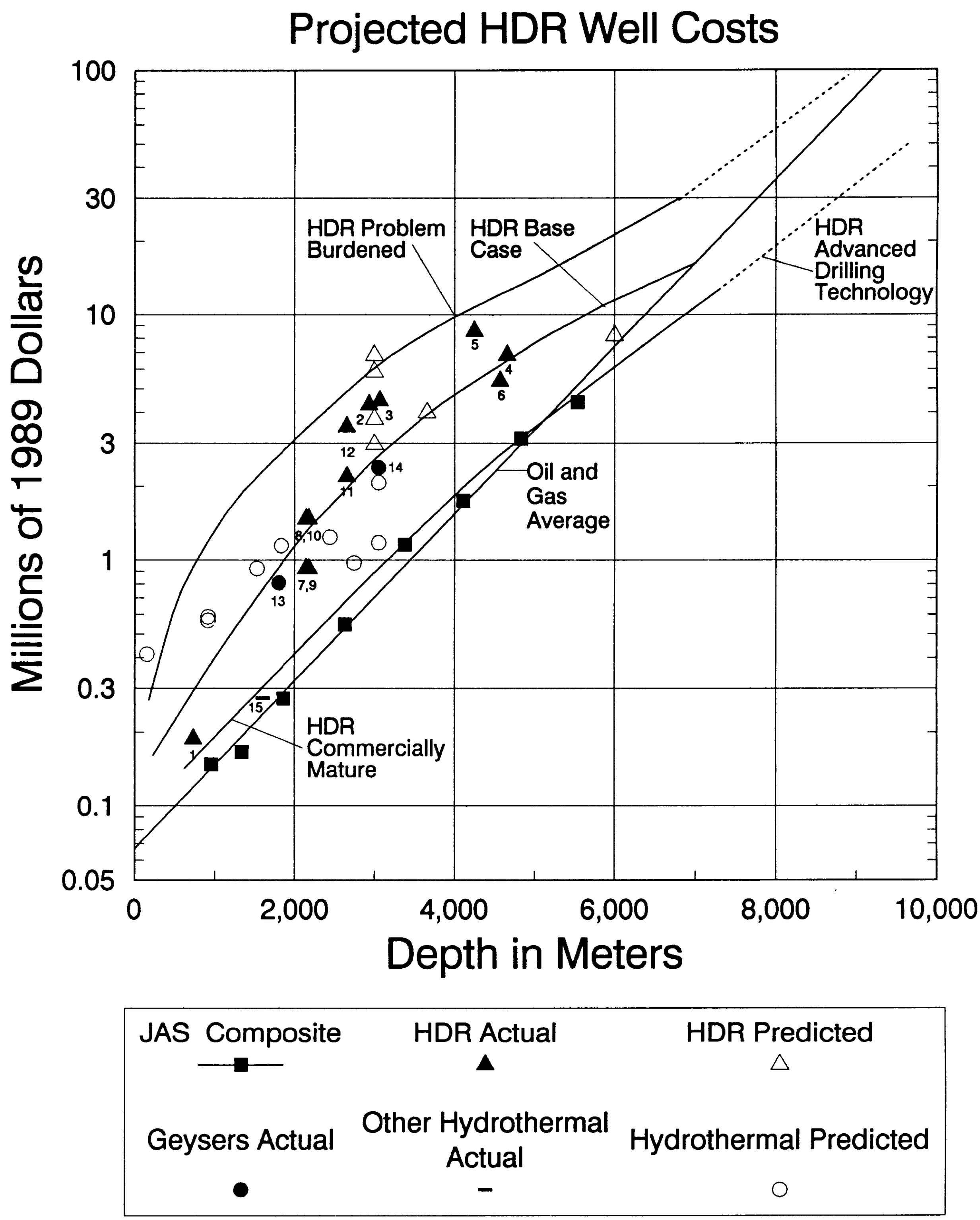


Figure 2.5 Projected HDR well drilling and completion costs for the base case with limits for problem-burdened, commercially mature, and advanced drilling technology shown.

3. HDR Reservoir Formation

To characterize the economics of hot dry rock geothermal energy utilization, we have evaluated several critical technical elements of HDR reservoirs and surface systems to show how they compare with existing natural hydrothermal systems. Geothermal power plants now operating throughout the world typically involve an underground reservoir containing natural steam and/or hot water which is brought to the surface by way of a set of drilled wells. Natural or indigenous geothermal fluid flows under artesian pressure or is pumped through a gathering system of pipes to a centrally located power plant, which may produce electricity, supply heat, or both. Reinjection wells are normally used to return the cooled fluid to the formation. The main feature that distinguishes an HDR system from these natural hydrothermal systems is the absence of a sufficient amount of spontaneously produced indigenous reservoir fluid.

Accordingly, HDR resources provide a degree of flexibility that is inherently absent from natural hydrothermal systems. Namely, HDR reservoir temperatures may be selected by drilling to a specified depth determined by the geothermal temperature gradient. Furthermore, if an HDR reservoir has too short a lifetime, remedial treatment is possible by redrilling to a hotter region of rock. In the hydrothermal case, the reservoir conditions, including *in situ* fluid temperature, pressure and composition, and formation permeability and porosity, are determined by existing natural conditions in that region. In contrast, the unique gradient relationship between reservoir temperature and depth in HDR systems provides a framework for exploring the economic tradeoffs of drilling deeper, hotter, more costly wells versus drilling shallower, cooler, less expensive wells balanced against the value of the product; that is, electricity or heat or both.

HDR reservoirs may exist in formations having permeabilities ranging from very low (<1 microdarcy) to high (>1 millidarcy) in which the rock itself is hot enough to be considered useful for energy extraction. Depending on the end use, temperatures may be as low as 100°C for space heating purposes or approaching 300°C for producing electricity.

One of the key characteristics of any HDR system is that the reservoir rock does not contain sufficient *in situ* fluids and/or permeability. Therefore, HDR systems, by definition, require stimulation to create a viable reservoir. Viability requires a sufficient volume of hot rock capable of extracting thermal energy for an extended period at commercially acceptable rates. Artificial fracturing methods are the main technique of reservoir stimulation used in low permeability HDR formations. Most concepts employ some modification of classical hydraulic fracturing to either open sealed natural joint structures in the rock mass or to create new ones.

Reasonable rates of energy extraction and sufficient reservoir lifetimes (~10 yr or greater) from HDR systems may be achieved using two fundamental approaches to mining the heat. First, if *in situ* formation permeabilities are low, an artificial system must be created to expose a circulating fluid to the hot rock by creating high-conductance flow passages with a sufficiently large heat-transfer surface area. In this case, recovery of most of the injected fluid may be achieved quite easily by taking advantage of the natural containment provided by the low permeability of the formation (Smith, et al. (1975)). But if the permeability is high, the techniques to contain and recover the fluid and to ensure uniform fluid contact with the hot rock surface are more demanding. The same approaches used for recovery of gas and oil by water drive or flooding methods may be quite applicable to high permeability formations for HDR applications. Both production and injection well networks would be arranged so that fluid loss to surrounding permeable formations at the perimeter of the developed geothermal field is minimal.

The choice of reservoir circulating fluid should be briefly discussed. For almost all HDR concepts considered for either low- or high-permeability formations, liquid water or steam has been selected. The main reasons for this are the poorer performance, significantly higher costs and potential environmental consequences associated with non-aqueous fluids. In principle, the idea of using an "inert" fluid that will not corrode or dissolve minerals is attractive. However the very fact that finite losses from the active reservoir will occur due to permeation has a real economic and environmental impact. The subsequent costs and the perceived (or real) environmental effects of this loss makes any fluid but water or air unequivocally not acceptable. The choice between a vapor system consisting of compressed air or steam and a pressurized liquid water system is based primarily on performance. Parasitic pressure losses per unit of energy recovered from a deep reservoir will be very high when a low-density gas is used as the transport medium. To reduce pumping or compressor power requirements, large diameter wellbores would be needed. These would be too costly. Furthermore, if steam were used, operation at lower pressures would be required to avoid premature condensation in the production well. A liquid water or liquid water-steam system has the very attractive feature of providing a substantial amount of buoyancy-driven flow due to the density difference between the cold injection well and the hot production well. All things considered, liquid water kept under sufficient pressure to avoid flashing is the best choice for first generation HDR systems where performance and stable operation are key factors. In future systems, liquid water-steam concepts could be considered but it is unlikely that air or non-aqueous fluids would ever be attractive.

Several HDR reservoir concepts for low-permeability formations are depicted in Figure 3.1a. The first idealized concept is a single vertical hydraulic fracture produced from one wellbore by fluid pressurization that exceeds the effective confining stress and strength of the rock. The required surface areas and reservoir volumes for heat extraction are created by continued high-pressure injection of fluid.

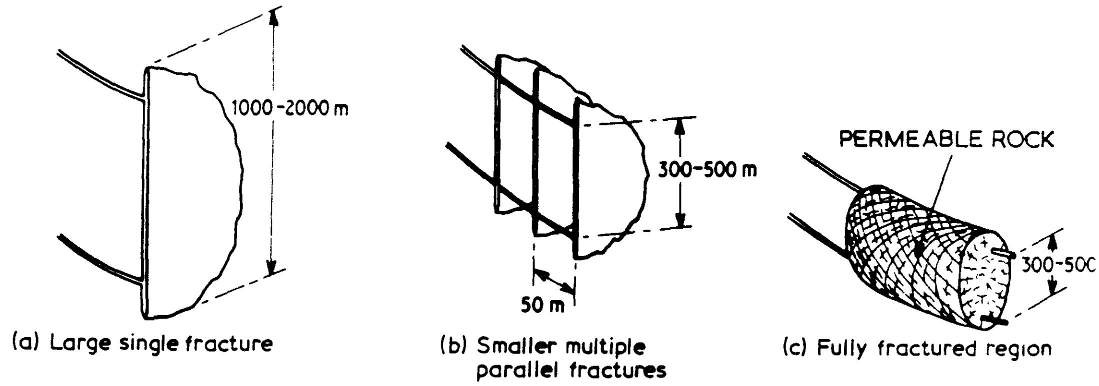


Figure 3.1a HDR reservoir concepts for low permeability formations. Half fractures shown with division at a vertical axis of symmetry. (a) large single fracture. (b) smaller multiple parallel fractures. (c) fully fractured regions in jointed rock. (from Armstead and Tester (1987)).

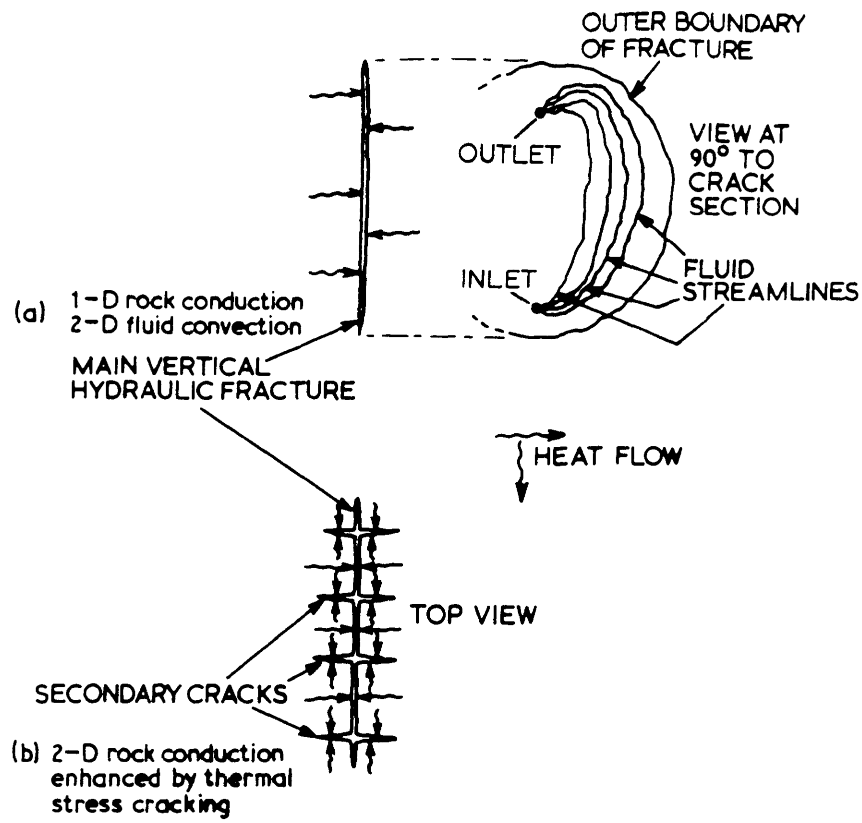


Figure 3.1b HDR reservoir heat transfer mechanisms. (a) fracture-dominated flow. (b) fracture-dominated flow with enhancement by thermal stress cracking (from Armstead and Tester (1987)).

The downhole system is then completed by directionally drilling a second wellbore to intersect the fractured region with sufficient separation from the first wellbore to avoid flow short-circuiting. Pressurized water is then circulated down one hole through the fractured region to remove energy from the rock and is recovered in a second hole. Energy is extracted at the surface using heat exchangers, and the cooled fluid is reinjected to complete a closed cycle. Even with low permeabilities, some makeup water is required. Because reservoirs of this type will most likely be formed at depths sufficient to ensure that the least principal earth stress is in the horizontal plane, in theory, hydraulically stimulated fractures should have near-vertical orientation. Assuming that the stress field is uniform and the physical strength properties of the formation are approximately isotropic and homogeneous, an ideal fracture of circular shape with an elliptical cross section should be formed (Smith et al. (1975) and Tester and Smith (1977)). Effective fracture radii will be typically 100 m or greater with widths of a few millimeters in cross section. Because the inherently low thermal conductivity of the rock quickly controls the rate of heat transfer to the circulating fluid, large fracture surface areas are required. For optimum performance of a reservoir of this type, the fluid should contact as much of the fracture surface as possible. Fracture conductances or permeabilities for self- or pressure-propped fractures should be sufficiently high to permit buoyant circulation across the faces of the fractures between the inlet and outlet points of the system as shown in Figure 3.1b. Multiple, parallel fracture concepts have also been proposed as a method of creating large reservoir areas and active volumes.

In *real* HDR reservoirs, the dominant feature will most likely be a network of interconnected fractures that results from activation of a set of natural joints (Batchelor (1984 (a,b), 1988) and Armstead and Tester (1987)) (see Figure 3.2). This is in contrast to the idealized set of single or parallel fractures that has been depicted in early HDR concepts (see Figure 3.1a). Nonetheless, regardless of how complex the reservoir is, the magnitude and orientation of the *in situ* stress field will influence the structure of the activated fracture network as will the geometry of the natural joints themselves.

The key objective in forming an HDR reservoir is to maximize heat extraction efficiency and reservoir lifetime. This requires knowledge of the extent and orientation of the fracture system in order to optimally locate the production and injection wells. Thus diagnostic methods for characterizing reservoir geometry are essential. Field work to date at Fenton Hill, Rosemanowes, and elsewhere has employed active and passive seismic methods, pressure transient, tracer techniques and other geophysical measurements to determine reservoir structural parameters. This is a very difficult task as it requires the deconvolution of only indirect evidence that results in a classical non-unique solution where more than one reservoir geometry can be found that consistently represents all available data. The development of reservoir diagnostic techniques involving both the hardware and the theoretical methodology to interpret data are key components in the HDR

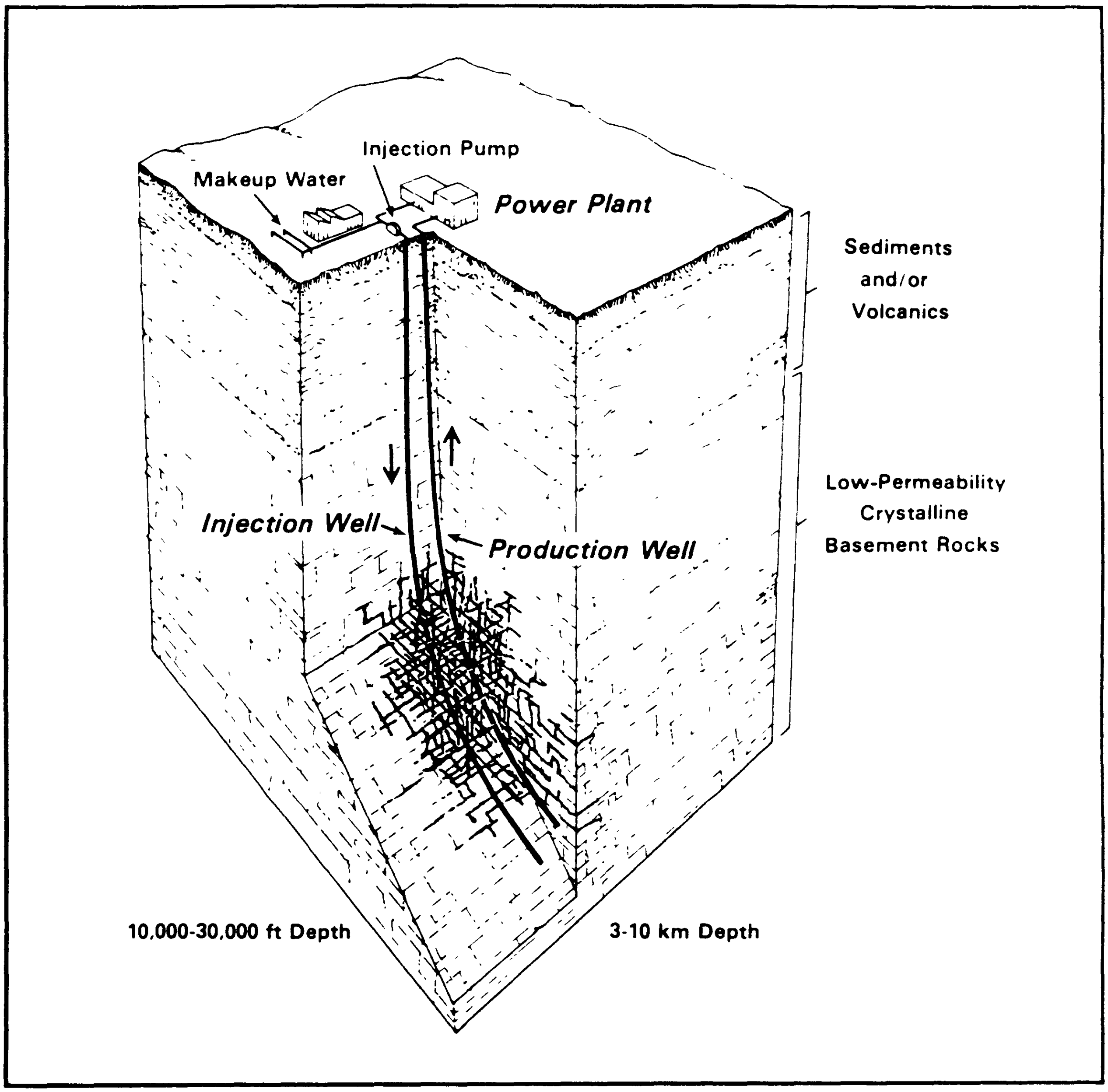


Figure 3.2 HDR reservoir concept for an interconnected network of fractures stimulated in a low-permeability formation (from Tester, Brown, and Potter (1989)).

research and development programs in existence today (see Tester, Brown, and Potter (1989), Batchelor (1984 (a,b), 1986), and Armstead and Tester (1987) for summaries).

If thermal exhaustion of an HDR fractured reservoir occurs because of insufficient surface area or active rock volume, remedial stimulation treatment is possible. For example, by proper orientation of the boreholes in a parallel, inclined arrangement as shown in Figure 3.1a, additional fracturing might be used to provide more accessible surface area in a hot region of rock. Sidetracking of the original wellbores to a new region and refracturing might also be an attractive method of re-stimulation.

Other methods of reservoir enhancement may occur naturally. Removal of heat from the vicinity of the fracture surface introduces thermal stress which may be sufficiently large to cause additional cracking of the rock. If thermal stress cracks propagate in such a way as to provide accessible flow channels for the circulating fluid as shown in Figure 3.1b, the performance and lifetime of an HDR reservoir could be substantially enhanced. Thermal stress cracking of this type increases the heat transfer efficiency by forming an extended surface penetrating into the hotter regions of the formation. As McFarland and Murphy (1976) point out, even without thermal stress cracking, the thermal contraction of the rock will increase the fracture gap width, thus allowing buoyancy effects to sweep fluid more uniformly over the available fracture surface area. There is strong evidence in early tests of the HDR Phase I reservoir at Fenton Hill that reservoir growth occurred as a direct result of thermal stress induced effects (Tester, et al. (1989)).

If thermal stress enhancement does not occur or if large, stable fracture domains cannot be produced, multiple fractures in inclined boreholes may be an acceptable alternative. Multiple parallel fracturing concepts have been suggested by Raleigh, et al. (1974) and R.M. Potter of LASL in 1972 and analyzed by Gringarten, et al. (1975) and Wunder and Murphy (1978). Multiple fracturing using hydraulic stimulation methods is currently under study for generating sufficient surface area to maintain reservoir lifetime (see Figure 3.1a). Even with networks rather than discrete fractures, multiple zone stimulation may be feasible to activate large rock volumes for heat extraction.

Developing and perfecting HDR stimulation methods have been a major focus of the U.S. and UK R&D programs during the past 15 years (see Armstead and Tester (1987), Batchelor (1984 (a,b), 1988, 1989b), and Brown et al. (1989) for details). Although the field efforts have made considerable progress, there is not yet sufficient knowledge regarding rock fracturing characteristics to absolutely guarantee that a fractured network of sufficient size and viability can be created and connected to an appropriately designed injection and production well system. Given this inherent uncertainty, we must make several assumptions regarding the formation of such a reservoir system in order to proceed with an economic assessment of HDR.

All studies have assumed that current fracturing technology (or some modest extension of it) is sufficient to create a viable HDR reservoir at depths of interest. In addition, they have estimated the costs associated with these stimulation methods. These include the costs of pumping at high pressures and rates, costs for fluids with special rheological properties, and the costs of diagnostic geophysical testing. Figure 3.3 provides an estimate of stimulation costs per kWe of net installed capacity for different temperature reservoirs. Also plotted on the same figure are specific estimates for stimulation costs taken from the economic assessment studies. Note that we have tried to account for the effect of resource grade on the stimulation costs by plotting costs as a function of initial reservoir temperature. Lower gradient regions will in general require deeper wells and/or higher well flow rates and therefore proportionately higher costs will result. Recent estimates of drilling and stimulation costs for HDR systems in the UK by Mortimer and Minett (1989) are consistent with the results shown in Figure 3.3.

This methodology for estimating stimulation costs falls short of providing a clear dependence of costs on the size of the reservoir. Consequently, we examined an alternate approach. In Figure 3.4, the estimated cost of stimulating an HDR doublet system is plotted as a function total effective reservoir surface area in m^2 per kWe of installed capacity. By using the installed capacity to normalize costs and reservoir size, the effect of fluid temperature (and hence gradient and depth) on conversion efficiency is accounted for. Data from the Bechtel, LANL, Meridian, Japan, and UK HDR economic studies are plotted along a regressed line (solid) for the composite base case that will be used in the economic projections described later in this report (see Sections 8 and 9). One should note that the Meridian Organic Rankine Cycle (ORC) estimates were not used in the regression. The dotted lines shown represent two times and one half of the composite base case stimulation costs to illustrate the range of estimates. Table 3.1 gives the calculations that were used in Figure 3.4. In all cases, these cost estimates should be regarded as only approximate in that the technology for creating HDR reservoirs is still under development.

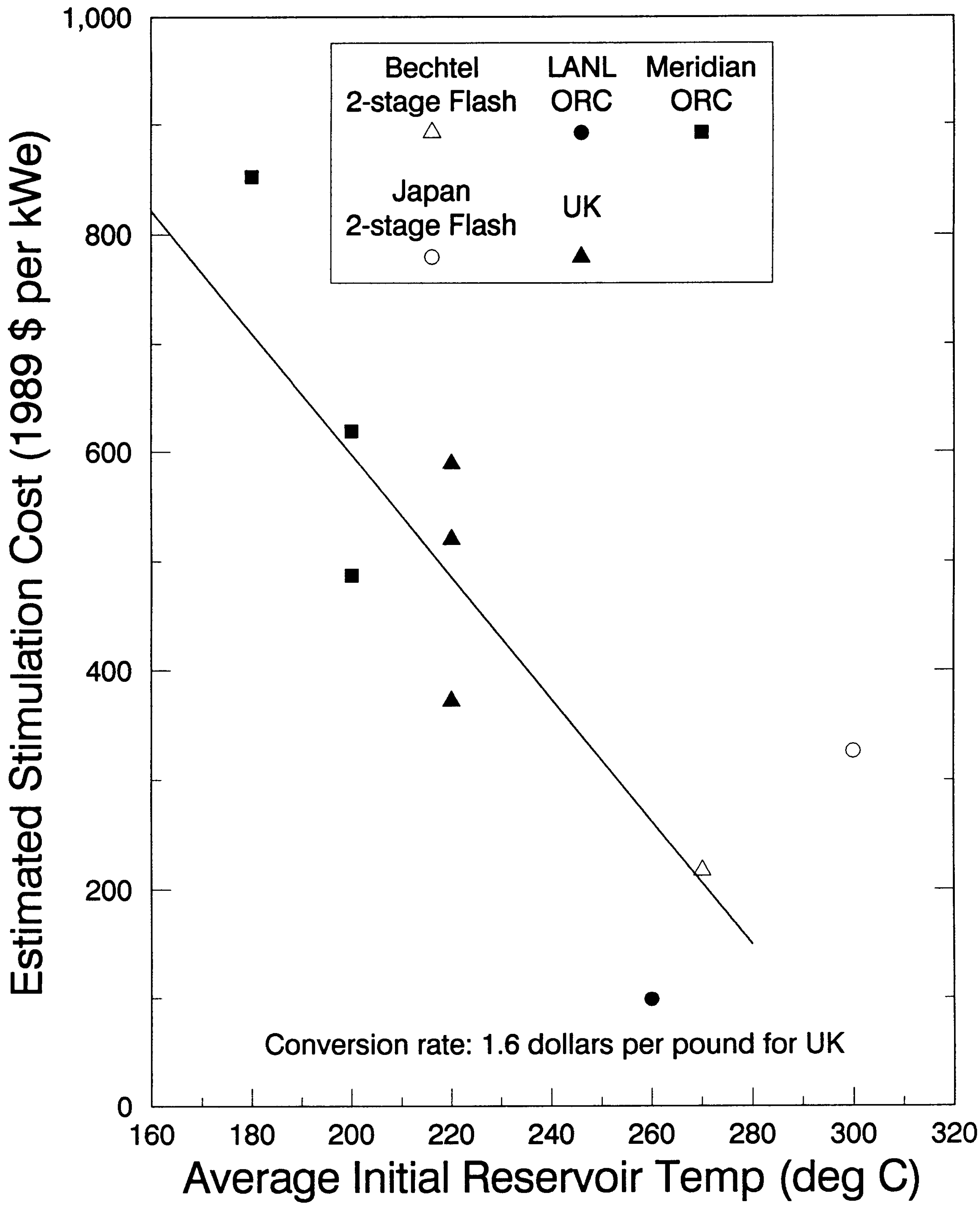


Figure 3.3 Estimated HDR reservoir stimulations costs in $ per kWe installed as a function of average initial reservoir temperature. Note that deg C = degrees Celsius = °C, ORC = Organic Rankine Cycle and 2-stage flash refers to power plant choices (see Section 6).

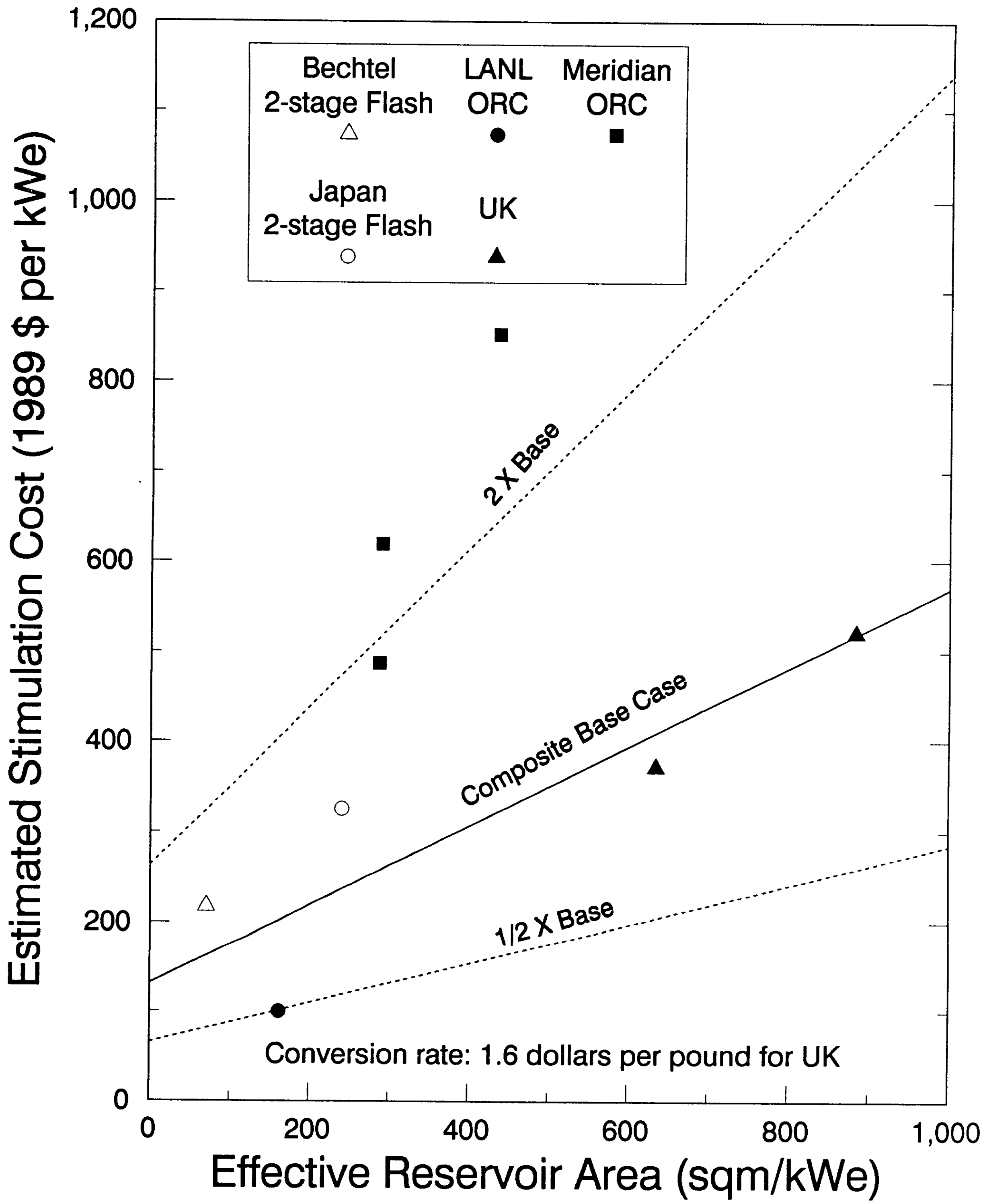


Figure 3.4 Estimated HDR reservoir stimulation costs in $ per kWe installed as a function of normalized effective reservoir surface area in sqm/kWe (m^2/kWe) installed.

TABLE 3.1. CALCULATIONAL SUMMARY FOR STIMULATION COST ESTIMATES

	Drawdown Parameter kg/sqm-s	Flowrate/ Reservoir kg/s	Area per Reservoir M sqm (4)	Number of Reservoirs	Reservoir Total Area M sqm (4)	Installed Capacity MWe	Reservoir Area sqm/kWe	Stimulation Cost 1989 M$ (5)	Stimulation Cost 1989 $/kWe
Reference	Table 7.1 (1)	Table 7.1 (2)	Calc	Table 7.1	Calc	Table 7.1	Calc	Table 7.1 (3)	Calc
Bechtel	0.000314	120	1.20	4	4.80	70	69	15.2	217
LANL	0.000144	46	1.00	12	12.00	75	160	7.4	99
Meridian	0.000122	57	1.47	19	27.87	64	436	54.5	852
	0.000145	62	1.34	19	25.51	88	290	54.5	619
	0.000145	78	1.69	19	32.09	112	287	54.5	487
Japan	0.000127	74	1.83	9	16.47	68.7	240	22.4	326
UK	0.000053	75	4.47	5	22.34	25.3	884	13.1	520
	0.000053	75	4.47	5	22.34	35.3	633	13.1	372
	0.000053	75	4.47	5	22.34	22.3	1003	13.1	589

Notes:

(1) – Where necessary, determined from drawdown rate and Heat Mining Figure 10.25.

(2) – For Meridian, estimated from fluid availability (function of reservoir temperature) and net installed capacity.

(3) – Adjusted by the MIT Composite Drilling Index from Table 2.1.

(4) – M sqm = Millions of square meters of effective heat transfer area (single-sided basis) for a planar fracture.

(5) – M$ = Millions of US dollars.

4. HDR Reservoir Performance Criteria

The temperature changes that may occur in the reservoir output fluid, as well as the rate of power production over the 20 to 40 year lifetime of an HDR system, are crucial in determining economic viability and in developing an optimal strategy for reservoir management. The most desirable approach is to maintain a constant output temperature while maximizing the mass flow rate of fluid through the reservoir. This will not be possible because any finite-sized HDR system will have a finite rate of temperature decline or drawdown. The energy drawdown rate for a fractured HDR reservoir with low formation permeability will depend on the following factors:

- Accessible fracture surface area and rock volume
- Mass flow rate $\dot{m}_w$ of produced fluid
- Reservoir temperature distribution
- Distribution of fluid across the fractured surface, and through the fractured region
- Thermal properties of the rock (density, heat capacity, and conductivity)
- Net impedance to flow and allowable pressure drop
- Water loss rates

Section 5 of the report considers the quantitative representation of these factors in specific performance models of HDR reservoirs. Here we would like to first discuss the qualitative features of performance.

High reservoir temperatures, high production flow rates, low impedance, and large reservoir surface areas and volumes are desirable--leading to lower rates of thermal drawdown which is the primary measure of energy extraction effectiveness. Furthermore with low impedance to flow, parasitic pumping losses will be minimized and in the optimal case, "*self-pumped*" systems are possible as a result of buoyancy drive.

The issue of water loss raises some speculation about induced seismic effects and the possible economic impact of a large makeup supply of water in arid regions of the U.S. It should be emphasized that proper pressure management of the HDR system, which in extreme cases may require downhole pumping from the production well, can control or eliminate all water losses should they become a critical issue.

Furthermore, in all testing to date, no measurable seismic risk has occurred.

The distribution of fluid uniformly across large surface areas and through large volumes of the fractured rock comprising the reservoir is crucial to achieving acceptable reservoir lifetimes. In petroleum engineering terminology, this concept is expressed as sweep efficiency or maximized swept rock areas and volumes. In practice, achieving high sweep efficiencies through large volumes of fractured rock has only been demonstrated on a small-scale. Commercially-sized HDR reservoirs have yet to be demonstrated in the field, although they represent the modular extension of concepts already proved for smaller, prototype HDR reservoirs (Armstead and Tester (1897)).

In any assessment of HDR economics, assumptions regarding the energy extraction performance of the reservoir are required. In order to fully appreciate the inherent uncertainties that are carried with these assumptions, one must look not only at what has been demonstrated in the field but also at the extent of the extrapolation of that performance required to meet the specifications of larger, commercial-sized systems.

Alternatively, the economic model itself can be used to specify what reservoir performance parameters (fluid temperatures, flow rates, etc.) are required to make the system viable--for example, to produce electric power at competitive breakeven busbar prices. This was, in fact, the fundamental approach used to establish HDR feasibility in the early economic modeling efforts (see for example, Milora and Tester (1976), Tester et al. (1979) and Cummings and Morris (1979)). Base case reservoir temperatures, fluid flow rates and drawdown rates were bracketed using existing hydrothermal reservoir data. These ranges were then tested for economic viability using the early models to estimate a break-even or busbar price for electricity. For example, initial fluid production temperatures ranging from 100 to 300°C and flow rates from 45 to 227 kg/s (100 to 500 lb/s or 360,000 to 1,800,000 lb/hr) were used in the first assessment of HDR economics by Milora and Tester (1976) to cover a range consistent with high grade to marginal liquid-dominated systems.

5. HDR Reservoir Performance Modeling

A proper understanding of reservoir thermal drawdown rates is required for scaling reservoir performance for economic assessments of HDR. For example, for a given set of assumptions, dealing with fluid flow rates and flow distribution, rock temperatures and reservoir structure, rates of temperature decline can be estimated as a function of produced fluid flow rate and reservoir volume or effective heat transfer area. This permits a quantitative assessment of the impact of finite reservoir drawdown on power output and thus on revenues over the lifetime of the power plant. For example, as temperature declines, the plant's efficiency drops, and less power is produced per kg of geofluid. If the drawdown rate is too fast, drilling new wells or redrilling old ones to hotter zones of rock will be required to sustain electric power output at acceptable levels.

The models used to predict or simulate the thermal performance of HDR systems range from very simplistic to extremely complex treatments of fluid flow and heat transfer effects in discretely fractured porous media. The primary models for HDR reservoirs developed to date include:

1. *Zeroth-order single fracture model* (Gringarten, et al. (1975), Armstead and Tester (1987)), 1-dimensional rock conduction coupled to 1-dimension convective flow in planar fractures of uniform aperture

2. *Single fracture model* (McFarland and Murphy (1976), Murphy, et al. (1981)), 1-dimensional rock conduction coupled to 2-dimensional convective flow in planar fractures of variable aperture

3. *Multiple interacting fracture model* (Wunder and Murphy (1978) and Zyvoloski (1983)), 2-dimensional rock conduction coupled to 1- or 2-dimensional convective flow in planar fractures

4. *Porous 3-D channel model* (Robinson and Kruger (1988), and Robinson and Jones (1987))

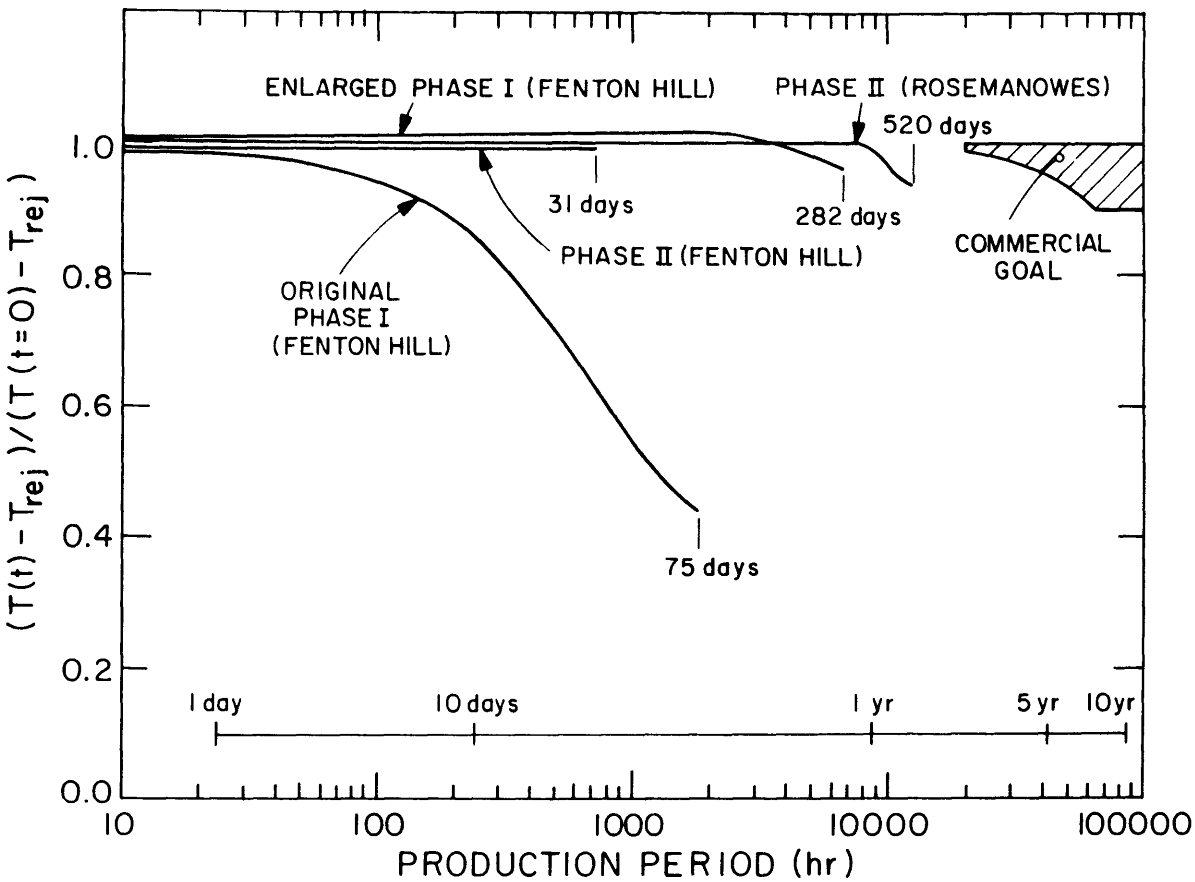
5. *Lumped parameter 3-D spherical model* (Elsworth (1989 a,b,c))

All of these models require specification of reservoir structure (fracture length, radius, aperture, spacing, and/or density and reservoir volume) in order to produce quantitative predictions of thermal performance. Typically one or more of these reservoir sizing parameters are fit to match observed field data such as depicted in Figure 5.1 from tests at Fenton Hill and Rosemanowes. Frequently, more than one model can adequately describe the data shown in Figure 5.1. This results in different values of reservoir geometric parameters or even worse in completely different modes or mechanisms for heat transfer. For example, a 3-D porous media model and a single fracture model have been used to match the 75-day test of the Phase I Fenton Hill system where a significant amount of drawdown occurred. In Figure 5.2a, a spherical, lumped parameter model (#5) developed by Elsworth (1989 a,b,c) fits the data quite well as does the single fracture and zeroth-order models (#1 and #2). The consequence of all this is that a unique reservoir geometry cannot be specified without more data.

The situation becomes even more uncertain when one tries to extrapolate to larger, commercial-sized HDR systems. Preliminary economic analyses of HDR suggest that only limited drawdown will be acceptable. A commercial goal of 5-10% of temperature decline over a 5 to 10 year period is depicted in Figure 5.1. In order to demonstrate that this goal is reachable, many people argue that you will have to test a commercial-sized system for a 5 to 10 year period to be sure that production temperatures can be sustained.

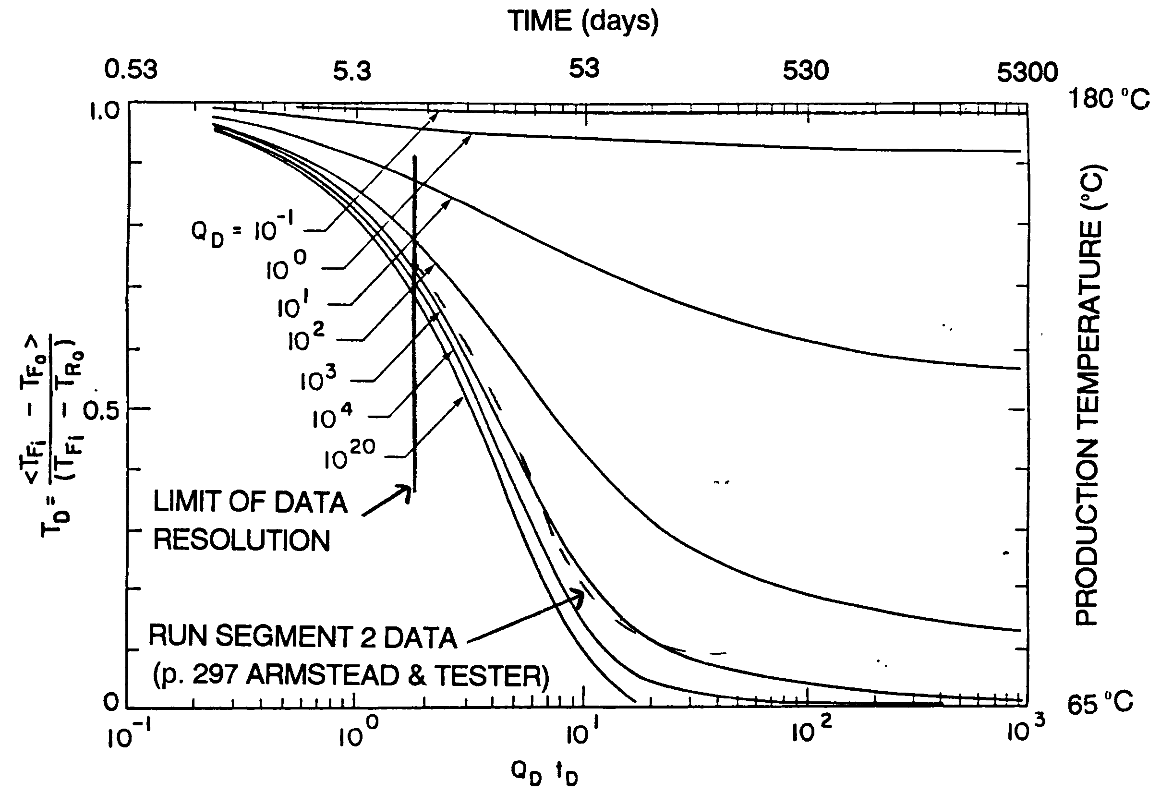
Although we cannot at this stage of model development accurately predict the future performance of any HDR reservoir much beyond the actual test period over which parameters were fit, modeling can be used generically in economic forecasting. For example, we can set the drawdown rate *a priori* at a particular value and study its economic impact in a sensitivity test. The more difficult question is what value of drawdown should be selected for the base case. Some of the HDR economic studies have neglected thermal drawdown while others have included it. For example, the most recent Bechtel study (1988) used a parallel, non-interacting fracture system whose thermal performance came from the single fracture model for predicting drawdown. They also included reservoir growth effects induced by thermal stress enhancement for some of their cases. We feel that it would be best to consider three generic levels of drawdown for each of the three HDR reservoir grades:

1. **Base case**--A 2% production fluid temperature decline per year with redrilling done every 5 years to restore fluid temperatures to original design levels. For modeling purposes this corresponds to a drawdown parameter $\dot{m}/R^2$ equal to 0.00014 kg/m$^2\cdot$s.

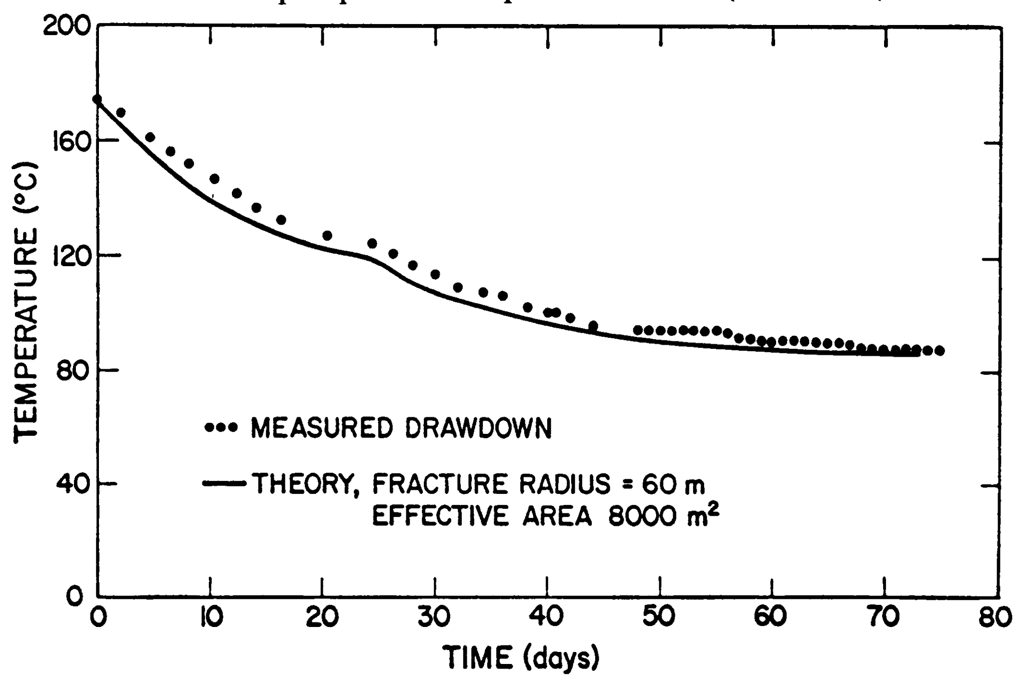


$T(t)$	=	produced fluid temperature at time t
$T(t=0)$	=	initial produced fluid temperature
T_{rej}	=	reinjection temperature

Figure 5.1 Composite of HDR prototype reservoir thermal drawdown data plotted as dimensionless drawdown versus the logarithm of time (adapted from Armstead and Tester (1987)).



5.2a. Lumped-parameter spherical model (Elsworth (1989 a,b,c))



5.2b. Single fracture model (Murphy, et al. (1981))

Figure 5.2 HDR reservoir modeling predictions of performance for the 75-day test of the Phase I Fenton Hill system.

2. **Optimistic zero drawdown case**--No temperature decline occurs either because the reservoir is sufficiently large at the outset of production or because the thermal drawdown in certain regions of the reservoir is completely compensated for by thermal stress induced growth.

3. **Pessimistic accelerated drawdown case**--A 4% production fluid temperature decline per year with redrilling done every 2 1/2 years to restore fluid temperatures to original design levels.

Our modeling of reservoir performance sensitivity also varied mass flow rates and flow impedance at constant $\dot{m}/R^2$ to alter reservoir pumping requirements at a fixed drawdown rate. For example, by decreasing the impedance from 0.14 GPa-s/m^3 to 0.01 GPa-s/m^3 in a 300°C reservoir at 3 km (Japanese conditions see Table 7.1c), the system would become self-pumping due to buoyancy drive and minimal pressure losses in the fracture system. This would increase plant output from 59.5 MWe to 68.7 MWe, and would have a direct effect on reducing busbar generating costs by about 15%.

We recognize that this approach significantly simplifies a complex situation regarding actual reservoir performance. However, it circumvents the non-uniqueness modeling issue while still capturing the important economic issue of declining performance. In a very real sense, we are saying that required levels of reservoir performance for economic viability can be specified exogenously. This procedure will establish goals for research and development efforts in the area of reservoir formation and stimulation--that is, how large and how productive does an HDR reservoir (per well pair) have to be to be commercially viable. These points will be discussed again in Section 8 when the composite HDR cases are introduced.

6. HDR Power Plant Options

The production of electricity from HDR geothermal resources can be accomplished in several ways. Technologies developed for low temperature energy sources such as solar, geothermal, and process waste heat are easily adaptable to the HDR system. Because pressurized hot water ranging in temperatures from about 150 to 300°C will be produced from HDR reservoirs, the following conversion options are possible (see Kestin, et al. (1980) and Tester (1982) for details).

1. Single and multi-stage flash cycles

2. Binary Rankine cycles employing organic working fluids (ORC)

3. Trilateral Wet Vapor Cycle (TWVC) (Smith (1981))

4. Total flow concepts such as the helical screw expander or the biphase turbine

Because HDR-produced fluids will most likely have low concentrations of dissolved salts and non-condensible gases, any of the four options cited above are technically acceptable on performance grounds--economic factors will eventually result in specific design selections that are best suited to a particular HDR system and its heat rejection conditions.

As pointed out by Tester, Brown, and Potter (1989), HDR systems can also be retrofitted to improve fossil conversion plants using cogeneration and feed water heating concepts. A key point to remember is that HDR fluid/rock temperatures are selected by choice depending on end use requirements and the economic "grade" of a specific resource which is largely expressed by its average thermal gradient. In some new design concepts under development, peaking as well as the more traditional, base load applications are possible for HDR systems.

For all applications for HDR that are envisioned, "off-the-shelf," commercial power plant systems are available. Further development of newer conversion technology such as the TWVC and total flow systems will undoubtedly increase the attractiveness of HDR by permitting operation at higher conversion efficiencies.

Estimated costs in 1989 $/kWe installed for HDR power plants are shown in Figure 6.1 as a function of the fluid production temperature that would enter the plant. An upper limit of 300°C was chosen to avoid problems of mineral transport and deposition with the HDR reservoir/power plant system. A nominal 50 MWe sized plant has been selected with costs shown for an appropriate range of conditions

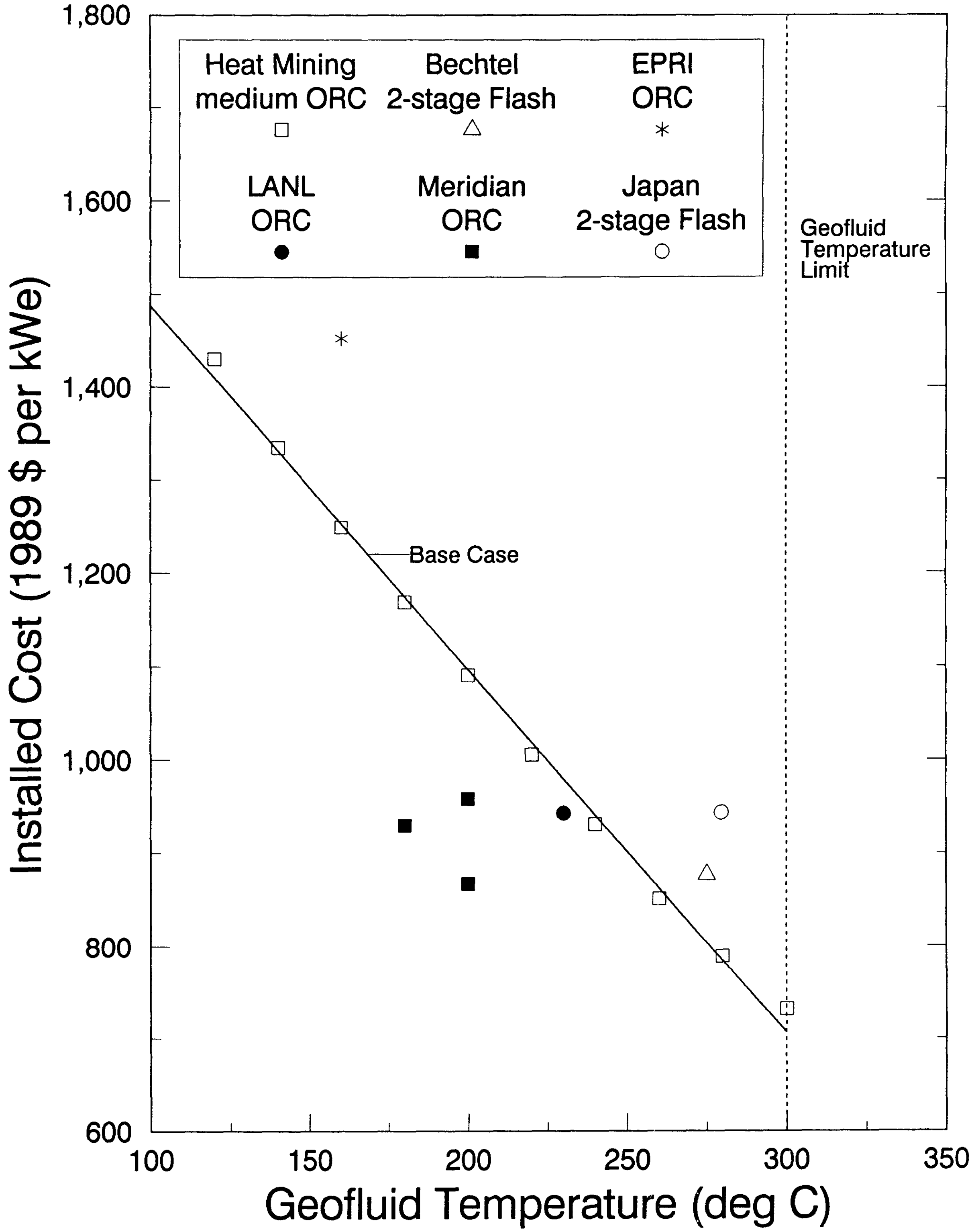


Figure 6.1 Estimated HDR power plant construction costs for the U.S. Base case cost estimates should only be used in the geofluid temperature range from 100° to 300°C.

that would be expected for applications in the U.S. A median or base case line is shown, but some variations are anticipated for different sites, geologic and ambient conditions, and plant designs. For example, heat rejection using wet cooling with ocean or river water would result in more efficient cycles, in general, with lower costs. Dry cooling or wet/dry cooling in regions of high ambient temperature and/or limited water availability would have lower efficiencies and somewhat higher costs on a $/kWe basis.

In order to achieve a common 1989 $ cost basis for plant costs, a composite cost index was developed. Table 6.1 shows the data used to develop the composite from several sources including the Chemical Engineering (CE) Plant Cost Index, Marshall and Swift (M & S) Equipment Cost Index, Nelson Refinery Construction Cost Index, and the Engineering News-Record (ENR) General Construction Cost Index. All cost indexes were normalized to 100 in 1965 and a linear average was used to estimate the MIT composite index as shown in Table 6.2. The composite index was then used to convert all plant costs from the studies to a 1989 $ basis. Data and conversions for plant costs are tabulated in Table 6.3. The generic cost curve from *Heat Mining* (Armstead and Tester (1987)) was also normalized and plotted for reference, and as can be seen from Figure 6.1, the base case line selected is approximately the same as the generic example from *Heat Mining* at a condensing temperature of 37°C. It is important to emphasize that these cost estimates are only to be used for HDR resources in the temperature range shown from 125 to 300°C; extrapolation outside the range could lead to serious errors.

Also plotted in Figure 6.1 are estimated power plant installed costs for the specific designs selected in the HDR economic studies. No total flow plant costs, other than the TWVC, were provided in the six studies. Estimated HDR power plant costs for the UK are plotted in a separate Figure 6.2 where estimated cost lines for generic ORC, TWVC, and flash plants built in the UK are shown (Shock (1986)). We did not use the UK plant cost figures to obtain base case estimates for U.S. plants because they were significantly different from all other estimates and showed very different trends with geofluid temperature. Furthermore, UK-based estimates would not necessarily be applicable for plant construction in the U.S. Based on the observed agreement among U.S. cost estimates, we would anticipate that estimated installed HDR power plant costs would be accurate to ±20%. At any rate, the uncertainty in plant costs is significantly lower than HDR drilling and stimulation costs discussed earlier in Sections 2 and 3 of this report.

TABLE 6.1. PLANT CONSTRUCTION COST INDEXES

YEAR	CE PLANT COST INDEX	M&S EQUIPMENT COST INDEX	NELSON REFINERY COST INDEX	ENR GENERAL COST INDEX 1913=100	ENR GENERAL COST INDEX 1982=100
1965	104	245	261	971	-
1966	107	253	273	1019	-
1967	110	263	287	1070	-
1968	114	273	304	1155	-
1969	119	285	329	1269	-
1970	126	303	365	1385	-
1971	132.2	321.3	406.0	1581	-
1972	137.2	332.0	438.5	1753	-
1973	144.1	344.1	468.0	1895	-
1974	165.4	398.4	527.7	2020	-
1975	182.4	444.3	575.5	2212	57.8
1976	192.1	472.1	615.7	2401	-
1977	204.1	505.4	653.0	2577	-
1978	218.8	545.3	701.1	2776	-
1979	238.7	599.4	756.6	-	78.5
1980	261.2	659.6	822.8	-	84.6
1981	297.0	721.3	903.8	-	92.5
1982	314.0	745.6	976.9	-	100.0
1983	316.9	760.8	1025.8	-	106.3
1984	322.7	780.4	1061.0	-	108.4
1985	325.3	789.6	1074.4	-	109.7
1986	318.4	797.6	1089.9	-	112.3
1987	323.8	813.6	1121.5	-	115.2
1988	342.5	852.0	1164.5	-	-
1989	355.4	895.1	1195.9	-	-

SOURCES:

1. Chemical Engineering, McGraw Hill, New York (1971-1990).

2. Oil and Gas Journal, McGraw Hill, New York (1971-1990).

3. Peters, M. S. and Timmerhaus, K. D., Plant Design and Economics for Chemical Engineers, 3rd ed., McGraw Hill, New York (1980).

4. Statistical Abstract of the United States 1989, 109th ed., U. S. Department of Commerce (1989).

TABLE 6.2. NORMALIZED COST INDEXES (1965=100.0) FOR ESTIMATING POWER PLANT COSTS

YEAR	CE PLANT COST INDEX	M&S EQUIPMENT COST INDEX	NELSON REFINERY COST INDEX	ENR GENERAL COST INDEX	MIT COMPOSITE PLANT COST INDEX
1965	100.0	100.0	100.0	100.0	100.0
1966	102.9	103.3	104.6	104.9	103.9
1967	105.8	107.3	110.0	110.2	108.3
1968	109.6	111.4	116.5	118.9	114.1
1969	114.4	116.3	126.1	130.7	121.9
1970	121.2	123.7	139.8	142.6	131.8
1971	127.1	131.1	155.6	162.8	144.2
1972	131.9	135.5	168.0	180.5	154.0
1973	138.6	140.4	179.3	195.2	163.4
1974	159.0	162.6	202.2	208.0	183.0
1975	175.4	181.3	220.5	227.8	201.3
1976	184.7	192.7	235.9	247.3	215.1
1977	196.3	206.3	250.2	265.4	229.5
1978	210.4	222.6	268.6	285.9	246.9
1979	229.5	244.7	289.9	309.4	268.4
1980	251.2	269.2	315.2	333.4	292.3
1981	285.6	294.4	346.3	364.6	322.7
1982	301.9	304.3	374.3	394.1	343.7
1983	304.7	310.5	393.0	419.0	356.8
1984	310.3	318.5	406.5	427.2	365.6
1985	312.8	322.3	411.6	432.4	369.8
1986	306.2	325.6	417.6	442.6	373.0
1987	311.3	332.1	429.7	454.0	381.8
1988	329.3	347.8	446.2	(476)	(400)
1989	341.7	365.3	458.2	(494)	(415)

(xxx) = Projected value.

TABLE 6.3. ESTIMATED HDR POWER PLANT COSTS

Study/ Plant Type	Geofluid Temp C	Net Installed Capacity MWe	Installed Cost M$	Installed Cost $/kW	Year Com-pleted	Installed Cost 1989 $ M$	Installed Cost 1989 $ $/kW
Bechtel/ Flash	275	70	56.5	807	1987	61.4	877
EPRI/ ORC	160	50	43.2	864	1978	72.6	1452
LANL/ ORC	230	75	55.0	733	1981	70.7	943
Japan/ Flash	280	90	76.0	844	1985	85.3	948
Meridian I/ ORC subcrit	180	64	52.4	819	1984	59.5	930
Meridian II/ ORC subcrit	200	88	67.2	764	1984	76.3	867
Meridian III/ ORC supercrit	200	112	94.5	844	1984	107.3	958
UK/ ORC	206	25.275	43.2	1709	1985	48.5	1918
UK/ TWVC	206	35.275	60.0	1701	1985	67.3	1909
UK/ Flash	206	22.275	29.6	1329	1985	33.2	1491
Heat Mining/	120	50	63.0	1260	1984	71.5	1430
generic medium ORC	140	50	58.8	1175	1984	66.7	1334
	160	50	55.0	1100	1984	62.4	1249
	180	50	51.5	1030	1984	58.5	1169
	200	50	48.0	960	1984	54.5	1090
	220	50	44.3	885	1984	50.2	1005
	240	50	41.0	820	1984	46.5	931
	260	50	37.5	750	1984	42.6	851
	280	50	34.8	695	1984	39.4	789
	300	50	32.3	645	1984	36.6	732
UK/ generic ORC	125	50	213.4	4267	1985	239.4	4789
	150	50	151.4	3027	1985	169.9	3397
	175	50	115.2	2304	1985	129.3	2586
	200	50	90.8	1816	1985	101.9	2038
UK/ generic TWVC	125	50	191.8	3837	1985	215.3	4306
	150	50	141.0	2821	1985	158.3	3166
	175	50	115.2	2304	1985	129.3	2586
	200	50	96.3	1926	1985	108.1	2162
UK/ generic Flash	125	50	133.4	2667	1985	149.7	2993
	150	50	92.1	1842	1985	103.3	2067
	175	50	74.8	1496	1985	83.9	1679
	200	50	65.4	1307	1985	73.3	1467

Conversion Rate: $1.6 per pound for UK

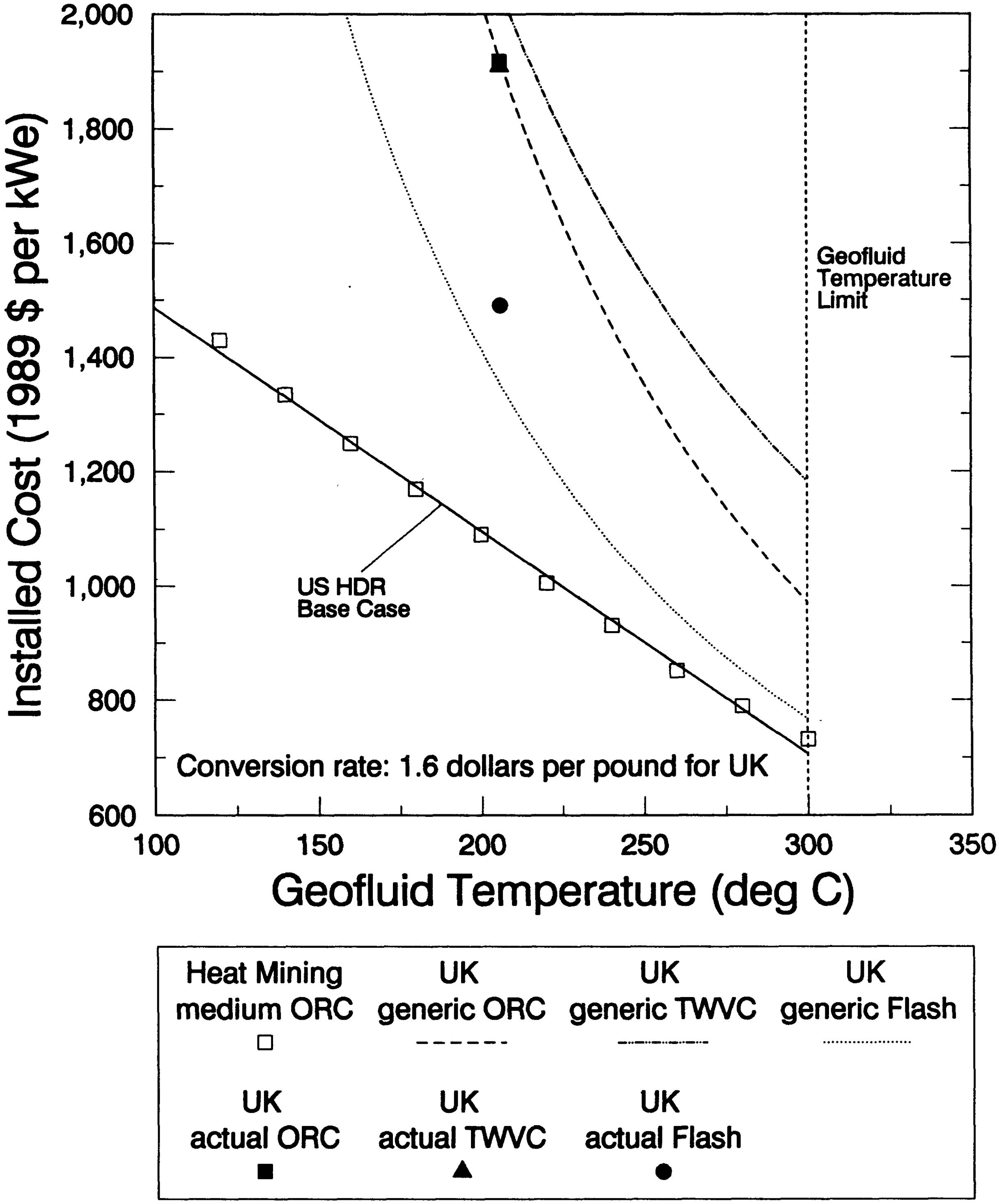


Figure 6.2 Estimated HDR power plant construction costs for the UK.

7. Comparison of HDR Economic Model Predictions

The relevant resource, reservoir performance, power plant, and economic conditions pertaining to all six studies have been summarized in Table 7.1 (a-f). A common data base structure was used so that comparisons can easily be made. In addition, key parameters have been tabulated for all six studies in Table 7.2 where one can easily see the dispersed distribution of resource, reservoir, and economic parameters and assumptions across the six studies. Therefore, any agreement in predicted breakeven electricity price must be regarded with caution. Nonetheless, one can see why certain studies predict high prices and others lower ones or where certain cost components are out of line. Figure 7.1 and Table 7.3 compare the breakdown of key cost components for each study in bar graph form. One can easily understand why the Meridian (1986), Japan (1986) and the UK (1986) studies give higher electricity prices.

As we have described in earlier sections, the major purpose of analyzing each study was to extract component cost information in order to guide us in developing a set of composite conditions. In addition, by reviewing the other assumptions regarding reservoir and power plant performance used in each study, we can construct a reasonable model that brackets the range of values assumed. Furthermore, by studying the range of costs and other factors, we have developed suitable intervals for parameter sensitivity studies.

Our overall approach was as follows:

(1) Analyze the six economic studies.

(2) Develop composite cases for low-, mid-, and high-grade HDR resources (30, 50, and 80°C/km, respectively).

(3) Develop a generalized model for both electricity and direct heat production.

(4) Establish base case conditions for the generalized model.

(5) Establish ranges for performance and cost parameters based on risks and opportunities for technological improvement.

(6) Conduct sensitivity/uncertainty studies with the generalized model.

TABLE 7.1 HDR ECONOMIC MODELS

BASIS, ASSUMPTIONS AND COST SUMMARIES

7.1a - (1) EPRI (1979)

7.1b - (2) LANL (Murphy (1982))

7.1c - (3) Japan (1986)

7.1d - (4) UK (Shock (1986))

7.1e - (5) Meridian (Entingh (1987))

7.1f - (6) Bechtel (1988)

TABLE 7.1a. HDR ECONOMIC MODELS
Basis, Assumptions and Cost Summary for Base Cases

MODEL/STUDY	EPRI (1979)

RESOURCE/RESERVOIR				Notes
Location (Generic vs. Specific)	generic			1
Average Gradient (deg C/km)	40			
Average Well Depth (km)	4			
Initial Ave Reservoir Temp (C)	175			2
Initial Fluid Production Temp (C)	160			
Flowrate per Well Pair (kg/s)	75			
Total Number of Wells	22			
Number of Injectors	11			
Number of Producers	11			
Water Loss Rate (%)	5			
Water Loss Rate – All Wells (kg/s)	41.25			
Reservoir Impedance (GPa-s/cum)	–			
Drawdown Parameter (kg/sqm-s)	0.0000442			
Drawdown Rate	15 C/5 yrs			
POWER PLANT				
Type of Plant (ORC/TWVC/Flash)	ORC			
Working Fluid	generic organic			7
Turbine Inlet Pressure (Bar)	–			
Turbine/Generator Output (MWe)	–			
Plant Pumping Power (MWe)	–			
Other Parasitic Power Loss (MWe)	–			
Net Installed Capacity (MWe)	50			
Reservoir Pumping Power (MWe)	–			
Average Net Power Output (MWe)	50			
ECONOMIC ASSUMPTIONS				
Annual Interest/Discount Rate (%)	9/12			3
Cost Year Basis	1978			
Project Lifetime (yrs)	30			
Capacity Factor (%)	85			
COSTS				
Individual Well Cost (M$)	–			
Total Well Costs (M$)	43.8			4
Stimulation Costs (M$)				
Fluid Distribution Costs (M$)	1.1			
Power Plant Installed Costs (M$)	43.2			
O & M Costs (M$/yr)	0.484			5
Make-up Water Costs (M$/yr)	–			8
Other Costs (M$)	12.2			6
Electricity Breakeven Price (cents/kWh)	4.32			

Notes:

1) These numbers represent the "reference case".

2) Calculated from reservoir depth and gradient.

3) 12% "real" equity rate and 9% "real" debt rate.

4) Includes stimulation costs. Excludes 11.7 M$ for redrilling.

5) 0.13 cents/kWh times 50 MWe at 85% capacity.

6) Includes exploration (43%), site development (8%), taxes(13%), and interest(35%).

7) Generic ORC (binary) plant design using organic working fluid and optimized for performance at 160 deg C geofluid temperature.

8) Included in O & M Costs.

TABLE 7.1b. HDR ECONOMIC MODELS
Basis, Assumptions and Cost Summary for Base Cases

MODEL/STUDY	LANL (Murphy, 1982)

RESOURCE/RESERVOIR				Notes
Location (Generic vs. Specific)	Fenton Hill			
Average Gradient (deg C/km)	55			1
Average Well Depth (km)	4.5			
Initial Ave Reservoir Temp (C)	260			
Initial Fluid Production Temp (C)	230			12
Flowrate per Well Pair (kg/s)	46			2
Total Number of Wells	9			3
Number of Injectors	5			
Number of Producers	4			
Water Loss Rate (%)	5			
Water Loss Rate – All Wells (kg/s)	28			
Reservoir Impedance (GPa-s/cum)	0.09			11
Drawdown Parameter (kg/sqm-s)	0.000144			13
Drawdown Rate	25 C/10 yrs			14
POWER PLANT				
Type of Plant (ORC/TWVC/Flash)	ORC			
Working Fluid	R-114			
Turbine Inlet Pressure (Bar)	–			
Turbine/Generator Output (MWe)	78			
Plant Pumping Power (MWe)	–			
Other Parasitic Power Loss (MWe)	3			4
Net Installed Capacity (MWe)	75			
Reservoir Pumping Power (MWe)	0			11
Average Net Power Output (MWe)	75			
ECONOMIC ASSUMPTIONS	Wellfield	Power Plant		
Annual Interest/Discount Rate (%)	17	17		10
Cost Year Basis	1981	1981		
Project Lifetime (yrs)	10	30		5
Capacity Factor (%)	85	85		
COSTS				
Individual Well Cost (M$)	8.5			
Total Well Costs (M$)	77			
Stimulation Costs (M$)	10			
Fluid Distribution Costs (M$)	7.5			6
Power Plant Installed Costs (M$)	55			
O & M Costs (M$/yr)	1.9			7
Make-up Water Costs (M$/yr)	0.45			8
Other Costs (M$)	4.9			9
Electricity Breakeven Price (cents/kWh)	4.4			

Notes:

1) Calculated from reservoir temperature and depth.

2) Flow rate per reservoir.

3) 9 wells service 12 reservoirs.

4) 2 MWe for dry cooling.

5) 10 years for wells and reservoirs, 30 years for surface plant.

6) For dry cooling heat rejector.

7) About half for taxes and insurance; the other half for miscellaneous.

8) About 0.1 cents/kWh or $2.00 per 1000 gallons.

9) For exploration, land, and site development.

10) Nominal interest and discount rates. With inflation at about 6%, this amounts to real rates of 10.4%.

11) Self-pumped reservoir due to buoyancy drive assumed. An individual fracture impedance of 1.5 GPa-s/cubic meter was assumed, but self-pumping even if impedance was 3 GPa-s/cubic meter per fracture. Since there are 16 fractures per reservoir, the reservoir impedance is 1.5/16 or 0.0937.

12) Time-mean fluid production temperature. Over a 10 year period, only a 5 deg C loss in temperature is assumed.

13) Based on an effective heat transfer area of a million square meters per reservoir.

14) This drawdown rate is equivalent to a 20% reduction in capacity over 10 years.

TABLE 7.1c. HDR ECONOMIC MODELS
Basis, Assumptions and Cost Summary for Base Cases

Model/Study	Japan (1986)

RESOURCE/RESERVOIR				Notes
Location (Generic vs. Specific)	generic			
Average Gradient (deg C/km)	120			
Average Well Depth (km)	3			
Initial Ave Reservoir Temp (C)	300			
Initial Fluid Production Temp (C)	280			
Flowrate per Well Pair (kg/s)	74			1
Total Number of Wells	13			2
Number of Injectors	4			
Number of Producers	9			
Water Loss Rate (%)	13			
Water Loss Rate – All Wells (kg/s)	83			
Reservoir Impedance (GPa-s/cum)	0.14			
Drawdown Parameter (kg/sqm-s)	0.000127			6
Drawdown Rate	74 C/ 15 yrs			
POWER PLANT				
Type of Plant (ORC/TWVC/Flash)	2-stage Flash			
Working Fluid	water			
Turbine Inlet Pressure (Bar)	–			
Turbine/Generator Output (MWe)	75			7
Plant Pumping Power (MWe)	6.3			
Other Parasitic Power Loss (MWe)	–			
Net Installed Capacity (MWe)	68.7			
Reservoir Pumping Power (MWe)	9.2			
Average Net Power Output (MWe)	59.5			
ECONOMIC ASSUMPTIONS				
Annual Interest/Discount Rate (%)	6			
Cost Year Basis	1985			
Project Lifetime (yrs)	15			
Capacity Factor (%)	–			
COSTS				3
Individual Well Cost (M$)	6			
Total Well Costs (M$)	76			
Stimulation Costs (M$)	23			
Fluid Distribution Costs (M$)	27			4
Power Plant Installed Costs (M$)	76			4
O & M Costs (M$/yr)	–			
Make-up Water Costs (M$/yr)	–			
Other Costs	81			5
Electricity Breakeven Price (cents/kWh)	10.6			

Notes:

1) Based on a total flow of 2400 cubic meters per hour for 9 reservoirs.

2) Add 3 wells every 5 years.

3) Conversion rate approximately 170 Yen per $.

4) Based on a 90 MWe plant.

5) Includes survey (29%), land (3%), building (7%), interest (44%), and miscellaneous (17%) costs.

6) Estimated from drawdown rate and Heat Mining Figure 10.25.

7) Gross power output given as a range of 75–90 MWe. We chose the lower value for our study evaluation. However, reported power plant costs are for a 90 MWe plant.

TABLE 7.1d. HDR ECONOMIC MODELS
Basis, Assumptions and Cost Summary for Base Cases

MODEL/STUDY	UK (Shock, 1986)

RESOURCE/RESERVOIR				Notes
Location (Generic vs. Specific)	generic/electric			
Average Gradient (deg C/km)	35			
Average Well Depth (km)	6			1
Initial Ave Reservoir Temp (C)	220			
Initial Fluid Production Temp (C)	200-212			
Flowrate per Well Pair (kg/s)	75			
Total Number of Wells	10			
Number of Injectors	5			
Number of Producers	5			
Water Loss Rate (%)	2			
Water Loss Rate - All Wells (kg/s)	7.5			
Reservoir Impedance (GPa-s/cum)	0.1			
Drawdown Parameter (kg/sqm-s)	0.00005			9
Drawdown Rate	5% in 25 yrs			
POWER PLANT				
Type of Plant (ORC/TWVC/Flash)	ORC	TWVC	Flash	2
Working Fluid	R-12	n-pentane	water	
Turbine Inlet Pressure (Bar)	41.2	26.5	-	
Turbine/Generator Output (MWe)	32.9	43.9	23.275	
Plant Pumping Power (MWe)	7.63	8.59	1	10
Other Parasitic Power Loss (MWe)	-	-	-	
Net Installed Capacity (MWe)	25.275	35.275	22.275	
Reservoir Pumping Power (MWe)	2.275	2.275	2.275	
Average Net Power Output (MWe)	23	33	20	
ECONOMIC ASSUMPTIONS				
Annual Interest/Discount Rate (%)	5	5	5	
Cost Year Basis	1985	1985	1985	
Project Lifetime (yrs)	25	25	25	
Capacity Factor (%)	90	90	85	
COSTS				
Individual Well Cost (ML)	8.424	8.424	8.424	
Total Well Costs (ML)	84.24	84.24	84.24	
Stimulation Costs (ML)	8.424	8.424	8.424	3
Fluid Distribution Costs (ML)	-	-	-	
Power Plant Installed Costs (ML)	27	37.5	18.5	4
O & M Costs (ML/yr)	1.84	2.15	1.58	5
Make-up Water Costs (ML/yr)	0.445	0.445	0.420	6
Other Costs	8.3	8.3	8.3	7
Electricity Breakeven Price (pence/kWh	6.7	5.1	7.6	8

Notes:

1) 8.5 in ID casing.

2) ORC plant based on a 170 C geothermal fluid temperature (see Shock (1986), Figure 25, page 77). TWVC plant based on Shock (1986), Table 9, page 83.

3) 10% of well costs.

4) Based on a maximum output about 8% larger than average output reported above (Shock (1986), page 197).

5) 30,000 pounds/yr/doublet + 175,000 pounds/yr/surface plant + 3% of surface plant capital cost

6) 26 pence/cum; 2% of reservoir flow + 1.4% of cooling tower flow

7) Connection charges, land water mains, and site preparation.

8) Costs are for 5 doublets. No economies of scale considered. If economies of scale are considered, prices are 5.2 (ORC), 4.2 (TWVC), and 5.5 (Flash) pence per kWh (Shock (1986), pages 114–115).

9) Estimated from drawdown rate and Heat Mining Figure 10.25.

10) Plant pumping power approximated for flash-type power plant.

TABLE 7.1e. HDR ECONOMIC MODELS
Basis, Assumptions and Cost Summary for Base Cases

Model/Study	Meridian (1987)

RESOURCE/RESERVOIR	CASE I	CASE II	CASE III	Notes
Location (Generic vs. Specific)	developing	developing	mature	1
Average Gradient (deg C/km)	55	61.7	61.7	4
Average Well Depth (km)	3	3	3	
Initial Ave Reservoir Temp (C)	180	200	200	
Initial Fluid Production Temp (C)	–	–	–	
Flowrate per Well Pair (kg/s)	–	–	–	
Total Number of Wells	37	37	37	
Number of Injectors	18	18	18	
Number of Producers	19	19	19	
Water Loss Rate (%)	–	–	–	
Water Loss Rate – All Wells (kg/s)	–	–	–	
Reservoir Impedance (GPa-s/cum)	–	–	–	
Drawdown Parameter (kg/sqm-s)	–	–	–	
Drawdown Rate	50 C/20 yrs	70 C/20 yrs	70 C/20 yrs	
POWER PLANT				
Type of Plant (ORC/TWVC/Flash)	ORC Subcrit	ORC Subcrit	ORC Supercrit	
Working Fluid	–	–	–	
Turbine Inlet Pressure (Bar)	–	–	–	
Turbine/Generator Output (MWe)	69	98	141	5
Plant Pumping Power (MWe)	3	7	25	5
Other Parasitic Power Loss (MWe)	2	3	4	2
Net Installed Capacity (MWe)	64	88	112	
Reservoir Pumping Power (MWe)	7	7	7	
Average Net Power Output (MWe)	57	81	105	
ECONOMIC ASSUMPTIONS				
Annual Interest/Discount Rate (%)	13	13	13	
Cost Year Basis	1984	1984	1984	
Project Lifetime (yrs)	20	20	20	
Capacity Factor (%)	80	90	90	
COSTS				
Individual Well Cost (M$)	6.9	3.8	3.0	
Total Well Costs (M$)	255	141	111	
Stimulation Costs (M$)	55	55	55	
Fluid Distribution Costs (M$)	23	23	23	
Power Plant Installed Costs (M$)	52.44	67.23	94.50	
O & M Costs (M$/yr)	13.1	8.4	5.0	
Make-up Water Costs (M$/yr)	–	–	–	
Other Costs (M$)	50	50	50	3
Electricity Breakeven Price (cents/kWh)	21.5	10.1	7.4	

Notes:

1) Case I - 1980 Installation
   Case II - 1990 Installation
   Case III - 2000 Installation

2) For dry cooling.

3) Exploration and proof of principle costs.

4) Calculated from well depth and initial reservoir temperature.

5) Turbine generator output calculated based on approximated plant pumping power values.

TABLE 7.1f. HDR ECONOMIC MODELS
Basis, Assumptions and Cost Summary for Base Cases

Model/Study	Bechtel (1988)

RESOURCE/RESERVOIR				Notes
Location (Generic vs. Specific)	Roosevelt Hot Springs, Utah			
Average Gradient (deg C/km)	78			1
Average Well Depth (km)	3.6			
Initial Ave Reservoir Temp (C)	270			
Initial Fluid Production Temp (C)	275			
Flowrate per Well Pair (kg/s)	120			
Total Number of Wells	8			2
Number of Injectors	4			
Number of Producers	4			
Water Loss Rate (%)	10			
Water Loss Rate – All Wells (kg/s)	48			3
Reservoir Impedance (GPa-s/cum)	0.08			
Drawdown Parameter (kg/sqm-s)	0.000314			
Drawdown Rate	1-3%/yr			
POWER PLANT				
Type of Plant (ORC/TWVC/Flash)	2-stage Flash			
Working Fluid	water			
Turbine Inlet Pressure (Bar)	15.5			
Turbine/Generator Output (MWe)	74			
Plant Pumping Power (MWe)	4			
Other Parasitic Power Loss (MWe)	-			
Net Installed Capacity (MWe)	70			
Reservoir Pumping Power (MWe)	20			4
Average Net Power Output (MWe)	50			
ECONOMIC ASSUMPTIONS	Wellfield	Power Plant		
Annual Interest/Discount Rate (%)	15.5	12		9
Cost Year Basis	1987	1987		
Project Lifetime (yrs)	30	30		
Capacity Factor (%)	90	90		
COSTS				
Individual Well Cost (M$)	3.359			
Total Well Costs (M$)	26.87			5
Stimulation Costs (M$)	12.71			5
Fluid Distribution Costs (M$)	9.3			5
Power Plant Installed Costs (M$)	56.5			6
O & M Costs (M$/yr)	3.65			7
Make-up Water Costs (M$/yr)	0.248			8
Other Costs	-			
Electricity Breakeven Price (cents/kWh)	4.98			

Notes:

1) Calculated from reservoir temperature and depth.

2) An additional 16 wells are drilled over the lifetime of the project.

3) Increases to a maximum of 144 kg/s as more wells are drilled.

4) Corresponds to the maximum pumping rate when all 24 wells are in operation (Bechtel (1988), Table 7-4, page 7-7).

5) Not including 2.7 M$ capitalized interest and 1.1 M$ preproduction costs.

6) Not including 10.5 M$ AFDC and 1.9 M$ preproduction costs.

7) 2.3 M$/yr for power plant. 1.35 M$/yr for wellfield. Excludes royalties, make-up water costs, and reservoir pumping power.

8) 0.045 cents/kWh for 70 MWe plant.

9) Corresponds to a "real" discount rate of 11% for wellfield and 7.7% for power plant.

TABLE 7.2. COMPARISON OF KEY RESOURCE AND POWER PLANT PARAMETERS

PARAMETER	HDR ECONOMIC STUDY					
	EPRI (1979)	LANL (1982)	Japan (1986)	UK TWVC (1986)	Meridian III (1987)	Bechtel (1988)
Site Grade	low	high	high	low	high	high
Average Gradient (deg C/km)	40	55	120	35	62	78
Average Well Depth (km)	4	4.5	3	6	3	3.6
Initial Ave Reservoir Temp (C)	175	260	300	220	200	270
Flowrate per Well Pair (kg/s)	75	46	74	75	78 (b)	120
Water Loss Rate (%)	5	5	13	2	–	10
Reservoir Impedance (GPa–s/cum)	–	0.09	0.14	0.1	–	0.08
Drawdown (a)	low	moderate	moderate	low	moderate	high
Net Installed Capacity (MWe)	50	75	68.7	35.275	112	70
Reservoir Pumping Power (MWe)	–	0	9.2	2.275	7	20
Average Net Power Output (MWe)	50	75	59.5	33	105	50
Project Lifetime (yrs)	30	10/30	15	25	20	30

Notes:

(a) Low corresponds to a drawdown parameter <0.0001 kg/sqm–s; moderate 0.0001–0.0002 kg/sqm–s; and high >0.0002 kg/sqm–s.

(b) Estimated. See Table 3.1.

TABLE 7.3. COMPARISON OF NORMALIZED CAPITAL COST COMPONENTS AND PREDICTED ELECTRICITY PRICES (1989 $ BASIS)

PARAMETER	HDR ECONOMIC STUDY					
	EPRI (1979)	LANL (1982)	Japan (1986)	UK TWVC (d) (1986)	Meridian III (1987)	Bechtel (1988)
Net Installed Capacity (MWe)	50	75	68.7	35.275	112	70
Individual Well Cost (M$)	–	6.3	5.8	8.2	3.0	4.0
($/kWe installed)	–	84.2	85.1	232.6	26.5	57.2
Total Well Costs (M$)	(b)	57.2	74.0	82.1	110.0	32.0
($/kWe installed)	–	762.9	1077.7	2326.4	982.2	457.8
Exploration Costs (M$)	7.9	3.6	44.2	8.1	49.6	–
($/kWe installed)	158.1	48.5	643.8	229.2	442.4	–
Stimulation Costs (M$)	(b)	7.4	22.4	8.2	54.5	15.2
($/kWe installed)	–	99.1	326.1	232.6	486.7	216.5
Fluid Distribution Costs (M$)	1.8	9.6	30.3	–	26.1	10.1
($/kWe installed)	37.0	128.6	336.7 (c)	–	233.1	144.4
Power Plant Costs (M$)	72.6	70.7	85.3	67.3	107.3	61.4
($/kWe installed)	1452.2	943.1	947.7 (c)	1908.8	957.8	877.3
Total Capital Cost (M$) (excl. AFDC)	137.1	148.7	256.3	165.7	347.4	118.7
($/kWe)	2741.3	1982.2	3730.1	4697.1	3102.2	1696.0
Average Net Power Output (MWe)	50	75	59.5	33	105	50
Total Capital Cost ($/kWe output)	2741.3	1982.2	4306.9	5020.9	3309.0	2374.4
Redrilling/Restimulation Costs (M$)	14.9	–	45.4	–	–	94.4
(M$/yr)	0.50	–	3.03	–	–	3.15
Other O & M Costs (M$/yr)	0.81	3.02	–	4.66	5.68	4.24
Electricity Breakeven Price (cents/kWh)	6.46	4.56	11.03	6.67	7.74	5.62

Notes: (a) All costs normalized to 1989$ using cost indexes in Figure 1 for drilling and plant construction costs.
Stimulation and exploration cost normalization based on drilling cost index.
Electricity breakeven price normalized on a hybrid, weighted cost index.
(b) Total well and stimulation costs are $55.8M or $1117/kWe installed.
(c) Based on 90 MWe installed.
(d) Conversion rates for UK: $1 per pound for wellfield; $1.6 per pound for power plant.

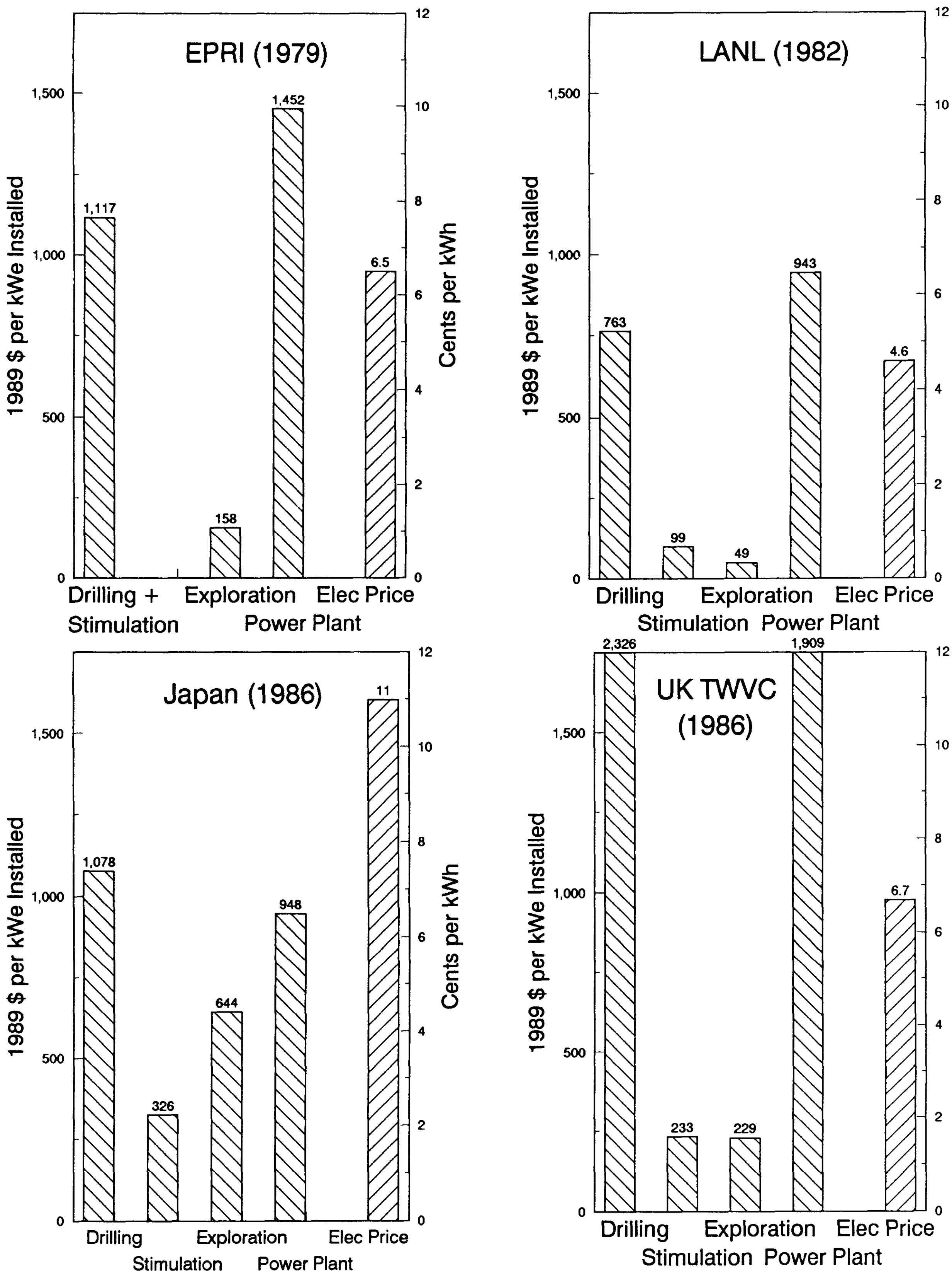


Figure 7.1 Key component costs and predicted breakeven electricity prices for the six HDR economic models reviewed. All costs normalized to 1989 $.

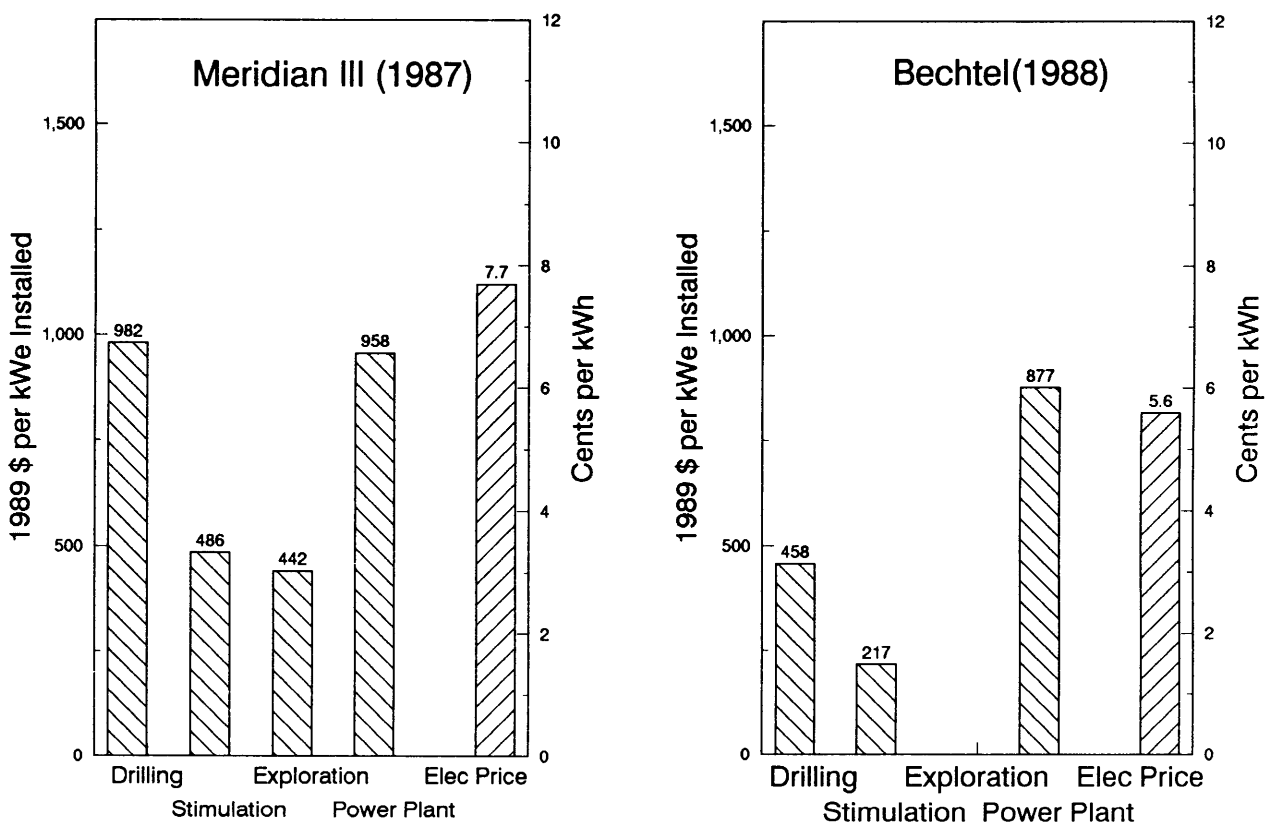


Figure 7.1 (continued)

8. Composite HDR Model Predictions

The approach for creating a revised assessment model of HDR economics is basically to use the system performance and economic assumptions made in the six previous studies as a basis for formulating a new set of composite conditions for three representative gradients. We have followed this approach for each cost component and reservoir and plant performance related parameter to establish the composite conditions listed in Table 8.1. Footnotes are provided to elaborate on the methodology or source used to select a particular parameter.

The three HDR resource grades (30, 50, 80°C/km) were selected to cover a range of average temperature gradient conditions from 20° to 100°C/km. One should note that, in practice, of course each site's characteristics would have to be used in the assessment as was done in the Japanese (Hori, et al. (1981)) and Bechtel (1988) studies. In addition, in Sections 4 and 5, we discussed the key issues relating to reservoir performance. For the composite cases, the base case thermal drawdown rate of 2% per year was selected. This corresponds to an effective drawdown parameter of 1.4×10^{-4} $kg/m^2 \cdot s$. Redrilling and restimulation are done at 5 year intervals to restore reservoir temperatures to their initial values. This is shown in Figure 8.1. For comparison, the cases of no drawdown and drawdown with no redrilling are also shown. For the cases with drawdown, the thermal power levels (P(t)) follow an error function dependence on (effective reservoir area)/($\dot{m}\sqrt{t}$) as given by equation (10.31) in Armstead and Tester (1987).

The resulting set of base case conditions for each HDR resource grade was utilized in two different economic models to estimate breakeven electricity prices:

1. *Fixed annual charge rate (FCR)* approach with a 15.34% annual charge rate suggested by Entingh (1986) used. This rate includes effects for the weighted cost of capital (13%), sinking fund depreciation (1.24%), retirement dispersion allowance (0.67%), Federal and State income tax (3.21%), accelerated depreciation (-2.81%), investment tax credit (-1.97%), and property tax and and insurance (2.00%). We have included a 9% charge for AFDC to be consistent with Entingh's methodology. We also treated redrilling and restimulation costs as average increments to O&M.

2. *Levelized lifecycle cost analysis (LL)* based on EPRI methodology. F. Roach of Los Alamos provided the software which is similar to the BICYCLE code developed at LANL (Hardie (1981)) to implement EPRI's methodology. We established economic parameters to maintain consistency with the Meridian FCR approach. Specific inputs include:

TABLE 8.1. COMPOSITE HDR ECONOMIC MODEL
Basis, Assumptions and Cost Summary

RESOURCE/RESERVOIR	High-Grade	Mid-Grade	Low-Grade	Notes
Average Gradient (deg C/km)	80	50	30	
Average Well Depth (km)	3.06	4.10	4.83	
Initial Ave Reservoir Temp (C)	260	220	160	
Initial Fluid Production Temp (C)	240	200	145	
Flowrate per Well Pair (kg/s)	73	84	110	
Total Number of Wells	10	12	20	1
Number of Injectors	5	6	10	
Number of Producers	5	6	10	
Water Loss Rate (%)	5	5	5	
Water Loss Rate - All Wells (kg/s)	18.3	25.2	55.0	
Reservoir Impedance (GPa-s/cum)	0.10	0.08	0.07	
Drawdown Parameter (kg/sqm-s)	0.00014	0.00014	0.00014	3
Drawdown Rate (%/yr)	2	2	2	4
POWER PLANT				
Type of Plant (ORC/TWVC/Flash)	ORC/Flash	ORC	ORC	5
Working Fluid (based on performance)	NH3/H2O	Isobutane	R-32	5
Net Installed Capacity (MWe)	50	50	50	
Reservoir Pumping Power (MWe)	3.50	4.45	11.12	6
Average Net Power Output (MWe)	46.5	45.55	38.88	
ECONOMIC ASSUMPTIONS				7
Nominal Equity Return Rate (%)	15	15	15	
Nominal Debt Interest Rate (%)	11	11	11	
Inflation Rate (%)	4	4	4	
Cost Year Basis	1989	1989	1989	
Project Lifetime (yrs)	20	20	20	
Capacity Factor (%)	90	90	90	
COSTS				
Individual Well Cost (M$)	2.3	5.4	7.1	
Total Well Costs (M$)	23.1	64.9	142.8	
Exploration Costs (M$)	4.3	7.4	9.1	8
Stimulation Costs (M$)	10.2	11.5	17.4	2
Fluid Distribution Costs (M$)	10.0	10.0	10.0	9
Power Plant Installed Costs ($/kW)	912	1085	1335	
Power Plant Installed Costs (M$)	45.6	54.2	66.8	
Total Capital Costs (M$)	93.2	148.0	246.2	
Total Capital Costs w/AFDC (M$)	101.6	161.3	268.4	7,10
Wellfield O & M Costs (M$/yr)	1.88	2.26	3.76	9
Power Plant O & M Costs (M$/yr)	2.56	2.56	2.56	9
Make-up Water Costs (M$/yr)	0.23	0.31	0.69	11
Total O & M Costs (M$/yr)	4.7	5.1	7.0	
Redrilling/Restimulation Costs (M$)	20.0	38.2	96.1	12
Electricity Breakeven Price (cents/kWh)	5.5/6.1	8.2/9.3	16.0/18.1	13

Notes:

1) Using Figures 14.3–14.4 from Heat Mining (Armstead and Tester, 1987).

2) Stimulation costs based on Figure 3.4.

3) Effective heat transfer area per well pair = 1.64–2.47 M sq. meters.
Effective reservoir volume per well pair = 820–1234 M cu. meters.

4) See Figure 8.2.

5) Working fluids selected for operational performance. See Tester (1982).
Flash (2-stage) and NH3 ORC cycles have equivalent performance at 260 C.

6) Pumping power = [(# of well pairs)(mw) + mloss] [mw] [reservoir impedance]

(1000 kg/cubic meter)^2 (0.80) (10^6 W/MW)

where mw is the flowrate per well pair and mloss is the total water loss rate.
The value 0.80 is the overall pump eficiency.
Sample calculation:[(5)(73)+18.3][73][0.1*10^9]/(0.8*10^12)=3.5 MWe
We have assumed that frictional pressure losses in piping and well tubulars are balanced by buoyancy-driven pressure gain.

7) Based on Meridian guidelines.

8) Based on Heat Mining Table 14.1.

9) Based on Bechtel (1988) study.

10) AFDC (Interest during construction) = 9% of capital costs.

11) Based on water loss rate at $1.50 per 1000 gallons.

12) Drilling and stimulation costs for a new well pair (high- and mid-grades) or 2 new well pairs (low-grade) in years 5, 10, and 15.

13) First number from levelized life-cycle cost analysis. Second number from fixed charge rate cost analysis. E.g. (levelized)/(fixed charge).
Additional economic parameters (from Meridian):
   a) Straight line depreciation.
   b) Costs depreciated over plant lifetime.
   c) 50% debt, 50% equity.
   d) Debt amortized over plant lifetime, proportional debt repayment.
   e) Combined income tax rate = 36%.
   f) Investment tax credit = 10%
   g) Property tax and insurance.

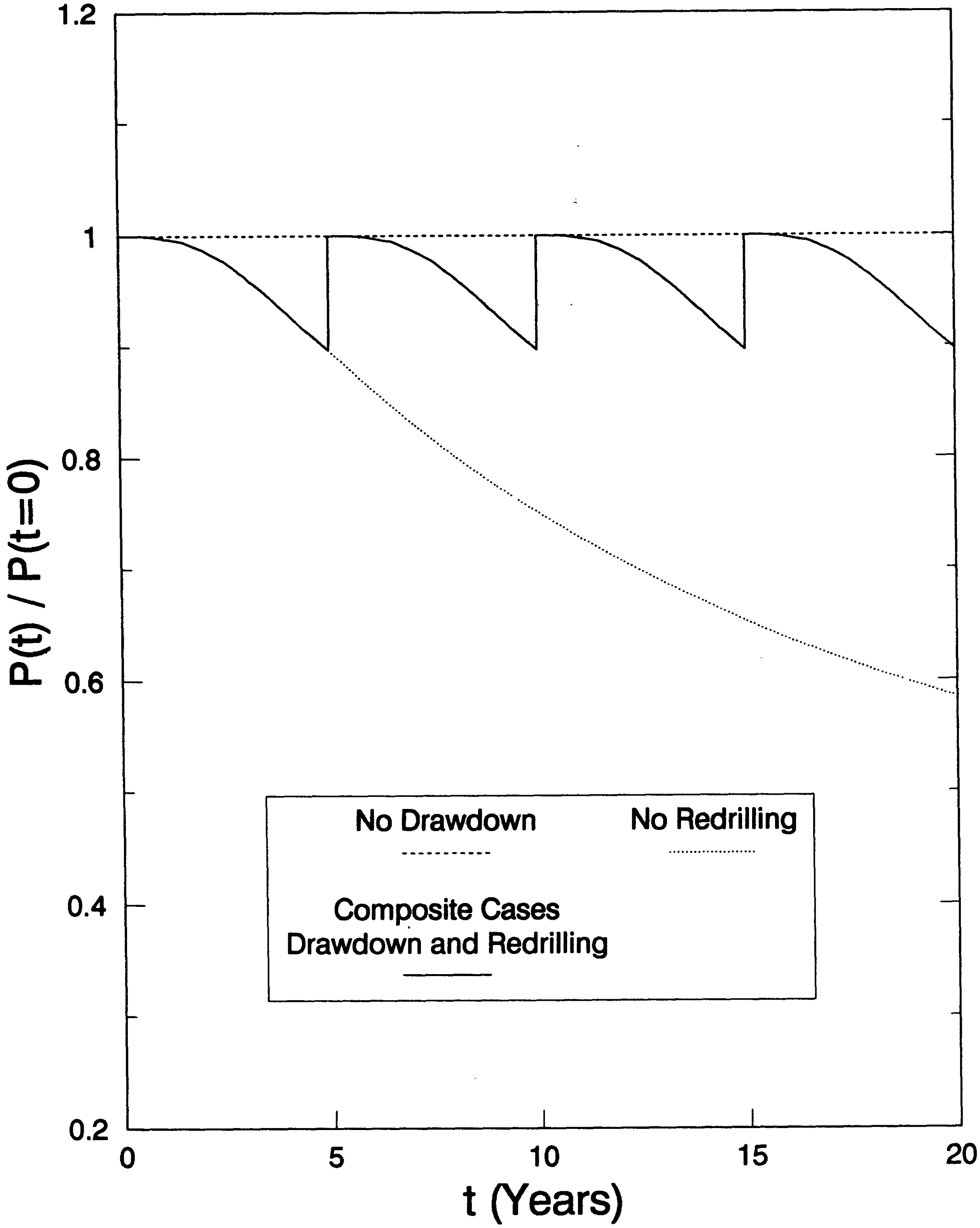


Figure 8.1 Net thermal performance levels for the composite cases as a result of thermal drawdown and redrilling/restimulation. For comparison, the cases of no drawdown and drawdown with no redrilling are shown. P(t) is the thermal power extracted at time t.

(a) Straight line depreciation
(b) Costs depreciated over 20-year plant lifetime
(c) 50% debt at 11% nominal interest rate
(d) 50% equity at 15% nominal return rate
(e) Inflation rate of 4%
(f) Debt amortized over 20-year plant lifetime with a proportional repayment schedule
(g) A combined Federal and State income tax rate of 36%
(h) An investment tax credit of 10%
(i) Property tax and insurance of 2%
(j) Redrilling/restimulation costs treated as O&M in the year they occur

Thermal drawdown was treated in both methodologies by lowering the plant capacity factor. In the FCR model, it was averaged over the 20-year lifetime and in the LL model, it was changed yearly to reflect reduced or increased output.

Base case breakeven electricity prices for the composite high, mid, and low grade HDR systems were estimated using the Fixed Charge Rate (FCR) and Levelized Lifecycle (LL) methodologies described in Section 8. Results are shown in Table 8.2 in 1989 $. A breakdown of costs in $ and $/kWe installed is also tabulated. Figure 8.2 shows some of the same data in bar graph form.

Several general conclusions can be drawn from our projections assuming base case performance and costs:

(1) High-grade (80°C/km) HDR resources are competitive at today's energy prices.

(2) Mid-grade (50°C/km) HDR resources are only marginally competitive at today's energy prices. With higher oil prices >30$/bbl and/or environmental costs associated with fossil-fuel fixed systems, e.g., an acid rain or carbon tax, mid-grade HDR systems would be competitive.

(3) Low-grade (30°C/km) HDR resources would not be competitive for electricity production until significantly higher energy prices exist. Although it should be noted for direct heat (space or process heating) or for cogeneration applications, low-grade HDR resources would compete much more favorably because Second Law efficiencies for conversion of HDR thermal energy into electricity are not relevant (see Section 11).

TABLE 8.2. COMPARISON OF NORMALIZED CAPITAL COST COMPONENTS AND PREDICTED ELECTRICITY PRICES (1989 $ BASIS)

Composite HDR Economic Model

PARAMETER	HDR ECONOMIC STUDY		
	High-Grade	Mid-Grade	Low-Grade
Average Gradient (deg C/km)	80	50	30
Individual Well Cost (M$)	2.3	5.4	7.1
($/kWe installed)	46.1	108.1	142.8
Total Well Costs (M$)	23.1	64.9	142.8
($/kWe installed)	461.2	1297.8	2856.8
Exploration Costs (M$)	4.3	7.4	9.1
($/kWe installed)	85.5	147.5	182.2
Stimulation Costs (M$)	10.2	11.5	17.4
($/kWe installed)	204.1	230.6	348.9
Fluid Distribution Costs (M$)	10.0	10.0	10.0
($/kWe installed)	200.3	200.3	200.3
Power Plant Costs (M$)	45.6	54.2	66.8
($/kWe installed)	912.3	1084.8	1335.1
Total Capital Cost (M$) (excl. AFDC)	93.2	148.0	246.2
($/kWe)	1863.3	2961.0	4923.3
Average Net Power Output (MWe)	46.5	45.6	38.9
Total Capital Cost ($/kWe output)	2003.6	3250.2	6331.5
Redrilling/Restimulation Costs (M$)	20.0	38.2	96.2
(M$/yr)	1.0	1.9	4.8
Other O & M Costs (M$/yr)	4.7	5.1	7.0
Electricity Breakeven Price (cents/kWh)			
Levelized Life-Cycle Cost Analysis	5.5	8.2	16.0
Fixed Charge Rate Cost Analysis	6.1	9.3	18.1

Predictions using the composite HDR model are in general agreement with the normalized results of the several of six previous HDR economic studies. This agreement, however, is fortuitous unless the individual component costs for each model are close to one another. Most of the time, there was only minimal agreement on specific component costs such as drilling, stimulation, or power plant costs. But to the extent that the studies agreed on their methodology, we were able to use their data to justify and specify critical cost components in the revised composite model.

On another note, we recently received a copy of a paper by Harrison, Doherty, and Coulson (1989) that updates the Shock (1986) study of HDR economics in the UK. Although we did not have time to review their results in detail, they are very consistent with the numbers we project for mid- to low-grade HDR resources.

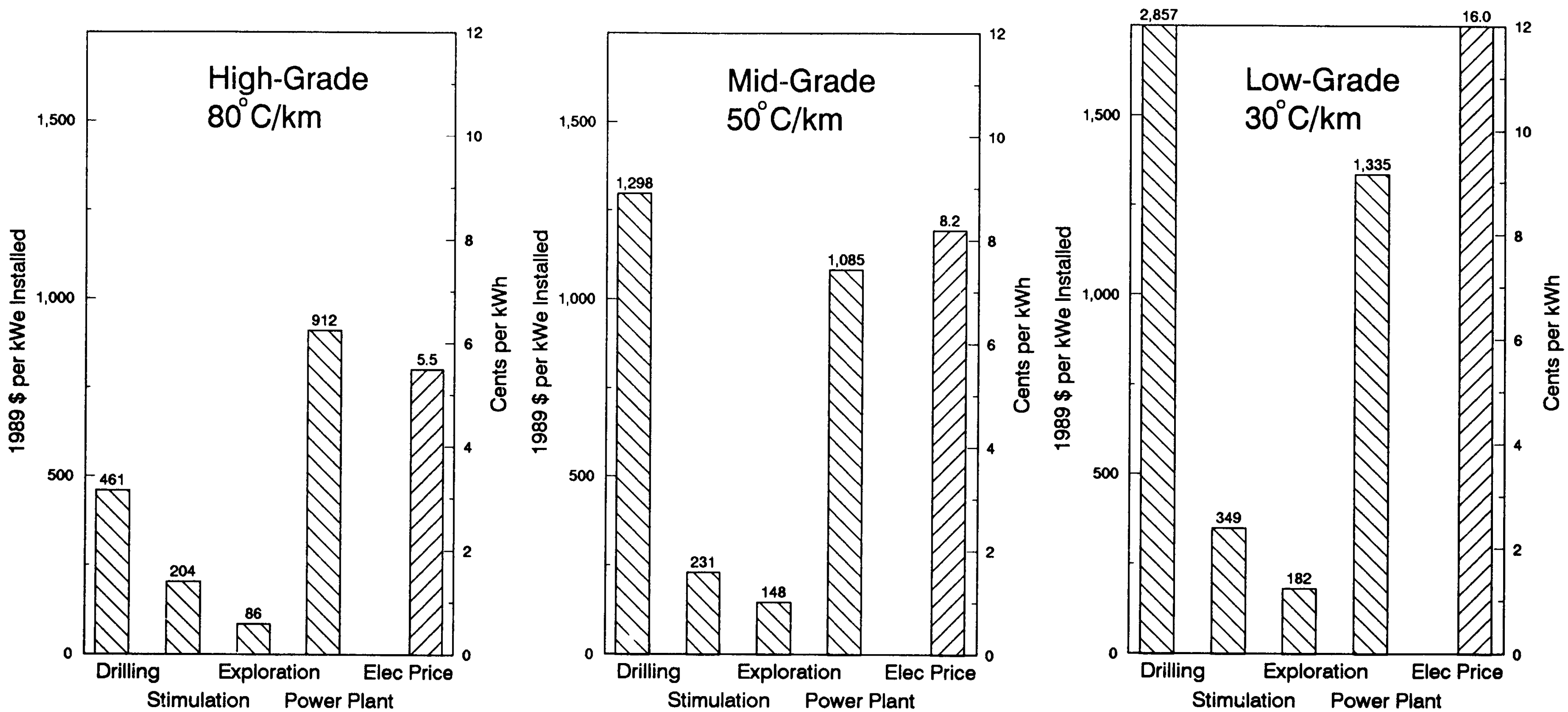


Figure 8.2 Key component costs and predicted breakeven electricity prices for the three composite HDR cases. All costs are in 1989 $.

9. Generalized HDR Economic Model for Electricity Production

Building on the models presented in Sections 7 and 8, a generalized HDR economic model was developed. To distinguish it from other treatments, we have labelled it the *MIT HDR* model, with no Institute endorsement implied. For a given set of parameters which define a technology case, the model calculates breakeven electricity price as a function of gradient. To cover a range of reservoir performances and costs, the following four technology cases were considered:

Today's Technology (TODAY) Case - Reflects today's relatively high drilling and completion costs (see Figure 2.5, HDR Base Case line) with poor reservoir performance at a level comparable to the Fenton Hill System.

Commercial Base (BASE) Case - Keeps same drilling and completion costs as the TODAY case, but reflects the improved reservoir performance required for commercial operation.

Technically Optimized Doublet (DOUBLET) Case - Combines good reservoir performance with optimized drilling and completion costs (see Figure 2.5, HDR Commercially Mature line).

Technically Optimized Triplet (TRIPLET) Case - Maintains same optimized drilling costs as DOUBLET case, but improves reservoir performance with a configuration of 1 injector and 2 producer wells per reservoir.

The specific parameters used to define these cases are detailed in Table 9.1.

The model calculates several important engineering parameters, including:

Average Well Depth: Calculated by optimizing breakeven electricity price subject to the maximum reservoir temperature constraint.

Initial Reservoir Temperature: Depth times gradient plus 15°C.

Geothermal Fluid Temperature: Initial Reservoir Temperature minus a specified temperature approach (see Table 9.1).

Geothermal Fluid Availability: $\Delta H - T_0 \Delta S$, where T_0 = 27.8°C (82°F). The enthalpy (H) and entropy (S) are functions of temperature and are determined from steam table values for saturated liquids.

Utilization Efficiencies: Linear interpolation from 41% at 100°C to 62% at 300°C. Based on Armstead and Tester (1987) Figure 14.3.

Effective Reservoir Area: Calculated from the drawdown parameter, the geothermal fluid availability, and the utilization efficiency.

Overall Pressure Drop: Calculated as the sum of the pressure drop in wells (injector and producer) which were estimated using standard pipe flow data (Shaw and Loomis (1926)); pressure drop in the reservoir calculated as specified reservoir impedance times flow rate; and the buoyancy-driven pressure gain.

Pumping Power: Overall pressure drop times flow rate divided by pump efficiency.

The model calculates costs on a per kWe installed basis. This has the advantage of eliminating plant size as a model parameter. However, results will be most accurate for facilities in the 25-100 MWe installed capacity range, since this is the range upon which most of the correlations are based. This capacity range also corresponds to the most probable size of HDR plants to be built.

Highlights of calculating the electricity breakeven price follow:

- A fixed annual charge rate approach is used because it is easy to implement and use. As seen in Table 8.1, both the fixed annual charge rate and the levelized lifecycle approaches give the same trends, with the fixed charge rate yielding about 15% higher electricity breakeven prices. The economic parameters (see Table 9.1) are the same as in the composite base cases.

- The drilling and completion, stimulation, and power plant costs were based on the cost correlations presented earlier in this report (see Table 9.1).

- All other costs (exploration, fluid distribution, operating and maintenance) are calculated on the same basis as the HDR composite cases discussed in Section 8.

- Results are presented in 1989 dollars.

The key results of the *MIT HDR* economic model are presented in Figure 9.1 and Table 9.2. Detailed results from the model for all economic and engineering calculations are contained in Appendix A.1. A sensitivity and uncertainty analysis of the model is presented in the next section.

TABLE 9.1. MIT HDR MODEL - CASE DEFINITIONS

TECHNOLOGY CASE	TODAY	BASE	DOUBLET	TRIPLET
ENGINEERING PARAMETERS				
Water Loss Rate (%)	5	5	5	2.5
Capacity Factor (%)	86	86	86	90
Redrilled Wells / Initial Wells	0.5	0.5	0.5	0.17
# Injectors / # Producers	1.0	1.0	1.0	0.5
Pump Efficiency (%)	80.0	80.0	80.0	80.0
Drawdown Parameter (kg/sqm-s)	0.00014	0.00014	0.00014	0.00007
T Reservoir - T Geofluid (deg C)	15.0	15.0	15.0	15.0
Maximum Reservoir T (deg C)	300.0	300.0	300.0	300.0
Production Well Flowrate (kg/s)	40.0	75.0	75.0	75.0
Reservoir Impedance (GPa-s/cum)	0.30	0.10	0.08	0.08
Injector Well Casing ID (in)	7	7	7	8.681
Producer Well Casing ID (in)	7	7	7	7
ECONOMIC PARAMETERS				
Fixed Charge Rate (%)	15.34	15.34	15.34	15.34
AFDC Rate (%)	9.0	9.0	9.0	9.0
Project Lifetime (yrs)	20.0	20.0	20.0	20.0
COST CORRELATIONS				
Drilling and Completion (Figure 2.5)	Base	Base	Mature	Mature
Stimulation (Figure 3.4)	2X Base	Base	0.5X Base	0.5X Base
Power Plant (Figure 6.1)	Base	Base	0.9X Base	0.9X Base

TABLE 9.2. MIT HDR MODEL - RESULTS

GRADIENT deg C/km	BREAKEVEN ELECTRICITY PRICE (1989 $ basis) cents/kWh			
	TODAY	BASE	DOUBLET	TRIPLET
20	129.8	85.3	60.9	46.6
30	37.5	23.5	15.5	12.3
40	18.4	11.9	8.1	6.7
50	12.1	8.2	5.5	4.8
60	9.4	6.6	4.6	4.1
70	8.1	5.8	4.2	3.8
80	7.1	5.3	3.9	3.6
90	6.6	4.9	3.8	3.5
100	6.2	4.7	3.7	3.4

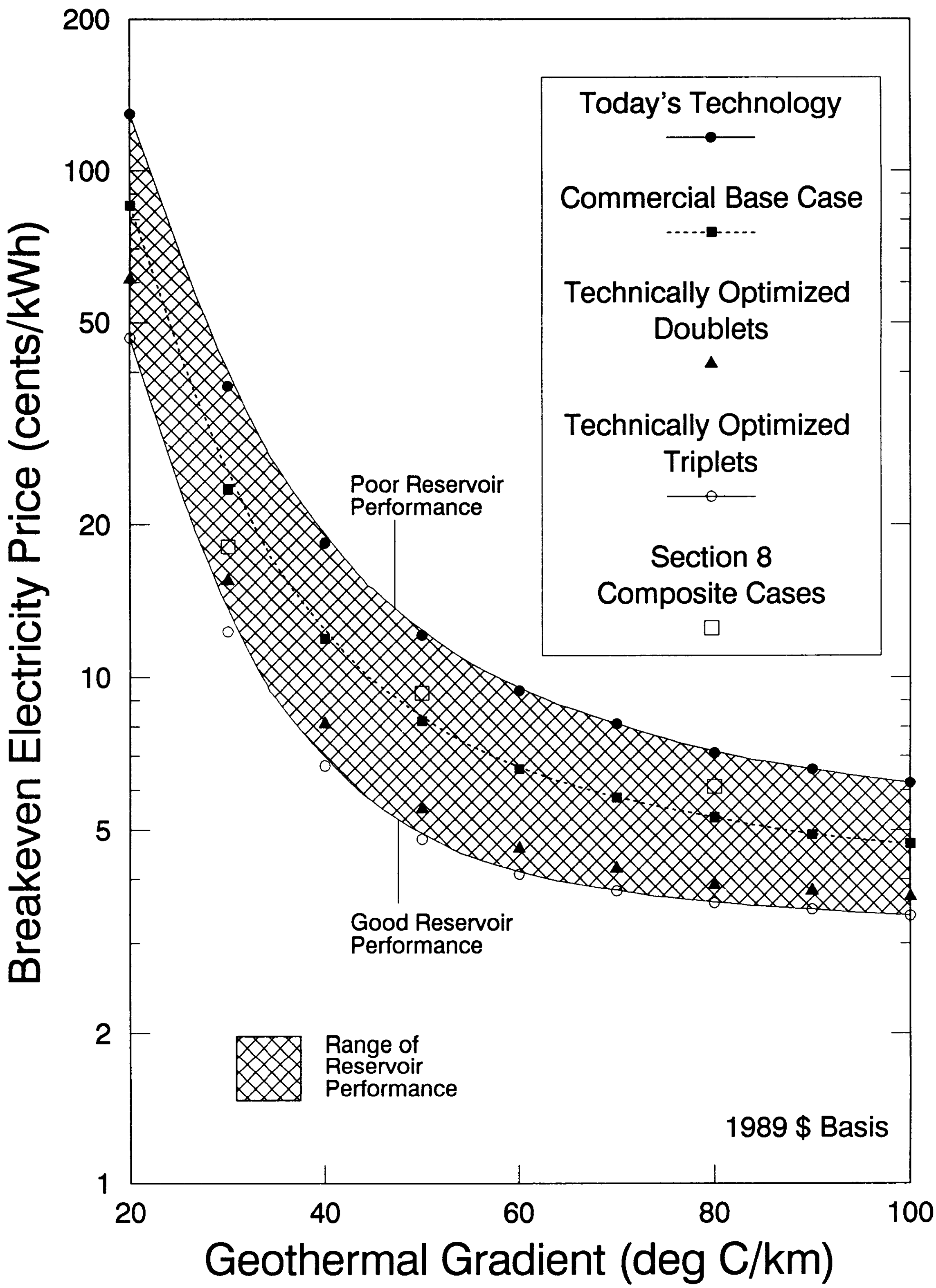


Figure 9.1 *MIT HDR* economic model results for electricity breakeven price as a function of gradient and reservoir performance.

To get a better feel for the results, compare Figure 9.1 to Figure 2.1. (Note: Figure 9.1 has a logarithmic y-axis compared to a linear one for Figure 2.1). These graphs have the same form and the discussion of Figure 2.1 applies equally to Figure 9.1. As the gradient decreases, drilling and completion costs become more dominant and drive the busbar costs up exponentially. Much of the range in costs at a given gradient is a result of reservoir performance. Poor performance translates into low flowrates of geothermal fluids per well pair or per reservoir, which drive up the costs.

One place the model results differ with the discussion in Section 2 is in optimum reservoir production temperatures (i.e., drilling depth). Figure 9.2 summarizes the model results. At 40°C/km and above, the model advises to drill to a depth associated with the maximum allowable reservoir temperature (300°C). Only at lower gradients is an optimum found at lower reservoir temperatures (180-200°C for 20°C/km and 220-245°C for 30°C/km). Optimum drilling depth is explored in more detail in the next section.

Finally, Figure 9.1 plots the composite cases from Section 8. For high- and mid-grade cases, these points fall slightly above the commercial base case line. This reflects the general model's optimization using fewer, but deeper wells. For the low-grade case, the point falls closer to the technically optimized case lines. This is because the low-grade composite case uses a flowrate of 110 kg/s, while the mid- and high-grade composite cases have flow rates around the 75 kg/s value used by the generalized model. The higher flowrate is indicative of optimized reservoir performance and moves the point closer to the model's technically optimized results.

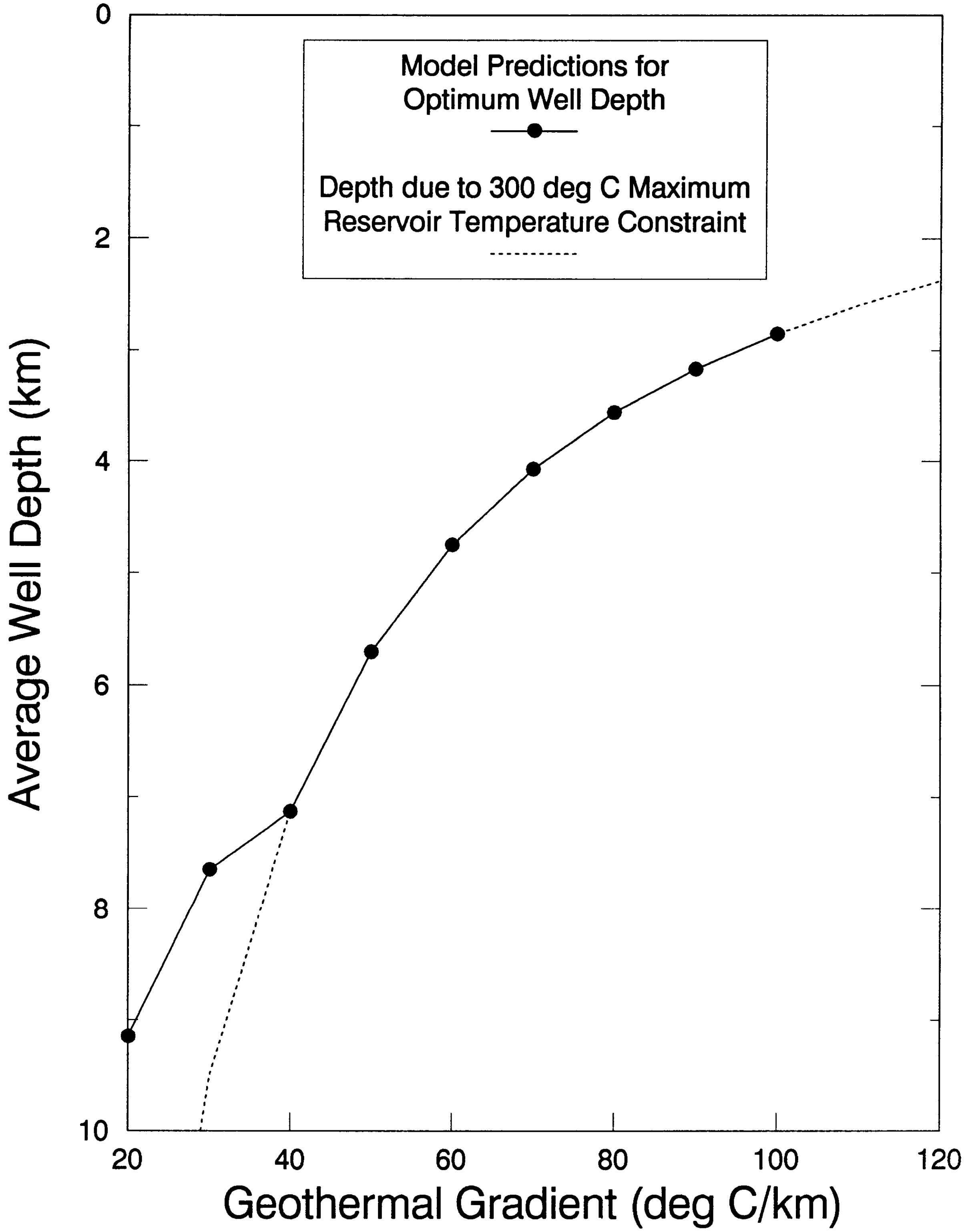


Figure 9.2 *MIT HDR* economic model predictions for optimum well depth as a function of gradient for the commercial base case.

10. Sensitivity and Uncertainty Analysis

Case studies were performed with the *MIT HDR* economic model to determine the sensitivity of the model to certain model parameters. This phase of the investigation focused on areas with the greatest uncertainty, specifically optimum well depth, drilling and completion costs, stimulation costs, and thermal drawdown rates. The results are presented in Figures 10.1-10.4 and in Appendix A.2.

The *MIT HDR* economic model suggests that it is more economical to drill deeper wells than those used in the composite cases described in Section 8. However, as seen in Figure 10.1, the optimum is not well defined. Also, the model does not account for the increased risks associated with increasing well depths. Therefore, a major uncertainty is associated with the model's prediction of optimum average well depth. Figure 10.2 plots the model's prediction of optimum average well depth as a function of gradient. Also plotted are the drilling depths yielding costs 10% and 25% above optimum. To illustrate a cost/risk trade-off, let's look at the 40°C/km gradient resource in detail. Here, the model suggests we can drill to a depth of 7.1 km to minimize busbar costs. However, drilling to 5.6 km will only increase the busbar costs 10%. The key question is whether the extra risk of drilling wells 1.5 km deeper can be justified by a potential 10% savings in cost. We are currently investigating methods to upgrade the model to include these risk trade-offs.

The foundation of the economic predictions are the cost correlations for drilling and completion, stimulation, and power plant construction. Of these, we are least certain about the stimulation costs and most confident in the power plant costs. However, the model itself is most sensitive to drilling and completion costs. Figure 10.3 shows the effect on the base case results for a doubling and halving of the drilling and completion costs and the stimulation costs. Except at high gradients, the sensitivity to stimulation costs is much less than the sensitivity to drilling and completion costs. At high gradients (above 80°C/km), the sensitivities are of the same order of magnitude, but the sensitivity to drilling and completion costs are still two to three times those of stimulation costs. The power plant cost sensitivity curve (not shown) is similar to the stimulation curve.

The model predicts a fairly large range of electricity prices associated with reservoir performance. The performance range in Figure 9.1 is primarily due to variations in geothermal fluid flowrate per reservoir for a given drawdown. To explore the sensitivity to variations in thermal drawdown rate at a given reservoir production flowrate, the three drawdown scenarios described in Section 5 were modeled. Comparing the results shown in Figure 10.4 to the range in Figure 9.1, the model is much more sensitive to production flowrate than drawdown. Thus, maximizing flowrate per reservoir is desirable, even at the expense of increasing drawdown rate. Of course, this principle cannot be carried to the extreme limit of an unacceptably high rate of drawdown that would not permit an adequate payback of the capital investment in drilling and stimulation.

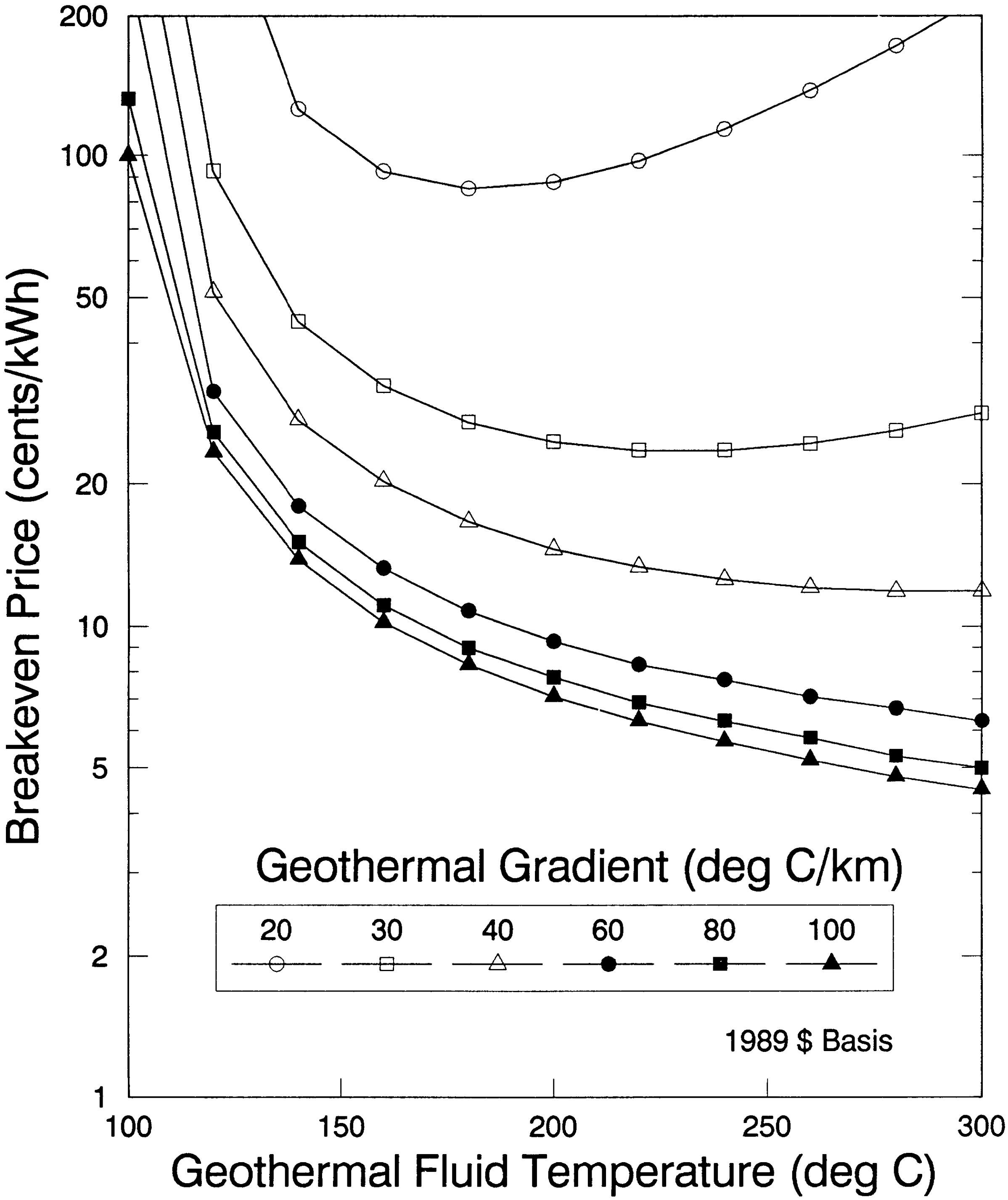


Figure 10.1 *MIT HDR* economic model predictions of electricity breakeven price as a function of geothermal fluid temperature and gradient for the commercial base case. For a given gradient, increasing fluid temperatures denote deeper wells. The flatness of the curves implies that there is some uncertainty in determining the optimum well depth for a given gradient.

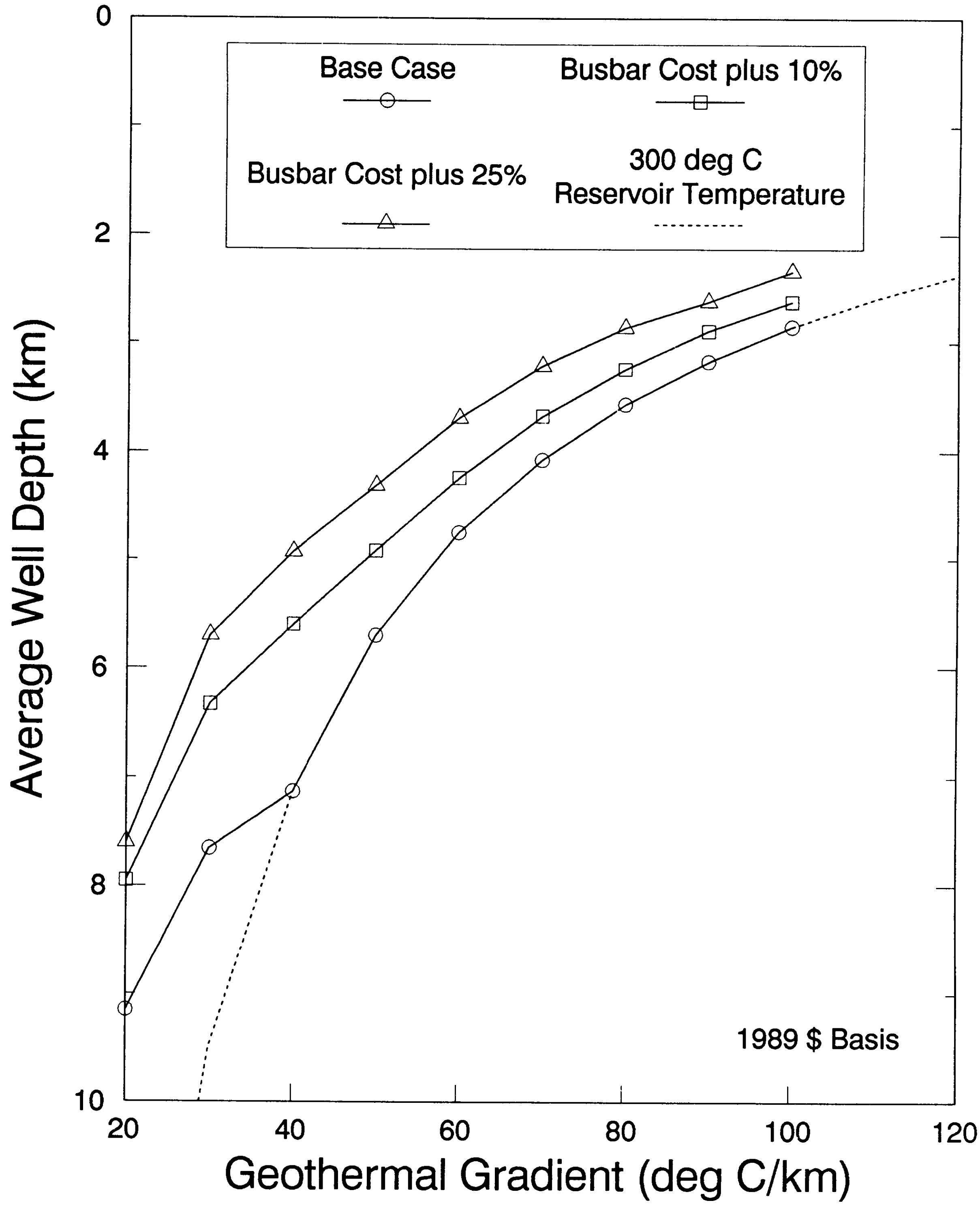


Figure 10.2 *MIT HDR* economic model predictions for average well depth as a function of gradient for the commercial base case. In addition to the base case line, depths that corresponded to electricity costs 10% and 25% greater than the base case were determined from Figure 10.1.

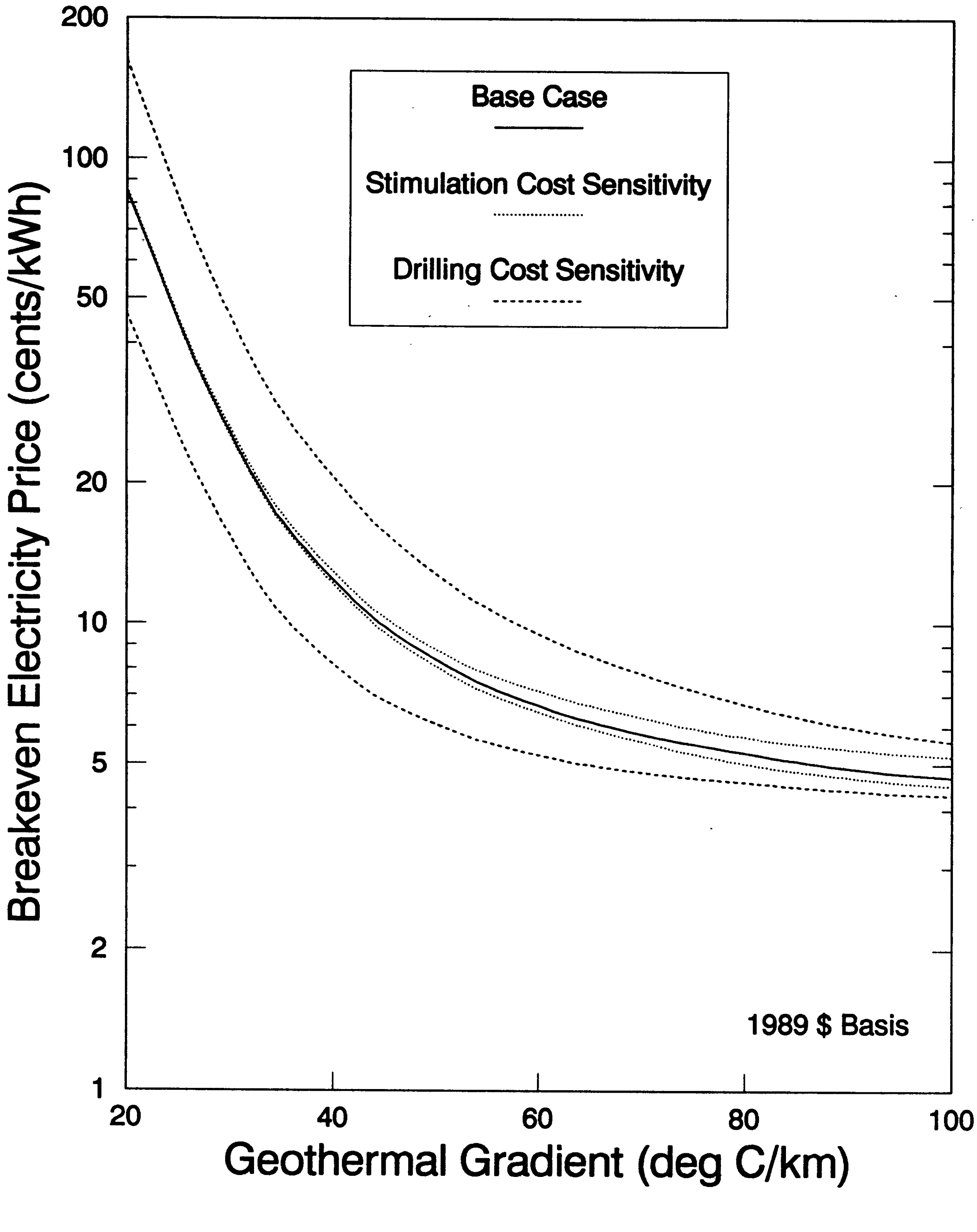


Figure 10.3 Sensitivity of the *MIT HDR* economic model base case (solid line) to doubling and halving the drilling and completion costs (dashed lines) and the stimulation costs (dotted lines).

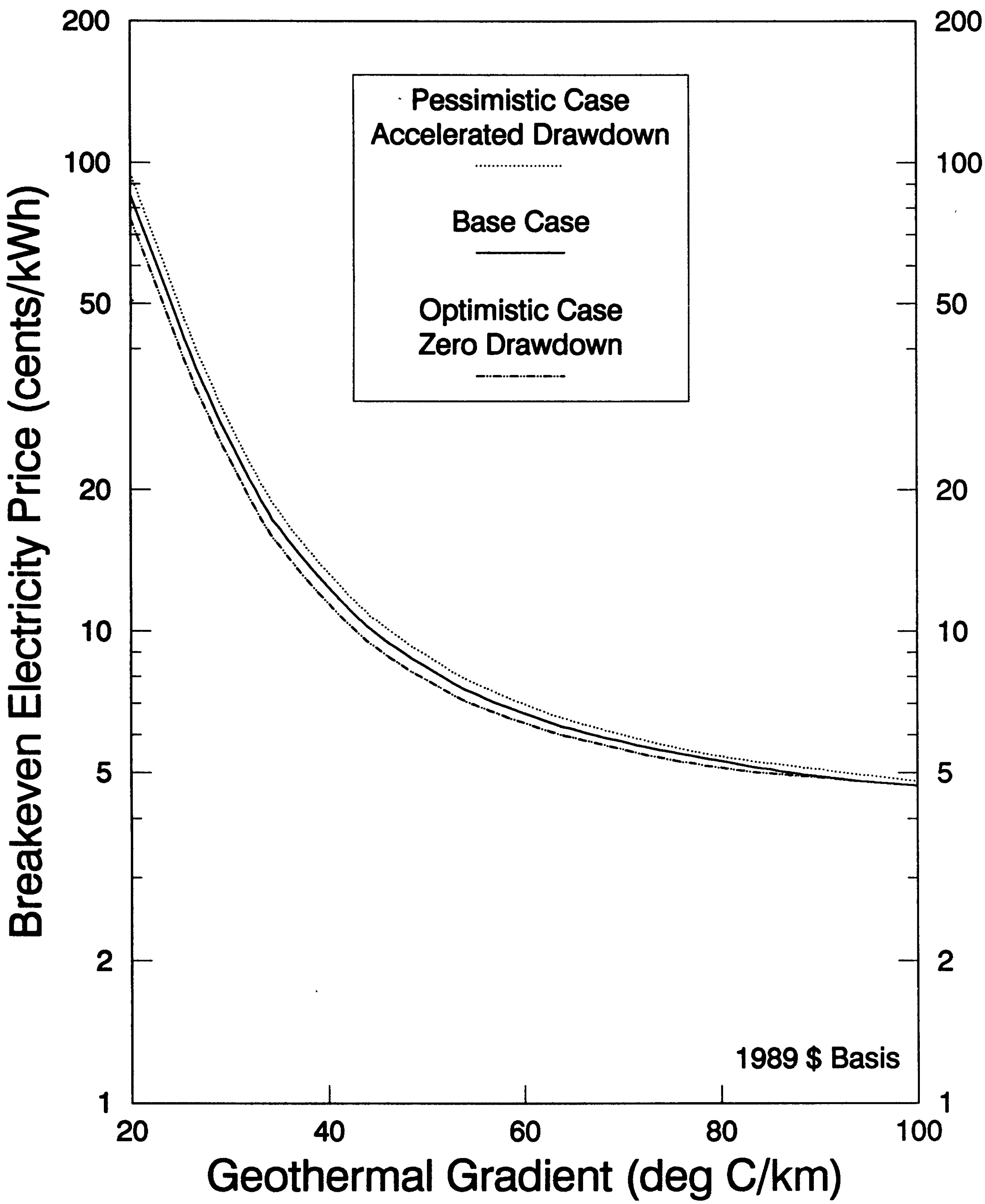


Figure 10.4 Sensitivity of the *MIT HDR* economic model to drawdown. The three cases are explained in detail in Section 5.

11. The *MIT HDR* Economic Model for Direct Thermal Use

To effectively use our energy resources, the "quality" or temperature of the energy sources should match the quality required by the end-use. For example, electricity is produced most efficiently with a high quality energy source, such as fossil fuels. However, burning fossil fuels for space heating, which does not require a high quality energy source (delivery temperatures are 25-30°C), is an inefficient use of fossil fuels. Conversely, lower quality energy sources such as HDR, have lower conversion efficiencies than fossil fuels for electrical production, but make much more efficient sources of energy for space heating.

In this chapter, we examine the economics of HDR geothermal energy for direct thermal use, specifically space heating and industrial process heating. Three cases are considered:

(1) Industrial process heating for an integrated, cascaded process.

(2) Space heating for a non-cascaded system.

(3) Space heating for a fully cascaded system.

The industrial process heat requires a higher quality of heat than the space heating cases. A fully cascaded space heating system will use heat more efficiently than a non-cascaded system.

The *MIT HDR* economic model for Electricity Production was modified to calculate the economics of direct heat uses. The key modifications were:

-Defining available enthalpy (analogous to availability for electricity production case) as $H(T_{gf})$ - $H(T_{rej})$, where T_{rej} is the geothermal fluid reinjection temperature.

-Defining a thermal efficiency (analogous to utilization efficiency for electricity production case).

-Reporting results on a million BTU per hour (10^6 BTU/hr) basis (as opposed to a per kWe installed basis).

-Using a cycle efficiency (MWe/MWt) to convert stimulation, exploration, and fluid distribution cost correlations from an electricity basis to a thermal basis. The cycle efficiency is calculated as the utilization efficiency times the availability divided by the available enthalpy.

-Treating the pumping requirement as an O&M cost. The cost of electricity is taken as 5¢/kWh.

All costs associated with the surface electricity plant were set to zero for the thermal case. The reported breakeven cost for the heat does not include charges for a delivery system, and, therefore, is similar to busbar cost for electricity. Heat distribution costs will add about $\$2/10^6$ BTU to the price of the heat (Armstead and Tester (1987)).

The direct thermal use cases used the same engineering and economic parameters as in the electricity production case. In addition, the reinjection temperature and thermal efficiency were defined as follows:

Case	Reinjection Temperature		Thermal Efficiency
	°C	°F	%
Industrial Process Heating	80	176	80
Non-Cascading Space Heating	37.8	100	70
Fully Cascaded Space Heating	27.8	82	80

The results are presented in Figures 11.1-11.3. For each case, Appendix A.3 summarizes the results for all gradients and provides detailed results for 30°C/km, 50°C/km, and 80°C/km. As expected, a higher reinjection temperature, which implies a higher quality heat requirement, translates into a higher cost of heat. However, even for industrial process heat, the commercial base case is competitive with fossil fuel generated heat ($\$3\text{-}4/10^6$ BTU, Armstead and Tester (1987)) for mid- and high-grade gradients (>50°C/km). In addition, for low- to mid-grade gradients, the drilling depths calculated by the model are significantly less for direct thermal use than for electricity production. This leads to a much less dramatic rise in price with decreasing gradient. As a result, for low-grade resources (<40°C/km), direct thermal use is much closer to being economically viable than electricity production.

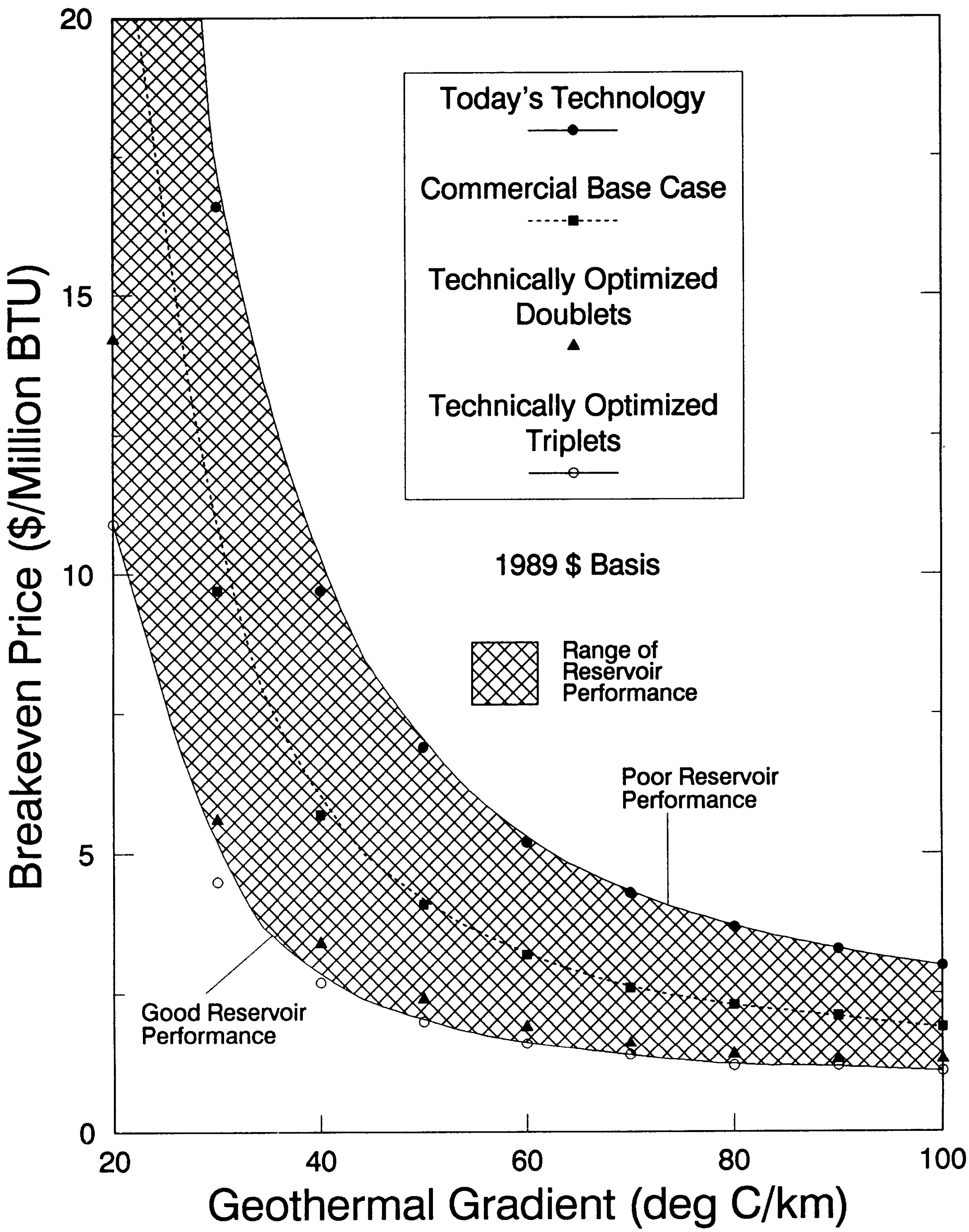


Figure 11.1 *MIT HDR* economic model results for the price of industrial process heat as a function of gradient and reservoir performance. The price is given in 1989 $ and excludes the cost of a delivery system.

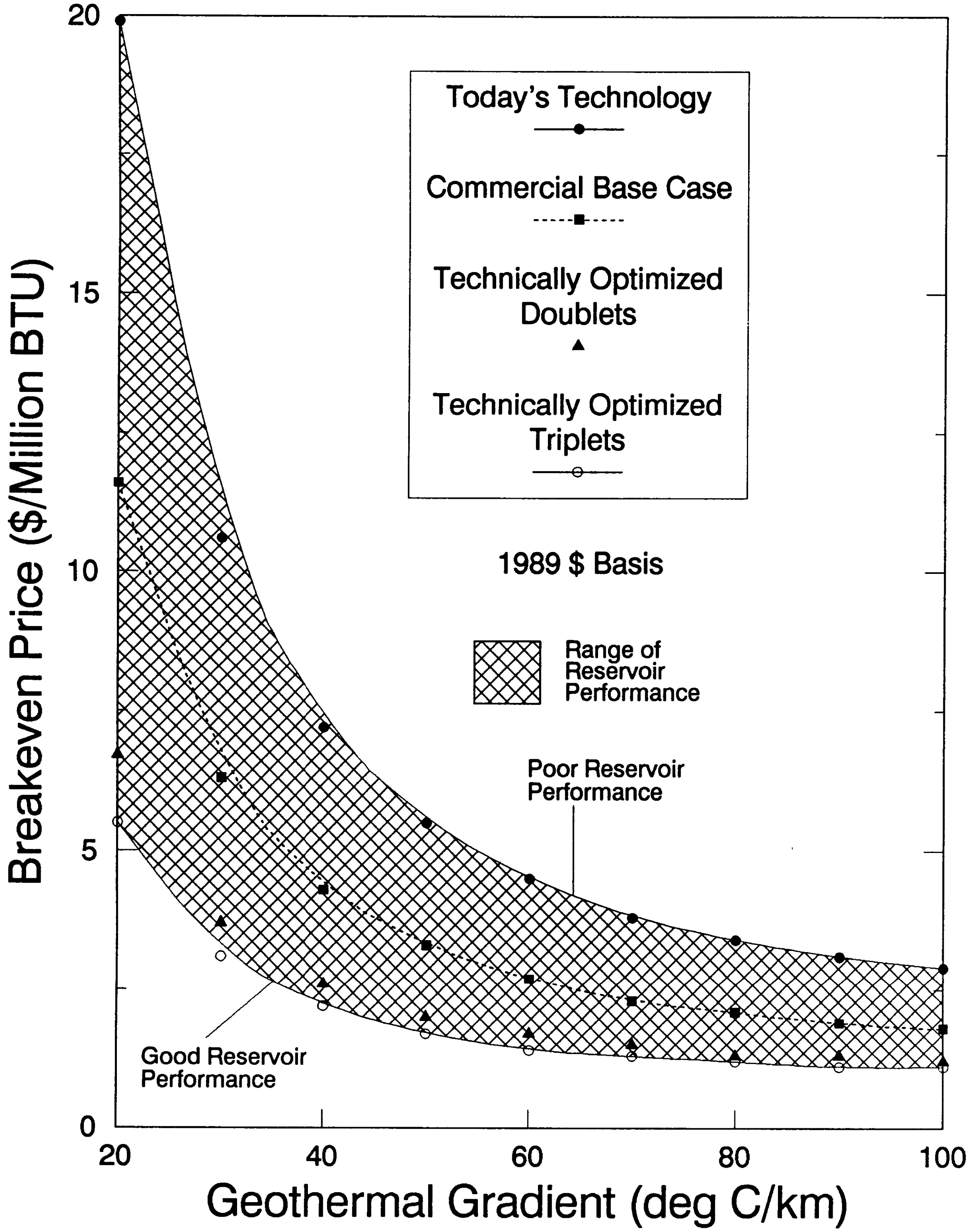


Figure 11.2 *MIT HDR* economic model results for the price of space heat for a non-cascading system as a function of gradient and reservoir performance. The price is given in 1989 $ and excludes the cost of a delivery system.

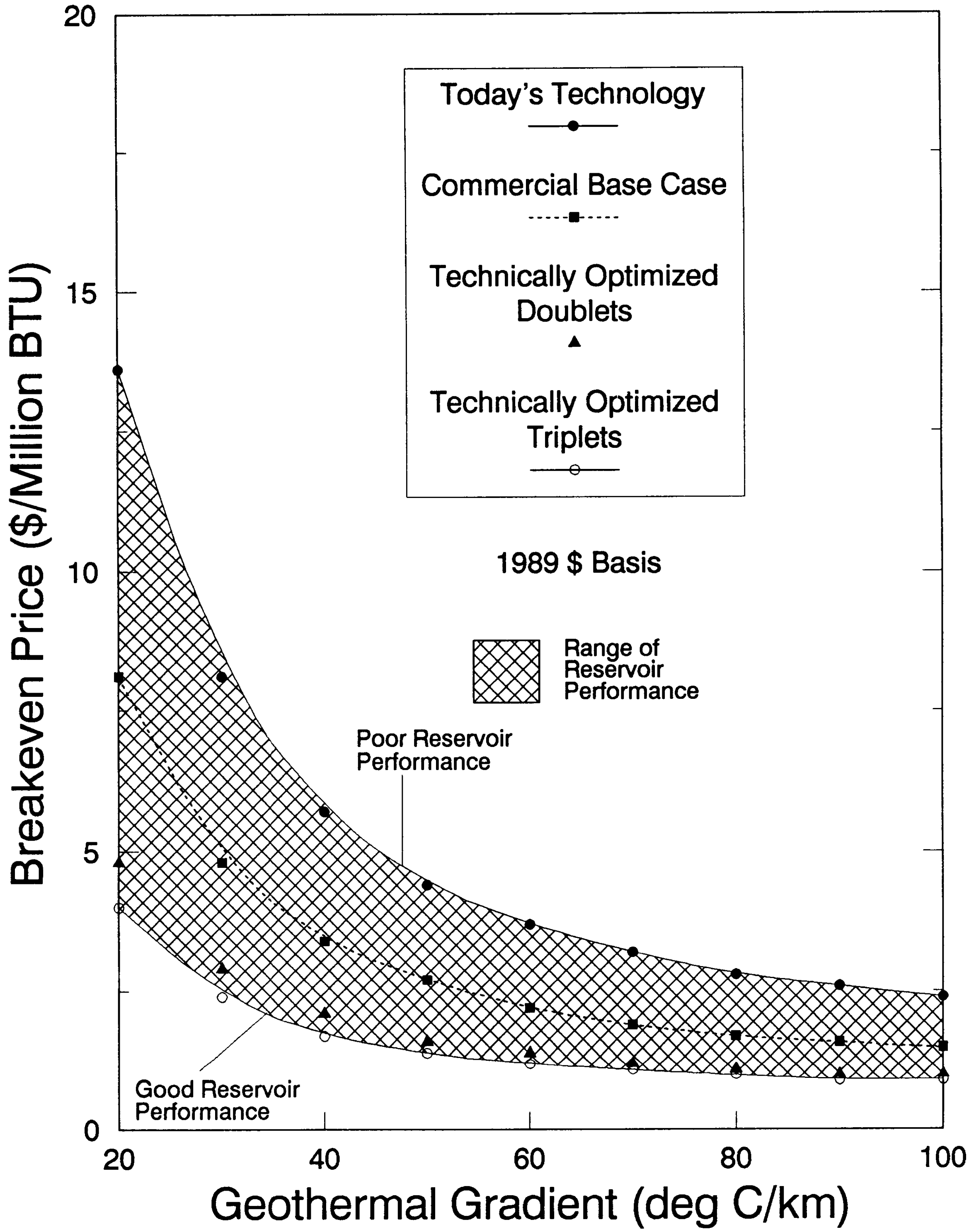


Figure 11.3 *MIT HDR* economic model results for the price of space heat for a fully cascaded system as a function of gradient and reservoir performance. The price is given in 1989 $ and excludes the cost of a delivery system.

12. Economic Projections for HDR in the U.S. by Region

The purpose of this section is to develop an HDR supply curve for the U.S. by regions. As a first step, the country is divided into regions consistent with U.S. Department of Energy procedures (see Table 12.1). Based on information provided by Entingh and Gilshannon (1990) (see Appendix B.1), the surface area over five classes of geothermal temperature gradients are calculated for each region. The five classes are:

Class 1 - <20°C/km
Class 2 - 20-30°C/km
Class 3 - 30-50°C/km
Class 4 - 50-70°C/km
Class 5 - >70°C/km

For each class, the electricity production potential per unit area corresponding to providing a continuous supply of energy for a 20-year period is estimated. Appendix B.2 contains the methodology, assumptions, and calculations used in this estimate. The results are:

Class 1 - 11.3 MWe/km^2
Class 2 - 15.1 MWe/km^2
Class 3 - 21.4 MWe/km^2
Class 4 - 42.7 MWe/km^2
Class 5 - 64.1 MWe/km^2

The 20-year supply curve is generated by estimating the amount of potential HDR produced electricity available at a given price. The electricity production capacity for a class is calculated by multiplying the potential per unit area presented above times the area in a region from Table 12.1 times a developable fraction. For this report, a developable fraction of 25% was used. The costs for a given class and technology level are taken from the *MIT HDR* economic model (see Appendix B.3). In generating the supply curve (Figure 12.2), area weighted average costs are used (see Table 12.2). The supply curve shows that a large electric energy potential from HDR is available at prices competitive with fossil fuels. The next section discusses some Research and Development goals that will help the U.S. realize the potential of HDR geothermal energy.

TABLE 12.1. AREAL DISTRIBUTION OF HDR TEMPERATURE GRADIENTS BY CLASS AND REGION

REGION	SQUARE MILES				
	CLASS 1	CLASS 2	CLASS 3	CLASS 4	CLASS 5
1	57,487	5,525	0	0	0
2	26,282	12,954	15,195	373	0
3	63,818	45,925	10,125	676	0
4	246,063	110,126	13,890	0	0
5	281,831	33,446	8,232	0	0
6	155,166	141,232	241,446	10,155	607
7	123,802	44,090	87,082	26,825	1,533
8	37,758	156,470	325,190	41,700	3,179
9	59,987	135,333	131,088	27,471	25,467
10	115,760	330,701	244,367	86,621	38,491

REGION	SQUARE KILOMETERS				
	CLASS 1	CLASS 2	CLASS 3	CLASS 4	CLASS 5
1	148,882	14,309	0	0	0
2	68,067	33,550	39,352	967	0
3	165,278	118,937	26,222	1,751	0
4	637,265	285,210	35,973	0	0
5	729,899	86,620	21,319	0	0
6	401,857	365,769	625,308	26,300	1,571
7	320,628	114,186	225,528	69,474	3,970
8	97,787	405,232	842,193	107,998	8,232
9	155,357	350,492	339,497	71,146	65,956
10	299,799	856,465	632,874	224,334	99,687

REGION	STATES
1	CT, ME, MA, NH, RI, VT
2	NJ, NY
3	DE, DC, MD, PA, VA, WV
4	AL, FL, GA, KY, MS, NC, SC, TN
5	IL, IN, MI, MN, OH, WI
6	AR, LA, NM, OK, TX
7	IA, KS, MO, NE
8	CO, MT, ND, SD, UT, WY
9	AZ, CA, HA, NV
10	AK, ID, OR, WA

TABLE 12.2a. HDR CUMULATIVE POTENTIAL AND AVERAGE COST FOR 20 YEARS OF PRODUCTION USING TODAY'S TECHNOLOGY

REGION	CLASS 5		CLASS 5+4		CLASS 5+4+3		CLASS 5+4+3+2		CLASS 5+4+3+2+1	
	GWe	cents/kWh	GWe	cents/kWh	GWe	cents/kWh	GWe	cents/kWh	GWe	cents/kWh
1	0	0.0	0	0.0	0	0.0	54	37.5	475	119.3
2	0	0.0	10	9.4	220	18.0	347	25.1	540	62.5
3	0	0.0	19	9.4	159	17.3	608	32.2	1,075	74.6
4	0	0.0	0	0.0	192	18.4	1,269	34.6	3,071	90.5
5	0	0.0	0	0.0	114	18.4	441	32.6	2,505	112.7
6	25	7.1	306	9.2	3,644	17.6	5,025	23.1	6,161	42.8
7	64	7.1	806	9.2	2,010	14.7	2,441	18.7	3,348	48.8
8	132	7.1	1,286	9.2	5,782	16.3	7,311	20.8	7,588	24.8
9	1,057	7.1	1,817	8.1	3,629	13.2	4,952	19.7	5,392	28.7
10	1,597	7.1	3,995	8.5	7,373	13.0	10,606	20.5	11,454	28.6
TOTAL	2,875	7.1	8,239	8.6	23,123	14.9	33,054	21.7	41,609	43.9

TABLE 12.2b. HDR CUMULATIVE POTENTIAL AND AVERAGE COST FOR 20 YEARS OF PRODUCTION USING COMMERCIALLY MATURE TECHNOLOGY

REGION	CLASS 5		CLASS 5+4		CLASS 5+4+3		CLASS 5+4+3+2		CLASS 5+4+3+2+1	
	GWe	cents/kWh	GWe	cents/kWh	GWe	cents/kWh	GWe	cents/kWh	GWe	cents/kWh
1	0	0.0	0	0.0	0	0.0	54	23.5	475	78.3
2	0	0.0	10	6.6	220	11.7	347	16.0	540	40.8
3	0	0.0	19	6.6	159	11.3	608	20.3	1,075	48.5
4	0	0.0	0	0.0	192	11.9	1,269	21.7	3,071	59.0
5	0	0.0	0	0.0	114	11.9	441	20.5	2,505	73.9
6	25	5.3	306	6.5	3,644	11.4	5,025	14.8	6,161	27.8
7	64	5.3	806	6.5	2,010	9.7	2,441	12.2	3,348	32.0
8	132	5.3	1,286	6.5	5,782	10.7	7,311	13.4	7,588	16.0
9	1,057	5.3	1,817	5.8	3,629	8.9	4,952	12.8	5,392	18.7
10	1,597	5.3	3,995	6.1	7,373	8.7	10,606	13.2	11,454	18.6
TOTAL	2,875	5.3	8,239	6.1	23,123	9.8	33,054	14.0	41,609	28.6

TABLE 12.2c. HDR CUMULATIVE POTENTIAL AND AVERAGE COST FOR 20 YEARS OF PRODUCTION USING TECNICALLY OPTIMIZED DOUBLETS

REGION	CLASS 5		CLASS 5+4		CLASS 5+4+3		CLASS 5+4+3+2		CLASS 5+4+3+2+1	
	GWe	cents/kWh	GWe	cents/kWh	GWe	cents/kWh	GWe	cents/kWh	GWe	cents/kWh
1	0	0.0	0	0.0	0	0.0	54	15.5	475	55.7
2	0	0.0	10	4.6	220	7.9	347	10.7	540	28.6
3	0	0.0	19	4.6	159	7.7	608	13.5	1,075	34.1
4	0	0.0	0	0.0	192	8.1	1,269	14.4	3,071	41.7
5	0	0.0	0	0.0	114	8.1	441	13.6	2,505	52.6
6	25	3.9	306	4.5	3,644	7.8	5,025	9.9	6,161	19.3
7	64	3.9	806	4.5	2,010	6.7	2,441	8.2	3,348	22.5
8	132	3.9	1,286	4.5	5,782	7.3	7,311	9.0	7,588	10.9
9	1,057	3.9	1,817	4.2	3,629	6.1	4,952	8.6	5,392	12.9
10	1,597	3.9	3,995	4.3	7,373	6.1	10,606	8.9	11,454	12.8
TOTAL	2,875	3.9	8,239	4.4	23,123	6.8	33,054	9.4	41,609	20.0

TABLE 12.2d. HDR CUMULATIVE POTENTIAL AND AVERAGE COST FOR 20 YEARS OF PRODUCTION USING TECNICALLY OPTIMIZED TRIPLETS

REGION	CLASS 5		CLASS 5+4		CLASS 5+4+3		CLASS 5+4+3+2		CLASS 5+4+3+2+1	
	GWe	cents/kWh	GWe	cents/kWh	GWe	cents/kWh	GWe	cents/kWh	GWe	cents/kWh
1	0	0.0	0	0.0	0	0.0	54	12.3	475	42.7
2	0	0.0	10	4.1	220	6.6	347	8.7	540	22.2
3	0	0.0	19	4.1	159	6.4	608	10.8	1,075	26.3
4	0	0.0	0	0.0	192	6.7	1,269	11.5	3,071	32.1
5	0	0.0	0	0.0	114	6.7	441	10.9	2,505	40.3
6	25	3.6	306	4.1	3,644	6.5	5,025	8.1	6,161	15.2
7	64	3.6	806	4.1	2,010	5.6	2,441	6.8	3,348	17.6
8	132	3.6	1,286	4.0	5,782	6.1	7,311	7.4	7,588	8.8
9	1,057	3.6	1,817	3.8	3,629	5.3	4,952	7.1	5,392	10.4
10	1,597	3.6	3,995	3.9	7,373	5.2	10,606	7.4	11,454	10.3
TOTAL	2,875	3.6	8,239	3.9	23,123	5.7	33,054	7.7	41,609	15.7

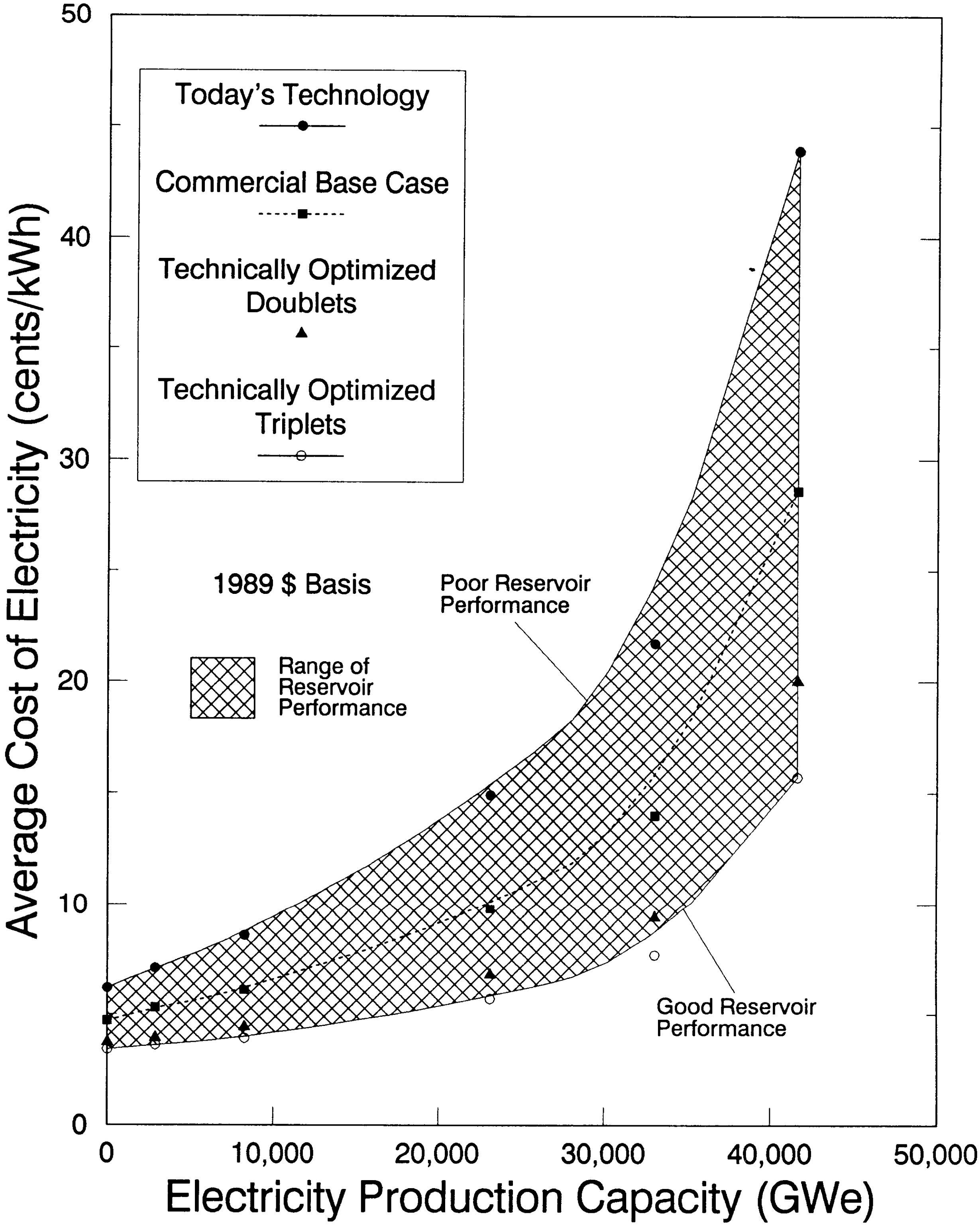


Figure 12.1 Predicted HDR electrical energy supply curve for total U.S. A continuous production of electricity at the levels shown above is assumed for 20 years.

13. Recommended Research and Development for HDR Technology

At this point, we can identify where research should be focussed to improve the commercial viability of lower grade HDR resources ($<50^{\circ}C/km$). The technologically optimized cases are first guesses of how far advanced drilling and reservoir stimulation technology might go with a sustained R&D effort. Coupled to these technologically-driven decreases in costs for HDR are the ever increasing costs for fossil-fueled and nuclear electric power systems, particularly when the total fuel cycle and costs of environmental externalities are properly factored in.

In principle, hot dry rock systems are inherently quite simple to construct and operate in comparison to other advanced alternatives such as fusion, solar photovoltaics or magnetohydrodynamics systems. HDR electric power plants reach the optimal economy of scale in the 30 to 80 MWe range--making them particularly well-suited to current U.S. utility plans for incremental capacity increases. In addition, HDR systems have minimal environmental impact with essentially no effluents (no CO_2, no particulates, no SO_x or NO_x) and they have continual availability for base load application, in comparison to renewables such as solar and wind power. All of these arguments suggest that HDR development should be given more attention in our national energy strategy.

Based on the results of the revised HDR economic model, we conclude that a USDOE funded R&D effort should be sustained in order to continue the development of certain crucial elements of HDR technology, including:

1. Improved drilling technology to lower drilling and completion costs. This will open up the low- to mid-grade HDR resource for commercial development.

2. Reservoir formation and stimulation technique development to improve reservoir performance, including flow impedance reduction.

3. Reservoir diagnostic technique development using seismic, tracer, and other geophysical methods for geometry characterization and system design optimization.

4. Modeling of the thermal-hydraulic and geochemical behavior of fractured HDR reservoirs to reduce risk.

5. Evaluation of untested concepts such as operation with multiple production wells (e.g. triplet arrangement); cyclic operation with pumped storage for peaking power supply or hybrid/cogeneration applications.

6. Site specific resource application and economic assessment; for example, comparing the characteristics of a high gradient site on the margins of an existing hydrothermal system in the western U.S. with those of a lower gradient region in the eastern U.S.

These six tasks will require both field and laboratory programs involving industry, the national laboratories, and universities. To stimulate private sector development of HDR, the USDOE should consider (1) continuation of the Phase II program at Fenton Hill with a minimum of two years of reservoir testing with heat extraction and parallel efforts of modeling and data analysis and (2) the development of a second HDR site with an industrial contractor through the demonstration stage of a 5 to 10 MWe power plant and (3) a supporting university-based R&D effort.

In order to implement this program, the budget recommendations estimated by the NRC review panel in 1987 (National Research Council (1987)) have been updated and modified below in Table 13.1:

TABLE 13.1 HDR R&D BUDGET RECOMMENDATIONS

	Fiscal Year				
Component	1991	1992	1993	1994	1995
	(millions of $)				
(1) Fenton Hill testing through Phase II	10.0	10.0	8.0	<5.0	<1.0
(2) Second site development through 5-10 MWe demonstration	10.0	15.0	15.0	25.0	20.0
(3) Supporting university-based R&D on reservoir formation, diagnostics and modeling	1.5	1.0	1.1	1.2	1.1

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15. Appendices

A. Detailed *MIT HDR* Economic Model Results

A.1 Electricity Generation

This appendix documents the calculational results from the *MIT HDR* economic model for electricity generation. Four technology cases are presented for each of nine gradients. One page of detailed results for each case follow the summary sheet. The discussion of these results is contained in Chapter 9.

****
HDR SUMMARY REPORT
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GRADIENT DEG C/KM	CASE	DEPTH KM	PRICE CENTS/KW	FOR 50 MW NET OUTPUT # WELLS	CAP COST MM$	O&M COST MM$/YR
20.0	TODAY	8.80	129.8	53.3	2493.859	71.813
20.0	BASE	9.15	85.3	28.8	1644.903	46.125
20.0	DOUBLET	8.10	60.9	44.8	1144.909	37.875
20.0	TRIPLET	8.25	46.6	32.6	994.597	17.436
30.0	TODAY	7.55	37.5	23.7	709.231	22.524
30.0	BASE	7.65	23.5	12.8	444.736	14.046
30.0	DOUBLET	6.80	15.5	18.3	281.111	11.506
30.0	TRIPLET	6.95	12.3	13.0	249.573	6.833
40.0	TODAY	7.13	18.4	12.3	344.021	11.645
40.0	BASE	7.13	11.9	6.7	221.908	7.662
40.0	DOUBLET	6.52	8.1	8.6	143.535	6.374
40.0	TRIPLET	6.67	6.7	6.1	130.721	4.379
50.0	TODAY	5.70	12.1	12.5	219.360	8.827
50.0	BASE	5.70	8.2	6.8	147.733	6.070
50.0	DOUBLET	5.70	5.5	6.7	94.857	4.962
50.0	TRIPLET	5.70	4.8	5.1	88.960	3.869
60.0	TODAY	4.75	9.4	12.7	165.919	7.637
60.0	BASE	4.75	6.6	6.8	116.204	5.398
60.0	DOUBLET	4.75	4.6	6.8	77.056	4.588
60.0	TRIPLET	4.75	4.1	5.1	74.195	3.775
70.0	TODAY	4.07	8.1	12.8	139.302	7.054
70.0	BASE	4.07	5.8	6.8	100.562	5.067
70.0	DOUBLET	4.07	4.2	6.8	67.871	4.398
70.0	TRIPLET	4.07	3.8	5.1	66.584	3.729
80.0	TODAY	3.56	7.1	12.9	120.542	6.646
80.0	BASE	3.56	5.3	6.9	89.624	4.836
80.0	DOUBLET	3.56	3.9	6.8	63.225	4.304
80.0	TRIPLET	3.56	3.6	5.1	62.734	3.707
90.0	TODAY	3.17	6.6	12.9	109.741	6.416
90.0	BASE	3.17	4.9	6.9	83.324	4.705
90.0	DOUBLET	3.17	3.8	6.8	60.630	4.253
90.0	TRIPLET	3.17	3.5	5.1	60.582	3.697
100.0	TODAY	2.85	6.2	13.0	102.934	6.275
100.0	BASE	2.85	4.7	6.9	79.347	4.623
100.0	DOUBLET	2.85	3.7	6.8	58.800	4.218
100.0	TRIPLET	2.85	3.4	5.1	59.066	3.689

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HDR CASE REPORT
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GRADIENT (deg C per km) = 20.0 USING TODAY'S TECHNOLOGY
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 129.8

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	40.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.30
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	8.80
INITIAL RESERVOIR TEMPERATURE (deg C)	191.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	176.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.118
UTILIZATION EFFICIENCY (%)	49.0
EFFECTIVE RESERVOIR AREA (sqm/kWe)	388.9
OVERALL GEO FLUID PRESSURE DROP (psia)	1189.
INJECTOR WELL PRESSURE DROP (psia)	314.
RESERVOIR PRESSURE DROP (psia)	1740.
PRODUCER WELL PRESSURE DROP (psia)	345.
BUOYANCY CORRECTION (psia)	1209.
PUMPING POWER / NET INSTALLED POWER (%)	18.7

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	37663.
STIMULATION COSTS	604.
SURFACE POWER PLANT COSTS	1190.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	908.
TOTAL CAPITAL COSTS	40566.
CAPITAL COST YEARLY CHARGE RATE	6783.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	149.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	11.
REDRILLING/RESTIMULATION COSTS	957.
TOTAL OPERATING AND MAINTENANCE COSTS	1168.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 20.0 USING COMMERCIALLY MATURE TECHNOLOGY
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 85.3

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.10
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	9.15
INITIAL RESERVOIR TEMPERATURE (deg C)	198.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	183.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.128
UTILIZATION EFFICIENCY (%)	49.7
EFFECTIVE RESERVOIR AREA (sqm/kWe)	351.7
OVERALL GEO FLUID PRESSURE DROP (psia)	1930.
INJECTOR WELL PRESSURE DROP (psia)	1051.
RESERVOIR PRESSURE DROP (psia)	1088.
PRODUCER WELL PRESSURE DROP (psia)	1154.
BUOYANCY CORRECTION (psia)	1363.
PUMPING POWER / NET INSTALLED POWER (%)	27.4

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	21183.
STIMULATION COSTS	286.
SURFACE POWER PLANT COSTS	1163.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	1052.
TOTAL CAPITAL COSTS	23885.
CAPITAL COST YEARLY CHARGE RATE	3994.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	72.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	10.
REDRILLING/RESTIMULATION COSTS	537.
TOTAL OPERATING AND MAINTENANCE COSTS	670.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 20.0 USING TECNICALLY OPTIMIZED DOUBLETS
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 60.9

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.08
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	8.10
INITIAL RESERVOIR TEMPERATURE (deg C)	177.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	162.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.098
UTILIZATION EFFICIENCY (%)	47.5
EFFECTIVE RESERVOIR AREA (sqm/kWe)	481.5
OVERALL GEO FLUID PRESSURE DROP (psia)	1859.
INJECTOR WELL PRESSURE DROP (psia)	931.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	1000.
BUOYANCY CORRECTION (psia)	941.
PUMPING POWER / NET INSTALLED POWER (%)	36.1

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	12652.
STIMULATION COSTS	171.
SURFACE POWER PLANT COSTS	1121.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	481.
TOTAL CAPITAL COSTS	14625.
CAPITAL COST YEARLY CHARGE RATE	2445.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	99.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	13.
REDRILLING/RESTIMULATION COSTS	321.
TOTAL OPERATING AND MAINTENANCE COSTS	484.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 20.0 USING TECNICALLY OPTIMIZED TRIPLETS
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 46.6

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	2.5
CAPACITY FACTOR (%)	90.0
REDRILLED WELLS / INITIAL WELLS	0.17
NO. INJECTORS / NO. PRODUCERS	0.5
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00007
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.08
INJECTOR WELL CASING ID (inches)	8.681
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	8.25
INITIAL RESERVOIR TEMPERATURE (deg C)	180.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	165.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.102
UTILIZATION EFFICIENCY (%)	47.8
EFFECTIVE RESERVOIR AREA (sqm/kWe)	918.6
OVERALL GEO FLUID PRESSURE DROP (psia)	2060.
INJECTOR WELL PRESSURE DROP (psia)	1163.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	1021.
BUOYANCY CORRECTION (psia)	994.
PUMPING POWER / NET INSTALLED POWER (%)	37.3

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	10356.
STIMULATION COSTS	267.
SURFACE POWER PLANT COSTS	1110.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	545.
TOTAL CAPITAL COSTS	12479.
CAPITAL COST YEARLY CHARGE RATE	2086.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	71.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	7.
REDRILLING/RESTIMULATION COSTS	90.
TOTAL OPERATING AND MAINTENANCE COSTS	219.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 30.0 USING TODAY'S TECHNOLOGY
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 37.5

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	40.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.30
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	7.55
INITIAL RESERVOIR TEMPERATURE (deg C)	241.5
GEOTHERMAL FLUID TEMPERATURE (deg C)	226.5
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.204
UTILIZATION EFFICIENCY (%)	54.3
EFFECTIVE RESERVOIR AREA (sqm/kWe)	202.8
OVERALL GEO FLUID PRESSURE DROP (psia)	570.
INJECTOR WELL PRESSURE DROP (psia)	269.
RESERVOIR PRESSURE DROP (psia)	1740.
PRODUCER WELL PRESSURE DROP (psia)	316.
BUOYANCY CORRECTION (psia)	1755.
PUMPING POWER / NET INSTALLED POWER (%)	4.7

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	11346.
STIMULATION COSTS	441.
SURFACE POWER PLANT COSTS	994.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	541.
TOTAL CAPITAL COSTS	13522.
CAPITAL COST YEARLY CHARGE RATE	2261.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	78.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	6.
REDRILLING/RESTIMULATION COSTS	295.
TOTAL OPERATING AND MAINTENANCE COSTS	429.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 30.0 USING COMMERCIALLY MATURE TECHNOLOGY
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 23.5

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.10
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	7.65
INITIAL RESERVOIR TEMPERATURE (deg C)	244.5
GEOTHERMAL FLUID TEMPERATURE (deg C)	229.5
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.210
UTILIZATION EFFICIENCY (%)	54.6
EFFECTIVE RESERVOIR AREA (sqm/kWe)	196.0
OVERALL GEO FLUID PRESSURE DROP (psia)	1165.
INJECTOR WELL PRESSURE DROP (psia)	879.
RESERVOIR PRESSURE DROP (psia)	1088.
PRODUCER WELL PRESSURE DROP (psia)	1026.
BUOYANCY CORRECTION (psia)	1827.
PUMPING POWER / NET INSTALLED POWER (%)	9.2

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	6111.
STIMULATION COSTS	218.
SURFACE POWER PLANT COSTS	982.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	564.
TOTAL CAPITAL COSTS	8075.
CAPITAL COST YEARLY CHARGE RATE	1350.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	40.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	5.
REDRILLING/RESTIMULATION COSTS	158.
TOTAL OPERATING AND MAINTENANCE COSTS	255.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 30.0 USING TECNICALLY OPTIMIZED DOUBLETS
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 15.5

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.08
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	6.80
INITIAL RESERVOIR TEMPERATURE (deg C)	219.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	204.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.163
UTILIZATION EFFICIENCY (%)	51.9
EFFECTIVE RESERVOIR AREA (sqm/kWe)	265.8
OVERALL GEO FLUID PRESSURE DROP (psia)	1259.
INJECTOR WELL PRESSURE DROP (psia)	781.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	880.
BUOYANCY CORRECTION (psia)	1272.
PUMPING POWER / NET INSTALLED POWER (%)	13.5

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	3316.
STIMULATION COSTS	124.
SURFACE POWER PLANT COSTS	973.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	249.
TOTAL CAPITAL COSTS	4863.
CAPITAL COST YEARLY CHARGE RATE	813.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	54.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	7.
REDRILLING/RESTIMULATION COSTS	86.
TOTAL OPERATING AND MAINTENANCE COSTS	199.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 30.0 USING TECNICALLY OPTIMIZED TRIPLETS
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 12.3

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	2.5
CAPACITY FACTOR (%)	90.0
REDRILLED WELLS / INITIAL WELLS	0.17
NO. INJECTORS / NO. PRODUCERS	0.5
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00007
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.08
INJECTOR WELL CASING ID (inches)	8.681
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	6.95
INITIAL RESERVOIR TEMPERATURE (deg C)	223.5
GEOTHERMAL FLUID TEMPERATURE (deg C)	208.5
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.170
UTILIZATION EFFICIENCY (%)	52.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	502.5
OVERALL GEO FLUID PRESSURE DROP (psia)	1394.
INJECTOR WELL PRESSURE DROP (psia)	980.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	904.
BUOYANCY CORRECTION (psia)	1361.
PUMPING POWER / NET INSTALLED POWER (%)	13.8

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	2690.
STIMULATION COSTS	176.
SURFACE POWER PLANT COSTS	958.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	279.
TOTAL CAPITAL COSTS	4303.
CAPITAL COST YEARLY CHARGE RATE	719.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	39.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	4.
REDRILLING/RESTIMULATION COSTS	24.
TOTAL OPERATING AND MAINTENANCE COSTS	118.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 40.0 USING TODAY'S TECHNOLOGY
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 18.4

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	40.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.30
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	7.13
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	111.6
OVERALL GEO FLUID PRESSURE DROP (psia)	-270.
INJECTOR WELL PRESSURE DROP (psia)	254.
RESERVOIR PRESSURE DROP (psia)	1740.
PRODUCER WELL PRESSURE DROP (psia)	331.
BUOYANCY CORRECTION (psia)	2595.
PUMPING POWER / NET INSTALLED POWER (%)	-1.2

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	5181.
STIMULATION COSTS	361.
SURFACE POWER PLANT COSTS	766.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	456.
TOTAL CAPITAL COSTS	6964.
CAPITAL COST YEARLY CHARGE RATE	1164.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	43.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	3.
REDRILLING/RESTIMULATION COSTS	139.
TOTAL OPERATING AND MAINTENANCE COSTS	236.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 40.0 USING COMMERCIALLY MATURE TECHNOLOGY
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 11.9

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.10
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	7.13
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	111.6
OVERALL GEO FLUID PRESSURE DROP (psia)	362.
INJECTOR WELL PRESSURE DROP (psia)	819.
RESERVOIR PRESSURE DROP (psia)	1088.
PRODUCER WELL PRESSURE DROP (psia)	1051.
BUOYANCY CORRECTION (psia)	2595.
PUMPING POWER / NET INSTALLED POWER (%)	1.6

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	2763.
STIMULATION COSTS	181.
SURFACE POWER PLANT COSTS	766.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	456.
TOTAL CAPITAL COSTS	4366.
CAPITAL COST YEARLY CHARGE RATE	730.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	23.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	3.
REDRILLING/RESTIMULATION COSTS	74.
TOTAL OPERATING AND MAINTENANCE COSTS	151.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 40.0 USING TECNICALLY OPTIMIZED DOUBLETS
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 8.1

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.08
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	6.52
INITIAL RESERVOIR TEMPERATURE (deg C)	276.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	261.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.276
UTILIZATION EFFICIENCY (%)	57.9
EFFECTIVE RESERVOIR AREA (sqm/kWe)	140.4
OVERALL GEO FLUID PRESSURE DROP (psia)	527.
INJECTOR WELL PRESSURE DROP (psia)	750.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	921.
BUOYANCY CORRECTION (psia)	2014.
PUMPING POWER / NET INSTALLED POWER (%)	3.0

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	1496.
STIMULATION COSTS	97.
SURFACE POWER PLANT COSTS	774.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	219.
TOTAL CAPITAL COSTS	2785.
CAPITAL COST YEARLY CHARGE RATE	466.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	29.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	4.
REDRILLING/RESTIMULATION COSTS	40.
TOTAL OPERATING AND MAINTENANCE COSTS	124.

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*HDR CASE REPORT*
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GRADIENT (deg C per km) =  40.0 USING TECNICALLY OPTIMIZED TRIPLETS
ELECTRICITY BREAKEVEN PRICE (cents/kWh) =   6.7

                    ***ECONOMIC PARAMETERS***

FIXED CHARGE RATE (%)                              15.3
AFDC RATE (%)                                       9.0
PROJECT LIFE (years)                               20.0

                   ***ENGINEERING PARAMETERS***

WATER LOSS RATE (%)                                 2.5
CAPACITY FACTOR (%)                                90.0
REDRILLED WELLS / INITIAL WELLS                    0.17
NO. INJECTORS / NO. PRODUCERS                       0.5
PUMP EFFICIENCY (%)                                80.0
DRAWDOWN PARAMETER (kg/sqm-s)                   0.00007
TEMP RESERVOIR - TEMP GEOFLUID (deg C)             15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)          300.0
PRODUCTION WELL FLOWRATE (kg/s)                    75.0
RESERVOIR IMPEDANCE (GPa-s/cum)                    0.08
INJECTOR WELL CASING ID (inches)                  8.681
PRODUCER WELL CASING ID (inches)                  7.000

                    ***ENGINEERING RESULTS***

AVERAGE WELL DEPTH (km)                            6.67
INITIAL RESERVOIR TEMPERATURE (deg C)             282.0
GEOTHERMAL FLUID TEMPERATURE (deg C)              267.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)          0.290
UTILIZATION EFFICIENCY (%)                         58.5
EFFECTIVE RESERVOIR AREA (sqm/kWe)                264.6
OVERALL GEO FLUID PRESSURE DROP (psia)             611.
INJECTOR WELL PRESSURE DROP (psia)                 941.
RESERVOIR PRESSURE DROP (psia)                     870.
PRODUCER WELL PRESSURE DROP (psia)                 953.
BUOYANCY CORRECTION (psia)                        2152.
PUMPING POWER / NET INSTALLED POWER (%)             3.2

                   ***CAPITAL COSTS (k$/MWe)***

DRILLING AND COMPLETION COSTS                     1210.
STIMULATION COSTS                                  124.
SURFACE POWER PLANT COSTS                          753.
SURFACE FLUID DISTRIBUTION COSTS                   200.
EXPLORATION COSTS                                  244.
TOTAL CAPITAL COSTS                               2531.
CAPITAL COST YEARLY CHARGE RATE                    423.

        ***OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)***

WELLFIELD MAINTENANCE COSTS                         20.
SURFACE PLANT MAINTENANCE COSTS                     51.
WATER COSTS                                          2.
REDRILLING/RESTIMULATION COSTS                      11.
TOTAL OPERATING AND MAINTENANCE COSTS               85.
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HDR CASE REPORT
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GRADIENT (deg C per km) = 50.0 USING TODAY'S TECHNOLOGY
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 12.1

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	40.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.30
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	5.70
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	111.6
OVERALL GEO FLUID PRESSURE DROP (psia)	132.
INJECTOR WELL PRESSURE DROP (psia)	203.
RESERVOIR PRESSURE DROP (psia)	1740.
PRODUCER WELL PRESSURE DROP (psia)	265.
BUOYANCY CORRECTION (psia)	2076.
PUMPING POWER / NET INSTALLED POWER (%)	0.6

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	2772.
STIMULATION COSTS	361.
SURFACE POWER PLANT COSTS	766.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	262.
TOTAL CAPITAL COSTS	4361.
CAPITAL COST YEARLY CHARGE RATE	729.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	43.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	3.
REDRILLING/RESTIMULATION COSTS	78.
TOTAL OPERATING AND MAINTENANCE COSTS	175.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 50.0 USING COMMERCIALLY MATURE TECHNOLOGY
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 8.2

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.10
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	5.70
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	111.6
OVERALL GEO FLUID PRESSURE DROP (psia)	507.
INJECTOR WELL PRESSURE DROP (psia)	655.
RESERVOIR PRESSURE DROP (psia)	1088.
PRODUCER WELL PRESSURE DROP (psia)	841.
BUOYANCY CORRECTION (psia)	2076.
PUMPING POWER / NET INSTALLED POWER (%)	2.3

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	1478.
STIMULATION COSTS	181.
SURFACE POWER PLANT COSTS	766.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	262.
TOTAL CAPITAL COSTS	2887.
CAPITAL COST YEARLY CHARGE RATE	483.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	23.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	3.
REDRILLING/RESTIMULATION COSTS	41.
TOTAL OPERATING AND MAINTENANCE COSTS	119.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 50.0 USING TECNICALLY OPTIMIZED DOUBLETS
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 5.5

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.08
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	5.70
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	111.6
OVERALL GEO FLUID PRESSURE DROP (psia)	289.
INJECTOR WELL PRESSURE DROP (psia)	655.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	841.
BUOYANCY CORRECTION (psia)	2076.
PUMPING POWER / NET INSTALLED POWER (%)	1.3

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	741.
STIMULATION COSTS	90.
SURFACE POWER PLANT COSTS	689.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	151.
TOTAL CAPITAL COSTS	1872.
CAPITAL COST YEARLY CHARGE RATE	313.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	23.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	3.
REDRILLING/RESTIMULATION COSTS	21.
TOTAL OPERATING AND MAINTENANCE COSTS	98.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 50.0 USING TECNICALLY OPTIMIZED TRIPLETS
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 4.8

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	2.5
CAPACITY FACTOR (%)	90.0
REDRILLED WELLS / INITIAL WELLS	0.17
NO. INJECTORS / NO. PRODUCERS	0.5
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00007
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.08
INJECTOR WELL CASING ID (inches)	8.681
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	5.70
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	223.2
OVERALL GEO FLUID PRESSURE DROP (psia)	438.
INJECTOR WELL PRESSURE DROP (psia)	803.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	841.
BUOYANCY CORRECTION (psia)	2076.
PUMPING POWER / NET INSTALLED POWER (%)	1.9

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	584.
STIMULATION COSTS	115.
SURFACE POWER PLANT COSTS	689.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	157.
TOTAL CAPITAL COSTS	1745.
CAPITAL COST YEARLY CHARGE RATE	292.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	17.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	2.
REDRILLING/RESTIMULATION COSTS	6.
TOTAL OPERATING AND MAINTENANCE COSTS	76.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 60.0 USING TODAY'S TECHNOLOGY
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 9.4

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	40.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.30
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	4.75
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	111.6
OVERALL GEO FLUID PRESSURE DROP (psia)	400.
INJECTOR WELL PRESSURE DROP (psia)	169.
RESERVOIR PRESSURE DROP (psia)	1740.
PRODUCER WELL PRESSURE DROP (psia)	221.
BUOYANCY CORRECTION (psia)	1730.
PUMPING POWER / NET INSTALLED POWER (%)	1.8

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	1751.
STIMULATION COSTS	361.
SURFACE POWER PLANT COSTS	766.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	180.
TOTAL CAPITAL COSTS	3259.
CAPITAL COST YEARLY CHARGE RATE	545.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	43.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	3.
REDRILLING/RESTIMULATION COSTS	53.
TOTAL OPERATING AND MAINTENANCE COSTS	150.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 60.0 USING COMMERCIALLY MATURE TECHNOLOGY
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 6.6

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.10
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	4.75
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	111.6
OVERALL GEO FLUID PRESSURE DROP (psia)	604.
INJECTOR WELL PRESSURE DROP (psia)	546.
RESERVOIR PRESSURE DROP (psia)	1088.
PRODUCER WELL PRESSURE DROP (psia)	700.
BUOYANCY CORRECTION (psia)	1730.
PUMPING POWER / NET INSTALLED POWER (%)	2.7

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	934.
STIMULATION COSTS	181.
SURFACE POWER PLANT COSTS	766.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	180.
TOTAL CAPITAL COSTS	2261.
CAPITAL COST YEARLY CHARGE RATE	378.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	23.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	3.
REDRILLING/RESTIMULATION COSTS	28.
TOTAL OPERATING AND MAINTENANCE COSTS	105.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 60.0 USING TECNICALLY OPTIMIZED DOUBLETS
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 4.6

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.08
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	4.75
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	111.6
OVERALL GEO FLUID PRESSURE DROP (psia)	386.
INJECTOR WELL PRESSURE DROP (psia)	546.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	700.
BUOYANCY CORRECTION (psia)	1730.
PUMPING POWER / NET INSTALLED POWER (%)	1.7

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	430.
STIMULATION COSTS	90.
SURFACE POWER PLANT COSTS	689.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	104.
TOTAL CAPITAL COSTS	1514.
CAPITAL COST YEARLY CHARGE RATE	253.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	23.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	3.
REDRILLING/RESTIMULATION COSTS	13.
TOTAL OPERATING AND MAINTENANCE COSTS	90.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 60.0 USING TECNICALLY OPTIMIZED TRIPLETS
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 4.1

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	2.5
CAPACITY FACTOR (%)	90.0
REDRILLED WELLS / INITIAL WELLS	0.17
NO. INJECTORS / NO. PRODUCERS	0.5
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00007
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.08
INJECTOR WELL CASING ID (inches)	8.681
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	4.75
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	223.2
OVERALL GEO FLUID PRESSURE DROP (psia)	510.
INJECTOR WELL PRESSURE DROP (psia)	670.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	700.
BUOYANCY CORRECTION (psia)	1730.
PUMPING POWER / NET INSTALLED POWER (%)	2.2

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	339.
STIMULATION COSTS	115.
SURFACE POWER PLANT COSTS	689.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	107.
TOTAL CAPITAL COSTS	1451.
CAPITAL COST YEARLY CHARGE RATE	243.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	17.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	2.
REDRILLING/RESTIMULATION COSTS	4.
TOTAL OPERATING AND MAINTENANCE COSTS	74.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 70.0 USING TODAY'S TECHNOLOGY
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 8.1

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	40.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.30
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	4.07
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	111.6
OVERALL GEO FLUID PRESSURE DROP (psia)	591.
INJECTOR WELL PRESSURE DROP (psia)	145.
RESERVOIR PRESSURE DROP (psia)	1740.
PRODUCER WELL PRESSURE DROP (psia)	189.
BUOYANCY CORRECTION (psia)	1483.
PUMPING POWER / NET INSTALLED POWER (%)	2.7

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	1245.
STIMULATION COSTS	361.
SURFACE POWER PLANT COSTS	766.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	139.
TOTAL CAPITAL COSTS	2712.
CAPITAL COST YEARLY CHARGE RATE	453.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	43.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	3.
REDRILLING/RESTIMULATION COSTS	40.
TOTAL OPERATING AND MAINTENANCE COSTS	137.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 70.0 USING COMMERCIALLY MATURE TECHNOLOGY
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 5.8

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.10
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	4.07
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	111.6
OVERALL GEO FLUID PRESSURE DROP (psia)	673.
INJECTOR WELL PRESSURE DROP (psia)	468.
RESERVOIR PRESSURE DROP (psia)	1088.
PRODUCER WELL PRESSURE DROP (psia)	600.
BUOYANCY CORRECTION (psia)	1483.
PUMPING POWER / NET INSTALLED POWER (%)	3.0

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	664.
STIMULATION COSTS	181.
SURFACE POWER PLANT COSTS	766.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	139.
TOTAL CAPITAL COSTS	1950.
CAPITAL COST YEARLY CHARGE RATE	326.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	23.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	3.
REDRILLING/RESTIMULATION COSTS	21.
TOTAL OPERATING AND MAINTENANCE COSTS	98.

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HDR CASE REPORT
****

GRADIENT (deg C per km) = 70.0 USING TECNICALLY OPTIMIZED DOUBLETS
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 4.2

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.08
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	4.07
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	111.6
OVERALL GEO FLUID PRESSURE DROP (psia)	455.
INJECTOR WELL PRESSURE DROP (psia)	468.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	600.
BUOYANCY CORRECTION (psia)	1483.
PUMPING POWER / NET INSTALLED POWER (%)	2.1

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	270.
STIMULATION COSTS	90.
SURFACE POWER PLANT COSTS	689.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	80.
TOTAL CAPITAL COSTS	1330.
CAPITAL COST YEARLY CHARGE RATE	222.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	23.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	3.
REDRILLING/RESTIMULATION COSTS	9.
TOTAL OPERATING AND MAINTENANCE COSTS	86.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 70.0 USING TECNICALLY OPTIMIZED TRIPLETS
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 3.8

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	2.5
CAPACITY FACTOR (%)	90.0
REDRILLED WELLS / INITIAL WELLS	0.17
NO. INJECTORS / NO. PRODUCERS	0.5
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00007
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.08
INJECTOR WELL CASING ID (inches)	8.681
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	4.07
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	223.2
OVERALL GEO FLUID PRESSURE DROP (psia)	561.
INJECTOR WELL PRESSURE DROP (psia)	574.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	600.
BUOYANCY CORRECTION (psia)	1483.
PUMPING POWER / NET INSTALLED POWER (%)	2.5

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	212.
STIMULATION COSTS	115.
SURFACE POWER PLANT COSTS	689.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	82.
TOTAL CAPITAL COSTS	1299.
CAPITAL COST YEARLY CHARGE RATE	217.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	17.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	2.
REDRILLING/RESTIMULATION COSTS	3.
TOTAL OPERATING AND MAINTENANCE COSTS	73.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 80.0 USING TODAY'S TECHNOLOGY
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 7.1

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	40.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.30
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	3.56
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	111.6
OVERALL GEO FLUID PRESSURE DROP (psia)	735.
INJECTOR WELL PRESSURE DROP (psia)	127.
RESERVOIR PRESSURE DROP (psia)	1740.
PRODUCER WELL PRESSURE DROP (psia)	165.
BUOYANCY CORRECTION (psia)	1298.
PUMPING POWER / NET INSTALLED POWER (%)	3.3

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	892.
STIMULATION COSTS	361.
SURFACE POWER PLANT COSTS	766.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	111.
TOTAL CAPITAL COSTS	2331.
CAPITAL COST YEARLY CHARGE RATE	390.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	43.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	3.
REDRILLING/RESTIMULATION COSTS	31.
TOTAL OPERATING AND MAINTENANCE COSTS	129.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 80.0 USING COMMERCIALLY MATURE TECHNOLOGY
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 5.3

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.10
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	3.56
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	111.6
OVERALL GEO FLUID PRESSURE DROP (psia)	725.
INJECTOR WELL PRESSURE DROP (psia)	409.
RESERVOIR PRESSURE DROP (psia)	1088.
PRODUCER WELL PRESSURE DROP (psia)	525.
BUOYANCY CORRECTION (psia)	1298.
PUMPING POWER / NET INSTALLED POWER (%)	3.3

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	476.
STIMULATION COSTS	181.
SURFACE POWER PLANT COSTS	766.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	111.
TOTAL CAPITAL COSTS	1734.
CAPITAL COST YEARLY CHARGE RATE	290.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	23.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	3.
REDRILLING/RESTIMULATION COSTS	16.
TOTAL OPERATING AND MAINTENANCE COSTS	94.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 80.0 USING TECNICALLY OPTIMIZED DOUBLETS
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 3.9

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.08
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	3.56
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	111.6
OVERALL GEO FLUID PRESSURE DROP (psia)	507.
INJECTOR WELL PRESSURE DROP (psia)	409.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	525.
BUOYANCY CORRECTION (psia)	1298.
PUMPING POWER / NET INSTALLED POWER (%)	2.3

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	188.
STIMULATION COSTS	90.
SURFACE POWER PLANT COSTS	689.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	68.
TOTAL CAPITAL COSTS	1236.
CAPITAL COST YEARLY CHARGE RATE	207.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	23.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	3.
REDRILLING/RESTIMULATION COSTS	7.
TOTAL OPERATING AND MAINTENANCE COSTS	84.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 80.0 USING TECNICALLY OPTIMIZED TRIPLETS
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 3.6

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	2.5
CAPACITY FACTOR (%)	90.0
REDRILLED WELLS / INITIAL WELLS	0.17
NO. INJECTORS / NO. PRODUCERS	0.5
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00007
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.08
INJECTOR WELL CASING ID (inches)	8.681
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	3.56
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	223.2
OVERALL GEO FLUID PRESSURE DROP (psia)	600.
INJECTOR WELL PRESSURE DROP (psia)	502.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	525.
BUOYANCY CORRECTION (psia)	1298.
PUMPING POWER / NET INSTALLED POWER (%)	2.6

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	148.
STIMULATION COSTS	115.
SURFACE POWER PLANT COSTS	689.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	69.
TOTAL CAPITAL COSTS	1222.
CAPITAL COST YEARLY CHARGE RATE	204.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	17.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	2.
REDRILLING/RESTIMULATION COSTS	2.
TOTAL OPERATING AND MAINTENANCE COSTS	72.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 90.0 USING TODAY'S TECHNOLOGY
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 6.6

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	40.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.30
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	3.17
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	111.6
OVERALL GEO FLUID PRESSURE DROP (psia)	846.
INJECTOR WELL PRESSURE DROP (psia)	113.
RESERVOIR PRESSURE DROP (psia)	1740.
PRODUCER WELL PRESSURE DROP (psia)	147.
BUOYANCY CORRECTION (psia)	1153.
PUMPING POWER / NET INSTALLED POWER (%)	3.8

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	689.
STIMULATION COSTS	361.
SURFACE POWER PLANT COSTS	766.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	95.
TOTAL CAPITAL COSTS	2111.
CAPITAL COST YEARLY CHARGE RATE	353.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	43.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	3.
REDRILLING/RESTIMULATION COSTS	26.
TOTAL OPERATING AND MAINTENANCE COSTS	123.

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HDR CASE REPORT
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GRADIENT (deg C per km) = 90.0 USING COMMERCIALLY MATURE TECHNOLOGY
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 4.9

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.10
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	3.17
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	111.6
OVERALL GEO FLUID PRESSURE DROP (psia)	765.
INJECTOR WELL PRESSURE DROP (psia)	364.
RESERVOIR PRESSURE DROP (psia)	1088.
PRODUCER WELL PRESSURE DROP (psia)	467.
BUOYANCY CORRECTION (psia)	1153.
PUMPING POWER / NET INSTALLED POWER (%)	3.4

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	367.
STIMULATION COSTS	181.
SURFACE POWER PLANT COSTS	766.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	95.
TOTAL CAPITAL COSTS	1609.
CAPITAL COST YEARLY CHARGE RATE	269.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	23.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	3.
REDRILLING/RESTIMULATION COSTS	14.
TOTAL OPERATING AND MAINTENANCE COSTS	91.

****
HDR CASE REPORT
****

GRADIENT (deg C per km) = 90.0 USING TECNICALLY OPTIMIZED DOUBLETS
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 3.8

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.08
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	3.17
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	111.6
OVERALL GEO FLUID PRESSURE DROP (psia)	547.
INJECTOR WELL PRESSURE DROP (psia)	364.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	467.
BUOYANCY CORRECTION (psia)	1153.
PUMPING POWER / NET INSTALLED POWER (%)	2.5

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	142.
STIMULATION COSTS	90.
SURFACE POWER PLANT COSTS	689.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	61.
TOTAL CAPITAL COSTS	1183.
CAPITAL COST YEARLY CHARGE RATE	198.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	23.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	3.
REDRILLING/RESTIMULATION COSTS	6.
TOTAL OPERATING AND MAINTENANCE COSTS	83.

****
HDR CASE REPORT
****

GRADIENT (deg C per km) = 90.0 USING TECNICALLY OPTIMIZED TRIPLETS
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 3.5

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	2.5
CAPACITY FACTOR (%)	90.0
REDRILLED WELLS / INITIAL WELLS	0.17
NO. INJECTORS / NO. PRODUCERS	0.5
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00007
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.08
INJECTOR WELL CASING ID (inches)	8.681
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	3.17
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	223.2
OVERALL GEO FLUID PRESSURE DROP (psia)	630.
INJECTOR WELL PRESSURE DROP (psia)	446.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	467.
BUOYANCY CORRECTION (psia)	1153.
PUMPING POWER / NET INSTALLED POWER (%)	2.8

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	112.
STIMULATION COSTS	115.
SURFACE POWER PLANT COSTS	689.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	62.
TOTAL CAPITAL COSTS	1178.
CAPITAL COST YEARLY CHARGE RATE	197.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	17.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	2.
REDRILLING/RESTIMULATION COSTS	2.
TOTAL OPERATING AND MAINTENANCE COSTS	72.

****
HDR CASE REPORT
****

GRADIENT (deg C per km) = 100.0 USING TODAY'S TECHNOLOGY
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 6.2

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	40.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.30
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	2.85
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	111.6
OVERALL GEO FLUID PRESSURE DROP (psia)	936.
INJECTOR WELL PRESSURE DROP (psia)	102.
RESERVOIR PRESSURE DROP (psia)	1740.
PRODUCER WELL PRESSURE DROP (psia)	132.
BUOYANCY CORRECTION (psia)	1038.
PUMPING POWER / NET INSTALLED POWER (%)	4.2

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	560.
STIMULATION COSTS	361.
SURFACE POWER PLANT COSTS	766.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	84.
TOTAL CAPITAL COSTS	1972.
CAPITAL COST YEARLY CHARGE RATE	330.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	43.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	3.
REDRILLING/RESTIMULATION COSTS	23.
TOTAL OPERATING AND MAINTENANCE COSTS	120.

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HDR CASE REPORT
****

GRADIENT (deg C per km) = 100.0 USING COMMERCIALLY MATURE TECHNOLOGY
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 4.7

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.10
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	2.85
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	111.6
OVERALL GEO FLUID PRESSURE DROP (psia)	797.
INJECTOR WELL PRESSURE DROP (psia)	328.
RESERVOIR PRESSURE DROP (psia)	1088.
PRODUCER WELL PRESSURE DROP (psia)	420.
BUOYANCY CORRECTION (psia)	1038.
PUMPING POWER / NET INSTALLED POWER (%)	3.6

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	299.
STIMULATION COSTS	181.
SURFACE POWER PLANT COSTS	766.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	84.
TOTAL CAPITAL COSTS	1530.
CAPITAL COST YEARLY CHARGE RATE	256.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	23.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	3.
REDRILLING/RESTIMULATION COSTS	12.
TOTAL OPERATING AND MAINTENANCE COSTS	89.

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HDR CASE REPORT
****

GRADIENT (deg C per km) = 100.0 USING TECNICALLY OPTIMIZED DOUBLETS
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 3.7

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.08
INJECTOR WELL CASING ID (inches)	7.000
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	2.85
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	111.6
OVERALL GEO FLUID PRESSURE DROP (psia)	580.
INJECTOR WELL PRESSURE DROP (psia)	328.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	420.
BUOYANCY CORRECTION (psia)	1038.
PUMPING POWER / NET INSTALLED POWER (%)	2.6

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	109.
STIMULATION COSTS	90.
SURFACE POWER PLANT COSTS	689.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	56.
TOTAL CAPITAL COSTS	1145.
CAPITAL COST YEARLY CHARGE RATE	192.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	23.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	3.
REDRILLING/RESTIMULATION COSTS	5.
TOTAL OPERATING AND MAINTENANCE COSTS	82.

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HDR CASE REPORT
****

GRADIENT (deg C per km) = 100.0 USING TECNICALLY OPTIMIZED TRIPLETS
ELECTRICITY BREAKEVEN PRICE (cents/kWh) = 3.4

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (years)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	2.5
CAPACITY FACTOR (%)	90.0
REDRILLED WELLS / INITIAL WELLS	0.17
NO. INJECTORS / NO. PRODUCERS	0.5
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (kg/sqm-s)	0.00007
TEMP RESERVOIR - TEMP GEOFLUID (deg C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (deg C)	300.0
PRODUCTION WELL FLOWRATE (kg/s)	75.0
RESERVOIR IMPEDANCE (GPa-s/cum)	0.08
INJECTOR WELL CASING ID (inches)	8.681
PRODUCER WELL CASING ID (inches)	7.000

ENGINEERING RESULTS

AVERAGE WELL DEPTH (km)	2.85
INITIAL RESERVOIR TEMPERATURE (deg C)	300.0
GEOTHERMAL FLUID TEMPERATURE (deg C)	285.0
GEOTHERMAL FLUID AVAILABILITY (MWe-s/kg)	0.333
UTILIZATION EFFICIENCY (%)	60.4
EFFECTIVE RESERVOIR AREA (sqm/kWe)	223.2
OVERALL GEO FLUID PRESSURE DROP (psia)	654.
INJECTOR WELL PRESSURE DROP (psia)	402.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	420.
BUOYANCY CORRECTION (psia)	1038.
PUMPING POWER / NET INSTALLED POWER (%)	2.9

CAPITAL COSTS (k$/MWe)

DRILLING AND COMPLETION COSTS	86.
STIMULATION COSTS	115.
SURFACE POWER PLANT COSTS	689.
SURFACE FLUID DISTRIBUTION COSTS	200.
EXPLORATION COSTS	57.
TOTAL CAPITAL COSTS	1147.
CAPITAL COST YEARLY CHARGE RATE	192.

OPERATING AND MAINTENANCE COSTS (k$/MWe/yr)

WELLFIELD MAINTENANCE COSTS	17.
SURFACE PLANT MAINTENANCE COSTS	51.
WATER COSTS	2.
REDRILLING/RESTIMULATION COSTS	2.
TOTAL OPERATING AND MAINTENANCE COSTS	72.

A.2 Sensitivity and Uncertainty Analysis

MIT HDR economic model results follow for the following sensitivity and uncertainty analyses:

- optimum well depth.
- drilling and completion costs.
- stimulation costs.
- thermal drawdown rates.

Discussion of these results is contained in Chapter 10.

****
PRICE VS. DEPTH REPORT
****

*** TODAY'S TECHNOLOGY ***

ELECTRICITY BREAKEVEN PRICE (CENTS/KWH)

TGF	GRADIENT (DEGREES C / KM)								
DEGREES C	20	30	40	50	60	70	80	90	100
100.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.
120.	344.0	159.5	106.6	85.6	75.0	68.8	65.1	62.6	61.
140.	167.0	71.1	46.2	36.6	31.4	28.6	26.8	25.6	24.
160.	134.9	51.2	32.5	24.6	21.1	18.8	17.5	16.7	16.
180.	130.0	42.8	26.1	19.5	16.3	14.6	13.4	12.7	12.
200.	137.8	38.9	22.6	16.8	13.7	12.2	11.1	10.5	10.
220.	155.3	37.5	20.7	14.9	12.1	10.5	9.7	9.0	8.
240.	183.0	37.8	19.4	13.6	11.1	9.5	8.6	8.1	7.
260.	223.1	39.3	18.6	12.8	10.2	8.7	7.8	7.3	6.
280.	279.5	41.9	18.4	12.2	9.5	8.2	7.2	6.7	6.
300.	358.0	45.7	18.5	11.8	9.0	7.7	6.8	6.2	5.

*** COMMERCIAL BASE CASE ***

ELECTRICITY BREAKEVEN PRICE (CENTS/KWH)

TGF	GRADIENT (DEGREES C / KM)								
DEGREES C	20	30	40	50	60	70	80	90	100
100.	0.0	0.0	0.0	793.2	260.6	169.1	132.0	112.2	99.
120.	399.5	92.7	51.3	37.8	31.5	28.0	25.8	24.4	23.
140.	125.7	44.5	27.4	21.2	18.0	16.2	15.1	14.4	13.
160.	92.6	32.4	20.3	15.4	13.3	11.9	11.1	10.6	10.
180.	85.4	27.1	16.7	12.6	10.8	9.7	9.0	8.6	8.
200.	88.0	24.6	14.6	11.1	9.3	8.4	7.8	7.4	7.
220.	97.5	23.6	13.4	10.0	8.3	7.4	6.9	6.6	6.
240.	113.7	23.6	12.6	9.2	7.7	6.8	6.3	6.0	5.
260.	137.7	24.4	12.1	8.6	7.1	6.3	5.8	5.4	5.
280.	172.1	26.0	11.9	8.3	6.7	5.9	5.3	5.0	4.
300.	220.6	28.3	11.9	7.9	6.3	5.5	5.0	4.7	4.

NOTE: A price of 0.0 means net electricity produced is negative (i.e. pumping requirement is greater than power plant output).

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PRICE VS. DEPTH REPORT
****

*** TECHNICALLY OPTIMIZED DOUBLETS ***

ELECTRICITY BREAKEVEN PRICE (CENTS/KWH)

TGF DEGREES C	GRADIENT (DEGREES C / KM) 20	30	40	50	60	70	80	90	100
100.	0.0	1358.6	123.0	73.7	57.4	49.4	44.7	41.6	39.4
120.	135.4	40.0	26.0	21.1	18.8	17.5	16.7	16.2	15.8
140.	69.7	23.8	15.7	13.1	11.8	11.1	10.7	10.4	10.2
160.	60.9	18.4	12.0	9.9	9.0	8.4	8.1	8.0	7.8
180.	64.6	16.2	10.2	8.2	7.4	7.0	6.7	6.6	6.5
200.	76.2	15.5	9.2	7.2	6.5	6.1	5.8	5.7	5.6
220.	96.7	15.8	8.5	6.6	5.8	5.4	5.2	5.0	5.0
240.	129.2	16.8	8.2	6.2	5.3	4.9	4.7	4.6	4.5
260.	179.6	18.6	8.1	5.8	5.0	4.5	4.3	4.2	4.1
280.	257.5	21.3	8.2	5.6	4.7	4.2	4.0	3.9	3.8
300.	378.6	25.0	8.4	5.4	4.5	4.0	3.8	3.6	3.5

*** TECHNICALLY OPTIMIZED TRIPLETS ***

ELECTRICITY BREAKEVEN PRICE (CENTS/KWH)

TGF DEGREES C	GRADIENT (DEGREES C / KM) 20	30	40	50	60	70	80	90	100
100.	0.0	0.0	130.0	69.5	52.3	44.3	39.7	36.7	34.6
120.	128.7	35.2	23.0	18.8	16.8	15.7	14.9	14.4	14.1
140.	56.1	20.0	13.6	11.5	10.5	10.0	9.6	9.4	9.2
160.	46.9	15.1	10.3	8.7	8.0	7.6	7.4	7.2	7.1
180.	48.5	13.1	8.7	7.2	6.6	6.3	6.1	6.0	5.9
200.	56.6	12.4	7.7	6.3	5.8	5.5	5.3	5.2	5.1
220.	71.2	12.4	7.1	5.8	5.2	4.9	4.7	4.6	4.6
240.	95.0	13.1	6.8	5.4	4.7	4.5	4.3	4.2	4.1
260.	132.1	14.3	6.7	5.0	4.4	4.1	4.0	3.9	3.8
280.	190.1	16.3	6.7	4.8	4.2	3.8	3.7	3.6	3.5
300.	281.0	19.1	6.9	4.6	3.9	3.6	3.4	3.3	3.3

NOTE: A price of 0.0 means net electricity produced is negative (i.e. pumping requirement is greater than power plant output).

TABLE A.1. DATA FOR FIGURE 10.3

Geothermal Gradient deg C/km	Base Case Breakeven Electricity Price (cents/kWh)				
	Double Drilling	Double Stimulation	Baseline	Half Stimulation	Half Drilling
20	162.7	86.3	85.3	84.8	46.4
30	41.8	24.1	23.5	23.2	14.1
40	19.9	12.4	11.9	11.7	7.8
50	12.5	8.6	8.2	7.9	6.0
60	9.4	7.1	6.6	6.4	5.2
70	7.8	6.3	5.8	5.6	4.8
80	6.7	5.7	5.3	5.0	4.6
90	6.0	5.4	4.9	4.7	4.4
100	5.6	5.2	4.7	4.5	4.3

TABLE A.2. DATA FOR FIGURE 10.4

Geothermal Gradient deg C/km	Base Case Breakeven Electricity Price (cents/kWh)				
		Accelerated Drawdown	Base Case	Zero Drawdown	
20		94.8	85.3	75.9	
30		25.6	23.5	21.4	
40		12.8	11.9	11.0	
50		8.7	8.2	7.7	
60		6.9	6.6	6.3	
70		6.0	5.8	5.6	
80		5.4	5.3	5.1	
90		5.1	4.9	4.9	
100		4.8	4.7	4.7	

A.3 Direct Thermal Use

The *MIT HDR* economic model results for direct thermal use are presented in this appendix. Three end-use cases are considered: industrial process heat, non-cascading space heat, and fully cascaded space heat. For each end-use case, a summary is presented, with details of three representative gradients (30°C/km, 50°C/km, and 80°C/km) for each of the four technology cases. Discussion of these results is contained in Chapter 11.

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*  HDR SUMMARY REPORT   *
*INDUSTRIAL PROCESS HEAT*
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GRADIENT DEG C/KM	TECHNOLOGY	DEPTH KM	PRICE $/MMBTU	FOR MMMBTU/HR NET OUTPUT # WELLS	CAP COST MM$	O&M COST MM$/YR
20.0	TODAY	6.55	40.9	85.8	1459.428	64.030
20.0	BASE	6.60	23.2	44.9	790.949	42.698
20.0	DOUBLET	6.25	14.2	51.8	427.075	35.609
20.0	TRIPLET	6.40	10.9	36.4	359.264	25.689
30.0	TODAY	5.20	16.6	57.3	559.452	31.563
30.0	BASE	5.55	9.7	26.7	317.827	19.877
30.0	DOUBLET	5.35	5.6	28.8	156.510	16.126
30.0	TRIPLET	5.55	4.5	20.1	138.530	11.958
40.0	TODAY	4.72	9.7	39.3	323.850	19.288
40.0	BASE	4.77	5.7	20.6	182.414	12.797
40.0	DOUBLET	4.92	3.4	19.5	94.501	9.517
40.0	TRIPLET	5.07	2.7	13.8	85.817	7.108
50.0	TODAY	4.40	6.9	30.1	227.995	13.554
50.0	BASE	4.40	4.1	16.0	130.962	8.941
50.0	DOUBLET	4.30	2.4	16.7	64.260	7.206
50.0	TRIPLET	4.75	2.0	10.6	65.842	4.677
60.0	TODAY	3.70	5.2	29.6	163.915	12.023
60.0	BASE	3.70	3.2	15.8	95.714	7.897
60.0	DOUBLET	4.05	1.9	13.6	52.969	5.307
60.0	TRIPLET	4.20	1.6	9.6	51.732	3.882
70.0	TODAY	3.47	4.3	25.4	134.482	9.838
70.0	BASE	3.52	2.6	13.3	81.342	6.204
70.0	DOUBLET	3.82	1.6	11.6	47.055	4.162
70.0	TRIPLET	3.92	1.4	8.4	46.287	3.058
80.0	TODAY	3.31	3.7	22.1	117.384	8.233
80.0	BASE	3.31	2.3	11.8	71.971	5.215
80.0	DOUBLET	3.56	1.4	10.5	43.187	3.529
80.0	TRIPLET	3.56	1.2	7.9	42.077	2.751
90.0	TODAY	3.17	3.3	19.7	106.356	7.120
90.0	BASE	3.12	2.1	10.8	65.852	4.556
90.0	DOUBLET	3.17	1.3	10.5	39.003	3.480
90.0	TRIPLET	3.17	1.2	7.9	38.638	2.753
100.0	TODAY	2.85	3.0	19.7	95.347	6.984
100.0	BASE	2.85	1.9	10.5	60.404	4.326
100.0	DOUBLET	2.85	1.3	10.5	36.046	3.449
100.0	TRIPLET	2.85	1.1	7.9	36.208	2.757

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HDR CASE REPORT
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GRADIENT (DEG C PER KM) = 30.0 USING TODAY'S TECHNOLOGY
INDUSTRIAL PROCESS HEAT BREAKEVEN PRICE ($/MMBTU) = 16.6

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	40.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.30
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	5.20
INITIAL RESERVOIR TEMPERATURE (DEG C)	171.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	156.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.320
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	26.
CYCLE EFFICIENCY (%)	13.2
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1721.
INJECTOR WELL PRESSURE DROP (psia)	189.
RESERVOIR PRESSURE DROP (psia)	1740.
PRODUCER WELL PRESSURE DROP (psia)	199.
BUOYANCY CORRECTION (psia)	408.
PUMPING POWER (kWe/(MMBTU/HR))	17.9

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	504012.
STIMULATION COSTS	35309.
SURFACE FLUID DISTRIBUTION COSTS	9702.
EXPLORATION COSTS	10428.
TOTAL CAPITAL COSTS	559452.
CAPITAL COST YEARLY CHARGE RATE	93544.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	9883.
PUMPING COSTS	7484.
WATER COSTS	713.
REDRILLING/RESTIMULATION COSTS	13483.
TOTAL OPERATING AND MAINTENANCE COSTS	31563.

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HDR CASE REPORT
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GRADIENT (DEG C PER KM) = 30.0 USING COMMERCIALLY MATURE TECHNOLOGY
INDUSTRIAL PROCESS HEAT BREAKEVEN PRICE ($/MMBTU) = 9.7

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.10
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	5.55
INITIAL RESERVOIR TEMPERATURE (DEG C)	181.5
GEOTHERMAL FLUID TEMPERATURE (DEG C)	166.5
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.365
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	22.
CYCLE EFFICIENCY (%)	13.7
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1908.
INJECTOR WELL PRESSURE DROP (psia)	649.
RESERVOIR PRESSURE DROP (psia)	1088.
PRODUCER WELL PRESSURE DROP (psia)	688.
BUOYANCY CORRECTION (psia)	517.
PUMPING POWER (kWe/(MMBTU/HR))	17.3

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	278895.
STIMULATION COSTS	16464.
SURFACE FLUID DISTRIBUTION COSTS	10039.
EXPLORATION COSTS	12430.
TOTAL CAPITAL COSTS	317827.
CAPITAL COST YEARLY CHARGE RATE	53143.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	4611.
PUMPING COSTS	7258.
WATER COSTS	624.
REDRILLING/RESTIMULATION COSTS	7384.
TOTAL OPERATING AND MAINTENANCE COSTS	19877.

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HDR CASE REPORT
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GRADIENT (DEG C PER KM) = 30.0 USING TECNICALLY OPTIMIZED DOUBLETS
INDUSTRIAL PROCESS HEAT BREAKEVEN PRICE ($/MMBTU) = 5.6

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.08
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	5.35
INITIAL RESERVOIR TEMPERATURE (DEG C)	175.5
GEOTHERMAL FLUID TEMPERATURE (DEG C)	160.5
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.339
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	24.
CYCLE EFFICIENCY (%)	13.4
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1703.
INJECTOR WELL PRESSURE DROP (psia)	626.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	660.
BUOYANCY CORRECTION (psia)	452.
PUMPING POWER (kWe/(MMBTU/HR))	16.7

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	131696.
STIMULATION COSTS	8548.
SURFACE FLUID DISTRIBUTION COSTS	9839.
EXPLORATION COSTS	6427.
TOTAL CAPITAL COSTS	156510.
CAPITAL COST YEARLY CHARGE RATE	26169.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	4968.
PUMPING COSTS	6981.
WATER COSTS	672.
REDRILLING/RESTIMULATION COSTS	3506.
TOTAL OPERATING AND MAINTENANCE COSTS	16126.

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HDR CASE REPORT
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GRADIENT (DEG C PER KM) = 30.0 USING TECNICALLY OPTIMIZED TRIPLETS
INDUSTRIAL PROCESS HEAT BREAKEVEN PRICE ($/MMBTU) = 4.5

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	2.5
CAPACITY FACTOR (%)	90.0
REDRILLED WELLS / INITIAL WELLS	0.17
NO. INJECTORS / NO. PRODUCERS	0.5
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00007
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.08
INJECTOR WELL CASING ID (INCHES)	8.681
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	5.55
INITIAL RESERVOIR TEMPERATURE (DEG C)	181.5
GEOTHERMAL FLUID TEMPERATURE (DEG C)	166.5
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.365
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	45.
CYCLE EFFICIENCY (%)	13.7
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1838.
INJECTOR WELL PRESSURE DROP (psia)	797.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	688.
BUOYANCY CORRECTION (psia)	517.
PUMPING POWER (kWe/(MMBTU/HR))	16.3

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	107955.
STIMULATION COSTS	13165.
SURFACE FLUID DISTRIBUTION COSTS	10039.
EXPLORATION COSTS	7370.
TOTAL CAPITAL COSTS	138530.
CAPITAL COST YEARLY CHARGE RATE	23163.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	3458.
PUMPING COSTS	7144.
WATER COSTS	326.
REDRILLING/RESTIMULATION COSTS	1030.
TOTAL OPERATING AND MAINTENANCE COSTS	11958.

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*HDR CASE REPORT*
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GRADIENT (DEG C PER KM) =  50.0 USING TODAY'S TECHNOLOGY
INDUSTRIAL PROCESS HEAT BREAKEVEN PRICE ($/MMBTU) =   6.9

                ***ECONOMIC PARAMETERS***

FIXED CHARGE RATE (%)                           15.3
AFDC RATE (%)                                    9.0
PROJECT LIFE (YEARS)                            20.0

               ***ENGINEERING PARAMETERS***

WATER LOSS RATE (%)                              5.0
CAPACITY FACTOR (%)                             86.0
REDRILLED WELLS / INITIAL WELLS                 0.50
NO. INJECTORS / NO. PRODUCERS                    1.0
PUMP EFFICIENCY (%)                             80.0
DRAWDOWN PARAMETER (KG/SQM-S)                0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)          15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)       300.0
PRODUCTION WELL FLOWRATE (KG/S)                 40.0
RESERVOIR IMPEDANCE (GPA-S/CUM)                 0.30
INJECTOR WELL CASING ID (INCHES)               7.000
PRODUCER WELL CASING ID (INCHES)               7.000
THERMAL EFFICIENCY (%)                          80.0

                ***ENGINEERING RESULTS***

AVERAGE WELL DEPTH (KM)                         4.40
INITIAL RESERVOIR TEMPERATURE (DEG C)          235.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)           220.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)         0.609
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)       13.
CYCLE EFFICIENCY (%)                            16.8
OVERALL GEO FLUID PRESSURE DROP (PSIA)         1250.
INJECTOR WELL PRESSURE DROP (psia)              160.
RESERVOIR PRESSURE DROP (psia)                 1740.
PRODUCER WELL PRESSURE DROP (psia)              183.
BUOYANCY CORRECTION (psia)                      833.
PUMPING POWER (kWe/(MMBTU/HR))                   6.8

               ***CAPITAL COSTS ($/MMBTU/HR)***

DRILLING AND COMPLETION COSTS                177868.
STIMULATION COSTS                             28056.
SURFACE FLUID DISTRIBUTION COSTS              12346.
EXPLORATION COSTS                              9725.
TOTAL CAPITAL COSTS                          227995.
CAPITAL COST YEARLY CHARGE RATE               38122.

     ***OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)***

WELLFIELD MAINTENANCE COSTS                    5182.
PUMPING COSTS                                  2850.
WATER COSTS                                     374.
REDRILLING/RESTIMULATION COSTS                 5148.
TOTAL OPERATING AND MAINTENANCE COSTS         13554.
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HDR CASE REPORT
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GRADIENT (DEG C PER KM) = 50.0 USING COMMERCIALLY MATURE TECHNOLOGY
INDUSTRIAL PROCESS HEAT BREAKEVEN PRICE ($/MMBTU) = 4.1

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.10
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	4.40
INITIAL RESERVOIR TEMPERATURE (DEG C)	235.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	220.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.609
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	13.
CYCLE EFFICIENCY (%)	16.8
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1351.
INJECTOR WELL PRESSURE DROP (psia)	515.
RESERVOIR PRESSURE DROP (psia)	1088.
PRODUCER WELL PRESSURE DROP (psia)	582.
BUOYANCY CORRECTION (psia)	833.
PUMPING POWER (kWe/(MMBTU/HR))	7.4

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	94863.
STIMULATION COSTS	14028.
SURFACE FLUID DISTRIBUTION COSTS	12346.
EXPLORATION COSTS	9725.
TOTAL CAPITAL COSTS	130962.
CAPITAL COST YEARLY CHARGE RATE	21898.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	2764.
PUMPING COSTS	3081.
WATER COSTS	374.
REDRILLING/RESTIMULATION COSTS	2722.
TOTAL OPERATING AND MAINTENANCE COSTS	8941.

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HDR CASE REPORT
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GRADIENT (DEG C PER KM) = 50.0 USING TECNICALLY OPTIMIZED DOUBLETS
INDUSTRIAL PROCESS HEAT BREAKEVEN PRICE ($/MMBTU) = 2.4

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.08
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	4.30
INITIAL RESERVOIR TEMPERATURE (DEG C)	230.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	215.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.586
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	14.
CYCLE EFFICIENCY (%)	16.5
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1168.
INJECTOR WELL PRESSURE DROP (psia)	503.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	565.
BUOYANCY CORRECTION (psia)	770.
PUMPING POWER (kWe/(MMBTU/HR))	6.6

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	39837.
STIMULATION COSTS	7053.
SURFACE FLUID DISTRIBUTION COSTS	12103.
EXPLORATION COSTS	5267.
TOTAL CAPITAL COSTS	64260.
CAPITAL COST YEARLY CHARGE RATE	10745.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	2875.
PUMPING COSTS	2770.
WATER COSTS	389.
REDRILLING/RESTIMULATION COSTS	1172.
TOTAL OPERATING AND MAINTENANCE COSTS	7206.

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HDR CASE REPORT
****

GRADIENT (DEG C PER KM) = 50.0 USING TECNICALLY OPTIMIZED TRIPLETS
INDUSTRIAL PROCESS HEAT BREAKEVEN PRICE ($/MMBTU) = 2.0

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	2.5
CAPACITY FACTOR (%)	90.0
REDRILLED WELLS / INITIAL WELLS	0.17
NO. INJECTORS / NO. PRODUCERS	0.5
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00007
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.08
INJECTOR WELL CASING ID (INCHES)	8.681
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	4.75
INITIAL RESERVOIR TEMPERATURE (DEG C)	252.5
GEOTHERMAL FLUID TEMPERATURE (DEG C)	237.5
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.693
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	24.
CYCLE EFFICIENCY (%)	18.0
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1121.
INJECTOR WELL PRESSURE DROP (psia)	682.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	645.
BUOYANCY CORRECTION (psia)	1076.
PUMPING POWER (kWe/(MMBTU/HR))	5.2

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	35965.
STIMULATION COSTS	9546.
SURFACE FLUID DISTRIBUTION COSTS	13231.
EXPLORATION COSTS	7099.
TOTAL CAPITAL COSTS	65842.
CAPITAL COST YEARLY CHARGE RATE	11009.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	1822.
PUMPING COSTS	2296.
WATER COSTS	172.
REDRILLING/RESTIMULATION COSTS	387.
TOTAL OPERATING AND MAINTENANCE COSTS	4677.

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HDR CASE REPORT
****

GRADIENT (DEG C PER KM) = 80.0 USING TODAY'S TECHNOLOGY
INDUSTRIAL PROCESS HEAT BREAKEVEN PRICE ($/MMBTU) = 3.7

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	40.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.30
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	3.31
INITIAL RESERVOIR TEMPERATURE (DEG C)	280.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	265.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.829
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	10.
CYCLE EFFICIENCY (%)	20.0
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1054.
INJECTOR WELL PRESSURE DROP (psia)	121.
RESERVOIR PRESSURE DROP (psia)	1740.
PRODUCER WELL PRESSURE DROP (psia)	148.
BUOYANCY CORRECTION (psia)	955.
PUMPING POWER (kWe/(MMBTU/HR))	4.2

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	67286.
STIMULATION COSTS	28025.
SURFACE FLUID DISTRIBUTION COSTS	14707.
EXPLORATION COSTS	7366.
TOTAL CAPITAL COSTS	117384.
CAPITAL COST YEARLY CHARGE RATE	19627.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	3809.
PUMPING COSTS	1767.
WATER COSTS	275.
REDRILLING/RESTIMULATION COSTS	2383.
TOTAL OPERATING AND MAINTENANCE COSTS	8233.

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HDR CASE REPORT
****

GRADIENT (DEG C PER KM) = 80.0 USING COMMERCIALLY MATURE TECHNOLOGY
INDUSTRIAL PROCESS HEAT BREAKEVEN PRICE ($/MMBTU) = 2.3

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.10
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	3.31
INITIAL RESERVOIR TEMPERATURE (DEG C)	280.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	265.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.829
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	10.
CYCLE EFFICIENCY (%)	20.0
OVERALL GEO FLUID PRESSURE DROP (PSIA)	991.
INJECTOR WELL PRESSURE DROP (psia)	387.
RESERVOIR PRESSURE DROP (psia)	1088.
PRODUCER WELL PRESSURE DROP (psia)	471.
BUOYANCY CORRECTION (psia)	955.
PUMPING POWER (kWe/(MMBTU/HR))	4.0

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	35886.
STIMULATION COSTS	14012.
SURFACE FLUID DISTRIBUTION COSTS	14707.
EXPLORATION COSTS	7366.
TOTAL CAPITAL COSTS	71971.
CAPITAL COST YEARLY CHARGE RATE	12034.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	2031.
PUMPING COSTS	1661.
WATER COSTS	275.
REDRILLING/RESTIMULATION COSTS	1247.
TOTAL OPERATING AND MAINTENANCE COSTS	5215.

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HDR CASE REPORT
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GRADIENT (DEG C PER KM) = 80.0 USING TECNICALLY OPTIMIZED DOUBLETS
INDUSTRIAL PROCESS HEAT BREAKEVEN PRICE ($/MMBTU) = 1.4

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.08
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	3.56
INITIAL RESERVOIR TEMPERATURE (DEG C)	300.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	285.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.931
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	9.
CYCLE EFFICIENCY (%)	21.6
OVERALL GEO FLUID PRESSURE DROP (PSIA)	620.
INJECTOR WELL PRESSURE DROP (psia)	417.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	525.
BUOYANCY CORRECTION (psia)	1192.
PUMPING POWER (kWe/(MMBTU/HR))	2.2

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	14860.
STIMULATION COSTS	7139.
SURFACE FLUID DISTRIBUTION COSTS	15835.
EXPLORATION COSTS	5354.
TOTAL CAPITAL COSTS	43187.
CAPITAL COST YEARLY CHARGE RATE	7221.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	1809.
PUMPING COSTS	925.
WATER COSTS	245.
REDRILLING/RESTIMULATION COSTS	550.
TOTAL OPERATING AND MAINTENANCE COSTS	3529.

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HDR CASE REPORT
****

GRADIENT (DEG C PER KM) = 80.0 USING TECNICALLY OPTIMIZED TRIPLETS
INDUSTRIAL PROCESS HEAT BREAKEVEN PRICE ($/MMBTU) = 1.2

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	2.5
CAPACITY FACTOR (%)	90.0
REDRILLED WELLS / INITIAL WELLS	0.17
NO. INJECTORS / NO. PRODUCERS	0.5
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00007
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.08
INJECTOR WELL CASING ID (INCHES)	8.681
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	3.56
INITIAL RESERVOIR TEMPERATURE (DEG C)	300.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	285.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.931
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	18.
CYCLE EFFICIENCY (%)	21.6
OVERALL GEO FLUID PRESSURE DROP (PSIA)	715.
INJECTOR WELL PRESSURE DROP (psia)	511.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	525.
BUOYANCY CORRECTION (psia)	1192.
PUMPING POWER (kWe/(MMBTU/HR))	2.5

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	11702.
STIMULATION COSTS	9075.
SURFACE FLUID DISTRIBUTION COSTS	15835.
EXPLORATION COSTS	5466.
TOTAL CAPITAL COSTS	42077.
CAPITAL COST YEARLY CHARGE RATE	7036.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	1357.
PUMPING COSTS	1090.
WATER COSTS	128.
REDRILLING/RESTIMULATION COSTS	177.
TOTAL OPERATING AND MAINTENANCE COSTS	2751.

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*   HDR SUMMARY REPORT   *
NON-CASCADING SPACE HEAT
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GRADIENT DEG C/KM	TECHNOLOGY	DEPTH KM	PRICE $/MMBTU	FOR MMMBTU/HR NET OUTPUT # WELLS	CAP COST MM$	O&M COST MM$/YR
20.0	TODAY	4.30	19.9	99.8	612.530	47.313
20.0	BASE	4.40	11.6	51.4	331.751	31.810
20.0	DOUBLET	4.20	6.7	55.3	139.280	26.875
20.0	TRIPLET	4.75	5.5	34.2	140.683	19.716
30.0	TODAY	3.50	10.6	73.6	295.210	30.752
30.0	BASE	3.60	6.3	37.7	162.627	20.388
30.0	DOUBLET	4.00	3.7	32.4	77.436	15.120
30.0	TRIPLET	4.20	3.1	22.7	73.800	12.082
40.0	TODAY	3.37	7.2	51.4	200.405	20.948
40.0	BASE	3.42	4.3	26.9	111.349	13.940
40.0	DOUBLET	3.87	2.6	22.7	56.351	10.054
40.0	TRIPLET	4.07	2.2	15.9	54.918	7.900
50.0	TODAY	3.25	5.5	39.9	153.436	15.783
50.0	BASE	3.30	3.3	20.9	87.168	10.357
50.0	DOUBLET	3.80	2.0	17.3	47.512	7.146
50.0	TRIPLET	3.95	1.7	12.3	46.542	5.563
60.0	TODAY	3.15	4.5	32.6	127.248	12.521
60.0	BASE	3.20	2.7	17.0	74.138	8.078
60.0	DOUBLET	3.65	1.7	14.3	42.389	5.482
60.0	TRIPLET	3.80	1.4	10.2	42.338	4.148
70.0	TODAY	3.07	3.8	27.5	111.665	10.260
70.0	BASE	3.07	2.3	14.6	65.952	6.633
70.0	DOUBLET	3.47	1.5	12.4	39.391	4.450
70.0	TRIPLET	3.57	1.3	9.0	39.420	3.374
80.0	TODAY	2.96	3.4	24.1	101.035	8.781
80.0	BASE	2.91	2.1	13.2	60.274	5.717
80.0	DOUBLET	3.26	1.3	11.3	37.334	3.830
80.0	TRIPLET	3.36	1.2	8.2	37.907	2.851
90.0	TODAY	2.82	3.1	22.1	93.046	7.856
90.0	BASE	2.77	1.9	12.1	56.586	5.054
90.0	DOUBLET	2.92	1.3	11.2	33.957	3.741
90.0	TRIPLET	3.02	1.1	8.1	35.237	2.796
100.0	TODAY	2.45	2.9	23.1	80.552	8.073
100.0	BASE	2.40	1.8	12.7	49.134	5.206
100.0	DOUBLET	2.75	1.2	10.6	33.211	3.409
100.0	TRIPLET	2.80	1.1	7.7	34.138	2.618

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HDR CASE REPORT
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GRADIENT (DEG C PER KM) = 30.0 USING TODAY'S TECHNOLOGY
NON-CASCADING SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 10.6

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	40.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.30
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	70.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	3.50
INITIAL RESERVOIR TEMPERATURE (DEG C)	120.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	105.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.284
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	33.
CYCLE EFFICIENCY (%)	5.3
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1778.
INJECTOR WELL PRESSURE DROP (psia)	125.
RESERVOIR PRESSURE DROP (psia)	1740.
PRODUCER WELL PRESSURE DROP (psia)	130.
BUOYANCY CORRECTION (psia)	217.
PUMPING POWER (kWe/(MMBTU/HR))	23.7

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	253508.
STIMULATION COSTS	34834.
SURFACE FLUID DISTRIBUTION COSTS	4458.
EXPLORATION COSTS	2410.
TOTAL CAPITAL COSTS	295210.
CAPITAL COST YEARLY CHARGE RATE	49361.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	12695.
PUMPING COSTS	9933.
WATER COSTS	916.
REDRILLING/RESTIMULATION COSTS	7209.
TOTAL OPERATING AND MAINTENANCE COSTS	30752.

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HDR CASE REPORT
****

GRADIENT (DEG C PER KM) = 30.0 USING COMMERCIALLY MATURE TECHNOLOGY
NON-CASCADING SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 6.3

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.10
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	70.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	3.60
INITIAL RESERVOIR TEMPERATURE (DEG C)	123.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	108.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.296
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	32.
CYCLE EFFICIENCY (%)	5.5
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1703.
INJECTOR WELL PRESSURE DROP (psia)	414.
RESERVOIR PRESSURE DROP (psia)	1088.
PRODUCER WELL PRESSURE DROP (psia)	430.
BUOYANCY CORRECTION (psia)	228.
PUMPING POWER (kWe/(MMBTU/HR))	21.8

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	138496.
STIMULATION COSTS	16927.
SURFACE FLUID DISTRIBUTION COSTS	4606.
EXPLORATION COSTS	2597.
TOTAL CAPITAL COSTS	162627.
CAPITAL COST YEARLY CHARGE RATE	27192.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	6496.
PUMPING COSTS	9127.
WATER COSTS	879.
REDRILLING/RESTIMULATION COSTS	3886.
TOTAL OPERATING AND MAINTENANCE COSTS	20388.

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HDR CASE REPORT
****

GRADIENT (DEG C PER KM) = 30.0 USING TECNICALLY OPTIMIZED DOUBLETS
NON-CASCADING SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 3.7

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.08
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	70.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	4.00
INITIAL RESERVOIR TEMPERATURE (DEG C)	135.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	120.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.345
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	27.
CYCLE EFFICIENCY (%)	6.2
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1526.
INJECTOR WELL PRESSURE DROP (psia)	460.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	480.
BUOYANCY CORRECTION (psia)	283.
PUMPING POWER (kWe/(MMBTU/HR))	16.8

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	62512.
STIMULATION COSTS	7683.
SURFACE FLUID DISTRIBUTION COSTS	5211.
EXPLORATION COSTS	2030.
TOTAL CAPITAL COSTS	77436.
CAPITAL COST YEARLY CHARGE RATE	12948.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	5581.
PUMPING COSTS	7028.
WATER COSTS	755.
REDRILLING/RESTIMULATION COSTS	1755.
TOTAL OPERATING AND MAINTENANCE COSTS	15120.

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HDR CASE REPORT
****

GRADIENT (DEG C PER KM) = 30.0 USING TECNICALLY OPTIMIZED TRIPLETS
NON-CASCADING SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 3.1

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	2.5
CAPACITY FACTOR (%)	90.0
REDRILLED WELLS / INITIAL WELLS	0.17
NO. INJECTORS / NO. PRODUCERS	0.5
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00007
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.08
INJECTOR WELL CASING ID (INCHES)	8.681
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	70.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	4.20
INITIAL RESERVOIR TEMPERATURE (DEG C)	141.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	126.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.370
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	51.
CYCLE EFFICIENCY (%)	6.6
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1650.
INJECTOR WELL PRESSURE DROP (psia)	592.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	505.
BUOYANCY CORRECTION (psia)	317.
PUMPING POWER (kWe/(MMBTU/HR))	16.5

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	52945.
STIMULATION COSTS	12960.
SURFACE FLUID DISTRIBUTION COSTS	5521.
EXPLORATION COSTS	2374.
TOTAL CAPITAL COSTS	73800.
CAPITAL COST YEARLY CHARGE RATE	12340.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	3907.
PUMPING COSTS	7246.
WATER COSTS	369.
REDRILLING/RESTIMULATION COSTS	560.
TOTAL OPERATING AND MAINTENANCE COSTS	12082.

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HDR CASE REPORT
****

GRADIENT (DEG C PER KM) = 50.0 USING TODAY'S TECHNOLOGY
NON-CASCADING SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 5.5

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	40.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.30
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	70.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	3.25
INITIAL RESERVOIR TEMPERATURE (DEG C)	177.5
GEOTHERMAL FLUID TEMPERATURE (DEG C)	162.5
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.525
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	18.
CYCLE EFFICIENCY (%)	9.0
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1601.
INJECTOR WELL PRESSURE DROP (psia)	116.
RESERVOIR PRESSURE DROP (psia)	1740.
PRODUCER WELL PRESSURE DROP (psia)	125.
BUOYANCY CORRECTION (psia)	380.
PUMPING POWER (kWe/(MMBTU/HR))	11.6

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	116692.
STIMULATION COSTS	25571.
SURFACE FLUID DISTRIBUTION COSTS	7505.
EXPLORATION COSTS	3667.
TOTAL CAPITAL COSTS	153436.
CAPITAL COST YEARLY CHARGE RATE	25655.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	6882.
PUMPING COSTS	4849.
WATER COSTS	496.
REDRILLING/RESTIMULATION COSTS	3557.
TOTAL OPERATING AND MAINTENANCE COSTS	15783.

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HDR CASE REPORT
****

GRADIENT (DEG C PER KM) = 50.0 USING COMMERCIALLY MATURE TECHNOLOGY
NON-CASCADING SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 3.3

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.10
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	70.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	3.30
INITIAL RESERVOIR TEMPERATURE (DEG C)	180.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	165.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.535
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	18.
CYCLE EFFICIENCY (%)	9.1
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1477.
INJECTOR WELL PRESSURE DROP (psia)	379.
RESERVOIR PRESSURE DROP (psia)	1088.
PRODUCER WELL PRESSURE DROP (psia)	408.
BUOYANCY CORRECTION (psia)	398.
PUMPING POWER (kWe/(MMBTU/HR))	10.5

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	62992.
STIMULATION COSTS	12718.
SURFACE FLUID DISTRIBUTION COSTS	7647.
EXPLORATION COSTS	3811.
TOTAL CAPITAL COSTS	87168.
CAPITAL COST YEARLY CHARGE RATE	14575.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	3595.
PUMPING COSTS	4382.
WATER COSTS	486.
REDRILLING/RESTIMULATION COSTS	1893.
TOTAL OPERATING AND MAINTENANCE COSTS	10357.

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HDR CASE REPORT
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GRADIENT (DEG C PER KM) = 50.0 USING TECNICALLY OPTIMIZED DOUBLETS
NON-CASCADING SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 2.0

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.08
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	70.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	3.80
INITIAL RESERVOIR TEMPERATURE (DEG C)	205.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	190.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.647
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	15.
CYCLE EFFICIENCY (%)	10.9
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1178.
INJECTOR WELL PRESSURE DROP (psia)	437.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	483.
BUOYANCY CORRECTION (psia)	612.
PUMPING POWER (kWe/(MMBTU/HR))	6.9

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	28921.
STIMULATION COSTS	6175.
SURFACE FLUID DISTRIBUTION COSTS	9103.
EXPLORATION COSTS	3314.
TOTAL CAPITAL COSTS	47512.
CAPITAL COST YEARLY CHARGE RATE	7944.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	2975.
PUMPING COSTS	2891.
WATER COSTS	402.
REDRILLING/RESTIMULATION COSTS	877.
TOTAL OPERATING AND MAINTENANCE COSTS	7146.

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HDR CASE REPORT
****

GRADIENT (DEG C PER KM) = 50.0 USING TECNICALLY OPTIMIZED TRIPLETS
NON-CASCADING SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 1.7

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	2.5
CAPACITY FACTOR (%)	90.0
REDRILLED WELLS / INITIAL WELLS	0.17
NO. INJECTORS / NO. PRODUCERS	0.5
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00007
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.08
INJECTOR WELL CASING ID (INCHES)	8.681
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	70.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	3.95
INITIAL RESERVOIR TEMPERATURE (DEG C)	212.5
GEOTHERMAL FLUID TEMPERATURE (DEG C)	197.5
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.681
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	28.
CYCLE EFFICIENCY (%)	11.4
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1243.
INJECTOR WELL PRESSURE DROP (psia)	557.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	507.
BUOYANCY CORRECTION (psia)	690.
PUMPING POWER (kWe/(MMBTU/HR))	6.8

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	24057.
STIMULATION COSTS	9186.
SURFACE FLUID DISTRIBUTION COSTS	9553.
EXPLORATION COSTS	3746.
TOTAL CAPITAL COSTS	46542.
CAPITAL COST YEARLY CHARGE RATE	7782.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	2119.
PUMPING COSTS	2961.
WATER COSTS	200.
REDRILLING/RESTIMULATION COSTS	283.
TOTAL OPERATING AND MAINTENANCE COSTS	5563.

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HDR CASE REPORT
****

GRADIENT (DEG C PER KM) = 80.0 USING TODAY'S TECHNOLOGY
NON-CASCADING SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 3.4

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	40.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.30
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	70.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	2.96
INITIAL RESERVOIR TEMPERATURE (DEG C)	252.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	237.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.868
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	11.
CYCLE EFFICIENCY (%)	14.3
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1216.
INJECTOR WELL PRESSURE DROP (psia)	106.
RESERVOIR PRESSURE DROP (psia)	1740.
PRODUCER WELL PRESSURE DROP (psia)	126.
BUOYANCY CORRECTION (psia)	755.
PUMPING POWER (kWe/(MMBTU/HR))	5.3

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	58454.
STIMULATION COSTS	25291.
SURFACE FLUID DISTRIBUTION COSTS	12018.
EXPLORATION COSTS	5271.
TOTAL CAPITAL COSTS	101035.
CAPITAL COST YEARLY CHARGE RATE	16894.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	4160.
PUMPING COSTS	2227.
WATER COSTS	300.
REDRILLING/RESTIMULATION COSTS	2094.
TOTAL OPERATING AND MAINTENANCE COSTS	8781.

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*HDR CASE REPORT*
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GRADIENT (DEG C PER KM) = 80.0 USING COMMERCIALLY MATURE TECHNOLOGY
NON-CASCADING SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 2.1

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.10
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	70.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	2.91
INITIAL RESERVOIR TEMPERATURE (DEG C)	248.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	233.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.848
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	11.
CYCLE EFFICIENCY (%)	14.0
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1097.
INJECTOR WELL PRESSURE DROP (psia)	335.
RESERVOIR PRESSURE DROP (psia)	1088.
PRODUCER WELL PRESSURE DROP (psia)	393.
BUOYANCY CORRECTION (psia)	718.
PUMPING POWER (kWe/(MMBTU/HR))	4.9

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	30860.
STIMULATION COSTS	12585.
SURFACE FLUID DISTRIBUTION COSTS	11761.
EXPLORATION COSTS	5067.
TOTAL CAPITAL COSTS	60274.
CAPITAL COST YEARLY CHARGE RATE	10078.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	2269.
PUMPING COSTS	2055.
WATER COSTS	307.
REDRILLING/RESTIMULATION COSTS	1086.
TOTAL OPERATING AND MAINTENANCE COSTS	5717.

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HDR CASE REPORT
****

GRADIENT (DEG C PER KM) = 80.0 USING TECNICALLY OPTIMIZED DOUBLETS
NON-CASCADING SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 1.3

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.08
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	70.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	3.26
INITIAL RESERVOIR TEMPERATURE (DEG C)	276.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	261.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.986
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	10.
CYCLE EFFICIENCY (%)	16.2
OVERALL GEO FLUID PRESSURE DROP (PSIA)	699.
INJECTOR WELL PRESSURE DROP (psia)	375.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	461.
BUOYANCY CORRECTION (psia)	1007.
PUMPING POWER (kWe/(MMBTU/HR))	2.7

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	12966.
STIMULATION COSTS	6554.
SURFACE FLUID DISTRIBUTION COSTS	13588.
EXPLORATION COSTS	4226.
TOTAL CAPITAL COSTS	37334.
CAPITAL COST YEARLY CHARGE RATE	6243.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	1953.
PUMPING COSTS	1125.
WATER COSTS	264.
REDRILLING/RESTIMULATION COSTS	488.
TOTAL OPERATING AND MAINTENANCE COSTS	3830.

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HDR CASE REPORT
****

GRADIENT (DEG C PER KM) = 80.0 USING TECNICALLY OPTIMIZED TRIPLETS
NON-CASCADING SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 1.2

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	2.5
CAPACITY FACTOR (%)	90.0
REDRILLED WELLS / INITIAL WELLS	0.17
NO. INJECTORS / NO. PRODUCERS	0.5
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00007
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.08
INJECTOR WELL CASING ID (INCHES)	8.681
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	70.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	3.36
INITIAL RESERVOIR TEMPERATURE (DEG C)	284.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	269.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	1.026
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	18.
CYCLE EFFICIENCY (%)	16.8
OVERALL GEO FLUID PRESSURE DROP (PSIA)	726.
INJECTOR WELL PRESSURE DROP (psia)	474.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	482.
BUOYANCY CORRECTION (psia)	1100.
PUMPING POWER (kWe/(MMBTU/HR))	2.6

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	10531.
STIMULATION COSTS	8655.
SURFACE FLUID DISTRIBUTION COSTS	14123.
EXPLORATION COSTS	4597.
TOTAL CAPITAL COSTS	37907.
CAPITAL COST YEARLY CHARGE RATE	6338.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	1407.
PUMPING COSTS	1148.
WATER COSTS	133.
REDRILLING/RESTIMULATION COSTS	163.
TOTAL OPERATING AND MAINTENANCE COSTS	2851.

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*   HDR SUMMARY REPORT   *
FULLY CASCADED SPACE HEAT
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GRADIENT DEG C/KM	TECHNOLOGY	DEPTH KM	PRICE $/MMBTU	FOR MMMBTU/HR NET OUTPUT # WELLS	CAP COST MM$	O&M COST MM$/YR
20.0	TODAY	3.40	13.6	100.1	367.565	41.095
20.0	BASE	3.50	8.1	51.3	199.784	27.265
20.0	DOUBLET	3.90	4.8	44.2	91.620	20.577
20.0	TRIPLET	4.10	4.0	31.0	87.043	16.686
30.0	TODAY	3.25	8.1	61.8	213.610	24.943
30.0	BASE	3.35	4.8	31.7	117.545	16.477
30.0	DOUBLET	3.80	2.9	27.0	56.581	12.274
30.0	TRIPLET	4.00	2.4	18.9	54.757	9.904
40.0	TODAY	3.17	5.7	44.1	152.289	17.531
40.0	BASE	3.22	3.4	23.0	84.391	11.634
40.0	DOUBLET	3.72	2.1	19.2	43.233	8.396
40.0	TRIPLET	3.92	1.7	13.5	42.592	6.655
50.0	TODAY	3.15	4.4	33.6	121.592	13.156
50.0	BASE	3.15	2.7	17.9	68.156	8.764
50.0	DOUBLET	3.65	1.6	14.9	37.112	6.136
50.0	TRIPLET	3.85	1.4	10.5	37.221	4.730
60.0	TODAY	3.05	3.7	27.9	102.167	10.621
60.0	BASE	3.10	2.2	14.6	59.390	6.853
60.0	DOUBLET	3.55	1.4	12.3	34.013	4.711
60.0	TRIPLET	3.70	1.2	8.7	34.178	3.596
70.0	TODAY	2.97	3.2	23.7	90.422	8.821
70.0	BASE	2.97	1.9	12.7	53.213	5.706
70.0	DOUBLET	3.37	1.2	10.8	31.795	3.878
70.0	TRIPLET	3.52	1.1	7.7	32.489	2.883
80.0	TODAY	2.86	2.8	21.0	82.244	7.627
80.0	BASE	2.81	1.7	11.5	48.831	4.973
80.0	DOUBLET	3.21	1.1	9.7	30.776	3.283
80.0	TRIPLET	3.26	1.0	7.1	30.843	2.540
90.0	TODAY	2.47	2.6	21.9	69.682	7.743
90.0	BASE	2.47	1.6	11.7	42.324	4.913
90.0	DOUBLET	2.87	1.0	9.6	27.918	3.219
90.0	TRIPLET	2.92	0.9	7.1	28.551	2.507
100.0	TODAY	2.35	2.4	20.4	65.078	7.100
100.0	BASE	2.35	1.5	10.9	40.243	4.457
100.0	DOUBLET	2.70	1.0	9.1	27.352	2.949
100.0	TRIPLET	2.75	0.9	6.7	28.208	2.276

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HDR CASE REPORT
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GRADIENT (DEG C PER KM) = 30.0 USING TODAY'S TECHNOLOGY
FULLY CASCADED SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 8.1

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	40.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.30
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	3.25
INITIAL RESERVOIR TEMPERATURE (DEG C)	112.5
GEOTHERMAL FLUID TEMPERATURE (DEG C)	97.5
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.296
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	28.
CYCLE EFFICIENCY (%)	4.2
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1769.
INJECTOR WELL PRESSURE DROP (psia)	116.
RESERVOIR PRESSURE DROP (psia)	1740.
PRODUCER WELL PRESSURE DROP (psia)	121.
BUOYANCY CORRECTION (psia)	207.
PUMPING POWER (kWe/(MMBTU/HR))	19.8

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	180669.
STIMULATION COSTS	28361.
SURFACE FLUID DISTRIBUTION COSTS	3077.
EXPLORATION COSTS	1503.
TOTAL CAPITAL COSTS	213610.
CAPITAL COST YEARLY CHARGE RATE	35717.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	10654.
PUMPING COSTS	8295.
WATER COSTS	769.
REDRILLING/RESTIMULATION COSTS	5226.
TOTAL OPERATING AND MAINTENANCE COSTS	24943.

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HDR CASE REPORT
****

GRADIENT (DEG C PER KM) = 30.0 USING COMMERCIALLY MATURE TECHNOLOGY
FULLY CASCADED SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 4.8

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.10
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	3.35
INITIAL RESERVOIR TEMPERATURE (DEG C)	115.5
GEOTHERMAL FLUID TEMPERATURE (DEG C)	100.5
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.308
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	27.
CYCLE EFFICIENCY (%)	4.4
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1654.
INJECTOR WELL PRESSURE DROP (psia)	384.
RESERVOIR PRESSURE DROP (psia)	1088.
PRODUCER WELL PRESSURE DROP (psia)	399.
BUOYANCY CORRECTION (psia)	217.
PUMPING POWER (kWe/(MMBTU/HR))	17.8

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	98913.
STIMULATION COSTS	13797.
SURFACE FLUID DISTRIBUTION COSTS	3205.
EXPLORATION COSTS	1630.
TOTAL CAPITAL COSTS	117545.
CAPITAL COST YEARLY CHARGE RATE	19654.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	5464.
PUMPING COSTS	7456.
WATER COSTS	739.
REDRILLING/RESTIMULATION COSTS	2818.
TOTAL OPERATING AND MAINTENANCE COSTS	16477.

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HDR CASE REPORT
****

GRADIENT (DEG C PER KM) = 30.0 USING TECNICALLY OPTIMIZED DOUBLETS
FULLY CASCADED SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 2.9

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.08
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	3.80
INITIAL RESERVOIR TEMPERATURE (DEG C)	129.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	114.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.362
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	23.
CYCLE EFFICIENCY (%)	5.2
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1489.
INJECTOR WELL PRESSURE DROP (psia)	436.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	455.
BUOYANCY CORRECTION (psia)	271.
PUMPING POWER (kWe/(MMBTU/HR))	13.6

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	45181.
STIMULATION COSTS	6221.
SURFACE FLUID DISTRIBUTION COSTS	3797.
EXPLORATION COSTS	1382.
TOTAL CAPITAL COSTS	56581.
CAPITAL COST YEARLY CHARGE RATE	9461.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	4649.
PUMPING COSTS	5711.
WATER COSTS	629.
REDRILLING/RESTIMULATION COSTS	1285.
TOTAL OPERATING AND MAINTENANCE COSTS	12274.

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HDR CASE REPORT
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GRADIENT (DEG C PER KM) = 30.0 USING TECNICALLY OPTIMIZED TRIPLETS
FULLY CASCADED SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 2.4

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	2.5
CAPACITY FACTOR (%)	90.0
REDRILLED WELLS / INITIAL WELLS	0.17
NO. INJECTORS / NO. PRODUCERS	0.5
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00007
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.08
INJECTOR WELL CASING ID (INCHES)	8.681
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	4.00
INITIAL RESERVOIR TEMPERATURE (DEG C)	135.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	120.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.387
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	42.
CYCLE EFFICIENCY (%)	5.5
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1611.
INJECTOR WELL PRESSURE DROP (psia)	562.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	480.
BUOYANCY CORRECTION (psia)	301.
PUMPING POWER (kWe/(MMBTU/HR))	13.5

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	38413.
STIMULATION COSTS	10655.
SURFACE FLUID DISTRIBUTION COSTS	4066.
EXPLORATION COSTS	1623.
TOTAL CAPITAL COSTS	54757.
CAPITAL COST YEARLY CHARGE RATE	9156.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	3266.
PUMPING COSTS	5912.
WATER COSTS	308.
REDRILLING/RESTIMULATION COSTS	417.
TOTAL OPERATING AND MAINTENANCE COSTS	9904.

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HDR CASE REPORT
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GRADIENT (DEG C PER KM) = 50.0 USING TODAY'S TECHNOLOGY
FULLY CASCADED SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 4.4

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	40.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.30
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	3.15
INITIAL RESERVOIR TEMPERATURE (DEG C)	172.5
GEOTHERMAL FLUID TEMPERATURE (DEG C)	157.5
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.545
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	15.
CYCLE EFFICIENCY (%)	8.0
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1612.
INJECTOR WELL PRESSURE DROP (psia)	112.
RESERVOIR PRESSURE DROP (psia)	1740.
PRODUCER WELL PRESSURE DROP (psia)	121.
BUOYANCY CORRECTION (psia)	361.
PUMPING POWER (kWe/(MMBTU/HR))	9.8

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	92109.
STIMULATION COSTS	20905.
SURFACE FLUID DISTRIBUTION COSTS	5835.
EXPLORATION COSTS	2743.
TOTAL CAPITAL COSTS	121592.
CAPITAL COST YEARLY CHARGE RATE	20331.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	5799.
PUMPING COSTS	4113.
WATER COSTS	418.
REDRILLING/RESTIMULATION COSTS	2825.
TOTAL OPERATING AND MAINTENANCE COSTS	13156.

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HDR CASE REPORT
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GRADIENT (DEG C PER KM) = 50.0 USING COMMERCIALLY MATURE TECHNOLOGY
FULLY CASCADED SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 2.7

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.10
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	3.15
INITIAL RESERVOIR TEMPERATURE (DEG C)	172.5
GEOTHERMAL FLUID TEMPERATURE (DEG C)	157.5
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.545
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	15.
CYCLE EFFICIENCY (%)	8.0
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1475.
INJECTOR WELL PRESSURE DROP (psia)	361.
RESERVOIR PRESSURE DROP (psia)	1088.
PRODUCER WELL PRESSURE DROP (psia)	387.
BUOYANCY CORRECTION (psia)	361.
PUMPING POWER (kWe/(MMBTU/HR))	9.0

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	49125.
STIMULATION COSTS	10452.
SURFACE FLUID DISTRIBUTION COSTS	5835.
EXPLORATION COSTS	2743.
TOTAL CAPITAL COSTS	68156.
CAPITAL COST YEARLY CHARGE RATE	11396.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	3093.
PUMPING COSTS	3763.
WATER COSTS	418.
REDRILLING/RESTIMULATION COSTS	1489.
TOTAL OPERATING AND MAINTENANCE COSTS	8764.

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HDR CASE REPORT
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GRADIENT (DEG C PER KM) = 50.0 USING TECNICALLY OPTIMIZED DOUBLETS
FULLY CASCADED SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 1.6

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.08
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	3.65
INITIAL RESERVOIR TEMPERATURE (DEG C)	197.5
GEOTHERMAL FLUID TEMPERATURE (DEG C)	182.5
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.655
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	13.
CYCLE EFFICIENCY (%)	9.7
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1191.
INJECTOR WELL PRESSURE DROP (psia)	418.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	460.
BUOYANCY CORRECTION (psia)	557.
PUMPING POWER (kWe/(MMBTU/HR))	6.0

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	22476.
STIMULATION COSTS	5082.
SURFACE FLUID DISTRIBUTION COSTS	7093.
EXPLORATION COSTS	2462.
TOTAL CAPITAL COSTS	37112.
CAPITAL COST YEARLY CHARGE RATE	6205.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	2572.
PUMPING COSTS	2527.
WATER COSTS	348.
REDRILLING/RESTIMULATION COSTS	689.
TOTAL OPERATING AND MAINTENANCE COSTS	6136.

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HDR CASE REPORT
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GRADIENT (DEG C PER KM) = 50.0 USING TECNICALLY OPTIMIZED TRIPLETS
FULLY CASCADED SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 1.4

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	2.5
CAPACITY FACTOR (%)	90.0
REDRILLED WELLS / INITIAL WELLS	0.17
NO. INJECTORS / NO. PRODUCERS	0.5
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00007
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.08
INJECTOR WELL CASING ID (INCHES)	8.681
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	3.85
INITIAL RESERVOIR TEMPERATURE (DEG C)	207.5
GEOTHERMAL FLUID TEMPERATURE (DEG C)	192.5
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.700
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	23.
CYCLE EFFICIENCY (%)	10.4
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1247.
INJECTOR WELL PRESSURE DROP (psia)	541.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	491.
BUOYANCY CORRECTION (psia)	655.
PUMPING POWER (kWe/(MMBTU/HR))	5.8

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	19078.
STIMULATION COSTS	7649.
SURFACE FLUID DISTRIBUTION COSTS	7612.
EXPLORATION COSTS	2883.
TOTAL CAPITAL COSTS	37221.
CAPITAL COST YEARLY CHARGE RATE	6224.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	1804.
PUMPING COSTS	2528.
WATER COSTS	170.
REDRILLING/RESTIMULATION COSTS	227.
TOTAL OPERATING AND MAINTENANCE COSTS	4730.

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HDR CASE REPORT
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GRADIENT (DEG C PER KM) = 80.0 USING TODAY'S TECHNOLOGY
FULLY CASCADED SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 2.8

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	40.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.30
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	2.86
INITIAL RESERVOIR TEMPERATURE (DEG C)	244.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	229.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.871
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	9.
CYCLE EFFICIENCY (%)	13.1
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1269.
INJECTOR WELL PRESSURE DROP (psia)	102.
RESERVOIR PRESSURE DROP (psia)	1740.
PRODUCER WELL PRESSURE DROP (psia)	120.
BUOYANCY CORRECTION (psia)	694.
PUMPING POWER (kWe/(MMBTU/HR))	4.8

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	47729.
STIMULATION COSTS	20874.
SURFACE FLUID DISTRIBUTION COSTS	9584.
EXPLORATION COSTS	4057.
TOTAL CAPITAL COSTS	82244.
CAPITAL COST YEARLY CHARGE RATE	13752.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	3626.
PUMPING COSTS	2024.
WATER COSTS	262.
REDRILLING/RESTIMULATION COSTS	1715.
TOTAL OPERATING AND MAINTENANCE COSTS	7627.

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HDR CASE REPORT
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GRADIENT (DEG C PER KM) = 80.0 USING COMMERCIALLY MATURE TECHNOLOGY
FULLY CASCADED SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 1.7

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.10
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	2.81
INITIAL RESERVOIR TEMPERATURE (DEG C)	240.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	225.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	0.852
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	10.
CYCLE EFFICIENCY (%)	12.8
OVERALL GEO FLUID PRESSURE DROP (PSIA)	1127.
INJECTOR WELL PRESSURE DROP (psia)	322.
RESERVOIR PRESSURE DROP (psia)	1088.
PRODUCER WELL PRESSURE DROP (psia)	375.
BUOYANCY CORRECTION (psia)	658.
PUMPING POWER (kWe/(MMBTU/HR))	4.4

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	25190.
STIMULATION COSTS	10384.
SURFACE FLUID DISTRIBUTION COSTS	9363.
EXPLORATION COSTS	3895.
TOTAL CAPITAL COSTS	48831.
CAPITAL COST YEARLY CHARGE RATE	8165.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	1978.
PUMPING COSTS	1838.
WATER COSTS	267.
REDRILLING/RESTIMULATION COSTS	889.
TOTAL OPERATING AND MAINTENANCE COSTS	4973.

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HDR CASE REPORT
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GRADIENT (DEG C PER KM) = 80.0 USING TECNICALLY OPTIMIZED DOUBLETS
FULLY CASCADED SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 1.1

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	5.0
CAPACITY FACTOR (%)	86.0
REDRILLED WELLS / INITIAL WELLS	0.50
NO. INJECTORS / NO. PRODUCERS	1.0
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00014
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.08
INJECTOR WELL CASING ID (INCHES)	7.000
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	3.21
INITIAL RESERVOIR TEMPERATURE (DEG C)	272.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	257.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	1.008
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	8.
CYCLE EFFICIENCY (%)	15.2
OVERALL GEO FLUID PRESSURE DROP (PSIA)	712.
INJECTOR WELL PRESSURE DROP (psia)	368.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	450.
BUOYANCY CORRECTION (psia)	977.
PUMPING POWER (kWe/(MMBTU/HR))	2.3

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	10712.
STIMULATION COSTS	5460.
SURFACE FLUID DISTRIBUTION COSTS	11173.
EXPLORATION COSTS	3430.
TOTAL CAPITAL COSTS	30776.
CAPITAL COST YEARLY CHARGE RATE	5146.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	1672.
PUMPING COSTS	981.
WATER COSTS	226.
REDRILLING/RESTIMULATION COSTS	404.
TOTAL OPERATING AND MAINTENANCE COSTS	3283.

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HDR CASE REPORT
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GRADIENT (DEG C PER KM) = 80.0 USING TECNICALLY OPTIMIZED TRIPLETS
FULLY CASCADED SPACE HEAT BREAKEVEN PRICE ($/MMBTU) = 1.0

ECONOMIC PARAMETERS

FIXED CHARGE RATE (%)	15.3
AFDC RATE (%)	9.0
PROJECT LIFE (YEARS)	20.0

ENGINEERING PARAMETERS

WATER LOSS RATE (%)	2.5
CAPACITY FACTOR (%)	90.0
REDRILLED WELLS / INITIAL WELLS	0.17
NO. INJECTORS / NO. PRODUCERS	0.5
PUMP EFFICIENCY (%)	80.0
DRAWDOWN PARAMETER (KG/SQM-S)	0.00007
TEMP RESERVOIR - TEMP GEOFLUID (DEG C)	15.0
MAXIMUM ALLOWABLE RESERVOIR TEMP (DEG C)	300.0
PRODUCTION WELL FLOWRATE (KG/S)	75.0
RESERVOIR IMPEDANCE (GPA-S/CUM)	0.08
INJECTOR WELL CASING ID (INCHES)	8.681
PRODUCER WELL CASING ID (INCHES)	7.000
THERMAL EFFICIENCY (%)	80.0

ENGINEERING RESULTS

AVERAGE WELL DEPTH (KM)	3.26
INITIAL RESERVOIR TEMPERATURE (DEG C)	276.0
GEOTHERMAL FLUID TEMPERATURE (DEG C)	261.0
GEOTHERMAL FLUID AVAIL ENTH (MWt-S/KG)	1.028
EFFECTIVE RESERVOIR AREA (K SQM/MMBTU/HR)	16.
CYCLE EFFICIENCY (%)	15.5
OVERALL GEO FLUID PRESSURE DROP (PSIA)	767.
INJECTOR WELL PRESSURE DROP (psia)	459.
RESERVOIR PRESSURE DROP (psia)	870.
PRODUCER WELL PRESSURE DROP (psia)	461.
BUOYANCY CORRECTION (psia)	1022.
PUMPING POWER (kWe/(MMBTU/HR))	2.4

CAPITAL COSTS ($/MMBTU/HR)

DRILLING AND COMPLETION COSTS	8570.
STIMULATION COSTS	7255.
SURFACE FLUID DISTRIBUTION COSTS	11406.
EXPLORATION COSTS	3612.
TOTAL CAPITAL COSTS	30843.
CAPITAL COST YEARLY CHARGE RATE	5157.

OPERATING AND MAINTENANCE COSTS ($/MMBTU/HR/YR)

WELLFIELD MAINTENANCE COSTS	1229.
PUMPING COSTS	1060.
WATER COSTS	116.
REDRILLING/RESTIMULATION COSTS	135.
TOTAL OPERATING AND MAINTENANCE COSTS	2540.

B. Distribution of Geothermal Gradients by Region

B.1 Distribution of Geothermal Gradients by State

The raw data for calculating Table 12.1 was obtained from Entingh and Gilshannon (1990) and is contained in Table B.1. The area represents land area only (i.e. excludes areas of lakes and rivers) and was obtained from the *Information Please Almanac* (1989). The percentage for each class was obtained from Kron and Stix (1982) for the continental U.S. Alaska was assumed to be similar to California on the grounds that commercially-inaccessible regions of Alaska are similar to the large and low-gradient Sierra Nevada region of California. Estimates for Hawaii were taken from Idaho data, since both states include the effects of passage over a major crustal *hot spot* over long periods of time.

TABLE B.1. HDR TEMPERATURE GRADIENTS BY STATE

STATE	REGION	AREA sq miles	CLASS 1 %	CLASS 2 %	CLASS 3 %	CLASS 4 %	CLASS 5 %
Alabama	4	50,767	60.0	40.0	0.0	0.0	0.0
Alaska	10	570,833	19.0	45.0	26.0	6.0	4.0
Arizona	9	111,508	25.0	36.0	35.7	3.0	0.3
Arkansas	6	52,078	43.0	30.0	25.0	2.0	0.0
California	9	151,299	19.0	45.0	26.0	6.0	4.0
Colorado	8	103,595	1.0	27.0	66.0	5.5	0.5
Connecticut	1	4,872	100.0	0.0	0.0	0.0	0.0
Delaware	3	1,932	0.0	10.0	55.0	35.0	0.0
Dist. of Col.	3	63	100.0	0.0	0.0	0.0	0.0
Florida	4	54,153	65.0	35.0	0.0	0.0	0.0
Georgia	4	58,056	68.0	25.0	7.0	0.0	0.0
Hawaii	9	6,645	1.0	11.0	54.0	28.0	6.0
Idaho	10	82,412	1.0	11.0	54.0	28.0	6.0
Illinois	5	55,645	73.0	20.0	7.0	0.0	0.0
Indiana	5	35,932	91.0	8.0	1.0	0.0	0.0
Iowa	7	55,965	95.0	3.0	2.0	0.0	0.0
Kansas	7	81,778	3.0	20.0	77.0	0.0	0.0
Kentucky	4	39,669	85.0	15.0	0.0	0.0	0.0
Loisiana	6	44,521	0.0	40.0	58.0	2.0	0.0
Maine	1	30,995	96.0	4.0	0.0	0.0	0.0
Maryland	3	9,837	45.0	15.0	40.0	0.0	0.0
Massachusetts	1	7,824	99.5	0.5	0.0	0.0	0.0
Michigan	5	56,954	99.0	1.0	0.0	0.0	0.0
Minnesota	5	79,548	90.0	5.0	5.0	0.0	0.0
Mississippi	4	47,233	53.0	35.0	12.0	0.0	0.0
Missouri	7	68,945	90.0	10.0	0.0	0.0	0.0
Montana	8	145,388	5.0	55.0	38.0	2.0	0.0
Nebraska	7	76,644	8.0	25.0	30.0	35.0	2.0
Nevada	9	109,894	3.0	24.0	44.0	12.0	17.0
New Hampshire	1	8,993	60.0	40.0	0.0	0.0	0.0
New Jersey	2	7,468	35.0	15.0	45.0	5.0	0.0
New Mexico	6	121,335	12.5	33.0	50.0	4.0	0.5
New York	2	47,337	50.0	25.0	25.0	0.0	0.0
North Carolina	4	48,843	65.0	30.0	5.0	0.0	0.0
North Dakota	8	60,300	7.0	7.0	81.0	5.0	0.0
Ohio	5	41,004	65.0	35.0	0.0	0.0	0.0
Oklahoma	6	68,655	32.0	30.0	35.0	3.0	0.0
Oregon	10	96,184	3.0	21.0	38.0	27.0	11.0
Pennsylvania	3	44,888	50.0	43.0	7.0	0.0	0.0
Rhode Island	1	1,055	100.0	0.0	0.0	0.0	0.0

TABLE B.1. HDR TEMPERATURE GRADIENTS BY STATE
Continued

STATE	REGION	AREA sq miles	CLASS 1 %	CLASS 2 %	CLASS 3 %	CLASS 4 %	CLASS 5 %
South Carolina	4	30,203	45.0	50.0	5.0	0.0	0.0
South Dakota	8	75,952	1.0	7.0	78.0	12.0	2.0
Tennessee	4	41,155	89.5	10.0	0.5	0.0	0.0
Texas	6	262,017	36.5	18.0	45.0	0.5	0.0
Utah	8	82,073	18.0	16.2	43.0	22.0	0.8
Vermont	1	9,273	93.0	7.0	0.0	0.0	0.0
Virginia	3	39,704	85.0	10.0	5.0	0.0	0.0
Washington	10	66,511	5.4	67.0	22.4	5.0	0.2
West Virginia	3	24,119	13.0	87.0	0.0	0.0	0.0
Wisconsin	5	54,426	99.0	1.0	0.0	0.0	0.0
Wyoming	8	96,989	10.0	26.5	60.0	3.0	0.5

B.2 Potential HDR Electricity Production by Class

The electric power (P) that could be generated continuously by HDR per unit area (A) is a function of the reservoir height or thickness (h), average density (ρ), average heat capacity (C_p), and drawdown ($\Delta T/\Delta t$).

$$P/A = h\, \rho\, C_p\, (\Delta T/\Delta t) \qquad \text{(B1)}$$

Using values of ρ = 2700 kg/m^3 and C_p = 839 J/kg•K and a drawdown of 70°C over 20 years, yields

$$P/A = 251\, h \quad \text{MWt/km}^2 \qquad \text{(B2)}$$

A cycle efficiency (η_c) converts from MWt to MWe, as follows

$$P/A = 251\, h\, \eta_c \quad \text{MWe/km}^2 \qquad \text{(B3)}$$

The results of these calculations are shown in Table B.2 for the 5 HDR temperature gradient classes. The cycle efficiencies are a function of fluid production temperature and were determined from Armstead and Tester (1987) Figure 14.2 using a fluid production temperature averaged over the 20 year period and a condenser temperature of 37.5°C. The assumed reservoir thickness is also shown in Table B.2, with a larger thickness associated with the higher gradients because of improved accessibility at higher gradients.

TABLE B.2. POTENTIAL HDR ELECTRICITY PRODUCTION BY CLASS

CLASS	INITIAL RESER. TEMPERATURE (1) deg C	AVE FLUID TEMPERATURE (2) deg C	CYCLE EFF. (3)	THICK-NESS km	POTENTIAL PRODUCTION (4) MWe per sq km
1	180	130	0.09	0.5	11.3
2	225	175	0.12	0.5	15.1
3	300	250	0.17	0.5	21.4
4	300	250	0.17	1	42.7
5	300	250	0.17	1.5	64.1

(1) - Based on Section 9 results.
(2) - Initial reservoir temperature - 15 deg C - 70/2 deg C.
15 deg C is temperature approach; 70 deg C is the 20 year drawdown .
(3) - From Armstead and Tester (1987), Figure 14.2.
(4) - Based on 20 years of continuous production.

B.3 HDR Electricity Cost by Class and Technology Level

To assign the cost of electricity to an HDR temperature gradient class, a temperature gradient from Section 9 was chosen to represent each class. The results are shown in Table B.3.

TABLE B.3. ELECTRICITY COST BY CLASS

CLASS	GRADIENT deg C/km	ELECTRICITY COST, cents/kWh			
		TODAY	MATURE	DOUBLET	TRIPLET
1	20	129.8	85.3	60.9	46.6
2	30	37.5	23.5	15.5	12.3
3	40	18.4	11.9	8.1	6.7
4	60	9.4	6.6	4.6	4.1
5	80	7.1	5.3	3.9	3.6