Article from:

Proceedings of the Fifth Annual Geothermal Conference and Workshop, June 23-25, 1981, San Diego, California. Palo Alto, California: Electric Power Research Institute, 1981.

2486

WHAT NEXT IN GEOTHERMAL POWER DEVELOPMENT?

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INTRODUCTION Forecasting the future of geothermal power development is a speculative but necessary activity for both government and the private sector. A forecast may be based upon a simple extrapolation of historical data (time-series analysis) or it may be based upon a sensitivity analysis of postulated cause-and-effect mechanisms subject to external control (regression analysis). This paper will attempt to examine the importance of some of these discretionary variables on the future of geothermal development.

Before making any projections, an historical perspective is in order. Figure 1 shows that previous forecasts for electric power development by the year 2000 have declined. This trend primarily reflects more realism in the assessment of developing an alternative energy source by the electric utility industry in a period of reduced demand growth rather than a decrease in the resource potential itself. The total electric power resource potential above 150 C estimated in 1976 was 153,000 MWe as opposed to the most recent estimate of 95,000 - 150,000 MWe. The projected level of development by the year 2000 is thus clearly not constrained by resource potential.

THE PERCEPTION OF RISK If development is not presently resource-constrained, then what factors are impeding development? The comments which follow primarily concern liquid-dominated resources. The Geysers dry-steam field is following an orderly and predictable course of development which is essentially independent from that of liquid-dominated resources. This is because The Geysers resource has been calibrated to the extent that acceptable bounds on risk exist. The technology problems and their solutions are known, power plant reliability is understood, institutional problems are in clear perspective, and the economics are favorable. Once this stage of development is realized in the liquid hydrothermal industry, the full potential of the resource will be developed.

Risk, whether technical or otherwise, always translates into an economic factor. If the risk adjusted rate of return for geothermal power is not competitive with alternate opportunities for investment, then development will flounder.

In order to assess risks and to what extent and how they must be quantified, an examination of the development process is required. The process comprises the major phases of geophysical survey, land acquisition, exploratory drilling and reservoir characterization, production well drilling, and plant construction. The typical timing of these development activities is shown in Figure 2. Table 1 shows the status of geothermal leasing on public lands through 1980. The highest bid in 1980 was submitted by Chevron USA for 10.26 acres in the Heber KGRA at $4,403 an acre, or $45,776 for the parcel. The largest leased parcel was in Oregon's Alvord KGRA, for which Getty Oil bid $20.99 per acre for 14,461 acres. Apparently, the perceived risks are not presently a deterrent to the first two phases of geothermal development.

Once lease rights are acquired, exploration and field development may occur. Table 2 gives the number of deep geothermal wells drilled by location during the period 1978-80 and the total footage drilled during the period between 1973 and 1980. Approximately 3 million feet of hole have been drilled, half of which is on liquid hydrothermal resource prospects. At today's well costs of $130/ft., this represents an investment approaching $400 million. Again, one could conclude that the perceived risk at this stage of development is not the primary present deterrent.

The next phase of development beyond exploration and discovery involves fluid production, utilization for electric power production, and disposal. To date, four power plants have been constructed on liquid-dominated resources and two have actually been operated. The federally funded Raft River 5 MWe binary plant and the federally cost-shared 3 MWe flash-steam plant in Hawaii are essentially complete but have not been operated. Magma's 11 MWe East Mesa binary plant and SCE's 10 MWe Brawley flash-steam plant have both shown the operating potential of these resources. The 21 MWe installed capacity at East Mesa and Brawley is 1/3 of one percent of the estimated 6,000 MWe potential of Imperial Valley alone.

Figure 3 shows competitive KGRA land leasing activity on federal lands since 1974 and Figure 4 shows the trend of geothermal well completions as compared to utility commitments to power plants at liquid-dominated sites. Three important observations can be made from this information:

- Utility commitments are lagging about 12 years behind the pace of leasing.
- The pace of leasing has tapered off due to the lack of interest on the part of utilities.
- Although there is presently a significant gap between power plant commitments and the available potential of completed wells, the situation should improve over the next few years to where the wells are more fully utilized.

Clearly, the rate of power plant development and operation does not reflect the same level of activity as exists elsewhere in the geothermal development process. What are the constraining factors and how may they be altered? Although electric power demand growth is down considerably nationwide, geothermal resources are predominantly co-located with areas of continuing demand growth and development is not constrained by lack of demand.

Pure economic factors, i.e., those not associated with technological considerations, are contributing to the constraints. Utilities have encountered increasing difficulties in long-term debt financing and are being constantly squeezed by increasing costs on one hand and regulatory pressure to minimize rate increases on the other. This financial climate accentuates the inherent conservatism of the utility industry, placing a premium on minimizing risk. Figure 5 outlines the spectrum of risks which the power industry must assess in evaluating geothermal power development. Obviously, the best means of quantifying these elements of risk is through experience. Since domestic liquid-dominated development experience is lacking, one must resort to a review of international experience as well as domestic dry-steam development history.

GEOTHERMAL EXPERIENCE AND ECONOMIC VIABILITY

Approximately 2,000 MWe of geothermal electric capacity is presently operational world wide, of which 75% utilizes dry-steam resources. International experience has been highly favorable, from both technical and economic viewpoints. Plant capacity factors have typically exceeded 80% and power costs have consistently been among the lowest of the generating mix of the systems involved. There have been only two instances of documented failure to produce rated capacity once commitment to hardware was made. The Onikobe plant in Japan produces only half of its rated 25 MWe capacity and approximately 8 MWe is being produced by a 30 MWe unit in Krafla, Iceland, with an additional 30 MWe turbine generator purchased but uninstalled. In both cases, limited fluid production has been responsible for failure to meet rated output.

The state of the art in geothermal reservoir engineering is admittedly in its infancy. However, multi-well flow testing for periods of several months or more (depending upon permeability and reservoir volume) provides a reliable basis for at least a conservative estimate of reservoir capacity and longevity. As production increases in terms of flow volume and duration, reliability increases and risk declines. Reservoir recharge is hypothesized to occur in many instances. The Wairakei geothermal field in New Zealand, which has been in full production longer than any other liquid-dominated field, has an estimated recharge of over 80% based on gravity surveys (Hunt, T.M., N.Z.J. Geol. Geophys., Vol. 2).

The historical trends in geothermal power plant sizes are shown in Figures 6, 7 and 8. Figure 6 shows the fraction of total worldwide installed capacity attributable to different plant sizes and indicates the total installed capacity. Figure 7 shows the same information for the U.S. Figure 8 illustrates the trends in the largest and average geothermal plant sizes in the U.S. and worldwide from 1920 to 1980. These trends reflect the graduated step-out philosophy in assessing resource viability.

The economics of geothermal energy, like all natural resources, are strongly site-dependent. Such factors as reservoir temperature, permeability, depth, rock type, salinity, and geochemistry can all strongly influence power costs. Comparisons among different technologies are complicated by not only resource-related assumptions, but also costing methodology assumptions. Table 3 illustrates typical comparisons according to different economic "conventions." The influence of site-specific variables is readily apparent in the comparison between the Heber and Baca sites. The reasons for high costs on the proposed SDG&E binary plant (Heber) are straightforward. At 365°F, the binary plant requires approximately 2 1/2 times the brine flow rate as the 550°F flash plant (Baca). This higher brine flow dictates larger piping, valves, and injection pumps. The lower temperature necessarily means a 20% lower thermal efficiency, which requires approximately 20% larger condensers, cooling towers, water circulating pumps, and 20% more make-up water. In addition, the lower vapor pressure of the 365°F brine causes wells to be low in productivity unless they are pumped. The binary plant will use approximately 5MWe of parasitic power for downhole pumps, which is not required for the 550°F resource, plus an additional 2MWe of parasitic power for injection pumps. Downhole pumps will add $2.5 million to initial capital costs and will require frequent maintenance and replacement.

Table 4, taken from a paper entitled "Economic Review of Advanced Fuel and Power Technologies" prepared internally by Bechtel, compares different power technology generation costs using slightly optimistic but even-handed assumptions about each alternative. The table shows that the cost of geothermal power is competitive and should not pose a detriment to development.

The conclusion of this section is that the risks associated with near-term geothermal development are more perceived than real. Nevertheless, they pose an important obstacle. Longer-term geothermal development requires the ability to exploit the less economic resources (especially the lower-temperature resources) and technological innovation will clearly be a prerequisite to significant development.

THE ROLE OF TECHNOLOGY IN FUTURE DEVELOPMENT
The history of technological success in dealing with geothermal problems has been impressive. The once unmanageable Salton Sea high-salinity resource can now be economically produced and utilized. New materials, instrumentation, drill bits, cements, and other innovations have greatly increased component reliability and life. Although substantial improvements have been realized, it is clear that continued technological innovation will be required if the bulk of the resource base is to be developed. Figure 9 (from USGS Circular 790) illustrates the resource-temperature distribution. It is clear from this figure that the majority of the resource base exists at temperatures below 200°C, where present technology is at best marginally economic. The economic degradation with declining reservoir temperature is primarily attributable to the dramatic increase in geothermal flow rates required per kWe as temperature declines. As previously mentioned, a 365°F resource requires 2½ times more fluid supply than a 550°F resource to produce equivalent power. Since well productivity also typically declines with temperature, the economic impact on field development (number of wells) and fluid handling costs is dramatic. The prospects for technological advances to compensate for these thermodynamic penalties are fortunately high. Under DOE sponsorship, the development of improved drill bits, lost circulation control methods, reservoir stimulation, downhole pumping equipment, and more efficient binary technology is well underway. Even moderate success in these programs can result in significant reductions in moderate-temperature power costs.

A PRAGMATIC COURSE, FIRST-GENERATION POWER PLANTS So far, the pattern for growth of the average geothermal plant size (see Figure 8) has been similar to the pattern followed by the size of steam power plants, which is shown for the U.S. in Figure 10. It is anticipated that larger and more economical geothermal plants will be designed and built in the future.

A trend has appeared in the early stage of liquid-dominated hydrothermal resource development which parallels development at The Geysers as well as previous international development. This is the 10-20 MWe "icebreaker" plant concept. The operation of efficient and integrated small plants will enable developers and utility companies to generate revenues while reservoirs and utilization technologies are being tested prior to the construction of larger power plants. Table 5 lists the announced plans for new geothermal power plants outside The Geysers through 1990. The use of small plants to quantify the risks associated primarily with the reservoir and fluid production and disposal, as well as the power plant, is clearly an integral part of the development strategy. As was shown in Figure 4, power plant commitments have already begun to more closely match the successful completion of wells, in terms of MWe.

The similarities between geothermal and conventional power development and the current plans for geothermal plants indicate convincingly that the continued expansion of geothermal power generating capabilities will rely heavily on small first-generation plants. This approach, supplemented by continuous technological advances, should make credible a 10,000 - 20,000 MWe forecast for the year 2000.

REFERENCES

1. Booz Allen & Hamilton Inc. (1980), "Geothermal Industry Assessment", NTIS no. DOE/PE/70090-T2.

2. U.S. Department of Energy (1980), "Geothermal Progress Monitor", Reports 4 and 5, NTIS no. DOE/CE-0009/5.

3. U.S. Geological Survey(1978), "Assessment of Geothermal Resources in the United States-1978", Circular 790.

4. U.S. Geological Survey, Conservation Division, Office of Deputy Conservation Manager for Geothermal, Menlo Park, CA.

5. Federal Power Commission (1971), "The National Power Survey, Part 1", U.S. Government Printing Office.

FIGURE 1

COMPARISON OF RECENT GEOTHERMAL ELECTRIC ENERGY UTILIZATION PROJECTIONS FOR THE YEAR 2000

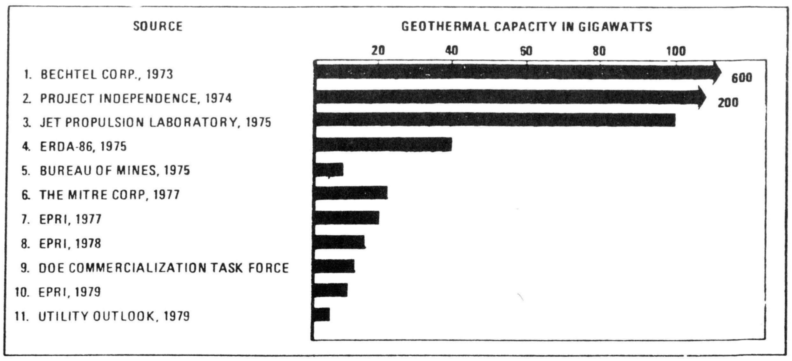
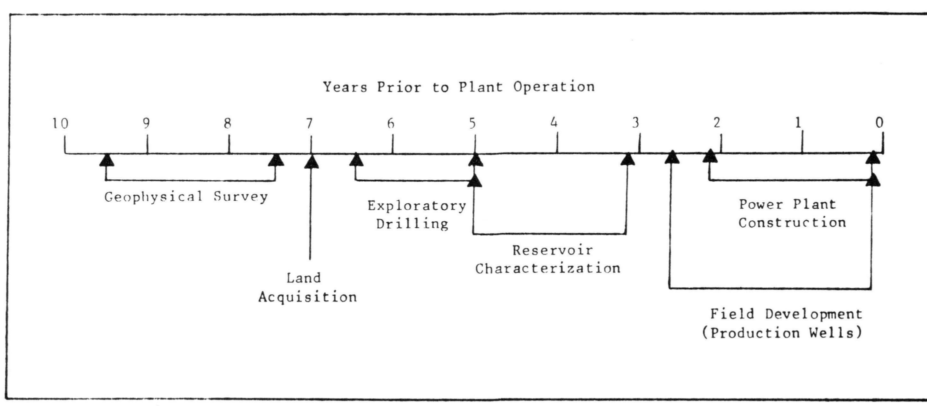


FIGURE 2

TYPICAL HYDROTHERMAL POWER DEVELOPMENT SEQUENCE



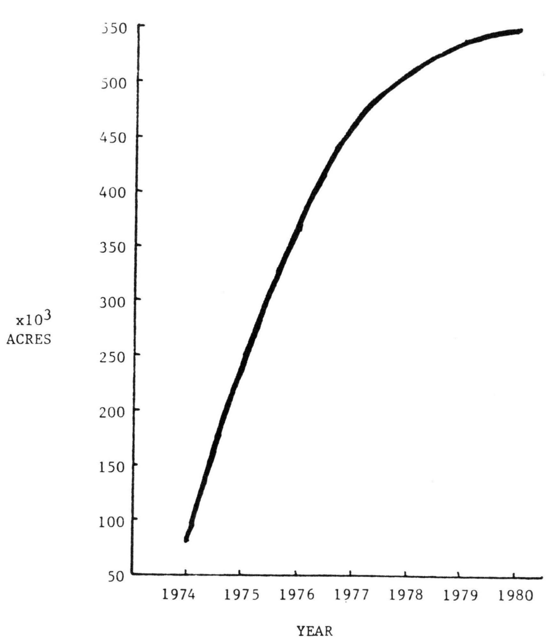


FIGURE 3

COMPETITIVE LEASING OF FEDERAL KGRA LANDS

FIGURE 4

UTILITY LIQUID-DOMINATED HYDROTHERMAL POWER PLANT COMMITMENTS AND SUCCESSFUL WELL COMPLETIONS VERSUS TIME

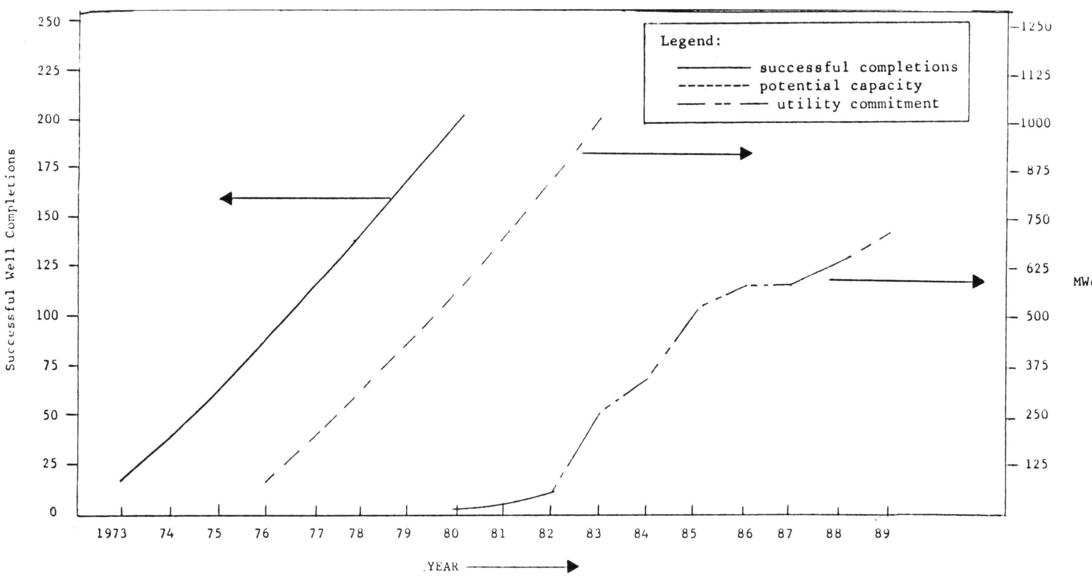
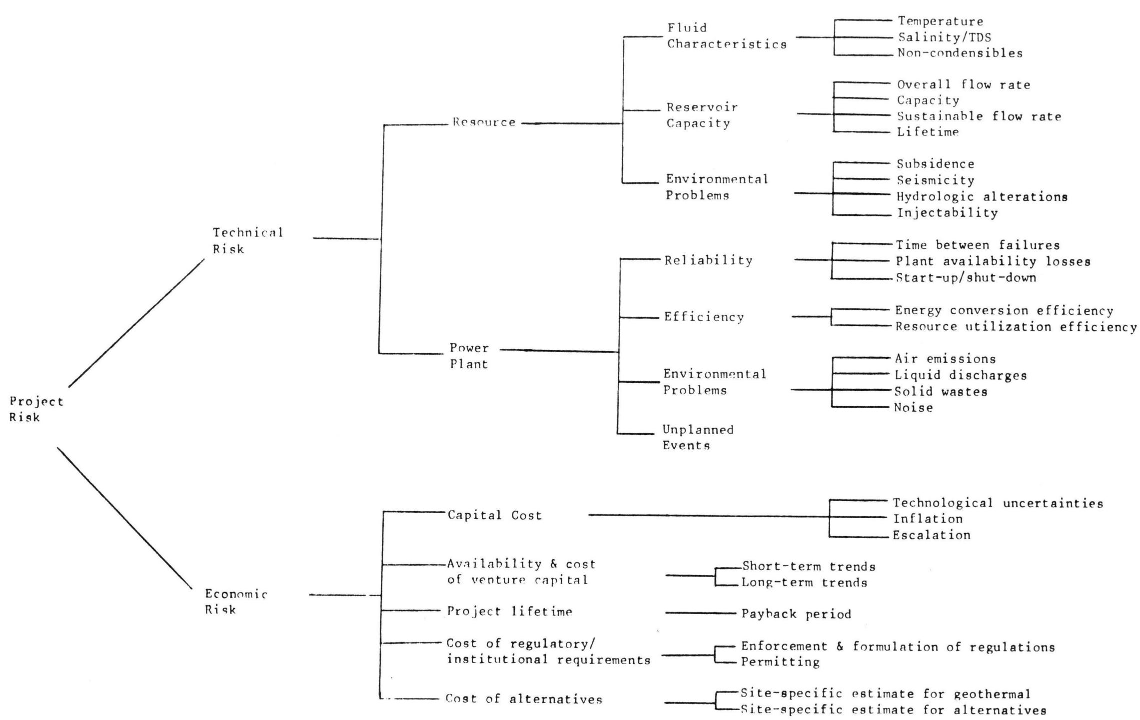


FIGURE 5

SOURCES OF RISK ASSOCIATED WITH GEOTHERMAL POWER SYSTEMS



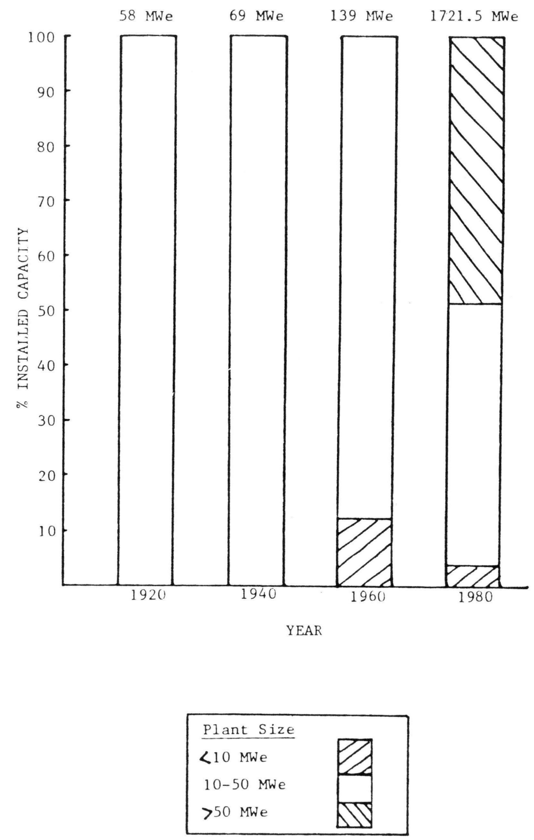
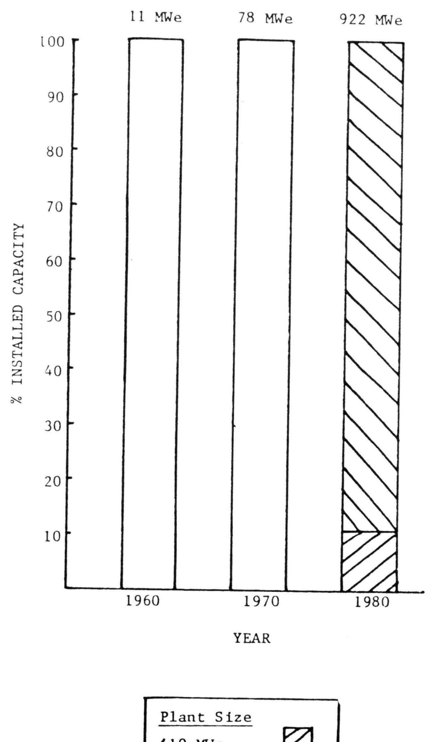


FIGURE 6

PROPORTION OF WORLD-WIDE GEOTHERMAL POWER GENERATED BY DIFFERENT PLANT SIZES

FIGURE 7

PROPORTION OF U.S. GEOTHERMAL POWER GENERATED BY DIFFERENT PLANT SIZES



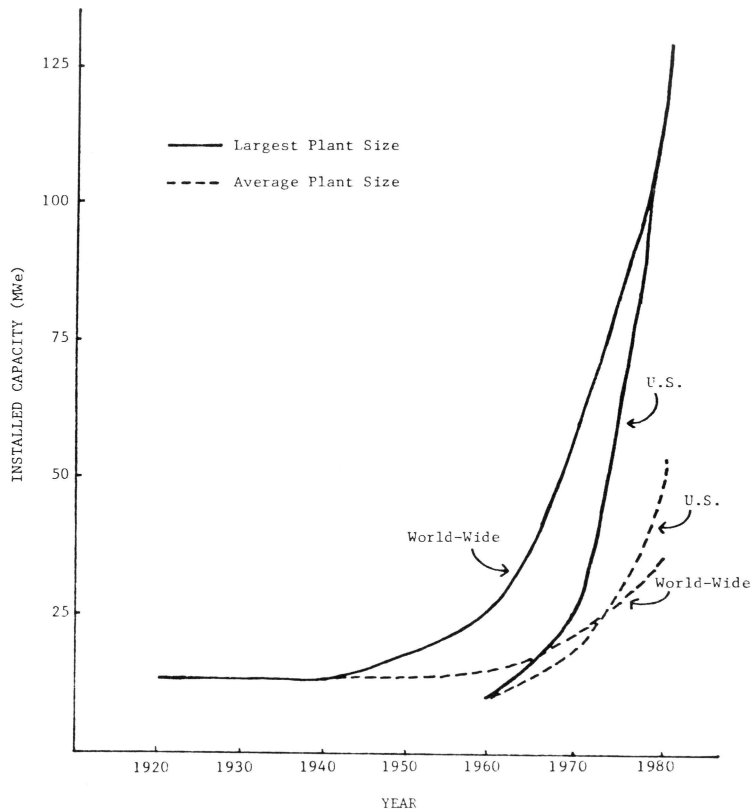


FIGURE 8

TRENDS IN LARGEST AND AVERAGE PLANT SIZES FOR WORLD AND U.S.

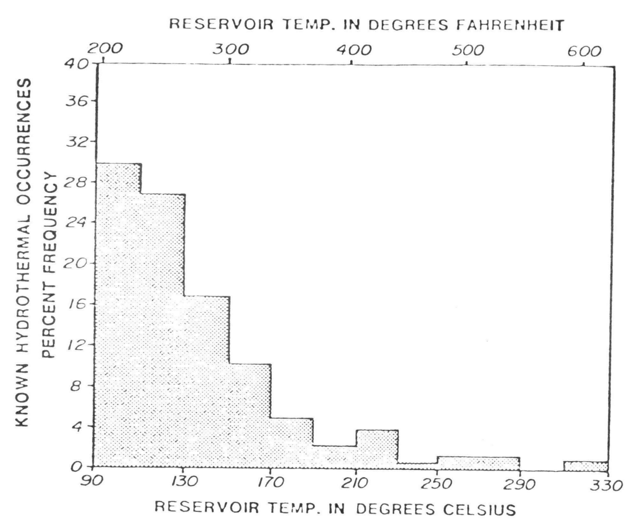


FIGURE 9

PERCENT FREQUENCY OF IDENTIFIED U.S. HYDROTHERMAL RESOURCES BY TEMPERATURE

FIGURE 10

GROWTH TREND FOR LARGEST STEAM ELECTRIC TURBINE GENERATORS IN SERVICE (U.S.)

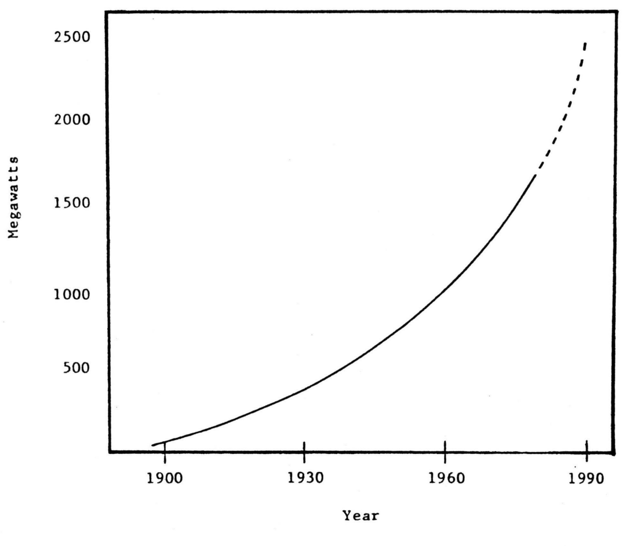


TABLE 1

CHANGES IN THE STATUS OF GEOTHERMAL LEASING ON PUBLIC LAND DURING FY 1980

Source: Reference

STATE	NUMBER OF LEASES[1]			ACREAGE LEASED[1]		
	1979	1980	CHANGE	1979	1980	CHANGE
Alaska	-0-	-0-	-0-	-0-	-0-	-0-
Arizona	13	13	-0-	21,541	21,541	-0-
California[2]	57	56	-1	68,943	67,830	-1,113
Colorado	25	22	-3	34,927	30,476	-4,451
Idaho	136	86	-50	246,722	153,427	-93,295
Montana	6	-0-	-6	10,687	-0-	-10,687
Nevada[3]	499	647	+148	954,577	1,201,257	+246,680
New Mexico	121	120	-1	220,155	210,014	-10,141
Oregon	150	233	+83	228,929	375,740	+146,811
Utah	278	269	-9	472,507	453,677	-18,830
Virginia	11	11	-0-	19,774	19,774	-0-
Washington	-0-	2	+2	-0-	5,120	+5,120
Wyoming	4	4	-0-	7,448	7,448	-0-
TOTAL	1,300	1,463	+163	2,286,210	2,546,304	+260,094

[1] As of September 30 in the respective years

[2] Includes one lease of 120 acres on Indian land.

[3] Includes one prospecting permit on 79,590 acres on Indian land.

TABLE 2

NUMBER OF DEEP WELLS COMPLETED AND TOTAL FOOTAGE DRILLED 1973-80

YEAR / STATE	1978		1979		1980		1973-80 TOTAL	
	NO.	FOOTAGE	NO.	FOOTAGE	NO.	FOOTAGE	NO.	FOOTAGE
ARIZONA	-	-	5	21235	-	-	8	48923
CALIFORNIA								
Geysers	24	190183	30	208961	40	292638	212	1574052
Imp. Valley	12	92227	10	64844	7	60424	77	524526
Other	3	17035	3	13543	1	9104	16	97066
HAWAII	1	5595	1	6500	1	7000	5	29668
IDAHO	7	38385	2	14356	1	7981	16	106569
LOUISIANA	1	16234	1	15231	2	32942	4	64407
MARYLAND	-	-	1	5562	-	-	1	5562
MONTANA	-	-	-	-	-	-	1	6790
NEW MEXICO	1	6254	2	13010	4	23380	16	111495
NEVADA	4	21503	12	72523	8	57399	40	229211
OREGON	1	4003	2	12874	3	13004	10	51501
SOUTH DAKOTA	1	4266	1	4112	-	-	2	8378
TEXAS	1	2628	3	24320	1	13940	5	40888
UTAH	3	20742	2	17654	-	-	15	114176
TOTAL	59	419055	75	494725	68	517812	428	3013212

TABLE 3

ESTIMATED BUSBAR COST OF POWER AT BACA AND HEBER PLANTS (Mills/kWh)*

Start Up	Geothermal	Initial Year of Operation	Levelized Current Dollars	Levelized Constant Dollars
1982	PNM Baca Flash Demo (50% DOE funded plant)	42	62	36
1982	Baca Subsequent unit (no DOE funds)	43	64	36
1985	SDG&E Heber Binary Demo (cost estimates ignore 50% DOE funding)	89	129	75

*in year of start-up dollars

assumptions:

PNM - 80% capacity factor
escalation 7% to 1982

SDG&E - 75% capacity factor
escalation 7% per year to 1985

TABLE 4

POWER TECHNOLOGIES COST SUMMARY
(Constant 1979 $)

Power Technology	Size	Year	Total Capital Investment $ Millions	Capital Investment $/kWe	Mills/kWh Break-even	Mills/kWh 5% ROI AFIT	Equivalent $/MMBtu Break-even	Equivalent $/MMBtu 5% ROI AFIT
Nuclear — light water reactor**	1,200 MWe	1979	900	750	16	26	4.70	7.60
Conventional coal-fired plant with scrubbing	800 MWe	1979	475	595	19	27	5.60	7.80
Combined cycle								
No. 2 distillate fuel	800 MWe	1979	300	375	29	34	8.50	10.00
Integrated coal gasification	100 MWe	1985	145	1,450	34	52	10.00	15.20
Atmospheric fluidized bed combustion	600 MWe	1990	400	680	24	33	7.10	9.70
Pressurized fluidized bed combustion	400 MWe	1990	300	750	25	34	7.30	10.00
		2000	210	700	23	30	6.80	8.80
Geothermal	100 MWe							
Steam		1985	45	450	23	29	6.90	8.50
Brine		1985	75	750	31	39	9.20	11.40
Breeder reactor**	2-unit 3,000 MWe	1985	4,500	1,500	25	44	7.40	12.90
		1990	3,900	1,300	23	39	6.70	11.40
		2000	3,300	1,100	21	34	6.00	10.00
Magnetohydrodynamics	1,000 MWe	2000	1,250	1,250	27	42	7.80	12.30
Fuel cells	100 MWe	1990	100	1,000	46	58	13.60	17.00
		2000	75	750	43	52	12.60	15.20
Biomass — power	150 MWe	2000	165	1,100	46	58	13.50	17.10
Wind	2 MWe	1985	3.7	1,850	45	78	13.20	22.90
		1990	3.0	1,500	37	64	10.70	18.80
		2000	2.0	1,000	25	43	7.30	12.60
Ocean thermal energy conversion	100 MWe	1990	230	2,300	38	67	11.30	19.60
		2000	210	2,100	35	61	10.30	17.90
Solar photovoltaic	200 MWe	2000	180	900	35	62	10.30	18.20
Solar thermal	150 MWe	1990	398	2,650	49	95	14.30	27.80
		2000	300	2,000	38	73	11.20	21.40

*Basic premises used in the analyses are presented in Section V, Economic Criteria.
**Based on nuclear fuel valued at $0.62/MMBtu equivalent to U_3O_8 value of $40/lb.

TABLE 5

PROPOSED U.S. GEOTHERMAL POWER PLANTS OUTSIDE THE GEYSERS

STATE	AREA	DEVELOPER	UTILITY	PLANT	PLANT TYPE	NET OUTPUT MWE	YEAR ON LINE	PLANT COST $ 000
CA	Brawley	Union Oil	SCE					
CA	Brawley	CU-I Venture	CDWR		Flash	45	1984	
CA	Brawley	Union Oil	SCE	SCE				
CA	Coso	California Energy	US NAVY	COSO #1	Flash	20	1983	
CA	Coso	California Energy	US NAVY	COSO #2	Flash	55	1989	
CA	East Mesa	Republic Geothermal	SDG&E		Flash	50	1982	80,000
CA	Reber	Chevron	SDG&E		Binary	45	1985	128,400
CA	Reber	Chevron	SCE	SCE #1	Flash	50	1983	
CA	Reber	Chevron	SCE	SCE #2	Flash	100	1986	110,000
CA	Mono-Long Valley	Magma Power	SCE		Hybrid	20	1985	
CA	Niland	Union Oil	SCE	SCE				
CA	Niland	Union Oil	SCE	SCE PILOT		10	1982	
CA	Niland	Magma Power	SDG&E	SDG&E# 1	Flash	26	1983	30,000
CA	Niland	Magma Power	SDG&E	SDG&E# 2	Flash	49	1985	50,000
CA	Wendel-Amedee	Geoproducts	CDWR		Hybrid	50	1985	60,000
CA	Westmorland	Republic Geothermal			Flash	48	1984	
HI	Puna	Thermal-Dillingham	HELCO			25	1988	
HI	Puna	State of Hawaii	HELCO	HGP-A	Flash	3	1981	7,000
ID	Raft River	INEL/EG&G			Binary	5		24,000
NM	Valles Caldera	Union Oil	PNM	BACA #1	Flash	45	1983	
NV	Northern Nevada	Phillips Petroleum	NORNEV	NORNEV#1	Binary	10	1982	
NV	Northern Nevada	Phillips Petroleum	NORNEV	NORNEV#2	Binary	10		
NV	Northern Nevada	Phillips Petroleum	NORNEV	NORNEV#3	Flash	10		
UT	Roosevelt H.S.	Phillips Petroleum	UP&L	UP&L #1	Flash	20	1983	20,000
UT	Roosevelt H.S.	Phillips Petroleum	UP&L	UP&L #2	Flash			
UT	Roosevelt H.S.	Phillips Petroleum	UP&L	UP&L #3				
STATUS TOTAL						2,237		670,574