EVALUATION OF THE EFFECTS OF GEOTHERMAL RESERVOIR FLUID TEMPERATURE ON THE COSTS OF STEAM PRODUCTION AND POWER GENERATION

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INTRODUCTION

This report provides a preliminary evaluation of the effect of reservoir temperatures on the cost of geothermal hot water wells and flash-steam gathering systems to support a 50,000 kW power plant. Comparisons are made of the capital investments required for each case and the corresponding payout period based on steam costs of 6 mill/kWh of power generated.

In order to show how the reservoir temperatures and steam cost affect the cost of electric power delivered to the high tension bus at the power plant, capital costs estimates were prepared and economic analyses made to determine the cost of electric power for each corresponding case.

DISCUSSION:

A. STEAM PRODUCTION FACILITIES

In order to determine the cost of the steam production facilities, it was first necessary to establish the basic design and steam requirements for the power plant.

A two-stage steam flash concept was employed for geothermal hot water reservoir temperatures above 350° F. In order to optimize hot water usage and minimize geothermal well costs. The amount of flashed steam produced diminishes rapidly as the reservoir temperature drops below 350° F. For this reason it is preferable to use a binary fluid cycle power plant to reduce field production costs when reservoir temperatures approach the lower values. The amount of fluid produced by flash-flowing diminishes. Also, the fluid temperature drops, resulting in a closer temperature approach and greater surface requirement in the binary fluid heat exchanger train. For this reason the 300° F. reservoir temperature case was evaluated on the binary fluid cycle power plant and the production facilities were cost estimated on the basis of mechanically pumped wells.

The type of pump considered suitable for this service is the deep well vertical shaft driven pump. Costs are based on vendor's best estimates because pumps of suitable capacity are still in the developmental stage. Submersible pumps were not considered suitable because the motors are likely to over-heat and fail in the hot geothermal well environment.

For conservative estimating, the initial wells were assumed to be spaced on 40 acre centers. Each well is equipped with a high pressure steam flash separator, from which the steam is piped to a common manifold and delivered to the power plant.

The hot water from the steam separators is piped to a common low pressure steam flash separator which is located adjacent the power plant. In this manner the low pressure steam line is kept short; the water lines can be sized for a relatively high pressure drop, and the water is brought closer to its point of disposal, which is by reinjection in wells located on the opposite side of the plant and assumed to be located at least 3,000 feet from the production wells.

Requirements for reinjection wells are based on one reinjection well for every two production wells. The requirments for production wells was predicted on a flow rate of 1500 gpm per well. Flow tests on other hot water geothermal fields have shown these to be reasonable bases for designs and cost estimating.

The cost of each production and reinjection well was estimated at $250,000. Intangible drilling costs were taken at $150,000, based on our estimated casing program cost of $100,000.

An additional expense item of $35,000 was added to each production well for flow testing and evaluation.

Geothermal wells typically exhibit a decline in production during the early years and a "levelling off" in the decline curve with time. For each case considered we have added costs for additional production and reinjection wells, based on our estimate of a probable decline curve and life of the wells.

The tangible costs of the production facilities were depreciated on a straight line basis rather than on a unit of production basis because the incremental well additions cannot be produced at any greater rate than that which is required to make up the production decline to sustain the total production fixed by the power plant. The average useful life of the production well was taken as 20 years for depreciation purposes.

Each production well requires a separator and steam and water lines which were estimated to cost $194,000 average per installation. The reinjection wells are fed by 100% spared pumps, taking suction from the common low pressure separator. Incremental addition of reinjection wells requires only piping costs, estimated at $78,000, plus well costs of $250,000.

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Reinjection pump discharge head requirements were predicated on overcoming static and velocity head losses incurred in flowing to the reinjection wells. In some instances, it has been found that the pump can be shut down and by-passed once reinjection flow is established because the static head exerted by the column of water in the well is sufficient to maintain flow.

The cash flow analysis for the steam production facilities was predicted on the following:

1. Gross revenue based on steam sale price of 6 mills/kWh of electric power generated by the power plant, operating at 85% average annual availability.

2. Royalty payment to lease holders of 10% of gross revenues.

3. Depreciation on a straight line basis for 20 years.

4. Interest payment of 8% on the yearly net capital requirements.

5. Depletion allowance of 22% of gross income, but not to exceed 50% of taxable income.

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6. Income taxes were calculated at an effective rate of 52% on the taxable income. This rate was determined by taking 48% for Federal income tax and Arizona State income tax of 8% on income after Federal taxes.

The project schedule and capital expenditures for the steam production facilities are paced by the construction schedule for the power plant. Six months are provided for drilling exploratory and step-out wells to establish the existence of adequate steam and to negotiate a contract with the utility company.

24 months are provided for construction of the power plant during which time the additional wells required to make up the total required production would be drilled and surface facilities installed to deliver the steam to the power plant and to dispose of the waste water. These are admittedly tight schedules but they could be realized by preselecting the engineering and procurement services so that the long lead items could be purchased at the earliest date.

Since the surface facilities do not have to be purchased until the end of the second year, a cost escalation of 5% per year is included in the cost estimate. The capital cost estimate also includes an overall contingency of 15%.

The summary of the capital costs and payout periods for the three principal cases are shown in Tables 1, 2 and 3.

B. THE POWER PLANT

Summarized in Table 4 are the capital costs of the power plant and the cost of electricity delivered to the high tension bus for each of the corresponding geothermal reservoir temperature cases used for evaluating the cost of the steam production facilities.

Plant costs are based on using steam turbine drives for the generator. The steam turbines are of the double admission design to accept high and low pressure steam delivered to the power plant from the two-stage flash separators in the steam production facilities.

As a basis for cost comparison with a flash steam power plant, the cost of a binary power cycle plant (Magmamax) is presented for the highest (450°F) geothermal reservoir temperature case. Costs are also presented for the Magmamax plant using geothermal hot water at a reservoir temperature of 300° F. At this low temperature level only the binary fluid cycle plant is considered practicable.

All plant capacities were based on 50,000 kW except for the 300° F. reservoir temperature Magmamax plant. The latter was based on 20,000 kW in order to limit the total number of geothermal production wells required to substain a single plant installation.

The 50,000 kW flash steam power plants were based on the following design parameters:

CASE	1	2	3
Reservoir temperature, °F.	450	400	350
First flash pressure, Psia	95	95	75
First flash steam flow, Lb/Hr	670,000	568,000	485,000
Second flash pressure, Pisa	20	20	20
Second flash steam flow, Lb/Hr	389,000	584,000	800,000
Condenser pressure, "HG Abs	4	4	4
Condenser duty, M^2 Btu/Hr	983	1,071	1,207
Cooling water circ., gpm	51,800	56,500	63,700

Cooling Tower design parameters:

Design wet bulb temperature	75° F.
Approach temperature	8° F.
Temperature range	38° F.

Plant costs and condenser vacuum ejector steam requirements were based on an assumption that the noncondensible gases entering with the steam would not exceed one percent by weight.

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The plant was assumed to be situated on a relatively flat area with good soil bearing. No special allowance was made in the cost estimate for piling, and only a nominal amount of grading work was assumed necessary.

The turbine building is a fabricated steel structure containing control room, office space, change room, maintenance shop and store room in addition to the turbine-generator set, associated electrical equipment and bridge crane.

The capital cost estimate includes the cost of the power plant and substation. Cost elements making up the estimate include equipment costs, field erection materials and labor, construction overhead and profit. To this sum is added 15% contingency and 8% for engineering.

Total capitalization includes interest during construction. Based on the projected rate of expenditure over the two year construction period interest payment equal to one year's amount was considered adequate.

CONCLUSIONS:

Economic evaluations were made of the capital investments required for the geothermal steam production facilities and for the power plant to determine payout period and cost of electric power.

These order-of-magnitude costs provide a basis for establishing the economic viability of the geothermal project for a range of anticipated reservoir fluid temperatures.

While geothermal reservoir temperatures in excess of 600°F have been encountered in some fields, this evaluation was limited to a maximum temperature of 450°F per instructions of GKS Corporation.

Based on a geothermal steam sale price of 6 mills per kW/Hr of electricity produced, the payout period for the steam production facilities ranged from 9 years for 450°F reservoir temperature to 19 years for 350°F reservoir temperature. The cost of electricity delivered to the plant high tension bus varied from 10.67 mills/kWh to 10.88 mills/kWh for the same corresponding reservoir temperatures.

The cost of electricity for the 300°F reservoir case utilizing a binary fluid Magmamax cycle was 16.20 mills/kWh.

RECOMMENDATIONS:

The results of this preliminary evaluation are adequate for the purposes intended; however, it is recommended that a detailed economic analysis of the geothermal project be undertaken to determine definitive costs when the geothermal reservoir and fluid conditions are determined by actual flow tests on multiple wells.

TABLE I

CASE I 450° BHT
50 MW
85% L.F. (7450 Hr/Yr)
372.3×10^6 Kwh/Yr.
Cost in $1000

Well Requirements:

	Initial	30 Year Total
Production, P	8	22
Reinjection, R	4	7

YEAR	WELLS INSTALLED	WELL COSTS EXPENSED	WELL COSTS TANGIBLE	SURFACE FACILITY	WELL TEST EXPENSE	ACCUMULATED WELLS & FACIL. COSTS	INCOME LESS 10% ROYALTY	DEPRECIATION	8% INTEREST	OPERATIONS COST	TAXABLE INCOME	DEPLETION	TAXES 52%	ACCUMULATED PROFIT (LOSS)	UNRECOVERED CAPITAL INVESTMENT
1973	4P	600	400		140	1,140			91					(831)	1231
1974	4P/1R	750	500		140	2,530			210					(2331)	2831
1975	3R	450	300	2,118		5,398	1005	166	456	80	(147)			(2478)	5260
1976	2P	300	200	388	70	6,356	2011	195	492	160	794			(1684)	4859
1977							2011	195	389	160	1267			(417)	3397
1978							2011	195	272	160	1384/967	483	252	232	2070
1979							2011	195	166	160	1490	491	520	711	905
1980	2P	300	200	388	70	7,314	2011	225	143	160	1113	491	323	1010	478
1981							2011	225	38	160	1588	491	570	1537	0
1982							2011	225		160	1626	491	590	2082	
1983							2011	225		160	1626	491	590	2627	
1984	2P/1R	450	300	466	70	8,600	2011	260		160	1071	491	302	2935	
1985							2011	260		160	1591	491	572	3463	
1986							2011	260		160	1591	491	572	3991	
1987							2011	260		160	1591	491	572	4519	
1988	2P	300	200	388	70	9,558	2011	290		160	1191	491	364	4855	
1989							2011	290		160	1561	491	556	5369	
1990							2011	290		160	1561	491	556	5883	
1991							2011	290		160	1561	491	556	6397	
1992	2P/1R	450	300	466	70	10,844	2011	330		160	1001	491	265	6642	
1993							2011	330		160	1521	491	536	7136	
1994							2011	330		160	1521	491	536	7630	
1995							2011	195		160	1656	491	606	8189	
1996	2P	300	200	388	70	11,802	2011	165		160	1316	491	429	8585	
1997							2011	165		160	1686	491	621	9159	
1998							2011	165		160	1686	491	621	9733	
1999							2011	165		160	1686	491	621	10,307	
2000	2P/1R	450	300	466	70	13,088	2011	175		160	1156	491	346	10,626	
2001							2011	175		160	1676	491	616	11,195	
2002							2011	175		160	1676	491	616	11,764	
2003							2011	175		160	1676	491	618	12,333	
2004							2011	135		160	1716	491	637	12,921	
2005							2011	135		160	1716	491	637	13,509	

TABLE 2

CASE II 400°F BHT

Well Requirements:

	Initial	30 Year Total
Production, P	10	28
Reinjection, R	5	9

YEAR	WELLS INSTALLED	WELL COSTS EXPENSED	WELL COSTS TANGIBLE	SURFACE FACILITY	WELL TEST EXPENSE	ACCUMULATED WELLS & FACIL. COSTS	INCOME LESS 10% ROYALTY	DEPRECIATION	8% INTEREST	OPERATIONS COST	TAXABLE INCOME	DEPLETION	TAXES 52%	ACCUMULATED PROFIT (LOSS)	UNRECOVERED CAPITAL INVESTMENT
1973	5P	750	500		175	1425			114					(1039)	1539
1974	5P/2R	1050	700		175	3350			277					(2541)	3627
1975	3R	450	300	2,700		6800	1005	210	566	85	(306)			(2847)	6723
1976	3P	450	300	582	105	8237	2011	255	644	170	387			(2460)	6963
1977							2011	255	557	170	1029			(1431)	5679
1978							2011	255	454	170	1132			(299)	4292
1979							2011	255	343	170	1243/944	472	245	227	3039
1980	3P/1R	600	400	660	105	10,002	2011	305	376	170	455	227	119	336	3458
1981							2011	305	277	170	1259	491	399	705	2293
1982							2011	305	183	170	1353	491	448	1119	1083
1983							2011	305	87	170	1449	491	498	1579	0
1984	3P	450	300	582	105	11,439	2011	350		170	936	468	244	1803	
1985							2011	350		170	1491	491	520	2283	
1986							2011	350		170	1491	491	520	2763	
1987							2011	350		170	1491	491	520	3243	
1988	3P/1R	600	400	660	105	13,204	2011	405		170	731	365	190	3419	
1989							2011	405		170	1436	491	491	3873	
1990							2011	405		170	1436	491	491	4327	
1991							2011	405		170	1436	491	491	4781	
1992	2P/1R	450	300	466	70	14,490	2011	445		170	876	438	228	4991	
1993							2011	445		170	1396	491	471	5425	
1994							2011	445		170	1396	491	471	5859	
1995							2011	260		170	1581	491	567	6382	
1996	2P	300	200	388	70	15,448	2011	220		170	1251	491	395	6747	
1997							2011	220		170	1621	491	588	7289	
1998							2011	220		170	1621	491	588	7831	
1999							2011	220		170	1621	491	588	8373	
2000	2P/1R	450	300	466	70	16,734	2011	205		170	1116	491	325	8673	
2001							2011	205		170	1636	491	595	9223	
2002							2011	205		170	1636	491	595	9773	
2003							2011	205		170	1636	491	595	10,323	
2004							2011	160		170	1681	491	619	10,894	
2005							2011	160		170	1681	491	619	11,465	

TABLE 3

CASE III 350°F BHT

Well Requirements:

	Initial	30 Year Total
Production, P	15	30
Reinjection, R	8	11

YEAR	WELLS INSTALLED	WELL COSTS EXPENSED	WELL COSTS TANGIBLE	SURFACE FACILITY	WELL TEST EXPENSE	ACCUMULATED WELLS & FACIL. COSTS	INCOME LESS 10% ROYALTY	DEPRECIATION	8% INTEREST	OPERATIONS COST	TAXABLE INCOME	DEPLETION	TAXES 52%	ACCUMULATED PROFIT (LOSS)	UNRECOVERED CAPITAL INVESTMENT
1973	7P	$1050	$700		$245	$1995			$160					$(1455)	$2155
1974	8P/4R	1800	1200		280	5275			435					(3970)	5870
1975	4R	600	400	4031		10,306	1005	315	872	105	(887)			(4857)	10,873
1976	4P	600	400	776	140	12,222	2011	375	1012	210	(326)			(5193)	12,000
1977							2011	375	960	210	466			(4727)	11,159
1978							2011	375	892	210	534			(4193)	10,250
1979							2011	375	820	210	606			(3587)	9,269
1980	4P/1R	750	500	854	140	14,466	2011	445	910	210	(444)			(4031)	10,622
1981							2011	445	850	210	506			*(3525)	9,671
1982							2011	445	774	210	582/308	154	72	(3169)	8,716
1983	4P	600	400	776	140	16,382	2011	445	697	210	659	329	172	(3011)	7,784
1984							2011	500	765	210	(204)		(106)	(3109)	8,558
1985							2011	500	685	210	616	308	160	(2961)	7,602
1986							2011	500	608	210	693	346	180	(2794)	6,589
1987							2011	500	527	210	774	387	201	(2608	5,516
1988	2P/1R	450	300	466	70	17,668	2011	540	541	210	200	100	52	(2560)	4,828
1989							2011	540	386	210	875	437	228	(2350)	3,641
1990							2011	540	291	210	970	485	252	(2117)	2,383
1991							2011	540	190	210	1071	491	302	(1839)	1,074
1992							2011	540	86	210	1175	491	356	(1511)	0
1993							2011	540		210	1261	491	400	(1141)	
1994	1P/1R	150	100	272	35	18,225	2011	560		210	1056	491	294	(870)	
1995							2011	245		210	1556	491	554	(359)	
1996							2011	185		210	1616	491	585	181	
1997							2011	185		210	1616	491	585	721	
1998							2011	185		210	1616	491	585	1261	
1999							2011	185		210	1616	491	585	1801	
2000							2011	115		210	1686	491	621	2375	
2001							2011	115		210	1686	491	621	2949	
2002							2011	115		210	1686	491	621	3523	
2003							2011	115		210	1686	491	621	4097	
2004							2011	60		210	1741	491	650	4671	
2005							2011	60		210	1741	491	650	5162	

* Net operating loss carry-over lost - totaling $3,251 (5 year basis expired)

TABLE 4

SUMMARY

BASES: 50,000 Kw Capacity
7450 Operating Hours/Year
372,300,000 Kwh/Year Operation

* 20,000 Kw
7450 Hr/Yr.
149,000,000 Kwh/Yr.

Case	1		2		3		4		5*	
BHT, °F	450		400		350		450		300	
Type	Flash Steam		Flash Steam		Flash Steam		Binary Cycle		Binary Cycle	
	$1000	($/Kw)	$1000	($/Kw)	$1000	($/Kw)	$1000	($/Kw)	$1000	($/Kw)
Plant Cost Inc. Substation	8,201	(164)	8,362	(167)	8,608	(172)	9,020	(180)	7,011	(350)
Int. During Const.	615	(12)	627	(13)	646	(13)	676	(14)	526	(26)
Total Capitalization	8,816	(176)	8,989	(180)	9,254	(185)	9,696	(194)	7,537	(376)
Annual Costs	$1000	(Mills/Kwh)	$1000	(Mills/Kwh)	$1000	(Mills/Kwh)	$1000	(Mills/Kwh)	$1000	(Mills/Kwh)
Fixed Charges @ 18%	$1,587	(4.27)	1,618	(4.35)	1,666	(4.48)	1,883	(5.06)	1,357	(9.10)
Operating Costs	150	(0.40)	150	(0.40)	150	(0.40)	200	(0.54)	165	(1.10)
Labor and Material Fuel Cost	2,234	(6.00)	2,234	(6.00)	2,234	(6.00)	2,234	(6.00)	894	(6.00)
	$3,971		4,002		4,050		4,317		2,416	
Electricity Cost at Plant Bus		(10.67)		(10.75)		(10.88)		(11.60)		(16.20)