**SMALL GEOTHERMAL ELECTRIC SYSTEMS
FOR
REMOTE POWERING**

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FOR REMOTE POWERING***

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ABSTRACT

This report describes conditions and costs at which quite small (100 to 1,000 kilowatt) geothermal systems could be used for off-grid powering at remote locations. This is a first step in a larger process of determining locations and conditions at which markets for such systems could be developed.

The results suggest that small geothermal systems offer substantial economic and environmental advantages for powering off-grid towns and villages. Geothermal power is most likely to be economic if the system size is 300 kW or greater, down to reservoir temperatures of 100°C. For system sizes smaller than 300 kW, the economics can be favorable if the reservoir temperature is about 120°C or above. Important markets include sites remote from grids in many developing and developed countries. Estimates of geothermal resources in many developing countries are shown.

Introduction

This report concentrates on the capabilities and costs of geothermal "binary" power conversion systems because they are the most likely to be economical at geothermal reservoirs with relatively low fluid temperatures. Such geothermal resources are very common in some regions of the world. U.S. firms built about 300 MWe of geothermal binary units in the last decade. While most of those units have capacities of 5,000 kilowatts (kW) and larger, U.S. firms have manufactured and installed binary units as small as 300 kW. [1] Flashed-steam power plants, useful at temperatures above 150°C, have also been constructed in small sizes. [2]

The systems described here have net capacities on the order of 100 to 1,000 kW. They would be suitable for serving populations of 100 to 5,000, depending on the local per-capita demand. Because these systems are smaller than the grid-connected geothermal electric systems recently built in the U.S. (3 to 50 MW), they will cost somewhat more on per-kilowatt basis. Special attention is paid here to how project costs scale to system size, and to ensuring reliability of power for portions of the load during system outages.

The report provides performance and cost estimates for a modal system of 300 kilowatt capacity working from a resource temperature of 120°C. Effects on the cost of electricity of variations in some system parameters are shown. The purpose is to assist interested parties in making estimates of where such systems could be economically useful.

System Description

The power system gets its energy from a geothermal reservoir containing hot water. The geothermal fluid is produced through a well that is similar to an oil well. If this well is not self-flowing, is fitted with a downhole pump to increase the well flow rate and to ensure that the pressure of the water is high enough at all times to keep it from flashing into steam as it rises up the well and is piped a short distance to the power plant.

Figure 1. Schematic of an air-cooled geothermal binary electric system.

The "binary" geothermal power conversion cycle derives its name from the fact that it uses two fluids, the geothermal fluid and a working fluid with a low boiling temperature, for example, a hydrocarbon such as isopentane. In the power plant the geothermal fluid passes through a heat exchanger, where its heat is transferred to and vaporizes the working fluid.

The heat exchanger is a long cylindrical shell with bundles of tubes inside it. The geothermal fluid passes in one direction through tubes, while the working fluid passes in the opposite direction in the shell, absorbing heat and vaporizing. From the heat exchanger, the geothermal fluid is pumped back into the ground through an injection well.

The vaporized working fluid drives the turbine-generator. As it exits the turbine, the low-pressure vapor is liquefied in the condenser and repressurized by the hydrocarbon pump for its return to the heat exchanger. Waste heat is ejected to the atmosphere through the condenser. Because the fluids are always contained within the pipes, turbine, heat exchanger, or condenser, the system releases essentially no gases to the atmosphere.

Typically, the small systems described here will require only one production well and one injection well (or other means of brine disposal). The flow rate of geothermal fluid required by the plant decreases with increasing fluid temperature and increases with increasing power plant size. If either the resource temperature or well flow rates are relatively low, then plants of capacities on the order of 500 kW or greater may require two production wells.

Special Features

Some features of the technology are described here.

1. The plants are very transportable. For 100 to 300 kW plants, the entire plant including the cooling system can be built on a single skid that fits in a standard trans-ocean shipping container.

2. Binary power plants can accommodate a wide range of geothermal reservoir temperatures, 100 to 150°C. (Above 150°C, flashed-steam plants are usually less expensive.) The conversion efficiency is quite low at the lower temperatures, and therefore the cost of power becomes higher. Reservoir temperature is the physical factor to which overall project costs are most sensitive.

3. The demand for electric capacity per person at off-grid sites will range from 0.2 kW in less-developed areas to 1.0 kW or higher in developed areas. A 100 kW plant could serve 100 to 500

people. A 1,000 kW plant would serve 1,000 to 5,000 people.

4. The design of the power plants and their interactions with the wells includes provisions for handling fluctuating loads, including low instantaneous loads ranging from 0 to 25 percent of the installed capacity.

Figure 2. Barber-Nichols 2 X 350 kilowatt plant at Wineagle, California. Plant availability has been more than 98 percent since it was installed in 1985.

5. Power plant designs emphasize a high degree of computer-based automation, demonstrated successfully at the Wineagle and Wendell-Amedee plants in California. The plants are designed to be self-starting. Only semi-skilled labor is needed to monitor plant operation, on a part-time basis. Completely unattended operation might also be possible, with plant performance monitored and controlled remotely through a satellite link.

6. The system releases no greenhouse gases (CO_2 , NO_x , or SO_x) to the atmosphere. There may be very small leakages of the binary-cycle working fluids, but these do not contain chlorine or fluorine and are non-greenhouse gases. [3]

7. All wells would be drilled by truck-mounted rigs, either heavy-duty water-well rigs or light-duty oil/gas-well rigs. At very remote sites, both drilling rig and power system equipment can be transported by helicopter.

8. Injection well costs can be relatively low. For these small systems, because the geothermal flow rates are relatively small, there will rarely be a need to inject the fluid back into the production reservoir.

Any shallow aquifer not used for drinking water could be used for reinjection. If the fluids are clean enough to be disposed of on the surface, then the disposal costs can be quite low.

9. Field piping costs are low. All wellheads are located near the power plant module. Inexpensive plastic or carbon steel pipe is used to connect wells.

Figure 3. Truck-mounted drilling rig. Such rigs can drill to 2 km or more, at relatively inaccessible locations.

10. Geothermal direct heat applications can be attached to these electric systems inexpensively. Applications needing temperatures not higher than 65°C might be attached in series to the power-plant fluid outlet line. Some production wells will have greater flow capacity than that needed by the power plant -- part of this fluid could be used for higher-temperature direct uses connected in parallel to the power plant.

11. Critical backup need is estimated to range from 1 to 5 percent of the installed geothermal capacity. The very high availability factors for geothermal systems, on the order of 98 percent, substantially reduce the cost of special features needed to ensure that power is always available. Small critical loads, e.g., medical refrigeration or pumping of drinking water, could be supported against brief unscheduled outages either by a diesel engine (that is also used for

system startup) or by small amounts of battery storage. Planned outages for system maintenance, and the rare instances of longer-duration unscheduled outages, could be supported by small truck-mounted diesel generators. One such truck would be able to service 5 to 30 small geothermal units.

Cost and Performance Details

Some aspects of system design and cost estimates are described here. Details about performance and costs are provided in the Appendix. The details there can provide insights about how these systems can be configured to optimize certain aspects of costs.

Many of the inputs and results shown here are defined for a "modal" system that assumes a 300 kW power plant installed at a 120°C geothermal reservoir.

Power Plant Core Module: Estimates of the cost and performance of small binary power plants form the most critical and novel part of this analysis. The detailed estimates used here were provided by Ken Nichols, of Barber-Nichols Inc., Arvada, Colorado, a manufacturer of small binary units. The estimates have been reviewed by Dan Schochet, of ORMAT, Inc., Sparks, Nevada (another manufacturer of such units) and found to be reasonable for U.S. installations.

The Flashed-Steam Alternative: Geothermal Power Company, Elmira, New York, has built and installed a number of small noncondensing flashed-steam power plants, sized between 500 and 1,000 kW. [2] No cooling system is needed. The plants are mounted on a single skid and are very easy to install. These plants are generally more economical than binary plants when steam of 150°C or higher can be produced from geothermal wells.

Features to Ensure System Reliability

The systems described here are envisioned as not being connected to a power grid. Therefore, certain items have been added to the general design and cost estimates to ensure that the system can follow relatively low instantaneous loads and that critical loads can be maintained during brief periods of unplanned and planned system outage. These items are representative of what might be included, and

would not necessarily be prescribed for every system.

Low Load Factors: U.S. geothermal electric systems are designed to work at high constant throughput. Costs have been added to the estimates made here to account for design features and equipment needed to allow these plants to follow relatively low instantaneous loads in non-grid applications. Further details will have to be developed for the exact means by which these systems would support low partial loads. It is likely that three levels of features would be involved: (a) Simple throttling of the turbine in the load range of 50 to 100 percent, with brine flow relatively unabated; (b) Some production well throttling, plant bypass valves, and a brine surge tank added to the system, to accommodate the load range of 10 to 50 percent; (c) Shedding power into a dissipative resistive load to accommodate loads in the range of 0 to 10 percent.

Cold-Start Power: These plants may require some electrical power to start them from cold conditions. If the geothermal well flow is artesian, then the plant will self-start once the primary heat exchanger is warmed up. Under other conditions, 5 to 10 percent of the plant's nominal capacity may be needed to start the plant. The systems costed here include a self-starting diesel-generator. This diesel would also serve as the backup power for small critical loads.

Battery Storage: If additional critical backup power is needed, it could be furnished from battery storage. Cost estimation factors are included in the Appendix. The "modal" geothermal power system described and costed here does not include battery storage.

Diesel Truck Backup: Truck-mounted diesel generators could be used to back up these plants during brief periods of scheduled maintenance and other brief outages. In many instances, a number of these small plants in a region would be served by one truck, with a relatively low overall cost per geothermal system. At many sites, the diesel truck would have to supply only certain "semi-critical" loads during this servicing period.

System Capacity Factor

The capacity factor (CF, system annual utilization factor) has a strong impact on any capital-intensive

project. The cost of power values shown in this report assume CF's of 0.80, typical of U.S. grid-connected geothermal plants. Off-grid applications might see this reduced to as low as 0.30, especially during the initial few years of operation at sites where the geothermal system provides the first substantial electricity to a market. Cost of electricity will be inversely proportional to the CF actually experienced. E.g., for a CF 0.50, the cost of power will be 8/5 times that estimated for a CF of 0.80.

Cost of Power Results

Parameters and costs for the modal system are shown in Tables 1 and 2.

Table 1. Specifications of Modal System	
Resource Temperature, °C:	120
System Net Capacity, kW:	300
Plant Flow Need, kg/kWh:	235
Number of Wells:	2
Production Well Flow, kg/hr:	70,500
Production Well Depth, m:	300
Production Pump Power, kW	46
Injection Pump Power, kW	16
Plant Self-Start Power, kW	21
Critical Backup (via batteries):	None
Scheduled Backup:	50 kW for 7 days/year
Capacity Factor:	0.80

The cost of power from this system installed in the U.S., 10.5 ¢/kWh, is quite acceptable for many remote applications. Costs outside of the U.S. might be 5 to 20 percent higher. The costs do not include expenses for local electricity distribution poles, wires, and transformers.

Useful estimates of the costs against which these geothermal systems compete come from the U.S. Department of Energy Office of Solar Energy Conversion [6]. In 1991 dollars, power from diesel generators was estimated to cost 46 to 103 ¢/kWh, (at fuel prices ranging from \$0.40 to \$1.00/liter). Power from solar photovoltaic systems (including battery

Table 2. Estimated Costs of Modal System, 1993 \$	
A. Capital Costs, \$1000	
Exploration:	200
Wells:	325
Field, Other:	94
Power Plant:	659
Self-Start Power:	18
Backup Batteries:	0
Backup Truck:	10
B. O&M Costs, \$1000/Year	
Field:	32
Plant:	26
Backup Systems:	5
Electricity Cost, (levelized in 1993 constant dollars):	10.5 ¢/kWh

storage) was estimated to cost 75 to 100 ¢/kWh in 1991, and projected to cost 34 to 60 ¢/kWh in 2000. In that study, the equivalent cost of extending an electric grid was estimated to be as high as 7 to 9 ¢/kWh per km of grid for systems of low capacity. Considering those estimates, it seems likely that geothermal electricity that costs as much as 30 ¢/kWh could be economically attractive in many settings.

Table 3 shows effects on the cost of power of a number of variations of system conditions and configurations. The estimated cost of power for a 1,000 kW plant at a 140°C reservoir is 4.7 ¢/kWh, very attractive under most conditions. Even if the capacity factor of that plant were as low as 30 percent, the 12.5 ¢/kWh cost would be acceptable in many circumstances.

Note also in Table 3 the effects on the cost of power if one or more of the geothermal wells does not have to be drilled or paid for by the projects.

Table 3. Effects of System Variations on the Cost of Power		
Case	Changes from Modal Case Conditions	Cost of Power, Cents/Kwh
Modal Case	Modal Case Conditions: (120°C fluid; 300 kW capacity; 80% capacity factor)	10.5
Hotter Geothermal Fluid	- 140°C fluid	9.1
Larger Plant	- 1,000 kW capacity	5.6
Lower Capacity Factor	- 40% capacity factor	21.0
Hotter Geothermal Fluid and Larger Plant	- 140°C fluid - 1,000 kW capacity	4.7
Cooler Geothermal Fluid and Smaller Plant	- 100°C - 100 kW capacity	34.6
Hotter Geothermal Fluid, Larger Plant, and Very Low Capacity Factor	- 140°C fluid - 1,000 kW capacity - 30 percent capacity factor	12.5
Artesian Flow in Production Well	- No downhole production pump	7.8
Surface Disposal of Spent Brine	- Injection well not needed	9.0
Artesian-Flowing Production Well Exists and Surface Disposal of Spent Brine	- Production well capital cost = \$0 - No downhole production pump - Injection well not needed	5.5

Markets for These Systems

The market potential for these systems is large. Estimates of the geothermal resource potential, in units of MW capacity for 30 years (1 MW = 1,000 kW), for high-temperature resources for a number of countries are shown in Table 4 [4]. The available amount of lower-temperature resource in each country will tend to be larger. The countries are grouped by regions that could be served by coordinated efforts to market, install, and maintain small geothermal systems.

The characteristics of off-grid markets for electricity service present some challenges for electricity supply decision makers and geothermal developers. The general task is to find sites where currently unsatisfied demand or rapidly growing demand for power is collocated with relatively easy-to-access geothermal resources. Another consideration is that in most cases the proposed geothermal facilities should not be situated too far from locations with some mechanical-servicing capability, to keep ordinary maintenance costs reasonable.

Situations where geothermal systems could be of economic or societal advantage include: (a) Substitution for diesel or other oil-fueled capacity where baseload demand is already established (e.g., small grids on some islands); (b) Indications of pent-up demand in commercial, manufacturing, or mining operations; (c) Locations where geothermal can be paired with other generation options, such as hydropower or biomass [5]; and (d) Situations where

it is feasible to site a new socially-necessary facility (e.g., a regional hospital or educational center) near a geothermal resource.

These systems are likely to be especially valuable in rural development programs and projects. Where geothermal resources are present, their development can provide both electricity and inexpensive crop drying through direct use of geothermal heat.

Perhaps the single most important thing that can be done to identify and define such markets is to broadcast information about the availability, performance, and costs of small geothermal electric systems to non-U.S. energy officials, rural development agencies, and entrepreneurs who are aware of locations and conditions where such systems would be useful.

Figure 4. This 880 kW ORMAT unit at Wabuska, Nevada is water cooled. It was installed in 1984.

Table 4. Potential for Geothermal Electric Power in Developing Countries
(Capacity, Megawatts for 30 years)

Africa, Rift Valley		Asia		Central America		Pacific Islands	
Burundi	50	China	2,000	Costa Rica	3,500	Fiji	50
Djibouti	500	India	200	El Salvador	2,000	Papua N G	300
Ethiopia	5,000	Indonesia	16,400	Guatemala	4,000	Solomon Is.	50
Kenya	3000	Philippines	8,000	Honduras	500	Tonga	50
Malawi	50	Taiwan	200	Mexico	8,000	Vanuatu	40
Mozambique	50	Thailand	100	Nicaragua	4,000		
Rwanda	200	Vietnam	100	Panama	200		
Somalia	50						
Tanzania	600						
Uganda	500						
Zambia	50						
Africa, Other		Caribbean Islands		Europe		South America	
Comoro Is.	50	Dominica	500	Azores	100	Argentina	1,000
Malagasy	300	Grenada	100	Former USSR	4000	Bolivia	1,000
Sudan	300	Monteserrat	100	Greece	500	Chile	1,500
Zaire	500	Nevis - St. Kitts	50	Hungary	300	Colombia	1,500
		St. Lucia	100	Poland	50	Ecuador	1,000
		St. Vincent	50	Turkey	500	Peru	1,000
						Venezuela	500
TOTAL						77,500	

APPENDIX: Details of Cost Estimates and Assumptions

This Appendix provides details of cost estimates and assumptions. The cost factors were combined in a PC-computer model, GT-SMALL, to estimate the overall system costs and the cost of power. Copies of the model can be obtained from Entingh [11]. Most of the inputs and results described here are defined for a "modal" system that assumes a 300 kW power plant installed at a 120°C geothermal reservoir. Costs are given in 1993 U.S. dollars. The abbreviation "\$K" means \$1000.

Power Plant Core Module

The scope of the equipment costed in Tables A-1 and A-3 is that within the "power plant core module" in Figure 1: brine-to-hydrocarbon heat exchanger, hydrocarbon circulation pump, turbine, generator, and dry cooling condenser and fans. The power consumed by those pumps and fans is accounted for within the plant core module performance values, Table A-2.

Adjustments were made to the performance and cost values in Tables A-1 and A-2. (a) Cost and power consumption of brine production pumps and injection pumps were calculated separately. (b) The values in Table A-1 are for typical grid-connected plants, running at an annual capacity factor of about 80 percent. Seven percent was added to those costs to cover modifications to these plants to allow them to follow instantaneous loads as low as 15 percent of the nominal capacity. (See further discussion below.) (c) \$80/kW was added to cover the costs of a power transformer and relay equipment.

Table A-1. Power Plant Capital Cost, \$/kW			
Power Module Net Size, kWe	Plant Inlet Temperature, °C		
	100	120	140
100	2535	2210	2015
200	2340	2040	1860
500	2145	1870	1705
1000	1950	1700	1550

Table A-2. Power Plant Brine Flow Requirement, 1000 kg/hr			
Power Module Net Size, kWe	Plant Inlet Temperature, °C		
	100	120	140
100	50	24	14
200	100	47	27
500	227	111	65
1000	456	227	130

Table A-3. Power Plant O&M Requirements				
Plant Size, kWe:	100	200	500	1000
Operator-Monitor (hr/yr)	300	400	500	800
Maintenance (hr/yr)	200	250	300	400
Working Fluid (\$/yr)	200	400	850	1200
Maintenance Parts (\$/yr)	400	500	600	800

The fully loaded cost for O&M labor in the U.S. in 1993 was about \$25/hr for the operator-monitor, and about \$55/hr for skilled maintenance workers.

Features to Ensure System Reliability

Cost estimates for special items to ensure very high reliability for off-grid systems are documented here.

Low Load Factors: A "Lowest Instantaneous Load Factor" (LILF) was defined here to account for costs incurred to allow these plants to follow relatively low instantaneous loads in non-grid applications. The LILF implies a multiplier applied to the power plant core module capital cost. Our initial rough estimates of the multipliers, against the base cost of the core power module, are 1.20, 1.07, and 1.05 for LILF's of 0, 15, and 25 percent, respectively.

Cold-Start Power: The systems costed here include a self-starting diesel-generator, sized at 7 percent of the capacity of the plant core module. This adds about 1.3 percent to the capital cost.

Battery Storage: Costs for battery storage are estimated as follows. The longest duration needed is 7 days, time enough to move a diesel truck to the location for longer backup. Utility-grade lead-acid batteries cost about \$150 per kWh of storage. The capacity factor (CF) for critical loads for use of this critical storage is estimated to be 0.25. For a 10 kW peak battery storage system, 7 days X 24 hours/day X 0.25 (CF) X 10 kW = 420 kWh of storage need, and the battery cost = 420 X 150 = \$63K. The balance of system costs (inverters, structural supports, wiring), at \$500 per kW, is \$5K. The total capital cost is \$68K. The O&M costs for this subsystem are essentially nil. [7] The modal system described in this report does not include battery storage.

Diesel Truck Backup: We estimate that a 50 kW diesel-generator truck would cost no more than \$100K and that \$5K would cover operating this for one week of scheduled maintenance at each site. The cost estimates here assume that one such truck would serve about ten small plants in a region, resulting in a \$10K initial capital cost per geothermal system for this aspect of backup power.

Other Estimates and Assumptions

1. **Exploration Cost:** The cost to discover the local geothermal resource cannot be ignored. The estimate of \$200K assumes an organized regional approach to exploration and test drilling, so that each stand-alone system does not bear all of the risk of exploration failure at any particular site.

2. **Casing Plan:** The casing plan for the two 1000-foot production wells at the 100°C, 1,000 kW plant at Wendell-Amedee, California is: 34.6 cm (13 5/8 inch) O.D. to 750 feet, then 24.4 cm (9 5/8 inch) O.D. to 1000 feet [9, Meidav]. The production well should, in general, be sized to allow setting a line-shaft brine production pump at about 600 feet. Available pumps require a casing I.D. of about 31.8 cm (12 1/2 inch).

3. **Well Costs:** Costs are estimated to be: \$650

per meter for wells up to 500 m deep; \$800/m for wells 500 to 1000 m deep; and \$1,000/m for total depths greater than 1000 m. The production well for the modal system is set at 300 meters (984 feet) and costs \$195K. One production well will generally be sufficient, unless the design entails both low reservoir temperature and "high" (e.g., 1,000 kW) power plant capacity. The modal injection well is set at 200 m (656 feet) deep and thus costs \$130K. This well is assumed to inject fluid in a "disposal" manner into an aquifer that lies above the geothermal reservoir. Wells are assumed to have 30 year lifetimes.

4. **Field Piping Cost:** a. **Production Wells:** It is assumed that the power plant is located very near the wellhead, and that \$10K will cover hookup costs. b. **Injection wells:** These will be located within 500 feet of the power plant; the pipe will cost about \$25K.

5. **Geothermal Fluid Pumps:** The cost of the fluid pumps is included in the cost estimate for the field. Costs were estimated from background literature and interviews [9, Frost]. Note that variable-speed motors are sometimes used on these pumps to help the plant follow varying loads. a. **Downhole Production Pump:** The pump is sized to produce a pressure boost of 200 psi plus other losses equivalent to about 30 psi. Power consumption is estimated from a standard flow times pressure boost equation, with an overall pumping efficiency of 70 percent. The nominal pump is expected to cost about \$70K, but at some low flow rates the cost might be as low as \$40K. This pump would be overhauled at roughly 2-year intervals. b. **Brine Injection Pump:** An 80 psi pressure boost from this pump is assumed, at an overall efficiency of 75 percent. The cost of pump with motor is estimated to be \$580 per motor horsepower.

7. **Pumping Power Requirements:** The estimated power (kW) needed for the brine production and injection pumps is subtracted from the net output of the power plant core module. In precise terms, this means that the actual net output of the systems will be about 5 to 15 percent lower than indicated by the nominal net output shown in the Tables, but the estimated cost of power accounts for these losses.

8. **Surface Disposal Cost:** Disposing the brine to the surface is included as an option in the GT-SMALL model. If the number of injection wells is

set to zero, the model sets the brine disposal cost to \$50K to cover the cost of disposal gutters, ditches, etc. In addition, the following terms are set to zero: Injection well cost, injection piping cost, brine injection pump cost, and brine injection pump power. This reduces the cost of power for the modal system by about 14 percent, a large saving if surface disposal is acceptable from an environmental point of view.

9. Field O&M: The field annual O&M cost is set at 4 percent of total field capital cost (excluding costs of exploration and of production pumps). For the modal case system, this is about \$18K per year. This is reasonable, since the reservoir temperatures and concentrations of dissolved minerals are relatively low compared to some geothermal systems for which general O&M requirements are a somewhat higher percentage per year (e.g., 6 to 7 percent). Additional costs for refurbishing the downhole production pumps are calculated separately.

10. Cooling Systems: The costing here assumes dry cooling systems integrated into the power plant module. When dry-bulb temperatures exceed about 27 °C, the net power output from a dry-cooled system will be reduced. At sites where this occurs for a high fraction of the year, evaporative (wet) cooling is more appropriate. Capital costs will be slightly less for wet-cooled systems, but on-site erection of the cooling towers will be required. Other useful cooling methods, depending on site conditions, include direct cooling from surface water or cooling ponds.

11. Flashed-Steam Alternative: Geothermal Power Company has indicated that noncondensing flashed-steam power plants, sized between 500 and 1,000 kW,

can be installed for about \$1350 per kW. [2]

12. Economics Assumptions: Costs are shown in mid-1993 dollars. The cost of power (cents/kWh) is calculated using levelized revenue requirements equations. The assumptions used are those employed in recent U.S. Department of Energy analyses. [8] The nominal discount rate is 11.0 percent. The assumed rate of future inflation is 3.9 percent. The project life is assumed to be 30 years. Taxes, tax incentives, and royalties are ignored. The consequent current-dollar annual fixed charge rate for capital items is 11.67 percent. The O&M cost levelization factor (for the 30 year project life and stated inflation rate) is 1.453. The equivalent constant-dollar annual fixed charge rate is 8.03 percent. Interest during construction is set at 8 percent of the capital costs. These assumptions are reasonable for funding of project development through national utilities. Private financing would increase the cost of funds somewhat.

Cost Sensitivities

Table A-4 shows effects on electricity cost of certain variations in system parameters. The values will allow readers to make rough estimates of the cost of power for locations where geothermal resource conditions are known. The values shown there are relative to the 10.7 cents/kWh cost of power estimated for the "modal" system.

For example, for a system where the reservoir temperature is 130°C (the multiplier from Table A-4 is 0.90) and the system net capacity is 200 kW (the multiplier is 1.30) the estimated cost of power would be: $10.7 \times 0.90 \times 1.30 = 12.5$ cents/kWh.

Table A-4. Effects on Cost of Power of Varying Project Parameter Values (Ratio to cost of power from modal system. Values for the modal system are shaded.)						
1. Power Plant Net Output, kW:	Value:	100	200	300	500	1000
	Multiplier:	2.16	1.30	1.00	0.76	0.56
2. Geothermal Reservoir Temperature, °C:	Value:	100	110	120	130	140
	Multiplier:	1.53	1.17	1.00	0.90	0.83
3. Production Well Depth, meters:	Value:		200	300	500	1000
	Multiplier:		0.95	1.00	1.10	1.44
4. Injection Well Depth, meters:	Value:	[a] 0		200	300	500
	Multiplier:	0.86		1.00	1.04	1.12
Note: [a] The 0 meter injection well depth assumes disposal of the geothermal fluid is to the surface.						

References and Credits

- [1] Firms with experience in the design and/or construction of small binary or binary-like geothermal power plants include: Barber/Nichols, Arvada, Colorado; Ormat, Inc., Sparks, Nevada; Ben Holt Company, Pasadena, California; Exergy, Inc., Hayward, California.
- [2] Firms with design and/or construction expertise for small flashed steam plants include: Ben Holt Company, Pasadena, California; Geothermal Power Company, Elmira, New York; Douglas Energy Systems, Placentia, California.
- [3] See P.M. Wright, Geothermal Resources Council Transactions, 1993, page 537, for estimates of emissions from geothermal electric plants.
- [4] Geothermal Resource Potential, brochure of the U.S. National Geothermal Association, March 1993.
- [5] Tsvi Meidav and Joshua Meidav, "Renewable Energy Development in Frontier Areas," International Conference on Regional Development, Ben Gurion University, Beer Sheva, Israel, December 1993.
- [6] Solar 2000, A Collaborative Strategy, Volume 1, Figure 8, U.S. Dept. of Energy, February 1992.
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