GL01264

Dr. Stan Ward.
University of Utah Research Institute
391 Chipeta Way Suite A
Salt Lake City, Ut.
84108

GEOTHERMAL POTENTIAL 1978
B. Greider
Vice President IEC
May 17, 1978

Interest in using the heat of the earth to provide an indigenous source of energy has begun to increase almost as rapidly as energy bills in the United States. Natural resource development companies and groups of investors are increasing their exploration for accumulations of heat that can be used in electrical generation, space heating and cooling, agriculture, and industrial process heating.

Developers expect the natural sources of heat above 450° F in the western United States to produce electricity at prices competitive with low sulfur coals shipped from the Powder River basin of Wyoming to the electricity generating centers supplying western Nevada and California. Water within the low energy 150° F temperature range can provide processing heat, if the source is in a location where the energy can be used in the U.S. It is expected that sulfur limits for fuel oil will be set similar to coal. To meet such standards, additional investment and costs will be required to prepare acceptable fuel. With such increases in cost, new uses for geothermal heat (energy) will become practical. When that happens, more people will become interested in joining the exploration search to find and develop new deposits of heat for production of energy.

The development of a geothermal reservoir is capital-intensive, requires expert planning, and long times from initial expenditure until positive income is achieved. The utilization of a developed project requires extensive engineering, approximately two years in negotiation with governmental agencies, and a lot of money.

The costs of maintaining and operating the producing fields is about four to five times greater than the capital investment. An important portion of this cost is associated with the injection system that collects the water after the heat is removed and then returns it to the subsurface reservoirs. Reducing these costs is an essential objective if geothermal is to be competitive with other fuels.

Countries with high fuel costs and geothermal sites are now developing a wide variety of geothermal plants. Japan appears to be building the most efficient flash systems for use in hydrothermal areas rimming the Pacific Ocean.

The assessment of geothermal energy resources by considering this energy to simply be the heat of the earth provides estimates of gigantic size. Useful geothermal reserve assessment requires professional analysis. The goal is to determine how much heat can be produced at a useful rate and temperature for at least twenty years from one area. This demands a

Dear Stan:
Most of this is old hat to you. This is the basic format of the presentation I made at the GRC short course for the Wash. D.C. workers
Regards Bob.

thorough understanding of the manner in which heat is transported to areas of accumulation, how it accumulates, the methods and costs to find, produce, and convert to a useable form of energy. With those studies in hand, a person can then determine what part of this resources can be sold in competition with other fuels and thereby establish the size of the reserve.

Accessments of the supply of geothermal energy have been published by government agencies, private companies, universities and inter-governmental agencies such as the United Nations. These estimated supplies have been prepared in megawatts per year, joules per year, giga watt centuries, giga calorie centuries, per cent of the national energy budget, the equivalent bbl(s) of oil, and per cent electricity generated per year.

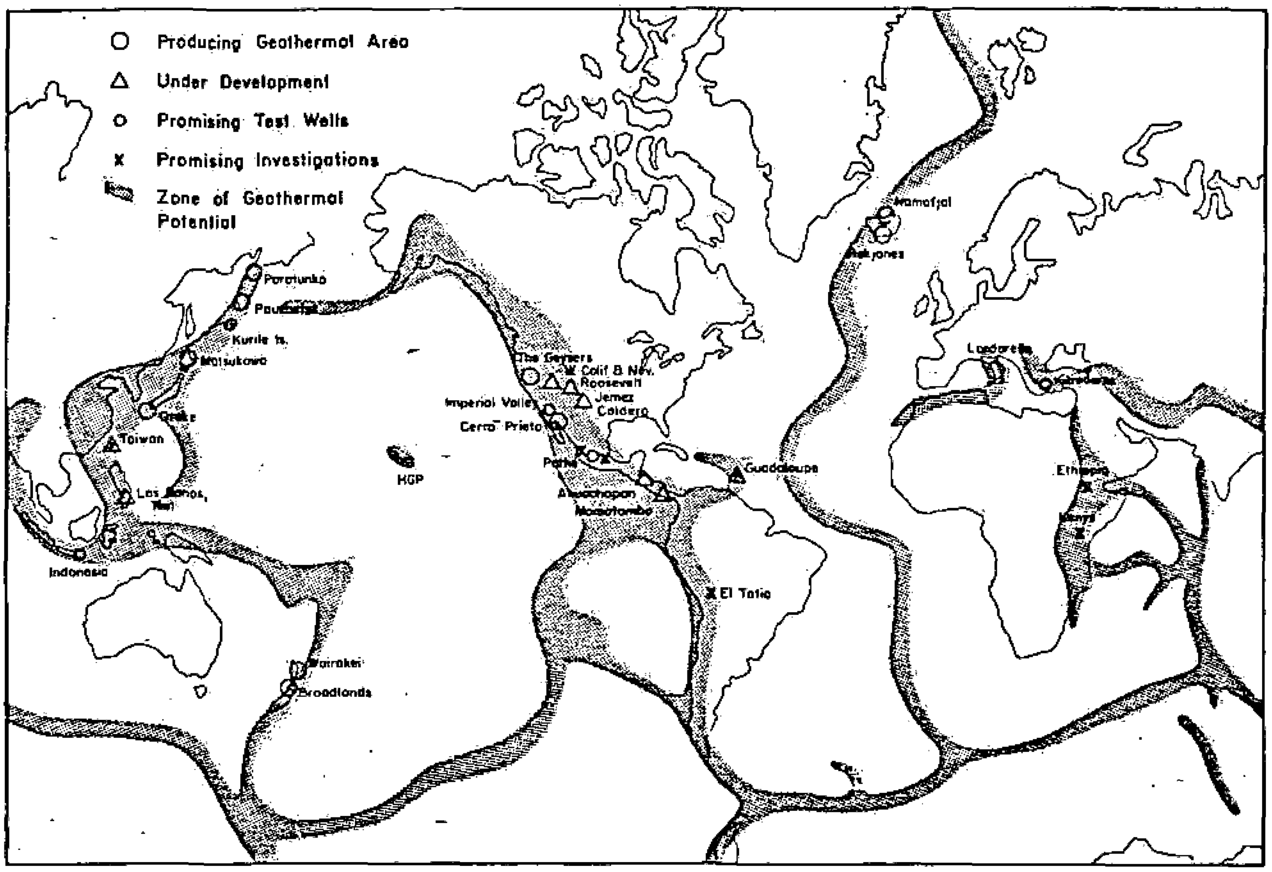
The supply has been related to all the heat present above an arbitrary temperature datum, the amount of heat between certain temperature levels, that heat contained in producing water, and that heat contained in the rock framerock transferred to the moving body of water, and the amount that could be produced if the government would provide various incentives.

These incentives have included tax credits, deductions in tax calculations, investment tax credits, rapid depreciation, and extensive depletion allowances. Other incentives include aid in exploration, aid in developing, engineering of generating plants, financing of generating plants, and reservoir engineering studies. Very little has been prepared showing the increased benefit to governmental programs, including tax revenue by demonstrating the increased flow of dollars from projects that would become profitable with this aid compared to project tax revenues that would be commercial without this aid.

The actual potential of geothermal energy is affected by how the resource and reserves are calculated. These calculations must consider availability and application of the governmental incentives, the price of other energy sources, versus the market price of geothermal energy, and the reliability of the production forecast. The size of required investment, and the expected profit generated by those investments, plus the availability of lands to explore will be the motivating forces in determining the true potential of geothermal energy development in the United States.

The most important factor in converting any resource into a reserve is how the individuals that are actively dedicated to discovery and development, attack the problem. The key to successful reserve development is the quality of the people assigned to the task.

A casual examination of geothermal areas of the world, shown in figure 1, will allow even the uniniated to estimate the supply of geothermal energy that is presently useful in the generation of electricity. The world's total geothermal generating capacity in development and developing projects with significant reservoir testing, is approximately 2,600 megawatts. The potential areas identified by preliminary investigation of sufficient extent to allow analogies with development areas is estimated to have an additional 12,000 megawatts of indicated reserves. Inferred reserves of an additional 20,000 megawatts of electricity capacity may be developed within the next 20 years. The existence of geothermal energy does not assure the resource will be converted to a reserve. In a free economy the competition in the market place and the return on the potential investment will determine if and when these resources will become useful.



GEOTHERMAL POWER DEVELOPMENT

MAP 1

The United States has the greatest producing capacity in the world at this time. The Geysers in northern California produces and has more capacity building than any other commercial producing geothermal country in the world. Those areas capable of commercial production or that have commercial plants under engineering design are listed in Table I.

Table I

World Geothermal Generating Capacity

In Megawatts

Country	Area	Operating Capacity	Engineering & Construction
U. S. A.	The Geysers	502	450
	Roosevelt	- -	80
	Heber	- -	110
	E. Mesa	- -	60
	Other	- -	200
Italy	Larderello	385	
	Travale	15	
	Mt. Amiato	22	
New Zealand	Wairakei	150	
	Broadlands		165
	Kawerau	10	
Japan	Matsukawa	20	
	Otake	13	55
	Onuma	10	
	Oninobe	25	
	Hatchobaru		55
	Takinow		55
Mexico	Cerro Prieto	75	75
	Pathe	3.5	
El Salvador	Ahuachapan	35	60
Nicaragua	Momotombo		30
Iceland	Namafjell	2.5	
	Krafla		55

Table I (cont.)

World Geothermal Generating Capacity

In Megawatts

Country	Area	Operating Capacity	Engineering & Construction
Phillipines	Tiwi		100
USSR	Pauzhetsk	5	
	Paratunka	1	
Turkey	Kizildere		2.5
	TOTAL	1274.0	1552.5

Geothermal energy properly located may be useful for its contained thermal energy without being converted to electricity. In many geothermal areas of the world, this is the simplest and cheapest source of energy. Interest in using this source of energy is directly related to the need for local thermal energy, and the cost of other sources of heat. Space heat and cooling, industrial processing, and agricultural uses are the most significant uses of this fuel. The present non-electrical use of the contained thermal energy in geothermal areas of the world is about 7,000 MW thermal or 5×10^{14} J/D. This is equivalent to the BTU content of 105,000,000 bbl(s) of oil per year.

EPRI this year estimated non-electrical uses of geothermal energy in the world should be about 20,000 megawatts thermal within the next 10 years. If this comes to pass, the thermal equivalent of approximately 148,000,000 bbl(s) of oil per year can be saved. This appears to be worth pursuing as the potential use is 200 to 300 times this projected use.

GEOTHERMAL PRINCIPLES

A quick review of the heat principles involved in geothermal development will provide the foundation for assessing the value of geothermal energy accumulations. Heat is the energy contained in a body whose molecules are in motion. When heat is transferred from one substance to another, energy is transferred to that substance. Heat flow is a measure of the amount of heat (energy) being transferred from a substance of higher temperature to a substance of lower temperature.

If a well is drilled into a fluid-saturated system, the heat is transported from the rocks to the well bore by either vapor (steam) or liquid. There must be sufficient horizontal and vertical permeability to allow the fluid to move easily. A 6,000 ft. to 8,000 ft. well must sustain flow rates of more than 100,000 lbs. of steam per hour, or 500,000 lbs. of water (above 325^{0} F) per hour for 20 to 25 years to be considered commercial for electricity generation. Direct use of heat for industrial heating or space heating and cooling does not require such high heat output. The lower temperatures for such uses can be found in a greater number of anomalies, however, their usefulness is dependent upon low costs being achieved in development and production.

The geologic model that is generally accepted by geothermal explorers and developers (Figure 2) has three basic requirements to function:

1. A heat source (presumed to be an intrusive body) that is above 1200^{0} C and within 16 Km of the surface.

2. Meteoric waters circulating to depths of 10,000 ft. - 20,000 ft. where heat is transferred from the conducting impermeable rocks above the heat source.

3. Vertical permeability above the heat source connecting the conducting rocks with a porous permeable reservoir that has a low conductivity impermeable heat retaining member at its top.

Water, expanding upon being heated, moves buoyantly upward in a hot concentrated plume. Cold waters move downward and inward from the basin's margins to continue the heat transfer process. Heat is transported by convection in this part of the model.

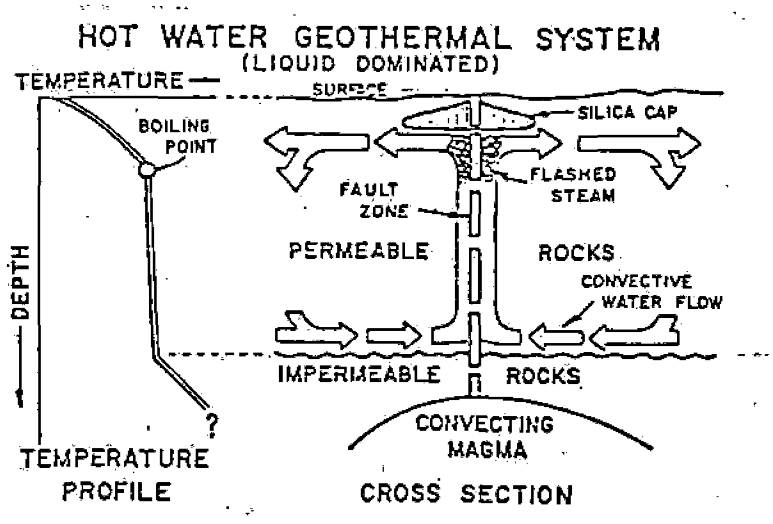


Fig. 2 — Geological Model of a Hot Water Geothermal System (after White, 1973).

Geologic investigation is the necessary ingredient that makes all other techniques useful. Broad reconnaissance of the surface data integrated into subsurface data is used to find an area of general interest. The ingenuity of the prospect finder in using data available to all workers determines whether an exploration program moves into advanced stages of using the proper combinations of the above methods. Geologic interpretation of the data acquired may justify the money required for exploratory drilling. The results of the drilling must be integrated into the geologic investigation to determine if a promising prospect is present.

The investigation must establish that:

1. High heat flow or strong temperature gradients are present at depth.

2. The geology provides reasonable expectation that a reservoir sequence of rocks is present at moderate depths from 2000' to 6000'.

3. The sequence of rocks offers easy drilling with minimal hole problems.

4. A high base temperature and low salinity waters as indicated by geochemistry of water sources should be present. The surface alteration and occurrence of high heat flow should cover an area large enough to offer the chance for a field capacity of more than 200 MW.

Interpretation of geochemical data requires professional skill in geology and chemistry. If the geology is well known, useful information can be developed.

Geophysical surveys are useful in predicting the general area and depth of high temperature rocks and water. Rocks at depth are better conductors of electricity (natural and induced currents) when there is an increase in temperature, an increase in porosity, an increase in clay minerals, or an increase in salinity in their contained fluids.

Table I from C. Heinzelman's presentation of October 15, 1977, illustrates exploration techniques and associated costs. The overall amount of money (per successful prospect) required is 2.5 million to 4.75 million 1977 dollars. This provides for limited failure and follow-up costs, but does not include the other exploration failures and land costs.

Table I

EXPLORATION TECHNIQUES & APPROXIMATE COSTS

Objective	Technique	Approximate Cost ($)
Heat Source & Plumbing	Geology	$ 15,000
	Microseismicity	15,000
Temperature Regime	Gravity	20,000
	Resistivity	25,000
	Tellurics & sagnetotellurics	40,000
	Magnetics	15,000
	Geochemistry (Hydrology)	12,000
	Temperature Gradient 20 holes	100,000
	Stratigraphic Holes (4)	160,000- 240,000
Reservoir Characteristics	Exploratory wells (3)	1,800,000-4,000,000
	Reservoir test	250,000
Total to Establish a Discovery		$2,472,000-4,752,000

This is probably the minimum expenditure to move a portion of the resource into a reserve.

Upon deciding that a significant geothermal anomaly exists, the rate of engineering expenditures must increase rapidly to determine whether the development can proceed. Essentially, there are no set figures for what it costs to develop a geothermal field. The basic reason for this is that each depends upon engineering the development to be compatible with the geology of the accumulation, and the requirements of the electricity generating system. The electricity generating system must be designed within the constraints of available temperature, rate of production, and ambient conditions of the field site. The key variables are:

1. Temperature of the fluids produced.
2. Composition of the reservoir fluids.
3. Composition of surface or near surface fluids.
4. Geology of the reservoir framework.
5. Flow rates that can be sustained by the reservoir.
6. Cost of drilling in the prospect area.
7. Well spacing and geometry of the producing and injection sites.
8. Turbine system to be used.
9. General operating costs in the area.

Test Wells - Thermal evaluation requires the drilling of test holes. Heat flow and temperature gradient evaluation requires drilling to intermediate depths. Confirmation drilling requires holes drilled to the actual reservoir for diagnostic evaluation.

Heat flow and temperature gradients measured in the upper 100 to 500 ft. depth are useful in describing the area where the heat transfer is most intense. When mapped, these do give a qualitative analysis as to the location and shape of the hottest near-surface heat accumulation. Linear projection of temperatures obtained near the surface cannot be used to predict the temperatures that will be encountered 2000-3000 ft. below the surface, even if the section below has a uniform lithology and the geothermal graident is a straight slope. The temperature for a fluid-saturated system cannot be projected to a maximum above that for boiling water at the pressure calculated for the depth of projection. At some point along the boiling point curve, the temperature of the system may become isothermal and the rocks and fluids will have the same temperature for many hundreds of feet deeper. The rock temperature may decrease as a hole is drilled deeper if the hole is on the descending edge of a plume of hot water or merely below the spreading top of a plume. Heat flows from a hot body to a cooler body. This is not a function of being above or below a reference point of depth.

So that the performance of the geothermal cell can be predicted, deep tests must be drilled. These holes must be of sufficient size to adequately determine the ability of the reservoir to produce fluids above 365° F at rates of more than 100,000 lbs. of steam per hour or 500,000 lbs. of liquid per hour. Although it is desirable that these fluids have less than 32,000 ppm dissolved solids and less than one (1) percent non-condensable gases in solution, they may be extremely corrosive and dangerous to test.

To determine if a commercial development is possible, three or four wells must test the reservoir to obtain the basic reservoir engineering data on producibility rates that are necessary. Reservoir pressure drawdown and buildup analysis must be conducted to determine reservoir permeability and extent. Fluid characteristics and analysis of non-condensibles present require extensive flow tests. Injectivity testing is required to develop plans for disposal and pressure maintenance systems. Rocks may produce fluids easily, but may not accept them on return to the reservoir. This must be established in the laboratory and confirmed in the field.

A review of the costs associated with finding, developing, and producing geothermal energy must consider that the actual dollar amounts reported are for a specific time and place. The following costs will be different than the amounts reported by each of the United Nations' symposia. This illustrates that changes in the required money are still being experienced in dry steam, high temperature flash, and moderate temperature flash or binary systems. The costs to find geothermal systems continue to increase as geologists learn there are cold holes very near hot areas; there are hot areas within an overall cold area; there can be a steam zone within a hydrothermal area; and there can be two different types of geothermal systems, vapor and liquid dominated, vertically separated within the same geographic area.

Development wells in the depth range of 5,000' to 10,000' are being drilled and completed for $500,000 - $1,500,000. Injection wells are being completed in the same cost range. The ratio of producers to injectors depends upon reservoir characteristics. The ratio will be between 1:1 or 1:2 for hot water systems. Water-steam lines from the producing wells to the generating plant can be estimated to cost $35 to $100/KW capacity. This cost is dependent upon the volume of fluid per kwh, the development pattern, and the plant location in relation to the producing wells. The amount of surface area used should be the minimum possible to achieve the maximum economic recovery. The engineering design work determines the most economical layout.

Techniques developed to drill slanted holes from a central platform can be used in developing geothermal reservoirs that have a broad area of heat with a local area of intense heat and where injection is feasible. Slant drilling is more costly than vertical drilling. Production pipelines are reduced in length if the plant is located adjacent to the producing islands. This results in a more efficient operation. The geology and geometry of the reservoir determines feasibility of using this method.

Condensate return, pipelines' design, and cost depend upon the uses for the condensate. If the condensate is mixed with the brine that is not flashed, a mixture similar to the produced fluids can be returned to the injection sites and return lines will be similar in size and cost as the production lines. If the condensate is used in the cooling system and allowed to evaporate, a small diameter pipeline can be used to return cooled water to injection lines. If this is so, the condensate pipeline can cost as little as $4-$15 per KW.

Plants built to use steam produced directly from a dry steam reservoir are the lowest in cost to build. PG&E's plant #15 is expected to cost $320/KW with provisions for H_2S treatment. This is an increase of 250% over the average of the 1961-1974 period. In the same period, the cost of electricity generated averaged about 5.6 mills per net kilowatt hour. 1979 costs will have increased the price of electricity to 25 to 30 mills per kilowatt hour from steam fields.

Hot water flash plants have an extremely broad range of cost. This is because the temperature and chemical characteristics of the produced fluids and unit size have a wide range. This creates costs from $400 per kilowatt to as much as $700 per kilowatt. Double flash 45 net MW operating on low solids fluids at temperatures around 450° F most likely can be constructed for $450 to $475 per net kilowatt. Fluids 100° F cooler will require plants costing $100 more per kilowatt capacity.

Binary units designed for using low bioling point fluids to drive the turbine are experimental designs. No plant greater than 5 MW has been operated so cost criteria are tenuous. Present estimates for approximately 50 MW plants range from Ben Holt Engineering's estimate of $500 per kilowatt to Ford Bacon & Davis shell and tube system at $655/kwh. A small 10 MW binary system is being constructed by Imperial Magma. This has a reported cost of $1,000 per KW.

A summary of estimated development costs after exploration expenses for the field supply, power plant, and ancillary equipment for a 50 megawatt hot water flash unit is as follows:

Table II

Development Wells (12)	$ 10,800,000
Injection Wells (6)	5,400,000
Pipelines	2,800,000
Miscellaneous Field Expense (includes interest & working capital)	9,000,000
Power Plant	25,000,000
TOTAL	$ 53,000,000

ECONOMIC CONSIDERATIONS

To obtain a comparison of geothermal fuels with the more widely used fuels is quite difficult, because each geothermal area requires a plant design specifically useful for that local area. The California Geyser's steam price of 16.5 mills per kwh is as inexpensive as geothermal energy can be produced in the U.S. today. This is a dry steam fuel, and the operators have more than a decade of experience in drilling, completions, and production operations. Optimum techniques have been developed so that maximum steam production per dollar invested can be maintained. The high energy content of this fluid provides a competitive heat rate, easy to construct collection systems, and the most simple of plant and reinjection facilities. The actual cost of the wells are frequently as high as $750,000 - $1,000,000, but the operation and the high utility of the steam allows a minimal price for the energy.

The wide variation of estimates of fuel costs and electricity generating costs derives from treatment of fuel processing and storage expense, income taxes, ad valorem taxes, insurance, interest during construction, return on investment required, and specific requirements for plants in the area of operation for the estimating companies. The utility usually expects to earn a minimum of 20% ROI on its equity portion. The exploration and producing investors have learned that a minimum acceptable rate of return on investment for their portion of the projects is also 20% ROI. The average conventional energy venture (non-geothermal) usually obtains about twice this rate of return.

The return on investment for the developer is most sensitive to the price received for the energy. Next to reliability of supply, the utilities desire to use geothermal energy in its electricity generating systems is dependent upon its price being low enough to make its use worthwhile. Much like coal and uranium, geothermal fuel prices will be a negotiated price between the supplier and the user. Each field will have significant differences in design so a uniform price cannot be expected for construction of the production facilities, or construction of the utilities conversion plant.

The nature of the reservoir geometry and the ability of the reservoir to respond to changes in production, rates, and temperatures, will determine the final costs for producing electricity from each geothermal project.

The basic structure of price must provide an attractive rate of return to the prospector. To achieve this, the prospector's risk capital investment and time at risk before income must be minimized. Most important, the revenue should reflect the actual value of the energy sold.

COST COMPARISONS

The cost comparisons between the various sources of energy that will be available and useable for electricity generation during the next decade will affect the rate of geothermal energy's growth. The economic desirability of the production or use of a fuel is sensitive to its price. Regulatory requirements have direct effect upon production and construction costs. The tax treatment for each fuel system is a dynamic one. This makes it very difficult to assess the resulting economics.

The amount of money needed to construct and operate plants to use each fuel is a strong component of how much the customer will pay per unit of fuel. The heat rate of the energy conversion system determines the amount of fuel needed to supply the plant. In electricity generating plants, the heat rate is the number of BTU's required to produce a net kilowatt hour. The average coal and oil burning plant uses 8,500 to 10,500 BTU/kwh. A nuclear plant uses about 14,000 BTU/kwh. Geothermal plants use between 21,000 to 33,000 BTU per net kwh.

OIL

Electricity produced from oil fired plants is directly related to the cost of low sulfur fuel oil. An oil fired turbine generator plant costs between \$385.00 and \$400.00 per kw. A combined cycle plant is about \$300.00 per kw. The difference in heat factor, operating cost, and available capital for these plants establish which will be used for meeting the increased demand and plant replacement schedule within a utilities service area. The estimated cost of fuel oil in mills per kwh developed by Stanford Research Institute, is approximately 23 mills per kwh. Strong competition between suppliers results in a stabilizing effect upon the overall price of oil. Utility planners have estimated the range of price of oil to be 20.5 to 21 mills per kwh. These cost ranges combined with new plant costs will produce electricity between 33 and 44 mills per kwh.

COAL

Coal prices are related to specific sources of supply and dedication of specific sources of coal to certain plants. Coal does not presently have the wide range of usefulness that oil enjoys today. This limits the substitution of one coal for another.

The price of steam coal and plant construction costs to meet environmental requirements result in an estimated price of 35 mills for electricity generated in new coal plants. Fuel suppliers currently estimate coal can be delivered within a one-thousand mile radius for 9 to 10 mills per kwh if surface mining methods are used.

NUCLEAR

Nuclear fuel plants appear to offer the least expensive electricity for a non-indigenous source of energy.

The utility industry estimates they will be paying 6 to 6.5 mills per kwh for nuclear fuels and plant costs in 1977 dollars will be $800 to $1000 per KW. The estimated cost of electricity from such plants will be between 32 to 34 mills per KWH.

GEOTHERMAL

Comparison of conventional electricity prices with geothermal steam, electricity prices are a matter of public record. This is the least expensive of all thermal systems employed in the U.S. To obtain a comparison of hot water flash steam plants, it is necessary to use developments outside of the USA for performance factors. Economics of hot water flash to steam projects continue to be impressive. Cerro Prieto's development is very encouraging as exploratory work confirms this development can exceed 500 MW. The improvement in heat recovery with double flash units would reduce the cost of electricity and increase the size of reserves significantly. Seventy-five megawatts have now been developed and work is underway for the next 75 MW. The first unit of 75 MW was developed for $264/KW, and produced electricity for approximately $.008 tax free. Today, costs would be about twice that amount. The generation cost includes the well field operation as this is an integrated operation. It is estimated the second 75 MW plant will produce electricity for about 16 mills tax free.

It is possible to use the development work now in progress at Momotombo Nicaragua to evaluate the costs of developing a hot-water-flash-field today. DeGolyer McNaughton, the international consulting firm and Herman Dykstra, a reservoir engineering consultant, have completed examination of all the field test data from Momotombo. Tests using bottom hole pressure devices in selected wells were combined with full field flowing tests. The firm concluded that double flash turbines could produce 96 MW for more than 30 years using the portion of the reservoir developed. Subsequent completion tests have demonstrated more than 100 MW capacity.

Turbine specifications are now being prepared to have 8 plant turbine with 80 psig first stage and 20 psig second stage. The power plant for this 225° C field may have two 35 MW units in operation by mid 1980. The estimated cost for the electricity generating plant installed will be $460/KW. A savings of $26 million in foreign exchange would result from this development.

STEAM

Geyser's steam price of 16.5 mills per kwh is about as inexpensive as geothermal energy can be produced today. The 1978 price of 16.5 mills per kwh is well below the competitive value of this energy. 20 mills per kwh would be a price more nearly reflecting its actual value in an area using oil or coal for electricity generation.

Plants to use a dry steam are the lowest in cost to build. PG&E's plant #15 is expected to cost $320/KW with provisions for H_2S treatment. This is an increase of 250% over the average of the 1961-1974 period. In the same period, the cost of electricity generated averaged about 5.6 mills per net kilowatt hour. 1979 operating costs will have increased the price of electricity to 25 to 30 mills per kilowatt hour.

Summarizing the preceding discussion on comparison of costs and resultant prices of electricity, we can tabulate oil, coal, nuclear vs. geothermal as follows:

	Oil	Coal	Nuclear
Fuel mills per kwh	20-23	9-11	6-7
Plant $/KW	300-400	580-950	800-1000
Electricity Busbar mills/kwh	33-44	35-36	32-34

	Geothermal		
	Steam	Flash 450° F	Binary
Fuel mills per kwh	14.5-16	16-20	26-30
Plant $/KW	320	450-475	500-1000
Electricity Busbar mills/kwh	22.5-24	25-30	40-48

RESERVE ESTIMATES

With these competitive conditions and an idea of the required investments in plant and fields, we can now estimate the potential reserves identified in relation to the proven reserve.

The proven reserves of the Geysers is now 908 megawatts. The potential reserves are another 1100 MW. To infer that the hot water area surrounding the dry steam reservoir will be productive of waters that will be used in flash steam plants is reasonable. Inferred hot water flash reserve should be approximately 1,000 MW.

The proven reserves in the Imperial Valley are 400 megawatts. Potential reserves of Brawley, East Mesa, Heber, Niland, and Westmoreland total 1600 MW. Reserves have been inferred with another 1,000 MW in these and similar anomalies within the province. Considerable work must be done on conversion systems, and deep drilling in the California portion of the Imperial Valley if another 5,000 MW are to be moved from the resource category into the reserve category in the next 20 years.

Coso, Lassen, Mono-Long Valley, Mammoth, Randsburg, can be credited with about 700 MW of inferred reserves. Sufficient drilling has not been done in these areas to estimate reservoir quality, water characteristics, and temperature distribution.

In the western Utah area, Roosevelt is the only area with proven reserves. It appears that sufficient testing and plant design work has been completed to assign 80 MW to that classification. 120 MW potential and 300 MW inferred reserves can be assigned to Roosevelt on information now available. The remainder of that general area including Cove Fort - Sulfurdale, Thermal-Black Mountain should have 1,000 megawatts potential reserves and 500 MW inferred.

Testing of potential areas in Nevada has not progressed to the stage where proven reserves can be assigned. The potential reserves of Phillips' three areas, and Chevrons' two areas in the northern half of the state, indicates 400 MW reserve. An additional 600 MW can be inferred on the basis of drilling data being extrapolated with geophysical surveys. With continued confirmation success in the Carson sink area, an additional 500 MW could be moved from resource to inferred reserves. New Mexico's Valles Caldera is considered as having 100 MW potential reserve. From the size of the anomaly and the temperature indicated by surface springs, an inferred reserve of another 300 MW should be assigned. This area has a total reserve of 400 MW.

Oregon does not have proven reserves except in the direct use of the heat contained in the subsurface waters around Klamath Falls. The exploration for geothermal energy useful for generation of electricity has been encouraging in the northeast extension of the Gerlach-Baltazor trend into Oregon from northwest Nevada. The Alvord area has 200 MW potential reserves and 100 MW inferred. Between Alvord and Vale Hot Springs another 400 MW can be inferred. An additional 300 MW can be inferred from other heat flow and geophysical survey work in the general area.

This table summarizes these reserve catagories.

SUMMARY

ELECTRICITY GENERATION RESERVES

	Proven (Measured) MW	Potential (Indicated) MW	Inferred (Geol-Geoph) MW
Geysers	908	1,100	1,000
Imperial Valley	400	1,600	1,000
Coso-Lassen, Long-Valley, Mammoth, Randsburg			700
Roosevelt	80	120	300
Cove Fort, Sulferdale, Black Mountain-Thermal		1,000	500
N. Nevada		400	600
New Mexico		100	300
Alvord Area		200	100
Alvord to Vale			400
Other Oregon SE			300
Subtotal	1,388	4,500	5,200
Total Reserves	11,188 MW		

no. Snake R. plain
Rio Grande R.

The direct use of geothermal heat in the U.S. is on a local project basis except in Klamath Falls, Oregon and Boise, Idaho. Local greenhouse operations, individual processing plants in industrial and agricultural projects are found throughout the western U.S., Alaska, Texas and Southeast Appalachians. It is estimated these present direct uses represent proven reserves of 35 MW.

Reserves cannot be assigned to geopressure-geothermal projects. It is hoped the government research work in progress can develop sufficient data to provide inferred reserves in 20 years.

Reserves now identified in the three catagories total 11,088 MW. This rapid build up from the reserve of 500 MW existing just four years ago demonstrates an aggressive search for and investment in producing areas. The 164,000,000 barrels of fuel oil that will be saved annually for electricity generation when this is developed is about 1/10 the amount of direct use potential existing today.

An oil accummulation to provide 164,000,000 bbls per year for 30 years would require 4.9 billion bbls to be available for production. Consider that less than .2 of 1% of all wildcats drilled in the U.S. during the last four years discovered producible reserves over the life of the field greater than 1 mm bbls of oil.

To assess the impact of the development of this reserve now identified plus the stimulus such development will give to exploration requires an assumption that the governmental agencies believe indigenous sources of energy are necessary to the economy of the USA.

In 1975 the forecast of the growth of geothermal capacity spanned 5,000 MW to 20,000 MW on line by 1985. The forecast by B. Greider at the 1975 United Nations Symposium was that 6,000 MW capacity would be on line by 1985. This required a reserve of 11,000 megawatts be discovered. The reserve has been discovered. The majority of the prospects contributing to this growth were on federal lands. These same prospects were recognized to be primarily in a temperature range that during most of the productive lifetime the reservoir would produce fluids at less than 400° F. The basic assumption underlying these forecasts was that viable economic incentives for geothermal would be similar to ones for other natural resource developments.

Stanford Research Institute, The University of California, Riverside, and Science Application Inc. have each provided thoughtful studies on the effect of tax incentives for the development of geothermal resources. The effect of such tax treatment has been focused on the resulting price of electricity or upon how much income this would "shelter" for the producer.

Each study has sidestepped the critical question of how large a capacity can be economically developed from recognized prospects with the subject incentives. How many would be developed lacking such economic stimuli. The next question that should have been answered is: what is the flow back to government agencies in tax revenues if certain incentives are initiated? This demands careful analysis of the possibility of reduced tax flow from projects that are certain to be developed without the incentives versus the increased tax revenue from those projects that would not have been developed without the incentives.

Consideration of the dynamic effect of taxation regulations on an incipient industry will show a tremendous benefit to government agencies in increased tax revenues. Robert Rex prepared the following two illustrations demonstrating the flow of monies to federal, state, and county agencies for a single 48 net MW project on federal lands and the effect if 1,000 MW developed on federal leases.

ESTIMATED GOVERNMENT REVENUES
FROM FIELD DEVELOPMENT PROGRAM

1000 MW PROJECT

10% Federal Royalty Payments	$1,462,500,000
Federal Income Taxes	1,243,750,000
State Income Taxes	1,398,125,000
Ad Valorem Taxes	345,625,000
	$4,450,000,000

ASSUMES:
25 MILS/KWH
30 YEAR PROJECT LIFE
6% ANNUAL INFLATION RATE

ESTIMATED GOVERNMENT REVENUES
FROM FIELD DEVELOPMENT PROGRAM

EAST MESA 48 MW PROJECT

10% Federal Royalty Payments	$ 70,200,000
Federal Income Taxes	67,110,000
State Income Taxes	16,590,000
Ad Valorem Taxes	59,700,000
	$ 213,600,000

ASSUMES
25 MILS/KWH
30 YEAR PROJECT LIFE
6% ANNUAL INFLATION RATE

If the reserves now known on federal lands are developed additional ones will be added in the process of development and by the increased exploration attracted to the area of successful development. Five thousand megawatts production on federal lands and two thousand MW on non-federal lands should return to the government 903 million dollars in revenues each year over the first 30 years of the projects lives. 7.02 billion dollars would flow to the federal government as royalty, 9.4 billion as income tax. 2.3 billion would be allocated to the various states' income tax revenues and more than 8.4 billion dollars to local county governments as ad valorum taxes.

SUMMARY

In 1973 the geothermal reserves in the U.S. were 500 MW. Reserves identified since 1970 total about 11,100 MW. This is enough energy to supply the total electrical needs for 11,000,000 people. To generate the same electricity using fuel oil 164 million barrels per year would be needed. Five billion barrels of oil would need to be discovered to supply the equivalent energy for 30 years.

Geothermal energy can compete with the other types of energy now being used in the U.S. To do so, the energy must be available from its reservoir at a temperature above 400^{o} F. Below this temperature, operating cost rise significantly as the number of wells to produce and reinject the fluid increases.

Tax incentives must be provided to encourage significant investment in the mid temperature hot water resources if this type of energy is to be developed.

The cost of the plants rise rapidly as the temperature of the reservoir decreases. The volume of fluid required to move through the system increases rapidly to supply the required heat. There are economic limits established by temperature that must be recognized. If the BTU content of a ton of coal drops, there is a point where it is not useable for power production. The same is true for oil and gas fluids as their associated water or inert gas ratio increases. Geothermal fluids quality and usefulness is also dependent upon its BTU content per unit volume produced. The building of power plants for mid temperature projects is critical to the utilization of this large resource.

For this reason, it is difficult to present a specific cost of electricity produced by broad types of resource. The probable range of prices for electricity generated from steam and hot water reservoirs today is:

	Mills/KWH
Steam 450^{o} F and above	22.5 - 24
Hot water flash - below 400^{o} F	36 - 50
above 400^{o} F	25 - 30
Binary	40 - 48

The expected value of a geothermal project, the field costs and the resulting costs to generate electricity are affected by the interrelated variables such as:

- Temperature of fluids
- Composition of fluids
- Geology of reservoir
- Cost drilling
- Flow rate per well
- Well spacing
- Turbine system
- Operating costs.

Research must continue on how to make fluids with temperatures below 400^{0} F useful. The technology is now mature. There are vast quantities of heat in this resource awaiting the solution to the economic problems of using this low grade heat.

Risk capital must be readily available in units of 10 to 15 million dollars at the beginning of exploration. Development to 400 MW may require up to 100 million dollars investment before payout of the first 50 MW unit is obtained. The investor with sufficient money to carry out a successful program will compare the return of invested capital offered by similar projects (utilizing similar technology and business know-how). The projects offering the best rate of return for similar risk and investment will usually be the ones selected for funding.

The biggest problem in obtaining risk capital is the uncertainty of the business. This includes the discrimination in tax treatment of hot water versus steam. This precludes being able to market the energy at competitive prices and obtain as favorable rate of return as other industries offer. Prospective investors should have assurance that government rules and regulations will encourage the discovery and use of this energy.

The expected value of a geothermal project, the field costs and the resulting costs to generate electricity are affected by the interrelated variables such as:

- Temperature of fluids
- Composition of fluids
- Geology of reservoir
- Cost drilling
- Flow rate per well
- Well spacing
- Turbine system
- Operating costs.

Research must continue on how to make fluids with temperatures below 400° F useful. The technology is now mature. There are vast quantities of heat in this resource awaiting the solution to the economic problems of using this low grade heat.

Risk capital must be readily available in units of 10 to 15 million dollars at the beginning of exploration. Development to 400 MW may require up to 100 million dollars investment before payout of the first 50 MW unit is obtained. The investor with sufficient money to carry out a successful program will compare the return of invested capital offered by similar projects (utilizing similar technology and business know-how). The projects offering the best rate of return for similar risk and investment will usually be the ones selected for funding.

The biggest problem in obtaining risk capital is the uncertainty of the business. This includes the discrimination in tax treatment of hot water versus steam. This precludes being able to market the energy at competitive prices and obtain as favorable rate of return as other industries offer. Prospective investors should have assurance that government rules and regulations will encourage the discovery and use of this energy.

REFERENCES

Armstead, H.C.H., 1973, Geothermal economics, in Geothermal energy, review of research and development: UNESCO (Earth series).

Austin, A.L., Higgens, G.H., and Howard, J.H., 1973, The total flow concept for recovery of energy from geothermal hot brine deposits: Livermore, California, Lawrence Livermore Laboratory (3 April).

Axtell, L., Geothermal Services, San Diego, California; Bailey, J.R., Centurion Sciences, Tulsa, Oklahoma, Maxwell, R., Gulf Oil, Denver, Colorado; Otte, C., Union Oil, Los Angeles, California, 1975 in Greider, B., Survey of industry exploration cost increase 1974-1975: San Francisco, California (March).

Bailey, D.G., 1972, Exploration for geothermal energy in El Salvador: United Nations Progress Report.

Bloomster, C.H., 1975, Geocost: A computer program for geothermal cost analysis: Battelle Pacific Northwest Laboratories, USAEC Contract A.T. (45-1) 1830 (February).

Butler, D.R., 1975 Geothermal energy's contribution to the total energy spectrum: Am. Assoc. Petroleum Geologists National Conference, Dallas, Texas.

Combs, Jim, 1971, Heat flow and geothermal resource estimates for the Imperial Valley, Cooperative Geological-Geophysical-Geochemical Investigations of Geothermal Resources in the Imperial Valley of California: University of California, Riverside, p. 5-27.

Cheng, P., Lau, K.H., and Lau, L.S., 1975, Numerical modelling of geothermal reservoirs: The Hawaiian Geothermal Project, summary report for phase 1, p. 83-110.

Diment, W.H., Urban, T.C., Sess, J.H., Marshall, B.F., Munroe, R.J. and Lacherbruch, A.H., 1975; Temperatures and heat contents based on conductive transport of heat; U.S. Geol. Survey Circ. 726, p. 84-121.

Dorfman, M., 1974, Potential geothermal resources in Texas: Univ. of Texas, Technical Memorandum ESL-TM-3.

Facca, G., and Ten Dam, A., 1964, Geothermal power economics: Los Angeles, California, Worldwide Geothermal Exploration Co. (September).

Finney, J.P., 1972, The Geysers geothermal power plant: Chem. Engineering Progress, v.68, no. 7, p. 83.

Fournier, R.O., and Rowe, J.J., 1966, Estimation of underground temperatures from the silica content of water from hot springs and wet stream wells: Am. Jour. Science, v. 264, p. 685-697.

Fournier, R.O., and Truesdell, A.H., 1973, An emperical Na-K-Ca geothermometer for natural waters: Geochim, et Cosmochem, Acta, v. 37, p. 1255-1275

Fournier, R.O., White, D.E. and Truesdell, A.H., 1974, Geochemical indicators of subsurfac temperatures, part 1, basic assumptions: U.S. Geol. Survey Jour. Research, v.2, no. 3, p. 259-262.

Greider, B., 1975, Status of economics and financing geothermal power production in 2nd U.N. Symposium on the Development of Geothermal Resrouces (in press).

Greider, B., Geothermal Energy Cordilleran Hingeline - West, Rocky Mountain Association of Geologists - 1976 Symposium

Greider, B., 1973, Economic considerations for geothermal exploration in the western United States: Symposium on Geothermal Energy by the Colorado Geological Survey, Denver, Colorado.

Hayashida, T., 1970, Cost analysis on the geothermal power: UN Symposium on the Developmen and Utilization of Geothermal Resrouces, Pisa, Proceedings (Geothermics, Spec. Iss.2), v. 2, pt. 1, p. 950

Herrin, E., 1973, Development of reservoirs from overpressured areas beneath the Gulf Coas Plain of Texas, final report: AFOSR Contract No. 72-2395, NITS-AD 766855 (March).

Holt, B., and Brugman, J., 1974, Investment and operating costs of binary cycle geothermal power plants: U.S. National Science Foundation Conference on Research for the Development of Geothermal Energy Resources (September).

Hose, R.K., and Taylor, B.F., 1974, Geothermal systems of northern Nevada: U.S. Geol. Survey Open-File Report 74-271, 27 p.

James, R., 1968, Warakei and Larderello: Geothermal power stations compared: New Zealand Jour. Sci. (December), p. 706-719.

______, 1970, the economics of the small geothermal power station: UN Symposium on the Development and Utilization of Geothermal Resources, Pisa, Proceedings (Geothermics Spec. Iss. 2), v. 2, pt. 2, p. 1697

Jones, P.H., 1970, Geothermal resources of the northern Gulf of Mexico basin: UN Symposium on the Development and Utilization of Geothermal Resources, Pisa, Proceedings Geothermics, Spec. Iss. 2), v. 2, pt. 1, p. 14

Kaufman, A., 1964, Geothermal power, an economic evaluation: U. S. Dept. Interior, Bureau of Mines Information Circular 8230.

Kaufman, S., Shephard, B.P., and Wilson, J.S., 1974, An Analysis of the potential use of the geothermal energy for power generation along the Texas Gulf Coast: Austin, Texas, Dow Chemical Co. (for the State of Texas).

Klemenic, J., 1974, An estimate of the economics of uranium concentrate production from low grade sources: U.S. Atomic Energy Seminar, Grand Junction, Colorado.

Kunze, J.F., and Miller, L.G., 1975, Geothermal R&D project report for period July 1, 1975, to September 30, 1975: ANCR 1281 Aerojet Nuclear Co., 54 p.

Oesterling, W.A., 1964-1965, Reports and lithologic well logs of Beowawe wells to Sierra Pacific Power Co.

Otte, C., 1975, the role of geothermal energy in the United States: Statement before House Ways and Means, House of Representatives, Washington, D.C., 11 March.

Olmstead, F.H., Glancy, P.A., Harrill, J.R., Rush, F.E. and Van Denburgh, A.S., 1975, Preliminary hydrogeologic appraisal of selected hydrothermal systems in northern and central Nevada: U.S. Geol. Survey Open-File Report 75-56, 267 p.

Paredes, S., 1973, Cerro Prieto development costs: Field trip presentation, Geothermal Resource meeting, El Centro, California, 17 October 1973.

Petrick, W.R., 1974, Test electromagnetic soundings, Roosevelt Hot Springs, KGRA: University of Utah - NSF Technical Report 74-1, 17 p.

Renner, J.L., White, D.E. and Williams, D.L., 1975, Hydrothermal convection systems: U.S. Geol. Survey Circular 726, p. 5-57.

Truesdell, A.H. and White, D.E., 1973, Production of superheated steam from vapor-dominated reservoirs: Geothermics, v. 2, p. 145-164.

United Nations, 1972, Survey of geothermal resources, Republic of El Salvador: New York Dept. of U.N. Participating and Executing Agency.

U.S. Atomic Energy Commission, 1974, Nuclear power growth 1974-2000: Washington, D.C., U.S.A.E.C. Office of Planning and Analysis, Wash. 1139.

U.S. Department of the Interior, 1974, Project Independence, task force report: ERDA (November)

Waring, G.A. 1965, Thermal springs of the United States and other countries of the world--a summary: U.S. Geol. Survey Prof. Paper 492, 383 p.

White, D.E., 1973, Characteristics of geothermal resources: Geothermal Energy, Stanford Univ. Press, p. 69-93.

______, Muffler, L.J.P., and Truesdell, A.H., 1971, Vapor-dominated hydrothermal systems compared with hot-water systems: Econ. Geol., v. 66, p. 75-97.

Wollenberg, H.A., Asaro, F., Bowman, H., McEvilly, T., Morrison, R., and Witherspoon, P., 1975, Geothermal energy resource assessment: Energy and Environment Division, Lawrence Berkeley Laboratory, University of California, UCID 3762, 92 p.

Worthington, J.D., 1974, Geothermal development: status report, in Energy resources and technology: New York, Atomic Industrial Forum.

Young, H.C., and Mitchell, J.C., 1973, Geothermal investigations in Idaho, part 1, Idaho Dept. of Water Administration, Water Information Bulletin No. 30, 39 p.

GEOPRESSURE - GEOTHERMAL RESERVOIRS

Tertiary basins around the world have been discovered to have reservoirs at greater than normal pressure gradients. These geopressured zones frequently have higher than normal geothermal gradients. Exploration and field development for oil and gas production in Texas and Louisiana has outlined an area of interest extending several hundred miles from the Rio Grande River to the Delta of the Mississippi parallel to the Gulf Coast. I have not recognized any reserves in this catagory.

The economics of developing this combination of kinetic energy, low grade heat energy, and methane, is unfavorable at this time. Uncertainty as to the producibility is caused by the knowledge that to have geopressure, the sand formations must be discontinuous and the reservoirs must be confined in a limited areal configuration. Without such limits, normal temperatures and pressures would exist. In the deeper reservoirs of the geopressured areas, higher temperatures have been reported by Louisiana State University personnel. These deeper reservoirs (18,000' to 19,000') are reported to be at temperatures above 400°F. The low permeabilities reported with the moderate reservoir thickness (400') will require a maximum producing rate of 20,000 bbls per day (instead of the 40,000 bbls usually used) per well if excessive drawdown is to be avoided. The wells would probably require 640 acre spacing to eliminate well interference effects. The producer-injector ratio should be planned for 1:1. However, an initial testing period for the first modules can confirm this assumption.

The Department of Energy plans a deep $6,000,000 well test of this type of geopressured prospect. The results will be valuable in trying to design a workable method to recover and use this very expensive submarginal energy accumulation. Tables III, IV, and V, synthesize my opinions.

Table III

GEOPRESSURE ECONOMICS

BASIS

Reservoir Thickness (assumed)	400'
Permeability/Ft.	Less than 10 md
Surface Pressure (desired)	3,000 PSI - 4,000 PSI
Flow Before Injection req'd	1.0 - 1.1 billion bbls
Time Before Injection	Less than 2 years
Minimum spacing producers (interference)	640 acres
Draw Down Limit	3500 PSI
Injection Pressure	5000 PSI
Net Methane in Solution	75 SCF/bbl

Table IV

GEOTHERMAL ECONOMICS

SCOPE FACILITIES

Field Size	200 MW
Barrels Per Year	600 Million
Barrels Per Day Per WL 11	20,500
10 Wells Each	25 MW Unit
80 Producers	80 Injectors
Plant Net	200 x .85
Plant Load Factor	70%

Operating costs and taxes can only be estimated. It is certain they will not be less than those experienced in keeping a gas or oil field in operating for 30 years.

Table V

INVESTMENT & REVENUE

160 Wells @ \$6 $\overline{M}$ Eac. (includes surface facilities)		\$960 $\overline{M}$
Heat @ .020/kwh	Gas @	\$ 1.75 $\overline{MCF}$
Energy Revenue		21.25 $\overline{M}$/Yr
Gas Revenue		85.75 $\overline{M}$/Yr
Revenue Total		\$107.00 $\overline{M}$/Yr.

EXPENSE

Operating Costs \$200/Well/Day	= \$12 $\overline{M}$/Yr
Property & State Tax 15% x Gross/Yr	= 16 $\overline{M}$
Total Expense	= \$28 $\overline{M}$

INCOME

Income - \$107$\overline{M}$ - \$28M)	= \$79 $\overline{M}$
Net \$79M x 50% (Income Taxes)	= \$39.5 $\overline{M}$
Payout \$960/\$39.5 = 24 Years ROI	= 4%

There are adequate problems to solve in utilization of geopressured-geothermal reservoirs. These are primarily related to geologic problems. Discontinuous sands form the reservoir rocks in geopressured systems. The lack of continuity prevents fluid moving to lower pressured zones in a natural adjustment to normal pressure results in the abnormal geopressures. This very discontinuity results in limited reservoirs of restricted areal extent.

In many geologic situations, faulting and fracturing provide the plumbing that allows geothermal fluids to move into the producing reservoirs. The vertical movement of fluids along these faults is thought to be an important factor necessary for high production rates over the long life required for energy production.

Geopressured reservoirs have no such plumbing, otherwise, their pressures would be normal. The sealed faults in the geopressured areas will cause rapid pressure decline unless produced volumes are compensated by having equal volumes reinjected into the same sand bodies. It is for this reason this source of energy must remain an energy resource with no defined reserves.

A-3 Geothermal Potential

Dr. Stan Ward.
University of Utah Research Institute
391 Chipeta Way Suite A
Salt Lake City, Ut.
84108

GEOTHERMAL POTENTIAL 1978
B. Greider
Vice President IEC
May 17, 1978

Interest in using the heat of the earth to provide an indigenous source of energy has begun to increase almost as rapidly as energy bills in the United States. Natural resource development companies and groups of investors are increasing their exploration for accumulations of heat that can be used in electrical generation, space heating and cooling, agriculture, and industrial process heating.

Developers expect the natural sources of heat above 450^{o} F in the western United States to produce electricity at prices competitive with low sulfur coals shipped from the Powder River basin of Wyoming to the electricity generating centers supplying western Nevada and California. Water within the low energy 150^{o} F temperature range can provide processing heat, if the source is in a location where the energy can be used in the U.S. It is expected that sulfur limits for fuel oil will be set similar to coal. To meet such standards, additional investment and costs will be required to prepare acceptable fuel. With such increases in cost, new uses for geothermal heat (energy) will become practical. When that happens, more people will become interested in joining the exploration search to find and develop new deposits of heat for production of energy.

The development of a geothermal reservoir is capital-intensive, requires expert planning, and long times from initial expenditure until positive income is achieved. The utilization of a developed project requires extensive engineering, approximately two years in negotiation with governmental agencies, and a lot of money.

The costs of maintaining and operating the producing fields is about four to five times greater than the capital investment. An important portion of this cost is associated with the injection system that collects the water after the heat is removed and then returns it to the subsurface reservoirs. Reducing these costs is an essential objective if geothermal is to be competitive with other fuels.

Countries with high fuel costs and geothermal sites are now developing a wide variety of geothermal plants. Japan appears to be building the most efficient flash systems for use in hydrothermal areas rimming the Pacific Ocean.

The assessment of geothermal energy resources by considering this energy to simply be the heat of the earth provides estimates of gigantic size. Useful geothermal reserve assessment requires professional analysis. The goal is to determine how much heat can be produced at a useful rate and temperature for at least twenty years from one area. This demands a

Dear Stan:
Most of this is old hat to you. This is the basic format of the presentation I made at the GRC short course for the Wash. D.C. workers
Regards Bob.

thorough understanding of the manner in which heat is transported to areas of accumulation, how it accumulates, the methods and costs to find, produce, and convert to a useable form of energy. With those studies in hand, a person can then determine what part of this resources can be sold in competition with other fuels and thereby establish the size of the reserve.

Accessments of the supply of geothermal energy have been published by government agencies, private companies, universities and inter-governmental agencies such as the United Nations. These estimated supplies have been prepared in megawatts per year, joules per year, giga watt centuries, giga calorie centuries, per cent of the national energy budget, the equivalent bbl(s) of oil, and per cent electricity generated per year.

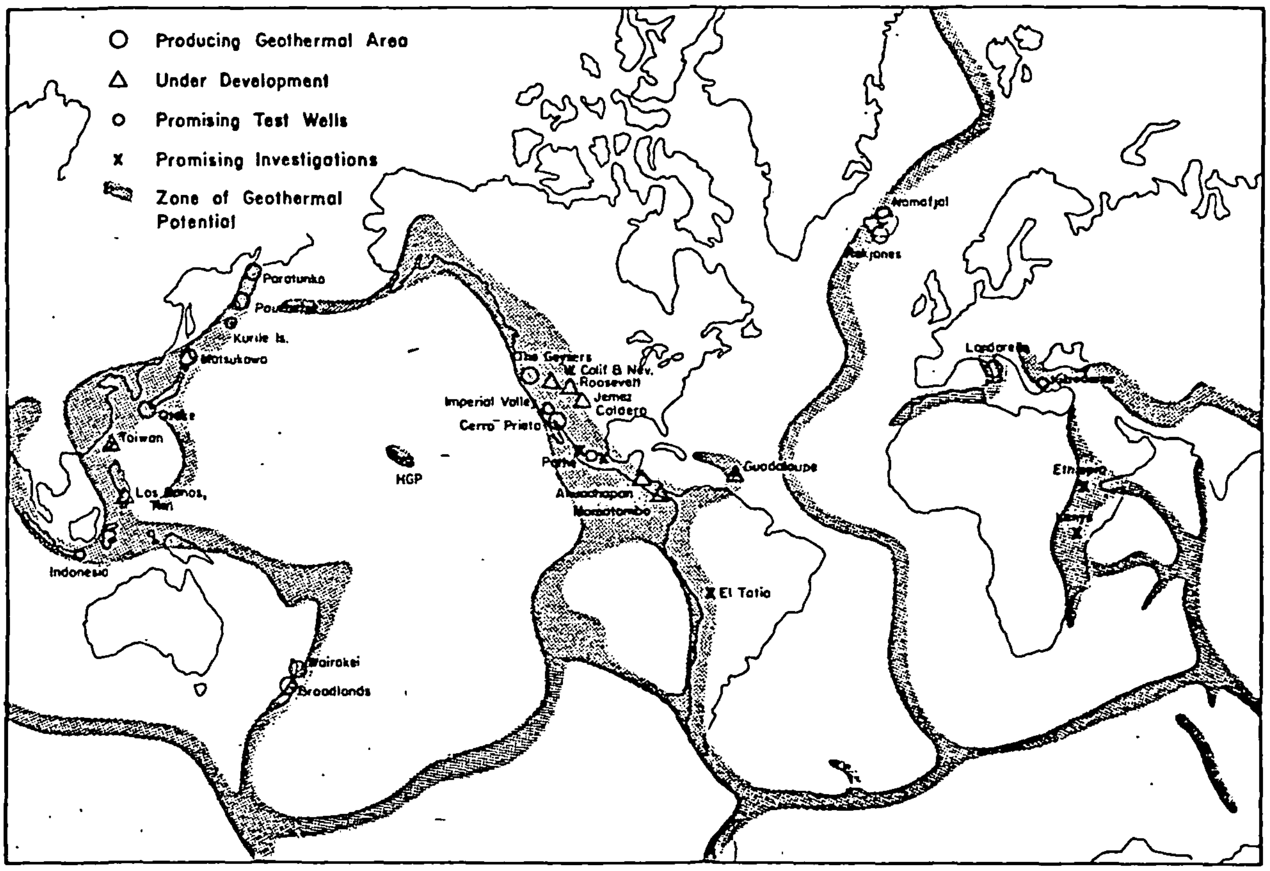
The supply has been related to all the heat present above an arbitrary temperature datum, the amount of heat between certain temperature levels, that heat contained in producing water, and that heat contained in the rock framerock transferred to the moving body of water, and the amount that could be produced if the government would provide various incentives.

These incentives have included tax credits, deductions in tax calculations, investment tax credits, rapid depreciation, and extensive depletion allowances. Other incentives include aid in exploration, aid in developing, engineering of generating plants, financing of generating plants, and reservoir engineering studies. Very little has been prepared showing the increased benefit to governmental programs, including tax revenue by demonstrating the increased flow of dollars from projects that would become profitable with this aid compared to project tax revenues that would be commercial without this aid.

The actual potential of geothermal energy is affected by how the resource and reserves are calculated. These calculations must consider availability and application of the governmental incentives, the price of other energy sources, versus the market price of geothermal energy, and the reliability of the production forecast. The size of required investment, and the expected profit generated by those investments, plus the availability of lands to explore will be the motivating forces in determining the true potential of geothermal energy development in the United States.

The most important factor in converting any resource into a reserve is how the individuals that are actively dedicated to discovery and development, attack the problem. The key to successful reserve development is the quality of the people assigned to the task.

A casual examination of geothermal areas of the world, shown in figure 1, will allow even the uniniated to estimate the supply of geothermal energy that is presently useful in the generation of electricity. The world's total geothermal generating capacity in development and developing projects with significant reservoir testing, is approximately 2,600 megawatts. The potential areas identified by preliminary investigation of sufficient extent to allow analogies with development areas is estimated to have an additional 12,000 megawatts of indicated reserves. Inferred reserves of an additional 20,000 megawatts of electricity capacity may be developed within the next 20 years. The existence of geothermal energy does not assure the resource will be converted to a reserve. In a free economy the competition in the market place and the return on the potential investment will determine if and when these resources will become useful.



GEOTHERMAL POWER DEVELOPMENT

MAP 1

The United States has the greatest producing capacity in the world at this time. The Geysers in northern California produces and has more capacity building than any other commercial producing geothermal country in the world. Those areas capable of commercial production or that have commercial plants under engineering design are listed in Table I.

Table I

World Geothermal Generating Capacity

In Megawatts

Country	Area	Operating Capacity	Engineering & Construction
U. S. A.	The Geysers	502	450
	Roosevelt	- -	80
	Heber	- -	110
	E. Mesa	- -	60
	Other	- -	200
Italy	Larderello	385	
	Travale	15	
	Mt. Amiato	22	
New Zealand	Wairakei	150	
	Broadlands		165
	Kawerau	10	
Japan	Matsukawa	20	
	Otake	13	55
	Onuma	10	
	Oninobe	25	
	Hatchobaru		55
	Takinow		55
Mexico	Cerro Prieto	75	75
	Pathe	3.5	
El Salvador	Ahuachapan	35	60
Nicaragua	Momotombo		30
Iceland	Namafjell	2.5	
	Krafla		55

must be sufficient horizontal and vertical permeability to allow the fluid to move easily. A 6,000 ft. to 8,000 ft. well must sustain flow rates of more than 100,000 lbs. of steam per hour, or 500,000 lbs. of water (above 325^{o} F) per hour for 20 to 25 years to be considered commercial for electricity generation. Direct use of heat for industrial heating or space heating and cooling does not require such high heat output. The lower temperatures for such uses can be found in a greater number of anomalies, however, their usefulness is dependent upon low costs being achieved in development and production.

The geologic model that is generally accepted by geothermal explorers and developers (Figure 2) has three basic requirements to function:

1. A heat source (presumed to be an intrusive body) that is above 1200^{o} C and within 16 Km of the surface.

2. Meteoric waters circulating to depths of 10,000 ft. - 20,000 ft. where heat is transferred from the conducting impermeable rocks above the heat source.

3. Vertical permeability above the heat source connecting the conducting rocks with a porous permeable reservoir that has a low conductivity impermeable heat retaining member at its top.

Water, expanding upon being heated, moves buoyantly upward in a hot concentrated plume. Cold waters move downward and inward from the basin's margins to continue the heat transfer process. Heat is transported by convection in this part of the model.

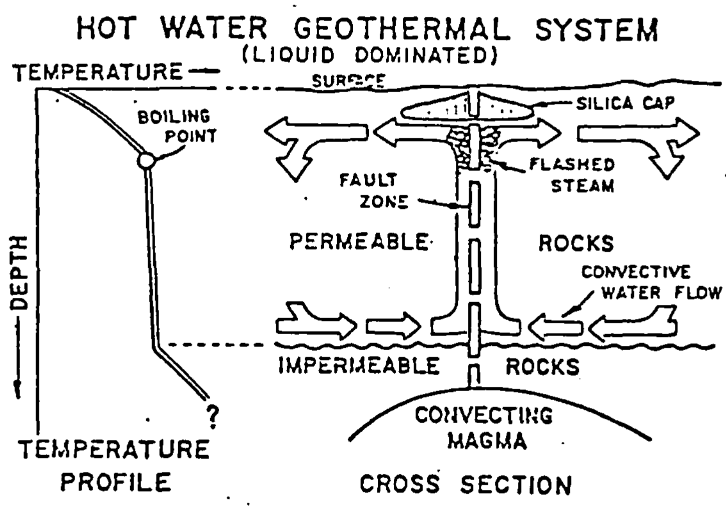


Fig. 2 — Geological Model of a Hot Water Geothermal System (after White, 1973).

Geologic investigation is the necessary ingredient that makes all other techniques useful. Broad reconnaissance of the surface data integrated into subsurface data is used to find an area of general interest. The ingenuity of the prospect finder in using data available to all workers determines whether an exploration program moves into advanced stages of using the proper combinations of the above methods. Geologic interpretation of the data acquired may justify the money required for exploratory drilling. The results of the drilling must be integrated into the geologic investigation to determine if a promising prospect is present.

The investigation must establish that:

1. High heat flow or strong temperature gradients are present at depth.

2. The geology provides reasonable expectation that a reservoir sequence of rocks is present at moderate depths from 2000' to 6000'.

3. The sequence of rocks offers easy drilling with minimal hole problems.

4. A high base temperature and low salinity waters as indicated by geochemistry of water sources should be present. The surface alteration and occurrence of high heat flow should cover an area large enough to offer the chance for a field capacity of more than 200 MW.

Interpretation of geochemical data requires professional skill in geology and chemistry. If the geology is well known, useful information can be developed.

Geophysical surveys are useful in predicting the general area and depth of high temperature rocks and water. Rocks at depth are better conductors of electricity (natural and induced currents) when there is an increase in temperature, an increase in porosity, an increase in clay minerals, or an increase in salinity in their contained fluids.

Table I from C. Heinzelman's presentation of October 15, 1977, illustrates exploration techniques and associated costs. The overall amount of money (per successful prospect) required is 2.5 million to 4.75 million 1977 dollars. This provides for limited failure and follow up costs, but does not include the other exploration failures and land costs.

Table I

EXPLORATION TECHNIQUES & APPROXIMATE COSTS

Objective	Technique	Approximate Cost ($)	
Heat Source & Plumbing	Geology	$ 15,000	
	Microseismicity	15,000	
Temperature Regime	Gravity	20,000	
	Resistivity	25,000	
	Tellurics & sagnetotellurics	40,000	
	Magnetics	15,000	
	Geochemistry (Hydrology)	12,000	
	Temperature Gradient 20 holes	100,000	
	Stratigraphic Holes (4)	160,000-	240,000
Reservoir Characteristics	Exploratory wells (3)	1,800,000-4,000,000	
	Reservoir test	250,000	
Total to Establish a Discovery		$2,472,000-4,752,000	

This is probably the minimum expenditure to move a portion of the resource into a reserve.

Upon deciding that a significant geothermal anomaly exists, the rate of engineering expenditures must increase rapidly to determine whether the development can proceed. Essentially, there are no set figures for what it costs to develop a geothermal field. The basic reason for this is that each depends upon engineering the development to be compatible with the geology of the accumulation, and the requirements of the electricity generating system. The electricity generating system must be designed within the constraints of available temperature, rate of production, and ambient conditions of the field site. The key variables are:

1. Temperature of the fluids produced.
2. Composition of the reservoir fluids.
3. Composition of surface or near surface fluids.
4. Geology of the reservoir framework.
5. Flow rates that can be sustained by the reservoir.
6. Cost of drilling in the prospect area.
7. Well spacing and geometry of the producing and injection sites.
8. Turbine system to be used.
9. General operating costs in the area.

Test Wells - Thermal evaluation requires the drilling of test holes. Heat flow and temperature gradient evaluation requires drilling to intermediate depths. Confirmation drilling requires holes drilled to the actual reservoir for diagnostic evaluation.

Heat flow and temperature gradients measured in the upper 100 to 500 ft. depth are useful in describing the area where the heat transfer is most intense. When mapped, these do give a qualitative analysis as to the location and shape of the hottest near-surface heat accumulation. Linear projection of temperatures obtained near the surface cannot be used to predict the temperatures that will be encountered 2000-3000 ft. below the surface, even if the section below has a uniform lithology and the geothermal graident is a straight slope. The temperature for a fluid-saturated system cannot be projected to a maximum above that for boiling water at the pressure calculated for the depth of projection. At some point along the boiling point curve, the temperature of the system may become isothermal and the rocks and fluids will have the same temperature for many hundreds of feet deeper. The rock temperature may decrease as a hole is drilled deeper if the hole is on the descending edge of a plume of hot water or merely below the spreading top of a plume. Heat flows from a hot body to a cooler body. This is not a function of being above or below a reference point of depth.

So that the performance of the geothermal cell can be predicted, deep tests must be drilled. These holes must be of sufficient size to adequately determine the ability of the reservoir to produce fluids above 365° F at rates of more than 100,000 lbs. of steam per hour or 500,000 lbs. of liquid per hour. Although it is desirable that these fluids have less than 32,000 ppm dissolved solids and less than one (1) percent non-condensable gases in solution, they may be extremely corrosive and dangerous to test.

To determine if a commercial development is possible, three or four wells must test the reservoir to obtain the basic reservoir engineering data on producibility rates that are necessary. Reservoir pressure drawdown and buildup analysis must be conducted to determine reservoir permeability and extent. Fluid characteristics and analysis of non-condensibles present require extensive flow tests. Injectivity testing is required to develop plans for disposal and pressure maintenance systems. Rocks may produce fluids easily, but may not accept them on return to the reservoir. This must be established in the laboratory and confirmed in the field.

A review of the costs associated with finding, developing, and producing geothermal energy must consider that the actual dollar amounts reported are for a specific time and place. The following costs will be different than the amounts reported by each of the United Nations' symposia. This illustrates that changes in the required money are still being experienced in dry steam, high temperature flash, and moderate temperature flash or binary systems. The costs to find geothermal systems continue to increase as geologists learn there are cold holes very near hot areas; there are hot areas within an overall cold area; there can be a steam zone within a hydrothermal area; and there can be two different types of geothermal systems, vapor and liquid dominated, vertically separated within the same geographic area.

Development wells in the depth range of 5,000' to 10,000' are being drilled and completed for $500,000 - $1,500,000. Injection wells are being completed in the same cost range. The ratio of producers to injectors depends upon reservoir characteristics. The ratio will be between 1:1 or 1:2 for hot water systems. Water-steam lines from the producing wells to the generating plant can be estimated to cost $35 to $100/KW capacity. This cost is dependent upon the volume of fluid per kwh, the development pattern, and the plant location in relation to the producing wells. The amount of surface area used should be the minimum possible to achieve the maximum economic recovery. The engineering design work determines the most economical layout.

Techniques developed to drill slanted holes from a central platform can be used in developing geothermal reservoirs that have a broad area of heat with a local area of intense heat and where injection is feasible. Slant drilling is more costly than vertical drilling. Production pipelines are reduced in length if the plant is located adjacent to the producing islands. This results in a more efficient operation. The geology and geometry of the reservoir determines feasibility of using this method.

Condensate return, pipelines' design, and cost depend upon the uses for the condensate. If the condensate is mixed with the brine that is not flashed, a mixture similar to the produced fluids can be returned to the injection sites and return lines will be similar in size and cost as the production lines. If the condensate is used in the cooling system and allowed to evaporate, a small diameter pipeline can be used to return cooled water to injection lines. If this is so, the condensate pipeline can cost as little as $4-$15 per KW.

Plants built to use steam produced directly from a dry steam reservoir are the lowest in cost to build. PG&E's plant #15 is expected to cost $320/KW with provisions for H_2S treatment. This is an increase of 250% over the average of the 1961-1974 period. In the same period, the cost of electricity generated averaged about 5.6 mills per net kilowatt hour. 1979 costs will have increased the price of electricity to 25 to 30 mills per kilowatt hour from steam fields.

Hot water flash plants have an extremely broad range of cost. This is because the temperature and chemical characteristics of the produced fluids and unit size have a wide range. This creates costs from $400 per kilowatt to as much as $700 per kilowatt. Double flash 45 net MW operating on low solids fluids at temperatures around 450° F most likely can be constructed for $450 to $475 per net kilowatt. Fluids 100° F cooler will require plants costing $100 more per kilowatt capacity.

Binary units designed for using low bioling point fluids to drive the turbine are experimental designs. No plant greater than 5 MW has been operated so cost criteria are tenuous. Present estimates for approximately 50 MW plants range from Ben Holt Engineering's estimate of $500 per kilowatt to Ford Bacon & Davis shell and tube system at $655/kwh. A small 10 MW binary system is being constructed by Imperial Magma. This has a reported cost of $1,000 per KW.

A summary of estimated development costs after exploration expenses for the field supply, power plant, and ancillary equipment for a 50 megawatt hot water flash unit is as follows:

Table II

Development Wells (12)	$ 10,800,000
Injection Wells (6)	5,400,000
Pipelines	2,800,000
Miscellaneous Field Expense (includes interest & working capital)	9,000,000
Power Plant	25,000,000
TOTAL	$ 53,000,000

ECONOMIC CONSIDERATIONS

To obtain a comparison of geothermal fuels with the more widely used fuels is quite difficult, because each geothermal area requires a plant design specifically useful for that local area. The California Geyser's steam price of 16.5 mills per kwh is as inexpensive as geothermal energy can be produced in the U.S. today. This is a dry steam fuel, and the operators have more than a decade of experience in drilling, completions, and production operations. Optimum techniques have been developed so that maximum steam production per dollar invested can be maintained. The high energy content of this fluid provides a competitive heat rate, easy to construct collection systems, and the most simple of plant and reinjection facilities. The actual cost of the wells are frequently as high as $750,000 - $1,000,000, but the operation and the high utility of the steam allows a minimal price for the energy.

The wide variation of estimates of fuel costs and electricity generating costs derives from treatment of fuel processing and storage expense, income taxes, ad valorem taxes, insurance, interest during construction, return on investment required, and specific requirements for plants in the area of operation for the estimating companies. The utility usually expects to earn a minimum of 20% ROI on its equity portion. The exploration and producing investors have learned that a minimum acceptable rate of return on investment for their portion of the projects is also 20% ROI. The average conventional energy venture (non-geothermal) usually obtains about twice this rate of return.

The return on investment for the developer is most sensitive to the price received for the energy. Next to reliability of supply, the utilities desire to use geothermal energy in its electricity generating systems is dependent upon its price being low enough to make its use worthwhile. Much like coal and uranium, geothermal fuel prices will be a negotiated price between the supplier and the user. Each field will have significant differences in design so a uniform price cannot be expected for construction of the production facilities, or construction of the utilities conversion plant.

The nature of the reservoir geometry and the ability of the reservoir to respond to changes in production, rates, and temperatures, will determine the final costs for producing electricity from each geothermal project.

The basic structure of price must provide an attractive rate of return to the prospector. To achieve this, the prospector's risk capital investment and time at risk before income must be minimized. Most important, the revenue should reflect the actual value of the energy sold.

COST COMPARISONS

The cost comparisons between the various sources of energy that will be available and useable for electricity generation during the next decade will affect the rate of geothermal energy's growth. The economic desirability of the production or use of a fuel is sensitive to its price. Regulatory requirements have direct effect upon production and construction costs. The tax treatment for each fuel system is a dynamic one. This makes it very difficult to assess the resulting economics.

The amount of money needed to construct and operate plants to use each fuel is a strong component of how much the customer will pay per unit of fuel. The heat rate of the energy conversion system determines the amount of fuel needed to supply the plant. In electricity generating plants, the heat rate is the number of BTU's required to produce a net kilowatt hour. The average coal and oil burning plant uses 8,500 to 10,500 BTU/kwh. A nuclear plant uses about 14,000 BTU/kwh. Geothermal plants use between 21,000 to 33,000 BTU per net kwh.

OIL

Electricity produced from oil fired plants is directly related to the cost of low sulfur fuel oil. An oil fired turbine generator plant costs between $385.00 and $400.00 per kw. A combined cycle plant is about $300.00 per kw. The difference in heat factor, operating cost, and available capital for these plants establish which will be used for meeting the increased demand and plant replacement schedule within a utilities service area. The estimated cost of fuel oil in mills per kwh developed by Stanford Research Institute, is approximately 23 mills per kwh. Strong competition between suppliers results in a stabilizing effect upon the overall price of oil. Utility planners have estimated the range of price of oil to be 20.5 to 21 mills per kwh. These cost ranges combined with new plant costs will produce electricity between 33 and 44 mills per kwh.

COAL

Coal prices are related to specific sources of supply and dedication of specific sources of coal to certain plants. Coal does not presently have the wide range of usefulness that oil enjoys today. This limits the substitution of one coal for another.

The price of steam coal and plant construction costs to meet environmental requirements result in an estimated price of 35 mills for electricity generated in new coal plants. Fuel suppliers currently estimate coal can be delivered within a one-thousand mile radius for 9 to 10 mills per kwh if surface mining methods are used.

NUCLEAR

Nuclear fuel plants appear to offer the least expensive electricity for a non-indigenous source of energy.

The utility industry estimates they will be paying 6 to 6.5 mills per kwh for nuclear fuels and plant costs in 1977 dollars will be $800 to $1000 per KW. The estimated cost of electricity from such plants will be between 32 to 34 mills per KWH.

GEOTHERMAL

Comparison of conventional electricity prices with geothermal steam, electricity prices are a matter of public record. This is the least expensive of all thermal systems employed in the U.S. To obtain a comparison of hot water flash steam plants, it is necessary to use developments outside of the USA for performance factors. Economics of hot water flash to steam projects continue to be impressive. Cerro Prieto's development is very encouraging as exploratory work confirms this development can exceed 500 MW. The improvement in heat recovery with double flash units would reduce the cost of electricity and increase the size of reserves significantly. Seventy-five megawatts have now been developed and work is underway for the next 75 MW. The first unit of 75 MW was developed for $264/KW, and produced electricity for approximately $.008 tax free. Today, costs would be about twice that amount. The generation cost includes the well field operation as this is an integrated operation. It is estimated the second 75 MW plant will produce electricity for about 16 mills tax free.

It is possible to use the development work now in progress at Momotombo Nicaragua to evaluate the costs of developing a hot-water-flash-field today. DeGolyer McNaughton, the international consulting firm and Herman Dykstra, a reservoir engineering consultant, have completed examination of all the field test data from Momotombo. Tests using bottom hole pressure devices in selected wells were combined with full field flowing tests. The firm concluded that double flash turbines could produce 96 MW for more than 30 years using the portion of the reservoir developed. Subsequent completion tests have demonstrated more than 100 MW capacity.

Turbine specifications are now being prepared to have 8 plant turbine with 80 psig first stage and 20 psig second stage. The power plant for this 225^{o} C field may have two 35 MW units in operation by mid 1980. The estimated cost for the electricity generating plant installed will be $460/KW. A savings of $26 million in foreign exchange would result from this development.

STEAM

Geyser's steam price of 16.5 mills per kwh is about as inexpensive as geothermal energy can be produced today. The 1978 price of 16.5 mills per kwh is well below the competitive value of this energy. 20 mills per kwh would be a price more nearly reflecting its actual value in an area using oil or coal for electricity generation.

Plants to use a dry steam are the lowest in cost to build. PG&E's plant #15 is expected to cost $320/KW with provisions for H_2S treatment. This is an increase of 250% over the average of the 1961-1974 period. In the same period, the cost of electricity generated averaged about 5.6 mills per net kilowatt hour. 1979 operating costs will have increased the price of electricity to 25 to 30 mills per kilowatt hour.

Summarizing the preceding discussion on comparison of costs and resultant prices of electricity, we can tabulate oil, coal, nuclear vs. geothermal as follows:

	Oil	Coal	Nuclear
Fuel mills per kwh	20-23	9-11	6-7
Plant $/KW	300-400	580-950	800-1000
Electricity Busbar mills/kwh	33-44	35-36	32-34

	Geothermal		
	Steam	Flash 450^{o} F	Binary
Fuel mills per kwh	14.5-16	16-20	26-30
Plant $/KW	320	450-475	500-1000
Electricity Busbar mills/kwh	22.5-24	25-30	40-48

RESERVE ESTIMATES

With these competitive conditions and an idea of the required investments in plant and fields, we can now estimate the potential reserves identified in relation to the proven reserve.

The proven reserves of the Geysers is now 908 megawatts. The potential reserves are another 1100 MW. To infer that the hot water area surrounding the dry steam reservoir will be productive of waters that will be used in flash steam plants is reasonable. Inferred hot water flash reserve should be approximately 1,000 MW.

The proven reserves in the Imperial Valley are 400 megawatts. Potential reserves of Brawley, East Mesa, Heber, Niland, and Westmoreland total 1600 MW. Reserves have been inferred with another 1,000 MW in these and similar anomalies within the province. Considerable work must be done on conversion systems, and deep drilling in the California portion of the Imperial Valley if another 5,000 MW are to be moved from the resource category into the reserve category in the next 20 years.

Coso, Lassen, Mono-Long Valley, Mammoth, Randsburg, can be credited with about 700 MW of inferred reserves. Sufficient drilling has not been done in these areas to estimate reservoir quality, water characteristics, and temperature distribution.

In the western Utah area, Roosevelt is the only area with proven reserves. It appears that sufficient testing and plant design work has been completed to assign 80 MW to that classification. 120 MW potential and 300 MW inferred reserves can be assigned to Roosevelt on information now available. The remainder of that general area including Cove Fort - Sulfurdale, Thermal-Black Mountain should have 1,000 megawatts potential reserves and 500 MW inferred.

Testing of potential areas in Nevada has not progressed to the stage where proven reserves can be assigned. The potential reserves of Phillips' three areas, and Chevrons' two areas in the northern half of the state, indicates 400 MW reserve. An additional 600 MW can be inferred on the basis of drilling data being extrapolated with geophysical surveys. With continued confirmation success in the Carson sink area, an additional 500 MW could be moved from resource to inferred reserves. New Mexico's Valles Caldera is considered as having 100 MW potential reserve. From the size of the anomaly and the temperature indicated by surface springs, an inferred reserve of another 300 MW should be assigned. This area has a total reserve of 400 MW.

Oregon does not have proven reserves except in the direct use of the heat contained in the subsurface waters around Klamath Falls. The exploration for geothermal energy useful for generation of electricity has been encouraging in the northeast extension of the Gerlach-Baltazor trend into Oregon from northwest Nevada. The Alvord area has 200 MW potential reserves and 100 MW inferred. Between Alvord and Vale Hot Springs another 400 MW can be inferred. An additional 300 MW can be inferred from other heat flow and geophysical survey work in the general area.

This table summarizes these reserve catagories.

SUMMARY

ELECTRICITY GENERATION RESERVES

	Proven (Measured) MW	Potential (Indicated) MW	Inferred (Geol-Geoph) MW
Geysers	908	1,100	1,000
Imperial Valley	400	1,600	1,000
Coso-Lassen, Long-Valley, Mammoth, Randsburg			700
Roosevelt	80	120	300
Cove Fort, Sulferdale, Black Mountain-Thermal		1,000	500
N. Nevada		400	600
New Mexico		100	300
Alvord Area		200	100
Alvord to Vale			400
Other Oregon SE			300
Subtotal	1,388	4,500	5,200
Total Reserves	11,188 MW		

The direct use of geothermal heat in the U.S. is on a local project basis except in Klamath Falls, Oregon and Boise, Idaho. Local greenhouse operations, individual processing plants in industrial and agricultural projects are found throughout the western U.S., Alaska, Texas and Southeast Appalachians. It is estimated these present direct uses represent proven reserves of 35 MW.

Reserves cannot be assigned to geopressure-geothermal projects. It is hoped the government research work in progress can develop sufficient data to provide inferred reserves in 20 years.

Reserves now identified in the three catagories total 11,088 MW. This rapid build up from the reserve of 500 MW existing just four years ago demonstrates an aggressive search for and investment in producing areas. The 164,000,000 barrels of fuel oil that will be saved annually for electricity generation when this is developed is about 1/10 the amount of direct use potential existing today.

An oil accummulation to provide 164,000,000 bbls per year for 30 years would require 4.9 billion bbls to be available for production. Consider that less than .2 of 1% of all wildcats drilled in the U.S. during the last four years discovered producible reserves over the life of the field greater than 1 mm bbls of oil.

To assess the impact of the development of this reserve now identified plus the stimulus such development will give to exploration requires an assumption that the governmental agencies believe indigenous sources of energy are necessary to the economy of the USA.

In 1975 the forecast of the growth of geothermal capacity spanned 5,000 MW to 20,000 MW on line by 1985. The forecast by B. Greider at the 1975 United Nations Symposium was that 6,000 MW capacity would be on line by 1985. This required a reserve of 11,000 megawatts be discovered. The reserve has been discovered. The majority of the prospects contributing to this growth were on federal lands. These same prospects were recognized to be primarily in a temperature range that during most of the productive lifetime the reservoir would produce fluids at less than 400° F. The basic assumption underlying these forecasts was that viable economic incentives for geothermal would be similar to ones for other natural resource developments.

Stanford Research Institute, The University of California, Riverside, and Science Application Inc. have each provided thoughtful studies on the effect of tax incentives for the development of geothermal resources. The effect of such tax treatment has been focused on the resulting price of electricity or upon how much income this would "shelter" for the producer.

Each study has sidestepped the critical question of how large a capacity can be economically developed from recognized prospects with the subject incentives. How many would be developed lacking such economic stimuli. The next question that should have been answered is: what is the flow back to government agencies in tax revenues if certain incentives are initiated? This demands careful analysis of the possibility of reduced tax flow from projects that are certain to be developed without the incentives versus the increased tax revenue from those projects that would not have been developed without the incentives.

Consideration of the dynamic effect of taxation regulations on an incipient industry will show a tremendous benefit to government agencies in increased tax revenues. Robert Rex prepared the following two illustrations demonstrating the flow of monies to federal, state, and county agencies for a single 48 net MW project on federal lands and the effect if 1,000 MW developed on federal leases.

ESTIMATED GOVERNMENT REVENUES
FROM FIELD DEVELOPMENT PROGRAM

1000 MW PROJECT

10% Federal Royalty Payments	$1,462,500,000
Federal Income Taxes	1,243,750,000
State Income Taxes	1,398,125,000
Ad Valorem Taxes	345,625,000
	$4,450,000,000

ASSUMES:
25 MILS/KWH
30 YEAR PROJECT LIFE
6% ANNUAL INFLATION RATE

ESTIMATED GOVERNMENT REVENUES
FROM FIELD DEVELOPMENT PROGRAM

EAST MESA 48 MW PROJECT

10% Federal Royalty Payments	$ 70,200,000
Federal Income Taxes	67,110,000
State Income Taxes	16,590,000
Ad Valorem Taxes	59,700,000
	$ 213,600,000

ASSUMES
25 MILS/KWH
30 YEAR PROJECT LIFE
6% ANNUAL INFLATION RATE

If the reserves now known on federal lands are developed additional ones will be added in the process of development and by the increased exploration attracted to the area of successful development. Five thousand megawatts production on federal lands and two thousand MW on non-federal lands should return to the government 903 million dollars in revenues each year over the first 30 years of the projects lives. 7.02 billion dollars would flow to the federal government as royalty, 9.4 billion as income tax. 2.3 billion would be allocated to the various states' income tax revenues and more than 8.4 billion dollars to local county governments as ad valorum taxes.

SUMMARY

In 1973 the geothermal reserves in the U.S. were 500 MW. Reserves identified since 1970 total about 11,100 MW. This is enough energy to supply the total electrical needs for 11,000,000 people. To generate the same electricity using fuel oil 164 million barrels per year would be needed. Five billion barrels of oil would need to be discovered to supply the equivalent energy for 30 years.

Geothermal energy can compete with the other types of energy now being used in the U.S. To do so, the energy must be available from its reservoir at a temperature above 400° F. Below this temperature, operating cost rise significantly as the number of wells to produce and reinject the fluid increases.

Tax incentives must be provided to encourage significant investment in the mid temperature hot water resources if this type of energy is to be developed.

The cost of the plants rise rapidly as the temperature of the reservoir decreases. The volume of fluid required to move through the system increases rapidly to supply the required heat. There are economic limits established by temperature that must be recognized. If the BTU content of a ton of coal drops, there is a point where it is not useable for power production. The same is true for oil and gas fluids as their associated water or inert gas ratio increases. Geothermal fluids quality and usefulness is also dependent upon its BTU content per unit volume produced. The building of power plants for mid temperature projects is critical to the utilization of this large resource.

For this reason, it is difficult to present a specific cost of electricity produced by broad types of resource. The probable range of prices for electricity generated from steam and hot water reservoirs today is:

		Mills/KWH
Steam 450° F and above		22.5 - 24
Hot water flash - below 400° F		36 - 50
	above 400° F	25 - 30
Binary		40 - 48

REFERENCES

Armstead, H.C.H., 1973, Geothermal economics, in Geothermal energy, review of research and development: UNESCO (Earth series).

Austin, A.L., Higgens, G.H., and Howard, J.H., 1973, The total flow concept for recovery of energy from geothermal hot brine deposits: Livermore, California, Lawrence Livermore Laboratory (3 April).

Axtell, L., Geothermal Services, San Diego, California; Bailey, J.R., Centurion Sciences, Tulsa, Oklahoma, Maxwell, R., Gulf Oil, Denver, Colorado; Otte, C., Union Oil, Los Angeles, California, 1975 in Greider, B., Survey of industry exploration cost increases 1974-1975: San Francisco, California (March).

Bailey, D.G., 1972, Exploration for geothermal energy in El Salvador: United Nations Progress Report.

Bloomster, C.H., 1975, Geocost: A computer program for geothermal cost analysis: Battelle Pacific Northwest Laboratories, USAEC Contract A.T. (45-1) 1830 (February).

Butler, D.R., 1975 G othermal energy's contribution to the total energy spectrum: Am. Assoc. Petroleum Geologists National Conference, Dallas, Texas.

Combs, Jim, 1971, Heat flow and geothermal resource estimates for the Imperial Valley, Cooperative Geological-Geophysical-Geochemical Investigations of Geothermal Resources in the Imperial Valley of California: University of California, Riverside, p. 5-27.

Cheng, P., Lau, K.H., and Lau, L.S., 1975, Numerical modelling of geothermal reservoirs: The Hawaiian Geothermal Project, summary report for phase 1, p. 83-110.

Diment, W.H., Urban, T.C., Sess, J.H., Marshall, B.F., Munroe, R.J. and Lacherbruch, A.H., 1975; Temperatures and heat contents based on conductive transport of heat; U.S. Geol. Survey Circ. 726, p. 84-121.

Dorfman, M., 1974, Potential geothermal resources in Texas: Univ. of Texas, Technical Memorandum ESL-TM-3.

Facca, G., and Ten Dam, A., 1964, Geothermal power economics: Los Angeles, California, Worldwide Geothermal Exploration Co. (September).

Finney, J.P., 1972, The Geysers geothermal power plant: Chem. Engineering Progress, v.68, no. 7, p. 83.

Fournier, R.O., and Rowe, J.J., 1966, Estimation of underground temperatures from the silica content of water from hot springs and wet stream wells: Am. Jour. Science, v. 264, p. 685-697.

Fournier, R.O., and Truesdell, A.H., 1973, An emperical Na-K-Ca geothermometer for natural waters: Geochim, et Cosmochem, Acta, v. 37, p. 1255-1275

Fournier, R.O., White, D.E. and Truesdell, A.H., 1974, Geochemical indicators of subsurfac temperatures, part 1, basic assumptions: U.S. Geol. Survey Jour. Research, v.2, no. 3, p. 259-262.

Greider, B., 1975, Status of economics and financing geothermal power production in 2nd U.N. Symposium on the Development of Geothermal Resrouces (in press).

Greider, B., Geothermal Energy Cordilleran Hingeline - West, Rocky Mountain Association of Geologists - 1976 Symposium

Greider, B., 1973, Economic considerations for geothermal exploration in the western United-States:-Symposium-on Geothermal Energy by the Colorado Geological Survey, Denver, Colorado.

Hayashida, T., 1970, Cost analysis on the geothermal power: UN Symposium on the Developmen and Utilization of Geothermal Resrouces, Pisa, Proceedings (Geothermics, Spec. Iss.2), v. 2, pt. 1, p. 950

Herrin, E., 1973, Development of reservoirs from overpressured areas beneath the Gulf Coas Plain of Texas, final report: AFOSR Contract No. 72-2395, NITS-AD 766855 (March).

Holt, B., and Brugman, J., 1974, Investment and operating costs of binary cycle geothermal power plants: U.S. National Science Foundation Conference on Research for the Development of Geothermal Energy Resources (September).

Hose, R.K., and Taylor, B.F., 1974, Geothermal systems of northern Nevada: U.S. Geol. Survey Open-File Report 74-271, 27 p.

James, R., 1968, Warakei and Larderello: Geothermal power stations compared: New Zealand Jour. Sci. (December), p. 706-719.

________, 1970, the economics of the small geothermal power station: UN Symposium on the Development and Utilization of Geothermal Resources, Pisa, Proceedings (Geothermics Spec. Iss. 2), v. 2, pt. 2, p. 1697

Jones, P.H., 1970, Geothermal resources of the northern Gulf of Mexico basin: UN Symposium on the Development and Utilization of Geothermal Resources, Pisa, Proceedings Geothermics, Spec. Iss. 2), v. 2, pt. 1, p. 14

Kaufman, A., 1964, Geothermal power, an economic evaluation: U. S. Dept. Interior, Bureau of Mines Information Circular 8230.

Kaufman, S., Shephard, B.P., and Wilson, J.S., 1974, An Analysis of the potential use of the geothermal energy for power generation along the Texas Gulf Coast: Austin, Texas, Dow Chemical Co. (for the State of Texas).

Klemenic, J., 1974, An estimate of the economics of uranium concentrate production from low grade sources: U.S. Atomic Energy Seminar, Grand Junction, Colorado.

Kunze, J.F., and Miller, L.G., 1975, Geothermal R&D project report for period July 1, 1975, to September 30, 1975: ANCR 1281 Aerojet Nuclear Co., 54 p.

Oesterling, W.A., 1964-1965, Reports and lithologic well logs of Beowawe wells to Sierra Pacific Power Co.

Otte, C., 1975, the role of geothermal energy in the United States: Statement before House Ways and Means, House of Representatives, Washington, D.C., 11 March.

Olmstead, F.H., Glancy, P.A., Harrill, J.R., Rush, F.E. and Van Denburgh, A.S., 1975, Preliminary hydrogeologic appraisal of selected hydrothermal systems in northern and central Nevada: U.S. Geol. Survey Open-File Report 75-56, 267 p.

Paredes, S., 1973, Cerro Prieto development costs: Field trip presentation, Geothermal Resource meeting, El Centro, California, 17 October 1973.

Petrick, W.R., 1974, Test electromagnetic soundings, Roosevelt Hot Springs, KGRA: University of Utah - NSF Technical Report 74-1, 17 p.

Renner, J.L., White, D.E. and Williams, D.L., 1975, Hydrothermal convection systems: U.S. Geol. Survey Circular 726, p. 5-57.

Truesdell, A.H. and White, D.E., 1973, Production of superheated steam from vapor-dominated reservoirs: Geothermics, v. 2, p. 145-164.

United Nations, 1972, Survey of geothermal resources, Republic of El Salvador: New York Dept. of U.N. Participating and Executing Agency.

U.S. Atomic Energy Commission, 1974, Nuclear power growth 1974-2000: Washington, D.C., U.S.A.E.C. Office of Planning and Analysis, Wash. 1139.

U.S. Department of the Interior, 1974, Project Independence, task force report: ERDA (November)

Waring, G.A. 1965, Thermal springs of the United States and other countries of the world--a summary: U.S. Geol. Survey Prof. Paper 492, 383 p.

White, D.E., 1973, Characteristics of geothermal resources: Geothermal Energy, Stanford Univ. Press, p. 69-93.

________, Muffler, L.J.P., and Truesdell, A.H., 1971, Vapor-dominated hydrothermal systems compared with hot-water systems: Econ. Geol., v. 66, p. 75-97.

Wollenberg, H.A., Asaro, F., Bowman, H., McEvilly, T., Morrison, R., and Witherspoon, P., 1975, Geothermal energy resource assessment: Energy and Environment Division, Lawrence Berkeley Laboratory, University of California, UCID 3762, 92 p.

Worthington, J.D., 1974, Geothermal development: status report, in Energy resources and technology: New York, Atomic Industrial Forum.

Young, H.C., and Mitchell, J.C., 1973, Geothermal investigations in Idaho, part 1, Idaho Dept. of Water Administration, Water Information Bulletin No. 30, 39 p.

GEOPRESSURE - GEOTHERMAL RESERVOIRS

Tertiary basins around the world have been discovered to have reservoirs at greater than normal pressure gradients. These geopressured zones frequently have higher than normal geothermal gradients. Exploration and field development for oil and gas production in Texas and Louisiana has outlined an area of interest extending several hundred miles from the Rio Grande River to the Delta of the Mississippi parallel to the Gulf Coast. I have not recognized any reserves in this catagory.

The economics of developing this combination of kinetic energy, low grade heat energy, and methane, is unfavorable at this time. Uncertainty as to the producibility is caused by the knowledge that to have geopressure, the sand formations must be discontinuous and the reservoirs must be confined in a limited areal configuration. Without such limits, normal temperatures and pressures would exist. In the deeper reservoirs of the geopressured areas, higher temperatures have been reported by Louisiana State University personnel. These deeper reservoirs (18,000' to 19,000') are reported to be at temperatures above 400°F. The low permeabilities reported with the moderate reservoir thickness (400') will require a maximum producing rate of 20,000 bbls per day (instead of the 40,000 bbls usually used) per well if excessive drawdown is to be avoided. The wells would probably require 640 acre spacing to eliminate well interference effects. The producer-injector ratio should be planned for 1:1. However, an initial testing period for the first modules can confirm this assumption.

The Department of Energy plans a deep $6,000,000 well test of this type of geopressured prospect. The results will be valuable in trying to design a workable method to recover and use this very expensive submarginal energy accumulation. Tables III, IV, and V, synthesize my opinions.

Table III

GEOPRESSURE ECONOMICS

BASIS

Reservoir Thickness (assumed)	400'
Permeability/Ft.	Less than 10 md
Surface Pressure (desired)	3,000 PSI - 4,000 PSI
Flow Before Injection req'd	1.0 - 1.1 billion bbls
Time Before Injection	Less than 2 years
Minimum spacing producers (interference)	640 acres
Draw Down Limit	3500 PSI
Injection Pressure	5000 PSI
Net Methane in Solution	75 SCF/bbl

Table IV

GEOTHERMAL ECONOMICS

SCOPE FACILITIES

Field Size	200 MW
Barrels Per Year	600 Million
Barrels Per Day Per WL 11	20,500
10 Wells Each	25 MW Unit
80 Producers	80 Injectors
Plant Net	200 x .85
Plant Load Factor	70%

Operating costs and taxes can only be estimated. It is certain they will not be less than those experienced in keeping a gas or oil field in operating for 30 years.

Table V

INVESTMENT & REVENUE

160 Wells @ $6 M̄ Eac. (includes surface facilities)		$960 M̄
Heat @ .020/kwh	Gas @	$ 1.75 M̄CF
Energy Revenue		21.25 M̄/Yr
Gas Revenue		85.75 M̄/Yr
Revenue Total		$107.00 M̄/Yr.

EXPENSE

Operating Costs $200/Well/Day	= $12 M̄/Yr
Property & State Tax 15% x Gross/Yr	= 16 M̄
Total Expense	= $28 M̄

INCOME

Income - $107M̄ - $28M)	= $79 M̄
Net $79M x 50% (Income Taxes)	= $39.5 M̄
Payout $960/$39.5 = 24 Years	ROI = 4%

There are adequate problems to solve in utilization of geopressured-geothermal reservoirs. These are primarily related to geologic problems. Discontinuous sands form the reservoir rocks in geopressured systems. The lack of continuity prevents fluid moving to lower pressured zones in a natural adjustment to normal pressure results in the abnormal geopressures. This very discontinuity results in limited reservoirs of restricted areal extent.

In many geologic situations, faulting and fracturing provide the plumbing that allows geothermal fluids to move into the producing reservoirs. The vertical movement of fluids along these faults is thought to be an important factor necessary for high production rates over the long life required for energy production.

Geopressured reservoirs have no such plumbing, otherwise, their pressures would be normal. The sealed faults in the geopressured areas will cause rapid pressure decline unless produced volumes are compensated by having equal volumes reinjected into the same sand bodies. It is for this reason this source of energy must remain an energy resource with no defined reserves.