How steam is produced and handled at The Geysers

Illustrated tour of the only commercial U.S. geothermal development shows typical field operations from geology to electrical output

Robert E. Snyder, Engineering Editor

10-second summary

Unique properties of superheated steam dictate field development by well clusters around a plant site. Here's how operators plan such developments, how they deliver steam to the utility for power generation and how they get paid for their production.

EXPLORATION AND DEVELOPMENT is continuing in the world's largest geothermal project—California's Geysers area, 90 miles north of San Francisco. Five rigs are active for several operators and clusters of new wells are being completed to serve as sites for additional power plants. However, only Union Oil Co. of California, the company most responsible for modern development at The Geysers, has commercial production.

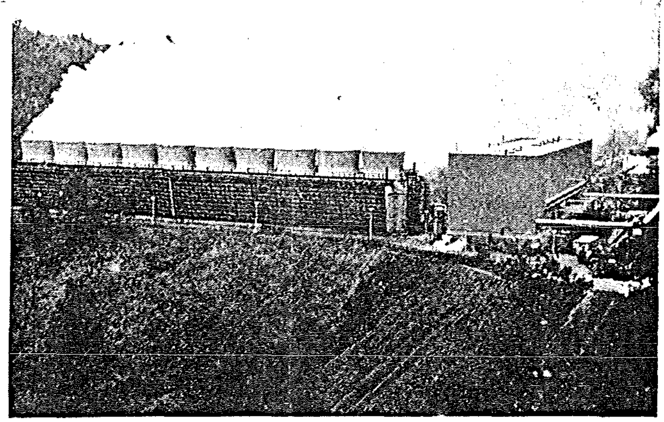
Including active locations and abandoned sites, over 150 wells have been drilled in a roughly rectangular, 4-mile-wide, 7-mile-long area extending southeastward to include the latest Castle Rock Springs development. There are perhaps some 100 wells in this area capable of commercial production.

Eleven generating units presently in operation are producing a total net output of 502 megawatts (mw). In perspective, this would be enough electrical power, at a rule-of-thumb of one kw per person, to supply the needs of a city of 500,000. In terms of fossil fuel to produce the same output, it is equivalent to about 19,000 barrels of oil per day.

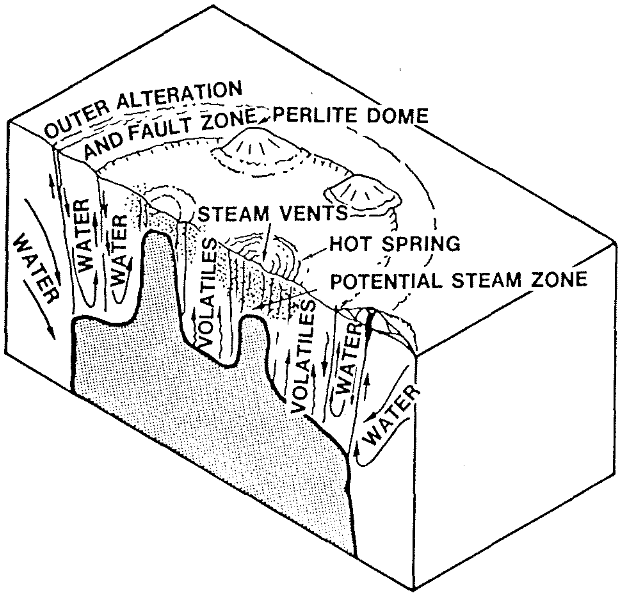
Plants 12, 13, 14 and 15, tentatively scheduled pending application approval by the regulatory agency, will bring total net output to 897 mw.

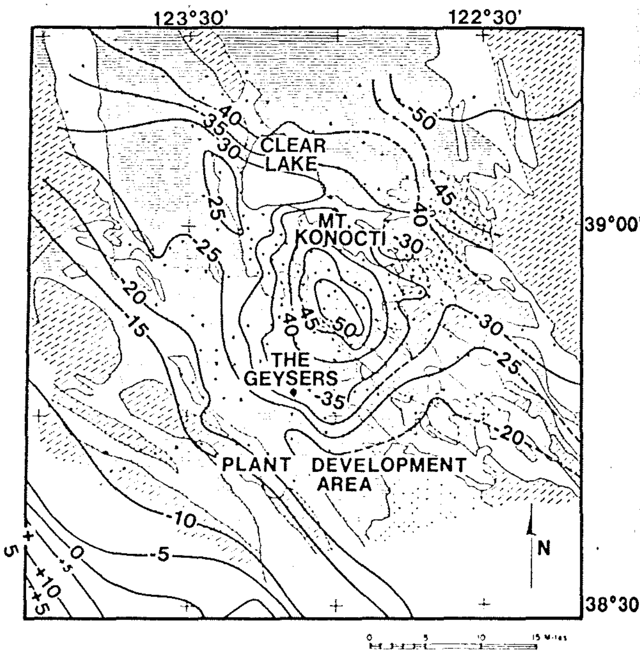
The most common figure mentioned for future potential of The Geysers is 1,500-2,000 mw, and theoretical studies place possible capacity of the 100-square-mile surrounding Geysers KGRA (Known Geothermal Resource Area) even higher. But all operators emphasize that the short production history of wells and the early state of the art in geothermal reservoir analysis make practical "reserve" estimations nearly impossible.

Well production is measured in pounds per hour (pph) of dry, superheated steam. Operators look for 150,000-



Power plant in The Geysers field contains two 55-megawatt turbine generator units. Note two steam lines entering from right. Huge cooling tower system cools turbine exhaust condensate and auxiliary systems to 80°F. Nearly 80% of the condensate is evaporated. (Courtesy PG&E)





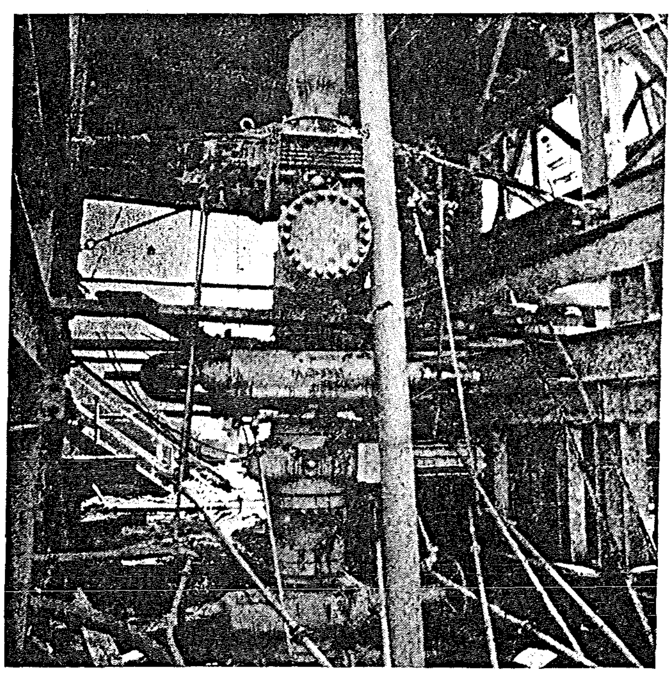
Underlying heat source for The Geysers field and surrounding 100-square mile geothermal area is likely a deeply buried magma intrusion, with local geothermal cells, illustrated schematically at left. Negative gravity anomaly, right, shows probable center of main magma body, some 10 miles northeast of The Geysers. (After Austin et al.[1])

200,000 pph from a new completion. Rates of 380,000 pph have been tested.

Turbine units now being installed require about 1 million pph. New plants with two such units would require 14-16 typical wells.

Because of energy losses in gathering lines, it is desirable to have wells as close as possible, generally within ½ mile, to the plant site. This requirement is the basis for the cluster system under which plants and wells are developed.

Operating conditions do not involve particularly high pressures or extreme temperatures, as might be expected.



BOP stack of Geysers well drilling in mud phase above steam zone shows 13⅜-inch wellhead and wing valves, master valve, steam gate, BOP, banjo box, top BOP, bell nipple and flowline. Bell nipple is replaced by rotating head for steam drilling and banjo box is connected to blooey line and muffler.

Reservoir pressures of 450-500 psig are reduced to 125 psig at the wellhead by expansion and cooling of the flowing steam. Reservoir temperatures are generally less than 500°F. Corresponding wellhead temperatures would be about 370°F, considering a typical super heat condition of less than 20°F. And turbines are designed to handle dry, 355°F, 114 psia steam at the inlet.

However, operators and equipment handlers must be constantly aware of the tremendous energy inherent in the nonconventional product they produce and deliver.

Between reservoir and generating plant, erosion by entrained particles and dust in the dry vapor is more significant than corrosion. After condensation within plants, or at any venting spot, associated gases and liquids may release small amounts of corrosive and noxious elements. Most noticeable is the minor concentration of H_2S in the atmosphere, which accelerates corrosion of bare steel such as racked drill pipe and, of course, any exposed copper cables and electrical contacts.

Development history. After The Geysers was discovered in 1847 and its hot mineral water first used in a resort and spa for adventurous Californians making the long, tortuous journey into the rugged area, shallow wells were drilled in the 1920s to power a small steam engine driven generator.

Magma Power Co. obtained several leases in 1955 and Magma and Thermal Power Co. then drilled six successful wells. Pacific Gas and Electric Co. (PG&E) installed the first 12-mw plant in 1960. Earth Energy Co., a Pure Oil Co. subsidiary, obtained adjacent leases in 1965 in the course of the Pure-Union Oil Co. merger. In 1967, Union-Magma and Thermal formed a joint venture which now controls some 15,000 acres in The Geysers with Union as operator.

Union will supply steam to all but two of the existing and proposed plants. Pacific Energy Corp. will supply 55-mw Plant 15 from a well cluster being developed just

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southwest of the main field complex. Burmah Oil & Gas (formerly Signal) will support PG&E's $17½-million, 135-mw Plant 13 from 15-20 wells located in the Castle Rock area, 5 miles to the southeast.

Geology. The reservoir consists of highly fractured, slightly metamorphosed sedimentary and igneous rocks of Cretaceous and upper Jurassic age, known locally as the Franciscan graywake.

The predominant heat source for geothermal activity is believed to be a large magmatic body buried perhaps 10 miles or more below the surface. A closed negative gravity anomaly centered 10-15 miles northeast of The Geysers may generally define this large, relatively less-dense magma intrusion.[1,2]

The government now has designated this general area as a Known Geothermal Resource Area, and under provisions of the Geothermal Act of 1970, leasing within such areas must be done by competitive bidding.

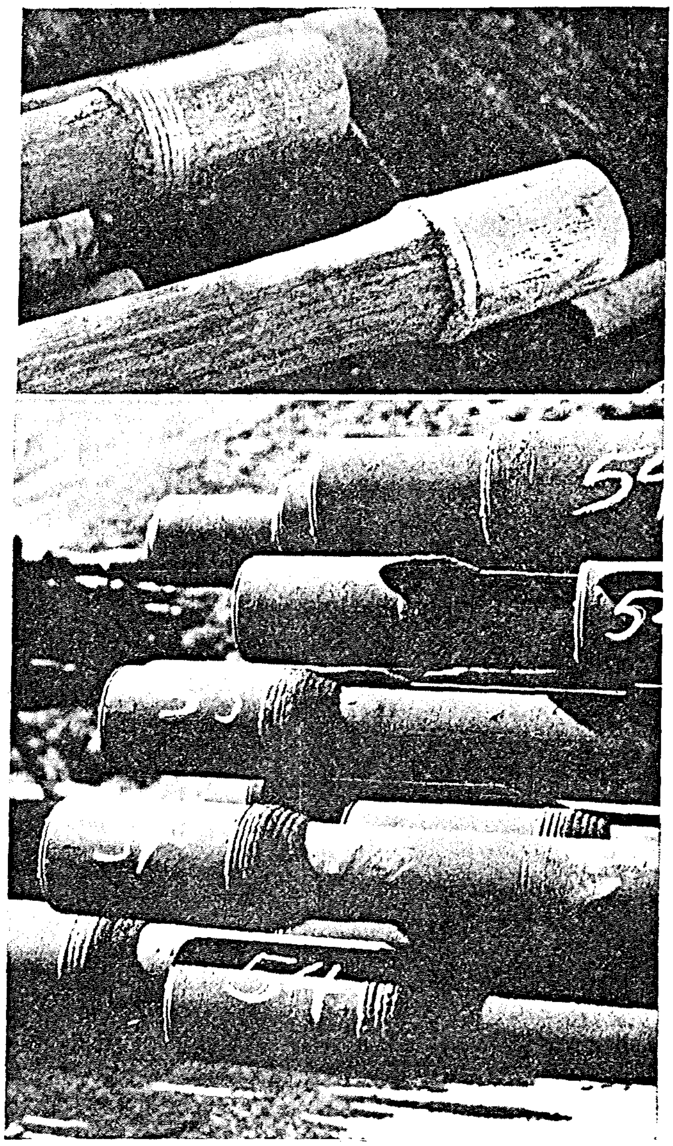
Smaller intrusions from the main chamber result in characteristic elliptical patterns on the surface which can be identified in aerial photographs. Extinct volcano cones are visible from high points in the field.

Conditions for producing dry steam that can be used directly are fairly rare. Besides the underlying heat source, the steam zone must have a high fracture permeability that is, or once was, connected to a surface water source. At The Geysers, these surface connections have long been nearly sealed by secondary mineral deposits.

To generate dry steam *in situ,* the fractured rock must not be completely flooded and an excess ratio of heat to water must be maintained.

Steam plants are also operational in Italy, New Zealand, northwestern Mexico, Japan and Russia. In the United States, geothermal exploration continues at a strong pace in many areas, including The Geysers, but no other type of system—hot water, dry rock, etc.—is operational. The next largest area of interest is in the Imperial Valley, where experiments are under way with heat exchange or "binary" systems to utilize the hot, corrosive underground brines found in one area, and other lower temperature fluids.

Steam production does decline in Geysers wells, contrary to early beliefs that the supply is inexhaustible. But well life is dependent on many variables such as spacing, depth, natural permeability and completion design. One example well on 5-acre spacing declined to 70,000 pph from 140,000 pph in five years.[3] Pressure buildup tests indicated that a major factor was reservoir pressure depletion, not well bore plugging. Wider spacings, of course, cut this decline significantly.

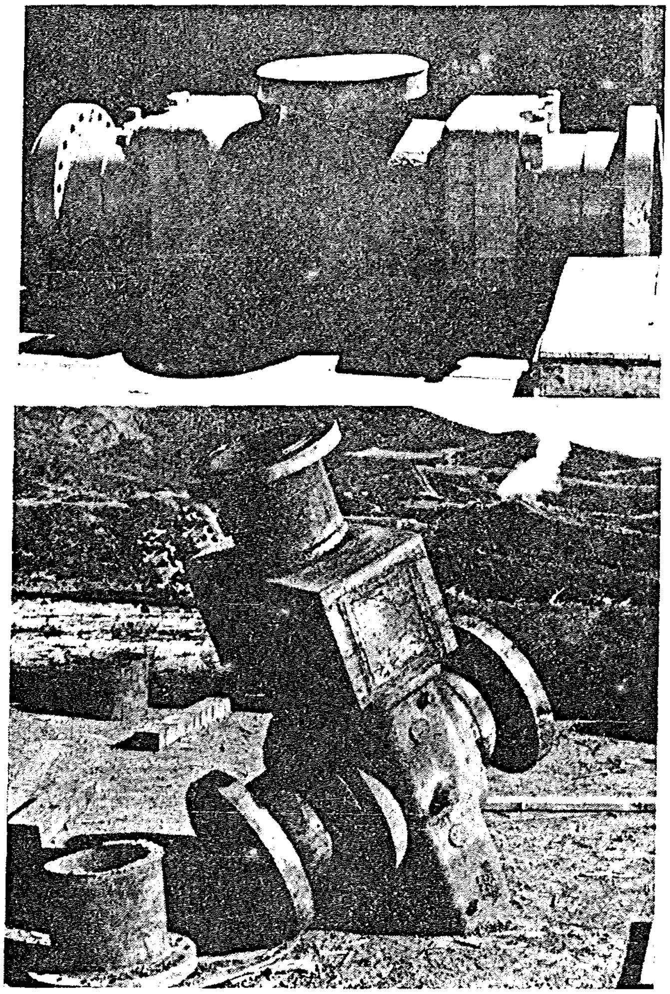


High velocity dry steam and entrained particles can damage drilling equipment. Top photo shows severely eroded tool joint shoulders. Lower photo shows typical hard band protection used to minimize erosion. Softer band is used on box OD to prevent casing wear. Harder material on shoulder takes direct force of flowing steam. Note that racked pipe is coated with a protective material to minimize atmospheric corrosion.

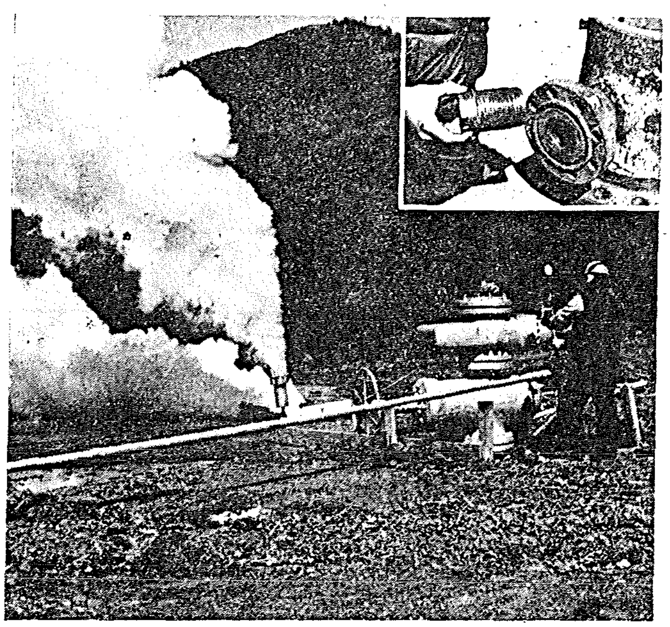
Some recharging may be possible with controlled injection but no quantitative evaluations of this effect are available. Presently, the remaining 20% of the condensed liquid from generating plants is reinjected. Too much water injected on close spacings may also flood-out nearby wells by temporarily altering the *in situ* super heat environment.

Pressure increases with depth but drilling costs also increase rapidly and rate of flow decreases due to the longer steam conduit to surface. A well at 10,000 feet, for example, may deliver 20% less than a comparable completion at 5,000 feet. These are major factors in designing completion systems.

Well and plant siting. Commercial operation generally follows exploratory and confirmation drilling by five years due to plant application lead times, delays for pipe line



Two types of banjo boxes. One style, utilizing a heavy BOP body, top, has double flanges for blooey line. When one side wears, the other flange can be used, to double life. Another style BOP body, bottom, is modified with addition of extra heavy welded box to serve as a vortex chamber for steam flow.



Wellhead on new completion not yet tied to gathering system has two ANSI 300 series, 500 psi 12-inch gate valves. As per common gas well practice, the lower valve is never opened or closed under differential pressure, to protect its sealing capability. Inner thread in wing valve outlet, inset, and hardened protector allow plug to be installed through a lubricator assembly for changing bad valves under pressure.

construction and operator evaluation after discovery.[3]

Plants can be sited after a discovery well and confirmation wells prove a significant "block of power." This has been done with as few as two wells. Then the required number of wells are completed to guarantee adequate steam supply, and the utility proceeds with plant design and construction. As output declines, additional wells are drilled.

Operator planning centers around plant capacity and its expected life. Sufficient acreage must be set aside within the "block" to accommodate additional wells.

With four new plants proposed and much exploratory area to be investigated, this general operational procedure indicates that significant drilling and completion activity will likely continue for several years.

How wells are drilled. Basic problems facing drillers are the steep terrain, hard abrasive formations from surface to TD and erosional effects of near sonic fluid velocities.

In narrow, grass-covered canyons between 2,500-3,000-foot mountain ridges, hillsides are very steep with 1,000-foot elevation changes per one-half mile, in some places. Often surface site economics dictate well locations and the hole may have to be deviated to reach a desired target.

A typical well may be 6,000-7,000 feet deep. Such a well may have 20-inch conductor to 150-200 feet, 13⅜-inch to 2,000-2,500 feet, and a 9⅝-inch liner to 6,000 feet (or higher), overlapping the 13⅜-inch by 200-250 feet. The steam zone is completed open hole using compressed air as the bit cooling medium.

Hole sizes for this program are 17½-inch opened to 26-inch, 17½-inch, 12¼-inch and 8¾-inch. One operator has dense graywake from top to bottom, and hard formation rock bits of the non-sealed bearing type are used. Another area contains a problem serpentine section that is cased off.

Mud programs generally specify fresh water and gel, with lime viscosifier in the surface hole. The 12-inch hole is drilled with water, gel and a gel extender, and lignite. High temperatures may dehydrate and thicken mud, making additional treatment necessary.[4]

Water loss is no problem in the dense rock. Solids must be kept low with screens, desanders and desilters. For lost circulation, an inexpensive initial plug may be used followed by cement-type plugs.

Deviated holes may be desirable for economic location selection, as noted above. A controlled natural drift also

Geysers power plant development

Year	Unit no.	Supplier	Output, megawatts		
			Gross	Net	Cum.
1960	1	G. E.	12	11	11
1963	2	Elliot	14	13	24
1967	3	Elliot	28	27	51
1968	4	Elliot	28	27	78
1971	5	Toshiba	55	53	131
1971	6	Toshiba	55	53	184
1972	7	Toshiba	55	53	237
1972	8	Toshiba	55	53	290
1973	9	Tosoiba	55	53	343
1973	10	Toshiba	55	53	396
1975	11	Toshiba	110	106	502
	12	Toshiba	110	106	608
	13	G. E.	135	130	738
	14	Toshiba	110	106	844
	15	G. E.	55	53	897

Steam handling systems must be designed to deliver only superheated, particle-free steam to the turbine inlet at 350°F, 114 psi

may be allowed to cause the hole to cut as many fault planes as possible to expose maximum fracturing.

Heavy assemblies are used in the 17½-inch hole. In one well, three 9⅜ and seven 8-inch collars, and 10 joints of heavy weight drill pipe were used. Drill pipe may be 4½-inch, 20 pound, or 5-inch, 19.5 pound. With less prominent shoulders to erode, the larger diameter pipe may be preferable. In 8¾-inch hole, six 6½-inch collars and heavy weight pipe are commonly used.

Prior to drilling into steam zones, the system is converted to air. Rates of 3,000-4,000 cubic feet per minute are common, supplied from commercial compressor units. Pressures may be 140-150 psi initially, increasing to 450-600 psi as large volumes of steam are penetrated.

When air is connected, the BOP stack is modified by replacing the bell nipple with a rotating head and connecting up the "banjo box," a heavy walled erosion resistant chamber that diverts high velocity steam and particles into the blooey line to the muffler.

Old style mufflers have been replaced with a new style, vertical centrifugal unit of Union Oil Co. design into which steam and drilling particles flow tangentially, partially cushioned by an injected stream of water. This system promises to greatly cut potentially harmful and annoying noise, and extend muffler life.

The BOP stack, in the mud phase, is mounted on the 13⅜-inch head and 12⅜-inch bore master gate valve. A wear ring protects this valve during drilling. The stack then consists of a steam gate (with blank steel ram), a 12-inch, single gate BOP, the banjo box, a 12-inch double gate BOP (with DP and collar rams) and the bell nipple. Wing valves on the head are connected to kill and choke lines.

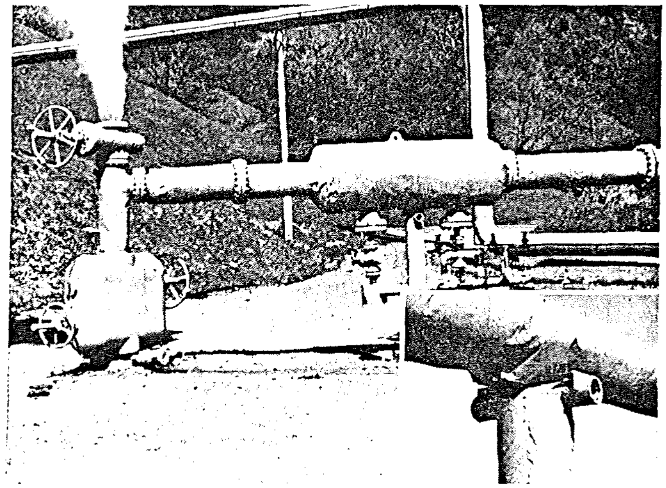
The 13⅜-inch is cemented with 100% excess 50/50 Pozmix, 35-40% silica flour. Liner is cemented with 50/50 Pozmix, 35% silica flour, friction reducer and retarder as needed. Neat cement is usually tailed in.

In the drill string, a metal-metal lower float valve is used to withstand 400°-500°F temperatures.

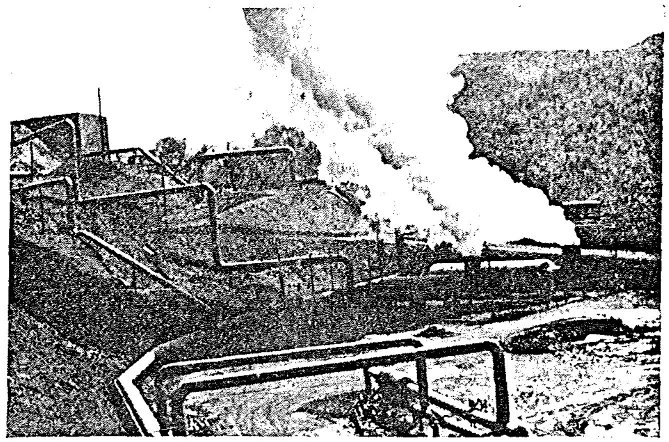
An average well now costs $500,000-$550,000, with 20-25% tangibles, including the wellhead. A rig may be on the hole 40-60 days.

Well capacity is first estimated using an orifice in the blooey line and flowing temperature. With the rig off, isochronal back flow tests similar to those used for gas wells give better evaluations of sustained flow rates.

Surface equipment consists of the 13⅜-inch wellhead with wing valves, two master valves, the tee, a top access valve (used almost exclusively to clean out the well after long shutdowns), and in the flowline: a centrifugal dust and particle remover and a differential pressure meter. All equipment is insulated with compressed 3-inch fiber glass pad and covers dyed an aesthetic green color.



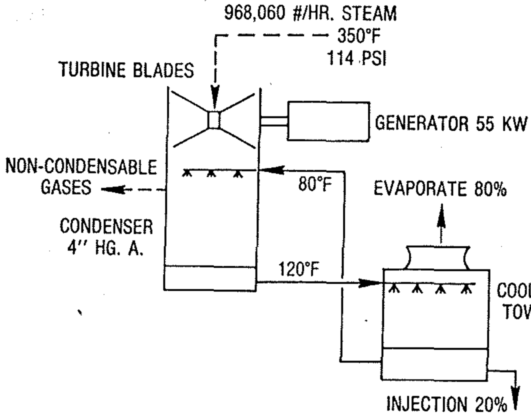
Producing well covered with fiber glass insulation has top access valve and centrifugal horizontal particle separator in the flowline. Two dirt legs under separator, vent small amounts of steam to blow out residue. All lines have expansion joints and flexible restraining mounts, inset, to permit movement with temperature changes.



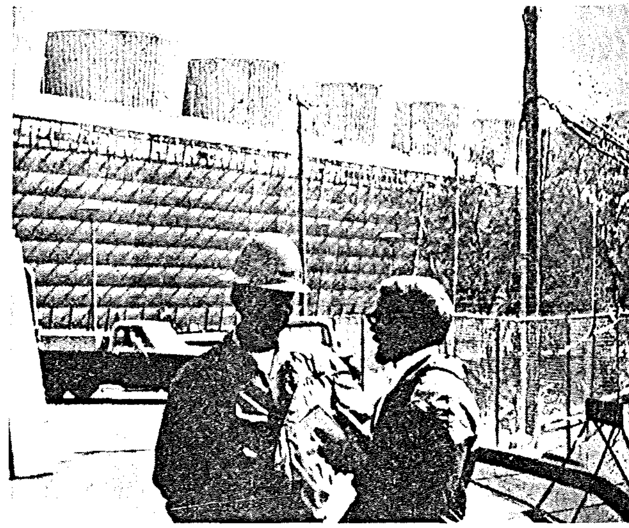
During temporary plant shutdown, steam is vented through large mufflers to keep gathering system and wells at proper temperature. Intermittent operation is avoided as wells are sensitive to shut in and start up. Occasional system shutdown gives opportunities for reservoir pressure build-up tests.

Great care is taken to keep the dry steam particle free. The centrifugal horizontal particle trap mentioned above has a cone shaped nose facing the flow, with spiral vanes that create a high speed whirl to throw particles into the dirt leg. Units are reportedly 99% effective in removing 10-micron or larger particles. Dirt legs and other traps located at changes of direction are vented slightly to blow particles out of the line.

Gathering systems must be carefully sized to assure proper productivity at least cost. Depending on conditions, lines may be 10-16 inches at the well, increasing to 24 inches, 30 inches and finally 36 inches at the plant entry. Too-large lines may not be desirable, as cooling effects may counteract increased productivity from lower pressures.



Simplified power plant schematic shows flow of dry steam through turbine blades, condenser and cooling tower. Portion of steam is diverted through ejectors that maintain vacuum on condenser to draw off gases. Other systems use 2 kw of output leaving 53 kw net. Operating voltage is primarily 115 or 230 kv.



Plant Superintendent Bill Pearce, left, discusses operations of PG&E's Plants 5 and 6 with *World Oil's* Robert E. Snyder during recent visit to The Geysers.

Control valves at the plants, regulate line pressure, venting the system at the plant during shutdown. Wells are not normally shut in except for extended downtime as cooling and startup introduce liquids into the system, shock the well and loosen rock particles. Back-up rupture discs along the line set at about 180 psi are final protection against pressuring the system to 400-500 psi reservoir pressures.

How plants operate. Turbines are designed to accept 350°F, 114 psia dry steam. Liquids and particulate matter may damage the system.

Steam strikes the double sided turbine and converts its heat energy to rotational velocity which is transferred directly to the generator. The steam discharges into a chamber kept at 4 inches of mercury absolute pressure. Steam is condensed in this chamber, and hot water at 120°F is pumped to a large cooling tower.

From the first chamber, noncondensable gases are also drawn off, then cooled in additional condenser units before venting. Steam generally contains less than 1% noncondensable gases, in the following proportions:[5]

Carbon dioxide	79%
Hydrogen sulfide	5%
Methane	5%
Ammonia	7%
Nitrogen	3%
Hydrogen	1%
Ethane	trace

Tower water at 80°F is also used to cool lubricating oil and the turbine blade hydrogen cooling system.

In the over-all process, some 80% of the steam condensate is evaporated. The remaining 20% is reinjected into the producing reservoir. Liquids are not discharged into streams of the area.

Some H_2S is returned to the reservoir in injected fluid; the output to the atmosphere from a geothermal plant is estimated to be one-fourth that of a coal plant. And total CO_2 discharge from the comparable sized fossil fuel plant is 20 times that of a geothermal plant.[5]

Still, released gases give the area a sulfur odor typical of that around any large hot mineral spring. And protective coatings must be used on exposed steel where surface corrosion would be a problem.

How operators are paid for steam. All steam is purchased by PG&E according to a lengthy, negotiated formula that considers PG&E's cost of power generation by fossil and nuclear fuels.[6] The price is revised each Jan. 1, using the previous year's data. The formula considers the following:

1. A constant 2.11 mills/kwh
2. PG&E's fossil fuel costs for preceding year
3. Fossil fuel costs for 1968 (31.66 cents/million Btu)
4. Lowest operating net heat rate, Btu/kwh, of the most efficient fossil fuel unit (8,274 Btu/kwh to date). And the comparable value for 1968 (same)
5. Average net cost of fuel for PG&E's nuclear plants for previous year, and
6. Total output from fossil and nuclear plants in previous year.

In 1974 and 1975, PG&E's base price, excluding 0.50 mills/kwh effluent disposal payment, was 3.23 and 6.89 mills/kwh, respectively. One independent report presented estimates of prices more than double that amount by 1985.[6]

ACKNOWLEDGMENT

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