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SAND--93-0866C

DE93 011670

An Estimate of the Cost of Electricity Production from Hot-Dry Rock

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APR 19 1993
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Abstract

This paper gives an estimate of the cost to produce electricity from hot-dry rock (HDR). Employment of the energy in HDR for the production of electricity requires drilling multiple wells from the surface to the hot rock, connecting the wells through hydraulic fracturing, and then circulating water through the fracture system to extract heat from the rock. The basic HDR system modeled in this paper consists of an injection well, two production wells, the fracture system (or HDR reservoir), and a binary power plant. Water is pumped into the reservoir through the injection well where it is heated and then recovered through the production wells. Upon recovery, the hot water is pumped through a heat exchanger transferring heat to the binary, or working, fluid in the power plant. The power plant is a net 5.1-MW_e binary plant employing dry cooling. Make-up water is supplied by a local well. In this paper, the cost of producing electricity with the basic system is estimated as the sum of the costs of the individual parts. The effects on cost of variations to certain assumptions, as well as the sensitivity of costs to different aspects of the basic system, are also investigated.

Cost Summary

The following table summarizes the capital and operating cost estimates for the basic system:

Table 1: Cost Summary for the Basic System

Capital costs:		O&M:		
Plant	$ 9.9M	Plant	$1.0M/yr	2.5 ¢/kW·hr
Injection well	$ 5.9M	Well field	$0.6M/yr	1.5 ¢/kW·hr
Production wells (2)	$10.8M			
Fracturing	$ 4. M	Total	$1.6M/yr	4.0 ¢/kW·hr
Water well	$ 0.8M			
Total	$31.4M ($6200/kW_e installed)			

For a 5.1-MW_e plant, the total capital translates to an installed cost of about $6200/$kW_e$. At a discount rate of 4.6% over thirty years, capital recovery is $1.95M/yr. At 90% plant availability, this translates to about 4.9 ¢/kW·hr. When O&M costs are included, the total levelized cost is estimated to be 8.9 ¢/kW·hr.

In arriving at the estimates in Table 1, no optimization for plant capacity has been performed. It is possible that a larger or smaller plant could result in reduced cost. The calculations and assumptions used to arrive at the above figures follow.

Primary Assumptions

The primary assumptions are:

1. Two production wells and one injection well,
2. Binary power cycle with dry-cooling,
3. Plant availability is 90%,

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4. Thermal-to-electric conversion efficiency is 17%,
5. Temperature of reservoir water at the inlet to the heat exchanger is 450°F (230°C),
6. Ambient air temperature is 80°F,
7. Pressure at the reservoir injection wellhead is 4000 psi,
8. Pressure at the reservoir production wellheads is 1500 psi,
9. Reservoir flow is 1000 gallons per minute (gpm),
10. Reservoir pump characteristics:
    a. pump efficiency is 0.80 and
    b. pump motor efficiency is 0.92,
11. Well depth is 13,100 ft (4000 m), and
12. No thermal depletion of the reservoir.

In order to achieve an inlet water temperature at the heat exchanger of 450°F (230°C) with a well depth of 13,100 ft (4000 m), an average geothermal gradient in excess of 60°C/km would be necessary.

Plant Thermodynamics

For dry cooling with an ambient air temperature of 80°F, the temperature of the working fluid leaving the condenser will be approximately 120°F and the temperature of the reservoir fluid leaving the heat exchanger will be about 140°F. Assuming no pressure drop across the heat exchanger, the enthalpy (h) at the inlet and outlet are (all thermodynamic properties from Wark)

$$h(450°F,\ 1500psi) = 432.0\ btu/lb$$
$$h(140°F,\ 1500psi) = 111.7\ btu/lb$$

This yields

$$\Delta h = 320.3\ btu/lb \text{ of reservoir water}$$

Then the thermal recovery from the reservoir is

$$v(450°F,\ 1500psi) = 0.01937\ ft^3/lb$$

$$\begin{aligned}P_t &= [320.3\ btu/lb]\cdot[(1000\ gal/min)(min/60\ s)]/[(0.01937\ ft^3/lb)(7.48\ gal/ft^3)] \\ &= 36{,}800\ btu/s = 38.8\ MW_t\end{aligned}$$

At 17% thermal-to-electric conversion efficiency, the gross plant electrical output is

$$P_g = 0.17P_t = 6.6\ MW_e$$

Reservoir Pump Parasitic Losses

If head losses within the plant are ignored, the pump can be assumed to work between the pressure at the production wellheads, 1500 psi, and that at the injection wellhead, 4000 psi. For these working pressures, the required pump capacity to obtain a 1000-gpm flow rate is given by:

$$\begin{aligned}W_p &= [(1000\ gal/min)/(7.48\ gal/ft^3)]\cdot[(4000\ lb/in^2 - 1500\ lb/in^2)(144\ in^2/ft^2)] \\ &= 48x10^6\ ft\cdot lb/min = 1460\ hp\end{aligned}$$

At a pump efficiency of 0.8, a pump rated at 1825 hp is needed. For a pump motor efficiency of 0.92, the pump parasitic losses will be:

$$P_p = 1980\ hp = 1.5\ MW$$

Plant net electrical output is then 5.1 MW_e. These calculations do not account for in-plant electrical power requirements. The major in-plant parasitic loads, such as the condenser pumps, are accounted for in the thermal-to-electrical conversion efficiency. Plant lighting and miscellaneous power requirements could be an additional 25kW to 50kW drain; however, twenty-five to fifty kilowatts is smaller than the uncertainty in these calculations.

Plant Cost

The capital cost for a binary plant employing dry cooling is about \$1500/kW_g and plant O&M will be from 10% to 15% of plant cost per year (Nichols). This gives plant capital and O&M costs of:

Plant capital:	\$9.9M
Plant O&M:	\$0.99M to \$1.5M per year

It is uncertain how much maintenance would be required for the heat exchanger, but it should be equal to or less than that required for a hydrothermal binary plant. Also, this is a relatively small plant, thus it is not unreasonable that it would be highly automated, allowing unattended overnight operation. Then plant O&M will be assumed to be near the lower end of the above bound: about \$1M/year. Based on net power of 5.1 MW_e and 90% availability, plant O&M costs are estimated to be 2.5 ¢/kW·hr

Make-Up Water

The estimated water loss from an HDR reservoir is from 5% to 15%. For a 1000-gpm flow rate, the water losses would be from 50 gpm to 150 gpm. A single water well should be able to supply 300 gpm and, therefore, be adequate to supply make-up water. This water well is assumed to be drilled to 3000 ft at a cost of \$250/ft. The pump for the water well will cost in the neighborhood of \$60k. Then the capital cost for make-up water is:

(3000 ft)(\$250/ft) + \$60,000 = \$810k

This estimate does not account for water rights. In many areas all water rights are sold. Thus, even after digging a well, water rights must be purchased before water can be consumed. The purchase price of water rights in the western U.S. can exceed the cost of purchasing municipal water in nearby communities.

Also, it is assumed that this water well will supply the water for fracturing the reservoir. However, it should be noted that for a twenty-million-gallon fracture, which is not unreasonable, a 300 gpm well will require a month and a half to produce the water for reservoir creation.

Reservoir Fracturing

In estimating the cost of building and operating an electrical generating station employing energy from HDR, probably the greatest uncertainty is in estimating the requirements for creation of the reservoir. For the purpose of estimating the cost of creating an HDR reservoir, the water volume and the pressure are needed.

One HDR reservoir for which fracturing data are available is at Fenton Hill, NM. Hydraulic fracturing of this reservoir was conducted from 1982 through 1984. The largest of these experiments was in December 1983 when 5.63 million gallons of water were pumped at 7000 psi (Duchane, 1991). The Fenton Hill reservoir has also been extended during experimental work.

The fluid volume of the Fenton Hill reservoir has been estimated at 2200 m^3 from tracer tests (Robinson and Kruger). However, this is only 580,000 gallons, an order of magnitude less water than was pumped in the December 1983 fracture experiment alone. Therefore, it must be assumed that during fracture the reservoir is highly dilated and will hold significantly more water than during production.

Estimates of the volumetric extent of the Fenton Hill reservoir range from 2.9×10^6 m^3 to 28×10^6 m^3 of rock (Robinson and Kruger). The best estimate of the volumetric extent of the accessible reservoir is 16×10^6 m^3 (Duchane). This value corresponds roughly to the rock volume enclosed by two-thirds of the micro-seismic events that have been recorded during fracturing and operations at the site. The porosity of the Fenton Hill reservoir is admittedly uncertain but has been estimated at 0.003 (Robinson and Kruger). It is expected that the porosity in an HDR reservoir will decrease with increasing distance from the injection well. Therefore, any single-valued estimate of porosity must represent an average. Assuming an average porosity of 0.003 and a rock volume of 16×10^6 m^3 yields a total water volume of 48,000 m^3 or about 13×10^6 gallons. When compared to the known data and history of the Fenton Hill site, a water volume of 13×10^6 gallons for creation of this reservoir in a single fracture event is not unreasonable. For this analysis, it will be assumed that 13×10^6 gallons pumped at 7000 psi are required to create a reservoir the size of that at Fenton Hill.

The pressure on the injection well at the Fenton Hill reservoir is limited to about 4000 psi to avoid reservoir expansion. This pressure limitation results in a flow limitation in the current two-well configuration of about 100 gpm. It has been estimated that a second production well at Fenton Hill could allow increasing the flow rate seven-fold. While it is not certain that the flow rate could be increased seven times, there is no doubt that a second production well would more than double the maximum achievable flow rate. Then a second production well at Fenton Hill would allow a flow rate somewhere between 200 gpm and 700 gpm. For the system being modeled here, somewhere between one and one-half and five times the flow rate possible at Fenton Hill is required.

If it is assumed that the achievable flow rate increases linearly with reservoir size, a reservoir somewhere between one and a half and five times as large as the Fenton Hill reservoir is needed to obtain a flow rate of 1000 gpm in a system consisting of one injection well and two production wells. Then, assuming 13×10^6 gallons at 7000 psi are required to produce the Fenton Hill reservoir, somewhere between 19×10^6 gallons and 65×10^6 gallons of water at 7000 psi are required to achieve a reservoir capable of sustaining a flow rate of 1000 gpm.

It should be noted that in terms of necessary heat capacity to support the power plant, an assumption of linearly increasing reservoir size is reasonable. However, as mentioned previously, flow is limited primarily by injection pressure, which, in turn is limited primarily by rock strength and in-situ stresses. So it is not certain that increasing reservoir size in itself will allow increased flow. The alternative of assuming a maximum obtainable flow capacity and requiring additional well fields and reservoirs to achieve the total required flow rate is discussed in a later section.

At a pressure of 7000 psi, the cost for well fracturing is \$1.50/hp·hr. For 19×10^6 gallons, the energy requirements for fracturing are given by:

$$(19 \times 10^6 \text{ gal})(\text{ft}^3/7.48 \text{ gal})(7000 \text{ lb/in}^2)(144 \text{ in}^2/\text{ft}^2) = 2.6 \times 10^{12} \text{ ft·lb}$$
$$= 1.3 \times 10^6 \text{ hp·hr}$$

At a rate of \$1.50/hp·hr, this operation would cost \$1.9M. A 65×10^6-gal, 7000-psi fracture operation requires 4.4×10^6 hp·hr at a cost of \$6.6M. A cost of \$4M, approximately in the middle of the above two values, will be used. These calculations allow for no excess on-site capacity during fracturing.

Fracturing Summary

To summarize, in order to estimate the cost of creating the reservoir, the following assumptions were made:

1. Fracturing the Fenton Hill reservoir in one operation would require pumping 13×10^6 gallons of water at 7000 psi,

2. If a second production well were drilled at Fenton Hill, the maximum achievable flow rate would increase from 100 gpm to between 200 gpm and 700 gpm, and

3. The maximum achievable flow rate through a reservoir will increase linearly with reservoir volume.

Based on the above assumptions, it was estimated that between $19x10^6$ gallons and $65x10^6$ gallons of water, pumped at 7000 psi would be required for reservoir creation. At current rates, the cost of fracturing would be between $1.9M and $6.6M. An estimate of $4M is used in this analysis.

Well Costs

The drilling and well completion costs are based on a well depth of 13,100 ft (4000 m). When estimating drilling costs, the injection well was charged for mobilization, demobilization, and site costs. For the production wells, the only similar charges are those for moving the drill rig on site. It was assumed that the injection well could be drilled without directional control, however, charges for mud motors and directional control are included in the cost estimates for the production wells, since it is expected that these wells would need to be guided to intersect the fracture cloud. The estimated daily operating cost and casing schedule for well drilling and completion are given in the following tables:

Table 2: Day Rate

Rig rate	$10,000
Fuel costs	0
Camp expense	$500
Drilling supervision	$1000
Mud logging	$1000
Transportation	$1200
Water	$500
Miscellaneous	$1000
Daily operating cost	$15,200

Table 3: Casing Schedule

Depth	Hole Size	Casing Size
50 ft	48 in	42 in
300 ft	36 in	30 in
1500 ft	26 in	20 in
4500 ft	17 1/2 in	13 3/8-in liner
10,000 ft	12 1/4 in	9 5/8 in
13,100 ft	8 3/4 in	7-in liner

Based on the data in the above tables and the previous discussion, the drilling and completion costs are summarized in Table 4. The contingency cost given in Table 4 can be considered the best estimate or expected cost of drilling problems. Since the totals do not include contingency costs, they represent the expected cost for drilling and completion of trouble-free wells. Because of the expected geology in a region where HDR wells would be drilled, it may be possible to reduce the well costs by convincing the regulating agencies that many of the precautions required in oil, gas, and hydrothermal drilling are unnecessary. This might save as much as 10% of the well cost. The estimates in the above table allow for state and federal regulations regarding drilling safety and operations.

For well-field O&M, daily maintenance and operations will cost about $200k/yr. This cost assumes one person's labor plus maintenance and repair contracts. Additionally, hydrothermal wells require work-over and clean-out every one to two years depending primarily on brine chemistry. It should be possible to maintain a certain amount of control over the chemistry in HDR wells, thus reducing the maintenance schedule when compared to hydrothermal wells. On this basis, it is assumed that each HDR well will need work-over every three years; thus the site average will be one well per year.

Clean-out and work-over will require a work-over rig for about 15 days at $10k/day ($150k). Mobilization and demobilization of the rig will cost another $100k. Materials for work-over (wellhead, cement, casing, etc.) are estimated to cost between $150k and $500k. Using the lower bound for materials yields an estimate of $400k for work-over. Combining work-over and daily maintenance, well field O&M is estimated to cost $600k/yr. For a net 5.1-$MW_e$ plant operating at 90% availability, this is about 1.5 ¢/kW·hr.

Table 4: Well Cost by Account

	Injection Well	Production Well
Mob, demob, and site	$620k	$140k
Operating cost	$1763k	$1710k
(Rig cost)	($1160k)	($1125k)
Mud cost	$579k	$457k
Bits and tools	$792k	$792k
Directional		$132k
Logging	$187k	$187k
Casing	$991k	$991k
Cement	$539k	$539k
Blow-out preventer equipment	$51k	$53k
Wellhead equipment	$90k	$90k
Completion	$120k	$120k
Testing	$200k	$200k
Contingency	$529k	$513k
Total	$5,932k	$5,411k

Notes:
1. Operating cost includes rig cost
2. Totals do not include contingency cost

Cost Summary

A summary of the estimated capital and O&M costs for the basic HDR system are given in Table 5.

Table 5: Cost Summary for the Basic System

Capital costs:		O&M:		
Plant	$ 9.9M	Plant	$1.0M/yr	2.5 ¢/kW·hr
Injection well	$ 5.9M	Well field	$0.6M/yr	1.5 ¢/kW·hr
Production wells (2)	$10.8M			
Fracturing	$ 4. M	Total	$1.6M/yr	4.0 ¢/kW·hr
Water well	$ 0.8M			
Total	$31.4M ($6200/kW$_e$ installed)			

At 4.6% interest over thirty years, capital recovery is $1.95M/yr. For a net 5.1-MW$_e$ plant operating at 90% availability, this is about 4.9 ¢/kW·hr.

This completes the cost analysis for the basic plant. In the following sections, some of the assumptions made previously are examined, the sensitivity of the results to these assumptions is discussed, and, in some cases, the costs associated with alternative assumptions are estimated.

Thermal Depletion

It has been assumed that no thermal depletion of the reservoir will occur. This is not realistic; however, there are no data on which to make an informed estimate of thermal depletion for an HDR reservoir. In order to maintain full plant output, it may be necessary to drill new wells and/or fracture new rock one or more times over the life of the power plant. The capital costs associated will drilling three new wells and creating a new reservoir are given in Table 6.

Table 6: Capital Costs for New Wells and Reservoir After Fifteen Years

Injection Well	$ 5.9M
Production Wells (2)	$10.8M
Fracturing	$ 4. M
Total	$20.7M

With a discount rate of 4.6%, three new wells and a reservoir fifteen years into the life of the power plant would have a present value of $10.5M. Capital recovery for $10.5M at 4.6% over thirty years is $650k/yr which translates to approximately 1.6 ¢/kW·hr.

This is not to imply that it is expected that three new wells and a new reservoir will be needed after fifteen years. There are a large number of possible approaches to compensating for any thermal depletion that may occur. Only when there are data and models on which to make predictions of the thermal depletion for a given operational scenario can reasonable predictions of required new capacity and costs be made.

Reservoir Pumping Costs

The requirement to pump water at high-pressure through the reservoir results in a significant cost. Besides the capital cost of a 2000-hp pump, the high-pressure requirements to dilate the reservoir require that the production and injection wellheads, as well as the connecting pipe, be rated for high pressure. Also, the reservoir side of the heat exchanger must contain high-pressure tubing.

All of the above requirements, due to high-pressure pumping, increase capital costs; however, there is another cost due to reservoir pumping requirements: the parasitic power losses. In the base case, the pump reduced the net plant output by 1.5 MW_e. This represents a fourth of the capacity of the plant. Removal of the high-pressure pumping requirement could reduce levelized costs by up to 25% through increased plant output alone.

Fracturing Costs

Perhaps the greatest uncertainty in the cost estimates are those associated with reservoir creation. As discussed previously, in the basic system an estimate of $4M was used. However, this value is based on a rather crude estimate of the water volume necessary to create the Fenton Hill reservoir in a single operation and an admittedly questionable assumption of a linear relationship between reservoir volume and the maximum achievable flow rate. Table 7 shows the effect on capital and levelized costs of variations in the cost of reservoir creation.

Table 7: The Results of Different Reservoir Fracturing Costs

Fracture Cost	Total Capital Cost		Capital Recovery	Levelized Cost
$1M	$28.4M	$5600/kW installed	4.4 ¢/kW·hr	8.4 ¢/kW·hr
$4M	$31.4M	$6200/kW installed	4.9 ¢/kW·hr	8.9 ¢/kW·hr
$6M	$33.4M	$6600/kW installed	5.2 ¢/kW·hr	9.2 ¢/kW·hr

According to the data in Table 7, reducing the cost of fracturing the reservoir by 75% (from $4M to $1M) will reduce capital costs by 10% and levelized costs by 5%. A 50% increase in fracturing costs (from $4M to $6M) increases capital costs by 6% and levelized costs by 3%. From these data it appears that the effect of fracturing cost on project cost is not nearly as large as the uncertainty in the fracturing cost itself.

Flow Rate Uncertainty

In the basic system, it was assumed that the achievable flow rate increases linearly with reservoir volume. The only way that this assumption makes sense is if the reservoir volume is increased by increasing the length of the well bore exposed to the fracture cloud. However, it is by no means certain that this would be successful. It may be that rock strength and in-situ stresses will essentially determine the maximum possible flow rate regardless of reservoir size.

As discussed previously, a second production well at Fenton Hill would allow an increase in flow rate from the current 100 gpm to between 200 gpm and 700 gpm. If it is assumed that a second production well would result in a flow rate of 500 gpm, then two reservoirs the size of Fenton Hill, each with one injection well and two production wells, would be needed to supply 1000 gpm.

At a pressure of 7000 psi, the energy requirements for a 13×10^6-gallon fracture operation are given by:

$$(13 \times 10^6 \text{ gal})(\text{ft}^3/7.48 \text{ gal})(7000 \text{ lb/in}^2)(144 \text{ in}^2/\text{ft}^2) = 1.8 \times 10^{12} \text{ ft}\cdot\text{lb}$$
$$= 880 \times 10^3 \text{ hp}\cdot\text{hr}$$

At a cost of \$1.50/hp·hr, each fracture operation would cost \$1.3M for a total fracture cost of \$2.6M.

Plant O&M would be no different for the duel-reservoir case than for the base case: \$1M/yr or about 2.5 ¢/kW·hr. However, well field O&M would be higher for the duel-reservoir case. As with the base case, it is assumed that daily maintenance and operations will cost about \$200k/yr. However, under the same rational discussed previously, two wells per year would need work-over. This would require a work-over rig for about 30 days at \$10k/day (\$300k). Mobilization and demobilization will cost another \$100k and materials are estimated to cost about \$150k/well (\$300k). This yields a total of \$900k/yr for well field O&M. At a plant availability of 90%, this translates to 2.2 ¢/kW·hr. The costs for the duel-reservoir case are summarized in Table 8.

Table 8: Cost Summary for Duel-Reservoir Case

Capital Costs:		O&M:		
Plant	\$ 9.9M	Plant	\$1.0M/yr	2.5 ¢/kW·hr
Injection wells (2)	\$11.4M	Well field	\$0.9M/yr	2.2 ¢/kW·hr
Production wells (4)	\$21.6M			
Fracturing (2)	\$ 2.6M	Total	\$1.9M/yr	4.7 ¢/kW·hr
Water well	\$ 0.8M			
Total	\$46.3M (\$9100/kW_e installed)			

In estimating well costs, mobilization and demobilization of the drill rig is charged to one injection well. The other injection well is charged only for moving the drill rig on site. Capital recovery for \$46.3M over 30 years at a discount rate of 4.6% is \$2.9M/yr. For a net 5.1-MW_e plant operating at 90% availability, this translates to about 7.2 ¢/kW·hr. Comparison of Table 8 with either Table 1 or Table 5 indicates that both the capital and the O&M costs for the duel-reservoir case are significantly higher than for the base case.

Conclusions

The cost of an HDR electrical generating system consisting of a single injection well, two production wells, and a dry-cooled binary power plant has been estimated. Also, the uncertainty and sensitivity of the cost of a number of aspects of this system have been discussed. These are summarized in the following table:

Table 9: Cost Summary

	Levelized Cost*	Difference
Basic System	8.9 ¢/kW·hr	---
Pumping Parasitic Losses	6.9 ¢/kW·hr	- 23%
95% Plant Availability	8.4 ¢/kW·hr	- 5%
Fracture Cost Uncertainty	8.4 - 9.2 ¢/kW·hr	- 5% to + 3%
New Reservoir (@ 15 years)	10.5 ¢/kW·hr	+ 18%
Duel-Reservoir System	11.9 ¢/kW·hr	+34%

* Levelized cost includes O&M and capital recovery at 4.6% over 30 years

The third item in Table 9 was included because there is some uncertainty in the plant availability. Hot-brine hydrothermal plants generally achieve availabilities significantly higher than 90%, sometimes producing over 100% of rated capacity for extended periods of time. There is no reason to believe that an HDR plant delivering baseload power should not do as well. Thus, the 90%-availability assumption may be conservative and the third line in Table 9 gives an indication of the effect on cost.

Technically, the greatest uncertainty in the development of the HDR resource for production of electricity is the reservoir; what flow rate can be achieved, what are the fracturing requirements, how large must the reservoir be, what are the thermal depletion characteristics, etc. However, the greatest proportion of the cost associated with production of electricity from HDR is not associated with the reservoir. Even at an estimate of $4M for fracturing, this is still less than 13% of the total capital cost.

The greatest cost in an HDR project is drilling the wells. Well costs are estimated to account for more than 50% of the capital costs of the basic system and more than 70% of the capital costs of the duel-reservoir system; therefore, drilling is an attractive target for cost reduction. However, reducing drilling costs is not a simple task. People have been drilling holes in the ground to extract fluids for longer than a century; drilling is a mature industry. Also, the problem is not just the cost of making the hole. Inspection of Table 4 reveals that from 25% to 30% of the well costs are for materials used in completing the well: cement, casing, and wellhead. So, even if the holes are free, completion materials will still cost $1.6M per well. Without the development of new completion methods, current completion practices significantly limit the cost reductions possible even with the development of a revolutionary drilling technology.

An indirect approach to reducing the significance of well costs would be to increase the productivity per well. Considering the increased cost of the duel-reservoir system, significant expenditures to avoid the necessity of a second reservoir can be justified. The flow rate in the basic system was assumed to be 1000 gpm using three wells. If it is possible to double the flow rate to 2000 gpm, the cost per installed kilowatt could be significantly reduced, even if fracturing costs also doubled. Since plant capital costs would also increase, doubling the flow rate would not halve the levelized cost, but initial calculations indicate that it could be reduced by more than 25%. This is on the order of the largest reduction factor in Table 9.

Note: Work performed at Sandia National Laboratories is supported by the U.S. Department of Energy under contract DE-AC04-76DP00789

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