MODELING PERFORMANCE AND ECONOMICS OF POWER GENERATION BY ENERGY RECOVERED FROM COPRODUCED GEOTHERMAL FLUIDS

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Abstract

There is a broad regime of conditions within which coproduced hot water from oil and gas wells could generate electricity at competitive cost using packaged, binary generators. Cost competitiveness depends primarily on temperature, wellfield configuration, generator unit capacities, and water flowrates. In a range of 190 to 250 degrees Fahrenheit (°F), and from 10 to 70 gallons per minute (gpm, or 340 to 2,400 barrels per day [BPD]) per production well, a levelized cost of energy (LCOE) is estimated to range from 20 cents per kilowatt-hour (¢/kWh) to 2 ¢/kWh, respectively for a 5-spot well layout pattern. Figure 1 depicts such trends. Unit capacity determines LCOE for any matchup of generator rating with temperature, wellfield configuration, and well productivity. Figure 2 illustrates declining LCOE trends as wellfield configurations add production wells feeding a 200-kW generator. This could encourage industry to offer a range of unit capacities.

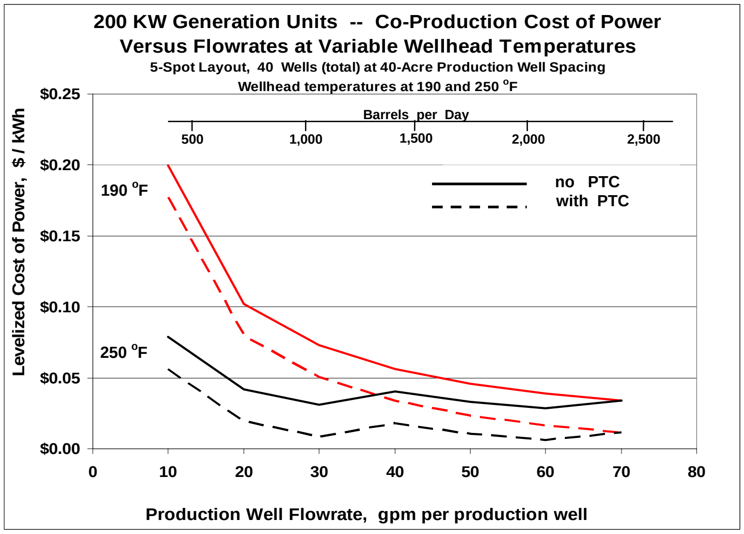
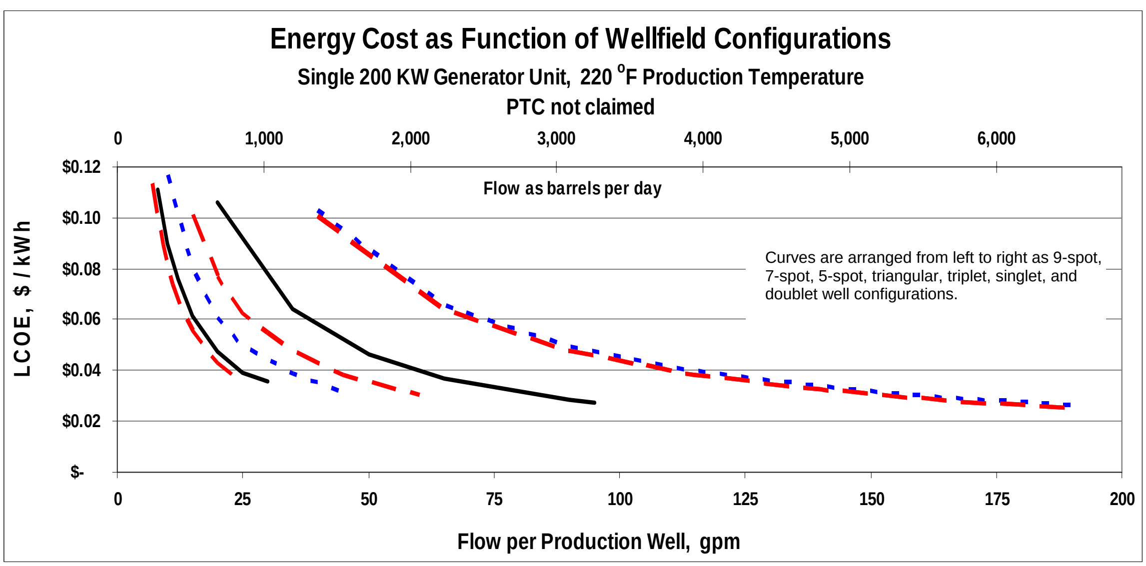


Figure 1 -- Effect of Production Well Flowrate and Wellhead Temperature on Levelized Cost of Energy

Figure 2 -- Effects of Wellfield Configuration



Modeling Power Generation from Coproduced Geothermal Fluids

Introduction

This analysis estimates power generation economics for oil or gas wellfield installations with flowrates of coproduced geothermal water above about 10,000 pounds per hour per production well (about 20 gpm or 700 BPD per well), and with wellhead temperatures ranging upward from 190 degrees °F. Under these conditions, producing wells could be harnessed together to produce electrical power at competitive cost. Modular, packaged generation sets are available at ratings of about 200 kW, operating on binary power cycles, and the results here are largely based on the 200-kW capacity. However, energy costs are sensitive to generator capacity, so comparisons are given to show electrical costs using 50- and 100-kW capacities for the packaged generation units.

The key variables of interest for estimating coproduction electricity costs include:

- Resource and ambient temperatures
- Flowrates of geothermal fluid
- Wellfield installation layout patterns
- Parasitic pumping power requirements
- Costs for installation and operation.
- Access to distribution or transmission.

The scale of such applications is expected to be small in a developmental phase of implementing coproduction power projects. Initially, for example, sub-megawatt capacities might be generated from small numbers of wells configured as production units. This analysis defines a production unit to comprise a set of one or more production wells connected to one central injection well for return of produced waters. A sole exception to this definition is a singlet production unit configuration, consisting of a single production well without an associated injection well.

Electing to develop coproduced geothermal power would consider these key questions:

1. Does coproduced power cost less than purchased power?
2. What are pay-off times for converting from combustion drives to electric motors for production equipment such as wellhead pumpjacks?

A pending task report by the National Renewable Energy Laboratory (NREL) expands on this analysis and the coproduction model. That report will provide details on methodology and bases for the selected cost and performance results discussed here.

Case Studies

Figures 3 and 4 on the next two pages summarize estimated values of levelized cost of energy for a series of cases based on variable production flowrates, well pattern configurations, and wellhead temperatures. They show that sites with conditions in favorable regimes of temperature, well flow-rates, and wellfield configurations could become competitive power projects.

Figure 3 complements Figure 1 from the Abstract, above. The test cases shown are for a configuration using multiple 5-spot production units, each having four production wells and a central injection well. It shows the cost effects of variable production flowrates combined with changing the temperature of produced fluids. Each group of three curves corresponds to production well spacings of 60, 40, and 10 acres per well, top to bottom, respectively.

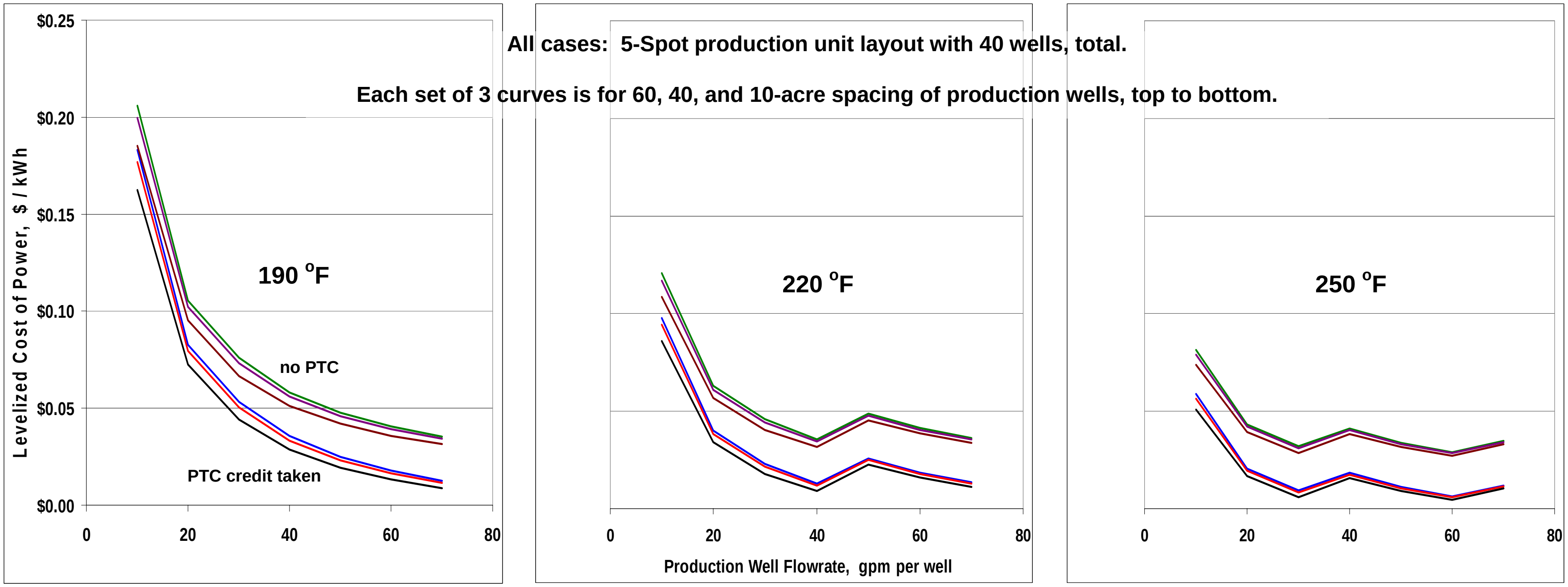
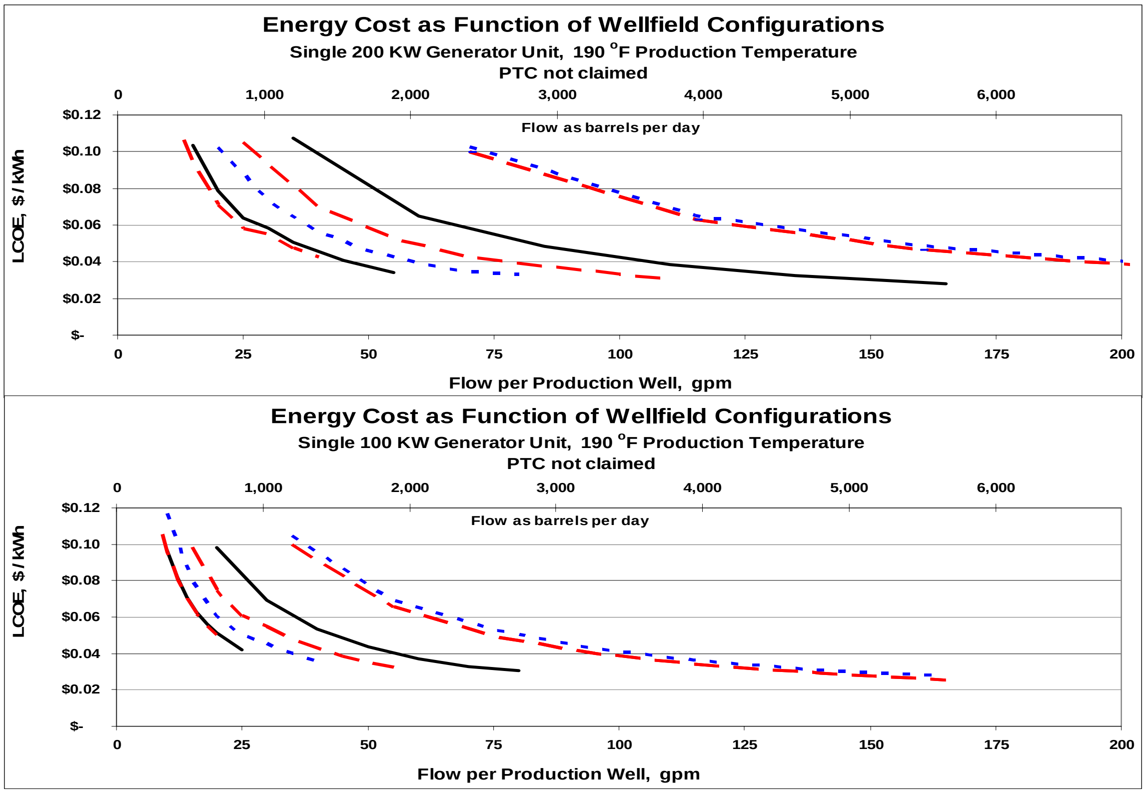


Figure 3 – Cost of Energy versus Production Well Flowrate
at Wellhead Temperatures of 190°F, 220°F, and 250°F
All cases use generation unit capacities of 200 kW

The upper group of three curves in each panel of Figure 3 results from excluding a federal production tax credit (PTC) from cost terms, while the lower groups of curves take credit for the PTC, reducing the levelized costs of energy by just over 2 ¢/kWh.

The panels show cases run at temperature increments of 30 °F.

Figure 4 shows two sets of cases plotting LCOE versus production well flowrate for all seven well configuration cases, using a single production unit. The two plots compare 100- and 200-kW generator capacities at a production temperature of 190°F. Figure 4 complements Figure 2, which illustrates a 200-kW case at 220 °F. These two plots are on common scales, so the visual effect shows the proportions between cases and configurations for all curves. This layout gives a good sense of the transitions between generation capacities. Other cases (more production wells, more production units, variable generator capacities) will scale from these plots.



Curves are arranged from left to right as 9-spot, 7-spot, 5-spot, triangular, triplet, singlet, and doublet well configurations. In the bottom panel, the 9-spot and 7-spot curves are virtually coincident. PTC is excluded.

Figure 4 – Cost of Energy as a Function of Flowrate for All Wellfield Configurations

The flowrate ranges for each wellfield configuration in Figure 4 were selected to capture LCOE estimates between two pragmatic end-points: (a) a low-cutoff gpm value that limits LCOEs to about 10 ¢/kWh; and (b) a maximum gpm value that delivers enough recoverable geothermal heat to operate a single generator unit at just under 100 percent of its nominal capacity.

The plots show that near the low-cutoff rate, LCOE takes on a steep trend. And if production flowrates go higher than the maxima, the generator loadings would exceed 100 percent.

While these cases were forced to stay under 100 percent generator utilization, the model is set up to automatically add generation units in cases for which capacity utilization would exceed 100 percent. This practice effectively reduces the geothermal fluid flow per generation unit each time a unit is added by the model. This gives a cost effect which graphically corresponds to sliding up and to the left on the single-unit LCOE curves in Figure 4. That process will give a sawtooth pattern in the model estimates as flowrates increase, just what one would expect. The sawtooth pattern develops in Figure 3 as rising temperature and increasing production flowrates deliver more energy to a generation unit.

Interpretation

Some specific observations include:

1. As temperature levels of produced fluids decrease, the sensitivity of LCOE to production well flowrates increases, as indicated by the pronounced changes in slope of the 190°F curves beginning below about 40 gpm per well. For higher temperatures, the changes in sensitivity of the cost curves occur at progressively lower flowrates. That means that as temperature rises, competitive electricity costs may occur over ever-widening ranges of wellhead flowrates.

2. The analysis assumed that increasing wellfield thermal productivity (i.e., increasing geothermal energy recovery with some combination of well counts, flowrates, and temperatures) would be accommodated by adding modular generation sets of one capacity, rather than progressively raising the individual generation unit capacity to keep up with the productivity. This reflects both the pre-existence of field gathering systems (hence little or no piping costs to incur), and a limited variety of packaged power unit capacities for this kind of application. This assumption causes the cost curves to become nearly flat above a combination of flow and temperature at which a production unit produces sufficient energy to drive more than one generator set near their design rating.

   In practice, if a viable power market were to evolve at the scale of applications that this analysis addresses, industry may offer packaged generator units over a series of discrete capacities. This would allow manufacturers to capture the benefits of standardization, assembly-line production, and progressive economies of scale. Likewise, it would help field developers to optimize long-term power costs and better plan their field build-out schedules. As illustrated by this analysis, the benefits to project cost competitiveness are apparent as reductions in LCOE.

3. The approach of this analysis uses a basic wellfield scheme for routing combined well flows within each production unit (of any particular configuration) to a dedicated facility with one or more generator sets per production unit. Schemes for optimizing such installations in actual practice could also include extending gathering system headers to connect multiple production units to share centralized generator facilities. This practice would spread generator costs across more wells, but would also increase the cost of piping in the overall installation. This model does not yet address that configuration.

4. Finally, this analysis assumes that field piping may need to be added to transport geothermal fluids to generating units. For existing oil or gas wellfields that will not always be the case. The coproduction model can optionally omit the costs of surface piping from the total capital cost of an estimate.

Coproduced Geothermal Energy -- Recovery and Conversion

Figure 5 diagrams general component groups in a binary geothermal power system.

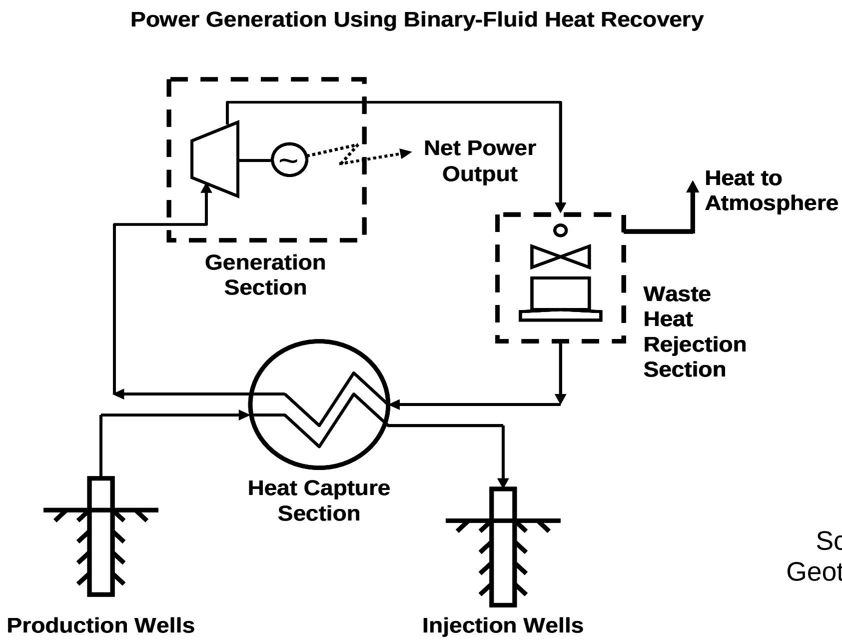


Figure 5

Schematic of a Binary Geothermal Power System

In brief, a binary geothermal power system has three essential sections:

- Heat capture – a heat transfer section transferring thermal energy from hot geothermal fluid into a low-boiling fluid such as single or mixed light organic compounds, ammonia, or an ammonia/water mixture, to drive the power cycle.
- Generation – a power train comprising a flash evaporator and a centrifugal energy recovery device such as a turbine, which drives a generator to produce electricity. The power train includes instrumentation to regulate the unit's overall performance and to synchronize the unit with a power distribution system.
- Waste heat rejection – a heat transfer section discarding low-temperature "waste" heat from the binary drive fluid. This section rejects the waste heat to the surroundings, either to ambient air or to a water source.

The geothermal fluid gives up a portion of its heat energy to the binary system drive fluid in the heat capture section, and then is pumped to injection wells to return to the source reservoir. For the temperature conditions cited here – 190 °F to 250 °F – the model used power cycle efficiencies of about 6.5 to 9.2 percent.

Results and Conclusions

The NREL coproduction model used in this analysis calculates performance and power costs for production and generator units in a wellfield array. This is a step in the direction of addressing an economic potential for generating electric power from a United States coproduction geothermal resource with a very large capacity. In 2006 the Massachusetts Institute of Technology (MIT) reported on an assessment of enhanced geothermal systems (1). That work estimates a potential competitive capacity for generating geothermal power from coproducing resources at over 10 gigawatts (GW) for temperatures up to 280°F. Over half of that estimated capacity occurs in five states, in order of capacity: Oklahoma, Texas, Kansas, California, and Wyoming.

Another recent analysis by Petty and Porro sponsored by NREL (2), estimated a competitive coproduction resource for the United States at about 40 GW of power generation potential. That resource update shares common values of estimated generation costs with the present analysis. They estimated that a large fraction of the coproduction resource could be developed with LCOE values below 10 ¢/kWh, consistent with ranges of costs estimated in this analysis.

As summarized above relative to Figures 3 and 4, a significant domain does exist across which coproduced geothermal water may be cost competitive for onsite power development projects. Now, adding Figures 6 through 9 for consideration, additional details can be observed:

1. Figure 3 contrasts the trends of energy cost as a function of produced-fluid flow rate at three temperature levels. The family of curves shows that as fluid temperatures rise, the LCOE sensitivity to well spacing and flowrates decreases. This reflects three factors.

    a. First, the rate of energy recovery per pound increases with temperature, reducing the relative cost of gathering-system piping components compared to the costs of energy conversion equipment.
    b. Second, efficiency of energy conversion also rises with temperature, adding to the net value of increased energy content per pound of fluid.
    c. Third, as power available increases with temperature, the generation system capital costs grow by an incremental addition of packaged generation units. The units are added at constant unit capacities and unit costs.

2. Figure 3 shows that the levelized energy costs become decreasingly variable as production flowrates reach about 50 to 60 gpm per well (1,700 to 2,100 bbld per well) using fixed generator unit costs. So if a market for coproduction systems were to develop and encourage vendors to broaden their range of packaged power units at various generation capacities, then economies of scale should be expected to appear, allowing the LCOE values estimated here to be improved.

3. Figure 3 also demonstrates that levelized energy costs are relatively insensitive to production well spacing. At low flows the cost differences due to changing well acreages are greatest, showing a change of roughly 0.5 to 1 ¢/kWh at a 10 gpm flowrate per production well, over a range of 10 to 60 acres per production well. However, at this low flowrate, the economics of the cases are all inherently less favorable than at higher flows because of low energy yield at low flow. Smaller generator package capacities should help to offset this cost impact, depending on how the unit capital cost of small generators trends with size.

4. As shown in Figures 4, 6, and 7, LCOE varies with the ratio of production to injection wells. The model starts each case by assigning a generator unit per production unit. For a given total well count and flowrate per production well, the production unit thermal output changes with configuration and flowrate. And as the configuration adds production wells, the generator capacity becomes more fully utilized, so that additional generators may be assigned per production unit.

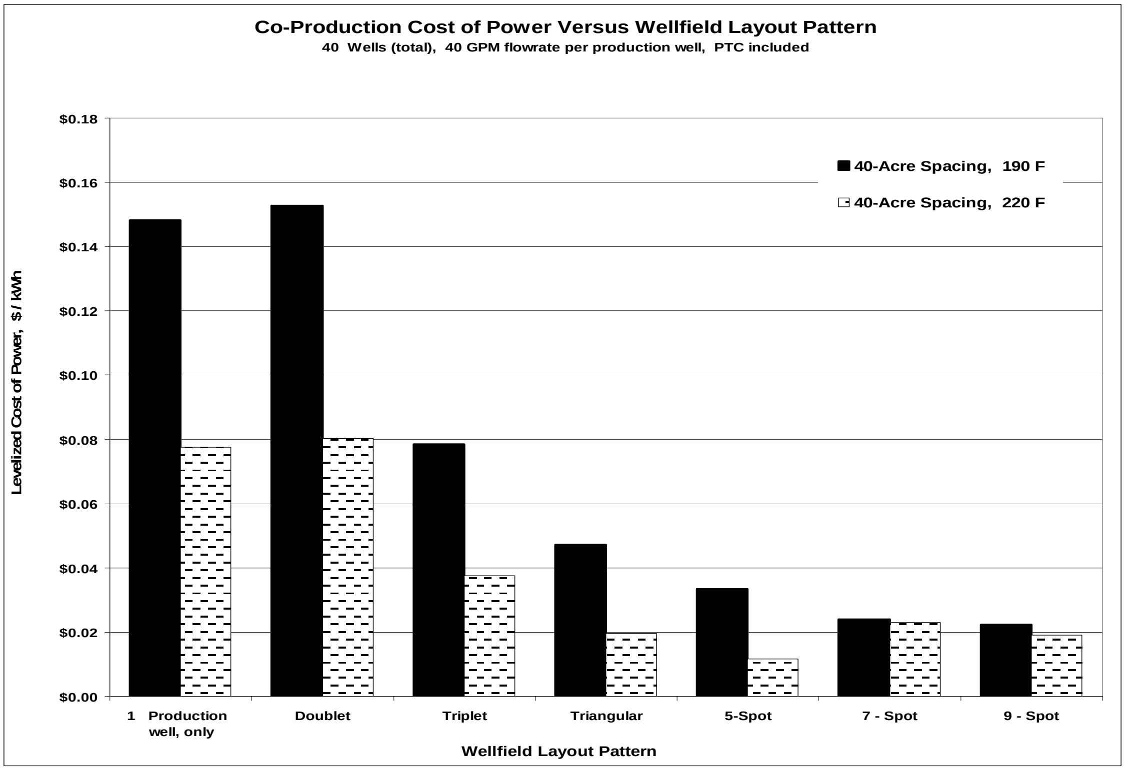
   This is not simply a basis for selecting production unit geometries to minimize cost of electricity. The trend of cost versus flowrates from each production unit reflects the consideration that wellfield configurations depend on the resource conditions. This will be a design domain where reservoir engineering and power development intersect. Independent of generation system design and costs, reservoir engineering can determine that, while Figures 6 and 7 may indicate particular configurations to be more costly for power generation, the increased well productivity might also offset increased surface piping costs. Alternatively, if fewer total wells are needed per unit of energy recovered, that source of savings may justify increased surface piping costs, as well. Either of these outcomes would tend to drive down the levelized cost of energy, despite choosing a generation configuration that is not optimized on a standalone basis.

   These considerations also will lead to evaluating arrays of power generation units by ganging multiple production units to feed common generation facilities.

5. Figure 8 presents data similar to Figure 1, with the roles of temperature and flow reversed in the plot. This emphasizes the breakpoints in cost trends as functions of temperatures. It also shows how LCOE begins to rise markedly as temperature falls below a threshold at which a production unit delivers energy to satisfy a substantial fraction of a generator unit's nameplate capacity. Again, tailoring the generator unit capacity to the production unit's energy delivery would limit the generator turndown ratio and help keep the LCOE from escalating at the capacity steps that call for adding generator modules.

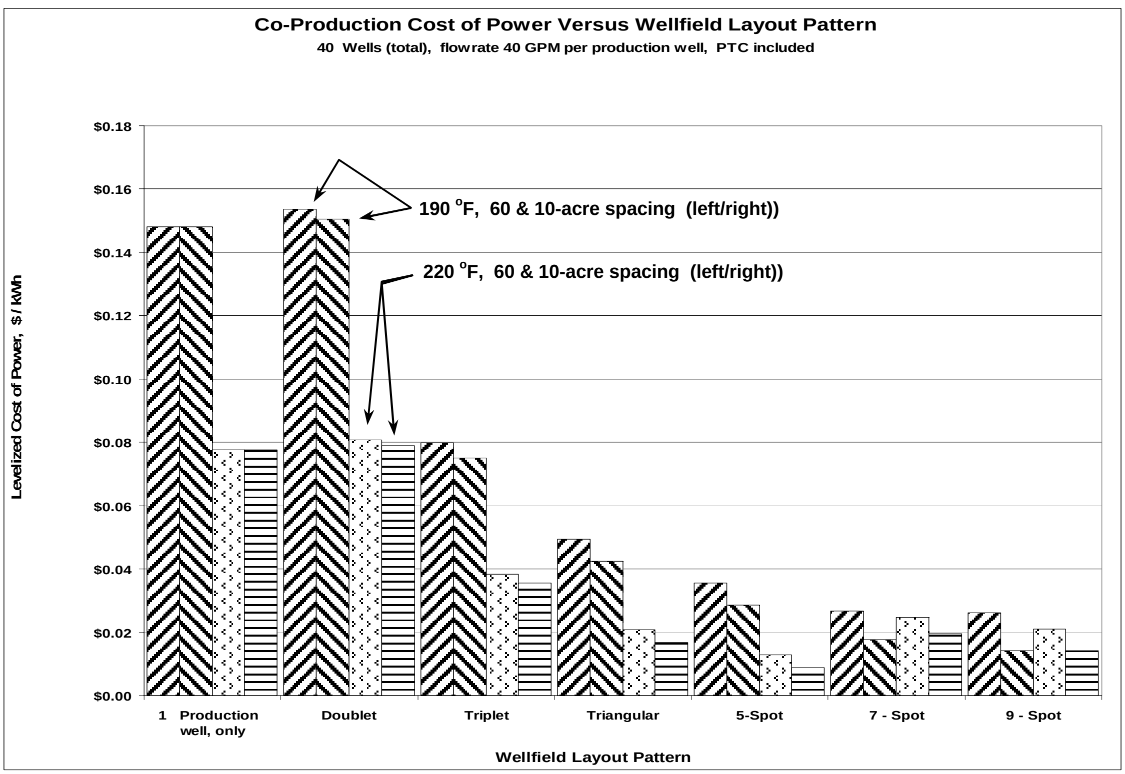
6. Figure 9 illustrates the last observation in point 4, preceding. This shows the impacts: geometry and generator capacity effects on LCOE. The LCOE curve for a 50-kW and 100-kW generator capacities are lower than the LCOE curve for a 200-kW unit because at all conditions, the chosen unit capacity is more effectively used. For both the 100- and 200-kW capacities, the trend of LCOE favors a mid-range configuration of wells per production unit. It gives a better match between resource energy delivery and generator energy demand.

7. This early set of test runs used a base-case generation unit capacity of 200 kW, because that is at the low end of one vendor's system capacities in an equipment line they are developing. However, for small wellfield configurations and low temperatures, the 200-kW capacity leads to high cost estimates in this analysis. For example, for a field of production wells flowing at 40 gpm each, at a temperature of 190°F, the seven configurations used in this analysis yielded LCOE values in a range of about 4 to 17 ¢/kWh (without applying a federal PTC). For a temperature of 220°F, the LCOE range became 3.6 to 10 ¢/kWh. Applying the PTC reduces the LCOE by a little over 2 ¢/kWh in these cases.



Figures 6 and 7 -- Effects of Wellfield Configuration on Cost of Electricity

(comparing conditions for 190°F and 220°F production temperatures)



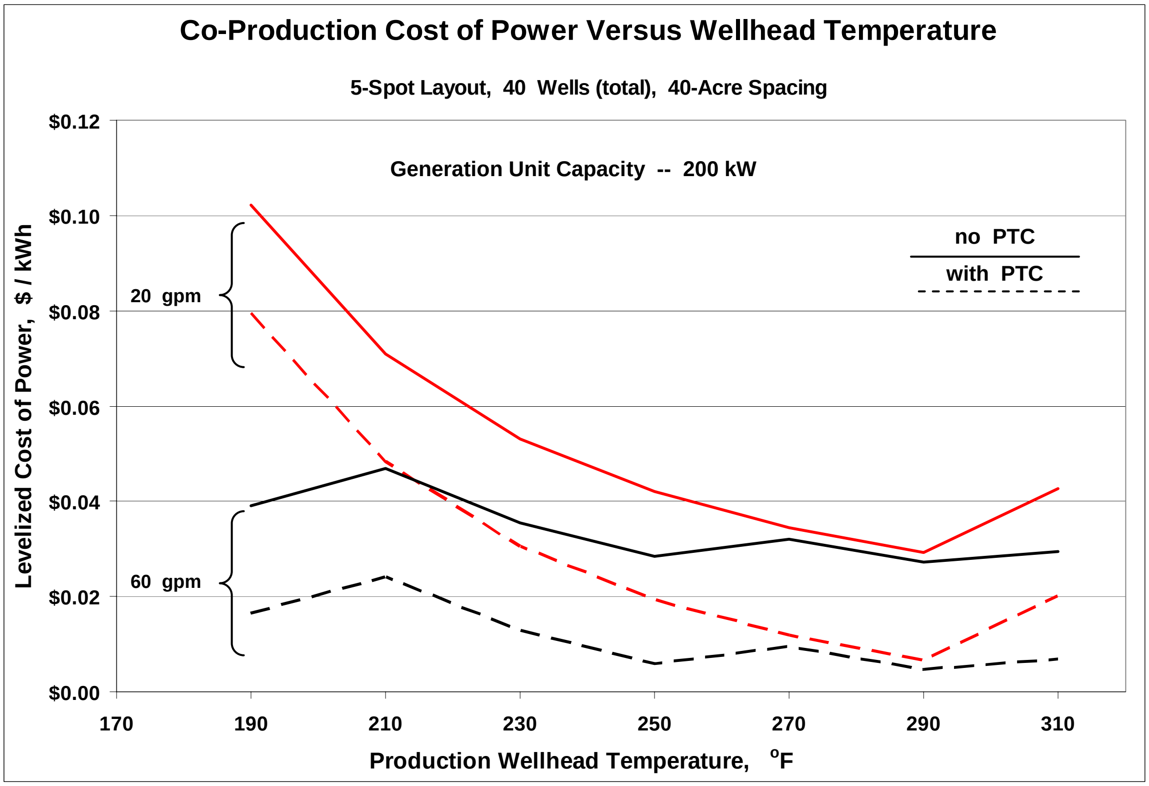
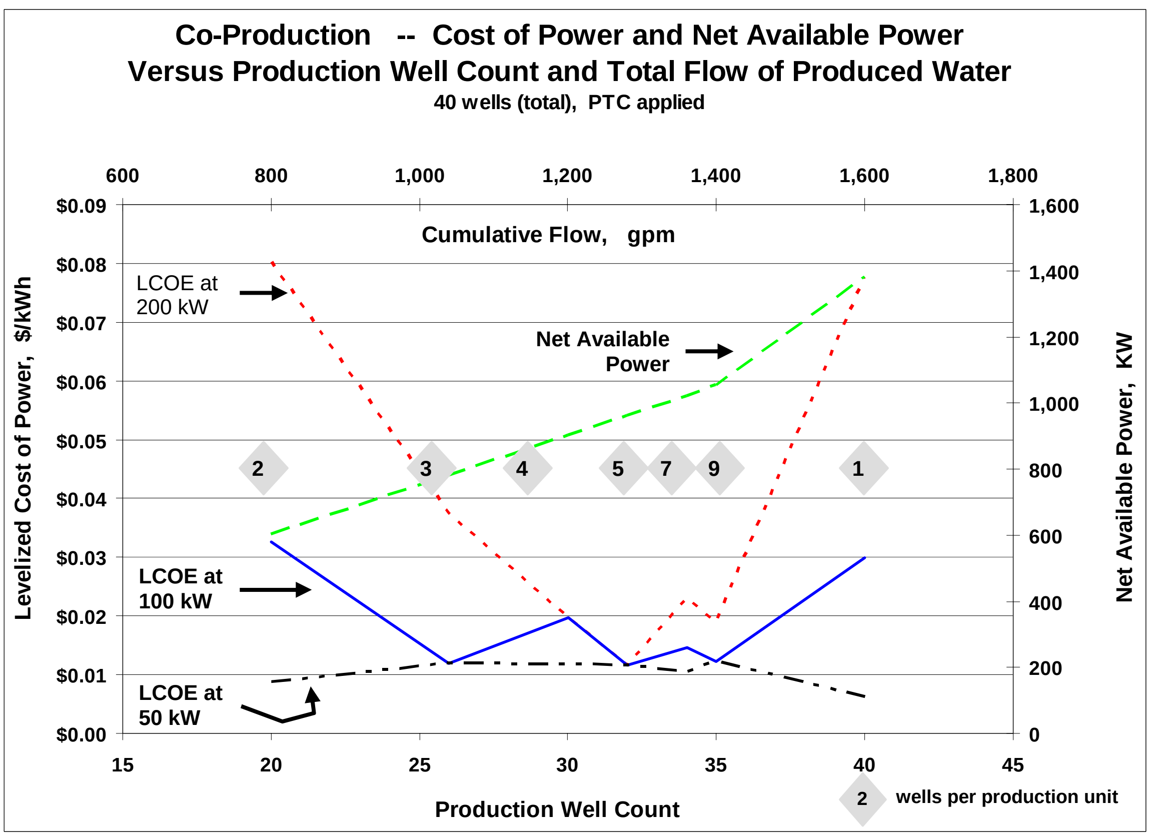


Figure 8 -- Variation in LCOE with Wellhead Temperature and Flowrates

Figure 9 -- Comparison of Configuration and Generation Capacity Effects



References

1. Tester, Jefferson, et al, "The Future of Geothermal Energy – Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century," Massachusetts Institute of Technology, Cambridge, MA, 2006.
2. Petty, Susan, Porro, Gian, "Updated U.S. Geothermal Supply Characterization," National Renewable Energy Laboratory ,NREL; March 2007)

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Appendix A -- Model Description and Data Parameters

Model Organization and Method

This analysis uses a spreadsheet model that computes performance and economic factors for geothermal coproduction power projects. The model is laid out to construct parametric case profiles, and to compute results for those profiles to illustrate trends of relationships among variables that define the performance and cost for such projects.

The model includes correlations for computations of mass, energy, and costs:

- Estimates of piping installation costs for this model were compiled in November 2006, using contacts in oil and gas processing industries, and construction cost data sources such as those published by Perry ("Chemical Engineers' Handbook") and Means ("Construction Cost Estimating").
- Physical properties of water, such as density and viscosity, have been correlated as functions of temperature, from references such as Smith and VanNess ("Introduction to Chemical Engineering Thermodynamics"), Himmelblau ("Basic Principles and Calculations in Chemical Engineering"), and McCabe and Smith ("Unit Operations of Chemical Engineering").
- Energy conversion efficiencies are based on binary systems performance data from a recently released analysis of enhanced geothermal systems potential in the United States. That analysis was produced for the U.S. Department of Energy's Geothermal Technologies Program (GTP), under the management of the Massachusetts Institute of Technology (1). For the range of 190°F to 250°F used in this analysis, the conversion efficiencies range from about 6.9 to 9.2 percent.
- Material and energy balances are incorporated for produced geothermal fluid, with recovered thermal energy going to power generation according to the correlated binary system performance.

Case Study Parameters

This analysis examined a series of parametric case studies to evaluate coproduction performance and economics.

- Resource condition: temperature and flowrate of produced water
- Site conditions
- Wellfield configuration – total number of wells and ratio of the numbers of production to injection wells, acreage per production well, resultant geometry of a production unit comprising the specified mix of well types. Appendix B gives sketches of the seven configurations used in the model.
- Conversion efficiency of power generation system, heat rejection temperature
- System costs: generation unit cost and capacity, piping system size and costs, operating costs, capacity factor
- Project financial parameters: fixed charge rate, discount terms, project book life, tax considerations.

Table A-1 lists key parameters, most of which are user-defined input variables.

TABLE A-1

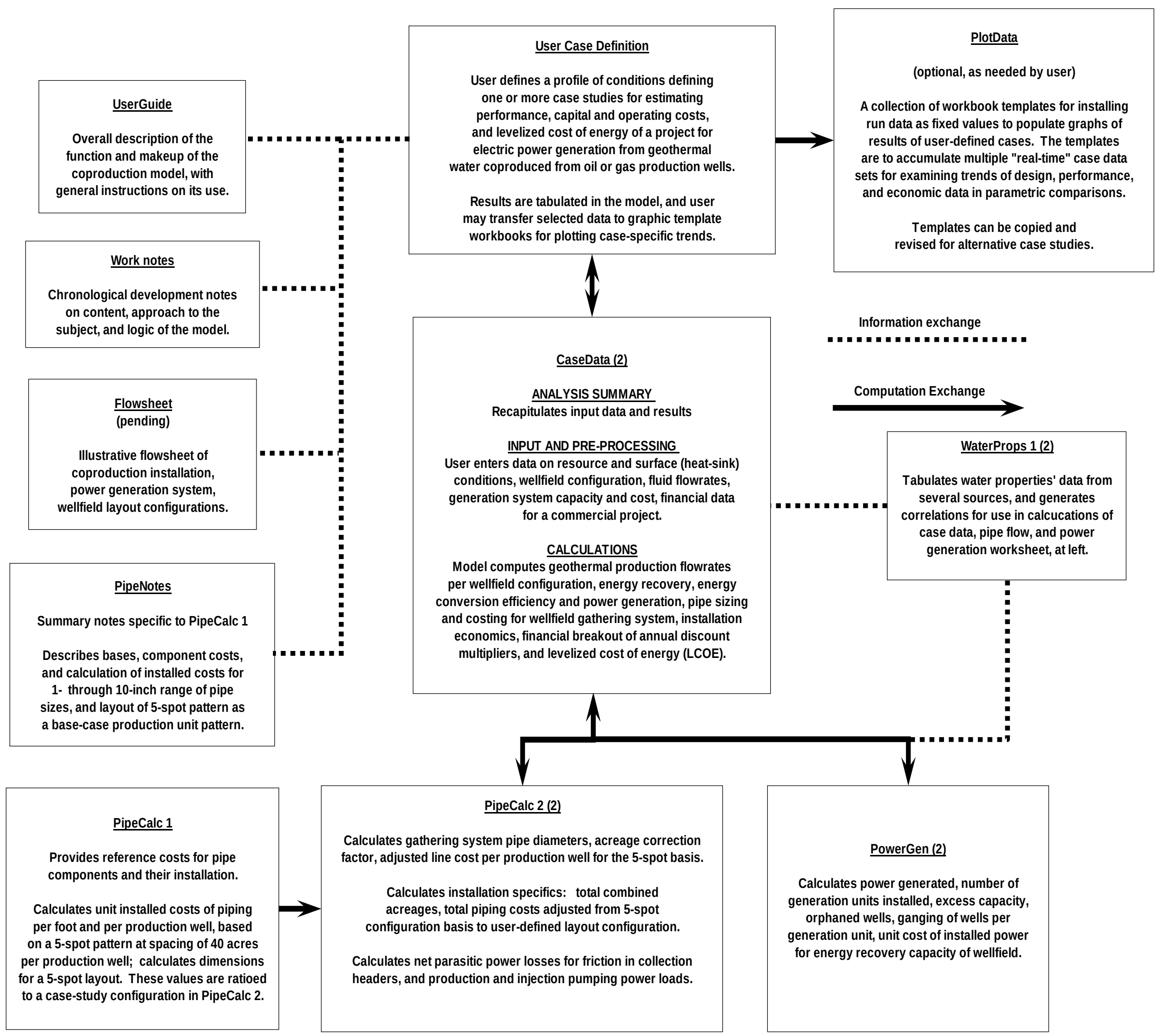
Terms Used in Estimating Coproduced Geothermal Power Economics

Attributes	Terms	Units	Values Used
Resource Conditions	Wellhead temperature	°F	190, 220, 250
	Flowrate per production well	gpm (also available as barrels per day)	10 to 70
	Injection back-pressure	psig*	100
Site conditions	Ambient temperature	°F	59
Wellfield Configuration		well patterns	7 combinations of production and injection well layouts
		production well spacing	10, 40, 60
		Production well pump horsepower	10
		Wellfield production unit layouts	Variable, row-and-column matrix according to well count and layout pattern
		Total well count, production & injection	Variable
Financial Terms	fixed charge rate		0.128
	weighted average cost of capital		0.112
	project term (book life)	years	25
	production tax credit	¢ per kWh, term	$0.02 for 10 years
	Bare equipment installation cost multiplier		1.3
	Fixed O&M	$ / kW-year	
	Fixed distribution cost	$ / kW-year	
	Variable O&M	$ / kW-hour	$0.005
	Variable transmission cost	$ / kW-hour	
	Grid connection cost	$ / MW-mile	$1,000
	Distance to nearest grid connection	miles	1
System Components	power generation unit	Unit costs $/kW	$1,000
		Capacity per generator unit kW	50, 100, and 200
		Brine/ambient temperature approach , °F	66
		Capacity Factor	95 %
		conversion efficiency	computed from reference data
	gathering system piping	unit costs	computed from flow data
		lengths, line size	computed from wellfield geometry and production flows

*psig -- pounds per square inch gauge pressure

Figure A-1 depicts the organization of the coproduction model flowsheet in terms of functional blocks of data and computation flow.

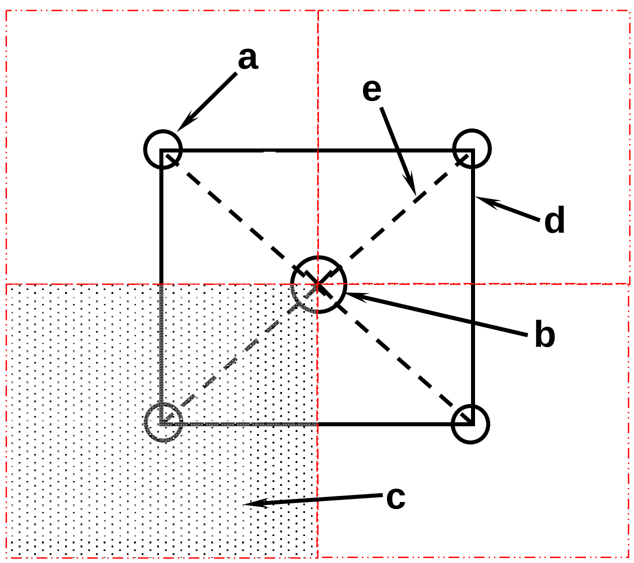
Figure A-1
Coproduction Model Layout



5-Spot Wellfield Production Unit Configuration

The configuration of the coproduction cost model relies on locating power generation units at centrally cited injection wells. This serves to define the wellfield geometry with which piping costs are estimated in the model.

For example, for sizing the piping systems for the seven wellfield configurations, the coproduction model uses definitions that all production and injection wells have respectively identical flowrates, and that the configuration geometries are scaleable to the user-specified acreage per production well. Piping costs are calculated based on these assumptions, using the input data values for flowrates and acreages for each case profile. There is a data input variable that gives the model an option to include or omit the calculated cost of the production gathering system piping from the total capital cost used to compute the LCOE. Injection piping is assumed to exist, and is not estimated as a cost component.



Basic Layout of a 5-Spot Production Unit

A 5-spot pattern serves as the basis for calculating header lengths from production wells to a central injection well for each of the other six layout configurations. The image at left shows the relationships for a single production header length in terms of a production well acreage.

In this 5-spot pattern, four production wells (**a**) are arranged in a square layout around a central injection well (**b**), where each production well occupies a plot (**c**) of "**n**" acres. The production unit (**d**) has the same area as each production well, individually.

The length, $\mathbf{L_s}$, of each side of the production unit (**d**) is $\mathbf{L_s} = (43{,}560\ n)^{1/2}$ feet. The length ($\mathbf{L_h}$) of each production well collection header (**e**) is $\mathbf{L_h} = \mathbf{L_s}$ cosine (45°).

This basic unit measurement for a 5-spot pattern is ratioed up or down according to the well counts and resultant relative dimensions of the other six configurations, as illustrated in the sketches on the preceding page, using the same unit area per production well.