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A PRACTICAL APPROACH TO PRODUCING VAPOR-DOMINATED RESERVOIRS

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Abstract

This paper presents arguments for initially producing Geysers steam wells at wellhead pressures in excess of 200 psig instead of the normal practice of producing at minimum wellhead pressures. A conceptual model is presented which defines a flow equilibrium resulting from a "constant pressure source" whose location is a function of the withdrawal rate from the reservoir. Based on this model, it is argued that producing at elevated wellhead pressures is equal to producing at minimum wellhead pressures, assuming the mass withdrawal is the same. Additional benefits of producing at elevated wellhead pressures are discussed and include minimizing casing and reservoir rock thermal transients and scaling and bridging of the wellbore.

SFGI's experience has been favorable but due to a very high capacity factor and very few outages, a comparison of performance of other areas of The Geysers is inconclusive.

Introduction

Santa Fe Minerals, Inc. (SFMI, formerly Occidental Geothermal, Inc.) operates an 80 MW (net) power plant and attendant steam field at The Geysers in Northern California. The first well on the lease was spud on February 16, 1980 and the project began commercial operation on April 10, 1984. SFMI's experience in producing this lease has evolved an operational philosophy of maintaining wellhead pressures in excess of 200 psig. This philosophy appears to deviate from other operator's practices of producing at minimum flowing wellhead pressures typically in the range of 125 to 150 psig. SFMI was afforded the opportunity of producing at elevated wellhead pressures because of the development of an excess steam deliverability in anticipation of an early high decline rate typical of Geysers wells during the first few months of production.

SFMI also believed there were additional benefits of initially operating wells at higher wellhead pressures which included minimizing casing and reservoir rock thermal transients and scaling of the wellbore and nearby reservoir. This paper discusses the production of steam wells at elevated wellhead pressures by presenting a conceptual model of the reservoir, the production dynamics of the model, analysis of wellbore and inflow performance relationships, and qualitatively discussing mechanical and heat transfer aspects of the wellbore and reservoir during production.

Geysers Conceptual Reservoir Model

A conceptual model of The Geysers reservoir is shown in Figure 1. The major components of the model are a shallow steam zone at the top, a main steam zone in the middle, and a steam generation source at the bottom. The shallow steam zone is connected to the main steam zone by a flow path with length x, and the steam generation source is connected to the main steam zone by a flow path with variable length y, which is a function of Q_5. The system is initially at equilibrium, but this does not necessarily mean the shallow steam zone is in equilibrium with the main steam zone. The two zones may be so poorly connected that the shallow steam zone could have an equilibrium pressure and temperature substantially lower than the main steam zone due to heat loss to the surface and buildup of non-condensible gases. The shallow steam zone could also initially have been perched water or a non-condensible gas zone with the wellbore acting as a flow path between the two zones. An example of a shallow steam zone is the Thermal Shallow Reservoir presented by Mogen and Maney (1985).

The steam generation source in this conceptual model is depicted as being below the main steam zone because we have defined a flow path from the steam generation source to the main steam zone that is a function of the withdrawal rate. In actuality, the steam generation source is integral to the main steam zone and

The inflow performance curves were based on the deliverability equation presented by Rawlins and Schellhardt (1936):

$$Q_1 = C(P^2_{static} - P^2_{flow})^{0.75}$$

This equation is used assuming surface conditions and maximum steam flowrates (at 110 psig) of 100,000 lbs./hr.(curve A), 150,000 lbs./hr. (curve B), and 200,000 lbs./hr. (curve C).

The results are shown in Figure 3 and are what would be expected. At high flowrates the wellbore is the limiting factor and there is very little change in flowing bottomhole pressure. At low flows, the reservoir is the limiting factor. This would indicate that maintaining elevated producing wellhead pressures on high productivity wells does not measurably change the bottomhole flowing pressure and the only reason to produce these wells at elevated wellhead pressures would be to minimize thermal effects. In the case of a well whose inflow performance matches curve A (100,000 lbs./hr.), there is a substantial change in the bottomhole flowing pressure. However, this theoretical curve was determined assuming constant enthalpy without considering the superheating of the steam as it travels in the reservoir to the wellbore. In the reservoir, this lower pressure and therefore temperature would cause higher heat transfer rates between the reservoir rock and the steam. This could possibly increase the specific volume of steam to such an extent that the mass flow is decreased resulting in a flattening of curve A at lower wellhead pressures. This phenomena has actually occurred in a few wells during short term flow tests but only when flowing wellhead pressures have been below 100 psig. Producing these lower productivity wells at elevated wellhead pressures minimizes the possibility of the specific volume change becoming the limiting factor for flow from the reservoir.

The analysis of the wellbore and inflow performance relationship should be performed on individual wells to determine actual bottomhole flowing conditions. The wellbore profile presented is restrictive due to the depth of the production and not typical of the majority of the wells in the Geysers.

Additional Benefits of Operational Philosophy

Prior to start up a production review was performed on The Geysers open file wells to analyze their initial production performance. The wellbore mechanical aspects of production with respect to temperature changes and casing problems was also analyzed to determine if we could improve steam well performance.

A problem in The Geysers that could be minimized by producing wells at higher wellhead pressures is casing failures resulting from thermal contraction and expansion of the casing occuring every time a well was flowed and then shut-in. For example, by keeping a minimum wellhead pressure at 200 psig instead of 150 psig the decrease in temperature difference between producing and shut-in is 22.4% (assuming a maximum wellhead pressure of 470 psig). This is a significant improvement and should substantially decrease the risk of casing problems.

In the review of The Geysers wells, there appeared to be a significant amount of scaling in the bottom portion of the casing and bridging of the open hole which required cleaning out in the first year of production. To reduce these problems it was reasoned that the departure from initial reservoir equilibrium conditions needs to be minimized and that producing superheated steam near the wellbore may not be advantageous because of the chemical changes occuring in the steam during production and shut-in conditions. This is very important with regard to our model because the shallow steam zone increases the possibility of such problems. As an example, if the initial pressure and temperature of the shallow steam zone is substantially lower than the shut-in pressure and temperature of the main steam zone, the shallow steam zone acts as a heat sink condensing steam flowing from the main steam zone. The steam that has entered the shallow steam zone may be subjected to a drastically different geochemical environment because of the conditions that initially existed in the shallow steam zone. When the well is returned to production the condensed steam in the shallow zone is flashed or is produced as a liquid if there is not enough heat or time available. Although the actual causes of scaling in the wellbore are not well understood, by maintaining higher wellhead pressures these affects should be minimized.

The two remaining reasons for operating at higher flowing wellhead pressures are to create a more uniform pressure drawdown of the reservoir and to eliminate transmission of pipeline pressure and temperature spikes from being transmitted down the wellbore during a power plant outage.

most probably exists as a complex combination of insitu liquid water in the main steam zone fracture or matrix volume, a deeper liquid layer, meteoric recharge, injected steam condensate, or possibly even a deeper steam zone.

Production Dynamics

The production dynamics of this model are consistent with the dynamics of vapor-dominated systems presented by Truesdell and White (1973), with the added constraint that the steam generation source rate (Q_5) seeks to maintain an equilibrium flow equal to production from the main steam zone ($Q_3 + Q_4$). This constraint requires the reservoir to have a constant pressure boundary. A constant pressure boundary, in the petroleum engineering sense, is probably an incorrect term for a vapor-dominated geothermal reservoir. Instead, we should consider a "constant pressure source" that is moving in the reservoir. This "constant pressure source" appears more reasonable because the steam and liquid water in the reservoir will always seek a thermodynamic equilibrium which is very close to initial condition equilibrium. This is because the reservoir rock temperature is always at or near initial condition temperature (ignoring cooling of the rock due to cold water injection). At the "constant pressure source," the generation of steam is the mechanism available to the system for attaining an equilibrium. Also, if we assume instantaneous equilibrium, the constant pressure source is stationary as long as there is any liquid water available which can be converted to steam.

This model of a moving "constant pressure source" could be another possible explanation for the pressure history of Cobb Mountain No. 1 presented by Lipman, et. al. (1978). A "constant pressure source" which has moved further away from a well due to increased production would cause the experienced initial static pressure decline and stabilization of pressure of Cobb Mountain No. 1, if Q_5 reached a flow equilibrium with $Q_3 + Q_4$. This was hinted at by Grant et. al. (1982) but was not discussed in any detail.

The above discussion assumes $Q_3 + Q_4$ does not exceed the maximum steam generation rate (Q_5) which would be reasonable in a reservoir initially at or near thermodynamic equilibrium due to high initial liquid saturation. In a reservoir or portion of a reservoir that has experienced pressure depletion, the steam generation source has already migrated some distance away and $Q_3 + Q_4$ might exceed the maximum Q_5 rate forcing the flow equilibrium to equal the maximum Q_5 rate.

This is likely to happen with increasing production from the shallow zone because of the fixed distance x and decreasing pressure in the main steam zone. An example of this occurring in The Geysers is the Thermal Shallow Reservoir (Mogen and Maney 1985).

This tendency towards a flow equilibrium and a "constant pressure source" are the basic arguments that lead us to the conclusion that producing wells at elevated wellhead pressures is equal to producing wells at minimum wellhead pressures. A power plant requires a certain mass flowrate and producing wells at minimum wellhead pressures will increase the volumetric flowrate but will not change the mass withdrawal from the reservoir. As long as the mass flowrates out of the reservoir are equal, there should be no difference in the location of the "constant pressure source".

However, the possibility exists that by producing at elevated wellhead pressures we can improve steam recovery. In the case of producing at minimum wellhead pressure, it would appear that a higher proportion of steam would be produced from the matrix near the wellbore because of the higher differential temperature available to vaporize liquid water in the near wellbore matrix. If this is the case, producing at elevated wellhead pressures may actually increase drainage radius because of the decreased production from the near wellbore and there would be a change in the location of the constant pressure source. This effect is not obvious and needs to be studied further.

Also, in an area that is in equilibrium at initial conditions, producing at elevated wellhead pressures minimizes the pressure and temperature changes in the reservoir near the wellbore, which should allow the reservoir to reach a flow equilibrium more rapidly.

Wellbore Versus Inflow Performance Considerations

From the perspective of individual wellbores, it appears that some wells may benefit from the philosophy of producing at elevated wellhead pressures more than others. Wellbore and inflow performance curves were developed to determine if this is the case. The wellbore performance, assuming the idealized wellbore shown in Figure 2, was determined using the following equation of vertical flow of gas derived by R. V. Smith (1950):

$$Q_1 = 393.7 \left[\frac{d^5}{G T_a z_a f X} (P_2^2 - e^s P_1^2) \frac{S}{e^s - 1} \right]^{0.5}$$

Operational Experience

SFGI's experience of operating wells at greater than 200 psig flowing wellhead pressures has been favorable. To date, wells have experienced no noticeable bridging or scaling problems, and the stabilized lease decline is consistent with other operators. One of the results of this operational philosophy was our wells did not experience the high decline typical of a Geysers well in the first few months of production. Instead, a moderate decline rate was spread out over a longer period of time, with the decline rate slowly leveling out to a typical Geysers decline rate. This type of performance is typical of curtailed conditions. Also, our production forecast has been more predictable because of the minimal amount of downhole problems. This is a very important consideration when there is no capability of transferring steam from other power plant areas.

The design of the power plant has allowed us to run at very high capacity factors and outages that would thermally cycle the well's casing and wellbore have been minimal. Due to this sharp reduction in outages with respect to other steam field operators experience, it is difficult to determine whether maintaining higher wellhead pressures or our minimum outage record has been the reason for the favorable performance. A longer production history is required to provide a definitive comparison.

A possible drawback to this operational philosophy is that due to higher wellbore heat losses and less superheating of the steam in the reservoir, the water production to the surface is higher than would be expected from wells produced at minimum wellhead pressures. This higher water production may or may not be a negative aspect because of the trend of desuperheating steam prior to entering the steam turbines.

The philosophy of operating wells at a minimum 200 psig wellhead pressure is constantly being reviewed and will definitely be evolving in the near future. The next step will be to determine at what minimum wellhead pressure we should operate at with regard to the declining average reservoir pressure and the change in the well deliverability at these lower reservoir pressures.

Conclusions

An operational philosophy of maintaining flowing wellhead pressures in excess of 200 psig has been implemented on SFGI's lease. Based on the conceptual model presented, this philosophy should be equal to operating wells at minimum wellhead pressures because there is no difference in net mass withdrawal. Maintaining flowing wellhead pressures above 200 psig should minimize casing failures, and may minimize wellbore scaling and bridging problems. SFMI's operational experience is favorable but due to very high capacity factors and very few outages, a comparison of performance of other areas of The Geysers is inconclusive. We are continuing to expand on our operational philosophy to optimize our production with respect to the decreasing reservoir pressure to determine if and when we should begin producing at wellhead pressures below 200 psig.

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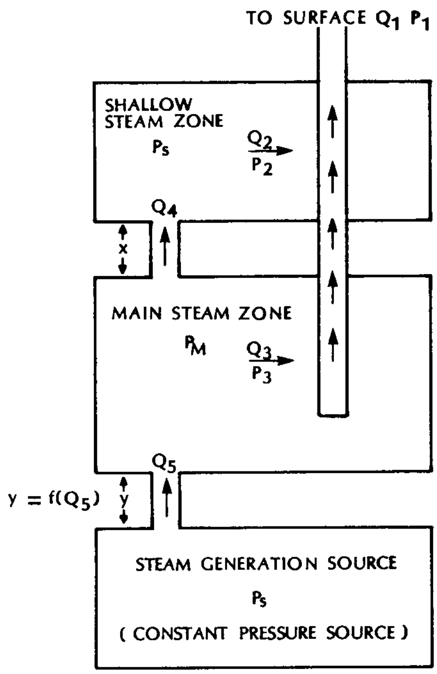

Figure 1.
Geysers Conceptual Reservoir Model

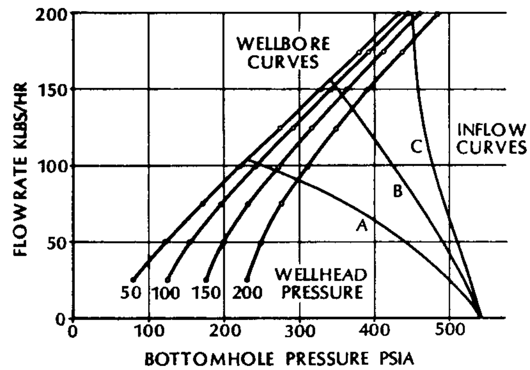

Figure 3.
Wellbore vs. Inflow Performance Relationship

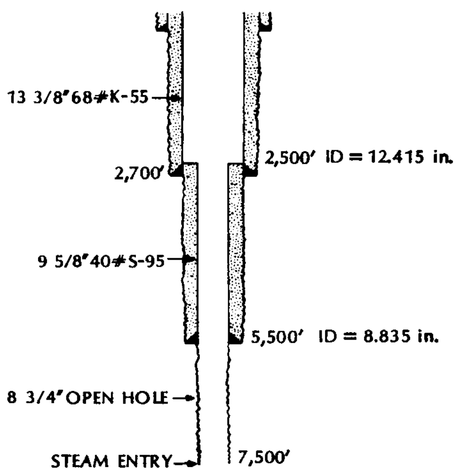

Figure 2.
Wellbore Profile