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A NEW DECLINE CURVE ANALYSIS METHOD APPLIED TO THE GEYSERS

Jericho L. P. Reyes, Kewen Li and Roland N. Horne

Stanford Geothermal Program
Stanford University
Stanford, CA, USA 94305
e-mail: jlpreyes@pangea.stanford.edu, kewenli@pangea.stanford.edu, horne@stanford.edu

ABSTRACT

A decline curve analysis model was developed based on the theory of fluid flow mechanisms with relative permeability and capillary pressure included. The model reveals a linear relationship between the production rate and the reciprocal of the cumulative production. The model was applied to the production data of 61 production wells in The Geysers geothermal field and a linear relationship was found between the production rate and the reciprocal of the accumulative production for the wells, especially at the late period of production. Comparison with common methods to estimate reservoir reserves indicates that the new method gives a more definite estimate of reservoir behavior. The method can also calculate two constants obtained from the linear relationship that have physical significance and can be used to characterize the regional geological properties of the reservoir.

INTRODUCTION

Estimating reserves and predicting production performance in geothermal and petroleum reservoirs is an important but difficult task for reservoir engineers. Many papers regarding decline curve analysis methods (Chen and Teufel, 2000; Faulder, 1997; Fetkovich, 1980; Fraim and Wattenbarger, 1987; Palacio and Blasingame, 1993 and Rodriguez and Cinco-Ley, 1993) have been published. However most of the existing decline curve analysis approaches are based on the empirical exponential, hyperbolic, and harmonic equations suggested by Arps (1945). Each approach has some disadvantages. For example, the exponential decline curve tends to underestimate reserves and production rates; the harmonic decline curve has a tendency to overpredict the reservoir performance. This is not surprising for empirical techniques.

One common method to evaluate well behavior is the flow rate decline curve analysis. Sanyal et al. (1991) describes a systematic approach to this analysis by developing a method to estimate the static pressures, as well as correct the fluctuations of the wellhead pressure to correctly reflect the true decline in productivity. The methods used in the approach still uses the empirical techniques, i.e. either the harmonic or exponential decline curves. The main problem with this is that we do not know exactly which method to adopt to describe the production trend correctly.

We previously developed a model to characterize the spontaneous water imbibition into gas-saturated rocks (see Li and Horne, 2001a). The model reveals a linear relationship between the imbibition (production) rate and the reciprocal of the gas recovery (cumulative production). Although this model was derived for spontaneous water imbibition, according to our derivation it is suitable for gravity drainage or other displacement process if a piston-like saturation change is assumed. In this study, we used this model to analyze the production performance of The Geysers geothermal field.

The objectives of this study include developing a decline curve analysis method based on analytical models, and applying this to the Geysers. The study also aims to compare the results to the existing decline curve methods. Since the model is based on fluid flow mechanisms, it also aims to interpret the physical significance of the parameters derived from the analysis. Finally, the study aims to compare the results to existing empirical techniques that forecast well behavior.

THEORY

Li and Horne (2001) developed an analytical method derived from the observed linear relationship between the production rate and the reciprocal of the recovery, especially in the late period of production. The mathematical model developed previously to characterize the spontaneous water imbibition into gas-saturated rocks was the basis of this method. The model is expressed as follows:

$$q_w = a\frac{1}{R} - b \qquad (1)$$

where q_w is the water imbibition rate; R is the recovery in terms of pore volume. a and b are two constants associated with capillary and gravity forces respectively. The details on deriving Eq. 1 and calculating a and b are described in Li and Horne (2001).

We can extend this model to geothermal reservoirs. Constant a is expressed as follows:

$$a = \frac{Ak_w(S_{wf} - S_{wi})}{\mu_w L} P_c \qquad (2)$$

where A and L are the cross-section area and the characteristic height of the matrix respectively, μ_w is the viscosity of water, S_{wi} is the initial water saturation and S_{wf} is the water saturation behind the interface of steam-water; k_w is the effective permeability of the water phase at S_{wf}. Similarly, P_c is the capillary pressure at S_{wf}. Constant b is expressed as follows:

$$b = \frac{Ak_w}{\mu_w}\Delta\rho g \qquad (3)$$

where $\Delta\rho$ is the density difference between water and steam and g is the gravity constant.

Eq. 1 could be expressed as follows in terms of cumulative steam production instead of recovery:

$$q_s = a_v\frac{1}{N_p} - b \qquad (4)$$

where q_s is the steam production rate and N_p is the accumulative steam production. a_v is defined as follows:

$$a_v = aV_p \qquad (5)$$

here V_p is the pore volume controlled by the production well or the reservoir.

The maximum cumulative steam production may be estimated by setting the steam production rate to zero or an economic limit once the linear relationship between the steam production rate and the reciprocal of the accumulative steam production is obtained. Then the reserve volume controlled by this well can be calculated, which is equal to a_v/b according to Eq. 4.

METHOD

We applied this method to data from The Geysers geothermal field. The Geysers production database was made available by the California Division of Oil, Gas and Geothermal Resources. The Geysers database contains production data for 502 wells around The Geysers field area. As an illustrative example, this report will describe two wells from The Geysers database, namely McKinley 1 and Thorne 1, located in the Lake and Sonoma Counties. McKinley 1, a redrilled active producer well owned by the Calpine Geysers Company, has a depth of 2219.18 feet. Thorne 1, also an active producer well, has a depth of 6842 feet. Figure 1 and 2 show the steam production flowrate history for McKinley 1 and Thorne 1 wells.

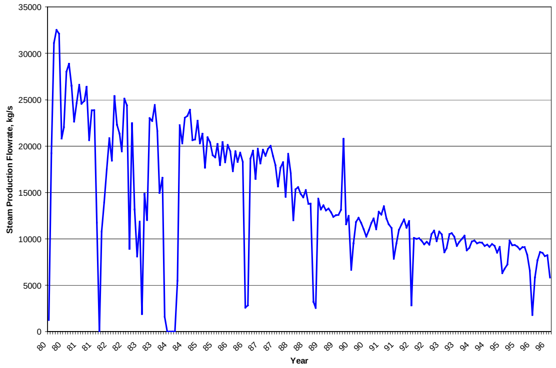

Figure 1: Steam production rate history of McKinley 1.

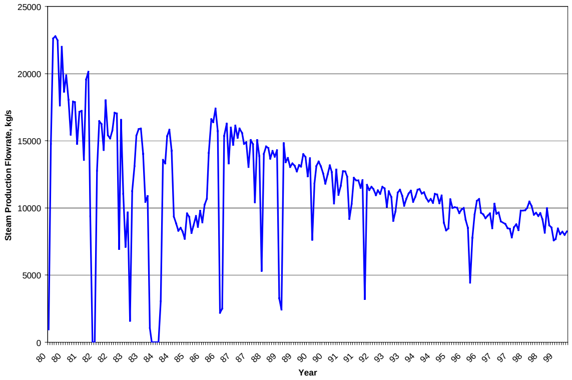

Figure 2: Steam production rate history of Thorne 1.

The production data for the wells correspond to various values of flowing wellhead pressure, it is therefore difficult to decipher the true decline trend without normalizing the flow rates with the standard flowing pressure, p_f. Sanyal et al. (1991) accomplished this normalization using:

$$W_n = \frac{\left(p^2 - p_{std}^{\ 2}\right)}{\left(p^2 - p_f^{\ 2}\right)} W \tag{6}$$

where W_n is the normalized production rate, p_{std} is the standard flowing wellhead pressure, W is the production rate, and p is the static pressure, which can be calculated as:

$$p^2 = \left(\frac{W}{C}\right)^{1/n} + p_f^{\ 2} \tag{7}$$

where C is an empirical parameter (Energy Resources Conservation Board, 1975), and n is the turbulence factor lying between 0.5 to 1.0. If C is assumed to be constant, its value can be approximated using:

$$C_i = \frac{W_i}{\left(p_i^{\ 2} - p_{fi}^{\ 2}\right)^n} \tag{8}$$

by taking a statistically representative value of C_i, based on the first few months of production of a well.

We plot the steam production rate with the reciprocal of the cumulative production in Figures 3 and 4 for McKinley 1 and Thorne 1. These plots show the original production rates with the normalized production rates, substituting n values for 1 and 0.5.

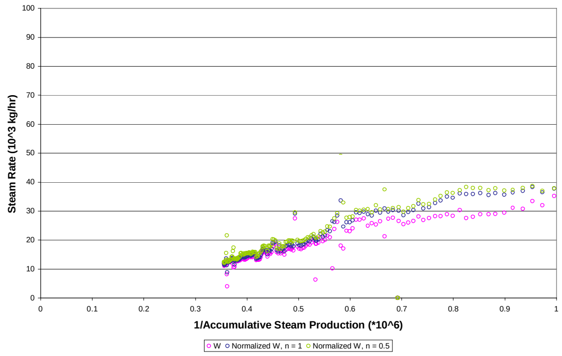

Figure 3: Relationship between the steam production rate and the reciprocal of the cumulative steam production for McKinley 1 using the original and normalized production rates with n = 0.5 and 1.

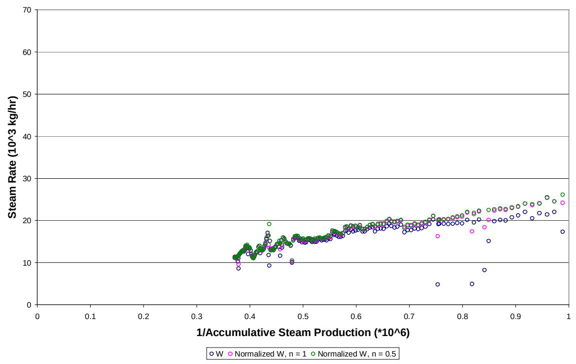

Figure 4: Relationship between the steam production rate and the reciprocal of the cumulative steam production for Thorne 1 using the original and normalized production rates with n = 0.5 and 1.

We see from these figures that normalization produces a significant reduction in the fluctuations of the rates, and the choice of n value has little affect on the W_n calculated. We chose $n = 1$ for further calculations.

At late time, the plots in Figure 3 and 4 show the relationship between the steam production rate and the reciprocal of the cumulative steam production. The relationship is closely linear, so the two constants a_v and b could be calculated using the linear model represented by Eq. 4.

Since the fluid flow mechanism Eq. 4 is based on two-phase fluid flow, we need to identify at which point the production history is based on two-phase flow. Reyes (2003) explored the historical production data of the Geysers in detail and one of the findings was that the majority of the wells at around 1991 – 1992. A method was developed to identify this point. We took the 177 wells that had this dry-out point and apply the decline curve method discussed in this study. Figures 5 and 6 show the linear trend suggested by Eq. 4 at a late time period for McKinley 1 and Thorne 1 well production histories. We also identify in these figures where the dry-out point is, which is essentially where the linear trend ends.

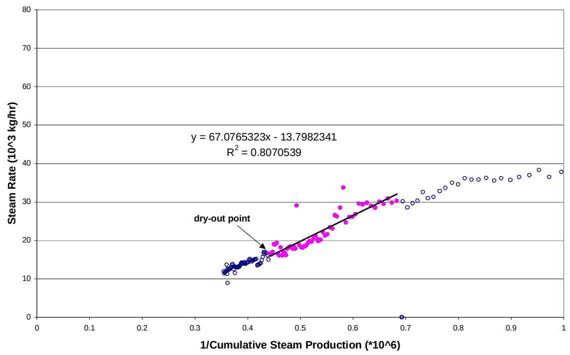

Figure 5: Relationship between the steam production rate and the reciprocal of the accumulative steam production for McKinley 1.

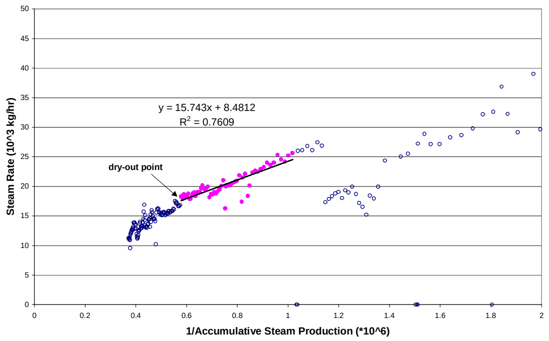

Figure 6: Relationship between the steam production rate and the reciprocal of the accumulative steam production for Thorne 1.

We compared the decline curve method developed so far to the existing empirical decline curve analysis methods. We discuss these methods here in brief.

Harmonic decline is defined by:

$$-\frac{1}{W}\frac{dW}{dt} = D(t) \qquad (9)$$

where t is the time in years and $D(t)$ is the decline rate in years. The harmonic trend rate at any instant is directly proportional to the productivity at that instant.

Exponential decline is defined by:

$$-\frac{1}{W}\frac{dW}{dt} = D \qquad (10)$$

where D is the constant decline rate.

If the decline trend is exponential, one should get a linear trend by plotting the logarithm of W versus time. If the decline trend is harmonic, we expect a linear trend by plotting W versus. We therefore make plots for both methods, with time plotted as cumulative production. Figures 7 and 8 are the harmonic plots for McKinley 1 and Thorne 1, respectively, and Figures 9 and 10 are exponential plots for McKinley 1 and Thorne 1. We also fit the linear decline trends that these methods predict.

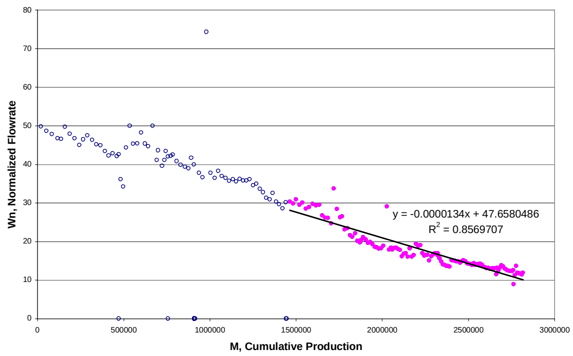

Figure 7: Harmonic decline curve analysis for McKinley 1.

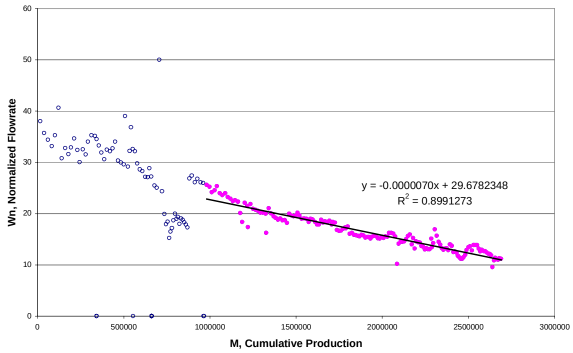

Figure 8: Harmonic decline curve analysis for Thorne 1.

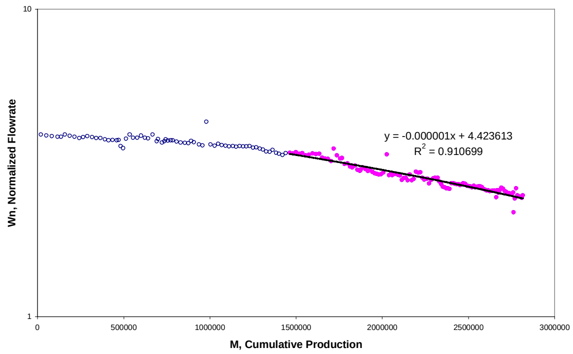

Figure 9: Exponential decline curve analysis for McKinley 1.

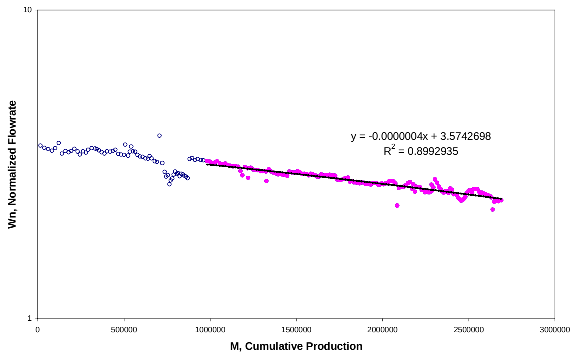

Figure 10: Exponential decline curve analysis for Thorne 1.

We can therefore compare these three methods by calculating cumulative production values from the fitted linear trends.

RESULTS

The product of the effective permeability of the water phase and the area controlled by the production well may be evaluated according to Eq. 3 using the value of constant b. The maximum cumulative steam production N_{pmax} can also be estimated once the values of the two constants a_v and b are available ($N_{pmax} = a_v/b$). Figures 5 and 6 fitted linear trends based on the relationship presented in Eq. 4. To facilitate the calculation of N_{pmax}, we need negative values for the constant b to have a positive value for N_{pmax}. We observe 61 wells out of 177 that show this trend, as the rest of the wells do not have the suitable linear decline trends to estimate the cumulative steam production. Table 1 shows the values a_v, b, and N_{pmax} for the 61 wells.

Table 1: Values of a_v, b, and N_{pmax} for 61 wells at the Geysers.

Well Name	a_v	b	N_{pmax}
Abel 1	124.89	1.3179	10552486
Beigel 2	114.98	24.679	2146373
Beigel 3	177	40.134	2267458
CA-5634 21-12	252.6	164.02	6493270
CA-5636 68B-21	231.42	39.865	17226255
CA-5636 87C-21	142.3	16.769	11784259
CA-5636 87D-21	118.96	17.037	14321621
CA-5637 68-21	162.87	24.097	14795235
CA-5639 15D-28	1.7388	22.614	13005521
CA-5639 44-28	1143.1	410.61	3592074
CA-5639 44B-28	505.95	153.13	3026584
CA-5639 53-33	96.492	87.801	9099304
CA-5639 63-29	27.006	4.131	1529660
CA-5639 63A-29	150.8	47.554	3153448
CA-5639 85-28	45.048	110.34	2449387
CA-958 37-34	217.13	47.15	2171510
CA-958 37A-34	1034.4	139.7	13505414
CA-958 37C-34	11.869	103.92	8755582
CA-958 56B-34	53.173	2.1445	4033062
D & V 1	106.31	8.3701	7873295
D & V 12	362.71	23.806	6563370
D & V 2	62.403	4.3597	6986363
D & V 6	106.98	185.41	1733128
D & V A-2	180.61	3.4866	19304579
D & V A-4	5.511	44.813	8131555
DX State 4596 25	4.3668	24.272	5558304
DX State 4596 50	96.168	7.7706	8080235
DX State 4596 60	174.05	2.2221	12767021
DX State 4596 74	249.86	116.02	4643400
DX State 4596 82	34.36	74.882	2179336
GDC 1	31.628	17.082	5400911
GDC 10	865.4	107.73	12448579
GDC 11	385.37	58.459	15169577
GDC 19	571.32	432.29	7566513
GDC 2	116.44	36.352	3121951
GDC 20-29	23.563	31.075	13188049
GDC 23	1103.6	488.12	4422979
GDC 24	130.73	506.11	3871414
GDC 7	252.54	34.341	13598242
LF State 4597 1	78.321	16.879	2155105
LF State 4597 13	73.992	5.3874	7281057
LF State 4597 29	148.48	21.703	14616783
LF State 4597 31	108.97	14.698	13488116
LF State 4597 36	89.406	14.875	1663759
LF State 4597 42	38.882	64.02	1646520
LF State 4597 5	163.22	10.347	6339297
McKinley 1	45.363	2.9425	6486564
McKinley 10	335.6	47.759	14230930
McKinley 3	96.735	0.4107	4245619
McKinley 9	112.83	8.645	7661969
MLM 2	83.772	5.7483	6861839
Modini 1	102.79	4.7799	4650161
Modini 3	164.37	15.889	9666606
Modini 4	362.06	23.432	6471855
Ot St 4596 16	53.325	0.2358	4421941
Ot St 4596 29	5.7716	39.769	6890464
Sulphr Bank 10	6.2969	24.7	3922565
Sulphr Bank 20	115.46	6.2601	54218777
Sulphr Bank 21	68.766	0.2717	3951080
Sulphr Bank 26	74.59	3.9897	5348840
Tocher 3	64.679	22.422	3466658

We performed a similar calculation for N_{pmax} using harmonic and exponential decline analysis and made a comparison with the developed method. We summarize this comparison in Figure 11. In this figure, we also plot the corresponding in-situ water saturation, which was inferred in Reyes (2003).

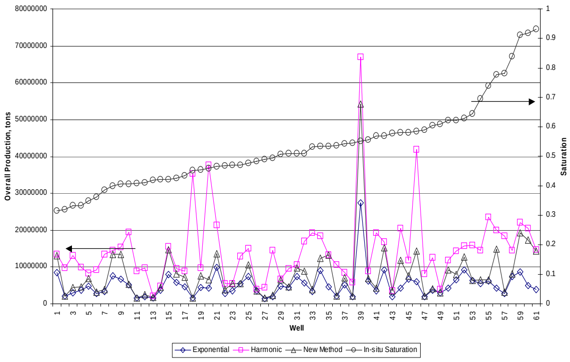

Figure 11: Comparison of the calculated N_{pmax} *values between the decline curve methods with the in-situ water saturation (Reyes, 2003).*

Figure 11 shows us that almost all of the N_{pmax} values calculated from the new decline curve method lie between the exponential and harmonic N_{pmax} values. Since exponential analysis often underestimate the reserves, and harmonic analysis often overestimates the reserves, we can say that the method gives a more suitable estimation. A more accurate snapshot of the reserves in geothermal wells is crucial in the development strategies often undertaken in geothermal power plants. It is also observed that the trend of increasing value of the inferred in-situ water saturation plotted is not reflected in the cumulative production values for any of the three methods.

Another facet of the new decline curve method is the calculation of a_v and b, which implies that these wells may have similar recoverable reserves and reservoir properties. This phenomenon may be related to the region and the geology. We map these two constants with respect to their location in the Geysers map, and Figure 12 and 13 shows the spatial relationships of these two constants.

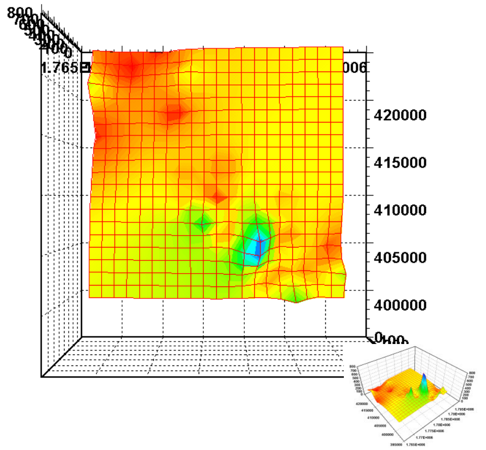

Figure 11: Aerial view contour plot of the imbibition index (a_v) values on the Cartesian plane of 61 Geyser wells (inset: 3D view).

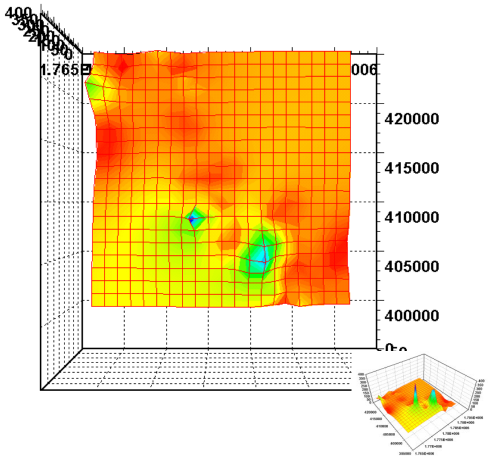

Figure 12: Aerial view contour plot of the gravity force constant (b) on the Cartesian plane of 61 Geyser wells (inset: 3D view).

We see from the figures that generally we see similar values a_v and b, which implies that these wells may have similar recoverable reserves and reservoir properties, except for two spots in particular with larger values. Li and Horne (2003) refers to a_v as the imbibition index because it representative of the recovery rate by spontaneous imbibition. Greater values of a_v suggest faster imbibition. The constant b corresponds to the gravity forces. Larger values suggest differing geological properties in these two spots, compared to the rest of the field.

It is interesting to note that near these two spots, there are two significant injection wells present, McKinley 5 and MLM 1. These two wells contribute more injection water than the other 23 wells identified with injection records in the 503 wells surveyed. Also present in these spots are other injection wells such as CA-1862 21-28 and Davies Estate 1.

DISCUSSION

From Figure 11, there is no apparent relationship between the in-situ water saturation that were inferred in the Reyes (2003) study and the decline curve indices. A possible explanation for this is that the pore volumes that the individual wells drain for their production differ in each well. Other factors that may explain the discrepancy could be the varying field properties like permeability or porosity that may differ from well to well.

The development of a decline curve analysis method that is based on fluid flow mechanisms is very useful, especially if the uncertainty of choosing between the present methods is crucial to the economic viability of the project. Also, the knowledge of other factors that might affect the decline curve properties of the data, i.e. transition from multiphase to single-phase production, can be taken into account in this model. It is especially useful for geothermal reservoirs, where phase transitions is more apparent than that in oil-gas systems.

The presence of significant injection wells near the zones of large values of a_v and b indicate that this is an alternative way to determine where to inject in a geothermal reservoir. Since reinjection schemes are often subject to comprehensive studies that include observing significant decreases in reservoir pressure, among others, knowing values of a_v and b can be another way to determine if a certain region in a geothermal reservoir is a prime spot for reinjection. Since a_v and b pertain to the imbibition index and gravity forces, respectively, these two parameters are critical to the effectiveness of any reinjection strategy. Higher imbibition indices that correspond to higher imbibition rates, and higher gravity force numbers mean that reinjection will be undertaken in a more efficient way.

Also, to aid with present reinjection strategies in geothermal reservoirs, with the knowledge of both properties, we can make decisions on whether changing both properties will enhance our reinjection scheme, especially if the values are equal to or lower than the average found in the field.

Eq. 4 was derived for a simple linear fluid flow. Due to the complexity of reservoir conditions, it may be necessary to modify Eq. 4 by considering heterogeneity, fracture density, compressibility, boundary conditions, radial flow, and other factors.

CONCLUSIONS

Based on the present study, the following conclusions may be drawn:

1. An analytical decline curve analysis model was developed based on the theory of fluid flow in porous media and was verified using the production data from the geothermal reservoirs at The Geysers.
2. The relationship between the production rate and the reciprocal of the cumulative production is linear and may be used to estimate reservoir properties and recoverable reserves.
3. There is no apparent relationship between the inferred in-situ water saturation (Reyes, 2003), and the cumulative production values found in the decline curve methods.
4. The decline curve analysis method based on fluid flow mechanisms gives us a definite estimate of reservoir behavior, compared to the choice faced in using empirical methods.
5. Physical parameters derived from the decline curve analysis discussed can be used to describe regional and reservoir properties and can be used in practical ways such as to design reinjection strategies.

ACKNOWLEDGEMENT

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