Discussion of Thermal Well Test Analysis

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Abstract *Thermal recovery by steam injection is considered to be a promising method for achieving a high ultimate recovery. A composite reservoir may occur during any enhanced oil recovery (EOR) project like steam injection into an oil reservoir. Thermal falloff test analysis offers a quick way to obtain an estimate of the swept volume and steam zone properties. Most of the models used for the analysis assume two-region composite reservoirs with different but uniform properties separated by a sharp vertical interface as an impermeable boundary. The swept zone therefore acts as a closed reservoir and pressure response is characterized by pseudo steady state (PSS) behavior. Most of the studies have considered vertical wells because of the simpler method of well test analysis compared to horizontal wells. However, steam assisted gravity drainage (SAGD) process using horizontal well pairs is a promising recovery technique. Numerical simulation study of steam injection in both vertical and horizontal wells (SAGD well pairs) was done to evaluate the applicability and accuracy of thermal well test analysis method and the effects of several parameters on the results. Primary results showed that quite reasonable estimates were obtained. Some trends seen on the pressure plots, however, cannot be explained using the existing models and there are errors associated with the volume estimates that could be related to the simplifying assumptions of the conventional models.*

Keywords— *Composite Reservoir, Thermal Falloff Test, Pseudo Steady State, Swept Volume*

I. Introduction

A composite reservoir may occur naturally or may be created artificially, for example during steam injection into an oil reservoir or cold water injection into a hot oil reservoir. In these representations of a composite reservoir, the portion of the reservoir in the immediate vicinity of wellbore that is occupied by the injected fluid becomes the inner region, while the uninvaded portion of the reservoir becomes the outer region. Each region is defined by its particular rock and/or fluid properties. The radial distance to the discontinuity is called the front radius. This discontinuity may be the result of a phase shift, significant temperature or permeability change. Due to the irregularity in the shape, it is better to express the front radius in terms of swept volume.

Monitoring of swept volume over time is very important for assessing the success of a thermal project. It is used to estimate the cumulative heat losses and thermal efficiencies. Thermal well test analysis offers a quick way to obtain an estimate of the swept volume. It can also provide estimates of flow capacity and skin factor and is used for reservoir characterization.

Pressure transient behavior of composite reservoirs has received considerable attention since early 1960's. Pressure falloff tests are commonly analyzed to estimate swept volume for steam injection projects. Estimation of steam zone properties and swept volume from falloff test data is mostly based on the composite reservoir model with two regions having highly contrasting fluid mobilities presented in [1] (Satman et al., 1980). This method is called the pseudo steady state (PSS) method since the swept zone behaves as a closed reservoir for a short duration during which the pressure response is characterized by PSS behavior. Based on this model, many investigators (e.g. [2]-[4]) estimated flow properties and swept volume.

Well test analysis is an inverse solution and the objective is to characterize and identify the system (reservoir properties) by matching the obtained data to the model. Selection of the correct model is therefore very important. The objective of this work is to present some fundamental concepts and to consider the applicability of the data analysis based on the conventional models. This paper will present further analysis of thermal well tests for vertical and horizontal wells and summarises some of the results and general trends observed during the analysis of different cases.

II. Methodology of Falloff Test Analysis

Since steam may be treated as liquid or gas, the falloff data could be analyzed by liquid or gas well testing method. When average steam properties are evaluated, liquid well testing analysis could be applied to steam injection falloff tests. Pressure analysis technique should suffice for all practical purposes, and real gas analysis is in fact unnecessary because of the relatively small pressure changes common in steam pressure falloff tests. During practical steam injection falloff tests, the shut-in time is much less than the injection time. Therefore, the MDH (Miller-Dyes-Hutchinson) method of analyzing buildup (or falloff) data can be used. This method will be used throughout this study.

Equations are presented in field units. The purpose of this section is to investigate some of the fundamentals involved and to introduce the method of analysis used in the interpretation of falloff data.

A. *Vertical Well Test Analysis*

Based on the model of [1], during the early-time period of well tests and after the end of short wellbore storage effect, the infinite-acting radial flow occurs. The plot of pressure versus shut-in time yields a semilog straight line related to the flow capacity of the swept region. Using the slope of this line, steam effective permeability and skin factor may be calculated as:

$$k_{ec} = \frac{162.6(q_s)_{sc} B_s \mu_s}{m_s h} \quad (1)$$

$$s = 1.1513\left(\left(\frac{p_{wfs} - p_{1hr}}{m_s}\right) - \log\left(\frac{k_{ec}}{\phi \mu_s c_t r_w^2}\right) + 3.23 \right) \quad (2)$$

Where formation volume factor, B_s, and viscosity of steam, μ_s, are evaluated at the average pressure and temperature. Because of the high mobility contrast at the boundary between the inner and outer regions, the boundary acts as a closed one. Thus, the infinite-acting radial flow is followed by the PSS flow. The pressure versus shut-in time yields a Cartesian straight line, characteristic of the swept volume. Using the slope of this line, the swept volume can be calculated as:

$$V_{sc} = \frac{5.615(q_s)_{sc} B_s}{24 m_c \phi c_t} \quad (3)$$

Where c_t is the total compressibility, almost equal to the two-phase compressibility, $c_{2\phi}$ ([5]):

$$c_{2\phi} = (0.18513)\frac{<\rho C>}{\phi}\left(\frac{\rho_w - \rho_s}{L_v \rho_w \rho_s}\right)^2 (T + 460) \quad (4)$$

Where

$$<\rho C> = (1-\phi)\rho_f C_f + \phi S_w \rho_w C_w \quad (5)$$

During steam injection, phase changes take place between steam and water when pressure changes. With the pressure change, specific volume of each phase changes, but this change is small in comparison with the volume changes caused by phase change [5]. Therefore, the compressibility of each phase can be ignored and the compressibility as a result of the phase change (called two-phase compressibility) is almost equal to the total compressibility.

For steam, the flow rate $(q_s)_{sc}$ is the actual steam injection rate given by:

$$(q_s)_{sc} = (q_w f_s)_{sc} (\rho_w)_{sc} (\upsilon_s)_{sc} \quad (6)$$

When average fluid and rock properties are to be used, the average pressure and temperature must be determined. This study uses the volume-weighted average of pressures in the swept zone at the instant of shut-in as average pressure. The steam saturation temperature corresponding to the saturation pressure may be obtained from published steam property tables or diagrams. The average temperature calculated in this manner is almost the same as the volume-weighted average of temperatures in the swept zone at the instant of shut-in. These average values are used to read the values of steam and water density, steam specific volume and viscosity and specific enthalpy of evaporation (needed in the equations) from steam tables.

For precise estimation of permeability and swept volume (equations 1 and 3), it is very important to select the correct straight lines. To achieve this, semilog pressure derivative, $dp_{ws}/d\ln(\Delta t)$ is used to identify various flow regimes. The semilog pressure derivatives are calculated from the falloff data using differentiation algorithm, and a log-log plot of this derivative versus shut-in time is prepared. The plot will exhibit a unit slope line for wellbore storage period, a constant derivative value for infinite-acting radial flow and a unit slope line for PSS flow.

B. *Horizontal Well Test Analysis*

The advantage of horizontal wells over vertical wells to provide larger surface areas of contact with the reservoir makes horizontal wells a suitable choice for efficient oil recovery. Steam assisted gravity drainage (SAGD) process using a horizontal well pair has been applied successfully to the Athabasca oil sands and other fields over years. In this method two horizontal wells are drilled with vertical spacing of about 5 meters. The bottom well is considered as producer while the upper one is injector. Heat will be transferred into the reservoir by injection of steam via injector. The formation and its contents will gradually be heated up to the steam temperature. Pressure behavior of horizontal wells is different from vertical wells and the analysis is in fact more complicated.

The steam chamber for a horizontal well may not be ellipsoidal in shape and symmetric around the wellbore due to the effects of gravity, anisotropy and heterogeneities. Such asymmetries can mask parts of the PSS flow regime and make the calculations unreliable. The application of thermal well testing methods for determination of swept volume has not been discussed in details for horizontal wells and most of the studies, except a few ([4] and [6]), have considered vertical wells.

Several transient flow regimes may be observed prior to PSS flow in falloff test of a horizontal well. These flow regimes can be identified by characteristic slopes on a log-log plot of pressure derivative versus shut-in time. The possible flow regimes are:

- Wellbore storage (unit slope line)

- Early-time radial flow regime (zero slope line)
- Early-time linear flow regime (half slope line)
- Pseudo-radial flow regime (zero slope line)
- Late-time linear flow regime (half slope line)
- PSS flow regime (unit slope line)

Transient pressure falloff data prior to PSS flow regime may be used to obtain an estimate of the permeability (mobility) of the steam chamber. The slope of the straight line on a semilog plot of pressure versus time for the early radial flow is related to permeability of the steam zone as:

$$m_{s1} = \frac{28.96(q_s)_{sc} B_s \mu_s}{L k_{rg} \sqrt{k_x k_z}} \qquad (7)$$

Similar equation is obtained for the pseudo-radial flow. Except for wellbore storage and early radial flow, none of the other transient flow regimes are usually observed prior to PSS flow (this was also the case in most of the simulated falloff tests considered here). Early linear flow, however, is observed in some of the cases. Skin factor can be calculated from the early radial flow as described for the vertical wells. Pressure versus shut-in time yields a straight line at late-time whose slope can be used to calculate the steam chamber volume as in the case of vertical wells (equation 3).

III. Simulation of the Falloff Tests

To investigate the application of thermal well testing, several simulation studies were performed and analysed. The reader is referred to ([7]-[10]) for detailed simulation study and results. The thermal simulator STARS (CMG 2015) was used to simulate the steam falloff tests. Steam is injected into the reservoir models until appreciable rock volumes are swept. Pressure falloff tests are then simulated by shutting the injection well and reading the wellbore gridblock pressures as a function of time. The data are analysed using the methodology described earlier.

The sample analysed was obtained from an oil sand reservoir in Athabasca region. Fig. 1 shows the measured viscosity data. The molar mass of Athabasca oil sample was measured to be 534 kg/kgmole. The oil density at standard conditions (1.01325 bara and 15.56 °C) was estimated 1.01286 g/cm^3. These data are used as input for simulation purposes in this study. Table 1 represents the reservoir and fluid properties used in the vertical and horizontal well simulation studies. The water/oil and gas/oil relative permeabilities of [11] are used.

For the vertical well case, the reservoir model consists of a formation area of approximately 150000 ft^2 and thickness of 40 ft. The injector is located in the center of the reservoir. The reservoir model for the horizontal injector consists of a formation of 200 ft×100 ft×50 ft. The producer is located at the bottom of the reservoir while the injector is 15 ft above it.

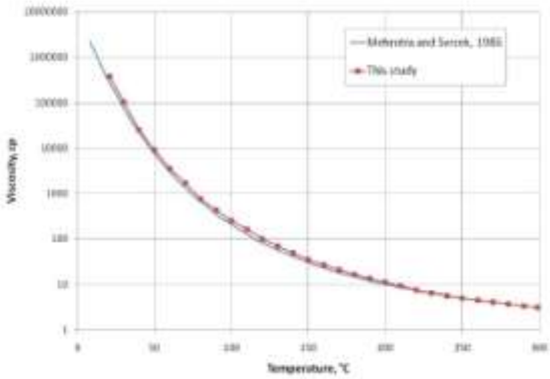

Fig. 1 Viscosity of Athabasca sample versus temperature [8]

Table 1 Reservoir and fluid parameters for vertical and horizontal well study

a) Vertical well

Initial reservoir pressure, psia	700
Initial reservoir temperature, °F	93
Porosity, fraction	0.35
Initial water saturation, % PV	21
Initial oil saturation, % PV	79
Horizontal absolute permeability, md	700
Vertical absolute permeability, md	70
Pore compressibility, psi^{-1}×10^{-6}	300
Water compressibility, psi^{-1}×10^{-6}	4
Oil compressibility, psi^{-1}×10^{-6}	4.7
Formation thickness, ft	40
Formation volumetric heat capacity, BTU/(ft^3-°F)	35
Formation thermal conductivity, BTU/(ft-D-°F)	24
Oil density at standard conditions, lb/ ft^3	63.23
Injected steam temperature, °F	580
Injected steam quality, fractional vapor mass	0.8

b) Horizontal well

Initial reservoir pressure, psia	700
Initial reservoir temperature, °F	93
Porosity, fraction	0.3
Initial water saturation, % PV	21
Initial oil saturation, % PV	79
Horizontal absolute permeability, md	7000
Vertical absolute permeability, md	2100
Pore compressibility, psi^{-1}×10^{-6}	300
Water compressibility, psi^{-1}×10^{-6}	4
Oil compressibility, psi^{-1}×10^{-6}	4.7
Formation thickness, ft	50
Formation volumetric heat capacity, BTU/(ft^3-°F)	113
Formation thermal conductivity, BTU/(ft-D-°F)	78
Oil density at standard conditions, lb/ ft^3	63.23
Injected steam temperature, °F	400
Injected steam quality, fractional vapor mass	0.85

For the vertical and horizontal well base cases, rate of injection is 500 and 200 STB/D for 30 and 20 days, respectively. The injection well is then shut in for 24 and 50 hours, respectively, to read the wellbore gridblock pressures.

Because of the high viscosity of Athabasca heavy oil and in order to have some initial flow, the reservoir is first heated up to initiate the communication between the horizontal injector and producer. This is done by using the STARS's heater control. The injection flow rate and producing bottom-hole pressure are held constant. Heat loss is allowed from the formation to the upper and lower layers surrounding the reservoir.

IV. Results and Discussion

Several simulated falloff tests were analysed in [7]. The purpose was to evaluate the accuracy of thermal well testing and to investigate the effects of different parameters on the results. After this primary study, a more detailed study of thermal well test method for vertical wells with applications to Athabasca reservoir was given in [8]. Viscosity, molar mass and density of Athabasca oil sample were measured in the laboratory and this data was used as input for simulation purposes.

Using the techniques described, effective permeability to steam, skin factor and swept volume were calculated. Results were then compared with the corresponding values obtained from simulation (i.e. permeability at volume weighted average steam saturation within the swept zone and the simulated swept volume).

Permeability is highly overestimated in some cases. Steam saturations decrease gradually from the wellbore block towards the steam front, but the saturations decrease faster along the steam front. Thus, it is reasonable that the calculated permeability from well tests should reflect the permeability of a high steam saturation zone around the injection well. It was tried to minimize the wellbore storage effect in this study, but a possible explanation for the overestimation of steam permeability can be the wellbore storage effect which masks portions of the radial flow.

The estimation of volume by PSS method is a material balance calculation, independent of geometry. However, the effect of gravity and irregular shapes of the swept zones can make the flow regime identification more difficult and therefore affect the accuracy of estimates. The method assumes cylindrical swept zone while gravity makes it irregular in shape. Another problem with the model is the sharp saturation gradients at the steam front which makes the estimations unreliable.

Analysis of the effect of dip shows that the method works as in the case of non-dipping reservoirs. For the case of 90° dipping angle (equivalent to a horizontal well), the volume is underestimated a little bit. Therefore, it seems that thermal well testing method is also applicable to horizontal wells, and the method was applied in another study ([9]) to SAGD process for a typical Athabasca heavy oil reservoir and effects of several operating parameters on well test results were studied. Further analysis of thermal well tests is presented in [10] for vertical and horizontal wells and some of the results and general trends obtained from the analysis of different cases are summarized.

Reference [6] states that the PSS method gives the total volume of the steam chamber plus hot water zone. However, mobility contrast at the first front (steam front) is in fact high enough in this study, so that it behaves as a closed boundary. In other words, the pressure responses first reflect the effect of this front and the estimated volume includes only steam zone.

The error of calculations of the swept volume for steam injection through vertical and horizontal wells using the PSS method, in some cases is as high as 30%. The overestimation of the swept volume by this method may possibly be the result of short injection time prior to conducting the falloff test. However, very long injection time before shut-in proved to have an adverse effect on the estimation of permeability and swept volume due to highly irregular swept region shape and the possibility of early breakthrough.

Some kind of linear flow can be observed after the early radial flow for long injection time in horizontal wells, as shown in Fig. 2.

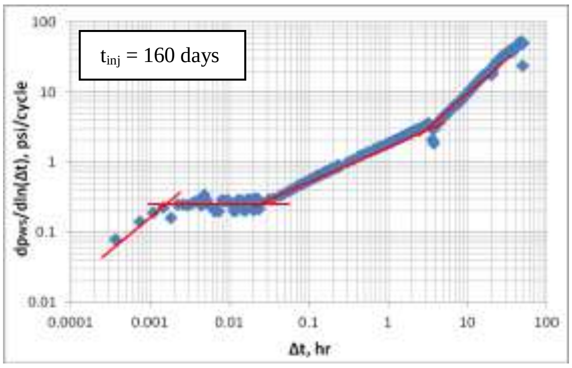

Fig. 2 Pressure derivative plot for a horizontal well with long injection time

The asymmetric shape of the swept zone and volume overestimation can be due to the effect of gravity and the location of the producer. Elimination of the producer, on the other hand, resulted in highly underestimated values of permeability and steam chamber volume.

Shape of steam chamber at high injection rates shows some irregularities and breakthrough at the time of shut-in and this may affect the accuracy of estimations. As the rate increases, however, the radial flow representing the steam swept zone and a second radial flow (representing the unswept zone) become clearer, as shown in Fig. 3 and 4. The unswept zone pressure response is masked by other flow regimes in most of the cases, obviously by the boundary effect which is not a totally closed one.

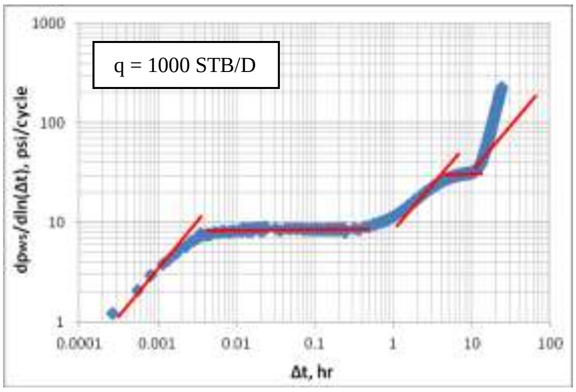

Fig. 3 Pressure derivative plot for a vertical well with high injection rate

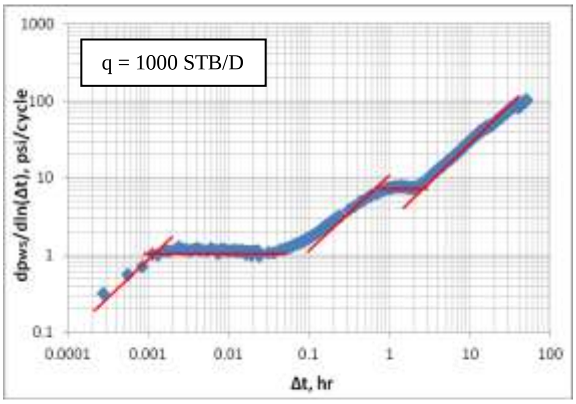

Fig. 4 Pressure derivative plot for a horizontal well with high injection rate

Estimation of flow capacity and swept volume depends on the vertical positions where pressure data are measured (practically, the location of pressure gauges). However, this effect is not very important for reservoirs that are not too thick. The vertical and lateral distances between the producer and injector also affect the estimations.

In SAGD process, as the vertical distance between the producer and injector increases, the possibility of early breakthrough is less and the difference between simulated and calculated volume becomes smaller. For small distances, the chamber growth is extremely hampered.

Some of the errors associated with the results obtained in this study may be due to the simplifying assumptions of the method of analysis. For example, simulator considers heat loss to the formation while it is not included in the analysis method. In a previous study ([12]), several examples from literature and a few synthetic tests, affected by heat loss, were analysed using different methods. A general procedure is proposed to ensure reliable analysis even if huge heat loss happens.

In some cases, the trend of pressure data cannot be fitted very well using the conventional composite reservoir model. This is probably because the PSS model does not consider the effect of tilted fronts due to gravity and an intermediate region between the inner and outer region to avoid sharp saturation gradients. To be more realistic, new models are proposed for well test analysis of composite reservoirs that take into account some of the assumptions overlooked in the previous models including heat loss, gradual property variation and gravity effects (e.g. [13]-[16]).

V. Conclusions

Primary results of this work showed that the swept volume and permeability can be estimated from pressure falloff tests. The effects of several reservoir and operating parameters such as injection time prior to shut-in and injection rate were investigated. These parameters can affect the accuracy of the analysis.

The permeability estimate from vertical well test analysis was overestimated by 10-20 percent in most of the cases. In the case of horizontal wells, the errors were less than 10 percent in most runs. In some cases, permeability is highly overestimated and it may reflect the permeability of a high steam saturation zone around the wellbore.

The PSS method was used to obtain the swept volume for steam injection through vertical and horizontal wells, and the error of calculations was less than 15 percent in most of the cases. However, the method can be sensitive to the increased non-uniformity of the swept volume in extreme cases.

The overestimation of swept volume may possibly be due to short injection time effect on the falloff responses. However, very long injection time before shut-in proved to have an adverse effect on the estimations due to highly irregular swept region shape and the possibility of early breakthrough.

As the injection rate increases, the accuracy of volume estimation gets worse, while the radial flow representing the steam swept zone becomes clearer and a second radial flow representing the unswept zone may also be observed in some cases. This behavior was observed for both vertical and horizontal wells.

Better estimates of swept volume seem to be obtained by increasing the steam quality. However, this is not valid over the whole range of qualities, especially for extreme values. The vertical and lateral distance between producer and injector affect the estimations.

Application of the PSS method for volume estimation should be reconsidered because of its simplifying assumptions and drawbacks briefly named in this study. It just considers the data on the PSS straight line assuming a sealed boundary while the boundary is not really sealed. It ignores the low saturation zone between the high saturation steam zone and the outer zone and therefore results in wrong slopes.

NOMENCLATURE

B = fluid formation volume factor, bbl/STB
c = isothermal compressibility, psia^{-1}
C = heat capacity, BTU/lbm-°F
f_s = steam quality, fraction
h = formation thickness, ft
k = permeability, md
k_{ec} = calculated effective permeability, md
k_{rg} = gas relative permeability, fraction
L = effective horizontal well length, ft
L_v = latent heat of vaporization, BTU/lbm
m_c = Cartesian slope of pressure versus shut-in time, psi/hr
m_s = semilog slope of pressure versus shut-in time, psi/cycle
m_{s1} = semilog slope of pressure versus shut-in time for early radial flow, psi/cycle
p = pressure, psia
p_{wfs} = wellbore gridblock pressure at the instant of shut-in, psia
p_{ws} = shut-in wellbore gridblock pressure, psia
p_{1hr} = pressure at the shut-in time of 1 hour (from the radial flow straight line), psia
q = flow rate, STB/D
r_w = wellbore radius, ft
s = skin factor, dimensionless
S = saturation, fraction
T = temperature, °R
V_{sc} = calculated swept volume, ft^3

Greek symbols

Δt = shut-in time, hr
μ = viscosity, cp
v = specific volume, ft^3/lbm
ρ = density, lbm/ft^3
ϕ = porosity, fraction

Subscripts

f = formation
g = gas (steam)
o = oil
s = steam
sc = standard conditions
t = total
w = water or wellbore
x = horizontal
z = vertical
2ϕ = two-phase

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