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Estimation of Skin Factor by Using Pressure Transient Testing Results of a Single Rate Well Test

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Abstract

About one-fifth of the natural gas used by Americans each winter comes from natural gas storage sites. Gas storage is the primary means for the gas industry to manage fluctuations in supply and demand. Natural gas can be stored in a variety of ways. Most commonly, it is held in underground formations, in depleted oil or gas reservoirs, or in natural aquifers.

Many gas storage wells show a decline in deliverability as a function of time due to several damage mechanisms. The remedial operations such as stimulation and workovers are used to restore the loss in deliverability and to enhance the productivity of a well.

Candidate selection for the stimulation or workover process is generally based on well history. Skin factor is an important parameter to predict the well performance. Skin is usually calculated from a multi rate well test (MRT). However performing a MRT on a regular basis is an unattractive activity when considering the economic issues. First of all, performing a well test may cause temporary production or injection interruptions. Secondly, the cost associated with well test is considered as an operating expense, a fact that does not help the overall economics of operating a Gas Storage Field. Single Rate tests (SRT) are also performed to estimate the deliverability, but they do not contain sufficient data in order to estimate true skin factor.

The objective of this study is to introduce a new methodology to enhance the current practices of estimating true skin factor from a SRT. This method includes history matching of the actual MRT and then estimation of skin value from SRT using the history matched model. Using this methodology it is shown that change in the skin can be estimated with reasonable accuracy.

Introduction

Traditionally, gas storage wells in the Appalachian basin are

evaluated by multi rate test or single rate test data. The results of the single rate test data are extrapolated to estimate the Absolute Open Flow (AOF) value of the well. The new value is compared in order to make decision on need for remedial treatments.

Candidate selection is generally based on the well performance history. Skin factor is an important parameter to predict this performance. Change in Skin (ΔS) generally is a good indicator whether a well needs remedial operations or not. Skin factor is usually calculated from a well test by conventional well test analysis. To maintain an accurate estimate of the well performance for the candidate selection, gas storage wells need to be tested regularly. However, performing a well test regularly is not quite economic. First, performing a well test may cause temporary production or injection interruptions and second, the cost associated with well test is considered an OpEx (Operating Expense), a fact that does not help the overall economics of operating a Gas Storage field.

Each year Gas Storage operators spend thousands of their OpEx dollars to test storage wells. In industry, multi rate tests (MRT) and single rate tests (SRT) are being performed to have a qualitative assessment for candidate well selection by comparing the AOF (absolute open flow potential) of the wells or they are being performed to have an approximate estimation of the skin factor. Since, a MRT causes temporary production interruptions and a SRT do not contain sufficient data to estimate the “true skin factor”, getting the best possible and reliable reservoir and well bore characterization from the performed tests becomes very important.

The objective of this study is to introduce a new methodology to enhance the current practices of estimating the true skin factor from a SRT. This method includes history matching of the actual MRT and then estimation of skin value from SRT using the history matched model. Using this methodology change in skin has been studied.

In this study, optimization of well test analysis has been aimed. This optimization can have two dual benefits for the storage operators. It can reduce OpEx by reducing the number of multi rate tests that must be performed, thus fewer production/ injection interruptions, while by improving the analysis process a more realistic assessment of the damage over time (identified by skin) becomes possible.

Using a commercial numerical simulator and well test data representative of an actual gas storage field located in Ohio we verified the methodology mentioned above.

Literature Review and Background

The first widely known well test analysis method was presented by Rawlin and Schelhardt¹ in 1936 with the deliverability equation shown below.

$$q = C(P_R^2 - P_{wf}^2)^n \quad (1)$$

This equation is not as accurate as the pseudo-steady state equation, which is

$$P_R^2 - P_{wf}^2 = aq + bq^2 \quad (2)$$

The coefficients a, and b are usually estimated with isochronal or modified isochronal tests². Cullender³ proposed the isochronal test method, consisting of equal duration of flow periods of a well and at the end of the each flow period shutting the well in for stabilization. In the low permeability reservoirs, waiting for stabilization can be very long. Katz et al⁴ presented a new type of well test, modified isochronal test. This test is widely used in industry. In a modified isochronal test, the duration of the flow periods (drawdown periods) is same with the shut-in (buildup) periods so there is no wait for stabilization. The pressure vs. time data of a modified isochronal test is in Figure 1.

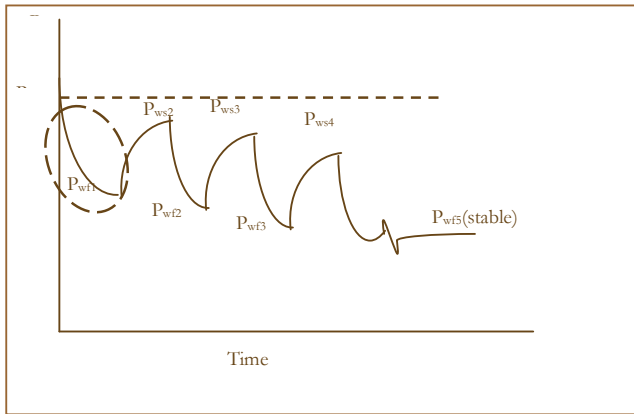


Figure 1: Pressure profile of a modified isochronal test.

Swift and Kiel⁵ introduced a significant analysis of gas well testing including the non-Darcy flow. They obtained the non-Darcy factor (D) from drawdown tests. From at least two drawdown period, apparent skin factors (S'_1, S'_2) were calculated with the below equation:

$$s' = 1.151 \left[\left(\frac{P_i^2 - (P_{wf}^2)_{t=1hr}}{m} \right) - \log \left(\frac{k}{(\phi)(\mu)(\bar{c})(r_w)^2} \right) + 3.23 \right] \quad (3)$$

And if the flow rates changes slowly in the drawdown period, the equation becomes,

$$s' = 1.151 \left[\left(\frac{P_i^2 - P_{wf}^2}{q} \right)_{t=1hr} \left(\frac{1}{m} \right) - \log \left(\frac{k}{(\phi)(\mu)(\bar{c})(r_w)^2} \right) + 3.23 \right] \quad (4)$$

From the two drawdown periods two apparent skin factors were calculated and there are two different flow rates for each period. By using the formula:

$$s' = S + (D)(q) \quad (5)$$

A plot of S' vs. q should result in a straight line and the slope of the line gives D factor and the intercept gives the true skin factor (S).

In industry, estimation of the k, S and D is based on this method. They use the three drawdown periods of the multi rate test, which is a modified isochronal test performed on the well with three drawdown and three buildup periods, to estimate three apparent skin factors, S'_1, S'_2, S'_3 , and based on the formula $s' = S + (D)(q)$, they get a plot of q vs. S' with a line of extrapolation between the three points. The slope of the line is non-Darcy factor, D, and the intercept is true skin factor, S. So, a multi rate test is a basically a modified isochronal test with three drawdown periods followed by a three buildup periods. In industry, single rate test is preferable because it requires shorter time steps to perform and it is more economical. A single rate test contains only a drawdown period and sometimes a buildup period following the drawdown period.

Since evaluation of true skin factor require at least two drawdown periods, a single rate test is not enough for this estimation. In this paper, a new methodology is introduced to estimate the true skin factor from using the drawdown data of a single rate well test.

Methodology

In this paper, we present a step by step approach of a new method to estimate the change in the true skin factor with time by using single rate well test data. There are 4 steps involved in achieving the objective of this study.

1. Identifying a well with at least one detailed pressure vs. time data of a multi rate test followed by a single rate test with its pressure vs. time data.
2. Analyzing the multi rate test data by using one of the conventional analytical analysis methods to calculate permeability (k) and skin factor (S).
3. Building a numerical simulation model to history match the actual data.
4. Estimating the parameters to be adjusted during the history match and modifying them until getting a match of the pressure data of the actual multi rate test with the simulated model's pressure response.
5. Performing a single rate well test on the history matched model. Modifying only skin factor parameter while keeping the other parameters constant to history match the single rate well test.

At the end of this procedure, change of the true skin factor with time (in reality, there is a time gap between the multi point test and single point test) is estimated as well as the reservoir permeability. It is a fact that the history matched model is one probable version of reality in which there can be several possibilities. Thus, our history matched model is non-unique but the key in this method is consistency and attributing the change in the well production behavior to skin. In order to test the accuracy of this method two cases are studied with different skin estimations on the same well. A verification study was also performed with two numerical simulation models.

1. Data Acquisition (Field Data)

The data used in this study is detailed pressure vs. time data of each flow/buildup period of a multi rate test followed by an at least one single rate test. The data has been obtained from a gas storage field located in Ohio. The fluid PVT properties were known with some other parameters like porosity and well bore radius. The permeability distribution near the well bore, distances to the boundaries and skin are the unknown parameters.

2. Analytical Well Test Analysis

The data of three drawdown periods of the actual multi rate test is analyzed by using the conventional well test analysis methods. Since the permeability of the reservoir does not change with time, the values of permeability, calculated from each drawdown period, should be the same. Calculated parameters, which are permeability (k), non-Darcy skin factor, also called as true skin factor (S) and non-Darcy factor (D), are used as initial values for history matching. The other input model parameters such as fluid PVT properties or flow rates for the each drawdown period of the multi rate test are same as those used in the well test analysis of the actual data. So, they are the known parameters of the actual field. Radius of investigation is also another parameter calculated by conventional analysis to determine the area under the influence of the multi point test.

3. Generating the Numerical Simulation Model

Calculated parameters from the actual data are used as initial input values to the numerical model. These parameters, k, S and D, are decided as the parameters to be adjusted during the history match process. Other input values of the model are assumed to be the known parameters of actual field with reasonably accuracy. The grid size of the numerical model is also changed from coarse grid size to the fine grid size. Actually, local grid refinement has been (LGR) applied to the simulation model in order to get the best and the most reliable match of pressure history with the actual data. The time step is adjusted according to the actual well test's time steps.

4. History Match of Multi Point Test

Getting the best match of simulator generated well test data, which is pressure vs. time data from the multi rate test performed on the numerical simulation model with the actual data is summarized under this section. Firstly, the parameters to be adjusted during the history match are selected. These parameters are unknown parameters of the actual field and since our aim is to get the pressure match at the end of the each drawdown/buildup period of the multi point test, these properties should be major contributors to the well response in the transient flow. The parameters decided to be adjusted during the history match are permeability (k), non-Darcy skin factor (S) and non-Darcy factor (D). Calculated values of these properties from analytical analysis are set as initial values in the matching process. The matching starts with the first drawdown period of the multi rate test. Those parameters are modified until a good match is obtained with the actual data. It is a step-wise matching process which is matching one flow period at a time to finally converge to a single set of reservoir

parameters for the entire multi rate test. It means that if there is a need to change the value of these parameters, it should be done at the beginning of the test. For example, if there is a problem in the third drawdown period although the match is obtained in the previous flow periods, everything should start from the scratch. The parameters should be changed with new values at the beginning of the first drawdown period and they should be kept constant until an acceptable match is obtained with the last buildup period of the multi point test. When the match is obtained with the last buildup period of the multi rate test, the parameters are finalized and called "Realization #1" which is consisted of k_1 , S_1 and D_1 . At this point, we have modeled the actual reservoir.

5. Estimation of True Skin Factor from the Single Point Test

The next set of pressure data, to get a match with, is the single rate well test data. In the previous step the numerical simulation model was modified to represent the actual reservoir with adjusted k, S and D parameters. In this step firstly a single rate test (SRT) is performed on the history matched numerical model and the match process starts with the pressure vs. time data of this SRT with the actual SRT data. However, in this step, the true skin factor (S) is the only parameter to be adjusted during the process while keeping the other two parameters, k and D, constant. Wattenbarger and Ramey⁶ showed that D is not constant for high-drawdown wells and it is a function of viscosity near the wellbore. In this study D-factor was kept constant since the average pressure of the well tests do not vary much; hence the amount of the change in viscosity near to the wellbore is really small. At the time the match is obtained we have a set of finalized parameters called "Realization #2" which is consisted of true skin factor S_2 , and the original k and D. Thus, we obtain a new skin factor from the SPT and it shows that there is a change in the skin, delta skin, which is equal to:

$$\Delta S = S_2 - S_1 \dots\dots\dots (6)$$

Verification

Homogeneous System:

To verify the methodology and the results of the field examples, a simplified radial simulation model was built to history match with a high resolution Cartesian numerical model. In this verification process an actual physical reservoir is substituted with the Cartesian model.

Both models are homogeneous with different reservoir/well characteristics. The parameters adjusted during the history match are permeability, skin factor and non-Darcy factor.

Table 1 shows these values. The values of Cartesian model are not changed during the whole matching process since it is the control environment and is substituted with an actual field. The parameters of radial model shown in the table are the initial values to be set in the matching process.

Table 1: Input reservoir parameters of both numerical models.

A multi rate well test followed by a single rate well test was performed on both models. The matching of MRT started with the above parameters. After adjusting the permeability as 100 md, skin factor as 3.38 and non-Darcy factor as 1.02E-04 in the radial model, a match was obtained. The results are illustrated in Figure 2 showing pressure (psia) vs. time (days) data of both multi rate tests in a Cartesian plot. Blue line represents the Cartesian model's data (which is substituted with actual data) and the red line is the match of radial model's data.

After getting the match with the multi rate test data, a SRT was performed on the Cartesian model with a changing skin factor equal to 2.5. The change in the skin factor from the MRT to the SRT in the Cartesian model becomes;

$$\Delta S = S_2 - S_1$$

$$\Delta S = 2.5 - 1.2$$

$$\Delta S = 1.3$$

On the radial model a single rate well test was performed to get a match with the Cartesian model's SRT data. The match was obtained when the skin factor of the radial model was modified to $S=4.68$ while keeping the other parameters constant ($k=100\text{md}$ and $D=1.02\text{E-}04$). Figure 3 shows the result of the match of single rate test in a Cartesian plot.

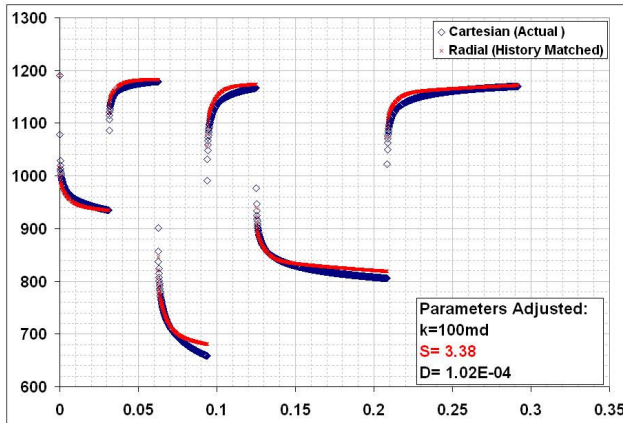


Figure 2: History match of multi rate test data of Cartesian numerical model for verification, homogeneous case.

Cartesian Numerical Model		Radial Numerical Model	
Permeability, md	80	Permeability, md	50
Skin factor	1.2	Skin factor	0
Non-Darcy factor	9.00E-05	Non-Darcy factor	0

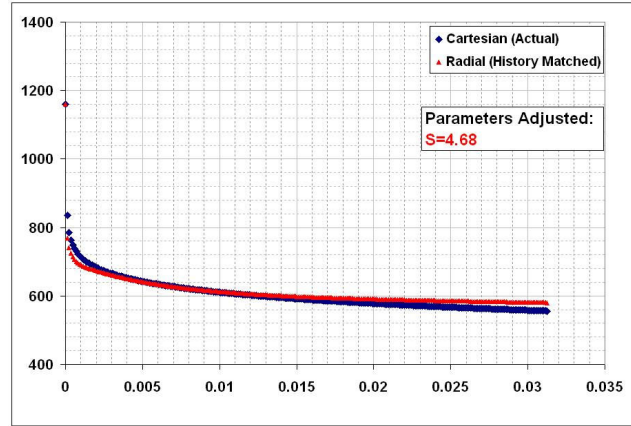


Figure 3: History match of the single rate test data of the radial numerical model with the Cartesian model's data for verification

As a result, the match was obtained when the $\Delta S = 1.3$ in the radial model.

$$\Delta S = S_2 - S_1$$

$$\Delta S = 4.68 - 3.38$$

$$\Delta S = 1.3$$

Heterogeneous System:

In this case, heterogeneity was introduced to the Cartesian model by changing only permeability values. Figure 4 shows the permeability distribution. The permeability can be averaged around 90 md inside of the drainage area. Skin factor was put as 1.28 and D factor as 9E-05 inside the model. A multi rate test was performed on this model. By analyzing the pressure vs. time data of three drawdown periods, three different permeability values and apparent skin factors were calculated (Table 2). True skin factor and non-Darcy factor were estimated by regression of flow rates and calculated apparent skin factors (Table 3).



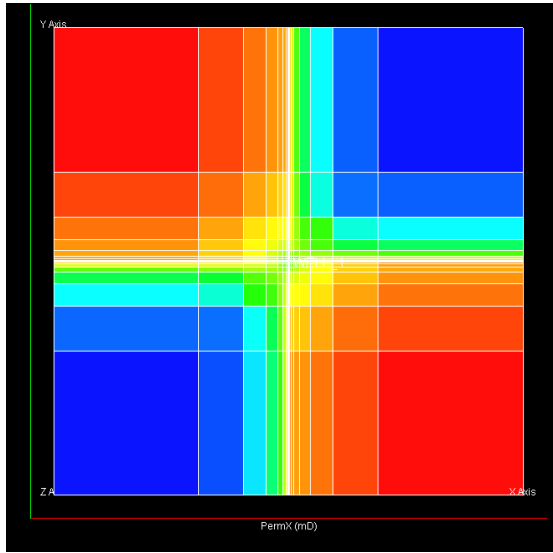


Figure 4: Permeability distribution on the locally refined grids of the Cartesian heterogeneous model. The minimum permeability is 10 md and the maximum is 150 md.

Table 2: The results of the analytical analysis done for the heterogeneous Cartesian model.

	DD-1	DD-2	DD-3
Flow Rate, Mscf/D	6800	12000	8500
Permeability,md	89	103	108
Apparent Skin Factor	3.09	5.26	5.01

Table 3: Comparison of the input parameters of the heterogeneous Cartesian simulation model with its calculated values.

	Model Input	Calculated
k(averaged)	90 md	100 md
S	1.28	2.69
D	9E-05	2E-4

The permeability values could not be obtained equal from each drawdown period and the estimated true skin factor and non-Darcy factor are different from the input values. There can be two reasons for these. First, the analytical analysis followed in this study is based on the assumption that each drawdown period should start with a stabilized pressure value. However, in a multi rate test (modified isochronal test) there is no wait for the stabilization in each buildup period. So, the drawdown periods do not start with a stabilized pressure, which affects the estimation of the permeability from the analytical methods. Second, in the Cartesian model the permeability values on the grids near to the well bore are low and gradually increasing to the boundaries. This low value of permeability may cause extra pressure drop near to the well bore, hence extra skin factor, since in the simulator the input skin parameter directly affects the well bore, not the first grid next to the well bore. This extra skin effect is resulted in the analytical analysis.

Like the previous case, a radial homogeneous model was built to history match with the heterogeneous Cartesian simulation model. The calculated parameters from analytical analysis were set to be initial values of the homogeneous radial model.

The parameters adjusted during the history match are again permeability, skin factor and non-Darcy factor. The match was obtained with the permeability value as 95 md, skin factor as 2.95 and D factor as 1.9E-04 (Figure 5).

After getting the match with the multi point test data, a SPT was performed on the Cartesian model with a changing skin factor equal to 1.5. The change in the skin factor from the MRT to the SRT in the Cartesian model becomes;

$$\Delta S = S_2 - S_1$$

$$\Delta S = 1.5 - 1.28$$

$$\Delta S = 0.22$$

On the radial model a single point test was also performed to match with the Cartesian model's SRT data. The match was obtained when the skin factor of the radial model was modified to $S=3.17$ while keeping the other parameters constant ($k=95$ md and $D=1.9E-04$). Figure 6 shows the results of this case. At the end of the history match the change in skin was estimated equal to $\Delta S=0.22$.

$$\Delta S = S_2 - S_1$$

$$\Delta S = 3.17 - 2.95$$

$$\Delta S = 0.22$$

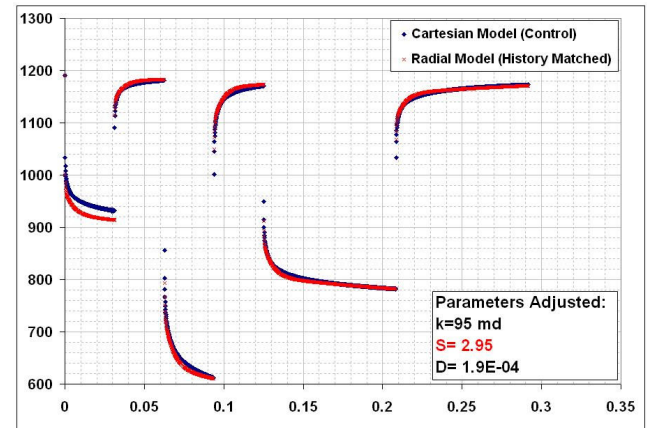


Figure 5: Pressure (psia) vs. Time (days) data of the multi rate test. History match of radial model's multi rate test data with data of Cartesian model for verification.

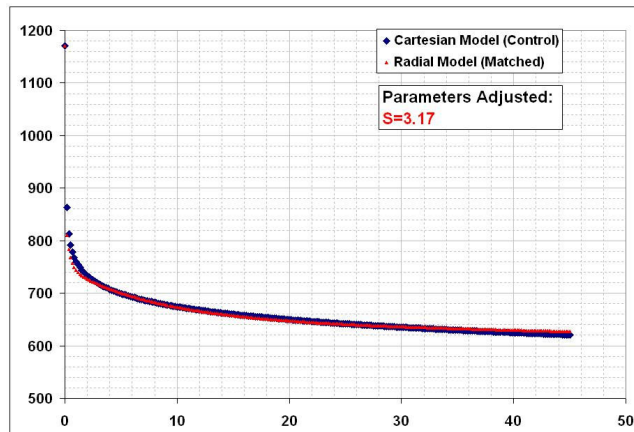


Figure 6: Pressure (psia) vs. time (hours) data of the single rate test. Match of radial model's data with cartesian model's data.

Field Examples

To evaluate the accuracy of the methodology introduced in this paper, two wells from a gas storage field in Ohio were selected. The gas formation is Clinton sand stone and the filed properties are shown in Table 4.

Table 4: The Reservoir Properties of the Gas Storage Field Located in Ohio.

Gas Storage Reservoir Characteristics	
Average formation depth	1200 ft
Porosity	14%
Average thickness of formation	10 ft
Specific gravity of gas	0.585

The field has more than 300 producer/injector wells on which at least one of the three well tests performed. These tests are Absolute Open Flow Test (AOF), single rate test (SRT) and multi rate test (MRT). Two wells, Well A and Well B were selected to be used.

Well A

The multi rate test was performed in October of 1997 and the single rate test in September/1998 on this well. The well was stimulated in 1969. The known properties of the well are wellbore radius as 0.26 ft, thickness as 10 ft, and permeability of the reservoir near to the well bore as ranging between 296 to 428 md.

The duration of the multi rate test is 7 hours with three drawdown periods and three buildup periods. The last flow period is 2 hours followed by a two hour long shut-in period. The flow rate changes slightly during the flow periods. Single rate test, on the other hand, consists of only one flow period with slightly changing rate for 45 minutes. From the rate point test's pressure data permeability was calculated as 230 md with analytical analysis. The estimated true skin factor is -2.03 and the non-Darcy factor is 0.0003.

Radius of investigation is another parameter estimated with analytical analysis as 312 ft. Considering this parameter as well as the skin factor and well bore storage effects, the numerical model was refined to fine grid sizes from the coarse grid sizes not only in the drainage area (investigation radius)

of the well test but also in the whole reservoir. The local grid refinement (LGR) of the numerical model is in Figure 7.

Case 1:

The history matching started with the initial values of k , S and D calculated with analytical equations. After modifications of these parameters a match was obtained with the actual multi point test data. The result of the pressure vs. time data match is in Figure 8, in Cartesian coordinates. At the end of the multi rate test the match was obtained with parameters; permeability as 387.5 md, true skin factor as 0 and non-Darcy factor as 0.000145.

After getting a pressure match with multi rate test data, a single rate test was performed on the numerical model without changing any parameters adjusted in the previous step. Figure 9 shows the result of the pressure match of single rate test. Without changing the parameters k , S and D the match could not get obtained. On the figure, the blue line shows the actual data. The orange line shows the numerical simulation model's data with the parameters adjusted in the previous step. The value 15210 is the flow rate of the test in Mscf/d. Value of the numerical model's flow rate is same with the actual fields. By adjusting the skin factor parameter, from 0 to 2 while keeping the other parameters constant (values of k and D from the previous MRT match), the match got obtained. The green data-line of Figure 9 shows the pressure match of numerical model's pressure data with the actual test data. As a result, there is a 2 unit difference in the skin factor from the multi rate test to the single rate test.

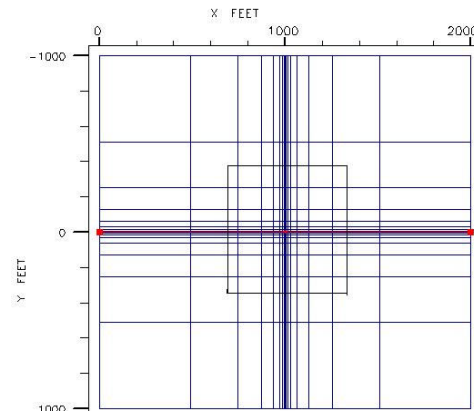


Figure 7: LGR of the numerical model for history matching of Well A

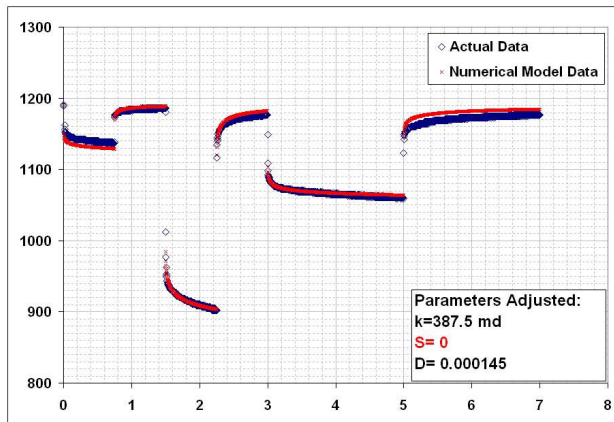


Figure 8: History match of the multi rate test data of Well A

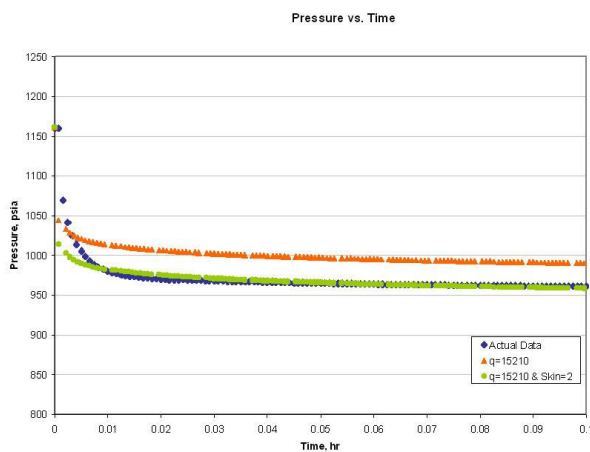


Figure 9: History match of single rate test pressure data with the data of Well A.

Case 2:

In order to test the change in skin factor, another numerical simulation model was created to history match with the well test data of Well A. This model is similar with the model used in Case 1. However, the area of the model has been changed as well as non-Darcy factor. The pressure match of the multi rate test was obtained with the parameters shown on the Figure 10. The match was achieved by adjusting the non-Darcy factor as 0.00016 and skin factor as 1. The permeability values are same for both numerical model cases as 387.5 md.

The pressure match of single rate test was obtained after modifying the skin factor to 3 while keeping the values of the other two parameters constant as estimated in the MRT match. Figure 11 shows pressure vs. time data of numerical model and of actual well in Cartesian coordinates. The y axis is the pressure data with psia unit whereas the x-axis is the time in hours.

For Well A, both models responded similar performance with different values of the skin factor. In the first case, the match had been obtained with $S=0$, which has been adjusted as 2 in the single point test-match. Delta skin is equal to 2. In the second case the skin factor has been estimated as 1 to get a match with the multi rate test data and it has been modified as

3 at the end of the single rate test-match. For both cases Delta skin is 2.

This result should not be interesting when considering the fact that having obtained a set of reservoir parameters that match the actual reservoir response does not mean that those parameters are 100% accurate and same with the unknown actual reservoir parameters. The combinations of these estimated parameters play an important role in history matching to have a reliable numerical model that will represent the actual reservoir.

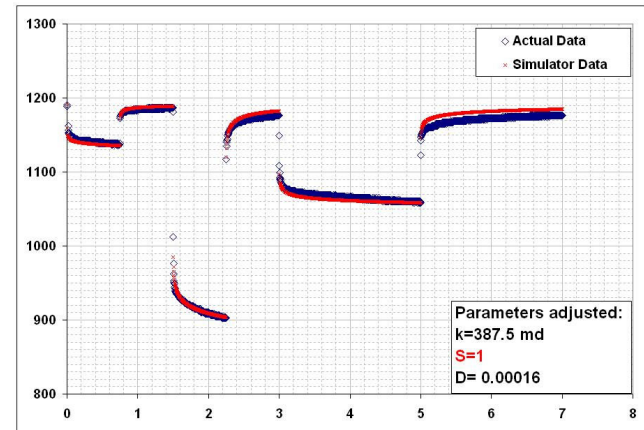


Figure 10: History match of the multi rate test data of the model with the actual data of Well A. (Case 2)

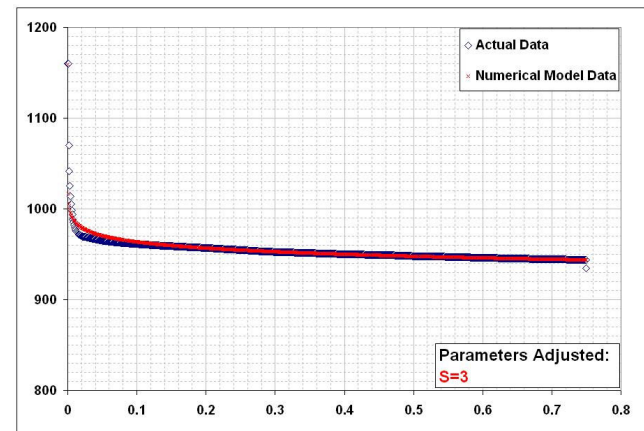


Figure 11: History match of the single rate test data of the model with the actual data of Well A. (Case 2)

Well B

On this well, the multi rate test was performed in October of 1997 and the single rate test in September, 1998. There was a stimulation treatment in 1996. The wellbore radius is 0.3 ft and the thickness is 15 ft. Permeability of the reservoir near to the wellbore ranges from 60 to 75md.

The duration of both tests is same with the tests of Well A and the flow rates change slightly during the flow periods. From the multi rate test's pressure data permeability is calculated as 70 md with analytical analysis. The estimated true skin factor is -1.16 and the non-Darcy factor is 0.00005. LGR is applied to the grid system of the numerical model as

well in order to get more analogous pressure response in/near to the well bore.

After modifications of the parameters, calculated to be used as the initial values of the numerical model, a match was obtained with the actual multi rate test data. Figure 12 shows the pressure match and the adjusted parameters; permeability as 71 md, true skin factor as -0.6 and non-Darcy factor as $2.439\text{E-}5$.

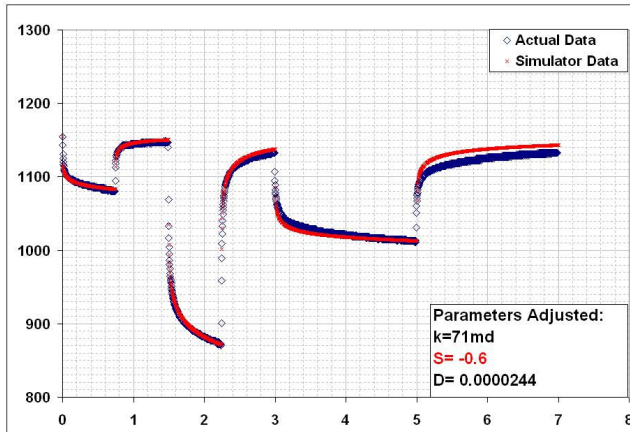


Figure 12: History match of multi rate test data with the actual data of Well B.

In the next step, a single rate test was performed on the numerical model to be matched with the actual SRT data of Well B. Figure 13 shows this match in Cartesian plot with pressure (psia) vs. time (hr) data. The blue line represents the actual well test data. The green line shows the numerical data with the parameters adjusted at the end of the multi point test match. In the previous step, skin factor was modified as -0.6 to get the match. In this step, we could not get it with this value of skin. The red line of the figure was obtained by adjusting the skin factor parameter from -0.6 to 1.3 while keeping the other parameters constant.

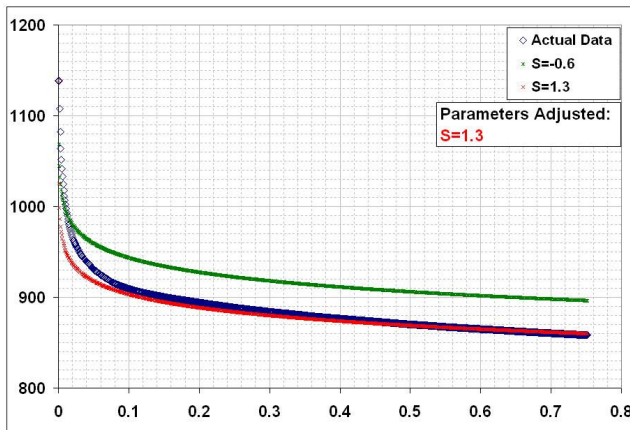


Figure 13: History match of single rate test data with the actual data of Well B.

Conclusions

In this study change in skin with time in a gas storage well is studied. The objective is achieved by introducing the new procedure to enhance the current practices of estimating the

true skin factor from a single rate test data. The new skin factor was compared with the previous value estimated from a multi rate test. The methodology included history matching of the actual multi rate test and then estimation of skin value from single rate test using the history matched model.

The following conclusions may be drawn from this study:

1. This method gives the opportunity to improve the accuracy of the reservoir and well parameters obtained from the analytical well test analysis since it uses those results as the initial parameters of the numerical simulation model, built for history matching.
2. The method was used in two actual well examples. The results showed that estimation of the true skin factor from a single rate test is possible. In one well, two cases studied with different reservoir parameters. Each case gave the same ΔS .
3. The method is verified with two numerical simulation models. Cartesian model was a substitute of a real field and the radial model was built to history match the data with the Cartesian data. Skin factor of the Cartesian model was changed from multi rate test value to another in the single rate test. This change is ΔS_1 . The radial model's skin factor modified from its multi rate test value to match the single rate test data. This change in the skin is ΔS_2 . In this study it has been verified that:

$$\Delta S_1 = \Delta S_2$$
The technique gave the same ΔS values on the two cases. The accuracy and consistency of the method is verified.
4. The estimation of the reservoir parameters by analytical analysis in the presence of heterogeneity is studied. It is shown that the accuracy of the estimation depends on the existence of stabilized pressure at the beginning of the each drawdown period of the multi rate test and the assumption that the reservoir should be homogeneous in order to get the correct results. The change in the permeability near the wellbore may cause extra pressure drop in the numerical simulation model, and can be resulted in extra skin effect.
5. Keeping the non-Darcy factor constant may be a limitation on this study but some previous works showed that it can be constant under low-drawdown wells.

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Table 5: Summary of the heterogeneous case of verification part.

Cartesian Model	Input Parameters	Analytical Analysis	Input for SPT	$\Delta S = 1.5 - 1.28$ $\Delta S = 0.22$
Permeability, md	Non-uniform, avg= 90	Avg= 100	Non-uniform	
Skin factor	1.28	2.69	1.5	
Non-Darcy Factor	9.00E-05	2.00E-04	9.00E-05	
Radial Model	Input Parameters	Parameters adjusted(MPT)	Match of SPT	$\Delta S = 3.17 - 2.95$ $\Delta S = 0.22$
Permeability, md	100	95	95	
Skin factor	2.69	2.95	3.17	
Non-Darcy Factor	2.00E-04	1.90E-04	1.90E-04	