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PRESSURE TRANSIENT BEHAVIOUR OF A HORIZONTAL STEAM INJECTION WELL IN A NATURALLY FRACTURED RESERVOIR

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ABSTRACT

Naturally fractured reservoirs constitute majority of the reservoirs documented on earth. Tectonic activities on earth have produced widespread natural fractures which properties should be accounted for in reservoir simulation. The intrinsic properties of naturally fractured reservoirs make accurate simulation of the reservoir challenging and still have been a topic of discussion. Studying the pressure and pressure-derivative behaviour of a well has been proven in literature to be an accurate method for reservoir characterization and reservoir evaluation. The pressure transient behaviour of vertical and horizontal production wells has been well researched and presented in literature but little information exist on the pressure transient behaviour of a horizontal steam injection well in a naturally fractured reservoir. Therefore, this paper focuses on the pressure transient behaviour of a horizontal steam injection well in a naturally fractured reservoir to accurately characterize the reservoir. Simulation studies are conducted using Computer Modelling Group (CMG) software, STARS, a thermal recovery simulator. A base model of a horizontal steam injection well in a dual porosity reservoir is constructed and the pressure transient behaviour is studied through parameter variation. Results show that we can observe a radial flow regime, followed by a downward dip due to the gas injection, another downward dip due to the dual porosity storativity and finally pseudoradial flow due to the pressure transient reaching the boundary. The negative or close to negative pressure-derivative observed in the first downward is due to the high compressibility nature of steam. The presence of steam injection and the dual porosity may mask other flow regimes in the model and further test designs could be constructed in the future to further study the pressure transient behaviour of a horizontal steam injection well in a naturally fractured reservoir.

Keywords: naturally fractured reservoir, dual porosity, steam injection, horizontal well, closed boundary.

1. INTRODUCTION

Most of the reservoirs on Earth are most likely to contain natural fractures and they are complex systems to characterize to engineers [1]. This makes it imperative to be able to characterize and understand the complex and irregular systems of a naturally fractured reservoir. The numerical and mathematical calculations depicting a naturally fractured reservoir are a challenge as its characterization is complex. The fractures and matrix of a naturally fractured reservoir have intrinsic properties compared to a single continuum reservoir. The matrix to fracture interactions also must be considered and characterize to properly model and evaluate naturally fractured reservoirs [2]. The application of pressure transient testing allows the reservoir to be described and the productivity evaluated. The pressure transient behaviour of steam injection wells in horizontal and vertical wells in a homogeneous reservoir has been well researched in literature. However, the pressure transient behaviour of a steam injection well in naturally fractured reservoirs has not been fully studied. This leaves a gap in understanding and fully characterizing reservoirs with natural fractures and a single horizontal steam injection well. Successful characterization of naturally fractured reservoirs penetrated by the steam injection well through pressure and pressure-derivative data will lead to the accurate identification of its performance with steam injection. The successful characterization of naturally fractured reservoirs with steam injection would be monumental as the majority of the reservoirs on Earth have fracture networks, with also steam injection potentially being an efficient and effective method in heavy crude oil recovery [3].

This study focuses on naturally fractured reservoirs, as they make up a large portion of the reservoirs on earth. The reservoir model is a dual porosity, closed boundary reservoir with heavy oil, requiring thermal recovery. Therefore, this project will focus on steam injection. The steam will be introduced into the reservoir through a horizontally penetrating well.

The purpose of this work is to study the pressure and pressure-derivatives of a horizontal steam injection well in a naturally fractured reservoir and to characterize a naturally fractured reservoir penetrated by a horizontal steam injection well.

2. BACKGROUND

A. Naturally fractured reservoirs

The characterization of naturally fractured reservoirs falls behind that of a single porosity continuum due to the practical difficulty of evaluating matrix and fracture parameters [2]. There exist complexities in developing naturally fractured reservoir models due to the need to consider the properties of the matrix and the fractures as well as their interactions. The dynamics and mechanisms that surround the naturally fractured systems of a reservoir are dissimilar to that of a reservoir with single porosity. Due to the presence of dual porosity and dual permeability in natural fractures, the properties of a naturally fractured reservoir is significantly different from single-porosity and permeability reservoirs, a multitude of

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factors must be considered [4]. In Dean and Lo's [4] study, even though that the fracture systems vary in the rock often the fractures in the region are assumed to be well-connected and that the network of the fractures behaves as an equivalent porous medium.

Dean and Lo [4] also in their study stated that the natural fractured systems are best classified and characterized using fractal geometry despite not yet establishing a strong relation between fractured system and fractals. However, the classification of naturally fractured reservoirs using fractal geometry is increasingly gaining support. Studies conducted by Baker and Kuppe[2] in characterizing naturally fractured reservoirs include utilizing the Geological Approach where the method characterizes the reservoir based on the perspective on the creation and causation of the geological settings. They also utilized the Engineering Approach where the properties of the fracture networks are understood using permeability and storativity data from production and pressure transient data. Combination of the two techniques is reported to give a more accurate characterization of the reservoir [2].

B. Well test interpretation

A well test is conducted to record the data of the well during production. The data is then used to evaluate the reservoir characteristics. The data obtained during the transient flow is then recorded and analyzed to describe the flowing behaviour of the reservoir. Bourdet *et al.* [5] proposed using the pressure-derivatives recorded to interpret and evaluate the reservoir as the response is considered to be more complete. The log of the pressure-derivatives stresses on the flow regime of the transient radial flow, which is the primary interest in conducting transient pressure tests. A better representation is also obtained using the pressure-derivative as the term is present in the diffusivity equation. Wei [6] also reports that the pressure-derivatives can better represent the nature of naturally fractured reservoirs, where the permeability of the natural fractures has a much higher permeability value compared to that of the permeability of the matrix. Wei [6] used pressure-derivatives in investigating the properties of complex fracture networks to predict and characterize their behaviour as conventional plots may not define intricacies as accurately as reported by Bourdet *et al.* [5] in 1989.

The effects of wellbore storage are seen during the early time in the pressure-derivative type curve when the well is produced after shut-in. The effects dominate the early time region as fluids in the wellbore enters the wellhead during production after the shut-in period. The wellbore storage effects are seen as a unit slope line on the log-log pressure plot to time as seen on Figure-1. The characteristics shape of the various flow regimes and conditions are also shown in Figure-1, where radial flow pattern is illustrated by a horizontal line (zero slope). If the reservoir has a constant pressure boundary, then the flow regime is steady-state and the slope at the late time will be a continuously falling line [5].

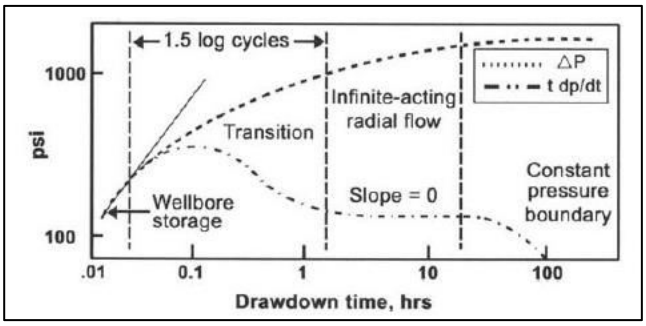

Figure-1. Log-log pressure and pressure-derivative plot [5].

After the wellbore storage effects, the pressure derivate behaviours form a second asymptote when the transient phase begins. The region between the two straight asymptotes is the transition region. As a straight line is produced during the transient radial flow in the log-log pressure-derivative graph, the pressure-derivative plot can replace the conventional pressure plot to determine the transmissibility of the formation. The pressure-derivative curve shows a more unique and specific curve shape compared to the pressure curves produced from the conventional pressure plot, which makes the pressure-derivative more accurate in mapping the reservoir characteristics. Therefore, refinements and adjustments are not needed as the wellbore storage effects and the transient radial flow curve is unique, making the curve match more direct and the analysis process more simplified [5].

Upon matching the constant-derivative part of the data, the transmissibility value can be determined. The matching of the well bore storage data on the asymptote on the type curve allows us to determine the wellbore storage value *C* and the dimensionless wellbore storage coefficient can help us determine the skin factor, *S*. The transient well test analysis using the pressure-derivative leads to a more accurate representation of the reservoir as the curves produced and the intricacies of the slope behaviour is more defined compared to conventional pressure plots. The intricacies mentioned are often ignored in conventional pressure plots as they are not obvious. The improved sensitivity of the pressure-derivative analysis leads to a more accurate reservoir characterization and interpretation [5].

C. Pressure transient behaviour in horizontal wells

Horizontal wells are increasingly becoming popular as they can increase the well productivity. A horizontal well in a reservoir with natural fractures can be very beneficial as it can reach much more fissures and fracture networks compared to a vertically well [7]. This sparked interest in the study of pressure transient behaviour in horizontal wells with the increase of horizontal drilling. However, well test data interpretation is complex with horizontal wells due to their complicated geometry. Lichtenberger [8] acknowledges pressure transient analysis as one of the more accurate methods in characterization and description of vertical and horizontal wells. Lichtenberger [8] also found in his research that

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horizontal wells display dominant regimes such as linear and radial flow through pressure transient analysis conducted. During early time flow, the transient pressure behaviour of a vertical well is similar to that of a horizontal well. This is due to the similar physics surrounding flow between two parallel boundaries by the horizontal and vertical well.

In Figure-2, we can observe the general flow patterns of a horizontal well. We can observe that the horizontal well exhibits some flow regimes that are similar to vertical wells. At early times, fluid flows into the wellbore in a vertical radial manner, where fluid flow converges after wellbore storage effects ends. As time passes, flow becomes linear which shows a half-slop on the derivative plot instead of a unit slope during radial flow. After that, the fluid flow into the wellbore becomes pseudo-radial, or horizontal radial. Lichtenberger [8] states the horizontal well is synonymous with a vertical well having vertical fractures during this period.

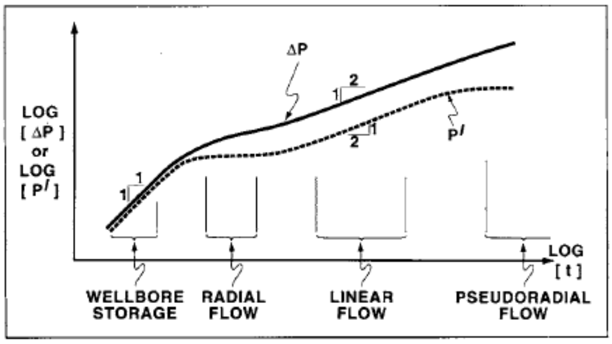

Figure-2. Dimensionless pressure of vertical and horizontal wells [19].

D. Pressure transient analysis of dual porosity reservoirs

Reservoirs with natural fractures differ from conventional reservoirs due to the presence of dual porosity. The pressure-derivative of the dual porosity reservoir is different from the single porosity reservoir. Bourdet *et al.* [5] studied two models of reservoirs with dual porosity nature, the pseudosteady-state interporosity flow and transient interporosity flow and the transient pressures produced.

For the pesudosteady-state interporosity model, Bourdet*et al.* [5] observed that the transition period of the pressure-derivative curve becomes a very noticeable drop as shown in Figure-3, instead of a flattened straight line as observed in single porosity reservoirs.

In the pseudosteady-state interporosity model, the transition flow becomes the early transition and late transition states, where they are represented by dimensionless properties. If there are wellbore storage effects during the early transition period, the pressure-derivative response will deviate from the curve produced from the corresponding dimensionless parameter. However, the wellbore storage effect diminishes during the late transition period, and the pressure-derivative curve obtains an accurate match as seen in Figure-3 [5]. The results from Bourdet *et al.* [5] are consistent with the research of Xingping *et al.* [9] as seen in Figure-4. Xingping *et al.* [9] results show that transient flow period of a double porosity reservoir is represented by a concave decreasing drop. The pressure-derivative pattern then becomes a horizontal straight line, representing the total fluid flow of the matrix and fracture.

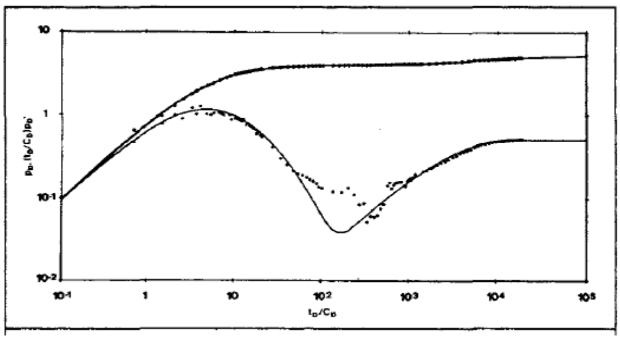

Figure-3. Pressure-derivative curve for different geometry blocks for Pseudosteady-state Interporosity Flow [5].

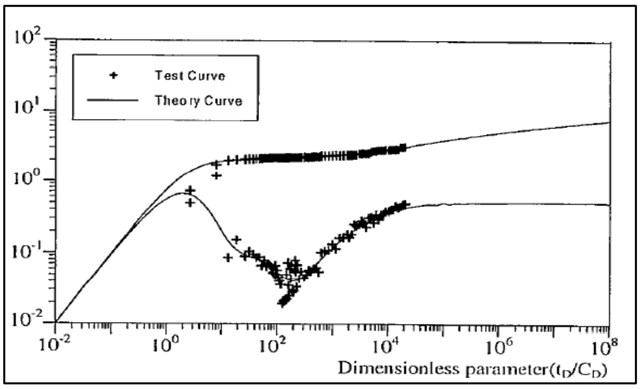

Figure-4. Matching pressure curves of double porosity data [9].

For the model with transient interporosity flow, the pressure-derivative curve obtained shows a different result compared to the single porosity and pseudosteady interporosity flow. In Figure-5, we can observe that the pressure-derivative in the transition period becomes almost horizontal line with a constant derivative value. The curve from the drawdown response does not decrease below the constant derivative value [5]. For spherical matrix blocks, the pressure-derivative line remains above the constant derivative value while for slab matrix blocks the pressure- derivative line is at tangent to the constant derivative value of 0.25 for a certain period of time.

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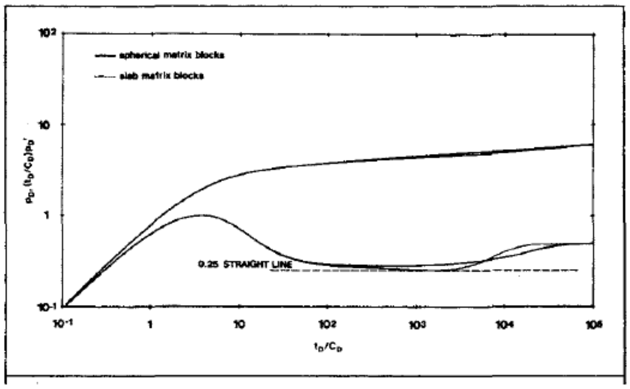

Figure-5. Pressure-derivative curve for different geometry blocks for transient interporosity flow [5].

The utilization of pressure-derivative in double porosity reservoirs highlights the intricacies in the minute pressure changes as observed by Bourdet *et al*. [5] and Xingping *et al*. [9]. This allows for more define reservoir characterization and the time limits of each flow also can be determined. The pseudosteady-state model is typically used when the transition period is long. The result produced might be ambiguous for short transition periods, where the pseudosteady-state model can produce similar results as the transient-state model [5].

3. METHOD

In this project, a model that can represent naturally fractured reservoirs as accurately as possible in order to study pressure and pressure-derivative data for reservoir characterization is produced. The model is a closed bounded dual porosity dual permeability reservoir penetrated by a horizontal steam injection well. The modeling application used in this project is Computer Modeling Group (CMG) with BUILDER, a pre-processing model building application and STARS, simulation software for thermal enhanced oil recovery covering heat transfer and fluid flow. Tables 1 to 4 show the rock and fluid properties adopted from CMG heavy oil reservoir model template.

Table-1. Model properties.

Property	Value
Grid Top	1000ft
Grid Thickness	20ft
Matrix Porosity, φ_{matrix}	0.29
Fracture Porosity, φ_f	0.01
Permeability I and J direction, k_{matrix}	0.1md
Permeability K direction, k_{matrix}	0.1md
Fracture Permeability I and J direction, $k_{fracture}$	1000 md
Fracture Permeability Z direction, $k_{fracture}$	1000 md
Fracture Spacing I,J,K direction	10 ft
Oil Saturation	0.8
Oil Saturation - Fracture	0.8
Temperature	120 °F
Matrix Compressibility, C_{matrix}	3e-006 psi-1
Fracture Compressibility. C_{frac}	3e-006 psi-1
Wellbore Radius, r_w	0.28

Table-2. Liquid phase viscosities of model components.

Temperature (°F)	**Water viscosity** (Aqueous, cp)	**Oil viscosity** (Oleic, cp)
75	0	5780
100	0	1380
150	0	187
200	0	47
250	0	17.4
300	0	8.5
350	0	5.2
500	0	2.5
800	0	2.5

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Table-3. Water-oil relative permeability tables.

S_w	K_{rw}	K_{row}
0.45	0.000000	0.40000
0.47	0.000056	0.36100
0.50	0.000552	0.30625
0.55	0.00312	0.22500
0.60	0.00861	0.15625
0.65	0.01768	0.10000
0.70	0.03088	0.05625
0.75	0.04871	0.02500
0.77	0.05724	0.01600
0.80	0.07162	0.00625
0.82	0.08229	0.00225
0.85	0.10000	0.00000

Table-4. Liquid-gas (Liquid Saturation) relative permeability tables.

S_l	K_{rg}	K_{rog}
0.45	0.20000	0.00000
0.55	0.14202	0.00000
0.57	0.13123	0.00079
0.60	0.11560	0.00494
0.62	0.10555	0.00968
0.65	0.09106	0.01975
0.67	0.08181	0.02844
0.70	0.06856	0.04444
0.72	0.06017	0.05709
0.75	0.04829	0.07901
0.77	0.04087	0.09560
0.80	0.03054	0.12346
0.83	0.02127	0.15486
0.85	0.01574	0.17778
0.87	0.01080	0.20227
0.90	0.00467	0.24198
0.92	0.00165	0.27042
0.94	0.00000	0.30044
1.00	0.0000	0.40000

4. RESULTS AND DISCUSSIONS

A. Horizontal producer well in a naturally fractured reservoir

In analysing the pressure transient behaviour, a horizontal producer well is first constructed in a naturally fractured reservoir. From Figure-6, we can observe that the model exhibits radial flow regime in the middle time region. After the radial flow period, we can observe a dual porosity marker, which is characterized by a downward dip before transitioning into the pseudosteady-state flow regime as depicted by the unit slope line, when the pressure transient has reached the boundary. This agrees with the study of Xingping *et al.* [9], as we can observe a similar flow regime pattern in Figure-7.However, the model used by Xingping *et al.* [9] is an infinite-acting model, where we can observe a pseudo-radial flow instead of a pseudosteady-state flow as the pressure transient will not reach the boundary in an infinite-acting model.

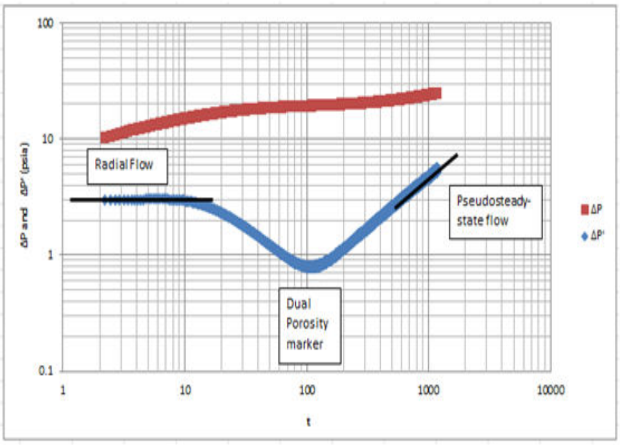

Figure-6. Pressure and pressure-derivative values for a horizontal producer well in a NFR.

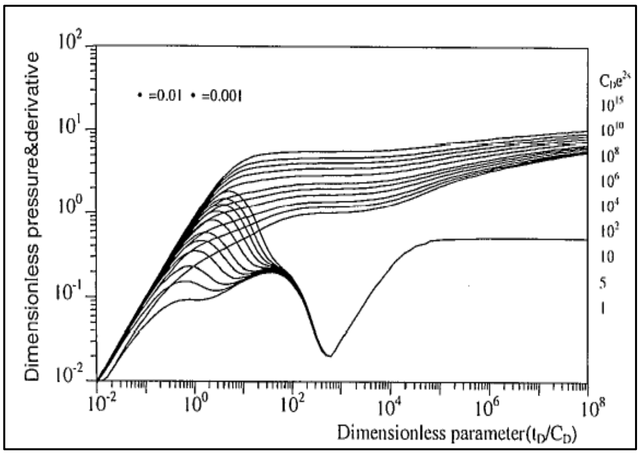

Figure-7. Pressure and pressure-derivative type curves for a horizontal well in an infinite reservoir [9].

B. Horizontal water injection well in a naturally fractured reservoir

In Figure-8, we can observe a similar pressure and pressure transient behaviour for a horizontal water injection well instead of a producer well. This flow regime is similar in that of Figure-7, where we can observe the dual porosity marker as well as the pseudosteady-state flow regime as a result of the pressure transient reaching the boundary.

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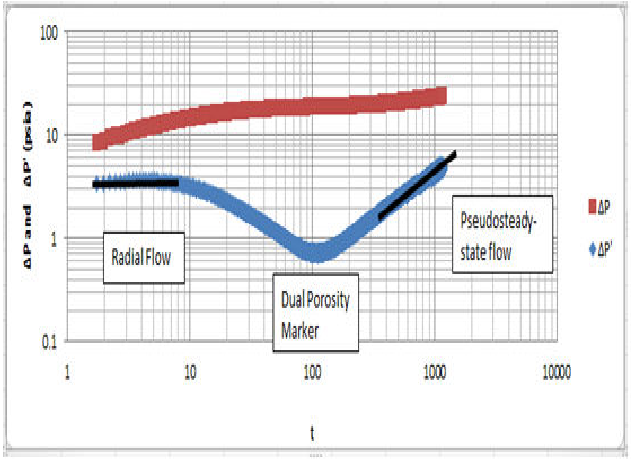

Figure-8. Pressure and pressure-derivative values for a horizontal water injection well in a NFR.

C. Horizontal steam injection well in a single porosity reservoir

Analysis of Figure-9 shows that when steam is injected through a horizontal well in a single porosity reservoir, the dual porosity marker becomes absent as predicted. We can also observe that the pressure-derivative plot becomes negative after the radial flow regime. This agrees with the findings of Habte *et al*. [10], of which the pressure-derivative reports negative values when gas is injected during implementation of Water-Alternating-Gas (WAG) into a single porosity reservoir. The paper stated that the high mobility and compressibility of the gas made it easier to be injected with minimal pressure loss in the wellbore due to expansion of the gas. As time passes, the high compressibility of the gas causes pressure to decrease leading to negative pressure-derivative values as observed in Figure-10.

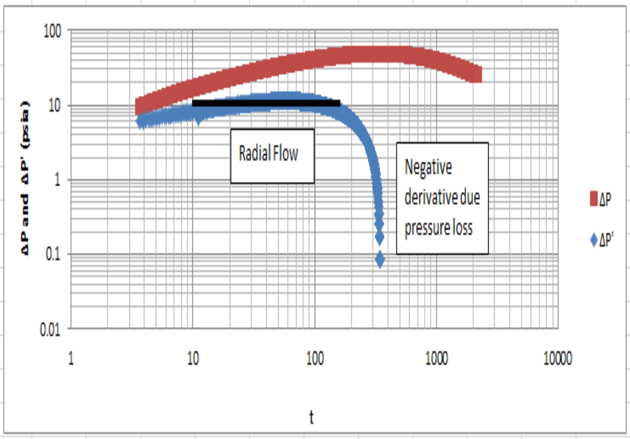

Figure-9. Pressure and pressure-derivative values for a horizontal steam injection well in a single porosity reservoir.

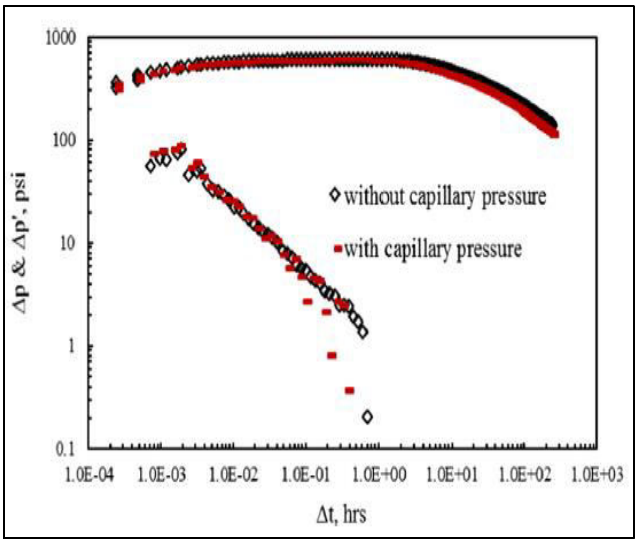

Figure-10. Pressure and pressure-derivative values for gas injection [10].

D. Horizontal steam injection well in a naturally fractured reservoir

In Figure-11, we can observe some noticeable changes in the pressure-derivative plot compared to Figure- 8 (water injection in a NFR) when steam is injected into the naturally fractured reservoir. The radial flow regime observed in Figure-8 is replaced by a shorter radial flow regime and a downward dip, followed by the dual porosity marker characterized by a downward dip, before entering into pseudosteady-state flow when the pressure transient has reached the boundary. The initial downward dip is due to the compressibility and mobility of gas, as observed and discussed earlier in Figure-9, coherent with the findings of Habte *et al.*[10]. From Figure-11, it can also be observed that the radial flow regime is not apparent as it is masked by the downward dips caused by gas injection and the dual porosity nature of the reservoir.

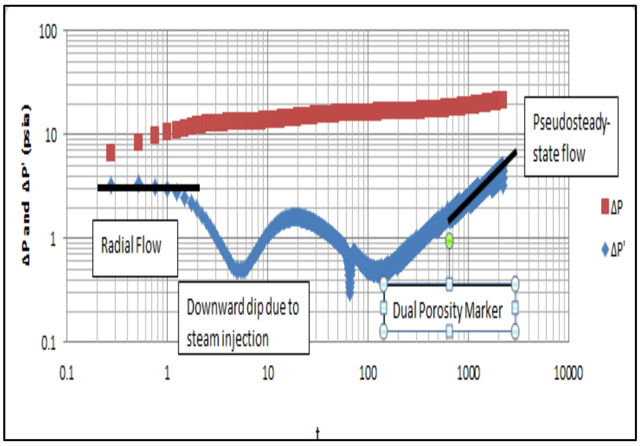

Figure-11. Pressure and pressure-derivative values for a horizontal steam injection well in a NFR.

From the pressure-derivative, we can obtain the permeability value through the formula:

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$$\Delta P' = 70.6 \frac{qB\mu}{kh} \quad (1)$$

Where q is the flowrate (stb/day), B is the oil formation volume factor (bbl/stb), μ is the viscosity (cp), k is the permeability (md) and h is the formation thickness (ft). The pressure-derivative value during radial flow is 3 psia.

Q = 1 stb/day
B =1.02 bbl/stb
μ = 902 cp
h= 20 ft

$$3 = 70.6 \frac{(1)(1.02)(902)}{k(20)}$$

k = 1082.58 md

The value of the permeability obtained is almost similar to the input value of the matrix permeability, which is 1000 md.

E. Horizontal steam injection well in a naturally fractured reservoir with varying storativity ratio values

In Figure-12, we can observe the effects of varying the fracture porosity of the NFR model as presented in Table-5, with the total porosity of the model being 0.30. As the storativity ratio, ω decreases it increases the size of the downward dip. This agrees with the findings of Fekete[11], as observed in Figure-13. As the ω approaches 1, the downward dip gradually disappears and the properties of the reservoir gradually approach that of a single porosity reservoir.

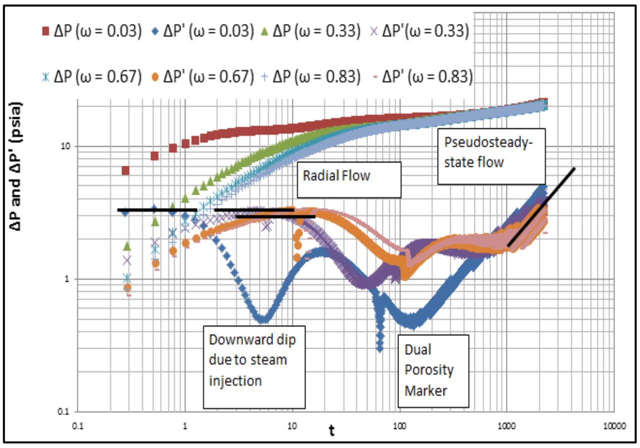

Figure-12. Pressure and pressure-derivative values for a horizontal steam injection well in a NFR with fracture porosity variation.

Storativity ratio:

$$\omega = \frac{\varphi_f C_{frac}}{\varphi_f C_{frac} + \varphi_{matrix} C_{matrix}} \quad (2)$$

Table-5. Fracture porosity and storativity ratio values.

Fracture porosity	Storativity ratio, ω
0.01	0.03
0.10	0.33
0.20	0.67
0.25	0.83

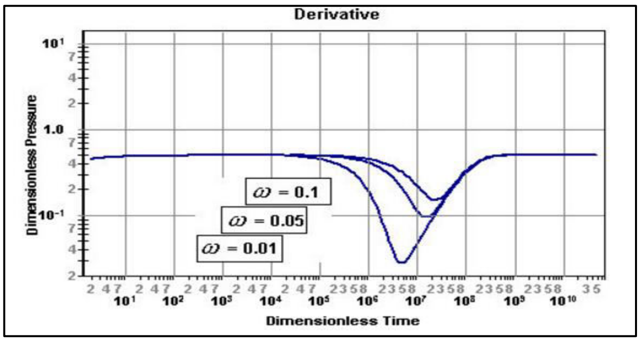

Figure-13. The effect of storativity ratio on dimensionless pressure [11].

F. Horizontal steam injection well in a naturally fractured reservoir with varying interporosity flow coefficient values by varying fracture spacing

In Figure-14, we can observe the effects of varying the Fracture Spacing of the NFR model as presented in Table-6. As the Interporosity Flow Coefficient value, λ increases the downward dip due to the dual porosity feature gradually shifts to the left. This agrees with the findings of Fekete [11] as observed in Figure-15. In Figure-15, it can be seen that a change in the λ value shifts the position downward dip due to the dual porosity feature. Whereas, the downward dip due to the gas injection also shifts to the left and the pressure-derivative value becomes positive as λ increases, showing the full dip feature. In this section, the value of λ is controlled by the fracture spacing, which has an inversely proportional relationship with shape factor, α. As the fracture spacing increases, the fracture networks become less and it gradually resembles a single porosity reservoir. The negative pressure-derivative value observed in Figure-14 is similar to the negative pressure value observed in the pressure-derivative plot of the horizontal steam injection well in a single porosity reservoir, where steam is injected into a single porosity reservoir model.

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Table-6. Fracture porosity and storativity ratio values.

Fracture spacing, x y z (ft)	**Shape Factor, α**	**Interporosity flow coefficient, λ**
25 25 20	0.023	4.468 x 10-7
15 15 10	0.076	1.481 x 10-7
10 10 10	0.12	2.352 x 10-7
5 5 5	0.48	9.408 x 10-7

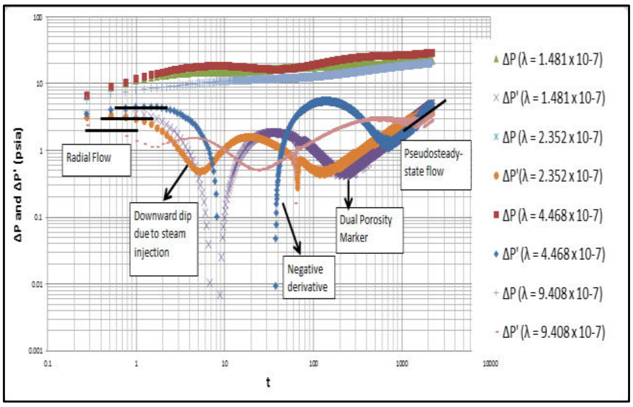

Figure-14. Pressure and pressure-derivative values for a horizontal steam injection well in a NFR with fracture spacing variation.

Shape Factor, α:

$$\alpha = 4 \times \left(\frac{1}{L_x^2} + \frac{1}{L_y^2} + \frac{1}{L_z^2}\right) \quad (3)$$

Interporosity Flow Coefficient, λ:

$$\lambda = \alpha \times r_w^2 \left(\frac{k_{matrix}}{k_{fracture}}\right) \quad (4)$$

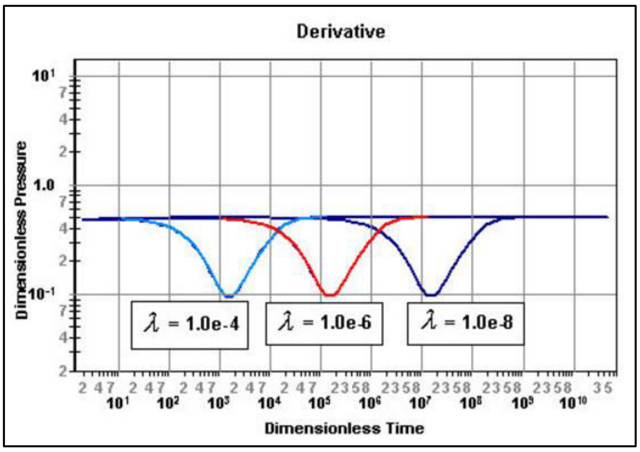

Figure-15. The effect of interporosity flow coefficient on dimensionless pressure [11].

G. Horizontal steam injection well in a naturally fractured reservoir with varying interporosity flow coefficient values by varying fracture permeability

In Figure-16, we can observe the effects of varying the Fracture Permeability of the NFR model as presented in Table-7. As the λ increases the downward dip due to the dual porosity feature gradually shifts to the left. However, the shift here is not obvious as the fracture permeability affects the change in pressure as well, giving different pressure change and pressure-derivative values. Whereas, the downward dip due to the gas compressibility becomes negative as the fracture permeability increases. According to Habte *et al.* [10], their findings have stated that the negative pressure-derivative value is due to the decrease in pressure-drop over time from the compressible gas. As the fracture permeability increases, more gas is able to flow around the reservoir easily, and pressure will increase rapidly during early injection times. The higher and faster increase in pressure will lead to decreasing pressure loss in the wellbore over time, which leads to the negative pressure-derivative value observed in the Figure-16.

Table-7. Fracture permeability and interporosity flow coefficient.

Fracture permeability, k_f (md)	**Interporosity flow coefficient, λ**
10000	2.352 x 10-8
1000	2.352 x 10-7
100	2.352 x 10-6

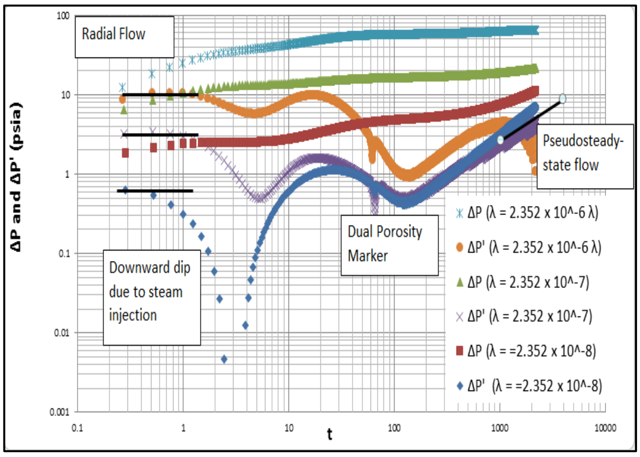

Figure-16. Pressure and pressure-derivative values for a horizontal steam injection well in a NFR with fracture permeability variation.

5. CONCLUSIONS

The pressure transient behaviour of a horizontal steam injection well in a closed boundary dual porosity naturally fractured reservoir was investigated in this study. The characterization and evaluation of naturally fractured

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reservoirs with steam injection presents a complex challenge as there is a need to model the fracture networks and the matrix. It was found that the compressibility of the steam and the dual porosity nature of the reservoir is quite dominant on the derivative plot. When steam is injected, the downward dip shown on the derivative plot is due to the compressibility of the steam as more steam is injected over time. The high mobility and ease of steam travelling through the reservoir lead to decreasing pressure loss condition in the wellbore.

In the pressure-derivative plot of a horizontal steam injection well in a naturally fractured reservoir, the radial flow regime is identified in the middle time region, followed by a downdip or in some cases a negative pressure-derivative due to steam injection. After that, another downdip is observed, which is the characteristic of a dual porosity reservoir, followed by pseudosteady-state flow regime (unit slope line) as the pressure transient reaches the reservoir boundary. During the radial flow regime the permeability is obtained which gives a value of 1000 md, similar to the fracture permeability input. The effects of steam injection and the dual porosity feature is found to be dominant in the derivative plot, which may mask or hide other flow regimes which are supposed to be seen on the derivative plot.

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