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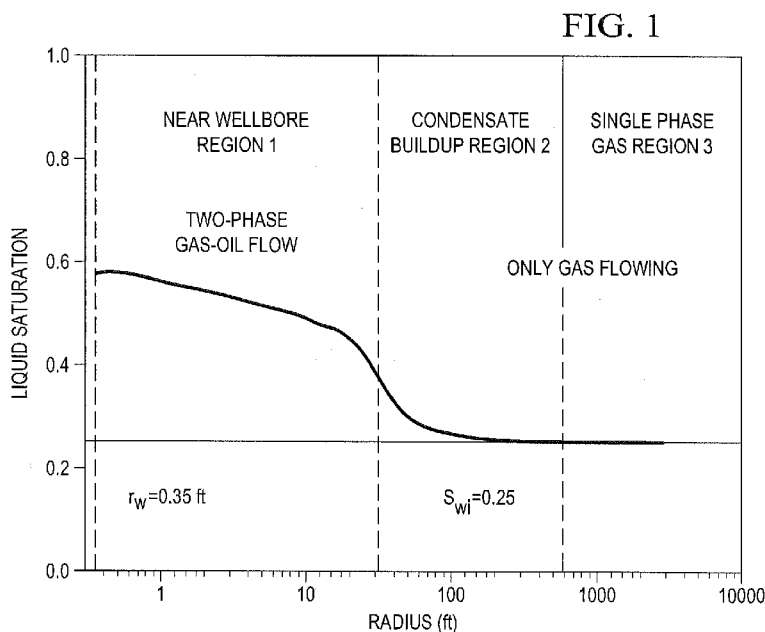
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(57) Abstract: Multiphase flow behavior in gas condensate reservoirs is analyzed, and in particular estimating gas condensate well deliverability. Inflow performance relationship (IPR) measures for gas condensate wells are analytically generated and made available. The inflow performance relationship measures of gas condensate wells incorporate the effect of condensate banking as pressure near the well bore drops below the dew point. The inflow performance relationship measures are based on formation rock relative permeability data and Constant Composition Expansion (CCE) experiment data.

PATENT APPLICATION**INVENTOR: ALI M. AL-SHAWAF****ATTORNEY DOCKET: 04159.715109****PREDICTING PERFORMANCE OF GAS CONDENSATE RESERVOIRS****Cross Reference To Related Applications:**

[0001] This application claims priority from U.S. Provisional Application No. 61/724,534, filed November 9, 2012 and U.S. Non-Provisional Application No. 13/888,123, filed May 6, 2013.

BACKGROUND OF THE INVENTION**1. Field of the Invention**

[0002] The present invention relates to reservoir analysis of performance of subsurface hydrocarbon reservoirs, and more particular to prediction of the performance of gas condensate reservoirs.

2. Description of the Related Art

[0003] Gas condensate reservoirs differ from dry gas reservoirs. Understanding the phase and fluid flow behavior relationships has been required in order to make accurate engineering computations for gas condensate systems. Condensate dropout occurs in the reservoir as the pressure falls below the dew point. As a result of such condensate dropout, gas phase production from gas condensate wells decreases significantly.

[0004] Well productivity is an important issue in the development of most low and medium permeability gas condensate reservoirs. Liquid build up around the well has been found to cause a significant reduction in productivity, even in lean gas condensate reservoirs where the maximum liquid drop out indicated by test data is as low as 1%. However,

accurate forecasts of gas condensate productivity has been difficult because of the need to understand and account for complex processes that occur in the near-well region.

[0005] The production performance of a gas condensate well is easy to predict as long as the well flowing bottomhole pressure (known as FBHP) is above the initial reservoir fluid dew point pressure. The gas condensate well production performance in such conditions is similar to a dry gas well.

[0006] Once the FBHP of a gas condensate well falls below the dew point, the well performance starts to deviate from that of a dry gas well. With pressure below the dew point, condensate begins to drop out, beginning first near the wellbore. Immobile initially, the liquid condensate accumulates until a critical condensate saturation (known as the minimum mobile condensate saturation) is reached. This rich liquid zone grows outward deeper into the reservoir as reservoir depletion continues.

[0007] Estimates have been made of the productivity of gas condensate reservoirs. So far as is known, none of these estimation methods have been simple to use. Some estimation methods required use of modifications required to be made in the finite difference simulation processing of reservoir data. Other estimation methods have used simulation models of reservoir component gases and their pressures and states during projected reservoir life, which required simplification by certain assumptions. The estimates were thus accurate only if the simplifying assumptions were sound.

SUMMARY OF THE INVENTION

[0008] Briefly, the present invention provides a new and improved computer implemented method of obtaining measures in a data processing system of predicted performance of a gas condensate well in a subsurface reservoir. Component composition expansion data based on measurements from fluid from the well is received in the data processing system. Relative

permeability data regarding formations containing the gas condensate of the well is also received, as well as bottom hole pressure data of the well. A measure of dew point of gas condensate in the well based on the component composition expansion data is obtained by the data processing system, and the data processing system determines if the bottom hole pressure of the well is above the dew point of the gas condensate of the well. If not, an estimated productivity index of the gas condensate well is formed for single phase flow of the well; and an estimated productivity index of the gas condensate well is formed for two phase flow of the well. An estimated predicted performance of the well is then formed as a function of formation relative permeability and the estimated productivity index of the gas condensate well for two phase flow. If the bottom hole pressure of the well is above the dew point of the gas condensate of the well a measure of borehole pressure of the well is obtained and an estimated predicted performance of the well as a function of borehole pressure and relative gas permeability of the well is formed in the data processing system. The estimated predicted performance of the well is then assembled.

[0009] The present invention also provides a new and improved data processing system for obtaining measures of predicted performance of a gas condensate well in a subsurface reservoir. The data processing system includes a processor which receives component composition expansion data based on measurements from fluid from the well, relative permeability data regarding formations containing the gas condensate of the well, and bottom hole pressure data of the well. The processor obtains a measure of dew point of gas condensate in the well based on the component composition expansion data, and determines if the bottom hole pressure of the well is above the dew point of the gas condensate of the well. If not, the processor forms an estimated productivity index of the gas condensate well for single phase flow of the well, and also forms an estimated productivity index of the gas condensate well for two phase flow of the well. The processor further forms an estimated

predicted performance of the well as a function of formation relative permeability and the estimated productivity index of the gas condensate well for two phase flow. If the bottom hole pressure is above the dew point, the processor obtains a measure of borehole pressure of the well, and forms an estimated predicted performance of the well as a function of borehole pressure and relative gas permeability of the well. The processor then assembles in memory the estimated predicted performance the well. An output display of the data processing system forms a display of selected ones of the determined measure of estimated predicted performance of the well.

[0010] The present invention also provides a new and improved data storage device having stored in a computer readable medium computer operable instructions for causing a data processing system to obtain measures in a computer system of predicted performance of a gas condensate well in a subsurface reservoir. The instructions stored in the data storage device cause the data processing system to receive component composition expansion data based on measurements from fluid from the well; relative permeability data regarding formations containing the gas condensate of the well; and bottom hole pressure data of the well. The instructions stored in the data storage device cause the data processing system to obtain a measure of dew point of gas condensate in the well based on the component composition expansion data, and determine if the bottom hole pressure of the well is above the dew point of the gas condensate of the well. If the bottom hole pressure of the well is not above the dew point, the instructions cause the data processing system to form an estimated productivity index of the gas condensate well for single phase flow of the well, then form an estimated productivity index of the gas condensate well for two phase flow of the well and form an estimated predicted performance of the well as a function of formation relative permeability and the estimated productivity index of the gas condensate well for two phase flow. If the bottom hole pressure of the well is above the dew point, the instructions cause

the data processing system to obtain a measure of borehole pressure of the well, and form an estimated predicted performance of the well as a function of borehole pressure and relative gas permeability of the well. The instructions then cause the data processing system to assemble in memory the estimated predicted performance the well.

BRIEF DESCRIPTION OF THE DRAWINGS

- [0011] Figure 1 is a plot of flow behavior in a gas condensate well.
- [0012] Figure 2 is a plot of constant composition expansion data for synthetic gas condensate compositions.
- [0013] Figure 3 is a diagram of a fine scale radial simulation model for a well.
- [0014] Figure 4 is a plot of a group of sets of Corey relative permeability curves.
- [0015] Figure 5 is a plot of well productivity index as a function of time.
- [0016] Figure 6 is a plot of oil saturation profiles around a well as a function of time.
- [0017] Figure 7 is a plot of gas relative permeability as a function of productivity index ratio for a rich condensate fluid.
- [0018] Figure 8 is a plot of gas relative permeability as a function of productivity index ratio for a lean condensate fluid.
- [0019] Figure 9 is a comparative plot of well productivity index as a function of time for rich and for lean condensate fluids.
- [0020] Figure 10 a plot of productivity index ratios of rich versus lean condensate fluids.
- [0021] Figure 11 is a plot of pseudopressure as a function of gas production rate for several reservoir pressures.

[0022] Figure 12 is a plot of bottomhole pressure as a function of gas production rate for several reservoir pressures.

[0023] Figure 13 is a plot of inflow performance relationship for an example reservoir pressure.

[0024] Figure 14 is a plot illustrating threshold saturation in tight relative permeability curves.

[0025] Figure 15 is a plot of oil saturation distribution as a function of various bottomhole pressures for an example reservoir pressure.

[0026] Figure 16 is a plot of inflow performance relationship for another example reservoir pressure.

[0027] Figure 17 is a plot of pseudopressure as a function of gas production rate for an example reservoir pressure.

[0028] Figure 18 is a plot of oil saturation distribution as a function of various bottomhole pressures for an example reservoir pressure.

[0029] Figure 19 is a plot of oil saturation distribution as a function of various bottomhole pressures for another example reservoir pressure.

[0030] Figure 20 is a plot of oil saturation distribution as a function of various bottomhole pressures for another example reservoir pressure.

[0031] Figure 21 is a graphical illustration depicting development of a linear relationship between oil saturation and constant composition expansion data for a well.

[0032] Figure 22 is a plot of inflow performance relationship according to the present invention for an example reservoir pressure.

[0033] Figure 23 is a plot of pseudopressure versus gas rate for the same reservoir pressure as that of the data of Figure 22.

[0034] Figure 24 is a comparative plot of inflow performance relationships according to the present invention versus data obtained from simulation models.

[0035] Figure 25 is a plot of well productivity index as a function of time.

[0036] Figure 26 is a plot of oil saturation profiles around a well as a function of time for radial cell models.

[0037] Figure 27 is a plot of constant composition expansion data for an example field case according to the present invention.

[0038] Figure 28 is a plot illustrating the relative permeability of the example field case.

[0039] Figure 29 is a plot of production data of two tests conducted according to the present invention.

[0040] Figure 30 is a plot of pseudopressure versus gas rate for a test according to the present invention.

[0041] Figure 31 is a plot of pseudopressure versus gas rate for a test according to the present invention.

[0042] Figure 32 is a plot of the inflow performance relationship according to the present invention for a second example reservoir pressure.

[0043] Figure 33 is a plot of pseudopressure versus gas rate for the same reservoir pressure as that of the data of Figure 32.

[0044] Figure 34 is a comparative plot of inflow performance relationships according to the present invention versus data obtained from simulation models.

[0045] Figure 35 is a plot comparing inflow performance relationships according to the present invention versus data obtained from field observed data.

[0046] Figure 36 is a functional block diagram of a set of data processing steps performed in a data processing system for prediction of the performance of gas condensate reservoirs according to the present invention.

[0047] Figure 37 is a functional block diagram of a set of processing steps showing in more detail portions of Figure 36.

[0048] Figure 38 is a functional block diagram of a set of processing steps showing in more detail portions of Figure 36.

[0049] Figure 39 is a schematic block diagram of a data processing system for rock facies prediction of subsurface earth formations according to the present invention.

DETAILED DESCRIPTION OF THE PREFERRED EMBODIMENTS

[0050] In the drawings, Figure 1 schematically indicates flow behavior of a gas condensate well in three regions. Region 1 represents an inner near-wellbore region, as shown in Figure 1, where both condensate and gas are mobile. It is the most important region for calculating condensate well productivity, as most of the pressure drop occurs in Region 1. The flowing composition (GOR) within Region I is constant throughout and a semi-steady state regime exists. This means that the single phase gas entering Region 1 has the same

composition as the produced well stream mixture. The dew point of the producing well stream mixture equals the reservoir pressure at the outer edge of Region 1.

[0051] Region 2 is the region where the condensate saturation is building up. The condensate is immobile, and only gas is flowing. The loss in productivity due to liquid build-up is mostly influenced by the value of gas relative permeability (k_{rg}) near the well when compared with the value of k_{rg} in the reservoir further away. The loss in productivity is known to be more sensitive to the relative permeability curves than to fluid PVT properties. Condensate saturations in Region 2 are approximated by the liquid dropout curve from a Constant Volume Depletion (CVD) experiment, corrected for water saturation.

[0052] Region 3 is the region in the gas condensate reservoir where no condensate phase exists (above the dew point). Region 3 only exists in a gas condensate reservoir that is currently undersaturated. It contains a single phase (original) reservoir gas.

[0053] The pseudosteady state rate equation for a gas condensate well is a known relationship available in the literature. For example, according to "Natural Gas Production Engineering," M. Kelkar, Penn Well Corporation, 2008, the relation as expressed in field units is given by:

(1)

$$q_{sc} = \frac{(703 \times 10^{-6}) kh [m(p_r) - m(p_{wf})]}{T \left[\ln \left(\frac{r_e}{r_w} \right) - 0.75 + S \right]}$$

where q_{sc} (the flow rate is in (Mscf/d), k (permeability is in md), h (height is in ft.), $m(p_r)$ (the real pseudopressure) and $m(p_{wf})$ (the well flowing pseudopressure) are in (psi²/cp), T is in (°R), and r_e and r_w are in feet.

[0054] The relationship can be used to estimate the gas production rate as long as bottomhole flowing pressure (BHFP) is above the dew point of reservoir fluids, that is, an

undersaturated reservoir. The relationship is, however, applicable only for single phase gas flow. As soon as BHFP drops below the dew point pressure of reservoir fluid, condensate begins to drop out. The condensate drop out begins first near the well bore and the well performance starts to deviate from that of a dry gas well. Liquid condensate accumulates until the critical condensate saturation (the minimum mobile condensate saturation) is reached. This rich liquid bank/zone grows outward deeper into the reservoir as depletion continues.

[0055] Liquid accumulation, or condensate banking, causes a reduction in the gas relative permeability, and acts as a partial blockage to gas production which leads to potentially significant reduction in well productivity. To quantify the impact of gas condensation phenomena the present invention provides methodology to generate inflow performance relationships (IPR) of gas condensate reservoirs using analytical procedures.

[0056] The present invention utilizes constant composition expansion (CCE) data or, alternatively, CVD data along with the relative permeability curves. The present invention combines fluid properties (CCE or CVD data) with rock properties (relative permeability curves) to provide a methodology of analytical solution that is accurate enough to estimate the IPR curves of gas condensate reservoirs.

Fluid Description

[0057] Figure 2 is a plot of CCE data for sample fluids used as example reservoir gas condensates. The CCE data are obtained as laboratory test data performed to measure the change in volume of a gas condensate fluid as a function of pressure. Two different synthetic gas-condensate compositions were used to generate the Rich, Intermediate and Lean fluids represented in Figure 2. The Rich fluid is composed of three components which are methane (C1, 89%), butane (C4, 1.55%) and decane (C10, 9.45%). While a four-component composition was used to generate the Intermediate and Lean condensate mixtures at different

reservoir temperatures. The four components are methane (C1, 60.5%), Ethane (C2, 20.0%), Propane (C3, 10.0%), and decane (C10, 9.25%). The characteristics of the condensate mixtures are outlined in Table 1.

Table 1: Fluid Properties

	Rich Gas	Intermediate Gas	Lean Gas
Initial Reservoir Pressure (psia)	7000	5500	5000
Dew Point Pressure (psia)	5400	3250	2715
Reservoir Temperature (°F)	200	260	340
Maximum Liquid Dropout (%)	26	20	8.5

Reservoir Description

[0058] An Eclipse 300 compositional simulator of the type available from Schlumberger was used for simulation of gas condensate productivity for the gas condensate sample fluids identified above. The conventional three parameter Peng-Robinson equation of state was used to simulate the PVT properties of the gas condensate fluids. A one-dimensional radial compositional

model with a single vertical layer and 36 grid cells in the radial	Porosity (%)	20
	Absolute permeability (md)	10
	Reservoir height (ft.)	100
	Irreducible water saturation (%)	0
	Rock Compressibility (psi ⁻¹)	4.0E-06

direction was used as a test case as shown in Figure 3. Homogenous properties were used in the fine scale model as described in Table 2.

Table 2: Reservoir Properties Used in the Fine Radial Model

[0059] A single producer well 20 in the simulation lies at the center of the reservoir and is assumed to be perforated across the height of the reservoir. The model has been refined near the well bore to accurately observe the gas condensate drop out effect. For that purpose, the size of the radial cells has been logarithmically distributed with the inner most grid size is 0.25 ft according to the following Equation:

$$\frac{r_{i+1}}{r_i} = \left[\frac{r_e}{r_w} \right]^{1/N} \quad (2)$$

[0060] Besides having very small grid blocks around the well, the time steps have been refined at initial times which led to a very smooth saturation profile around the well. The fully implicit method was chosen for the gas condensate productivity simulation runs.

[0061] The most accurate way to determine gas-condensate well productivity is by fine-grid numerical simulation, either in single-well models with a fine grid near the well or in full-field models using local grid refinement. A large part of the pressure drawdown occurs within 10 feet of the well, so that radial models are used with the inner grid cell having dimensions of about one foot.

Relative Permeability Curves

[0062] It is known that relative permeability changes affect the flow significantly in a gas-condensate reservoir once the pressure falls below dew-point pressure. Accurate knowledge about relative permeability curves in a gas condensate reservoir would be ideal information. Usually, however, this is not the case, as the relative permeability curves are rarely known accurately.

[0063] Different sets of relative permeability curves were used in the test data examples described herein. These curves were generated based on Corey equations as illustrated below:

$$K_{ro} = \left(\frac{K_{rg}}{1 - S_{or}} \right)^{2n} \quad (4)$$

where (n) is the gas relative permeability exponent, (m) is the oil relative permeability exponent and (S_{or}) is the residual oil saturation. Fractures (X-Curves), Intermediate and tight relative permeability curves were generated by changing (n) and (m) exponents from 1 to 5 and changing (S_{or}) from 0 to 0.60. A naming convention (Corey- #) was used for the relative permeability curves for identification purposes. Figure 4 shows three sets of relative permeability curves. Corey-1 (X-curve) is generated based on $n = 1$, $m = 1$ and $S_{or} = 0$. Corey-14 is generated based on $n = 3$, $m = 4$ and $S_{or} = 0.20$. The third curve, Corey-24 is generated based on $n = 5$, $m = 4$ and $S_{or} = 0.60$.

Generation of IPR Measures

[0064] Inflow Performance Relationships (IPR) data in the form of measures or curves indicating inflow performance relationships are very important to predict the performance of gas or oil wells. However, generating IPR curves using a simulator is not straight-forward since the IPR represents an instantaneous response of the reservoir at a given reservoir pressure for a given bottomhole pressure. This cannot be generated in a single run since the bottom hole pressure changes in a simulation run, depending on how much oil or gas is produced. The average pressure also changes and in a manner which does not directly correspond.

[0065] To generate IPR measures or curves, a composite method is utilized with the present invention. A simulator is run at a fixed bottomhole pressure. The bottomhole pressure is then varied from high to low values. Rate profiles are generated for a particular bottomhole pressure and average reservoir pressure as the reservoir pressure depleted. Using various runs, the rate at a given reservoir pressure and a given bottomhole pressure are then selected, then combined them into one curve to generate an IPR curve.

Analytical Approach for Estimating Gas Condensate Well Productivity

[0066] The IPR measures or curves were plotted both as a function of pressure as well as pseudo-real pressure, and it was noticed that plotting the pseudopressure versus the gas rate results in two clear straight lines for every reservoir pressure, as shown in Figure 11. Correspondingly it was noted that plotting bottom hole flowing pressure versus the gas rate results in IPR curves as shown in Figure 12. A peculiar behavior of IPR curves is noted when plotted as a function of pseudo-real pressure. The lines are parallel above dew point, as expected, since the productivity does not change. Below dew point, for different reservoir pressures, the lines are parallel for certain pressure ranges. However, as the reservoir pressure depletes, the slope becomes gentler. This is an indication of improved productivity. This is a result of re-evaporation of liquid phase as the pressure declines. This type of trend is difficult to capture and then evaluate using pressure data.

[0067] As soon as reservoir pressure drops below the dew point (P_d), which is 3250 psi in this example, a productivity loss occurs which is characterized by the straight line below P_d in the pseudopressure plot as shown in Figure 11. To illustrate the methodology of the present invention, $P_r = 5400$ psi is taken as an example for illustration as shown in Figure 13.

[0068] The pseudosteady-state gas rate equation (Equation 1 above) is required for use according to the present invention, which requires that a pseudopressure function be available in terms of normal pressure. Data available in Tulsa University Center of Reservoir Studies (TUCRS) was utilized to generate the pseudo-pressures from normal pressures based on fluid properties for each fluid composition of the fluid samples mentioned above.

[0069] The pseudopressure plot in Figure 13 clearly shows that there are two distinct productivity indices. A first productivity index (J) which is constant for single phase gas flow (where FBHP is above P_d), and $J = \frac{q_{sc}}{[m(p_r) - m(p_{wf})]}$ a second productivity index (J^*) which is for two phase flow (where FBHP is below P_d). Referring back to the pseudosteady - state gas rate Equation (1) above, the productivity index in terms of pseudopressure is given by:

$$J = \frac{q_{sc}}{[m(p_r) - m(p_{wf})]} \quad (5)$$

where J in field units is in: (MMscfd/psia²/cp).

[0070] Looking back at Figure 13, the slopes can be defined as follows:

$$\text{Slope of the line above } P_d = (-1/J) \quad (6)$$

$$\text{Slope of the line below } P_d = (1/J^*) \quad (7)$$

[0071] After analyzing several cases, with the present invention it was found that productivity ratio can be determined by dividing the slope above P_d by slope below P_d as

$$\text{following; } \frac{\text{Slope of the line above } P_d}{\text{Slope of the line below } P_d} = \frac{(-\frac{1}{J})}{(-\frac{1}{J^*})} = \frac{J^*}{J} \cong \text{Productivity Ratio} \quad (8)$$

[0072] Since the productivity Index (J , for a single phase gas) is always higher than productivity Index (J^* , for two phase flow), the productivity ratio (J^*/J) is always less than one. Not only that, it has been found with the present invention that the productivity ratio (J^*/J) is very much correlated to K_{rg} (S_{or}) for each relative permeability curve used as will be described below.

Procedure - Initial Reservoir Pressure is above the P_d

[0073] When initial reservoir pressure is above the dew point P_d , the pseudo steady state gas rate Equation (2) will be used to estimate the gas rate when $\text{FBHP} > P_d$. Since initial

reservoir pressure is above the P_d , the productivity index (J) is constant for bottomhole pressures above the P_d , as described above. When FBHP drops below the P_d , it is necessary as described below to estimate (J^*) first to be able to calculate the gas rate analytically.

[0074] After estimating (J), when initial reservoir pressure is above dew point, knowledge of $k_{rg}(S_o)$ as a multiplier is used to get J^* as following:

$$\frac{J^*}{J} = \text{Productivity Ratio} \cong K_{rg}(S_o^*) \quad (9)$$

[0075] After estimating J^* which has constant but higher slope than J as shown before on the pseudo-pressure plot, J^* is used to estimate the gas rate for all bottomhole pressures below the P_d using the following equation, as follows:

$$m(P_{wf}) = \left(-\frac{1}{J^*}\right)q + b \quad (11)$$

[0076] Knowledge of the rate and FBHP at the P_d is then used based on the pseudo-steady state gas rate equation above dew point. Then the intercept b can be calculated as follows:

$$b = m(P_d) + \frac{q_d}{J^*} \quad (12)$$

where b in field units is in (psi²/cp).

[0077] Now, the straight line pseudo-pressure equation set forth above is complete to estimate the gas rate for any FBHP less than the P_d , as follows:

$$q = [b - m(P_{wf})] J^* \quad (13)$$

where the units of measure are as identified previously.

Procedure - Initial Reservoir Pressure is below the P_d

[0078] Figure 11 shows three examples of IPR lines where initial reservoir pressure is below the P_d . To be able to generate the IPR curves for cases where initial reservoir pressure below the P_d , the following procedure is followed:

(14)

$$J = \frac{q_{sc}}{[m(p_r) - m(p_{wf})]} = \frac{(703 \times 10^{-6})kh}{T \left[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + S \right]}$$

Estimate the Productivity Index (J*)

[0079] As described above, that productivity ratio (J^*/J) is correlated to $k_{rg}(S_{or})$, but in cases where initial reservoir pressure is below P_d , liquid re-vaporization plays a very important role into determining productivity of gas condensate reservoirs. By examining the constant composition expansion data as shown in Figure 2, it can be seen that as soon as pressure drops below the P_d , liquid saturation immediately reaches a maximum value (Max_So_CCE) around the P_d , then it falls gradually as a function of pressure. The present invention utilizes constant composition expansion data to generate the IPR curves to account for this phenomenon of liquid vaporization as pressure drops below the P_d . It has been found that using a fixed value of $k_{rg}(S_{or})$ or $k_{rg}(Max_SoCCE)$ underestimates the gas productivity for cases where initial reservoir pressure is below the P_d .

[0080] Therefore, for any reservoir pressure below P_d , k_{rg} needs to be estimated at the corresponding pressure and oil saturation from the constant composition expansion data according to the following equation:

$$\frac{I^*}{J}(P_r) = \text{Productivity Ratio} \cong k_{rg}(S_{oCCE}) \quad (15)$$

[0081] To estimate the Productivity Index (J), if an IPR curve for the case where reservoir pressure above the P_d is available, the productivity index (J) of this case could be used to estimate J^* as a function of pressure using constant composition expansion data as will be explained. For cases where IPR curves above the P_d are not available, the productivity index (J) can be estimated using pseudo-steady state gas rate equation, Equation (1) as described above.

[0082] To estimate the Gas Rate, the gas rate can be directly estimated from the following equation:

$$q = [m(P_r) - m(P_{wf})] J^* \quad (16)$$

General Procedure for Generating IPR Curves

[0083] The above described procedure for generating IPR curves assumes that $S_{or} = \text{Max_So_CCE}$, but it is not always the case in real field applications. Since S_{or} is a rock property while Max_So_CCE is a fluid property, one can expect them to be different in most of the cases in field applications.

[0084] For that purpose, several cases were analyzed where S_{or} could be equal to, less than or greater than Max_So_CCE . Based on an evaluation, it has been found according to the present invention that the maximum of the two values should be used to correctly capture the fluid behavior around the well bore, and hence accurately estimate the gas productivity

[0085] The procedure to estimate productivity index (J^*) for generating IPR measures or curves is exactly the same as the procedure outlined above for the case where $S_{or} = \text{Max_So_CCE}$ but with some modifications as given by Table 3 below. This procedure is used for flowing pressure less than dew point. In effect this recognizes that if reservoir pressure is above dew point, then to calculate the IPR curve for bottom hole pressure below dew point, a constant slope (J^*) based on K_{rg} estimate is necessary to be used as stated below. However, once the reservoir pressure drops below dew point, it is necessary to use K_{rg} as a function of average pressure.

Table 3: General Procedure for Generating IPR Curves

Case	Cases where P_r above P_d	Cases where P_r below P_d
$S_{or} = \text{Max_So_CCE}$	Use $K_{rg}(S_{or})$	$K_{rg}(\text{So_CCE}) = f(P)$
$S_{or} < \text{Max_So_CCE}$	Use $K_{rg}(\text{Max_So_CCE})$	
$S_{or} > \text{Max_So_CCE}$	Use $K_{rg}(S_{or})$	

Importance of Threshold Oil Saturation (S_o^*)

[0086] It has been found that accurate estimation of gas productivity depends not only on S_{or} but also depends on Threshold oil saturation (S_o^*) for reservoirs having tight oil relative permeability curves. Figure 14 shows an oil relative permeability curve that was generated based on $S_{or} = 0.20$ and a high value of oil exponent ($m=4$). This higher value of oil exponent makes the oil relative permeability very low and eventually makes oil immobile until its saturation exceeds S_{or} to a threshold (S_o^*) which is in this case 0.48 as shown in Figure 14. After testing several tight relative permeability curves, it was found that for practical applications, we can determine the threshold (S_o^*) can be determined to be corresponding to $K_{ro} = 1\%$.

[0087] Therefore, in generating IPR curves, it is more important to know S_o^* than S_{or} . S_o^* can be defined as a minimum saturation needed to make oil mobile (i.e., K_{ro} is at least 1% of the end point value). It is a strong function of the curvature of the relative permeability curve. Hence, Table 3 can be used but replacing S_{or} with S_o^* as follows:

Table 4: General Procedure for Generating IPR Curves with S_o^*

Case	Cases where P_r above P_d	Cases where P_r below P_d
$S_o^* = \text{Max_So_CCE}$	Use $K_{rg}(S_{or})^*$	$K_{rg}(S_o_CCE) = f(P)$
$S_o^* < \text{Max_So_CCE}$	Use $K_{rg}(\text{Max_So_CCE})$	
$S_o^* > \text{Max_So_CCE}$	Use $K_{rg}(S_o^*)$	

[0088] This is the most common case where in many field situations, the residual oil saturation in condensate reservoirs can be as high as 0.5. Keeping in mind that threshold saturation (S_o^*) plays the most important rule in tight rocks as explained earlier.

[0089] The Rich condensate fluid with Maximum Liquid Dropout (26%) is being used for this case where it is less than $S_o^*=0.48$ as shown previously in Figure 14. Referring back to Table 3.4, it can be seen that in this case the productivity ratio is determined by $K_{rg}(S_o^*)$.

[0090] Figure 15 shows an observation similar to previous cases. The near well bore saturation does not change with change in bottom hole pressure for a given reservoir pressure.

[0091] Since in this case Threshold (S_o^*) is higher than $Max_S_o_CCE$. This value of S_o^* should be used to get the corresponding K_{rg} and hence estimate the well productivity for the cases where reservoir pressure is above the P_d . By following the procedure outlined above for situations where initial reservoir pressure is above the P_d , an IPR curve can be generated as shown in Figure 16. It should be kept in mind that the only change for the case where Threshold (S_o^*) > $Max_S_o_CCE$ is to use the larger value of the two, which is in this case the S_o^* .

$$\frac{J^*}{J} = \text{Productivity Ratio} = K_{rg}(S_o^*) \quad (17)$$

[0092] To illustrate an example for the case where Initial Reservoir Pressure is below P_d , to correctly generate the slope of IPR curve on pseudo-pressure plot, it is necessary to account for re-vaporization. Again the fine grid model is utilized to capture the condensate behavior near the well bore as was done in the earlier example.

[0093] Figures 18, 19 and 20 show S_o distribution for saturated reservoirs. On examination it is possible to notice that S_o is decreasing gradually as a function of reservoir pressure from about 0.62 when $P_r=6900$ psi (Figure 15) to almost 0.30 when $P_r=1000$ psi (Figure 20). This observation is exactly what was concluded from the previous example - that oil re-vaporization close to the well bore is a strong function of decreasing reservoir pressure.

[0094] Another important conclusion that can be seen in the previous example is that S_o builds up to uniform value close to the well bore for each saturated reservoir pressure. This

uniform S_o remains almost constant as FBHP decreases. Therefore, a valid assumption for the application of the present invention is to assume a uniform S_o for every saturated pressure under consideration. Figure 20 shows an example of an extreme case where all the oil evaporates at very low flowing pressure.

[0095] With this understanding of gas condensate behavior around the well bore, the need to utilize the constant composition expansion data as a tool to mimic condensate re-vaporization process is evident as reservoir pressure depletes. The constant composition expansion data of a Rich fluid is shown in Figure 2.

[0096] Since in this case Threshold (S_o^*) is greater than Max_ S_o _CCE, the approach is to develop a linear relationship between the S_o^* and the constant composition expansion data as shown in Figure 21.

[0097] Careful examination of Figure 15 and Figures 18 through 20 indicates that actual liquid dropout around the well bore is much greater than Max_ S_o _CCE and is closer to Threshold (S_o^*). After testing several cases under this category it was determined that using K_{rg} (Max_ S_o _CCE) overestimates the gas rate, since it does not account for revaporization of liquid.

[0098] From the foregoing it is very clear that condensate banking (Accumulation) is tied up with two factors. The first factor is Fluid Properties (Maximum S_o from constant composition expansion) and the second factor is Rock Properties (Immobile S_o). Accordingly, although actual liquid dropout around the well bore is much greater than Max_ S_o _CCE, it would still be desirable to utilize the constant composition expansion data along with relative permeability curves to come up with a robust analytical procedure that is accurate enough to estimate the well productivity.

[0099] As will be shown, different fluids have a similar productivity loss for the same relative permeability curve used, confirming that it is the relative permeability which is the most important in determining the productivity loss.

[00100] An engineering approximation is thus to model the behavior below dew point pressure. The constant composition expansion data of the Rich fluid is shown previously in Figure 2. As stated before it is assumed that the area around the well bore behaves like the constant composition expansion data for every designated saturated pressure. Following the procedure outlined for situations where initial reservoir pressure is below the P_d , it is useful consider an example at $P_r = 4000$ psi. After estimating the Productivity Index (J) as shown in step (I) of the procedure, one can estimate Productivity Index (J^*) as following:

$$\frac{J^*}{J} = \text{Productivity Ratio} = K_{rg}(S_o^*_{CCE}) \quad (18)$$

[00101] At $P_r = 4000$ psi, one can estimate S_o from the linear relation between the S_o^* and constant composition expansion data as shown in Figure 21. The next step is to go back to relative permeability curves to estimate K_{rg} at the corresponding S_o from this linear relation. After that P can be calculated directly from Equation (18). The IPR curve is shown in Figure 22 along with the pseudopressure plot in Figure 23. The complete IPR curves of this case are determined in this manner.

[00102] Before finishing this example it is helpful to examine the well productivity index shown in Figure 5 while running at constant rate condition. As was expected, it was found that the productivity ratio is very close to $K_{rg}(S_o^*)$ as following:

$$\frac{\text{Min Well PI}}{\text{Max Well PI}} = 0.11 \approx K_{rg}(S_o^*) = 0.14 \quad (19)$$

[00103] Based on the PT ratio we can define productivity loss as following:

$$\text{Productivity loss} = 1 - \frac{\text{Min Well PI}}{\text{Max Well PI}} \quad (20)$$

[00104] In this example the productivity loss is 0.89. This means that this well will experiences an 89 % productivity loss as soon as FBHP reaches the P_d .

[00105] Looking back at Figure 5 it can be seen that the well restores some of its productivity after about 5 years of production which is the same behavior we have seen in the previous example. Figure 26 shows the saturation profiles as a function of time which shows the re-evaporation process.

[00106] It can be seen through the examples that productivity ratio is approximately equal to K_{rg} estimated at S_{or} (or S_o^*) for each set of relative permeability curves. A number of relative permeability curves (over 20 sets of curves) ranging from X-curves (Fractures), through Intermediate and ending up with tight relative permeability curves. A sensitivity study also examined the effects of fluid richness on gas productivity by using two fluid compositions (Lean and Rich fluids).

[00107] The results of the sensitivity study have been checked with simulation results. The simulation runs have been done under Constant Rate mode of production utilizing the Fine Compositional Radial Model. Testing this wide range of relative permeability curves has confirmed that indeed a very strong correlation exists between the Productivity Index Ratio and $K_{rg}(S_o^*)$. Figures 7 and 8 show clearly that for both Rich and Lean fluids, the relationship between the PI Ratio and $K_{rg}(S_o^*)$ is linear with a correlation coefficient close to one.

[00108] Another important outcome of this sensitivity analysis is that the loss in productivity is more sensitive to the relative permeability curves than to fluid pressure-volume-temperature or PVT properties. Figure 9 shows the well PI versus time for the Rich and Lean fluids using the same relative permeability set. Figure 9 also shows an example of what was observed by testing the wide range of relative permeability curves, which is that by using the same relative permeability set, the Rich and Lean fluids have the same effect. This

confirms that it is the relative permeabilities which are most important in determining the productivity loss.

[00109] Figure 10 summarizes the results of the sensitivity study done on the Rich and Lean fluids by using the wide range of relative permeability curves. Figure 10 shows clearly that for each set of relative permeability used, the Rich and Lean fluids have the same productivity ratio and hence the same productivity loss.

[00110] Application of the methodology described above is now presented for a field case. Both compositional model data and relative permeability curves have been provided for this field case. A nine component compositional model is being used with Peng-Robinson equation of state (PR3) to simulate phase behavior and laboratory experiment (constant composition expansion) are shown in Table 5. Tables 5 and 6 show fluid composition and properties and for the field case, respectively.

Table 5: Fluid Composition for the Field

Component	Composition (Fraction)
'H2S'	0
'CO2'	0.0279
'N2'	0.0345
'C1'	0.7798
'C2-C3'	0.1172
'C4-C6'	0.215
'C7-C9'	0.0132
'C10-C19'	0.00445
'C20+'	0.00145

Table 6: Fluid Properties for the Field Case

	Field Case
Initial Reservoir Pressure (psia)	9000
Dew Point Pressure (psia)	8424
Reservoir Temperature (°F)	305
Maximum Liquid Dropout (%)	3

[00111] The Relative permeability curves are shown in Figure 28. As it is common in field applications what matters here is the Threshold (S_o^*). Although $S_{or} = 0.20$, the Threshold (S_o^*) = 0.32 which corresponds to about $K_{ro} = 1\%$ as a practical value. As has been mentioned earlier above, accurate estimation of gas productivity depends on the value of K_{rg} estimated at Threshold (S_o^*) which equals 0.32 in this example.

[00112] In situations where work is in a production environment in a field where no knowledge is available about relative permeability curves, and the only thing available is some production data, a procedure as follows is used. Since initial reservoir pressure is above the P_d , it is known that the pseudopressure versus gas rate plot will have two straight lines as explained earlier. Therefore, in order to generate an IPR curve for a given reservoir pressure, all that is needed are two test points. One point should be above the P_d and the other point should be below the P_d .

[00113] Figure 29 shows an example of two production data tests. One of the test data points as chosen to be at the P_d . It should be understood that any available test data above the P_d is suitable for this purpose.

[00114] The productivity index (J) is estimated utilizing P_r and the test data at the P_d using the following equation:

$$J = \frac{q_{sc}}{[m(p_r) - m(p_{wf})]} \quad (21)$$

[00115] Another way to estimate J is to plot the test points above the P_d on the pseudopressure plot as shown in Figure 30, and then J can be calculated from the following equation:

$$\text{slope} = -\frac{1}{J} \quad (22)$$

[00116] Based on the value of J so determined, one is then able to generate the first portion of the IPR curve using the following equation:

$$q = [m(P_r) - m(P_{wf})].J^* \quad (23)$$

where q is in (MMscfd), $m(P_r)$ and $m(p_{wf})$ are in (psi²/cp), and J^* in (MMscfd/psi²/cp).

[00117] Then the test points below the P_d are plotted on the pseudopressure plots as shown in Figure 31. Then J^* can be determined from the slope in the manner previously described. The generated IPR curve and the pseudopressure plot are shown in Figures 32 and 33 respectively.

[00118] A flowchart F (Figure 36) indicates the basic computer processing sequence of the present invention and the computation taking place in a data processing system D (Figure 39) for prediction of performance of gas condensate reservoirs according to the present invention. The processing sequence of the flow chart F is performed separately for wells in the reservoir of interest in the gas condensate reservoir.

[00119] Receive and Store Input Data (Step 100): During step 100, the data processing system D receives and stores in memory input data of the types set forth above about the gas

condensate well, including constant composition expansion data, rock permeability data, reservoir pressure data.

[00120] Initial Reservoir Pressure Above Dew Point Decision (Step 102): During step 102, a determination is made whether the initial reservoir pressure is above the dew point P_d for the gas condensate well fluid.

[00121] Form Single Phase Gas Rate Estimate (Step 104): If the initial reservoir pressure is above the dew point, processing proceeds to step 104 for forming a gas rate estimate for single phase fluid. Further details of step 104 are shown in Figure 37 and described below.

[00122] Form Two Phase Gas Rate Estimate (Step 106): If the initial reservoir pressure is determined during step 102 to be below the dew point, processing proceeds to step 106 for forming a gas rate estimate for single phase fluid. Further details of step 106 are shown in Figure 38 and described below.

[00123] Store/Display Gas Rate Estimate (Step 108): After gas rate estimates are formed during either step 104 or 106, during step 108 the gas rate estimates so determined are stored in memory of the data processing system D and are available for display for use by analysts and engineers.

[00124] Gas Rate Estimate for Single Phase (Step 104): The processing steps for determination or forming of gas rate estimates for a single phase fluid of step 104 are set forth in Figure 37. As has been discussed above, the productivity index is constant in this case as indicated at step 110, and the pseudo steady state gas rate equation (Equation 2) is used as indicated at step 112 to determine an estimate of the gas rate. Processing then proceeds to step 108, as noted above.

[00125] Gas Rate Estimate for Two Phase (Step 106): The processing steps for determination or forming of gas rate estimates for a single phase fluid of step 106 are set forth in Figure 38. As indicated, an estimate of the productivity index J for single phase flow is formed in the manner described with respect to Equation 11 during step 130. During step 132 an estimate of the productivity index J^* for two phase flow is formed as described above. During step 134 an estimate of gas relative permeability k_{rg} at the corresponding pressure and oil saturation is formed by the data processing system D according to Equation 17. During step 136, an estimate of the gas rate is determined in the data processing system D according to the relationship expressed in Equation 18. Processing then proceeds to step 108, as noted above.

Data Processing

[00126] As illustrated in Figure 39, the data processing system D according to the present invention includes a computer C having a processor 200 and memory 202 coupled to the processor 200 to store operating instructions, control information and database records therein. The computer C may, if desired, be a portable digital processor, such as a personal computer in the form of a laptop computer, notebook computer or other suitable programmed or programmable digital data processing apparatus, such as a desktop computer. It should also be understood that the computer C may be a multicore processor with nodes such as those from Intel Corporation or Advanced Micro Devices (AMD), an HPC Linux cluster computer or a mainframe computer of any conventional type of suitable processing capacity such as those available from International Business Machines (IBM) of Armonk, N.Y. or other source..

[00127] The computer C has a user interface 204 and an output data display 206 for displaying output data or records of predicted gas performance of the gas condensate

reservoir according to the present invention. The output display 206 includes components such as a printer and an output display screen capable of providing printed output information or visible displays in the form of graphs, data sheets, graphical images, data plots and the like as output records or images.

[00128] The user interface 204 of computer C also includes a suitable user input device or input/output control unit 208 to provide a user access to control or access information and database records and operate the computer C. Data processing system D further includes a database 210 stored in computer memory, which may be internal memory 202, or an external, networked, or non-networked memory as indicated at 212 in an associated database server 214.

[00129] The data processing system D includes program code 216 stored in non-transitory form in memory 202 of the computer C. The program code 216 according to the present invention is in the form of non-transitory computer operable instructions causing the data processor 200 to perform the computer implemented method of the present invention in the manner described above and illustrated in Figures 36, 37 and 38.

[00130] It should be noted that program code 216 may be in the form of microcode, programs, routines, or symbolic computer operable languages that provide a specific set of ordered operations that control the functioning of the data processing system D and direct its operation. The instructions of program code 216 may be may be stored in non-transitory form in memory 202 of the computer C, or on computer diskette, magnetic tape, conventional hard disk drive, electronic read-only memory, optical storage device, or other appropriate non-transitory data storage device having a computer usable medium stored thereon. Program code 216 may also be contained on a data storage device such as server 218 as a non-transitory computer readable medium.

[00131] The data processing system D can be a computer of any conventional type of suitable processing capacity, such as a mainframe, a personal computer, laptop computer, or any other suitable processing apparatus. It should thus be understood that a number of commercially available data processing systems and types of computers may be used for this purpose.

[00132] From the foregoing, it can be seen that the present invention provides a new analytical procedure is provided to predict or estimate well deliverability of gas condensate reservoirs. The present invention analytically generates inflow performance relationship or IPR measures, which can be plotted as curves, of gas condensate wells by incorporating the effect of condensate banking as the pressure near the well bore drops below dew point. Other than basic reservoir properties, the information needed to generate the IPR measures is rock relative permeability data and data from Constant Composition Expansion (CCE) experiments on gas condensate reservoir fluids.

[00133] As has been described, it has been found that the most important parameter in determining productivity loss is the gas relative permeability at immobile oil saturation. It has also been observed that at low reservoir pressures some of the accumulated liquid near the well bore re-vaporizes. This revaporization can be captured by using CCE data.

[00134] As described, the present invention provides two ways of predicting IPR curves. One method involves an approach using the basic reservoir properties, relative permeability data and CCE information, so that one can predict IPR curves for the entire pressure range. Comparison with simulation results validates this approach.

[00135] Another method uses field data to predict the IPR curves above and below the dew point pressure. This method does not require reservoir data; instead, it uses point information from the IPR curve and predicts the IPR curve for the entire bottom hole pressure range. Both

synthetic and field data are used to validate this second approach. In addition to predicting the IPR curve under current conditions, the present invention can also predict future IPR curves if CCE data are available.

[00136] With the present invention a simple yet accurate analytical methodology is provided to estimate the predicted performance and in particular gas rate productivity to estimate the productivity of gas condensate reservoirs without having to run reservoir simulations. Further, with the present invention, the production rate can be determined based on knowledge obtained about the well relatively simply. Data in the form of well pressures, CCE (Constant Composition Expansion) data and formation relative permeability data or curves are the required input data for gas rate performance prediction according to the present invention. The present invention allows well performance evaluation quickly without time consuming reservoir simulations of reservoir gas presence and states.

[00137] The invention has been sufficiently described so that a person with average knowledge in the matter may reproduce and obtain the results mentioned in the invention herein. Nonetheless, any skilled person in the field of technique, subject of the invention herein, may carry out modifications not described in the request herein, to apply these modifications to a determined methodology, or in the performance of the same, requires the claimed matter in the following claims; such techniques and procedures shall be covered within the scope of the invention.

[00138] It should be noted and understood that there can be improvements and modifications made of the present invention described in detail above without departing from the spirit or scope of the invention as set forth in the accompanying claims.

CLAIMS

What is claimed is:

1. A computer implemented method of obtaining measures in a data processing system of predicted performance of a gas condensate well in a subsurface reservoir, the method comprising the computer processing steps of:

(a) receiving component composition expansion data based on measurements from fluid from the well;

(b) receiving relative permeability data regarding formations containing the gas condensate of the well;

(c) receiving bottom hole pressure data of the well;

(d) obtaining a measure of dew point of gas condensate in the well based on the component composition expansion data;

(e) determining if the bottom hole pressure of the well is above the dew point of the gas condensate of the well, and,

(f) if not:

(1) forming an estimated productivity index of the gas condensate well for single phase flow of the well;

(2) forming an estimated productivity index of the gas condensate well for two phase flow of the well;

(3) forming an estimated predicted performance of the well as a function of formation relative permeability and the estimated productivity index of the gas condensate well for two phase flow; or

(g) if so:

(1) obtaining a measure of borehole pressure of the well;

(2) forming an estimated predicted performance of the well as a function of borehole pressure and relative gas permeability of the well; and

(h) assembling in the memory the estimated predicted performance the well.

2. The computer implemented method of Claim 1, wherein the predicted performance of the well comprises the gas rate.

3. The computer implemented method of Claim 1, wherein the step of forming an estimated predicted performance of the well when the borehole pressure is above the dew point of the gas condensate comprises the step of:

forming an estimated performance of the well under pseudo steady state conditions for the gas condensate.

4. The computer implemented method of Claim 1, wherein the step of forming an estimated predicted performance of the well when the borehole pressure is below the dew point of the gas condensate comprises the step of:

forming a measure of relative gas permeability as a function of saturation of the well.

5. The computer implemented method of Claim 1, further including the step of:

forming an output display of selected ones of the determined measure of estimated predicted performance of the well.

6. A data processing system for obtaining measures of predicted performance of a gas condensate well in a subsurface reservoir, the data processing system comprising:

- (a) a processor performing the steps of:
 - (1) receiving component composition expansion data based on measurements from fluid from the well;
 - (2) receiving relative permeability data regarding formations containing the gas condensate of the well;
 - (3) receiving bottom hole pressure data of the well;
 - (4) obtaining a measure of dew point of gas condensate in the well based on the component composition expansion data;
 - (5) determining if the bottom hole pressure of the well is above the dew point of the gas condensate of the well, and,
 - (6) if not:
 - (i) forming an estimated productivity index of the gas condensate well for single phase flow of the well;
 - (ii) forming an estimated productivity index of the gas condensate well for two phase flow of the well;

(iii) forming an estimated predicted performance of the well as a function of formation relative permeability and the estimated productivity index of the gas condensate well for two phase flow; or

(7) if so:

(i) obtaining a measure of borehole pressure of the well;

(ii) forming an estimated predicted performance of the well as a function of borehole pressure and relative gas permeability of the well; and

(8) assembling in the memory the estimated predicted performance the well; and;

(b) an output display forming a display of selected ones of the determined measure of estimated predicted performance of the well.

7. The data processing system of Claim 6, wherein the predicted performance of the well comprises the gas rate.

8. The data processing system of Claim 6, wherein the processor in forming an estimated predicted performance of the well when the borehole pressure is above the dew point of the gas condensate performs the step of:

forming an estimated performance of the well under pseudo steady state conditions for the gas condensate.

9. The data processing system of Claim 6, wherein the processor in forming an estimated predicted performance of the well when the borehole pressure is below the dew point of the gas condensate performs the step of:

forming a measure of relative gas permeability as a function of saturation of the well..

10. A data storage device having stored in a computer readable medium non-transitory computer operable instructions for causing a data processing system to obtain measures in a computer system of predicted performance of a gas condensate well in a subsurface reservoir, the instructions stored in the data storage device causing the data processing system to perform the following steps:

(a) receiving component composition expansion data based on measurements from fluid from the well;

(b) receiving relative permeability data regarding formations containing the gas condensate of the well;

(c) receiving bottom hole pressure data of the well;

(d) obtaining a measure of dew point of gas condensate in the well based on the component composition expansion data;

(e) determining if the bottom hole pressure of the well is above the dew point of the gas condensate of the well, and,

(f) if not:

(1) forming an estimated productivity index of the gas condensate well for single phase flow of the well;

(2) forming an estimated productivity index of the gas condensate well for two phase flow of the well;

(3) forming an estimated predicted performance of the well as a function of formation relative permeability and the estimated productivity index of the gas condensate well for two phase flow; or

(g) if so:

(1) obtaining a measure of borehole pressure of the well;

(2) forming an estimated predicted performance of the well as a function of borehole pressure and relative gas permeability of the well; and

(h) assembling in the memory the estimated predicted performance the well.

11. The data storage device of Claim 10, wherein the predicted performance of the well comprises the gas rate.

12. The data storage device of Claim 10, wherein the instructions include instructions causing the data processing system in forming an estimated predicted performance of the well when the borehole pressure is above the dew point of the gas condensate to perform the step of:

forming an estimated performance of the well under pseudo steady state conditions for the gas condensate.

13. The data storage device of Claim 10, wherein the instructions include instructions causing the data processing system in forming an estimated predicted performance of the well

when the borehole pressure is below the dew point of the gas condensate to perform the step of:

forming a measure of relative gas permeability as a function of saturation of the well.

14. The data storage device of Claim 10, wherein the instructions includes causing the data processing system to form an output display of selected ones of the determined measure of estimated predicted performance of the well.

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FIG. 1

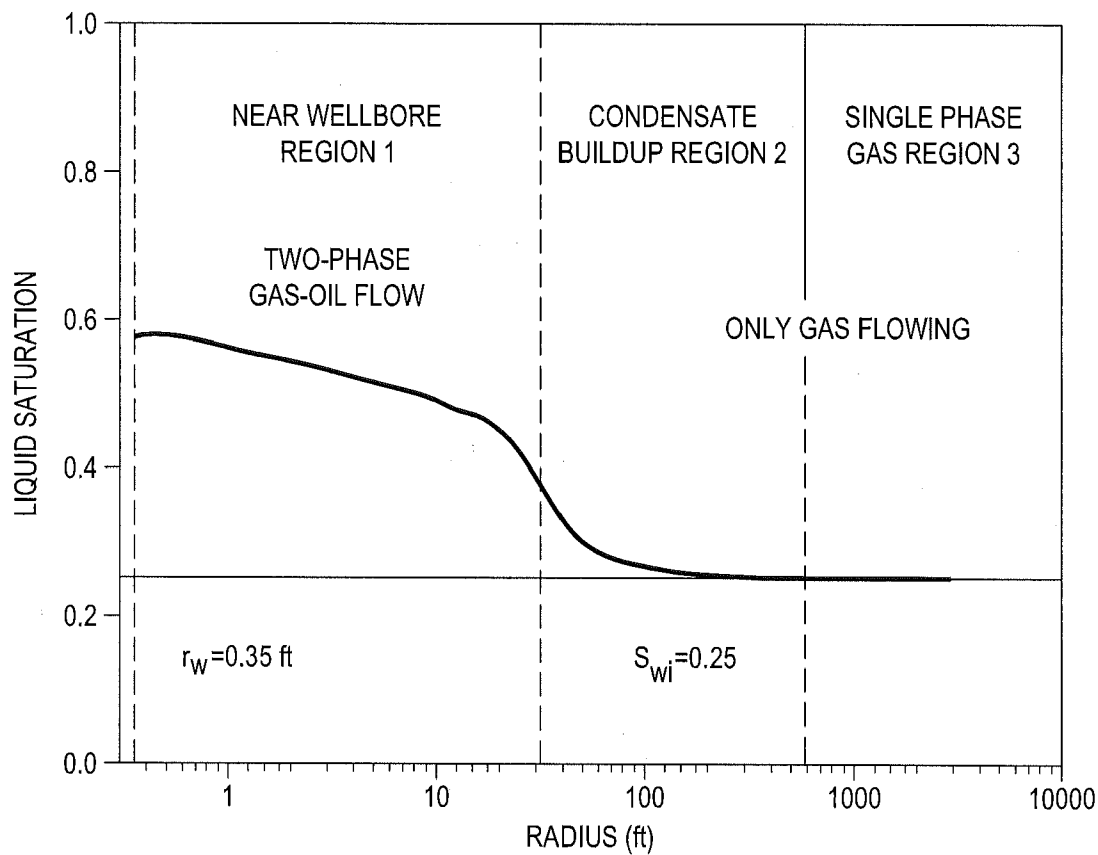
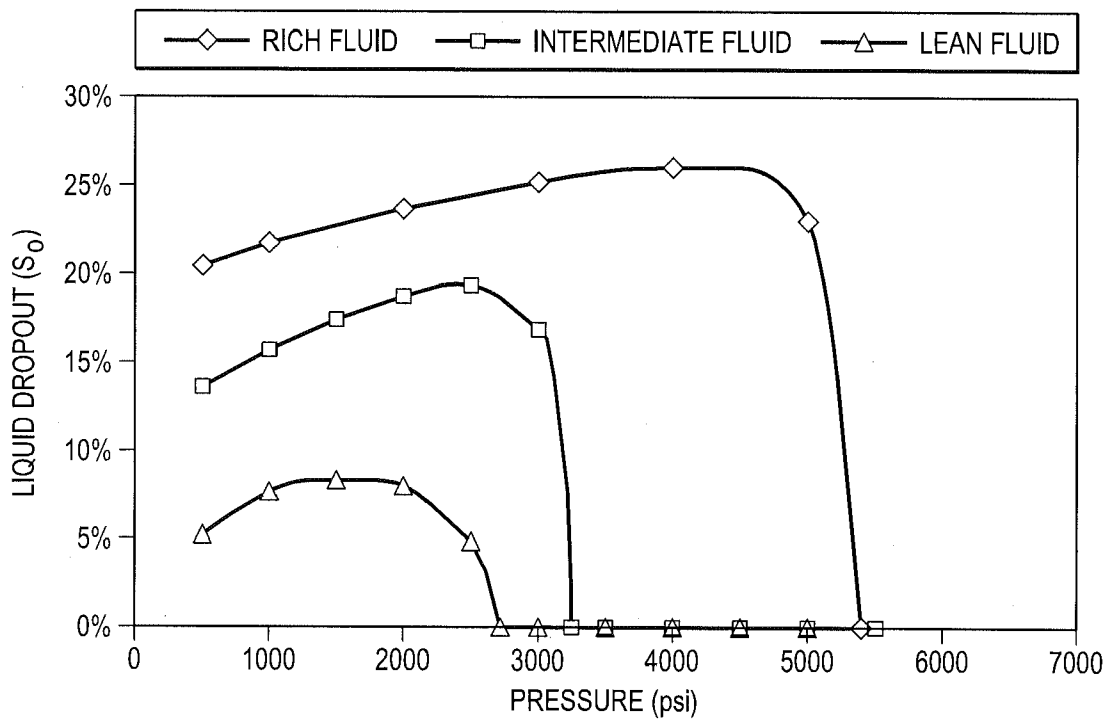
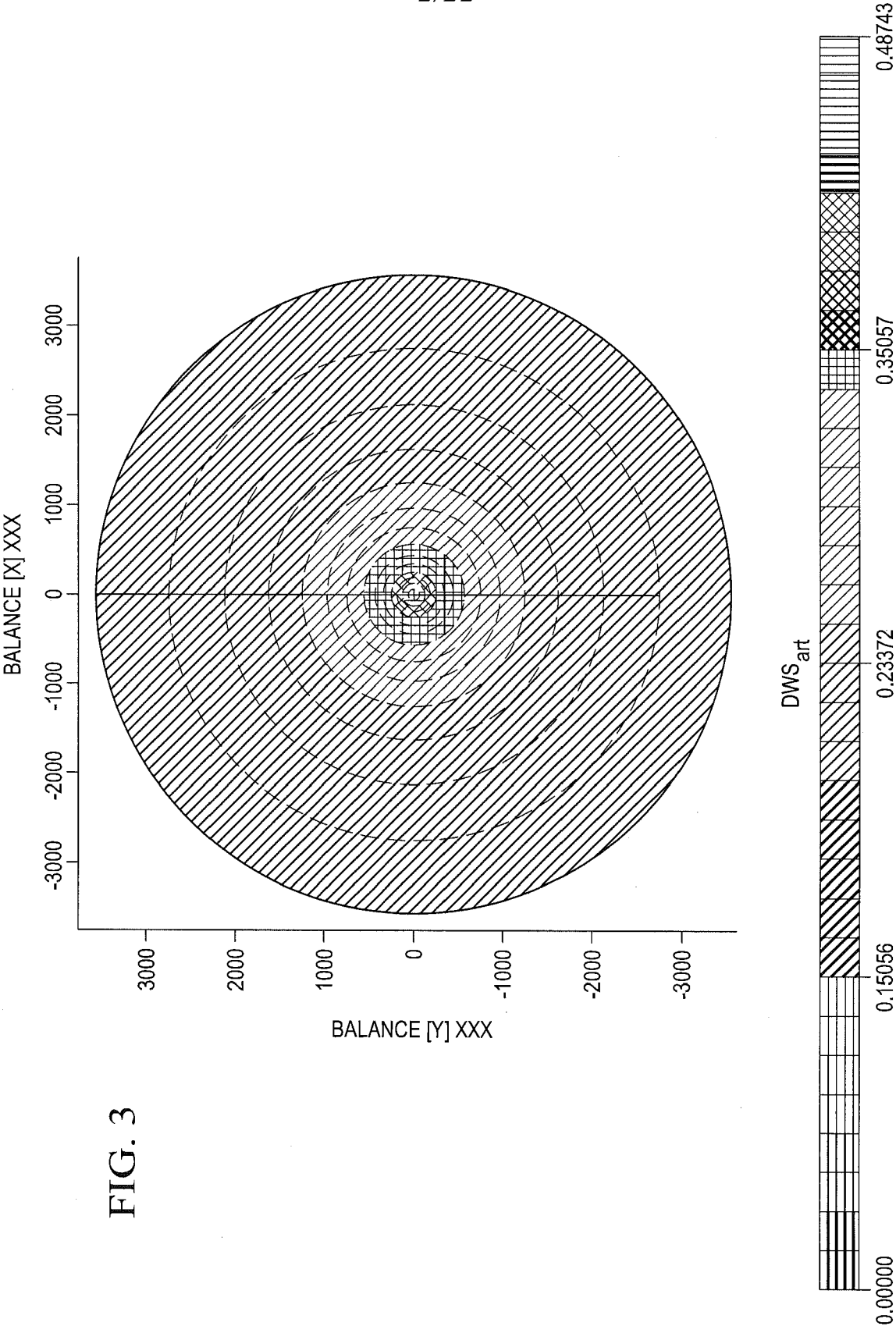
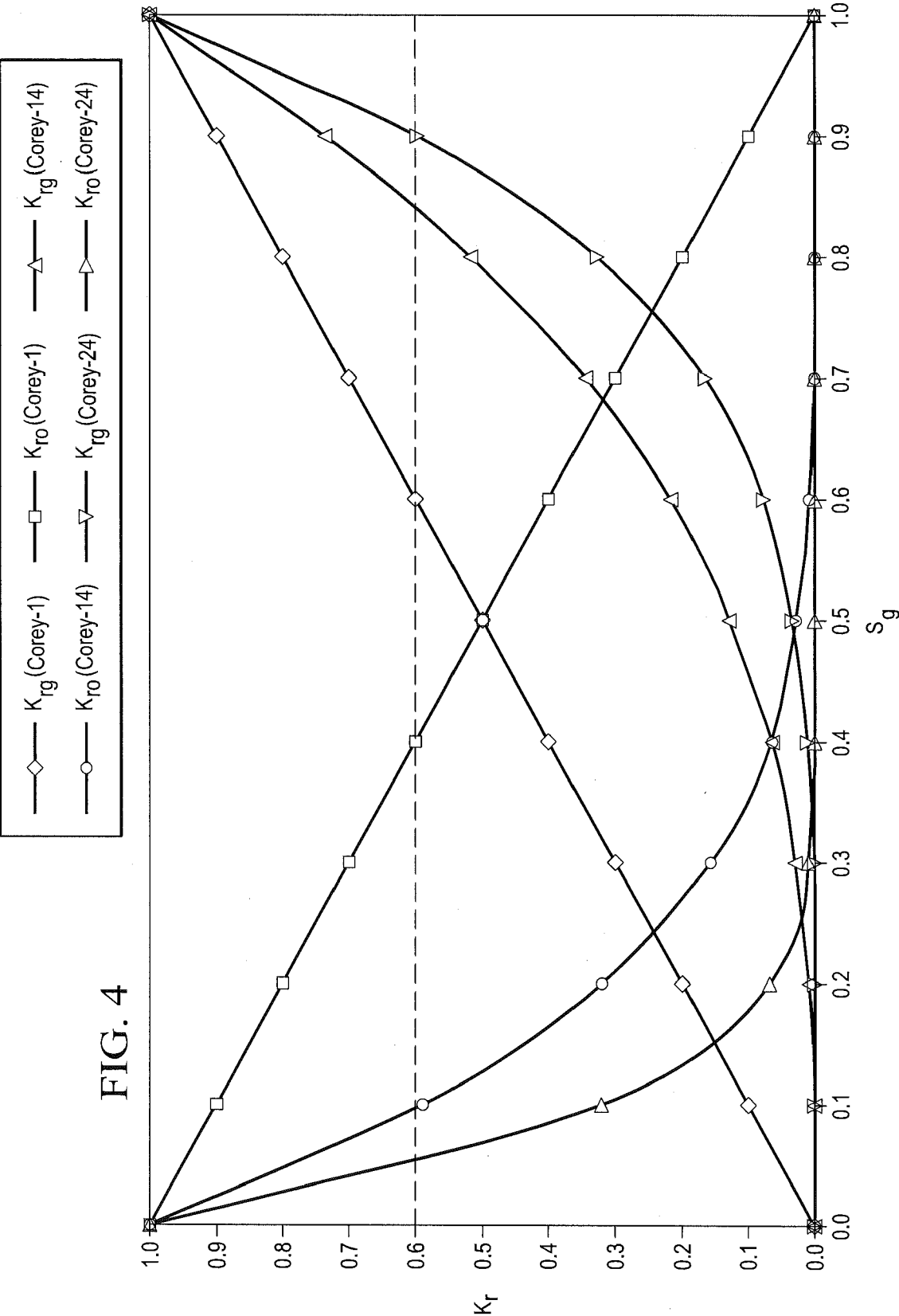


FIG. 2





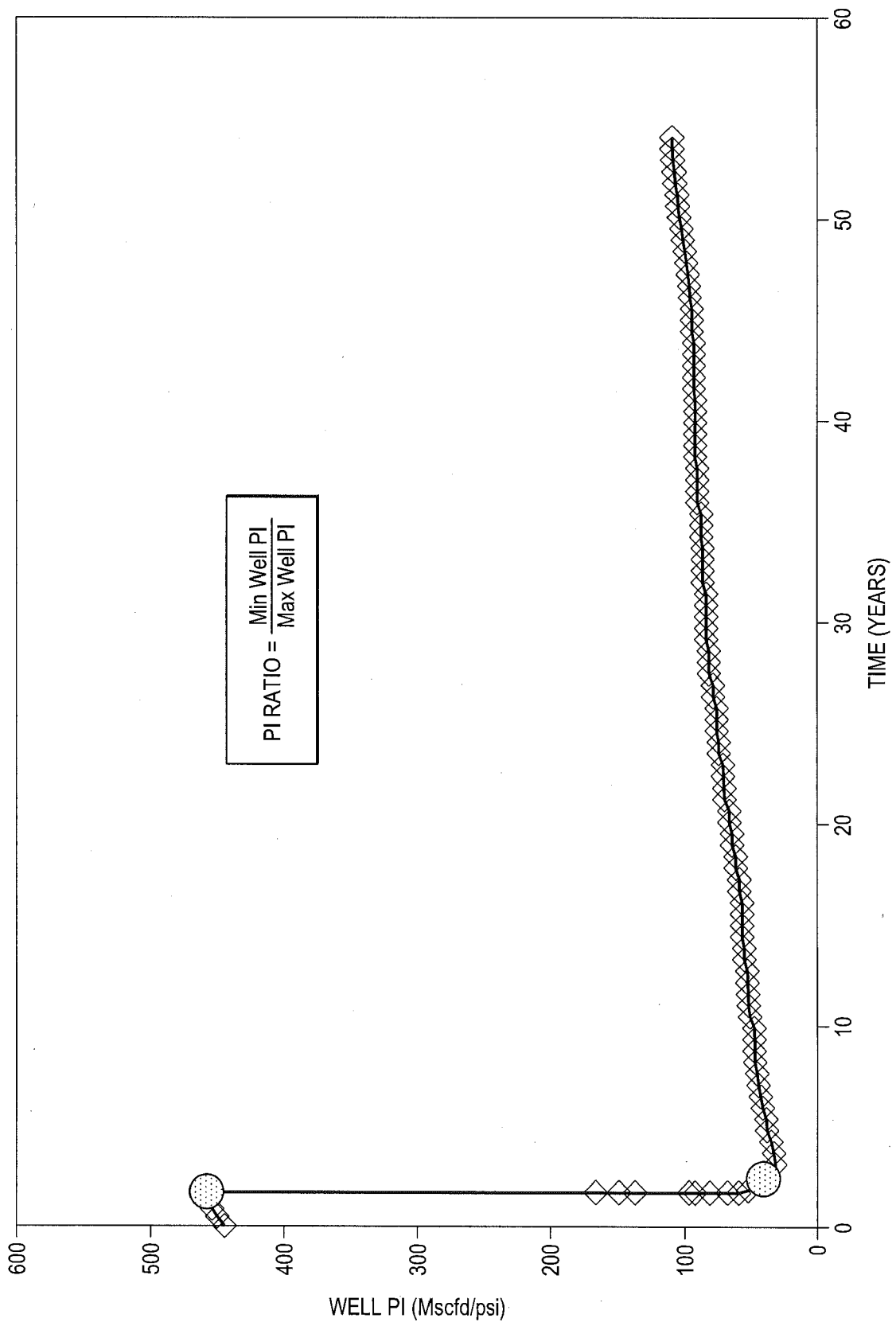
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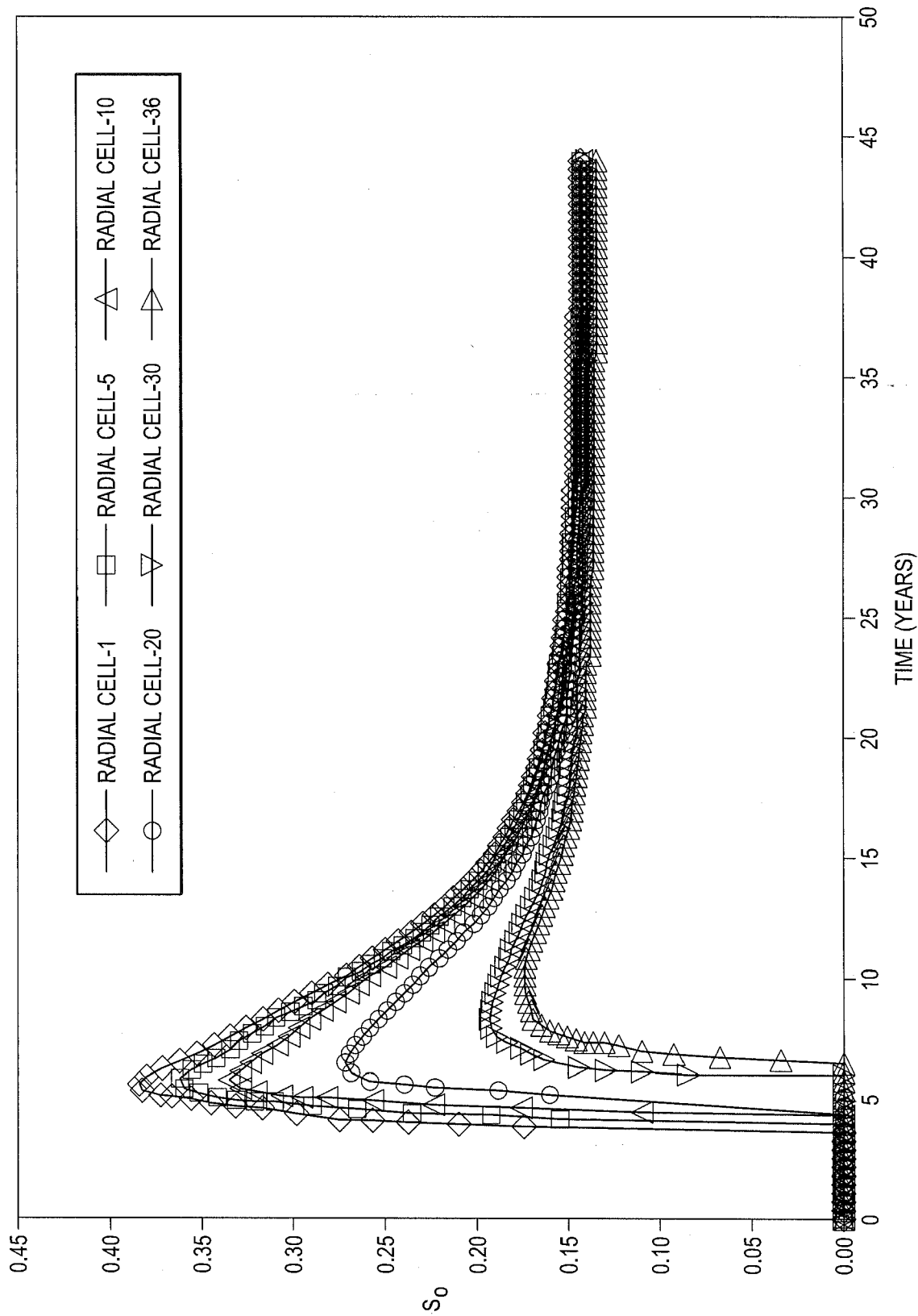
FIG. 5

PRODUCTIVITY INDEX (FINE RADIAL MODEL)



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FIG. 6



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RICH- $K_{rg}(S_o^*)$ vs PI RATIO

FIG. 7

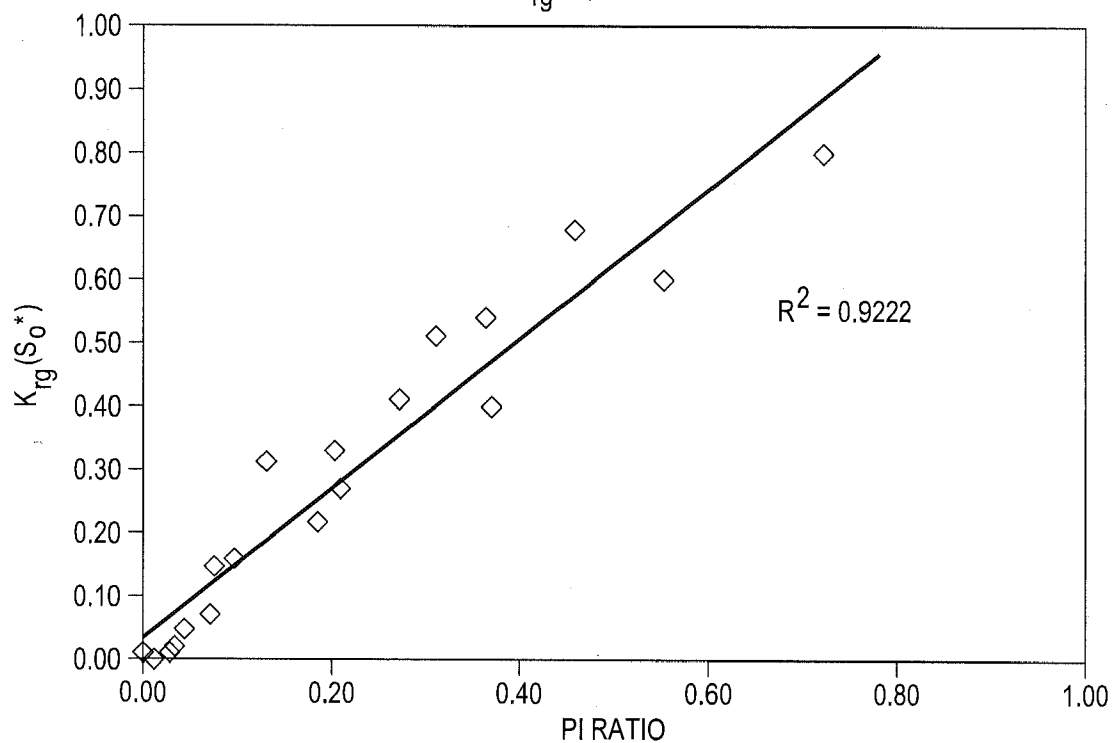
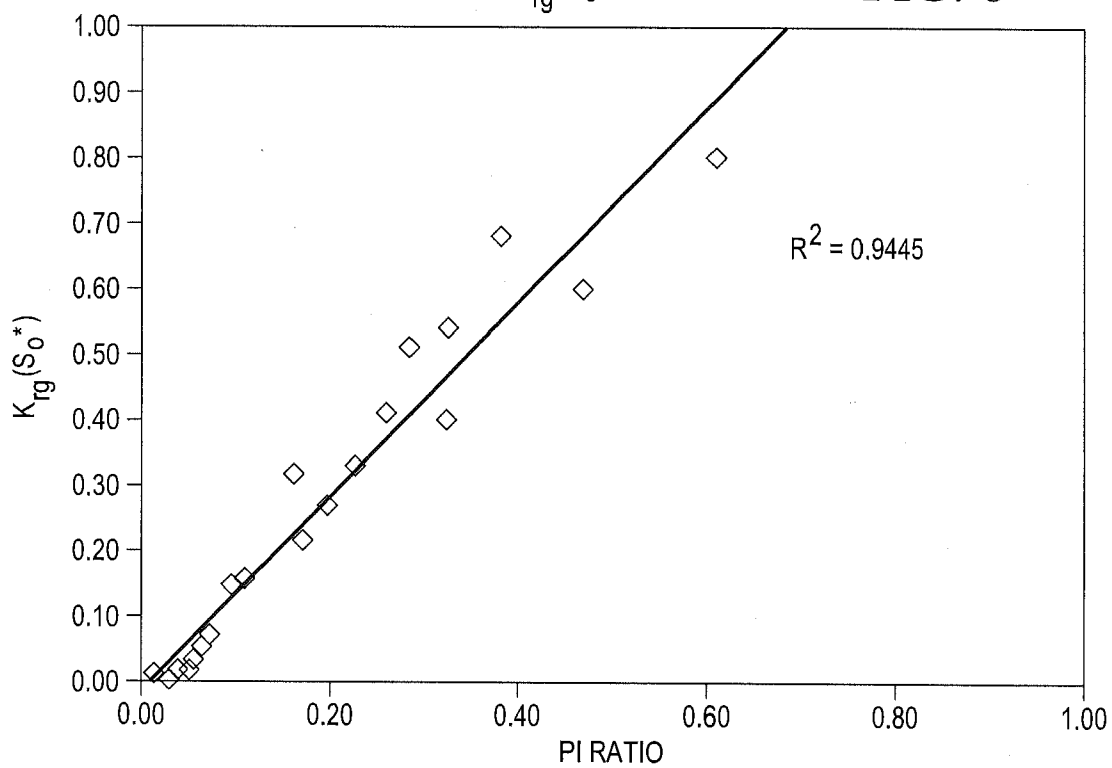
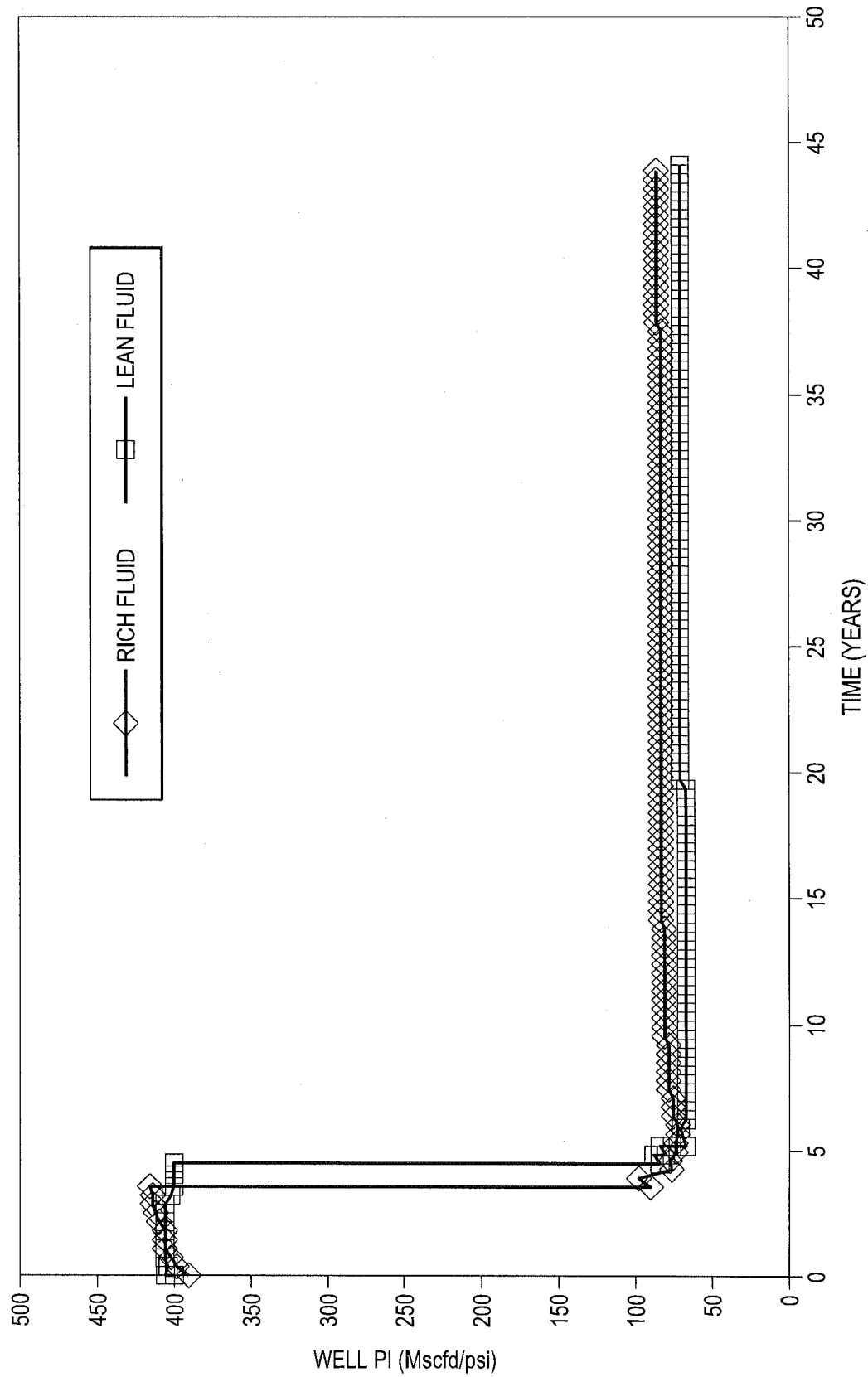
LEAN- $K_{rg}(S_o^*)$ vs PI RATIO

FIG. 8



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FIG. 9



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FIG. 10

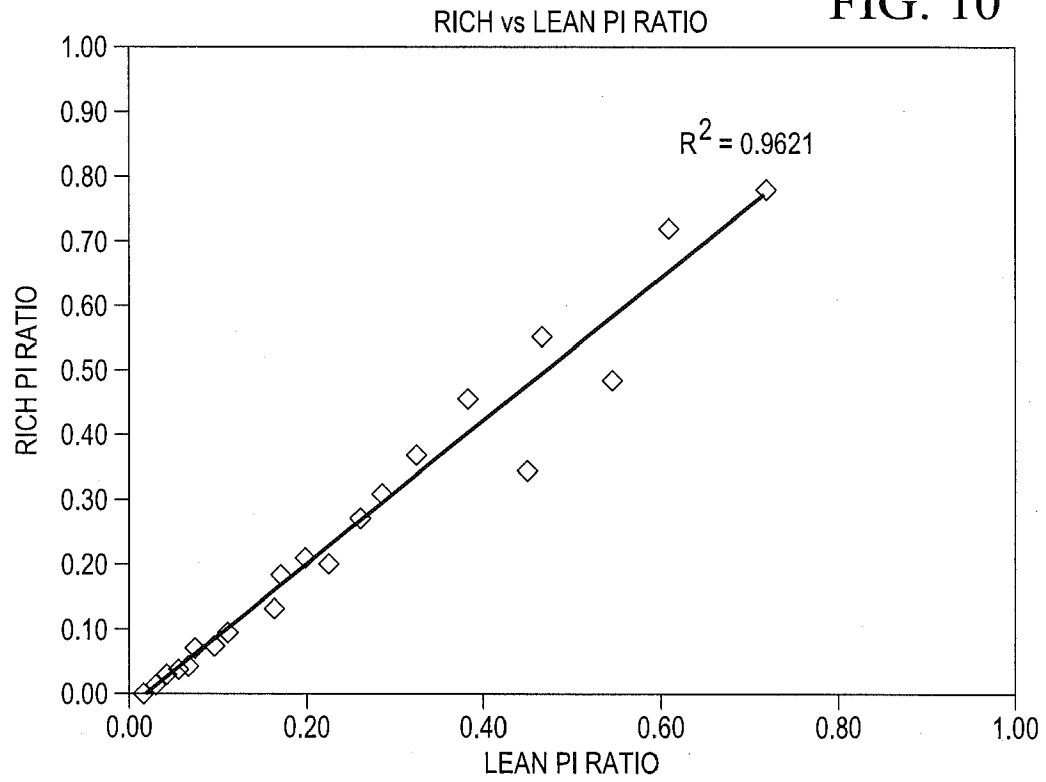
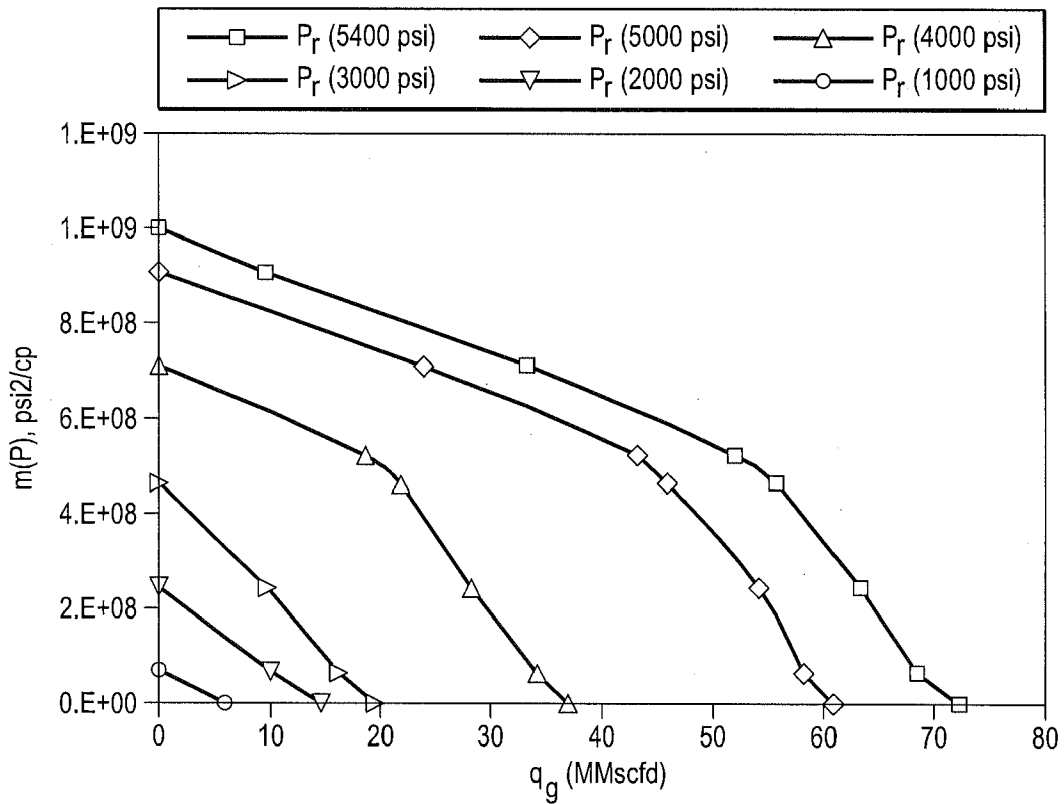
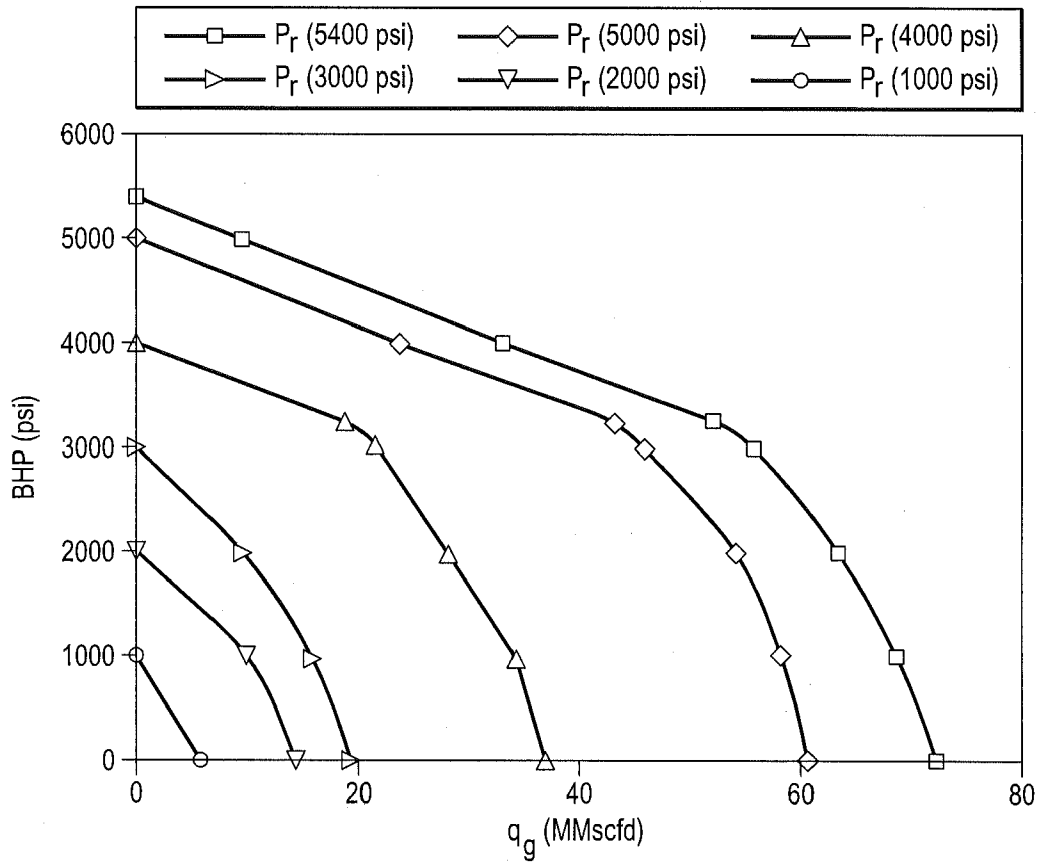


FIG. 11



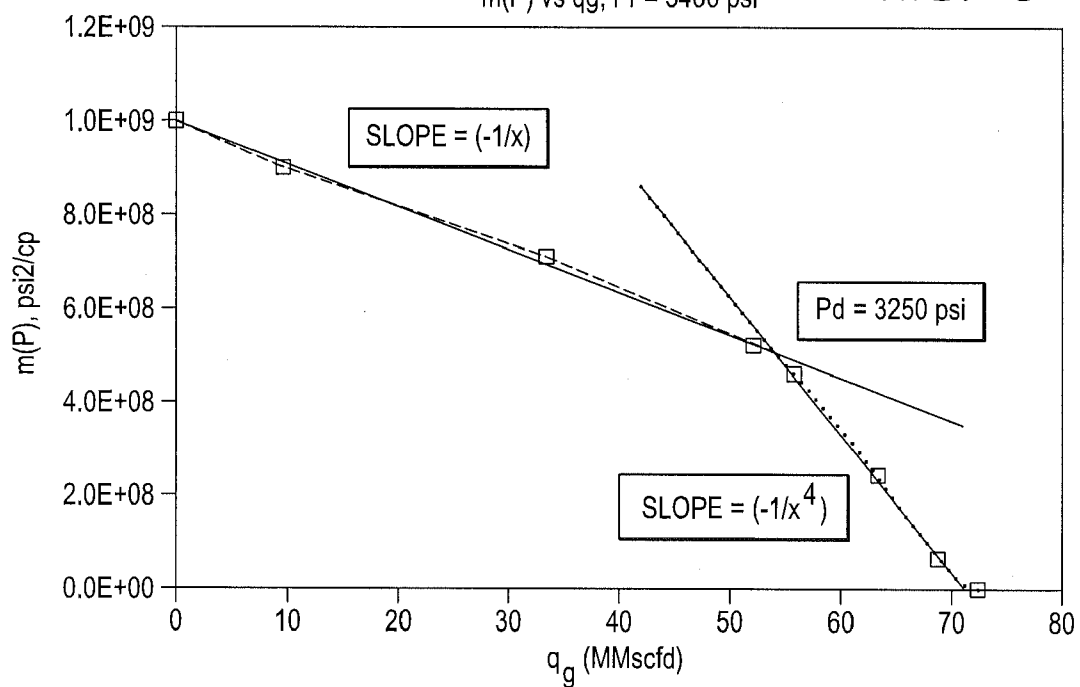
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FIG. 12



$m(P)$ vs q_g , $P_r = 5400$ psi

FIG. 13



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FIG. 14

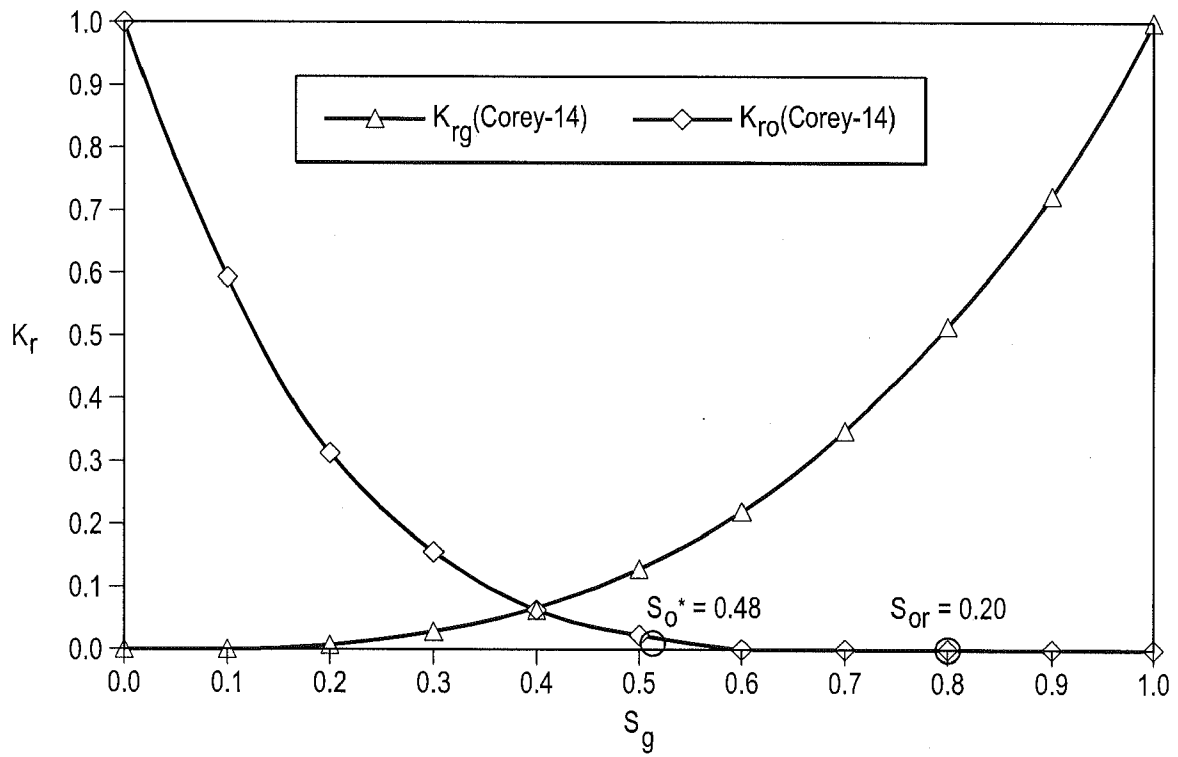
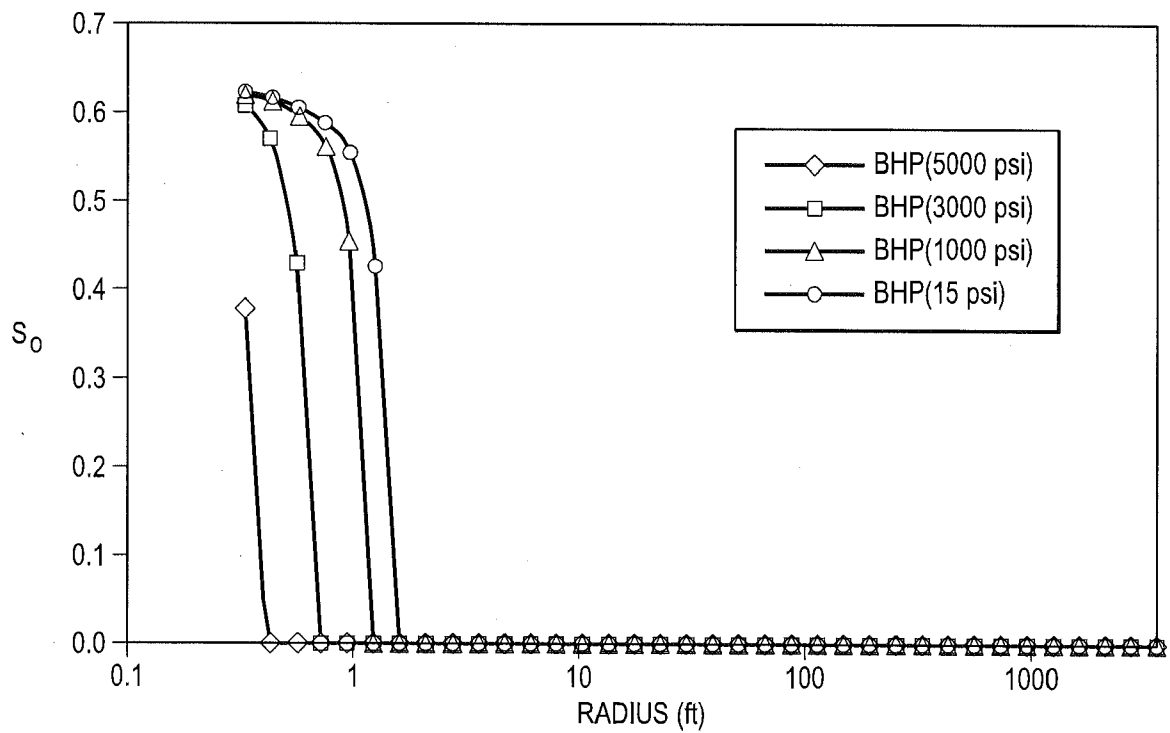


FIG. 15



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FIG. 16

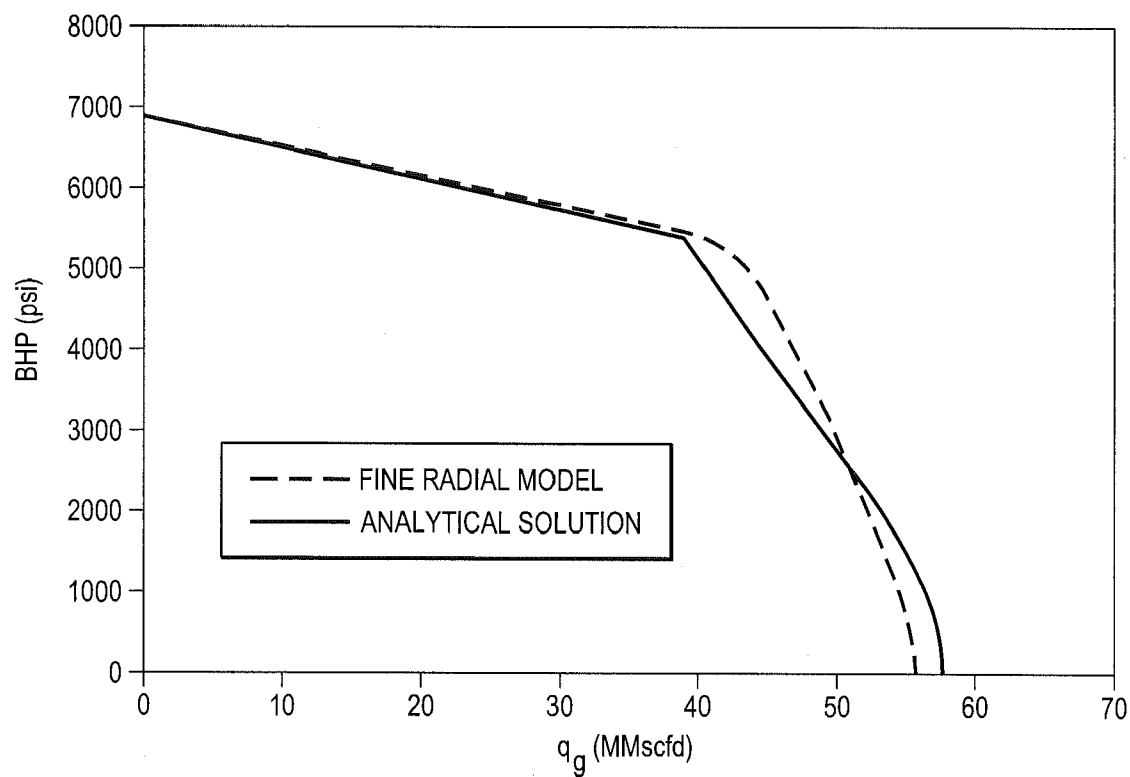
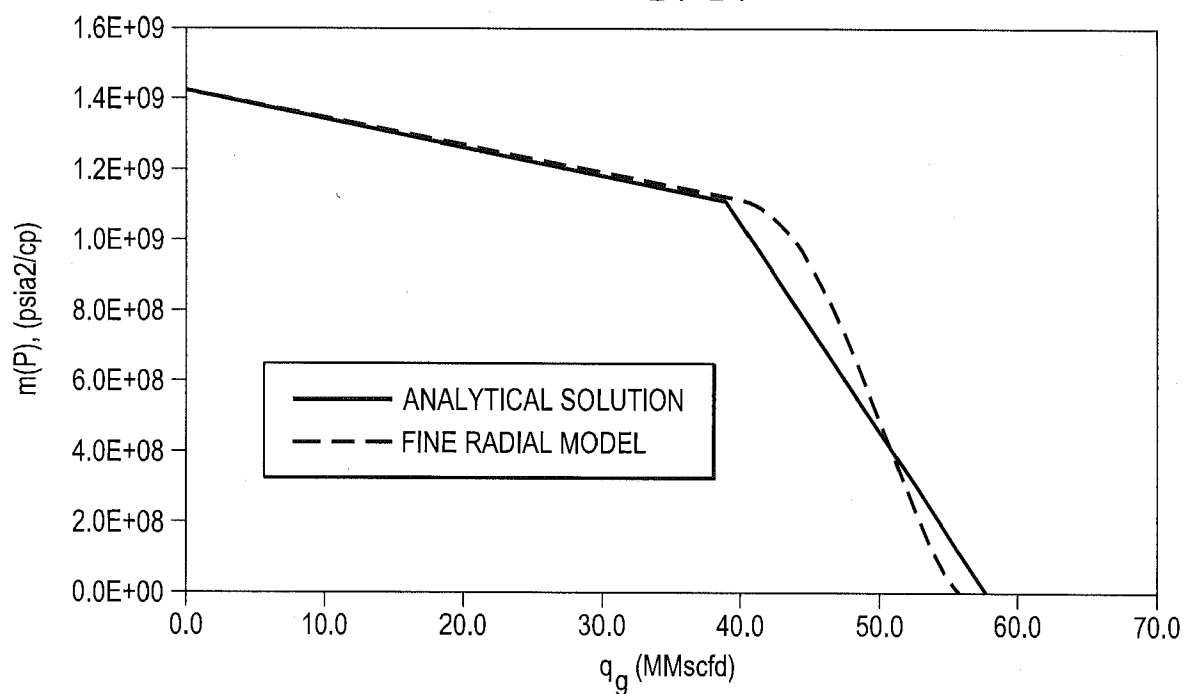


FIG. 17



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FIG. 18

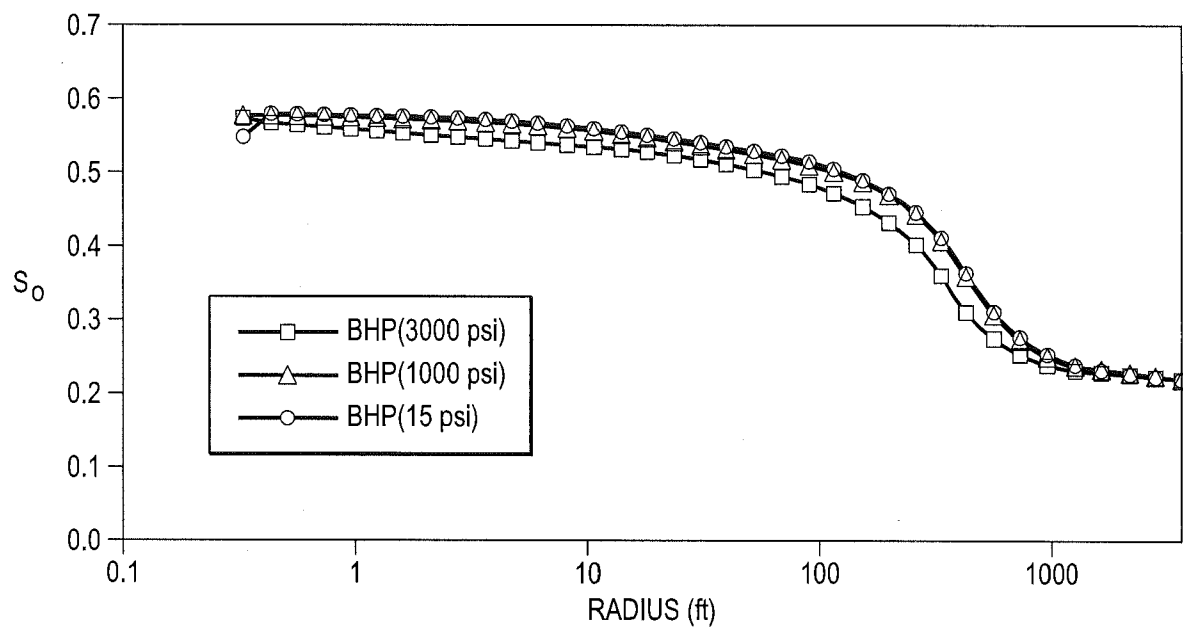
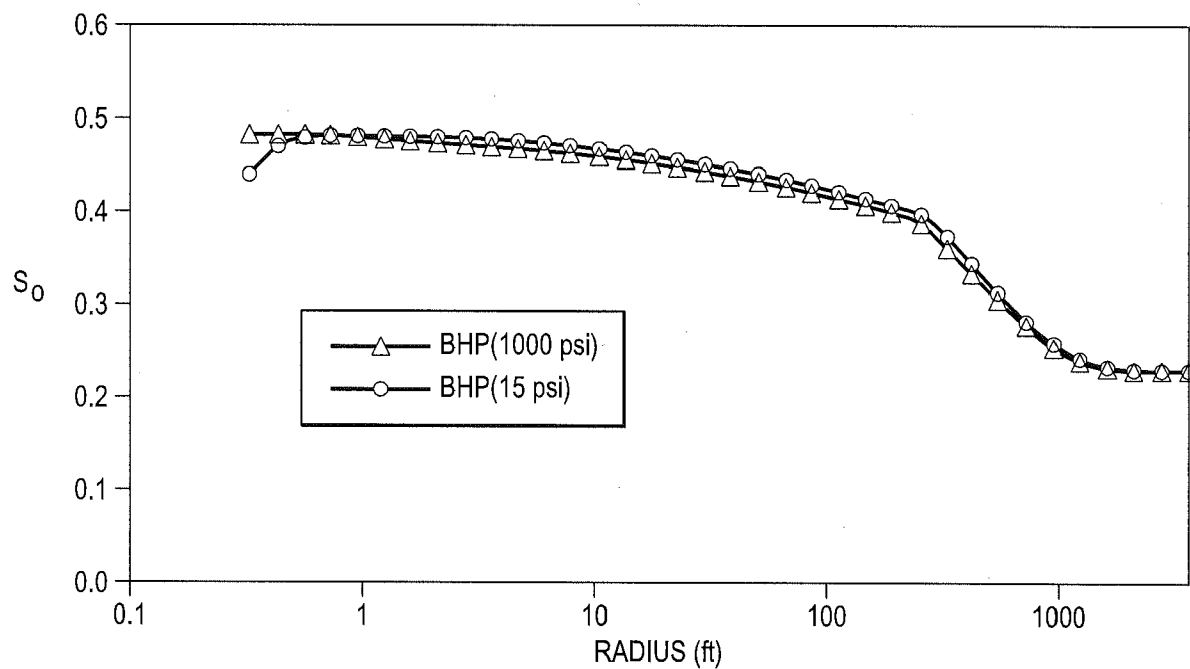


FIG. 19



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FIG. 20

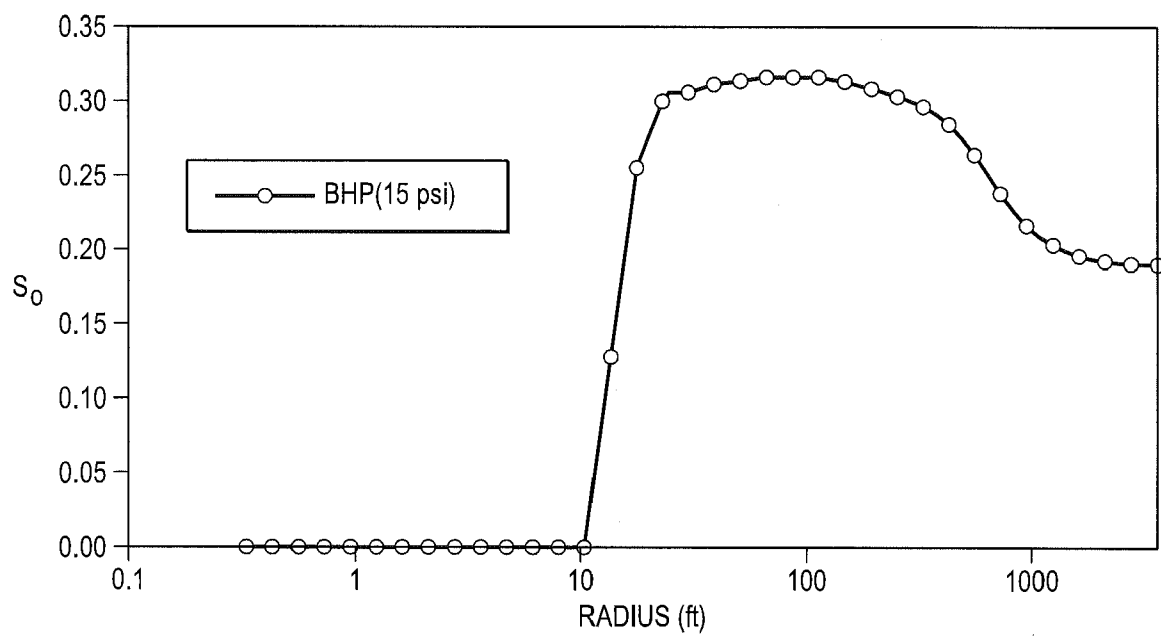
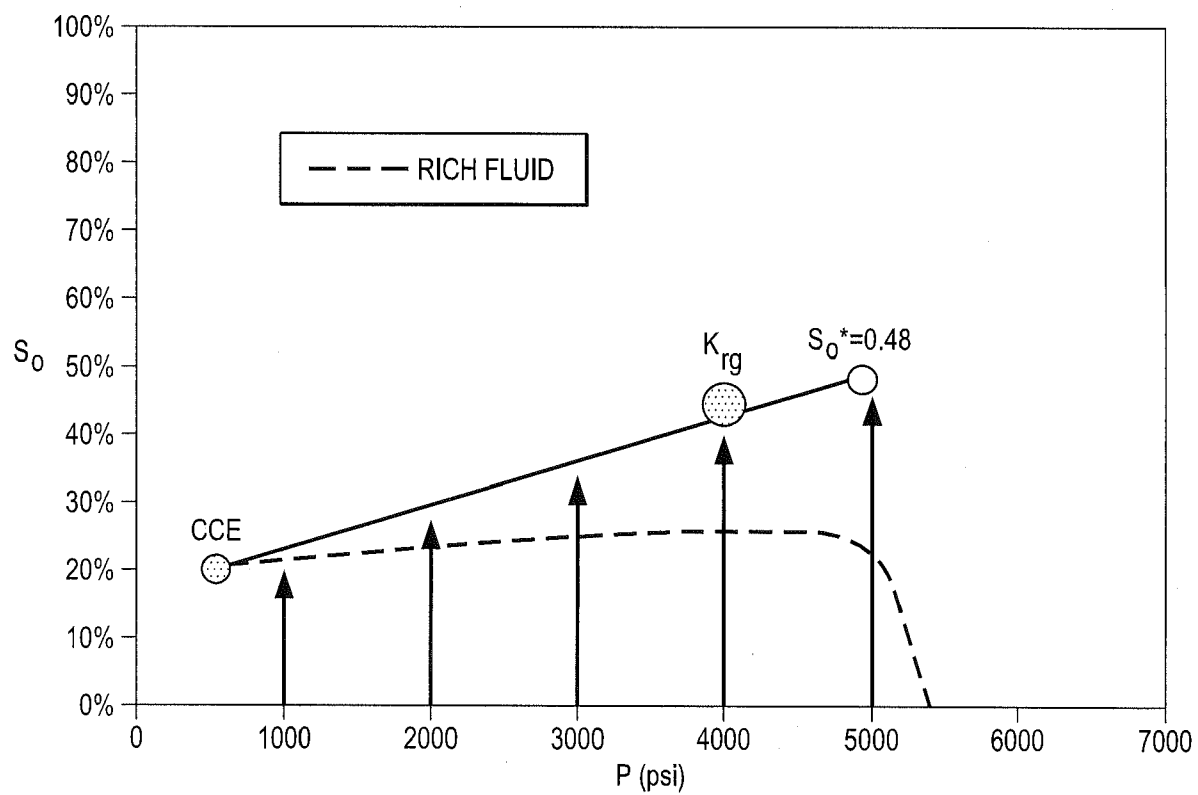


FIG. 21



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FIG. 22

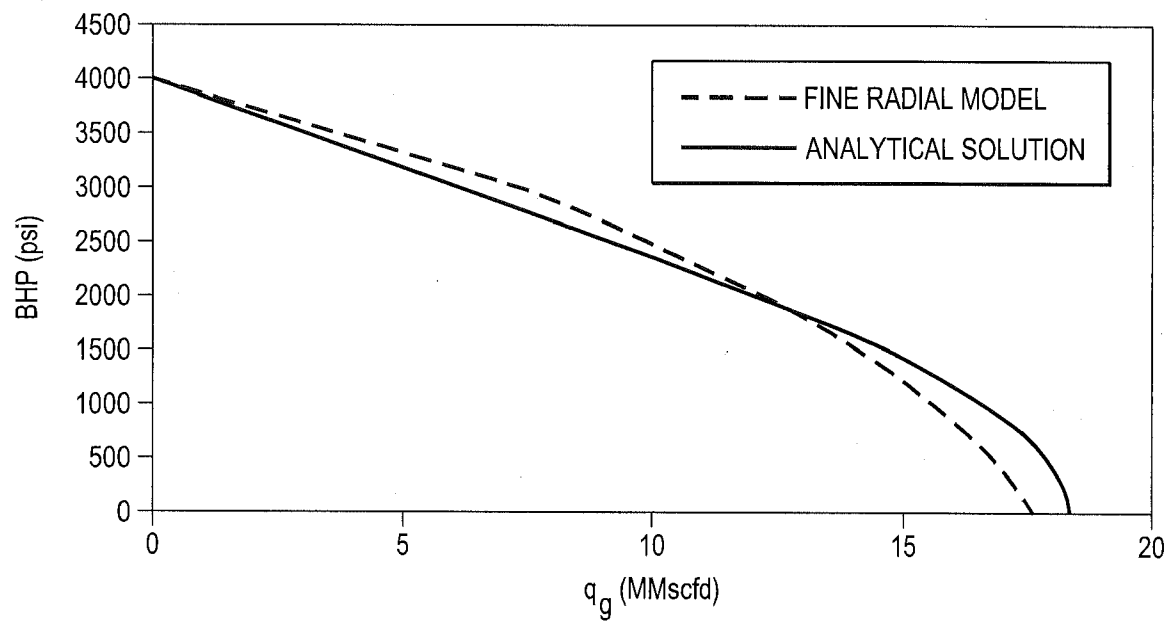
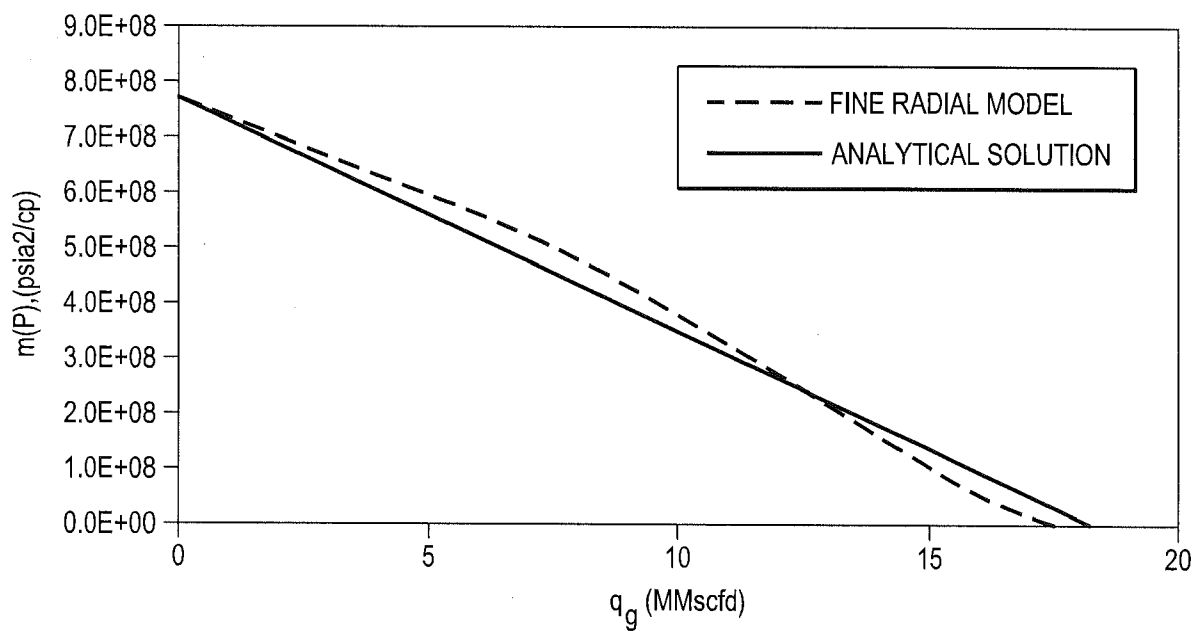
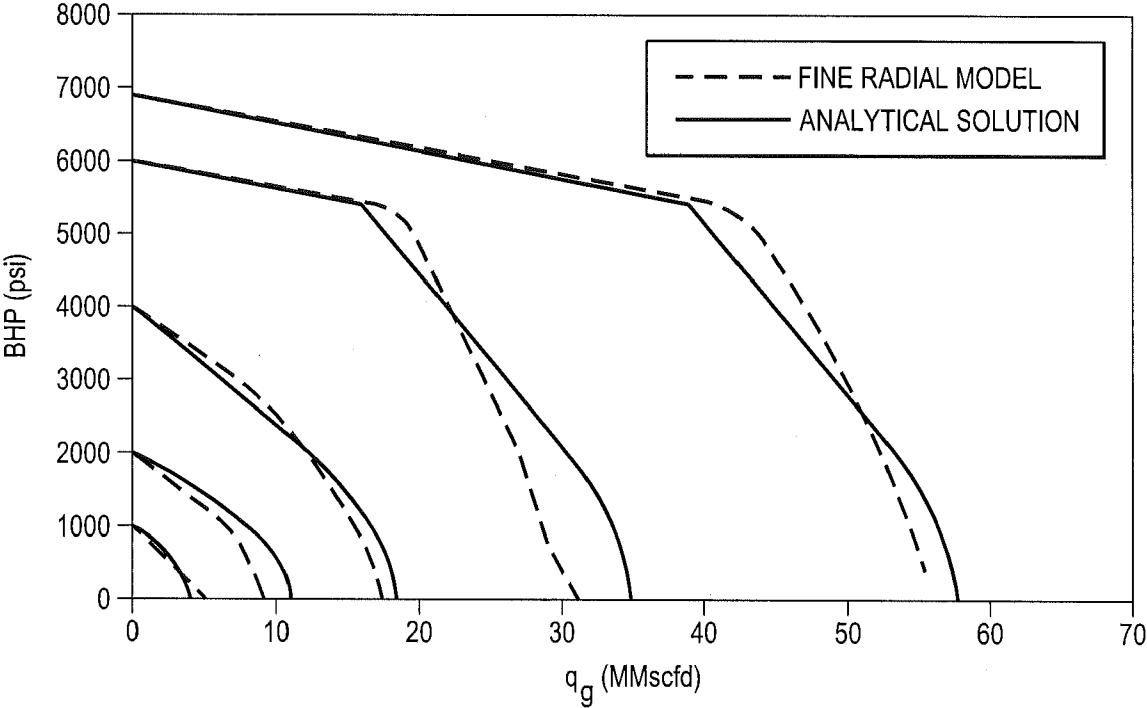


FIG. 23



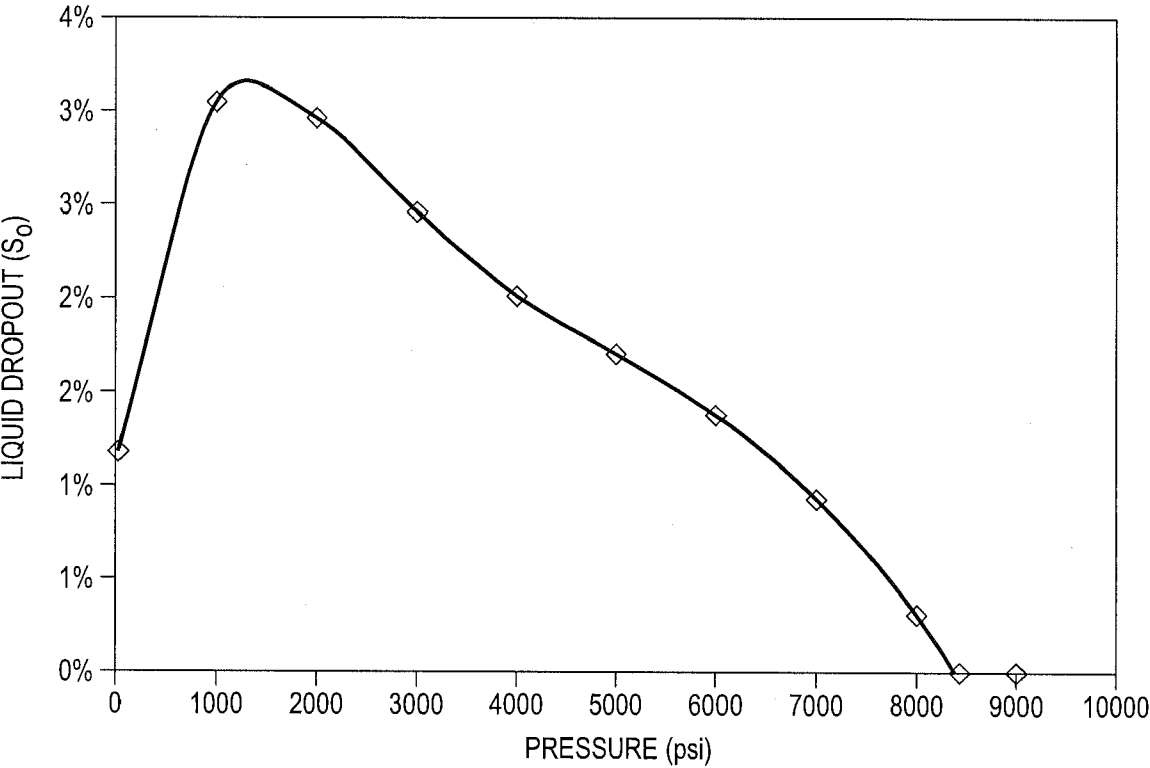
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FIG. 24



LIQUID DROPOUT CURVE (CCE)

FIG. 27



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FIG. 25

PRODUCTIVITY INDEX (FINE RADIAL MODEL)

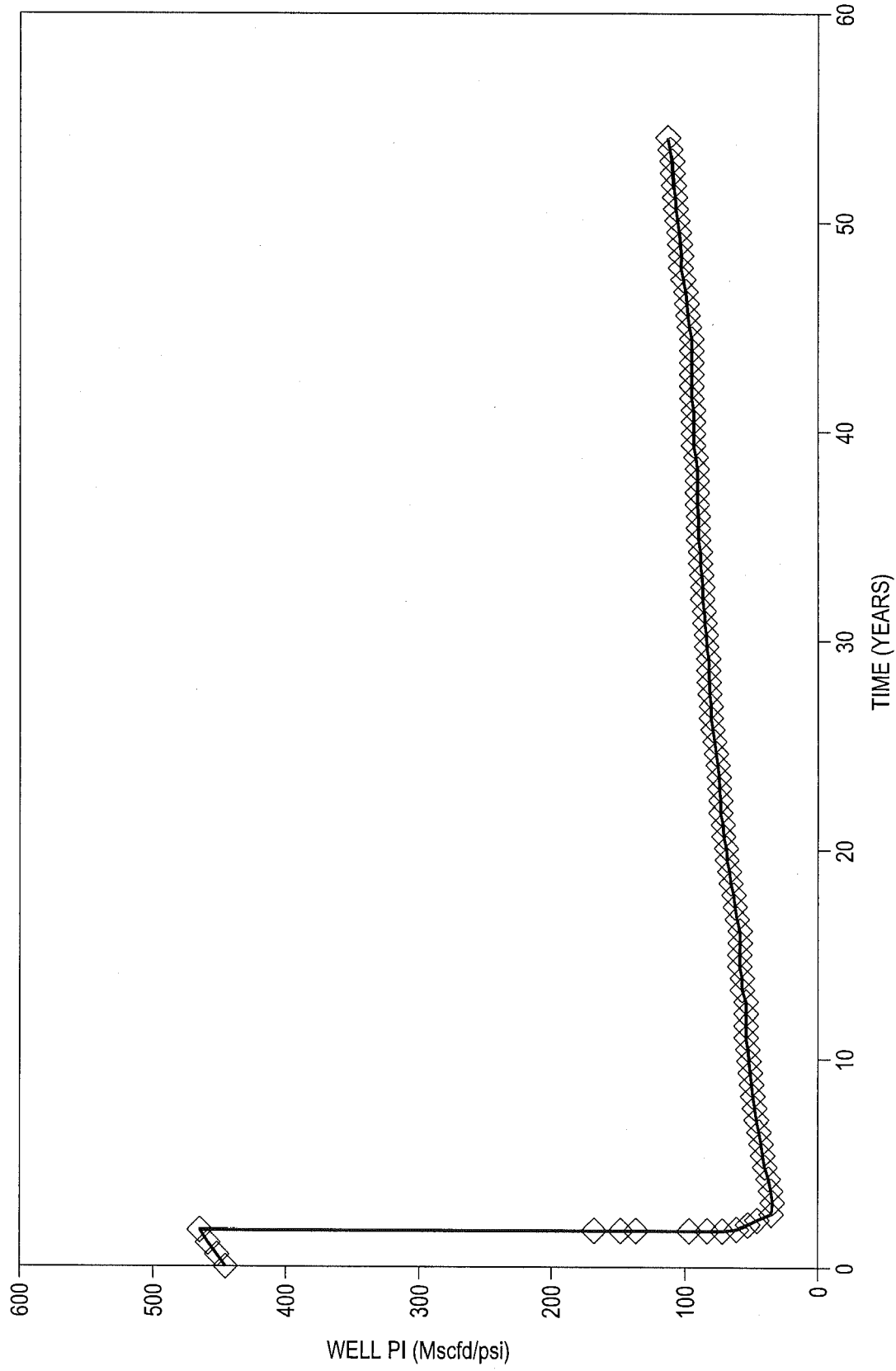
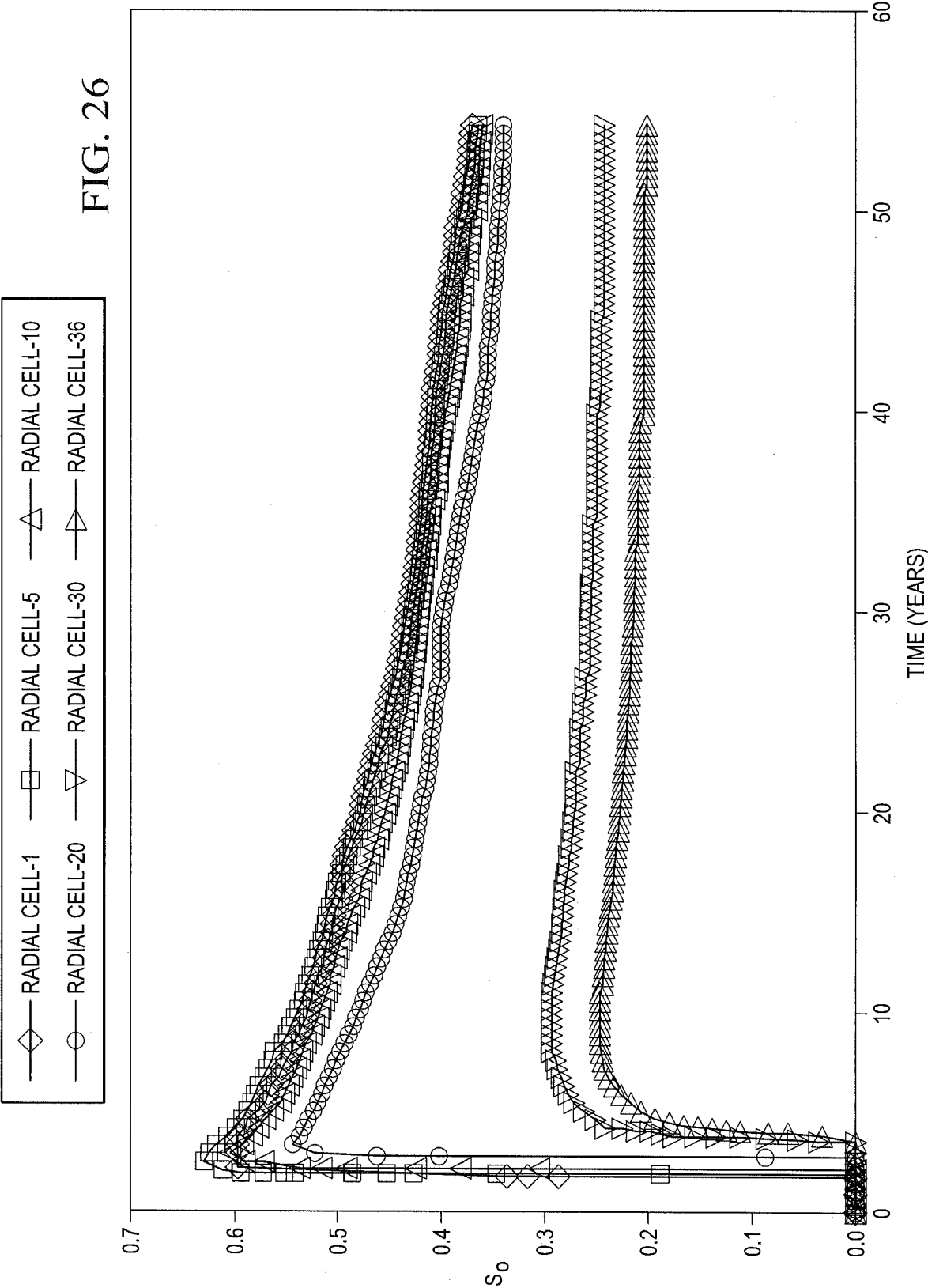
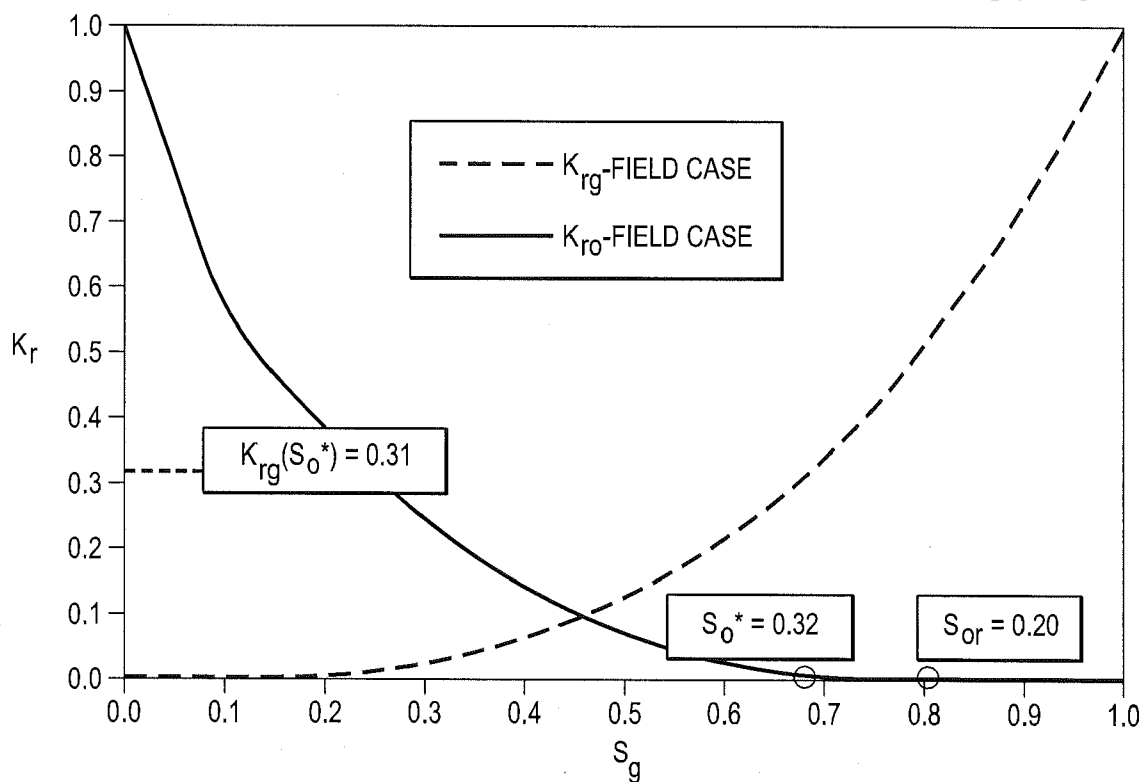


FIG. 26



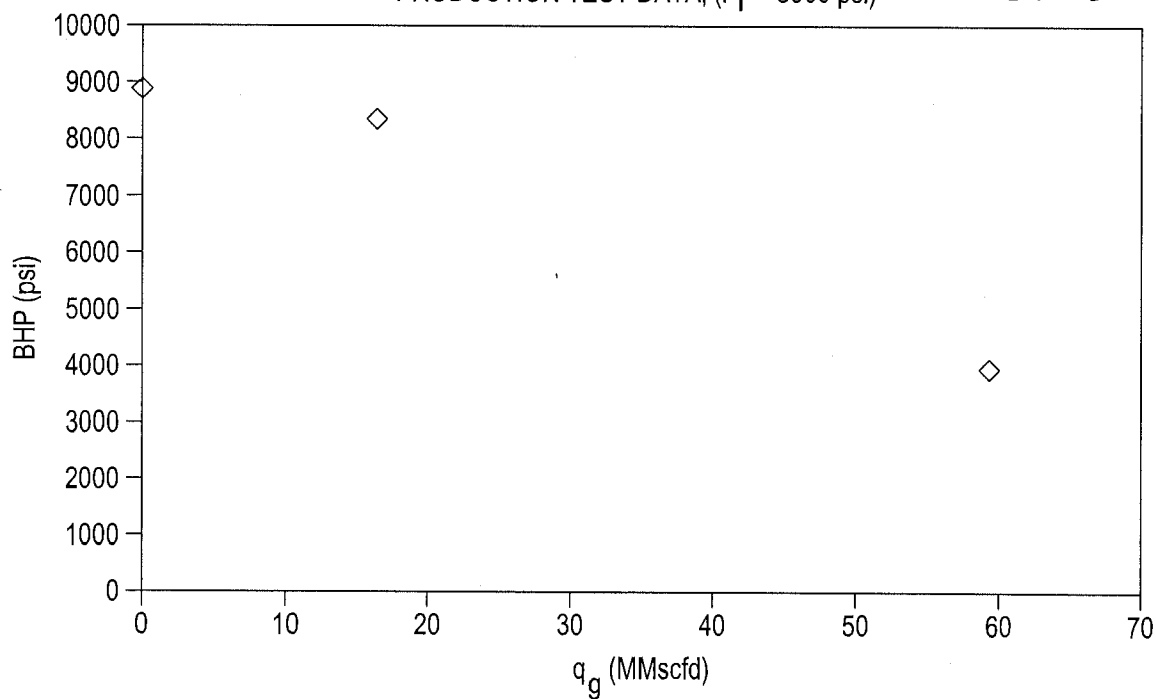
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FIG. 28

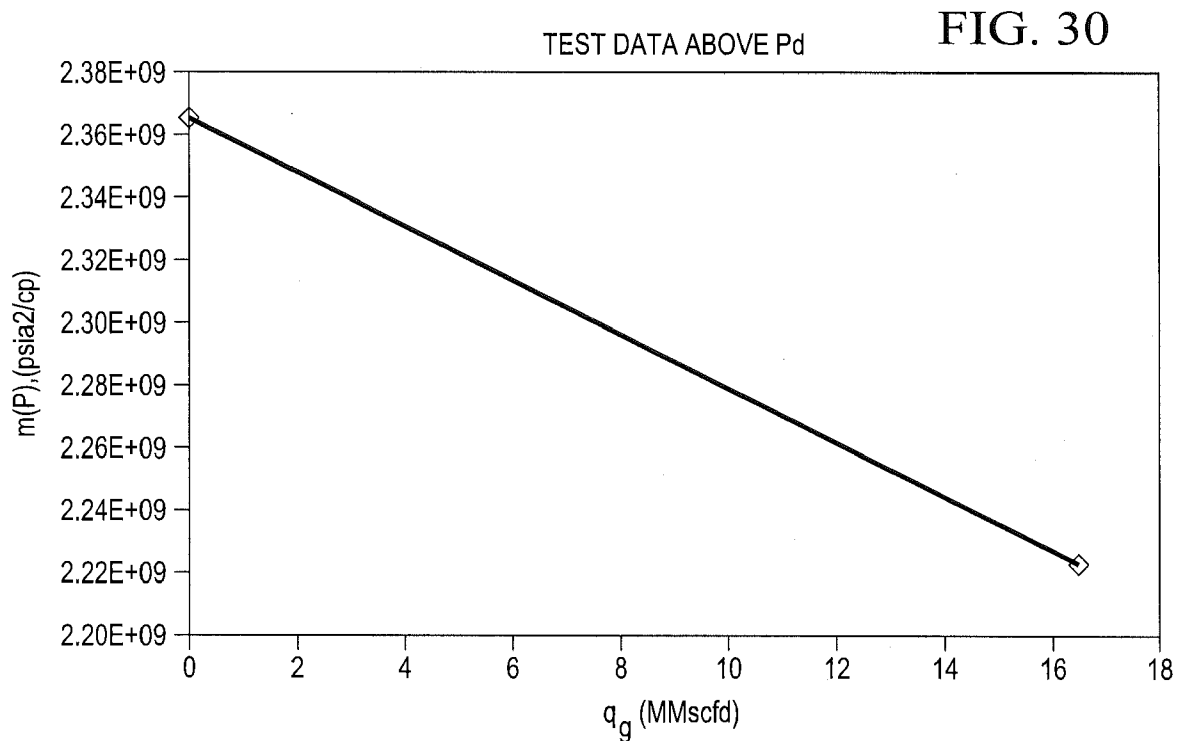
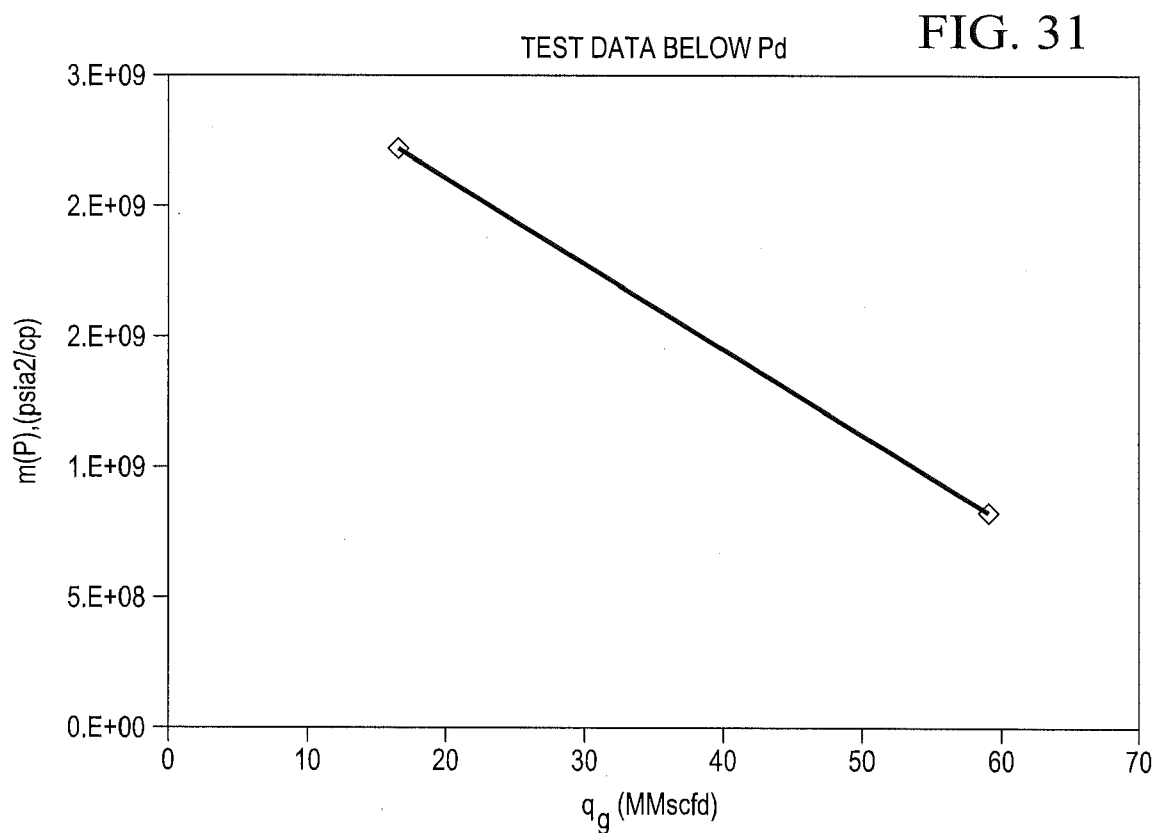


PRODUCTION TEST DATA, ($P_r = 8900$ psi)

FIG. 29



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FIG. 32

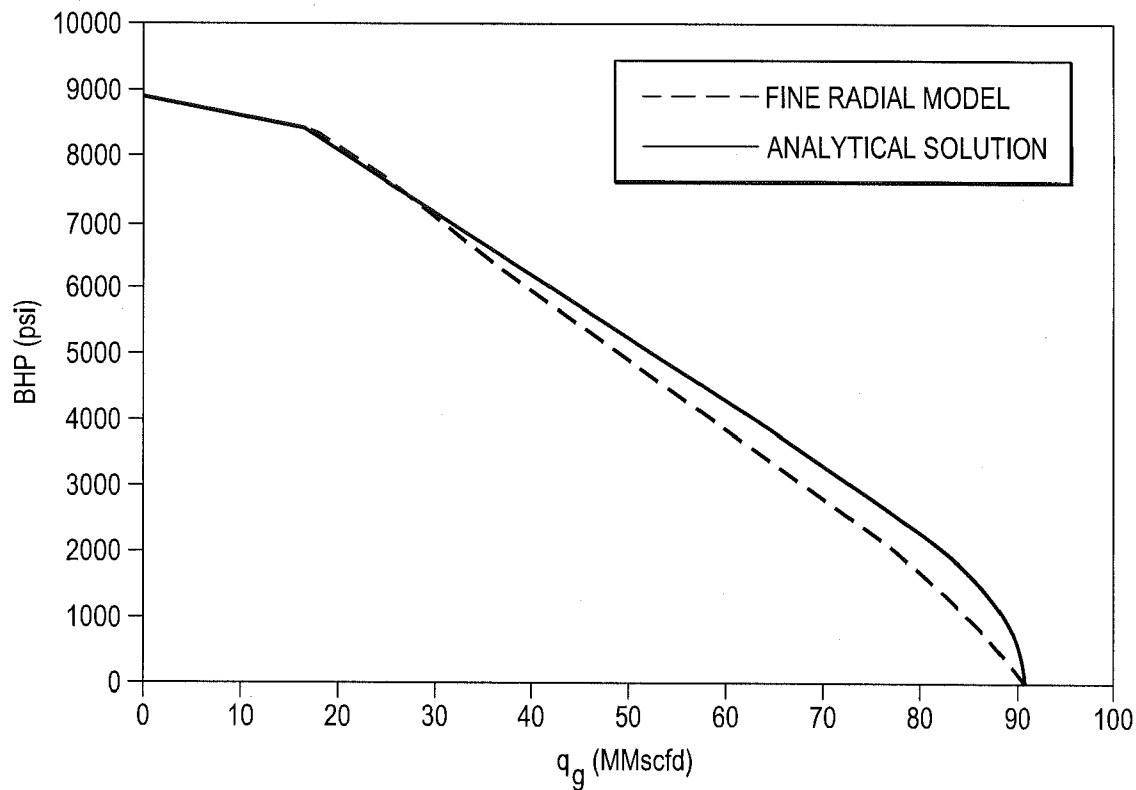
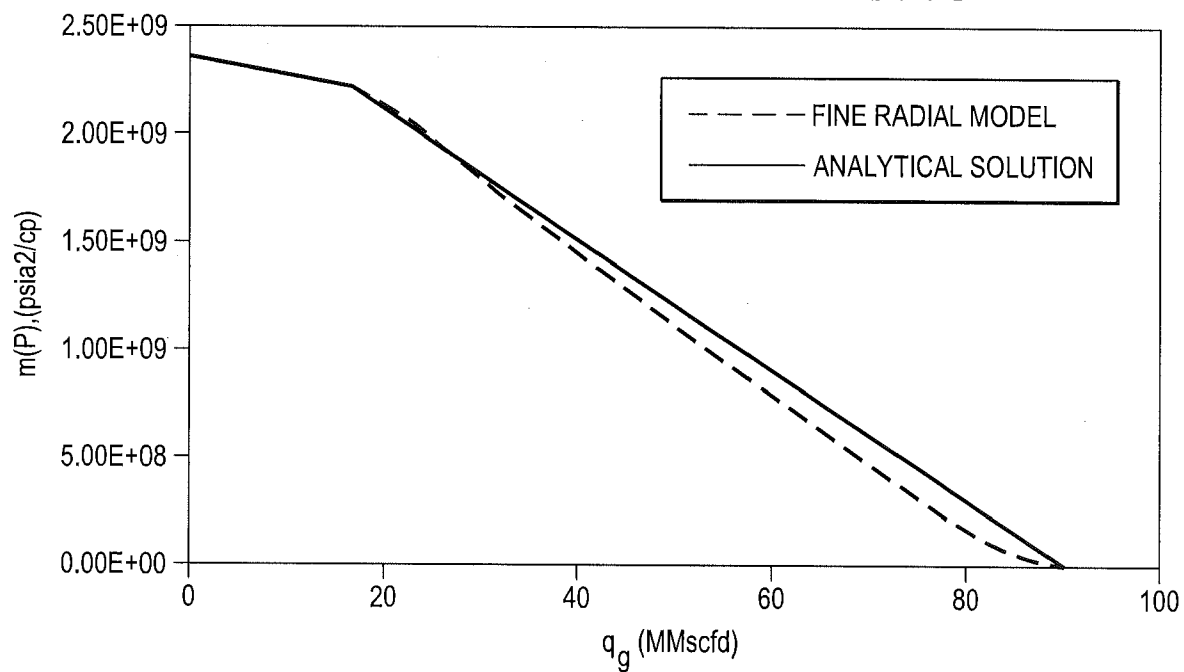
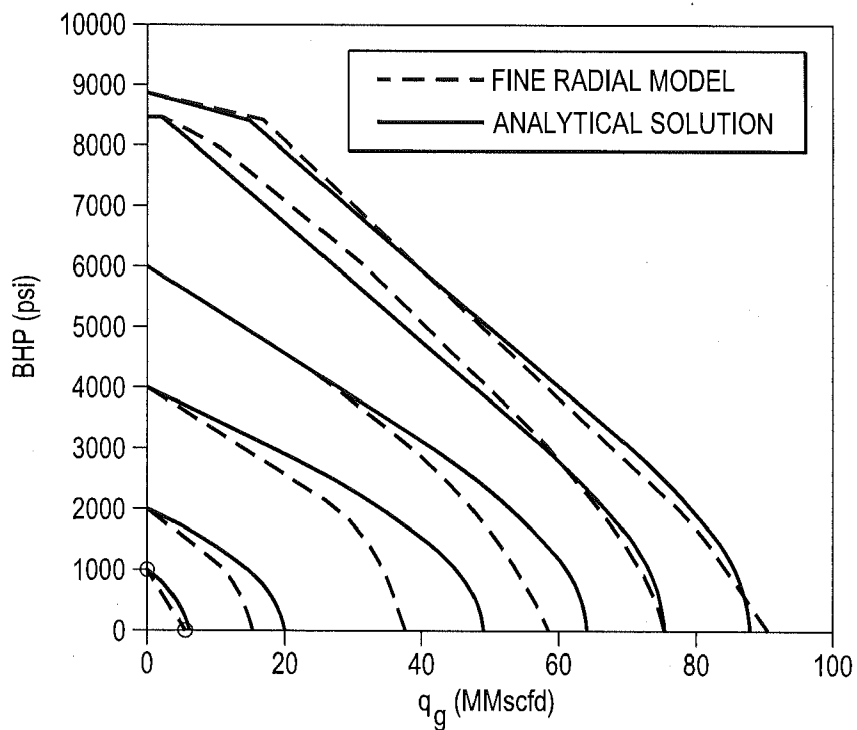
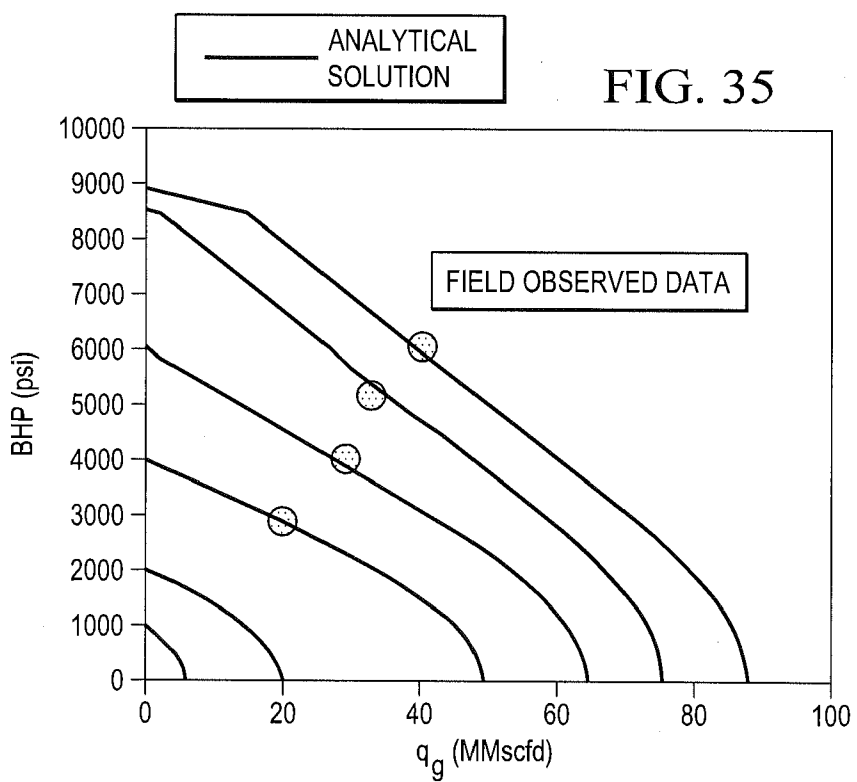


FIG. 33



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FIG. 34



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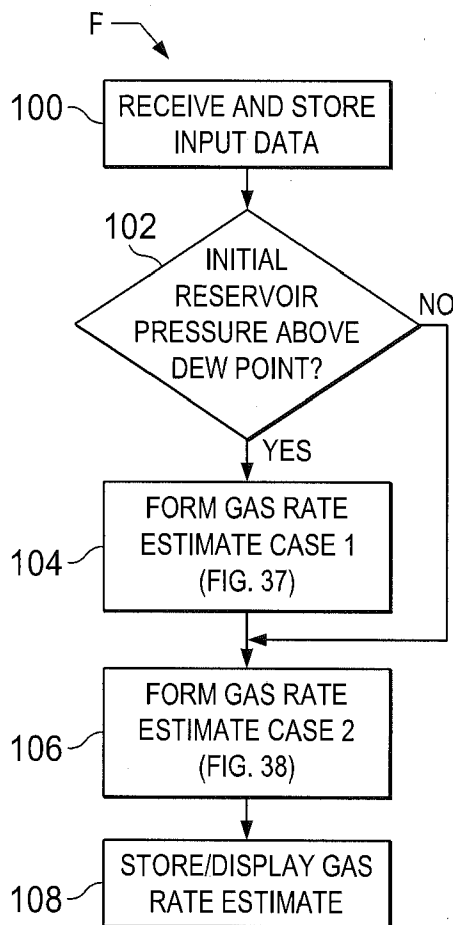


FIG. 36

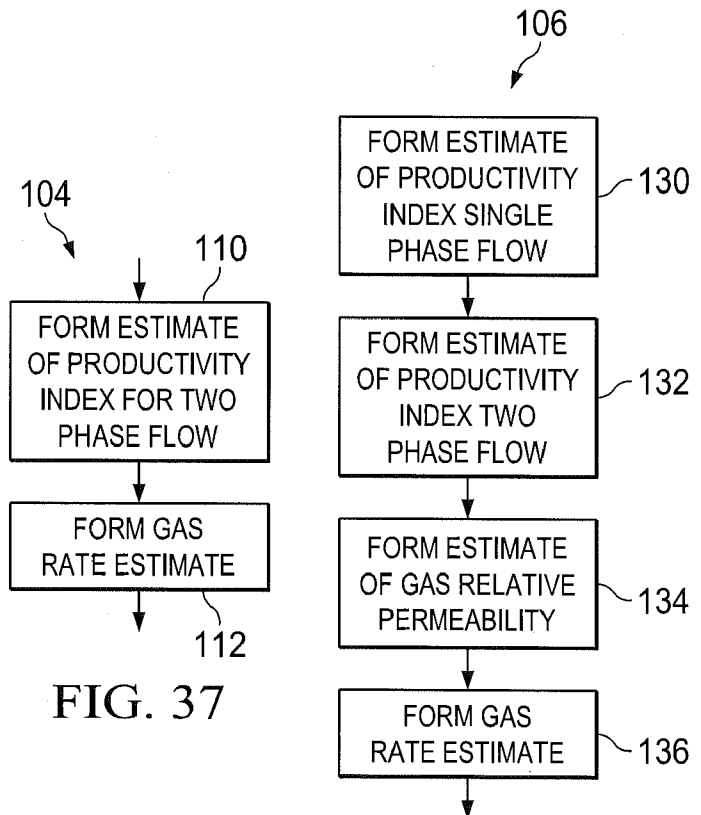


FIG. 37

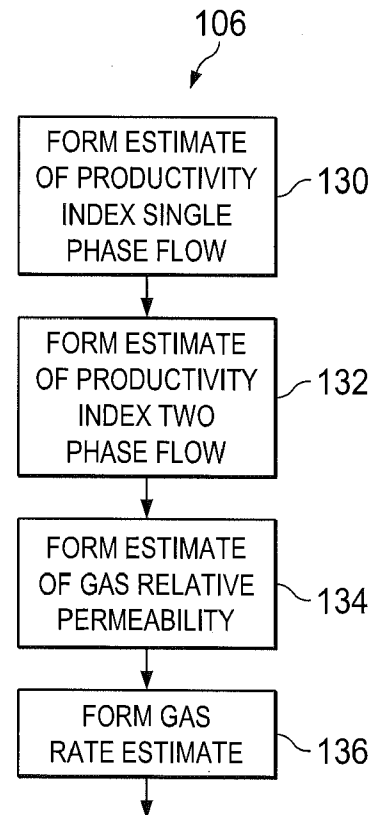


FIG. 38

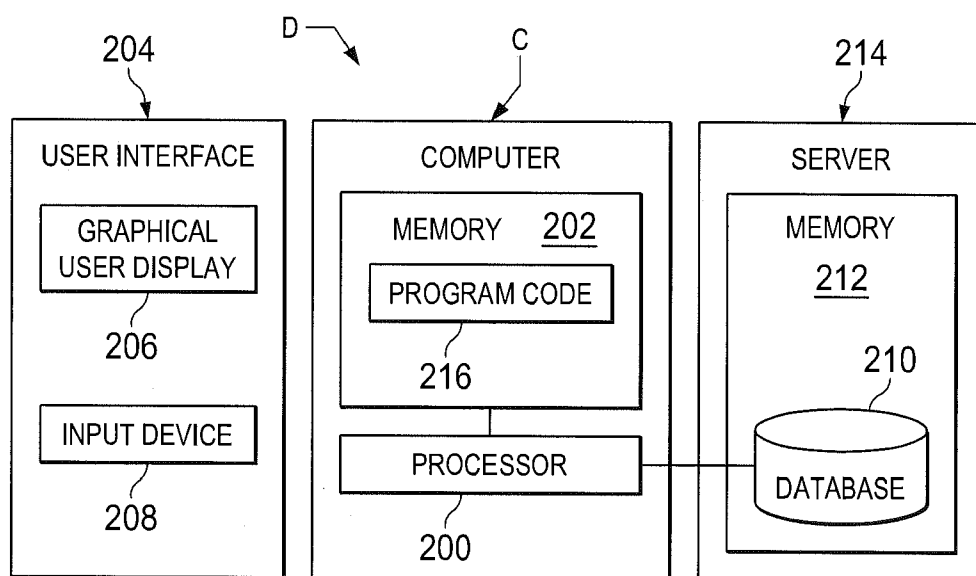


FIG. 39