EFFECT OF WATER AND FORMATION COMPRESSIBILITY AND WATER VAPOR ON ORIGINAL GAS IN PLACE ESTIMATION USING MATERIAL BALANCE CALCULATION

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ผลของการอัดตัวของน้ำและชั้นหินและไอน้ำที่มีต่อการประมาณปริมาณก๊าซเริ่มต้นโดยใช้การคำนวณสมดุลมวลสาร

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วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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วรวุฒิ สิทธิธนาสุทธิ์ : ผลของการอัดตัวของน้ำและชั้นหินและไอน้ำที่มีต่อการประมาณปริมาณก๊าซเริ่มต้นโดยใช้การคำนวณสมดุลมวลสาร (EFFECT OF WATER AND FORMATION COMPRESSIBILITY AND WATER VAPOR ON ORIGINAL GAS IN PLACE ESTIMATION USING MATERIAL BALANCE CALCULATION)
อ. ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร. สุวัฒน์ อธิชนากร, 165 หน้า.

ในการพัฒนาแหล่งผลิตก๊าซ การประมาณปริมาตรก๊าซเริ่มต้นเป็นตัวแปรสำคัญในการตัดสินการลงทุน การประมาณที่ไม่แม่นยำจะทำให้ตัดสินใจลงทุนผิดพลาดได้ ซึ่งผลกระทบหลักที่ทำให้เกิดค่าความผิดพลาด มาจากการขยายตัวของน้ำและชั้นหิน และไอน้ำ การละเว้นผลกระทบเหล่านี้จะทำให้ค่าประมาณปริมาณก๊าซเริ่มต้น สูงกว่าความเป็นจริง จุดประสงค์ของวิทยานิพนธ์นี้จะศึกษาผลกระทบทั้ง 3 ต่อการประมาณปริมาณก๊าซเริ่มต้น ระหว่างการผลิตจากแหล่งกักเก็บในสภาวะต่างๆ รวมไปถึงศึกษาผลกระทบของช่วงเวลาที่ใช้ในการประมาณฯ ที่แตกต่างกัน

การศึกษาประกอบด้วย 2 ส่วน (1) การประมาณฯในแหล่งกักเก็บที่มีผลกระทบของการอัดตัวของน้ำและชั้นหิน โดยใช้วิธีสมดุลมวลสารแบบธรรมดา วิธีสมดุลมวลสารของ Ramagost และวิธีสมดุลมวลสารปรับปรุงจาก Ramagost ในการประมาณฯ และ (2) การประมาณฯในแหล่งกักเก็บที่มีผลกระทบของการอัดตัวของชั้นหินและไอน้ำ โดยใช้วิธีสมดุลมวลสารแบบธรรมดา วิธีสมดุลมวลของ Humphreys และวิธีสมดุลมวลสารปรับปรุงจาก Humphreys ในการประมาณฯ

การศึกษาส่วนแรก พบว่า วิธีสมดุลมวลสารปรับปรุงจาก Ramagost ประมาณฯได้แม่นยำที่สุดเมื่อมีข้อมูลการผลิตมาก และวิธีการสมดุลมวลสารของ Ramagost ประมาณฯได้แม่นยำที่สุดเมื่อมีข้อมูลการผลิตจำกัด นอกจากนั้น ค่าความผิดพลาดจะเพิ่มขึ้นเมื่อความดันแหล่งกักเก็บเริ่มต้นสูงขึ้น ในส่วนที่ 2 วิธีสมดุลมวลสารปรับปรุงจาก Humphreys ประมาณฯได้แม่นยำที่สุดเมื่อข้อมูลการผลิตมาก และวิธีการสมดุลมวลสารของ Humphreys ประมาณฯได้แม่นยำที่สุดเมื่อมีข้อมูลการผลิตจำกัด แนวโน้มค่าความผิดพลาดจะเพิ่มขึ้นเมื่อความดันแหล่งกักเก็บเริ่มต้นสูงขึ้นซึ่งเหมือนกับส่วนที่ 1 และในส่วนเพิ่มเติมด้านประมาณไอน้ำที่เปลี่ยนแปลงไปจะมีผลต่อการประมาณฯน้อยที่ความดันเริ่มต้นน้อย แต่จะมีผลต่อการประมาณฯมากขึ้นที่ความดันเริ่มต้นสูง

ภาควิชา วิศวกรรมเหมืองแร่และปิโตรเลียม……….ลายมือชื่อนิสิต..
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WORAWUT SITTHITHANASUT. EFFECT OF WATER AND FORMATION COMPRESSIBILITY AND WATER VAPOR ON ORIGINAL GAS IN PLACE ESTIMATION USING MATERIAL BALANCE CALCULATION. ADVISOR: ASST. PROF. SUWAT ATHICHANAGORN, Ph.D., 165 pp.

In gas field development, one of the most important decision factors is reserve estimation. Inaccurate reserve estimation can lead to incorrect economic decision and production plan. The main reasons that may lead to an error in such estimation are water and formation expansion and water vaporization. Exclusion of such factors can result in error of original gas in place when using material balance equation. The objective of this thesis is to study the effect of water and formation expansion and water vapor in OGIP estimation in dry gas reservoirs having different reservoir conditions. This study also investigates how the length of data affects the estimation.

The study consists of two parts: (1) estimation of OGIP for reservoirs with significant water and rock compressibility, the conventional, Ramagost and modified Ramagost methods are used to determine OGIP and (2) estimation of OGIP for reservoirs with significant rock compressibility and water vapor, the conventional, Humphreys and modified Humphreys methods are used to compute OGIP.

In the first part, it was found that modified Ramagost method provides the most accurate OGIP estimates when a lot of production data are available and the Ramagost method provides the best results when limited production data are available. Furthermore, the error rises when the initial pressure is higher. In the second part, modified Humphreys method provides the most accurate OGIP estimates when a lot of data are available and the Humphreys method provides the best results when limited production data are available. Similar to the first part of study, higher initial pressure results in higher error of OGIP estimate. The increase in water vapor content does not change the magnitude of the error for reservoirs with low initial pressures but increases the error for reservoirs with high pressure.

Department: Mining and Petroleum Engineering….. Student’s Signature:……......…..............
Field of Study: Petroleum Engineering……..……..Advisor’s Signature:…......……..............
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List of Abbreviations

BCF	Billon cubic foot
BHP	Bottom hole pressure
EOS	Equation of state
MCF	Thousand cubic foot
OGIP	Original gas in place
PVT	Pressure Volume Temperature
SCAL	Special core analysis
WOC	Water-oil contact

Nomenclature

A	cross section area
$\frac{a}{V_M^2}$	force of attraction between the molecules or the molecules and the wall of container
a_c	value of a_T at critical temperature
b	molar volume due to the volume occupied by the molecule
B_g	gas formation volume factor
c_e	effective compressibility (psi^{-1})
c_f	formation compressibility (psi^{-1})
c_w	water compressibility (psi^{-1})
f	shale fraction
G	original gas in place (MCF)
G_p	cumulative gas production (MCF)
h	thickness of reservoir
k_{rg}	relative permeability to gas
k_{ro}	relative permeability to oil
k_{rw}	relative permeability to water
k_{rowg}	relative permeability to oil for oil/water/gas system
k_{row}	relative permeability to oil for oil/water system
M	molecular weight
N	mole of gas
p	pressure (psi)
p_c	capillary pressure
R	universal gas constant
S_w	water saturation
S_g	gas saturation
T	temperature
V	volume
V_f	formation volume
V_p	pore volume
V_w	water volume

x	liquid phase mole fraction
y	vapor phase mole fraction
z	gas compressibility (psi^{-1})

GREEK LETTER

Δ	difference
ϕ	porosity
ω	pitzer acentric factor for each pure substance
α	non-dimensional temperature

SUBSCRIPTS

1, 2, 3	component number
a	apparent
c	critical
i	initial condition
sc	standard condition

CHAPTER I

INTRODUCTION

1.1 Background

Estimation of OGIP and gas reserve is important when making economic assessment and production plan. An error in OGIP and gas reserve estimation may lead to incorrect decision on production strategy. In most cases, water and formation compressibility as well as water vapor are often neglected in the determination of OGIP and reserve when material balance is performed. However, as the reservoir pressure declines as a result of gas production, the connate water and rock expands, contributing to the production of gas. The expansion of water vapor in the gas phase also contributes to the production of hydrocarbon gas. Thus, these effects should be accounted for when performing material balance p/z plot. Exclusion of water and rock compressibility and water vapor may result in over-estimation of OGIP and reserve, particularly in the case of over-pressure reservoir.

In order to account for water and formation compressibility, Ramagost method may be employed. However, Ramagost method assumes water and formation compressibility to be constant. In this study, the method will be modified in order to account for changes in water and formation compressibility as the reservoir pressure declines during the production of gas. For water vapor expansion, Humphreys method may be used. Similar to Ramagost, Humphreys assumes water and formation compressibility to be constant in his method. In this study, this assumption will be relaxed in the same fashion as in the case of modified Ramagost method.

1.2 Objective

1. To quantify the effect of water and rock expansion on estimation of OGIP and gas reserve.
2. To quantify the effect of water vapor on the estimation of OGIP and gas reserve.

3. To determine the best method of gas material balance when water and rock expansion has non-negligible effect.
4. To determine the best method of gas material balance when water vapor has non-negligible effect.

1.3 Scope of work

1. Review reservoir and fluid data from the Gulf of Thailand and literature.
2. Construct a hypothetical gas reservoir model using ECLIPSE 300 in order to accommodate water content in the gas phase.
3. Perform reservoir simulation with the well being shut in from time to time in order to generate reservoir pressure and cumulative gas and water production data as a function of time. The simulation cases to be performed include:
   a. variation in initial reservoir pressure
   b. variation in rock compressibility
   c. variation in water vapor content
4. Perform material balance using reservoir pressure and cumulative gas and water production obtained from the simulation.

   The methods used in the analysis of OGIP and reserve include:
   a. Conventional *p/z* method
   b. Ramagost method
   c. Modified Ramagost method
   d. Humphey method (cases with water vapor content)
   e. Modified Humphey method (cases with water vapor content)

   The amount of data used in the analysis is varied as follows:
   a. From initial condition to the point when reservoir pressure is 25% depleted
   b. From initial condition to the point when reservoir pressure is 50% depleted
   c. From initial condition to the point when reservoir pressure is 75% depleted

    d. From initial condition to the point when reservoir is depleted (abandoned)

5. Analyze the results obtained from different methods and different amounts of data used in the material balance analysis.

1.4 Thesis outline

This thesis paper proceeds as follows:

Chapter II presents literature review and works related to material balance calculation and compressibility.

Chapter III presents theories related to the study of effect of water and formation compressibility affect and water vapor on original gas in place estimation which are the equation of state, phase behavior of dry gas and the original gas in place by material balance equation.

Chapter IV describes the simulation model used in this study.

Chapter V discusses the results of reservoir simulation obtained from different values of controlled variables.

Chapter VI provides conclusions and recommendations for further study.

CHAPTER II

LITERATURE REVIEW

This chapter discusses some works related to gas material balance calculation which consist of

1) Original gas in place calculation by material balance equation which account for water and formation expansion and water vaporization.

2) Relationship of pressure, temperature and pore volume compressibility by core experiment.

3) Phase equilibrium of water and hydrocarbon by both core experiment and equation of state calculation.

2.1 Previous works

Dodson [1] studied the relations of pressure, volume, temperature and solubility for natural gas-water mixture by measuring the solubility of natural gas in liquid water and solubility of vapor water in natural gas at pressure from 500 to 5,000 psi and temperature from 100^o to 250^o F using 2 kinds of brine (low total solid brine at 8,630 ppm. and high total solid brine at 34,100 ppm.). From the experiment, the solubility of natural gas in water/brine decreases when the pressure depletes. However, temperature has less effect on natural gas solubility. And gas solubility in low salinity is higher than that in high salinity. For the solubility of water vapor in natural gas, both pressure and temperature significantly affect water vapor solubility. The lower the pressure, the higher the water vapors in natural gas, and the higher the temperature, the higher the solubility. However, salinity has a slightly effect on water vapor solubility.

In 1969, Von Gonten and Choudhany [2] studied the effect of pressure and temperature on pore volume compressibility by core experiment. Sandstone core samples were used in the experiment with compact pressure up to 15,000 psi and temperature at 75^oF and 400^oF. The compressibility at 400^oF is on average about 12% higher than the one at 75^oF. The experiment results also show the compressibility is the function of compact pressure. The compressibility at 14,000 psi is about one-third of the one at 1,000 psi.

In 1971, Hammerlindl [3] presented the gas reserve estimation which account for water and formation expansion in a high pressure reservoir. He obtained the original gas in place by using the original gas in place calculated from convention method at early time called apparent original gas in place, G_a multiplied by an adjustment factor, *ADJ* which accounting for water and formation expansion.

In 1981, Ramagost and Farshad [4] introduced their material balance equation to estimate original gas in place in high pressure reservoir which having significant effect of water and formation expansion. They conducted the p/z with correction term versus cumulative gas production plot instead of the conventional p/z plot to obtain original gas in place in North Ossun field, Louisiana.

Roach [5] introduced a plot which can obtain original gas in place without knowing rock compressibility. He rearranged the material balance equation which accounts for water and rock expansion in a form of straight line function. The original gas in place is equal to $slope^{-1}$ and the rock compressibility is the intercept of vertical axis.

Bette and Heinemann [6] used a compositional simulator to account for water vapor in a gas-condensate reservoir in Arun field to determine the original gas in place. The Arun field is located on the northern coast of Sumatra, Indonesia with initial reservoir pressure of 7,100 psig and temperature of 352°F at depth of 10,000 foot. The gas in place calculated from the p/z plot corrected for water vaporization is accurately matched to the initial gas volume of the core measurement.

Ambastha [7] estimated original gas in place for geo-pressure reservoir by accounting for water and rock compressibility effects. Normally, initial pressure gradient of gas reservoir is close to pressure gradient of water (9.7 – 11.3 kPa/m). So, the production performance depends on only gas compressibility. But for geo-pressure reservoir (pressure gradient 14.7 to 19.3 kPa/m), the initial pressure gradient is higher than the hydrostatic gradient. In this case water and rock compressibilities significantly affect original gas in place estimation. The authors used Ramagost and Farshad's approach to make a plot between $p(1\text{-}c_e\, \Delta p)/z$ versus G_p to estimate initial gas in place.

Humphreys [8] modified the material balance equation for original gas in place estimation by accounting for water vapor in gas-condensate reservoir. In gas condensate reservoir, pore space is filled with hydrocarbon vapor, hydrocarbon liquid, connate liquid water, and water vapor. During production, connate water may vaporize as water vapor as the pressure declines. From an experiment to determine water vapor content of a 0.6 gravity hydrocarbon gas at 350^{o}F constant temperature at 6,000 psi to 1,000 psi, it was found that the mole percent of water vapor in pore volume significantly increases from 4.0 mole % to 13 mole %. This indicates that not accounting for water vapor volume can lead to significant error in reserve estimation.

Lapene [9] introduced a new three-phase equilibrium calculation for hydrocarbon-water system by modifying Rachford-Rice equation. Conventionally, the three-phase equilibrium is calculated by performing two-phase equilibrium calculation to identify amount of hydrocarbon component in vapor and liquid in each components combined with using steam properties to take water into account instead of real three-phase equilibrium calculation. But the new algorithm, called free-water flash calculation accounts for the solubility of vapor water in hydrocarbon phase and assumes the solubility of hydrocarbon in water is negligible. And water in liquid phase is defined as pure water.

CHAPTER III

THEORY AND CONCEPT

There are main two theories related with the study of effects of water and formation compressibility and water vapor on original gas in place estimation.

The first part is “the equation of state” in which various equations are applied to explain the relationship between physical parameters which are the volume of gas, pressure and temperature. And the second part reviews different material balanced methods to estimate original gas in place for dry gas reservoirs, namely, conventional, Hammerlindl, Ramagost, Roach and Humphreys methods. The conventional one neglects water and rock expansion and water vapor while the first three do include effects of water and rock expansion and the last one do include effects of rock expansion and water vapor. In addition to the four established methods, a discussion of modified Ramagost method and modified Humphreys are presented in this chapter.

.

3.1 Equation of state

The equation of state explains the relationship of pressure, temperature and volume in mathematical term. Many equations of state were developed via experiment or kinetic theory. Most equations started with the study of ideal gas which is considered as hypothetical gas. Then the form of the ideal gas equation was used as a base of equation for real gas.

3.1.1 Ideal gas

The equation of state for ideal gas is a starting point in the real gas equation. There are 3 major assumptions for ideal gas behavior as follows:

1) the volume occupied by the molecules is not considerable with respect to the volume occupied by the gas.

2) there are no interaction forces between the molecules or the molecules and the walls of container.

3) all collisions of molecule are perfectly elastic, meaning that there is no internal energy loss upon collisions.

The equation of state for ideal gas is derived by combining Boyle's equation, Charles's equation and Avogadro's law.

Boyle's equation

Boyle [10] did an experiment and found that the volume of an ideal gas is inversely proportional to pressure for a given mass of gas when temperature is constant. This can be expressed as

$$V \sim \frac{1}{p} \; or \; pV = constant \tag{3.1}$$

Charles's equation

Charles [10] experimentally discovered that the volume of ideal gas is directly proportional to temperature for a given mass of gas when pressure is constant. This can be expressed as

$$V \sim T \; or \; \frac{V}{T} = constant \tag{3.2}$$

Avogadro's law

Avogadro's law [10] states that under the same condition of temperature and pressure, equal volume of all ideal gas contains the same number of molecules. The number of molecules is equal to 2.73 x 10^{26} molecules per pound mole of ideal gas.

Combining of the equations and law above, we come up with the equation of state for ideal gas as

$$pV = nRT \tag{3.3}$$

where

p = absolute pressure of gas (psi)

T = absolute temperature of gas (°R)

V = volume occupied by gas (ft^3)

R = universal gas constant = 10.732 psia cu ft/lb mole °R

n = mole of gas (lb mole)

Mixture of ideal gas

In case of gas mixture, there are mixture laws introduced by many authors to describe the behavior of gas mixture.

Dalton's law of partial pressure

Dalton's law [10] states that the total pressure of gas mixture is the sum of the partial pressure of each component

$$p_{total} = \sum_{i=1}^{n} p_i \tag{3.4}$$

The partial pressure of each component is determined as

$$p_i = n_i \frac{RT}{V} \tag{3.5}$$

Thus,

$$p_{total} = n_1 \frac{RT}{V} + n_2 \frac{RT}{V} + n_3 \frac{RT}{V} + \dots \tag{3.6}$$

The partial pressure ratio of component *i* to the total mixture pressure is

$$\frac{P_i}{P_{total}} = \frac{n_i}{n_{total}} = y_i \tag{3.7}$$

where

y_i = the mole fraction of the *i* th component in the gas mixture

Amagat's law of partial volumes

Amagat's law [10] states that the total volume of gas mixture is the sum of the partial volume of each component.

$$V_{total} = \sum_{i=1}^{n} V_i \tag{3.8}$$

The partial volume of each component is determined as

$$V_i = n_i \frac{RT}{P} \tag{3.9}$$

Thus,

$$V_{total} = n_1 \frac{RT}{P} + n_2 \frac{RT}{P} + n_3 \frac{RT}{P} + \ldots \tag{3.10}$$

The partial pressure ratio of component *i* to the total mixture pressure is

$$\frac{V_i}{V_{total}} = \frac{n_i}{n_{total}} = y_i \tag{3.11}$$

Apparent molecular weight of a gas mixture

The molecular weight of gas mixture is determined by sum of the molecular weight of each component multiplied by mole fraction of the component.

$$M_a = \sum_{i=1}^{n} y_i \, M_i \qquad (3.12)$$

where

M_a = the apparent molecular weight in the gas mixture

M_i = the molecular weight of the i th component in the gas mixture

3.1.2 Real gas

Real gas behaves differently from ideal gas due to the effect of intermolecular forces exerted between molecules and imperfect elastic of molecular collision. There are many equations developed to describe the pressure-volume-temperature relationship for real gases.

Van Der Waals' equation of state

In 1873, Van Der Waals [11] proposed the first real gas equation of state based on the ideal gas equation of state with correction terms as

$$\left(p + \frac{a}{V_M^2}\right)(V_M - b) = RT \qquad (3.13)$$

where

$\frac{a}{V_M^2}$ is the force of attraction between the molecules or the molecules and the walls of container

b is the molar volume due to the volume occupied by the molecules

The compressibility equation of state

The compressibility equation of state [10] is the real gas equation of state based on the ideal gas equation of state. The compressibility factor is introduced to the real gas equation of state as a correction factor. It can be expressed as

$$pV = znRT \tag{3.14}$$

where
z = gas compressibility factor.

The gas compressibility factor is the ratio of the actual volume of gas to the volume of the gas at the same pressure and temperature that acts as ideal gas.

$$z = \frac{V_{actual}}{V_{ideal}} \tag{3.15}$$

Redlich-Kwong's equation of state

Redlich-Kwong [12] propose the equation of state by taking into account the temperature dependencies of the molecule attraction term as

$$p = \frac{RT}{V_M - b} - \frac{a}{\sqrt{T}V_M(V_M + b)} \tag{3.16}$$

where

$$a = 0.42747\frac{R^2T_c^{2.5}}{P_c} \tag{3.17}$$

$$b = 0.08664\frac{RT_c}{P_c} \tag{3.18}$$

Soave's equation of state

Soave [13] modified the equation by replacing $a/\sqrt{T}$ term with a temperature dependent term, a_T. So the modified equation is called Soave Redlich-Kwong equation of state which is expressed as

$$p = \frac{RT}{V_M - b} - \frac{a_T}{V_M(V_M + b)} \tag{3.19}$$

where

$$a_T = a_c \alpha \tag{3.20}$$

$$a_c = 0.42747 \frac{R^2 T_c^2}{P_c} \tag{3.21}$$

$$b = 0.08664 \frac{RT_c}{P_c} \tag{3.22}$$

a_c is the value of a_T at the critical temperature and α is a non-dimensional temperature dependent term which has a value of 1.0 at the critical temperature. The value of α can be obtained as

$$\alpha^{1/2} = 1 + m(1 - T_r^{1/2}) \tag{3.23}$$

$$m = 0.480 + 1.574\omega - 0.17\omega^2 \tag{3.24}$$

$$\omega = -\log P_{vr} + 1 \text{ at } T_r = 0.7 \tag{3.25}$$

where ω is the Pitzer acentric factor for each pure substance

p_{vr} is the reduced vapor pressure.

Peng-Robinson's equation of state

Peng and Robinson [14] proposed a different form of the molecular attraction term. Their equation is expressed as

$$p = \frac{RT}{V_M - b} - \frac{a_T}{V_M^2 + 2bV_M - b^2} \tag{3.26}$$

where

$$a_c = 0.42747\frac{R^2T_c^2}{P_c} \tag{3.27}$$

$$\mathrm{b} = 0.07780\frac{\mathrm{RT_c}}{\mathrm{P_c}} \tag{3.28}$$

and

$$\alpha^{1/2} = 1 + m(1 - T_r^{1/2}) \tag{3.29}$$

$$m = 0.37464 + 1.5422\omega - 0.26992\omega^2 \tag{3.30}$$

3.2 Estimation of original gas in place for dry-gas reservoir

To estimate the original gas in place, there are three main techniques as decline curve analysis, volumetric calculation and material-balance calculation. This study focuses on the material-balance calculation for dry-gas reservoir.

3.2.1 Material balance for gas reservoir

Material balance equation is based on principle of conservation of mass. Generally, the gas material balance equation is expressed as

$$G(B_g - B_{gi}) + \left(\frac{GB_{gi}(c_wS_{wi} + \bar{c}_f)(p_i - p)}{1 - S_{wi}}\right) + W_e = G_pB_g + W_pB_w \tag{3.31}$$

In depletion-drive reservoir with low and moderate initial pressure (< 0.5 psi/ft pressure gradient), we assume that the water influx and water production terms are neglected and gas expansion is the main driving mechanism in reservoir. The expansion of rock and water are neglected during pressure depletion. Thus, the general material equation for depletion drive reservoirs becomes

$$G\left(B_g - B_{gi}\right) = G_p B_g \tag{3.32}$$

Equation (3.32) can be rewritten as

$$G_p = G(1 - \frac{B_{gi}}{B_g}) \tag{3.33}$$

And we know that

$$\frac{B_{gi}}{B_g} = \frac{p z_i}{p_i z} \tag{3.34}$$

Substituting Equation (3.34) into Equation (3.33), we get

$$G_p = G(1 - \frac{p z_i}{p_i z}) \tag{3.35}$$

$$\frac{p}{z} = \frac{p_i}{z_i}(1 - \frac{G_p}{G}) \quad = \frac{p_i}{z_i} - \frac{p_i}{z_i G} G_p \tag{3.36}$$

A plot between p/z and G_p is a straight line with slope equal to p_i/z_iG and the x-intercept equal to the original gas in place. The plot is illustrated in Figure 3.1.

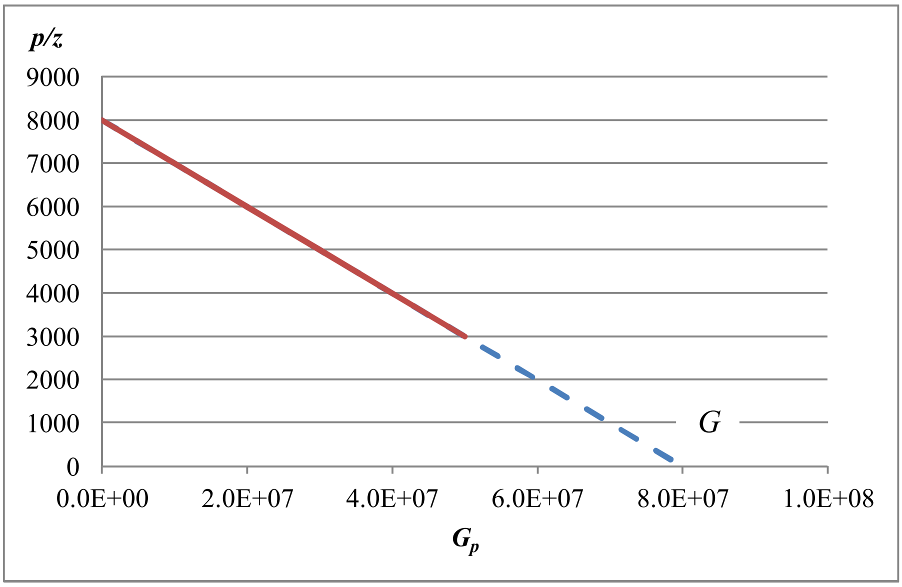

Figure 3.1: Example of p/z and G_p plot

3.2.2 Material balance calculation for geo-pressured gas reservoir

In the case of geo-pressure or higher pressure gradient (about 0.5-1.0 psi/ft), the contribution from water and formation expansion and water vaporization will be larger and significantly affects material balance calculation. There are 4 techniques to determine more accurate original gas in place in geo-pressure reservoir. There techniques are Hammerlindl method, Ramagost method, Roach method and modified Ramagost method developed in this study.

3.2.2.1 Hammerlindl method

Hammerlindl [3] calculated the gas original in place by using the original gas in place calculated from conventional method at early time called apparent original gas in place, G_a multiplied by an adjustment factor which accounts for water and formation expansion. G and ADJ can be expressed as

$$G = G_a(ADJ) \tag{3.37}$$

ADJ is derived from simplifying of Equation (3.31) as

$$G_p = G\left(1 - \frac{B_{gi}}{B_g}\right) + \frac{GB_{gi}}{B_g}\frac{\left(c_w S_{wi} + \bar{c}_f\right)}{(1 - S_{wi})}(p_i - p) \tag{3.38}$$

and the apparent original in place as

$$G_{ap} = G_a\left(1 - \frac{B_{gi}}{B_g}\right) \tag{3.39}$$

Then, we assume for early time data, $G_p = G_a$

$$G\left(1 - \frac{B_{gi}}{B_g}\right) + \frac{GB_{gi}}{B_g}\frac{\left(c_w S_{wi} + \bar{c}_f\right)}{(1 - S_{wi})}(p_i - p) \quad = G_a\left(1 - \frac{B_{gi}}{B_g}\right) \tag{3.40}$$

$$G = G_a(B_g - B_{gi})/(B_g - B_{gi} + B_{gi}\frac{\left(c_w S_{wi} + \bar{c}_f\right)}{(1 - S_{wi})}(p_i - p)) \tag{3.41}$$

Defining

$$ADJ = (B_g - B_{gi})/(B_g - B_{gi} + B_{gi}\frac{\left(c_w S_{wi} + \bar{c}_f\right)}{(1 - S_{wi})}(p_i - p)) \tag{3. 42}$$

Simplifying

$$ADJ = \left(\frac{\frac{p_i}{z_i}}{\frac{p}{z} - 1}\right)/\left(\frac{\frac{p_i}{z_i}}{\frac{p}{z}} + \frac{\left(c_w S_{wi} + \bar{c}_f\right)(p_i - p)}{1 - S_{wi}}\right) \tag{3. 43}$$

Figure 3.2 shows the plot by Hammerlindl method compare with conventional method.

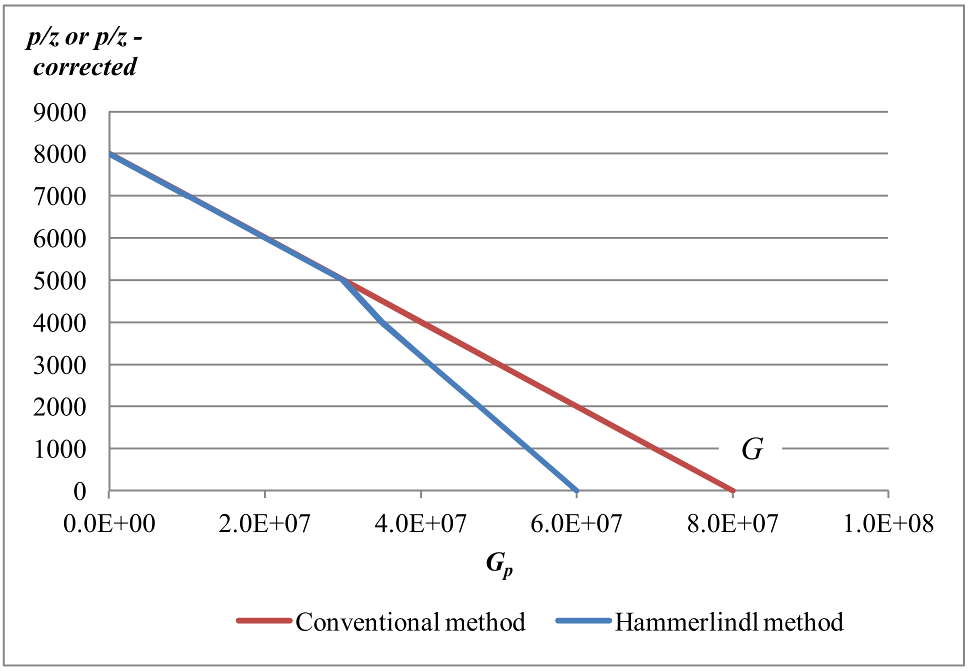

Figure 3.2: Example of *p/z or corrected p/z vs.* G_p plot by conventional and Hammerlindl method

3.2.2.2 Ramagost method

Ramagost and Farshad [4] introduced a method to include the effects of change in water volume, ΔV_w and pore volume occupied by formation, ΔV_f. The general form of material balance equation can be expressed as

$$GB_{gi} = (G - G_p)B_g + \Delta V_w + \Delta V_f \tag{3.44}$$

The expansion of water term as the reservoir pressure depletes can be expressed with isothermal water compressibility, c_w as

$$c_w = -\frac{1}{V_w}\left(\frac{\partial V_w}{\partial p}\right)_T \cong -\frac{1}{V_{wi}}\left(\frac{\Delta V_w}{\Delta p}\right) \tag{3.45}$$

$$\Delta V_w = -c_w V_{wi} \Delta p \tag{3.46}$$

The original water volume, V_{wi} in terms of the original gas in place can be written as

$$V_{wi} = \frac{S_{wi} G B_{gi}}{(1 - S_{wi})} \tag{3.47}$$

Substituting Equation (3.47) into Equation (3.46), the equation becomes

$$\Delta V_w = c_w (p_i - p) \frac{S_{wi} G B_{gi}}{(1 - S_{wi})} \tag{3.48}$$

The decrease in pore volume , ΔV_p as the pressure depletes can be expressed as

$$c_f = -\frac{1}{V_p}\left(\frac{\partial V_p}{\partial p}\right)_T \tag{3.49}$$

$$\bar{c_f} = \frac{1}{V_{pi}}(\frac{\Delta V_p}{\Delta p}) \tag{3.50}$$

$$c_f = -\frac{1}{V_p}\left(\frac{\partial V_p}{\partial p}\right)_T \tag{3.51}$$

$$\Delta V_p = \bar{c}_f V_{pi} \Delta p \tag{3.52}$$

The original rock pore volume in terms of the original gas in place can be written as

$$V_{pi} = \frac{G B_{gi}}{(1 - S_{wi})} \tag{3.53}$$

Substituting Equation (3.53) into (3.52), we have

$$-\Delta V_p = \bar{c}_f (p_i - p) \frac{G B_{gi}}{(1 - S_{wi})} = \Delta V_f \tag{3.54}$$

Substituting Equations (3.48) and (3.54) into (3.39), we obtain

$$GB_{gi} = \left(G - G_p\right)B_g + c_w(p_i - p)\frac{S_{wi}GB_{gi}}{(1 - S_{wi})} + \bar{c}_f(p_i - p)\frac{GB_{gi}}{(1 - S_{wi})} \tag{3.55}$$

After simplification, Equation (3.55) becomes

$$G\left[1 - \frac{\left(c_w S_{wi} + \bar{c}_f\right)(p_i - p)}{(1 - S_{wi})}\right]\frac{B_{gi}}{B_g} = G - G_p \tag{3.56}$$

Substituting $B_{gi}/B_g = pz_i/p_iz$ into Equation (3.56) and rearranging, we obtain

$$\frac{p}{z}\left[1 - \frac{\left(c_w S_{wi} + \bar{c}_f\right)(p_i - p)}{(1 - S_{wi})}\right] = \frac{p_i}{z_i} - \frac{p_i}{z_i}\frac{G_p}{G} \tag{3.57}$$

Then a plot of $\frac{p}{z}\left[1 - \frac{\left(c_w S_{wi} + \bar{c}_f\right)(p_i - p)}{(1 - S_{wi})}\right] vs. G_p$ will give a straight line The x-intercept will provide the value of original gas in place. Figure 3.3 shows the plot by Ramagost method compare with conventional method.

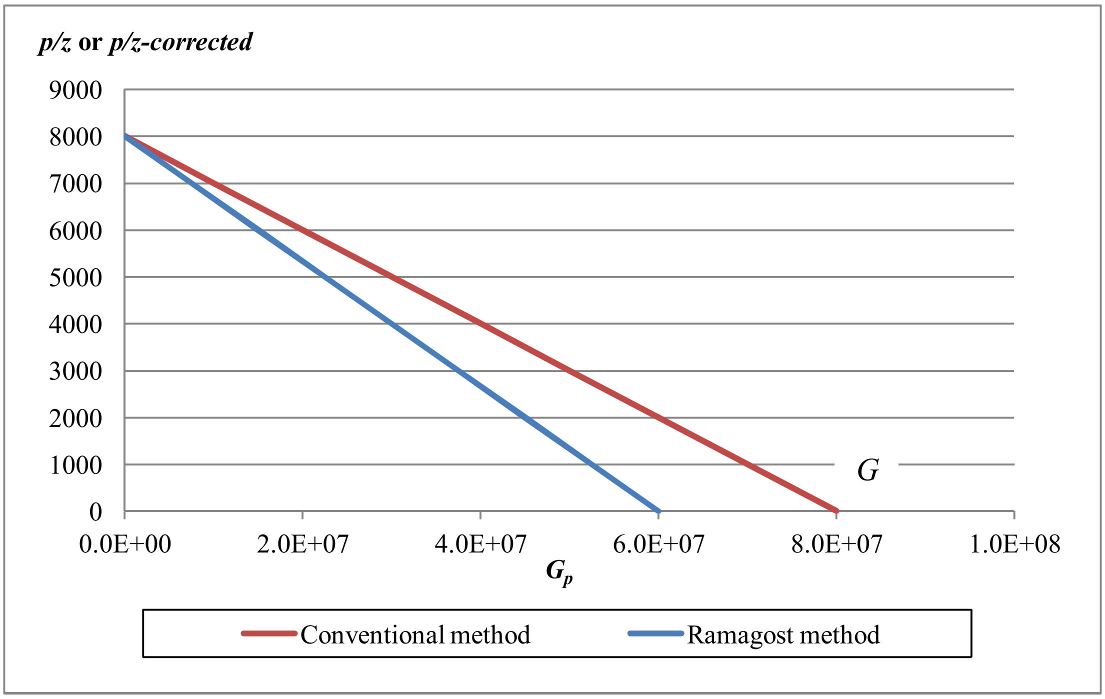

Figure 3.3: Example of *p/z or corrected p/z vs.* G_p plot by conventional and Ramagost method

3.2.2.3 Roach method

Roach [5] method can obtain original gas in place without knowing of rock compressibility. Firstly, he rearranged Equation (3.57) to be equation as follows:

$$(\frac{p_i z}{p z_i} - 1)/(p_i - p) = \left(\frac{p_i z}{p z_i}\right) G_p/(p_i - p)\frac{1}{G} - (c_w S_w + c_f)/(1 - S_w) \tag{3.58}$$

Equation (3.58) is a form of straight line function. It can be simplified to

$$Y = mX + b \tag{3.59}$$

where

$$Y = (\frac{p_i z}{p z_i} - 1)/(p_i - p) \tag{3.60}$$

$$X = \left(\frac{p_i z}{p z_i}\right) G_p/(p_i - p) \tag{3.61}$$

Then make a plot between *Y* and *X* is a straight line. The original gas in place is equal to *slope*$^{-1}$ and the rock compressibility is the intercept of *Y*-axis. Figure 3.4 is an example plot using by Roach method.

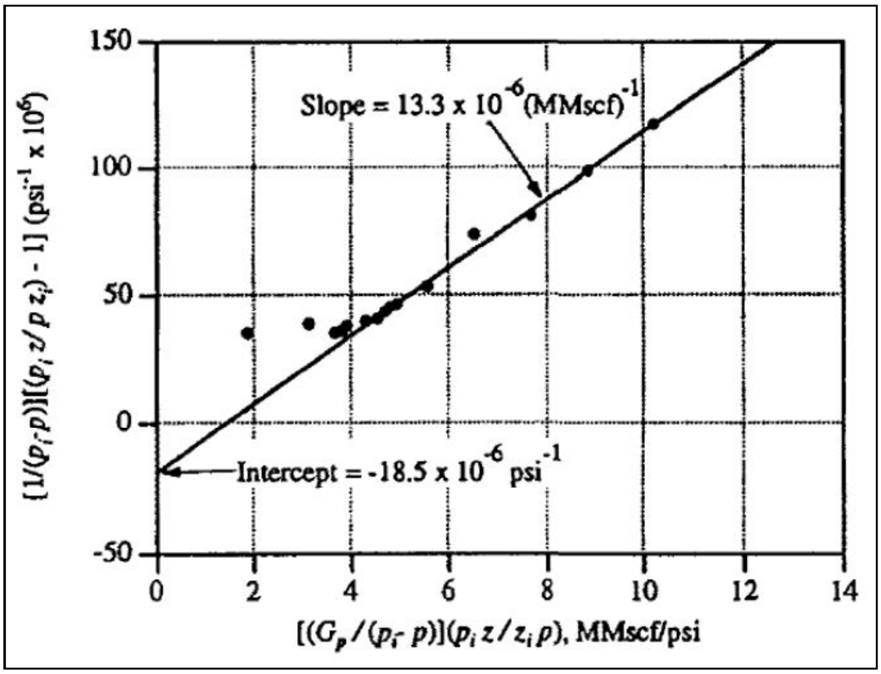

Figure 3.4: Example of *Y vs. X* plot by Roach method (after Lee [15])

3.2.2.4 Modified Ramagost method

As water and formation compressibility change with pressure, we propose using the variation of formation and water compressibility values at pressure and temperature at the time of measurement instead of using average compressibilities in Ramagost method. The same kind of plot between *corrected p/z* and G_p is made in order to determine the original gas in place. This method is called modified Ramagost method in this study.

3.2.3 Material balance calculation for geo-pressure gas reservoir with water vaporization

3.2.3.1 Humphreys method

Water vaporization in dry gas or gas-condensate reservoirs often occurs during pressure depletion of high pressure and high temperature reservoirs. The material balance equation accounting for phase change (water vaporization) was developed by Humphreys et al. [8] in 1991 for gas-condensate reservoirs. However, the same principle applies for dry gas reservoirs. In their study, the effects of rock compressibility were also included. However, the effects of water expansion were neglect. The reservoir pore volume consists of initial volume of hydrocarbon and water vapor, V_{vi} and initial volume of liquid water, V_{wi} as

$$V_{pi} = V_{vi} + V_{wi} \tag{3.62}$$

The liquid water is formed in term of initial water saturation as

$$V_{wi} = S_{wi} V_{pi} \tag{3.63}$$

and the initial reservoir volume of the vapor as

$$V_{vi} = (1 - S_{wi}) V_{pi} \tag{3.64}$$

Let us define the fraction of the initial vapor phase volume for water vapor as

$$y_{wi} = \frac{V_{wvi}}{V_{vi}} \tag{3.65}$$

and the fraction of the initial hydrocarbon gases as

$$1 - y_{wi} = \frac{V_{hvi}}{V_{vi}} \tag{3.66}$$

So,

$$V_{hvi} = V_{pi}(1 - S_{wi})(1 - y_{wi}) \tag{3.67}$$

Since the initial hydrocarbon vapor is original gas in place

$$V_{hvi} = GB_{gi} \tag{3.68}$$

Then,

$$V_{pi} = \frac{GB_{gi}}{(1 - S_{wi})(1 - y_{wi})} \tag{3.69}$$

The equation above can be further developed for depletion at pressure above and below the dew point.

Depletion at pressure above the dew point

For pressure above the dew point, hydrocarbon gas is not condensed. Part of water vaporizes. This reduces the liquid water saturation. The volume of liquid phase becomes

$$V_w = S_w V_p \tag{3. 70}$$

So, the volume of the vapor phase is

$$V_v = (1 - S_w)V_p \tag{3. 71}$$

Defining the fraction of the vapor phase volume for water vapor as

$$y_w = \frac{V_{wv}}{V_v} \tag{3.72}$$

and the fraction of the hydrocarbon gases as

$$1 - y_w = \frac{V_{hv}}{V_v} \tag{3.73}$$

then

$$V_{hv} = V_p(1 - S_w)(1 - y_w) \tag{3.74}$$

So, the current hydrocarbon vapor phase is

$$V_{hv} = (G - G_p)B_g \tag{3.75}$$

The current reservoir pore volume is

$$V_p = \frac{(G - G_p)B_g}{(1 - S_w)(1 - y_w)} \tag{3.76}$$

At high pressure, gas condensate reservoir may have a rather significant change in pore volume during pressure depletion. The change in reservoir formation (rock) volume can be expressed in terms of the formation compressibility as

$$\Delta V_f = \frac{\overline{c_f}(p_i - p)GB_{gi}}{(1 - S_{wi})(1 - y_{wi})} \tag{3.77}$$

The material balance equation for pressure above the dew point becomes

$$\frac{GB_{gi}}{(1 - S_{wi})(1 - y_{wi})} = \frac{(G - G_p)B_g}{(1 - S_w)(1 - y_w)} + \frac{\overline{c_f}(p_i - p)GB_{gi}}{(1 - S_{wi})(1 - y_{wi})} \tag{3.78}$$

$$G\frac{(1-S_w)}{(1-S_{wi})}\frac{(1-y_w)}{(1-y_{wi})}\frac{B_{gi}}{B_g}\left[1-\bar{c_f}(p_i-p)\right]=G-G_p \tag{3.79}$$

Substituting $B_{gi}/B_g = pz_i/p_iz$ and rearranging, the equation becomes

$$\frac{(1-S_w)}{(1-S_{wi})}\frac{(1-y_w)}{(1-y_{wi})}\left[1-\bar{c_f}(p_i-p)\right]\frac{p}{z}=\frac{p_i}{z_i}-\frac{p_i}{z_i}\frac{G_p}{G} \tag{3.80}$$

$$\frac{(1-S_w)}{(1-S_{wi})}\frac{(1-y_w)}{(1-y_{wi})}\left[1-\bar{c_f}(p_i-p)\right]\frac{p}{z}\ vs.G_p \tag{3.81}$$

Depletion at pressure below the dew point

For pressure below the dew point, liquid hydrocarbon forms in the reservoir. Part of water still exists as vapor. This reduces the liquid water saturation. As liquid hydrocarbon forms the volume hydrocarbon vapor gets smaller. The material balance equation becomes

$$\frac{GB_{gi}}{(1-S_{wi})(1-y_{wi})}=\frac{\left(G-G_p\right)B_g}{(1-S_w-S_o)(1-y_w)}+\frac{\bar{c_f}(p_i-p)GB_{gi}}{(1-S_{wi})(1-y_{wi})} \tag{3.82}$$

and

$$\frac{(1-S_w-S_o)}{(1-S_{wi})}\frac{(1-y_w)}{(1-y_{wi})}\left[1-\bar{c_f}(p_i-p)\right]\frac{p}{z}=\frac{p_i}{z_i}-\frac{p_i}{z_i}\frac{G_p}{G} \tag{3.83}$$

3.2.3.2 Modified Humphreys method

To study the effect of formation expansion and water vaporization to original gas in place estimation in dry gas reservoir, as formation compressibility change with pressure, we propose using the variation of formation compressibility values at pressure and temperature at the time of measurement instead of using average compressibilities in Humphreys method. The same kind of plot between *corrected p/z* and G_p is made in order to determine the original gas in place. This method is called modified Humphreys method in this study.

As this study focuses on dry gas reservoir, Humphreys and modified Humphreys method based on depletion above the dew point are used to study formation expansion and water vaporization effects.

CHAPTER IV

RESERVOIR SIMULATION MODEL

In order to study the reservoir conditions that water and formation expansion and water vaporization can affect the original gas in place estimation, we used ECLIPSE E300 simulation program (compositional simulator). For phase behavior, the cubic Peng-Robinson equation of state was applied.

The simulation model consists of five main sections as follows:

4.1 Grid section

4.2 PVT section

4.3 SCAL section

4.4 Initialization section

4.5 Schedule section

4.1 Grid section

The Grid section is the section used to set basic reservoir geometry and rock properties. The reservoir size, grid block size, number of cells, porosity and permeability are set in this section. A 3D-Catesian grid model is used to represent a hypothetical homogeneous reservoir. The grid geometry and properties are illustrated in Table 4.1.

Table 4.1: Grid geometry and properties

Description	**Value**
Reservoir size	1500x1500x100 ft^3
Grid geometry	
Number of cells	50x50x10
X grid block size	30 feet
Y grid block size	30 feet
Z grid block size	10 feet
Properties	
Porosity	20%
X permeability	100 mD
Y permeability	100 mD
Z permeability	10 mD

4.2 PVT section

The PVT section is used to input fluid properties, initial temperature, water compressibility and formation compressibility. This study uses ECLIPSE E300 in which fluid properties are set in term of composition. H_2O and methane are the main component. The mole fraction of H_2O: methane is varied from 0%:100%, 10%:90%, 20%:80%, 30%:70%, 40%:60% to 50%:50%. The initial reservoir temperature is set at 329^{o}F at depth of 8,000 feet representing a typical dry gas reservoir in the Gulf of Thailand.

The phase equilibrium is obtained via Peng-Robinson's equation of state. Table 4.2 shows physical properties of each component which are used in the equation of state.

Table 4.2: Physical properties of each component

Component	Boiling points (°R)	Critical pressure (psia)	Critical temp. (°R)	Critical volume (ft^3/lb-mole)	Molecular weight	Acentric factor
H_2O	671.67	3197.828	1165.14	0.8970	18.015	0.344
Methane (C_1)	200.88	667.78	343.08	1.5698	16.043	0.013

The water compressibility and the formation compressibility are function of pressure. Table 4.3 and Figure 4.1 show the water compressibility and pressure relation at constant temperature of 329°F. This set of data is obtained from the study of Dodson et.al. [1]. Santa Rosa Sandstone, Berea Sandstone and Grain Stone formation compressibilities obtained from Fatt[15] and Harari et. al. [16] are shown in Tables 4.4 to 4.6. Figure 4.2 compares formation compressibilities versus pressure for the three reservoir rocks.

Table 4.3: Water compressibility at 329°F (after Dodson [1])

Pressure (psi)	Compressibility (psi^{-1})
800	4.17×10^{-6}
1,000	4.16×10^{-6}
2,000	4.10×10^{-6}
3,000	4.00×10^{-6}
3,566	3.90×10^{-6}
4,000	3.80×10^{-6}
5,000	3.67×10^{-6}
6,000	3.56×10^{-6}
7,000	3.45×10^{-6}
8,000	4.17×10^{-6}

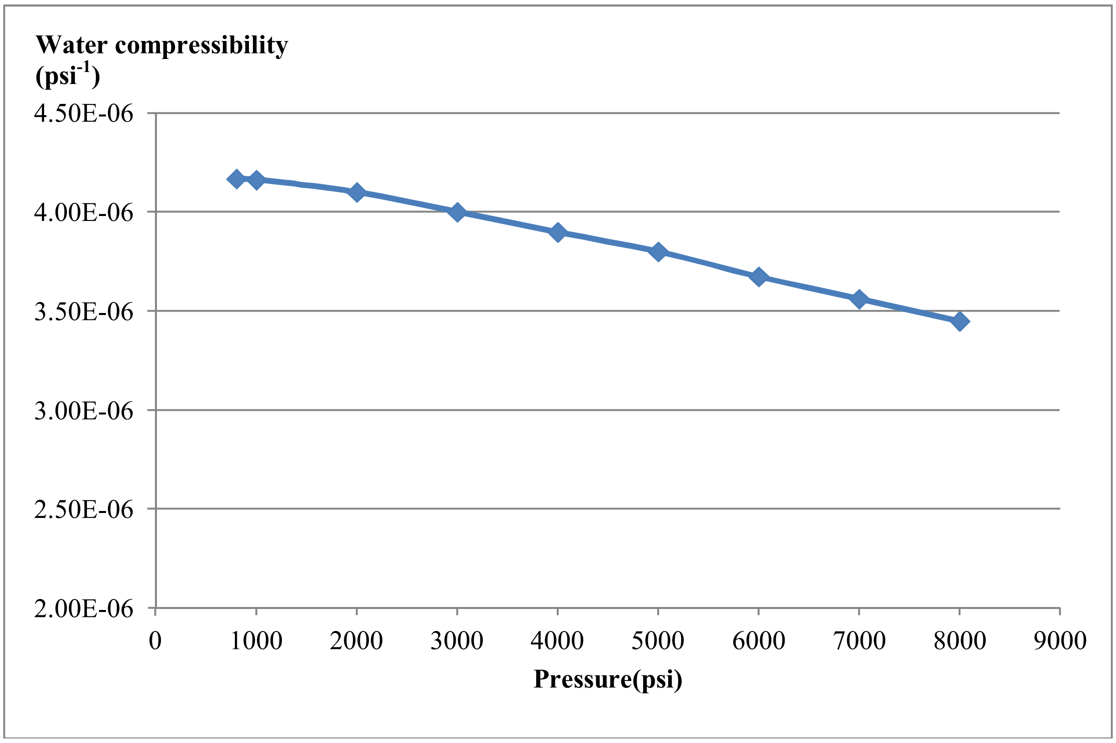

Figure 4.1: Water compressibility curve at 329°F (after Dodson [1])

Table 4.4: Santa Rosa Sandstone formation compressibility (after Fatt [16])

Pressure (psi)	Compressibility (psi^{-1})
800	$3.29x10^{-5}$
900	$3.20x10^{-5}$
2000	$2.25x10^{-5}$
4000	$1.40x10^{-5}$
6000	$1.10x10^{-5}$
8000	$8.50x10^{-6}$

Table 4.5: Berea Sandstone formation compressibility (after Harari [17])

Pressure (psi)	**Compressibility (psi^{-1})**
800	$3.50x10^{-5}$
1000	$2.70x10^{-5}$
1500	$1.60x10^{-5}$
2000	$1.20x10^{-5}$
2500	$9.00x10^{-6}$
3000	$8.00x10^{-6}$
3500	$7.00x10^{-6}$
4000	$6.00x10^{-6}$
4500	$4.50x10^{-6}$
5000	$4.00x10^{-6}$
6000	$4.00x10^{-6}$
7000	$4.00x10^{-6}$
8000	$4.00x10^{-6}$

Table 4.6: Grainstone formation compressibility (after Harari [17])

Pressure (psi)	**Compressibility (psi^{-1})**
800	$1.74x10^{-5}$
1000	$1.50x10^{-5}$
1500	$1.20x10^{-5}$
2000	$9.00x10^{-6}$
2500	$7.00x10^{-6}$
3000	$6.00x10^{-6}$
3500	$5.50x10^{-6}$
4000	$5.00x10^{-6}$
4500	$5.00x10^{-6}$
5000	$5.00x10^{-6}$
6000	$5.00x10^{-6}$
7000	$5.00x10^{-6}$
8000	$5.00x10^{-6}$

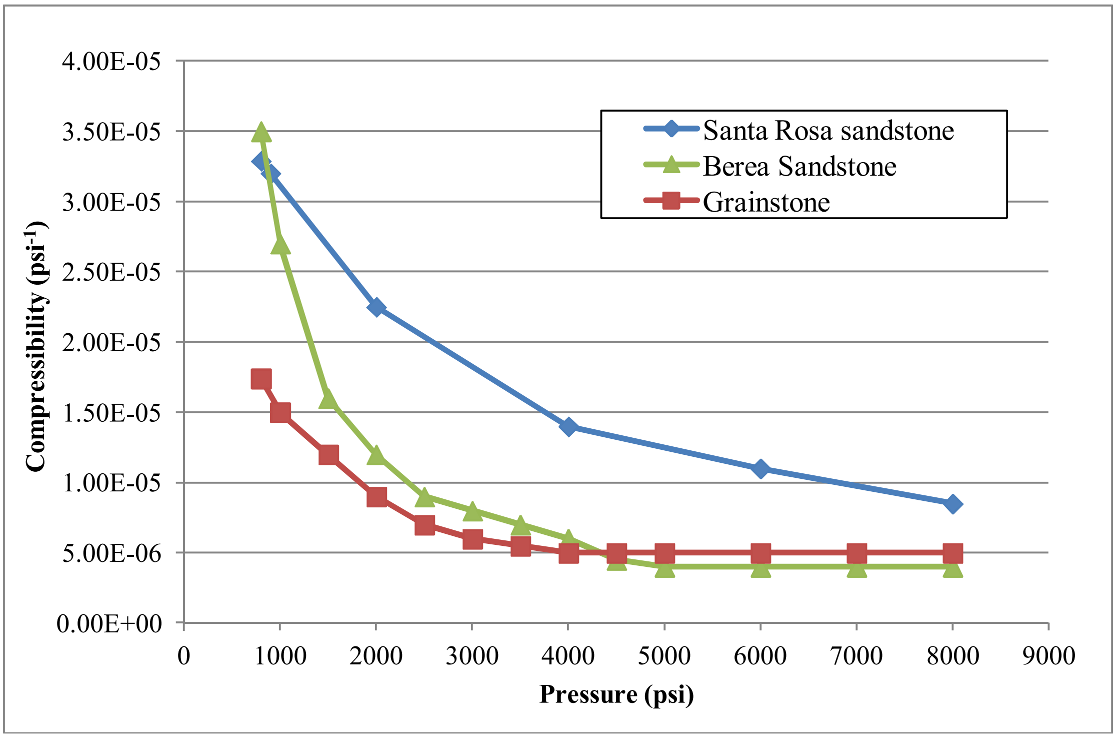

Figure 4.2: Formation compressibility (after Fatt [16] and Harari [17])

4.3 SCAL section

The simulation model uses 3-phase relative permeability for oil/water/gas system. Water saturation function, gas saturation function and oil saturation function used in study are shown in Tables 4.7 to 4.9 and Figures 4.3 to 4.5, respectively.

k_{rg} is relative permeability to gas

k_{rw} is relative permeability to water

k_{rowg} is relative permeability to oil for oil/water/gas system

k_{row} is relative permeability to oil for oil/water system

S_w is saturation of water

S_g is saturation of gas

p_c is capillary pressure

Table 4.7: Water saturation function

S_w	k_{rw}
0.25	0.00
0.30	0.00
0.35	0.02
0.40	0.05
0.45	0.08
0.50	0.14
0.55	0.21
0.60	0.29
0.65	0.39
0.70	0.50
1.00	1.00

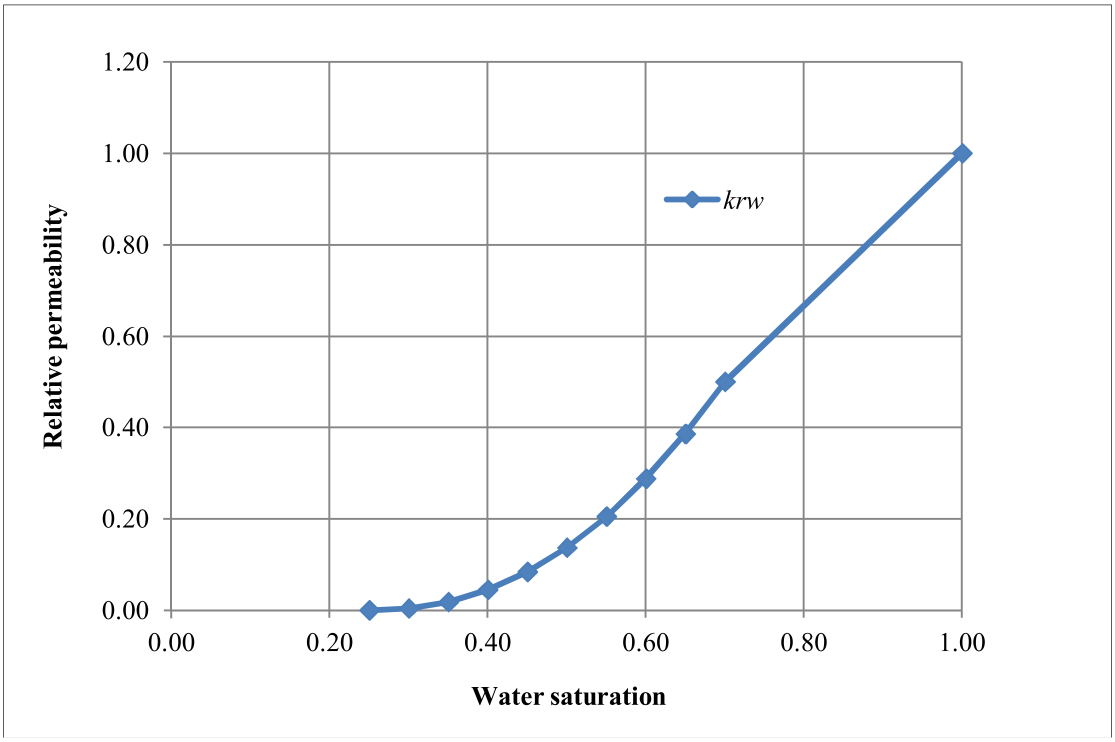

Figure 4.3: Water saturation function

Table 4.8 Gas saturation function

S_g	k_{rg}
0	0.00
0.30	0.00
0.35	0.00
0.40	0.00
0.45	0.00
0.50	0.01
0.55	0.04
0.60	0.11
0.65	0.23
0.70	0.44
0.75	0.80

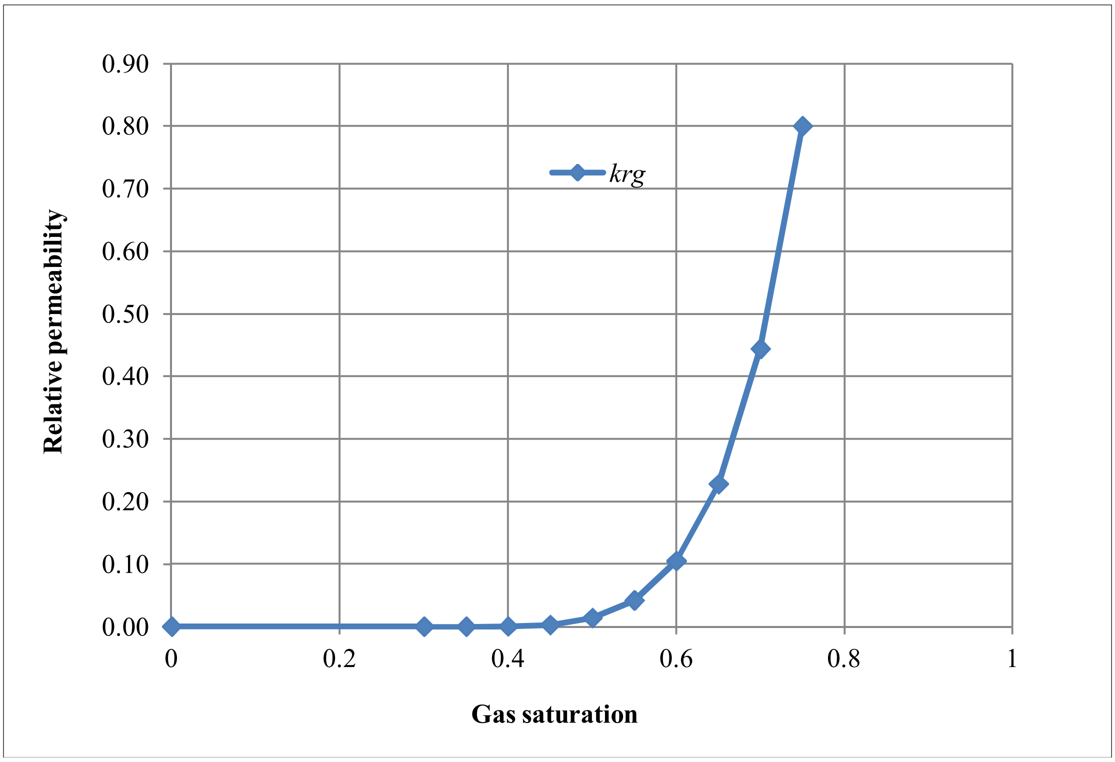

Figure 4.4: Gas saturation function

Table 4.9: Oil saturation function

S_o	k_{row}	k_{rog}
0.00	0.00	0.00
0.10	0.02	0.00
0.15	0.04	0.01
0.20	0.06	0.03
0.25	0.10	0.05
0.30	0.15	0.09
0.35	0.23	0.14
0.40	0.31	0.21
0.50	0.49	0.38
0.60	0.67	0.58
0.75	0.80	0.80

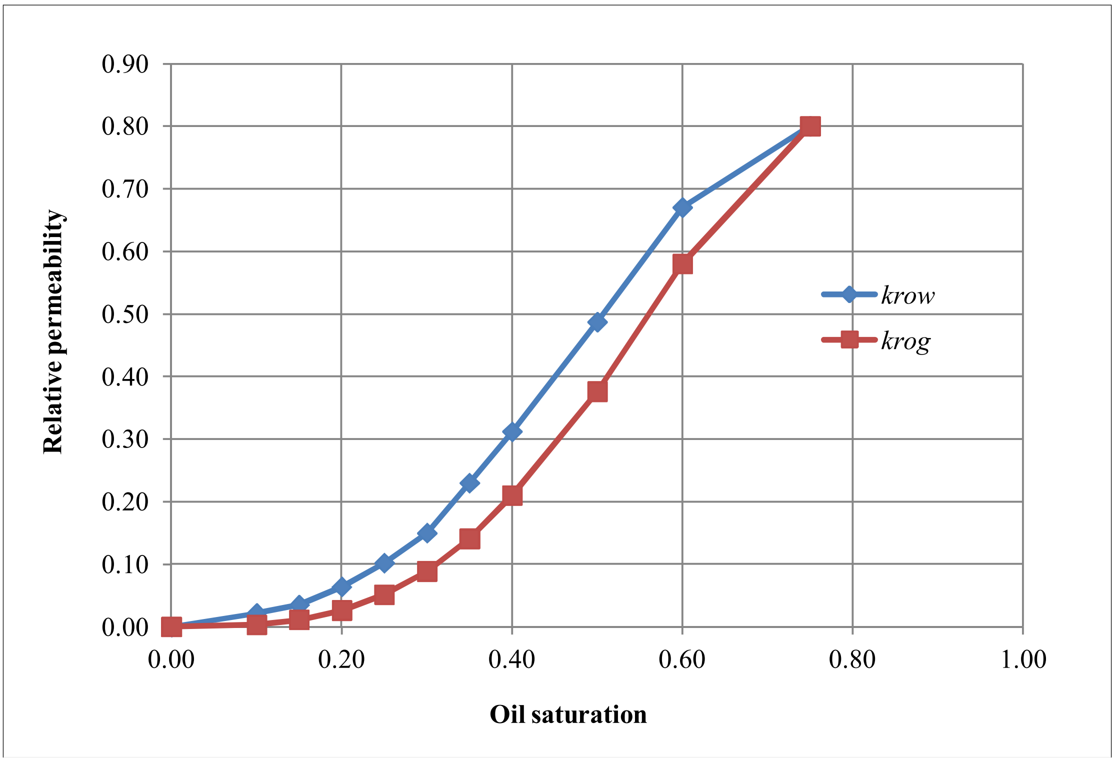

Figure 4.5: Oil saturation function

4.4 Initialization section

Initialization section is used to specify the initial conditions of the model. Three main parameters are defined in this section:

1) datum depth
2) water-oil contact (WOC) depth
3) initial reservoir pressure at datum depth

Datum depth and water-oil contact are specified depth at 8,000 and 8,900 feet, respectively. The initial reservoir pressure is varied from 3,566 to 8,000 psi for different cases.

4.5 Schedule section

This section specifies the well specifications which are well bore inside diameter, perforation interval, production target and bottom hole pressure (BHP) target as shown in Table 4.10.

Table 4.10: Well specification

Description	**Value**
Well bore inside diameter	6 1/8"
Perforation interval	100 feet
Gas production target	10,000 MCF/day
BHP target	800 psi

The simulation model has a single well which is set the gas production target 10,000 MCF/day and the minimum bottom-hole pressure of 800 psi.

The simulation is used to simulate the production history in order to obtain pressure depletion profile and cumulative gas production (G_p) which are used to calculate the OGIP by different material balance equations. Then, we assume the OGIP obtained from simulation program as actual OGIP. The actual OGIP will be compared with OGIP estimated from material balance equation in term of error in Chapter 5.

CHAPTER V

RESULTS AND DISCUSSIONS

This chapter explains the result and provides discussion on the estimation of original gas in place using different material balance methods to account for water and rock compressibilities and water vapor of dry gas reservoirs.

The first part deals with the effect of water and formation compressibility on OGIP estimate. Three material balance methods used in this study are conventional method, Ramagost method and modified Ramagost method. The effects of available data, initial reservoir pressure, and formation compressibility on OGIP estimates are discussed.

Since the amount of data used in material balance analysis is crucial to the estimate of the original gas in place, the following amounts of data are analyzed in order to compare the errors of OGIP estimates obtained at different degrees of depletion:

a. From initial condition to the point when reservoir pressure is 25% depleted
b. From initial condition to the point when reservoir pressure is 50% depleted
c. From initial condition to the point when reservoir pressure is 75% depleted
d. From initial condition to the point when reservoir is abandoned

In addition, the initial reservoir pressure has a significant effect on the contribution of the water and rock expansion terms in material analysis. Therefore, the following conditions of initial reservoir pressure are studied in order to quantify the errors of OGIP estimates obtained under different reservoir conditions:

a. Initial reservoir pressure of 3,566 psi. (normal pressure)
b. Initial reservoir pressure of 4,000 psi.
c. Initial reservoir pressure of 5,000 psi.
d. Initial reservoir pressure of 6,000 psi.
e. Initial reservoir pressure of 7,000 psi.
f. Initial reservoir pressure of 8,000 psi.

In this study, the water compressibility variation as a function of pressure is obtained from Dodson and Standing [1] as shown in Figure 5.1. Three formation compressibilities for three different rocks, namely, Santa Rosa sandstone, Berea

Sandstone, and Grainstone obtained from Fatt [16] and Harari [17] are shown in Figure 5.2.

The second part discusses the effect of formation expansion and water vaporization on OGIP estimates based on results obtained from conventional, Humphreys, and modified Humphreys methods. The studied parameters are the degree of depletion, and initial reservoir pressure which are the same as in the first part. And in order to study the effect of water vaporization on OGIP estimation, different water contents in gas phase are studied in order to quantify the errors of OGIP estimates obtained under different water contents as follows:

a. Water content 10 % mole
b. Water content 20 % mole
c. Water content 30 % mole
d. Water content 40 % mole
e. Water content 50 % mole

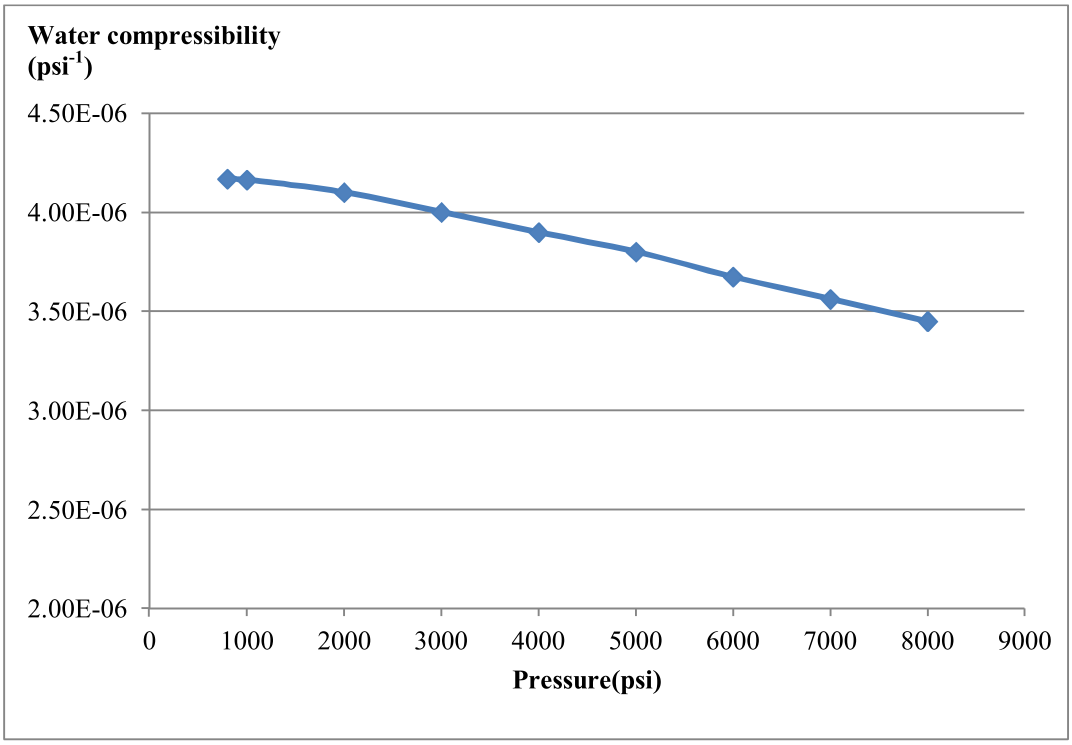

Figure 5.1: Water compressibility curve at 329^{o}F (after Dodson [1])

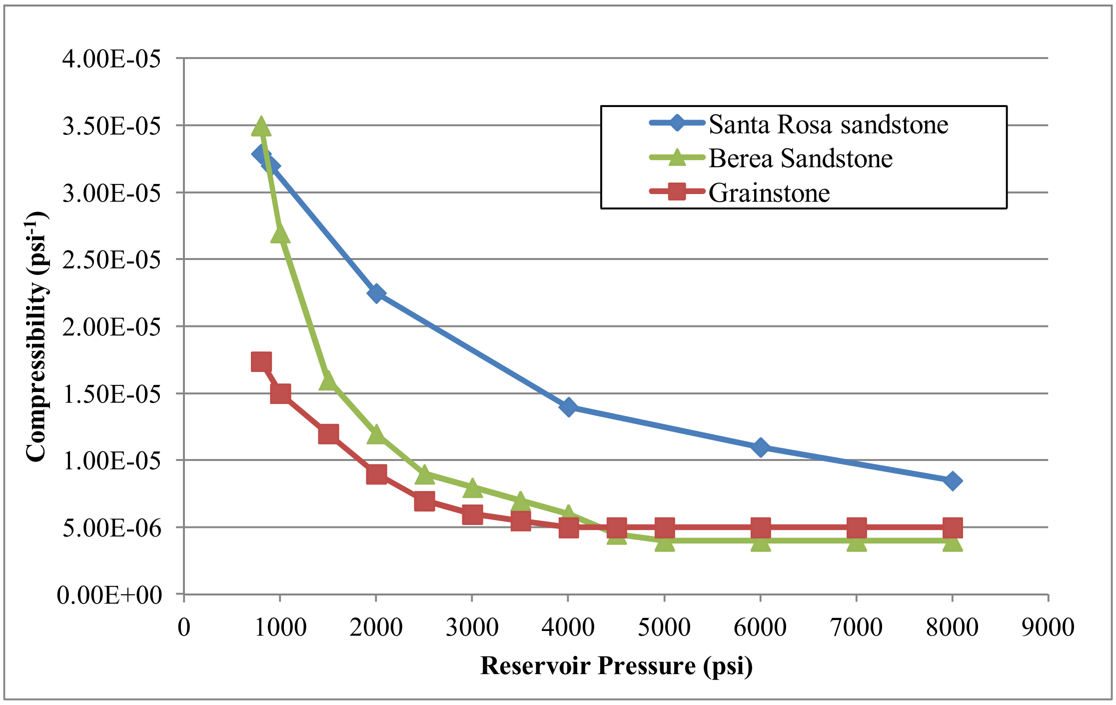

Figure 5.2: Formation compressibility; Santa Rosa sandstone, Berea sandstone and Grainstone (after Fatt [16] and Harari [17])

5.1 Effect of water and formation compressibility

This part reports the comparison of OGIP estimated from 3 different material balance methods in term of error for different formation compressibilities, namely, Santa Rosa sandstone, Berea sandstone and Grainstone. The method of analysis, degree of depletion and effect of initial pressure are first discussed for each formation compressibilities. Then, the errors of OGIP estimates obtained for different formation compressibilities are compared.

5.1.1 Santa Rosa sandstone reservoir

Santa Rosa sandstone studied by Fatt [16] has the highest average formation compressibility among three kinds of rock used in this study. The formation compressibility varies from $3.29\text{x}10^{-5}$ psi^{-1} at 800 psi to $8.50\text{x}10^{-6}$ psi^{-1} at 8,000 psi and $2.02\text{x}10^{-5}$ psi^{-1} on average.

5.1.1.1 Method of analysis

There are 3 methods for OGIP estimation to discuss in this section which are conventional method, Ramagost method and modified Ramagost method. Figures 5.3 and 5.4 show *p/z* plot used to estimate OGIP based on the 3 methods when the initial reservoir pressure is 3,566 and 8,000 psi, respectively.

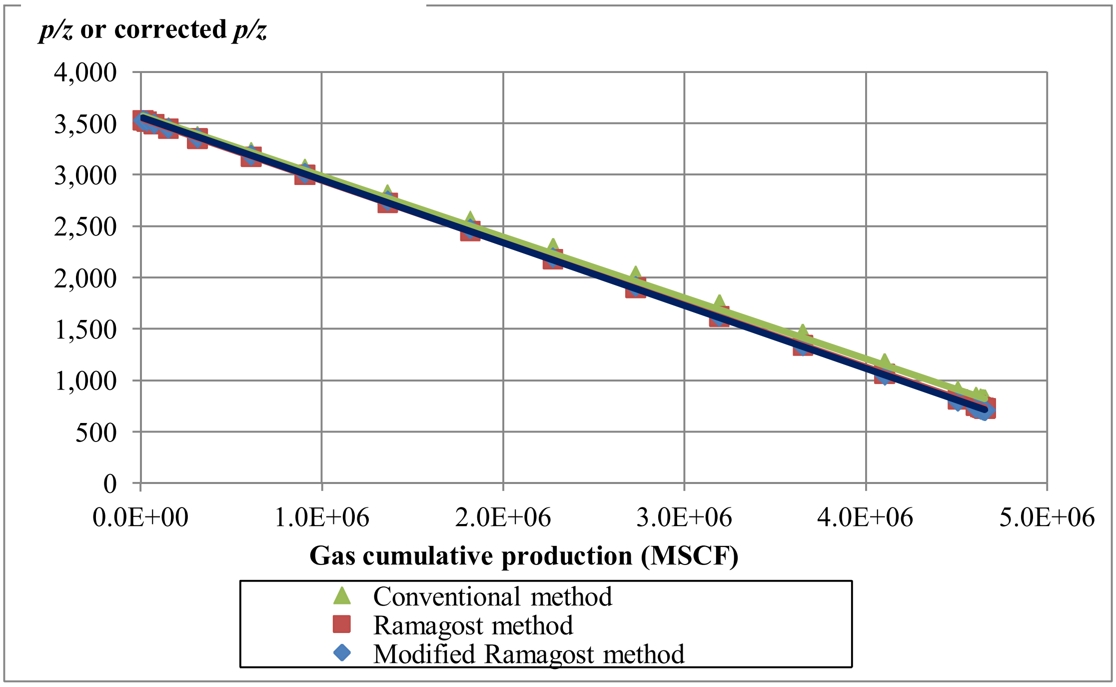

Figure 5.3: *p/z* or corrected *p/z* vs. G_p plot by 3 different methods for Santa Rosa sandstone reservoir with initial pressure 3,566 psi

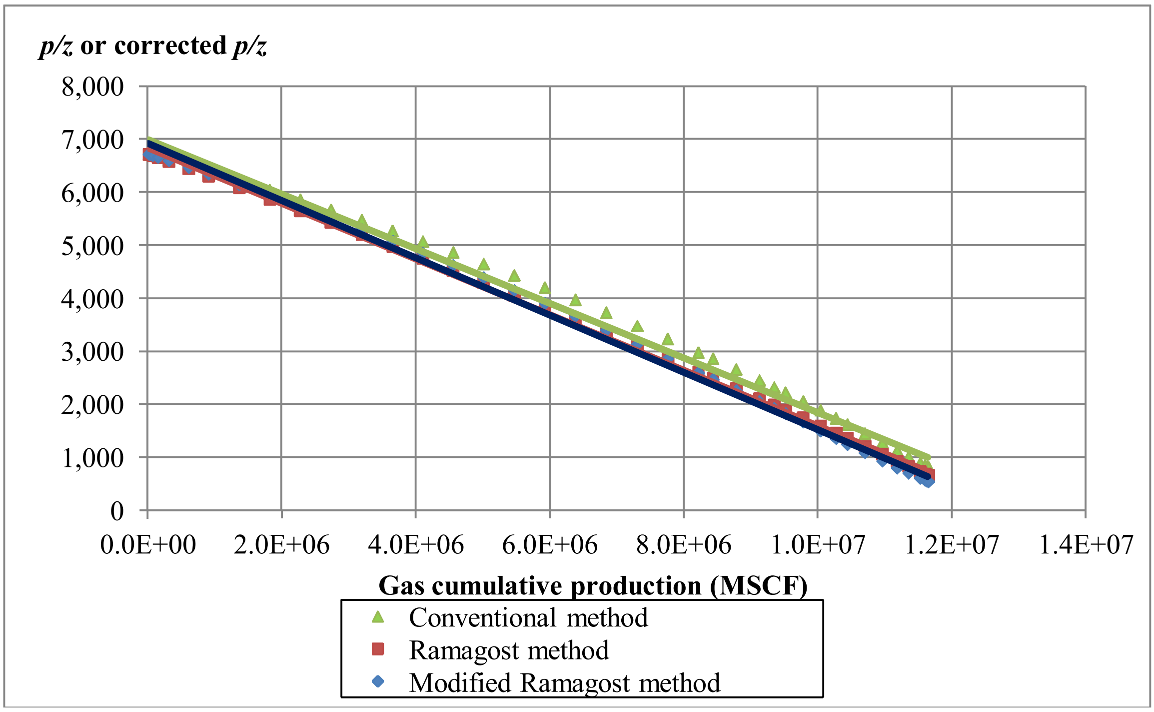

Figure 5.4: *p/z* or corrected *p/z* vs. G_p plot by 3 different methods for Santa Rosa sandstone reservoir with initial pressure 8,000 psi

Tables 5.1-5.4 show estimates of original gas in place by 3 material balance methods. The error of OGIP estimates for Santa Rosa sandstone reservoirs using different methods are shown in Figures 5.5-5.8. The estimates of OGIP by Ramagost and modified Ramagost methods are more accurate than those by conventional method as depicted in Figures 5.5-5.8. Please note that positive error means overestimation while negative error means underestimation. The conventional and Ramagost methods yield overestimation in all cases. Underestimation occurs in a few cases analyzed by modified Ramagost method.

Comparing between conventional method and Ramagost method for the case that production data are available until abandonment, inclusion of water and formation expansion terms reduces the error from 3.49% to 0.6% for a reservoir with initial pressure 3,566 psi and from 6.52% to 2.34% for a reservoir with initial pressure 8,000 psi. The modified Ramagost method proposed in this study yields even smaller error than the other two methods. The error is -0.20% for a reservoir with initial pressure 3,566 psi and 0.55% for a reservoir with initial pressure 8,000 psi. The difference in error among the three methods becomes larger when the reservoir has high initial pressures. The modified Ramagost method has the smallest magnitude of error in these cases because it takes into account the variation in water and formation compressibilities when the pressure of the reservoir decreases while the original Ramagost method uses average water and formation compressibilities.

Table 5.1: Original gas in place estimation for Santa Rosa sandstone reservoir based on production data at abandonment

Initial pressure (psi)	Original gas in place, G (MCF)			
	Actual	Conventional method	Ramagost method	Modified Ramagost method
3,566	5,834,667	6,038,118	5,869,601	5,994,674
4,000	6,553,452	6,790,777	6,613,445	6,541,963
5,000	8,176,600	8,489,739	8,262,301	8,158,342
6,000	9,749,667	10,162,396	9,878,506	9,734,776
7,000	11,275,141	11,822,239	11,457,259	11,272,401
8,000	12,759,621	13,591,686	13,058,104	12,829,874

Table 5.2: Original gas in place estimation for Santa Rosa sandstone reservoir based on production data at 75% depletion

Initial pressure (psi)	Original gas in place, G (MCF)			
	Actual	Conventional method	Ramagost method	Modified Ramagost method
3,566	5,834,667	6,171,686	5,882,841	5,876,715
4,000	6,553,452	6,998,230	6,647,497	6,614,120
5,000	8,176,600	8,962,353	8,380,331	8,359,881
6,000	9,749,667	10,863,690	10,080,616	10,056,323
7,000	11,275,141	12,788,600	11,768,293	11,746,271
8,000	12,759,621	14,587,760	13,387,288	13,321,012

Table 5.3: Original gas in place estimation for Santa Rosa sandstone reservoir based on production data at 50% of depletion

Initial pressure (psi)	Original gas in place, *G* (MCF)			
	Actual	Conventional method	Ramagost method	Modified Ramagost method
3,566	5,834,667	6,349,660	5,910,911	5,961,700
4,000	6,553,452	7,281,140	6,709,402	6,767,642
5,000	8,176,600	9,342,493	8,476,786	8,588,448
6,000	9,749,667	11,471,140	10,252,242	10,454,027
7,000	11,275,141	13,837,183	12,089,640	12,471,683
8,000	12,759,621	15,985,367	13,796,770	14,282,700

Table 5.4: Original gas in place estimation for Santa Rosa sandstone reservoir based on production data at 25% depletion

Initial pressure (psi)	Original gas in place, *G* (MCF)			
	Actual	Conventional method	Ramagost method	Modified Ramagost method
3,566	5,834,667	6,615,011	5,954,263	6,114,276
4,000	6,553,452	7,588,474	6,777,816	6,971,043
5,000	8,176,600	9,864,837	8,610,859	8,993,174
6,000	9,749,667	12,286,483	10,482,204	11,043,724
7,000	11,275,141	14,866,893	12,397,011	13,188,064
8,000	12,759,621	17,352,562	14,195,657	15,240,896

When estimating OGIP at 75% pressure depletion, we can still observe that the modified Ramagost method still provides the most accurate OGIP estimates. For example, the error for the conventional, Ramagost and modified Ramagost methods for a reservoir with initial pressure 8,000 psi is 14.33%, 4.92%, and 4.40%, respectively when 75% data are available. But when estimating at 50% and 25% pressure depletion, the Ramagost method becomes the most accurate OGIP method. For example, the error for the conventional, Ramagost and modified Ramagost methods for a reservoir with initial pressure of 8,000 psi is 25.28%, 8.13%, and 11.94%, respectively when 50% data are available and the error becomes 36.00%, 11.25%, and 19.45%, respectively when 25% data are available. The reason that the Ramagost method has good performance when there is smaller magnitude of pressure depletion in the reservoir is because of smaller variation in water and rock compressibilities during the production of gas. Please also note that the difference in errors between the conventional method and the methods accounting for water and formation expansion (Ramagost and modified Ramagost) becomes more pronounced when less data are used in the analysis.

Figures 5.9 and 5.10 show volumetric expansion of connate water and formation during different stages in pressure decline based on Ramagost (blue line), and modified Ramagost (red line) methods in comparison with correct expansion calculated from ideal *p/z* straight line (green line) for a reservoir with initial pressure 3,566 psi and 8,000 psi, respectively. In both figures, the expansion volume calculated by Ramagost method is closest to the correct expansion when the pressure depletion is 50% or less. But when the pressure depletion is 75% or more, the modified Ramagost method provides better calculation, i.e., the expansion from modified Ramagost method is closer to the correct expansion. These are the reason why Ramagost method gives less error of OGIP estimates when the pressure depletion is 50% or less and modified Ramagost method gives less error when the pressure depletion is 75% or more.

As summarized in Table 5.5, we learned that the modified Ramagost method is suitable for estimating OGIP based on data available at 75% of pressure depletion and abandonment the Ramagost method yields the most accurate OGIP estimate based on data available at 25% and 50% pressure depletion. If the conventional method is used, the error can be as high as 36.00% in the case of 8,000 psi initial pressure reservoir and 25% depletion. The highest error from Ramagost method at 25% and 50% depletion is 11.25% while the highest error from modified Ramagost at 75% of pressure depletion and abandonment is 4.45%. Thus, using the right method for right percentage of depletion will give us a maximum error of 11.25%.

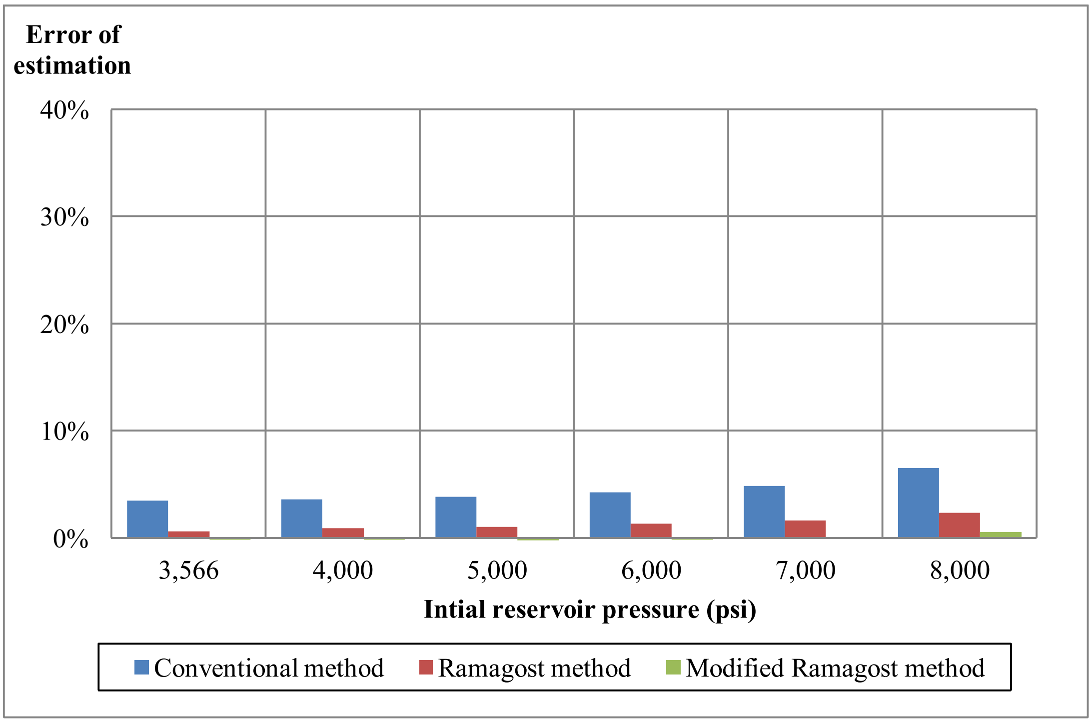

Figure 5.5: Error of G estimated by different methods for Santa Rosa sandstone reservoir based on production data at abandonment

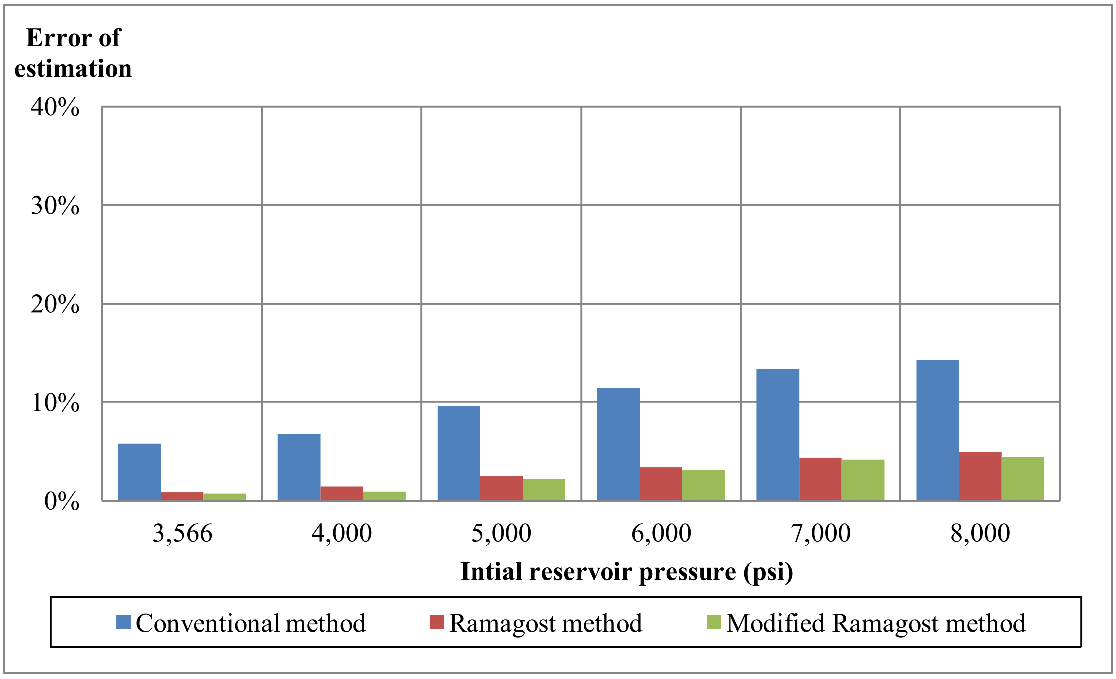

Figure 5.6: Error of G estimated by different methods for Santa Rosa sandstone reservoir based on production data at 75% pressure depletion

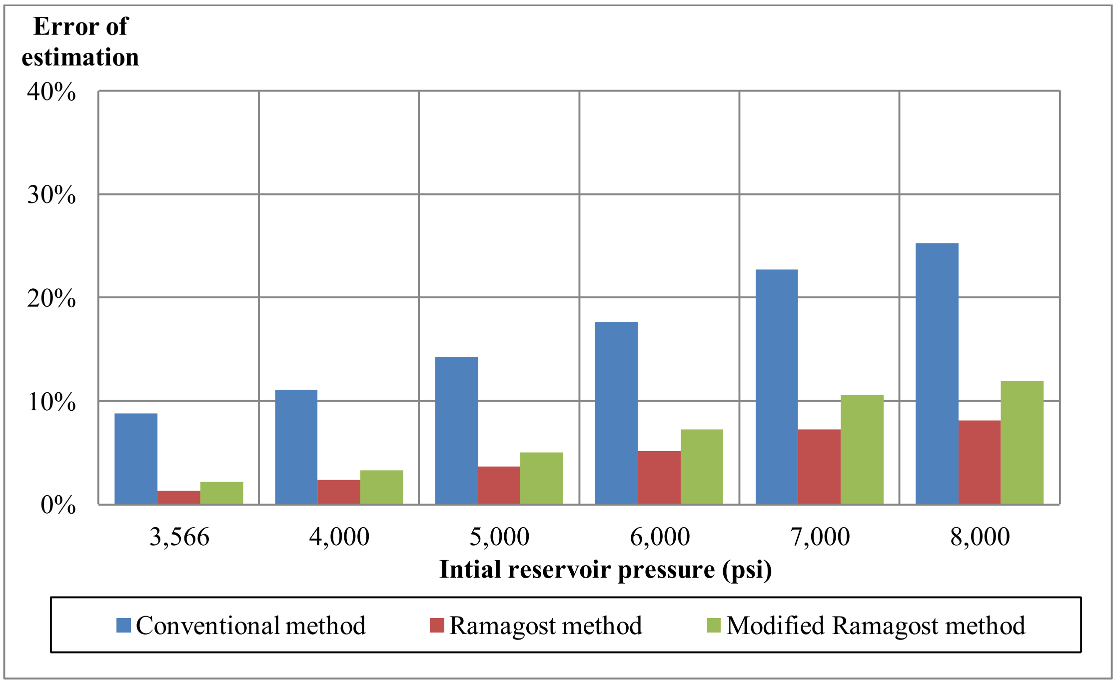

Figure 5.7: Error of *G* estimated by different methods for Santa Rosa sandstone reservoir based on production data at 50% pressure depletion

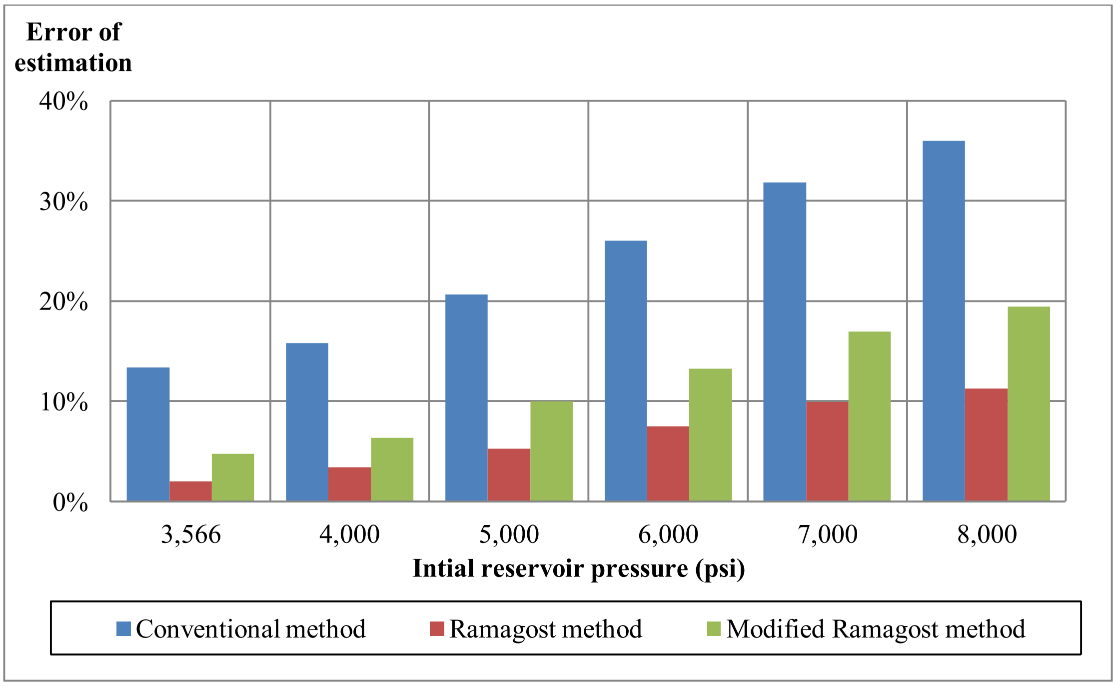

Figure 5.8: Error of *G* estimated by different methods for Santa Rosa sandstone reservoir based on production data at 25% pressure depletion

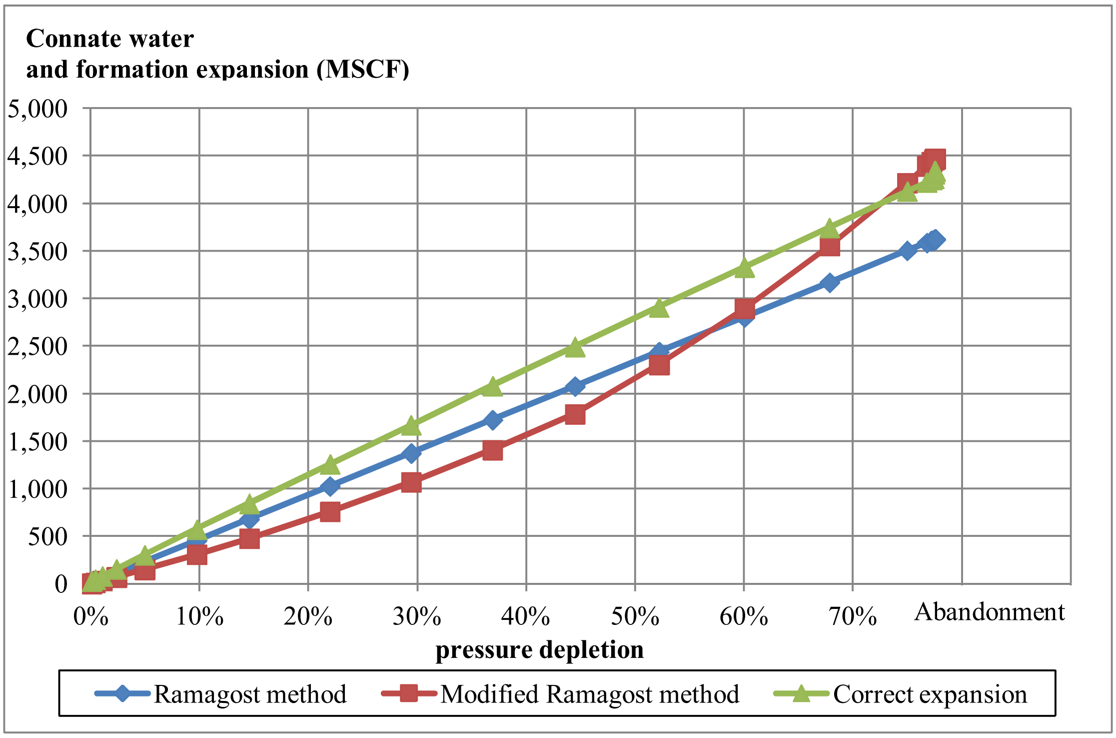

Figure 5.9: Connate water and formation expansion for Santa Rosa sandstone reservoir with initial pressure 3,566 psi

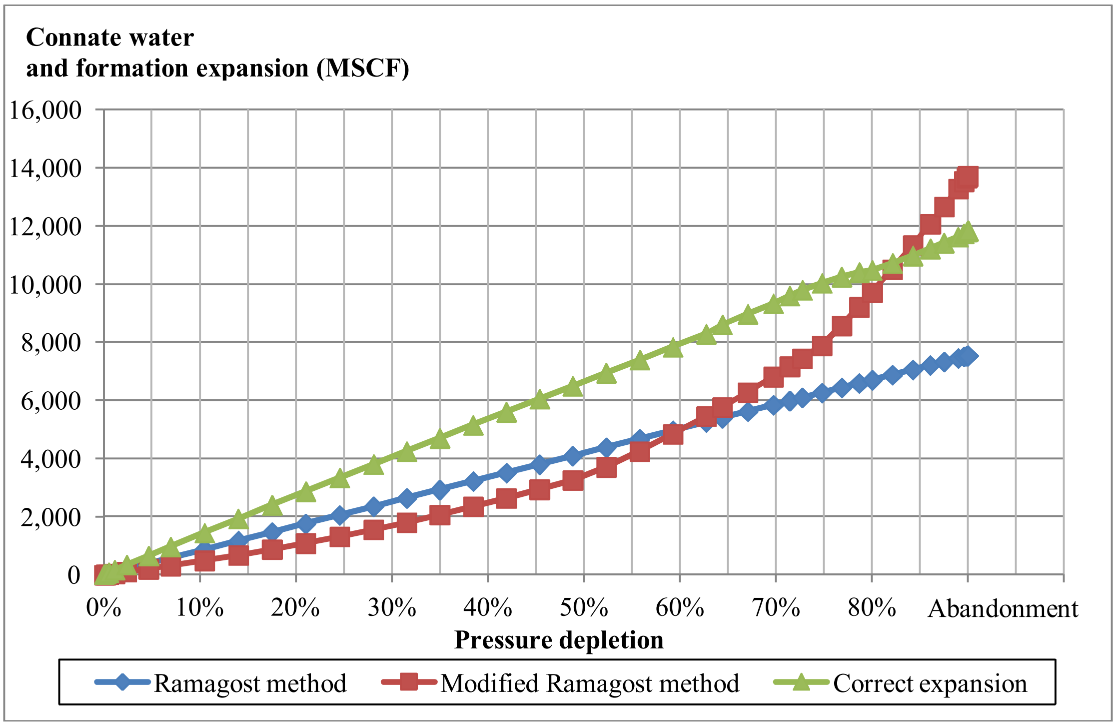

Figure 5.10: Connate water and formation expansion for Santa Rosa sandstone reservoir with initial pressure 8,000 psi

Table 5.5: The number of the most accurate OGIP estimates for conventional, Ramagost and modified Ramagost method for Santa Rosa sandstone reservoir

	Range of production data available			
	at abandonment	75%	50%	25%
Conventional method	0	0	0	0
Ramagost method	0	0	6	6
Modified Ramagost method	6	6	0	0

5.1.1.2 Degree of depletion

As availability of production data is important in OGIP estimation, we performed *p/z* plots based on different stages of pressure depletion and analyzed for the errors in OGIP estimates. The results of the analysis on different degree of depletion are shown in Figure 5.11-5.13. The error of OGIP estimate for all the 3 methods decreases when more production data are available. For example, in case of conventional method as shown in Figure 5.11, when OGIP estimates are computed based on 25% pressure depletion and 50% pressure depletion for a reservoir with initial pressure 3,566 psi, the overestimation of OGIP reduces from 13.37% to 8.83%. For a reservoir with initial pressure 8,000 psi, the error reduces from 36.00% to 25.28%. When the modified Ramagost method is used, the error for reservoir with initial pressure of 8,000 psi decreases from 19.45% to 11.94% when data used in the analysis are extended from 25% pressure depletion to 50% pressure depletion. A lesson learned from the results is that one should be aware of overestimation error when a short duration of production data is available.

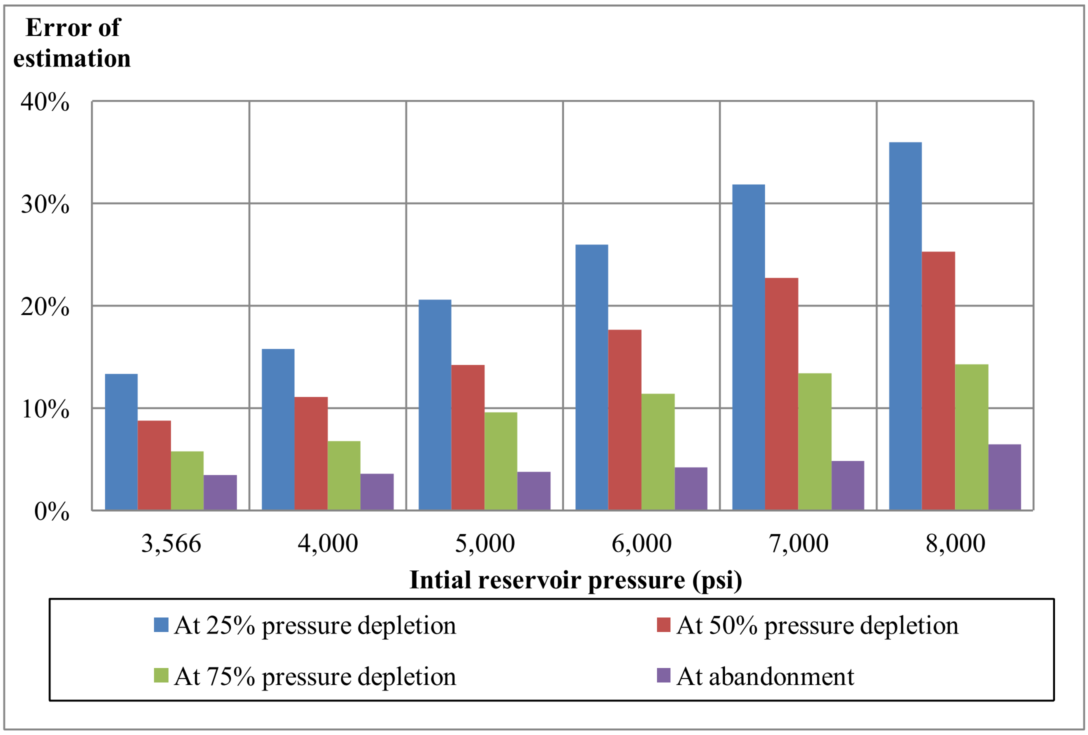

Figure 5.11: Error of *G* estimated by conventional method for Santa Rosa sandstone reservoir based on different degree of depletion

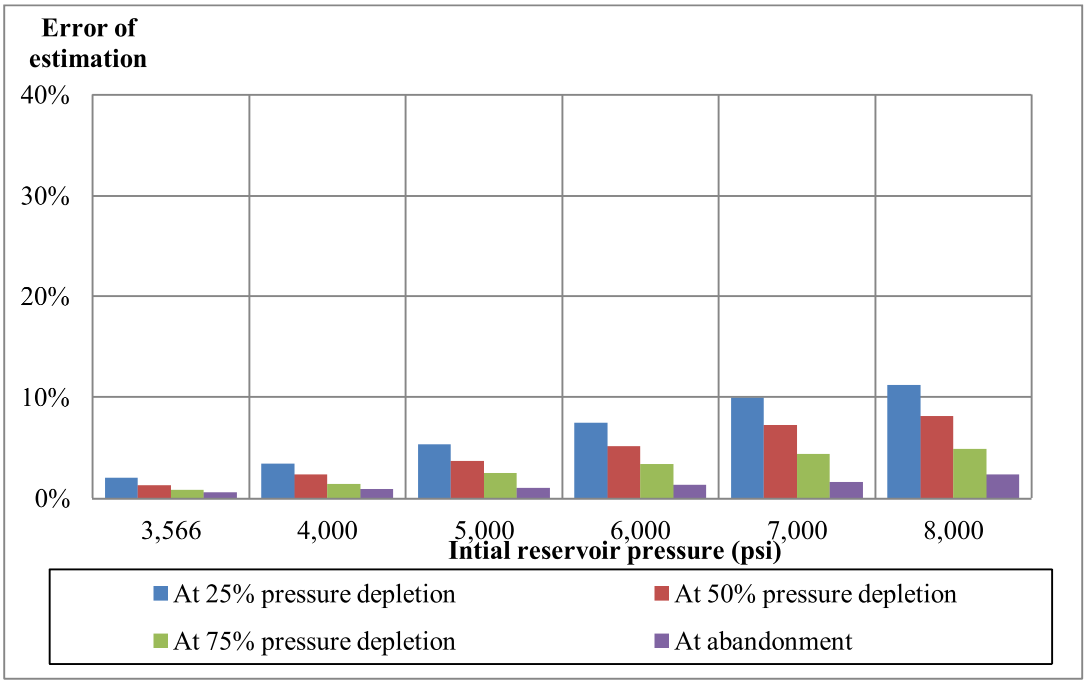

Figure 5.12: Error of *G* estimated by Ramagost method for Santa Rosa sandstone reservoir based on different degree of depletion

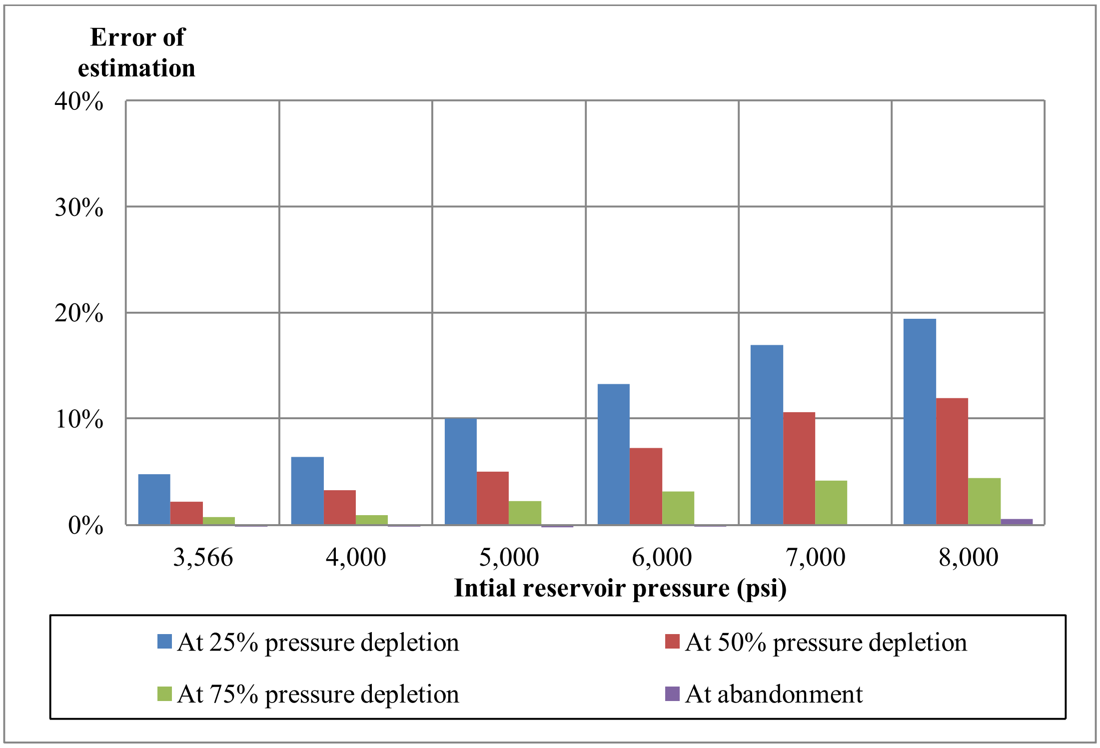

Figure 5.13: Error of *G* estimated by modified Ramagost method for Santa Rosa sandstone reservoir based on different degree of depletion

5.1.1.3 Effect of initial pressure

As the decline in reservoir pressure affects the expansion of water and formation, the initial reservoir pressure has a significant impact on OGIP estimates. As seen in Figures 5.5-5.8, the error of OGIP estimate for a reservoir with high initial pressure is higher than that for a reservoir with low initial pressure. This observation is true for almost all methods of analysis and all lengths of data used in the analysis. For example, in the case of Ramagost method, which is the most accurate method when base on production data at 25% and 50% pressure depletion, the error of OGIP estimates increase from 2.05% to 11.25% and 1.31% to 8.13%, respectively when the reservoir pressure is changed from 3,566 psi to 8,000 psi. The same hand of increasing error when the initial pressure increases can be seen in the modified Ramagost method when 75% of data are available. However, this trend cannot seen at abandonment because the errors are very small (between -0.22 and 0.55%).

5.1.2 Berea sandstone reservoir

Berea sandstone has a moderate average formation compressibility among three kinds of rock used in this study. It has the formation compressibility varying from 3.50×10^{-5} to 4.0×10^{-6} psi^{-1} at pressure 800 to 8,000 psi and 1.08×10^{-5} psi^{-1} on average.

5.1.2.1 Method of analysis

The estimates original gas in place by different material balance methods for Berea sandstone reservoir are shown in Tables 5.6-5.9. The error of OGIP estimates for Berea sandstone reservoirs using different methods are shown in Figures 5.14-5.17. The trends of error when estimates by different methods are the same as in the case of Santa Rosa sandstone reservoirs. The estimates of OGIP by Ramagost and modified Ramagost methods are more accurate than those by conventional method as shown in Figures 5.14-5.17.

Comparing between conventional method and Ramagost method for the case that production data are available until abandonment, inclusion of water and formation expansion terms reduces the error from 5.05% to 3.26% for a reservoir with initial pressure 3,566 psi and reduces from 9.03% to 6.68% for a reservoir with initial pressure 8,000 psi. The modified Ramagost method proposed in this study yields results in smaller error than the other two methods. The error is 1.10% for a reservoir with initial pressure 3,566 psi and 4.44% for a reservoir with initial pressure 8,000 psi. The difference in error among the three methods becomes larger when the reservoir has high initial pressures. The modified Ramagost method has the smallest magnitude of error because it takes into account the variation in water and formation compressibilities when the pressure of the reservoir decreases while the original Ramagost method uses average water and formation compressibilities.

When estimating OGIP at 75% pressure depletion, we can still observe that the modified Ramagost method still provides the most accurate OGIP estimates. For example, the error for the conventional, Ramagost and modified Ramagost methods for a reservoir with initial pressure 8,000 psi is 19.91%, 14.35%, and 14.13%, respectively when 75% data are available. But when estimating at 50% and 25%

pressure depletion, the Ramagost method becomes the most accurate OGIP method. For example, the error for the conventional, Ramagost and modified Ramagost methods for reservoir with initial pressure 8,000 psi is 37.49%, 26.19%, and 31.13%, respectively when 50% data are available and the errors become 55.62%, 37.79%, and 46.66%, respectively when 25% data are available. The Ramagost method has good performance at early stages of depletion because there is small variation in water and rock compressibility during the narrower range of pressure depletion. Also note that the difference in errors among the three methods becomes more pronounced when less data are used in the analysis.

Figures 5.18 and 5.19 show volumetric expansion of connate water and formation during different stages in pressure decline based on Ramagost (blue line), and modified Ramagost (red line) methods in comparison with correct expansion calculated from ideal *p/z* straight line (green line) for a reservoir with initial pressure 3,566 psi and 8,000 psi, respectively. In both figures, the expansion volume calculated by Ramagost method is closest to the correct expansion when the pressure depletion is 50% or less. But when the pressure depletion is 75% or more, the modified Ramagost method provides better calculation, i.e., the expansion from modified Ramagost method is closer to the correct expansion. These are the reason why Ramagost method gives less error of OGIP estimates when the pressure depletion is 50% or less and modified Ramagost method gives less error when the pressure depletion is 75% or more.

As summarized in Table 5.10, we learned that the modified Ramagost method is suitable for estimating OGIP based on data available at 75% of pressure depletion and abandonment while the Ramagost method yields the most accurate OGIP estimate based on data available at 25% and 50% pressure depletion. If the conventional method is used, the error can be as high as 55.62% in the case of 8,000 psi initial pressure reservoir and 25% depletion. The highest error from Ramagost method at 25% and 50% depletion is 37.79% while the highest error from modified Ramagost at 75% of pressure depletion and abandonment is 14.13%. Thus, using the right method for right percentage of depletion will give us a maximum error of 37.79%.

Table 5.6: Original gas in place estimation for Berea sandstone reservoir based on production data at abandonment

Initial pressure (psi)	Original gas in place, *G* (MCF)			
	Actual	Conventional method	Ramagost method	Modified Ramagost method
3,566	6,186,011	6,498,645	6,387,500	6,254,343
4,000	6,992,404	7,361,929	7,239,431	7,083,702
5,000	8,851,749	9,334,608	9,184,216	8,972,100
6,000	10,706,470	11,369,261	11,175,421	10,914,482
7,000	12,556,465	13,524,109	13,259,829	12,970,695
8,000	14,406,275	15,706,462	15,368,558	15,046,083

Table 5.7: Original gas in place estimation for Berea sandstone reservoir based on production data at 75% pressure depletion

Initial pressure (psi)	Original gas in place, *G* (MCF)			
	Actual	Conventional method	Ramagost method	Modified Ramagost method
3,566	6,186,011	6,765,820	6,548,363	6,521,263
4,000	6,992,404	7,673,114	7,431,848	7,392,438
5,000	8,851,749	10,002,080	9,630,076	9,622,000
6,000	10,706,470	12,377,995	11,872,595	11,803,383
7,000	12,556,465	14,715,922	14,095,517	14,071,508
8,000	14,406,275	17,274,764	16,473,118	16,442,444

Table 5.8: Original gas in place estimation for Berea sandstone reservoir based on production data at 50% pressure depletion

Initial pressure (psi)	Original Gas in place, *G* (MCF)			
	Actual	Conventional method	Ramagost method	Modified Ramagost method
3,566	6,186,011	7,034,838	6,712,044	6,783,737
4,000	6,992,404	8,081,658	7,686,596	7,787,663
5,000	8,851,749	10,690,893	10,074,090	10,264,858
6,000	10,706,470	13,540,541	12,641,856	12,953,477
7,000	12,556,465	16,433,882	15,244,324	15,694,726
8,000	14,406,275	19,807,524	18,179,136	18,897,857

Table 5.9: Original gas in place estimation for Berea sandstone reservoir based on production data at 25% pressure depletion

Initial pressure (psi)	Original Gas in place, *G* (MCF)			
	Actual	Conventional method	Ramagost method	Modified Ramagost method
3,566	6,186,011	7,413,685	6,936,937	7,135,952
4,000	6,992,404	8,518,117	7,953,394	8,184,282
5,000	8,851,749	11,425,132	10,539,760	10,945,354
6,000	10,706,470	14,683,985	13,371,554	14,087,873
7,000	12,556,465	18,334,825	16,473,585	17,454,545
8,000	14,406,275	22,418,496	19,849,735	21,128,881

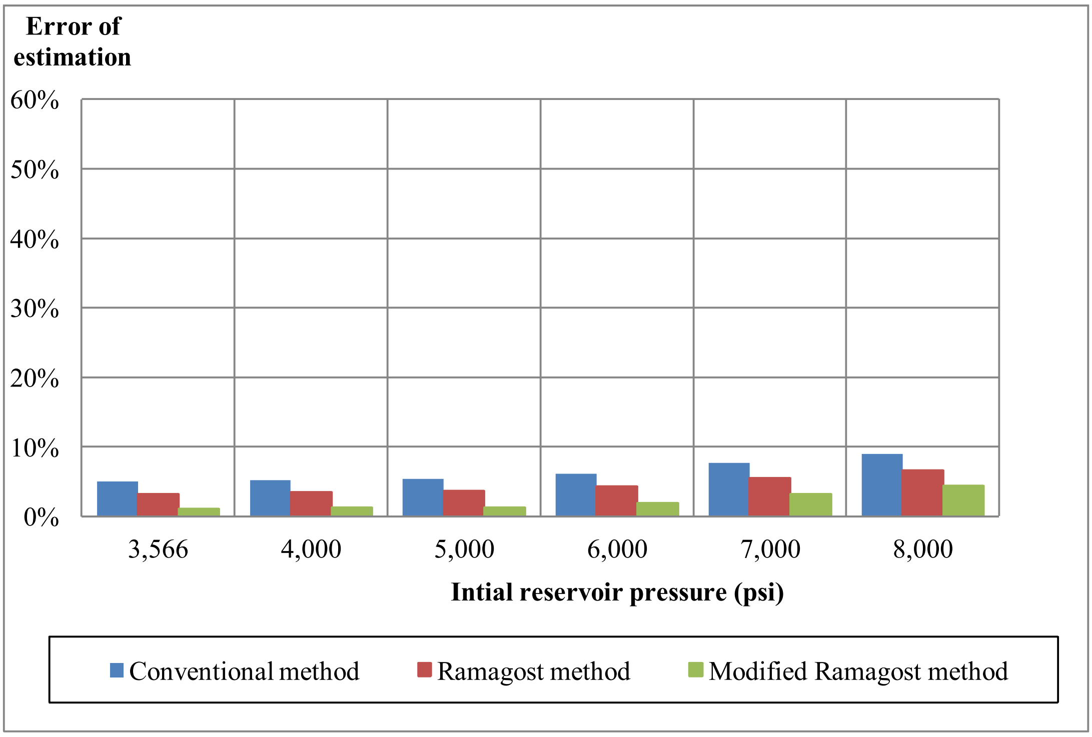

Figure 5.14 Error of G estimated by different methods for Berea sandstone reservoir based on production data at abandonment

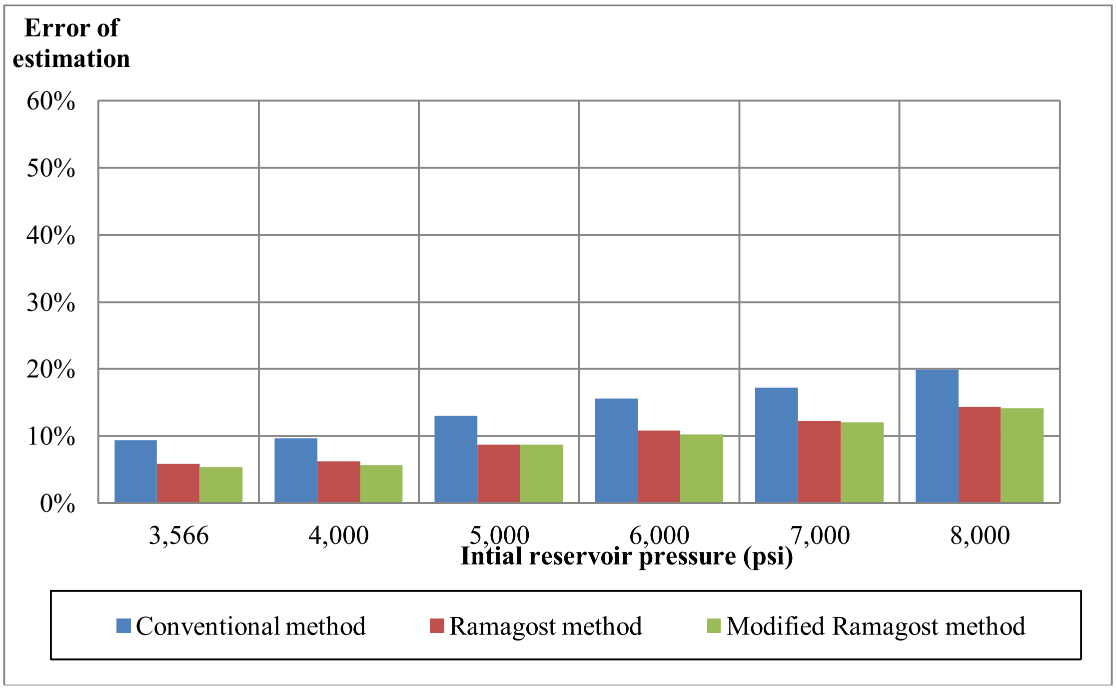

Figure 5.15: Error of G estimated by different methods for Berea sandstone reservoir based on production data at 75% pressure depletion

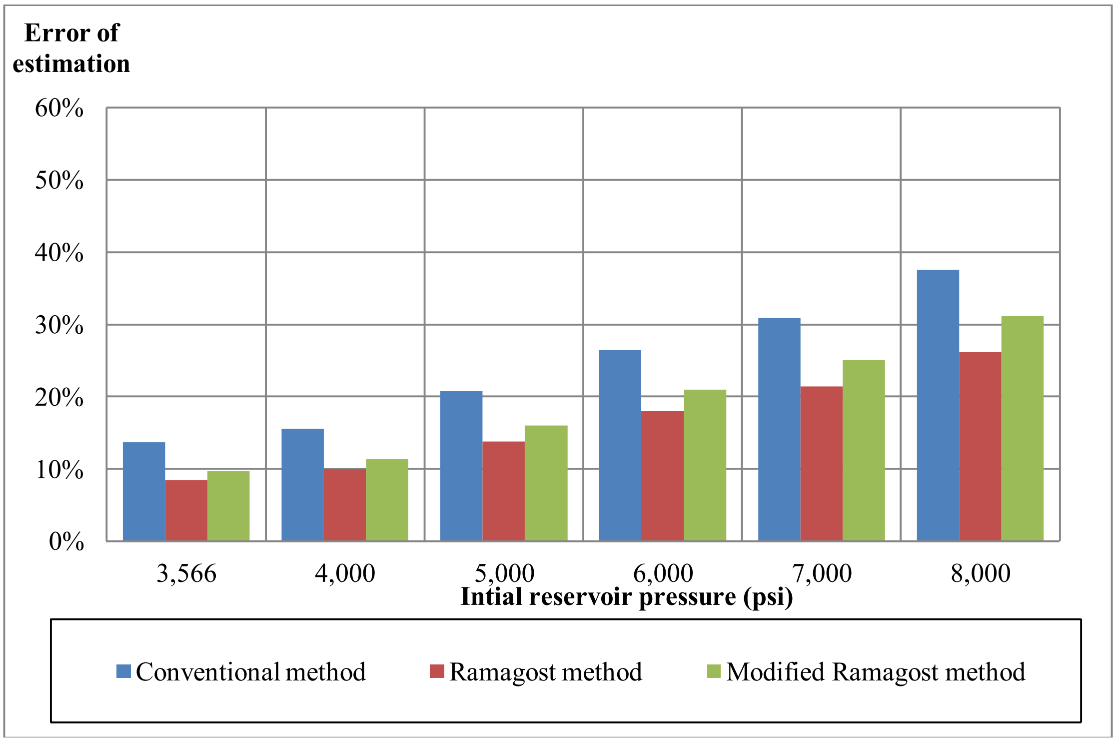

Figure 5.16: Error of *G* estimated by different methods for Berea sandstone reservoir based on production data at 50% pressure depletion

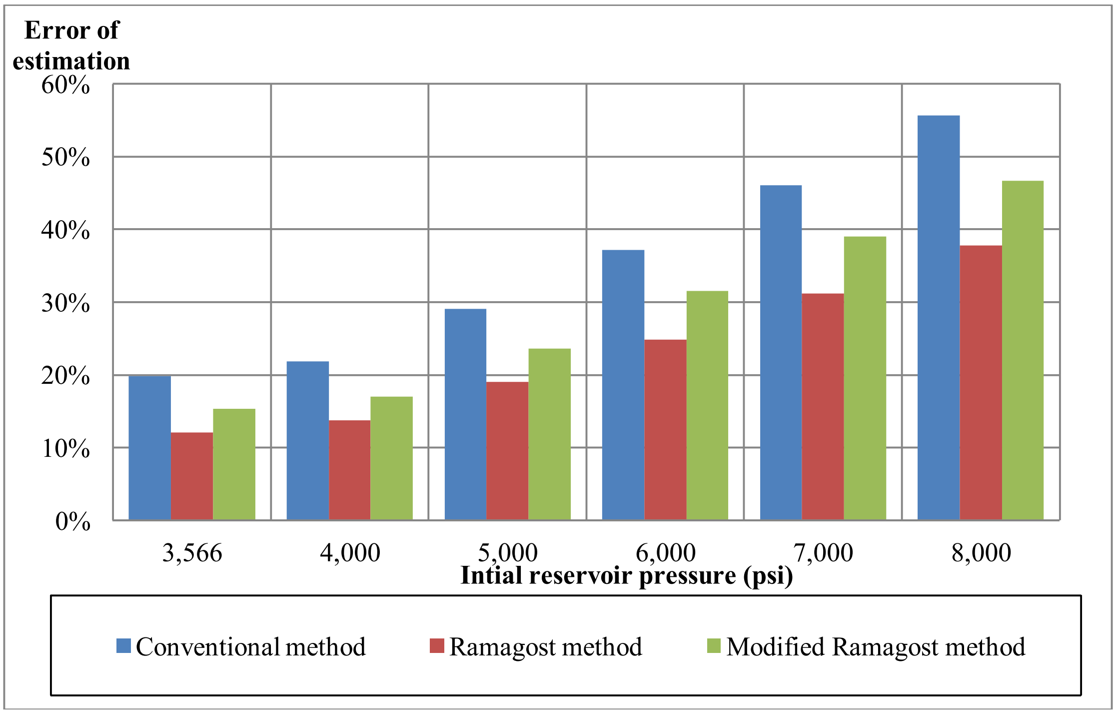

Figure 5.17: Error of *G* estimated by different methods for Berea sandstone reservoir based on production data at 25% pressure depletion

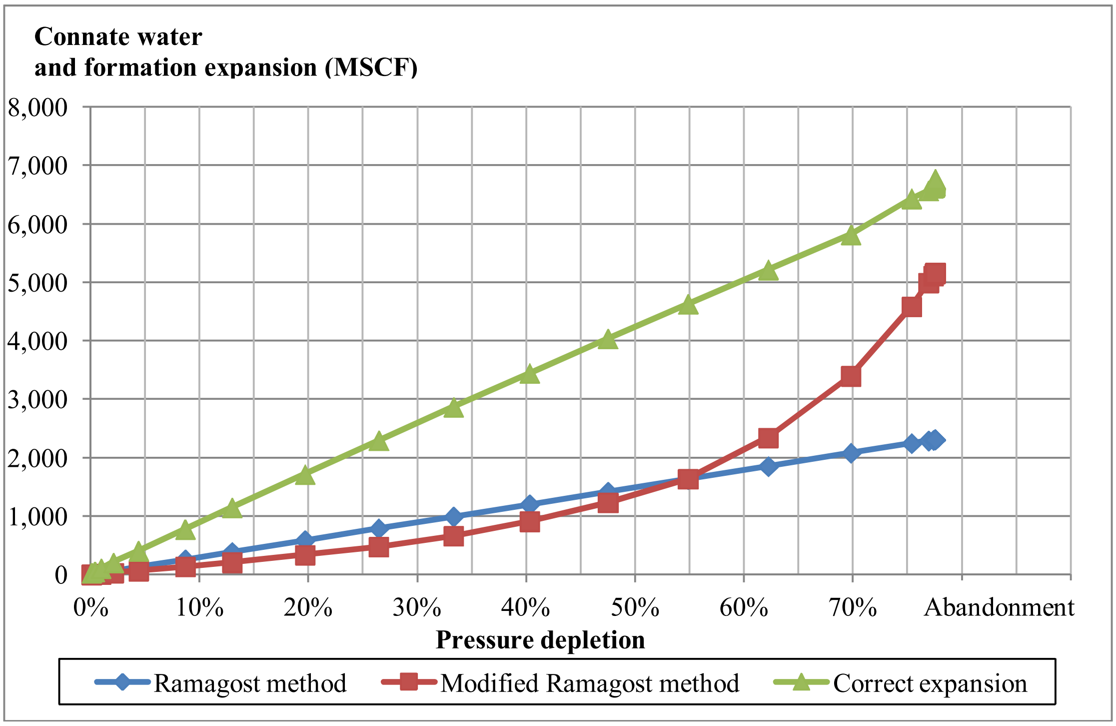

Figure 5.18: Connate water and formation expansion for Berea sandstone reservoir with initial pressure 3,566 psi

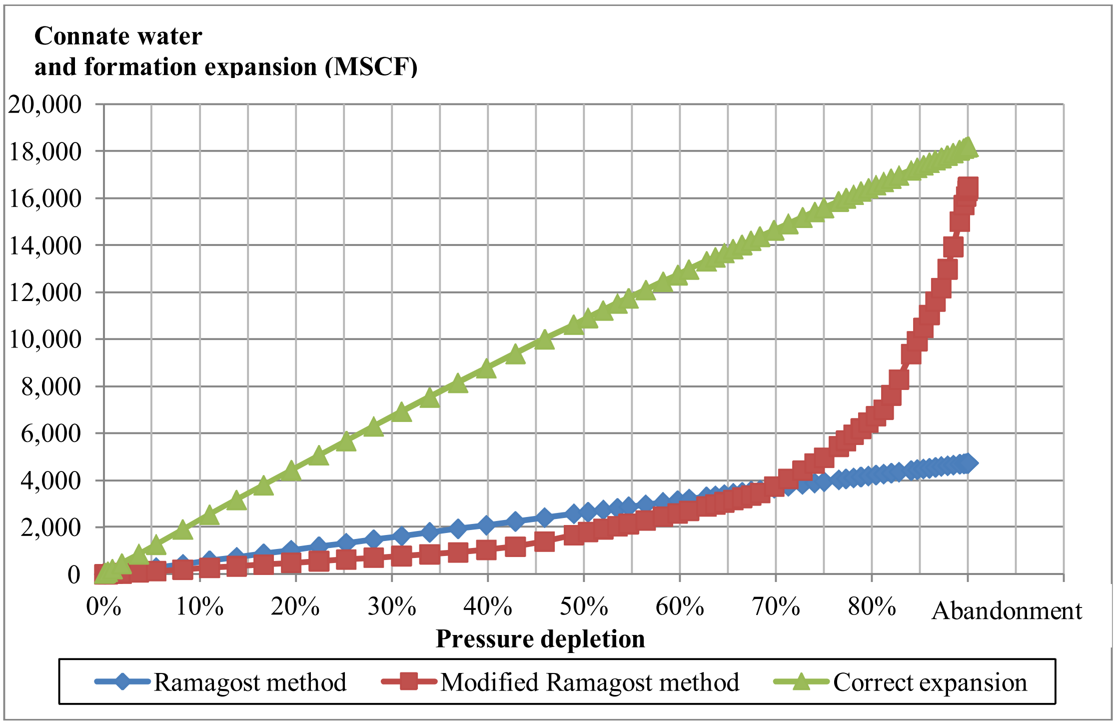

Figure 5.19: Connate water and formation expansion for Berea sandstone reservoir with initial pressure 8,000 psi

Table 5.10: The number of the most accurate OGIP estimates for conventional, Ramagost and modified Ramagost method for Berea sandstone reservoir

	Range of production data available			
	at abandonment	75%	50%	25%
Conventional method	0	0	0	0
Ramagost method	0	0	6	6
Modified Ramagost method	6	6	0	0

5.1.2.2 Degree of depletion

The trend of error of OGIP estimated based on different estimation periods in moderate formation compressibility reservoir are the same as the one in high compressibility reservoir i.e., the more production data available, the more accurate the OGIP. As we performed *p/z* plots based on different stages of pressure depletion and analyzed for the errors in OGIP estimates, the results of the analysis based on different degree of depletion are shown in Figure 5.20-5.22. In case of conventional method as shown in Figure 5.20, when OGIP estimates are computed based on 25% pressure depletion and 50% pressure depletion for a reservoir with initial pressure 3,566 psi, the overestimation of OGIP reduces from 19.85% to 13.72%. For a reservoir with initial pressure 8,000 psi, the error reduces from 55.62% to 37.49%. When the modified Ramagost method is used, the error for a reservoir with initial pressure of 8,000 psi decreases from 46.66% to 31.18% when data used in the analysis are extended from 25% pressure depletion to 50% pressure depletion as shown in Figure 5.22. Thus, one should be aware of high overestimation error when short duration of production data is used in the analysis.

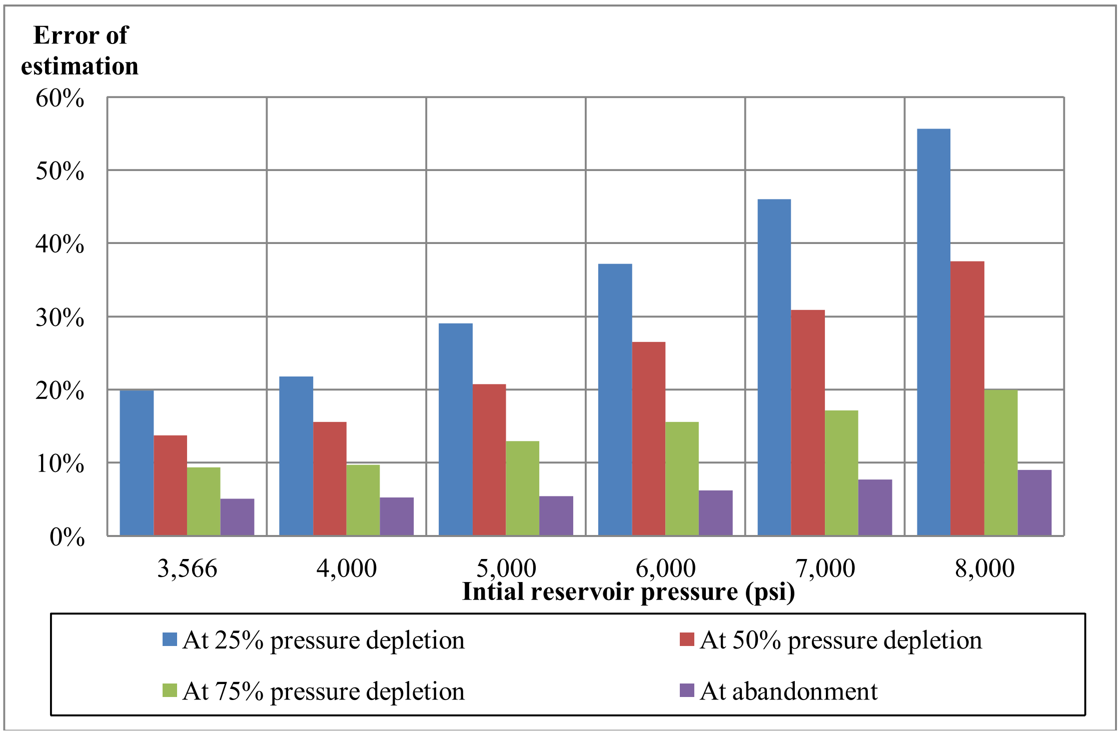

Figure 5.20: Error of *G* estimated by conventional method for Berea sandstone reservoir based on different degree of depletion

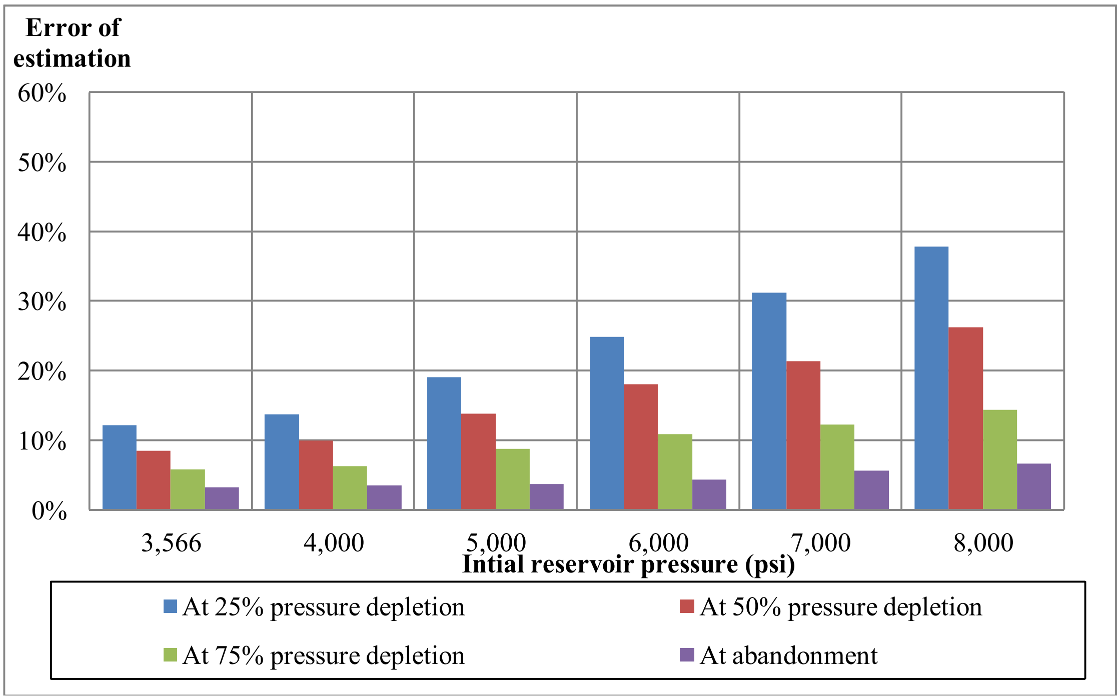

Figure 5.21: Error of *G* estimated by Ramagost method for Berea sandstone reservoir based on different degree of depletion

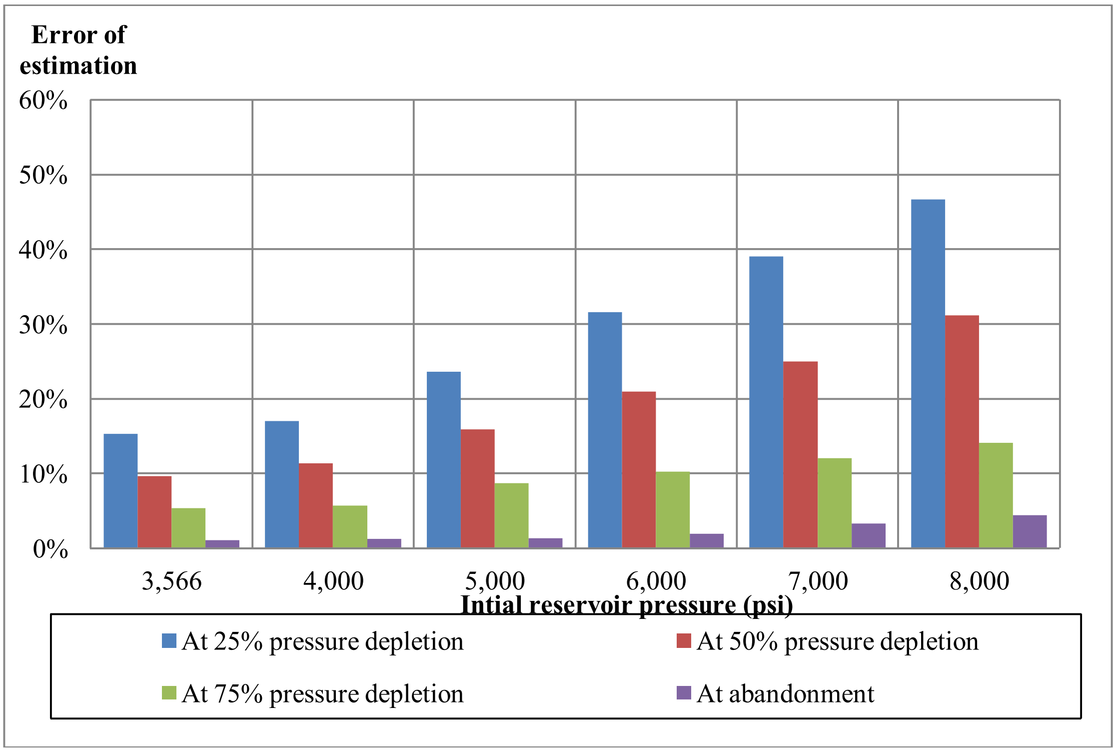

Figure 5.22: Error of *G* estimated by modified Ramagost method for Berea sandstone reservoir based on different degree of depletion

5.1.2.3 Effect of initial pressure

As the decline in reservoir pressure affects the expansion of water and formation, the initial reservoir pressure has a significant impact on OGIP estimates. In moderate formation compressibility reservoir, the trend of error for different initial reservoir pressures is the same as in case for high formation compressibility reservoir. As depicted in Figures 5.14-5.17, the error of OGIP estimate for a reservoir with high initial pressure is higher than that for a reservoir with low initial pressure. This observation is true for all methods of analysis and all lengths of data used in the analysis. For example, in the case of modified Ramagost method, which is the most accurate method when based on production data at abandonment and 75% pressure depletion, the error of OGIP estimates increase from 1.10% to 4.44% and 5.42% to 14.13%, respectively when the reservoir pressure is changed from 3,566 psi to 8,000 psi.

5.1.3 Grainstone reservoir

Grainstone is a kind of carbonate rock. It has the lowest average formation compressibility among three kinds of rock used this study. The formation compressibility is 1.74×10^{-5} psi^{-1} at 800 psi decreases to 5.0×10^{-6} psi^{-1} at 8,000 psi and 0.78×10^{-5} psi^{-1} on average.

5.1.3.1 Method of analysis

In case of Grainstone reservoir, the trends of error when estimates by different methods are the same as in the case of Santa Rosa and Berea sandstone reservoirs. The estimates original gas in place by the three material balance methods are shown in Tables 5.11-5.14. The error of OGIP estimates for Grainstone reservoirs are shown in Figures 5.23-5.26. The estimates of OGIP by Ramagost and modified Ramagost methods are more accurate than those by conventional method as shown in Figures 5.23-5.26.

Comparing between conventional method and Ramagost method for the case that production data are available until abandonment, inclusion of water and formation expansion terms reduce the error from 2.48% to 1.32% for a reservoir with initial pressure 3,566 psi and reduces from 3.63% to 2.21% for a reservoir with initial pressure 8,000 psi. The modified Ramagost method proposed in this study provides smaller error than the others two methods. The error is 0.45% for a reservoir with initial pressure 3,566 psi and 1.03% for a reservoir with initial pressure 8,000 psi. The difference in error among the three methods becomes larger when the reservoir has high initial pressures. The modified Ramagost method has the smallest magnitude of error because it takes into account the variation in water and formation compressibilities when the pressure of the reservoir decreases while the original Ramagost method uses average water and formation compressibilities.

We can observe that the modified Ramagost method still provides the most accurate OGIP estimates when estimating OGIP at 75% pressure depletion. For example, the error for the conventional, Ramagost and modified Ramagost methods for a reservoir with initial pressure 8,000 psi is 11.00%, 10.46% and 6.91%, respectively when 75% data are available. But when estimating at 50% and 25% pressure depletion, the Ramagost method becomes the most accurate OGIP estimates. For example, the error for the conventional, Ramagost and modified Ramagost methods for a reservoir with initial pressure 8,000 psi is 18.34%, 10.46%, and 12.48%, respectively when 50% data are available and the errors becomes 25.72%, 14.41% and 17.33%, respectively when 25% data are available.

Figures 5.27 and 5.28 show volumetric expansion of connate water and formation during different stages in pressure decline based on Ramagost (blue line), and modified Ramagost (red line) methods in comparison with correct expansion calculated from ideal *p/z* straight line (green line) for a reservoir with initial pressure 3,566 psi and 8,000 psi, respectively. In both figures, the expansion volume calculated by Ramagost method is closest to the correct expansion when the pressure depletion is 50% or less. But when the pressure depletion is 75% or more, the modified Ramagost method provides better calculation, i.e., the expansion from modified Ramagost method is closer to the correct expansion. These are the reason why Ramagost method gives less error of OGIP estimates when the pressure depletion is 50% or less and modified Ramagost method gives less error when the pressure depletion is 75% or more.

As summarized in Table 5.15, we learned that the modified Ramagost method is suitable for estimating OGIP based on data available at 75% of pressure depletion and abandonment while the Ramagost method yields the most accurate OGIP when estimate OGIP based on data available at 25% and 50% pressure depletion. If the conventional method is used, the error can be as high as 25.72% in the case of 8,000 psi initial pressure reservoir and 25% depletion. The highest error from Ramagost method at 25% and 50% depletion is 14.41% while the highest error from modified Ramagost at 75% of pressure depletion and abandonment is 6.91%. Thus, using the right method for right percentage of depletion will give us a maximum error of 14.41%.

Table 5.11: Original gas in place estimation for Grainstone reservoir based on production data at abandonment

Initial pressure (psi)	Original Gas in place, *G* (MCF)			
	Actual	Conventional method	Ramagost method	Modified Ramagost method
3,566	5,714,006	5,855,501	5,789,474	5,739,607
4,000	6,387,559	6,545,394	6,470,685	6,414,084
5,000	7,883,349	8,096,361	8,005,364	7,925,963
6,000	9,298,938	9,568,049	9,453,552	9,354,513
7,000	10,639,214	10,983,406	10,842,912	10,724,315
8,000	11,912,773	12,344,668	12,175,844	12,035,939

Table 5.12: Original gas in place estimation for Grainstone reservoir based on production data at 75% pressure depletion

Initial pressure (psi)	Original Gas in place, *G* (MCF)			
	Actual	Conventional method	Ramagost method	Modified Ramagost method
3,566	5,714,006	5,929,690	5,819,672	5,788,446
4,000	6,387,559	6,701,241	6,541,341	6,523,179
5,000	7,883,349	8,348,191	8,128,415	8,110,450
6,000	9,298,938	10,005,432	9,686,785	9,692,713
7,000	10,639,214	11,628,866	11,198,332	11,233,448
8,000	11,912,773	13,223,429	12,677,504	12,735,955

Table 5.13: Original gas in place estimation for Grainstone reservoir based on production data at lower than 50% of depletion

Initial pressure (psi)	Original Gas in place, *G* (MCF)			
	Actual	Conventional method	Ramagost method	Modified Ramagost method
3,566	5,714,006	6,080,919	5,892,917	5,911,667
4,000	6,387,559	6,842,472	6,608,886	6,646,372
5,000	7,883,349	8,660,714	8,287,360	8,385,104
6,000	9,298,938	10,407,120	9,902,562	10,038,384
7,000	10,639,214	12,236,346	11,527,361	11,726,043
8,000	11,912,773	14,098,019	13,158,510	13,399,484

Table 5.14: Original gas in place estimation for Grainstone reservoir based on production data at lower than 25% of depletion

Initial pressure (psi)	Original Gas in place, *G* (MCF)			
	Actual	Conventional method	Ramagost method	Modified Ramagost method
3,566	5,714,006	6,215,125	5,956,266	6,034,072
4,000	6,387,559	7,051,213	6,708,276	6,827,358
5,000	7,883,349	8,942,308	8,430,222	8,615,804
6,000	9,298,938	10,964,579	10,191,628	10,444,233
7,000	10,639,214	12,945,393	11,904,208	12,209,626
8,000	11,912,773	14,976,651	13,629,555	13,976,754

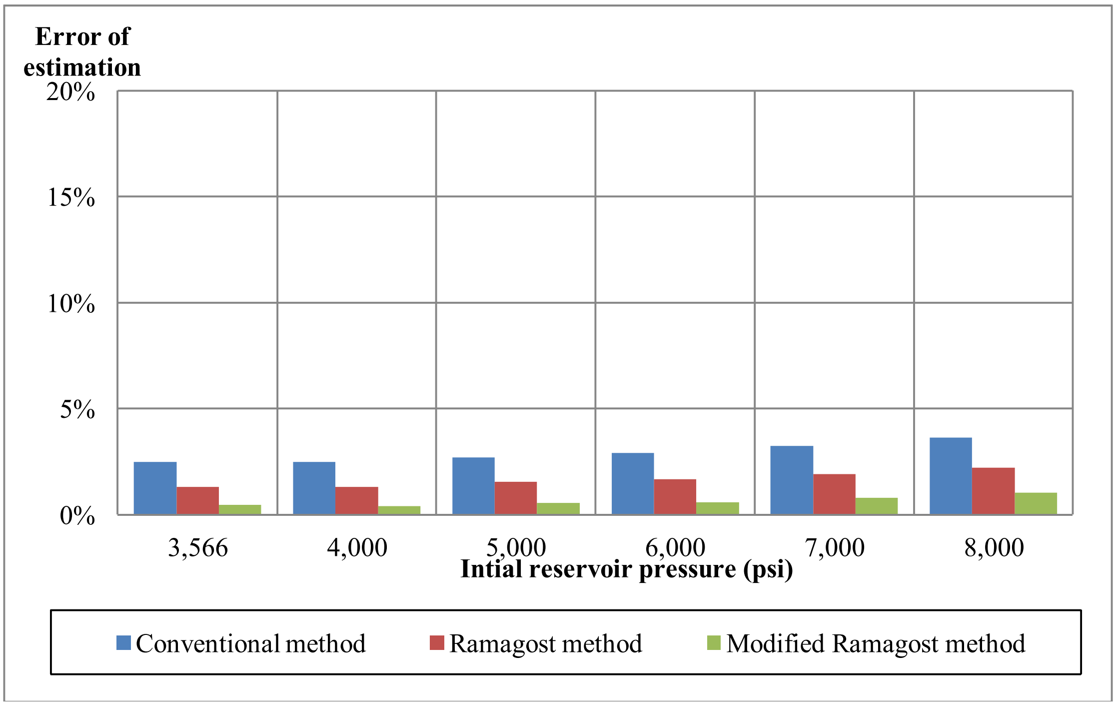

Figure 5.23: Error of *G* estimated by different methods for Grainstone reservoir based on production data at abandonment

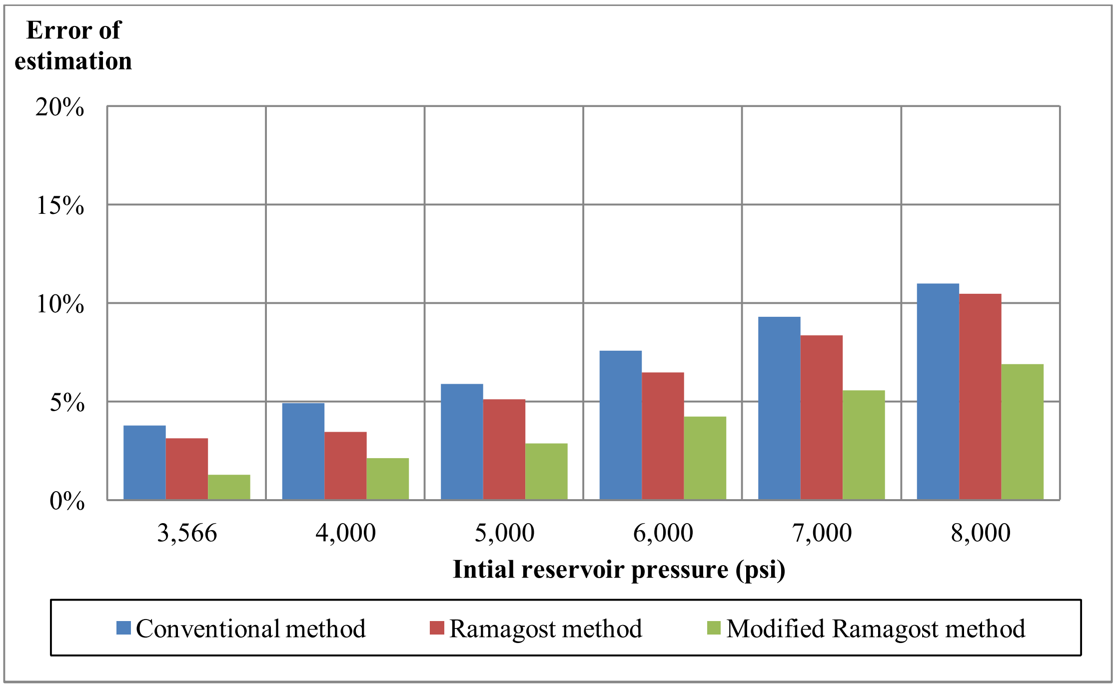

Figure 5.24: Error of *G* estimated by different methods for Grainstone reservoir based on production data at 75% pressure depletion

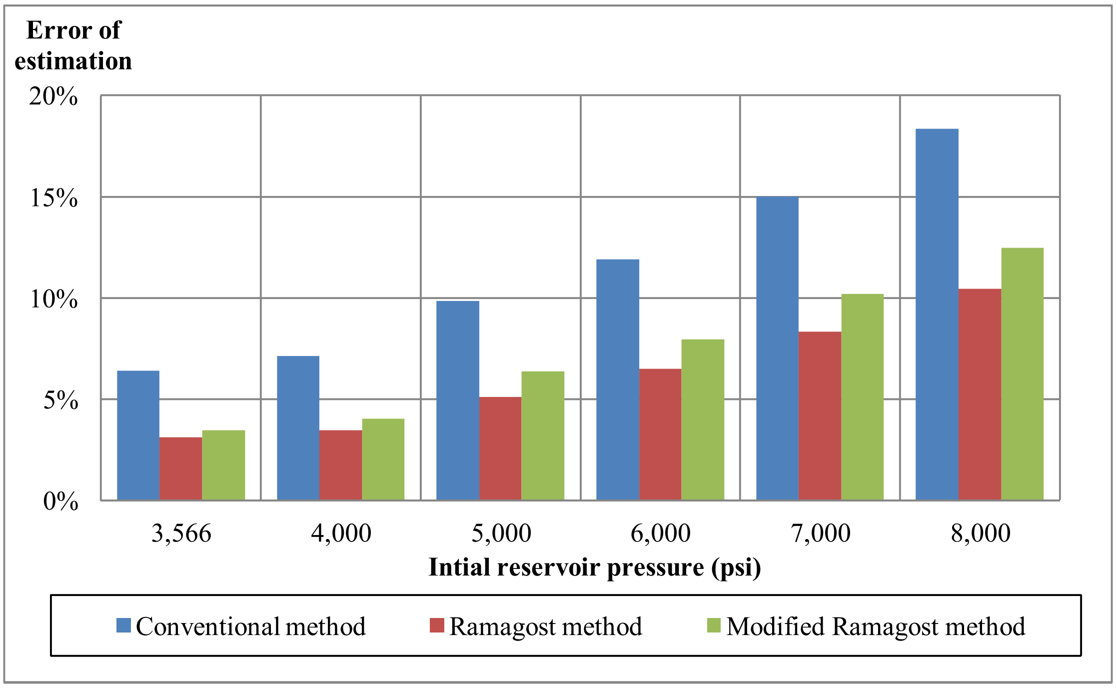

Figure 5.25: Error of *G* estimated by different methods for Grainstone reservoir based on production data at 50% pressure depletion

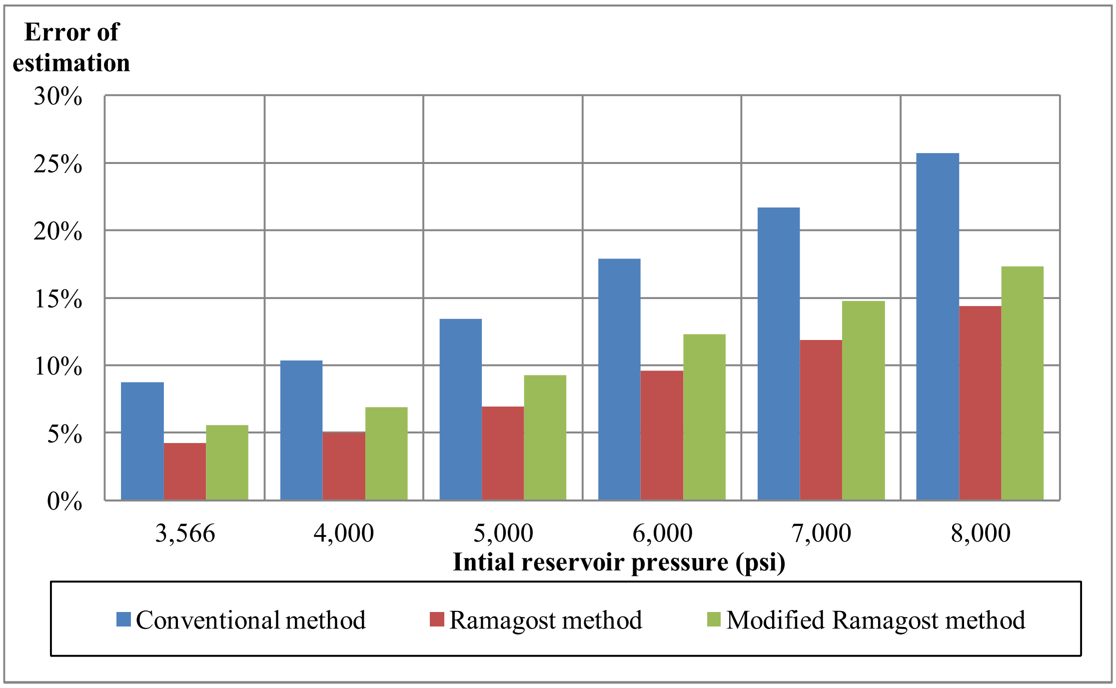

Figure 5.26: Error of *G* estimated by different methods for Grainstone reservoir based on production data at 25% pressure depletion

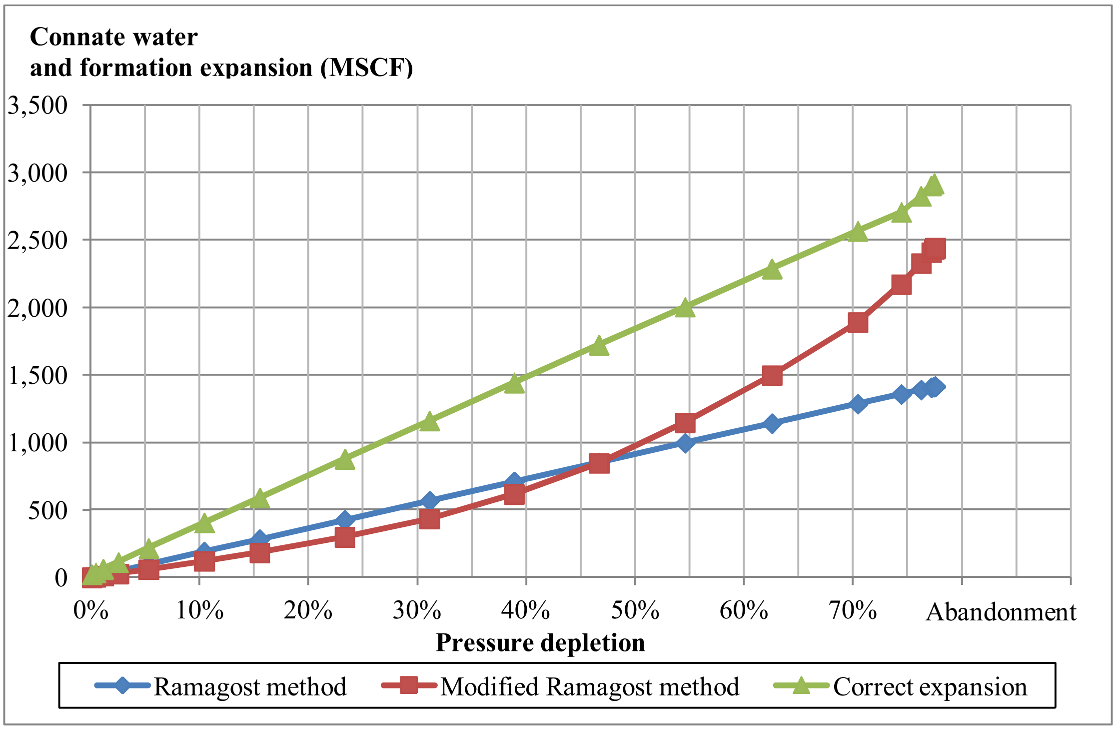

Figure 5.27: Connate water and formation expansion for Grainstone reservoir with initial pressure 3,566 psi

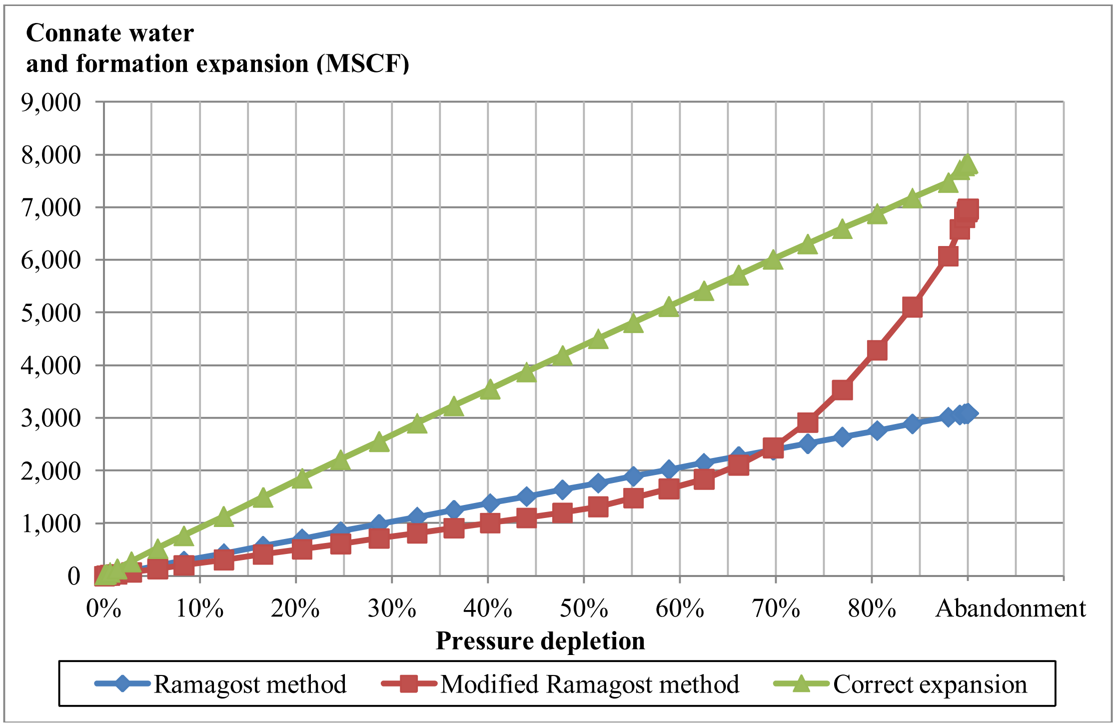

Figure 5.28: Connate water and formation expansion for Grainstone reservoir with initial pressure 8,000 psi

Table 5.15: The number of the most accurate OGIP estimates for conventional, Ramagost and modified Ramagost method for Grainstone reservoir

	Range of production data available			
	at abandonment	75%	50%	25%
Conventional method	0	0	0	0
Ramagost method	0	0	6	6
Modified Ramagost method	6	6	0	0

5.1.3.2 Degree of depletion

The trend of error of OGIP estimate for the three methods based on different estimation periods in low formation compressibility reservoir are the same as the one in high and moderate compressibility reservoir, i.e., the more production data available, the more accurate the OGIP. As we performed *p/z* plots based on different stages of pressure depletion and analyze for the errors in OGIP estimates, the results of the analysis on different degree of depletion are shown in Figure 5.29-5.31. In case of conventional method as shown in Figure 5.29, when OGIP estimate is computed 25% pressure depletion and 50% pressure depletion for a reservoir with initial pressure 3,566 psi, the overestimations of OGIP reduces from 8.77% to 6.42%. For a reservoir with initial pressure 8,000 psi, the error reduces from 25.72% to 18.34%. When the modified Ramagost method is used, the error for a reservoir with initial pressure of 8,000 psi decreases from 17.33% to 12.48% when data used in the analysis are extended from 25% pressure depletion to 50% pressure depletion as shown in Figure 5.31.

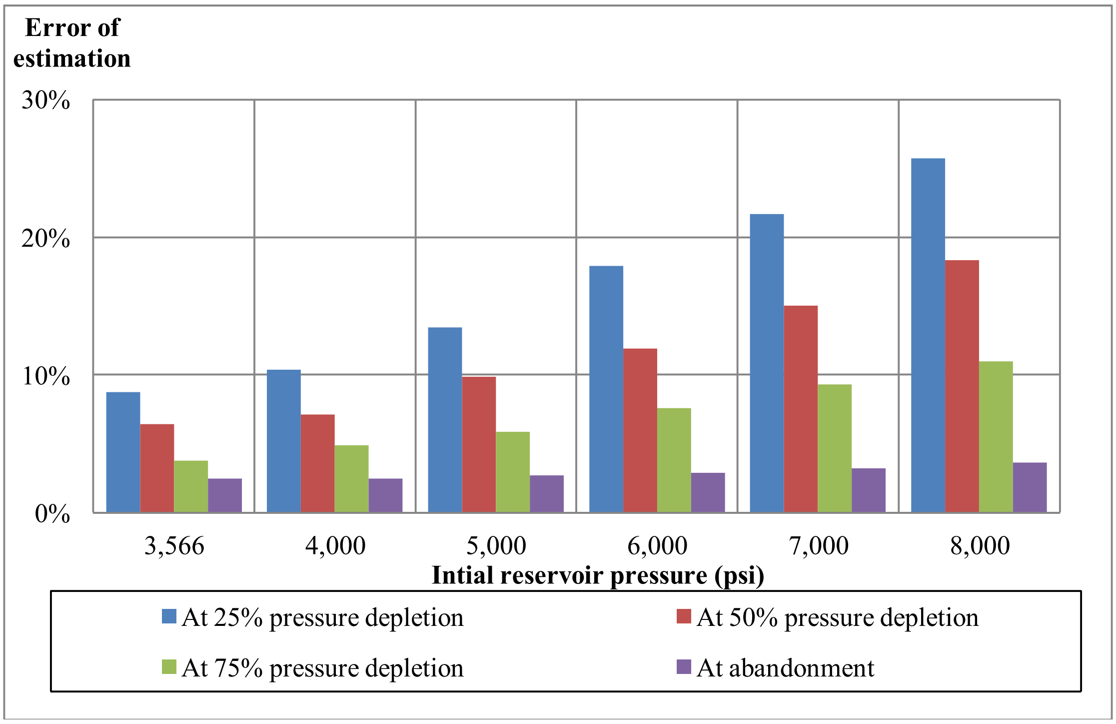

Figure 5.29: Error of *G* estimated by conventional method for Grainstone reservoir based on different degree of depletion

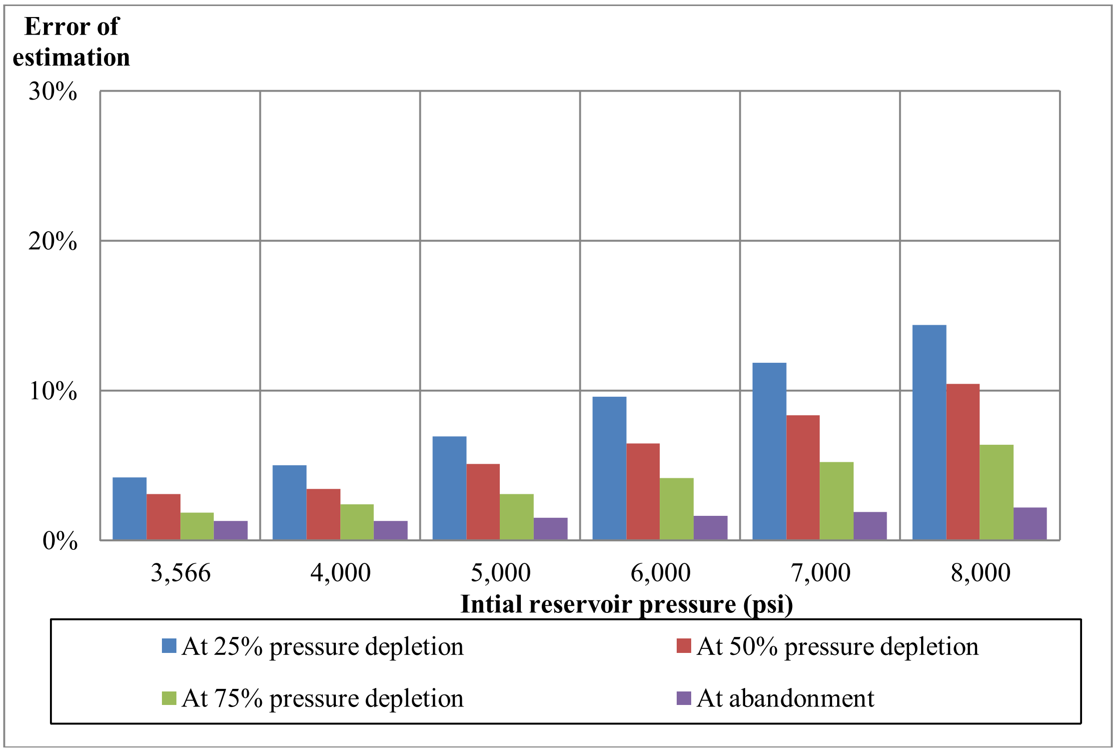

Figure 5.30: Error of *G* estimated by Ramagost method for Grainstone reservoir based on different degree of depletion

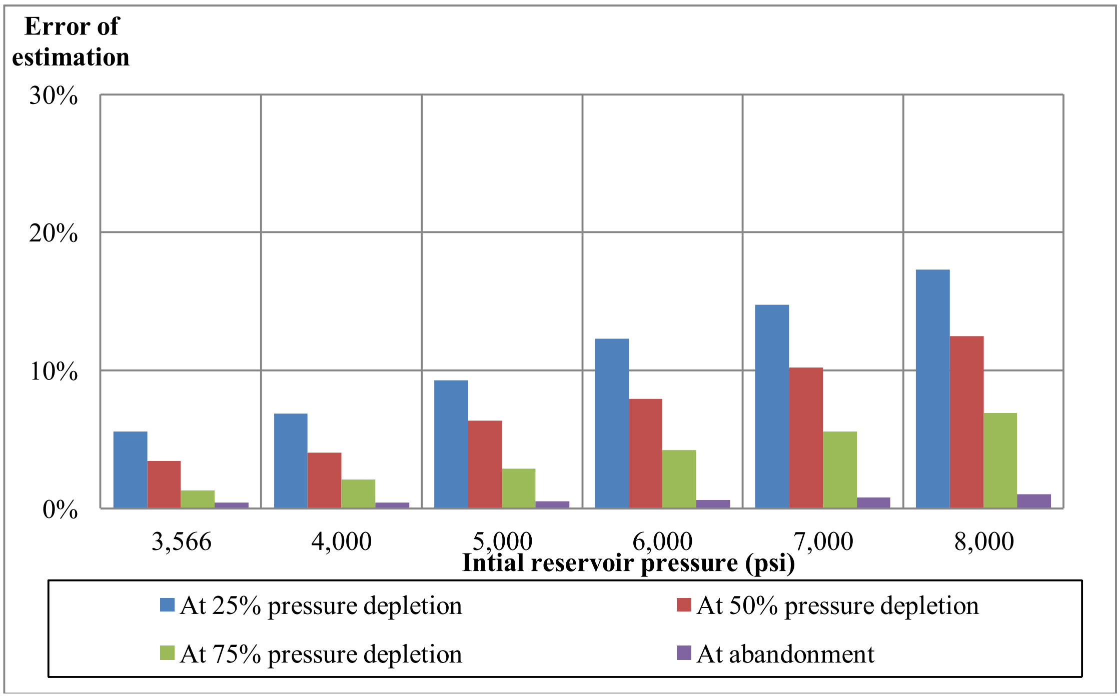

Figure 5.31: Error of *G* estimated by modified Ramagost method for Grainstone reservoir based on different degree of depletion

5.1.3.3 Effect of initial pressure

In case of low formation compressibility reservoir, the trend of error for different initial reservoir pressures is the same as in case of high and moderate formation compressibility reservoir. As the decline in reservoir pressure affects the expansion of water and formation, the initial reservoir pressure has a significant impact on OGIP estimates. As seen in Figures 5.23-5.26, the error of OGIP estimate for a reservoir with high initial pressure is higher than that for a reservoir with low initial pressure. This observation is true for all methods of analysis and all lengths of data used in the analysis. For example, in the case of modified Ramagost method, which is the most accurate method based on production data at abandonment and 75% of depletion, the error of OGIP estimates increase from 0.45% to 1.03% and 1.30% to 6.91%, respectively when the reservoir pressure is changed from 3,566 psi to 8,000 psi.

5.1.4 Effect of different rock compressibilities

As the three types of rock used in this study have different average compressibilities and different degrees of variation in compressibility as the pressure decreases, the errors of OGIP estimates are different in magnitude. Figures 5.26–5.31 plot the error of OGIP estimates based on three different methods (conventional, Ramagost and modified Ramagost) and data available at 25% pressure depletion for Santa Rosa sandstone, Berea sandstone, and Grainstone for which compressibilities are shown in Figure 5.2.

As depicted in Figure 5.32-5.37, comparing among different rocks, Grainstone yields the lowest error when conventional method is used because of its lowest compressibility variation while Berea sandstone gives the highest error due to its largest variation in compressibility. For Grainstone reservoir at initial pressure 3,566 psi, the error of OGIP estimate is 8.77% while error is 13.37% for Santa Rosa Sandstone and 19.85% for Berea sandstone.

In Ramagost method, Santa Rosa sandstone yields the lowest error while Berea sandstone still gives the highest error due to its largest variation in compressibility. For Grainstone reservoir at initial pressure 3,566 psi, the error of OGIP estimate is 4.24% while the others two rocks have bigger error as 2.05% for Santa Rosa sandstone and 12.14% for Berea sandstone. At high initial pressure 8,000 psi, Santa Rosa sandstone still gives the lowest error when the Ramagost method is used.

When estimating OGIP by modified Ramagost method Santa Rosa sandstone reservoir yields the lowest error at 4.79% and 19.45% in a reservoir with initial pressure 3,566 psi and 8,000 psi, respectively. Grainstone reservoir yields the second lowest error at 5.60% and 17.33% in a reservoir with initial pressure 3,566 psi and 8,000 psi, respectively. And Berea sandstone reservoir yields the highest error at 15.36% and 46.66% in a reservoir with initial pressure 3,566 psi and 8,000 psi, respectively.

In summary, Berea sandstone, which has the highest degree of variation in rock compressibility (although its average compressibility is not the highest among the three rocks used in this study), has the highest error while the other rocks which have lower degree of rock compressibility variation have less errors.

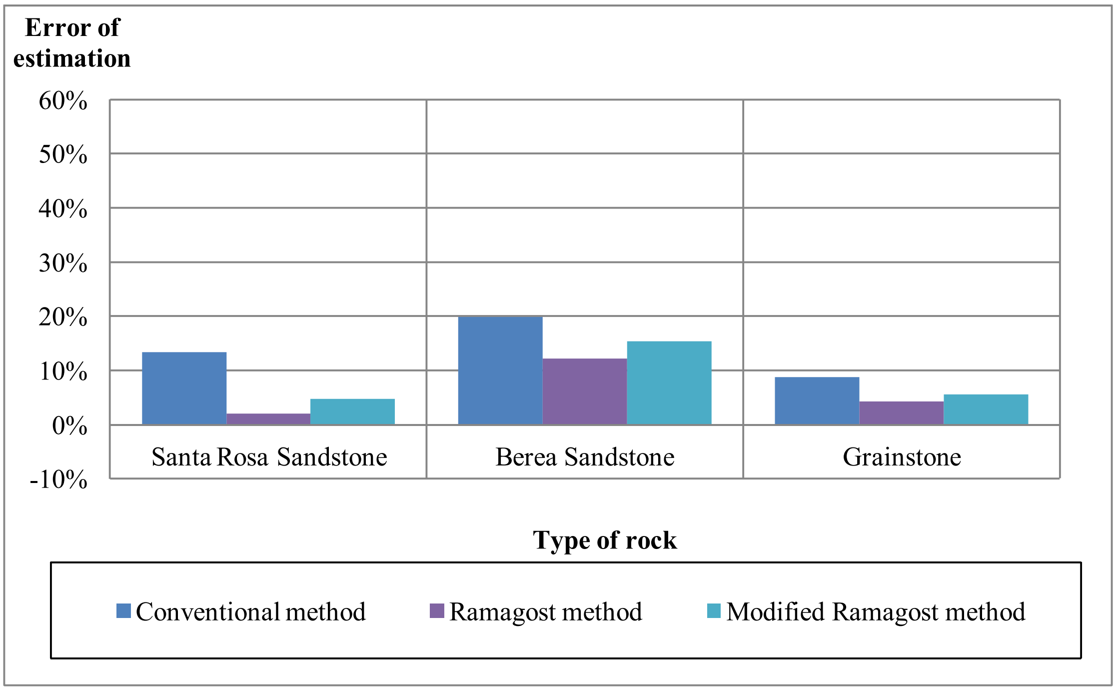

Figure 5.32: Error of G estimation for three types of rock for a reservoir with initial pressure 3,566 psi based on data at 25% pressure depletion

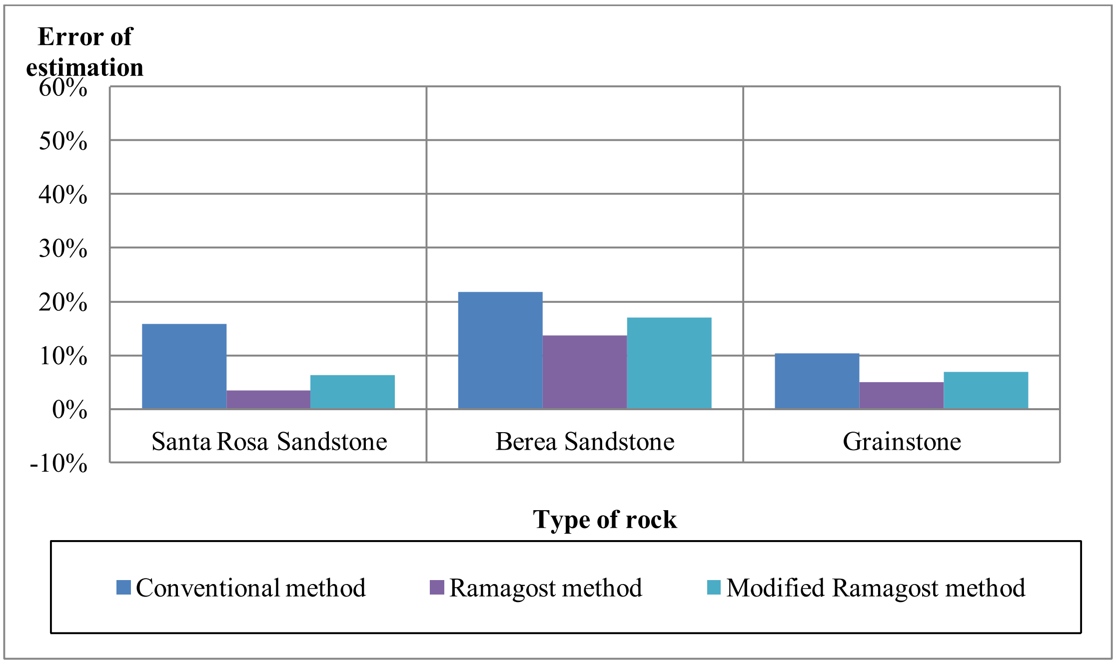

Figure 5.33 Error of *G* estimation of three type of rock for a reservoir with initial pressure 4,000 psi based on data at 25% pressure depletion

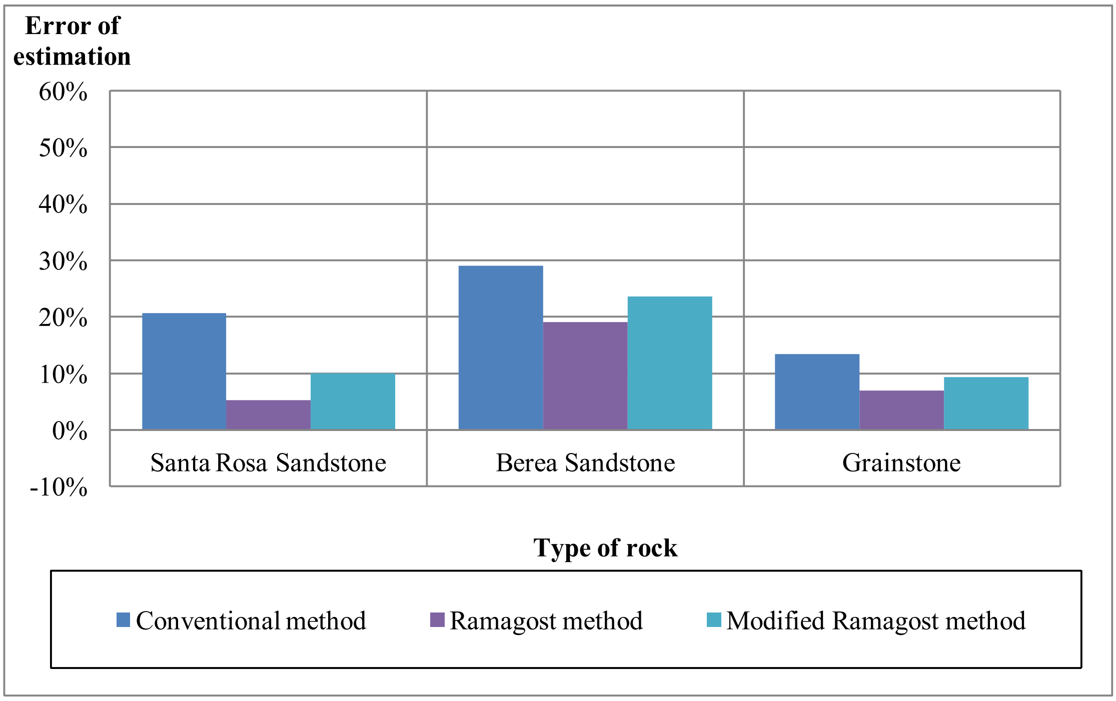

Figure 5.34: Error of *G* estimation of three type of rock for a reservoir with initial pressure 5,000 psi based on data at 25% pressure depletion

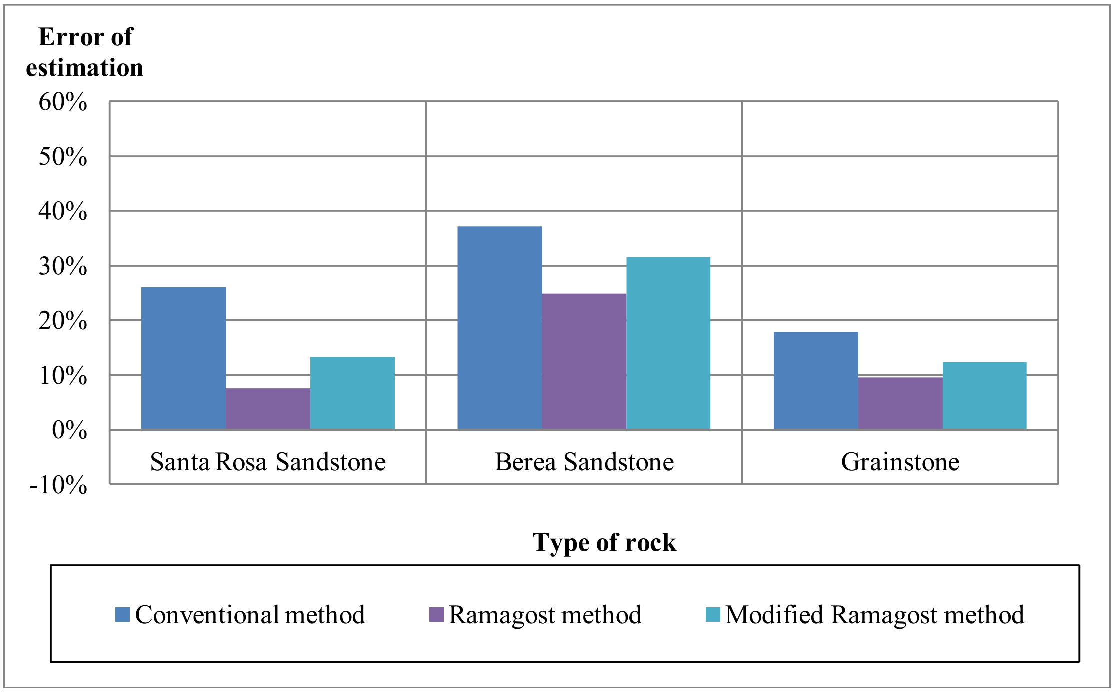

Figure 5.35: Error of *G* estimation of three type of rock for a reservoir with initial pressure 6,000 psi based on data at 25% pressure depletion

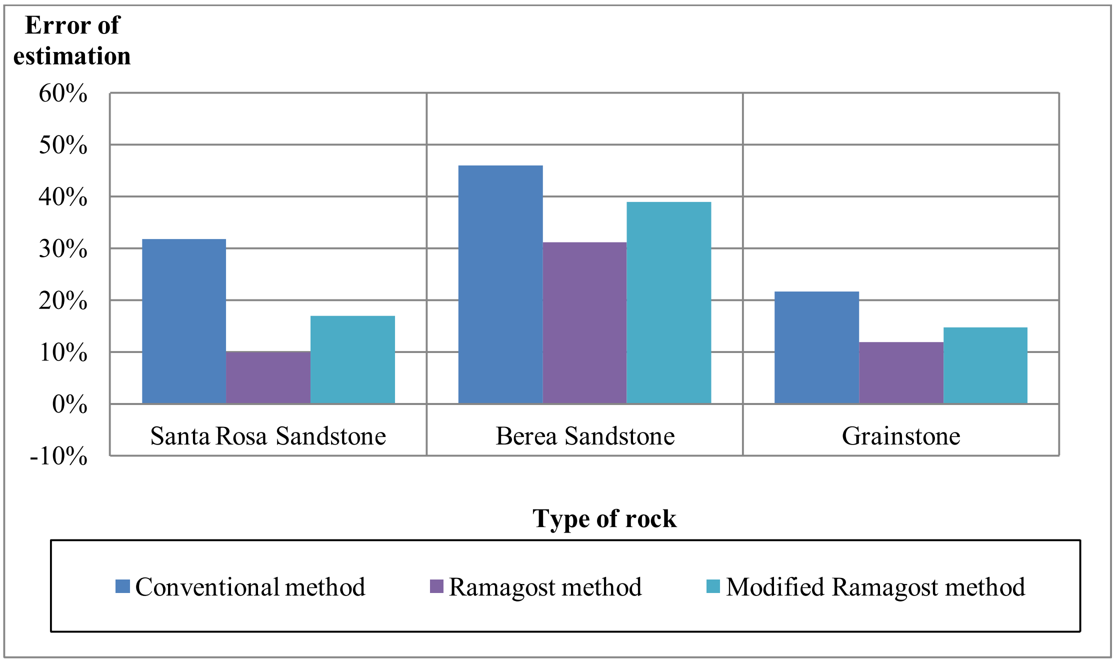

Figure 5.36: Error of *G* estimation of three type of rock for a reservoir with initial reservoir pressure 7,000 psi based on data at 25% pressure depletion

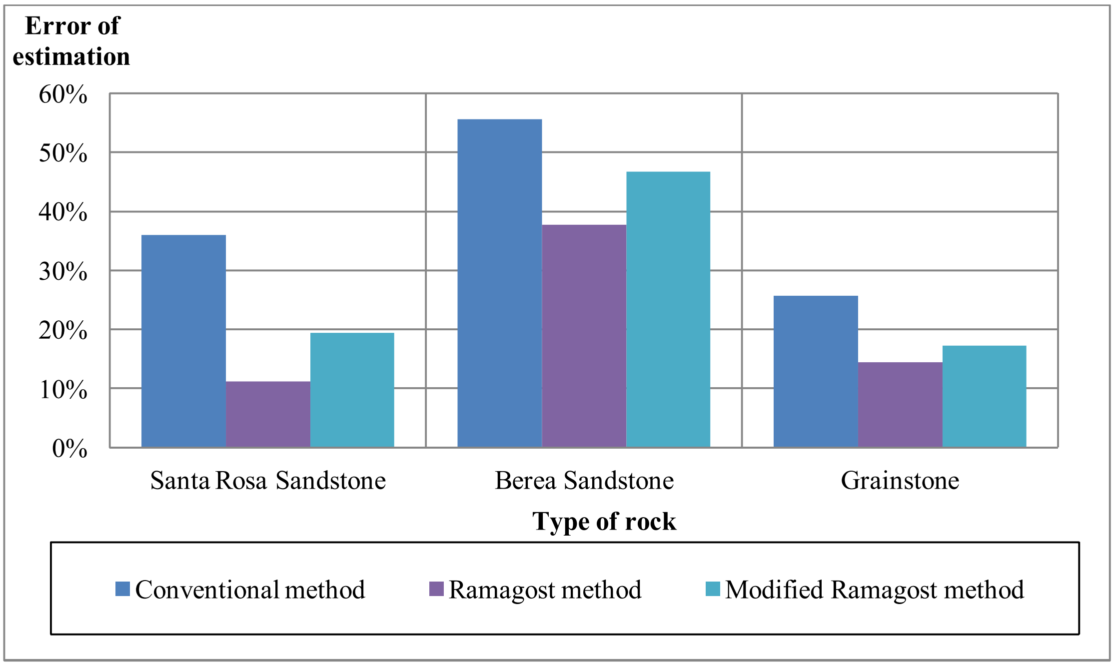

Figure 5.37: Error of G estimation of three type of rock for a reservoir with initial reservoir pressure 8,000 psi based on data at 25% pressure depletion

5.2 Effect of formation compressibility and water vapor

The second part of this chapter reports the comparison of calculated OGIP based on 3 material balance methods (conventional, Humphreys and modified Humphreys) in term of error. The method of analysis, length of data, effect of initial pressure and of water content are discussed for each type of reservoir rock which has different formation compressibility characteristics. Then, the errors of OGIP estimates obtained for different formation compressibilities are compared.

5.2.1 Santa Rosa sandstone reservoir

Santa Rosa sandstone studied by Fatt [16] has the highest average formation compressibility among three kinds of rock used in this study. The formation compressibility varies from 3.29×10^{-5} psi^{-1} at 800 psi to 8.50×10^{-6} psi^{-1} at 8,000 psi and 2.02×10^{-5} psi^{-1} on average.

5.2.1.1 Method of analysis

There are three methods for original gas in place estimation to discuss in this section which are conventional method, Humphreys method and modified Humphreys method. Figures 5.38 and 5.39 show *p/z* plot used to estimate OGIP based on the three methods when the water content is 10% and the initial reservoir pressure is 3,566 and 8,000 psi, respectively. As the corrected *p/z* plotted by Humphreys and modified Humphrey method, we subtract the formation expansion and the water vapor amount from G_p. Consequently, the OGIP estimates using Humphreys and modified Humphrey method will be lower.

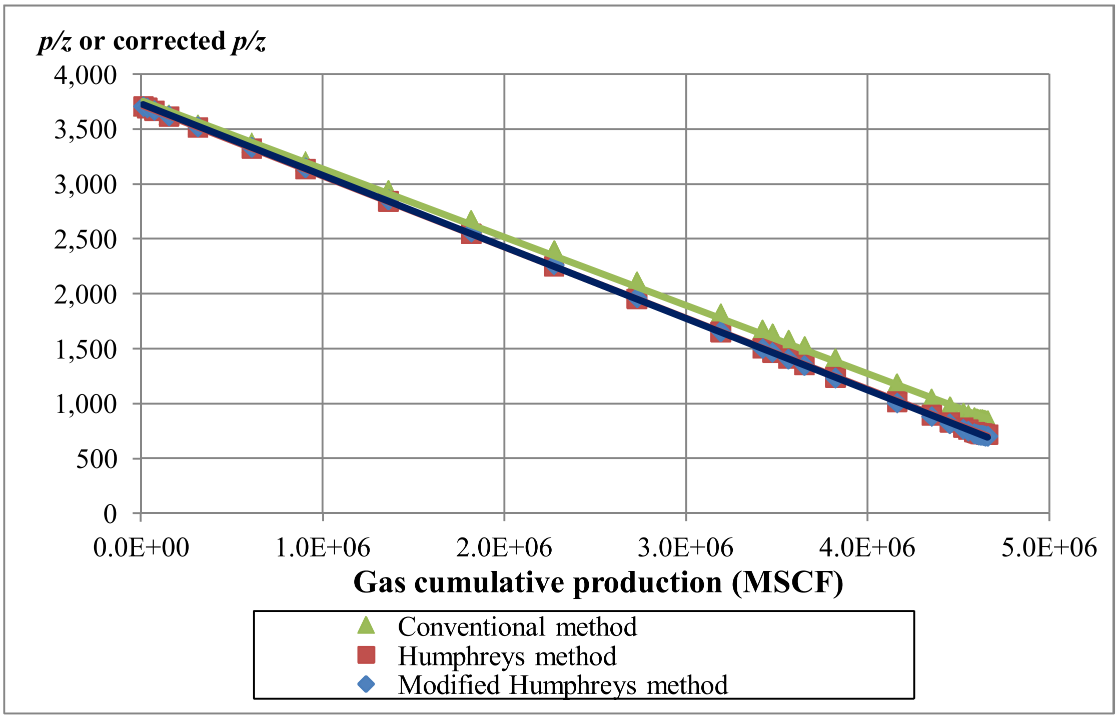

Figure 5.38: *p/z* or corrected *p/z* vs. G_p plot by different method for Santa Rosa sandstone reservoir at water content 10% and initial reservoir pressure 3,566 psi.

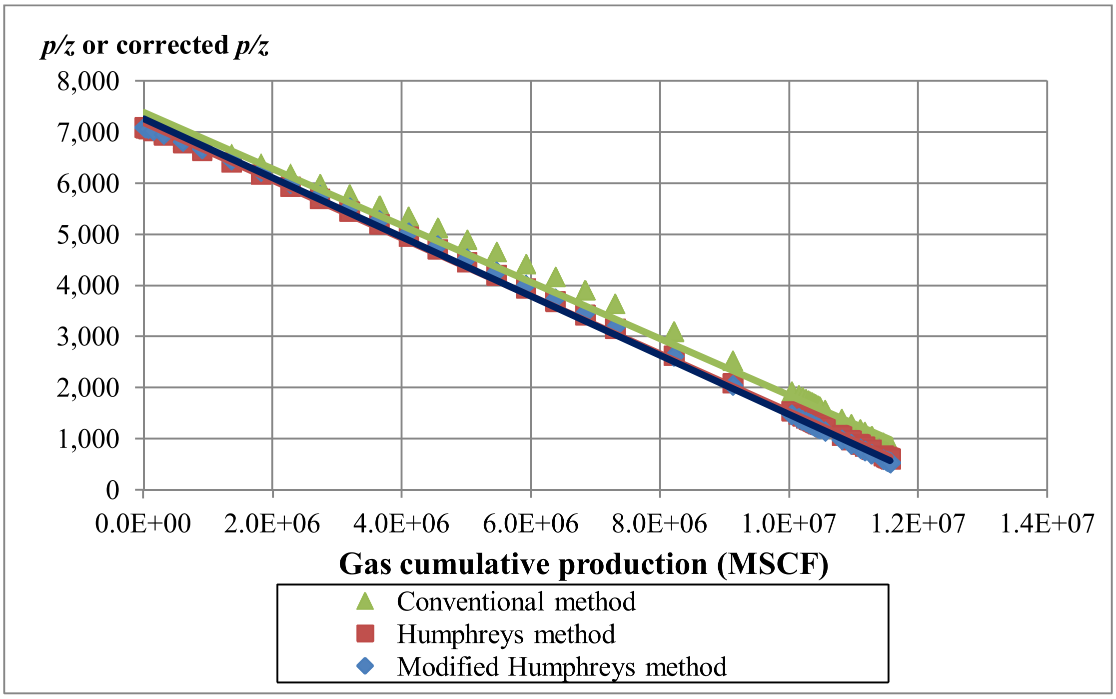

Figure 5.39: *p/z* or corrected *p/z* vs. G_p plot by 3 different methods for Santa Rosa sandstone reservoir at water content 10% and initial reservoir pressure 8,000 psi

Table 5.16: Original gas in place estimation for Santa Rosa sandstone reservoir and water content 10% based on production data at abandonment

Initial pressure (psi)	Original Gas in place, *G* (MCF)			
	Actual	Conventional method	Humphreys method	Modified Humphreys method
3,566	5,719,633	5,988,862	5,737,199	5,707,295
4,000	6,440,013	6,762,567	6,471,970	6,427,907
5,000	7,660,825	8,085,646	7,723,990	7,659,284
6,000	9,063,823	9,561,926	9,155,416	9,073,902
7,000	10,382,569	11,053,153	10,535,112	10,409,771
8,000	11,634,490	12,421,652	11,864,518	11,708,454

Table 5.17: Original gas in place estimation for Santa Rosa sandstone reservoir and water content 10% based on production data at 75% pressure depletion

Initial pressure (psi)	Original Gas in place, *G* (MCF)			
	Actual	Conventional method	Humphreys method	Modified Humphreys method
3,566	5,719,633	6,107,579	5,741,627	5,721,080
4,000	6,440,013	6,935,403	6,487,590	6,452,166
5,000	7,660,825	8,265,339	7,766,254	7,707,250
6,000	9,063,823	10,133,218	9,320,918	9,294,136
7,000	10,382,569	11,802,867	10,771,901	10,744,384
8,000	11,634,490	13,788,891	12,285,223	12,312,960

Table 5.18: Original gas in place estimation for Santa Rosa sandstone reservoir and water content 10% based on production data at 50% pressure depletion

Initial pressure (psi)	Original Gas in place, G (MCF)			
	Actual	Conventional method	Humphreys method	Modified Humphreys method
3,566	5,719,633	6,379,369	5,771,739	5,818,864
4,000	6,440,013	7,234,378	6,542,427	6,581,673
5,000	7,660,825	8,914,784	7,936,508	8,027,898
6,000	9,063,823	10,840,650	9,525,926	9,672,952
7,000	10,382,569	12,727,628	11,052,452	11,244,598
8,000	11,634,490	14,976,939	12,654,222	12,968,551

Table 5.19: Original gas in place estimation for Santa Rosa sandstone reservoir and water content 10% based on production data at 25% pressure depletion

Initial pressure (psi)	Original Gas in place, G (MCF)			
	Actual	Conventional method	Humphreys method	Modified Humphreys method
3,566	5,719,633	6,563,659	5,801,717	5,910,320
4,000	6,440,013	7,520,978	6,601,537	6,735,827
5,000	7,660,825	9,331,466	8,051,257	8,299,286
6,000	9,063,823	11,527,722	9,756,798	10,119,068
7,000	10,382,569	13,787,234	11,363,397	11,835,952
8,000	11,634,490	16,554,779	13,127,427	13,849,454

Tables 5.16-5.19 show the estimates of original gas in place by 3 material balance methods when water content in the reservoir is 10%. The error of OGIP estimates for Santa Rosa sandstone reservoirs using different methods are shown in Figures 5.40-5.43. The estimates of OGIP by Humphreys and modified Humphreys methods are more accurate than those by conventional method as illustrated in Figures 5.40-5.43.

Comparing between conventional method and Humphreys method for the case that production data are available until abandonment, inclusion of formation expansion and water vapor terms reduces the error from 4.71% to 0.31% for a reservoir with initial pressure 3,566 psi and 6.77% to 1.98% for a reservoir with initial pressure 8,000 psi. The modified Humphreys method proposed in this study yields smaller error than the other two methods. The error is -0.22% for a reservoir with initial pressure 3,566 psi and 0.64% for a reservoir with initial pressure 8,000 psi. The difference in error among the three methods becomes larger when the reservoir has high initial pressure. The modified Humphreys method has the smallest magnitude of error because it takes into account the variation in formation compressibilities when the pressure of the reservoir decreases while the original Humphreys method uses average formation compressibilities.

When estimating OGIP at 75% pressure depletion, we can still observe that the modified Humphreys method still provides the most accurate OGIP estimates. The error for the conventional, Humphreys and modified Humphreys methods for a reservoir with initial pressure 8,000 psi is 18.52%, 5.59%, and 5.42%, respectively when 75% data are available. But when estimating at 50% and 25% pressure depletion, the Humphreys method becomes the most accurate OGIP estimates. The error for the conventional, Humphreys and modified Humphreys methods for a reservoir with initial pressure 8,000 psi is 28.73%, 8.73%, and 11.94%, respectively when 50% data are available and the error becomes 42.29%, 12.83% and 19.04%, respectively when 25% data are available. The Humphreys method has good performance at early stages of depletion because there is small variation in rock compressibility during the narrower range of pressure depletion. The difference in errors between the conventional method and the methods accounting for formation expansion and water vapor (Humphreys and modified Humphreys) becomes more pronounced when less data are used in the analysis.

Figures 5.44 and 5.45 show volumetric expansion of formation and water vapor during different stages in pressure decline based on Humphreys (blue line), and modified Humphreys (red line) methods in comparison with correct expansion calculated from ideal *p/z* straight line (green line) for a reservoir with initial pressure 3,566 psi and 8,000 psi, respectively. In both figures, the expansion volume calculated by Humphreys method is closest to the correct expansion when the pressure depletion is 50% or less. But when the pressure depletion is 75% or more, the modified Humphreys method provides better calculation, i.e., the expansion from modified Humphreys method is closer to the correct expansion. These are the reason why Humphreys method gives less error of OGIP estimates when the pressure depletion is 50% or less and modified Humphreys method gives less error when the pressure depletion is 75% or more.

As summarized in Table 5.20, we learned that the modified Humphreys method is suitable for estimating OGIP based on data available at 75% of pressure and abandonment while the Humphreys method yields the most accurate OGIP estimate based on data available at 25% and 50% pressure depletion. . If the conventional method is used, the error can be as high as 42.29% in the case of 8,000 psi initial pressure reservoir and 25% depletion. The highest error from Humphreys method at 25% and 50% depletion is 12.83% while the highest error from modified Humphreys at 75% of pressure and abandonment is 5.42%. Thus, using the right method for right percentage of depletion will give us a maximum error of 12.83%.

In case of water content in the reservoirs 20%-50%, the trends of error when estimates by different methods are the same as in the case of water content in reservoirs 10% as shown in APPENDIX A-1)

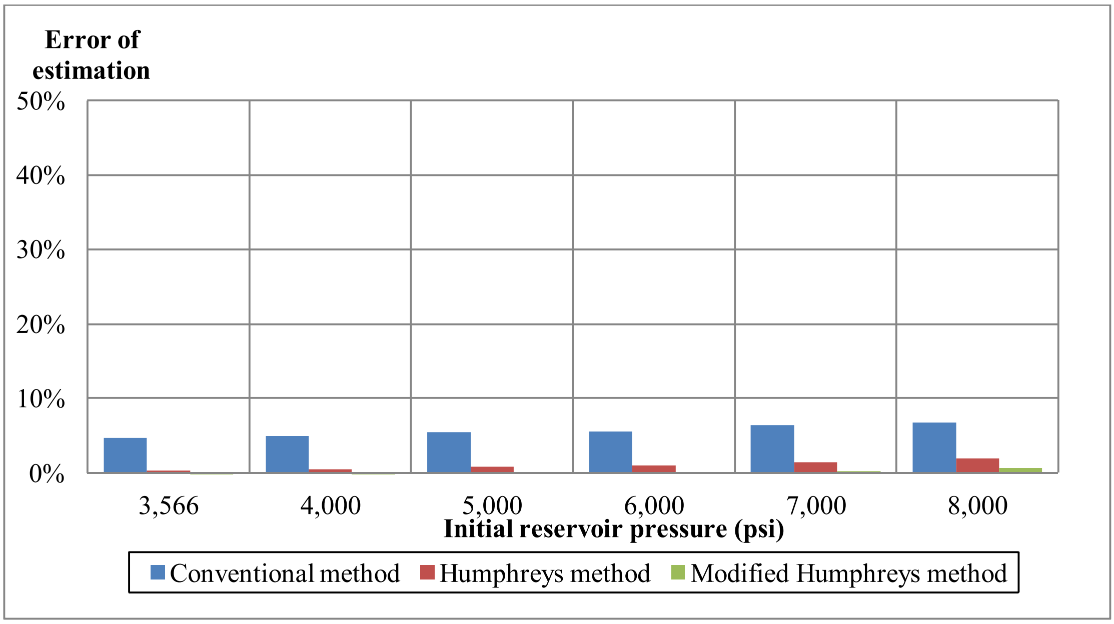

Figure 5.40: Error of *G* estimated by different methods for Santa Rosa sandstone reservoir and water content 10% based on production data at abandonment

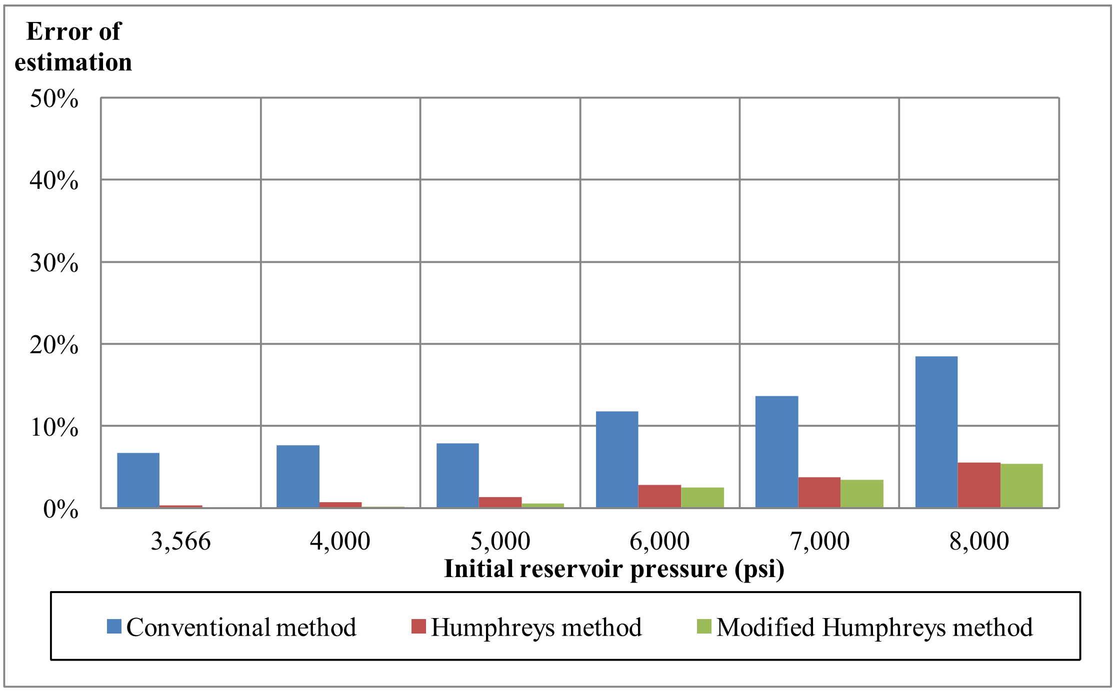

Figure 5.41: Error of *G* estimated by different methods for Santa Rosa sandstone reservoir and water content 10% based on production data at 75% pressure depletion.

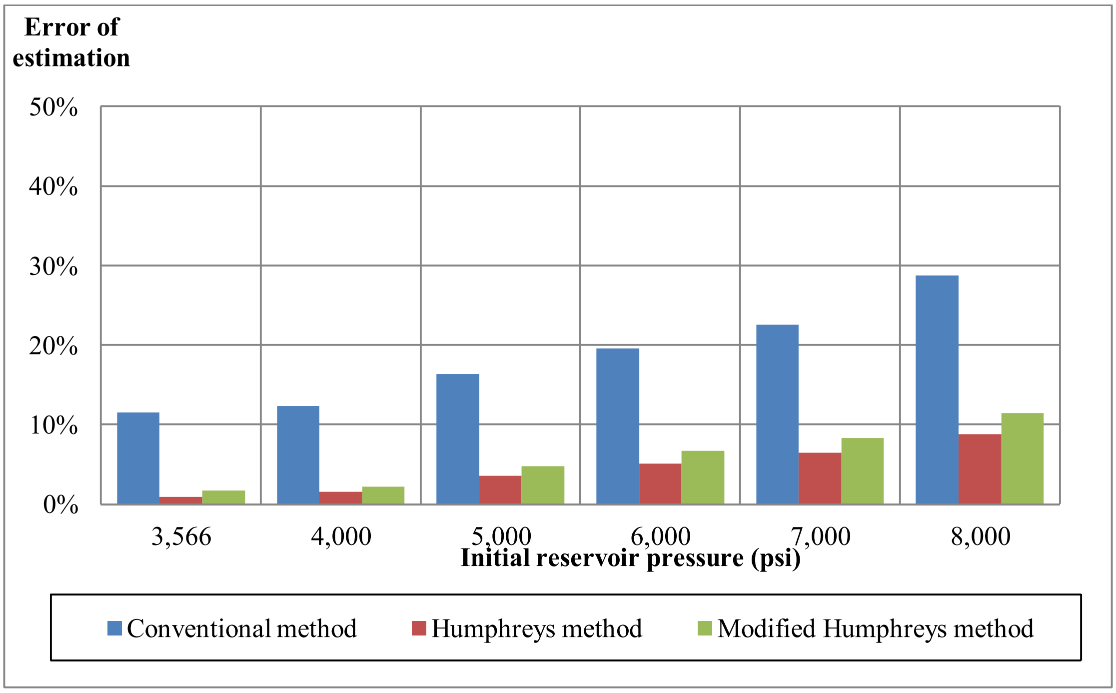

Figure 5.42: Error of *G* estimated by different methods for Santa Rosa sandstone reservoir and water content 10% based on production data at 50% pressure depletion.

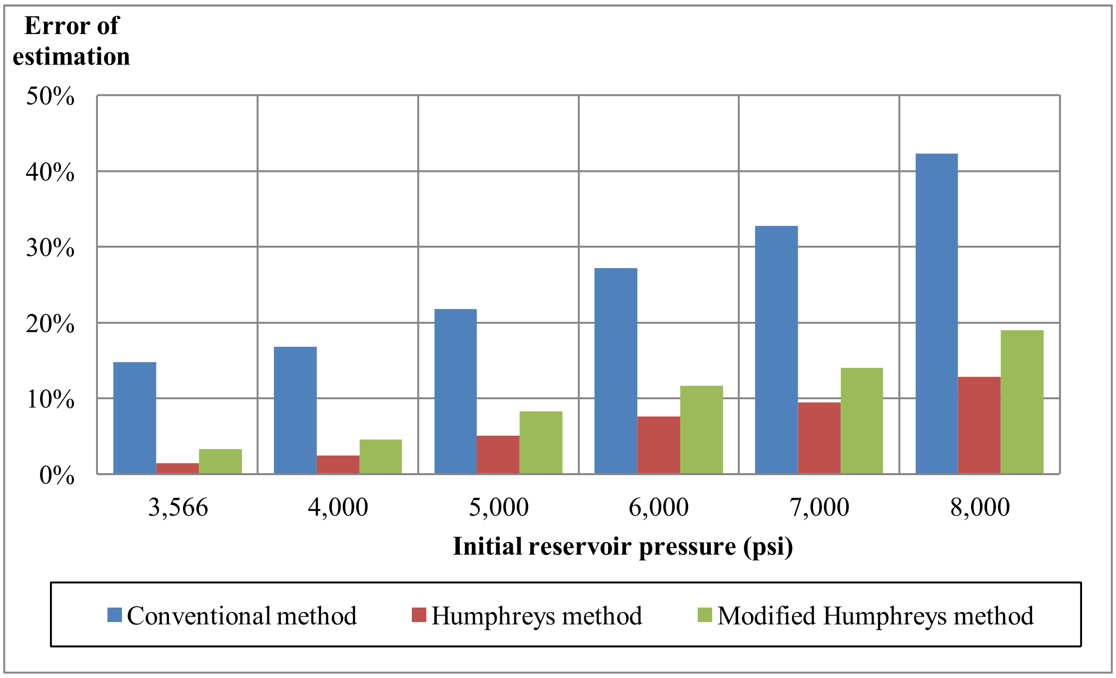

Figure 5.43: Error of G estimated by different methods for Santa Rosa sandstone reservoir and water content 10% based on production data at 25% pressure depletion

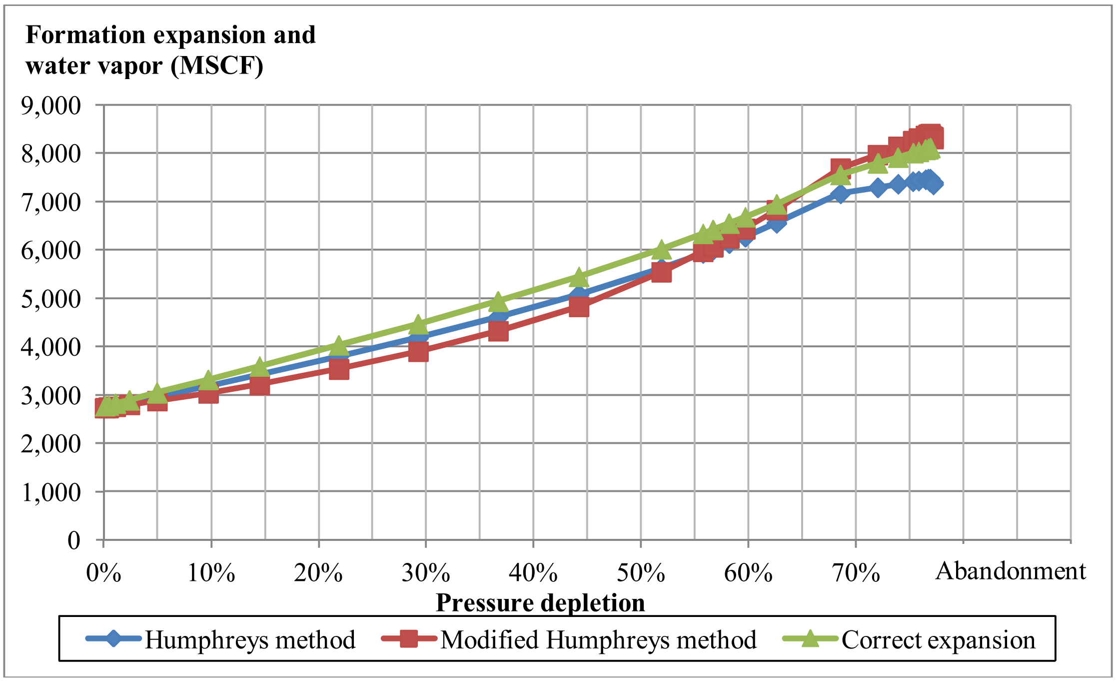

Figure 5.44: Formation expansion and water vapor for Santo Rosa sandstone reservoir with initial pressure 3,566 psi

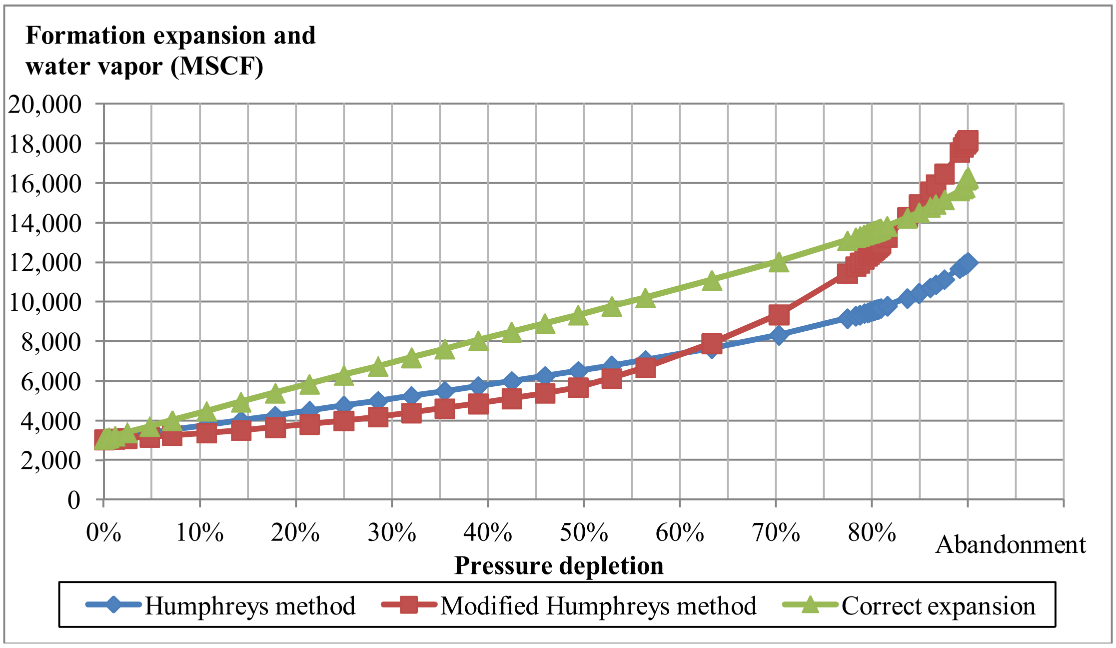

Figure 5.45: Formation expansion and water vapor for Santo Rosa sandstone reservoir with initial pressure 8,000 psi

Table 5.20: The number of the most accurate OGIP estimates for conventional, Humphreys and modified Humphreys method for Santa Rosa sandstone reservoir

	Range of production data available			
	at abandonment	75%	50%	25%
Conventional method	0	0	0	0
Humphreys method	0	0	6	6
Modified Humphreys method	6	6	0	0

5.2.1.2 Degree of depletion

The error of OGIP estimate for the three methods decreases when more production data are available. Figures 5.46 - 5.48 show the example of results of the analysis using different degree of depletion for the case with water content 10%. In case of conventional method as shown in Figure 5.46, the error of OGIP estimates at 25% pressure depletion and at 50% pressure depletion for a reservoir with initial pressure 3,566 psi, the error reduces from 14.76% to 11.53%. For a reservoir with initial pressure 8,000 psi, the error reduces from 38.11% to 26.44%. When the modified Humphreys method is used, the error for reservoir with initial pressure of 8,000 psi decreases from 15.29% to 9.24% when data used in the analysis are extended from 25% pressure depletion to 50% pressure depletion. A lesson learned from the results is that one should be aware of overestimation error when a short duration of production data is available.

In case of water content in the reservoirs 20%-50%, the trends of error when estimates using different lengths of data are the same as in the case of water content in reservoirs 10% as shown in APPENDIX A-2)

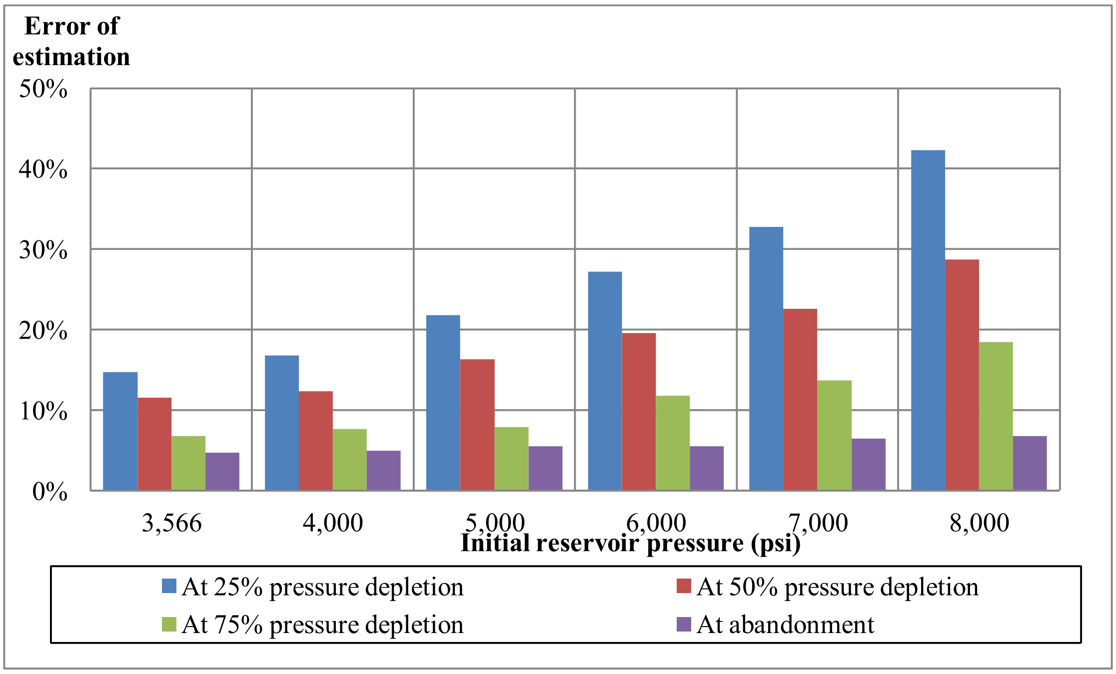

Figure 5.46: Error of *G* estimated by conventional methods for Santa Rosa sandstone reservoir and water content 10% based on different degree of depletion

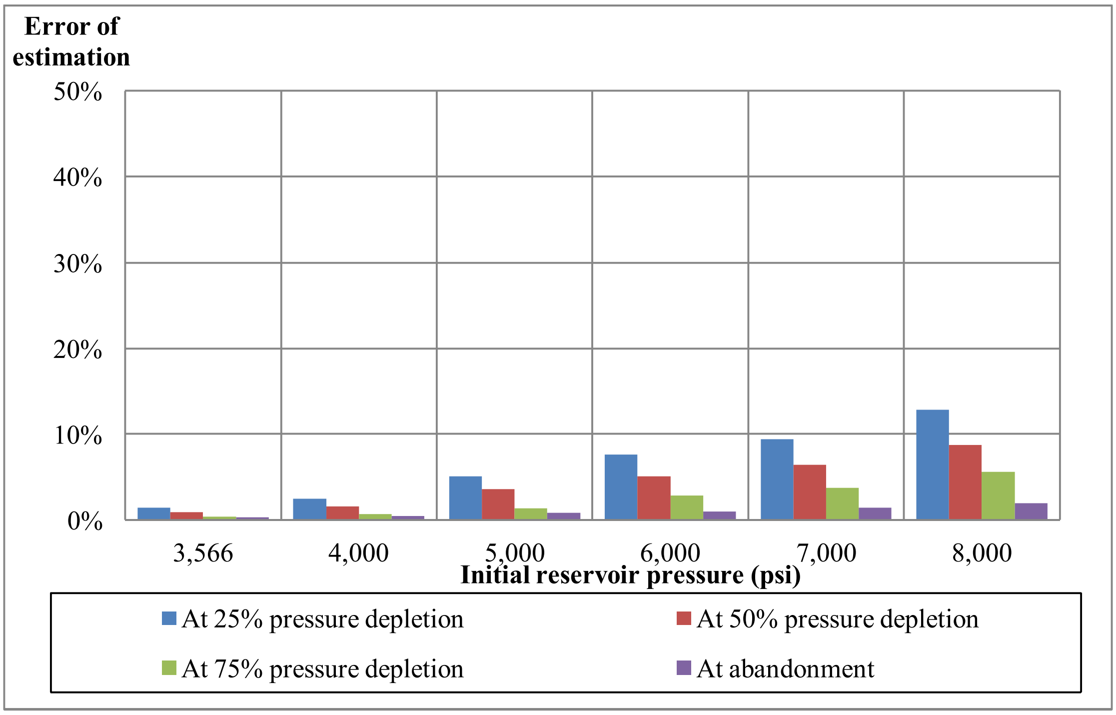

Figure 5.47: Error of G estimated by Humphreys methods for Santa Rosa sandstone reservoir and water content 10% based on different degree of depletion

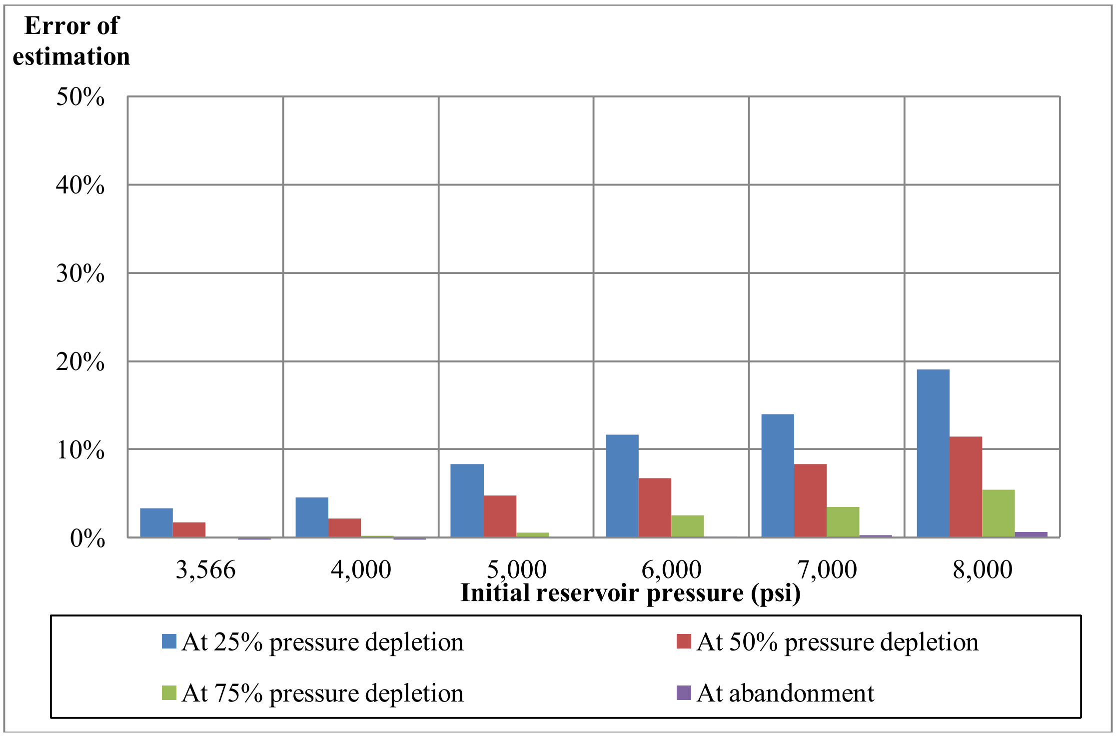

Figure 5.48: Error of G estimated by modified Humphreys for Santa Rosa sandstone reservoir and water content 10% methods based on different degree of depletion

5.2.1.3 Effect of initial pressure

The initial reservoir pressure has impact on OGIP estimate as the decline in reservoir pressure affects the formation expansion and water vaporization. As seen in Figures 5.40-5.43, the error of OGIP estimate for a reservoir with high initial pressure is higher than that for a reservoir with low initial pressure. This observation is true for all methods of analysis and all degree of depletion used in the analysis. For example, in the case of Humphreys method, which is the most accurate method when calculating OGIP at 50% and 25% pressure depletion, the error of OGIP estimates increase from 0.91% to 8.76% and 1.44% to 12.83%, respectively when the reservoir pressure is changed from 3,566 psi to 8,000 psi. The same hand of increasing error when the initial pressure increases can be seen in the modified Humphreys method when based on production data at abandonment and 75% pressure depletion.

5.2.1.4 Water content

As the decline in reservoir pressure increases the water vaporization, OGIP estimation may be impacted by the magnitude of initial reservoir pressure. Figures 5.49-5.51 show the error of OGIP estimate for the case with different water contents in the reservoir from 10%-50% when production data are available at 25% pressure depletion. In a reservoir with low initial pressure, the change in water content has small effect on OGIP estimate. As seen in a reservoir with initial pressure 3,566 psi and 4,000 psi, the errors are almost same for all water contents. For example, in Figure 5.43, when the water content in reservoir increases from 10% to 50% in a reservoir with initial pressure 3,566 psi, the error from modified Humphreys method is 3.33%, 2.82%, 3.60%, 3.90%, and 4.18%, respectively. But in a reservoir with initial pressure from 5,000 to 8,000 psi, the higher water content generally results in higher error. This observation is generally true for every estimation method and every length of available data. In a reservoir with initial pressure 8,000 psi, the error increases from 19.04% to 16.64%, 18.92%, 20.35%, and 22.72% when the water content increase from 10% to 20%, 30%, 40%, and 50%, respectively.

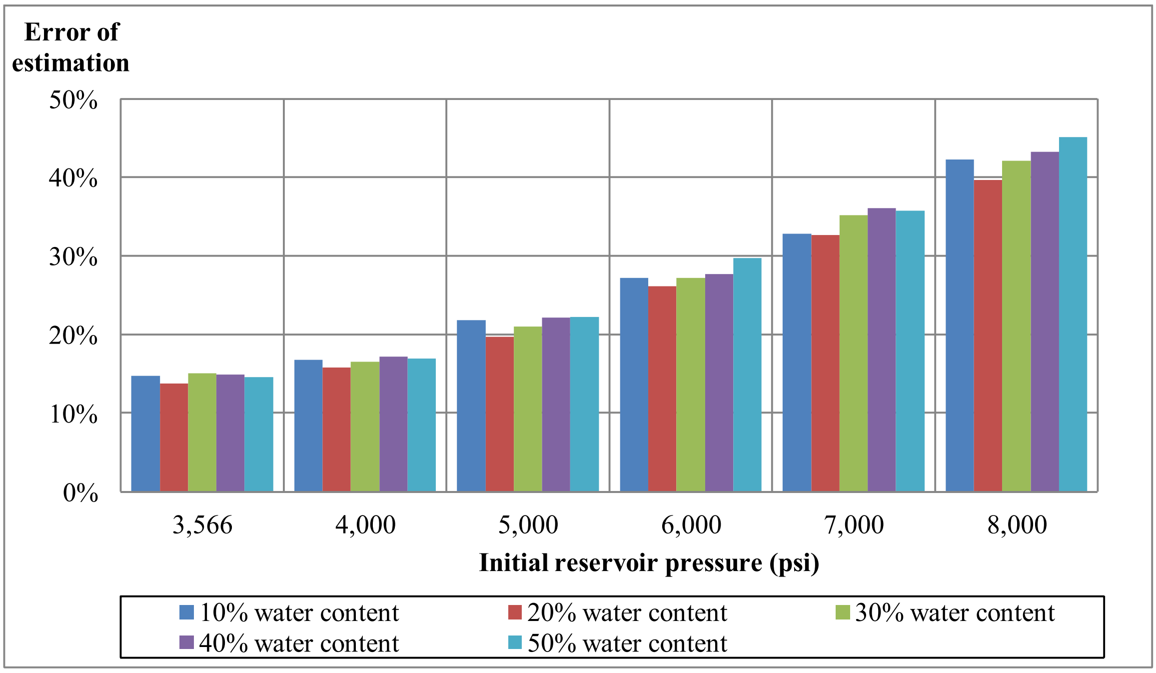

Figure 5.49: Error of *G* estimated by conventional method for Santa Rosa sandstone reservoir with different water contents based on production data at 25% pressure depletion

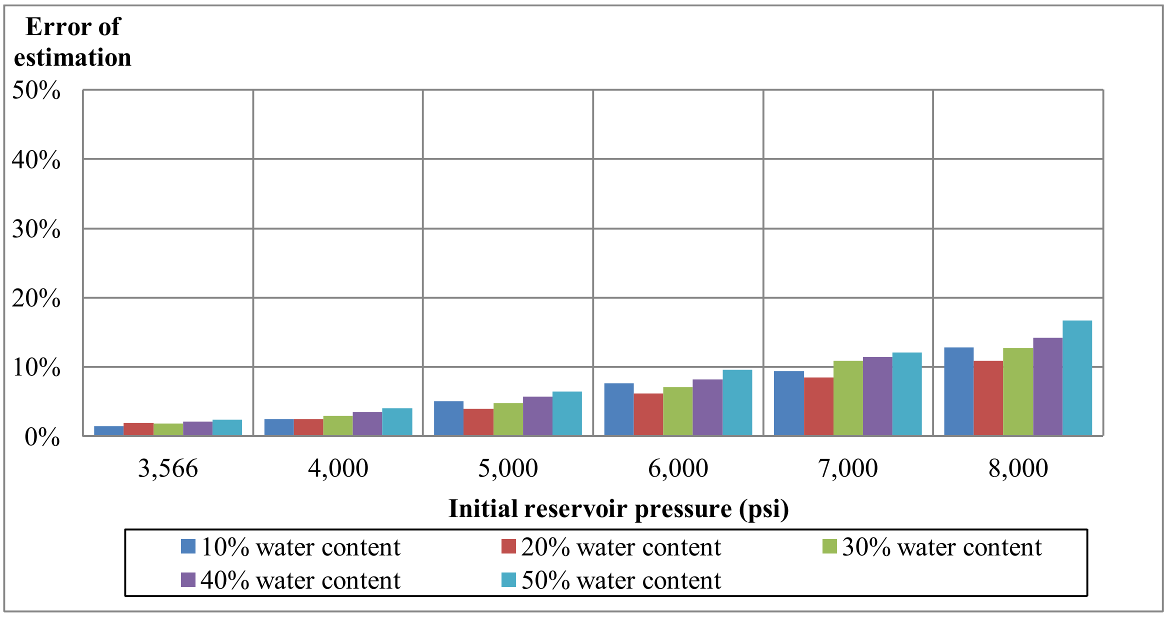

Figure 5.50: Error of *G* estimated by Humphreys method for Santa Rosa sandstone reservoir with different water contents based on production data at 25% pressure depletion

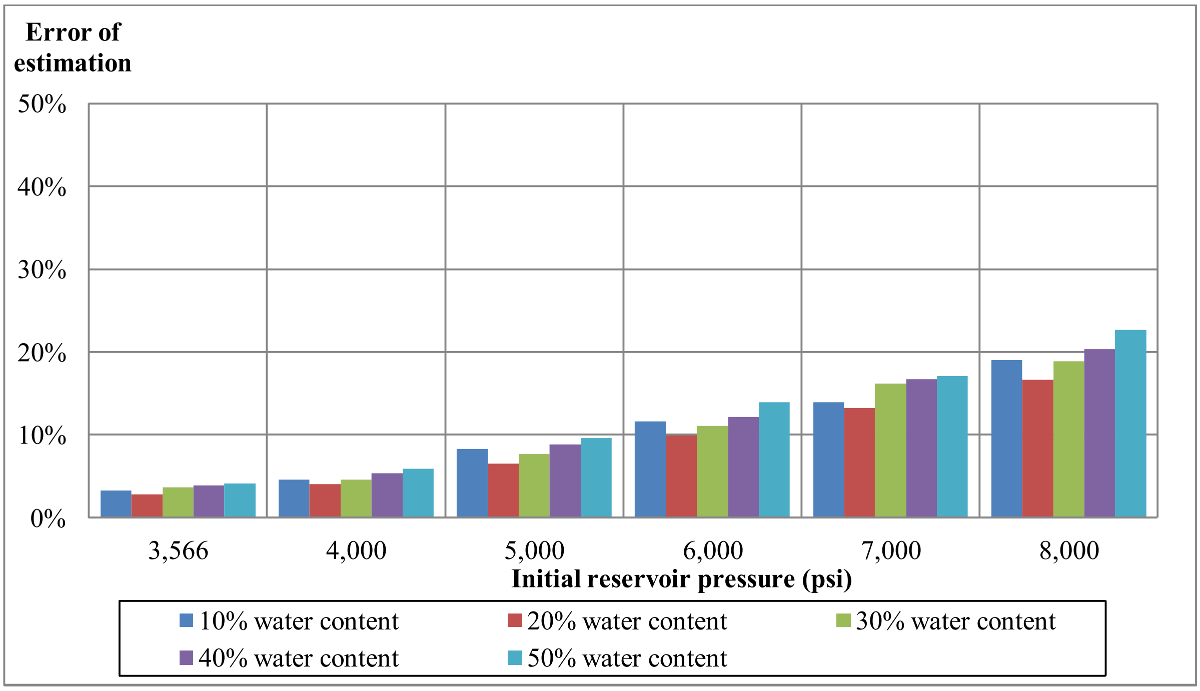

Figure 5.51: Error of *G* estimated by modified Humphreys method for Santa Rosa sandstone reservoir with different water contents based on production data at 25% pressure depletion

5.2.2 Berea sandstone reservoir

Berea sandstone has moderate average formation compressibility among three kinds of rock used in this study. It has the formation compressibility varying from 3.50×10^{-5} to 4.0×10^{-6} psi^{-1} at pressure 800 to 8,000 psi and 1.08×10^{-5} psi^{-1} on average.

5.2.2.1 Method of analysis

Tables 5.21-5.24 show the estimates original gas in place by 3 material balance methods base on water content 10%. The error of OGIP estimates for Berea sandstone reservoirs using different methods are shown in Figures 5.52-5.55. The trends of error when estimates by different methods are the same as in the Santa Rosa sandstone reservoir. The estimates of OGIP by Humphreys and modified Humphreys methods are more accurate than those by conventional method as illustrated in Figures 5.52-5.55.

Comparing between conventional method and Humphreys method for the case that production data are available until abandonment, inclusion of formation expansion and water vapor terms reduce the error from 7.01% to 2.34% for a reservoir with initial pressure 3,566 psi and reduces from 7.97% to 3.35% for a reservoir with initial pressure 8,000 psi. The modified Humphreys method proposed in this study yields smaller error than the other two methods. The errors are 1.20% for a reservoir with initial pressure 3,566 psi and 1.88% for a reservoir with initial pressure 8,000 psi. The difference in error among the three methods becomes larger when the reservoir has high initial pressures. The modified Humphreys method has the smallest magnitude of error because it takes into account the variation in formation compressibilities when the pressure of the reservoir decreases while the original Humphreys method uses average formation compressibilities.

When estimating OGIP at 75% pressure depletion, we can still observe that the modified Humphreys method still provides the most accurate OGIP estimates. For example, the errors for the conventional, Humphreys and modified Humphreys methods for reservoir with initial pressure 8,000 psi is 25.06%, 13.12% and 12.77%, respectively when 75% data are available. But when estimating at 50% and 25% pressure depletion, the Humphreys method becomes the most accurate OGIP estimates. The error for the conventional, Humphreys and modified Humphreys methods for reservoir with initial pressure 8,000 psi is 40.54%, 19.06%, and 22.46%, respectively when 50% data are available and the errors becomes 55.75%, 25.96% and 31.14%, respectively when 25% data are available. The Humphreys method has good performance at early stages of depletion because there is small variation in rock compressibility during the narrower range of pressure depletion. The difference in errors between the conventional method and the methods accounting for formation expansion and water vapor (Humphreys and modified Humphreys) becomes more pronounced when less data are used in the analysis.

Figures 5.56 and 5.57 show volumetric expansion of formation and water vapor during different stages in pressure decline based on Humphreys (blue line), and modified Humphreys (red line) methods in comparison with correct expansion calculated from ideal p/z straight line (green line) for a reservoir with initial pressure 3,566 psi and 8,000 psi, respectively. In both figures, the expansion volume calculated by Humphreys method is closest to the correct expansion when the pressure depletion is 50% or less. But when the pressure depletion is 75% or more, the modified Humphreys method provides better calculation, i.e., the expansion from modified Humphreys method is closer to the correct expansion. These are the reason why Humphreys method gives less error of OGIP estimates when the pressure depletion is 50% or less and modified Humphreys method gives less error when the pressure depletion is 75% or more.

As summarized in Table 5.25, we learned that the modified Humphreys method is suitable for estimate OGIP base on data available 75% of pressure depletion and abandonment while the Humphreys method yields the most accurate OGIP when estimate OGIP base on data available 25% and 50% pressure depletion. The highest error from Humphreys method at 25% and 50% depletion is 25.96% while the highest error from modified Humphreys at 75% of pressure depletion and abandonment is 12.77%. Thus, using the right method for right percentage of depletion will give us a maximum error of 25.96%.

In case of water content in the reservoirs 20%-50%, the trends of error when estimates by different methods are the same as in the case of water content in reservoirs 10% as shown in APPENDIX A-1)

Table 5.21: Original gas in place estimation for Berea sandstone reservoir and water content 10% based on production data at abandonment

Initial pressure (psi)	Original Gas in place, *G* (MCF)			
	Actual	Conventional method	Humphreys method	Modified Humphreys method
3,566	6,064,068	6,489,453	6,205,697	6,136,549
4,000	6,871,389	7,361,598	7,038,039	6,954,787
5,000	8,723,494	9,382,310	8,958,333	8,854,022
6,000	10,555,810	11,355,868	10,864,038	10,722,152
7,000	12,368,441	13,333,333	12,762,124	12,590,440
8,000	14,167,596	15,296,532	14,641,570	14,433,353

Table 5.22: Original gas in place estimation for Berea sandstone reservoir and water content 10% based on production data at 75% pressure depletion

Initial pressure (psi)	Original Gas in place, *G* (MCF)			
	Actual	Conventional method	Humphreys method	Modified Humphreys method
3,566	6,064,068	6,621,455	6,245,614	6,206,155
4,000	6,871,389	7,587,775	7,125,687	7,094,410
5,000	8,723,494	9,720,681	9,122,966	9,088,299
6,000	10,555,810	11,878,264	11,128,205	10,947,700
7,000	12,368,441	14,885,083	13,537,064	13,605,541
8,000	14,167,596	17,718,269	15,842,697	15,976,528

Table 5.23: Original gas in place estimation for Berea sandstone reservoir and water content 10% based on production data at 50% pressure depletion

Initial pressure (psi)	Original Gas in place, *G* (MCF)			
	Actual	Conventional method	Humphreys method	Modified Humphreys method
3,566	6,064,068	7,076,368	6,448,873	6,517,857
4,000	6,871,389	8,022,873	7,331,441	7,397,603
5,000	8,723,494	10,584,142	9,546,407	9,668,402
6,000	10,555,810	13,368,615	11,856,851	12,053,145
7,000	12,368,441	16,401,610	14,265,029	14,580,067
8,000	14,167,596	19,910,839	16,867,755	17,349,866

Table 5.24: Original gas in place estimation for Berea sandstone reservoir and water content 10% based on production data at 25% pressure depletion

Initial pressure (psi)	Original Gas in place, *G* (MCF)			
	Actual	Conventional method	Humphreys method	Modified Humphreys method
3,566	6,064,068	7,342,947	6,576,433	6,704,545
4,000	6,871,389	8,432,134	7,526,921	7,677,275
5,000	8,723,494	11,287,263	9,889,175	10,146,163
6,000	10,555,810	14,481,463	12,390,652	12,833,037
7,000	12,368,441	18,052,382	15,041,802	15,632,239
8,000	14,167,596	22,065,859	17,846,193	18,579,278

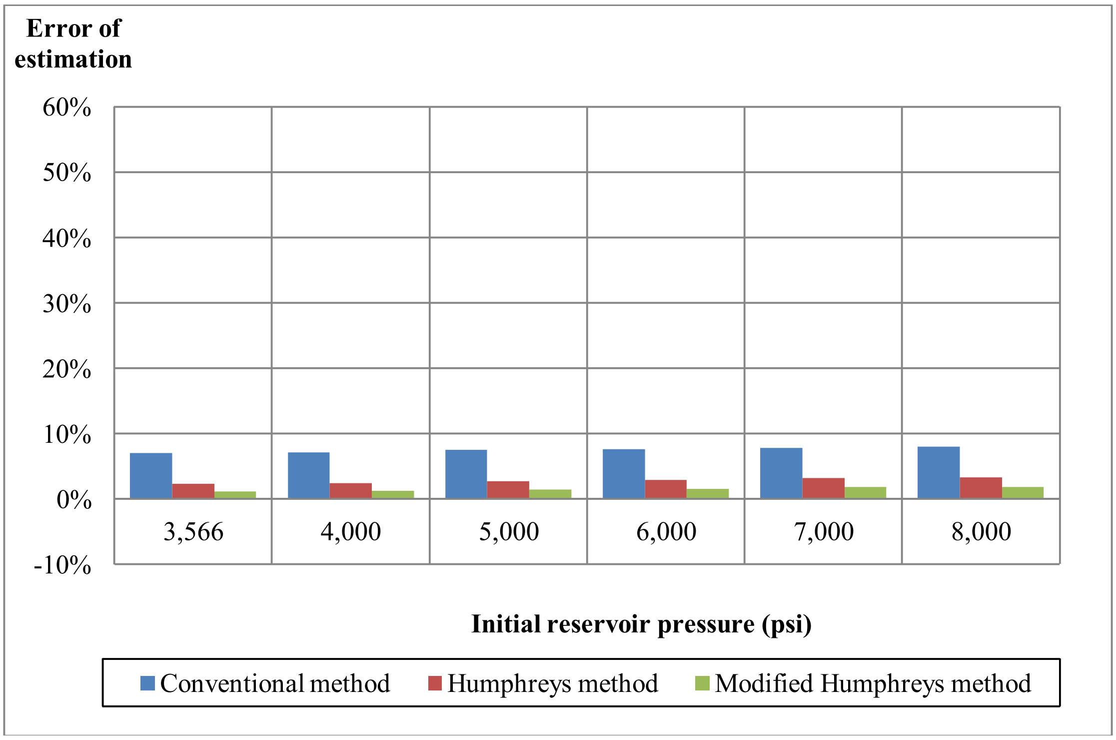

Figure 5.52: Error of *G* estimated by different methods for Berea sandstone reservoir and water content 10% based on production data at abandonment

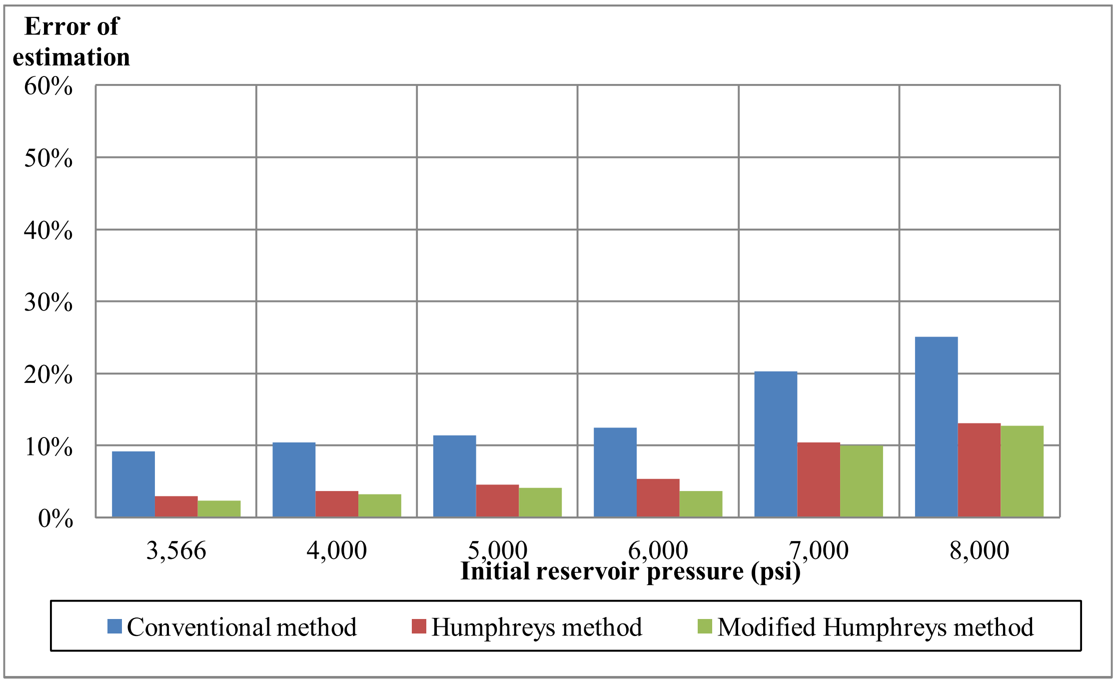

Figure 5.53: Error of *G* estimated by different methods for Berea sandstone reservoir and water content 10% based on production data at 75% pressure depletion

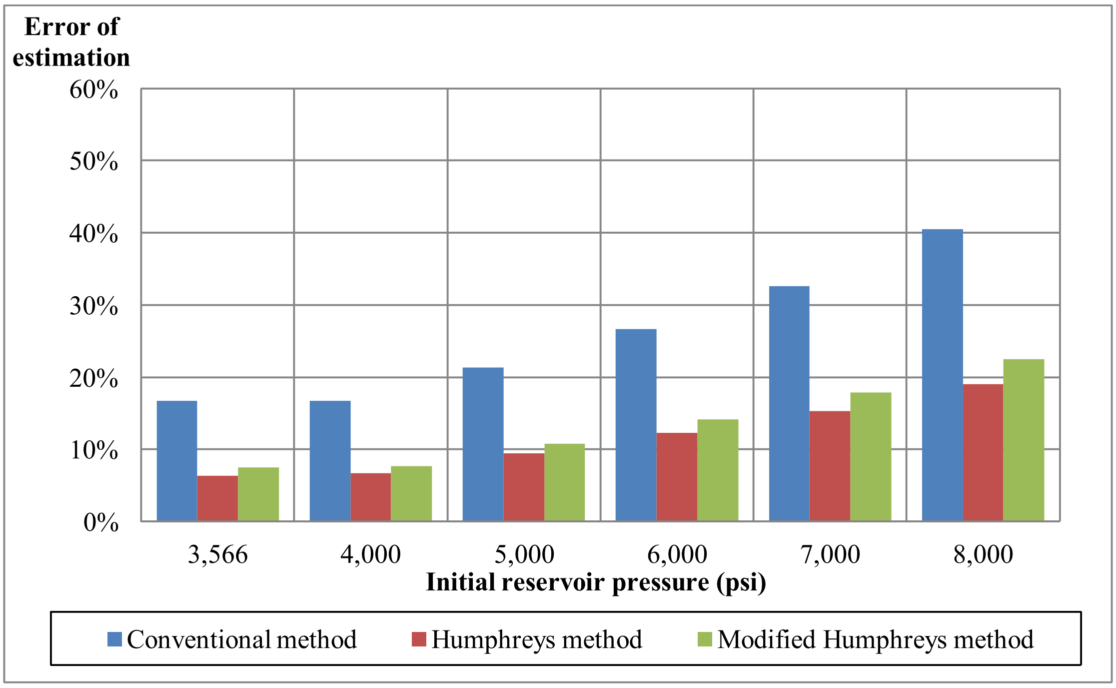

Figure 5.54: Error of *G* estimated by different methods for Berea sandstone reservoir and water content 10% based on production data at 50% pressure depletion

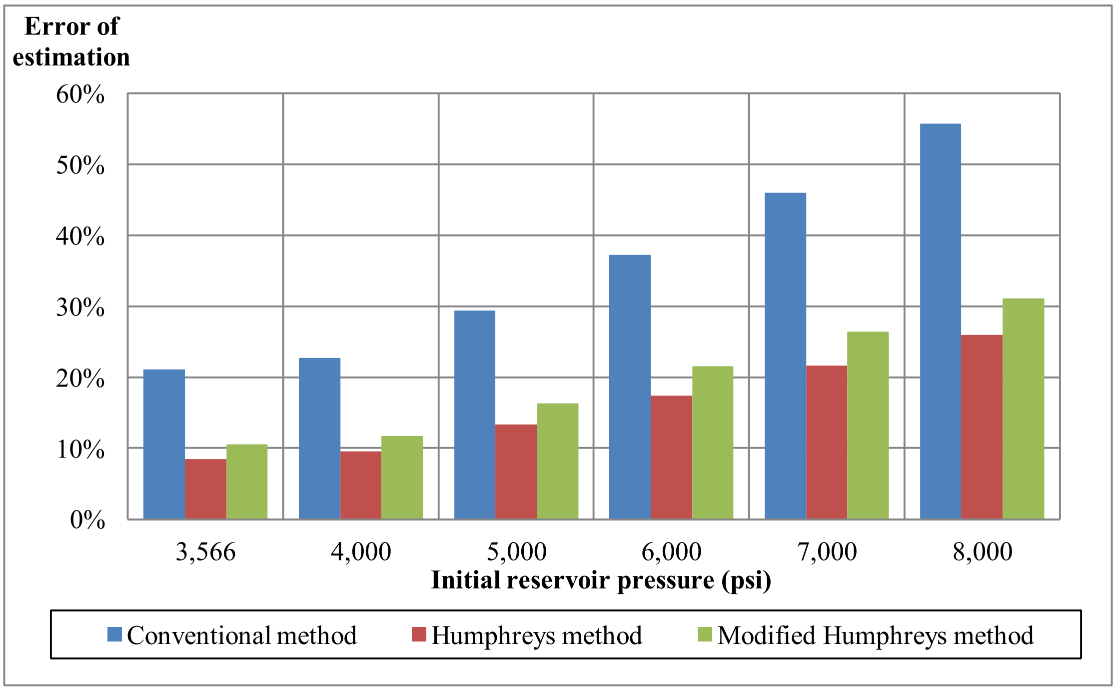

Figure 5.55: Error of *G* estimated by different methods for Berea sandstone reservoir and water content 10% based on production data at 25% pressure depletion

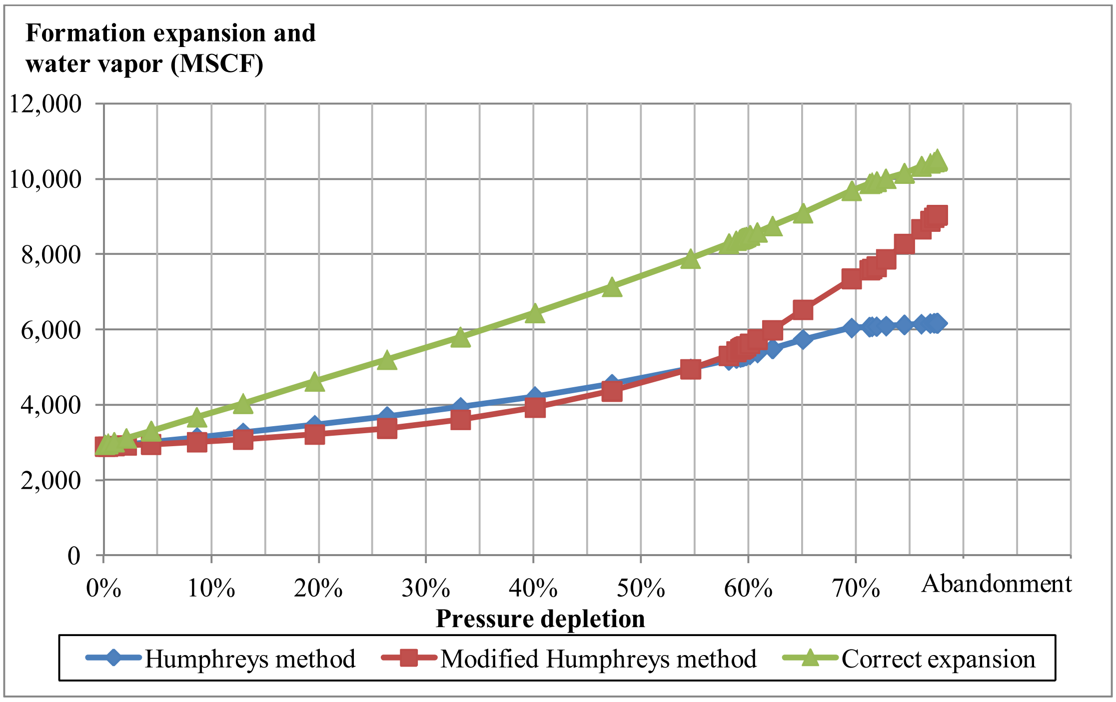

Figure 5.56: Formation expansion and water vapor for Berea sandstone reservoir with initial pressure 3,566 psi

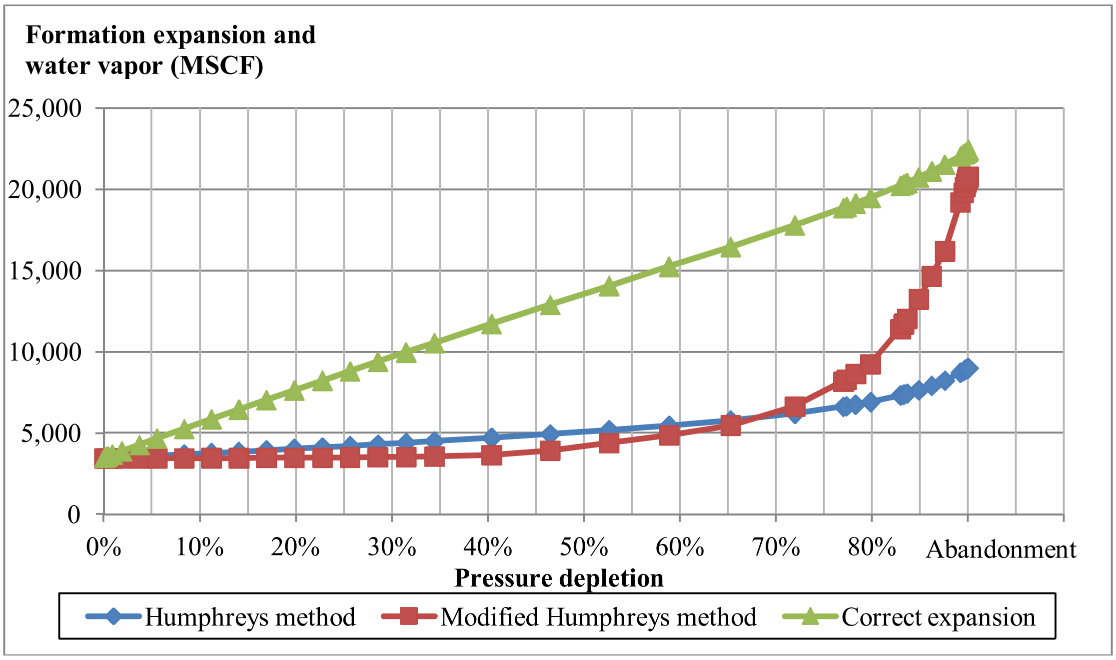

Figure 5.57: Formation expansion and water vapor for Berea sandstone reservoir with initial pressure 8,000 psi

Table 5.25: The number of the most accurate OGIP estimates for conventional, Humphreys and modified Humphreys method for Berea sandstone reservoir

	Range of production data available			
	at abandonment	75%	50%	25%
Conventional method	0	0	0	0
Humphreys method	0	0	6	6
Modified Humphreys method	6	6	0	0

5.2.2.2 Degree of depletion

The error of OGIP estimate for the three methods decreases when more production data are available. Figures 5.58-5.60 show the example of results of the analysis on different degree of depletion for the case with water content 10%. In case of conventional method as shown in Figure 5.58, the error of OGIP estimates at 25% pressure depletion and at 50% pressure depletion for a reservoir with initial pressure 3,566 psi, the error reduces from 21.09% to 16.69%. For a reservoir with initial pressure 8,000 psi, the error reduces from 55.75% to 40.54%. When the modified Humphreys method is used, the error for reservoir with initial pressure of 8,000 psi decrease from 31.14% to 22.46% when data used in the analysis are extended from 25% pressure depletion to 50% pressure depletion. Thus, one should be aware of overestimation error when a short duration of production data is available.

In case of water content in the reservoirs 20%-50%, the trends of error when estimates using different lengths of data are the same as in the case of water content in reservoirs 10% as shown in APPENDIX A-2)

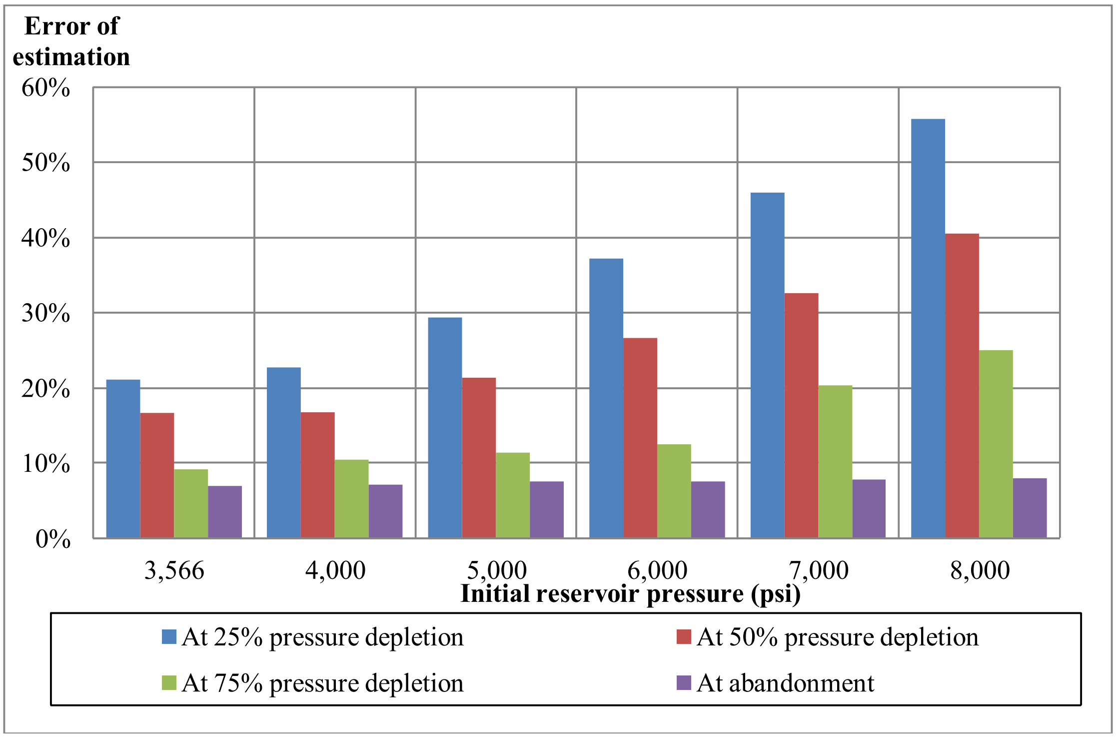

Figure 5.58: Error of *G* estimated by conventional method for Berea sandstone reservoir and water content 10% based on different degree of depletion

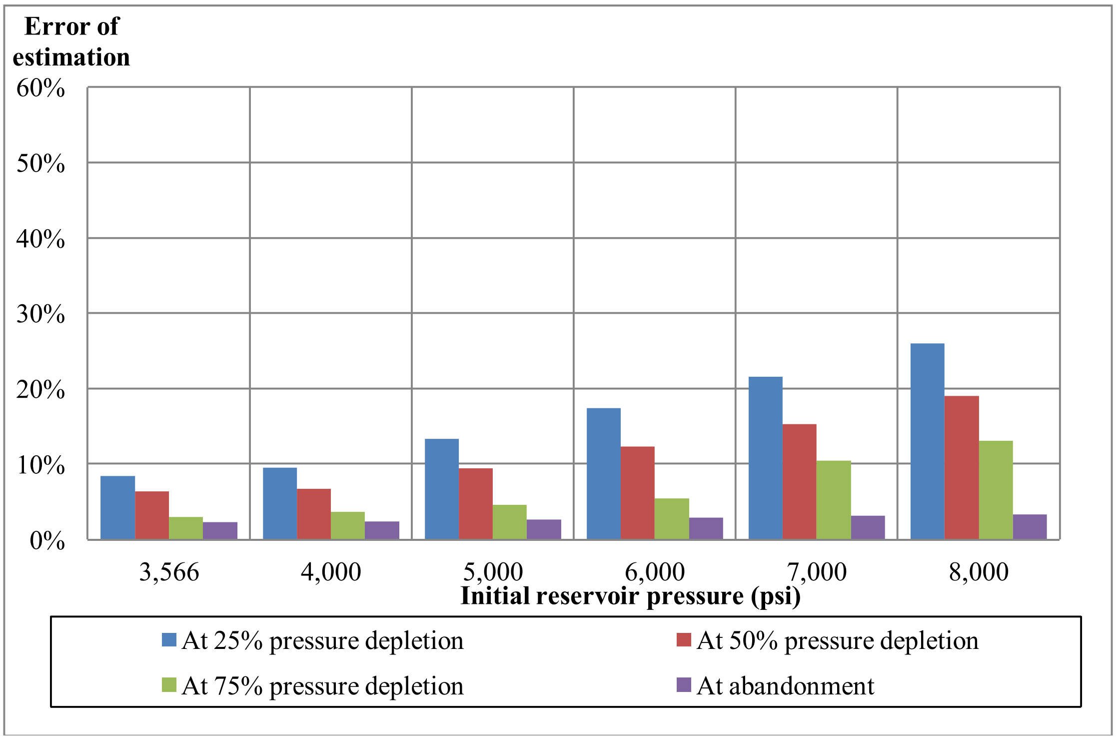

Figure 5.59: Error of *G* estimated by Humphreys method for Berea sandstone reservoir and water content 10% based on difference degree of depletion

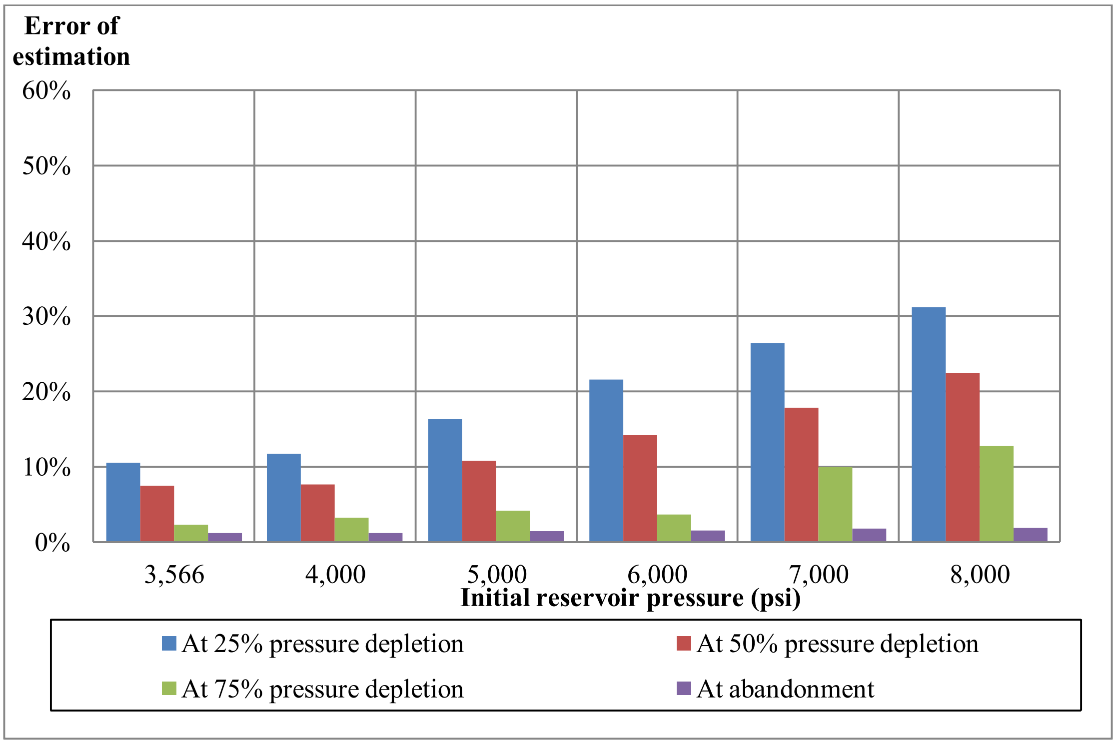

Figure 5.60: Error of *G* estimated by modified Humphreys method for Berea sandstone reservoir and water content 10% based on different degree of depletion

5.2.2.3 Effect of initial pressure

The impact of initial reservoir pressure on OGIP estimates for Berea sandstone reservoir is same trend as in Santa Rosa sandstone reservoir. As the decline in reservoir pressure affects the formation expansion and water vaporization, the initial reservoir pressure has a significant impact on OGIP estimates. As seen in Figures 5.52-5.55, the error of OGIP estimate for a reservoir with high initial pressure is higher than that for a reservoir with low initial pressure. This observation is true for all methods of analysis and all degree of depletion used in the analysis. For example, in the case of modified Humphreys method, which is the most accurate method when calculate OGIP at depletion and 75% pressure depletion, the error of OGIP estimates increase from 1.20% to 1.88% and 2.34% to 12.72%, respectively when the reservoir pressure is changed from 3,566 psi to 8,000 psi.

5.2.2.4 Water content

As the decline in reservoir pressure, the water vaporization impacts to OGIP estimation may be impacted by the magnitude of initial reservoir pressure. Figures 5.61-5.63 show the error of OGIP estimate for the case with different water content in reservoir from 10%-50% when production data are available at 25% pressure depletion. In a reservoir with every initial pressure condition, the higher water content, results the higher error. For example, in Figure 5.63 shows the trend of error estimated by modified Humphreys method in a reservoir with initial pressure 8,000 psi, the error increases from 31.14% to 34.05%, 35.15%, 37.43%%, and 46.91% when the water content in reservoir increases from 10% to 20%, 30%, 40%, and 50%, respectively.

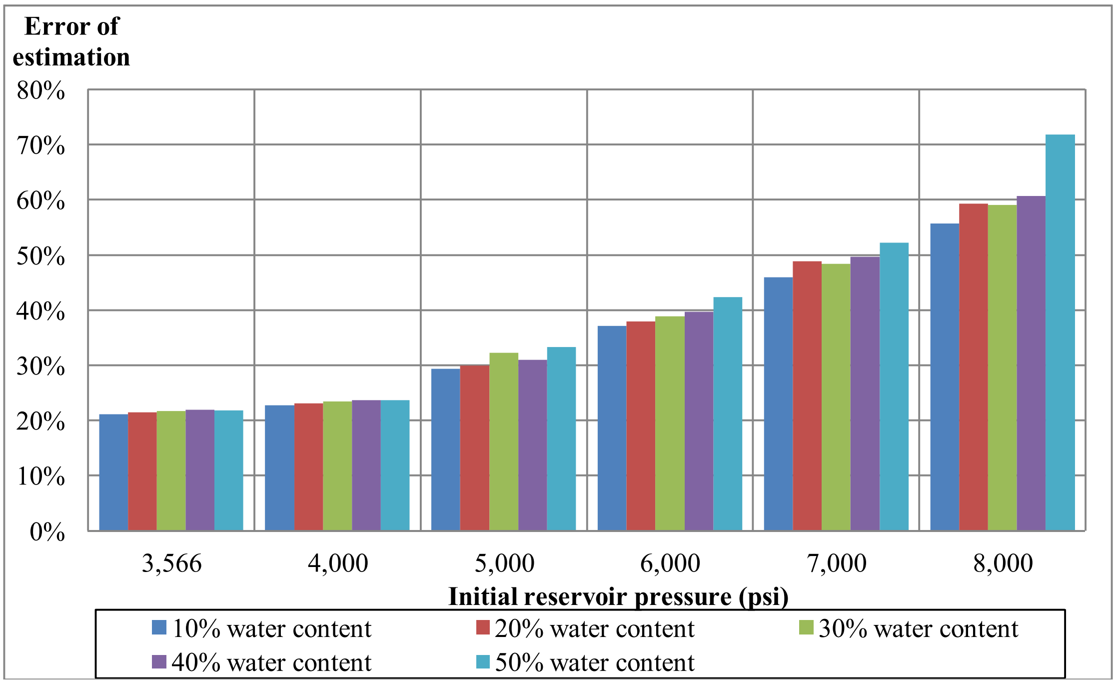

Figure 5.61: Error of G estimated by conventional method for Berea sandstone reservoir and different water content based on production data lower than 25% pressure depletion

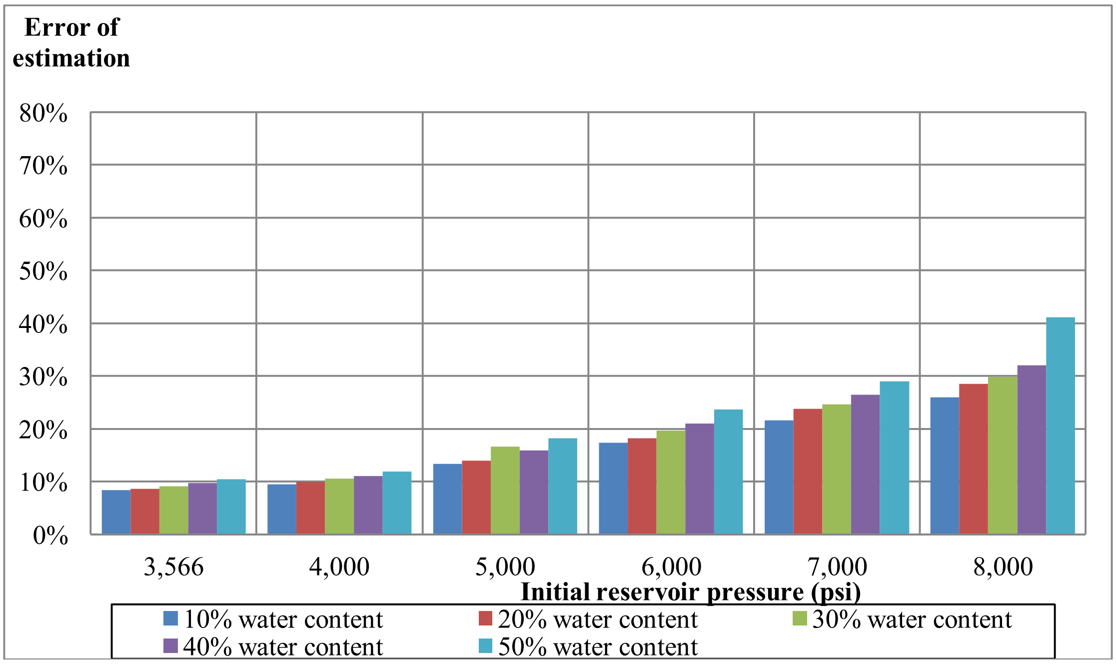

Figure 5.62: Error of G estimated by Humphreys method for Berea sandstone reservoir and different water content based on production data lower than 25% pressure depletion

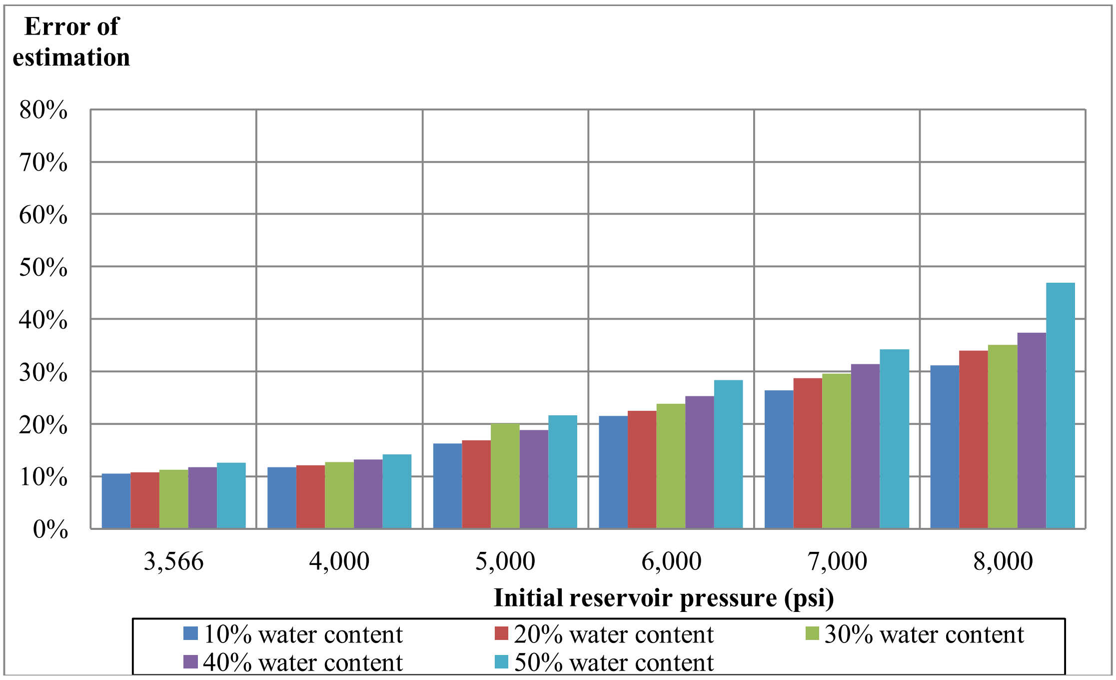

Figure 5.63: Error of *G* estimation by modified Humphreys method for Berea sandstone reservoir and different water content based on production data lower than 25% of depletion

5.2.3 Grainstone reservoir

Grainstone is a kind of carbonate rock. It has the lowest average formation compressibility among three kinds of rock used this study. The formation compressibility is 1.74×10^{-5} psi^{-1} at 800 psi decreases to 5.0×10^{-6} psi^{-1} at 8,000 psi and 0.78×10^{-5} psi^{-1} on average.

5.2.3.1 Method of analysis

Tables 5.26-5.29 show the example estimates original gas in place by three material balance methods in Grainstone reservoir and water content 10%. And the error of OGIP estimates using different methods are shown in Figures 5.64-5.67. The estimates of OGIP by Humphreys and modified Humphreys methods are more accurate than those by conventional method as illustrated in Figures 5.64-5.67.

Comparing between conventional method and Humphreys method for the case that production data are available until abandonment, inclusion of formation expansion and water vapor terms reduce the error from 3.83% to 0.70% for a reservoir with initial pressure 3,566 psi and reduces from 4.11% to 1.24% for a reservoir with initial pressure 8,000 psi. The modified Humphreys method proposed in this study yields smaller error than the others two methods. The errors are 0.14% for a reservoir with initial pressure 3,566 psi and 0.46% for a reservoir with initial pressure 8,000 psi. The difference in error among the three methods becomes larger when the reservoir has high initial pressures. The modified Humphreys method has the smallest magnitude of error because it takes into account the variation in formation compressibilities when the pressure of the reservoir decreases while the original Humphreys method uses average formation compressibilities.

When estimating OGIP at 75% pressure depletion, we can still observe that the modified Humphreys method still provides the most accurate OGIP estimates. For example, the error for the conventional, Humphreys and modified Humphreys methods for reservoir with initial pressure 8,000 psi is 11.16%, 4.91%, and 4.85%, respectively when 75% data are available. But when estimating at 50% and 25% pressure depletion, the Humphreys method becomes the most accurate OGIP estimates. For example, the error for the conventional, Humphreys and modified Humphreys methods for reservoir with initial pressure 8,000 psi is 18.21%, 7.62%, and 9.00%, respectively when 50% data are available and the errors becomes 26.27%, 11.24%, and 13.36%, respectively when 25% data are available. The difference in errors between the conventional method and the methods accounting for formation expansion and water vapor (Humphreys and modified Humphreys) becomes more pronounced when less data are used in the analysis.

Figures 5.56 and 5.57 show volumetric expansion of formation and water vapor during different stages in pressure decline based on Humphreys (blue line), and modified Humphreys (red line) methods in comparison with correct expansion calculated from ideal *p/z* straight line (green line) for a reservoir with initial pressure 3,566 psi and 8,000 psi, respectively. In both figures, the expansion volume calculated by Humphreys method is closest to the correct expansion when the pressure depletion is 50% or less. But when the pressure depletion is 75% or more, the modified Humphreys method provides better calculation, i.e., the expansion from modified Humphreys method is closer to the correct expansion. These are the reason why Humphreys method gives less error of OGIP estimates when the pressure depletion is 50% or less and modified Humphreys method gives less error when the pressure depletion is 75% or more.

As summarized in Table 5.30, we learned that the modified Humphreys method is suitable for estimate OGIP base on data available 75% pressure depletion and abandonment while the Humphreys method yields the most accurate OGIP when estimate OGIP base on data available 25% and 50% pressure depletion. If the conventional method is used, the error can be as high as 26.87% in the case of 8,000 psi initial pressure reservoir and 25% depletion. The highest error from Humphreys method at 25% and 50% depletion is 11.28% while the highest error from modified Humphreys at 75% pressure depletion and abandonment is 4.85%. Thus, using the right method for right percentage of depletion will give us a maximum error of 11.28%.

In case of water content in the reservoirs 20%-50%, the trends of error when estimates by different methods are the same as in the case of water content in reservoirs 10% as shown in APPENDIX A-1)

Table 5.26: Original gas in place estimation for Grainstone reservoir and water content 10% based on production data at abandonment

Initial pressure (psi)	Original Gas in place, *G* (MCF)			
	Actual	Conventional method	Humphreys method	Modified Humphreys method
3,566	5,601,339	5,816,042	5,640,521	5,609,316
4,000	6,276,976	6,518,067	6,326,811	6,288,660
5,000	7,769,070	8,079,195	7,829,880	7,778,978
6,000	9,168,008	9,531,605	9,252,381	9,188,001
7,000	10,479,802	10,898,174	10,590,042	10,514,706
8,000	11,715,291	12,196,262	11,860,389	11,769,393

Table 5.27: Original gas in place estimation for Grainstone reservoir and water content 10% based on production data at lowers than 75% of depletion

Initial pressure (psi)	Original Gas in place, *G* (MCF)			
	Actual	Conventional method	Humphreys method	Modified Humphreys method
3,566	5,601,339	5,925,338	5,646,702	5,622,738
4,000	6,276,976	6,637,834	6,355,528	6,326,406
5,000	7,769,070	8,260,013	7,910,683	7,880,452
6,000	9,168,008	9,888,003	9,420,360	9,409,194
7,000	10,479,802	11,495,869	10,870,364	10,890,411
8,000	11,715,291	13,022,834	12,243,744	12,283,262

Table 5.28: Original gas in place estimation for Grainstone reservoir and water content 10% based on production data at lowers than 50% of depletion

Initial pressure (psi)	Original Gas in place, *G* (MCF)			
	Actual	Conventional method	Humphreys method	Modified Humphreys method
3,566	5,601,339	6,048,138	5,734,568	5,748,299
4,000	6,276,976	6,810,686	6,429,796	6,450,555
5,000	7,769,070	8,590,558	8,060,303	8,118,506
6,000	9,168,008	10,293,177	9,601,594	9,688,651
7,000	10,479,802	12,060,516	11,125,407	11,250,217
8,000	11,715,291	13,847,649	12,608,156	12,769,700

Table 5.29: Original gas in place estimation for Grainstone reservoir and water content 10% based on production data at lowers than 25% of depletion

Initial pressure (psi)	Original Gas in place, *G* (MCF)			
	Actual	Conventional method	Humphreys method	Modified Humphreys method
3,566	5,601,339	6,132,013	5,750,774	5,806,502
4,000	6,276,976	6,994,063	6,509,792	6,584,158
5,000	7,769,070	8,850,106	8,169,475	8,286,330
6,000	9,168,008	10,818,505	9,831,461	9,993,080
7,000	10,479,802	12,743,554	11,418,240	11,614,639
8,000	11,715,291	14,862,827	13,036,928	13,280,314

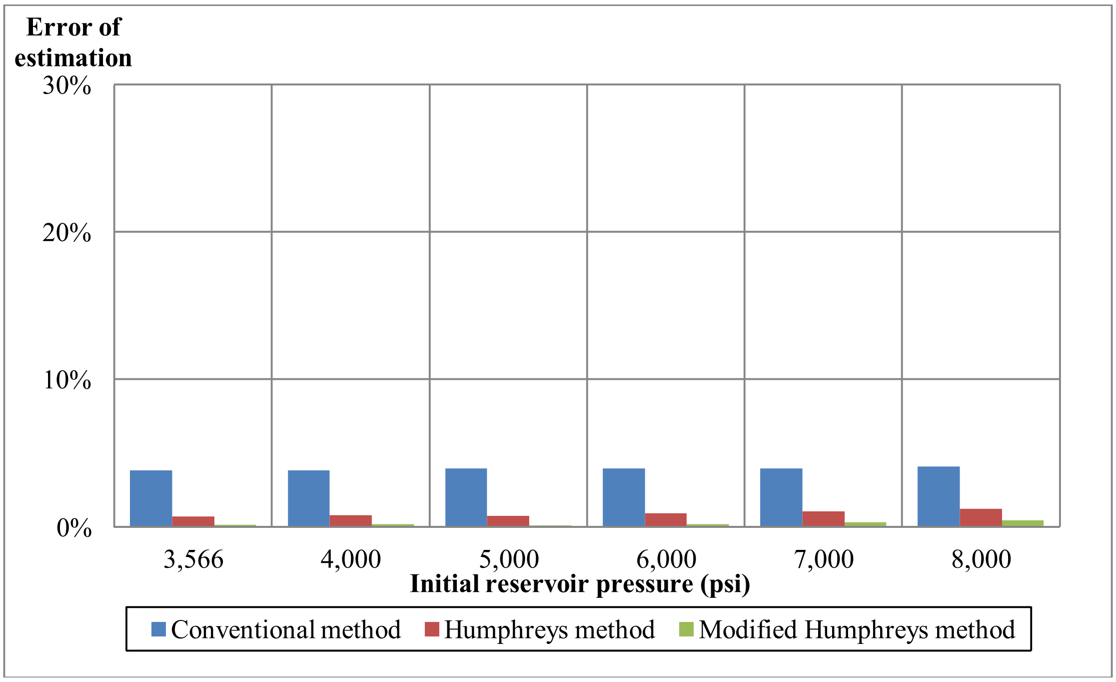

Figure 5.64: Error of *G* estimated by different method for Grainstone reservoir and water content 10% based on production data at abandonment

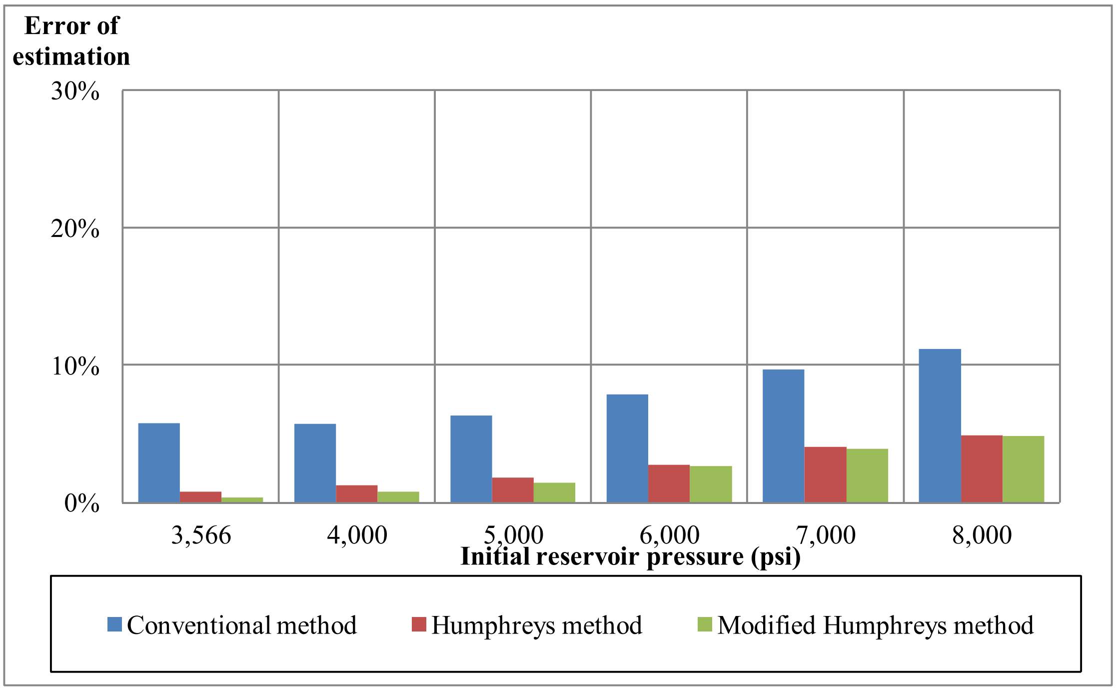

Figure 5.65: Error of *G* estimated by different method for Grainstone reservoir and water content 10% based on production data at lower than 75% pressure depletion

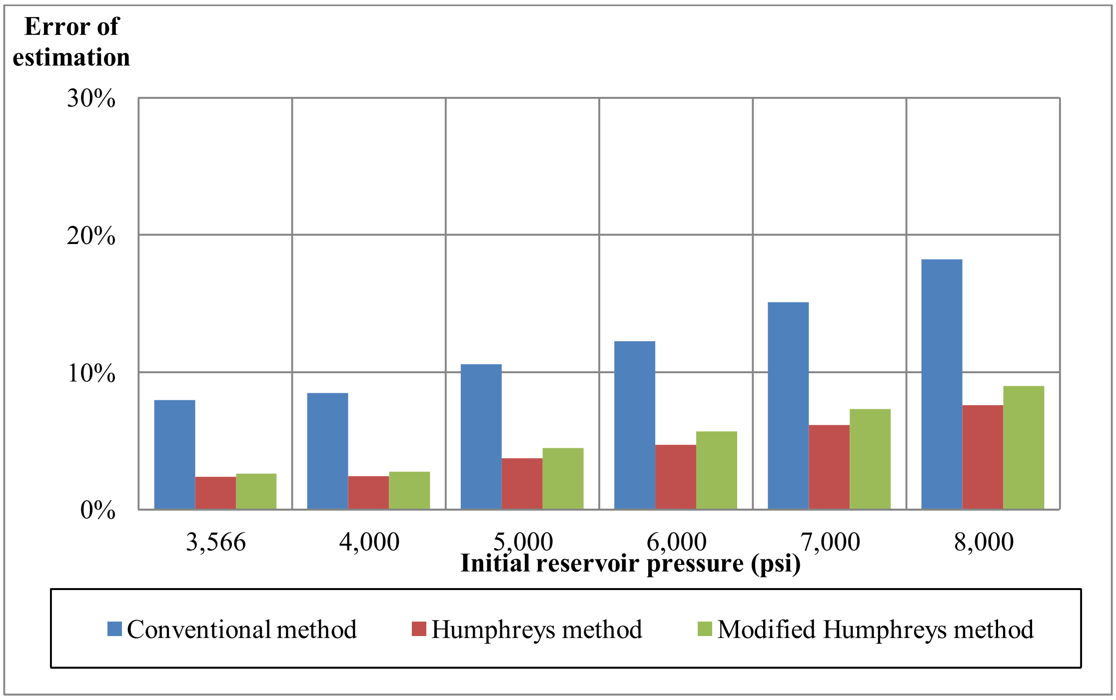

Figure 5.66: Error of *G* estimated by different method for Grainstone reservoir and water content 10% based on production data at lower than 50% pressure depletion

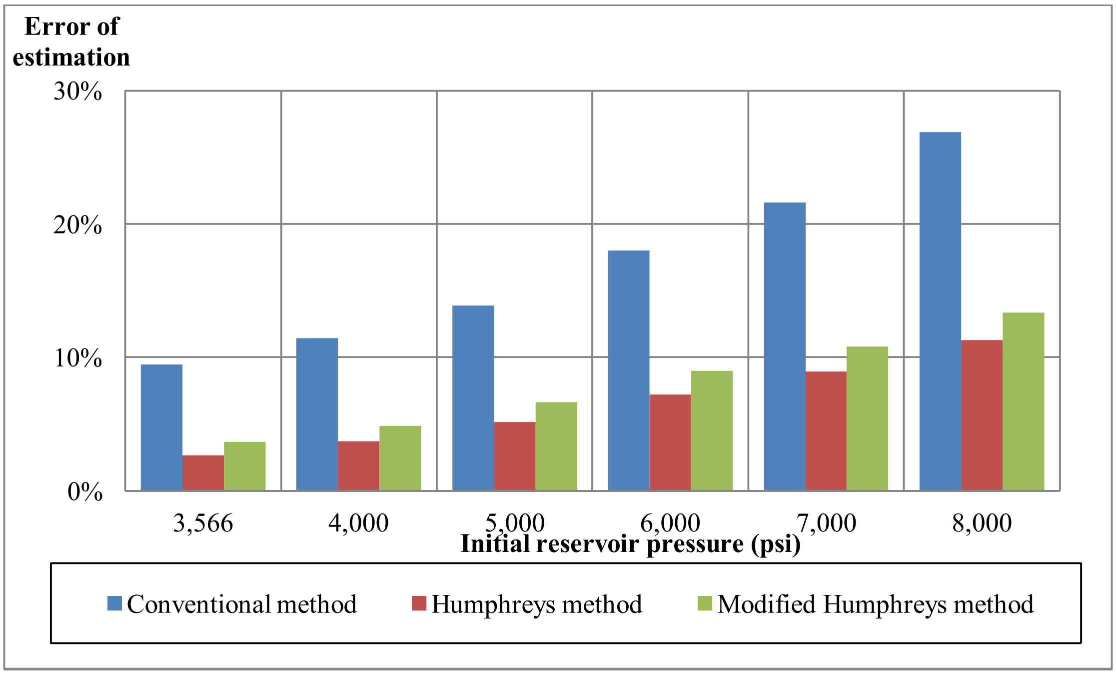

Figure 5.67: Error of *G* estimated by different method for Grainstone reservoir and water content 10% based on production data at lower than 25% pressure depletion

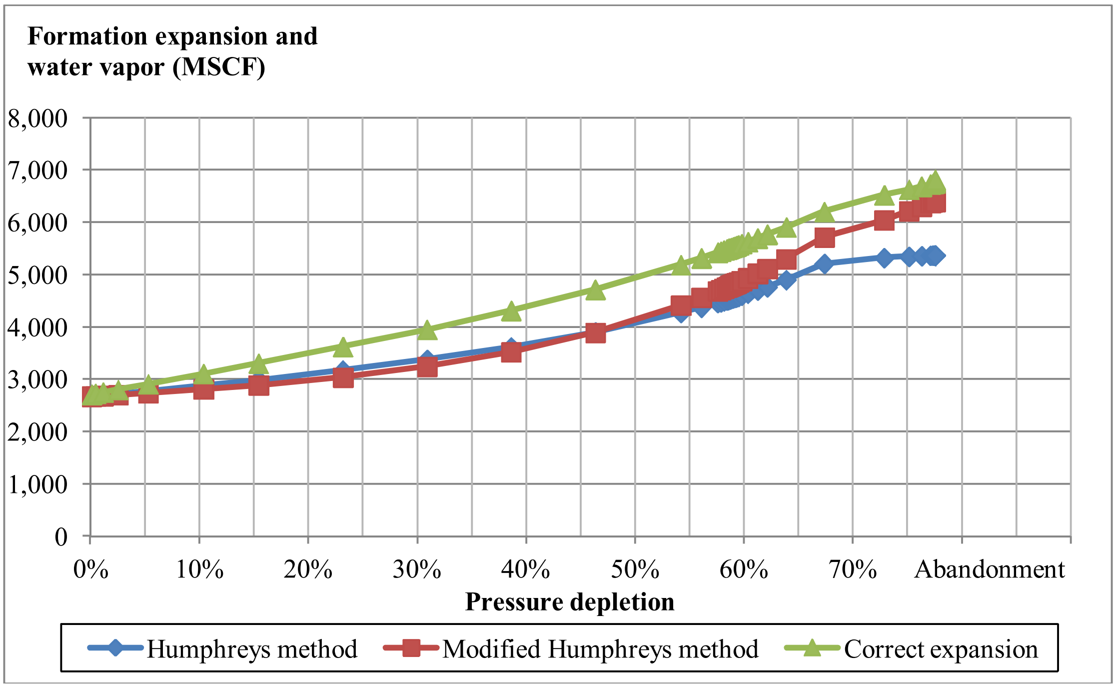

Figure 5.68: Formation expansion and water vapor for Grainstone reservoir with initial pressure 3,566 psi

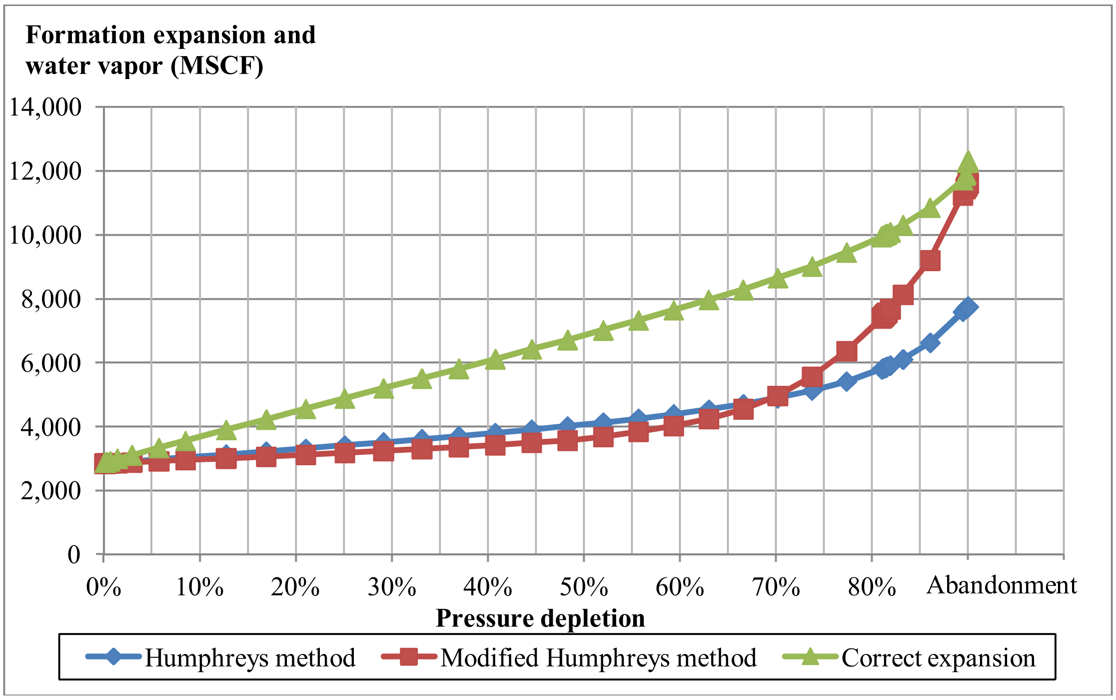

Figure 5.69: Formation expansion and water vapor for Grainstone reservoir with initial pressure 8,000 psi

Table 5.30: The number of the most accurate OGIP estimates for conventional, Humphreys and modified Humphreys method for Grainstone sandstone reservoir

	Range of production data available			
	at abandonment	75%	50%	25%
Conventional method	0	0	0	0
Humphreys method	0	0	6	6
Modified Humphreys method	6	6	0	0

5.2.3.2 Degree of depletion

The error of OGIP estimate for the three methods decreases when more production data are available. Figures 5.70-5.72 show the errors in OGIP based on different degree of depletion for the case with water content 10%. In case of conventional method as shown in Figure 5.70, the error of OGIP estimates at 25% pressure depletion and at 50% pressure depletion for a reservoir with initial pressure

3,566 psi, the error reduces from 9.47% to 7.98%. For a reservoir with initial pressure 8,000 psi, the error reduces from 26.87% to 18.20%. When the modified Humphreys method is used, the error for reservoir with initial pressure of 8,000 psi decrease from 13.36% to 9.00% when data used in the analysis are extended from 25% pressure depletion to 50% pressure depletion. A lesson learned from the results is that in the low formation compressibility reservoir, one should be aware of overestimation error when a short duration of production data is available.

In case of water content in the reservoirs 20%-50%, the trends of error when estimates using different lengths of data are the same as in the case of water content in reservoirs 10% as shown in APPENDIX A-2)

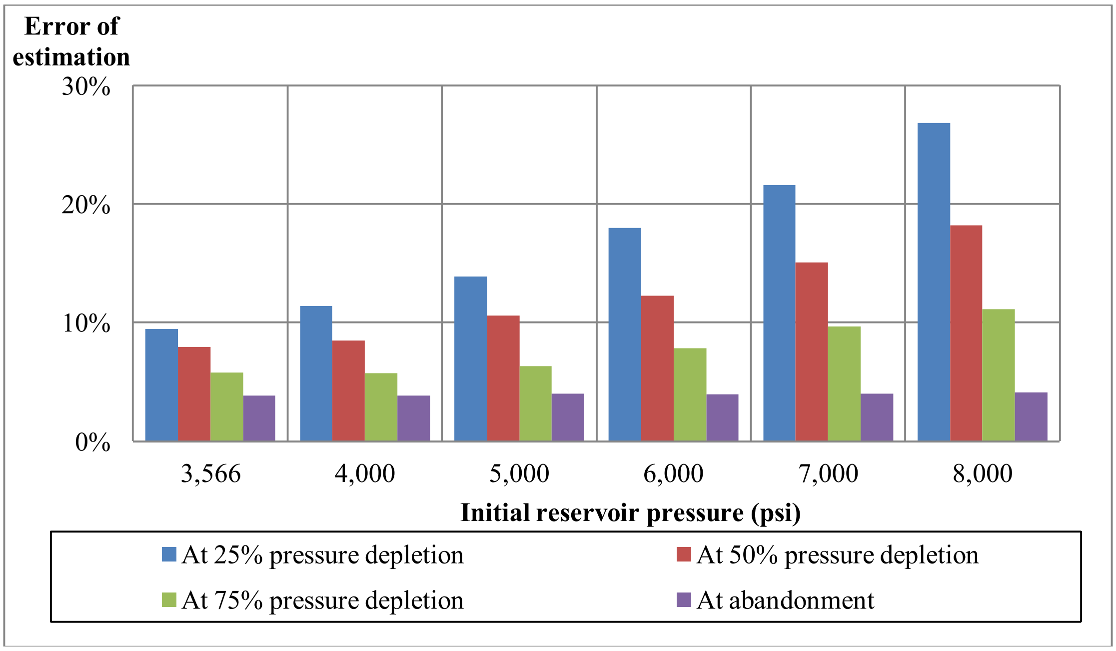

Figure 5.70: Error of *G* estimate by conventional method for Grainstone reservoir and water content 10% based on different degree of depletion

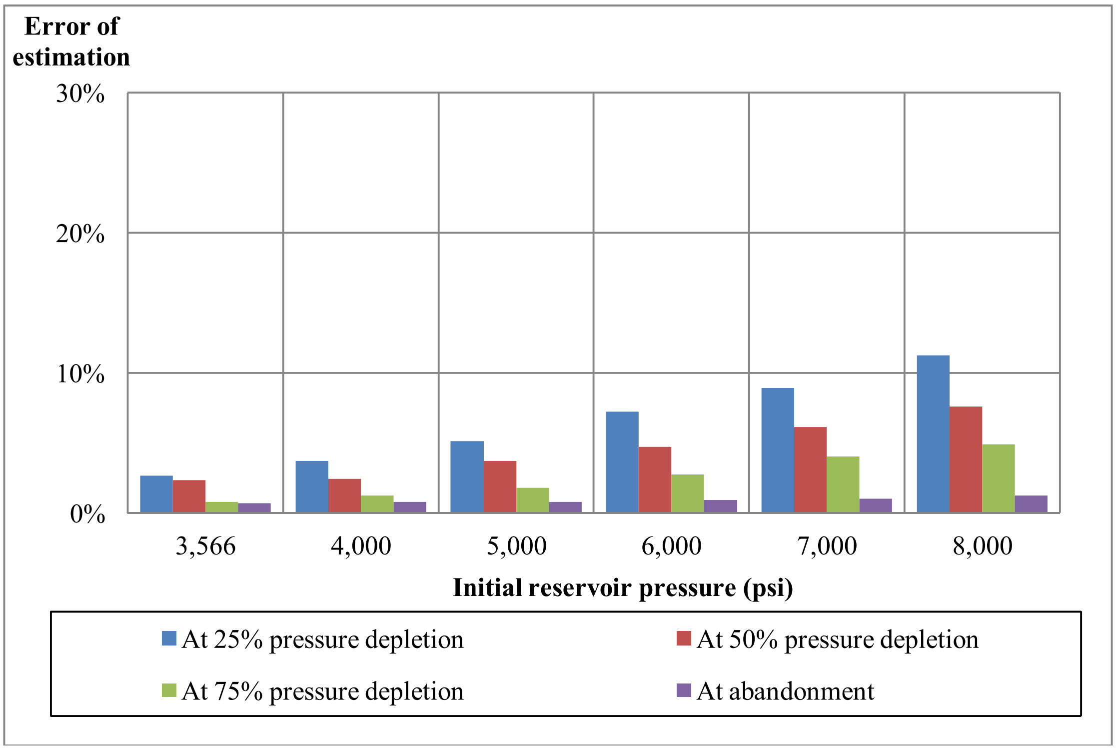

Figure 5.71: Error of *G* estimated by Humphreys method of Grainstone reservoir and water content 10% based on different degree of depletion

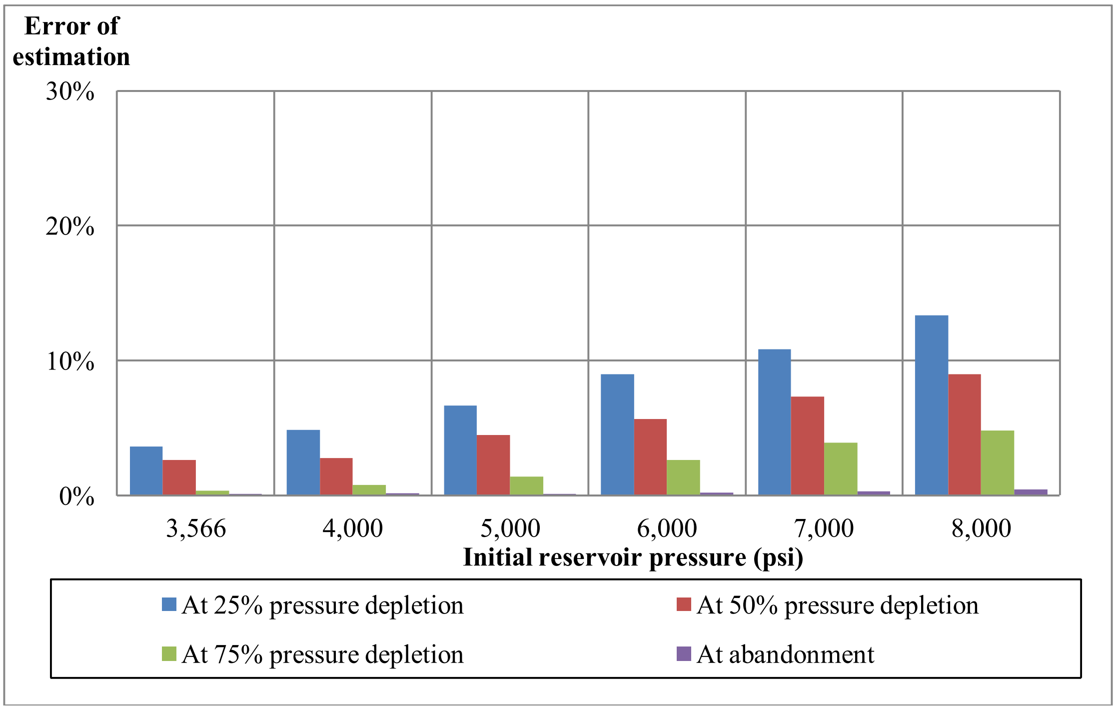

Figure 5.72: Error of *G* estimated modified Humphreys method of Grainstone reservoir and water content 10% based on different degree of depletion

5.2.3.3 Effect of initial pressure

The impact of initial reservoir pressure on OGIP estimates for Grainstone is the same trend as in cases of Santa Rosa and Berea sandstone reservoirs. As seen in Figures 5.64-5.67, the error of OGIP estimate for a reservoir with high initial pressure is higher than that for a reservoir with low initial pressure. This observation is true for all methods of analysis and all lengths of data used in the analysis. For example, in the case of modified Humphreys method, which is the most accurate method when calculate OGIP at abandonment and 75% pressure depletion, the error of OGIP estimates increase from 0.14% to 0.46% and 0.38% to 4.85%, respectively when the initial reservoir pressure is changed from 3,566 psi to 8,000 psi.

5.2.3.4 Water content

As the decline in reservoir pressure, the water vaporization impacts to OGIP estimation when have the water content in reservoir. Figures 5.73-5.75 show the example error of OGIP estimate base on different water content in reservoir from 10% to 50% when production data are available at 25% pressure depletion. In reservoirs with all initial pressure conditions, the change in water content has small effect on OGIP estimate. The errors are almost same for all water contents. For example, in Figure 5.63, when the water content increase from 10% to 50% in a reservoir with initial pressure 8,000 psi, the error from modified Humphreys method is 0.46%, 0.63%, 0.73%, 0.51, and 0.70%, respectively.

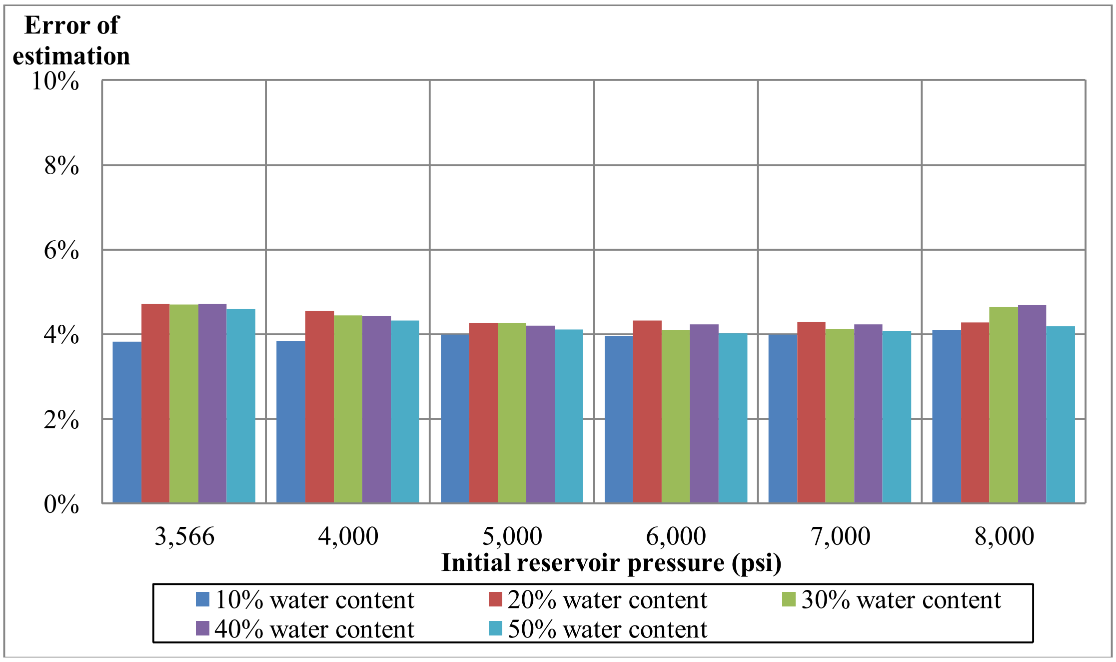

Figure 5.73: Error of G estimation by conventional method for Grainstone reservoir and different water contents based on production data at 25% pressure depletion

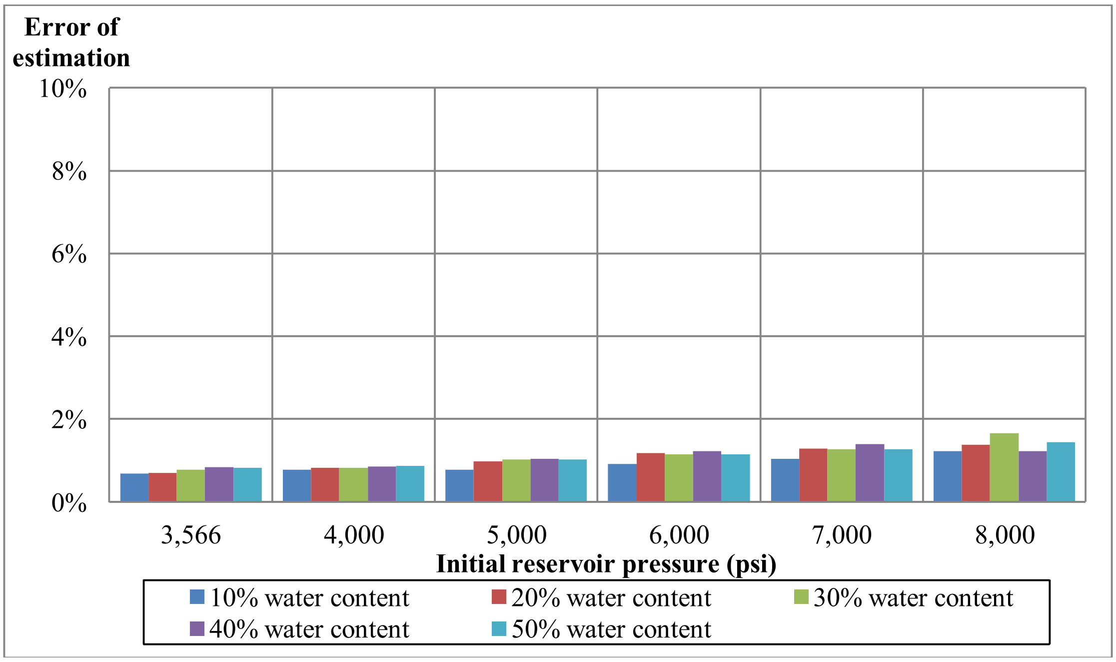

Figure 5.74: Error of G estimation by Humphreys method for Grainstone reservoir and different water contents based on production data at 25% pressure depletion

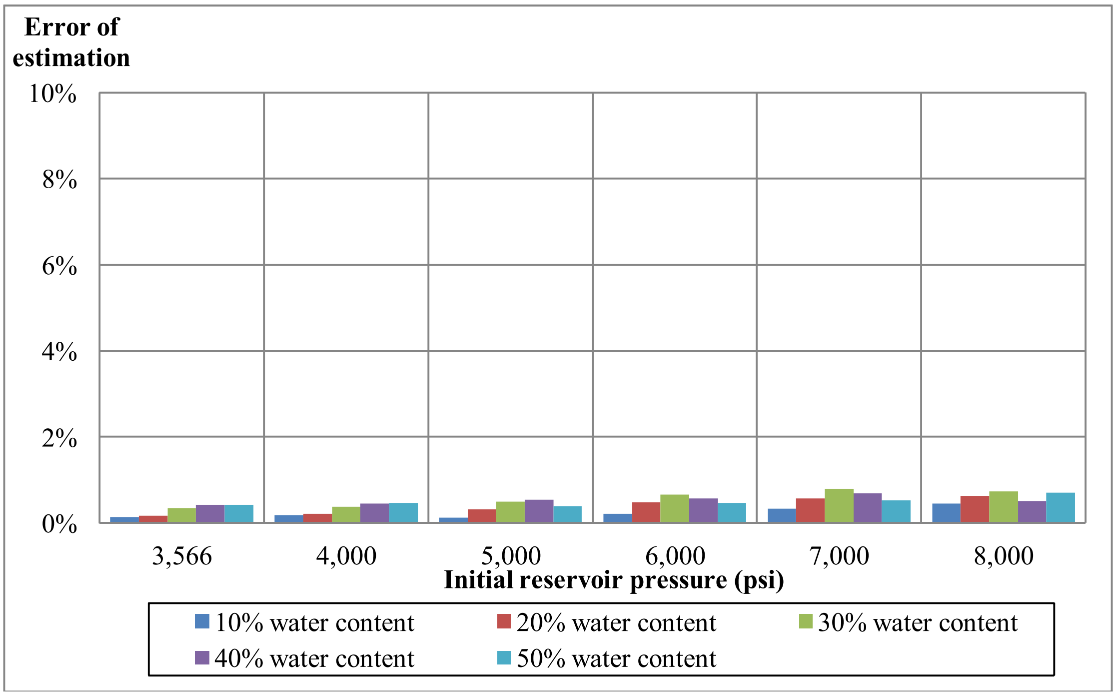

Figure 5.75: Error of *G* estimation by modified Humphreys method for Grainstone reservoir and different water contents based on production data at 25% pressure depletion

5.2.4 Effect of different rock compressibilities

As the three types of rock used in this study have different average compressibilities and different degrees of variation in compressibility as pressure decreases, the errors of OGIP estimates are different in magnitude. Figures 5.64–5.69 plot the error of OGIP estimates based on three different methods (conventional, Humphreys and modified Humphreys) with water content 10% and data at 25% pressure depletion for Santa Rosa sandstone, Berea sandstone, and Grainstone for which compressibilities are shown in Figure 5.2.

As depicted in Figure 5.76-5.81, comparing among different rocks, Grainstone yields the lowest error when conventional method is used because of its lowest compressibility variation while Berea sandstone gives the highest error due to its largest variation in compressibility. For Grainstone reservoir at initial pressure 3,566 psi, the error of OGIP estimate is 9.47% while error is 14.76% for Santa Rosa Sandstone and 21.09% for Berea sandstone.

In the Humphreys method, Santa Rosa sandstone yields the lowest error in a reservoir with low initial pressure (3,566 to 5,000 psi) and Grainstone yield the lowest error in a reservoir with high initial pressure (6,000, 7,000, and 8,000 psi) while Berea sandstone still gives the highest error due to its largest variation in compressibility. For Santa Rosa sandstone reservoir at initial pressure 3,566 psi, the error of OGIP estimate is 1.44% while the others two rocks have bigger error at 2.67% and 8.45% for Grainstone and Berea Sandstone, respectively. But at high initial pressure 8,000 psi, Grainstone reservoir gives the lowest error at 9.47%. Santa Rosa reservoir yields the second lowest error at 14.76%. And Berea sandstone reservoir yields the highest error at 21.09%.

When estimating OGIP by modified Humphreys method in a reservoir with low initial pressure (3,566 to 4,000 psi), Santa Rosa sandstone reservoir yields the lowest error at 3.33% and 4.59% respectively. Grainstone reservoir yields the second lowest error at 3.66% and 4.89%, respectively. And Berea sandstone reservoir yields the highest error at 10.56% and 11.73%, respectively. But at higher initial pressure (5,000 to 8,000 psi), Grainstone reservoir gives the lowest error. For example, in a reservoir with initial pressure 8,000 psi, Grainstone reservoir gives the lowest error at 13.36%. Santa Rosa reservoir yields the second lowest error at 19.04%. And Berea sandstone reservoir yields the highest error at 31.14%.

In case of water content in the reservoirs 20%-50%, the trends of error are the same as in the case of water content in reservoirs 10% as shown in APPENDIX A-3)

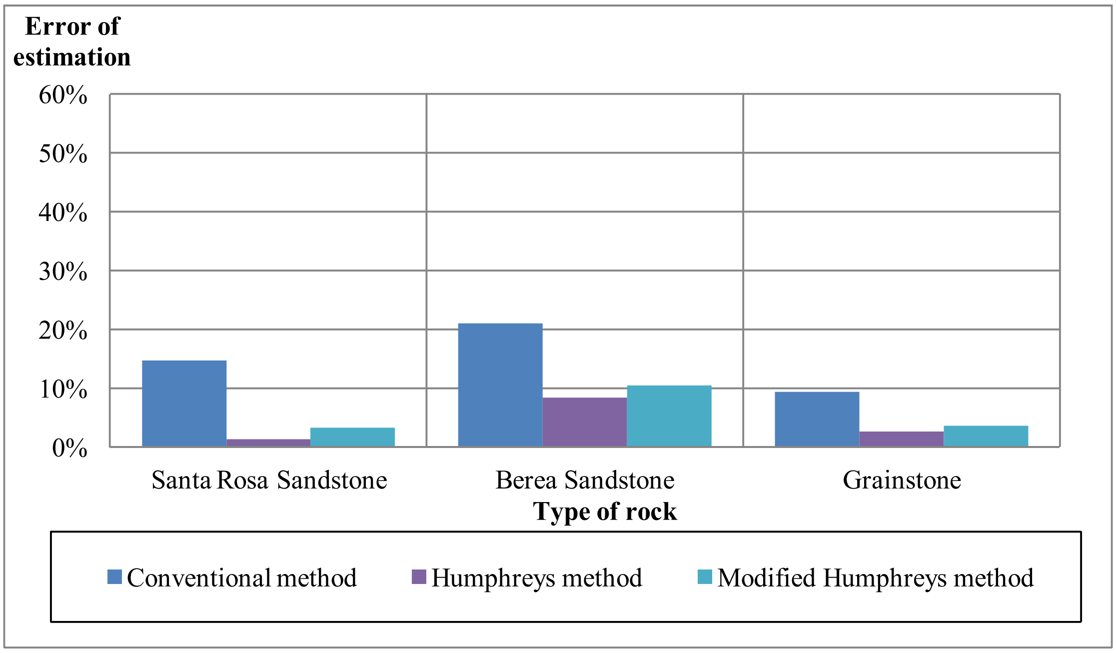

Figure 5.76: Error of G estimated by different methods for different reservoir rock at initial reservoir pressure 3,566 psi and water content 10% based on data at 25% pressure depletion

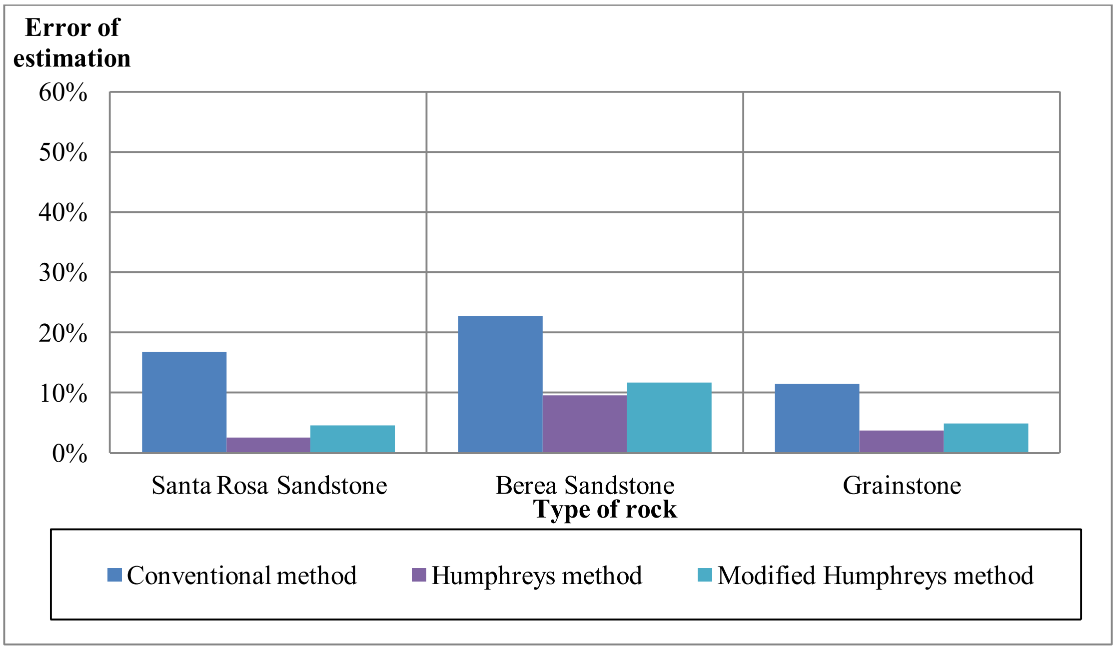

Figure 5.77: Error of G estimated by different methods for different reservoir rock at initial reservoir pressure 4,000 psi and water content 10% based on data at 25% pressure depletion

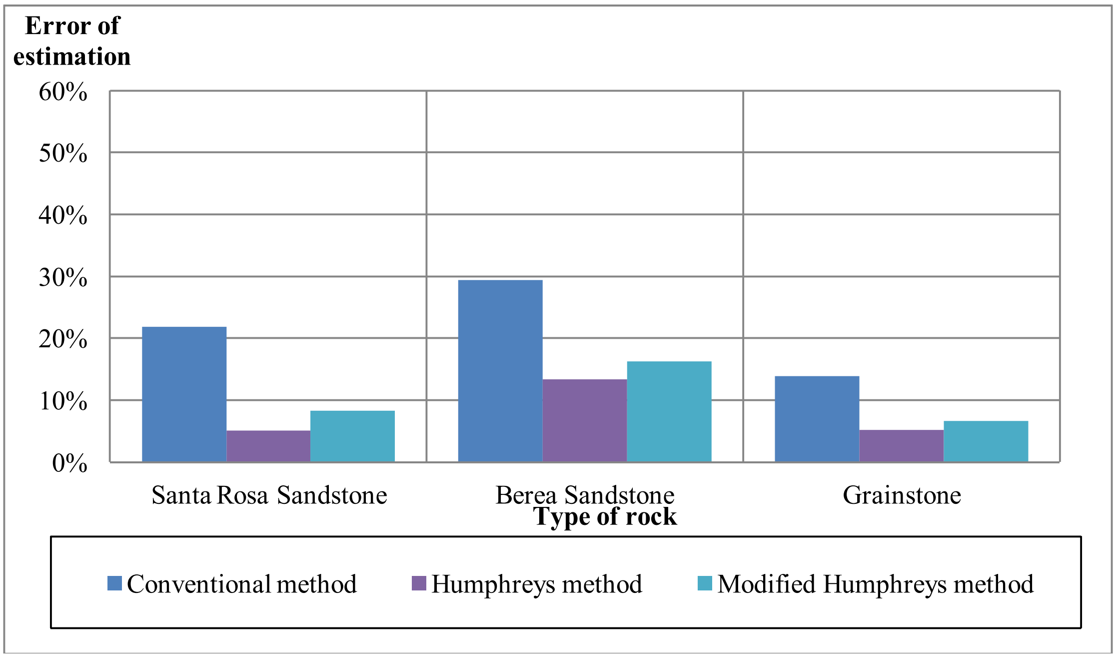

Figure 5.78: Error of *G* estimated by different methods for different reservoir rock at initial reservoir pressure 5,000 psi and water content 10% based on data at 25% pressure depletion

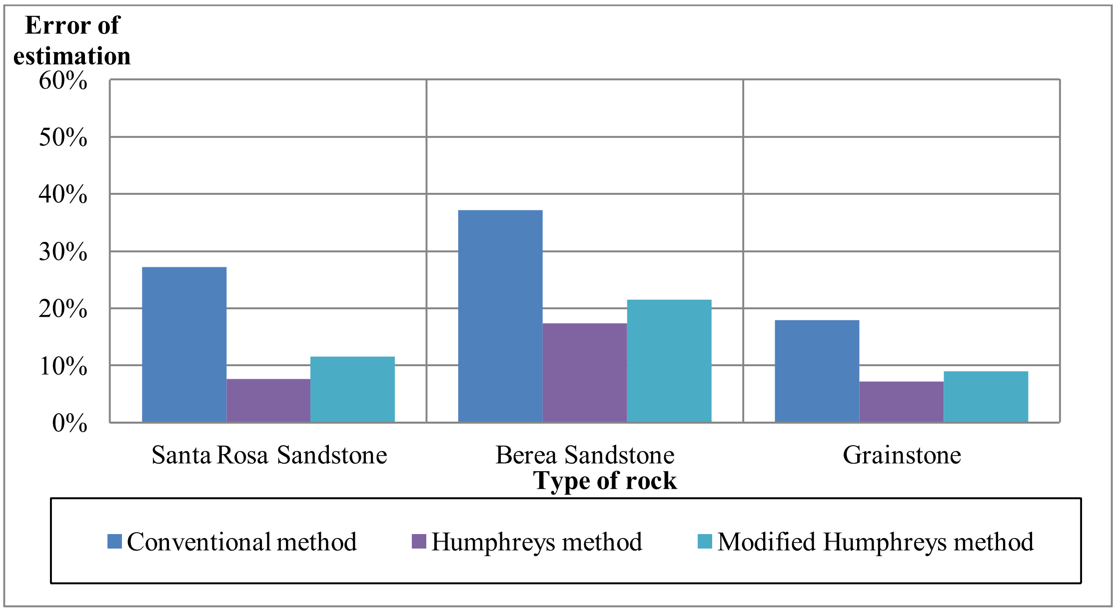

Figure 5.79: Error of *G* estimated by different methods for different reservoir rock at initial reservoir pressure 6,000 psi and water content 10% based on data at 25% pressure depletion

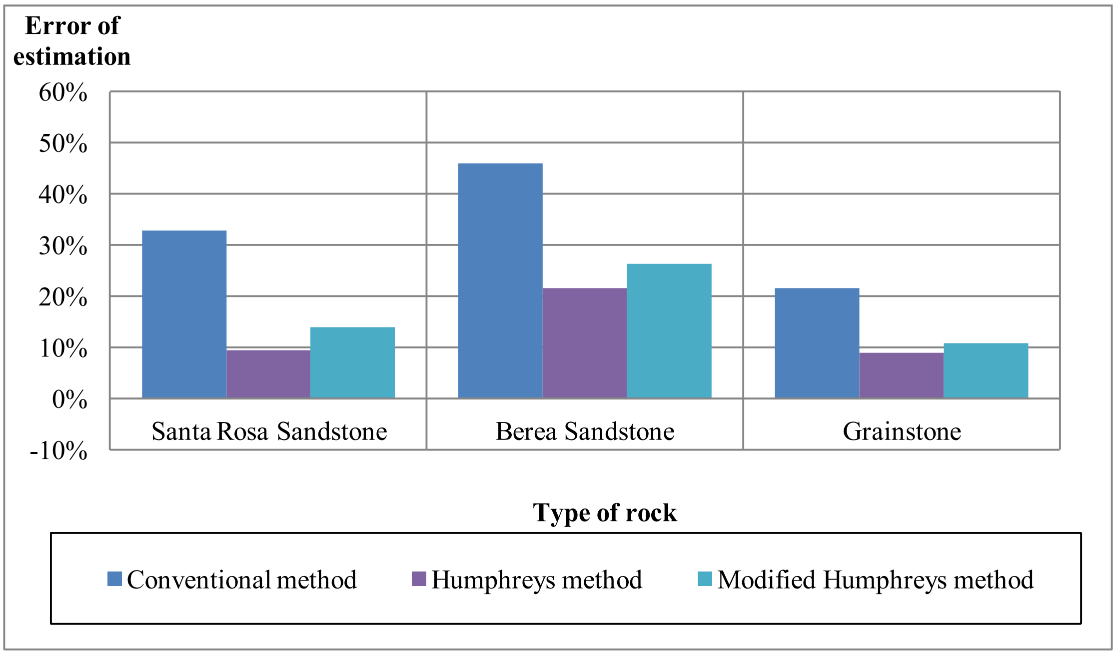

Figure 5.80: Error of *G* estimated by different methods for different reservoir rock at initial reservoir pressure 7,000 psi and water content 10% based on data at 25% pressure depletion

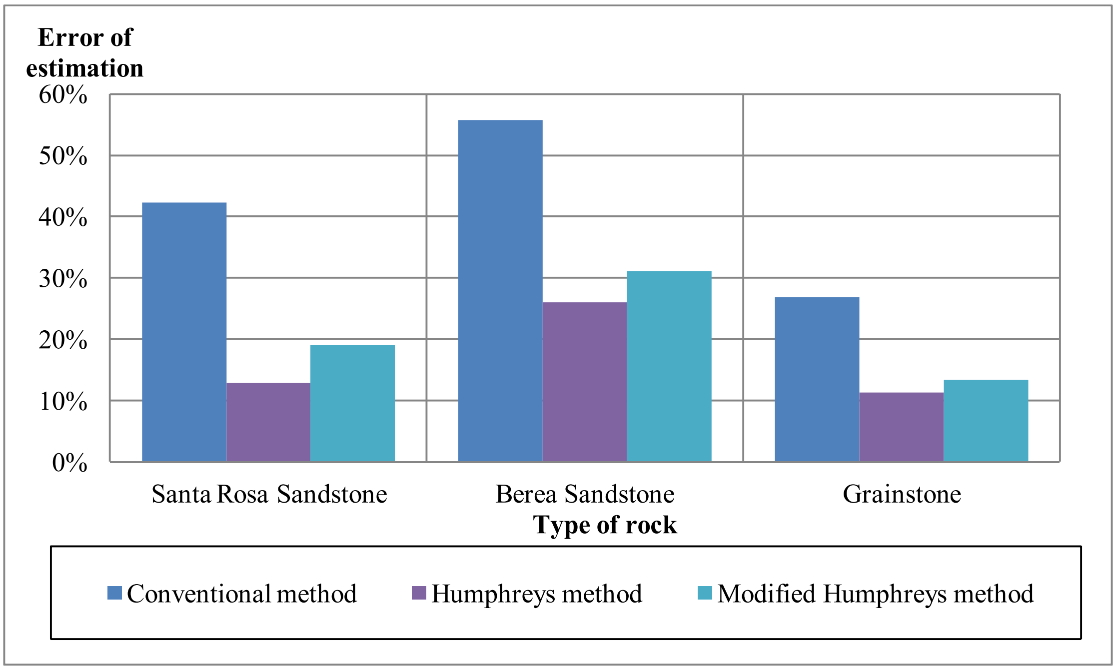

Figure 5.81: Error of *G* estimated by different methods for different reservoir rock at initial reservoir pressure 8,000 psi and water content 10% based on data at 25% pressure depletion

CHAPTER VI

CONCLUSIONS AND RECOMMENDATIONS

This chapter summarizes the effects of different parameters on OGIP estimation when the reservoir has significant water and rock compressibility and water vapor, especially in the case of high pressure reservoirs based on three different methods of analysis: conventional, Ramagost, and modified Ramagost. Recommendations for further study are also included.

6.1 Conclusions

6.1.1 Effect of water and formation compressibility

The results from the study show that conventional *p/z* method provides poor estimates of original gas in place when there is significant contribution from connate water expansion and rock expansion. The Ramagost and modified Ramagost methods can improve the estimation of original gas in place by including the effect of connate water expansion and rock expansion. The performance of the two methods for different conditions is summarized as follows:

- Exclusion of connate water and formation expansion in the material balance calculation can cause a high error in OGIP estimates. For Santa Rosa reservoir with initial pressure of 4,000 psi, the error in OGIP is around 16% when the reservoir pressure is 25% depleted. After the connate water and formation expansion are accounted for, the error is reduced to around 3% by using Ramagost method.
- In term of the best method for material balance analysis for dry-gas reservoir being affected by expansion of water and formation, the Ramagost method provides the closest estimate to actual original gas in place during early stages of depletion while the modified Ramagost method proposed in this study is best when used at later stage of production (more than 50% pressure depletion).

- As the reservoir pressure is depleted during gas production and more production data are available, estimation of original gas in place becomes more accurate. This is particularly important in the case of high pressure reservoirs. As in the reservoir with pressure 8,000 psi, the error can be as high as 55.62% (for Berea sandstone) when data at 25% pressure depletion are used. When longer production data are included, the error of OGIP is reduced.
- The initial reservoir pressure has a tremendous effect of accuracy of original gas in place estimation. The higher the initial pressure, the higher the error in OGIP estimate are obtained from the three methods (conventional, Ramagost, and modified Ramagost). This is due to larger variation in water and rock compressibility as the reservoir pressure declines. Thus, one should be aware of higher magnitudes of error when dealing with high pressure reservoirs.
- In term of rock compressibility, rock with high degree of compressibility variation as the reservoir pressure declines has high error in the estimate of original gas in place.

6.1.2 Effect of formation compressibility and water vapor

When there is significant contribution from water vapor and rock expansion in a dry gas reservoir, the results from the study show that conventional p/z method provides poor estimates of original gas in place. The Humphreys and modified Humphreys methods can improve the estimation of original gas in place by including the effect of water vapor and rock expansion. The performance of the two methods for different conditions is summarized as follows:

- Exclusion of formation expansion and water vapor in the material balance calculation can cause a high error in OGIP estimates. For Santa Rosa sandstone reservoir with initial pressure of 4,000 psi, the error in OGIP is around 17% when the reservoir pressure is 25% depleted. After the formation expansion and water vapor are accounted for, the error is reduced to around 3% by using Humpheys method.

- In term of the best method for material balance analysis for dry gas reservoir being affected by expansion of formation and water vapor, the Humphreys method provides the closest estimate to actual original gas in place during early stages of depletion while the modified Humphreys method proposed in this study is best when used at later stage of production (more than 50% pressure depletion).
- As the reservoir pressure is depleted during gas production, estimation of original gas in place becomes more accurate as more production data are available.
- The initial reservoir pressure has a tremendous effect of accuracy of original gas in place estimation. The higher the initial pressure, the higher the error in OGIP estimate are obtained from the three methods (conventional, Humphreys, and modified Humphreys). This is due to larger variation in rock compressibility as the reservoir pressure declines. Thus, one should be aware of higher magnitudes of error when dealing with high pressure reservoirs.
- In term of water content, the variation of water content in reservoir does not have much effect on material balance analysis when it is included in the material balance calculation. Due to phase equilibrium between vapor and liquid water, the mole fraction of water vapor is the same for all variations of water content in the reservoir. Thus, the error of OGIP estimate is insensitive to variation of water content. However, the water content still needs to account for
- In term of rock compressibility, rock with high degree of compressibility variation when the reservoir pressure declines has high error in the estimate of original gas in place.

Thus, it is recommended that reservoir engineers responsible for reserve estimation should use Ramagost or modified Ramagost method when the reservoir has significant effect of water and formation expansion and Humphreys or modified Humpheys methods when there is water content in the reservoir to minimize error of

OGIP estimation. Also OGIP estimates need to be update as more production data become available.

6.2 Recommendations

The assumptions used in this study such as homogeneous reservoir properties, formation compressibility and temperature are specifically made in the simulation setup. The results and discussions are limited to these assumptions. In order to study the effects of connate water expansion, formation expansion, and water vapor, we recommend the followings:

- Local sections of production data may be analyzed in the determination of OGIP in the *p/z* plot. In this study, we always include data from the beginning of the production in the analysis. However, we observed in this study that the *p/z* plot under the effect of connate water expansion, formation expansion, and water vapor is not a straight line. It tends to curve towards the correct OGIP at late time. Therefore, using only the latest production data in the *p/z* plot might provide better results.
- Effect of heterogeneity in the reservoir properties such as permeability may have an effect in OGIP estimation. Further study is needed.

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APPENDICES

APPENDIX A

A-1) Error of original gas in place estimated by different methods for reservoirs with significant formation compressibility and water vapor

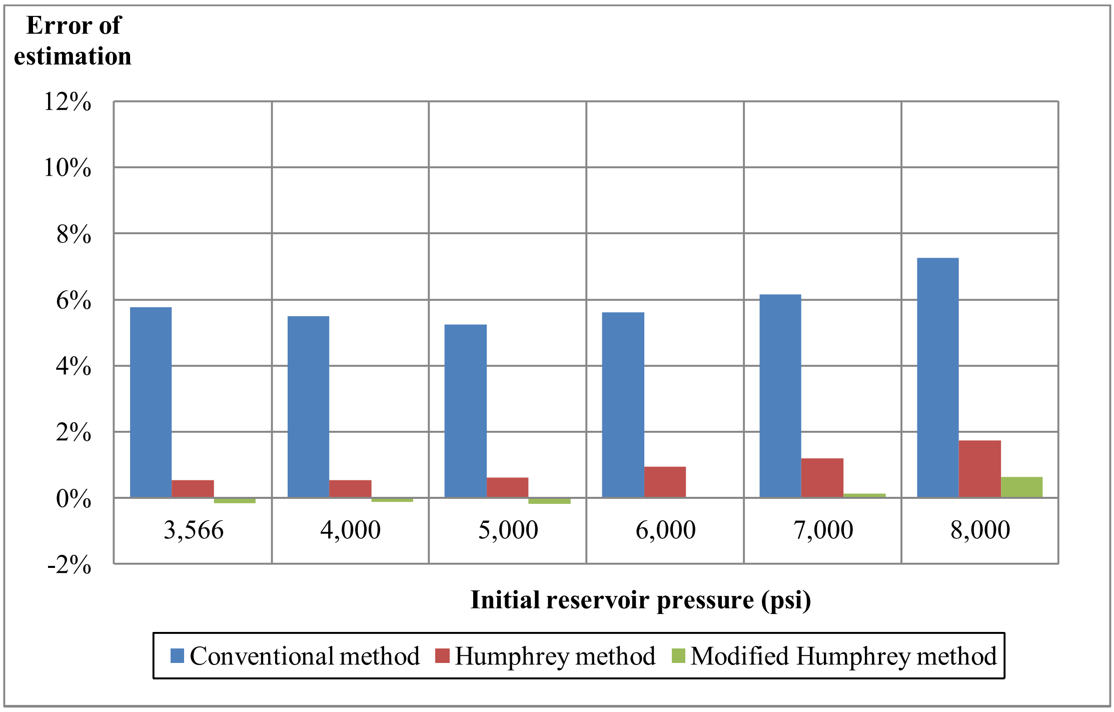

Figure A-1. 1: Error of *G* estimated by different methods for Santa Rosa sandstone reservoir and water content 20% based on production data at abandonment.

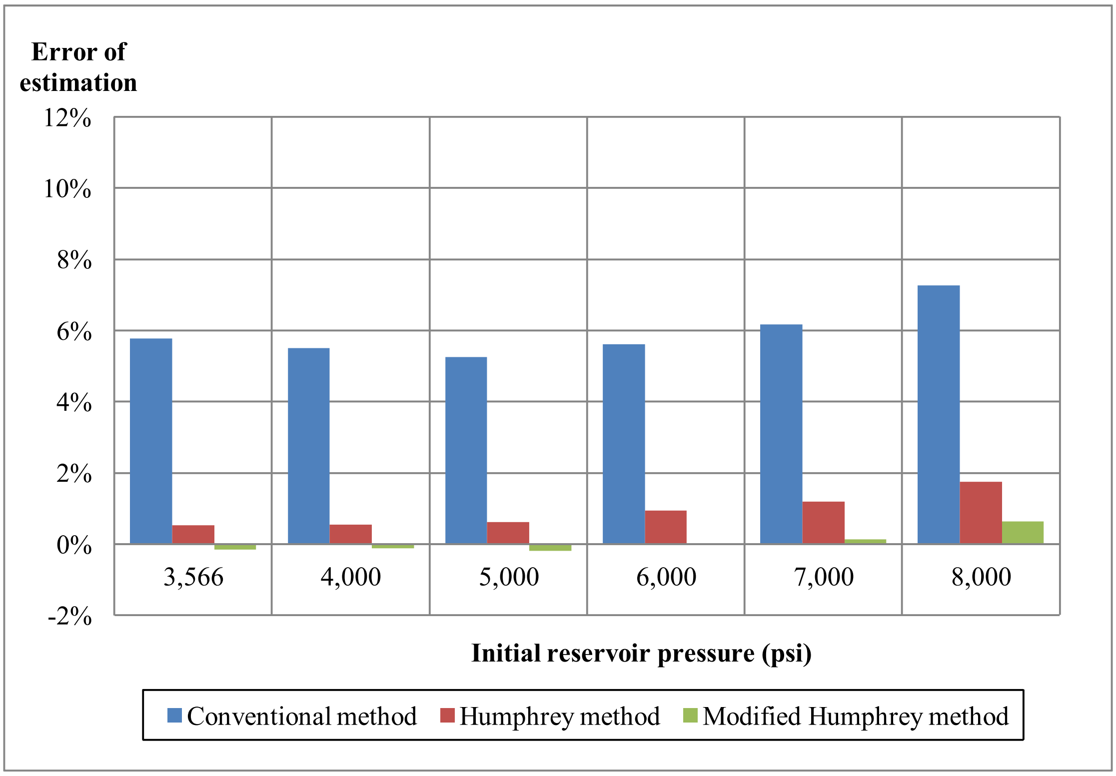

Figure A-1.2: Error of *G* estimated by different methods for Santa Rosa sandstone reservoir and water content 30% based on production data at abandonment.

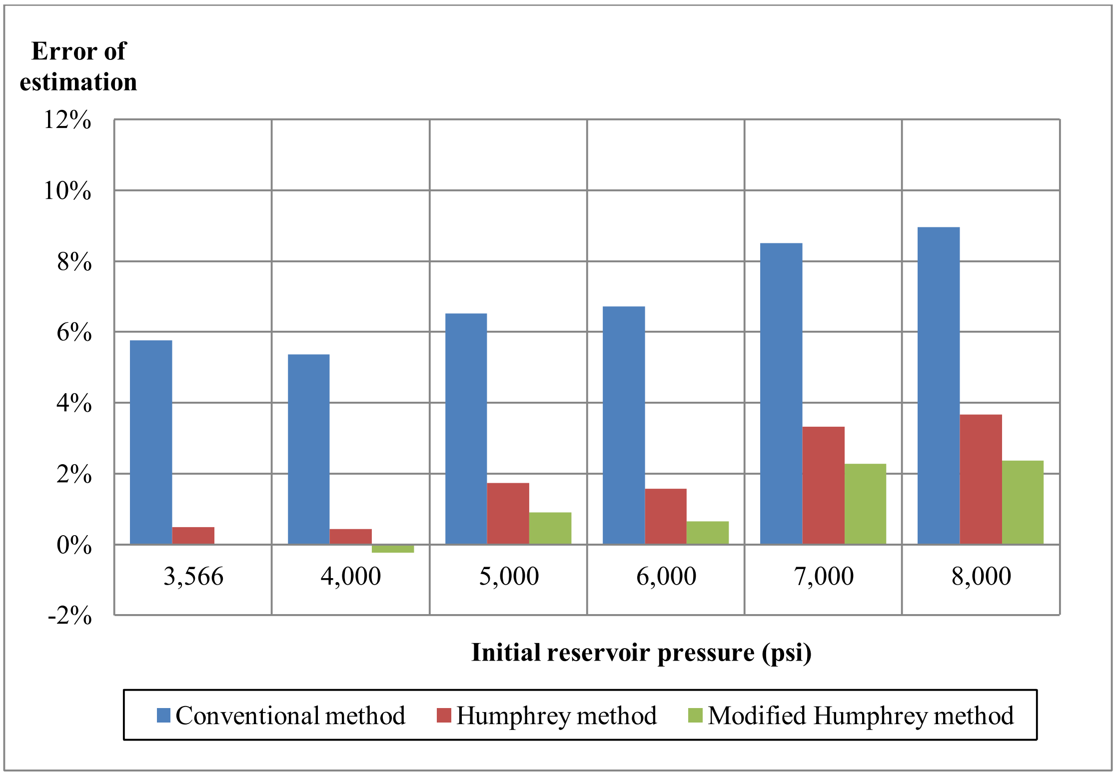

Figure A-1.3: Error of *G* estimated by different methods for Santa Rosa sandstone reservoir and water content 40% based on production data at abandonment.

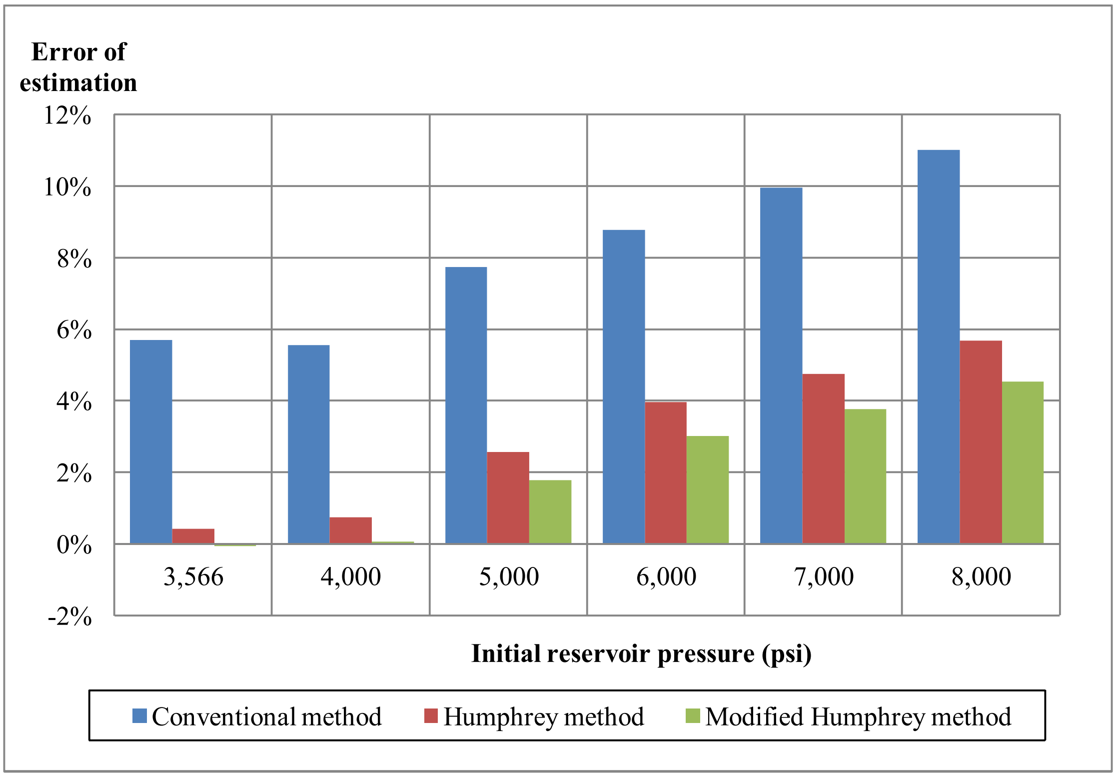

Figure A-1.4: Error of G estimated by different methods for Santa Rosa sandstone reservoir and water content 50% based on production data at abandonment.

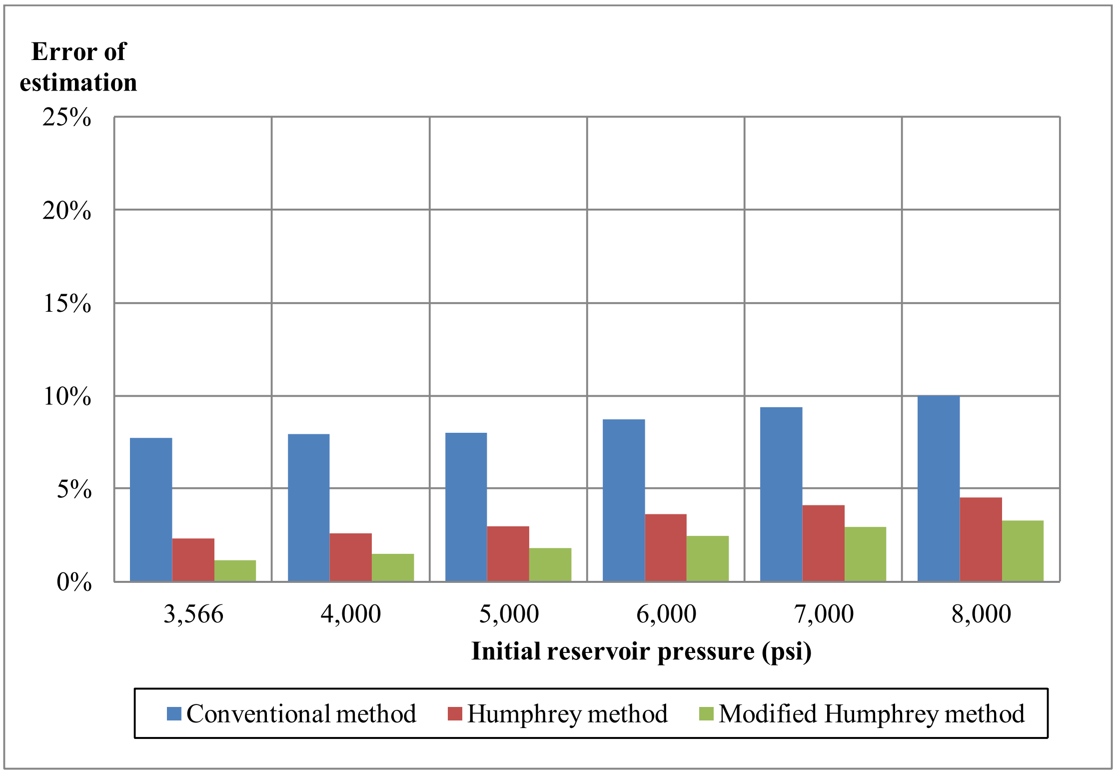

Figure A-1.5: Error of G estimated by different methods for Berea sandstone reservoir and water content 20% based on production data at abandonment.

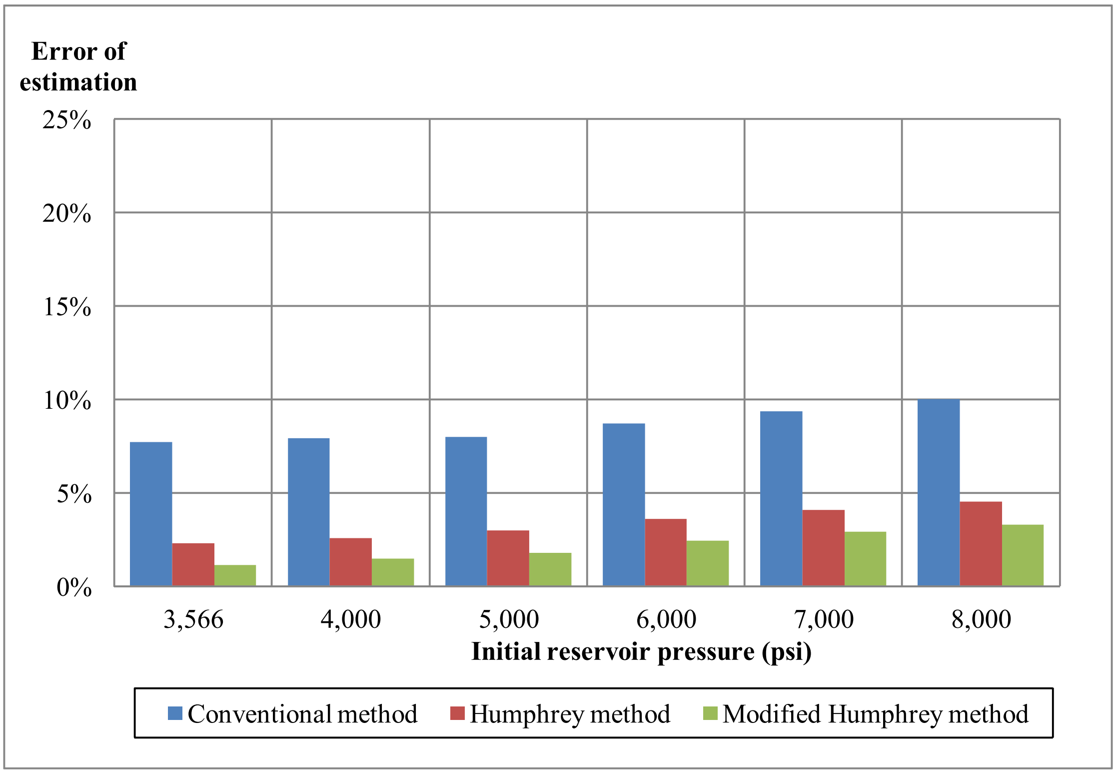

Figure A-1.6: Error of *G* estimated by different methods for Berea sandstone reservoir and water content 30% based on production data at abandonment.

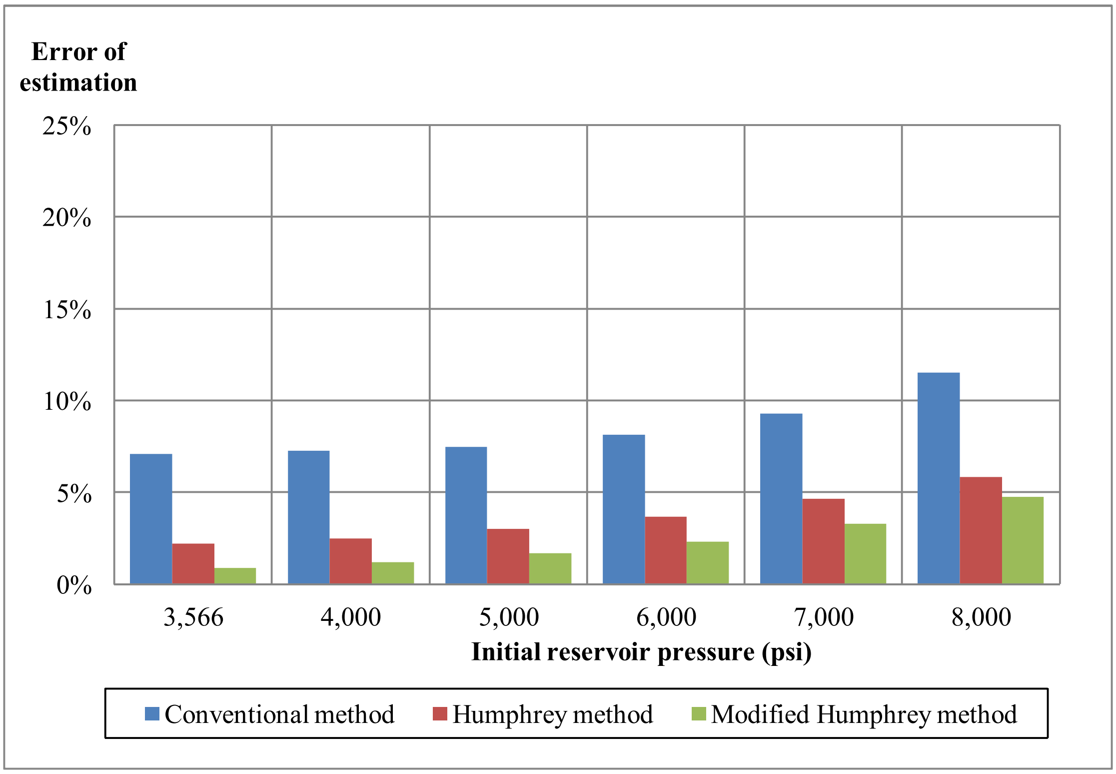

Figure A-1.7: Error of *G* estimated by different methods for Berea sandstone reservoir and water content 40% based on production data at abandonment.

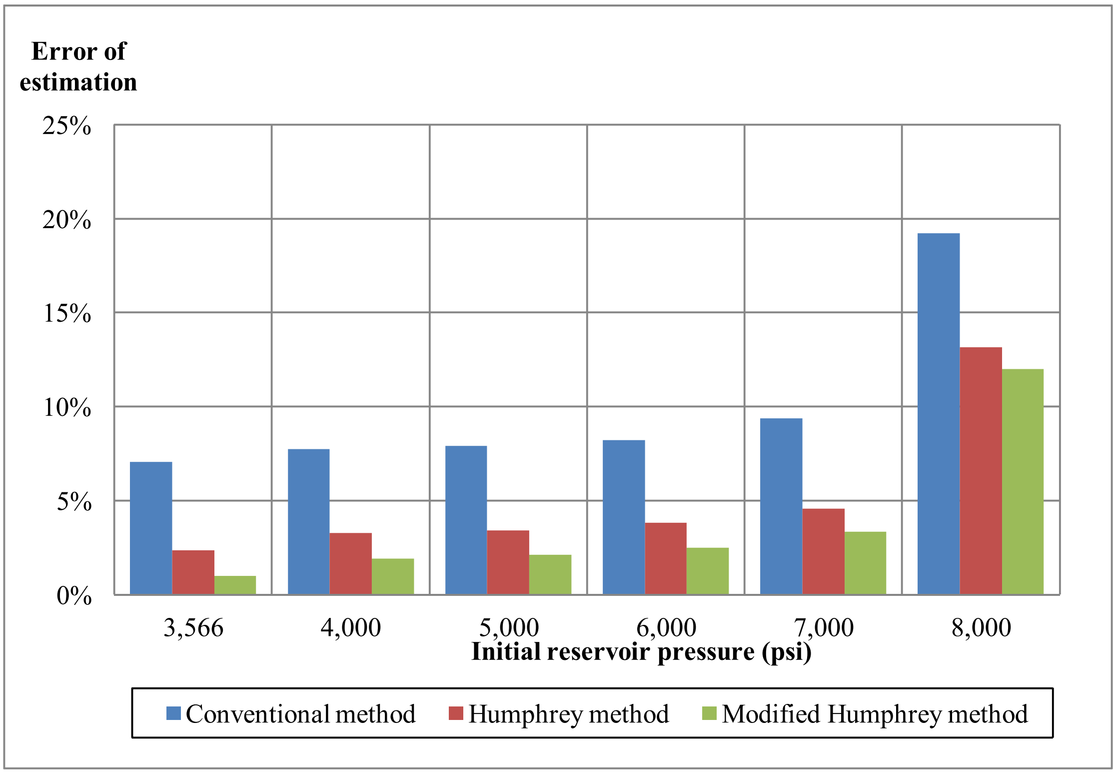

Figure A-1.8: Error of *G* estimated by different methods for Berea sandstone reservoir and water content 50% based on production data at abandonment.

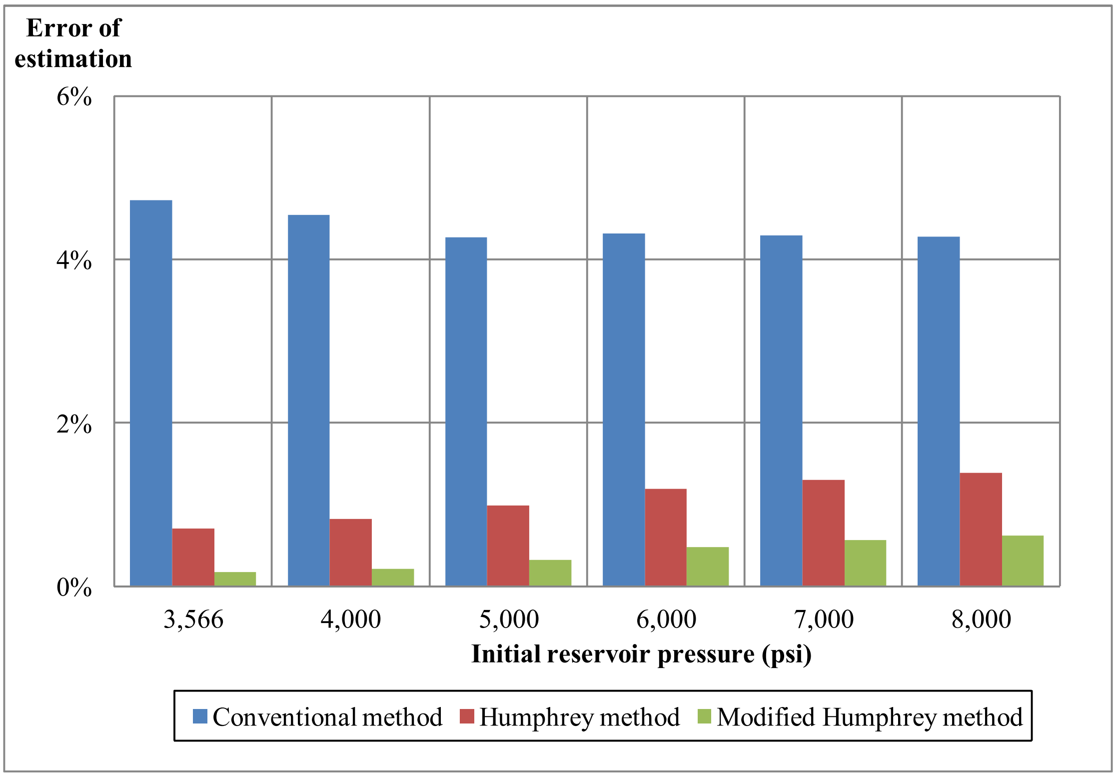

Figure A-1.9: Error of *G* estimated by different methods for Grainstone reservoir and water content 20% based on production data at abandonment.

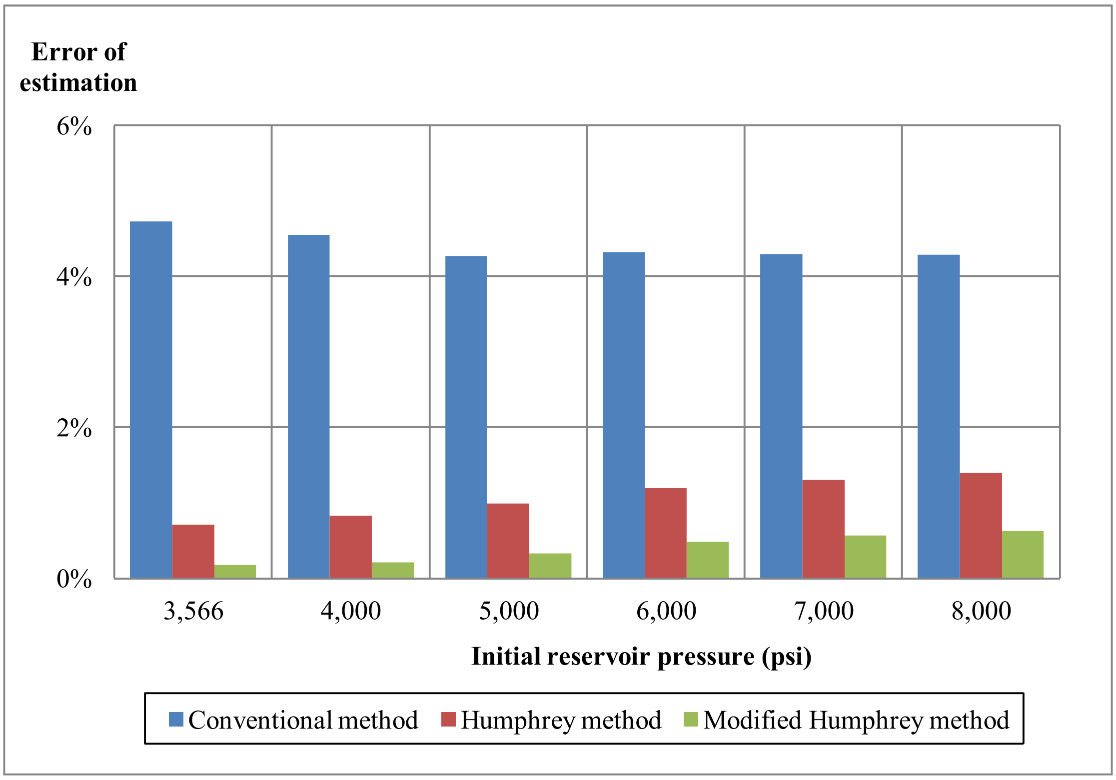

Figure A-1.10: Error of G estimated by different methods for Grainstone reservoir and water content 30% based on production data at abandonment.

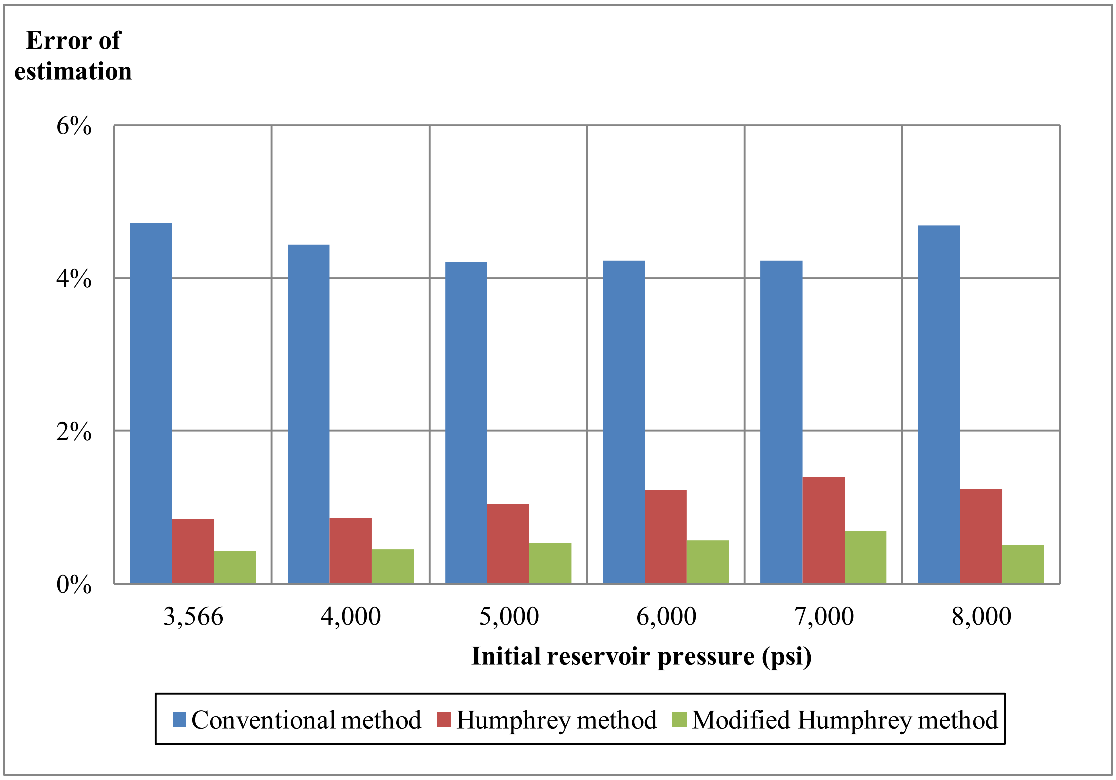

Figure A-1.11: Error of G estimated by different methods for Grainstone reservoir and water content 40% based on production data at abandonment.

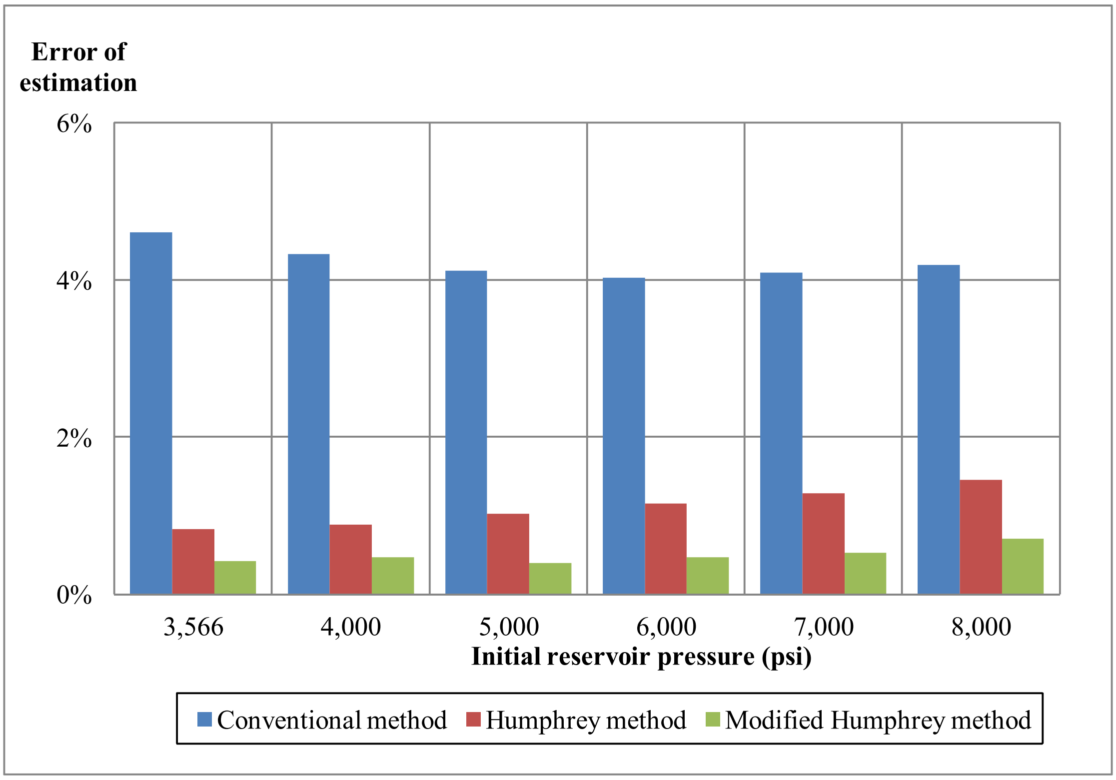

Figure A-1.12: Error of *G* estimated by different methods for Grainstone reservoir and water content 50% based on production data at abandonment.

A-2) Error of original gas in place estimation for reservoirs with significant rock compressibility and water vapor base on different length of data

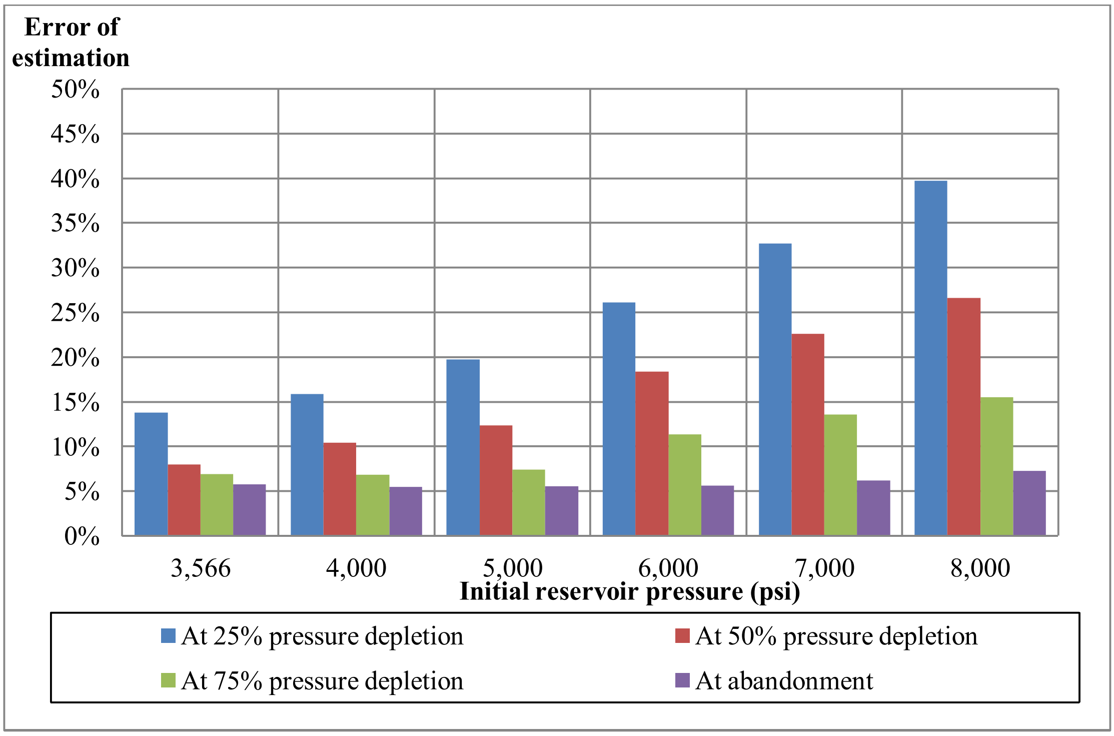

Figure A-2.1: Error of *G* estimated by conventional methods for Santa Rosa sandstone reservoir and water content 20% based on different lengths of data.

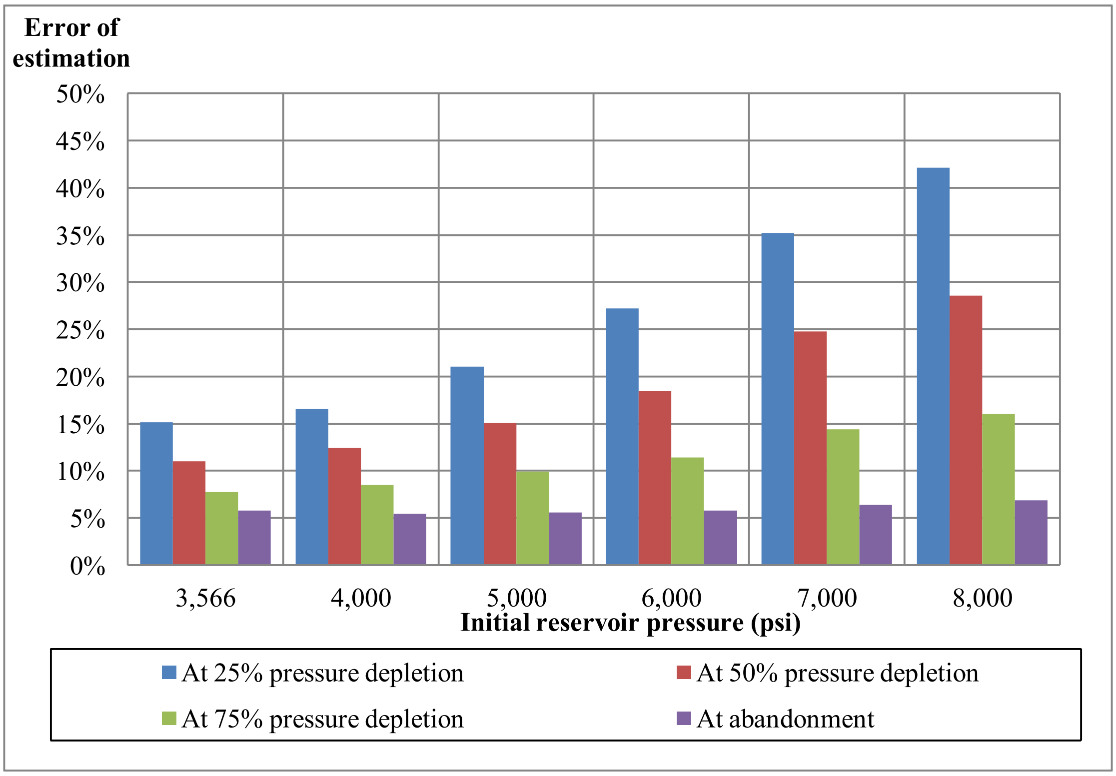

Figure A-2.2: Error of *G* estimated by conventional methods for Santa Rosa sandstone reservoir and water content 30% based on different lengths of data.

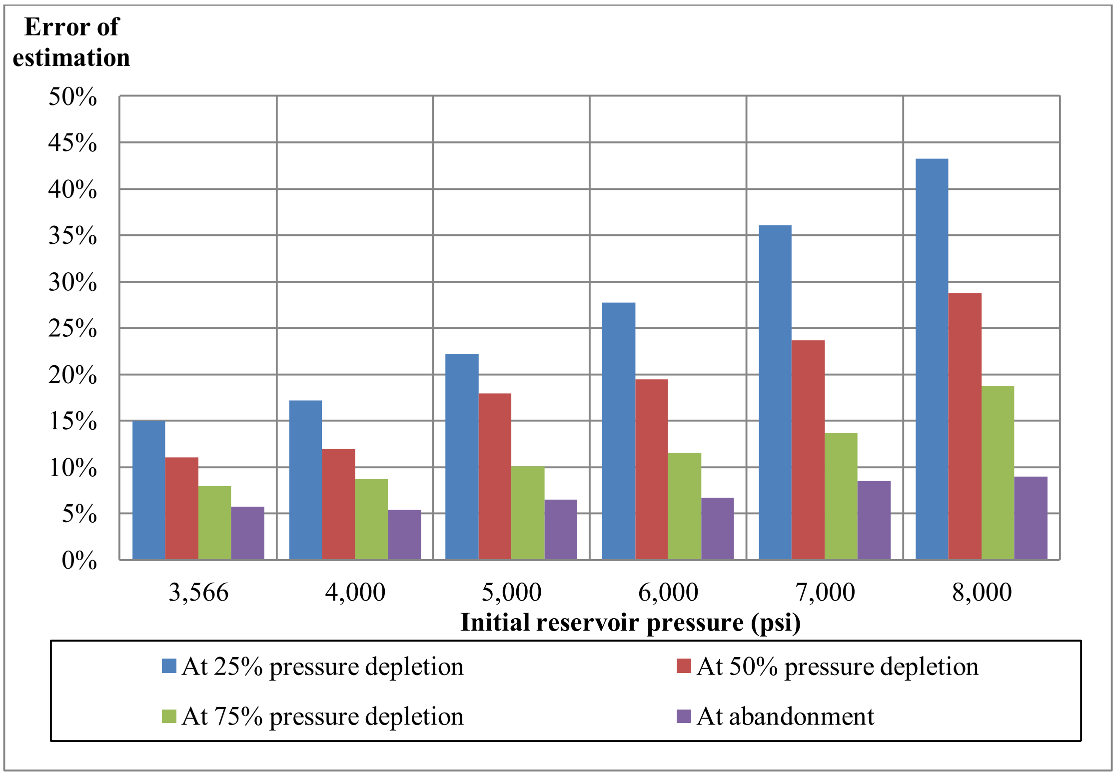

Figure A-2.3: Error of *G* estimated by conventional methods for Santa Rosa sandstone reservoir and water content 40% based on different length of data.

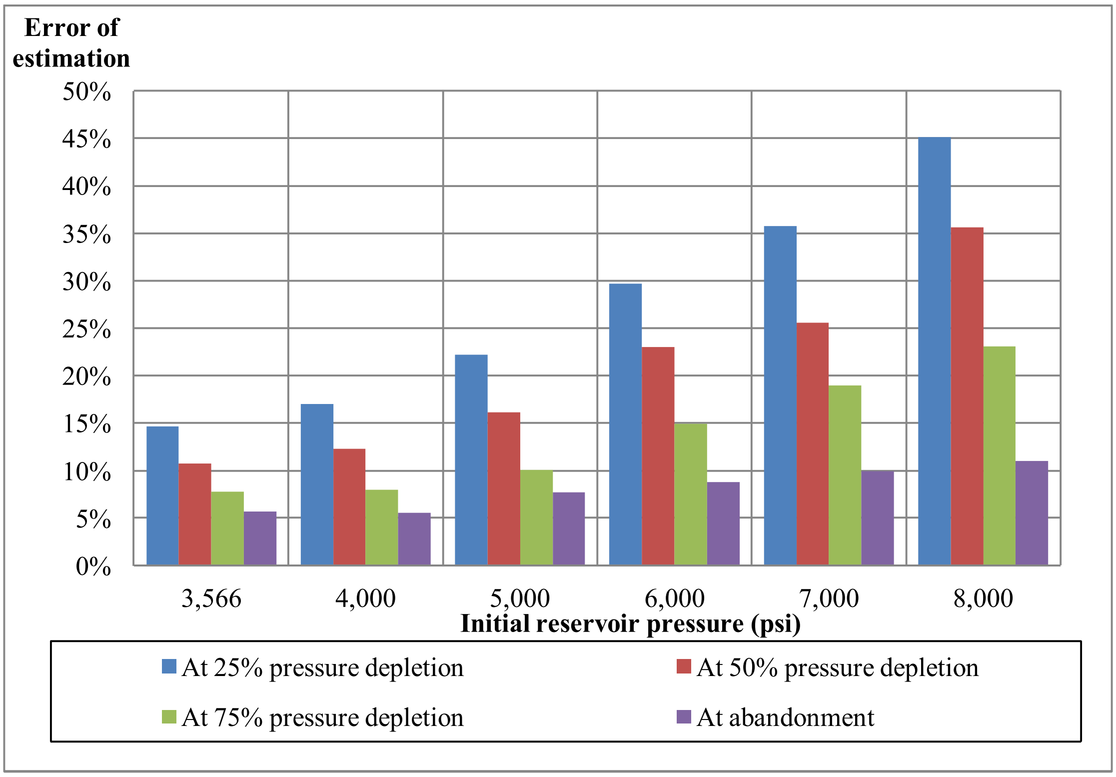

Figure A-2.4: Error of *G* estimated by conventional methods for Santa Rosa sandstone reservoir and water content 50% based on different length of data.

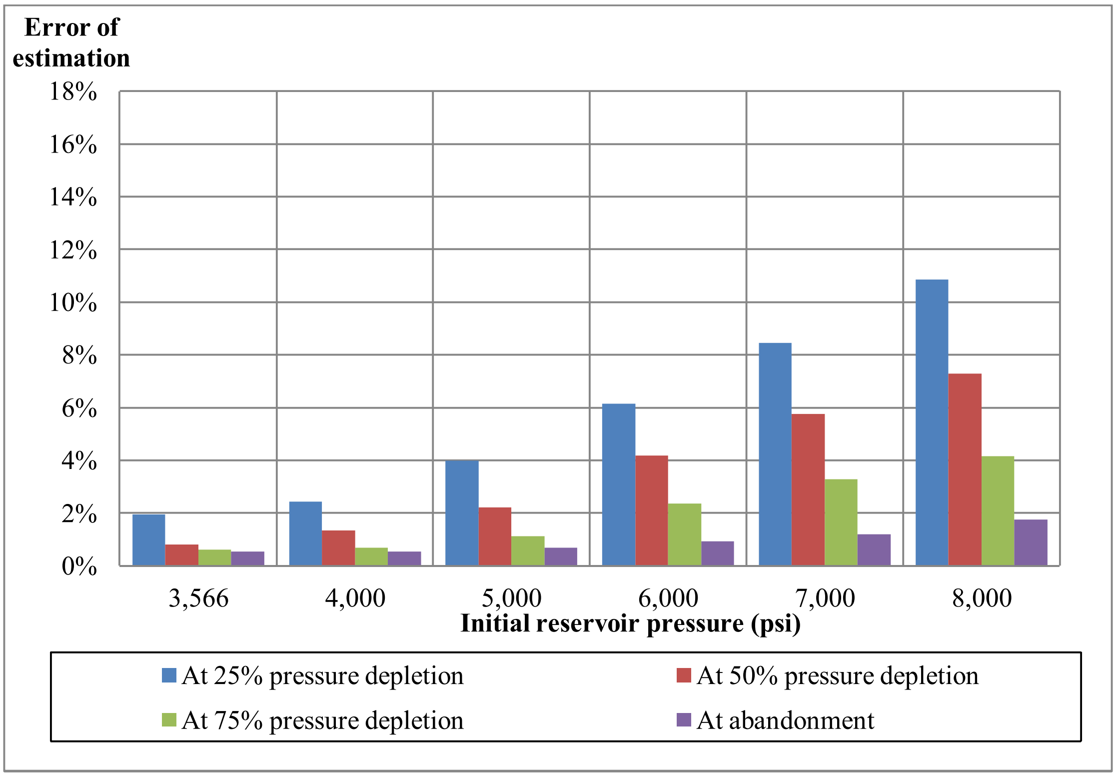

Figure A-2.5: Error of *G* estimated by Humphreys methods for Santa Rosa sandstone reservoir and water content 20% based on different length of data.

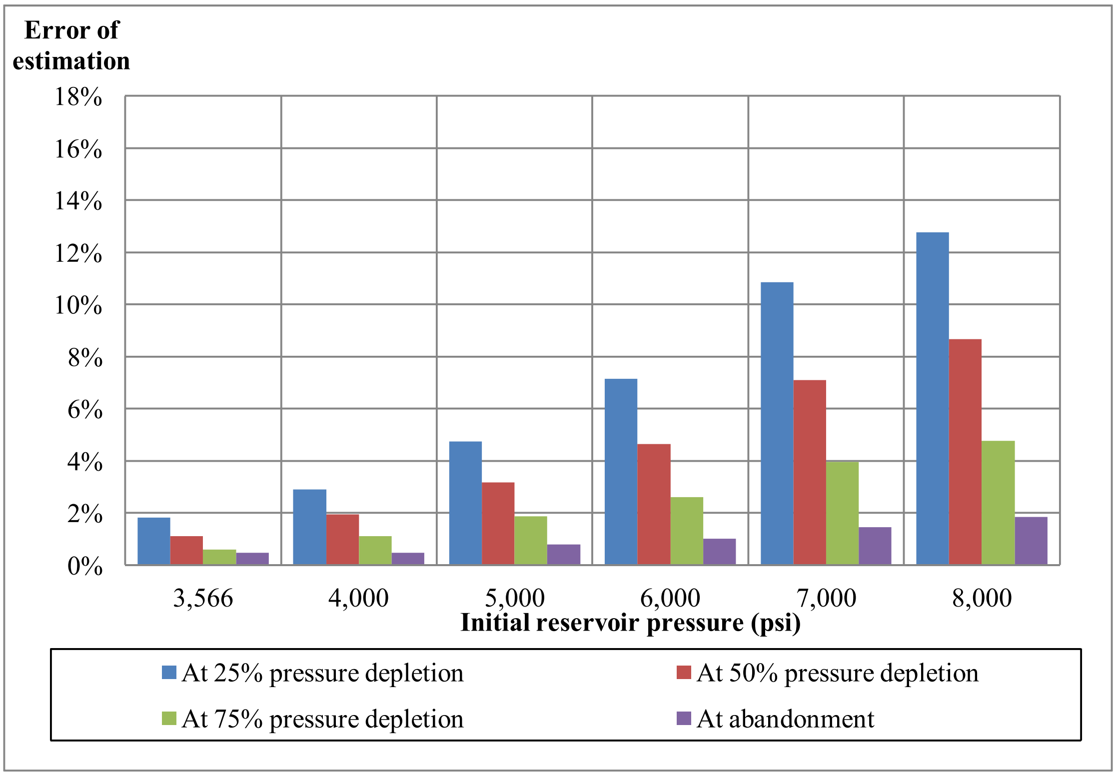

Figure A-2.6: Error of *G* estimated by Humphreys methods for Santa Rosa sandstone reservoir and water content 30% based on different length of data.

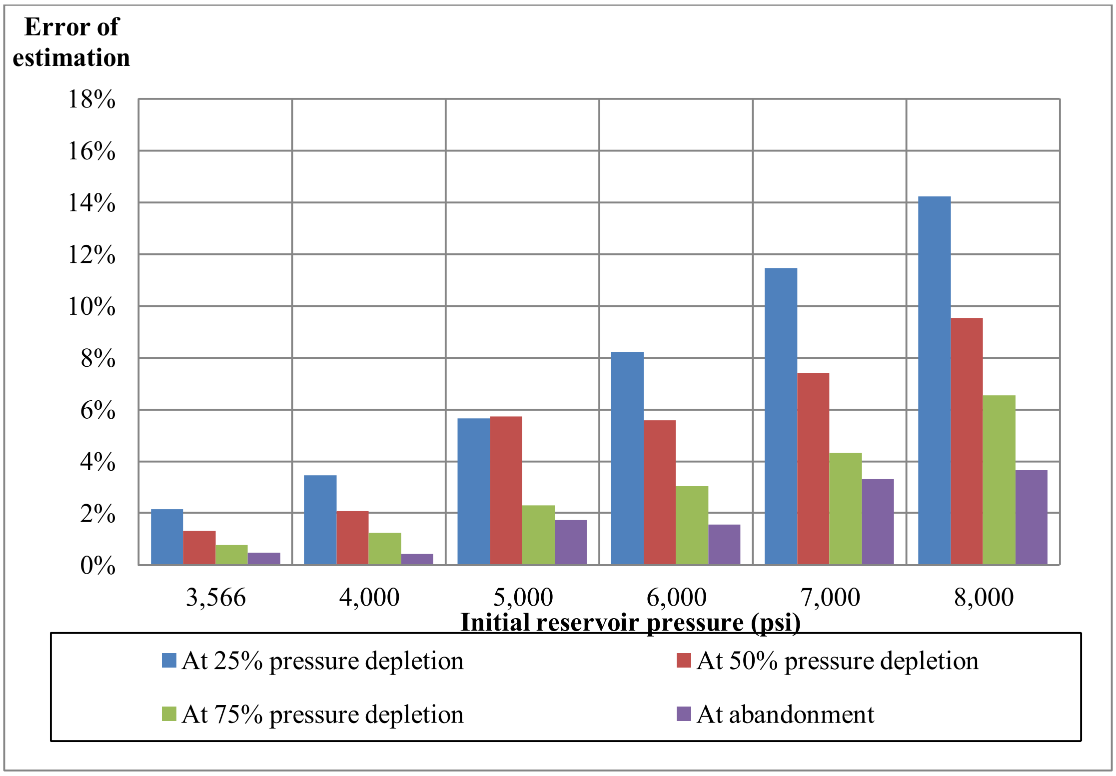

Figure A-2.7: Error of *G* estimated by Humphreys methods for Santa Rosa sandstone reservoir and water content 40% based on different length of data.

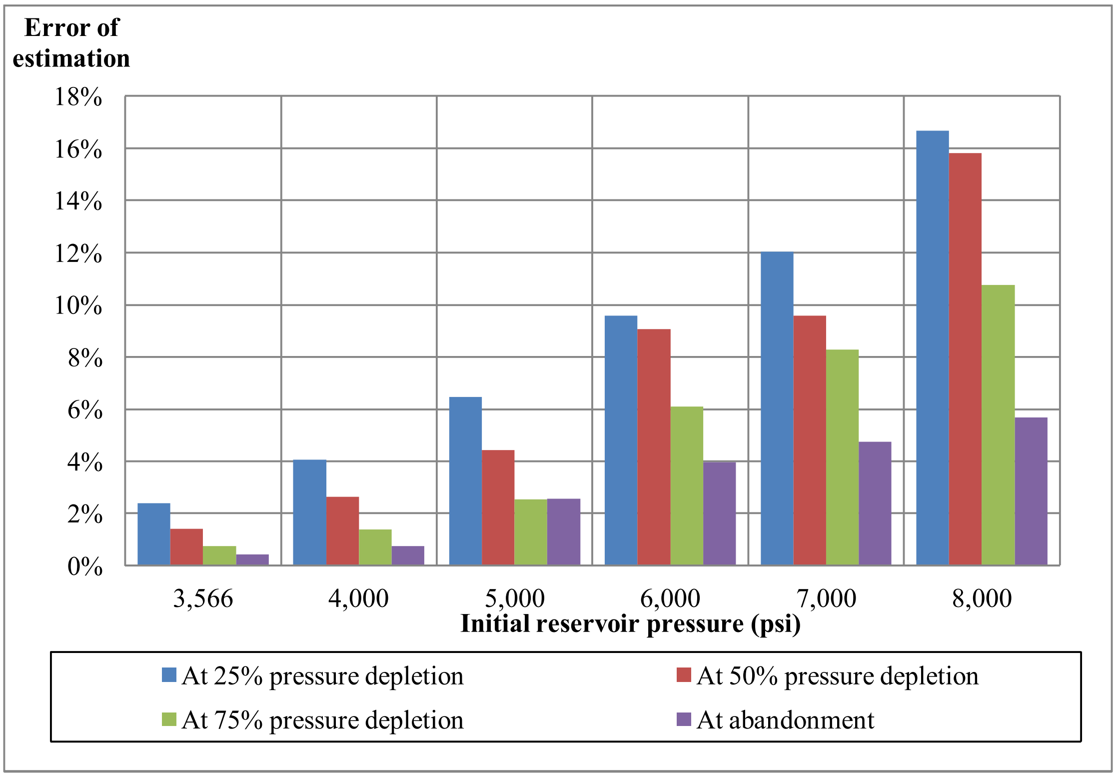

Figure A-2.8: Error of G estimated by Humphreys methods for Santa Rosa sandstone reservoir and water content 50% based on different length of data.

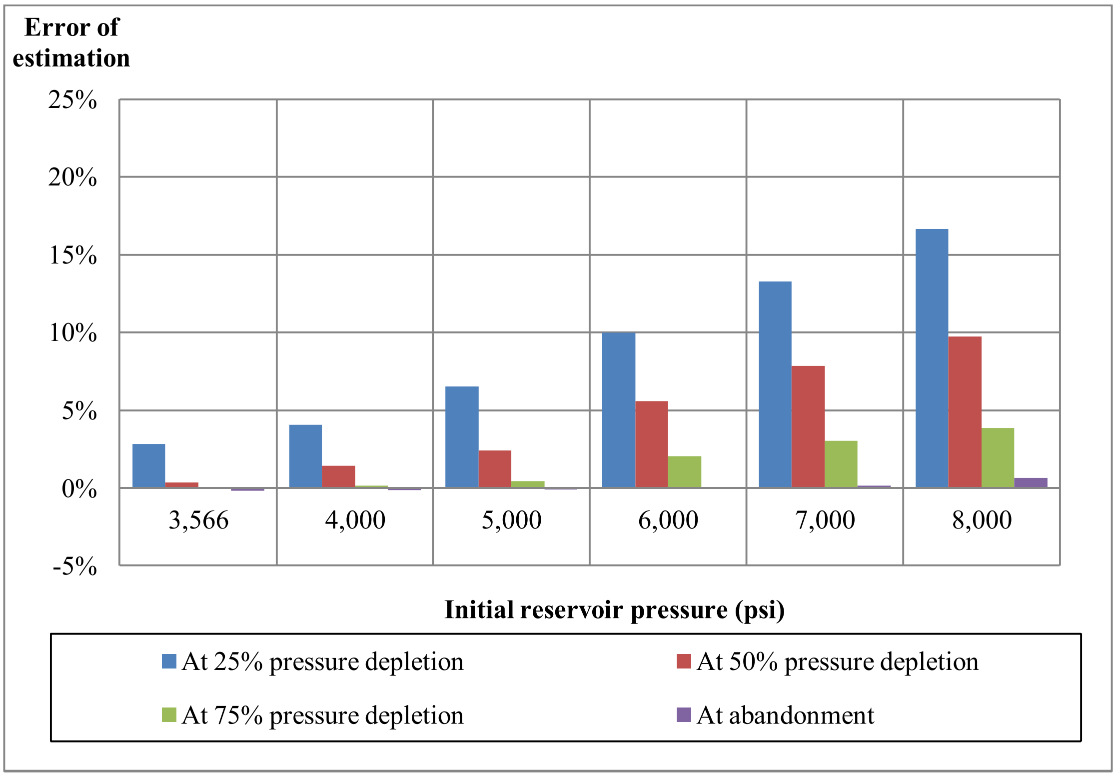

Figure A-2.9: Error of G estimated by modified Humphreys methods for Santa Rosa sandstone reservoir and water content 20% based on different length of data.

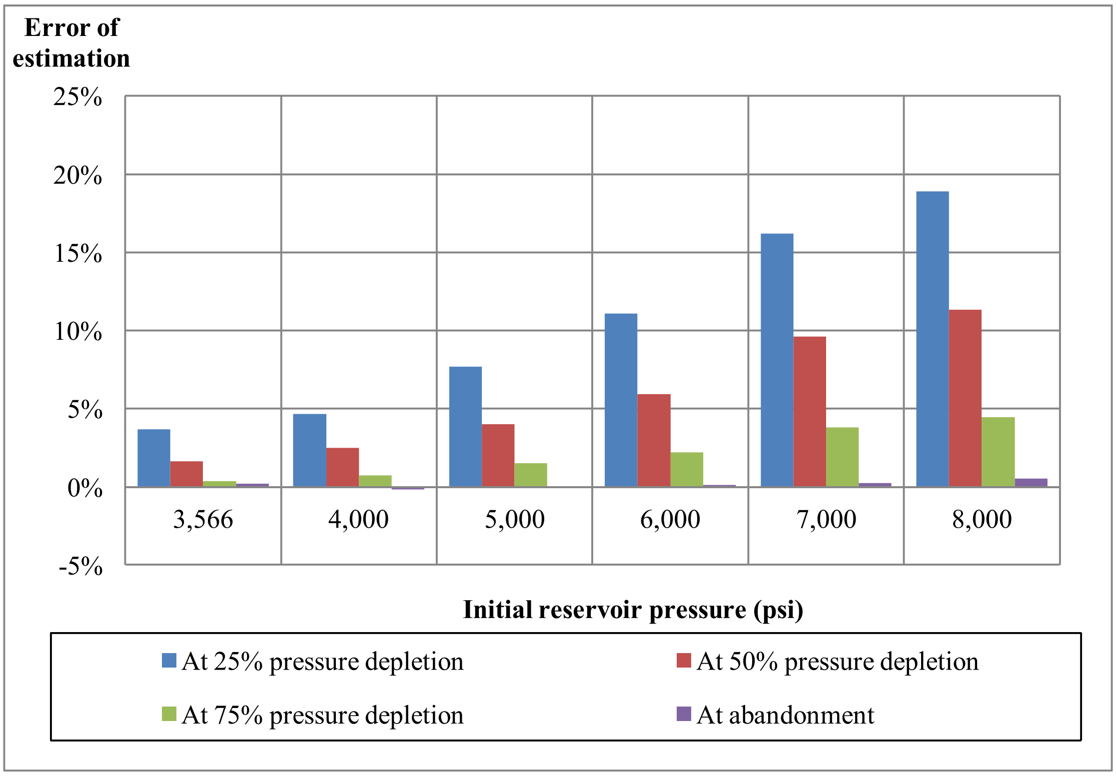

Figure A-2.10: Error of *G* estimated by modified Humphreys methods for Santa Rosa sandstone reservoir and water content 30% based on different length of data.

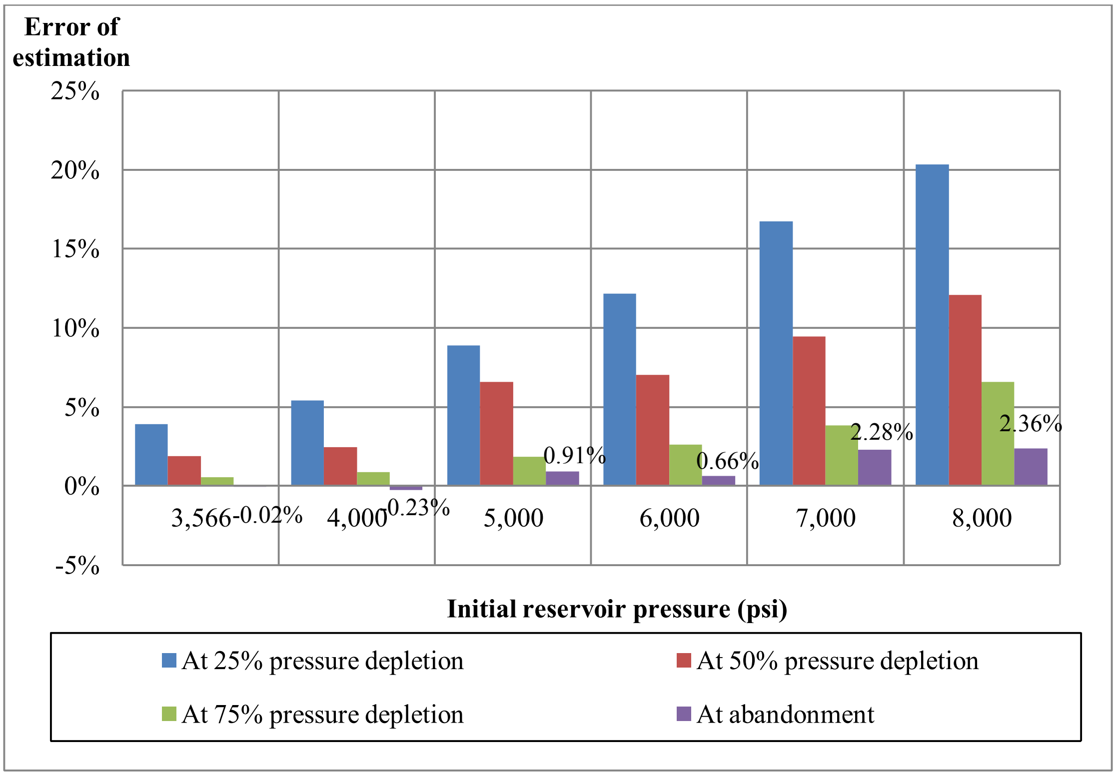

Figure A-2.11: Error of *G* estimated by modified Humphreys methods for Santa Rosa sandstone reservoir and water content 40% based on different length of data.

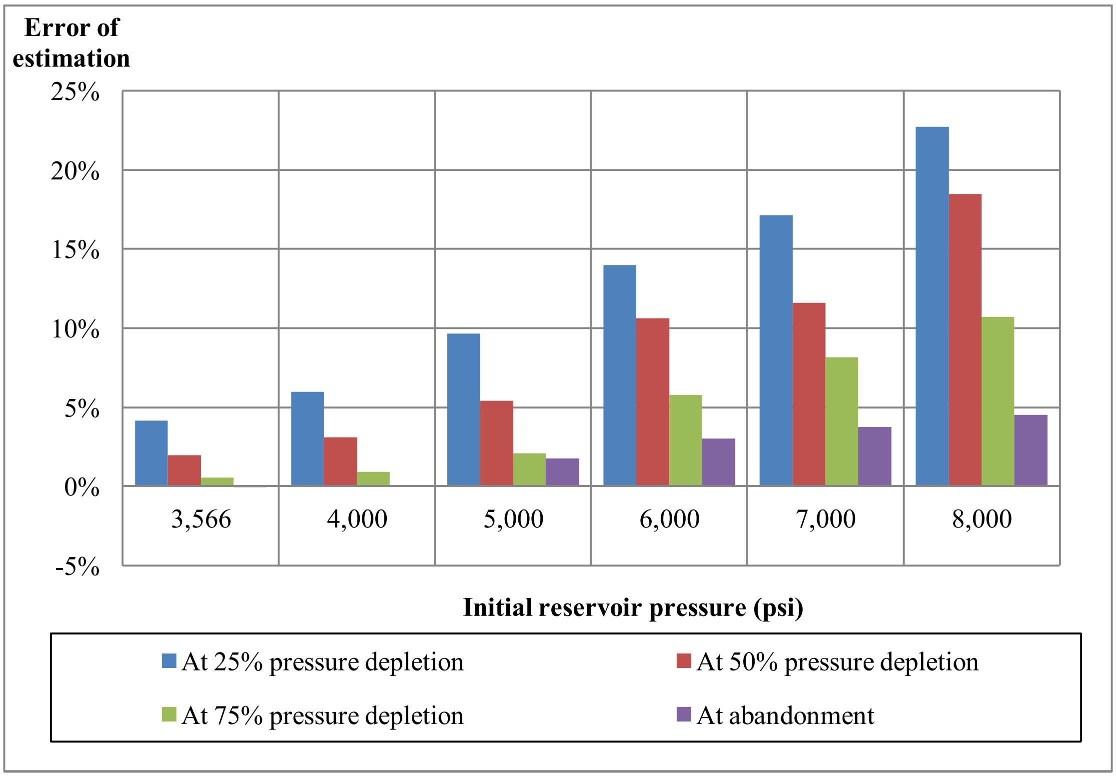

Figure A-2.12: Error of *G* estimated by modified Humphreys methods for Santa Rosa sandstone reservoir and water content 50% based on different length of data.

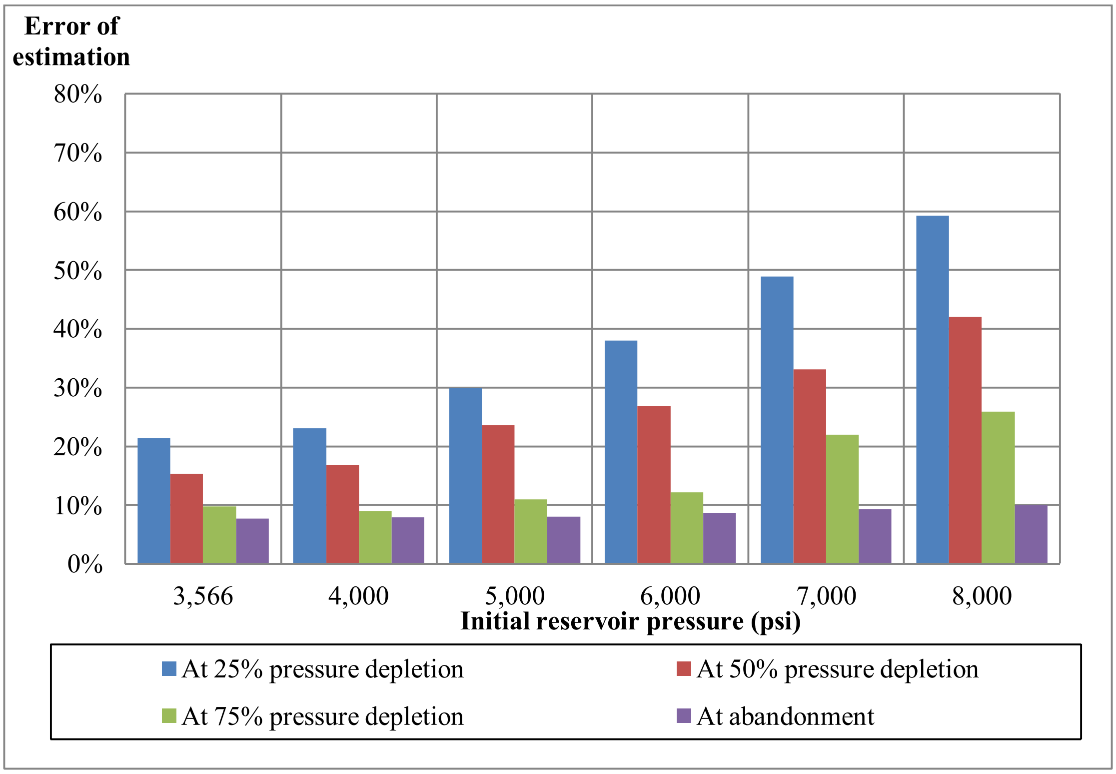

Figure A-2.13: Error of *G* estimated by conventional methods for Berea sandstone reservoir and water content 20% based on different length of data.

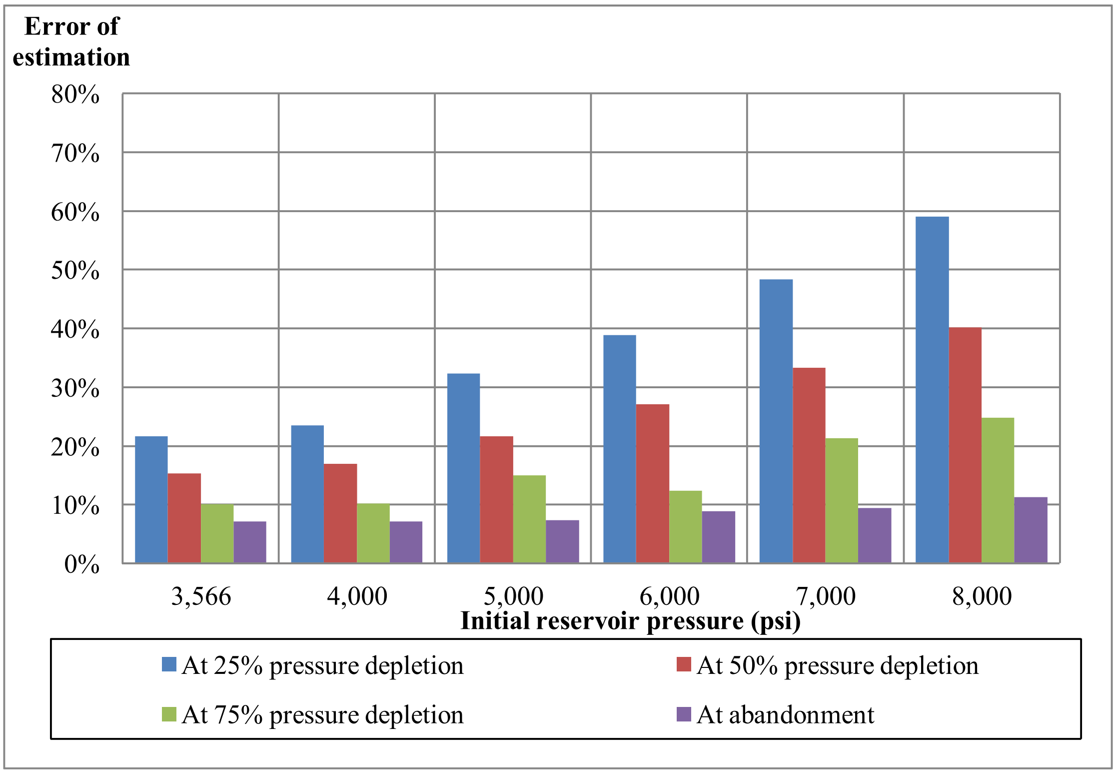

Figure A-2.14: Error of *G* estimated by conventional methods for Berea sandstone reservoir and water content 30% based on different length of data.

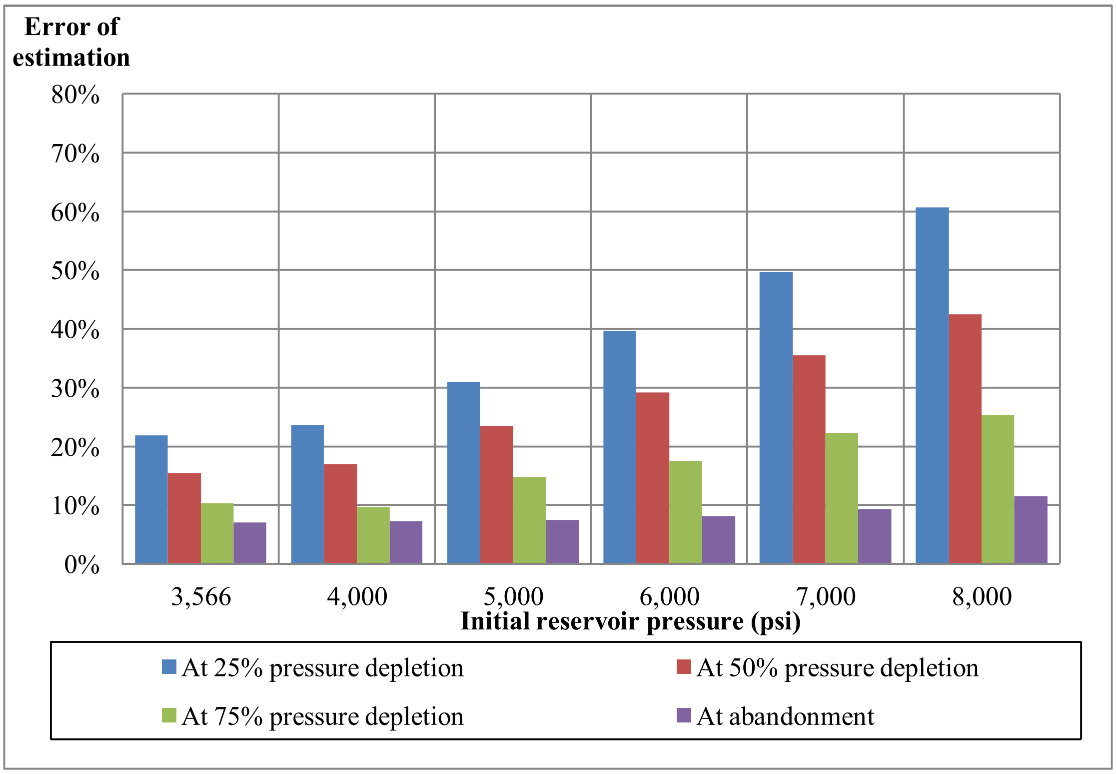

Figure A-2.15: Error of *G* estimated by conventional methods for Berea sandstone reservoir and water content 40% based on different length of data.

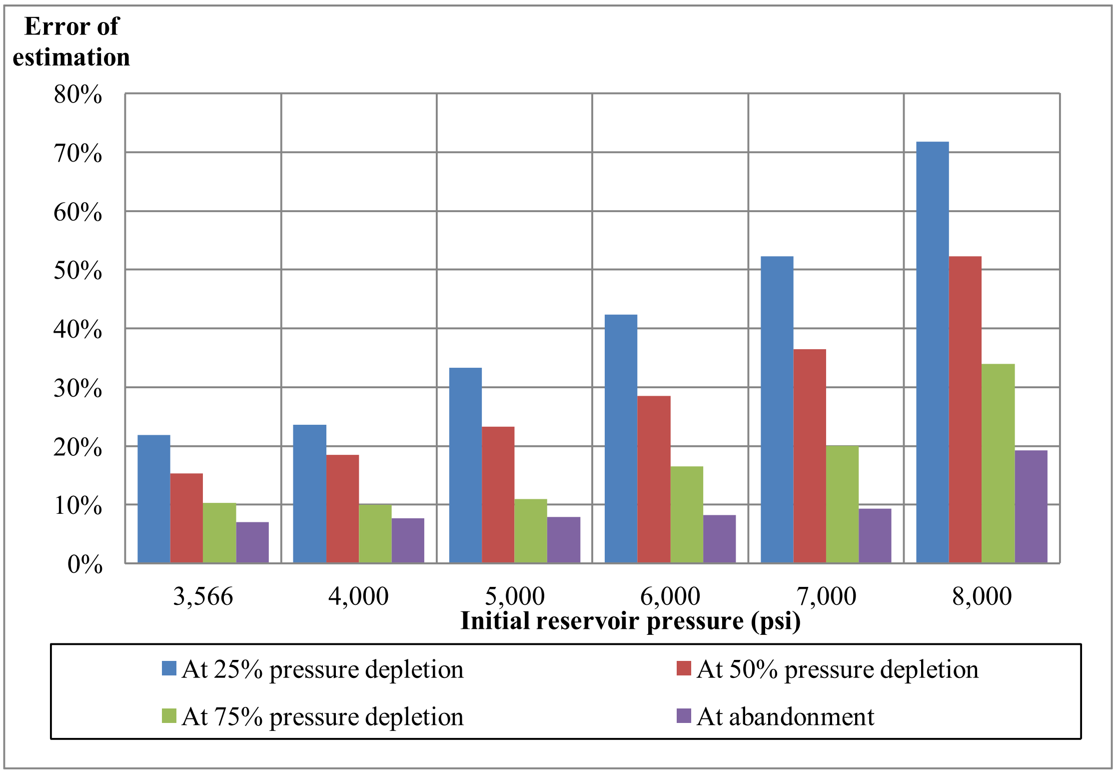

Figure A-2.16: Error of *G* estimated by conventional methods for Berea sandstone reservoir and water content 50% based on different length of data.

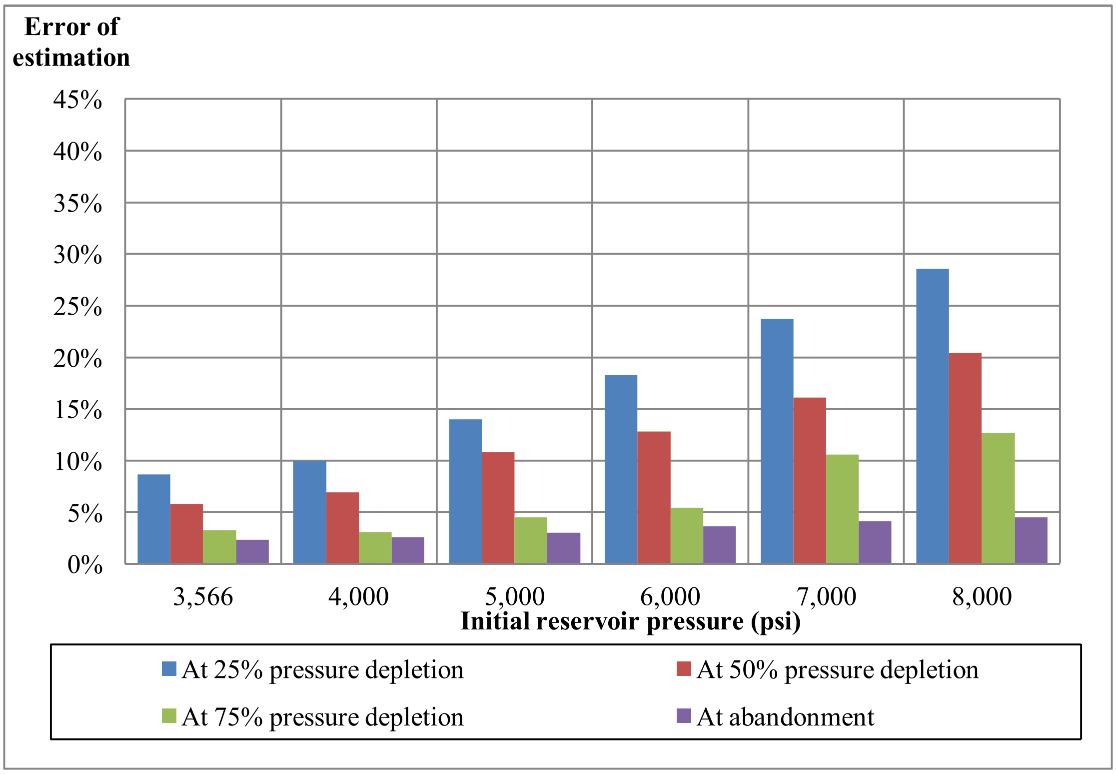

Figure A-2.17: Error of *G* estimated by Humphreys methods for Berea sandstone reservoir and water content 20% based on different length of data.

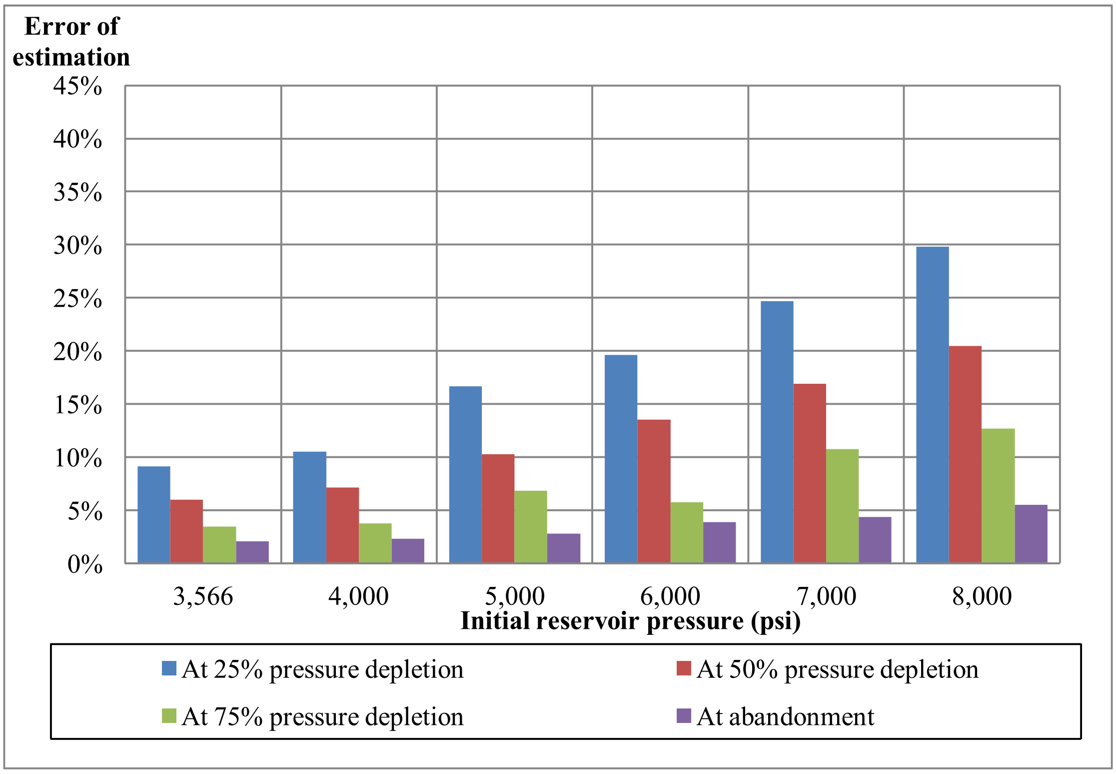

Figure A-2.18: Error of *G* estimated by Humphreys methods for Berea sandstone reservoir and water content 30% based on different length of data.

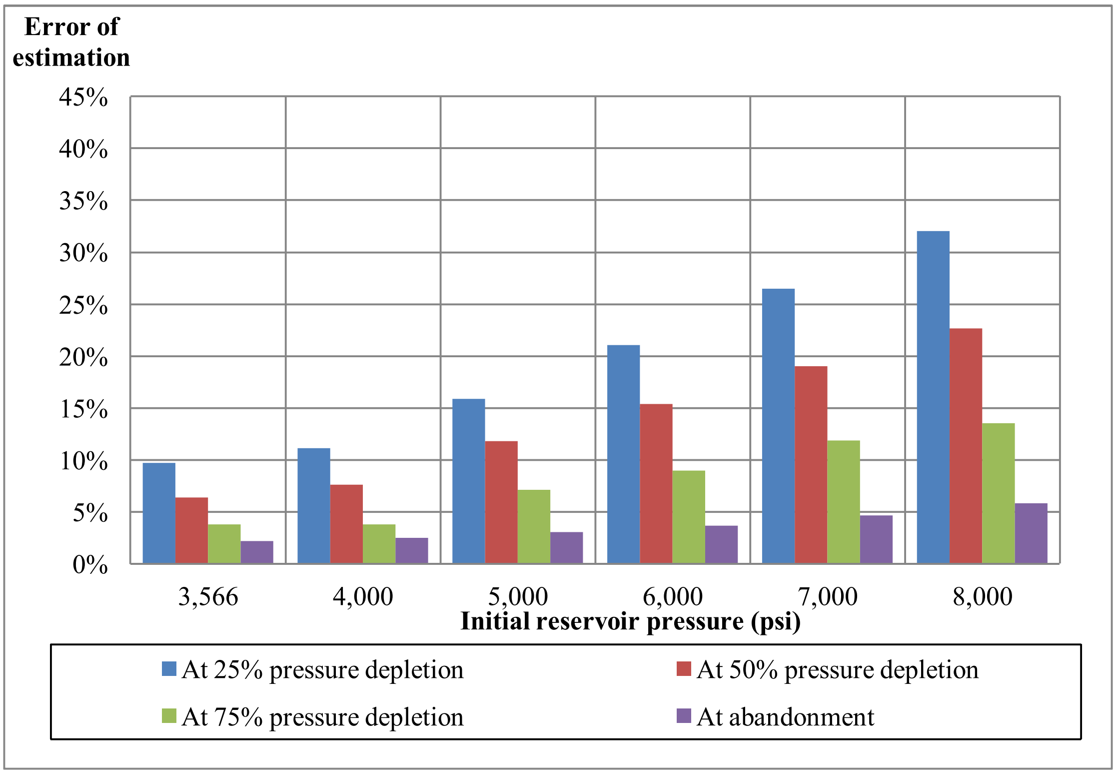

Figure A-2.19: Error of *G* estimated by Humphreys methods for Berea sandstone reservoir and water content 40% based on different length of data.

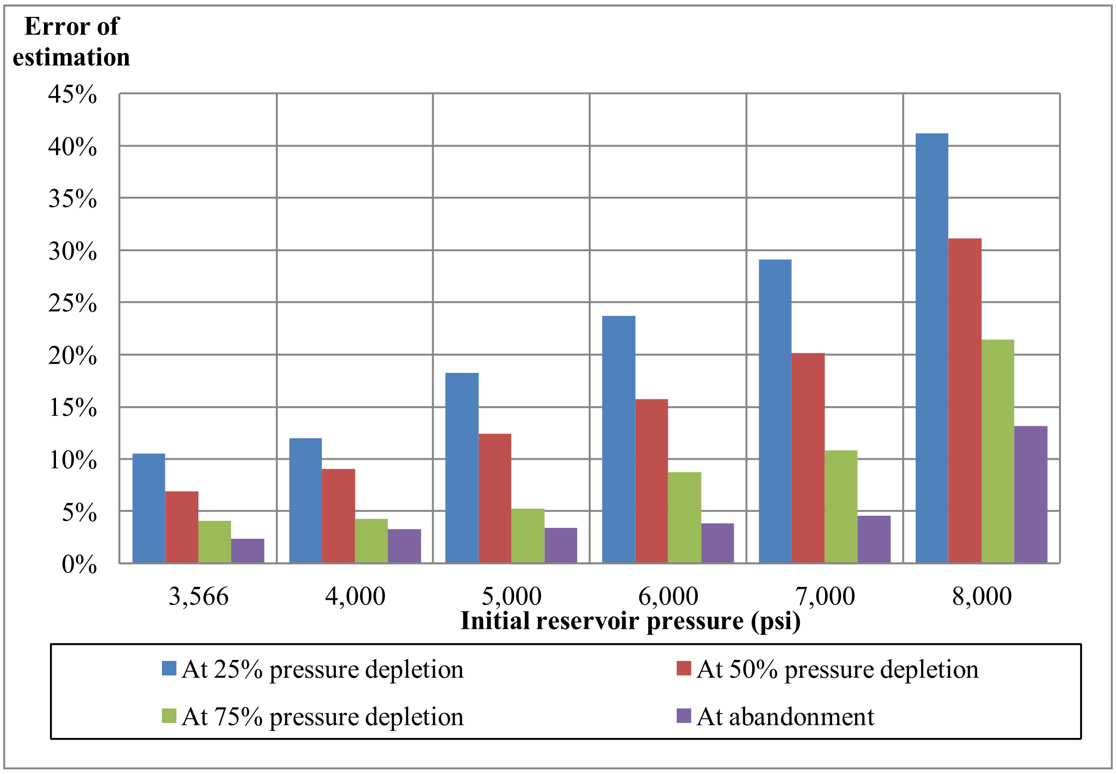

Figure A-2.20: Error of *G* estimated by Humphreys methods for Berea sandstone reservoir and water content 50% based on different length of data.

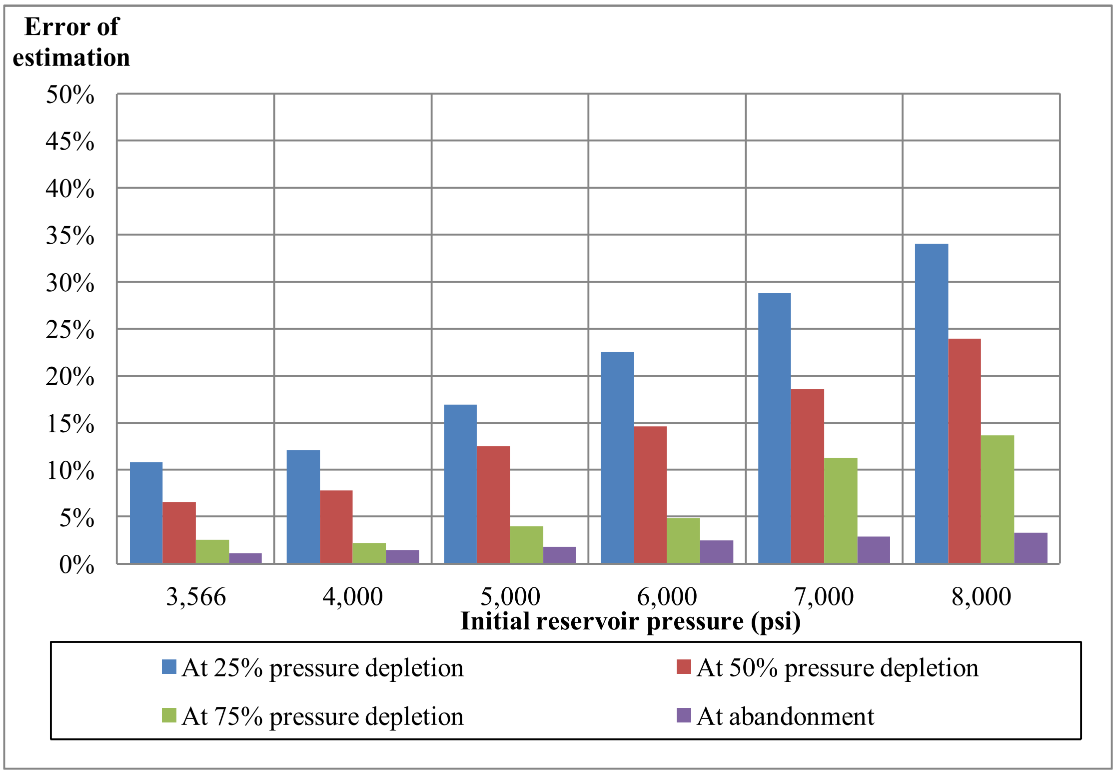

Figure A-2.21: Error of *G* estimated by modified Humphreys methods for Berea sandstone reservoir and water content 20% based on different length of data.

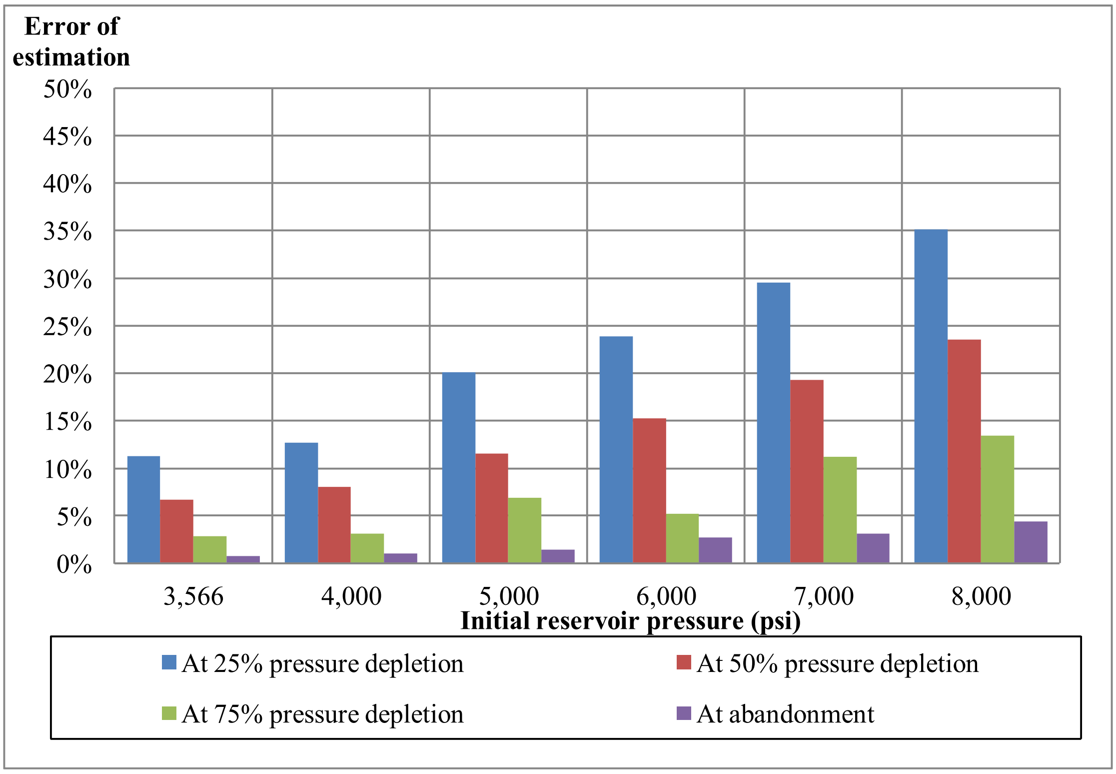

Figure A-2.22: Error of *G* estimated by modified Humphreys methods for Berea sandstone reservoir and water content 30% based on different length of data.

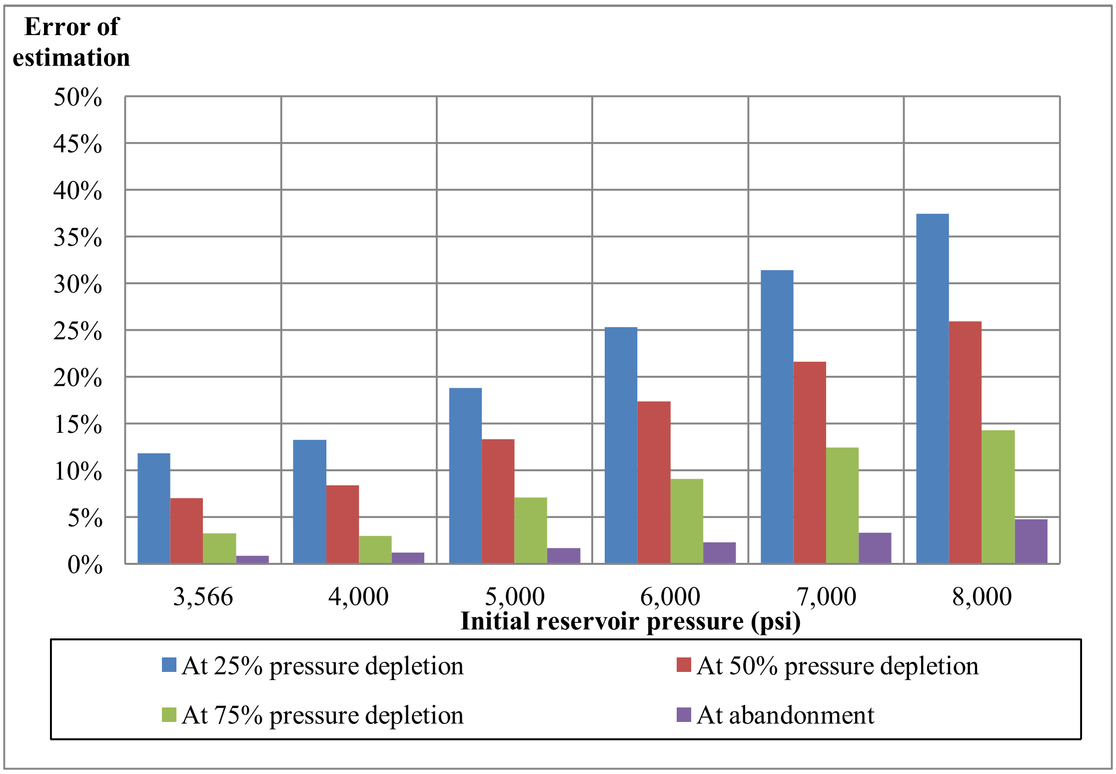

Figure A-2.23: Error of *G* estimated by modified Humphreys methods for Berea sandstone reservoir and water content 40% based on different length of data.

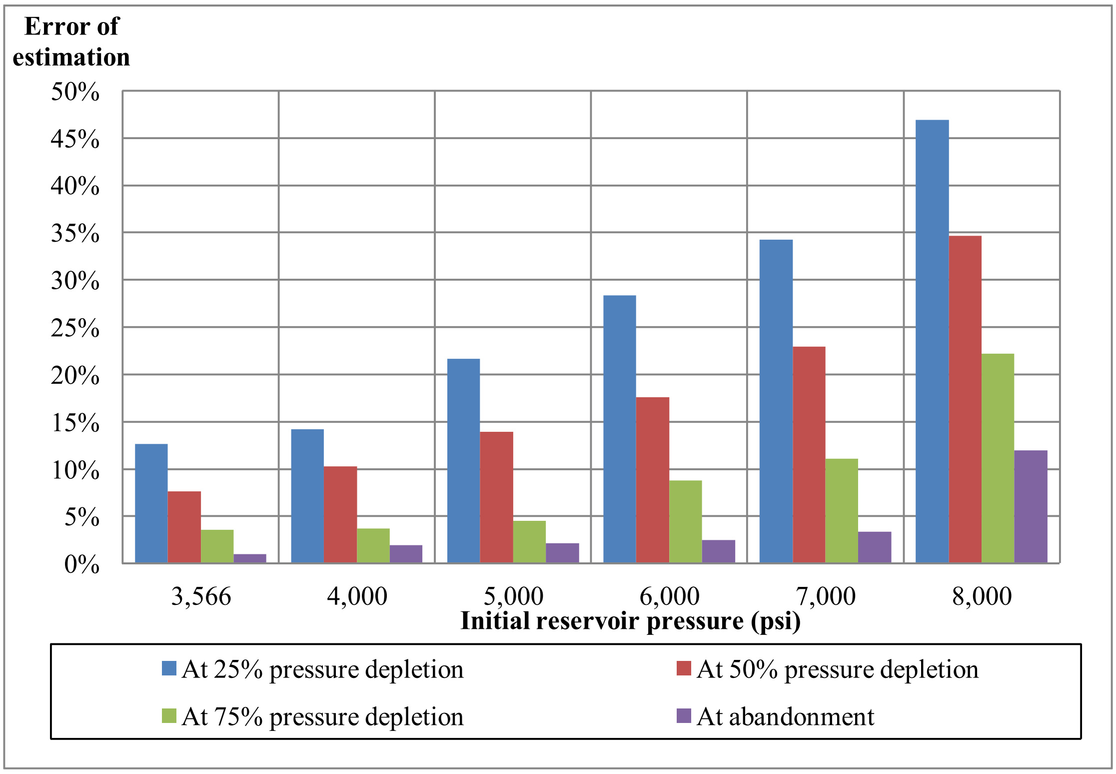

Figure A-2.24: Error of *G* estimated by modified Humphreys methods for Berea sandstone reservoir and water content 50% based on different length of data.

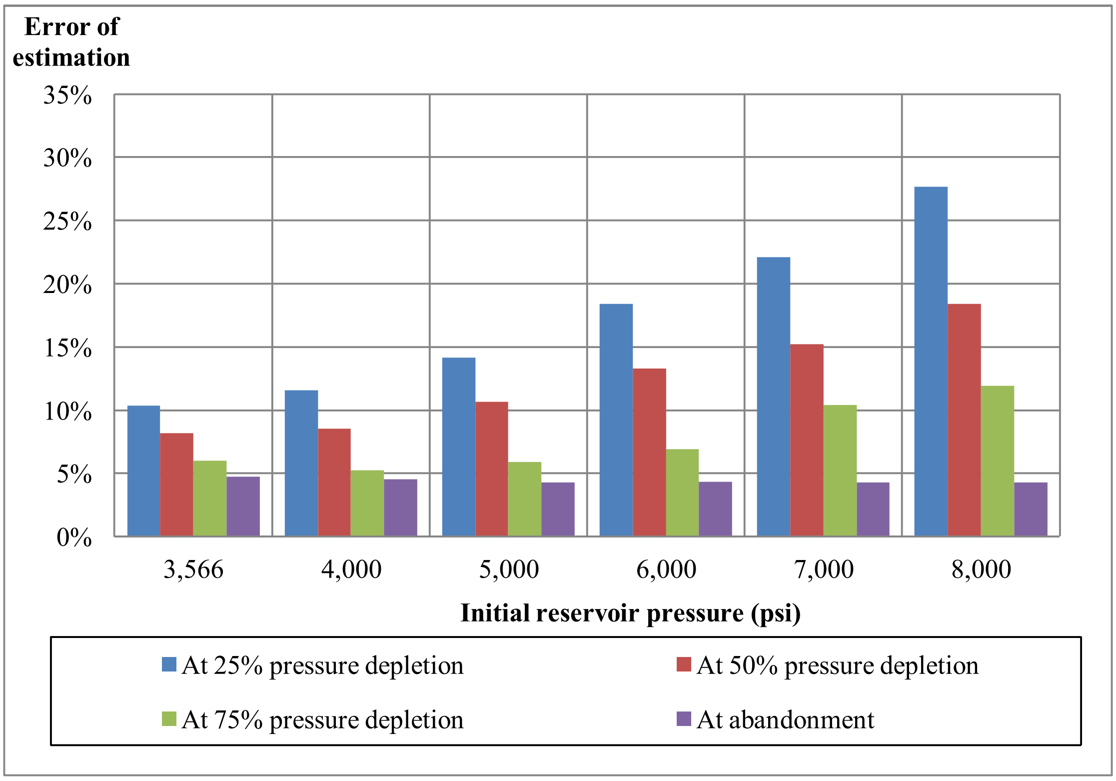

Figure A-2.25: Error of *G* estimated by conventional methods for Grianstone reservoir and water content 20% based on different length of data.

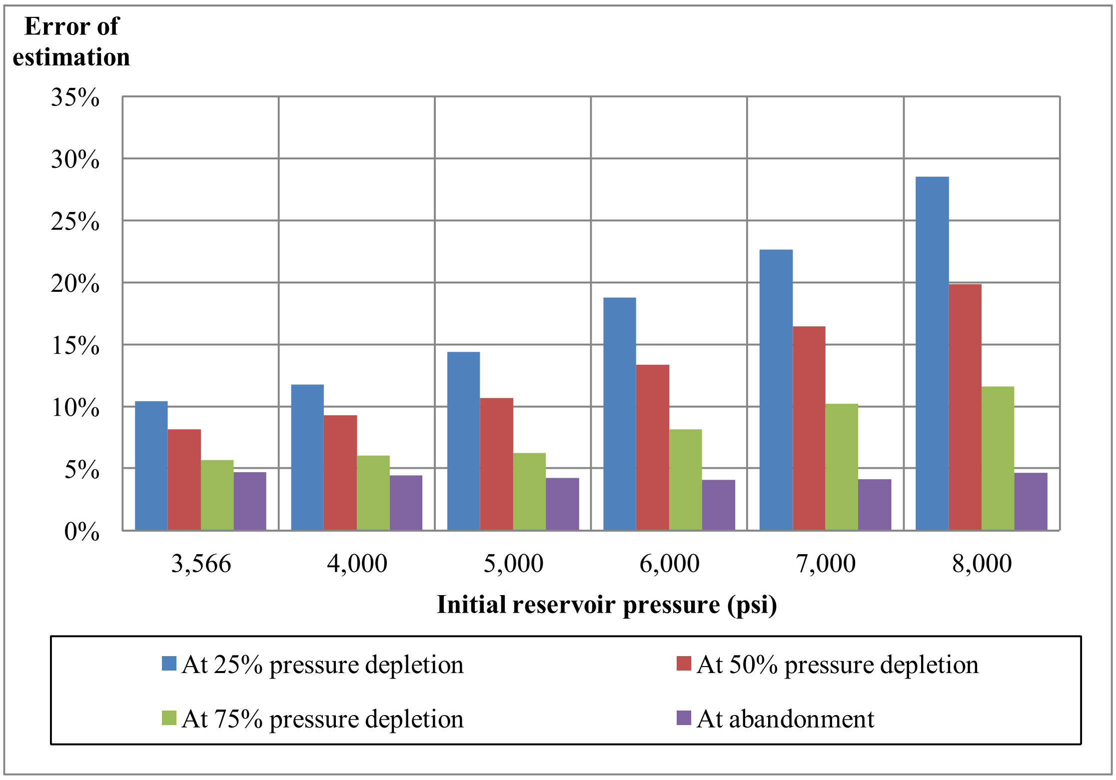

Figure A-2.26: Error of G estimated by conventional methods for Grianstone reservoir and water content 30% based on different length of data.

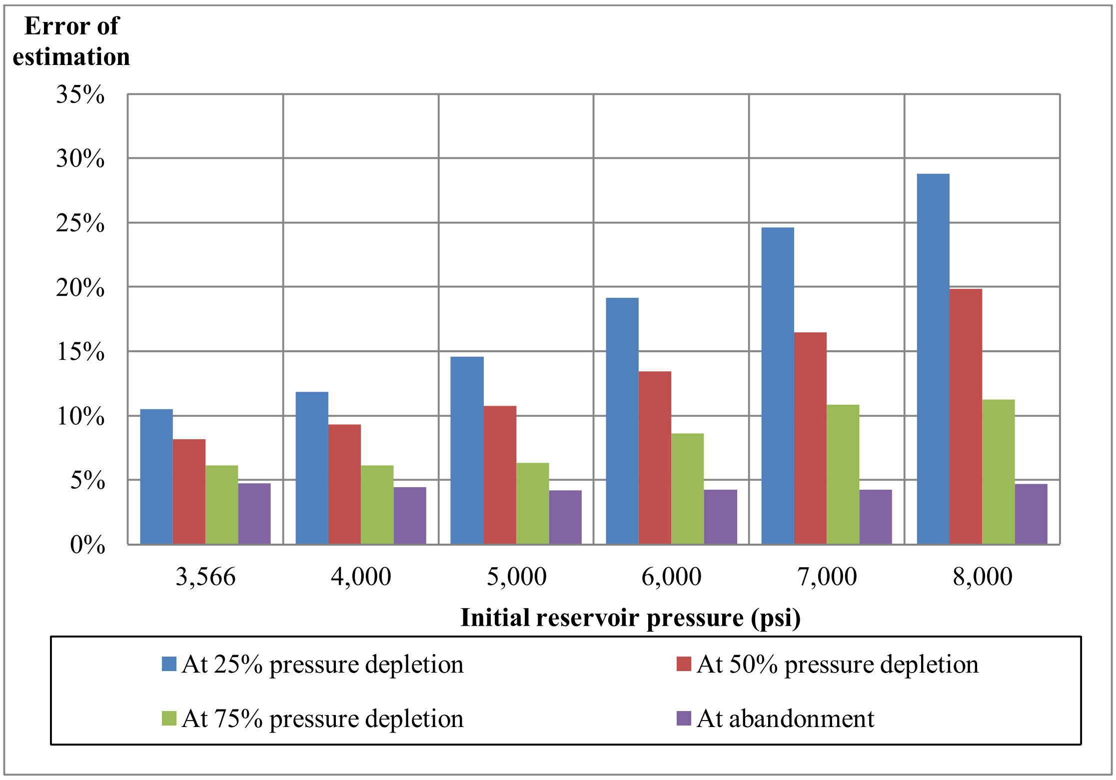

Figure A-2.27: Error of G estimated by conventional methods for Grianstone reservoir and water content 40% based on different length of data.

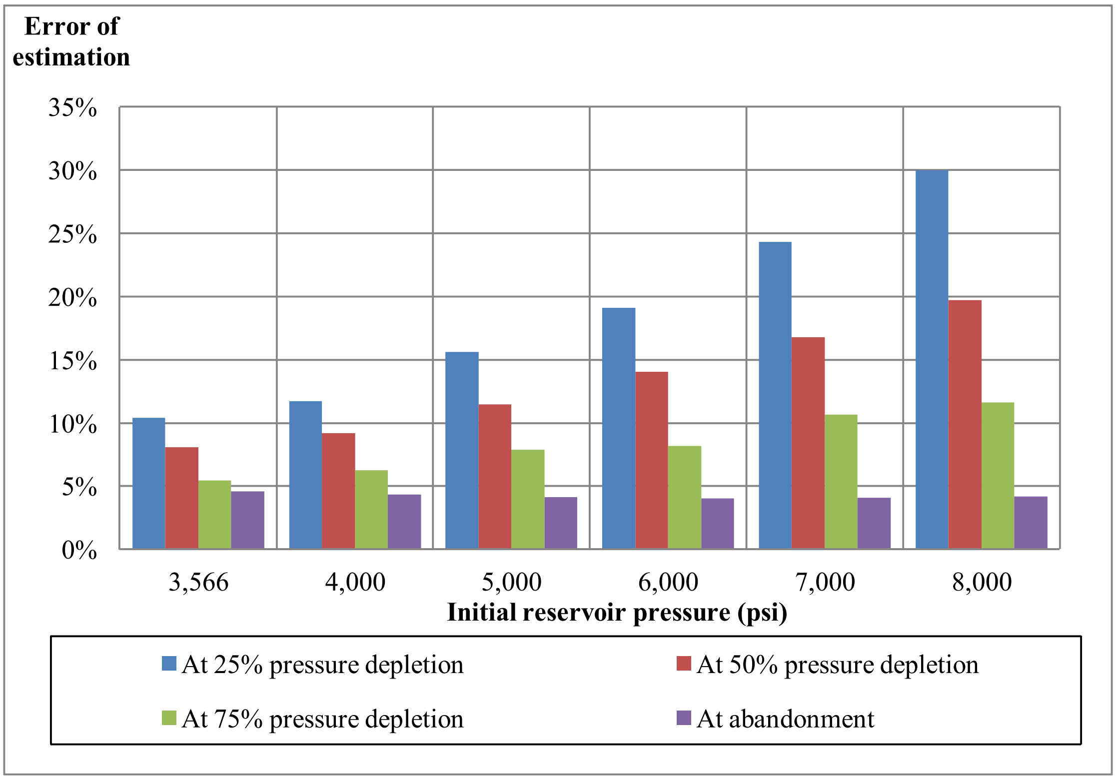

Figure A-2.28: Error of *G* estimated by conventional methods for Grianstone reservoir and water content 50% based on different length of data.

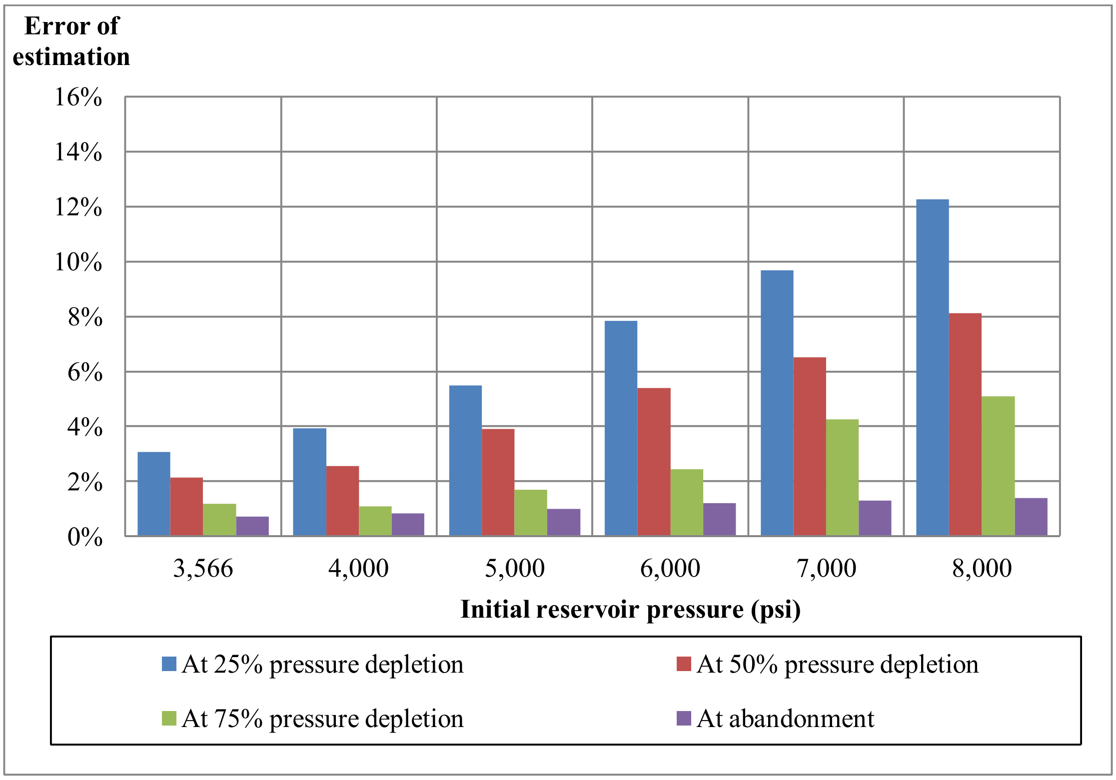

Figure A-2.29: Error of *G* estimated by Humphreys methods for Grianstone reservoir and water content 20% based on different length of data.

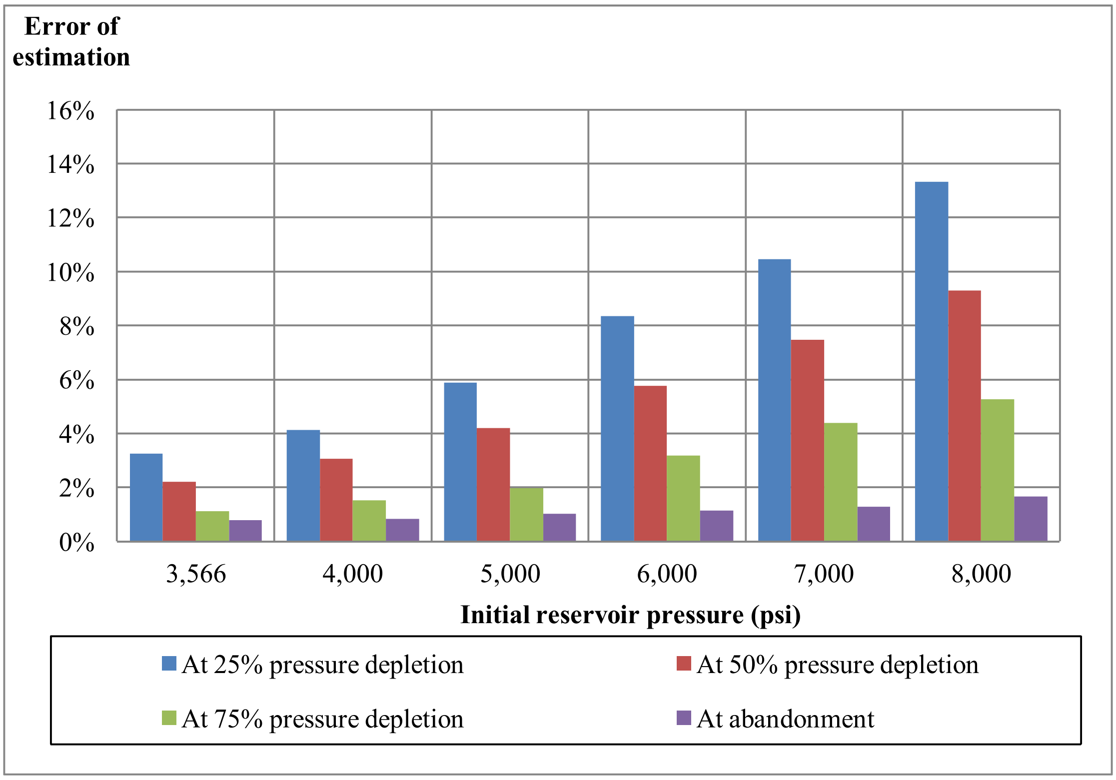

Figure A-2.30: Error of *G* estimated by Humphreys methods for Grianstone reservoir and water content 30% based on different length of data.

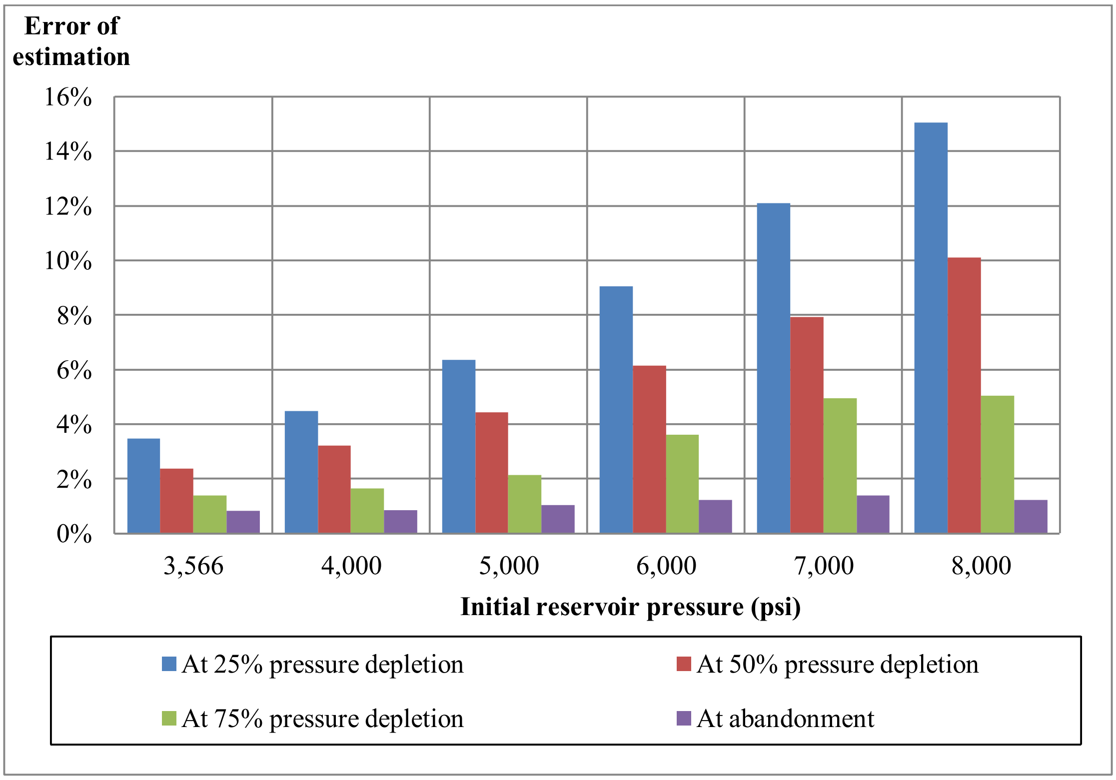

Figure A-2.31: Error of *G* estimated by Humphreys methods for Grianstone reservoir and water content 40% based on different length of data.

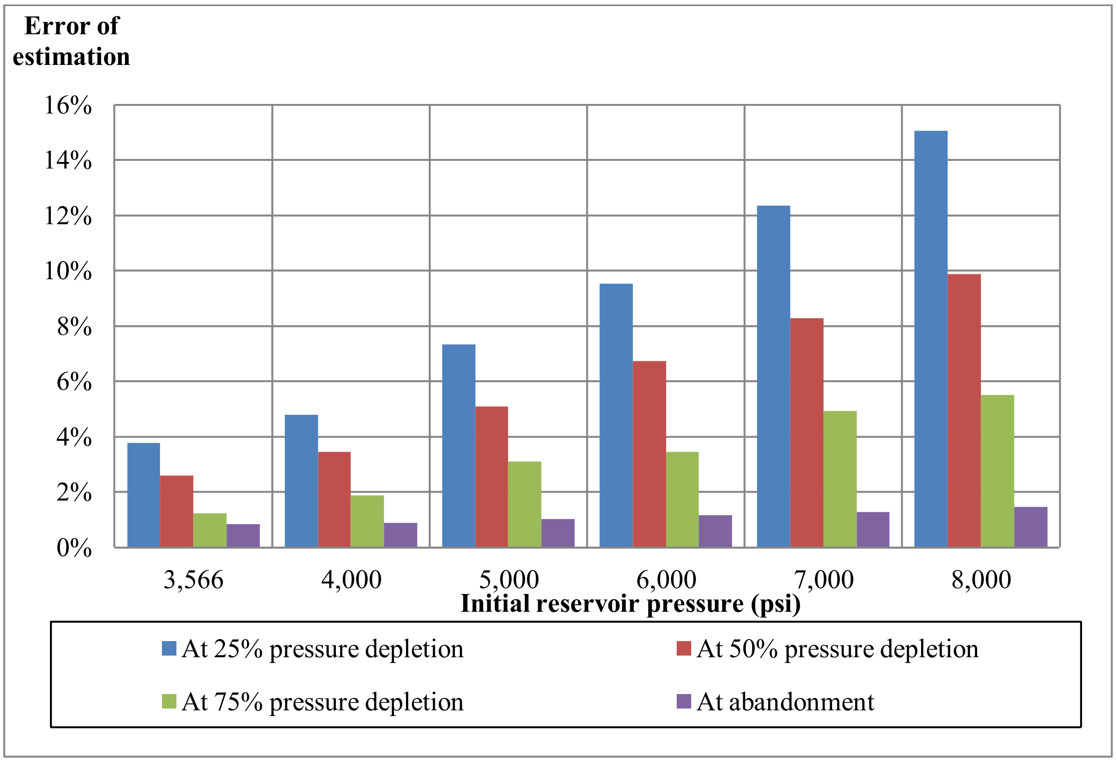

Figure A-2.32: Error of *G* estimated by Humphreys methods for Grianstone reservoir and water content 50% based on different length of data.

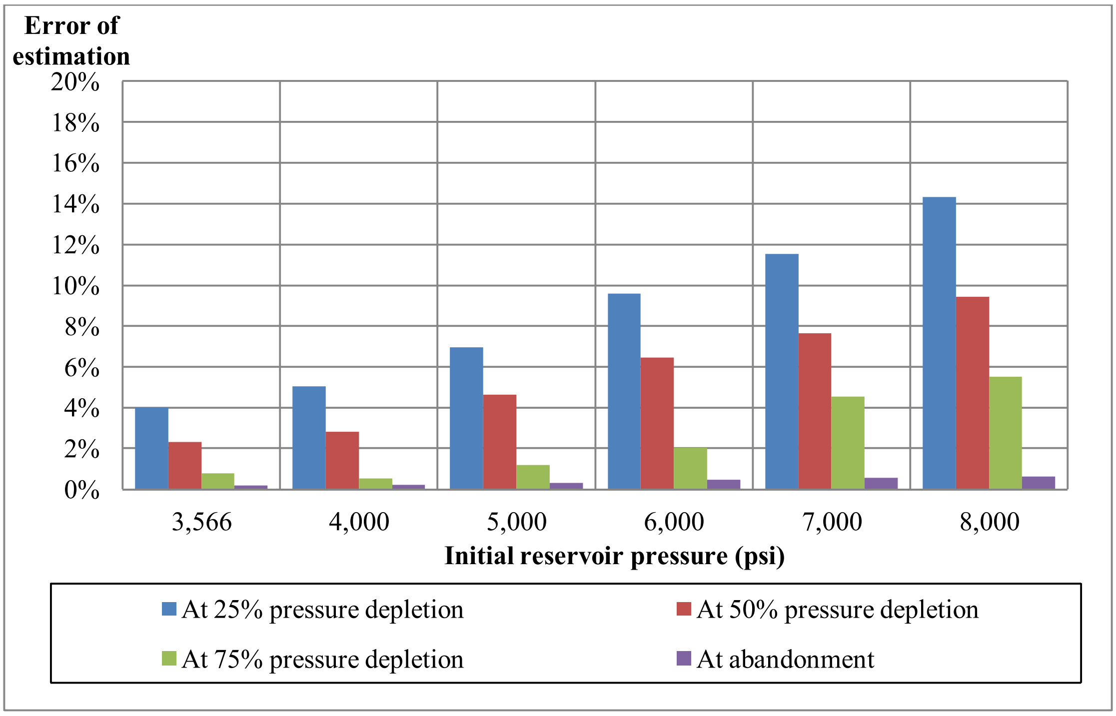

Figure A-2.33: Error of *G* estimated by modified Humphreys methods for Grianstone reservoir and water content 20% based on different length of data.

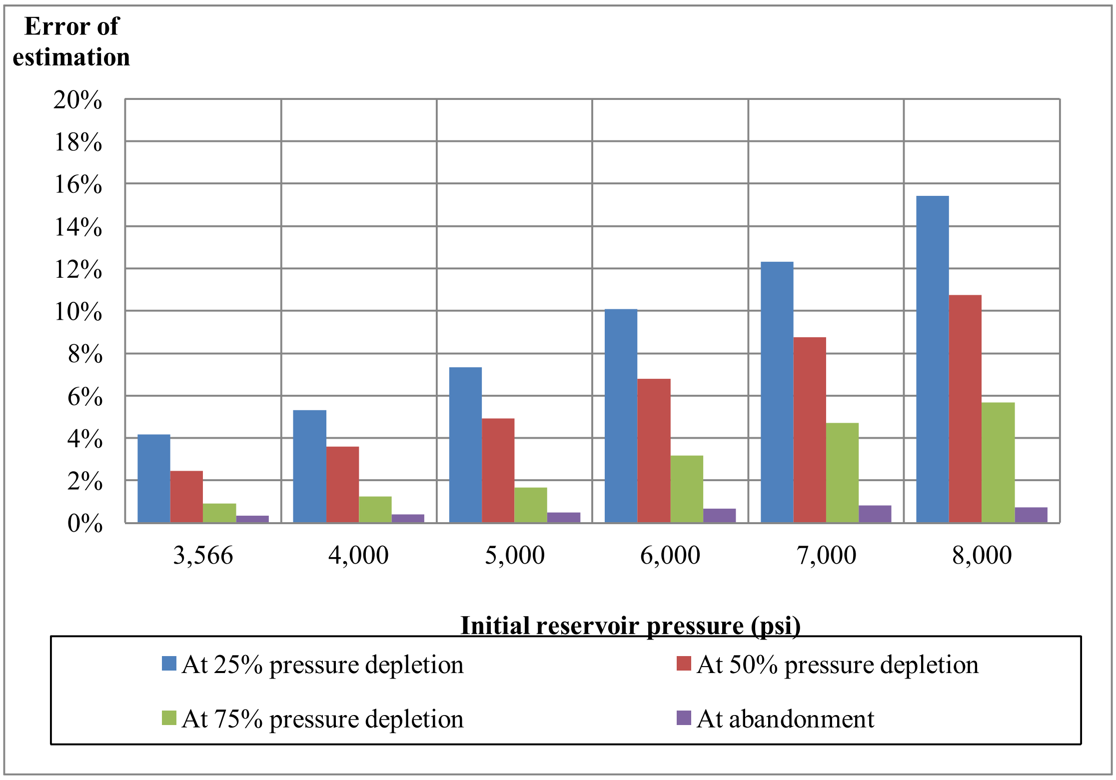

Figure A-2.34: Error of *G* estimated by modified Humphreys methods for Grianstone reservoir and water content 30% based on different length of data.

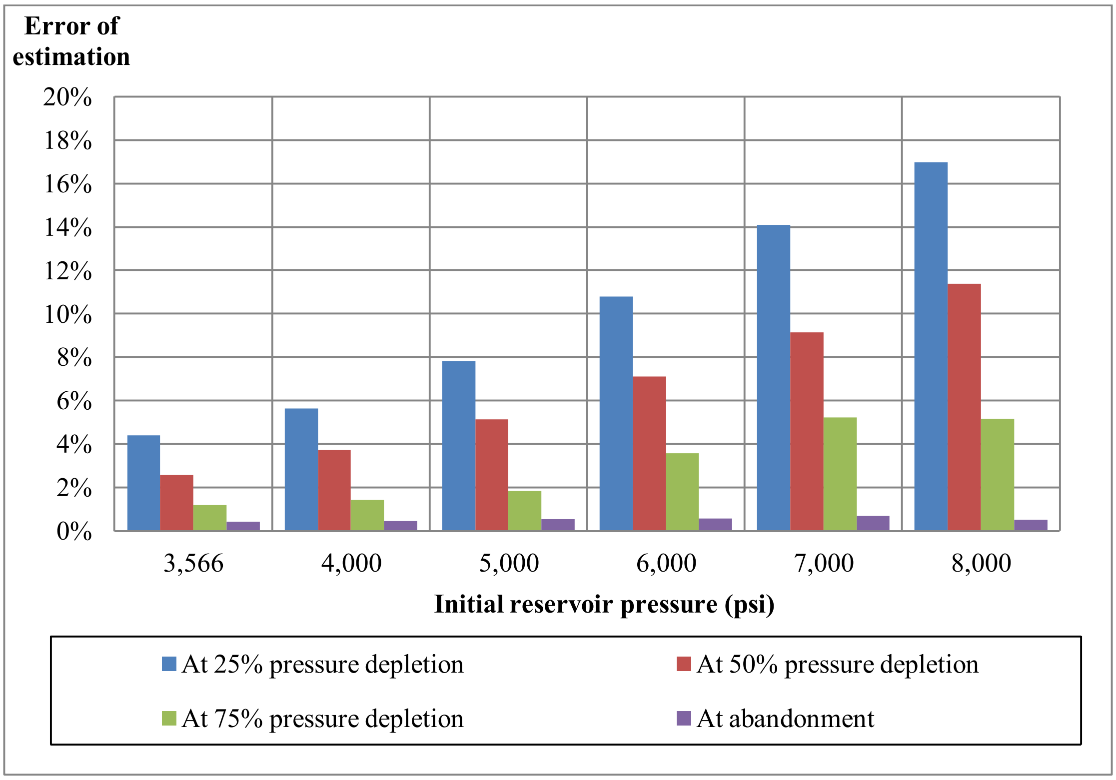

Figure A-2.35: Error of *G* estimated by modified Humphreys methods for Grianstone reservoir and water content 40% based on different length of data.

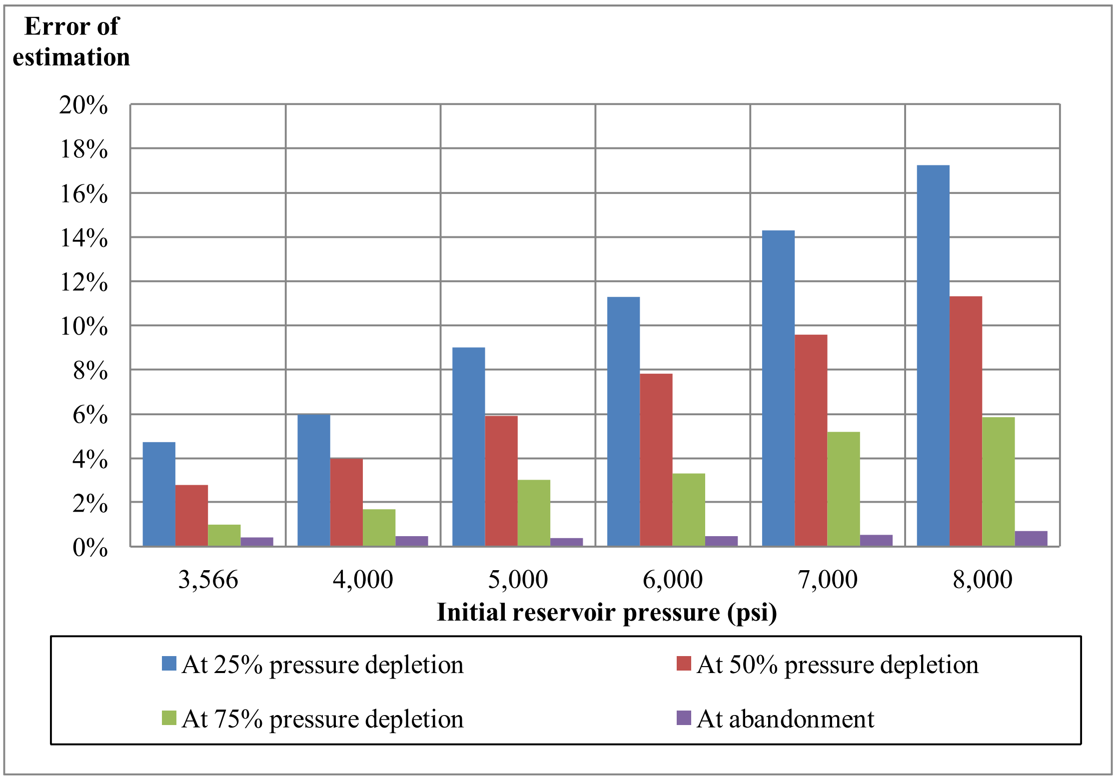

Figure A-2.36: Error of *G* estimated by modified Humphreys methods for Grianstone reservoir and water content 50% based on different length of data.

A-3) Error of original gas in place estimation for reservoirs with significant rock compressibility and water vapor with different type of rock

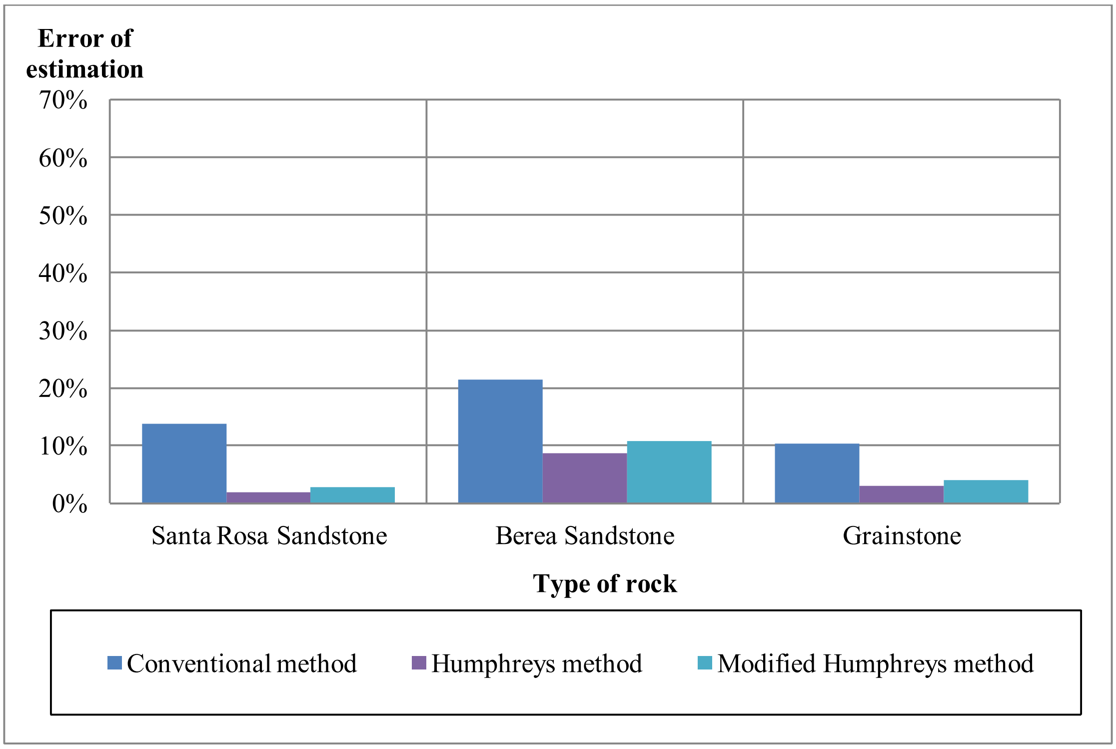

Figure A-3.1: Error of G estimated by different methods for different reservoir rock at initial reservoir pressure 3,566 psi and water content 20% based on data at 25% pressure depletion

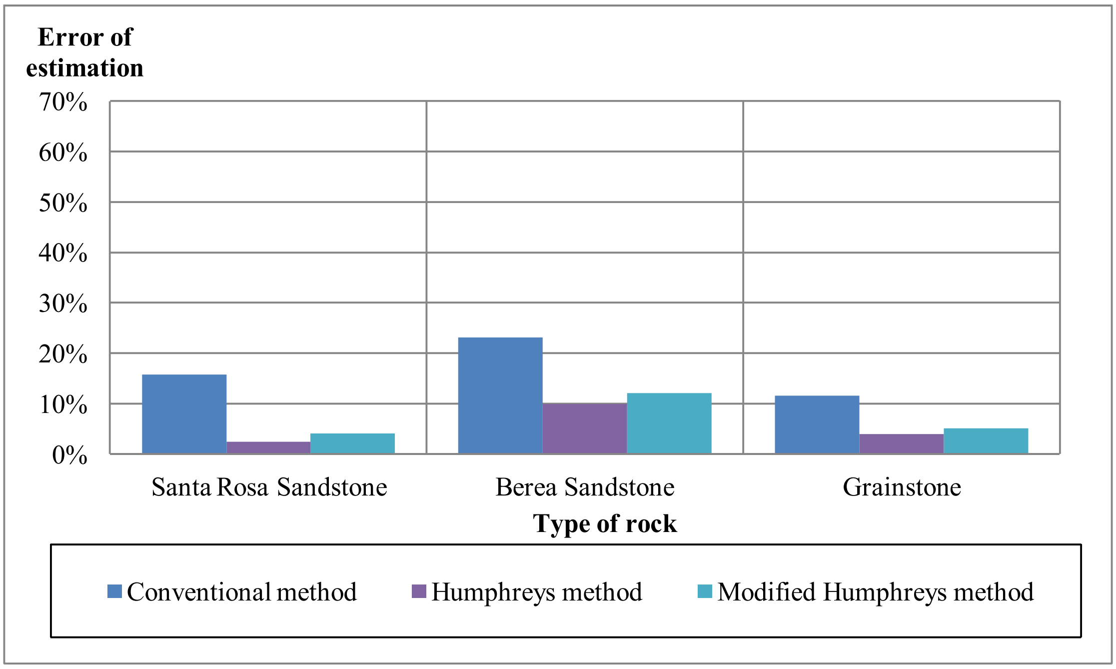

Figure A-3.2: Error of *G* estimated by different methods for different reservoir rock at initial reservoir pressure 4,000 psi and water content 20% based on data at 25% pressure depletion.

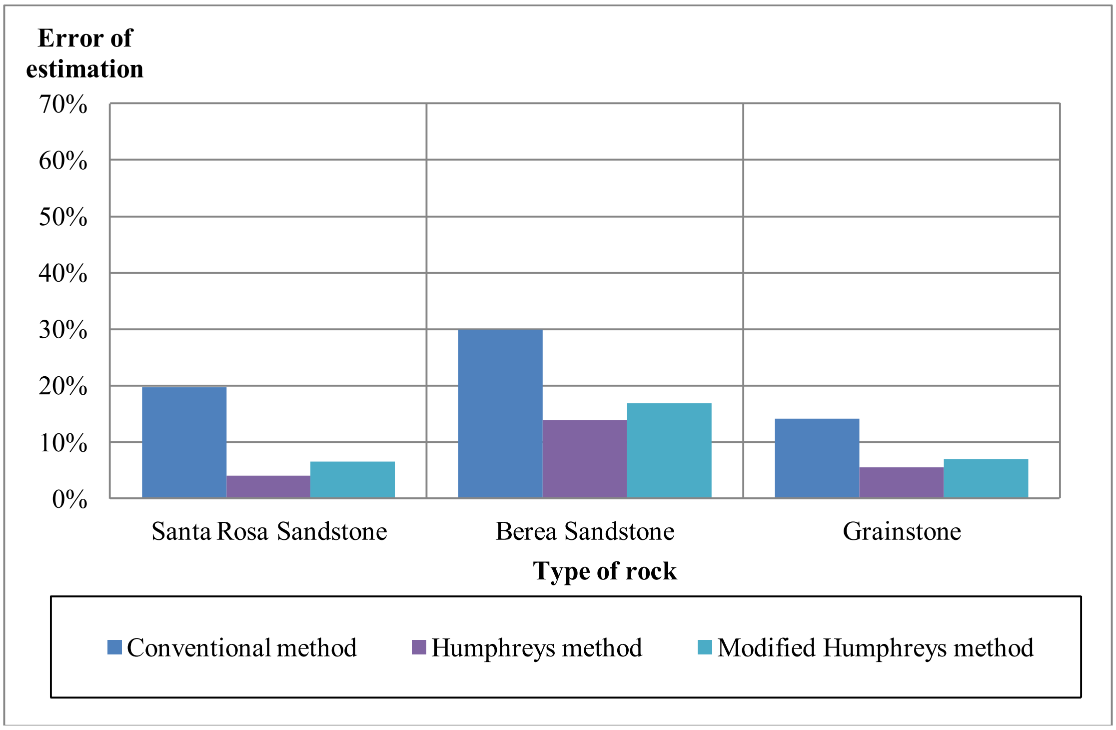

Figure A-3.3: Error of *G* estimated by different methods for different reservoir rock at initial reservoir pressure 5,000 psi and water content 20% on data at 25% pressure depletion.

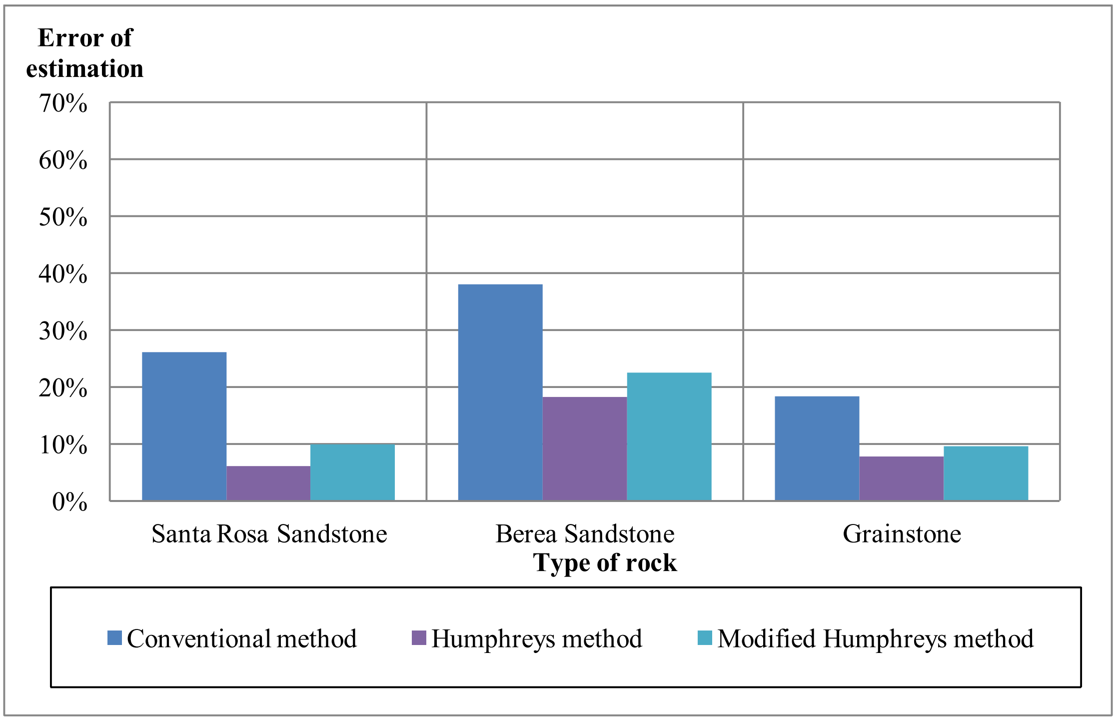

Figure A-3.4: Error of G estimated by different methods for different reservoir rock at initial reservoir pressure 6,000 psi and water content 20% on data at 25% pressure depletion.

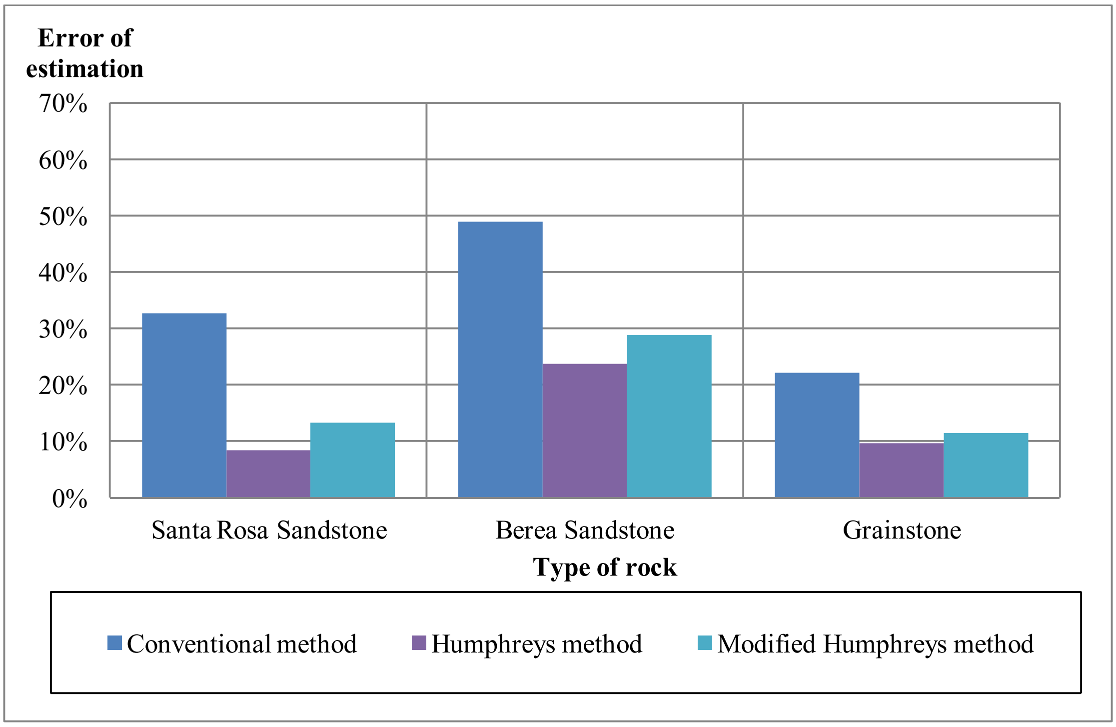

Figure A-3.5: Error of G estimated by different methods for different reservoir rock at initial reservoir pressure 7,000 psi and water content 20% on data at 25% pressure depletion.

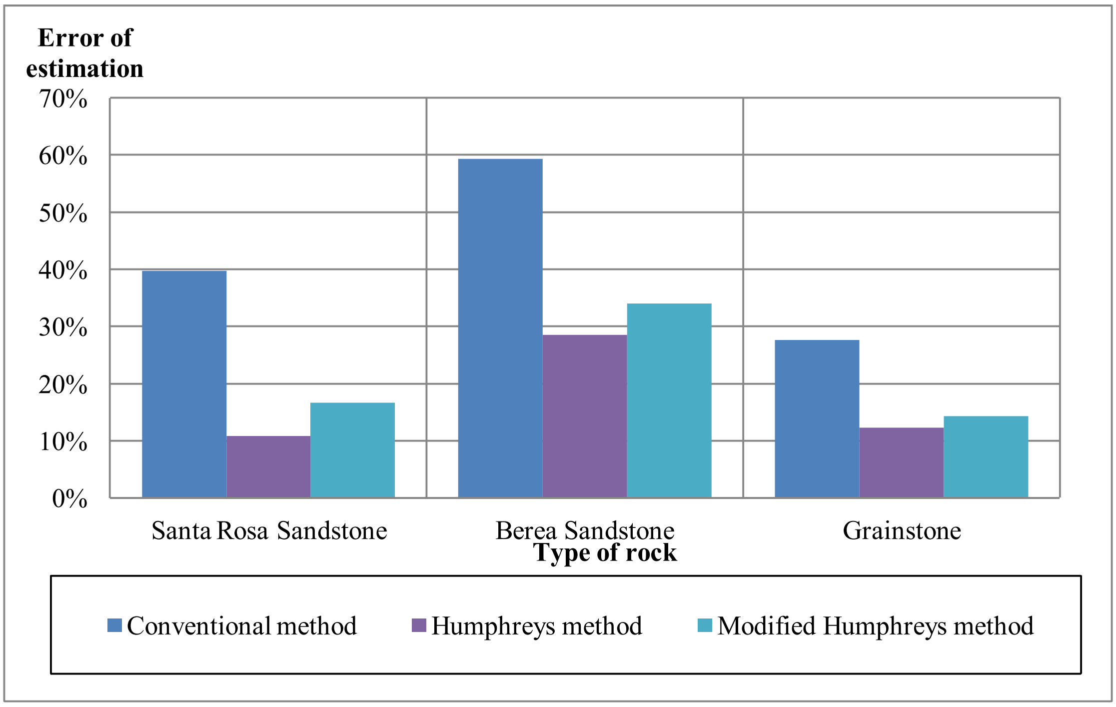

Figure A-3.6: Error of G estimated by different methods for different reservoir rock at initial reservoir pressure 8,000 psi and water content 20% on data at 25% pressure depletion.

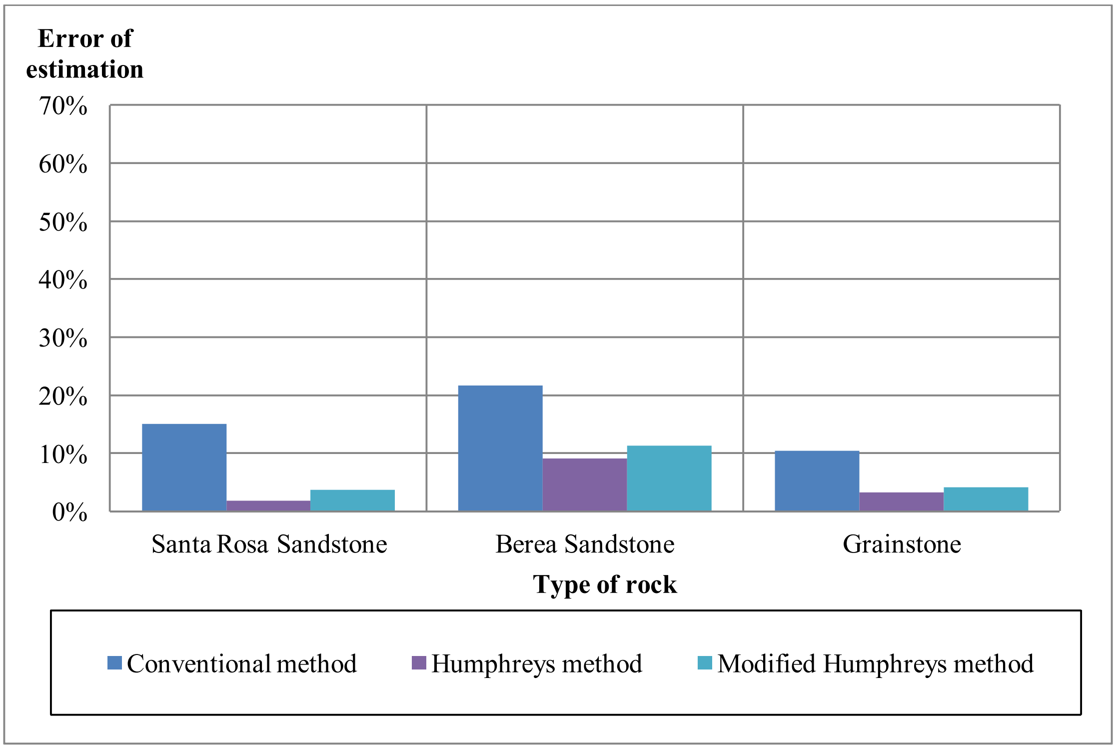

Figure A-3.7: Error of G estimated by different methods for different reservoir rock at initial reservoir pressure 3,566 psi and water content 30% on data at 25% pressure depletion.

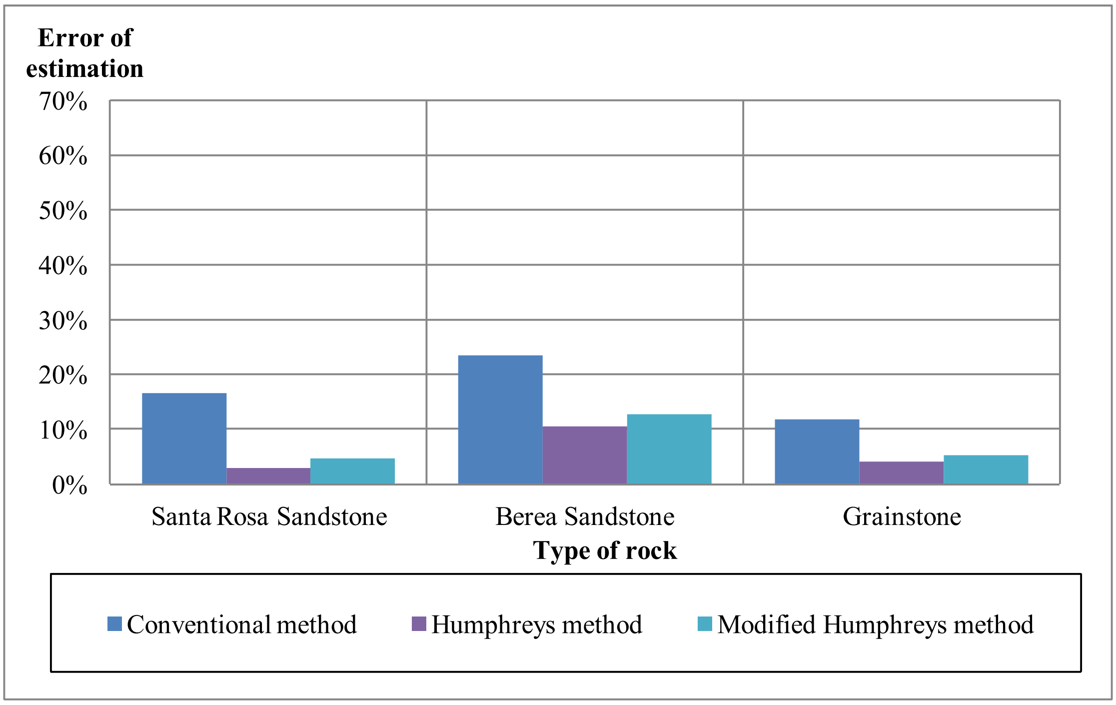

Figure A-3.8: Error of G estimated by different methods for different reservoir rock at initial reservoir pressure 4,000 psi and water content 30% on data at 25% pressure depletion.

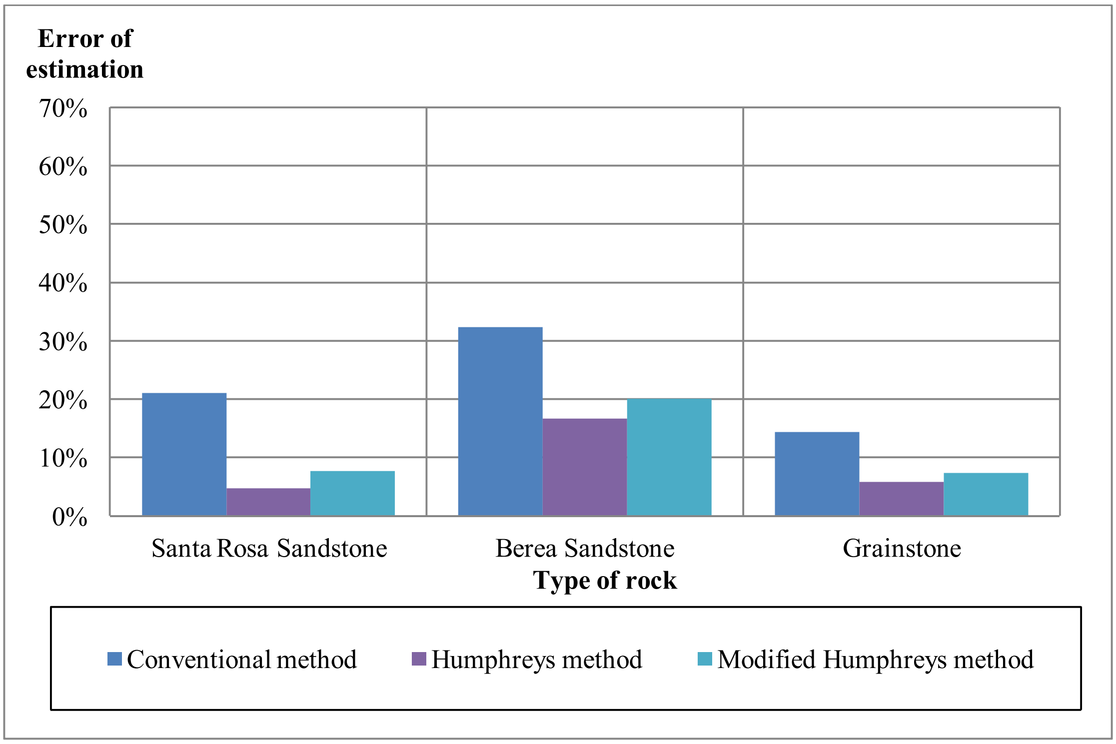

Figure A-3.9: Error of G estimated by different methods for different reservoir rock at initial reservoir pressure 5,000 psi and water content 30% on data at 25% pressure depletion.

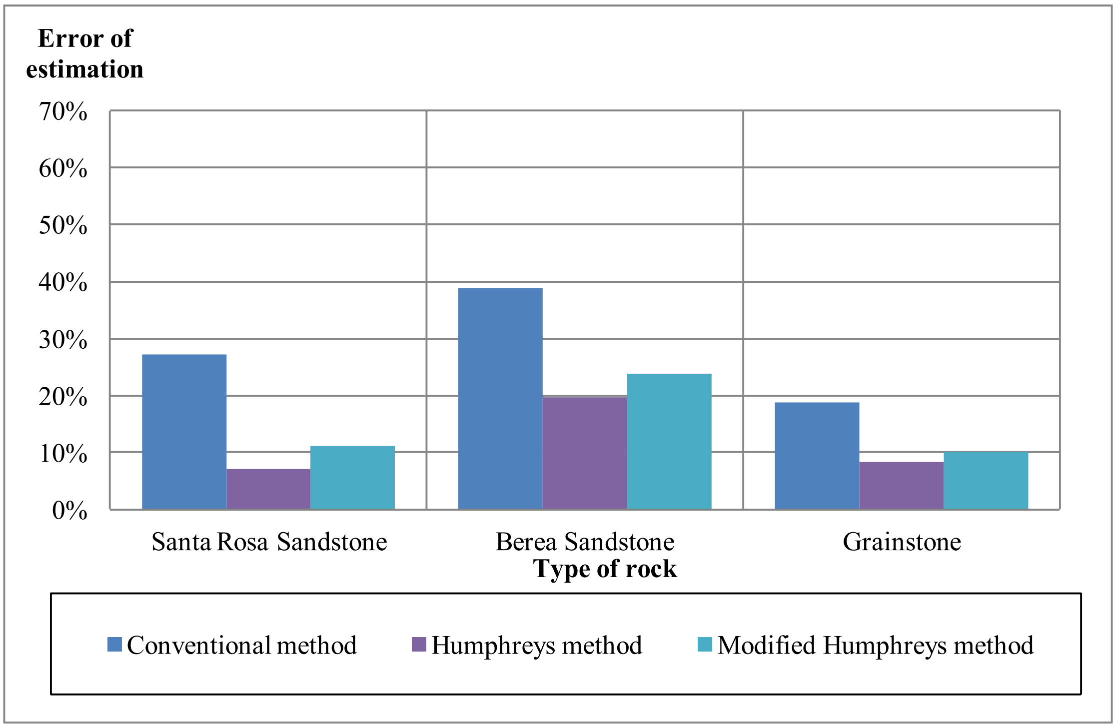

Figure A-3.10: Error of *G* estimated by different methods for different reservoir rock at initial reservoir pressure 6,000 psi and water content 30% on data at 25% pressure depletion.

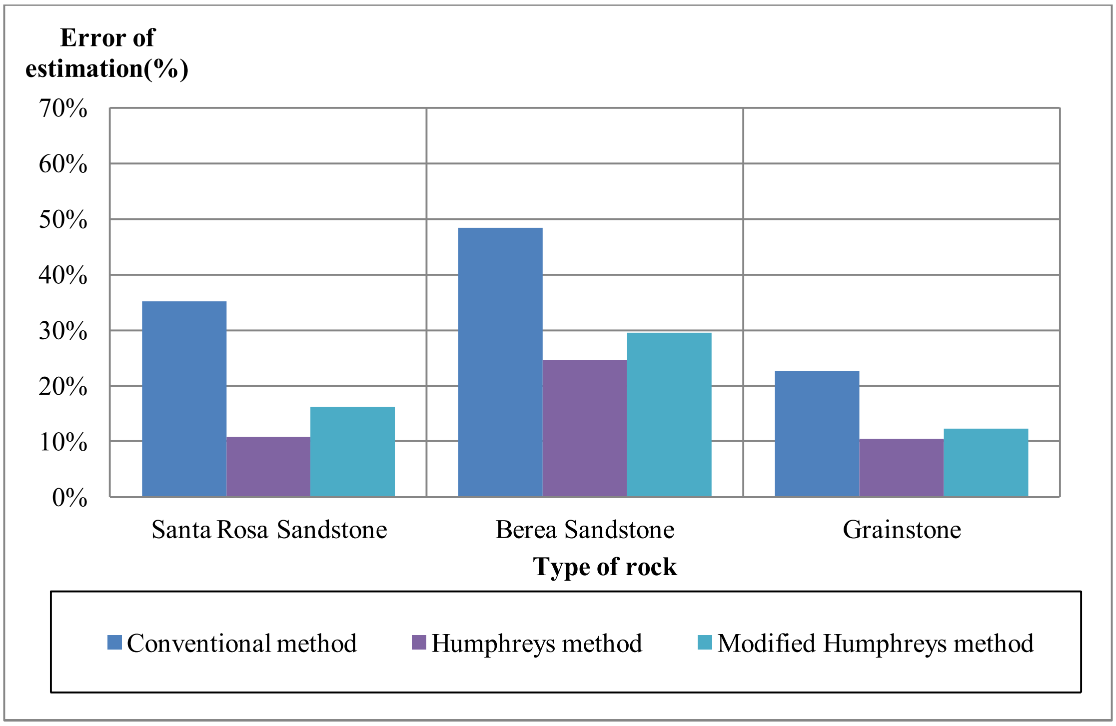

Figure A-3.11: Error of *G* estimated by different methods for different reservoir rock at initial reservoir pressure 7,000 psi and water content 30% on data at 25% pressure depletion.

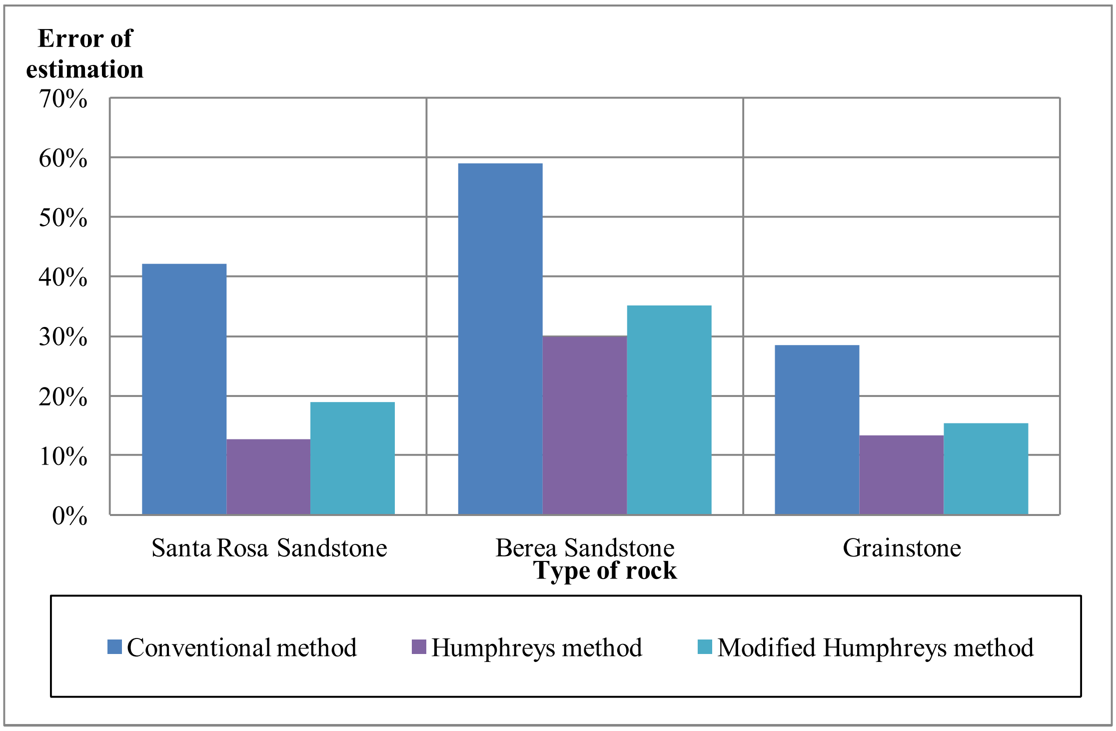

Figure A-3.12: Error of *G* estimated by different methods for different reservoir rock at initial reservoir pressure 8,000 psi and water content 30% on data at 25% pressure depletion.

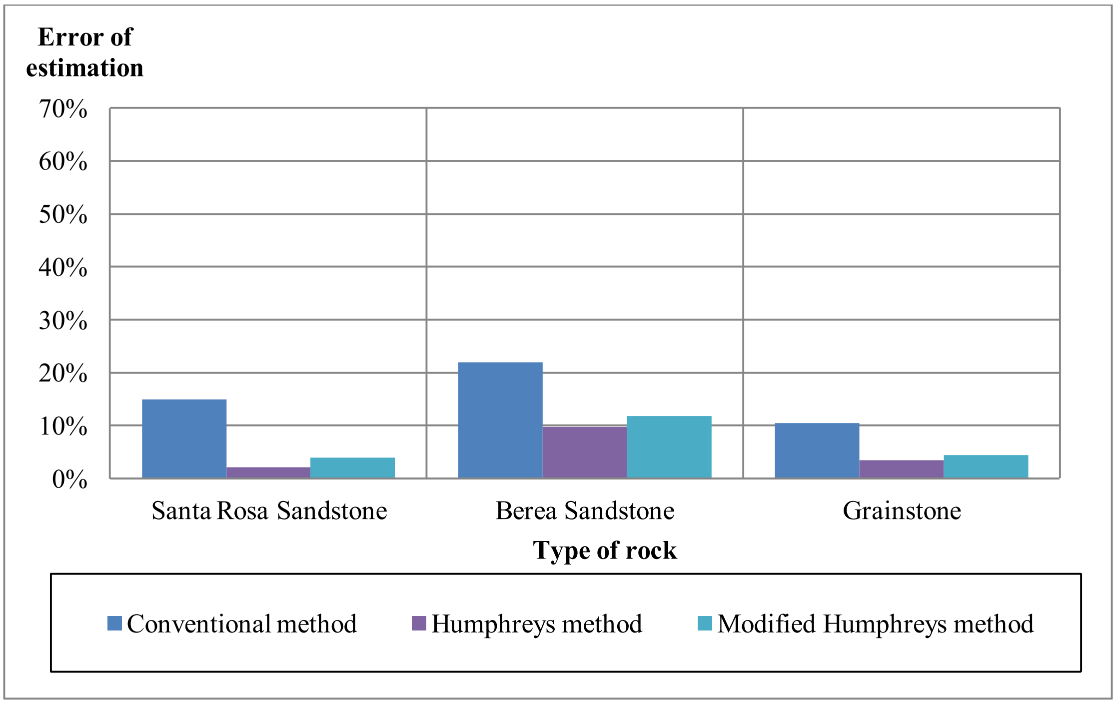

Figure A-3.13: Error of *G* estimated by different methods for different reservoir rock at initial reservoir pressure 3,566 psi and water content 40% on data at 25% pressure depletion.

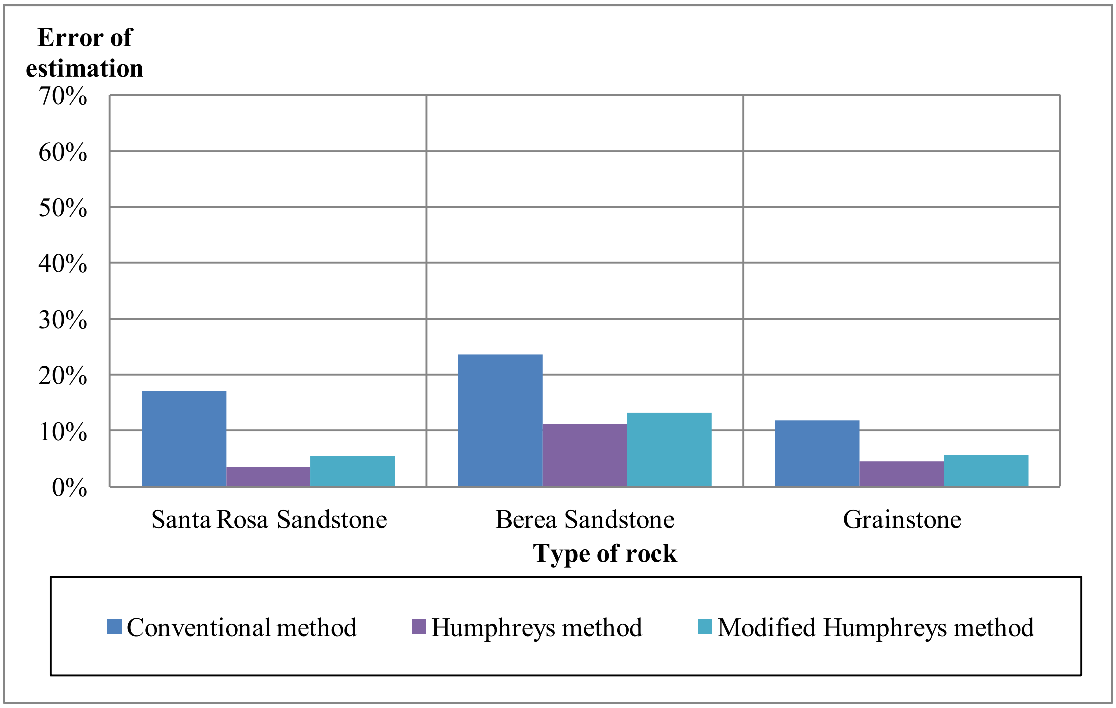

Figure A-3.14: Error of *G* estimated by different methods for different reservoir rock at initial reservoir pressure 4,000 psi and water content 40% on data at 25% pressure depletion.

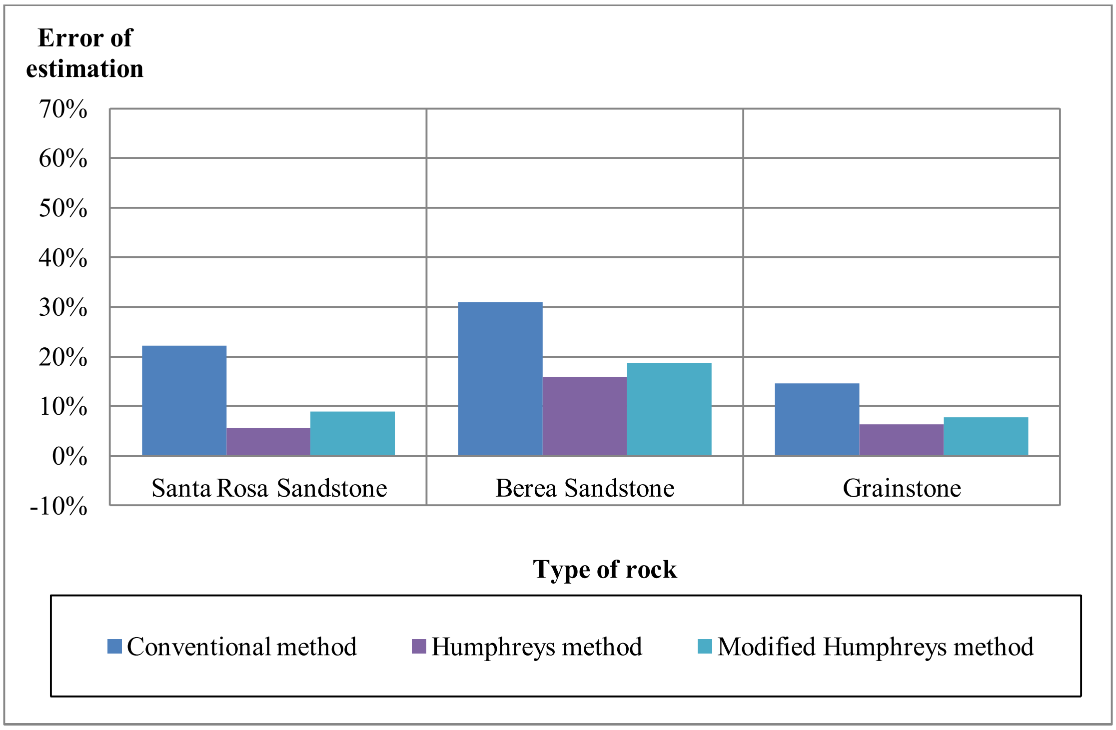

Figure A-3.15: Error of *G* estimated by different methods for different reservoir rock at initial reservoir pressure 5,000 psi and water content 40% on data at 25% pressure depletion.

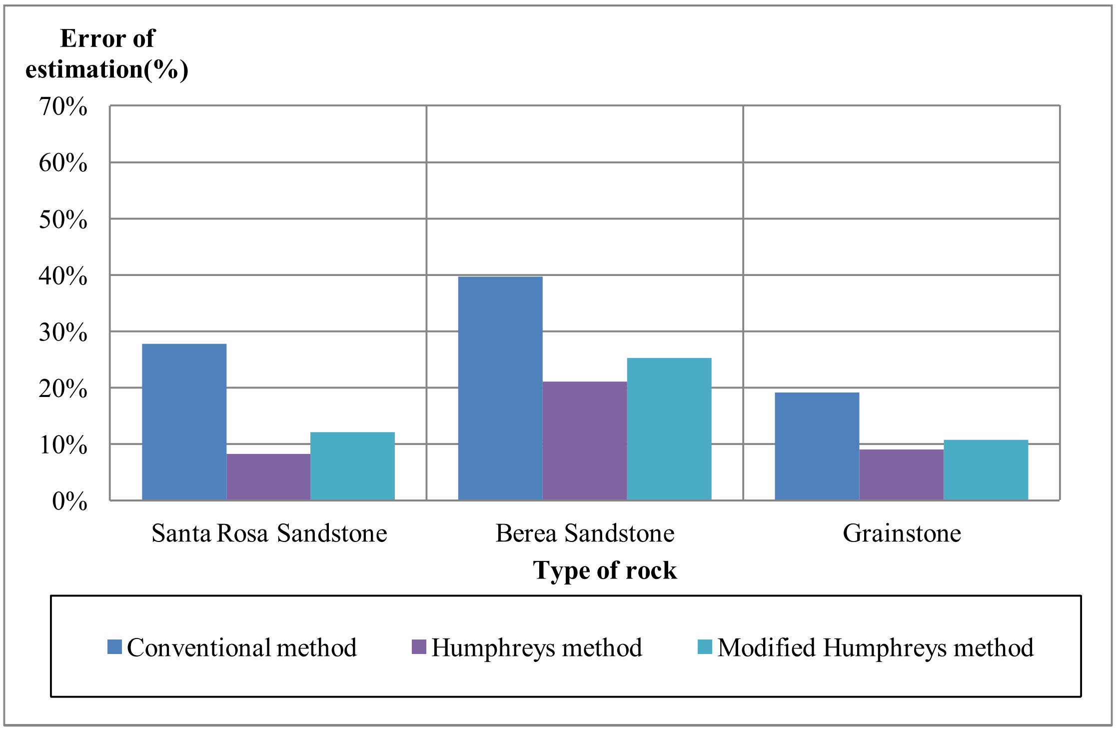

Figure A-3.16: Error of *G* estimated by different methods for different reservoir rock at initial reservoir pressure 6,000 psi and water content 40% on data at 25% pressure depletion.

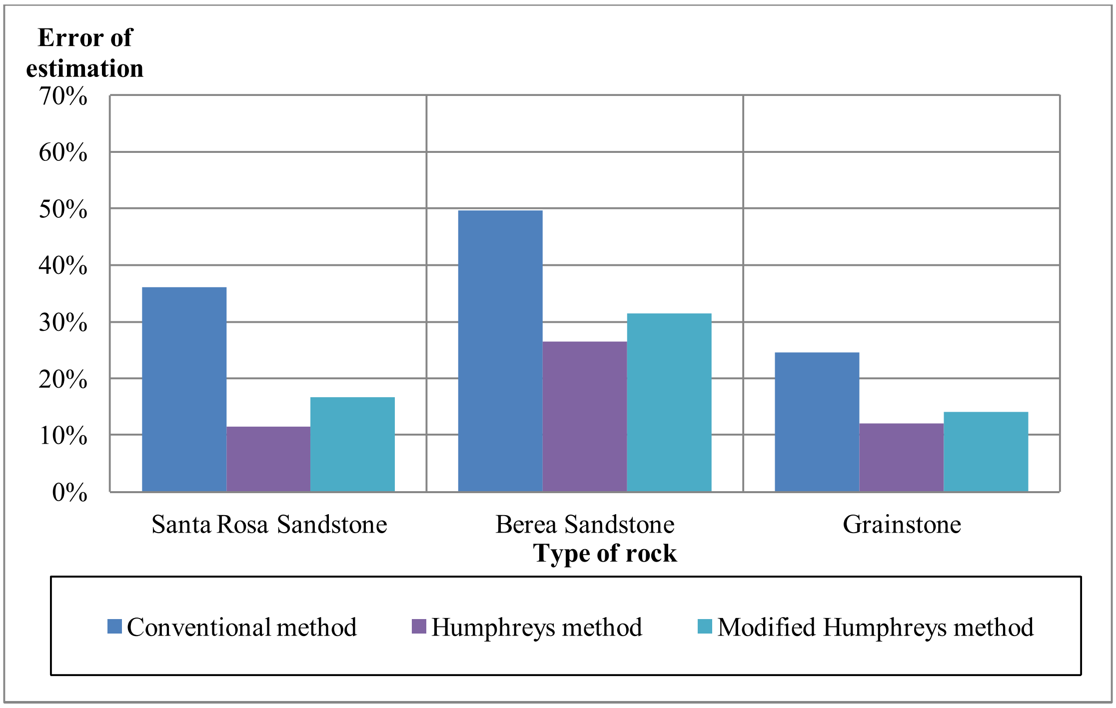

Figure A-3.17: Error of *G* estimated by different methods for different reservoir rock at initial reservoir pressure 7,000 psi and water content 40% on data at 25% pressure depletion.

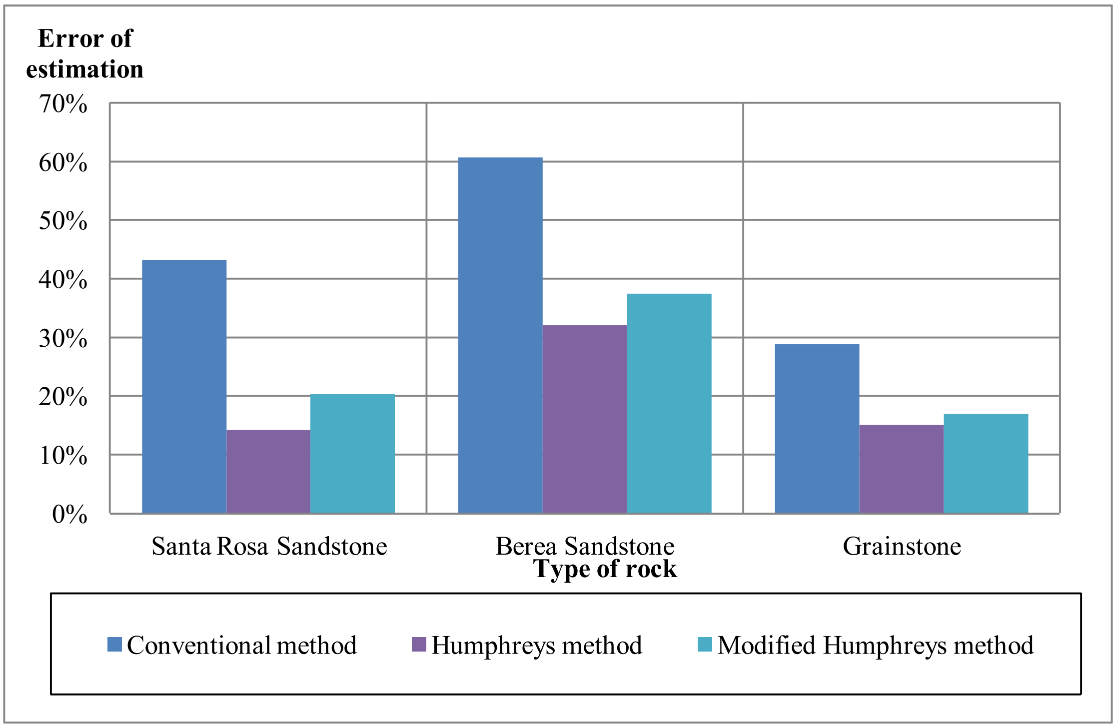

Figure A-3.18: Error of *G* estimated by different methods for different reservoir rock at initial reservoir pressure 8,000 psi and water content 40% on data at 25% pressure depletion.

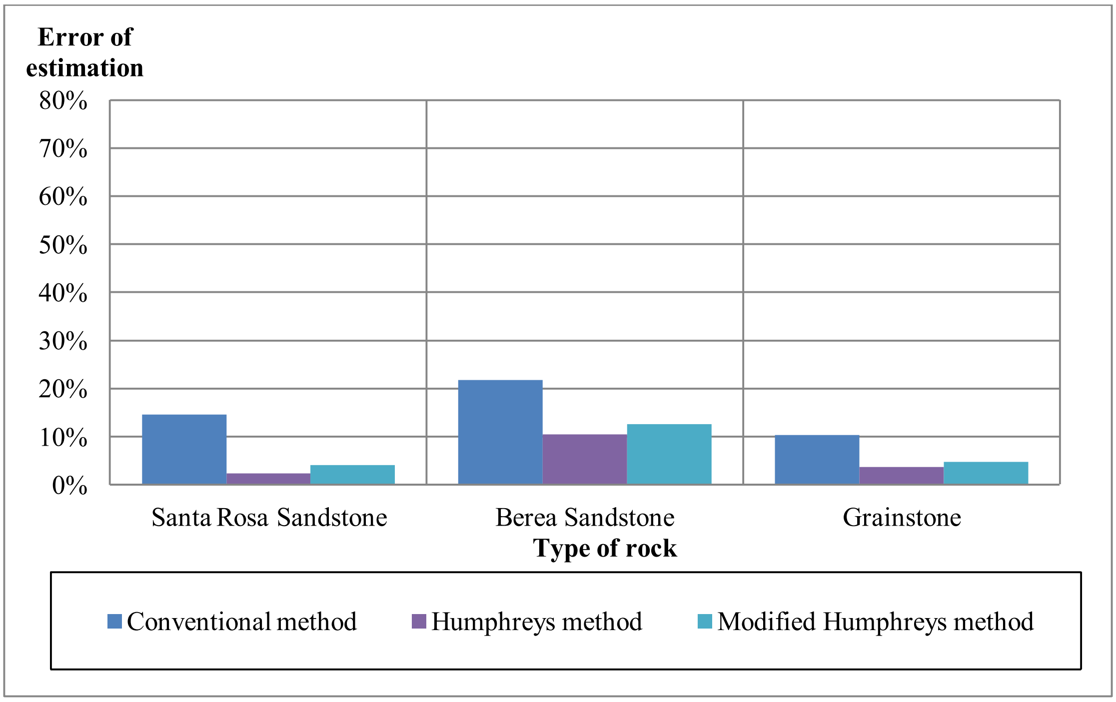

Figure A-3.19: Error of *G* estimated by different methods for different reservoir rock at initial reservoir pressure 3,566 psi and water content 50% on data at 25% pressure depletion.

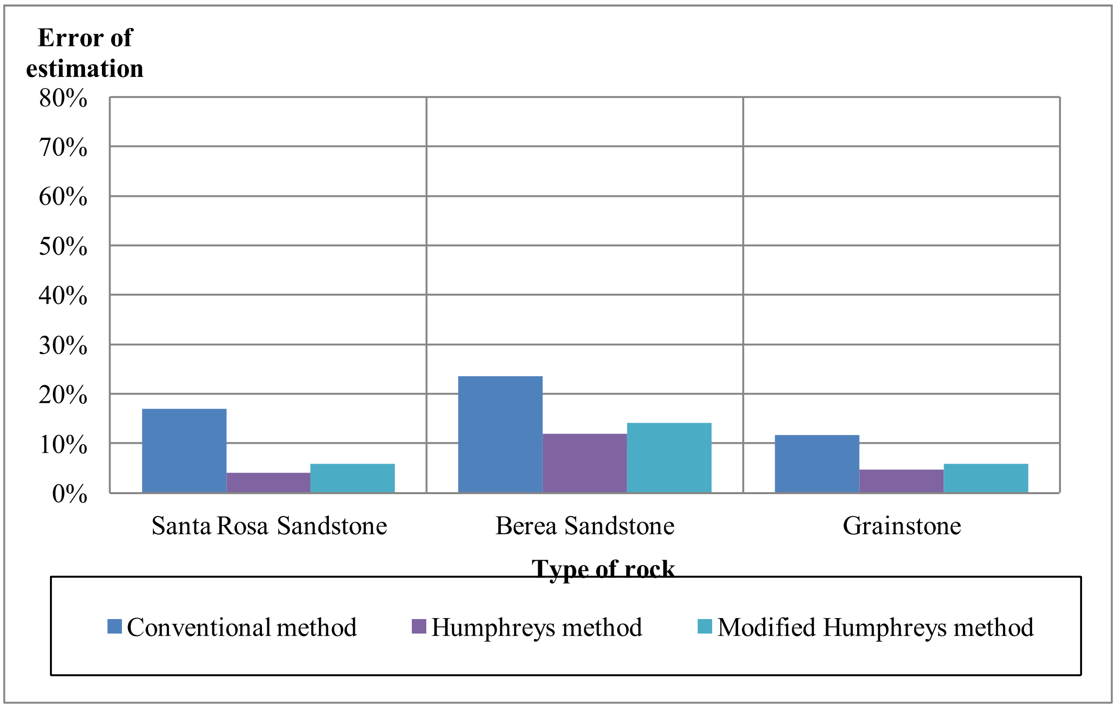

Figure A-3.20: Error of *G* estimated by different methods for different reservoir rock at initial reservoir pressure 4,000 psi and water content 50% on data at 25% pressure depletion.

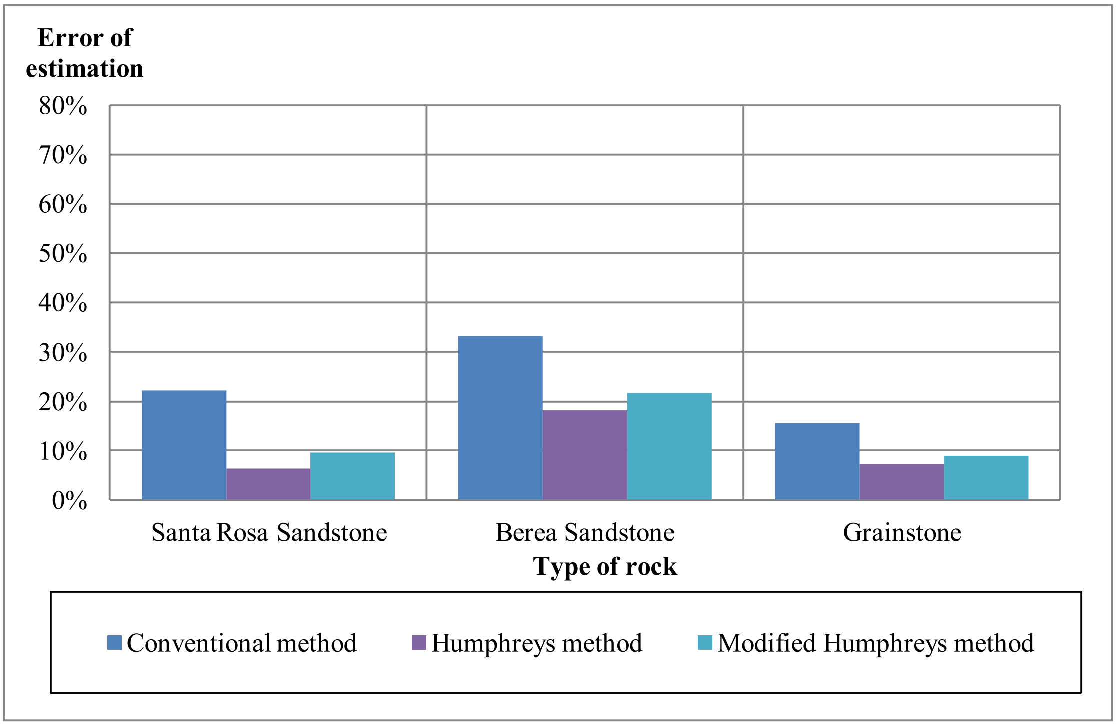

Figure A-3.21: Error of *G* estimated by different methods for different reservoir rock at initial reservoir pressure 5,000 psi and water content 50% on data at 25% pressure depletion.

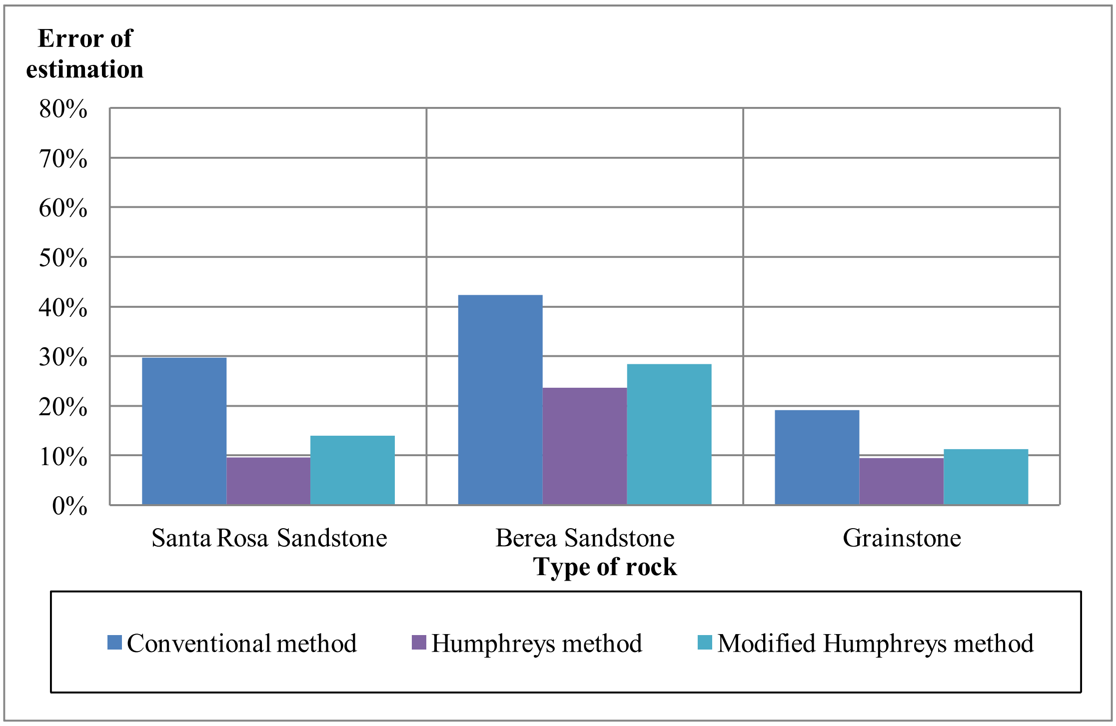

Figure A-3.22: Error of G estimated by different methods for different reservoir rock at initial reservoir pressure 6,000 psi and water content 50% on data at 25% pressure depletion.

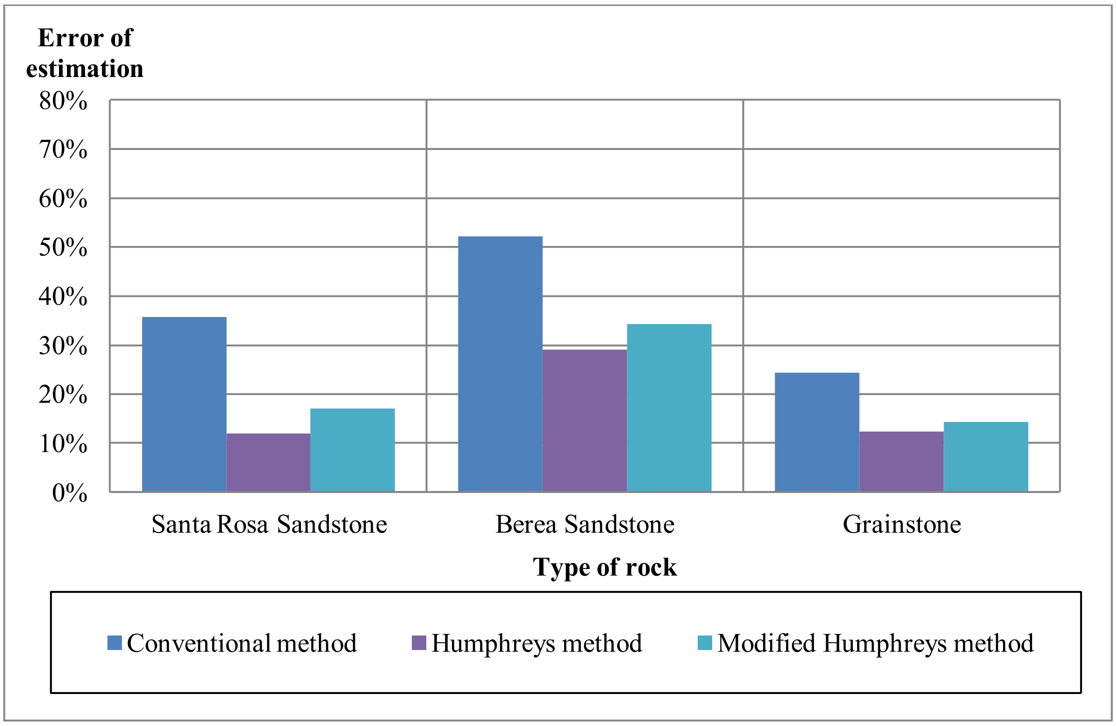

Figure A-3.23: Error of G estimated by different methods for different reservoir rock at initial reservoir pressure 7,000 psi and water content 50% on data at 25% pressure depletion.

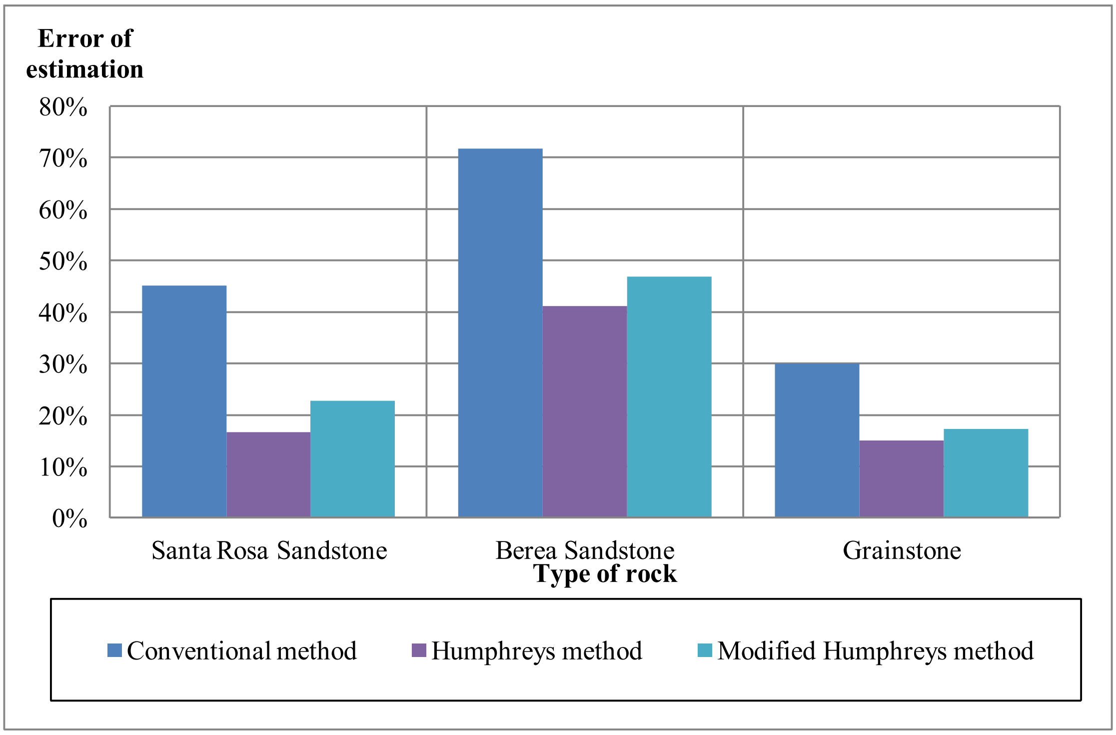

Figure A-3.24: Error of *G* estimated by different methods for different reservoir rock at initial reservoir pressure 8,000 psi and water content 50% on data at 25% pressure depletion.

VITAE

Worawut Sitthithanasut was born on January 19th, 1982 in Bangkok, Thailand. He grew up and studied in Phichit province until High school. Then he received his Bachelor of Engineering in Mechanical Engineering from Faculty of Engineering, Chiang Mai University in 2004. He has been a graduate student in the Master's Degree Program in Petroleum Engineering in the Department of Mining and Petroleum Engineering, Chulalongkorn University since 2009.