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Modeling Hydraulic Fracture System For Low Recovery Gas Reservoir

{ Fracture Gas Wells in Low Permeability Layers (AG Sand Formation) }

In Jake South Field

نمذجة نظام التشقق الهيدروليكي لمكمن غازي منخفض الانتاجية (تشقيق الآبار الغازية عند الطبقات ذات النفاذية المنخفضة) في حقل جيك الجنوبي

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الاستهلال ....

(اقرأ باسم ربك الذى خلق)سورة العلق الايه ١

Dedication

We would like to donate this unpretentious effort to

Our parents ; who lighting the path for us to move forward, advising and motivating us by their wide wisdom to reach this level of life and without them we would not become the persons who we are today.

OUR BROTHERS AND SISTERS ; Who stand with us, allow us to use their purpose when we needed to complete this research.

. **FOR PETROLEUM STUDENTS ;** who will share and upgrade the oil industry revolution in our great country Sudan. We are humble to offer this modest work and we hope that assisting to guide and understand some principle of an oil industry process. Thanks all for supporting and encouraging**.**

Finally; our best friends……..

AKNOWLEGMENTS:

First of all; we would like to thank God for his blessing on us to achieve this work.

Secondly; we would like to give many thanks to the castle of science Sudan university of science & technology; as well as college of petroleum engineering & technology generally, and department of petroleum engineering especially.

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for his guidance and assistance. In addition; for his wisdom and authoritative knowledge. That has upper hand in accomplishing the research in its current view.

Abstract

In this searching in order to Enhance the productivity of low permeability wells in **JF** "**JAKE FIELD**" hydraulic fracture was performed specifically on low permeability layers(AG Formation charactristic with low permeability due the compaction of layers) in this case permeability less than 0.05 darcay ,

Hydraulic fracture is performed to **well-JS-01** and **well –JS-04** In order to increase the well productivity & field recovery factor ,CMG software used with given model (Jake field) and by alternating the fracture parameter and trying different scenario of production,

The parameters of fracture to achieve permeability improvement and they are:

The fracture width (0.3048m)& the fracture half length (95.0976m)

The change in oil & gas production and water production was also monitored with the change in the permeability of layers on which the hydraulic fracture was performed ,

Then it was concluded that the productivity of wells improved after performing hydraulic fracture processon them , and that the process also lead toan improvement the field recovery factor .

التجريد ....

في هذا البحث من أجل تعزيز إنتاجية الآبار منخفضة النفاذية في "JAKE FIELD" JF تم إجراء التشقق الهيدروليكي على وجه التحديد في الطبقات منخفضة النفاذية ((AG Formation) ذات نفاذية منخفضة بسبب ضغط الطبقات) وفي هذه الحالة كانت النفاذية أقل من (**٠,٠٥ دارسي**)، تم إجراء الكسر الهيدروليكي على الابار JS - 01 - و JS 04 - من أجل زيادة انتاجية الابار والحقل ككل ، تم استخدام برنامج CMC مع نموذج معين (Jake field) ومن خلال وضع عرض وطول الشق وتجربة سيناريو مختلف للإنتاج ، وكانت الابعاد للشق لتحقيق تحسين النفاذية هي :

عرض الشق (**٠,٣٠٤٨ متر**) ونصف الكسر بطول (**٩٥,٠٩٧٦ متر**) .

تم رصد التغيير في إنتاج الغاز والنفط ,وإنتاج المياه ايضا مع التغيير في نفاذية الطبقة التي يتم إجراء التكسير الهيدروليكي عليها من اجل تقيم التحسين في انتاجية الابار المعينة وايضا معامل انتاجية الحقل قبل وبعد عملية التشقق الهيدروليكي ، حيث تم التوصل الى ان انتاجية الابار تحسنت بعد اجراء عملية التشقق عليها وان العملية تؤدي الى تحسين معامل انتاجية الحقل .

THE CONTENT :

CHAPTER 1 1

INTRODUCTION :.. 2

1.1.1hydraulic fracture………………….. 2

1.1.2hydraulic fracturing ……………:.. 2

1.1.3The process…………………….. :.. 2

1.1.2 Fracturing Equipment :.. 2

1.1.GAS RESERVOIR :………….. 3

1.1.1.Retrograde gas-condensate reservoir. ….. 3

1.1.2.Near critical gas condensate reservoir……………..………………5

1.1.3.Dry-gas reservoir…………………….. 6

1.1.4.Wet-gas reservoir………………….. 6

1.2.low permeability:……………... 8

. 1.3.Formation of tight-gas reservo…………………………………............. 10

1.4.AG sand formation:…………………… 12

1.4.1.About AG formation :…………………….................................... 12

1.4.2.Reservoir and Geology Introduction of Abu Garbra: ………………………13

1.4.3.Production situation……………….. 13

1.5.PROBLEM STATEMENT……………….. 14

1.6.THE OBJECTIVE………………… 15

CHAPTER 2 16

2.1. LITERATURE REVIEW.. 17

2.1.1 Case study 17

2.1.2. hydraulic fracture history... 18

2.1.3 hydraulic fracture 21

2.1.3.1 the geology.. 21

2.1.3.1.1. FORMATION EVALUATION :.. 21

2.1.3.1.3. PERMEABILITY :... 22

2.1.3.1.4. POROSITY : 22

2.1.3.1.5. CABILLARY PRESSURE : 22

2.1.3.1.6. Logging ANALYSIS :... 22

2.1.3.1.7. MECHANICAL PROPERTIES :.. 22

2.1.3.2 the process 23

2.1.3.2.1. Hydraulic fracturing process 23

2.1.4 horizontal well complition 25
Horizontal well completion 25
The benefits of horizontal well: 25
There are several conditions should be considered for selection of horizontal well completion: 26
The methods of horizontal well completion: 26
2.1.4 fracturing fluid 28
Fracturing fluids 28
There are criteria can be considered to achieve successful stimulation: 28
The additives include: 29
Essentially four types of fracturing fluids: 29
The main disadvantage is returned water contain residual breakers the water is not reusable. 30
CHAPTER 3 31
3.1. METHODOLOGY 32
3.1.1 Methodology Introduction 32
CMG software 32
IMEX MODEL 32
The β Model (Black Oil Model) 33
GEM –SIMULATOR 34
ADAPTIVE IMPLICIT FORMULATION 34
PROPERTIES 35
COMPLEX RESERVOIRS 35
GEOMECHANICAL MODEL 36
WELLS 36
MATRIX SOLUTION METHOD 37
SIMULATION RESULTS FILES 37
PORTABILITY 37
PVT Correlation 38
The correlation theory 39
Standing 39
2-VasquezBeggs 39
3=Glose 40
CHAPTER 4 41
1.1.RESULTS AND DISCUSSION 48
Hydraulic fracture implementing on two well 48

Well JS-01 performance before fracture..49
Well JS-04 performance before fracture..50
Field performance..51

CHPTER 5 53

5.1. CONCLUSIONS 60
5.2. RECOMMENDATIONS: 61

CHAPTER 6 62

6.1. REFERENCES: 63

List of Figures

Fig(1.1) Retrograde gas condensate reservoir……………………………………4

Fig(1.2) liquid shrinkage curve……………………………………………………5

Fig(1.3) Dry gas reservoir……………………………………………………..6

Fig(1.4) wet gas reservoir…………………………………..…..……………...7

Fig(3.1) Numerical Simulation Model Description……………...……………..40

Fig(3.2) Relative permeability vs water saturation…..………………………...41

Fig(3.3) Relative permeability vs gas saturation………………………………41

Fig(3.4) Oil gas capillary pressure vs gas saturation………………..………..42

Fig(3.5) Oil gas capillary pressure vs water saturation……………………...42

Fig(3.6) Hydraulic Fracture Geometry…………………………………………43

Fig(4.1) Cumulative Gas & water production before fracture well JS-0-1……………………………………………………………………..…48

Fig(4.2) Cumulative Gas & water production before fracture well JS-0-4…………………………………………………………………...…...49

Fig(4.3) Gas recovery factor vs Time…………………………………...…......50

Fig(4.4) water cut %.........................…………………………………………....51

Fig(4.5) Cumulative Gas production with fracture performed in JS-01………..52

Fig(4.6) Cumulative Water production with fracture performed in JS-01 ……..53

Fig(4.7) Cumulative Gas production with fracture performed in JS-04………..54

Fig(4.8) Cumulative water production with fracture performed in JS-04……………………………………………………………..………………55

Fig(4.9) gas recovery factor after fracture……………………………….……..…56

Fig(4.12) water cut % after fracture……………………………….……..…57

NOMENCLATURE

SYMBOLS	ABBERVIATION
JK	Jake Field
EOR	Enhance oil recovery
CMG	Computer Modeling Grouping
GEM	Geo science Equation of State Modeling
IMEX	Implicit-Explicit Black oil simulator
STARS	Steam Thermal and advanced Processes Reservoir
CUM OIL	Cumulative oil

Symbols	Abbreviation
WOR	Water oil ratio
CUM liquid	Cumulative liquid
P	System Pressure (pisa)
Rs	The Gas solubility (SCF/STB)
γo	Specific gravity of the stock tank
γg	Specific gravity of the solution(Fraction)
γgs	Gas gravity of the reference separator pressure
T	Temperature ,R
CUM GAS	Cum gas

SYMBOL	**ABBREVIATION**
C1,C2,C3	Coefficient values of certain magnitudes for gas solubility equation Vasquez Beggs
A,B,C	Coefficient values of certain magnitudes for bubble Point pressure for Glose
Pb	Bubble point pressure (pisa)
Bob*	Is a correlating number is defined by
X	.0125 API-.00091(T-460) 'for Standing'
Bo	Oil formation volume factor
Bg	Gas formation volume factor

CHAPTER 1
GENERAL INTRODUCTION

Chapter 1

Introduction :

1.1.1 hydraulic fracture

1.1.2 hydraulic fracturing :

hydraulic fracturing is a technique used to enable the extraction of natural gas or oil from shale and other forms of “tight” rock (in other words, impermeable rock formations that lock in oil and gas and make its production difficult). Large quantities of water, chemicals, and sand are blasted into these formations at pressures high enough to crack the rock, allowing the once-trapped gas and oil to flow to the surface.

1.1.3 The process :

The process starts with the drilling of a long vertical or angled well that can extend a mile or more into the earth. As the well becomes close to the rock formation where the natural gas or oil exists, drilling then gradually turns horizontal and extends as far as thousands of feet. Then casings are inserted into the well, and the space between the rock and the casing is fully or partially filled with cement. Small holes are made in the casing with a perforating gun, or the well is constructed with pre-perforated pipe. Fracking fluid is then pumped in at a pressure high enough to create new fractures or open existing ones in the surrounding rock. This allows the oil or gas to flow to the surface for gathering, processing, and transportation, along with contaminated wastewater that is stored in pits and tanks or disposed of in underground wells.

1.1.2 Fracturing Equipment :

Hydraulic fracturing requires an extensive amount of equipment, such as high-pressure, high-volume fracking pumps; blenders for fracking fluids; and storage tanks for water, sand, chemicals, and wastewater. This infrastructure, plus more, typically arrives at drill sites via heavy trucks.

1.1. Gas Reservoir :

In general, if the reservoir temperature is above the critical temperature of the hydrocarbon system, the reservoir is classified as a natural gas reservoir. On the basis of their phase diagrams and the prevailing reservoir

conditions, natural gases can be classified into four categories:

- Retrograde gas-condensate
- Near-critical gas-condensate
- Wet gas
- Dry gas

1.1.1. Retrograde gas-condensate reservoir.

If the reservoir temperature T lies between the critical temperature Tc and cricondentherm Tct of the reservoir fluid, the reservoir is classified as a retrograde gas-condensate reservoir. This category of gas reservoir is a unique type of hydrocarbon accumulation in that the special thermodynamic behavior of the reservoir fluid is the controlling factor in the development and the depletion process of the reservoir. When the pressure is decreased on these mixtures, instead of expanding (if a gas) or vaporizing (if a liquid) as might be expected, they vaporize instead of condensing.

❖ **The associated physical characteristics of this category are:**

• Gas-oil ratios between 8,000 to 70,000 scf/STB. Generally, the gas-oil ratio for a condensate system increases with time due to the liquid dropout and the loss of heavy components in the liquid.
• Condensate gravity above 50° API
• Stock-tank liquid is usually water-white or slightly colored.
There is a fairly sharp dividing line between oils and condensates from

a compositional standpoint. Reservoir fluids that contain heptanes and
are heavier in concentrations of more than 12.5 mol% are almost always
in the liquid phase in the reservoir. Oils have been observed with heptanes and heavier
concentrations as low as 10% and condensates as high
as 15.5%. These cases are rare, however, and usually have very high tank liquid gravities

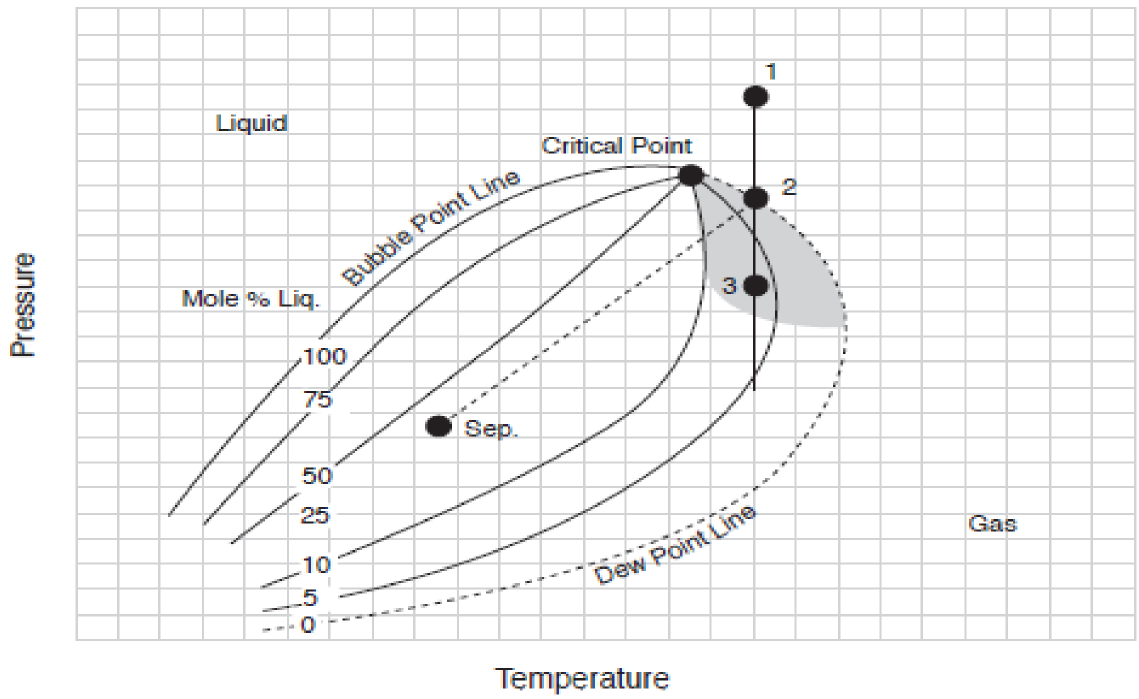

Figure 1-1 . Typical P-T diagram for Retrograde gas-condensate system

1.1.2. Near-critical gas-condensate reservoir.

If the reservoir temperature
is near the critical temperature, as shown in Figure 1-13, the hydrocarbon mixture is classified as a near-critical gas-condensate. The volumetric behavior of this category of natural gas is described through the isothermal pressure declines as shown by the vertical line 1-3 in Figure 1-1 and also by the corresponding liquid dropout curve of Figure 1-1. Because all the quality lines converge at the critical point, a rapid liquid buildup will immediately occur below the dew point (Figure 1-1) as the

pressure is reduced to point 2.

This behavior can be justified by the fact that several quality lines are crossed very rapidly by the isothermal reduction in pressure. At the point where the liquid ceases to build up and begins to shrink again, the reservoir goes from the retrograde region to a normal vaporization region.

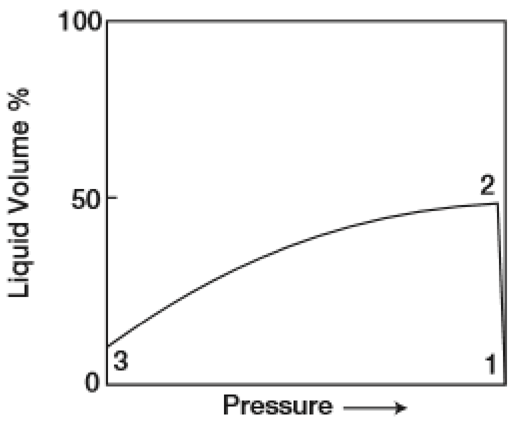

Figure1-2 . Liquid shrinkage curve

1.1.3. Dry-gas reservoir.

The hydrocarbon mixture exists as a gas both in the reservoir and in the surface facilities. The only liquid associated with the gas from a dry-gas reservoir is water. A phase diagram of a dry-gas reservoir is given in Figure 1-16. Usually a system having a gas-oil ratio greater than 100,000 scf/STB is considered to be a dry gas.

Kinetic energy of the mixture is so high and attraction between molecules so small that none of them coalesce to a liquid at stock-tank conditions of temperature and pressure.

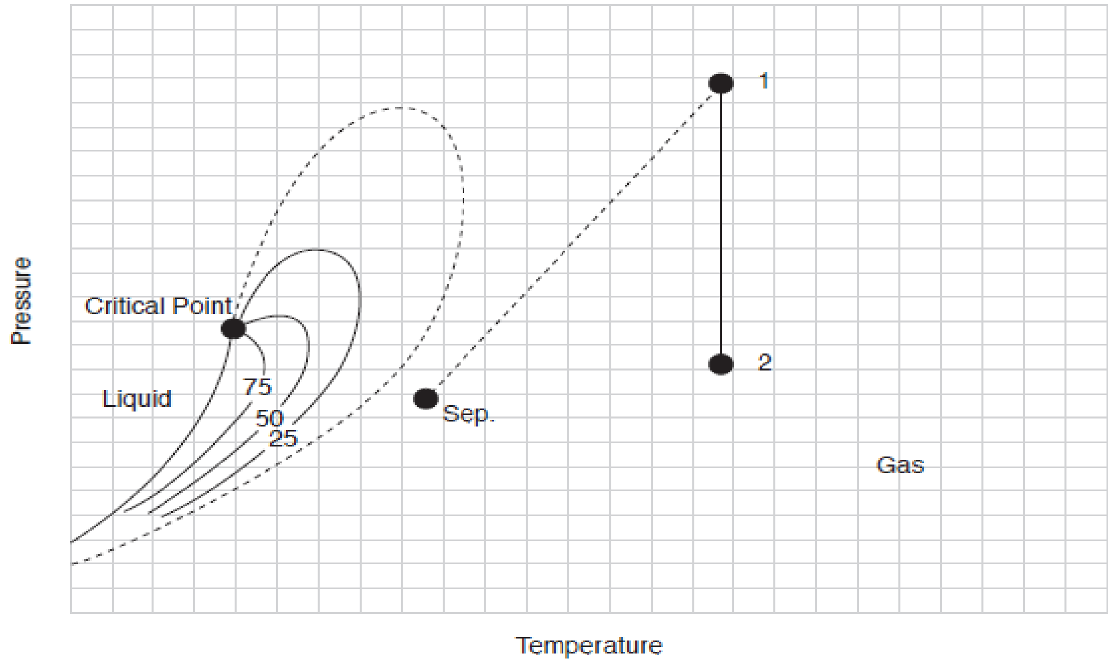

Figure 1-3 . Typical P-T diagram for Dry Gas system

1.1.4. Wet-gas reservoir.

A typical phase diagram of a wet gas is shown in Figure 1-15, where reservoir temperature is above the cricondentherm of the hydrocarbon mixture. Because the reservoir temperature exceeds the cricondentherm of the hydrocarbon system, the reservoir fluid will always remain in the vapor phase region as the reservoir is depleted isothermally, along the vertical line A-B.

As the produced gas flows to the surface, however, the pressure and temperature of the gas will decline. If the gas enters the two-phase region, a liquid phase will condense out of the gas and be produced from the surface separators. This is caused by a sufficient decrease in the kinetic energy of heavy molecules with temperature drop and their subsequent change to liquid through the attractive forces between molecules.

Wet-gas reservoirs are characterized by the following properties:

- Gas oil ratios between 60,000 to 100,000 scf/STB
- Stock-tank oil gravity above 60° API
- Liquid is water-white in color
- Separator conditions, i.e., separator pressure and temperature, lie within

  the two-phase region

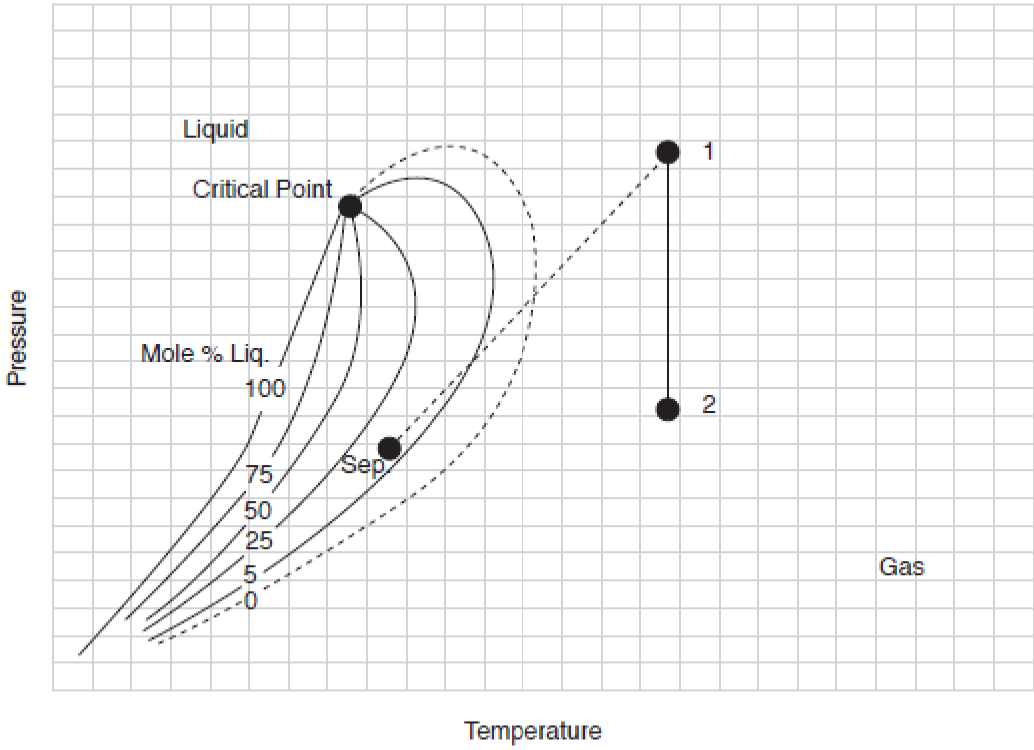

Figure 1-4 . Typical P-T diagram for Wet Gas system

1.2. low permeability:

Gas well and low permeability

Permeability is a property of rock that measure and ability the fluid can transmint in porous media.

Also defined a measurement of the ability of a fluid to flow through the rock.

Permeability K is a very important property so that measure the capacity and controlling of fluid inside the formation and movement it.

Permeability defined mathematically by darcy equation in 1958,

V=-k/u*dp/dl

V=apparent fluid flowing velocity,cm/sec

K=permeability,md

U=fluid viscosity,cp

dp/dl=pressure drop per unit length,atm/cm

Low permeability means reduction in porous media due to compaction in formation and high homogeneity.

Low permeability refer to unconventional reservoir either consist oil or gas but the most common unconventional reservoir is gas reservoir as known tight gas reservoir(unconventional gas reservoir).

The different between the conventional and unconventional reservoir that the conventional reservoir is essentially a high to medium permeability therefore the unconventional reservoir cannot produce at economic flow rate due to low permeability so used a stimulation or any recovery method such as hydraulic fracturing or EOR methods.

Tight gas reservoir:-

Gas reservoir containing only free gas as known gas reservoir so the mixture of hydrocarbon inside the reservoir depending on the composition of a gas.

The mixture may be dry,wet, and condensate gas anywise the tight gas reservoir with low permeability less than .01md

Tight gas reservoir also defined as a gas bearing sandstone or carbonate matrix which appear an in-situ permeability to gas of less than .01md.

Classification of tight gas reservoir:

There are several tight reservoir such as oil tight, gas tight,

Shale gas and shale oil.most of them will be coverd in this classification from a geologic perspective.

1.3. Formation of tight-gas reservoir

What makes a tight reservoir?

There are several factors governed that can make tight reservoir so the factor related to the nature of fluid, the rock parameters which are effective porosity, viscosity, fluid saturation and capillary pressure.

But we can say the effective permeability is a main reason of tight reservoir yet those are controlled by depositional and post depositional environments the reservoir is subjected to .

Gas well:

There are many types of production well

1-well that produce oil and gas.

2-well that produce only gas.

3-well that produce only oil.

Gas well drilling and completion:

Drilling is one of the most stages in oil and gas industry .it involves alot of procedures and special equipment using in this aspect but in this section doesnot provide all the overall

description of drilling.

There are some problem facing when drill natural gas wells and affect the drilling of natural gas can be mentioned below:

• There could be a need for higher grade casing because of the occasional need for higher burst rating in gas wells.
• When using oil based drilling fluids, gas solubility could be a problem. Oil based systems can partially mask the existence of a gas kick, thereby creating well control situations in gas wells.

• Although not exclusive to gas wells, but more likely to occur,
when the reservoir fluid is associated with corrosive gases,
such as H_2S and CO_2, there would be increase demands from the casing selection, using corrosion resistant alloys.

• Although all industry well control schools stress that to handle well control issues in gas wells is similar to oil wells, the
wellhead equipment (blowout preventer or BOP, flanges, connections, etc.) could require higher premium products on
some gas wells because of higher wellhead pressures and leak
potential.

1.4. AG sand formation:

1.4.1. About AG formation :

The Fula sub-basin is a rift structure with units rich in petroleum accumulation within the Muglad Basin. In the past, thick sandstones of Bentiu were considered the main petroleum accumulation targets sealed by faults and anticlines, and most
petroleum generated by the Abu Gabra Formation source kitchen migrated to the upper formations along big faults, and sandstones within the Abu Gabra are thin with poor permeability and porosity caused by compaction. Recently, some works
have been done especially on the Abu Gabra Formation, including interpretation of small faults, seismic sedimentary analysis,
and thin layer inversion, resulting in new petroleum discoveries within the Middle Abu Gabra, which reveals good petroleum accumulation abilities.
Comprehensive study shows that there are many small faults developed within the Abu Gabra, which could seal sandstones
laterally and forming effective faulted blocks. Sandstones of delta and sub-water channels could be found. Within the AG4 and
AG 2 formations, there are mainly lacustrine facies. As the channel sandstones regressed, the area of alluvium fans decreased.
The Abu Gabra shale has high organic matter abundance, high hydrocarbon generating potential and kerogen type I, II with
middle to high maturity. Although sandstones of the Abu Gabra have relatively low permeability and porosity, these sandstones
have good logging response on hydrocarbon could be sealed by local surrounding mudstones. All the above reveals that the Abu
Gabra combination is a near-source reservoir combination. Low-amplitude anticline and structure-lithology reservoir models are
favorite reservoir models in the Fula sub-basin. In the west slope, especially the lower places of the slope, are areas of huge

sedimentary accumulation and should be favorite prospects. As for the east slope, low-amplitude anticlines bounded by small faults that developed during Abu Gabra deposition should be a favorite area for exploration, which has been proved by successful drilling activities. In the Fula sub-basin, the Abu Gabra structure-lithology complex reservoir combination should be the favorite type for drilling as per under these two key factors, the petroleum could be well accumulated. Currently, there have been two important petroleum discoveries of channel sandstones and delta sheet sandstones in the Abu Gabra, proving that the Abu Gabra still has good potential for drilling.

1.4.2. Reservoir and Geology Introduction of Abu Garbra:

- Abu Garbra formation is very deep, it is middle porosity and middle permeability reservoir. Formation - thickness is 1000－3300m, include three layer, oil and gas mainly spread in upper section, thickness is 400-600m, middle section is major mudstone and little fine sandstone, thickness is 2-6m.
- Abu Garbra is very complex and contains several oil, water and gas layer. Abu Garbra is normal pressure system, average pressure coefficient is 0.93, average
- temperature gradient is 3℃/100m, average salinity is 1858mg/L, major content is $NaHCO_3$, API viscosity is 29.7.

1.4.3. Production situation

Analyzed the production information of Abu Garbra, the production situation, Abu Garbra formation is very complex and contain several oil, water and gas layer, some wells perforated several layers, production is very complex. Some wells are shut.

Because of the casing perforation completion in Abu Garbra formation and no sand control and water control, the production wells are heavily sand production and water production. It causes low production and shut wells.

So,sand control and water control are major problem in Abu Garbra formation.

1.5. Problem statement

- natural gas provided about 23% of the total world energy supply Sudan is number 55 in natural gas reservoir country
- The gas obtained from natural underground reservoirs either as free gas or gas associated with crude oil ,The gas obtained from natural underground reservoirs either as free gas or gas associated with crude oil Contains large amounts of methane (CH_4) along with decreasing amounts of other hydrocarbon Impurities such as(H_2S, N_2, and CO_2) are often found with the gas generally comes saturated with water vapor.
- Conventional natural gas generally occurs in deep reservoir either associated with crude oil (associated gas) or in reservoirs that contain little or no crude oil (non associated gas)
- in Muglad basin Abugabra Formation is Deepest Formation Which charactrized by Low Permeability and porosity Caused by compaction .

1.6. The objective

Study of the effect of hydraulic fracturing in AG formation permeability

The effect of hydraulic fracture for different well location.

Evaluate the permeability improvementement.

Evaluate effect of process in the certain wells performance .

Evaluate the production Enhancement after hydraulic fracture process implemented .

CHAPTER 2 THEORETICAL BACKGROUND AND LITERATURE REVIEW

Chapter 2

2.1. Literature review

2.1.1 Case study

• Case study

Jake oilfield is located in the northeastern part of Muglad basin which is the largest known rift basin in Sudan interior, trending northwest-southeast and covering 120, 000 km2. The basin is around 800 km in length and 200 km in width. From the structural point of view, the Jake field can be divided into three compartments; the southern, central and northern compartments.
Formation characteristics
For Jake-S Oilfield, from bottom to top, the formations are:Sharaf, Abu Gabra, Bentiu, Aradeiba , Zarqa, Ghazal, Baraka, Amal, Tendi/Senna, Adok and Zeraf.
Aradeib : Lithology is thick mudstone and sandstone interbed; **Bentiu:** lithology is massive sandstone with mudstone;
The target of this study is Bentiu and it can be classified as 6 sands and 12 sublayers
Reservoir characteristics
Via core analysis, the porosity is 14%～37%， average is 24%， permeability is 500 ×10- 3～7000 ×10- 3μm2， and average is 2100×10- 3μm2. The reservoir is of middle and high porosity and high permeability. The diagenesis of the rock is weak, featuring unconsolidated cementing of sandstone and good physical property.

2.1.2. hydraulic fracture history

- (Smith, Miller and Haga 1987) they stated that Operationally, fracturing high permeability formation is different from fracturing low permeability formations due to the expected high leak-off rate, which influences fracturing pressure as a function of time. In addition, because of the desired high fracture conductivity, the concept of tip screen-out is applied (Hunt and SoIiman 1994). In tip screen-out, the fracture is designed in such a way that by the time the fracture reaches the desired length, the leading pad volume has leaked off into the formation. After the pad volume has leaked off, the presence of the proppant- ladenfluid at the leading edge of the fracture inmates the screen-out process. Continued injection of the proppant laden fluid causes the fracture to widen or balloon
  .
- Hunt and SoIiman (1994) results state that: Fracturing of damaged, high permeability formations should increase production and change the expectedpressure profile in the formation, possibly preventing sand production. Thus, fracturing is a viable completion option for high permeability formations where wellbore damage and/or the potential for sand production exists. When fracturing a high permeability formation, the fracture should be designed to extend beyond the external radius of the damaged region. Fractures that fail to extend beyond the damaged region will not improve production to optimum levels and will not significantly decrease the potential for sand production. It is unnecessary to generate significant fracture length beyond the external radius of the damaged region. However,it is always prudent to include a safety factor in the fracture design To properly design a fracture treatment it is important to run a pre-frac well test to determine formation permeability, amount of wellbore damage, and extent of wellbore damage. These parameters determine the necessity of a fracture, and optimum length and conductivity of the fracture. When fracturing a high permeability formation,a minimum fracture conductivity is required to improve production and decrease pressure drop in the formation. Generally, high fracture conductivities are desired to minimize pressure drop and gradient within the reservoir during production.

- Fracture conductivity may decline during production. Therefore, to assure that production improvement is maintained and sand production is minimized over the life of the well, the initial conductivity should be greater than the minimum required to improve production and decrease pressure drop in the formation. Fracture damage limits production improvement and increases the pressure drop and gradients, however, the degree of fracture damage must be severe before a pronounced effect is detected .

- Permeability reduction in the near-fracture vicinity must be great or damage must penetrate deep into the formation before a significant decline in productionimprovement and .a pronounced pressure drop result. Deep damage away from the fracture can be minimized by properly designing the frac-pack treatment.During production, the majority of the reservoir fluid will enter the part of the fracture outside the damaged region when the fracture extends beyond the damaged region. The topic of how to optimize fracture half-length has been discussed at length in the Petroleum Literature since the 1970s (Wei and Holditch 2009). Effective fracture lengths are frequently observed to be much less than anticipated fracture lengths. This is seen in lower than expected production or evidenced in pressure transient analysis results. A precursor to the poor fracture performance is poor recovery of the fracturing fluid; often less than 50% is recovered during clean-up. In many reservoirs this unrecovered fracturing fluid remains immobile within the formation creating an obstruction to flow. This significantly compromises effective frac length and results in decreased production. During the fracturing process and subsequent closure of the fracture, the bulk of the fracturing fluid invades the reservoir matrix along the fracture face, referred to as the “invaded zone”. This fluid is forced into the reservoir by the significant pressure differential between fracturing pressure and reservoir pressure. Once in the matrix, removal of fluid from the invaded zone can be very difficult as it is held by relative permeability, irreducible saturation, and/ro capillary pressure effects (Tudor, Nevison, and Allen 2009).
- The science of hydraulic fracturing has predominately been focused on fracture geometry and proppant placement to maximize production rates and cumulative production. Current technology for hydraulically fracturing tight reservoirs, including shales, often focuses on complex fracture volumes rather than bi-wing geometry to create and maximize the formation stimulated area. This in turn results in optimized commercial production rates. Within the conventional bi-wing hydraulic fracturing theory it is well understood that the optimized fracture length is inversely proportional to reservoir permeability. Similarly, the created fracture volume model used on shales tends to follow the same theory that optimized created volume is inversely proportional to the reservoir permeability. Both

conventional bi-wing and the created volume fracturing theories require that the fracture matrix be a substantial distance from the wellbore.

- Maimona Washie (2012) made a Geochemical evaluation carried to evaluate the source rock in Abu Gabra, pyrolysis analysis results of 617 geochemical rock samples from Azraq wells and 337 geochemical rock samples from Neem wells, used to evaluate the richness of source rock (TOC), kerogen type (HI, S2) and thermal maturity (Tmax). VRo readings of 119 rock samples from Azraq wells and 73 geochemical rock samples from Neem wells used to measure the thermal maturity. Based on the main key parameters used to evaluate shale gas in Marine basins there is high feasibility of shale gas in Lacustrine basin.
- Elham Khair and Muhammad Farid (2016) conducted a Preliminary Evaluation of Silica Sand in Sudan with Respect to Fracure Sand. Three samples were collected from different areas in Sudan and a series of laboratory tests were performed according to the API recommended practice API RP 19C. More than 10% of fine has been produced from the different samples under stress of 3000 Psi; which indicate that the sample can be used as proppant for reservoir with the closer pressure less than 3000 Psi; for pressure above 3000 Psi, the samples have to be coated for strength improvement.

2.1.3 hydraulic fracture

2.1.3.1 the geology

❖ **Hydraulic fracturing geology**

The normal oil and gas extraction is through drilling rocks that trap pertroleum and natural gas , this process occurs simply due to the difference in the pressure between the surface and the reservoir , however not all of the oil and gas are located in conventional and accessible reservoirs , many oil and gas recourses are trapped in impermeable sedimentary rock formations .

Thus the geology of hydraulic fracturing can be discussed from these prospectives :

2.1.3.1.1. FORMATION EVALUATION :

In general conventional natural oil and gas can easier be produced than the unconventional gas and oil in tight formations which is so difficult and expensive as well .
Basically conventional oil and gas reservoirs have permeability in range of (0.01 - 1 D) , but tight formations have a permeability level of (.001 darcy - 1*10^-9 darcy) .
As an example of tight formations is shale formations and also hydrocarbons that are trapped in sandstone or limestone that are typically nonporous .
We can consider tow types of tight formations :

(A) Tight sandstone or formations that were compressed during Geological time and before hydrocarbon immigrates into it .
(B) Tight shale formation which might be the original source rock that retained the oil and gas as it was formed .

2.1.3.1.2. FORMATION INTEGRITY :

The formation integrity test (FIT) is carried out to confirm the strength of the formation and the well casing shoe by increasing the bottom hole pressure into a design pressure .

So(FIT) shows the formation below the shoe will not fail while drilling subsequent sections with a higher bottom hole pressure .

The results of the test are used to design the mud program for the subsequent section and to set safe limits on casing shut-in or choke pressures for well control purposes .

2.1.3.1.3. PERMEABILITY :

Permeability is considered to be one of the important factor to determine the possibility of applying hydraulic fracturing . also the permeability of a formation affects the formation breakdown pressure in hydraulically fractured wells which (after been proven in laboratory)means that lower permeable rocks have a lower breakdown pressure and vise versa .

2.1.3.1.4. POROSITY :

Porosity is the ratio of void volume to bulk volume . It is obtained by determining two of the three variables : pore volume , bulk volume and grain volume .

The type of porosity test to be used depends on the formation being tested .

2.1.3.1.5. CABILLARY PRESSURE :

Capillary pressure is used to characterize the reservoir by indicating water saturation and size of pore channels and to notice the productive and nonproductive intervals .

2.1.3.1.6. Logging ANALYSIS :

Logging operations are a very important part of formation evaluation .

Logs can be classified into electrical and lithology logs and both types can be obtained during the drilling operation .

Lithology logs (which includes temperature logs , gamma ray logs and SP logs) are useful in describing the different layers encountered as the borehole is drilled and also to identify the fractures present .

2.1.3.1.7. MECHANICAL PROPERTIES :

Most of the tight gas reservoirs are thick layered systems that must be fractured to produce a commercial a mount of the hydrocarbons , so for the optimization of this process it is very important to understand and determine the mechanical properties of al the layers above , within and below the gas pay intervals .The properties like Youngs modulus helps to determine the width of the fracture .The most important property is the minimum compressive stress or the fracture closure pressure . when the pressure inside the fracture is greater than the closure pressure , the fracture is open and when the pressure inside the fracture is less than the closure pressure , the fracture is closed .

2.1.3.2 the process

2.1.3.2.1. Hydraulic fracturing process

In order to maximize the production potential of the well the formation will be hydraulically fractured .

In preparation for the fracturing process the casing will be perforated into the horizontal portion of the well using tubing conveyed perforating guns containing explosive charges .

The perforated intervals are spaced approximately 50 to 80 feet apart and create a connection between the production casing and the shale formation .

with the initial perforating complete , the tubing and perforating guns are pulled to the surface and the workover rig is replaced by a hydraulic fracturing crew consisting of a number of a high-pressure pumps and blending equipment , this equipment will pump a mixture of a water and proppant (usually sand) through the newly created perforations in the production casing and into the shale formation .

first , water is passed from a water storage into the working tanks , the water is then pulled into a hydration unit which provides the ability to gel the fluid before it is transferred to the blender .

At the blender , proppant and small amount of chemicals that aid in the fracturing process are added .

The blender transfers the fluid and the proppant mixture to the pump trucks , the fracturing pumps increase the pressure of the fluid , sending it back through the high pressure side of the manifold to the factory where it enters the well .

The entire fracturing process is controlled from the treatment monitoring vane.

When the fracturing fluid reaches the perforations , pressure builds until the shale formation fractures allowing fluid to enter into the formation . Additional fractures are created along natural zones of weakness in the shale , these fractures are contained within the shale formation well below the ground .

After an initial stage of fluid called the pad is pumped to create a fracture area , proppant is added tp the fluid and is distributed throughout the newly created fracture network .

At the conclusion of fracturing treatment , the proppant allows the fracture to remain open so that the natural gas can flow into the production casing and to the surface . this completes the first of several stages in the fracturing process .

This process is repeated by lowering and pumping down in isolation plug and perforating guns into the wellbore to complete the next stage of fracturing .

This time the tools are conveyed into the well by a wireline unit which allows the fracturing process to proceed much faster and more efficiently .

On the bottom of the perforating gun a composite bridge plug is placed to isolate the newly fractured zone , this ensures that the subsequent fracturing treatment is contained in the current zone . the perforating gun is again fired at roughly 50 to 80 foot intervals creating a connection between the production casing and the shale formation . the fracturing process is then repeated until all of the stages are completed .

Atypical shale well as approximately eight to twelve stages of fracturing .

At the conclusion of the process fracturing operations the plugs removed and the production can start .

2.1.4 horizontal well complition

Horizontal well completion

Completion as known is set of installation specific equipments in a well that has been drilled either vertical or horizontal to prepare for production or injection.

Horizontal well is high angle well(with a tendency of generally greater than 85).

The conception of horizontal wells is related with moderate to low permeability specially in unconventional reservoir by creation multiple fracture along the wellbore.

The main purpose of drilling and complete horizontal well is enhance production rate that achieved by expose a large area of pay zone to contact with reservoir.

The benefits of horizontal well:

1-Reduce gas and water coning due to reduced drawdown in the reservoir.

2-increase production rate.

3-reduction in sand production.

4-lowering pressure drop around the wellbore.

5-In case of injection wells, long horizontal well will provide higher injectivity rates.

To carry out the horizontal well completion will depend on the production constrains and reservoir characteristic.

There are several conditions should be considered for selection of horizontal well completion:

1-The degree of rock consolidation.

2-The anticipate flow rate.

3- The shale reactivity and stability.

4- The completion longevity.

5-The degree of grain sorting and limitation.

The methods of horizontal well completion:

The selected of completion method should be designed to appropriate production program and reservoir properties.

There are various methods can be utilize to complete horizontal wells such as:

1-open hole completion:

Open hole completion is used to consolidate formation that will not collapse when beginning the production.

2-pre-drilled or slotted liner:

Slotted liner or perforated liner are common use to complete horizontal well or multilateral wells.

In general the slotted liner is used to unconsolidated formation or to avoid sand production. the liner or perforated slotted is install and hang off in production casing. also can be used to prevent the hole sloughing or wellbore collapse.

3-pre-drilled or slotted liner with external casing packers:

The packers are usually used to provide an effective seal between zones So this is completion method is using when isolation zones are required to improvement liner completion method.

External casing packers are install in a well as attached part of liner and after raise they seal against the inner diameter of bore hole.

Also are used to linked with slotted liner ,screens , and sliding sleeves.

4-casing cemented or perforated(cased hole):

This approach is defined as casing or liner is run on the well and cemented in place with perforation to create path so this method comparing with other methods is distinguish by **:**

Provides highest degree of wellbore control.

Reservoir management.

The cased hole completion is use in non naturally fractures reservoir.

Cased hole completion is the best choice where horizontal well being drilled to minimize the coning problems.

5-open hole with gravel pack:

Gravel pack completion is common use to poorly consolidate formation that consist of performing horizontal gravel packing across open hole interval.

The advantage of gravel pack is productivity maintaince.

There are requirements to successful for the gravel pack clean, stable undamaged well prior to running gravel pack screen.

2.1.4 fracturing fluid

Fracturing fluids

Fracturing fluid is defined as fluid pumping down at high pressure and high rate to create a complex network fracturing systems within the reservoir to allow more produce of hydrocarbon.

The composition of fracturing fluids are fluids, chemical additives and proppants.

Proppants is solid particles using to keep fracture conductive path from reservoir to wellbore.

A wide variety of materials are used as proppants such as sand, ceramics and other materials.

Conductivity path created by proppants is depend on size of proppants, concentration of proppants, distribution of proopants.

once the reservoir is split ,fracturing fluid enters to the fissures and transport proppants to prevent rocks leak off due to the nature of rocks.

The most common of the fracturing fluids using now days is 'slick water 'that compose of water with a small amount of polymer that will be reduce the frictional pressure drop so the particular polymer that used is hydroxypropyl guar (HPG).

There are criteria can be considered to achieve successful stimulation:

- It should be appropriate with the formation material.
- It should be Compatible with the formation fluid.
- It must be easy to remove from the formation.
- It must be stable and have low friction pressure.
- Preparation of fluid to be simple and easy to perform in the field.
- Effective low cost.

Friction pressure is referred as the pressure loss when fluid flowing through flowing paths and it carry out in opposite direction of fluid flow.

The additives include:

A. Gelling agents.
B. Crosslinkers.
C. Breakers.
D. Fluid loss additives
E. Bactericides
F. Clay control agents
G. Surfactants and non-emulsion agents.

Essentially four types of fracturing fluids:

1- water base fluids:

The composition of water base fluid is water mixed with clay control agents ,friction reducer.

Often a water recovery agent (WRA) is added to try and minimize water block effects.

The advantages of this type are**:**

1. Low cost
2. Ease of mixing
3. Ability to recover and reuse of water.

The main disadvantage is low viscosity leads to create narrow fracture width as well can be pumped at high very rates (60 to 120bpm).

2-linear Gel:

Is composed of water, clay control agent and gelling material such as Guar, HPG or HEC.

Chemicals breakers also added to decrease damage to the proppant pack.

The advantages of this type are**:**

1. Low cost
2. Viscosity is better than water base fluids.

The main disadvantage is returned water contain residual breakers the water is not reusable.

3-crosslinked Gels:

Are fluids as linear gels consist same materials but additional crosslinker to increase the viscosity.

The viscosity is play an important role to improve the fracture width when the fracturing fluids have high viscosity the transport of proppants is high and minimize the friction pressure.

4-Foam/Poly Emulsions:

Are fluids that are consist of water mixed with materials are not miscible with water such as Nitrogen ,carbon dioxide or hydrocarbon like propane, diesel or condensate.

This type of fluids have distinguished properties**:**

1. Have very good loss control.
2. Very clean.
3. Provide excellent proppants transport

5-oil based fluids:

This type is a special type that is used on water-sensitive formations due to damage which originate when contact with water base fluid.

The first use of fluid to stimulate a well via hydraulic fracture is gasoline at the base fluid, Palm Oil as the gelling agent and Naphthenic Acid as the crosslinker.

The disadvantages of oil based fluids**:**

- Environmental and safety impact compare with water base fluids.
- It is not good using gelled oil can occur problems when using high viscous crude oil
- When using refined oils such as diesel the cost is very high.

CHAPTER 3
METHODOLOGY

Chapter 3

3.1. METHODOLOGY

3.1.1 Methodology Introduction

In order to achieve the objectives of this project, the upcoming methodology had been followed:

1- CMG software
2- Data collection

CMG software

CMG softwares are a group of softwares in reservoir simulation it's consist:

1) WinProp
2) GEM
3) IMEX
4) CMOST
5) Builder (Preprocessor)
6) STARS
7) Results.

IMEX MODEL

Primary and secondary oil recovery process in conventional and unconventional reservoir .

The β Model (Black Oil Model)

In this model of the fluid flow problem it is
assumed that there are:

• three phases: oil, water and gas.

• Usually water is the wetting phase, oil has an intermediate wettability and gas is the nonwetting phase.

• Water and oil are assumed to be immiscible and they do not exchange mass or change phase.

• Gas is assumed to be soluble in oil but usually not in water.

• the fluids are at constant temperature and in thermodynamic equilibrium throughout the reservoir.

GEM –SIMULATOR

Gem is a product of CMG(Computer modeling grouping) is used in compositional ,chemical and unconventional reservoir that implement enhancing recovery processes such as injection gas in reservoir may be miscible or immiscible and hydraulic fracturing.

The simulation of these processes requires special handling of both the thermodynamic and the fluid flow aspects of the reservoir.

GEM is an efficient, multidimensional, equation-of- state (EOS) compositional simulator which can simulate all the important mechanisms of a miscible gas injection process, i.e. vaporization and swelling of oil, condensation of gas, viscosity and interfacial tension reduction, and the formation of a miscible solvent bank through multiple contacts.

Some of the additional features of GEM are listed in the following.

ADAPTIVE IMPLICIT FORMULATION

GEM can be run in explicit, fully implicit and adaptive implicit modes. In many cases, only a small number of grid blocks need to be solved fully implicitly; most blocks can be solved explicitly. The adaptive implicit option selects a block's implicitness dynamically during the computation and is useful for coning problems where high flow rates occur near the wellbore, or in stratified reservoirs with very thin layers. Several options are provided for selecting implicit treatment.

PROPERTIES

GEM utilizes either the Peng-Robinson or the Soave- Redlich-Kwong equation of state to predict the phase equilibrium compositions and densities of the oil and gas phases, and supports various schemes for computing related properties such as oil and gas viscosities.

The quasi-Newton successive substitution method, QNSS, as developed at CMG, is used to solve the nonlinear equations associated with the flash calculations. A robust stability test based on a Gibbs energy analysis is used to detect single phase situations. GEM can align the flash equations with the reservoir flow equations to obtain an efficient solution of the equations at each timestep.

CMG's WINPROP equation of state software can be used to prepare EOS data for GEM.

COMPLEX RESERVOIRS

GEM uses CMG's Grid Module for interpreting the Reservoir definition keywords used to describe a complex reservoir. Grids can be of Variable Thickness - Variable Depth type, or be of corner-point type, either with or without user-controlled Faulting. Other types of grids, such as Cartesian and Cylindrical, are supported as well as locally Refined Grids of both Cartesian and Hybrid type. Note that Hybrid refined grids are of a locally cylindrical or elliptical nature that may prove useful for near-well computations.

Regional definitions for rock-fluid types, initialization parameters, EOS parameter types, sector reporting, aquifers, ... are available. Initial reservoir conditions can be established with given gas-oil and oil-water contact depths. Given proper data (such as from WINPROP), fluid composition can be initialized such that it varies with depth. A linear reservoir temperature gradient may also be specified.

Aquifers are modelled by either adding boundary cells which contain only water or by the use of the analytical aquifer model proposed by Carter and Tracy.

Dual porosity modelling can be done with GEM. Each cell is assigned separate matrix and fracture pore spaces. Shape factors describing flow between porosities are implemented based on the work of Gilman and Kazemi. Additional transfer enhancements are available to account for fluid placement in the fractures. The GEM user can also specify a dual permeability model which allows fluid flow between adjacent matrix blocks. This option is useful when matrix-matrix mass transfer processes are important, such as in situations dominated by gas-oil gravity drainage processes.

GEOMECHANICAL MODEL

Several production practices depend critically on the fact that the producing formation responds dynamically to changes in applied stresses. These include plastic deformation, shear dilatancy, and compaction drive in cyclic injection/production strategies, injection induced fracturing, as well as near-well formation failure and sand co-production. A geomechanical model consisting of three submodules is available for treating aspects of the above problems. The coupling between the geomechanical model and the simulator is done in a modular and explicit fashion. This increases the flexibility and portability of the model, and decreases computational costs.

WELLS

Bottom hole pressure and the block variables for the blocks where wells are completed are solved fully implicitly. If a well is completed in more than one layer, its bottom hole pressure is solved in a fully coupled manner; i.e., all completions are accounted for. This eliminates convergence problems for wells with multiple completions in highly stratified reservoirs.

A comprehensive well control facility is available. An extensive list of constraints (maximum/minimum bottomhole or wellhead pressures, rates, WCUTs, GORs, ...) can be entered. As constraints are violated, new constraints can be selected according to the user's specifications. Various actions and apportionments are available.

Up to three hydrocarbon streams can be controlled on the surface: Oil, Intermediate Liquid and Gas. Various types of surface separation facilities can be used to generate these streams, including the modelling of EOS and plant separator stages, where the latter are described using key-component tables.

The gas cycling option in GEM allows for the preferential stripping of components and the addition of a make-up gas stream to the recycling gas stream.

MATRIX SOLUTION METHOD

GEM uses AIMSOL, which is a state-of-the-art linear solution routine based on incomplete Gaussian Elimination as a preconditioning step to a GMRES iteration. AIMSOL has been developed especially for adaptive implicit Jacobian matrices.

For almost all applications, the default control values selected by GEM will enable AIMSOL to perform efficiently. Thus, GEM users do not require detailed knowledge of the matrix solution methods.

GEM uses run-time dimensioning as well to make the most efficient use of computer resources.

SIMULATION RESULTS FILES

Various types of Simulation Results Files can be written while GEM is running, including files for CMG's RESULTS. RESULTS is CMG's visualization software that can be used to examine 2-D and 3-D reservoir displays, as well as XY plots of important dynamic data.

PORTABILITY

GEM has been run on many computers from many manufacturers, such as IBM, SGI, and SUN, as well as PCs.

GEM uses the data set that you create initially and then creates three other files. Each GEM run may create an output restart file (RST), an output Simulation Results File (SRF), and an output file.

PVT Correlation

CMG softwer generate the fluid and rock properties using different correlations to represent oil and gas properties

Properties	Correlation methods
1- Formation volume factor 2- solubility 3- bubble point pressure	Standing
	Vazquez-Beggs
	Glaso
	Lasater

Oil compressibility	Vazquez-Beggs
	Glaso

Gas critical properties correlationsp	Standing Sutton

Relative permeability	Stone’s first model
	Stone’s second model

The correlation theory

Standing

Solubility **RS**

$\boldsymbol{Rs}$ = γg[(P18.2 + 1.4)10x]^1.2048

Bubble-Point Pressure **Pb**

$\boldsymbol{Pb}$ = 18.2[γg0.8310a- 1.4]

Oil formation volume factor **Bo**

$\boldsymbol{Bo}$=0.9759+0.000120[(γg γo)0.5+ 1.25(T −460)] 1.2}

2-VasquezBeggs

Solubility **RS**

$\boldsymbol{Rs}$ = $C1\ \gamma gs\ PC2\ e$C3 (API /T)]

Bubble-Point Pressure **Pb**

$\boldsymbol{Pb}$ = $[(C1Rs\ \gamma gs /)10_a]C2$

Oil formation volume factor **Bo**

$\boldsymbol{Bo}$ = 1 + $C1Rs$ + (T− 520)($API\ \gamma gs$)[$C2$+ $C3RS$]

3=Glose

Solubility **RS**
$\boldsymbol{Bo} = 1 + C1Rs + (T-520)(API\ \gamma gs)[C2 + C3RS]$

Bubble-Point Pressure **Pb**
$\boldsymbol{Pb}* = (Rs\ \gamma g/)a(t)b(API)c$

Oil formation volume factor **Bo**
$\boldsymbol{Bo} = 1 + 10A$

Initial Conditions:

Reference pressure: 13800.0 KPa
Reference depth: 1380 m
Water gas contact: 1433 m

Water properties :

Density : 1000.8 kg/m3
Compressibility : 4.85e-7 1/kpa
Ref pressure : 101.325 kpa
Viscosity : 0.37 cp

Materials and Methods

Numerical Simulation Model Description

Using a commercial black oil simulator (CMG-GEM), we set up a reservoir model with three-phase flow of gas, oil and water(JAKE Field model).

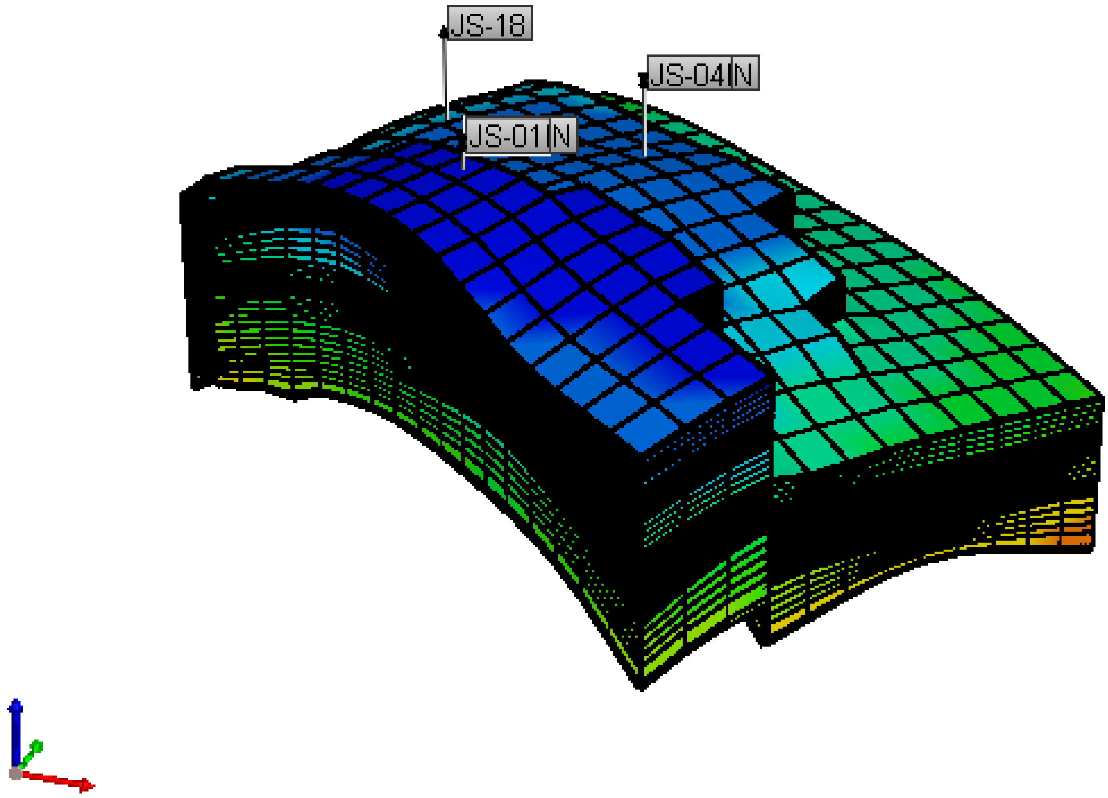

Figure 3-1 . Schematic Diagram for Formation and Sub- layers for the Model

Reservoir and Fluid Properties

Relative Permeability Curves

- The two-phase flow (oil-water) relative permeability curves in this study are shown in

  - Relative permeability vs water saturation

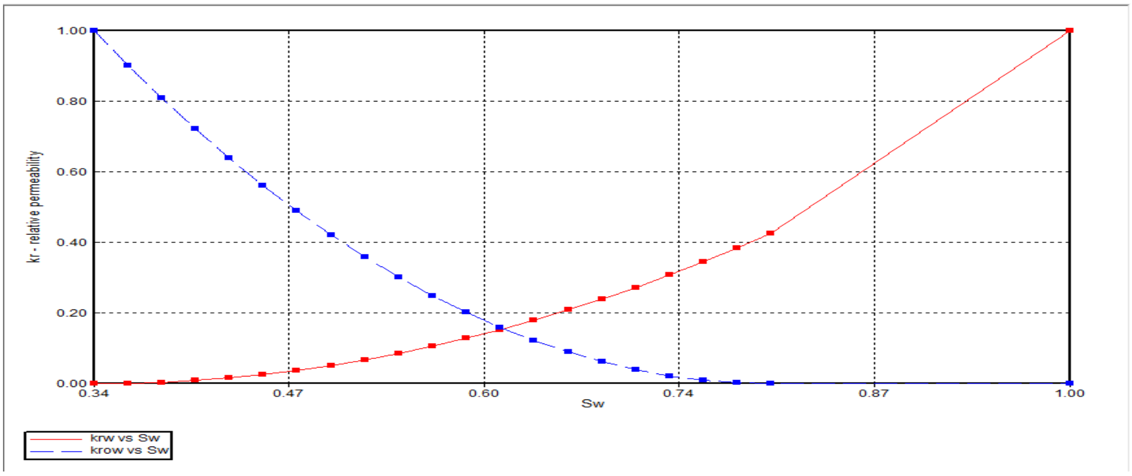

Figure3-2 Relative permeability vs water saturation

- Relative permeability vs gas saturation

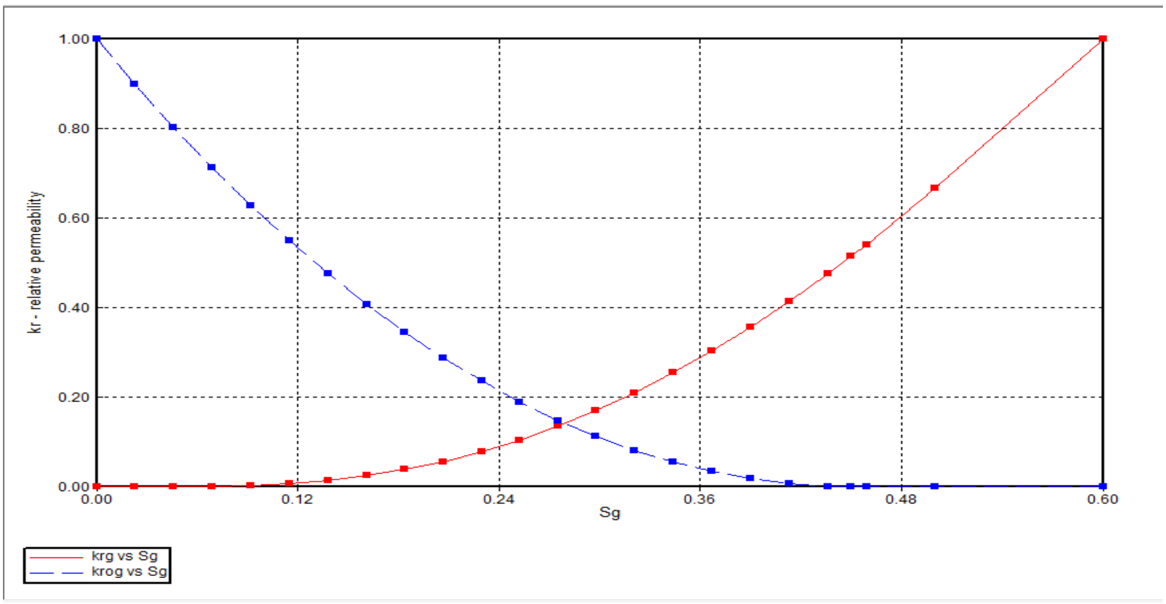

Figure 3-3 Relative permeability vs gas saturation

- Oil gas capillary pressure vs gas saturation

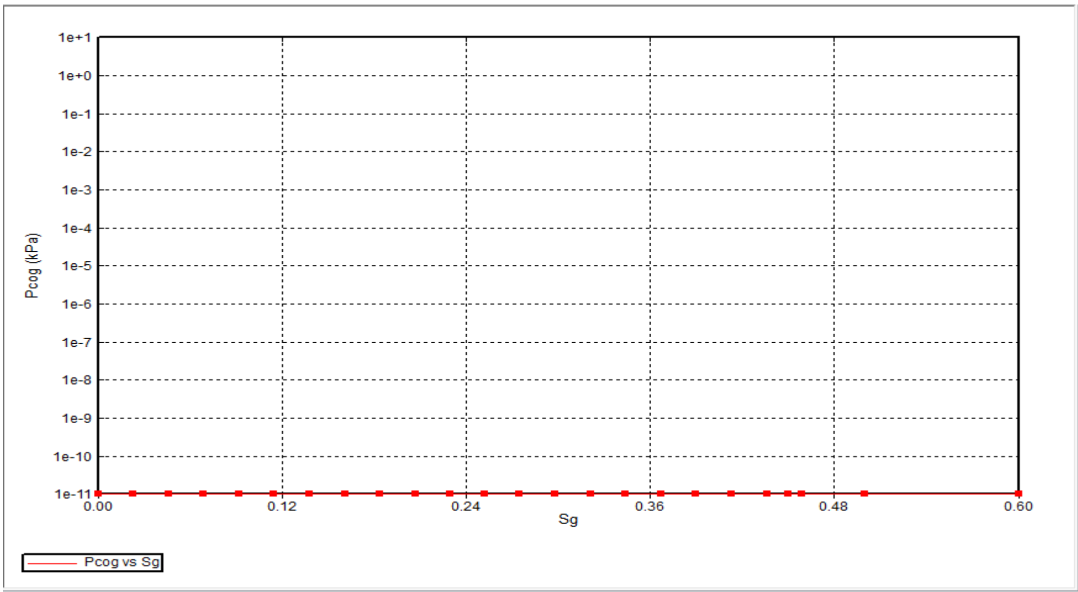

Figure 3-4 Oil gas capillary pressure vs gas saturation

- Oil gas capillary pressure vs water saturation

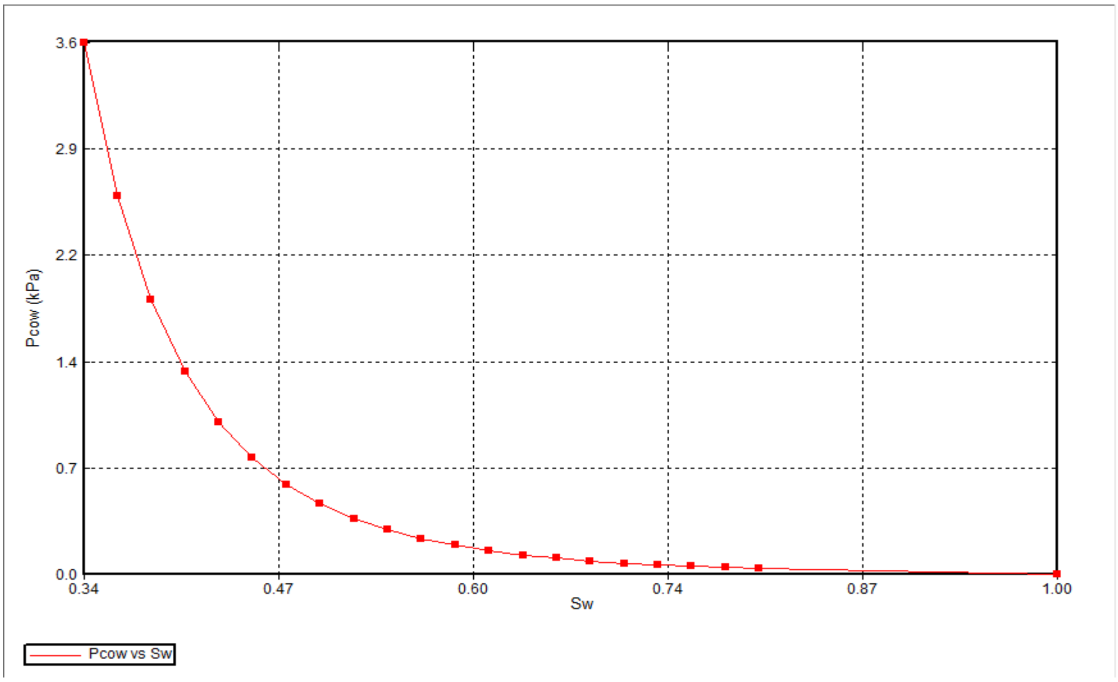

Figure 3-5 . Oil gas capillary pressure vs water saturation

Hydraulic Fracture Geometry

The model comprises a hydraulicfracture and planar fractures

The hydraulic fractures have an assumed a width of (0.3048m), a propped fracture half-length of (95.0976 m), and a permeability of 1500 mD

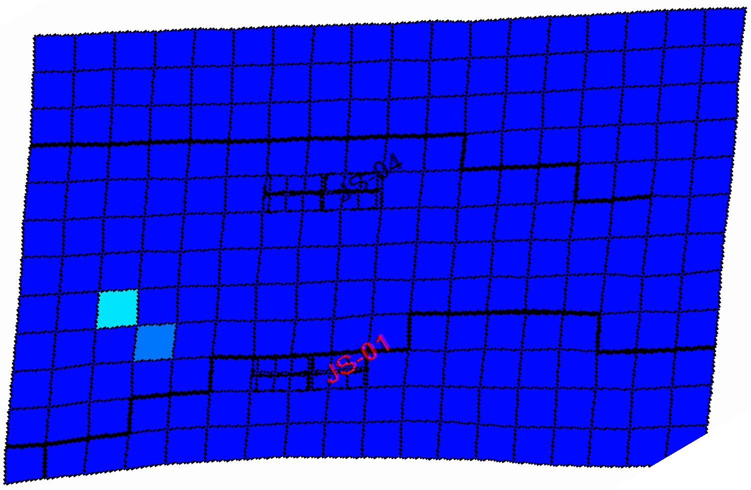

Figure 3-6 horizontal shape of the fracture

Formation fracture pressure

It is possible to hydraulically fracture a formation by applying pressure to the wellbore. When a formation fractures, cracks are created within the rock matrix, and fluid in the wellbore will be lost into the fractures. The pressure required to create a fracture is termed “fracture pressure.”

- Fracture pressure is expressed as either:

- A pressure—psi, bar, or kPa.

- A fluid gradient—psi/ft, Bar/m, or kPa/m.

- A fluid weight equivalent—ppg, kg/l, or SG.

Knowing the fracture pressure is essential for workover and intervention operation, as exceeding fracture pressure would lead to severe fluid loss and a consequent loss of the hydrostatic overbalance. Fluid loss to the formation also carries a risk of formation damage, and the severe losses associated with a fractured formation are very damaging. The impact on productivity is likely to be severe. Most operating companies will have policy and procedures in place to ensure that fracture pressure is not accidentally exceeded during completion and workover operations. However, there are occasions when fracturing is a required part of the intervention. Fracture pressure is deliberately exceeded during the installation of frac-pack sand control completions. It is also routinely exceeded during acid fracturing and propped frac stimulation operations.

Fracture pressure is related to the weight of formation matrix (rock and sediments), and the fluid occupying the pore spaces above the zone of interest. These two factors combine to produce what is termed “overburden pressure.” Although the density of the overlying formation varies with depth, a rough approximation of fracture pressure can be estimated if it is assumed that average density of the overlying formation and the associated liquids is roughly equivalent to a gradient of 1 psi/ft (22.6 kPa/m). For most completion and intervention activities, fracture pressure will have been determined during the drilling of the well by performing a leak-off test (LOT).

Governing equations

the fracture width is marked by w and is a function of distance x from the wellbore.

The maximum fracture width w_0 occurs at x = 0, where a fracture wing touches the wellbore.

The fracture half-length is expressed by x_f, the fracture height by h_f and the wellbore radius by r_w.

$$x_f=.68(GQ_O{}^3/1-_V*m*hf^{\,4})^{1/5}*t^{4/5} \text{ ———— } (1)$$

$$w_o=2.5(1-_V*Q^2{}_O*u/G*hf)^{1/5}*t^{4/5} \text{ ———— } (2)$$

where G is the shear modulus, Q the fluid injection rate, μ the fluid viscosity and t the time.

Chapter 4
Results & Discussion

Chapter 4

1.1. Results and Discussion

In order to achieve permeability improvement Average values were taken after a continuous number of experiments and the characteristics of the formation. Accordingly, a specific scale was set for the fracture width and the half length . The width values must be small and fracture half length long due the hydraulic fracture for Enancement mut be long and narrow

Fracture width (0.3048 m) with half length(95.0976 m)

Hydraulic fracture implementing on two well:

- **JS-01**
- **JS-04**

The fracture implementing on two well to study the effect of hydraulic fracture fore different well location .
At first show the performance of wells before the fracture perfoemed to evaluate the amount of production improvement for three ways :
Comulative Gas peoduction , Comulative Oil production and Comulative water production

❖ Well JS-01 performance before fracture

- **Cumulative Gas production**
- **Cumulative Water production**

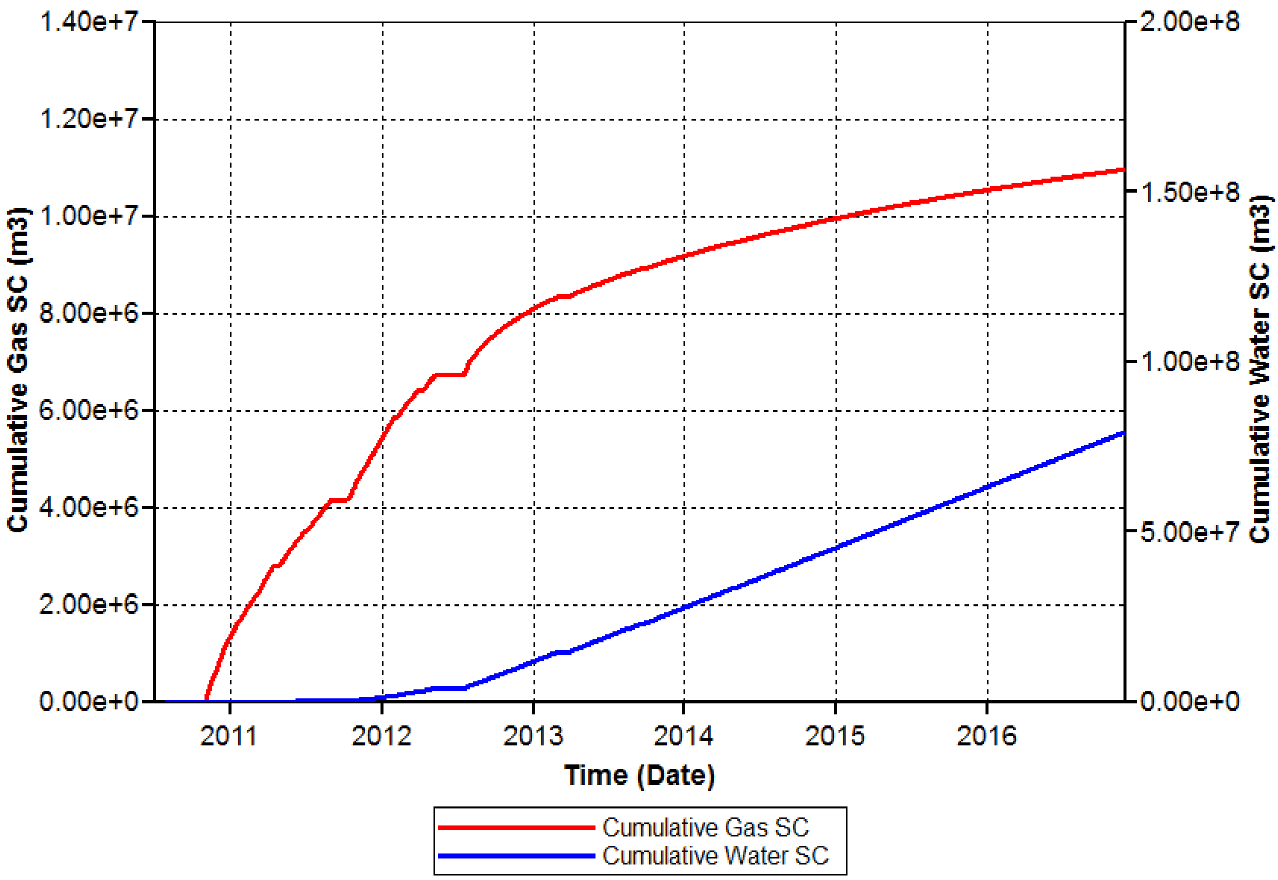

Figure 4-1 Well JS-01 performance

❖ Well JS-04 performance before fracture

- **Cumulative Gas production**
- **Cumulative Water production**

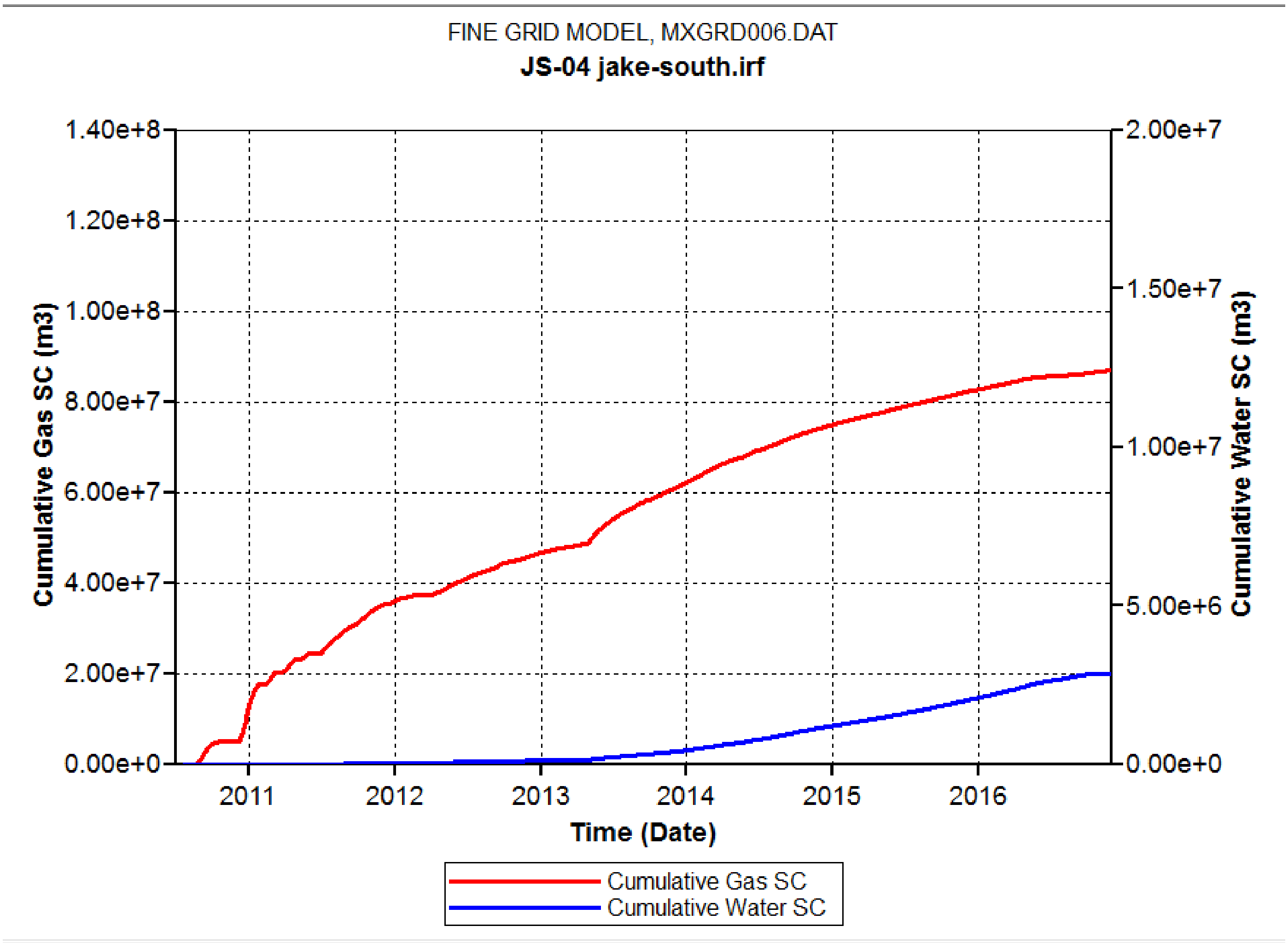

Figure 4-2 Well JS-04 performance

❖ Field performance before fracture process

☒ Gas recovery factor

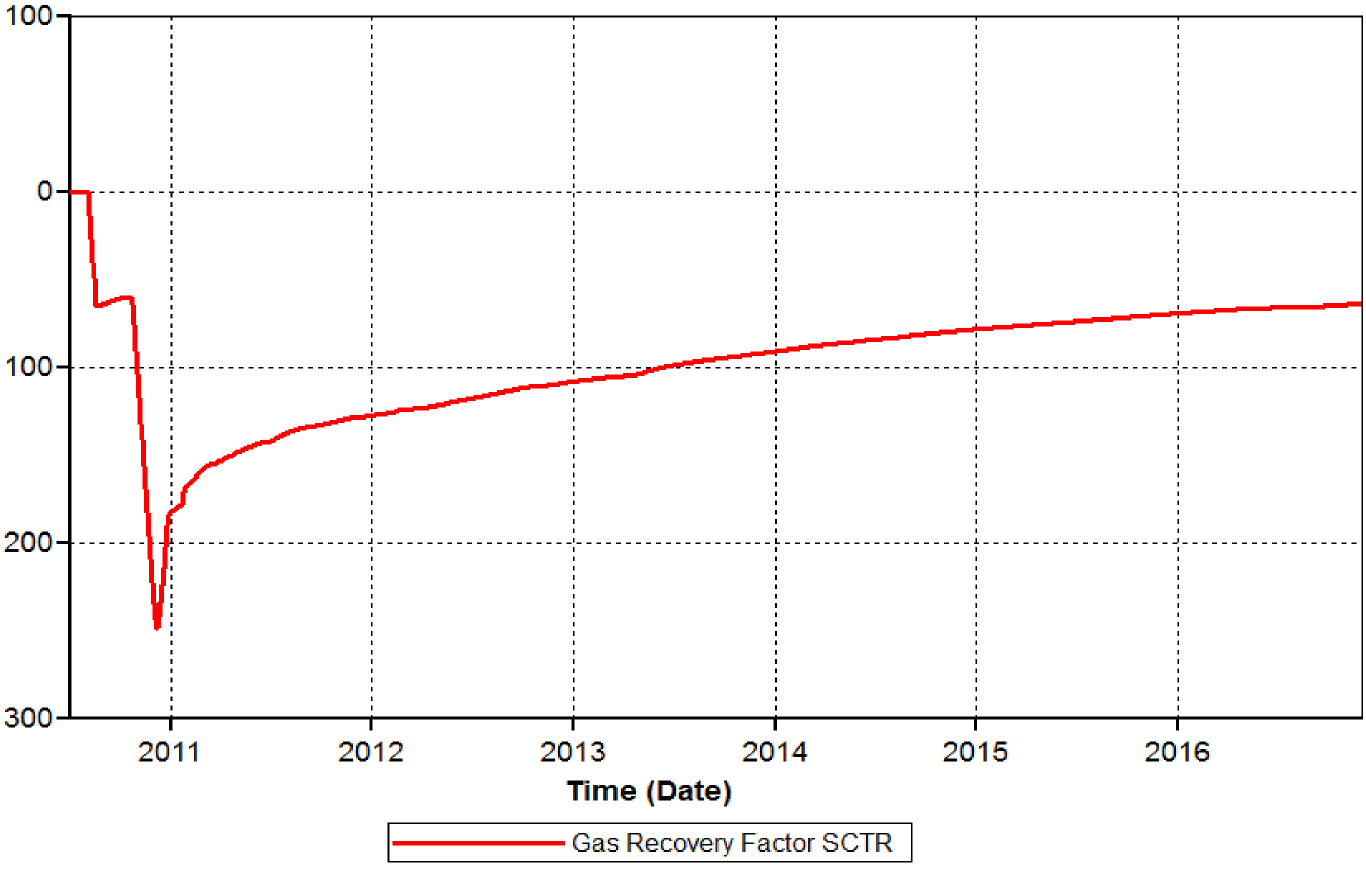

Figure 4-3 Gas recovery factor

☒ **Water cut %**

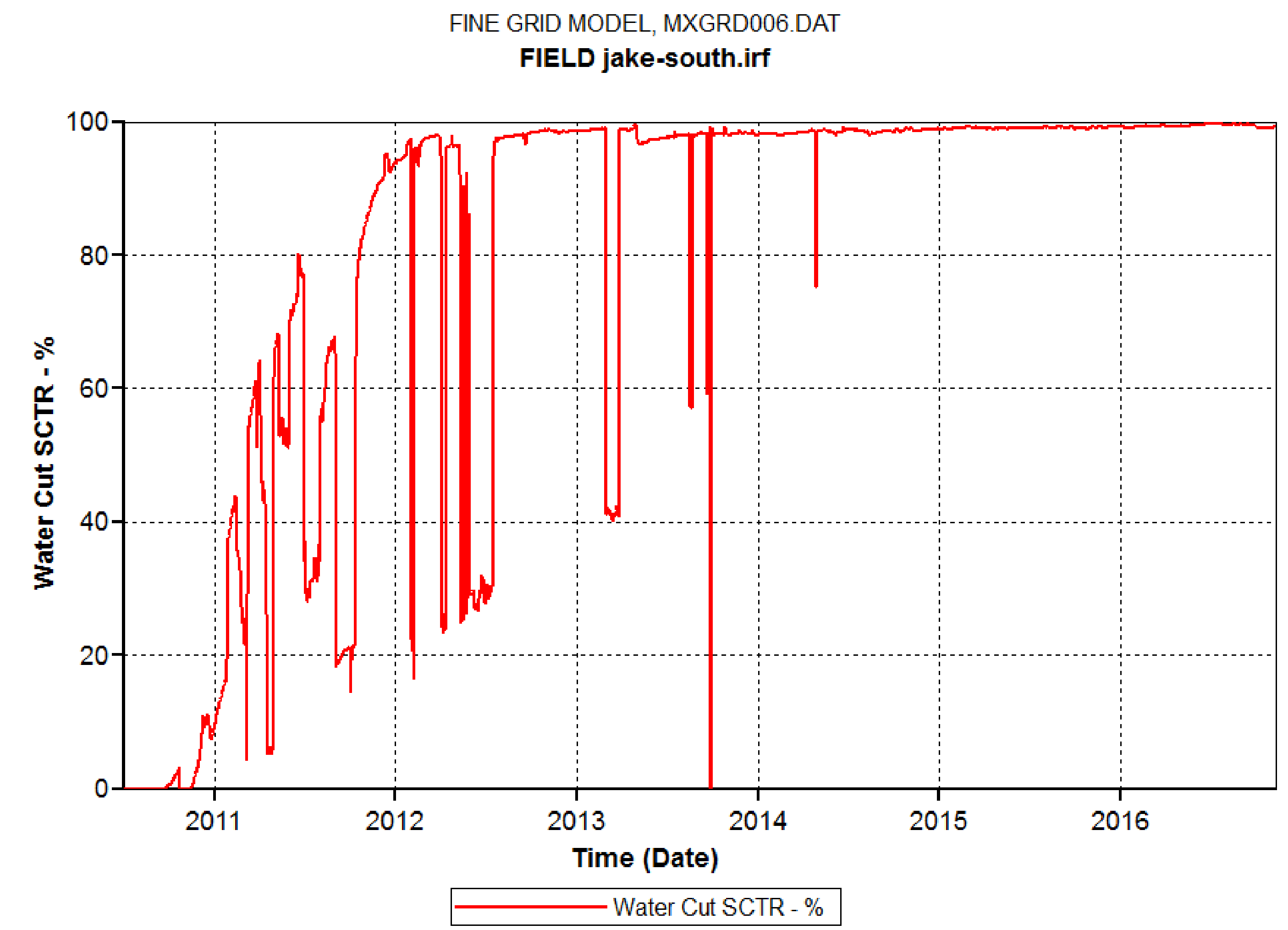

Figure 4-4 field water cut %

☒ Water cut is indicate to the amount of water produced to the total liquid produced .

❖ Well JS-01 performance with fracture –Width (0.3m) & half length (95.09m)

- **The Effect on Gas production**

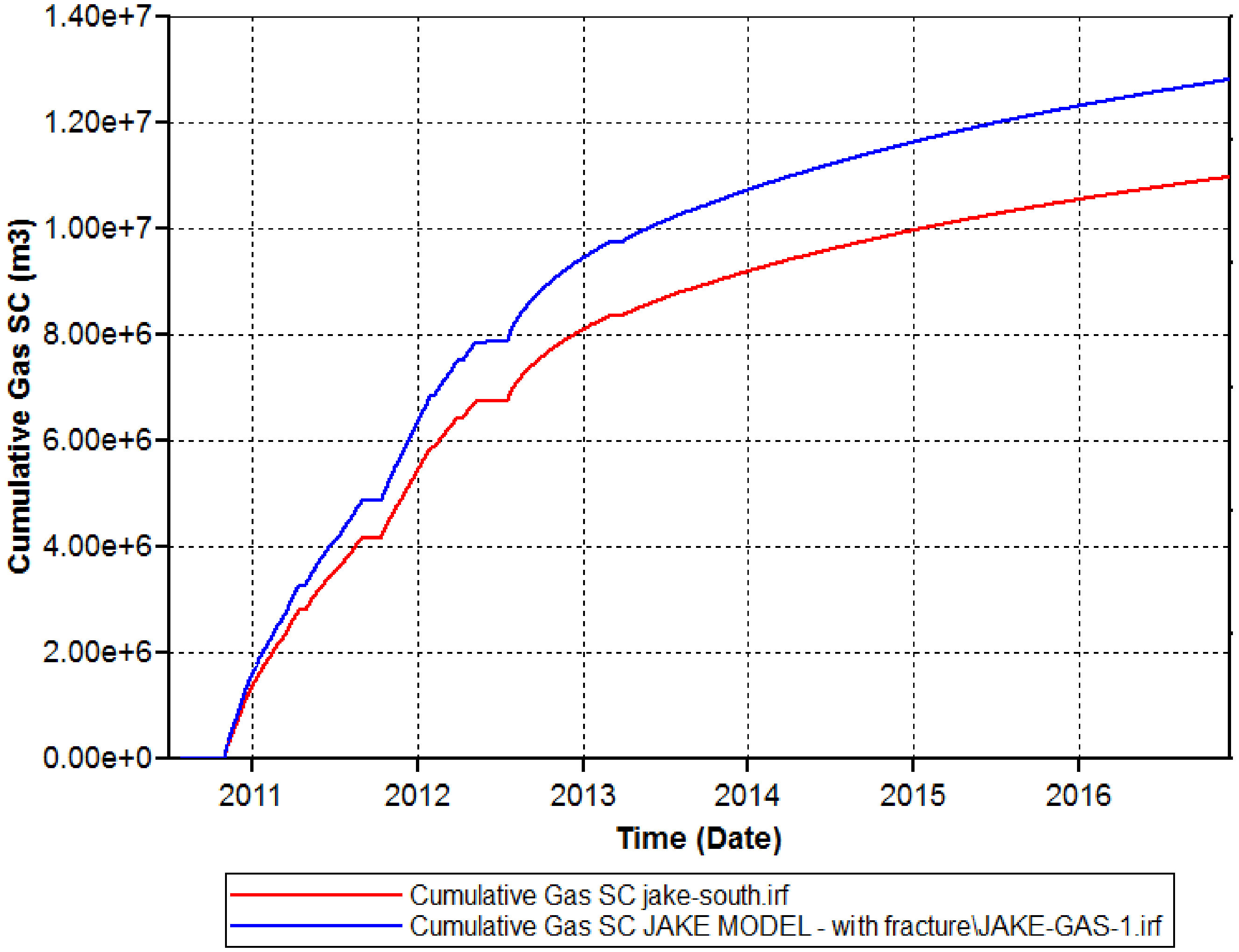

Figure4-5 The Effect of fracture on Gas production

☒ When hydraulic fracture performed in JS-01 the Cumulative Gas increase as response of permeability improvement

- **The Effect on Water production**

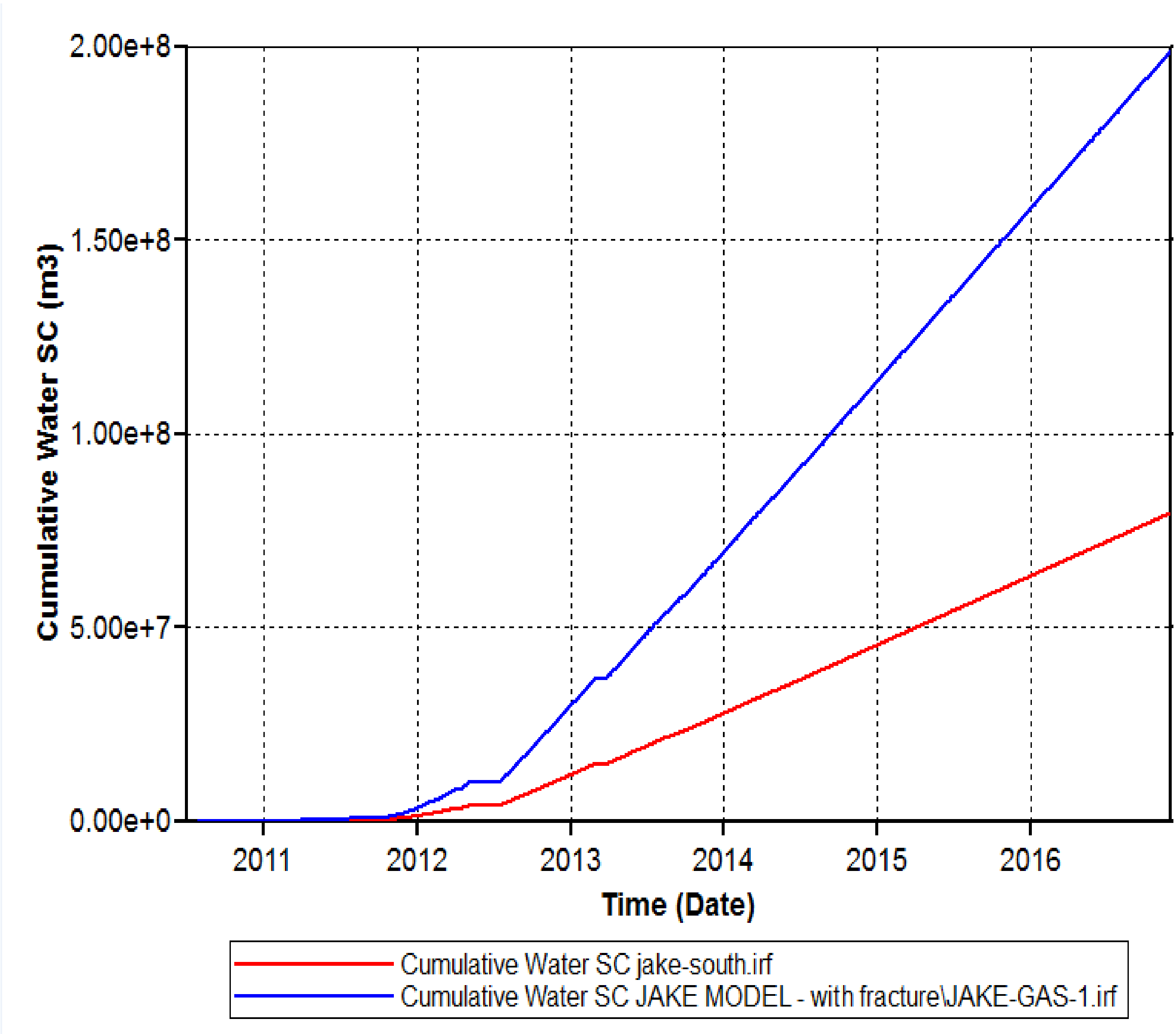

Figure 4-6 The Effect of fracture on Water production

- When hydraulic fracture performed in JS-01 the Cumulative water increase as response of permeability improvement

❖ Well JS-04 performance with fracture –Width (0.3m) & half length (95.09m)

- **The Effect on Gas production**

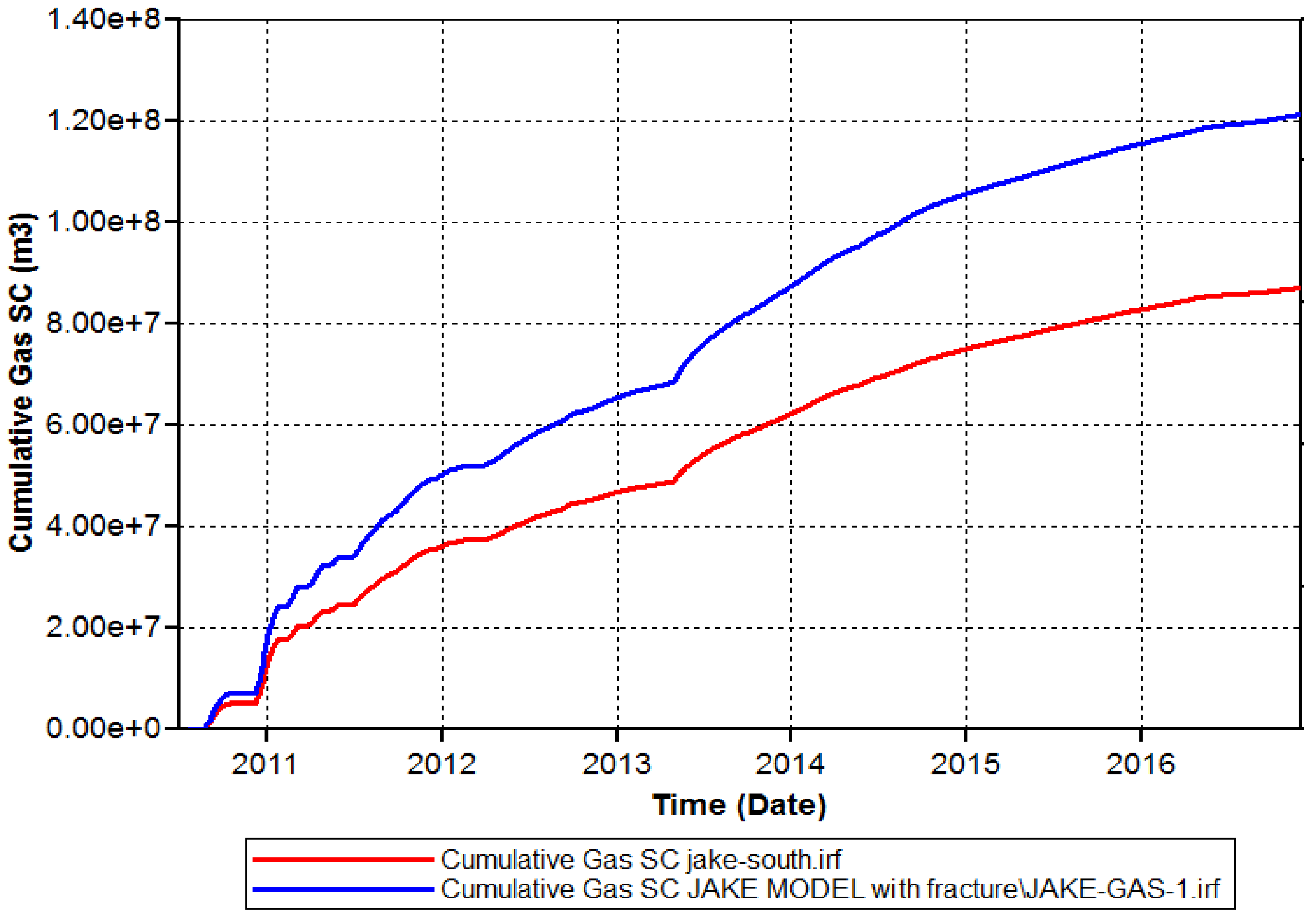

Figure4-7 The Effect of fracture on Gas production

☒ When hydraulic fracture performed in JS-04 the Cumulative GAS increase as response of permeability improvement

- **The Effect on Water production**

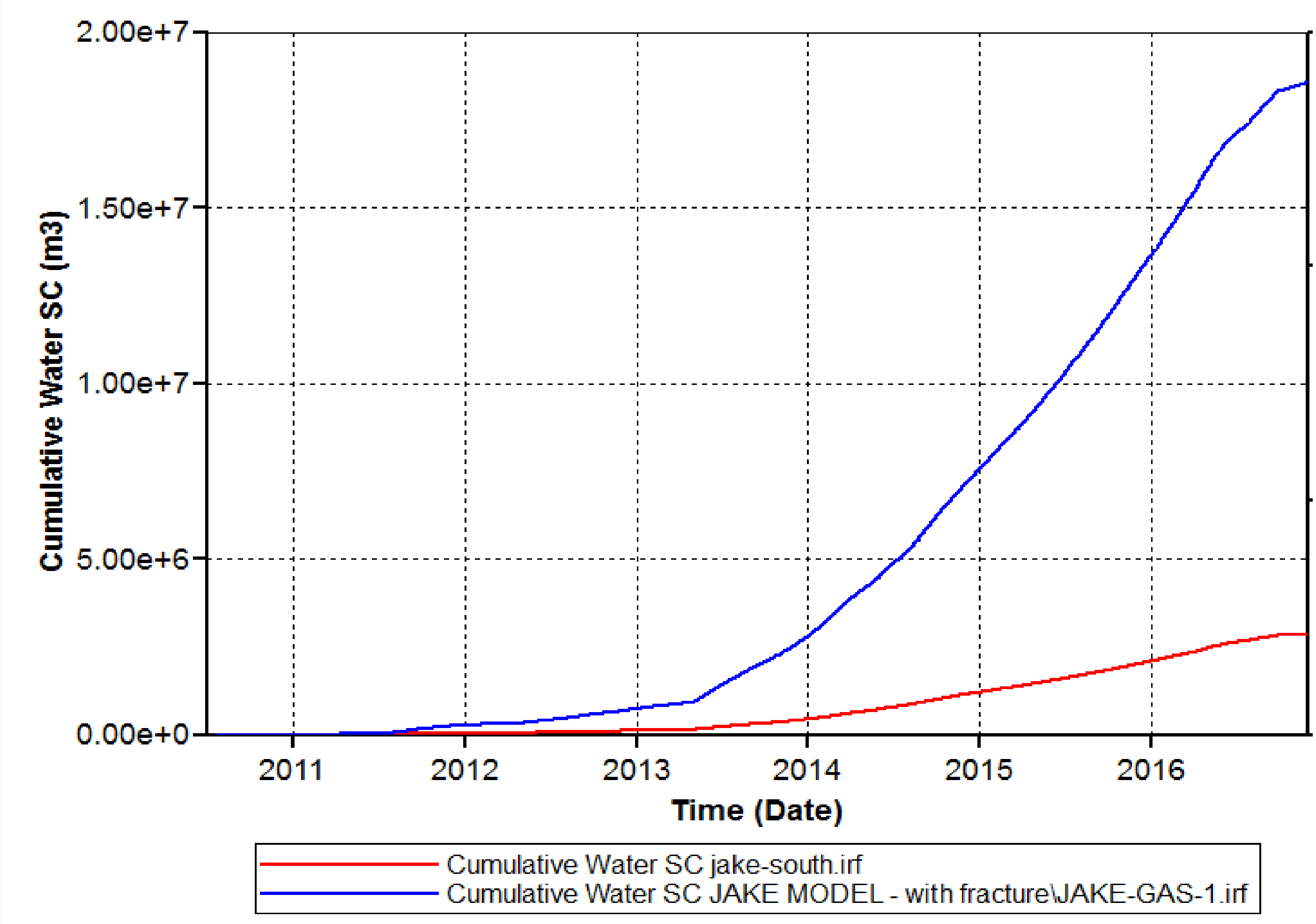

Figure4-8 The Effect of fracture on Water production

- When hydraulic fracture performed in JS-04 the Cumulative Water increase as response of permeability improvement

❖ Field performance after performed hydraulic fracture:

- Gas recovery factor
- Water cut %

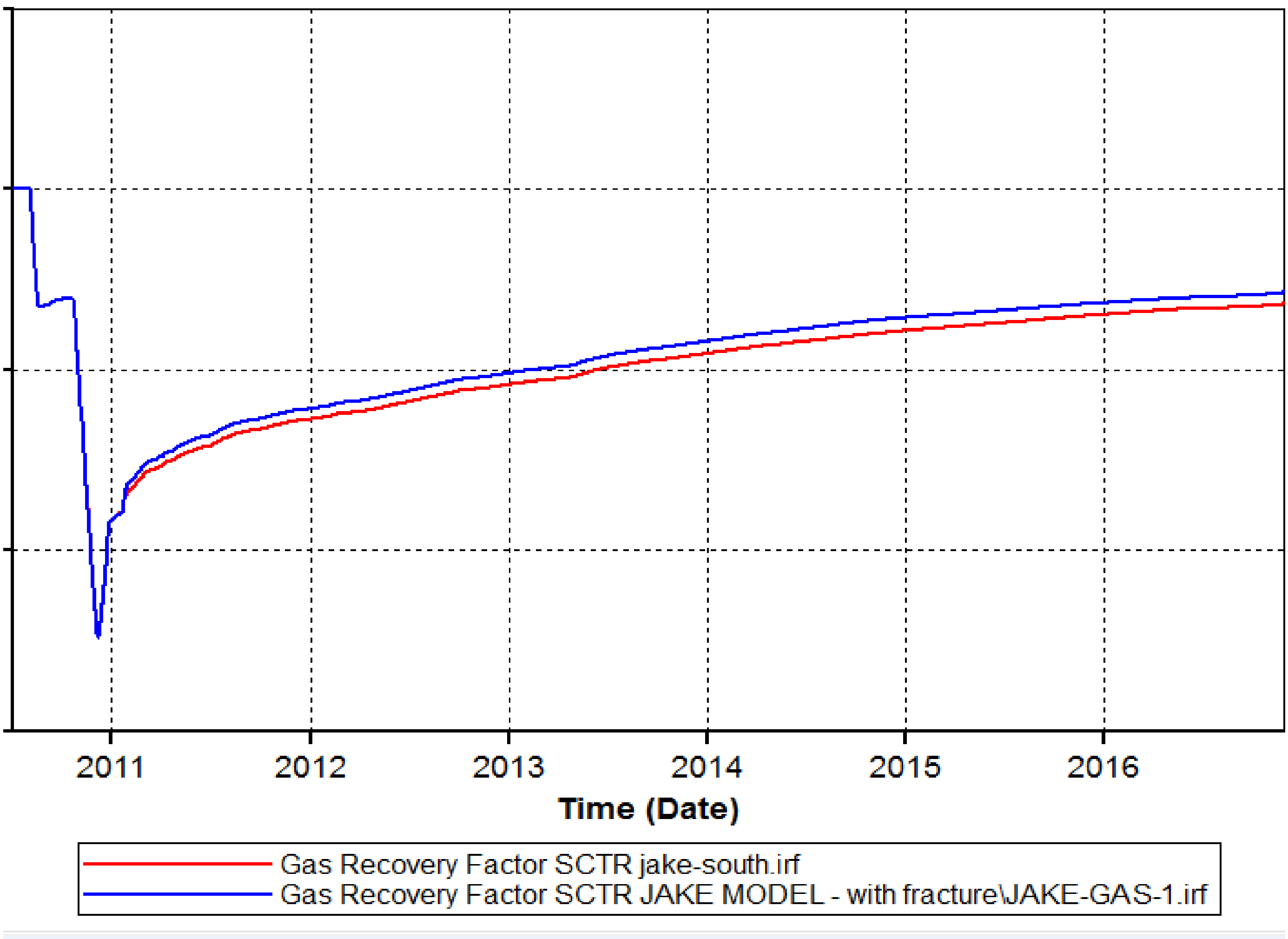

Figure4-11 The Effect of fracture on field

- Gas Recovery Factor of Jake field increace after perfomed Hydraulic fracture at low permeabiity wells .

- **Water cut %**

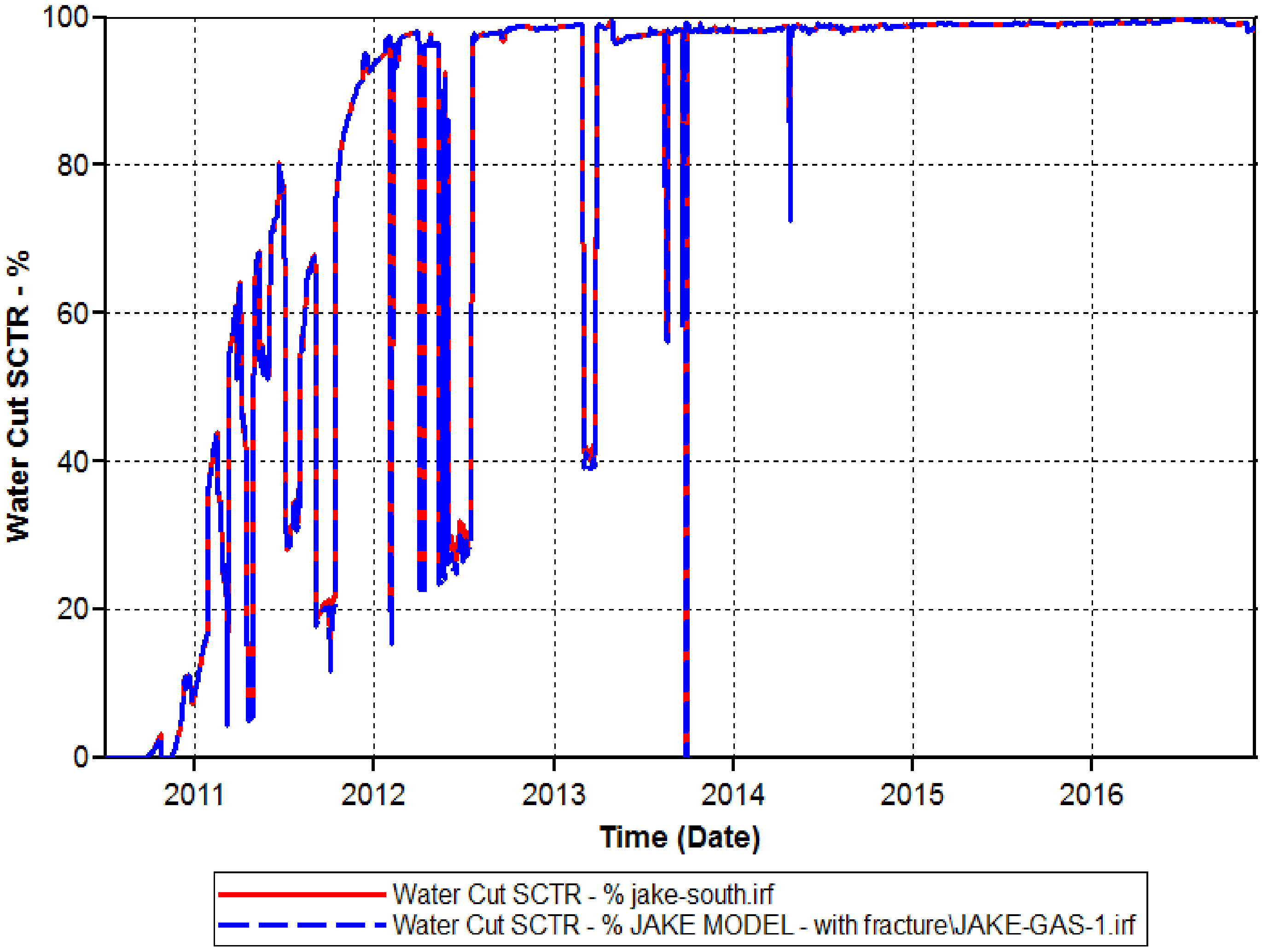

Figure4-13 The Effect of fracture on field water cut %

- Water ut doesnot change that indicate hydraulic fracture significantly increase the cumulative gas & oil as the same time the produced water slightly increaace .

CHAPTER 5
CONCLUSION &
RECOMMENDATIONS

Chpter 5

5.1. Conclusions

- Hydraulic fracture Good Candidates For Fracturing
  - Sufficient Recoverable Reserves
  - Sufficient Reservoir Pressure
  - Low Permeability (Less Than 10 mD)
  - O/W And O/G Not Very Close
  - Good Cementation
- Different analyzing approaches were applied on the results to evaluate the effect of hydraulic fracture .
- that the productivity of wells improved after performing hydraulic fracture processon them
- that the process also lead toan improvement the field recovery factor .
- permeability is improved when its compared to those had been indeuced by Hydraulic fracture .
- Cumulative water take place on evaluation due Water production more costiy and effect on hydraulic fracture program successful .

5.2. Recommendations:

- Hydraulic fracture is essential for most low permeability oil &gas wells .
- Increase reservoir permeability are required for more oil &gas gain.
- It’s better to set fracture width (0.3048m) and half length (95.0976m) if it possible as field and company possibilities.
- Maintain indeuced permeability by using propping agent with high stability in high temprature to keept the fracture open .
- In our research we specify scenarios that by select particular width and change the half length which select the best one that provide significant result of production. But due to our resources can't select the optimize half length of fracturing so that supposed to optimize the half length because to our devices can't reach the our destination

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