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RESEARCH ARTICLE

SIMULATION UNCERTAINTIES IN TIGHT GAS RESERVOIRS; CASE-STUDY ON WHICHER RANGE FIELD IN WESTERN AUSTRALIA

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ABSTRACT

Modelling tight gas unconventional reservoirs can be a complex task, as there are different uncertainties involved due to geological complications. Moreover, intrinsic characteristics of tight gas reservoirs, makes them very prone to formation damage which can affect the future production rates and increases the simulation uncertainties. The Whicher Range field in Perth Basin is a large undeveloped 'unconventional' tight gas reservoir in Western Australia. Gas-in-place estimations of up to 6 TCF have been reported. Other tight sand reservoirs have been identified in the Perth Basin, but none has been put into commercial production. Whicher Range provides a long and comprehensive case history of drilling and testing programs which, thus far, have not provided a viable well completion or field development plan. To study the associated simulation uncertainty, we developed there reservoir model and the model calibrated with available production data to be used to evaluate the reservoir behavior and possible future production scenarios. Simulation outcomes were compared with the field history data and the deviation from the field results was discussed. Result show that, if the uncertainties such as geological complexities, or formation damage (either phase trapping or fines migration) are not taken into account, the production rate can be significantly overestimated. It is also pointed out that due to the lack of lateral continuity in fluvial systems the deterministic estimation Gas Initial in Place (GIIP) can also be significantly over estimated. Associated risk of occasioning a dry well in fluvial meandering reservoirs with this degree of heterogeneity is very high. It is recommended that a thorough and meticulous study should be carried out and proper field development strategies should be established to enable the further development of this type of fields. It is very important to implement these data to construct a representative model. From the data obtained from the Whicher Range field, it is concluded that the field has potential to be developed and to be produced if the right strategy and technique is put in place.

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INTRODUCTION

Modelling unconventional reservoirs involve several uncertainties. There are many parameters that affect the reliability of a model, including geological uncertainties, reservoir heterogeneity and variety mechanisms of formation damage. These can change the history of the reservoir and significantly deviate the production results from forecasted simulation results. A general procedure is available to transfer the uncertainty into the model (Barua *et al*., 1986; Brown and Smith, 1984; Ding *et al*., 1992; Haldorsen and Damsleth, 1990; Ovreberg *et al*., 1992) but to analyse the uncertainty, a systematic computation is still required (Ballin *et al*., 1993).Also, formation damage can also take place during exploration, drilling and production phase. While the wettability state can change due to the fines migration (Krueger, 1986), There are also different damage mechanism(s) proposed in tight gas unconventional reservoirs(Bennion, 1999; Bennion and Thomas, 1994; Byrom and Coulter, 1996; Jamaluddin and Nazarko, 1998; Monaghan *et al*., 1959; Qutob and Byrne, 2015)listed as follow:

- Mechanically induced
- Chemically induced
- Biologically induced

A tight gas reservoir can also be very sensitive to the water. Formation damage can occur if water is introduced into the reservoir during different development stages (Bennion and Thomas, 2000; Bennion and Thomas, 2005; Katz and Lundy,

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1982), particularly when the connate water saturation is sub normal. As a result, the purpose of this study is to evaluate the degree of deviation to which the field production data can have from simulation results, by performing a case study on Whicherrange (WR) tight gas field in Western Australia.

Whicher range tight gas field

Whicherrangetight gas field is located in the southwest region of Western Australia around 20 km south of Busselton. Discovered in 1968 with the drilling of the first well Whicher range 1 (WR-1). Four more wells,WR-2, WR-3, WR-4, and WR-5 have since being drilled. WR-2 and WR-3 has been plugged and abandoned due to very tight formations and high water production after fracturing respectively. However due to the fact that the Whicher range is a tight gas reservoir with very low permeability and porosity, the production from this field so far have been below expectations and the commercial recovery has not been viable, despite the execution of several stimulation and intervention techniques such as hydraulic fracturing. The study of well test data has also shown that the formation damage occurred during drilling and stimulation phase, due to the swelling of the clays from being in contact with fluids used in the wellbore. The Whicher range field has been divided into two regions, Whicher range north and Whicher range south. Whicher range north has two specific reservoir zones separated by a fault. The two regions are not in communication which each other as the gas samples from the regions have different content. The lithology is made up of coals, carbonaceous shale, and sandstone deposited from a fluvial system.

Geological Development

Whicher Range Field is located in the South Perth Basin which is part of the Perth onshore and offshore sedimentary basin in Western Australia. South Perth Basin in a north –south intracratonic rift basin containing a series of sub-basins, troughs and ridges, mostly comprised of Early Permian to Late Cretaceous sedimentary sequences. Perth Basin is confined to the east by the Darling Fault, to the west by the Indian Ocean continental shelf, to the north by Southern Carnarvon Basin and to the south by the South Coast. The main rifting phase was during the breakup of Gondwana resulting in the separation of Australian from India. The Whicher Range Gas field is a large gas accumulation in tight sandstones of Permian age. The main reservoir rock is the Willespie Formation which is part of the Sue Group. The geology is dominated by intensive faulting and folding in the form of an anticline(Fig.2.)The sediments were deposited in fluvial channel type depositional environment.

Sue Group is characterised by interbedded sandstone, siltstone and coal deposits. It is sub divided into the Woodynock Sandstone, Rosabrook Coal Measures, Ashbrook Sandstone, Redgate Coal Measures and Willespie Formations. Sue group is overlain by the Sabina Sandstone (continental sedimentation) which is overlain by the Leasuer Sandstone (deposited during fluvial sedimentation). The focus of this study is the Sue Group; in particular the Willespie Formation which contains the Whicher Range field.

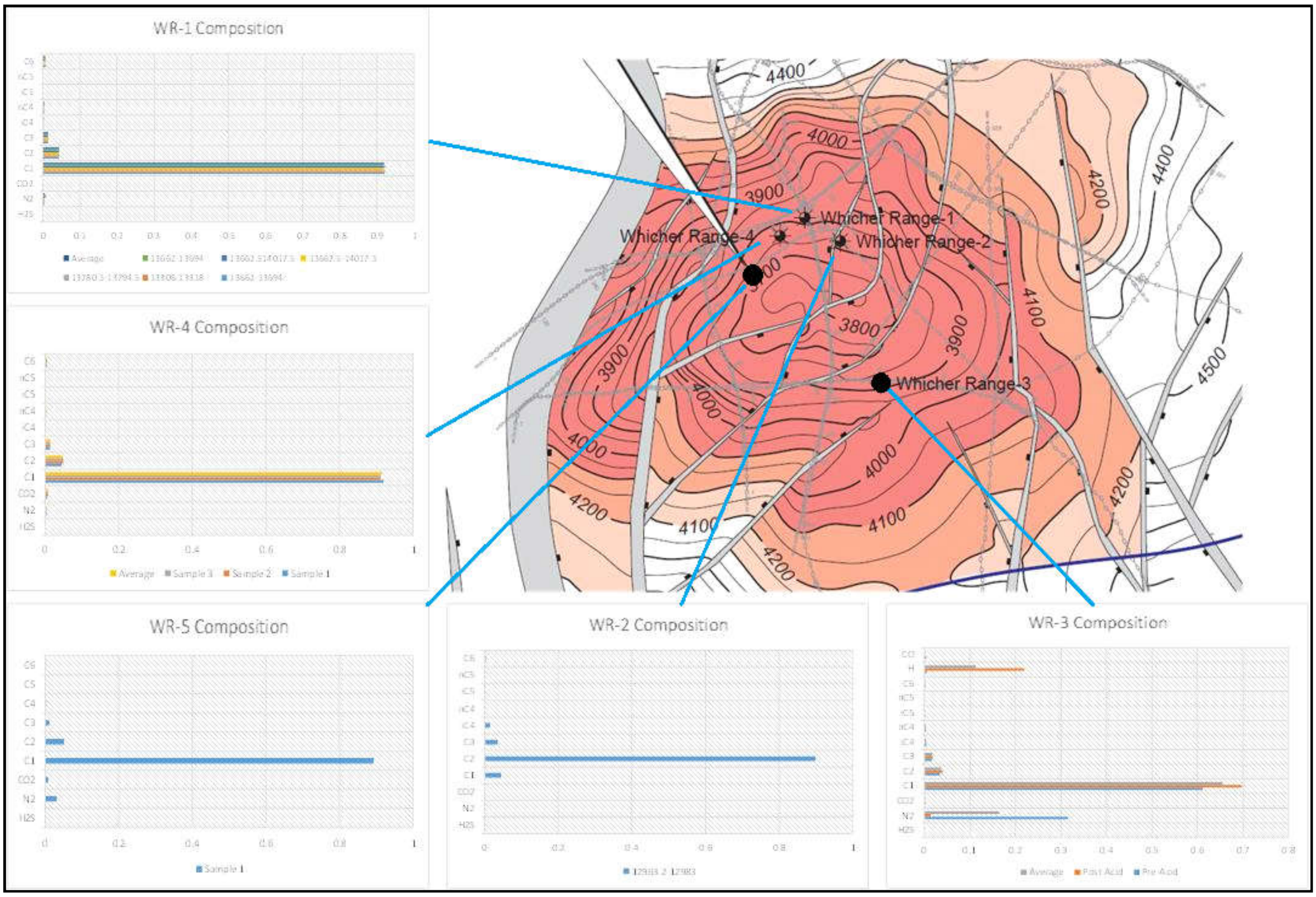

Figure 1. WR north, the gas composition breakdown shows that it can be considered as single reservoir

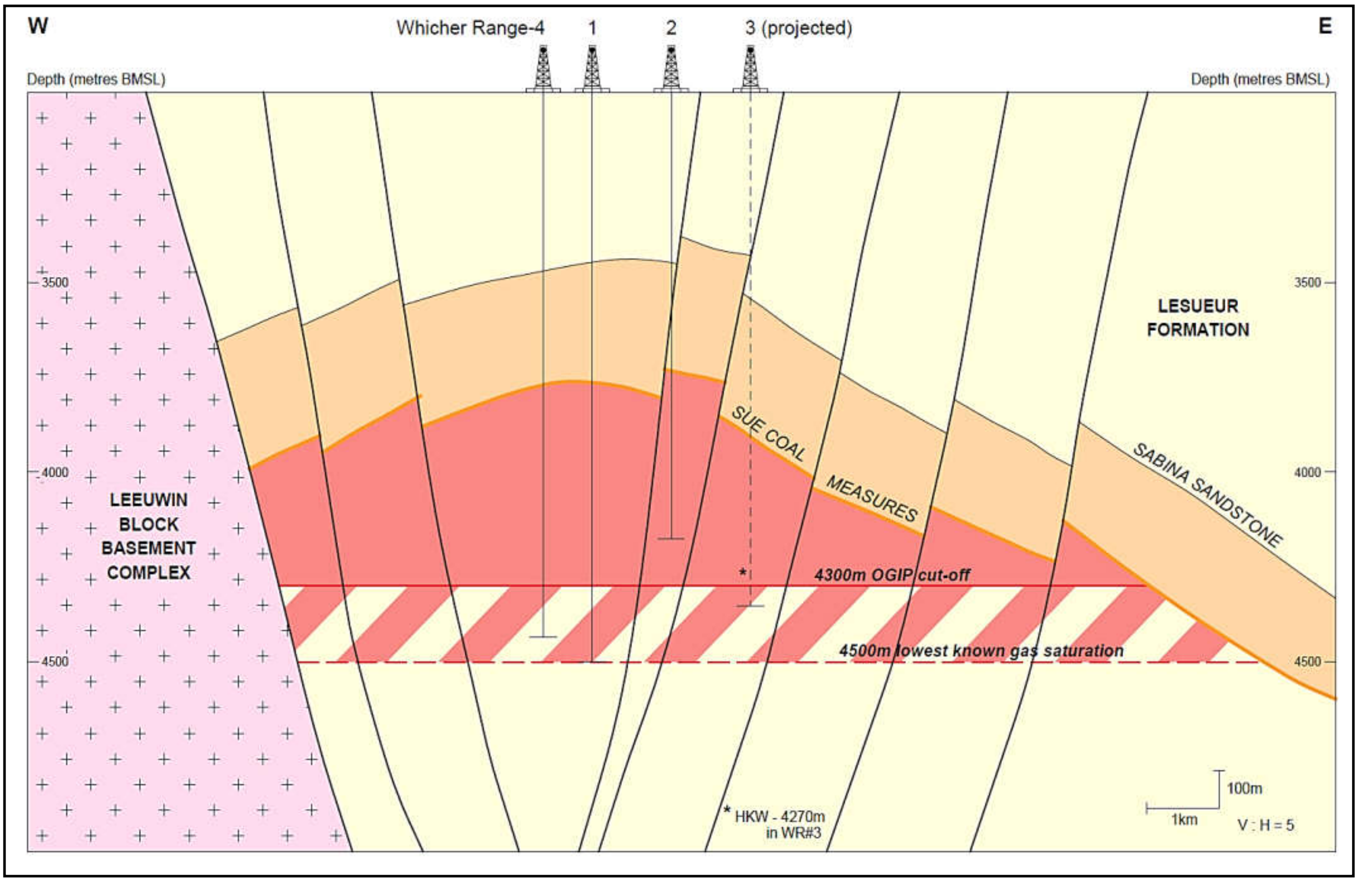

Figure 2. Whicher Range Geologic Schematic

Table 1. Geological Characteristics of Sue Group

Formation Name	Characteristics
Willespie Formation	1060 m of sedimentary thickness. Poorly sorted feldspathic sandstone with conglomerate, siltstone, shale and sporadic thin sub-bituminous coal. Coal seams are common with thicknesses generally less than 0.5m. Sandstone porosity is good. Alluvial to upper deltaic deposition environment within a lacustrine setting.
Redgate Coal Measure	146 m of thickness. Poorly sorted feldspathic sandstone overlying the Ashbrook Sandstone. Alluvial depositional environment i.e. braided streams to swamp and lacustrine deltas.
Ashbrook Sandstone	262 m of sediments. Poorly sorted felspathic sandstone unit, without major coal seams overlying the Rosabrook Coal Measures. A lacustrine deltaic environment of deposition.
Rosabrook Coal Measures	198 m of fluvial sediments. Poorly sorted felspathic sandstone interbeded with siltstone and shale overlying the Woodynook Sandstone. The bituminous coal seams range from 0.1m to 4.5m in thickness. The deposition environment is interpreted to be fluvial plain setting.
Woodynook Sandstone	118 m of fluvial sediments. Poorly sorted sandstone unit overlying the Mosswood Formation. The depositional environment is interpreted to be fluvial.

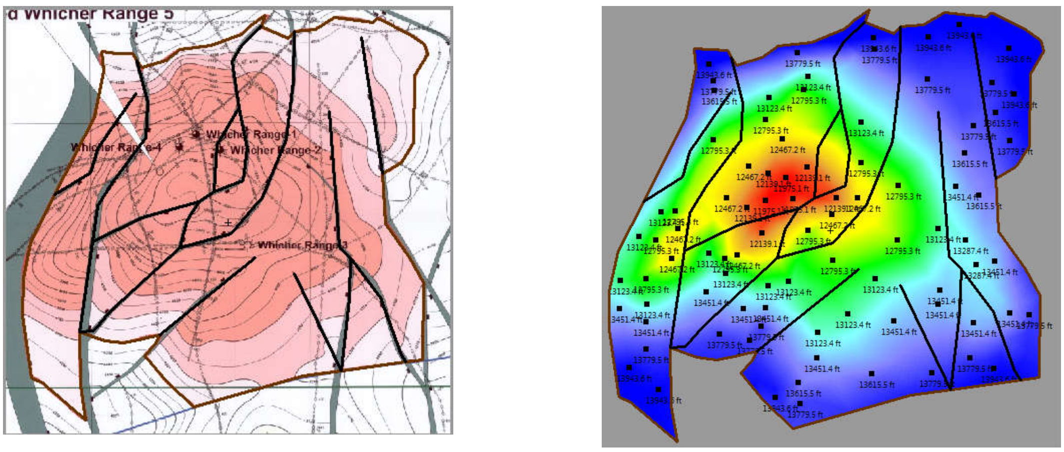

Figure 3. Top of Wilespie formation

The coals and carbonaceous shales in the Willespie Formation were deposited in an alluvial plain-wet fan delta platform, under cold temperate climatic conditions, probably both as low lying peat swamps and raised peat swamps (McCabe 1984). Defines the characteristics of the Sue Group.

Field development history

In order to compare the simulation results with the field history data, some key information of the field history can be discussed as follow:

Whicher Range 1

WR-1 was brought to development on 1968 by Union Oil Development Corporation. A well was drilled to a TD of 4653 m and an overall interval of 738 m was brought to production. An overall flow of 5.5 MMscf was recorded. Well stimulation took place in WR to increase the production by applying water bashed fracturing fluid, however after fracturing the flow rate dropped and resulted in well abandonment.

Whicher Range 2

Mesa Australia Limited drilled WR2 in 1980 to the depth of 4375 m using WBM as drilling fluid. Unlike expectations the flow rate of WR2 was even less than WR-1 and after studying the formation in WR2 it was concluded that due the presence of dolerite dyke the formation is rather too tight with even lower permeability and porosity than WR-1. As a result of unsatisfactory rate the well was plugged and abandoned.

Whicher Range 3

BP Petroleum Development Australia Pty Ltd drilled WR3 in 1982 to the TD of 4496 m. a high water production in this field indicated a high communication of aquifer with gas reservoir. Attempts were made to increase the gar production by acidulation and hydraulic fracturing (water based fluid) the formation, however the results were poor for production and consequently, the well was plugged and abandoned.

Whicher Range 4

In 1997 WR-4 was brought to development by Amity Oil and its Venture participants. A TD of 4575 m was reached and production commenced. The well was fractured using water based fracturing fluid and resulted in reducing the gas flow rate. Also, it was observed that only a small amount of water used in fracturing the formation in WR-4 was produced back to surface which suggested a high water invasion into formation and hence reducing the permeability dramatically. Second attempt to improve productivity of WR-4 was conducted by applying CO_2 in fracturing the formation. Gas production rate was increased as a result of CO_2 fracturing, but not enough flow rates for economical production, thereby, resulted in WR-4 abandonment.

Whicher Range 5

Amity oil completed WR5 in 2003. Considering all the fall backs from WBM as drilling fluid, WR5 took advantage of underbalanced air drilling to reduce induced formation damage. Side tracks and hydraulic fracturing were performed on WR5 but didn't result in any satisfactory production.

First Order Reservoir Simulation

In this section, an attempt has been made to produce the most possible model and, subsequently calibrate the model with production history of the field. It should be also noted that the field was not put on production for a long period of time as the production rate never reached economical thresholds.

Generating Static Model

Reservoir Structure and Geometry

The first step involved the creation of static geological model of the reservoir. RubisEcrin software was used to numerically simulate the reservoir. A surface map of the north flank of the field is uploaded to the software. This surface map is the top Sue Coal /Willespie formation. The surface map (Fig. 3) is digitized by manually defining contour lines and elevations into the software. The reservoir boundaries are defined and all the faults are plotted with zero transmissibility and leakage. It should be mentioned that the fault leakage should be properly studied and unfortunately Ecrin does not have the capability of sharp shifting the layers across the fault, as the interpolation method is used to correlate map data points. As a result smooth surface changes should be expected on the structural surface map.

The brown line indicates reservoir boundaries and black lines the location of the faults. The faults are assumed to have a vertical plane of 90 degree, in reality faults are oblique and software is not able to create oblique faults and graben structure. The elevation changes of the field are also shown and it reveals an anticlinal structure which forms the structural trap.

Depth of the layers was created through petrophysical evaluation of the available logs. Fourteen(14) stratigraphic layers are constructed. Applying Rock typing plus FZI, these layers were further reduced into ten (10) reservoir layers. The geometry of the reservoir is constructed by using a rectangular gridding system with 27 grids in X and Y direction and 3Zgrids for each layer adding up to 33 grids in Zdirection.

The 3D geometrical frame model generated (Fig.4).The seismic data quality is low but the modelled layers are compared to comply with available seismic interpretations to confirm the structure.

Populating Petrophysical Data

Porosity and permeability distribution in the field are critical factors governing fluid distribution and recovery of the reservoir. These are mainly controlled by the facies changes of the field. In order to populate the petrophysical data, two methods can be used. First method is statistical inference, this method is more applicable for conventional reservoirs with some degree of heterogeneity.

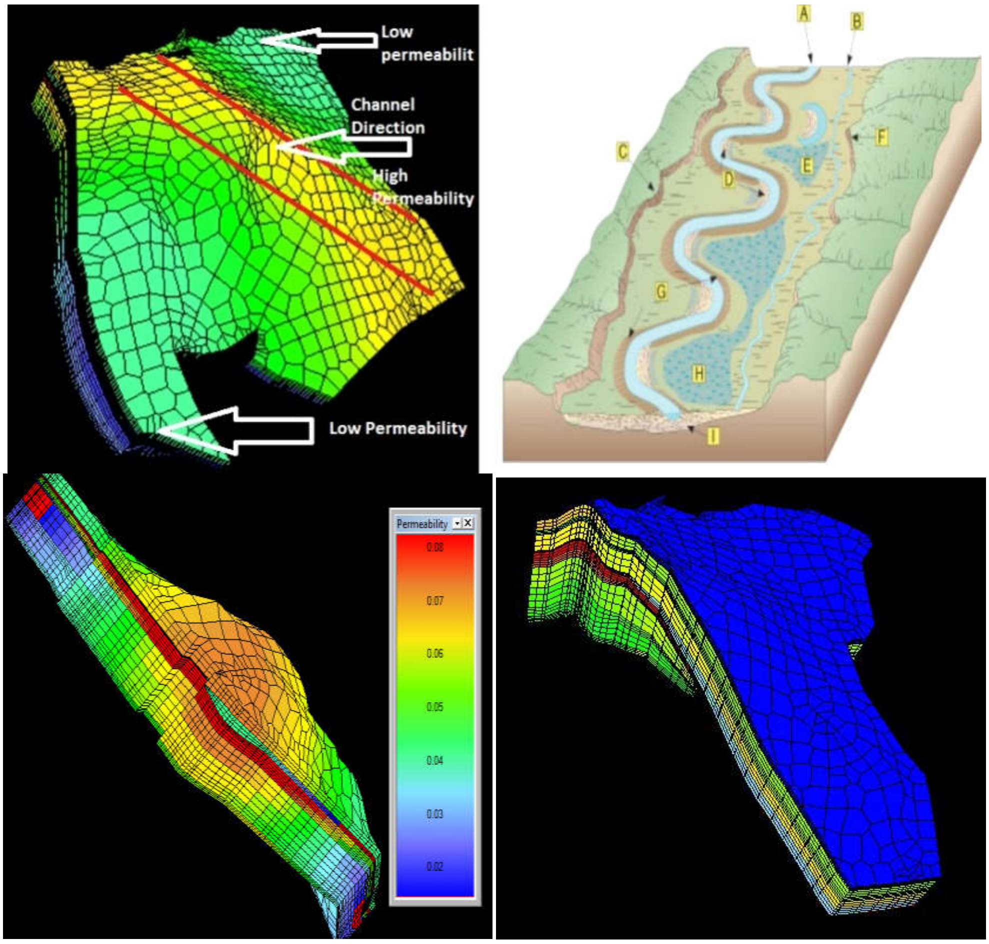

Figure 4. Permeability Distribution

The more powerful method is to apply the geological and the depositional history of the field and correlate facies changes with the knowledge acquired from log interpretations. The discussed method is a dominant way to populate porosity and permeability data in heterogeneous and anisotropic reservoirs. WR field geological studies represent that the channels were extended NW-SE and based on the dipmeter, evaluation the flow direction was observed to be SE. The facies were defined from the gamma ray logs, and calibrated with Sonic Porosity. High porosity data are populated alongside of the channel with a higher porosity on the NE decreasing to the flanks in each layer. Permeability is calculated based on the rock typing correlations and defined for the software. Figure 5clearly illustrates the direction of the main channels. Reservoir compartmentalization cannot be modelled due to software limitations but it should be mentioned that four main fracture sets have been found in the field. However no further data was found to be studied but applying fracture density into the software will significantly affect fluid dynamics in the reservoir as the dual permeability system will be applied.

Fluid Components and Rock-Fluid Properties

Two main types of the fluid are defined for the software water and gas. To generate gas PVT model, the Gas composition is used. Z factor calculated from Dranchuk correlation is used with an internal formation volume factor. Generated data are as shown in Figure 6.Reservoir Rock-fluid model (SCAL) data and relative permeability curves are generated using the power law Brook-Corey correlation method.

Dynamic Reservoir Model

Having the static model, the next stage is to define dynamic properties of the reservoir as the static model does not represent the pressure and saturation distribution in the reservoir. To generate the dynamic model, due to production data scarcity, Two wells (WR-1, WR-4) implemented into the model. The reservoir model initialized and simulated. Initially the production rate calculated by the software was 10 MMscf/d from WR-1. The model calibration was required to construct a representative model.

Model Calibration and History Matching

Based on the field history, well one was drilled in 1968 and the initial flow rate was a stabilized 5 MMscf/d. To increase the flow rate, the well was fractured using water based fracturing fluid and disregarding that reservoir contains water sensitive clay minerals. The fracturing process completely damaged the well and reduced the gas flow rate to almost zero. After reopening side tracks in well 1 and well 4, an acceptable well test was performed on well 4 with a short period of 6 days. Those data, regardless of their short duration, were used to calibrate the model. As mentioned above, the model initial flow rate was 10 MMscf/d.

Two attempts was made to calibrate the model. In the first attempt reservoir permeability multiplier adjusted to 0.5 and the flow rate dropped to around 5 MMscf/day which is equal to initial production of well number 1 (before introducing the damage). Results are illustrated in figure 7 and figure 8.

Since the main reason for low flow rate is the well damage, in the next attempt, the skin factor is manipulated to about 5 and a perfect match is achieved.

However as mentioned earlier, the field data are of low quality and the duration is also very short, consequently the history matching will have uncertainties involved.

Volumetric Gas in Place Calculation

Having a representative model, the volumetric reserve calculation is performed. The volumetric Gas Initially in Place (GIIP) is calculated to be 12.2 Tscf from the entire geometry, which can be considered for probabilistic reserve calculation. However it should be noted that due to very low permeability and compartmentalized nature of the reservoir. The hydraulic diffusivity of the reservoir is very low and as a result, the drainage radius of the wells would also be low. In order to calculate the drainage radius, an appropriate well test data is required with long enough duration to reach radial flow and consequently to use the concept of isothermal compressibility. In this case due to the tight nature of reservoir, the well test was not long enough to observe radial flow as a result a drainage radius of 2000 ft is assumed, new boundaries are created in the software and recoverable volumes are calculated for all existing wells.

DISCUSSION

In this section the associated uncertainty and a comparison between the simulation results and the field history is discussed;From a geo-mechanical perspective, due to continental crust movements the field is tectonically active.

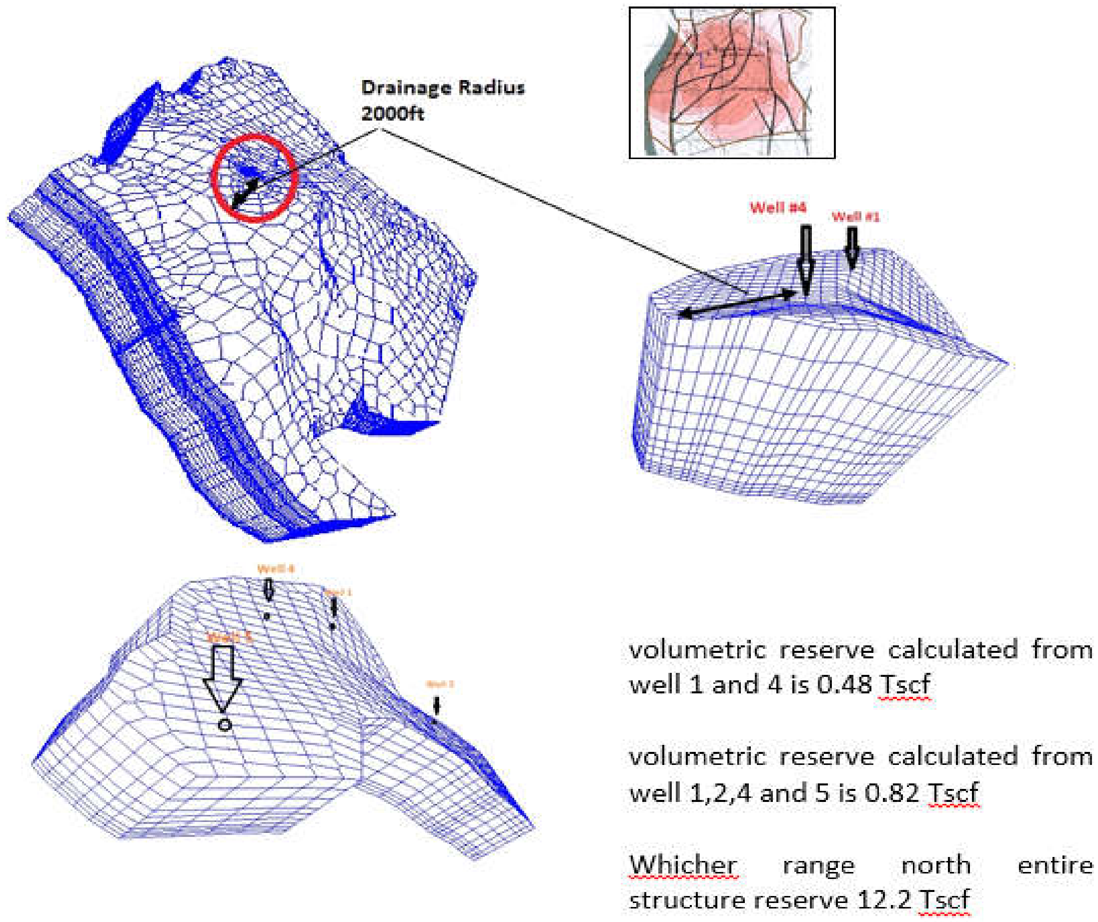

Figure 5. Volumetric Reserve from Drainage Radius

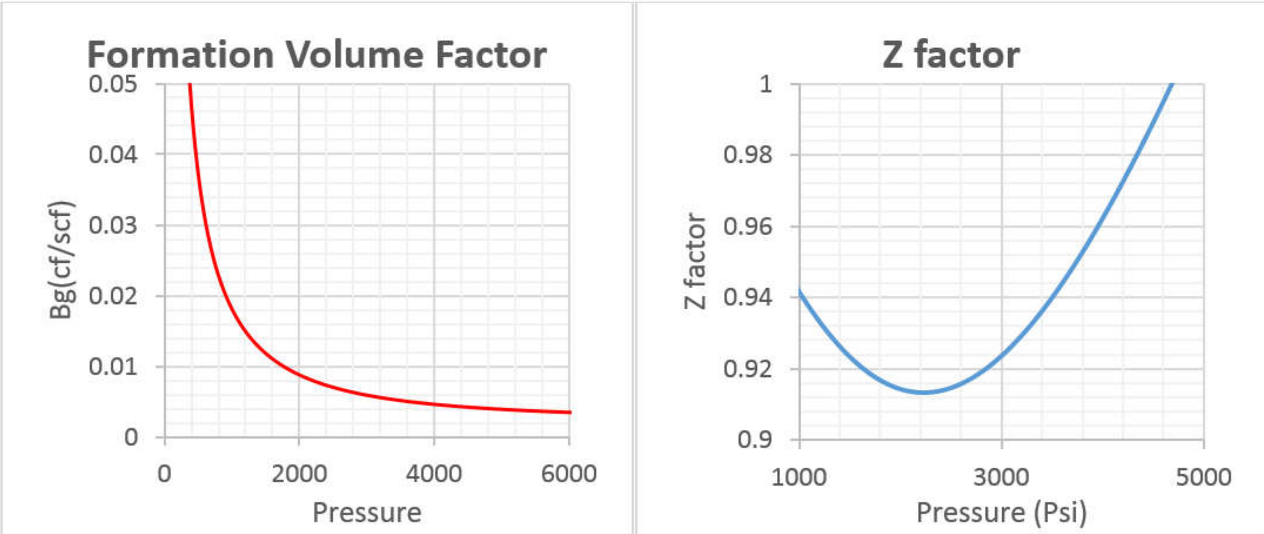

Figure 1. Formation Volume Factor, internal Bg by Ecrin (left) and Z factor, Dranchuk Correlation by Ecrin (right)

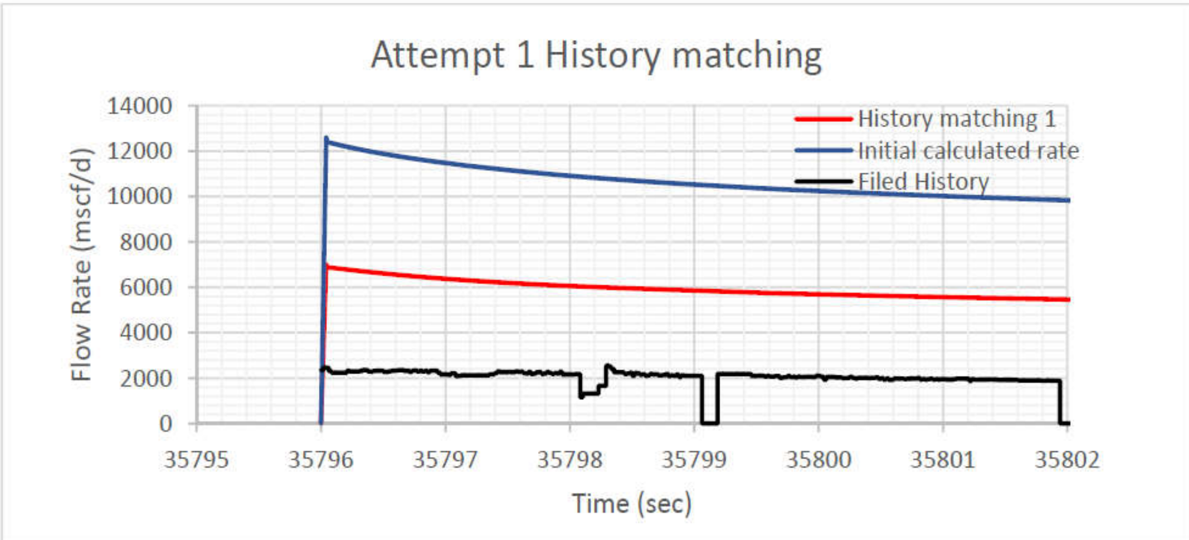

Figure 7. History matching, first attempt

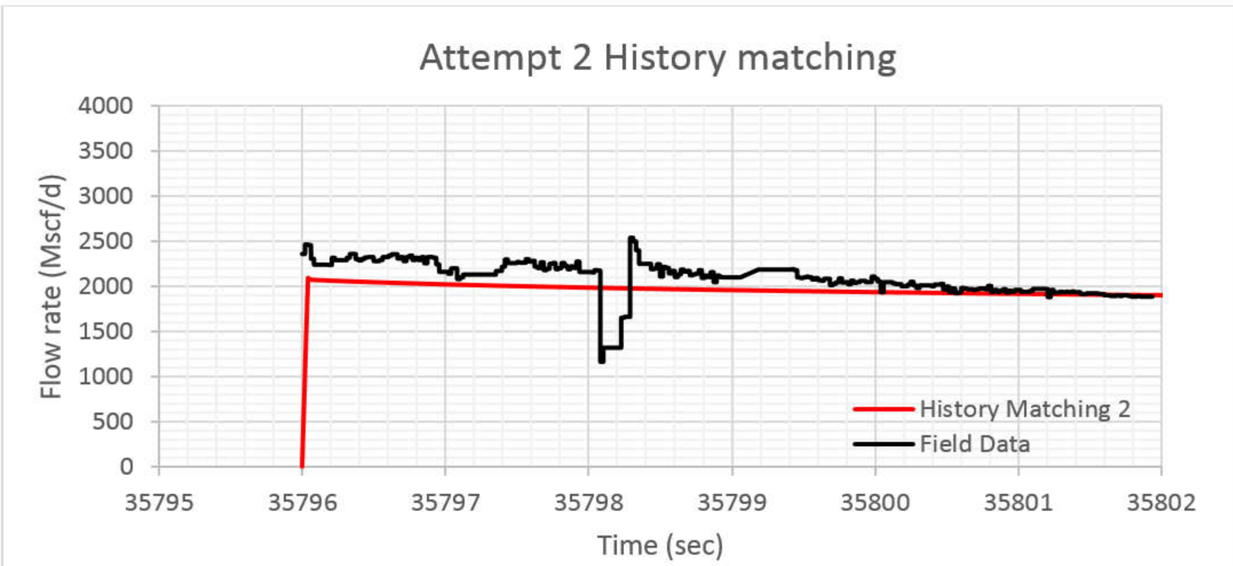

Figure 8. History matching, second attempt

The consequence of above activities resulted in a highly fractured, faulted and folded system. Graben structure resulted from oblique faulting, and led to extreme compartmentalization, thereby, questioning the lateral continuity of stratigraphic layers in the field. In addition to geo-mechanical complexities, the fluvial meandering system depositional system means that the reservoir contains a network of channels with a very low lateral continuity. Petroleum system associated with meandering system can be very risky to invest on, as there are a lot of lateral pinch outs and abandoned channels representing hydrocarbons with no lateral extent. Furthermore, from the reservoir engineering perspective, capillary pressure and permeability are two major factors highly governing the fluid distribution in the reservoir. Fluvial depositional system contributed to variable grain sizes due to river current change. This creates anomalies and irregular facies and consequently heterogeneous permeability distribution in the reservoir. Hence, fluid distribution will not be consistent bringing further uncertainty into the model. In this occasion, accommodating all these irregularities in the model is almost impossible, as the simulator, by default, will create a very homogeneous structure resulting in an overestimation of GIIP and recovery factor. Defining heterogeneity and populating accurate data into the simulator, requires a high quality seismic and petrophysical data, which hasn't been acquired during the exploration and development stage. As a result there will be a high uncertainties involved with the generated model.

To highlight the degree of deviation, the following matters can be highlighted;

- The simulated production rate was stabilizedat approximately 10 mmScf/d whereas the actual flow rate, at its optimum condition was 4 mmScf/d
- The deterministic (Volumetric) gas in place was calculated to be 13 tcf, whereas the 6 tcf was previously reported.

Conclusion

In this study we have studied the degree of uncertainty in WR tight gas field. A numerical model was developed and the volumetric estimation of GIIP, as well as the production rate was compared with real production data. The following points were observed

- Significant uncertainties are involved in simulating the unconventional tight gas reservoirs with a fluvial deposition environment.
- Before proceeding with the development a comprehensive and meticulous study on lateral continuity of the reservoir rock should be carried out.
- In tight gas fluvial system; Instead of a deterministic approach, a stochastic model should be generated to embrace the degree of uncertainty.
- A complete production data should be acquired with no interruption to achieve more accurate forecasting.

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