Completion design optimization of multilateral well to maximize hydrocarbon production in a bottom water drive reservoir

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***Abstract* - Maximum reservoir contact (MRC) can help increase reserves recovery from the reservoir by many folds. It can lead to effective reservoir drainage, effective sweep and delayed coning and cusping. MRC can achieved using horizontal wells, multilateral wells and extended reach drilling (ERD). However, the long horizontal wellbore can pose some serious production problems. Higher pressure drawdown around the heel of the well can cause non-uniform fluid influx along the wellbore and higher production rates at the heel. This can lead to early breakthrough of water or gas. Early Water breakthrough in Horizontal well completion in a bottom water drive reservoir is major issue which needs to be addressed in detail using available technical knowledge, previous experience and modern techniques. The prime reason behind this is inability to model the pressure gradients that exist from the heel to toe in the horizontal part of the wellbore which can lead to inaccurate estimates of water breakthrough time and rate. In a heterogeneous reservoir, water and gas breakthrough can be delayed using inflow control devices which regulates flow from the reservoir into the wellbore. This paper focuses on the, Development of three dimensional Geological model and validating it using history matching; Use of well segmentation concept to compute frictional and acceleration losses in the horizontal section of the wellbore and assess its impact on well production; Estimate the incremental oil production using inflow control devices in a multilateral well. And Outcome of the study is ICD installation in horizontal wells can significantly increase the cumulative oil production and reduce water production.**

***Keywords* - Maximum reservoir contact, History matching, Segmentation, Inflow control device, Lateral, Horizontal well, Vertical Well, Optimization, water cut**

I. INTRODUCTION

Maximum reservoir contact (MRC) can help increase reserves recovery from the reservoir by many folds. It can lead to effective reservoir drainage, effective sweep and delayed coning and cusping. MRC can achieved using horizontal wells, multilateral wells and extended reach drilling (ERD). Challenges presented by maturing oil fields and diminishing areas of "easy oil", fuelled development of a new generation of wells, better known as Maximum Reservoir Contact (MRC) wells [2]. However, the long horizontal wellbore can pose some serious production problems. Higher pressure drawdown around the heel of the well can cause non-uniform fluid influx along the wellbore and higher production rates at the heel. This can lead to early breakthrough of water or gas. A multisegment well model can determine how the fluid flow rate, the wellbore contents and the pressure vary throughout the well, and can provide a more accurate treatment of cross flow and multiphase flow [3].

II. RESERVOIR DESCRIPTION

This field is one of the most prolific producers of in Upper Assam Basin, India. It is a faulted anticline, about 35 sq km in size at the Arenaceous Top level, with the major axis of the structure trending in NE-SW direction. The structure is bisected by eight major NE-SW normal faults heading towards southeast with a maximum throw of 200m while there are six NE-SW trending normal faults heading towards northeast with a throw of 80m, except one with a throw of more than 200m. A depth contour map on top of Oligocene sand reservoir has been prepared and presented as Figure-1. This reservoir is oil-bearing with an initial gas cap and a strong bottom water drive. The original oil-water margin was at around 2568 m true vertical depth below sea level (TVDSS) while the original gas-oil margin was at 2522 m TVDSS (refer Figure1). The oil pay thicknesses of the structure in Oligocene sand reservoir ranges from 12m to 35.5m. The gas pay of the gas cap zone ranges from 0 to 27m.The reservoir porosity ranges from 18% to 24%, whereas the permeability varies from 100 mD to 500 mD.

This reservoir is having bottom water drive with active support. Currently this field is experiencing problems such as high water cut, cessation of flow due to high water cut. High water cut in Horizontal wells is mainly due to higher pressure drawdown around the heel invoking a cone to form leading in high water production and early water breakthrough.

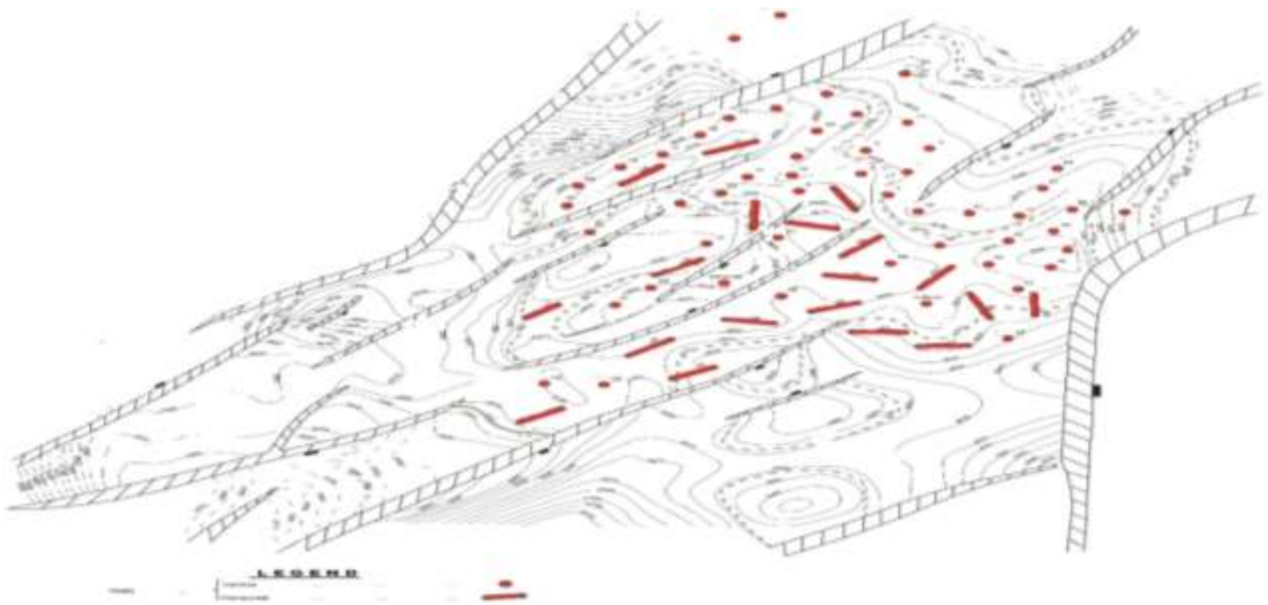

Figure-1: Depth contour map on top of Oligocene sand

III. THEORY

Multilateral Wells

Multilateral-well technology (Figure-2) is revolutionizing the way that reservoirs are accessed by wells. The ability to create wells with multiple branches that can target widely spaced reservoir compartments provides engineers unlimited options in optimizing economic extraction of oil and gas. Along with this opportunity comes the inherent complexity of these well architectures. The goal of this type of well is increase production rates, improve production recovery and maximize production from that zone. Maximum reservoir contact wells may be drilled for several miles into pay zone with multilaterals in stacked, forked, fishbone, or other configurations resulting in PI exceeding 100 bbl/d/psi [1].

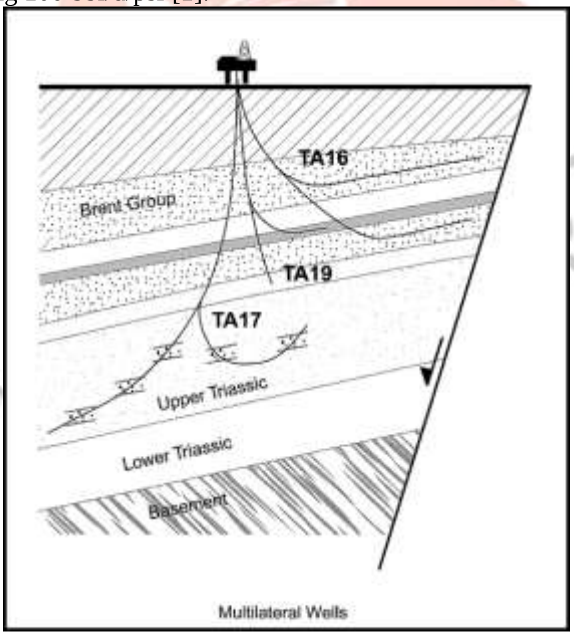

Figure-2: Multilateral well schematic (Source: Multilateral wells in the Tern field, UK North Sea. From Black et al., 1999)

Well Segmentation

The need to simulate advanced wells (horizontal and multilateral wells and smart' wells containing flow control devices) requires a correspondingly sophisticated type of well model to be implemented in reservoir simulators. The model must be able to determine the local flowing conditions (the flow rate of each fluid and the pressure) throughout the well, and to allow for pressure losses along the wellbore and across any flow control devices [3].

The pressure drop along the wellbore is calculated differently in the standard well model and the multi-segmented well model. Only the hydrostatic pressure drop is considered in the standard well model.

$$\Delta P = \Delta P_{Hyd} = \rho g h \qquad (1)$$

Where ΔP is pressure drop , ΔP_{Hyd} is hydrostatic pressure drop , ρ is density of fluid, g is acceleration due to gravity and h is height.

Thus, for the standard model, the pressure drop due to acceleration and friction is assumed to be small and, therefore, neglected.

However, in a segmented well model (Figure-3), to compute the density in the wellbore, the well is divided into segments between adjacent connections. For each of those segments, the volume formation factor is used to compute the average density based on average pressure in the grid cells that the segment penetrates. Hence, the density is allow to vary along the wellbore.
After the density is computed, the pressure drop along the well trace can be computed corresponding to the connection depth.
Benefits of a multi-segmented well model include:-

- Accurate calculation of wellbore pressure gradient.
- Proper representation of well trajectory
- Ability to model downhole flow control devices
- Cross flow can be modeled more realistically, as fluid mixture can vary throughout the well.

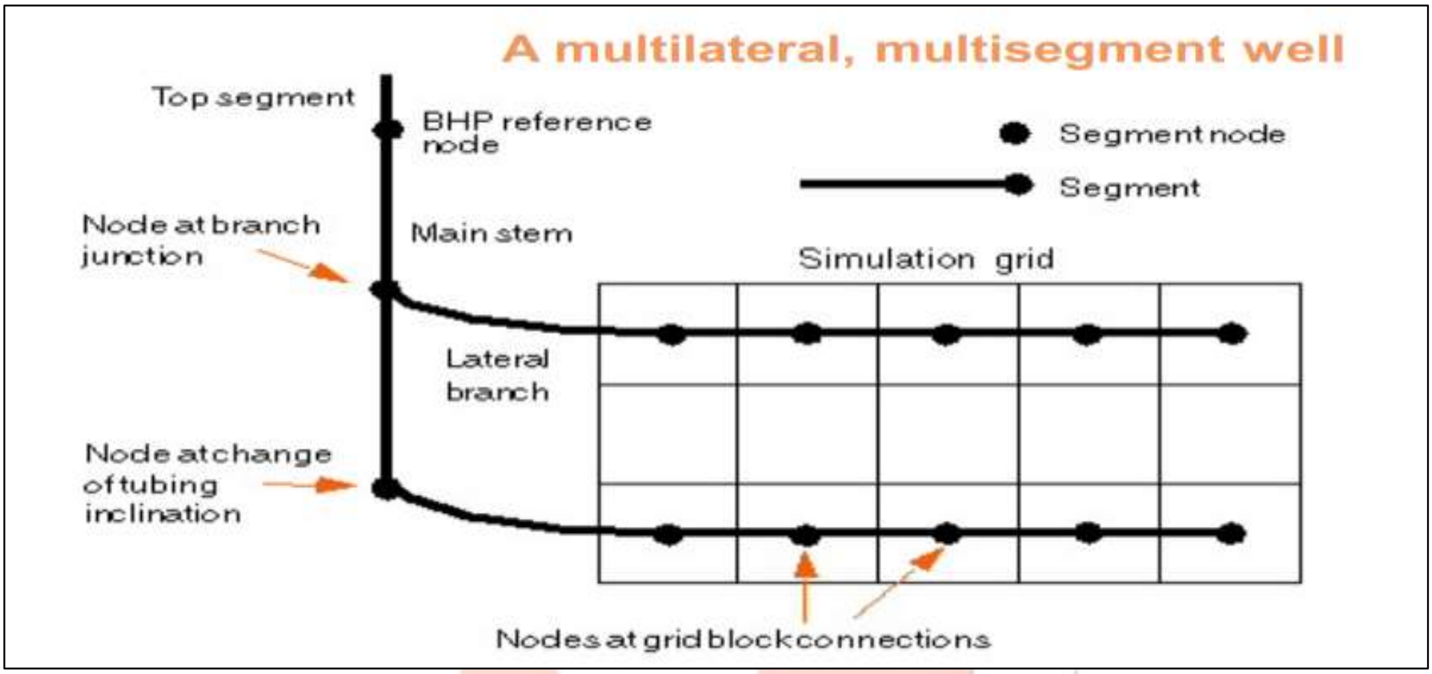

Figure-3: Multilateral and Multi segment well schematic

Inflow Control Devices

Controlled flow of fluid from the reservoir is crucial to obtain maximum recovery from the reservoir. Inflow control devices attempt to balance the pressure differential across the completion to delay the entry of unwarranted fluids. This allows clean hydrocarbon production for a longer time period from the well. Inflow control devices (Figure-4) are used in horizontal wellbores to mitigate the effects of frictional pressure losses that result in production problems, such as coning at well heel due to increased drawdown in comparison to the toe. The ICD contains an orifice having an opening that is adjustable in size and is disposed in the device to permit communication of fluid from one end of the body to the other.
A horizontal or a highly deviated well encounters pressure drops which have slightly different behavior than the vertical section. This includes Pressure drop due to gravity, acceleration and friction. The latter two are insignificant and can be ignored in case of a vertical well but for a horizontal section with pressure that has fallen below the initial bubble point pressure; these two components becomes significantly important. Apart from the above analysis, pressure drop also incurs at the well bore near the perforation. Inflow Control Devices regulates the pressure drop across the perforation, hence different correlation are used to simulate the pressure drop in case of ICD installations.
The pressure drop across the ICD is governed by fluid properties, fluid flow rate and ICD configurations. For Spiral ICDs, the pressure drop over a given well segment is given by

$$\Delta P_{sicd} = \left\{ {\rho_{cal} \cdot \mu_{mix}}/{\rho_{mix} \cdot \mu_{cal}} \right\}^{0.25} \cdot \frac{\rho_{mix}}{\rho_{cal}} \cdot \alpha_{sicd} \cdot \left(\frac{Q}{n}\right)^2 \qquad (2)$$

where, ρ_{cal} and μ_{cal} are density and viscosity of a known fluid respectively which is used for calibration of the devices. ρ_{mix} and μ_{mix} are the mixture density and viscosity respectively. Based on the measurements of a calibration fluid flow through a particular type of SICD, an empirical constant α_{sicd} is defied. Q is the total inflow and n is the number of valves in each segment.
Nozzle Type ICD is similar to AFCV but the aperture is static. The pressure drop is the sum of pressure drop across reservoir and across ICD. Reservoir Pressure drop is a Darcy effect whereas ICD pressure loss is based upon Bernouli principle.

$$\Delta P_{total} = \Delta P_{F1} + \Delta P_{N1} + \Delta P_{F2} + \Delta P_{N2} + \cdots + \cdots + \Delta P_{Fn} + \Delta P_{Nn} \qquad (3)$$

where, n is the total number of nozzles installed,

ΔP_F is the Darcy pressure drop across the Reservoir : $= \frac{\mu L}{KA} q$ (4)

ΔP_N is the Bernouli pressure drop across the ICD :$= \frac{\rho}{2A^2} q^2$ (5)

The ICD are set up in petrel and requires the following parameters – channel x-section area, inner and outer diameter of the tubing. Appropriate design and planning for an ICD completion requires knowledge of reservoir and geology, such as permeability, porosity, reservoir pressure, as well as oil/water saturation distribution, accurate modeling of the near wellbore fluid flow and reasonable understanding of dynamic of reservoir condition [4].

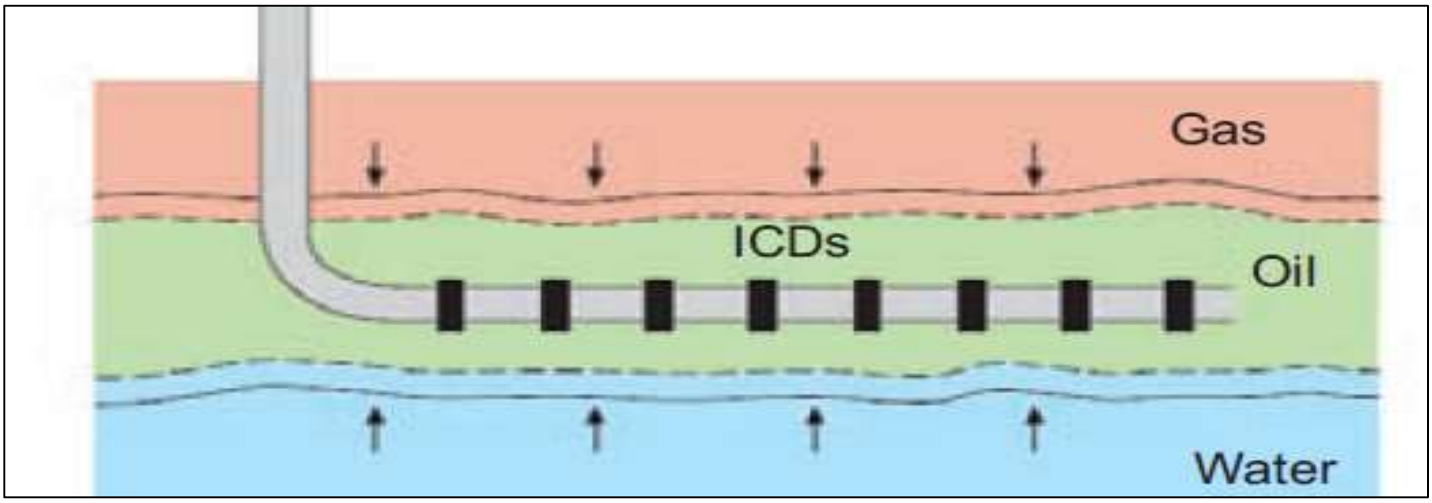

Figure 4 ICD Completion showing uniformity in contact movement (Ref: JPT-May 2010)

IV. METHODOLOGY ADOPTED

Following methodology was adopted for observing the effect of pressure drop on early water breakthrough in horizontal wellbore also effect of placing ICD in horizontal wellbore on water breakthrough.

- Numerical Simulation three dimensional geological model
- History matching
- Sensitivity analysis
  - Multilateral well with and without MSW
  - Multilateral well with MSW and Nozzle ICD
  - Multilateral well with MSW and Spiral ICD
- Results and Discussion
- Conclusion

V. NUMERICAL SIMULATION MODEL

The 50m by 50m gridding of the original model was upscaled to 100m by 100m. The vertical resolution was reduced approximately by a factor of two, increasing average cell height from 0.5m to 1m. The geomodel was resampled into upscaled grid to capture rock types, porosity, and permeability and saturation distribution. The porosity was resampled arithmetically with weighting by pore volume. The resultant upscaled simulation grid has 120x72 xs86 (743040 cells) having 308326 active cells and upscaled model was migrated into the Eclipse Simulator. Further reduction on active blocks was carried out reducing the number of grid blocks in aquifer region and conducting re-dimensions to the pore volume of the aquifer grid cell. Porosity, permeability & reservoir thickness distribution of the geomodel with well location has been shown in Figure-5 through Figure-7 respectively.

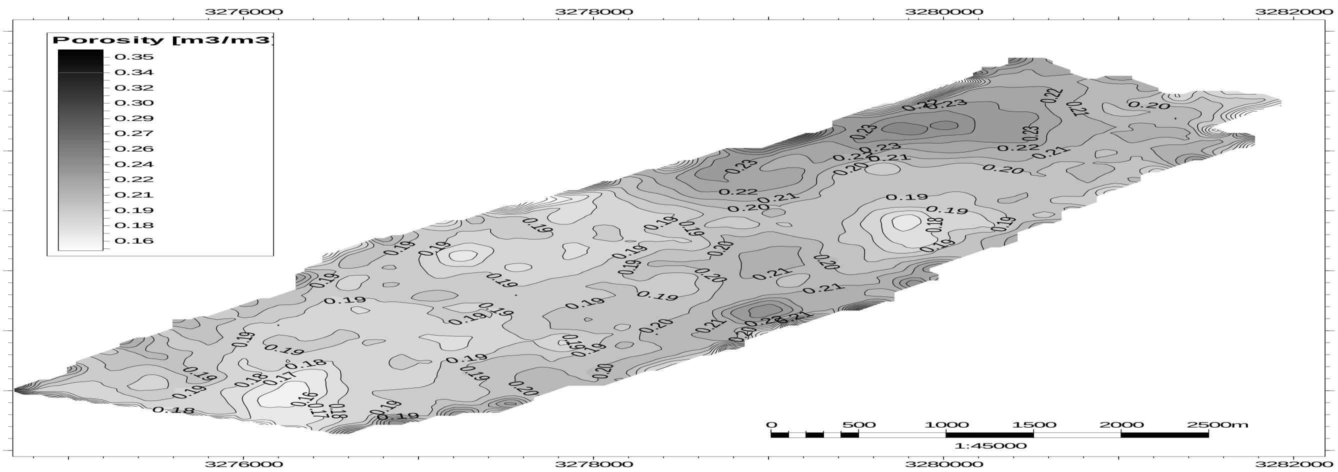

Figure-5: Porosity distribution of the geomodel

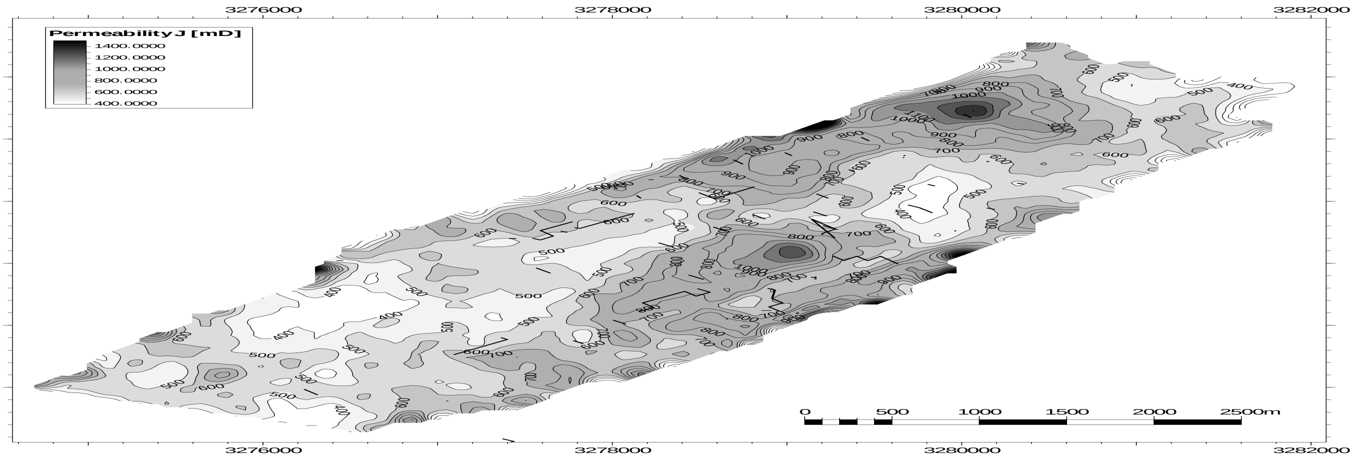

Figure-6: Permeability distribution of the geomodel

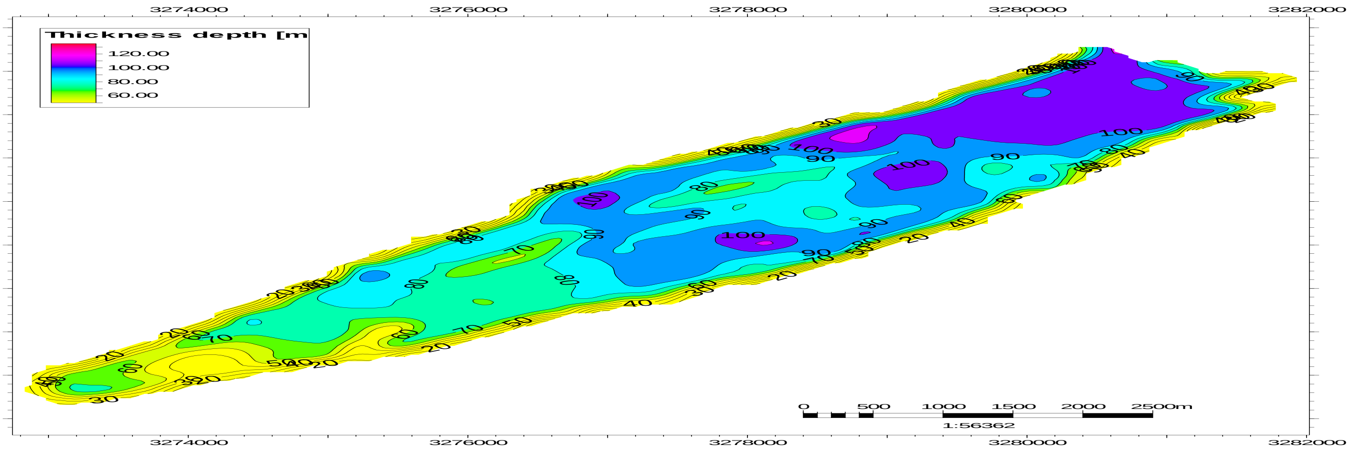

Figure-7: Reservoir thickness distribution of the geomodel

VI. HISTORY MATCHING

History Matching was conducted using Eclipse Black oil simulator (E100). Liquid rate control was kept as the control parameter for pressure match followed by Oil rate control for finer tunings. Sensitivities to Kv/Kh ratios were studied as part of the uncertainty assessment. In addition, core K and Phi values were used to validate the K-Phi transform used in the static model. Relationships for relative permeability endpoints were established and implemented in the model based on the SCAL analysis.

Typical reservoir parameters considered for production data history-matching were as follows:

- Global permeability multiplier
- Anisotropy ratio (Kv/Kh)
- Analytical aquifer strengths / directions
- Fluid contacts (GOC / FWL)

Most of the above mentioned history-match parameters used was applied globally, except for few cases, in which there were reasons to believe that the production data at any well could only better be matched by using any local regions etc. To preserve the sanctity and predictability of the models, these local modifications were done to the minimum extent, as far as possible. The results of History Match analysis is shown in Figure-8.

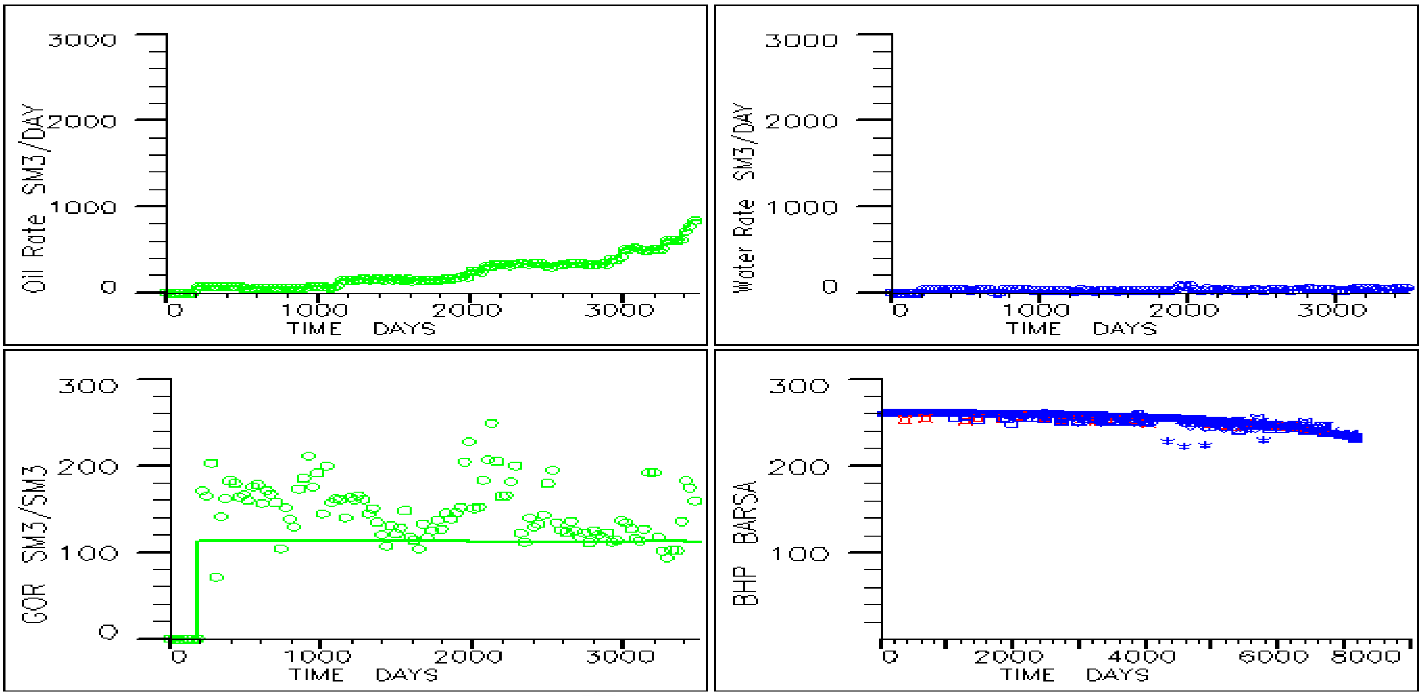

Figure-8: History match results at field level

History matching was done satisfactorily on this field for a period of 10 years on oil rate, water rate and pressure.

VII. SENSITIVITY ANALYSIS

This model was used to perform sensitivity on Multilateral well with and without Multi segment and with various Nozzle and Spiral ICD completions.
From above a total of four cases were constructed, details of which is given below.

Case-1: Multilateral well completion without Multi segmentation
Case-2: Multilateral well completion with Multi segmentation
Case-3: Multilateral well completion with Multi segmentation & Nozzle ICD
Case-4: Multilateral well completion with Multi segmentation & Spiral ICD

The prediction cases for reservoir were run using well production-rate control. The wells were given the production constraint as per the surface handling capacities. The wells were subjected to certain other constraints as shown in Table-1.

Table-1: Well-level constraints for prediction runs

Constraints	Value
Maximum individual well production rate	Decided based on historical well production rate in the reservoir
Completion type	Single Completion : bottom-to-top
Minimum well bottom-hole pressure	50 - 100 bars, depending upon the segment performance
Maximum water-cut	95%
Minimum economic limit on oil-rate	1 m^3/day
Maximum GOR constraint	1500 m^3/m^3

Case-1
In Case-1 performance prediction of multilateral well H-1 has been carried out in three dimensional history matched model without any well segmentation. Schematic of the well has been presented in Figure-9.
Case-2
In Case-2 performance prediction of multilateral well H-1 has been carried out in three dimensional history matched model with well segmentation. Schematic of the well has been presented in Figure-9.
Case-3
In Case-3 performance prediction of multilateral well H-1 with Nozzle ICD has been carried out in three dimensional history matched model with well segmentation. Schematic of the well has been presented in Figure-10. The well under consideration in this study was dynamically simulated with 3 Nozzle ICDs along the horizontal section of the parent bore and the lateral.
Case-4
In Case-3 performance prediction of multilateral well H-1 with Spiral ICD has been carried out in three dimensional history matched model with well segmentation. Schematic of the well has been presented in Figure-10. Schematic of the well has been presented in Figure-10. The well under consideration in this study was dynamically simulated with 3 Spiral ICDs along the horizontal section of the parent bore and the lateral.

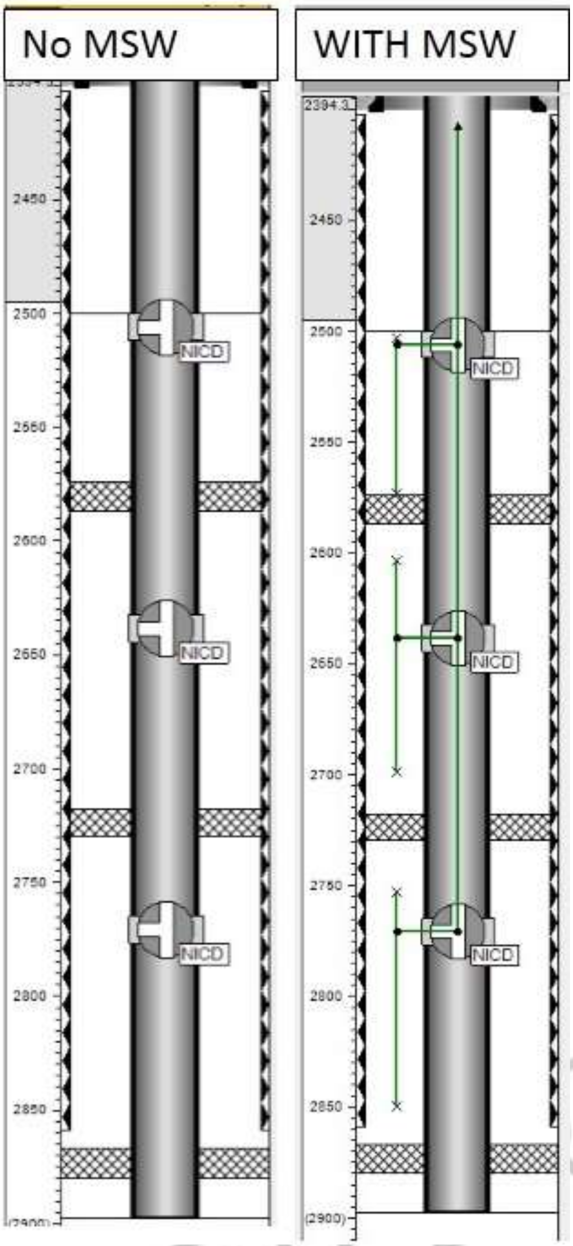

Figure-9: Well completion schematic with well segmentation and without well segmentation

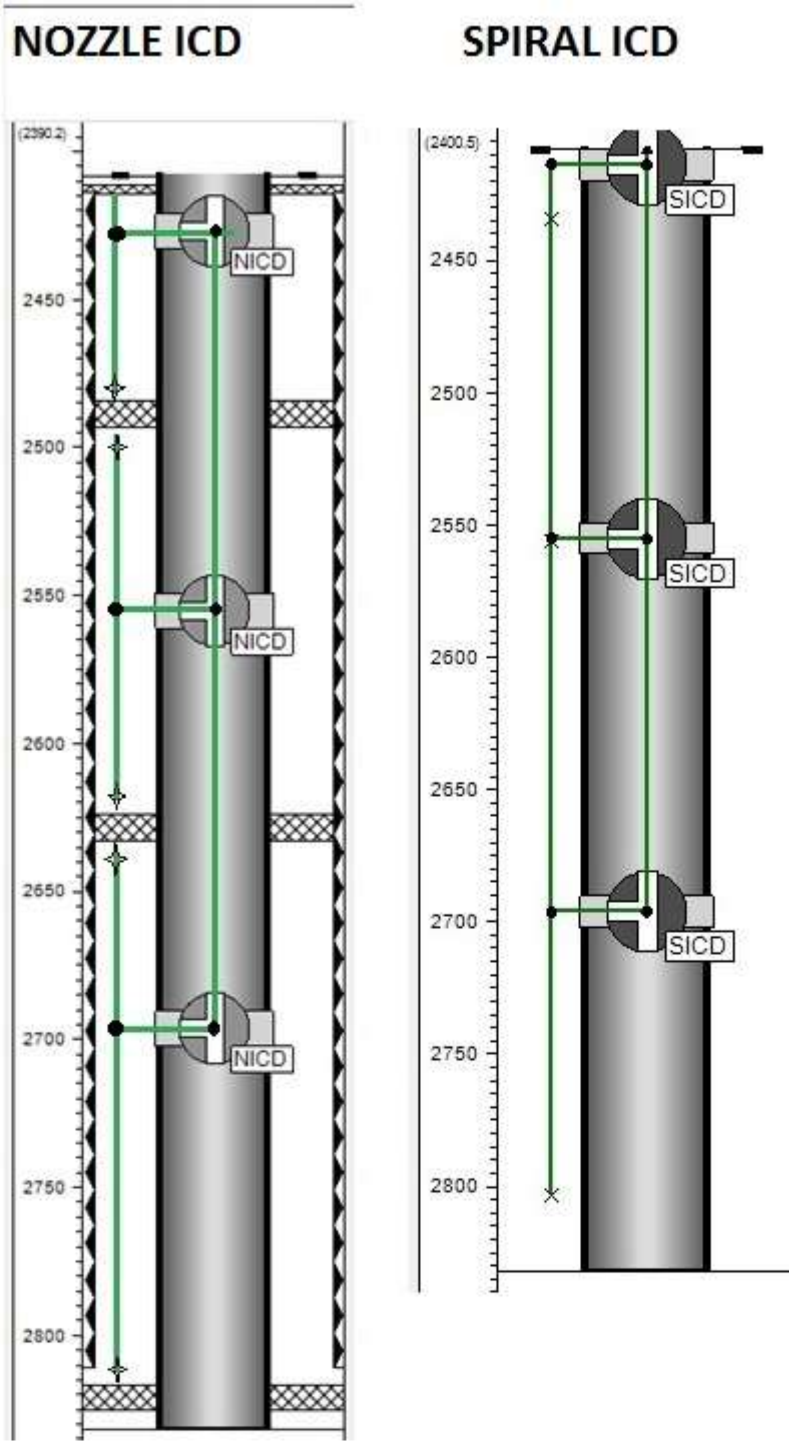

Figure- 10: Well completion schematic with Nozzle and Spiral ICD

VIII. RESULTS AND DISCUSSION

Water Cut response

It can be seen from Figure-11 that there is change in water-cut response for the different completion types. The No-Segmentation case (Red curve) gives a uniform increase in water-cut, thus signifying that the water front moves uniformly through the length of the horizontal well bore. However, the water-cut response for the Multi-Segmentation case (Blue curve) gives a sudden increase in the water-cut during early-time as the water cones into the heel of the well before it reaches the toe, this is practically the case one would expect in a heterogeneous reservoir.

The well with ICDs - spiral and nozzle (Black and Brown curves respectively) produce with a lower water cut as the drawdown is balanced by the ICD across the length of the borehole.

Incremental Oil Production

Figure-12 is a comparison of simulation results - cumulative oil produced from the well with No-Segmentation (red curve), Segmentation (blue curve), and Nozzle ICD installed (brown curve) and Spiral ICD installed (black curve). It is clear that well with

spiral ICD installed produces the maximum oil, followed by the well with Nozzle ICD as the water-free production phase is prolonged and drawdown balanced.
The well with Segmentation produces less oil as compared to the well with no-segmentation as the well with segmentation waters out early and as would be the case practically. Table-2 presents oil production cumulative at the end of prediction for the three different cases.

Table-2: Oil production cumulative from all the four simulation cases.

Case	Oil Production Cumulative (Sm3)-End Of Prediction
No-Segmentation	95675.2
Segmentation	129225.8
Nozzle ICD	197331.6
Spiral ICD	202822.4

Figure-11: Water cut for different completions types

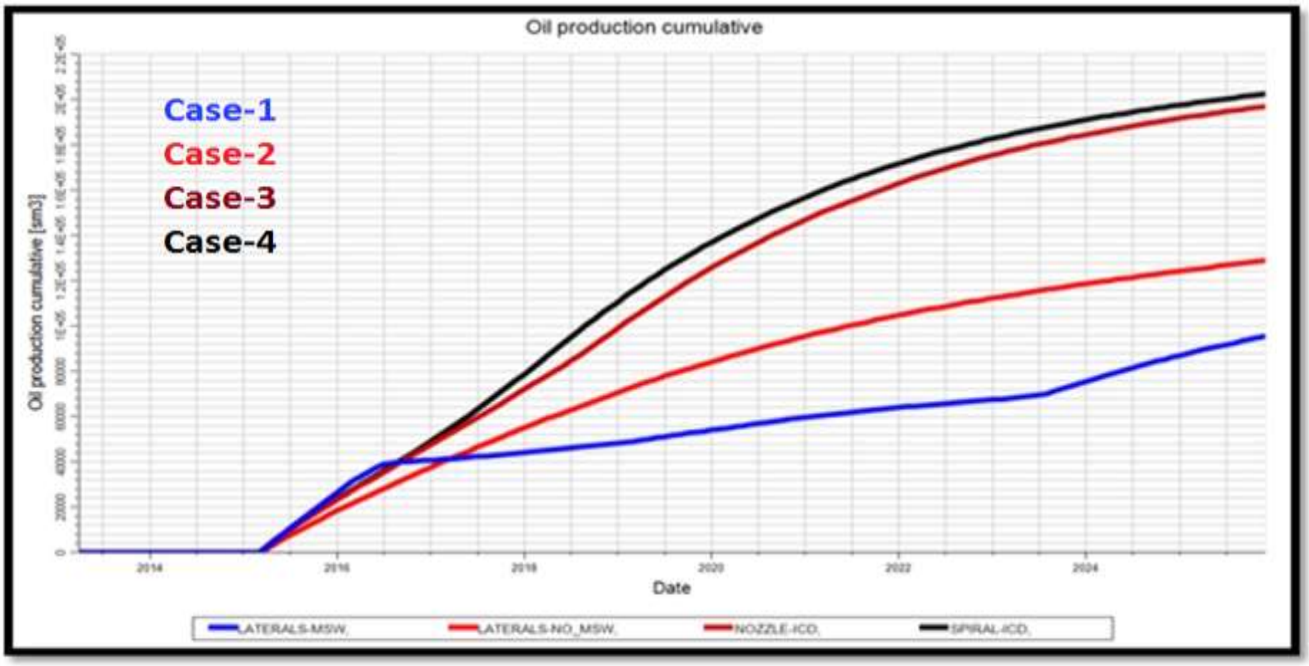

Figure-12: Oil Production Cumulative for different completion types

IX. CONCLUSION

- The well with Segmentation produces less oil as compared to the well with no-segmentation as the well with segmentation waters out early and as would be the case practically.

- Well with spiral ICD installed produces the maximum oil, followed by the well with Nozzle ICD as the water-free production phase is prolonged and drawdown balanced.

X. ABBREVIATIONS

MRC	Maximum Reservoir Contact
ERD	Extended Reach Drilling
EOP	End of Prediction
MSW	Multi Segment Well
ICD	Inflow Control Devices
SICD	Spiral ICD
NICD	Nozzle ICD

XI. REFERENCES

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