Exploitation Strategy for BCS Sands in Sobhasan Complex, Mehsana, Gujarat, India*

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Abstract

BCS (Below Coal Sand) sands in Sobhasan Complex field in Mehsana-Ahmedabad Tectonic block of Cambay Basin are thin, low resistivity sandstone reservoir developed between Sobhasan and Mandhali member of Kadi Formation of Lower Eocene age. Development of these reservoirs has gained importance in recent times as the days of easy oil are at its last leg and most of our big fields are matured and at declining stage of production. Increasing oil prices have further made the development of such reservoirs techno-economically viable and attractive.

BCS sands overly the Lower Tongue of Cambay Shale and are overlain by the Bottom Coal of Sobhasan Member. They are developed throughout the field. Sand geometry and log motifs reveal the presence of tidal flat environment at the time of deposition of these layers. Towards the southern part of the field, thickness of these layers increases with an improvement in sand facies and favourable entrapment conditions.

Block of well MW#16 is located in the South Western part of the field. It is bound by two sub-parallel north-south trending west hading and two northeast-southwest trending south hading faults. Gasoil/shale contact (GOC/GSC) has been observed in the block as well as in nearby blocks in BCS pays. GOC in this block is at -1,597 m MSL. Since no oil-water contact is observed in this block, lowest known oil i.e. 1,636.5 m MSL based on well data of MW#16 has been taken as the limit. Well logs indicate good continuity of the sand along the East-West and North-South direction. Block has permeability, porosity, oil saturation and oil iso-pay of the order of 15-50 md, 13-24%, 40-67% and 2-10 m respectively.

BCS sands were put into production through exploratory well MW#16 in December 2004, which started producing @45 m3/d. Block has produced at a peak oil rate of 60 m3/d from 4 wells in 2008-09. Well production performance indicates the energy support from the gas cap. Wells produce at a sustained rate of 15-20 m3/d with negligible water cut. Pressure drop of about 30 Kg/cm^2 is observed after a production of 7-8%.

Reservoir Model has been created in PETREL software with grid size of 39x75x3 in X, Y and Z directions and cell size of 50m X 50m cell. Porosity and water saturation maps have been generated based on well values.

Reservoir simulation on ECLIPSE 100 simulator considering the reservoir as saturated brings forth the fact that limited gas cap support is not sufficient for optimal exploitation of this reservoir. Additional energy support in terms of water injection is essential for effective exploitation of these pay zones. Current paper deals with the details of the reservoir simulation study carried out in block of well MW#16 and the development strategy formed based on the study. After a very good history match of pressures, seven prediction variants have been studied considering different scenarios of development from Business As Usual to infill producer locations, conversion to water injectors, new water injectors etc. Variant VI which considers three new in-fill locations, two oil producers and one water injector and conversion of an existing well to water injector is found to be most suitable for the block. Recovery in this variant increases to 33.1% from 19.72% in base variant.

Introduction

Sobhasan Complex, located at a distance of 7 km from Mehsana City in Gujarat state of India (Figure 1), is a multi-layered multi-block oil and gas sandstone reservoir where oil is found at four levels from top to bottom – Kalol, Sobhasan, BCS and Mandhali. The main sands Sobhasan, Kalol and Mandhali were put on production in late 60's and 70's and are at a mature stage of development. Sobhasan Complex comprises of six fields geographically near one another– Sobhasan, West Sobhasan, South Sobhasan, Mewad, South Mewad and Kherwa. It was put on production in 1969 and has produced about 18 % Of OIIP of the field to date. Current study pertains to the less exploited, low resistivity BCS sands, which came into production in 1995 through well SOB#172. It is the first development scheme for BCS sands. Block of well MW#16 in BCS-III pay zone in Mewad field, which is located in western part of Sobhasan complex and encompasses an area of 7 km^2 has been considered for the study. This block was put on production in December 2004 through well MW#16 at 27 m3/d of oil and has produced about 7% of OIIP.

Geological Setting and Depositional Environment

Sobhasan Complex is located in Ahmedabad-Mehsana tectonic block of Cambay Basin which has been established as a narrow elongated rift graben surrounded by Saurashtra craton on the west, Aravalli swell on northeast and Deccan craton to the south east (Pandey et. al.). Mehsana-Ahmedabad block lies between Khari and Vatrak rivers in north and south respectively. Sobhasan Complex lies to the east of Mehsana Horst between South Warosan low and Kherwa low. Sobhasan structure is a doubly plunging anticline trending NNE in the north and NW in the southern part. It consists of numerous local lows and highs with varying trends dissected by many faults into independent blocks. Kalol and Kadi formations of Middle to lower Eocene are the main hydrocarbon producing sands (Table 1).

BCS sands overly the Lower Tonge of Younger Cambay Shale and are overlain by Bottom Coal of Sobhasan Complex. They are divided into three subunits – BCS-I, II and III. Above BCS-I, a coal layer is present throughout the area with varying thickness. Deposition of these sands took place under the regressive phase of Tidal Flat environment (Joshi et al). Two dominant features associated with tidal flat sequences (Tidal channel fill and tidal point bars) are present in the area.

Block of well MW#16 is located in the southwestern part of the field. It is bounded by two sub-parallel north-south trending west hading and two northeast-southwest trending south hading faults. Gas-oil/shale contact (GOC/GSC) has been observed in the block as well as in nearby blocks in BCS pays. GOC in this block has been taken at 1,597 m MSL. Since no oil-water contact is observed in this block, lowest known oil i.e. 1,636.5 m MSL based on well data of MW#16 has been taken as the limit. Log motifs are similar and correlatable in wells along N-S as well as E-W profiles (Plate 1 and Plate 2). It is observed that well MW#26 has an additional development of sandstone, which is confined to this well only. Block has permeability, porosity, oil saturation and oil iso-pay of the order of 15-50 md, 13-24%, 40-67% and 2-10 m respectively. Structure contour maps on top of BCS-III and iso-pay maps are given in Figure 2 and Figure 3.

Development History

Block came on production in December 2004 with exploratory well MW#16 at 45m3/d. Currently, four wells i.e. MW#16, 22, 26 and 27 are completed in these sands. Main pressure support appears to be from gas cap as the wells MW#22 and 27 which are closer to gas cap gas area are producing at a consistent rate. To date, 7% of OIIP has been produced from the block (Figure 4).

Reservoir Simulation

Simulation study has been carried out on ECLIPSE 100 simulator on geological model based on REC maps. Grid size of 39x75 with cell size of 50m x 50m has been taken. BCS-III pay has been divided into three sub-layers in dynamic model. Porosity and water saturation maps were generated on PETREL software based on well data using Sequential Gaussian simulation method (Figure 5 and Figure 6). As no laboratory test data is available, PVT data was generated using standard correlations in PETREL RE module based on available oil and gas composition data of well MW#16, considering the block as saturated reservoir. Initial solution GOR of 155 V/V has been considered in the model. Initially, relative permeability data of well SB#148 has been considered which has been modified for history match. As no core permeability data or well test data is available, initially, constant permeability of 15 md given in REC data is taken in the model. Based on the flow equation, permeability values of 35-40 md are calculated. Near the wells, permeability value is considered in this range.

For history match, well-wise pressure production data up to September 2009 has been considered. Mainly, history match of pressure has been attempted in the study on block and well level both. As GOR data is not available for any of the wells, it could not be matched. Water cut has been observed in MW#16. However, reservoir being bounded by faults in all sides, possibility of aquifer support is ruled out. Only apparent justification seems to be that water is coming from the top fractured coal layer. Hence, water in this well could not be matched. All other wells have very little water cut. Very good history match of pressure has been obtained in the block. Some of the history match plots are given in Figure 7 and Figure 8. Oil Saturation maps (initial and at the end of history) are given in Figure 9.

For performance prediction, seven variants from BAU to in-fill drilling without any pressure support to infill drilling with water injection were studied. It was observed that simply adding new wells would not help in improving the recovery from the block, as there is limited support from the gas cap. Recommended variant VI considers two new locations CMW-1 and CMW-2 from September 2011 as oil producers and one location CMW-3 as a water injector from April 2011 along with conversion of well MW#16 into a water injector in April 2011. It predicts oil production of 0.206 MMm3 i.e. 33.1% of OIIP by 2025 against 19.43% recovery in BAU. Peak oil rate is at 52 m3/d in 2010-11 and peak water injection is at180 m3/d through three WI in 2011-14.

Conclusions

Block of well MW#16 is a saturated reservoir with small gas cap. Permeability is in the range of 15-40 md. With the current understanding of reservoir, it is observed that without any additional pressure support, the wells cease to flow due to high GOR and pressure depletion within next 4 to 5 years and additional locations do not add much to the ultimate recovery from the block. Exploitation of this reservoir through infill wells and water injection appears to be the best development strategy. For better understanding of the reservoir, there is a need of acquisition of data like PVT, core analysis, special core studies etc., for BCS sands.

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Reference

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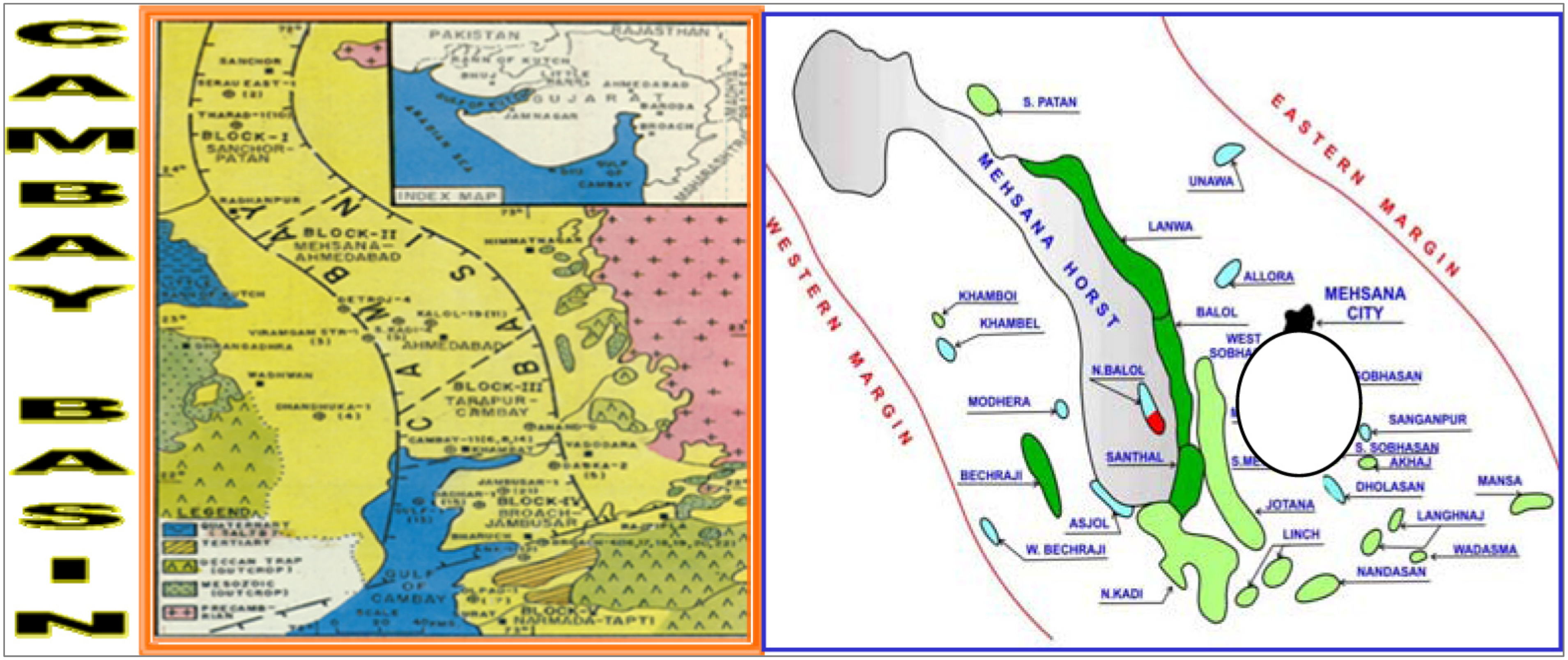

Figure 1. Location Map of Mehsana - Ahmedabad Tectonic block and Sobhasan Field.

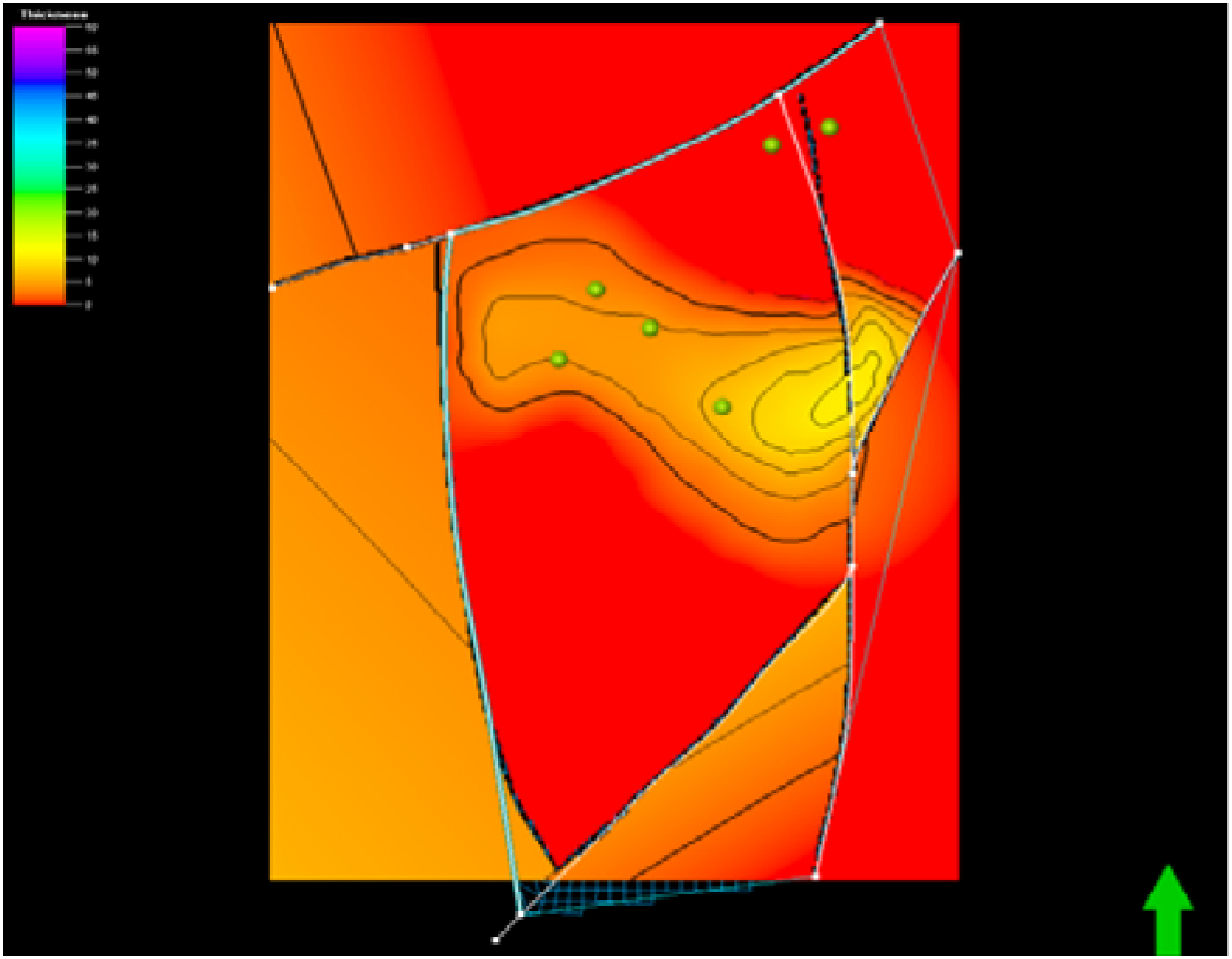

Figure 2. Iso - Pay Map of BCS - III, block of MW#16.

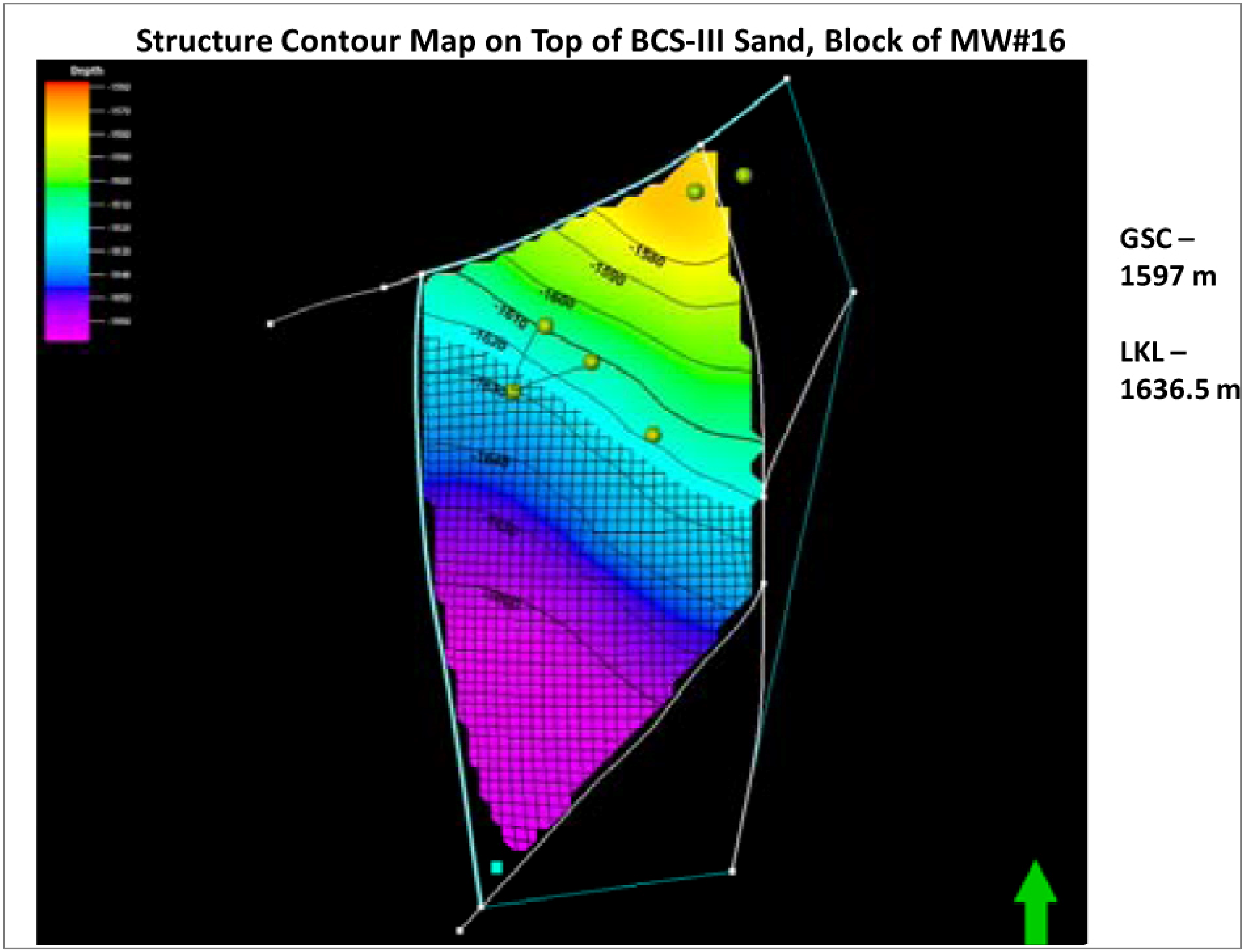

Figure 3. Structure contour map on top of BCS-III Sand, block of MW#16.

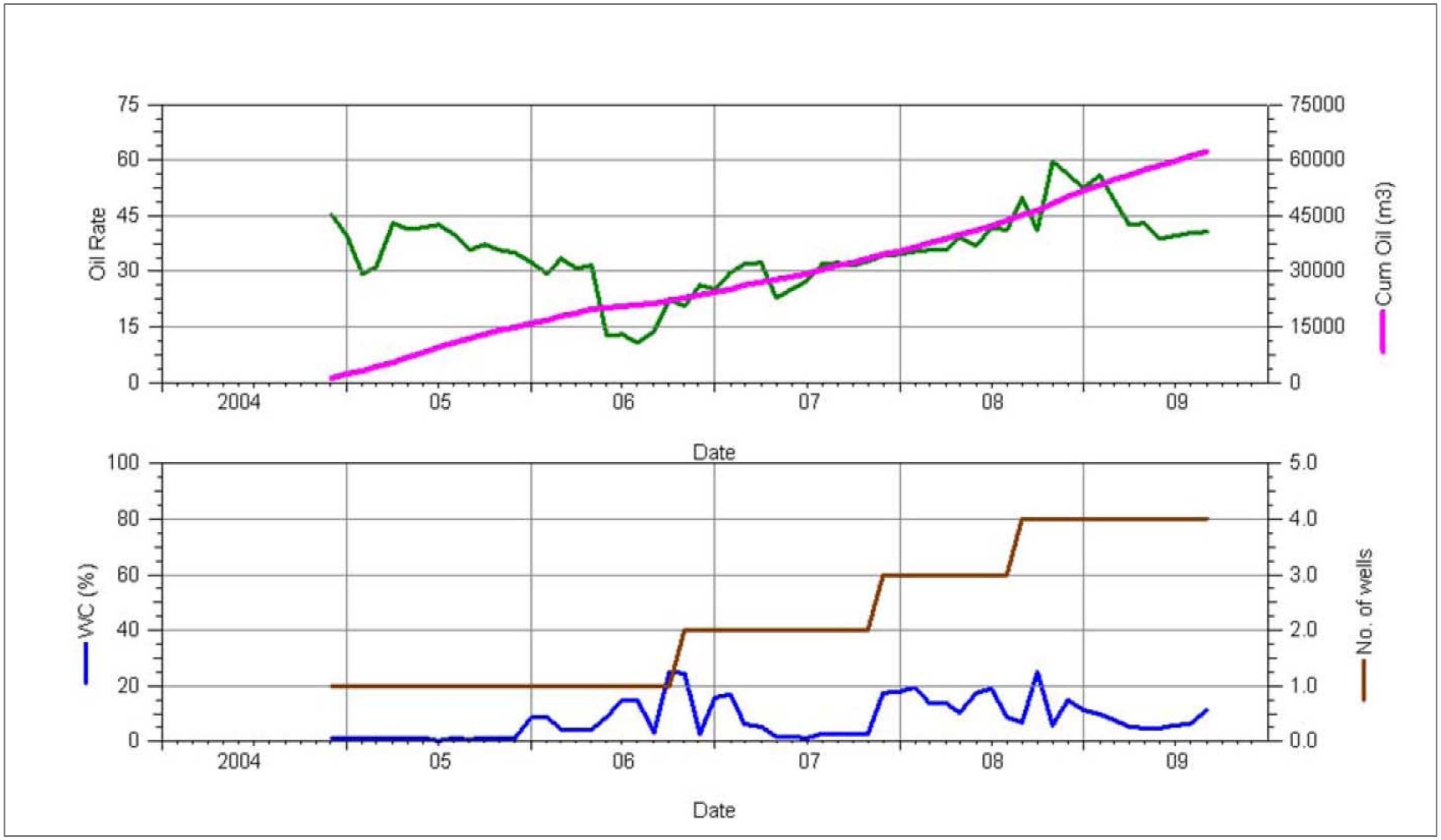

Figure 4. Performance history of block of MW#16.

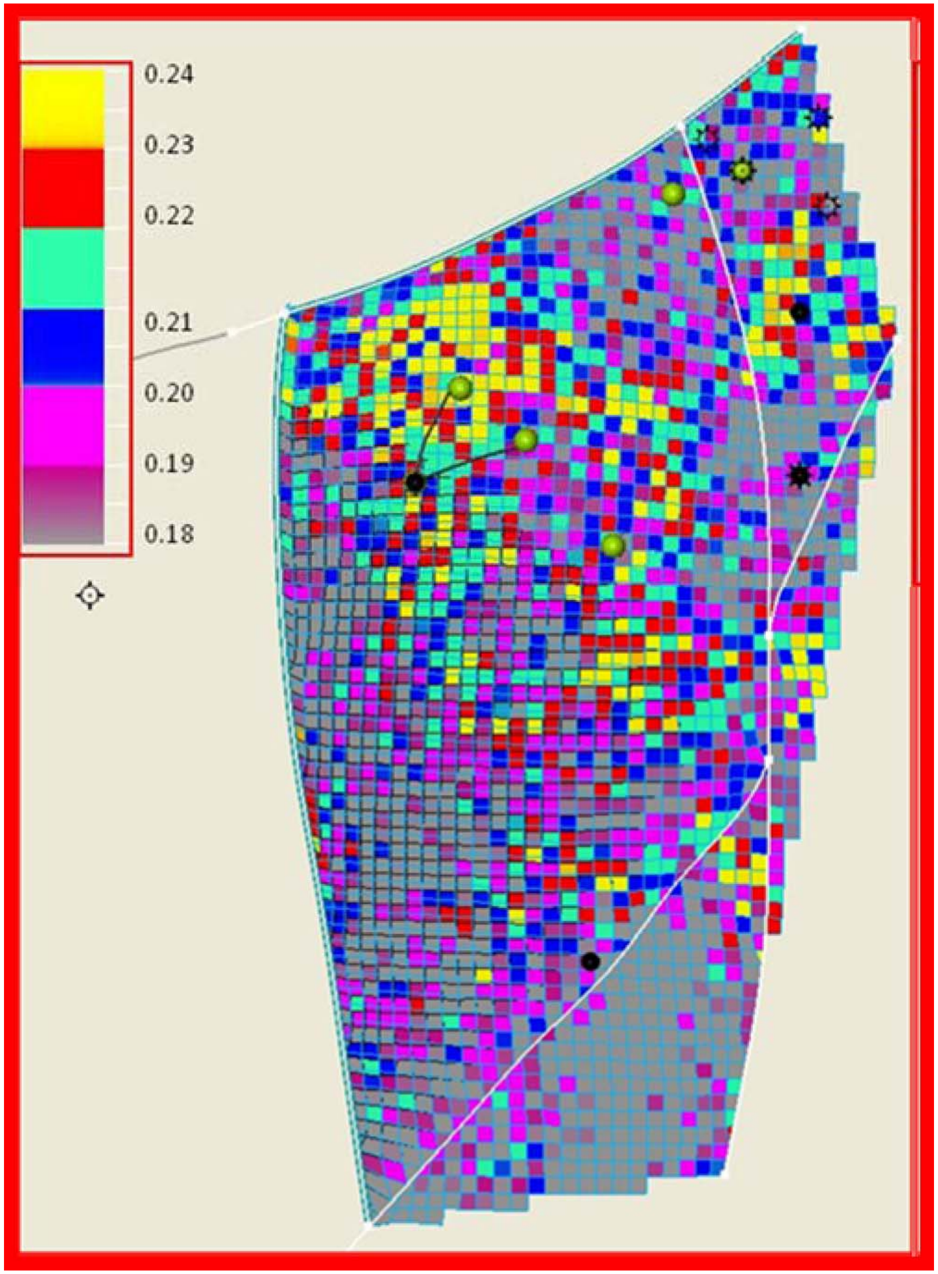

Figure 5. Iso - porosity of block of MW#16.

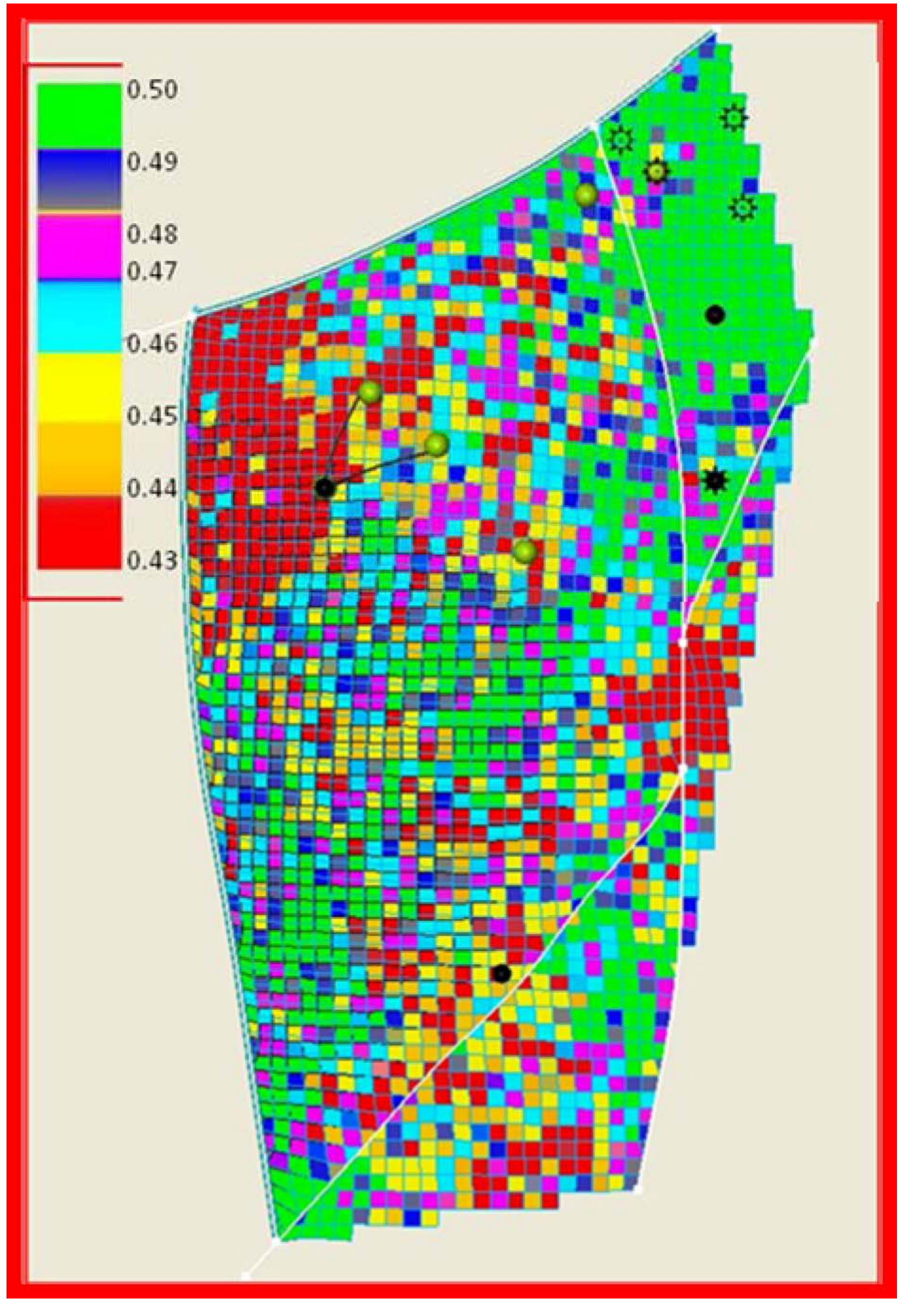

Figure 6. Iso - water saturation of block of MW#16.

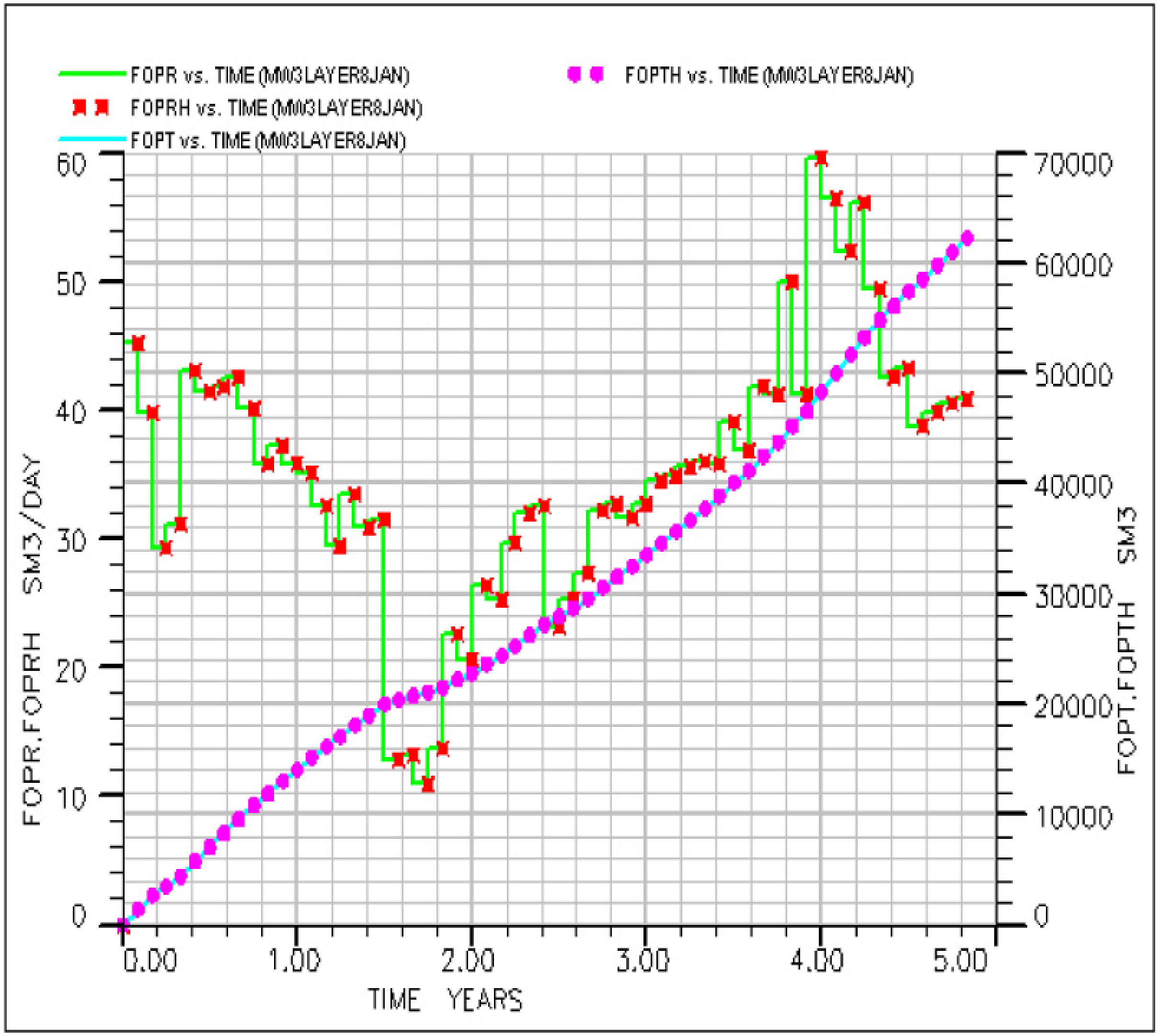

Figure 7. History match of oil production block of MW#16, BCS－III Sand.

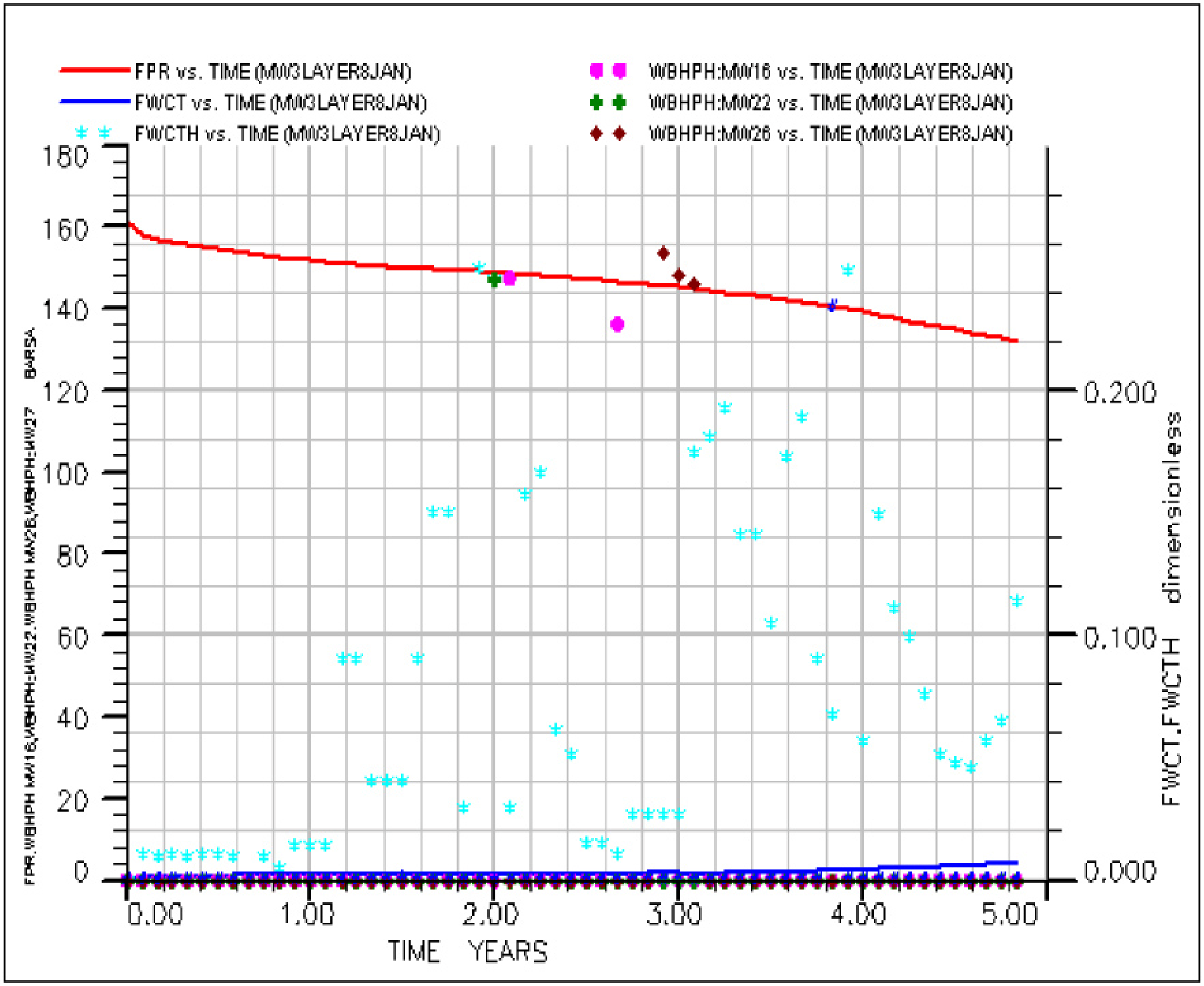

Figure 8. History match of pressures block of MW#16, BCS – III Sand.

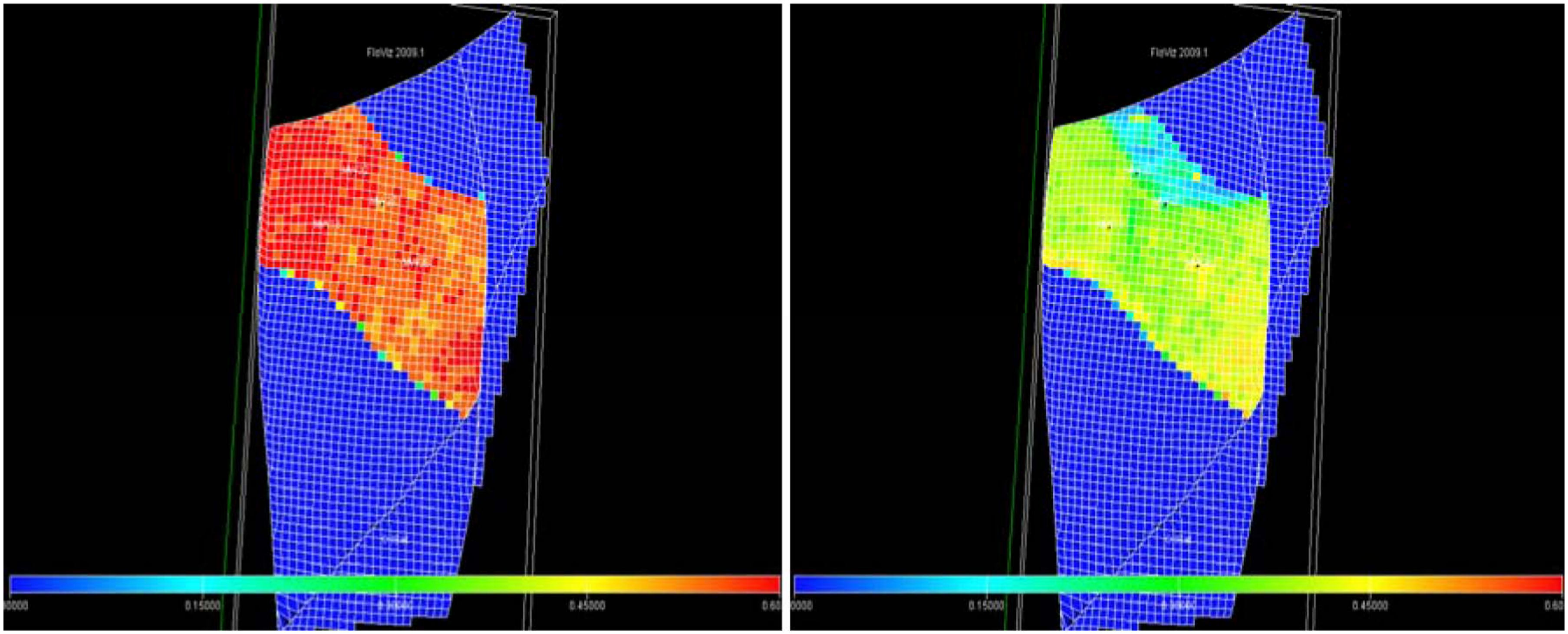

Figure 9. Oil saturation map, initial and at the end of history.

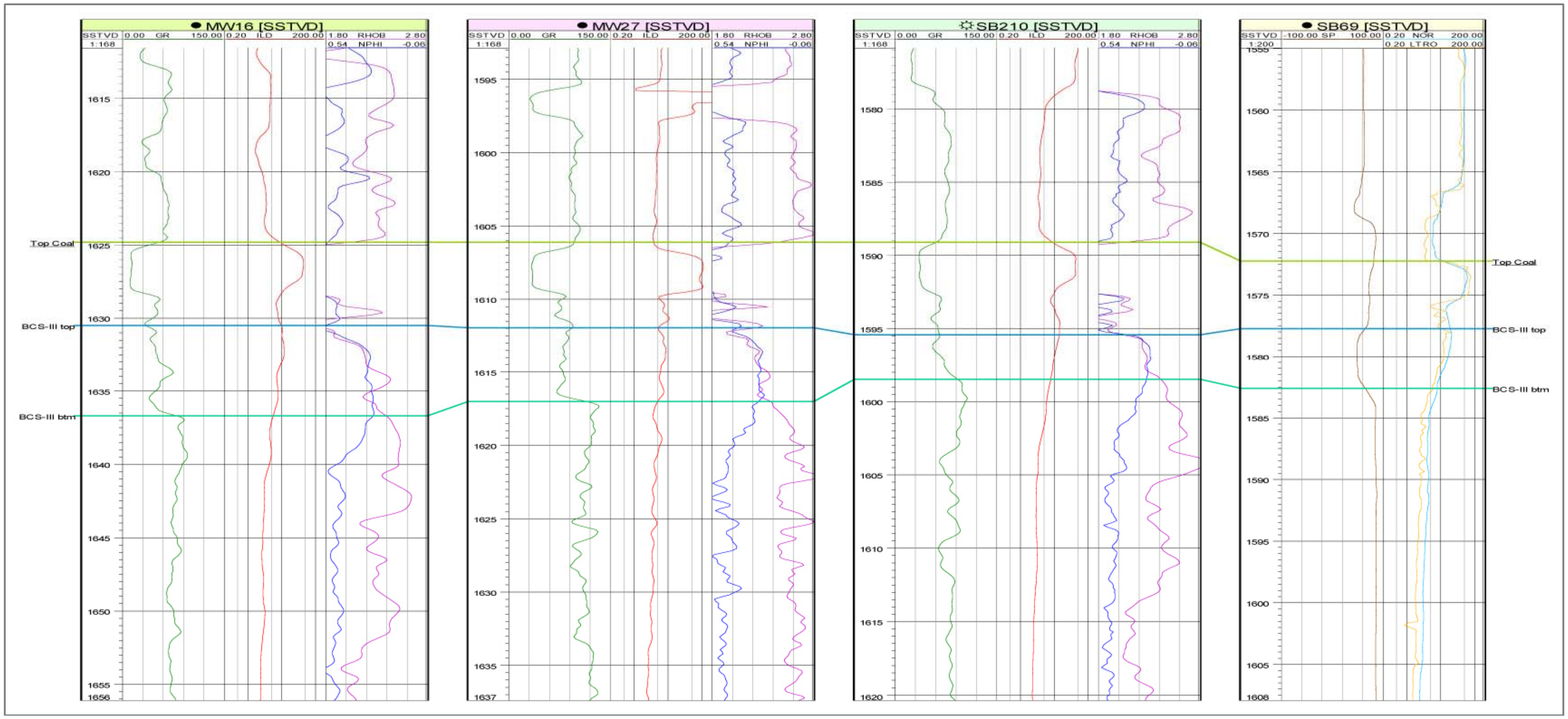

Plate 1. Log correlation profile across MW#16, 27, SB#210, 69 BCS－III pay zone.

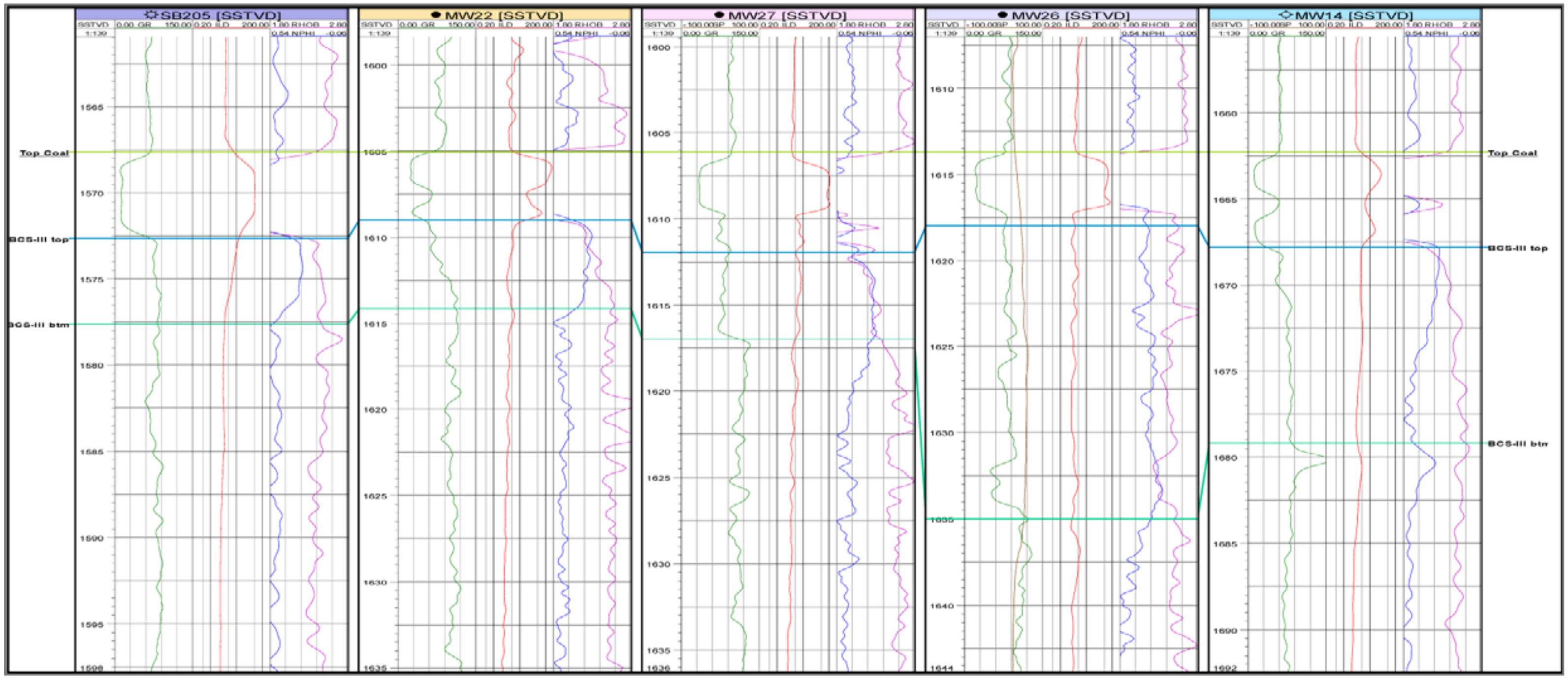

Plate 2. Log correlation profile across SB# 205, MW#22, 27, 26, 14, BCS - III pay zone.

AGE	FORMATION	PAY HORIZON	APPROX. THICKNESS, m	BRIEF LITHOLOGICAL DESCRIPTION
Upper Eocene to Oligocene	Tarapur Shale	-	60-100	Greenish, with little sand
Middle Eocene	Kalol	Kalol Pays (Kalol I to VI)	150-300	Alterations of coal, shale and sand stone.
Early Eocene	Kadi	U. Tongue Mehsana (Sobhasan Pays Ia, Ib, II, III) BCS-I,II,III	10-100 50-200	Dark gray shale Sand with intercalations of coal and shale (Sandwiched between two coal beds namely top Coal and Bottom Coal) Below a coal layer
		Lr. Tongue Mandhali (MP-I to MP-VIII)	10-40 50-350	Dark gray shale Alternations of shale and fine grained sand stone, and/or siltstone with some coal seams in between)
	Older Cambay Shale	-	2100	Dark gray shale (Occasionally carbonaceous and silty)
Paleocene	Olpad	-	20-1500	Trap conglomerates with occasional clay stone
Upper Cretaceous	Deccan Trap	-	-	Basalt

Table 1. Generalised stratigraphy of Sobhasan Complex.