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Hydrocarbon Wealth Management: Rejuvenation of a Brown Field through Analysis of Existing Water Injection System

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Abstract

A private company acquired operatorship of a brown oil field in 2020 from a National Oil Company (NOC) of India to enhance production from the field. Due to Covid-19 outbreak, operatorship was transferred in 2021. Soon as the company took over the operation, it met with surprises in terms of a smaller number of flowing oil wells due to operational reasons. However, the most disturbing was the significantly lower field water injection rate than reported by the NOC. The company undertook pressure measurement in wells to find reasons for production non-sustainability and reduced injectivity. Based on poor analysis of pressure data, the best injection well in the largest producing reservoir was interpreted to be hydrodynamically unconnected with the up-dip producers and recommended for disconnection from injection network by subsurface team to increase water injection rate from the remaining injectors. The study team reviewed the geological model and categorically ruled out discontinuity of the sand body with its up-dip producers. The Management ordered third-party review to resolve uncertainty and suggest remedial measures to improve water injection performance. The review of historical production, injection, pressure data and movement of oil water contact with time has improved the understanding of the inter and intra reservoir pressure communications in the field. The data synthesis has confirmed sand/hydrodynamic continuity between producers and injectors. Performance review of injection wells and the Water Injection Plant (WIP) have brought out bottlenecks in the system. The poor-quality injection water and the lapses in upkeeping of WIP were the primary reasons for loss of injectivity. WIP revamping and replacement of the existing oversized micron filter with smaller size have been recommended. To ensure uninterrupted water injection, conversion of one injector to pilot dump flooder has been suggested, a first of kind in India.

Keywords: *Dump Flooder, Non-Compatible Injection Water, Sand Continuity*

1.0 Introduction

Dhansiri Valley (Figure 1) situated on the Eastern bank of the Brahmaputra River is sandwiched between NE-SW trending Naga Schuppen belt on the East and Southwest and Mikir Massif in the West. It is the southern part of the Assam-Arakan basin separated from the North part of the basin by an East-west trending major Jorhat Fault-it houses major producing fields which together account for 90% of the proven hydrocarbon reserves. The case history pertains to one of the major producing fields out of these clusters which was acquired recently by the new player under MPEC.

The valley[1,2] witnessed sparse graben-filling sediments deposited from the Permian age to basaltic flows of the Early Cretaceous age. The event was followed by an extensive late Cretaceous-Oligocene sequence deposited in a passive margin setting. The setting underwent differential erosion at places and filling by a thick pile

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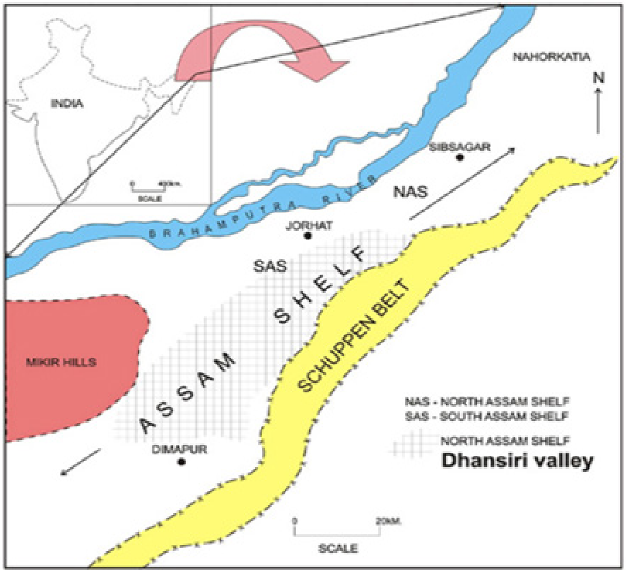

Figure 1. Geological Setting of the study area.

of Miocene to recent sediments. The total sedimentary thickness in the area is of the order of 3.5 km with the maximum thickness nearing 5 km in the deeper part of the Dhansiri Valley. It homes prolific reservoirs at different stratigraphic levels starting from fractured Basement reservoir to Sylhet, Kopili, Barail, Bokabil, Tipam and Namsang reservoirs (Figure 2) which have been charged in different parts of the basin depending

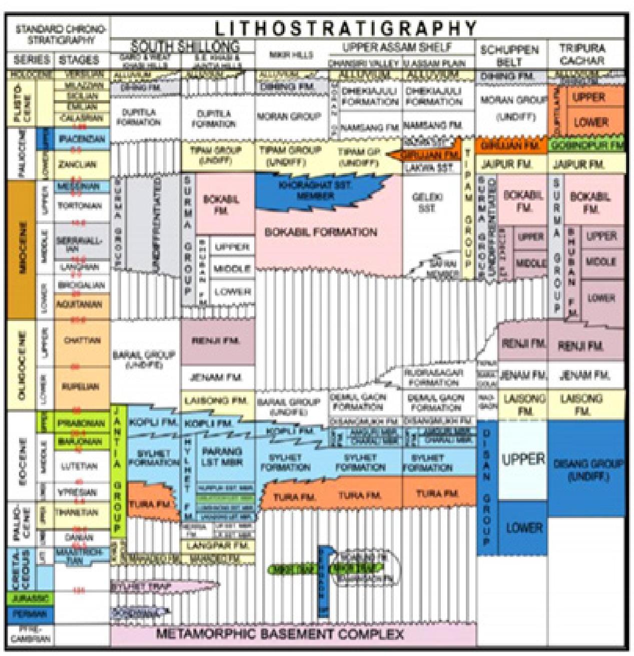

Figure 2. General stratigraphy of Assam-Arakan basin.

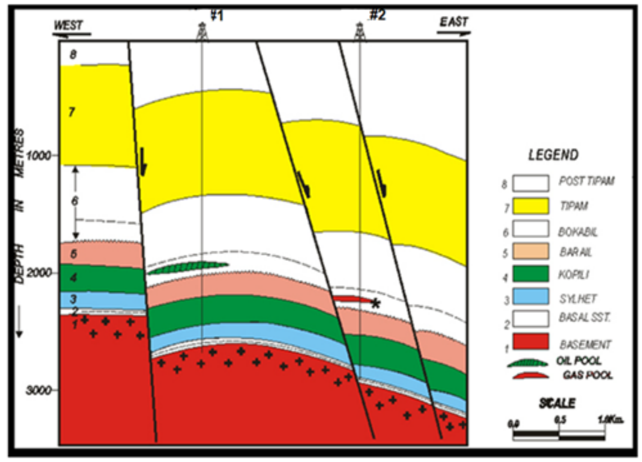

Figure 3. Geological cross-section along well #1 and well #2 of the field.

upon prevailing entrapment conditions; some of which are yet to be thoroughly probed for commercial production. Hydrocarbon entrapment in the valley has been grouped into three types of structural traps namely the faulted horst and graben, the inverted normal fault, and the compressed normal fault. The hydrocarbon entrapment in the younger Bokabil formation of this field is seen primarily in the compressed hanging wall, down-thrown side of the structure (Figure 3). The critical analysis indicates that the faulted down-thrown side of a normal fault with a reasonably high throw (>200 m) was compressed and translated into a normal fault with a compressed faulted down-thrown side-hydrocarbon accumulated in the crestal part of this compressed faulted down-throw side of the block.

Dhansiri Valley underwent strong tectonic upheaval[3-7]. The southeast-dipping shelf was over-thrusted by the Himalaya Mountain Range in the north and Naga Hills in the Southeast. Its evolution went through a series of rift, drift, and collision stages. The sedimentary record of rift sediments is preserved in grabens, while the drift and collision stages are characterised by the passive margin and foreland sequences respectively with the presence of entrapped hydrocarbons in major fault blocks of the poly-tectonic sub-basin at almost all the stratigraphic levels.

The major accumulation of hydrocarbons in Dhansiri Valley is at a deeper stratigraphic level within Tura (Upper Palaeocene-Lower Eocene), Sylhet (Middle Eocene), Kopili (Upper Eocene) formations and the Precambrian fractured basement near the Schuppen Belt, in horst-graben settings and relatively lesser accumulations are at a shallower level within the Bokabil Formation (Lower Miocene) away from the Schuppen Belt accumulated in the hanging wall of compressive structures. Tipam (Upper Miocene) and Namsang (Pliocene) which are mainly gas bearing form the youngest lot of hydrocarbon reservoirs in the area. The accumulations are controlled by the tectonic elements, even the lenticular sands charged with the hydrocarbons occur only at the structurally highest part. Thick carbonaceous shale of Upper Eocene age is the source rock for the generation of hydrocarbons in Dhansiri Valley.

The Dhansiri Valley went through more than one phase of tectonic and sedimentation processes and was heavily influenced by the movement of the Indian plate about the Eurasian and Burmese plates. The sediments were deposited during rift, drift and collision phases with the oldest Gondwana sediments restricted in the grabens. These were followed by the Paleogene sediments deposited in the passive margin setting and the deposition of Neogene and Quaternary in foreland settings.

This field was discovered in early 1999 with the drilling of well #1 which produced oil on testing from multiple pay zones of Lower Bokabil sand within the Miocene series of Neogene deposited in a Foreland setting. Through the drilling of well #2 in the adjacent fault block (Figure 3), the gas accumulation in Paleogene has also been confirmed but commercial production is yet to be established. No hydrocarbon accumulation has so far been reported in the deep-sitting fractured basement of the Precambrian Age in this field.

Sediments of Bokabil formation which overlies Barails of Oligocene consist predominantly of mudstone, siltstone, and thin sand streaks in between and were supposedly deposited during Miocene as evident from the upper part of the side wall core from well #7. The lower part of the core is devoid of palynofossils, but the presence of broken Nummulites Ssp suggests early Oligocene or older age. The sedimentation probably took place under fluctuating near-shore shallow marine conditions in this field.

Overlying sediments of Tipam formation (Upper Miocene) which consists predominantly of sandstone with thin clay bands. These have been deposited in fluvial environments and are overlain by the sediments of the Namsang Formation. The Namsang Formation (Pliocene) consists of unconsolidated sand intercalated with clay and lignite. These sediments have been deposited in the fluvial environment and are followed by sands, silts, and clays of Post-Namsang (Quaternary) deposition.

1.1 Brief Details of Brown Field

The field was awarded to a new player by the National Oil Company under the Model Production Enhancement Contract (MPEC) to enhance the production from the field. The term of the contract is such that the company must maintain and pay the entire revenue to be generated from the sale of hydrocarbon from the base production profile defined as the business-as-usual profile in the contract document at its own cost to avoid penalty from the owner, the NOC in this case. The company can turn this brownfield contract into a profit-making business only if it can enhance production through improved field management and possible infill drilling in the upswept area while reducing the cost of production from the producing block of #1 (Figure 3). Establishing Commercial production from a nonproducing block of #2 (Figure 3) and non-producing sands other than Bokabil formation within the producing block of #1 offers upside potential for the company. The scope of the present study is the producing sands of a block of #1 which has been considered for the BAU profile in the contract. Figure 4 shows the base map of the field showing drilled wells with a polygon defining the contract area awarded to the company under the present agreement with the NOC. As

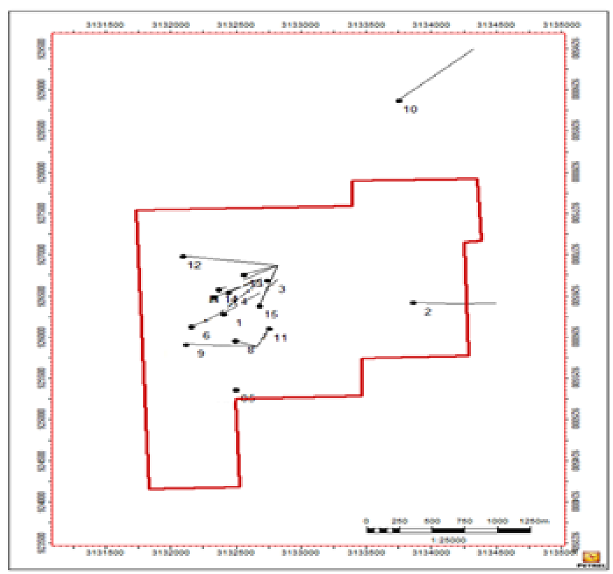

Figure 4. Base map showing the wells along with the contract area boundary.

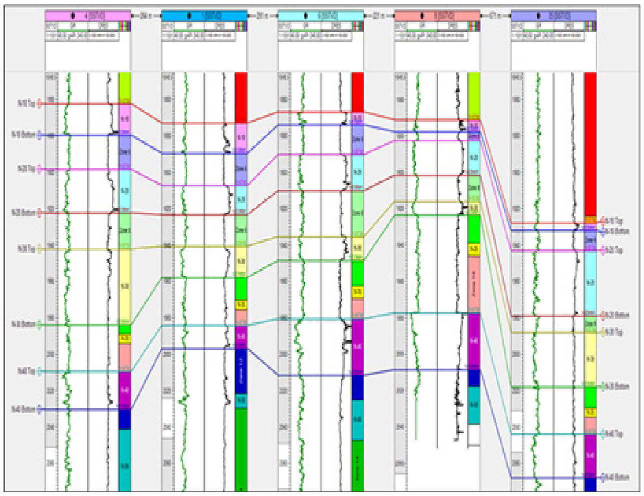

Figure 5. Well correlation panel shows the pay sands of the Lower Bokabil formation.

stated above, all the wells inside the polygon except #2 are completed in Bokabil reservoirs of a block of well #1. Well #2 is a gas well completed in Sylhet formation and is separated from the block of well #1 by a fault as shown in Figure 3.

Figure 5 shows the stacking of producing Lower Bokabil reservoirs from N-40 to N10 and above in the field. Figure 6 shows the locations of producers and injectors in the field. Production in the field started from well #1 in 1999, which produced oil from N-20 sand.

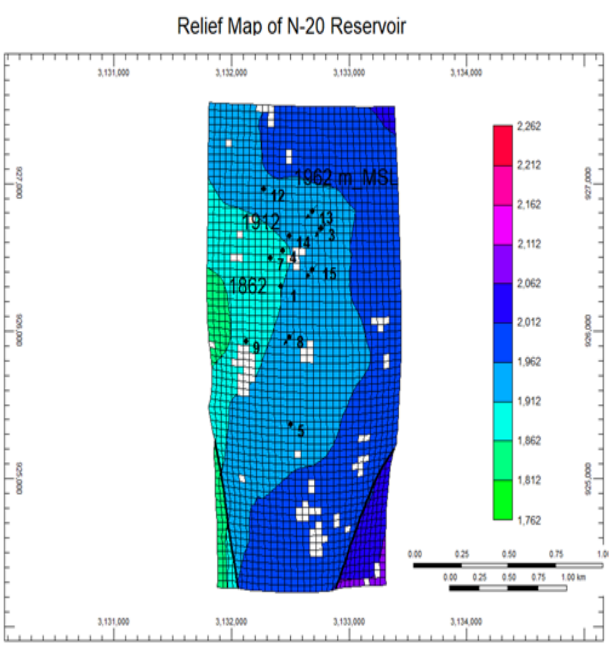

Figure 6. Relief map on top of major producing N-20 sand.

Subsequently, wells #3, #4, #5, #6 and #7 were put into production from different Lower Bokabil pay sands. #3 and #4 started cutting high water from lower respective pay sands, thereafter, cement squeeze and re-perforation jobs were carried out in the wells, and they were completed in upper pays encountered in the well. Later wells viz. #8, #9, #12 and #14 also started producing from Bokabil formation. Two producers #3 and #8 were converted as water injectors subsequently in April 2011 and November 2014 respectively in N-10 + N-20 and N-30 sands for pressure maintenance. Later in 2019, two new injectors #15 and #13 were also completed in sand N-30 and N-10 respectively. Currently, there is no production from N-40 sand as the producers have been zone-transferred to upper sands. The producing sands in a block of well #1 are N-40, N-30, N-20, and N-10 and above (Figure 6) situated in the Lower Bokabil formation.

2.0 Materials and Methods

The following analysis has been carried out.

i. Depleted Pressures in subsequent wells drilled in the major N-20 reservoir with time (sand continuity).
ii. Depleted Pressure in N-10 reservoir due to production from N-20 reservoir (pressure communication between N-20 and N-10 reservoirs).
iii. Depleted Pressure in above N-10 reservoir due to production from N-10 and N-20 reservoirs (pressure communication between N-20 and N-10 reservoirs).
iv. Non depleted Pressure in N-30 reservoir (pressure non-communication between N-20 and N-30 reservoirs).
v. Depleted Pressure in subsequent wells drilled in the N-30 reservoir (sand continuity).
vi. Limited Production from N-40 reservoir and little depletion in pressure (pressure non-communication between N-30 and N-40 reservoirs).
vii. Noticeable downtime of Water Injection Plant (historical reported daily water injection rate questionable).
viii. Significant rise in Oil Water Contact (OWC) in well #8 (Sand continuity between well #8 and well #1).
ix. Drastic jump in daily/instantaneous water injection rate with the conversion of well #8 as an injector (high well injectivity of well #8).

x. Drastic reduction in field water injection rate subsequently despite the addition of 3 new injectors (Possible breakdown of one water injection pump-imposed capacity constraint).
xi. Rapid deterioration in injection rate in well #8 (incompatible injection water).
xii. Poor health of the Water Injection Plant (Site inspection confirmed the absence of a micron water filter in the filtration unit and a non-functioning chemical dosing pump for mixing bactericides and KCL).

3.0 Theory/Calculations and Results

3.1 Exploitation Status of the Brown Field

The summary of exploitation status and the extent of pressure depletion in various Bokabil Reservoirs are shown in Table 1 and Table 2. As evident from these tables and Figure 7, the major contribution of oil production is from the N-20 reservoir which is in pressure communication with the N-10 reservoir. These

Table 1. Exploitation status of Bokabil Reservoirs in the field

Exploitation Status of the Field							
Sand/ Reservoir	HCPV	STOIIP	Cumulative Production (MMm3)		Recovery Factor, % of STOIIP		Remarks
	MMm^3	MMm^3	As of April 2011, / Pre-Water Injection	As of Aug 2021,	As of April 2011, / Pre- Water Injection	As of Aug 2021,	
N-10 and above	0.96	0.76	0.060	0.121	7.9	15.9	
N-20	2.82	2.25	0.140	0.212	6.2	9.4	
N-30	0.84	0.67	0.056	0.094	8.4	14.0	Well #6 coming led production distributed equally between N-30 and N-40 sands
N-40	1.16	0.93	0.030	0.098	3.2	10.5	
Total, Bokabil	5.78	4.61	0.286	0.525	6.2	11.4	

Table 2. Depletion in reservoir pressure of producing Bokabil sands in the field

Exploitation Status of the Field				
Sand/ Reservoir	OWC m, MSL	Initial Reservoir Pressure, Kg/cm^2	Bubble Point Pressure, Kg/cm^2	Current Reservoir Pressure, Kg/cm^2
N-10 and above	1962	205	139	100
N-20	1962	215	150	105
N-30	1970	210	160	150
N-40	2007	216	167	180

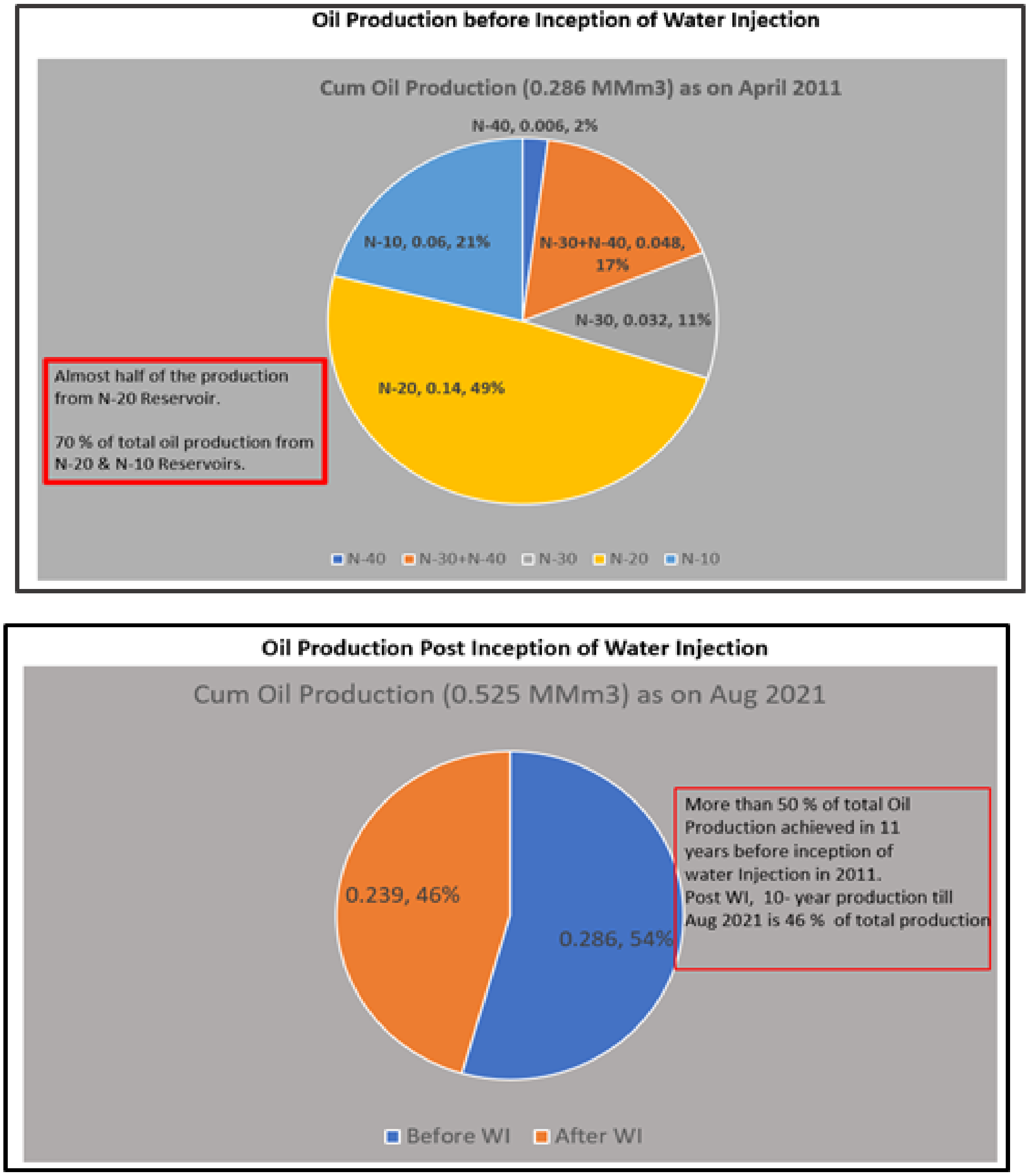

Figure 7. Oil contribution from major producing N-20 reservoir pre and post-water injection period.

two reservoirs have experienced the highest depletion in reservoir pressure, and their current reservoir pressures are significantly lower than the bubble point pressure. The wells completed in N-10 and N-20 reservoirs are producing high GOR indicating the possibility of formation of secondary gas cap and its expansion towards downdip. On the other hand, reservoir N-40 which is still above bubble point pressure is currently not well on production. Producing wells in N-40 were prematurely zone transferred to upper sands for a quick gain of production without undertaking suitable remedial water shut-off jobs using polymer etc to revive them and put them back into production. Being the lowermost sand in the stack, the aquifer support is significantly better than N-20 and N-10 reservoirs. The current pressure in the N-30 reservoir is close to bubble point pressure, and from this reservoir as well, the producers were zone transferred prematurely to upper reservoirs. The recovery factor of the N-40 reservoir is only 10% of STOIIP whereas the recovery factor of the N-30 reservoir is 14%. Both these reservoirs have better aquifer support and there is the likelihood of bypassed oil in these reservoirs that can be suitably exploited using the combination of infill drilling and zone transfer of wells from upper reservoirs where pressure has depleted significantly below the bubble point pressure.

3.2 Pressure Maintenance through Peripheral Water Injection

The peripheral water injection in the fields started in 2011 with the conversion of well #3 as an injector. Subsequently wells #8, #15 and #13 were completed as injectors to boost

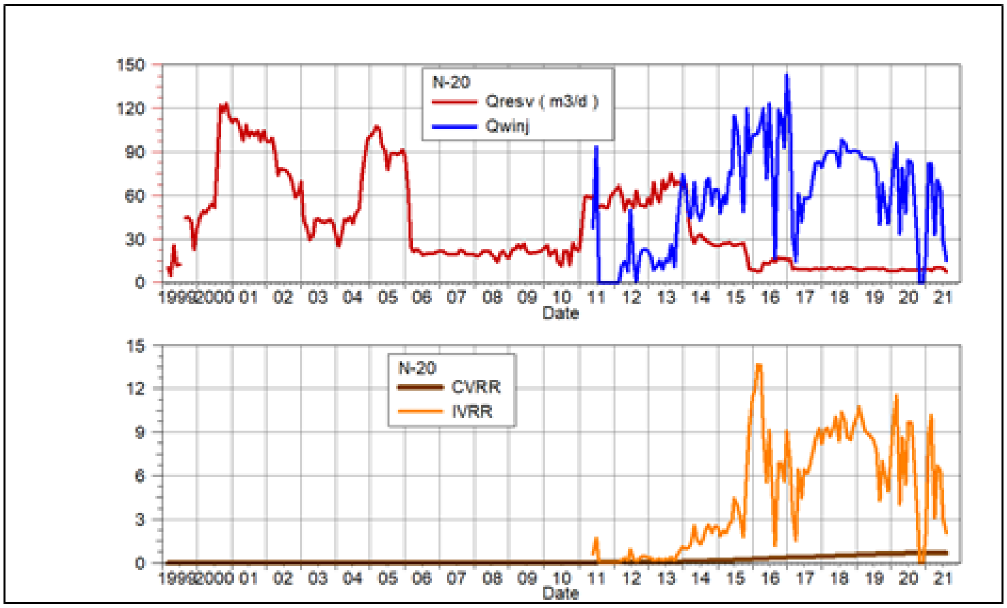

Figure 8. Voidage compensation profile in N-20 sand.

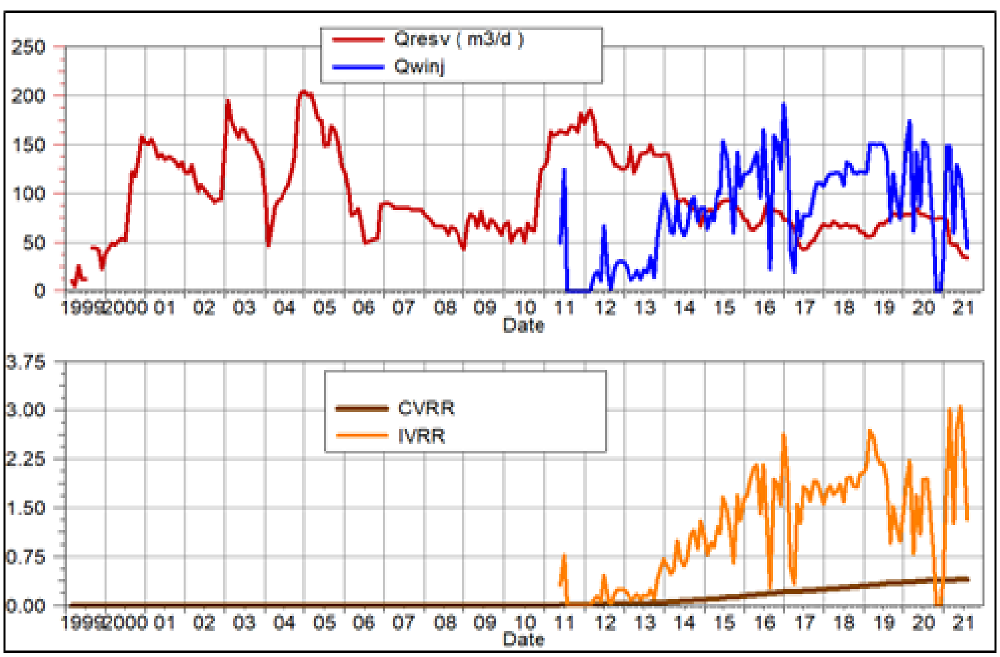

Figure 9. Voidage compensation profile in the field.

the water injection rate in the field and arrest rapid decline in reservoir pressure.

Figures 8 and 9 show the Cumulative Voidage Replacement Ratio (CVRR) and Incremental Voidage Replacement Ratio (IVRR) in major producing N-20 reservoirs and the field. Though the CVRR is less than 1 mainly because of the late start of water injection, the IVRR is significantly high (9 for the N-20 reservoir and 3 for the field). Despite very high IVRR, the expected pressure rise in the target reservoirs has not taken place. Due to a lack of surveillance data on water injection wells, the reason for the same could not be ascertained by the previous operator (the NOC).

3.3 Review of Geological Model Given Non-Commensurate Response of Water Injection

Despite substantial improvement in the IVRR of the N-20 reservoir (Figure 8) and the field (Figure 9) in general, no significant improvement in the pressure of N-10 and N-20 reservoirs was noticed. At one point in time, this led to the belief by the current operator that the existing geological model has perhaps failed to capture the reservoir non-connectivity issue of the producers with the peripheral injection wells located downdip. The Petrel geological model was therefore reviewed by the study team, and an attempt was made to map the possibility of discontinuity between injectors and the producers. The area around the most significant water injector #8 which is a dedicated water injector for the N-20 reservoir and whose current injectivity is significantly low despite high SBHP in the well was reinvestigated for possible non-connectivity with the up-dip producer #1 which accounts for major production from N-20 reservoir. The discontinuity between #8 and the major producer #1 could not be conclusively established in the geological model.

3.4 Review of Historical Pressure and Water Injection Data

The present study was undertaken to offer possible explanations before making a final decision to disconnect well #8 from the injection network. Well, #8 is possibly the only well where N-20 is so well developed with a massive thickness of over 35 m of blocky sand development and therefore disconnecting it without proper understanding would have far-reached implications. The study considers the analysis of all historical pressure-production-injection data of the field since inception to understand the declining trend in reservoir pressure measured in the new wells that came up subsequently. As evident from the water injection profile (Figure 10(a)), there was a significant improvement in the instantaneous water injection rate when well #8 was added to the injection network. The time lag between the jacking up of the field injection rate and the drilling of well #8 is because of delayed injection

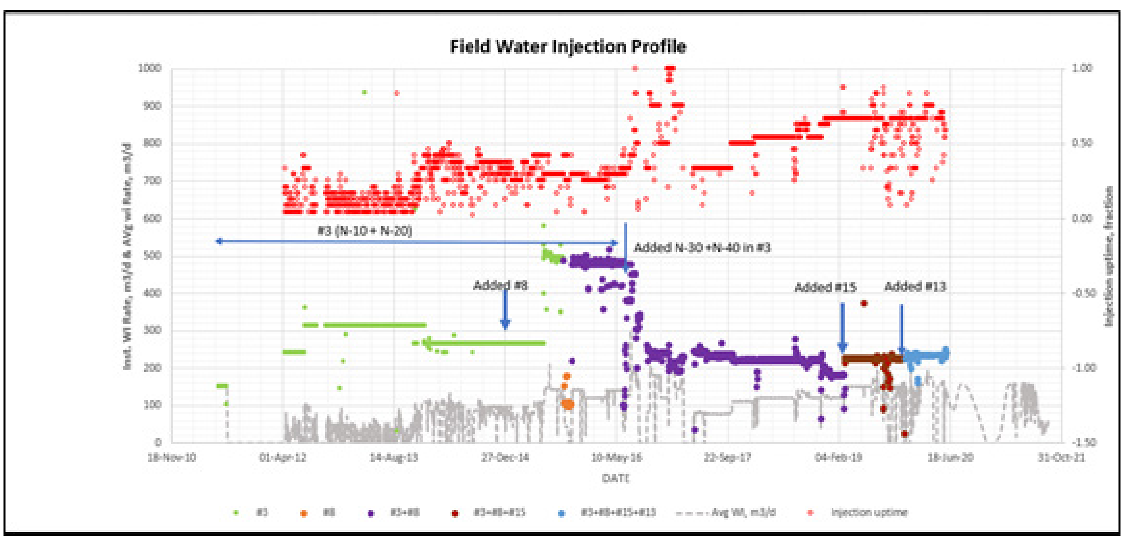

Figure 10(a). Historical water injection profile.

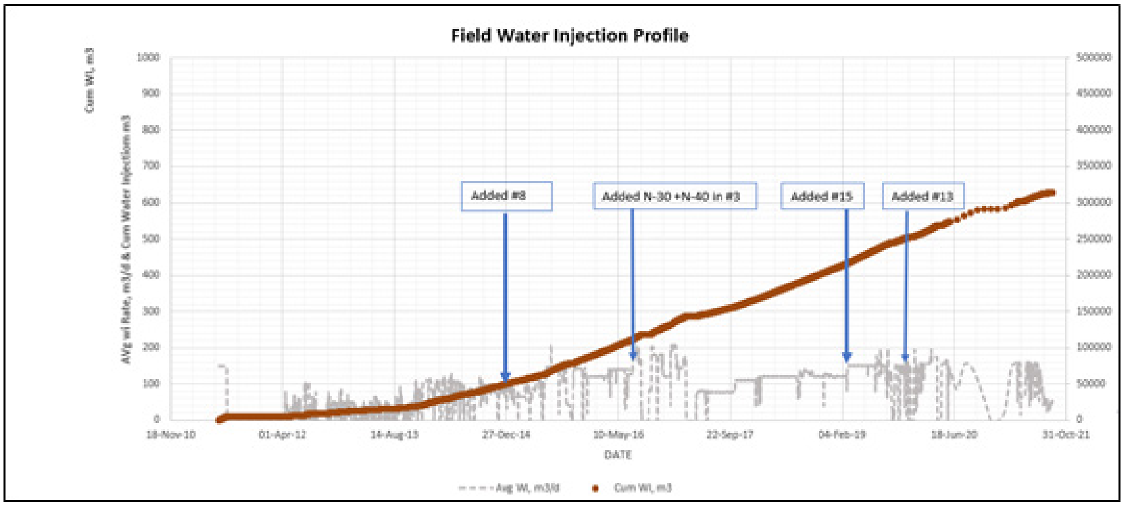

Figure 10(b). Historical water injection profile.

pipeline connection as the site was immediately used to drill another development well #9 from the same location. Once it got connected, the instantaneous water injection rate jumped to 500 m^3/day from the level of less than 300 m^3/day. This establishes the fact that well #8 which is a dedicated water injector for N-20 had initially a very good injectivity. From the figure of the injection profile, it is also clear that the gain in injection rate was wrongly assigned to the existing injector #3 for an initial few months. Injector #3 had not gone under any kind of well intervention in this period. The reported water injection profile in Figure 10 also brings out bottlenecks in the water injection plant such as malfunctioning of MIPs thereby limiting surface water injection handling capacity. Despite the addition of two new injectors #15 and #13 during 2019-2020, the reported instantaneous water injection rate remained unchanged and flat at the level of around 250 m^3/day. This indicates that only one out of the two MIPs (Figure 12) that were operational during 2015-16 when well #8 was added was functioning post-2016 and therefore surface water injection capacity was reduced to half of the initial capacity of 500 m^3/day with two MIPs. It is also evident that during 2015-16, the injection uptime was highest reaching almost 100% culminating in an instantaneous water injection rate equalling the average field water injection rate for a brief period. Pre and post this brief period, the injection uptime is significantly low. Limitations of surface water injection capacity were not alone responsible for inefficient water injection in the field, the poor quality of injection water also added to the woes as well injectivity was reduced significantly in a short period.

After ascertaining that well #8 had initial good injectivity, the proper understanding and explanation were required for the current low injectivity and high SBHP in the well despite alarmingly low N-20 reservoir pressure. Loss of injectivity could be attributed to scale deposition, perforation blockage and damage around the wellbore of well #8 due to poor quality of injection water (discussed later) if it is proved that N-20 sand in well #8 is in communication with well #1. Therefore, before zeroing on and doubting the quality of injection water as the responsible factor, a thorough analysis of historical pressure and production data of all the wells was undertaken to disprove the perception that well #8 was not in communication with the major N-20 producer well #1.

When well #8 was drilled in mid-2010 almost 10 years of production, the OWC in N-20 Reservoir had already risen by about 15 m from its initial level of 1962 m (MSL) (Figure 12). Not only that, starting from 1935 m MSL till 1955 m MSL was in a transition zone indicating thereby dynamicity of the rising aquifer. The viscous force affected by oil production in well #1 did not allow the rising aquifer to establish saturation redistribution in well #8. The Pressure Build Up (PBU) study in the well on 22nd August

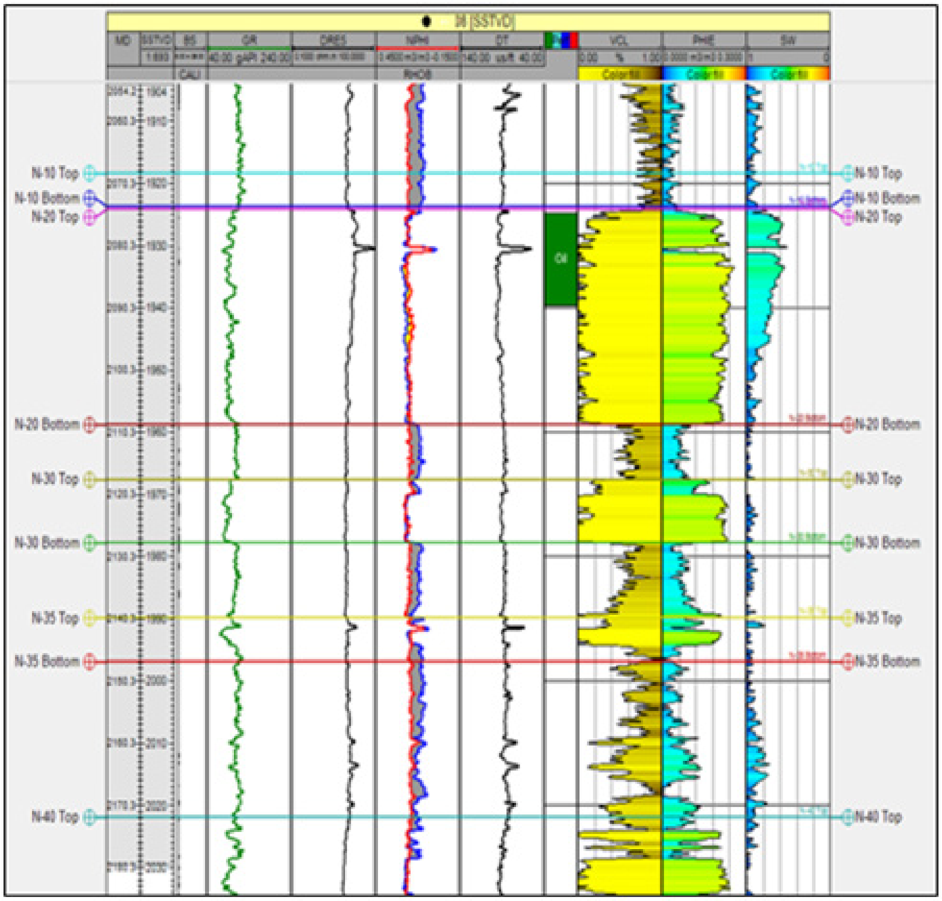

Figure 11. Rise in OWC in well #8 drilled in 2011.

2010 showed a depleted pressure of 174 kg/cm^2- a clear indication that N-20 in well #8 was in communication with the N-20 reservoir in well #1. It is also evident that aquifer support alone was not commensurate with the voidage created by the production of N-20 sand. Though initially proposed to be an injector as per plan, well #8 was completed as a producer in N-20, it was later converted as an injector in November 2014 after cement squeezing the producing interval 2075-78 m and re/additionally perforating interval 2075-79 and 2079-84 m. An identical depleted level of pressure of 174 kg/cm^2 was also measured in N-20 sand in well #9 which was drilled back-to-back from the same site. This establishes that wells #1, #8 and #9 are hydro dynamically connected.

3.5 Health of Water Injection Plant

After having established the continuity and hydro-dynamical connectivity of major producing N-20 sand, it was now the turn to examine the health of the water injection plant which is situated at a close distance from three injectors namely wells #3, #13 and # 15. Only one injector #8 is located at about 5 km from the centrally located injection plant at the field GGS (Figure 12).

Physical examinations of all the equipment at WIP brought the pathetic conditions of various components of WIP which made it amply clear that not only the reported injection up time was questionable but also the quality of injection water was not up to the mark in want of proper mixing of KCL and dosing of bactericides and corrosion inhibitors. Water was being injected without micron filters in place and there was rampant power outage issue that prevented continuous water injection from the plant. A complete list of discrepancies after visual inspection of the water injection plant is shown in Table 3.

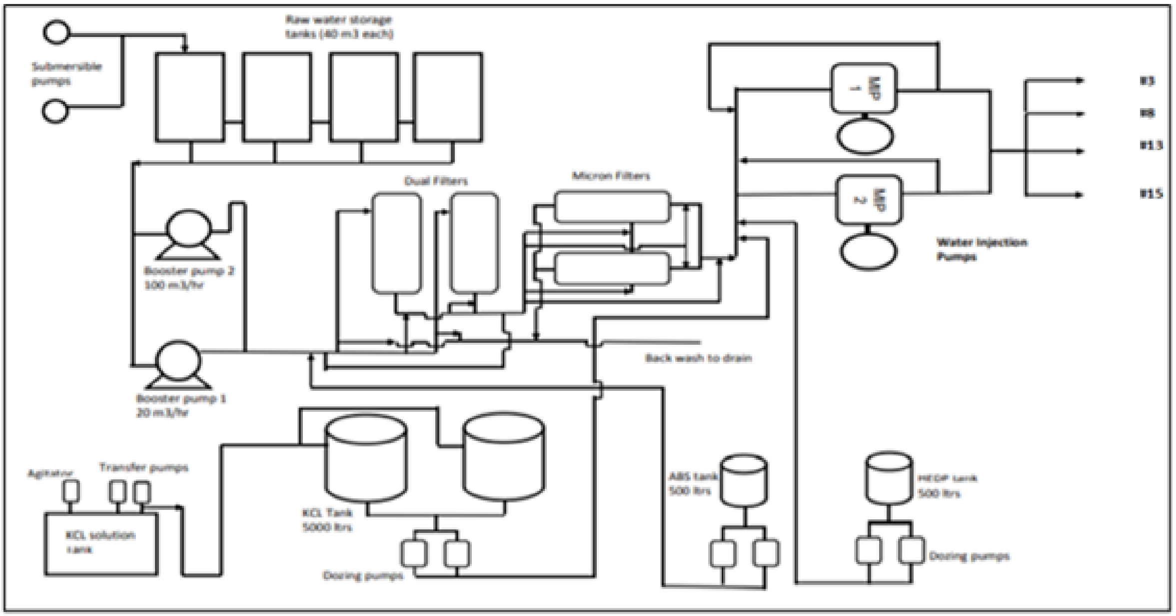

Figure 12. Water injection facilities at GGS.

Table 3. Defective list of equipment in water injection plant

1. Both the KCL dosing pumps are in damaged condition/breakdown condition
2. Aluminium bisulphate dosing pumps have been damaged since the handover. Chemicals are added directly to the raw tank in a batch fashion (non-continuous)
3.Booster-1 has been defective since the handover
4. 3 Nos of main gate valves (at manifold) are passing/leaking
5. Booster pump-1 flow rate capacity (10 KL/Hr) is not compatible with MIP-2 flow rate of 20 KL/Hr
6. The SS gate valve of the KCL dosing pump inlet and delivery line are defective
7. MIP-1 is not handover by the NOC
8. The MIP-2 circulation gate valve is damaged
9. All the inlet strainer mesh is not available
10. Micron media filter is not available
11. Delivery line NRV of MIP-3 is defective
12. KCL Storage tank-1 has been damaged since the handover
13. Both the KCL storage tank inlet and delivery line gate valves are defective
14. KCL transfer pump gate valves are defective

The plant needed complete revamping to ensure the availability of quality injection water to the wells continuously with the provision of power backup during outages. Special attention is to be given to the maintenance of the water injection line to the far-off water injector #8 which is situated away from the injection plant.

4.0 Discussion

Proposed Action Plan to Improve Water Injection Rate in the Brown Field

To jack up reservoir pressure and improve water injection efficiency, two-pronged actions have been proposed.

- Continue existing Powered Water Injection (PWI) in three injectors (#3, #15 and #13) after changing both the micron filters, repairing the KCL mixer, dosing pumps etc as mentioned in Table 3 to ensure continuous injection as well as quality of injection water through stringent monitoring.
- Convert well #8 to dump flooder – a new initiative by the company.

4.1 Dump Flooding

The concept of pressure maintenance through "Dump Flooding" may be a novel idea in India, but it has been successfully implemented worldwide. For example, Qatar Petroleum has been using this technique for its two offshore giant fields for the last few decades. A schematic of dump flooding is shown in Figure 13.

Electro-log study of wells of the field has brought out that overlying water-bearing sand at ~1600 m in the Upper Bokabil formation is quite extensive (Figure 14). This hydrostatic pressure aquifer in Upper Bokabil will be perforated in well #8 to serve as a source of injection water for the depleted N-20 reservoir underneath. The existing completed interval in the reservoir (N-20) will be re/additionally perforated and an acid stimulation job will be carried out to improve its water intake capacity. The interval to be reperforated, additionally perforated in the producing N-20 reservoir of Lower Bokabil and the intervals to be perforated in the Upper Bokabil aquifer to dump flood the underlying N-20 reservoir in the same well are tabulated below.

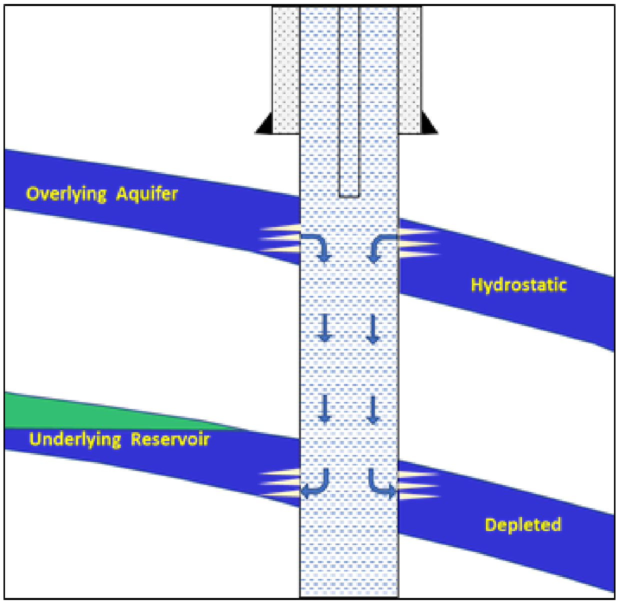

Figure 13. Schematic of a dump flooder.

Post conversion of well#8 as "Dump Flooder", a Production Logging Tool (PLT) will be carried out after a fortnight to assess the success of dump flooding in the field. This pilot project will be performed through a work-over rig. The NOC has supported and given in-principal approval of the pilot dump flooding proposal in the field to improve water injection performance.

Based on the results of the "Pilot Dump Flooding" in well #8, further courses of action such as conversion of other suitable injectors to dump flooders and discontinuance of existing Powered Water Injection Plant at the GGS may be decided to be implemented in a phased manner, if deemed favourable.

5.0 Conclusions

1. N-10 and N-20 reservoirs need immediate jacking up of reservoir pressure before any infill well

Table 4. Perforation intervals for the dump flooder

Well No	Lower Bokabil (Producing Reservoir)		Upper Bokabil (Aquifer)	Cement top behind 5-1/2" Casing
	Existing interval to be reperforated	New Perforation to be added	New Perforation	
#8	2075-2084 m (N-20)	2096-2108 m (N-20)	1716-1722 m 1702-1708 m	1690 m

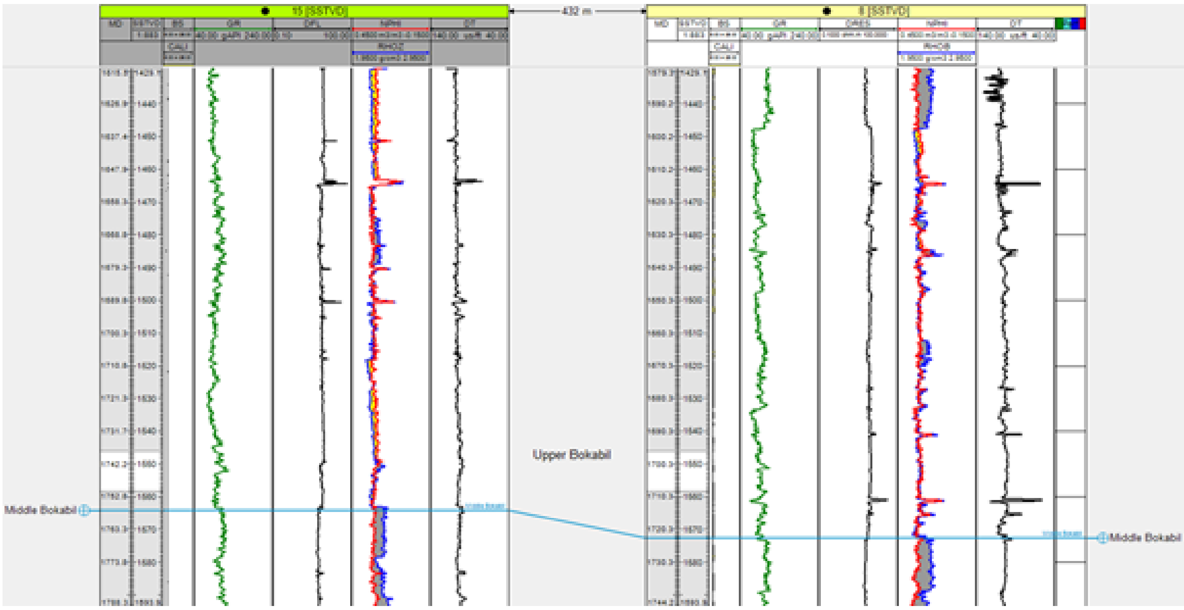

Figure 14. The upper Bokabil aquifer in the field serves as the source of water for dump flooding. (Shown on well logs of Injectors #8 and #15 above overlying Middle Bokabil).

could be drilled to enhance production from these reservoirs.

2. Low recovery from the field is attributed to inefficient water injection facilities and premature zone transfer.
3. Pre-mature zone transfers of wells completed in lower sands N-30 and N-40 have left substantial oil yet to be produced from these reservoirs where pressure is reasonably good.
4. Major producing reservoirs N-20 and N-10 are in communication and the low recovery factor from these reservoirs is because of the rapid decline in reservoir pressure to the level of 100 kg/cm^2 which is much lower than bubble point pressure.
5. A complete overhauling and revamping of water injection facilities is required to ensure continuous and quality water injection to improve well injectivity and quantum of daily injection rate.
6. A pilot dump flooder has been proposed and if proven effective, more wells may be converted/ added as dump flooders.
7. The implementation of pilot dump flooding has the potential to replace the existing water injection facilities thereby offering a huge reduction in production cost from the field.

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