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Carbon Storage Focused Reservoir Management of a Mature Indian Oilfield : A Design Case Study

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Abstract— CO2 injection is a well-documented method for improving hydrocarbon production rates and increasing oilfield recovery factors. In light of climate concerns, there has been a significant push to utilize CO2 injection for the dual objectives of enhancing oil recovery and carbon storage. Despite the proliferation of CCUS related literature, practical considerations related to reservoir management are rarely discussed. Intelligent reservoir management of a field from primary to tertiary recovery phases yields an understanding of key physical properties and mechanism that govern oil recovery. A well-managed reservoir is also better prepared to benefit from CO2 injection for the synergistic objectives of oil recovery and carbon storage. In this work, we address several underexplored areas in CCUS research:

1. Optimization of primary and tertiary depletion plans to "prepare" a field for carbon storage, taking into consideration pressure, free gas saturation, and liquid phase saturation distributions. Design parameters include appropriate production/injection depths and pattern design/rates.
2. Utilization of primary phase learnings to accelerate the reservoir into tertiary phase (skipping waterflooding) to maximize carbon storage.
3. The balance of technical and commercial considerations for gas injection design, including gas supply constraints.

Optimizing oil reservoir development for carbon storage is particularly important in countries with absent or nascent CCUS policies. In our work, we present an integrated carbon storage focused development strategy for a mature Indian oilfield. We leverage multiple analytical and numerical tools to perform an integrated analysis of a depleted stacked pay reservoir. The work uses actual field data from multiple sources with over 30 years of dynamic data. The reservoir has a storage potential of over 5 million metric tonnes, with an incremental oil recovery factor of 11%. Eliminating the waterflooding stage adds approximately 0.5 million tonnes of storage. Continual production of aquifer water adds an estimated 0.35 million tonnes of storage potential annually. The client has over 50 reservoirs at various developmental stages; this work highlights the tremendous potential of these fields for carbon storage with an integrated reservoir management approach.

Keywords— reservoir management, CCUS, carbon storage, EOR, reservoir simulation, reservoir engineering

I. INTRODUCTION

Energy production and consumption are key elements of modern economic growth. There is a strong correlation between energy consumption and economic growth [1]. Liquid fossil fuels are a key component of the energy mix, contributing up to 34% of worldwide energy usage [2]. While energy sources are diversifying, liquid fossil fuels are still a key energy source in developing countries such as India. The rapid development of the Indian economy is expected to intensify the energy demand from fossil fuels. This will inevitably lead to increased CO2 emissions. CO2 emissions have been rising worldwide, reaching 36.3 billion tonnes in 2021 [2]. One of the key mitigation strategies for excessive atmospheric carbon is injection into depleted oil reservoirs. Given the lack of CCUS incentives in India, CO2 EOR is a commercially viable method to store captured CO2.

CO2 injection into oil reservoirs is a well-known and practiced technique to recover additional oil beyond secondary and primary recovery techniques. The earliest successful CO2 injection project was the SACROC flood in 1972. Since then, multiple commercial-scale CO2 floods have been performed worldwide. Fig. 1 summarizes the history of CO2 injection in the USA [3]. In these projects, the goal of CO2 injection is to increase oil recovery. There have been recent efforts to incorporate geological storage as another objective [4,5]. For example, the Weyburn oilfield was the first CO2 EOR and storage project, with a storage capacity of approximately 25 million tonnes [6]. There have been multiple studies addressing the co-optimizing of CO2 EOR and storage [7,8]. Many of these studies have simplifying assumptions and fail to address practical challenges found in brownfields, such as uneven reservoir pressure, fluid saturations, and high free gas saturation. Overcoming these challenges is critical to ensuring the success of the CO2 storage process.

As highlighted in Fig. 1, there is a large amount of reservoir management expertise in successfully deploying and monitoring CO2 injection projects. In this work, this reservoir management expertise is leveraged to design a successful carbon storage project. The design work presented here is under consideration for field implementation by the client.

This study is suitable for the B section of the MIT A&B symposium, on the topic of carbon sequestration. We demonstrate how learnings gleaned from primary phase data sources can be used to successfully design a carbon storage-focused CO2 injection project. This is of relevance to many mature fields, particularly in Asia, with sub-optimal reservoir management practices, a lack of secondary phase data, or poor commercial incentives for carbon storage. We demonstrate our integrated reservoir management approach with a field case study.

II. Background and Analysis

A. Reservoir background

The oilfield under study is a stacked pay reservoir consisting of multiple facies types distributed across 8 sandstone layers (Fig. 2). These limestone and coal-bearing sandstones were deposited in shallow marine to lagoonal conditions, while the overlying Tura Sandstone Formation (Early Eocene) under a fluvio-deltaic environment. The hydrocarbon prospects are confined to Lower Eocene sand ranges, a sequence of predominantly arkosic sandstones interbedded with shales, carbonaceous shales, silty and tight calcareous sandstones and occasional coals. The average sequence thickness is of the order of 100 m and the gross pay thickness is about 18 to 25 m with individual sandstone unit thicknesses ranging between 1 to 5 m.

Petrophysical analysis revealed depositional trends, with numerous shale intrusions separating the pay zones, creating barriers to fluid movement vertically and laterally (Fig. 3). Well-sections through the observed trends showed that along the NE-SW direction, sand continuity is more pronounced among the blocky and coarsening upward sand bodies (orange color section). Sections along NW-SE directions revealed a direction of sand continuity with some continuity among the fining upward sand bodies (pink and cyan color sections). These are likely channels (yellow color polygons in Fig. 3) dissecting a shallow marine deposit sand depicted in the orange section (pink color-filled polygons in the orange section of Fig. 3). Understanding these channel connections and trends is critical to discerning sand continuity trends. For example, the heterogeneous fining upwards sand packages are suitable for gas EOR applications. The injection patterns were selected following these sand continuity trends, supported by production and pressure analysis.

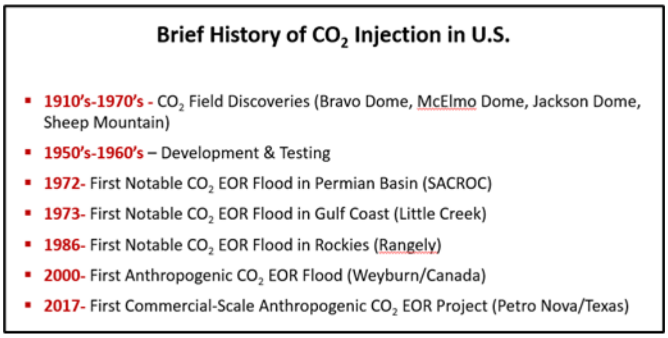

Fig 1. Brief history of CO2 injection in the USA (adapted from [3]).

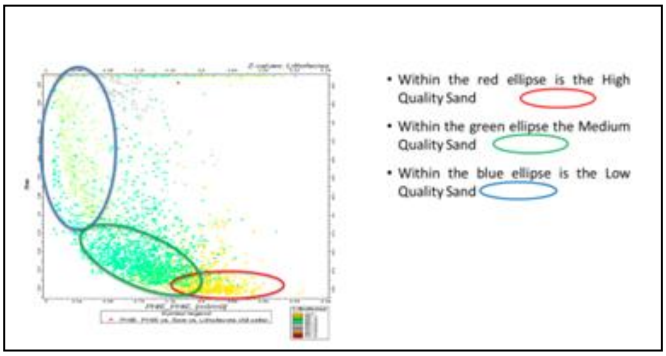

Fig. 2. Various facies types clustered into 3 major sand groups.

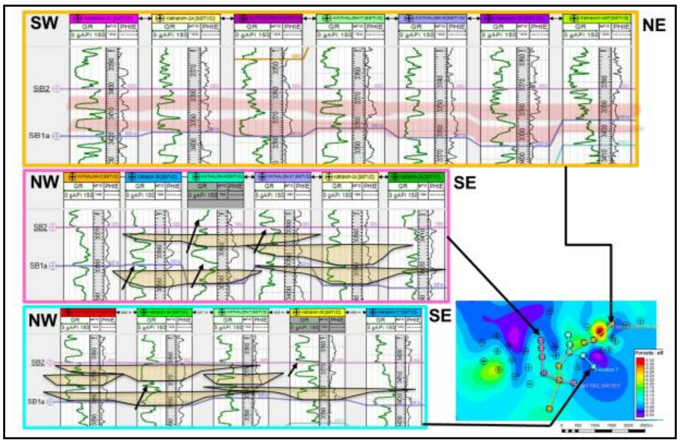

Fig. 3.Sand trends distributed across the reservoir, highlighting depositional directions and pay zone connectivity.

B. Connectivity Analysis and Depletion Study

The disconnected, discrete nature of the Eocene reservoirs has traditionally presented a barrier to successful waterflooding and gas flooding. Vertical and lateral connectivity was ascertained by combining pressure, production, and petrophysical data. The production volumes and pressure values were analyzed and the K-means clustering algorithm was applied to delineate sectors with different production behavior (Fig. 4). Using the Dynamic Time Warping algorithm, production trends such as water-cut, GOR, and oil production were clustered. The analysis was performed using data from the primary phase of production (i.e. prior to any water or gas injection). Several observations can be made:

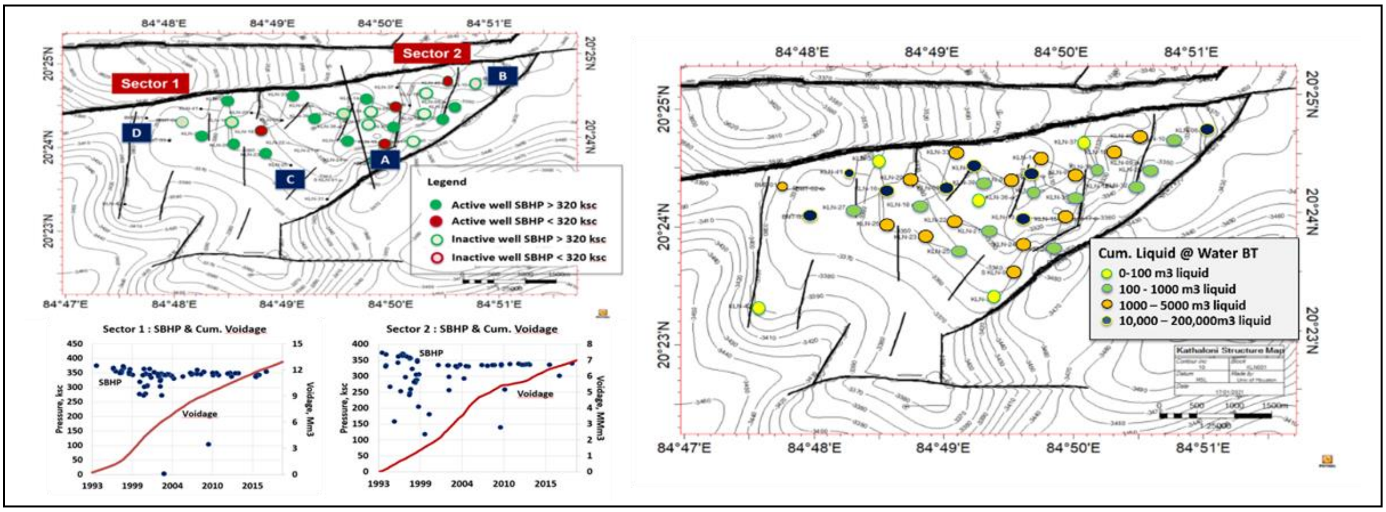

Fig. 4.(a)Field data clustered into two major sectors for further connectivity analysis. The labels A, B, C, and D are potential injection locations to raise reservoir pressure and maintain an even reservoir pressure. (b)Reservoir-aquifer connectivity analysis to discern aquifer direction and connectivity. Here the cumulative liquid production at water breakthrough is shown to highlight the areas with stronger and weaker aquifer connectivity.

1. The pressure depletion and water cut evolution trends reveal two major compartments in the field. (Sector 1 and 2 in Fig.4(a)). This observation was confirmed by subsequent geochemical analysis.
2. Using the sand continuity analysis from petrophysics with the pressure depletion trends, several key locations for pressure support were determined. These areas (labeled A,B,C,D in Fig. 4(a)) are strategic locations for raising the pressure to above the Minimum Miscibility Pressure (MMP) for CO2 injection.
3. The water-cut trend analysis with pressure depletion profile indicated the direction and strength of a strong edge and weaker bottom water aquifer system. The aquifer water movement was consistent with the petrophysical analysis, acting in a NE-SW direction (Fig 4(b)).
4. Production analysis with sand continuity aid the selection of injection locations with maximum carbon storage and /or EOR potential.

A geomodel was constructed using various data sources such as seismic data and petrophysical information, supported by an understanding of regional geology. The geomodel construction was also guided by dynamic data analysis. Production-pressure data analysis was combined with sand trends from log data to yield a facies trend map (Fig. 5). Calibration of the numerical simulation model was performed by integrating production, pressure, and petrophysical analysis. The calibrated numerical model was used to optimize injection parameters for the CO2 injection phase.

III. KEY RESULTS

With the calibrated model, several optimization variables were considered following Equation (1),

$$J = \left(\propto_1 f(\Delta P) + \propto_2 f(S_g) \right) \qquad (1)$$

where J = objective function to be minimized, ΔP is the difference between the initial pressure and localized grid block pressure, S_g is the free gas saturation and $\propto_1, \propto_2$ are the weighting factors (set at 0.5). The purpose of the optimization was to use the calibrated numerical model to find optimum injection locations and production rates.

Table 1 outlines the range of variables tested for the primary, secondary and CO2 injection phases. The goal of the optimized variables is to ensure carbon storage objectives are met by ensuring miscibility between injectant and in-situ oil and maximizing sweep efficiency. To summarize,

1. The production rates for each well were rebalanced by location and zone to avoid excessive gas production, maintain pressure balance, and minimize bypassed oil. Optimum injection locations were selected to re-pressurize the reservoir and optimize reservoir recovery. The injection location, timing, and depth were selected using a genetic algorithm.
2. CO2 injection was performed without any waterflooding. The reservoir was fast-tracked from primary to tertiary recovery phase. The injected CO2 was initially immiscible with in-situ oil but turned miscible after 1.5 years. Injecting CO2 without a prior waterflood yielded more pore volume for storage

TABLE 1. Variable ranges for optimizing injection parameters.

Parameters	Unit	Min	Max	Phase
Production rate	klpd	0	150	Primary, Tertiary
VRR	-	0.85	1.1	Tertiary
Depth of Injection	-	1	3	Tertiary
WAG Ratio	-	0.5:1	5:01	Tertiary
NCYCLES	1/year	1	6	Tertiary
HCPVi CO2	-	0.3	3	Tertiary

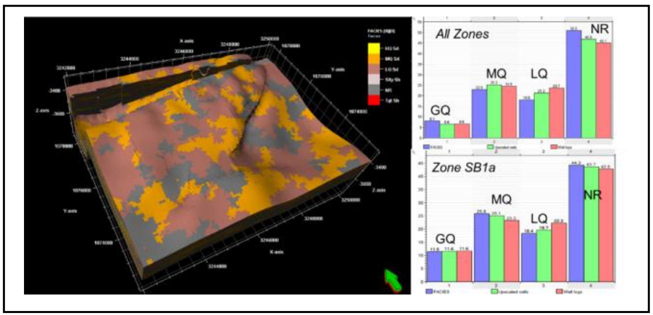

Fig. 5. Facies model used in the static geomodel.

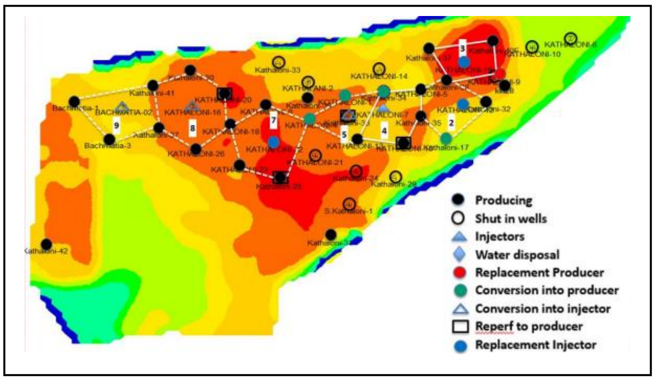

Fig. 6. Multiple injection patterns tested with the calibrated numerical simulation model. The map shows the remaining HCPV.

Following the optimization of the production and injection parameters, pattern injection locations were selected, utilizing existing wellbores (Fig. 6).

Table 2 shows the CO2 storage potential of the field over a 10-year injection period. The pilot injection consists of 2 patterns and the full field injection scheme includes an additional 5 patterns (making 7 patterns in total). The patterns were selected based on sand continuity (areal and vertical), and existing wellbores. The injection and production parameters were calibrated based on current pressure and saturations.

TABLE 2. Incremental oil (recovery factor %) and CO2 stored (million metric tonnes) for pilot and field-wide injection.

	Incremental oil, RF%	**CO2 stored, mmtonnes**
Pilot injection	11.2	0.67
Full field	10.1	5.1

Additional storage potential within the reservoir-aquifer system was investigated by calculating the effect of maintaining water production from high water-cut wells and increasing injection rates to maintain voidage replacement. The water production rates simulated were constrained by the existing water processing facilities available on-site. The produced water is expected to be treated and repurposed (Fig. 7). Table 3 highlights the additional storage created by producing aquifer water using current wellbores.

TABLE 3. Additional storage created by producing aquifer water using current wellbore.

Net reservoir water production rate	**Annual net water volume produced from aquifer**	**Annual CO2 storage potential**
m3/d	**m3**	**metric tons**
180	65,700	35,930

Table 2 and 3 highlight the impact of optimizing the production, injection rates, and reservoir pressure for the pilot and field injection patterns. Several observations on these results:

1. The CO2 injection increases the recovery factor by 10 – 11% while storing 0.6 (pilot) to 5 million tonnes (full-field) of CO2. This yields a gross utilization ratio between 8 – 13 Mcf/bbl.
2. A continuous CO2 injection scheme was used to maximize both storage and optimize oil recovery. CO2 injection was performed continuously for 11 years, with the average daily injection rates of approximately 100 (pilot) – 250 (full-field) m3/d. This volume honors well bore rate constraints and CO2 supply limitations. This volume was approximately 3 -5% of HCPV within the pattern areas.
3. The injection locations and depths were guided by the connectivity analysis from primary phase production-pressure analysis and log data. The calibrated numerical simulation model confirmed the viability of the selected patterns to maximize carbon storage within the reservoir while increasing oil recovery.
4. Besides the storage potential in the depleted oil zone, the reservoir is underlain by a large aquifer. Material balance work indicates that the aquifer pore volume is several times larger than the reservoir pore volume. There is therefore a large storage potential in the aquifer. By depleting the aquifer, an additional storage potential of 0.04 million tonnes per year is available.
5. While the reservoir storage potential is approximately 5 million tonnes, there are more than 50 other candidate reservoirs within the portfolio of the client company. These collectively add up to 25 billion barrels of oil in place, a large storage capacity. The size of the prize is extremely large considering many of these reservoirs are connected to large aquifers.
6. The water produced by various production wells (many having water cuts greater than 90%) can be treated and used for other purposes such as agriculture. This has two benefits; first, the produced water leaves additional pore volume for carbon storage. Secondly, the produced water is an alternative water source, which is especially important in drought-prone areas in India.

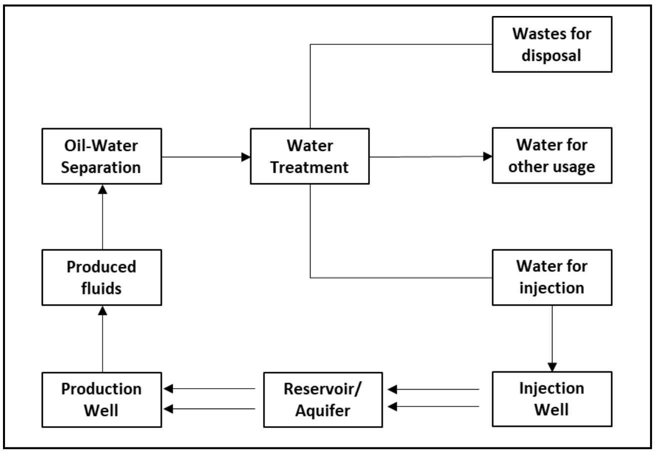

Fig.7. Water injection schematic for the wells producing from reservoir and aquifer.

IV. Conclusions

Several conclusions from this study are:

1. Integrated reservoir characterization utilizing static and primary phase dynamic data (well logs, core data, production and pressure data) validates an understanding of sand continuity and injection locations for CO2 injection. This approach allows reservoir managers to design a carbon storage project without prior injection data.
2. The storage potential of the reservoir was demonstrated through numerical simulation over a 10 year injection period. The storage potential is up to 5 million tonnes in the reservoir and a further 0.4 million tonnes in the aquifer.
3. The aquifer storage potential is large; many of the existing wellbores can further deplete the aquifer. However, water processing facilities will need to be upgraded for a larger throughput.
4. The work performed can be easily adapted to many of the existing mature oil fields in Northeast India, with similar geological characteristics. The size of the storage potential in both the oil reservoir and aquifer is huge. Increasing oil production (through EOR) makes the carbon storage projects economically viable.

V. Acknowledgment

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VII. Author Biographies

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