Study on the Effectiveness of Carbon Dioxide Injection for enhanced gas recovery in depleted Reservoirs

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Abstract- This study addresses the challenge of optimizing oil recovery in gas field XYZ of the Niger Delta region, particularly focusing on the effectiveness of CO_2 injection as an enhanced oil recovery (EOR) technique. The aim was to evaluate how CO_2 injection impacts hydrocarbon recovery and produced water management compared to conventional production methods. Utilizing a proprietary software, a detailed reservoir model was developed, which included various geological features and fluid properties. The results demonstrated that CO_2 injection significantly improved cumulative gas production, achieving 6.03E+6 MSCF compared to 4.1991E+6 MSCF in the production only case. Additionally, the CO_2 injection strategy maintained a stable bottom hole pressure of 1000 psi, while the production only case experienced a dramatic drop in production rates, declining to 396.66 MSCF/d before ceasing operations. The findings concluded that CO_2 injection not only enhances oil recovery but also improves water management strategies within the reservoir, highlighting its potential as a viable solution for optimizing hydrocarbon extraction.

Index Terms- CO_2 Injection, Climate Change, Enhanced Gas Recovery, Depleted Reservoirs, Petrel reservoir simulation software

I. INTRODUCTION

The implementation of advanced technologies and innovations in the world today has led to a drastic increase in the global energy demands, these innovations are mostly driven by energy. More than 70% (seventy percent) of these energy demands are met by fossil fuels, which are highly responsible for the high emission of greenhouse gases (mostly CO2) into the atmosphere, this devastating effect as led to climate change (Jyoti Shanker Pandey, 2020). In respect of the Intergovernmental Panel on Climate Change (IPCC), the sixth assessment report claims that climate change has significantly disrupted the biodiversity and ecosystem of the earth with a 1.1 °C rise in global temperature (Guarav pandev, 2022). Also, the Paris agreement set the targets to limit the global temperature rise to 1.5 °C to caution the intense environmental impacts of greenhouse gases (S. Yadav et al, 2022). However, it is reported that for the international community to achieve its NetZero goals by 2030, at least one gigaton of CO_2 needs to be sequestered per year. This objective can only be carried out by carbon capture and sequestration technologies [CCS] (Jyoti et al, 2020). This method involves the Capture of CO_2 from Power plants, big industrial machines, refineries and processing facilities. But after capturing CO_2 from different sources, the question remains how to sequester it? The major answer to this question is to store the CO2 in depleted reservoirs where it can be deposited for a longer period of time with emitting into the atmosphere.

This method of sequestration serves double purpose, First, it helps to reduce the risk of climate change by storing the CO_2 far beneath the earth's crust which is covered by layers of rocks (Overburden) that serves as a seal to prevent the CO_2 from escaping into the surface. Secondly this method of sequestration will help in improving Enhanced Oil Recovery techniques by injecting the CO_2 into the reservoir which will help to maintain the pressure in the reservoir and increase the rate of production in the reservoir. In (Sarah Adiba Binti, 2013) analysis of CO_2 storage, they demonstrated the feasibility of injecting CO_2 into the ocean where the CO_2 will then form hydrate, also these hydrates can then sink to the ocean floor due to their higher density compared to seawater offering a stable storage solution. Although this method offers a stable storage solution, but there are still fears that oceans vessels mostly submarines could potentially distort the stability of the CO_2 hydrate. Hence the most efficient and reliable way of sequestering the CO2 is by depositing them in depleted reservoirs which consist of seals to prevent the CO2 from escaping. Technically, the process of this study starts with injection of CO_2 into the subsurface formation of a depleted reservoir, the simulation will focus on the injection of the CO_2 as well as monitoring the response of the reservoir in terms of pressure, water cut, production rate and other components. The simulation will be done using the petrel software environment which involves the visualization of two wells (a producer and an injection well). The paper will also analyze the effectiveness of CO_2 injection on production in "gas field XYZ" compared to ordinary production. The results of this simulation will be presented in graphs which gives a more visible analysis of what exactly is happening in the reservoir.

The application of carbon dioxide sequestration and injection to depleted oil reservoirs has been firmly established as an effective enhanced oil recovery (EOR) technique, utilizing either full or partial miscibility to displace residual oil (Dai et al., 2017). According to (Ahmed hamzah et all,2021) Carbon dioxide improves the microscopic displacement efficiency of crude oil, because it helps to decrease the viscosity of the oil through oil swelling. However, in (Honari et al., 2015) they acknowledged that the implementation of CO_2 injection to enhance gas recovery (EGR) in gas reservoirs is a complex process, and is further complicated by gas adsorption on reservoir rock surfaces, the miscibility of CO_2 and natural gas, also the potential for premature CO2 breakthrough in production wells (Honari et al., 2015).

Depleted gas reservoirs, with primary recovery factors exceeding 60%, offer greater CO_2 storage capacity than oil reservoirs (Kuhn and Munch, 2013). Unlike oil reservoirs, CO_2 and natural gas are fully miscible at reservoir conditions, which will require costly sweetening processes for separation. However, CO_2 in the gas makes it harder to extract pure methane, driving up costs. To minimize this, we need to understand how CO_2 spreads in the reservoir to control the injection amount. Furthermore, limited research has studied the impact of residual hydrocarbon saturation on multiphase flow characteristics in depleted gas reservoirs. (Saeedi and Rezaee, 2012) experimentally investigated how residual gas saturation affects multiphase flow in sandstone samples, concluding that early-stage CO2 injectivity may be low but improves with continued injection. (Snippe and Tucker, 2014) numerically modeled CO2 storage in depleted gas fields and saline aquifers, finding that lateral CO2 migration in open systems is influenced by absolute permeability, residual gas saturation, and mineral surface areas. (Raza et al, 2016) reviewed the negative effects of residual gas saturation on storage capacity and injectivity in depleted gas reservoirs, attributing the capacity reduction to decreased brine mobility and the density and viscosity of gas mixtures dissolving into supercritical CO2.

II. LITERATURE REVIEW

Climate change

Fossil fuels (coal, oil and gas) are by far the largest contributor to global climate change, accounting for over 75 per cent of global greenhouse gas emissions and nearly 90 per cent of all carbon dioxide emissions. Climate change is a pressing issue for the planet and it's inhabitants . It has a diverse effect on the entire population of the earth including humans, plants and animals. This section of literature review will include the nature of climate change, causes , impacts and potential mitigation strategies.

A. Causes Of Climate Change

According to united nations, it is explained that as greenhouse gas emissions blanket the earth, they trap the sun's heat. This leads to global warming and climate change. The world is now warming faster than at any point in recorded history. Some of the causes of climate change includes:

1 Power generation – energy generation is a leading drive to climate change, the generation of electricity and heat by burning of fossil fuels (coal, oil or gas) produces a very large sum of greenhouse gases such as carbon dioxide , nitrous oxide which blankets the earth and traps the sun's heat. Most electricity today is still generated by burning fossil fuels. Coal generates about 60% of china's energy demand in terms of electricity. This number is still significantly huge if we truly want to combat climate change. Generally, the generation of electricity is mostly done by fossil fuel.

2 Manufacturing industry – manufacturing and industry produce emissions, mostly from burning fossil fuels to produce energy for making things like cement, iron, steel, electronics, plastics, clothes and other goods. Mining and other industrial processes also release gases.

3 Transportation – the emissions from transportation means such as vehicles, trains, ships , heavy worries etc all contributes to the emission of greenhouse gases to the atmosphere. Most cars, lorries, ships and planes run on fossil fuels. That makes transportation a major contributor of greenhouse gases, especially carbon-dioxide emissions. Road vehicles account for the largest part, but emissions from ships and planes continue to grow.

4 Deforestation - cutting down forests to create farms or pastures, or for other reasons, causes emissions, since trees, when they are cut, release the carbon they have been storing. Each year approximately 12 million hectares of forest are destroyed. Since forests absorb carbon dioxide, destroying them also limits nature's ability to keep emissions out of the atmosphere. Deforestation, together with agriculture and other land use changes, is responsible for roughly a quarter of global greenhouse gas emissions. (source – united nations).

5 Powered buildings and human causes – globally, residential and commercial buildings consume over half of all electricity. As they continue to draw on coal, oil, and natural gas for heating and cooling, they emit significant quantities of greenhouse gas emissions. Growing energy demand for heating and cooling, with rising air-conditioner ownership, as well as increased electricity consumption for lighting, appliances, and connected devices, has contributed to a rise in energy-related carbon-dioxide emissions from buildings in recent years. Our homes and our use of power, how we move around, what we eat and how much we throw away all contribute to greenhouse gas emissions. So does the consumption of goods such as clothing, electronics, and plastics. A large chunk of global greenhouse gas emissions are linked to private households. Our lifestyles have a profound impact on our planet. The wealthiest bear the greatest responsibility: the richest 1 per cent of the global population combined account for more greenhouse gas emissions than the poorest 50 per cent.

B. Effects Of Climate Change

Every day, climate change is causing a variety of effects on our world including changes in ecosystems, extreme weather events, and growing sea levels. Already visible worldwide, these consequences will likely worsen in the years ahead.

Leading global organization of researchers the Intergovernmental Panel on Climate Change (IPCC) has released numerous studies outlining the consequences of climate change. According to the IPCC's 2014 assessment, human activity clearly warms the land, sea, and atmosphere. Their study also revealed that climate change is already influencing human and natural systems. It is causing more heat waves, stronger rainstorms, and rising sea levels.

According to a 2018 study by James Hansen, a former NASA scientist, worldwide sea level rise is speeding up and might reach greater meters by the century's end. For coastal towns and areas worldwide, this might have serious ramifications. Apart from the physical consequences of climate change, the IPCC has also noted the social and financial repercussions of the crisis. Among these are migration, displacement, and conflict as well as a worldwide rise in poverty level. The study further cautions of the possibility for "tipping points" at which time climate change might cause permanent alterations in the systems of the planet like the melting of the Greenland ice sheet or the fall of the amazon rainforest. It is crucial to point out that climate change's consequences are not uniformly felt. Though they have contributed the least to greenhouse gas emissions, often the most susceptible to the effects of the crisis are developing nations. Many elements, including poverty, poor infrastructure, and geography, contribute to this.

*CO_2 Injec*tion

Picture a sponge saturated in water(oil). Squeezing it (natural pressure) only gets some of the water out. Consider now forcing air (CO_2) into the sponge. This extra pressure enables more oil to be squeezed out. Therefore, CO_2 injection is the process by which carbon dioxide (CO_2) is driven deep underground into rock formations, to help displace a certain amount of residual oil from the reservoir. According to (Bo wei et all, 2023) there are two main reasons for this process:

1)INCREASED OIL/GAS RECOVERY – Injecting CO_2 into oil and gas reservoirs helps to raise the pressure and drive out more oil and gas. This aids in getting extra hydrocarbon from current wells.

2) CO_2 is captured from industrial and power plants, then injected into deep geological formations where it is safely stored, therefore stopping it from escaping

into the atmosphere and helping to lessen the effects of climate change.

High-temperature CO_2 is pumped into the reservoir to produce a thick combination that mixes with the oil. This makes the oil move better towards the wells used to get it out of the ground, because it makes the oil to be less thick. (Charwarwan Khan et al, 2012). The operational process of CO_2 injection into natural gas reservoirs is very expensive and presents significant risks regarding both the outcome and possible field contamination (C Hussien, et all 2012), the main worry being that mixing injected CO_2 with the original gas will lower output.

From a technical perspective, the problems resulting from the combination of CO_2 and natural gas are the main reason for the somewhat low level of interest in CO_2-EGR. Under gas-gas mixing circumstances, injected CO_2 moved to the production wells—a phenomenon known as CO_2 breakthrough—which (B feather and Archer, 2010) claim is the reason for the low level of interest in CO_2-EGR. This caused a notable decrease in natural gas output and a notable rise in CO_2 production. But generally, although CO_2 gas mixing is a concern, it can be controlled by means of good reservoir management and production control.

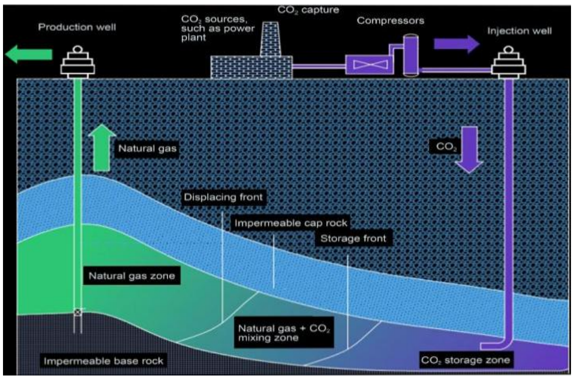

Fig 1 – CO injection for Enhanced Gas Recovery view (source: Lui:2018)

CO_2 Hydrates

CO2 hydrates are what?

Understanding what hydrates are, how they develop, and under what circumstances they form is crucial for clarifying what CO2 hydrates are.

Under low temperature and high pressure settings, clathrate hydrates also known as hydrates are solid, ice-like form of gases that develop when gas molecules like methane or CO2 combine with liquid water. The gas molecules then become trapped in a cage-like structure formed by water molecules, resulting in a solid, ice-like substance. (Qanbari et al,2011). According to (Yussof et al 2013), hydrates are made when gas molecules like methane or CO2 mix with liquid water under certain conditions (low temperature and high pressure). The gas molecules then become trapped in a cage-like structure made of water molecules, which gives the substance a solid, ice-like look.

The guest molecules within the clathrate hydrates are held in place by weak Vanderwaal forces within a lattice structure formed by hydrogen bonded water molecules (Morteza et al, 2024). Clathrate is divided into 3 main structures, Structure I(sI), Structure II (sII), Structure H(sH). Each other these structures is composed of a unique arrangement of different water molecules leading to different size and types of cavities that can accommodate guest molecules .

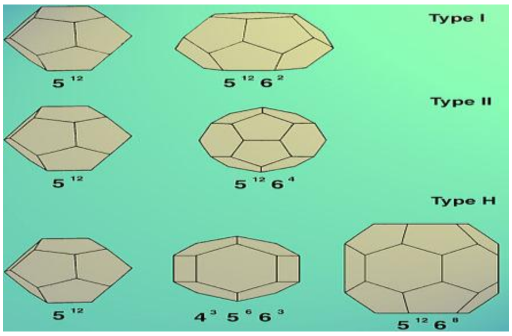

Fig 2 – Cages building different gas hydrate structures (source: WIKIPEDIA)

Figure 2 mostly shows polyhedral structures made by water molecules that make up the cavities among the clathrate hydrates. Among these are Pentagonal dodecahedron (5^12), tetrakaidecahedron (5^12 6^2), hexakaidecahedroon (5^12 6^4), irregular dodecahedron (4^3 5^6 6^3), and icosahedron (5^12 6^8). The figures in the subscripts show how many of each kind of polygon (like pentagons, hexagons) make up the faces of the cavity. The several forms of hydrate structure are described as follows:

1. Structure I (sI) Hydrate: This is a cubic crystal structure that usually forms when small molecules, like methane (C1) and ethane (C2) that are between 0.4 and 0.55 nm in size, are present. There are 46 water molecules in the unit cell of sI hydrate. They make two tiny 5^12 holes and six bigger 5^12 6^2 holes. Separated and without faces shared with other cavities are the little ones.

2. Structure II (sII) Hydrate: This is a different type of cubic crystal structure that usually forms with guest molecules that are between 0.6 and 0.7 nm in size, such as propane (C3) and butane (C4). Some smaller molecules, like nitrogen (N2) and oxygen (O2), can also make sII hydrates. Containing 136 water molecules distributed across 16 tiny 5^12 cavities, the unit cell of sII hydrate is bigger than sI. Eight big 5^12 6^4 cavities also. Under this arrangement, the little cavities have common surfaces.

3. Structure H (sH) Hydrate needs two different guest molecules to form one big and one small and has a hexagonal crystal lattice. Unit cell contains the single big 5^12 6^8 cavity for the large guest molecule; the small guest molecules stabilize the three small 5^12 cavities as well as the two medium-sized 4^3 5^6 6^3 cavities.

Further more, (Aminnaji et al, 2024) stress that although the link between guest molecule size and hydrate structure is usually consistent, it is also dependent on the particular pressure and temperature settings. To make this clear, they point out that methane, which is normally found in Structure I hydrates, can turn into Structure II or even Structure H hydrates under very high pressure. This finding emphasizes the dynamic character of gas hydrate formation as well as the intricate interaction between guest molecule size and the surrounding environment in determining the last hydrate structure.

Research by (Sloan and Koh, 2007) shows that CO2 hydrates may be employed in several ways, including carbon capture and storage (CCS). Injecting CO2 into subsurface formations or deep-sea sediments helps to transform it into stable hydrates, therefore keeping it from being released into the air. Researchers like (Ohgaki et al,2004) and (Kang et al,2008) have looked at this process a lot. Also, CO2 hydrates can be used to make and store gas. Arctic areas have a lot of natural gas hydrates, which include methane.

Formation of CO_2 Hydrates

Under low temperature and high pressure in the presence of liquid water, CO2 hydrates are CO2 gas molecules trapped in a cage like lattice structure of water molecules. For CO2 hydrate to form, it needs more pressure than methane hydrates at the same temperature. This is because CO2 molecules are bigger and have a linear shape. Also, their Van Der waals forces are weaker. (Hu and Xiao, 2023) showed that CO2 hydrates don't form on their own in the environment. At temperatures ranging from 273.85 K to 282.65 K, the phase equilibrium pressure for CO2 hydrate formation ranges from 1.38 to 3.95 MPa. This calls for specialized tools and a lot of energy input to get the desired conditions. Therefore, we should think of Polar areas as natural habitat for CO2 hydrates.

Moreover, the creation process itself has kinetic issues. Initial formation of hydrates takes place at the boundary between CO2 gas and water, where the contact area is maximum. However, as the hydrate layer expands, it becomes a barrier that slows down the formation process by preventing more CO2 from reaching water. (Xiao, 2023) notes that despite these difficulties, CO2 hydrates have great potential for uses like carbon capture and storage and air conditioning because they can hold a lot of gas and have a good temperature for changing between phases. To get around the fact that it's hard to make them, this is what you should do.

Enhanced Gas Recovery (EGR)

EGR is a method known as enhanced gas recovery which includes the use of CO2 injected into a reservoir to help natural gas production increase and CO2 be stored. Injecting CO2 into the reservoir under high pressure and temperature causes the CO2 to mix with the natural gas. This improved miscibility helps the displacement process by guiding the natural gas to the production wells. The CO2 injection also raises the reservoir pressure, therefore releasing the residual gas that was formerly trapped. The project will fully explain this situation in this Context.

Improved Methods of Recovering Gas

Gas Injection is divided into miscible and immiscible gas injection. Miscible injection is when a gas like nitrogen or carbon dioxide is injected into the reservoir gas. This changes the pressure and composition of the reservoir, which pushes more gas to the production wells. Immscible gas injection involves injecting nitrogen or dry gas, which is not soluble in the reservoir gas. This gas can enhance recovery by substituting the reservoir gas.

Another method is water flooding, water is pumped into the reservoir to drive the gas toward the production wells. Most often utilized together with other approaches to maximize recovery is this one.

Then there is Chemical flooding. In this method, chemicals are pumped into the reservoir to change the characteristics of the fluids, which makes it easier to get the gas out. Less frequently used in gas reservoirs than in oil reservoirs is this method.

Eclipse schlumberger
Eclipse Schlumberger is a reservoir simulation software used in simulating different types of reservoirs. It is the most widely used simulator in the petroleum industry. It is currently owned by SLB (a oil and gas servicing company).

A. Historical Development and Evolution of ECLIPSE

Eclipse emerged from a research conducted at the Atomic Energy Research Establishment (AERE) in Harwell, UK, during the 1970s. This research focused on developing numerical techniques for solving the complex equations governing fluid flow in porous media. In the early 1980s, the technology was acquired by Exploration Consultants Limited (ECL), a UK-based petroleum engineering consultancy. ECL further developed the software and released it commercially as Eclipse.

Initially, Eclipse primarily focused on black oil simulations, which are simpler models suitable for reservoirs with relatively straightforward fluid behavior. Due to its robustness and accuracy, Eclipse gained its popularity among oil and gas companies, making it become a leading reservoir simulator in the North Sea and other regions.

B. Expansion and Enhancements (mid-1990s – 2000s)

In 1995, Schlumberger acquired ECL, bringing Eclipse into its software portfolio. This provided significant resources for further development and expansion. This also led to Eclipse's capabilities being extended to include compositional and thermal simulation, and allowing it to handle more complex reservoirs with varying fluid compositions and temperature effects. With the rise of parallel computing, Eclipse was adapted to run on high-performance computers, enabling simulations of larger and more complex reservoirs. A user-friendly graphical interface was introduced, making Eclipse more accessible to a wider range of users. Eclipse was integrated with other Schlumberger software tools, creating a more streamlined workflow for reservoir characterization and management.

C. Continued Advancements (2010s – present)

New features were added to address the challenges of simulating unconventional resources, such as shale gas and tight oil, which require specialized modeling techniques. Improvements were made to the underlying physics models, including more accurate representations of multiphase flow, geomechanics, and chemical reactions. Some features were introduced to automate tasks and optimize simulation workflows, increasing efficiency and reducing turnaround time.

D. Characteristics and features of eclipse slb

Eclipse can handle a wide range of reservoir types, It can handle everything from simple "black oil" reservoirs to complex systems with different types of fluids (like gas condensates) and thermal effects. It simulates primary production, waterflooding, gas injection, and even advanced methods like chemical flooding. It models reservoirs with simple or complex geometries, using different grid types to accurately represent the subsurface.

In addition, Eclipse Can simulate giant fields with millions of grid cells, this is as a result of the efficient algorithms and the ability to run on high-performance computers. It Incorporates detailed models of fluid flow, phase behavior, rock properties, and other physical phenomena allowing users to fine-tune parameters and incorporate their own data to create highly accurate models. It also provides a visual environment for building models, setting up simulations, and visualizing results. Reservoir engineers greatly benefits from these characteristics that Eclipse provides. Some of the uses of Eclipse to Reservoir Engineers include to:

- Predict reservoir performance
- Optimize production strategies
- Reduce risks and uncertainties
- Make informed decisions about field development

E. Features of ECLIPSE

The core simulators in ECLIPSE SLB are the fundamental building blocks for different types of reservoir simulations. The core simulators are as follows:

1. Eclipse Black Oil: The industry standard for simulating reservoirs with relatively simple fluid behavior (oil, gas, and water). It's efficient and suitable for many conventional oil and gas fields

2. Eclipse Compositional: Used for reservoirs with more complex fluids, where the composition of the oil and gas changes significantly with pressure and temperature. It's crucial for gas condensate and volatile oil reservoirs.

3. Eclipse Thermal: Simulates processes where temperature plays a major role, such as steam injection for heavy oil recovery, in-situ combustion, and geothermal energy production

Petrel software

A. PETREL background

The Petrel software was developed in Norway by a company called Technoguide . Technoguide was formed in 1996 by former employees of Geomatic, some of whom were key programmers involved in the early development of RMS. Technoguide made 3D geologic modeling more accessible to all subsurface technical staff, including those without specialist training. Developed for PCs and the Windows OS, Petrel was commercially available in 1998. The Petrel user interface has a pre-arranged workflow to facilitate its use (Wikipedia).

In 2002, Schlumberger acquired Technoguide and the Petrel software tools. Schlumberger currently supports and markets Petrel. Newer versions of Petrel include additional functionality such as geological modeling, seismic interpretation, uncertainty analysis, well planning, and links to reservoir simulators.

B. Features of PETREL Software

The petrel software provides a wide range of features for modelling any kind of reservoir, some of these features includes:

Data integration and visualization
Petrel Integrates diverse geological and geophysical data, which includes seismic surveys, well logs, production data, and reservoir simulation results. It provides a 3D seismic interpretation, well logs reading, and reservoir modelling visualization tools. Allowing users to interactively survey the subsurface structures and properties.

Geologic modelling
Petrel is perfect in creating geologic models, including structural models that indicates faults and folds. It also accurately develops stratigraphic models indicating the distribution of rock layers.

Reservoir simulation
It supports reservoir simulation workflows to predict reservoir performance and optimize production strategies. It also offers tools for production forecasting, well performance analysis, and reservoir management optimization.

C. PETREL Interface

Petrel's interface is designed to be user-friendly and efficient, it provides a seamless workflow for geoscientists and engineers. Although the specific layout differs slightly between versions, the core elements remain consistent. Some Key Interface Components

Main Window- the main window is composed of:

C. Menu Bar: Offers access to various commands and functions, organized into categories like File, Edit, View, Tools, etc.

D. Toolbar: Provides quick access to frequently used tools and commands.

E. Project Tree: Displays the hierarchical structure of the project, including data sets, interpretations, and models.

F. 3D View: The primary window for visualizing 3D seismic data, well logs, and geological models.

G. Map View: Used for creating 2D maps and cross-sections.

H. Log Plot View: For displaying well log data and performing log analysis.

Toolboxes

I. Seismic Interpretation Toolbox: Contains tools for seismic horizon picking, fault interpretation, and seismic attribute analysis.

J. Well Log Analysis: Toolbox: Provides tools for editing well logs, performing log calculations, and generating log plots.

K. Geological Modeling Toolbox: Includes tools for building structural and stratigraphic models, as well as performing uncertainty analysis.

L. Reservoir Simulation Toolbox: Offers tools for setting up reservoir simulation models, running simulations, and analyzing results.

Data Panels

M. Data Panel: Displays information about the currently selected data object, such as seismic volumes, well logs, or geological models.

N. Property Panel: Allows users to modify properties of selected objects, such as horizon colors, well log symbols, or model parameter

III. MATERIALS AND METHODOLOGY

The methodology for this study on enhanced gas recovery (EGR) in gas field XYZ of the Niger Delta region involves using Petrel software to develop a detailed reservoir model. This process includes several important steps: preparing and organizing a static model that captures key geological features, fluid properties, and well data. Additionally, the methodology includes checks to ensure the accuracy of volume calculations, modeling for gas injection scenarios, and creating different operational cases to assess the effectiveness of CO2 injection methods.

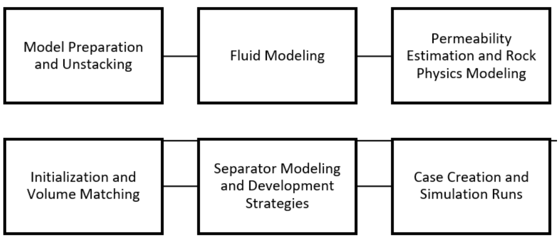

Fig 3 – Methodology Workflow

a) Model Preparation and Unstacking

The initial phase of the methodology involved preparing the stacked static model of field XYZ in the Niger Delta using Petrel software. This model included essential components such as two wells (an injector and a producer), horizons, faults, well logs, fluid boundaries, surface maps, fluid contacts, skeletons, intersections, aquifers, and various properties including Vb, Vsh, acoustic impedance, porosity models, height functions, Sw, Bo, Bg, permeability, and capillary pressure. The first step was to unstack the model to facilitate the creation of fluid models. This process allowed for a detailed analysis of each layer within the reservoir and ensured that all geological features were accurately represented. The unstacking process proved crucial for isolating the different geological layers and understanding their individual contributions to fluid flow and recovery potential.

b) Fluid Modeling

After unstacking the model, fluid modeling became the next step, as it was essential for simulating the behavior of hydrocarbons within the reservoir. This involved developing a black oil model along with a compositional model specifically for CO2 (100% by composition). The black oil model served as a baseline for conventional oil behavior, while the compositional model allowed for a more nuanced understanding of how CO2 interacted with the existing fluids in the reservoir. The creation of these models was facilitated by Petrel's built in tools, which enabled users to define fluid properties based on laboratory data and field observations. Accurate fluid modeling proved critical in EOR studies, as it directly influenced predictions regarding recovery efficiency and overall production performance.

c) Permeability Estimation and Rock Physics Modeling

With the fluid models established, the Petrel calculator tool was utilized to estimate permeability parameters: PERMX, PERMY, and PERMZ. In this step, PERMX was set equal to PERMY to represent static permeability conditions, while PERMZ was defined as 0.1 of PERMX to account for vertical permeability constraints typically observed in tight reservoirs. This estimation was vital as it impacted fluid flow dynamics within the reservoir during injection processes. Subsequently, rock physics functions were modeled, focusing on saturation and compaction effects. These functions were essential for understanding how changes in pressure and saturation levels affected rock behavior and fluid movement within the reservoir.

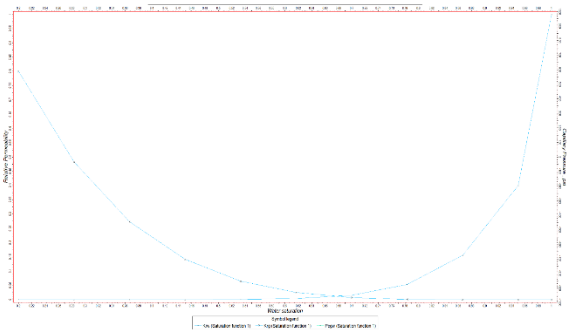

Fig 4 – Relative permeability curve from the model

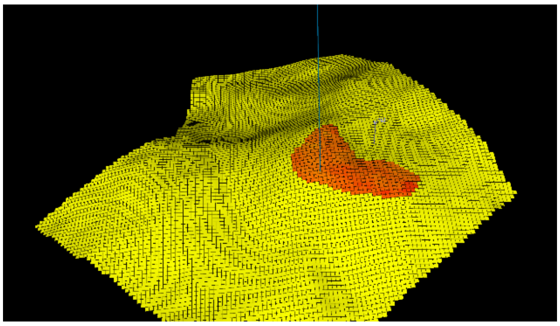

Fig 5 – Snap shot of Wells penetrating the formation

d) Initialization and Volume Matching

After establishing the permeability parameters and rock physics functions, an initialization simulation was run to assess the model's accuracy in representing static conditions. The results indicated a volume difference of only 0.458% from the static volume, confirming that the model was well calibrated to reflect actual reservoir conditions. This step was critical in ensuring that any subsequent simulations accurately represented the physical state of the reservoir before any production or injection activities commenced. A close match between simulated volumes and static volumes indicated that the model could reliably predict future behaviors under different operational scenarios.

e) Separator Modeling and Development Strategies

The next phase involved modeling a separator for the CO2 to understand how the gases would behave when introduced into the reservoir during EOR operations. This included defining operational parameters such as pressure and temperature conditions that would influence gas behavior upon injection. Following the separator modeling, two distinct production strategies were developed: (1) production only, and (2) production with CO2 injection starting after four years of natural production under similar conditions. Each strategy was designed to evaluate different recovery scenarios over time while incorporating realistic operational timelines based on typical field practices. The minimum production rate was set at 1.1229 MSCF/d, with a bottom hole pressure minimum of 1000 psi, a gas rate of 4000 MFt3/d, and a gas injection rate of 5000 MSCF/d. The minimum conditions for shut off were established as the minimum values provided, and the rates were proposed rates to be maintain

f) Case Creation and Simulation Runs

With development strategies defined, two specific cases were created corresponding to each strategy within Petrel's simulation framework. This involved importing the Vertical Flow Performance (VFP) data where necessary to ensure accurate representation of well performance during different operational phases. Running these cases allowed for the analysis of how each strategy performed in terms of oil recovery rates over time compared to natural production alone. The simulation results provided insights into the effectiveness of CO2 versus the natural production method in enhancing oil recovery from field XYZ.

IV. RESULT AND DISCUSSION

Results

A. Bottom Hole Pressure (BHP) Analysis

The analysis of Bottom Hole Pressure (BHP) provided significant insights into reservoir behavior and the effectiveness of various production strategies employed during the study. Initially, BHP in both cases was tracked together for one year, showing a consistent reduction across all scenarios as the reservoir responded to natural depletion. After this period, BHP for both the CO2 injection and production only cases stabilized, maintaining a steady pressure until approximately 7 years and 8 months into the simulation, at which point the production only case experienced a dramatic drop to zero production. In contrast, the CO2 injection case demonstrated remarkable resilience, sustaining a stable BHP of 1000 psi, as illustrated in Figure 6. This stability indicated that CO2 injection effectively maintained reservoir pressure, thereby enhancing oil recovery potential even as natural depletion progressed. The differences observed in BHP across these strategies underscored the critical role of gas injection in influencing reservoir dynamics and highlighted the potential advantages of CO2 injection in sustaining pressure and improving overall recovery efficiency.

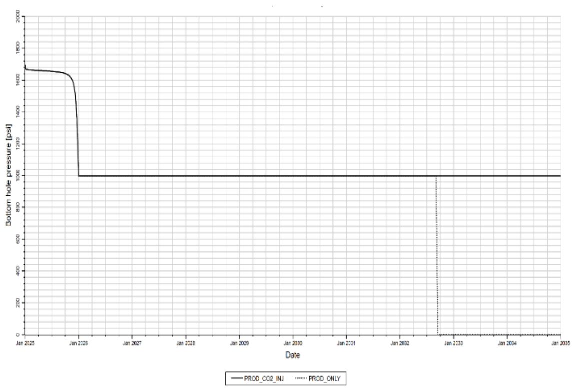

Fig 6 – BHP Result plot

B. Cumulative gas production

The cumulative gas production results from the simulation provided a clear indication of the effectiveness of the various Iinjection strategies used to enhance recovery from the reservoir. The CO2 injection case achieved the highest cumulative gas production, totaling 6.03E+6 MSCF. This result underscored the effectiveness of CO2 in mobilizing hydrocarbons and maintaining reservoir pressure over time. The substantial gas production observed in the CO2 injection case demonstrated the ability of CO2 to enhance oil recovery through mechanisms such as miscibility and viscosity reduction. These mechanisms facilitated a greater displacement of oil and gas within the reservoir, allowing for more efficient extraction of resources. In contrast, the production only case lagged behind, with a cumulative gas production of 4.1991E+6 MSCF. This outcome highlighted the limitations associated with relying solely on natural depletion methods without any gas injection support. The comparison between these two cases illustrated how enhanced recovery techniques, particularly those involving CO2 injection, significantly improved overall production outcomes and emphasized the potential benefits of incorporating advanced recovery methods in oil extraction operations.

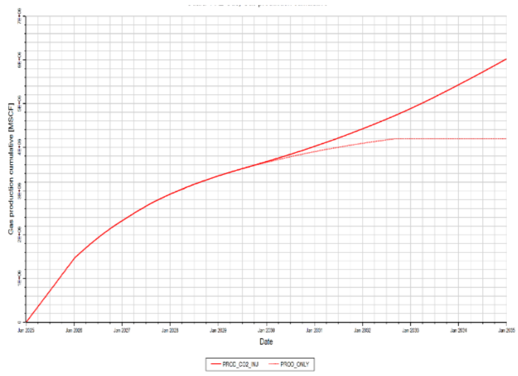

Fig 7 – Gas Cumulative production

C. Cumulative water production

The analysis of cumulative water production revealed significant differences among the various production strategies, highlighting the influence of gas injection on water management within the reservoir. In the case where CO2 was injected, cumulative water production reached 1.281 million stock tank barrels (STB). In contrast, the production only scenario exhibited lower cumulative water production, totaling 1.216 million STB. This difference in outcomes illustrated the natural depletion process that occurred in the absence of any supplementary gas injection support. The findings indicated that the introduction of CO2 not only enhanced oil recovery but also affected the dynamics of water production. The increased cumulative water output in the CO2 injection scenario suggested that gas injection played a crucial role in altering reservoir pressure and fluid flow, thereby influencing overall water management strategies. Meanwhile, the lower water production in the production only case reaffirmed the limitations of relying solely on natural reservoir depletion processes without additional interventions. Overall, these results underscored the importance of incorporating gas injection techniques to optimize both oil recovery and water management in oil reservoirs.

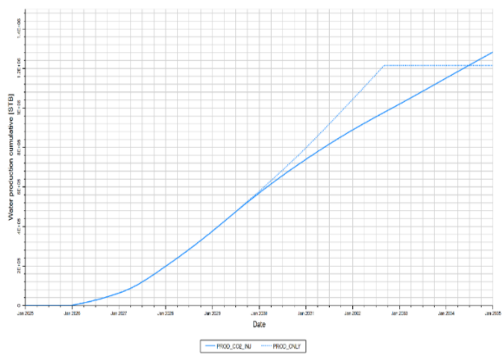

Fig 8 – Water Production Cummulative

D. Gas production rate

The analysis of gas production rates throughout the simulation provided critical insights into the effectiveness of various injection strategies used to enhance hydrocarbon recovery from the reservoir. Over the ten year period, gas production rates displayed a declining trend across all cases, reflecting the natural depletion patterns typical of reservoir dynamics. In the case involving CO2 injection, performance proved to be significantly stronger, with a gas production rate reaching 1,675.4 MSCF/d by the end of the ten years. This elevated production rate suggested that CO2 injection not only improved initial recovery but also sustained higher levels of gas output over time. The enhanced performance was likely attributed to CO2's ability to maintain reservoir pressure and improve fluid flow characteristics. Mechanisms such as miscibility and viscosity reduction played crucial roles in facilitating this process.

Conversely, the production only case experienced a notable decline, with gas production dropping to just 396.66 MSCF/d before ceasing operations at 7 years and 8 months. This stark contrast highlighted the limitations of relying solely on natural reservoir pressure and underscored the advantages of employing CO2 injection as a means to optimize hydrocarbon recovery. Overall, the findings reinforced the importance of selecting appropriate injection strategies to maximize production efficiency in oil and gas reservoirs.

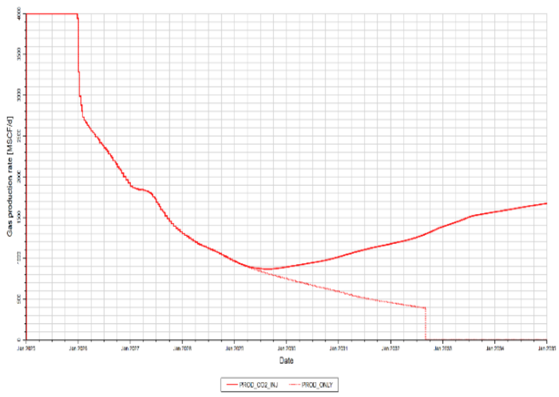

Fig 9 – Gas production rate

E. Water cut

The water cut analysis provided essential insights into the performance of the various production strategies employed in the study, particularly concerning the management of produced water alongside hydrocarbon recovery. In the case of CO2 injection, a distinct trend was observed. Initially, this method recorded an all time high water cut of 0.55034; however, by the end of the ten year period, it stabilized at a lower value of 0.29693. This reduction in water cut after approximately four years and six months indicated that CO2 injection likely enhanced the efficiency of oil recovery while effectively mitigating excessive water production. This improvement can be attributed to CO2's ability to maintain reservoir pressure and increase oil mobility, allowing for a more favorable extraction process.

In contrast, the production only case demonstrated a continuous increase in water cut, which reached 0.77945 before concluding at seven years and eight months. This upward trend highlighted the limitations associated with natural depletion methods, where rising water production often resulted from reservoir pressure decline and inadequate management strategies. The findings underscored the challenges faced in conventional oil recovery techniques, emphasizing the need for more effective approaches to balance hydrocarbon extraction with produced water management. Overall, the analysis illustrated how different production strategies can significantly impact both oil recovery efficiency and water management in oil fields.

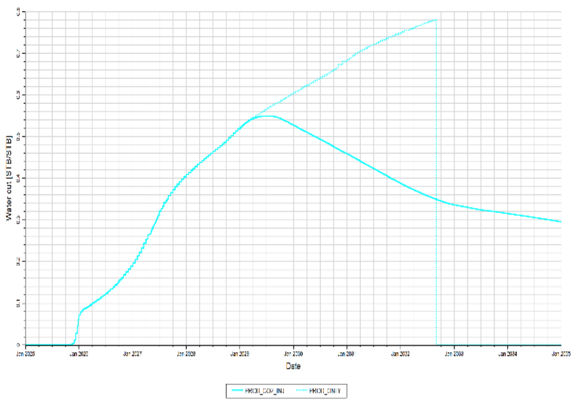

Fig 10 – Water cut

Discussion

The results of this study on enhanced oil recovery (EOR) in gas field XYZ reveal significant insights into the effectiveness of CO2 injection compared to conventional production methods. In figure 6, the Bottom Hole Pressure (BHP) analysis demonstrated that while both strategies experienced initial pressure declines due to natural reservoir depletion, the CO2 injection case exhibited remarkable resilience, maintaining a stable BHP of 1000 psi throughout the simulation period. This stability is crucial as it indicates that CO2 injection not only mitigates pressure drop but also enhances oil recovery potential by improving fluid mobility within the reservoir. While in figure 7, the cumulative gas production results further underscore the advantages of CO2 injection, with a total of 6.03E+6 MSCF produced compared to just 4.1991E+6 MSCF from the production only method. This disparity highlights CO2's role in mobilizing hydrocarbons through mechanisms such as miscibility and viscosity reduction, which facilitate more efficient extraction processes. Additionally, the cumulative water production analysis revealed that CO2 injection resulted in a higher cumulative water output (1.281 million STB) than the production only case (1.216 million STB), suggesting that gas injection influences not only oil recovery but also water management dynamics within the reservoir. The gas production rates corroborated these findings, with CO2 injection sustaining a higher rate of 1,675.4 MSCF/d compared to a decline to 396.66 MSCF/d in the production only scenario, further emphasizing the efficacy of CO2 in optimizing hydrocarbon recovery over time. Lastly, in figure 10 the water cut analysis illustrated how CO2 injection improved recovery efficiency while mitigating excessive water production, stabilizing at a lower value of 0.29693 after four years and six months, in contrast to the increasing trend observed in the production only case. Collectively, these results highlight the critical advantages of incorporating CO2 injection techniques in EOR operations, demonstrating their potential to significantly enhance oil recovery while effectively managing produced water in oil reservoirs.

V. CONCLUSION

This study demonstrated that CO2 injection is a highly effective method for enhancing gas recovery in gas field XYZ, significantly outperforming conventional production techniques. The analysis revealed that CO2 injection not only maintained reservoir pressure but also improved the overall efficiency of hydrocarbon extraction while managing produced water effectively. The results indicated a substantial increase in cumulative gas production and a favorable reduction in water cut, underscoring the advantages of implementing advanced recovery methods in oil fields. These findings contribute valuable insights into sustainable practices within the oil industry, suggesting that CO2 injection can play a crucial role in maximizing resource recovery while addressing environmental concerns related to greenhouse gas emissions.

VI. RECOMMENDATION

Based on the findings of this study, several recommendations can be made for future research and practical applications in enhanced oil recovery. First, it is advisable to conduct further field trials to validate the simulation results and optimize CO2 injection parameters under varying reservoir conditions. Additionally, integrating advanced monitoring technologies could enhance real time assessment of reservoir behavior during CO2 injection operations, allowing for timely adjustments to maximize recovery efficiency. Furthermore, exploring hybrid approaches that combine CO2 injection with other enhanced recovery techniques may yield even greater improvements in hydrocarbon extraction. Finally, policy frameworks should be developed to encourage the adoption of CO2 EOR practices, promoting both economic benefits and environmental sustainability within the oil industry.

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