International Journal of Atmospheric and Oceanic Sciences
2018; 2(2): 27-34
http://www.sciencepublishinggroup.com/j/ijaos
doi: 10.11648/j.ijaos.20180202.12
ISSN: 2640-1142 (Print); ISSN: 2640-1150 (Online)

Review Article

Investigation on the Water-Alternating Gas Oil Recovery Potential Based on Injection Well Location for the Albertine Oil Reservoir, Uganda

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To cite this article:
Marembo Micheal, Asasira Sonia. Investigation on the Water-Alternating Gas Oil Recovery Potential Based on Injection Well Location for the Albertine Oil Reservoir, Uganda. *International Journal of Atmospheric and Oceanic Sciences.* Vol. 2, No. 2, 2018, pp. 27-34.
doi: 10.11648/j.ijaos.20180202.12

Received: November 24, 2018; **Accepted**: December 13, 2018; **Published**: January 22, 2019

Abstract: Uganda is naturally endowed with vast resources ranging from oil to precious stones including diamond among others. Venturing into exploration and development of these resources has recently taken a center stage. Currently, the Ugandan oil reservoir located in the Albertine region, Western Uganda has only been appraised and production has not begun. This study uses standard correlation equations, field analogs, and compares with existing literature to predict the future oil recovery potential of the Albertine reservoir using water flooding and water-alternating gas (WAG) as the enhanced oil recovery methods using Carbon dioxide as the injection gas. Field analogue results indicate that the oil recovery factor during primary production is 8% to 15% while the oil recovery factor during secondary production ranges from 18.2% to 62%. Simulation results show an oil recovery factor of 9.81% and 36.85% during primary and secondary production respectively. The optimum well location is 800ft from the producer with an oil recovery factor of 36.85%. Well location has an effect on over all oil recovery factor and higher recovery factor is achieved when the injection well is 800 ft from the producer. Water flooding yields 31.67% of the original oil in place (OOIP) while Carbon dioxide yields 62.30% of OOIP. When WAG injection process is preceded by waterflooding, the oil recovery factor is 5.57% higher than when WAG process is preceded by Carbon dioxide injection.

Keywords: Injection Well Location, Water Alternating Gas Injection, Primary Production, Secondary Production, Oil Recovery Facto, Conventional Reservoir

1. Introduction

Uganda is naturally endowed with vast resources ranging from oil to precious stones. Venturing into exploration and development of these resources has recently taken a center stage. According to the ministry of energy and mineral development, Uganda has an estimated oil reserve of 6.5 billion barrels of oil with speculations of even more and services including health, electricity, and education are expected to improve [1]. However, of that aforementioned quantity, only 1.4 to 1.7 billion barrels are subject to extraction with anticipation that more will be harnessed in the near future. The oil field lies in the Albertine graben region (Lake Albert basin) and covers an area of about 500 kilometers long and 45 kilometers wide and the formation is mainly mesozoic-cenozoic rift basin [2]. The field is strategically located in Uganda's western region near the democratic republic of Congo and stretches to Lake Edward in the south, and borders with South Sudan in the north. The term graben is used to mean a depressed crust of the earth's surface lying between two geological fault lines which depicts the most intensively surveyed Ugandan sedimentary basins [3]. The oil reservoirs in Uganda range from conventional to heavy reservoirs and are deposited in the fluvial and unconsolidated sands with excellent reservoir properties [4, 5]. Figure 1 shows the geographical location of the Albertine graben reservoir.

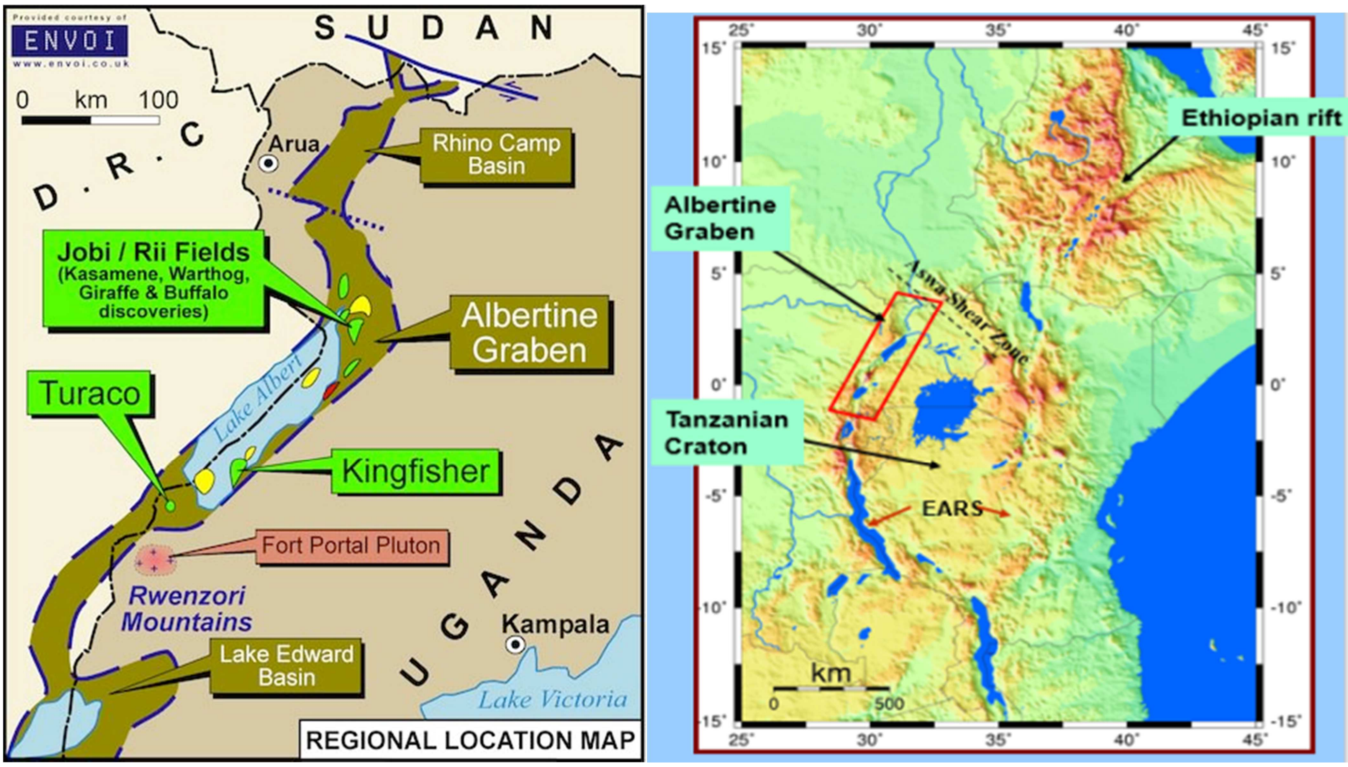

Figure 1. *Geographical location of the Albertine graben.*

Currently, the Ugandan oil field located in the western region has only been appraised and no production has begun. According to the ministry of energy and mineral development, production is anticipated to begin in the year 2020. Uganda National Oil Company Limited signed a Memorandum of Understanding (MoU) with China National Offshore Oil Company (CNOOC) to work together to start a partnership in exploration in the Albertine Graben [6]. Source rocks from the sampled wells in the oil fields indicate low amounts of S2 and TOC and hydrogen index ranging from 88.2 to 414.3 mgHC/gTOC [7]. To effectively ensure optimum reservoir production based on high recovery factor output, it is paramount to predict the behavior of the reservoir performance under primary depletion and water injection. A host of researchers have used field analogous parameters, Empirical equations, and numerical simulations to predict the oil recovery factors for Ugandan oil fields during the primary and secondary production stages respectively [4]. The primary recovery factor obtained from field analogs ranges between 5% and 15% [4]. However, there is not enough literature published about the effect of well location on oil recovery factor for Ugandan oil fields after primary production. None of the studies have effectively predicted the future oil recovery potential of the Albertine basin based on enhanced oil recovery techniques like WAG.

This study investigates the recovery potential of WAG based on injection well location. According to the United States environmental protection agency, 2017, not only is an injection well used to place fluid underground deep down geologic formations but also is used for preventing salt water intrusion. Usage of injection wells began in the 1930s as a way of disposing off the produced brine during oil production. Since then, a number of injection wells have been used to improve oil recovery, to store carbon dioxide, and to dispose of waste. Optimizing the design of the injection well location from the producer well for improved oil recovery has not only been an economic point of view but also a primary goal in improving efficiency. Understanding the flow mechanism of the injected water enables optimization of the injector location for a reservoir needing pressure support [8]. Well location optimization plays a critical role in maximizing recovery and involves robust design procedures and expected ultimate recovery is also important in quantifying the recovery factors [9, 10]. The optimum injector location for most situations is halfway between the pattern center and the down dip producer row [11]. Field development optimization planning of well locations with reservoir uncertainty poses many difficulties [12]. First waterflooding is carried out following primary production and the injection wells are varied at different locations. After determining the optimum injection well location, WAG process begins. The WAG process involves two cases. Case 1 involves preceding the WAG injection process with waterflooding while case 2 involves preceding the WAG injection process with Carbon dioxide. WAG injection is effective as gas typically has greater microscopic sweep efficiency and water has better macroscopic sweep efficiency [13]. Carbon dioxide has proved successful to enhancing oil recovery in majority of the conventional reservoirs [14, 15]

2. Methodology

2.1. Existing Methods to Estimate the Oil Recovery Factor

Advanced screening method has been used for recovery mechanism identification [16]. It is anticipated that, once production begins in 2020, the precision of recovery factor narrows and analytical methods like material balance are used. As production goes on, the decline curve analysis gives a useful option for analyzing the recovery factor range. The available methods for estimating the recovery factors are summarized in table 1. Table 2 summarizes the main recovery mechanisms for each respective stage of production. Since the Albertine reservoir is still in appraisal stage, the recovery factors for both the natural energy and the water flood are obtained based on field analogs and standard empirical correlations [17]. Part of the petrophysical data of the rock data for the rock and fluid properties obtained during the exploration stage. Furthermore, the published petrophysical data of the rock is utilized and compared with other similar reservoirs around the world to obtain a close to perfect set of data to use in conducting numerical simulation [18]. The data is then run in the commercial simulator CMG IMEX to validate the results obtained. The simulation involves a 15-year natural energy production period. During this time, the oil recovery is monitored with respect to the declining natural drive pressure. Water injection process is then simulated, and the oil recovery noted. The injection well locations are varied with respect to the producer well location to determine their influence on overall oil recovery factor and the injected water volumes. The water volumes would help estimate the amount of water to be used in future and the right injection pressures thereby reducing on the total water treatment costs. To maintain the pressure during the waterflood, the abandonment pressure is set equal to the initial reservoir pressure. From the empirical equations, the oil recovery factor during the waterflood is obtained as below based on Arps Equation

$$RF = 0.549[(\frac{\phi(1-s_{wc})}{B_{oi}})^{0.0422}(\frac{k\mu_w}{\mu_{oi}})^{0.0770}S_{wc} - 0.1903(\frac{p_i}{p_a})^{-0.2159}] \quad (1)$$

From the above equation, the input points for Albertine oil field for permeability (k), initial water saturation (S_{wc}), formation thickness, viscosity for water and initial oil (μ_w and μ_{oi}), formation volume factor (B), and porosity (Φ) are obtained from the published data and standard data for reservoirs showing similar trend to the Ugandan fields [4].

Tables

Table 1. *Oil recovery determination methods.*

During the initial (Appraisal) stage	During the production stage	Computational approach
Field analogy.	Decline curve analysis (Hyperbolic, exponential, and harmonic) (Forest and Grab, 1987)	Numerical simulations (can be used during the appraisal and production stages)
Statistical analysis based on empirical correlations and advanced screening.	Decline curve analysis (Hyperbolic, exponential, and harmonic) (Forest and Grab, 1987)	Numerical simulations (can be used during the appraisal and production stages)
Volumetric methods	Material balance equations (Muscat's and Turner's methods) (Forest and Grab, 1987)	Sophisticated methods

Table 2. *Main recovery mechanisms.*

Primary recovery	Secondary recovery	Tertiary recovery
Gravity drainage	Water injection	Thermal recovery (Continuous steam injection, cyclic steam injection, in-situ combustion, hot water injection, steam assisted gravity drainage)
Solution gas drive	Air injection	Chemical recovery (Polymer flooding, alkaline-surfactant-polymer flooding, alkaline-polymer, surfactant-polymer, micellar flooding)
Natural water influx	Hydrocarbon gas injection (CH_4) (immiscible and miscible)	And others
Compaction drive	Non-hydrocarbon gas injection (N_2, CO_2)	
Combination drive	Water alternating gas (WAG), Surfactant alternating gas (SAG), Nano alternating gas (NAG)	
	And others	

2.2. Estimation of the Oil Recovery Factor for the Albertine Reservoir Using the Standard Data Bases

Advanced screening approach which uses data mining and statistical methods, can be used to predict the trends and patterns for large databases [19]. A host of researchers have used advanced screening to determine the permeability within the sandstone reservoirs that have electrofacies [20]. These help determine the ultimate oil recovery for a reservoir that is still in the appraisal stage like for the case of the Albertine field. The advanced screening uses database processing, principal component analysis, cluster analysis, and classification tree analysis to establish the platform for determining the oil recovery [21]. For this study, only the database processing is used to establish and estimate the oil recovery factor for the Albertine oil field. The reservoirs around the world having similar characteristics like for the Albertine reservoir are used as reference points as shown in table 3 below. Several databases are used since a single database would not have complete reservoir information. The filtering mechanism is developed to come up with a better suit for the Albertine reservoir. The online digital analogue knowledge system, the tertiary oil recovery information system, and the oil and gas journal databases are used to compile the necessary information. The database parameters are compared with the Albertine properties to establish the range of suitable parameters and thereby the range of the possible oil recovery factor.

Table 3. *Reference database for estimation of the Ugandan Albertine oilfield recovery factor.*

Field	Country	T ^{0}F	P_i, psi	K, mD	μ_o cp	Φ%	API-gravity	RF%	Mechanism
Lanwa	India	149	1610	5000	550	29	13	11.5	Strong aquifer
Nasser	Libya	170	2457	1500	4	22	39	38.6	Strong aquifer
Suizhon	China	145	2074	2600	70	32	16	22	Weak aquifer
Pewitt Ranch	USA	120			16	24	19	36	
Suffield	Canada	82	1424	1000	97	26.5	14	22	Strong aquifer
Emlichheim	Germany	95	1200	6000	175	30.0	24.5	20	

2.3. Reservoir Description and Numerical Simulation

Having obtained the data for the Albertine oil field from literature and the accessible databases coupled with correlations, the next step is to validate the obtained recovery factor through a numerical reservoir simulation. The reservoir considered is a conventional type reservoir with the parameters as reflected in table 4 below. The reservoir is first produced based on the natural energy of the reservoir for a period of 15 years. The injector well and the producer well are located at strategic positions to yield the maximum oil output. The area of the reservoir is 400000ft^2. The grid block width in the I direction is 1000ft and the grid block width in the j direction is 400ft. The total number of layers are 3 while 50 and 20 blocks are considered in the I and J directions respectively. The rock fluid properties are obtained using correlations for the sandstone and conglomerate water wet sandstone properties as shown in table 5. During depletion stage, the producer has a flowing bottom-hole pressure of 100 psi. For the injection period, the forecast time is 30 years. Initially the injector is placed at a distance of 1000 ft from the producer as shown in figure 2. The reservoir depth is 400ft, the initial reservoir pressure is 520 psi, and the water-oil contact is at a depth of 510 ft while the gas-oil contact is at a depth of 400 ft. The reservoir is predicted to operate under initial primary depletion of 15 years. The primary production enables identify the exact time when injection should be initiated. Water injection will begin after a few years of primary depletion to maintain the pressure of the reservoir. The symbol I is for the injector and the symbol P is for the producer. D is the distance between the injector and the producer. Hence the order is P0ID implying, the injector is at a distance D from the reference point of the producer. To perform the WAG process, the CO_2 and Water injection wells are located in the same position. The WAG injection process is useful in determining the full-scale oil recovery factor at the field level. Case one involves injecting water first prior to beginning the WAG process while case two involves injecting the Carbon dioxide first prior to beginning the WAG process. The two cases are then compared with each other and results are deduced.

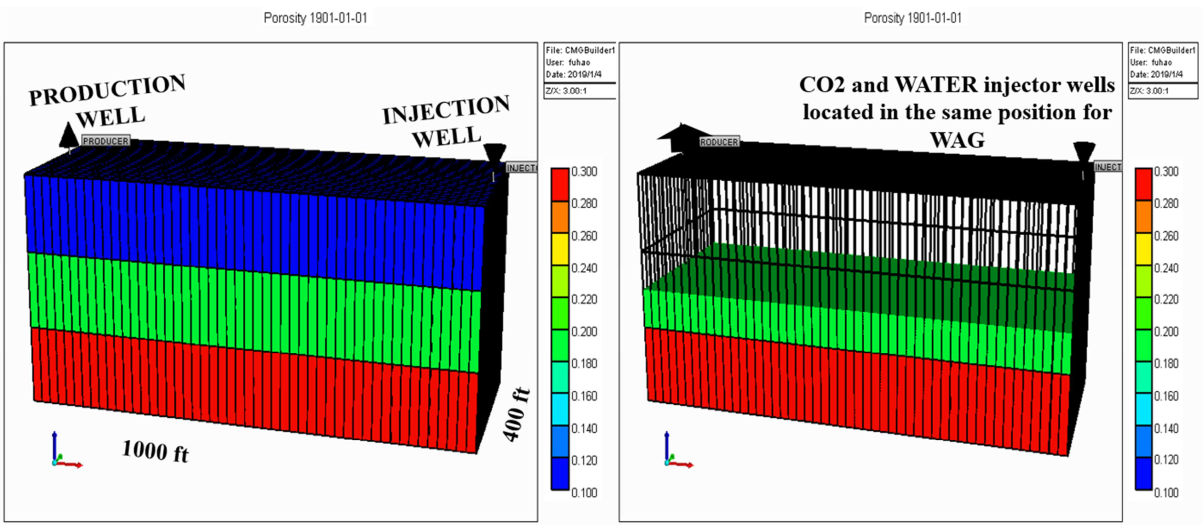

Figure 2. *Location of the injector and the producer.*

Table 4. *Petro physical rock properties.*

Parameter	Value	Range
Porosity	0.1, 0.2, 0.3	
Permeability I, J, K (md)	1000, 1000, 100	
Injection rate, STW (bbl/day)	1000	
Initial reservoir pressure (psi)	520	0-3000
BHP, Producer (psi)	100	
Reservoir depth (ft)	400	
Reservoir thickness (ft)	64	
Reservoir temperature (^{0}F)	90	
Bubble point pressure (psi)	200	
Gas density (gravity API)	0.9	
Reference pressure for water properties	14.965	
Water salinity	10000	
Water-Oil contact (ft)	510	
Gas-Oil contact (ft)	400	
Producer well location	1 10 1: 3	
Injector well location	50 10 1: 3	

Table 5. *Rock fluid correlation factors.*

SWCON	0.2
SWCRIT	0.2
SORW	0.2
WORG	0.1
SGCRIT	0.1
KRGCL	0.8
POR	0.3
PERMI	100

3. Results and Discussions

3.1. Results

During secondary production, the obtained recovery factor for the Albertine reservoir range between 18.2% and 62% while the field analogs show a recovery factor of 8% to 15% during the primary production. Table 6 shows the parameters from the filtered databases that tally with the Albertine oil field parameters as obtained during the exploration and appraisal phase. During the primary production, the oil recovery factor is 9.81% as shown in figure 3. This simulated oil recovery has a 1.1% error variance from the field analogs of 8% to 15%. Implying the simulated results have a positive correlation with the field analog results. Figure 4 shows the recovery factor when water injection process begins. The oil recovery suddenly raises from 9.81% to about 36.85%. This implies that analyzing the well location with respect to the producer well would yield the optimum oil recovery factor which is the main concern of this paper. Figure 3 shows the comparison of oil recovery factor during the primary and secondary production stages. While figure 4 shows the daily oil production rates during primary and secondary production. The oil recovery is low when the injector is at a distance of 60 ft from the producer at 9.81% and increases to 36.85% when the distance is increased to 800 ft from the producer. Figure 5 illustrates the effect of injection well location with respect to the production well on oil recovery factor. Implying that, placing the injector far away from the producer leads to increased oil recovery. However, a distance far away from the producer like 1000 ft leads to a low recovery implying the injection well should not be placed too far away from the production well. Table 7 shows the position of the injector with respect to the producer while table 8 shows a comparison between the simulated oil recovery factor based on the well location. A comparison with the calculated oil recovery factor using the empirical equations is conducted to determine the optimum well location from the producer. From the simulation results, the injection well should be placed at 800 ft from the producer since the simulated recovery factor of 36.85% when the injection well is located 800 ft from the producer is within the range of the calculated recovery factor using the empirical equations. The oil recovery factor using the empirical equations for secondary production is distance is 18.2% to 62%. The hydrocarbon pore volume pressure decreases tremendously during the primary production and secondary production to 105 psi and 190 psi respectively. Figure 6 shows the comparison between hydrocarbon pore volume during primary and secondary production. The WAG injection procedure was conducted based on two case studies. Case 1 involved preceding the WAG injection process with water flooding, while case two involved preceding the WAG injection process with CO_2 injection. Secondary water injection proceeded by WAG injection was conducted on field scale as shown in figure 7 and figure 8 respectively. Figure 7 shows that there was a steady rate of oil recovery for a certain period of time beyond which any increase in water injection would not significantly cause a change in oil recovery factor. The oil recovery factor for the water injection was 31.6% of the original oil in place (OOIP). When WAG was proceeded by water injection, CO2 injection was carried out for two days followed by water flooding. Figure 8 shows that there was faster rate of oil recovery than for mere water flooding process. Tertiary WAG injection resulted in additional oil recovery of close to 24.67% of the OOIP. CO_2 injection yielded a maximum oil recovery of 62.3% of the OOIP as shown in figure 9. The WAG process after CO_2 injection yielded an oil recovery of 19.1% as shown in figure 10 which was lower than when the WAG process was preceded by waterflooding. Figure 11 shows the comparison of the oil recovery factor of the two cases.

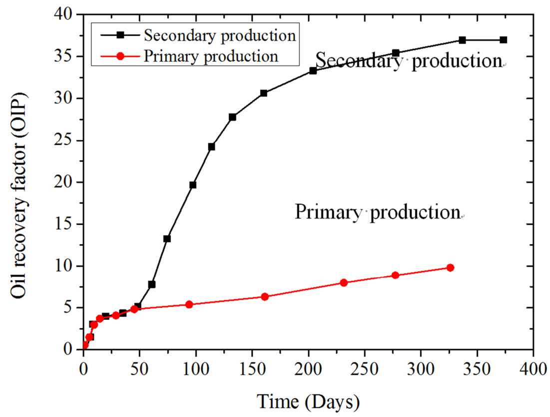

Figure 3. *Comparison of Oil recovery factor during primary production and secondary production.*

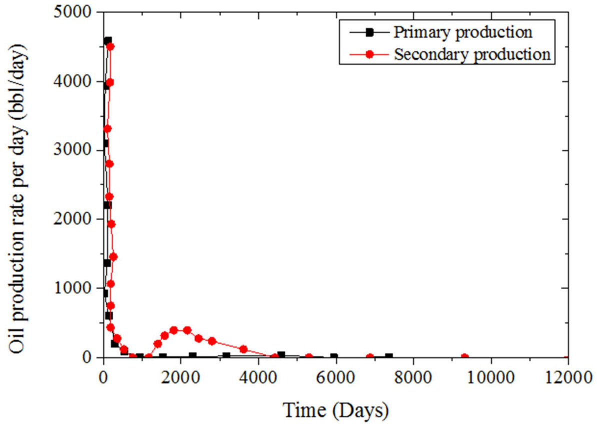

Figure 4. *Comparison between daily oil production rate for primary and secondary production.*

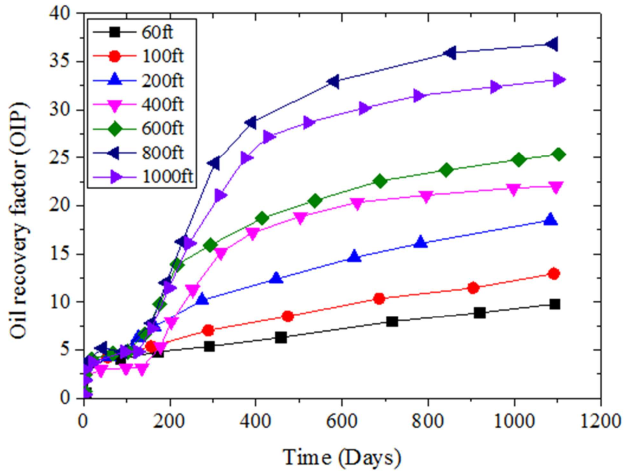

Figure 5. *Effect of the injector well position from the producer on oil recovery.*

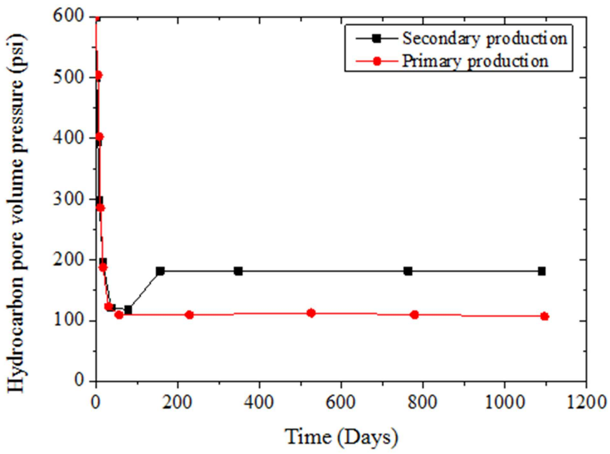

Figure 6. *Hydrocarbon pore volume comparison during primary production and secondary production.*

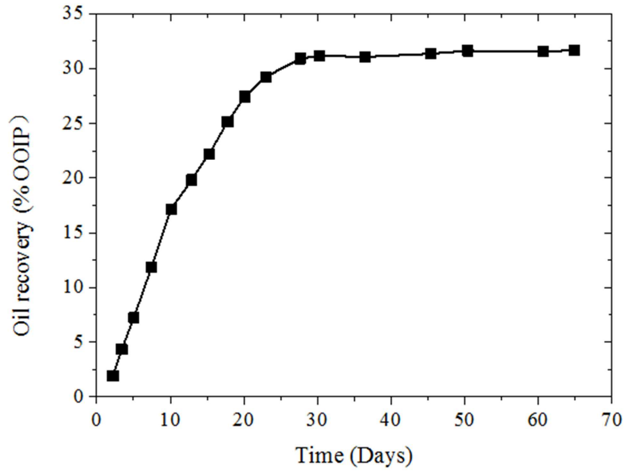

Figure 7. *Oil recovery against time during secondary water injection before WAG injection process.*

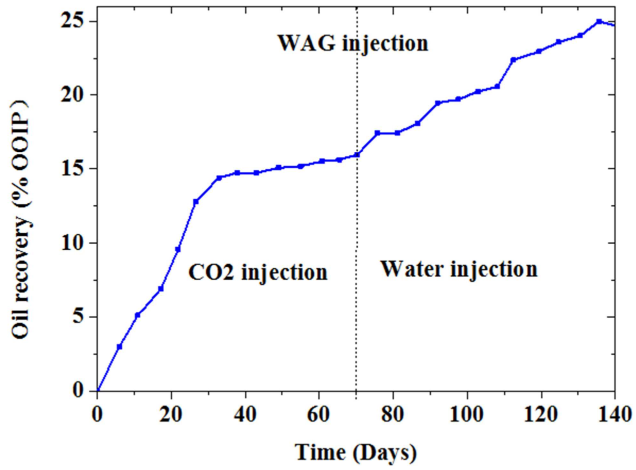

Figure 8. *Oil recovery against time for the WAG injection process after waterflooding.*

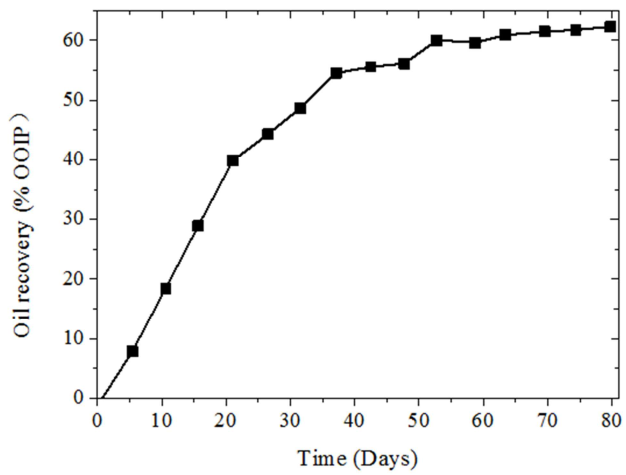

Figure 9. *Oil recovery factor against time during CO_2 injection before the WAG injection process.*

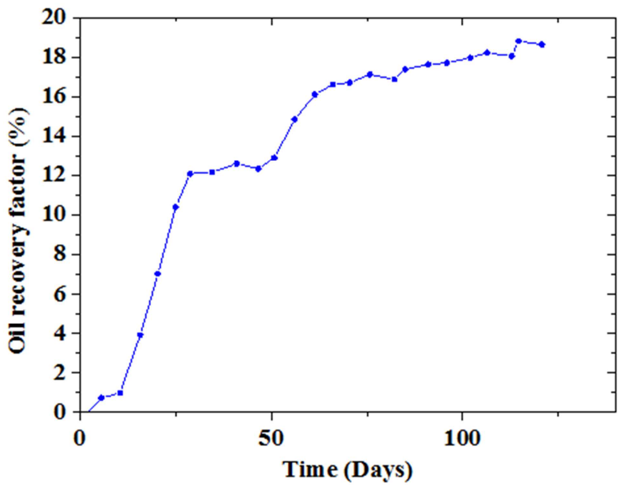

Figure 10. *Oil recovery factor against time for the WAG injection process after CO_2 injection.*

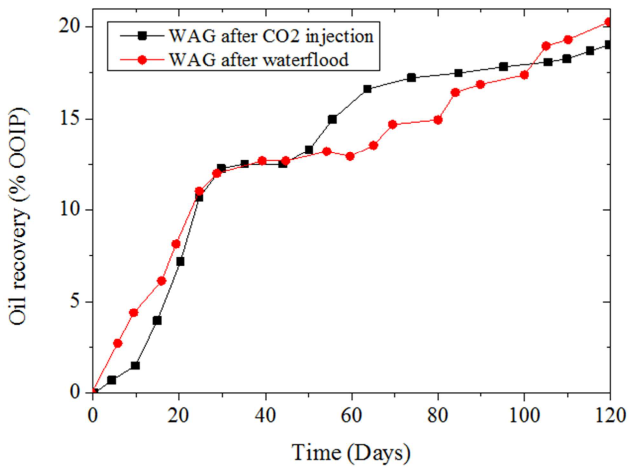

Figure 11. *Oil recovery factor against time for the WAG injection cases.*

Table 6. *Developed database for the Albertine oilfield parameters.*

Parameter	Filtered value range	Mean
Pressure (psi)	80-2907	2500
Permeability (mD)	1000-7000	2000
Viscosity (cp)	3-600	10
Temperature (°F)	62-250	100
Porosity (%)	20-42%	30
API Gravity	9-47	20

Table 7. *Position of the injector with respect to the producer.*

Injector distance from the producer, ft	Oil recovery factor,%
P0I60	9.81
P0I100	12.69
P0I200	18.52
P0I400	22.04
P0I600	25.37
P0I800	36.85
P0I1000	33.15

Table 8. *Comparison of the simulated oil recovery factor based on well location and the known database oil recovery factor from other conventional oil fields.*

Well location, ft	Simulated RF,%	Calculated RF from empirical equations for water injection
P0I60	9.81	18.2% - 62%.
P0I100	12.69	18.2% - 62%.
P0I200	18.52	18.2% - 62%.
P0I400	22.04	18.2% - 62%.
P0I600	25.37	18.2% - 62%.
P0I800	36.85	18.2% - 62%.
P0I1000	33.15	18.2% - 62%.

3.2. Discussion

There is good response between the simulated results and the recovery prediction methods. The study analyzed the influence of the injection well location through a series of varying distances from the producer. The traditional two-well system was adopted since the Albertine reservoir is not on a large scale, however, future studies should focus on well pattern optimization. Placing the injection well extremely far from the production well would not yield high oil recovery factor since there would be non-uniform sweep. Well optimization has a direct influence on oil recovery factor. The result of the additional oil recovery when WAG is preceded by waterflooding is higher at 24.67% than when WAG is preceded by carbon dioxide injection at 19.1%. This is mainly due to the effects of gas trapping that limits gas flow and enable the oil to flow through the pore spaces with the aid of waterflooding leading to improved oil recovery. Waterflooding yields lower oil recovery than carbon dioxide injection because, due to the low interfacial tension between gas and oil, the gas injection that followed waterflooding displaces more of the oil from the small pore throats hence enhancing microscopic sweep efficiency and improving overall recovery.

4. Conclusions

The oil recovery factor for the Albertine oil field in Uganda has been predicted. Several databases were used to compare with the petro physical properties of the oilfield in Uganda. Field scale waterflooding and Carbon dioxide injection coupled with WAG injection process have been compared and the following observations are summarized.

1. The oil recovery factor from the field analogs is between 8% and 15% while the calculated oil recovery factor using water as the injection fluid for the empirical correlation equation is between 18.2% and 62%. The simulated oil recovery factor during primary production is 9.81% and the optimum oil recovery factor due to well location is 36.85%. Field analogs data is suitable for estimating the oil recovery factor for an oil reservoir still in the appraisal stage like for the case of the Albertine oil field.
2. Oil recovery factor predicted using numerical simulation tallies with the obtained oil recovery factor from the empirical correlations. Water injection

recovers more oil than the primary production and would be the immediate solution after depletion. Well injection location has a huge effect on oil recovery factor. High recovery factor is obtained when the injection well is located far away from the producer well. This enables more sweep.

3. Both secondary water and carbon dioxide injections yield good recovery factors of 31.6% of the OOIP and 62.3% of the OOIP respectively. The additional oil recovered due to WAG injection preceded by waterflooding was 12% OOIP higher than when WAG was preceded by carbon dioxide.
4. Further research should focus on other EOR methods like SAGD, Gas injection, well pattern, and others.

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