FIELD DEVELOPMENT PLAN USING RESERVOIR SIMULATION FOR TASOUR OIL FIELD, BLOCK 32, Say'un- Masilah Basin, Yemen

1-Salem Hussein Ahmed Algarbi, 2-Abdulrahman Ali Naji Alsharif, 3-Patil Dhananjay, 4-Dr.Rohan Kumar

Department Of Petroleum Engineering, School Of Chemical Engineering and Physical Science, Lovely Professional University, Punjab, INDIA

Abstract

Field development planning entails a significant amount of investment and a large range of criteria relating to the reservoir's geological and structural features, operational scheduling, and economic scenario. The significance of this issue necessitates the development of methodologies that can aid in management decision-making, resulting in better recovery strategies that increase both reserves and production and the reservoirs' viability.

The aim of this research is to use reservoir simulation to establish a field development plan for the Tasour field in order to achieve technically and canonically high oil recovery.

The Hadramaut region in south-central Yemen is home to the Block 32 development area. adjacent to the productive Nexen/Occidental Masila fields, which have total reserves of $1.5 billion. a billion and a half barrels . Block 32 was awarded to Clyde Petroleum in For the next ten years, he had a succession of partners[12].

Introduction

The discovery of Tasour oil field following over 1500 km of 2D seismic and 5 dry holes, the discovery was made in late 1997. The locality is characterized by a dendritic drainage pattern of jebels (plateaus) that is highly dissected. Wadis (valleys) interfering between gently dipping block-faulted Say'un-Masila basin sediments from the Jurassic, Cretaceous, and Tertiary periods[3].

OOIP Estimation for Tasour Field was done using two methods (Volumetric method and Monte Carlo simulation) in the beginning of this research, and different techniques were used to forecast Tasour field results, including Decline curve analysis and Monte Carlo simulation. Mathematical simulation, with development forecasted until 2024. The data was analyzed using Microsoft Excel 2013 and MBAL Software, and the DCA model was identified as a hyperbolic model[4].

The history matching was done to test the reservoir model before using it for forecasting, and it was found that the overall field output and accuracy of the history matching were satisfactory. The simulation forecast for the base case then worked well Eclipse 100 software was used. Depended on the results of base case forecast which ended at APR 2024 Different field development scenarios examine the prospect of improving oil recovery by infill drilling of producers and injectors.

To assess the best scenario, four simulation runs were performed in accordance with the study's objectives. Production wells with both vertical and horizontal well geometry, as well as injection wells, are among the scenarios. The first scenario (Case 01) The second scenario was generated by adding two vertical output wells to the base case. (Case 02) was created by combining two vertical and horizontal output wells. The first scenario (Case 01) has been applied to the base case. The third scenario (case 03) came to fruition by adding two horizontal wells to the foundation, which were added in the second scenario (Case 02) in this case. The final situation is (case 04) After analyzing the 3D grid for the third scenario (Case 03), we'll find a new optimal position for a horizontal production well (X8) in an un-swept region with good oil saturation and pressure, as well as one water the injection well) .(T-7INJ) to complete the project increase oil recovery and pressure help[5].

The optimum scenario for Tasour Field development plan,which has the highest oil recovery and demonstrates favorable economics, included new wells in addition to wells that were added in the third scenario to the base case in comparison to the other possibilities.

Methodology

This chapter discusses the procedure of using the analytical analysis strategies to achieve the objectives of the research project. Also, it will illustrate the type of data and procedures used to predict hydrocarbon reservoir performance for an optimum field advancement plan[6].

Data Type Required:

Different data will be collected and used to conduct better reservoir performance analysis to optimum field development technique for the Tour field. The data needed can be summed up as the following:

- Geological, Geophysical and Petro physical Data.
- Well logs data.
- PVT Data.
- Reservoir Rock Data (SCAL and RCA).
- Wells Production History Data.
- Wells Injection History Data.
- Pressure data[7].

Table: 1. Data Required for Reservoir Performance Analyses.

Method	Required Data
Volumetric Method	**Reservoir Area. Reservoir Thickness. Reservoir Porosity. Reservoir Saturation. Reservoir Formation volume factors**
Monte Carlo Simulation	**Area and Thickness (Bulk Volume). Net Gross Ratio. Porosity. Saturation. Relative Permeability. Rock Compressibility. PVT Data.**
Decline Curve Analysis	**Field Production Rate History.**

Field development plan

The optimal strategy of field development plan will be conducted with the highest net present value based on the findings of the reservoir output review mentioned in chapter four. The various field development scenarios investigated the possibility of improving oil recovery through infill drilling of producers and injectors, as well as conversion oil out production, to carry out the Tasour field development plan, The best scenario was determined after four simulation cycles[8]. For each case, the simulation run ended on 01-APR-2024. For this project, Schlumberger's ECLIPSE simulator was used. ECLIPSE is a three-phase, three-dimensional Black Oil simulator that is widely used in the industry. With the aid of an active aquifer, a history match to historical measurements was achieved. In addition, the high water output profile indicates that the aquifer is involved. As a result, it was decided that an aquifer should be used in future simulations[9,10].

Tasour Field Development Scenarios:

First Scenario (Case 01):

Case 01 is a straightforward development strategy that includes two additional producer wells (X1 and X2) in addition to the base case.

Table:2 shows the location and date of the addition of new vertical and horizontal wells.

Well Name	Adding Time	Location			
		I	J	K	K
X1	Feb 2009	66	16	1	10
X2	Oct 2009	80	19	1	6

Second Scenario (Case 02):

The recovery factor can be increased by adding one vertical and one horizontal output well to the base case in the development strategy, as seen in the first scenario (Case 01). In this scenario, we will expand the area by adding one vertical and one horizontal output well (X3, X4) to the base case, which were introduced in the first scenario (Case 01).

Table 3. New vertical and horizontal wells location and time of adding

Well Name	Adding Time	Location			
		I	J	K	K
X3	Mar 2010	57	16	16	16
		58	16	16	16
		59	16	16	16
		60	16	16	16
X4	Sep 2010	45	13	1	7

Third Scenario (Case 03):

The recovery factor can be increased by adding two horizontal output wells to the base case in the development plan, as seen in the second scenario (Case 02). In this scenario, we can expand the area by adding two horizontal wells (X5, X6) to the base case, which were introduced in the second scenario (Case 02).

Table:4. New vertical and horizontal wells location and time of adding

Well Name	Adding Time	Location			
		I	J	K	K
X5	Apr 2011	73	15	2	3
		74	14	2	3
		75	13	2	3
X6	Nov 2011	93	22	1	2
		94	23	2	2
		95	22	2	2

Table:5. New vertical and horizontal wells cumulative production

Well Name	Cum. Oil Rate (STB)	Cum. Water Rate (STB)
X1	312,736.90	**38,453,263.00**
X2	424,396.90	**36,640,601.00**
X3	588,038.26	**50,851,963.00**
X4	541,284.18	**34,185,715.00**
X5	581,312.41	**46,908,685.00**
X6	532,475.47	**44,817,526.00**

Fourth Scenario (Case 04):

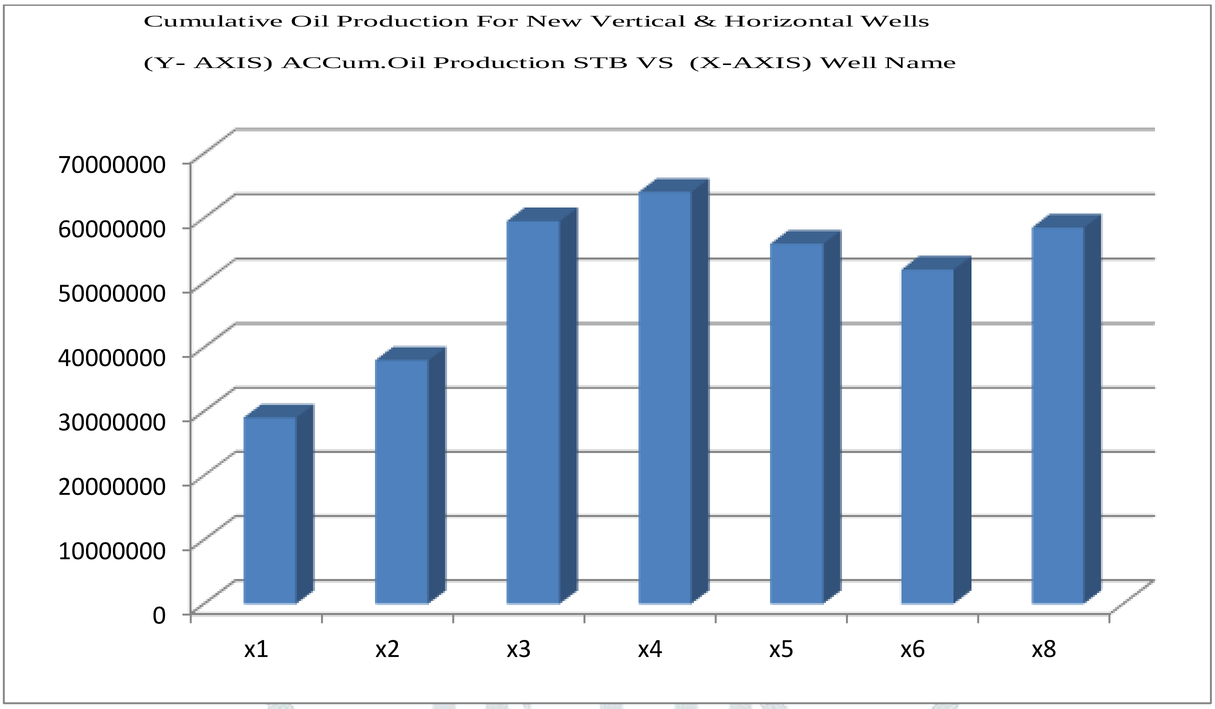
We will pick a new optimum position for a horizontal production well (X8) in an un-swept region with strong oil saturation and pressure, as well as one water injection well to pressure support and improve oil recovery, after analysing the 3D grid for the third scenario (Case 03).The new wells, in addition to the wells that were added to the base case in the third scenario (Case 03).

Well Name	Adding Time	Location			
		I	J	K	K
X7INJ	Feb 2010	78	23	1	5
X8	Apr 2010	126	23	1	2
		125	23	2	4
		124	23	4	6
		123	23	6	8

Table:6. New horizontal production well and injection well location and time of adding

The oil recovery was aided by reservoir pressure and water injection, as the total oil output for the field reached 45.497 MMSTB, with a recovery factor of 49.43 percent. The incremental oil generated by four horizontal, three vertical, and one water injection wells was estimated to be 3.778 MMSTB. The difference in combined oil output from both sources was used to assess this; Base case and Case 04 are two examples of cases.

Figure:1. New vertical & horizontal wells cumulative oil production



5.4. Selected Development Plan Scenario:

After implementing four scenarios and analysing the effects, the final scenario, which includes four new horizontal and three vertical output wells as well as one injecting well (T7INJ) for water injection, outperformed the baseline scenario. The final scenario (Case04) is the best in terms of oil recovery as compared to the other scenarios.

5.4 Result and Discussion:

The model's best development strategy indicates that the Tasour Field will produce 45.497 MMSTB by 2024, which is 49.43 percent of the original Oil-in-Place (Case04). In comparison to the Base Case, this example will result in a 4.1 percent increase in recovery. Forecasting case that has been improved (Case 04). The findings will be used to prepare Tasour Field's future growth strategy.

Table:7. Summary of cumulative oil production and recovery factor for all scenarios

Development Scenario	New infill wells	Cumulative oil MMSTB	Recovery factor RF%
Base Case	No infill well	41.719	**45.3**
First Scenario (Case01)	2 Vertical wells	42.389	**46**
Second Scenario (Case02)	3 Vertical wells and 1 Horizontal well	43.544	**47.3**
Third Scenario	3 Vertical wells	44.715	**48.58**

(Case03)	and 3 Horizontal wells		
Fourth Scenario (Case04)	3 Vertical wells, 4 Horizontal wells and 1 water injection well	45.497	**49.43**

Conclusion:

1-The OOIP of Tasour Field measured using a simulation model (Eclipse software) was 92.043 MMSTB, while the results from two additional methods (Volumetric process and Monte Carlo simulation) were (95.824 MMSTB and 93.656 MM STB, respectively)

Based on the results of the reservoir performance study, four scenarios were explored to see whether infill drilling of producers and injectors could increase oil recovery:

a. The first scenario (case 01) is a straightforward development strategy that adds two vertical producer wells (X1& X2) to the base case, with a recovery factor of 46%.

b. The field was built in the second scenario (case 02) by adding one horizontal well (X3) and one vertical well (X4) to the base case, with a recovery factor of 47.3 percent in this case.

c. The third scenario (case 03) established the field by adding two horizontal wells (X5, X6) to the base case, which were added in the second scenario (Case 02), with a recovery factor of 48.58 percent.

d. In the fourth scenario (Case 04), the field was formed by drilling one horizontal well (X8) in an un-swept region with good oil penetration and pressure, as well as one water injection well (X7INJ) to support the pressure support applied in the third scenario (Case 03), with a recovery factor of 49.43 percent.

e. Finally, the last scenario (Case04) is the best scenario in terms of oil recovery and net present value as compared to the others.

f. Case 04 Predictions show that drilling the proposed wells would result in a 3.778 MMSTB incremental recovery until APR 2024.

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