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A Simulation Case Study for Different Scenarios of Pressure Maintenance to Revive Oil Production From Nukhul Reservoir at East Zeit Oil Field

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Abstract

This paper describes a simulation study for pressure maintenance in the Nukhul reservoir of the East Zeit Field, offshore Gulf of Suez, Egypt. Results of a black-oil reservoir simulation study have been used as the basis for evaluation of pressure maintenance project alternatives. Different operating scenarios have been examined for their efficiencies in terms of recovery. Alternatives considered are: (1) Base case (continued natural depletion) (2) recompletion using gas shut-off (3) infill wells (4) water injection (5) gas injection (6) simultaneous injection of gas and water. Production is mainly derived from solution gas drive. The study concludes that gas injection into the crest of the reservoir will be the most efficient pressure maintenance program. Water injection and other production scheme would be less efficient and show low oil recovery.

Keywords: simulation, secondary recovery, pressure maintenance, gas injection, water injection, gas shut-off.

1. Introduction

East Zeit field is an offshore oil and it is one of many fields lies on B-Trend, located in the southern area of Gulf of Suez about 80 Km north of Hurghada city - Egypt. East Zeit Concession is bounded to the North by Sidki field and to the South by Hilal field (GUPCO's fields) (Figure 1). East Zeit field was discovered by GUPCO (The Gulf of Suez Petroleum Company) in 1976. The field was later put on production in 1985 by ESSO Company, the operator of the Offshore East Zeit Contract Area, on behalf of its co-ventures and KNOC (Korea National Oil Corporation , is a six -partner joint venture[1,2]. Since field production start-up in October 1990, 18.507 MMSTB oil or about 27.59 % of the Nukhul East reservoir original oil in place has been produced. The reservoir pressure has declined from 5342 psia initially to about 1657 psia in November 2007, various pressure maintenance alternatives have been examined to arrest reservoir pressure decline and to optimize the ultimate oil recovery of the Nukhul East reservoir. This work presents prediction results of the Nukhul East reservoir simulation model using a three-dimensional, three-phase, black-oil simulator. Conceptual design of each pressure

Fig. 1. Location map of East Zeit field.

maintenance alternative is described. The Nukhul East reservoir description and performance history are presented first.

2. Reservoir Description

East Zeit reservoir is located in the East Fault block of the Nukhul structure, which is a horst adjoined by the F4 and F6 fault blocks as shown in Figure 2. These blocks, which all contain productive reservoirs, are separated by well-defined faults.

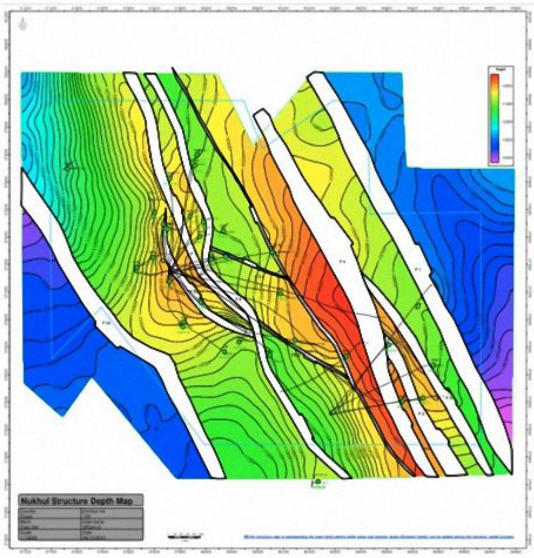


Fig. 2. Top Nukhul depth structural map.

There is a good correlation between porosity versus permeability derived from cores (the available cores only from well B-1). This data was utilized to generate porosity-permeability and horizontal-vertical permeability cross plots so that permeability can be distributed in the 3D model as a function of porosity and vertical permeability as a function of horizontal permeability. The following plots (Figure 3 &4) show the cross plots of porosity-permeability and Kv-Kh in all reservoirs. The porosity and permeability are almost good, averaging 7% and 124 md, respectively. Overall lateral continuity of the Nukhul reservoir is judged to be very goad and it is fully communicated as shown from pressure performance as shown in Figure 5[3].

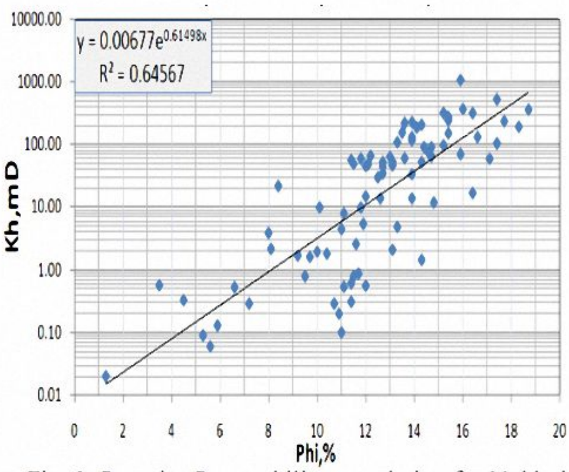


Fig. 3. Porosity-Permeability correlation for Nukhul EFB well B-1 core.

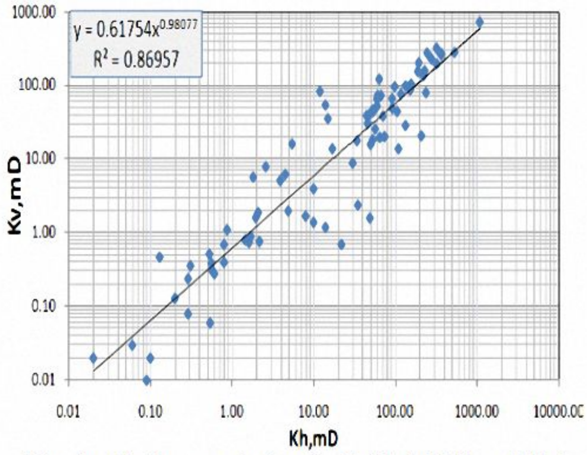


Fig. 4. Kh-Kv correlation for Nukhul EFB well B-1 core.

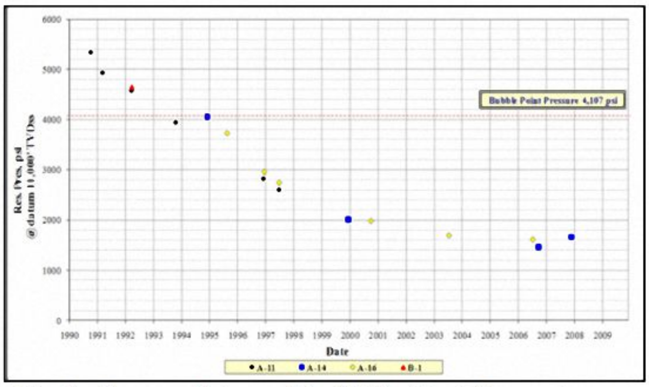


Fig. 5. Pressure history of the Nukhul East Reservoir.

The Nukhul East reservoir is characterized by 3 rock types after applying the concept of rock typing was used to sub-divide the reservoir into hydraulic flow units for better understanding of variation of rock quality and identifying the range of each rock type in terms of rock quality (porosity and permeability). The best well in terms of petrophysical interpretation quality was chosen in Nukhul reservoir to be used in the rock typing definition. Logs of effective porosity, permeability, Flow Zone Indicator (FZI), resistivity and water saturation were used to establish the best classification of the ranges and number of rock types as a base to define both the initial saturation and the fluid flow behavior as shown in Figure 6&7[4-6].

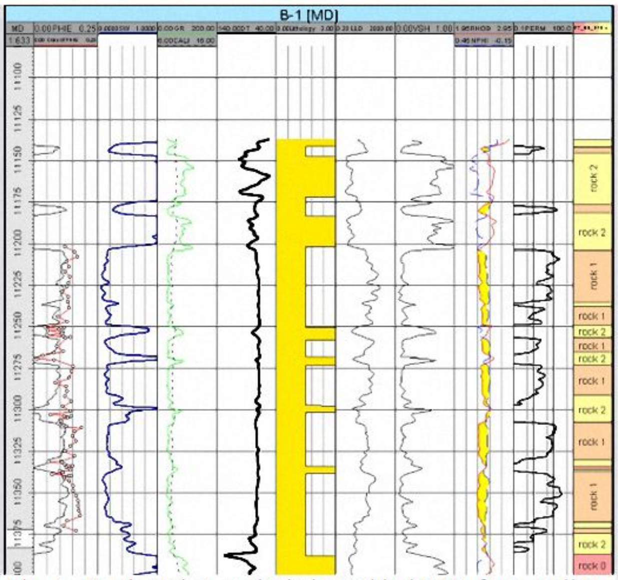


Fig. 6. Rock typing analysis in Nukhul EFB from well B-1.

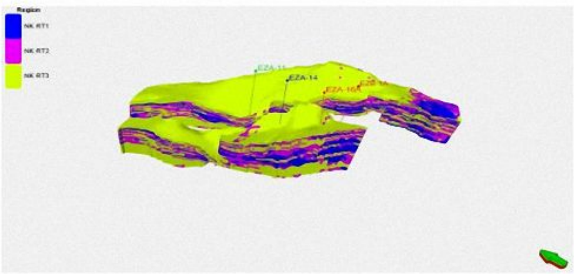


Fig. 7. Rock typing in Nukhul EFB.

The available samples were averaged and smoothed using SCAL software to be properly used in the dynamic model as shown in Figure 8.

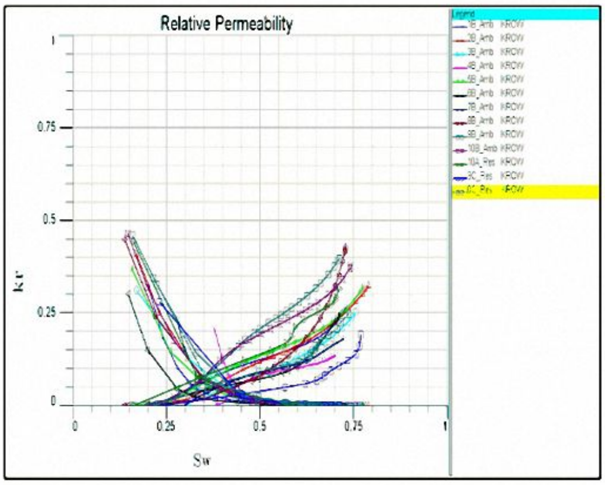
The residual oil saturation (Sor) was determined for each rock type as a function of initial water saturation (Swi) from the available core plugs for Nukhul reservoir. Using horizontal end point scaling option, a curve was created for each rock type with varying initial water saturation (Swi) and residual oil saturation in water (Sor) as seen in Figure 9.

Table 1: Water saturation from SCAL report vs. rock typing.

Rock Type	**Porosity**	**Sw (Rock Typing) *Used in model initialization,%***	**Sw (SCAL Report),%**
1	> 10 %	15.8	17.2
2	6 – ≤ 10 %	26.1	27.8
3	≤ 6 %	41.5	37.8

An integrated analysis of observation data (RFT data, logs) and pressure gradient calculation indicate fluid contact for Nukhul East Reservoir at -11045 ft TVDss as Oil Down To (ODT) obtained from A-11 logs which is not seen a clear WOC in the reservoir. A Water Up To (WUT) level was recorded from well GS 392-2 at -11370 ft TVDss. The field's OWC lies in the interval from -11045 to -11370 ft TVDss as shown in Figure 10.

Fluid properties determined from laboratory experiments. Analysis of the chemical and physical characteristics of a recombined surface sample was carried out by EPRI Laboratories, as the sample was taken from well A-11, about 3 years after the reservoir came on stream, it is considered to be representative of the original reservoir fluid. The laboratory evaluation of the fluid showed that the Nukhul reservoir is undersaturated at its initial pressure of 5342 psia. A bubble point pressure of 4107 psia was determined. Figurers 11-14 and table 2 show the used PVT in the simulation model[7-8].



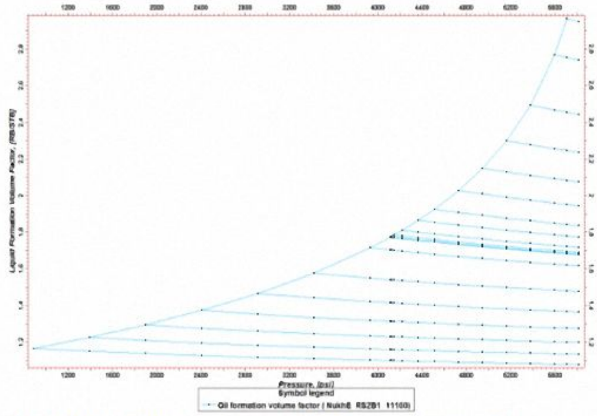


Fig. 11. Oil formation volume factor versus pressure for dynamic model.

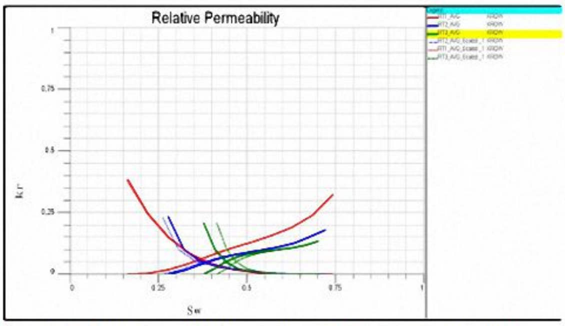


Fig. 9. Oil-water relative permeability – end point scaling for different rock.

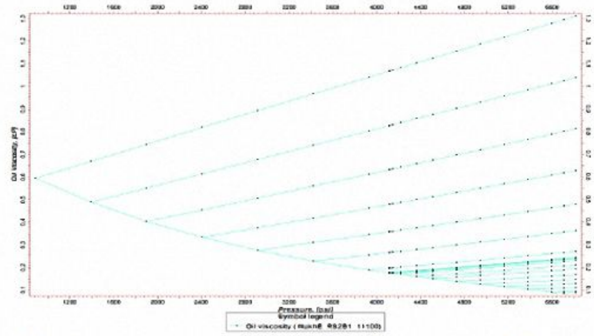


Fig. 12. Viscosity versus pressure for dynamic model.

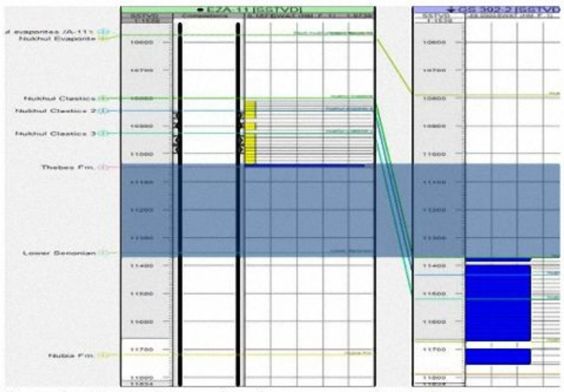


Fig. 10. OWC determination uncertainty since no contact was observed of any wells.

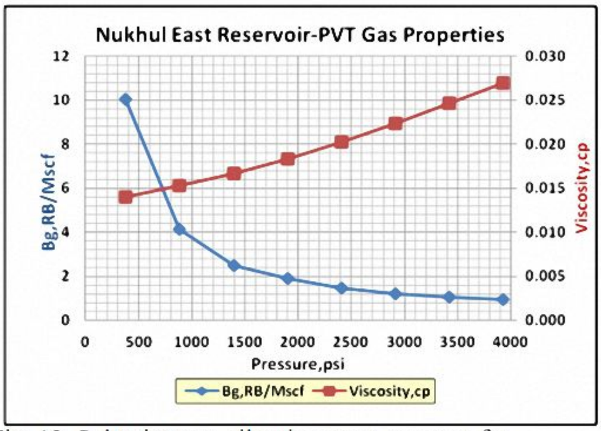


Fig. 13. Soluation gas-oil ratio versus pressure for dynamic model.

Table 2: Water properties data for Nukhul Reservoir.

Pressure, psia	βw,rb/STB	Cw,psi^{-1}	μ,cp	ρ, Ib/ft^3
5342	1.0686	3.93E-06	0.18634	62.428

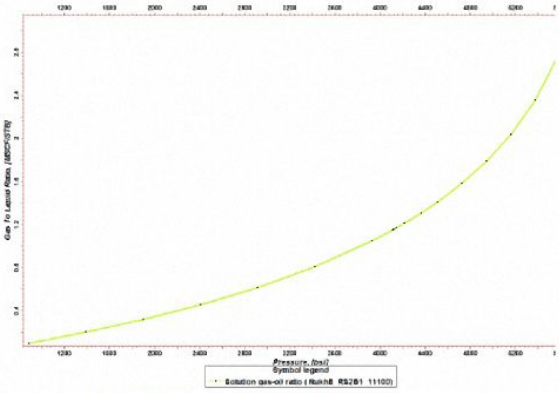


Fig. 14. Nukhul EFB Reservoir -PVT gas properties.

3. Reservoir Performance History

Figure 5 shows static pressure surveys were taken from four wells (wells A-11, A-14, A-16A and B-1) shown that these wells are fully communicated. An RFT job was conducted for well B-1A in March 1992. The job results showed pressure depletion in the reservoir and the formation of a secondary gas cap as a result of well A-11 production as shown in Figure 15. On March 2007, the Nukhul East fault block reservoir had produced 18.507 MMSTB, 38.68 BSCF gas, but only 0.248 MMSTB water as shown in Figure 16. , representing some 27.59% of its STOIIP of 67 MMSTB. Production comes from 3 wells (A-11, A-14, A-16A) drilled from 1 platform (Platform A). The production rate on October 1990 was 4,500 BOPO, with 1200 SCF/STB GOR and 0 % water cut from well A-11. Well A-14 was put on production in December 1994 followed by A-16A in July 1995. Figure 17 represents the historical gas oil ratio for the 3 producers in A-wells Nukhul field, both well A-11 and well A-14 have the same GOR performance where the GOR ranges 3.5 – 5.5 MSCF/STB. Well A-16A being the shallowest of the three producers was expected to have a similar GOR trend or even higher GOR values as reservoir pressure decreases. The recorded GOR for well A-16A show a different GOR behavior starting from mid 2000 as GOR starts decreasing.
Field water-cut rose to its maximum of 20% in July 2006 from well A-14 only and Well A-16A not produced water anymore. As mentioned from cumulative water production & water cut values this reservoir is solution gas drive because there is not any water influx support.

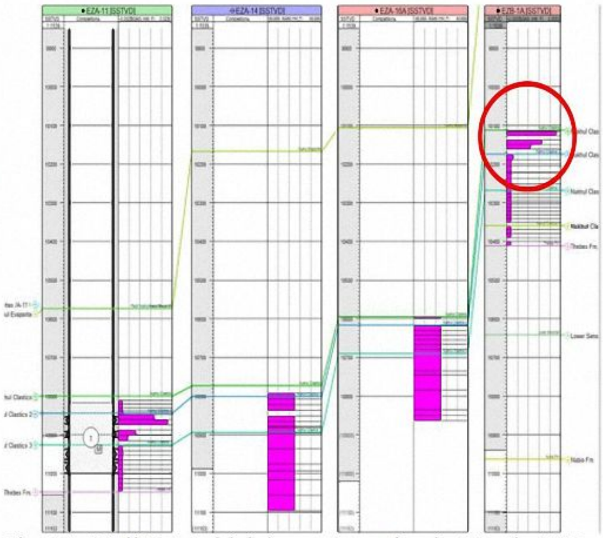


Fig. 15. Well B-1A (right) gas saturation in March 1992.

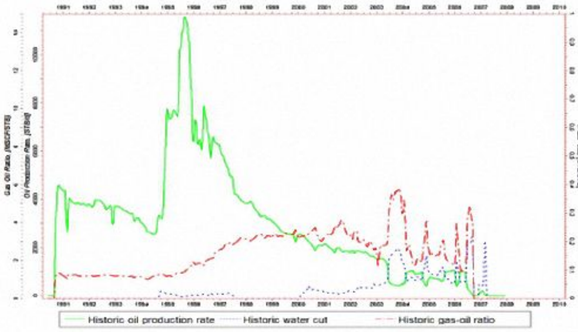


Fig. 16. Field historic production performance.

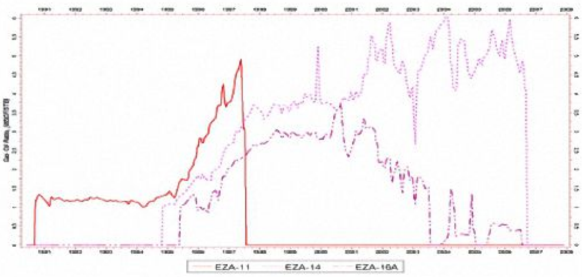


Fig. 17. Historic GOR of well A-11, A-14 and A16A.

4. Model Construction

4.1 Selection of Simulation Tool

ECLIPSE-reservoir simulation software (from SCHLUMBERGER) can simulate reservoirs using several secondary recovery scenarios. Choice of the proper simulator to represent a particular reservoir requires an understanding of the reservoir and a careful examination of the data available. ECLIPSE offers multiple choices of numerical simulation techniques for accurate and fast solutions for all kinds of reservoirs and all degrees of complexity-structure, geology, fluids and development scheme [9].

4.2 Model Design and Description of Selected Area

A Cartesian three dimensional three-phase, black-oil model has been developed for this simulation study. Figure 18 shows a three dimensional ECLIPSE grid model with the well locations, based on many sensitivity runs on the simulation grid the following model dimensions are the optimum dimensions for simulation running time. The model has the following specifications:
Model dimensions are (24*131*26)
ΔX=50 ft, ΔY=50 ft.
Total number of cells =143,052 cell
ΔZ depends on the unit formation thickness.

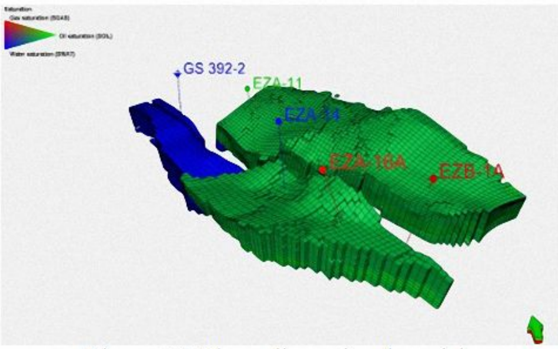


Figure 18: Three dimensional model.

5. Model History Matching

Reservoir pressure history matching was done by modifying the permeability, Kv/Kh ratio, cell pore volume (uncontrolled area) as shown in Table 3; change Rs versus depth and OWC level.

To match the gas and production, relative permeability data and inter cell cross flow were adjusted. This was done by modifying the shape of the relative permeability curve for each rock type. The relative permeability data were adjusted locally surrounding well A-11. In addition to the initial three rock regions based on relative permeability adjustment [10-12].

Table 3: A-Wells Match Parameters Summary.

Parameter	Min. value	Max. Value	Used Value
Permeability Multiplier	5	80	10
K_v/K_h Ratio	0.0001	0.1	0.01
Fault	0	1	1
Pore Volume	0.8	1	Cut from
OWC	-	-	-11100

The OWC was used as a match parameter during the matching phase. The final OWC was a result after several sensitivity runs is identified -11100 ft TVDss. Well A-16A has started production in July 1995. The recorded GOR started to decrease since October 2001. Figure 19 shows a well section for wells A-14 (left) and A-16A (right). The expected GOR performance for well A-16A should be higher or at least equal to the GOR values recorded from well A-14 in the case both wells are communicated. The pressure behavior for the initial match results showed higher reservoir pressures than the observed data, which indicates larger volumes than the actual reservoir volumes. Figure 20 shows the cut segments from the uncontrolled areas to achieve the reservoir volumes that simulate reality. After cutting those segments, the initial STOIIP in the matched model became 67 MMSTB. Actual oil rate was input into the model on a monthly basis. The next plots show the final results of the history match of A-Wells model. For the producing wells, A-11, A-14 and A-16A, the upper left curve shows the measured oil rate (dark green points) and calculated oil rate (light blue line). The upper right curve shows the water-cut observed (blue points) and calculated water-cut (blue line). The lower left curve represents the GOR observed (red points) and calculated GOR (red line). While the lower right curves shows observed static pressure points (red dots) and the calculated well static pressure (black line), as shown in Figures 21-23.

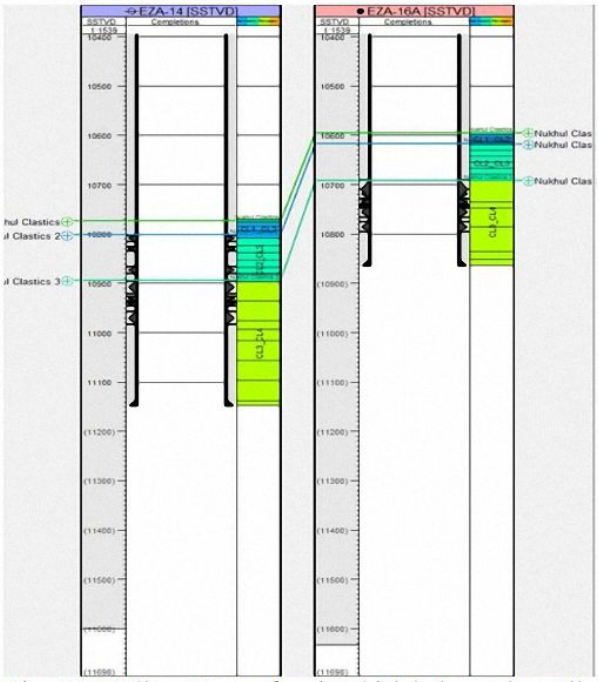


Fig. 19. Well A-16A perforation (right) shows the well has higher structure.

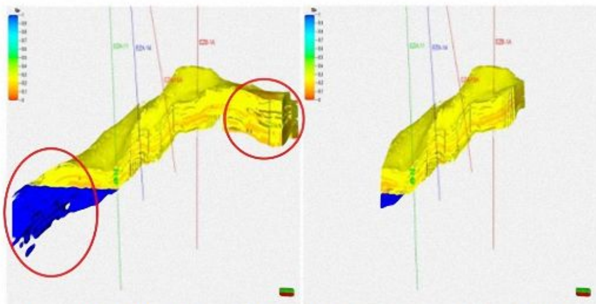


Fig. 20. Initial Static Model (left) vs. Final matched Model (right).

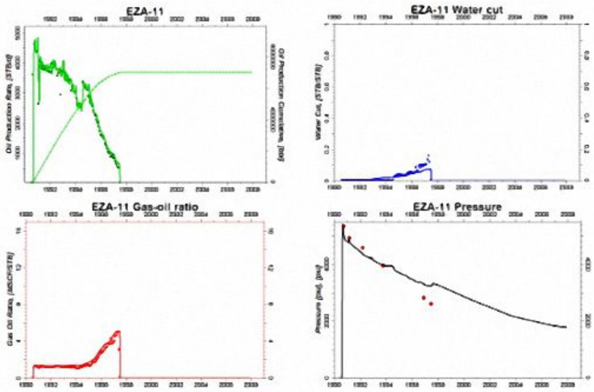


Fig. 21. A-11 match results.

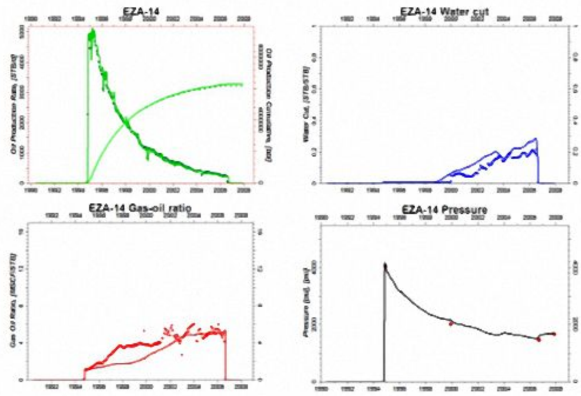


Fig. 22. A-14 match results.

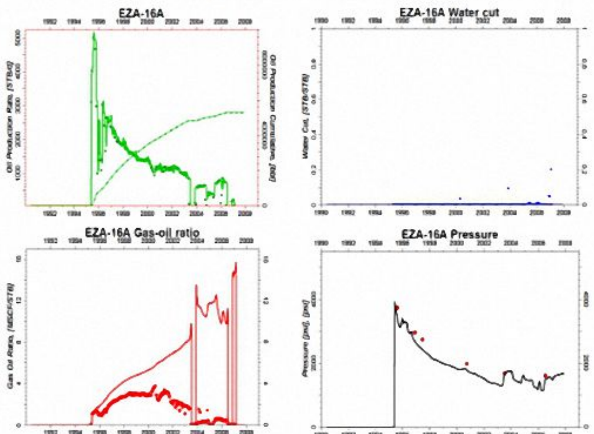


Fig. 23. A-16A match results.

6. Prediction Results

Different pressure maintenance alternatives have been studied to show the effect of different scenarios on reservoir oil recovery to investigate future development and production strategies for the reservoir. The prediction for production scenarios made for four different operating scenarios:

1. A base case scenario in which the existing reservoir production strategy is maintained;
2. Further development of the reservoir using recompletion by applying gas shut-off technique;
3. Further development of the reservoir with infill wells to drain the partially swept areas;
4. Further development of the reservoir using water injection project;
5. Further development of the reservoir using gas injection project.
6. Simultaneous injection of gas and water (WAG).

The benefits of each of the different development strategies were evaluated on the basis of the final oil recovery factor and incremental reserves. In the predictions it was assumed that gas & water source that used in the prediction scenario comes from the East Zeit field production for water &gas phase, regarding to bottom hole pressure, injection pressure, GOR, WC and economic limit constrain is based on field operating conditions and cost per barrel. Pressure maintenance was assumed to start on Jan 2012 to the end of prediction on Jan 2031. The maximum GOR constraints used for prediction are 10,000 SCF/STB for all prediction scenarios. The minimum flowing bottom hole pressure was 500 psig with the maximum injection pressure 5500 psig in all prediction cases. The minimum oil rates for all prediction cases were estimated at 50 BOPD/well. A total of 22 cases were run to evaluate the effects on oil recovery of each alternative due to additional drilling, re-completion (gas shut-off), and various injection rates. Tables 4 and 5 show the prediction results for all cases. A-Wells field has produced till March 2007 with a recovery 27.59%. Since that date all wells were shut down by 2007, a do-nothing prediction run was not performed. A gas shut-off was performed to control the increasing GOR on wells A-11 & A-14. Two cases were tested for the gas shut-off approach. The cumulative oil production from this case was 21.47 MMSTB around 32.01 % recovery factors.

Three side tracks were proposed for well A-11. Three sensitivity cases were run to test the performance of each of the side tracks. But the results of these three cases are unattractive. Pressure maintenance by water injection for the Nukhul East reservoir will not be attractive. The predicted ultimate oil recovery is very low and the investment required is very high. The best water injection alternative result is only 0.17% increase in the ultimate oil recovery. This case calls for one injector and one producer. The maximum injection rate achieved would be 10,000 BWPD during the period of injection. High water cut reached to 90% and low oil production rates 50 BOPD or low pressure in the producer well would limit the ultimate oil recovery of a water injection program. Gas injection into the crest of the reservoir of at least 10MMSCF/D through well B-1 appears to be the best pressure maintenance program considered. Since the gas injection is the best scenario. So, many different scenarios have been tested (optimization runs) to select the best injection rate and the number of injector wells that give high recovery factor. Ultimate oil recovery for the gas injection case with existing producers is 25.07 MMSTB by the year Jan 2031. This is about 9.78 % increase over primary recovery. WAG technique has been tested by injection gas then water alternative through well A-14 by the following rates 10MMSCF/D for gas injection and 10,000 BWPD for water injection .The results of this scenario shown that increase in incremental oil production about 0.94 MMSTB. WAG ration is the ratio of injected water to gas in terms of duration (i.e., the time over which injection takes place) [4-8], whereas 0.9:1 WAG ratio is recommended for oil-wet rocks. Slug size refers to the cumulative of water and gas injected during a WAG. The slug volume is usually expressed as a percentage of the reservoir pore volume [13-17]. Total slug of water and gas is equal to 25% of the pore volume.

7. Results & Discussion

Many runs have been made with Eclipse program for gas shut-off, sidetrack wells, water injection, gas injection and WAG technique and results show the following: From Table 4, it can be seen that the case of gas injection gives the highest recovery compared to other cases. This is attributed to the fact that the wettability of the reservoir is oil wet which is gas injection is the best candidate for this type of reservoirs. This explains the high recovery rate obtained from this method compared to others. The case with gas shut-off also did well. The least is the water injection scenarios.

Table 4: Gas injections from well B-1 and produce from well A-11 & A-14 provided the highest recovery factor compared to other techniques.

Case	End of Production	Incremental Oil Production. (STB)	Recovery Factor,%	Run Name
Base case	1-Mar-07	0	27.59%	Final Match
Gas injection from well B-1 ,produce from well A-11 & A-14	1-Jan-31	3,180,728	32.33%	P_BI_GINJ
Gas Shut-off (A-11& A-14 on production)	1-Jan-31	2,962,708	32.01%	P1114WO
Gas Shut-off (A-14)	1-Jan-31	2,861,962	31.86%	P_WO14
WAG Technique (A-14)	1-Jan-31	943,701	29.00%	P_WI14_WAG
Water Injection (Start production from well A-11 in Jan 2012)	1-Sep-12	113,376	27.76%	P_A11WI14
Water Injection (Start production from well A-11 in Jan 2017)	1-Jun-20	116,916	27.76%	P_A11WI14_2017
A-11 Side Track – ST1	4-Jan-12	1,548	27.59%	P_A11ST1
A-11 Side Track – ST2	4-Jan-12	1,532	27.59%	P_A11ST2
A-11 Side Track – ST3	1-Feb-12	1,110	27.59%	P_A11ST3

After running much sensitivity runs on different gas injection scheme, different well configurations as shown in Table 5 found that case (P_A16_GINJ_5_1500) and (P_B1_A16_GINJ_4_1000) are the best scenarios based on the recovery factor only. The difference between two cases regarding to field cumulative production just 63,091 bbl .So, the decision to decide which scenario can be applicable from both cases is related to management team and the available budget.

Table 5: Optimization runs for gas injection scenarios.

Case Name	Produced Well	Reservoir Fluid Produced Rate, rb/day	Limit. Min BHP (psi)	Injection Well	Surface Injection Rate, Mscf/day	Limit Max BHP (psi)	Add Reserve for A-11 STB	Add Reserve for A-14 STB.	Total Reserve, STB	Field Cumulative Production. (STB)	RF, %
P_B1_GInj	A-11, A-14	500	500	B-1	10000	5500	88,702	3,092,024	3,180,726	21,688,065	32.33%
P_B1_GINJ_1000	A-11, A-14	1000	500	B-1	10000	5500	64,127	6,195,890	6,260,017	24,767,356	36.92%
P_B1_GINJ_1500	A-11, A-14	1500	500	B-1	10000	5500	64,232	5,024,896	5,089,128	23,596,467	35.18%
P_B1_GINJ_8_500	A-11, A-14	500	500	B-1	8000	5500	83,149	3,068,409	3,151,558	21,658,897	32.29%
P_B1_GINJ_8_1000	A-11, A-14	1000	500	B-1	8000	5500	64,170	5,843,713	5,907,883	24,415,222	36.40%
P_B1_GINJ_8_1500	A-11, A-14	1500	500	B-1	8000	5500	57,700	5,029,136	5,086,836	23,594,175	35.17%
P_B1_A16_GINJ_4_500	A-11, A-14	500	500	B-1, A-16	4000 Per each	5500	88,548	3,327,919	3,416,467	21,923,806	32.68%
P_B1_A16_GINJ_4_1000	A-11, A-14	1000	500	B-1, A-16	4000 Per each	5500	63,295	6,499,210	6,562,505	25,069,844	37.37%
P_B1_A16_GINJ_4_1500	A-11, A-14	1500	500	B-1, A-16	4000 Per each	5500	60,055	6,365,417	6,425,472	24,932,811	37.17%
P_A16_GINJ_6_500	A-11, A-14	500	500	A-16	6000	5500	80,890	3,341,167	3,422,057	21,929,396	32.69%
P_A16_GINJ_6_1000	A-11, A-14	1000	500	A-16	6000	5500	64,821	6,152,675	6,217,496	24,724,835	36.86%
P_A16_GINJ_6_1500	A-11, A-14	1500	500	A-16	6000	5500	60,052	6,196,250	6,256,302	24,763,641	36.92%
P_A16_GINJ_5_1000	A-14	1000	500	A-16	5000	5500		6,133,258	6133258	24640597	36.73%
P_A16_GINJ_5_1500	A-14	1500	500	A-16	5000	5500		6,362,381	6,362,381	24,869,720	37.08%

8. Conclusions

The main conclusions from this study are listed below:

1- The STOIIP final figure is 67 MMSTB.
2- The simulated area of A-wells is well communicated.
3- A-11 proposed side tracks exceeded maximum GOR limit (10 MSCF/day) upon production due to the presence in higher structure than A-11's. This case didn't add to the historical production cumulative.
4- Water injection scenario resulted in rapid water breakthrough in A-11. Water injection case added only 0.12 MMSTB. This result is due to that the reservoir is oil wet that has been confirmed by wettability test and relative permeability curves.
5- Gas injection into the crest of the reservoir is the most favorable pressure maintenance program considered in view of oil recovery. Gas injection for well A-16 & B-1 and produce from well A-11 & A-14 results in highest recovery among tested scenarios (added around 6.5 MMSTB over historical production) about 37.17% OOIP of

Nukhul reservoir will ultimately be produced by gas injection compared to 27.59 % OOIP by the end of production at 2007. A separate economic study has been conducted to evaluate prediction scenarios and confirmed that gas injection project is valid economically as shown in table 6.

6- Gas shut-off is the best second scenario comes after gas injection based on recovery factor comparison.
7- WAG technique has been tested and has increase the oil recovery by 29% with WAG ration 0.9:1 and a slug size of 25% of the pore volume.

9. Future Work

1- Investigation of the ability to apply enhanced oil recovery methods to this field.

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Table 6: The result of different gas injection scenarios based on different injection rate and oil price value.

Case Name	Produced Well	Reservoir Fluid Produced Rate,	Injection Well	Surface Injection Rate, Mscf/day	Add Reserve for A-11 STB	Add Reserve for A-14 STB.	Total Reserve, STB	Field Cumulative Production (STB)	RF, %	Oil Price= 90 $		Oil Price= 70 $		Oil Price= 110 $	
										NPV,$	DPI	NPV,$	DPI	NPV,$	DPI
P_B1_GInj	A-11, A-14	500	B-1	10000	88,702	3,092,024	3,180,726	21,688,065	32.33%	101,390,252	8.37	72,583,584	6.28	130,196,920	10.47
P_B1_GINJ_1000	A-11, A-14	1000	B-1	10000	64,127	6,195,890	6,260,017	24,767,356	36.92%	205,549,517	15.95	150,683,488	11.96	260,415,546	19.94
P_B1_GINJ_1500	A-11, A-14	1500	B-1	10000	64,232	5,024,896	5,089,128	23,596,467	35.18%	225,044,708	17.37	165,301,223	13.02	284,788,192	21.71
P_B1_GINJ_8_500	A-11, A-14	500	B-1	8000	83,149	3,068,409	3,151,558	21,658,897	32.29%	98,214,994	8.14	70,202,736	6.11	126,227,252	10.18
P_B1_GINJ_8_1000	A-11, A-14	1000	B-1	8000	64,170	5,843,713	5,907,883	24,415,222	36.40%	101,259,156	8.36	72,485,287	6.27	130,033,026	10.46
P_B1_GINJ_8_1500	A-11, A-14	1500	B-1	8000	57,700	5,029,136	5,086,836	23,594,175	35.17%	218,391,157	16.88	160,312,309	12.66	276,470,006	21.11
P_B1_A16_GINJ_4_500	A-11, A-14	500	B-1, A-16	4000 Per each	88,548	3,327,919	3,416,467	21,923,806	32.68%	107,320,353	8.04	76,654,766	6.03	137,985,941	10.05
P_B1_A16_GINJ_4_1000	A-11, A-14	1000	B-1, A-16	4000 Per each	63,295	6,499,210	6,562,505	25,063,844	37.37%	216,739,313	15.21	158,698,454	11.41	274,780,172	19.02
P_B1_A16_GINJ_4_1500	A-11, A-14	1500	B-1, A-16	4000 Per each	60,055	6,365,417	6,425,472	24,932,811	37.17%	267,631,587	18.55	196,858,110	13.91	338,405,063	23.19
P_A16_GINJ_6_500	A-11, A-14	500	A-16	6000	80,890	3,341,167	3,422,057	21,929,396	32.69%	114,501,304	16.79	84,040,633	12.59	144,961,976	20.99
P_A16_GINJ_6_1000	A-11, A-14	1000	A-16	6000	64,821	6,152,675	6,217,496	24,724,835	36.86%	218,731,507	31.17	162,193,727	23.37	275,269,287	38.97
P_A16_GINJ_6_1500	A-11, A-14	1500	A-16	6000	60,052	6,196,250	6,256,302	24,763,641	36.92%	262,517,179	37.21	195,024,765	27.90	330,009,593	46.52
P_A16_GINJ_5_1000	A-14	1000	A-16	5000		6,133,258	6133258	24640597	36.73%	216,145,348	51.86	161,005,156	38.88	271,285,540	64.83
P_A16_GINJ_5_1500	A-14	1500	A-16	5000		6,362,381	6,362,381	24,869,720	37.08%	263,209,278	62.93	196,294,272	47.19	330,124,284	78.68

Note:
Limit.Min BHP (psi)= 500
Limit.Max BHP (psi)= 5500

Abbreviations

BOPD	Barrel Oil Per Day
BWPD	Barrel Water Per Day
FZI	Flow Zone Indicator
ODT	Oil Down To
OOIP	Original Oil In Place
RFT	Repeat Formation Test
RSVD	Gas in Solution Versus Depth
Sor	Residual Oil Saturation
Swi	Initial Water Saturation
WAG	Water Alternative Gas
WOC	Water Oil Contact
WUT	Water Up To

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