Integrated Field Development Plans of Akkas Gas Field

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Abstract:

Akkas gas field is the biggest natural gas field in Iraq that is located in the western desert area. The field contains around (9 BSCF) of approved gas reserve from the conventional rock source.

This paper presents field development planning process combined with economic analysis comprises, the number of wells that yields in maximum net present value (NPV), the recovery factor and raw gas production rates for the total number of suggested wells that have been estimated, as well as the cumulative gas produced with time.

The development plans were elaborated concerning different types of well geometries and operational constraints. Full comparison analysis for all presented plans regarding NPV, recovery factor, discounted cash flow versus production time, forecasted production rate, as well as forecasted cumulative production with time have been presented.

Sensitivity analysis has been made to determine well and reservoir controlling parameters that leads for best operating field development plans.

The study shows the effectiveness of horizontal well type compared with vertical wells; as well as, the effect of reservoir permeability on field development plans, the results show that the field could be operated at target plateau rates of (250, 500 and 750 MMSCF/D). It also shows the superior effect of stimulation processes in increasing the NPV and field recovery factor using less number of wells

Keywords: Akkas field, Gas field development, Economic analysis.

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الخطط المتكاملة لتطوير حقل عكاز الغازي

الخلاصة:

حقل عكاس الغازي هو أكبر حقل مكتشف للغاز الجاف في العراق، ويقع في منطقة الصحراء الغربية. هذا الحقل يحتوي على حوالي (9) بليون قدم مكعب قياسي من المخزون الغازي المثبت ضمن مصادر الصخور الرملية.

في هذه الدراسة أقترحت العديد من خطط التطويرمقترنة بالتحليل الاقتصادي لتحديد عدد الابار التي تعطي أعلى صافي ارباح أقتصادية، وحساب معامل الاستخلاص و معدلات الانتاج لجميع الابار المقترحة لكل خطة تطوير، كذلك قيمة الانتاج التراكمي.

كما تم دراسة كفاءة الابار الافقية مقارنة مع الابار العمودية، كما بينت خطة بدأ الانتاج في الابار المحفورة مع الوقت أعتمادا على كفاءة فعاليات الحفر والاكمال.

تم تقديم دراسة مقارنة تحليلية شاملة لجميع خطط التطوير لتحديد عدد الابار التي تعطي أعلى صافي ارباح أقتصادية، حساب معامل الاستخلاص و معدلات الانتاج المستقبلية للابار المقترحة لكل خطة تطوير، كذلك قيمة الانتاج التراكمي المستقبلي.

كما تم دراسة حساسية خصائص الابار والمكمن لمعدلات الانتاج والاستخلاص الكلي للمكمن لبيان العامل المؤثر الاكبر في خطط تطوير الحقل. كما بينت الدراسة أمكانية تطوير الحقل بمعدلات أنتاج حقلي (250, 500 و 750 مقمق باليوم). كما بينت أيضا تفوق تائير التنشيط للابار على زيادة صافي الارباح الاقتصادية من خلال زيادة معامل الاستخلاص بعدد آبار اقل.

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1- Introduction:

Akkas gas field is the biggest dry gas field in Iraq, which is located in the western desert area (Al-Anbar) province. The field contains about (9 BSCF) [1] of approved gas reserve from the conventional rock source (Khabour) formation. Moreover, a recent study prevailed that the Silurian hot shale, which is one of the field's formations, may also contains about (4.55 BSCF) of recoverable gas [2]. This field has not been developed because of the country's traditional focus on oil reservoir during the past; but currently, Iraqi authority has paid great attention to utilize this high clean energy for both domestic requirements and support the world demands.

Field development planning comprises a great amount of investments and involves a high number of parameters related to the geological and structural characteristics of the reservoir, to the operational scheduling and the economic scenario. The importance of this study that can help in the management decision making process, leading to better recovery strategies that increase both reserves and profitability of reservoirs.

The use of reservoir simulation is very important to provide reliable production forecast and correct predictions for field recovery potential. During the initial field development phase the amount of available information for the reservoir is very restricted and it is very difficult to obtain a correct reservoir model. Therefore, the use of analytical simulation models provides more appropriate and lead to better results. In this study, advance software technology IHS-Fekete "Evolution" software [3] has been used, the software has full capability to verify different scope plans, forecast different types of well geometry including vertical, inclined, horizontal, hydraulically fractured as well as any combination of these types; moreover, the software has the capability to evaluate the performance of hydraulically fractured gas wells.

This work present technical and economical field development plans, including a robust optimization procedure that uses the production forecasts generated by reservoir optimization for the evaluation of an objective-function (NPV). This methodology helps in the decision making process granting a correct evaluation of relevant parameters in field recovery planning and it provides adequate solutions for any number of runs.

1.1- Field description:

The reservoir is an anticline dome extended along North Western-South Eastern of dimensions (L50*W18) Km at the Northern of Khabour formation which considered the main natural productive zone [1].

The reports of MoO [1] divided this structure into seven sub-layers based on rock types and shale content. The main layers of Akkas field are the (upper Khabour) and (Lower Khabour), which consist of sandstone rocks and contains the biggest quantities of natural gas reserve of this field. The net pay thickness of upper Khabour (129 ft) and for lower Khabour (140 ft), the measured porosity (7.6 % and 9.7 %) for upper and lower Khabour

respectively. While, the average water saturation of upper Khabour (52.5 %) and for lower Khabour (35.6 %).

The report prevailed that the average core permeability around (0.07-1.2 md) for upper and lower Khabour respectively, while the well test analysis shows that the permeability range (3 to 80 md) for vertical and horizontal directions respectively. While, the initial reservoir pressure is 3800 psi, and temperature of 220 F at datum of 2120 m. The shale volume range between (0 – 40%).

2-The stages of development plans:

Three main stages have been implemented in executing successful gas field development plans, which involves (A- Scoping, B- Forecasts and C- Comparison), the following description may give a useful knowledge of each stage:

A- *Scoping:* is one of the procedures that help make the development program so powerful. Scoping is used to input all required reservoir and economic data and run a large number of scenarios quickly and efficiently. *Scoping* is a starting point to evaluate a whole range of scenarios for economically developing a gas field. It gives answers to questions that may raise for "1-How many wells are needed to develop a field, 2-What is the effect of permeability, 3-What type of well or completion - vertical, hydraulic fracture, horizontal, 4-When the wells come on stream, 5- When does drilling another well becomes uneconomic and 6-Project life" [3]

B- *Forecasts:* is where the engineers' takes the knowledge learned from running various scoping analyses and applies a more in depth study to the most likely and/or most productive scoping scenarios. The *Forecasts* allow the engineers to manipulate particular parameters for each individual well placement, well production start time, and well type to help achieve a further assessment and devise a direction for a future development strategy [3].

C- *Comparison:* this section allows seeing all scopes and forecasts currently created in one plot for quick and easy better decision.

The advantages of the presented field's development plans are to establish the (1-the number of wells to be drilled to reach production objectives; 2- the recovery techniques to be used to extract the fluids within the reservoir; 3- the starting time of wells to come on stream; 4- the best location of drilled wells; 5- the reasonable maximum field gas rate; 6- the break number of wells becomes uneconomic; 7- the effects of horizontal on gas production; 8- comparing the effectiveness of vertical wells and horizontal wells; 9- the effect of the horizontal wells length on production; 10- the effect of uncertainties of permeability or net pay on production and 11- the economics of particular development scenarios).

2.2-Reservoir parameters and Economic sensitivity analysis

Implementation sensitivity analyses on parameters such as, the permeability, net pay, skin, surface gas loss, the maximum gas rate, as well as using economics such as gas price, well/facilities costs, drilling cost, and royalties in determining the optimum production scenarios.

The economic sensitivity analysis is very important for a recovery strategy planning, the parameters like gas price that is strongly influenced by technical and political circumstances tend to show significant variations throughout the project life [4]. The use of the advance software tools allows an accurate evaluation of the potential of each alternative comprised in the set of recovery patterns presented by the methodology regarding different feasible economic scenarios, and the objective at this stage of the methodology is to identify the alternatives that present low financial risk and that are less influenced by economic scenario alterations.

In this study, the reservoir data mentioned in field description section, as well as the following economic values of well cost ($ 7 MM), gas compression cost ($ 200/Hp), operating cost ($ 400/well/month), average gas price ($ 3), other variable cost ($ 0.25/MSCF), working interest (80 %), surface gas lost (5%), royalties (2 %) and discount rate (5 %), have been taken in evaluating the plateau targets and the feasibility of the development plans.

3-Work development Plans:

Based on the parameters mentioned in reservoir description section, the material balance calculation of gas recoverable reserves for Akkas field have been estimated around (2.832 BSCF) and (5.191 BSCF) for upper and lower Al-Khabour formations respectively. The total estimate is very close to that announced by both MoO [1] and other technical reports [2].

Line spot pattern has been used in distribution wells location either vertical open hole or horizontal wells, with an equal lateral section length from (500 - 3000 ft) parallel to reservoir length. The vertical wells have been assumed penetrating the entire Khabour formation, with the perforations have been taken place within the upper and lower Khabour intervals only. While, the horizontal wells are assumed penetrating the two intervals using bilateral horizontal sections.

The study assumed no gas condensate may occur during production; moreover, no production comes from the hot shale (Sullirian) zone, which needs special technology to produce the absorbed gas.

The uncertainty in reservoir permeability values between measured cores and well test analysis has been taken into consideration with the sensitivity analysis.

In particular, because the break-point for the gas field development is generally low compared to oil fields [4], as well as the development planning comprises a great amount of investments [5]; therefore, the development plans need to be established taking long-term stable recovery into consideration. Thus, the running flow duration for Akkas field development has been taken 20 years that allows in evaluating the feasibility of the suggested development plans.

Note, due to very big number of the graphical results for *Scope, Forecast* and *Comparison* runs and the big number of scenarios that take the effect of bottom hole operating pressures, stimulation effect, production pipe diameter, as well as the economic variation; we have presented only some of selected plots for the suggested cases, which

may show the wide analysis achieved by the study. However, all details of scopes, forecasts and comparison can be submitted to Ministry of oil soonest requested.

Several field development plans have been suggested based on the target plateau rates of (250, 500 and 750) MMSCF/D for period of (20) years, which allows in determining the taken into consideration reservoir and wells operating pressure; as well as the uncertainty of reservoir permeability. Moreover, the economic parameters such as well drilling cost, operating cost, gas price, compression cost and working efficiency. These plans could be demonstrated as follows. All Scopes for all presented scenarios have been runs using (40) vertical or horizontal wells, this allows in determining the real numbers of vertical or horizontal wells may require in the forecast stages.

Secnario-1; Plateau rate (250) MMSCF/D; operating bottom hole pressure (3150) psia, skin factor taken from well test analysis (15). This scenario shows the sensitivity of permeability variation between measured core values and that obtained from well test analysis on recovery factor and production rate; therefore the permeability sensitivity of (3, 10, 40 and 80 md) have been considered in this scenario, as shown in Figs. (1-8) that can be illustrated as follows;

Scope -1; the plateau could be sustained the plateau of (250) MMSCF/D for a period of (3) years, and then undergoes a decline rate about (1.25) MMSCF/D/Month for about (10) years, then declines by (1.8) MMSCF/D/Month for (5) years, at which the field reaches its abandonment production rate.

Scope -2; the plateau could be sustained the plateau of (250) MMSCF/D for a period of (10) years, and then undergoes a decline rate approximately (1.82) MMSCF/D/Month for about (3) years, then declines by (5.0) MMSCF/D/Month for (2) years.

Scope -3; the plateau could be sustained the plateau of (250) MMSCF/D for a period of (13) years, and then undergoes sharp decline rate about (16.7) MMSCF/D/Month for the last (1) year, at which the field reaches its abandonment production rate.

Scope -4; the plateau could be sustained the plateau of (250) MMSCF/D for a period of (13.5) years, and then undergoes very sharp decline rate about (250) MMSCF/D/Month for the last (1) year, at which the field reaches its abandonment production rate.

Scope -1H; the plateau could be sustained the plateau of (250) MMSCF/D for a period of (6) years by the first eight wells put them in production, and then could be sustained the plateau of (210) MMSCF/D for a period of (8) years by another twelve wells added them in production. Then the field undergoes a decline rate about (2.85) MMSCF/D/Month for about (6) years, to reaches its final rate of (10) MMSCF/D at the end of forecasted period of (20) years.
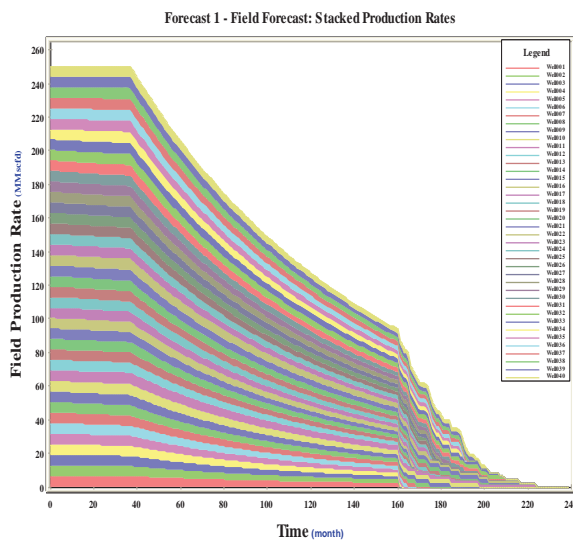
Fig. (1) Field production rate versus time-Scenario-1, Scope-1
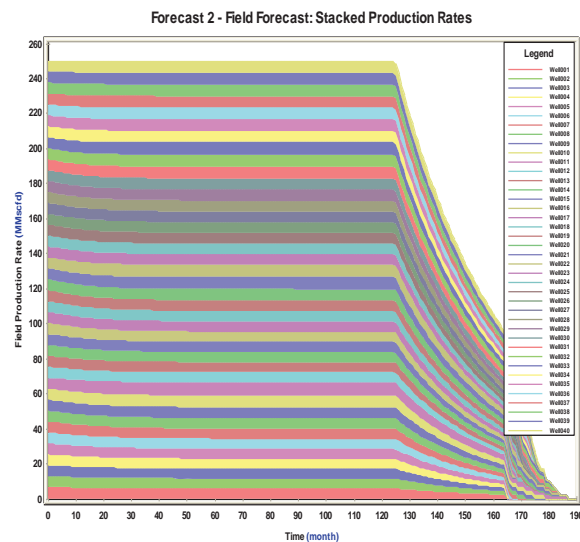
Fig. (2) Field production rate versus time-Scenario-1, Scope-2
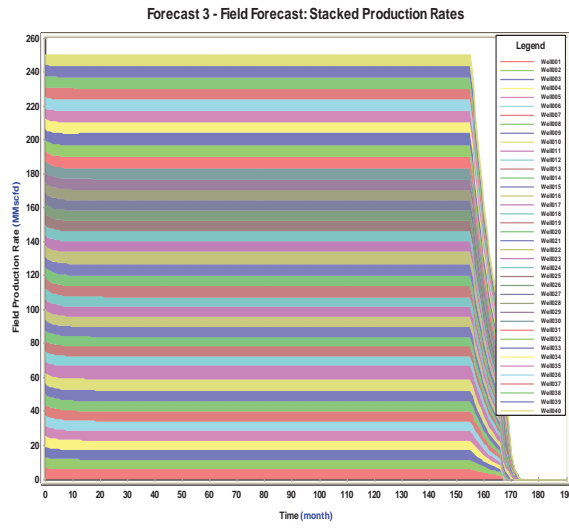
Fig. (3) Field production rate versus time-Scenario-1, Scope-3
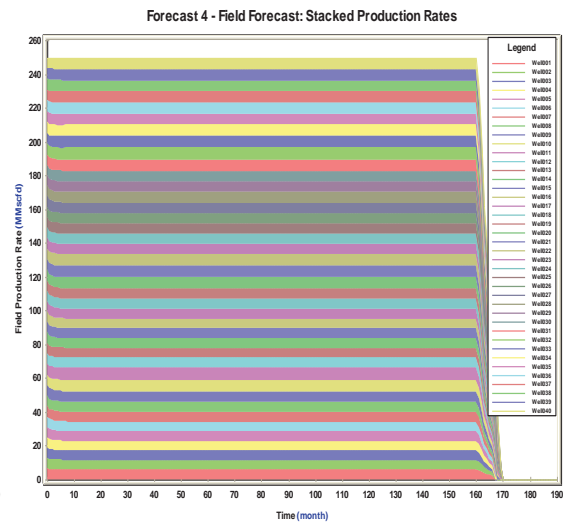
Fig. (4) Field production rate versus time-Scenario-1, Scope-4
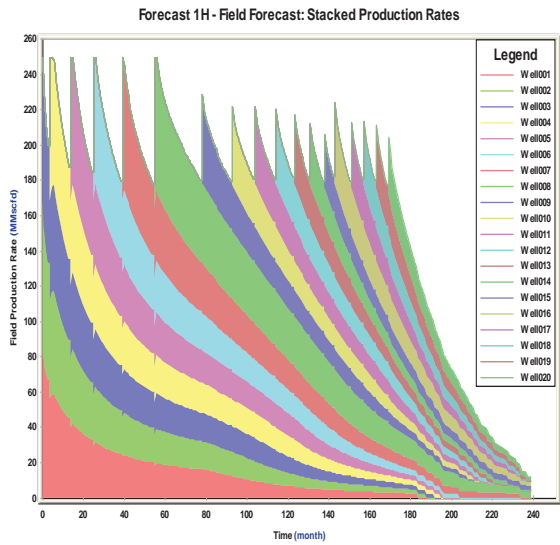
Fig. (5) Field production rate versus time-Scenario-1, Scope-1H
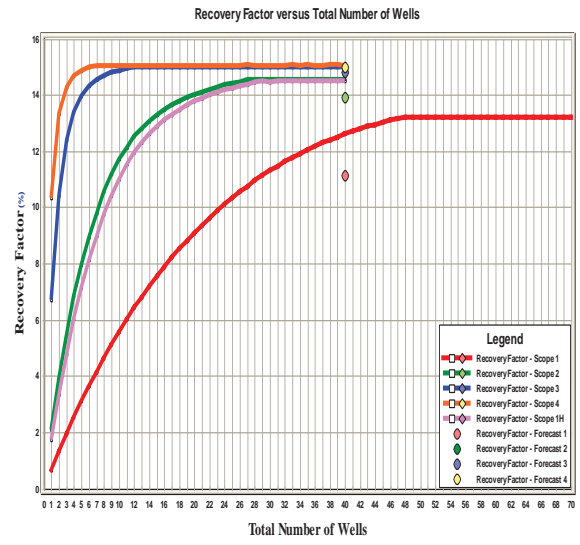
Fig. (6) Field recovery factor versus No. of wells; Scenario-1, Scopes-1, 2, 3, 4
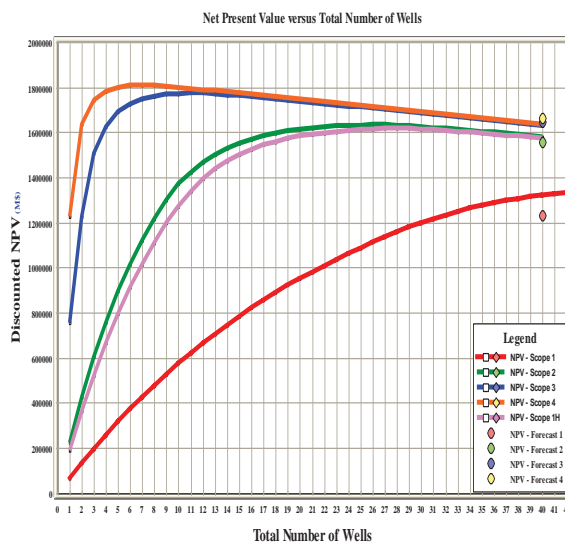
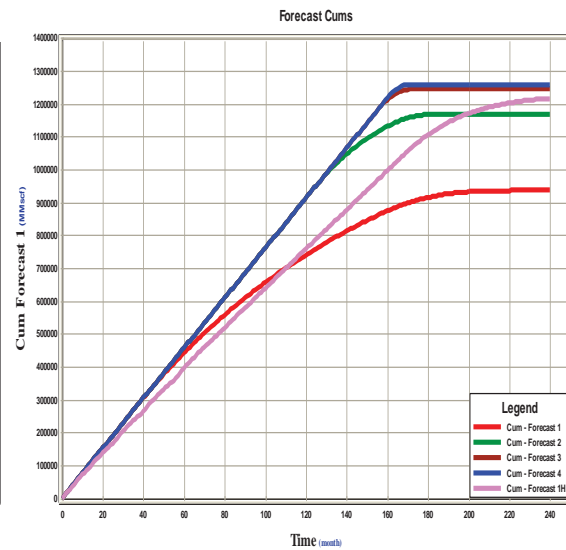**Fig. (7) NPV versus No. of wells; Scenario-1, Scopes-1,2,3,4 and1H**

Fig. (8) Field cumulative production versus time-Scenario-1, Scope-1,2,3,4

Table (1) Summarizes the results of scenario-1, on field development strategy.

Plateau (250) MMSCF/D, P_{wf}=3150 psia, r_w=4.25 in, S=15					
Parameters	Scope-1	Scope-2	Scope-3	Scope-4	Scope-1H
Sustained Plateau period, months	40	125	155	165	75
Average decline rate, MMSCF/D/Month	1.4	4.15	16.7	25	3.3
Abandonment period, months	220	195	170	170	240
Recovery factor	13	14.25	15	15	
No. of wells required for maximum RF	50	30	16	8	30
Maximum NPV $MMM	1.3	1.6	1.75	1.8	1.6
No. of wells required for maximum NPV	42	25	12	6	25
Cumulative production MMMSCF	920	1180	1300	1300	1220

   Secnario-2; Plateau rate (500) MMSCF/D; operating bottom hole pressure (3150) psia, skin factor taken from well test analysis (15). This scenario shows the sensitivity of permeability variation between measured core values and that is obtained from well test analysis on recovery factor and production rate; therefore the permeability sensitivity of (3,

10, 40 and 80 md) have been considered. It is compared with the case of (20) horizontal wells on field production as shown in Figs. (9-16).
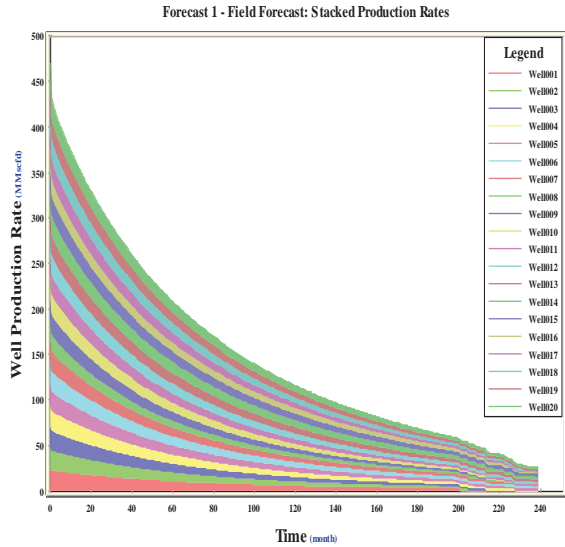

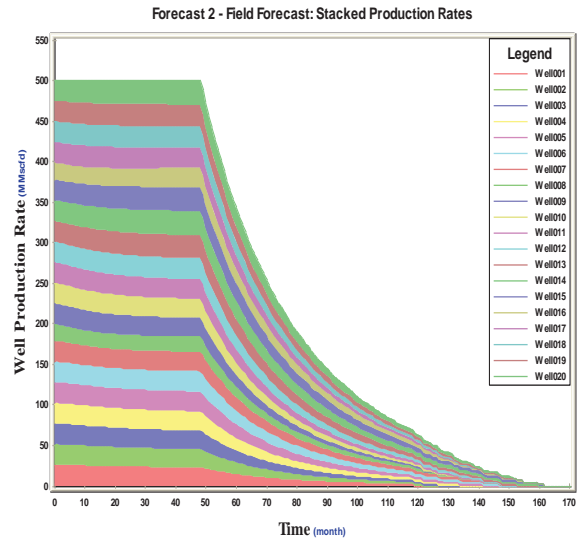**Fig. (9) Field production rate versus time-Scenario-2, Scope-1**

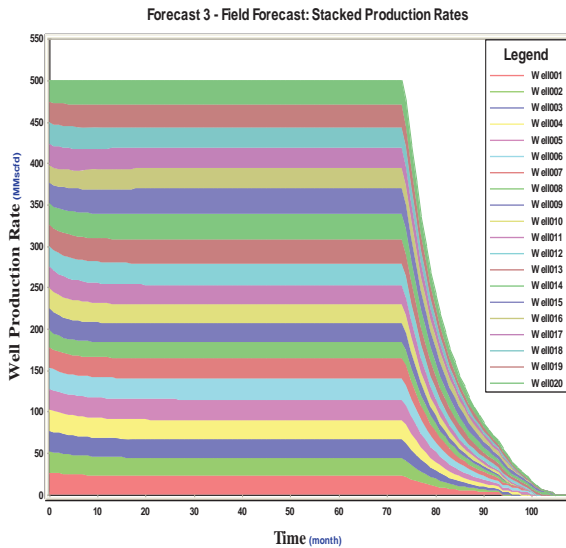**Fig. (10); Field production rate versus time-Scenario-2, Scope-2**

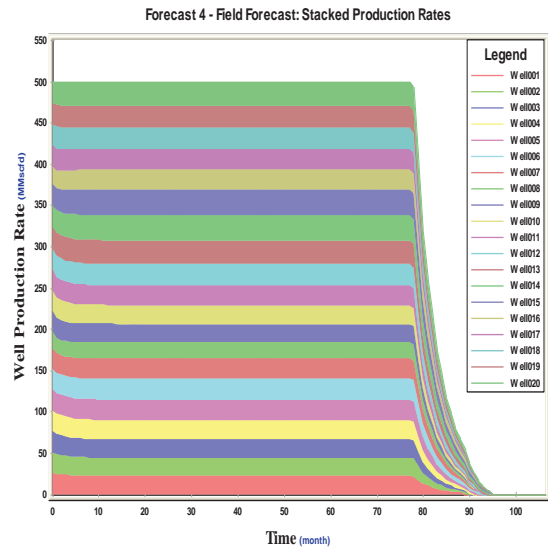**Fig. (11) Field production rate versus time-Scenario-2, Scope-3**

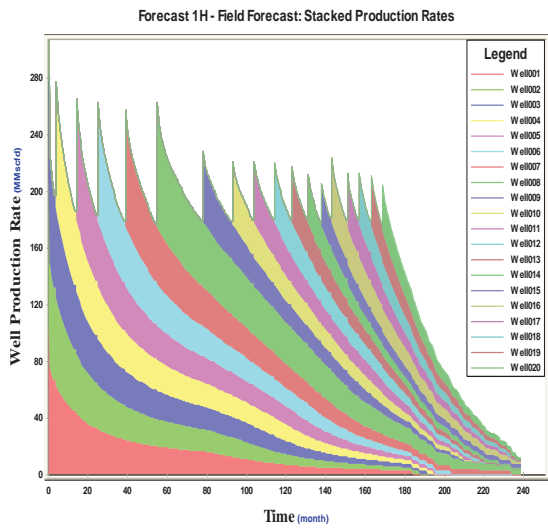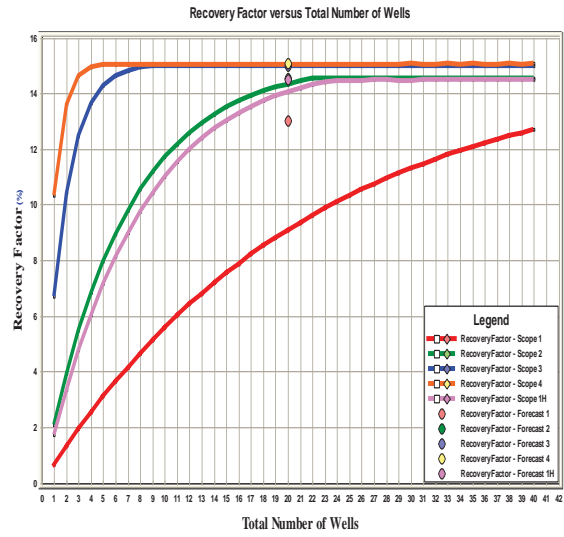**Fig. (12) Field production rate versus time-Scenario-2, Scope-4**

Fig. (13); Field production rate versus time-Scenario-2, Scope-1H

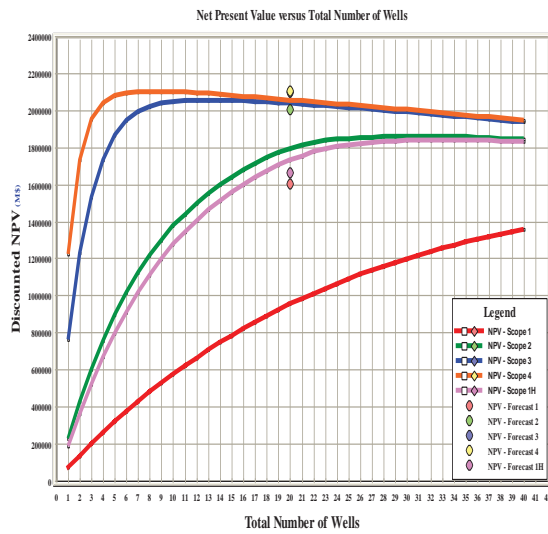**Fig. (14); Field recovery factor versus No. of wells; Scenario-2, Scopes-1,2,3,4 and1H**

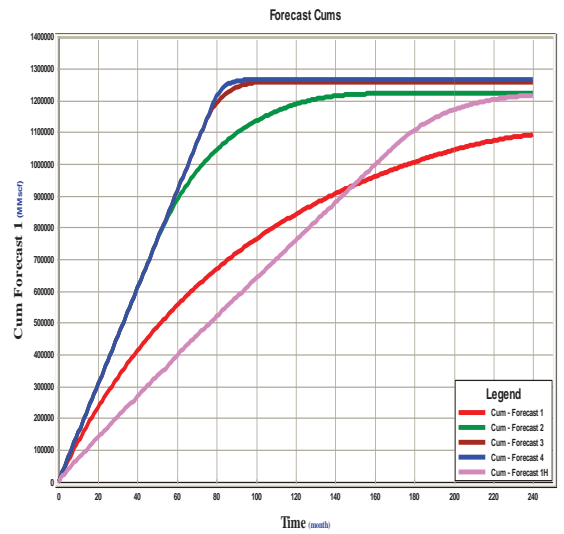**Fig. (15) NPV versus No. of wells; Scenario-2, Scopes-1,2,3,4 and1H**

Fig. (16) Field cumulative production versus time-Scenario-2, Scopes-1,2,3,4

Table (2) Summarizes the results of scenario-2, on field development strategy.

Plateau (500) MMSCF/D, P_{wf}=3150 psia, r_w=4.25 in, S=15					
Parameters	Scope-1	Scope-2	Scope-3	Scope-4	Scope-1H
Sustained Plateau period, months	------	50	75	80	------
Average decline rate, MMSCF/D/Month	1.98	4.54	16.7	29.4	2.85
Abandonment period, months	220	195	170	170	240
Recovery factor	12.5	14.5	15	15	14.5
No. of wells required for maximum RF	40	24	12	6	25
Maximum NPV $MMM	1.4	1.85	2.05	2.1	1.85
No. of wells required for maximum NPV	40	24	12	6	25
Cumulative production MMMSCF	1100	1220	1250	1250	1200

Secnario-3; this scenario is built same as scenario (2) of plateau rate (500) MMSCF/D, but implementing horizontal wells instead of verticals; operating bottom hole pressure (3150) psia, reservoir permeability (10 md) and the skin factor has been taken (0). This scenario shows the sensitivity of lateral section lengths on recovery factor and production rate, as shown in Figs. (17-20). Hence, Fig. (18) Shows the break number of wells becomes uneconomic in this scenario.
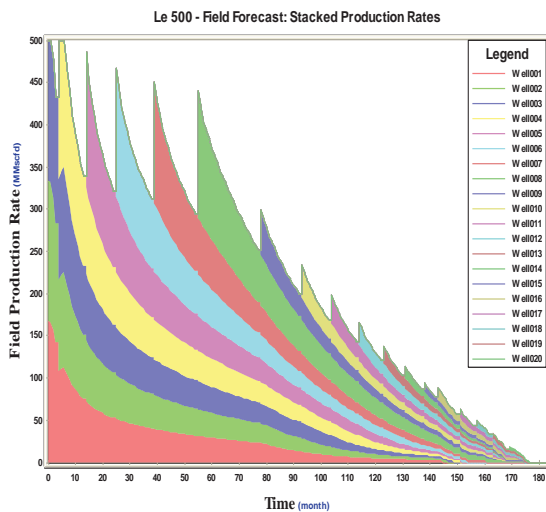

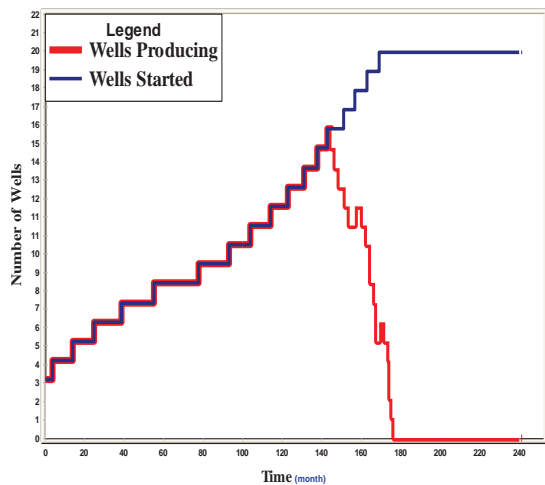**Fig. (17); Field production rate versus time-Scenario-3, Scopes-1,2,3,4 and 5**

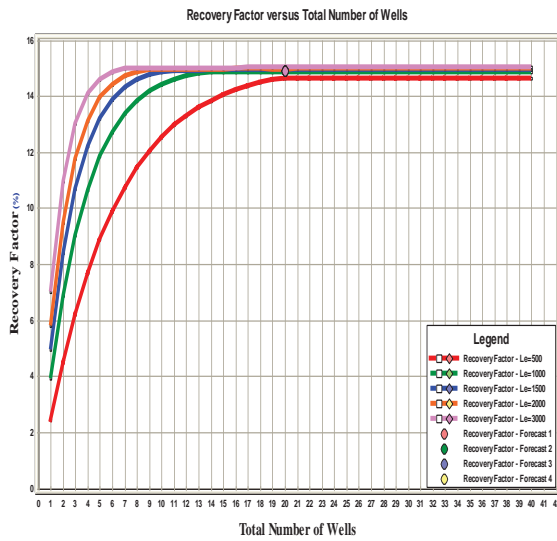**Fig. (18); starting time of wells to come on stream, Scope-1,2,3,4 and 5**

Fig. (19) Field recovery factor versus No. of wells; Scenario-3, Scopes-1,2,3,4 and 5
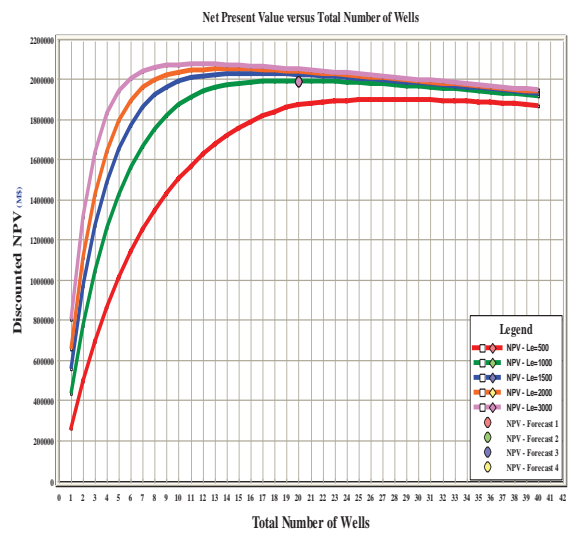
Fig. (20) NPV versus No. of wells; Scenario-3, Scopes-1,2,3,4 and 5

Table (3) Summarizes the results of scenario-3, on field development strategy.

Plateau (500) MMSCF/D, P_{wf}=3150 psia, r_w=4.25 in, S=0					
Parameters	Scope-1	Scope-2	Scope-3	Scope-4	Scope-5
Sustained Plateau period, months	12	12	12	12	12
Average decline rate, MMSCF/D/Month	3.1	3.1	3.1	3.1	3.1
Abandonment period, months	175	175	175	175	175
Recovery factor	14.3	15	15	15	15
No. of wells required for maximum RF	22	18	12	10	8
Maximum NPV $MMM	1.9	2.0	2.05	2.08	2.2
No. of wells required for maximum NPV	28	20	14	12	10
Cumulative production MMMSCF	1250	1250	1250	1250	1250

Secnario-4; Plateau rate (750) MMSCF/D; (20) horizontal wells of (ID 7 inches), operating bottom hole pressure (3150) psi. This scenario shows also the sensitivity of lateral section lengths of horizontal wells; as well as permeability variation between measured core values and that is obtained from well test analysis on recovery factor and production rate, as shown in Figs. (21-30). In this scenario, Figs (27 and 28) show the effect of stimulation on both recovery factor and NPV respectively, compared with those

can be obtained using horizontal wells of (2000) and (4000) ft of Scopes 1H and 2H respectively.
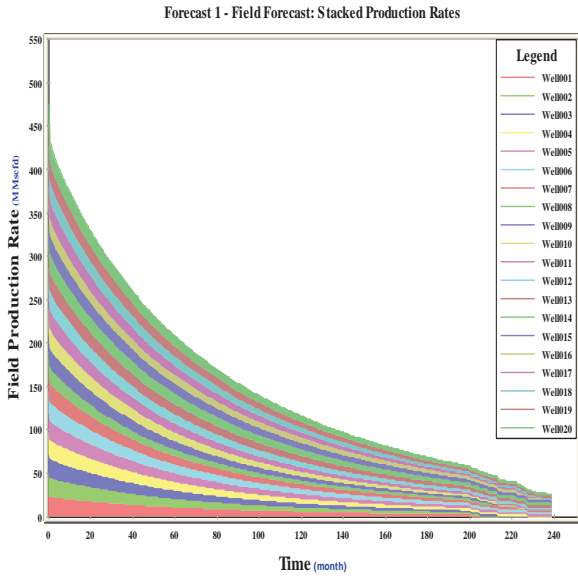

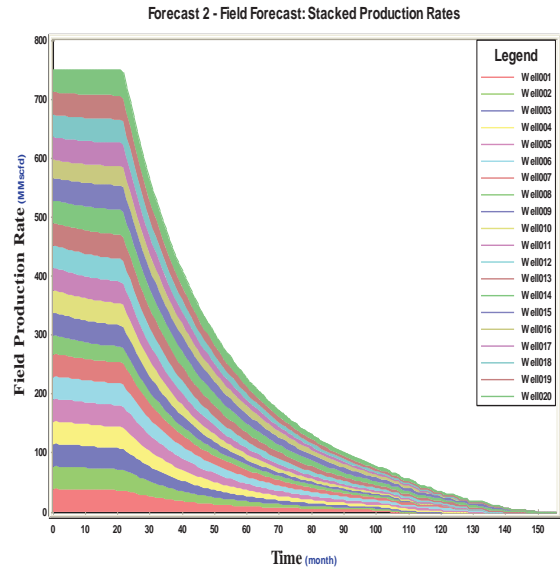**Fig. (21) Field production rate versus time-Scenario-4, Scope-1**

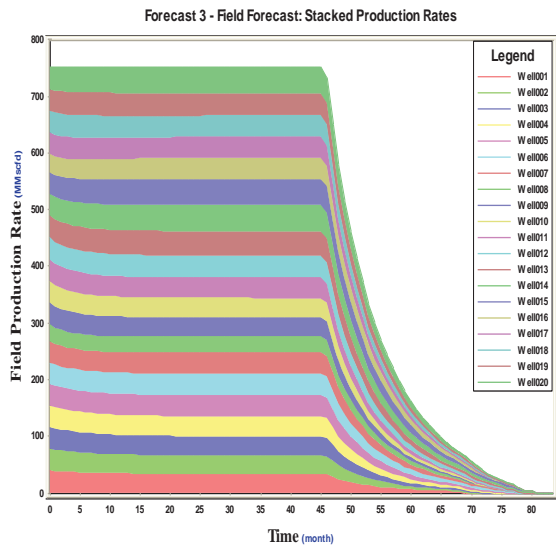**Fig. (22) Field production rate versus time-Scenario-4, Scope-2**

Fig. (23) Field production rate versus time-Scenario-4, Scope-3
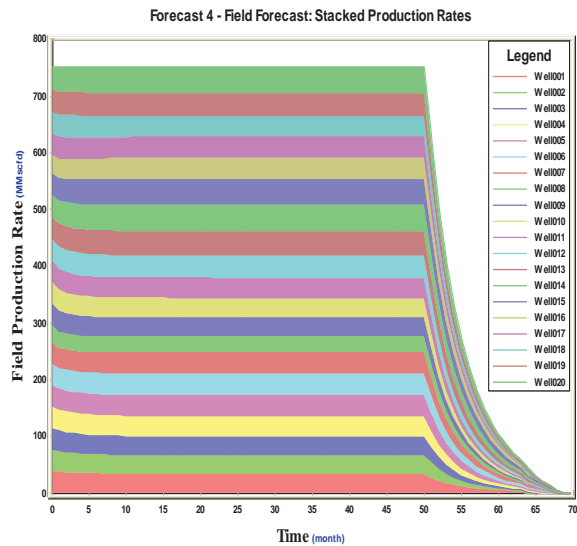

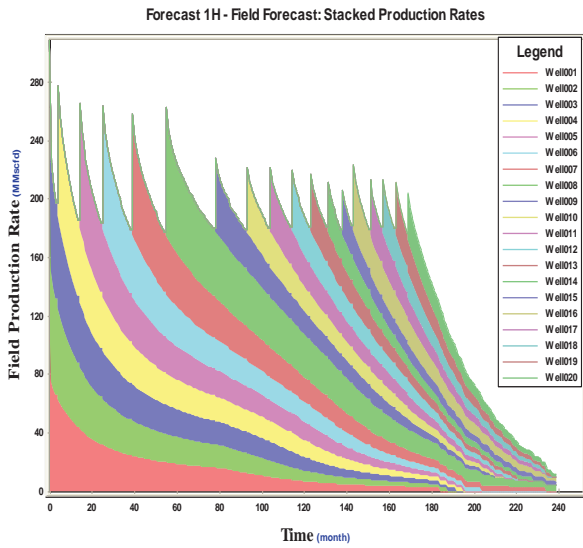**Fig. (24) Field production rate versus time-Scenario-4, Scope-4**

Fig. (25) Field production rate versus time-Scenario-4, Scope-1H
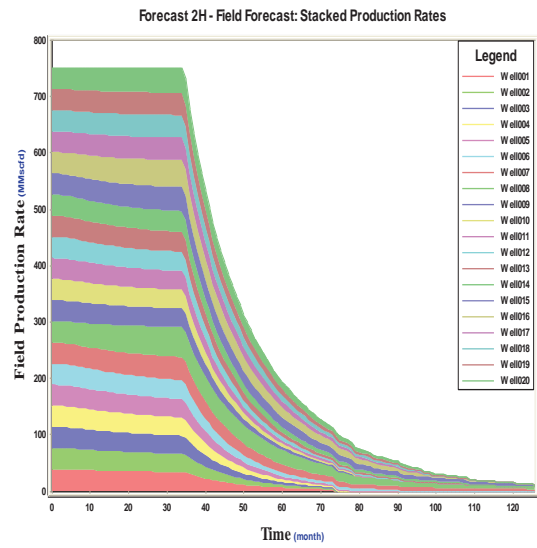

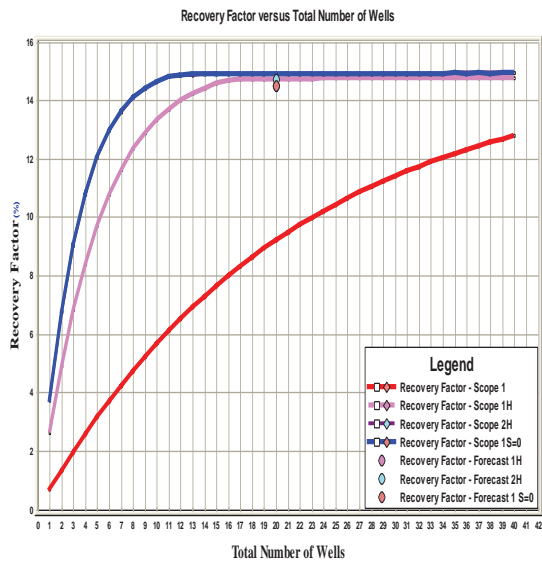**Fig. (26) Field production rate versus time-Scenario-4, Scope-2H**

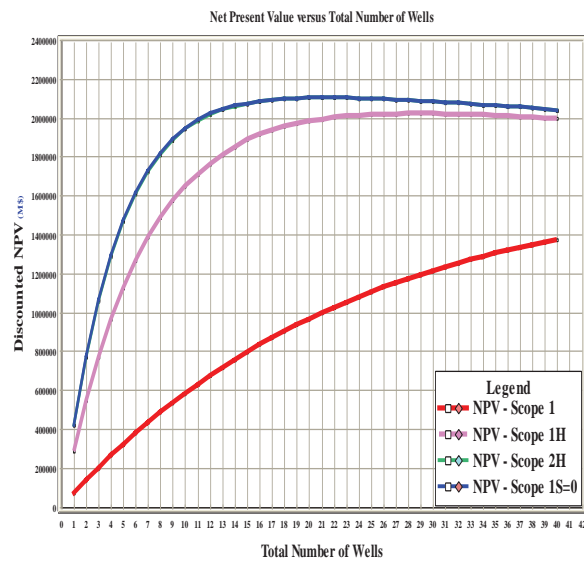**Fig. (27) Field recovery factor versus No. of wells; Scenario-4, Scopes-1,1H,2H, and 1 S=0**

Fig. (28) NPV versus No. of wells; Scenario-4, Scopes-1,1H,2H, and 1 S=0
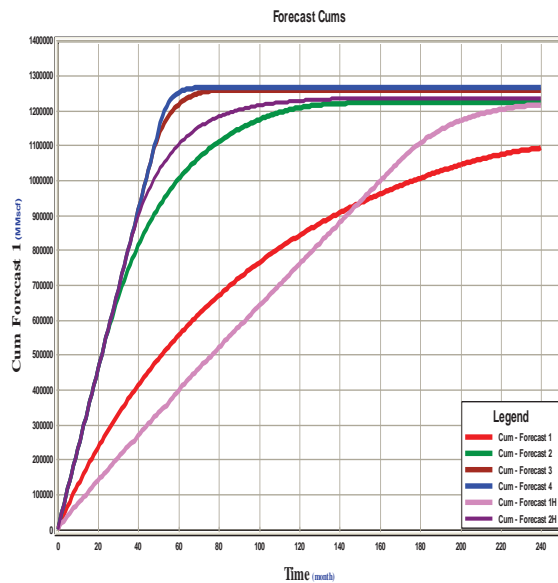
Fig. (29) Field cumulative production versus time-Scenario-4, Scopes-1,2,3,4,
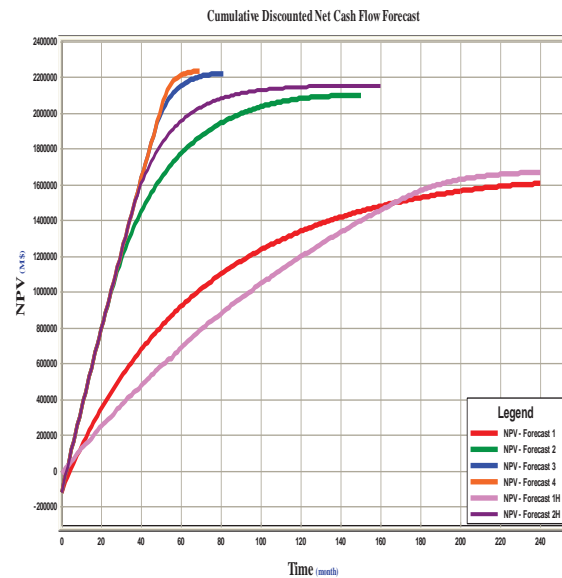
Fig. (30) NPV versus production time; Scenario-4, Scopes-1,2,3,4, 1H and 2H

Table (4) Summarizes the results of scenario-4, on field development strategy.

Plateau (750) MMSCF/D, P_{wf}=3150 psia, r_w=7 in, S=0						
Parameters	Scope-1	Scope-2	Scope-3	Scope-4	Scope-1H	Scope-2H
Sustained Plateau period, months	-----	20	45	50	-----	35
Average decline rate, MMSCF/D/Month	1.79	6.52	21.4	30	0.83	8.82
Abandonment period, months	240	150	80	70	240	120
Recovery factor	12.5	14.5	15	15	14.8	15
No. of wells required for maximum RF	40	22	10	5	17	12
Maximum NPV $MMM	1.4	1.9	2.15	2.2	2.0	2.1
No. of wells required for maximum NPV	40	36	15	8	24	20
Cumulative production MMMSCF	1100	1210	1250	1250	1200	1250

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Results and Discussion:

The feasibility of any specified development plans is indicated by the recovery factor, gas produced per well and the Net Present Value (NPV). Therefore, the net present value (NPV) has been considered as the objective-function to be maximized, as well as the cumulative oil production (Np). The objective was to identify from graphs, strategies that allow the simultaneous maximization of gas production and Net Present Value. (NPV), which could be illustrated as follows;

Scenario -1; shows the comparison between the five scopes, shows that the maximum recovery factor of (15%) could be obtained by implementing Scopes (4) and (3) by drilling (7) and (13) vertical wells respectively. While, a recovery factor of (14.5%) can be obtained in Scope (2) by drilling (28) vertical wells. However, the less recovery factor of (13%) can be obtained in Scope (1) by drilling (50) vertical wells.

Hence, it can also compare Scope (1) and Scope (1H), as both using same reservoir permeability of (3 md), it can be noticed that the recovery factor of (14.5 %) can be obtained using (28) horizontal wells of lateral section (2000 ft), compared to maximum recovery factor of (13 %) using (50) vertical wells.

Therefore, the NPV should be evaluated for all Scopes and Forecast scenarios that can help in the management decision making process, leading to better recovery strategies that increase both reserves and profitability of reservoirs.

Evaluation of NPV shows that Scopes (1, 2, 3, and 4) give the maximum values of (\$ 1.3, 1.6, 1.78 and 1.8 MMM) which can be obtained using (40, 25, 12 and 8) vertical wells respectively. However, Scope (1) could compared with Scope (1H), in which the later gives the maximum NPV of (\$ 1.6 MMM) using (26) horizontal wells.

Scenario -2 Scope-1 undergoes an immediate decline in production rates of (1.98) till the end forecasted period of (240) months; therefore, sustaining plateau rate of (500) MMSCF/D in (3 md) reservoir permeability requires more than 40 vertical wells. While, (20) vertical wells are able in sustaining Scope (2) at plateau target of (500) MMSCF/D for (4) years, then a decline rate of (4.54) MMSCF/D/Month for (9) years. Scope (3) can sustain the plateau target of (500) MMSCF/D for (6) years, then a decline rate of (16.7) MMSCF/D/Month for (6) years. Scope (4) can sustain the plateau target of (500)

MMSCF/D for (6.5) years, then a decline rate of (29.4) MMSCF/D/Month for (1.5) years. It can also be noticed that using (20) horizontal wells cannot raise the field production to the plateau target of (500) MMSCF/D if the reservoir permeability is (3 md).

Scenario -3 The Scopes and Forecasts (1, 2, 3, 4 and 5) using lateral section lengths of (500, 1000, 1500, 2000 and 3000 ft) respectively, all cases are capable to sustain the plateau rate of (500) MMSCF/D for period of (1) year. However, the recovery factor can be reached to (15 %) by all cases, using (7, 10, 13, 16 and 21) horizontal wells of lateral sections of (3000, 2000, 1000 and 500 ft) respectively.

This scenario shows the effectiveness of horizontal well drilling to achieve same recovery factor that can be obtained using (8-12) horizontal wells of (3000-500 ft) compared to (25-40) vertical wells in scenario-2.

Scenario -4 This shows the importance of permeability and lateral section length for the periods of gas sales to reach maximum NPV. It can be noticed that the NPV ($ 2.2 MMM) after 6 and 7.5 years if reservoir permeability of (80) and (40) md respectively. The NPV will be about ($2.1 MMM) after 12 years if reservoir permeability (10) md, and about ($1.6 MMM) after 20 years if reservoir permeability (3) md. While, for the application of horizontal wells, the NPV will be ($ 2.1 MMM) for (4000 ft) lateral sections and ($ 1.7 MMM) for (2000 ft) lateral sections.

This scenario shows also the superior effect of stimulation in increasing the NPV throughout increasing the field recovery factor using a smaller number of wells, as shown in Figs. (27 and 28).

Conclusions:

The following conclusions could be extracted from the study and can be summarizing as follows;

1- The reservoir has great potential of gas reserve both free gas and shale gas.
2- The recovery factor obtained by natural gas flowing around (15 %).
3- The maximum number of wells that yields maximum RF and NPV could be less than 30 wells.
4- The superiority of well stimulation in increasing the NPV throughout increasing the field recovery factor using less number of wells.

Nomenclature:

NP	Cumulative gas production	MSCF
NPV	Net present value	$
RF	Recovery factor	Fraction
BSCF	Billion standard cubic foot	

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