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Recovery factor in fractured reservoirs: lessons learned from 100 fractured fields

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Abstract: One hundred fractured reservoirs from around the world were evaluated to determine how ultimate recovery was affected by inherent reservoir and fluid properties, such as porosity, permeability, viscosity, mobility ratio, S_w, wet ability, fracture distribution, and drive mechanism vs. the choice of reservoir management strategy, e. g., optimization of production rate and type of EOR technique. Fractured oil reservoirs were divided into four groups. Type Ⅰ reservoirs have little matrix porosity and permeability. Fractures provide both storage capacity and fluid-flow pathways. Type Ⅱ reservoirs have low matrix porosity and permeability. Matrix provides some storage capacity and fractures provide the fluid-flow pathways. Type Ⅲ (microporous) reservoirs have high matrix porosity and low matrix permeability. Matrix provides the storage capacity and fractures provide the fluid-flow pathways. Type Ⅳ (macroporous) reservoirs have high matrix porosity and permeability. Matrix provides both storage capacity and fluid-flow pathways, while fractures merely enhance permeability. Results of studying 26 Type Ⅱ and 20 Type Ⅲ reservoirs demonstrate that recovery factor is controlled by different factors in these two reservoir types. Recovery factor in Type Ⅱ reservoirs is sensitive to aquifer-drive strength and optimization of flow rate. Type Ⅱ reservoirs are easily damaged by excessive production rates, but when managed properly, some achieve good recovery without the need for secondary or enhanced recovery programs. Recovery factor in Type Ⅲ reservoirs is affected by inherent rock and fluid properties, particularly matrix permeability, API gravity, wet ability, and fracture intensity. The choice of proper EOR technique is essential for optimum exploitation. No Type Ⅲ reservoir is produced to final depletion without the aid of some type of secondary or EOR technique. Recognition of the differences between Type Ⅱ and Type Ⅲ fractured reservoirs should lead to better choices of exploitation strategy.

Key words: recovery factor; fractured reservoirs; drive mechanism; fractured reservoir classification

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0 Introduction

The 100 fractured reservoirs examined in this study have a combined recoverable oil and gas reserve of 90 billion bbls of oil equivalent. Fractured reservoirs are often considered to be short-lived with high flow rates, rapid production declines, and low ultimate recovery factors. Engineers often look unfavorably on fractured reservoirs because they are difficult to characterize and recovery techniques must be carefully and judiciously applied in order to avoid production problems. This can drive up the time, cost and risk of developing a reservoir. However, many of these prejudices are unfounded. Often they derive from a bad experience early in the career of a person now in a decision-making position. Fractured reservoirs that have been properly developed have ultimate recoveries that compare favorably with much conventional sandstone and carbonate reservoirs.

In order to provide a more solid footing for understanding the controls on the recovery in various types of fractured reservoir, we examine 46 of these reservoirs in the Type Ⅱ and Type Ⅲ categories throughout the world. Only reservoirs, for which a comprehensive spectrum of parameters was available, were chosen for study. The effect on recovery of both inherent parameters and reservoir management techniques were examined, in order to achieve a thorough understanding of the relative importance of each variable.

1 Fractured reservoirs versus conven-tional reservoirs

Although porosity and permeability vary widely in fractured reservoirs, Type Ⅰ, Ⅱ and Ⅲ fractured reservoirs have low matrix permeability' s and could not be produced economically without the presence of fractures. High permeability-low porosity fractures in a low permeability-higher porosity matrix provides the mechanism for recovery of hydrocarbons. However, this dual-porosity system adds a measure of complexity that is absent in conventional reservoirs[1]. The production characteristics of fractured reservoirs differ from those of conventional reservoirs in several fundamental ways[2,3]:

① Because of the high transmissivity of the fracture network, pressure drop around a producing well is very low and pressure gradients do not play a significant role in production. Production is driven instead by complex mechanisms that govern fracture/matrix-block communication.

② In fractured reservoirs with some matrix permeability, the pressure decline per barrel of oil produced is low compared to conventional reservoirs. This occurs because fluid expansion, gravity drainage, and imbibitions provide a continuous supply of oil from matrix blocks into the fractures during production.

③ The GOR of fractured reservoirs normally remains lower throughout production, if the reservoir is properly managed. This occurs because liberated gas flows preferentially upward through fractures to the top of the reservoir rather than horizontally toward the nearest well bore as in a conventional reservoir. The liberated gas creates a secondary gas cap, or expands an existing gas cap, and the gas content of produced oil is lowered accordingly.

④ Fractured reservoirs lack transition zones. The oil-water and gas-oil contacts are knife-sharp surfaces, both prior to and during production, since the high permeability of the fracture network provides a mechanism for rapid re-equilibration of fluid contacts.

⑤ Water cut in fractured reservoirs is strictly a function of production rate. The petrophysical characteristics of the reservoir rocks and the PVT properties of the fluids have insignificant effect on water production.

⑥ Convective circulation occurs during the production of many fractured reservoirs. As a result, PVT properties are constant throughout a fractured reservoir, compared to a conventional reservoir where bubble point varies as a function of depth within the oil column. Because of these fundamental differences, mistaking a fractured reservoir for a conventional reservoir early in the field-development phase can lead to mistakes in exploitation strategy that have profoundly negative effects on reservoir performance. Most wells completed in newly discovered fractured reservoirs produce at high IP. If investment decisions are made, as they sometimes are, by assuming that those high production rates can be maintained over extended periods of time, the field may be economically doomed from the start. When wells in fractured reservoirs are flowed at excessively high rates, GOR can increase rapidly instead of remaining low as in a properly managed field. This eventually leads to a rapid decline in reservoir pressure. Rapid pressure decline can change the delicate balance of recovery mechanisms that feed matrix oil into the fractures and drastically decrease recovery factor. Finally, if an incorrect secondary recovery technique is chosen, ultimate recovery may be further reduced. The most common example of poor reservoir management is water flooding a fractured reservoir. The inevitable early water breakthrough leaves a large amount of unrecovered oil behind in bypassed matrix blocks.[3]

2 Recovery efficiency in fractured reservoirs

C&C Reservoirs' digital reservoir analogs system[4] currently contains nearly one thousand producing reservoirs worldwide. There are more than one hundred fractured reservoirs which can be analyzed and compared based on their depositional facies, reservoir architecture, rock properties, fracture networks, fluid types, reservoir development strategies, EOR techniques and production histories. The advanced search engine provided in the system allowed us to easily find all of the fractured reservoirs in the relational database and to group them into the four reservoir types defined in the abstract. Using this data, we were able to systematically evaluate genetically related reservoirs and identify the common factors that control reservoir performance and recovery efficiency in each group.

Data obtained on the 100 fractured reservoirs examined in this study indicate that overall, their ultimate recoveries are somewhat lower than those of many conventional reservoirs, but they still compare favorably with some conventional reservoir types. Fig. 1 shows the distribution of ultimate recovery factors for the 56 fractured oil reservoirs and 8 fractured gas reservoirs for which reliable data are available. Overall, the Type Ⅰ, Ⅱ, Ⅲ and Ⅳ fractured oil reservoirs have an average ultimate recovery factor of 26%-somewhat skewed towards the upper end-while the 8 fractured gas reservoirs have an average ultimate recovery factor of 61%. Two thirds of the oil reservoirs have recovery factors > 20%, which is certainly high enough to be commercially attractive. Three quarters of the gas reservoirs have recovery factors > 60%. The low recovery factors in two of the gas reservoirs are caused by water encroachment into fractured depletion-drive reservoirs.

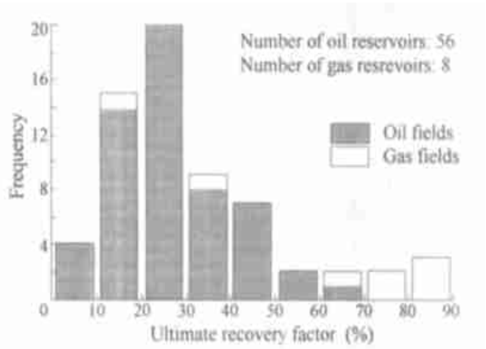


Fig. 1 Distribution of ultimate recovery factor for fractured reservoirs of all types

Next, let's look at the distribution of recovery factors for Type Ⅱ and Type Ⅲ fractured oil reservoirs. Ultimate recovery factors for the 20 of the 26 Type Ⅱ oil reservoirs for which reliable data are available range from 9% to 56% with an average value of 26% (Fig. 2). The recovery factors form a near normal distribution, with preponderance of values near the mean. Ten of the twenty reservoirs have recovery factors between 20% and 30%, while five have recovery factors < 20% and five have recovery factors > 30%. Ultimate recovery factors for the 15 of the 20 Type Ⅲ oil reservoirs for which reliable data are available range from 7.6% to 44% with an average value of 24% (Fig. 3). The recovery factors have a bimodal distribution, with one mode in the 10%-20% class interval and the other in the 30%-40% class interval. One reservoir has a recovery factor < 10% and one reservoir has a recovery factor > 40%. The remaining reservoirs have recovery factors that fall between 10% and 40%. The data clearly indicate that Type Ⅱ and Type Ⅲ fractured oil reservoirs have very different distributions in recovery factor and comprise two distinct genetic groups. The following section examines possible causes and implications of these differences.

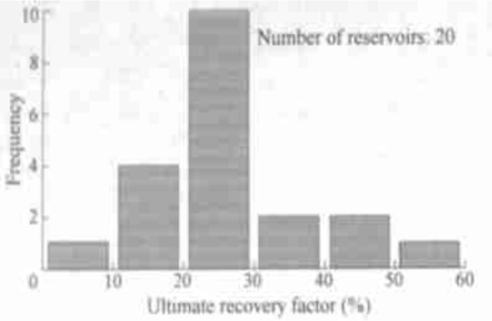


Fig. 2 Distribution of ultimate recovery factor for Type Ⅱ fractured oil reservoirs

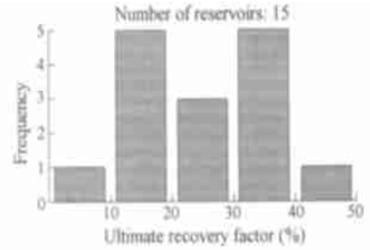


Fig. 3 Distribution of ultimate recovery factor for Type Ⅲ fractured oil reservoirs

3 Factors controlling recovery efficiency in Type Ⅱ and Type Ⅲ fractured oil reservoirs

3.1 Type Ⅱ reservoirs

Type Ⅱ reservoirs have low matrix porosity and permeability. Matrix provides some storage capacity and fractures provide the fluid-flow pathways. Type Ⅱ fractured oil reservoirs most commonly occur in brittle rocks such as dolomite, tight limestone, tight sandstone and volcanism. Cross plots of ultimate recovery factor versus core porosity, air permeability, production-derived permeability, oil viscosity, mobility ratio, API gravity, well spacing, net/gross ratio and residual water saturation showed little correlation between these parameters and recovery efficiency. This suggests that in tight Type Ⅱ reservoirs, recovery factor is more dependent upon the nature of the fracture network than on the matrix properties of the rock or fluid properties of the oil. Because the fracture network in these brittle ideologies tends to be extensive, it is commonly connected to downdip or underlying regional aquifers. As a result, 16 of the 20 Type Ⅱ reservoirs for which recovery factors are available have water drives or combination drives that include water drive as one of the components (Fig. 4). Water plus solution-gas drive reservoirs have the highest recovery factors, while water-drive reservoirs are a close second. Secondary recovery and EOR techniques have been applied to many of the reservoirs. However, some of the highest recovery efficiencies were achieved by unassisted primary recovery from reservoirs with strong bottom water drive (Fig. 5). Reservoirs with strong bottom water drive had excellent recovery without the assistance of any secondary recovery/EOR techniques while reservoirs with weaker water drives or other drive mechanisms have lower recovery factors even when subjected to secondary recovery/EOR techniques (see Table 1). Reservoirs with less efficient drive mechanisms, including weaker water drives, have lower ultimate recovery factors even when subjected to secondary recovery or EOR programs (Fig. 5, Table 1).

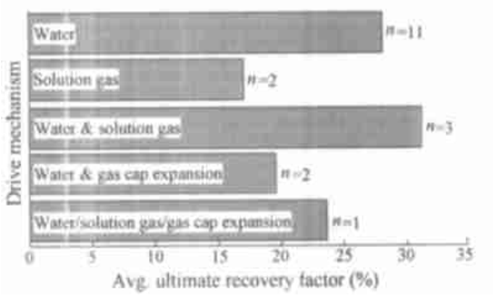


Fig. 4 Ultimate recovery factor as a function of drive mechanism for Type Ⅱ fractured oil reservoirs

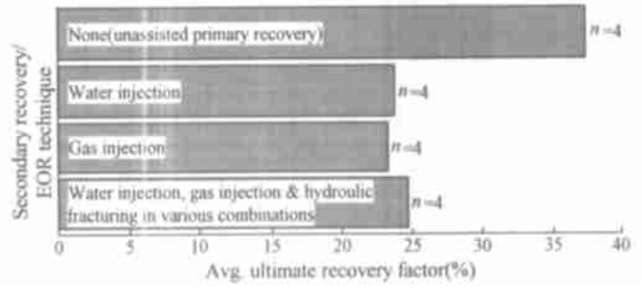
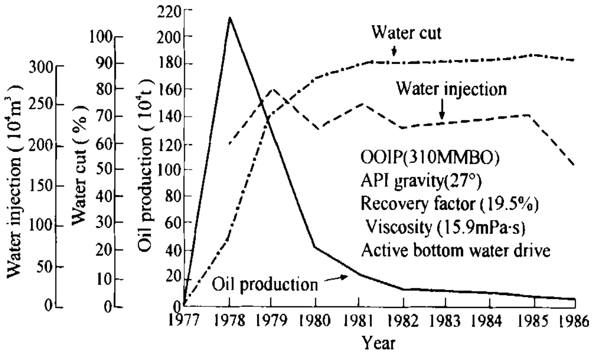


Fig. 5 Ultimate recovery factor as a function of secondary recovery/EOR technique for Type Ⅱ fractured oil reservoirs

A few Type Ⅱ fractured oil reservoirs with strong water drive did not deliver optimal recoveries because of poor management of water production. Because Type Ⅱ reservoirs tend to have fracture networks that are connected to aquifers, high production rates can lead to rapid water incursion and premature production decline. For example, the Yanling Field, a Type Ⅱ fractured karstic carbonate oil reservoir in northeastern China, was produced at a very high rate during its first two years onstream. Wells were drilled into the top of the reservoir and completed open hole. The excessively high production rate prevented much matrix oil from draining into the fractures, leading to rapid pressure and production decline in the reservoir (Fig. 6)[5,6]. A water injection program undertaken to reverse the pressure decline only served to create a water incursion problem. In the end, Yanling Field had an abbreviated production life and achieved < 20% ultimate recovery.



Matrix ϕ (1.3%), matrix $K(1.2\times10^{-3}\mu m^2)$
Fracture ϕ (3.4%), max. bulk $K(5.323\mu m^2)$

Fig. 6 Yanling Field, a Type Ⅱ fractured karstic carbonate oil reservoir in northeastern China

Table 1 Type Ⅱ fractured reservoirs

Field	Country	Basin	Hydrocarbon type	Reservoir lithology	Drive mechanism	Secondary recovery/EOR technique	Ultimate recovery factor (%)
Altamont-Bluebell	USA	Unita	Light oil	Sandstone	Solution gas	Microbial injection	
Amposta Marino	Spain	Gulf of Valencia	Heavy oil	Limestone	Strong bottom water	Unassisted primary recovery	56.0
Augila-Nafoora	Libya	Sirte	Light oil	Basement	No data	No data	22.0
Bibi Hakimeh	Iran	Zagros	Medium oil	Limestone/dolomite	Water/gas cap expansion	Gas injection	15.0
Casablanca	Spain	Gulf of Valencia	Light oil	Limestone/dolomite	Strong bottom water	Unassisted primary recovery	47.5
Dineh-Bi-Keyah	USA	Colorado plateau	Light oil	Volcanics	Solution gas	No data	
Gachsaran	Iran	Zagros	Light oil	Limestone/dolomite	Water/solution gas	Gas injection	26.6
Gela	Italy	Caltanisetta	Heavy oil	Dolomite	Strong bottom water	Unassisted primary recovery	11.0
Haft Kel	Iran	Zagros	Light oil	Limestone/dolomite	Water/solution gas	Gas injection	27.0
Jatibarang	Indonesia	Northwest Java	Medium oil	Volcanics	Solution gas	No data	
La Paz	Venezuela	Maracaibo	Light oil	Limestone	Solution gas	Water injection	
Lama	Venezuela	Maracaibo	Light oil	Limestone	Water/solution gas/gas cap expansion	No data	23.5
Liubei	China	Bohai Bay	Light oil	Dolomite	Water	Water injection (poor efficiency)	20.0
Maozhou	China	Bohai Bay	Light oil	Dolomite	Water	Water injection (poor efficiency)	27.5
Maxi	China	Bohai Bay	Light oil	Sandstone	Water/solution gas	Water injection/hydraulic fracturing	40.0
Nido	Philippines	Northwest Palawan	Heavy oil	Limestone	Strong bottom water	Unassisted primary recovery	35.0
Paris	Iran	Zagros	Light oil	Limestone/dolomite	Water/gas cap expansion	Gas injection	24.0
Ragusa	Italy	Iblean Plateau	Heavy oil	Dolomite	Water	No data	30.0
Renqiu	China	Bohai Bay	Medium oil	Dolomite	Water	Water injection	25.0
Samgori	Georgia	Kura	Light oil	Volcanics	Water	No data	
Spraberry Tend	USA	Midland	Light oil	Sandstone	Solution gas	Horizontal drilling/hydraulic fracturing/water injection (poor efficiency)	9.0
Tirrawarra	Australia	Cooper	Light oil	Sandstone	Solution gas	Gas injection/hydraulic fracturing	25.0
Vega	Italy	Ragusa	Heavy oil	Limestone/dolomite	Water	No data	15.0
West Cat Canyon	USA	Santa Maria	Heavy oil	Dolomite	Fluid expansion & pore volume contraction/solution gas/gravity drainage	No data	
Yanling	China	Bohai Bay	Medium oil	Dolomite	Water		18.5
Yihezhuang	China	Bohai Bay	Light oil	Limestone/dolomite	Weak Water		22.5

Casablanca Field, a Type Ⅱ fractured karstic carbonate oil reservoir in offshore Spain, has rock and fluid properties similar to those at Yanling (Fig. 7). It was developed similarly. Producing wells were drilled into the top 1/3 of the reservoir and completed open hole. However, at Casablanca, the operator carefully controlled production rate by reducing choke size whenever water cut reached 2% of the total liquids production from any given well. No secondary recovery or EOR techniques were applied. By simply controlling production rate and water cut, Casablanca Field has achieved an ultimate recovery factor of >45%[7]. Thus, optimization of flow rate and careful management of water production are perhaps the most critical factors for maximizing recovery factor in Type Ⅱ fractured oil reservoirs.

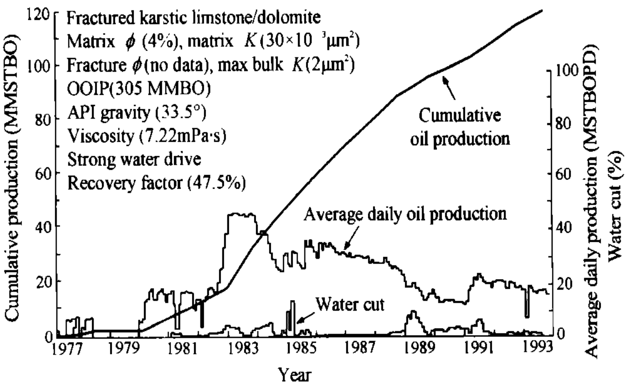


Fig. 7 Casablanca Field, a Type Ⅱ fractured karstic carbonate oil reservoir in offshore Spain[7]

3.2 Type Ⅲ reservoirs

Type Ⅲ (microporous) reservoirs have high matrix porosity and low matrix permeability. Matrix provides the storage capacity and fractures provide the fluid-flow pathways. Type Ⅲ fractured oil reservoirs most commonly occur in ductile rocks such as chalk, diatomite and siliceous shale (Table 2).

Table 2 Type Ⅲ fractured reservoirs

Field	Country	Basin	Hydrocarbon type	Reservoir lithology	Drive mechanism	Secondary recovery/EOR technique	Ultimate recovery factor(%)
Dan	Denmark	North Sea Central Graben	Light oil	Primary chalk	Solution gas/gas cap expansion	Horizontal drilling/hydraulic fracturing	11.0
Ekofisk	Norway	North Sea Central Graben	Light oil	Primary chalk	Solution gas	Water injection, gas injection	35.0
Eldfisk	Norway	North Sea Central Graben	Light oil	Primary chalk	Solution gas	Hydraulic fracturing	23.5
Fahud	Oman	Oman Foredeep	Light oil	Chalky limestone	Gravity drainage	Water injection(poor efficiency)/gas injection	18.0
Giddings	USA	Gulf of Mexico	Medium & light oil	Primary chalk	Solution gas	Horizontal drilling/hydraulic fracturing	
Idd El Shargi	Qatar	Arabian Gulf	Medium oil	Chalky limestone	Gravity drainage	Horizontal drilling	
Kraka	Denmark	North Sea Central Graben	Light oil	Primary chalk	Solution gas/gas cap expansion	Horizontal drilling	
Lisburne	USA	North Slop	Medium oil	Limestone/dolomite	Solution gas/gas cap expansion	Horizontal drilling/hydraulic fracturing/water	7.6
Lost Hills	USA	San Joaquin	Heavy & medium oil	Chert/diatomite	Solution gas	Hydraulic fracturing/water injection	17.0
Midale	Canada	Williston	Light oil	Dolomite	Solution gas	Horizontal drilling/water injection(poor efficiency)	31.0
Natih	Oman	Oman Foredeep	Light oil	Chalky limestone	Gravity drainage	Water injection(poor efficiency)/gas injection	22.0
Norman Wells	Canada	Western Canada	Light oil	Chalky limestone	Solution gas	Horizontal drilling/water injection	37.0
Pearsall	USA	Gulf of Siberia	Medium oil	Primary chalk	Solution gas	Horizontal drilling/hydraulic fracturing	12.0
Salym	Russia	Western Siberia	Light oil	Chert/shale	Solution gas	Hydraulic fracturing/water injection	
Skjold	Denmark ?	North Sea Central Graben	Light oil	Primary chalk	Solution gas/water(weak)	Water injection	30.0
South Belridge	USA	San Joaquin	Heavy & light oil	Chert/diatomite	Solution gas	Hydraulic fracturing/water injection	15.0
Three Bar	USA	Tobosa	Light oil	Chert	Solution gas	CO_2 injection/water injection	
Valhall	Norway	North Sea Central Graben	Light oil	Primary chalk	Solution gas	Horizontal drilling/hydraulic fracturing/water injection	29.0
Weyburn	Canada	Williston	Light oil	Dolomite	Solution gas	Horizontal drilling/water injection(poor efficiency)	30.0
Yibal-A	Oman	South Oman	Light oil	Primary chalk	Solution gas/water	Water injection	44.0

Cross plots of ultimate recovery factor versus core porosity, air permeability, production-derived permeability, oil viscosity, mobility ratio, API gravity, well spacing, net/gross ratio and residual water saturation revealed several relationships. Air permeability of the matrix rock and API gravity of the oil showed a moderate positive correlation with recovery factor, mobility ratio and net/gross ratio showed a weak positive correlation with recovery factor, and residual water saturation showed a weak negative correlation with recovery factor. Thus, rock and fluid properties exert a more significant control on ultimate recovery in Type Ⅲ reservoirs than in Type Ⅱ reservoirs. Because most of the Type Ⅲ reservoirs are composed of ductile lithologies, fractures tend to be localized around faults (Fig. 8)[8,9], and areas of maximum curvature on flexures and generally do not connect to down-dip or underlying aquifers. Fig. 8 shows in the Type Ⅲ Austin Chalk oil reservoir, most fractures are concentrated on the downthrown side of faults. Well production rate is dependent on the number of fractures intersected. Wells that penetrate heavily fractured areas adjacent to faults outperformed wells that missed the fracture network by as little as 100 ft. To increase the success rate, seismic data were used to identify well-fractured areas (modified from Kuich[8]).

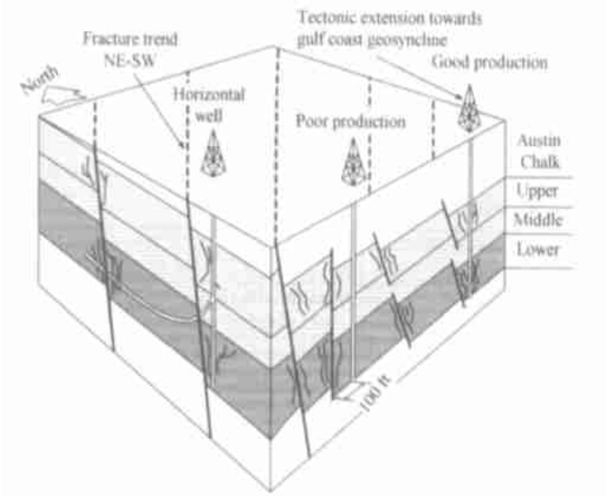


Fig. 8 Block diagram illustrating the importance of fracture density and connectivity on recovery efficiency in the Type Ⅲ Austin Chalk oil reservoir, Giddings Field, Texas

All of the reservoirs produce by solution-gas, gas-cap-expansion and gravity-drainage drive or by combination drives in which one of these drive mechanisms dominates (Fig. 9). Water drive only occurs in 3 of the 20 Type Ⅲ reservoirs, where it forms one component of combination-drive mechanisms (Table 2). In contrast to Type Ⅱ reservoirs, the application of secondary recovery and EOR techniques is essential for maximizing recovery. Many different techniques have been applied to Type Ⅲ reservoirs, often in combination with one another. Their success has been quite variable (Fig. 10).

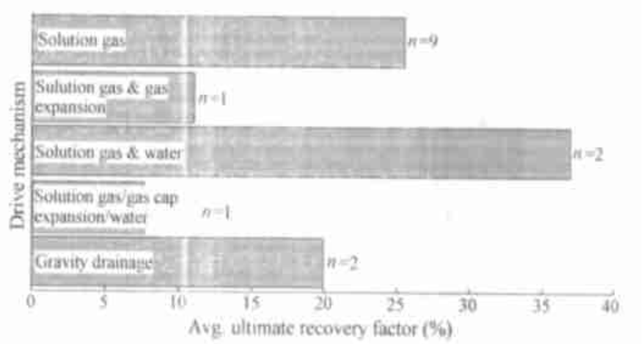


Fig. 9 Ultimate recovery factor as a function of drive mechanism for Type Ⅲ fractured oil reservoirs

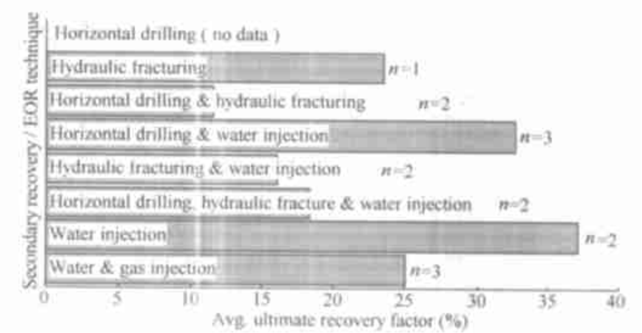


Fig. 10 Ultimate recovery factor as a function of secondary recovery/EOR technique for Type Ⅲ fractured oil reservoirs

Recovery factors were compared for 17 Type Ⅲ fractured oil reservoirs for which the wettability and fracture intensity had been determined. All of the well-fractured, water-wet Type Ⅲ reservoirs have ultimate recovery factors ＞25%, while all of the well-fractured, oil-wet Type Ⅲ reservoirs have ultimate recovery factors＜25% (Fig. 11). In poorly fractured reservoirs, in which bypassed oil is commonly left behind in matrix blocks, ultimate recovery factors are ＜20% regardless of wettability (Fig. 11). The reason for the large disparity in recovery factor between water-wet and oil-wet Type Ⅲ reservoirs is that water can penetrate micro-porosity in water-wet

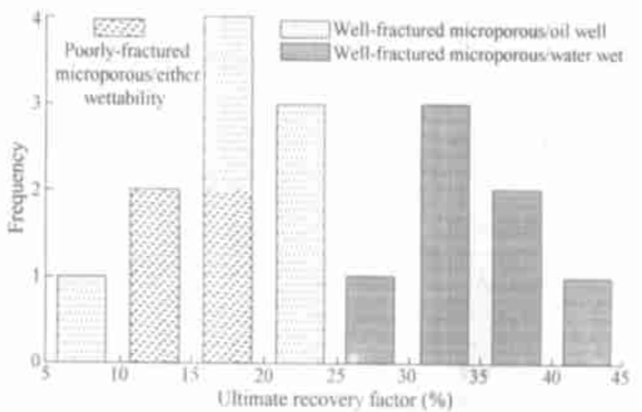


Fig. 11 Recovery factor distribution for 17 Type Ⅲ fractured oil reservoirs as a function of wettability and fracture intensity

reservoirs by capillary imbibitions, thus providing an efficient primary recovery mechanism, while it cannot do so in an oil-wet reservoir[10].

For the same reason, water injection into a water-wet reservoir is far more efficient than water injection into an oil-wet reservoir. Therefore, secondary water flooding of a water-wet reservoir further increases its ultimate recovery factor, but often has little effect on an oil-wet reservoir.

Two case studies illustrate the profound effect that wet ability can have on ultimate recovery factor in Type Ⅲ fracture oil reservoirs. Ekofisk Field, in the Norwegian sector of the North Sea, produces from several water-wet, Type Ⅲ primary chalk reservoirs. The field came onstream in the early 1970s, ramped up to full production in about 5 years, and almost immediately went into steep decline (Fig. 12)[11, 12]. Water injection was begun in the late 1980s and sequentially applied to three different chalk reservoirs. The reservoirs were very responsive to waterflooding, the production decline was reversed, a secondary production peak that was almost as high as the primary production peak was reached in the late 1990s, and the field achieved a recovery factor under waterflood of > 35%. In contrast, Natih Field in Oman produces from an oil-wet, Type Ⅲ diagenetic chalk reservoir. The field came on-stream in the late 1960s, was ramped up to full production in a few years, and quickly went into steep pressure and production decline (Fig. 13)[13, 14]. The primary production profile is almost identical to that at Ekofisk (compare Fig. 12 and Fig. 13). Pressure maintenance water injection was begun in the early 1970s, but did not arrest the production decline. After the failure of the water-injection program, crestal gas injection was begun to induce gravity drainage. Although gas injection arrested the production decline, it was not able to reverse the decline, as water injection did at Ekofisk. Because of the poor response to water injection, this oil-wet reservoir achieved an ultimate recovery factor of only 22%. Natih Field might have achieved a greater ultimate recovery if a different secondary recovery program had been chosen (e. g., crestal gas injection only).

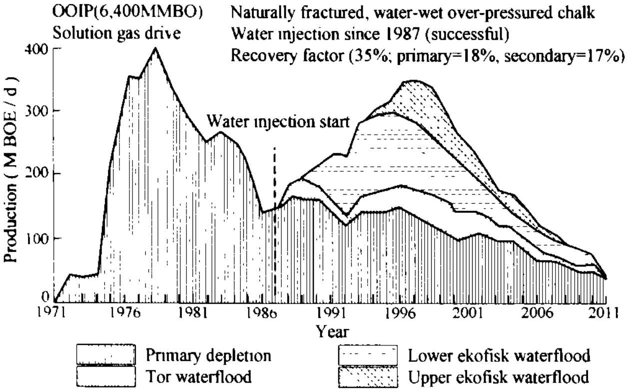
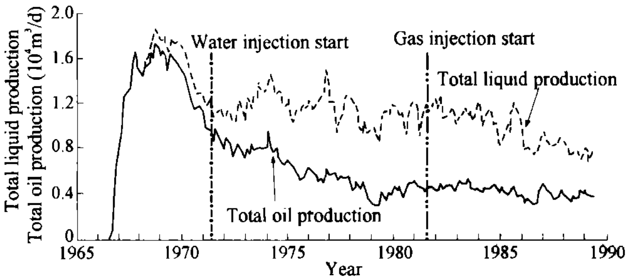

OOIP(6,400MMBO)
Solution gas drive
Naturally fractured, water-wet over-pressured chalk
Water injection since 1987 (successful)
Recovery factor (35%; primary=18%, secondary=17%)

Fig. 12　Ekofisk Field, in the Norwegian sector of the North Sea, produces from several water-wet, Type Ⅲ primary chalk reservoirs



OOIP (3,000 MMBO)
Initially solution gas drive, followed by gravity drainage
Naturally fractured, oil-wet chalky limestone reservoi
Water injection began in 1972 (failed)
Crestal gas injection since 1982 (successful)
Recovery factor (22%)

Fig. 13　Natih Field in Oman produces from an oil-wet, Type Ⅲ diagenetic chalk reservoir

4 Conclusions

Type Ⅱ fractured oil reservoirs have low matrix porosity and permeability. Matrix provides some storage capacity and fractures provide the fluid-flow pathways. Type Ⅲ (microporous) fractured oil reservoirs have high matrix porosity and low matrix permeability. Matrix provides the storage capacity and fractures provide the fluid-flow pathways. Previous fractured reservoir classifications did not distinguish between Type Ⅱ and Type Ⅲ reservoirs, instead combining all fractured reservoirs with low matrix permeability together into one group. By studying mature, well-documented fields that produce from 26 Type Ⅱ and 20 Type Ⅲ fractured oil reservoirs, it was demonstrated that recovery factor is controlled by different factors in these two reservoir types. In Type Ⅱ reservoirs, recovery factor appears to be more dependent on the nature of the fracture network than on the matrix properties of the rock or the fluid properties of the oil. Because fracture networks in Type Ⅱ reservoirs tend to be extensive, they are commonly connected to downdip or underlying regional aquifers. Recovery factor in Type Ⅱ reservoirs is very sensitive to aquifer-drive strength and optimization of flow rate. Type Ⅱ reservoirs are easily damaged by excessive production rates. When properly managed, some achieve good recovery factors without the need for secondary or enhanced recovery programs. Rock and fluid properties exert a more significant control on ultimate recovery factor in Type Ⅲ reservoirs. Recovery factor in Type Ⅲ reservoirs is affected by fracture intensity, wet ability, matrix permeability, API gravity, mobility ratio, net/gross ratio, and residual water saturation. The choice of proper EOR technique is essential for optimizing recovery. No Type Ⅲ reservoir was produced to final depletion without the aid of some type of secondary recovery or EOR technique.

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裂缝性油气藏采收率：100个裂缝性油气田实例的经验总结

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摘要： 通过对世界上100个裂缝性油气藏的综合评价，研究储集层及流体本身的性质（包括孔隙度、渗透率、黏度、可动油比例、含水饱和度、润湿性及裂缝分布特征等）和驱动机制及油藏管理战略（优化日产量和采用不同类型的提高采收率技术）对其最终采收率的影响。将裂缝性油气藏分为4类：I类的基质几乎没有孔隙度和渗透率，裂缝是储存空间和流体流动的通道；II类的基质有较低的孔隙度和渗透率，基质提供储存空间，裂缝提供流动通道；III类（微孔隙）的基质具有高孔隙度和低渗透率，基质提供储存空间，裂缝提供流动通道；IV类（大孔隙）的基质具有高的孔隙度和渗透率，基质提供储存空间和流动通道，裂缝仅增加渗透率。对26个II类油气藏和20个III类油气藏的开采历史的研究表明：II类油气藏的采收率受水驱强度和最优日产量控制，日产量过高会很容易破坏II类油气藏，一些II类油气藏如果管理得当，采收率可以很高，不需要二次或三次采油；III类油气藏的采收率主要受岩石和流体本身性质的影响，特别是基质渗透率、流体重度、润湿性以及裂缝强度等，不进行二次或三次采油不可能完全开采，往往需要采用一些提高采收率的专门技术。以往将II类和III类裂缝性油气藏归为一类，认识它们的区别将有助于选择更好的开发策略。

关键词：采收率；裂缝性油气藏；驱油机理；裂缝性油气藏分类

enhanced crossflow membrane filtration of oily waste water using the membrane as a cathode[J]. Journal of Membrane Science, 1999, 156(1): 49-60.

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Pilot-plant of oily wastewater treatment for reinjection of low permeability oilfield

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Abstract: In order to meet the strict water quality standards, a pilot plant examination of oil wastewater treatment for reinjection to low permeability oil field was carried out in Liaohe Oilfield. Oil remover was added to the wastewater before it went into the precipitation tank. Then, the oil content of oily wastewater dropped from 20g/L to 150mg/L, as well as the suspended solid from 10g/L to 3g/L. EDUR multiphase pump air floatation was applied, which could reduce the contents of oil and suspend solid to 5mg/L and 30mg/L, respectively. Finally, after a novel technology of guhr dynamic membrane ultra filtration, the content of oil and suspended solid in oily wastewater was all lower than 2mg/L, and the average diameter of suspended solid was about 1μm. Guhr filter that has a low operational cost is in possession of the merits of both packed bed and ultra filtration membrane.

Key words: oily wastewater; reinjection; low permeability; guhr filter

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