


Article

Review of Marginal Oil Resources in Highly Depleted Reservoirs

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Abstract: The term “marginal oil resource” refers to an oil reservoir that has hydrocarbon resource preservation but cannot meet the criteria of resources under the U.S. Securities and Exchange Commission (SEC) standards. When oilfields step into their late life, most of their economic petroleum reserves have been well developed, and their focuses need to be switched to their intact marginal resources. In this paper, reservoir characteristics and key petrophysical properties of marginal oil resources are introduced to classify marginal oil resources into four types for identifying potential development opportunities. Primary recovery and its following development strategy are applied to fully utilizing their economic returns. Waterflooding, low salinity waterflooding (LSW) and enhanced oil recovery processes are reviewed to illustrate its potential uplift on oil production and application challenges such as higher clay content in marginal resources than in commercial reservoirs. An oilfield is presented as a case study to demonstrate the classification of marginal resources and illustrate successful economic development including learnings and challenges. This paper highlights the development potential of marginal resources and proposes a clear guidance for policy makers on how to tailor a development strategy supporting their economic development. This review could increase certainty on forecasting performance of marginal resources.

Keywords: marginal resources; economic analysis; waterflooding; low salinity waterflooding



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1. Introduction

1.1. Marginal Resources

The U.S. Securities and Exchange Commission (SEC) defines oil reserves as those that are “judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment” [1]. Based on these SEC standards, petroleum reserves are classified as either proved, proved developed, proved undeveloped, probable or possible reserves. However, because a marginal resource reservoir is not within an effective thickness laid out in these standards, marginal resources are not found among these reserve classifications. Indeed, the limited thickness of a marginal resource’s formation accounts for its classification as a resource rather than a reserve.

The concept of an oil marginal resource refers to oil formation that has resource identification but can neither meet the criteria to be evaluated as a reserve nor count as an economic reserve. Although an application of hydraulic fracturing or enhanced oil recovery (EOR) processes can result in an industrial oil flow criterion, this kind of resource still does not meet the SEC reserve evaluation standards and, therefore, effective reserve and

economic evaluations cannot be carried out. Until now, as the base of their total reserves' calculations is not established, the amounts of marginal resources have not been stated in any oilfield development plan nor formally included in the world's reserve statistics.

Marginal resources can be divided into two types: Marginal Type I and Marginal Type II [2]. A Marginal I resource can be defined as a resource formation identified as a sandstone formation for which its thickness cannot meet the effective thickness standard of 0.2 m. This type of marginal resource has been perforated and developed, but when compared to a commercial pay zone, its development is less effective. As shown in Table 1, the average permeability, porosity, and initial oil saturation (S_o) are 180 mD, 25% and 45%, respectively, which are less than the ones of poor reserves. A Marginal II resource is used to indicate a resource formation that is not recognized as a sandstone formation. Compared with Marginal Type I, its permeability, porosity, and oil saturation are 60 md, 20% and 35%, respectively, indicating worsen reservoir quality.

Table 1. Properties of different resource types. S_o : initial oil saturation. The arithmetic average method is applied to calculate the permeability.

Resource Classifications		Permeability (mD)	Porosity (%)	S_o (%)
Economical reserves		400+	26	80
Poor reserves		200+	25	68
Marginal resources	Type I	180	25	45
	Type II	60	20	35
	Average	21	20	40

Marginal resources can be further divided into two basic types according to their physical properties and contact relationships with other reserve layers. (1) Isolated marginal resources comprise a single layer that is composed only of a marginal resource, with a separation layer of larger than 0.5 m from a reserve layer. Based on different types of marginal reservoirs, they can be called either the Marginal Type I isolated resources or Marginal Type II isolated resources. A marginal resource with a sandstone thickness but without reaching an effective thickness criterion can be regarded as an isolated marginal resource. (2) Connected marginal resources comprise a marginal formation at the top or bottom of a reserve layer called a connected marginal resource. A junction boundary is in contact with the reserve layer or, if there is a separation layer, the thickness of the separation layer is less than 0.4 m. Based on different marginal types, they can be divided into Marginal Type I connected resources or Marginal Type II connected resources. Compared with isolated and connected marginal resources of either Type I or Type II, their reservoir quality is very similar, as shown in Table 2. The contact relationships with other reserve layers do not affect their own reservoir quality.

Table 2. Average properties for different resource types.

Resource Type	Porosity (%)	Permeability (mD)	Shale Content	Sorting Degree	Median Grain Size (μm)
Reserves	26	1000	8.73	2.91	130
Isolated I	25	200	15.92	4	71
Connected I	24	160	14.55	3.83	78
Isolated II	20	40	20.71	4.22	47
Connected II	20	88	19.23	4.08	54
Average of Marginal	22	118	17.65	4.01	62

For mature oilfields, developing marginal oil resources is usually featured as uncertain economics, possessing high risk and doubtful profitability. However, they are considered as a hot topic across major oil consumption regions where energy security is a major concern. Otombosoba (2018) studied exogenous factors affecting the development of marginal

resources in emerging economies, such as China, Nigeria, India, Indonesia, Malaysia and Venezuela. Successful development depends on the principle of sustainability, with the consideration of political, social, economic, legal and technological issues [3]. Adetoba (2012) summarized the key challenges faced by developing marginal resources in Nigeria. Funding and lack of technological know-how seem to be two main concerns [4]. Economical assessment directly affects a development decision. Acheampong (2021) proposed a real option method in valuing marginal resources in UK considering various uncertainties [5]. This method shows advantages over a traditional discounted-cash-flow method in management decision. Greenhouse gas emissions have been an increasingly important factor controlling the development of marginal resources. Masnadi et al. (2021) studied greenhouse gas emissions effects on marginal resources and concluded that carbon intensity was determined by the magnitude of an oil demand decline [6].

1.2. Recovery Processes

Around the world, a large portion of oilfields has been developed through water flooding and has now entered a stage of high water cut [7]. In this case, it is a common desire to tap the residual potential of old oilfields with limited costs. Therefore, marginal resources, an example of a resource type that held little value in the past, is now of great research significance.

1.3. Waterflooding

Waterflooding processes are heavily utilized in conventional oil reservoirs and can be applied for the development of marginal resource reservoirs. The mechanisms of waterflooding have been well understood since the 1970s [8]. It has also become an important recovery process for marginal resources. Hu (2008) presented a new redevelopment concept for marginal resources by waterflooding in mature oil fields under PetroChina [9]. The expected recovery of waterflooding is about 33.6%, with average water displacement efficiency of 56%, while field performance indicated that displacement efficiency can range 60–80%. Its controlling factors were identified as layer heterogeneity, connectivity, an oil-water mobility ratio, and well patterns. Bo and Zhao (2008) leveraged a subdivision of oil layers to improve the performance of waterflooding in the Gaotaizi oil zone, Daqing Oilfield [10]. The subdivision was achieved by considering a sublayer number and sandstone thickness, layer connection and a fingering coefficient. Field performance showed that oil production was increased by 18 t/d and water cut was reduced by 0.42%. A successful reservoir management can guarantee the successful development of marginal fields. Ge et al. (2011) presented a reservoir management program in waterflooding development in the Bohai field, including water management, infill drilling and EOR. Controlling a rising rate of water was the main goal of water management [11]. They implemented water injection optimization, sand plugging and balancing reservoir energy by smart water injection to successfully reduce a water-cut increasing rate from 20% per year to 3.5% per year. Imuokhuede et al. (2020) proposed screening criteria for waterflood projects in the Niger Delta marginal reservoir by using simulations [12]. Reservoir depth, gas saturation, residual oil saturation, oil gravity, oil viscosity and the presence of an aquifer were selected as controlling parameters. Their results indicated that oil saturation of less than 33%, gas saturation of greater than 15% and oil viscosity of less than 30 cP were favorable for waterflooding. During a production and displacement process, it has been observed that isolated marginal resources can effectively provide a functional production capacity [2]. The reason is that in the development process of a connected marginal reservoir, displacement is more likely to occur in layers with high permeability, especially after water breakthrough. In this case, low permeability layers cannot be efficiently used. Wei et al. (2020) applied Nuclear Magnetic Resonance (NMR) to characterize a residual oil distribution during a core waterflooding test. Their results showed that the residual oil saturation was higher at the outlet of cores, and an improved viscous force could further reduce it [13].

1.4. Low Salinity Waterflooding

In recent years, increasing research has been focused on the specific types of waterflooding such as hot water injection [14], water injection in heavy oil reservoirs [15], and low salinity waterfloods [16,17]. In particular, research activities on low salinity waterflooding have sharply increased from 2 to 360 publications from 1960 to 2018 [18].

In 1997, Tang and Morrow reported that oil recovery could be improved by low salinity waterflooding (LSW) [19]. They conducted four imbibition and waterflooding tests and examined the effects that changes in salinity had on the waterflooding outcome. Their results showed that at $t_D > 10,000$ (t_D was dimensionless time), the final oil recovery increased as salinity decreased. In their view, the possible reason for this phenomenon could be due to a change in wettability. They thought that water wetness would increase with sustained high-water saturation conditions because of a combination of the effects of oil and water interfaces [19].

Later, Zhang and Morrow performed an experimental study of LSW on cores with different permeabilities [20]. The permeabilities of their cores were 60 mD, 400 mD, 500 mD, and 110 md. For each core, two fluids (reservoir brine and low salinity brine) were used to perform 2 PV (pore volume) and 10 PV injection tests. Their results showed that, with the exception for core Berea 400, LSW produced lower residual oil saturation and better recovery efficiency. However, although the recovery of LSW and reservoir brine did not show a big difference, after the injection of distilled water, an increase in differential pressure appeared and contributed 3.8% of OOIP (original oil in place) in a 2 PV test [20].

Another study by Tang and Morrow in 1999 pointed out three conditions for a low salinity effect (LSE): a significant clay fraction, presence of connate water and exposure to crude oil to create mixed-wet conditions based on tests conducted on Berea-sandstone cores [21]. In this case, more research on not only laboratory core tests but also field experiments are needed. In 2004, BP (British Petroleum) reported that up to 60% of residual oil in an oilfield was produced by using a LSW process [22]. Within the area of a radius of about 13 to 14 ft around a wellbore, low-salinity effects can reduce the residual oil caused by HSW (high SW), which was about 13% of OOIP [23]. However, they also reported an unsuccessful example in a North Sea field in which both field pilot tests and laboratory tests failed, although the conditions were all met [24].

Such a huge difference in LSW between different fields could also be evidence of the complexity of its mechanisms. As Bartels et al. mentioned, LSW is a “cooperative process in which multiple mechanisms are acting on different length and time scales” [18]. From the literature, it has been found that the mechanisms of LSW are composed of several different effects, such as fines migration [16,21], mineral dissolution [25], variation in interface viscoelasticity [26] and a pH change effect [17,23].

As mentioned above, Tang and Morrow found that water wetness increased as water saturation increased [21]. Berg et al.’s research provided direct evidence that showed that wettability modification in a clay surface is one of the mechanisms for LSW [27]. Furthermore, Yousef et al. designed an experiment with composite rock samples from a carbonate reservoir [28]. Although the target of their study was to improve recovery by applying the injection of seawater, their dilution liquid injection test also proved that “altering the salinity and ionic content of the injection water can alter the rock wettability toward a more water-wet state” [28].

1.5. Enhanced Recovery

A long period of low oil prices has forced oil companies to seek lower cost reserves to develop. EOR technology can provide an effective method to effectively increase production of marginal resources, especially for reservoirs after waterflooding. Wang et al. (2019) introduced polymer injection combined with short well spacing tests in the Daqing oilfield. Both lab tests and pilot results indicated that this strategy combined with injection management can improve volumetric sweep efficiency and increase a recovery factor by around 10% with an additional cost of USD 10/bbl [29]. They examined a residual oil distri-

bution after polymer flooding based on CT scanning. The sweep efficiency could be further increased around 11.4% than the one of waterflooding. Resnyanskiy and Babadagli (2010) studied the implementation of surfactant injection in a marginal oilfield, Sinclair field [30]. They applied numerical simulation to model this reservoir, match history and forecast surfactant injection. They indicated that its recovery factor could reach 80%, and surfactant injection was expected to possibly provide new life to the Sinclair field. Water-alternating-gas (WAG) injection was also recommended to increase oil recovery in ultra-high water-cut reservoirs. Kong et al. (2021) experimentally investigated the performance of WAG and found that WAG could further improve oil recovery by around 15% above the base of waterflooding [31]. CO₂ injection has been an increasingly important recovery process for mature oilfields, as it could trigger miscible flooding to enhance oil production and reduce greenhouse gas emissions [32]. Nanoparticles have also been tested in the laboratory to increase oil production [33]. For heavy oil marginal reservoirs, a well-designed thermal recovery process could significantly improve oil recovery [34–38].

2. An Oilfield

An oilfield is presented as a case study to demonstrate the classification of marginal resources and illustrate successful economic development including learnings and challenges. This oilfield is located in China. Reservoir rocks are lacustrine and fluvial-deltaic sandstones, with siltstone deposits in the middle of an upper Cretaceous layer. After 70 years exploitation, this oilfield has now entered an ultra-high water cut period. Its sandstone reservoir distribution is wide and thick with high heterogeneity.

Since 2010, this oilfield has become a target of waterflooding due to the nature of its reserve, which contains thin layers that are low in porosity and permeability. This kind of reserve has contributed 30% of the geological resources in this oilfield. However, after three rounds of production adjustments with waterflooding, the remaining oil in these thin layers has been difficult to produce any further. Therefore, it is imperative to find other resources to support a further development of this oilfield. During its development process, marginal resources, once considered uneconomic resources, should now be strongly considered. Although the effective thickness of marginal resource formation in this field is thinner than common reserve formations, it has been proven that it has 28% of the total geological resources and has already been produced during three rounds of development adjustments. Thus, it can be considered an important supplement for the development of this oilfield. In order to study the development status of different types of reserves after extremely high water cut and water saturation occurring in this oilfield, a large number of coring wells were drilled in different well sectors (Liu, 2020). According to core data, water flooding conditions and exploitation degree of poor reserves were comprehensively analyzed.

Due to poor reservoir properties of marginal resources, such as layers thinner than 0.2 m, they cannot be effectively identified by well log curves or even laboratory tests in the same manner as for standard resources. Thus, property and development characteristics of marginal resource reservoirs are not well understood. Although marginal resources remain unlisted in both SEC standards and SPE (Society of Petroleum Engineers) reserves evaluation system because their reserves cannot be well estimated, they nonetheless play a crucial role in ramping up production and extending the life of depleted oilfields. This is particularly true in the case of the studied oilfield with its original well pattern still intact during the late stage of its development process.

Marginal resources can be studied based on core data analysis. After primary recovery, waterflooding is a main production process. In the past development, they were only targeted as supplementary perforations and not included as a main evaluation and development object. The results of their resource quantity assessment show that in the total resource quantity of this oilfield, marginal resources with an effective thickness less than 0.2 m and poor reserves with an effective thickness between 0.2 m and 0.5 m account for 27.9% and 19.3%, respectively (Figure 1). These two types of resources, therefore, constitute

the main object of the current oilfield development plan and become the principal reserves supporting the future production of this oilfield.

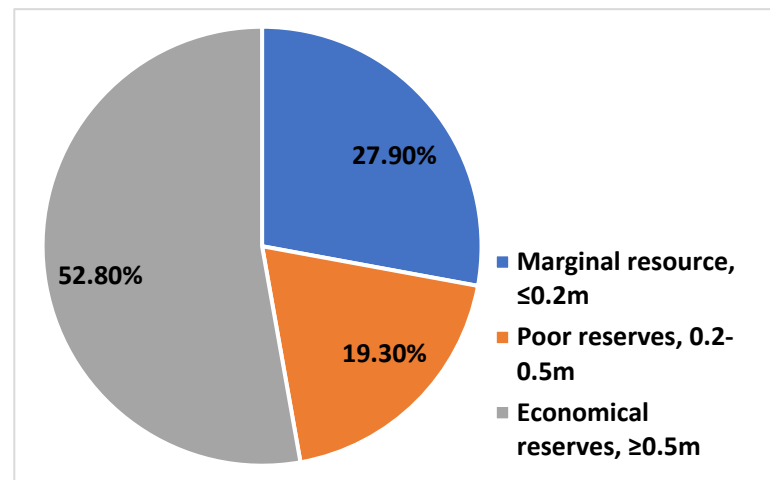


Figure 1. Geological resource distribution of the studied oilfield (data from [2]).

2.1. Key Reservoir Properties of the Oilfield

The concept of oil occurrence is an index for petroleum engineers to visually evaluate cores for the studied oilfield. It is evaluated by an oily area percentage and an oil saturation degree. Oil occurrence, from high to low, is divided from 1 to 5 degrees, respectively (Figure 2).

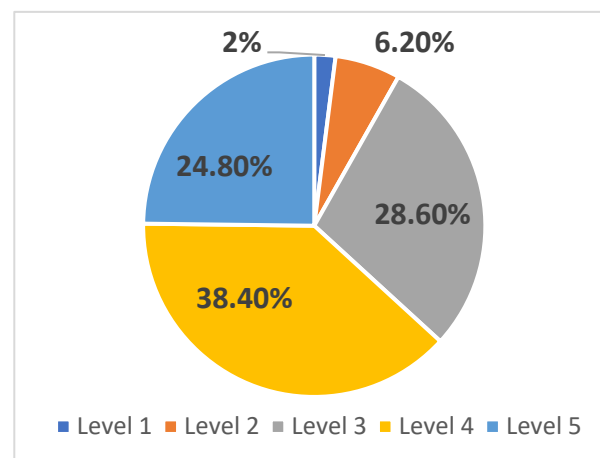


Figure 2. Oil occurrence level distribution for the marginal resource in the studied oilfield.

The oil occurrence level of a marginal resource is mainly three, four or five and its shale content is as high as 20.44% in this oilfield. The excessive shale content not only brings water sensitivity problems to a water-flooding production process but also brings significant challenges to laboratory analysis and test work. Meanwhile, the permeability of most parts of the marginal resource reservoir is less than 20 mD, and the parts where permeability is less than 10 mD yield the portion of 40% (Figure 3). The thickness of these layers is 61% of the total marginal resource thickness. Among these marginal resource layers, some layers have such a low permeability that they cannot meet the permeability standard of an effective thickness, while other layers are too thin to be classified as a marginal layer due to the limitation of logging interpretation accuracy. Generally, the permeability of marginal resources is between 1 and 200 mD; however, due to the diversity of production locations and challenges, this classification standard is not comprehensive. Although this oilfield's subsequent overall statistics can be used to shed light on this phenomenon, the

inconsistency of operational standards brings great difficulties to the understanding of marginal resources.

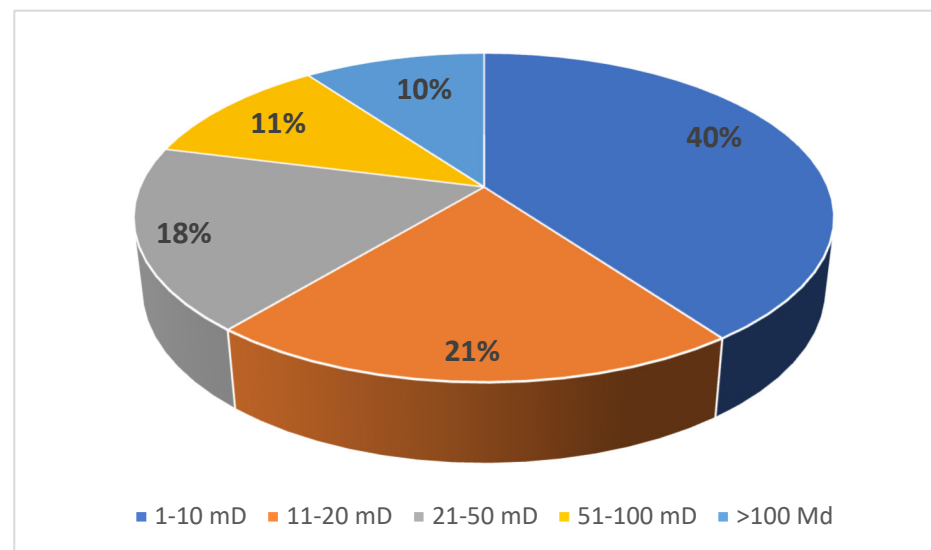


Figure 3. Permeability distribution of marginal resources in the studied oilfield.

Yet another property of marginal resource reservoirs is original oil saturation. In general, original oil saturation is relatively low, ranging from 37% to 44% on average, and porosity is typically between 20% and 22% (Table 1).

According to experimental mercury injection data of the marginal resources found in this oilfield [2], pore radius distributions for different permeability cores are similar, and the distribution range is roughly the same (Figure 4). However, huge differences in curve shapes are found on pore throat radius curves. For cores with different permeabilities, the smaller the core permeability, the smaller the range of a throat radius. Therefore, a throat radius can, in fact, be a major factor in determining the flow behavior of a marginal resource reservoir.

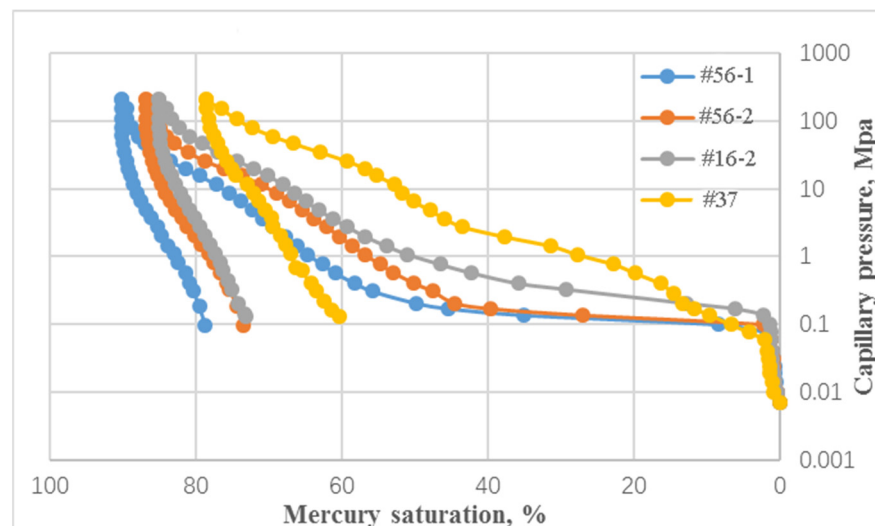


Figure 4. Capillary pressure curves comparisons.

2.2. Reservoir Classifications and Key Properties

Based on the types of marginal resources defined above, the marginal resources found in the studied oilfield are divided into four categories: an Isolated Marginal I resource, a Connected Marginal I resource, an Isolated Marginal II resource and a Connected Marginal

II resource. By the end of 2017, 162 cored wells were drilled in this oilfield, and a mass of core analysis data was obtained. All core data were classified into these different resource types. The average properties, such as porosity, permeability, shale content, sorting, and median granularity of the core data are shown in Table 2 (Liu, 2020). The sample size for each property is from 25,000 to 65,000. Due to the huge quantity of data, these average properties are considered to be physical properties for their corresponding resource types.

After comparing all properties from the reserve layers to the connected Marginal II resource, porosity, permeability, and median granularity were found to decrease as the resource level reduced, and shale content and sorting were observed to increase. However, instant recovery efficiency data show that there is still a substantial amount of oil remaining in the marginal resources (Liu, 2020).

3. Development Study

In this section, development strategies for the studied oilfield are proposed and studied. The region under study in this oilfield has passed through the following stages: primary recovery, water injection, primary well pattern infilling and secondary well pattern infilling. After the secondary infilling, production conditions in this region were improved, and the production status of its marginal resources was greatly improved. However, some parts in Marginal I resource formation and a small part in the reserve formation were still poorly developed. In addition, most Marginal II resources remained undeveloped. In this case, both the marginal resource layers and the reserve layer were set as a development target.

The third infilling wells in the studied region have been proposed, and the average production rate of these new wells was 2 t/d; however, the daily production of 38% of the wells was less than 1 t. In the entire region, daily production increased from 189 t to 400 t. After these adjustment wells were placed into production, the production of the region's original wells also increased. However, due to large well spacing and layer to layer disturbance, the development of these third infilling wells was not ideal.

As mentioned above, adjustment wells developed some new reservoir layers and curbed decline in production. However, the properties of the target layers, which are poor reserves and marginal resource layers, are of low quality: The shape and distribution of the residual oil are complex, single well production is low and the water cut is high. In this case, more stimulation methods are needed to stabilize production. Accurate perforation and smaller well spacing should be primary solutions for these marginal resources.

The development principle for a marginal resource is to combine development with poor and even normal reserves layers. However, the disadvantage of this development principle is that displacement will not be effective in a marginal resource due to significant differences in properties between two types of resources. Analyzing the production of third infilling wells shows that the proportion of the wells with a daily production lower than 2 t is high (Figure 5). The reason for this low production is that a marginal resource layer is thick, which results in larger interlayer disturbances. On the other hand, due to huge differences in properties between marginal resource and commercial oil layers, water tends to flow through existing flow channels. In this case, the development of an independent strategy for marginal resources that is based on the third well pattern is conducted.

In independent development areas, several new wells are planned and only have perforation on marginal resource layers. After a year of operation, a pilot zone commences water injection. The production from this pilot zone increases, and water cut decreases. The development outcome is better than that found among other adjustment wells in the same block. This shows that marginal resources in the studied oilfield can be economically developed with existing production equipment and well patterns and can be a main target for subsequent development of this oilfield. Due to the confidentiality of the production data for the time being, we cannot report it here and hope that it will be available in the near future. The safety issue also needs to be considered during developing marginal reservoirs. Due to a thin reservoir layer, water injection may cause formation failure, affecting the

surface's operations. Monitoring reservoir pressure is also important to guarantee safe drilling of infill wells.

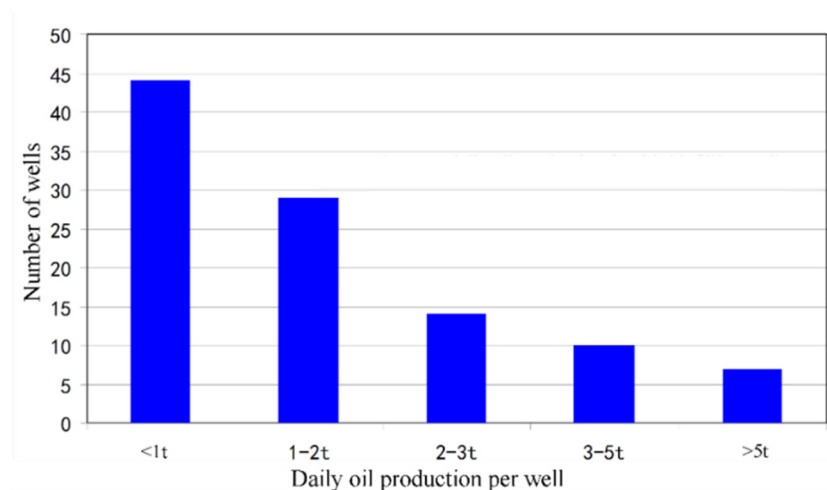


Figure 5. Daily production for third infilling wells at the initial production stage, with average of 2.04 t.

4. Conclusions

Due to their poor physical properties and thin layer thickness, developing marginal resources confers few economic benefits. However, marginal resources can still be effectively and economically developed during later stages of established oilfield development, as they reduce development costs through leveraging existing wells and production equipment. The development strategies proposed for the studied region in the current oilfield demonstrate that a marginal resource can be effectively developed by using appropriate well patterns and well completion. Infill wells and waterflooding have a great potential to enhance well performance-targeting marginal resources. A detailed core description can help us in understanding marginal resources. A safety issue is also an unneglected component for their development. The current study indicates that this region can be part of a sound economic development plan to target marginal resources found in highly depleted conventional sandstone reservoirs and make use of existing production equipment and wells.

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