

STUDY OF THE DEVELOPMENT PROCESS FEATURES OF THE DARWIN BANK OIL FIELD

Zamiq Bakhtiyar MIRZAJANOV, Assoc. Prof.
Azerbaijan State University of Oil and Industry

Aghabey AGHABEYLI
Azerbaijan State University of Oil and Industry
Department of “Oil and Gas Engineering”
Master's student in Petroleum Engineering,
E-mail: agabeyagabeyli98@gmail.com

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Abstract: This paper analyzes the current development state of the Darwin Bank oil field located in the Azerbaijani sector of the Caspian Sea. The aim of the study is to assess field performance, identify the main factors affecting production rates, and determine possible directions for improving production efficiency under mature-field conditions. Due to the limited availability of detailed field data, the research is based on typical parameters of analogous oil fields and simplified engineering assumptions. The study evaluates the influence of bottom-hole pressure and water cut on production behavior. The results show that well productivity is strongly affected by the relationship between reservoir pressure and bottom-hole pressure. A decrease in pressure drawdown leads to reduced fluid inflow and lower production rates. At the same time, multiphase flow conditions create nonlinear production behavior, making performance prediction more complex. Special attention is given to water cut, which significantly reduces net oil production and worsens the quality of produced fluids. The comparison between theoretical production potential and actual performance indicates reservoir pressure depletion, increased water production, and declining well productivity. Overall, the Darwin Bank field is characterized as a mature field at a late stage of development. The results suggest that production efficiency may be improved through pressure maintenance, water control, and optimization of well operating conditions.

Keywords: field development, well productivity, reservoir pressure, water cut, production efficiency.

Introduction

One of the main priorities in modern petroleum engineering is to maximize the oil recovery factor from existing fields. This requires a detailed understanding of reservoir geology, petrophysical properties, and physical processes occurring within the formation. In multiphase oil–gas–water systems, flow behavior is especially complex, and its proper assessment is essential for developing an effective field development strategy. Offshore fields are even more challenging due to technical limitations, restricted infrastructure, and strict safety requirements. Therefore,

production optimization is particularly important on offshore platforms, where multiphase flow regimes such as bubbly, slug, and annular flows directly affect production stability and efficiency [1].

The reserves and production history of the Darwin Bank field reflect its long-term exploitation. According to various sources, the initial balance reserves are estimated at approximately 3 million tons of oil and 0.5 billion m³ of gas. However, during its production history, about 16–17 million tons of oil and 1.4–1.5 billion m³

of gas have already been produced. These indicators show that the field is highly depleted. More than 700 wells, approximately 776, have been drilled in the field, and by the 2020s, more than 780 wells were reported, indicating intensive long-term development [2].

Maintaining reservoir energy is a key issue in field development. At the initial stage, production is mainly supported by natural reservoir energy, when pressure and well productivity are relatively high. Over time, reservoir pressure declines, leading to lower production rates and the need for additional technological measures, such as water or gas injection and artificial lift methods. In modern petroleum engineering, field development analysis is supported not only by empirical observations but also by mathematical modeling and reservoir simulation, which help forecast production behavior and support scientifically based optimization decisions [3].

Currently, the Darwin Bank field is considered to be at a mature, or late, stage of development. Studies indicate that approximately 70–80% of recoverable reserves have already been produced. This stage is characterized by declining reservoir pressure, reduced well productivity, and increasing water cut. In 2015, the expected production rate from wells drilled from new platforms was estimated at about 5 tons/day, confirming the low-productivity stage of the field. At the same time, earlier projects planned production rates of up to 50 tons/day for some platform wells, showing significant productivity differences across the field [2].

Object

The objective of this study is to analyze the current development state of the Darwin Bank oil field and evaluate the main factors affecting its production performance. Special attention is given to the influence of water cut and bottom-hole pressure on net oil production and theoretical flow rate. The study also aims to identify the key production challenges typical for mature offshore fields, including reservoir pressure decline, increasing water production, and reduced well productivity. Based on the obtained results, possible directions for production optimization are proposed.

Methods

In this study, a simplified methodological approach was applied to analyze the development

characteristics of the Darwin Bank oil field and evaluate production optimization possibilities. Due to the limited availability of detailed open-source geological, reservoir, and operational data, the research was based on analytical calculations, simplified mathematical models, and the analog-field approach. To make the calculations suitable for preliminary engineering assessment, the reservoir was assumed to be isothermal, homogeneous, and isotropic, while the filtration process was considered radial. Although these assumptions do not fully reflect the real complexity of the Darwin Bank field, which is characterized by heterogeneity, multilayer structure, and tectonic complexity, they are commonly used in petroleum engineering for initial evaluations and allow the main development trends to be identified.

In order to assess well productivity, the inflow performance relationship, or IPR approach, was first applied. This model describes the relationship between the pressure drawdown and the production rate of the well. In its simplest linear form, the IPR equation can be expressed as follows:

$$q = J(P_r - P_{wf})$$

Where q is the production rate, j is the productivity index, P_r is the reservoir pressure, and P_{wf} is the bottom-hole flowing pressure.

However, it should be noted that the linear IPR model has certain limitations. It is mainly applicable to single-phase liquid flow and does not fully describe the behavior of multiphase systems. In mature oil fields, especially under conditions of pressure depletion, dissolved gas begins to separate from the oil, leading to two-phase or three-phase flow in the reservoir and wellbore. As a result, the relationship between pressure and flow rate becomes nonlinear. Therefore, the application of a more realistic model is required for evaluating production behavior in multiphase systems [4, 5].

For this reason, the Vogel model was applied in the next stage of the study. The Vogel model is widely used for oil wells producing under solution-gas drive conditions and makes it possible to account for the nonlinear character of multiphase flow. The model is expressed as follows:

$$\frac{q}{q_{max}} = 1 - 0.2 \left(\frac{P_{wf}}{P_r} \right) - 0.8 \left(\frac{P_{wf}}{P_r} \right)^2$$

Where q is the production rate at a given bottom-hole pressure, q_{max} is the maximum theoretical production rate, P_{wf} is the bottom-hole flowing pressure, and P_r is the reservoir pressure.

In addition to inflow performance analysis, a material balance approach was used to evaluate the development stage of the field. Material balance is one of the classical methods in reservoir engineering and allows the relationship between produced reserves and reservoir pressure decline to be assessed. In simplified form, this approach can be expressed as:

$$N_p = N \frac{(P_i - P)}{P_i}$$

Where N_p is the cumulative produced oil, NNN is the initial oil in place or recoverable reserves considered in the simplified calculation, P_i is the initial reservoir pressure, and P is the current reservoir pressure.

Through this approach, the effect of increasing water cut on oil production was qualitatively analyzed, and it was shown that a high water content reduces the economic efficiency of production. In addition, changes in the gas-oil ratio were also considered as one of the important factors affecting the development process. An increase in the gas-oil ratio is associated with a decrease in reservoir pressure and leads to changes in multiphase flow regimes. This, in turn, affects flow stability both inside the wellbore and in pipelines. In the study, this factor was qualitatively evaluated, and its impact on the production process was analyzed in a generalized manner [6].

Based on generalized information available from open sources, the daily production rate for one platform was assumed to be approximately 5 tons per day. For the purpose of calculation, it was assumed that an average of 12 wells were operating on the platform. This assumption is based on typical well density and production distribution patterns observed in offshore fields. By assuming that the total production is distributed evenly among the wells, the average production rate per well was determined. The average production rate per well was calculated as follows:

$$q_{well} = \frac{q_{platform}}{n}$$

If the platform production rate is assumed to be 5 tons per day and the number of operating wells is 12, then the average production rate per well is:

$$q_{well} = \frac{5}{12} = 0.42 \text{ tons/day}$$

This value indicates a very low average well productivity, which is typical for mature and highly depleted fields. Such a low production level may be explained by reservoir pressure decline, increasing water cut, deterioration of reservoir energy, and possible inefficiencies in the drainage of remaining oil-saturated zones. In order to evaluate the production structure more accurately, different water cut scenarios were considered. Water cut was varied from 10% to 80%, and its effect on net oil production was analyzed. The net oil rate was calculated using the following expression:

$$q_0 = q_l(1 - W_c)$$

Where q_0 is the net oil production rate, q_l is the total liquid production rate, and W_c is the water cut expressed as a fraction.

This approach makes it possible to determine how much of the produced liquid is actually oil and how much is water. For example, if the total liquid production remains constant while water cut increases, the amount of produced oil decreases significantly. This is one of the main problems in mature fields, where high water production may make further exploitation economically less attractive.

Results

The results of the analysis are presented in the tables below.

The results show that the Darwin Bank field is at a mature stage of development, with declining reservoir energy, increasing water cut, reduced well productivity, and unstable multiphase flow conditions. Water cut significantly affects net oil production: at a constant total production rate of 5 t/day, oil output decreases from 4.5 t/day at 10% water cut to 1.0 t/day at 80% water cut.

Table 1

Water cut impact

Water cut (%)	Total production rate (t/day)	Oil production (t/day)
10	0.42	0.378
20	0.42	0.336
30	0.42	0.294
40	0.42	0.252
50	0.42	0.210
60	0.42	0.168
70	0.42	0.126
80	0.42	0.084

Table 2

Total platform production, 12 wells

Water cut (%)	Total production rate (t/day)	Oil production (t/day)
10	5	4.5
20	5	4.0
30	5	3.5
40	5	3.0
50	5	2.5
60	5	2.0
70	5	1.5
80	5	1.0

Table 3

Theoretical production rate based on bottom-hole pressure (12 wells)

Bottom-hole pressure (bar)	Flow rate (m ³ /day)	Aproximate production (t/day)
180	12.0	10.0
170	19.0	15.3
160	26.0	20.7
150	33.0	26.0
140	41.3	32.7
130	49.7	39.3
120	58.0	46.0
110	65.5	52.0
100	73.0	58.0
90	80.5	64.0
80	88.0	70.0
70	93.3	74.3
60	98.5	78.5
50	103.8	82.8
40	109.0	87.0

This confirms that increasing water content reduces the useful hydrocarbon component and lowers production efficiency. Bottom-hole pressure also strongly influences well productivity. As pressure decreases from 180 bar to 40 bar, the theoretical flow rate increases from 12 m³/day to 109 m³/day, showing the importance of pressure drawdown for fluid inflow. However, bottom-hole pressure should be optimized rather than simply reduced, since excessive drawdown may cause gas liberation, water breakthrough, and unstable flow. Overall, production optimization should focus on increasing net oil production

through water control, selective well operation, artificial lift optimization, and pressure management.

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DARVIN BANKASI NEFT YATAĞININ İŞLƏNMƏ PROSESİNİN XÜSUSİYYƏTLƏRİNİN TƏDQIQI

Dos. Zamiq Bəxtiyar MİRZƏCANOV

Azərbaycan Dövlət Neft və Sənaye Universiteti

Ağabəy AĞABƏYLİ

Azərbaycan Dövlət Neft və Sənaye Universiteti

“Neft və Qaz Mühəndisliyi” kafedrası

Neft-qaz mühəndisliyi ixtisası üzrə magistrant

E-mail: agabeyagabeyli98@gmail.com

Xülasə: Bu məqalədə Xəzər dənizinin Azərbaycan sektorunda yerləşən Darvin bankası neft yatağının hazırkı işlənmə vəziyyəti təhlil edilir. Tədqiqatın məqsədi yatağın hasilat göstəricilərini qiymətləndirmək, hasilat səviyyəsinə təsir edən əsas amilləri müəyyən etmək və yatağın yetkin işlənmə mərhələsində hasilat səmərəliliyinin artırılması istiqamətlərini araşdırmaqdır. Yataq üzrə ətraflı məlumatların məhdud olması səbəbindən tədqiqat analoji neft yataqları üçün xarakterik olan tipik parametrlərə və sadələşdirilmiş mühəndis fərziyyələrinə əsaslanır. İşdə quyudibi təzyiqin və sulaşmanın hasilat prosesinə təsiri qiymətləndirilmişdir. Nəticələr göstərir ki, quyuların məhsuldarlığı lay təzyiqi ilə quyudibi təzyiq arasındakı əlaqədən əhəmiyyətli dərəcədə asılıdır. Təzyiq düşümünün azalması maye axınının zəifləməsinə və hasilatın aşağı düşməsinə səbəb olur. Eyni zamanda, çoxfazlı axın şəraiti hasilat davranışını qeyri-xətti edir və onun proqnozlaşdırılmasını çətinləşdirir.

Tədqiqatda sulaşmanın təsirinə xüsusi diqqət yetirilmişdir. Sulaşmanın artması xalis neft hasilatını əhəmiyyətli dərəcədə azaldır və hasil olunan mayenin keyfiyyətini pisləşdirir. Nəzəri hasilat potensialı ilə faktiki hasilat göstəricilərinin müqayisəsi lay təzyiqinin azalmasını, su hasilatının artmasını və quyuların məhsuldarlığının aşağı düşməsinə göstərir. Ümumilikdə, Darvin bankası yatağı işlənmənin son mərhələsində olan yetkin yataq kimi xarakterizə olunur. Nəticələr göstərir ki, hasilat səmərəliliyi lay təzyiqinin saxlanılması, suya nəzarət və quyuların iş rejiminin optimallaşdırılması hesabına artırıla bilər.

Açar sözlər: yatağın işlənməsi, quyuların məhsuldarlığı, lay təzyiqi, quyuların sulaşması, hasilatın səmərəliliyi.

ИССЛЕДОВАНИЕ ОСОБЕННОСТЕЙ ПРОЦЕССА РАЗРАБОТКИ НЕФТЯНОГО МЕСТОРОЖДЕНИЯ «БАНКА ДАРВИНА»

Доцент Замик Бахтияр МИРЗАДЖАНОВ

Азербайджанский Государственный Университет Нефти и Промышленности

Агабей АГАБЕЙЛИ

Азербайджанский Государственный Университет Нефти и Промышленности

Кафедра «Нефтегазовая инженерия»

Магистрант по специальности «Нефтегазовая инженерия»

E-mail: agabeyagabeyli98@gmail.com

Резюме: В данной статье анализируется текущее состояние разработки нефтяного месторождения Дарвинская банка, расположенного в азербайджанском секторе Каспийского моря. Целью исследования является оценка показателей работы месторождения, выявление основных факторов, влияющих на уровень добычи, а также определение возможных направлений повышения эффективности добычи в условиях зрелой стадии разработки. В связи с ограниченной доступностью детальных промысловых

данных исследование основано на типичных параметрах аналогичных нефтяных месторождений и упрощённых инженерных допущениях. В работе оценивается влияние забойного давления и обводнённости на характер добычи. Результаты показывают, что продуктивность скважин в значительной степени зависит от соотношения между пластовым и забойным давлением. Снижение депрессии давления приводит к уменьшению притока флюида и, соответственно, к снижению дебита. Одновременно условия многофазного потока формируют нелинейный характер добычи, что усложняет прогнозирование работы системы.

Особое внимание уделено влиянию обводнённости, которая существенно снижает чистую добычу нефти и ухудшает качество добываемой продукции. Сравнение теоретического добычного потенциала с фактическими показателями указывает на истощение пластового давления, рост добычи воды и снижение продуктивности скважин. В целом месторождение Дарвинская банка характеризуется как зрелое месторождение, находящееся на поздней стадии разработки. Полученные результаты показывают, что эффективность добычи может быть повышена за счёт поддержания пластового давления, контроля обводнённости и оптимизации режимов работы скважин.

Ключевые слова: разработка месторождения, продуктивность скважин, пластовое давление, обводнённость, эффективность добычи.