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Production Dynamics and Development Optimization in Mature Offshore Oil Fields: An Integrated Development Curve and Shewhart Control Approach

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Abstract

Mature offshore oil fields commonly exhibit declining oil production, increasing water production, deterioration of reservoir performance, and increasingly complex production management requirements. This study presents an integrated production performance assessment of the Darwin Bank, Pirallahi Island, and Gurgan-Deniz offshore oil fields in the Absheron petroleum province of the Caspian Sea using long-term development curves, Shewhart statistical process control (SPC) charts, water cut analysis, water injection history, gas production behavior, and voidage replacement ratio (VRR). Historical production records from the initial development stages to the recent period were analyzed to distinguish long-term production trends from operational and development-related changes. The three fields exhibited substantially different production trajectories. Gurgan-Deniz experienced the most rapid production buildup and subsequent depletion, Darwin Bank showed the most prolonged production history, whereas Pirallahi Island exhibited persistent high water production and complex late-stage redevelopment behavior. The integrated Shewhart analysis identified periods of statistically abnormal oil, water, gas, and water cut behavior, providing an operational framework for identifying changes requiring reservoir management attention. In Pirallahi Island, the recent increase in water injection and an estimated VRR of approximately 1.34 are consistent with active pressure support and redevelopment conditions. Based on the identified production constraints, potential reservoir management measures, including selective water shut-off, well interventions, infill drilling, and appropriately selected enhanced oil recovery (EOR) methods, are identified for further field-specific evaluation. The main contribution of the study is the integration of long-term development curves with Shewhart-based statistical control of oil, water, gas, water cut, and injection behavior to identify production changes and support targeted reservoir management decisions. The proposed framework provides a practical data-based approach for monitoring reservoir performance and supporting the continued development of mature offshore oil fields under data-limited conditions.

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1. Introduction

Oilfield development is an open system. The production evolution pattern is influenced by natural factors such as reservoir geology and physical percolation properties and artificial interventions such as geological reserves put into production year by year and continuously increasing recoverable reserves. These influences run through the whole process of oilfield development [1]. Currently, most conventional fields are being developed using a reservoir pressure maintenance system. Waterflooding optimization goals change over the field's life. At early stages of field production, water is injected to maintain the reservoir energy and to maximize the oil production, while in maturing fields with an increased water/oil ratio, the focus is shifted to reducing water production without losses in oil production [2]. According to Ye et al. [3], waterflooding is the most widely adopted and commercially mature secondary recovery technology for conventional oil reservoirs. This technology entails injecting water into reservoirs to maintain or increase subsurface pressure after primary recovery. Water injection also drives oil towards producers to increase the oil production rate, and waterflood management is used to increase the oil recovery factor [3,4].

Although the transition toward sustainable and renewable energy systems is receiving increasing attention, oil, natural gas, and coal are expected to remain significant contributors to global energy supply and economic development in the coming decades. At the same time, declining productivity in mature oil fields has increased the need for effective production strategies and more efficient exploitation of existing hydrocarbon resources [5,6]. Achieving these objectives requires a comprehensive understanding of reservoir geology and its influence on hydrocarbon distribution and recovery. Reservoirs originate from geological processes, including sedimentation, diagenesis, and subsequent tectonic modification, which determine their internal architecture and petrophysical properties. However, the complexity of subsurface formations and the incomplete nature of available geological and engineering data make reservoir characterization inherently uncertain. Reliable characterization is therefore essential for assessing hydrocarbon potential and supporting development decisions in both conventional and unconventional reservoirs [7]. Although additional data acquisition and advances in analytical techniques can improve geological understanding, uncertainties cannot always be eliminated. Consequently, uncertainty assessment should be integrated into reservoir evaluation, risk analysis, and development planning. A fundamental objective is to distinguish between the information required for reliable decisions and the knowledge that can realistically be obtained from available data and investigation methods [8].

The management of mature oil fields requires an integrated assessment of long-term production trends, remaining recovery potential, and changing reservoir performance. Babadagli (2007) [9] reviewed reservoir management strategies for mature fields, emphasizing the importance of remaining oil assessment, waterflood optimization, well placement decisions, and continuous data acquisition. These considerations are particularly relevant to long-producing fields, where declining oil output may coincide with increasing water production and changing operating conditions.

The continued reliance on fossil fuels highlights the importance of reliable reservoir performance forecasts and sound decision-making across alternative production scenarios. The accuracy of these forecasts depends not only on the simulation techniques employed

but also on how effectively geological uncertainties are represented and historical production data are matched. If these factors are insufficiently considered, reservoir models may fail to capture the actual production dynamics and may consequently provide less reliable predictions. Although uncertainty quantification can be achieved by conducting reservoir simulations across multiple geological models, this strategy often requires substantial computational resources and extended processing time. Furthermore, difficulties in achieving convergence may reduce the efficiency of this approach [9].

However, a critical challenge in the management of brownfields (late-stage oil and gas reservoirs) is the persistent misalignment between existing development systems and the increasingly complex geological characteristics of the productive strata. As reservoirs mature, heterogeneities such as compartmentalization, fracture networks, varying permeability zones, and fluid contacts become more pronounced, making accurate prediction and control of reservoir behavior significantly more difficult. This discrepancy frequently results in suboptimal recovery rates, inefficient well placement, and increased operational costs.

The primary driver of this "inadequacy gap" lies in the imbalance between the rapid pace of field development activities—particularly aggressive drilling campaigns—and the comparatively slow and resource-intensive processes of acquiring, processing, and interpreting geological and reservoir data. Modern drilling technologies enable operators to drill and complete wells at unprecedented speeds; however, the subsurface understanding required to guide these operations often lags behind. Geological models, which are foundational for decision-making, rely on data from seismic surveys, well logs, core samples, and production history. The integration and interpretation of these datasets require time, advanced computational resources, and expert analysis.

As a result, decisions are frequently made based on incomplete or outdated models, increasing uncertainty and the risk of inefficient reservoir exploitation. This temporal mismatch between information acquisition and operational execution can be understood as a form of an information–time paradox in reservoir management: the need for rapid decision-making conflicts with the requirement for high-quality, comprehensive data. In brownfields, where remaining reserves are more difficult to access and economic margins are tighter, this paradox becomes particularly critical.

To mitigate this challenge, there is a growing emphasis on adaptive reservoir management strategies, real-time data acquisition, and the integration of digital technologies such as machine learning and automated history matching. These approaches aim to reduce the lag between data generation and decision-making, thereby narrowing the inadequacy gap and improving overall recovery efficiency.

1.1. The Information–Time Paradox

In practice, the formulation of a development strategy occurs much faster than the extraction of meaningful insights from subsurface data. Consequently, a comprehensive understanding of a reservoir's structural complexity usually only emerges during the final stages of exploitation—typically when the water cut has already reached critical levels [10]. At this juncture, there is an urgent need for robust methods to adapt development systems to actual geological conditions, specifically to target "stagnant" or bypassed oil zones that were missed during earlier phases.

1.2. The Challenge of Subsurface Heterogeneity

In the high-water-cut period, the permeability of the reservoir will change with long-term water flooding, which will have a great impact on the reservoir's heterogeneity, fluid migration, and the distribution of remaining oil. Deep adjustment decisions have a greater impact [11]. The water cut of an oil field rises after a long period of water flooding

development. Enhancing liquid for oil increment is an effective way to sustain stable production and improve recovery factors in the mid–late life of reservoirs developed by water flooding [12].

To justify the parameters of an optimization process, it is essential to have a precise understanding of reservoir heterogeneity and the properties that govern the efficiency of hydrocarbon recovery. Reservoir heterogeneity is a key factor governing fluid transport, production performance, and hydrocarbon recovery, particularly in mature fields and geologically complex formations. It describes the spatial variability in reservoir properties in both vertical and horizontal directions. Such variability develops through the interaction of several geological processes, including differences in depositional facies, post-depositional diagenesis, and tectonic deformation. Changes in compaction, cementation, and mineral dissolution, together with structural alterations, produce variations in porosity, permeability, and fluid saturation. Consequently, reservoir properties and internal connectivity may vary considerably across the formation, complicating geological characterization, production forecasting, and the selection of appropriate development strategies. Research into reservoir heterogeneity encompasses both conventional systems, such as carbonate and deltaic reservoirs, and unconventional formations, including tight sandstones and shales. Particular attention has been directed toward understanding how spatial variations in reservoir properties affect residual oil distribution and overall production performance [13].

The role of heterogeneity extends beyond hydrocarbon production to other subsurface applications, including geological storage. In porous formations, spatial variations in rock properties can significantly influence fluid migration pathways, displacement patterns, and trapping mechanisms. Therefore, heterogeneity must be incorporated into field-scale assessments to obtain more reliable predictions of subsurface fluid movement and retention [14]. From a geological perspective, complete uniformity in natural reservoirs is unrealistic; rather, reservoirs exhibit different degrees and patterns of heterogeneity, depending on their depositional history and subsequent geological evolution [15].

1.3. Methodological Shift Under Data Scarcity

On many mature assets, the available dataset is limited to basic geophysical logs and standard production records, with more detailed data being too sporadic for meaningful statistical analysis. This creates a fundamental methodological hurdle: the need to develop innovative modeling approaches that can facilitate effective decision-making even when operating with a minimum baseline of information [16,17].

Efficient management of mature hydrocarbon reservoirs remains an important component of sustainable energy development, complementing the ongoing expansion of renewable energy resources and supporting responsible resource utilization in Azerbaijan [18,19]. In this context, improving production efficiency in mature oil fields contributes not only to enhanced hydrocarbon recovery but also to the broader objectives of sustainable energy systems by maximizing the utilization of existing resources while reducing the need for additional field development.

1.4. Research Hypothesis and Methodological Complementarity

The research hypothesis of this study is that the integrated use of long-term development curves and Shewhart control charts provides a more comprehensive diagnostic assessment of mature-field production behavior than either method used independently. Development curves characterize long-term production trends and major development stages, including production buildup, peak production, and decline, but do not specifically identify statistically abnormal annual deviations. In contrast, Shewhart control charts

identify annual observations that fall outside the calculated control limits but provide less information about the broader historical development trajectory. Their integration combines the long-term temporal context provided by development curves with the statistical identification of abnormal annual variations, supporting a more targeted interpretation of production dynamics and associated reservoir management conditions. The contribution of this study is not the introduction of a new statistical theory, but the demonstration of the complementary diagnostic value of established methods when applied to long-term production and injection data from mature offshore oil fields.

1.5. Geological Setting and Geostructure

The study areas, namely the Darwin Bank, Pirallahi Island, and Gurgan-Deniz oil fields, are located in the equatorial part of the eastern Absheron anticlinal zone, extending in a northwest–southeast direction. The Darwin Bank field is situated in the shallow-water part of the Caspian Sea, approximately 6 km north of Pirallahi Island. In this area, the seafloor is covered by sand and shell-bearing layers, underlain by deposits of the Productive Series. The water depth and seafloor morphology in the field area provided favorable conditions for the construction of pile-supported offshore trestles. The water depth is approximately 10 m in the southern part and increases to 25 m in the northern part. The Pirallahi Island field is located east of the Absheron Peninsula, approximately 60 km from Baku, within the shelf zone. The field is 12 km long, with a width of approximately 4.5 km in the north and 1.5 km in the south. It consists of two structural culminations—the northern and southern uplifts. The Gurgan-Deniz field is located southeast of the Darwin Bank and Pirallahi Island fields (Figure 1) [20].

The geological succession of the Darwin Bank, Pirallahi Island, and Gurgan-Deniz oil fields comprises a Cenozoic sedimentary sequence extending from the Middle Miocene to the Recent Caspian deposits, with a total thickness of approximately 1100–1200, 1500–1600 and, 2900–3000 m, respectively. The oldest deposits encountered in the field belong to the Middle-Upper Miocene Diatom Formation, which consists predominantly of massive gray claystones interbedded with thin layers of fine-grained sandstone. The thickness of the Diatom Formation penetrated by exploration wells is approximately 20 m. The Diatom Formation in Darwin Bank consists of sandy micaceous clays. With a penetrated thickness of 100 m, these deposits contain numerous shell remains.

The overlying Pontic stage in the Pirallahi Island field is represented mainly by dark gray claystones with sparse, thin sandstone interbeds. These deposits are characterized by the presence of abundant marl interlayers and gypsum horizons and attain a maximum thickness of approximately 160 m. The penetrated thickness of the Pontic deposits in the Gurgan-Deniz field is approximately 80–100 m and consists mainly of clays.

The Productive Series (PS) sediments in Darwin Bank, with a maximum thickness of 1900 m, consist of sand, sandstone, siltstone, and clay. Due to the erosion of the crest part of the fold, the PS is represented by the suites of the lower subdivision, among which only the Pre-Kirmaki (PK) and Kirmaki suites (KS) are oil-bearing. The oils of the suites are bounded by tectonically sealed traps (Figure 2a).

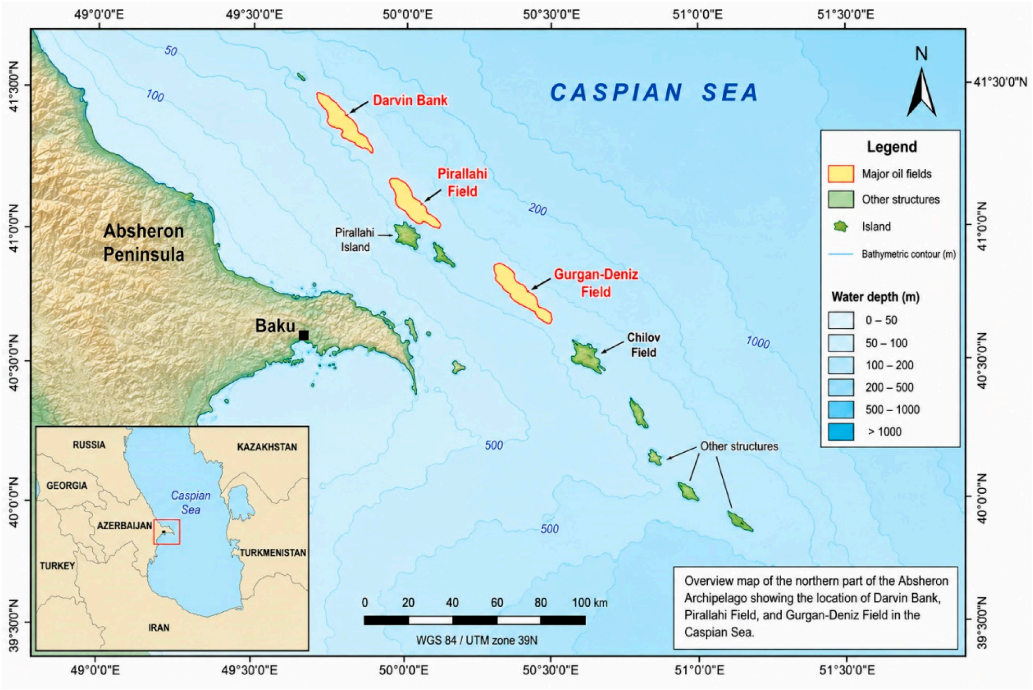


Figure 1. Geological setting of the target fields.

The principal hydrocarbon-bearing interval is the PS, which consists of cyclic alternations of sandstone, unconsolidated sand, siltstone, and claystone, reaching a maximum thickness of approximately 1500 m in the Pirallahi Island field. Owing to erosion of the upper part of the Productive Series, the preserved stratigraphic succession is represented predominantly by its lower subdivision, including the Gala suite (GaS), PK, KS, Post-Kirmaki sandy (PKS), and Post-Kirmaki clayey (PKC) horizons. Among these units, the PK, KS, and, locally, the GaS horizon within the southern Pirallahi anticline constitute the main oil-producing reservoirs. The flanks and periclinal closures of the structure are bordered by deposits of the Balakhany suite of the Productive Series (Figure 2b).

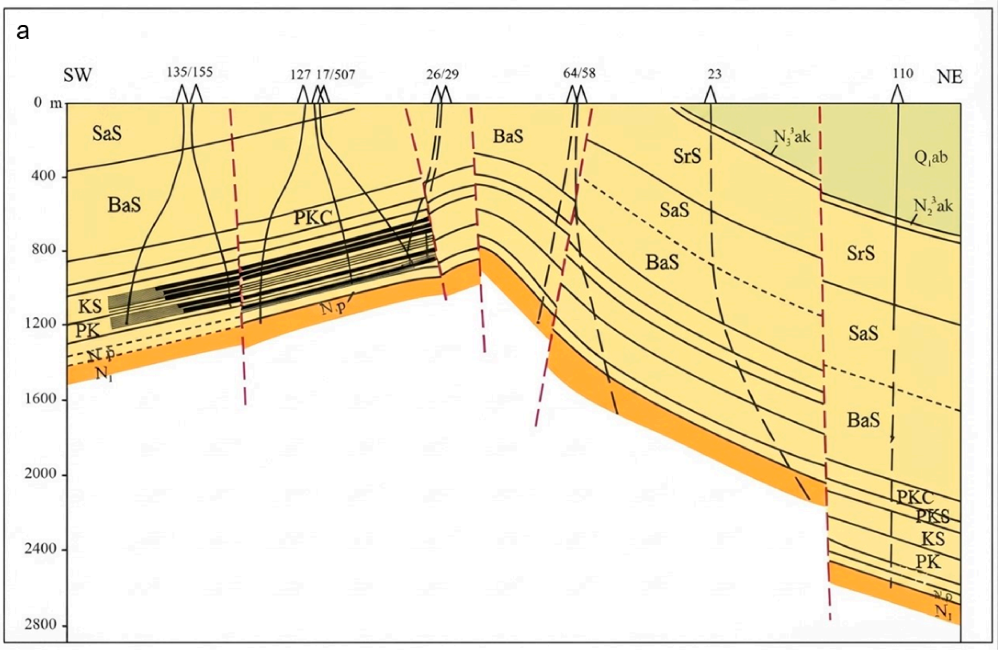


Figure 2. *Cont.*

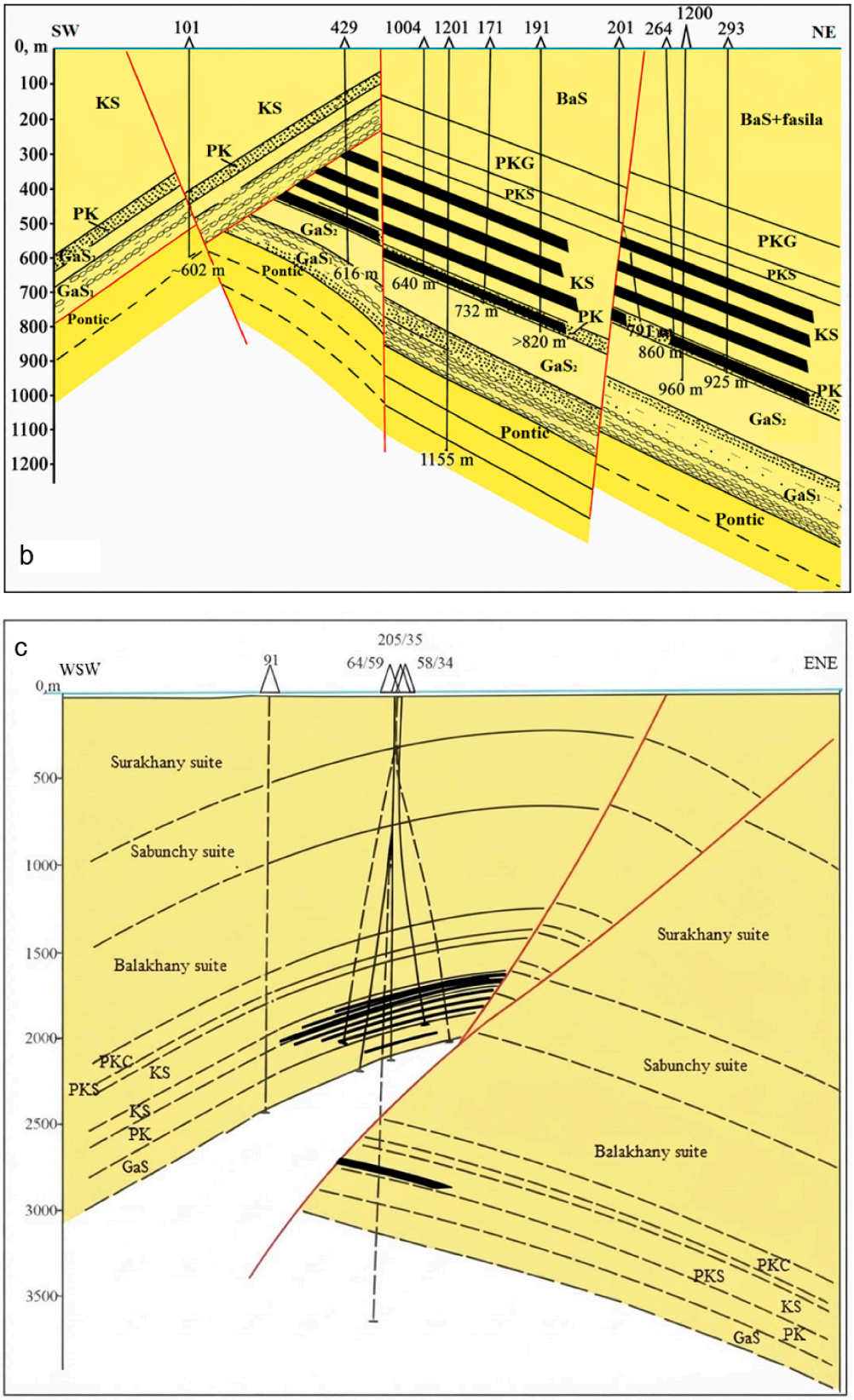


Figure 2. Geological profile of the studied areas: (**a**) Darwin Bank; (**b**) Pirallahi Island; (**c**) Gurgan-Deniz fields [21,22].

The upper part of the PS in the Gurgan-Deniz oil field, which is the main exploitation target, has been eroded. Here, the PS section comprises sediments ranging from the GaS to the Surakhany suite. Primarily, the PK and KS suites are oil-bearing in the hanging

wall of the thrust fault that complicates the structure. In the footwall of the thrust, the KS is oil-bearing. The oil deposits of the Gurgian-Deniz fold are of tectonic-fault-sealed, lithologically bounded, and mixed types (Figure 2c).

The reservoir intervals are characterized by laterally variable sandstone bodies interbedded with low-permeability claystones and siltstones, reflecting the heterogeneous depositional environment of the Productive Series. This lithological heterogeneity exerts a significant influence on reservoir quality, fluid distribution, and the efficiency of field development.

The sandy horizons of KS and PK suites of the Pirallahi Island oil field constitute the principal oil- and gas-bearing intervals. The reservoir rocks are composed predominantly of sandstone and unconsolidated sand, providing the primary storage and flow capacity for hydrocarbons [23–26]. Structurally, the field represents a fault-bounded (tectonically sealed) reservoir, where hydrocarbon accumulation is controlled by tectonic sealing associated with fault systems.

2. Materials and Methods

The overall workflow of the proposed integrated reservoir performance analysis framework is illustrated in Figure 3. The methodology comprises six sequential stages: data acquisition and quality control, data preprocessing, development curve (DC) analysis, statistical process control using Shewhart control charts, reservoir performance evaluation based on the water cut and voidage replacement ratio (VRR), and integrated interpretation for reservoir management decision support.

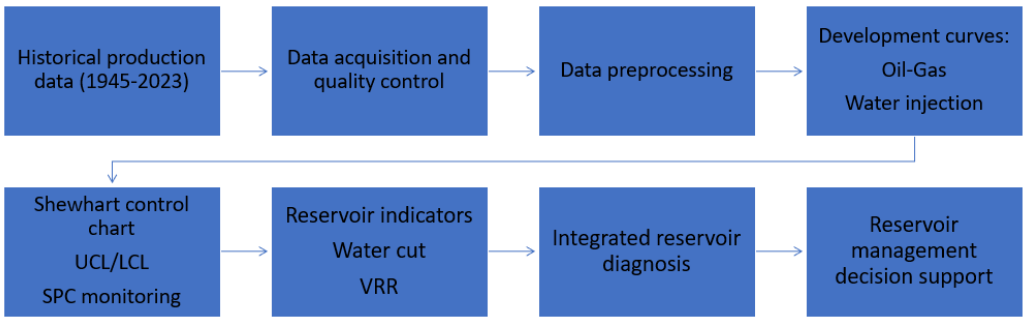


Figure 3. Workflow of the proposed integrated reservoir performance analysis framework.

The main objective of this study is to improve strategic and tactical production management in the oil field groups through the integrated application of DC and Shewhart control charts. The approach is based on statistical and mathematical analysis of historical production data and encompasses both long-term forecasting and real-time operational control.

The dataset used in this study comprises validated field production data collected from the fields over the period 1945–2023. The database includes daily and monthly records of oil, gas, and water production, water injection data, gas factor, water cut, well operating conditions, and technical intervention records. Prior to analysis, the dataset underwent quality control, consistency verification, outlier screening, and standardization to ensure the reliability and reproducibility of the subsequent analyses.

To characterize production decline behavior over time, DCs construction and analysis was applied using the Grapher program. Model parameters included initial oil, gas, water, production, gas factor, water cut, liquid production, development rate, oil production per well, and water production per well. This analysis enabled forecasting of future production trends and provided a basis for strategic decision-making regarding reservoir performance.

At the tactical level, Shewhart control charts were employed to monitor production performance in real time. Production data for each well were analyzed as a function of time,

and statistical parameters, including the mean (μ) (central control limit (CCL)) and standard deviation (σ), were calculated. Control limits (CLs) were defined as $\mu + 3\sigma$ for the upper control limit (UCL) and $\mu - 3\sigma$ for the lower control limit (LCL). These charts allowed for the identification of out-of-control points, which were interpreted as potential indicators of technical issues, reservoir behavior changes, or deviations in operational conditions.

The principal novelty of this study is the development of an integrated analytical framework that combines DC analysis and Shewhart statistical process control for comprehensive evaluation of mature oil field performance. The proposed framework establishes a two-level reservoir management strategy in which DCs support long-term production forecasting while Shewhart control charts enable continuous operational monitoring and early detection of production anomalies. By integrating predictive trend analysis with statistical process monitoring, the framework improves reservoir performance assessment, facilitates timely engineering decisions, and provides practical decision support for managing mature heterogeneous reservoirs under data-limited conditions.

The analysis was conducted using the Microsoft Excel and Grapher (2D@3D Graphing Software) programs for preliminary data processing. Computational procedures and visualization processes were automated to ensure reproducibility and accuracy of the results.

Considering that the Darwin Bank, Pirallahi Island, and Gurgan-Deniz oil fields are in a mature stage of development, with increasing water cut and significant reservoir heterogeneity, the applied methods were adapted to reflect the specific geological and operational conditions of the field. This enhances the practical relevance of the study and supports its applicability in real field operations. Furthermore, the proposed workflow can be readily applied to other mature heterogeneous reservoirs where long-term production records are available but detailed geological characterization is limited, thereby extending its applicability beyond the target fields.

2.1. Strategic and Tactical Control in Field Development: The Role of Development Curves and Shewhart Charts

Hydrocarbon field development is a complex, multi-factor process [19,20]. In modern petroleum engineering, the primary objective is not just to increase production volume [21], but to optimize this process from both an economic and technical standpoint. At the heart of this optimization lie two crucial tools: DCs, the "long-term memory" of the field, and Shewhart control charts, which measure its "instantaneous reactions." [27,28].

2.2. Macro Perspective: Forecasting the Future with Development Curves

Field DCs are the fundamental indicators that visualize the depletion dynamics of a reservoir. They are one of the most widely used forecasting techniques due to their simplicity, ease of implementation, and reliance on actual production data [29].

These curves allow engineers to understand which stage of the life cycle a field is currently in [30]. Below are the characteristics of DCs:

Reserve Estimation: Through DCs, the Estimated Ultimate Recovery (EUR) of remaining reserves is calculated with high precision. This is the cornerstone to building future development plans.

Strategic Decision-Making: The slope of the curves dictates when to transition to secondary (waterflooding) or tertiary (enhanced oil recovery (EOR)) recovery methods.

Economic Limit: By foreseeing the point at which production will no longer be profitable, it creates the groundwork for timely field conservation or the implementation of new technological interventions.

For this purpose, production performance curves were developed and subjected to analysis in order to evaluate the exploitation period of the target oil fields (Figure 4a–c).

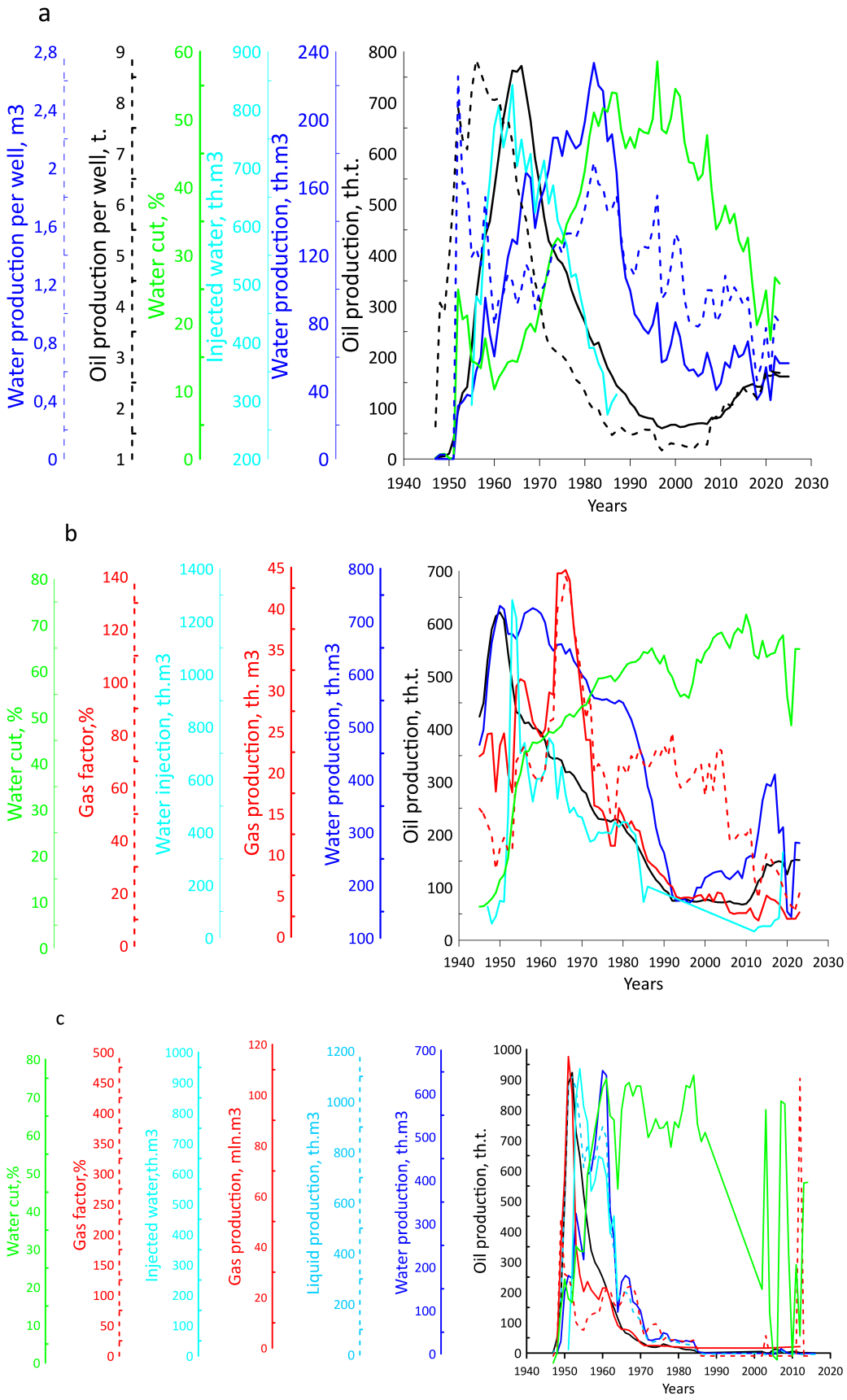


Figure 4. Reservoir development curves illustrating the transition from natural depletion to water-flooding and late-stage high water cut conditions: (**a**) Darwin Bank; (**b**) Pirallahi Island; (**c**) Gurgan-Deniz fields.

Based on the curves, it is clear that the reservoir has gone through the classical multi-stage development trajectory and is now approaching the late stage of its life. This can be interpreted from the behavior of the key indicators.

In the initial stage (early development), oil production increases sharply, while the gas–oil ratio remains relatively low and stable. This indicates that reservoir energy (pressure) is still high and production is mainly driven by natural energy. Water production and water cut are low at this stage, and injection is either absent or minimal.

In the transition to the middle stage, oil production reaches its peak and then begins to decline gradually. At the same time, water production and water cut increase rapidly. This is explained by water breakthrough, when injected or edge water reaches the production wells. The increase in water injection on the graph confirms that an active waterflooding system has been implemented to maintain pressure and displace oil. During this period, fluctuations or increases in the gas–oil ratio may occur, which can be related to gas liberation or gas coning.

In the later stage, a high (sometimes very high) water cut is observed, while oil production declines significantly. This indicates that the reservoir has entered a mature phase. Water production remains high and may stabilize, but oil output continues to decrease. Fluctuations in gas production suggest reservoir heterogeneity or changes in operating conditions.

In the final stage, oil production drops to very low levels, and the water cut approaches its maximum. The system effectively becomes water-dominated. Changes in the balance between injection and production suggest that some wells may have been shut in or that operating strategies have been optimized (for example, to control excess water production).

In total, the reservoir is initially produced under natural drive (high oil, low water); then it is supported by active waterflooding (increasing injection and water cut); and is then finally in a late-stage, high-water-cut, low-oil-production phase.

At this stage, the main technical challenge is excessive water production and declining oil output. To improve performance, potential measures may include selective water shutoff, well interventions, EOR methods, and further optimization of the production system.

2.3. Micro Perspective: Operational Stability with Shewhart Charts

Statistical process control (SPC) has played an important role in many fields, such as in manufacturing processes, aiming at monitoring the improvement or deterioration of product quality. Control charts are one of the most widely applied tools or monitoring schemes in SPC [31–34].

No matter how perfect strategic plans are, daily operational errors and unexpected technical failures can hinder overall efficiency. This is where Shewhart control charts act as the “sentinel” of the process.

The Shewhart method categorizes process variations into two groups: common-cause (natural) variations and special-cause variations. Common-cause variation is a natural part of the process and is generally thought to be limited to three standard deviations of the mean. Special-cause variation results from an assignable cause or external source to the process [35].

SPC charts allow us to observe and identify trends in quality, performance, and other outcomes, which facilitate continuous improvement to the system itself, without a reliance on late inspection. It helps us tighten our feedback loops and identify “common-cause” issues before they become a problem. Since common-cause variation is a natural part of the process, reducing it requires fundamental changes to the process itself. This means that it is a collective responsibility rather than something that can be blamed on individuals working in the system. SPC also helps us recognize that just because we improve part of a

process (local optimization; optimization of development process), it does not necessarily mean the whole process (global optimization) is improved [36].

Using defined UCL and LCL, engineers intervene only when significant deviations occur [37]. This eliminates the risk of "over-adjustment." Even if a well's production indicators have not yet reached a critical threshold, a consistent downward trend observed on a Shewhart chart serves as an early warning for potential major issues, such as encroaching water breakthrough.

2.4. Voidage Replacement Ratio (VRR)

To calculate the *voidage replacement ratio (VRR),* we compare the volume of fluids injected into the reservoir to the volume of fluids produced (at reservoir conditions). This tells us if the current operation is maintaining, increasing, or failing to support the reservoir pressure.

Based on the 2023 data points from our three charts, here is an estimation:

Data extraction (estimated for 2023).

Oil production (Qo): 150,000 tons.

Gas production (Qg): 3,000,000 m^3.

Injected water (Q_{iw}): 325,000 m^3.

The VRR formula.

The formula for VRR is:

$$VRR = \frac{Injecter\ Volume\ (at\ reservoir\ conditions)}{Produced\ Volume\ (at\ reservoir\ conditions)} \quad (1)$$

$$Produced\ Volume = (Qo \cdot Bo) + (Qg \cdot Bg) + (Qw \cdot Bw) \quad (2)$$

where B is the formation volume factor, which adjusts surface volumes to high-pressure reservoir volumes.

2.5. Calculation (Simplified Approximation)

Using standard industry assumptions for a mature/depleted field:

Oil volume (reservoir): Assuming a density of 0.850 and Bo = 1.2, the produced oil takes up $\approx$ 212,000 m^3 in the reservoir.

Gas volume (reservoir): In a depleted field (low pressure), gas expands. Assuming Bg $\approx$ 0.01, the produced gas takes up $\approx$ 30,000 m^3.

Total produced volume: $\approx$242,000 m^3 (excluding produced water, which would make this number higher).

Injected volume: 325,000 m^3.

$$VRR = \frac{325{,}000}{242{,}000} = 1.34 \quad (3)$$

Resulting VRR $\approx$ 1.34.

2.6. Technical Interpretation

The calculated VRR of approximately 1.34 indicates that the volume of injected water exceeds the produced fluid volume during the analyzed period. This value is consistent with active water injection and pressure support conditions in the field. However, a VRR greater than 1.0 does not by itself constitute direct evidence of an increase in reservoir pressure because the actual pressure response also depends on reservoir connectivity, fluid and rock compressibility, heterogeneity, and the spatial distribution of injected fluids.

The recent increase in water injection indicates a transition from the earlier period of limited or interrupted injection toward more active pressure support and waterflood-

ing conditions. These operations may contribute to maintaining reservoir pressure and supporting continued production; however, the effectiveness of pressure support and its contribution to incremental oil recovery cannot be established from the VRR value alone.

The produced water volume is an important component of the produced fluid side of the VRR calculation. Therefore, the calculated VRR should be interpreted using the total produced fluid volume, including produced water, together with the injected water volume. The resulting value of approximately 1.34 indicates an injection-dominated condition during the analyzed period, rather than providing direct proof of reservoir pressure increase or successful redevelopment.

Overall, the observed increase in water injection and the calculated VRR are consistent with active pressure maintenance and waterflooding practices during the recent development period. Further evaluation using reservoir pressure measurements, injection and production allocation data, well-level performance, and reservoir simulation would be required to determine the actual pressure response and the effectiveness of the redevelopment measures.

3. Results

3.1. Integrated Management: Synergy in Efficiency

The combined application of these two tools creates a perfect synergy in field management. While DCs answer the question "Where are we going?", Shewhart charts answer "Are we on the right track?"

In the optimization process, Shewhart control charts provide statistical control of production data, while DCs characterize historical production trends and can be used to support the forecasting of future oil and gas production rates in petroleum engineering [38]. This is because production data cleared of "noise" and chaos is the most reliable source for building future models.

Thus, to succeed in modern oil and gas field development, we must simultaneously monitor both the distant horizons (curves) and the steps beneath our feet (control charts). This is the only way to utilize resources with maximum efficiency.

Incorporating key development parameters, Shewhart control charts were developed to regulate the exploitation of the target fields [39]. Their analysis enables a comprehensive evaluation of reservoir dynamics and serves as a basis for optimizing field development strategies. Initially, Shewhart control charts were constructed based on oil production data to support the regulation of the target fields' development. This provides a fundamental basis for analyzing production behavior and guiding subsequent reservoir management decisions (Figure 5a–c).

The comparative interpretation of the oil production dynamics profiles of the Darwin Bank, Pirallahi Island, and Gurgan-Deniz offshore fields demonstrates distinctly different production trajectories, reflecting differences in field development history, reservoir response, production maturity, and the effectiveness of later-stage exploitation. Despite their location within the same broader Absheron offshore petroleum province, the three fields exhibit substantially different rates of production buildup, peak production, decline behavior, and subsequent redevelopment.

The Darwin field demonstrates the most prolonged and sustained high-production stage among the analyzed fields. Production increased rapidly from only 1.72 thousand tons in 1947 to more than 700 thousand tons per year during the early and mid-1960s, reaching a maximum of approximately 772.1 thousand tons in 1966. After this peak, the field entered a long-term decline, with production decreasing progressively to approximately 170–230 thousand tons/year during the 1990s–2000s. Nevertheless, production subsequently recovered, reaching approximately 166 thousand tons in 2024, indicating

renewed production activity and/or improved utilization of the remaining reserves. The overall Darwin profile therefore consists of an initial development and rapid buildup stage, a prolonged high-productivity period, a mature-field decline stage, and a later stabilization/recovery phase.

It should be noted that the production history of the Gurgan-Deniz field was significantly affected by a prolonged interruption in field development. In 1987, a major accident occurred at the field, resulting in the suspension of production and development activities for approximately 15 years. Consequently, the production profile of the Gurgan-Deniz field reflects not only the natural depletion of the reservoir but also a long period of operational inactivity. This interruption should be taken into account when comparing its oil production trend with that of the Darwin Bank and Pirallahi Island fields, as the lower and discontinuous production levels during this period cannot be attributed solely to reservoir performance.

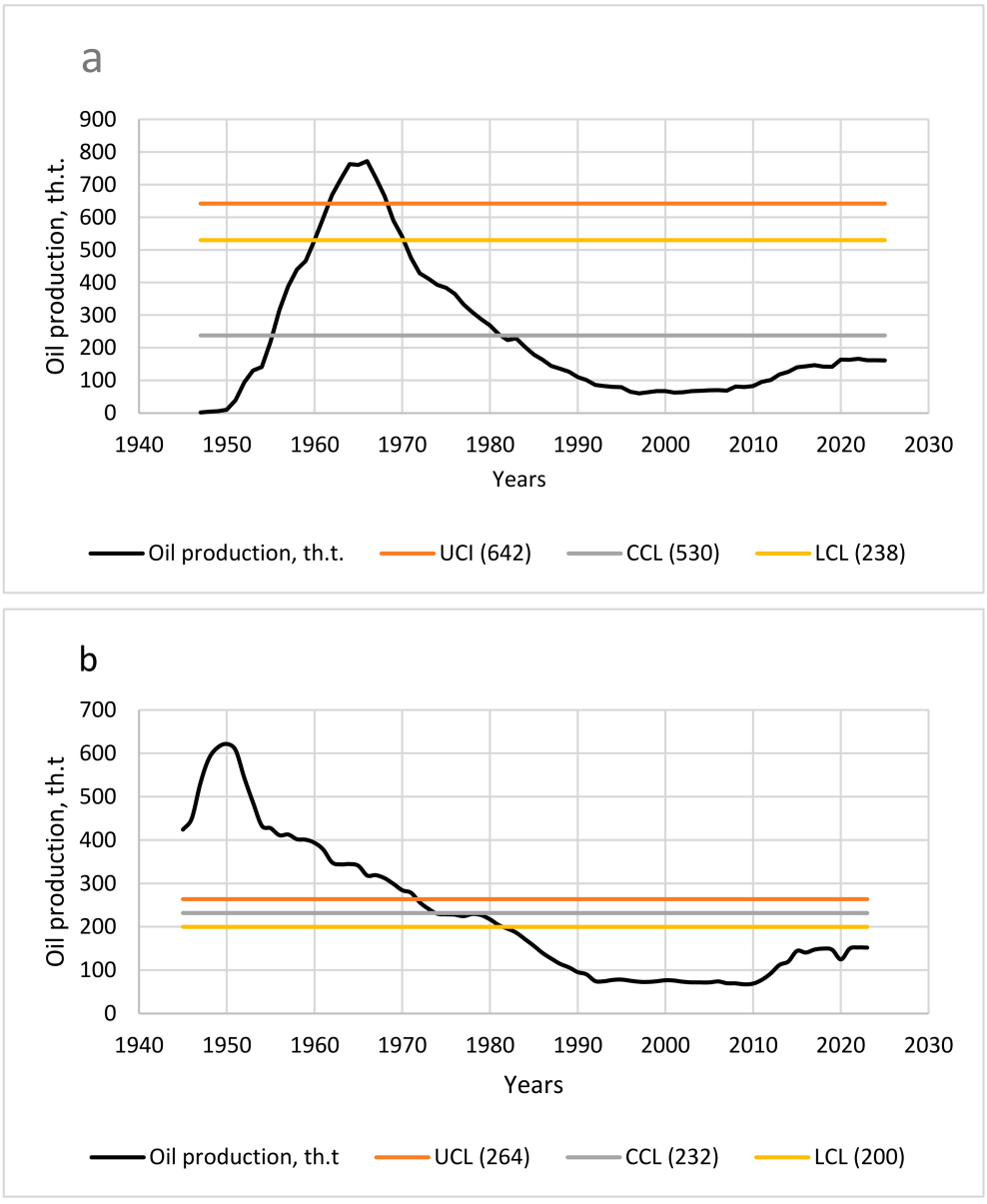


Figure 5. *Cont.*

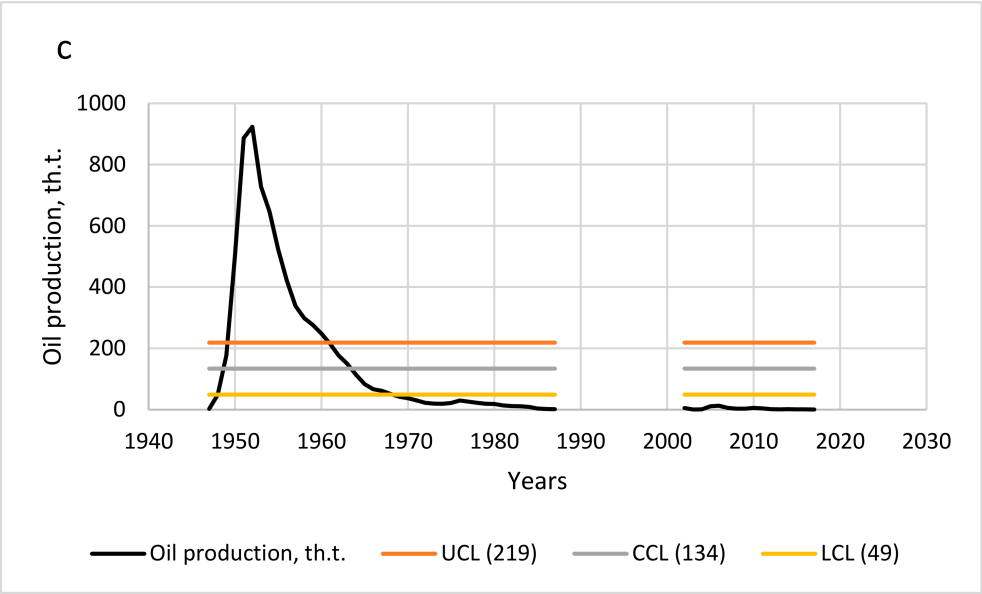


Figure 5. Oil production stability envelope with control limits: (**a**) Darwin Bank; (**b**) Pirallahi İsland; (**c**) Gurgan-Deniz fields.

So, the Gurgan-Deniz field displays a much sharper and shorter production cycle. Production increased extremely rapidly from 2.3 thousand tons in 1947 to 923.7 thousand tons in 1952, representing the highest annual production level among the three fields considered. Following this maximum, production declined almost continuously, falling below 100 thousand tons by 1965 and to less than 20 thousand tons/year after the mid-1973s. By the late 1980s, production had become extremely low. The available record subsequently indicates renewed but very limited production after 2002, generally remaining below approximately 12 thousand tons/year, with only minor fluctuations through 2017.

The Pirallahi Island field occupies an intermediate position in terms of production behavior, although its production history differs considerably from that of Gurgan-Deniz. Unlike the very rapid rise and subsequent near-exhaustion observed in Gurgan-Deniz, the Pirallahi Island field shows a more extended production history characterized by a relatively prolonged exploitation period and later-stage fluctuations. The available graph also indicates pronounced changes in production and water production behavior during the mature stage, suggesting the increasing influence of reservoir depletion and water involvement on field performance.

The comparison indicates three characteristic production development patterns. Gurgan-Deniz represents the most rapid depletion trajectory, characterized by an exceptionally fast rise to maximum production followed by a prolonged and pronounced decline. The Darwin Bank field exhibits a broader and more sustainable production cycle, with a slower buildup, a high-production plateau extending over several years, and significant production maintained after the main decline phase. The Pirallahi Island field shows a more complex mature-field behavior, in which long-term exploitation is accompanied by changes in production performance and increasing water production effects.

From a reservoir management perspective, the contrasting profiles suggest that the magnitude of peak production alone does not determine long-term field productivity. Gurgan reached the highest peak but subsequently experienced a very strong decline, whereas Darwin Bank maintained substantially higher production over a much longer period and demonstrated a later recovery in output. This contrast may indicate differences in reservoir connectivity, effective drainage, development intensity, well density evolution, pressure support, and the timing and effectiveness of secondary or enhanced production

measures. Therefore, the comparative production histories of the Darwin Bank, Pirallahi Island, and Gurgan-Deniz fields provide an important basis for evaluating the long-term production sustainability and reservoir management efficiency of mature offshore oil fields in the Absheron region.

A particularly important observation is that Darwin Bank and Gurgan-Deniz show almost opposite production histories: the Gurgan-Deniz field achieved an earlier and higher peak but underwent rapid depletion, whereas Darwin reached its maximum later and maintained commercially significant production for a much longer period. This difference is particularly useful for interpreting the contrasting reservoir performance of these offshore fields.

Subsequently, Shewhart control charts were constructed based on water production data to regulate and control water production within the target fields. The analysis of these charts enables a more detailed assessment of water encroachment and supports improved reservoir management strategies (Figure 6a–c).

The water production histories of the Darwin Bank, Pirallahi Island, and Gurgan-Deniz fields reveal substantially different patterns of water breakthrough, water influx, and long-term reservoir behavior. Although all three fields are located within the broader Absheron offshore petroleum system, their water production profiles indicate different stages of reservoir development and different responses to prolonged exploitation.

The Darwin Bank field shows a relatively gradual increase in water production during the early development period. Water production remained very low during 1947–1951, after which it increased sharply to approximately 31.31 thousand m^3 in 1952 and continued to rise during the following decades. The maximum values were reached during the late 1970s to early 1980s, with water production increasing to approximately 233.31 thousand m^3 in 1982. This period corresponds to the most pronounced water production stage in the Darwin record. After 1982, water production declined considerably, reaching approximately 76–100 thousand m^3 during the 1990s. During the 2000s and early 2010s, the field generally maintained a comparatively moderate and relatively stable water production level, although several fluctuations are evident. By 2025, water production was approximately 56 thousand m^3. Thus, the Darwin profile can be characterized by an initial low-water stage, a prolonged increase and maximum water production phase, followed by a long-term decline and later stabilization.

The Pirallahi Island field exhibits a fundamentally different water production pattern. Water production was already very high at the beginning of the available record, reaching approximately 698 thousand m^3 in 1949. During the 1950s and 1960s, production fluctuated around 650–730 thousand m^3, indicating a persistently high water production regime. Subsequently, a long and relatively systematic decline developed. Water production decreased from more than 700 thousand m^3 in the early production period to approximately 550 thousand m^3 during the 1970s, approximately 300–400 thousand m^3 during the late 1980s and early 1990s and approximately 165–225 thousand m^3 during the second half of the 1990s and early 2000s. After 2000, the trend changed: water production began to increase again, reaching approximately 300 thousand m^3 in 2014, 360 thousand m^3 in 2015, and about 410 thousand m^3 in 2017. The subsequent values show continued fluctuations, with water production remaining at several hundred thousand cubic meters per year.

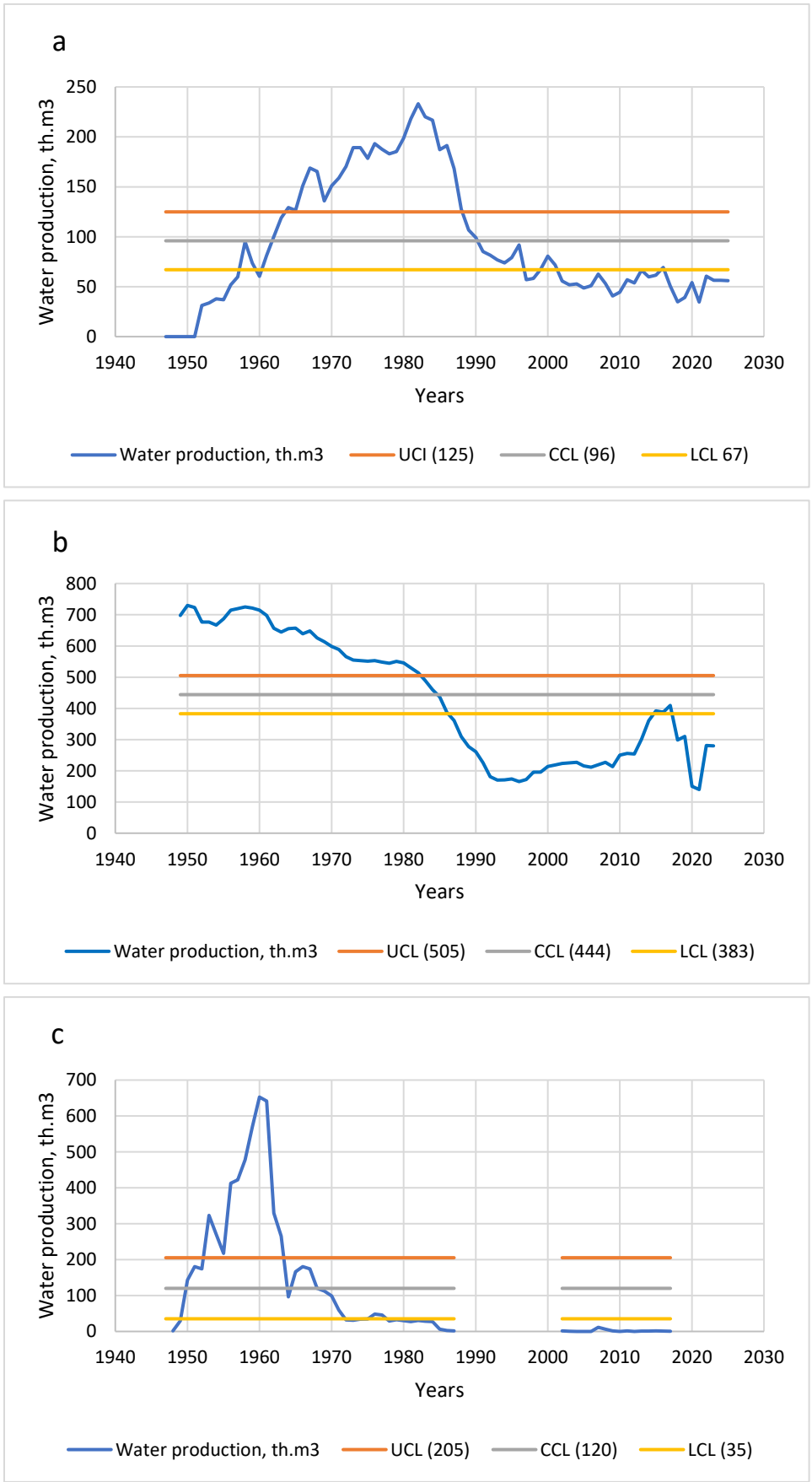


Figure 6. Water production stability envelope with control limits: (**a**) Darwin Bank; (**b**) Pirallahi Island; (**c**) Gurgan-Deniz fields.

The Gurgan-Deniz field displays the most distinctive water production trajectory. Water production increased rapidly during the initial development period, from only 1.3 thousand m^3 in 1947 to 143.12 thousand m^3 in 1950 and approximately 323.42 thousand m^3 in 1953. A second major increase occurred during the late 1958s, when water production reached 478.0 thousand m^3 in 1957, 569.12 thousand m^3 in 1959, and a maximum of approximately 652.92 thousand m^3 in 1960. Thereafter, water production decreased very rapidly, falling to approximately 329 thousand m^3 in 1962 and below 100 thousand m^3 in 1964. During the 1970s, water production remained relatively low, generally below 50 thousand m^3/year, and subsequently declined to only a few thousand cubic meters by the mid-1980s. The available record shows a prolonged interruption in production data between 1987 and 2002, followed by very low water production after 2002, generally around 0.1–12 thousand m^3/year.

The comparative analysis demonstrates three contrasting water production regimes. Gurgan-Deniz experienced the most rapid development of water production and the earliest transition to a low-water-production stage. Its maximum water production was reached relatively early, followed by a pronounced and sustained decline. Pirallahi Island, in contrast, maintained extremely high water production volumes over several decades and subsequently experienced a long-term decline followed by a notable increase in the later production period. The Darwin Bank field occupies an intermediate position: water production increased more gradually, reached its maximum considerably later than Gurgan-Deniz, and then declined to a moderate level that has generally been maintained during the recent period.

The relationship between the water production and oil production profiles provides an additional indication of contrasting reservoir performance. Gurgan-Deniz shows a rapid coincidence of high water production with its early high oil production period, followed by a strong decline in both production indicators. This pattern is consistent with a relatively rapid transition toward a mature, low-productivity reservoir stage. Darwin Bank shows a much more prolonged production history, with water production reaching its maximum around the early 1980s, considerably later than the field's maximum oil production period. This temporal difference suggests that the strongest water production phase developed after the main oil production peak, indicating progressive changes in reservoir fluid balance during mature-field exploitation. The production history of Pirallahi Island is more complex, with persistently high water production during the early and middle stages, followed by a long decline and a renewed increase in the later period. This behavior may reflect changes in well operation, reservoir management, drainage conditions, or water influx during successive stages of field development.

The control limit envelopes further demonstrate that the three fields differ in the stability of their water production processes. The Darwin Bank field has a comparatively broad historical variation in water production, while the Pirallahi Island field maintains substantially higher absolute water production volumes and shows a pronounced long-term shift in the production level. Gurgan-Deniz exhibits the strongest temporal contrast, changing from a high-water-production regime during its early development to extremely low water production during the late stage of the available record. These differences indicate that water production was not controlled by a single common trend across the three fields but was strongly influenced by field-specific reservoir characteristics and development history.

Overall, the water production histories suggest that Gurgan-Deniz underwent the fastest water production escalation and subsequent depletion, Pirallahi experienced the most persistent high-volume water production, and Darwin Bank field developed a later but prolonged period of elevated water production followed by stabilization. The contrasting

trajectories are important for assessing mature-field performance because changes in water production provide an indirect indication of evolving reservoir conditions, particularly during the late stages of oil field development. When evaluated together with oil production trends, these water production histories provide a stronger basis for distinguishing between reservoir depletion, increasing water involvement, and changes associated with subsequent field redevelopment.

Subsequently, Shewhart control charts were constructed based on gas production data to regulate gas production within the study fields. The analysis of these charts provides insights into gas behavior and supports more effective reservoir management (Figure 7a,b).

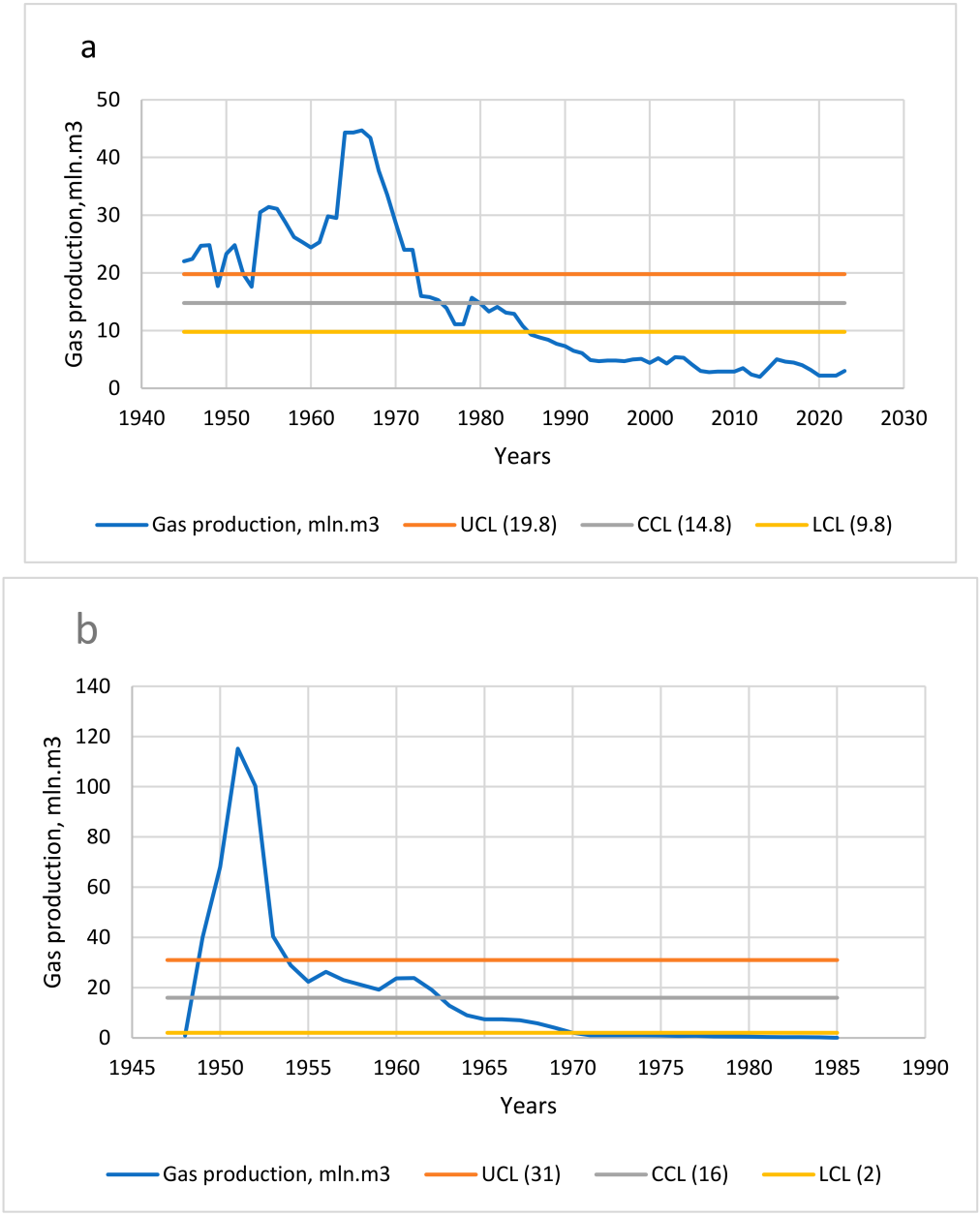


Figure 7. Gas production stability envelope with control limits: (**a**) Pirallahi Island; (**b**) Gurgan-Deniz fields.

3.2. Analysis of Oil and Gas Production Dynamics

The provided charts illustrate the production trends for oil (in thousand tons) and gas (in million m^3) alongside statistical control limits. These charts represent the typical life cycle of a mature field.

3.2.1. Production Dynamics and Trends

In production, three stages are singled out:

Peak era (1945–1966): Both oil and gas production reached their absolute historical peaks during this period. Oil production peaked at approximately 772 th.t. (Darwin Bank field), 600–620 th.t (Pirallahi Island field), and 923.7 th.t. (Gurgan-Deniz field), while gas production reached its zenith at about 45 and 115.2 mln.m^3 respectively (except for the Darwin Bank field). This reflects the early stage of field development with high reservoir energy.

Long-term decline (1966–2004): A sharp and continuous decline is observed starting from the early 1966s. By the mid-1970–1980s, production levels for both resources fell below their respective LCL.

Stagnation and slight recovery (1990–2023): Production hit its "floor" during the 1990s. While gas production remained at a steady low (approx. 5 mln.m^3), oil production shows a slight recovery trend after 2010, rising to about 150 th.t.

3.2.2. Reasons for the Decline (Technical and Geological)

The systematic drop below the control limits is driven by several "special-cause" factors:

Natural reservoir depletion: As the easily extractable reserves were produced during the 1950s and 60s, the natural energy of the reservoir began to diminish.

Drop in reservoir pressure: Especially critical for gas production; as pressure falls, the flow rate decreases significantly, eventually requiring artificial lift or compression.

Increasing water cut: Over time, water replaces the extracted oil in the reservoir. The low production levels seen between 1990 and 2010 indicate a period where wells likely produced high volumes of water with very little oil.

Aging infrastructure: The decline in the 80s and 90s was likely compounded by aging equipment and the economic challenges of maintaining production in a depleting field.

3.2.3. Statistical Control Summary

The charts utilize three key benchmarks:

UCL: The ceiling of "normal" historical performance.

CCL: The historical mean or average production level.

LCL: The floor of the expected process range.

Thus, both processes are currently "out of statistical control." Since 1985, production has consistently stayed below the LCL, proving that the decline is not a random fluctuation but a result of the fundamental depletion of the resource base. The recent uptick in oil production suggests the implementation of EOR techniques or new drilling technologies.

The charts below illustrate the water injection (waterflooding) process, which is a secondary recovery method used to maintain reservoir pressure and displace oil toward production wells (Figure 8a,b).

The Darwin Bank field was operated under a depletion-drive regime until 1955. In order to maintain reservoir pressure, peripheral and in-pattern water injection into the reservoirs was initiated in 1955. An analysis of the water injection carried out during 1955–1987 shows that peripheral water injection was more effective. The effectiveness of both injection methods was short-lived. During the water injection period, a total of 18,738.19 thousand m^3 of water was injected into the field. Since 1987, the water injection process in the field has been discontinued (Figure 8a) [40].

In the Gurgan-Deniz field, water injection into the PK reservoir began in 1951, while injection into the KS reservoir commenced in 1954. The injection process was mainly carried out within Blocks II and III, where these horizons were developed more intensively. Water

injection continued until 1964, inclusive, during which a total of 7762 thousand m^3 of water was injected [40].

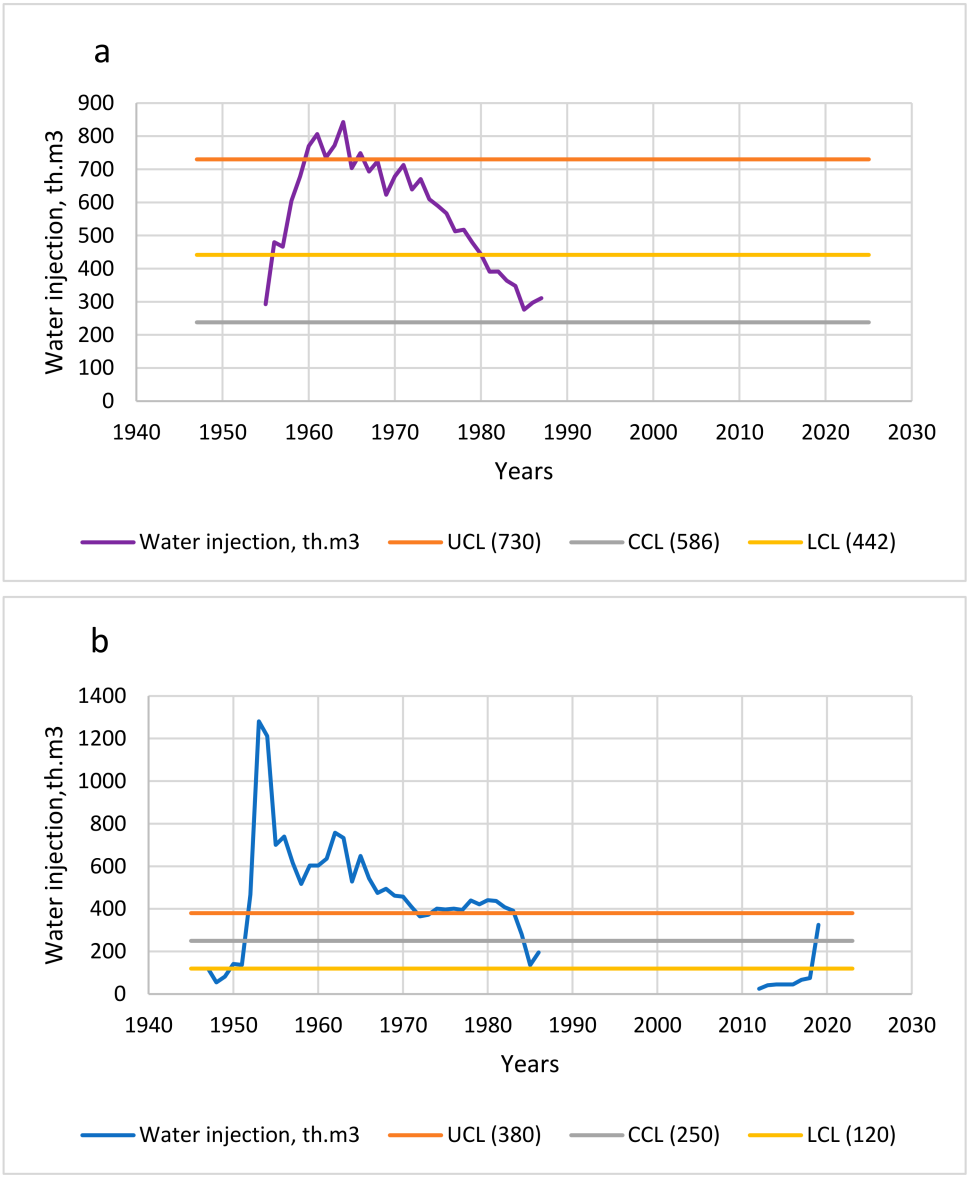


Figure 8. Water injection stability envelope with control limits: (**a**) Darwin Bank; (**b**) Pirallahi Island.

The water injection process was discontinued in both because it did not produce the expected reservoir pressure maintenance and production benefits.

Based on the data from 1945 to 2023 (Pirallahi Island field), the following is a detailed analysis of its character and the underlying causes.

3.2.4. Process Characterization

The water injection history is highly erratic and can be divided into four distinct phases:

Initial build-up and extreme peak (1947–1953): There is a massive, sudden surge where injection volumes skyrocketed from near zero to an absolute peak of nearly 1282 $th.m^3$. This is far above the UCL of 380.

High-volume volatility (1953–1966): Injection remained very high but fluctuated wildly (between 500 and 1200 $th.m^3$), suggesting an aggressive attempt to stabilize falling oil production seen in previous charts.

Gradual decline and cessation (1957–1986): A steady decrease occurred as the process likely became less efficient or the field reached its economic limit, eventually dropping below the LCL and stopping entirely around 1986.

The "gap" and modern resumption (1986–2023): There is a long period of zero injection for about 26 years. Injection only resumed after 2012, showing a sharp upward trend in recent years (reaching over 325 th.m^3).

3.2.5. Primary Causes for the Trends

Pressure Maintenance (The Peak)

The massive spike in the early 1950s was likely a reaction to the rapid primary depletion of the field. As natural gas and oil were extracted (as seen earlier charts), the reservoir pressure dropped. Engineers injected massive amounts of water to "push" the remaining oil toward the surface.

3.2.6. Secondary Recovery Efficiency

The fluctuations between 1960 and 1970 were likely caused by adjusting injection rates to manage "water breakthrough." This happens when the injected water finds a path of least resistance and reaches the production well too quickly, bringing water instead of oil.

3.2.7. Economic and Technical Halt (The 26-Year Gap)

The total stop in injection from the late 1986s until 2012 can be attributed to the following:

High water cut: By the 1986s, the wells were likely producing mostly water, making the cost of injecting more water economically unfeasible.

3.2.8. Regional Instability/Infrastructure Decay

Following the collapse of previous economic systems, many older fields lacked the investment needed to maintain complex water injection pumps and filtration systems.

3.3. The Rise of the Water Cut

As we saw in the 1986s decline, the "water cut" (the ratio of water produced to total liquids) eventually reaches a point where it is no longer profitable to continue. Usually, when the water cut reaches 95–98%, the recovery process is considered finished for that specific technology. Even after the best waterflood, about 30–50% of the oil often remains trapped in the pores of the rock due to capillary forces.

3.4. Impact of Modern Resumption (Post-2012)

The recent rise in injection seen in the graph is an attempt to increase the ultimate recovery factor beyond what was achieved in the 1986s. This is often done through the following:

Infill drilling, i.e., placing new wells in areas the original 1953s waterflood missed.

Chemical EOR, i.e., adding polymers to the water to make it "thicker" (more viscous), which prevents fingering and improves the sweep of that trapped residual oil.

Given that oil production is currently much lower than its 1953s peak despite renewed water injection, the field is likely in the "final recovery" phase, where every extra percent of oil recovered requires significant energy and investment.

3.5. Field Rehabilitation (The Recent Rise)

The resumption of injection after 2012 is a classic sign of brownfield redevelopment.

For this purpose, new technology (EOR) is required. When selecting appropriate methods for the efficient extraction of reserves and substantiating their application in the fields, geological and physical parameters (oil viscosity, occurrence depth, permeability

of reservoir rocks, reserve utilization rate) must be taken into account. The authors identified that thermal methods—including in situ *combustion, hot water injection, and steam injection*—are effective for managing the target reservoir's development and enhancing the oil recovery factor (ORF). The use of these methods will improve filtration and allow for better sweep efficiency [38].

3.6. Gas Factor

The provided chart illustrates the variation in the gas factor (m^3/t) for the Pirallahi field from 1945 to 2023. Along with the actual gas factor values, statistical control limits are also indicated on the chart (Figure 9).

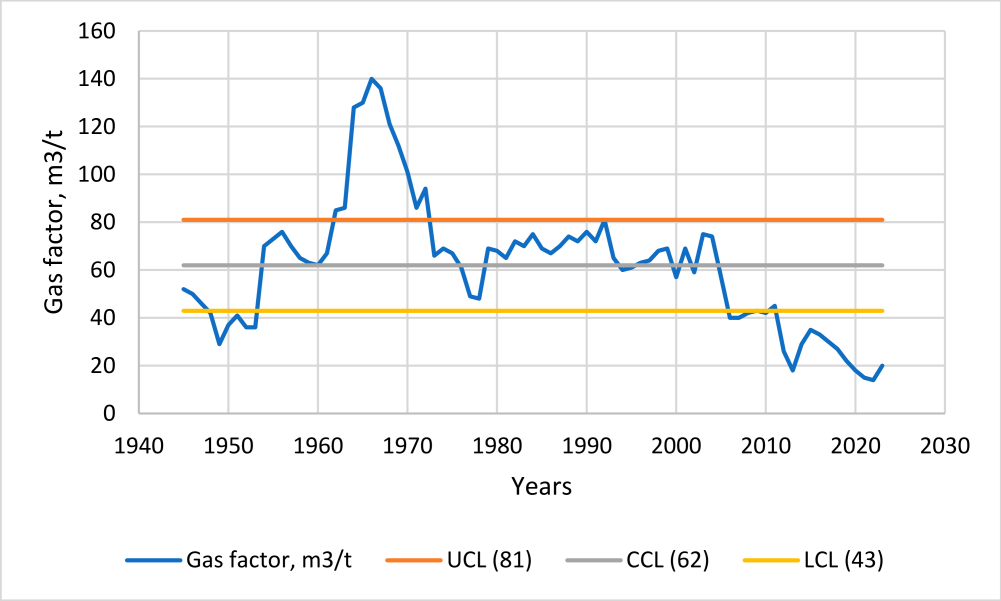


Figure 9. Gas factor stability envelope with control limits.

Analysis by Period

From 1945–1960 (initial period): The graph begins with fluctuating movements. While the gas factor dropped to around 30–40 m^3/t in the early 1950s, an upward trend was observed in the following years.

The 1960s (peak period): This period represents the highest gas factor for the field. Between 1964 and 1966, the indicator rose sharply to approximately 140 m^3/t, significantly exceeding the UCL (81). This indicates a very high gas-to-oil ratio during that time.

From 1970–2005 (stabilization period): From the 1970s to the early 2000s, the gas factor remained relatively stable. The values mostly fluctuated within the control limits (between 43 and 81) and often hovered around the central line (62).

From 2005–2023 (decline period): A continuous and sharp decline in the gas factor is observed starting from 2005. The indicator fell below the LCL (43) in 2006 and has continued to decrease, currently sitting below 20 m^3/t.

Thus, the chart clearly demonstrates the dynamics of the gas factor over the long-term operation of the Pirallahi field. The steady decline observed over the last 20 years suggests changes in the gas-to-oil ratio or reservoir pressure during the field development process.

This final chart for the water cut (%) is the "smoking gun" that connects all previous data. It shows the percentage of water in the total liquid volume produced. In a mature field, as more water is pumped in (injection), the amount of water coming out of the production wells inevitably rises (Figure 10a–c).

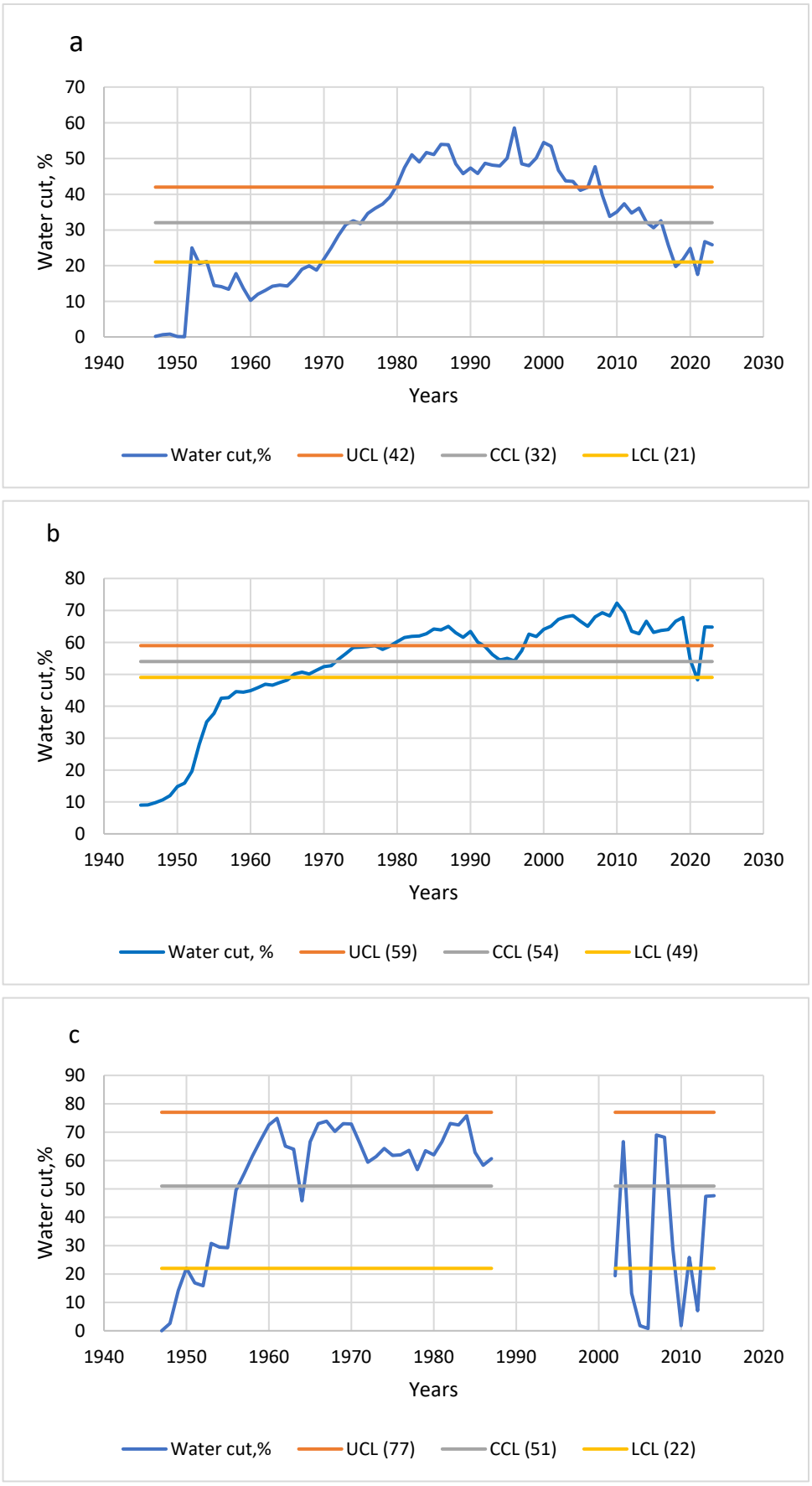


Figure 10. Shewhart control chart for the water cut in the target oil fields: (**a**) Darwin Bank; (**b**) Pirallahi Island; (**c**) Gurgan-Deniz fields.

3.7. Comparative Interpretation of Water Cut Behavior

Darwin Bank shows the most pronounced long-term increase in the water cut among the three fields. During the early production period, the water cut remained relatively low, but it progressively increased with field maturity and approached or exceeded the central control level. The later part of the record indicates a more pronounced water-dominated production regime, with fluctuations around the control limits. This pattern suggests a gradual intensification of water encroachment and/or increasing water production associated with reservoir depletion and prolonged field operation. The relatively wide separation between the upper and lower control limits (42% and 21%) indicates substantial variability in water cut behavior over the production history.

Pirallahi Island demonstrates a fundamentally different pattern. Its control limits are concentrated within a comparatively narrow and high water cut range: 49–59%, with a central level of 54%. This indicates that water cut was generally high throughout the analyzed production period and that the field operated under a persistent water production regime. Compared with Darwin, the narrower control envelope suggests relatively more stable water cut behavior, despite the high proportion of water in total liquid production. Thus, Pirallahi can be characterized by a high but comparatively stable water cut, which is consistent with a mature field with sustained water involvement.

Gurgan-Deniz exhibits the greatest variability in the water cut. Its control limits extend from 22% to 77%, with a central control level of 51%, indicating a much wider range of water cut fluctuations than in Darwin or Pirallahi. Such a broad control envelope reflects substantial changes in the relationship between oil and water production during the field's development history. The field therefore appears to have experienced periods of both a relatively low and very high water cut, rather than maintaining a stable water production regime. This behavior may be associated with rapid changes in reservoir conditions, heterogeneous water movement, and the changing effectiveness of production and water injection practices.

However, the three fields show distinct water cut development patterns. Darwin is characterized by a gradual increase and progressive intensification of water production, Pirallahi by a persistently high but comparatively stable water cut, and Gurgan-Deniz by the widest fluctuations and the greatest degree of variability. The control charts therefore indicate different reservoir responses to long-term exploitation: Darwin reflects progressive water involvement, Pirallahi represents a relatively stable high-water-cut mature system, whereas Gurgan-Deniz shows a highly variable water production regime. These differences are particularly important when interpreting the effectiveness of water injection and the remaining production potential of the three mature fields. The figure identifies these charts specifically as Shewhart control charts for the water cut in the Darwin Bank, Pirallahi Island, and Gurgan-Deniz fields.

3.7.1. Primary Causes for the High Water Cut

Channeling and fingering: Because water is less viscous (thinner) than oil, it often creates "channels" or "fingers" through the rock. Instead of pushing all the oil ahead of it, the water finds a fast path to the production well, leading to an early and high water cut.

Coning: In some wells, if the production rate is too high, the water underlying the oil zone is sucked upward into the wellbore in a cone shape, "shutting off" the oil flow.

Poor sweep efficiency: The high water cut indicates that the 1950s–1970s waterflood was aggressive but perhaps not perfectly targeted, leaving pockets of "bypassed oil" while circulating the same water through the system.

3.7.2. Explaining the Recent "Dip"

The sharp drop in the water cut around 2020 (falling below the LCL) is particularly interesting when compared to other charts:

Well workovers/recompletions were carried out. In addition, specific high-water-producing zones were identified and plugged (water shut-off treatments), and new infill wells were drilled in "dryer" parts of the reservoir.

Increased oil production: This dip perfectly correlates with the slight rise in oil production we saw in first chart (see Figure 5). Reducing the water cut "made room" in the wellbore for more oil flow.

3.8. Technical Conclusion (Connecting All Charts)

When we look at all data together, we see a complete story of reservoir life management that divided into four phases.

Phase 1, characterized by high oil and gas production, a low water cut and natural flow of fluids to the bottom of producing wells.

Phase 2, characterized by massive water injection, causing water breakthrough, which led to an increased water cut.

Phase 3, where the field reaches a "limit state" (70%+ water cut), leading to production collapse.

Phase 4 (current), characterized by modern intervention (infill drilling/EOR), which has stabilized the VRR at 1.34 and successfully managed to lower the water cut temporarily to boost oil recovery.

The verdict: The process is currently in a "managed decline." While the field is old, the data suggests that the recent technical interventions are successfully extracting oil that was previously considered "lost" to water.

4. Discussion

The results demonstrate that the long-term production behavior of the three mature offshore oil fields in the eastern part of the Absheron Peninsula [41,42] is not governed by oil production decline alone. The contrasting production trajectories of Darwin Bank, Pirallahi Island, and Gurgan-Deniz indicate that field performance reflects the combined effects of depletion, water movement, reservoir heterogeneity, injection history, and the sequence of field development. The differences in the timing and magnitude of oil and water production changes are particularly important because they indicate that the response of each field to continued development and secondary recovery has been field-specific.

Darwin Bank exhibits the most prolonged production history among the three fields. Its long-term production behavior is consistent with a gradual transition from earlier development stages toward a mature production regime rather than a single rapid depletion episode. The persistence of oil production over an extended period may be related to the sequential development of reservoir intervals and continued field management activities during different stages of its production history. The relatively prolonged productive period also indicates that the field response cannot be adequately represented by a single decline trend. Instead, changes in production behavior should be considered in relation to the successive stages of field development and reservoir management.

Gurgan-Deniz shows a different production trajectory, characterized by a rapid production buildup followed by a pronounced long-term decline. This behavior is consistent with a reservoir system in which a substantial part of the production response occurred during the earlier development stage, followed by increasing effects of depletion as the field matured. The subsequent variability in water production further suggests that the decline in oil production cannot be interpreted solely as a reduction in reservoir potential.

Changes in water movement and the distribution of produced fluids may also have influenced the late-stage production response. Thus, the Gurgan-Deniz history illustrates the importance of considering both depletion and fluid production behavior when evaluating mature-field performance.

Pirallahi Island displays another characteristic mature-field behavior, with persistently high water production and evidence of late-stage redevelopment. The high water cut regime indicates that a considerable proportion of produced liquid consists of water, which can reduce the efficiency of additional oil recovery if injected water preferentially moves through high-permeability pathways or previously swept zones. Such behavior may be associated with reservoir heterogeneity, preferential flow, channeling, fingering, or coning; however, the available historical production data do not allow these individual mechanisms to be distinguished directly. The observed production pattern is therefore interpreted as being consistent with increasingly complex water management requirements during late-stage development.

The different field responses also provide a mechanistic interpretation of the contrasting effectiveness of secondary recovery. Where water movement is relatively well controlled, injection can contribute to pressure maintenance and displacement of remaining oil. Conversely, where preferential water movement or highly watered-out intervals dominate production, additional injection may increase water handling without producing a proportional increase in oil production. This distinction is particularly relevant to Pirallahi Island, where the recent increase in water injection and an estimated VRR of approximately 1.34 indicate a substantial injection–production imbalance. The VRR value should not be interpreted as direct evidence of a corresponding increase in reservoir pressure because the calculation is based on simplified assumptions. Nevertheless, the combination of renewed injection, water cut behavior, and oil production response is consistent with ongoing pressure support operations and redevelopment activities, although their effectiveness and impact on reservoir pressure and oil recovery cannot be established from the VRR value alone.

The combined use of long-term development curves and Shewhart control charts provides complementary diagnostic information for assessing mature-field production behavior. Development curves alone characterize long-term production trajectories and reveal the successive stages of buildup, maturity, and decline, but they do not independently establish whether a particular annual observation represents a statistically unusual deviation. Shewhart charts alone identify observations outside the established control limits but provide less information about the broader development trajectory and the historical context in which these deviations occur. The integrated approach combines the strengths of both methods: Development curves establish the long-term production context, while Shewhart charts help identify statistically unusual annual variations within that context. This distinction supports a more differentiated interpretation of field performance, helping to distinguish gradual changes associated with long-term field evolution from individual deviations that may warrant further investigation. However, statistical deviations do not by themselves establish their geological or operational causes, which must be evaluated using the available field history and supporting data.

The water cut results reinforce the importance of selective rather than uniform reservoir intervention. The broad variability observed in Gurgan-Deniz and the persistently high water cut regime in Pirallahi Island indicate that field-wide increases in injection should be evaluated together with the corresponding water and oil responses. Where excessive water production is associated with specific intervals or wells, selective water shut-off, workover, or recompletion may provide a more appropriate intervention than simply increasing injection. Infill drilling can similarly be targeted toward poorly swept or bypassed reservoir

compartments where the production history indicates remaining development potential. These measures are intended to improve the effectiveness of reservoir management rather than increase injection volume without considering the resulting fluid production response.

For reservoirs in which conventional waterflooding has become less effective, EOR may provide an additional recovery option. In situ combustion, hot water injection, and steam injection may be considered where reservoir depth, permeability, oil viscosity, thermal properties, and remaining reserves satisfy the relevant screening criteria. These methods are not presented as universally applicable solutions, because their suitability cannot be established solely from the historical production data analyzed in this study. Reservoir-specific screening, laboratory studies, and/or numerical simulation would be required before implementation.

Overall, the comparison of the three fields shows that mature-field management should be condition-based rather than based on a uniform development strategy. Darwin Bank, Gurgan-Deniz, and Pirallahi Island exhibit different combinations of production decline, water production behavior, and injection response, and these differences imply different management priorities. The principal scientific and practical contribution of the study is therefore the integration of long-term production trajectories with statistical monitoring to relate observed changes in field performance to potential reservoir management actions. Under data-limited conditions, this framework can support the identification of periods requiring closer investigation and can provide a basis for considering water control, targeted infill development, injection optimization, or EOR screening as appropriate to the observed field condition.

5. Conclusions

The integrated analysis of development curves, Shewhart statistical control charts, water production behavior, the water cut, water injection, gas production dynamics, and the voidage replacement ratio (VRR) provides a data-based assessment of the long-term development and current production conditions of the Darwin Bank, Pirallahi Island, and Gurgan-Deniz offshore oil fields. The main conclusions are as follows:

1. The three fields exhibit distinct long-term production trajectories. Gurgan-Deniz experienced the most rapid production buildup followed by pronounced decline, Darwin Bank demonstrated the most prolonged production history, whereas Pirallahi Island was characterized by persistent high water production and more complex late-stage redevelopment behavior. These differences are consistent with variations in depletion history, water movement, reservoir heterogeneity, injection history, and stages of field development.
2. Water production and water cut behavior represent important constraints on mature-field performance. The high and variable water cut patterns observed in the studied fields indicate increasing water involvement during mature development. Such behavior may be associated with heterogeneous flow, preferential water movement, channeling, coning, or incomplete sweep; however, the available historical production data do not allow the individual contribution of these mechanisms to be determined directly. Accordingly, water management measures should be considered selectively rather than through uniform increases in water injection.
3. Development curves and Shewhart control charts provide complementary information for mature-field management. Development curves characterize the long-term evolution of production and identify major stages of field development and decline, whereas Shewhart charts identify statistically abnormal deviations in oil, water, gas, water cut, and injection behavior. Their integrated interpretation therefore provides a

practical basis for distinguishing gradual long-term changes from abnormal production behavior requiring further operational or reservoir management assessment.

4. The recent production and injection behavior of Pirallahi Island indicates an active redevelopment stage. The recent decrease in the water cut, together with an increase in oil production, combined with an estimated VRR of approximately 1.34, is consistent with increased pressure support activity and changing production conditions. The simplified VRR estimate should be refined using measured reservoir PVT properties and produced fluid volumes; therefore, it should not be interpreted alone as direct evidence of reservoir pressure recovery. The results nevertheless support the consideration of controlled injection, selective water shut-off, well interventions, and targeted infill drilling as field management measures.
5. The integrated framework has practical value but also important limitations. The approach can support condition-based decisions concerning water management, injection optimization, well redevelopment, infill drilling, and screening of EOR options in mature offshore fields with limited modern reservoir data. EOR methods, including thermal approaches, should be evaluated only after reservoir-specific screening based on depth, permeability, oil viscosity, thermal properties, and remaining reserves. Because the present analysis relies primarily on historical production and injection data, detailed reservoir characterization, laboratory studies, and calibrated numerical simulation remain necessary for confirming individual mechanisms and designing field-scale recovery projects.

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Abbreviations

The following abbreviations are used in this manuscript:

PS	Productive Series
PK	Pre-Kirmaki
KS	Kirmaki Suite
PKS	Post-Kirmaki Sandy
PKC	Post-Kirmaki Clayey
GaS	Gala Suite
BaS	Balakhany Suite
SDGs	Sustainable Development Goals
VRR	Voidage Replacement Ratio
DCs	Development Curves

UCL	Upper Control Limit
LCL	Lower Control Limit
CCL	Central Control Limit
EOR	Enhanced Oil Recovery

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