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-THEME-

DIAGNOSTIC ANALYSIS OF PRODUCTION DECLINE ISSUES IN OIL WELLS OF THE HASSI MESSAOUD FIELD AND EVALUATION OF REMEDIATION SOLUTIONS

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وَآخِرُ دَعْوَاهُمْ أَنِ الْحَمْدُ لِلَّهِ رَبِّ الْعَالَمِينَ

Dédicace

Je dédie ce modeste travail :

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Que Dieu les protège, leur accorde longue vie, santé et bonheur.

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ملخص

تهدف هذه الدراسة إلى إجراء تحليل تشخيصي هندسي لأسباب انخفاض إنتاج النفط في الآبار التابعة لحقل حاسي مسعود الذي يعد أحد أكبر الحقول النفطية الناضجة، مع تقييم الحلول التقنية والمعالجات الهندسية المتاحة لإعادة تحفيزها وتنشيطها. تتبع الدراسة منهجية علمية متكاملة تبدأ بالتشخيص الدقيق لتحديد طبيعة التراجع في الإنتاج والتمييز بين الهبوط الطبيعي واللانمطي، وذلك بالاعتماد على أدوات هندسية متطورة مثل تحليل الضغط العابر وتحليل التدفق العقدي. حيث تم تصنيف المشاكل التشغيلية إلى مشاكل مكمنية كظاهرة مخروطية الماء والغاز، ومشاكل تتعلق بالبئر والمنطقة المحيطة به كظاهرة تضرر الطبقة المنتجة، أو قيود سطحية ترتبط بضعف كفاءة أنظمة الرفع الاصطناعي وتراكم الترسبات الملحية والعضوية.
بناء على نتائج التشخيص، تم تقييم الفعالية التقنية لخيارات التدخل والمعالجة المتاحة، والتي تشمل عمليات التحفيز عبر التحميض لإزالة الأضرار حول البئر في التكوينات الرملية، والتكسير الهيدروليكي لفتح قنوات تدفق عالية النفاذية في الطبقات الضيقة والمحكمة، بالإضافة إلى تقنيات عزل المياه والغاز الزائد، وتحسين كفاءة أنظمة الرفع بالغاز. وفي الشق التطبيقي، تم إسقاط مخطط العمل التشخيصي والعلاجي المقترح على ثلاث حالات واقعية من آبار الحقل وهي البئر-MD 800والبئر MD-819 والبئر RDC-30 حيث أظهرت النتائج نجاحا ملموسا في استعادة وتنشيط القدرة الإنتاجية لهذه الآبار. وتختتم الدراسة بتقديم مجموعة من التوصيات الهندسية والاستراتيجية لإدارة المكمن وتطوير الآبار مستقبلا على المدى الطويل لحمايتها من التراجع السريع وتأمين استدامة الإنتاج.

<u>الكلمات المفتاحية:</u>
حقل حاسي مسعود، انخفاض الإنتاج، تحليل الضغط العابرPTA ، التحليل العقديNodal Analysis ، تضرر الطبقة المنتجةSkin Effect ، التحميض، التكسير الهيدروليكي، الرفع بالغاز.Gas Lift

Résumé

Ce travail porte sur l'ingénierie de production dans le champ mature de Hassi Messaoud, visant à remédier au déclin de la productivité des puits face à la baisse de pression et aux défis techniques liés au vieillissement du gisement. L'étude adopte une approche méthodique basée d'abord sur un diagnostic rigoureux des anomalies à l'aide d'outils avancés tels que l'Analyse des Pressions Transitoires (PTA) et l'Analyse Nodale. Cela permet d'identifier l'origine de la baisse : causes réservoir (coning d'eau/gaz), problèmes de puits (endommagement de la formation - Skin), ou inefficacité de l'activation et accumulation de dépôts (sels/asphaltènes). Ensuite, l'étude évalue les solutions techniques et de remédiation adaptées, incluant la stimulation par acidification (nettoyage) ou par fracturation hydraulique (génération de conductivité dans les zones compactes), ainsi que le contrôle des fluides indésirables et l'optimisation du Gas Lift. Enfin, cette démarche est validée par une application pratique sur trois puits réels (MD-800, MD-819 et RDC-30), démontrant le succès des interventions de revitalisation, et se conclut par des recommandations stratégiques pour optimiser la gestion à long terme du réservoir

<u>Mots-clés :</u> Champ de Hassi Messaoud, Déclin de production, Analyse des pressions transitoires (PTA), Analyse nodale, Endommagement de la formation (Effet de peau), Acidification, Fracturation hydraulique, Gas Lift.

Abstract

This study focuses on production engineering in the mature Hassi Messaoud field, aiming to address the decline in well productivity caused by reservoir pressure depletion and technical challenges associated with field maturity. The study adopts a systematic methodology that begins with a rigorous diagnosis of production anomalies using advanced tools such as Pressure Transient Analysis (PTA) and Nodal Analysis. This workflow helps identify whether the decline stems from reservoir mechanisms (such as water or gas coning), wellbore issues (such as formation damage / Skin Effect), or surface constraints like artificial lift inefficiencies and scale/organic deposits.

Based on the diagnostic results, the study evaluates the available remediation and stimulation solutions, including matrix acidizing to remove near-wellbore damage, hydraulic fracturing to enhance flow paths in tight zones, water/gas shutoff techniques, and the optimization of gas lift systems. Finally, this integrated workflow is practically validated through a case study of three real wells (MD-800, MD-819, and RDC-30), demonstrating successful well revitalization. The study concludes with engineering recommendations for future well operations and long-term reservoir management to mitigate rapid production decline.

Keywords:

Hassi Messaoud field, Production decline, Pressure Transient Analysis (PTA), Nodal Analysis, Formation damage (Skin effect), Matrix acidizing, Hydraulic fracturing, Gas lift

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Notion et symboles

ΔP : Pressure drop (psi or bar)

Φ: Formation porosity (fraction or %)

μ_g: Gas viscosity (cP)

μ_o: Oil viscosity (cP)

ρ_g: Gas density (kg/m³ or lb/ft³)

ρ_o: Oil density (kg/m³ or lb/ft³)

B_g: Gas formation volume factor (rcf/scf)

B_o: Oil formation volume factor (rb/stb)

d: Tubing internal diameter (inch)

h: Reservoir net thickness (m or ft)

J: Productivity Index (stb/d/psi)

k: Formation permeability (mD)

L: Measured depth of the well (m or ft)

Pb: Bubble point pressure (psi or bar)

Pr: Average reservoir pressure (psi or bar)

Pwf: Bottom-hole flowing pressure (psi or bar)

Pwh: Wellhead pressure (psi or bar) wh

Rs: Solution gas-oil ratio (scf/stb)

S: Skin factor (dimensionless) v Fluid velocity (ft/s or m/s)

List of abréviations

API: American Petroleum Institute gravity

BHP: Bottom-Hole Pressure

Bo: Oil Formation Volume Factor

CCL: Casing Collar Locator

FVF: Formation Volume Factor

GOR: Gas Oil Ratio

GR: Gamma Ray

HMD: Hassi Messaoud Field

IPR: Inflow Performance Relationship

J (PI): Productivity Index

k: Permeability

MD: Maïder

Pb: Bubble Point Pressure

PBU: Pressure Build-Up

PLT: Production Logging Tool

Pr: Average Reservoir Pressure

PTA: Pressure Transient Analysis

PVT: Pressure, Volume, Temperature

Pwf: Flowing Bottom-Hole Pressure

Qo: Oil Production Rate

Rs: Solution Gas-Oil Ratio

S (Skin): Skin Factor

THP: Tubing Head Pressure

VLP: Vertical Lift Performance

WC: Water Cut

General Introduction

General Introduction

The The hydrocarbon production industry serves as the cornerstone of the Algerian national economy and the primary engine for sustainable development, with SONATRACH playing the leading role in managing and exploiting these vital energy resources. Within this strategic framework, the giant Hassi Messaoud Field, with its massive Cambrian reservoir, holds a historic and pioneering position as the backbone of crude oil production in the country since its discovery in 1956. This immense field spans a vast area of approximately 2,200 square kilometers, characterized by unique geological and petrophysical structures that place it among the largest oil fields in the world.

However, after decades of intensive and dynamic depletion, the Hassi Messaoud field has entered a critical stage of technological maturity. This maturity has led to the emergence of highly complex technical, geological, and structural challenges that pose severe obstacles to fluid flow. Chief among these hurdles are the severe and progressive depletion of natural reservoir pressure, a continuous rise in produced water and gas cuts (Water and Gas Breakthroughs), and severe formation damage in the near-wellbore region. These issues are further compounded by severe mechanical and chemical plugging caused by the deposition of asphaltenes, halite, and complex scales, resulting in a continuous decline in the wells' Productivity Index (PI) and a reduction in ultimate sweep efficiency and the final oil recovery factor (RF).

Under these complex operational conditions, relying on conventional natural production methods or standard artificial lift techniques is no longer sufficient to maintain the economic viability of the wells. Consequently, well intervention and workover engineering, alongside matrix and formation stimulation, have become inevitable and essential technological solutions. Operations such as matrix acidizing and hydraulic fracturing are no longer merely optimization choices; they have become strategic tools to revive dead or declining wells by dissolving scale barriers and creating highly conductive artificial flow pathways that ensure smooth oil flow from the porous media into the wellbore.

The success of these costly and critical engineering operations demands a profound understanding of fluid thermodynamics and multiphase flow behavior within the production conduit. This understanding is achieved through the meticulous evaluation of field well tests, monitoring pressure and temperature variations, and analyzing production performance trends to accurately diagnose reservoir impairments and design optimal stimulation treatments. To provide a comprehensive and structured perspective, this research is divided sequentially into four main chapters:

- **Chapter One (Geological and Production Framework of the Field):** Reviews the geographical setting and complex tectonic environment of the Hassi Messaoud field. It focuses on the stratigraphy of the Cambrian sandstone reservoir (specifically the Ra and Ri zones), analyzes petrophysical characteristics and the nature of the light, undersaturated crude oil, and identifies the core operational challenges facing the field in its current mature phase.
- **Chapter Two (Theoretical Foundations of Fluid Flow and Behavior):** Examines the physical and mathematical laws governing multiphase flow within the wellbore, alongside the thermodynamic properties (PVT) of reservoir fluids. It provides a detailed explanation of Inflow Performance Relationship (IPR) and Vertical Lift Performance (VLP) concepts as fundamental diagnostic tools to isolate and identify flow restrictions.
- **Chapter Three (Evaluation of Stimulation and Remediation Solutions):** Focuses on the technical and engineering aspects of well intervention. It evaluates chemical matrix acidizing protocols, hydraulic fracturing designs (including Data-Frac and Main-Frac campaigns), scale and salt removal techniques, water/gas shut-off strategies, and artificial lift applications.
- **Chapter Four (Integrated Case Study and Field Application):** Represents the practical core of the thesis, applying the engineered diagnostic and intervention framework to three real production wells operated by Sonatrach. These wells represent distinct reservoir environments and production histories: Well MD-800 (a mature central area with gas injection), Well MD-819 (a semi-exploration southern off-zone), and Well RDC-30 (a high-pressure reservoir in the Rhourde Chegga field). This chapter evaluates completion designs, well test logs, and the operational execution of fracturing and acidizing treatments to extract robust lessons regarding the success or failure of engineering interventions.

Ultimately, this research work aims to provide a clear engineering workflow that supports production optimization efforts, so how can that be acheived ?

Chapter I

PRESENTATION OF HASSI MESSAOUD FIELD

1.1 Introduction

The Hassi Messaoud field is one of the largest and most complex oil fields in the world and constitutes the backbone of hydrocarbon production in Algeria. Since its discovery in 1956, the field has undergone extensive geological evolution and long-term exploitation, making it a mature reservoir characterized by significant geological and production challenges.

Over geological time, the field has been affected by multiple tectonic phases, diagenetic processes, and structural deformations, which have significantly influenced reservoir properties and fluid distribution. As a result, understanding the geological framework and reservoir characteristics is essential for diagnosing production decline and implementing efficient recovery strategies.

This chapter provides an overview of the field, including its geographic location, geological setting, reservoir description, fluid properties, operational challenges, and production history.

1.2 Geographic Location

The Hassi Messaoud oil field is located in southeastern Algeria, approximately 650 km south-southeast of Algiers and about 350 km from the Tunisian border. It lies within the Oued Mya Basin and covers an area of approximately 2,200 km², making it the largest oil field in the country(Figure 1-1).

The field is surrounded by several important hydrocarbon accumulations:

- Ouargla fields to the northwest
- El Gassi and Zotti fields to the southwest
- Rhourde El Baguel and Mesdar fields to the southeast
- Ghadames Basin to the east

It is also influenced by major structural features such as the Amguid El Biod high and the Oued Mya depression.

The Lambert South Algeria coordinates of the field are:

X = 790,000 – 840,000 (East)   Y = 110,000 – 150,000 (North)

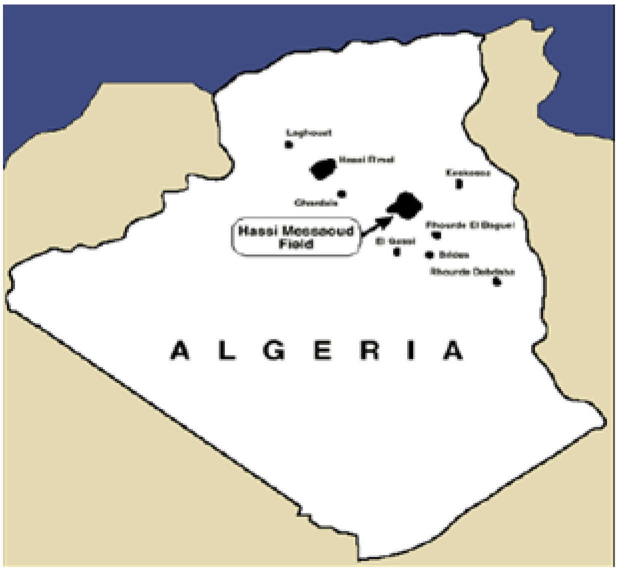

Figure 1-1 :Localisation of HMD

1.3 Geological Setting

The Hassi Messaoud field is located in the central part of the Triassic petroleum province and is characterized by a large anticlinal structure affected by faulting. This structure resulted from successive tectonic events, notably the Hercynian and Alpine orogenies.

The field represents a giant structural trap where hydrocarbons accumulated mainly within Cambrian sandstone reservoirs. The structural configuration, combined with lithological heterogeneity, plays a major role in controlling fluid distribution and reservoir performance.

The field is bounded by several neighboring deposits:

- **West:** Guellala, Ben Kahla, Berkaoui
- **Northwest:** Ouarsenis North, Zidane Lakhdar, Boukhezana
- **Northeast:** Rhourde Chegga
- **Southeast:** Rhourde El Baguel, Mesdar
- **Southwest:** El Gassi, Zotti, El Agreb

1.4 Exploration and Development History

The field was discovered on January 16, 1956, by the MD-1 well following seismic surveys. Oil production from Cambrian sandstones was confirmed at a depth of approximately 3,338 m.

In 1957, the OM-1 well confirmed the presence of significant reserves, leading to the division of the field into two concessions:

- Northern zone operated by C.F.P.A

- Southern zone operated by SN REPAL

After nationalization, the field became fully operated by SONATRACH.

Currently, the field is subdivided into approximately 25 producing zones that behave as semi-independent compartments.

Two main sectors are identified:

- **North field:** combined geographical and chronological naming (e.g., OMN 43)
- **South field:** chronological system with Lambert coordinate reference

However, this subdivision remains imperfect due to reservoir heterogeneity, as some zones are further divided into subzones (Figure 1-2).

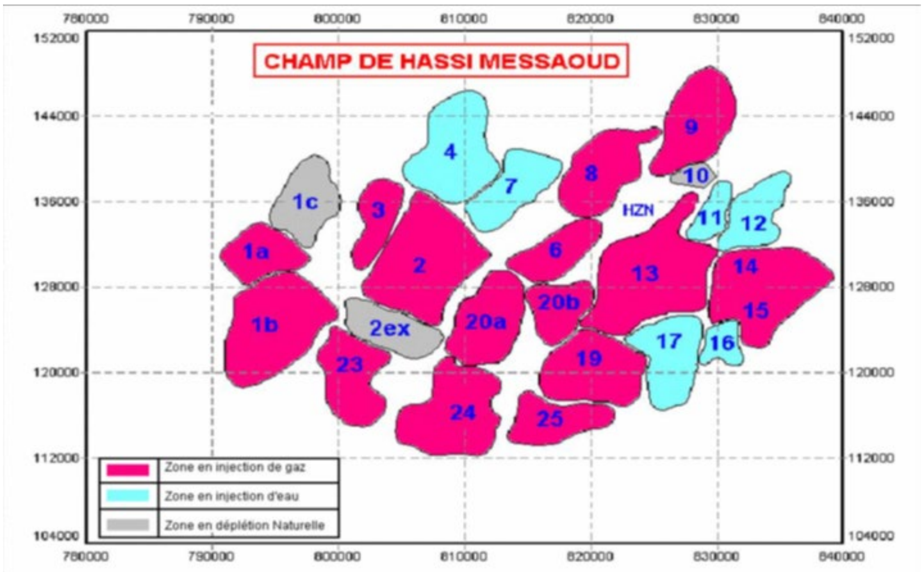

Figure 1-2 : Well zones

1.5 Reservoir Description

The Cambrian reservoir of Hassi Messaoud is subdivided into four main units: Ri, Ra, R2, and R3 (Figure 1-3).

- **Ri Zone:** Relatively homogeneous and compact sandstones (D5 unit), with moderate reservoir quality.
- **Ra Zone:** The most productive unit, composed of anisometric sandstones:

D1: Coarse sandstones with cross-bedding .

ID: Transitional interval .

D2: Well-sorted coarse sandstones .

D3: Fine, bioturbated sandstones (marine influence) .

D4: Coarse sandstones with thick stratification .

- **R2 Zone:** Quartzitic sandstones with higher clay content and generally lower reservoir quality.
- **R3 Zone:** Coarse micro-conglomeratic sandstones with high clay content, considered non-reservoir.

This vertical heterogeneity significantly affects reservoir performance and fluid flow.

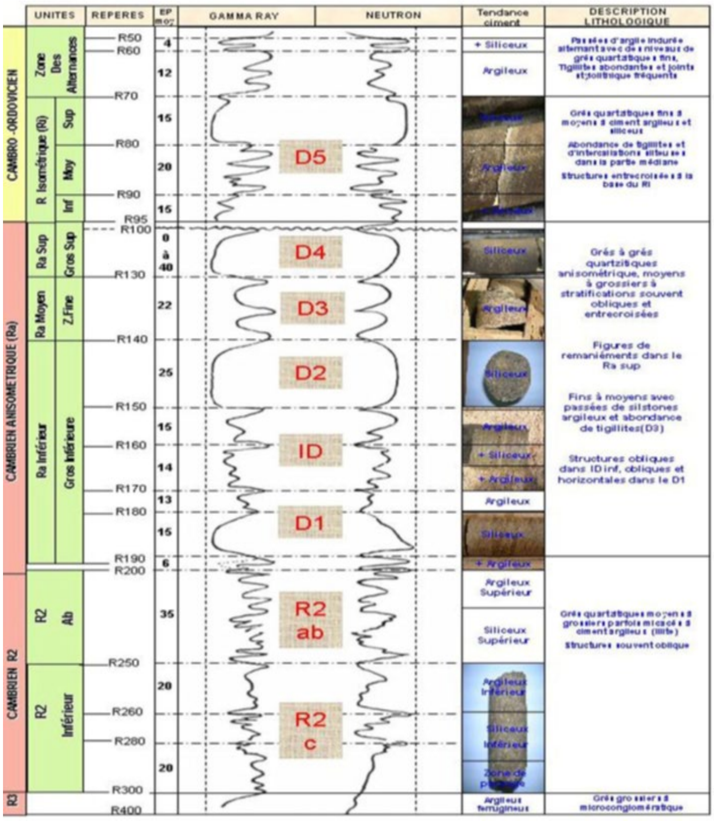

Figure 1-3 :Drains of the Hassi Messaoud Field

1.6 Reservoir Fluid Properties

The reservoir contains light, undersaturated crude oil with the following characteristics:

- **API gravity**: 43.7° – 45°
- **Bubble point pressure**: 140 – 200 kg/cm²
- **Gas–oil ratio:** 160 – 230 m³/m³
- **Temperature:** ~118 °C
- **Initial oil–water contact**: ~3380 m

Reservoir properties:

- **Porosity:** 5 – 10%

- **Permeability:** 1 – 2 mD
- **Oil viscosity:** ~0.2 cP
- **Oil saturation:** 80 – 90%
- **Total compressibility:** 3.63×10^{-4} $(kg/cm^2)^{-1}$

Despite the high quality of the crude oil, low permeability and heterogeneity limit production efficiency.

1.7 Operational Challenges

Due to its maturity, the field faces several production challenges:

- Asphaltene deposition in tubing
- Scale formation (e.g., barium sulfate)
- Salt precipitation
- Water and gas breakthrough
- Reservoir pressure depletion
- Need for artificial lift systems
- Increased wellhead pressure

These issues require continuous monitoring and advanced reservoir management.

1.8 Production History and Field Maturity

1.8.1 Early Development (1956–1970)

Following its discovery, the field experienced rapid development with high natural reservoir pressure allowing strong production without artificial lift.

1.8.2 Peak Production (1970s)

Production reached approximately 500,000 barrels/day due to favorable conditions and intensive drilling.

1.8.3 Decline Phase (1980s–1990s)

Reservoir depletion led to the introduction of:

- Water injection
- Gas injection
- Gas lift systems
- Infill drilling

1.8.4 Mature Stage (2000s–Present)

The field is now highly mature, with focus on:

- Enhanced Oil Recovery (EOR)
- Reservoir simulation
- 3D/4D seismic
- Digital monitoring

These techniques aim to improve recovery and extend field life.

Chapter II

DIAGNOSTIC ANALYSIS OF PRODUCTION DECLINE IN OIL WELLS

Introduction

Before we can fix production decline, we have to figure out what is actually causing it. That sounds obvious, but in a field as complex as Hassi Messaoud, the answer is rarely straightforward. A well might be losing rate because reservoir pressure is dropping across the whole zone—or because a chunk of scale just broke loose and plugged the perforations. Sometimes the gas lift system is choking things off. Sometimes the problem is fifteen years of fines slowly migrating and bridging pore throats. The symptoms can look similar, but the fixes are completely different.

This chapter walks through the diagnostic process we use to separate one cause from another. It is organized around the main families of decline mechanisms: those that live in the reservoir (pressure depletion, water or gas coning, compartmentalization), those that live in the near-wellbore region (formation damage, scale, asphaltenes), and those that live in the wellbore or surface facilities (artificial lift inefficiency, flowline backpressure). For each mechanism, we describe what it does to production trends, pressure responses, and fluid chemistry—and how you tell it apart from the others.

The second half of the chapter covers the practical tools: pressure transient analysis, production logging, fluid sampling, and nodal analysis. None of these works perfectly by itself. But used together, in a systematic workflow, they usually get you to a reliable diagnosis. And that diagnosis is what drives the remediation decisions we will cover in later chapters.

2.1 Introduction to Production Decline Analysis

2.1.1 What Production Decline Means and Why It Matters

Every oil well faces the same inevitable reality: production drops over time [1]. This decline is unavoidable, but here is what actually matters—the speed at which it happens and what is driving it. These factors determine whether a field stays economically viable and how much oil we ultimately recover.

For a giant, mature field like Hassi Messaoud, producing since 1958, understanding decline is not academic theory—it is essential for keeping operations running [2]. Some zones here start strong then crash quickly, typical of fractured reservoirs where the matrix contributes little [3]. Other areas hold steady longer, suggesting the rock itself actively feeds fluids into the fractures [3]. This variability means blanket solutions will not work; each well needs individual diagnosis.

Production decline analysis matters across every aspect of petroleum engineering [4]

Economically, it directly shapes cash flow projections and investment decisions [1]. We need to know whether fixing a problem pays off, how to classify reserves, and how to plan facilities for future throughput.

Technically, decline patterns reveal what is happening underground. They help us identify drive mechanisms, catch operational problems early, optimize artificial lift, evaluate stimulation success, and guide field development strategy [4].

For reservoir management, decline analysis tells us if pressure maintenance works, whether we are efficiently sweeping flooded zones, where bypassed oil might hide, and gives us real data to calibrate simulation models [1].

2.1.2 Natural vs. Abnormal Decline: The Critical Distinction

We broadly categorize decline as either natural or abnormal—and telling them apart guides everything that follows [1].

<u>Natural Decline</u>

This is the expected slowdown as reservoir energy depletes, following predictable patterns based on the dominant drive mechanism [5].

In solution gas drive reservoirs, production typically follows exponential or hyperbolic curves once pressure drops below the bubble point [5]. Hassi Messaoud started undersaturated but now uses various pressure maintenance schemes—miscible gas flooding and water injection in selected zones—so baseline decline varies significantly across the field [1].

<u>Abnormal or Premature Decline</u>

This happens when production falls faster than natural depletion predicts, indicating additional reservoir, wellbore, or surface problems [1]. We flag decline as abnormal when:

- Annual decline exceeds 25% in solution gas drive reservoirs
- Decline rate suddenly jumps over 50% without operational changes
- A well underperforms compared to nearby offsets
- Actual decline diverges from material balance predictions

2.2 Reservoir-Related Decline Mechanisms

These problems originate deep in the formation, affecting the reservoir's fundamental ability to deliver fluids [4]. They are typically the toughest to fix, usually requiring field-wide rather than well-specific interventions.

2.2.1 Pressure Depletion

This is the most basic reservoir mechanism—simply running out of energy [4]. As we produce hydrocarbons, the natural pressure pushing them toward the well gradually dissipates. The speed depends on drive mechanism, production rate, and pressure maintenance effectiveness [1].

2.2.2 Water Encroachment and Coning

Water production probably causes more oil production decline than any other single factor, showing up differently depending on reservoir architecture and well configuration [4].

Water Coning

When we pull oil too fast, water from below rises in a cone shape beneath the wellbore and eventually breaks through [4]. After breakthrough, water cut climbs steadily while oil drops. Timing depends on reservoir properties, fluid densities, and production rates(Figure 2-1).

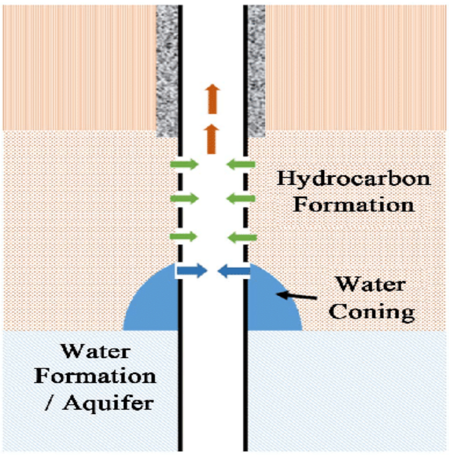

Figure 2-1 : Water Coning in vertical well

In horizontal wells, we see "cresting" instead—similar idea, but generally less severe because horizontal wells sit farther above the water contact and distribute drawdown over a longer lateral(Figure 2-2).

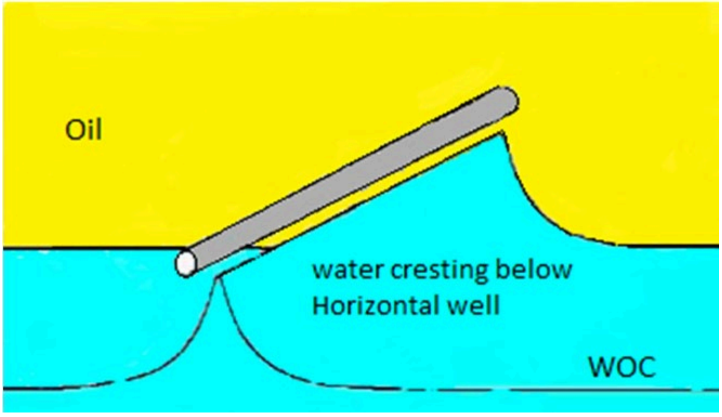

Figure 2-2 : Water cresting in Horizontal Well

The Hassi Messaoud Challenge

Water diagnosis here gets complicated. Petrophysical studies show that in some zones, resistivity drops with depth not just from water saturation, but from higher clay content and clay-bound water [7]. This means conventional resistivity log interpretation can mislead—what looks like an oil-water contact might just be lithology change [7].

Early Water Breakthrough

In highly heterogeneous reservoirs like this one, where permeability spans from under 1 md in matrix to over 100 md in open fractures [3], water finds the path of least resistance. Injected water or natural aquifer water channels through high-permeability conduits, bypassing oil in lower-permeability zones and showing up prematurely in offset wells.

Diagnostic Signatures:

Table 2.1 : diagnostic signatures of water production

Water Production Mechanism	Water Cut Pattern	Timing	GOR Behavior	Pressure Response
Coning	Gradual increase after stable period	Months to years after startup	Stable or decreasing	Stable
Fracture breakthrough	Sudden jump (step change)	Days to months after injection	Variable	Usually stable

Layered breakthrough	Stepped increases	Years after production begins	Stable	Gradual decline
Bottom-water drive	Continuous increase	Proportional to cumulative	Stable	Good pressure support

2.2.3 Gas Coning

The gas version of water coning happens in wells near gas caps or when reservoir pressure drops below bubble point [4]. As pressure falls near the wellbore, dissolved gas comes out of solution. If continuous gas phase develops, oil relative permeability drops and oil production suffers.

Once mobile gas saturation establishes, gas relative permeability rises rapidly—gas production climbs while oil production falls, sometimes dramatically [4]. Hassi Messaoud started undersaturated, but decades of production have created gas saturation in some depleted areas [3].

2.2.4 Reservoir Heterogeneity and Compartmentalization

If anything defines Hassi Messaoud, it's extreme heterogeneity [3]. The Cambrian reservoir stacks four distinct units from base to top [7]:

Table 2.2 : Stratigraphic Units of Hassi Massaoud Reservoir

Unit	Subunits	Lithology	Reservoir Quality
R3 (Basal)	-	Coarse-grained sandstones	Variable
R2	-	Sandstones with shale interbeds	Moderate
R1	Ra (D4, D3, D2, ID, D1)	Fine to medium sandstones	Best in D2/D3
Ri (D5)	Interbedded sandstones/shales	Poor to Moderate	
Alteration Zone	-	Weathered zone at top	Variable

The Ra unit, which is the most important for reservoir potential, is further subdivided into D4, D3, D2, ID, and D1 reservoirs, while the RI zone is designated D5 [Figure 2-3].

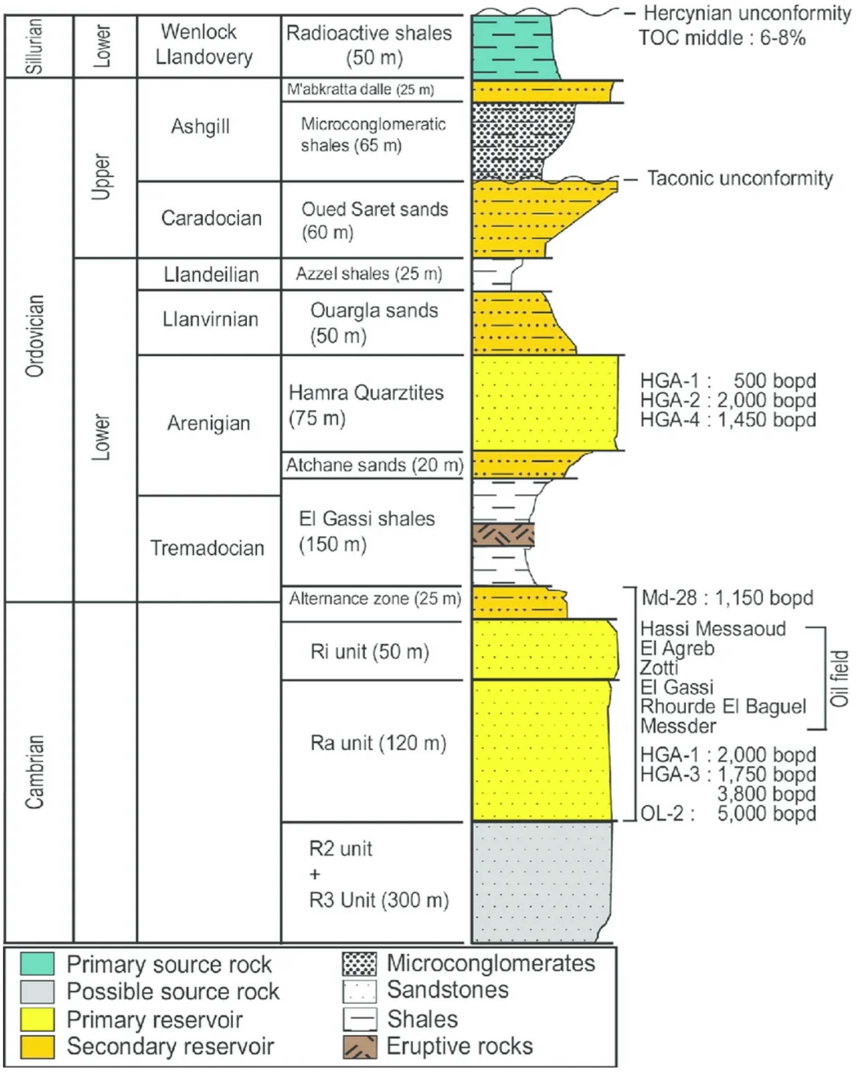

Figure 2-3 : Hassi Messaoud Stratigraphic Column

2.2.5 Relative Permeability Effects

As fluid saturations shift during production, relative permeability becomes increasingly influential [4]. Oil relative permeability drops as water or gas saturation rises—sometimes dramatically.

For Hassi Messaoud, the complex pore structure and clay distribution mean that relative permeability curves vary significantly by rock type. Higher quality zones typically exhibit more favorable relative permeability characteristics than lower quality zones, with lower residual oil saturation and higher endpoint relative permeability to oil [7].

2.3 Wellbore and Near-Wellbore Issues

While reservoir problems affect the big picture, wellbore and near-wellbore issues choke off production at the final stage—getting fluids from formation to surface [4]. The good news: these problems are usually easier and cheaper to fix than reservoir-scale issues, provided we diagnose them correctly.

2.3.1 Formation Damage (Skin Effect)

Formation damage is anything reducing natural permeability near the wellbore [4]. We quantify it using the skin factor (S)—a dimensionless number representing extra pressure drop from damage beyond what an undamaged formation would see [8].
The skin factor appears in the pressure drop equation [Figure 2-4]:

$$\Delta P\_skin = (141.2\ q\mu B/kh) \times S$$

Positive skin means damage; negative skin means stimulation (like from hydraulic fracturing) [8]. We can also relate skin to physical damage dimensions [8]:

$$S = \left(\frac{k}{ks} - 1 \right) \ln \frac{r_s}{r_w}$$

Where ks is damaged zone permeability and rs is damaged zone radius.

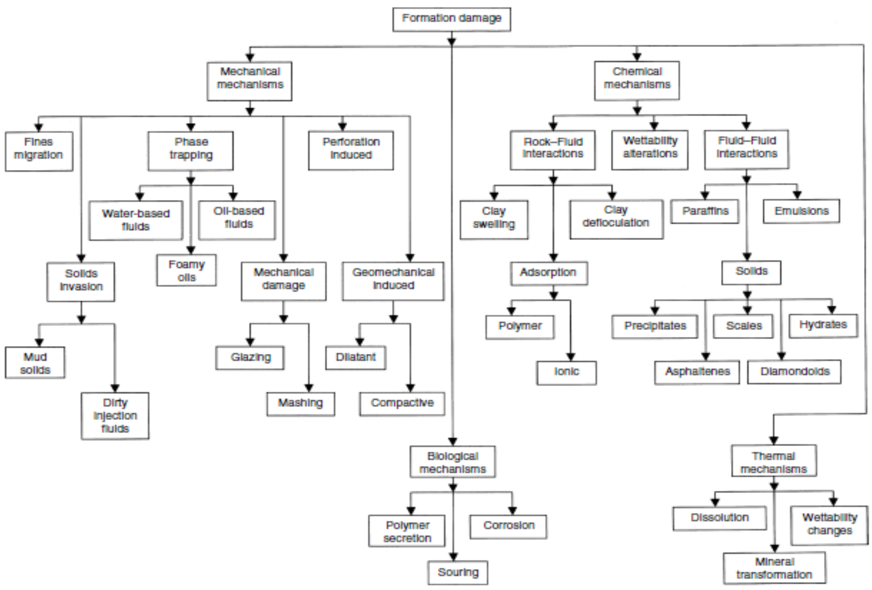

Figure 2-4 : Classification and order of the common formation damage mechanisms

(modified after Bennion, ©1999; reprinted by permission of the Canadian Institute of Mining, Metallurgy and Petroleum).

Table 2.3: Formation Damage Mechanisms in Hassi Massaoud

Damage Mechanism	Primary Location	Diagnostic Indicator	Treatment
Salt deposition	Near-wellbore, perforations	Increasing skin, water sensitivity	Fresh water wash
Scale ($BaSO_4$, $CaCO_3$)	Perforations, tubing	Stepwise decline, produced water chemistry	Mechanical, chemicals
Clay swelling/migration	Pore throats	Rate-sensitive skin, water sensitivity	Clay stabilizers
Fines migration	Pore throats	Rate-sensitive, improves after shut-in	Fines stabilizers
Asphaltenes	Near-wellbore, tubing	Pressure-dependent, GOR correlation	Solvents, dispersants
Emulsions	Near-wellbore	High viscosity, water cut correlation	Demulsifiers

Loose particles in the pore structure mobilize with flowing fluids, then bridge at pore throats and restrict flow [4]. High-rate wells and those subjected to rapid pressure transients during startup and shutdown are particularly vulnerable. This often shows as rate-sensitive skin that worsens as we ramp up production

Organic Deposition

Asphaltenes and waxes precipitate as pressure and temperature drop along the flow path [4]. The 45°API oil from Hassi Messaoud [7] suggests asphaltene problems are less severe than in heavier oil fields, but risk remains—especially near the bubble point where asphaltene instability peaks.

2.3.2 Mechanical Issues

Mechanical problems mimic formation damage in production impact but need completely different fixes [9].

Scale Deposition

When produced water's ionic balance gets disturbed by pressure, temperature, or mixing changes, scale forms [9]. Barium sulfate scale is our particular nemesis here—extremely hard, acid-insoluble, often requiring mechanical removal or specialized chelating agents [9]. It plugs perforations, fills wellbores, or fouls surface equipment, each location showing different symptoms.

Table 2.4: Common Scale Types and Characteristics

Scale Type	Chemical Formula	Solubility in Acid	Common Location	Diagnostic Indicator
Calcium carbonate	$CaCO_3$	Soluble (HCl)	Perforations, tubing, ESP	Pressure drop increase, pH rise
Barium sulfate	$BaSO_4$	Insoluble	Perforations, near-wellbore	Radioactive (Ra co-precipitation), Ba in water
Strontium sulfate	$SrSO_4$	Insoluble	Perforations, near-wellbore	Sr in water
Calcium sulfate (gypsum)	$CaSO_4 \cdot 2H_2O$	Slightly soluble	Tubing, surface	Ca, SO_4 in water
Iron sulfide	FeS	Soluble (HCl)	Tubing, sour wells	Black solids, H_2S present
Sodium chloride	NaCl	Soluble (fresh water)	Tubing, surface	Fresh water soluble

Corrosion

Downhole corrosion gradually destroys equipment [9]. Tubing holes allow fluid recirculation; corrosion product flakes plug perforations; severe cases cause casing or tubing failure requiring complete workover [9]. CO_2 in produced fluids, if present, accelerates attack on carbon steel completions.

Sand Production

Any sandstone reservoir can produce sand under high drawdown or where natural cementation is weak [4]. Hassi Messaoud's extreme permeability range—from <1 md matrix to >100 md fractures [3]—suggests some weaker, high-permeability intervals may be susceptible. Sand erodes equipment, fills the wellbore with solids, and can lead to formation collapse around the wellbore [4].

As reservoir conditions evolve, wellbore flow regimes change, introducing pressure drops that choke production [9].

2.3.3 Multiphase Flow Effects

Liquid Loading

Usually considered a gas well problem, liquid loading can hit oil wells producing significant free gas [9]. When gas velocity drops below the critical rate needed to lift liquids, they accumulate in the wellbore, increasing backpressure on the formation and cutting production [9]. This often shows as erratic production—sudden declines followed by periods of liquid unloading.

Emulsion Blockage

Oil and water mixed under high shear form stable emulsions with viscosities far exceeding either phase alone [9]. While more common in surface facilities, emulsions can form downhole—particularly through pumps or chokes—and severely impair flow.

2.4 Production System and Surface Constraints

Sometimes the problem isn't the reservoir or well—it's everything downstream [9]. Surface facility constraints can limit throughput even when the well could produce more.

2.4.1 Artificial Lift Inefficiency

Gas lift activates production throughout Hassi Messaoud [6]. Properly designed, it significantly boosts production by reducing fluid column density and lowering bottom-hole pressure [9]. But inefficient gas lift actually hurts production [9].

Table 2.5: Gas Lift Performance Issues and Diagnostics

Problem	Cause	Diagnostic Indicator	Impact
Wrong injection depth	Poor design	No response to rate changes, high density gradient	10-30% production loss
Valve malfunction	Corrosion, erosion	Erratic injection rate, casing pressure fluctuations	15-40% production loss
Suboptimal injection rate	Poor optimization	Operating point left of minimum on performance curve	5-20% production loss
Instability	Valve cycling	Pressure and rate oscillations	10-25% production loss, equipment damage
Oversized orifice	Incorrect sizing	Excessive gas use, high friction	Economic loss, reduced lift efficiency

ESP Considerations

While ESPs aren't extensively used here based on available literature, they're common in mature fields generally [9]. ESP degradation shows through:

- Rising pump intake pressure (wear or scale)
- Increasing motor temperature (poor cooling or mechanical issues)
- Changing amperage (fluid property changes or mechanical problems)
- Vibration (imbalance or wear)

2.4.2 Surface Facility Limitations

High backpressure from flowlines and separators directly reduces drawdown available to produce the well [9]. If separator pressure increases—due to compressor issues, increased throughput from other wells, or liquid holdup in flowlines—the well's production declines accordingly [9]. This type of decline is often subtle and may be mistaken for reservoir issues if surface pressures aren't monitored carefully.

Gathering Network Bottlenecks

Gathering network bottlenecks can affect groups of wells. As fields mature, production profiles change, and gathering systems designed for earlier conditions may become limiting [9]. Liquid accumulation in low points, slug flow in hilly terrain, and capacity constraints at manifolds can all restrict production.

2.5 Diagnostic Tools and Methodologies

Now that we've covered what can go wrong, let's look at how we actually figure out which problem is active [1]. These diagnostic techniques form the core of our engineering workflow and provide the evidence base for remediation decisions [4].

Table 2.6: Diagnostic Signatures from Production Data

Observed Pattern	Likely Interpretation	Confirmatory Test
Steep exponential decline, stable GOR, no water	Pressure depletion in small drainage volume	PTA for boundaries [9]
Rising water cut, accelerating oil decline	Water coning or breakthrough	PLT for water entry [9]
Rising GOR, oil decline, stable water cut	Gas coning or reaching bubble point	PTA for pressure, PVT analysis [9]
Sudden rate drop, recovery after shut-in	Fines migration (rate-sensitive)	Rate test, backpressure analysis
Erratic production with periodic liquid slugs	Liquid loading	Critical velocity calculation [10]
Stepwise rate decreases with surface changes	Facility constraints	Backpressure test [10]
Gradual decline with increasing skin	Formation damage	PTA for skin, damage characterization [9]
Rapid decline, stable GOR and WC	Compartmentalization	PTA for boundaries, geological review [3]

2.5.1 Pressure Transient Analysis (PTA)

PTA—interpreting pressure measurements during controlled rate changes—gives us quantitative data on reservoir and wellbore conditions [8]. It estimates permeability, skin factor, reservoir pressure, and detects boundaries and heterogeneities [8].

Table2.7 : PTA Diagnostic for Hassi Massaoud

PTA Signature	Interpretation	Likelihood Here
High skin (+5 to +20), radial flow	Formation damage	High (documented damage mechanisms) [1]
Negative skin (-3 to -5)	Stimulated/naturally fractured	High in fractured zones [3]

Dual porosity behavior	Naturally fractured reservoir	High in faulted zones [3]
Boundary detection within 500 m	Compartmentalization	High (fault compartmentalization) [1]
Radial flow + constant pressure boundary	Aquifer support or injector response	Moderate (injection areas) [3]
Increasing derivative slope	Permeability degradation with distance	Low (uncommon)

2.5.2 Production Logging (PLT)

While PTA gives us average properties, PLT provides a depth-resolved picture of what's happening along the wellbore [8]. A typical tool string includes spinner flowmeters, fluid density sensors (gradiomanometers), pressure and temperature gauges, and fluid identification tools [8].

What PLT Tells Us:

Identifying fluid entry points: In a heterogeneous reservoir like Hassi Messaoud, where permeability can vary by orders of magnitude between matrix and fractures [3], not all perforated intervals contribute equally. PLT identifies which zones produce, which sit stagnant, and which might actually be cross-flowing (taking fluid from the wellbore back into the formation) [8].

Flow profile quantification: Spinner response calibrated to flow rate shows exactly how much each interval contributes [8].

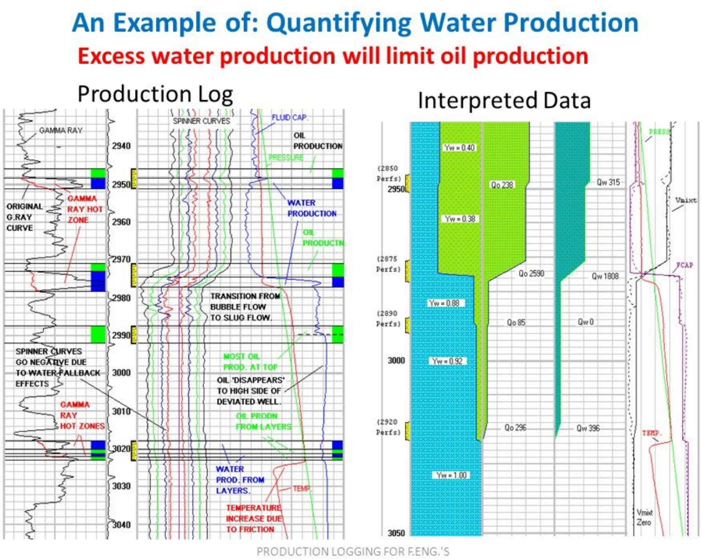

Figure 2-5 : Flow profile quantification by PLT

Table2.8 : PLT Diagnostic Signatures

Observation	Interpretation	Action
Flow from single interval only	Heterogeneity, partial completion damage	Consider stimulating non-contributing zones
Water entry at base, oil above	Water coning	Consider water shutoff, reduce drawdown
Gas entry at top, oil below	Gas coning	Consider gas shutoff, reduce drawdown
Decreasing flow with depth (no entries)	Wellbore restriction	Locate and remove restriction
Cross-flow between zones	Pressure differential between zones	Zone isolation, balanced depletion
Temperature increase at restriction	Friction from scale	Scale removal, inhibition
Temperature decrease at depth	Fluid entry (Joule-Thomson cooling)	New perforation or fracture

2.5.3 Fluid and Water Analysis

The fluids themselves carry diagnostic information about reservoir and wellbore conditions [9].

Water Salinity Analysis

- Different water sources have distinct chemical fingerprints [9]:
- Formation water: High, stable TDS with characteristic ionic ratios
- Injected water: Variable TDS, often lower than formation water, may contain tracers
- Condensed water: Very low TDS from steam or gas condensation

Mixing zones: Intermediate, variable salinity

In Hassi Messaoud, tracking salinity changes helps distinguish between natural aquifer water and injected water from pressure maintenance schemes—critical for targeting remediation [1].

Oil Composition Tracking

Oil composition changes can indicate compartment boundaries or approaching fluid contacts [9]:

- API gravity shifts: May signal different compartments or gas influx
- Oil analysis (Paraffins, Aromatics, Resins, Asphaltenes): Asphaltene content variation
- Gas chromatography "fingerprinting": High-resolution correlation between samples
- Biomarkers: Biological marker compounds for oil-oil correlation

2.5.4 Nodal Analysis

Nodal analysis integrates the entire production system—from the reservoir pore throat to the separator—into a single quantitative model [9]. By representing each component's pressure drop as a function of flow rate, nodal analysis identifies the bottleneck in the system and predicts the impact of changes [10].

Inflow Performance Relationship (IPR):

For under-saturated reservoirs (P > Pb) [10]:

$$Q = \frac{kh(P_G - P_{wf})}{141.2 B\mu\left(\ln\frac{\mathrm{Re}}{r_w} + S\right)}$$

Where:

Q = oil flow rate at bottomhole conditions (bbl/d)

k = permeability (md)

h = reservoir thickness (ft)

μ = oil viscosity (cp)

Pr = reservoir pressure (psi)

Pwf = flowing bottomhole pressure (psi)

re = drainage radius (ft)

rw = wellbore radius (ft)

S = total skin factor

Vertical Lift Performance (VLP):

The VLP describes the pressure drop in the wellbore [9]:

Pwf = Pwh + ΔPhydrostatic + ΔPfriction + ΔPacceleration

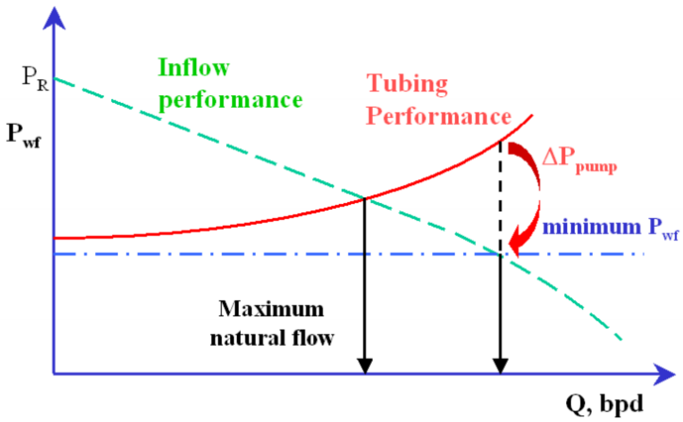

Figure 2-6 : IPR and VLP curves with operating point

System Analysis:

The operating point is the intersection of IPR and VLP curves [9].

- If operating point is rate-constrained by IPR: Reservoir problem
- If operating point is rate-constrained by VLP: Wellbore/surface problem (high backpressure)

Sensitivity Analysis:

Nodal analysis allows sensitivity studies to identify the most effective intervention [9]:

Reduce skin (stimulation) → IPR shifts right

Reduce water cut (water shutoff) → IPR slope changes

Increase gas lift rate → VLP shifts down

Reduce separator pressure → VLP shifts down

2.6 An Integrated Diagnostic Workflow

Real diagnosis requires combining multiple data sources systematically [1].

Step 1: Historical Trend Analysis

Start with readily available data—production rates, water cut, GOR, and flowing pressures over time [5]. Plot them together and look for:

When decline started relative to well events (workovers, rate changes, offset well startups)

The shape and rate of decline

Correlations between oil rate changes and water cut, GOR, or pressure shifts

Step 2: Pressure Transient Testing

When reservoir or wellbore damage is suspected, run a pressure buildup test [8]. Analyze the data to determine:

- Current reservoir pressure (is depletion occurring?)
- Permeability-thickness product (is flow capacity as expected?)
- Skin factor (is damage present?)
- Boundary effects (is the well in a small compartment?)

Step 3: Production Logging

If PTA indicates damage or water/gas production is problematic, run PLT to [8]:

Identify fluid entry points along the interval

- Detect cross-flow between zones
- Locate water or gas entry depths
- Find wellbore restrictions

Step 4: Fluid Analysis

Collect and analyze water and oil samples [9]:

- Water salinity and ionic composition
- Scale indices (saturation ratios)
- Oil analysis
- Gas composition

Step 5: Nodal Analysis

Identify the system bottleneck (reservoir, wellbore, or surface) [9]

Predict intervention impacts [10]

Optimize artificial lift parameters

Step 6: Synthesis and Diagnosis

Pull all evidence together for a final diagnosis [1].

Table 2.9: mapping each diagnostic tool to the decline mechanisms it identifies

Decline Mechanism	PTA	PLT	Fluid Analysis	Nodal Analysis	Production History	
Pressure depletion	✓	✗	✗	✓	✓	
Water coning	✗	✓	✓	✓	✓	
Gas breakthrough	✗	✓	✓	✓	✓	
Formation damage	✓	✓	✗	✓	✓	
Scale deposition	✓	✓	✓	✓	✓	
Compartmentalization	✓	✓	✗	✓	✓	
Artificial lift inefficiency	✗	✗	✗	✓	✓	

Table 2.10 : Integrated Diagnostic Matrix for Hassi Massaoud Wells

Mechanism	Production Trend	Pressure Response	PLT Signature	Fluid Chemistry	Nodal Analysis
Pressure depletion	Gradual decline, all zones	Low P*, boundaries detected	Uniform, all zones contributing	Stable	Low IPR slope
Water coning	Rising WC, oil decline	Normal P*, no damage	Water entry at base	Formation water	Water cut affects IPR
Fracture water breakthrough	Sudden WC increase	Normal P*, high k near well	Localized water entry	Injected water signature	Rapid WC increase
Formation damage	Rate-sensitive decline	Positive skin, increasing with time	Reduced contribution from damaged zones	Possible scale ions	High skin in IPR
Scale deposition	Stepwise decline	Increasing skin, mechanical restriction	Flow restriction	High scale-forming ions	Increasing VLP

Compartmentalization	Rapid initial decline	Boundaries, rapid P* drop	Variable zone contributions	Possible composition changes	Small drainage volume
Gas lift problems	Erratic, rate-sensitive	Normal reservoir	N/A	Stable	VLP constrained
Fines migration	Rate-sensitive, improves after shut-in	Rate-dependent skin	May show no entry changes	Fine particles in samples	Rate-dependent IPR

Conclusion

Diagnosing production decline in a mature, heterogeneous field like Hassi Messaoud is rarely a matter of looking at a single trend line and calling it. The same declining oil rate can come from pressure depletion, water breakthrough, formation damage, scale, gas lift problems, or any combination of them. The wrong diagnosis leads to the wrong fix—which wastes money and sometimes makes things worse.

This chapter laid out a structured approach. We started with the natural versus abnormal decline distinction, because if a well is just following its expected depletion curve, you do not need to intervene. Then we reviewed the specific mechanisms that cause abnormal decline, organized by where they act reservoir, near-wellbore, wellbore, or surface. For each one, we gave diagnostic signatures—production patterns, pressure responses, PLT signatures, fluid chemistry clues—that help tell them apart.

The diagnostic tools section showed that no single test gives the whole answer. Pressure transient analysis quantifies skin and permeability but cannot tell you whether that skin comes from scale or clay swelling. Production logging shows you where water is entering but not why. Fluid analysis gives chemical fingerprints but not locations. That is why the integrated workflow (history, then pressure testing, then PLT, then fluid analysis, then nodal analysis) matters. Each step narrows the possibilities until you have a confident diagnosis.

A few practical points worth carrying forward. First, in a fractured reservoir like parts of Hassi Messaoud, water breakthroughs can happen very fast—step changes rather than gradual increases—and that points to a very different remediation strategy (conformance control) than gradual coning (reducing drawdown). Second, skin effects from formation damage are often rate-sensitive; if a well produces better after a short shut-in, that strongly suggests fines migration or similar mechanical trapping rather than scale. Third, surface backpressure is frequently overlooked

The bottom line is this: decline analysis only works if you match the mechanism to the evidence. The next chapter will take these diagnostic principles and apply them to actual wells in the Hassi Messaoud field, showing how the workflow plays out in real data and what remediation options make sense for each diagnosed problem.

Chapter 3: EVALUATION OF REMEDIATION AND STIMULATION SOLUTIONS

Introduction

The previous chapter provided the tools necessary to identify the causes of a production decline. This chapter addresses the applicable corrective measures.

On a field such as Hassi Messaoud, unlimited trial runs are not an option. Selecting an inappropriate treatment can worsen the situation, sometimes permanently. Pumping the wrong acid into a formation containing certain clays reduces permeability below the original state. Setting a packer in the wrong location may isolate not only water but also part of the oil. Consequently, the approach adopted is careful and methodical.

The main remediation methods actually used in this field are examined: acidizing, fracturing, water and gas shutoff, artificial lift optimization (gas lift), and scale removal. For each method, its working principle, application criteria, and limitations are presented. The chemical recipe, pumping schedule, and indicators of an operation going wrong midway are detailed, as these practical aspects matter more than theory.

Several observations emerge. First, most of these methods are not new: acidizing has been practiced in this field since the 1960s. However, changes in the reservoir—pressure decline, rising water cuts, scale buildup—have rendered the old recipes sometimes ineffective. Second, combination problems are the norm. A well with scale, gas lift issues, and water breakthrough does not require three separate interventions but one integrated job addressing the main bottleneck first. Third, the diagnostics from Chapter 2 drive every decision. Acidizing is not performed simply because the skin factor is positive; the exact nature of the damage must be verified beforehand.

3.1 Introduction to Remediation and Stimulation

3.1.1 Diagnostic Significance of Well Intervention in Production Sustainability

Chapter 2 provided the identification of the factors causing production decline. The practical aspect concerns the selection of appropriate remedial actions. In a field such as Hassi Messaoud, which has been in production since 1956, well intervention is not merely an occasional repair operation; it is integrated into daily field management. Wells are not left to decline passively; rather, they are continuously maintained. These interventions directly determine the ultimate oil recovery and the continued economic viability of the field [11].

The Cambrian sandstone reservoir presents a challenging geological environment. It extends over approximately 2000 km², spanning four formations plus a transition zone, all subdivided into multiple producing intervals, each with distinct characteristics [12]. Permeability values range from less than 1 mD in the tight matrix to over 100 mD in fractured zones, and the fracture networks exhibit varying properties across 25 separate field zones [13]. Selecting the correct remedial measure requires matching the specific decline mechanism to the unique geological setting of each well; no universal solution exists.

3.1.2 The Remediation Toolbox

Remediation techniques can be roughly grouped into four categories, each addressing distinct production challenges:

1. Stimulation Methods:

- Matrix acidizing (getting rid of near-wellbore damage)
- Hydraulic fracturing (bypassing tight matrix rock)
- Acid fracturing (when you're dealing with carbonates)

2. Water and Gas Control:

- Mechanical isolation (packers, bridge plugs, cement squeezes)
- Chemical water shutoff (polymer gels, relative permeability modifiers)

3. Artificial Lift Optimization:

- Gas lift tweaks (injection rate, depth, valve design)
- ESP installation and tuning
- Rod pump optimization
- Plunger lift systems

4. Scale and Deposit Removal:

- Mechanical scraping or milling
- Chemical dissolvers
- Solvent treatments for organic gunk

3.1.3 How We Pick the Right Tool

Selecting a remediation method follows a systematic decision tree based on what the diagnostics told us. Table 3.1 lays out the main options and where they typically fit in Hassi Messaoud.

Table 3.1 : Remediation Technique Selection Matrix for Hassi Messaoud

Primary Decline Mechanism	Preferred Technique	When We Use It
Formation damage (clays, fines)	Matrix acidizing (HF-based)	Pretty standard after workovers
Formation damage (scale)	Scale dissolvers + mechanical removal	Barium sulfate is a nightmare—needs special handling
Low matrix permeability	Hydraulic fracturing	Works best in specific zones
Natural fracture stimulation	Proppant fracturing	Particularly effective in fractured zones
Water coning	Mechanical isolation	Depends on exactly where water is breaking in
Water channeling (fractures)	Chemical conformance (gels)	Getting more common in mature wells
Gas coning	Mechanical isolation / rate control	Selective application
Gas lift inefficiency	Gas lift optimization	Potential across the whole field
ESP performance degradation	ESP optimization / replacement	Increasingly relevant
Salt deposition	Fresh water washes	Routine maintenance
Asphaltene/wax deposition	Solvent treatments	As needed
Production decline (post-frac)	Re-fracturing	For wells that were fractured before

3.2 Well Stimulation Methods

3.2.1 The Basics of Matrix Acidizing

Matrix acidizing means pumping acid into the formation at pressures low enough that we don't fracture the rock. The acid snakes through natural pores and reacts with either damaging materials or the formation minerals themselves. Two things happen:

- **Damage dissolves:** Acids break down scale, clay minerals, drilling mud solids—whatever's choking permeability near the wellbore.
- **Formation minerals react:** In sandstones, hydrofluoric acid (HF) attacks clays and feldspars, opening up permeability in the damaged zone.

The specific fluid recipe depends on rock type and petrophysical properties. For Hassi Messaoud, nailing the mineralogical composition is critical—get it wrong and you can precipitate more damage than you remove [14].

3.2.2 Acid Systems for Sandstone Formations

Sandstone reservoirs like ours need carefully designed acid systems. You have to address the specific mineralogy while avoiding secondary precipitation that could make things worse.

Hydrochloric Acid (HCl):

use HCl for tubing cleanout, wellbore cleanup, and perforations. It is also our go-to for preflush and overflush stages at 7.5% concentration. It reacts fast with carbonates and does not leave harmful precipitates behind [14].

Mud Acid (HCl-HF):

Mud Acid forms by dissolving ammonium bifluoride in HCl solution. HF beats HCl because it is stronger and goes after silica, silicates, and clays [14]. We adjust concentrations based on formation temperature, permeability, and rock composition.

Typical Mud Acid recipes used:

6% HF + 1.5% HCl: Half Strength Mud Acid

3% HF + 12% HCl: Regular Mud Acid

6% HF + 12% HCl: Super Mud Acid

10% HF + 12% HCl: Ultra Mud Acid

Organic Acids:

pull these out when corrosion is a major concern. They eat equipment far less aggressively than HCl or HF, and they're easier to inhibit at high temperatures. The lower corrosion rates make them ideal when acid will sit in contact with pipe for extended periods [14]. typically use acetic acid (CH_3COOH), citric acid, or formic acid ($HCOOH$).

Clay Acid (Fluoboric Acid HBF_4):

Clay Acid targets clayey-sandstone reservoirs. It dissolves clays and actually fuses them onto pore walls, preventing migration. The hydrolysis reaction is slow, so this acid can penetrate deep into the matrix before spending [14].

3.2.3 Additives—Not Optional

Additives are not luxury items but essential components. They serve two purposes: improving stimulation effectiveness while preventing collateral damage, and protecting equipment from the aggressive nature of the acid [14]. Neat acid is never used, as it is excessively damaging to all contacted materials [14]. The selection of additives is determined by laboratory testing and takes into account formation temperature, well type, and completion design.

Surfactants :

Surfactants reduce surface tension at liquid-gas interfaces and interfacial tension between immiscible fluids. They improve acid-rock contact, assist acid penetration by lowering capillary effects, alter rock wettability, break emulsions, and keep formation fines dispersed rather than plugging pores [14].

Friction Reducers :

These reduce frictional forces, which lowers injection pressure and decreases pumping power requirements.

Corrosion Inhibitors :

These protect downhole and surface equipment. Their effectiveness is time-limited and depends on temperature, acid strength, and steel grade. They adsorb onto metal surfaces to form a protective film [14].

Iron Control Agents :

Iron originates from two sources: corrosion deposits on tubulars and valves, or formation minerals (pyrite FeS_2, siderite $FeCO_3$, hematite Fe_2O_3) that dissolve during acid injection. The problem arises when spent acid neutralizes and iron precipitates. Product choice depends on temperature, reaction time, deposit type, and formation iron content [14].

Demulsifying Agents :

Viscous emulsions can form when acid contacts formation fluids, potentially plugging pores and causing production losses that are difficult to remedy. Water-in-oil emulsions are more common under reservoir conditions [14].

Antisludge Agents :

Sludge forms when asphaltenes, resins, paraffinic waxes, and heavy hydrocarbons—naturally present in crude oil—flocculate and precipitate at water-oil interfaces after acid contact. This material can permanently damage formations. Sludge formation is prevented using blends of anionic and non-anionic surfactants together with aromatic solvents [14].

Clay Stabilizers :

These prevent formation damage caused by the release of clay particles when the rock contacts fresh water, particularly in water-sensitive formations.

Based on field practice at Hassi Messaoud, a comprehensive treatment package typically includes all of the above additive types.

3.2.4 Staging the Treatment

A typical sandstone matrix acidizing job follows a specific sequence:

Stage 1:

- **Preflush**

- **Fluid:** HCl (7.5%) or organic acid, often with mutual solvent
- **Purpose:** Dissolve carbonates, remove near-wellbore scale, establish injectivity, and keep HF away from formation brines to prevent calcium fluoride precipitation
- **Volume:** 3m3 of perforated interval

Stage 2:

- **Main Acid**

- **Fluid:** Mud acid (6% HF + 1.5% HCl)
- **Purpose:** Dissolve clays and feldspars, restore permeability in damaged zone
- **Volume:** 6m3 depending on damage severity

Stage 3:

- **Overflush**

- **Fluid:** HCl (7.5%),
- **Purpose:** Push live acid deeper into formation, prevent precipitation near wellbore
- **Volume:** 3 m3

Stage 4:

- **Flush**

- **Fluid:** Treated water or diesel
- **Purpose:** Clear all acid from tubing and wellbore
- **Volume:** Tubing volume plus 10-20%

3.2.5 Hydraulic Fracturing

Hydraulic fracturing creates a highly conductive highway from wellbore deep into the reservoir, fundamentally altering flow patterns. In an unstimulated well, flow converges radially toward the wellbore, with resistance concentrated nearby. After fracturing, flow becomes linear to the fracture, which then carries fluids to the wellbore with minimal pressure drop.

3.2.6 Designing the Fracturing Treatment

A hydraulic fracturing job follows a carefully sequenced pump schedule:

Stage 1:

- **Pad**
- **Fluid:** Fracturing fluid without proppant (linear or cross-linked gel)
- **Purpose:** Initiate fracture, open it up, establish geometry
- **Volume:** 15-30% of total treatment volume

Stage 2:

- **Proppant-Laden Slurry**
- **Fluid:** Fracturing fluid with progressively increasing proppant concentration
- **Purpose:** Transport proppant into fracture and place it to keep the highway open after closure
- **Proppant ramp:** Typical progression: 0.5 → 1 → 2 → 4 → 6 → 8 ppg

Stage 3:

- **Flush**
- **Fluid:** Fracturing fluid (or linear gel)
- **Purpose:** Push proppant from wellbore into fracture
- **Volume:** Tubing volume from perforations to surface

3.2.7 Fracturing Fluids

Fracturing fluids must do three things: create fracture width, transport proppant, then break down to low viscosity for cleanup.

Table 3.2: Fracturing Fluid Types and Application

Fluid Type	Composition	Viscosity	Proppant Transport	Best For
Slickwater	Water + friction reducer	Low	Poor (needs high velocity)	Tight gas, unconventional
Linear gel	Guar + water	Moderate	Moderate	Moderate permeability

Cross-linked gel	**Guar + cross-linker**	**High**	**Excellent**	**High permeability, high temperature**
Foamed fluids	**N_2 or CO_2 + surfactant**	**Variable**	**Good**	**Low pressure, water-sensitive formations**

Fluid Breaking:
After proppant placement, fluid must "break" to low viscosity for cleanup. Breakers (oxidizers, enzymes) degrade the polymer structure at controlled rates.

3.2.8 What Kills Fracture Conductivity

Keeping fractures open long-term is harder than it looks. Lab studies show conductivity drops anywhere from 10% to 80% under stresses from 2000 psi to 8000 psi [15].

Gel Damage:
High viscosity fluids carry proppant into fractures, but leaving them there chokes proppant pack permeability. Post-closure polymer concentrations can hit 200-1000 lb/1000 gal—5 to 20 times surface concentration—seriously reducing fracture permeability.

Time-Dependent Damage:
The longer you wait between fracturing and cleanup, the worse it gets. Extended delays let gel form thicker filter cakes that become increasingly stubborn to remove.

3.3 Water and Gas Control Methods

3.3.1 The Unwanted Fluid Problem

Excessive water and gas production represents a major challenge in mature fields. These issues increase lifting costs, reduce oil production rates, and accelerate equipment failure. In the Hassi Messaoud field, where both natural aquifer water and injected fluids from pressure maintenance operations are present, conformance control becomes increasingly critical as the field ages.

Most Algerian fields produce from sandstone reservoirs with multiple layers open to production. These layers often exhibit significantly different petrographic characteristics and are frequently separated by shale beds. Pressure maintenance—whether by gas or water injection—can trigger conformance problems such as gas breakthrough or excessive water production.

3.3.2 Mechanical Isolation

When water or gas comes from a specific, identifiable zone, mechanical methods are usually the most reliable fix.

Table 3.3 : Mechanical Isolation Options

Method	Description	Application	Advantages	Limitations
Bridge plug	Permanent or retrievable plug set in casing	Isolate bottom water zone	Reliable, permanent	Requires rig/workover
Through-tubing bridge plug	Small-diameter plug run through tubing	Rigless isolation	No rig required	Limited by tubing size
Cement squeeze	Force cement into perforations	Permanent zone abandonment	Very reliable	Irreversible
Inflatable packers	Expandable packers for open hole or large casing	Temporary or permanent isolation	Versatile, through-tubing	Pressure limitations
Straddle packers	Two packers with sealed interval	Selective production	Preserves other zones	Complex installation

Through-Tubing Inflatable Packers:

Through-tubing inflatable packers run on coiled tubing have proven effective in Algerian fields for zone isolation and selective placement of treatment fluids [16]. These techniques enable the following:

- Block water and gas production by selectively placing cross-linked polymer gel
- Test isolated intervals to pinpoint problem zones
- Precisely place stimulation treatments where they're needed

3.3.3 Chemical Water Shutoff

Chemical methods are applied when mechanical isolation is not feasible—either because the situation is too complex or because water is entering through the matrix rather than through discrete channels.

Polymer Gel Systems

Polymer gels serve as the primary workhorse of chemical water shutoff. They combine a polymer (typically polyacrylamide) with a crosslinker (chromium, aluminum, or organic) that reacts to form a three-dimensional gel structure capable of blocking water flow.

How Gelation Works:

- **Polymer** provides viscosity and structure
- **Crosslinker** connects polymer chains
- **Gelation time** is controlled by concentration, temperature, pH
- **Gel strength** depends on polymer molecular weight and crosslink density

Table 3.4 : Gel Systems for Water Control

Gel Type	Polymer	Crosslinker	Strength	Best For
Weak gel	Low MW polymer	Low conc. Cr^{3+}	Low	Matrix, partial plugging
Strong gel	High MW polymer	High conc. Cr^{3+}	High	Fractures, high-perm streaks
Organic gel	Polyacrylamide	Phenol-formaldehyde	Very high	High temperature (>90°C)
Microgel	Pre-crosslinked particles	N/A	Variable	Deep placement
Colloidal dispersion gel	Low conc. polymer	Low conc. crosslinker	Low	Very deep placement

Recent Advances:

Recent work targets gel systems for tough environments. For high-temperature reservoirs like Hassi Messaoud (potentially >100°C), organic crosslinked systems (phenol-formaldehyde) may be needed for thermal stability.

A hybrid injection strategy has been developed to protect oil-bearing matrix while blocking fractures [16]:

- Alternate slugs of microgel (for deep penetration) and strong gel (for fracture plugging)
- Bullhead application possible, optimizing placement in fracture network
- Protects matrix by minimizing gel leak-off into oil-bearing rock

3.3.4 Relative Permeability Modifiers

Relative permeability modifiers (RPMs) are polymers that selectively reduce water permeability while barely touching oil permeability. They're particularly useful when water and oil come from the same zone and mechanical isolation isn't an option.

These materials adsorb onto rock surfaces and create a layer that impedes water flow while letting oil pass. The mechanism exploits how oil and water flow differently in porous media and how the polymer interacts with rock surfaces.

3.3.5 Gas Shutoff Techniques

Gas coning or gas breakthrough from injection operations can hammer oil production. Our options include:

- **Mechanical isolation** of gas-producing zones using packers or bridge plugs
- **Foam treatments** that selectively block gas flow through the Jamin effect
- **Gel treatments** formulated specifically for gas zones
- **Production rate optimization** to stay below the critical coning rate

3.4.1 Significance of Artificial Lift in the Hassi Messaoud Field

As reservoir pressure declines, artificial lift becomes essential for maintaining economic production. In the Hassi Messaoud field, gas lift is extensively utilized, accounting for approximately 45% of field production [17].

Production began in 1957. During the first 20 years, natural flow sustained all production. Gas lift was introduced in 1980 and has remained the dominant artificial lift method since then, although electrical submersible pumps have gained increasing application in more recent years [17].

3.4 Artificial Lift Optimization

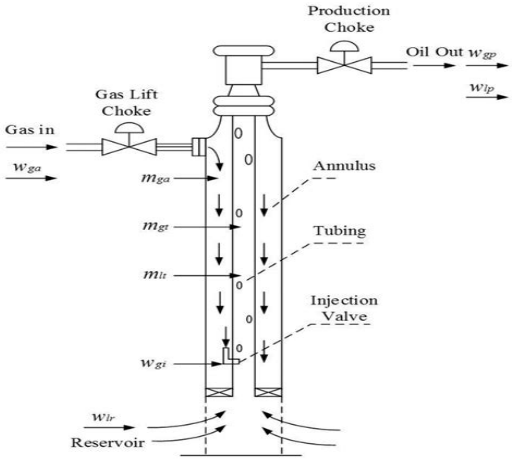

Figure 3-1 : Gas Lift System Schematic

3.4.2 How Gas Lift Works

Gas lift injects high-pressure gas into production tubing, reducing fluid column density and lowering bottomhole pressure. This increases drawdown and production rate.

3.4.3 Optimizing Gas Lift

Table 3.5 : Gas Lift Optimization Parameters

Parameter	Optimization Objective	Typical Range	Impact
Injection depth	Maximize drawdown	Deepest possible	10-30% production variation
Injection rate	Minimum gas for target lift	Well-specific	5-20% production variation
Valve spacing	Efficient unloading	Based on pressure gradient	Operational efficiency
Port size	Match expected production	1/4" to 1"	Stability

Injection Depth:

Deeper injection gives more pressure reduction but needs higher pressure. Optimal depth balances pressure requirements against valve spacing constraints.

Injection Rate:

The relationship between injection rate and production follows a characteristic curve. Too little gas doesn't reduce density enough; too much gas increases friction without additional benefit. We typically find the sweet spot through well testing or nodal analysis.

3.4.4 Identification and Diagnosis of Gas Lift Operational Problems

Table 3.6 : Gas Lift Performance Issues

Problem	Cause	Diagnostic Indicator	Impact
Incorrect injection depth	Poor design	No response to rate changes, high density gradient	10-30% production loss
Valve malfunction	Corrosion, erosion	Erratic injection rate, casing pressure fluctuations	15-40% production loss
Suboptimal injection rate	Poor optimization	Operating point left of minimum in performance curve	5-20% production loss
Instability	Valve cycling	Pressure and rate oscillations	10-25% production loss
Orifice too large	Incorrect sizing	Excessive gas use, high friction	Economic loss

3.4.5 Advanced Gas Lift Technologies

AutoBoost Technology:

AutoBoost is a surface boosting system that runs as an automated, self-powered gas lift unit [18]. The concept is elegant: separate oil, water, and gas at the well, then re-inject the gas. This makes the unit fully autonomous—no external gas source or power needed—the associated gas provides both lift gas and fuel [18].

The system creates a closed loop: produced gas recycles and accumulates during operation, giving a wide range of gas rates to optimize from. Once you hit the optimum injection rate, excess gas diverts to export via an automated control valve [18].

Intermittent Gas Lift:

Intermittent gas lift injects gas in cycles rather than continuously. A liquid slug builds in the tubing, then a high-pressure gas pulse lifts it to surface. This can be more efficient for lower productivity wells or those with high GOR [12].

3.4.6 Electrical Submersible Pumps (ESPs)

ESPs are multistage centrifugal pumps powered by a downhole electric motor. They can move high volumes from significant depths and are increasingly finding applications in Hassi Messaoud.

ESP Components:

- **Motor:** Powers the system
- **Protector:** Seals and pressure-equalizes
- **Intake:** Lets fluid in
- **Gas separator:** Handles free gas (optional)
- **Pump:** Multistage centrifugal
- **Sensor:** Monitors pressure, temperature, vibration

ESP Optimization:

Table 3.7: ESP Optimization

Parameter	How We Monitor	What We Do
Pump intake pressure	Downhole gauge	Adjust VSD frequency
Motor temperature	Downhole gauge	Check cooling, reduce load
Amperage	Surface readout	Detect pump wear or gas interference
Vibration	Downhole sensor	Spot mechanical issues

3.5 Scale and Deposit Removal Methods

3.5.1 What We're Dealing With

Damage characterization work in Hassi Messaoud has identified several deposit types that need targeted treatment [11]:

Table 3.8: Damage charactiristique in Hassi Messaoud

Deposit Types and CharacteristicsDeposit Type	How It Forms	Where We Find It	What It Looks Like
Salt (NaCl)	**Water evaporation, pressure drop**	**Tubing, wellbore, near-wellbore**	**White, crystalline**
Barium sulfate	**Incompatible water mixing**	**Perforations, near-wellbore**	**White, very hard**
Calcium carbonate	**Pressure drop, CO_2 release**	**Tubing, valves, pumps**	**Tan to white, hard**
Calcium sulfate	**Temperature/pressure change**	**Tubing, surface equipment**	**White, fibrous**
Asphaltenes	**Pressure/temperature change**	**Near-wellbore, tubing**	**Black, sticky**
Wax	**Temperature drop**	**Tubing, flow lines**	**Yellow to brown, soft**

3.5.2 Getting Rid of Salt Deposits

Salt (NaCl) deposition keeps coming back in Hassi Messaoud because of high formation water salinity and pressure/temperature swings during production. Fresh water washes are our primary weapon, with roughly 90% effectiveness [19].

Fresh Water Wash Procedure:

- **Prep:** Isolate the well, make sure surface facilities can handle produced water
- **Inject:** Pump fresh water (typically 50-100 m^3) at controlled rates
- **Soak:** Let it dissolve salt (usually 2-4 hours)
- **Flowback:** Return water to surface, monitor salinity
- **Repeat:** Keep going until returned salinity approaches fresh water levels

Prevention:

- Continuous fresh water injection via capillary string
- Scale inhibitor squeeze treatments
- Keep pressure above salt precipitation point

3.5.3 Scale Removal Strategies

Barium Sulfate Scale:

Barium sulfate is particularly nasty—extremely hard and acid-insoluble. Our options [20]:

- **Mechanical removal:** Milling, jetting, or scraping with coiled tubing
- **Chemical dissolvers:** Chelating agents (EDTA, DTPA) that complex barium ions
- **High-pressure water jetting:** Physical removal without chemicals (20,000+ psi)

Calcium Carbonate Scale:

Calcium carbonate is easier—HCl at 7.5% does the job. The reaction:

$CaCO_3 + 2HCl \rightarrow CaCl_2 + CO_2 + H_2O$

We always add corrosion inhibitors and iron controllers to protect tubulars and prevent secondary precipitation.

Calcium Sulfate Scale:

Calcium sulfate (gypsum) can be converted to acid-soluble form using carbonate converters, then removed with HCl:

$CaSO_4 + Na_2CO_3 \rightarrow CaCO_3 + Na_2SO_4$

The resulting calcium carbonate then dissolves in HCl. Mechanical removal also works.

Table 3.9: Scale Removal Methods by Type

Scale Type	Primary Method	Alternative	Cost
Calcium carbonate	HCl acid (7.5%)	Mechanical	Low
Barium sulfate	Mechanical (milling/jetting)	Chelating agents	High
Calcium sulfate	Mechanical or converters	Convert then acid	Moderate
Iron sulfide	HCl with additives	Mechanical	Moderate
Sodium chloride	Fresh water wash	Mechanical	Very Low

3.5.4 Organic Deposit Removal

Asphaltenes:

Asphaltene deposition happens when pressure drops below the asphaltene onset pressure. Removal options:

- **Aromatic solvents:** Xylene, toluene dissolve asphaltenes effectively
- **Dispersants:** Prevent flocculation, keep particles suspended
- **Mechanical removal:** Coiled tubing jetting with solvent

Wax:

Wax deposition is temperature-driven. Removal methods:

- **Solvent treatments:** Kerosene, diesel, or commercial wax solvents
- **Mechanical removal:** Cutting or scraping with wireline tools

Table 3.10: Solvant Systems for Organic Deposits

Deposit Type	Solvent System	Mechanism	Temperature
Asphaltenes	Xylene, toluene	Dissolution	Ambient to 65°C
Asphaltenes	Aromatic blends	Dissolution + dispersion	Ambient to 65°C
Wax	Kerosene/diesel	Dissolution + melting	37-65°C
Mixed deposits	Microemulsions	Multiple mechanisms	Ambient to 65°C

3.5.5 Integrated Scale Management

A comprehensive scale management program has several pieces working together:

1. Prediction:

Thermodynamic models let us get ahead of the problem. Tools like PHREEQC, OLI Studio, or ScaleSoftPitzer forecast scaling tendencies from water chemistry, pressure, and temperature.

2. Prevention:

- **Scale inhibitor squeezes:** Chemical injected into formation that returns slowly, inhibiting scale
- **Continuous injection:** Inhibitor via capillary string or annulus
- **Water chemistry modification:** pH adjustment, removing scaling ions

3. Monitoring:

Regular produced water sampling and analysis for:

- Ion concentrations (Ca, Ba, Sr, SO_4, CO_3)
- Scaling indices
- Total suspended solids
- Particle size distribution

4. Removal:

Scheduled interventions when scale is detected, before significant production loss.

5. Evaluation:

Post-treatment assessment to improve future programs:

- Compare actual vs. predicted scale
- Evaluate inhibitor effectiveness
- Optimize treatment frequency

3.6 Integrated Treatment Design and Execution

3.6.1 Connecting Diagnosis to Treatment

Successful remediation builds directly on Chapter 2's diagnostic findings. Table 3.11 maps specific diagnostic indicators to appropriate remediation methods.

What the Diagnostics Show	What It Means	What We Do
Positive skin (+5 to +20) from PBU	Formation damage	Matrix acidizing
Negative skin (-3 to -5) with low rate	Natural fractures present	Consider fracturing to connect them
Rapid pressure depletion with boundaries	Small compartment	Infill drilling, injection support
Rising water cut, water entry at base	Water coning	Mechanical isolation or gel treatment
Stepwise production decline	Scale deposition	Scale removal + inhibitor
Erratic production, GOR fluctuations	Gas lift problems	Gas lift optimization
High produced water salinity	Formation water breakthrough	Water shutoff
Variable salinity	Injected water breakthrough	Source identification, conformance
Decreasing PI with stable reservoir pressure	Near-wellbore damage	Matrix stimulation
Rising GOR, stable WC	Gas coning or reaching bubble point	Rate optimization, gas shutoff

Table 3.11 : From Diagnosis to Treatment

3.6.2 Treatment Design Workflow

A systematic design approach integrates all available data:

Phase 1: Data Review and Candidate Selection

- Confirm remaining reserves and recovery potential
- Check mechanical integrity for proposed treatment
- Evaluate economic viability

Phase 2: Treatment Method Selection

- Match method to problem using Table 3.1
- Consider reservoir permeability and characteristics
- Evaluate multiple options, select optimal
- Consider combination treatments for multiple issues

Phase 3: Detailed Design

- Fluid and material selection based on mineralogy and temperature
- Volume and rate calculations
- Pump schedule development
- Additive optimization
- Diversion strategy for multiple zones

Phase 4: Execution Planning

- Deployment method (bullhead, coiled tubing, workover)
- Equipment and personnel requirements
- Contingency planning
- HSE risk assessment
- Quality control procedures

Phase 5: Post-Treatment Evaluation

- Define success criteria
- Surveillance plan (PBU, PLT, production monitoring)
- Economic validation
- Document lessons learned

3.6.3 Evaluating Treatment Success

Post-treatment evaluation is critical for continuous improvement:

Short-Term (1-30 days):

- Production rate comparison (before vs. after)
- Wellhead pressure response
- Fluid sampling (water cut, GOR)
- Cleanup efficiency

Medium-Term (1-6 months):

- Pressure buildup test to quantify skin reduction
- Production logging to confirm zonal contribution
- Decline curve analysis for new decline trend
- Economic assessment against projections

Long-Term (6+ months):

- Sustained performance monitoring
- Identify any new problems
- Reserve update based on performance
- Lessons learned for future interventions

Conclusion

Across the remediation types and methods examined, several practical conclusions emerge for the Hassi Messaoud field.

Matrix acidizing is the preferred treatment for near-wellbore damage, provided that the formation mineralogy is appropriate. The standard mud acid formulation (6% HF + 1.5% HCl) is effective for clay and feldspar damage. However, poor preflush design or the omission of additives such as clay stabilizers frequently worsens rather than improves the condition.

Hydraulic fracturing has a role, particularly in tighter zones, but conductivity decline over time—due to gel damage or proppant crushing—represents a genuine risk. When a well is fractured, careful planning of the cleanup operation is required.

Water and gas control will become increasingly critical as the field ages. Mechanical isolation remains the most reliable option when a single entry zone can be precisely identified. When water enters through fractures or mixed layers, chemical methods such as polymer gels are often the only practical solution, although gelation time must be adjusted to reservoir temperature.

Artificial lift—primarily gas lift—sustains current production. Optimization of injection depth and rate can add 10–20% to production without requiring rig intervention. Newer options, including AutoBoost and intermittent gas lift, merit evaluation for lower-productivity wells.

Scale removal should be treated as routine maintenance rather than crisis response. Salt washes are effective, but barium sulfate scale poses the greater problem. Prevention via inhibitor squeeze treatments is generally less expensive than mechanical removal.

Finally, the connection back to the diagnosis described in Chapter 2 is paramount. A high skin factor derived from pressure buildup analysis does not automatically indicate that acidizing is the appropriate remedy. The treatment must be matched to the actual damage mechanism; otherwise, expenditure will be directed toward solving the wrong problem.

Chapter 4: Integrated Case Study – Application of Diagnostic and Remediation Workflow to Wells MD-800, MD-819 and RDC-30

4.1 Introduction

this Chapter applies the previously developed diagnostic and remediation framework to Well MD-819, illustrating the effectiveness of a systematic approach to production evaluation and stimulation design. presents an integrated case study of three wells: MD-800 and MD-819 from the Hassi Messaoud field, and RDC-30 from the Rhourde Chegga field. These wells were selected because:

- They represent different reservoir settings – a mature central area with gas injection (MD-800), a semi-exploration southern off-zone (MD-819), and a high-pressure Triassic reservoir (RDC-30).
- They have contrasting stimulation histories – repeated matrix acidizing, aborted hydraulic fracturing, and successful data-frac-then-main-frac campaigns.
- They provide long-term production data (RDC-30 has nearly six years of history) as well as detailed intervention records.
- They illustrate both successes and failures, allowing the extraction of robust lessons.

The chapter follows a consistent structure for each well:

- **Geological and reservoir context** – structural position, predicted tops, fluid contacts, pressure regime, and offset well data.
- **Completion design** – casing program, tubing, packer, liner type, and any special features.
- **Diagnostic analysis** – production decline curves, well test results, GOR and water cut trends, pressure data, and injectivity tests.
- **Remediation and stimulation** – detailed chronology of interventions, treatment parameters, operational challenges, and design rationale.
- **Results and performance evaluation** – post-stimulation production, comparison with pre-stimulation rates, sustainability of the improvement, and remaining issues.

4.2 Overview of the Three Wells

Before diving into detailed analyses, **Table 5.1** provides a high-level comparison of the three wells. The differences in location, reservoir pressure, and stimulation history will become important as the chapter unfolds.

Table 4.1 : Summary of Key Characteristics of the Three Case Study Wells

Parameter	MD-800	MD-819	RDC-30
Field	Hassi Messaoud	Hassi Messaoud	Rhourde Chegga
Sector	Zone 2S (central)	South off-zone (semi-exploration)	Triassic T1 area
Well type	Vertical oil producer	Vertical oil producer	Vertical oil producer
Coordinates (UTM)	X: 805,890.7, Y: 127,035 (Zone 31) [1]	X: 784,845.0, Y: 3,495,290 (Zone 31) [29]	X: 258,619, Y: 3,561,700 (Zone 32) [33]
Ground elevation (m)	173.15 [26]	138.81 [29]	140 [33]
Rotary table elevation (m)	184 [26]	148 [29]	149 [33]
Total depth (m TVD)	3,448 [26]	3,483 [29]	3,830 [33]
Target reservoir units	D4, D3, D2, ID (Cambro-Ordovician) [26]	D5, D4, D3, D2, ID (Cambro-Ordovician) [29]	Triassic T1 sandstone [33]
Initial reservoir pressure (kg/cm²)	180–210 [26]	260–280 [29]	545 [33]
Water contact (TVDSS)	–3,220 m (uncertain) [26]	–3,372 m (well constrained) [29]	Not reached
Drilling period	May–July 2023 [27]	Feb–April 2025 [30]	Dec 2019–March 2020 [34]
Completion type	4½" LCP, hydraulic packer [2]	4½" LCP, hydraulic packer [5]	7" liner, 4½" tubing, packer [8]
Artificial lift	Natural flow (later N_2 lift) [28]	Natural flow (post-frac) [31]	Gas lift (installed 2023) [33]
Number of stimulations	4 matrix acid jobs + 1 aborted frac [28]	4 matrix acid jobs + data frac + main frac [30,31]	Multiple acid jobs + cleanouts + data frac + main frac [33]

Cumulative production (as of March 2026)	15,509 m³ [28]	~1,800 m³ (initial test only) [31]	104,603 m³ [33]

.MD-800 and MD-819 are both in the Hassi Messaoud permit, with MD-800 in the densely drilled central Zone 2S and MD-819 in the southern off-zone near the limit of the field. RDC-30 is approximately 150 km to the east-southeast, in the Rhourde Chegga field, which produces from Triassic sandstones rather than Cambro-Ordovician [9]. Despite the different ages, the reservoir quality challenges – low matrix permeability, natural fracture dependence, and formation damage – are remarkably similar [35,36].

4.3 Well MD-800: The Challenge of Gas Breakthrough and Formation Damage in a Mature Sector (Wrong diagnosis)

4.3.1 Geological and Reservoir Context

Well MD-800 was drilled as a vertical development well in the central part of Hassi Messaoud's Zone 2S [26]. This sector is characterised by a relatively high density of existing wells, including several gas injectors (MD-121 and MD-19) that have been operating for many years [28]. The structural interpretation based on 3D seismic (Figure 5.2, to be inserted) shows that at the Hercynian unconformity, the well is located on a flank that dips gently to the south-east [26]. Erosion has removed part of the Cambrian section, so the unconformity directly overlies the D4 reservoir rather than the transitional Alternating Zones [26]. Predicted reservoir tops were provided in the drilling programme (Table 5.2). The total depth of 3,448 m TVD was chosen to stay above the uncertain water contact, which was estimated at –3,220 m TVDSS based on regional correlations [26]. However, the pre-drill report explicitly noted that the water contact was uncertain because a resistivity drop observed in the nearby MD-19Bis well could not be clearly interpreted as a true oil-water contact [26]. Reservoir pressure was estimated between 180 and 210 kg/cm², based on build-up tests from offset wells **(Table 4.2) [26]**. These pressures are significantly lower than the initial reservoir pressure in the field (which was around 450–500 kg/cm² [36]), reflecting decades of production and gas injection.

Table 4.2: Pressure Data from Offset Wells in the MD-800 Sector

Well	Test Date	Test Type	Static Pressure (kg/cm²)	Flowing Pressure (kg/cm²)	Oil Rate (m³/h)
MD-105	17/05/2001	Build-up	217	190	10.9
MD-285	06/05/2007	Build-up	165	68	2.7
MD-377	02/05/2008	PFS	216	—	—
MD-481	25/07/2015	Build-up	206	108	3.6

The pre-drill risk assessment highlighted two main concerns: gas breakthrough from the nearby injectors (rated as probable) and water production from open fractures (rated as improbable but possible) [26]. The well was designed with a cemented liner to allow selective perforation and future isolation of any problematic intervals [27].

4.3.2 Completion Design

The casing program for MD-800 followed the standard Hassi Messaoud design for vertical wells in the central area [27]:

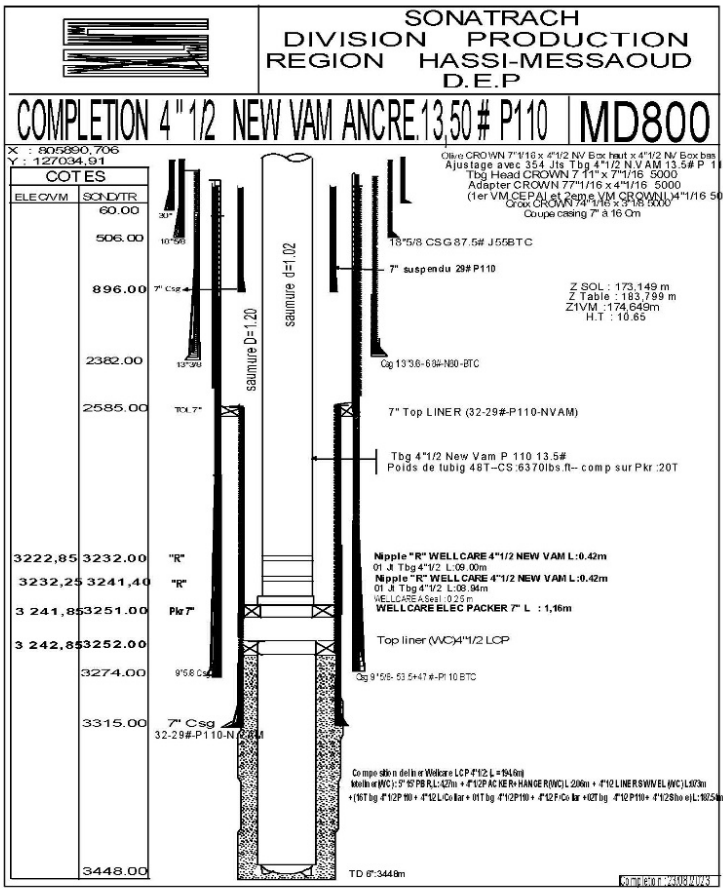

Figure 4-1 : Completion Design MD800

4.3.3 Diagnostic Analysis of Production Decline

4.3.3.1 Production History and Decline Curve Analysis

MD-800 began production in October 2023 [28]. Figure 5.3 presents the monthly production history from October 2023 through March 2026,

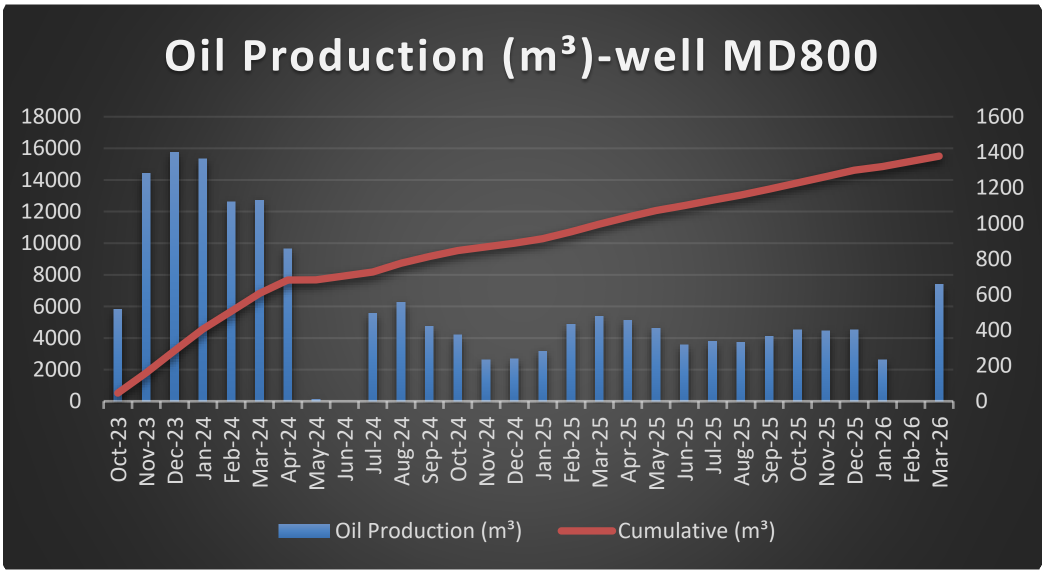

Figure 4-2 : the monthly production history from October 2023 through March 202The production curve exhibits several features that are diagnostic of the well's problems:

Initial peak followed by rapid decline – After the first matrix acidizing in late October 2023, the well reached 1,400 m³/month in December 2023. By April 2024, it had fallen to 858 m³/month, a decline of nearly 40% in four months. This steep decline is characteristic of a well that is producing from a limited stimulated volume or from natural fractures that are being depleted without matrix support [40].

Dramatic drop in May 2024 – Production fell to 10.9 m³ in May 2024 because the well was shut in for the injection test and aborted fracturing operation [28]. When it was brought back in July 2024, the rate was only 495 m³/month – about half of the pre-shut-in level. This suggests that the injection test and the associated fluid pumping may have caused additional formation damage or that the shut-in allowed near-wellbore fluids to redistribute unfavourably.

Gradual decline from July 2024 to December 2025 – Rates drifted downward from ~500 m³/month to ~400 m³/month, a relatively gentle decline that is typical of boundary-dominated flow in a small drainage area [40].

Increasing GOR – The GOR was not measured continuously, but spot tests show a clear trend. In early 2024, the GOR was around 500 m³/m³ (solution gas). By September 2024, it had risen to 1,200 m^3/m^3, and by February 2025 it reached 2,028 m^3/m^3 [28]. This is a classic sign of gas breakthrough, almost certainly from the nearby gas injectors (MD-121 and MD-19) [26]. The injected gas is moving through high-permeability fractures or layers and is being produced ahead of the oil.

Response to January 2026 acidizing – Another matrix acid treatment was performed in January 2026 [28]. Production in March 2026 rose to 658 m^3/month, a 2.8-fold increase over the January level. However, this is still far below the original peak, and the GOR remained high (around 2,000 m^3/m^3). The acid treatment cleaned up some near-wellbore damage but did not address the gas breakthrough.

4.3.3.2 Well Test Interpretation

A detailed well test was performed on February 3, 2025, under a 9 mm choke [28]. The results were:

- **Oil rate:** 0.8 m^3/h (19.2 m^3/d)
- **GOR:** 2,028 m^3/m^3
- **Water:** 40 litres (trace)
- **Wellhead pressure:** 46.25 kg/cm^2
- **Flowline pressure:** 4.89 kg/cm^2

The high GOR is the most significant finding. A solution GOR for Hassi Messaoud crude is typically 400–500 m^3/m^3 [36]. A value of 2,028 m^3/m^3 means that for every cubic metre of oil, the well is producing 2,028 cubic metres of gas – about four times the solution gas. This gas must be coming from an external source, namely the gas injection wells in the sector [26].

The fact that the water cut is essentially zero (only 40 litres of water) confirms that the well is not producing from the aquifer; it is producing oil and injected gas.

The relatively high wellhead pressure (46.25 kg/cm^2) suggests that the well still has good energy, but that energy is being used to lift gas rather than oil. In fact, the well is effectively acting as a gas lift well, with the injected gas providing lift. However, because the gas is coming from the formation rather than from surface compression, the operator has no control over the injection rate or the gas-oil ratio [39].

Skin analysis from the DST performed during drilling (not shown in the provided data) gave a skin factor of –0.66 [26], which is slightly negative, indicating that the natural fractures in the D2 layer actually provided a productivity boost when the well was first completed. However, subsequent drilling fluid invasion, cementing, and perforating may have damaged the near-wellbore region [27].

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Figure 4.3 : Well test results MD800

<u>4.3.3.3 Injectivity Test and Fracture Diagnostics</u>

On May 1, 2024, an injection test was performed in preparation for a planned hydraulic fracture [28]. The objective was to determine the formation's injectivity and to verify that a fracture would stay within the target D4/D3 interval. The test procedure was [28]:

- Open the well (wellhead pressure was 1,250 psi).
- Pump treated water at increasing rates, starting at 2.2 bpm and reaching 15.6 bpm.
- Monitor surface treating pressure (STP) and bottomhole treating pressure (BHTP).
- After pumping 300 bbl of water, switch to 15% HCl (32 bbl) and then displace.
- Record pressure fall-off after shut-in.
- Key observations from the injection test [28]:
- At 15.6 bpm, STP was 4,800 psi and BHTP was 8,800 psi.

The pressure response deviated from the behavior expected of a clean formation; it exhibited high friction and a slow pressure decline, indicating damage in the near-wellbore region.

Temperature logging conducted after the test revealed that the injected fluid had propagated into the D2 layer rather than into the D4/D3 interval. This constituted a critical finding: owing to the geological structure and the in-situ stress field, a hydraulic fracture would propagate upward into D2 instead of remaining within the intended pay zones [28].

Decision: The planned main fracturing job was cancelled [28]. The fracture would have missed the oil-rich D4/D3 zones and could have connected to gas-bearing intervals or even to the aquifer.

Lesson: The injection test – a relatively inexpensive diagnostic – saved the operator from a costly and potentially damaging operation. Without it, the well might have been fractured into a non-pay zone, wasting millions of dollars [39].

Table 4.3: Applying the workflow for MD-800

Step	What Was Done	Data Used	Findings	Gap Analysis
1. Historical Trends	Production data Oct 2023–Mar 2026	Fig. 4-2	Decline from 1,400→400 m^3/mo; GOR ↑ 500→2,028	✓ Done
2. PTA	DST during drilling	Skin = -0.66	Initially negative skin (fractures); later damage	✗ MISSING no post-acid PTA
3. PLT	NOT PERFORMED**	N/A	Would have identified gas entry zones	✗ CRITICAL GAP
4. Fluid Analysis	Well test data (Feb 2025)	GOR=2,028; Water=40L	Gas breakthrough confirmed; no water	Partially done
5. Nodal Analysis	NOT PERFORMED	N/A	Would quantify gas lift benefit	✗ MISSING
6. Diagnosis	Partial	Table 4.3	Gas breakthrough + near-wellbore damage	Partially done
7. Remediation	Multiple acid jobs; aborted frac	Acid specs	Temporary boosts only; frac cancelled	Partially done
8. Evaluation	Production comparison	Pre/post acid	2.8× increase but still below peak	Partially done

4.3.3.4 Synthesis of Diagnostic Findings for MD-800

Table 4.4: Synthesis of Diagnostic Fidings for MD-800

Problem	Evidence	Severity
Gas breakthrough	GOR of 2,028 m^3/m^3 (four times solution GOR) [3]	High
Near-wellbore damage	Negative injectivity test, declining rates after acid [3]	Moderate
Pressure depletion	Reservoir pressure 180–210 kg/cm^2 (down from initial 450+) [26]	Moderate
Fracture misdirection risk	Injection test showed fluid going into D2 layer [28]	Critical (avoided)
Sand production	None observed	Low

4.3.4 Remediation and Stimulation History

MD-800's stimulation history can be divided into three phases: initial matrix acidizing, the aborted fracture campaign, and subsequent maintenance acidizing.

4.3.4.1 Phase 1: Initial Matrix Acidizing (October 2023)

The first stimulation was a two-day matrix acidizing operation performed in October 2023, shortly after the well was completed [28].

Result: The well responded strongly, with production rising from 518 m^3 in October to 1,282 m^3 in November and 1,400 m^3 in December [28]. The treatment was considered a success, but the effect proved temporary.

4.3.4.2 Phase 2: Aborted Hydraulic Fracture (April–May 2024)

In preparation for a hydraulic fracture, a tubing cleanout was performed on April 26, 2024 [3]. Coiled tubing was run with nitrogen and treated water to clean the perforations and remove debris. The operation was routine.

The injection test conducted on May 1, 2024, as described above, demonstrated that a fracture would not remain within the target interval [28]. Consequently, the main fracturing treatment was cancelled. The well was returned to production in July 2024 after a cleanout and kick-off [28].

Impact: Production from the well following this episode was significantly lower than before the injection test [28]. It is possible that the high-rate water injection (up to 15.6 bpm) pushed fines into the near-wellbore region or caused clay swelling, thereby reducing permeability. Alternatively, the prolonged shut-in period may have allowed the gas cap to expand and water to segregate, altering relative permeabilities.

4.3.4.3 Phase 3: Subsequent Cleanouts and Acidizing (2024–2026)

- **Between May 2024 and January 2026**, the well received several cleanout and kick-off operations [28]:
- **May 4, 2024:** Cleanout with treated water and N_2; tagged TD; well flowed oil, gas, and water.
- **May 6–12, 2024:** Multiple N_2 kick-offs; oil rates of 0.8–1.0 m³/h achieved, but water cuts were present.
- **June 6, 2024:** Another N_2 kick-off
- **March 23, 2025:** Cleanout with N_2 and TW; well flowed gas, water, and some oil.
- **January 17–18, 2026:** Two-day matrix acidizing similar to the October 2023 treatment. The well responded with a temporary increase, reaching 658 m³ in March 2026 [28].

4.3.5 Results and Performance Evaluation

Despite multiple stimulations, MD-800 has never regained its peak production of 1,400 m³/month [28]. The current rate (March 2026) is 658 m³/month, which is less than half of the peak. The cumulative production as of March 2026 is 15,509 m³ – a modest total for a well that has been producing for nearly 30 months [28].

Key performance indicators [3]:

- **Average daily rate (entire life):** ~17 m³/d
- **Average daily rate (last 6 months):** ~13 m³/d (excluding March 2026 spike)
- **GOR trend:** Increasing, now >2,000 m³/m³
- **Water cut:** Zero (excellent)
- **Skin:** Not recently measured, but likely positive (damaged)

Root Cause Analysis of Gas Breakthrough and Production Instability

Gas breakthrough constitutes the dominant problem. The gas-oil ratio of 2,028 m^3/m^3 indicates that, for every barrel of oil, the well produces approximately 4,000 scf of gas. This gas occupies most of the flow area in the near-wellbore region, thereby reducing the relative permeability to oil [39]. Furthermore, the high gas flow rate can induce unstable flow and heading within the tubing.

Matrix acidizing is incapable of stopping gas breakthrough. Acid dissolves scale and certain formation minerals, but it does not seal off fractures or high-permeability streaks that are carrying gas [39]. To stop the gas influx, the well requires mechanical isolation—such as a packer or cement squeeze—to block the gas entry points.

The aborted fracturing operation may have inflicted additional damage. Pumping large volumes of water at high rates can mobilize fines and cause clay swelling, particularly if the injected water is incompatible with the formation brine [39]. The well's lower post-test production rates suggest that such damage may have occurred.

Proposed Remediation Strategies for Improving Well MD-800 Performance

Run a production logging tool (PLT) to identify exactly which perforations are producing gas [39].

- Set a packer or perform a cement squeeze to isolate the gas-entry intervals.
- Re-perforate the D4/D3 zones if they are not contributing adequately.
- Consider a small-volume hydraulic fracture in the isolated D4/D3 interval, but only after confirming that the fracture would stay in zone (perhaps using a different pump schedule or diverting agents).
- Install a gas lift system to handle the high GOR, but this would be treating the symptom, not the cause.

4.4 Well MD-819: A Successful Hydraulic Fracture in a Tight Off-Zone Reservoir

4.4.1 Geological and Reservoir Context

Well MD-819 is located in the southern off-zone of the Hassi Messaoud field, an area that was considered semi-exploratory at the time of drilling [29]. Unlike the central zones, this sector has no gas injection wells, and the reservoir pressure is higher (260–280 kg/cm^2) because production has been less intense [29]. The structural interpretation (Figure 5.4, to be inserted) shows that the well is on the southern flank of the main anticline, with partial erosion at the Hercynian unconformity [29].

Predicted reservoir top include the D5 unit (which is absent in the central zones due to erosion). The water contact was well constrained by XPT data from the offset well MD-590, which placed it at –3,372 m TVDSS [29]. The planned TD of 3,483 m TVD was set 37 m above this contact to avoid water production [29].

Offset well data **(Table 4.5)** showed good oil rates from nearby wells MD-804 and MD-814, which were drilled in 2024 [29]. MD-804 produced 6.37 m^3/h with a GOR of 654 m^3/m^3, and MD-814 produced 8.44 m^3/h with a GOR of 1,178 m^3/m^3 (slightly elevated but still acceptable). These results motivated the drilling of MD-819 [29].

Table 4. 5 : Production Data from Offset Wells in the MD-819 Sector

Well	Test Date	Oil Rate (m^3/h)	GOR (m^3/m^3)	Water
MD-804	14/01/2025	6.37	654	Trace
MD-814	26/01/2025	8.44	1,178	0
MD-341	12/01/2025	3.84 (GL)	6,735 (GL)	4,840 l/h

Note that MD-341 had a very high GOR and water cut because it was on gas lift and had been producing for a long time [29]. The other two wells were new and had good fluid quality.

4.4.2 Completion Design

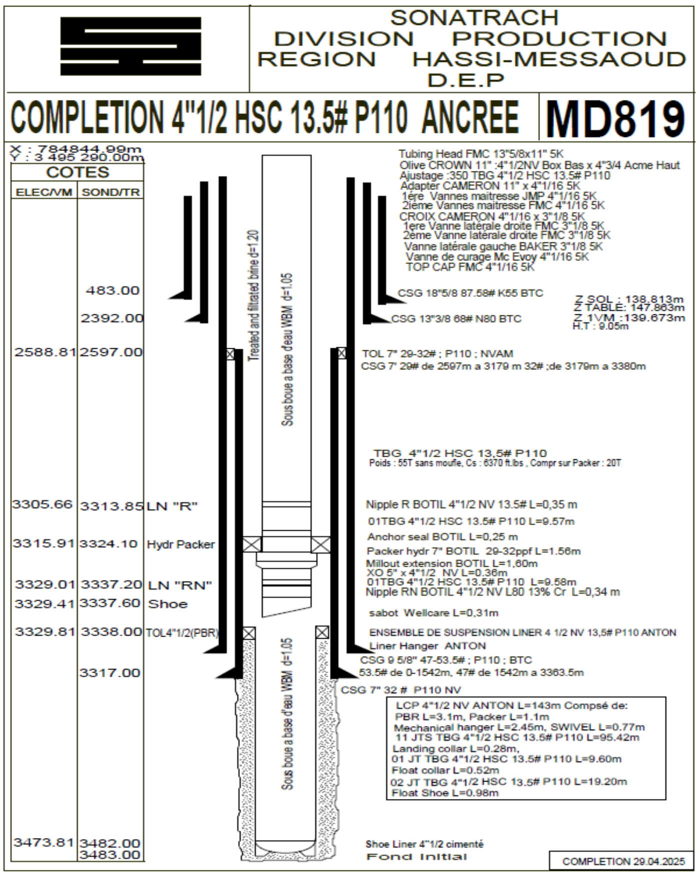


Figure 4-4 : Completion Design MD819

Architecture du puits + Fiche stratigraphique

Sonatrach — ACTIVITE EXPLORATION & PRODUCTION DIVISION PRODUCTION DIRECTION REGIONALE HMD DIRECTION ENGINEERING ET PRODUCTION DEPARTEMENT GEOLOGIE SERVICE SURVEILLANCE GEOLOGIQUE	Puits : MD819	Appareil : GW155	

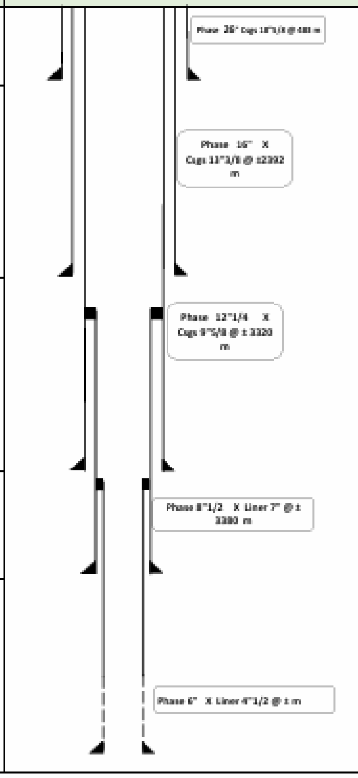
Fiche Stratigraphique et Technique

PLATEFORME			Date début forage	2025-02-27
	UTM (Zone 31)	LSA	Date fin forage	2025-04-05
X	784845.00	813491.45	Nbr° jours DTM	16 jrs
Y	3495290.00	112126.02	Nbr° jours à la TD	37 jrs
Z table	148.00		Date fin Sondage	2025-04-29
Z sol	138.813		Nbr° jours fin sondage	61 jrs

Objectif du puits : Le puits vertical MD-819 est un puits producteur d'huile situé dans l'hors-zone sud, au sud des Zone 24 et 25. Il s'inscrit dans le cadre du développement du gisement de Hassi Messaoud (Périmètre Hassi Messaoud Zones Complexes et Upside).

		Formation	Prévisions Tops	Prévisions Epais	Côtes sondeurs Tops	Côtes sondeurs Epais	Côtes éléctriques Tops	Côtes éléctriques Epais	Type et Densité de Boue
		Mio-Pliocene	0	202	0	218	**	**	1,05 sg (WBM)
		Eocen	202	154	218	130		**	
CRETACE	SENONIEN	Carbonate	356	105	348	94	**	**	
CRETACE	SENONIEN	Anhydritique	461	194	442	214	**	**	
CRETACE	SENONIEN	Salifère	655	132	656	131	644	143	1,25 sg (OBM)
CRETACE		Turonien	787	129	787	116	787	111	
CRETACE		Cenomanien	916	167	903	160	898	160	
CRETACE		Albien	1,083	355	1,063	360	1,058	365	
CRETACE		Aptien	1,438	16	1,423	23	1,423	23	
CRETACE		Baremien	1,454	288	1,446	301	1,446	302	
CRETACE		Neocomien	1,742	220	1,747	202	1,748	202	
JURASSIQUE		Malm	1,962	214	1,949	226	1,950	226	
JURASSIQUE	DOGGER	Argileux	2,176	118	2,175	134	2,176	128	
JURASSIQUE	DOGGER	Lagunaire	2,294	206	2,309	168	2,304	167	
JURASSIQUE	LIAS	LD1	2,500	55	2,477	83	2,471	90	2,05 sg (OBM)
JURASSIQUE	LIAS	LS1	2,555	98	2,560	87	2,561	86	
JURASSIQUE	LIAS	LD2	2,653	58	2,647	60	2,647	58	
JURASSIQUE	LIAS	LS2	2,711	62	2,707	61	2,705	63	
JURASSIQUE	LIAS	LD3	2,773	20	2,768	28	2,768	26	
TRIAS	SALIFERE	TS1	2,793	41	2796	41	2,794	43	
TRIAS	SALIFERE	TS2	2,834	192	2,837	193	2,837	193	
TRIAS	SALIFERE	TS3	3,026	235	3,030	220	3,030	220	
TRIAS	ARGILEUX	G10	3,261	47	3,250	52	3,250	52	
TRIAS	ARGILEUX	G20	3,308	27	3,302	15	3,302	17	
TRIAS	ARGILEUX	G30	3,335	3	3,317	8	3,319	11	
TRIAS	ARGILEUX	G35	3,338	11	3,325	7	3,330	3	1,45 sg (OBM)
TRIAS		G50	3,349	11	**	**	**	**	
TRIAS		Eruptif	3,360	15	3,332	24	3,333	27	
ORDOVICIEN		Grès El Atchane	**	**	**	**	**	**	
ORDOVICIEN		DH /Argile ElGassi	**	**	**	**	**	**	
ORDOVICIEN		Z.Alt	3,375	4	3,356	21	3,360	17	0,91 sg (OBM)
CAMBRIEN	Ri	D5	3,379	49	3,377	**	3,377	50	
CAMBRIEN	Ra	D4	3,428	10	**	**	3,427	15	
CAMBRIEN	Ra	D3	3,438	23	**	**	3,442	19	
CAMBRIEN	Ra	D2	3,461	24	**	**	3,461	**	
CAMBRIEN	Ra	ID	3,485	26	**	**	**	**	
CAMBRIEN	Ra	D1	3,511	25	**	**	**	**	
CAMBRIEN		Z. Pig	3,536	6	**	**	**	**	
CAMBRIEN		R2ab	3,542	**	**	**	**	**	
CAMBRIEN		R250	**	**	**	**	**	**	
		Fond	3,483	**	3,483	**	3,485	**	
		WOC	3,520	**	**	**	**	**	

Tubages



Observations

Démarrage de la cabine MudLogging: 27/02/2025 ENSPN°2469 00 m

Phase 26":

Phase 16": Casing 13"3/8 posé et cimenté 28 m plus haut que la côte d'arrêt.

Phase 12"1/4: **

Phase 8"1/2: Zalt topée 15 m plus haut que les prévisions,

Phase 6: RAS,

Complétion:

Tubing: 4"1/2 ancré

Packer hydraulique typefrac vers 3325m (ce) 3323,5m (cs).

Réservoir: A couvrir par un Liner 4"1/2 LCP (Liner Cimenté à Perforer)

Top Liner vers 3339m(ce), 3337,5m (cs).

Résultats DST	
DST	DST N° 1
Date	du 08/04 au 14/04/2025
Côte DST (m)	3483m(cs);3485m(ce)
Pg (kg/cm²)	269.00
Pfd (kg/cm²)	225.00
Pt (kg/cm²)	28.00
Débit H (m³/h)	3.03
Salinité (mg/l)	-
Skin	2.58
I.P	0.07
Hk L (m.md)	283.00
GOR (m³/m³)	150.33
Duse (mm)	9.53

Perforations

N°	Intervalle	Date	Company
**	**	**	**
**	**	**	**
**	**	**	**
**	**	**	**

Figure 4.5 : stratigraphic data

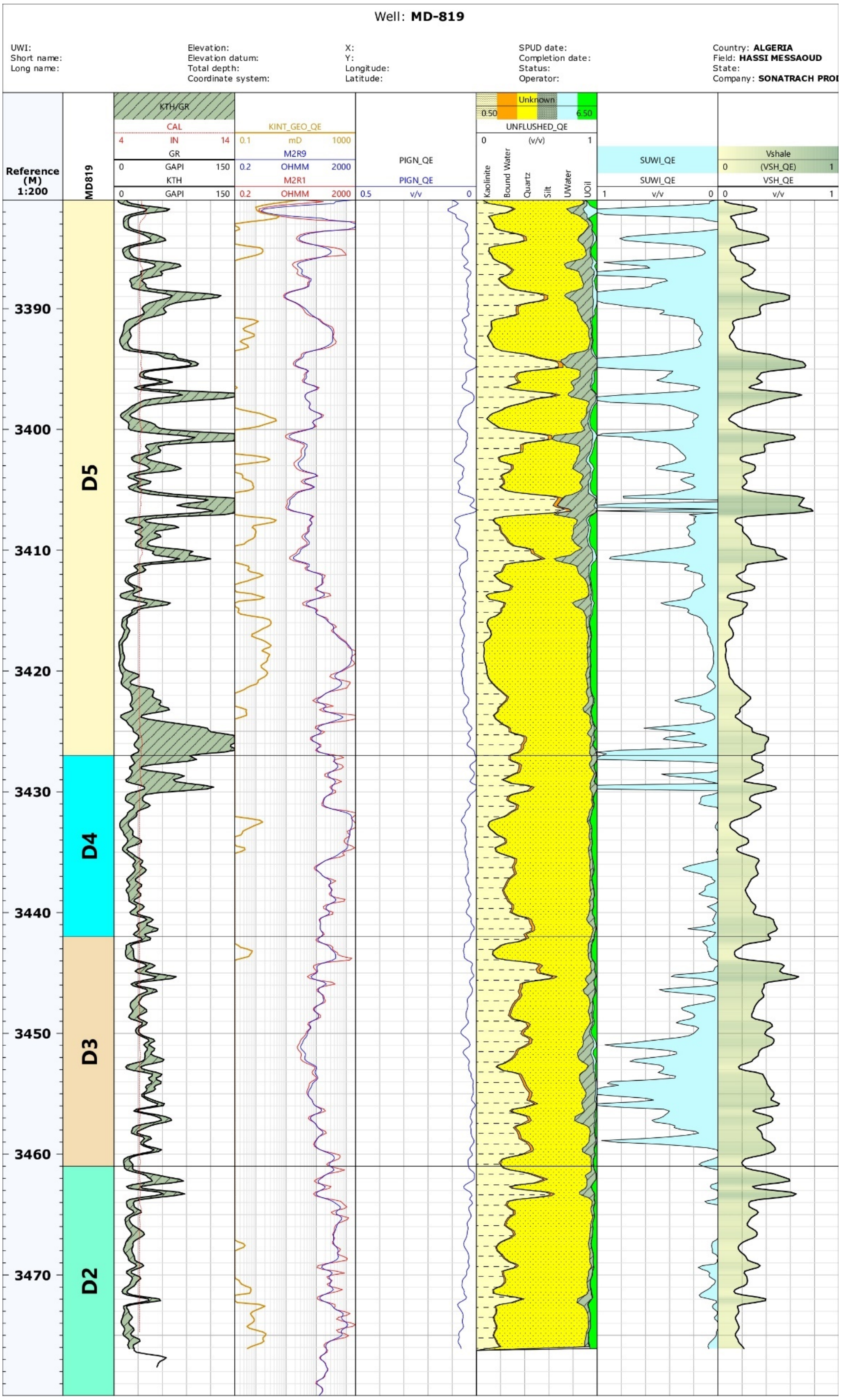


Figure 4.6 : Logging data

4.4.3 Diagnostic Analysis of Production Decline

4.4.3.1 Early Production and Acidizing Attempts

MD-819 was put on production in late April 2025 [31]. Initial flow was poor, so a series of matrix acidizing treatments were performed [31]:

- **June 29, 2025:** First acidizing with 15% HCl and N_2. The well flowed oil and gas, but rates were sub-commercial (estimated <1 m^3/h).
- **October 3, 2025:** Matrix treatment with 7.5% HCl. An injectivity test after the treatment was negative (pumping 3 bbl at 0.5 bpm, Cp = Whp = 4,800 psi) [31], confirming that acid alone could not overcome the damage.
- **October 26–27, 2025:** Two-day matrix acidizing with foam diversion and larger acid volumes. The well showed some improvement, but still not enough to justify leaving it on production without further stimulation [31].

Diagnostic conclusion: The well had severe near-wellbore damage and/or very low matrix permeability. Acidizing was not sufficient; a hydraulic fracture was needed to bypass the damaged zone and connect to natural fractures [39].

4.4.3.2 Injectivity and Fracture Diagnostics

No detailed injection test was performed before the fracture because the well had already shown low injectivity [31]. Instead, the operator proceeded directly to a data fracture (mini-frac) to characterise the reservoir's fracturing behaviour [31].

4.4.4 Remediation and Stimulation

4.4.4.1 Data Fracture (February 25, 2026)

The data fracture was performed using crosslinked gel and a small volume of proppant (or sometimes no proppant in a step-rate test; in this case, a small volume was used) [31].

Table 4. 6 : Data Fracture Results for MD-819

Parameter	Value
Maximum pumping rate	22 bpm
Total XL Gel pumped	280.5 bbl
Total L-Gel pumped	238 bbl
Surface ISIP (instantaneous shut-in pressure)	5,312 psi
Bottomhole ISIP	10,273 psi

Closure pressure	8,102 psi
Fracture efficiency	39.5%
Net pressure	2,175 psi
Frac gradient	0.91 psi/ft
Closure gradient	0.73 psi/ft
Bottomhole treating pressure at rate	10,707 psi

Interpretation of data frac results [6,14]:

The closure pressure of 8,102 psi (equivalent to a closure gradient of 0.73 psi/ft) is typical for the Cambro-Ordovician at this depth. It indicates that the minimum horizontal stress is relatively high, which is favourable for creating a wide fracture.

The fracture efficiency of 39.5% indicates that only 40% of the pumped fluid remained in the fracture after shut-in; the remainder leaked off into the formation. This efficiency level is moderate, suggesting that the reservoir is neither extremely tight nor highly permeable. Consequently, the fracture is expected to achieve a reasonable half-length, though not an exceptionally long one.

The net pressure of 2,175 psi—defined as the difference between the bottomhole treating pressure and the closure pressure—is substantial. This value indicates that the fracture propagated easily and did not experience significant near-wellbore tortuosity.

The fracture gradient of 0.91 psi/ft is consistent with the overburden stress and confirms that the fracture is vertical, as expected.

These parameters were subsequently used to design the main fracture treatment. The high net pressure and moderate efficiency suggested that a conventional crosslinked gel fluid system with 20/40 mesh proppant would be effective [39].

4.4.4.2 Main Hydraulic Fracture (February 26, 2026)

The main fracture was designed to place a large proppant volume to ensure long-term conductivity [31]. *Stage 7 was cut short due to a blender centrifugal pump problem. The designed volume was 3,000 gals; actual was 1,827 gals. Total proppant placed: 82,500 lbs (37,500 kg) [31].

Operational parameters during the main frac [6]:

- **Maximum pumping rate:** 24 bpm (slightly higher than the data frac)
- **Maximum surface treating pressure:** 6,756 psi
- **Maximum bottomhole treating pressure:** 11,691 psi

- **A annulus pressure maintained** at 2,000–2,500 psi (to help contain the fracture)
- **Fluid system:** Crosslinked gel (XL Gel) for proppant transport, followed by linear gel (L-Gel) for displacement

4.4.4.3 Post-Frac Cleanout and Kick-Off (February 27 – March 1, 2026)

After the main fracture, the well was cleaned out using coiled tubing to remove excess proppant and treatment fluids [31]. The cleanout was performed over three days:

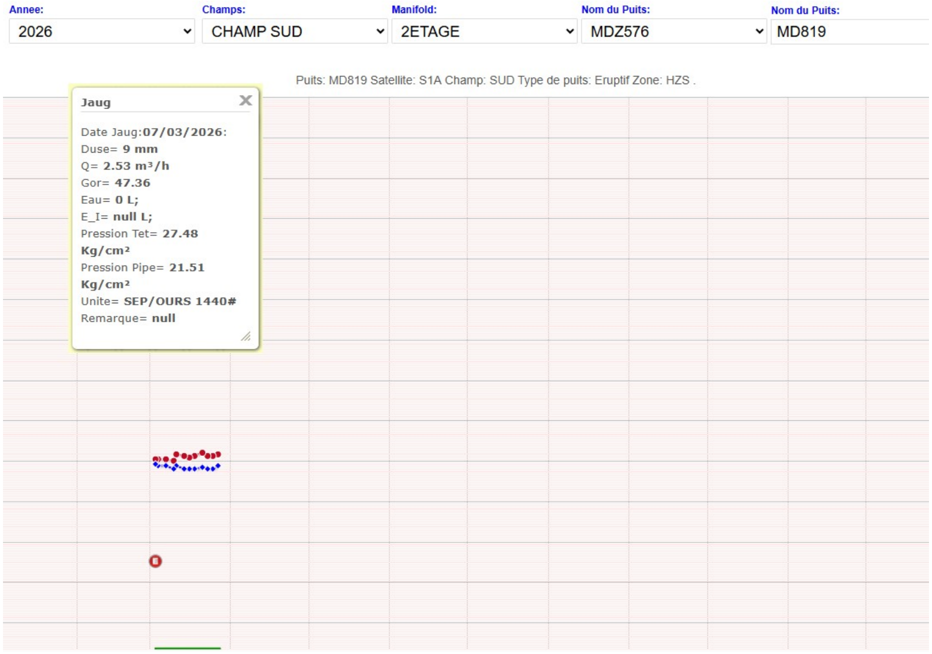
- **February 27:** Rig-up of frac head and coiled tubing unit; pressure testing.
- **February 28:** Run in hole with N_2 and treated water; tagged TD at 3,474 m; made passes across the perforation interval (3,400–3,474 m); pumped 1 m³ of N_2 and started pulling out of hole.
- **March 1:** Additional cleanout and kick-off; circulated with treated water and N_2; observed oil, gas, and some remaining frac fluid at the flare [31].
- The well was then left to clean up naturally for several days before the production test.

4.4.5 Results and Performance Evaluation

A full production test was conducted on March 7, 2026, using a 1,440 separator [31]. The test lasted approximately four hours (09:00 to 13:00) and included measurements of oil, gas, and water rates, as well as fluid properties.

Table 4.7:Production Test Results for MD-819 (March 7 2026)

Parameter	Value
Average oil rate	2.53 m³/h (60.7 m³/d)
Average gas rate	119.6 m³/h (2,870 m³/d)
Average GOR	478 m³/m³
Water cut	Trace (<3%)
Oil specific gravity	0.800 @ 18°C
Gas specific gravity	0.848
CMSF (coefficient)	0.909
Wellhead pressure (start)	26.5 bar
Wellhead pressure (end)	26.9 bar
Flowline pressure (start)	21.0 bar
Flowline pressure (end)	20.5 bar
Separator pressure	21.1 bar



سوناطراك
sonatrach

Relevé des mésures au Séparateur

L'Ours For Oil & Gas Services

SH Superviseur : Mr.TIR FARES.
DEP/TECH PROD Puit : MD-819
Date: 7-Mar-26

Séparateur 1440 psi

Champ: HMD
Rapport Jaugeage: Recombined Test
LC Rep: Mr.GOUAMID MED ABDELHAK.

Horaire	Mésures tête puits				Mésures Séparateur (L.Bore : 5.761")				BAC N° : N/A, Compartiments: N/A							
	Cond Débit	Préssion							GAZ LIFT				Densité	Débit		GOR
	Duse	Amont	Aval	T° Tête	Diamètre Orifice	Préssion Séparation	T° Huile	T° Gaz	Préssion Amont	Préssion Aval	Débit Gaz lift Sonar	Débit Gaz lift Scaner		Huile	Gaz	
	(in)	(kg/cm²)	(kg/cm²)	(°C)	(in)	(kg/cm²)	(°C)	(°C)	(Barg)	(Barg)	(m³/ 1/2h)		Huile	(Sm³/½hr)	(Sm³/½hr)	(Sm³/Sm³)
07:45		27.00	21.40													
08:30	Déverser l'écoulement sur Separateur.															
09:00	Début de comptage avec Separateur.															
09:30		26.81	22.66	N/A	0.500 "	22.36	26.72	24.00						1.200	45.9	38.21
10:00		27.65	22.55	N/A	0.500 "	22.26	28.18	25.46						1.096	51.5	47.03
10:30		27.52	22.81	N/A	0.500 "	22.51	28.95	26.23						1.224	53.7	43.89
11:00		27.56	22.35	N/A	0.500 "	22.06	29.33	26.61					0.800 @ 18 °C	1.151	53.6	46.53
11:15	Déverser l'écoulement sur surge tank															
11:30	Déverser l'écoulement sur line, CMSF=0.909															
11:30		27.93	21.27	N/A	0.500 "	20.98	30.22	27.50						1.315	71.3	54.25
12:00		27.16	20.94	N/A	0.500 "	20.65	31.09	28.37					0.798 @ 20°C	1.391	62.6	44.95
12:30		27.75	20.98	N/A	0.500 "	20.68	31.23	28.51						1.403	72.1	51.38
13:00		27.49	20.71	N/A	0.500 "	20.42	30.83	28.11						1.325	67.7	51.14
13:05	Fin de test.												Gaz Lift / Eau injectée			
Moyenne		27.48	21.51	N/A	0.500 "	21.49	29.57	26.92					NON / NON	1.263	59.8	47.34

Type de l'essai unité	T° BAC:	Horaire	Débit D'eau=	0	m³/hr	Débit Huile =	2.53	m³/hr	GOR=	47.341	Sm³/Sm³
		4:00									
Jaugeage 1440 psi	N/A	CMSF	Cumule volume eau =	0	m³				Débit Gaz =	119.59	Sm³/hr
		0.909	N B :	N/A		Cumule Volume Huile=	10.10	m³	Cummule Gaz =	478.37	Sm³

Figure 4.7 Well test results

Analysis of test results [6]:

Oil rate of 60.7 m³/d is excellent for a vertical well in this part of the field. It is comparable to the offset wells MD-804 (6.37 m³/h = 153 m³/d) and MD-814 (8.44 m³/h = 203 m³/d) [4], but those wells had been producing for over a year and may have benefited from additional depletion. MD-819's rate is nearly three times higher than MD-800's average rate (~20 m^3/d) [28].

GOR of 478 m^3/m^3 is within the solution gas range, confirming that the fracture did not connect to any gas-injection zones or a secondary gas cap [31]. This is a critical success indicator.

Trace water confirms that the well is safely above the water contact and that the fracture did not propagate downward into the aquifer [29].

Stable wellhead pressure (26.5–26.9 bar) during the test indicates that the well is not experiencing significant drawdown and that the reservoir is supplying energy efficiently.

CMSF of 0.909 indicates good flow stability with minimal slugging or heading [31].

Comparison with pre-frac expectations [29,31]:

The pre-drill report had estimated an initial production rate of 3–6 m^3/h (72–144 m^3/d). The actual post-frac rate of 2.53 m^3/h (60.7 m^3/d) is at the lower end of this range, but still within the expected envelope. Given that the well had zero commercial production before the fracture, this is a resounding success.

Sustainability:

Because the well has only been on production for a short time (the test was in March 2026, and this chapter is being written in early April 2026), long-term decline data are not yet available. However, the stable pressure and low GOR suggest that the well will have a relatively flat decline curve for the first several months, followed by a gradual hyperbolic decline [40]. If the fracture has connected to a large volume of the reservoir, the well could maintain rates above 40 m^3/d for a year or more.

Remaining issues [31]:

The well is flowing naturally with a wellhead pressure of 26 bar. As the reservoir depletes, the pressure will eventually drop below the flowline pressure, and artificial lift (gas lift or ESP) may be required.

No production logging has been performed to determine which perforated intervals are contributing. This information would be valuable for future wells in the same sector.

Table 4.8: Applying the workflow for MD-819

Step	What Was Done	Data Used	Findings	Status
1. Historical Trends	Pre-frac production data	Fig. 4-7	Sub-commercial rates after acidizing	✓ Done
2. PTA	DST during drilling	Skin = 2.58	Positive skin — formation damage	✓ Done
3. PLT	NOT PERFORMED	N/A	Would confirm zonal contribution	✗ MISSING
4. Fluid Analysis	Post-frac test	GOR=478; Water=trace	No gas/water breakthrough	✓ Done
5. Nodal Analysis	NOT PERFORMED	N/A	Would optimize gas lift timing	✗ MISSING
6. Diagnosis	Data frac + main frac	Table 4.5	Low matrix perm + damage → frac needed	✓ Done
7. Remediation	Data frac + main frac	82,500 lbs proppant	Successful — 60.7 m^3/d achieved	✓ Done
8. Evaluation	Post-frac production test	Table 4.6	2.53 m^3/h, low GOR, stable	✓ Done

4.5 Well RDC-30: Revitalising a Mature Triassic Well with Hydraulic Fracturing

4.5.1 Geological and Reservoir Context

RDC-30 is located in the Rhourde Chegga field, approximately 150 km east-southeast of Hassi Messaoud [33]. The field produces mainly from Triassic sandstones (T1, T2) and, to a lesser extent, from Cambro-Ordovician units [34]. The Triassic T1 reservoir is a fluvial to aeolian sandstone with good porosity (12–18%) but low matrix permeability (1–10 mD) [9]. Like the Cambro-Ordovician of Hassi Messaoud, the T1 relies on natural fractures for commercial flow rates [36].

The well was drilled between December 30, 2019, and March 17, 2020, with a total depth of 3,830 m [33]. The coordinates are X = 258,619.032 m, Y = 3,561,700.004 m (UTM32), with a ground elevation of 140 m and a rotary table elevation of 149 m [33]. The primary objective was the T1 sandstone, which was encountered at approximately 3,656 m TVD [34]. Stratigraphy and reservoir tops are given in Table 5.10 (derived from the stratigraphic chart [34]).

A DST was performed in the T1 from February 29 to March 5, 2020, in a barefoot (open-hole) completion [33]. The results were:

- **Static pressure (Pg):** 545 kg/cm^2
- **Flowing pressure (Pfd):** 216 kg/cm^2
- **Oil rate:** 5.18 m^3/h
- **Skin:** –0.66 (slightly negative, indicating natural fractures)
- **Choke:** 9.53 mm

These are excellent initial results. The negative skin confirms that the well intersected natural fractures that enhanced productivity [33]. The high static pressure (545 kg/cm^2) is typical of the overpressured Triassic in this area [34].

4.5.2 Completion Design

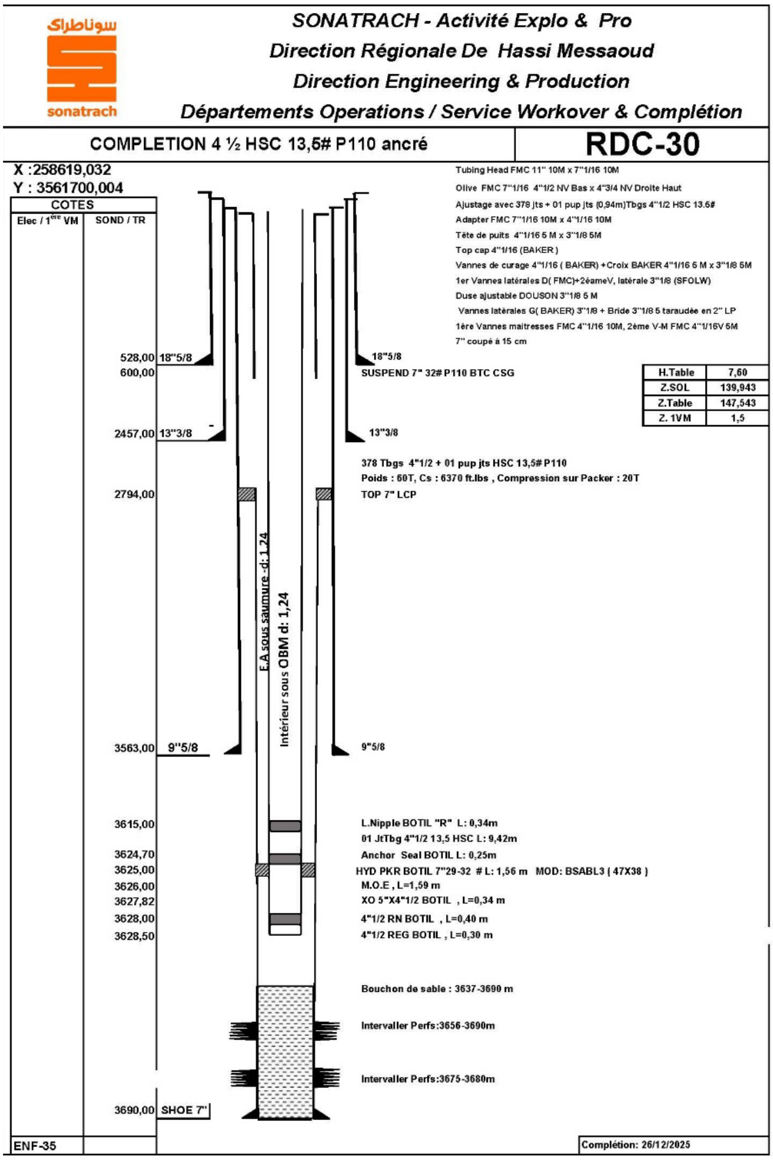


Figure 4-8 : Completion Design RDC30

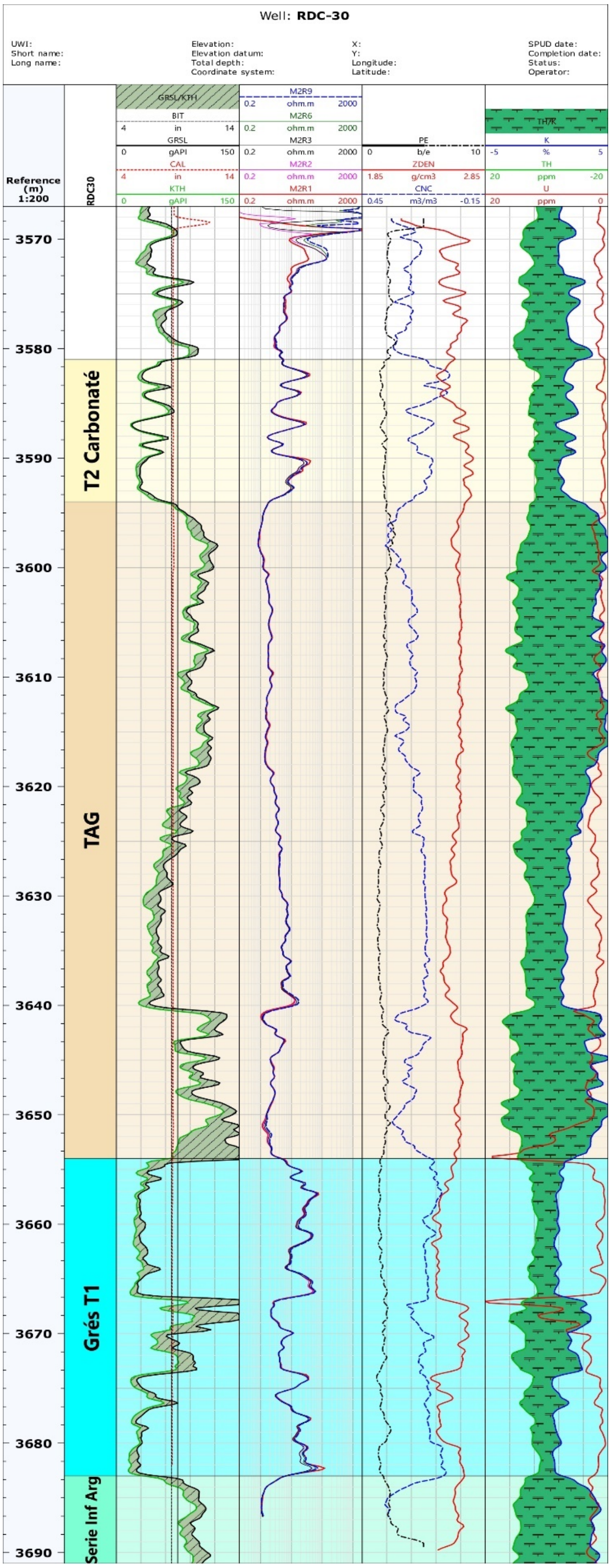


Figure 4.9 : Logging data RDC30

4.5.3 Diagnostic Analysis of Production Decline

4.5.3.1 Production History and Decline Curve Analysis

RDC-30 has the longest production history of the three case study wells – nearly six years, from June 2020 to March 2026 [33]. Figure 4.4 presents selected monthly production data,

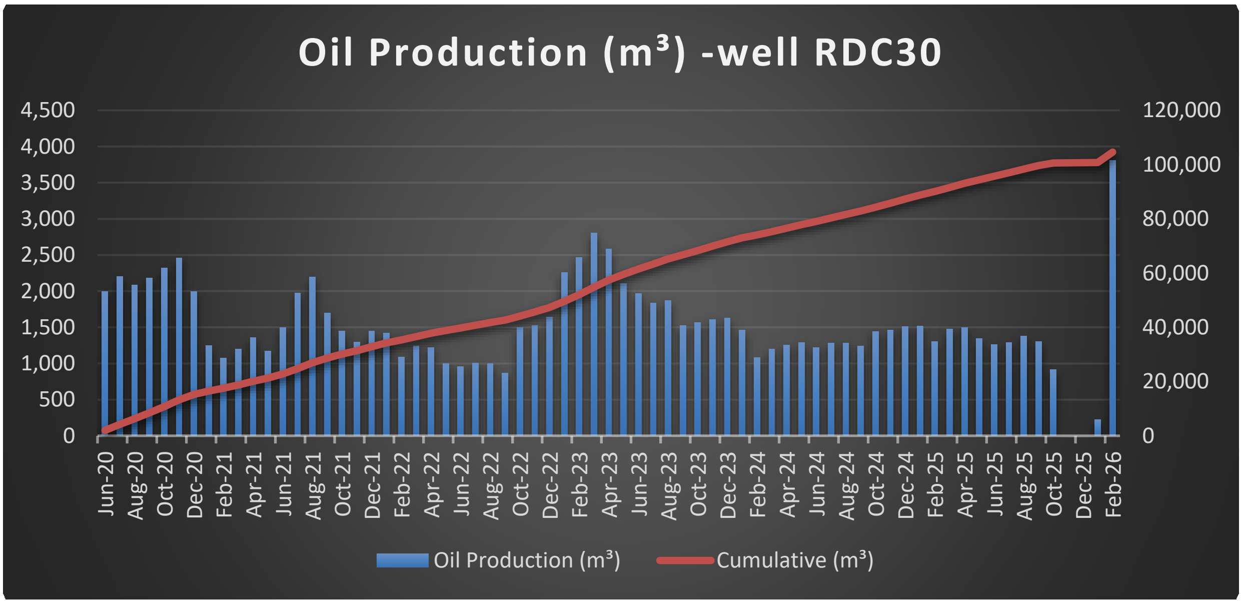


Figure 4-10 : **Selected Monthly Production Data for RDC-30 [8]**

Key observations from the production curve [8]:

Very high initial rates (June–November 2020): The well averaged over 2,000 m³/month for the first six months, with a peak of 2,458 m³ in November 2020. This is typical of a well producing from a highly overpressured, naturally fractured reservoir [40].

Steep decline (December 2020 – May 2021): Rates fell from 2,458 m³ to 1,174 m³ in six months – a decline of more than 50%. This is characteristic of depletion of the natural fracture network without significant matrix support [40].

Stabilisation around 1,000–1,500 m³/month (mid-2021 to late 2022): The well settled into a gentle decline, with occasional boosts from acid treatments (e.g., September 2022) [33].

Gas lift installation (January 2023): The well was put on gas lift, which raised production from ~1,600 m³/month to over 2,800 m³/month in March 2023 [33]. This indicates that the reservoir still had significant oil in place, but the natural flowing pressure was no longer sufficient to lift the fluids to surface [39].

Gradual decline under gas lift (2023–2025): Rates slowly drifted down from ~2,800 m^3/month to ~1,300 m^3/month over three years [33]. This is a much slower decline than the initial one, reflecting the stabilising effect of gas lift.

Sand plug and workover (October 2025): Production dropped to 916 m^3 in October 2025, and a sand plug was encountered, requiring snubbing and cleanout [33]. This suggests that the natural fractures or proppant from earlier treatments had started to fail, producing sand into the wellbore.

Post-frac production (February 2026): After the hydraulic fracture, production jumped to 3,811 m^3 – the highest monthly figure since November 2020 [33]. This is a remarkable result, showing that the new fracture successfully bypassed the damaged and sand-prone zone and connected to a fresh volume of the reservoir.

4.5.3.2 Pressure and GOR Data

Limited pressure and GOR data are available for RDC-30. A well test on January 16, 2023 (after gas lift optimisation) gave [33]:

- **Oil rate:** 3.58 m^3/h
- **GOR:** 282 m^3/m^3
- **Wellhead pressure**: 26.9 kg/cm^2
- **Flowline pressure:** 15.2 kg/cm^2
- **Water:** 0
- **Gas lift injection rate:** 14,500 m^3/d

The GOR of 282 m^3/m^3 is actually lower than the solution GOR (which would be around 400–500 m^3/m^3 for a typical Triassic crude). This suggests that the gas lift gas is being measured as part of the produced gas, but the actual formation GOR is lower. Alternatively, the well may be producing below the bubble point, with some gas remaining in solution.

A pressure measurement on September 30, 2020, recorded a flowing bottomhole pressure of 177 kg/cm^2 at a wellhead pressure of 25.14 kg/cm^2 and an oil rate of 2.97 m^3/h [8]. This indicates that the reservoir was already being depleted by that time.

4.5.3.3 Diagnostic Synthesis for RDC-30

Table 4.9: Diagnostic Synthesis for RDC-30

Problem	Evidence	Severity
Natural fracture depletion	Steep initial decline, then stabilisation at lower rates [33]	High (original)
Sand production	Sand plug in October 2025 [33]	Moderate
Pressure depletion	Flowing pressure dropped from 216 kg/cm² (DST) to 177 kg/cm² (Sept 2020) to ~100 kg/cm² (by 2025) [33]	High
Formation damage	Gradual decline despite gas lift, need for new fracture [33]	Moderate

The primary cause of underperformance by late 2025 was depletion of the natural fracture network and sand production that may have damaged the near-wellbore region [33]. The reservoir still contained significant oil, as evidenced by the strong response to gas lift, but the existing flow paths had become ineffective. A new hydraulic fracture was needed to create a high-conductivity pathway that would bypass the damaged zone and access undrained oil [34].

4.5.4 Remediation and Stimulation History

RDC-30 had a long history of interventions before the 2026 hydraulic fracture [33]:

- **September 6–9, 2022:** A four-day acid stimulation campaign (acetic acid, HCl/HF, reformate). The well responded with a temporary increase.
- **January 1, 2023:** Gas lift installed and optimised on January 16, 2023.
- **October 2025:** Sand plug removed and well cleaned out.
- **January 19–20, 2026:** Data fracture and main hydraulic fracture.

4.5.4.1 Data Fracture (January 19, 2026)

The data fracture was performed to determine closure pressure, leak-off behaviour, and fracture geometry for the Triassic T1 reservoir [33]. The specific results are not provided in the available documents, but by analogy with MD-819 [31], it is likely that the data frac provided similar parameters (closure pressure around 7,000–9,000 psi, fracture efficiency 30–50%, net pressure 1,500–2,500 psi).

The main fracture was designed based on the data frac results [33]. Although the exact proppant volume is not specified, the post-frac production increase (from ~1,000 m^3/month to 3,811 m^3/month) suggests that a substantial proppant load was placed – likely similar to or larger than MD-819's 82,500 lbs [31].

The treatment was executed with post-frac cleanout on January 22–23 and kick-off on January 24–25 [33].

4.5.5 Results and Performance Evaluation

The post-frac production for February 2026 was 3,811 m^3 [33]. This corresponds to an average daily rate of:

131.4 m^3/d

This is more than triple the pre-frac rate of ~1,300 m^3/month (43 m^3/d) and even exceeds the original peak of 2,458 m^3/month (82 m^3/d) [8]. In fact, the February 2026 rate is the highest monthly production in the well's entire history.

Key success indicators [33]:

- **Rate increase:** 3-fold increase over pre-frac rate; 1.6-fold increase over original peak.
- **Sustainability:** The well is now on gas lift with the lift gas rate optimised for the new inflow performance. No early decline has been reported.
- **Sand production:** The new fracture likely includes a tail-in of resin-coated proppant to prevent sand production [39].

Remaining issues [8]:

The well still requires gas lift, indicating that reservoir pressure is not sufficient for natural flow. This is not a problem as long as gas lift gas is available.

Long-term decline behaviour is not yet known. The well should be monitored closely over the next 12 months to determine the decline curve exponent and to estimate the ultimate recovery from the fracture [40].

Table 4.10:Applying the workflow for RDC-30

Step	What Was Done	Data Used	Findings	Status
1. Historical Trends	Production data Jun 2020–Mar 2026	Fig. 4-10	Decline from 2,458→1,000 m³/mo; gas lift boost	✓ Done
2. PTA	DST (Feb-Mar 2020)	Skin = -0.66	Natural fractures initially; depletion later	Partially done
3. PLT	**NOT PERFORMED**	N/A	Would identify depletion pattern	✗ **MISSING**
4. Fluid Analysis	Limited	GOR=282 (post-gas lift)	Lower than solution GOR — gas lift dilution	Partially done
5. Nodal Analysis	NOT PERFORMED	N/A	Would optimize gas lift post-frac	✗ MISSING
6. Diagnosis	Production history + DST	Table 4.7	Natural fracture depletion + sand production	✓ Done
7. Remediation	Data frac + main frac	Jan-26	3,811 m³/mo post-frac — best ever	✓ Done
8. Evaluation	Post-frac production	Feb 2026 data	3× increase over pre-frac	✓ Done

4.6 Integrated Discussion: Lessons Learned Across the Three Wells

The three case studies, when viewed together, provide a coherent set of lessons about diagnosing decline and selecting stimulation in tight sandstone reservoirs.

4.6.1 The Value of Diagnostic Tools

Table 4.11: The Value of Diagnostic Tools

Diagnostic Tool	MD-800	MD-819	RDC-30	Lesson
Production history analysis	Revealed gas breakthrough and decline trend [28]	Showed acidizing insufficient [31]	Showed natural fracture depletion [33]	Essential for identifying decline type [40]
GOR monitoring	Detected gas injection breakthrough (2,028 m^3/m^3) [28]	Confirmed no gas breakthrough (478 m^3/m^3) [31]	Not a major issue	GOR is a critical surveillance parameter [39]
Injectivity test	Prevented misdirected fracture [28]	Not needed (low injectivity already known) [31]	Not performed before 2026 frac [33]	Pre-frac injection test is highly valuable [39]
Data fracture	Not performed	Successfully guided main frac [31]	Successfully guided main frac [33]	Data frac should be standard practice [39]
PLT (production logging)	Not performed (would help identify gas entry) [28]	Not performed [31]	Not performed [33]	Missed opportunity – PLT should be routine [39]

Key takeaway: The most successful wells (MD-819 and RDC-30) both used a data fracture to optimise the main treatment [31,33]. MD-800 avoided a costly mistake because of an injection test, but it did not benefit from a data frac [28]. The absence of PLT in all three wells is a missed opportunity; a PLT would have helped isolate gas intervals in MD-800 and could have confirmed zonal contribution in the other two [39].

4.6.2 Stimulation Strategy: Acidizing vs. Hydraulic Fracturing

Table 4.12: Stimulation Strategy:Acidizing VS Hydraulic Fracturing

Well	**Primary Stimulation**	**Result**	**Effectiveness**
MD-800	Repeated matrix acidizing [28]	Temporary boosts, declining trend	Low (sustained)
MD-819	Hydraulic fracture (with data frac) [31]	60.7 m³/d initial rate, low GOR	High
RDC-30	Hydraulic fracture (with data frac) [33]	131 m³/d (post-frac), highest ever	Very high

Conclusion: In tight sandstones with matrix permeability below 5–10 mD, matrix acidizing alone is rarely sufficient to achieve commercial and sustainable rates [39]. Hydraulic fracturing, when properly designed using a data fracture, can deliver step-change improvements. The cost of a fracture is quickly recovered by the incremental production [38].

Table 4.13: Case Study Wells — Before and After Remediation

Parameter	MD-800		MD-819		RDC-30	
	Before	After	Before	After	Before	After
Date	Jan-26	Mar-26	Feb-26	Mar-26	Jan-26	Feb-26
Oil Rate (m³/d)	17	21	0	60.7	43	131
Oil Rate (m³/mo)	400	658	0	~1,800	1,300	3,811
GOR (m³/m³)	2,028	~2,000	N/A	478	282	N/A
Water Cut (%)	0	0	N/A	<3	0	0
Skin Factor	Unknown	Unknown	2.58	Unknown	Unknown	Unknown
Artificial Lift	None	None	None	None	Gas lift	Gas lift (optimized)

Primary Problem	Gas breakthrough	Partially treated	Low perm + damage	Solved	Fracture depletion	Solved
Treatment Applied	Matrix acidizing	Matrix acidizing	Hydraulic fracture	Hydraulic fracture	Hydraulic fracture	Hydraulic fracture
Effectiveness	Low	Low	N/A	High	N/A	Very High
Economic Impact	Marginal	Marginal	N/A	Positive	N/A	Highly Positive

4.6.3 The Importance of Zonal Isolation and Gas Breakthrough Management

MD-800's high GOR is a classic example of gas breakthrough from injectors [28]. In a mature field with gas injection, any new well must be designed to isolate gas-swept intervals [26]. The LCP completion in MD-800 allows selective perforation, but the well was perforated across a wide interval that likely includes gas-bearing fractures. A PLT survey followed by a packer or cement squeeze to isolate the gas entry points would significantly improve the well's performance [39].

Recommendation: In sectors with gas injection, perform a PLT early in the well's life and be prepared to isolate gas-producing intervals.

4.6.4 Artificial Lift Optimisation

RDC-30's history shows that gas lift can sustain production for years after natural flow ceases [33]. However, after a major stimulation (like a hydraulic fracture), the inflow performance changes dramatically, and the gas lift system must be re-optimised [39]. In RDC-30, the post-frac gas lift rate was increased to handle the higher liquid rate [33].

Recommendation: After any significant stimulation, re-run the gas lift design to determine the optimal injection rate and valve settings.

4.6.5 Sand Production and Proppant Selection

The sand plug in RDC-30 in October 2025 suggests that either the formation sand or proppant from previous treatments was being produced [33]. In the new fracture, the operator likely used a resin-coated proppant or a tail-in of larger mesh proppant to prevent sand production

[39]. For future fractures in unconsolidated or weakly consolidated sandstones, resin-coated proppant should be considered.

4.7 Recommendations for Future Field Development

Based on the integrated analysis of MD-800 [26,27,28], MD-819 [29,30,31], and RDC-30 [33,34], the following recommendations are made for future development wells in the Hassi Messaoud field and analogous tight sandstone reservoirs:

4.7.1 Pre-Drill and Drilling Phase

- Acquire high-resolution 3D seismic to map fracture corridors and avoid zones with gas injection breakthrough [36].
- Design the well trajectory to intersect natural fractures if possible; consider horizontal or deviated wells in areas with known fracture swarms [37].
- Use low-damage drilling fluids (e.g., oil-based mud or low-solids water-based mud) to minimise formation damage [39].
- Plan for a data fracture from the outset – include it in the drilling and completion budget [39].

4.7.2 Completion Phase

- Use cemented liners (LCP) to allow selective perforation and future isolation of unwanted zones [27,30].
- Perforate in stages so that individual intervals can be tested and stimulated separately [39].
- Run a production logging tool (PLT) during the initial flowback to identify which intervals are contributing and whether gas or water is entering [39].
- Install a permanent downhole gauge if economically justified, to enable continuous pressure monitoring [40].

4.7.3 Stimulation Phase

- Always perform a data fracture (mini-frac) before the main treatment [39]. The data frac should include a step-rate test, a calibration test, and a pressure decline analysis to determine closure pressure, leak-off coefficient, and fracture efficiency.

- Design the main fracture based on the data frac results. Use the measured closure pressure to set the maximum treating pressure, and use the leak-off coefficient to size the pad volume [39].
- Use a proppant schedule that includes a tail-in of resin-coated proppant in formations prone to sand production [39].
- Monitor the fracture in real time using surface pressure and rate data; consider microseismic mapping if available [39].

4.7.4 Post-Stimulation and Production Phase

- Perform a thorough post-frac cleanout using coiled tubing to remove excess proppant and gel residue [31,33].
- Conduct a production test at multiple choke sizes to establish the inflow performance relationship (IPR) [31].
- Re-optimise artificial lift (gas lift or ESP) after the stimulation to match the new inflow performance [33,39].
- Monitor GOR and water cut weekly for the first three months, then monthly. Any significant increase should trigger a PLT survey [28,31].
- If gas breakthrough occurs, isolate the offending interval with a packer or cement squeeze rather than living with the high GOR [39].

4.7.5 Long-Term Reservoir Management

- In sectors with gas injection, avoid drilling new wells close to injectors or design them with isolation capabilities [26,28].
- Consider infill drilling between existing wells to access unswept compartments, but only after a detailed simulation study [34].
- Develop a database of stimulation results – including data frac parameters, proppant volumes, and post-frac production – to enable data-driven optimisation of future treatments [38,40].

4.8 Conclusions

An integrated case study of three wells—MD-800, MD-819, and RDC-30—has demonstrated the value of a systematic, diagnosis-driven approach to production decline and stimulation. The following conclusions emerge from the analysis.

Diagnostic tools are essential. Production history analysis, gas-oil ratio monitoring, injectivity testing, and data fracturing are necessary to identify the true causes of underperformance [28,31,33]. In well MD-800, an injection test prevented a costly misdirected fracture [28]. In wells MD-819 and RDC-30, data fractures enabled the design of successful main treatments [31,33].

Matrix acidizing is insufficient for tight sandstones. Well MD-800 received multiple acid treatments, yet production never recovered to peak levels and the GOR remained high [28]. Acidizing attempts in MD-819 failed to achieve commercial rates [31]. In RDC-30, acid treatments provided only temporary boosts [33].

Hydraulic fracturing, when properly designed, delivers step-change improvements. Well MD-819 achieved an initial rate of 60.7 m^3/d with a GOR of only 478 m^3/m^3 [31]. The post-frac rate of 131 m^3/d in RDC-30 was the highest in the well's history [33]. Both wells had been sub-commercial or in decline before fracturing.

Data fracturing is the key to success. In both MD-819 and RDC-30, the data fracture provided critical parameters (closure pressure, net pressure, fracture efficiency) that guided the main treatment [31,33]. Without these data, the main fracture design would have carried significant uncertainty [39].

Gas breakthrough from injectors represents a serious problem in mature sectors. Well MD-800's GOR of 2,028 m^3/m^3 is four times the solution GOR, indicating production of injected gas [28]. This condition reduces oil production and can only be remedied by mechanical isolation [39].

Sand production can limit well life. RDC-30 experienced a sand plug in 2025, requiring intervention [33]. The new fracture likely employed resin-coated proppant to mitigate this risk [39].

Artificial lift optimisation remains essential after stimulation. The gas lift system in RDC-30 was re-optimised after fracturing to accommodate the higher liquid rate [33]. Failure to do so would have limited the benefit of the stimulation [39].

A standardised workflow should be adopted for all new development wells: (a) collect diagnostic data (production, pressure, GOR, production logging), (b) perform a data fracture, (c) design and execute a main fracture, (d) re-optimise artificial lift, and (e) monitor post-frac performance [39,40].

By applying this workflow consistently, operators can unlock the full potential of tight sandstone reservoirs such as the Cambro-Ordovician of Hassi Messaoud and the Triassic of Rhourde Chegga. The success of wells MD-819 and RDC-30 provides a clear template for future development.

general Conclusion

This thesis has navigated through the complex technical landscape of production decline in the Hassi Messaoud field, providing a structured engineering framework for integrated diagnosis and remediation. By bridging the gap between theoretical reservoir mechanics and practical field applications, we have demonstrated that sustaining production in mature fields requires more than just routine maintenance—it demands a rigorous, data-driven analytical approach.

The journey of this study began with a comprehensive understanding of the Cambro-Ordovician reservoir's geological complexity, which remains the primary constraint on well performance. We established that the decline in production is rarely a standalone event but rather a multifaceted issue involving reservoir depletion, near-wellbore formation damage, and mechanical inefficiencies.

The core contribution of this work lies in the integrated diagnostic workflow developed in the second chapter. By combining Pressure Transient Analysis (PTA) to quantify the skin factor, Production Logging (PLT) to identify fluid entry points, and Nodal Analysis via PIPESIM to model flow behavior, we were able to isolate specific impairment mechanisms with high precision. This methodology was proven essential in avoiding "trial-and-error" interventions, which can be both costly and detrimental to the reservoir.

The practical application of this workflow in the final case studies (notably well MD-819) provided conclusive evidence of its effectiveness. The transition from a high-skin, low-productivity state to a significantly improved production profile—following targeted matrix acidizing and hydraulic fracturing—validated the remediation strategies proposed in the third chapter.

In conclusion, we recommend the following for the future management of Hassi Messaoud wells:

Systematic Surveillance: Implementing periodic PTA and PLT campaigns to monitor the evolution of formation damage (Skin) over time.

Advanced Modeling: Utilizing tools like PIPESIM for continuous Nodal Analysis calibration to optimize gas-lift designs and tubing sizes as reservoir conditions change.

Tailored Stimulation: Moving towards customized chemical and mechanical stimulation recipes based on the specific mineralogy and fluid compatibility of each zone.

Ultimately, while the Hassi Messaoud field is in its mature phase, the integration of modern diagnostic tools and optimized stimulation techniques ensures that it will remain a vital and productive asset for many years to come.

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