Gas Recycling Optimization in Gas Condensate Reservoirs Using 3D Compositional Modeling

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Abstract

Gas condensate reservoirs undergo a decline in productivity due to retrograde condensation when the bottomhole flowing pressure falls below the dew point, leading to the formation of liquid droplets and subsequent obstruction near the wellbore. Utilizing dry gas reinjection serves as an established method for enhanced recovery, as it sustains reservoir pressure above the dew point, thereby facilitating the revaporization of the trapped condensate. This research employs a three-dimensional compositional reservoir simulator to meticulously optimize the efficiency of gas cycling under varying conditions of reservoir quality, fluid compositions, and well configurations. A sector model was developed using the Peng-Robinson equation of state (PR-EOS) calibrated to PVT data, which includes dual-permeability porous media to accurately capture the flow dynamics near the critical point.

The foundational scenario simulated natural depletion through the utilization of five vertical producers. Subsequent simulations assessed crestal gas injection methodologies by transforming one of the producers into a dry gas injector, calibrating injection rates to attain recycle ratios ranging from 0 to 1. The performance of horizontal wells was compared with that of vertical completions to evaluate recovery mechanisms dependent on geometry. Notable outcomes indicate a direct correlation between the optimal recycle ratio (R_{opt}) and condensate yield. For lean gases (20 stb/mmscf), a R_{opt} of 50% is required to optimize recovery, whereas for richer fluids (60 stb/mmscf), a R_{opt} of 75% is necessary to counteract vaporization hysteresis. Reservoir quality dictates the efficacy of well type. Horizontal wells in high-kh formations achieve 18-22% greater recovery than vertical wells for high-yield fluids, a result of improved contact with undersaturated zones. In contrast, in low-kh reservoirs, vertical injector-producer pairs exhibit superior performance due to enhanced vertical sweep efficiency and reduced coning risks.

The present study constructs a decision matrix pertinent to gas cycling projects, encompassing fluid richness, formation deliverability, and completion design. The outcomes furnish actionable insights for the optimization of injection strategies within retrograde condensate systems, especially in the context of heterogeneous or liquid-rich shale-condensate formations.

Introduction

Gas condensate reservoirs occupy a critical position within the oil and gas sector, serving as significant contributors to hydrocarbon production and meeting the increasingly demanding global energy needs. Initially, these reservoirs exist in a single-phase state. However, when the reservoir pressure falls below the dewpoint pressure, a phenomenon known as retrograde condensation ensues, resulting in the accumulation of condensate within the reservoir pores (Gao et al. 2020; Li et al. 2005). As illustrated in **Figure 1** (Behmanesh et al. 2018),

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Improved Oil and Gas Recovery
DOI: 10.14800/IOGR.1358
Received January 10, 2025; revised March 1, 2025; accepted April 14, 2024.

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the condensate dropout around the wellbore can lead to the formation of three distinct flow regions. This accumulation of condensate causes the obstruction of reservoir pores, thereby reducing the recovery of both gas and condensate (Hailong et al. 2024; Al-Marhoon and Al-Shidhani 2003; Zhao et al. 2024; Wang et al. 2018; Okporiri and Idigbe 2014; Aaditya 2014; Whitson and Whitson 2005).

Upon the reduction of the flowing bottomhole pressure in gas condensate wells below the dewpoint pressure, a marked decrease in productivity is noted. A region of elevated condensate saturation emerges proximate to the wellbore, subsequently diminishing gas permeability and deliverability (Shi et al. 2006; Ahmed et al. 1998; Bennion et al. 2001). Empirical data from the industry suggests that under depletion drive conditions, gas condensate reservoirs generally achieve gas recovery factors between 40% and 60%, and condensate recovery factors ranging from 10% to 30%.

To enhance the recovery of condensate from gas condensate reservoirs, an array of secondary and tertiary recovery methods is implemented. These methods encompass the displacement of gas and condensate through the utilization of various injection gases, including nitrogen, carbon dioxide, dry gas, or gas mixtures (Seah et al., 2014; Esmaeili et al 2023). The efficacy of these technologies is contingent upon a multitude of factors, such as the volume of residual gas and condensate reserves, the accessibility of the injected gas, the complexity and capacity of surface facilities, the geological and structural characteristics of the field, reservoir depths, and economic factors, including payback periods and production agreements.

Dry gas recycling emerges as the predominant method for enhanced recovery in gas condensate reservoirs. It functions to sustain reservoir pressure above the dewpoint, diminishes the dewpoint pressure of the newly formed gas mixture, and vaporizes the heavy components that have precipitated in the reservoir. This methodology has the potential to enhance gas recovery rates to 65%-80% and condensate recovery rates to 40%-60% (El Aily et al. 2016; Zhang et al. 2024; Serhii 2023). Critical factors that influence gas and condensate recovery during dry gas recycling encompass the variance between the reservoir pressure and the dew point pressure, the content of condensate, reservoir quality, and the production and injection patterns (Kerunwa, 2015; Izuwa et al. 2014; Cobanoglu et al. 2014; Rasoul et al. 2014; Nasiri et al. 2015).

The principal difficulty in the development of gas condensate reservoirs is the determination of an optimal scenario that maximizes recovery and minimizes investment risks to attract stakeholders. This study aims to determine the optimal gas-recycling ratio to maximize gas and condensate recovery while ensuring that the reservoir pressure remains above the dewpoint. A three-dimensional compositional simulation model, constructed using Petrel software, will be utilized to optimize the gas recycling ratio (Angang et al. 2020; Larry 2022). The study will evaluate reservoirs with varying condensate contents and quality levels, incorporating both vertical and horizontal well configurations. Simulations will be conducted using Eclipse software to identify the most effective production and injection strategies.

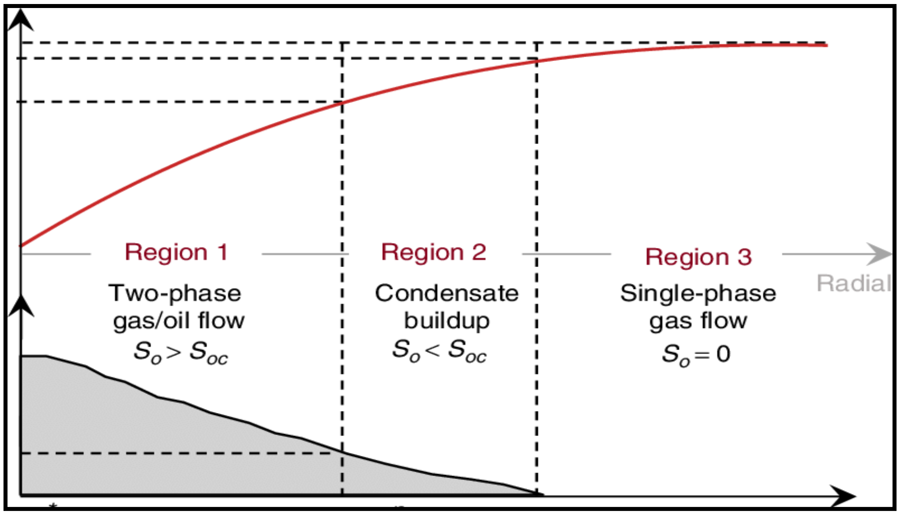

Figure 1—Flow regime depiction for a radial well from a gas condensate reservoir.

Materials and Methods

The research methodology initiates with the development of three-dimensional static reservoir models employing Petrel software. These models are engineered to depict reservoirs of varying qualities, distinguished by disparate porosity and permeability characteristics. The determination of these attributes is pivotal, as they substantially affect fluid movement and containment within the reservoir.

Simultaneously, pressure-volume-temperature (PVT) compositional models have been developed for three distinct gas condensate fluid samples. These samples exhibit condensate contents of 20, 40, and 60 stb/mmscf, respectively, and were created utilizing PVT software. The PVT models precisely capture the intricate phase behavior of the gas condensate fluids across varying pressure and temperature conditions. Subsequently, these PVT models are transferred from PVT to Petrel, thereby enabling the integration of fluid properties into the static reservoir models.

The research methodology initiates with the creation of three-dimensional static reservoir models, which encompass a spectrum of reservoir quality attributes, such as porosity and permeability characteristics, utilizing Petrel software (Calvin and Mattax, 1990). Furthermore, pressure-volume-temperature (PVT) compositional models are developed for three gas condensate fluid samples, each with differing condensate contents of 20, 40, and 60 STB/MMSCF, employing PVT software. Subsequently, these models are transferred from PVT to Petrel (Wood and Young, 1988; Akpabio et al., 2015; Curtis et al., 1999).

Subsequently, the creation of three-dimensional dynamic models is executed by integrating each static reservoir model with each of the three gas condensate models, culminating in a total of nine dynamic models. These models are meticulously constructed within the Petrel software environment (Yang et al. 2024). Initially, the models undergo simulation under depletion drive conditions, (which involves gas production without the implementation of gas injection, to ascertain the ultimate recovery of gas and condensate. These outcomes are established as the foundational benchmarks for assessing the supplementary recovery facilitated by gas recycling, which is subsequently modeled using the Eclipse software (Akinsete et al. 2021; Spivak and Dixon 1973; Pal 2013; Amini et al. 2011).

The study subsequently assesses the nine models across various dry gas recycling (ratios, specifically 0.9, 0.75, 0.5, and 0.25, initially employing vertical production wells. The procedure is replicated with horizontal production wells substituting the vertical ones. Ultimately, the outcomes from the distinct development scenarios are scrutinized for each reservoir quality and gas model combination. The scenarios are graded in accordance with condensate recovery to ascertain the optimal gas recycling ratio that maximizes condensate recovery.

Three-Dimensional Reservoir Static Model. The subject reservoir is a faulted anticline sandstone formation. It is overlain by shale and delineated by major faults to the northeast and southeast. The structure exhibits a dip from the northeast to the southwest. The reservoir comprises two vertically communicating zones within a depth range of 3500 ft to 4900 ft true vertical depth subsea (TVDss), featuring a distinct gas-water contact (GWC) at 4700 ft TVDss.

Five wells traverse the reservoir, as depicted in **Figure 2**. A three-dimensional structural model has been constructed employing four seismic horizons: 1) the uppermost shale's summit; 2) the apex of sand A; 3) the crest of sand B; and 4) the nadir of the lowermost shale.

Additionally, the model incorporates two major faults. The model’s grid dimensions are 39×37 cells in the X and Y directions, respectively, with a 100 m spacing, subdivided vertically into 61 layers, resulting in a total of 88,023 cells. A facies model was constructed based on facies logs from the five wells. Subsequently, porosity and permeability models were developed to represent three reservoir quality scenarios:

- Low quality reservoir (Average porosity = 10%, & Average Permeability = 100 md)
- Mid quality reservoir (Average porosity = 15%, & Average Permeability = 1000 md)

- High quality reservoir (Average porosity = 20%, & Average Permeability = 5000 md)

The reservoir's production strategy incorporates four wells designated as producers situated in the down-dip area and one injector well positioned at the crest for peripheral injection. Given the aquifer's weakness, an aquifer model was not integrated into the simulation. **Figure 3** offers a depiction of the constructed three-dimensional reservoir model, emphasizing its structural and property distributions.

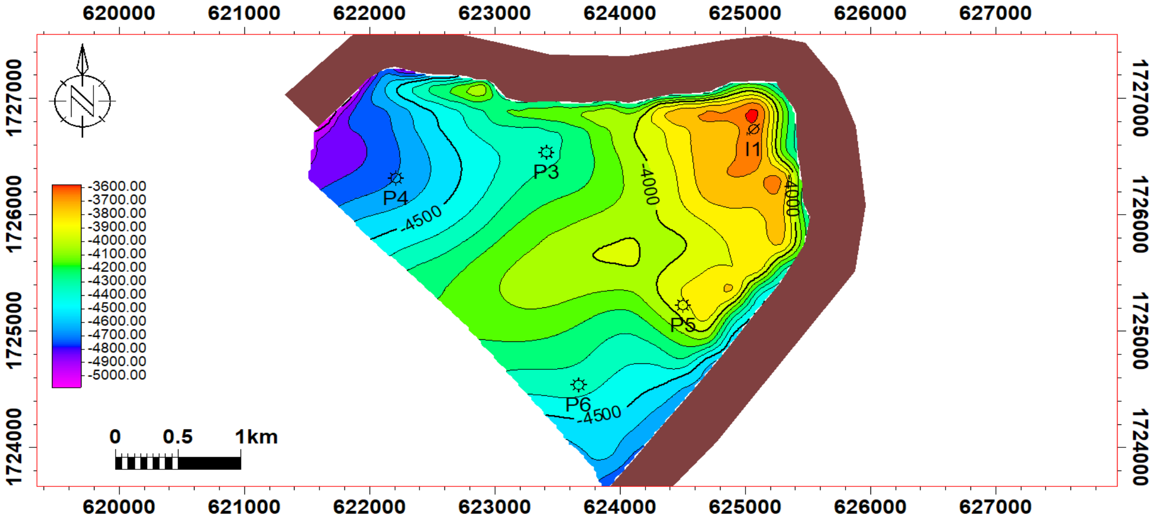

Figure 2—Reservoir structure contour map with penetrating wells.

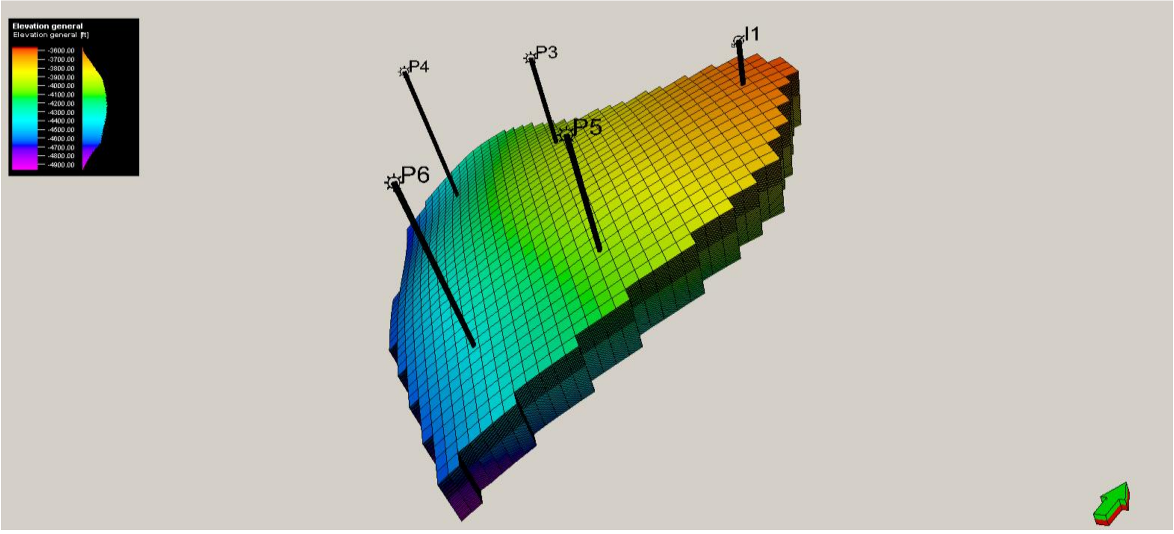

Figure 3—Reservoir three-dimensional model with penetrating wells.

PVT Model. Three samples of gas were procured from separate gas condensate reservoirs, each exhibiting condensate yields of 20, 40, and 60 stb/mmscf. Calibrated models were constructed for each sample employing the Peng-Robinson equation of state (EOS) within the PVT software. These EOS models were meticulously customized to precisely emulate the behavior of the reservoir fluids, considering their pressure, volume, and temperature (PVT) characteristics. The methodology for the development of these equations of state models encompassed the subsequent stages:

- Select equation of state type (Akpabio et al. 2014; Soave 1972; Peng and Robinson 1976; Jaubert and Mutelet 2004).
- Splitting pseudo component (Whitson 1984; Robinson and Peng 1978).

- Match dewpoint pressure with binary interaction coefficients.
- Match constant composition expansion (CCE), constant volume depletion CVD and separator tests available data using different EoS parameters (Coats and Smart 1986; Merrill et al. 1994).
- Match gas viscosity.
- Lump the composition into 8 compositions and rematch again if needed.
- Export PVT data as compositional model (EoS with its related parameters).

Figures 4 through 6 delineate the phase diagrams corresponding to the three gas samples, elucidating the unique characteristics of each reservoir fluid. Additionally, **Table 1** delineates the aggregated compositions for the three calibrated Equation of State (EoS) models.

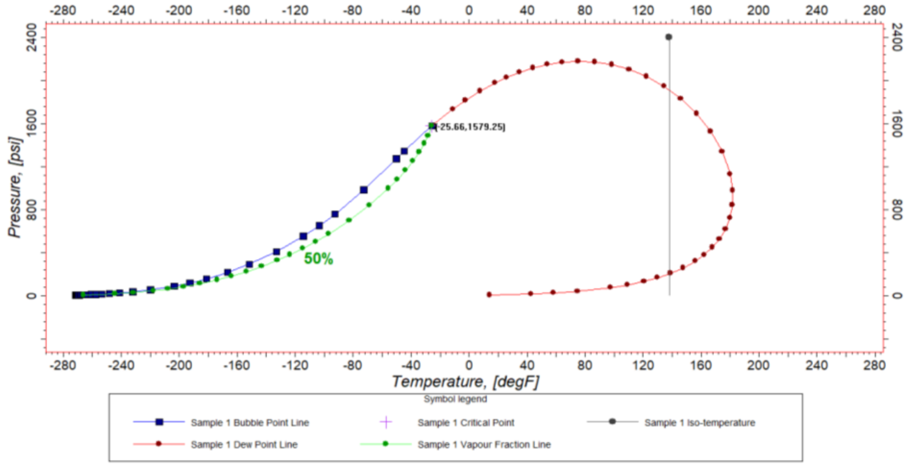

Figure 4—Phase diagram of gas with condensate yield of 20 stb/mmscf.

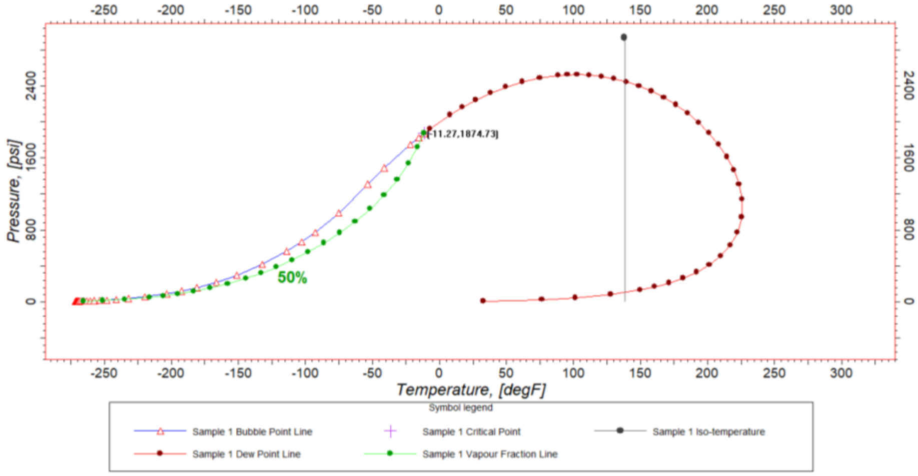

Figure 5—Phase diagram of gas with condensate yield of 40 stb/mmscf.

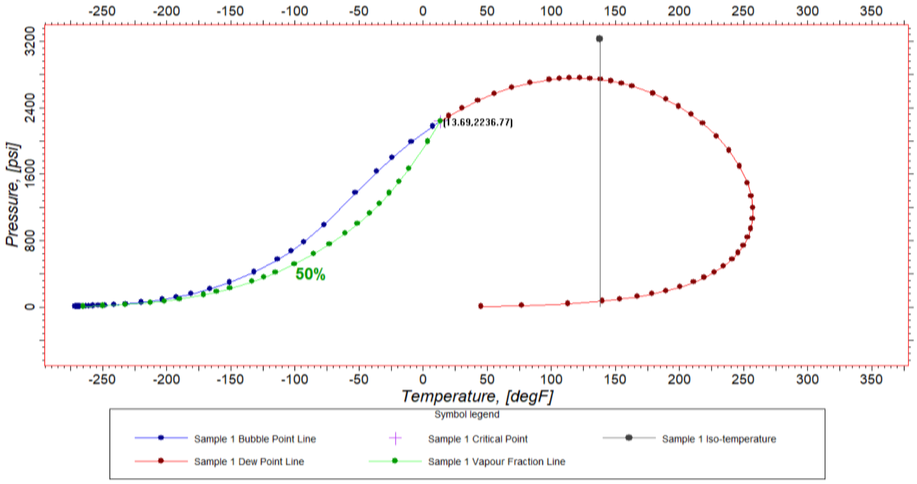

Figure 6—Phase diagram of gas with condensate yield of 60 stb/mmscf.

Table 1—Lumped compositions of the three calibrated gas PVT models.

Components	Gas composition with condensate yield of 20 stb/mmscf	Gas composition with condensate yield of 40 stb/mmscf	Gas composition with condensate yield of 60 stb/mmscf
	Mole percent, %	Mole percent, %	Mole percent, %
N_2	0.23	0.23	0.22
CO_2	0.13	0.13	0.12
C_1	80.04	78.15	76.37
C_2	8.41	8.22	8.04
C_3, iC_4 & nC_4	7.63	7.68	7.71
iC_5, nC_5 & C_6	1.96	2.71	3.38
C_7, C_8 & C_9	1.25	2.23	3.18
C_{10} & C_{11+}	0.34	0.65	0.96
Total	100	100	100

Dynamic Model Initialization. The establishment of the reservoir model necessitates the determination of pressure and fluid saturations within each grid cell at the outset of the simulation period, preceding the commencement of production or injection activities. The subsequent parameters and methodologies were utilized during the initialization process:

- Datum Pressure. The pressure within the reservoir at a true vertical depth of 4200 feet TVDss served as the reference point for delineating the three-dimensional pressure profile.
- Gas-Water Contact (GWC). The Gas-Water Contact was delineated at a true vertical depth of 4700 feet TVDss to determine fluid saturation.
- SCAL Data. The Special Core Analysis (SCAL) data was derived from log analysis and relative permeability data originating from an offset field. The initial water saturation (S_{wi}) was established at 11%. The capillary pressure between gas and water (P_{cgw}) was determined to be 0.
- PVT Models. Three distinct compositional PVT models were utilized, corresponding to condensate yields of 20, 40, and 60 STB/MMSCF, respectively.

Table 2 provides an overview of the initial conditions pertinent to the compositional models utilized for predictive simulations in scenarios involving depletion and gas recycling. Initially, simulations are executed to confirm the stability of the models and to determine the initial quantities of gas and condensate reserves, in the absence of production or injection activities. **Table 3** delineates the initial quantities of gas and condensate for the nine models under consideration.

Table 2—Initialized Compositional Models Conditions.

Items	Gas Reservoir		
	Condensate yield of 20 stb/mmscf	Condensate yield of 40 stb/mmscf	Condensate yield of 60 stb/mmscf
Initial pressure, psi	2400	2935	3225
Datum, ft TVDss	-4200	-4200	-4200
Dewpoint Pressure, psi	1900	2435	2725
Gas water Contact (GWC), ft TVDss	-4700	-4700	-4700
Capillary pressure @GWC	0	0	0
Reservoir Temperature, F	183.1	183.1	183.1

Table 3—Gas and condensate initially in place for the nine models.

Model	Reservoir quality	Gas condensate yield, stb/mmscf	Initial gas in place, bscf	Initial condensate in place, mmstb
1	Low	20	439	9
2	Low	40	541	22
3	Low	60	586	35
4	Mid	20	659	13
5	Mid	40	811	32
6	Mid	60	879	53
7	High	20	834	17
8	High	40	1033	41
9	High	60	1120	67

Base Case Operations. Utilization of five wells, comprising one crestal well and four wells positioned down-dip, is undertaken to establish the depletion scenario (without gas recycling), serving as the foundational case for the nine models. To investigate the impact of well geometry on condensate recovery, two foundational cases have been established. The initial foundational case is formulated with four down-dip vertical wells and a single vertical crestal well, while the second foundational case employs four down-dip horizontal wells alongside a single vertical crestal well. The production controls and constraints can be delineated as follows:

- The field control production amounts to 60 MMSCFD.
- The maximum production capacity of the well is 20 MMSCFD.
- The well's constrained bottom-hole flowing pressure is 650 Psi.
- The economic gas and oil production rates for the well are 1 MMSCFD and 20 STBD, respectively.
- Two stages of separation are utilized, with the first stage operating at 250 psi and 100 oF, and the second at 14.7 psi and 60 ºF.
- The forecasted production period spans 40 years, from 2024 to 2064.

Figures 7 to 9 depict the reservoir pressure performance and cumulative condensate production outcomes for the three gas models, which are characterized by low, intermediate, and high condensate content (20, 40, and 60 STB/MMSCF, respectively), in the context of vertical and horizontal producing wells under depletion conditions. During primary production, the reservoir pressure experiences a rapid decline. Condensate dropout occurs proximate to the production wells and within the reservoir pores where the pressure falls below the dew point pressure. As condensate is an immobile phase, it precipitates and results in a marked decrease in well productivity. The outcomes indicate that with an improvement in reservoir quality, cumulative condensate production increases for a given gas type (equivalent condensate yield), due to a lesser pressure drop and diminished impact of condensate blockage in reservoirs of superior quality. For reservoirs of equal quality, an escalation in gas condensate content results in elevated cumulative condensate production, ascribed to the larger volume of condensate. Additionally, for identical reservoir types, the recovery of condensate from horizontal and vertical wells is equivalent, thereby affirming that well geometry does not affect condensate recovery.

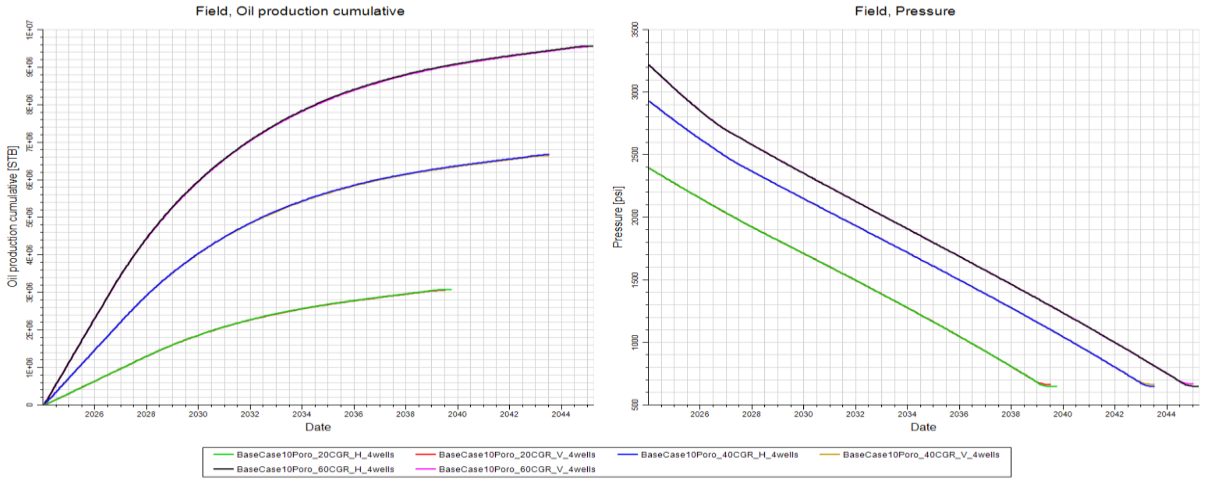

Figure 7—Cumulative condensate production and reservoir pressure in the depletion scenario for a low-quality reservoir.

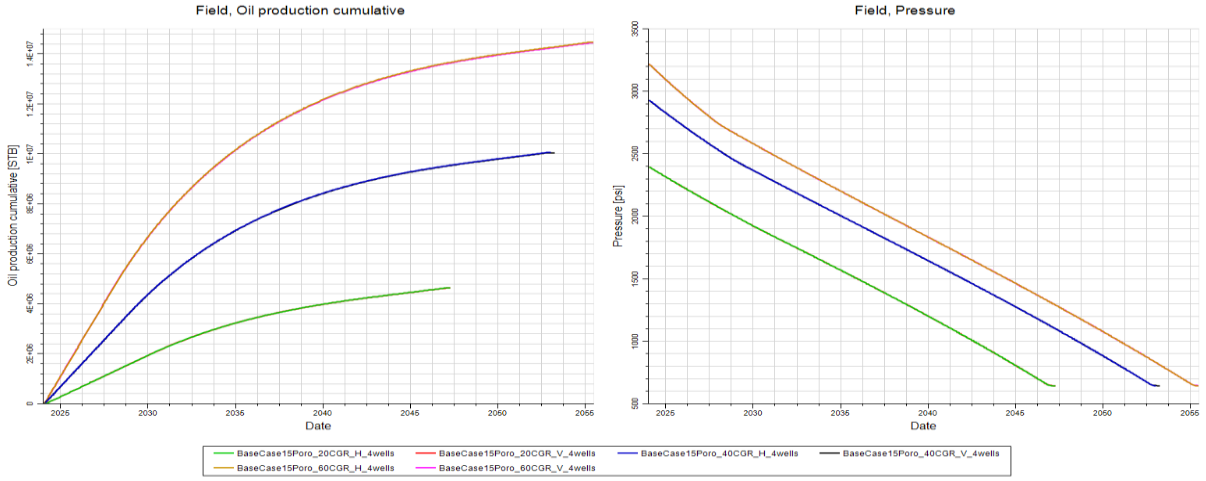

Figure 8—Cumulative condensate production and reservoir pressure in the depletion scenario for a mid-quality reservoir.

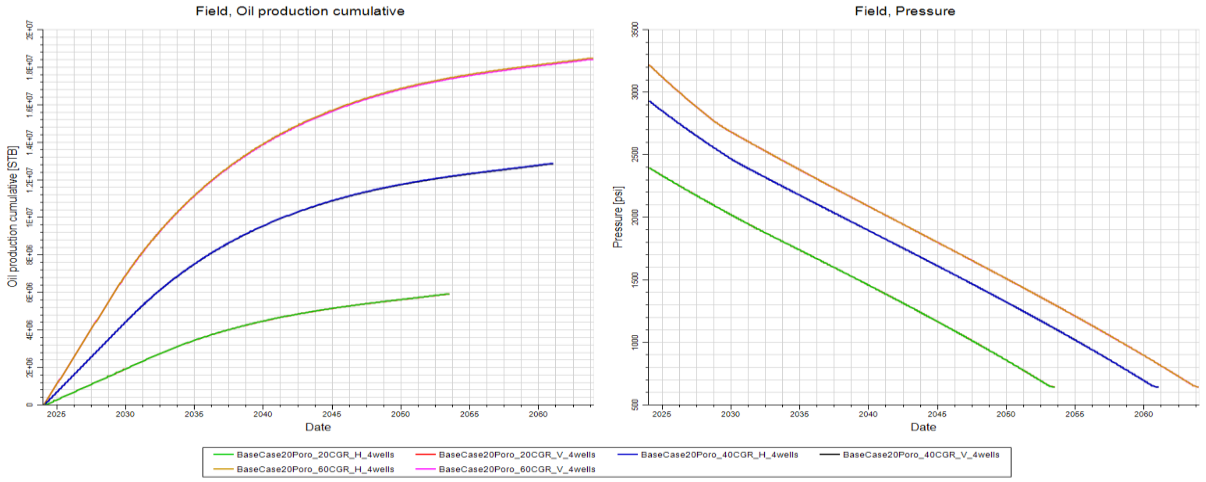

Figure 9—Cumulative condensate production and reservoir pressure in the depletion scenario for a for high-quality reservoir.

Gas Recycling Sensitivity Analysis. Utilizing a single crest well as an injector and four wells positioned down dip as producers, various gas recycling scenarios with differing proportions of dry gas injection were constructed. The dry gas composition is predominantly methane, constituting 98%, with the remaining 2% being ethane. It is presumed that 10% of the field's output is allocated for fueling generators and other equipment. Consequently, 90% of the produced dry gas will be utilized for a comprehensive injection scenario. Four distinct injection ratios for dry gas recycling—0.9, 0.75, 0.5, and 0.25—were employed to ascertain the optimal ratio for dry gas recycling, with two separate cases considered: one involving four vertical producing wells and the other involving four horizontal wells. The production controls and constraints can be encapsulated as follows:

- The field control production amounts to 60 MMSCFD.
- The maximum production capacity of the well is 15 MMSCFD.
- The well's constrained bottom-hole flowing pressure is 650 psi.
- The economic gas and oil production rates for the well are 1 MMSCFD and 20 stbd, respectively.
- Two stages of separation are utilized, with the first stage operating at 250 psi and 100oF, and the second at 14.7 psi and 60oF.
- The field gas re-injection ratios are 0.9, 0.75, 0.5, and 0.25, respectively.
- The constrained bottom-hole injection pressure for the well is 4000 psi.
- The forecasted duration of production is 40 years, spanning from 2024 to 2064.

Utilization of gas recycling results in greater cumulative condensate production compared to the depletion scenario, attributable to the following factors:

- The preservation of reservoir pressure through gas recycling, or a reduction in the rate of pressure depletion, which subsequently diminishes the condensate dropout phenomenon; the altered composition of the reservoir fluid after the injection of dry gas, which exhibits a reduced dew point pressure;
- and the vaporization of certain heavy components that precipitated out during gas extraction proximal to the wellbore.

The findings indicate that as reservoir quality improves, condensate production recovery increases with the same gas type when dry gas recycling is implemented. This is attributed to a reduced pressure drop near the wellbore and a diminished impact of condensate blockage, as evidenced by **Figure 10**. Conversely, with consistent reservoir quality, an increase in the gas condensate content results in higher cumulative condensate production, as depicted in **Figure 11**. Regarding the influence of well geometry, the horizontal well presents a longer production exposure area compared to the vertical well, leading to the subsequent effects:

- The pressure differential proximate to the wellbore of a horizontal well is diminished in comparison to that of a vertical well. Consequently, the condensate accumulation around the horizontal wellbore is reduced, which enhances both the gas and condensate production rates.
- The exposed production zone in horizontal producing wells is larger than that in vertical producing wells, leading to an earlier breakthrough of injected gas and a reduction in the condensate production rate.

Consequently, the production profile of condensate from horizontal wells exceeds that of vertical wells during the initial phase of production, followed by a decline over time. **Figure 12** illustrates the gas and condensate production profiles for horizontal and vertical wells within high-quality reservoirs, considering three gas models (20, 40, 60 STB/MMSCFD condensate yield).

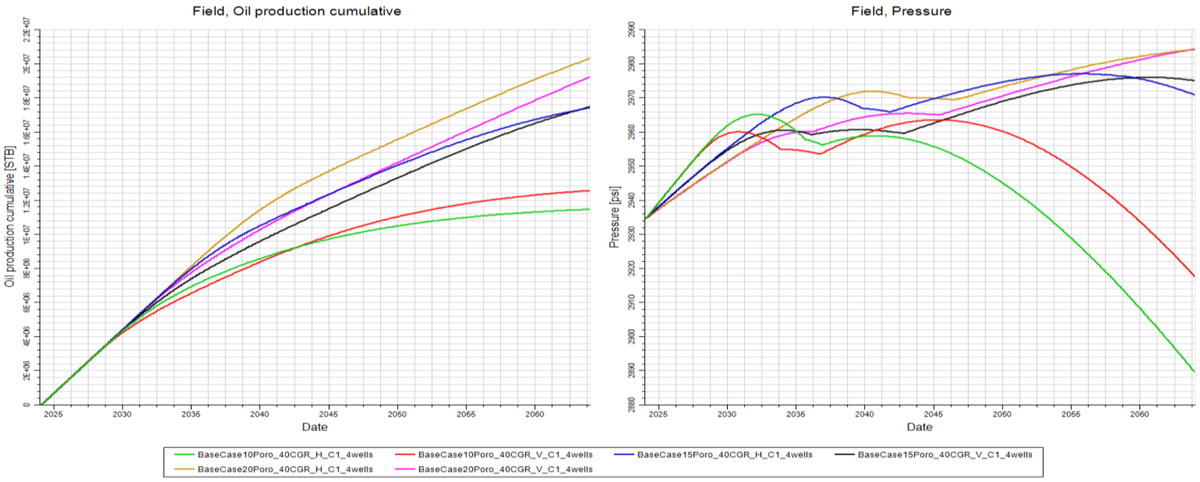

Figure 10—Cumulative condensate production and reservoir pressure under 0.9 dry gas recycling case for gas 40 stb/mmscf condensate yield.

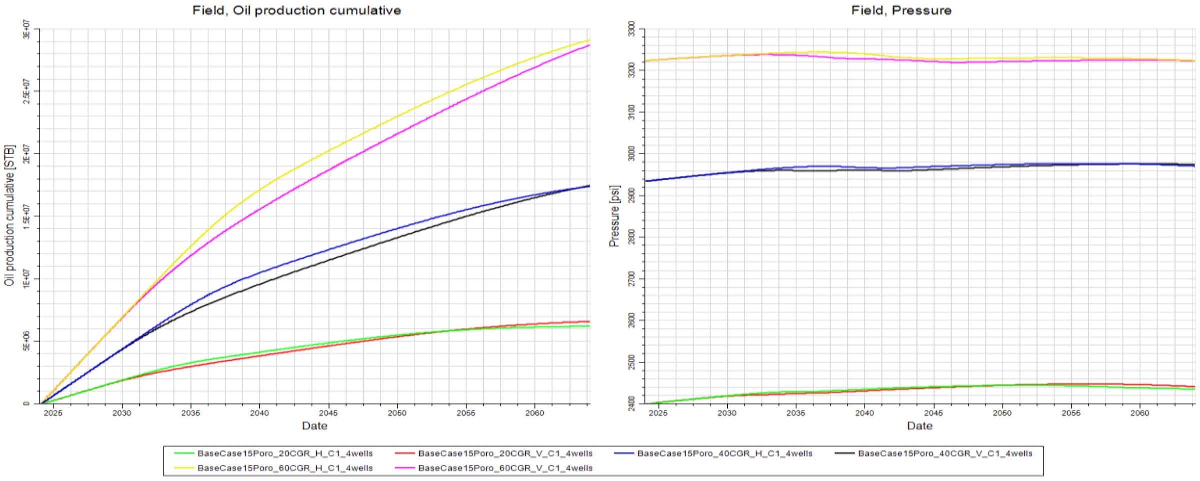

Figure 11—Cumulative condensate production and reservoir pressure under 0.9 dry gas recycling case for mid-quality reservoir.

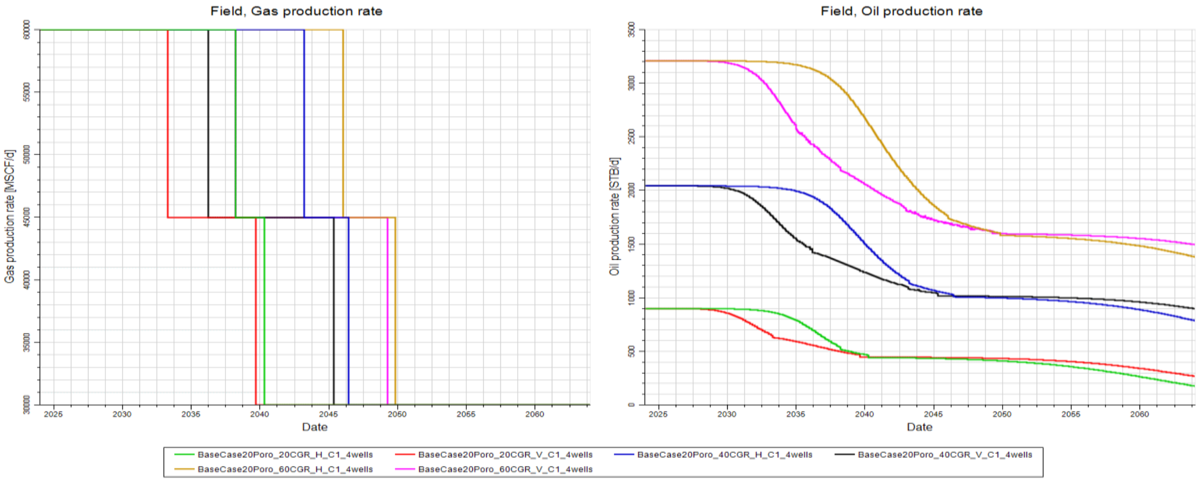

Figure 12—Gas and condensate production rate of horizontal and vertical wells for high-quality reservoir with the three gas models.

Results

Four distinct dry gas recycling ratios (0.9, 0.75, 0.5, and 0.25) were employed to ascertain the optimal dry gas injection ratio for each of the nine models featuring either vertical or horizontal production wells. The findings indicate that cumulative condensate production throughout the recycling process is subject to two counteracting influences. The initial influence pertains to the maintenance of pressure and the vaporization of residual condensate resulting from dry gas recycling, which tends to augment condensate production as the injection ratio escalates. The subsequent influence is attributed to the phenomenon of dry gas breakthrough at the production sites, which tends to diminish condensate recovery as the injection ratio intensifies. Consequently, the outcomes derived from the compositional models reveal varying optimal injection ratios for each gas reservoir.

Figure 13 depicts the relationship between cumulative condensate production and the injection ratio of dry gas in a low-quality gas reservoir, considering both vertical and horizontal production wells. In the case of vertical wells, a gas condensate yield of 20 STB/MMSCF yields an optimal injection ratio of 0.5, resulting in a cumulative condensate production of 4.56 MMSTB, marginally higher than the 4.53 MMSTB achieved with an injection ratio of 0.75. For gas with a condensate yield of 40 STB/MMSCF, the optimal injection ratio is 0.75, resulting in a cumulative condensate production of 13.23 MMSTB, which is greater than the 12.61 MMSTB produced with an injection ratio of 0.9. Similarly, gas with a condensate yield of 60 STB/MMSCF reaches its optimal injection ratio at 0.75, producing a cumulative condensate of 22.2 MMSTB, exceeding the 21.44 MMSTB produced with a 0.9 injection ratio. These outcomes suggest that as the condensate content rises, the optimal injection ratio also increases, a trend observed even in reservoirs of identical quality.

In the context of horizontal production wells, the optimal injection ratios remain consistent with those applicable to vertical wells. Nevertheless, vertical production wells exhibit superior condensate recovery in comparison to horizontal production wells when dealing with gases that yield condensate at rates of 40 and 60 STB/MMSCF. This disparity can be attributed to the diminished condensate loss proximate to the wellbore in vertical wells, which are less susceptible to the incursion of dry injected gas.

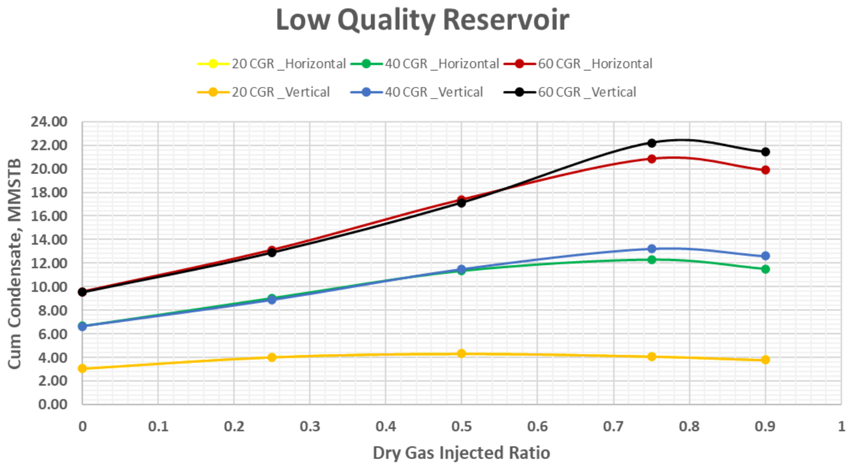

Figure 13—Accumulative condensate yield in relation to the injection ratio of dry gas for horizontal and vertical wells in a low-quality reservoir, utilizing three different gas models.

The outcomes for medium-quality reservoirs suggest that they exhibit the same optimal injection ratio as their low-quality counterparts, as depicted in **Figure 14**. In instance of gas possessing a condensate yield of 20 STB/MMSCF, an injection ratio of 0.5 facilitated a cumulative condensate recovery of 7.04 MMSTB. For gases with condensate yields of 40 and 60 STB/MMSCF, the optimal injection ratio was determined to be 0.75, resulting in cumulative condensate recoveries of 18.24 MMSTB and 29.89 MMSTB, respectively. These results indicate that condensate recovery in medium-quality reservoirs surpasses that in low-quality reservoirs, attributable to diminished pressure loss and condensate dropout. Additionally, scenarios involving horizontal production wells exhibited identical optimal injection ratios and condensate recoveries to those with vertical production wells.

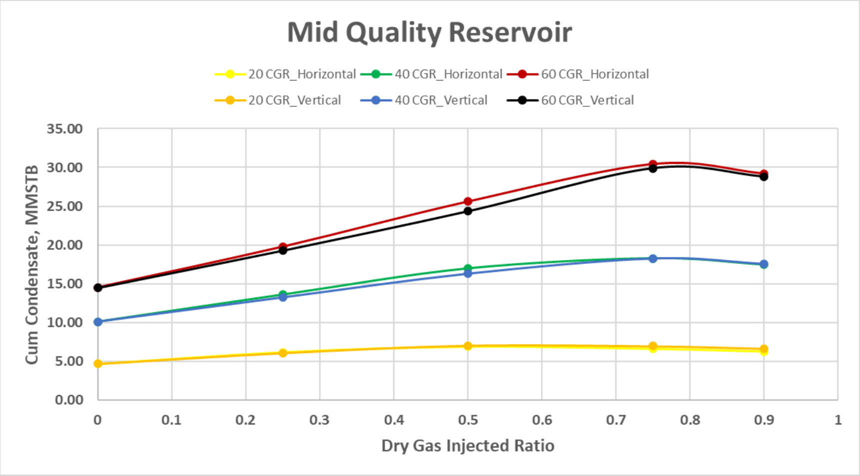

Figure 14—Accumulative condensate yield in relation to the injection ratio of dry gas for horizontal and vertical wells in a mid-quality reservoir, utilizing three different gas models.

Figure 15 delineates the relationship between cumulative condensate production and the injection ratio of dry gas within high-quality reservoirs, substantiating that the optimal injection ratios remain uniform across reservoirs of varying quality. Specifically, for gas exhibiting a condensate yield of 20 STB/MMSCF, the optimal injection ratio is established at 0.5, whereas for gases with condensate yields of 40 and 60 STB/MMSCF, the optimal injection ratio is determined to be 0.75.

In the context of horizontal production wells, the optimal injection ratios are analogous to those observed in vertical production wells. Nevertheless, horizontal wells exhibit a superior condensate recovery rate relative to vertical wells when dealing with gases that yield condensate at rates of 40 and 60 STB/MMSCF. This phenomenon can be attributed to the fact that condensate losses in proximity to the wellbore are more pronounced than those resulting from the penetration of injected dry gas in such scenarios.

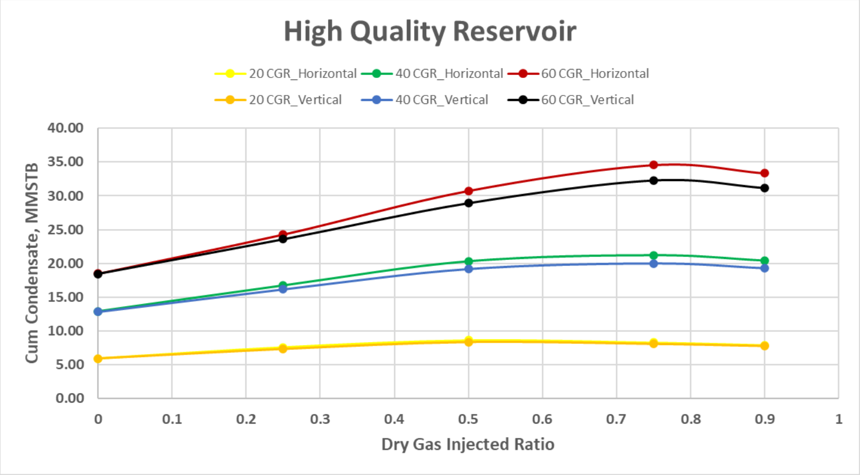

Figure 15—Cumulative condensate yield in relation to the injection ratio of dry gas for both horizontal and vertical wells within a high-quality reservoir, as modeled by three distinct gas models.

Furthermore, the findings across all reservoir qualities indicate that condensate recovery enhances with escalating injection ratios, particularly in the case of gas exhibiting a condensate yield of 60 STB/MMSCF in contrast to those with yields of 40 and 20 STB/MMSCF. This enhancement is attributed to the elevated condensate recovery attained when the reservoir pressure is sustained above the dew point, as well as to the augmented recovery of vaporized condensate.

Conclusions

Gas condensate reservoirs are of paramount importance in the oil and gas industry due to their intricate characteristics and substantial economic ramifications. A principal obstacle encountered in these reservoirs is the precipitation of heavier hydrocarbon components from the produced gas when the pressure falls beneath the dew point, which can occur proximate to the wellbore or within the reservoir's pores. This phenomenon results in diminished production efficiency. Dry gas recycling stands out as one of the most economically viable and efficacious strategies to address this challenge.

The present study utilized a three-dimensional compositional model to optimize the injection ratio of dry gas, with the aim of maximizing condensate recovery and net production. The model conducted a separate analysis of horizontal and vertical producing wells to assess the influence of well geometry on the optimal dry gas injection ratio and condensate recovery.

The modeling outcomes suggest that the cumulative production of condensate with the implementation of dry gas recycling surpasses that are observed under depletion conditions. In the case of reservoirs characterized by varying condensate content, the cumulative recovery of condensate exhibits an increase in correlation with reservoir quality when dry gas recycling is utilized.

The optimal dry gas injection ratio for low-condensate-yield gas reservoirs, (characterized by a yield of 20 STB/MMSCFD, is established at 0.5 of the produced gas. Conversely, for gas reservoirs with medium- and high-condensate yields, at 40 and 60 STB/MMSCFD respectively, the optimal injection ratio is determined to be 0.75 of the produced gas.

In reservoirs of high quality, horizontal wells exhibit a greater capacity for condensate recovery compared to vertical wells, particularly in gas reservoirs characterized by medium to high condensate yields, ranging from 40 to 60 STB/MMSCFD. In contrast, within reservoirs of low quality, vertical wells demonstrate superior performance in condensate recovery relative to horizontal wells. In reservoirs of moderate quality, the efficacy of condensate recovery is comparable between horizontal and vertical wells.

The results of this study offer preliminary guidelines for enhancing the optimization of gas-recycling ratios and may serve as a basis for subsequent research that integrates actual reservoir characteristics, operational parameters, and economic factors.

Abbreviations

3D	Three Dimensions.
STB	Stock Tank Barrel.
MMSCF	Million Standard Cubic Feet.
PVT	Pressure Volume Temperature.
GWC	Gas Water Contact.
TVDss	True Vertical Depth sub sea.
ft	Feet.
md	mile darcy.
Eos	Equation of state.
CCE	Constant Composition Expansion.
CVD	Constant Volume Depletion.
SCAL	Special Core Analysis Log.

Conflicting Interests

The author(s) declare that they have no conflicting interests.

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