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ABSTRACT

of the dissertation for the degree of Doctor of Philosophy

IMPROVEMENT OF RATIONAL CONTROL SYSTEMS FOR PHASE TRANSFORMATIONS DURING NATURAL GAS PRODUCTION AND PROCESSING

Specialty:	2525.01 – Oil and gas field development and operation
Field of science:	Technical sciences
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GENERAL CHARACTERISTICS OF THE WORK

Relevance of the topic and the degree of development. Global energy systems are undergoing major transformation and alternative energy sources are developing rapidly. Nevertheless, energy demand in industrial and residential sectors continues to rise worldwide. In this context, natural gas and hydrocarbon resources in general retain their strategic importance and remain essential for meeting global energy needs. Although reserves in existing hydrocarbon fields are gradually declining, investment in the sector remains substantial to ensure long-term energy security. Alongside conventional reservoirs, unconventional hydrocarbon resources, which require more advanced production technologies, are increasingly attracting scientific and industrial interest. At the same time, maximizing recovery from mature fields, improving production efficiency, optimizing field operations, and advancing existing technologies have become key priorities of the modern oil and gas industry.

Natural gas reservoirs mainly consist of multicomponent mixtures. During production, changing pressure and temperature conditions disturb phase equilibrium, causing liquid condensation, changes in flow structure, and, in some cases, hydrate formation. The complex variation of pressure and temperature throughout the reservoir–wellbore–surface production system has a significant influence on flow stability and production performance. Although this field has been extensively investigated in petroleum engineering, it remains highly relevant, with many unresolved issues continuing to be the subject of active research.

Accordingly, this dissertation examines the hydrodynamic and thermodynamic aspects of phase transformations occurring during natural gas production and primary processing, the development of flow regimes, their influence on production performance, and the design of rational flow management technologies. These topics represent important scientific challenges for the contemporary oil and gas industry. A comprehensive understanding of these processes can make a significant contribution to the efficient development of gas and gas-condensate reservoirs, optimization of production operations, and enhancement of hydrocarbon recovery.

Object and subject of the research. The dissertation investigates methods for managing processes arising from phase transformations in gas production systems. In this context, the object and subject of the research can be defined as follows.

The object of the research is the reservoir–well–surface equipment system exposed to various complications resulting from the effects of phase transformations occurring in the reservoir fluid during gas production. The subject of the research comprises the phase transformations occurring within the gas production system, artificial intelligence models applied for the diagnosis and prediction of the processes caused by these transformations, as well as well management technology integrated with these models.

Research aim and objectives. The dissertation aims to investigate the physical and thermodynamic nature of phase transformations occurring within reservoir–well–surface systems during natural gas and gas-condensate field development. It develops accurate diagnostic models and integrates them into well management technologies to improve production efficiency.

Based on theoretical, practical, and experimental analyses, operational approaches for unstable gas wells are enhanced. Artificial intelligence models are applied for early prediction of operational problems, while pressure and production-rate data are utilized to develop an intelligent self-management system for automatic optimization of well performance.

Research methods. Phase transformations occurring in the reservoir–wellbore system during gas and gas-condensate production, including retrograde condensation, liquid loading, and other operational complications, were investigated using an integrated combination of physical, thermodynamic, and statistical methods. The phase behavior of gas-condensate systems was evaluated using PVT analyses and reservoir simulation models. Processes occurring in the near-wellbore region, within the wellbore, and across the surface production system, including data from actual producing wells, were comparatively analyzed.

Data-driven machine learning approaches based on operational parameters were applied to predict liquid loading and production regimes in gas wells. Within this framework, decision tree and artificial neural network models were developed and trained using real-time and historical production data, while prediction performance was evaluated using statistical analysis methods.

Main provisions submitted for defense:

1. Scientific substantiation of the phase transformations and formation of colloidal-dispersed states occurring throughout the reservoir–well–process facility system during the development of natural gas and gas-condensate fields, and assessment of their impact on production well performance.

2. Accurate early-stage identification of operational problems in gas-producing wells through the application of artificial intelligence models, and development of early-warning and operational management measures.

3. Processing of data reflecting the time-dependent dynamics of well pressure and production rate under limited-data conditions using a GRU model, with the aim of improving analytical accuracy.

4. Development of a self-optimizing well management technology that accounts for processes occurring within the well through the application of intelligent self-management systems.

Scientific novelty of the research.

1. Phase transformations occurring throughout the reservoir–wellbore–surface production system during the exploitation of natural gas and gas-condensate reservoirs were comprehensively investigated, and the obtained results extended the existing scientific understanding;

1.1. The role of phase transformations in the formation of pressure build-up curves in gas production wells was evaluated. It was demonstrated that the early-stage pressure fluctuations are associated with thermobaric effects causing changes in phase distribution and its redistribution along the reservoir–wellbore system.

1.2. The scientific understanding of flow processes in the near-wellbore zone of gas-condensate reservoirs was further developed. In addition to the conventional three-zone approach, a four-zone near-wellbore model incorporating an aerosol and dispersed-phase zone was proposed, enabling more accurate evaluation of production processes.

2. Machine learning and artificial intelligence models based on the temporal evolution of well parameters were developed for the early diagnosis of liquid loading in gas production wells. Their ability to identify nonlinear and hidden patterns, providing improved diagnostic and prediction accuracy, was demonstrated.

3. Under limited-data conditions, a GRU-based deep learning model using time-series gas flow rate (or wellhead pressure) data was proposed to maximize the information extracted from available measurements. The model proved effective for diagnosing well failures even when bottomhole parameters were unavailable.

4. An integrated intelligent self-control framework was developed to account for downhole processes through self-optimizing models. Based on this framework, a technology for the automatic regulation of gas production well operating modes was proposed.

Theoretical and practical significance of the research. The obtained results demonstrate that this dissertation advances the fundamental understanding of phase transformation processes occurring throughout the reservoir–wellbore–surface production system, providing a scientific basis for more efficient management of gas production wells. In addition, the applicability of artificial intelligence models to gas production operations was investigated, confirming their effectiveness for process analysis and production forecasting.

The scientific findings were validated not only using domestic datasets but also with field data from reservoirs in different countries. The research combined established theoretical approaches with recent scientific developments, and the obtained results were verified against experimental and operational data, confirming their reliability and scientific validity.

The innovative technological solutions and artificial intelligence models proposed in this dissertation were developed using extensive datasets from operating wells and validated with practical field data, thereby enhancing their applicability for industrial implementation.

The research results have been applied in scientific studies conducted at the “Hydrogas Dynamics of Reservoir Systems” Laboratory of the Oil and Gas Institute under the Ministry of Science and Education of the Republic of Azerbaijan and have been included in the Institute's annual research reports.

Furthermore, the author, together with co-authors, won a research grant jointly organized by SOCAR and the “Partner Public Union for Scientific Development”. In 2023, under Contract No. “22TP-23LR”, the research team successfully completed and defended the project entitled “Methods for enhancing productivity of gas-condensate reservoirs operated under depletion drive considering reservoir characteristics”, and the project results were submitted to SOCAR for practical implementation.

Approbation and implementation. The principal findings of the dissertation were reviewed by the Scientific Council of the Oil and Gas Institute of the Ministry of Science and Education of the Republic of Azerbaijan. The results received a positive evaluation and were recommended for practical application. The outcomes of the research entitled “Mutual Solubility Processes of Liquid and Gas Phases During the Development of Gas-Condensate Reservoirs and Their Control Methods” were included among the Institute's most significant scientific achievements for 2024.

The main research results were also presented at a scientific seminar held at Azerbaijan State Oil and Industry University (ASOIU) in 2026 under the title “Application of artificial intelligence models to “Self-optimization” technologies for gas production wells”, where the proposed approaches attracted considerable scientific interest.

The principal provisions of the dissertation have also been presented and discussed at the following international scientific conferences and forums:

• International Scientific Conference dedicated to the 100th anniversary of the birth of National Leader Heydar Aliyev (Baku, Azerbaijan. 2023);

• 72nd Scientific and Technical Conference of Students, dedicated to the 100th Anniversary of National Leader Heydar Aliyev (2023, pp. 123–131);

• Science in the Modern World: Innovations and Challenges (Toronto, Canada. 2024);

• IV International Ordu Scientific Research Congress (Ordu, Türkiye. 2025. p. 596–604);

• The Sixth International Student Research and Science Conferences (Baku, Azerbaijan. 2025. p. 163–167);

• 21st International Petroleum and Natural Gas Congress and Exhibition of Turkey (IPETGAS 2023) (Ankara, Türkiye. 2023. p. 663–669).

Publications. The main findings of the dissertation have been published in 15 scientific works, including 9 journal articles and 6 conference proceedings. The journals in which the articles were published were selected in accordance with the requirements of the Higher Attestation Commission (AAC) of the Republic of Azerbaijan. Of these publications, three articles have been published in Web of Science (WoS) indexed journals.

Organization where the dissertation was conducted. The dissertation was carried out at the Azerbaijan State Oil and Industry University. In addition, part of the research was conducted at the "Hydrogas Dynamics of Reservoir Systems" Laboratory of the Oil and Gas Institute under the Ministry of Science and Education of the Republic of Azerbaijan.

Total volume of the dissertation in characters, indicating the volume of individual structural sections. The dissertation consists of an introduction, four chapters, conclusions, and a bibliography comprising 168 references. The dissertation contains 37 figures and 11 tables and has a total length of 166 pages, including the reference list.

The dissertation comprises a total of 237254 characters, distributed as follows: Introduction – 10921 characters; Chapter I – 61086; Chapter II – 50813; Chapter III – 58,714; Chapter IV – 52618; Conclusions – 3102 characters.

MAIN CONTENT OF THE DISSERTATION

The Introduction presents the objectives and tasks of the dissertation, substantiates the relevance of the research topic, its scientific and practical significance, and the necessity of conducting the study. It is emphasized that the development of technologically advanced control systems based on fundamental scientific principles offers considerable potential for improving the production efficiency of gas and gas-condensate wells. Accordingly, research in this area represents an important and timely scientific and engineering challenge.

Chapter One reviews existing theoretical and practical studies on the influence of phase transformations occurring throughout the reservoir–wellbore–surface production system during the development of natural gas and gas-condensate reservoirs. The analysis shows that phase transformations are among the key factors directly affecting hydrodynamic processes, flow regimes, and production performance[1]. Therefore, their accurate characterization and the further development of existing scientific and engineering approaches are of considerable importance.

The study confirms that precipitation of liquid hydrocarbon components from natural gas in the near-wellbore region and inside the wellbore is an unavoidable phenomenon during gas production. In gas-condensate reservoirs, retrograde condensation leads to condensate accumulation in the near-wellbore zone, resulting in reduced relative permeability, flow instability, cyclic liquid loading, pressure oscillations, and increased production losses[2].

Comparative analysis of experimental data and published studies indicates that these pressure oscillations influence not only the near-wellbore region but also induce cyclic stress variations within the reservoir, potentially reducing the integrity of both the reservoir rock

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[1] Coskuner, G. Production optimization of liquid loading gas condensate wells: a case study // Journal of Canadian Petroleum Technology. – 2003, 42 (11).

[2] Lea, J.F., Nickens, H.V. Solving gas-well liquid-loading problems // Journal of Petroleum Technology. – 2004, 56 (4), – p. 30–36.

and the well structure. Large-amplitude and irregular fluctuations of flow parameters also adversely affect the operation of surface production equipment. Consequently, comprehensive evaluation of the effects of pressure and temperature variations and phase transformations on flow behavior, together with realistic modeling of the well production system, is essential for production optimization and safe field operation. In general, the objective in developing such reservoirs is not to eliminate these phenomena entirely, but to minimize their impact through effective control strategies that ensure safe and efficient well performance. Equipping such wells with advanced autonomous control systems should therefore be regarded as a key requirement for optimizing production while maintaining reliable and safe operation.

Further investigations showed that the probability of hydrate formation under normal production conditions in actual natural gas reservoirs is relatively low. Nevertheless, the risk remains significant in localized cooling zones during well start-up, shut-in, and transient operating conditions[3]. Hydrate formation may reduce the effective flow area, increase pressure losses, decrease production rates, and disrupt equipment operation. Although chemical inhibitors, thermal treatment, mechanical cleaning, and other preventive methods are widely applied, this dissertation emphasizes the importance of incorporating hydrate formation risk into well control models and management technologies to enable its early diagnosis before operational problems occur.

Various technological approaches for controlling liquid accumulation caused by phase transformations in the near-wellbore region and inside the wellbore were comparatively evaluated. In the near-wellbore zone, the primary objective is to remobilize condensed liquids, eliminate liquid blockage, and improve the hydrodynamic communication between the reservoir and the well. This is commonly achieved through gas injection, cyclic pressure drawdown, chemical

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[3] Chen, D. Gas–Liquid Flow Pattern and Hydrate Risk in Wellbore during the Deep-Water Gas-Well Cleanup Process / Sun, Z. et al. // ACS Omega. – 2023, – 8 (14), – p. 12911–12921

treatments, and physical stimulation methods. Within the wellbore, gas lift, chemical agents, plunger lift systems, production pumps, and optimized well completion designs facilitate liquid removal, thereby improving flow stability and sustaining production. In both cases, the selection of an appropriate technology should be based on reservoir characteristics, well conditions, and techno-economic considerations[4]. This, in turn, requires more accurate diagnostic techniques and more adaptive production control systems.

Overall, the results presented in this chapter demonstrate that a thorough understanding of the thermodynamic processes governing phase behavior in gas and gas-condensate reservoirs, together with assessment of their hydrodynamic effects, is essential for optimizing well performance and ensuring safe production. Furthermore, integrating this knowledge into modern analytical and digital control frameworks is important from both scientific and practical perspectives.

Chapter Two provides a comprehensive analysis of the principal complications responsible for production decline and flow instability in gas and gas-condensate wells. The mechanisms responsible for these problems and the corresponding control strategies are systematically investigated.

Field experience indicates that, besides well testing and geophysical and laboratory analyses, comprehensive interpretation of operational data acquired during production provides one of the most effective approaches for identifying production-related complications in gas and gas-condensate wells.

For this purpose, the temporal variations of physicothermal parameters, including bottomhole, wellhead, and separator pressure (P) and temperature (T), fluid density (ρ_f), production rates of gas, condensate, water, and sand (Q), fluid composition (C_i), gas factor (G_a), water cut (S_a), mechanical impurities (M_q), technical conditions (D_q), filtration (S_s), choke opening (D_n), Christmas tree and manifold

[4] Tugan, M.F. Deliquification techniques for conventional and unconventional gas wells: Review, field cases and lessons learned for mitigation of liquid loading // Journal of Natural Gas Science and Engineering. – 2020, 83 (11).

parameters (D_{am}), as well as other physical indicators, including acoustic noise frequency (SK_t) and intensity (SK_i), vibration, and flow pulsation frequency (VT_t) and amplitude (VT_a), can be evaluated (1).

$$\begin{cases} P_{qd}, P_{qa}, T_{qd}, T_{qa}, P_s, T_s, \rho_f = f(t) \\ Q_q, Q_k, Q_s, Q_q = f(t) \\ C_i, G_a, S_a, M_q = f(t) \\ D_q, S_s, D_n, D_{am} = f(t) \\ SK_t, SK_i, VT_t, VT_a = f(t) \end{cases} \quad (1)$$

Equation (1) shows that these parameters form a unified dynamic system whose variables interact and evolve over time. Deviations from the expected behavior are treated as diagnostic indicators and classified as weak or strong signals. Timely detection of weak signals is especially important because it enables early intervention and more effective production control.

Phase diagrams of multicomponent systems show a highly sensitive relationship between mixture composition and thermodynamic state. Even minor compositional changes can markedly affect the system's phase behavior. The phase diagram constructed from the compositions of the test mixtures listed in Table 1 is shown in Figure 1.

Figure 1 shows that even a 1% increase in the heavy hydrocarbon content significantly alters the phase diagram, causing the system to shift from a single-phase to a two-phase region. Existing literature and field experience indicate that the heavy hydrocarbon content in natural gas may reach 5%.

The analysis demonstrates that, as observed in the third test, retrograde condensation may occur even when the heavy component content is below 5%, resulting in liquid accumulation in different parts of the production system and the transition from single-phase to two-phase flow.

Table 1.

Composition of the test mixtures

Component, Mole %	Test 1	Test 2	Test 3
N_2	6.25	6.25	6.25
CO_2	2.34	2.34	2.34
C_1	80.13	80.13	80.13
C_2	7.24	7.24	7.24
C_3	2.35	2.35	2.35
iC_4	0.72	0.22	0.22
nC_4	0.85	0.35	0.35
iC_5	0.09	0.59	0.09
nC_5	0.03	0.53	0.03
C_6	-	-	0.5
C_{7+}	-	-	0.5

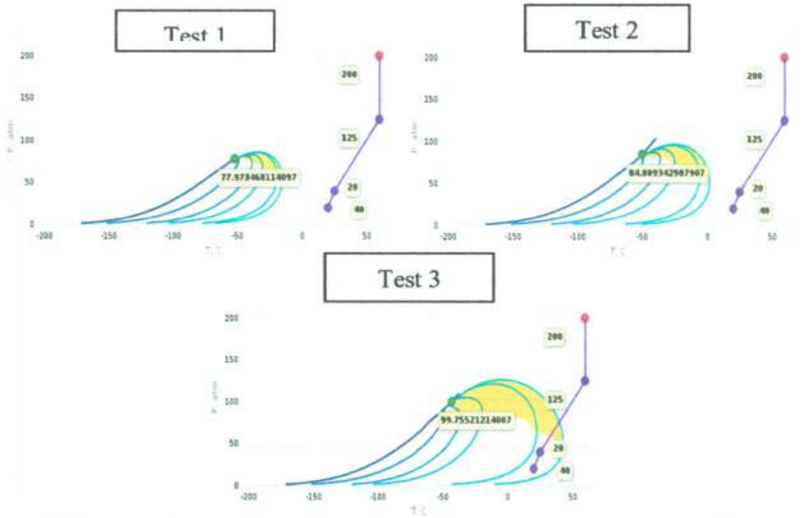

Figure 1. P–T phase diagram of hydrocarbon mixtures with different compositions

The flow toward the wellbore in a homogeneous medium was analyzed using the diffusion equation, showing that fluid density exhibits harmonic time-dependent behavior during filtration. This approach was extended to gas-condensate systems, assuming that retrograde condensation in porous media begins at higher pressures than those observed in a PVT cell. Based on this concept, a new four-zone near-wellbore model was proposed (Figure 2). It was demonstrated that this behavior increases condensate losses and reduces reservoir productivity; therefore, phase behavior and the stability of dispersed systems should be incorporated into production and control models.

According to the proposed model, Zone I represents the condensate blockage region; Zone II is the transition zone where gas and condensate flow simultaneously; Zone III corresponds to pressures approaching the retrograde condensation point, where condensate accumulates as a dispersed phase and promotes liquid blockage growth; and Zone IV is the region where only gas flow exists.

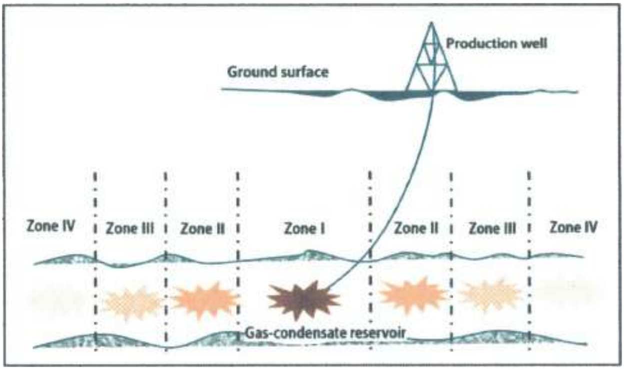

Figure 2. Schematic illustration of fluid phase transformations in the near-wellbore zone

The temporal variation of condensate saturation in each of the zones shown in Figure 2 is described by Equation (2), based on the general theory of oscillations:

$$S_i = S_{ai}\cos(\omega_{si}t + \varphi) \quad (2)$$

where S_i is the condensate saturation in the i-th zone, S_{ai} is the oscillation amplitude, ω_{si} is the filling–drainage frequency, t is time, and φ is the initial phase of the process.

Because the filtration velocity, flow area, and pressure gradient differ from one zone to another, the amplitude, frequency, and period of condensate saturation also vary. From Zone I to Zone IV, the oscillation frequency gradually decreases, and the superposition of oscillations generated in different zones produces complex bottomhole pressure fluctuations. This behavior was confirmed by comparison with field observations. As an example, the time dependence of bottomhole pressure for a gas-condensate production well is presented in Figure 3.

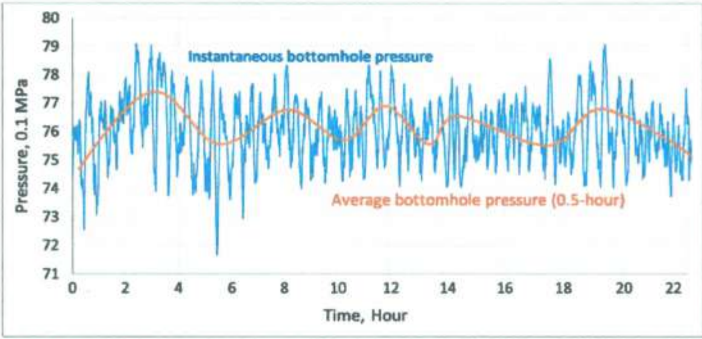

Figure 3. Variation of bottomhole pressure over time

Thus, the origin of pressure fluctuations with varying amplitudes, frequencies, and periods in bottomhole pressure behavior was explained, and it was proposed that this phenomenon be considered an important factor in well control technologies.

In general, the presence of liquid during gas flow creates a two-phase flow regime, causing deviations from classical models and increasing uncertainty in data interpretation. Therefore, solving this problem requires an integrated approach. Continuous monitoring of production parameters and proper interpretation of pressure build-up tests enable more accurate process evaluation and more effective selection of production control strategies.

The analysis shows that, after a producing well is shut in, changes in flow dynamics, fluid composition, phase behavior, and pressure–temperature–volume relationships cause the bottomhole pressure to vary non-monotonically with time. The main features of this behavior are:

1. Pressure build-up becomes non-monotonic when the gas–oil ratio exceeds 90 m³/m³, particularly above 350 m³/m³.

2. Pressure reaches its peak within the first 0–1 h, decreases during 1–2 h because of phase redistribution, and stabilizes after approximately 5 h.

3. When water cut exceeds 15–20%, phase redistribution occurs in two stages, resulting in a longer stabilization period.

The physical basis of this non-monotonic behavior is that, after well shut-in, the fluid entering the reservoir contributes not only to pressure buildup but also to compensating for volume changes occurring within the wellbore. This interaction can be expressed by the following volume balance equation:

$$V_{doh} = V_{qdzd} + V_{qdzdd} + V_{qgd} + V_{qggh} - V_{qgsh} \text{ və } V_i = f(P,T,C) \tag{3}$$

Here, V_{doh}denotes the volume of fluid entering the well, while the remaining terms represent the volume of the near-wellbore zone (V_{qdzd}), the deformed near-wellbore volume (V_{qdzdd}), the wellbore volume (V_{qgd}), the volume of the enlarged wellbore section (V_{qggh}), and the compressible fluid volume (V_{qgsh}), respectively. Since these volume components depend on pressure, temperature, and fluid composition, pressure build-up is governed not only by reservoir inflow but also by their combined effects. Neglecting these factors may lead to significant errors in the evaluation of hydrodynamic parameters.

Studies based on field data indicate that hydrate formation is rarely observed under normal operating conditions in gas production wells. The pressure–temperature analysis presented in Figure 4 shows that the operating points of both stable wells and unstable wells with declining production lie on the safe side of the hydrate stability curves. Under typical wellhead pressures of 3.5–70 MPa and temperatures of 20–120°C, hydrate formation is generally unlikely. However, during transient operating conditions, in localized cooling zones, and particularly downstream of the wellhead choke where pressure drops sharply, the likelihood of hydrate formation may increase. Because hydrate-related problems can have serious operational consequences, this risk should always be considered, and appropriate technological, thermal, and chemical prevention measures should be incorporated into well design. The effectiveness of any preventive method largely depends on its timely, appropriate, and well-targeted application.

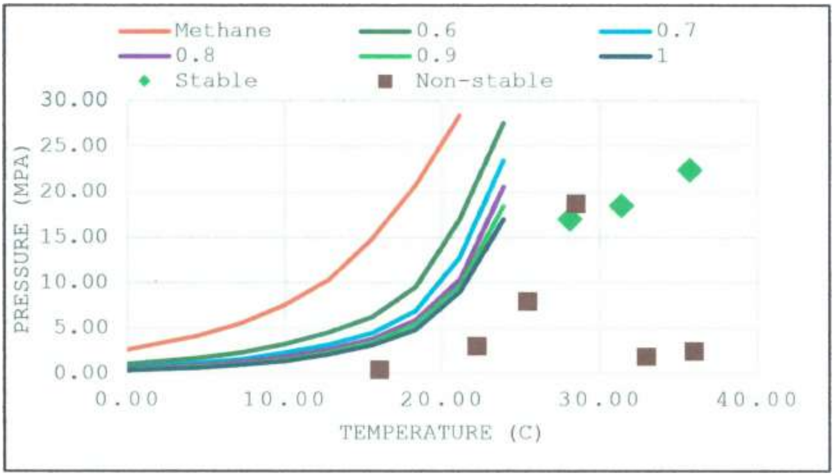

Figure 4. Pressure-temperature analysis of hydrate formation conditions in gas wells

The analysis shows that detecting and eliminating problems in gas production wells only after they occur cannot be considered an efficient approach. From both operational and safety perspectives, a more effective strategy is to predict potential well complications in advance and identify the weak signals that indicate their onset.

Chapter Three examines the scientific and practical limitations of existing methods for the early diagnosis and prediction of liquid loading in gas production wells and proposes new models to overcome these shortcomings.

Experimental observations and classical theory show that liquid loading in gas and gas-condensate wells is a dynamic process that manifests itself through changes in physical and hydrodynamic parameters at an early stage. Variations in gas and liquid production rates, pressure and temperature oscillations, as well as acoustic and vibration anomalies, can therefore serve as important diagnostic indicators. However, because such signatures may arise from different causes, existing methods often fail to detect, diagnose, and predict them accurately at the initial stage or produce significant errors.

Classical theoretical and empirical models were analyzed, revealing that their applicability is limited by the complexity of multiphase flow, varying well and reservoir conditions, challenges in fluid mechanics, and insufficient data. These factors were identified as the principal obstacles to developing a reliable and universal prediction model.

To overcome the limitations of conventional approaches, a decision tree algorithm was employed. The algorithm represents the nonlinear relationship between gas flow rate and wellhead pressure using simple if–then decision rules, allowing straightforward interpretation of the prediction results.

$$Gini\ index\ (t) = 1 - \sum_{i=1}^{n} p_i^2 \tag{4}$$

Here, t denotes the current node of the decision tree, while p_i^2 represents the proportion of samples belonging to each class. The Gini index measures node impurity, selecting the split with the lowest value for optimal classification. Its computational efficiency and simplicity make it well suited for practical applications.

The model was developed using a dataset of 228 samples, with 70% allocated for training and 30% reserved for independent testing. The results showed a classification accuracy of 80%, demonstrating that the model provides a more reliable approach for the rapid diagnosis of liquid loading in gas production wells than conventional methods. The decision rule of the first decision tree, constructed using gas flow rate (Q) and wellhead pressure (P) as input variables, is expressed by the following equation:

$$MY = \begin{cases} 1, \; Q \leq 15078.45 \text{ və } P \leq 6.85 \\ 0, \; Q \leq 15078.45 \text{ və } P > 6.85 \\ 1, \; 15078.45 < Q \leq 75365.30 \text{ və } P \leq 19.65 \\ 0, \; 15078.45 < Q \leq 75365.30 \text{ və } P > 19.65 \\ 0, \; Q > 75365.3 \end{cases} \quad (5)$$

Here, the model output is represented by the variable MY, where MY = 1 indicates that the well is liquid loaded, whereas MY = 0 corresponds to normal operating conditions. Equation (5) shows that the model first classifies the gas flow rate into predefined intervals and then evaluates the wellhead pressure within each interval to generate the final decision.

Because the highly nonlinear nature of multiphase flow limits the capability of decision trees, an artificial neural network was implemented to improve prediction accuracy. As expressed by Equation (6), the model learns the complex nonlinear relationships among the input variables and predicts the probability of liquid loading based on their combined influence.

$$y = f\left(\sum_{i=1}^{n} w_i x_i + b\right) \quad (6)$$

Here, x_i denotes the input variables, including wellhead pressure and gas flow rate; w_i the weight coefficients; b the bias term; f the activation function; and y the model prediction.

The model was developed using the same dataset of 228 samples, with 85% used for training and 15% reserved for independent testing. The five-layer neural network employed ReLU and Sigmoid activation functions, the Adam optimizer, and 150 training epochs. The overall architecture of the developed artificial neural network is shown in Figure 5.

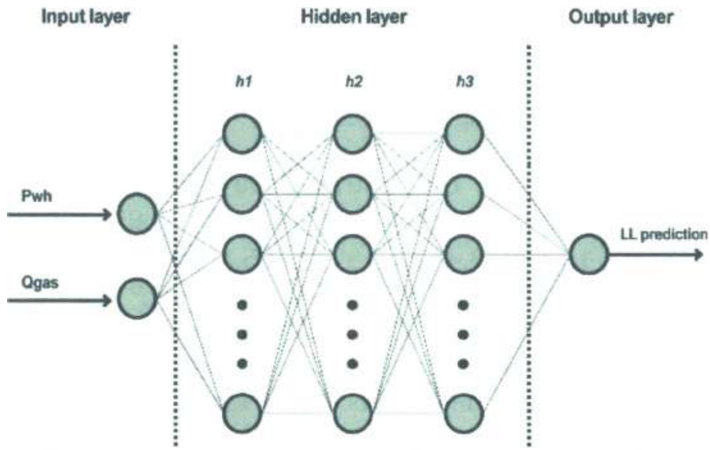

Figure 5. Architecture of a five-layer neural network system

The network consists of input, hidden, and output layers. The input layer receives the initial data, the hidden layers process it through successive transformations, and the output layer generates the final prediction. Among four models using different input combinations, the model incorporating both wellhead pressure and gas flow rate achieved the best performance, with a classification accuracy of 80%. Further comparison showed that the artificial neural network outperformed the decision tree on complex datasets, although its predictions were less interpretable.

To evaluate the proposed models, comparative testing was performed using two independent datasets published by Coleman and Veeken. The results obtained from Coleman's dataset of 50 vertical gas wells are presented in Table 2.

Table 2.

Forecast results of different models on Coleman's data set

	Turner et al. (1969)	Li et al. (2001)	Chen et al. (2016)	Liu et al. (2018)	I Decision Tree model	II Decision Tree model	ANN model
Correct predictions number	19/50	2/50	0/50	22/34	42/50	44/50	45/50
Correct predictions percentage (%)	38%	4%	0%	65%	84%	88%	90%

The conventional models showed relatively low accuracy: the Turner model achieved 38%, the Li model 4%, and the Chen model 0%, whereas the Liu model reached 65%. In contrast, the proposed Decision Tree I and Decision Tree II models achieved accuracies of 84% and 88%, respectively, while the ANN model attained the highest accuracy of 90%.

The results obtained using Veeken's dataset, consisting of 67 predominantly deviated gas wells, are presented in Table 3.

Table 3.

Forecast results of different models on VeeKen's dataset

	Turner et al. (1969)	Li et al. (2001)	Chen et al. (2016)	Liu et al. (2018)	I Decision Tree model	II Decision Tree model	ANN model
Correct predictions number	0/67	0/67	3/67	56/67	52/67	52/67	55/67
Correct predictions percentage (%)	0%	0%	5%	84%	78%	78%	82%

For this dataset, the Turner and Li models failed to correctly predict any cases, while the Chen and Liu models achieved accuracies of 5% and 84%, respectively. The proposed decision tree models reached an accuracy of 78%, whereas the ANN model achieved 82%.

As demonstrated, the effectiveness of the proposed models largely depends on the availability of high-quality and reliable data. However, in depleted reservoirs and long-producing wells, acquiring and processing such data is not always feasible. These limitations highlight the need for further research to extend the applicability of the proposed approaches and improve their reliability under data-scarce conditions.

Chapter Four presents the results of the theoretical and practical investigations, together with the development of a new technology for more intelligent control of gas production wells.

Liquid accumulation in a gas well increases the hydrostatic pressure, causing the well to transition from the normal (N) regime to the loaded (L) regime. Once the liquid column is removed, the well returns to the N regime and subsequently enters the unloaded (U) regime, resulting in cyclic pressure fluctuations. If the liquid cannot be completely lifted, the well eventually ceases production. As pressure and temperature decrease, the flow regimes evolve sequentially into: (1) highly dispersed state, (2) mist-like state, (3) mist and droplets, (4) mist and annular-like state, (5) annular, and (6) slug flow (Figure 6).

Since liquid loading develops gradually rather than suddenly, the subtle changes occurring in its early stages are difficult to detect. This highlights the limitations of conventional deterministic and empirical models and emphasizes the need for advanced diagnostic approaches capable of learning temporal dependencies.

The liquid loading process was evaluated using the pressure-loss balance, and analytical expressions were employed to determine the onset of liquid accumulation. The analysis showed that the temporal variation of gas production rate, bottomhole pressure, and wellhead pressure constitutes the principal diagnostic indicators of the process.

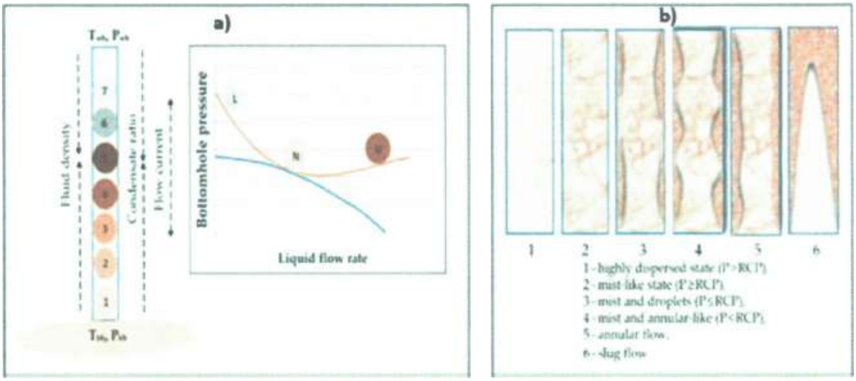

Figure 6. Flow regimes of gas-condensate fluids in the production tubing

It was also demonstrated that, even under limited-data conditions, the time-dependent behavior of these parameters provides reliable diagnosis of liquid loading. Therefore, a GRU model, capable of efficiently processing sequential time-series data, was selected as the optimal solution. Figure 4 illustrates the architecture of the GRU cell.

The GRU architecture consists of reset and update gates that determine which information from the previous hidden state is retained and which is updated. This process is expressed by Equation (7):

$$\tilde{h}_t = (1 - z_t) \odot h_{t-1} + z_t \odot \tilde{h}_t \tag{7}$$

where h_{t-1} represents the previous hidden state, $\tilde{h}_t$ the newly learned information, and z_t the update gate controlling the balance between them. This mechanism enables the model to learn long-term temporal dependencies and more accurately track subtle changes in production behavior. Based on this approach, the model was applied for the first time to the early prediction of liquid loading in gas production wells.

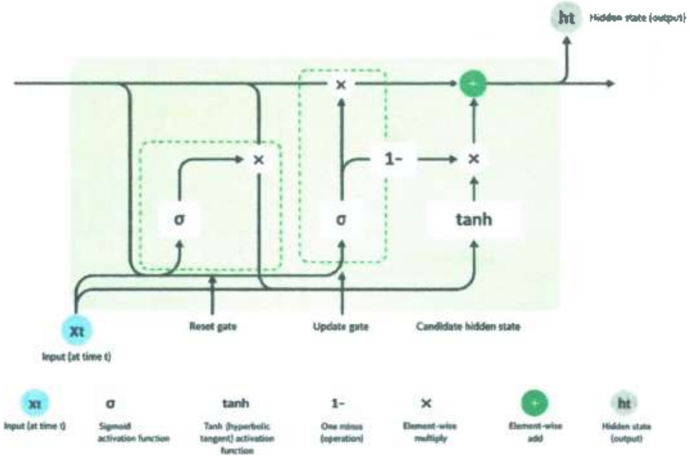

Figure 7. Structure of the GRU cell

The GRU model was developed using approximately 1,500 days of gas production data, divided into 1,200 days for training and 300 days for testing. A 10-day input window normalized with the MinMaxScaler method was used, while the model consisted of four GRU layers containing 50, 30, 30, and 20 neurons, respectively. The model achieved a mean squared error (MSE) of 78.58, a mean absolute error (MAE) of 3.35, and a mean absolute percentage error (MAPE) of 3.98%, demonstrating high accuracy for short-term gas production forecasting and early diagnosis of liquid loading.

Figure 8 compares the model predictions with the actual gas production rate. The GRU model predicted production with high accuracy during stable flow periods and identified abrupt production changes with only a one-day delay. This delay is attributed to the recurrent neural network architecture, which generates predictions using contextual information from preceding time steps. Nevertheless, the model adapted rapidly to changing conditions, demonstrating strong potential for real-time monitoring and early warning applications.

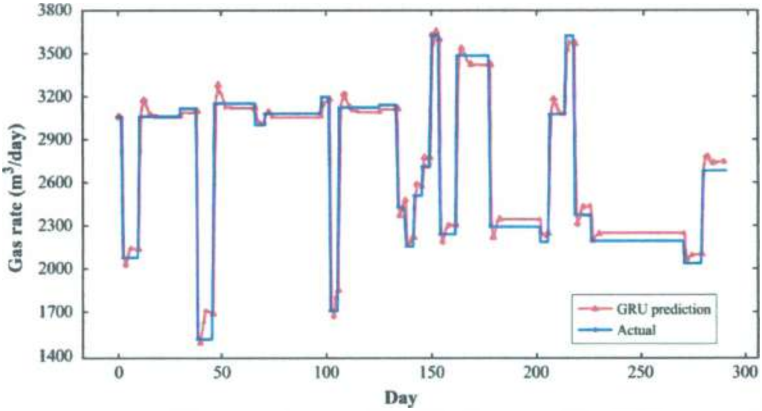

Figure 8. Comparison of GRU model predictions and actual gas production rate during the testing period

In gas-condensate wells, problems such as liquid loading, sand production, hydrate formation, water breakthrough, and paraffin or salt deposition may produce similar pressure and production responses. Consequently, conventional monitoring methods based on individual parameters are insufficient to accurately identify the underlying cause. To improve diagnostic accuracy, detect unstable flow regimes at an early stage, and automatically optimize well operating conditions, an integrated intelligent control system was proposed. The overall architecture of the proposed system is presented in Figure 9.

Within the proposed system, the decision tree and artificial neural network models evaluate the current well condition in real time and generate operational control decisions, while the GRU model analyzes the temporal behavior of gas production to predict unstable operating regimes and the risk of liquid loading. Data acquired from wellhead instrumentation, bottomhole pressure gauges, sand detectors, and gas, condensate, and water flowmeters, together with the outputs of the machine learning models, are processed on a unified platform and transmitted to the Liquid Loading Controller (LLC).

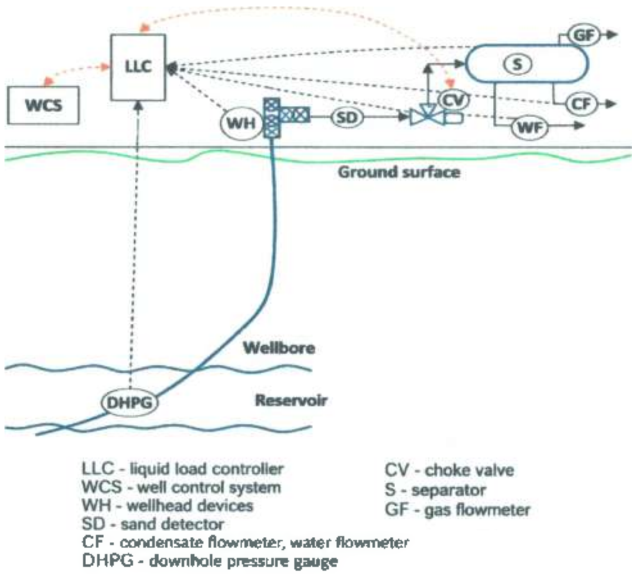

Figure 9. Schematic illustration of the wellhead choke and possible flow regimes in a gas-condensate well

The LLC performs an integrated analysis of all available information to assess the current well condition. For example, as shown in Figure 10, a decrease in wellhead pressure (Pwh) accompanied by an increase in bottomhole pressure (Pbh) and a decline in gas rate, while water production, sand detector readings, and hydrate indicators remain unchanged, is interpreted as evidence of condensate loading. Under these conditions the outputs of the GRU and other machine learning models switch from 0 to 1, confirming the occurrence of liquid loading. The system then automatically generates a control signal to adjust the position of the control valve (CV), thereby optimizing the well operating regime.

The proposed system is capable of detecting not only liquid loading but also other unstable flow conditions, including sand production, gas hydrate formation, water breakthrough, and paraffin or salt deposition. Depending on the identified problem, the corresponding warning and control signals are transmitted to the Well

Control System (WCS), where appropriate corrective actions are initiated. Consequently, by integrating artificial intelligence models, sensor data, and automated control mechanisms, the proposed system enables real-time well diagnostics, early detection of liquid loading, and safer, more stable, and more efficient operation of gas-condensate wells.

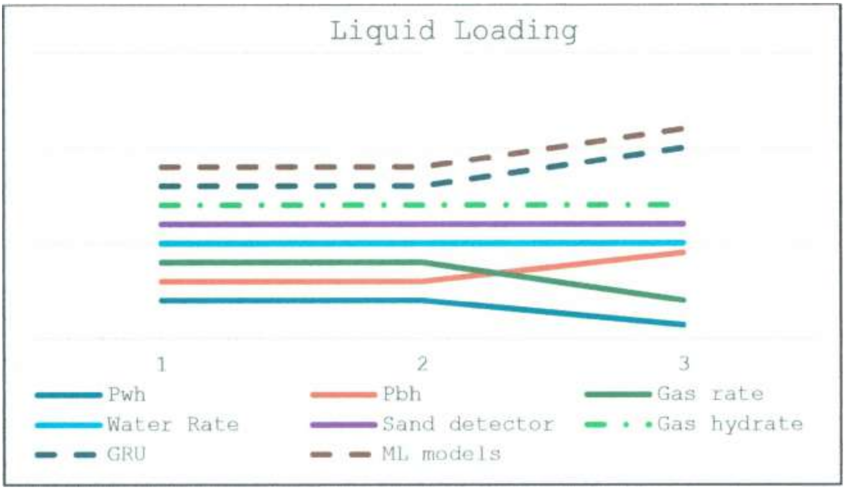

Figure 10. Diagnostic indicators for liquid loading detection

MAIN RESULTS

1. Analysis of the conducted research showed that, during fluid flow from the reservoir toward the wellbore, the gas–liquid system transforms into an aerosol–colloidal state composed of liquid clusters. The large specific surface area of these dispersed particles generates adsorption forces with the rock grains, resulting in immobile condensate accumulation within the well drainage zone. Based on this concept, a four-zone reservoir model incorporating aerosol and dispersed phases was proposed in addition to the conventional three-zone model, allowing more accurate evaluation of near-wellbore parameters [1, 2, 3].

3. The study showed that, under normal operating conditions, the pressure and temperature of gas wells generally remain outside the hydrate stability region; therefore, hydrate formation does not represent a persistent operational risk. However, during transient operations, such as well start-up and shut-in, or in localized cooling zones within the wellbore, rapid temperature reduction may create favorable conditions for hydrate crystal formation. Consequently, hydrate-related risks should be incorporated into well control technologies.

4. It was established that liquid loading in gas-condensate wells is not a sudden event but a progressive process accompanied by early changes in production parameters. Timely monitoring of production decline or fluctuations, pressure and temperature oscillations, acoustic signals, and other physical indicators in real time is therefore essential for early diagnosis of this phenomenon [14, 15].

5. During the interpretation of pressure build-up tests in gas-condensate wells, phase redistribution and condensate dropout considerably distort pressure-derivative curves. Therefore, accurate estimation of reservoir permeability and skin factor requires consideration of wellbore storage effects together with physical and thermal processes associated with phase transformations and phase slippage [4].

6. The effectiveness of methods used to remove liquid loading in gas production wells, including gas lift, plunger lift, and various artificial lift systems, depends on the specific operating conditions of

each well. In addition to techno-economic criteria such as reservoir pressure, gas–liquid ratio, and well geometry, comprehensive application of accurate diagnostic methods is essential when selecting the appropriate technology [7, 14].

7. The decision tree and artificial neural network models developed for predicting liquid loading in gas production wells achieved prediction accuracies of 80–90%. These data-driven approaches identify the onset of liquid loading in both vertical and deviated wells more reliably than conventional empirical models, such as the Turner model [5, 8, 9, 10, 11, 13].

8. A GRU-based deep learning model using only gas production time-series data was developed. Even when bottomhole and wellhead measurements are unavailable, this single-variable model effectively captures gas production dynamics and detects abrupt changes and potential liquid-loading risks with minimal delay. Moreover, when gas production data are unreliable, the same GRU framework can be implemented using bottomhole or wellhead pressure measurements [12].

A new automated control technology based on the self-optimizing principle for gas production wells was developed using fluid composition and the pressure differential between the bottomhole and wellhead. Integrated with machine learning and artificial intelligence models, this intelligent system stabilizes fluid flow, rapidly detects potential well malfunctions, and optimizes well operation in real time [6, 14, 15].

The main results of the dissertation are reflected in the following scientific works:

1. Alıyev, K.F., Ağasıyev, Ə.E. Hasilat quyusunda döyüntülərin quyudibi zonasında süzülmə prosesinə təsirinin qiymətləndirilməsi // Ümummilli Lider Heydər Əliyevin 100 illik yubileyinə həsr olunmuş tələbələrin 72-ci elmi-texniki konfransı, – 2023, – s. 123–131.

2. Alıyev, K.F., İsmayılov, R.Z. Retroqrad kondensasiya zamanı qazkondensat sistemlərinin kolloid hala keçməsinin fiziki-termodinamiki mahiyyəti haqqında // PAHTEI – Proceedings of Azerbaijan High Technical Educational Institutions, – 2024, 40 (5), – p. 79–88.

3. Fətəliyev, V.M. Təbii rejimdə işlənən yataqlarda qazkondensat flüidlərinin dispers hal keçidləri və onların fiziki-termodinamik mahiyyəti haqqında / V.M. Fətəliyev, N.N. Həmidov, H.R. Abbaszadə, K.F. Alıyev // Azərbaycan Neft Təsərrüfatı, – 2024, (09), – s. 32-39.

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8. Aliyev, K.F. Natural gas utilization based on full life cycle assessment: comparative assessment of environmental indicators of natural gas and other types of fuels // IV International Ordu Scientific Research Congress, – Ordu, Türkiye, – 2025, – p. 596–604.

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15. Fataliyev, V.M., Hamidov, N.N., Aliyev, K.F. Methods for optimizing the operation of a gas-condensate well under retrograde condensation condition // International Scientific Conference dedicated to the 100th anniversary of the birth of National Leader Heydar Aliyev, – ASOIU, Baku, 2023.

Author's contribution to the published works:

Publications [5, 6, 7, 8, 9] were completed independently by the author.

In publications [1, 2, 3, 4, 10, 11, 12, 13, 14, 15] the author was responsible for formulating the research problem, developing and justifying the research methodology, analyzing and validating the obtained results, and preparing the manuscripts for publication.

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