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Practice Design and Field Performance of a Continuous Gas Recirculation System for Liquid Unloading in High-Water-Production Gas Wells

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Abstract Liquid loading is a major operational challenge in gas wells with high water production, often resulting in reduced gas deliverability and premature well shut-in. To address this problem, this study investigates a continuous gas recirculation system that utilizes a portion of the produced natural gas as the lifting medium. The system compresses and reinjects the recycled gas through the tubing–casing annulus to enhance liquid transport and sustain gas production. The engineering design incorporates critical gas velocity calculations, gas injection parameter determination, wellbore pressure-loss analysis, and surface gathering-system considerations. The proposed configuration was implemented in the Y well group of the Yan'an Gas Field, Ordos Basin, China, to evaluate its field applicability.Field observations showed that Well Y1 maintained a daily gas production rate of 2.5–5.5 × 10^4 m^3/d and a daily water production rate of 180–250 m^3/d, with a circulating gas injection rate of 2.5–5.0 × 10^4 m^3/d. Well Y0 achieved a relatively stable daily gas production rate of approximately 2.0 × 10^4 m^3/d. In addition, the study presents a 20-year production forecast comparing the continuous recirculation system with conventional drainage measures and a no-treatment scenario. The field results indicate that continuous gas recirculation can support liquid unloading and restore gas production in severely liquid-loaded wells. This study provides an engineering basis for the design and field application of continuous gas recirculation systems in gas wells with high water production.
Keywords High-yield Water-gas Wells, Drainage and gas production process, Field Tests

Introduction As a clean energy source, demand for natural gas is growing steadily, and its role in the nation's economic development is becoming increasingly prominent. Among the gas fields currently under development in China, water-flooded gas fields account for more than 80%[1].Taking the Yan'an Gas Field as an example, this field is located in the southern part of the Ordos Basin and consists of low-permeability, tight, layered gas reservoirs. As development has entered the mid-late development stage, significant amounts of formation water have intruded into the reservoir, with some gas wells producing as much as several hundred m^3/d. The problem of fluid accumulation in gas wells is becoming increasingly severe, significantly affecting the field's stable production and recovery rate[2]. As gas fields enter the mid-to-late stages of development, the problem of fluid accumulation in the wellbores of in high-yield water-gas wells has become increasingly prominent, emerging as the core issue limiting stable production and recovery rate improvement in gas fields. Fluid accumulation not only reduces the gas well's fluid-carrying capacity and causes production to decline sharply until the well is flooded and production ceases, but it also triggers a water lock effect, causing reservoir damage and leading to problems such as equipment corrosion and scaling, which severely impact the production cycle and economic benefits of gas wells [3].

To address liquid accumulation in gas wells, two main categories of processes have been established: physicochemical methods (primarily foam drainage, plunger gas lift, and velocity string) and mechanical methods[4]. These are supplemented in the mid- to late stages of production by measures such as gas lift and coiled tubing to restore production. However, for high-yield water-gas wells that produce large volumes of water and require long-term, continuous, and stable drainage, existing conventional methods generally have limitations: foam drainage has limited liquid-carrying capacity; plunger air lift and velocity string operations are discontinuous; and equipment such as submersible electric pumps has poor adaptability to conditions with high gas-to-liquid ratios and incurs high maintenance costs[5]. Therefore, developing a new drainage and gas production process capable of achieving continuous, stable, and efficient drainage while adapting to the unique production patterns of high-yield water-gas wells has become an urgent technical challenge in current gas field development. The Continuous cyclic Drainage and Gas Production Process utilizes downhole or surface pressurization equipment,provide a continuous supply of external energy to the wellbore fluid,It is expected to fundamentally improve thedrainage dynamics in high-yield water-gas wells , It is a potentially effective approach to achieving long-term, stable production and extraction.At present, this process still requires further research in terms of theoretical design, equipment compatibility, and on-site application optimization.

To address the challenges associated with liquid loading and unstable production in gas wells with high water production, this study investigates the design and field performance of a continuous gas recirculation system. The system utilizes compressed produced gas to provide sustained lifting assistance through annular reinjection. The investigation focuses on three aspects: (1) determining gas injection requirements based on critical liquid-carrying velocity and wellbore flow characteristics; (2) integrating gas compression, separation, recirculation, and gathering facilities into a field-operable production system; and (3) evaluating the system's performance using production data from the Y well group in the Yan'an Gas Field. In addition, production forecasting and economic assessment are used to examine its potential long-term application. The findings are intended to provide practical guidance for continuous liquid unloading and production management in gas wells with high water production.

1 Design of a Continuous cyclic Drainage and Gas Production Process

1.1 Principles of Process Design

The principle behind the continuous cyclic drainage and gas production process involves using a specific compressor to pressurize a portion of the natural gas produced from the wellbore, which is then reinjected to the well bottom through the annular string. The injected natural gas mixes with the gas produced from the formation and rises through the production tubing to the surface. After separation and processing, it is pressurized again and reinjected to the well bottom, thereby forming a closed loop.Through this cycle, the flow velocity of natural gas within the wellbore is significantly increased, thereby enhancing its ability to carry liquid and effectively preventing fluid accumulated at the bottom of the well. This process is primarily designed to address the problem of severe liquid accumulation—caused by a rising water-to-gas ratio during production in high-yield water-gas wells—which leads to a decline in production. It aims to ensure stable production from gas wells and improve recovery rates.Compared with conventional processes such as foam drainage or plunger gas lift, the continuous cyclic drainage and gas production processoffers the advantage of not requiring the injection of chemicals or additional equipment into the wellbore; Instead, it relies on the natural gas's own circulation to maintain pressure and achieve continuous fluid production. This method is particularly suitable for gas wells with high daily water production and severe depletion of formation energy.

The principle behind this process can be summarized in the following four key technical points:1. Dynamic control of production pressure differential: By adjusting the gas injection rate and pressure, the bottom-hole flow pressure differential is modified to maintain the gas well in an optimal liquid-carrying production state; 2. Optimization of gas injection flow rate and injection volume: Based on the real-time gas-to-water ratio, well depth, and string configuration, calculate and control the optimal gas injection parameters to avoid Insufficient fluid flow from the bottom of the well; 3. Optimizing the economic model: Striking a balance between drainage efficiency and compressor operating costs, determining an economically viable circulation air volume, and maximizing benefits; 4.Adaptive response of the gathering and transportation system: Taking into account the constraints imposed by the pressurization cycle on pressure and gas volume fluctuations in the onshore gathering and transportation pipeline network, design a reasonable pressure regulation plan.

1.2 Changes in Production Pressure Differential

The reservoir supply pressure is the driving force that propels natural gas toward the wellbore, while the production differential is the key indicator of a gas well's production efficiency[6]. When a gas well produces large amounts of liquid, the accumulation of liquid in the wellbore causes the bottomhole flow pressure (Pwf) to rise, thereby reducing the production differential and causing the well's production rate to decline[7]. In the continuous cyclic drainage and gas production process, the production pressure differential (ΔP) is defined as the difference between the formation pressure (Pres) and the bottomhole flow pressure (Pwf), as shown in Equation (1):

$$\Delta P = P_{\text{res}} - P_{\text{wf}} \tag{1}$$

In the equation, Pres represents formation pressure (MPa); Pwf represents bottomhole flow pressure (MPa).

The calculation of the bottom-of-well flow pressure Pwf (MPa) requires a comprehensive consideration of the flow characteristics of both the gas and liquid phases, injection parameters, and wellbore geometry[8]. Based on the steady-state energy equation, see Equation (2):

$$P_{\mathrm{wf}} = P_{\mathrm{res}} - \Delta P_{\mathrm{g}} - \Delta \mathrm{P}_{\mathrm{fr}} - \Delta P_{\mathrm{ac}} + \Delta P_{\mathrm{in}} \quad (2)$$

In the equation, Pres represents formation pressure (MPa); Pg represents gravitational pressure drop (MPa); Pfr represents friction pressure drop (MPa); Pac represents acceleration pressure drop (MPa); and Pin represents the injection pressure contribution (MPa), which applies only to gas/liquid injection-circulation processes.

Injecting pressurized natural gas into the annulus can effectively reduce the density and height of the liquid column in the wellbore, thereby lowering the Well Bottom Flow Pressure(P_{wf}) and increasing the production pressure differential ΔP.A larger ΔP increases the flow velocity of natural gas in the wellbore, causing it to exceed the critical liquid-carrying velocity and thereby carry accumulated liquid to the surface[9]. Therefore, the essence of the Continuous cyclic Drainage and Gas Production Process is to maintain an optimal production pressure differential by dynamically regulating P_{wf}, thereby achieving efficient water and gas production[9]. Figure 1 illustrates how parameters such as bottom-hole flow pressure, wellhead oil pressure, reservoir supply pressure, and liquid level depth vary with well depth in the drainage and gas production process.As shown in the figure, as the liquid level depth increases, the bottom-hole flow pressure gradually increases while the gas reservoir supply pressure decreases. This means that the production pressure differential gradually decreases, which weakens the force driving natural gas from the reservoir toward the wellbore, resulting in a gradual decline in the gas well's production capacity.

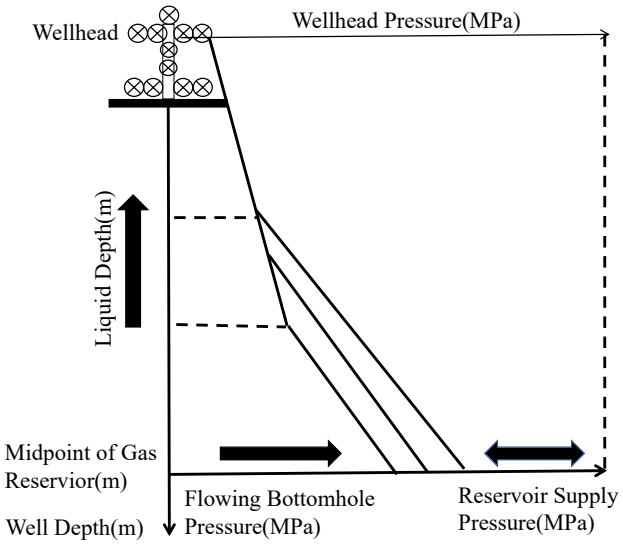


Fig.1. Graph of Changes in Bottom-of-Well Pressure Differential

2 Design of Optimal Gas Injection Flow Rate and Gas Injection Volume

In the continuous cyclic drainage and gas production process, the total gas volume at the wellhead consists of two parts: one part is separated and transported off-site, while the other part is pressurized by a compressor and reinjected into the annulus to form a cycle.Therefore, the core of process design is to determine the volume of circulating gas (i.e., the gas injection rate) that the wellhead compressor needs to supply to the wellbore.The objective of determining the gas injection rate is to ensure that the gas flow velocity within the wellbore reaches or exceeds the critical fluid-carrying velocity, thereby

preventing fluid accumulation. The calculation of the gas injection rate must take the following 3 factors into account.

2.1 Gas Pressurization and Injection

The wellhead compressor boosts the pressure of natural gas produced from the wellbore; the injection pressure typically ranges from 15 to 30 MPa. The gas is then injected into the wellbore through the annular string. The injection rate Qinj (m^3) must satisfy the critical fluid-carrying velocity requirement. Calculated using the modified Turner model[10], Equation (3) gives the minimum gas velocity Vcrit (m/s):

$$V_{\text{crit}} = \frac{1.593 \bullet \sigma^{0.25} \bullet \left(\rho_{\text{l}} - \rho_{\text{g}}\right)^{0.25}}{\rho_{\text{g}}^{0.5}} \tag{3}$$

In the equation, σ represents the liquid-gas interfacial tension (N/m); ρ_{l}、ρ_{g} represent the densities of the liquid and gas (kg/m^3), respectively.

When the target well falls outside the Tuner model, the Li Min model is used to correct it[11], as shown in Equation (4).

$$V_{\text{crit}} = 2.5 \bullet \sqrt{\frac{\sigma\left(\rho_l - \rho_g\right)}{\rho_g^{\,2}}} \tag{4}$$

The gas injection flow rate Qinj (m^3/s) required for the calculation is given in Equations (5) and (6).

$$Qinj = A \cdot \left(Vcrit - Vnat\right) \tag{5}$$

$$A = \frac{\pi D^2}{4} \tag{6}$$

In this equation, A represents the cross-sectional area of the oil pipe (m^2); Vnat represents the flow velocity of natural gas from the formation (m/s).

2.2 Amount of fluid accumulated in the wellbore

Determine the volume of accumulated liquid, V_{liquid} (m^3), using the Equation (7) shaft pressure gradient method or the acoustic liquid level measurement method[12].

$$V_{liquid} = A \cdot h_{liquid} \tag{7}$$

In the equation, A represents the cross-sectional area of the wellbore (m^2), and h_{liquid} represents the depth of the liquid level (m).

Next, calculate the amount of gas that needs to be injected during a given drainage cycle to completely remove the accumulated liquid. The purpose of calculating the periodic gas injection volume is to ensure that the total gas injection volume meets the periodic requirements of the continuous cycle[13]. At this point, the gas injection flow rate Q_{inj} is calculated using Equation (8).

$$Q_{\text{inj}} = \frac{V_{\text{liquid}} \bullet \rho_{\text{l}}}{\Delta \text{t} \bullet \rho_{\text{l}}} \tag{8}$$

In the equation, Δt is the target drainage cycle (s), ρ_l、ρ_g are the densities of the liquid and gas (kg/m³).

2.3 Gas-Liquid Mixing and Lifting

After the injected high-pressure gas mixes with the gas-liquid mixture produced from the formation at the well bottom, a low-density gas-liquid two-phase flow is formed, which rises through the production tubing to the surface.To optimize gas injection rates and accurately predict wellbore pressure drop, the Beggs-Brill method was used to calculate the pressure drop in two-phase gas-liquid flow through a vertical pipe[14].Total Pressure Drop in the Wellbore(ΔP_{total})consists of the gravitational pressure drop(ΔP_g)、the friction pressure drop(ΔP_{fr})and the acceleration pressure drop （ ΔP_{ac} ）,as equation（9）：

$$\Delta P_{total} = \Delta P_g + \Delta P_{fr} + \Delta P_{ac} \tag{9}$$

The gas injection rate must be optimized using an iterative method,Ensure the mixing flow rate $V_{mix} \geq V_{crit}$,Ensure the mixing flow rate.

2.4 Separation and Recycling

In the process (Fig.2), natural gas produced from the bottom is split into two streamsat the wellhead: the export stream and the circulation stream. The export gas is directed to a separator and then to a compressor for processing and subsequent delivery. The circulation gas, comprising a portion of the produced gas, is reinjected into the wellbore through a gas-lift valve to provide continuous lift by displacing the produced water.During the gas lift process, the injected high-pressure gas mixes with the liquid accumulated at the bottom of the wellbore to form a low-density gas-liquid two-phase flow. This significantly reduces the density of the liquid column in the wellbore, causing the liquid to be continuously lifted to the surface. By maintaining a sufficient gas lift flow rate, liquid accumulation within the wellbore is prevented, thereby ensuring stable drainage and gas production.

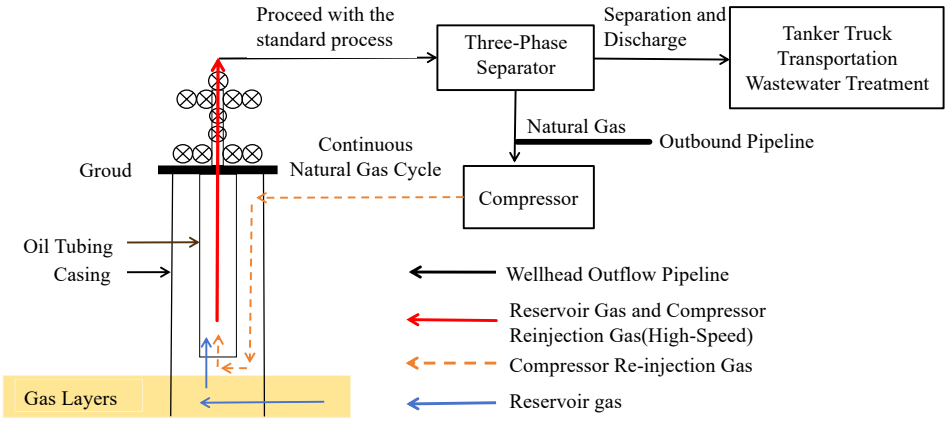


Fig.2. Flowchart of the Gas Injection Cycle for a Gas Well Compressor

During continuous cyclic water-gas separation operations, when the compressor draws gas through the wellhead gathering line, fluctuations in the instantaneous water-to-gas ratio can easily lead

to liquid carryover, causing compressor surging or a protective shutdown.To address this issue, two improvement measures are proposed: First, install a liquid separator manifold at the compressor's inlet to reduce the moisture content in the intake air; second, install a pneumatic control valve to monitor and regulate the intake air flow in real time, ensuring stable compressor operation.

3 Well Site Design

3.1 Economic Optimization

A key characteristic of low-permeability tight gas reservoirs is that average production per well is typically low, making it economically unfeasible to equip each well with its own skid-mounted compressor; Equation (10) is used to minimize costs[15].

$$C_{total} = C_{gas} \cdot Q_{inj} + C_{equip} \cdot P_{inj} \qquad (10)$$

In Equation (10), Cgas is the natural gas unit cost (CNY/m³), Cequip is the compression equipment operating and maintenance cost (CNY/MPa), and Qinj is the injection rate. Two constraints apply: (1) $Qinj \geq Qcrit$ to ensure liquid unloading; (2) $Pinj \leq Psafe$ to maintain wellbore integrity.

By minimizing the total cost function, it is possible to fully leverage the synergies among multiple wellheads at a single wellsite.In the development of cluster well fields, a circulating gas injection manifold is installed, and a single custom-built compressor is used to serve multiple wells in a specific area through distributed injection. To enhance the adaptability of the surface gathering and transportation system for high-yield water-gas wells, all produced gas at the wellsite is first pressurized using a compressor, and then a portion of the gas is reinjected into the target well.This configuration effectively mitigates the impact of fluctuations in individual well production and transmission pipeline pressure, thereby ensuring stable gas field production.

Using the methods described above, precise control over the gas injection rates for each well can be achieved in a multi-well production system. Fig.3 demonstrates the entire process of the new technology, gas production,gas-liquid separationand,gas reinjection, transportation.

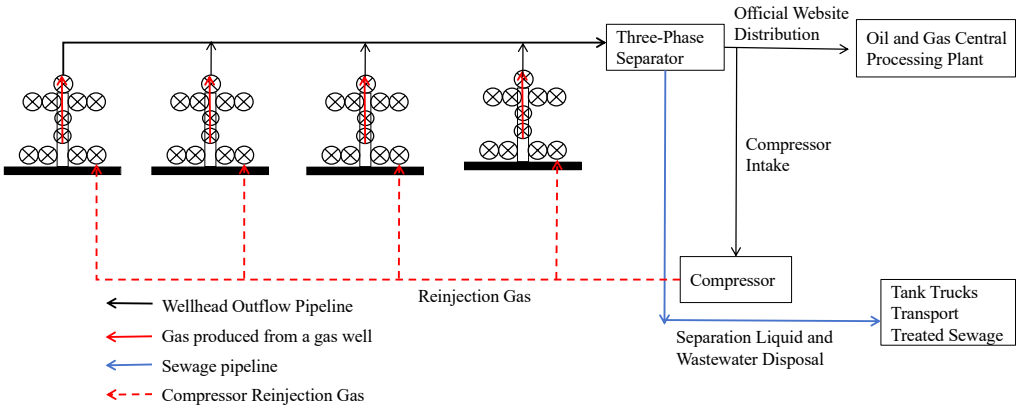


Fig.3. Process Flow Diagram for a Cluster Well Group

3.2 Gathering and Transportation Issues

In gas field development, surface constraints such as topographical limitations and pipeline network pressure thresholds have a significant impact on the regulation of production pressure differentials in gas wells.When the flow pressure at the wellhead falls below the minimum entry pressure of the transmission pipeline network, the available production pressure differential will be limited, resulting in reduced fluid carryover efficiency and, consequently, an exacerbation of fluid accumulation in the wellbore[16].To address this issue, the compressor unit should be installed upstream of the wellhead outlet, so that a portion of the pressurized natural gas is recirculated back into the wellbore to enhance the effectiveness of water drainage and gas production. For gas wells with varying levels of liquid production, this process should be designed on a case-by-case basis, as follows:

For medium-and low-liquid-yield wells, a conventional scheme is adopted: wellhead gas-liquid mixture is separated, and the dry gas is sent to the transmission pipeline. Gas velocity must exceed Turner's critical threshold to prevent liquid loading. Process sequence: wellhead → separator → transmission → gathering station.For high-water-cut wells, continuous cyclic drainage and gas production process is required using gas lift valves or jet pumps. Gas lift reduces mixture density via high-pressure gas injection; jet pumps use high-velocity fluid to entrain liquids. Process sequence: production → gas lift/jet pump → compression → annular injection → lifting → transmission → gathering station.Fig 4 shows the overall process flowchart.

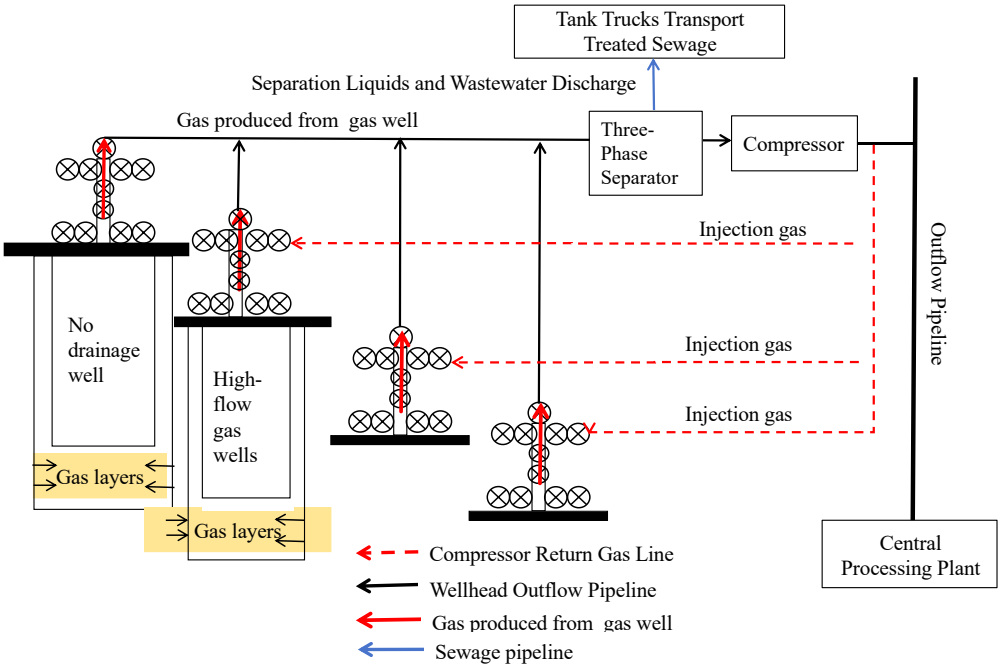


Fig.4. Flowchart of Gas Production from a Cluster of Wells

Based on the design considerations outlined in the 4 areas above, this approach implements an integrated gas production process encompassing “production, discharge, and transmission,” while simultaneously meeting the needs of gas wells with varying production conditions within the same well cluster.

4 On-Site Applications

This process was tested in four wells in the Y well group of the Yan'an Gas Field, and a field evaluation was completed.During the four-month trial period, daily gas production at Well Y-1 generally trended upward, stabilizing at 2.5 to 5.5 × 10^4 m^3 per day, with a cumulative gas production of 3.17 × 10^6 m^3.Daily water production ranges from 180 to 250 m^3, with a peak of 6.30×10^4 m^3. In contrast, daily gas production from Well Y0 remains stable at a lower rate of 2.0×10^4 m^3 .Daily water production ranges from 180 to 250 m^3, with a peak of 6.30×10^4 m^3. In contrast, daily gas production

from Well Y0 remains stable at a lower rate of 2.0×10^4 m^3.

4.1 Production Status Prior to Testing

Prior to implementation of the new process, Well Y1 had a water-free production period of only 29 days and was shut in on 2 March 2023 due to water loading, during which both high-pressure gas lift and foam drainage proved ineffective. Well Y0 experienced a water-free production period of 84 days, after which the produced WGR gradually increased to 6.7 $m^3/10^4$ m^3; intermittent production and foam drainage showed initial success but gradually lost effectiveness, and by July 2023, annulus nitrogen gas lift also failed to restore production.

4.2 Design for the Application of New Processes

The field implementation began with production resumption in the test well group, followed by application of the new process, which controls formation pressure differential through cyclic pressure-boosting gas injection to achieve water-controlled stable gas production. The four wells in the Y well group currently produce a combined daily gas rate of 5.2×10^4 m^3. However, Well Y0 is experiencing water loading, Well Y1 has high liquid production, Well Y2 exhibits low productivity, and the gas wells generally suffer from insufficient liquid-carrying capacity. The gas production flow diagram is shown in Fig. 5.To address these issues, the new process was applied to three wells Y0,Y1,and Y2,for cyclic gas injection, while the remaining wells continued production via skid-mounted equipment. At the wellhead, the produced gas is routed to a three-phase separator for gas-liquid separation. The separated natural gas then enters a compressor, where it is pressurized and reinjected into the production wells. This approach ultimately increases the gas flow velocity and enhances the liquid-carrying capacity in the wellbore, thereby achieving sustained gas production with incremental output and stable performance. During the four-month field trial, Well Y1 exhibited an overall increasing trend in daily gas production, eventually stabilising at 2.5×10^4~5.5×10^4 m^3/d, with a cumulative gas production of 3.17×10^6 m^3, daily water production is 180~250 m^3. Meanwhile, Well Y0 achieved a stable daily gas production of 2.0×10^4 m^3. These results demonstrate that the new technique can effectively restore productivity in water-loaded gas wells.

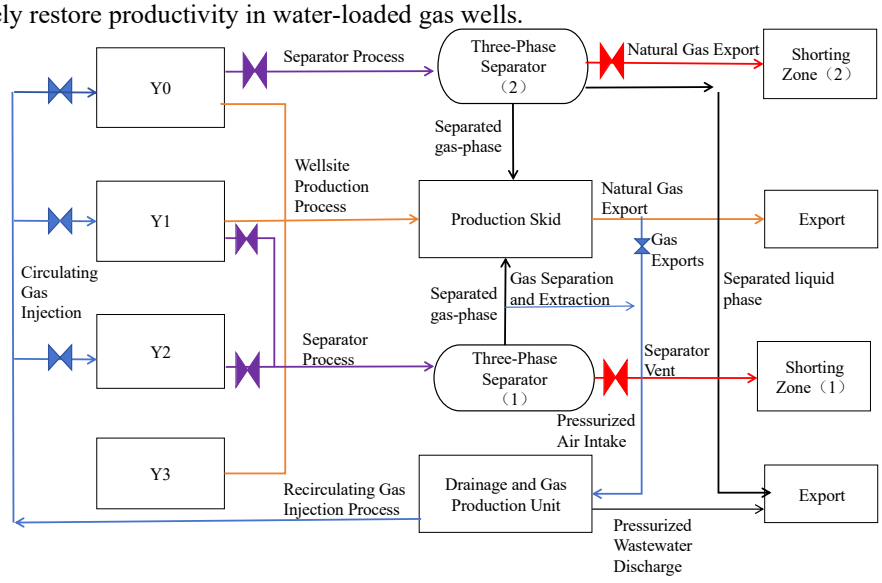


Fig.5. Flowchart of the Circulating Drainage and Gas Production Process for Well Y0

Well Y0 has a relatively high water production rate. A three-phase separator is connected to this well: after gas-liquid separation, the gas phase is routed to the production skid interface and then fed into the outflow pipeline network, while the liquid phase (produced water) is directed to the storage tank at the field station. In the later stage, when water production declines, the produced water can be routed directly to the production skid for off-site transport.Well Y1 also has a relatively high water production rate and adopts the same process configuration as Well Y0: the wellhead effluent is routed

to a three-phase separator for gas-liquid separation, with the gas phase entering the production skid interface and then feeding into the outflow pipeline network, and the liquid phase being directed to the field station storage tank. Subsequently, when water production decreases, it can likewise be routed directly to the production skid for off-site transport.Well Y2 has a relatively low water yield; it is connected directly to the production skid for off-site production.Well Y3 is a low-efficiency, low-yield well with a relatively small water output; it is also connected directly to the production skid for off-site production.The recirculating drainage and gas production unit is equipped with an intake pressure regulating valve, which allows the exhaust flow rate to be adjusted by controlling the intake pressure, thereby ensuring that the compressor operates within an appropriate load range. The compressor's exhaust flow rate can be adjusted within a range of 50% ~100%; additionally, the flow rate can be adjusted by regulating the engine speed, with an adjustment range of 70% ~ 100%.

4.3 Process Operation Situation

The wellhead and main equipment on site are connected in series, in the following order: wellhead—three-phase separator—circulating drainage and gas production unit—gas production tree—wellhead.A bypass valve is installed at the three-phase separator.Commence production in accordance with production allocation requirements.For in high-yield water-gas wells , adjust equipment operating times appropriately to manage the circulating drainage; other wells may continue production as usual.During production, production allocations, production methods, or work schedules may be adjusted based on actual production conditions.If well shutdown operations are encountered during unimpeded construction, when reopening the well, the wellhead pressure must first be reduced to a level below the safe operating pressure of the three-phase separator and the circulating drainage and gas production equipment before pressurization operations can resume. Refer to Table 1 below for production rates.

The wellhead and major equipment at the site are connected in series, in the following order: wellhead → three-phase separator → circulation drainage and gas production unit → gas production tree → wellhead.Develop production plans in accordance with production allocation requirements. For gas wells with high water output, implement cyclic water drainage operations and reasonably adjust equipment operating times; the remaining gas wells may be produced using skid-mounted equipment.During operations, dynamically adjust production allocation plans, production methods, and work schedules based on actual on-site production conditions. When reopening a well after shutdown operations, first relieve the wellhead pressure to within the safe operating pressure range of the three-phase separator and the circulating water and gas production unit before proceeding with pressurization operations. See Table 1 for specific production allocation parameters.

Table. 1 Test Well Group Operation

Well	Unrestricted flow during gas testing($10^4m^3/d$)	Oil Pressure (MPa)	Casing Pressure(MPa)	Production Allocation(m^3/d)
Y0	5.0392	4.0	20.43	4.0
Y1	3.1855	3.11	15.91	6.01
Y2	2.4705	4.29	18.54	0.8
Y3	/	/	/	/

During the implementation of the production process in the experimental well cluster, a design featuring a ring-shaped main line with bypass valves on the branch lines was adopted.This effectively

facilitates gas-liquid separation while effectively preventing sudden section plugging[17].Fig 6 shows the wellsite layout for the continuous cyclic drainage and gas production process,which clearly illustrates the flow paths of both the gas and liquid phases in this process.Due to the high water yield and high gas-to-water ratio in gas wells, the fluid produced through the wellhead tubing must pass through a three-phase separator for gas-water separation.After separation, the natural gas portion is recirculated to the compressor and injected into the annulus,

Export Section and no natural gas was diverted firstly all flows directly into the gathering and transmission pipeline network, The wastewater flows into a storage tank, where it awaits transfer to the wastewater treatment plant.The portion destined for export, along with all the natural gas that was not initially tapped, flows directly into the gathering and transmission pipeline network.

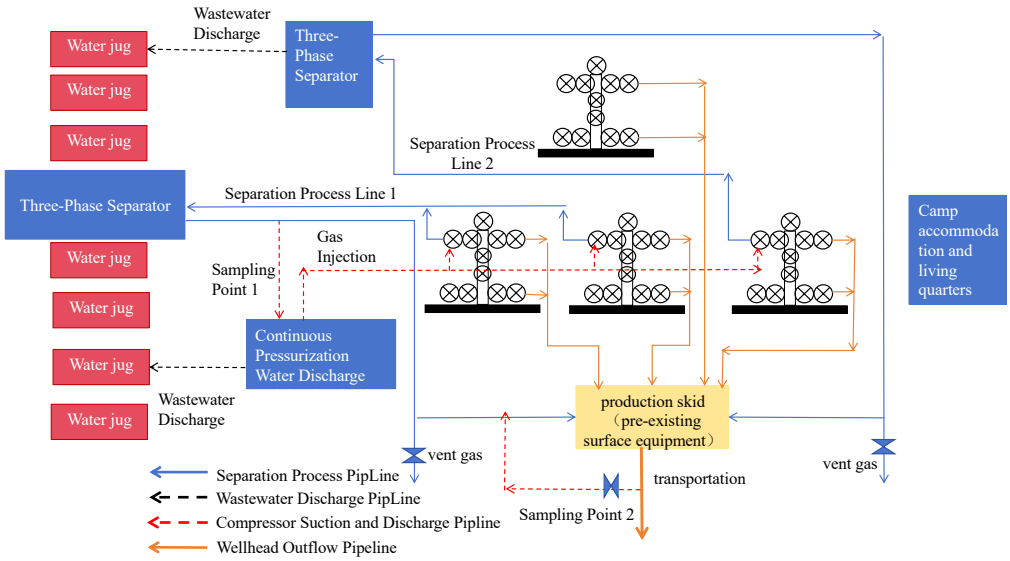


Fig.6. GroupLayout Plan of the Test Well Group

4.4 Analysis of Field Test Results

After Well Y1 resumed production, the oil pressure stabilized at 4.0 MPa and the casing pressure remained at 20 MPa, indicating that this process effectively maintained the dynamic equilibrium of the wellbore annular pressure system.The water-gas ratio gradually decreased from an initial value of nearly 100 $m^3/10^4m^3$ and stabilized within the range of 40~50 $m^3/10^4$ m^3; daily gas production stabilized at 2.5×10^4~5.5×10^4 m^3/d, and daily water production was 180~250 m^3/d.The cyclic gas injection rate corresponding to this production phase ranges from 2.5~5.0×10^4 m^3/d. As the gas injection rate increases, the wellbore's drainage capacity gradually improves, but the rate of increase in gas production shows a declining trend, indicating that the contribution of increased gas injection to gas production capacity is gradually diminishing.

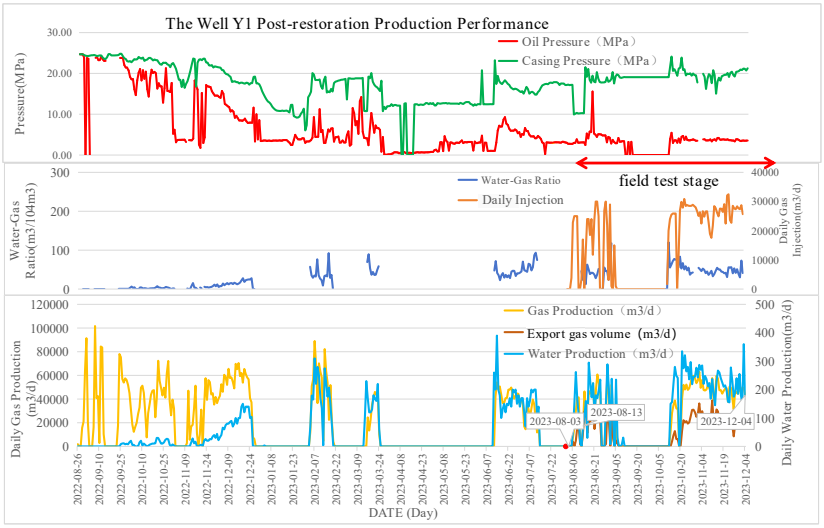


Fig.7. Production Performance of Well Y1 After Production Restoration

During the four months trial period, the well produced a total of 3.17×10^6 m^3, with daily gas production generally showing an upward trend and peaking at 6.3028×10^4 m^3, as shown in Fig. 8.

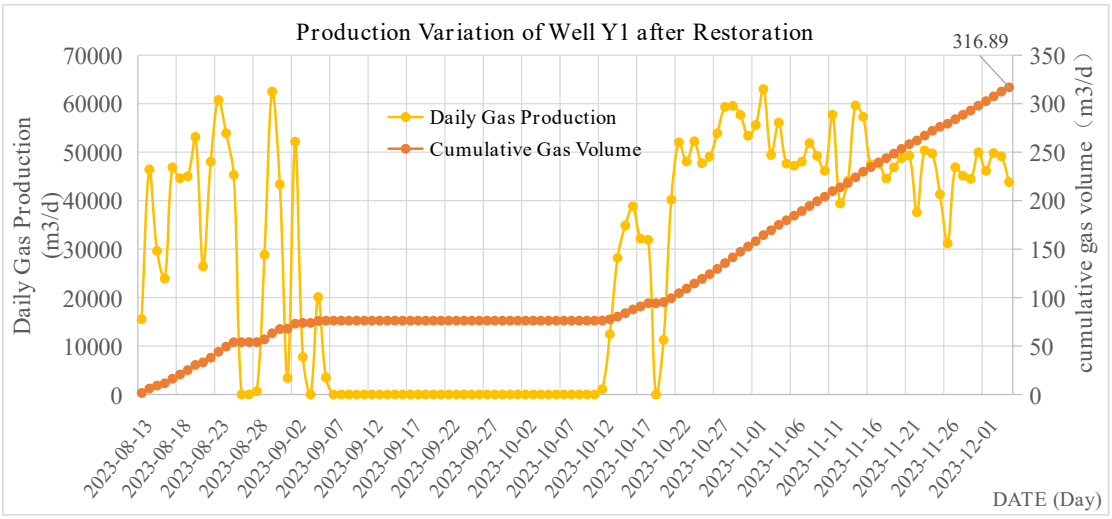


Fig.8. Production Variation of Well Y1 After Production Restoration

The trend in gas output is shown in Figure 9. During the first two months of the process implementation, daily gas output gradually increased. Due to the formation water lock effect, the values fluctuated significantly within the range of 5,000 to 20,000 m^3, consistent with the transient seepage patterns typical of the initial phase of restarting in high-yield water-gas wells . The cumulative gas output during the test phase was 1.4862×10^4 m^3.

During this period, the well's daily gas production gradually increased. Due to the formation water lock effect, the daily gas production fluctuated significantly, ranging from 0.05000~0.2 $\times$ 10^4 m^3, See Figure 9. The cumulative gas production during the test phase was 1.4862 $\times$ 10^4 m^3, which is consistent with the transient seepage behavior typical of high-yield gas wells during the initial phase of production resumption.

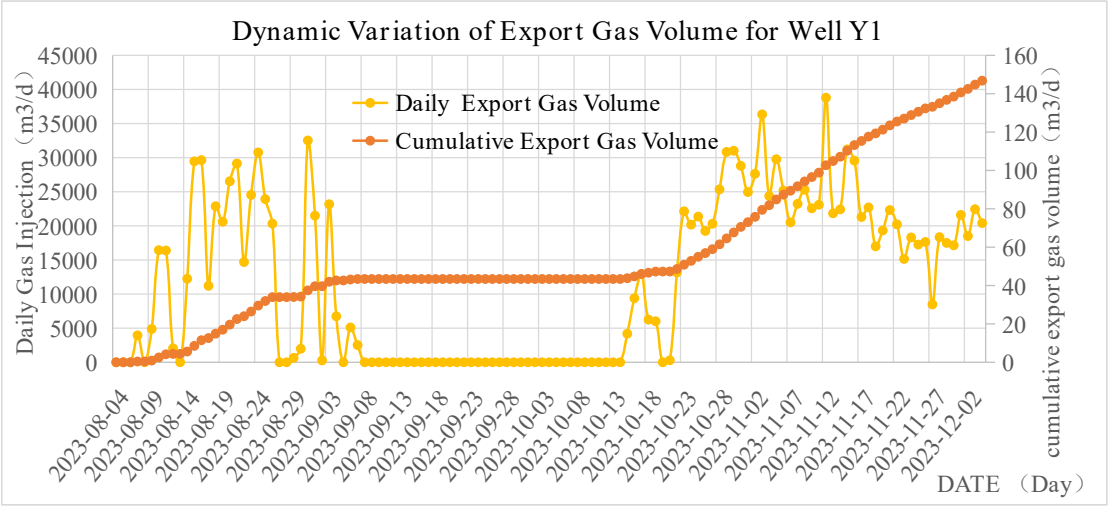


Fig.9 Changes in Gas Output from Well Y1

During the test of Well Y1, a comparison was made with the production curve of Well Y0, found that Y1 and Y0 share an active, water-rich reservoir within the formation and have a uniform, high-permeability pressure system, and their production operations influence one another. During the first round of blowout production following the flooding of Well Y0, Production reached 4.5×10^4 m^3/ day, followed by a 15 day period of declining output and eventual shutdown,see figure 10. Ultimately, daily gas production was stabilized at 2.0×10^4 m^3/ day by controlling the gas injection rate.

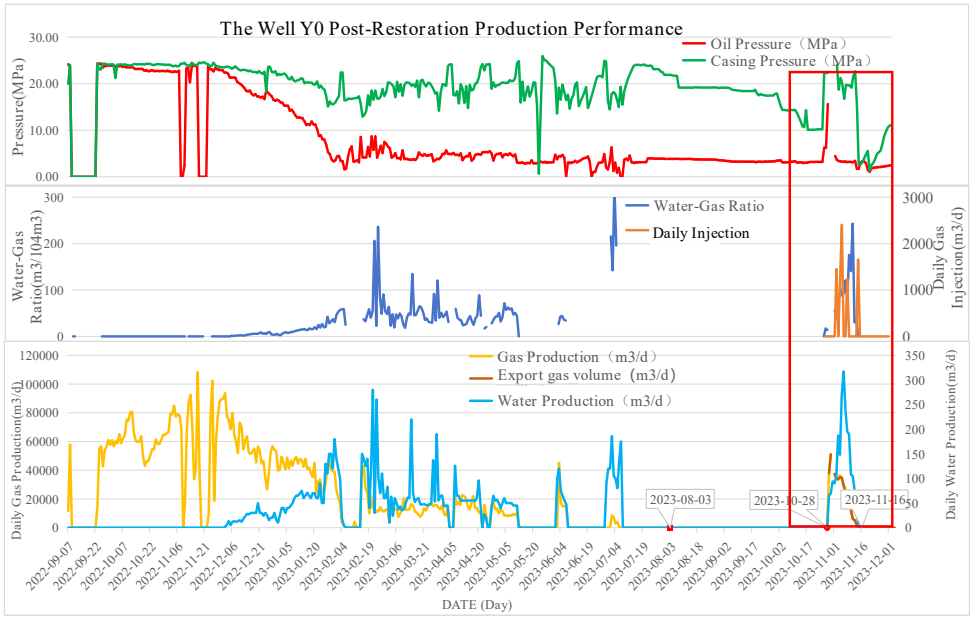


Fig.10. Production Update on the Resumption of Operations at Well Y0

Using a single-well model, this study compares gas production over the next 20 years under three scenarios: a new continuous cyclic drainage and gas production process applied to each of the two wells; the intermittent high-pressure nitrogen gas lift method currently used at the wellsite; and no measures taken.The results show that the new process at Y1 yielded a cumulative production of 54.5×10^6 m^3 of natural gas, while existing measures yielded a cumulative production of 17.9×10^6 m^3 ; at well Y0, the new process yielded a cumulative production of 62.1×10^6 m^3 of natural gas, while existing measures yielded a cumulative production of 18.1×10^6 m^3 (see Figures 11 and 12).

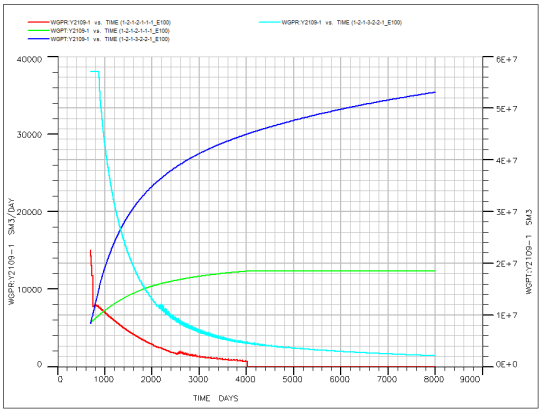


Fig.11. Y1 Production Forecasts

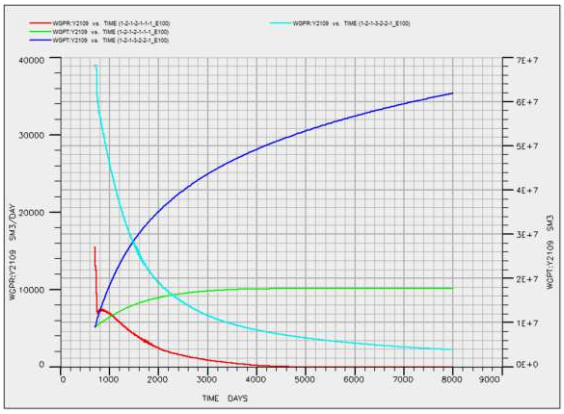


Fig.12. Y0 Production Forecasts

Table 2 presents a comparative assessment of economic benefits. Assuming a natural gas sales price of 1.28 CNY /m^3, the cumulative revenue from the new process is 8.83×10^7 CNY higher than that from the current measures and $1.1771.41\times10^8$ CNY higher than if no measures were taken.

Table. 2 Production Process Comparison

Well	Treatment Type	Predicted 20-Year Cumulative Gas Production (10^6 m^3)	Economic Cost (10^4 CNY/m^3)	Investment Capital (10^6 CNY)	Cumulative Revenue (10^6 CNY)
Y0	New Process	62.10	0.25	15.525	71.12
	Conventional Treatment	18.10	0.13	2.31	2.086
	No Treatment	8.72	0.00	0.00	11.17
Y1	New Process	54.50	0.25	13.63	56.14
	Conventional Treatment	17.90	0.13	4.90	18.01
	No Treatment	6.55	0.00	0.00	8.37

5 Conclusions and Understandings

(1) This paper proposes a continuous cyclic drainage and gas production process designed specifically for high-yield water-gas wells, which typically feature high gas production, high water production, high initial production rates, and short dry periods.This process uses a specialized compressor to continuously increase the pressure of a portion of the gas produced at the wellhead and reinject it into the annulus between the oil tubing and casing, thereby increasing the gas flow velocity within the wellbore, enhancing its fluid-carrying capacity, and continuously transporting accumulated fluid from the wellbottom to the surface.

(2) In field applications at the test well cluster, this process outperformed other methods that had been tried previously, such as foam drainage and high-pressure gas lift.Unlike intermittent operation techniques, continuous-cycle systems provide a steady, uninterrupted supply of lifting energy, effectively restoring the production capacity of gas wells shut down due to flooding and significantly extending the effective production cycle of such wells.

(3) Test results indicate that Well Y1 can maintain stable production when the critical value for continuous liquid discharge pressure in the continuous cyclic drainage and gas production process

exceeds 18 MPa.With a daily gas injection volume of 2.5~5.0 $\times 10^4$ m^3, the oil pressure in Well Y1 remains stable at 4.0 MPa, casing pressure at 20 MPa, daily gas production at 2.5~5.0 $\times 10^4$ m^3/day, daily water production at 180~250 m^3/day, and a water-to-gas ratio within the range of 40~50 $m^3/10^4$，The results of the numerical simulation also indicate that the cumulative gas production from the two wells can be increased by 36.6 and 44.1$\times 10^6 m^3$, respectively. The stability parameters described above indicate that continuous gas injection effectively offset the rise in bottom-hole pressure caused by fluid accumulation,thereby prevented repeated fluid accumulation and flooding in the wellbore, confirming the feasibility of this process for achieving long-term stable production in high-yield water-gas wells.

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