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DELIQUIFICATION TECHNIQUES AND PREVENTION: A CASE STUDY FOR THE SOUTHERN PANNONIAN BASIN

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Abstract: Liquid loading in gas wells leads to production challenges and decreases the overall recovery from these wells. Gas wells affected by liquid loading struggle to eliminate the liquid that accompanies the produced gas from the wellbore. The primary cause of liquid loading is a low gas flow rate or gas velocity. When the gas velocity falls below the critical threshold needed to transport liquid to the surface, the liquid begins to accumulate in the vertical section of a well, the lateral section of a horizontal well, and even within hydraulic fractures. Another indication of liquid loading is the high casing over tubing pressure. The focus of the case study on an onshore gas well is addressing the issue of liquid loading in Southern Pannonian Basin conditions. A well was selected that experienced a gradual decline in production and head pressure. A model was created using PipeSim software, followed by a sensitivity analysis under various operational scenarios. The significance of this study lies in optimizing the well parameters to prevent the occurrence of liquid loading. The paper is structured around relevant works, background, case study, methodology, results, and conclusions.

Keywords: Gas Well, Liquid Loading, Well Modeling, Well Performance Optimization, Southern Pannonian Basin, Gas Rate, Gas Velocity

1 INTRODUCTION

Gas-phase hydrocarbons produced from underground reservoirs often coexist with liquid-phase materials, which can impact the well's flowing characteristics. These liquids may originate from the condensation of hydrocarbon gas (condensate) or from interstitial water within the reservoir matrix. Since the higher-density liquid phase is typically discontinuous, it must be transported to the surface by the gas. If the gas phase does not generate enough transport energy to lift the liquids, they will accumulate in the wellbore. This accumulation creates additional back pressure on the formation, which can

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significantly reduce the well's production capacity. In low-pressure wells, liquid accumulation may completely kill the well, while in higher-pressure wells, it can cause varying degrees of slugging or churning, complicating routine well test calculations (Turner RG, Hubbard MG, Dukler AE 1969).

Liquid loading in gas wells can be challenging to detect and manage. A comprehensive diagnostic analysis of well data is essential to predict how quickly liquids will accumulate. Researchers have focused on determining the minimum gas flow rate needed to prevent this issue, considering various influencing factors. One significant factor is the water content of wet gas. As the wellbore temperature decreases, the water-gas ratio tends to decline, affecting the likelihood of liquid accumulation. Despite extensive studies on this topic, existing models in the industry still exhibit considerable inaccuracies, particularly regarding the prediction of the minimum gas flow rate necessary to avert liquid loading in the wellbore. Improving these predictive models is crucial for effective well management and operational efficiency (Nawankwo I. Abaku G. Kinate B.B. 2020).

The aim of this paper is to present a case study of an onshore gas well that is facing recurring issues related to liquid loading. Using PipeSim software, a base model of the well was meticulously developed. This was followed by a sensitivity analysis focusing on the formation of liquid loading under various operational scenarios. The study further explores and analyzes different strategies, including adjustments to the tubing diameter and choke settings. Understanding and predicting liquid loading is crucial for the safe production of gas fields (Ješić M. Martinović B. 2023).

This study is significant as it aims to optimize the well's performance and mitigate the risks associated with liquid loading. The findings of this study will provide practical solutions for industry practitioners and researchers dealing with onshore gas wells (Ješić M. Martinović B. 2023).

The remainder of the paper is structured as follows Section 2 is theoretical background and section 3 highlights related work. The experimental setup and its results from real-world applications are detailed in Sections 4 and 5, respectively. Finally, conclusions are presented in Section 6 (Ješić M. Martinović B. 2023).

2 THEORETICAL BACKGROUND

Liquid loading is the primary cause of production impairment in gas wells, leading to erratic slug flow and reduced output. If liquids are not continuously removed, the well may eventually become nonproductive or operate below its potential. Therefore, it is crucial to identify the causes of liquid loading and implement appropriate remedial actions. This usually happens when the production rate and reservoir pressure drop. Liquid loading can eventually cause the well to fail by causing irregular gas production and a drop in generated liquids.

2.1 Flow regimes

To understand the impact of liquids in a gas well, it's essential to examine the interaction between the liquid and gas phases under flowing conditions. Multiphase flow in a vertical conduit is typically characterized by four fundamental flow regimes, as illustrated in Figure 1. At any point in a well's operational history, one or more of these regimes may be present. The flow regime is influenced by the velocities of the gas and liquid phases as well as the relative proportions of gas and liquid at any specific location within the flow stream.

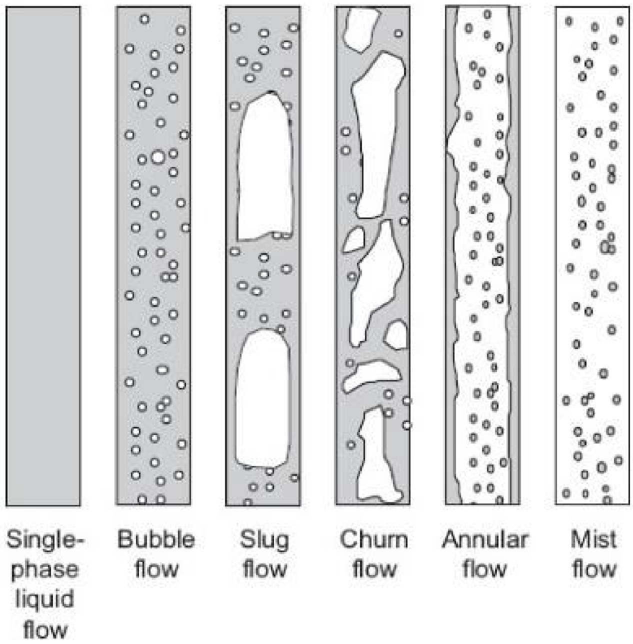

Figure 1 Flow regimes (Jan-Dirk J. 2017)

Bubble Flow: The tubing is nearly entirely filled with liquid, with free gas existing as small bubbles that rise through the liquid. The liquid makes contact with the wall surface, while the bubbles primarily serve to lower the overall density (Sankar, S., & Karthi, S. A., 2019).

Slug Flow: As gas bubbles rise, they expand and merge into larger bubbles and eventually form slugs. The liquid phase remains continuous, but the liquid film surrounding the slugs may descend. Both gas and liquid phases have a substantial impact on the pressure gradient (Sankar, S., & Karthi, S. A., 2019).

Slug-Annular Transition: The flow shifts from a continuous liquid phase to a continuous gas phase. Some liquid may be carried as droplets within the gas. Although gas influences the pressure gradient more significantly, the presence of liquid is still significant (Sankar, S., & Karthi, S. A., 2019).

Generally, most oil wells operate in the bubble flow and slug flow regimes along most of their length, while most gas wells function in the annular flow regime. Solving the equations based on the physical laws governing these flow types is a complex task. There are numerical simulators designed for sensitive industrial processes that require meticulous modeling. However, within the oil industry, a simpler approach is often taken. Empirical correlations have been developed through extensive experimentation. Some of these correlations are published, while others remain proprietary to oil or service companies.

The complexity of these correlations varies. Some are applicable across all flow regimes, while others have distinct correlations for each regime. Some methods incorporate basic physics, such as modeling gas/liquid interface behavior, while others rely entirely on empirical data. For an overview, we refer to Brill and Mukherjee (1999), Beggs and Brill Original, Govier and Aziz (2008). Many of these correlations are integrated into modern well simulators, but caution is warranted, as they are often only suitable for specific types of wells. It's important to note that the correlations used for oil properties can influence the results and may lead to inaccuracies. (Jan-Dirk, 2017)

Liquid loading in a gas well can be identified by various symptoms. If detected early and addressed promptly, appropriate actions can significantly reduce losses in gas production.

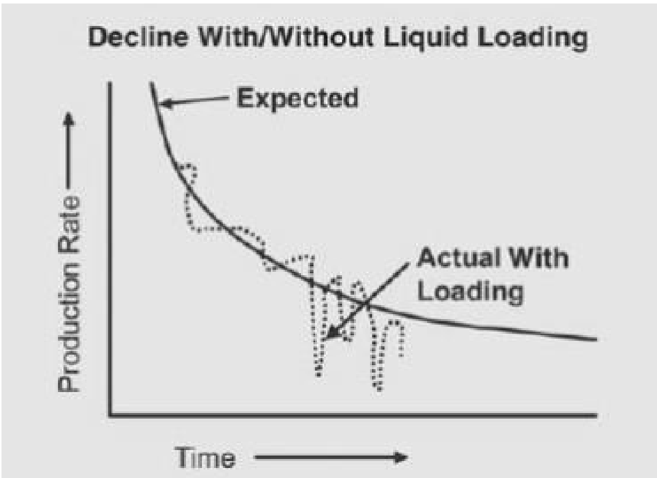

Figure 2 Decline curve showing onset of liquid loading (Lea, 2004)

2.2 NODAL analysis

In Nodal analysis, the system is divided into two subsystems at a specific location known as the nodal point. The first subsystem considers the inflow from the reservoir to the nodal point (Inflow Performance Relationship, or IPR), while the second subsystem addresses the outflow from the nodal point to the surface (Vertical Lift Performance, or VLP). The curves generated by these relationships on a pressure-rate graph are referred to as the inflow curve and the outflow curve, respectively. The intersection of these two curves indicates the optimum operating point, where pressure and flow rate are equal for both curves.

NODAL analysis is used as the primary approach. By employing nodal analysis, researchers can identify and analyze numerous factors that influence well performance, providing valuable insights into how the well is expected to behave under various scenarios. This method offers a comprehensive view of the entire well system, enabling precise predictions and targeted optimizations to enhance overall performance (Ješić M. Martinović B. 2023).

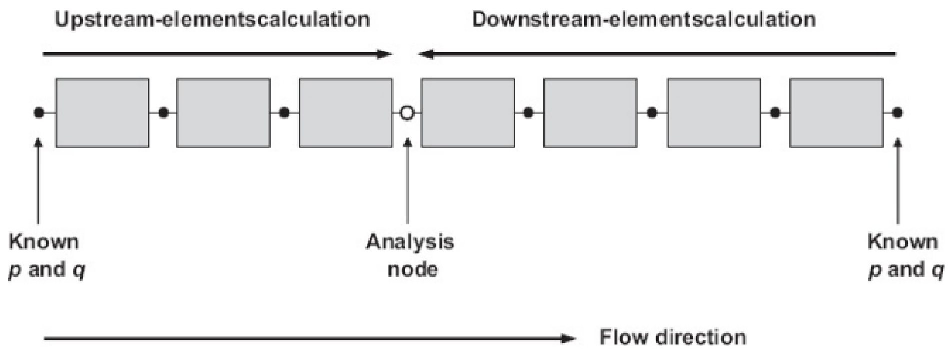

Figure 3 Procedure for Nodal analysis (Jan-Dirk J. 2017)

IPR Curve (Inflow Performance Relationship): The IPR curve represents the relationship between the reservoir pressure and the production rate of a well. It describes the ability of the reservoir to deliver fluids to the wellbore at different production rates. The difference between the reservoir pressure and the flowing bottomhole pressure of a well is the driving force for inflow into the wellbore. (Golan & Whitson, 1991)

VLP Curve (Vertical Lift Performance): The VLP curve represents the relationship between the tubing intake pressure (or flowing bottomhole pressure) and the production rate. It describes the ability of the production tubing to transport fluids from the wellbore to the surface at different rates. The intersection of the IPR and VLP curves is utilized to establish the rate of stable natural flow for an oil well. At this point of intersection, the reservoir's capacity to deliver fluids aligns with the tubing's capacity to transport those fluids to the surface, leading to a stable and balanced flow condition. This represents the rate at which the well can flow naturally while sustaining a consistent flowing bottomhole pressure (Ješić, Martinović, 2023).

A common method for analyzing well performance is through a Nodal Analysis plot, which enables a visual assessment of the impact of various system components (PipeSim, 2017).

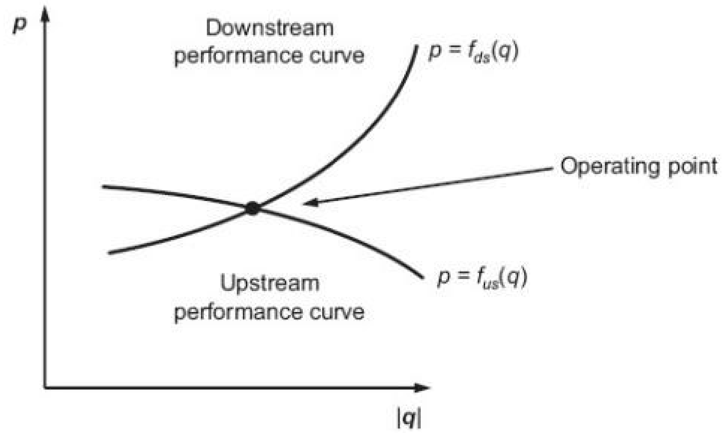

Figure 4 The intersection between the downstream and upstream performance curves defines the operating point (Jan-Dirk J. 2017)

1. The two curves do not intersect, indicating that the system cannot operate under the assumed conditions (i.e., the specified reservoir and manifold pressures).

2. The curves intersect at one or more points. Typically, we identify a single intersection, known as the operating point or working point. The desired flow rate can be obtained from the horizontal axis, while the corresponding pressure can be read from the vertical axis. (Jan-Dirk J. 2017).

Productivity index represents the ratio of the total liquid flow rate at the surface to the pressure drawdown at the midpoint of the producing intervals and represents the simplest equation within the IPR framework, as shown in Equation 1 (Golan & Whitson, 1991)

$$J = \frac{Q}{P_r - P_{wf}} \tag{1}$$

Where:

J – Productivity index, m³/d/bar

Q- Surface flowrate at standard conditions, m³/d

P_r – Static bottom hole pressure, bar

P_{wf} – Flowing bottom hole pressure, bar

Vogel gives the second available method in Eq. 2 (Vogel, 1968).

$$Q = Q_b + (Q_{max} - Q_b)(1 - 0.2\frac{P_{wf}}{P_b} - 0.8\frac{P_{wf}^2}{P^2}) \quad (2)$$

Where:

Q – Production rate, m³/d

Pb – Bubble point pressure, bar

Qmax – Maximum vogel rate, m³/d

Qb – Measured rate at bubble point, m³/d

We use this method when we have one measurement.

In traditional Nodal analysis, common locations for the analysis node correspond to various types of pressures, including:

- Flowing bottomhole pressure (Figure 5)
- Flowing tubing head pressure (just upstream of the wellhead choke)
- Flowline pressure, at the entrance of the flowline just downstream of the wellhead choke
- Manifold pressure, at the end of the flowline

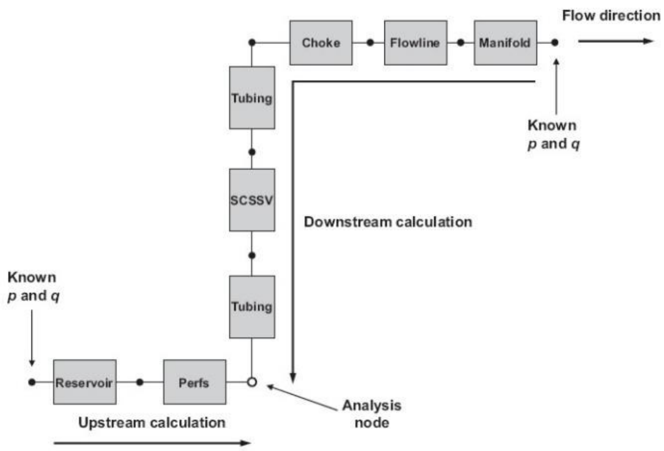

Figure 5 Nodal analysis configuration with analysis node at the well bottom (Jan-Dirk J. 2017)

3 RELATED WORK

Nwankwo (2019) Liquid loading in gas wells creates production challenges and decreases overall recovery. This issue arises when the upward gas velocity drops below a critical threshold, leading to liquid accumulation at the bottom of the well. This accumulation can reduce production rates and, in extreme cases, render the well inactive. While various methods have been suggested to predict the onset of liquid loading, understanding the impact of flow parameters is crucial for addressing this problem.

This study analyzes key flow parameters—including tubing wellhead pressure, water-gas ratio (WGR), condensate-gas ratio (CGR), tubing size, and flow regimes—using PROSPER software. The goal is to assess how these parameters influence liquid loading and optimize gas well production through effective selection and management of flow conditions. By varying and inputting flow and PVT parameters, results indicate that increased tubing wellhead pressure enhances the likelihood of liquid loading due to a corresponding rise in the minimum unloading flow rate.

James J. Sheng presented the project employed a combination of surfactant injection and gas lift to reduce liquid density and enhance flow. The project achieved a significant increase in overall recovery rates, showcasing the successful application of deliquification techniques in a multi-phase production environment.

Gool et al. (2008) developed a model that aligns well with real-life data to predict the gradual decline in well production rates caused by liquid loading. Their research focuses on identifying the key parameters that influence liquid accumulation and the subsequent impact on gas production, providing valuable insights for managing and mitigating liquid loading in gas wells. This model can be particularly useful for operators looking to optimize production strategies and reduce downtime associated with liquid loading issues.

Turner et al. (1969) researched the analysis and prediction of the minimum flowrate for the continuous removal of liquid from gas wells where they analysed the equation used for calculating the minimum flowrate from physical properties which was proposed by Jones (1947) and Duckler (1960).

A study by Joseph A. considers a broad perspective of how liquid loading has been managed over the years and develops classifications for liquid loading problems based on the sources of the liquids, the severity of the problem, the preventive measures and the treatment strategies available in the industry. A comparative analysis of some of the predictive models was made along with a new model using Matlab. The result shows that at pressures below 2500psi and pressures above 5000psia; the modified model perform better than Turner et al's model whereas at pressures between 2500 and 5000psia, Turner et al's model performed better than other models.

Schlumberger made attempt to address liquid loading issues using an integrated approach. Their report indicates that they analyzed available well data, assessed the current status and performance of the well, diagnosed its condition, selected the most suitable production system, managed the data, and optimized operations. To define the well model and align actual production data with simulated behavior, they employed composite system NODAL analysis using PipeSim software. Once the well model was validated, system analysis was used to evaluate future well performance and to select appropriate production systems by comparing results from various input parameters and conditions. Additionally, this analysis helped diagnose the causes of decreased gas production.

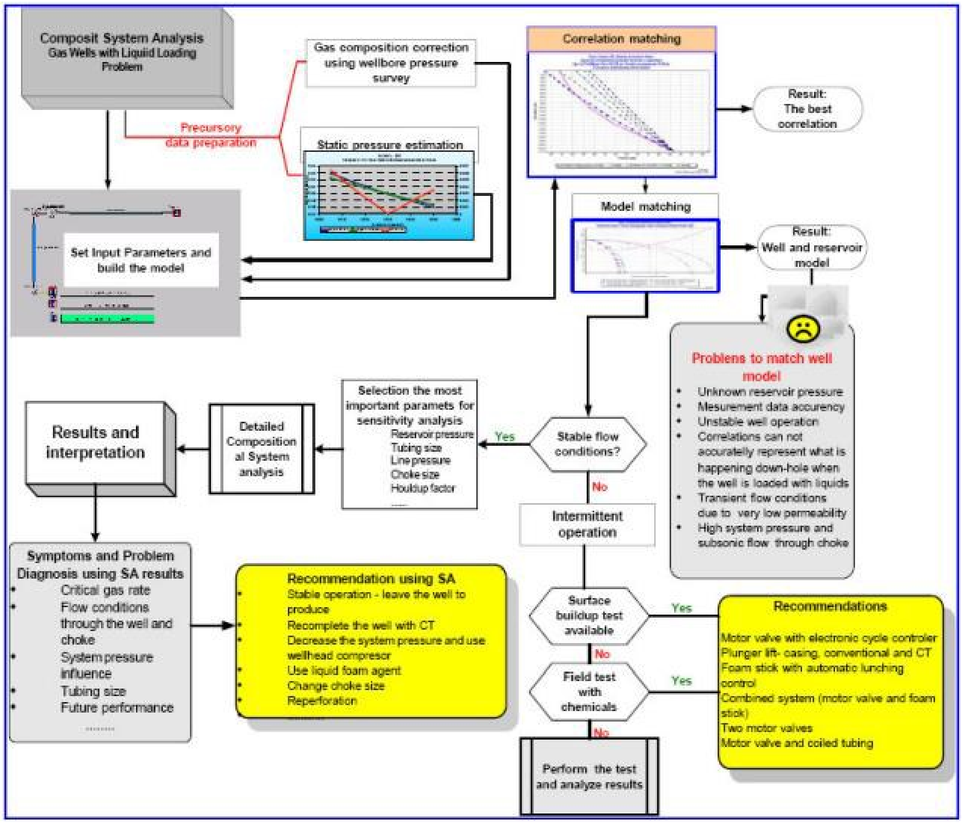

Figure 6 Well performance model for gas wells with liquid loading problem (Schlumberger, 2006)

In Figure 6 the flow chart of the procedure for defining well performance is shown.

4 CASE STUDY

Figure 7 shows the production profile created based on the data provided in section 4.2 (Data collection). Analyzing the production profile, we can conclude that the well was stopped in February 2024, due to issues related to liquid loading. On the production profile, it is observed that the well produces approximately 12,000 m^3/day after the workover. There is a gradual decrease in production over time. In April, production was recorded at 11,000 m^3/day, and it continued to decline, reaching 9,000 m^3/day in August. The well is produced with a surface choke that has a diameter of 3.3 mm. The goal is to determine the reasons for the decline in production and the decrease in the wellhead pressure.

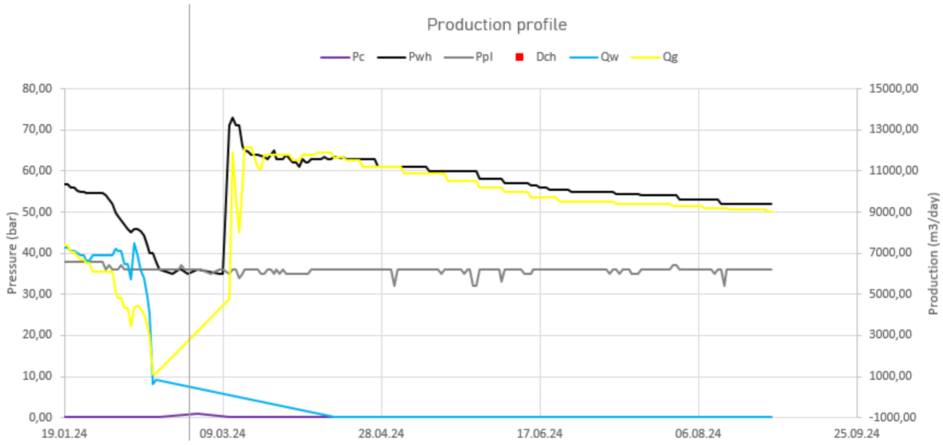

Figure 7 Production profile

4.1 Methodology

In this study, a methodology was used that consists of several steps providing a systematic approach to achieving our research objectives. In the following sections, these sequential phases are described in detail: Data Collection, Data Validation, Model Creation and Matching, Sensitivity Analysis, and Finalization of Results. Each step is clearly defined and aims to facilitate the understanding and interpretation of the data. Figure 8 illustrates the methodology which ultimately aims to provide solutions based on the results of the sensitivity analyses obtained (Ješić M. Martinović B. 2023).

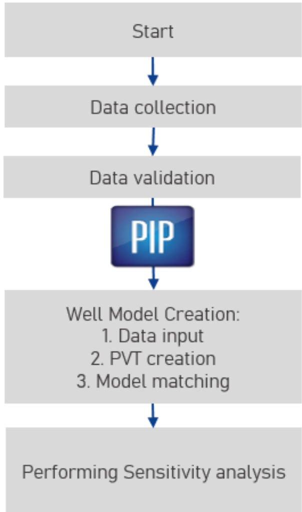

Figure 8 Schematic representation of methodology

The creation of a well model during NODAL analyses consists of the following steps:

1. Input Well completion details: Tubing size, casing size, completion type, and any artificial lift methods if applicable.

2. PVT data Input information such as fluid composition, density, viscosity, and components and value.

3. Define IPR: Establish the relationship between wellbore pressure and production rate.

4. Definition HD measurements: Data from the results of the last relevant measurements of dynamic pressure profiles in the well are entered.

5. Define VLP: Define the VLP models to characterize the well's response to changes in tubing and casing pressures

6. Run Nodal Analysis: PipeSim will calculate pressures, temperatures, and flow rates at different points in the well and production system (Ješić M. Martinović B. 2023).

7. Review Results: Analyze the simulation results, focusing on parameters such as wellhead pressure, tubing and casing pressures, flow rates, and temperature profiles. Evaluate the well's performance under different operating conditions (Ješić M. Martinović B. 2023).

8. Optimization: If necessary, adjust parameters such as choke size, completion design, or artificial lift settings to optimize well performance (Ješić M. Martinović B. 2023).

4.2 Data Collection

The data collected for this well was obtained from an onshore gas well that is facing issues with liquid loading. In Table 1, we can see the well facts and data obtained from the model, where we can conclude that the created model aligns with the actual data. Table 2 contains the data used to create the PVT dataset. Table 3 includes the data for hydrodynamic measurements, while Table 4 presents the input well completion details. Table 5 was used for entering information about the surface equipment

Table 1 Input data

Parameter	**Pres [bar]**	**Pbh [bar]**	**Pwh [bar]**	**Ppl [m³/day]**	**Qg [m/day]**	**Qf [bar]**
Input data	95	92,8	65	35	12312	0,4
Model results	95	92,9	66,9	35	12301	0,4

Table 2 PVT data

Serial number	**Components**	**Unit of measure**	**Value**
1.	Methane	mol %	97.91
2.	Ethane	mol %	0.14
3.	Propane	mol %	0.04
4.	Isobutane	mol %	0.00
5.	Butane	mol %	0.00
6.	Isopentane	mol %	0.00
7.	Pentane	mol %	0.00
8.	Hexane	mol %	0.00
9.	Nitrogen	mol %	1.49
10.	Carbon Dioxide	mol %	0.39
11.	Average molecular weight	g/mol	16.37
12.	Density relative to air	/	0.5660
13.	Density	kg/m3	0.6936

14.	Wobbe's index (bottom)	MJ/m3	44.44
15.	Lower heating value	MJ/m3	33.43

Table 3 HD measurements

Depth m	Pressure (kPa) – Level (m) Staircase Dynamic kPa	Dynamic Grad. kPa/m
0	6502	
200	6838	1,18
400	7127	1,45
600	7516	1,95
800	7998	2,41
900	8208	2,10
1000	8448	2,40
1100	8676	2,28
1200	8898	2,22
1250	9009	2,22
1300	9120	2,22
1345	9245	2,78

Table 4 Data on production equipment

Data on production equipment			
1	Inside diameter of column	124,26	[mm]
2	Column outer diameter	139,7	[mm]
3	Column section length	1469,39	[m]
4	Column grade	K-55	
5	Tubing inner diameter	62	[mm]
6	Tubing outer diameter	73,02	[mm]
7	Tubing section length	1342,4	[m]
8	Tubing grade	J-55	
9	Packer installation depth	1344,49	[m]
10	Special equipment (description, characteristics, installation depth)	✓	
11	Perforation top	1360	[m]

12	Perforated interval length	1	[m]	
13	Inclinometer data	✓		
14	Geothermal gradient	[°C/m]	[°C/m],	Not necessary, preferred

Table 5 Surface equipment data

Data on surface equpment			
1	Pipeline length	8600	[m]
2	Internal diameter of the pipeline	73	[mm]
3	Pipe wall thickness	7	[mm]
4	Coefficient of thermal conductivity of pipelines	X	[W/mK]
5	Absolute roughness of the inner wall of the pipeline	X	[mm]
6	Average digging depth	0,8 - 1 m	[m]
7	Soil temperature at the depth of burial	X	[°C]
8	Thermal conductivity coefficient of the soil	X	[W/mK]
9	Thermal conductivity coefficient of polyurethane foam insulation	X	[W/mK]
10	Separator pressure	36	[kPa]
11	Separator temperature	X	[°C]

4.3 Model creating

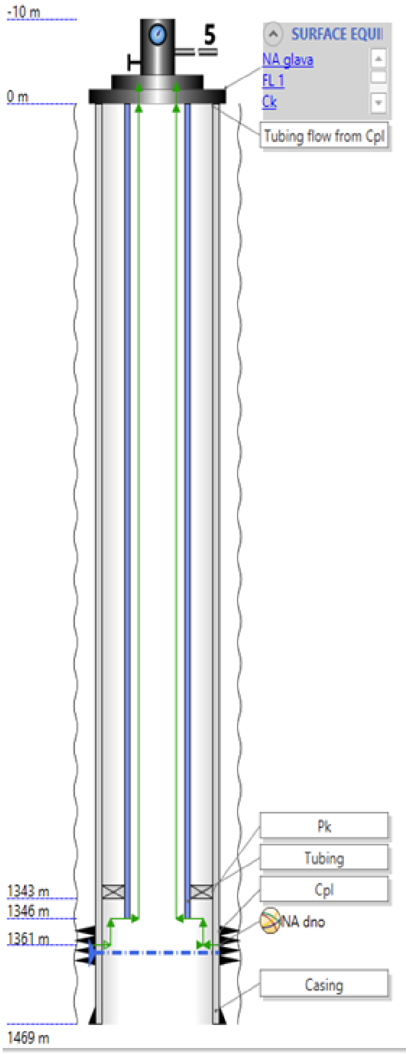

Figure 9 Sketch of well

When creating a model, the first step is to define the fluid characteristics, well construction, production, and pressures at Nodal points. The first Nodal point is defined at the bottom of the well, and the second at the wellhead. The correlations used in the model creation for Vertical Lift Performance are the Beggs and Brill Original, while the Inflow Performance Relationship is determined using the PI method (Beggs, 2008).

5 RESULTS AND DISCUSSION

In section 4.2 (Data Collection), Table 1 (Input Data) presents the actual data for the well. The results of the baseline model (the solution at the bottom and the solution at the top) are analyzed. The results indicate values that are approximately the same as those in the input data from Table 1, suggesting that the model is well constructed, that the data used for model execution is accurate and well validated, and that the model accurately represents the real behavior of the well in the virtual world. With an accurate model established, sensitivity analyses can be performed. The following section will conduct these sensitivity analyses and provide suggestions for addressing the issue of liquid loading.

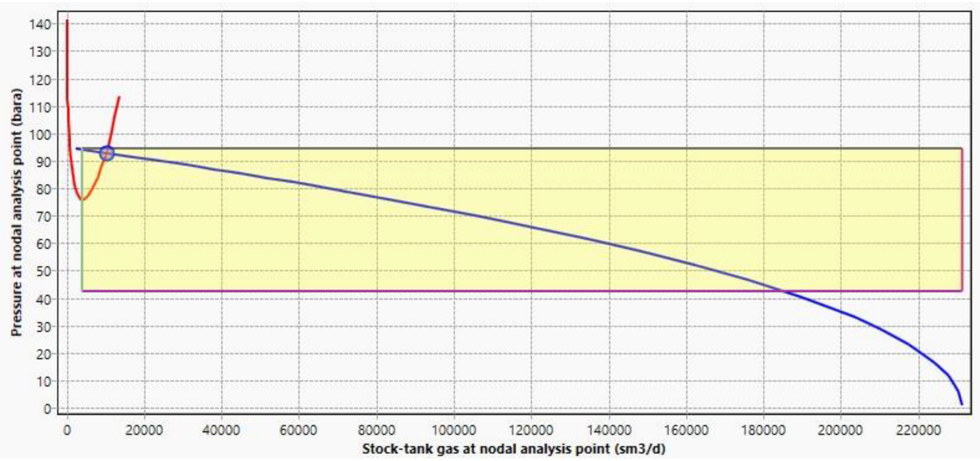

Figure 10 Nodal point at the bottom

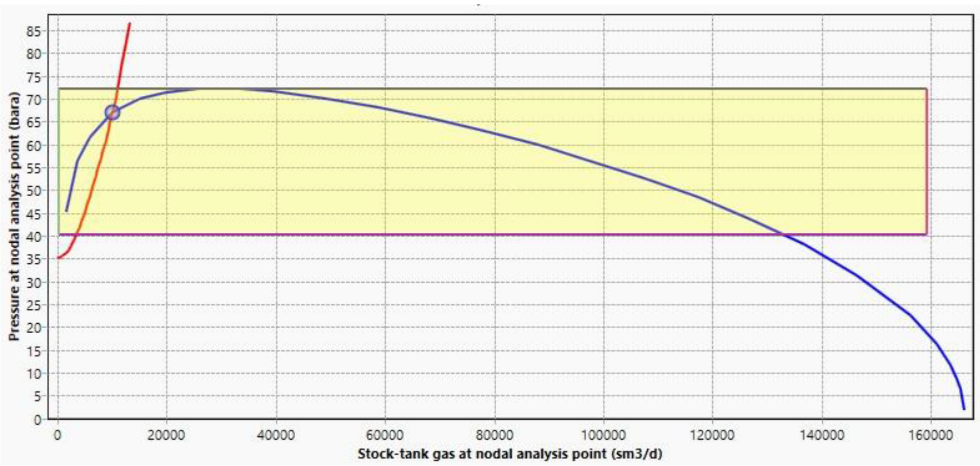

Figure 11 Nodal point at the head

Sensitivity analysis of the surface choke diameter

A sensitivity analysis of the surface choke diameter has been performed on the baseline well model. The choke diameter varied from the current diameter of 3.3 mm to 7 mm.

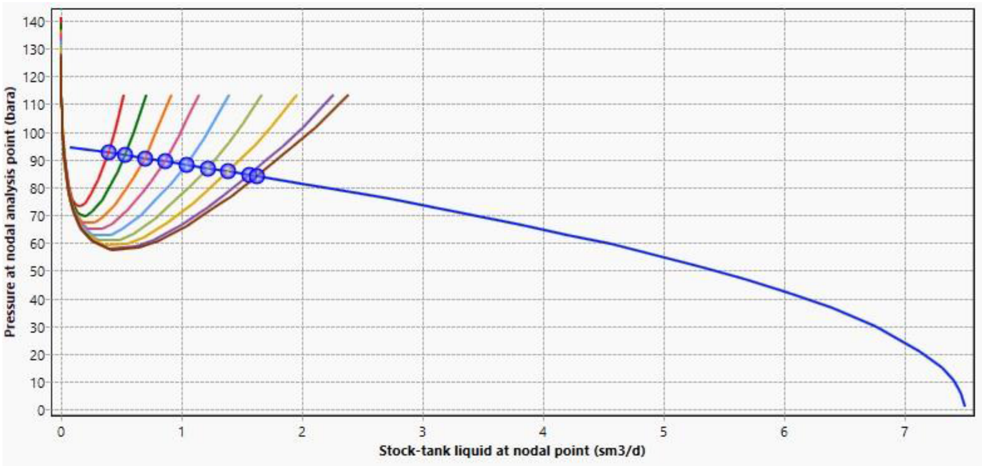

Figure 12 The solution at the bottom

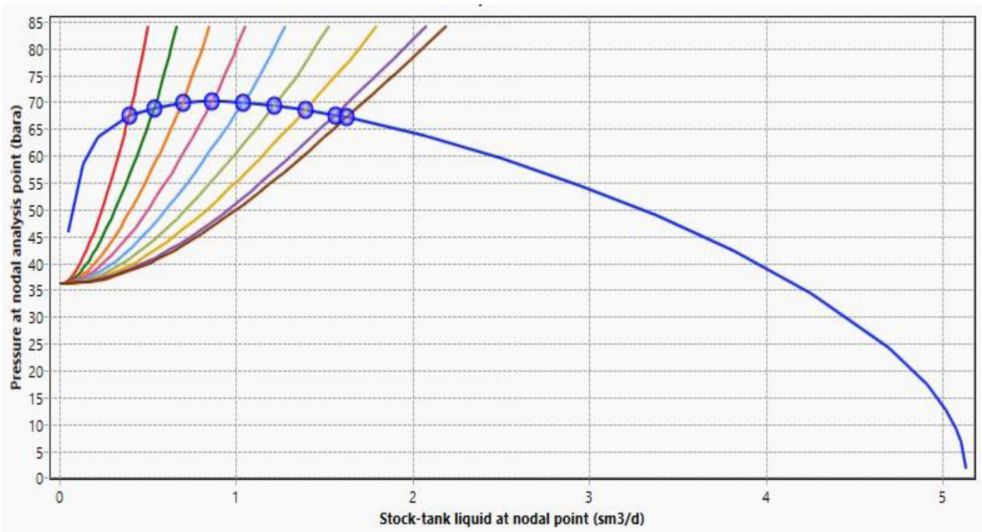

Figure 13 The solution at the head

What can be concluded from Figures 12 and 13 is that an increase in the diameter of the choke leads to a rise in gas production and a gradual decrease in bottom pressure. In further interpretations, a more detailed account of the results obtained from the sensitivity analysis of the surface choke will be provided.

Table 5 Results of the sensitivity analysis for the diameters of the surface choke

Diameter	**3.3 mm**	3.8 mm	4.3 mm	5.3 mm	5.8 mm	6.3 mm	6.8 mm	7 mm
Qg m^3/d	**12301**	16624	21598	26798	32172	37609	42985	48198
Pwh bar	**67,4**	68,7	69,8	70,1	69,9	69,4	68,5	67,5
Pbh bar	**92.4**	91.5	90.5	89.3	88.1	86.9	85.7	84.5

In the previously mentioned data from section 4.2, the gas production at the well is 12,312 m^3/day. Therefore, we can conclude that the choke installed at the well, which is 3.3 mm, is appropriate. The production we obtain with the 3.3 mm is 12,301 m^3/day.

Through sensitivity analysis of choke diameter changes, we have provided possible suggestions for addressing the issue of liquid loading. It is important to note that when deciding on the choke diameter, geological conditions and system conditions must be taken into account.

Sensitivity analysis of the liquid loading

Due to the intermittent production of water, an analysis of the liquid phase removal was conducted to determine the conditions for stable well operation. The analysis results show that the well is at risk of liquid phase retention. (Figure 14) The necessary critical gas velocity was obtained, as well as the production that needs to be achieved to avoid this risk.

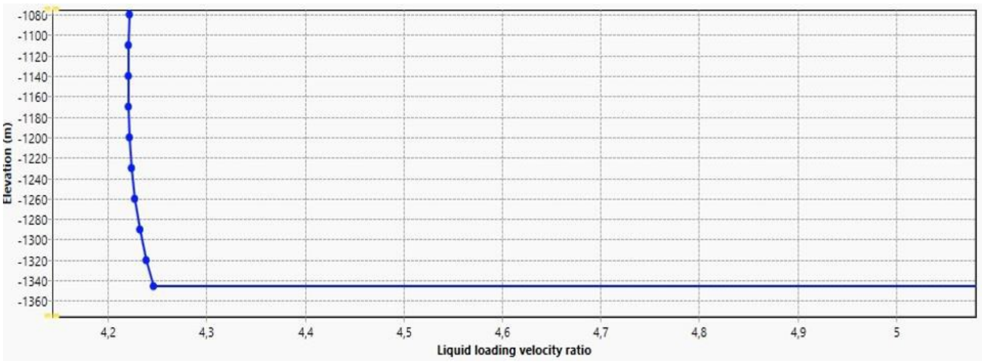

Figure 14 Liquid loading velocity ratio

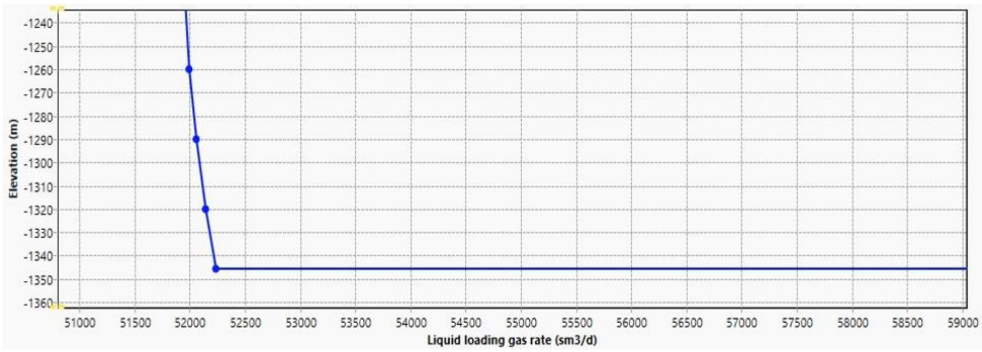

Figure 15 Liquid loading gas rate

In Figure 14, it can be concluded that the liquid loading velocity ratio is 4.25, while Figure 15 indicates a liquid loading gas ratio of 52,300 m³/d. Given that the liquid loading velocity ratio and liquid loading gas ratio have not been achieved, the well is at risk of liquid loading and is therefore a suitable candidate for chemical dosing. The initial solution to address the issue of liquid loading involves the dosing of chemicals. Under the specified conditions of this well type, the recommended practice is to administer the chemical foamers bi-monthly. Since PipeSim does not have the option for dosing the foamer, dosing is suggested based on the analysis of similar conditions in the well.

Sensitivity analysis of the tubing diameter

In the sensitivity analysis of tubing, several diameters were considered: 62 mm, 50.67 mm, 31.29 mm, and 26.21 mm. The objective of this sensitivity analysis is to identify the tubing diameter that achieves the most optimal conditions for mitigating the issue of liquid loading. It is essential to ensure that the liquid loading velocity ratio (LLVR) remains below 1, while also meeting the production requirements associated with the well.

	Operating point	ST Liq. at NA	P at NA	ST Gas at NA	BHP	P at WH
		sm3/d	bara	sm3/d	bara	bara
1	IDIAMETER=61.99...	0.3986104	92.44161	12302.77	92.44161	67.45001
2	IDIAMETER=50.67...	0.4134558	92.34484	12760.96	92.34484	69.39623
3	IDIAMETER=31.29...	0.3849366	92.53064	11880.74	92.53064	66.14021
4	IDIAMETER=26.21...	0.3319073	92.87512	10244.03	92.87512	59.85454

Figure 16 Output

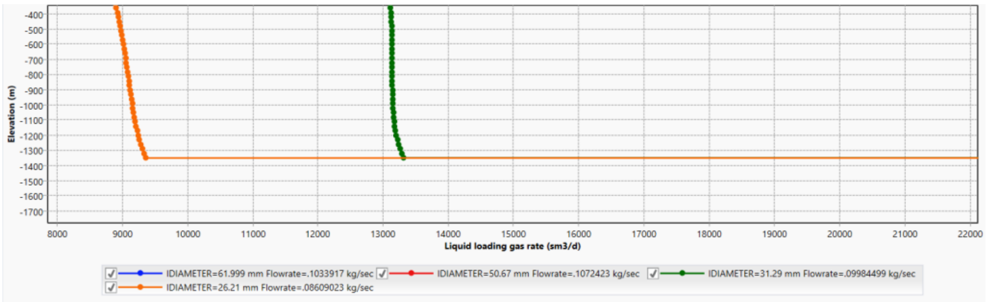

Figure 17 Liquid loading gas rate

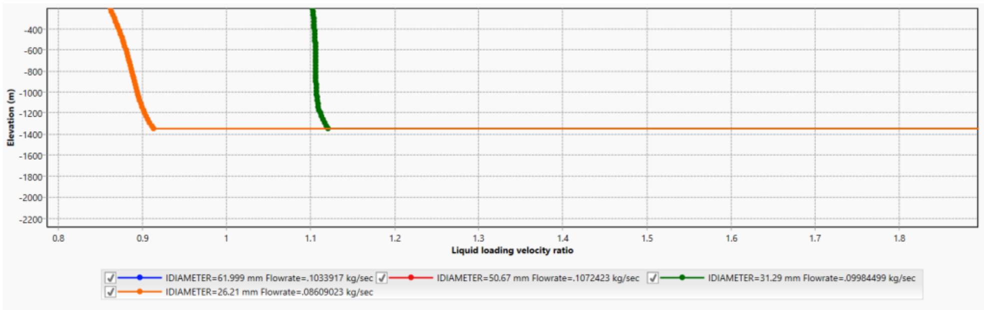

Figure 18 Liquid loading velocity ratio

The optimal solution indicates a tubing diameter of 26.21 mm if production conditions are not considered. The next step is to include both the tubing diameter and the choke diameter in the analysis to achieve better results that correspond to production conditions. LLVR=0,91 and LLGR=9300 m³/d.

Sensitivity analysis of the tubing diameter and choke diameter

In the analysis of tubing with different diameters and choke diameters (3.3 mm to 7 mm), it was found that better results were obtained compared to the analysis of tubing diameter alone. The optimal tubing diameter is 31.29 mm, with a choke diameter of 3.8 mm. This combination yields optimal production while successfully addressing the issue of liquid loading. The liquid loading gas rate (LLGR) is 13,400 m³/d, and the liquid loading vapor ratio (LLVR) is 0.9.

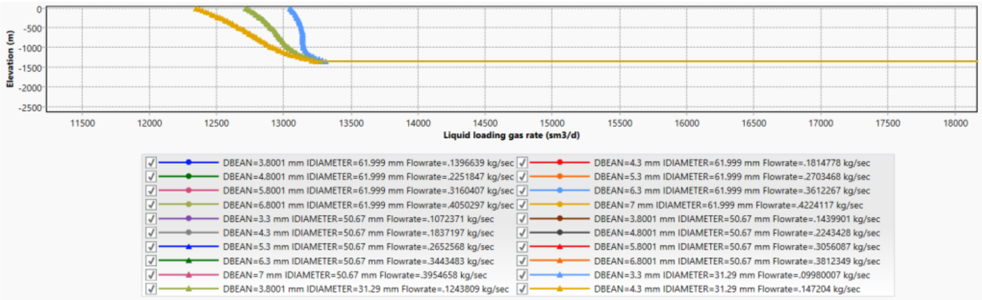

Figure 19 Liquid loading gas rate

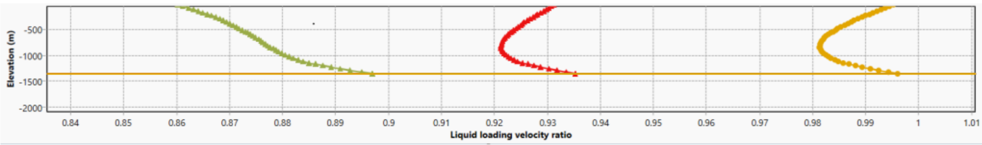

Figure 20 Liquid loading velocity ratio

	Operating point	P at NA	ST Gas at NA	BHP
		bara	sm3/d	bara
1	DBEAN=3.3 mm IDIAMETER=61.999 mm...	67.45001	12302.77	92.44161
2	DBEAN=3.8001 mm IDIAMETER=61.999...	68.63148	16618.87	91.52608
3	DBEAN=4.3 mm IDIAMETER=61.999 mm...	69.77052	21594.38	90.45917
4	DBEAN=4.8001 mm IDIAMETER=61.999...	70.11162	26795.14	89.33035
5	DBEAN=5.3 mm IDIAMETER=61.999 mm...	69.92023	32169.07	88.14876
6	DBEAN=5.8001 mm IDIAMETER=61.999...	69.35022	37606.27	86.93692
7	DBEAN=6.3 mm IDIAMETER=61.999 mm...	68.51661	42983.04	85.72169
8	DBEAN=6.8001 mm IDIAMETER=61.999...	67.50916	48195.23	84.52699
9	DBEAN=7 mm IDIAMETER=61.999 mm Fl...	67.06297	50263.54	84.0482
10	DBEAN=3.3 mm IDIAMETER=50.67 mm F...	69.39596	12760.34	92.34498
11	DBEAN=3.8001 mm IDIAMETER=50.67 m...	70.54523	17133.65	91.41627
12	DBEAN=4.3 mm IDIAMETER=50.67 mm F...	70.67652	21861.15	90.40161
13	DBEAN=4.8001 mm IDIAMETER=50.67 m...	70.14454	26694.96	89.35223
14	DBEAN=5.3 mm IDIAMETER=50.67 mm F...	69.1659	31563.4	88.28272
15	DBEAN=5.8001 mm IDIAMETER=50.67 m...	67.8838	36364.95	87.21507
16	DBEAN=6.3 mm IDIAMETER=50.67 mm F...	66.41798	40974.64	86.17762
17	DBEAN=6.8001 mm IDIAMETER=50.67 m...	64.84157	45363.85	85.17806
18	DBEAN=7 mm IDIAMETER=50.67 mm Fl...	64.19014	47057.21	84.78928
19	DBEAN=3.3 mm IDIAMETER=31.29 mm F...	66.14396	11875.39	92.53177
20	DBEAN=3.8001 mm IDIAMETER=31.29...	63.64419	14800.32	91.91294
21	DBEAN=4.3 mm IDIAMETER=31.29 mm F...	60.6571	17516.08	91.33461
22	DBEAN=4.8001 mm IDIAMETER=31.29 m...	57.56934	19910.72	90.8216
23	DBEAN=5.3 mm IDIAMETER=31.29 mm F...	54.57709	21977.62	90.37647
24	DBEAN=5.8001 mm IDIAMETER=31.29 m...	51.85046	23697.79	90.00433
25	DBEAN=6.3 mm IDIAMETER=31.29 mm F...	49.46865	25094.97	89.70094
26	DBEAN=6.8001 mm IDIAMETER=31.29 m...	47.42622	26224.02	89.45501
27	DBEAN=7 mm IDIAMETER=31.29 mm Fl...	46.7555	26581.89	89.37692
28	DBEAN=3.3 mm IDIAMETER=26.21 mm F...	59.84484	10249.71	92.87393

Figure 21 Output

In Figure 21 (Output) the depiction shows the optimal solution with the pressures given at the wellhead and bottom, as well as the production rate.

Results of Different Analyses

Diameters of the surface choke

Diameter	**3,3 mm**	3,8 mm	4,3 mm	4,8 mm	5,3 mm	5,8 mm	6,3 mm	6,8 mm	7 mm
Qg m^3/d	**12301**	16624	21598	26798	32172	37609	42985	48198	50267
Pwh bar	**67,4**	68,7	69,8	70,1	69,9	69,4	68,5	67,5	67,1
Pbh bar	**92.4**	91.5	90.5	89.3	88.1	86.9	85.7	84.5	84,1

Tubing diameter

Diameter	62 mm	50,67 mm	31,3 mm	**26,2 mm**
Qg m^3/d	12302	12760	11880	**10244**
Pwh bar	67,45	69,39	66,14	**59,85**
Pbh bar	92,44	93,34	92,53	**92,87**

Model matching

INPUT DATA			MODEL RESULTS		
Qg m3/d	12312		Qg m3/d	12301	
Pwh bar	65		Pwh bar	66,9	
Pbh bar	92,8		Pbh bar	92,9	

Diameters of the surface choke and tubing diameter

Diameter	3,3 61,9	3,8 61,9	4,3 61,9	4,8 61,9	5,3 61,9	5,8 61,9	6,3 61,9	6,8 61,9	7 61,9	3,3 50,67	3,8 50,67	4,3 50,67	4,8 50,67	5,3 50,67	5,8 50,67	6,3 50,67	6,8 50,67	7 50,67	3,3 31,29	**3,8** **31,29**
Qg m^3/d	12302	16618	21594	26795	32169	37606	42983	48195	50263	12760	17133	21861	26694	31563	36364	40947	45363	47057	11875	**14800**
Pwh bar	67,45	68,63	69,77	70,11	69,92	69,35	68,51	67,5	67,06	69,39	70,54	70,67	70,14	69,16	67,88	66,41	64,84	64,19	66,14	**64**
Pbh bar	92,44	91,52	90,46	89,33	88,14	86.94	85,72	84,52	84,04	92,34	91,41	90,4	89,35	88,28	87,21	86,17	85,17	84,78	92,53	**92**

Figure 22 Results of different analyses

Considering that this is a business project, the task is to select the optimal and profitable solution that would address the issue of liquid loading, maintain consistent production, and keep the bottom pressure stable.

6 CONCLUSION

The occurrence of liquid loading in gas wells is one of the most common and challenging problems encountered during exploitation. In this paper, we present possible solutions to the issue of liquid loading using the PipeSim program, which allows us to prevent or address the problem at the well through Nodal analysis.

The solutions outlined showcase various options, each with its own limitations or inadequacies for the specific conditions at the well. Therefore, this paper details all potential solutions for addressing the issue and ultimately identifies the most accessible and effective solution for resolving the problem. The first option defined as a possible solution for the liquid loading issue involves changing the diameter of the surface choke, but with the caveat of the system's limitations and the indication of reduced pressure at the bottom, which must be taken into account when selecting the choke diameter. The second option involves analyzing liquid loading to define LLGR and LLVR, addressing the liquid loading issue through chemical dosing. The third and fourth options suggest installing a tubing diameter of 31.29 mm and a choke diameter of 3.8 mm to resolve the liquid loading problem while maintaining production levels. Considering that this is a business project, the client has decided that the best option is to install a smaller diameter tubing and a larger diameter choke. As stated in the proposed analysis, the tubing diameter will be 31.29 mm, with the choke being 3.8 mm. With this combination of equipment, the well will no longer experience the issue of liquid loading.

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