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Gas Production Optimization with the Addition of Infill Wells through an Integrated Pipeline Scenario Model in Field Y

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ABSTRACT

The Y natural gas field was awarded a 10-year gas sales contract with a production target of 11 MMSCFD. Three infill wells were drilled to meet the production target. The pipeline network for these wells is then determined through an optimization scenario. The pipeline network scenario for infill wells is an optimization approach that aims to provide recommendations for modeling pipelines from infill wells that produce the largest volume of gas with the smallest bottlenecking effect, and the pressure drop that occurs can be minimized. The surface production network optimization scenario is then divided into three scenarios based on the productivity of each well. The Y Field production system was modeled using a reservoir simulator, a well simulator, and a total system simulator. Based on the simulation results, scenario 3 was identified as being able to produce the largest gas volume and the scenario with the smallest bottlenecking effect. Since the difference in gas volume and bottlenecking between scenario 2 and scenario 3 is insignificant at 0.06%, scenario 2 is recommended as the preferred pipeline modeling scenario for infill wells in Y Field.

Keywords: bottlenecking index analysis; gas reservoir; gas infill well; integrated pipeline network; well productivity

I. INTRODUCTION

Field Y is a natural gas field with a 10-year gas sales contract, with a gas production target of 11 MMSCFD at the end of the contract. With Y Field reserves of 490.74 BSCF, there is still a substantial amount of unutilized reserves, namely 166.178 BSCF. The Company drilled three infill wells in Field Y to meet the production target stipulated in the contract. Since the produced gas must be immediately delivered to consumers at the agreed flow rate, achieving the flow rate target is very important by the end of the contract.

The pipeline network scenario for the three infill wells is an optimization that provides recommendations for infill well pipeline network modeling that produces the most significant gas volumes with minimal bottlenecking and pressure drop. This network modeling aims to determine whether the infill wells should be connected to the same pipeline network as the nearest existing well or whether a separate pipeline network should be created. In addition, the bottlenecking index (BNI) analysis was conducted to assess bottlenecking in the three optimization scenarios and determine the infill well pipeline network model that produces the lowest bottlenecking value.

1.1 Natural Gas

Natural Gas is a gaseous fuel consisting mainly of methane (CH4), with supporting components such as ethane (C2H6), propane (C3H8), butane (C4H10), and various impurities such as water, H2S, CO2, and others. The composition and type of impurities may vary depending on the source of natural gas. (Chandra, 2006).

Natural gas with a high content of impurities, such as hydrogen sulfide, is called sour gas, which is acidic. After undergoing sweetening and dehydration processes, natural gas that is ready for sale is called sweet gas, which means it is clean, free of sour gas, tasteless, and odorless. Natural gas with impurities is still often encountered and requires purification. (Speight, 2018).

1.2 Volumetric Method

Initial Gas In Place (IGIP) can be determined using the volumetric method with the following equation.

$$G = \frac{43560 \times A \times h \times \emptyset (1 - S_{wi})}{B_{gi}} \quad (1)$$

This calculation is used to determine the IGIP at initial reservoir conditions. The recovery Factor (RF) at abandonment pressure is used to calculate the Estimated Ultimate Recovery (EUR) or total recoverable gas. RF is calculated using the following equation. (Lyons, 1996):

$$RF = (1 - \frac{B_{ga}}{B_{gi}}) = (1 - \frac{P_a Z_i}{P_i Z_a}) \quad (2)$$

The formula for calculating Estimated Ultimate Recovery or total recoverable gas is:

$$EUR = G \times RF \quad (3)$$

The calculation of the remaining reserves can be done using the following calculation:

$$RR = EUR - Gp \quad (4)$$

1.3 Material Balance Method

The P/Z vs Gp method was developed based on the Material Balance equation, where the amount of gas produced equals the initial number of moles of gas minus the amount of gas remaining in the reservoir. (Hardi et al., 2020)

If the reservoir gas volume is Vi, it can be expressed under standard conditions as follows. (Beggs, 1984):

$$V_i = OGIP \times B_{gi} \quad (5)$$

By substituting the above equation, the cumulative gas production Gp as a function of P/Z can be written as follows. (Beggs, 1984):

$$G_p = (-\frac{IGIP}{p_i/z_i})\frac{p}{z} + IGIP \quad (6)$$

1.4 Gas Deliverability

Flowability quantifies the ability of a well to produce fluids, such as gas. Gas production capability is often depicted in a graph $(P_R - Pwf^2)$ vs Qsc. A deliverability test is a well test conducted to determine the productivity of a gas well. The test involves three or more flow rates with flow rate, pressure, and other data calculated over time. The productivity parameter obtained from this test is the Absolute Open Flow Potential (AOFP), which represents the ability of a gas well to produce gas to the surface at a maximum flow rate with downhole pressure equal to atmospheric pressure (approximately 14.7 psia**)** **(**Ikoku, 1984).

1.5 Bottlenecking Index (BNI)

Bottlenecking Index (BNI) is a parameter that calculates the degree of flow resistance in a pipeline. Produced fluids flow from each well to the surface Gathering Station through the pipeline network, where the total flow rate is accumulated. The Bottlenecking Index is calculated by comparing the total maximum flow rate received at the Gathering Station (qGS) with the total maximum flow rate (qmax). Mathematically, the Bottleneck Index is expressed as:

$$BNI = \frac{q_{GS}}{(q_{max})_T} \quad (7)$$

The maximum value of BNI is 1, which occurs when the total maximum flow rate received by the Gathering Station equals the total maximum flow rate from each well. The higher the BNI value, the smaller the bottlenecking. Conversely, the lower the BNI value, the greater the bottlenecking. (Umam et al., 2023).

II. METHODS

Based on the flowchart in Figure 2.1, the research method begins with a literature study on reserve calculation, well productivity, and bottlenecking index. Furthermore, data collection is carried out as described in the flow chart, where the required data includes reservoir data ($\emptyset, S_{wi}, S_{gi}, P_r, T_r$)), PVP data ($composition, \gamma, Z, B_g, \mu_g$)), production test data (PBU, MIT), well data (well depth, tubing length, tubing diameter, choke size, wellhead pressure, bottomhole pressure), and flowline data (flowline length, flowline ID, flowline OD, flowline roughness). This research method integrates three simulators to represent reservoir modeling, existing well modeling, and surface production network modeling. The models in the simulator then become the base case for further optimization scenarios to obtain the most optimal infill well pipeline network model. This research method is also complemented by bottlenecking index analysis in each optimization scenario to obtain an optimization scenario with the least bottlenecking.

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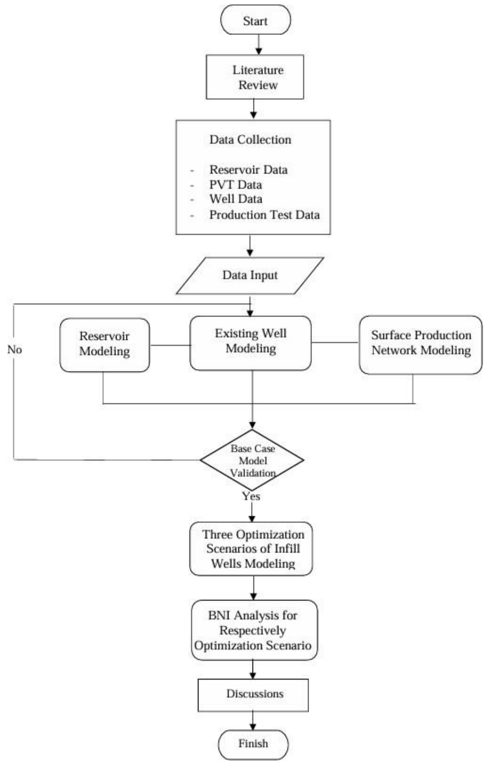

Figure 2.1 Research Flow Chart

Network modeling aims to determine whether infill wells should be combined in one pipeline network with existing wells or a separate pipeline network should be established. Before determining the infill well production network model as an optimization scenario, it is necessary to consider the combination of infill wells and existing wells based on the productivity of each well.

Wells with smaller flow rates will be referred to as low-productivity wells compared to wells with larger flow rates. Well productivity will be the basis for calculating the decrease in flow rate due to the addition of infill wells to the production network, which can also be referred to as flow rate loss. Figure 2.2 compares the productivity of both existing and infill wells.

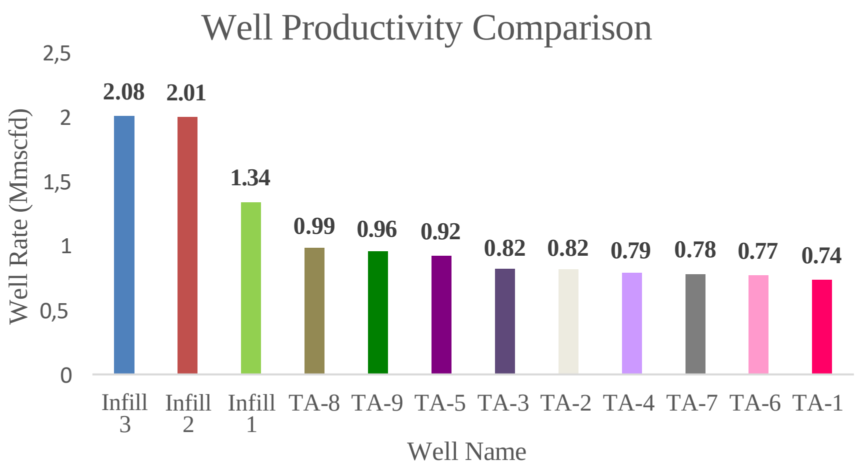

Figure 2.2. Well Productivity Comparison

Based on previous research on surface network optimization (Mehran et al., 2019), Merging infill wells with greater productivity with existing wells that also have greater productivity than other wells is necessary to reduce the loss rate due to pipeline merging. Figure 2.3 shows the position of infill wells in Field Y, but the distance between one well and another is assumed to be close. Considering the merging of production networks based on the loss rate when wells with small productivity are merged with wells with very large productivity, the surface production network optimization scenario of infill wells in Y Field is divided into three scenarios, as shown in Table 2.1.

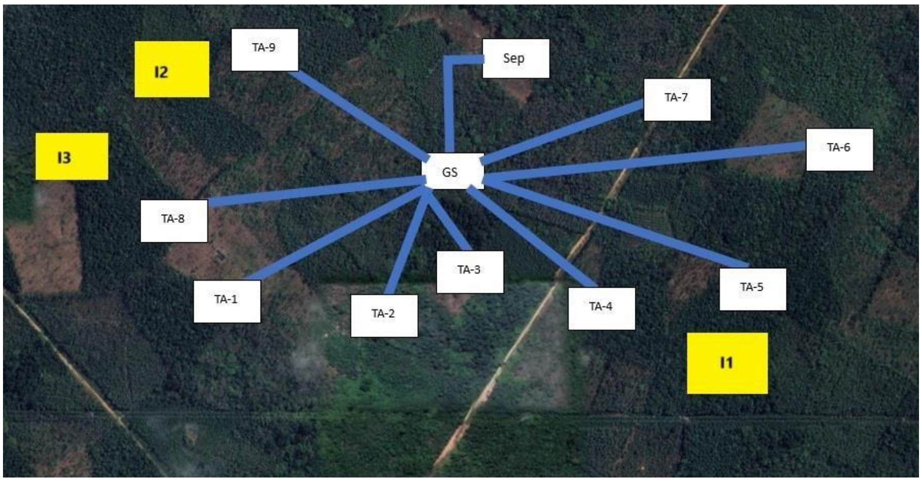

Figure 2.3. Position of Infill Wells in Field Y

Table 2.1. Y Field Infill Well Network Scenario

Scenario 1	Scenario 2	Scenario 3
Infill Well 3+ Well TA-8; Infill Well 2+ Well TA-9; Infill Well 1 + Well TA-5	Infill Well 3+ Infill Well 2; Infill Well 1 + Well TA-8	Infill Well 3; Infill Well 2; Infill Well 1

III. RESULTS AND DISCUSSION

Optimization through the infill well pipeline network scenario with an integrated model in Field Y is carried out by first calculating the reserves in Field Y. This reserve calculation is carried out to obtain the remaining reserves of Field Y, which will help determine whether the field is feasible to develop. Next, the necessary data is entered into the simulator, which will provide an overview of actual production in the field from the reservoir to the surface. The representation in the simulator will then become the base case developed through several optimization scenarios to determine the infill well pipeline model that produces the most significant gas volume.

3.1. Y Field Reserve Calculation

The Y Field reserves are calculated by first calculating the Initial Gas in Place (IGIP) using geological data. IGIP calculation uses the formula in Equation 1.1. The result of IGIP calculation using the volumetric method is 540.43 BSCF. Because Field Y has production data, the IGIP calculation uses the P/Z vs Gp material balance method in the reservoir modeling sub-program. The result is an IGIP value of 526.56 BSCF. Due to the difference in results, the IGIP data used to calculate reserves is obtained from the P/Z vs Gp material balance method because it is based on historical production data and is considered more representative of the actual reservoir conditions. Furthermore, Maximum Recovery Factor (RFmax) and Remaining Reserves (RR) data are required to determine whether the field is feasible to develop. Calculating the Maximum Recovery Factor at Pabandon = 150 psia using the formula in Equation 1.2. The result is an RFmax value of 93.21%. The results of the RFmax calculation are then used to calculate EUR. The calculation of Estimated Ultimate Recovery (EUR) uses the formula in Equation 1.3. The result is the EUR value of Field Y of 490.74 BSCF. The last and most important thing is to calculate the remaining reserves of Field Y. The result of this calculation is to determine whether Field Y can be optimized. The calculation of the remaining reserves uses the formula in Equation 1.4. The result of the remaining reserves of Field Y is 166,178 BSCF. It can be concluded that based on the large remaining reserves of Field Y, this field can be optimized by drilling infill wells.

3.2. Integrated Model Base Case Field Y

The Y Field Base Case integrated model consists of a reservoir model in the reservoir modeling sub-program and a well model in the well modeling sub-program, which is then integrated into the total system in the network modeling sub-program. This integration allows for forecasting and enabling infill well pipeline optimization scenarios as part of the development phase, in line with the buyer's contract.

Y Field Reservoir Modeling

Modeling the Y Field using a reservoir modeling simulator requires input reservoir fluid data (PVT) and physical properties of reservoir rocks. The input data is then used for history matching to ensure that the Y Field reservoir in the simulator matches the actual Y Field reservoir conditions. Field Y has been in production since 1979 and has production data, so it is more accurate to calculate IGIP using the P/Z vs Gp material balance method than the previously used volumetric method. The IGIP calculation results using the P/Z vs Gp material balance method processed with the reservoir modeling sub-program can be seen in Figure 3.1. The comparison of the two calculation results can be seen in Table 3.1.

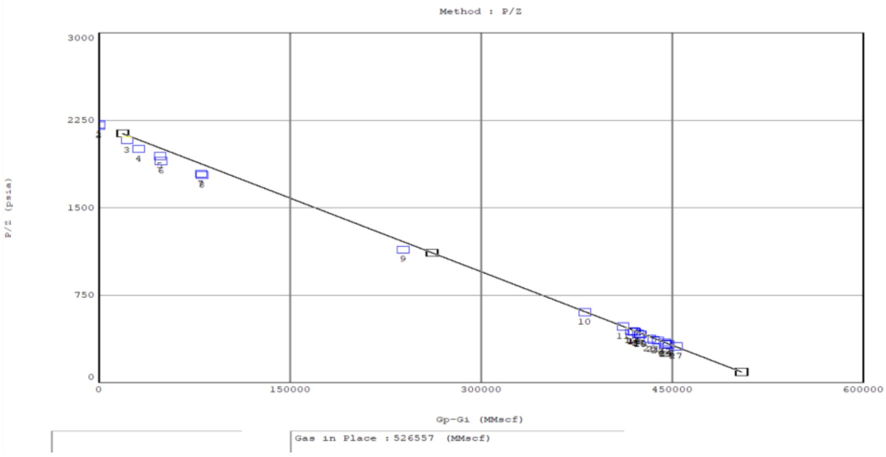

Figure 3.1. IGIP with P/Z vs Gp Method at Y Field

Table 3.1. Difference of IGIP Calculation Results

Methods	Value	Quantity
Volumetric	540.34	BSCF
MBAL P/Z vs Gp	526.56	BSCF
Difference	2.5	%

Based on the reservoir simulation results, a model close to actual conditions is obtained because the tank pressure and cumulative gas production from actual and simulated field data match. Thus, this reservoir model can be used for overall system modeling in the network modeling sub-program.

Y Field Gas Well Modeling

Gas well modeling uses the well modeling sub-program to analyze production performance from actual well conditions. The plot results obtained based on well-modeling simulation calculations show a flow rate graph against pressure (Q vs. Pwf) and tubing intake, thus forming an IPR curve along with the inflow and outflow system at wells in the Y field. The results of this simulation will later be used as a well model in the base case.

The well modeling sub-program creates Inflow Performance Relationship (IPR) curves by inputting the latest reservoir pressure according to the data taken on August 1, 2018, and C and n values in the IPR menu. Meanwhile, Vertical Lift Performance (VLP) construction was performed using 2.441-inch ID tubing data with a casing depth of 1292.9m. Table

3.2 shows the percent error between the actual and simulated gas rates, along with the actual pwf and simulated pwf of other existing wells.

Table 3.2. Differences between Well Test Results and Simulation of Existing Wells in Field Y

Well	Test Data		Simulation		Error	
	Qg (MMscf)	Pwf (psia)	Qg (MMscf)	Pwf (psia)	Qg (%)	Pwf (%)
TA-1	1.25	189	1.21	186	3.03	1.58
TA-2	1.62	229	1.60	224	1.23	2.18
TA-3	1.47	278	1.44	267	1.63	3.95
TA-4	1.60	241	1.57	232	1.62	3.73
TA-5	2.31	297	2.23	287	3.75	3.43
TA-6	1.47	226	1.43	218	2.91	3.54
TA-7	2.08	284	2.02	273	3.26	3.87
TA-8	2.37	301	2.29	294	3.24	2.49
TA-9	2.16	304	2.10	293	2.91	3.61

Integrated Modeling of Y Field

Modeling in the network modeling sub-program aims to form a surface network system model of the entire system integrated with the reservoir modeling sub-program and the production model of each well in the well modeling sub-program and to predict the future production performance of Field Y or perform forecasting. The first thing to do is to import reservoir/tank models from the reservoir modeling sub-program and wells from the well modeling sub-program, then complete the network and run the total system in the production performance menu. The production performance menu determines the production of the entire system up to the time interval specified in the prediction time and time step so that the prediction can be adjusted to the agreed contract time.

Figure 3.2 shows the prediction results from the base case integrated model where the gas rate obtained at the end of the contract period is 5.996 Mmscfd with cumulative gas production of 324.562 Bscf. Based on these results, the gas rate at the end of the contract period or on August 1, 2018, did not reach the production target as agreed, so the Company then optimized by adding infill wells so that production in the next ten years could increase and meet the target rate.

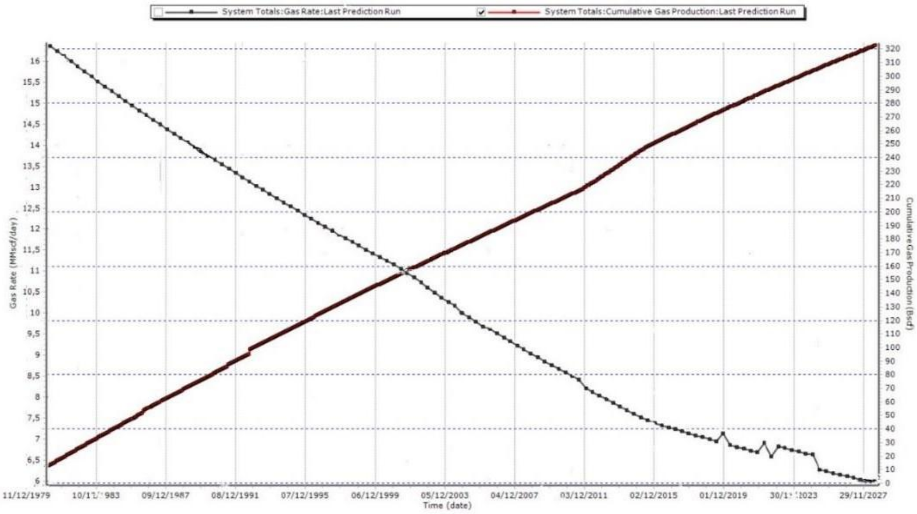

Figure 3.2. Y Field Base Case Prediction Results at the end of the contract period

3.3. Y Field Optimization Scenario with Infill Well Addition

Optimization in Field Y with the addition of infill wells aims to meet the production target in accordance with the gas rate agreement to be sold to consumers, which is 11 MMSCFD during the 10-year contract period. The stages in optimizing the gas flow rate are modeling the infill well in the well modeling sub-program, modeling the infill well production network into three optimization scenarios, and selecting the optimization scenario that produces the gas rate according to the production target.

Infill Well Modeling

Table 3.3 shows the percent error of the simulation results against the actual well-test results. Based on the error results on flow rate and pressure under all infill well simulation results with an error limit of 5%, the infill well model in the well modeling sub-program can be used for modeling in the network modeling sub-program.

Table 3.3. Differences between Well Test and Simulation of Infill Well in Field Y

Well	Test Data		Simulation		Error	
	Qg (MMscf)	Pwf (psia)	Qg (MMscf)	Pwf (psia)	Qg (%)	Pwf (%)
Infill-1	1.36	215	1.34	210	1.61	1.40
Infill-2	2.06	278	2.00	266	2.63	2.70
Infill-3	2.06	267	2.00	256	2.62	2.20

1st Scenario

Scenario 1 combines infill wells into one production line with existing wells with the greatest productivity. The Infill-3 well is combined in one production line with the TA-8 well because the TA-8 well has greater well productivity compared to other existing wells in Field Y, so the loss rate that occurs when the TA-8 well is combined with the Infill-3 well in one line will be smaller. Meanwhile, the Infill-2 well is combined with the TA-9 well, and the Infill-1 well is combined with the TA-5 well, which also has high productivity in one production line.

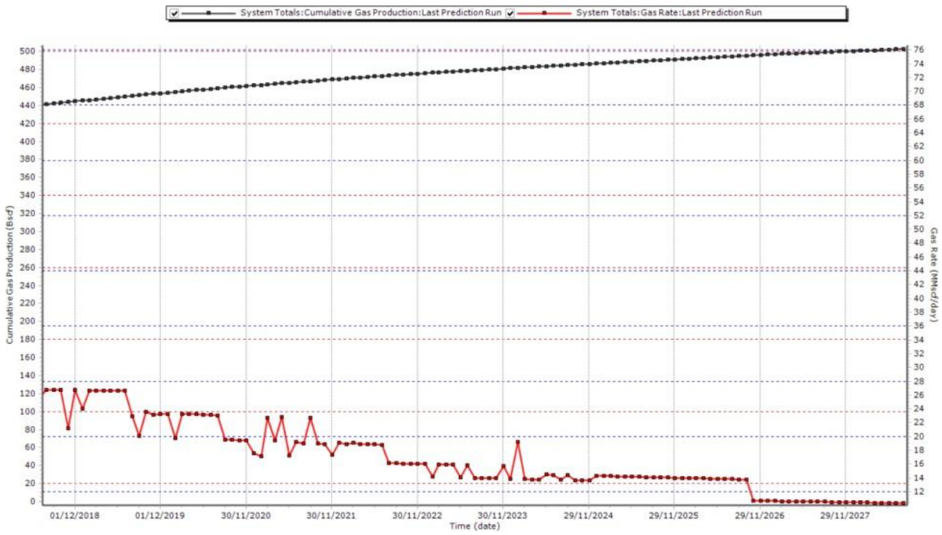

Figure 3.3. 1st Scenario Prediction Results

Figure 3.3 shows the results of running scenario 1 in the network modeling sub-program. The gas rate at the end of the contract is 10.19 Mmscfd, and cumulative gas production is 423 BSCF. The results of scenario 1 can increase the gas rate from the wells in Field Y but not reach the agreed-upon gas rate of 11 Mmscfd. The rate loss for each well combined in one production line are shown in Figure 3.4.

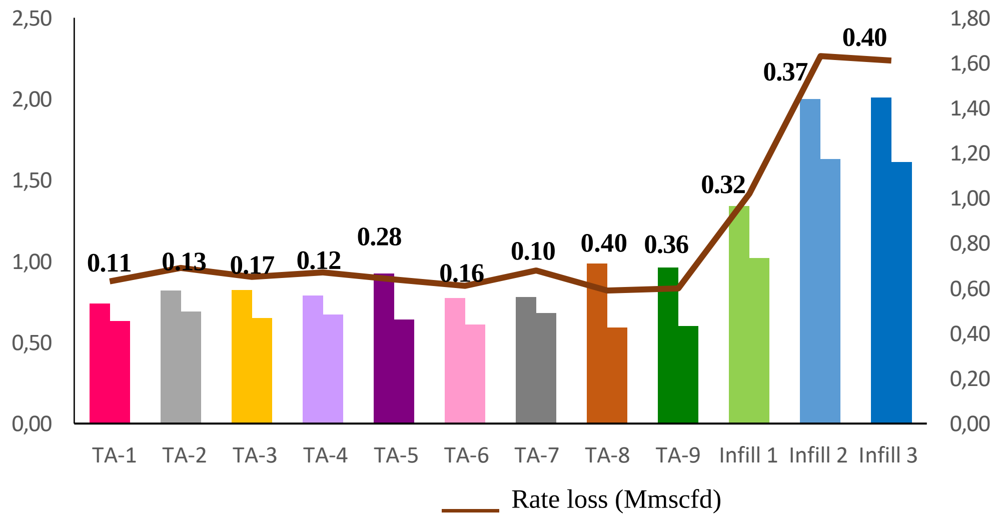

Figure 3.4. Rate Loss 1st Scenario

Table 3.4. 1st Scenario Pressure Profile

Well	Reservoir Pressure (Psig)	Pwf (Psig)	Wellhead Pressure (Psig)	Pressure at Manifold (Psig)	Pressure at GS (Psig)	Pressure at Separator (Psig)	*Base case* gas rate (MMSCFD)	1st Scenario Gas Rate (MMSCFD)
TA-1	369	310	254	75	69	60	0.74	0.63
TA-2	369	332	276	73	69	60	0.82	0.69

Well	Reservoir Pressure (Psig)	Pwf (Psig)	Wellhead Pressure (Psig)	Pressure at Manifold (Psig)	Pressure at GS (Psig)	Pressure at Separator (Psig)	*Base case* gas rate (MMSCFD)	1st Scenario Gas Rate (MMSCFD)
TA-3	369	349	278	71	69	60	0.82	0.65
TA-4	369	335	270	79	69	60	0.79	0.67
TA-5	369	342	296	81	69	60	0.92	0.64
TA-6	369	326	265	72	69	60	0.77	0.61
TA-7	369	346	281	79	69	60	0.78	0.68
TA-8	369	338	305	85	69	60	0.99	0.59
TA-9	369	341	298	83	69	60	0.96	0.60
Infill-1	369	347	276	81	69	60	1.34	1.02
Infill-2	369	345	281	83	69	60	2.00	1.63
Infill-3	369	339	283	85	69	60	2.01	1.61

Based on Figure 3.4, it can be seen that the wells that experience a relatively higher loss rate than other wells are those that are combined in one production network. However, the loss rate can be minimized because the combined wells have high productivity. The loss rates in existing wells and infill wells in scenario 1 are then adjusted to the pressure profile in Table 3.4.

Based on previous research (Yosefnejad et al., 2020), it is known that the manifold pressure in wells in the same production network has also increased. This increase in manifold pressure causes the wells connected to the manifold to experience back pressure. This is consistent with the results in the pressure profile table for scenario 1, where the three existing wells combined in one production network with infill wells experience an increase in wellhead pressure, and the manifold connecting the existing wells with the infill wells also has a large pressure. This can also be attributed to the loss rate that occurs in the wells in the network based on the difference in flow rates in the base case and the flow rate of each well after the scenario 1 simulation. It was found that the largest loss rate occurred in wells with increased wellhead pressure. Significantly compared to other wells, namely the TA-8 well. Scenario 1 could not meet the agreed gas rate, resulting in significant rate loss in several wells, so this scenario could not be implemented in Y Field.

2nd Scenario

Scenario 2 was conducted by combining infill wells into one production line with existing wells that have high productivity and combining two infill wells into one production line. Infill-3 wells are combined in one production line with Infill-2 wells, while Infill-1 wells are combined with TA-8 wells in one production line.

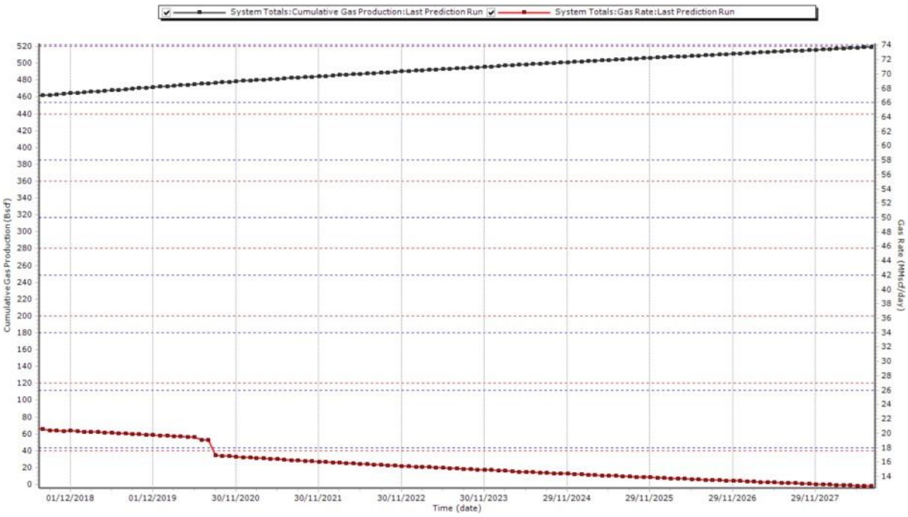

Figure 3.5. 2nd Scenario Prediction Result

Figure 3.5 is the prediction result of Scenario 2 in the network modeling sub-program, where the gas rate at the end of the contract is 12.68 Mmscfd and cumulative gas production is 339 BSCF. The results of Scenario 2 can increase the gas rate from wells in Field Y to an agreed-upon 11 Mmscfd. The rate loss for the wells in Field Y from Scenario 2 can be seen in Figure 3.6.

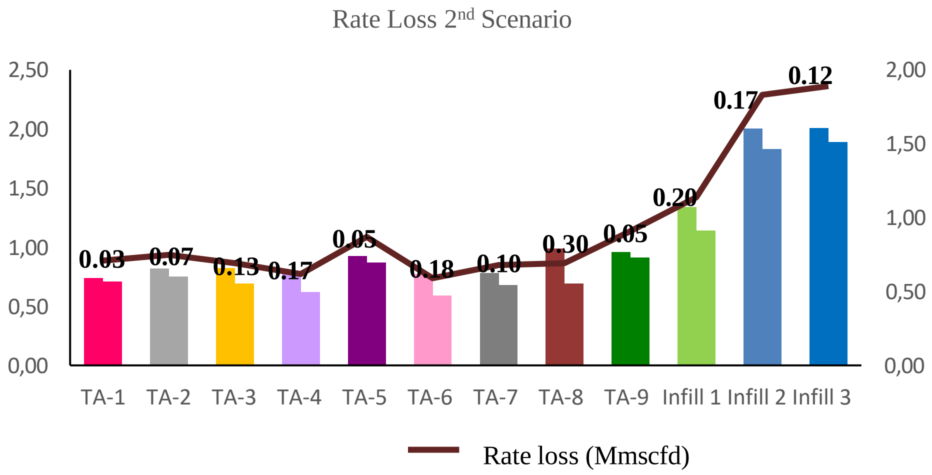

Figure 3.6. Rate Loss 2nd Scenarios

Table 3.5. 2nd Scenario Pressure Profile

Well	Reservoir Pressure (Psig)	Pwf (Psig)	Wellhead Pressure (Psig)	Pressure at Manifold (Psig)	Pressure at GS (Psig)	Pressure in Separator (Psig)	*Base case* Gas Rate (MMSCFD)	Gas Rate Scenario 2 (MMSCFD)
TA-1	426	365	304	86	69	60	0.74	0.71
TA-2	426	413	371	87	69	60	0.82	0.75
TA-3	426	406	358	87	69	60	0.82	0.69
TA-4	426	391	322	83	69	60	0.79	0.62
TA-5	426	420	358	86	69	60	0.92	0.87
TA-6	426	382	316	82	69	60	0.77	0.59
TA-7	426	413	350	86	69	60	0.78	0.68
TA-8	426	422	389	95	69	60	0.99	0.69
TA-9	426	421	367	87	69	60	0.96	0.91
Infill-1	426	423	361	95	69	60	1.34	1.14
Infill-2	426	412	321	83	69	60	2.00	1.83
Infill-3	426	413	328	83	69	60	2.01	1.89

Scenario 2 combines the two infill wells with the greatest productivity in one production network, namely Infill-1 and Infill-2 wells. Meanwhile, the Infill-3 well is combined in one production network with the TA-8 well, which is the existing well with the largest productivity. Based on Figure 3.6, it is known that in scenario 2 there is a loss rate in all wells in Field Y, but the loss rate that occurs in wells that are not combined in one pipeline network is not significant. A significant loss rate occurs at well TA-8, which follows the pressure profile for scenario 2 in Table 3.5. It is known that the wellhead pressure at well TA-8 is relatively high, and the manifold connecting well TA-8 to well Infill-1 also has considerable pressure. The increase in wellhead pressure at well TA-8 is due to the considerable pressure of the manifold, which exerts back pressure on the connected wells. In this case, because the productivity of the TA-8 well is smaller than that of the Infill-1 well, the loss rate due to the increase in wellhead pressure in the TA-8 well is greater. This is consistent with research from (Couper et al., 2009). Overall, scenario 2 can provide gas volumes that meet the production target and reduce the loss rate of wells in Field Y by combining infill and existing wells based on their productivity. In this scenario, the loss rate and back pressure can be minimized.

3rd Scenario

Scenario 3 was conducted by creating a pipeline network from each infill well separately and not combining it with the existing well. This aims to determine the volume of gas obtained when the infill wells have pipelines.

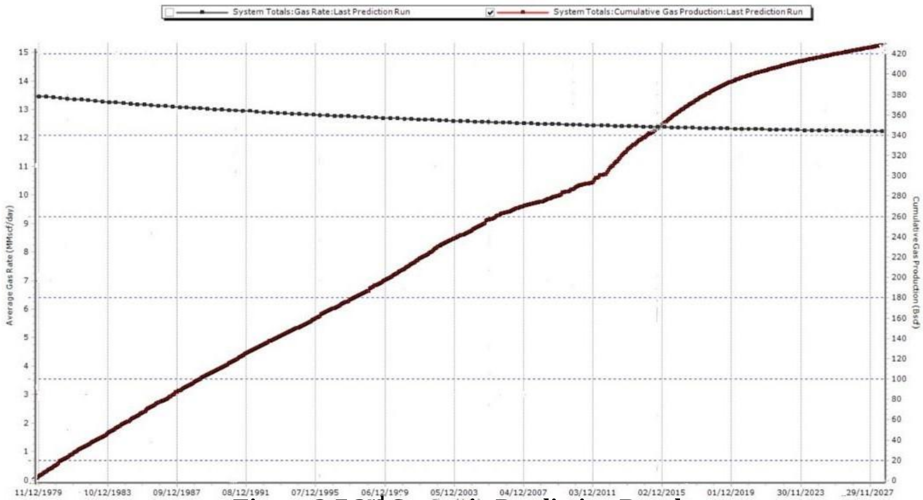

Figure 3.7 3rd Scenario Prediction Result

Figure 3.7 is the prediction result of scenario 3 in the network modeling sub-program, where the gas rate at the end of the contract is 12.76 Mmscfd, and cumulative gas production is 428.64 BSCF. Increase the gas rate from wells in Field Y to reach an agreed gas rate of 11 Mmscfd. The rate loss of wells in Field Y under scenario 3 is shown in Figure 3.8.

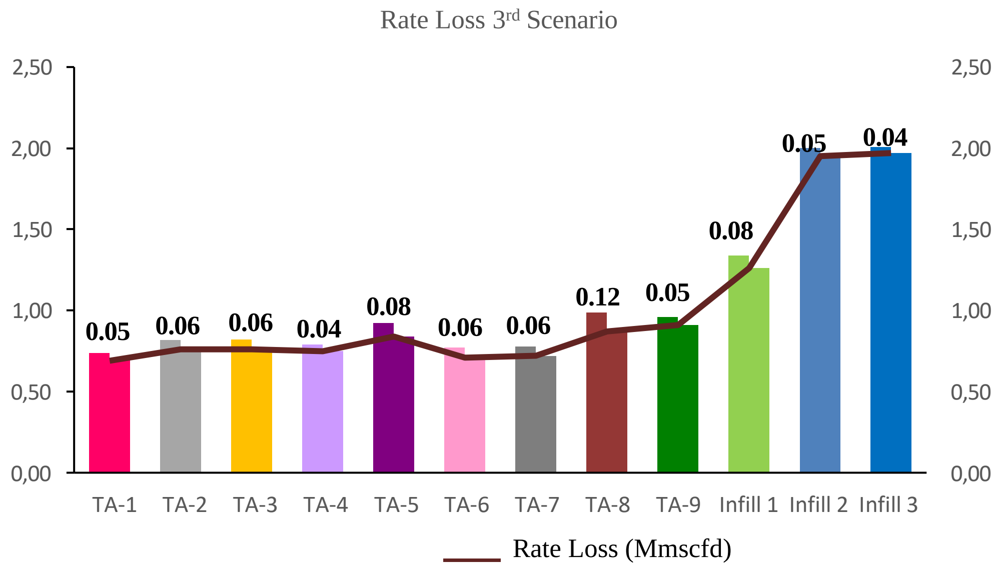

Figure 3.8. Rate loss 3rd Scenario

Table 3.6. 3rd Scenario Pressure Profile

Well	Reservoir Pressure (Psig)	Pwf (Psig)	Wellhead Pressure *(Psig)*	Pressure at Manifold (Psig)	Pressure at GS (Psig)	Pressure at Separator (Psig)	*Base case* Gas Rate (MMSCFD)	Gas Rate Scenario 3 (MMSCFD)
TA-1	391	363	291	75	69	60	0.74	0.69
TA-2	391	373	289	78	69	60	0.82	0.76

Well	Reservoir Pressure (Psig)	Pwf (Psig)	Wellhead Pressure (Psig)	Pressure at Manifold (Psig)	Pressure at GS (Psig)	Pressure at Separator (Psig)	*Base case* Gas Rate (MMSCFD)	Gas Rate Scenario 3 (MMSCFD)
TA-3	391	380	296	77	69	60	0.82	0.76
TA-4	391	375	297	79	69	60	0.79	0.75
TA-5	391	387	288	79	69	60	0.92	0.84
TA-6	391	370	298	81	69	60	0.77	0.71
TA-7	391	385	291	76	69	60	0.78	0.72
TA-8	391	389	290	78	69	60	0.99	0.87
TA-9	391	389	280	79	69	60	0.96	0.91
Infill-1	391	342	281	80	69	60	1.34	1.26
Infill-2	391	376	292	81	69	60	2.00	1.95
Infill-3	391	373	297	78	69	60	2.01	1.97

Scenario 3 does not combine infill wells with existing wells or other infill wells but creates a separate pipeline network for each infill well. This scenario aims to determine the volume of gas that can be obtained if each infill well has its pipeline network. Based on Figure 3.8, it is known that loss rates occur in all wells in Field Y, but the loss rate that occurs in Scenario 3 is not significant. This is in accordance with previous research (Shi et al., 2018). In scenario 3, no well merging is done, so the loss rate caused by the intervention of wells with large productivity in the same network does not occur.

Based on the pressure profile that occurs along the pipeline from the reservoir pressure to the separator at the surface, it can be seen that the wellhead pressure in scenario 3 is relatively the same, or there are no wells whose wellhead pressure has increased drastically. In addition, the manifold pressure in scenario 3 is also in the same range, so there is no large manifold pressure that impedes the flow of gas from the well, so the loss rate in scenario 3 is not significant (Carpenter, 2016). Overall, scenario 3 provides the most optimal gas volume, loss rate, and backpressure results, which can be minimized due to the separate infill well pipelines.

3.4. Bottlenecking Index (BNI) Analysis for Optimization Scenario

The bottlenecking index (BNI) calculation is a pipeline evaluation determining how much bottlenecking occurs in the production component. BNI calculation is obtained by comparing the total maximum flow rate received by the gathering station (qgs) with the total maximum flow rate from each well (qmax). The flow rate at the Gathering Station is obtained by summing the flow rate from each well, while the total maximum flow rate (qmax) T is obtained by summing the maximum flow rate from each well. BNI has a maximum price of 1. Theoretically, a larger BNI value indicates that the bottlenecking that occurs will be smaller. Meanwhile, the smaller the BNI value, the greater the bottlenecking. It can be concluded that the BNI value is inversely proportional to how much bottlenecking occurs in the field. The bottlenecking index results for the three optimization scenarios for Field Y can be seen in Table 3.8.

Scenario	Qgs	Qmax	BNI
1st Scenario	10.02	17.39	0.58
2nd Scenarios	11.37	17.39	0.65
3rd Scenarios	12.19	17.39	0.71

Based on the results of the bottlenecking index (BNI) analysis that has been carried out on each optimization scenario, it is known that scenario 3 is the scenario with the highest BNI value. BNI has a maximum value of 1, so scenario 3 has less bottlenecking than the other two scenarios. Scenario 3 is the only scenario not combining infill wells with existing wells, so scenario 3 has the smallest bottlenecking. It is known that bottlenecks can be caused by pipeline capacity that is not large enough to handle the combined flow rate of infill wells and existing wells. Another cause of bottlenecks in each optimization scenario is the presence of back pressure on existing wells due to infill wells that have high flow rates (Almohammad et al., 2016)..

IV. CONCLUSIONS

Based on the analysis and optimization process discussed above, the following are the conclusions of this research

1. The results obtained show that the third scenario is the scenario that produces the most optimal gas volume, which is 12.76 Mmscfd with cumulative gas production of 428.64 BSCF, and is the scenario that has the most optimal BNI value, which is 0.71. However, because the difference between the gas volume and BNI value in the second and third scenarios is not significant, the author chooses the second scenario as the optimization scenario for Field Y, which produces a gas volume of 12.68 Mmscfd and cumulative gas production of 339 BSCF. The second scenario uses fewer pipelines to reduce field operation costs.
2. Among the three optimization scenarios, the third has the highest BNI value, 0.71. This is in accordance with the theory, where the third scenario is one in which no infill well pipelines are combined with production well pipelines, so there are fewer obstacles in the production network and a greater volume of gas received at the Gathering Station.

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