

Improving the result of forecasting using reservoir and surface network simulation

R S Hendri^{1*}, J Winarta²

¹Oil Engineering Department, Faculty of Earth Technology and Energy, Universitas Trisakti, Jakarta, Indonesia

²Special Taskforce for Upstream Oil and Gas Business Activities, Jakarta, Indonesia

*Corresponding Author : rsitairesmi@trisakti.ac.id

Abstract. This study was aimed to get more representative results in production forecasting using integrated simulation in pipeline gathering system of X field. There are 5 main scenarios which consist of the production forecast of the existing condition, work over, and infill drilling. Then, it's determined the best development scenario. The methods of this study is Integrated Reservoir Simulator and Pipeline Simulator so-called as Integrated Reservoir and Surface Network Simulation. After well data result from reservoir simulator was then integrated with pipeline networking simulator's to construct a new schedule, which was input for all simulation procedure. The well design result was done by well modeling simulator then exported into pipeline simulator. Reservoir prediction depends on the minimum value of Tubing Head Pressure (THP) for each well, where the pressure drop on the Gathering Network is not necessary calculated. The same scenario was done also for the single-reservoir simulation. Integration Simulation produces results approaching the actual condition of the reservoir and was confirmed by the THP profile, which difference between those two methods. The difference between integrated simulation compared to single-modeling simulation is 6-9%. The aimed of solving back-pressure problem in pipeline gathering system of X field is achieved.

Keywords: integrated reservoir simulation, surface network simulation, tubing head pressure

1. Introduction

X Field is a gas field in South Sumatera that has been producing from five wells with IGIP estimation 80.06 BCF with reservoir structural configuration at 1450-1850 meters deep illustrated in Figure 1. In this paper, the authors analyze the producing wells in X Field; cumulative production from all 5 wells is 2.27 BSCF with recovery factor estimation approximately 2.8%.

There are several main scenarios which consist of the production forecast of the existing condition (do nothing), additional intervention activities such as Work over and Infill well. By doing a reservoir simulation (simulation model has 215 x 149 x 19 cells, or total grid cells of 608,665) including fluid properties (reservoir pressure 2259 psig, gas viscosity 0.01682 centipoise, gas Formation Volume Factor 0.0078, density of gas 0.2559 gr/cc) and then applying all five scenarios to the model by integration with the pipeline networking or, it is expected that this simulation would give an accurate prediction and also comparison between scenarios so that X Field can be best developed.



2. Research Method

Feasibility for additional X Field development began with reservoir simulation and integrated simulation where the expected result would represent actual conditions. Simulation process began with structural modeling, modeling reservoir condition by integrating existing data (geology and reservoir) mathematically to get reservoir performance for several well's condition and production profiles. Simulation model has 215 x 149 x 19 cells, or total grid cells of 608,665. In this study, Black Oil Reservoir Simulator and Pipeline Simulator were used. One of the required data for the reservoir simulation input is the Depth Structure Map made by reservoir modeling. Area shown in yellow is the prospect hydrocarbon (Figure 1).

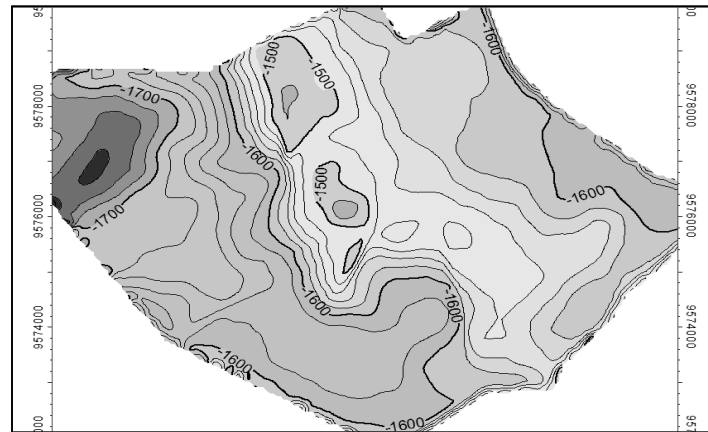


Figure 1. Depth structure map.

Reservoir simulation process began with several steps; data preparation, building model and grids, initialization, history matching and prediction. Initialization process included matching IGIP or total initial hydrocarbons in place with hydrocarbon control volume via volumetric method. History matching was done to ensure the model design represented actual reservoir conditions by changing the relative permeability and transmissibility (Figure 2).

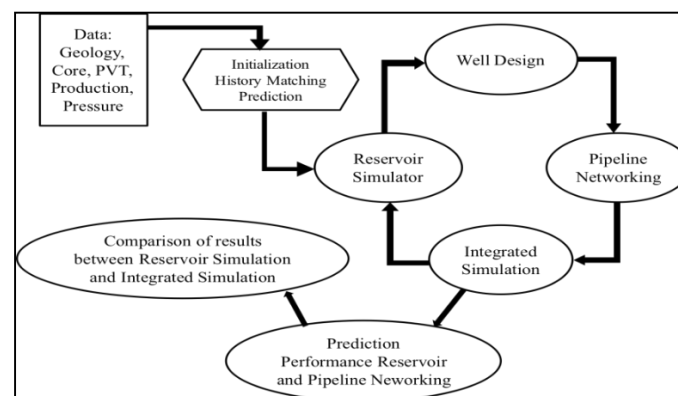


Figure 2. Workflow in integrated simulation.

Advanced processing included integration of reservoir simulation with pipeline networking of in-field well design with well modeling simulation. Combinations of all simulations were accomplished using Parallel Virtual Machine.

The methods of this study is Integrated between Reservoir Simulator and Pipeline Simulator so-called Integrated Reservoir and Surface Network Simulation. Advanced procedure included integration of reservoir simulation with pipeline networking of infill well design with well modeling simulation.

After result of well data from reservoir simulator was then integrated with pipeline networking simulator's to construct a new schedule, which was input for all simulation procedure. The well design result which was done by well modeling simulator was then exported into pipeline simulator. Reservoir prediction depends on the minimum value of Tubing Head Pressure (THP) for each well, where the pressure drop on the Gathering Network is not necessary calculated. The same scenario was done also for the single-reservoir simulation. Integration Simulation produces results approaching the actual condition of the reservoir and was confirmed by the THP profile which differ between those two methods.

3. Results and Discussion

Data for each well was input to well modeling simulator, which includes the process synchronization of well tests data (VLR/IPR Matching), needed to generate accurate output. In the synchronization of VLP of the Bottom Equipment (casing size, tubing depth, and tubing size) specification data has to be changed in order to match the simulation output and the well test results. Matching result between Cumulative Gas Production (Simulation) and Gas Production (Actual) of each well in X Field are displayed in Figures 3. This figure shown in blue is the result plot and red is straight line 45°. It means that the simulation result has already matched with the actual result.

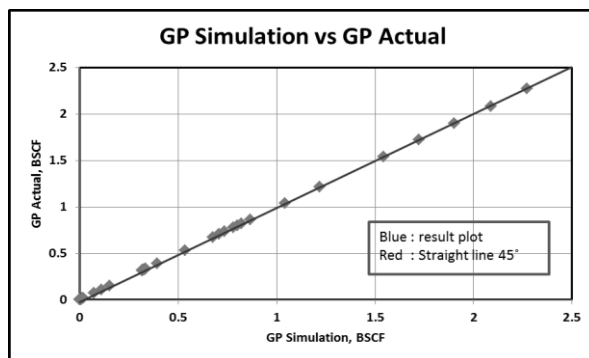


Figure 3. Cumulative gas simulation and actual.

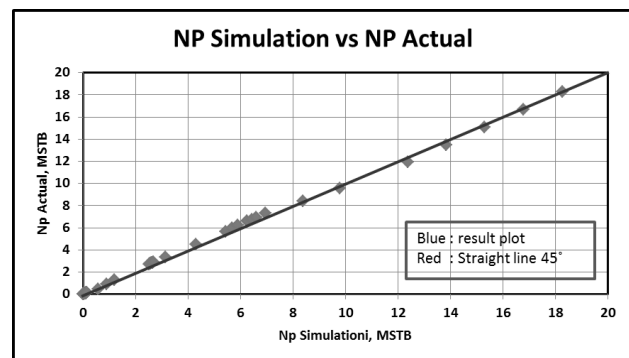


Figure 4. Cumulative oil between simulation and actual.

Matching result between Cumulative Oil Production in Simulation and Oil Production in Actual condition of each well in X Field is displayed in Figures 4. This figure shown in blue is the result plot and Red is Straight line 45°. It means that the simulation result has already matched with the actual result.

The network that was designed depends on field data whereas the output continued into the connecting software for integration with the reservoir *Source*. Integration was done by using the connection software collaboration of pipeline simulator and reservoir simulator. Surface network model is built by using pipeline simulator called Pipeline Network Map (Figure 5).

All the part of surface network have to be connected each other (Figure 6) including reservoir system from reservoir simulator. From those methode, it is known that the back pressure problem from each well to the surface tools such as separator and etc.

Well data from reservoir simulator was then integrated with pipeline simulator's well data to make a new schedule, which was input for full-simulation process. The same scenario was done for the single-simulation (Reservoir simulator only). X Field simulation comprises of five scenarios: Scenario I = Base Case (BC) + Work over, Scenario II = Scenario I + 1 Infill well, Scenario III = Scenario II + 1 Infill well, Scenario IV = Scenario III + 1 Infill well, Scenario V = Scenario IV + 1 Infill well.

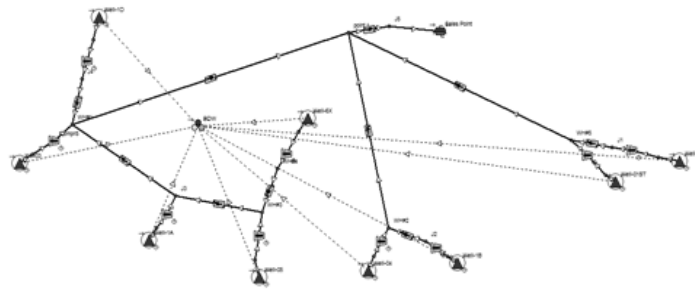


Figure 5. Pipeline network map.

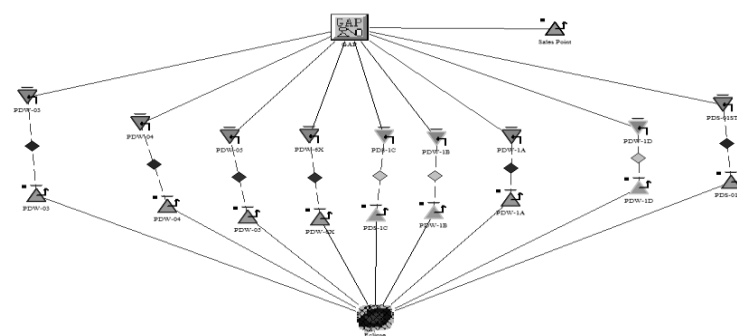


Figure 6. Conjunction network.

The Result of scenario I (Base Case+Work Over) is displayed in Figures 7. Base Case means do nothing that is no infill drilling but only Work over. Red line is the result of Reservoir simulator Rate, Blue line is the result of Integrated Simulator Rate. From 2013 in 12 MMSCFD to 2016 the rate of reservoir simulator declined whereas the integrated simulator rate only started to decline 5 years later. For reservoir simulator cumulative also less than integrated simulator cumulative. The integrated simulator cumulative has 4300 MMSCF.

The Result of scenario II (Scenario I + 1 Infill well) is displayed in Figures 8. Red line is the result of Reservoir simulator Rate, Blue line is the result of Integrated Simulator Rate. From 2013 in 12 MMSCFD to 2018, the rate of reservoir simulator declined whereas the integrated simulator rate only started to decline 6 years later. For reservoir simulator cumulative also less than integrated simulator cumulative. The integrated simulator cumulative has 4500 MMSCF.

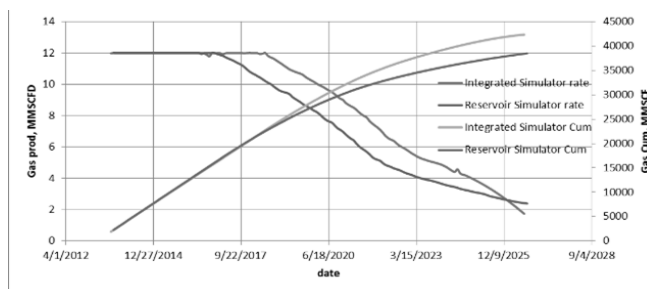


Figure 7. Gas flow rate-cumulative gas production difference (scenario I).

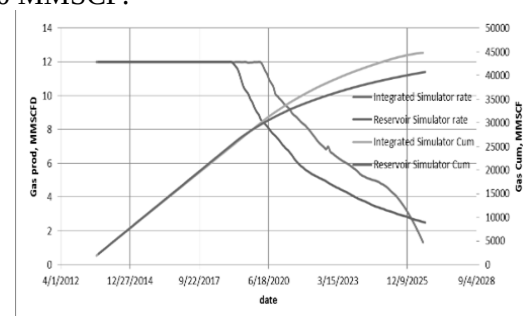


Figure 8. Gas flow rate-cumulative gas production difference (scenario II).

The Result of Scenario III (Scenario II + 1 Infill well) is displayed in Figures 9. Red line is the result of Reservoir simulator Rate, Blue line is the result of Integrated Simulator Rate. From 2013 in

12 MMSCFD to 2019 the rate of reservoir simulator declined whereas the integrated simulator rate only started to decline almost 8 years later. The integrated simulator cumulative has 4400 MMSCF.

The Result of Scenario IV (Scenario III + 1 Infill well) is displayed in Figures 10. Red line is the result of Reservoir simulator Rate, Blue line is the result of Integrated Simulator Rate. From 2013 in 12 MMSCFD to 2019 years later the rate of reservoir simulator declined whereas the integrated simulator rate only started to decline 8 years later. For reservoir simulator cumulative also less than integrated simulator cumulative. The integrated simulator cumulative has 4500 MMSCF.

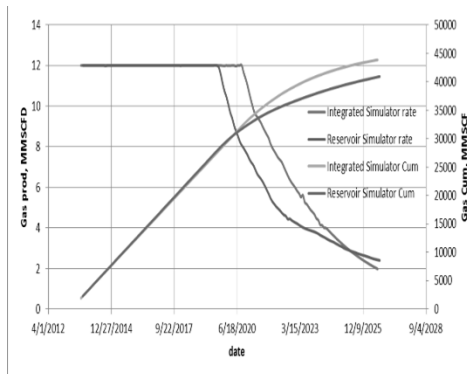


Figure 9. Gas flow rate-cumulative gas production difference (scenario III)

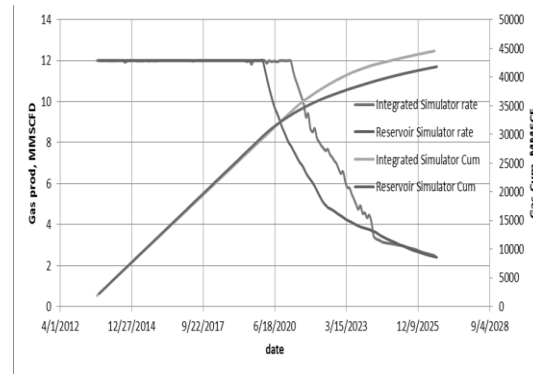


Figure 10. Gas flow rate-cumulative gas production difference (scenario IV)

The Result of Scenario V (Scenario IV + 1 Infill well) is displayed in Figures 11. Red line is the result of Reservoir simulator Rate, Blue line is the result of Integrated Simulator Rate. From 2013 in 12 MMSCFD to 2019, the rate of reservoir simulator declined whereas the integrated simulator rate only started to decline almost 9 years later. The integrated simulator cumulative has 4600 MMSCF.

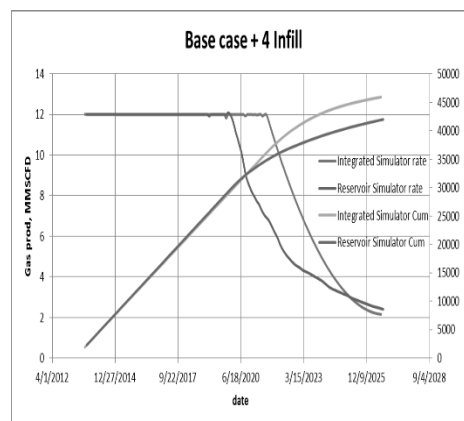


Figure 11. Gas flow rate cumulative gas production difference (scenario V).

From charts shown previously, it can be drawn the conclusion that there is a difference between these two methods. On average the difference ranges from 6% to 9% of cumulative gas production (also with the different plateau of 2 years). Reservoir simulation prediction depends on the minimum value of THP for each well, where pressure drop on the Gathering Network is not calculated. On the other side, the integrated simulation method covers all of the reservoir parameters until the Gathering Network is put into calculation. The difference of Tubing Head Pressure value is illustrated on Figure 12.

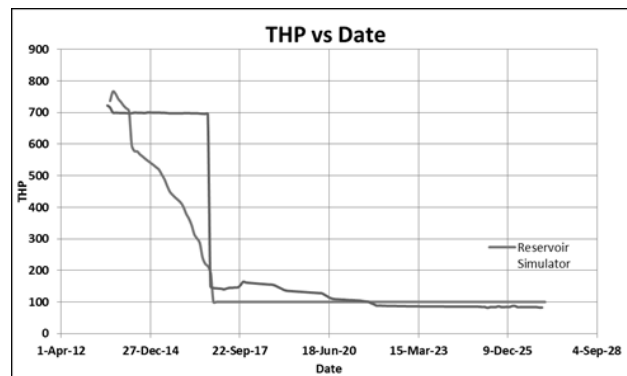


Figure 12. THP difference between single reservoir simulation & integrated simulation.

Integration of the reservoir and pipeline networking is accomplished by reservoir simulator and pipeline simulator. Before initiating integration, first step by making a well design for each existing well then combine with the pipeline networking from previous simulation (Table 1). The results are the same across 5 scenarios that have differences. This confirms single-simulation modeling has a limitation in determining Tubing Head Pressure (THP), but not the integrated modeling. Therefore, the aimed of solving back-pressure problem in pipeline gathering system of X field, is achieved.

Table 1. Comparison of scenarios.

Scenario	Comparison		
	Description	Int Cum(MMSCF)	Difference (%)
First	Base-Case + Work over	4300	9.1
Second	Scenario 1 + 1 infill	4500	9.0
Third	Scenario 1 + 2 Infill	4400	6.7
Fourth	Scenario 1 + 3 infill	4500	6.1
Fifth	Scenario 1 + 4 infill	4600	8.6

4. Conclusion

The difference between integrated reservoir and surface network simulation compared to single-simulation was about 6-9%. Five simulated scenarios show the same result that confirm single-simulation modeling has a limitation in determining Tubing Head Pressure (THP), but not the integrated modeling. Integration reservoir and surface network simulation produces results approaching the actual condition of the reservoir; this was confirmed by the THP profile difference between those two methods.

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