PROFESSIONAL TECHNICAL PAPER
ONLINE PRESENTATION
24 - 25 OCTOBER 2020

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Better Well Performance Diagnosis and Reservoir Management with Alternative Well Outflow Prediction from Your Desk: Well Modelling-Based Approach at Shallow Zone of Tunu Field, Mahakam

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Abstract. Shallow Zone of Tunu Field (TSZ) which was initially identified as drilling hazards has been extensively developed to produce gas from widespread and scattered gas-bearing sand reservoirs all over 1500 km^2 of deltaic area in Tunu Field with extremely good reservoir properties. It has been produced more than 600 Bscf with main reservoir characteristic: strong aquifer support with maintained reservoir pressure at hydrostatic. Water encroachment monitoring is critical for wellbore performance diagnosis and reservoir management. However due to operational limitations, water outflow measurement could not be implemented continuously: spot test performed by gathering separator, mobile testing unit concern, deltaic field environment, manpower, out of service equipment, etc. By having empirical observation, there is no clear relationship between variables: water outflow and wellhead flowing temperature (WHFT) for known variable of gas production rate (Q_g). This uncertainty is coming from several parameters that affect WHFT: multiphase flow rate, geothermal gradient, pressure drop in the tubing, specific heat of the gas, etc.

By using wellbore temperature profiles approach that developed originally for predicting temperature profiles of multiphase flow inside conduit, water outflow estimation could be estimated by reverse calculation of known variables. Well modeling-based approach has been initiated to predict water outflow based on available wellhead parameter: 1) Analytical Model; 2). Dynamic well modelling; 3) Steady-state well modelling. Model validation shows good performance in estimating water outflow. Water Gas Ratio - WHFT for Q_g variation chart could be generated automatically by in-house tool for specific well or field basis in order to be used for practical operation. Another approach is proposed if Q_g becomes unknown parameter/unreliable: Nodal Analysis coupled with wellbore temperature profiles approach by WHFP & WHFT matching at certain downstream operation condition (i.e. choke opening & flowline pressure mode). This "from your desk" approach could be an alternative for continuous/regular production test in order to estimate or predict well outflow prediction when facing operational constraints. The objective is to take better decision making for production optimization and reservoir management.

Keyword: *well outflow prediction, water encroachment, well modelling-based approach*

1 Background

Tunu is a mature giant gas field, covering an area of 75 km long and 15 km wide at eastern limit of Mahakam Delta. It consists of enormous multi-layer sand-shale series deposited within a deltaic environment. Discovered in 1977, the production commenced in 1990 and reached peak 1500 MMscfd in 1999. As one of the major gas suppliers in Indonesia and recently contributes to 35% of Mahakam gas production, this field has been produced more than 9000 Bscf of cumulative gas production (G_p) with more than 1300 drilled wells. This field constitutes a series of stacked fluvio-deltaic sand bodies deposited as channel fill or mouth bars lying between surface and 5000 mTVDss (Purwanto et al., 2017). The series are mainly divided into 2 zones as illustrated in **Figure 1**: 1). Shallow Zones from 0 to 2800 mTVDss and; 2). Main Zone from 2800 - 5000 mTVDss.

Shallow Zone of Tunu Field (TSZ) which initially was identified as drilling hazards has been extensively developed to produce gas from widespread and scattered gas-bearing sand reservoirs all over 1500 km^2 of deltaic area in Tunu Field. It corresponds to Pliocone fluvio-deltaic series in the interval of 600 - 2200 mTVDss, where the limited and individual gas accumulations are identified as fluvial and distributary channel reservoirs with good reservoir properties. Reservoir porosity is dominated at range 20 - 30% (Basa et al., 2017). TSZ development relies on the use of seismic with more than 160 seismic driven wells have been drilled with 82% success ratio (Basa et al., 2017). Recently, there are nearly 280 TSZ wells were drilled during the latest 13 years and TSZ reservoirs have been produced more than 600 Bscf and contributes 45% of Tunu field gas production as shown by **Figure 2.**

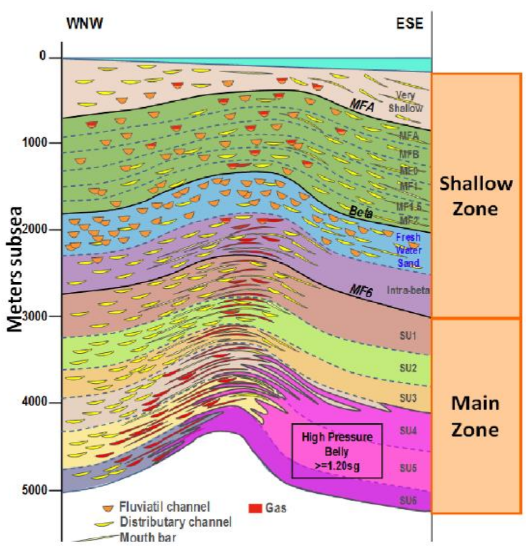


Figure 1. Tunu field vertical cross section

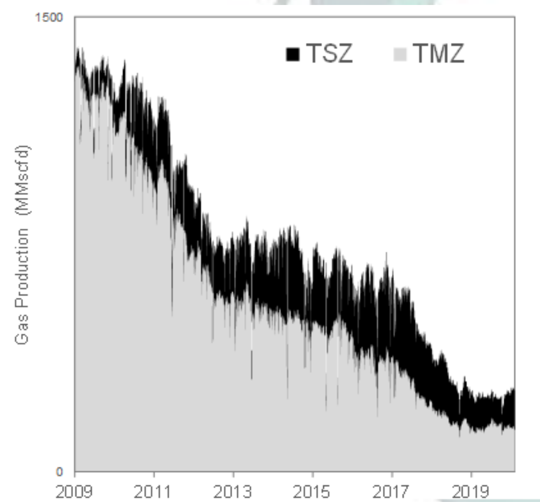


Figure 2. TSZ production contribution

Main reservoir characteristics in TSZ reservoirs are summarized as follow (Ashfahani et al., 2020):

1) Good reservoir properties. Unconsolidated sand is identified therefore adequate sand control technique, strategy and management should be implemented to monetize this type of reservoir.

2) Unconsolidated sand reservoirs with typically 3 - 5 m thin interbedded zones. Particle sizes are not uniform with U_c (d40/d90) of 11 referring to the sieve analysis of 20 samples from TSZ reservoirs. All TSZ wells requires sand control to mitigate the risk of producing sand (Wijaya et al., 2016).
3) Dry gas fluid reservoir with composition: Methane, C_1 > 90%. Two main theory are considered regarding fluid generation, secondary migration from the prolific Main Zone or a biogenic origin (Rengifo et al., 2012).
4) Reservoir pressure maintenance by strong aquifer support where pore pressure is generally identified as hydrostatic. Reservoir driving mechanism characteristics is clearly explained by Ashfahani et al. (2020) for TSZ reservoirs.

Figure 3 and **Figure 4** shows surface production data and Chan plot (Chan, 1995) respectively for water production behavior from two TSZ well samples. Water breakthrough (WBT) timing prediction could be predicted by available approach, such as Sobicinski-Cornelius (1965). Practically, actual gas production (Q_g) is considered above critical gas rate (Q_{gc}) for WBT approach (i.e. Chaney et al., 1956) in order to accept economics and field production target. This water production also critical for Material Balance Energy (MBE) Analysis for recovery evaluation and capturing aquifer characteristics, such as by Havlena-Odeh MBE approach (Ashfahani et al., 2020).

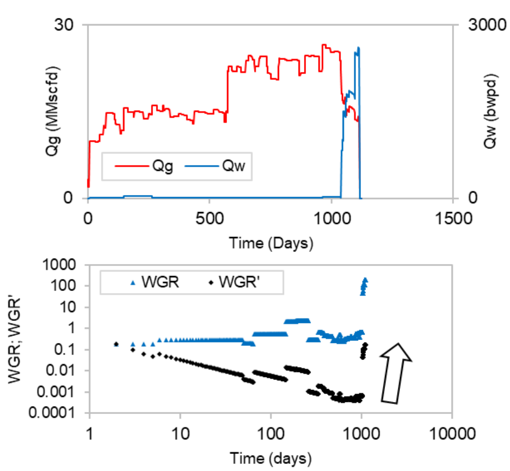


Figure 3. Water production history and water diagnostic chart of Well-U

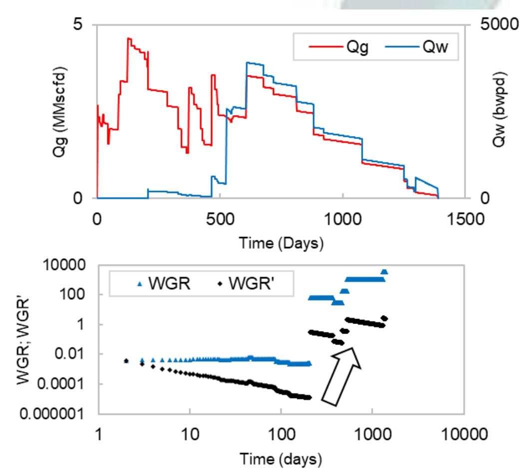


Figure 4. Water production history and water diagnostic chart of Well-K

In actual condition, Q_w is measured regularly, weekly or monthly, by gathering production testing separator with spot-mode record. It is performed in commingle mode with another producing wells and sometimes has operational challenges or limitations such as liquid counter instrument problem and separator capacity. Another alternative is by using swamp mobile separator-testing barge as shown by **Figure 5** that require well to be shut-in before production test due to test manifold are not available by configuration and safety reason in Tunu field. It is not preferable from well performance point of view since shut-in condition create worse condition of multiphase flow inside wellbore. Water outflow measurement (Q_w) for water encroachment monitoring is critical and become the key for well performance and reservoir management. Spot test of Q_w measurement create uncertainty of multiphase flow inside wellbore in practical operation.

In TSZ case, Q_g is defined as known variable since it is the interest parameter which measured and monitored daily (i.e. by production test-based potential estimation, actual gas flow rate measurement at well and flowline).

Figure 5. Mobile separator testing unit

Q_w estimation and prediction for TSZ wells was initiated with available regular wellhead data: wellhead flowing pressure (WHFP), wellhead flowing temperature (WHFT), choke opening, flowline pressure and Q_g. It was initiated as an alternative of production test that has several operational constraints. Water outflow could be estimated with wellbore temperature profiles approach that developed originally for predicting temperature profiles of multiphase flow inside conduit (pipeline/wellbore) which presented by several reports such as by Ramey (1962), Shiu & Beggs (1980), Hasan & Kabir (1996), Sagar et al. (1991). Reverse calculation could be performed by known variables of WHFT & Q_g.

This feature is also available in commercial well model tool or by in-house spreadsheet-based tool involving available equations. This initiative could support several operational activities such as:

- Alternative production test activities.
- To predict Q_w deliverable potential (defined water outflow) based on wellhead parameter.
- Perform multiphase flow well diagnosis for lifting performance.
- Estimate massive water production that impact to gas production (inflow productivity).
- Decision guidance of choking/un-choking activities for production optimization.
- Confirm water breakthrough due to coning effect.
- Production recovery and aquifer mechanism monitoring by MBE approach.

Another challenge also presence, how if Q_g measurement is not reliable and become unknown variable? Solution for this challenge also presented in this paper for well outflow prediction based on well modelling approach with available wellhead data. As described previously, the scope of this best initiative is for TSZ well in Tunu field which has characteristics of gas and water phase flow inside wellbore and has strong aquifer support that maintain reservoir pressure. Reservoir depth also limited to TSZ reservoirs area. However, this "from your desk" approach could be an alternative for continuous/regular production test in order to estimate or predict well outflow prediction when facing operational constraints. The objective is to take better decision making for production optimization and reservoir management.

2 Methodology

Initiative program for continuous well outflow estimation and prediction (focus on water outflow) was performed for conventional production test alternative. It starts with quite pragmatic approach, empirical data observation from many samples of production test data and following with more advanced approach by dynamic and steady state well model tool. Spreadsheet-based tool also was involved for analytical approach which consists of wellbore temperature profile data from available reports.

2.1 Empirical Observation

Quite pragmatic approach was considered by empirical approach that simply observe the trend of Q_w trend as impact from known Q_g and WHFT from actual production test data. This approach is more specific for certain field case in TSZ wells. Production test data from gathering separator or mobile testing unit were gathered and collected based on Q_g categories to observe Q_w trend as a function of WHFT. **Figure 6 & 7** shows chart for water outflow trend based this condition from 65 production test samples. There are several data that shows same WHFT for different Q_w and Q_g. It makes Q_w estimation or prediction will be uncertain with simply create linear function of WHFT for each Q_g categories. Significant different value of WHFT also observe for quite same Q_w value. From this observation, it could be concluded that WHFT for certain Q_w & Q_g is the function of reservoir contributor depth which Geothermal gradient in TSZ wells is the key (Ashfahani & Grahadiningrat, 2019). Another thing is the uncertainty U-value factor (overall heat transfer coefficient) during flowing which has different value for each case: reservoir contributor depth, multiphase flow condition, wellbore architecture that impact to heat/thermal transfer (convection, conduction). Empirical observation just implemented qualitatively for operational purpose, such as predict the presence of massive water outflow from the well based on known Qg value and recorded WHFT with known reservoir contributor depth. Another approach is needed to solve this uncertainty factors for practical purpose. Available well model tool is considered to estimate or predict water outflow performance.

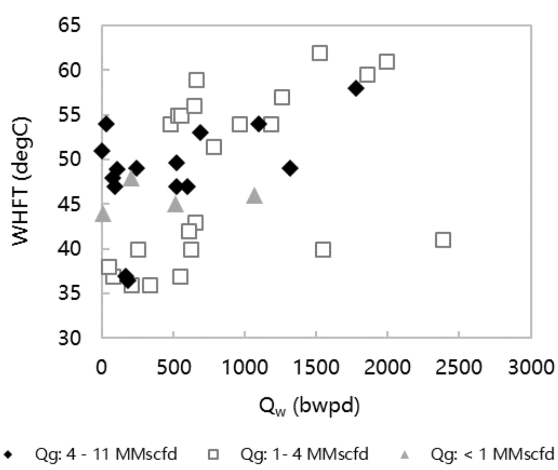


Figure 6. Empirical WHFT trend as a function of

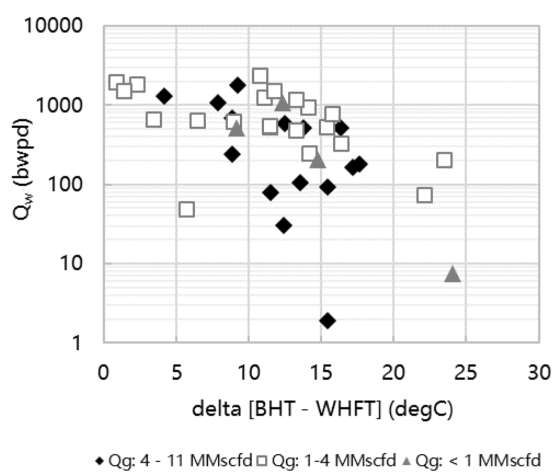


Figure 7. Water production rate as a function of

Q_w at certain Q_g categories Temperature difference (BHT-WHFT)

2.2 Analytical Wellbore Temperature Profile Model

Typical temperature vs. depth profiles for shut-in and flowing conditions are illustrated in **Figure 8**. Wellbore temperature profile during shut-in (static) depicts a typical geothermal gradient, with the temperature increasing with depth to that of the bottom-hole temperature (BHT). Every time a well is shut-in, the operating temperature will begin to move toward the shape of the natural geothermal profile. For flowing wellbore-temperature profiles for both oil and gas or multiphase flow, the wellhead temperature will be lower than the BHT. The amount of cooling as multiphase flows to the surface will depend on several factors: the relative amounts between phase, the specific heats between phase, flow rate and gas/liquid ratio. The vertical flow pressure drop that controls the gas liberated and the attendant cooling effect, and the thermal heat transfer rate from the wellbore. The temperature profile of a gas well may have a wellhead temperature lower than ambient. In any case, the wellhead temperature of a gas well will depend on: BHT, flow rate, pressure drop in the tubing, specific heat of the gas, etc (SPE-Petrowiki, 2015). For flowing temperature in wellbore, an equation for temperature in a well as a function of location L, is derived by Ramey (1962) that could be written as:

$$T_L = T_i - g_T\left[L - A\left(1 - e^{\left(-\frac{L}{A}\right)}\right)\right] \tag{1}$$

where,

T_i : temperature at fluid entry (L=0)
T_L : temperature at location L
g_T : geothermal gradient
A : relaxation distance, $wCp/\pi dU$
w : mass flow rate
C_p : specific heat of the flowing fluid
D : pipe diameter
U : overall heat transfer coefficient
L : distance from fluid entry

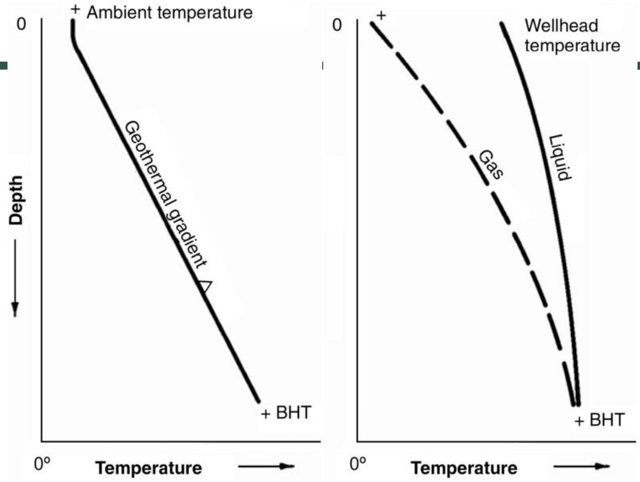


Figure 8. (left) Static well temperature profiles at shut-in condition;
(right) Producing-well-temperature profiles for both oil and gas (SPE-Petrowiki, 2015).

Assumption used in this approach is that the fluid and surroundings temperature are equal at the inlet to the pipe. This will be the case for flowing wells, where T1 is the reservoir temperature. Also included is the assumption that the heat loss is independent of time. This assumption limits application of **Eq. (1)** to wells that have been producing for a considerable length of time. When multiphase flow is occurring, the variables involved in evaluating the relaxation distance, A, a very difficult to determine, especially the overall heat transfer coefficient U and C_p. In view of this fact, Shiu & Beggs (1980) also developed an empirical method to estimate A based on measured temperature profiles from 270 wells.

In-house spreadsheet-based tool for wellbore temperature profile could be used to estimate or predict well outflow which in TSZ wells case is multiphase flow of gas and water. This tool is generated in-house based on available equation from Ramey (1962) and Shiu & Beggs (1980). This analytical tool is easy to use for operational purpose. By giving input of wellhead parameter: (Q_g, Q_w estimation, WHFP), reservoir depth & temperature by geothermal gradient. The result from this tool is simply by matching actual WHFT record with Q_w estimation. However, U-value & C_p should be adjusted in order to represent flowing temperature in TSZ wells. Due to this two variables uncertainty, other approach is initiated by available commercial well modelling tool in Mahakam.

2.3 Dynamic Well Modelling

Well outflow estimation and prediction was reported by Ashfahani, et al. (2019) for dynamic well modelling application in Mahakam during last 10 years. Dynamic model features mechanistic & empirical approach with basic conservation equations (mass, energy, momentum), constitutive correlations and flow pattern transition modeling (Bendiksen, et al, 1991; SPT, 2011; Staff et al., 2015; Hapsari, 2018). It is a powerful approach to generate well model where dynamic-transient phenomenon is become concern. In report from Ashfahani et al. (2019), dynamic well modelling approach used follows fundamental dynamic flow model OLGA for well application. For simplicity in basic theory, physical models are described in two-fluid model: gas & liquid (Bendiksen et al., 1991; Staff et al., 2015). Continuity equations are applied for gas, liquid bulk, and liquid droplets, which may be coupled through interphase mass transfer. Only two momentum equation are used, however a combined equation for the gas and possible liquid droplets and a separate one for the liquid film. A mixture energy conservation equation is applied. For thermal calculation, dynamic well model can simulate a pipeline with a totally insulated wall or with a wall composed of layers of different thickness, heat capacities and conductivities. The wall description may change along the pipeline to simulate, for instance, a well surrounded by rock of a certain vertical temperature profile, connected to a flowline with insulating materials and concrete coating, and an uninsulated riser. Dynamic well model computes heat-transfer coefficient from the flowing fluid to the internal pipe wall. Special phenomena, such as Joule-Thompson effect, are included, provided that the PVT package applied to generate the fluid property tables can describe such effects.

Figure 9 shows example of dynamic simulation result to match Q_w estimation based on actual wellhead parameter data for certain well. Detail model such as PVT fluid & well architecture, should be generated and it will impact to heat transfer distribution along wellbore during simulation. Initial condition & boundary condition has to be defined before simulation run. It could be taken from wellhead parameter data, reservoir data and shut-in condition data (i.e. water level, pressure and temperature). Model validation was performed based on wellhead parameter data. However, for regular operational purpose that require robust and quick generated model, dynamic well modelling is used only for specific case that need detail well diagnosis and analysis. Steady-state well modelling with available tool is initiated to accommodate these objectives.

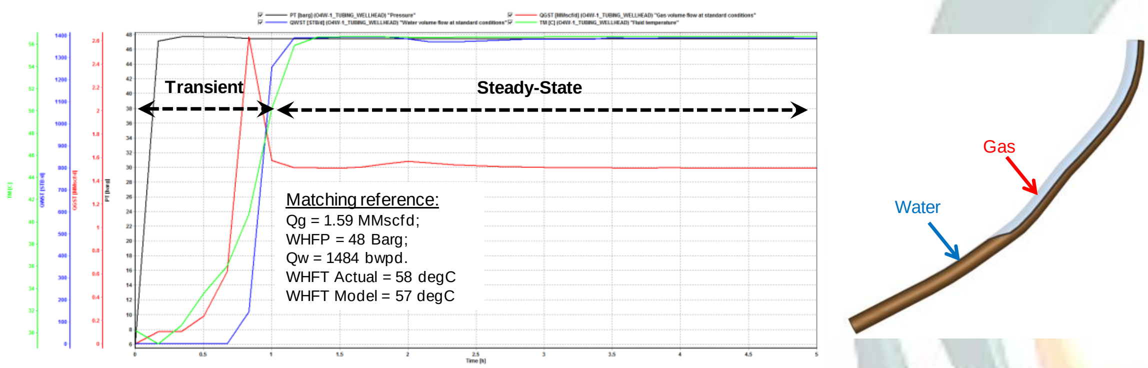


Figure 9. Water outflow estimation with dynamic well modelling (Ashfahani et al., 2019)

2.4 Steady-State Well Modelling

Steady-state well modelling is initiated by using available steady-state well modelling tool: IPM Prosper. Wellbore temperature profile is used to perform water outflow estimation and prediction by involving well data input such as well trajectory, PVT data, geothermal gradient of Tunu Field (3 ^{O}C/100m), and wellhead data (WHFP/T). Wellbore temperature profile is following wellbore heat loss by Chiu & Thakur (1991) and heat transfer during two-phase flow in wellbore by Hasan & Kabir (1991). For wellbore temperature profile, multiphase flow (liquid & gas) inside wellbore is involved with regime characteristics. These various flow regimes could be expected in as a function of the superficial velocities of gas and liquid flow. This approach is preferable to be selected since it introduce robust, easy to use for regular operational purpose and considering tool access availability in Mahakam. The result that discussed in this paper will be focused on approach with steady-state well modelling tool for well outflow estimation and prediction as a production test alternative.

3 Result

3.1.1 Result Comparison: Well-78 Case.

Model validation was performed for Well-78 based wellhead parameter data with different approaches. These approaches showed good performance in estimating WHFT based on wellhead data of Q_g, Q_w and WHFP as shown in **Table 1**. There are several highlight from this quick comparison of model validation.

Table 1. Well-78 approaches performance comparison

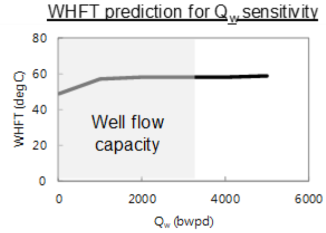
Approach	Qg (MMscfd)	Qw (bwpd)	WHFT (degC)	WHFP (Barg)
Actual	1.59	1484	58	48
Dynamic Model	1.50	1392	57	47
Steady-State Model	1.59	1484	58	48
Analytical Model	1.59	1484	58	48

Dynamic well model by OLGA Well Software: Water production could be estimated in order to match with WHFT and other wellhead parameter data.

PVT model is mandatory to be defined, detail well architecture and initial & boundary condition to perform simulation in dynamic condition. In this model, it considers totally insulated wall or with a wall composed of layers of different thickness, heat capacities and conductivities. The wall description may change along the wellbore that surrounded by rock of a certain vertical temperature profile, connected to a flowline with insulating materials and concrete coating, and an uninsulated riser (Bendiksen et al., 1991). **Steady-State well model by IPM-Prosper Software:** U-value (overall heat transfer coefficient) should be determined based on wellhead parameter data with U-value calculation feature which in this case U-value = 8 W/m^2/K. This value will be used to estimate flowing temperature along wellbore. U-value used is average U-value along wellbore for easy implementation. In actual this value is depend on wellbore architecture (casing & cement configuration) and has different value for each segment of depth that introduced at dynamic well model. There is a rule of thumb U-value that based on internal study with statistical approach, 22 W/m^2/K for 3.5” OD tubing/production casing and 16 W/m^2/K for 4.5” OD tubing/production casing. **Analytical wellbore temperature model by in-house spread-sheet based tool:** A coefficient (relaxing distance) should be adjusted in order to represent flowing temperature in TSZ wells. This A coefficient is difficult to be estimated and become function of U-value. There was an adjustment for for Well-78 for matching purpose. For well diagnosis purpose, **Figure 10** shows sensitivity analysis for Well-51 Well-78 for estimating WHFT based on Q_w actual single test data. Analytical approach gives good performance for 2 samples with A coefficient adjustment. This result could be used to predict Q_w based on wellhead parameter data. However important part is WHFT value reach stable value/saturated at Q_w > 2000 bwpd. However, this range still in TSZ well flow capacity range.

Well-51

	Q_g (MMscfd)	Q_w (bwpd)	WHFT (degC)	WHFP (Barg)
Actual	1.19	1199	57	45
Analytical	1.19	1199	57	45



Well-78

	Q_g (MMscfd)	Q_w (bwpd)	WHFT (degC)	WHFP (Barg)
Actual	1.59	1484	58	48
Analytical	1.59	1484	58	48

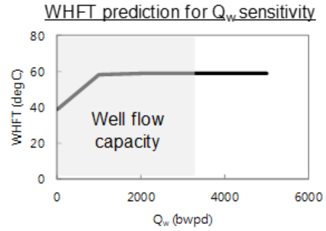
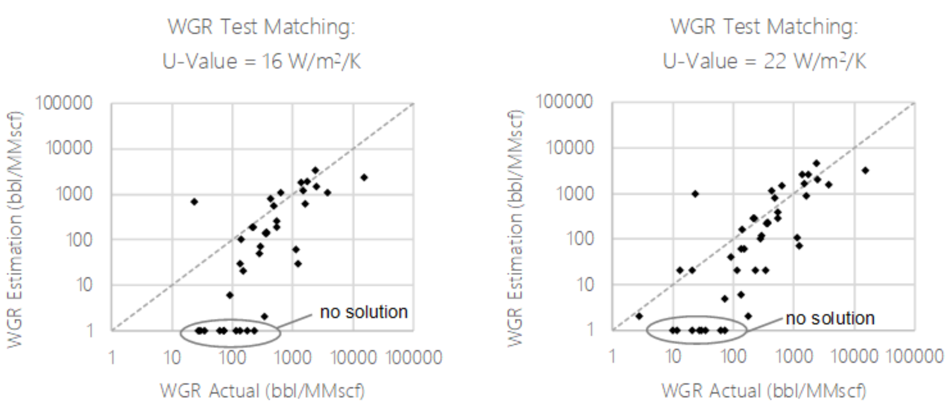


Figure 10. Analytical approach performance and sensitivity analysis for water outflow impact to WHFT

3.1.2 Steady-State Well Model Tool: Model Validation

Model validation for gathered TSZ wells actual production test was performed for 45 samples. These samples only for production test with water outflow measurement at surface (if gas outflow only, not involved in model validation). Simulation was generated by IPM-Prosper coupled with Open Server feature to perform multiple calculation of water outflow estimation (WGR) based on available wellhead data of WHFT, Q_g, reservoir depth, and Tunu geothermal gradient. Three variations of U-Value were involved in this estimation that refer to Mahakam internal reference: 16 & 22 W/m^2/K. Additional value 30 W/m^2/K was also used for sensitivity purpose. Tubing OD for this data samples mostly 3.5" with ID 2.99".

Figure 11 shows water outflow (WGR) estimation based on available wellhead data that with variation of U-Value. Certain value criteria of error were considered and qualitatively the model gives good performance of estimation or prediction. As U-Value increase to 30 W/m^2/K, "no solution" data is reduced. It indicates this U-Value is suitable for 45 gathered samples of TSZ actual production test.



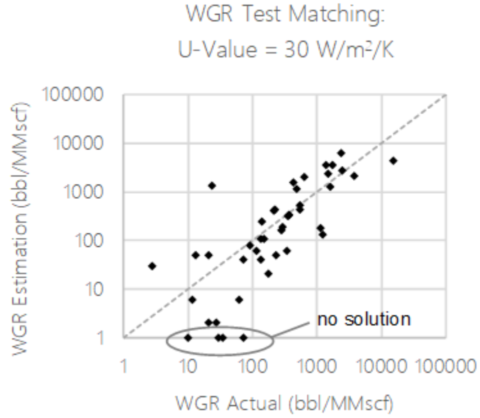


Figure 11. Water outflow (WGR) estimation based on available wellhead data with variation of U-value

Model performance rely on this U-Value, and it need to be re-determined in order to give good matching performance based on most samples data found. 50 data samples were involved which included single phase flow (gas only) and multiphase flow (gas & water) from production test. **Figure 12** shows statistical analysis to re-determined U-value for 50 samples including production test with gas outflow only. With same method of simulation with multiple calculation feature, the result shows P50 (50%) of frequency is around 30 W/m^2/K. As a reference, natural convention in air is 4 W/m^2/K and in water is 200 W/m^2/K. Based on this result, U-value for TSZ wells is re-determined in order to improve model matching performance. As mentioned before, since this approach is critical to U-value as an input, model calibration or matching is needed before going into model estimation or prediction such as perform model matching based on latest or available production test data in order to define U-value for specific well case.

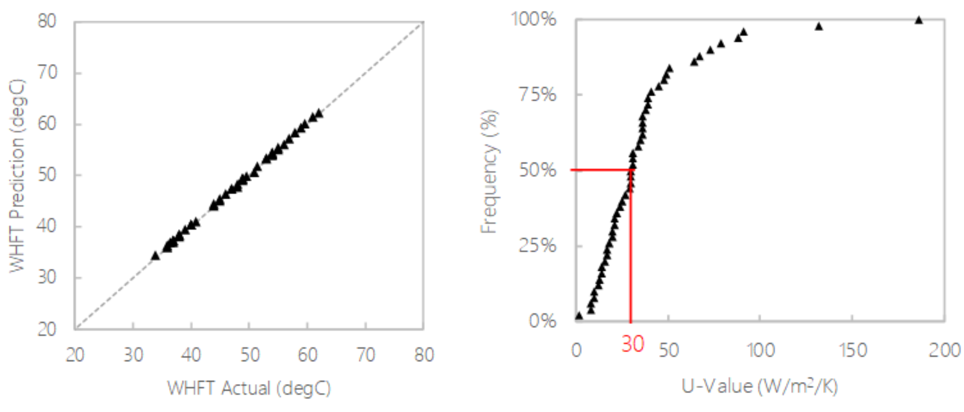


Figure 12. Re-determine U-value for TSZ wells with 50 data samples

Figure 13 shows the example of Water Gas Ratio - WHFT for Q_g variation chart that could be generated automatically by in-house tool for specific well or field basis in order to be used for practical operation.

This chart could be generated for certain case and documented for field site used purpose. This approach has objective to create alternative solution to perform quick well diagnosis or analysis.

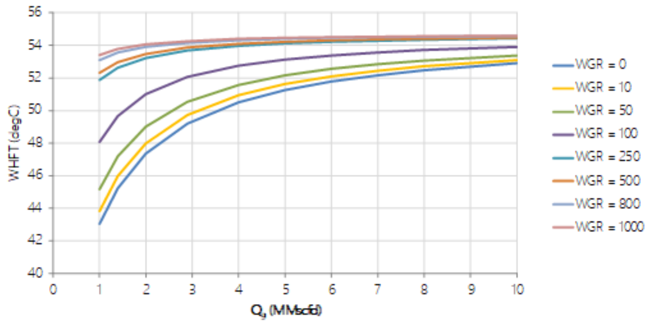


Figure 13. Generated water Gas Ratio - WHFT for Q_g variation chart

3.1.3 Challenge: Un-reliable Production Gas Rate (Q_g)

Previous description is implemented for case with known variable of Q_g which commonly become main interest for well surveillance or reservoir management. The challenge is presence, how if Q_g measurement is not reliable or we do not have any Q_g measurement or reference, or in extreme case we would like reduce Q_g measurement in well basis for cost optimization? Another fundamental approach could be considered: Nodal Analysis coupled with wellbore temperature profiles approach by WHFP & WHFT matching at certain downstream operation condition (i.e. choke opening & flowline pressure mode).

Since first time introduced in oil & gas well by Gilbert (1954) then popularized by Mach (1979) and Brown (1984) as Nodal Analysis, system analysis is commonly used to analyze the performance of system composed of multiple interacting components. It is based on the concept of continuity and has objective to combine the various components of the production system for an individual well to estimate production rates and optimize the components of the production system (i.e. well & surface facilities). The flow rate and pressure at the node can be calculated since:

1) Flow into the node equals flow out the node; 2) Only one pressure can exist at the node. Steady-state well modeling with empirical or mechanistic approach is generally used in Mahakam as reported by Ashfahani et al. (2019). Its application for well diagnostic, performance matching, and prediction for optimization are described. As illustrated by **Figure 14**, the basic idea is to match actual available WHFP & WHFT data with model estimation therefore we could estimate regularly well outflow (gas or liquid/water rate). By having this approach, we also could perform sensitivity analysis, such as: inflow productivity degradation, reservoir depletion, sand control integrity, flow regime, choke opening (i.e. sand erosion), etc. Once again, this simple approach could be implemented by available feature in commercial well model tool or by creating spreadsheet-based tool based on available equations.

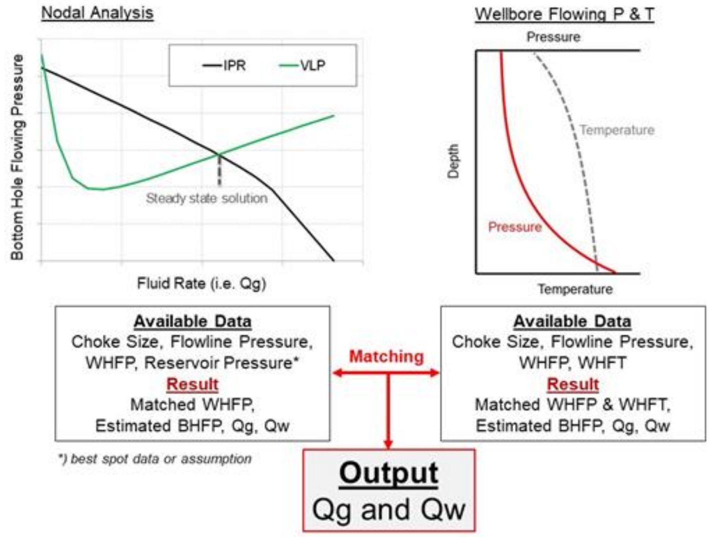
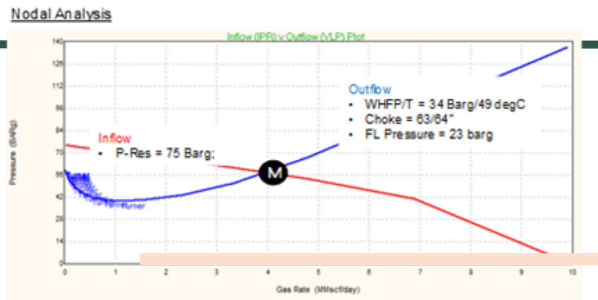


Figure 14. Wellbore temperature profile coupled with Nodal Analysis approach for well outflow estimation and prediction

Figure 15 shows the example of this approach implementation for well outflow estimation and prediction based on available wellhead data: WHFP, WHFT, flowline pressure and choke opening. Q_g measurement is not reliable since this instrument consider only single phase flow based on differential pressure of upstream and downstream of flow transmitter. Since multiphase flow was occurred inside wellbore with suspected massive water production. It created slugging flow regime based on interpretation from production operator. Production test become issue where gathering production test separator in platform is out of service. Production test with mobile testing unit will create impact to wellbore performance since it should be performed with shut-in condition during mobile testing and well connection. Well outflow (Q_g and Q_w) become uncertain for production improvement since material balance analysis will be based on these known variables. Production improvement initiative to reduce this slugging condition, by propose commingle Gravel Pack (GP) zones production with another gas zone potential. This strategy had objective to improve well gas production and reduce water production (Q_w) from Zone #1 (-50%) as an impact from higher BHFP that contributed from higher gas production contribution from Zone #2. This condition is expected to reduce severe slugging.



Parameter	Actual	M Model
Q_g (MMscfd)	3.5	3.9
WHFP (Barg)	34	34
WHFT (degC)	49	49
Q_w (bwpd)	?	2366
Choke Opening	63/64"	63/64"

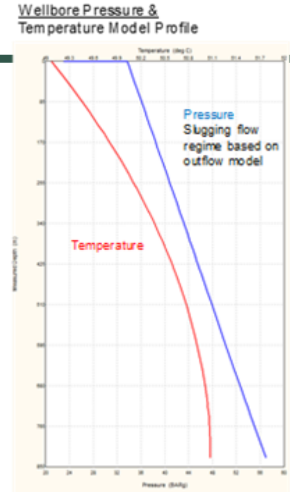
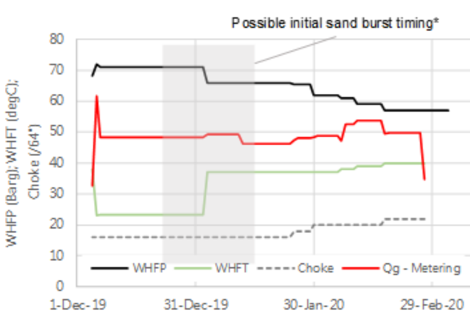
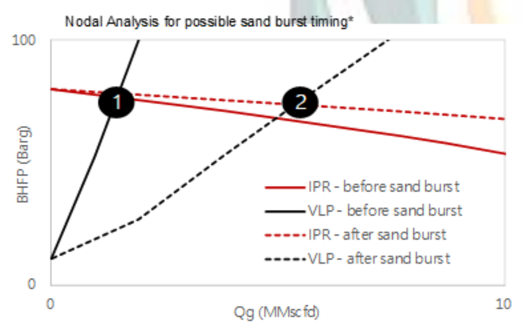


Figure 15. Wellbore temperature profile coupled with Nodal Analysis approach for Zone#1 contribution

Another approach implementation is for failed chemical sand control timing analysis after sand recovery was observed from physical check at surface. Nodal Analysis based approach showed possible sand burst event which suspected due to mechanical failure from chemical injected sand control rather than hydrodynamic erosion by massive water production. However, operation parameter (i.e bottomhole drawdown) was still inside operation envelope. This model physically was represented by lower inflow productivity and larger area of wellhead choke due to erosion that matched with wellhead parameter reading at surface. **Figure 19** shows the analysis of prediction that creates sand burst based on WHFP and WHFT history data. **Figure 20** shows sensitivity analysis for WGR that indicated no significant increase of WHFT. This sensitivity showed WHFP significant decrease if massive water production is flowing from reservoir into wellbore. It did not match with actual WHFP and WHFT data





Variables	Before Sand Burst (1) Actual	Before Sand Burst (1) Model	After Sand Burst (2) Actual	After Sand Burst (2) Model
WHFP	71	71	66	66
WHFT	32	32	37	37
Choke	16	16	16	28*
Skin		x		0.75x
Qg	1.5	1.5	?**	5.7

*) Choke opening area adjustment for matching.
**) Confirmed by sudden increase trend of Q_g by well performance team.

Figure 19. Well outflow analysis for sand control burst event

Therefore, based on this wellhead data, mechanical failure from chemical injected sand control is suspected become the cause of this problem. Tubing investigation confirmed this condition where sand was accumulated inside wellbore and covered reservoir contributor (~15 m above reservoir).

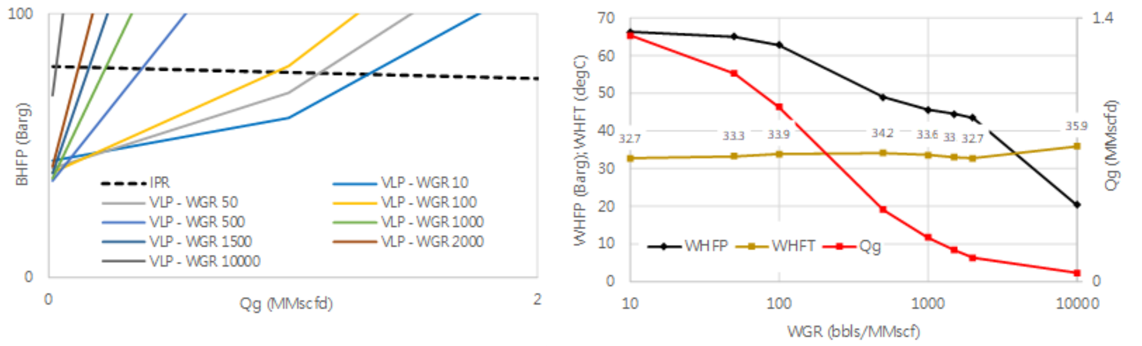


Figure 20. Sensitivity analysis for WGR to define sand control burst causing root: mechanical failure or hydrodynamic impact

Based on this operational example, Nodal Analysis based approach is powerful to preliminarily diagnose wellbore performance condition and problem before creating better decision making. Actual production test history from each well should be involved to calibrate and match the uncertainty variable such us U-value for thermal transmittance inside wellbore. This matched model then could be used for well outflow estimation and prediction.

4 Conclusion

Water encroachment monitoring in TSZ reservoirs or wells is critical for wellbore performance diagnosis and reservoir management. However due to operational limitations, water outflow measurement could not be implemented continuously. By having empirical observation, there is no clear relationship between variables: water outflow and WHFT for known variable of Q_g. This uncertainty is coming from several parameters that affect WHFT. By using wellbore temperature profiles approach, water outflow estimation could be estimated by reverse calculation of known variables. This paper present methodology and result for well modeling-based approach that has been initiated to predict water outflow based on available wellhead parameter: 1) Analytical Model; 2). Dynamic well modelling; 3) Steady-state well modelling. Model validation shows good performance in estimating water outflow. Water Gas Ratio - WHFT for Q_g variation chart could be generated automatically by in-house tool for practical operation. Another approach is proposed if Q_g becomes unknown parameter/unreliable: Nodal Analysis coupled with wellbore temperature profiles approach by WHFP & WHFT matching at certain downstream operation condition. This “from your desk” approach could be an alternative for continuous/regular production test in order to estimate or predict well outflow prediction when facing operational constraints. The objective is to take better decision making for production optimization and reservoir management.

Acknowledgements

Authors would like to thank to PT. PERTAMINA Hulu Indonesia and PT. PERTAMINA Hulu Mahakam management for permission to publish this paper.

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