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Well's Liquid Production Rate Prediction Method Utilizing Temperature Profile Reverse Calculation, One Step Closer to Virtual Production Test on Limited Wellhead Data

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Abstract. Wellhead data and the actual production rate measurement are the most parameters evaluated to be prepared for any production dynamic by still respecting to the downstream facility limitation. One of the them is liquid production rate. Case study discussed is Tunu Field in Mahakam. Although it is a gas field, liquid rate is important information to shut in high liquid producer wells prioritization in case of limitation on the production facility (i.e liquid transfer pump break down).

Production parameter is nearly blind on well level. Flowing pressure, temperature, and gas rate by orifice flowmeter are locally updated by weekly visit. While well's liquid production rate refers to periodical collective well test from test separator or clean up history by mobile testing unit. Unfortunately, 73% from 29 test separators were unfit to measure liquid due to aging. While mobile testing units were limited and costly for routine well production test.

Well's characteristics vary depend on the open reservoir. From average 220 active wells, most of them were strong water drive on shallow reservoir and depletion drive gas or retrograde condensate with water contact in the deeper reservoir. Therefore, liquid production was inevitable on the late production phase. With the absent of updated well test data, liquid producer well identification became very challenging. In 2021, liquid estimation accuracy on field level was 50% compared to actual liquid production. At this period, it was estimated 961 MMscf production lost on recorded emergency events due to false identification or ineffective decision in shut in high liquid wells.

The initiative came up with development of virtual well's liquid production prediction. The concept is reverse calculation of temperature profile estimation on flowing fluid inside conduit. The overall heat transfer coefficient (u-value) as one of critical parameter was categorized based well's completion type by referring to more than 1500 historical test data. It was combined with wellhead parameter and reservoir data to calculate estimated liquid. Using combination of nodal analysis software and VBA based spreadsheet, an in-house tool was developed to provide quick and consistent calculation on all of active wells. On the field level, the accuracy of liquid prediction was significantly increase to 90 – 110 % and all high liquid producers could be well identified in 15 minutes.

This initiative provided a quick and adequate well's liquid production estimation at free maintenance and operation cost to be ready at any time, one step closer to virtual well production test for wider application.

Keyword(s): temperature profile reverse calculation, overall heat transfer coefficient, virtual liquid production test

1 Background

Tunu is one of gas field located on Delta Mahakam. ~~Around~~ 220 active wells were scattered on remote locations. They are connected to nearest gathering test satellite (GTS). The downstream of all GTS are connected to the production manifold before going to Tunu's processing facilities which one of them could be considered as simple production facilities. The main task is to increase operating pressure from low pressure (~10 bar) to medium pressure (~ 25 bar). The wells are produced on low pressure system to maximize well potential. While medium discharge pressure is required to transport all the production fluid to downstream facilities ~~having~~ better liquid production handling. Therefore, the only main equipment on the process facilities are slug catcher, gas compressor and liquid transfer pump (LTP). The simplified flow diagram could be seen on figure 1.

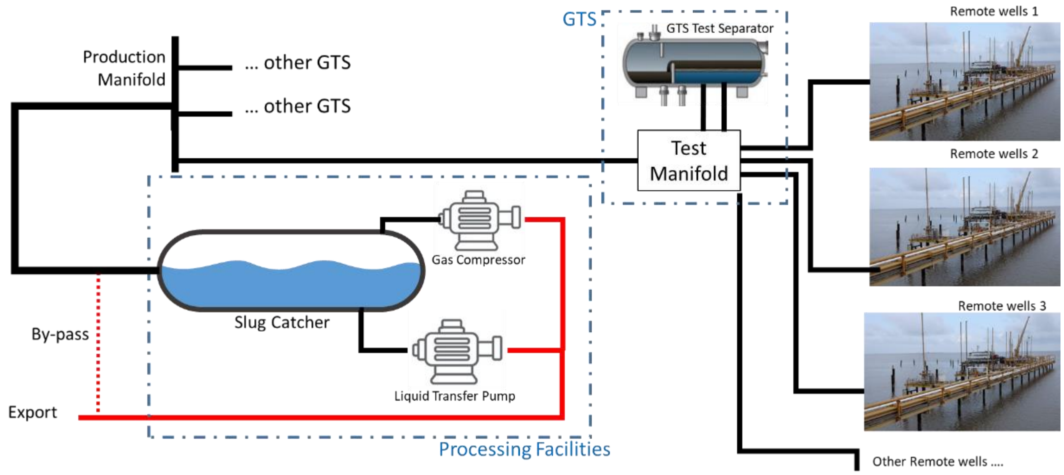

Figure 1. Simplified Tunu's production flow diagram

Although Tunu is gas field, ~~the~~ liquid production is an additional product that couldn't be avoided in the late of well production phase. Most of active wells are strong water drive on shallow reservoir and depletion drive gas or retrograde condensate with water contact in ~~the~~ deeper reservoir. A multiphase flow entering the production facilities will be separated inside slug catcher. The gas will be compressed to medium pressure, while the LTP passes back the liquid to the export line together with compressed gas.

LTP is one of critical equipment. The working philosophy is one active LTP and two standby LTPs as backup. LTP breakdown due to high vibration is the common issue encountered. In some cases, e.g. major sand production, all of LTP could fail in sequence. The impact, the production mode shall adapt with two possible scenarios to avoid process facility shut down due high level in slug catcher:

1. Bypass the production facility. The wells are operated in medium pressure mode with impact sensitive wells could die due to high back pressure, or
2. Shut in high liquid producer wells to delay liquid accumulation on slug catcher until the LTP repair is completed

Unfortunately, production parameter is nearly blind on well level. Flowing pressure, temperature, and gas rate by orifice flowmeter are locally updated by weekly visit. Well's liquid production rate refers to periodical collective well test from GTS test separator or clean up history by mobile testing unit. However, 73% of 29 GTS test separators were unfit to measure liquid due to aging. While mobile testing units were limited and costly for routine well production test. The impact, liquid producer well identification become very challenging. In 2021, liquid estimation accuracy on field level was 50% compared to actual liquid production. On the well level, the allocated liquid production was over/under estimated with no clear justification. For example, a well was labeled as high liquid producer where actually not producing any liquid after a confirmation by mobile testing unit. in other case, a gravel pack revival well was claimed as dry well where actually producing > 500 blpd liquid. It was estimated 961 MMscf production opportunity lost due to false identification or ineffective decision in ~~shut~~ in high liquid wells on 7 recorded emergency events due to LTP failure.

2 Initiative: Predicting Liquid Production by Temperature Profile Reverse Calculation

2.1 Temperature Profile Estimation Fundamental

Temperature profile in relation to depth on shut in and flowing well could be illustrated on figure 2. During shut-in, it could be represented by geothermal profile. However, temperature profile on flowing well depends on several factors: the fluid condition (mass flow rate) and the surrounding condition (overall heat transfer, gradient geothermal, flow entry temperature). The temperature at certain point inside flow conduits could be calculated using the equation (1).

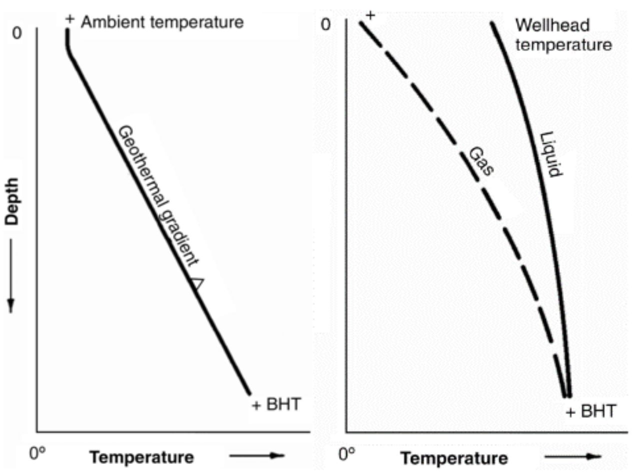

Figure 2. SI and flowing wells temperature profile (SPE-Petrowiki, 2015)

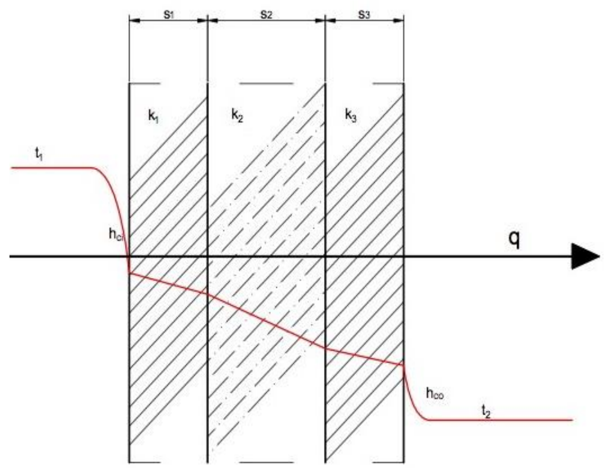

Figure 3. Multi-layered walls heat transfer (Engineering ToolBox, 2003)

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

Ti : temperature at fluid entry (L=0)
TL : temperature at location L
gT : geothermal gradient
A : relaxation distance, wCp/πdU
w : mass flow rate
Cp : specific heat of the flowing fluid
d : pipe diameter
U : overall heat transfer coefficient
L : distance from fluid entry

A reverse calculation could be performed to find the well's liquid rate production (*w* function) if the temperature at location (T_L) is known, which is WHFT on this case. While g_T, d, and L are common parameters input which could be easily retrieved from the field data.

2.2 Generating Overall Heat Transfer Coefficient based on Completion Type

Overall heat transfer coefficient (U) is the important parameter for accurate temperature profile calculation. Based on the equation (2) and illustration on figure 3, the thickness of material layer (s) and fluid convection heat transfer coefficient outside wall (h_{co}) are the parameters which control the U value if assuming similar fluid flow inside pipe. Simply, thicker tubing results in lower U, and water outside the tubing will give higher U compared to oil based mud due to higher $h_{co.}$ These parameters (s and h_{co}) variation could be found in different well architecture type.

$$U = \frac{1}{1 / hci + \Sigma (sn / kn) + 1 / hco} \tag{2}$$

U : the overall heat transfer coefficient (W/(m2 K))
kn : thermal conductivity of material in layer n (W/(m K))
hc i,o : inside or outside wall individual fluid convection heat transfer coefficient (W/(m2 K))
sn : thickness of layer n (m, ft)

As confirmation, U was calculated from more than 1500 well testing operation performed on various well architecture which could be generally grouped into six. The result is summarized on table 1, while schematic on each architecture are illustrated on figure 4.

Table 1. U-value on various well architecture type

ID	**Description**	**Mean**	**Median**	**U W/(m2 K)**
GP	**Gravel Pack** : 3.5" tubing with water on Ann. A	16.25	17.07	16.5
LA 3.5	**Light Architecture** : 3.5" tubing with OBM on Ann.A	11.40	11.15	12
LA 4.5	**Light Architecture** : 4.5" tubing with OBM on Ann.A	9.89	9.48	10
STD 4.5	**Old Standard** : 4.5" tubing with brine on Ann.A	14.94	15.20	15
SLA 3.5	**Shallow Light Architecture** : 3.5" tubing with Ann.A is designed cemented to surface	12.54	12.64	12.5
SLIM 4.5	**Slim Hole**: 4.5" tubing with brine on Ann.A	15.06	15.06	15
OS 3.5	**Opti Slim** : modified slim hole 3.5" tubing with OBM on Ann.A	12.16	11.73	12
OS 4.5	**Opti Slim** : modified slim hole 4.5" tubing with OBM on Ann.A	9.93	9.72	10

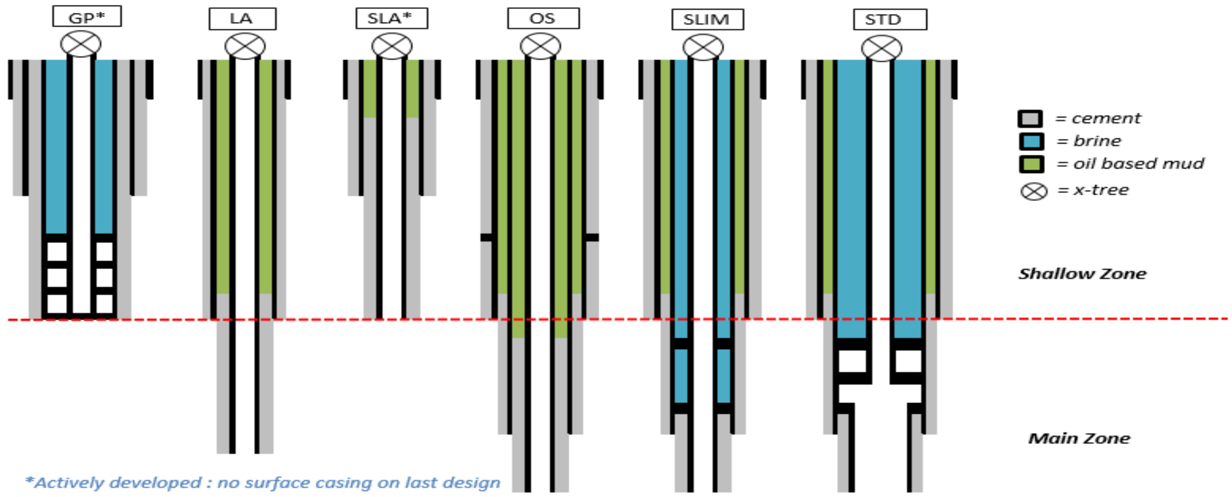

Figure 4. Well architecture general schematic

2.3 Developing In-house Tools to be ready in Any Emergency Event

Theoretically, knowing all above parameters are enough to calculate the estimated liquid rate. However, to practically calculate more than 200 dynamic active wells in less than 1 hour to define which liquid producer well to be shut-in during emergency case is another challenges. The initiative came up with a steady-stated well modeling software utilization to do liquid rate estimation iteration with minimum human error. In addition, development of VBA based spreadsheet tool connected to the software by communication protocol could boost the calculation speed around 15 minutes for all wells. This could give additional time for engineer to perform quality control before taking the decision to shut in the high liquid producer well. The general flow chart on the tool could be simplified on figure 5.
Interestingly on minor deep reservoir wells, it predicts high liquid production rate which contrast with actual condition due to high surface WHFT recorded. To anticipate this error, calculation of bottom hole flowing pressure is used as additional cut-off parameter to limit BHFP lower than the static reservoir pressure.

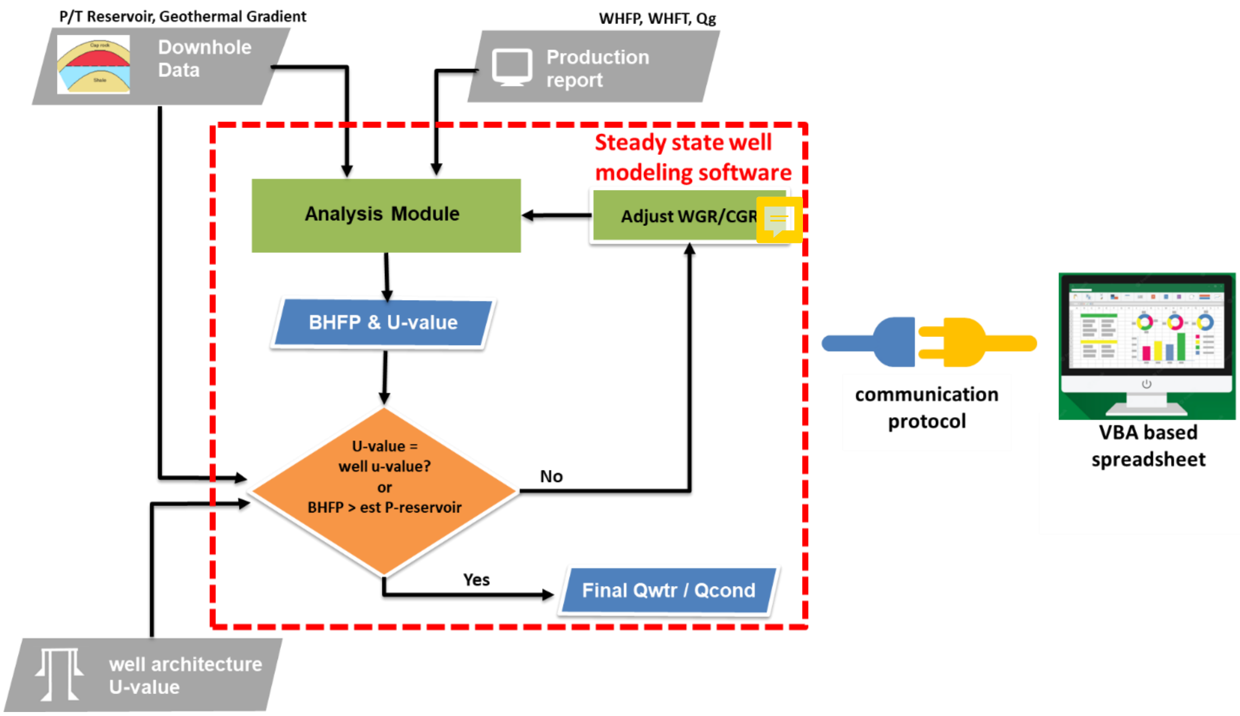

Figure 5. Simplified workflow on developed liquid prediction tools for Tunu field

3 Result

As final validation, cumulative active well liquid production prediction was compared with actual Tunu liquid in the last one year. Real liquid production was counted and daily recorded on two of Tunu's processing facilities, which are Area 1 & Area 2. The ratio of active well's number on each are was roughly 50:50. The plot of real daily liquid rate is shown on figure 6 with continuous line (red for Area 1 and blue for Area 2). The cumulative liquid production from all active well flowing to each processing facilities were calculated using the developed tool on several random date.

Before the tool was implemented, the cumulative well's predicted liquid using obsolete collective production test and historical clean up data is very underestimate which presented on the left side of the graph. However, after the implementation, the predicted liquid could consistently match with real liquid trend with accuracy 100 ± 10%. This could be concluded that the prediction method is proven to be applied on this field.

The other confirmation was performed on the test data reference which give average prediction accuracy on the wells level at 79%.

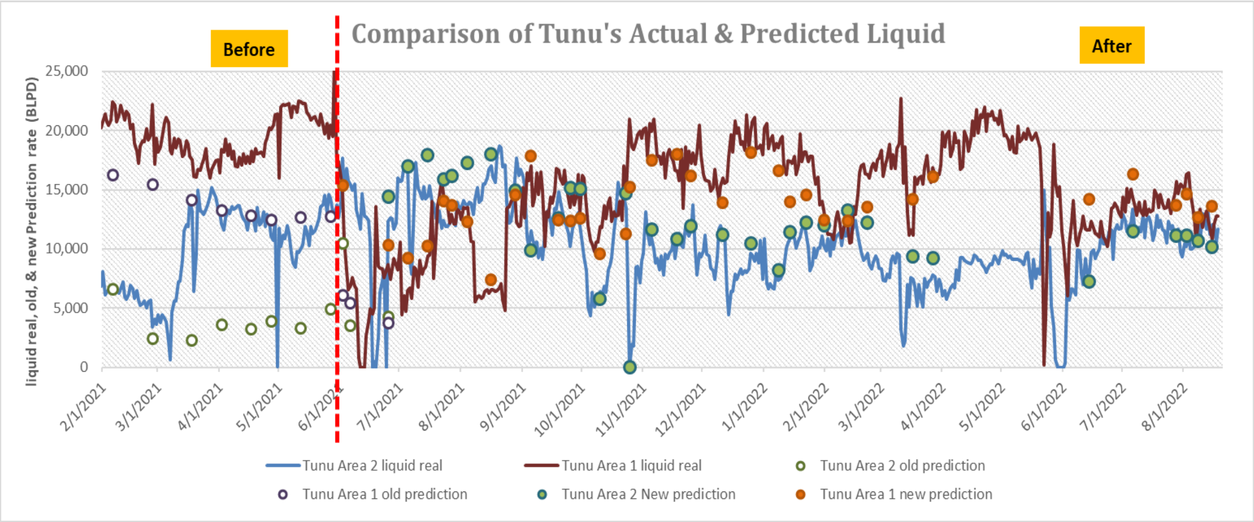

Figure 6. Comparison of Tunu's actual & predicted liquid

4 Conclusion

1. Reverse calculation of temperature profile estimation could be used as alternative to estimate well's liquid production rate.
2. Overall heat transfer coefficient (U) value could differ on every well architecture design.
3. A VBA based spreadsheet tool connected to the steady state well modelling software by communication protocol could boost the liquid production estimation calculation for around 200 wells in 15 minutes.
4. The initiative provides a quick and adequate well's liquid production estimation at free maintenance and operation cost to be ready at any time.

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