IATMI22-016

Unlocking Production Enhancement in Onshore Monobore Completion with Mechanical Artificial Lift

Mirza Azhari*[1], Djoko Soeseno[2], Sebastianus Riskadarto[3], Ibrahim Kunto Baskoro[4], and Radhintya Danas Okvendrajaya[5]
[1,2,3,4,5]PERTAMINA HULU INDONESIA
* Email: mirza.azhari@pertamina.com

Abstract. Monobore was implemented in PHSS since 1996, replacing conventional completion to reduce drilling cost and simplified rigless well intervention. today, more than 500 monobore wells has been completed. This project is expected to give at least 80BOPD gain per well, increasing production reliability, and economically profitable for company.

During the lifecycle of the well, Natural Flow will be the first method to exploit hydrocarbon from a reservoir. Later on, in extended NF period, gaslift could be used to modify wellbore liquid in order to be lifted by its pressure. As reservoir getting depleted, and watercut started to increase, at some point, GL will not be effective to make the well flow at stable rate. This period, as experienced by PHSS for some years back, has raised the sense of urgency to implement mechanical pumps, especially on monobore wells.

The main challenge is that slim monobore completion was designed to accommodate NF and GL well, but will give some limitations for mechanical pumps. Small wellbore diameter, absence of annulus and tight wellhead footprint in dual monobore completion, with additional equipment required to insert downhole pumps and sucker rod has to be addressed to solve the issue instead of adding future complexions.

Due to the lack of monobore wells with mechanical pumps in Indonesia, references are limited and pumps will be fabricated and shipped from overseas. Thus, well data and forecast has to be taken into account, since the pumps will ready at least 6 months after finalized design.

At first, well with liquid gross increment opportunity was chosen, not included those with sand/solid problems, as it is the major threat for mechanical pumps. Then, similar candidate are organized to finally came up with candidate tiers ranking. Lab test was also conducted, in together with gathering updated data from well reactivation attempts.

Discussion with service companies was done simultaneously to grab knowledge and evaluate artificial lift limitation in fluid tolerances, downhole pump capacity, surface footprint, power requirement and simplicity to conduct rigless operation. Finally, economic analysis and procurement strategy was developed to ensure company satisfaction in trial period while stay fair to vendor

Thru Tubing ESP and insert-PCP has been decided to be implemented to replace Permanent Coiled Tubing Gaslift (PCTGL) as current artificial lift. One major classification is TTESP will be use in dual monobore completion while iPCP is for single monobore due to surface footprint and economic consideration. 15 well is identified to be TTESP candidate in 3 Tiers, and <10 wells as iPCP candidates. This tier ranking system will provide candidate "backup" for every tier, that will simplify procurement and evaluation process.

Keyword(s): Thru Tubing ESP ; insert PCP ; Monobore ; Artificial Lift.

1 Background

PHSS produces Oil and Gas from Sangasanga Field in East Kalimantan. Main artificial lift used to produce Sangasanga Field is gaslift, that covered more than 90% of its total Oil Well. As of daily production, gaslifted wells contributes around 93% of PHSS daily oil production. This percentage showed that PHSS is highly dependent in gaslift network.

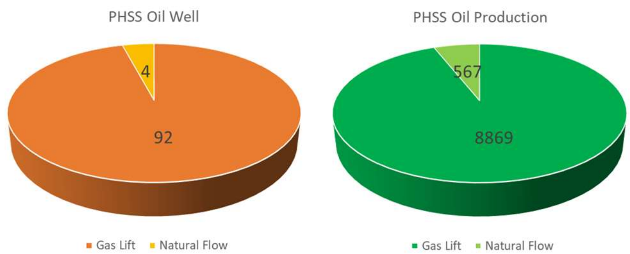

Figure 1 PHSS PCTGL Contribution

Gaslift was chosen to be the method to lift oil by several reasons, with the main reason is the fact that PHSS production was dominated by Gas before switching to Oil field more than 10 years ago. With existing gas facilities, relatively high reservoir pressure and reliable gas supply, then gaslift was superior compared with mechanical artificial lift. However, gaslift mechanism currently used in PHSS is divided by 2 type, mandrell gaslift as in conventional completed wells and Permanent Coiled Tubing Gaslift on monobore and dual monobore wells. This paper will mainly discuss about PCTGL conversion initiatives in monobore/dual monobore completion.

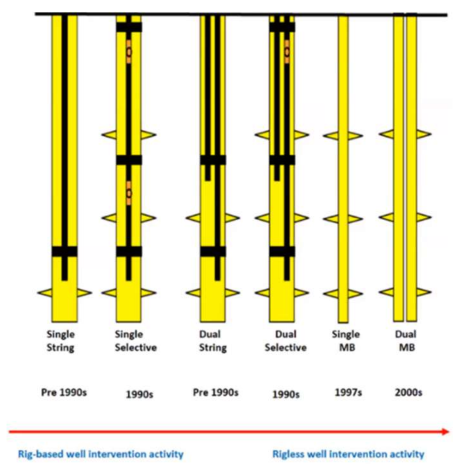

Figure 2 PHSS Completion Milestone

In average, gastift lifetime (period between service) in PHSS is considered high. The average lifetime of gaslift is almost a year. Pulling reasons are in fact mostly related to optimization/deepening necessity, due to PCTGL limitation for deepening the gas injection point. Some other pulling reasons are Production Decline (low volume tank), gaslift optimization (deepening), and reservoir problem (Watercut increment, HPPO & sand plugged string).

2 Problem identification

As the field is entering its "mature-state", that indicated by depleted reservoir pressure, watercut increment, challenging reservoir and fluid properties (HPPO, sand problem, deep zone reactivation), gaslift optimization to maintain and increase production was also getting harder.

- Necessity to gross up and reduce drawdown
  When watercut is increasing, the composite weight of the fluid increases, and minimize oil portion if liquid volume is stable. To maintain oil production, drawdown pressure has to be decreased, or in gaslift operation, it is means the needs of additional pressure and gaslift injection rate (and sometimes deepening gaslift injection depth)
- Optimize production by stabilize daily production fluctuation

  Current daily fluctuation of PHSS oil production is relatively high (10%). This is due to sudden change in gaslift network condition. Gaslift network consists of several equipment that covered both surface and subsurface, and like typical network, every well connected to a network will affect each other behavior.
- Decrease dependency to compressor reliability
  Access deeper zone
  In gaslift operation, deepening point of injection related to the increasing needs of gaslift pressure and volume. And since CTU was cut when installed at the first time, gas injection depth is fixed and permanent.

Regarding volume of PCTGL installation job, PHSS has average of 40 wells annually, with 3-4 wells/months. PCTGL installation is mainly focused on new wells or the wells that cease to flow from naturally flowing state.

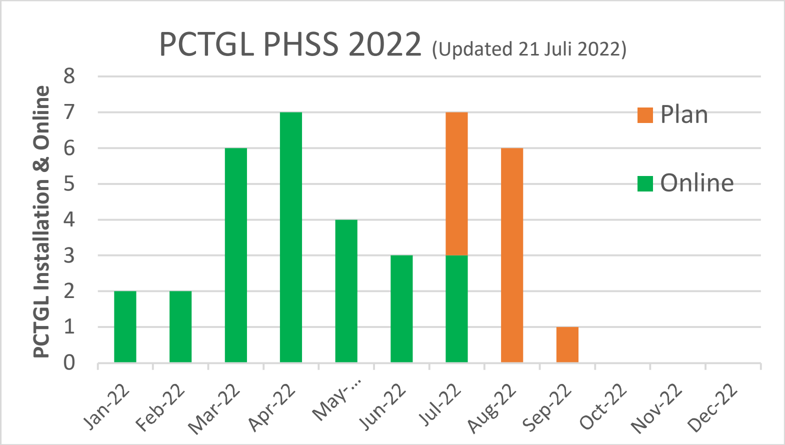

Figure 3 2022 PCTGL Program

On the other side, there is a field side by side with PHSS field, that previously operated by Pertamina EP, that mainly rely on mechanical pumps (ESP, SRP and HPU). Since the reorganization of Pertamina, PHSS and some parts of Pertamina EP Asset 5 is combined into PHI Regional 3 Zone 9, that allow borderless experiences and knowledge transfer to optimize field production operation.

3 Proposed Solution

Challenge to implement mechanical pump in PHSS Field is to accommodate pumps installation on monobore and dual monobore completion. Hence, lifetime and limitation of pumps in conventional completion has to be adjusted accordingly. But as a matter of fact, there is a pilot monobore completion wells that has been completed and produces naturally in Pertamina EP Sangasanga Field, and planned to install iSRP (insert SRP). iSRP, with all of its limitation, has been selected to be installed due to equipment availability concerns. This is because the procurement process of dedicated thru tubing pumps has long preparation and shipping process.

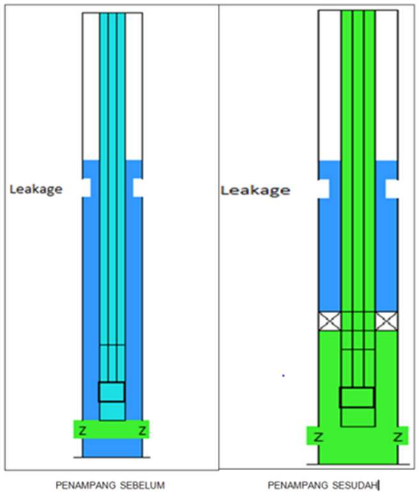

Figure 4 Insert SRP (iSRP) Well Diagram

SRP was also selected because that pilot monobore well is vertical well, that expected not giving rod and tubing friction that could lead to rod parted and tubing leak. But since most of PHSS wells are deviated, so artificial lift selection is limited to rodless pumps.
Beside well inclination, for Monobore completion, these are general issues that has to be addressed prior to artificial lift installation :

- Well influx has to be pre-defined accurately (swab well after perforation?)
- Pump intake will always be set above perforation
- Recommend to install downhole sand screen if formation has sand problem tendency
- Need special tools to install/pull off artificial lift (if planned to use E-Line/Slickline or CTU)
- Pumps (SRP, ESP and PCP) will be sensitive to solid content and GLR
- Surveillance will only rely on downhole sensor
- Electrical supply has to be reliable (minimize on-off operation)
- Fishing tools and scenario is needed due to high stuck/mechanical problem possibility

Summary of Artificial lift comparison that has been addressed to comply current PHSS Field condition is described as follows :

Table 1 Monobore Artificial Lift Comparison

iSRP		iPCP		TTESP	
Deployed using WL and Crane/Rigs		Deployed using WL and Crane/Rigs		Deployed using WL Equipment	
Pros	Cons	Pros	Cons	Pros	Cons
Currently available in Sangasanga field (downhole pump)	Relatively low rate (due to 2” plunger size). Est max rate is 350BPD	Fit to Monobore completion and has been installed in PHKT and PHM	Large wellhead footprint (drivehead and electrical motor)	Large range of fluid rate (100-1500 BPD) within several pump size	High rental cost and also high purchase cost (in case of LIH)
Long lifetime (> 1 year) for typical	Surface Unit availability (need HPU	Relatively more resilient to gas and solid	Lower capacity than TTESP (max 700 BPD ,with	Long lifetime (> 1 year) for typical	Not as flexible as conventional

Sangasanga wells (conventional completion)	additional unit or utilize PU from active wells)	(compared to ESP and SRP)	300 RPM & pump eff about 70%)	Sangasanga wells (conventional completion)	ESP in terms of solid and gas tolerance
Ideal for vertical well	Sensitive to solid and gas	3 Month fabrication and delivery time (some pumps has already available in country)	May shipped from outside Indonesia (3 month)	Relatively higher pump efficiency than PCP	Fabricated outside Indonesia, based on specific design
	Need additional completion tools to be installed in monobore (RBP and tubing stinger)		High BS&W wells need more time to get optimum pump efficiency		Long lead item (6-8 months fabrication and delivery period)
	Need existing slickline unit assessment for monobore operation		Need elastomer compatibility test with crude oil sample (sensitive to aromatic content)		

Table 2 Monobore A/L Summary

	Theoretical Rate (3.5" Tubing)	Gas Tolerance	Solid Tolerance	Current Limitation	Concerns	Next Step
Rod Pump	50-350 BPD	Poor	Poor	Low rate Poor for dual monobore	- Completion Tools - WL compatibility	Completion Tools Procurement
ESP	100-1500 BPD	Moderate	Poor	Cost vs Gain	Long fabrication and delivery	Procurement
PCP	80-900 BPD	Better	Moderate	Poor for dual monobore	Aromatic compatibility	Labtest and Procurement

With consideration from well deviation, surface footprint and compatibility for any kicd of crude oil, TTESP then chosen to be implemented as first monobore mechanical pumps in PHSS. However, to make increase pump lifetime and simplification of pump performance evaluation, some additional requirement has to be developed for TTESP candidate wells.

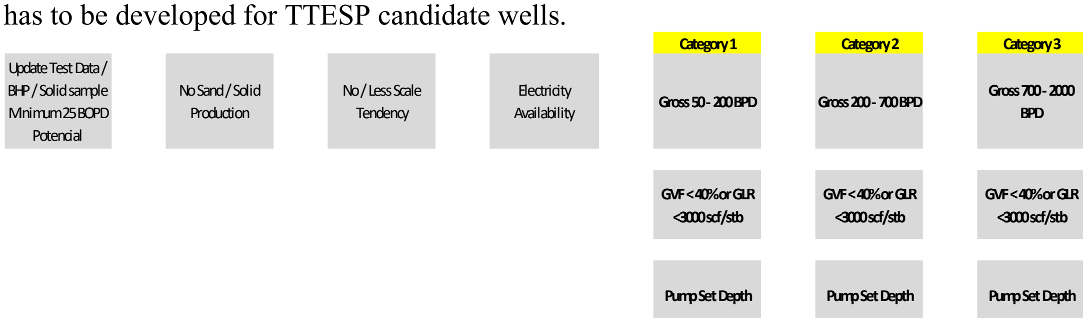

Figure 5 Artificial Lift Selection Flowchart

After screening all candidates, 7 primary wells were identified to be first batch that represented every category (based on gross liquid rate). Although, there are still challenges to implement TTESP on all those wells, due to high free gas into pump. This concern has been addressed, and mitigate by closely monitor daily production trend of those challenging wells, beside conducting downhole pressure survey if applicable to ensure well actual productivity.

Table 3 First Batch of TTESP Candidates

No	Well	Pump Type	Gross (BPD)	Net (BPD)	WC (%)	PSD (ft)	PIP (psi)	GOR (scf/STB)	Category
1	M-XXXL	190-380H	**247**	**247**	**0**	5000	161	50	2
2	M-XXXL	630-1300	**1173**	**152**	**87**	3300	1134	100	3
3	M-XXXL	217(310-900)	**581**	**75**	**87**	1600	222	0	2
4	M-XXXU	217(175-500)	**103**	**41**	**60**	2300	810	1340	1
5	N-XXXU	130-250H	**259**	**31**	**88**	8000	374	100	2
6	M-XXXL	130-250H	**129**	**26**	**80**	2800	600	895	1
7	M-XXXU	760	**501**	**19**	**96**	3400	284	2416	2

4 Conclusions

- TTESP will be the primary artificial lift to replace PCTGL in PHSS Field, due to its historical performance in Sangasanga field, and due to its flexibility to be installed on dual monobore compared with other mechanical artificial lift that has large surface footprint
- Free gas into pump is one of the main challenges in TTESP implementation. Frequency adjustment and field trial will be the method to evaluate actual TTESP performance
- Due to smaller diameter compared with artificial lift in conventional completion, monobore artificial lift will have higher sensitivity to formation fluid, and especially in mechanical pumps, it cannot be installed below perforation interval to reduce free gas into pump
- With existing PCTGL lifting, it is a challenge to define current well inflow performance, hence selected mechanical artificial lift could also operate in broad range of influx

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