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# Integrated Artificial Lift Excellence: Technologies, Operations, and the Digital Future

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# Reviving Idle Offshore Wells Through Insert PCP: Indonesia's First Field-Wide Application in East Kalimantan

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# Case Summary

**Asset Profile:**

- The East Kalimantan Field is a mature offshore field (> 400 wells and producing since 1972)
- Significant production decline.

**The Problem:**

- Over 50% idle wells, primarily due to gas supply for gas lift decline 30%.

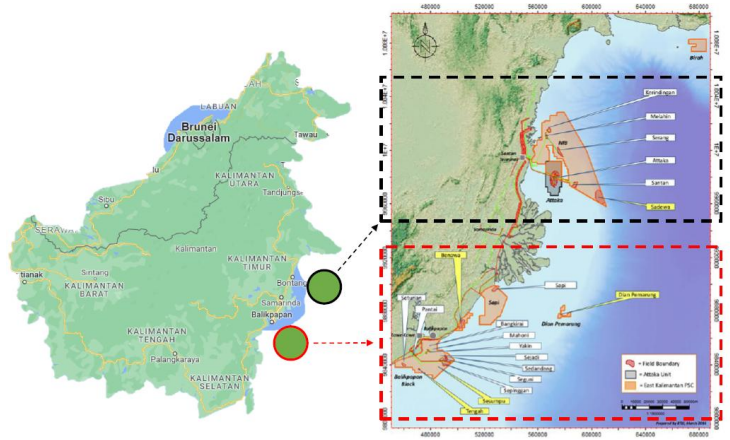
**Economic Barrier:**

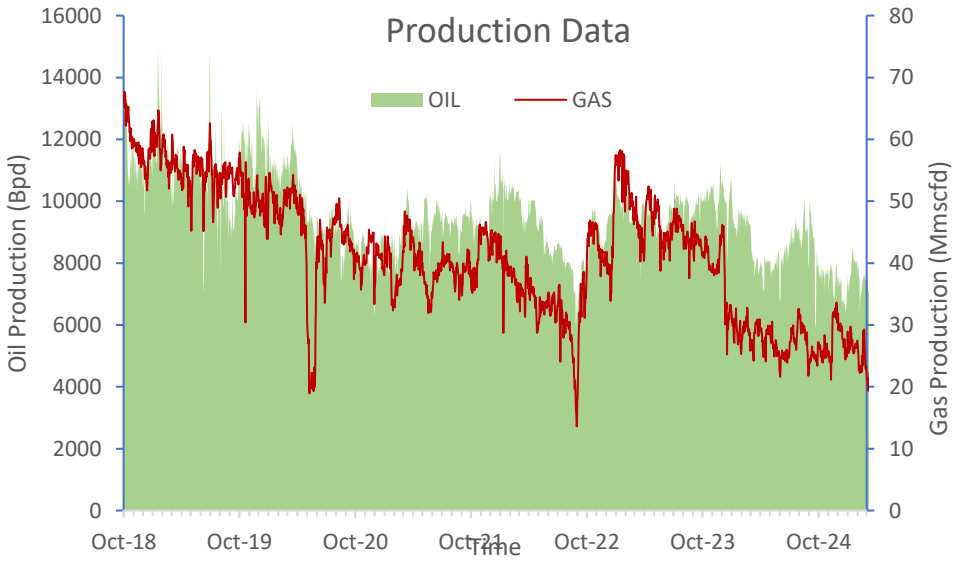
- Conventional workovers (ESP/PCP) = expensive + heavy logistics.
- Not feasible for low-medium rate wells

**The Goal:**

"Rig-less solution, No tubing retrieval and Low Cost"

**"The challenge was not reservoir potential, but intervention feasibility under limited gas availability"**



# Why Insert PCP

- Installed inside existing tubing, avoiding the need for a large workover rig.
- No Gas dependency
- Suitable for low-rate, sandy wells
- No tubing retrieval

Key Limits: Best for wells under 5,500 ft deep and less than 60° deviation.

**Footprint and Logistics (The "Rig-less" Requirement)**
**Deck Space**: Traditional offshore workovers require massive barges. The IPCP was selected because it can be installed using a Mini Hydraulic Jack Unit (HJU).

**Vessel Requirements:** The selection allowed the use of an Anchor Handling Tug Supply (AHTS) vessel rather than a full drilling rig or jack-up, drastically lowering the "entry barrier" for reviving a single well.

**"IPCP is the only method that eliminates both gas dependency and tubing retrieval but suitable for low-medium rate sandy wells"**

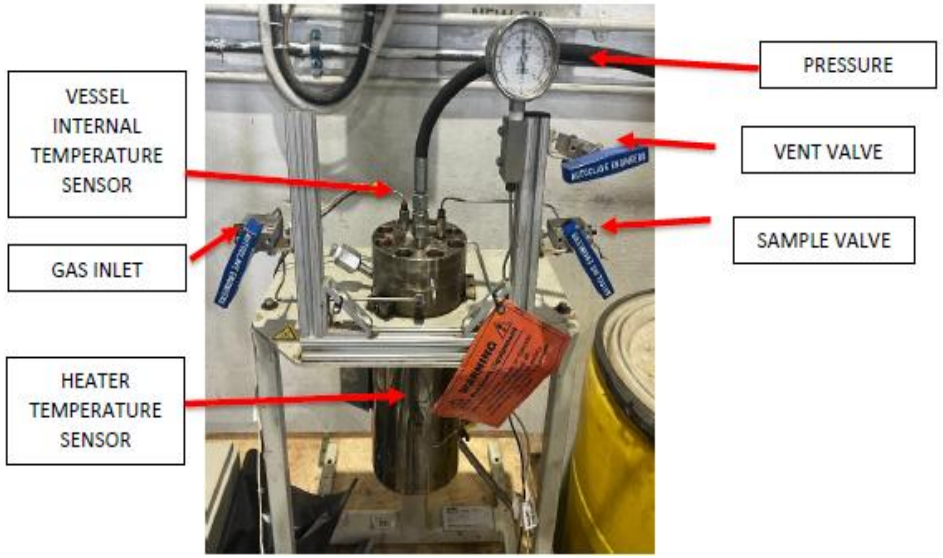
| Parameters | Artifical Lift Methods | | | | |
|---|---|---|---|---|---|
| | Gas lift | ESP | Insert ESP | PCP Tubular | Insert PCP |
| Gas dependency | Yes | No | No | No | No |
| Suitability for low rate wells | Yes | No | Yes | Yes | Yes |
| Operational footprint | Big | Small | Small | Small | Small |
| Tubing retrieval requirement | Yes | Yes | No | Yes | No |
| Offshore intervention cost | High | High | Low | Medium | Low |
| Equipment cost | High | High | High | Low | Low |
| Sand tolerance | High | Low | Low | High | High |

# Technical Compatibility

| Parameter | High Nitrile Soft | High Nitrile Hard | Fluorocarbon Hard | Hydrogenated High Nitrile Hard |
|---|---|---|---|---|
| Abbrassion Resistance | Excellent | Good | Poor | Excellent |
| Max Temp | 176F | 248F | 194F | 302F |
| H2S Resistance | Good | Good | Excellent | Excellent |
| CO2 Resistance | Poor | Good | Poor | Excellent |
| Aromatics | Poor | Good | Excellent | Good |
| Price | Low | Low | High | High |

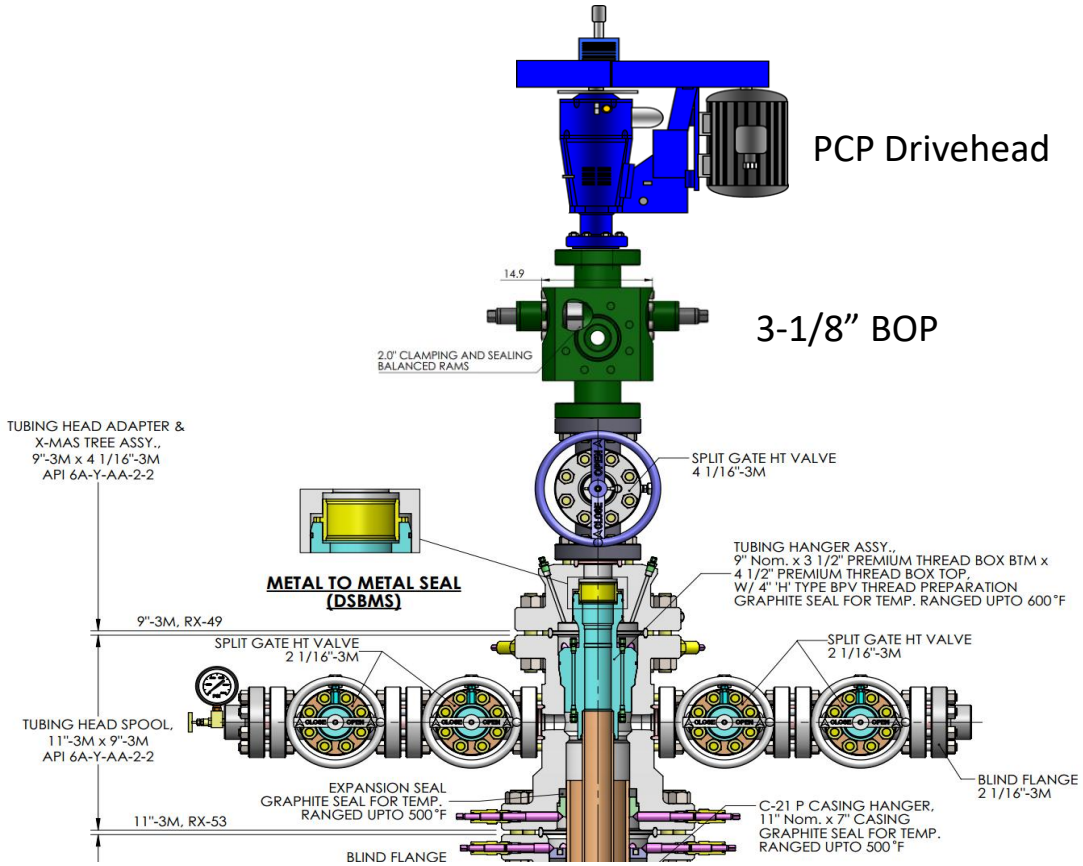
## Key Selection Driver: Elastomer

- **Challenge:** $CO_2$, aromatics. Temperature ~ 178 degF
- Performed Lab Testing for selection
- **Result:** selected High Nitrile Hard
- **The approach:** Ensures reliability → prevent swelling & premature failure

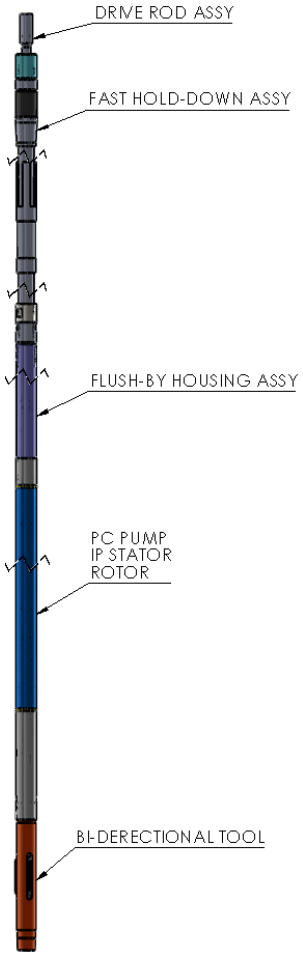


# Technical Compatibility

*Fully retrievable through tubing (no workover rig required)*




Surface Equipment




Downhole Equipment

# Typical Installation

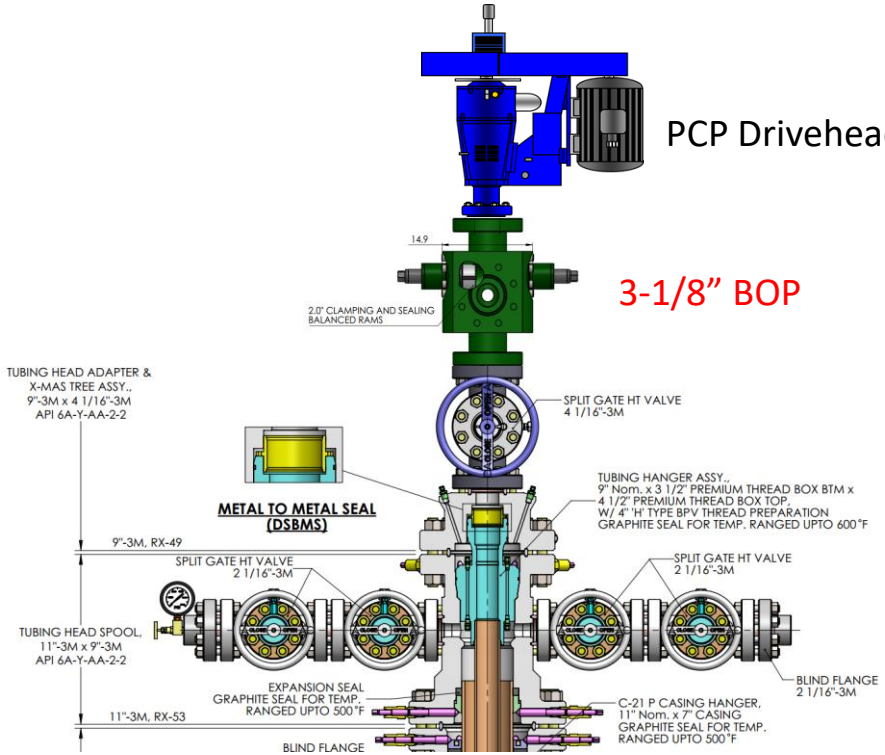
*Surface Equipment – Space and connection check compatibility is critical to ensure run ability & avoid failure during operation*

Requires a drive head, minimum space:

- 54” width
- 66” height

As most of the well in the EK Field is gas lift wells, critical check:

- Wellhead spacing
- Manhole size/clearance




# Typical Installation

*Downhole Equipment - Downhole check compatibility is critical to ensure run ability & avoid failure during operation*

## Key Checks:

- OD vs ID Compatibility
- Landing nipple restriction
- Rod-based system limitation

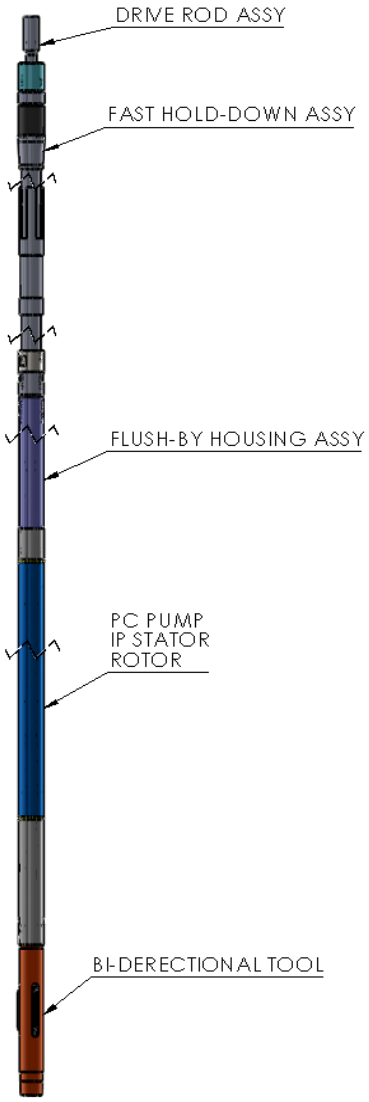
## Operational limits:

- Depth < 5,500 ft
- Deviation < 60 degree
- DLS < 8 deg/100 ft

*The typical IPCP downhole component and its OD are shown in Table 2.*

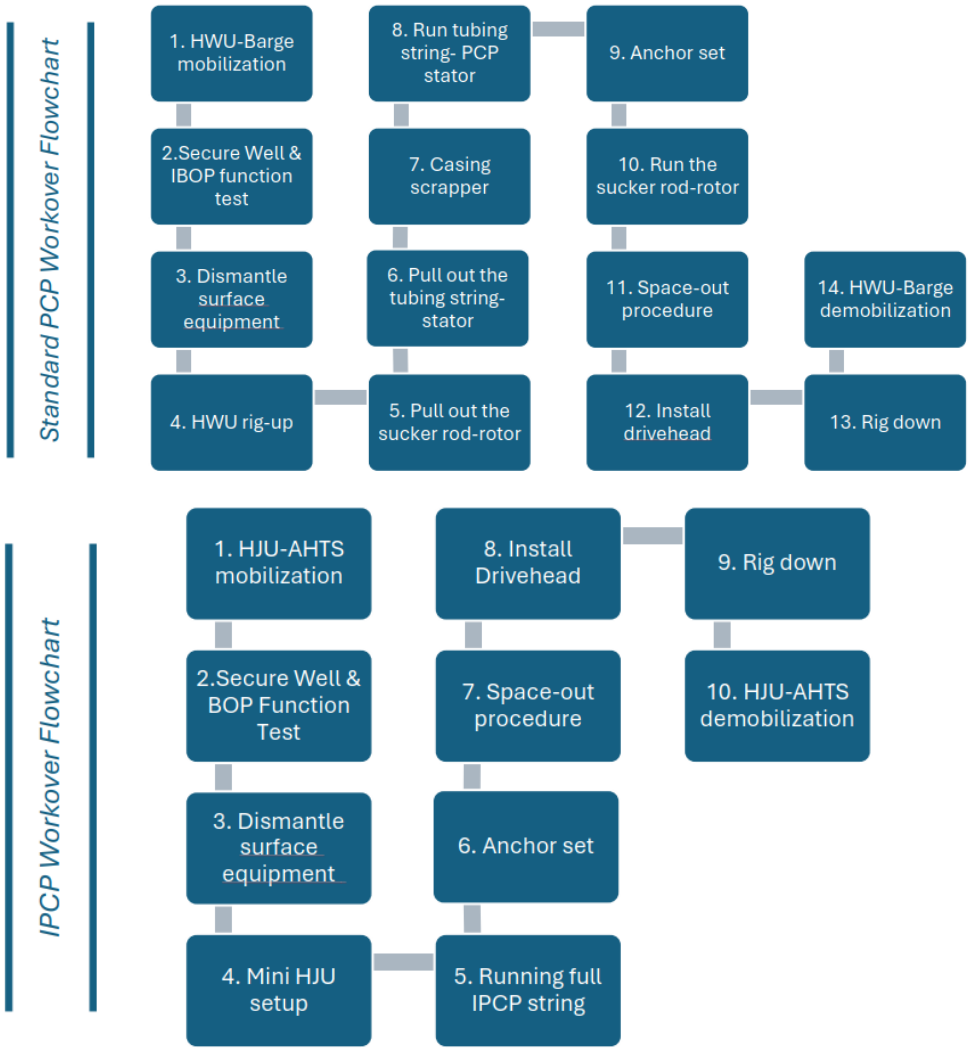
| Components | OD (Inches) |
|---|---|
| Polished rod 1-1/4" | 1.25 |
| Sucker rod 7/8" with centralizer | 2.375 |
| Drive rod | 1.125 |
| Insert Seal Assembly for 3.5" Tubing | 2.84 |
| Stator 31X1200 | 2.68 |
| Torsional Anchor | 2.64 |

| RUNNING DESCRIPTION | INSIDE DIAMETER ( inch ) | OUTSIDE DIAMETER ( inch ) |
|---|---|---|
| ***TUBING HANGER*** | | |
| | | |
| X - OVER 3-1/2" EUE PIN x 3-1/2" TKC PIN | 2.992 | 3.50 |
| | | |
| X - OVER 3-1/2" TKC BOX x 3-1/2" NS-CT PIN | 2.992 | 3.50 |
| | | |
| X - OVER 3-1/2" NS-CT BOX x 3-1/2" TSH BLUE PIN | | 3.50 |
| | | |
| 3-1/2" TSH BLUE, L - 80, TUBING PUP JOINT | 2.992 | 3.50 |
| | | |
| X - OVER 3-1/2" TSH BLUE BOX x 3-1/2" NS-CT PIN | 2.992 | 3.50 |
| | | |
| X - OVER TO GAUGE PORT COUPLING | 2.992 | 3.50 |
| | | |
| **3-1/2" EUE GAUGE PORT COUPLING** | **2.992** | **5.10** |
| | | |
| X - OVER TO GAUGE PORT COUPLING | 2.992 | 3.50 |
| | | |
| 3-1/2" NS-CT, 9.2 PPF, L - 80, TUBING PUP JOINT | 2.992 | 3.50 |
| | | |
| **3-1/2" NS-CT X - LANDING NIPPLE** | **2.812** | **4.50** |
| | | |
| 3-1/2" NS-CT, 9.2 PPF, L - 80, TUBING PUP JOINT | 2.992 | 3.50 |
| | | |
| X - OVER 3-1/2" NS-CT BOX x 3-1/2" EUE PIN | 2.992 | 3.97 |
| | | |
| 3-1/2" EUE PUP JOINT | N/A | 4.13 |



# IPCP Installation

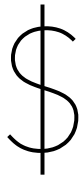
*40% Cost Reduction with 30% Faster Execution*




| Parameters | Artificial Lift Installation Comparison | |
|---|---|---|
| | HWU (Regular PCP Job) 225 klbs | Mini HJU (IPCP Job) 120 klbs |
| Jack Pull Out Distance (Ft) | 10 | 4 |
| Duration of work (days) | 6-7 | 4-5 |
| Mobilization unit | Barge | AHTS |
| Total Weight Frame (lbs) | 11000 | 6600 |
| Load capacity (klbs) | 500 | 255 |
| Setup time (hours) | 6 | 3 |
| Cost (kUSD) | 800-900 | 400-500 |
| Load on wellhead (klbs) | 88-110 | 33-37 |

- **Cost reduction up to 40%,** including vessel and offshore logistics expenses.
- **Installation time 30% faster** compared to conventional methods.
- **No HWU/barge required**
- **Suitable for low-medium wells** →cost reduction and easier logistics means **improved economics**

# Conclusion

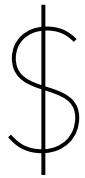


**40% Cost Reduction**

Reduction in total operational costs including vessel and offshore logistics.

**30% Time Savings**

Shorter installation duration compared to conventional barge methods.



**USD 350K Savings per Well**

Approximate workover cost savings achieved for each well intervention.

# THANK YOU