Unconventional Workflows for Identifying Immediate and Short-term Opportunities in a Mature Niger Delta Asset

by

Udeme M.P John, SPEC (Newcross), Georg Zangl (VHC-S)
Abiodun Ogunjobi (Newcross)

SPE Lagos Section, February 2018 Technical Meeting

@
Oakwood Park Hotel, Lekki-Epe Expressway, Lagos
Outline

- Introduction and Field Background
- Problem Statement
- Deciding on how to solve the problem
- Opportunity Identification and Ranking
  - Identification of Sand Potential
  - Reperforation of Existing Wells in New Sands
  - Identification of Infill Wells/Sidetracks Potential
  - New Well Locations
- Result comparison
- Conclusion
- Acknowledgement
Introduction/Background

Asset is located in the Eastern Niger Delta in Rivers State, approx. 40km SW of Port Harcourt.

Block is approx. 162sqkm and located in a mangrove habitat

3 producing fields: Awoba, Awoba Northwest, Ekulama, producing good quality 35°API sweet crude

Key Facts

- 3 producing fields
- 36,323 bopd gross (average daily rate Jan 2018)
- 1.89BMMIL 2P Oil in-place, 3.36Tcf 2P Gas in-place
- Cumulative gross production est. 536MMstb as at 31.12.17
- Current recovery factor of circa 32% for oil
- 528MMbbls oil, 99MMbbl condensate (2P reserves, gross) 1556 Bcf gas gross
- 50 wells, 86 production strings, more than 45 years of production history
- Porosity (18-34%), Permeability (Darcy range)
Low drainage point utilization and exploitation rate creates a sense of urgency for asset revitalization

- Averagely low wellbore utilization across the asset was increased from 21% (pre-acquisition) to 35% (post acquisition)

Immediate upside possible from focused WRM, including well optimization and improved water and sand handling.

- Near to mid-term upsides from infill wells, appraisal drilling, recompletions/reperforations

- Longer term upside from NAG development in Awoba
What did we have to do to ramp-up production?

Any approach must answer some critical questions

■ Has the reservoir technical limits been reached?

■ Can the drainage point utilization be increased?

■ What are the opportunities that can be executed to grow production?

■ Well Reopening
■ Through-Tubing
■ Re-perforation
■ Re-completion
■ Side-track/infill drilling
■ Etc

What will be the potential addition?

Asset contains:

- 86 strings (50 wells)
- 79 Sands (25 producing, 54 virgin)
- Field extension (appraisal/development)
- Multiple exploration prospects
- A fertile ground for opportunities
There is no one size fits it all approach

But we needed to be pragmatic and time to decision making was critical

- Conventional workflow are typically people intensive
- Required expensive industry tools and time consuming
- A data-driven workflow was first adopted (unconventional)-lasted for about 10 weeks
  - Data analytics (more than 45 years of production history)
    - Bayesian belief networks (BBN)
    - Linear regression \( y = kx + d \) (k is constant)
    - Multiple linear regression (MLR) \( y = au + bv + cw + dx \) (a, b, c, d are constants)
- The quick turn around from the unconventional workflows was key to the immediate execution of some opportunities hence our discussion today.
Fast Screening of Opportunities

4 Workflows in 10 weeks to screen all opportunities

1. Identification of sand potential
2. Reperf existing wells in other producing sands/Reperf existing wells in virgin sands
3. Identification of infill/sidetrack potential
4. Drilling in new areas/sands (Awoba NW)
To quantify the reduction of recoverable reserves, each complexity indices is correlated logarithmically with the recovery reduction ($\Delta RR$) and multiplied by the fluid mobility index, MI (for oil reservoirs)

$$\Delta RR = (\Delta RR_A + \Delta RR_S + \Delta RR_{RP}) \times MI_{HCP}.$$ 

Technical Recoverable Volume = OOIP*(1 - $\Delta RR$ )

**Reservoir Technical Limit**

A key aspect of reservoir management beside the reserve estimation is the determination of the recovery efficiency of the reservoir. Not all hydrocarbons which are identified in the reservoirs are technically recoverable due to certain factors

$RTL = f(RCI)$
Bayesian Belief Networks (BBN)

- BBN capture expert knowledge and allow for a concise representation of complex decision processes.
- BBN enable to do reasoning under uncertainty.
- Result: probabilistic score.

Benefits:
- Input probabilistic.
- Inputs are not always required.
- Input uncertainty is captured.
1. Identification of Sand Potential

Three Bayesian Networks

- Reservoir Architecture
- Reservoir Structure
- Reservoir Properties
- Fluid Properties

Reservoir Complexity Index

Reservoir Technical Limit

Correlation based on mature fields

Input

Reservoir Architecture
- depositional system
- stacked layer
- thickness variability
- # of compartments
- compartment type

Reservoir Structure
- depth
- dip
- dip variation
- boundary conditions
- gross thickness

Reservoir Properties
- lateral heterogeneity
- permeability Kv/Kh
- oil transition zone
- Oil column
- residual oil saturation
- Initial mobility ratio
- Formation damage
- net to gross ratio

Fluid Properties
- 2nd phase
- °API
- Bubble point to initial reservoir pressure ratio
- Bubble point to current reservoir pressure ratio
- HC precipitation
1. Identification of Sand Potential: Results

- Individual complexity scores were calculated for each sand and combined to an RCI.
- RCI of seven selected sands were used to estimate a reservoir technical limit trend (sands in red dot).
- The trend, which is data-driven, relates RTL to RCI to allow RTL to be calculated for each sand in the field.
- UR for this workflow is therefore a function of reservoir RTL and OOIP.
- High UR likely underestimated reserves.
- High UR above the RTL limit could mean that STOIIP is underestimated.

Data Driven Corelation between RTL and RCI
Identification of Sand Potential: Remaining Opportunities - Review of F1000X Sand

The DCA of this study shows that the currently active wells would be able to reach a recovery factor of 44.7%, 32.9 MMSTB short of a 2016 2P DUR.

The opportunities, which have been identified in this study, would be able to add 26 MMSTB to the table, increasing the URF to 51.9%, which is 2% less than the reported DUR. There is clearly some concurrence between the URF estimated during this study and that in the 2016 ARPR.

The RTL is 63%, which means that more than 6 MMSTB (11.1%) are left behind and would not be tapped by the identified opportunities.

Because of “main influence factors” or “dynamic influence factors” - waste of reservoir energy during operation, and sub-optimal development strategy that lead to poor displacement efficiency, UR < RTL

As technology improves (EOR, IOR, etc) EUR is changing but not so RTL
2. Reperf Existing Wells in New Sands

Calibration of Historical Data to Well Logs / Reservoir geometrical Attributes
- Standardization of well log data
- To enable log response to be consistent across stratigraphic section being analyzed and from one well to the other
- Generation of production & reservoir KPI’s (Production Potential, Cum. Prod., EUR.)
- Calibration of log / reservoir parameters with production KPI’s

New Sand Opportunity Assessment
- Identification of new opportunities in new sands
- Apply models to predict potential gain, cumulative production, water breakthrough, including uncertainty
- Reality check using offset wells, drainage radius analysis, RST data

Technical Feasibility
- Check accessibility of identified sand opportunities
- Combine sand opportunities into workover proposals
- High-level technical proposal
2. Reperf Existing Wells in New Sands

Step 1

- Standardization of Well Log Data

- Raw logs standardized to eliminate effects of different logging tools, measurement errors, etc.

\[ x = \frac{x - \text{xmean}}{\sigma} \]

- Well logs standardized well by well, independently on Ekulama field
2. Reperf Existing Wells in New Sands: Production KPI's

- Best 12 Months Average Historic Production Used as ‘Production Potential

Full well potential not exploited during first 12 months

This could be due to operations philosophy. E.g. sub-optimal welltest design, commissioning effects, etc.
3. Reperf Existing Wells in New Sands: Geometrical KPI’s

Production Potential in Awoba-Field Depends on Resistivity Score and Distance above IOWC

\[
\text{Predicted Potential} = 43.686 \times \text{RDscore} + 24.449 \times \text{Dist(OWC)} - 1538.3
\]

Resistivity score, and distance between the lowest perforation and the IOWC exhibited stronger on influence on historical production potential than did thickness of reservoir, length of perforation interval, gamma ray response.
2. Reperf Existing Wells in New Sands

- Blind Test: cross plot of observed vs. predicted production potentials in A-Field
2. Reperf Existing Wells in New Sands

- Estimated Ultimate Recovery Strongly Depends on Production Potential

**EUR vs. Production Potential, Ekulama F1 Sand**

**EUR vs. Production Potential, all Awoba Sands**
2. Reperf Existing Wells in New Sands

Reality check rationale:
- Discount cumulative production in case of drainage radius overlaps
- Eliminate opportunities if overlap exceeds ca. 70%
- Eliminate opportunities very close to the OWC
- Check predicted potential against offset well performance
2. Reperf Existing Wells in New Sands

Monte-Carlo Type Production Forecasts

Key Assumptions
- P10-P50-P90 initial rates from gain estimation (regression function & prediction belt)
- Discounted EUR after reality check used
- P50 decline rate determined iteratively to match P50 start rate and EUR
- Standard deviation of decline rate = 30% of P50 decline rate
3. Identification of Infill/Sidetrack Potential

- Workflow evaluates location between two existing wells which have produced from a layer and compares it with another infill location to determine best location(s) per sand.

- Its magnitude cannot be compared to locations in other sands

1. Estimate current rate, developed ultimate recovery (DUR), decline rate of historic producers using DCA
2. Estimate current rate with correlation
3. Compare both results for current rate and calculate standard deviation
4. Estimate remaining reserves per well
5. Create infill locations by Delaunay triangulation
6. Interpolate initial rate, decline and DUR from neighbors weighted by distance
7. Check drainage areas and discount DUR for overlap of drainage areas
8. Cross-check EUR of producers + new locations ≤ remaining reserves
9. Run probabilistic scoring engine (Bayesian Belief Network)
3. Identification of Infill/Sidetrack Potential

Step 1 & 2 & 3 & 4

- Estimate decline rate, ultimate recovery using DCA
- Estimate current rate from: DUR, HCIP, Remaining Oil, Net*Phi*So using MLR
- Calculate standard deviations
- Estimate remaining reserves per well
3. Identification of Infill/Sidetrack Potential

Step 5 & 6

- Create Infill Locations
- Interpolate initial rate, decline and DUR from neighbors weighted by distance

Estimation of Remaining Oil

Need to be consistent with ARPR, RTL and volumetrics
3. Identification of Infill/Sidetrack Potential

Step 5 & 6 & 7

- Create Infill Locations
- Interpolate initial rate, decline and DUR from neighbors weighted by distance
- Check drainage areas and discount DUR for overlap of drainage areas
3. Identification of Infill/Sidetrack Potential

Step 8 & 9

- Cross-check DUR of producers + new locations ≤ remaining reserves
- Run probabilistic scoring engine (Bayesian Belief Network)

Input

- Initial rate + StDev
- DUR + StDev
- Decline rate + StDev
- Proximity to producer
- Proximity to injector/aquifer
- Confidence (manual)
3. Identification of Infill/Sidetrack Potential

- Cross-check DUR of producers + new locations ≤ remaining reserves
- Rank results according to initial rate and visualize score

In this sand, location 16 and 17 looks promising. Others were not economically feasible. A combination of Loc 16 & 17 in an extended reach well yielded reserves estimate of circa 5MMSTB
4. Identification of New Well Location

- The Sweet Spot Index (SSI) is a score that uses numerical simulation models (or geological models with fluid initialization) to identify zones with high potential of production.

- Three Factors to Calculate the Sweet Spot Index SSI

  1. **Movable Oil in Place Indicator**
     - Difference of Initial and Residual Oil Saturation
     - Porosity

  2. **Reservoir Flow Indicator**
     - Reservoir Net KH
     - Viscosity

  3. **Pressure Potential Indicator**
     - Reservoir pressure
     - Abandonment pressure
     - *this factor is neglected here because of the strong aquifer support

\[
MOI = \sqrt{\frac{(S_{oi} - S_{or})}{S_{or}}} \phi
\]

\[
RFI = \sqrt{\frac{\ln K_x D_z NTG}{\mu}}
\]

\[
PPI = \sqrt{\frac{P - P_{abn}}{P_{abn}}}
\]
4. Identification of New Well Location

Sweet Spot Index

Calculation of Sweet Spot Index

\[ SSI = \frac{(RFI + 2 \times MOI)}{3} \]

Calculation of Cumulative Sweet Spot Index

\[ CumSSI = \sum_{k=1}^{Layers} SSI_{i,j} \]

It is possible to normalize the cum. SSI, when comparing reservoirs with different vertical discretization.
4. Identification of New Well Location

Cumulative Sweet Spot Index – B6000X

Almost any location within the rectangle is OK
Needs detailed study to define
4. Identification of New Well Location

Comparison PrevS – NDPlan 2008 and FDP 2017
- Same location as PrevS has suggested
- P50 Initial Rate 7% higher than PrevS estimate, 16% higher than 2017 FDP*
- P50 DUR 11% more than PrevS, but 2.8 times more than 2017 FDP

*New well HANCK 1
PrevS means Previous Study
4. Identification of New Well Location

- Best Drilling Target Location – B6000X
- Similar KH and STOIIP leads to assumption of similar production performance
- For similar well geometry

<table>
<thead>
<tr>
<th></th>
<th>Horizontal Permeability [mD]</th>
<th>DZ [ft]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Awoba NW-01 S</td>
<td>P90  1057</td>
<td>P50  2405</td>
</tr>
<tr>
<td>New Well Location</td>
<td>1646</td>
<td>2840</td>
</tr>
</tbody>
</table>

Maximum reservoir contact well geometry is highly recommended.
These low hanging fruits were executed in the first and second phase of the TT campaign.

- Well re-opening/flowline replacement, zone change, etc
- Eku 23T could not flow due to sand build-up. Work plans to carryout sand bailing has been put in place.
- Overall circa 8,000bopd was realized from the first and second phase of the campaign.
Conclusion

Independent consultants reviewed the opportunities in this study using expert knowledge, well logs, available numerical simulation, analytical reservoir and well models.

There were good alignment in most opportunities:

- 13 Through-tubing interventions
  - Expected to add circa 7,000bopd of incremental oil and 23.92MMSTB of reward

- 15 recompletions (subject to confirmation of POWCs and current reservoir pressures)
  - Expected to add circa 18,000bopd of incremental oil and 44.53MMSTB of reward

These opportunities became our immediate and short-term focus, in addition to appraisal drilling in Awoba NW (Workflow 4).

Several others opportunities identified (with no alignment in studies), mostly infill drilling, have been deferred and subject to additional data acquisition.

Proposal for further studies post data acquisition to define further oil development plans towards mid-to-long term development efforts is being put together.
Acknowledgement

- Management and Staff of Newcross Exploration and Production Limited
- Society of Petroleum Engineers (SPE)
- All in Attendance