MULTILATERAL WELLS CAN BE EMPLOYED IN HEAVY OIL FORMATIONS REQUIRING ADDITIONAL RESERVOIR EXPOSURE TO ACHIEVE TARGET PRODUCTION RATES AND IMPROVE ECONOMICS

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Introduction

- Patos-Marinza oilfield – redevelopment of an existing brownfield heavy oilfield:
  - Onshore field with > 2700 wells drilled to date.
  - Originally operated by Albpetrol (Albania National Oil Company).
  - Operated by Bankers Petroleum since 2005.
  - Multiple unconsolidated sandstone reservoirs with large variation in oil viscosity, and density.

- High viscosity oil requires very low well spacing (5° API oil, Live oil viscosity of 5,000 to 10,000 cP)

- Multilateral allows for more reservoir exposure at a reduced cost:
  - Requires a low cost junction which must meet the following requirements:
    Full drift of the intermediate and liner casings with a minimum of 3 laterals/legs
    Pressure and integrity up to full evacuation during production
    Debris integrity to hold back unconsolidated formation sand during production

- Oil production is a function of permeability, net pay, well length, skin & viscosity.
High Viscosity Challenges

- Wide range of API, formation depths, GOR at Patos-Marizna. 50 – 10,000+ cP.

- Wide range of dead & live oil viscosities:
  - Gorani 5/6 formations: 5,000-10,000 cP live, 25,000 to 50,000 dead (@ reservoir temp.)

- Similar completions and well spacing historically used for all formations, regardless of oil viscosity.

- Difficult to mobilize heavy crude within reservoir:
  - Too deep for thermal
  - Too heavy for polymer flooding
  - Optimize well spacing & length
  - Reduce $ per well (or per metre of reservoir exploited)
Analysis of Drilling Times & Costs by Well Section

Lateral section is smallest cost of current well design

Surface Casing: 2 days
Drilling intermediate hole: 4 days
Reaming intermediate hole: 1.5 days
Run intermediate casing and cement: 1 day
Drill lateral section, run liner: 4 days
Total: 12.5 days

Additional Legs are 7.5 days each including junction
Multilateral Solution

- Oil production is a function of permeability, net pay, well length, skin, viscosity.
- Multilateral allows for more reservoir exposure:
  - Well length (of all legs combined) increases with additional lateral length and/or additional laterals.
  - Permeability*, net pay, skin* and viscosity are set.
- Increase EUR, NPV per well.
- Analogous Development Strategies – Multilateral wells being used to exploit reservoirs similar to Patos-Marinza:
  - Venezuela Orinoco Oil Belt (Bare Field, San Diego Field, Zuata):
  - Canada Pelican Lake (Wabiskaw)
  - Oman Mukhaizna Field
  - Congo Zhatchi Field (Offshore)
- Design criteria had to be fit for Purpose design for Patos-Marinza based on well serviceability, unconsolidated sandstone and marginal economics. In addition to low cost the multilateral design following:
  - Full drift of the intermediate and liner casings with a minimum of 3 laterals/legs.
  - Pressure and integrity up to full evacuation during production.
  - Debris barrier to hold back unconsolidated formation sand during production.
  - Accessibility during the complete production cycle. Including coiled tubing cleanouts and pump placement.
Multilateral Summary

Modeling Assumptions:

- Targeting G5/G6
  - Gross Pay of 25m
  - Porosity = 25%
  - Water Saturation = 25%
  - Permeability = 250 mD
  - Reservoir Pressure = 15.3 MPa
  - Dead oil viscosity = 50000 cP
  - Live Oil viscosity = 7500 cP
  - API = 5°
  - Assumed bottom hole flowing pressure of 9 MPa
- Depth: 1530 m TVD, 2455 m MD
- Lateral length – 800 m
- Inter-lateral spacing: 50 m
- Real structure and well trajectories
- Grid 20m x 20m x 8 layers = 125,368 active blocks
Reservoir Model – History Match

4-well history match

Cumulative Fluids SC (bbl)
- 120,000
- 100,000
- 80,000
- 60,000
- 40,000
- 20,000
- 0

Time (Date)
- 2011-10
- 2012-1
- 2012-4
- 2012-7
- 2012-10
- 2013

Legend:
- Cumulative Liquid SC model
- Cumulative Liquid SC actual
- Cumulative Oil SC model
- Cumulative Oil SC actual
- Cumulative Water SC model
- Cumulative Water SC actual
Reservoir Model

Oil Viscosity

[Diagram showing oil viscosity over two different time periods, 2024-01-01 and 2011-08-01, with color scales indicating viscosity levels.]
Reservoir Model

Recovery Factor

Formula: Recovery Factor 2011-06-01

Formula: Recovery Factor 2024-02-01
Lateral Spacing Optimization

- Sensitivity analysis performed on optimum lateral spacing (80m, 50m, 35m).

- Also compared 3 leg lateral to 3 individual wells:
  - Max rate of 1 well limited to 150 bpd due to torque limit on pump.

- Additional sensitivity to review middle lateral only – indicative of full development scenario.

- 3 Leg lateral expected to perform best, optimum spacing is 50m but only slight improvement from 35m.
The description of multilateral junctions as per the industry recognized classification system referred to as Technology Advancement of Multilaterals (TAML) established in 1997:

**Level 6** - Pressure integrity at the junction achieved with casing and down-hole splitters (cemented).

**Level 5** - Pressure integrity at the junction achieved with packer or mechanical seal

**Level 4** – Main-bore and lateral cemented at junction

**Level 3** – Lateral liner anchored to main-bore, but not cemented

**Level 2** – Main-bore cased and cemented, lateral barefoot or drop liner

**Level 1** – Barefoot (or drop liner) main-bore and lateral
Multilateral Design

- The standard Patos-Marinza horizontal development well consists of a 7" intermediate casing with 4-1/2" slotted liner which is terminated utilizing a conventional sealed liner hanger. This represents the base design parameters for a multilateral well in the field.

- The multilateral system utilized in Patos-Marinza does not conform to other commercial systems available on the market.

- In comparison to the industry recognized TAML Level 1 to 6 conventional junctions the process is best described as a hybrid Level 5.

- The process does not have a metal to metal seal created by use of downhole splitters to qualify as a Level 6 junction. Similarly, the process does not conform entirely to the Level 5 which utilizes cased hole packing and slip type elements to tie-back inside the intermediate casing (or mother bore).

- Due to the economic costs and limitations associated with final wellbore configuration which are practical mature or marginal oil fields, the current commercially available Level 5 and 6 systems on the market were not acceptable. Therefore, in regards to the current industry nomenclature of TAML multilateral junction levels, the FCRL system is best referenced as a hybrid Level 5.

Note: Due to confidentiality constraints at the time of publishing, details on the mechanical method used to create the sealed full bore junctions were created cannot be disclosed.
The well design had to meet the following criteria:
- **Cost limited to a maximum of 40% per leg** of a standard horizontal.
- **Maintain full bore/drift** accessibility of intermediate casing and slotted liner(s).
- **Debris barrier**.
- **Pressure barrier** capable of holding maximum differential pressure of the reservoir during production, injection, and workover operations.

In addition to the cold production requirements of the Patos Marinza field the final design is believed to be expanded to the following:
- Able to withstand thermal steam injection temperatures.
- **Repeatable with other casing sizes and weights**.
The final result is a full drift pressure and debris sealed junction which can be repeated approximately every...
For simplicity, the initial pilot well was planned to be a dual lateral. The drilling operations were run without incident with the estimated time for each operation within 5% of planned. The following table represents the planned to actual operations time.

### 5108-ML Drilling Curve

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<th>Depth (meters)</th>
<th>Time (days)</th>
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<tr>
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<td>3</td>
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<td>5</td>
</tr>
<tr>
<td>0</td>
<td>6</td>
</tr>
</tbody>
</table>

- **Actual**
- **Planned**
Well cleanouts if required can be done utilizing either a bent joint or a unique positive latch assembly design specifically for this purpose (the pilot used the positive latch assembly) as illustrated below:
Results: Production vs Prediction

- Sand production of ~ 0.5%.
- Work-over operations confirmed a clean wellbore to TD of leg #1 after ~100 days on production.
- Producing rate of 80 bpd with higher water cut than expected.
- Oil quality is heavier than expected at 4.4 API.
- Initial rates were above predicted but fell off much high than predicted.
• Similarly, the actual drilling costs were in line with the estimated costs.

• Cost of junction for the initial pilot dual lateral was $160,000. Further reduction in cost is foreseen with future wells after taking in lessons learned.

• The cost for the 2nd leg being within 60% of the total cost of drilling a conventional horizontals. Based on estimates, additional legs (3rd, 4th, etc.) would be within 40%. Unlike other multilateral systems, the physical hardware costs are a fraction of the overall expenditure with the majority related to drilling time. Subsequent legs are not burdened.

• It is believed further cost reduction can be achieved by applying the lessons learned during the pilot phase to commercial development.
Conclusions

The main pilot project goals were to prove the concept of multilateral well drilling in P-M heavy oilfield and understand benefits in:

- Rate  Success likely
- EUR   Success likely
- F&D   Success likely

- Place a ML junction which would provide a debris and pressure seal  Success likely

- Service and clean out both legs  Not attempted at time of publication. No sand production has been seen on surface or bottom hole well left on production.
Conclusions (cont.)

• One multilateral with two legs drilled, completed and place on production in the G5 formation.

• The well was rig released in August and as of April 30\textsuperscript{th} has accumulated \textasciitilde32 Mbbl net oil.

• Producing at a rate of 80 bpd (12 m3/d), 70\% water.

• The current oil rate is lower than predicted.

• Oil quality is heavier than predicted at 4.4 API.

• The analogue is not 5258 but 5613 due to API & water.

• \textbf{5108 has modestly outperformed the analogue single leg 5613 to date.}

• Therefore, the cause of the fall off of production below predicted rates needs to be determined by further production tests of individual legs to ensure contribution – This has not been completed at the time of publishing.
Conclusions, Cont.

- Although initial pilot results are encouraging, further work testing and well intervention work needs to be conducted to determine cause of production drop off. Since no sand production has been seen the mechanical integrity of the junction is believed to be in place. Potential contributing factors may be related to the fine slots in conjunction with the very low API crude.

- Improved production and economics:
  - Reservoir modeling suggests 3 leg wells have improved economics (lower capital and operating costs vs three individual wells).
  - Reduction in capital costs leads to significant improvements in IRR, Payout, F&D compared to single well
  - Improved recovery factor, and improved project NPV.
  - Low risk trial with high reward. Reduction in F&D of >30%.
Summary

- Further testing needs to be done in a lighter oil environment to test economic benefit.

- This multilateral process was applied to an unconsolidated heavy oil reservoir on primary cold production. However, the system could be used in other applications such as typical in mature or marginal field settings.

- The lack of ‘out of the box’ 3rd party solution initiated a pilot project developing a simplified economic process.
Appendix
• Authors believe the **same system could be applied to other applications to improve exploitation of reserves in mature or marginal fields.** An example, of a light oil multi-layer carbonate field utilizing multiple legs to attain exposure to thin pay with bottom water constraints (*see Appendix slide illustration*).