Developing the Full Field Simulation Model of a Fractured Basement Reservoir West of Shetland Using INTERSECT

Dan Bonter
Reservoir Geoscientist
Hurricane Energy
Outline

1. Introduction to the Lancaster Field

2. Overview of fractured basement reservoir characteristics

3. Building the Lancaster static model

4. Dynamic modelling and uncertainty analysis

5. Future plans – the Lancaster Early Production System
The Lancaster Field
Hurricane Asset Locations

- Typhoon
- Schiehallion
- Foinaven
- Strathmore
- Shetland Islands
- Orkney Islands

SCOTLAND

Isle of Lewis
Isle of Skye
Orkney Islands
Shetland Islands
Aberdeen

Warwick
Whirlwind
Lancaster
Halifax
Lincoln
Typhoon
Solan
Strathmore
## Lancaster CPR 2017

<table>
<thead>
<tr>
<th></th>
<th>Reserves</th>
<th>Contingent Resources</th>
<th>EUR (Reserves + Resources)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low / 1P + 1C</td>
<td>28 MMbbl</td>
<td>129 MMbbl</td>
<td>157 MMbbl</td>
</tr>
<tr>
<td>Best / 2P + 2C</td>
<td>37 MMbbl</td>
<td>486 MMbbl</td>
<td>523 MMbbl</td>
</tr>
<tr>
<td>High / 3P + 3C</td>
<td>49 MMbbl</td>
<td>1,117 MMbbl</td>
<td>1,166 MMbbl</td>
</tr>
</tbody>
</table>

### Mega Blocks
- **Low ESP Rate**: 15,375 stb/d ($\text{205/21a-7Z (2016)}$)
- **Max ESP Rate**: 9,800 stb/d ($\text{205/21a-6 (2014)}$)

### Key Data Points
- **1,597m TVDSS (CPR 1C OWC)**
- **1,653m TVDSS (CPR 2C OWC)**
- **1,678m TVDSS (CPR 3C OWC)**

### Well Data
- **Wireline Oil Samples**: 205/21-7 (Deepest 1,669m TVDSS)
- **Mobile Oil Swabbed**: 205/21-4 (1,597m TVDSS)
Fractured Basement Reservoirs
What is Fractured Basement?

Definitions of Naturally Fractured Reservoirs, after Nelson 2001

Basement is a Type 1 Naturally Fractured Reservoir

Oil storage and mobility entirely depends on the fracture network.
What is Fractured Basement?

- Igneous or metamorphic rock underlying the sedimentary cover
- Lancaster is primarily tonalite and approximately 2.5 billion years old
- An extensive geological history has formed a well-developed fracture network
- Images from the Isle of Lewis, outcrop analogue
Lancaster Well
205/21a-4Z

Joints interpreted from image logs

Microfracturing visible on image log
Dual porosity interpretation

- No intergranular matrix porosity exists within the granite
- Dual porosity response is caused by interaction of different scales of fractures within the reservoir

Complex storage response – combination of wellbore and well connected fractures

<table>
<thead>
<tr>
<th>Dual porosity dip</th>
<th>Late time drop</th>
</tr>
</thead>
</table>

- No intergranular matrix porosity exists within the granite
- Dual porosity response is caused by interaction of different scales of fractures within the reservoir

Warren & Root interpretation of 205/21a-7Z natural flow PBU, Axis Well Technology 2016
Fault Zones

• Tectonic activity causes seismic scale faults

• These faults have related damage zones, where poroperm characteristics are enhanced

• This means that fault zones are associated with enhanced reservoir properties, and are therefore primary reservoir targets
Conceptual Model

1. Fault Zone Facies
   Preferentially higher poroperm characteristics
   Seismically identifiable features
   Widths based on log data

2. Fractured Basement Facies
   Permeable, connected fractures present between Fault Zones
   Contributes to flow

Dolerite – not modelled
Presence of dolerite cannot be predicted
Appears to have little to no impact on poroperm characteristics so is not modelled

Bimodal facies model constructed:
Two broad families of fracture to consider
Both fracture sets exist pervasively throughout both facies:

Joints
Features cutting the borehole
Can be interpreted on image logs
Include regional joints, cross joints, shear fractures etc.
Provide primary permeability pathways

Microfractures
Pervasive small-scale fracturing present throughout the reservoir
Individual features that are hard to distinguish on image logs
Contributes to bulk porosity; logs cannot distinguish joints from microfractures
Acts like a matrix component of a dual porosity system in a dynamic sense
Challenges when modelling fractured basement

- Large connected volumes identified on well test analysis – big structure to model
- Extremely high permeability in discrete joints
- Large variation in porosity and permeability between fractures and host rock
- Difficulty in identifying connected fluid phase in the reservoir – potential for complicated fluid distribution
- Conventional modelling software has not been designed with fractures in mind

Some of challenges have been addressed with the current modelling programme, some of them remain as uncertainties that are being worked on
Static Model
Fault Interpretation

• Combination of manual fault interpretation and automated techniques (ANT Tracking) to define the fault network on the field

• Good correlation between faults identified through ANT Tracking and log-interpreted Fault Zones
Petrel Fault Modelling

740 modelled faults
Manual fault interpretation is time consuming but ensures robustness of fault model for simulation

Faults modelled vertically to avoid simulation errors
Distance to Fault property enables modelling of Fault Zones

Current fault model underpopulated in the east, apparent reduction in faulting is artificial
Model Resolution

10x10 metre areal grid cells enable accurate modelling and stochastic variation of Fault Zone widths.
Properties in the model are distributed deterministically, based on whether the cell is within a Fault Zone
- Cells within Fault Zones are generally higher porosity and permeability

No reliable data exists for distribution of properties away from well control using conventional algorithms – no depositional or layering model exists for this ancient igneous rock

Each cell is attributed properties for the primary joint / fracture network and the secondary microfractures (treated as ‘matrix’ in the model)

Property Distribution

<table>
<thead>
<tr>
<th>Facies</th>
<th>Fracture / Joint porosity</th>
<th>Microfracture (“matrix”) porosity</th>
<th>Porosity average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fault Zone</td>
<td>2.3%</td>
<td>2.9%</td>
<td>5.2%</td>
</tr>
<tr>
<td>Fractured Basement</td>
<td>0.7%</td>
<td>2.9%</td>
<td>3.6%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Facies</th>
<th>Fracture / Joint permeability</th>
<th>Microfracture (“matrix”) permeability</th>
<th>Permeability average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fault Zone</td>
<td>796 mD</td>
<td>0.06 mD</td>
<td>352 mD</td>
</tr>
<tr>
<td>Fractured Basement</td>
<td>796 mD</td>
<td>0.06 mD</td>
<td>155 mD</td>
</tr>
</tbody>
</table>

Note that these are bulk average values for a representative elementary volume, including the tight rock and open fractures.
Dynamic Modelling & Uncertainty Analysis
Lancaster Simulation Model

Previous Eclipse Sector Model
4,000,000 cells

Equivalent results achieved in a fraction of the time, run in-house by Hurricane with support from Schlumberger

Current Full Field INTERSECT Model
79,552,000 grid cells
Porosity uncertainty modelling
History match impact of varying porosity

- History match of 205/21a-6 well test is insensitive to relatively large variations in average porosity

<table>
<thead>
<tr>
<th>Fracture Set</th>
<th>Fault Zone</th>
<th>Fractured Basement</th>
<th>Reservoir average</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Low Case</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>High conductivity</td>
<td>1.5 %</td>
<td>0.5 %</td>
<td>1.0 %</td>
</tr>
<tr>
<td>Dynamically compressible</td>
<td>2.0 %</td>
<td>2.0 %</td>
<td>2.0 %</td>
</tr>
<tr>
<td>All fractures</td>
<td>3.5 %</td>
<td>2.5 %</td>
<td>3.0 %</td>
</tr>
<tr>
<td><strong>Base Case</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>High conductivity</td>
<td>2.3 %</td>
<td>0.7 %</td>
<td>1.5 %</td>
</tr>
<tr>
<td>Dynamically compressible</td>
<td>2.9 %</td>
<td>2.9 %</td>
<td>2.9 %</td>
</tr>
<tr>
<td>All fractures</td>
<td>5.2 %</td>
<td>3.6 %</td>
<td>4.4 %</td>
</tr>
<tr>
<td><strong>High Case</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>High conductivity</td>
<td>3.0 %</td>
<td>1.0 %</td>
<td>2.0 %</td>
</tr>
<tr>
<td>Dynamically compressible</td>
<td>4.0 %</td>
<td>4.0 %</td>
<td>4.0 %</td>
</tr>
<tr>
<td>All fractures</td>
<td>7.0 %</td>
<td>5.0 %</td>
<td>6.0 %</td>
</tr>
</tbody>
</table>
Forecast impact of varying porosity

- Varying porosity has a large impact on forecast production
Aquifer support cases
**Aquifer Presence**

- Aquifer support is likely to be present
  - RPS, Axis and Schlumberger have all made this comment
  - Open fractures exist to the TD of 205/21a-4, they are highly likely to be present below this depth and must be filled with something
- The strength of this aquifer is currently unknown
  - Various scenarios have been modelled
- Simulation modelling is absolutely clear that the 205/21a-6 well test result cannot be matched using the expansion of oil within structural closure only
  - There must be significant pressure support from below structural closure – additional oil and/or a supportive aquifer
Impact of varying aquifer strength

- Varying the strength of the aquifer has little impact on the history match to the well test, but does significantly alter the single well forecast.
Modelling resolution issues
Kinks in forecast

- Some of the forecasts include unusual kinks in production later in field life
- This is a modelling artefact related to the vertical resolution of the model and the movement of water vertically
- Refining the model by a factor of 4 reduces the kink
- Refining the model by a factor of 8 removes the kink completely
- It is not a concern to overall volumes, and does not require refining the model for all cases as the run time would be unreasonably long
  - The current balance of accuracy to performance is reasonable
Resolving model resolution issue

- 30m layer height
- Drawdown is high enough by 2027 to cone water into the next layer
- By 2030, the well has declined enough that the drawdown is not sufficient to keep the coned water up
- When the water drops back down a layer, it causes a kink in production

- Refining the model by 4 times (7.5m layers) makes the coning profile more smooth
- Refining by 8 times (3.75m layers) makes it even smoother
- The smoother coning profile reduces the effect of the water movement on the production
Gas coning risk
Initial conditions

- Hurricane see no indications of initial gas cap being present in the reservoir
- According to the pressure trend, a theoretical gas cap would be present approximately 30m above the crest of the field
- Gas will begin to be liberated during production, forming a gas cap over time
- Different scenarios provide different estimates of how this gas cap may form over time
- Positioning of wells ensures this gas cap provides additional pressure support without the risk of coning early in field life
Gas cap generation – Hurricane dual porosity model

2024 – low gas saturation in ‘matrix’ top two layers (~1%), higher gas saturation in fractures top layer only (50-100%)

2018 – no gas cap

Intersection (i-882)

Well 205/21a-6

Crest of Lancaster

30m top layer

Hurricane | SIS Global Forum | September 2017
Gas cap generation – Hurricane dual porosity model

2018 – no gas cap

2033 – 100% gas saturation in to layer fractures, increasing saturation in matrix deeper down (still <5%)

2024 – low gas saturation in ‘matrix’ top two layers (~1%), higher gas saturation in fractures top layer only (50-100%)

Well 205/21a-6
Crest of Lancaster
Intersection

Intersection
Early Production System
Lancaster EPS

- The EPS is a two-well tieback to provide long term production data and generate cashflow to accelerate and optimise the Full Field Development on Lancaster.
# Summary of EPS Oil Profiles

## Inputs
- **OWC**:
  - **Low Case EPS**: Structural closure only (1,380m TVDSS)
  - **Base Case EPS**: Oil swab / 2C depth (1,597m TVDSS)
  - **High Case EPS**: Oil swab / 2C depth (1,597m TVDSS)

- **Porosity**:
  - **Low Case EPS**: Low case (2.9% average)
  - **Base Case EPS**: Base case (4.4% average)
  - **Base Case EPS**: Base Case (4.4% average)

- **Aquifer**:
  - **Low Case EPS**: Passive/weaker
  - **Base Case EPS**: Passive/weaker
  - **High Case EPS**: Active/stronger

- **Field plateau (20,000 bopd)**:
  - **Low Case EPS**: 3 years
  - **Base Case EPS**: 7 ½ years
  - **High Case EPS**: 12 ¼ years

## Cumulative oil production
- **Lancaster**:
  - **205/21a-6**: 22 MMbbl
  - **205/21a-7**: 14 MMbbl
  - **Lancaster**: 36 MMbbl

- **205/21a-6**:
  - **205/21a-7**: 14 MMbbl
  - **Lancaster**: 36 MMbbl

<table>
<thead>
<tr>
<th></th>
<th>Low Case EPS</th>
<th>Base Case EPS</th>
<th>High Case EPS</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Porosity</strong></td>
<td>Low case (2.9% average)</td>
<td>Base case (4.4% average)</td>
<td>Base Case (4.4% average)</td>
</tr>
<tr>
<td><strong>Aquifer</strong></td>
<td>Passive/weaker</td>
<td>Passive/weaker</td>
<td>Active/stronger</td>
</tr>
<tr>
<td><strong>Field plateau (20,000 bopd)</strong></td>
<td>3 years</td>
<td>7 ½ years</td>
<td>12 ¼ years</td>
</tr>
</tbody>
</table>

- **Cumulative oil production**:
  - **Lancaster**:
    - **205/21a-6**: 22 MMbbl
    - **205/21a-7**: 14 MMbbl
    - **Lancaster**: 36 MMbbl
  - **205/21a-6**:
    - **205/21a-7**: 14 MMbbl
    - **Lancaster**: 36 MMbbl
  - **Lancaster**:
    - **205/21a-6**: 22 MMbbl
    - **205/21a-7**: 14 MMbbl
    - **Lancaster**: 36 MMbbl
Data gathering during production

- Working closely with the facilities engineers to ensure all data streams are suitable to understanding reservoir behaviour.

- Main EPS goal is improving understanding of the reservoir to refine simulation model and optimise further development plans.
Forward Planning

- What is the difference in modelled pressure between High and Low cases?
  - ~40 psi after 1 year
  - ~80 psi after 2 years
  - ~135 psi after 3 years
- When will we be comfortable that we are in a High vs. Low case for Lancaster?