The Catcher Area Development

A Field Development Summary

With Matt Gibson and Martin O’Donnell
Agenda

• Catcher Area Location
• Development Scheme
• Field Introduction
• Subsurface Introduction
• Well Design and Execution
  – Completion Design
  – Well Clean Up and Suspension
• Wrap Up
Catcher Area Introduction

- **Block 28/9a**
  - 180km ESE Aberdeen
- **Central North Sea**
- **Western Terrace**
- **11 E&A wells and side tracks**
  - 6 field discoveries Catcher, Varadero, Burgman, Bonneville, Carnaby & Laverda
- **Eocene Tay and Palaeocene Cromarty Reservoir**
  - Spectrum of wholly injected reservoir sands through to remobilised and depositional
- **Premier Oil 50%, Cairn 20%, MOL Group 20% and Dyas 10%**
• Catcher, Varadero and Burgman Fields under development
• Production and Water Injection wells to be drilled from 3 drill centres
• FPSO production hub
  – Oil export by shuttle tanker
  – 125 bfpd liquid handling & injection capacity
  – 60,000 stb/d capacity
  – Gas export to SEGAL
Purpose built FPSO – Module Installation in Singapore
BW Catcher – Module Installation
The Catcher Development - Oil Fields

• Catcher
  – Tay and Cromarty reservoir
  – Juxtaposed across central NE-SW fault
  – Deepest Field @ c 4,700 ft tvdss

• Varadero
  – Tay reservoir
  – Fault bound to west

• Burgman
  – Tay Reservoir
  – Fault bound to west
  – Shallowest Field @ c. 3,500 ft tvdss

• Underlain by Cromarty aquifer
  – Probable source of injectites

• Reservoir properties
  – Oil Density 25-31 API
  – Oil Viscosity 2-12cP
  – GOR 200 – 300 scf/stb
  – Normal pressured reservoir

• Reservoir Management
  – Injection for voidage replacement
The Catcher Area Fields – Geology Overview

• Initially deposited as turbidites, significant remobilisation and injection upwards to shallower levels subsequently
  – Encasing Shale hydro fractured in the process
• Tay Formation is largely injected sands and forms main reservoir across all 3 fields, Cromarty significant in Catcher Field
  – Typically reservoir thickness 20-40ft, locally up to approx 60-80ft
• Complex and unresolvable 3D architecture with sands present in all orientations with varieties of scales
• Seismic data shows the gross container, the seismic amplitudes indicate the net pay
• Reservoir response is affected by tuning
  – Top reservoir / base reservoir / thickness uncertainty
  – Internal architecture poorly defined
  – Interference between different reservoir injections where present
  – Can’t see shale clasts or rafts, and uncertainty over where reservoir bifurcates
• Often unable to see reservoir where it’s thin, steep or water filled
The Catcher Area Fields – In The Seismic

Full stack reflectivity – increase in impedance is a peak (blue)
**Horizontal Development Wells**

**Challenges**
- Shallow reservoir <4500ft TVDSS
- Significant directional work
  - Inclination change 0° to 90°
  - Up to 130° azimuth change
  - Maximum completion length 3,000ft TVDSS
- Attempting to land into a gross reservoir targets with inherent depth uncertainty
- Unknown internal net sand architecture

**Solutions**
- Point-the-bit RSS
- Top spec well position survey equipment
- Geosphere – deep reading Azimuthal Resistivity
- Res-At-Bit proven extremely valuable
- Methodical pre-drill break down of well steering decisions

**Results so far**
- 7 wells on prognosis
Hole stability issue example – CTI1

Hydrofractured Shales

Stability issues Possible for wells?
Sand Face Completion Design
Completion Design Challenges

• Prevent sand production
• Deliver high productivity
• Preserve both for up to 2 year suspension
Sand Face Completion Design Process

• Statement of Requirements
  – Production & Inj Target Rates, Design life, Inflow monitoring (PDHG, Tracers)

• Core Testing
  – Strength measurements, Particle size distribution, Sand Retention Testing

• Fluids Testing
  – Shale sensitivity, Suspension issues, Oil leg Injection

• Desk top assessment of available technology
  – Open Hole Gravel Packs (OHGP)
  – Stand Alone Screens (SAS)
  – Expandable screens (ES)
  – Cased / perf & Frac pack
  – New technology
Sand Retention Testing

- Slurry testing = Non-compliant testing
- Coarse excluder screen shows no retention. c.50% of sand passes through screen.
- Medium excluder forms unstable pack. c.50% of sand passes through screen.
- In a cross flow or water hammer event expect sand to flow back into completion.

Pack testing = Compliant Technology Test
- Confinement with 16:30 gravel and coarse (300 micron) excluder screen suggests very low potential for solids production.
- Results suggest compliant technology appropriate.
- Selected OHGP
- Also avoids resorting (of sand with c. 10 - 15% fines content).
• Below images illustrate potential for shale delamination during well completion operations

• Solution - Run Pre Drilled Liner (PDL) to mitigate against shale swelling
• Screens run in brine
Well completion selection

• Selected OHGP & PDL
  – Compliant w/low solids risk + minimise shale risk
  – Run PDL in mud – screens then run in brine

• Lwr completion includes inflow tracers

• Upper Completion
  – 13 cr / 25 cr+ GRE for producers / injectors
  – Gas lift in both
  – Chemical Injection
  – PDHG in producers, WHP/T in injectors
  – Fluid loss control valve to isolate SF completion whilst running upper

• OHGP Challenges:
  – 3,000 ft installations in PDL a world first
  – High skin risk
  – Perceived as unconventional for injectors

• Alternative well concepts:
  – Production history + 4D - help understand production and injection performance.
  – Low angle C&P – need large sump
  – Frac & Pack - Long Horizontals, multiple geobody targets etc
Full Sequence Return Perm Testing

1. **Base Permeability Injection**
   - Formation → Well
   - Production

2. **Mud Application**
   - Formation → Well
   - Production

3. **Displacement**
   - Formation → Well

4. **Gravel Pack + Breaker**
   - Formation → Well
   - Production

5. **Drawdown**
   - Formation → Well
   - Production

6. **Injection**
   - Formation ← Well
Oil Leg Water Injection Challenge

- How can we best assure good injectivity at field start up?
  - Lab test the effectiveness of mutual solvent prior to well ops
  - Effectiveness of mutual solvent demonstrated in both in the lab and field

- Possible wax formation in injection tubing during suspension
  - Swap out results in ‘cold’ oil column.
  - May restrict injection at start up.

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Well Suspension Strategy

• Oil Leg Injection Wells
  – Use mutual solvent to assure high injectivity at start up

• Injection Well Suspension strategy
  – Risk of wax formation in injection tubing
  – Displace to base oil
  – Also reduces hydrate risk

• Producer suspension – leave hydrocarbons below tree
Well Clean Up Operations

Busy rig floor

Deluge system

Surface Flow Tree

Coltex flow line to Well Test Package

Well Test area

Water Injection Package

Air Compressors

NZ Package

NZ Gas Injection line
Successfully Delivering Across All Areas

• Fully integrated international project delivering on schedule
  – FPSO construction in South Korea and Japan – assembled in Singapore

• Subsea infrastructure installation complete:
  – Bundled subsea lines + risers installed

• Ongoing delivery of development wells:
  – Successful geosteering using latest technology in challenging formations
  – All wells achieving or exceeding well objectives
  – Installation of 3,000 ft OHGPs successful

• Well testing / clean up and suspension:
  – Proven high quality sands
  – Suspension programme as planned to preserve well PI / II
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