Base Management at BP
Base Management Workshop Agenda

• What is Base Management?
• Why is it important?
• How do we do it?
• Base Management Examples
The Base Management common process:

- Developed by a multi-disciplinary group of senior practitioners from around the globe.
- Sets out the framework for managing our production base.
- Supports the efficient delivery of BP’s proved developed reserves.

Applying the **best of BP everywhere** in BP

91% of production resides in the base
**BMcp elements**

A. Reservoir performance  
B. Well management  
C. System optimization
BMcp summary

The Base Management common process:

- Expert-designed and field proven –
- Multidisciplinary –
- Applied throughout most of the life of a field –
- Short to medium timeframe –
- Tasked with the efficient delivery of proved developed reserves –
- Framework focused on 3 key Elements –

by functional and business experts.
Petroleum and Reservoir Engineers, Geoscientists, Operations and Completions Engineers.
especially plateau and decline, but also in design & planning activities
within a year to 18 months.
BP’s Base.
Reservoir Performance, Well Management, and
system Optimization.
Reservoir performance
Reservoir performance summary

- Understand BM Aspects of Depletion Plan
  - Subsurface Description
  - Implement Depletion Strategy

- Forecast Short Term Performance
  - Technical Forecast
  - GFO Integration

- Monitor Reservoir Performance
  - Short Term Surveillance
  - Analysis

- Refresh Dynamic Understanding
  - Verification
  - Gaps
  - New Findings

- Opportunities and Lessons Learned
  - Hopper
  - Depletion Plan
  - Measure outcome
  - Lessons learned
Example 1: Predict Failure of Black-Start Well

• Problem Context
  – Dry black-start gas well suddenly experienced water break-through & progressively deteriorating performance.
  – Converted gas cap injector.
  – 148ft TVD of perforations in casing straddled by 2 packers and 20ft ported joint in tubing (sitting just under halfway point), preventing full wireline logging
  – Downhole surveillance from offset well had shown shallower than expected GWC.
  – Source of water could be either high permeability streaks or bottom-up aquifer drive.
  – Low Cv multi-stage gas choke installed (Cv 18).
  – Gas rate was depleting and choke fully open – which was also bringing well to sand control drawdown limit.
  – Initially, no other proven black-start option existed. Circa 8mmscf/d required.

• Question
  – When will the black-start well fail to provide sufficient re-start gas?
Example 1: Predict Failure of Black-Start Well

- Available Data
  - Flows into a 2-phase separator on its own.
  - Acoustic sand monitoring available.
  - Full suite of core samples.

- Approach
  - Full, choked, and no-flow tests to monitor WGR progression showed that the best scenario for gas availability was choked production. Not flowing the well did not arrest the WGR increase.
  - Dynamic simulation to assess stability and start-up concerns, and estimate final WGR.
  - GWC estimation and start-up analysis
Example 1: Predict Failure of Black-Start Well
Example 1: Predict Failure of Black-Start Well
Example 1: Predict Failure of Black-Start Well
Predict Failure of Black-start Well

Summary Approach

• Assessment of well test data and sand acoustic trends to understand well performance.
• Worked with Operations and Partners on well operating guidelines.
• Performed dynamic simulation and start-up analysis to understand stability and timeline to failure.
• Completed reservoir performance calculations to understand water level progression.

Answer

✓ Techniques applied determined gas well would fail to free flow ~ Feb 2018
Well management
Well management summary

Well Management

- Understand the wellstock – **Ensure Well Data availability**.
- Protect wellstock – **Well Integrity**.
- Identify opportunities and manage risks – **Well Reviews**.
- Evaluate and rank – **PRODUCTION HOPPER™**.
- Plan and execute well options.
- Measure wellwork impact – **WETS™**.
Example 2: New Well Flowback

• Context
  – New well start-up, 1400m reservoir section, 160bbls of OBM losses during drilling
  – Drilling rig has installed a cased and perforated completion & circulated the well to filtered brine before departure, as per BoD
  – Subsea well tied into an active subsea pipeline already conveying production from another field
  – Subsea pipeline tied into an offshore platform with a single processing train and multiple flow streams
  – Processed water discharged over-board to sea
  – Lab based fluid testing has confirmed emulsion formation between OBM filtrate and existing production fluids

• Questions
  – How much mud filtrate will come back?
  – How quickly will it come back?
  – Will the quantities cause emulsions, a plant upset and overboard OIW excursion?
  – What are the controls and contingencies?
Example 2: New Well Flowback
Example 2: New Well Flowback

Cause:
- Formation of Emulsions between produced and D&C fluids
- Emulsion Testing
  - Analogue flowbacks
  - Oil in Cuttings test
  - Filtrate volume contacted via completion

Control:
- Reduce processing load by curtailing other wet production
- Optimise production chemicals
- Manage gas lift rates
- Manage bean-up rates
- Emulsion Testing
  - Analogue flowbacks
  - Oil in Cuttings test
  - Filtrate volume contacted via completion

Risk Event:
- Plant Instability
  - MPFM & DHPG functioning
  - Real time monitoring
  - Establish well limits
  - Calculate Flux rates

Contingency:
- Divert gross fluid flow to FPS
- Perform a batch start-up

Consequence:
- OIW Excursion & Sea Pollution
- Poor well conditioning & reduced well PI
- Reputation impact
- Lost Value

Control and contingencies are in place
Control and contingencies are not yet in place, but are being worked
Controls and contingencies are identified but not yet worked
Example 2: New Well Flowback

Summary Approach
• Analogue data review
• Oil in Cuttings Test – to recognise filtrate volume produced with cutting
• Further eroded filtrate volume by normalising to reservoir section normalised
• Managed flow rates at start-up to manage dilution with existing well stock
• Communicated and integrated risk management tactics across stakeholder functions via ‘bow-tie’.
• Batch flow to mitigate instability dismissed due to potential impact to well clean-up.
• Amplified need for surveillance activities to monitor for (1) strength of controls (2) any potential event and (3) to verify performance of a contingency (if needed)

Answer
✓ Analogue review, managed flow rates and dilution factor led to maximum OIW < 25ppm. No requirement for FPS contingency
System optimization
System Optimization Summary

- Define System
  - Components
  - Constraints & Levers
  - Optimization Approach

- Generate and Protect – Within IPC and Growing IPC

- Progress Opportunities – Hopper

- Plan and Execute – Coordination with IFPcp

- Measure Performance and Lessons Learned – Assess and communicate
Example 3: Optimise Production in a Constrained System

• **Context**
  – Ongoing production optimisation in low well count, high value subsea system.
    • Producing stably and using steady-state simulation.
    • Well 1: Low watercut, no gas lift.
    • Well 2: Medium watercut, gas lift.
    • Well 3: High watercut, gas lift.
    • Riser gas lift and riser top choke valve.
    • Subsea MPFM.
    • Downward sloping subsea flowline from production manifold to riser.

• **Question**
  – What is the optimal well configuration to maximise rate?
Example 3: Optimise Production in a Constrained System

• Inputs
  – Well tests.
  – Understanding of constraints.
  – Well matched steady state simulation software with multi-variable optimisation algorithm.

• Opportunities vs. Challenges
  – Reduce riser top choke pressure drop.
    • Historically known to result in flowline and riser slugging.
  – Gas lift naturally flowing well.
    • Gas lift resulted in production increase (from simulation and field trial, but risked accelerating water breakthrough).
  – Shut in wet well to reduce back-pressure.
    • Wet well still produced significant oil rate so request seemed counter intuitive to Ops and assurance was required.
Example 3: Optimise Production in a Constrained System
Optimise Production in Constrained Systems

Summary Approach
• Matched well tests and updated system model.
• Simulated scenarios to test production impact.
• Flow Assurance to determine likelihood and severity of instability.
• Worked with Operations to systematically proceduralise well and topsides changes.
• Reservoir management review to assess impact of increased offtake on water breakthrough.
• Partners assurance on recommended course of action

Answer
✓ Wettest well turned off resulting in reduced back pressure on remaining two wells delivering a 5% production increment.
Questions & discussion
Base Management Summary

• Base Management expected to operationalise the depletion plan and is seen as the point of integration by other functions

• Base Management in BP is organised into three elements; Well Performance, Reservoir Management and System Optimisation

• Deliver solutions/risk management for both steady state and transient challenges within these 3 elements