Tahiti Project
Well Test and Flowback Operations

Well Test Network Meeting
Houston, Texas
May 2, 2008
Tahiti Well Test and Flowbacks Overview

- Introduction to the Tahiti Field
- Tahiti Well Test
  - SS001ST02BP01: August 20-31, 2004
- Flowback Objectives and Contingency Planning
- Review of operational issues and Lesson’s Learned
  - SS001ST02BP01: April 21–22, 2007
  - PN002ST00BP00: May 3-4, 2007
  - PS002ST00BP00: June 20-23, 2007
  - PS003ST00BP01: June 27-30, 2007
  - PN001ST03BP01: July 18-20, 2007
Tahiti Development Plan

- Subsea trees; 2 drill centers
- Drilling by drill ship or semi-sub
- Truss Spar
- Prod Capacity 125 MBOPD
- Plan for future waterflood
- Phased development
- 3 additional predrills – 6 wells available at First Oil
- 1st Prod late-2009 (Phase 1)
- Tahiti will be deepest GOM production
- First CVX use 15,000 psi Subsea Trees
Tahiti (GC 596-640) Prospect Summary

Discovery Date: April 2002
Water Depth: ~4,200 feet
Operator: Chevron (58%)
Partners: StatoilHydro (25%) and Total (17%)
Objective: Miocene ponded turbidite sheet sandstones
Trend: Subsalt Miocene salt withdrawal basin
Trap: Three-way subsalt structural trap against base salt truncation
Stratigraphic Uncertainty: M21 TST Correlation Cross-Section
Datum: Base of M-21B_40 Interval

North

Depositional Complex: Ponded sheet
Depositional Environment: Proximal sheet (confined)
Reservoir Architecture: Layered, massive sheet sands w/ isolated mass flow deposits

South

West (Updip) ~2900 feet East (Downdip)
GC 596 1 ST1
GC 596 1

West (Updip) ~2400 feet ~4300 feet East (Downdip)
GC 640 1 ST2 BP1
GC 640 1
GC 641 1 ST1

West (Updip) ~2300 feet East (Downdip)
GC 640 2 ST1
GC 640 2 BP2
GC 640 2 BP1

M21A
M21B
## Tahiti Project
### Well Test Reduces Uncertainty

<table>
<thead>
<tr>
<th>Uncertainty</th>
<th>Impact</th>
<th>Mitigation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir Complexity and Compartmentalization</td>
<td>Well count and recovery per completion, commingling</td>
<td>Appraisal program, well test, reprocess PSDM, geometric modeling, fault seal analysis</td>
</tr>
<tr>
<td>Well Construction and Design, Drilling issues at extreme depth, Effect of thick salt</td>
<td>Drilling and intervention costs, well reliability</td>
<td>Well test, Equipment Front End Engineering, Mechanical Earth Modeling</td>
</tr>
<tr>
<td>Completion technology at extreme depth and pressure</td>
<td>Pressure and loads exceeded on existing tools, completion reliability, intervention frequency</td>
<td>ETC and vendors designing and building well test tools for Tahiti ratings</td>
</tr>
<tr>
<td>Reservoir extent and quality</td>
<td>OOIP and deliverability (confirm $k_o$)</td>
<td>Appraisal well data collection and analysis, well test</td>
</tr>
</tbody>
</table>

### WELL TEST OBJECTIVES:

- Determine Zone Productivity
- Identify Local Reservoir Flow Geometry
- Obtain Large Volume Fluid Sample
- Evaluate Completion Concept
- Test Completion Equipment & Procedure
- Keep Well as Future Producer
Tahiti Well Test Results

- Rate: 15,055 BOPD, 7,945 psi with 785 psi total drawdown
- Well capacity in excess of 25,000 bopd with a 1,500 psi planned drawdown.
- Permeability ~670 md effective to oil (equates to just over 1 darcy absolute).
- Skin of 6.1 with a completion efficiency around 63% (for a world record depth frac pack)
- No indication of depletion.
- One sealing barrier at a distance of about 1,200’ (good match for mapped fault to the south).
- Geochemistry used to calibrate rates between layers.
- Good partner relations were key to timely well test changes
Tahiti Well Test Overview
Tahiti Flowbacks

Review of operational events and Lesson’s Learned

TransOceanc Deep Seas

TransOceanc Cajun Express
Example Flowback Objectives

- Unload fluid to low clear phase “water” cut.
  - Recover ZnBr2 and frac acids to minimize damage from fluid interaction during the shut-in prior to first oil.
  - Ensure fluid compatibility with subsea equipment metallurgy.
    - Get most low pH fluid back, bullhead base oil to below SCSSV.
  - Ensure that subsea choke and equipment on the spar can handle the fluids.
    - Reduce emulsions to a minimum, clean up any debris left in well.

- Ensure mechanical integrity of tubing and completion.
  - Evaluate PI and skin to ensure well meets expected deliverability.
    - Limited to ~10,000 bopd due to well test kit.
  - Safe ramp up to full capacity when the facility is available.
    - Check for leaks, function of PDHG and SCSSV, bleed off annular press.

Industry best practice states that “the most common reason for failure of sand control completions is inadequate flowback”. Flowbacks allow the completion to settle and reduce the chance that voids will persist.
Example Flowback Contingencies

- Well is difficult to clean up. Two additional days at maximum rate if:
  - Low PI indicates only part of a completion may be flowing
    - Chemical tracers added to frac-pack fluids for post-flowback analysis
    - Geochem will confirm contribution of each zone
    - ProTechnics chemical tracer analysis and Geochem are both available for rapid turn-around (48 hours) if samples are hotshot to Houston labs
  - Well continues slugging completion fluid or solids (proppant or sand)
    - Severe choke plugging does not allow continuous flow
    - Erratic Productivity Index does not exhibit a trend toward stabilization
  - Well continues cutting persistent clear fluid “water” phase
    - USITs were run to check zone isolation, no formation water expected; will monitor clear fluid phase properties (SG, pH, TDS and chlorides)
    - Hydrate risk if low salinity fluids, but sufficient methanol will be available to continue pumping throughout the test if needed
Example Flowback Contingencies

Completion failure. High skin or significant solids production:

- Set clear signposts for what is high and significant.
  - High Skin makes it difficult for project to reach rate objectives.
  - Frac analysis is usually diagnostic to identify problem completions; ProTechnics PackScan to be run on some lower completions.
  - Coiled tubing on location for possible acid treatment.
- Any solids other than minor trash during initial cleanup is a significant event.
  - Track PI during cleanup, measure skin during buildup.
  - Capture samples of any produced solids – proppant for each completion has been tagged with different Manganese Oxide tags.
- Clear documentation of any reservoir or completion issues seen during the flowback to be handed over to the Phase 2 Team.

Tubing leak; monitor tubing & annular pressure during flow & buildup.

- If leak detected, will pull tubing, repair and rerun. This would be followed by a short additional flow period to circulate oil to surface.
- Allows check of APB models to help optimize rampup at first production.
Example Flowback Contingencies

- What if gauge fails during flowback?
  - Plan will be to continue flowback and analyze using SSTT and SLB choke manifold pressures
    - Tubing will not be pulled once tubing hanger has been set – repair of connection or replacement of PDG will be deferred to Phase 2
    - Nodal models for each well will be prepared so that the flowing portion of the test may be run using surface pressures and rates

- Guidelines for nuisance shut-ins
  - Well will be reopened and ramped back up quickly (roughly 15 minute choke changes)

- Guidelines for loop current or weather delay
  - Follow Drilling, TransOcean and Marine Operations Group guidelines
    - Expected that rough seas > 7’ will interfere with barge operations
  - Have equipment and chemicals onsite to execute the Base Plan twice if operational or weather delays require killing the well and starting over
Example Flowback Operations

- Cycled the FBIV as required and confirmed that the well was open.
- Opened appropriate valves on the SSPT for monitoring the annulus pressure.
- Flowed the well on adjustable choke and directed the fluid to the well test area and the barge. Limited the pressure drop to 150 psi during the clean up period and to 300 psi during the well unloading phase for each step change on the adjustable choke. Maximum drawdown was limited to 1500 psi.
- Injected methanol; reduced injection rate when “water” cut dropped 50% and stopped injection completely when “water” cuts drops below 5%.
- Injected emulsion breaker and defoamer when gas broke out.
- Once the well had unloaded properly and the PI at the maximum flow rate was somewhat constant, it was put on a fixed choke. Maximum flow rate was limited to 10,000 bpd due to safety concerns with a single well test train.
- The well was then shut in after the flowback was considered satisfactory. The annulus pressure was bled off 30 mins prior to that.
- The build up analysis was performed for 6-8 hrs and the pressure was monitored at the SSTT and the downhole gage.
Flowback Results for Tahiti Phase 1 Wells

Provide valuable completion information for future planning

- Wells were successfully commissioned for production by cleaning up completion fluids, lifting debris, and circulating oil to surface.
- Completion and Wellbore integrity (no leaks)
- Stacked Frac-Packs performed as expected
  - High level of completion integrity
  - Favorable skins
- Build-up analysis on initial flowbacks
  - Reservoir architecture (near well-bore)
  - Baseline for future completion analysis
Tahiti Well Commissioning
Flowback Example: 640_1ST2BP1 Cleanup
Tahiti Well Commissioning
Cluster and End-member analysis for production allocation

Cluster Distance

Laboratory Mixtures

<table>
<thead>
<tr>
<th></th>
<th>M21 A-10</th>
<th>M21 B-40</th>
<th>Calculated Results</th>
</tr>
</thead>
<tbody>
<tr>
<td>100</td>
<td>100</td>
<td>0</td>
<td>100</td>
</tr>
<tr>
<td>20</td>
<td>20</td>
<td>80</td>
<td>23</td>
</tr>
<tr>
<td>20</td>
<td>20</td>
<td>80</td>
<td>18</td>
</tr>
<tr>
<td>40</td>
<td>40</td>
<td>60</td>
<td>36</td>
</tr>
<tr>
<td>40</td>
<td>40</td>
<td>60</td>
<td>32</td>
</tr>
<tr>
<td>50</td>
<td>50</td>
<td>50</td>
<td>45</td>
</tr>
<tr>
<td>50</td>
<td>50</td>
<td>50</td>
<td>45</td>
</tr>
<tr>
<td>60</td>
<td>60</td>
<td>40</td>
<td>51</td>
</tr>
<tr>
<td>60</td>
<td>60</td>
<td>40</td>
<td>51</td>
</tr>
<tr>
<td>80</td>
<td>80</td>
<td>20</td>
<td>74</td>
</tr>
<tr>
<td>80</td>
<td>80</td>
<td>20</td>
<td>77</td>
</tr>
<tr>
<td>80</td>
<td>80</td>
<td>20</td>
<td>77</td>
</tr>
<tr>
<td>80</td>
<td>80</td>
<td>20</td>
<td>77</td>
</tr>
<tr>
<td>0</td>
<td>100</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>0</td>
<td>100</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

Error ± 4% (Avg)
Flowback set up of the equipment on CEX PORT side

- Flare boom
- Steam Exchanger
- Choke manifold, Vx meter & Oilphase Sampler
- HP Scrubber
- Separator
- Dead oil tank
- LP Scrubber
- Offloading Pump
- Computer lab to right
- 100 bbl P tanks
Flow back set up of the Equipment on CEX Main Deck and STBD side

100 bbl P-tanks

Coiled Tubing Lift Frame

Chemical tanks

Oilphase Cabin

Chemical tanks

Fire-fighting equipment

Methanol tanks
R/U of the CTLF and flowhead to the landing String (DDS)
Flowback set up of the equipment on DDS

Steam Exchanger

Choke manifold & Oilphase Sampler

Well test line

Computer lab

LP Scrubber

Separator

HP Scrubber

100 bbls P tank

** VX meter not visible (in between computer lab and steam exchanger)**
Flowback set up of the equipment on DDS

- Flare
- HP Scrubber
- Computer lab
- 500 bbl slop tanks
- 100 bbl P-tanks
- Separator
Aerial view of Energy 111005 barge tethered to the DDS during the flowback operations

Single mooring line