Horizontal Well Injector/Producer Pair Platong Field, Pattani Basin, Thailand*

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Abstract

The ‘X’ Trend in the Pattani Basin of the Gulf of Thailand commenced oil production in 2001. The trend consists of a series of North-South oriented complexly faulted, extensional collapse grabens, and tilted half grabens. The Miocene-age clastic reservoirs can be generally characterized as small-compartmentalized fluvial reservoirs (5-60 feet in thickness). The reservoir sands are composed of multiple channel sands that have locally complex vertical and areal stacking patterns. Connectivity within these reservoirs is impacted by potential barriers including both mud-filled abandoned channels and fault compartmentalization. Primary oil production is typically low due to an absence of aquifer support. Waterflooding has been implemented to improve hydrocarbon recovery and sustain field production.

The Alpha Platform was infilled in 2012 with two horizontal wells (Alpha-02H and Alpha-03H). The two infill horizontal wells targeted a >25’ oil column in the ‘X’ reservoir sand which had a single existing deviated producer (Alpha-01) with low produced oil volumes due to water coning without gaslift capability. Both the Alpha-02H and Alpha-03H horizontal sections were placed at the same structural elevation below the gas cap in the upper portion of the oil leg. The wells were completed with three strings of casing and equipped with inflow control devices (ICD) and gas lift mandrels (GLM). Production commenced in February 2012 with combined oil production from the two horizontals ramping up to close to 4,000 bopd before both wells died with >90% water cut in February 2013. Alpha-03H was converted to a waterflood injector in August 2013 and commenced injection in the same month. After one month of maintaining a voidage replacement ratio (VRR) of 1:1 at Alpha03H, the Alpha-02H GOR and water cut dropped substantially with oil production ramping up to close to 1,000 bopd. After waterflooding in December 2014 the reservoir, pressure had improved significantly. Within the two-year period of waterflooding, the Alpha-02H watered out and died. The horizontal waterflooding period has ended and the project’s recovery factor (RF) is >30%. The Recovery Factor contribution from waterflood operations was >10%.
The reservoirs in the Gulf of Thailand are very complex and the reserves are quite marginal to develop. For these reasons, no dynamic modeling was attempted for this complexly faulted fluvial sand. A statistical model based on historical data was utilized to predict the benefit from both horizontal wells and waterflood operations. A comparison of current analogous reservoirs in the same trend with completed deviated injector/producer water floods shows about 50% higher recovery factor for this horizontal injector/producer waterflood.

The main lesson learned from utilizing horizontal wells as injectors is that it allows more flexibility in waterflood implementation and reservoir management strategy in complexly faulted reservoirs and potentially better connectivity leading to higher ultimate recovery factors. In order to capitalize on horizontal waterflood strategies it is necessary to fully utilize cross functional team work to identify target reservoirs from primary drilling programs and optimize production data by developing routine sampling collection methodologies.

Selected Reference

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- Pattani Basin Geology
  - Gulf of Thailand Tectonic Setting
  - Pattani Trend General Description
    - Structural History / Basin Evolution
    - Stratigraphy / Connectivity
  - Targeted Horizontal Reservoir Sand
    - Structure / Seismic Interpretation
    - Sand Thickness Relationships
    - Horizontal Well Results - Geological Interpretation

- Production/Reservoir Engineering
  - Horizontal Well Completion Design
  - Production Performance
  - Comparison of Horizontal injector / producer to alternative developments
  - Conclusions
  - Lessons Learned / Challenges
Presenter’s notes: This is an overview slide of the Asia and SE Asia tectonic setting leading to the origin of the Gulf of Thailand.

The image on the left shows the tectonic setting from Late Cretaceous to Eocene time as the Indo-Australian plate separated from Gondwanaland moving northwards to collide with the Eurasian plate. This formed a major thrust fault and subduction zone related to the plate collision with the Indo-Australian oceanic crust being subducted. This subduction opened the Gulf of Thailand 50Ma with “back-arc” extension transpression/transtension associated with right-lateral strike-slip faulting (shown on the figure to the right).
Presenter’s notes: Looking closer at the formation of the Gulf Thailand Basins we see north-south extensional faults forming the Cenozoic Basins which link up with the NNW trending Three Pagoda Transfer Fault.

The Pattani Basin is one of eleven N-S elongate “pull-apart” basins in the Gulf of Thailand associated with Eocene/Oligocene oblique slip.

The Western and Eastern Gulf of Thailand sub-segments are separated from one another by the Ko Kra Ridge with nine basins in the west and three basins in the east: the Pattani and Malay Basins and the smaller Khmer Basin.

The Pattani Basin, which is the focus of this presentation is the largest basin in the Gulf. Five sequences were recognized by Jardine in 1997 based on seismic reflection and well data.
Presenter’s notes: The next two slides detail the Gulf of Thailand Basin Evolution from Late Cretaceous to Present Day.

The section is West to East across the Pattani and Khmer Basins.

From Late Cretaceous to Eocene the India Plate separates from Gondwanaland moving north to collide with the Eurasian Craton. The resulting uplift created the “Pre-Tertiary Unconformity.”

From Late Eocene to Late Oligocene is the Himalayan Orogeny due to India-Eurasian plate collision. This creates the Mae-Ping and Three Pagoda Shear Systems and the elongate N-S rifted sub-basins.

“Sequence 1” Rift-fill deposits are Late Oligocene reddish brown claystones and siltstones predominate in lacustrine to alluvial deposits. At the End of the Oligocene wrenching along the Mae-Ping and Three Pagoda Faults causes uplift and creates the “Mid-Tertiary Unconformity.”

During the Lower Miocene continued clockwise rotation creates renewed extension and rifting.

“Sequence 2” Lower Redbeds formed as fluvial point bar and channel deposits in North and Central Pattani and Upper intertidal, fluvial and lower deltaic plains in the southern basin.
continued clockwise rotation of the Indochina block during the Middle Miocene leads to post-rift collapse and basin subsidence. "Sequence 3" “Lower Grey Beds” which are coastal plain and marginal marine deposits and “Sequence 4” “Upper Redbed” point bar and channel fill deposits in the fluvial-floodplain are deposited during this time period. Eustatic sea-level drop during the Latest-Middle to Early Upper Miocene creates the MMU unconformity. "Sequence 5", the youngest unit, was deposited from Upper Miocene to Present during continued compression and rotation with the basins continuing to subside and deepen. The “Upper Gray Beds” were deposited during a regional marine transgression and are delta plain to shallow marine deposits.
The diagram titled "Gulf of Thailand SIMPLE GEOLOGY OF SOUTH PATTANI BASIN" shows the generalized lithologies from the Pre-Tertiary Complex up through Sequences 1 to 5 from the Oligocene to Present Day.

The sample seismic line shows each sequence in a different color and highlights the extensive faulting through the entire section.

Source rock potential ranges from Sequence 1 to Sequence 3 deposits and Hydrocarbon potential from Sequence 2 to 4 deposits between the Mid-Tertiary to Mid-Miocene Unconformity.

The sandstone with the horizontal injector producer pair that we are going to discuss today is a Mid-Miocene point bar sand at the top of the “Upper Red Bed” Sequence 4 near the Mid-Miocene Unconformity.
Presenter’s notes: Here is a typical map view and three well strat section through these Mid-Miocene Pattani Basin fluvial deposits. They are generally characterized as small compartmentalized fluvial reservoirs (5-50 feet in thickness). The reservoir sands are composed of multiple channel sands that have locally complex vertical and areal stacking patterns. Connectivity within these reservoirs is impacted by potential barriers including both mud-filled abandoned channels and fault compartmentalization. Primary oil production is typically low due to an absence of aquifer support. Waterflooding has been implemented to improve hydrocarbon recovery and sustain field production.
Presenter’s notes: Here is a map view of the horizontal injector/producer pair. The offsetting deviated well control are the grey dots and the fault polygons are shown as black outlines.
Well control from fourteen wells with 400m well spacing defines the channel belt margins and a NNW-SSE orientation which is typically for the Pattani Basin.
The Stratigraphic Cross Section North to South from A-A’ with highlighted GR curves shows approx. 60 foot thick point bar sand and a stacked 40’ foot thick point bar deposit in one of the wells.
The RMS amplitude high amplitude response which are the green, yellow and red colors correlates well with the existing well control to define the margins of the thicker and more aerially extensive point bar deposit.
The lower amplitude response which are the pink and blue colors represents the abandoned channel mud-fill and flood plain deposits.
Presenter’s notes: So if we plot the point bar sand thickness vs. RMS amplitude response we see a good correlation between low amplitude response and sand thickness for the Non-Point Bar wells shown in Brown.

We also see a good correlation between the single thick point bar deposit wells and high amplitude response shown in yellow. The one well with the stacked point bar deposit having the highest amplitude and thickest sand thickness.

There are two wells which are anomalous. One with no sand thickness having a relatively high amplitude response and one well with 40' sand thickness having a relatively low amplitude response.
Presenter’s notes: If we use the combination of well control and RMS amplitude to define the point bar edges and sand thickness shaded in yellow we can estimate our reserve size based on a net-to-gross ratio of 98% in the point bar wells.

Average porosity is ~30% and average water saturation is ~40% to give an estimated oil in place of 4 MMbbls for this Mid-Miocene point bar sand.

The abandoned mud-filled channel deposits acting as a flow barrier are outlined by the thin black lines.
The map on the left is a structure map on top of the sand based on well control and seismic and shows the two horizontal wells Alpha-02H and Alpha-03H which were drilled as platform infill wells in 2012. The contour interval is 10’ with red being structural highs. Structural cross sections along both horizontal wells are shown on the right. The two infill horizontal wells targeted a >25' oil column in a reservoir sand which had a single existing deviated producer (Alpha-01) with low produced oil volumes due to water coning. The primary gas cap and water legs in the point bar can be seen with both wells placed at the same structural elevation approximately 1/3 - 2/3 between the gas/oil and oil/water contacts. Each horizontal has ~600m lateral section.
Horizontal Well Completion Design

- Based on the log data collected from the primary offset wells, the reservoir contains the possibility of significant permeability contrasts and high heterogeneity.

- Both the Alpha-02H and Alpha-03H were equipped with Inflow Control Device (ICD) screen completions to balance drawdown in the lateral section.

- In order to optimize production, both wells were installed with Gaslift Mandrels (GLM) to improve wellbore lifting efficiency.
The production performance of this reservoir can be divided into 3 periods:
- Reservoir testing
- Horizontal primary production
- Waterflooding
2010

- The Alpha-01 was selected to produce the ‘X’ reservoir and help with understanding the drive mechanism.
- After perforating the ‘X’ reservoir, the Alpha-01 well production increased to almost 2,000 BOPD and 7 MMSCFD with low water production.
- However, the well loaded-up and stopped flowing within a year due to depletion and water coning.
2012
- Infill drilling campaign was completed in February-2012
- Production from 2 HZ wells was ramped up to 4,000 BOPD

2013
- In March, oil production of Alpha-03H died with 100% water cut with higher GOR.
- Alpha-02H also reached 80% water cut after Alpha-03H 100% watered-out.
May-2013
- Both wells were shut-in because of very high water production and wait Alpha-02H converting
August-2013
- 11-Aug-2013 : Alpha-03H started injection
- 13-Aug-2013 : Alpha-02H was opened and found that the well watered out at 100% of water cut
  - Primary production ended

September-2013
- 1st month of injection, Alpha-02H had :
  - OOR Significantly dropped from 10,000 to 1,300 BCF/Blb.
  - Water cut: Continued decreasing from 100% to 60%

December-2015
- After 2 years of production, Alpha-02H was watered-out at 0.4 of cumulative VRR.
- The waterflood production was accordingly ended