Belridge Giant Oil Field,
Diatomite Pool
Presented at AAPG National Convention, Houston, April-11-06
Learnings from an Unusual Marine Reservoir in an Old Field

Malcolm Allan
Mahmood Rahman
Barbara Rycerski
April 2006
Benefits from our novel applications of existing technology and techniques

The diatomite reservoir in the Belridge giant field was discovered in 1911 but only became an economic target with the advent of hydraulic fracturing in the late 1970s. The reservoir has unique petrophysical properties:

- ultra-high porosity (45-75%)
- ultra-low permeability (0.01-2.0 mD brine perm.)

Successfully developing and producing unconventional reservoirs like diatomite requires using conventional technologies and techniques in new and unconventional ways:

1. **Open-hole log data** show us saturation changes and are needed for 3D modeling

2. **Open-hole formation pressures** are used to monitor the water injection program and to pick completion intervals in new injector wells

3. **Tiltmeter data from hydraulic fractures** are used to make well spacing & location decisions

4. **Horizontal wells** are exploiting thin pay zones that are uneconomic for vertical wells

The result.

-- Oil production rate is kept high and held flat
-- Producing volume of the field continues to expand

. . . . even after 30 years of development
Belridge Field

Geographic location map of Belridge Field

45 miles (75 km) west of Bakersfield
140 miles (225 km) northwest of Los Angeles

State of California

Sacramento
San Francisco
Los Angeles
San Diego
Kern County

Oil fields on west side of San Joaquin Valley

North Belridge
South Belridge
Cymric
McKittrick
Elk Hills
Midway Sunset
Land map of Belridge Field

DIATOMITE POOL, BELRIDGE FIELD:
12 miles long, ¾ mile wide, 4800 acres (85% Aera)
(19 by 1.2 km, 1950 ha)

SOUTH BELRIDGE

NORTHERN BELRIDGE

N. BELRIDGE (DOGGR)

S. BELRIDGE (DOGGR)

KEY DATES FOR DIATOMITE POOL
1911 – Diatomite pool discovered
(1942 – Development of overlying Tulare Fm heavy oil)
1977 – First successful hydraulic fracture in diatomite
1979 – Shell purchased assets of Belridge Oil Co.
1986 – Water injection began to mitigate subsidence
1997 – Aera Energy LLC formed from Shell & Mobil assets
Belridge Field has a huge surface footprint

<table>
<thead>
<tr>
<th>Pool Name</th>
<th>Size</th>
<th>Depth</th>
<th>Active Wells - AERA only (per DOGGR, Dec/05)</th>
<th>Cum. Prod. AERA only</th>
<th>Production</th>
<th>Production method</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tulare</td>
<td>7000 acres</td>
<td>400-1000 ft</td>
<td>1660 prod., 420 inj.</td>
<td>990 MMBO</td>
<td>Heavy Oil (11-15º API)</td>
<td>Slotted liner &amp; steamflood</td>
</tr>
<tr>
<td>DIATOMITE</td>
<td>4800 acres (4100 Aera)</td>
<td>800-2000 ft</td>
<td>3530 prod., 1140 inj.</td>
<td>370 MMBO, 485 BCFG</td>
<td>Light Oil (22-39º API)</td>
<td>Hydraulic fractures</td>
</tr>
<tr>
<td>Temblor &amp; 64 Zone</td>
<td>2100 acres</td>
<td>6000-7000 ft</td>
<td>40 prod., 0 inj.</td>
<td>890 BCFG, 70 MMBO</td>
<td>Gas &amp; light oil</td>
<td>Slotted liner and perfs</td>
</tr>
</tbody>
</table>

3 active pools + 8 drilling rigs + 20 workover rigs = very crowded infrastructure
Historical production and injection rates

Belridge Field - Diatomite

Little oil production before 1978 (first successful frac was in 1977)
Water injection began in 1987
Injection rates exceed gross production rates after 2002
Current production = **64,500 BOPD**, 85% watercut (Mar/06)

Existing technology and novel applications help maintain production
Depositional environment of Diatomite

Diatomite is the term given to the unconventional rock composed predominantly of the biogenic siliceous deposits of diatoms. In California, this rock type is common in the Central Valley and coastal basins. It is a major oil reservoir, and it is prolific producer when hydraulically fractured.

Diatoms are unicellular pelagic algae with siliceous skeletons deposited onto a mid-bathyal seafloor.
Sample is about 40% Opal A (mainly broken and whole diatoms) and minor organics. The remainder is about 15% mixed layer illite-smectite clays (with 30-40% expandable layers), 40% detrital quartz & feldspar, and minor pyrite.
Data coverage for Diatomite reservoir

All geologic, petrophysical, and completion data for the diatomite & deeper units over the entire Belridge Field and surrounding area are stored in a single unified database (Landmark’s OpenWorks®).

Directional & completion data updated nightly for all wells from corporate database.

Statistics as of Jan-06

9550 wells in database, (70% are in South Belridge), 750 more each year

5200 wells have sufficient logs to pick markers (typically GR, Rdeep, RHOB)

3800 wells have oil saturation calculations (need Rdeep & RHOB)

NOTE:

All wells without markers picked from logs have markers back-interpolated from structure grids

All wells without logs have petrophysical summation data back-interpolated from grids

All planned wells have back-interpolated porosity & saturation curves so that the completion intervals can be pre-planned & scheduled

Same database used by all geoscientists
Typical Open-Hole Logging Suite:
Triple combo (resistivity, and density/neutron)
+ dielectric in Steam Drive areas ('hot' wells with lowered $R_t$)
+ pressure survey (SFT or RFT) where needed

Cased Hole Logging:
Limited to injection profiles (every 2 yrs) for injectors

Logging suite and log examples, Diatomite

All wireline data captured digitally and available in a single Landmark database.

About 20-30% of ± 400 new wells drilled yearly and 10-20% of 300-400 replacement wells drilled yearly are logged.

Open-Hole Pressure Surveys:
2005: up to 30% of logged wells
2006: concentrating on injectors and filling in data gaps
Saturation changes can be found by comparing new and old logs.

Wells are 56 ft (17.0 m) apart and were logged 14 years apart.

Nearby injection frac?

Normal pressure depletion? (or flood response?)
Saturation changes show areas that need to be avoided during well completion

Water from a nearby injection well has flushed oil away.

Production from this 30 ft (9m) zone will be mainly water.

Well 7055-3
Completed: 1991-08-09 00:00:00

Well 7055D-3
Completed: 2005-05-29 00:00:00

Wells are 56 ft apart and were logged 14 years apart.

Resistivity is < 0.9 ohms
Purple dash line at 2 ohm

Oil Saturation < 10%
Purple dotted line at 50%
Pre-planning of completions requires a high density of logged wells

High density and good areal coverage of modern log data are essential for the creation of 3D structure and property models.

These models are used to predict porosity (RHOB) and oil saturation for an undrilled well, and generate Pseudo-Logs for it.

The Pseudo-Logs are used to pre-plan and schedule completion intervals.

If the well is logged and we get real log data, there is a final review, but predictions of porosity and saturation are normally very accurate.
Formation pressures can be used to monitor performance of water injection

Wet at unconformity due to “pancake” frac (frac is horizontal at top)

Any well completed in this 30 ft (9 m) zone will produce a lot of water

Several zones of lower oil saturations than ‘expected’

Probably little or no effect on oil productivity.

Slightly overpressured (due to over-injection)

Adequately supported by injection

Underpressured (poorly supported by injection)

Need to boost water injection volume or risk compaction of the weak formation
Formation pressures can guide completions

We are now using formation pressure data to decide the completion intervals of new or replacement multi-string water injection wells.

Multi-String Injectors:
- able to control and measure where water goes
- used along axis of field where pay is thickest (3-5 frac stages)
- used when need for injection conformance is greatest

Current injection support is excellent as formation pressure is at hydrostatic. Offset injector well is already adequately supporting this zone.

Additional injection support needed as formation pressure is below hydrostatic gradient.

Invalid pressures at tight zones or clay beds.

RECOMMENDATION: 2 injection intervals, each 300 ft high.

Dual completion shown, with position of Injection intervals.
Hydraulic fracture induces a characteristic deformation pattern (downhole & at surface)

Induced tilt reflects the geometry and orientation of created hydraulic fracture

Tiltmeters are used to map hydraulic fractures

Graphics courtesy of Pinnacle Technologies

Induced hydraulic fractures will tend to align with the plane of the maximum principal stress
Fracture azimuths control infill spacings and pattern configuration

Stages of Infill Development, Grande Area of South Belridge

Initial Waterflood
- 1979 to about 1986 (to present on flanks)
- 1986 to about 2002 (to present in ‘poorer’ areas)
- 2002+ (to present in ‘poorer’ areas)

Current Waterflood
- Since 2002, wells less than 50 ft apart

Primary
- 1 Producer per 2.5 Acre Pattern
- 2-1/2 acre spacing
- 330 FT (100 m)

Initial Waterflood
- 1 Producer : 1 Injector
- 2.5 Acre Pattern
- 1-1/4 acre spacing

5/16 acre spacing

2002+
- 6 Producer : 2 Injector
- 2.5 Acre Pattern

Producer

Injector

Ideal Fracture Azimuth
Horizontal wells are easy to plan and drill, and often more profitable than vertical wells

Thin pay zones (on the flanks & noses) are often uneconomic for vertical wells that would only be able to produce from a single hydraulic fracture stage accessing less than 400 ft of pay.

These thin vertical pay zones (< 400 ft pay) are best produced using horizontal wells.

3D geologic models make well planning very easy

Alignment of the wellbore in relation to the direction of the Fracture Azimuth is critical:

-- aligned with hydraulic fractures along the wellbore (longitudinal fracs, fewer fracs per well)

-- borehole aligned at ± 90° to the azimuth (transverse fracs, more fracs per well but poorer connection between well bore & frac plane).

160 horizontal wells drilled to Jan/06 (135 in South Belridge, 90% in last 3 years)
Horizontal wells can drain thin pay zones

Example showing how borehole is ‘toe-up’ and intersects thin but high quality pay (equivalent to 1200 ft of continuous pay in a vertical well)

NOTE:
Thin vertical pay zones (< 400 ft) become long horizontal pay zones (> 1200 ft) in a horizontal well

The surface location and vertical section of the horizontal well is placed outside the field boundaries where there may be less congestion and lower risk of casing shearing due to subsidence.

The horizontal section of the borehole is aligned along fracture azimuth and therefore the hydraulic fractures will be along the wellbore (more efficient & productive per frac than being transverse, but longitudinal wells have lower total area of frac plane surface per wellbore length)
Defining limits of economic production

The flanks and nose areas of the field are the most challenging

Example for South Belridge
West flank has thin pay but good productivity
East flank has thick pay but poor productivity due to lower gravity (more viscous) oil

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-- Thin pay (< 400 ft pay, only 1 frac stage) is uneconomic for a vertical well
-- Horizontal wells (with up to 10 frac stages) are being used very successfully to develop thin pay zones
-- West flank and SE nose are main areas for horizontal wells
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A pilot project is evaluating heavy oil (15-20º) on the east flank that would otherwise be uneconomic

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- No downdip wells with log data to define limits of oil saturation
- Computed extrapolation of data are invalid so edge-lines and dummy data points have to be added manually into 3D & 2D models

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Dip Section E (no vertical exaggeration)

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3D SoPhi model

PRODUCTIVE AREA OF FIELD
- Standard Vertical Wells
- Future potential?
The thick diatomite sequence of the Belridge giant oil field makes a unique reservoir with unusual petrophysical properties. The great pay thickness and high oil content make it an excellent resource that is being unlocked by new applications of existing technology and techniques.

Even though it is a relatively old field with a wealth of existing data, we continue to acquire more data. The reservoir is very challenging and we use the data to help us in novel ways:

1. Logs and formation pressure data are needed for monitoring saturation changes and for 3D modeling even though the field already has thousands of logs.
2. Formation pressure data help improve placement of injection water and guide completion intervals.
3. Knowing the azimuths of hydraulic fractures helps determine well placement when infilling a pattern with tighter spacing.
4. Horizontal wells are great at tapping pay that is too thin for an economic vertical well.

The result. . . .

-- Areal and vertical limits of economic production are still expanding
-- Oil production rate remains high and flat
-- Rock volume being economically drained continues to grow. . . . .
Assistance from co-workers and knowledge gained from work done by previous geoscientists is much appreciated.

Support and approval by Aera Energy’s management are also acknowledged.

END OF ORAL PRESENTATION
THUMBNAILS OF SLIDES PRESENTED
The Belridge giant oil field in the San Joaquin Valley, California, has produced more than 1.5 billion BO & 1.2 trillion CFG from multiple reservoirs since being discovered in 1911. Aera Energy LLC (a company owned jointly by Shell & ExxonMobil) currently produces 65 thousand barrels (10,300 cu m) of oil and 40 million CF (1.1 million cu m) of gas daily from a sequence of deep marine diatomite layers in the Miocene Monterey Formation. The diatomite sequence is vertically continuous for over 2,000’ (600 m) and covers about 4,100 acres (1,650 ha) inside Aera's field limits. Aera has over 3,500 producers and 1,100 water injectors actively maintaining oil production from the diatomite. Wells are very closely spaced, less than 50 ft (15m) apart in better areas, and hydraulic fracturing is essential for production from a reservoir that would be considered an excellent seal elsewhere.

Learnings from this field that can be readily applied elsewhere:
• Why we need another log when we have a 5-year old one 50 ft (15m) away
• Formation pressure logs can be used to fine-tune completion intervals in water injection wells
• Orientations of induced fractures can be measured, and control infill drilling locations
• Horizontal wells are easy to plan & drill, and can be more profitable than vertical wells
• Areal and vertical limits of economic production are still expanding

Reservoir management continues to be a challenge because of the size and complexity of the reservoir, and because of the 700-800 new wells being drilled annually to maintain production.