[PS]The Belridge Giant Oil Field: 100 Years of History and a Look to the Future*

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Abstract

April 2011 marks the 100th anniversary of the well that discovered the Belridge giant oil field in the San Joaquin Valley of California. During the 100 years the field has produced 1.6 billion of the approximately 6 billion barrels of the estimated original oil-in-place. The field is 45 miles WNW of Bakersfield and covers an area roughly 15 miles long and up to 2.5 miles wide. It has three totally separate and distinctly different producing zones:

- shallow Pleistocene fluviodeltaic sands producing heavy oil via steamflood;
- Miocene deepwater diatomite layers producing light oil via hydraulic fractures and with water injection pressure maintenance;
- deep Oligocene to lower Miocene marine sandstones producing gas and light oil via primary gas expansion.

Each zone was developed and reached maximum production rate at different times and using different completion strategies. The produced oil is sold at the field and pipelined to refineries in northern and southern California for processing.

Although down from its peak of 175,000 BOE per day in 1986, the field currently produces 77,400 BO and 37 MMCFG per day which makes it one of the largest onshore fields in the USA. Since discovery, over 15,000 wells have been drilled; today 5,900 producers and 2,100 injectors are still active. In each of the past few years, about 600 new wells have been drilled and completed. Even though production is in decline, the field has significant remaining oil in place and remains a very attractive target for continued development of known resources as well as for exploration below current production and around the periphery of the field. In recent years 3-D earth models coupled with an emphasis on optimizing the placement and retention of injected water and steam have helped improve recovery. Over 300 horizontal wells have been drilled in the fluviodeltaic sands and the diatomite.

In the 1930s the field had the deepest well drilled in North America. In the 1990s the field had the closest well spacing of any field in the world: vertical

and horizontal wells drilled 38 ft (11.5 m) apart and completed with sand-propped fracs. At the start of the 21st century the field is gearing up for many more years of activity with installation of a microseismic array, distributed temperature sensing in water injection wells, regular InSAR surveys, as well as ongoing interpretation of a 3D seismic survey covering the entire field for targets below the current producing zones.

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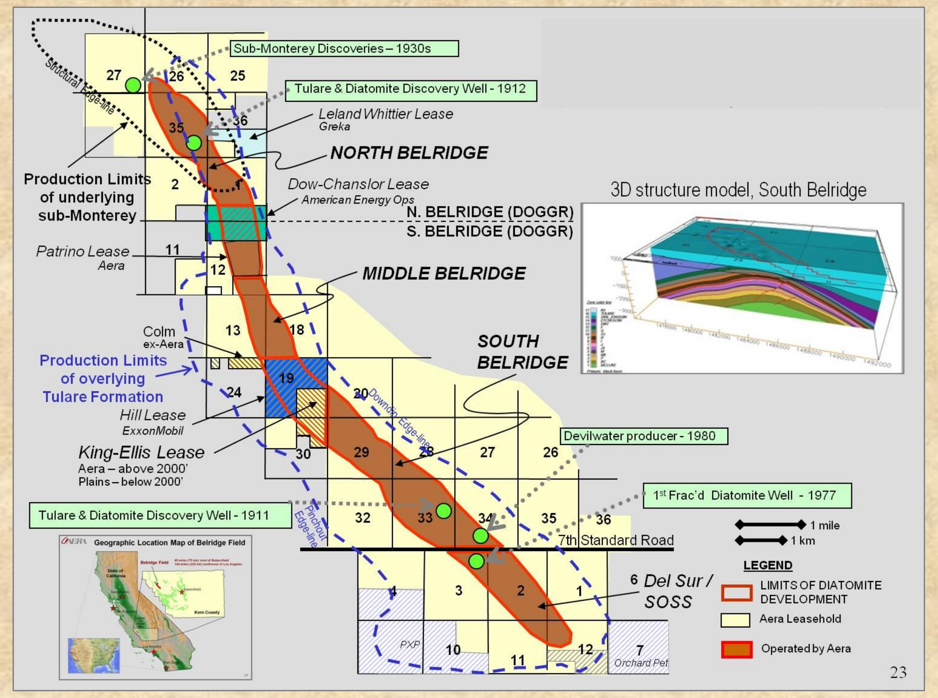
In the 1930s the field had the deepest well drilled in North America. In the 1990s the field had the closest well spacing of any field in the world: vertical and horizontal wells drilled 37.5 ft apart and completed with sand-propped fracs. At the start of the 21st century the field is gearing up for many more years of activity with installation of a microseismic array, distributed temperature sensing in water injection wells, regular InSAR surveys, as well as ongoing interpretation of a 3D seismic survey covering the entire field for targets below the current producing zones.



Location

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

Statistics

3 active pools
+ 5 drilling rigs
+ 15 workover rigs
= very crowded infrastructure

Pool Name	Productive Size	Depth	Active Wells (per DOGGR, Dec/10)	Cum. Prod. (Dec/08) Daily Prod. (Dec/10)	Production	Production method Drive mechanism
Tulare	11,000 acres	400-1,000 ft	1,727 prod., 513 steam inj.	990 MMBO 29,054 BO, 7.0 MMCFG	Heavy Oil (11-15° API)	Slotted liner & gravel-pack Steamflood
Diatomite	3,350 acres (3,000 Aera)	800-2,000 ft	4,121 prod., 1,387 WI, 326 Steam	370 MMBO, 485 BCFG 48,250 BO, 24.5 MMCFG	Light Oil (25-39° API)	Hydraulic fracture Waterflood, or primary, or steam
Sub-Monterey	2,450 acres (all Aera)	6-9,400 ft	49 prod., 0 inj.	890 BCFG, 70 MMBO 259 BO, 5.5 MMCFG	Gas & light oil	Slotted liner & shot perfs Primary (gas expansion)

Well counts and volumes are for entire field from DOGGR.

Aera share = +/- 90%

Geologic Setting

Hydrocarbon Systems

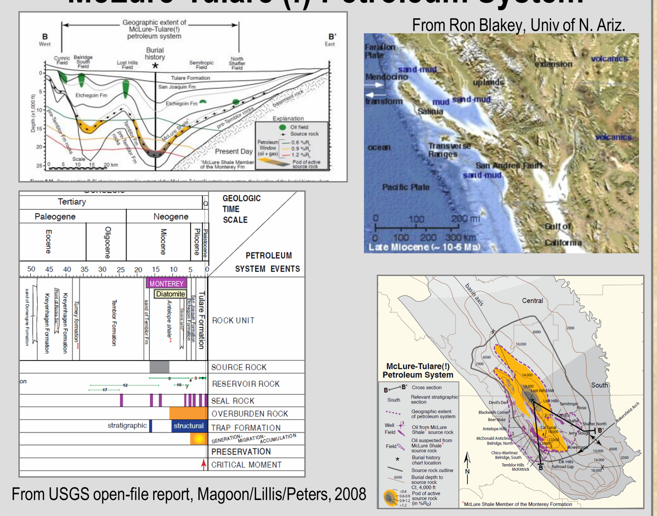
Belridge Field

The Belridge field is one of several giant oil fields along the western edge of the San Joaquin Valley. All are structural traps in elongate anticlines initiated during the Eocene in response to the stress fields set up by the right lateral strike-slip movement along the San Andreas fault, which is located on the western edge of the San Joaquin Valley.

Folding of the Pleistocene Tulare Formation which rests unconformably on the Pliocene San Joaquin & Etchegoin Formations, which in turn overlie the diatomites of the Miocene Monterey Formation and deeper horizons, testify to several periods of renewed uplift and folding within the slowly subsiding basin. Holocene alluvium overlies the Tulare Formation and represents the final stage of infilling and burial of the basin.

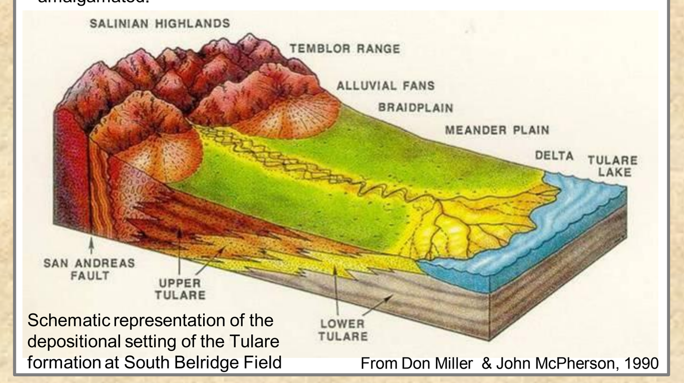
Like all the west-side fields, Belridge is in a fore-arc setting and is probably underlain by oceanic ophiolitic crust. The diatomite reservoirs were deposited in 600-1600 ft of water in an inland sea (similar to the present-day Sea of Cortez, Mexico) that communicated with the open ocean near San Francisco. However, with decreased subsidence coupled with basin infilling and closure of the northern outlet to the Pacific as the Mendocino triple-junction moved north, the shallow heavy oil reservoirs of the Tulare Formation were deposited in a fluvio-deltaic environment similar to many in foreland basins.

McLure-Tulare (!) Petroleum System



From USGS open-file report, Magoon/Lillis/Peters, 2008

Depositional Environments



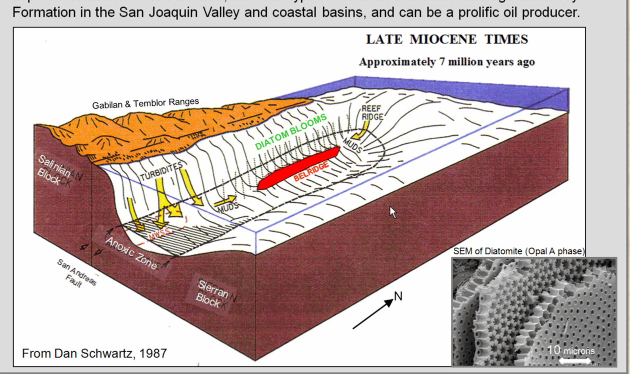
The Tulare Formation was deposited in the Pleistocene (1.8 MM to 1,000 years ago) as a prograding sequence of lacustrine and fluvio-deltaic deposits consisting of unconsolidated sands, silts, and muds. The reservoir sands are very heterogeneous with shoestring to sheet geometry, either stacked or amalgamated.

Schematic representation of the depositional setting of the Tulare formation at South Belridge Field. From Don Miller & John McPherson, 1990

Diatomite

Diatoms are unicellular pelagic algae with siliceous skeletons deposited onto a mid-bathyal seafloor.

Diatomite is the term given to a rock composed predominantly of the biogenic siliceous deposits of diatoms. In California, this rock type is common in the Miocene-age Monterey Formation in the San Joaquin Valley and coastal basins, and can be a prolific oil producer.



From Dan Schwartz, 1987

Reservoir Parameters

Tulare Formation

Reservoir Properties for South Belridge

THICKNESS:	400 to 700 ft Gross, 40 to 300 Net (developed areas)
DEPTH TO TOP:	400 to 900 ft below surface
PRODUCTIVE AREA:	8,700 Acres
PRODUCTIVE FACIES:	Braided/meandering fluvial, distributary channel/mouth bar
LITHOLOGY:	Very coarse to very fine grained sand; Lithic feldsarenite
POROSITY:	35% average, 29 to 42% range, all primary intergranular
PERMEABILITY:	3000 md average, 100 to 10000 md range (K air @ 300 psi)
INITIAL OIL SAT:	75% average, 20 to 85% range
RESIDUAL OIL SAT:	10 to 15%, post-steamflood
FVF:	1.03 RB/STB
OIL GRAVITY:	13 to 14° API
OIL VISCOSITY:	1800 Cp at 90°F, 7.9 Cp at 300°F
GOR:	35 SCFG/STBO
INITIAL RES. PRESS:	50 psi (crestal), 375 psi (deepest zones at OWC)
INITIAL RES. TEMP:	95° F
STEAMFLOOD RES. TEMP:	300 to 350° F

Diatomite

Diatomite productivity is controlled by its unique rock properties

Exceptional Vertical Thickness of Pay
- Thickness of pay can be 1000 to 1500 ft (300-450 m)
- Along the crest the pay zones can be stacked with few non-pay intervals

Very High Porosity
- Opal A has 55-65% Ø and mostly fluid-supported, with very little grain support
- Opal CT has 35-50% Ø and is grain-supported due to crystallization

Extremely Tight
- Very small pore throats and pore spaces often filled with skeletal fragments
- Opal A & Opal CT have matrix permeabilities ranging from 0.1 to 1 mD

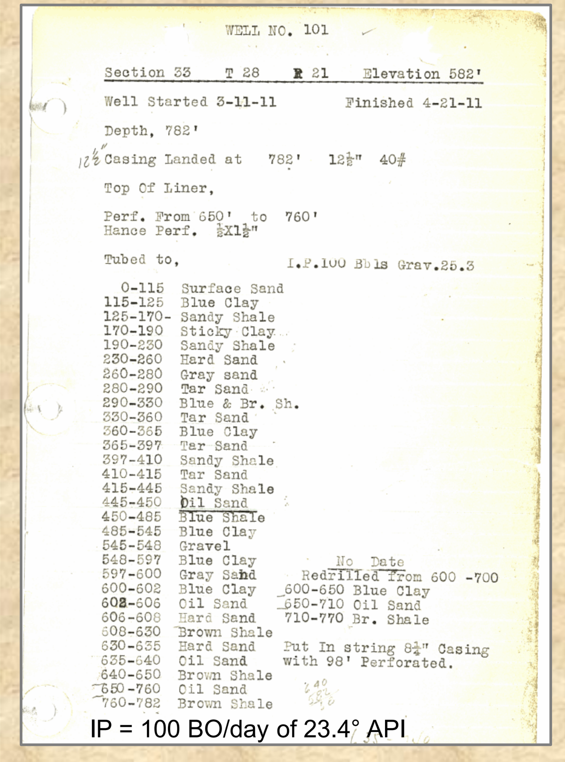
Large Surface Area
- One ft^3 of rock has 15 million ft^2 (340 acres, 140 ha) of surface area
- Water-wet and has high interstitial water saturation (S_{wi}) above 60%

Highly Compressible
- Opal A compressibility (Cr) ± 300 microsips, Opal CT ± 10-30 microsips
- Decrease in pore pressure results in compaction in the reservoir (especially in the shallower Opal A) which causes subsidence of the overburden and lateral movement at or near the unconformity with the overlying Tulare Formation

Reservoir Fluids move very Slowly
- Fluids move through the matrix at diffusion speed of only 1 to 3 ft (0.3-1.0 m) per year
- When hydraulically frac'd, fluids move by linear flow through micro-fractures towards the large planes of the induced hydraulic fractures

Early Days

Driller's Log and Lithology Log for Well 101, Section 33 (*discovery well, April 1911*)


WELL NO. 101

Section 33 T 28 R 21 Elevation 582'

Well Started 3-11-11 Finished 4-21-11

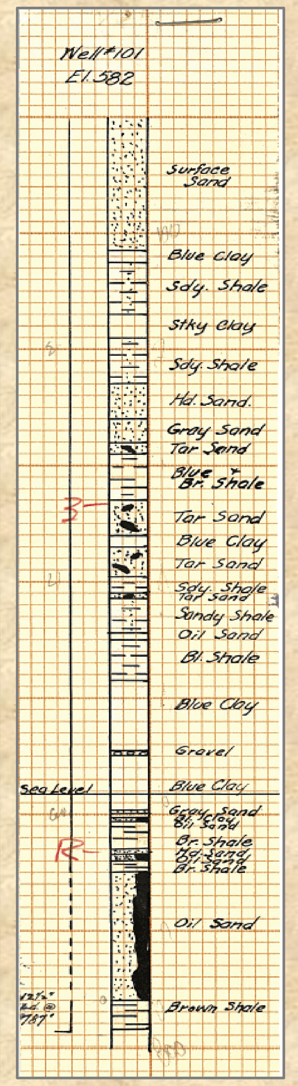
Depth, 782'

Casing Landed at 782' 12½" 40#

Top of Liner,

Perf. From 650' to 760'

IP = 100 BO/day of 23.4° API



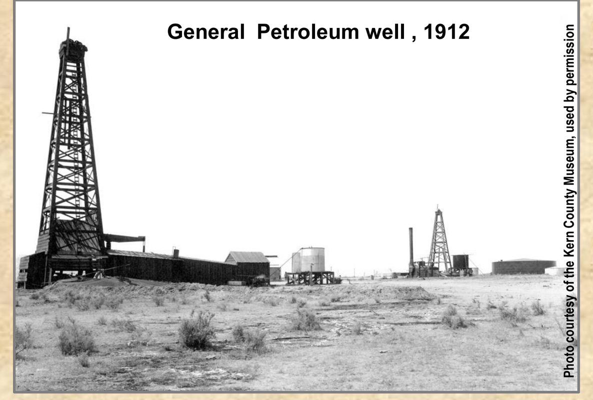
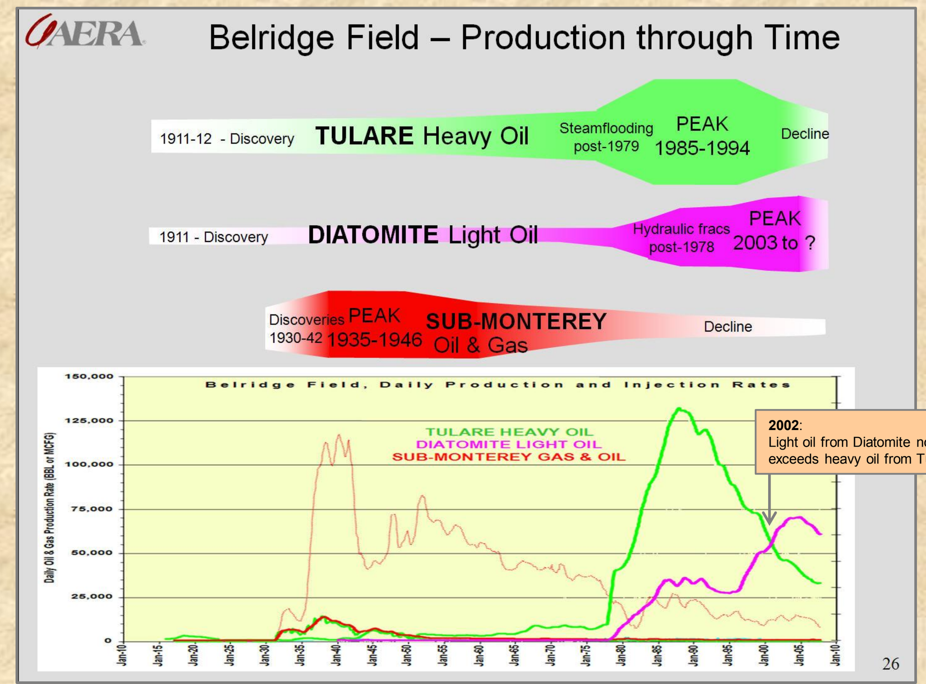

General Petroleum well , 1912

Photo courtesy of the Kern County Museum, used by permission


Three men working with machinery, circa 1912

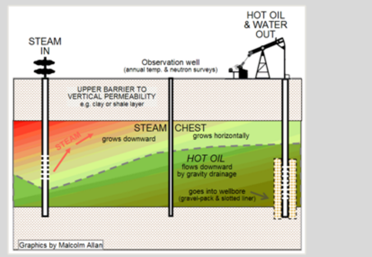


Current Operations

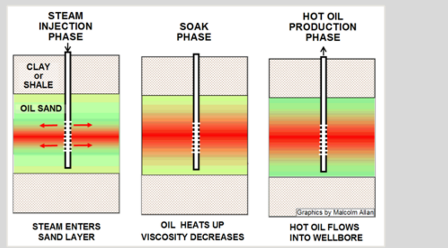
Tulare (Steam Flood)

Steam Flood Methods

Continuous Steam

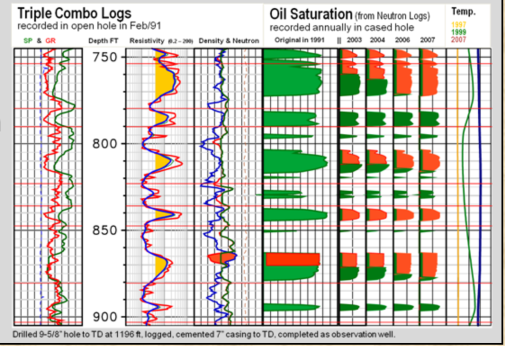


Cyclic Steam



Original liquid oil saturations (green) are being replaced over time by gas (red) as the steam chest develops from the top of each sand interval.

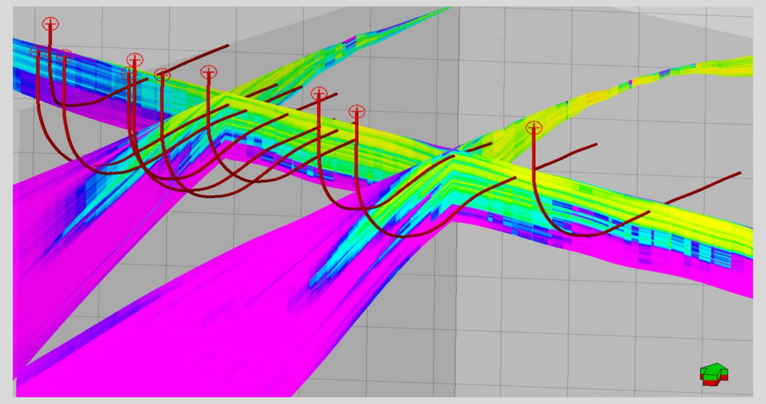
Neutron and temperature surveys run in cased hole provide time-lapse monitoring.



Drilled 9-5/8" hole to TD at 1196 ft, logged, cemented 7" casing to TD, completed as observation well.

Diatomite (Vertical and Horizontal Development)

Horizontal Wells can Drain Thin Pay zones

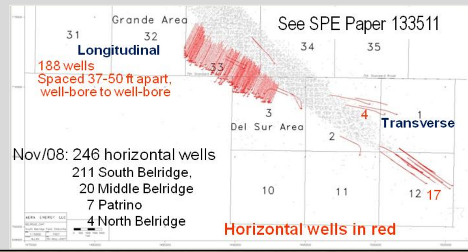


Thin vertical pay zones (< 400 ft) become long horizontal pay zones (> 1,000 ft) in a horizontal well

The first horizontal production wells in the Diatomite at Belridge were drilled by Mobil in the Del Sur Nose area and aligned NW/SE, parallel to the anticline axis. They have transverse hydraulic fractures.

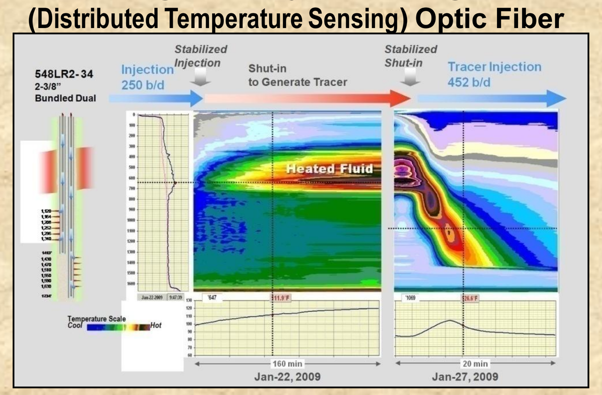
However, the area has limited productivity and nearly all the later horizontal wells have been 'longitudinal' and drilled along the flanks. Especially in Sections 33 and 3 on the west flank.

(Allan *et al.*, 2010)



NEW TECHNIQUES

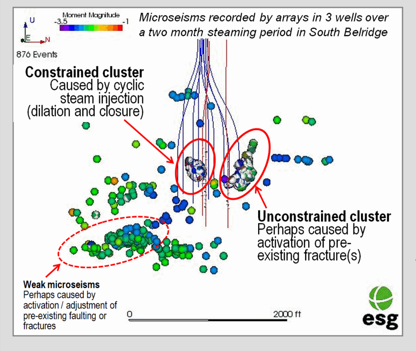
Monitoring Water Injection using DTS (Distributed Temperature Sensing) Optic Fiber



- Once installed, DTS is relatively immune to kinks or dog-legs
- DTS can measure dynamic and cumulative injection profile
- DTS technology has potential for replacing radioactive tracer profile surveys

(Rahman *et al.*, 2011)

Active Reservoir Monitoring



Microseismic can be used to monitor fracture growth and location.

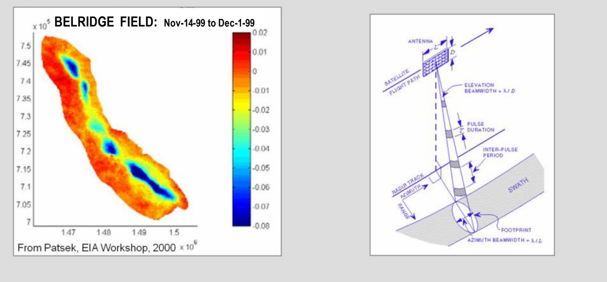
Cross-well Tomography

Electromagnetic and acoustic methods can be used to monitor dynamic changes in reservoir fluid content

Surface Subsidence measured by InSAR

InSAR (Interferometric Synthetic Aperture Radar) is used to monitor surface subsidence caused by reservoir compaction.

Satellites gather data every 24 days and comparisons of surface elevation with previous months are used to monitor conformance of injection and production across the field.

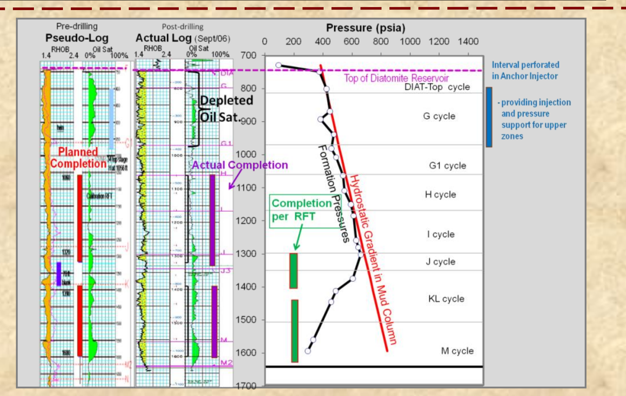


From Patsek, EIA Workshop, 2000

Waterflood Optimization with Open hole Formation Pressure Testing

- Pressure surveys in replacement producers indicate which zones are receiving pressure support
- Injector completion design based on pressure surveys to target zones not being supported by water injection

(Zannitto *et al.*, 2011)



THE FUTURE

The Belridge giant field still has many hundreds of millions of barrels available for recovery. Although production from the sub-Monterey in North Belridge and the Tulare oil sands is declining, the diatomite will sustain the field for many more decades. There is also the possible upside of exploration success in deeper zones throughout the field.

Steam production with low environmental impact

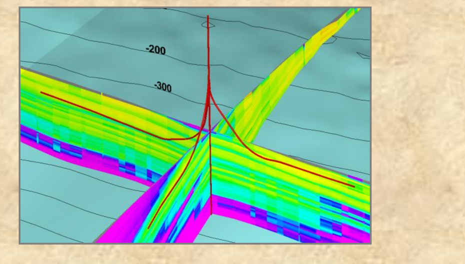
As the nation moves to a lower carbon use economy, there is a need to change the methods of heating the reservoirs


GreenSteam Biomass Plant


GlassPoint's solar panels for steam production

Drilling multiple wells with minimum surface impact

Possible redevelopment by multilateral horizontal wells



Final stage (in 2111..):
Recovery of heat from steamed reservoirs via low temperature geothermal projects

Timeline

1900 – 1910 – 1920 – 1930 – 1940 – 1950 – 1960 – 1970 – 1980 – 1990 – 2000 – 2010

- 1890 - Midway Sunset field
- 1896 - McKittrick field
- 1899 - Kern River field
- 1909: Cymric field
- 1910: Lost Hills field
- 1910: Lake View gusher at MWSS 125,000 BOPD blow out
- Jan. 1911: Belridge Oil Co. formed, purchases 30,800 acres from Mrs Hopkins for $1 million ($32.50/acre) [in 2011 dollars: $25 million at $810/acre]
- April 1911: South Belridge: Tulare & Diatomite discovered
- 1912: General Petroleum purchases south of 7th Standard Road
- 1912: North Belridge Tulare & Diatomite discovered
- 1919: Elk Hills field
- 1926: Standard Oil of NY (SOCONY) purchases General Petroleum
- 1930: Deepest well in North America (11,377 ft), 1st in field with electric log
- 1930-42: North Belridge sub-Monterey formations discovered
- 1937-42: Gas storage in N. Bel.
- 1948: 12,700 BO/day
- 1950: Cum. prod = 48.3 MMBO 12,700 BO/day, 410 wells
- 1956-59: *In situ* combustion pilot (12 companies) in oil sands of Tulare Formation south of 7th Standard Road
- 1963: Cyclic steaming begins in oil sands of Tulare Formation
- 1963-86: *In situ* combustion project (164 acres) in oil sands south of 7th Standard Rd.
- 1966: SOCONY (and General Petroleum) begin operating as Mobil
- 1978: Mobil has first successful hydraulic fracture of Diatomite
- 1979: Shell buys Belridge Oil Co. for $3.65 billion (mainly from Whittier & Buck families), gains 80% of field (Texaco & Mobil owned 35% and bid $1.8 billion but the majority owners wanted a single company to buy 100%)
- 1986: Peak Production 172,700 BOPD 114.4 MMCFG/day
- 1987-2007: Tulare Aquifer Lift project to reduce aquifer inflow
- 1993: 1st horizontal wells in Tulare Fm.
- 1995: 1st horizontal well in Diatomite
- 1997: Shell and Mobil merge upstream assets in California to form Aera Energy LLC
- 1999: Mobil and Exxon merge to form ExxonMobil
- 2000 to present: World's tightest well spacing (37.5 ft / 11.4 m)
- 2005: Continuous steam drive begins in Diatomite
- 2006: Largest 3D seismic survey in California
- 2011: -First exploration well in 20 years - Current Production: 77,400 BO/day, 37 MMCFG/day [Aera: 70,750 BO/day, 32 MMCFG/day]

The Belridge Giant Oil Field: 100 Years of History and a Look to the Future

Poster for
AAPG-PS / SPE-WR / SEG Western Regional Meeting
"Unlocking the Potential"
Anchorage, Alaska

May 9-11, 2011

Authors : *Malcolm Allan & Joseph Lalicata*