The Belridge Giant Oil Field - 100 Years of History and a Look to a Bright 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 covers an area roughly 22 miles long and 2.5 miles wide (35 by 4 km). It has three totally separate and distinctly different producing zones: Pleistocene shallow fluviodeltaic sands producing heavy oil via steamflood; Miocene deepwater diatomite layers producing light oil via hydraulic fractures and with water injection for pressure maintenance; and Oligocene to lower Miocene marine sandstones producing gas and light oil via gas expansion. Each of the vertically stacked zones requires different work models and different completion strategies to sustain production.

Although down from its peak of 160,000 BOE per day in 1986, the field currently produces 80,500 BOE per day which makes it one of the largest onshore fields in the USA. Since discovery via a surface oil seep, over 15,000 wells have been drilled although only 6,000 producers and 2,400 injectors are still active. However, new insights to the reservoirs have resulted in about 600 new wells being drilled and completed in each of the past few years.

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 as close as 37.5 ft (11.5 m) apart and completed with sand-propped hydraulic fracs. Continuing to successfully develop and produce the reservoirs requires applying conventional technologies and techniques in new and unconventional ways. Fit-for-purpose reservoir characterization studies in 2D and 3D, coupled with standardized workflows for modeling and documentation, build upon past fundamental knowledge using state-of-the-art software and databases to handle the immense quantity of data.

At the start of the 21st century the field is gearing up for many more years of activity with expansion of steam drives in the oil sands and in the diatomite shales, installation of a large microseismic array, distributed temperature sensing to monitor water movement in water injection wells, and regular InSAR surveys to monitor ground movements. Exploration wells are also being drilled for seismic targets that are well below the current producing zones.

Selected References

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The Belridge Giant Oil Field
- 100 Years of History and a Look to a Bright Future

Theme V: Reservoir Characterization from Outcrops to Drilling

2011 AAPG International Conference & Exhibition, Milan, Italy

Malcolm Allan and Joseph Lalicata

October 26, 2011

Last update: Oct-14-11

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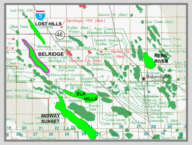
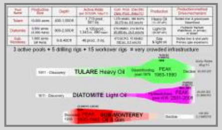
Outline of Presentation

Location Map for Belridge Giant Oil Field



Overview of Reservoirs and Production History



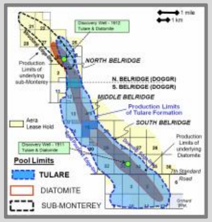
Geological Setting and Petroleum Systems

Parameter
Plate Tectonic Setting
Reservoir Interval Age
Depositional Environment Reservoir Lithology
Trapping Mechanism
Seals
Hydrocarbon Source

Early Days

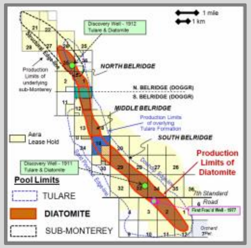
Sub-Monterey Pool (North Belridge)

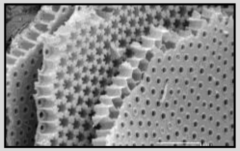
Tulare Pool



Diatomite Pool

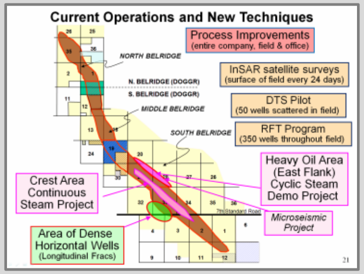
- Diatomite is a Unique, Unconventional Rock Type
- Type Log and Cross section
- Data Coverage
- Hydraulic Fractures are Key
- 3D Reservoir Models and Reservoir Limits
- Defining Limits of Pay





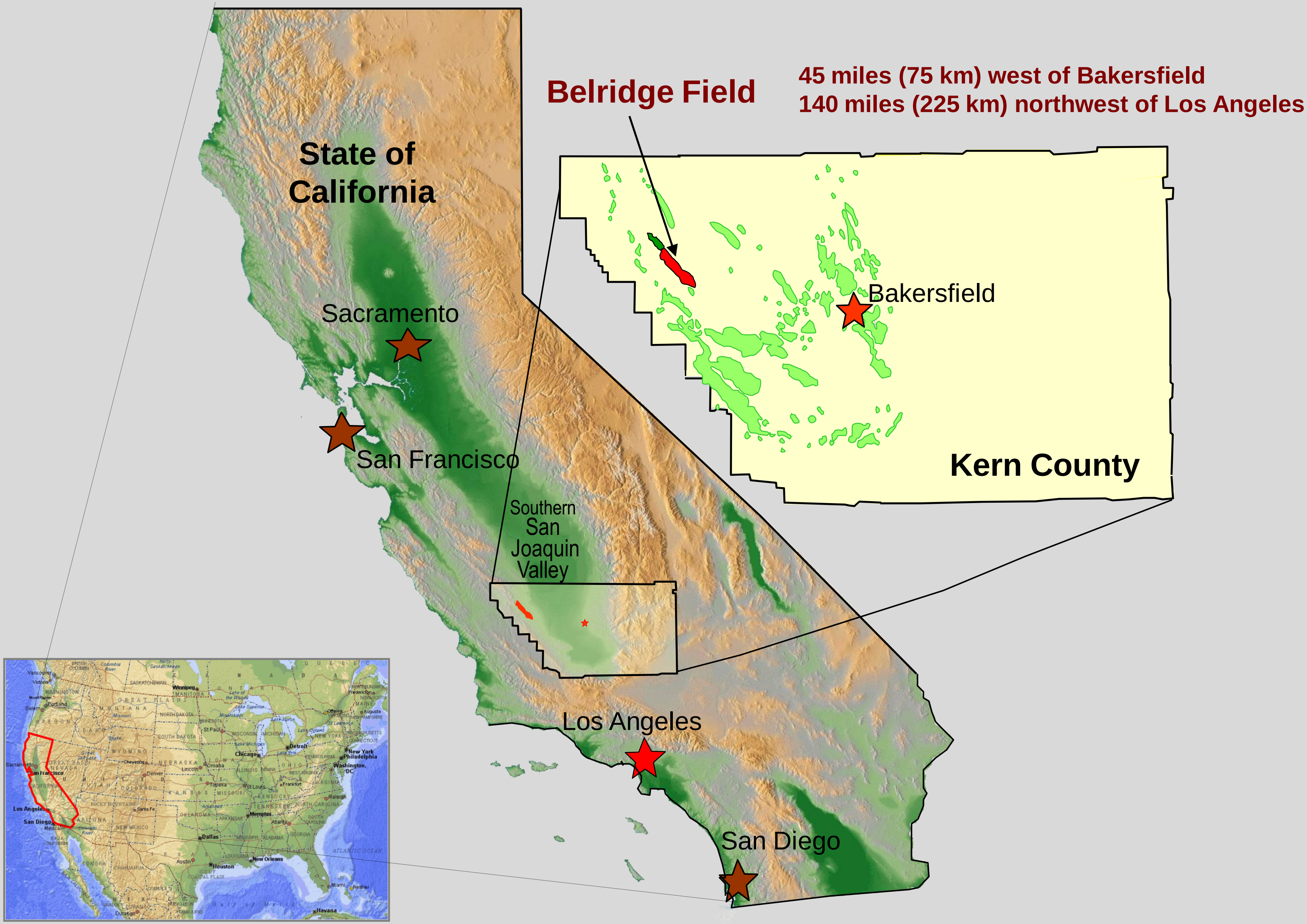
New Techniques to Improve Current Operations

- Horizontal Wells
- Pressure Surveys
- InSAR
- DTS
- Microseismic



Looking Towards a Bright Future

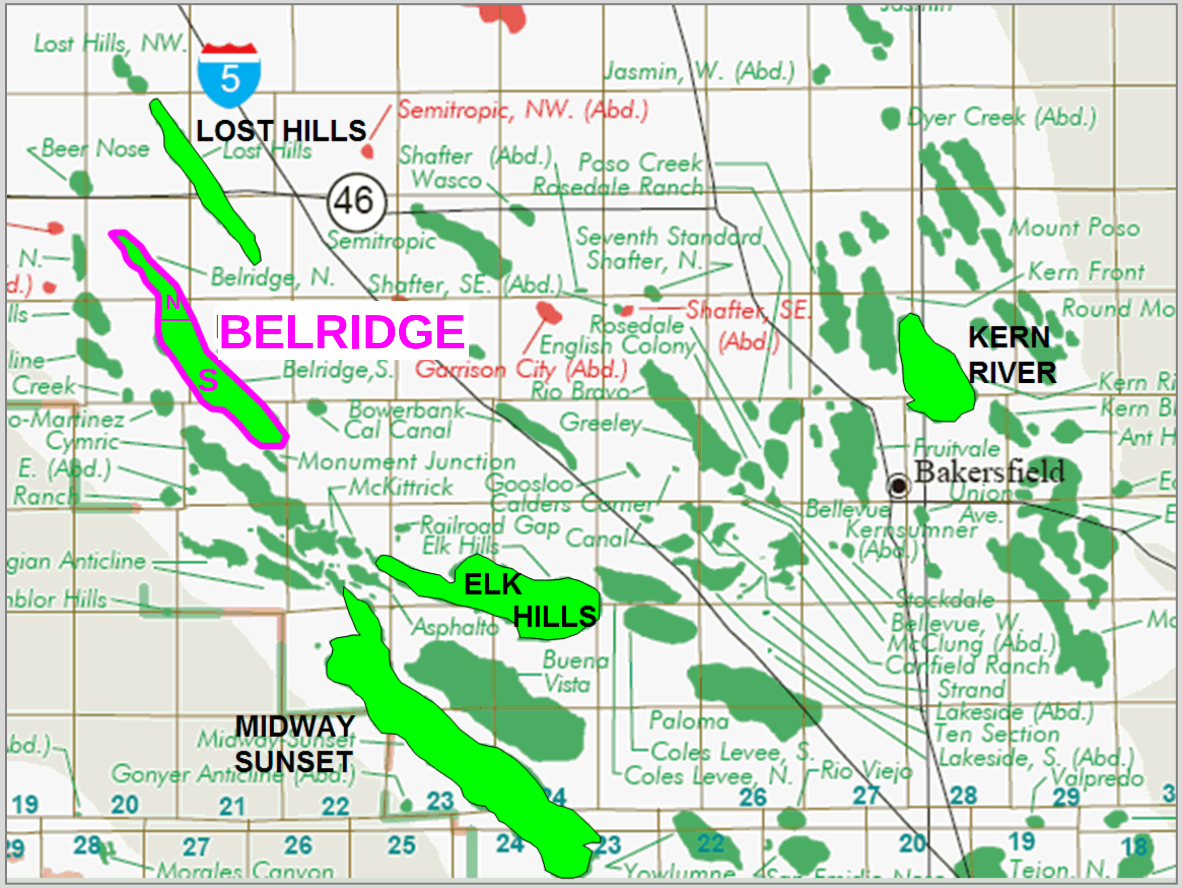
Geographic Location Map of Belridge Field



California's Top Oil Fields

Belridge Field

45 miles west of Bakersfield
140 miles northwest of Los Angeles



Rank	Field Name	State
1	Prudhoe Bay	AK
2	Sprayberry Trend Area	TX
3	Mars-Ursa (Miss. Canyon)	Offshore Gulf
4	Thunder Horse (Miss. Canyon)	Offshore Gulf
5	**Belridge South**	**CA**
6	Kuparuk River	AK
7	Wasson	TX
8	Atlantis (Green Canyon)	Offshore Gulf
9	Midway-Sunset	CA
10	Elk Hills	CA

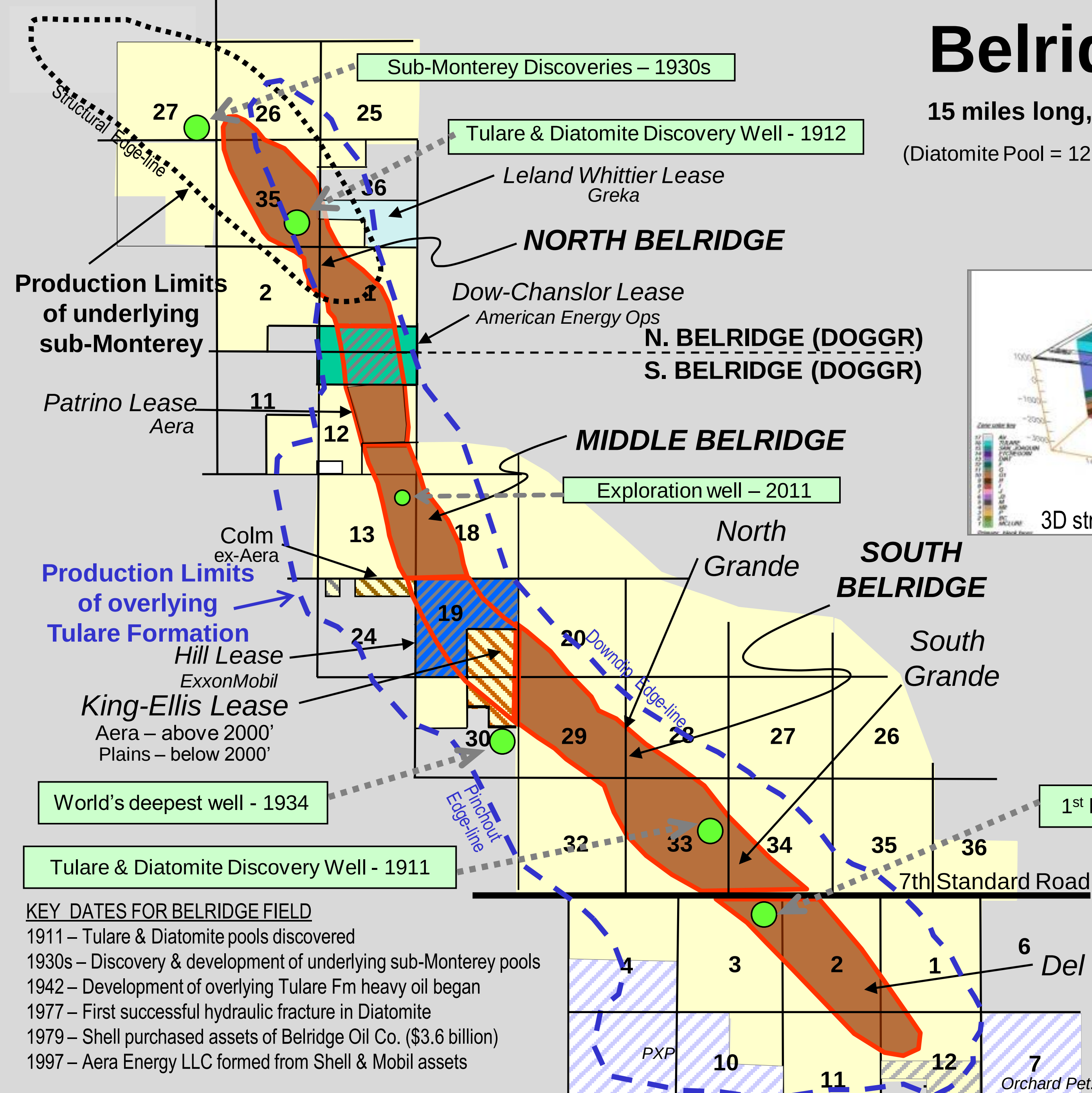
From list of 'Top 100 US Oil Fields
by 2009 Proved Reserves'
-from EIA, Dept. of Energy

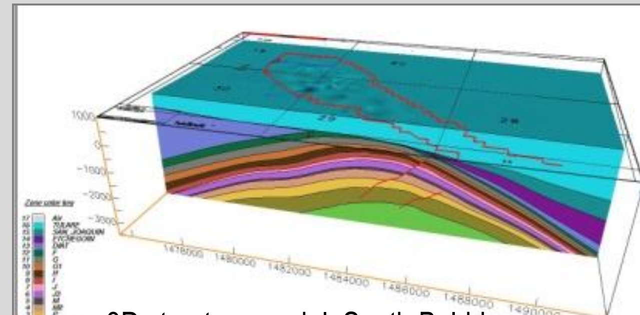
Three are in Kern County

Belridge Field

15 miles long, 2½ mile wide, 8000 acres

(Diatomite Pool = 12 miles long, 3/4 mile wide, 3350 acres)





3D structure model, South Belridge

KEY DATES FOR BELRIDGE FIELD

1911 – Tulare & Diatomite pools discovered
1930s – Discovery & development of underlying sub-Monterey pools
1942 – Development of overlying Tulare Fm heavy oil began
1977 – First successful hydraulic fracture in Diatomite
1979 – Shell purchased assets of Belridge Oil Co. ($3.6 billion)
1997 – Aera Energy LLC formed from Shell & Mobil assets

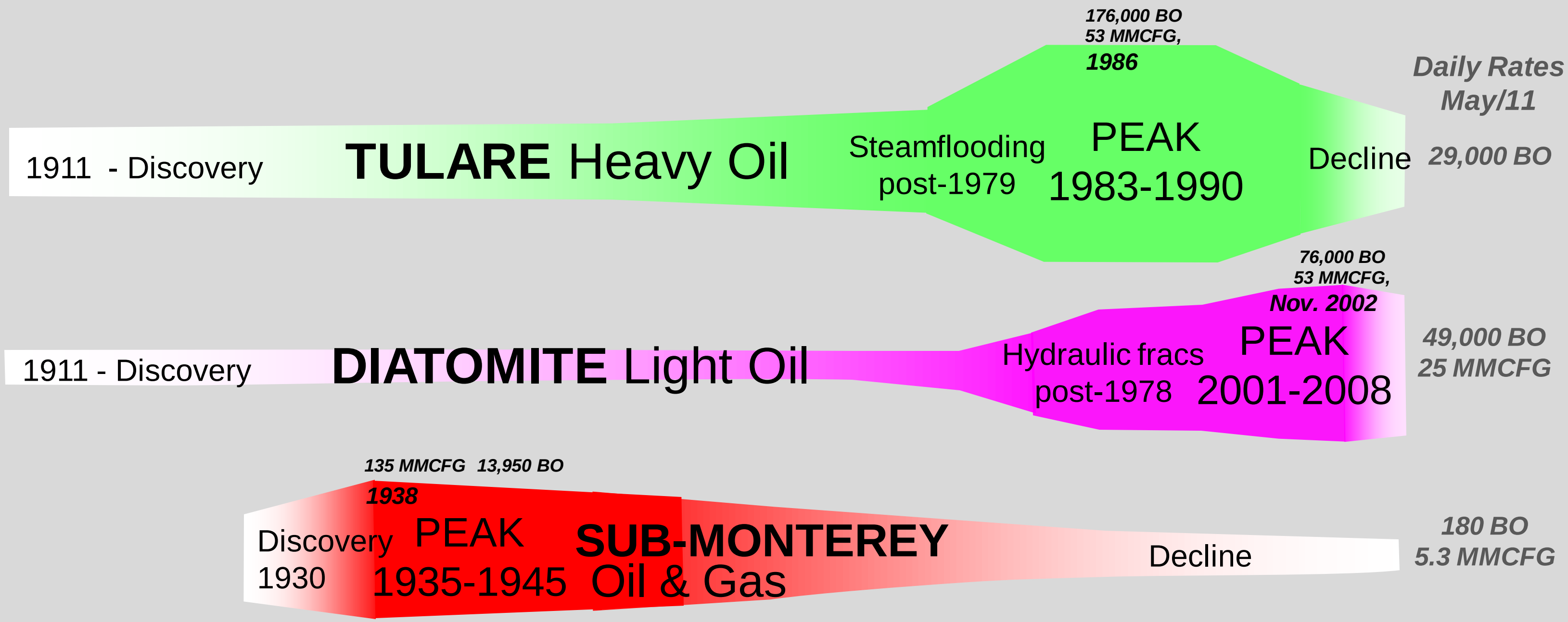
Belridge Field has a Huge Surface Footprint

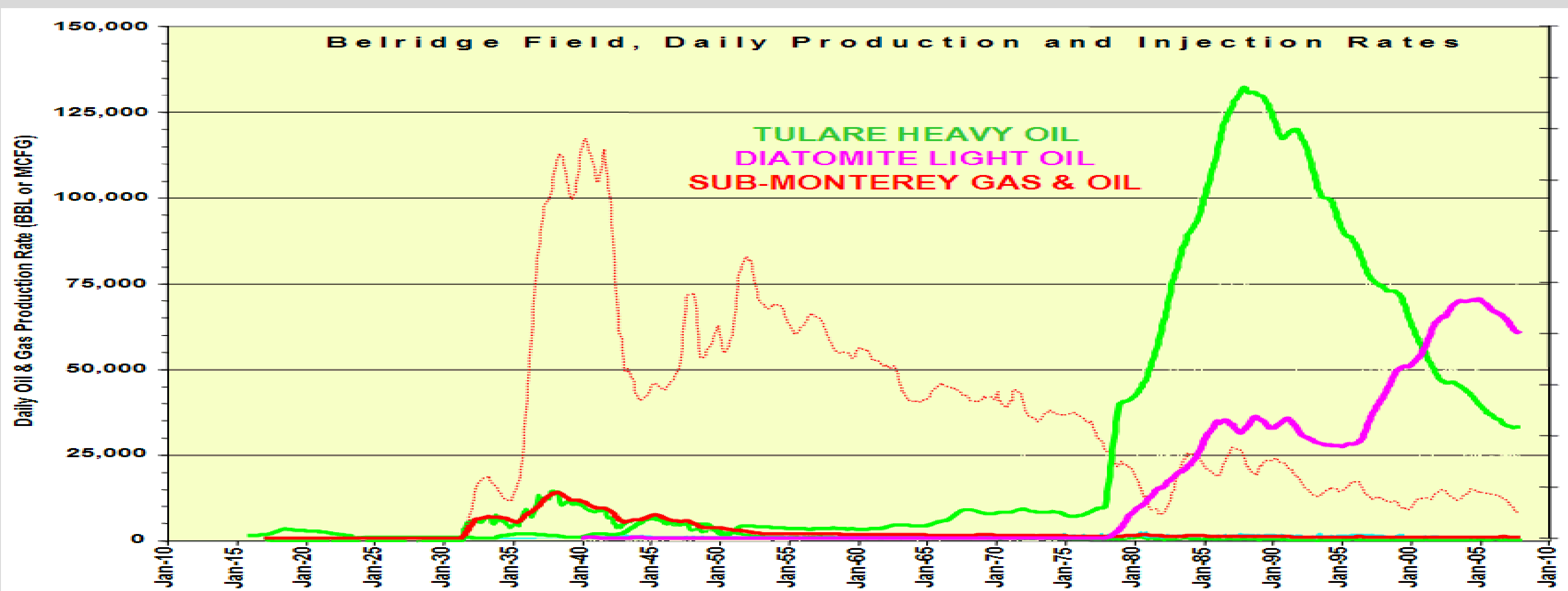
Pool Name'	Productive Size	Depth	Active Wells (per DOGGR, May/11)	Cum. Prod. (Dec/09) *Daily Prod. (May/11)*	Production	Production method Drive mechanism
Tulare	10,500 acres	400-1,000 ft	1,710 prod., 501 inj.	1,370 MMBO, 380 BCFG *29,275 BO, 6.6 MMCFG*	Heavy Oil (11-15º API)	Slotted liner & gravel-pack Steamflood
Diatomite	3,500 acres (3,000 Aera)	800-2,000 ft	4,129 prod., 1,343 WI, 380 Steam	270 MMBO, 214 BCFG *49,068 BO, 24.9 MMCFG*	Light Oil (25-39º API)	Hydraulic fracture Waterflood, or primary, or steam
Sub-Monterey	1,600 acres (all Aera)	6-9,400 ft	46 prod., 0 inj.	673 BCFG, 70 MMBO *182 BO, 5.3 MMCFG*	Gas & light oil	Slotted liner & shot perfs Primary (gas expansion)

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

©Sara Leen, National Geographic

Belridge Field – Production through Time

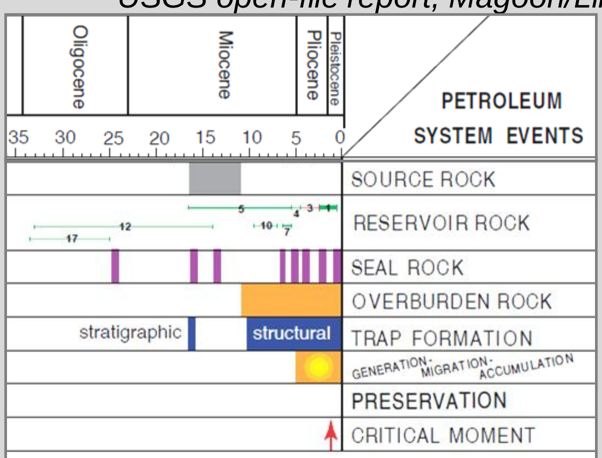


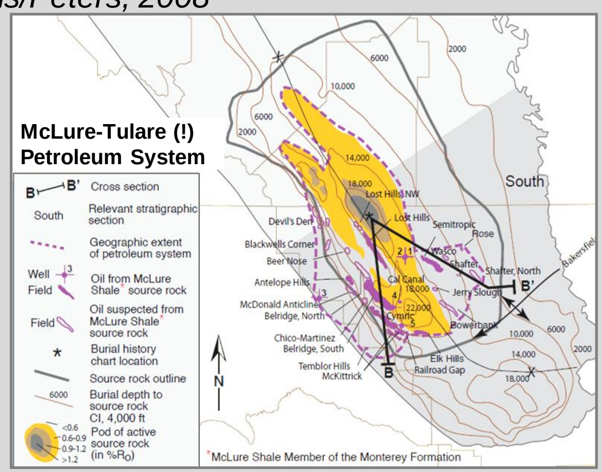


Petroleum Systems -- Belridge Field

Parameter	Sub-Monterey Formations	Diatomite (Reef Ridge Shale & Antelope Shale)	Tulare Formation
Plate Tectonic Setting	Fore-arc setting and probably underlain by oceanic ophiolitic crust. Anticline began in Eocene due to stress fields set up by right lateral strike-slip movement along the San Andreas fault to the west.		
Reservoir Interval Age	Oligocene to Lwr Miocene	Upper Miocene	Pleistocene
Depositional Environment Reservoir Lithology	Marginal marine Shelf sands	Inland sea with 600-1000 ft water depth (cf. present-day Sea of Cortez). Seasonally laminated diatomite	Fluvio-deltaics in filling basin. Loose sands and gravels
Trapping Mechanism	Elongated anticline, fault compartments	Elongated anticline Still not in hydrodynamic equilibrium	Updip sand pinchout to west, downdip OWC to east
Seals	Overlying shales and lateral sand pinchouts	Layered clay-rich zones at base of diatomite cycles form partial seals	Interbedded clays & mudstones as well as fault baffles and tar seals
Hydrocarbon Source	Low sulfur oil & gas from Eocene source rocks	Oil from mature Monterey shales to east that are basinal equivalents of reservoir units.	Oil leaked across basal unconformity from underlying diatomite. Now biodegraded and degassed.

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



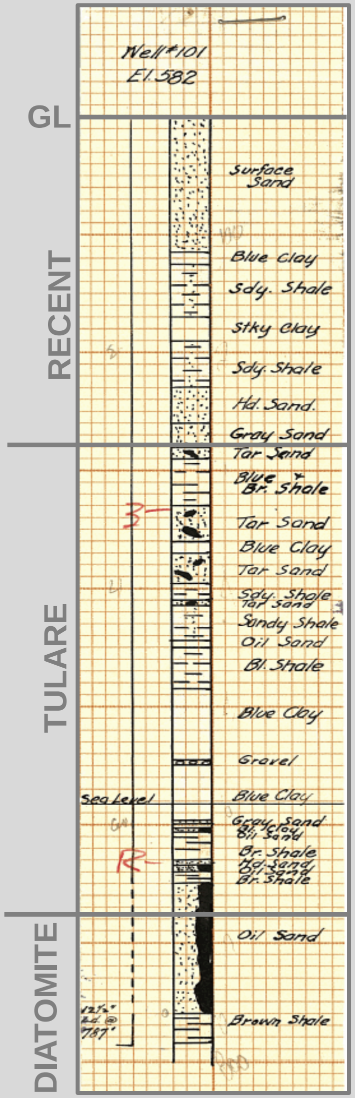


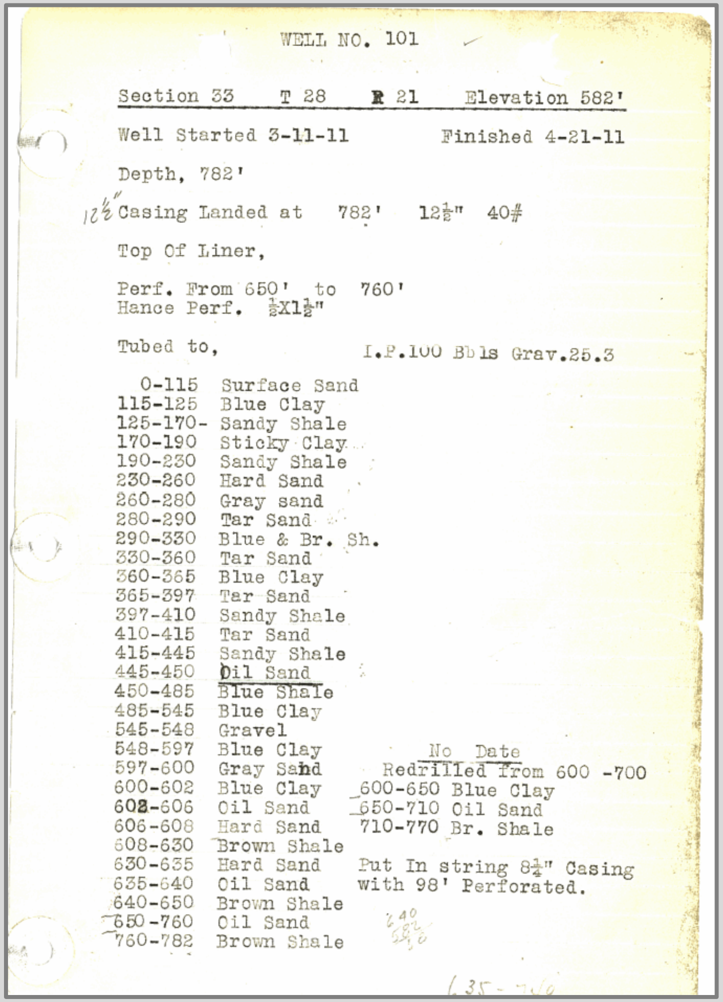
Paleogeography in late Miocene (± 5-1 Ma) e.g. Diatomite time by Ron Blakey at U. of N. Arizona

Discovery Well Drilled in April 1911

Driller's Log and Lithology Log for Well 101, Section 33

Well was spudded on an outcrop of oil-stained sand along the Chico-Martinez Creek as it crosses the slight surface expression of the Belridge anticline.





WELL NO. 101

Section 33 T 28 R 21 Elevation 582'

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

Depth, 782'

12½" Casing Landed at 782' 12½" 40#

Top Of Liner,

Perf. From 650' to 760'
Hance Perf. ½X1½"

Tubed to, I.P.100 Bbls Grav.25.3

0-115	Surface Sand
115-125	Blue Clay
125-170-	Sandy Shale
170-190	Sticky Clay
190-230	Sandy Shale
230-260	Hard Sand
260-280	Gray sand
280-290	Tar Sand
290-330	Blue & Br. Sh.
330-360	Tar Sand
360-365	Blue Clay
365-397	Tar Sand
397-410	Sandy Shale
410-415	Tar Sand
415-445	Sandy Shale
445-450	Oil Sand
450-485	Blue Shale
485-545	Blue Clay
545-548	Gravel
548-597	Blue Clay
597-600	Gray Sand
600-602	Blue Clay
602-606	Oil Sand
606-608	Hard Sand
608-630	Brown Shale
630-635	Hard Sand
635-640	Oil Sand
640-650	Brown Shale
650-760	Oil Sand
760-782	Brown Shale

No Date
Redrilled from 600 -700

600-650	Blue Clay
650-710	Oil Sand
710-770	Br. Shale

Put In string 8¼" Casing with 98' Perforated.

635-760

IP = 100 bbl/day of 23.4° API oil

Photos courtesy of the Kern County Museum, used by permission

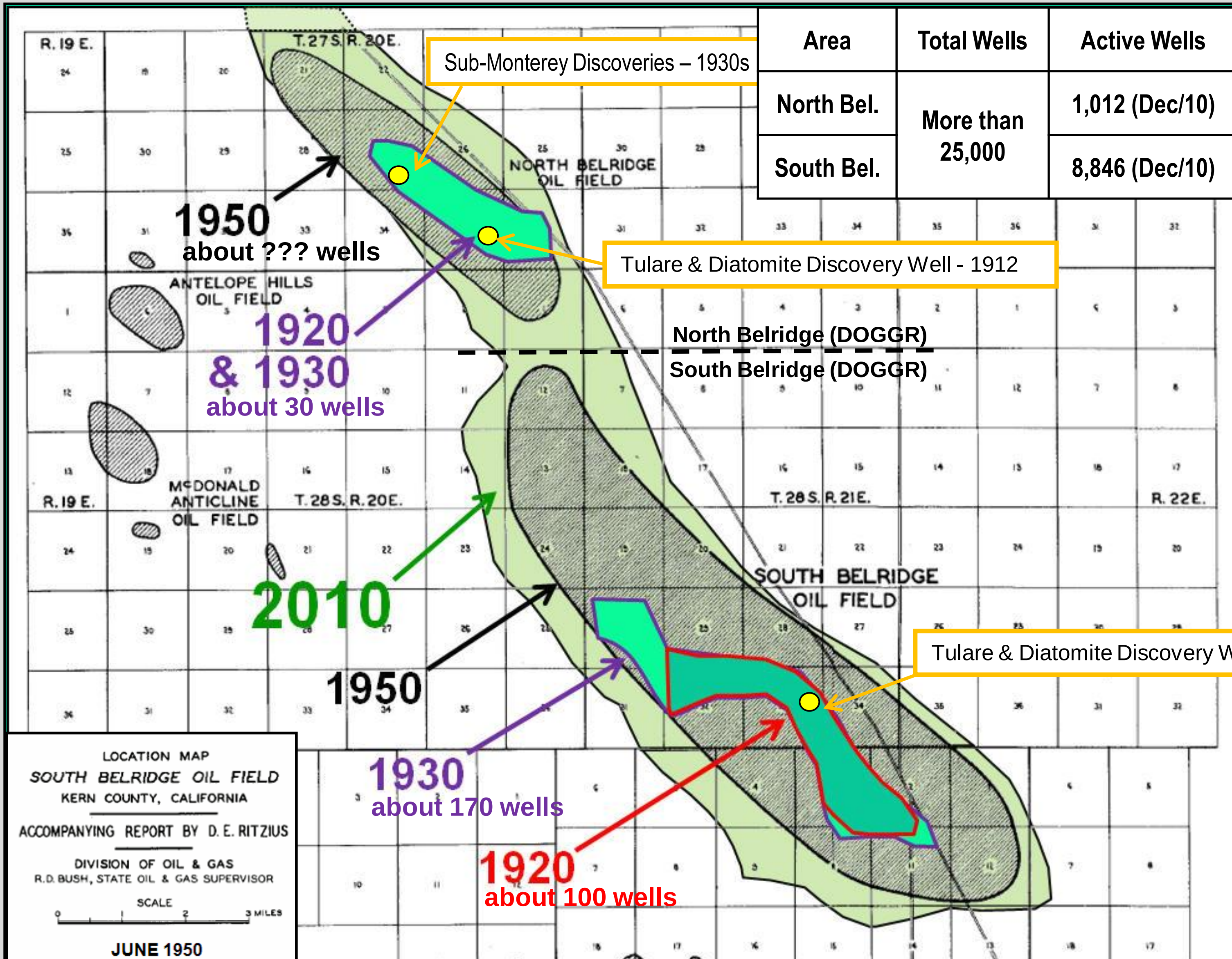
Soon after drilling discovery well

Three men working with machinery, circa 1912

AERA

Belridge Field has Expanded over the Years

Area	Total Wells	Active Wells
North Bel.	More than 25,000	1,012 (Dec/10)
South Bel.		8,846 (Dec/10)



Valuation Report in October, 1919

– *"… it is estimated that within ten years both pools will be commercially exhausted."*
– *"Southern Belridge Field is entirely drilled up"*
– *"Future production… is estimated to be about 1,800,000 barrels"*

Quotes from Valuation Report of the Belridge Oil Company's holdings

1920s and 1930s

By the late-1920s, steel derricks and diesel engines replaced wooden derricks powered by steam because of the increased safety, efficiency, and ability to handle longer casing strings.

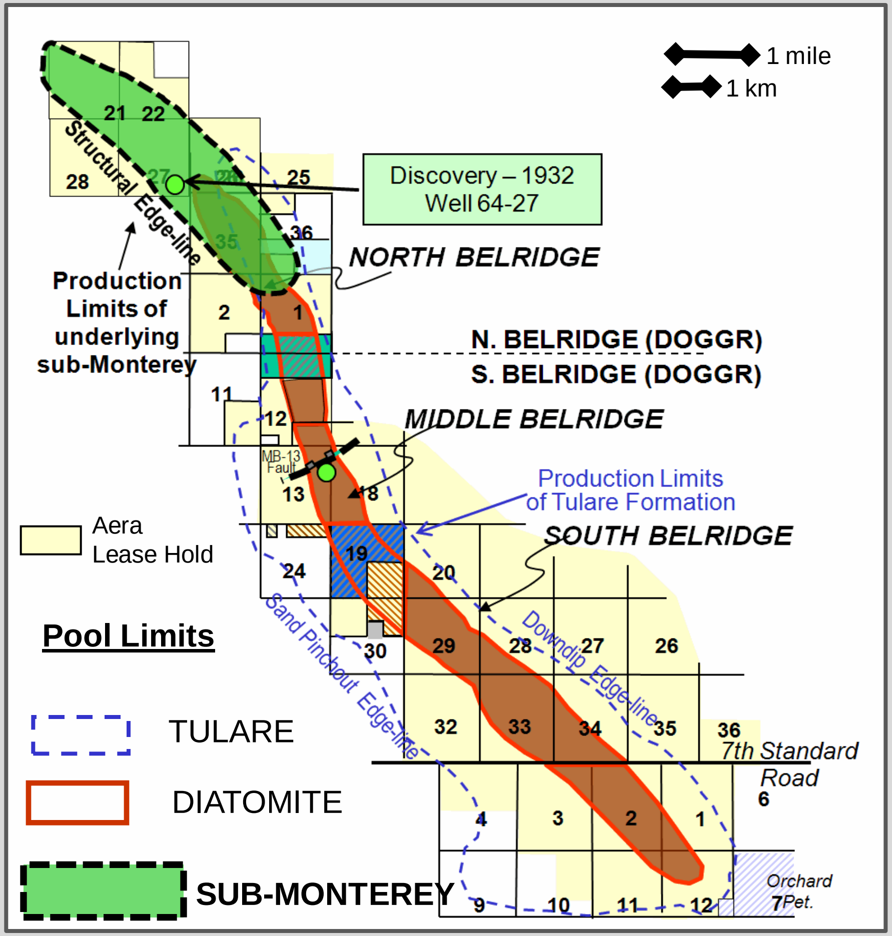
In June 1934, General Petroleum drilled Berry 1-30 to TD at 11,377 ft (*3468 m*)
– deepest well in world at the time
– mud log and driller's log only (before electric logs in California)

Also in the 1930s, the deeper sub-Monterey reservoirs were discovered at 6,000 to 8,000 ft (*1800-2450 m*) in North Belridge and became important petroleum resources for WW2.

Sub-Monterey Pool, North Belridge Field

KEY DATES FOR SUB-MONTEREY POOL
1930: Discovery year for Temblor Sand in Monterey Formation
1932: Discovery well for 64 Zone, well 64-27N, in sub-Monterey formations
1936-1984: 540 BCFG injected for gas storage and pressure maintenance.
1938: Peak production of 135 MMCFG/day and 13,950 BO/day
1930-1948 Total of 148 wells (8 dry holes) drilled in the sub-Monterey pools
1941 Discovery well for Y Sand; well 47-27N
1966: Discovery year for Carneros Sand
1979 – Shell purchased assets of Belridge Oil Co. ($3.6 billion)
2001: Program for recompletions / add-pays began
2011: Currently 46 active wells

NORTH BELRIDGE FIELD, Sub-Monterey Pool
4 miles long, 1 mile wide, 1600 acres
(6 by 1 km, 650 ha)

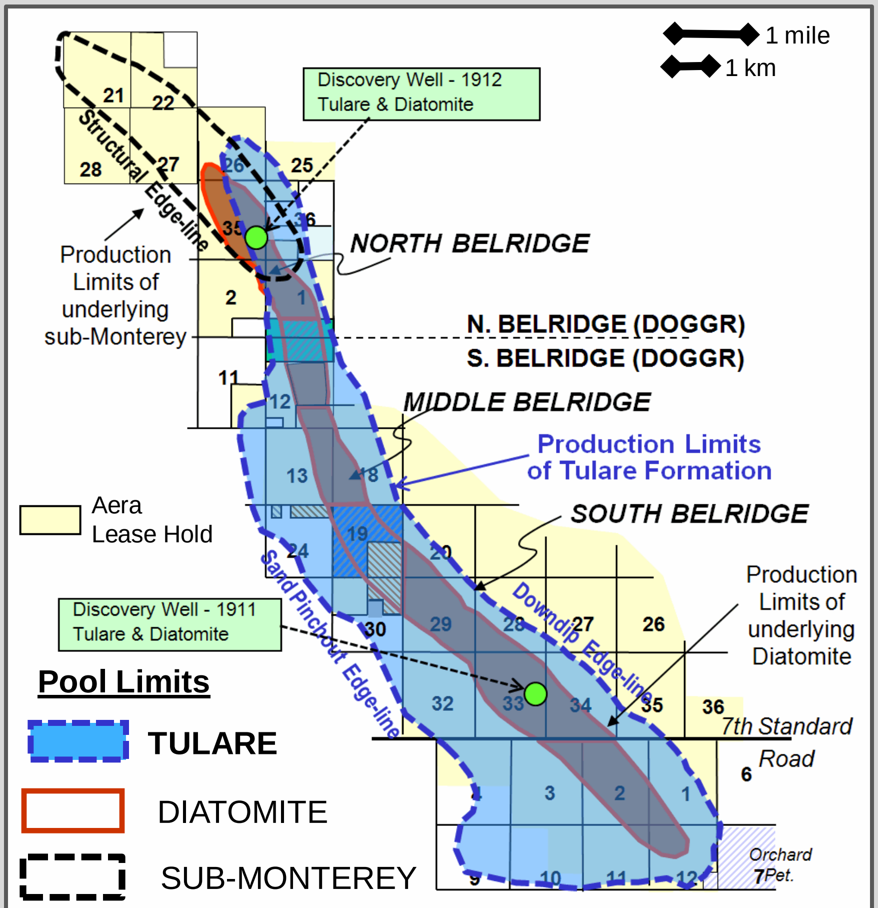


Pool Name	Sub-Monterey
Productive Size (Aera only)	1,600 acres (all Aera)
Reservoir Depth	6,000 – 9,400 ft
Active Wells (per DOGGR, May/11)	49 prod., 0 inj.
Aera Wells	46 prod. (100%) 0 inj.
Cum. Prod.	673 BCFG, 70 MMBO
Daily Production All Aera	5.3 MMCFG, 182 BO
Production	Gas & light oil
Completion Method	Slotted liner & shot perfs
Drive Mechanism	Primary (gas expansion)

Tulare Pool, Belridge Field

KEY DATES FOR TULARE POOL

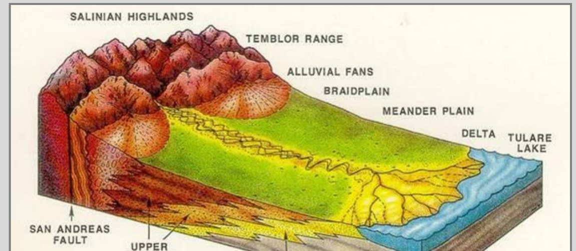
1911:
  Jan.: Belridge Oil Co. formed, purchases 30,800 acres from Mrs Hopkins for $1 million
  April: Well 101-33 TD'd at 782 ft, completed in Tulare and Diatomite, IP = 100 BOPD
1912: Discovery well for North Belridge
1956-59: In-situ combustion pilot (12 companies)
1963: Cyclic steaming begins
1963-1968: In-situ combustion project (Mobil)
1979 – Shell purchased assets of Belridge Oil Co. ($3.6 billion)
1986: Peak production of 172,700 BO/day, 114.4 MMCFG/day
1987-2007: Aquifer Lift project on east flank to reduce aquifer inflow
1993: First horizontal wells in Tulare



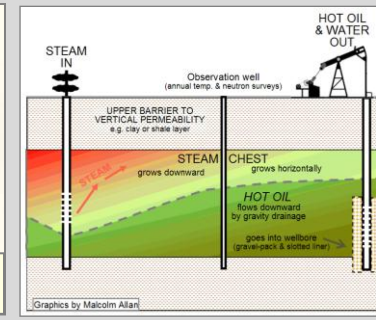
BELRIDGE FIELD, Tulare Pool

12 miles long, 3 mile wide, 10,500 acres

(18 by 5 km, 4300 ha)



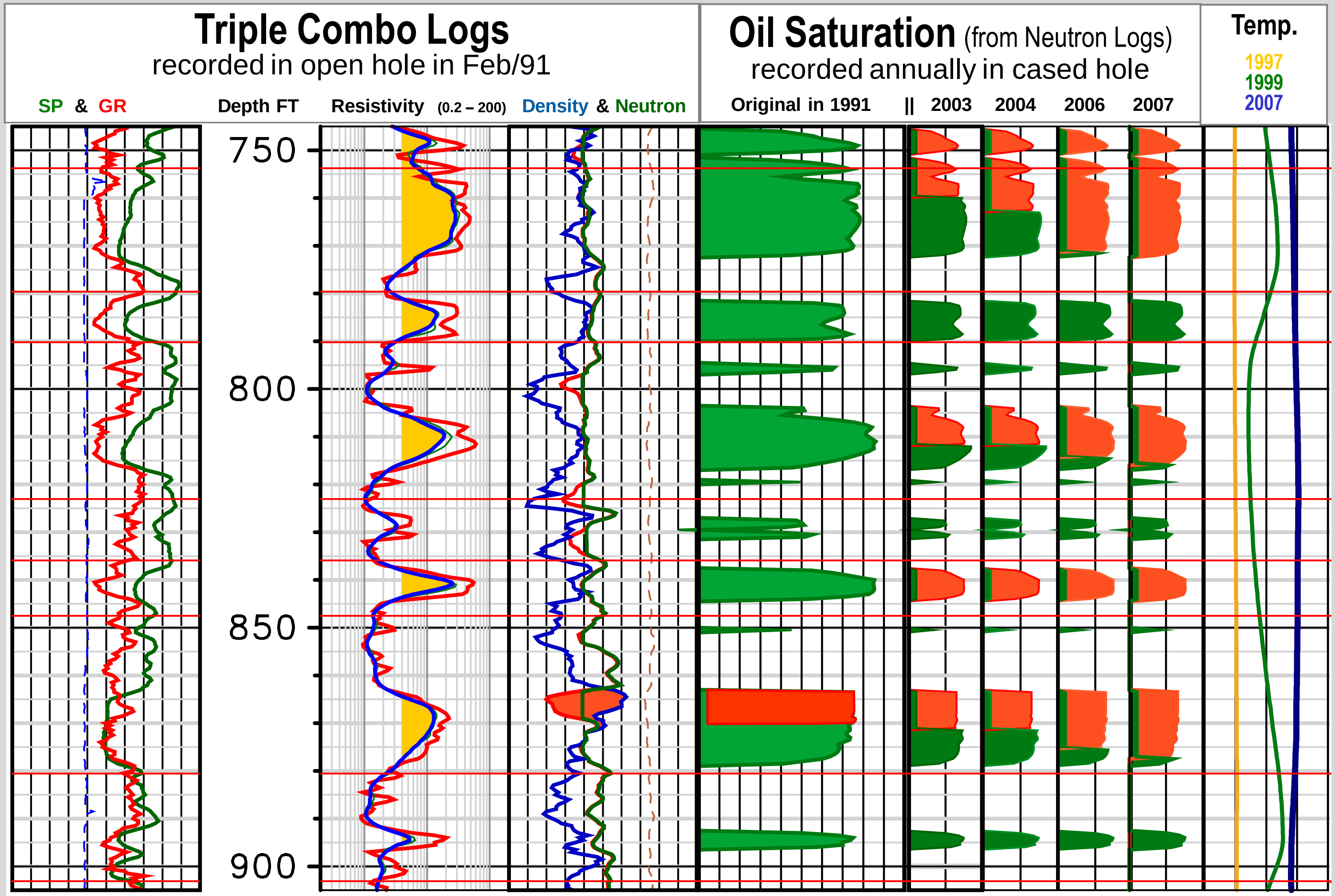
Schematic representation of the depositional setting of the Tulare formation at South Belridge Field
From Miller, D. M., McPherson, J. G. & Covington, T. E. 1990



Pool Name	Tulare
Productive Size (Aera only)	10,500 acres
Reservoir Depth	400-1,000 ft
Active Wells (per DOGGR, May/11)	1,710 prod., 501 steam inj.
Aera Wells (% of total)	1,579 prod (89%) 386 steam inj. (77%)
Cum. Prod.	1,370 MMBO, 380 BCFG
Daily Production (Aera only)	29,275 BO, 6.6 MMCFG (24,470 BO 84%)
Production	Heavy Oil (11-15º API)
Completion Method	Slotted liner & gravel-pack
Drive Mechanism	Steamflood (mainly continuous)

Reservoir Monitoring via Time-Lapse Logging, Tulare Formation

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.



Well 9035-11
SOSS

Neutron and temperature surveys are run in cased-hole observation wells every 2 years to 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 Pool, Belridge Field

KEY DATES FOR DIATOMITE POOL

1911:

Jan.: Belridge Oil Co. formed, purchases 30,800 acres from Mrs Hopkins for $1 million

April: Well 101-33 TD'd at 782 ft, completed in Tulare and Diatomite, IP = 100 BOPD

1912: Discovery well for North Belridge

To 1970s: – upper few tens of feet in Diatomite often completed with overlying Tulare oil sands so that light oil from Diatomite would 'dilute' heavy oil enough to allow economic production of heavy oil)

1977 – First successful hydraulic fracture in Diatomite

1979 – Shell purchased assets of Belridge Oil Co. ($3.6 billion)

1986 – Water injection began to mitigate subsidence

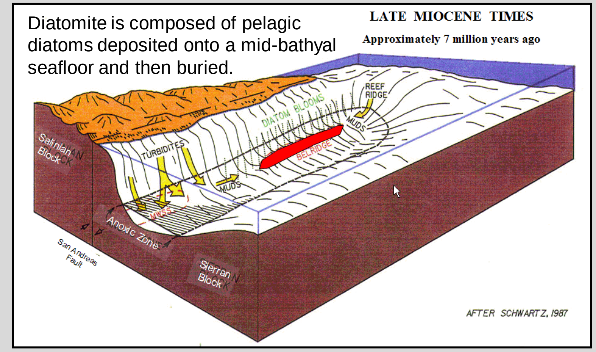
1997 – Aera Energy LLC formed from Shell & Mobil assets

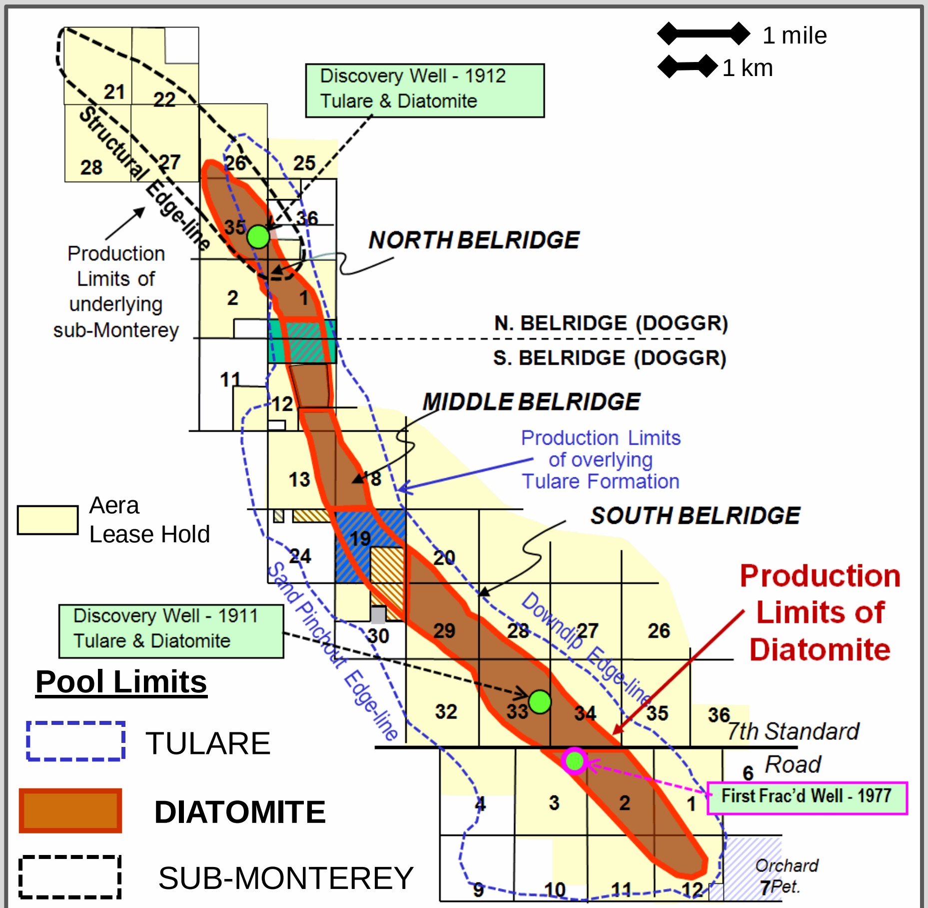
2002: Peak production of 76,100 BO/day, 52.9 MMCFG/day (Aera = 94%)

BELRIDGE FIELD, Diatomite Pool

12 miles long, 1 mile wide, 3500 acres

(20 by 2 km, 1400 ha)

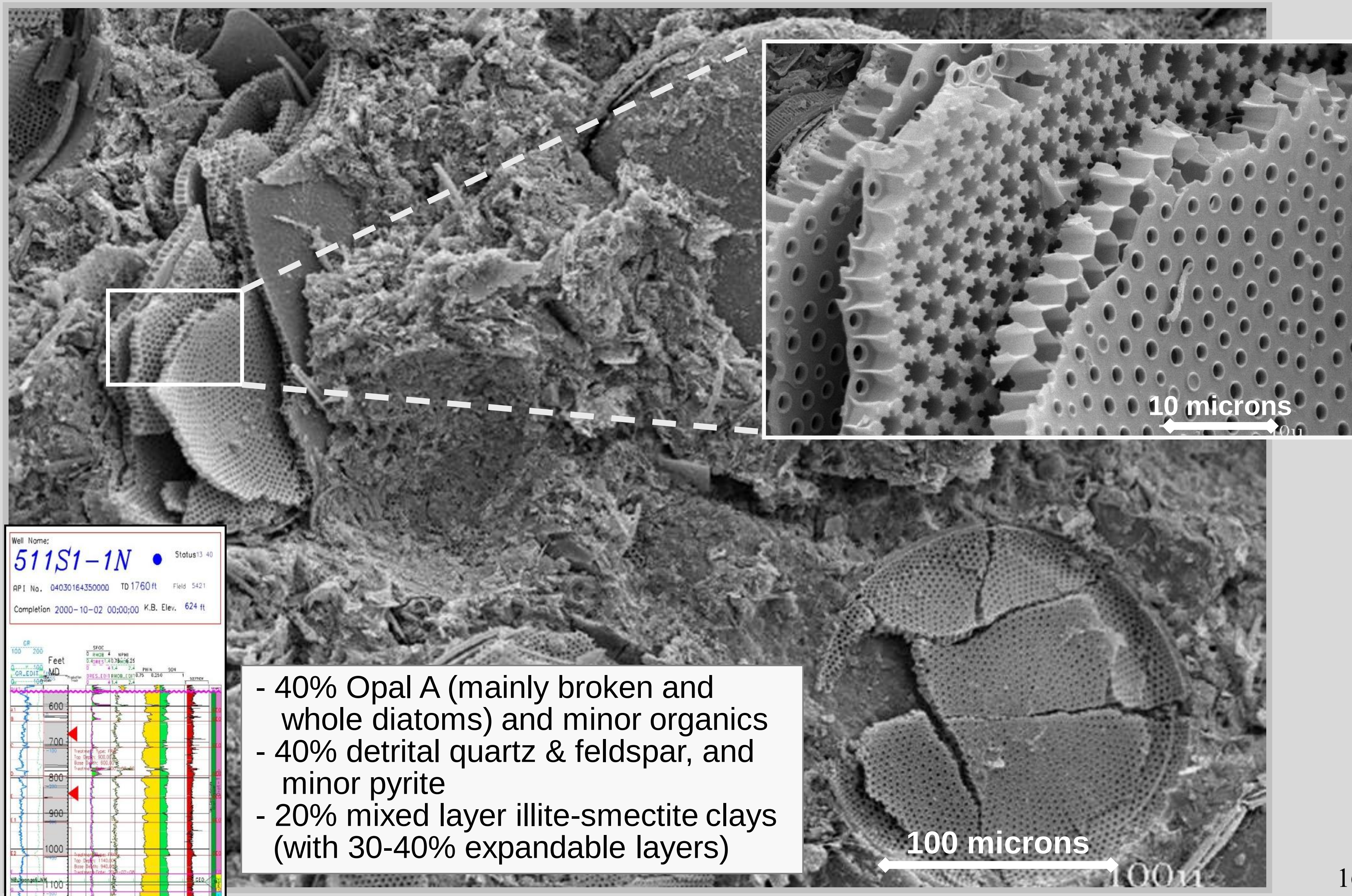




Pool Name	Diatomite
Productive Size (Aera only)	3,500 acres (3,000 Aera)
Reservoir Depth	800-2,000 ft
Active Wells (per DOGGR, May/11)	4,129 prod., 1,343 WI, 380 Steam
Aera Wells (% of total)	3,950 prod (96%), 1,162 water inj. (87%), 380 steam inj. (100%)
Cum. Prod.	270 MMBO, 214 BCFG
Daily Production (Aera only)	49,068 BO, 25.0 MMCFG (45,686 BO, 20.6 MMCFG)
Production	Light Oil (25-39º API)
Completion Method	Hydraulic fracture
Drive Mechanism	Waterflood, or primary, or steam

SEM Photo of Diatomite

Clay-rich Zone of Opal A, 848 ft in well 511S1-1N, North Belridge



- 40% Opal A (mainly broken and whole diatoms) and minor organics
- 40% detrital quartz & feldspar, and minor pyrite
- 20% mixed layer illite-smectite clays (with 30-40% expandable layers)

Unique Rock Properties Control Diatomite Productivity

Diatomite is an unconventional shale . . . .

Exceptional Vertical Thickness of Pay
- Thickness of pay can be 1000-1200 ft (*300-400 m*)
- Along the crest the pay zones can be stacked with few non-pay intervals

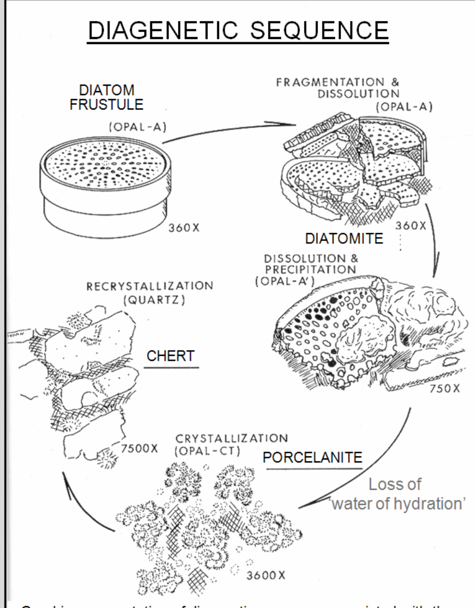
Very High Porosity
- Opal A has 55-65% Ø and mostly fluid-supported, with little grain support
- Opal CT has 35-50% Ø and is grain-supported due to crystallization

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

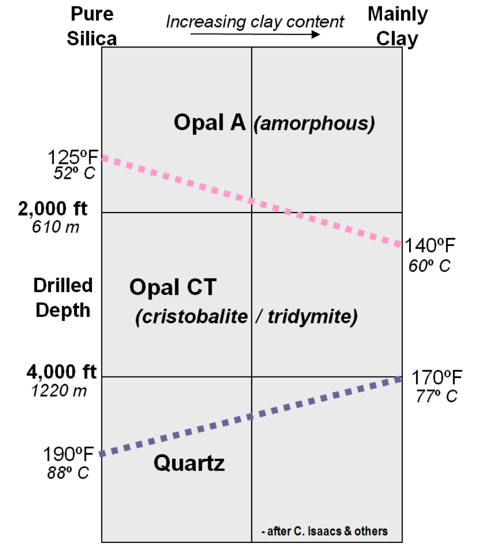
Large Surface Area
- One ft^3 of rock has 15 million ft^2 (340 acres, *140 ha*) of surface area
- Water-wet and has high interstitial water saturation (S_{wi}) above 50%

Highly Compressible
- Opal A compressibility (Cr) 100-300 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 at Diffusion Speed of only 1-3 ft (*0.3-1.0 m*) per year
- Fluids move by linear flow through micro-fractures towards the large planes of the induced hydraulic fractures



Graphic representation of diagenetic sequence associated with the diatom-to-chert transformation -- by Dan Schwartz (Shell, 1980s)

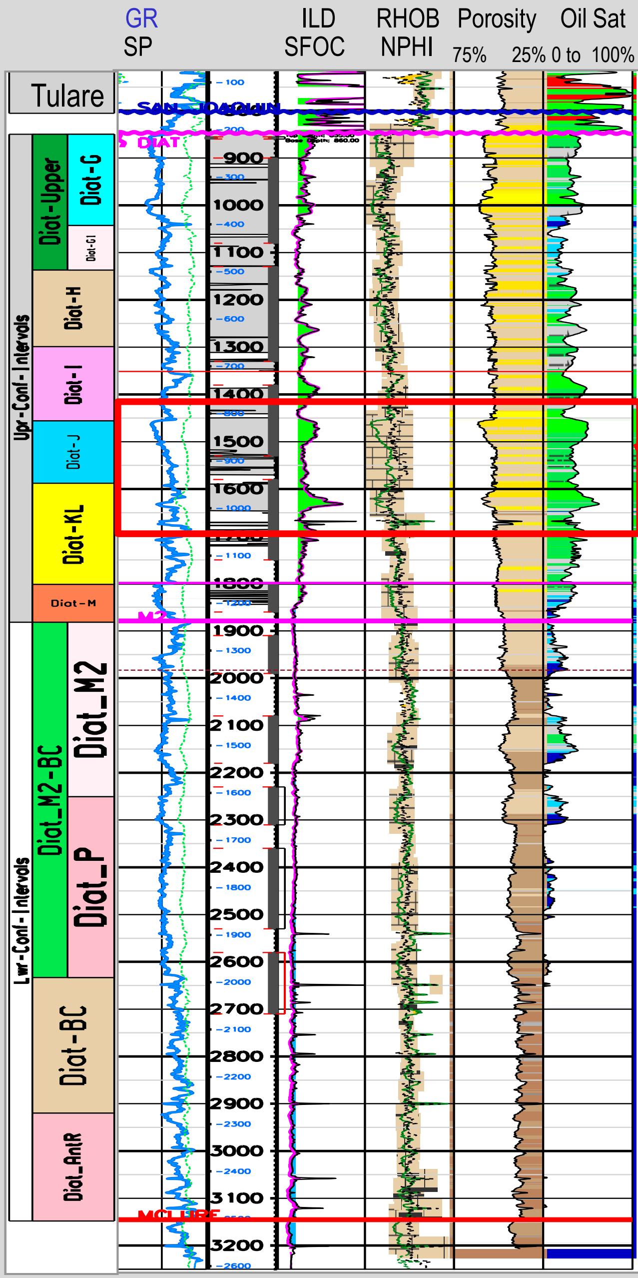


Type Log, Diatomite Reservoir

Cyclic Diatomite

Opal A shown as gray in depth track

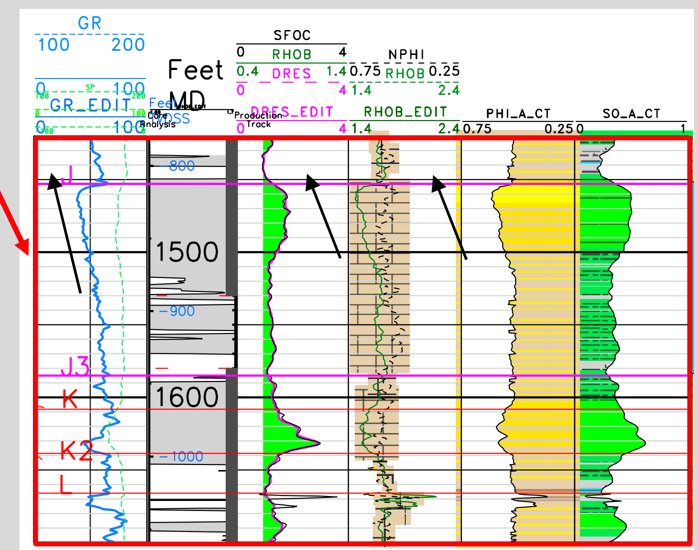
Brown Shale Opal CT



Lithostratigraphy = Chronostratigraphy

Note the 'cleaning upward' funnel patterns on the GR and RHOB / Porosity curves.

Each major cycle starts with a layered clay base and gets cleaner upwards until it is almost pure diatomite. It is then overlain by the clay-rich base of the overlying cycle

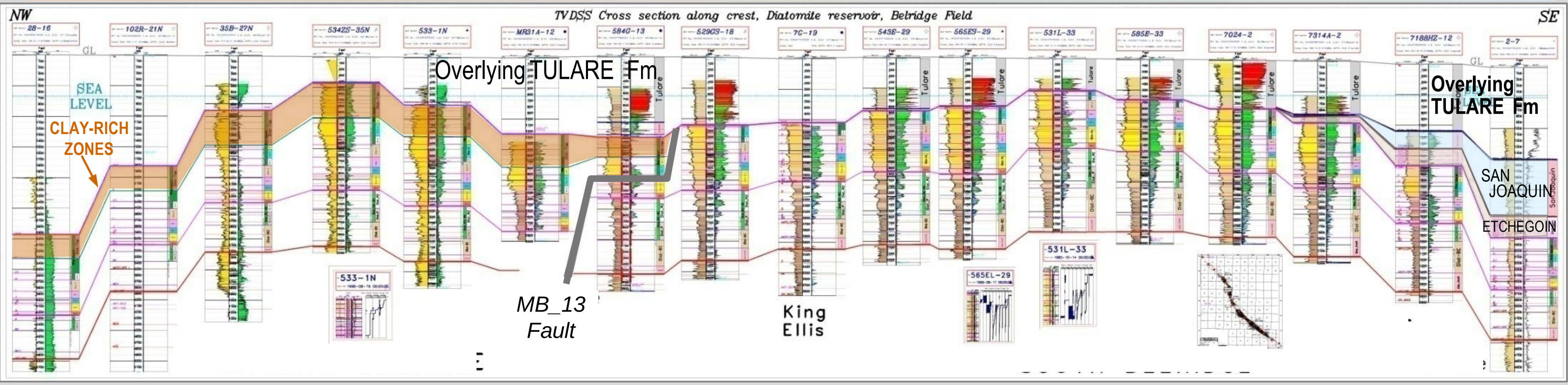


Each of the 9 production intervals (between DIAT & M2 markers) used for volumetrics and injection conformance has one or more major depositional cycles

Cross Section along the Crest, Belridge Field

NW
15 miles along crest of structure
SE

NW Nose | North Belridge | Middle Belridge | South Belridge: North Grande, South Grande, Del Sur | SE Nose Del Sur Nose

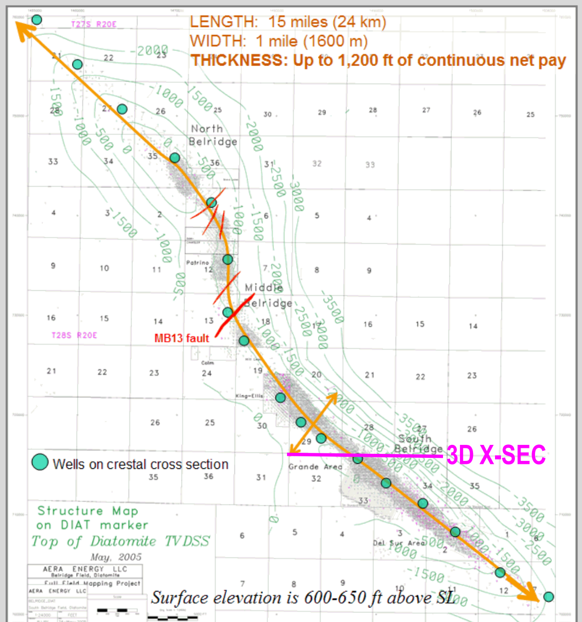


The “clay rich” zones A-E (shown in brown) in the upper Opal A exist in North Belridge and along the flanks.

These zones are preserved by down-faulting north of the MB-13 fault, and removed by erosion along the crest of the anticline south of Section 12.

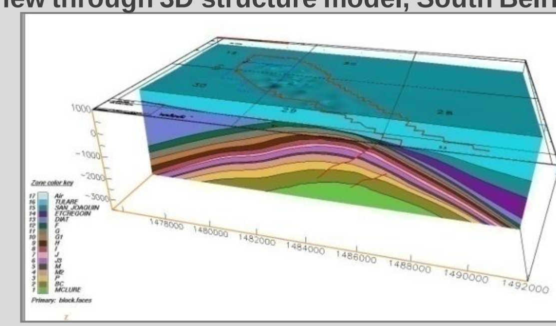
Transition between the Opal A and the diagenetically altered Opal CT:

- around the H & I marker in North Belridge, off the flanks, and on the southeast nose.
- around the M2 marker on the crest in Middle & South Belridge



The Etchegoin and San Joaquin Formations are eroded along the crest but are preserved on the Del Sur (SE) nose and on the flanks.

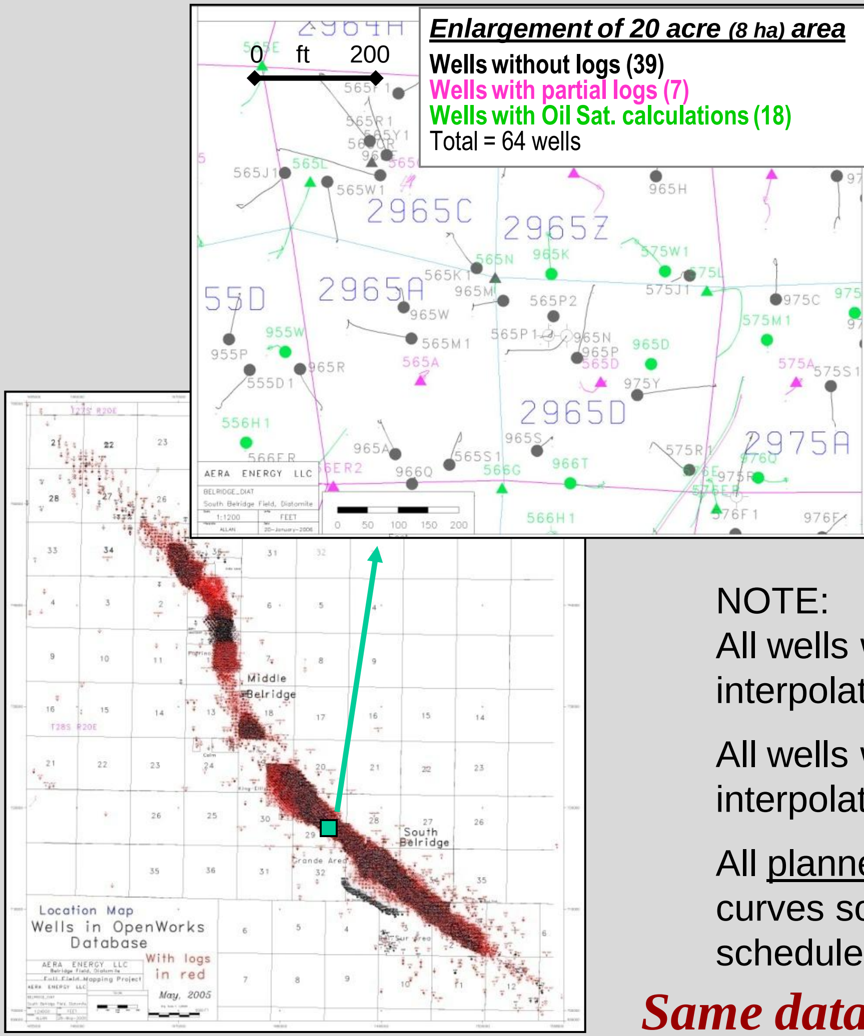
View through 3D structure model, South Belridge



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®).

Data for new wells and directional surveys updated nightly for all wells from enterprise database.



Statistics as of Sept. 2011

14,530 wells in database, (75% are in South Belridge), 700 more each year

6390 wells have sufficient logs to pick markers (typically GR, Rdeep, RHOB)

4660 wells have oil saturation calculations (need Rdeep & RHOB)

500 wells with pressure surveys (RFTs)

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 prior to drilling

Same database used by all Diatomite geoscientists

Reservoir Models & Pseudo-Logs are Essential for Pre-planning & Scheduling Completions

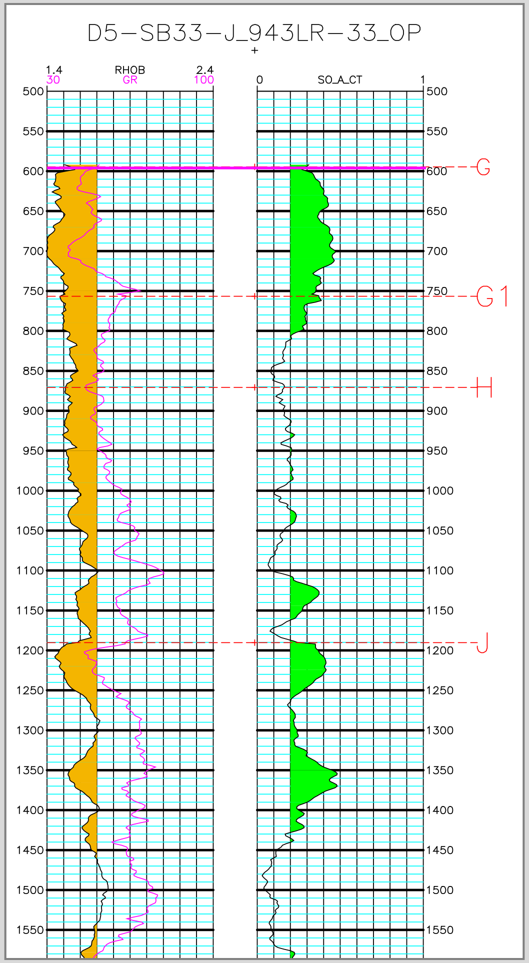
Excellent areal coverage of modern log data is essential for the creation of 3D structure and property models.

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

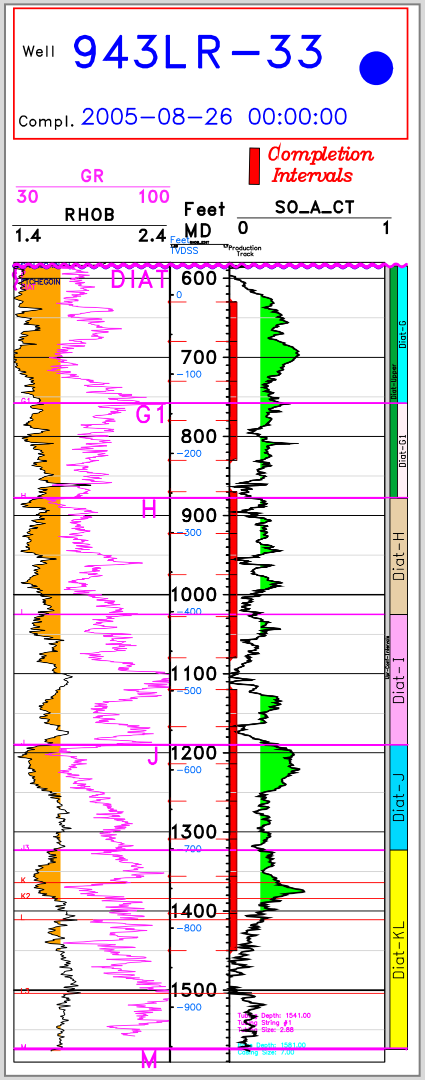
The pseudo-logs are used to pre-plan and schedule completion intervals.

If the well is logged and we get real log data, there is a final review, but predictions are normally very accurate.

May-05: Back-Interpolated Pseudo-Log curves for Planned Well



Aug-05: Logged Well



Hydraulic Fractures are Key to Diatomite Productivity, Pattern Geometry, and Well Spacing

Until the first successful hydraulic fracture in 1977 by Mobil, the only part of the Diatomite that was completed was the uppermost few tens of feet that were commingled with the overlying heavy oil zones of the Tulare Formation as a way to lower oil viscosity so it could be pumped out.

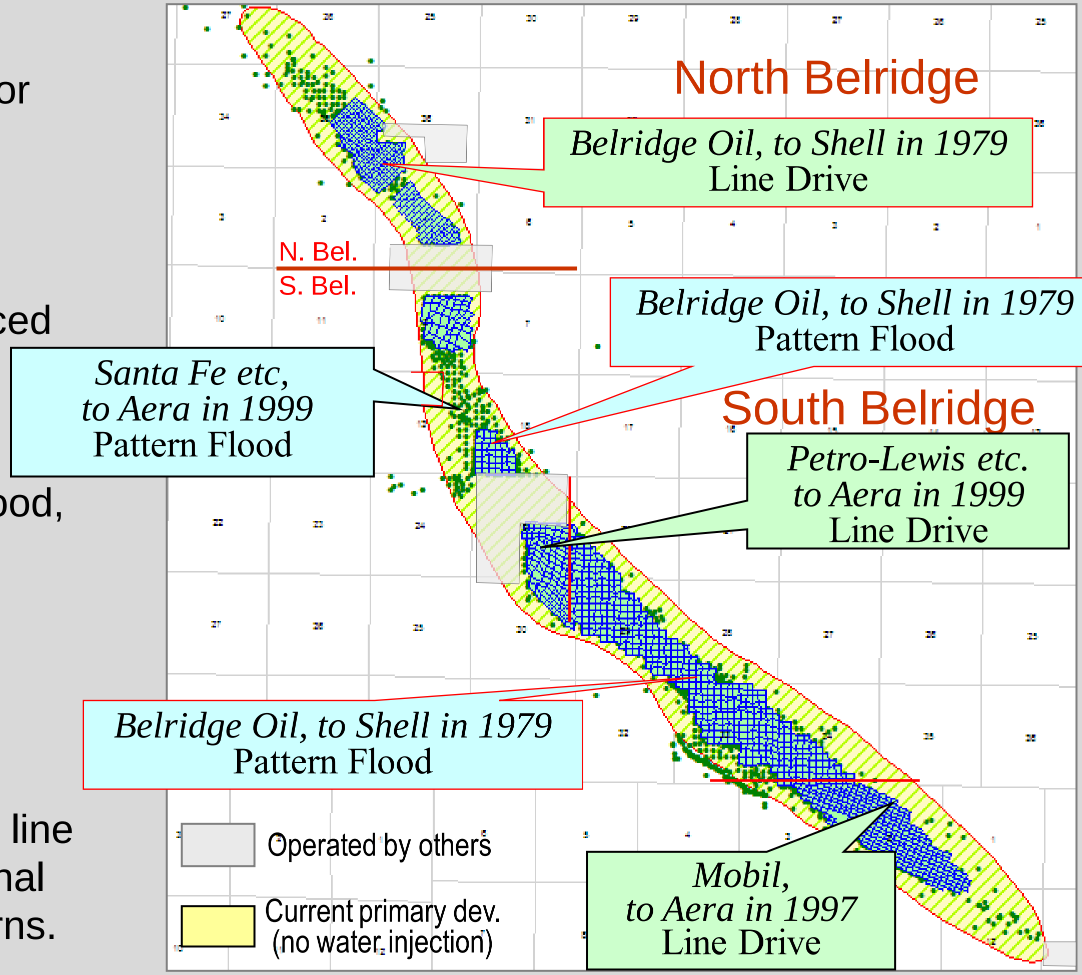
After 1977, sand-propped hydraulic fractures became the completion style for diatomite production wells.

With increased awareness of the importance of fracture azimuth and the ability to measure the geometry of induced fractures, patterns became increasingly complex.

As the diatomite became more understood, development strategies evolved:

1. Primary development
2. Compaction management
3. Infill drilling
4. Waterflood optimization

However, the pattern geometry of either line drive or pattern flood set up by the original operators still controls the current patterns.



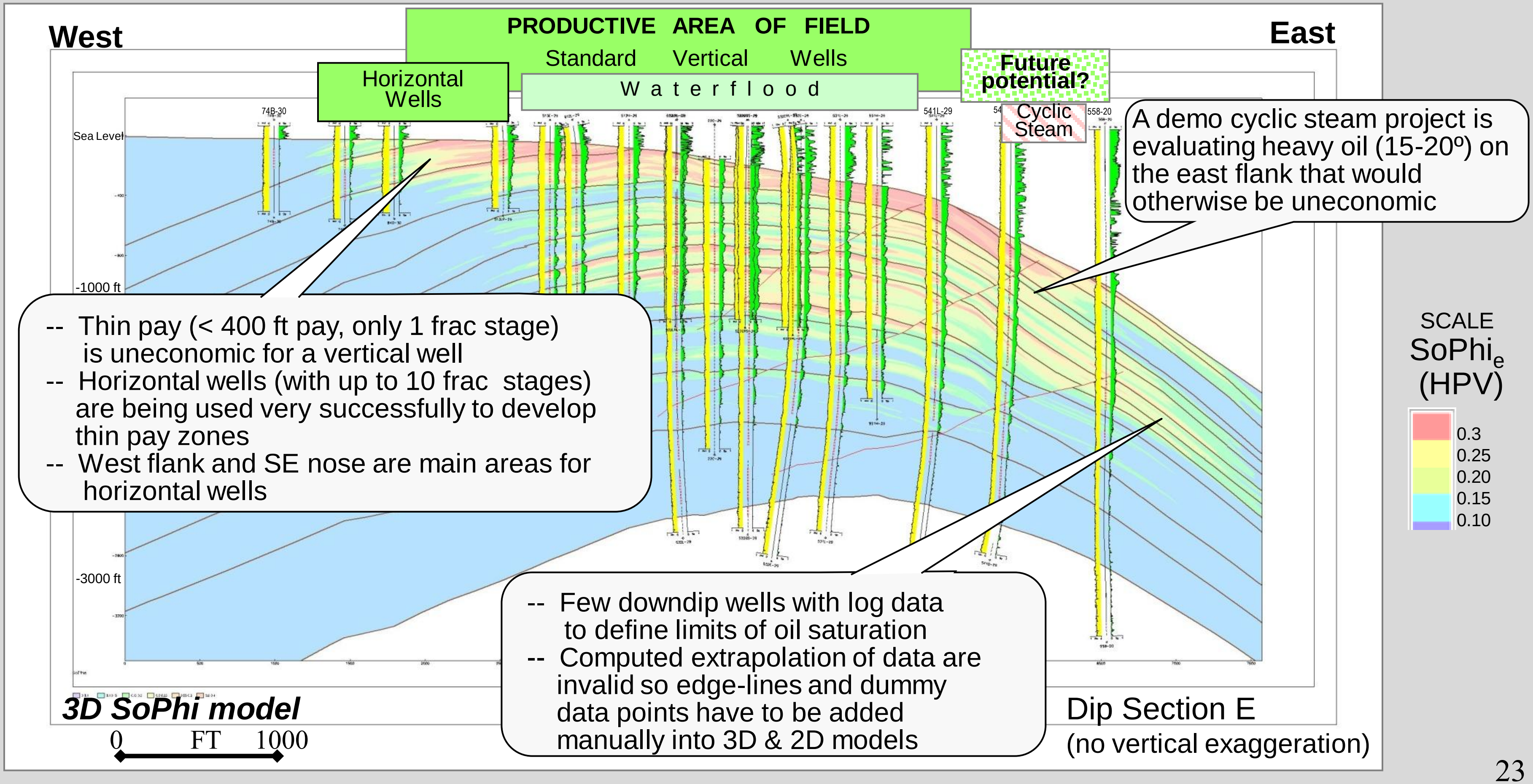
Defining Reservoir Limits is Still Challenging

The flanks and nose areas of the field are the most difficult.

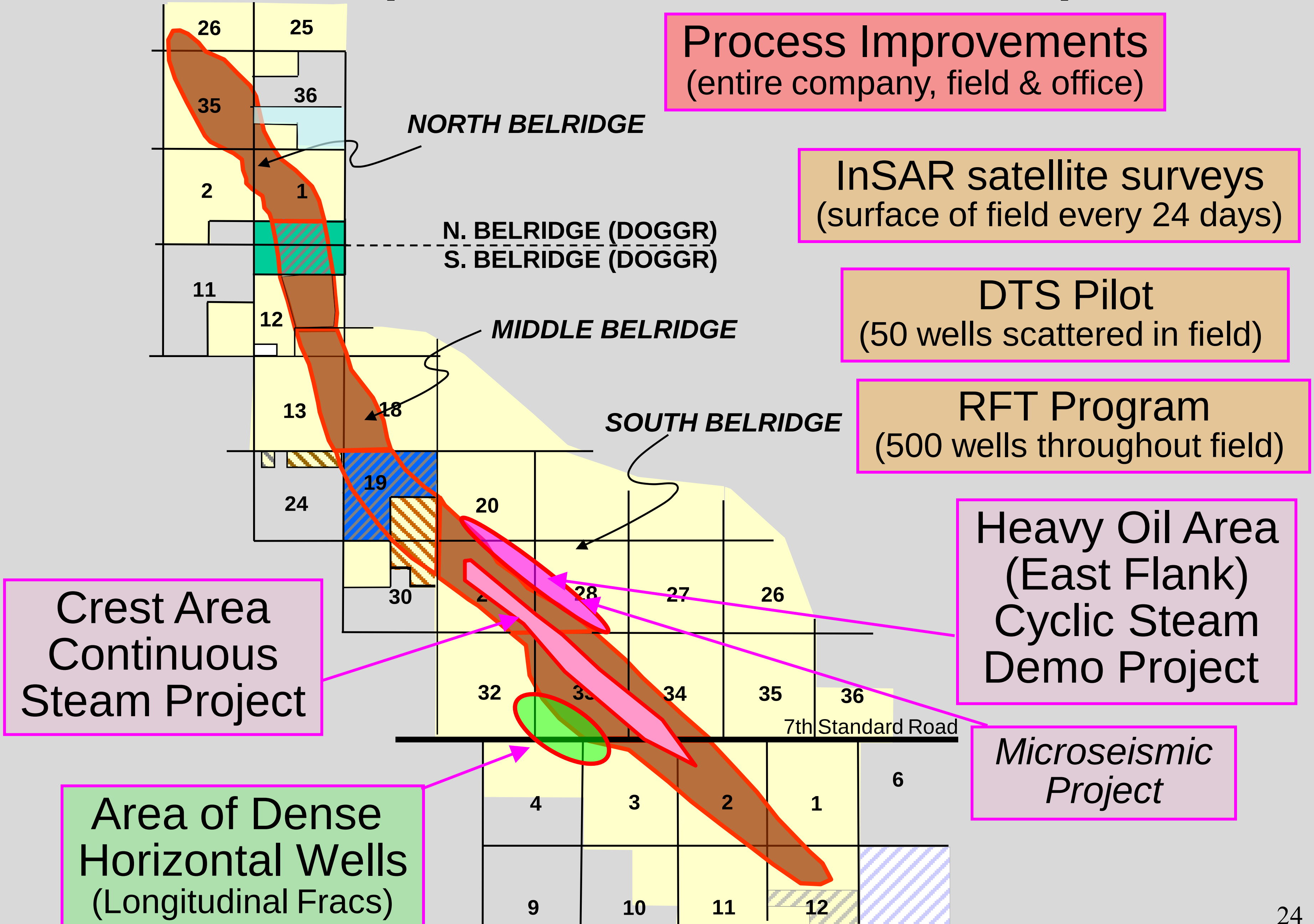
<u>Examples for South Belridge</u>

West flank & SE nose have thin pay but good productivity, especially from horizontal wells

East flank has thick pay but poor productivity due to lower gravity (more viscous) oil

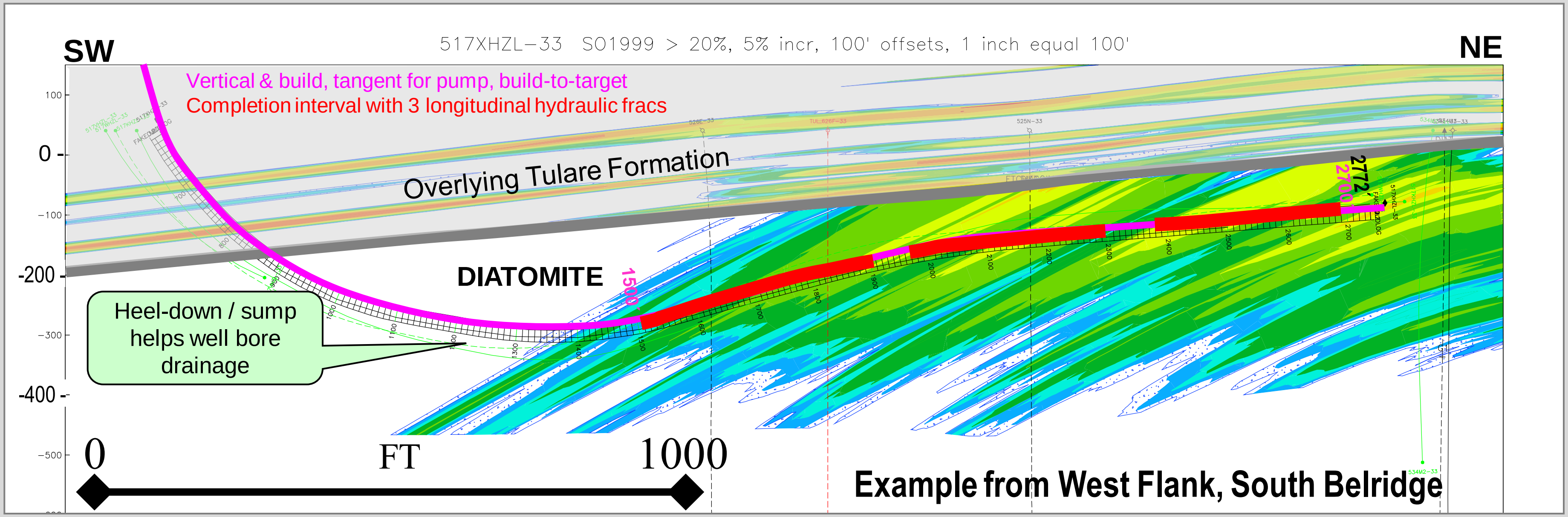


Current Operations and New Techniques



Horizontal Wells 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)

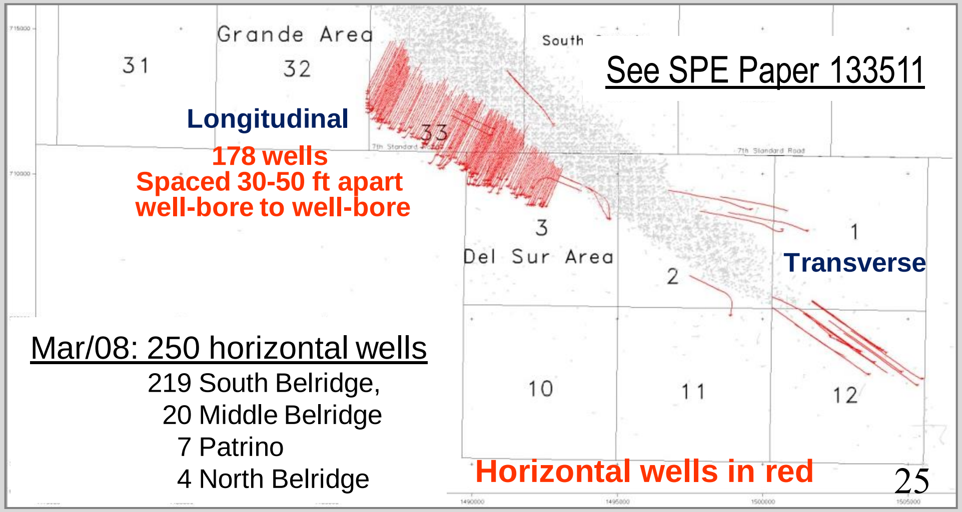


NOTE:

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

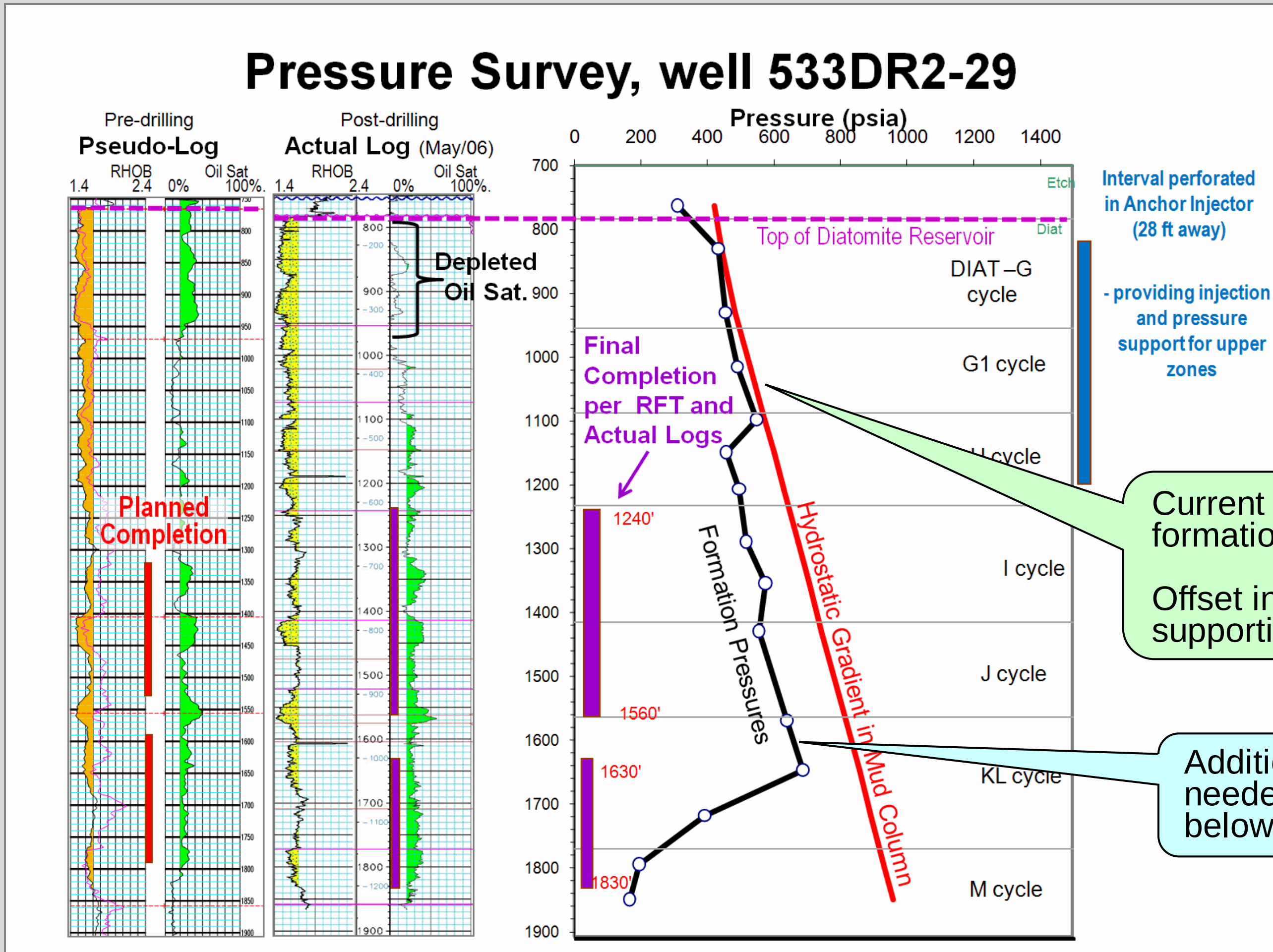
The first horizontal wells in the Diatomites at Belridge were drilled by Mobil in the nose of the Del Sur area and aligned NW/SE, parallel to the anticline axis. They have transverse hydraulic fractures.

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.



Formation Pressures Guide Completions

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



Interval perforated in Anchor Injector (28 ft away)

- providing injection and pressure support for upper zones

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

See SPE Paper 144128

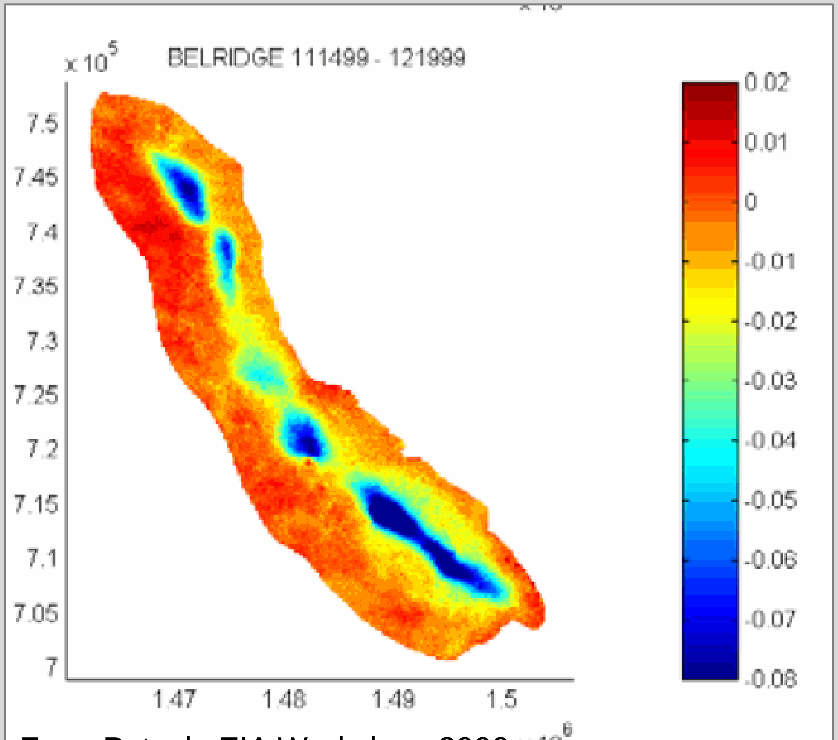
Advantages of Multi-String Injectors:
- -- able to control and measure where injection water goes
- -- used along axis of field where pay is thickest (3-5 frac stages)
- -- used when need for injection conformance is greatest

InSAR measures Surface Subsidence

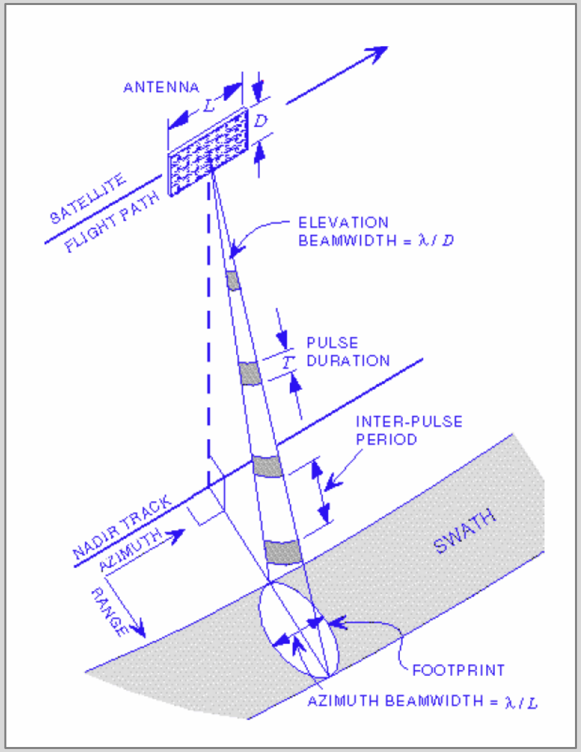
The diatomite reservoir is very weak and will compact without adequate pressure support. This compaction causes subsidence of the ground surface and also ‘dog-legs’ and eventually shearing of the well bores.

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

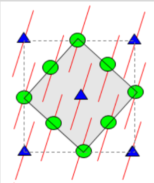
Satellites gather data every 24 days and comparisons of surface elevation with previous months are used to monitor conformance of injection and production across the field.



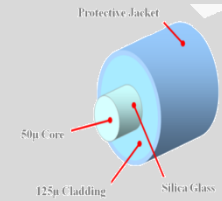
From Patsek, EIA Workshop, 2000



DTS Used to Measure Water Injection Profile



See SPE Paper 144116



Stop Injection

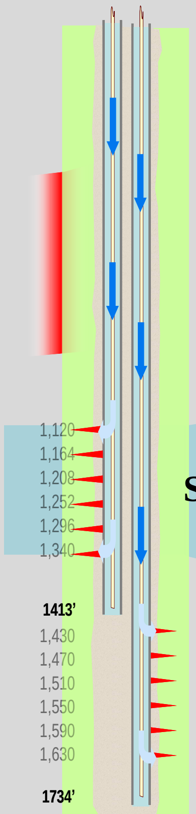
Resume Injection

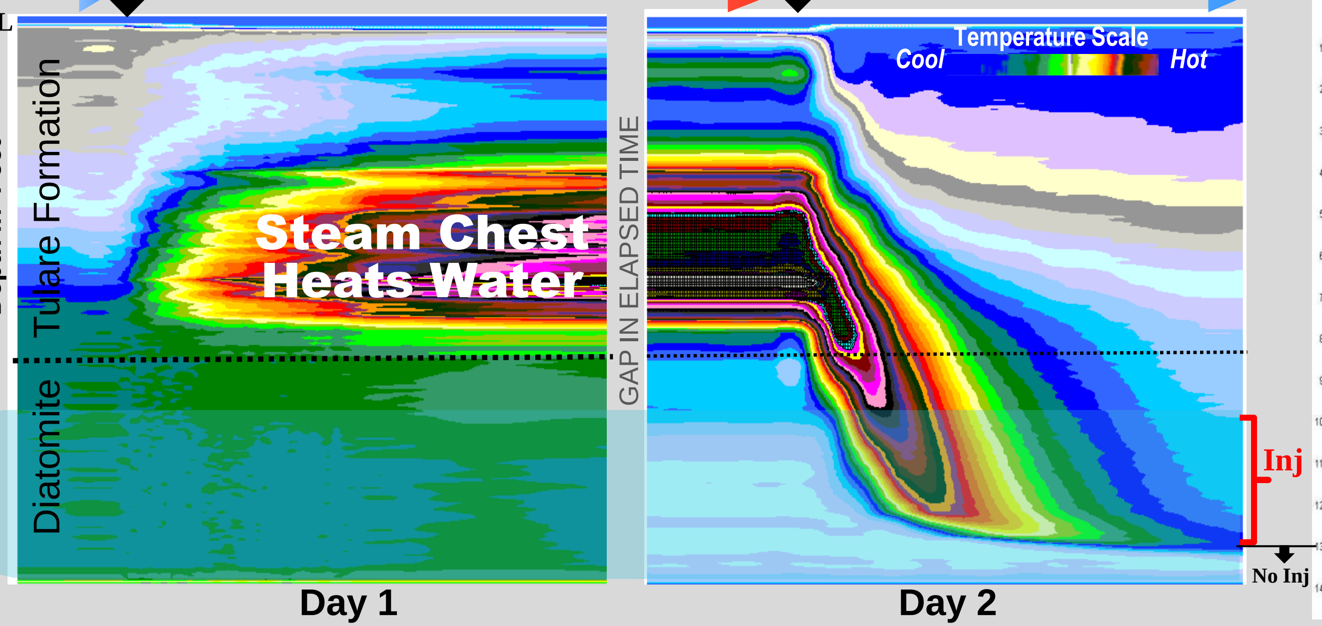
Inject

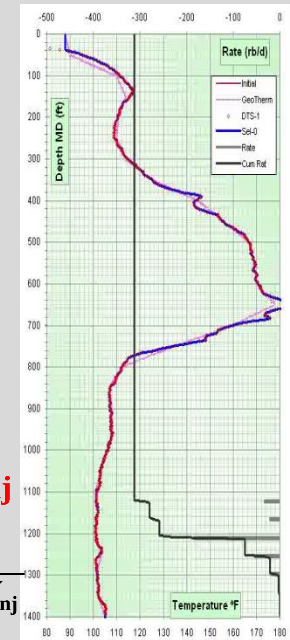
Warm-Back
(shut in to generate tracer of hot water)

Constant Injection Rate

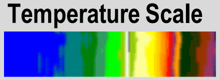
Well 548LR2-34



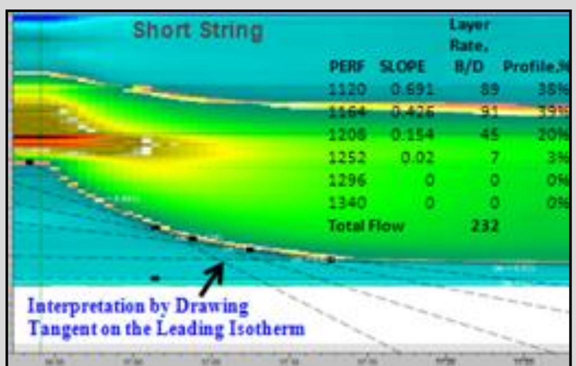




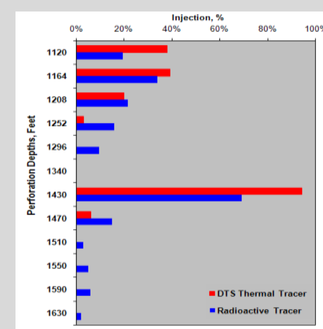
Temperature Scale

Cool  Hot

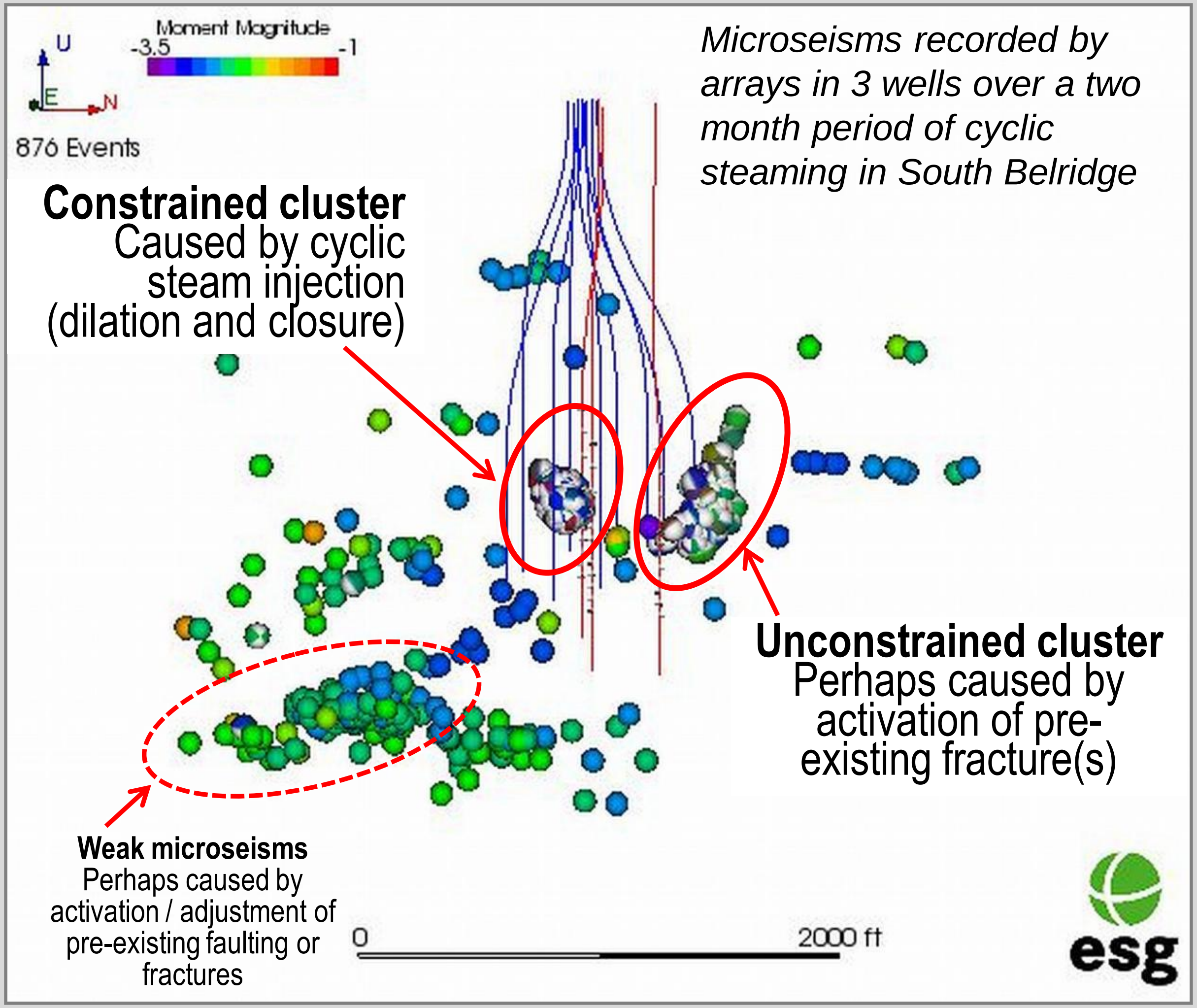
Interpretation of DTS Profile



DTS vs. RAT Profile



Active Reservoir Monitoring



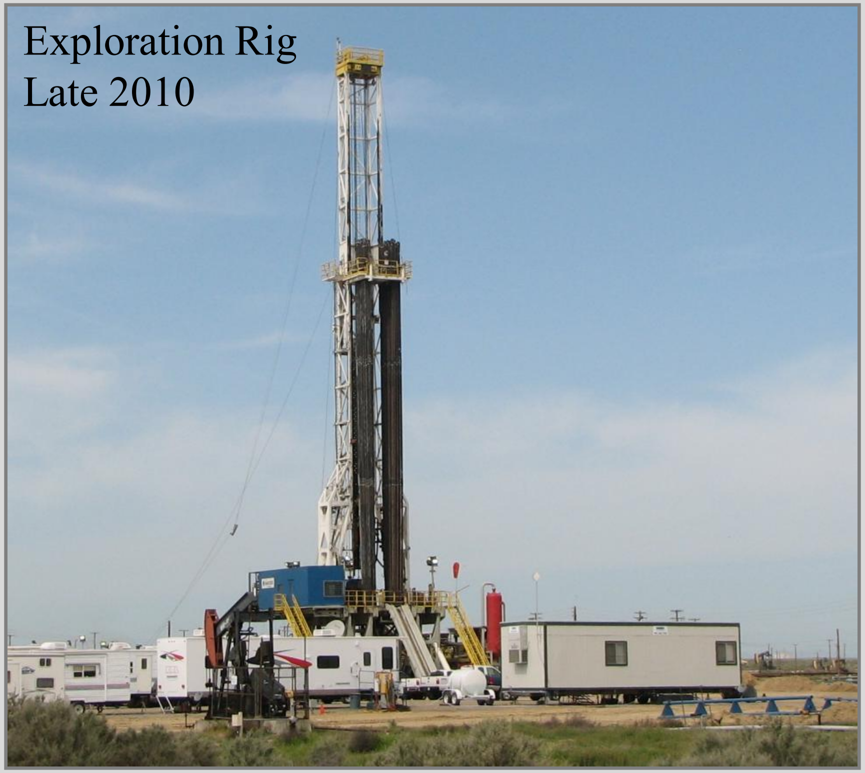
Cross-well Tomography

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

Microseismic is being used to monitor fracture growth and location during steaming cycles.

LOOKING TOWARDS A BRIGHT 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 reservoirs will sustain the field for many more decades.

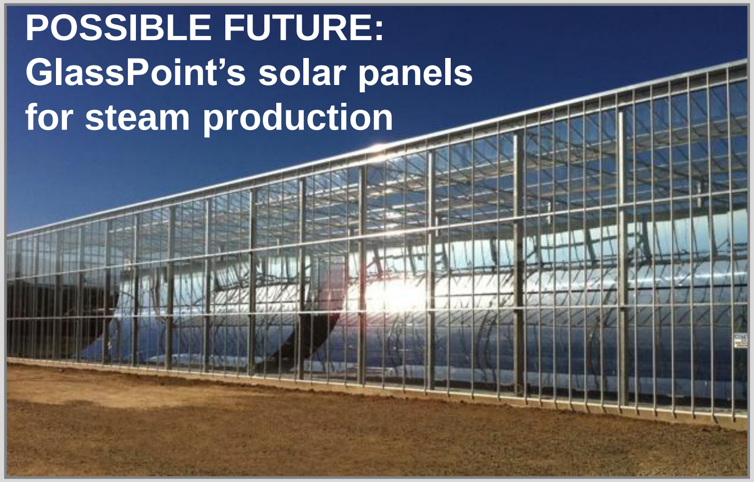

Exploration Rig
Late 2010

There is also the 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 heavy oil reservoirs in the Tulare Formation and in the Diatomite on the east flank.

If steam is used, it needs to be made at a cost that is competitive with current technology that uses natural gas . . .



Minimizing Surface Impact

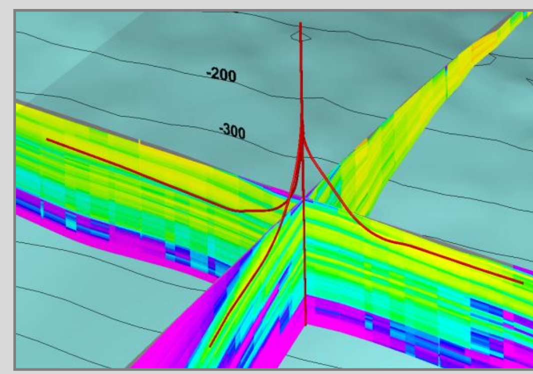
The surface of the field is the most crowded oil field in the world.

Tight well spacing (down to less than 30 ft [9 m]) in many areas coupled with surface piping (flow lines, etc.) and overhead electric lines cause many problems.

Possible solutions include horizontal wells that are spudded away from the field, wells with multiple laterals, and pad drilling.

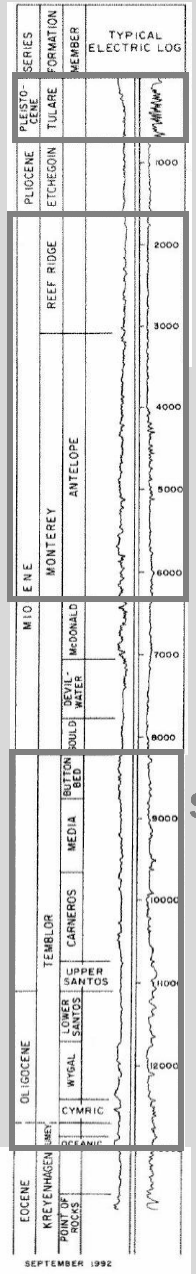
Drilling multiple wells with minimum surface impact

Possible redevelopment by multilateral horizontal wells



AERA

The Distant Future for the Belridge Field



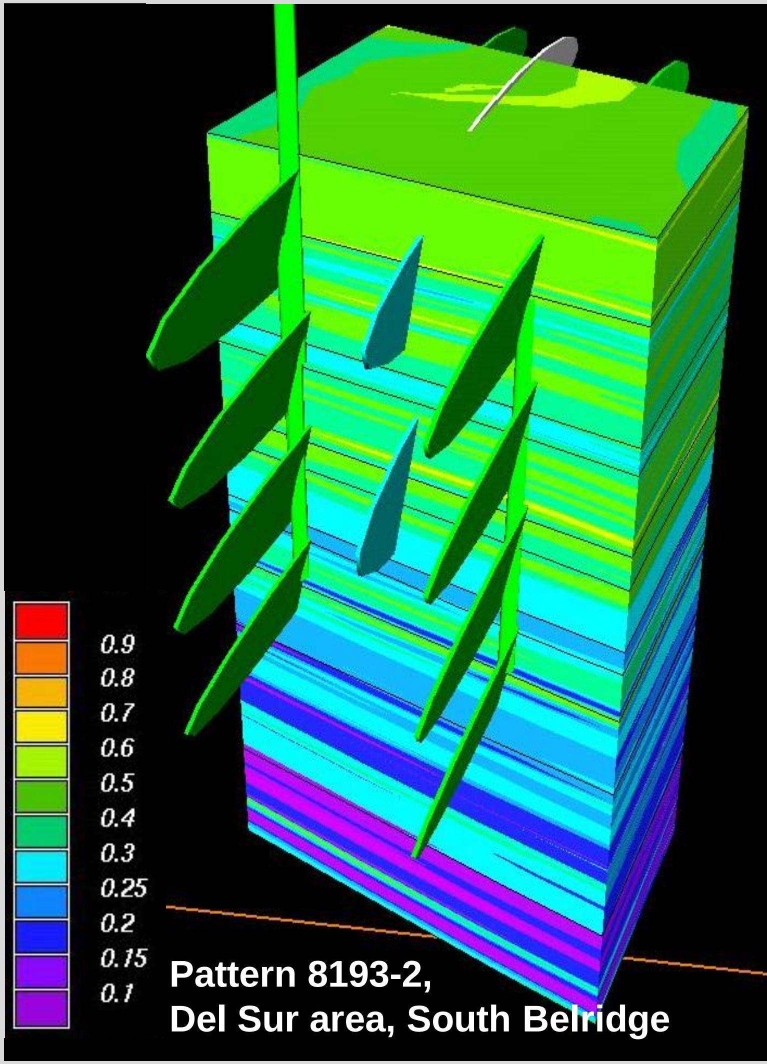
TULARE

DIATOMITE

SUB-MONTEREY

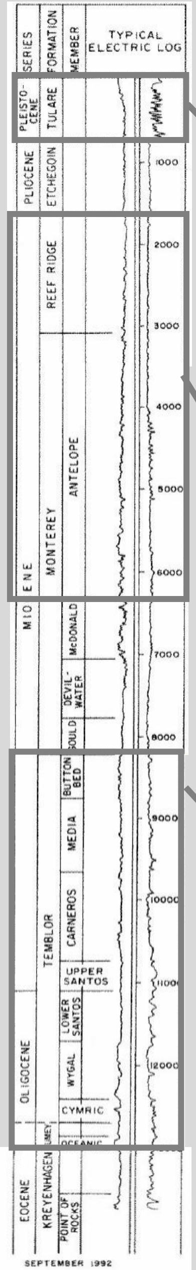
Final stage (in 2111..):
Recovery of heat from steamed reservoirs via low temperature geothermal projects

Challenges until then:
How to apply modern technology to a giant onshore field with stripper production rates per well but huge remaining oil volumes.



Frac Planes Displayed in 3D Cube from Oil Saturation Model, Diatomite Reservoir

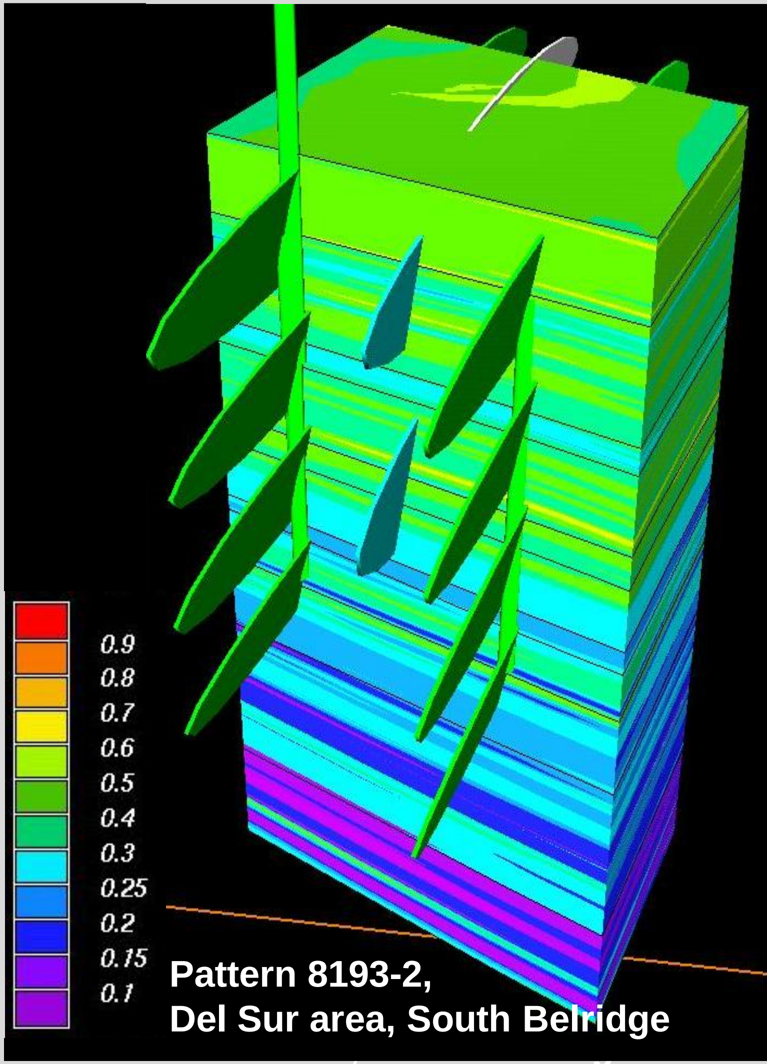
Summary for Belridge Field



Tulare Formation (Pleistocene)
- Trap: updip pinchout, downdip structure
- Fluvio-deltaic & lacustrine sands
- Heavy oil that needs to be steamed
- Slotted liner & gravel packs
- May/11 = 29,275 BOPD (*Aera = 24,470*)

Diatomite (Miocene Monterey)
- Trap: long narrow anticline
- Cyclic layers of diatomite
- Light oil via primary, waterflood & steam
- Sand-propped hydraulic fractures
- May/11= 49,068 BOPD, 25.0 MMCFGD
  (*Aera = 45,686 BOPD, 20.6 MCFGD*)

Sub-Monterey Formations (Miocene to Eocene)
- Trap: anticline
- Marine shelf sands
- Gas and light oil, still on primary
- Shot and jet perforations
- May/11 = 5.3 MMCFGD,182 BOPD
  (*all Aera*)

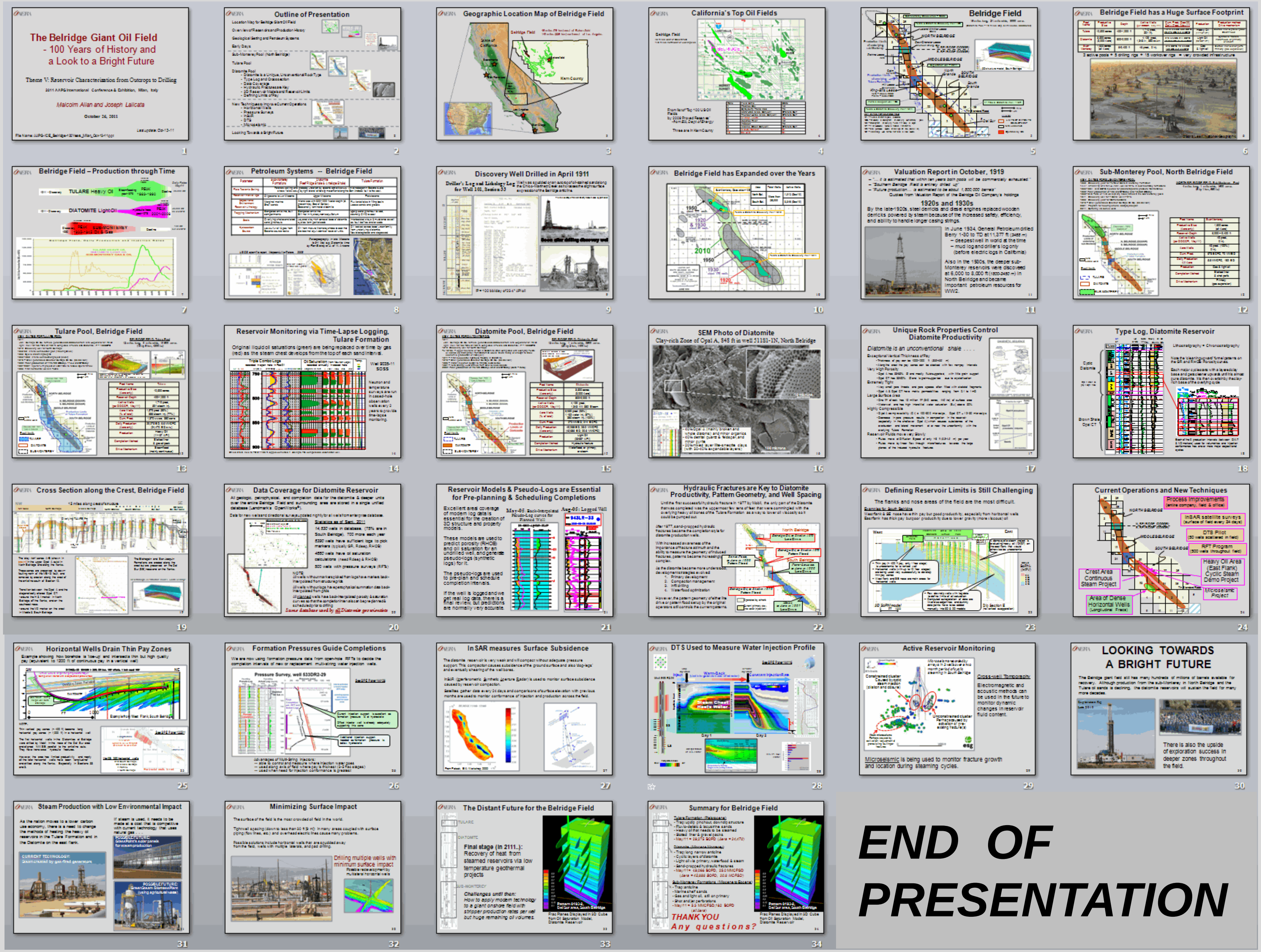


Frac Planes Displayed in 3D Cube from Oil Saturation Model, Diatomite Reservoir

THANK YOU

Any questions?

THUMBNAILS OF SLIDES PRESENTED



END OF PRESENTATION

Abstract and Biographies

The Belridge Giant Oil Field - 100 Years of History and a Look to a Bright Future

Allan, Malcolm E.[1]; Lalicata, Joseph J.[1] (1) Aera Energy LLC, Bakersfield, CA.

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 covers an area roughly 22 miles long and 2.5 miles wide (35 by 4 km). It has three totally separate and distinctly different producing zones: Pleistocene shallow fluviodeltaic sands producing heavy oil via steamflood; Miocene deepwater diatomite layers producing light oil via hydraulic fractures and with water injection for pressure maintenance; and Oligocene to lower Miocene marine sandstones producing gas and light oil via gas expansion. Each of the vertically stacked zones requires different work models and different completion strategies to sustain production.

Although down from its peak of 160,000 BOE per day in 1986, the field currently produces 80,500 BOE per day which makes it one of the largest onshore fields in the USA. Since discovery via a surface oil seep, over 25,000 wells have been drilled although only 6,000 producers and 2,400 injectors are still active. However, new insights to the reservoirs have resulted in about 600 new wells being drilled and completed in each of the past few years.

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 as close as 30 ft (9 m) apart and completed with sand-propped hydraulic fracs. Continuing to successfully develop and produce the reservoirs requires applying conventional technologies and techniques in new and unconventional ways. Fit-for-purpose reservoir characterization studies in 2D and 3D, coupled with standardized workflows for modeling and documentation, build upon past fundamental knowledge using state-of-the-art software and databases to handle the immense quantity of data.

At the start of the 21st century the field is gearing up for many more years of activity with expansion of steam drives in the oil sands and in the diatomite shales, installation of a large microseismic array, distributed temperature sensing to monitor water movement in water injection wells, and regular InSAR surveys to monitor ground movements. Exploration wells are also being drilled for seismic targets that are well below the current producing zones.

AAPG Search and Discovery Article #90135©2011 AAPG International Conference and Exhibition, Milan, Italy, 23-26 October 2011

Malcolm E. Allan is a reservoir management geologist with Aera Energy LLC. He began his career working internationally in Africa and the North Sea for Texaco before joining Occidental Petroleum to work in South America (Peru, Colombia), Middle East, and North Africa. After a few years with a small Canadian company in Egypt, Colombia, and Ecuador, he returned to California. Since then Malcolm has worked mainly on two of the giant oil fields in California: Belridge and Elk Hills. He is currently working for Aera Energy LLC on the diatomite reservoirs at the Belridge Field, doing reservoir characterization and field studies. He holds a B.Sc. degree in Geology and an M.Sc. in Petroleum Geology from Imperial College, University of London. He is a California state-registered geologist and a member of the AAPG, SPE, and SPWLA.

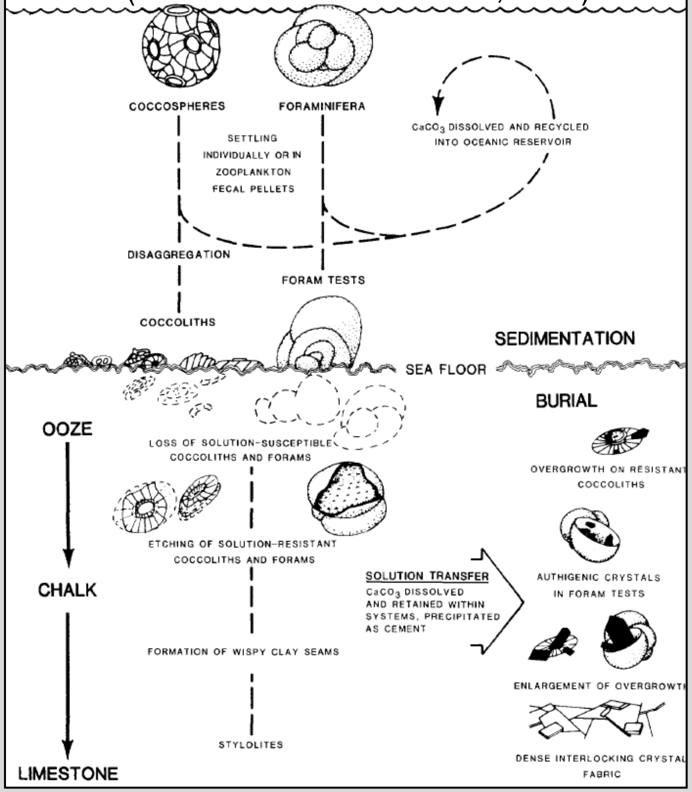
Joseph J. Lalicata is a geologist with Aera Energy LLC. He is involved in reservoir characterization studies, geocellular modeling, and reservoir development for the siliceous shale reservoirs at Belridge and Lost Hills fields, California. Prior to working at Aera, he worked on field studies of the turbidite reservoirs of the Wilmington Field (Los Angeles, California). He holds a B.Sc. in Geology from Binghamton University, New York and an M.Sc. in Geology from University of California, Santa Barbara. He is a member of the AAPG, SPE, and SPWLA.

North Sea Chalk - A Close Analog for Diatomite

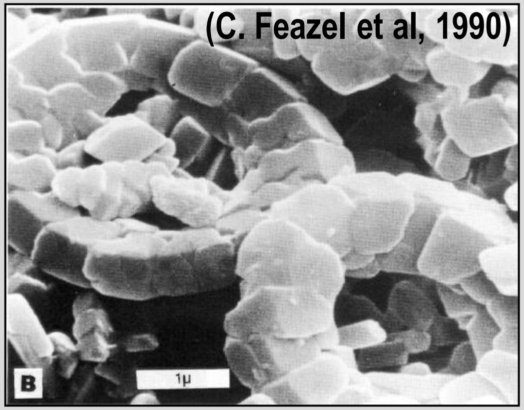
COMPARISON TABLE

Reservoir	Ekofisk Chalk ($CaCo_3$)	Belridge Diatomite (SiO_2)
Pay Thickness	200 to 900 ft (175-275 m) Net : Gross Ratio = 0.7	200 in flanks to 1200 ft on crest (175-400 m) Net : Gross Ratio = 0.7 to 1.0
Porosity	25 to 45% Porosity preserved due to deposition on structural highs, overpressuring of the reservoir, and early migration of hydrocarbons into the structure.	55-65% in Opal A (mostly fluid-supported, with little grain support). 35-50% in deeper Opal CT (grain-supported due to crystallization).
Permeability	Matrix permeabilities range from 1 to 10 mD. Reservoir permeabilities range from 1 to 100 mD due to high intensity of natural fractures plus fractures caused by compaction and shear.	Matrix permeabilities range from 0.1 to 1.0 mD. Reservoir permeabilities range from 1 to 10 mD due to natural fracturing.
Compressibility	Average of 100 microsips.	± 100-300 microsips in Opal A, ± 10-30 microsips in Opal CT
Compaction	North Sea chalk reservoirs compacted due to dissolution / reprecipitation when flooding with cold seawater started, and due to pore pressure decreases caused by net fluid withdrawal. Result is subsidence at the sea bed unless reservoir pressure is maintained.	Decrease in pore pressure results in compaction in the reservoir – especially in the shallower and weaker Opal – due to fragmentation/collapse of the diatoms. Compaction causes surface subsidence unless reservoir pressure is maintained.
Remedies	Platforms were raised 20 ft (6 m) in August, 1987.	Waterflooding and conformance monitoring.

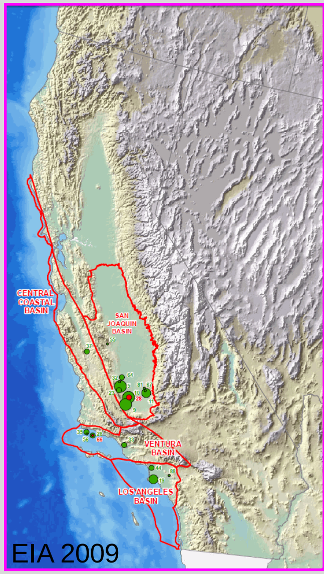
(Van den Bark and Thomas, 1980)



(C. Feazel et al, 1990)



California Shales compared to other US Shales



Map from '*Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays*' by US EAI (July/11)

Table data from various sources

Name of Shale Play	Monterey / Santos / Temblor	Bakken Shale	Eagle Ford Shale	Marcellus Shale	Barnett Shale
Depth (ft)	3,500 to 16,000'	4,500 to 8,000'	7,000 to 14,000'	4,000 to 9,000'	5,000 to 8,000'
Thickness (ft)	500 to 3,500'	20 to 100'	75 to 300'	<10 to 300'	100 to 500'
Porosity (%)	5 to 30%	3 to 12%	3 to 15%	2 to 9%	1 to 9%
Permeability (mD)	<0.0001 to 2	0.05 to 0.5	<0.0001 to 0.003	0.00001 to 0.01	0.00009 to 0.001
TOC (%)	0.1 to 12%	2 to 18%	0.6 to 7%	0.1 to 13%	4 to 8%
Technically Recoverable Resource	15.4 billion BO	3.6 billion BO	3.4 billion BO 21 TCF Gas	410 TCF Gas	3.6 billion BO 434 TCF Gas