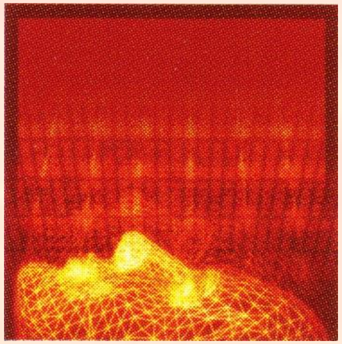

AKD Professional Solutions Inc.
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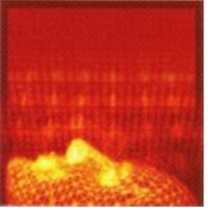
Mature Field Evaluation and Redevelopment

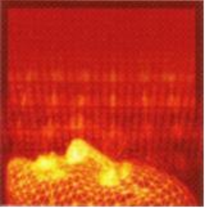
1-day Training covering an overview, case histories and lessons

Sharma Dronamraju, MS, MBA, PG

AKD Professional Solutions, Inc.

GeoIndia 2022: 5th South Asian Petroleum Conference and Exhibition, Jaipur, India



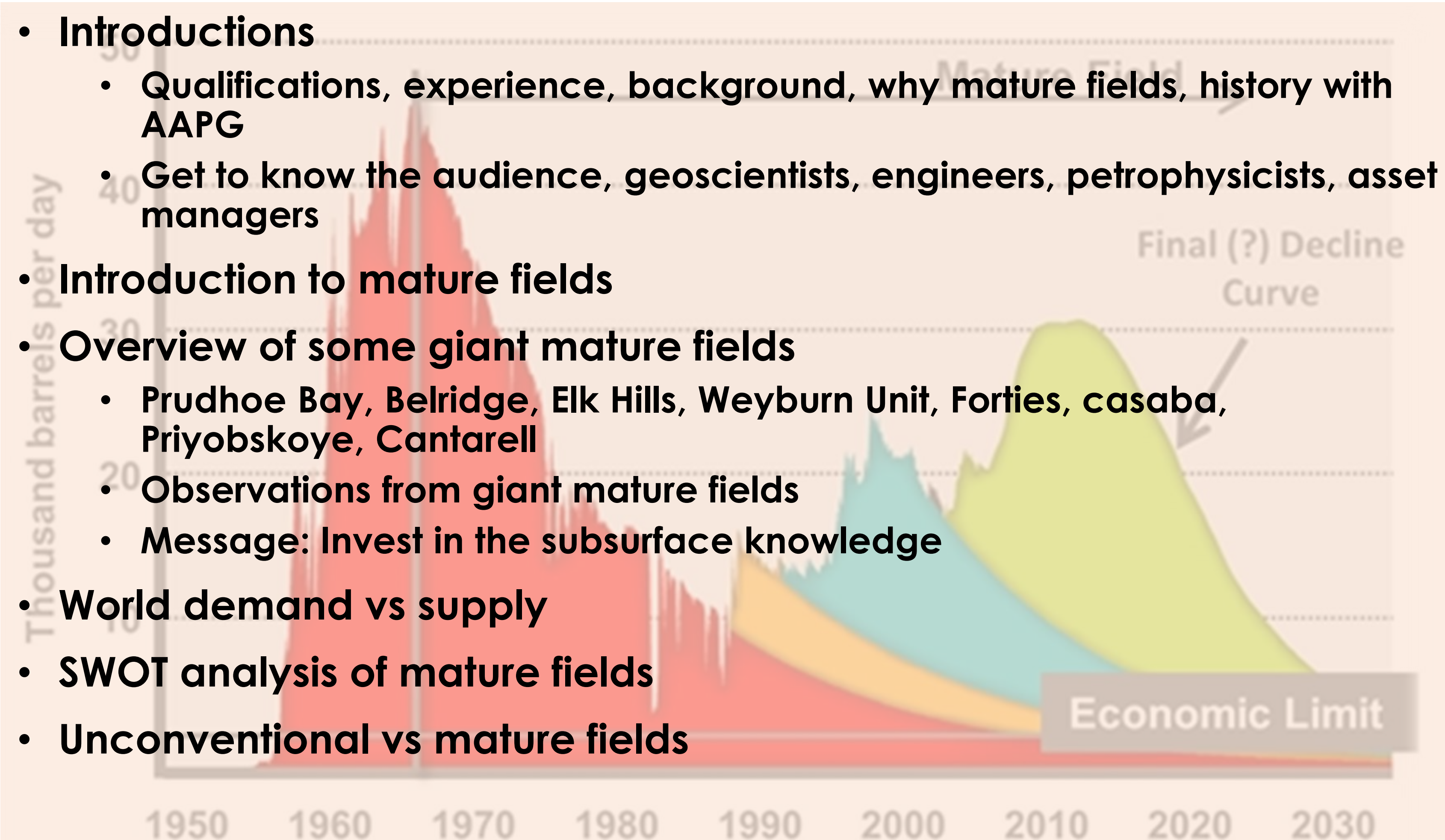


Course Format

Day	Content	Outcome	Tools
Day 1	• Introduction to Mature fields, economics, • Examples and case histories from GoM, North America, Middle East, South China Sea, and Argentina, lessons learned • Use of 3D seismic • Use of High-resolution Sequence Stratigraphy • Use of Static and Dynamic modeling. • Conclusions	• Lessons from case histories • Identification of problem • Address near-term production • Address long-term production and possible field extensions	Presentations and cases Case posters

Mature Fields: Introduction

- **Introductions**
  - **Qualifications, experience, background, why mature fields, history with AAPG**
  - **Get to know the audience, geoscientists, engineers, petrophysicists, asset managers**
- **Introduction to mature fields**
- **Overview of some giant mature fields**
  - **Prudhoe Bay, Belridge, Elk Hills, Weyburn Unit, Forties, casaba, Priyobskoye, Cantarell**
  - **Observations from giant mature fields**
  - **Message: Invest in the subsurface knowledge**
- **World demand vs supply**
- **SWOT analysis of mature fields**
- **Unconventional vs mature fields**



Petroleum Geologist

This what my parents think I do

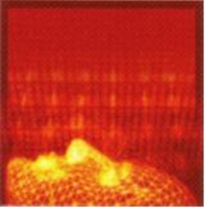
What my friends think I do

What society thinks I do

What my wife thinks I do

What I think I do

What I really do



About Myself

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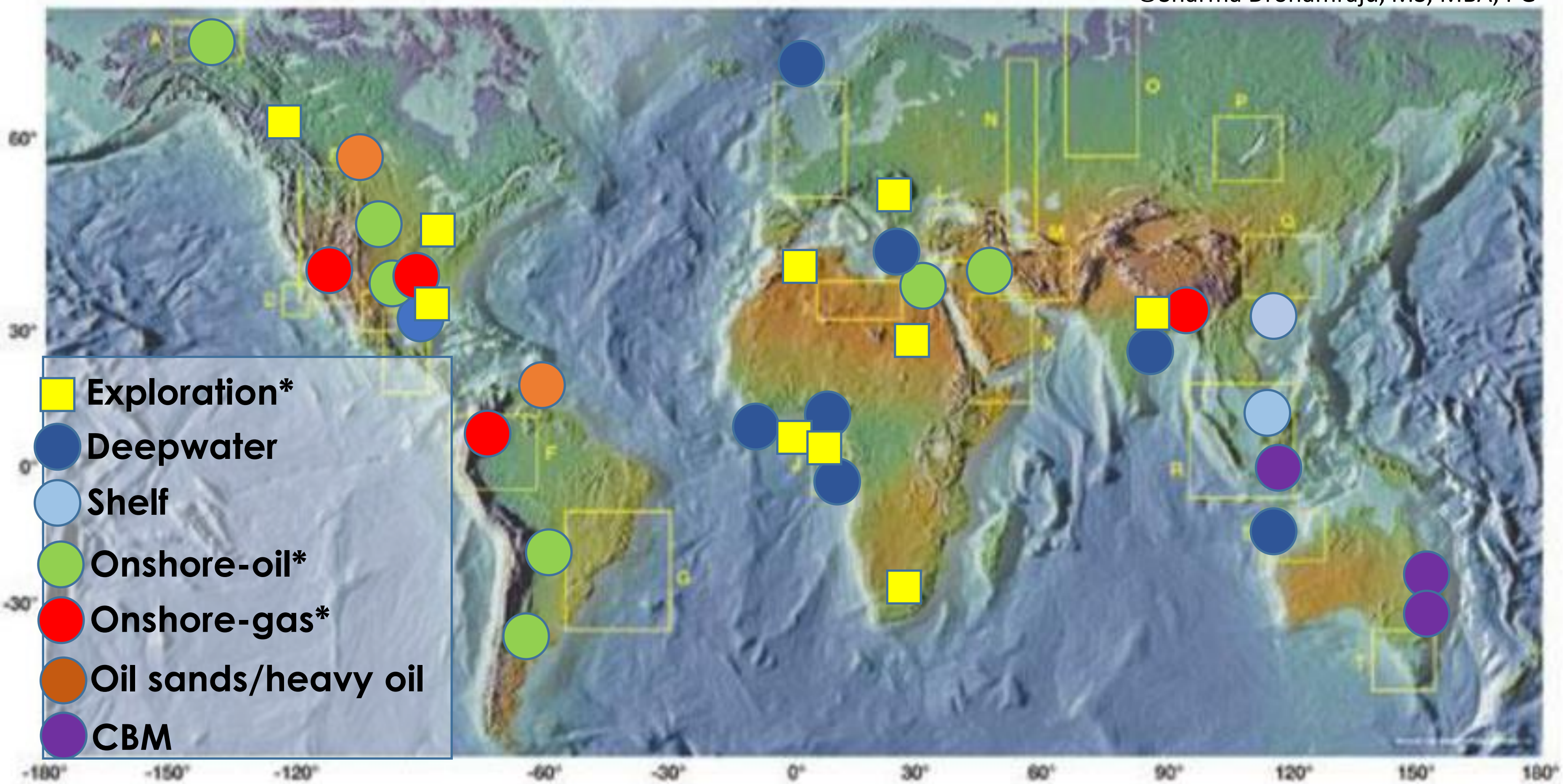
- **Sharma Dronamraju**
  - **MSc Applied Geology, Indian Institute of Technology**
  - **MS Geology, Texas A&M University**
  - **MBA, Rice University**
  - **MIT – Professional Program**
- Director, AKD Professional Solutions, Inc.:
  - AKD serves upstream oil and gas industry, worldwide in advising operating companies and independents in field appraisals, reservoir modeling, planning, field development, basin research& Intelligence, exploration, prospect maturation, A&D due diligence.
  - Oil fields and basins worked: US Onshore and offshore, GoM, Canada, West Africa (EG, Cameroon, Angola, EG, Nigeria), Argentina, Colombia, Iraq, Egypt, India, Malaysia, Indonesia, and Australia.
- Work History
  - Petrobras America, Marathon Oil, Landmark Graphics/Halliburton, Knowledge Systems, Fugro, ONGC.
  - **Consulting:** Knowledge Reservoir: Shell, Repsol, BP
  - **Teaching and Training:** Petrel/Sequence Stratigraphy/3D seismic: Pemex, Exxon, Shell, Oklahoma State, Bahrain, Kuwait, Malaysia, India
- Affiliations
  - AAPG, SEG, HGS, PG (TBPG #12543)

Oil Fields and Basins Worked

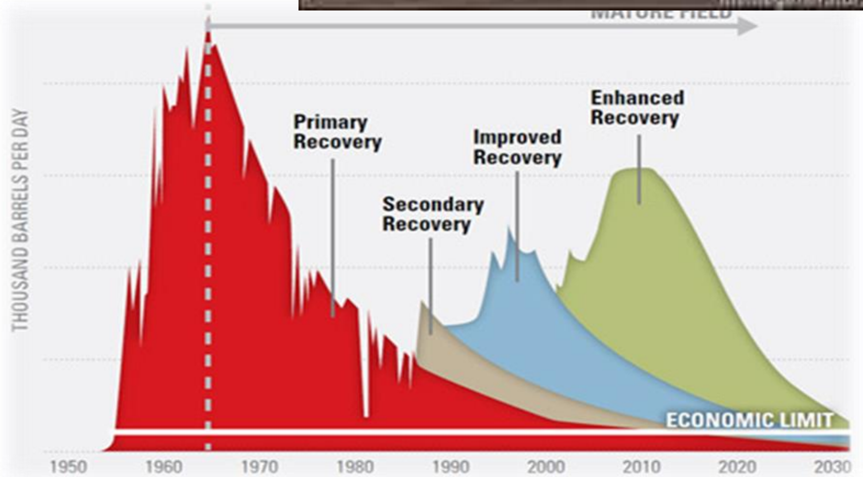


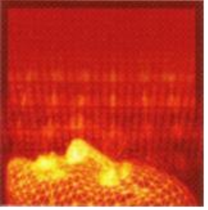
* Includes shale plays

Mature Fields: Introduction

Before Noon

- Mature Field definition and statistics
- Characteristics of mature fields
  - Prudhoe Bay, North Slope, Alaska
  - Belridge Field, San Joaquin basin, CA
  - Elk Hills, San Joaquin Basin, CA
  - Wayburn Unit, Bakken, Canada
  - Forties Field, North Sea, UK
  - Casabe Field, Colombia
  - Priyobskoye Field, Siberia
  - Cantarell Field, Mexico
- Common lessons

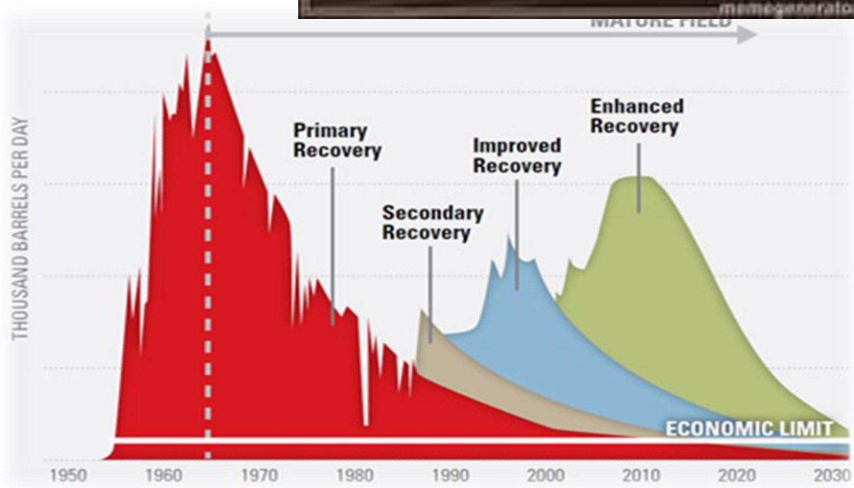




Mature Fields: Introduction

Afternoon

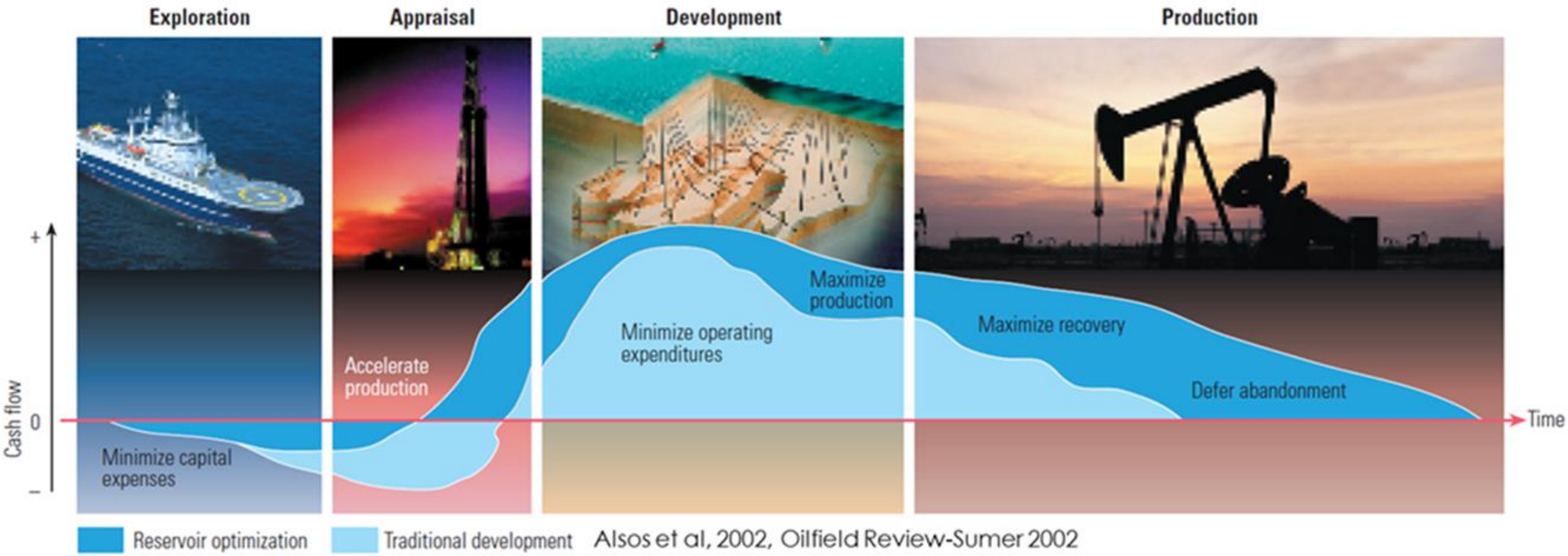
- Review of lessons
- How can a Geologist help?
  - 3D seismic
  - Sequence stratigraphy
  - Reservoir modeling
- Common lessons
- Conclusions



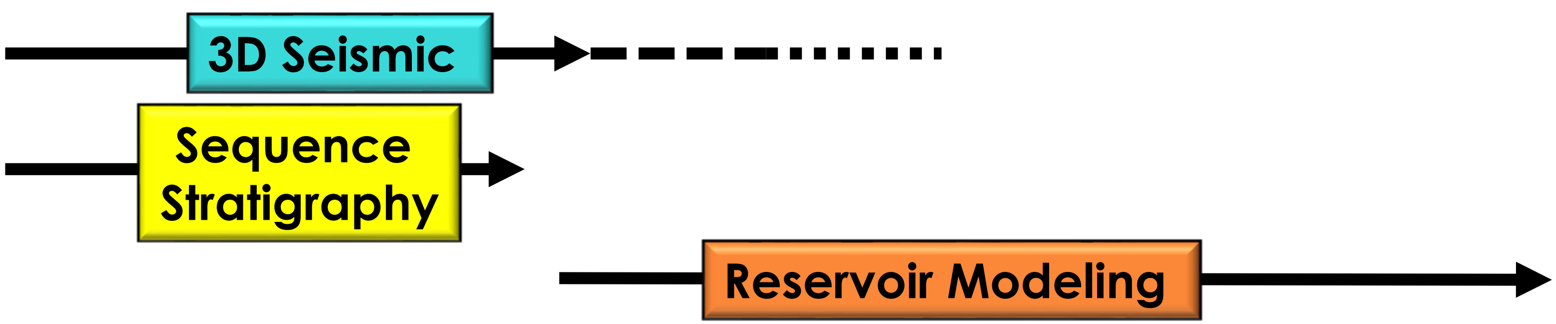
Astronomers vs Astronauts

- **Dr. Grant:**
  I have a theory that there are two kinds of boys. There are those that want to be astronomers, and those that want to be astronauts. The astronomer, or the paleontologist, gets to study these amazing things from a place of complete safety.
- **Erik:**
  But then you never get to go into space.
- **Dr. Grant:**
  Exactly. That's the difference between imagining and seeing: to be able to touch them. And that's... that's all that Billy wanted.

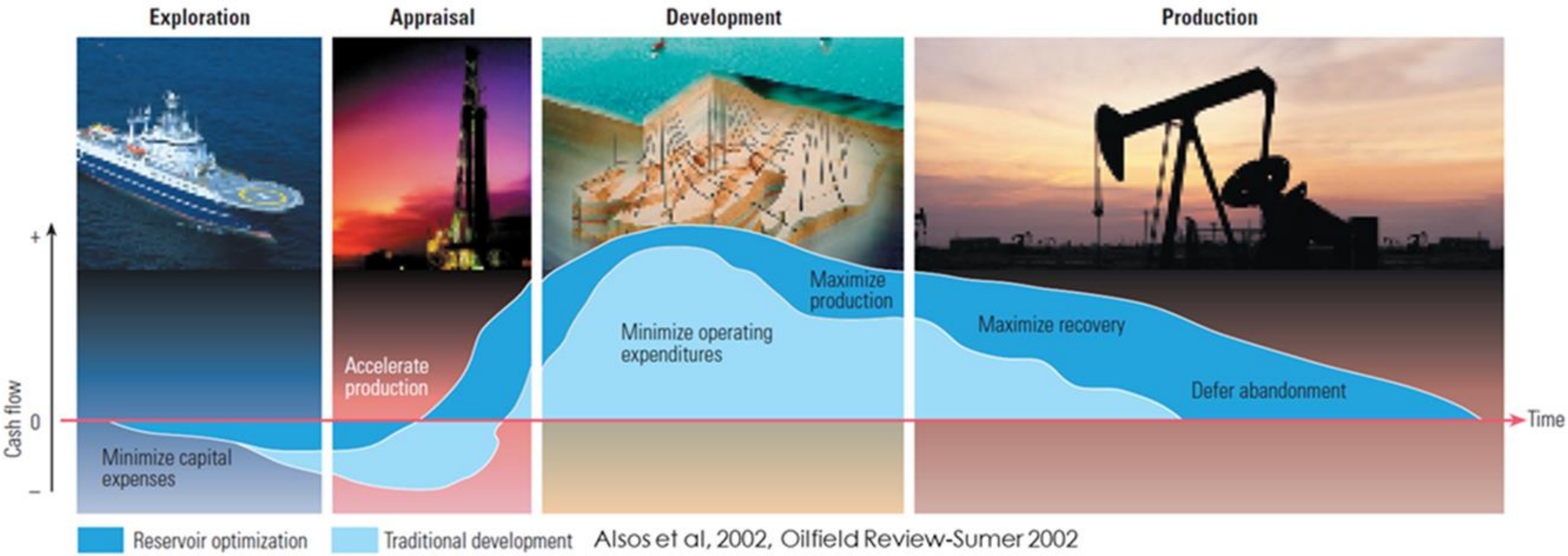
Oil field life cycle



Alsos et al, 2002, Oilfield Review-Sumer 2002



Oil field life cycle

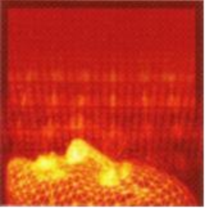


Alsos et al, 2002, Oilfield Review-Sumer 2002

3D Seismic

Sequence Stratigraphy

Reservoir Modeling



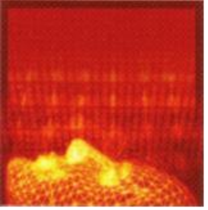
Oil field life cycle

- **Revitalization projects hold the promise of extending the economic limit of an asset years into the future. The infusion of capital for revitalization projects can arrest a steep decline, improve the lifting cost, and preserve the use of infrastructure for future purposes not yet defined.**
- **Preserving the infrastructure can be especially crucial if there is a reasonable probability that future discoveries near the area could benefit from existing processing capabilities.**
- **Lower Risk !**
  - **Low-risk cash flow, which can fund the investigation of new projects and prospects.**
  - **Lower overall project risk can be lower than those of a wildcat.**
  - **Existing data and lower cost of acquiring data**
  - **Data management can be a key factor**
  - **Engineering and geoscience staff already familiar with the asset.**

Mature Fields: Introduction

- **Introduction to mature fields**
  - **Definitions**
  - **Factors in classifying mature fields**
  - **World stats on mature fields**
  - **Supply vs demand**
- **Giant mature fields: Overview**
  - **Prudhoe Bay, Alaska**
  - **Elk Hills & Belridge fields, San Joaquin basin, CA**
  - **Weyburn unit, Saskatchewan, Canada**
  - **Forties field, North Sea**
  - **Casabe field, Colombia**
  - **Priyobskoye field, Siberia**
  - **Cantarell field, Mexico**
- **SWOT analysis of mature fields**
- **Unconventional Vs Conventional mature fields**
- **Next: digging deep: How a Geologist could help?**

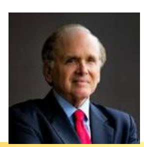
Prudhoe Bay field



Mature Fields: Introduction

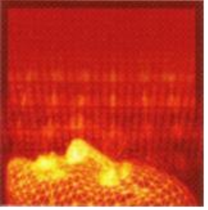
"A field is considered matured if it produced more than 50% of it's 2P reserves; produced for more than 25 years and declined less than 50% of its plateau production rate"

*CERA, 2011



- An oil field can be considered as mature when
  - Production rate has significantly declined and/ or when it is close to reaching its economic limit.
  - Has been in production for many years and has depleted its primary and secondary recovery.
- Consequently, facilities and technology at mature fields could be old.

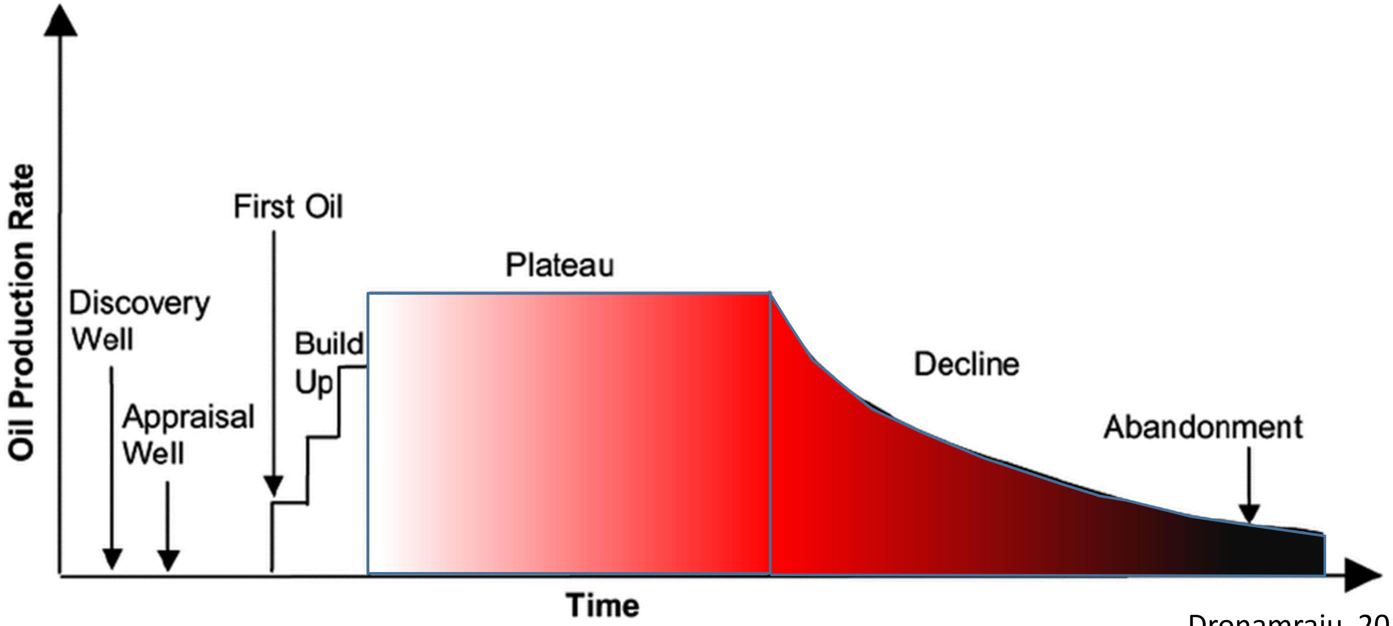
*Cambridge Energy Research Associates



Mature Fields: Introduction

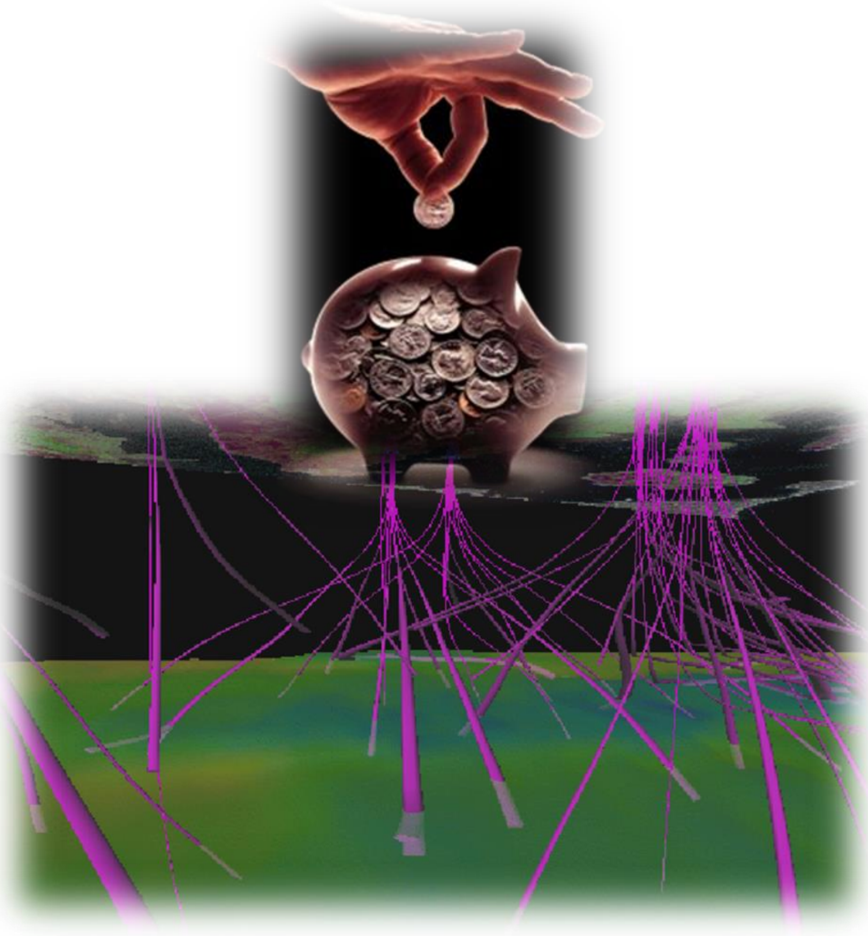
Definition

Simply put a mature field is past its peak production reached end of production plateau.



Dronamraju, 2018, pifnp talk, Houston

Mature Fields: Introduction



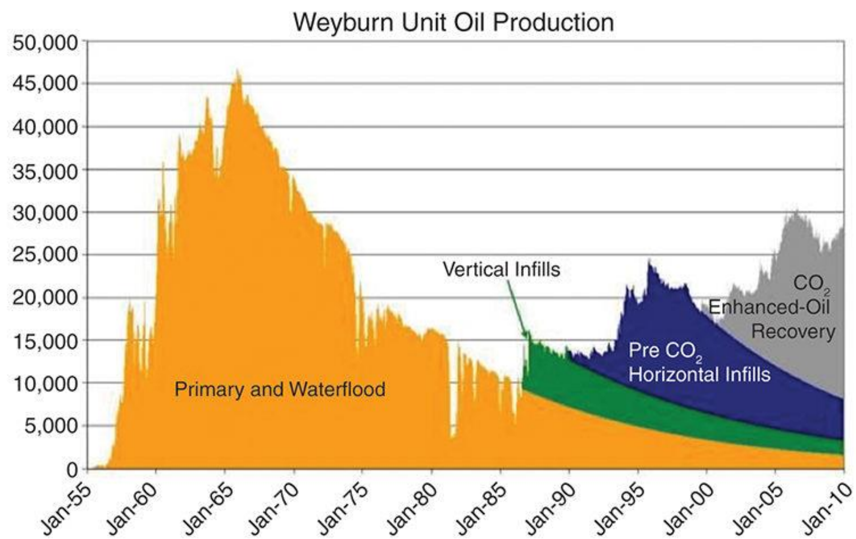
- **A mature field is one that reached the economic limit**
- **The economic limit is defined as the production rate below which the net operating cash flow from a project is negative. It can also be defined as a point in time that defines the project's economic life.**
- **When the economic limit of a field is reached, it becomes a financial liability. This means it costs more money to keep operations running.**

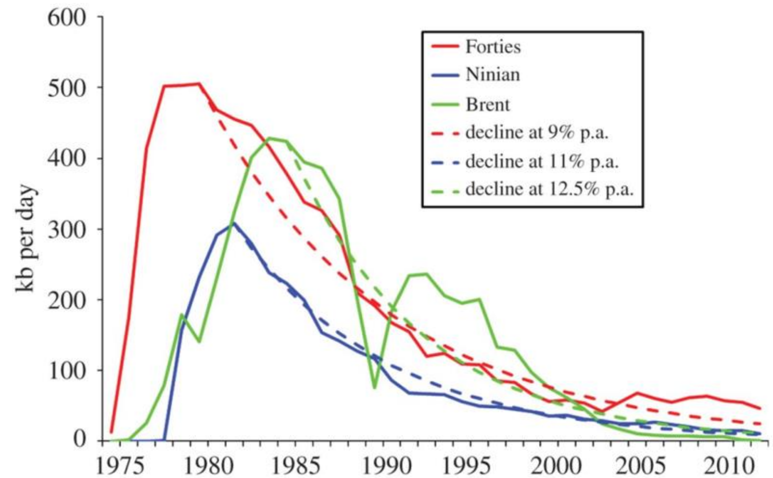
Mature Fields: Introduction

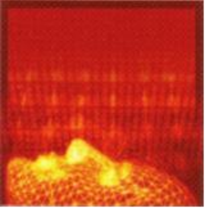
- An oil field can be considered as mature when its production rate has significantly declined and/ or when it is close to reaching its economic limit. A field might also be considered mature when it has been in production for many years and has depleted its primary and secondary recovery. Consequently, facilities and technology at mature fields could be old. However, far from being diminishing assets, these mature fields offer one of our most important opportunities to extract further oil and gas resources to meet future energy demands.
- While the world hydrocarbon demand is estimated to increase by approximately 1.5% per year, the number and size distribution of new discoveries are declining, whereas mature fields are more predictable (less risk and less uncertainty). Mature fields are also seen as attractive in uncertain times, given the benefits of regular, reliable cashflows.
- Mature fields, many in the secondary or tertiary production phases, account for over 70% of the World's oil and gas production.
- Considering, the average recovery factor being circa 70% for gas and circa 35% for oil, innovative methodologies, combining new techniques and technologies, are proving that revitalization activities can be economical, and thereby increasing ultimate recovery by 20% or more. The development of these mature assets is significant to the global economy.
- Simply boosting the recovery factor of the World's existing oil fields by 1% would provide for two to three years of worldwide consumption.

Mature Fields: Introduction

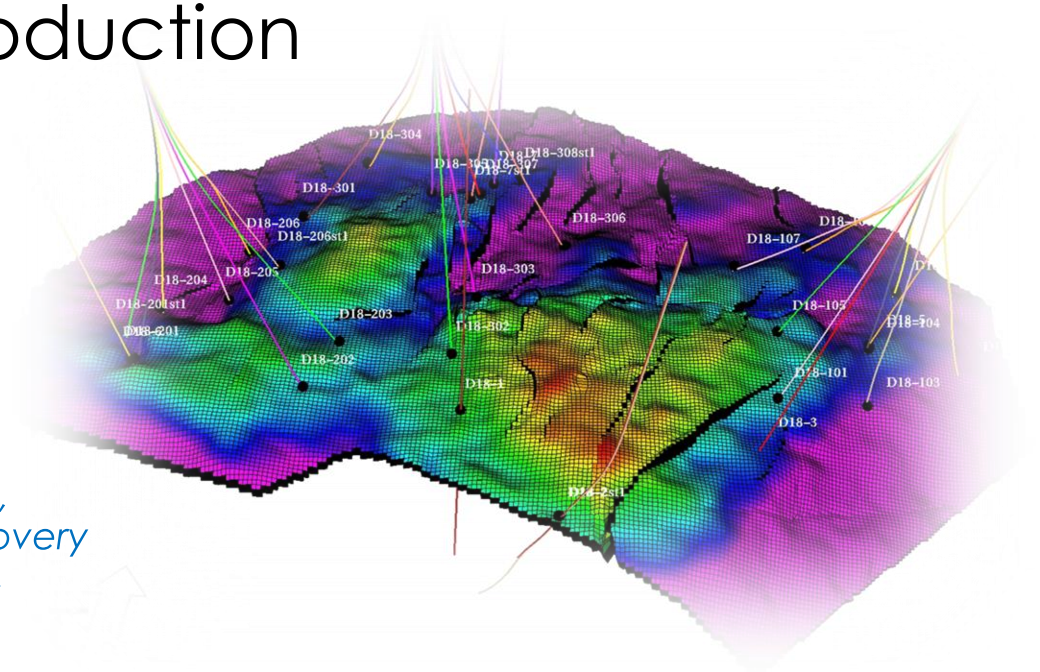
- The economic limit of an asset is calculated by weighing producing costs with abandoning costs, which in turn are weighed against revenue from oil revenues at a given rates and oil prices.
- Some abandonment strategies could be:
  - Extending the life of the field
  - Compensating a third party for the economic risks
  - Re-using facilities and infrastructure
- (Right)Production profiles for three UK North Sea oil fields, with indicative exponential decline curves.
  - Source: UK Department of Energy and Climate Change.







Mature Fields: Introduction

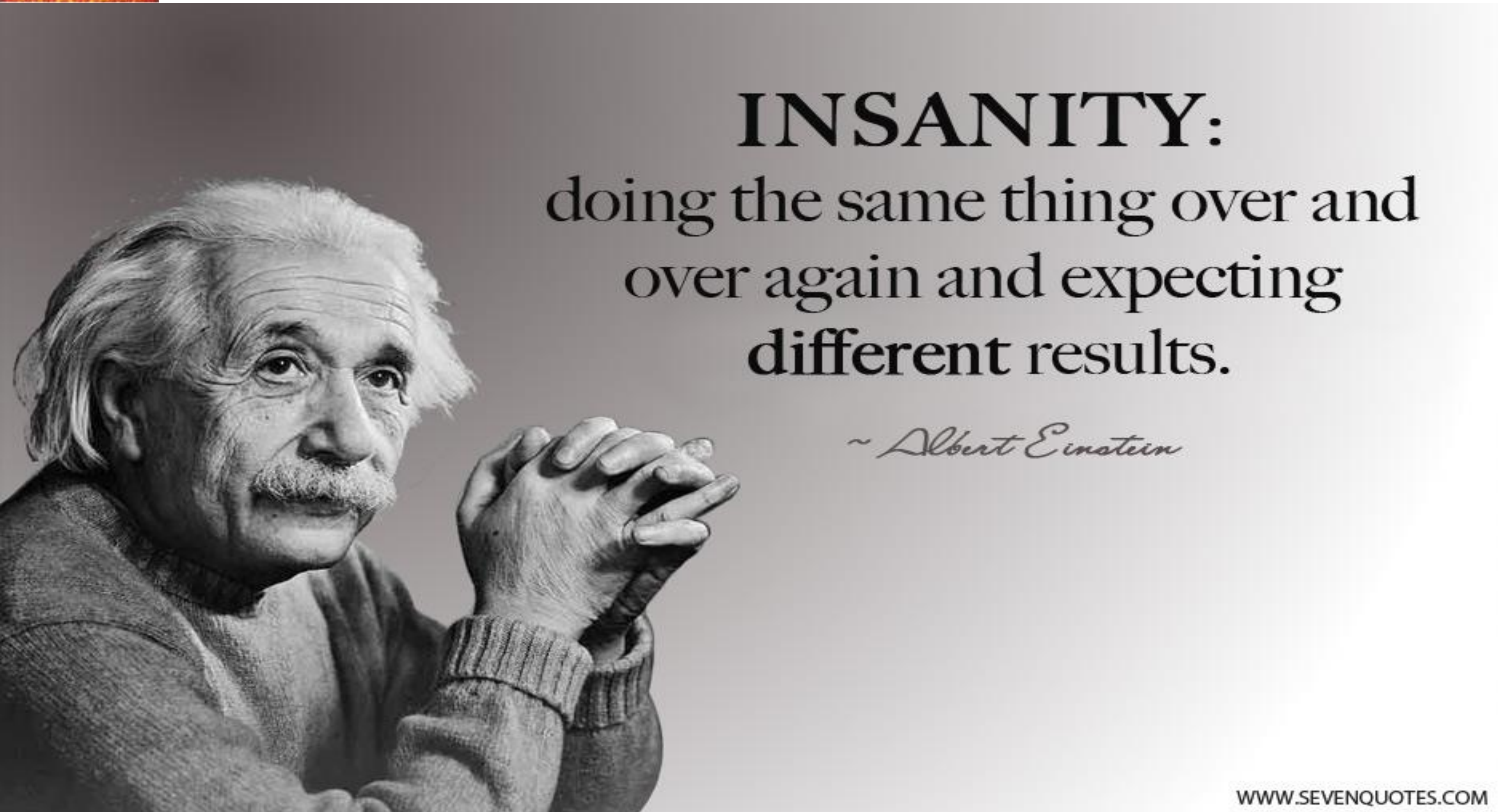


Some of the characteristics of a mature field are:

- *Economics and lifting costs*
- ***Geology:** Subsurface heterogeneity, complex geology, reservoir characterization*
- ***Engineering:** Fluid properties (gas, oil, condensate), wettability, drive, Recovery mechanism-water, steam, gas, CO2, chemical, polymer*

- Reporting standards and errors in metering : *reserves definition, have they changed wrt SPE2007 guidelines? Was there an audit?*
- Where is the field: *access to market, onshore/offshore, technology, land ownership, royalties, law suits.*
- Obsolete technology: *was there a 3D seismic?, reservoir model? access to technology*
- Leadership change and business focus: *who owns the field, risk apatite, financial strength, private/public ownership*
- Poorly organized data: ***old data and standards, poorly calibrated, digital?***

Mature Fields: Introduction



Mature Fields: Supply Side

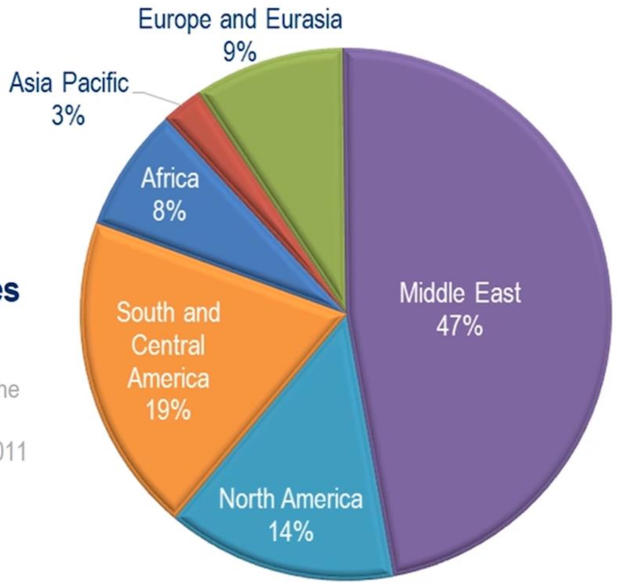
Reserves: Quantity of Petroleum Anticipated to be Commercially Recoverable

Reserves must be:

- Discovered
- Recoverable
- Commercial
- Remaining

Proven Oil Reserves
(End of 2015)

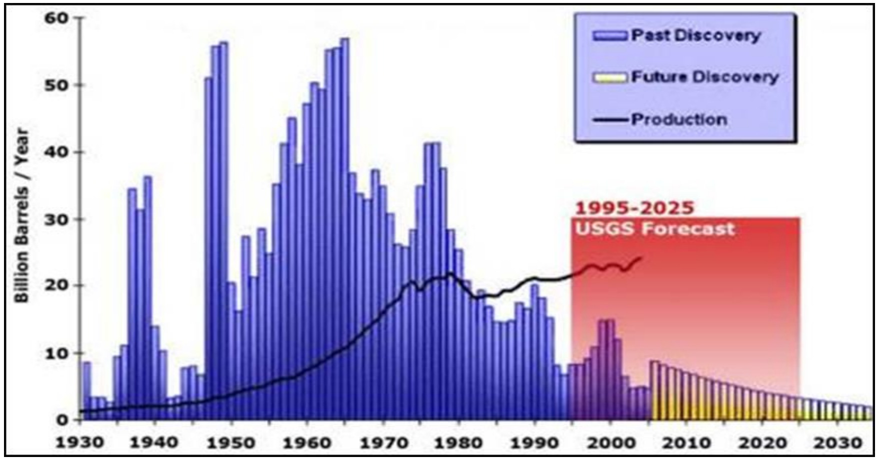
Guidelines for Application of the Petroleum Resources Management System, SPE 2011

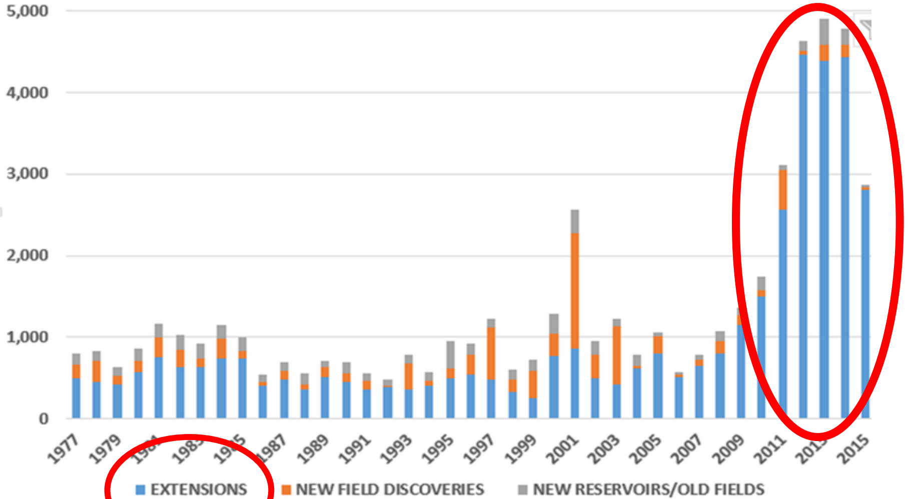


Not necessarily! The reserves reported in some countries may not have SPE backing. In fact, the numbers are just coming from Russia and China, and which could be 20% higher, and the Middle East, Southeast and South Asia could be 10-30% lower. New 3D seismic is being acquired on old fields in many Russian fields, which tend to grow their reserves by 20-30%. Other countries are following the trend.

Schlumberger, 2008

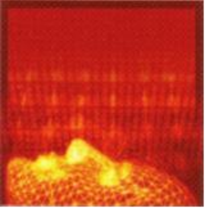
Mature Fields –Demand side





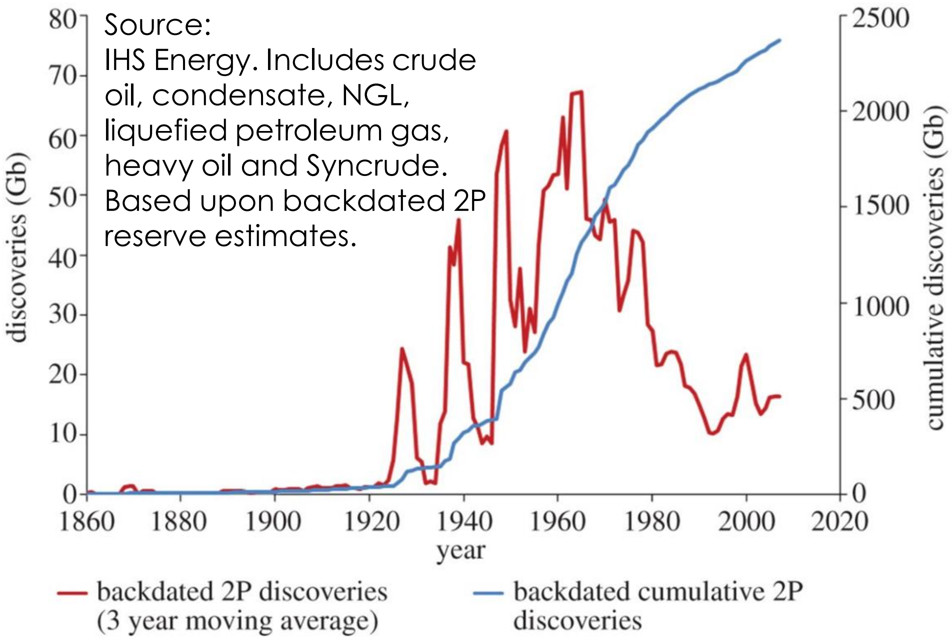
*International Energy Agency.org

- While the world hydrocarbon demand is estimated to increase by approximately **1.5% per year**, the number and size distribution of new discoveries are declining, whereas mature fields are more predictable (less risk and less uncertainty).
- Mature fields are also seen as ***attractive in uncertain times***, given the benefits of regular, reliable cashflows
- Far from being diminishing assets, these mature fields offer one of our most important opportunities to extract further oil and gas resources to meet future energy demands.



The Size of the Challenge….

Global trends in backdated discoveries and cumulative discoveries.

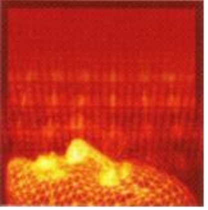


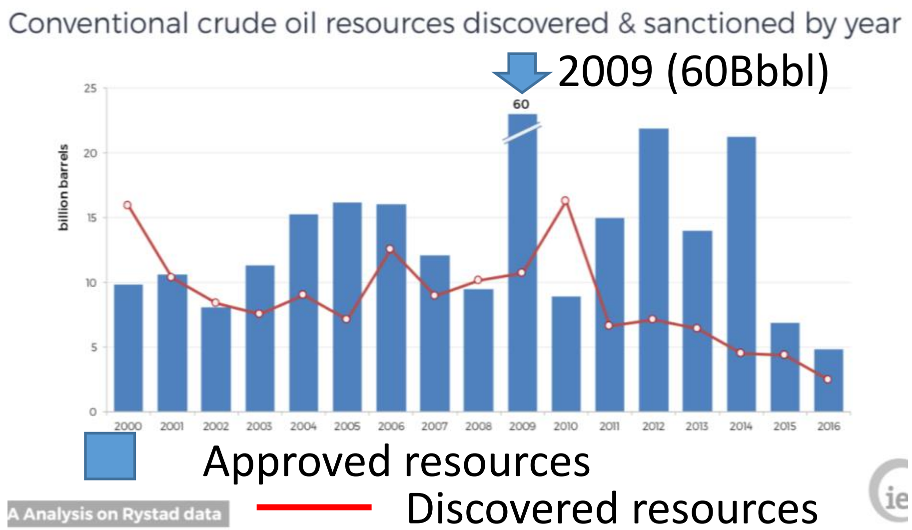
Unconventional Oil may help, but it requires a huge step change from even the current significant investment. In 2012 Unconventional oil production in the United States was approximately 2 million barrels a day.

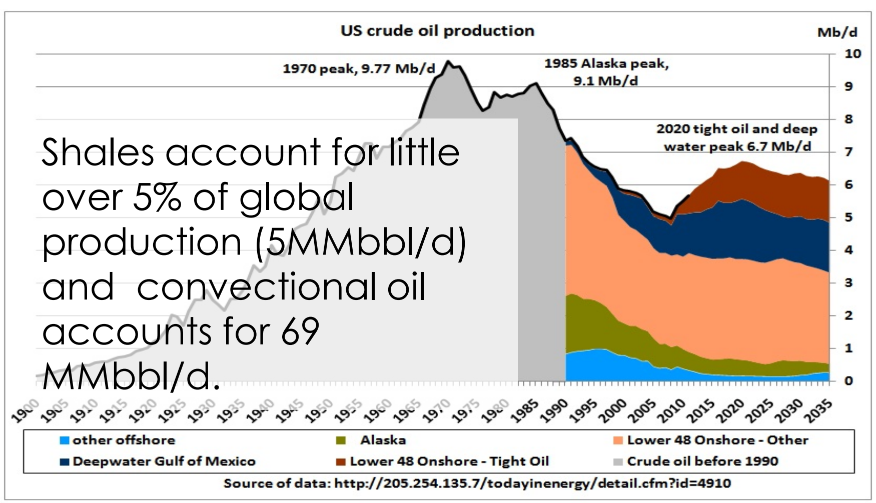
- In 2007 the IEA* predicted that 64 million barrels per day of **new oil** will be required to come onstream by 2030 to meet the anticipated demand at ~1.6% per year.
- Assuming an average conventional oil discovery size creates an additional supply of **20 Mbopd** (the current world conventional field average) this represents 3200 conventional fields, or **1391 fields every 10 years.**
- **In the 1990s just over 400 conventional fields were discovered, less than 1/3rd of the required discovery rate. 2.5% of these fields (10) produced (at 2001) over 100,000 barrels per day.**
- In the absence of multiple frontier plays, which contain world-beating elephant discoveries, or a huge increase in drilling discovery, conventional exploration alone cannot satisfy predicted worldwide demand.

*International Energy Agency, Paris

Supply vs Demand







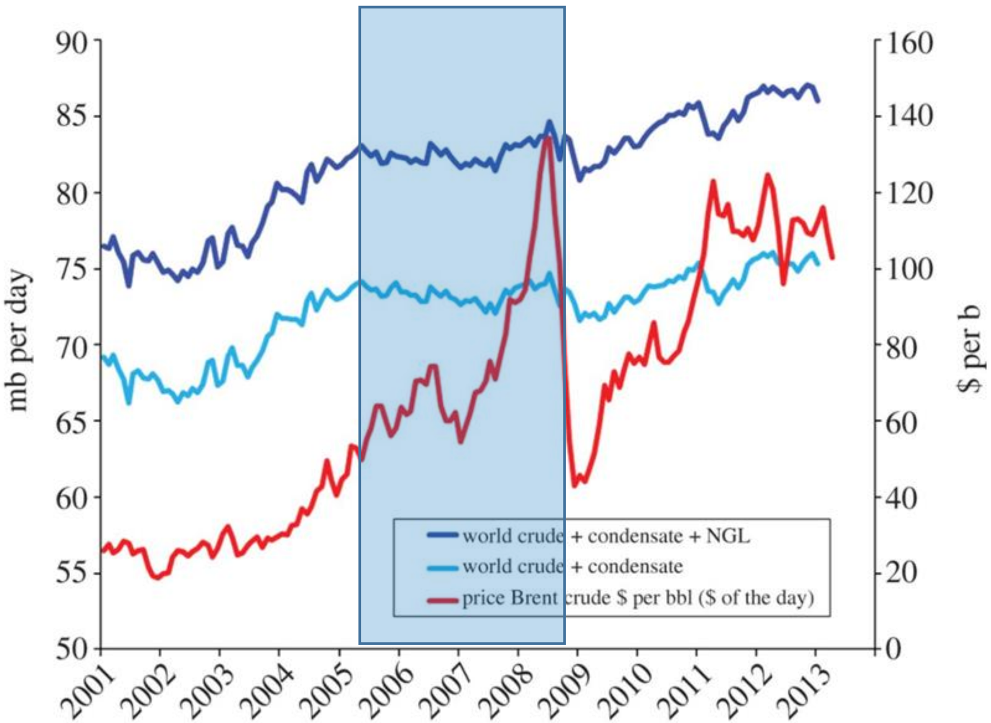
Shales account for little over 5% of global production (5MMbbl/d) and convectional oil accounts for 69 MMbbl/d.

- Discovered volumes hit all time low in 70 years, reflects budget cuts.
- **Globally only 2.4 Bbbls discovered in 2017, against 9 Bbbl in the past 15 years**
- The volume of the projects that received FID is the lowest since 1940s.
- US shale production by contract is all time high in 2016, thanks to the short production cycle.
- **Mature fields accounted for 51 million barrels of global daily production in 2017, Vs 16 million bpd, by new fields.**
- Shale and oil sands contributed 30 million bpd last year. (IEA)
- **IEA warns that US shale production cannot meet the demand on its own.**

Supply vs Demand

Global supply

$Oil price
monthly average



Source:
US Energy Information Administration.

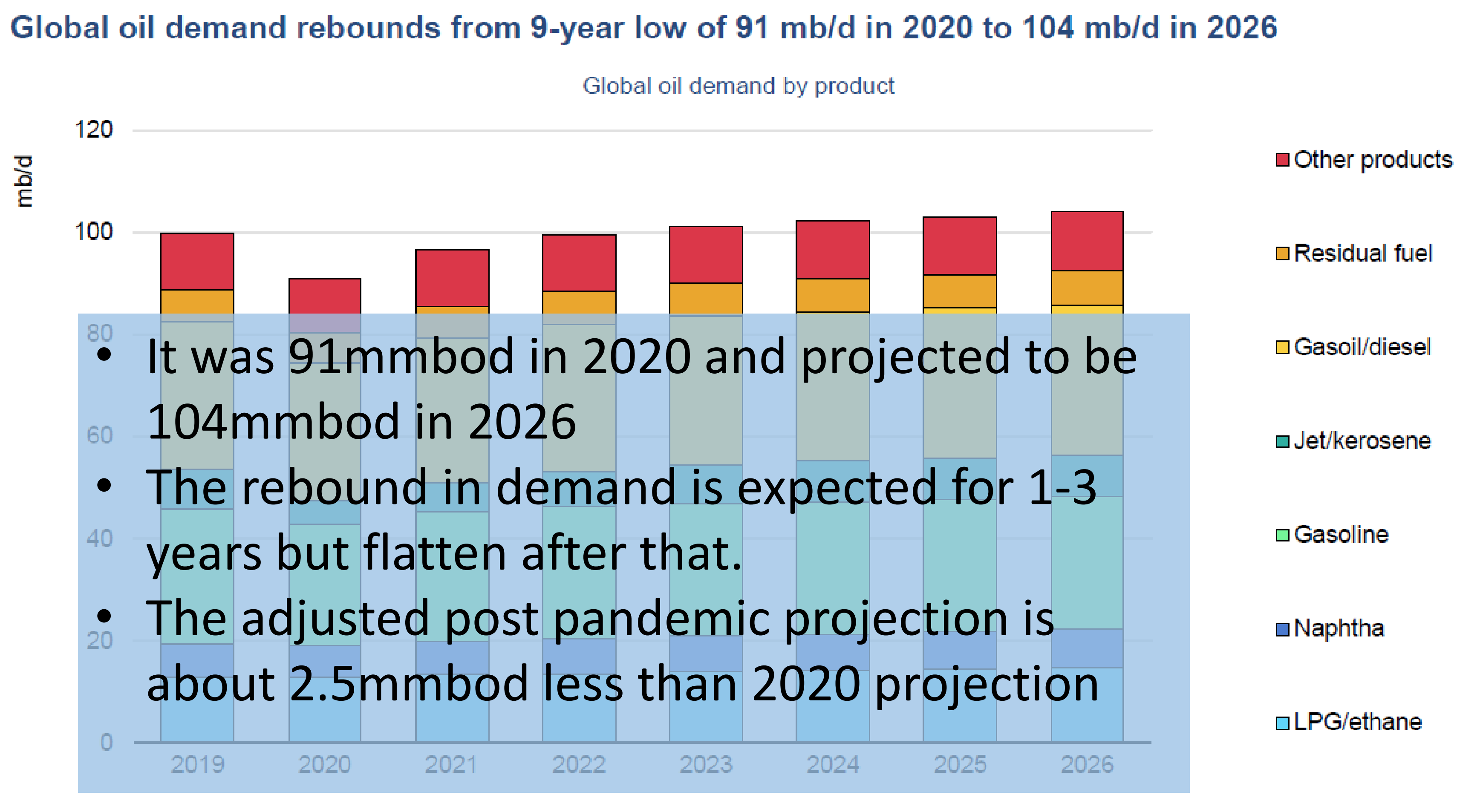
Monthly average crude oil price (right axis) and global oil supply (left axis).

Oil supply has been slow to respond to the doubling of crude oil prices since mid-2005.

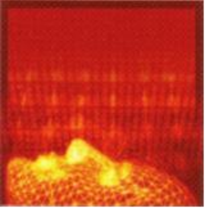
This is partly because of political conflicts in key regions (e.g. Iraq) and the strategies of key exporters (e.g. Saudi Arabia), but largely reflects the growing lead times on new projects (5–10 years) and the increasing difficulty and cost (up 50% since 2005) of finding and developing new resources.

Sometimes supply/demand relation does not hold for oil. Price of oil is lot complicated. But operators cashflow cycles must respond to oil price quickly to stay profitable.

Demand Vs Supply- Post-Pandemic

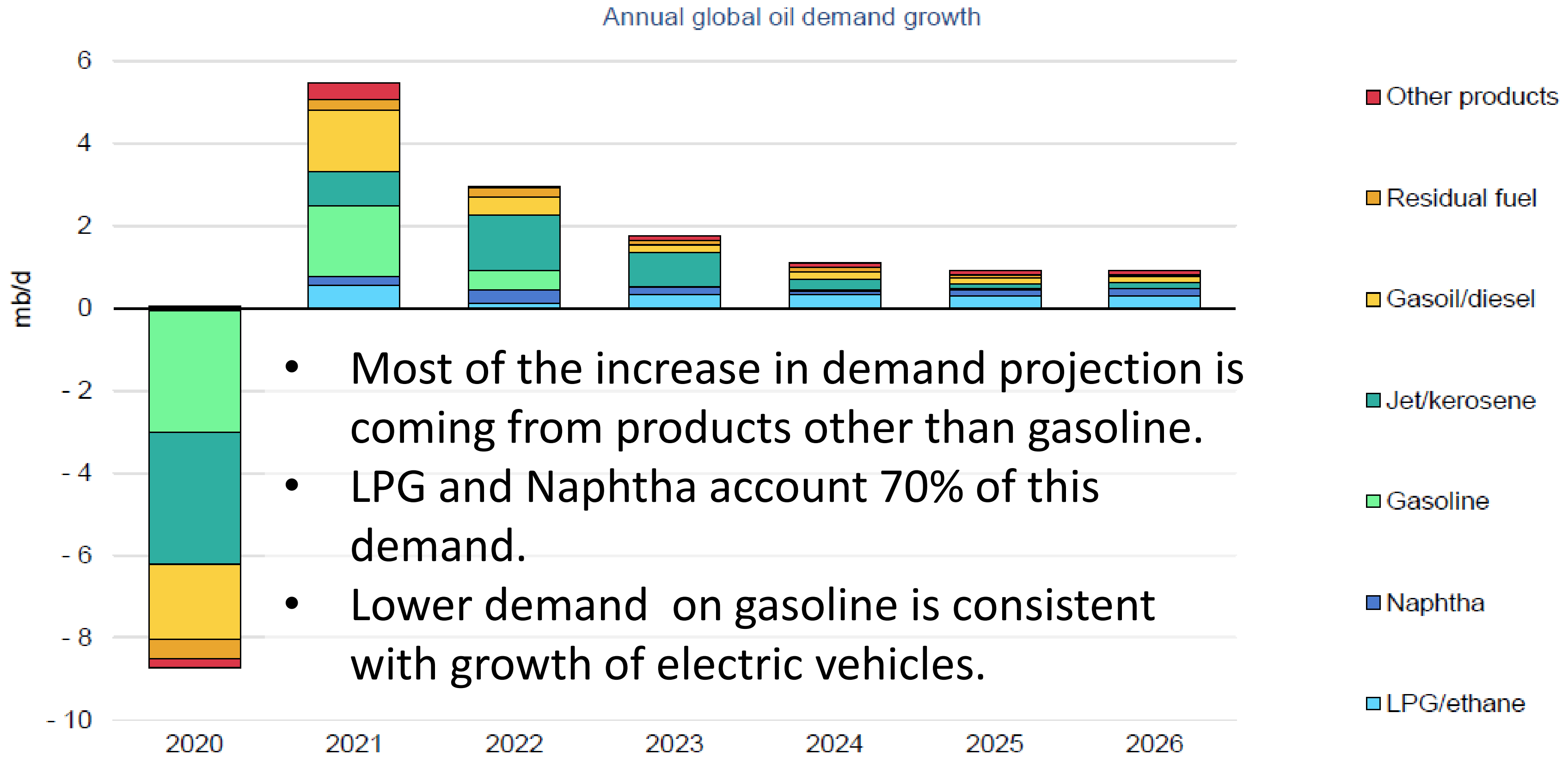


- It was 91mmbod in 2020 and projected to be 104mmbod in 2026
- The rebound in demand is expected for 1-3 years but flatten after that.
- The adjusted post pandemic projection is about 2.5mmbod less than 2020 projection



Demand Vs Supply- Post-Pandemic

Following a sharp recovery over 2021-2022, oil demand growth slows markedly



- Most of the increase in demand projection is coming from products other than gasoline.
- LPG and Naphtha account 70% of this demand.
- Lower demand on gasoline is consistent with growth of electric vehicles.

Demand Vs Supply- Post-Pandemic

Asia Pacific provides 90% of global oil demand growth

Global oil demand by region (mb/d)

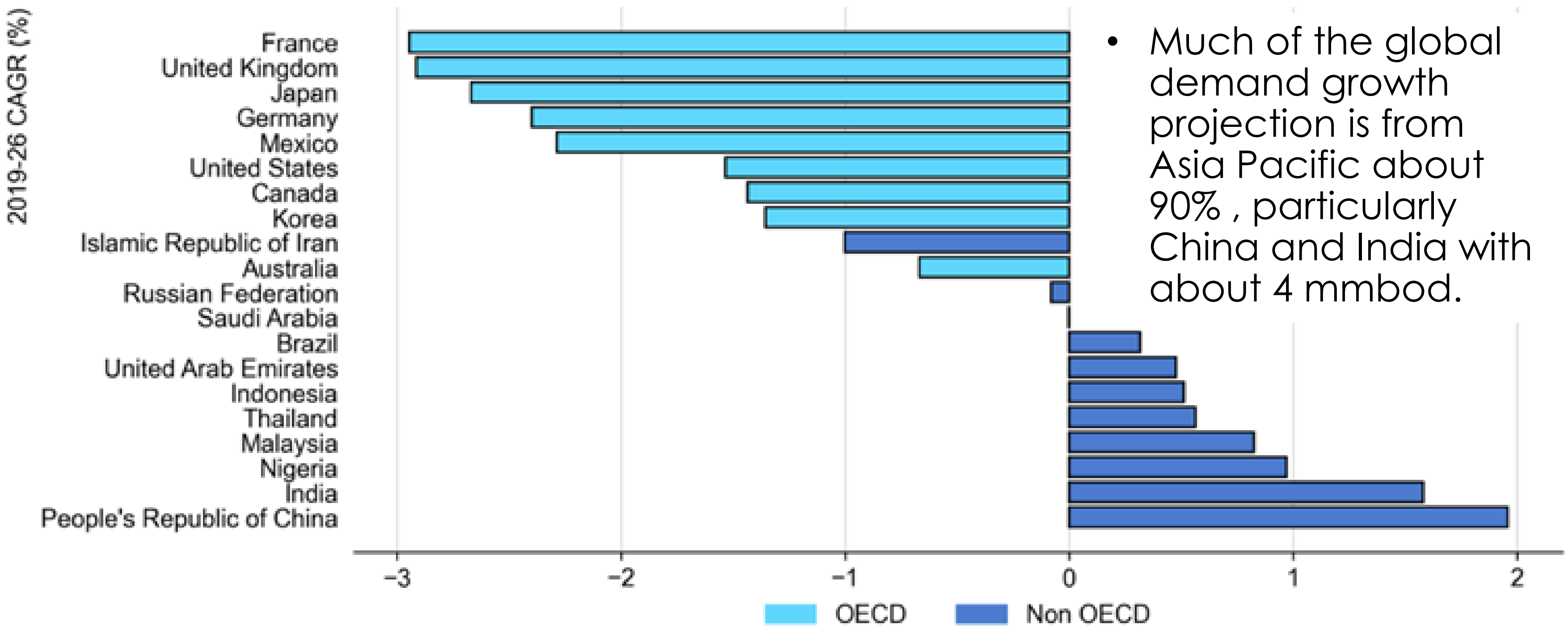
	2019	2020	2021	2022	2023	2024	2025	2026	2019-26 Growth	2019-26 Growth
North America	25.3	22.2	23.8	24.5	24.7	24.7	24.6	24.6	-0.4%	-0.7
Central and South America	6.6	5.9	6.3	6.6	6.7	6.7	6.8	6.9	0.7%	0.3
Europe	15.7	13.8	14.6	14.8	15.0	15.0	14.9	14.9	-0.8%	-0.8
Africa	4.2	3.8	4.0	4.2	4.4	4.5	4.7	4.8	1.7%	0.5
Middle East	8.3	7.6	7.9	8.2	8.4	8.5	8.7	8.9	0.9%	0.6
Eurasia	4.4	4.2	4.3	4.4	4.5	4.6	4.6	4.7	1.1%	0.4
Asia Pacific	35.2	33.4	35.6	36.9	37.7	38.2	38.9	39.3	1.6%	4.1
World	**99.7**	**91.0**	**96.5**	**99.4**	**101.2**	**102.3**	**103.2**	**104.1**	**0.6%**	**4.4**

- Much of the global demand growth projection is from Asia Pacific about 90% , particularly China and India with about 4 mmbod.

Demand Vs Supply- Post-Pandemic

Gasoline's future is outside the OECD

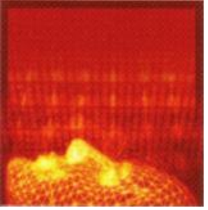
Top 20 gasoline consumers: expected 2019-2026 growth



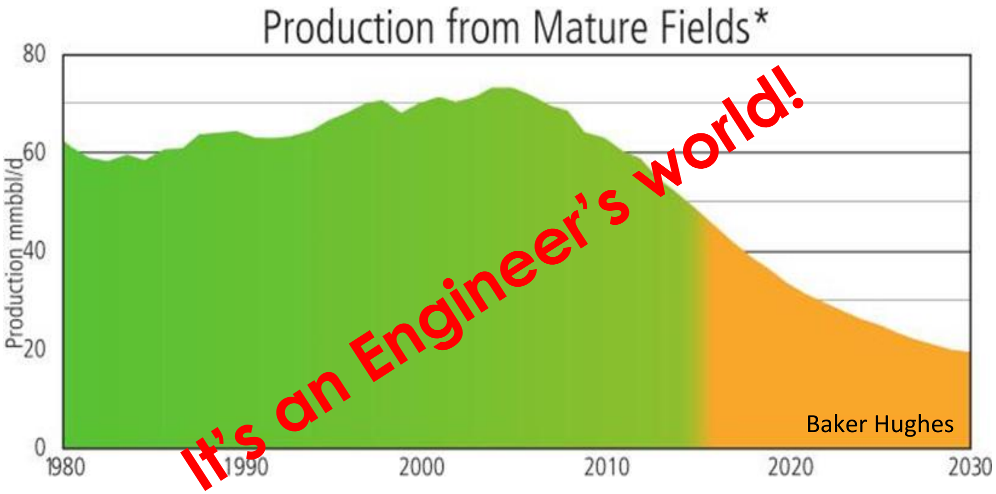
- Much of the global demand growth projection is from Asia Pacific about 90% , particularly China and India with about 4 mmbod.

Shifting Economics

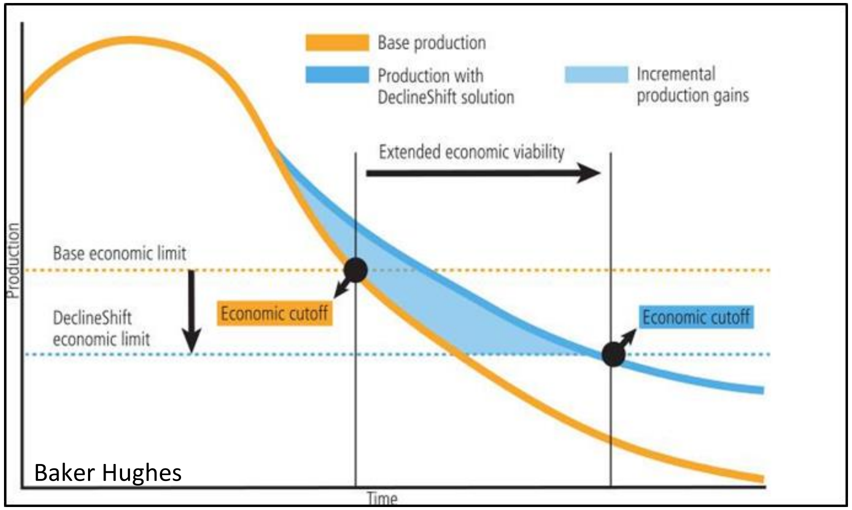
The best place to find oil is where it has been found already..Really?



Shifting Economics



- The best place to find oil is where it has been found already..Really?
- **But it may help explain why 70% of global oil and gas production from the fields that are 30 years old!**
- Decline is inevitable, but a modern approach to life cycle management could slow the decline and even reverse it.

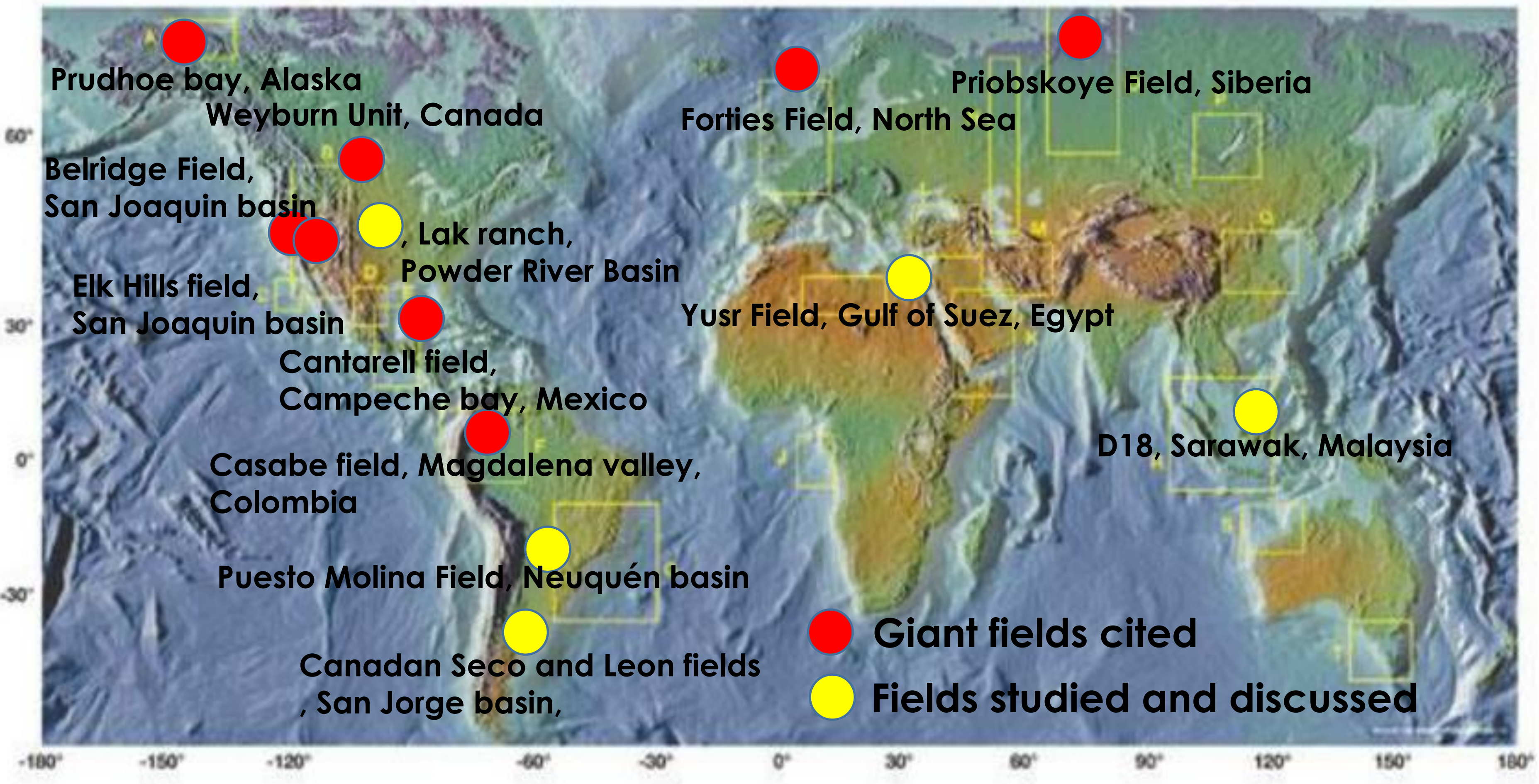


1. Addressing wells: Optimizing production by rejuvenating producing well, reactivating shut-in wells, down hole pumps, workovers, skin treatment, etc.
2. Addressing reservoirs: EOR/IOR/operational efficiencies, infill drilling, maintaining reservoir pressures, and other reservoir management practices.
3. Finding new reserves: Bypassed, poorly appraised and developed, new data acquisition!

Figure 1.1. Listening doesn't equal learning.

"They don't give us time to learn anything in school; we have to listen to the teacher all day."

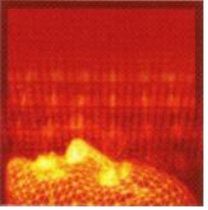
Giant Mature Fields: Quick overview



Mature Field Revivals

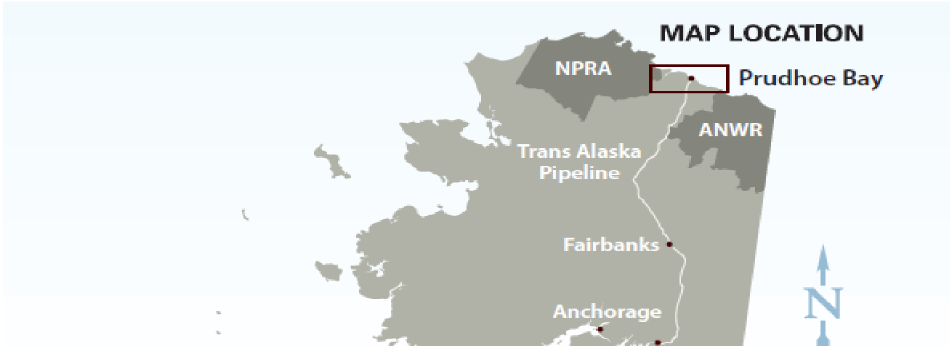
- Prudhoe Bay, North Slope Alaska, USA
- Elk Hills, San Joaquin Basin, CA, USA
- Belridge Field, San Joaquin Basin, CA, USA
- Weyburn Unit, Saskatchewan, Canada
- Forties Field, North Sea, UK
- Casabe Field, Columbia
- Prioskoye Field, Siberia, Russia
- Cantarell Field, Mexico

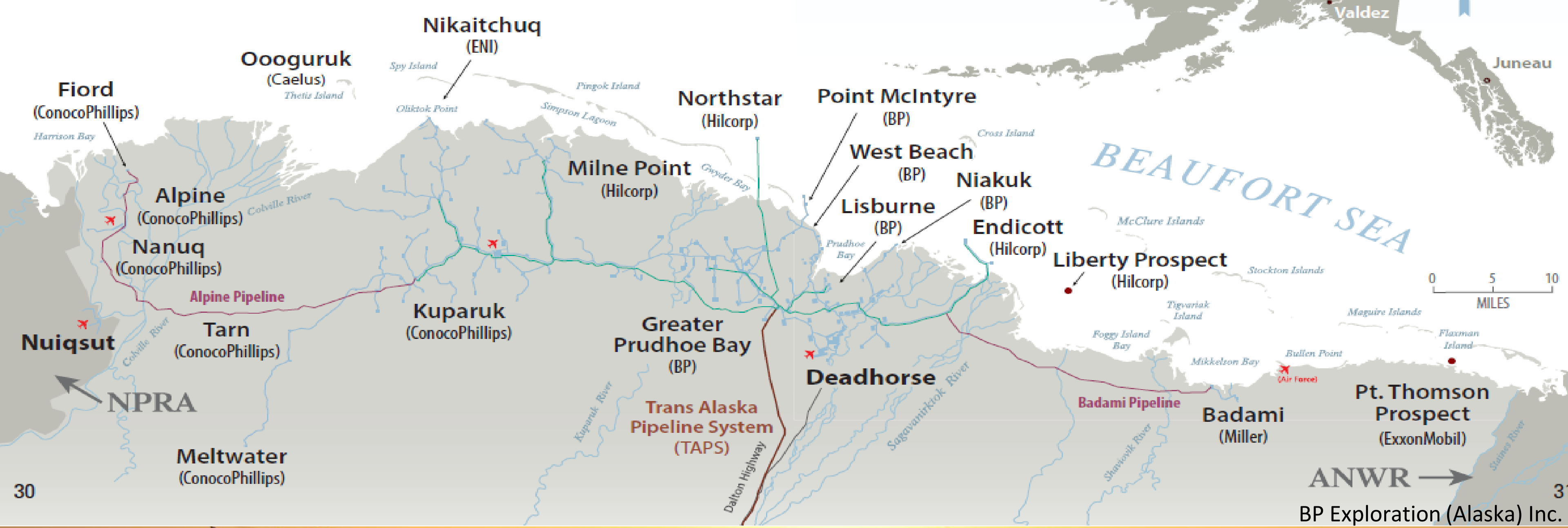

Have a break. Have a KitKat
Time for a Break
?



North Slope, Alaska

Prudhoe Bay is located about 600 air miles north of Anchorage and about 1,200 miles south of the North Pole. It is about 250 miles north of the Arctic Circle. This region includes the Arctic National Wildlife Refuge (ANWR), the Central Arctic (area between the Colville and Canning Rivers), the National Petroleum Reserve Alaska (NPRA), the Beaufort Sea Outer Continental Shelf (OCS), and the Chukchi Sea OCS areas.



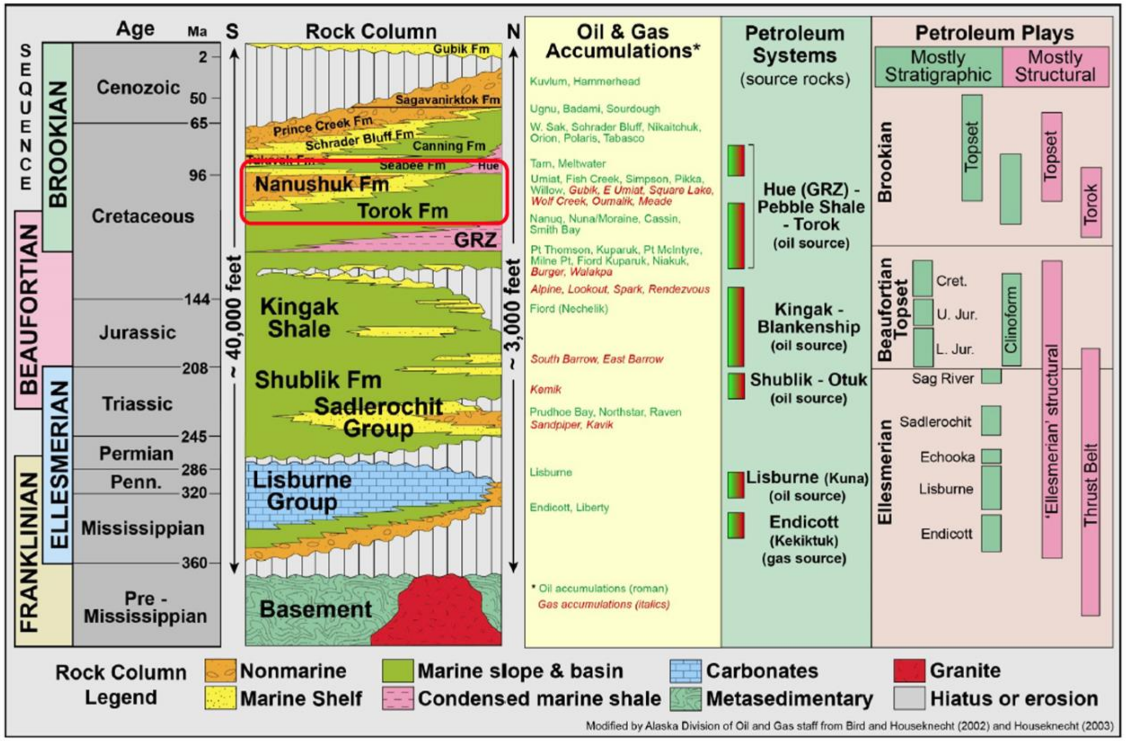


BP Exploration (Alaska) Inc.

Prudhoe Bay, Alaska

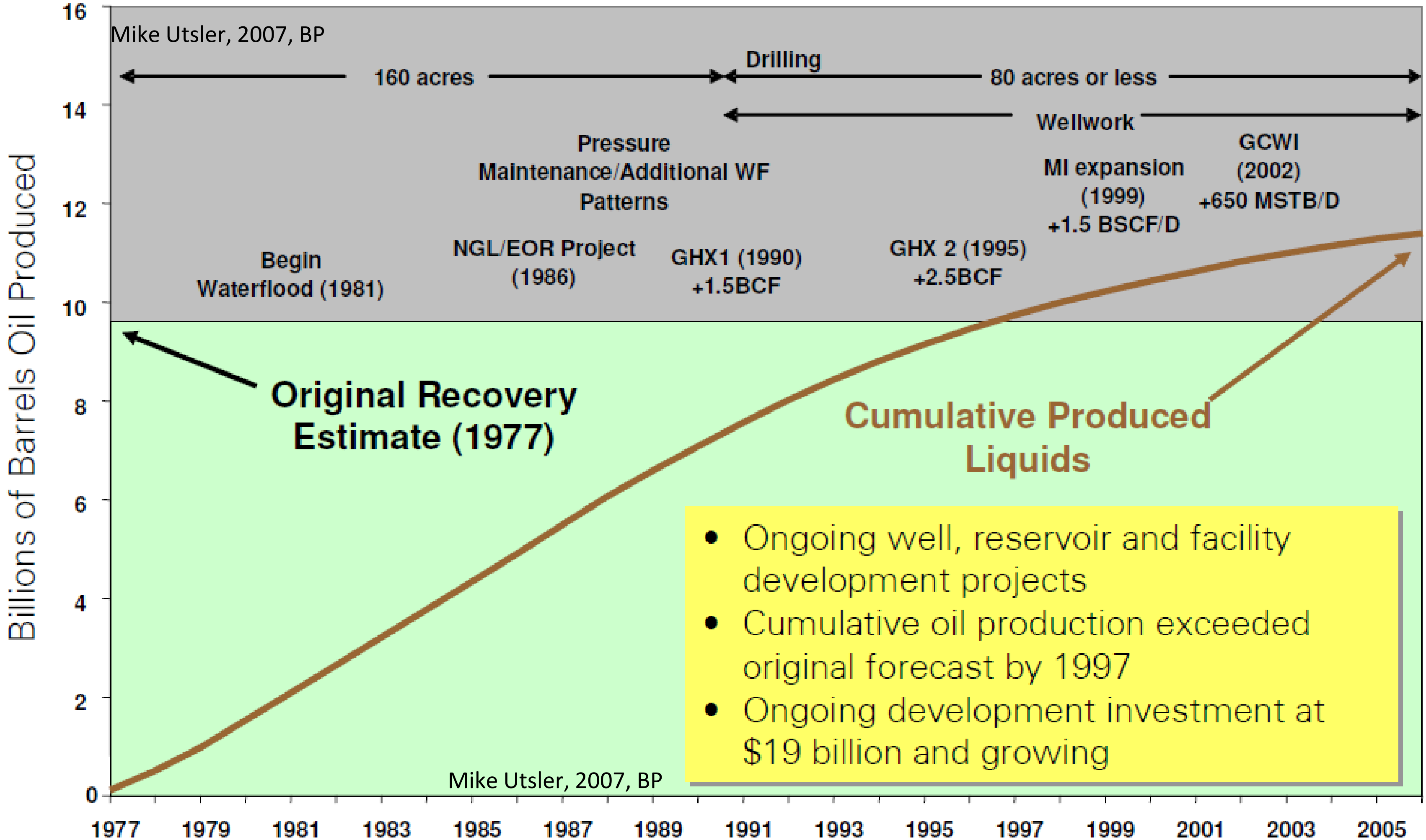
- Largest Oil Field in North America
- Extensive and successful development
  - 60 square miles
  - 11 major facility locations
  - 42 Drill sites
  - 1200 active wells
- Future challenges
  - Managing declining oil rate, and increasing water and gas rates
  - Ongoing developments, light and heavy oil, to offset steep natural decline
- Technology development and deployment is key
  - Arctic specific
  - Advanced reservoir processes
  - World class drilling and workover
  - Facility upgrades

North Slope Petroleum System

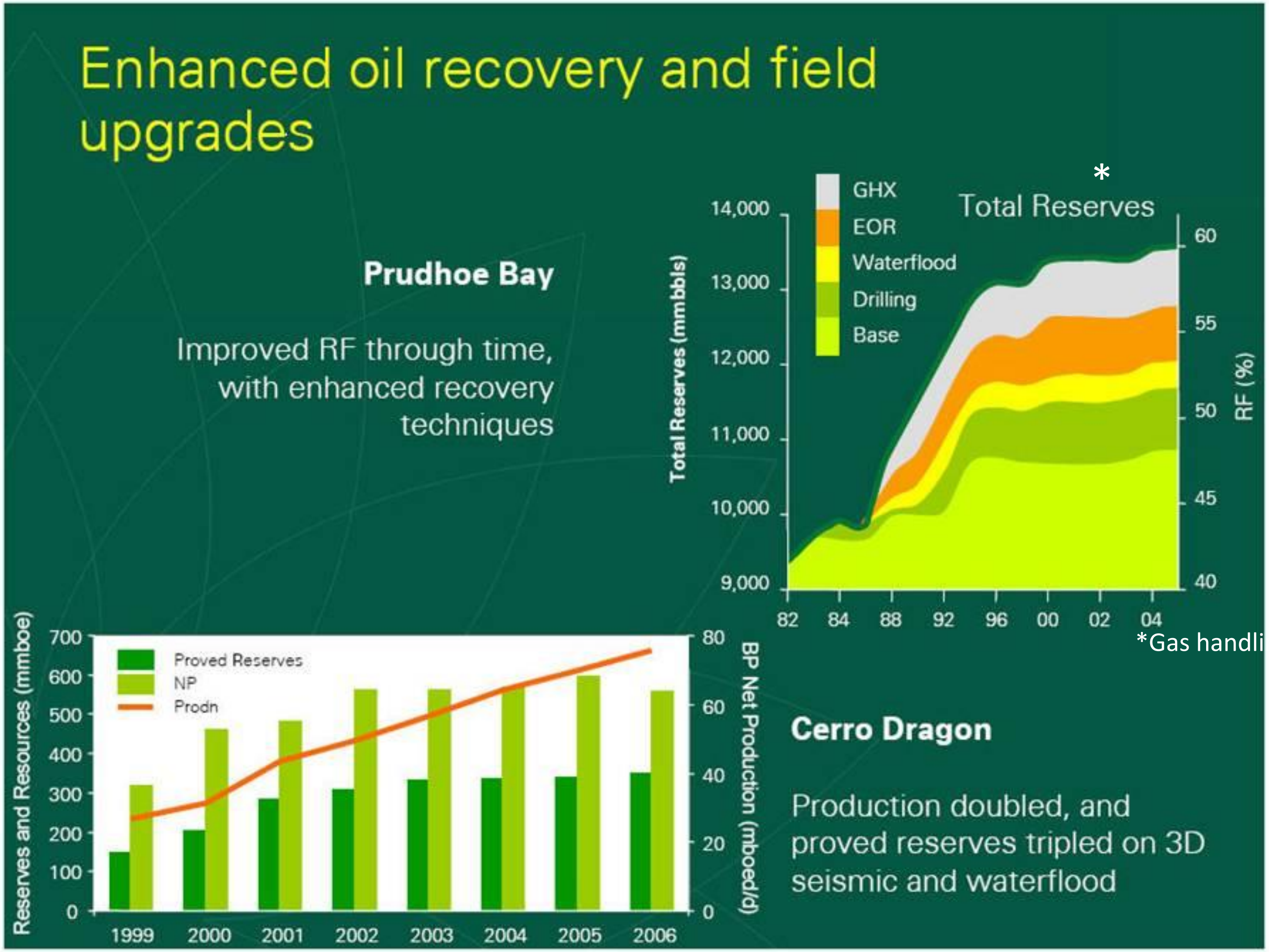


Mike Utsler, 2007, BP

Prudhoe Bay, Alaska



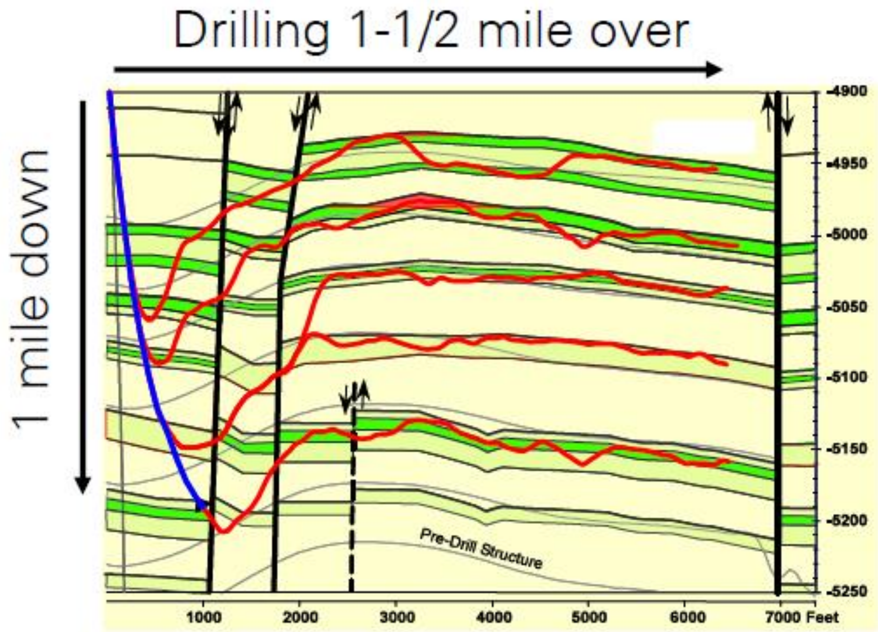
Prudhoe Bay, Alaska



Mike Utsler, 2007, BP

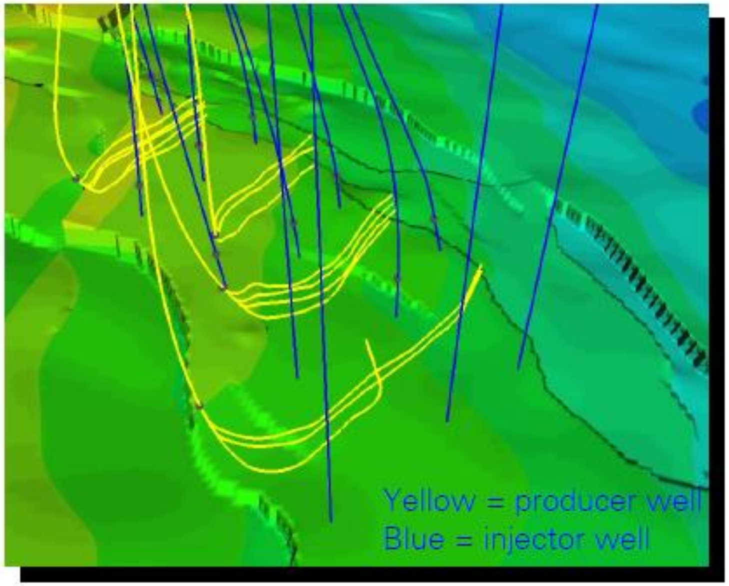
Prudhoe Bay, Alaska

Seismic imaging and directions drilling enabled new development



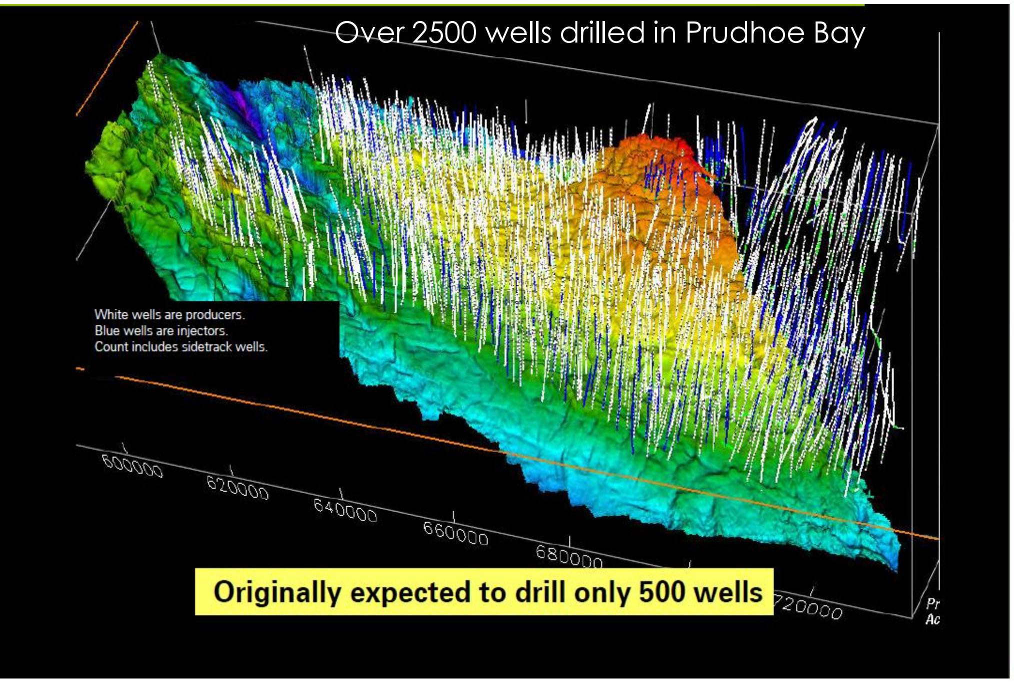
Technologies required to drill and operate these multi-lateral well did not exist eight years ago

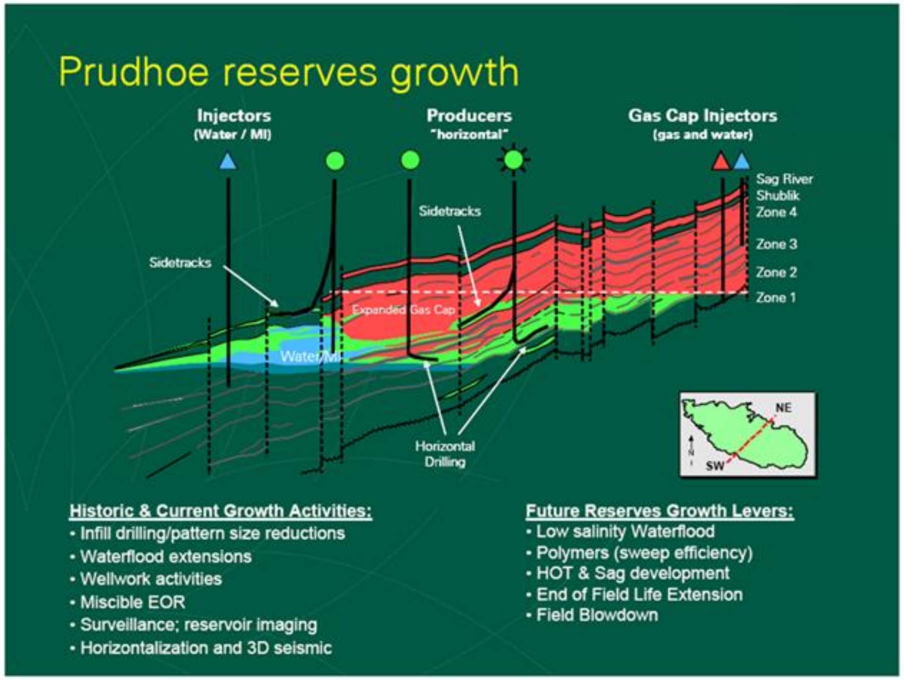
Now 15 are producing and over 20 more are planned, but not all are approved



Mike Utsler, 2007, BP

Prudhoe Bay, Alaska



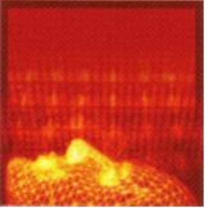


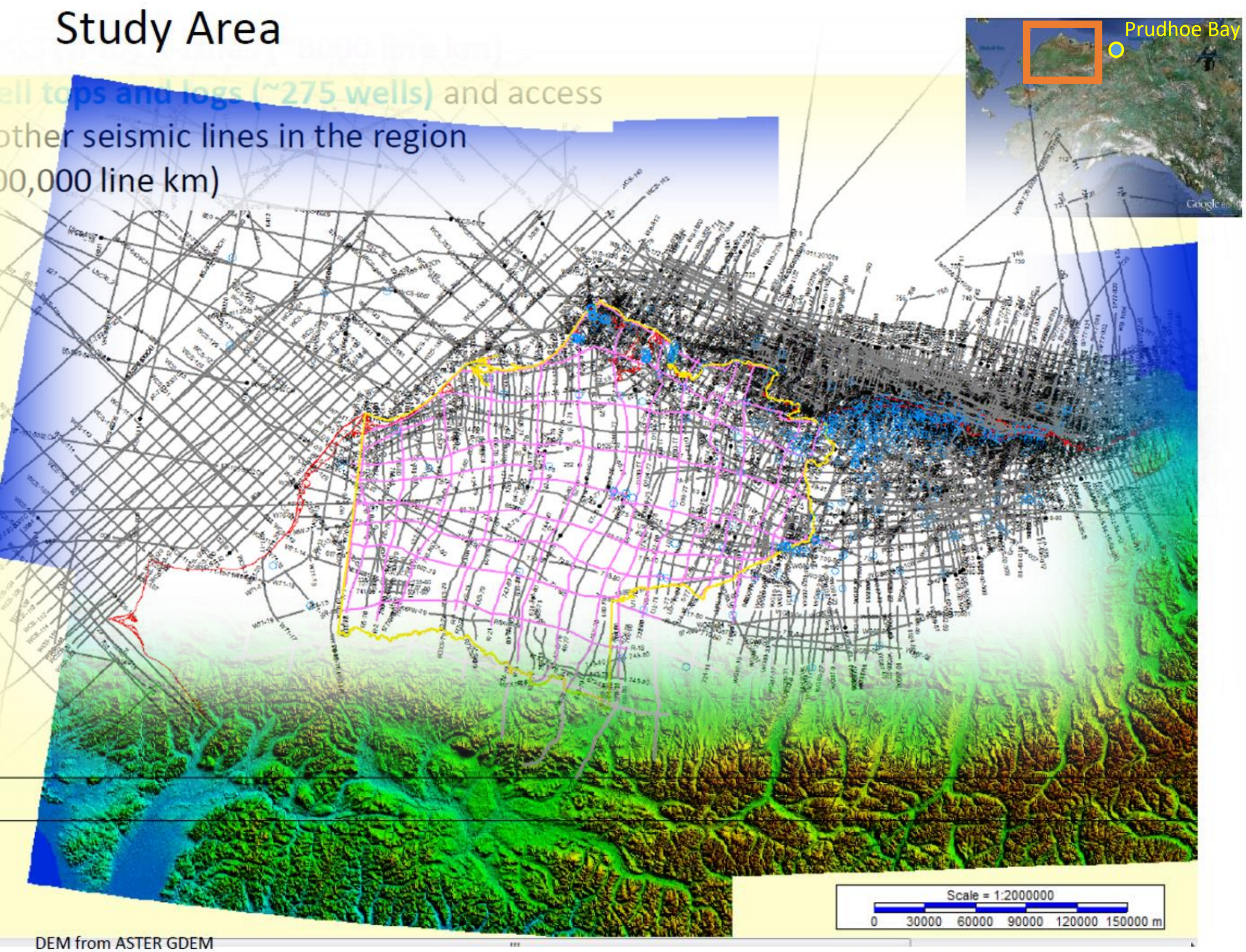
- Current production is about 282Mbbls, 55% of Alaska production.
- Cumm: 12.5 Bbbls, added 141 Billion royalty revenue
- Producing since 1977, 40 years, against 30 projection
- Operated by BP -26%, COP: 36%, Exxon: 21%, Unocal 1%

Mike Utsler, 2007, BP

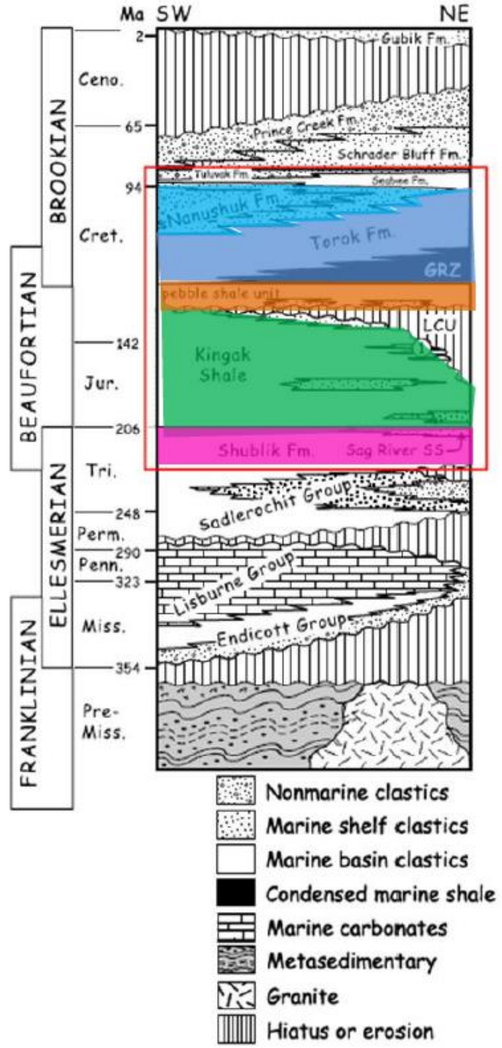
Prudhoe Bay, Alaska

National Petroleum Reserve in Alaska



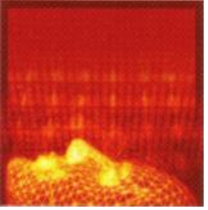


DEM from ASTER GDEM



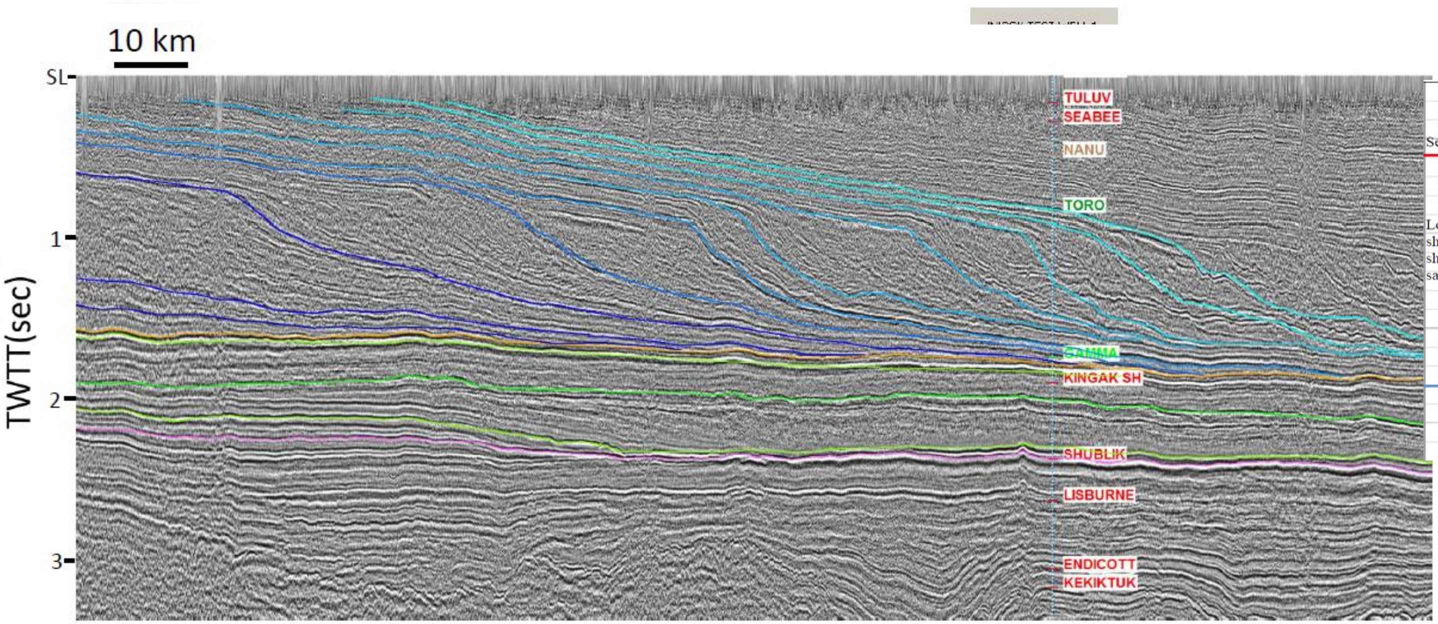
Modified from Houseknecht and Bird, 2009

Mike Utsler, 2007, BP

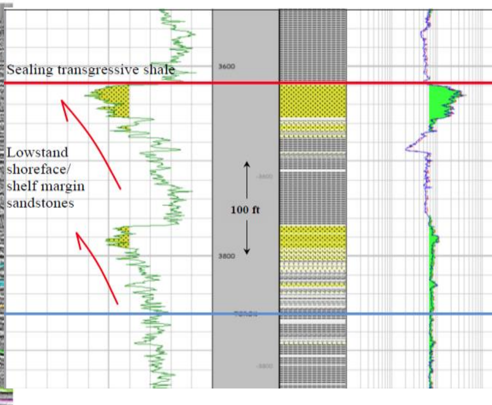


Prudhoe Bay, Alaska

National Petroleum Reserve in Alaska

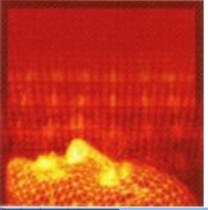


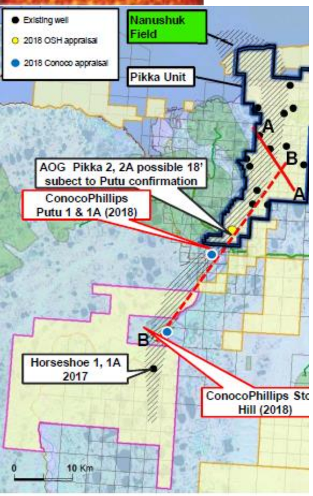
Pika, Willow, and Umiat discoveries

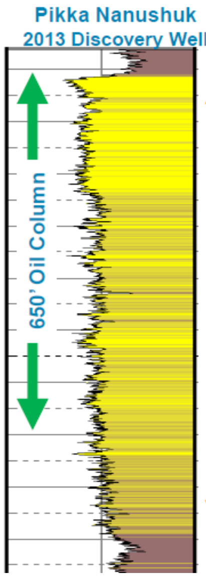


- About 200,000-line km seismic and ~275 wells
- Merged the data and formation top anchored in seismic
- Interpretation of structure, structural restoration, and stratigraphy
- Used Chronostratigraphy, not Lithostratigraphy
- Several dip and strike-trending cross sections
- Sequence stratigraphy and geomodelling.

Pika discovery, Nanushuk Exploration







Pikka (2013) - Horseshoe (2017) Nanushuk Discovery

- Major oil discovery with significant upside
- 500 - 1.2* billion barrels of recoverable light oil
- 80,000 - 120,000 bopd* potential

(* Repsol March 9, 2017 Press Release)

Willow Nanushuk Discovery 2017

- Recoverable resource > 300 mmbbl**
- 100,000 bopd potential

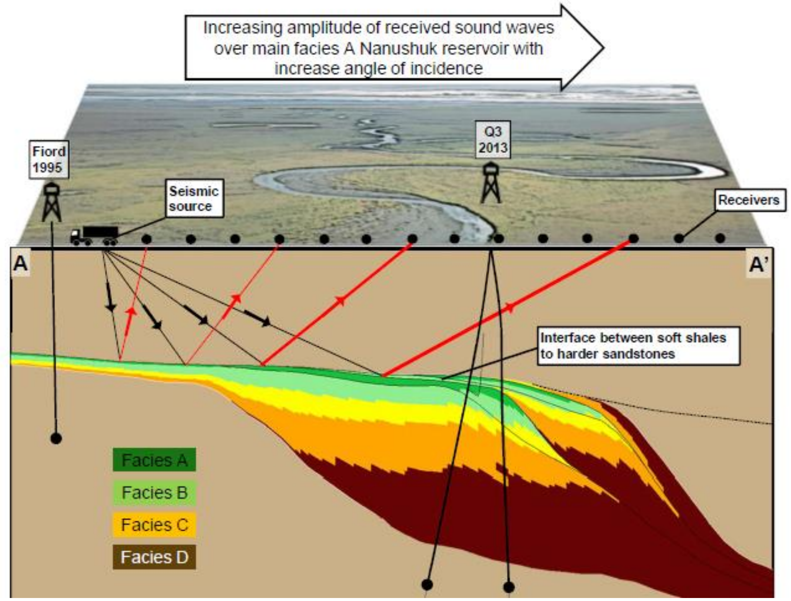
(** ConocoPhillips Jan 13, 2017 Press Release)

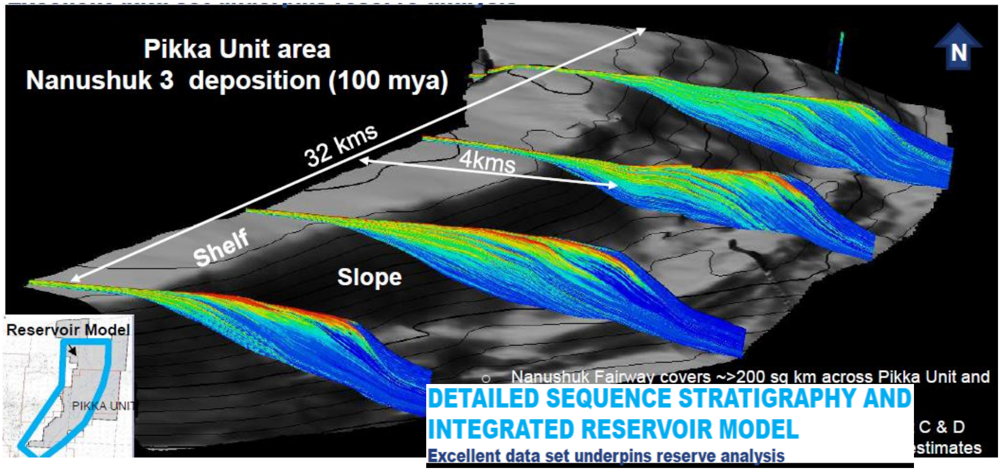
Conoco appraising Pikka - Horseshoe trend 2018

- Putu well planned only 3 miles from Pikka location

NANUSHUK RESERVOIR IDENTIFICATION

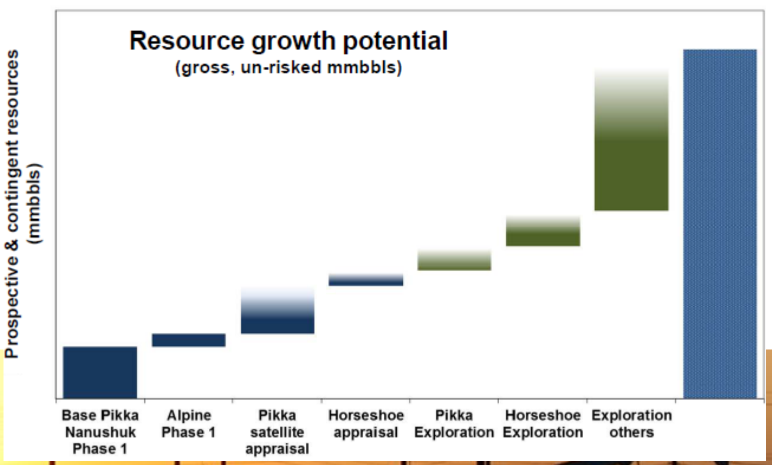
How was it missed? 3D seismic delineates key zones

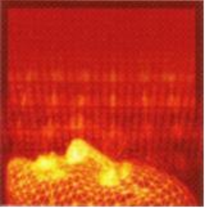




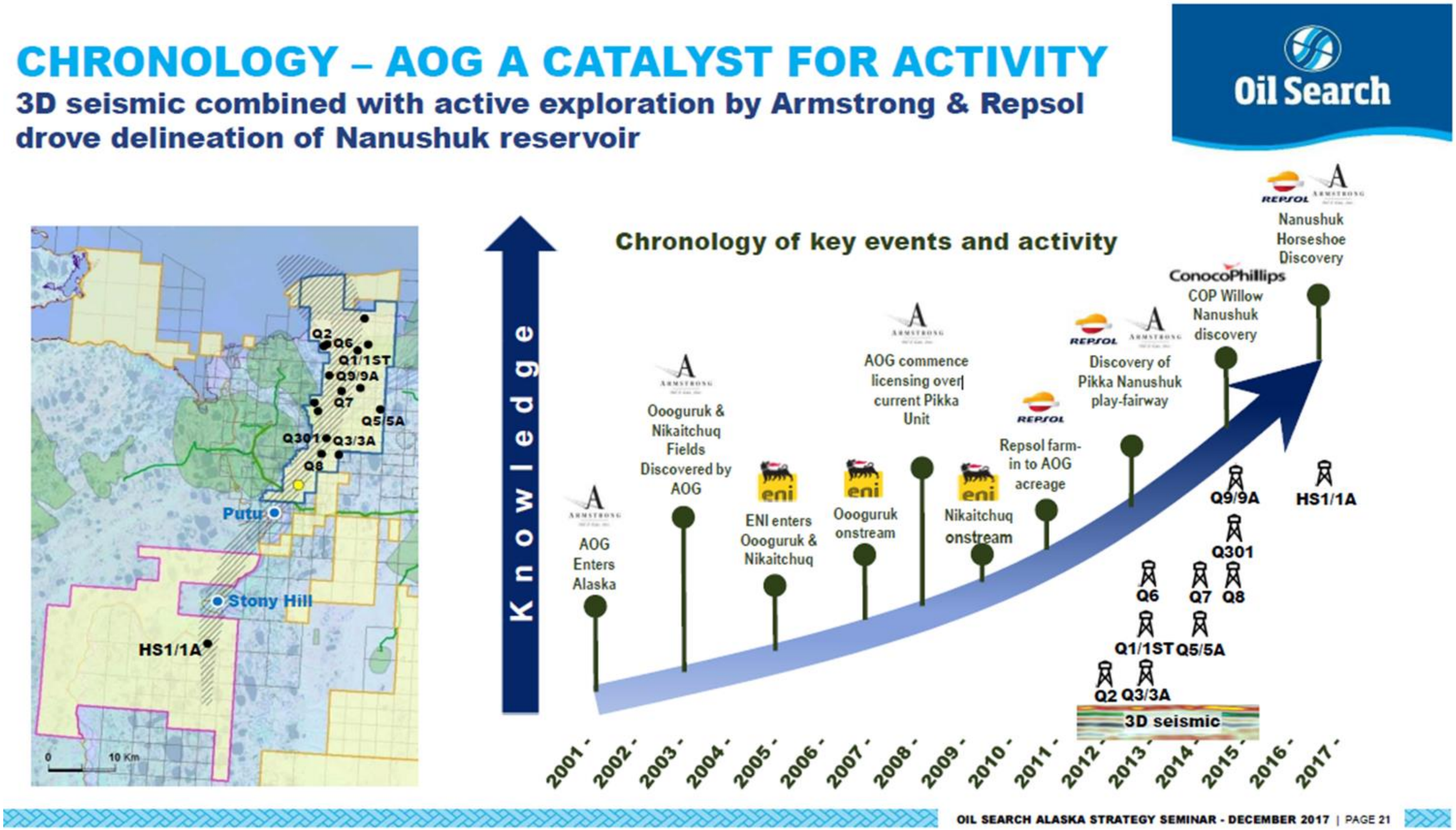
DETAILED SEQUENCE STRATIGRAPHY AND INTEGRATED RESERVOIR MODEL

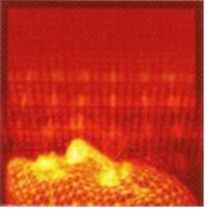
Excellent data set underpins reserve analysis



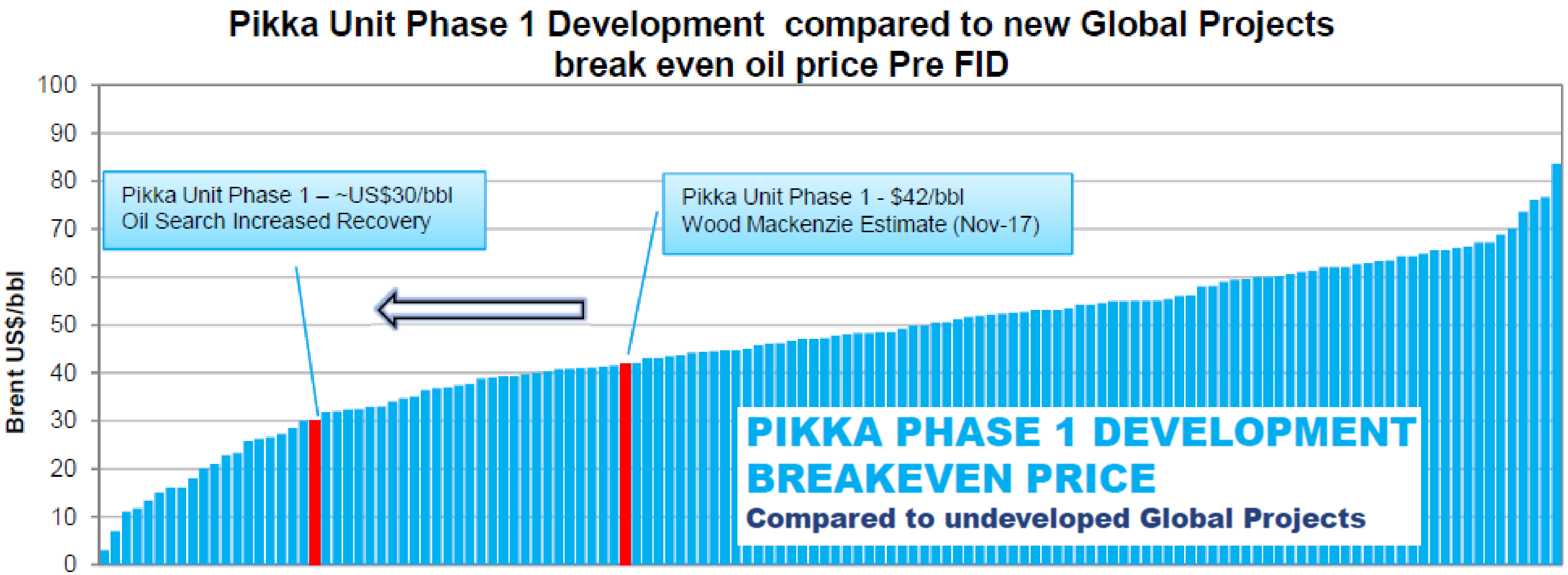


Pika discovery, Nanushuk Exploration

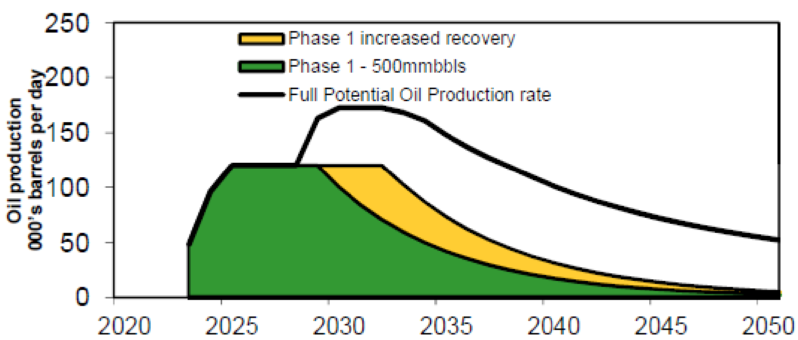


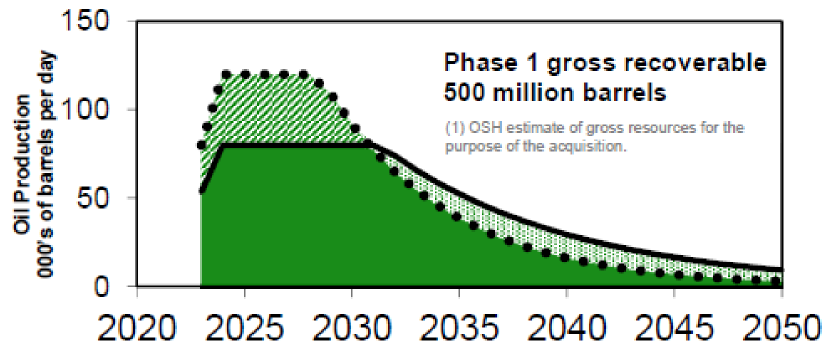


Pika discovery, Nanushuk Exploration

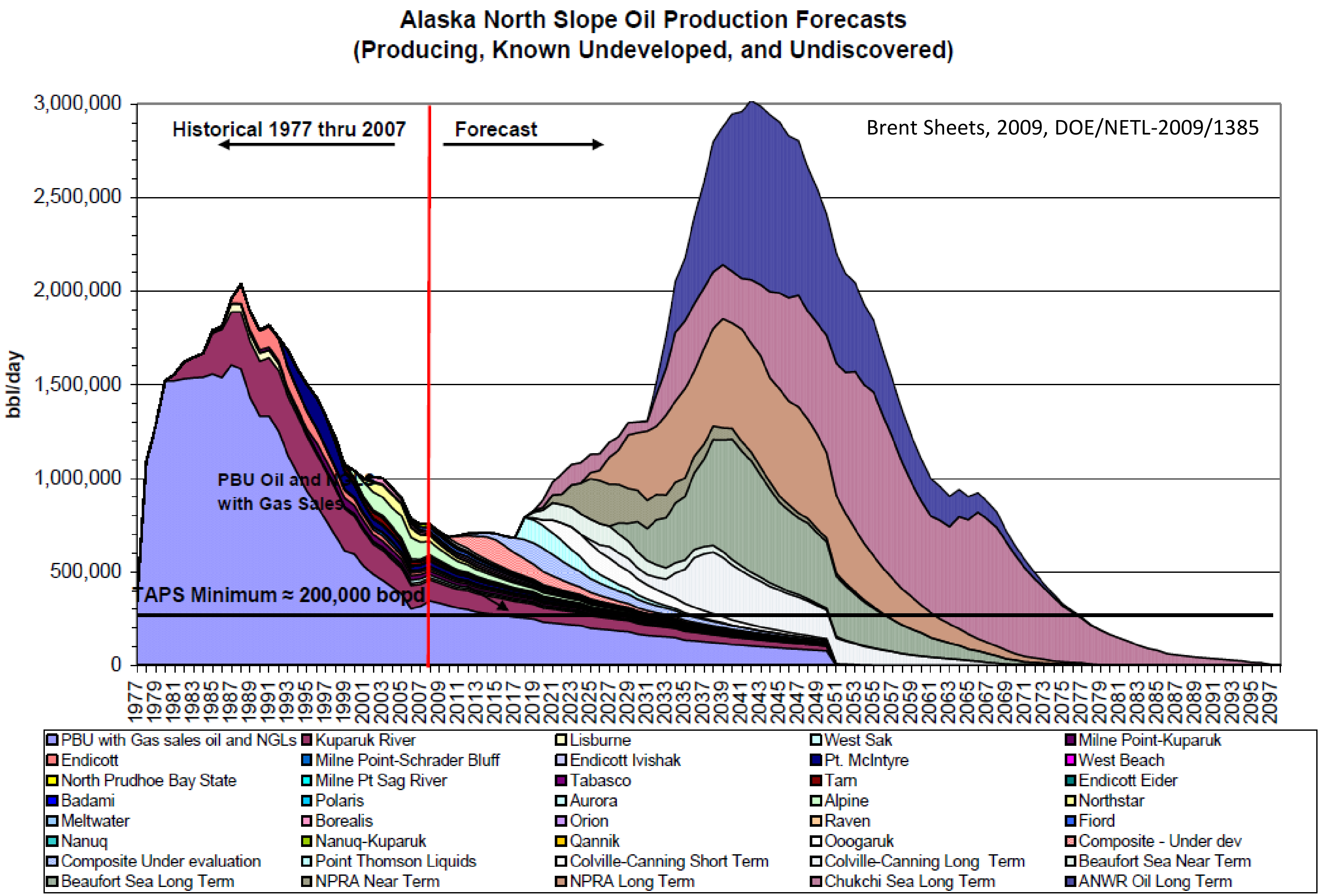


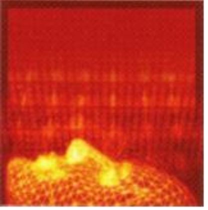
Source: Wood Mackenzie
Upstream Insights
Global upstream project tracker: Q317





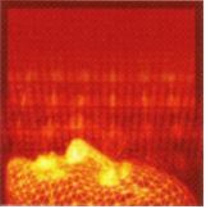
North Slope, Alaska





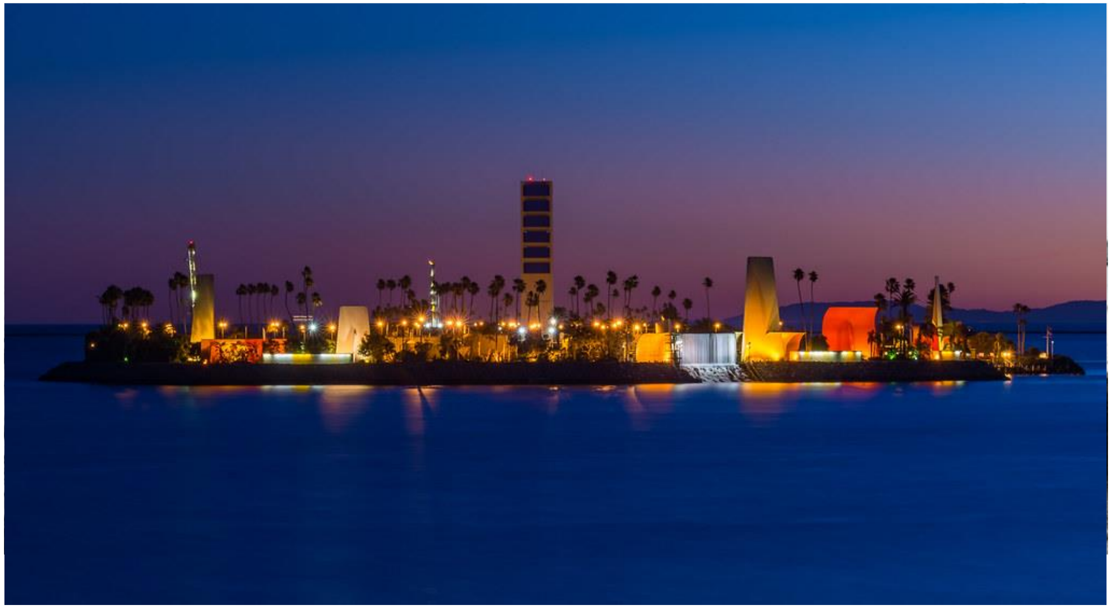
Lessons

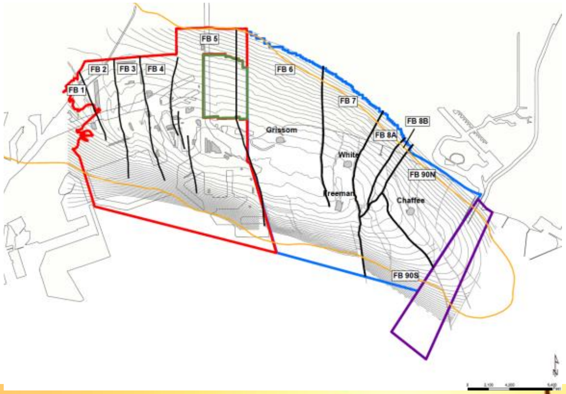
- North slope Alaska (Prudhoe Bay and the rest) is a very mature with **50 years of production**, yet a very active exploration region, calling for **$19Bn investment,** even today! Existing resource is projected **2050**, and the undeveloped resource projection is up to **2098**.
- Managed subsurface **knowledge through new 3D seismic** and technologies enabled long **term value creation**.
- One of the **lowest break evens in US ~$30!**
- Alaska has every verity of hydrocarbons, light to heavy crude, and gas.
- Recent discoveries, Pika and Horseshoe by Repsol and Conoco show **completely new plays in a mature basin**.
- **3D seismic** data and **reservoir modeling** enabled to land several multi-laterals in conventional reservoirs.
- **Sequence stratigraphy** aided by state of art science and technology in modeling are responsible for extending mature North Slope fields to another **70 years**.



San Joaquin Basin, CA

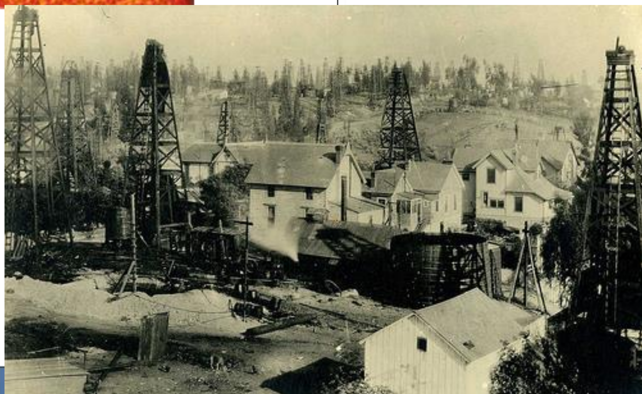
Willmington Field, Long Beach, CA

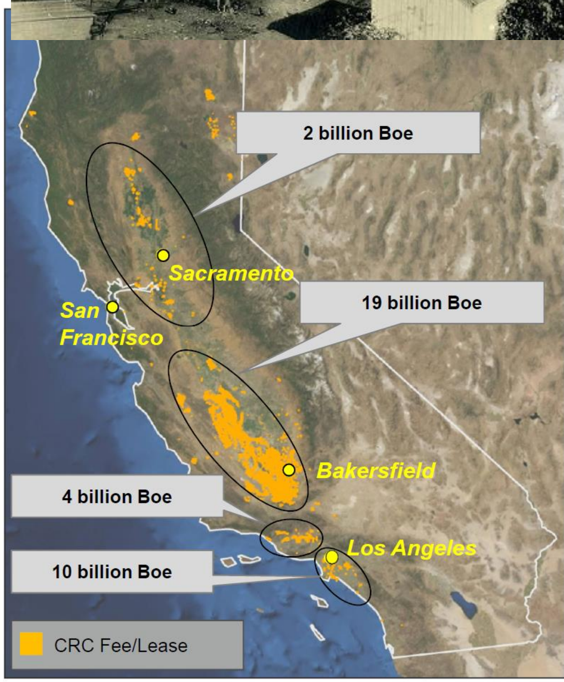


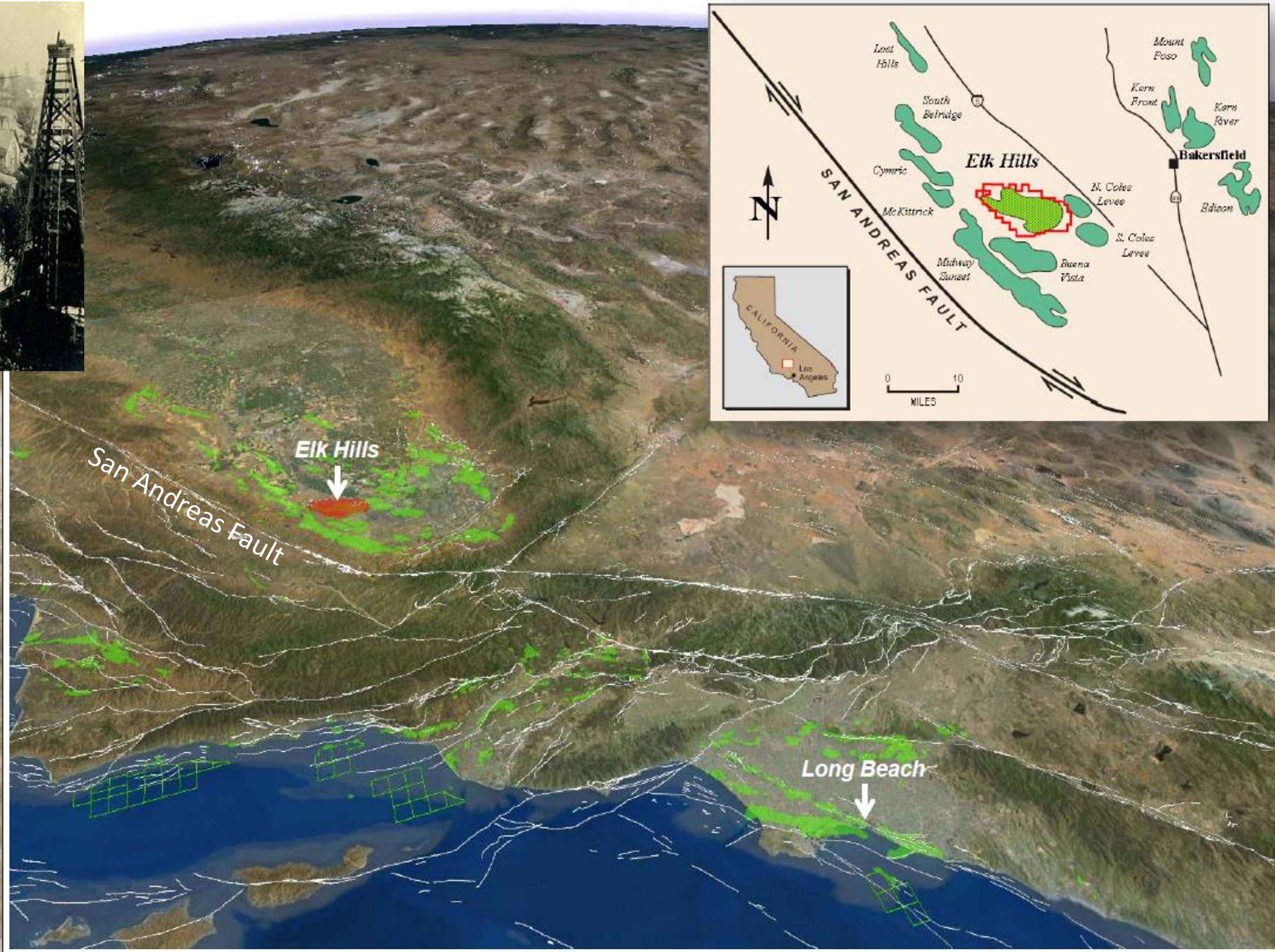


- Discovered in 1932. 3rd largest field in US, with initial estimated of 3Bblin in 2000.
- 7 major stacked turbidite reservoirs, 1428 wells
- 100% 3D seismic coverage
- Mature waterflood with 9% decline
- OOIP: 7MMBO; Cumm: 2.7MMBO, RF: 35%

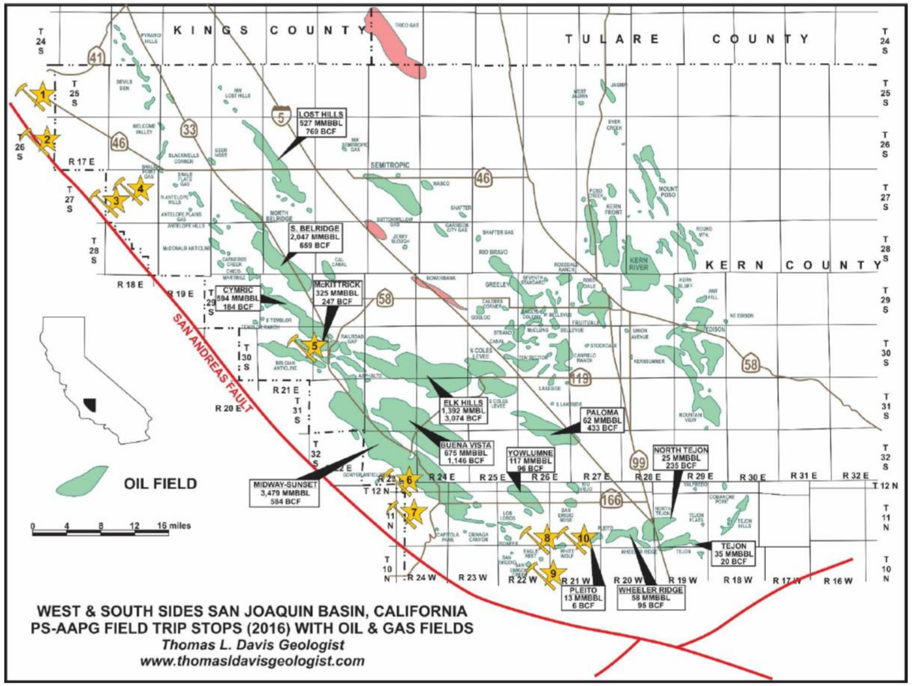
Elk Hills Field, San Joaquin Basin, CA

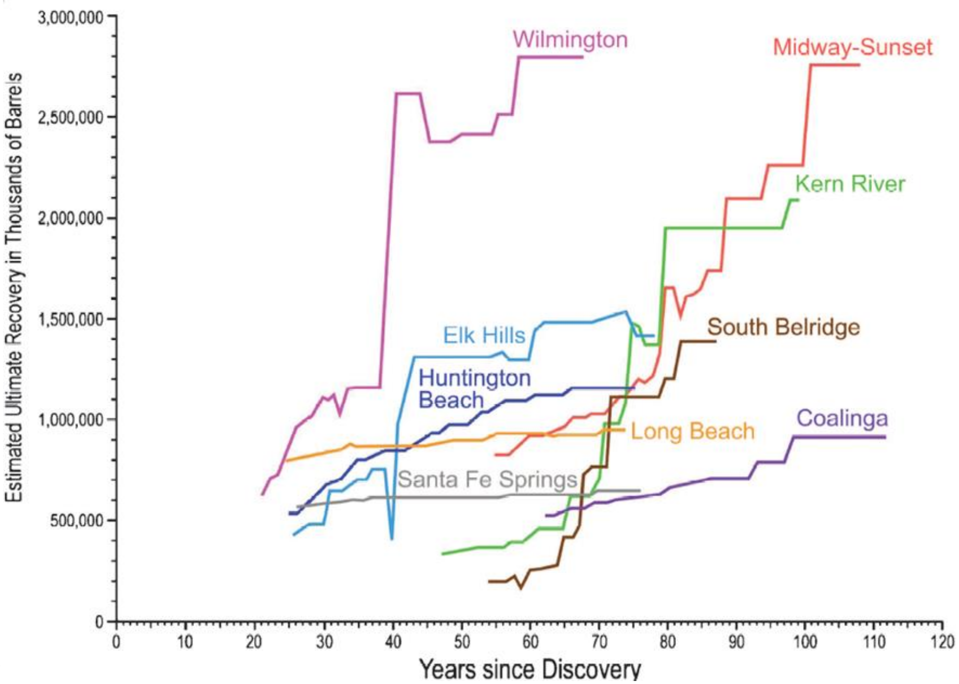






Elk Hills Field, San Joaquin Basin, CA

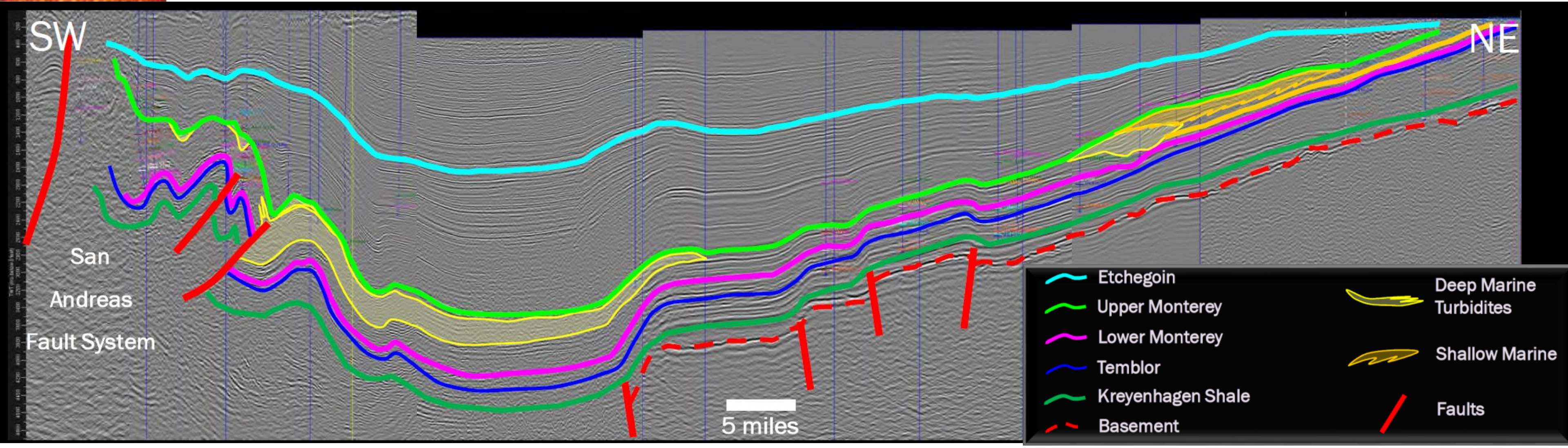


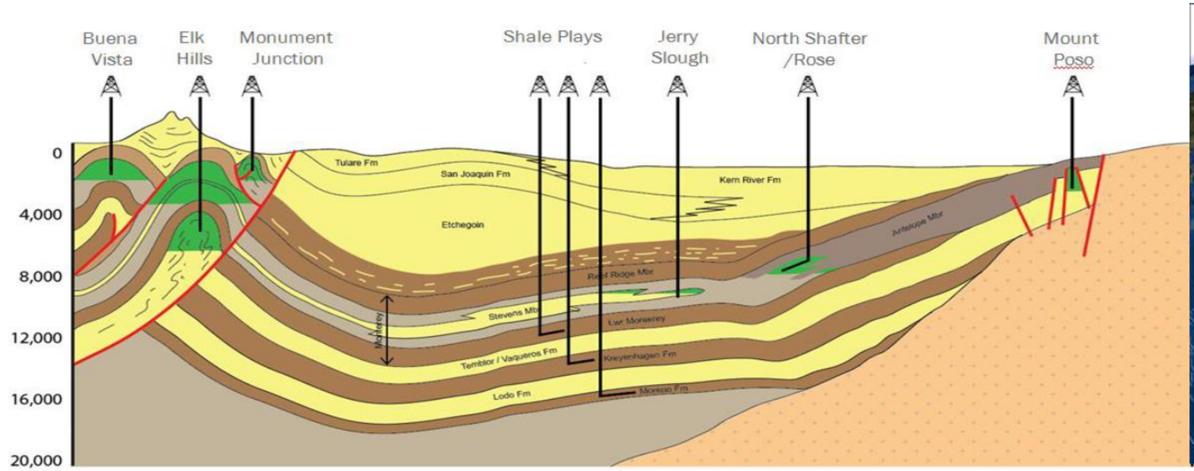


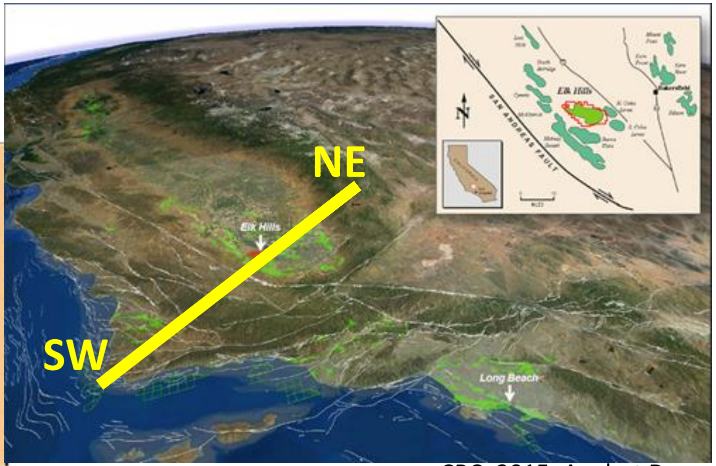
Rank	Field Name	State
1	Prudhoe Bay	AK
2	Sprayberry Trend Area	TX
3	Mars-Ursa (Miss. Canyon)	Offshore Gulf
4	Thunder Horse (Miss. Canyon)	Offshore Gulf
5	**Belridge South**	**CA**
6	Kuparuk River	AK
7	Wasson	TX
8	Atlantis (Green Canyon)	Offshore Gulf
9	Midway-Sunset	CA
10	Elk Hills	CA

- San Joaquin basin has three of the top 10 giant fields in US. Many of these fields share the unique and young geology, with reservoirs from Cretaceous to Pleistocene.
- **All of these fields experienced 2nd and 3rd lives after 40-50 years of production**. This is due to constant update of subsurface knowledge and the right use of technology
- Recent USGS estimates **1.4-5.6 BBbl** of recoverable oil (Gautier, et al, 201 in 10 fields in the San Joaquin basin.

Elk Hills Field, San Joaquin Basin, CA

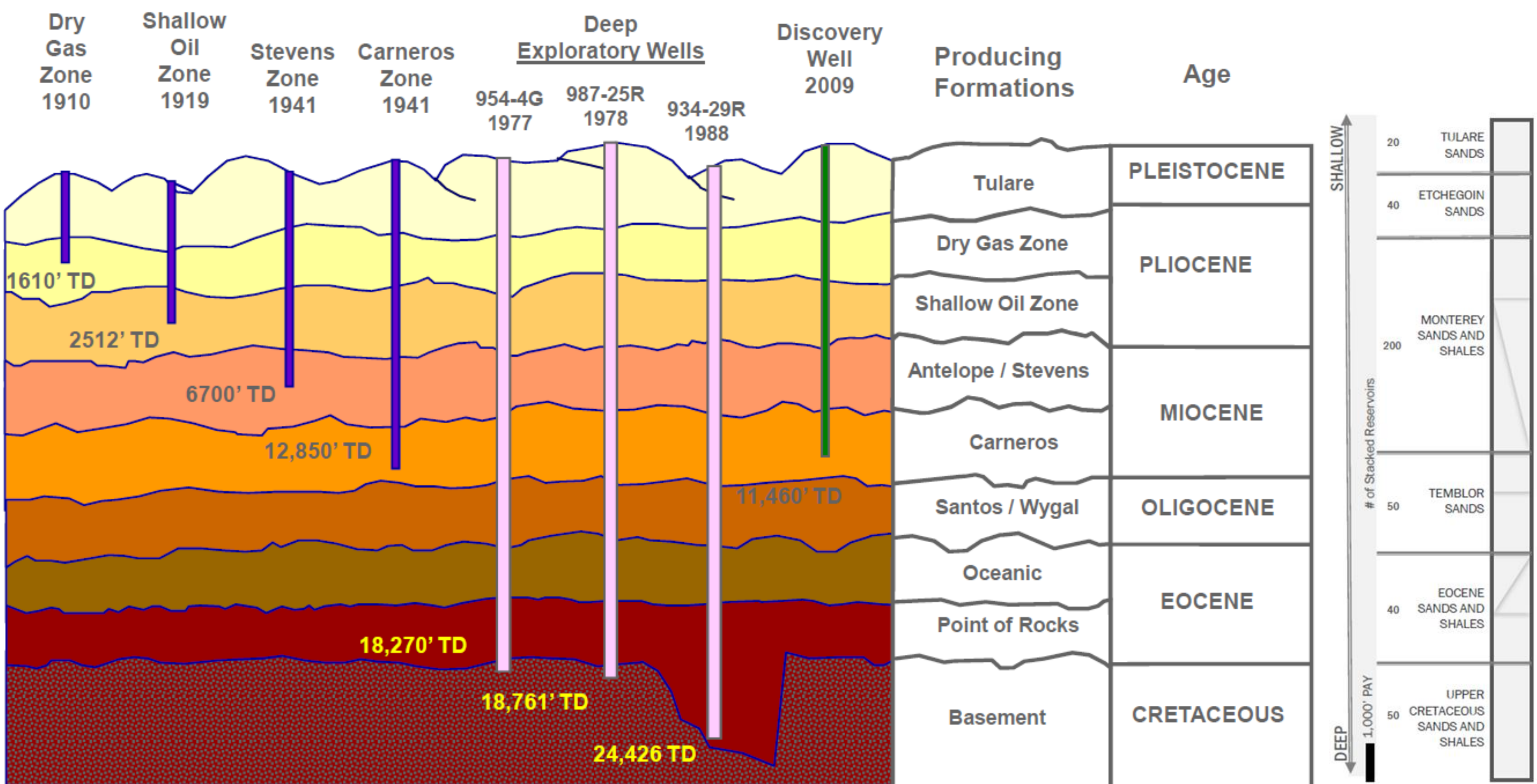






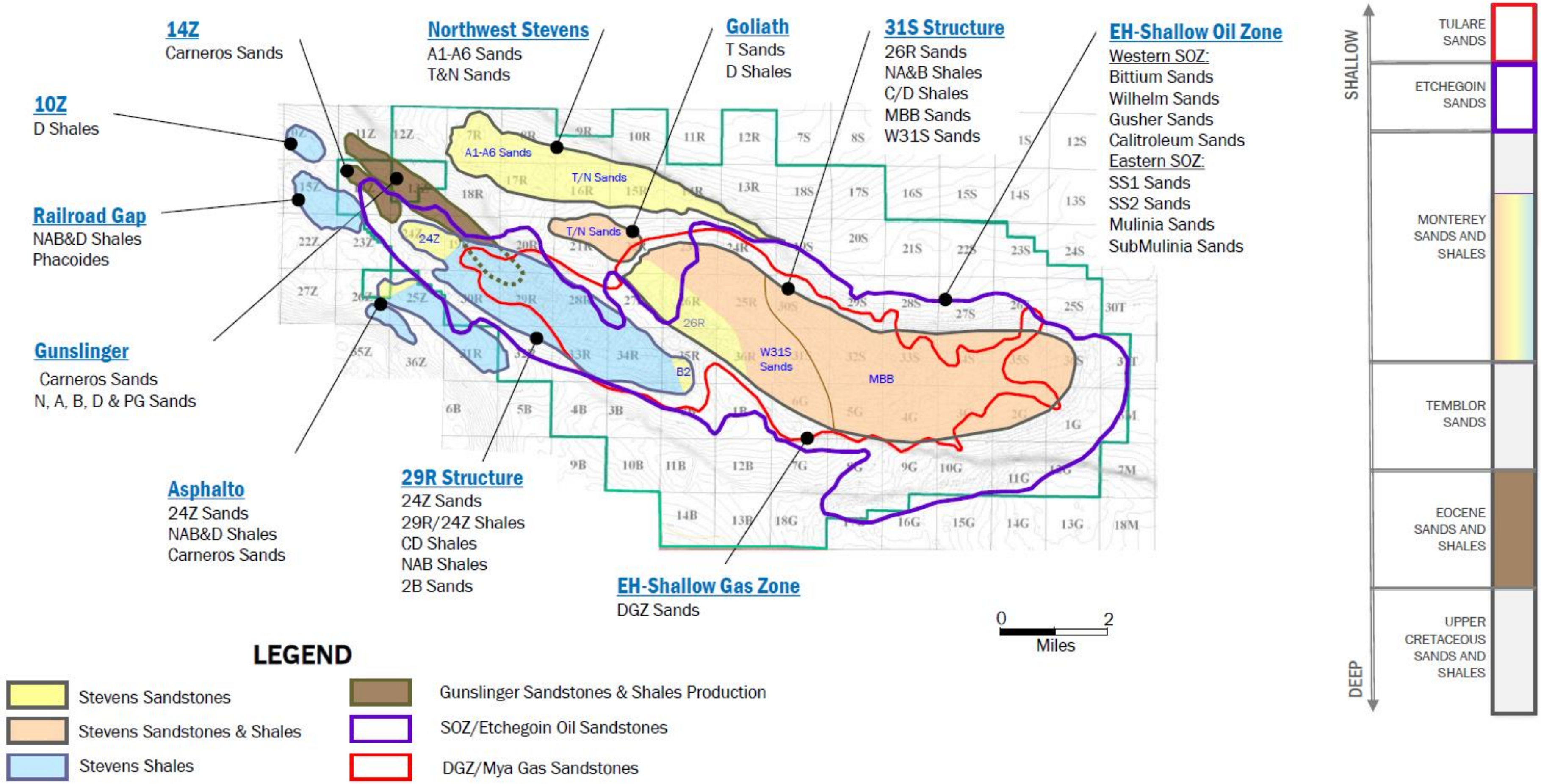
CRC, 2015, Analyst Day

Elk Hills Field, San Joaquin Basin, CA

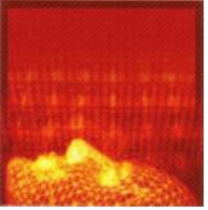


CRC, 2015, Analyst Day

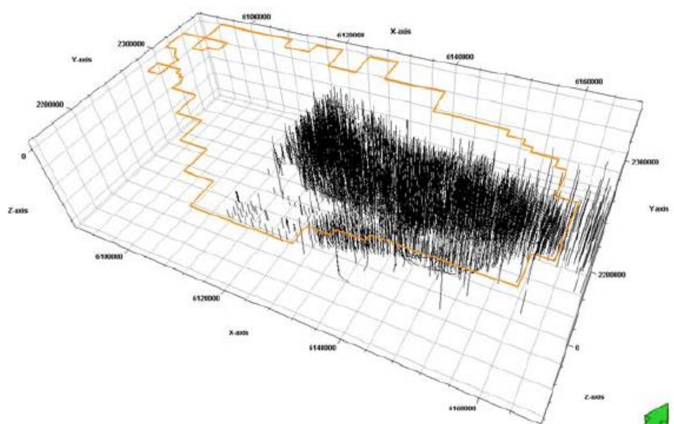
Elk Hills Field, San Joaquin Basin, CA

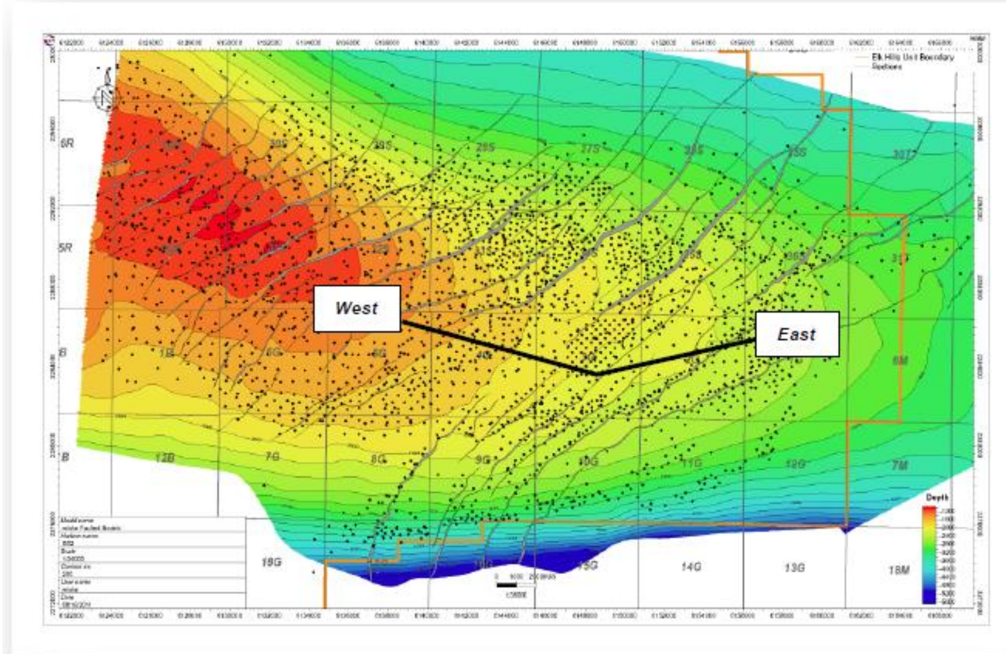


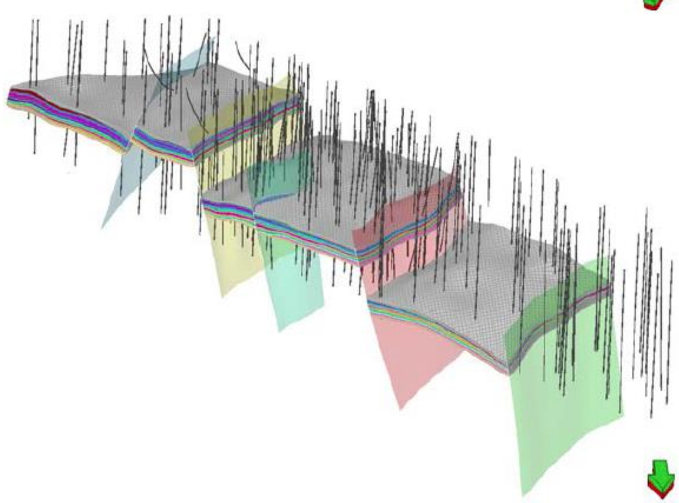
CRC, 2015, Analyst Day

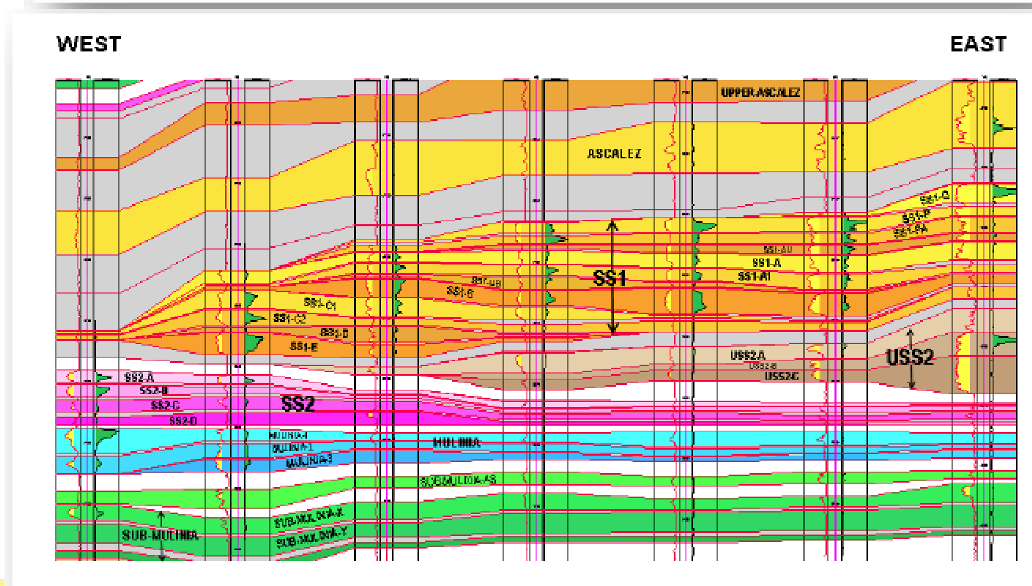


Elk Hills Structure, CA









Elk Hills Field, San Joaquin Basin, CA

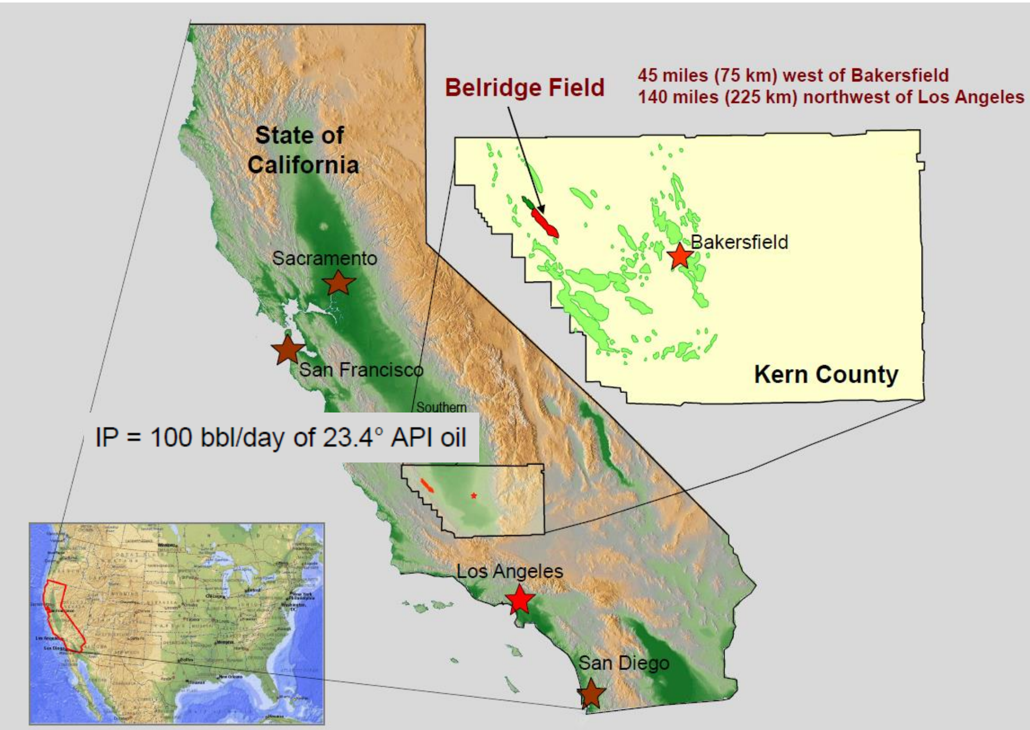
Number of Well Types: 8,643 **Well Types Having Production:** 7,235 **Well Types Having Injection:** 841

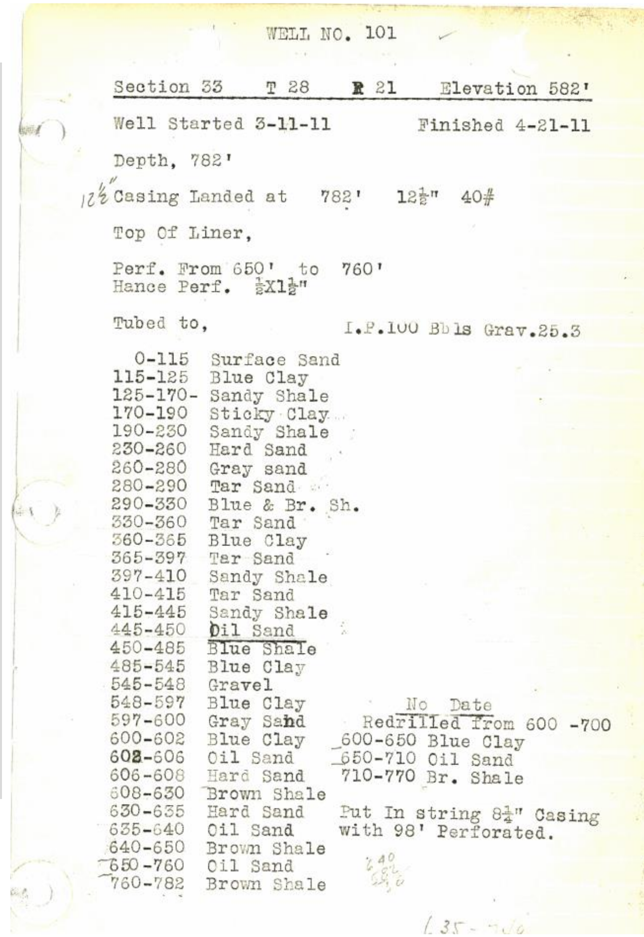
Oper: Occidental of Elk Hills, Inc. 00495

- 2017 Average Net production 53MBOE/d
- 11Billion OOIP with cumm production of 2.7 Billion BOE
- ~3400 producing wells

CRC, 2015, Analyst Day

Belridge Giant Oil Field, San Joaquin Basin, CA





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,

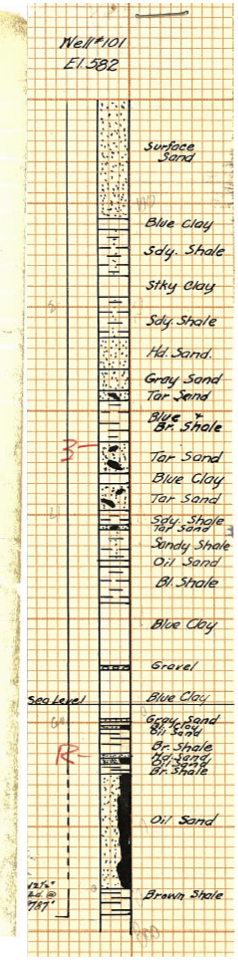
Perf. From 650' to 760'
Hance Perf. ½X1½"

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.

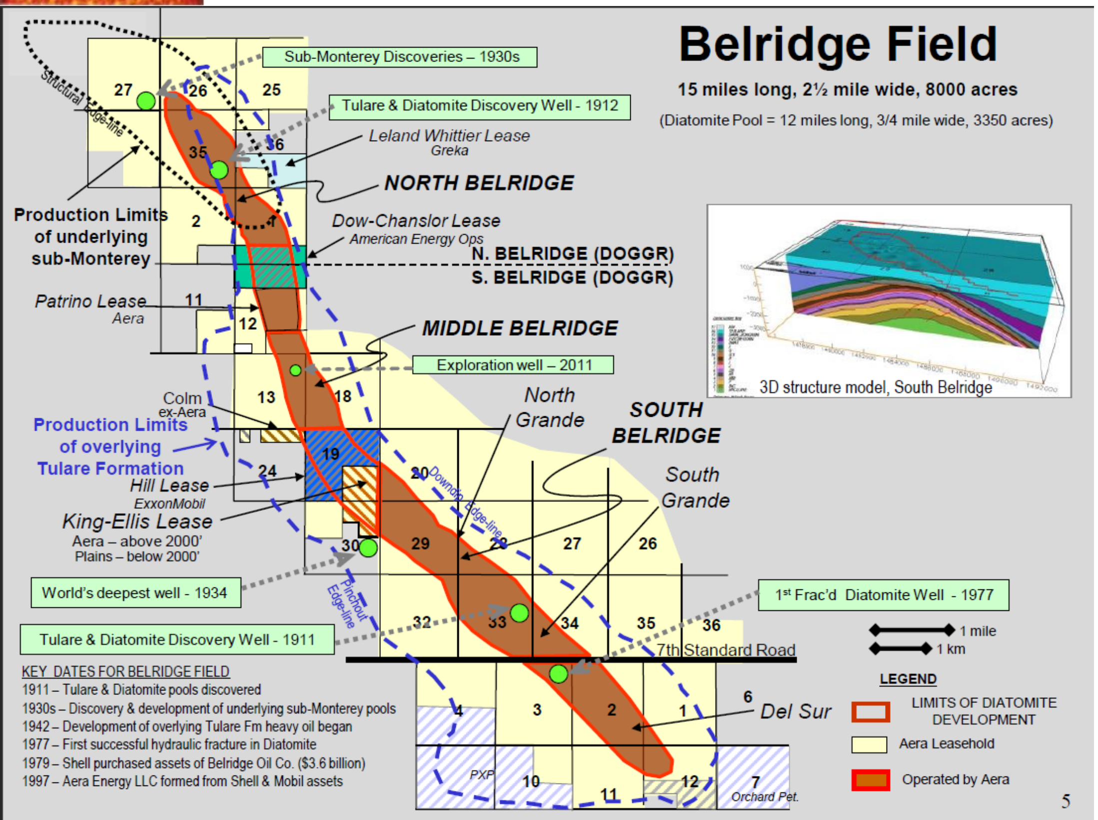


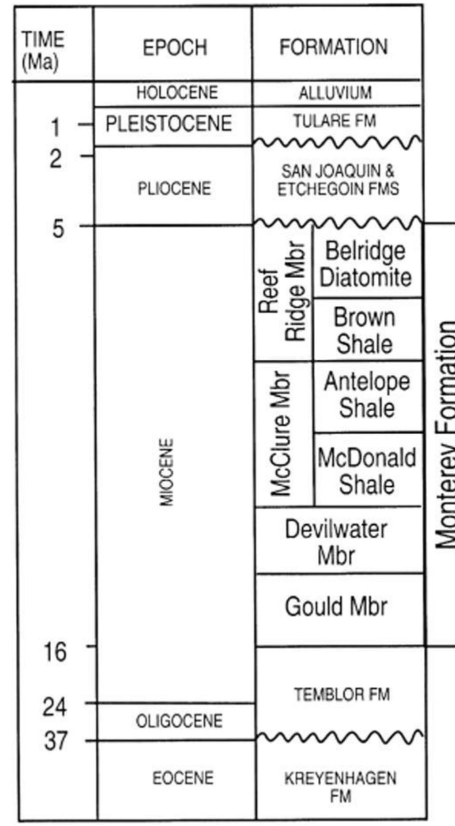
The Belridge Giant Oil Field - 100 Years of History and a Look to a Bright Future*

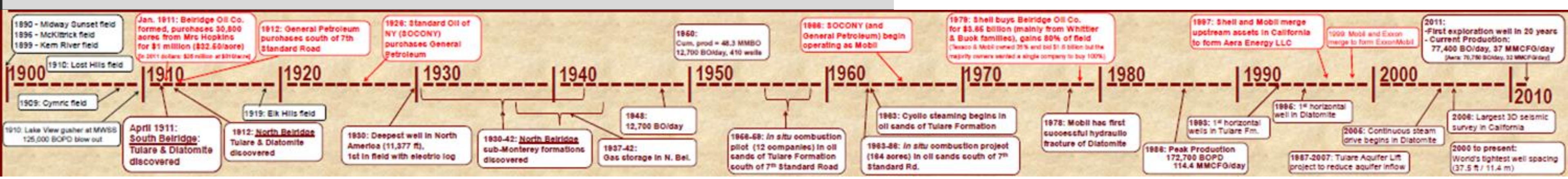
Malcolm E. Allan[1] and Joseph J. Lalicata[2]

Search and Discovery Article #20124 (2012)
Posted January 17, 2012

Belridge Giant Oil Field, San Joaquin Basin, CA



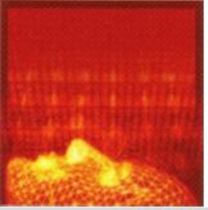




Belridge Giant Oil Field, San Joaquin Basin, CA

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)

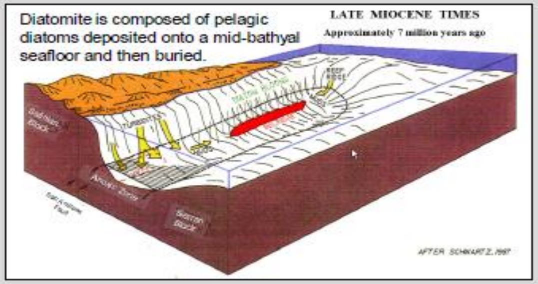
3 active pools + 5 drilling rigs + 15 workover rigs = very crowded infrastructure

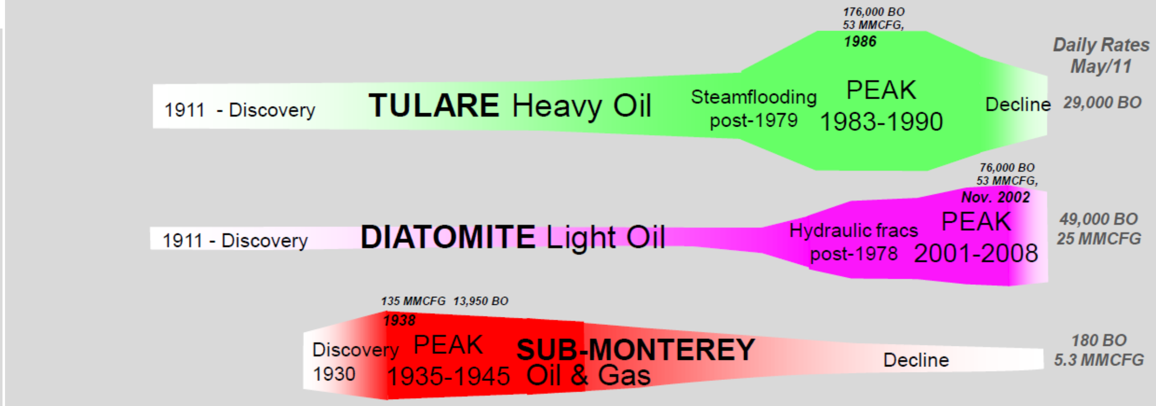


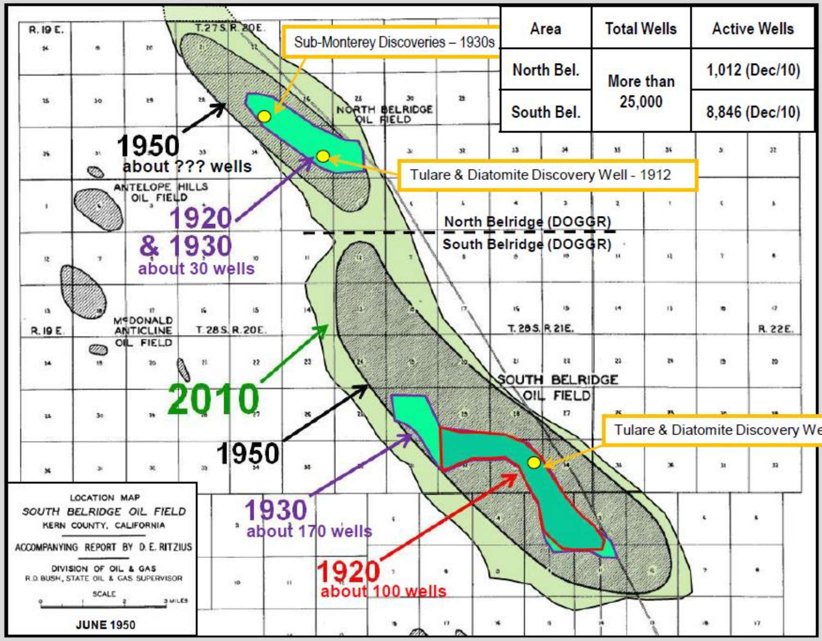
Belridge Giant Oil Field, San Joaquin Basin, CA

BELRIDGE FIELD, Diatomite Pool

12 miles long, 1 mile wide, 3500 acres
(20 by 2 km, 1400 ha)

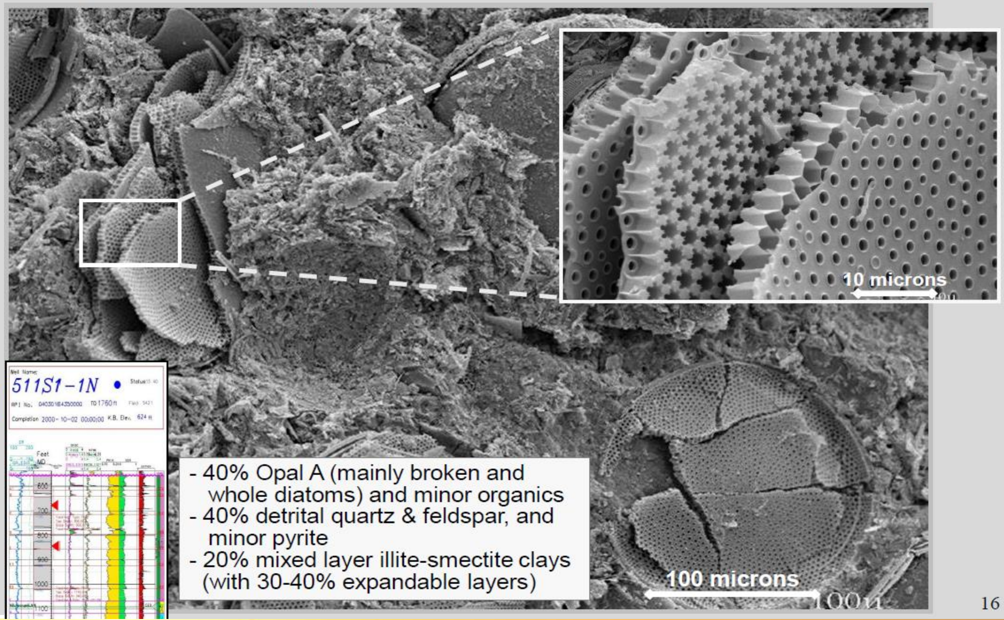




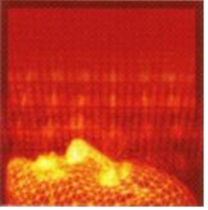


Area	Total Wells	Active Wells
North Bel.	More than 25,000	1,012 (Dec/10)
South Bel.		8,846 (Dec/10)

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)



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

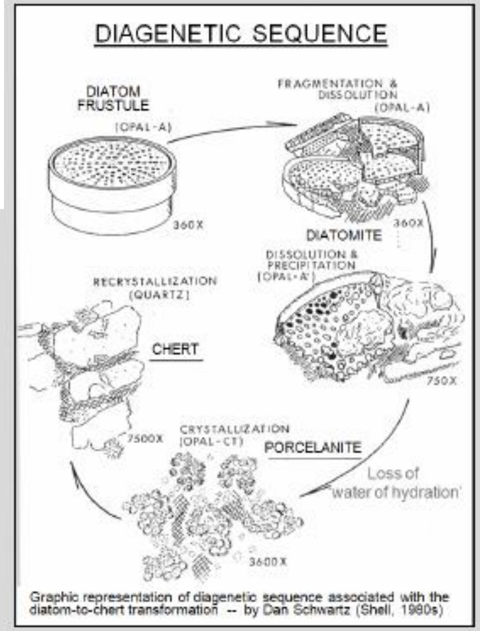
- One ft^3 of rock has 15 million ft^2 (340 acres, *140 ha*) of surface area
- Water-wet and has high interstitial water saturation (S_{wi}) above 50%

Highly Compressible

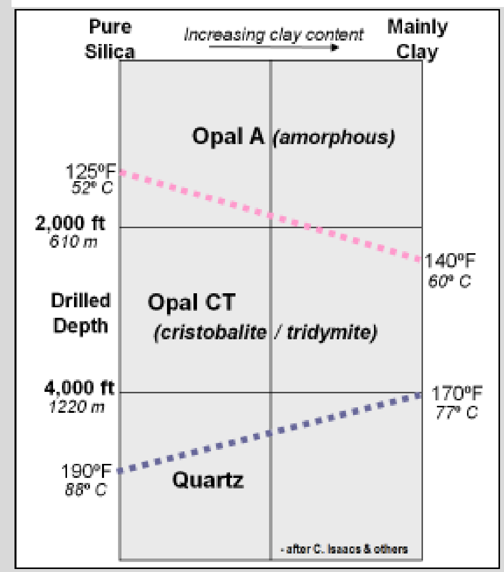
- Opal A compressibility (Cr) 100-300 microsips, Opal CT ± 10-30 microsips
- Decrease in pore pressure results in compaction in the reservoir (especially in the shallower Opal A) which causes subsidence of the overburden and lateral movement at or near the unconformity with the overlying Tulare Formation

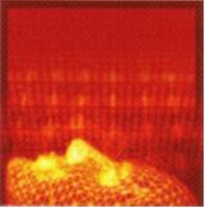
Reservoir Fluids move very Slowly

- 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)

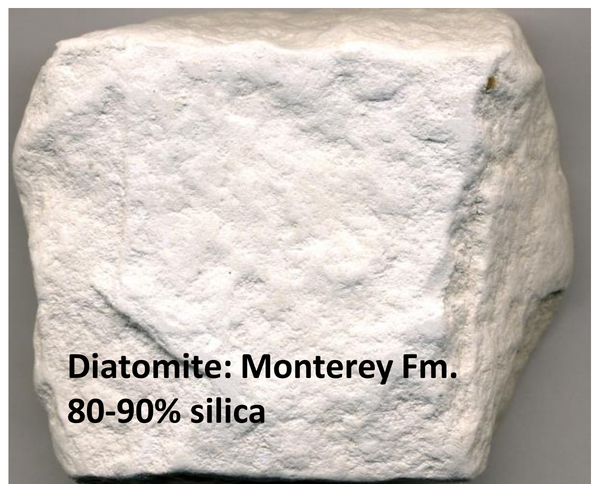




Belridge Giant Oil Field, San Joaquin Basin, CA

Monterey Fm: alternate layers of Diatomite and organic rich shale

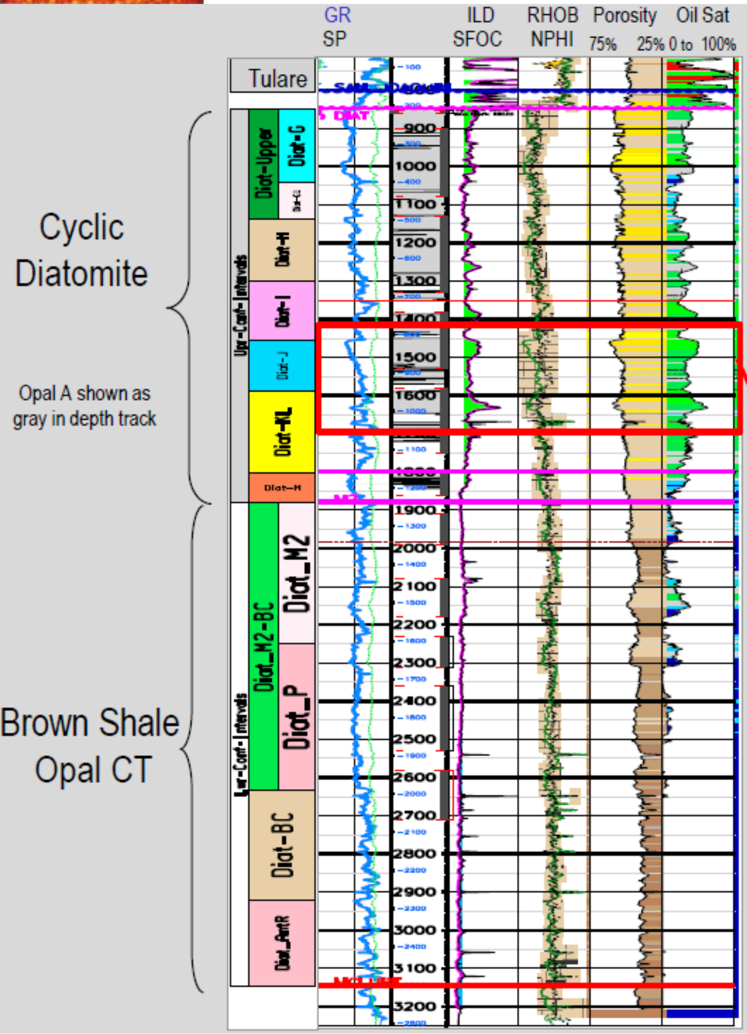
Tar seepages in the beach



Diatomite: Monterey Fm. 80-90% silica

Sandstone saturated with heavy oil: Tulare Fm.

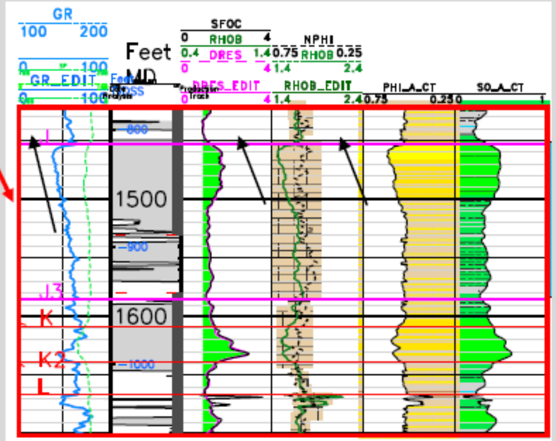
Type log of diatomite reservoir



Lithostratigraphy = Chronostratigraphy

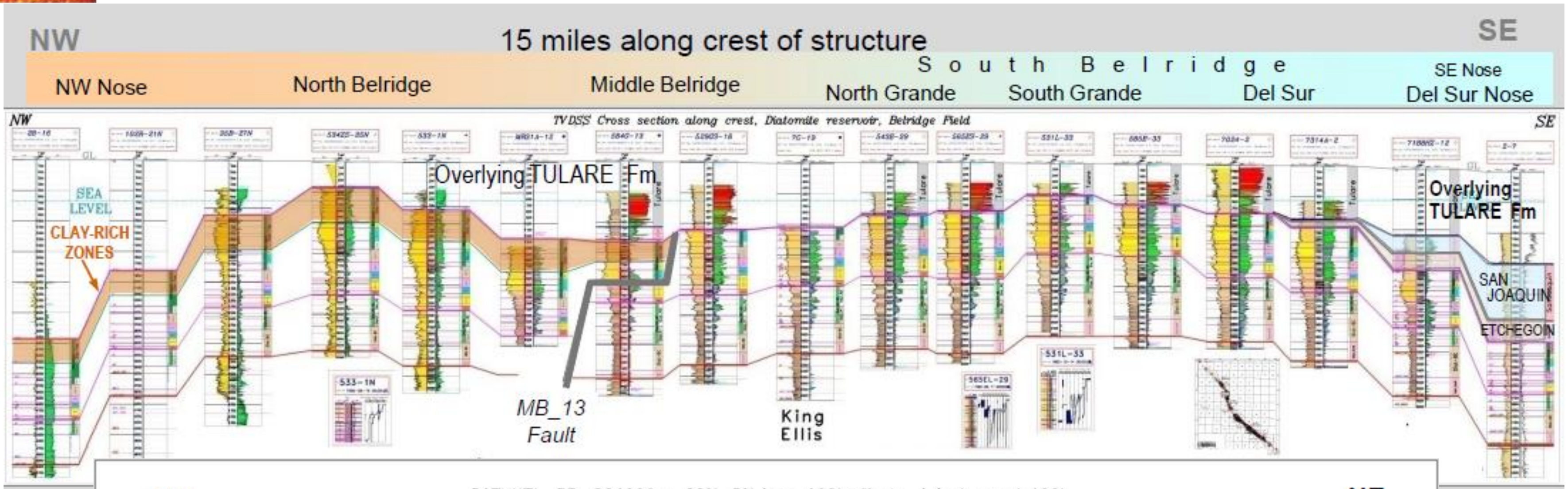
Note the ‘cleaning upward’ funnel patterns on the GR and RHOB / Porosity curves.

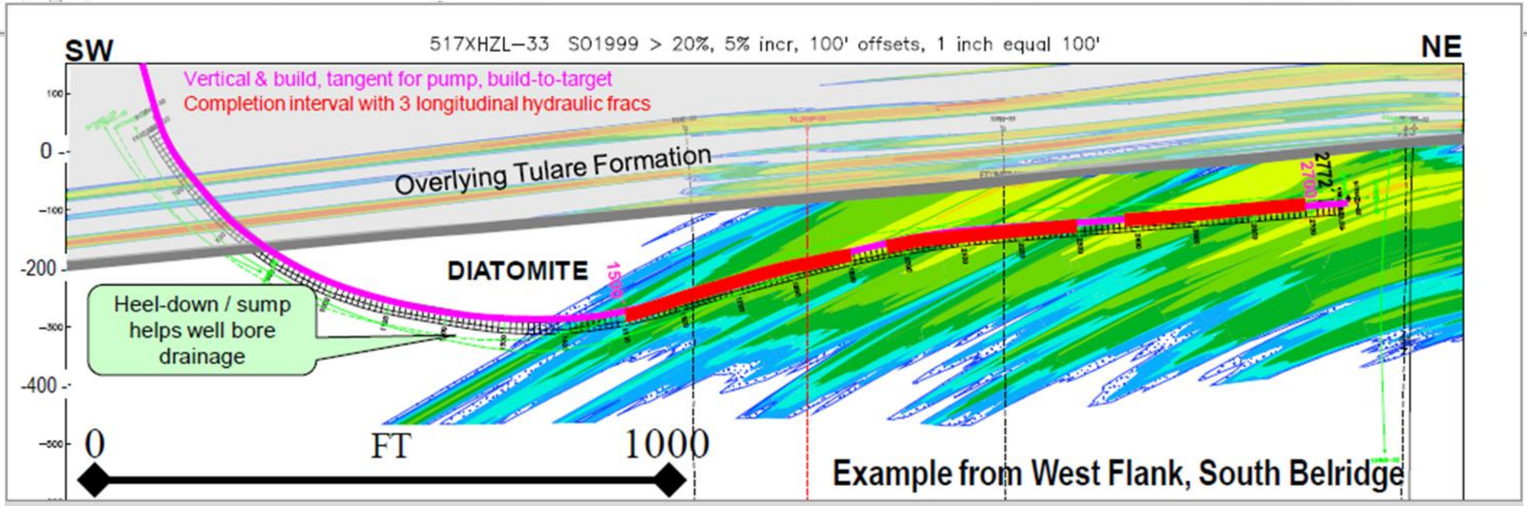
Each major cycle starts with a layered clay base and gets cleaner upwards until it is almost pure diatomite. It is then overlain by the clay-rich base of the overlying cycle

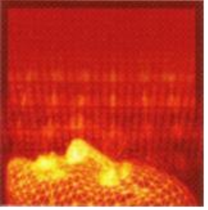


Each of the 9 production intervals (between DIAT & M2 markers) used for volumetrics and injection conformance has one or more major depositional cycles

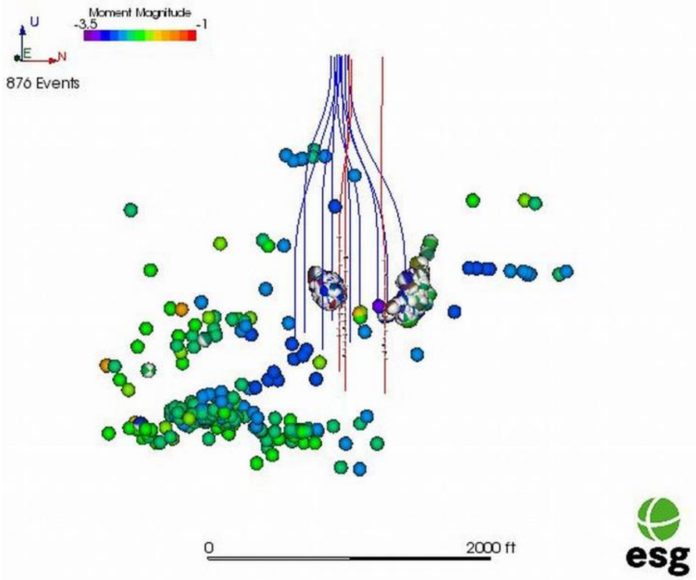
Horizontal wells

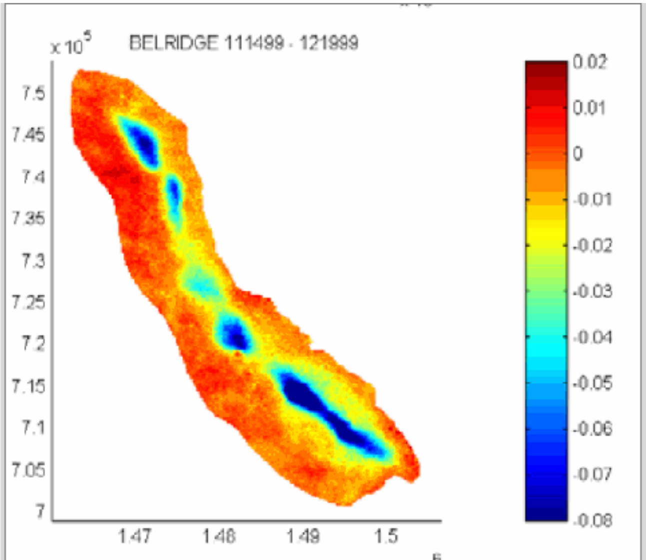




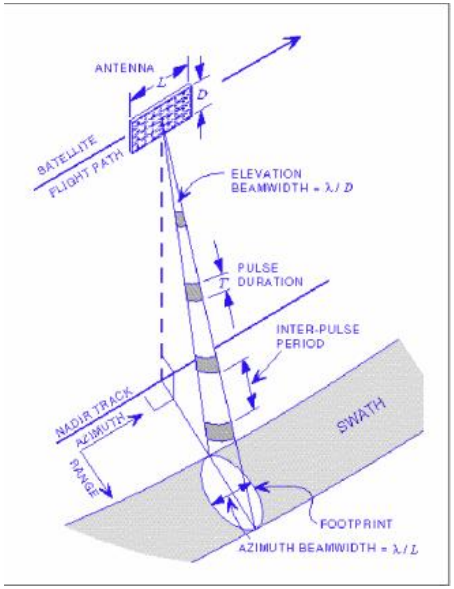


Technology backed production





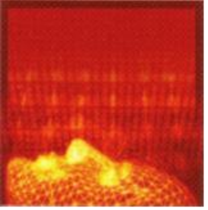
From Patsek, EIA Workshop, 2000



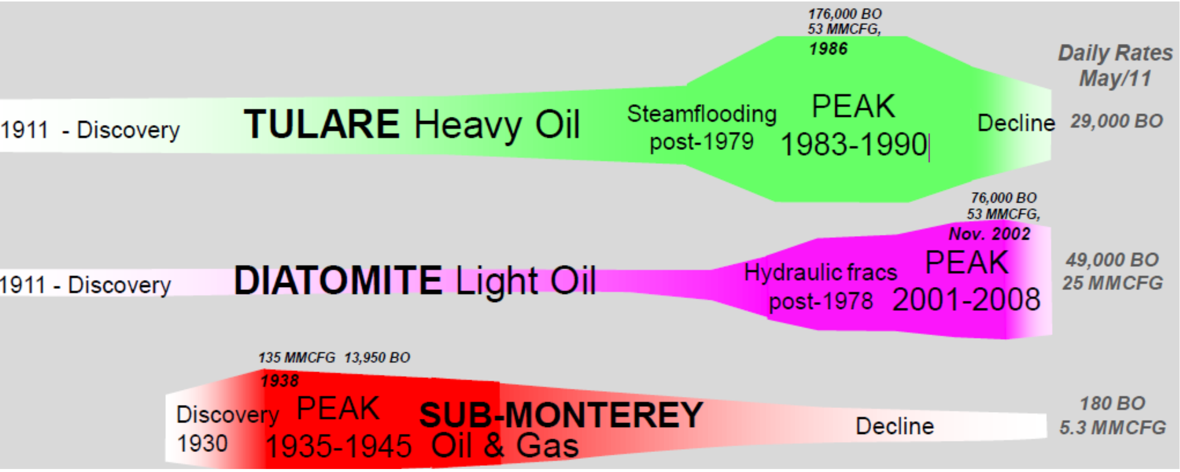
The diatomite reservoir is very weak and will compact without adequate pressure support. This compaction causes subsidence of the ground surface and also 'dog-legs' and eventually shearing of the well bores.

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

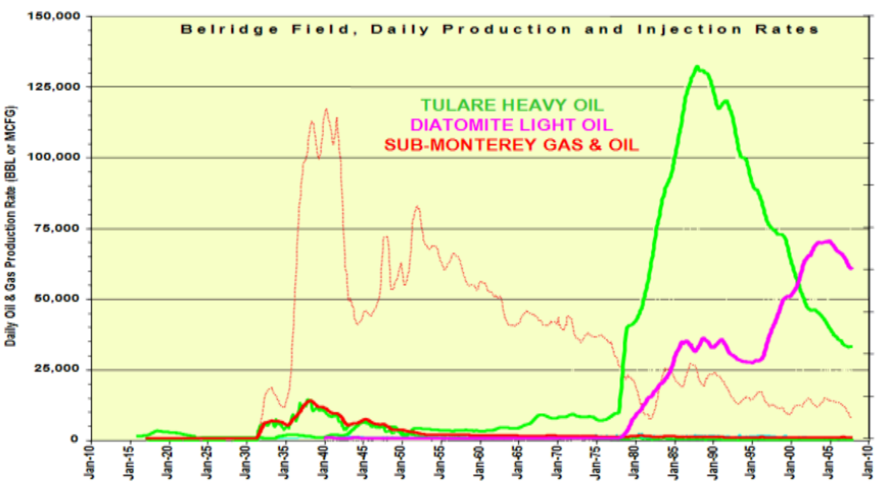
Satellites gather data every 24 days and comparisons of surface elevation with previous months are used to monitor conformance of injection and production across the field.



Belridge Giant Oil Field, San Joaquin Basin, CA



- 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 fluvio-deltaic sands and the diatomite.



Daily oil production 2016 in barrels of oil equivalent (BEQ/D)

Belridge Diatomite 45,590 BEQ/D

Belridge Tulare 30,335 BEQ/D

Total 75,000bopd and 37MMcft per day

Peak: 176,000bbls (1986)

Apprx: 6Bn OOIP, and cumm of 1.6Bn bbls

Infrastructure

Producing Wells 6,431 wells. Tulare 1,429 wells; Diatomite 5,002 wells

Steam Injection Wells 1,401 wells

Water Injection Wells 1,355 wells

Pipelines (intrafield) 250 miles

Roads 400 miles

Lessons

- San Joaquin basin, CA hosts 3 of the top10 giant fields in the US. Many of these fields share the unique and young geology, with reservoirs from Cretaceous to Pleistocene. All of these fields experienced 2^{nd} and 3^{rd} lives after 40-50 years of production. This is due **constant update of subsurface knowledge** and right use of technology
- At 53,000 bbls/day Elks hills is still a better bargain than many unconventional plays, at California prices. This has ben possible due to technology and efficiencies in operations. Belridge produces 75,000bbl/day, from 6000 wells and 2400 injectors.
- Almost every field is covered with 3D surveys and employed fit-for-purpose reservoir model, for placing accurate horizontal wells and to guide water/steam flood production.
- Reservoirs are exploited with a wholistic, petroleum systems and chronostratigraphic approach.
- Pressure maintenance and field subsidence is monitored by satellite! and microseismic and cross well tomography is used to monitor fracture growth with production and dynamic changes in the fluid content.
- These fields have ~6000 active wells and a dynamic database of subsurface and very challenging reservoirs, such as diatomite. New wells are drilled using detained stratigraphic modeling, as opposed to geometric EOR/waterflood pattern drilling.

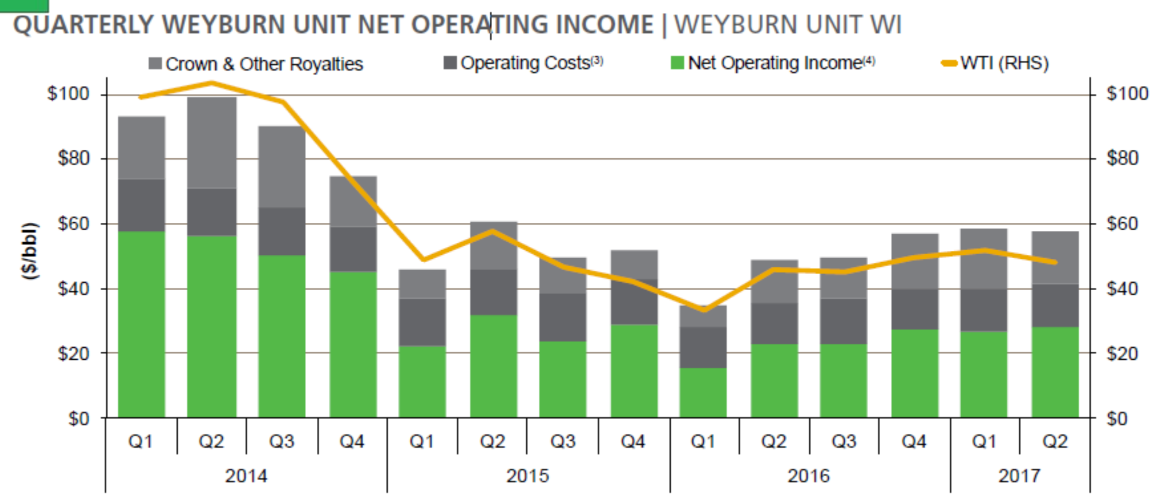
[A millennial job interview](https://www.youtube.com/watch?v=Uo0KjdDJr1c)

https://www.youtube.com/watch?v=Uo0KjdDJr1c

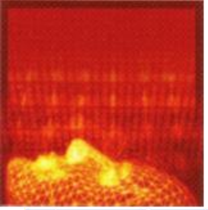
Weyburn Unit, Saskatchewan, Canada

- The Weyburn Unit is located approximately 129 km southeast of Regina, Saskatchewan
- Current gross production: 25,000 Boe/d at an average water cut of 88.0%., 31 API, with a reserve life of ~50 years.
- Weyburn Unit is serving as one of the world's largest geological CO_2 storage projects, injecting 2.5 MM tons every year!

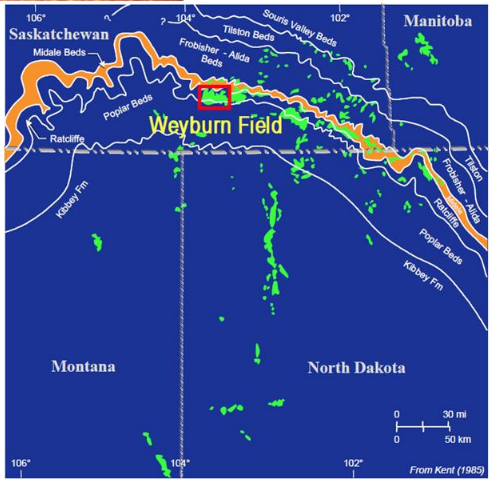
- Base decline is 3% ! Reversed from~10% in late 70's
- Operating costs are low and maintained significant operating income under price pressure

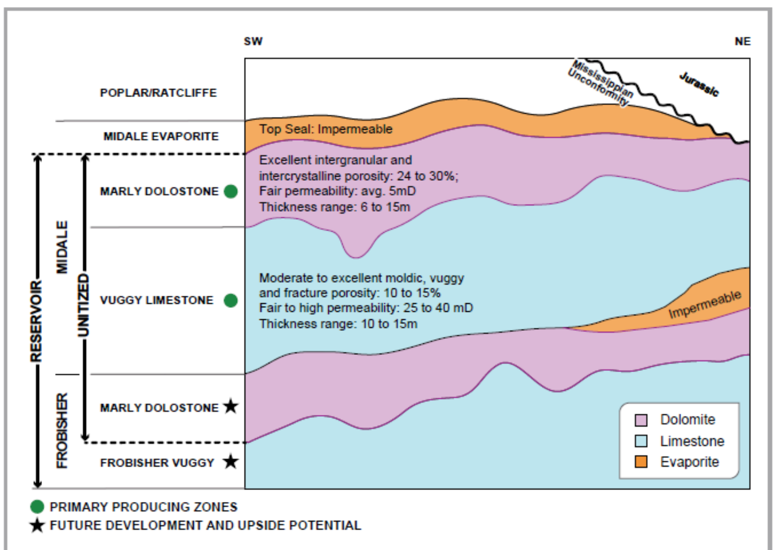


www.CenovusEnergy.com



Weyburn Unit, Saskatchewan, Canada



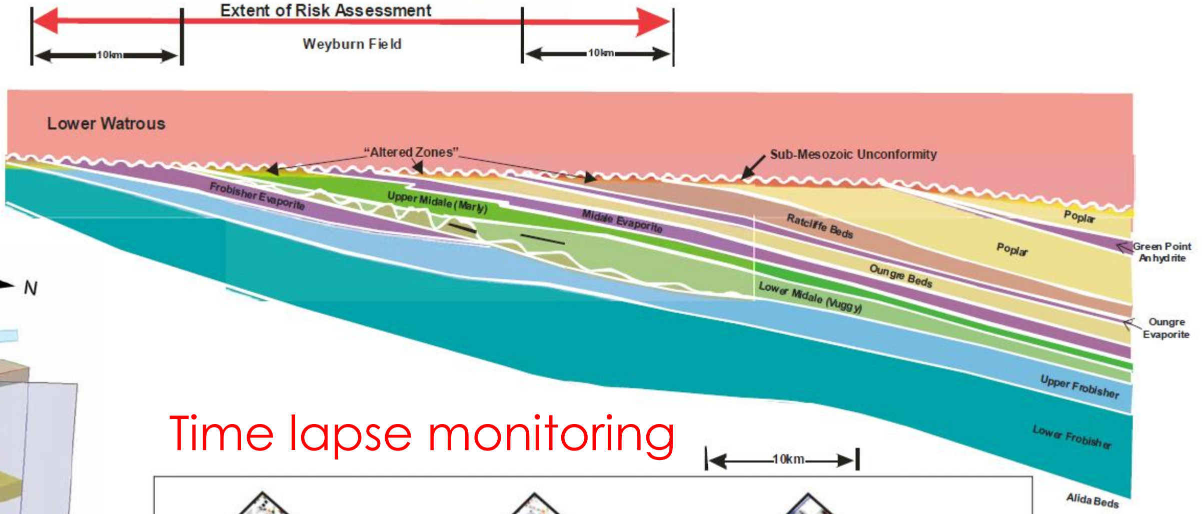


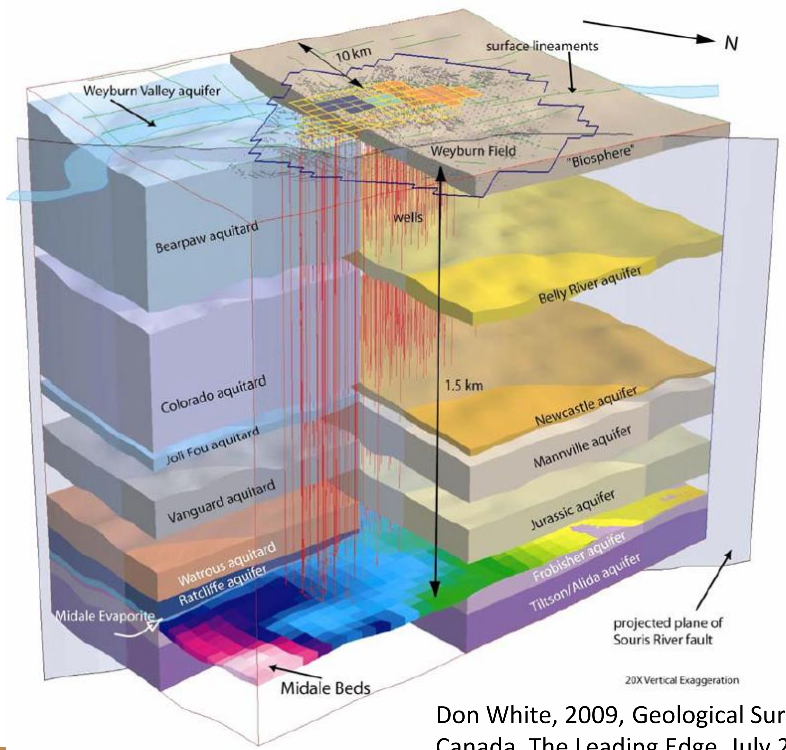
- **The Mississippian aged Midale Beds are the primary reservoir interval at Weyburn**
  - » Divided into an upper dolomite "Marly" unit and a lower limestone "Vuggy" unit
- **The reservoir units are directly overlain by the Midale Evaporite, forming a top seal**
- **CO_2 is typically injected into the same interval as the offsetting producing well**
- **While not part of the Weyburn Unit, the underlying Frobisher Vuggy has similar characteristics to the Midale Vuggy and has been proven to be productive**

Weyburn Unit, Saskatchewan, Canada

3D static Model

The 3D static model serves both oil production as well as to store CO2, a greenhouse gas.





Time lapse monitoring

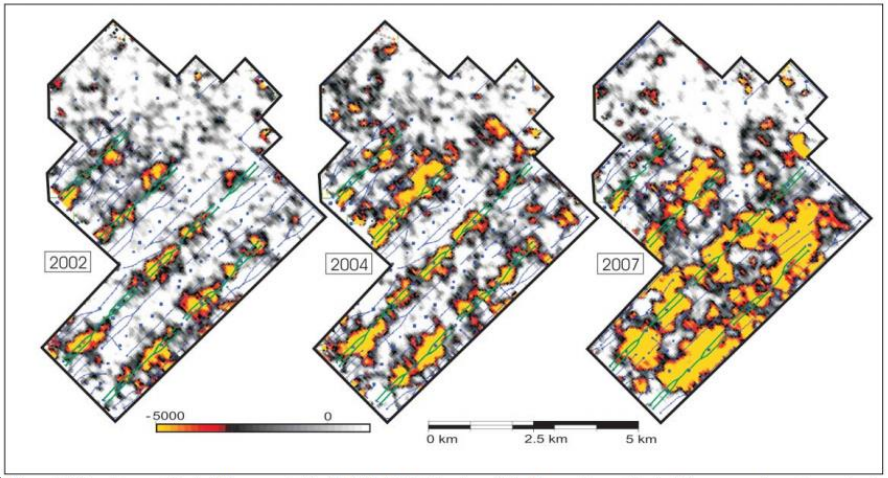
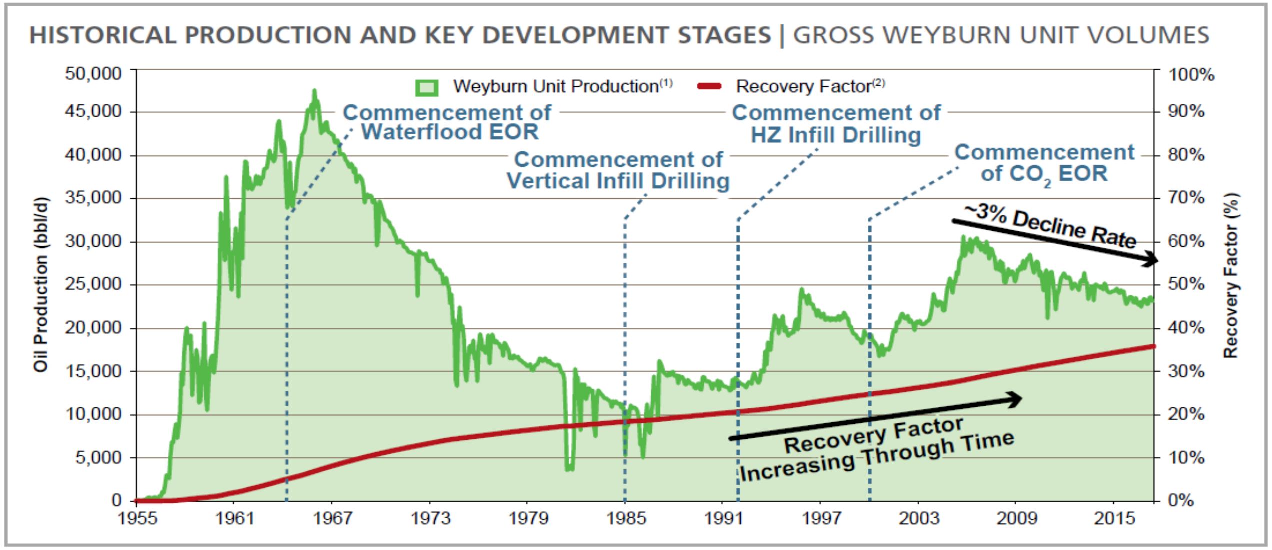


Figure 5. Time-lapse amplitude difference maps for the Midale Marly horizon. Only the negative amplitude differences are shown to accentuate CO_2 saturation effects. Dual-leg wells are either production (black) or CO_2 injection (green) wells.

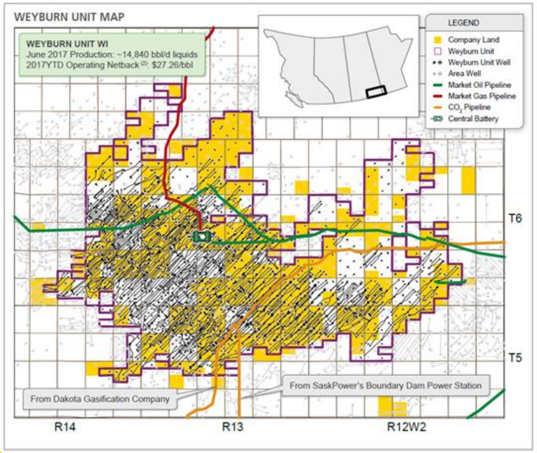
Don White, 2009, Geological Survey of Canada, The Leading Edge, July 2009

Weyburn Unit, Saskatchewan, Canada.



- Weyburn Unit 55,000 acres (220km2)
- 1.4 Billion bbls OOIP
  - Sour crude 25-43 API
  - 160 million bbls incremental
- ~ 300 injector wells
  - 160 water only
  - 110 WAG
  - 17 CO2 only
- 700 producers
- ~50% wells are Hz and 50% Vertical
- Recovery factor ~48% increased through time, may exceed 60%

- Primary Production
- Waterflood EOR-1964
- Infill drilling1985-1999
- CO2, EOR development



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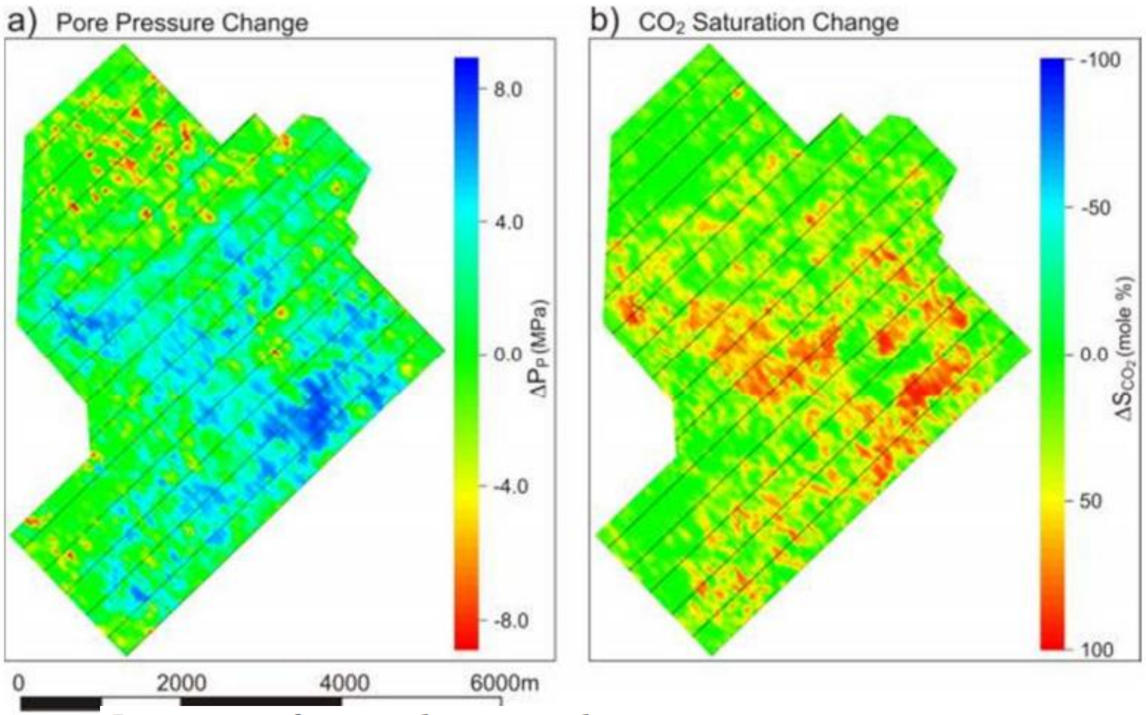
Weyburn Unit, Saskatchewan, Canada



Inversion of prestack seismic data:

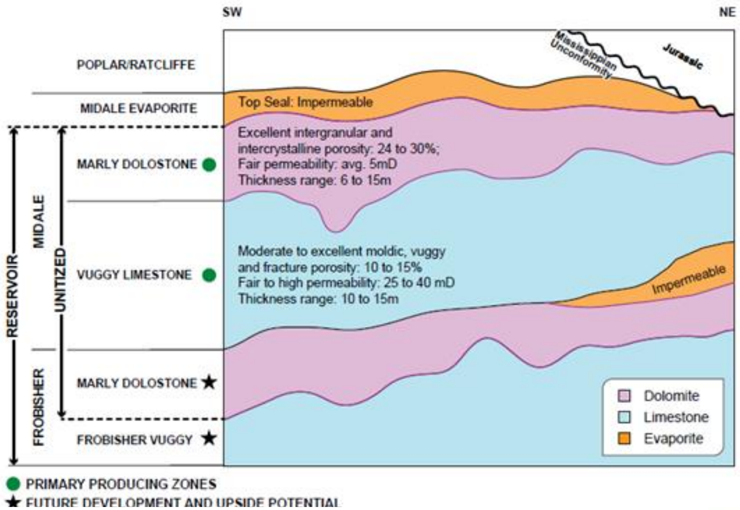
. Semi-quantitative CO2 saturation and P changes

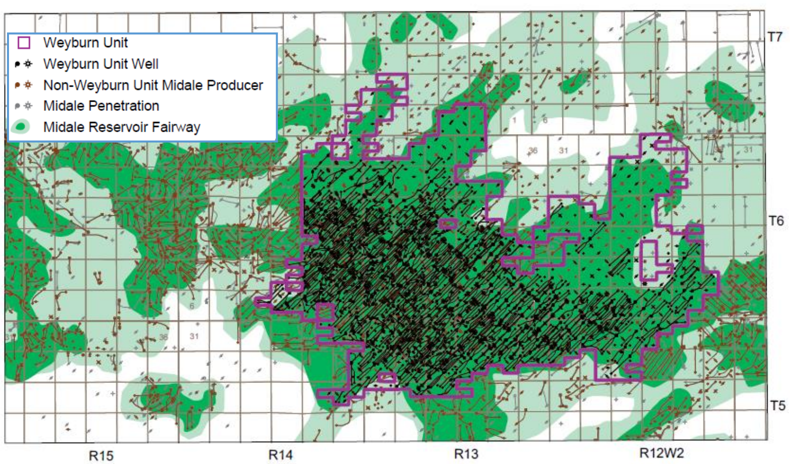
. Results are model-based

.Characterization of reservoir rock physics is essential

. Monitoring survey design is important as "long offset" data are required

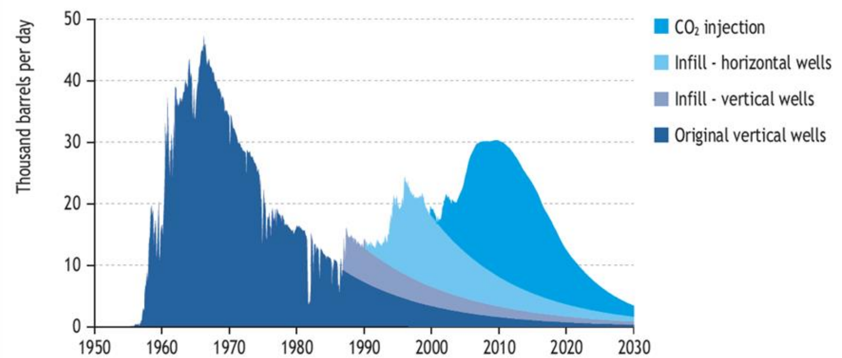
Weyburn Unit, Saskatchewan, Canada.



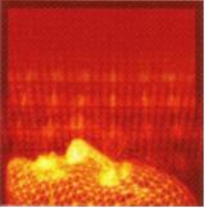


- Mississippian Midale Fm. is the main reservoir, capped by Evaporite Top seal
- Reservoir distribution is very well understood regionally due to extensive well control, core analysis, subsurface mapping and seismic data.
- Securing extensive subsurface geology knowledge turned the field in to Low Risk asset.

Figure 9.8 • A case study of oil reserves growth: the impact of technology on oil production from the Weyburn field in Canada



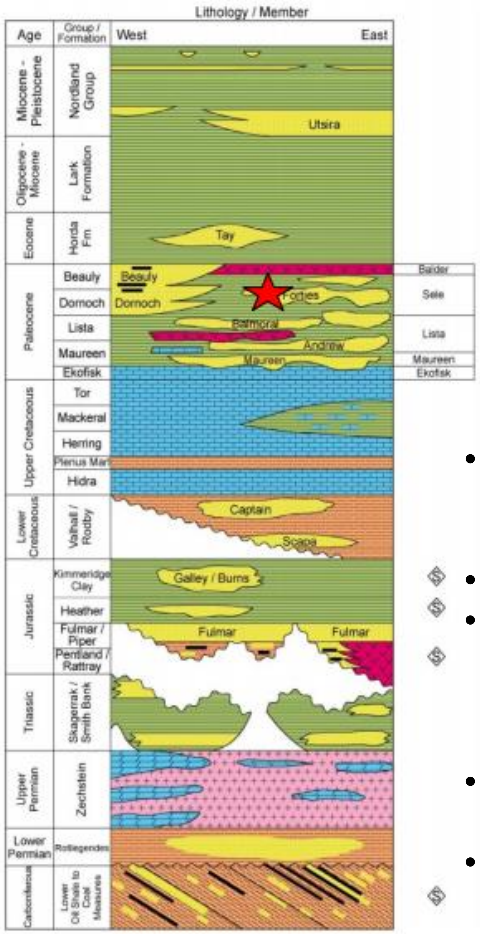
Source: PTRC Weyburn-Midale website (www.ptrc.ca).



Lessons

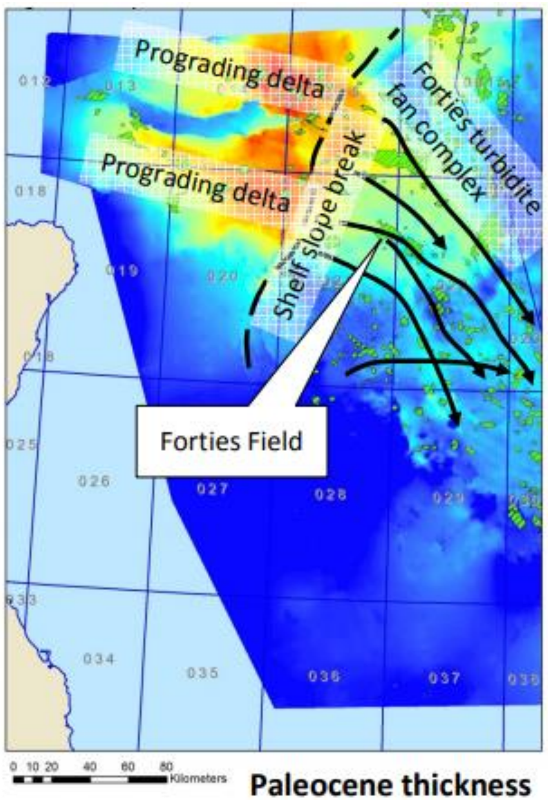
- Its is possible to reverse the decline! The decline rate for a mature field is~3% the lowest in the world!
- Recovery factor ~50%, exceeds some North Sea operations.
- Weyburn unit achieved this through a combination of technologies with Firsts!; CO2, 3D seismic, modeling, data maintenance.
- It is a success case of using 4D seismic for movement of CO2 in reservoir. One of the world's largest and most successful CO2 injection and sequestration projects
- A classic learning exercise on mature field development with reversal of decline, use of subsurface technologies.

Forties Field, North Sea



Stratigraphic column

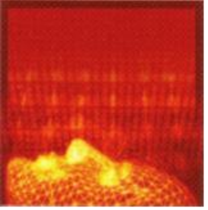
- Forties field was discovered in the North Sea in 1970, with production of 10,000 bbl/day
- ~5Bbbl in place, 2.5Bbbl cumm. 50% RF
- Apache Corp acquired in 2003, when the reserves were assessed to be 141MMbbls. Shot a new 3D seismic, and placed the reserves at 880MMbbls.
- Current production is about 60,000bbls/day
- Paleocene progradation and slope-turbidite channel architecture

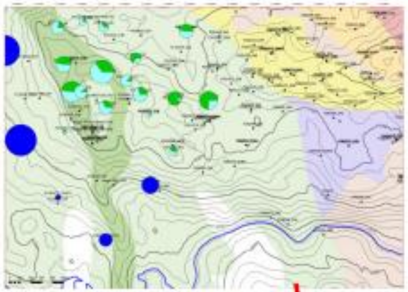


Paleocene thickness

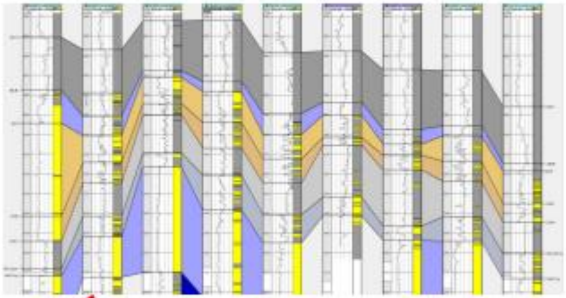
Rose et ak, 2011, Devex may 2011

Data integration key to finding bypassed pay

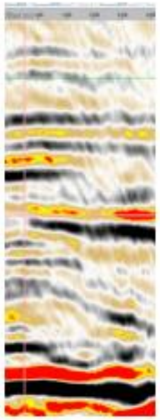




Production history, structure and gross architecture

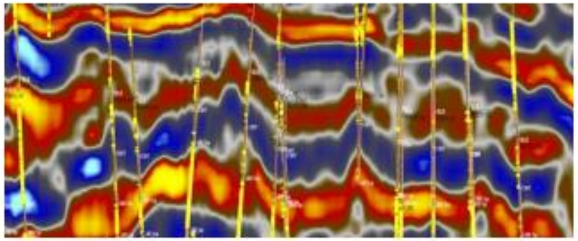


Detailed sand distribution and stratigraphy from wells

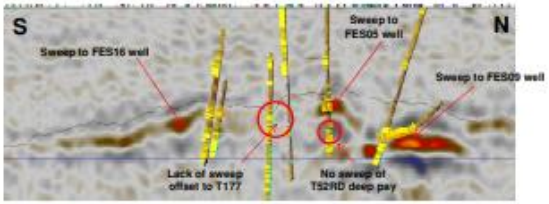


Offset gathers

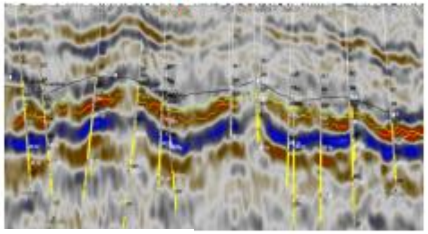
Bypassed pay target: Evidence for hydrocarbon, Reservoir, Trap.



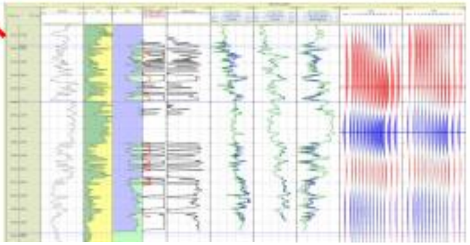
Seismic inversion data



4D seismic

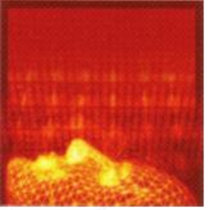


Angled stacks

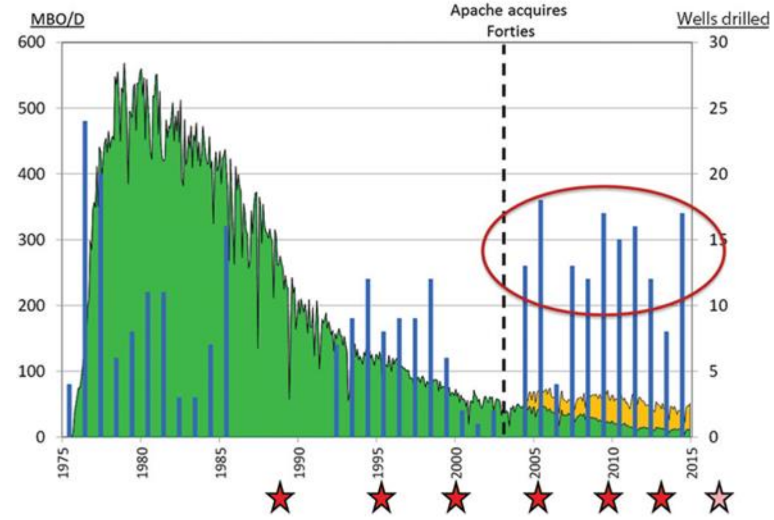


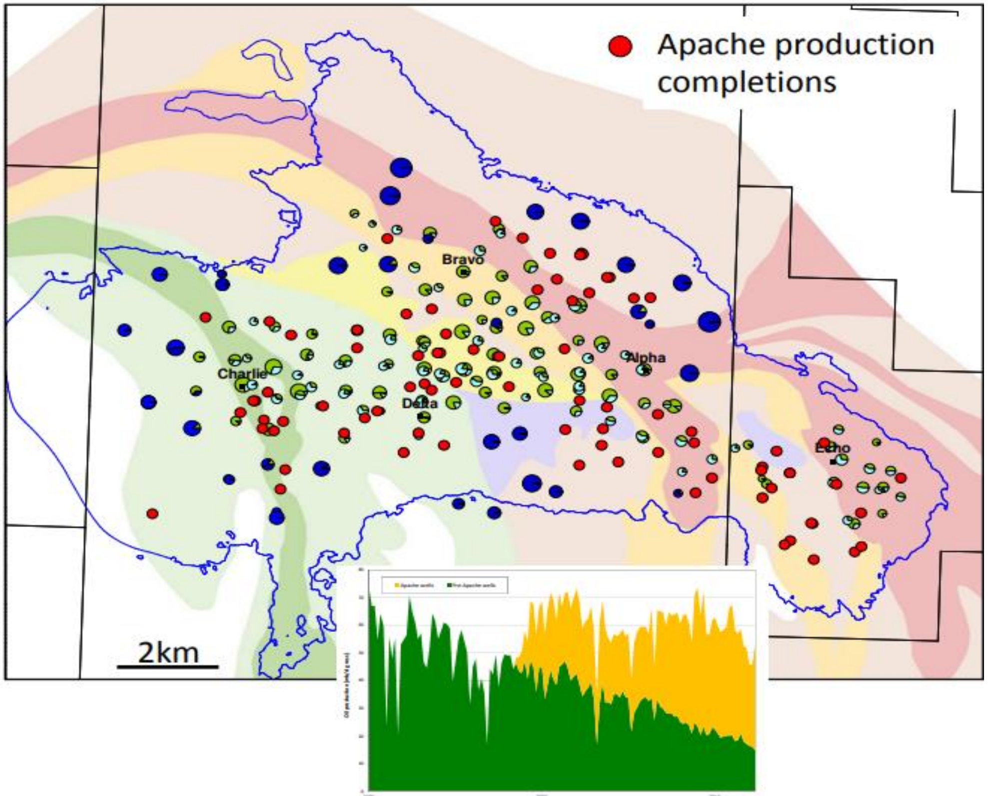
Synthetics modeling

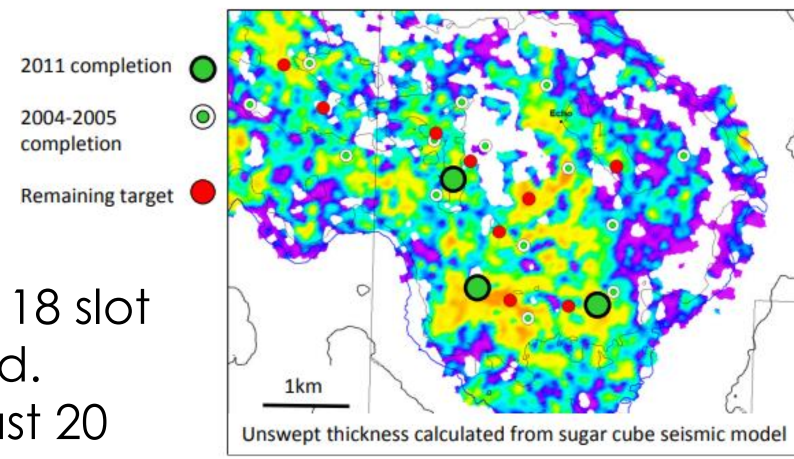
Rose et ak, 2011, Devex may 2011



Forties Field, North Sea



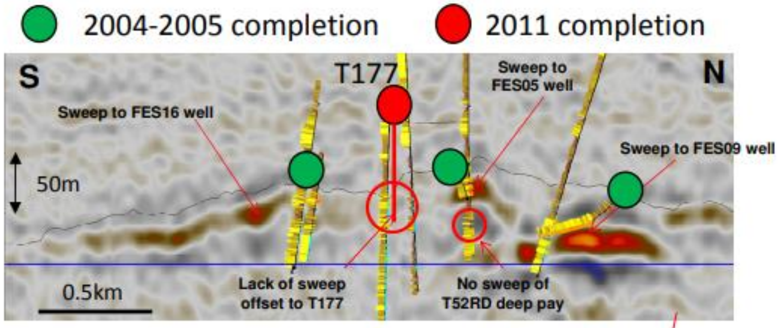




- Additional processing facilities and an 18 slot platform is commissioned in Alpha field.
- The field life has been extended at least 20 more years.

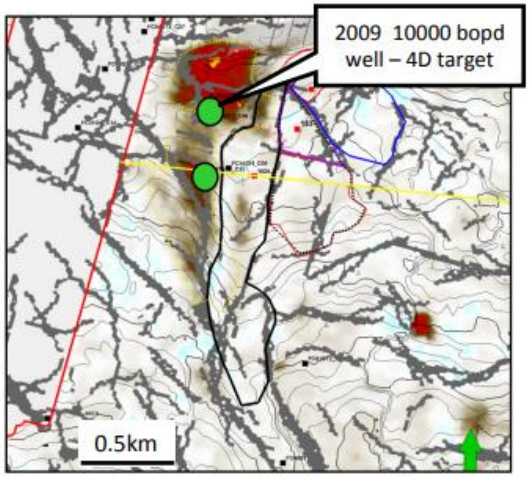
Rose et ak, 2011, Devex may 2011

Forties Field, North Sea

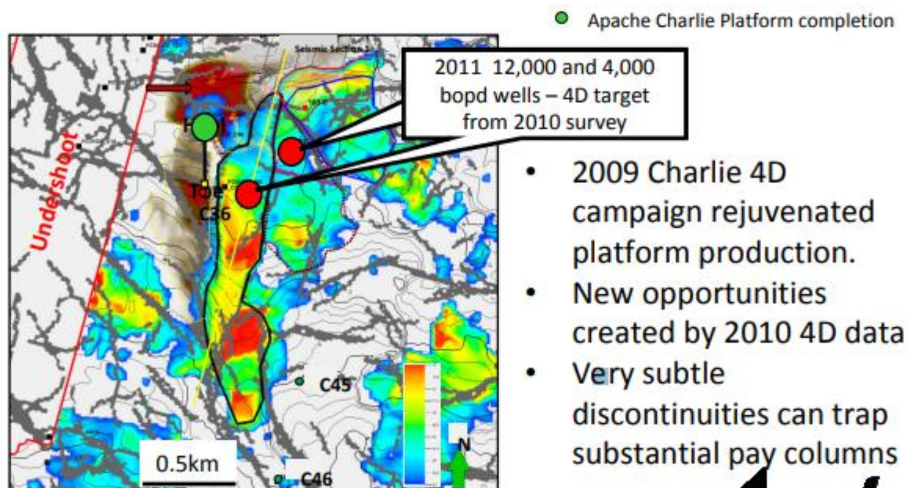


2000-2010 4D calibration – red sweep
Target 177 drilled March 2011 – IP 4,000 bopd

- Chronostratigraphic anchoring of wells in 3d seismic, identification of reservoir architecture and stratigraphic trapping.
- 4D seismic and angled stacks/AVO technology is leveraged to full extent to identify unswept areas, attic oil, and bypassed oil.



2000-2010 4D sweep



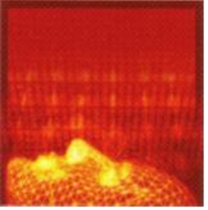
2010 4D attic thickness

- 2009 Charlie 4D campaign rejuvenated platform production.
- New opportunities created by 2010 4D data
- Very subtle discontinuities can trap substantial pay columns

Apache

Rose et ak, 2011, Devex may 2011

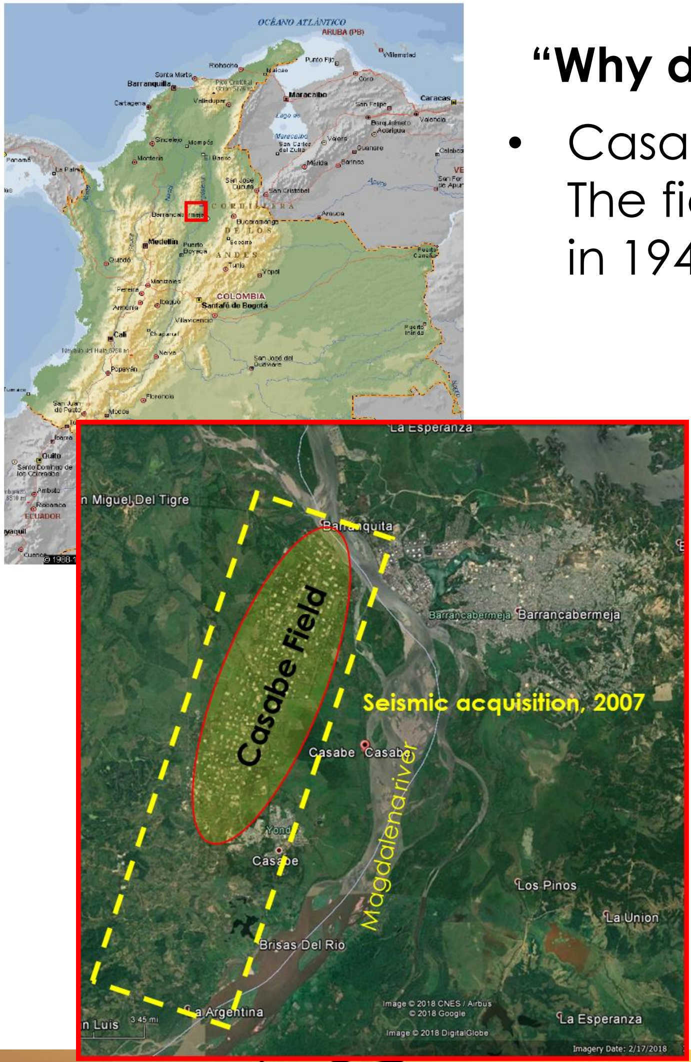
Staples et al, 2015, Search and Discovery Article #20303 (2015)



Lessons

- Forties field reached "economic limit" as per the definition on 2003. Apache acquired the field at this stage and revitalized the field.
- Forties field another text book case of mature redevelopment, where both reserves base and production decline has been improved.
- 3D seismic and 4D seismic monitoring enabled upgrataion of the water injection and extended the life for 20 years. Increased production from 41Mbbl to 60Mbbls/day. Reserves were remapped from 141MMbbls to 880MMbbls.
- Chronostratigraphic anchoring of wells in 3D seismic, identification of reservoir architecture and stratigraphic trapping.
- Once again seeing is believing!

Casabe Field, Colombia



"Why do we need seismic, we have 100s of wells".

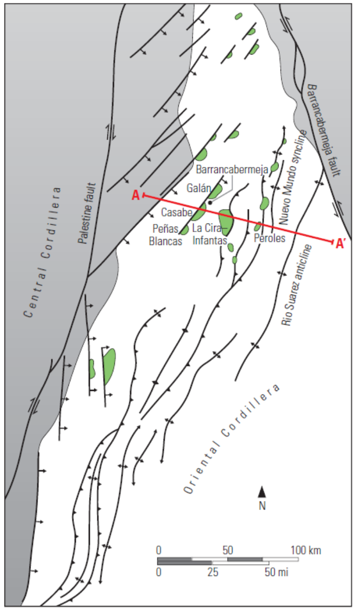
- Casabe field is about 350km north of Bogata, Colombia. The field was discovered in 1941 and production started in 1945. A 3-way closure, 8km long 3-way closure.

- Peaked at 46,000 b/d in 1953, with 414 wells. The field is under water injection since 1985, and cummed 297 MMb in 2008.
- Ecopetrol conducted secondary recovery in 1980s, but failed to arrest/reverse the decline due to subsurface uncertainties, poor placement of wells, early water break, sand production, that forced shutting down the water injection.

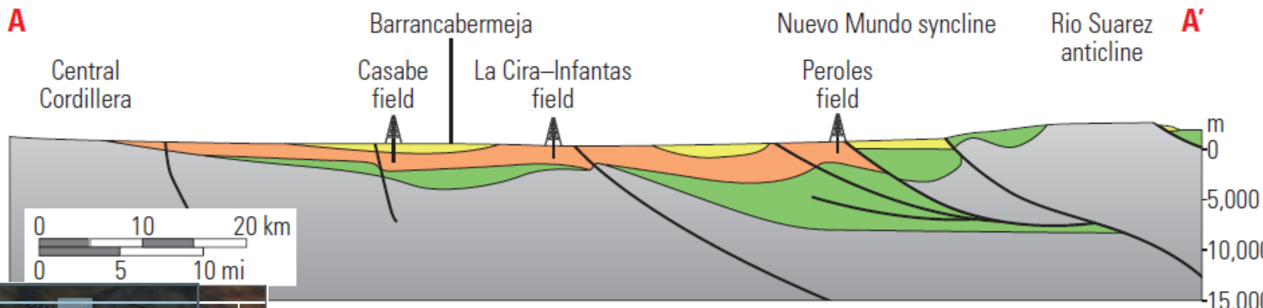
Gabaretto et al, 2009, SPE 122868

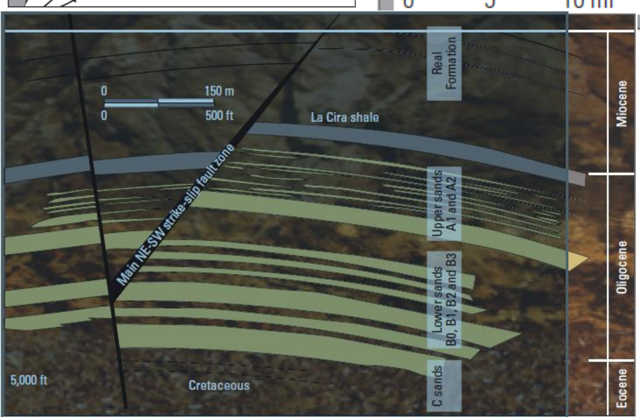
Casabe Field, Colombia

Amaya et al, 2010, Oilfield Review Spring 2010, 22,no.1



- Casabe field is located in the Middle Magdalena valley Basin (MMVB), which is a pericratonic basin, part of extensional arc basin during Triassic-Jurassic;
- A series of intermontane basins formed as rifts, and subsequently uplifted and shortened in Eocene.

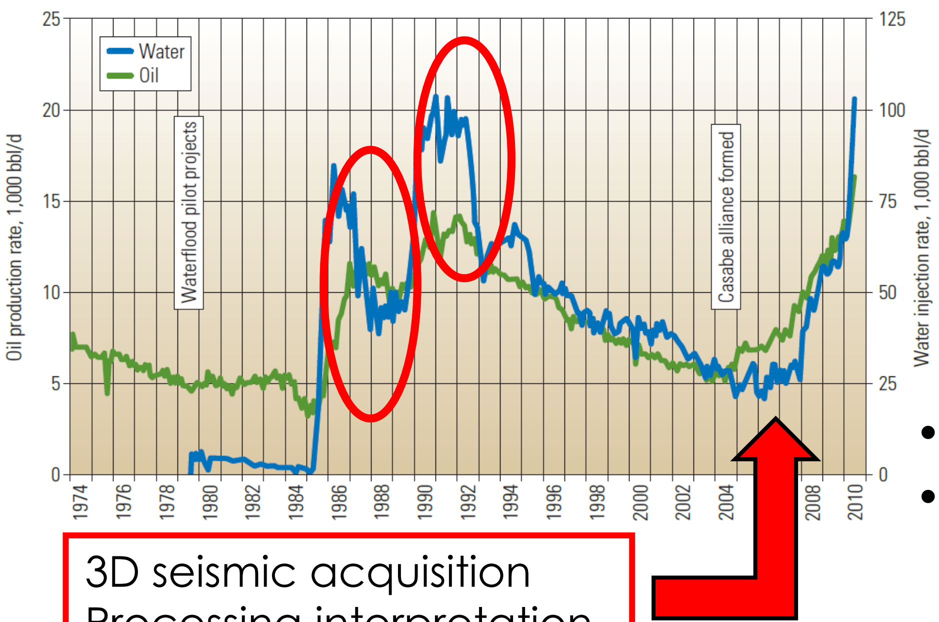




- The basin is limited on west by transform fault (Palestine fault) that separates Cordilleran massifs. Evidently, this resulted in series of basins that sourced giant fields, with a well developed petroleum system and sediments from Jurassic to Miocene.
- Reservoirs Paleocene age, sealed by Oligocene, La Circa shale.

Casabe Field, Colombia

Two phases of successful injections and response. But early water breakthrough resulted in rapid decline.

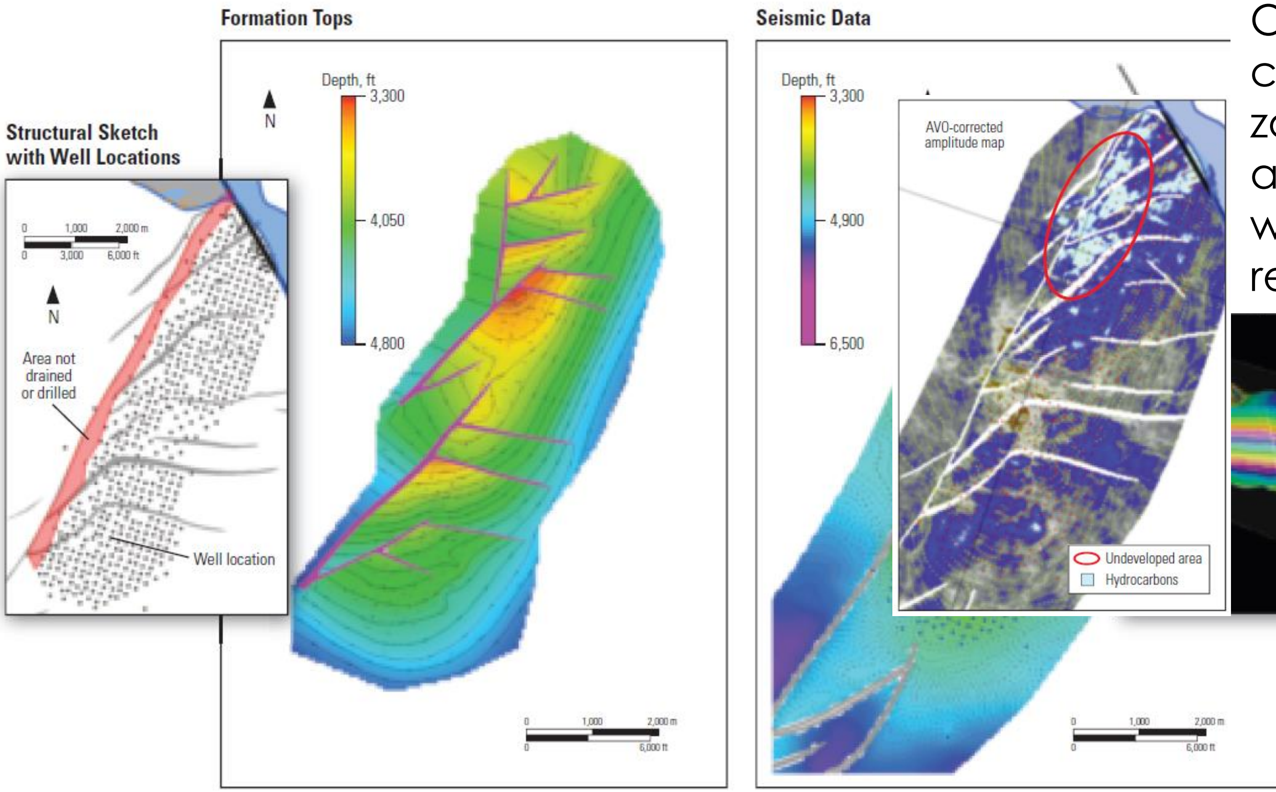


3D seismic acquisition
Processing interpretation

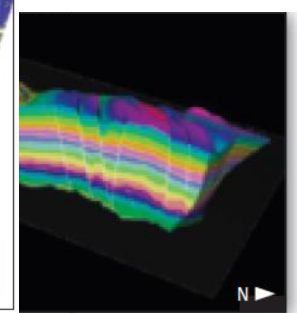
- Casabe pilot water injections started in 1970s, but not until 1985 real waterflooding began. There were severe water break throughs, resulting in unsuccessful pressure maintenance and collapse of wells, which forced them to stop injections.
- **2004: New 3D seismic acquired**
- Production increased from **5200 bbl/d in 2005, to 16,000bbl/d in 2010.**
- Recovery factor increased from **16% to 22%.**

Amaya et al, 2010, Oilfield Review Spring 2010, 22,no.1

Casabe Field, Colombia

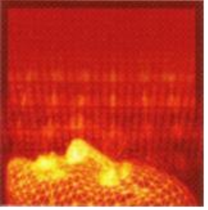


Operator avoided drilling close to the major faulted zone to the western boundary and in complicated areas with poorly understood fault relationships.

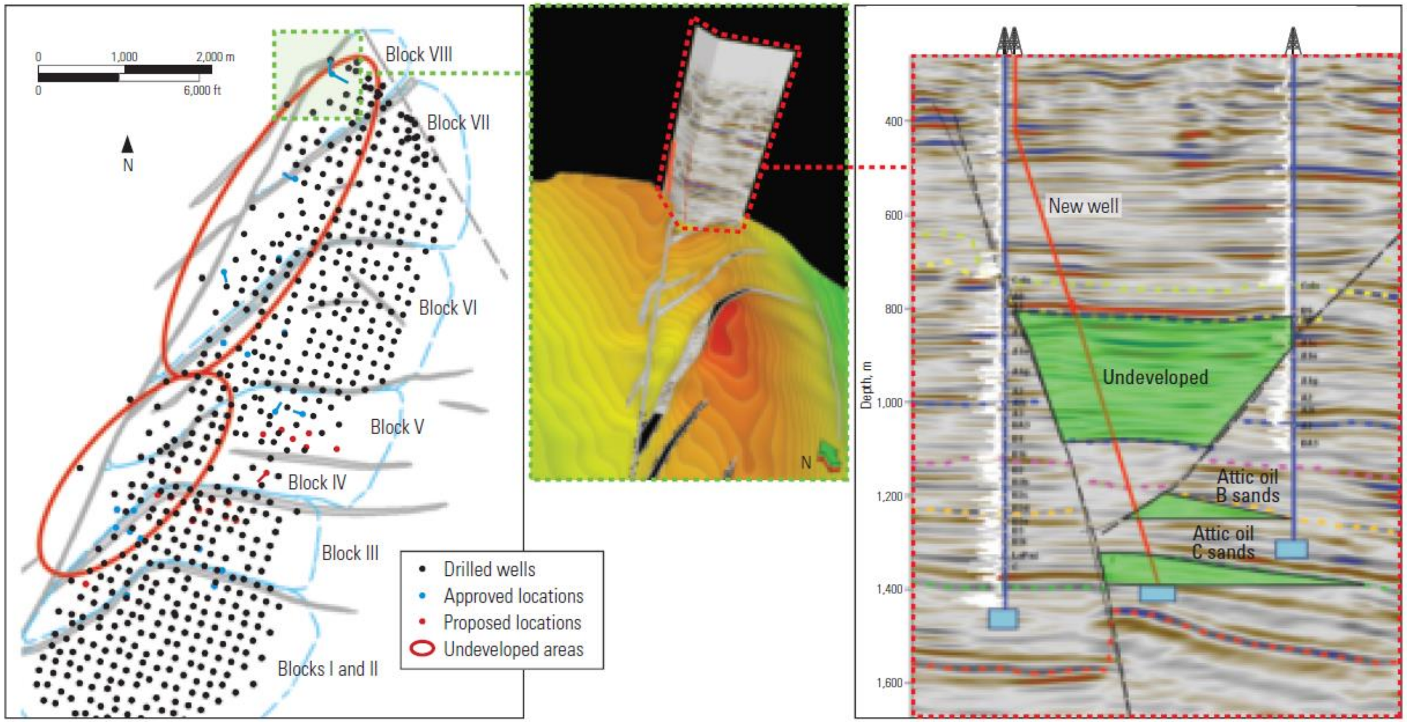


- The seismic based maps acquired in 2007-09 enabled finding a large 20sq km area in the north, with poor well penetrations.
- Pre-stack Seismic inversion, attributes, and AVO analysis provided the basis for behind the casing pay and attic oil between wells.

Amaya et al, 2010, Oilfield Review Spring 2010, 22,no.1



Casabe Field, Colombia

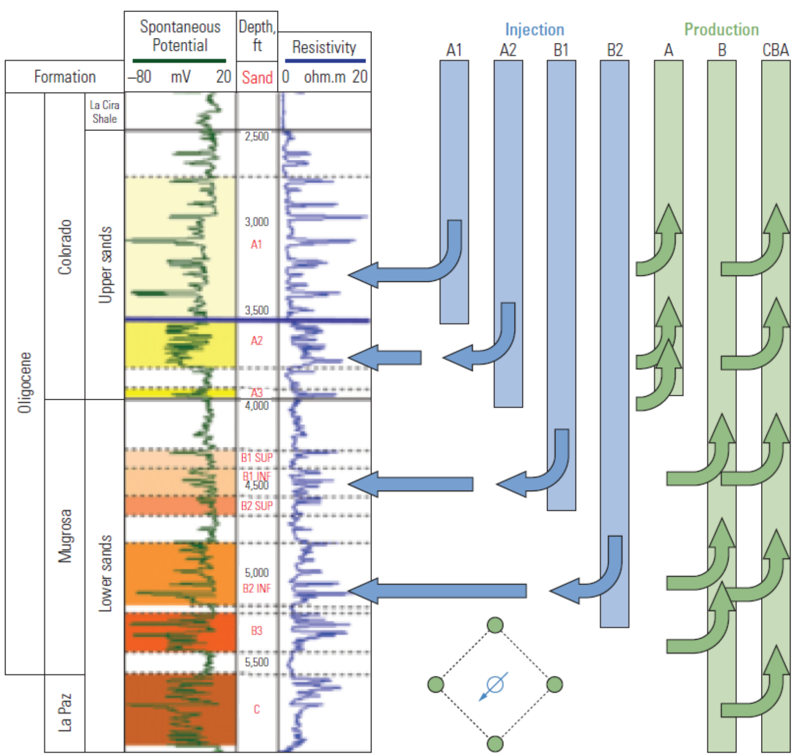


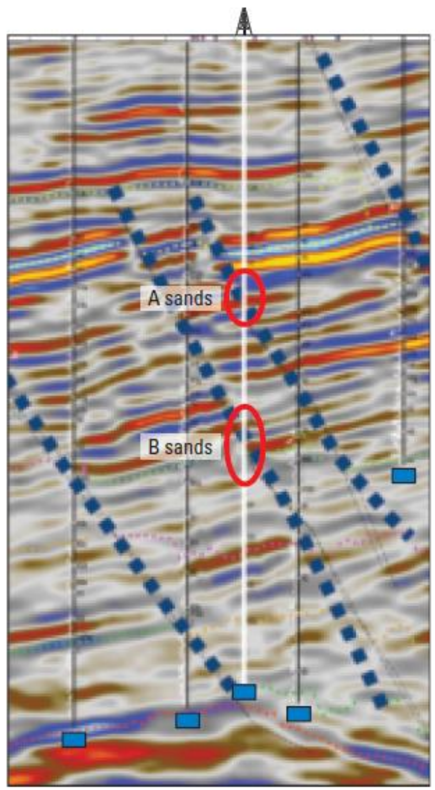
The result was planning 150 new wells and estimation of by passed oil was about **5MMbbl, in 15 reservoirs with average thickness of 3ft**

- **Though operator of was aware of attic oil in such as large field, the maps and fault positions were imprecise to help plan wells.**
- After much seismic work, facies maps, accurate structure maps, a new reservoir architecture was developed. Still there was no static model !

Amaya et al, 2010, Oilfield Review Spring 2010, 22,no.1

Casabe Field, Colombia



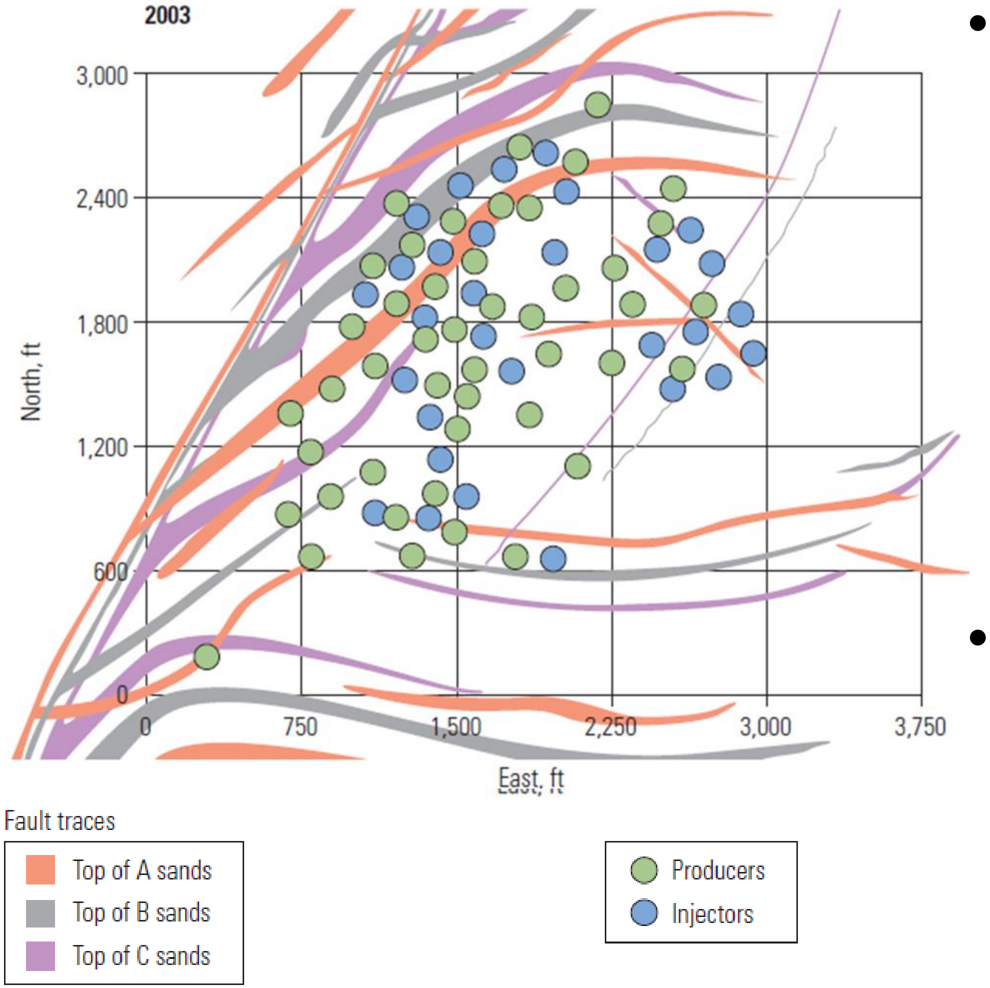


The increased knowledge of the subsurface enabled reducing the number of injection wells from 4 to 1, and less number wells co-mingled production

New seismic and interpretation also revealed pay between wells as attic oil.

Amaya et al, 2010, Oilfield Review Spring 2010, 22,no.1

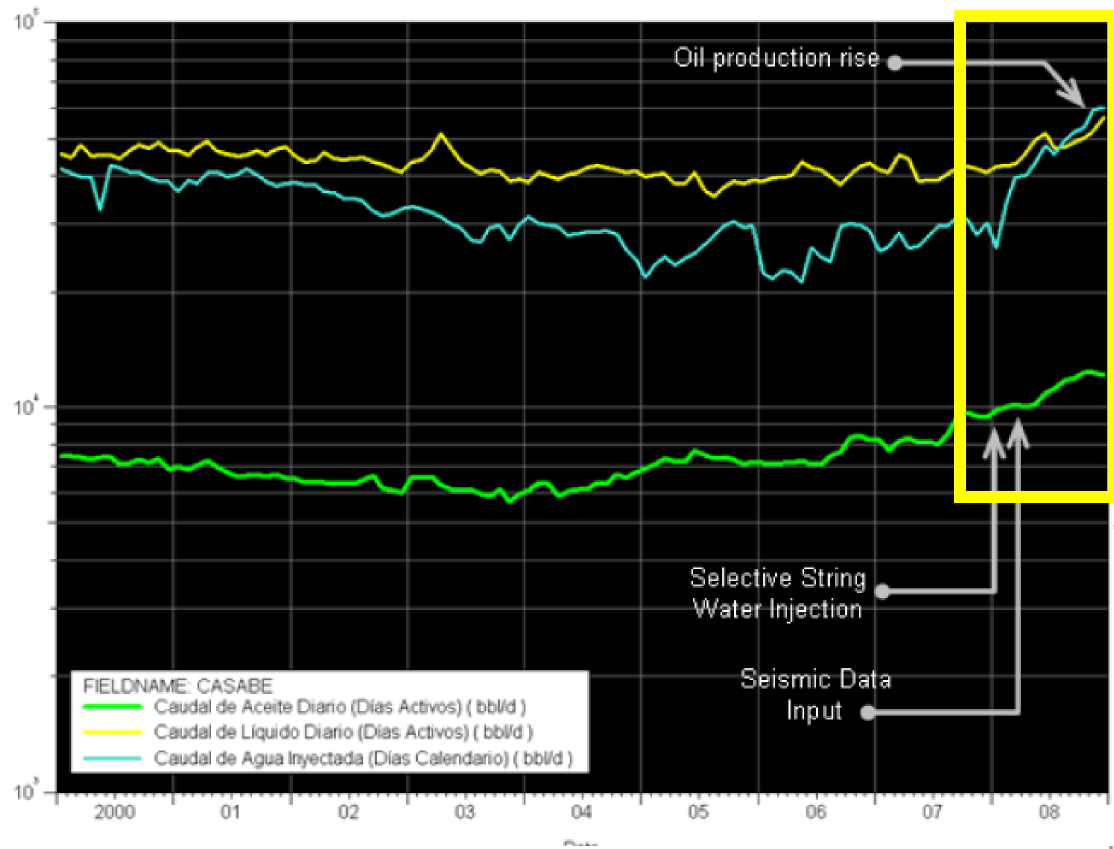
Casabe Field, Colombia

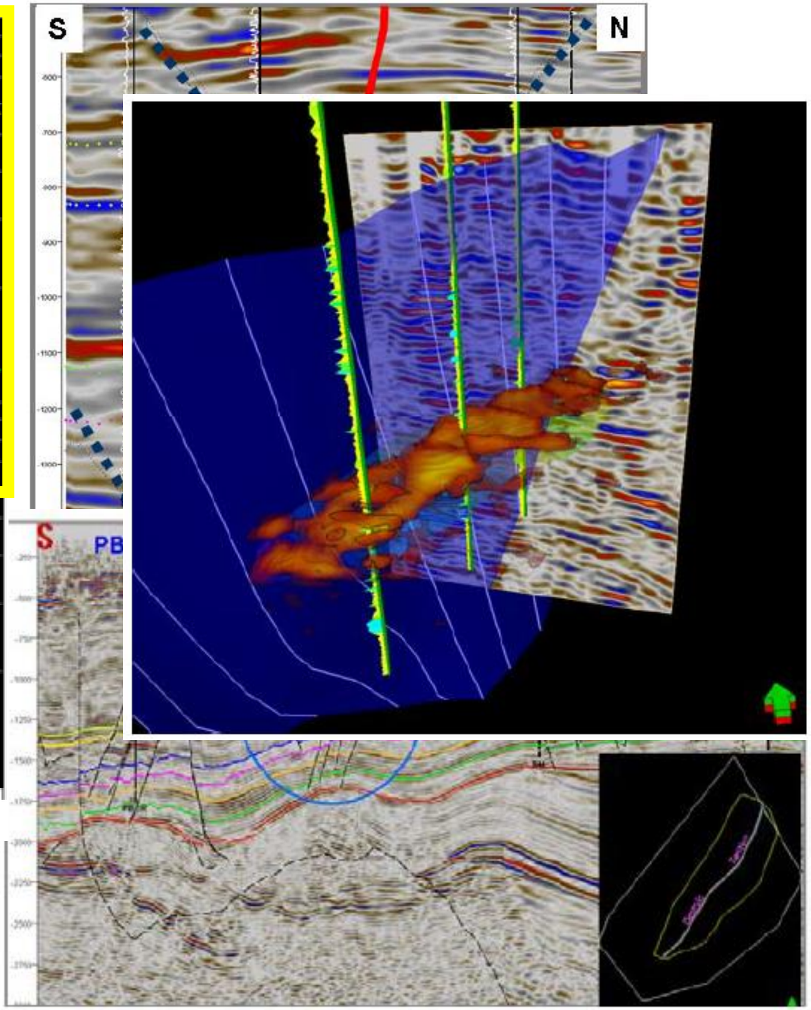


- The previous injection geometric injection pattern of 4 wells was changed to precise location of injector and producers based on the facies maps and ensuring bottom hole locations in the same blocks.
- Sweep efficiency and production was increased by 50% in one year after successful injections

Amaya et al, 2010, Oilfield Review Spring 2010, 22,no.1

Casabe Field, Colombia

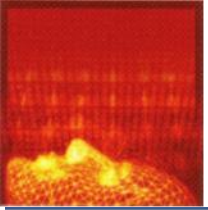




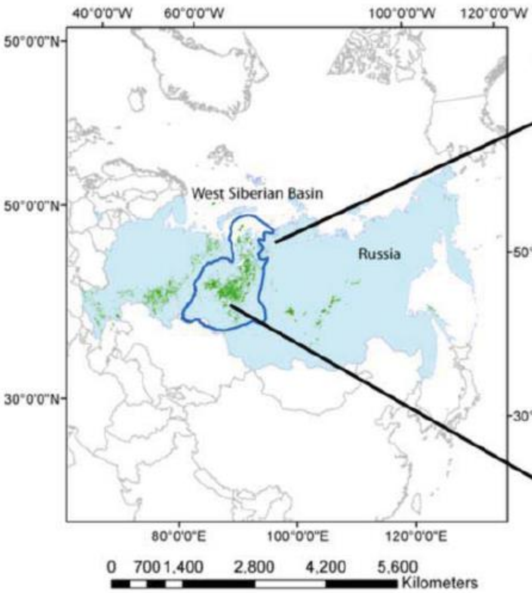
Gabaretto et al, 2009, SPE 122868

Lessons

- Casabe field demonstrates a classical case of using 3D seismic to help waterflood and finding new upside in field.
- The increased knowledge of the subsurface enabled reducing the number of injection wells from 4 to 1, and less number wells co-mingled production
- Prestack Seismic inversion, new interpretation, attributes, and AVO analysis provided the basis for behind the casing pay and attic oil between wells, reduced uncertainty, and refined fault interpretation, which ultimately identified pay in the updip structure.
- Reginal coverage of the data enabled additional near field prospect to the southeast.
- Production increased from 5200 bbl/d in 2005, to 16,000bbl/d in 2010. Recovery factor increased from 16% to 22%.
- New subsurface knowledge enabled planning 150 new wells and estimation of by-passed oil was about 5MMbbl, in 15 reservoirs with average thickness of 3ft

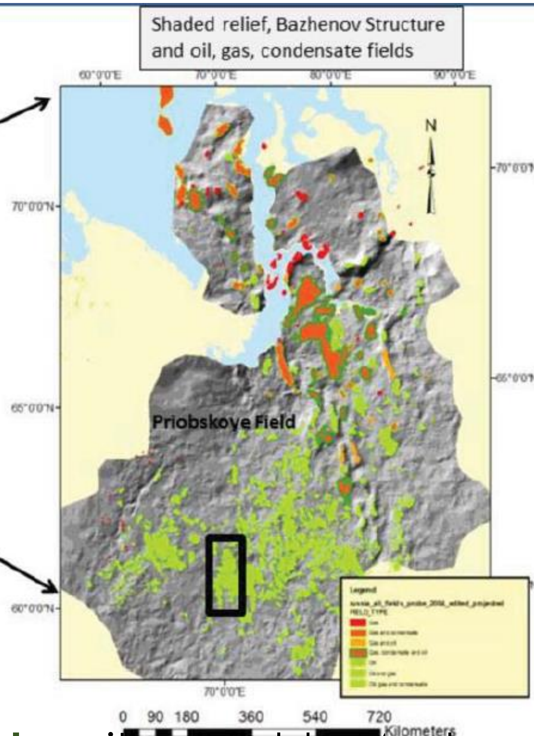


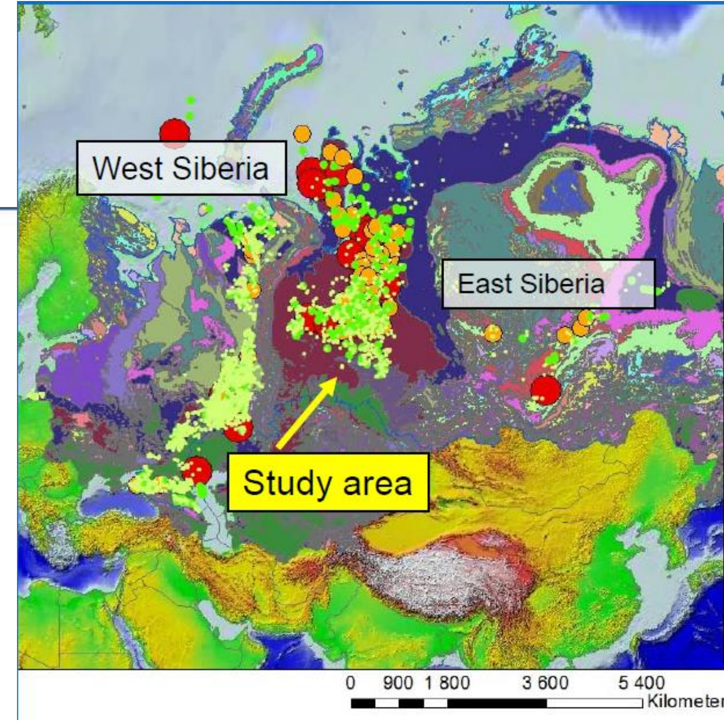
Priobskoye Field, Siberia

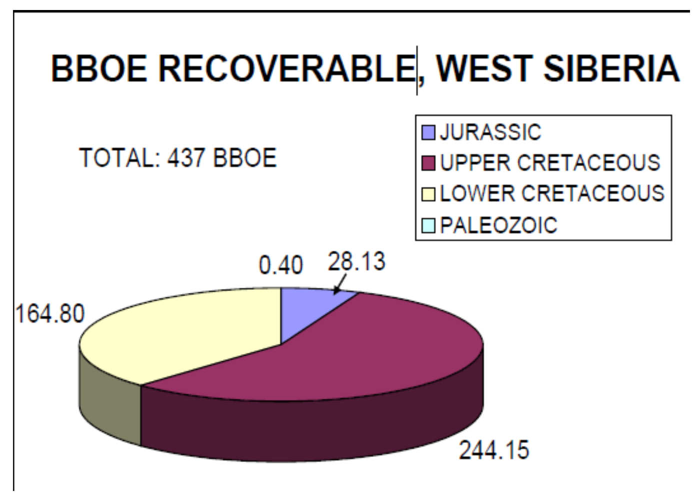


*oil and gas fields are colored green

Figure 1. Index map to the West Siberian basin.

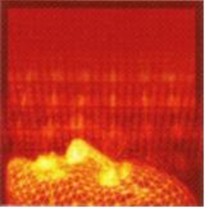






- The extent of **Bazhenov shale**, with oil fields. Much of the oil is trapped in stratigraphic traps. Applying sequence stratigraphy more oil fields are found even today.
- World's 6th largest field in stratigraphic trap (CERA, 2011)

Hafizov, et al, 2014, AAPG #20269



- The Priobskoye field was discovered in 1982 and put into development in 1988. The total area of the field is 5,446 km2.

  Its the largest oil field in Khanty-Mansi Autonomous Area-Yugra, which has a complex geological structure and is considered to be multi-zone and low productive.

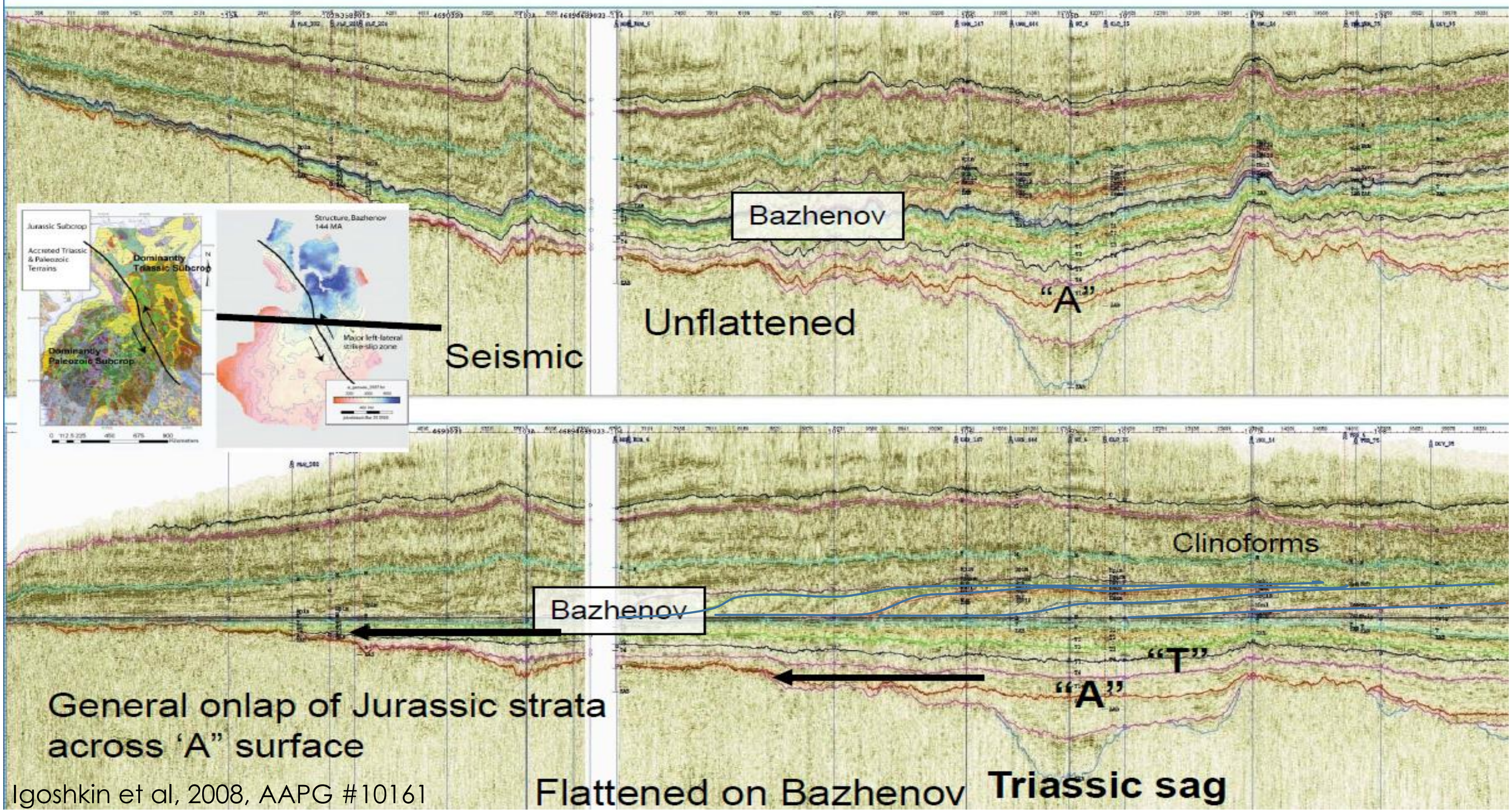
  The majority of the predicted oil reserves are concentrated in the northern half of the field. The deposit is located on the territory of a compact population of small indigenous peoples of the north, Khanty-more than 50%, Mansi-33%, Nenets-6%, Selkups -1%.

  The Priobsky license area developed by Rosneft has initial recoverable reserves of 1.6 billion tonnes and its current recoverable reserves amount to 1.2 billion tonnes as of January 1, 2019.

  The cumulative output has exceeded 430 million tonnes of oil. About 25 million tonnes of oil is produced at the field annually, which account for 4.5% of the total Russian production.

  The Priobskoye field is estimated to account for over 11% of Rosneft's total oil production.

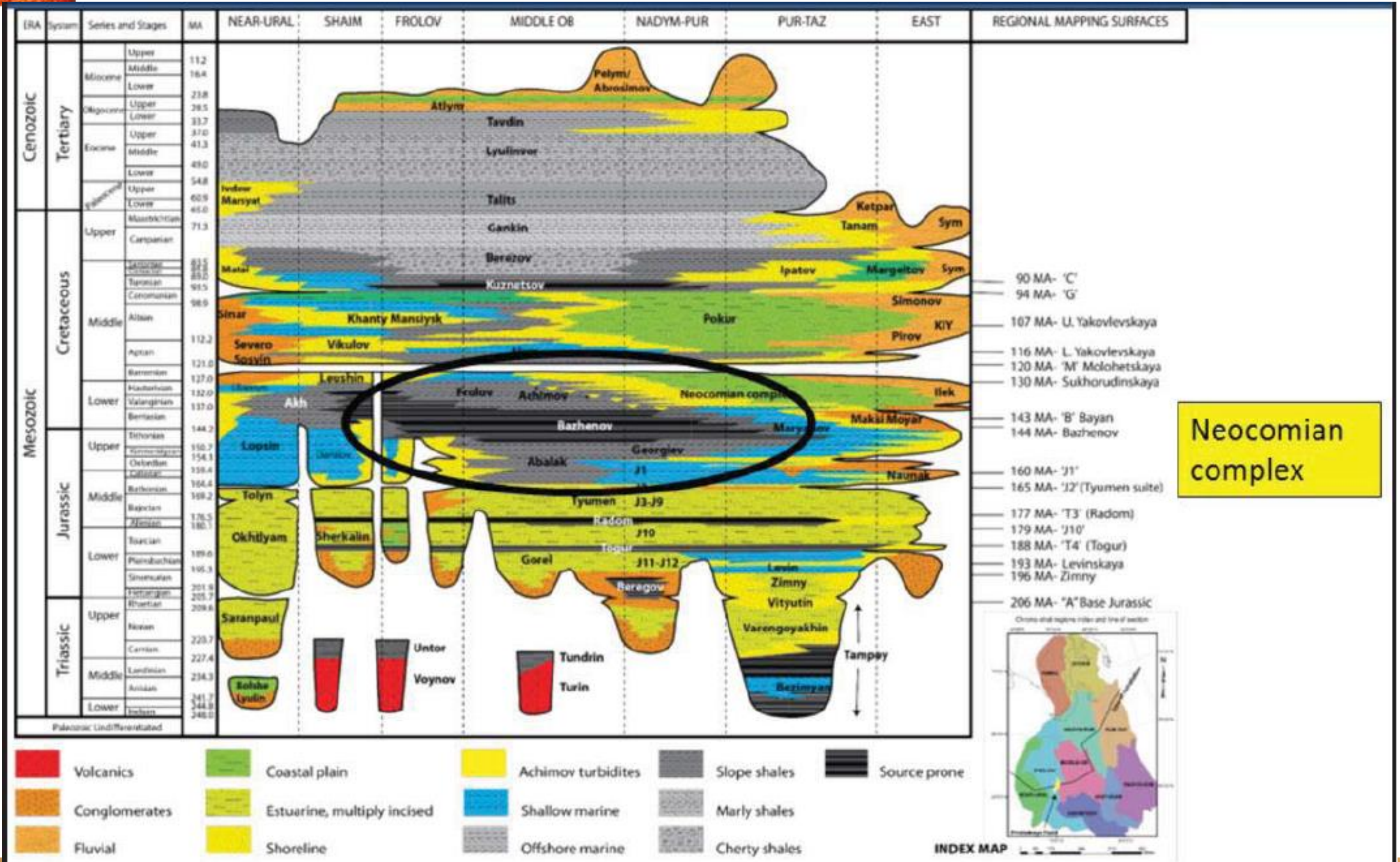
Priobskoye Field, Siberia



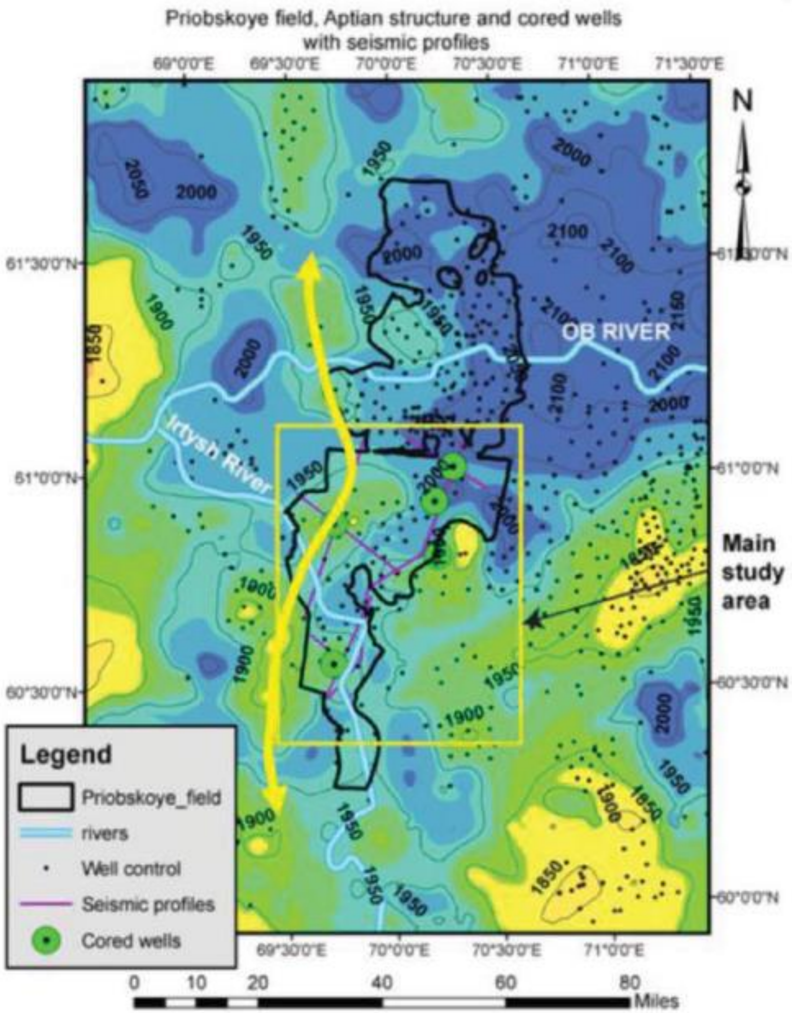
Igoshkin et al, 2008, AAPG #10161

Priobskoye Field, Siberia

Hafizov, et al, 2014, AAPG #20269



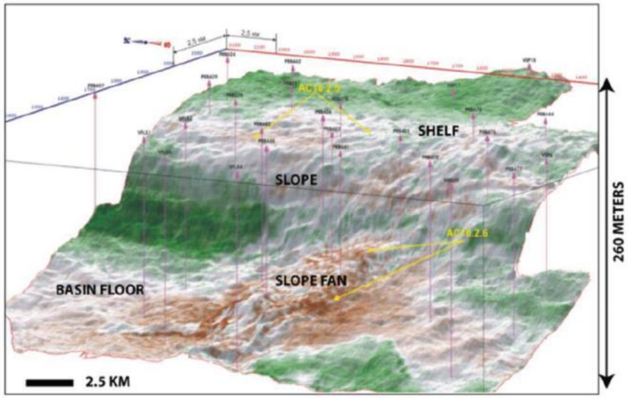
Priobskoye Field, Siberia



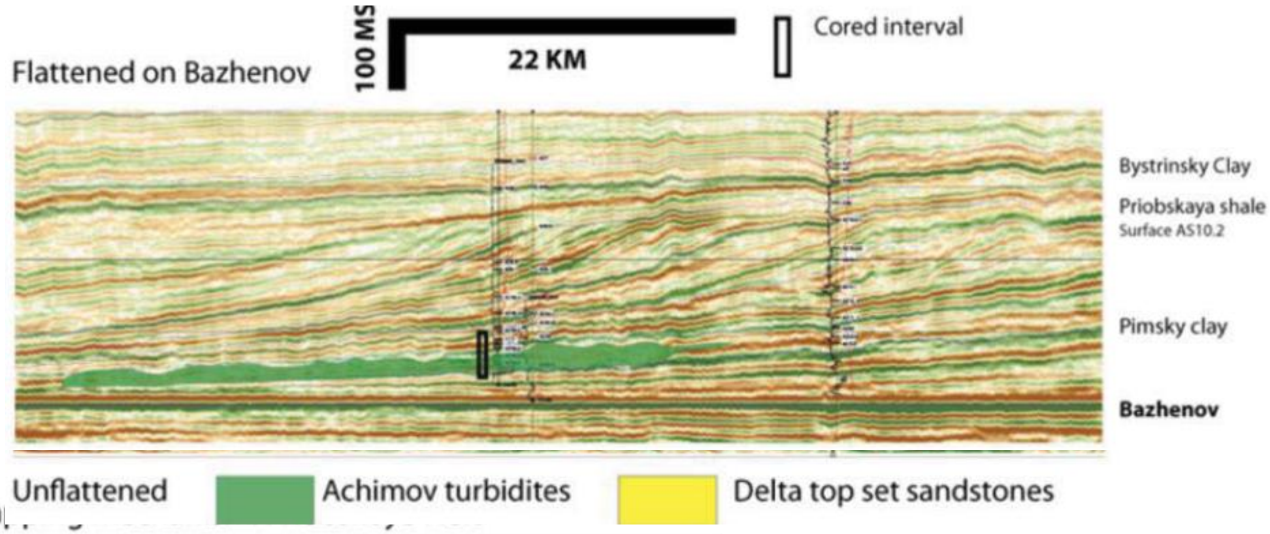
- Map of Priobskoye field with core locations, on Aptian "M" horizon (Top Seal)
- Huge stratigraphic trap
  - 5.3Bbbl and 1.17tcf gas
  - >5000SqKm of stratigraphic trap
- Gentle ramp on Aptian surface, with no structural closure

Hafizov, et al, 2014, AAPG #20269

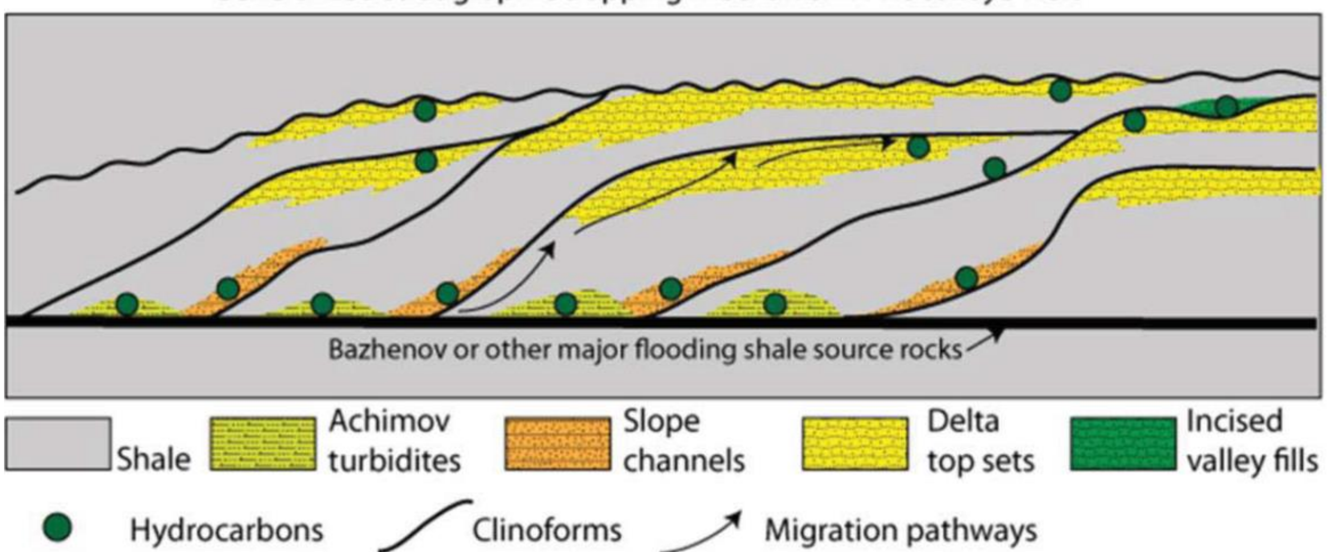
Priobskoye Field, Siberia



Slide courtesy Vladimir Igoshkin, Geoseis Co., Tyumen



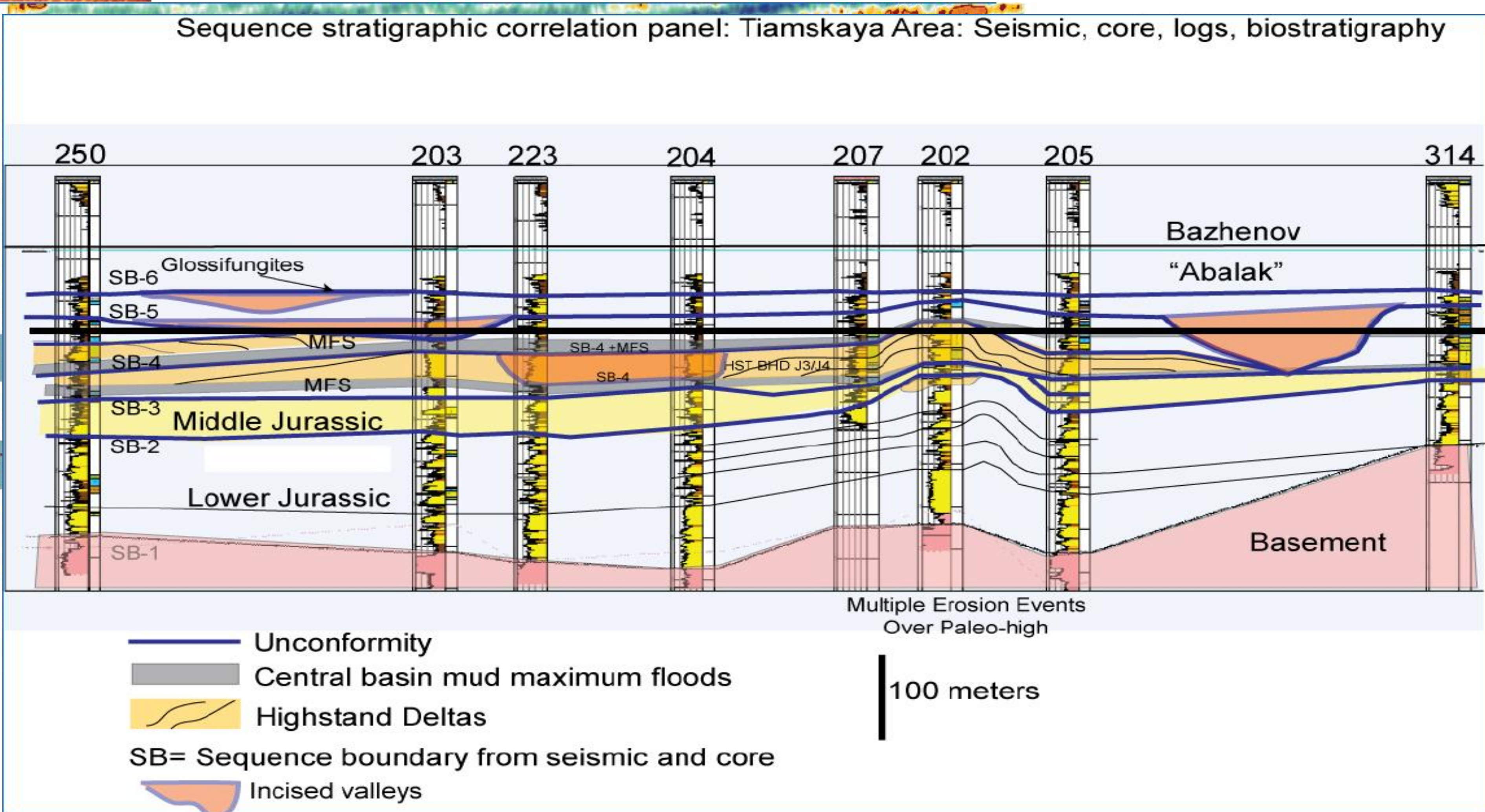
Generalized stratigraphic tra



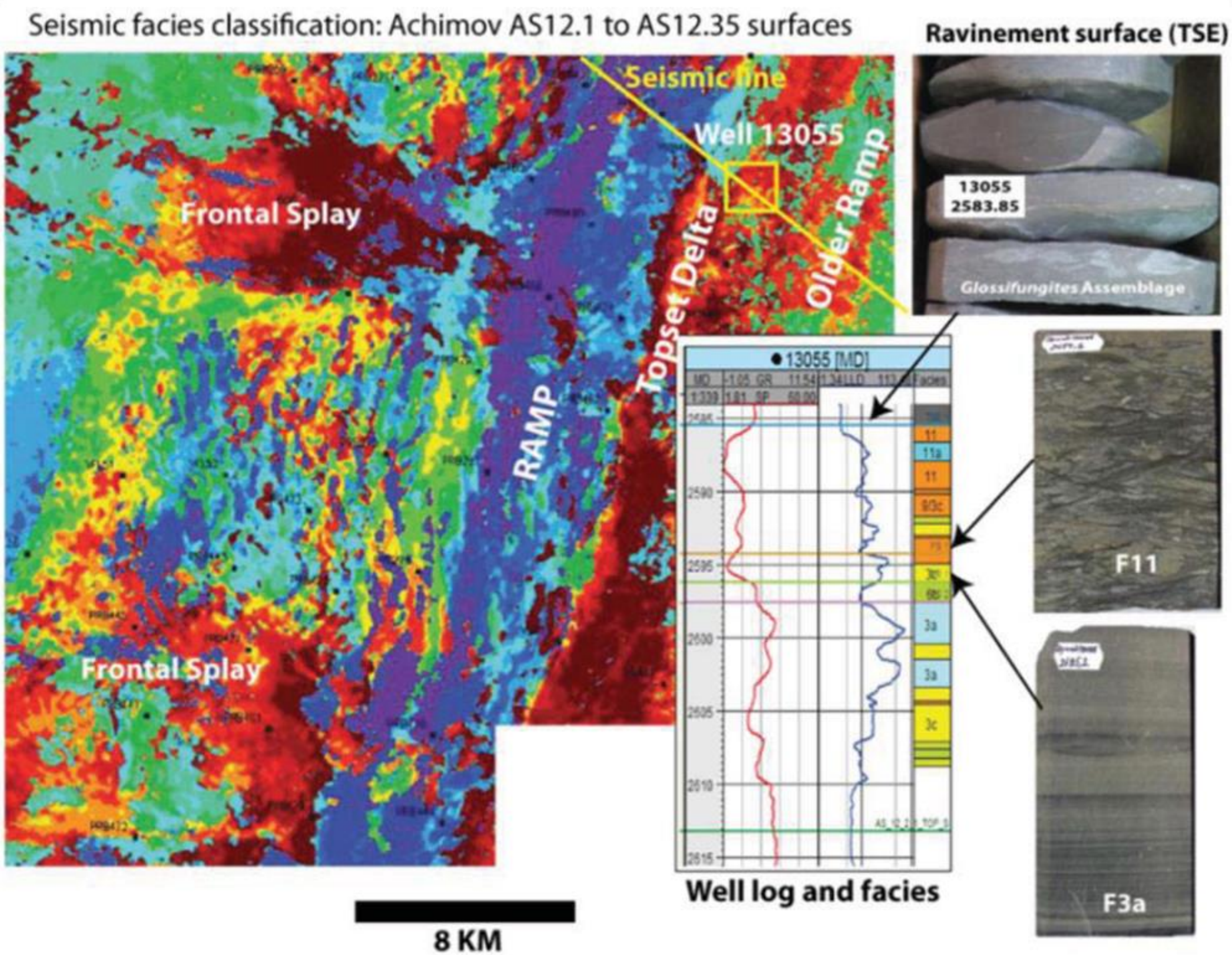
Thick Achimov Turbidites in basin floor fans and sheets

Hafizov, et al, 2014, AAPG #20269

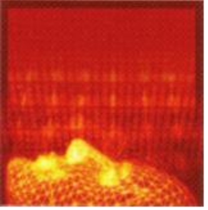
Priobskoye Field, Siberia



Priobskoye Field, Siberia

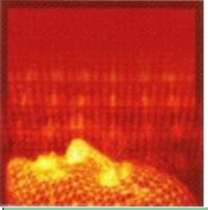


- Seismic facies classification based on wavelet shape and amplitudes seen 10ms below the clinoforms, on unconformity
- Debrite slumps on shallow ramp
- Frontal splays and sheet deposits

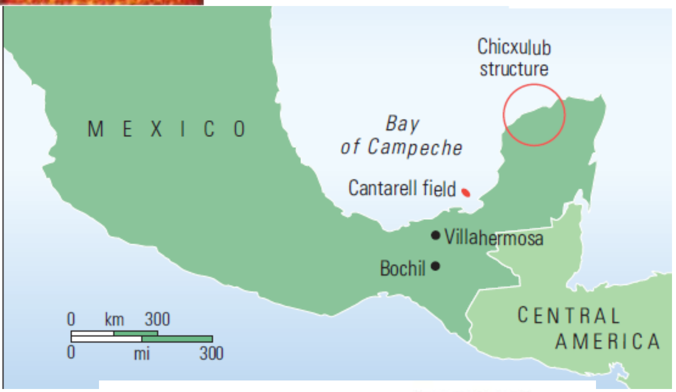


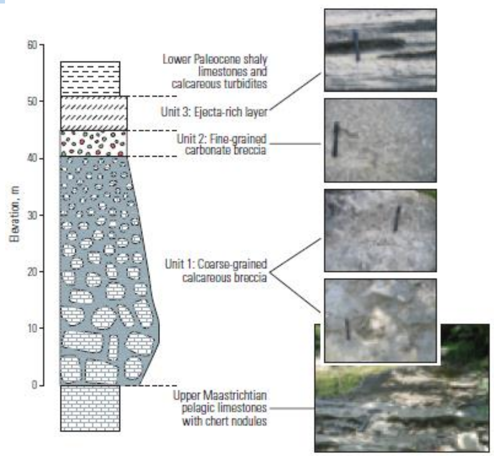
Lessons

- Siberia is proved to be one the richest oil provinces. Much of the oil is due to the rich source rock potential of upper Jurassic **Bazhenov shale**.
- Based on the area covered the Bazhenov shale, West Siberia could be the world’s largest field. Only we discover now with renewed seismic stratigraphic interpretation.
- Huge stratigraphic trap
  - 5.3Bbbl and 1.17tcf gas
  - >5000SqKm of stratigraphic trap
- Priobsoye field and other adjoining fields in the play produce from transgressive and low stand fans, in purely stratigraphic trapping conditions.
- Seismic sequence analysis and seismic facies helped identify low stand fans and in in planning drilling locations.



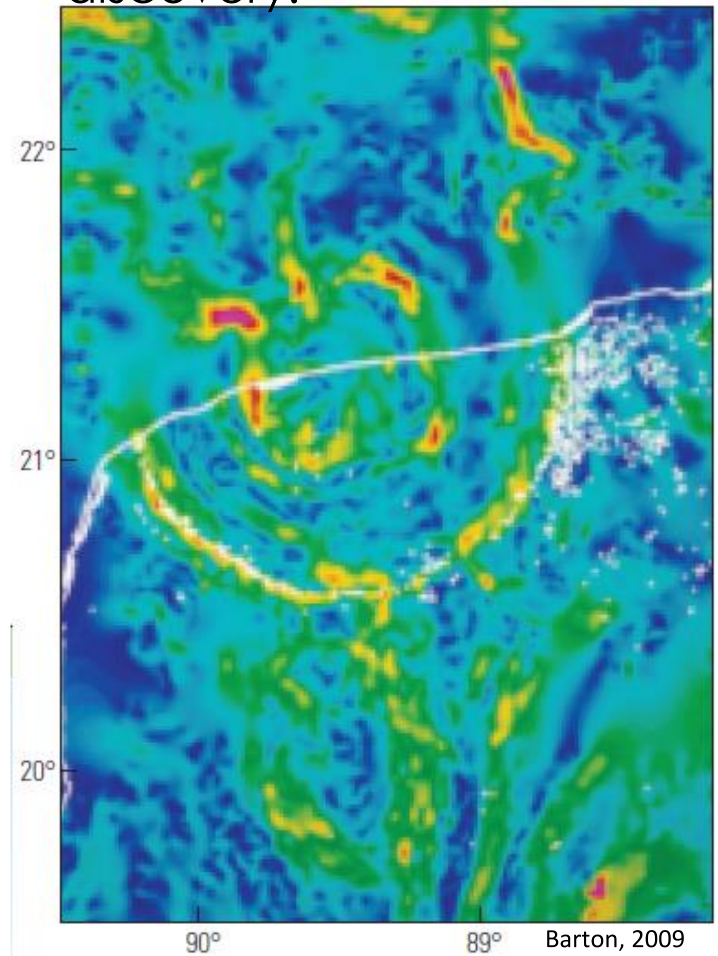
Cantarell field, Mexico



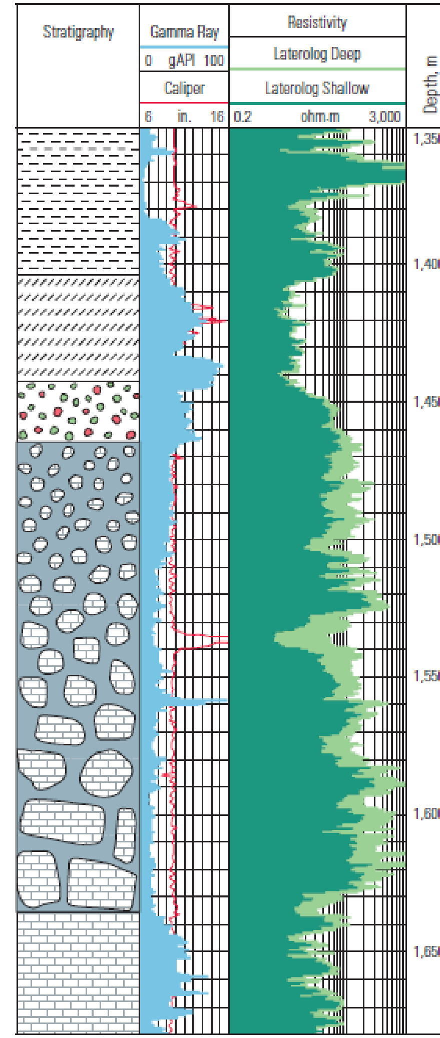


^ Outcrop analog of the K-T boundary carbonate breccia succession at Bochil, Tabasco, southeastern Mexico. Although the impact-related deposit is thinner here than in the Cantarell field, this outcrop exhibits the same stratigraphy, including the fining-upward trend in Unit 1 and the fine-grained ejecta of Unit 3. Additionally, an Ir anomaly has been documented in the uppermost layer of Unit 3 here. The length of the pencil in the top four photographs (*right*) is 13 cm [5 in.]. The length of the rock hammer in the bottom photograph is 46 cm [18 in.].

Truly an Earth shattering discovery!



Barton, 2009



Cantarell, Mexico

Oilfield	Country	2007 Projection	2010 Projection	Projected 2007-2010 % change
Ghawar	Saudi Arabia	5.6	5.0	-11%
Cantarell	Mexico	1.76	1.23	-30%
North and South Rumaila	Iraq	1.3	1.3	0%
Greater Burgan	Kuwait	1.28	1.3	1.6%
Safaniyah	Saudi Arabia	1.2	1.35	13%
Sonatrach Operated Fields (including Hassi Messaoud)	Algeria	1.15	1.0	-14%
Daqing Fields	China	0.86	0.74	-13%
Gachsaran	Iran	0.7	0.7	0%
Azeri Chirag Guneshli	Azerbaijan	0.69	1.2	73%
Samotlorskoye	Russia	0.62	0.62	0%
Ahwaz Asmari	Iran	0.66	0.56	-14%
Northern Fields	Kuwait	0.57	0.82	44%
Upper Zakum	United Arab Emirates	0.56	0.62	11%
Bu Hasa	United Arab Emirates	0.55	0.73	33%
Ku-Maloob-Zaap	Mexico	0.54	0.77	43%

Discovered in 1976 and production began in 1979! Second highest producing with 2.14 MMbbl/day in 2004, after Ghawar field in Saudi Arabia.

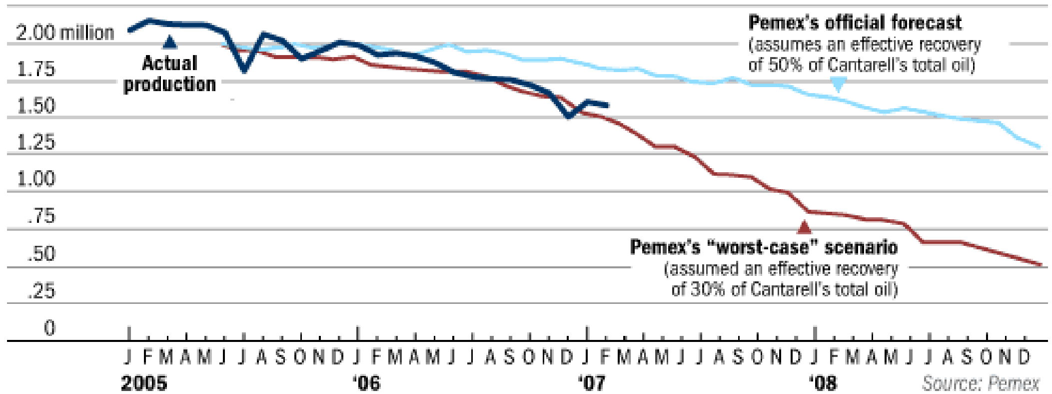
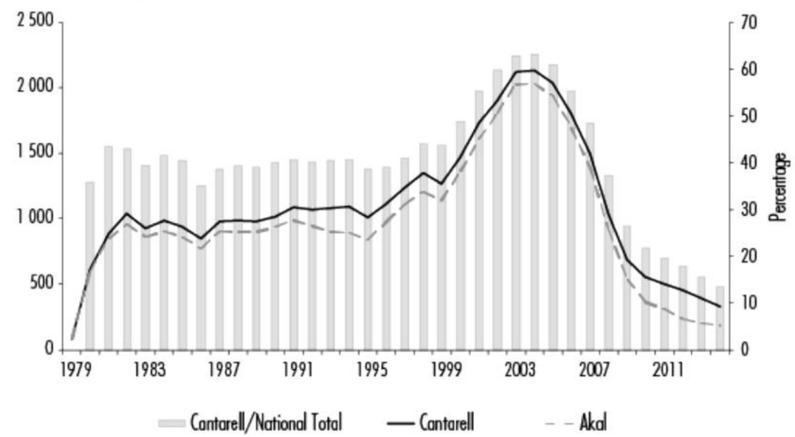
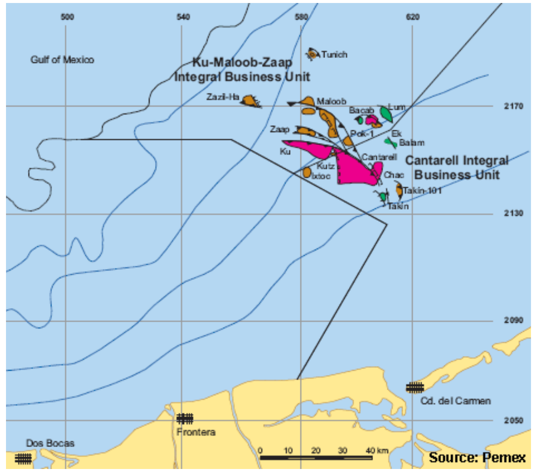


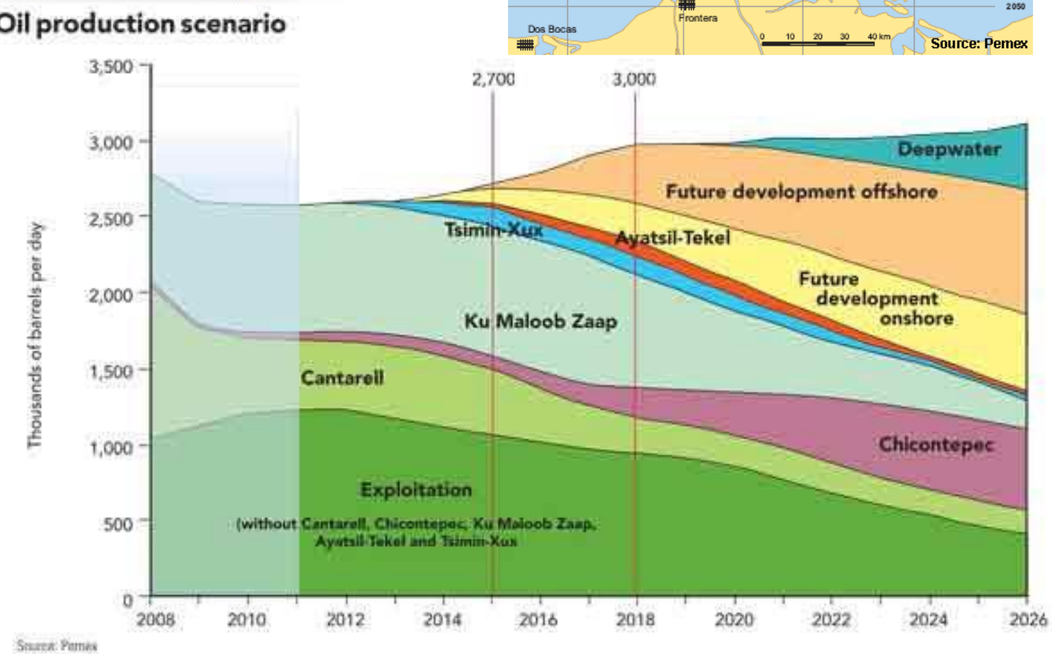
Figure 2. Oil Production at Cantarell. Thousands of Barrels Per Day.



Ramo, 2015, National University of Mexico, Vol 46, no 183

Cantarell, Mexico

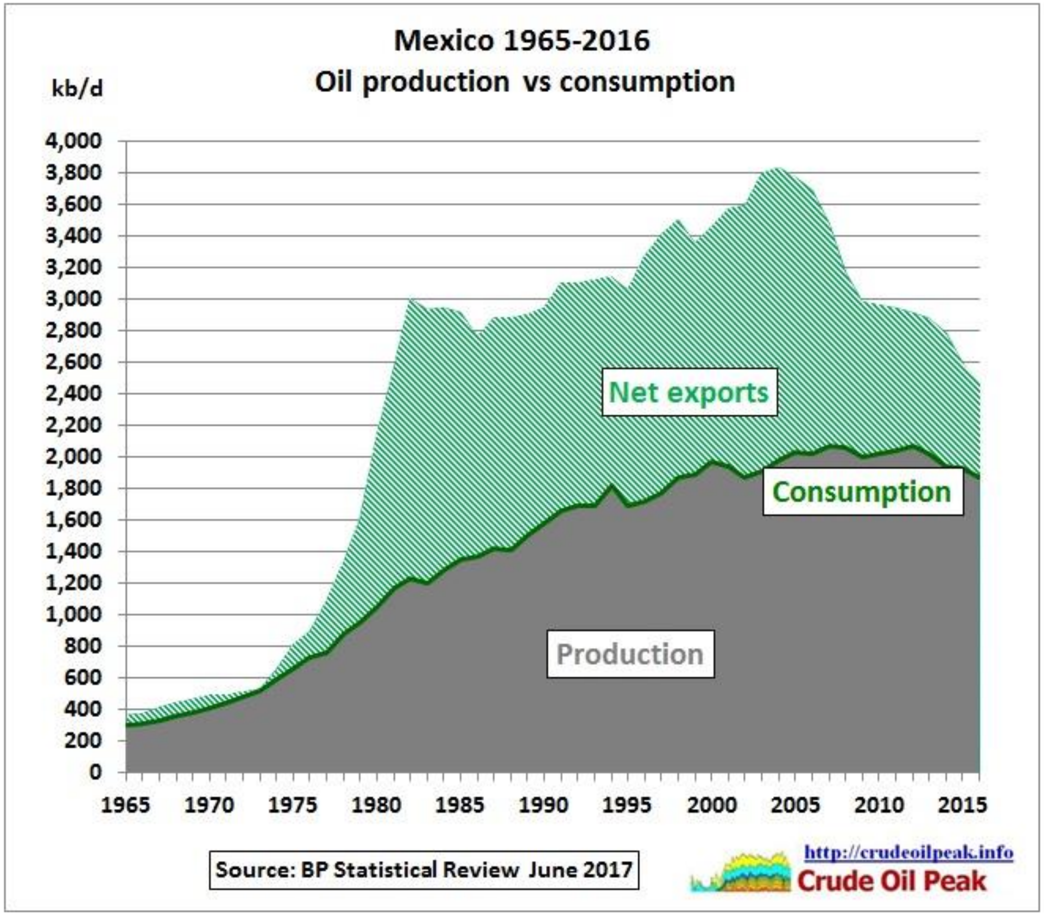




Source: Pemex

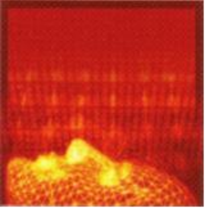
- From 2016 and onwards, production is expected to continue declining, but at a slower pace, thanks to substantial contribution from the new discoveries in the Litoral De Tabasco (Xikin, Esah and Batsil) and Cantarell (Cheek), infill drilling at Ku as well as the deepwater project Lakach. "
- Cantarell complex has 4 fields: Aka, Nohoch, Chac, and Kutz, covering ~162 sqkm. Akal structure covers 91% of the complex with ~35Bbbl of OOIP, and 1200m of column!!

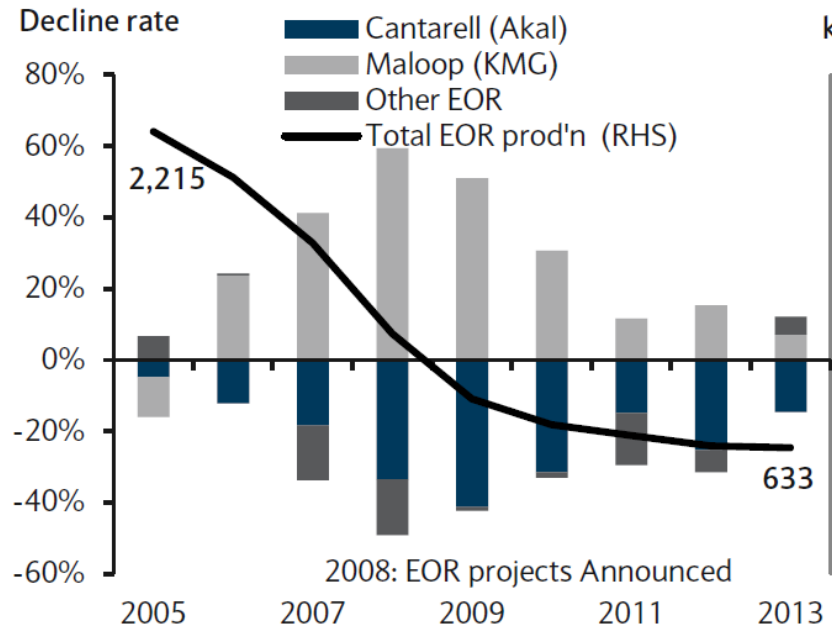
Cantarell, Mexico



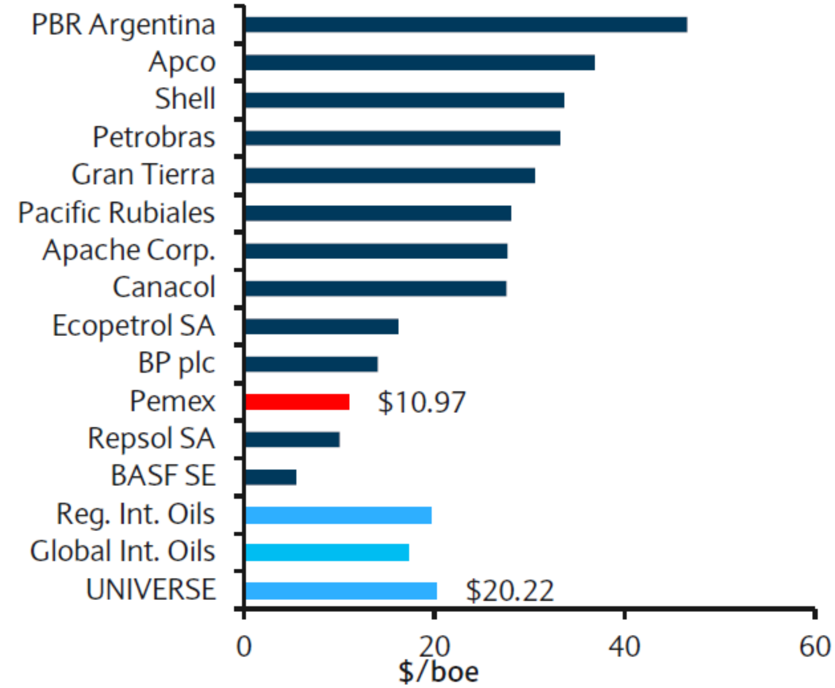
- Cantarell used to produce almost the entire Mexico production that is now, 2.0~ MMbbl/d.
- Cantarell produces ~190 Mbbl/d now (2016) 15% decline from previous year.
- Bulk of the Mexico production is from KMZ Fields, close to 900Mbbl/d.
- The structure was estimated to contain 42.6Bboe in 2013 *(Ivanhoe and Leckie, 1993: 87-91)*

Cantarell, Mexico





Source: CNH/SENER, Barclays Research

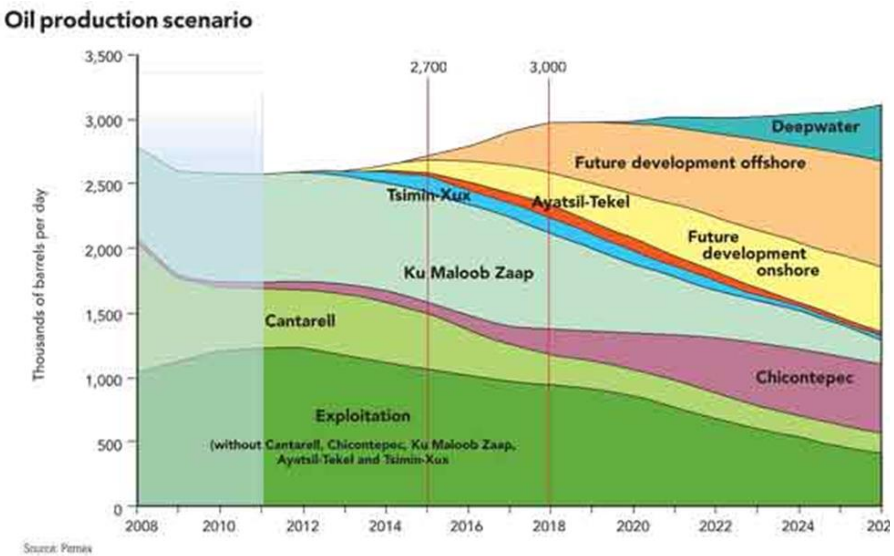


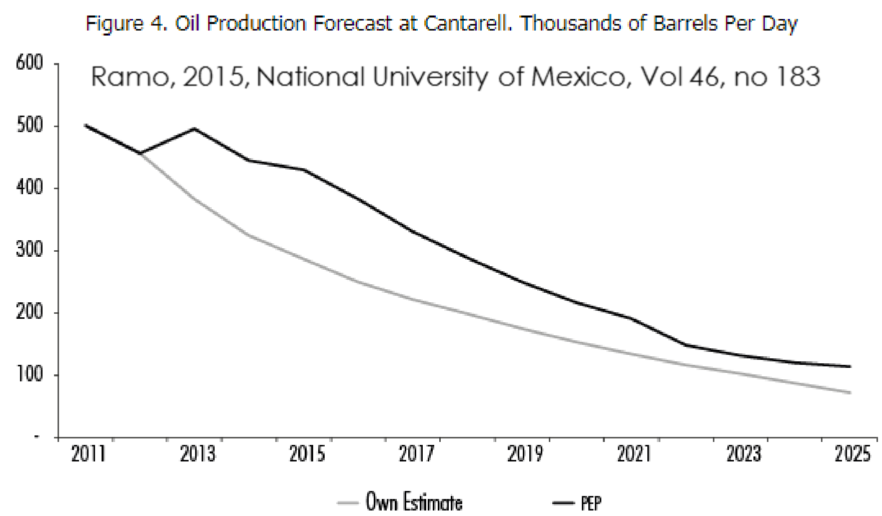
Note: Three-year average of 2010-12 averaged F&D costs. Source: IHS Herold Performance Metrics for S. and Cent. America, Barclays Research

Loss of production is Cantarell is compensated by EOR efforts in KMZ fields and other fields.

Pemex is one of the most efficient operators with lifting costs close to $11, compared to its counterparts in Latin America and Shell

Cantarell, Mexico

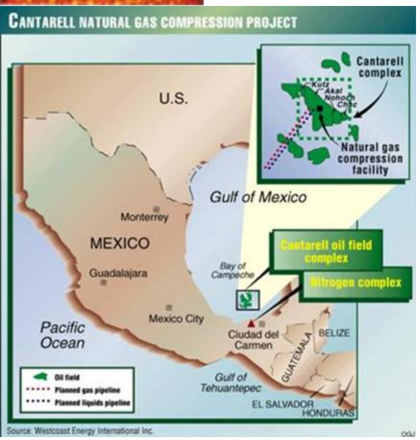


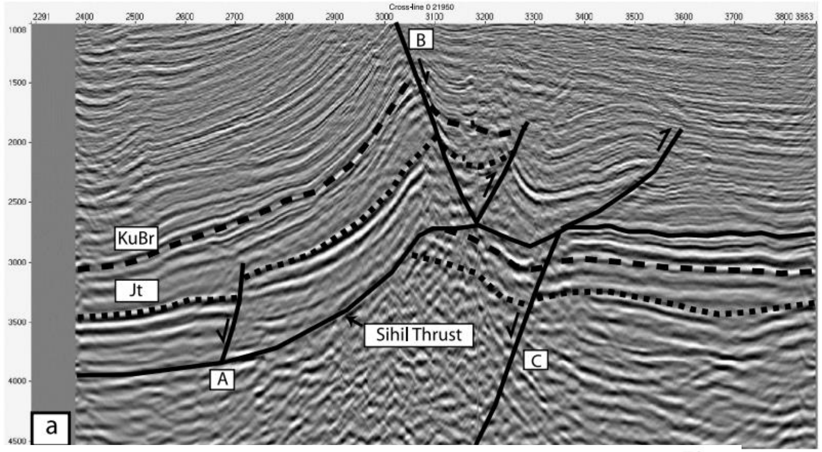


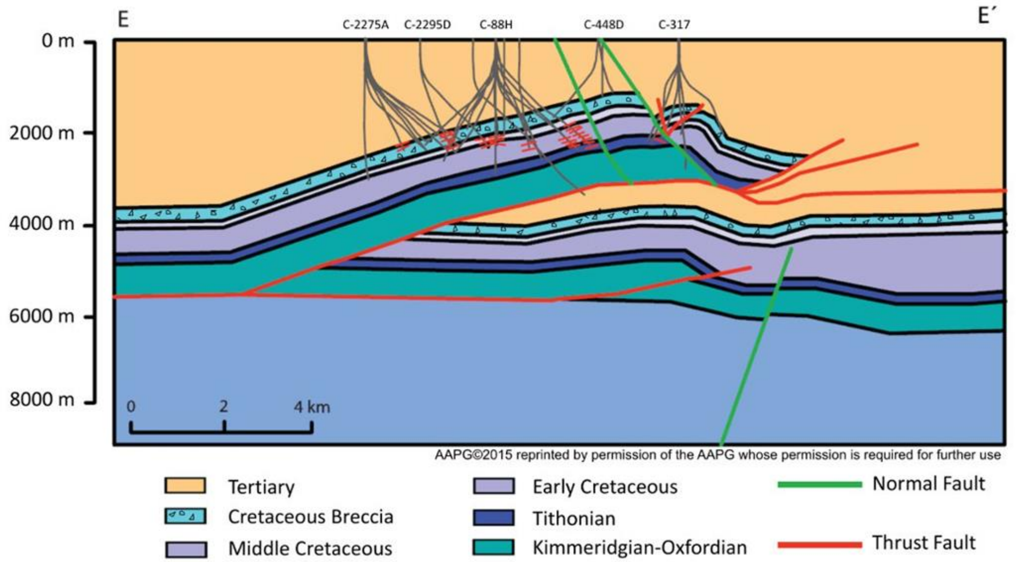
Source: Pemex PEP and own estimates.

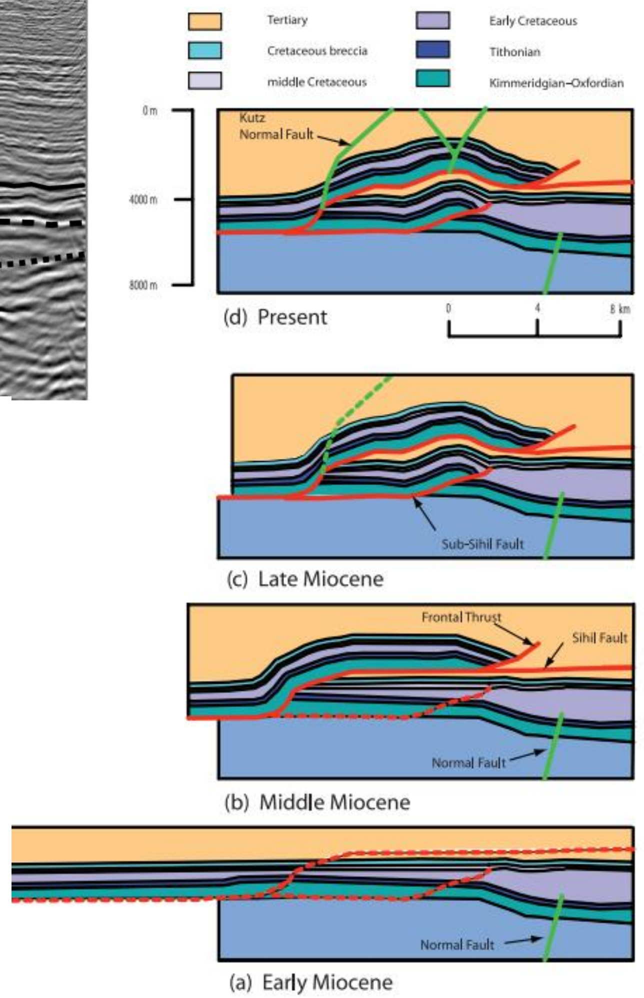
- Cantarell is expected to have significant future production, especially from deeper Sihil structure.
- Future production depends on improving the subsurface image and identifying the effecting sweeping mechanism for EOR.

Cantarell Field, Mexico







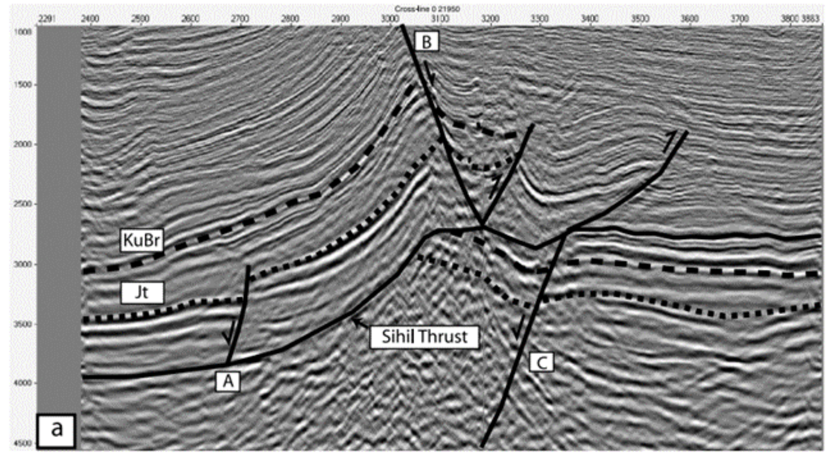


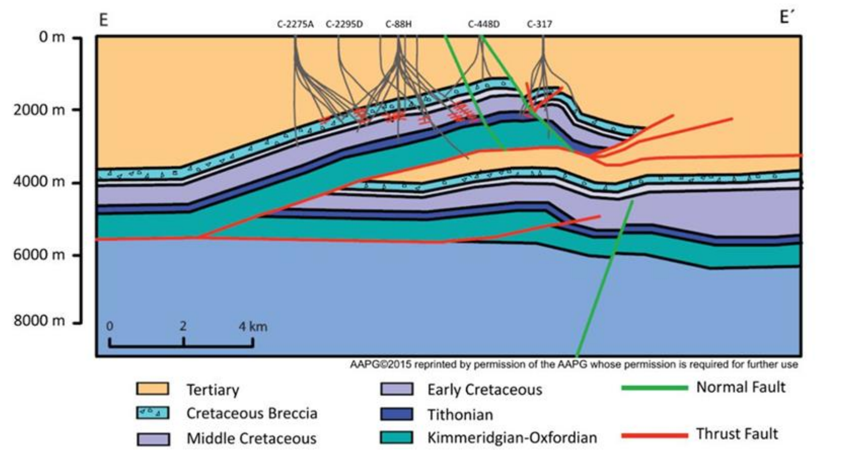
Mitra et al, 2005, AAPG Bulletin, v 89, No 1

Cantarell Field New Interpretation

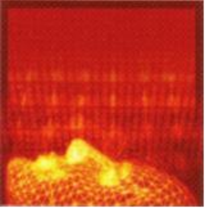
Cantarell Interpretation sequence

- Seismic Interpretation
    - Seismic interpretation in 2D sections
    - Construction of series of cross sections
    - 3D structural model integrating structural cross sections, seismic interpretation, well tops and dipmeter data
  - Two main surfaces (1) Top upper Cretaceous breccia, and (2) top of Tithonian.
  - These two surfaces and faults were used to establish structural geometry at large scale
- Sihil- deeper upside
  - The detailed seismic interpretation and structural restoration delineated entirely new structure, part of autochthonous sheet.



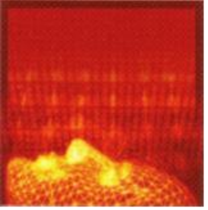


Mitra et al, 2005, AAPG Bulletin, v 89, No 1

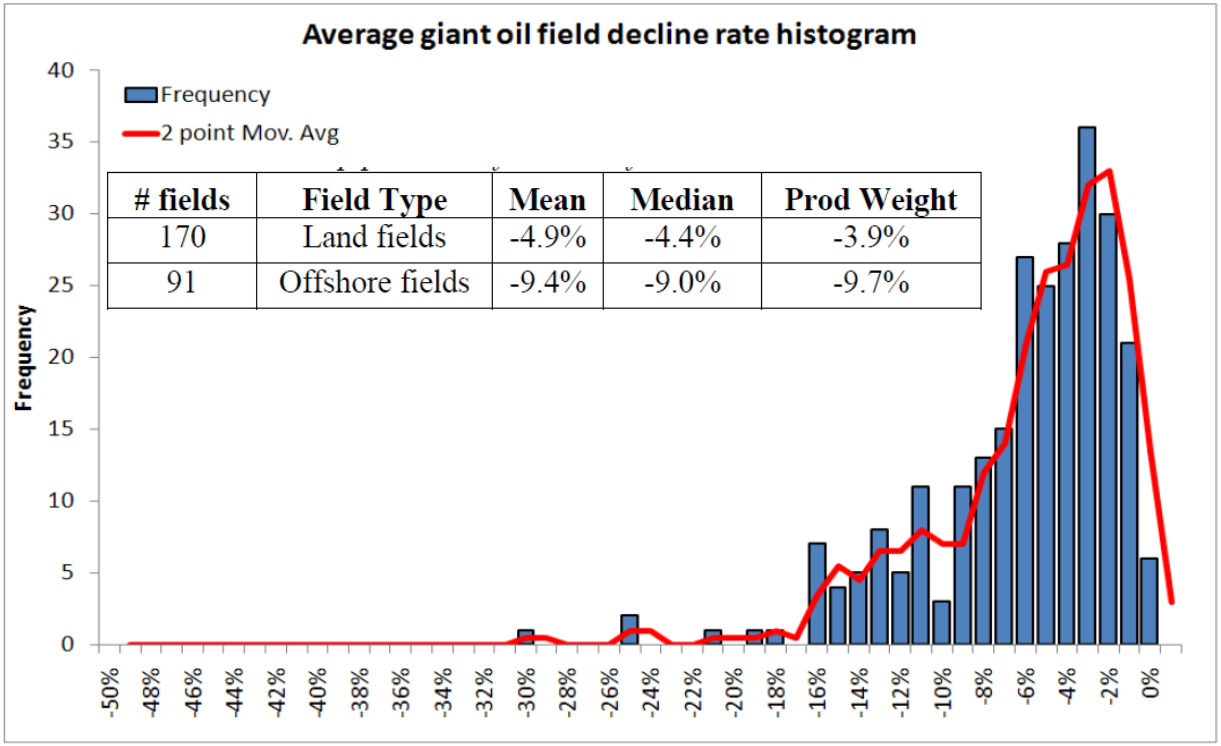


Lessons

- Cantarell is literally an earth shattering discovery, producing from an impact carbonate breccia, formed due to the Chicxulub meteorite impact.
- Cantarell is one on of the classic giant fields of the world, that supplied 100% of current Mexican production, which peaked at ~2.1BBbl/day. Production was enhanced temporarily with N2, and that followed steep decline because of N2 breakthrough.
- Economic pressures forced a steep decline. ~15-17%
- Seeing is believing. 3D seismic provided a powerful image, which proved to e complex thrust faulting, with Signiant pay in autochthonous block, Sihil structure.
- Detailed subsurface studies may reveal true potential of Sihil autochtonous block.



Giant mature fields



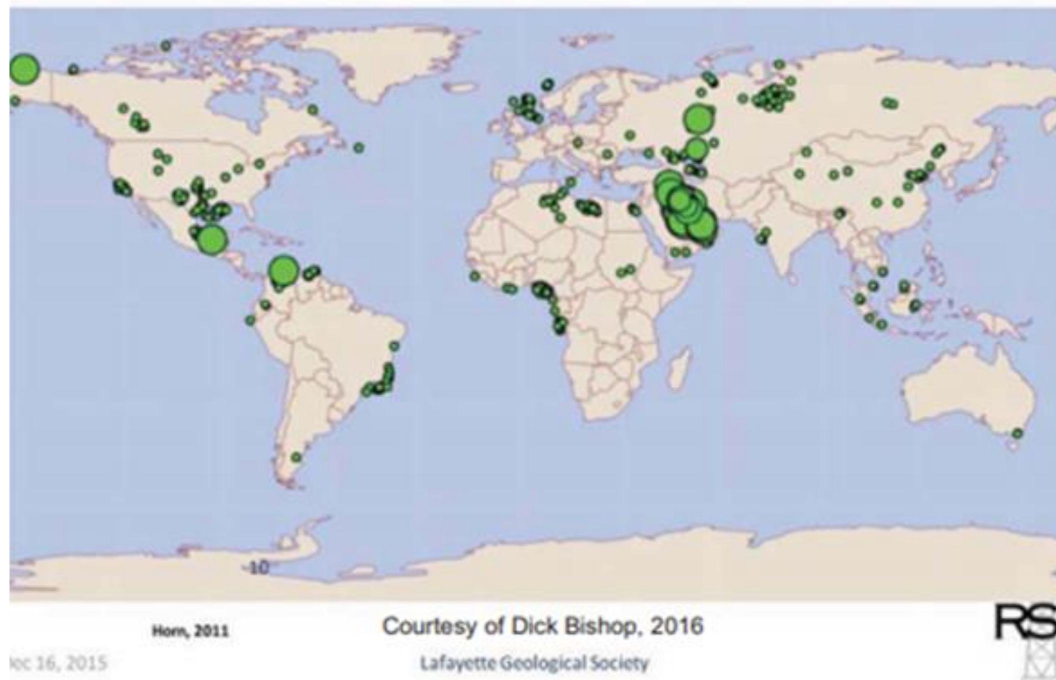
# fields	Field Type	Mean	Median	Prod Weight
170	Land fields	-4.9%	-4.4%	-3.9%
91	Offshore fields	-9.4%	-9.0%	-9.7%

Most giant fields leave the plateau phase and reach the onset of decline when around 40% of the URR has been produced, and combined with IEA's average depletion factor, it is not surprising that the majority of the fields are categorized as in decline. Höök et al. (2009)

Histogram of the decline rate distribution of the 261 post plateau giant fields as of the end of 2005. About 65% are onshore and 35% offshore. Significant differences occur between different subgroups. The offshore fields cluster together around -10% and the land fields around -4%. OPEC fields tend to decline slower than non-OPEC fields.

Giant Mature Fields

- Oil: EUR ~500MMbo
- Oil &Gas EUR ~500MMboe
  - Gas conversion =6000cft/bbl
- Gas field~3 tcf gas
- Super-giant fields ~5Bboe
- Mega-giant fields ~10Bboe

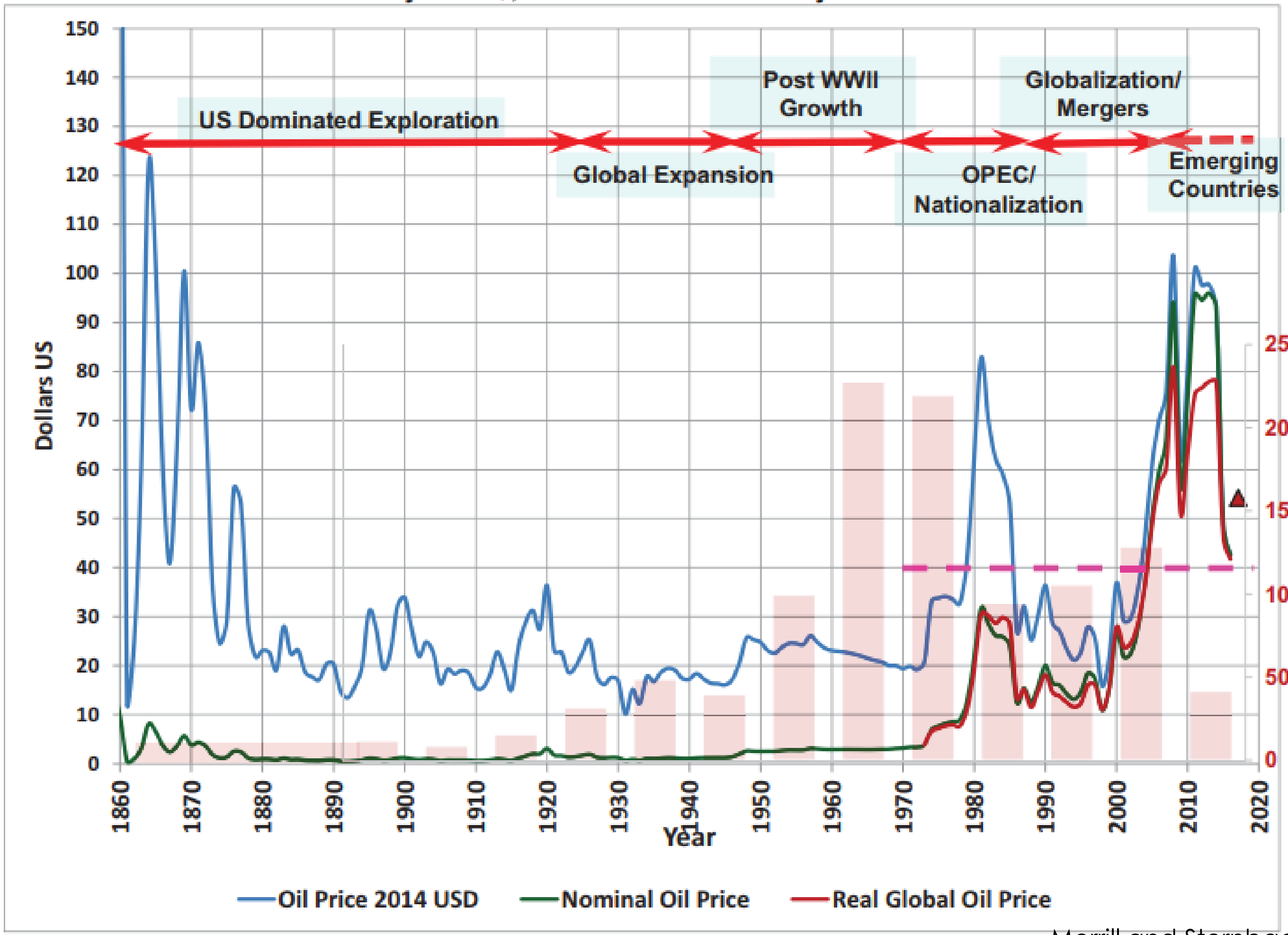


957 Giant Fields
97 Super-giant Fields
7 Mega-giant Fields

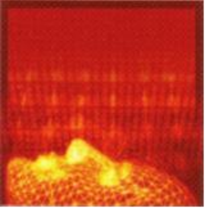
Merrill and Sternbach,2017, AAPGSD#70267

Giant Mature Fields

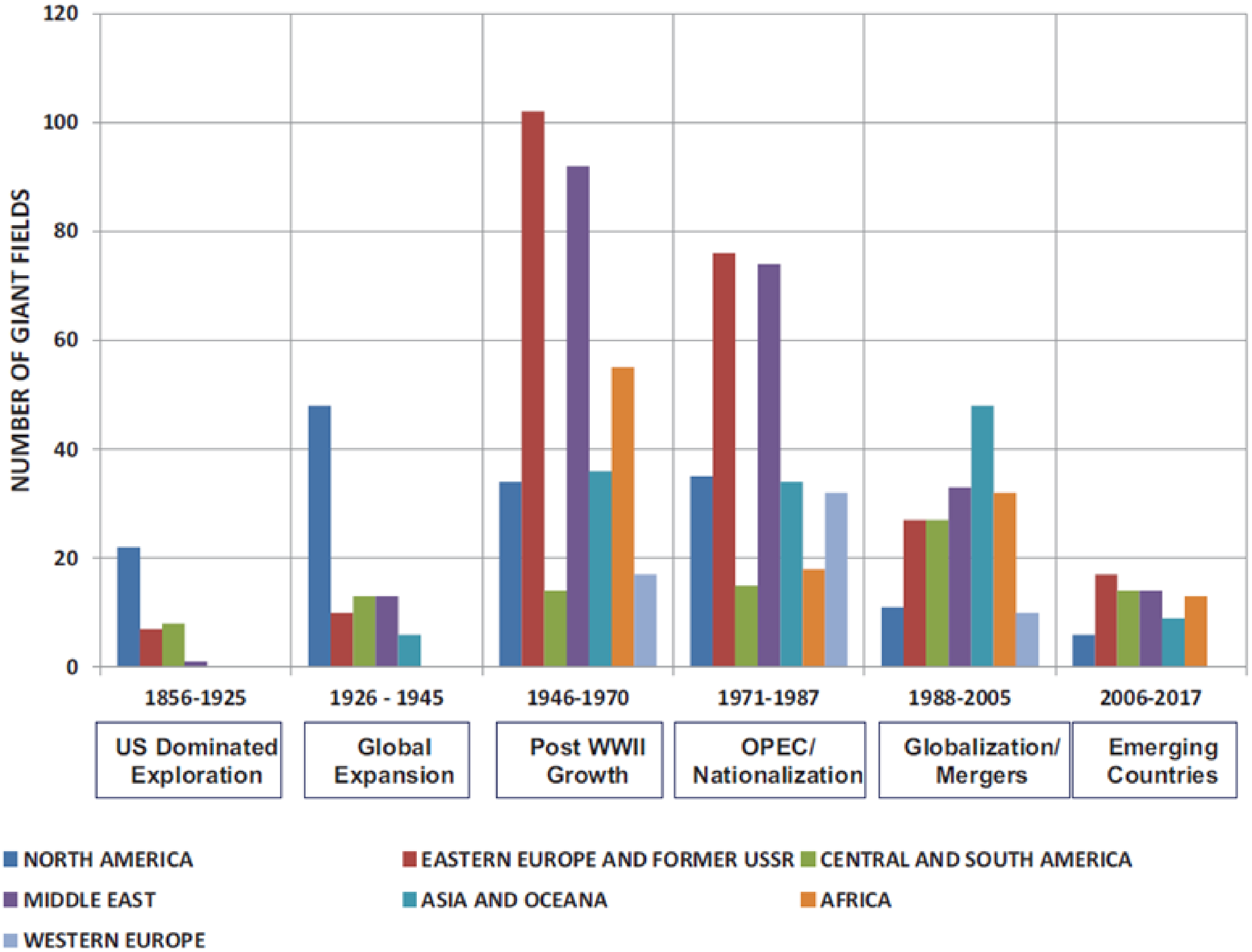
Nominal = Inflation Adjusted $; Real Global Price = Adjusted for US Dollar Value



Merrill and Sternbach,2017, AAPGSD#70267

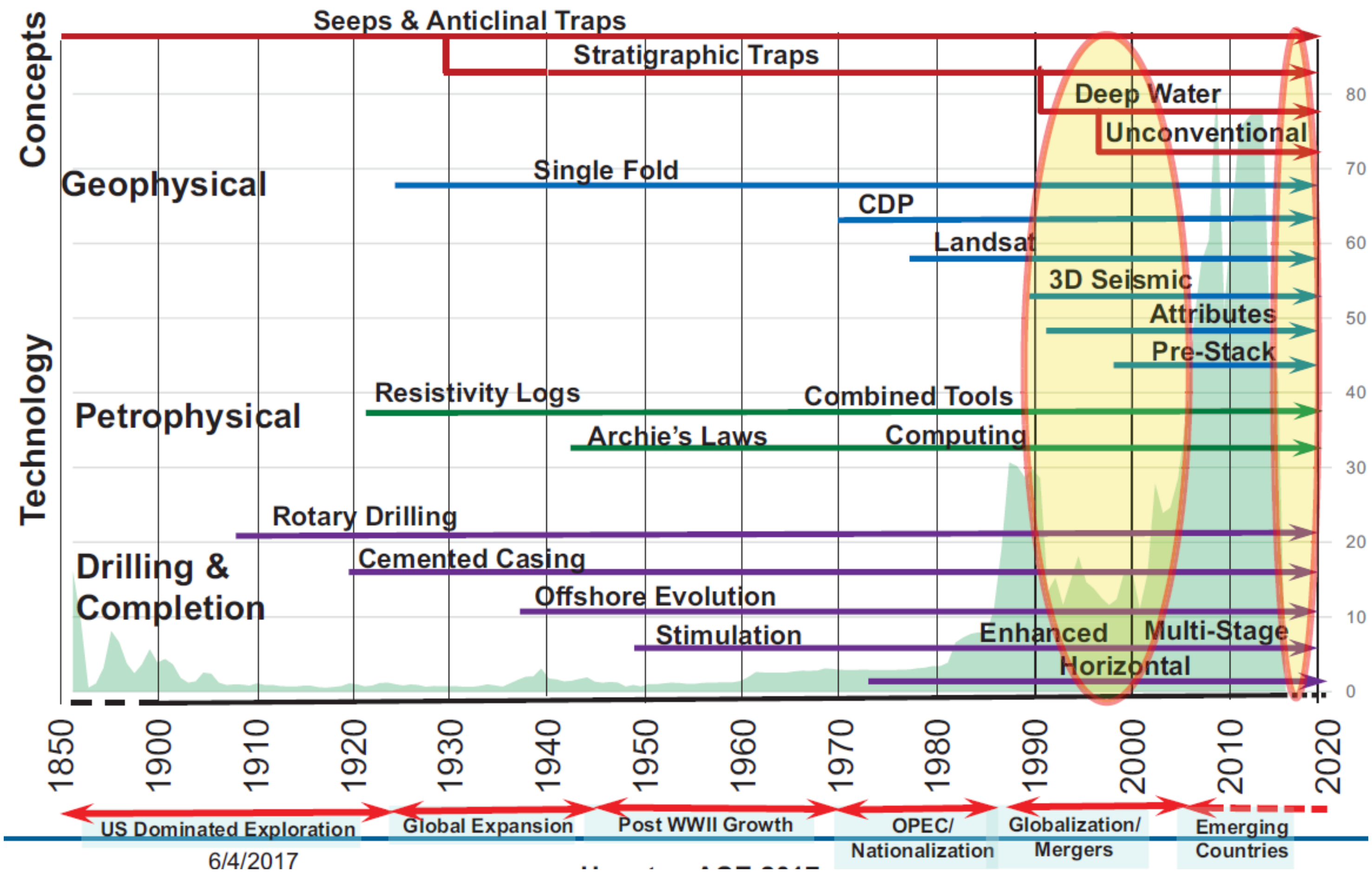


Giant Mature Fields

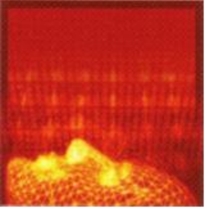


Merrill and Sternbach,2017, AAPGSD#70267

Giant Mature Fields



Merrill and Sternbach,2017, AAPGSD#70267



Mature Field: SWOT

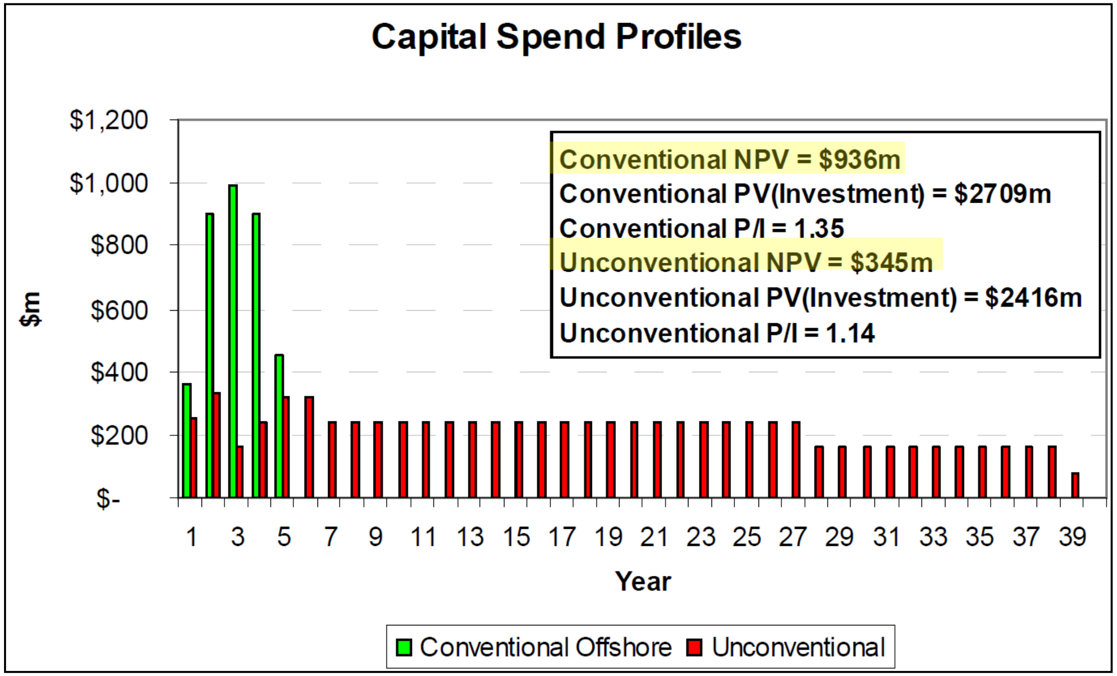
Strengths
- The asset, Proved reserves: infrastructure and surface facilities
- Experienced staff and local knowledge
- Current transpiration, processing and marketing
- In-field exploration potential

Opportunities
- Rejuvenation/revitalizing
- Developing new dependent markets, gas, derivatives markets
- New Technologies in G&G and IOR/EOR
- Production optimization
- In-field upside potential

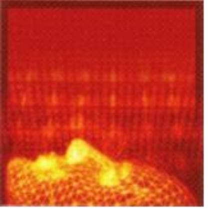
Weaknesses
- Mostly depleted zones and areas with high water cuts
- Old facilities and infrastructure
- Limited data and lack of data management
- Personnel allocation (typically understaffed)

Threats
- Attractive new investments
- Unfavorable crude oil price
- Environmental and social issues
- Government/Royalties
- Lack of incentive/opportunity costs

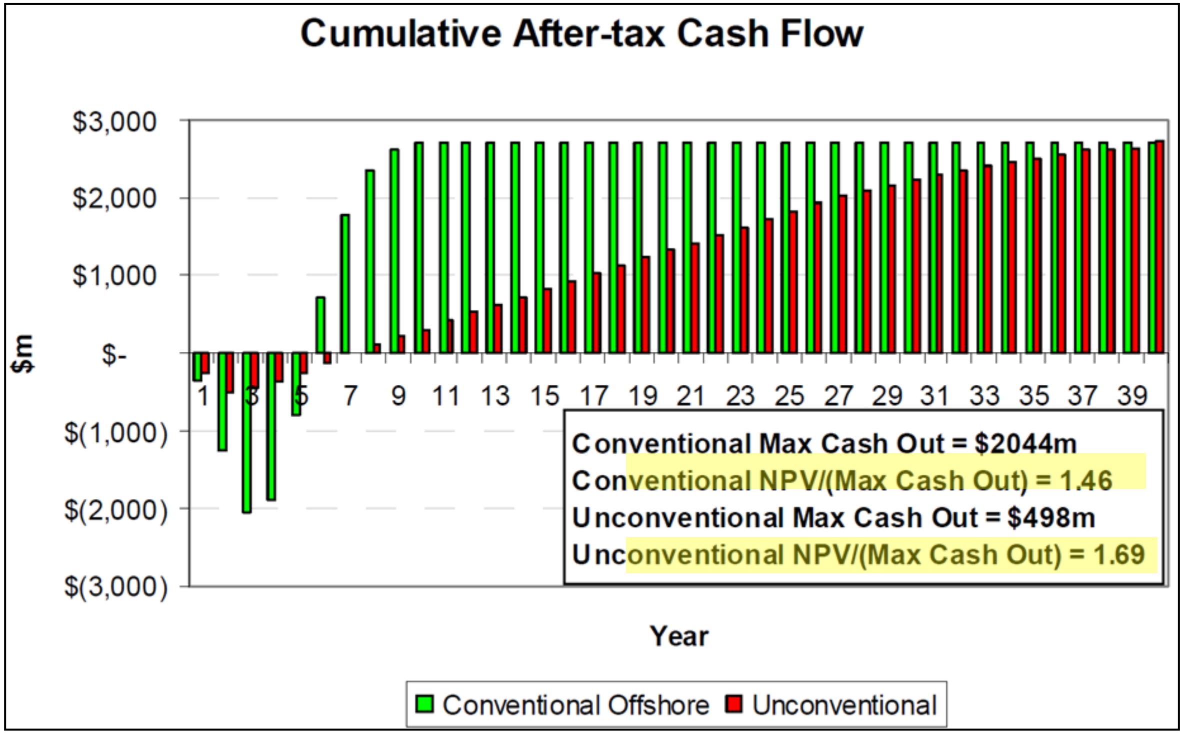
Unconventional vs. Conventional Production



In conventional plays, the capital is up front followed by a long revenue stream requiring minimal additional capital investment. In unconventional plays, significant capital spending continues at a high rate throughout field life; given the high decline rates of individual wells, continuous drilling is the only way to maintain production at profitable levels. Even discounted to today's dollars, the total capital requirements of an unconventional development are much, much larger than the NPV of the project.

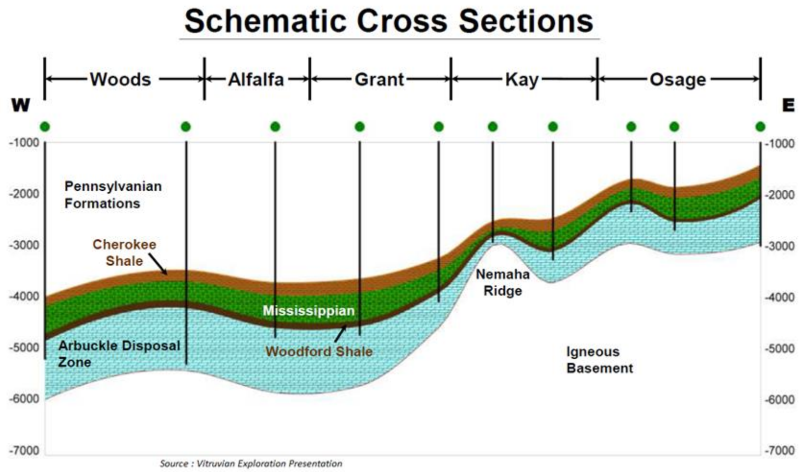


Unconventional vs. Conventional Production



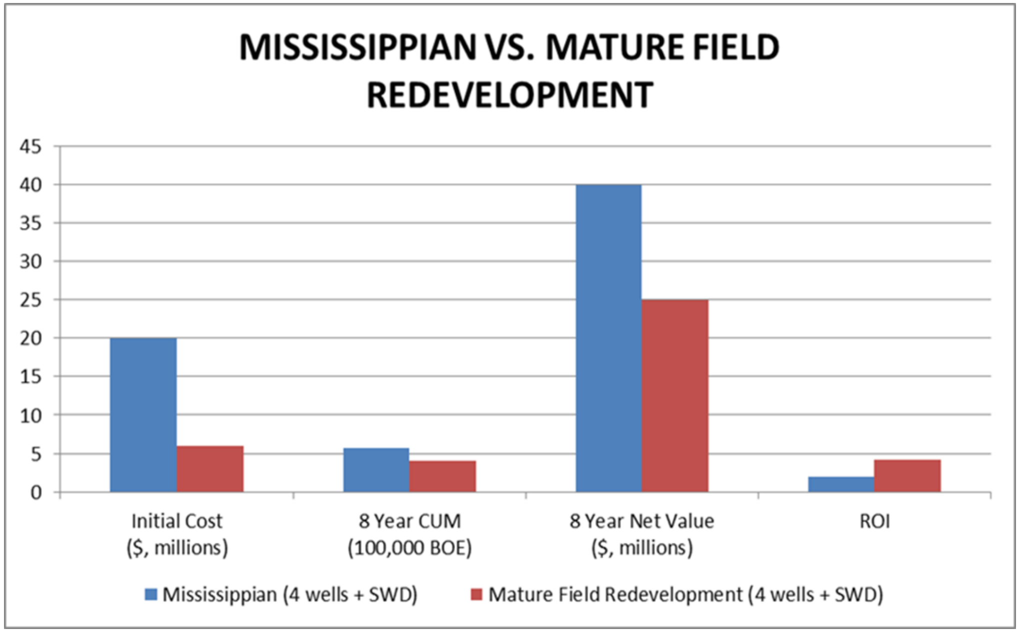
So how unconventional plays stay profitable? The projects are expected to be self funded after few years. The revenue goes to drilling campaign to stay profitable, these are operating expenses, not treated as capital. Note that the metric here not P/I or just NPV. The two assets are compared on same metric, NPV/(max. Cash flow) after tax.

Unconventional vs. Conventional Production



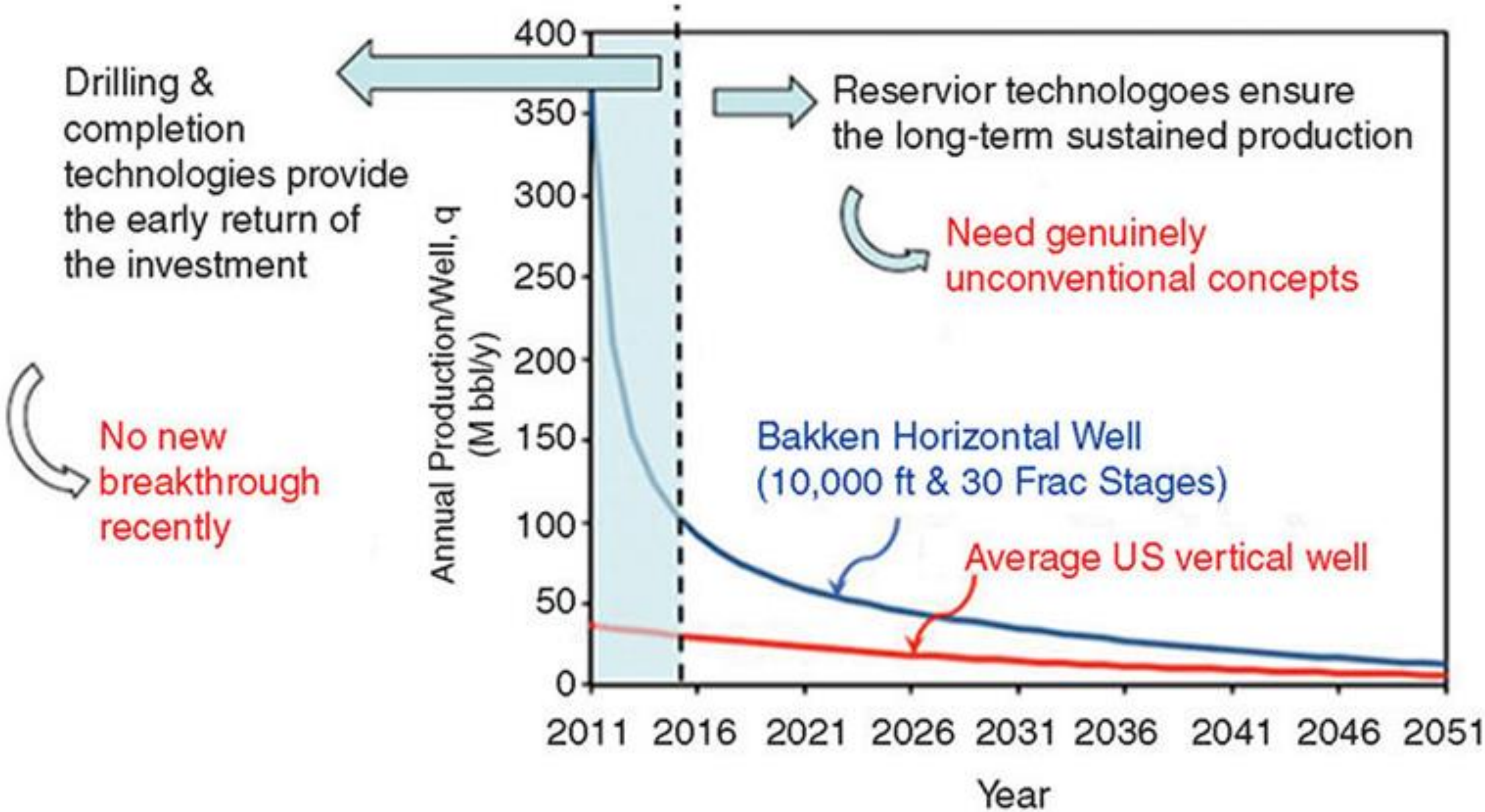
- The Mississippian Lime extends from Kansas through northeastern Oklahoma, maintains roughly a 6,000-foot depth and has lower well costs compared to other popular formations such as the Bakken or the Eagle Ford.
- Parameters:
  - Wells: Four vertical wells and one new salt water disposal well for each type of prospect
  - Foot Print: 1,280 acres required for the Mississippian lime project and 160 acres for the mature field redevelopment prospect
  - Assumed average pricing for drilling, completion, and commodity prices
  - 8 year economic model

Unconventional vs. Conventional Production

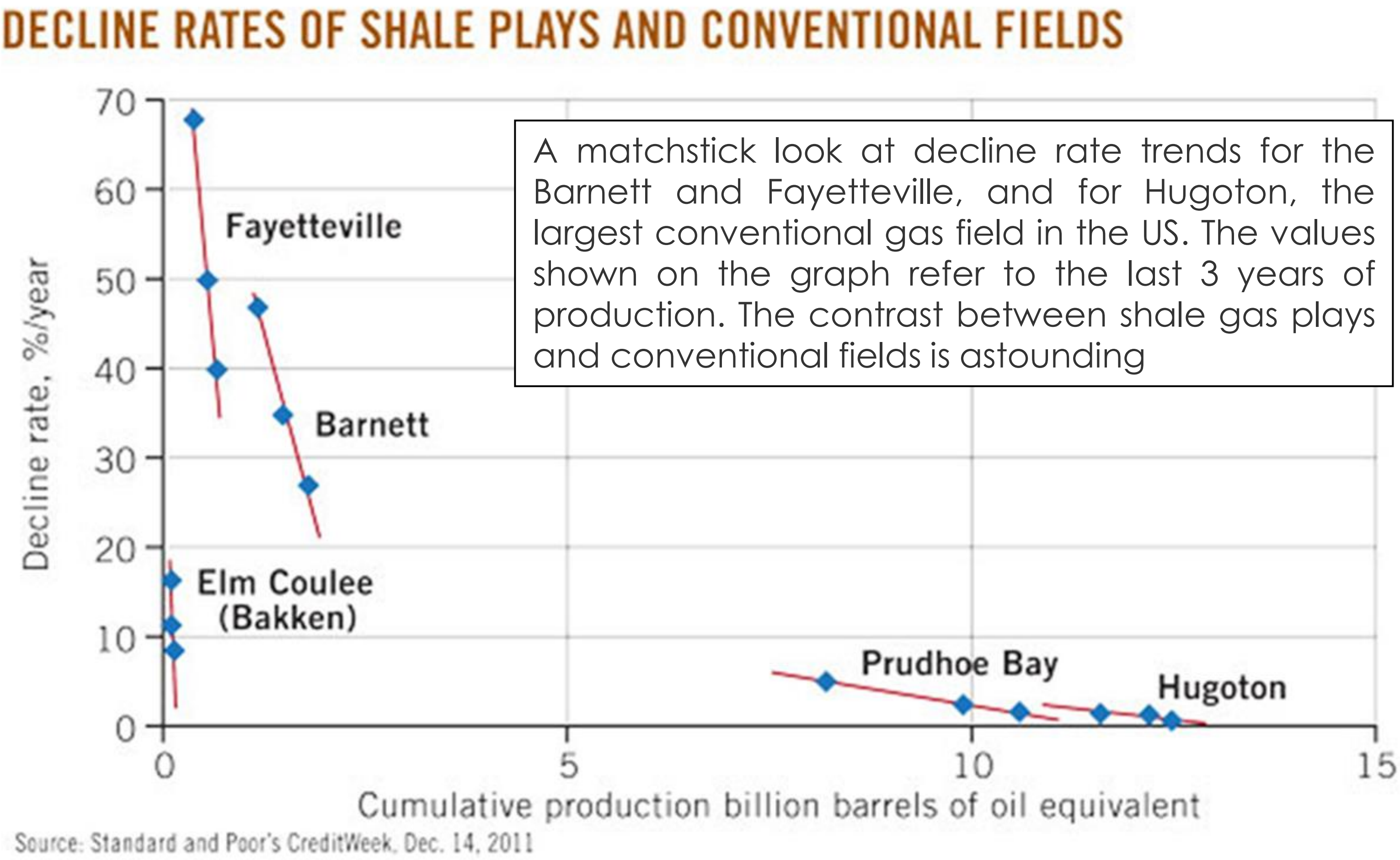


- **ROI :** "conventional" mature field redevelopment is twice that of Mississippian Lime play ("unconventional", because it requires a substantially lower capital investment),
- **Risk and Capex/Opex:** Conventional mature field redevelopment projects present a lower risk and Capex/Opex, compared to the operational risks and elevated costs associated with unconventional drilling.
- Mature field redevelopment prospect requires only about 1/4th of the initial capital necessary to develop the Mississippian Lime play project

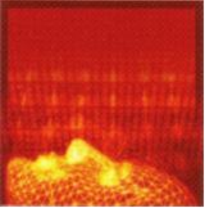
Unconventional vs. Conventional Production



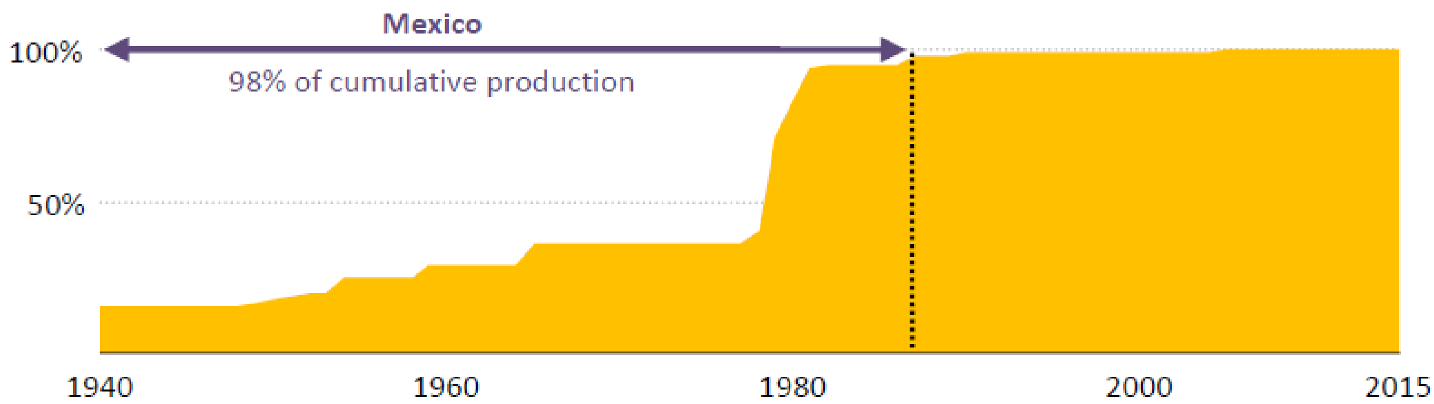
Unconventional vs. Conventional Production

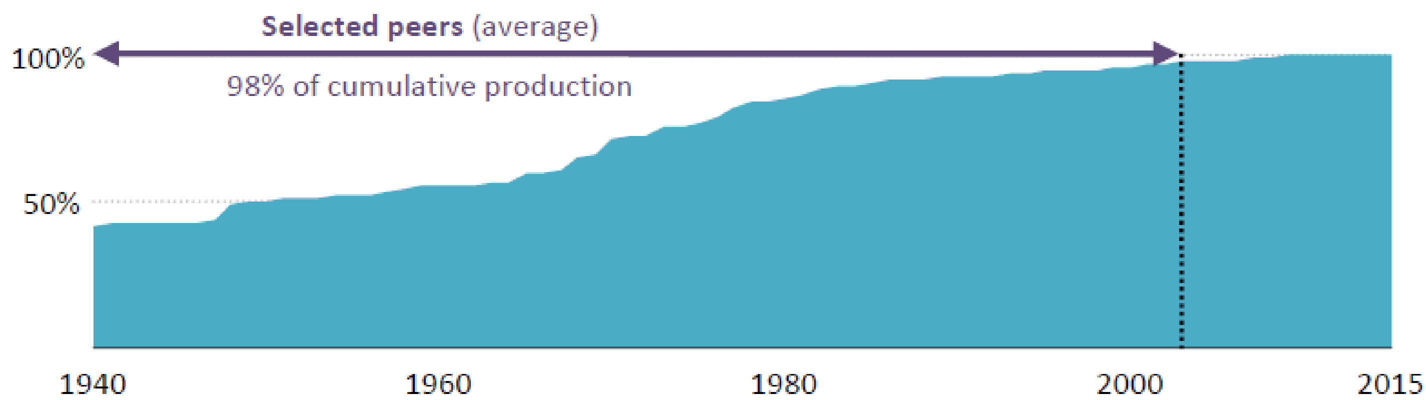


A matchstick look at decline rate trends for the Barnett and Fayetteville, and for Hugoton, the largest conventional gas field in the US. The values shown on the graph refer to the last 3 years of production. The contrast between shale gas plays and conventional fields is astounding



Mexico Outlook Energy Special Report 2016, IEA

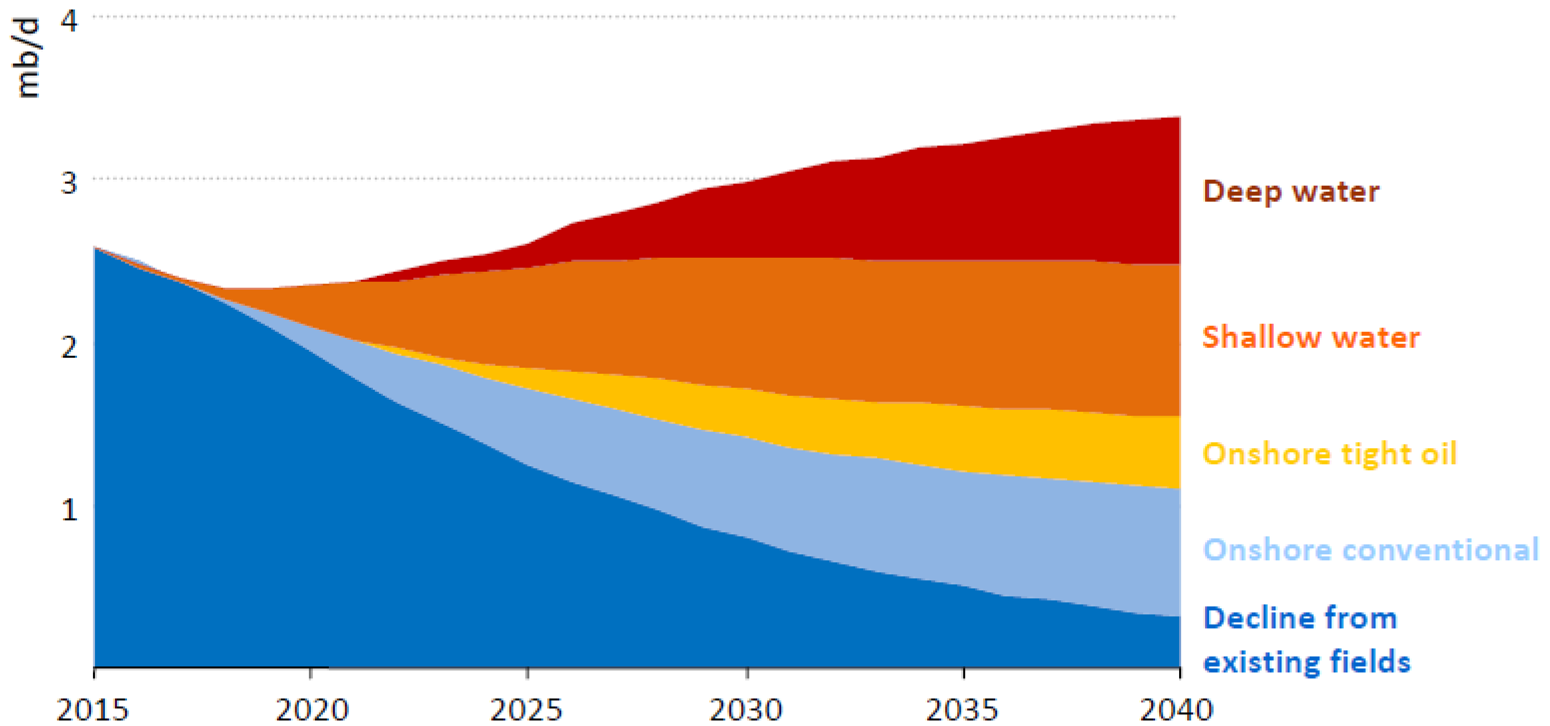




Almost all of Mexico's cumulative production to date comes from fields that started operation more than 25 years ago

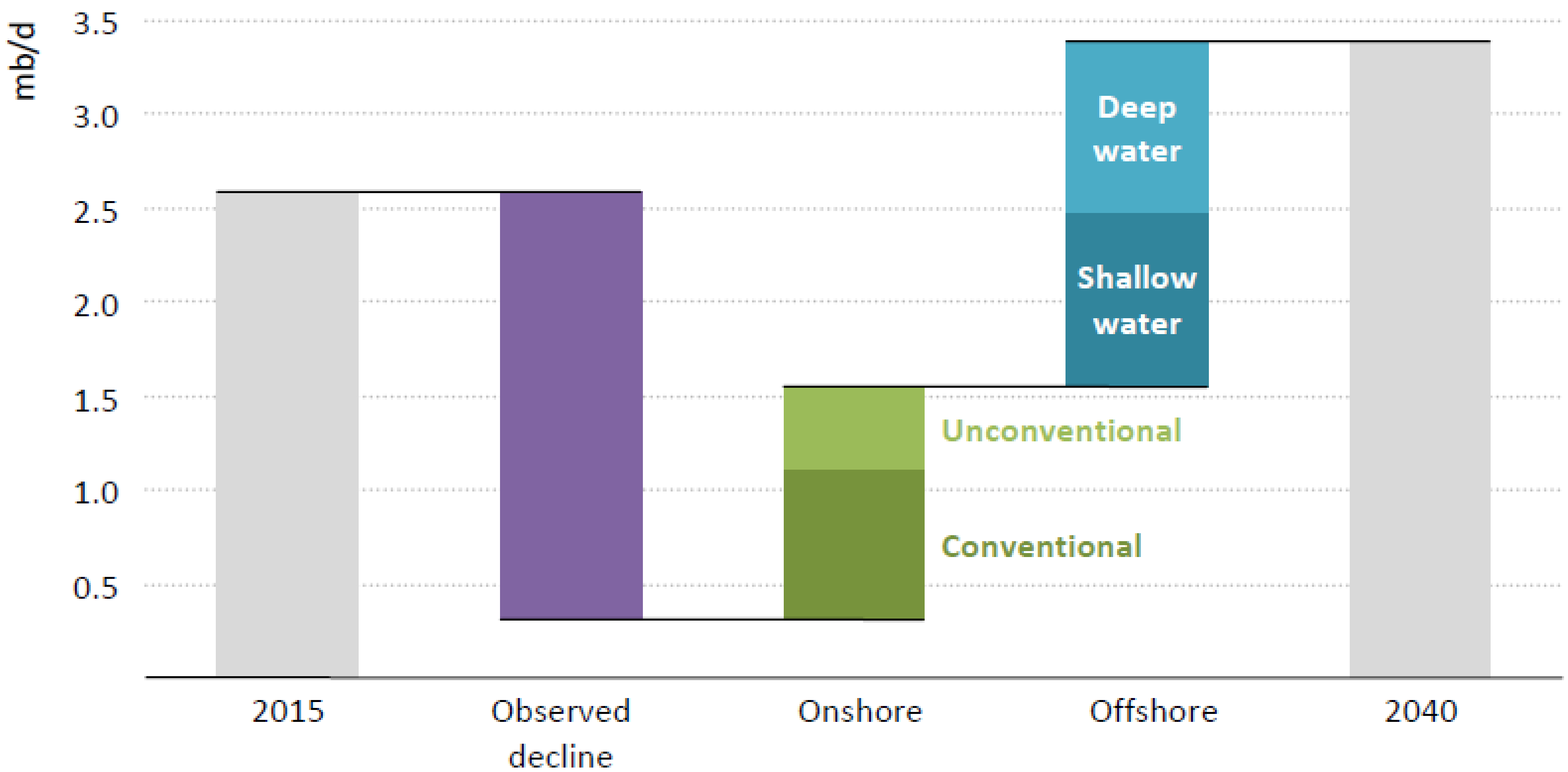
Note: The selected peers are the United States, United Kingdom, Venezuela, China and Russia.

Mexico Outlook Energy Special Report 2016, IEA



Mexico's oil output gets back on a rising path in the New Policies Scenario, but it takes time for new projects to offset declines

Mexico Outlook Energy Special Report 2016, IEA



Production from a range of sources needs to be mobilised to offset decline in Mexico's existing fields

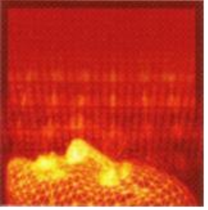
Mexico Outlook Energy Special Report 2016, IEA

Remaining technically recoverable oil resources by category in Mexico, end-2014 (billion barrels)

	Technically recoverable resources	Cumulative production	Remaining recoverable resources	Remaining % of URR	Proven reserves
Conventional onshore	41.6	20.3	21.2	51%	3.0
Tight oil	13.1	0.0	13.1	100%	0.0
Shallow offshore	48.4	28.3	20.1	42%	7.8
Deep offshore	15.0	0.0	15.0	100%	0.0
Total Mexico	**118.0**	**48.6**	**69.4**	**59%**	**10.8**

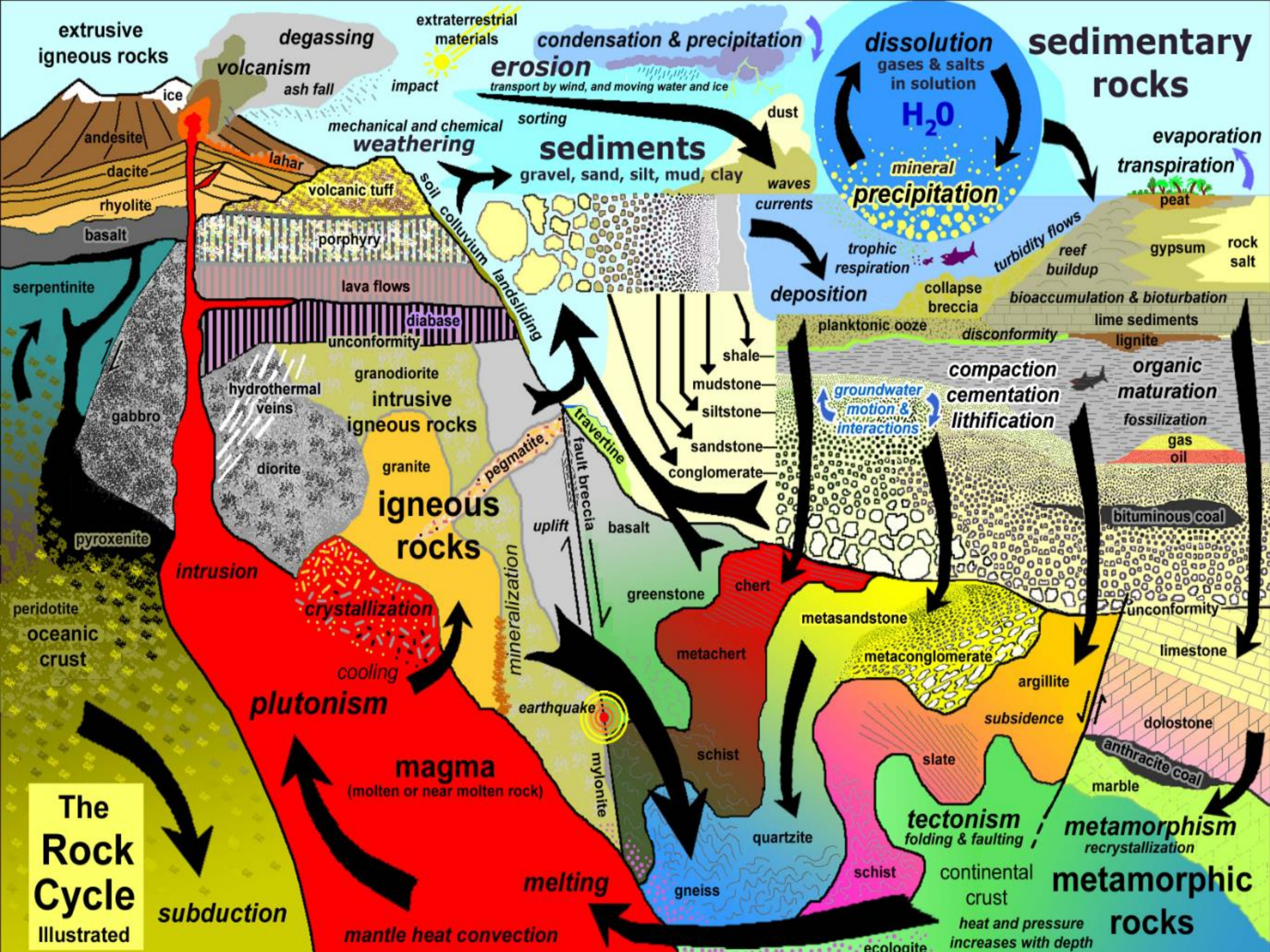
Notes: Data include crude, condensate and natural gas liquids. URR = ultimately recoverable resources.

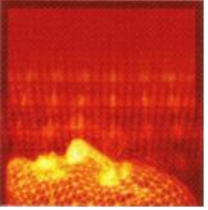
Sources: IEA; SENER.



Conclusions & Lessons

- An oil field can be considered as mature when its production rate has significantly declined and/ or when it is close to reaching its economic limit. A field might also be considered mature when it has been in production for many years and has depleted its primary and secondary recovery. Consequently, facilities and technology at mature fields could be old. However, far from being diminishing assets, these mature fields offer one of our most important opportunities to extract further oil and gas resources to meet future energy demands.
- While the world hydrocarbon demand is estimated to increase by approximately 1.5% per year, the number and size distribution of new discoveries are declining, whereas mature fields are more predictable (less risk and less uncertainty). Mature fields are also seen as attractive in uncertain times, given the benefits of regular, reliable cashflows.
- Far from being diminishing assets, these mature fields offer one of our most important opportunities to extract further oil and gas resources to meet future energy demands.
- While addressing the field declines wells, reservoirs, and fluid behavior is important, reevaluating the fields with the continued investment in 3D seismic and wells, as if they are new appraisals is essential to really reverse the decline.


The Rock Cycle Illustrated
extrusive igneous rocks
degassing
volcanism
ash fall
extraterrestrial materials
impact
condensation & precipitation
erosion
transport by wind, and moving water and ice
dissolution
gases & salts in solution
H_2O
mineral precipitation
sedimentary rocks
evaporation
transpiration
ice
andesite
dacite
rhyolite
basalt
lahar
volcanic tuff
mechanical and chemical weathering
sorting
sediments
gravel, sand, silt, mud, clay
dust
waves
currents
peat
soil
colluvium
landsliding
porphyry
lava flows
diabase
unconformity
serpentinite
trophic respiration
turbidity flows
reef buildup
gypsum
rock salt
deposition
collapse breccia
bioaccumulation & bioturbation
planktonic ooze
disconformity
lime sediments
lignite
shale
mudstone
siltstone
sandstone
conglomerate
compaction cementation lithification
groundwater motion & interactions
organic maturation
fossilization
gas
oil
granodiorite
hydrothermal veins
intrusive igneous rocks
gabbro
diorite
granite
pegmatite
travertine
fault breccia
uplift
basalt
igneous rocks
bituminous coal
pyroxenite
intrusion
crystallization
mineralization
greenstone
chert
metasandstone
unconformity
peridotite
oceanic crust
cooling
metachert
metaconglomerate
argillite
limestone
plutonism
earthquake
subsidence
dolostone
schist
slate
anthracite coal
marble
magma
(molten or near molten rock)
mylonite
quartzite
tectonism
folding & faulting
metamorphism
recrystallization
continental crust
metamorphic rocks
schist
melting
gneiss
subduction
heat and pressure increases with depth
mantle heat convection
ecologite



Some definitions, keep sake…

Categories of hydrocarbon liquids.

— *Crude oil* is a heterogeneous mix of hydrocarbons that remain in liquid phase when extracted to the surface. Crude oil is commonly classified by its density, measured in degrees of *API gravity* with higher API indicating lighter oil.[3] Industry definitions vary, but heavy oil is typically less than 20° API.

— *Condensate* is a very light, volatile liquid, typically 50–75° API, which condenses from produced gas when it cools at the surface. Condensate is generally mixed with crude oil and produced volumes are rarely reported separately.

— *Natural gas liquids* (*NGLs*) is a generic term for the non-methane fraction of natural gas (mostly ethane to pentane) that is either liquid at normal temperatures and pressures, or can be relatively easily turned into a liquid with the application of moderate pressure.

— *Extra-heavy oil* is crude oil with an API gravity of less than 10° and typical viscosity more than or equal to 10 000 centipoise.[4] Most current production is from the Orinoco belt in Venezuela.

— *Oil sands* (or tar sands) are a near-surface mixture of sand, water, clay and bitumen, where the latter has an API gravity less than 10° and typical viscosity 10 000–1 000 000 centipoise. The bitumen is the degraded remnant of conventional oil when oil in near-surface accumulations has been altered by the loss of the lighter hydrocarbon molecules, primarily by bacterial oxidation and biodegradation and by dissolution in groundwater. The remaining oil becomes progressively richer in bitumen, denser and more viscous. Most current production is from Alberta and uses surface mining to depths up to 65 m. The bitumen can be diluted or upgraded to a synthetic crude for transport by pipeline.

— *Tight oil* (or shale oil) is light crude oil contained in shale or carbonate rocks with very low permeabilities that can be produced using horizontal wells with multi-stage hydraulic fracturing. Most current production is from the Bakken and Eagle Ford shales in the USA.

— *Kerogen oil* (or ‘oil shale’ oil) is the oil obtained from processing the kerogen contained in fine-grained sedimentary rocks. This involves mining and crushing the rock, heating for prolonged periods at high temperatures, driving off a vapour and distilling. *In situ* processes are also under development, but neither approach is likely to be economic for the foreseeable future.

— *Gas-to-liquids* (*GTLs*) are derived through the liquefaction of methane using the Fischer–Tropsch process. This involves steam reforming of natural gas to produce carbon monoxide and hydrogen followed by catalysed chemical reactions to produce liquid hydrocarbons and water.

— *Coal-to-liquids (CTLs)* are derived either by pyrolysis of coal (low yield) or by gasification followed by a Fischer–Tropsch process (high yield).

— *Biofuels* are transport fuels derived from biological sources. At present, these consist of either ethanol produced through the yeast fermentation of sugar or starch-rich arable crops, or biodiesel derived from seed oils. Second generation cellulosic biofuels using non-food feedstocks are also under development.