Advanced Reservoir Engineering

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Chapter 7 Field Development Plan-
Development Well Pattern Design and Adjustment

Section 1 Reservoir/Field Development Planning

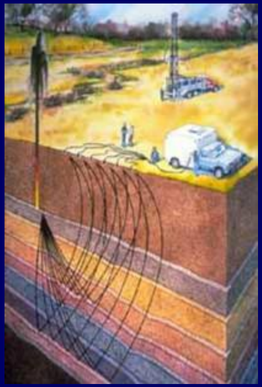
Section 2 Zonation for Multi-payzones Development and Well Pattern Design

Section 3 Residual Oil/Bypassed Plays and Development System Adjustment

Section 1 Reservoir/Field Development Planning

Petroleum Industry

Geological survey



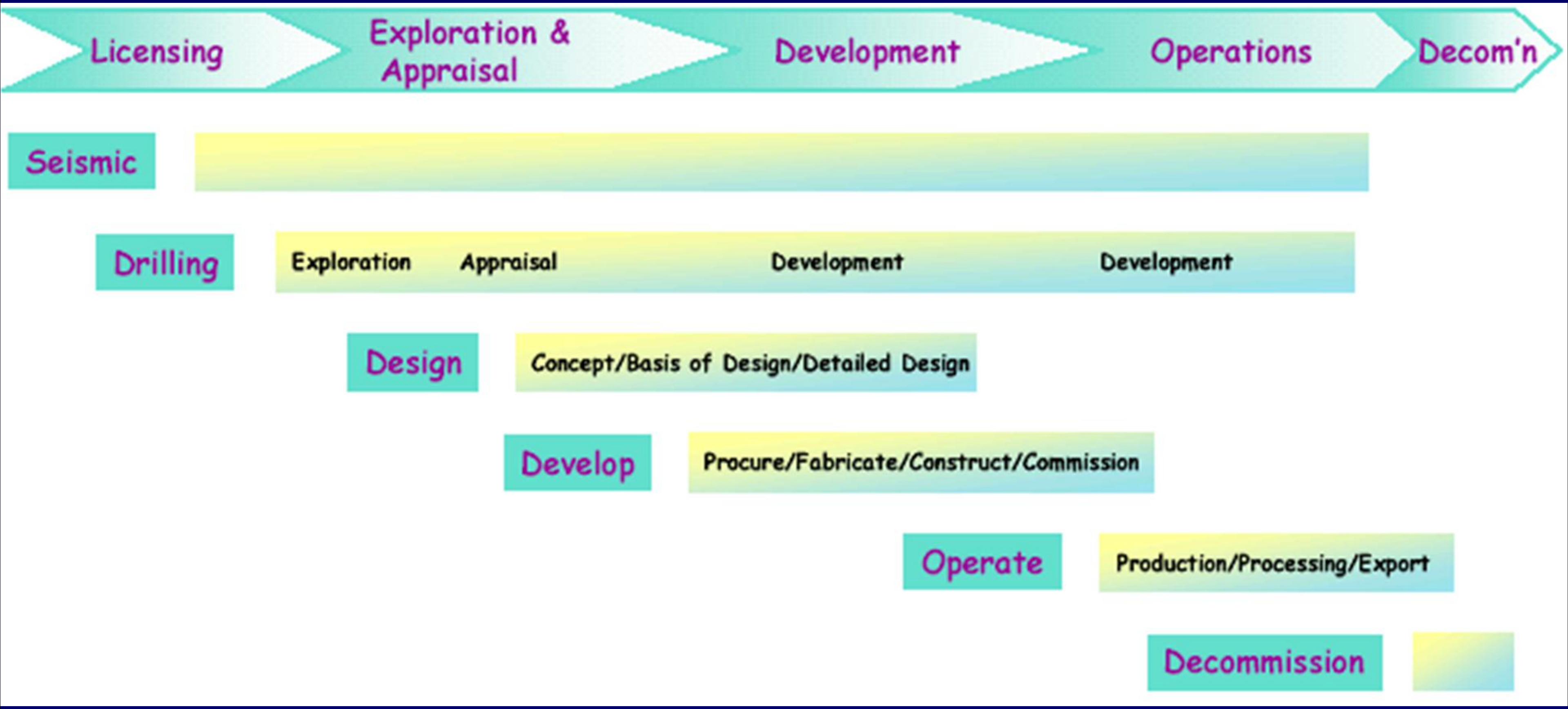
Exploration

Development and Production

Refining

Marketing

Oil and Gas Exploration and Production Cycle



Oil or Gas Field Life Cycle

Field Development Planning (FDP)

If commercial

Geology+
Geochemistry
Geophysics+
Engineering

1-3 years

- Geologic structure
- No of Flow units
- Rservoir Properties
- Fluids Properties
- Size of reservoir
- Driving Mechanism
- No Producing wells
- No of Injection wells
- Expected workovers

1-5 years

- Payzones
- Well pattern
- Drilling & Completion
- Well Testing
- On line reservoir model updating and fine-tuning
- Flow Lines
- Surface Facilities for produced and injected fluids: Separators, Compressors, Pump stations, Measuring System

10-50 years

- Production System Surveillance
- Downhole Data Acquisition
Asset Management

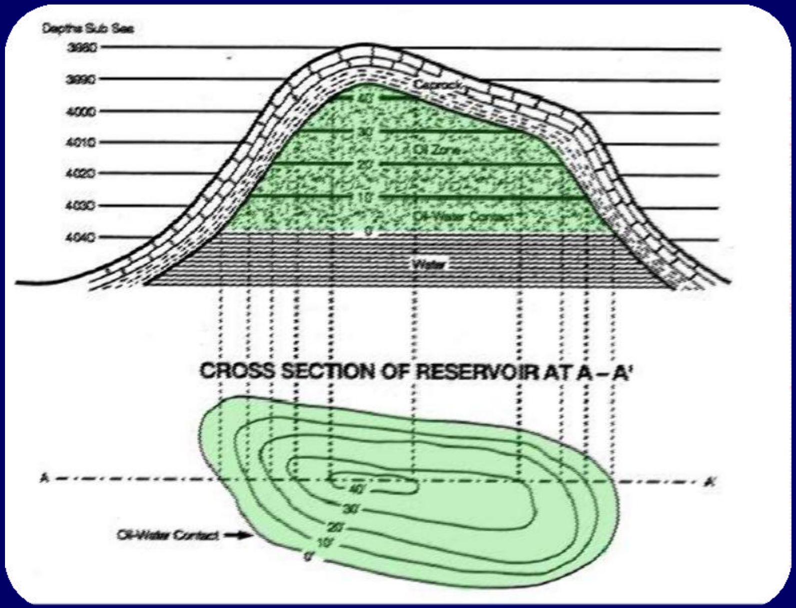
Task 1 Data Collection

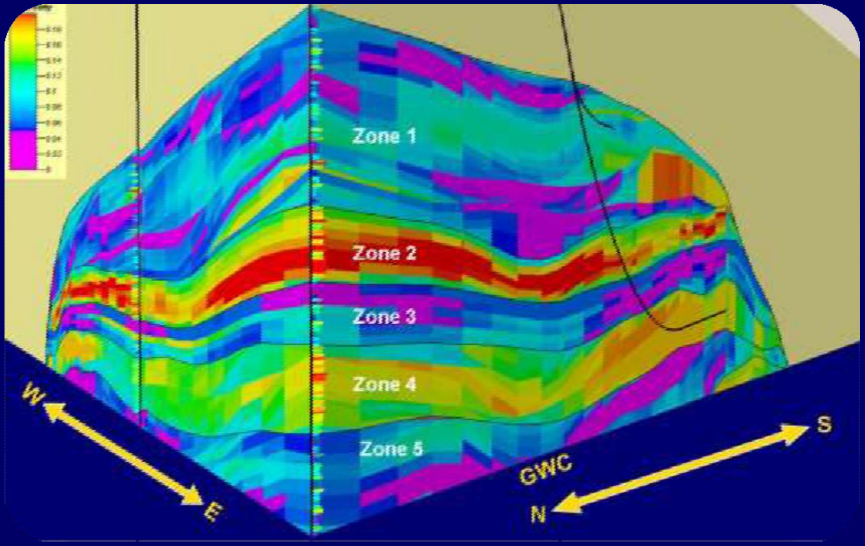
Classification	Data	Acquisition Timing	Responsibility
Seismic	Structure, stratigraphy, faults, bed thickness, fluids, inter-well heterogeneity	Exploration	Seismologists, Geophysicist
Geological	Depositional environment, diagenesis, lithology, structure, faults, and fractures	Exploration, discovery & development	Exploration & development geologists
Logging	Depth, lithology, thickness, porosity, fluid saturation, gas/oil, water/oil and gas/water contacts, and well-to-well correlations	Drilling	Geologists, petrohysicists, and engineers
Coring		Drilling	Geologists, drilling and reservoir engineers, and laboratory analysts
Basic	Depth, lithology, thickness, porosity, permeability, and residual fluid saturation		
Special	Relative permeability, capillary pressure, pore compressibility, grain size, and pore size distribution		
Fluid	Formation volume factors, compressibilities, viscosities, chemical compositions, phase behavior, and specific gravities	Discovery, delineation, development, and production	Reservoir engineers and laboratory analysts
Well Test	Reservoir pressure, effective permeability-thickness, stratification, reservoir continuity, presence of fractures or faults, productivity and injectivity index, and residual oil saturation	Discovery, delineation, development, and production and injection	Reservoir and production engineers
Production & Injection	Oil, water, and gas production rates, and cumulative production, gas and water injection rates and cumulative injections, and injection and production profiles	Production & Injection	Production and reservoir engineers

From A. Satter & G. Thakur

Task 2 Reservoir Study for FDP

- Reservoir characterization for size, complexity, productivity and the type and quantity of fluid it contains
- Reservoir modelling is a standard tool for solving a variety of fluid flow problems involved in recovery of oil and gas from the porous media of reservoirs.
- Evaluation of Development Strategies
  - Evaluation Recovery schemes: natural depletion; natural depletion assisted by water (Water-flood), gas injections, alternate water and gas injection, etc.
  - Oil, Gas and Water Production Forecast





Expected Reservoir Study Outcomes

- Original Hydrocarbon in place - OHIP
- Recoverable Hydrocarbons (Reserves and Reserves classification: Proven, Probable, Possible)
- Oil, water and gas production profile (for field, well, flow units)
- Fluid Porosity map
- Permeability (vertical and horizontal) map
- Initial Static Pressure map
- Actual Static Pressure map (for brown fields)
- Fluids Saturation map
- Most probable reservoir drive mechanism and its strength

- Gas-Oil and the Oil-Water Contact depth
- Number of production wells to be drilled
- Duration of Natural Flow period for each well
- Identification of the most effective Secondary Hydrocarbon Recovery technique to be adopted
- Number of injection wells to be drilled (if required)
- Number of disposal wells to be drilled (if required)
- Surface and downhole coordinates of planned wells to be drilled
- Water or Gas Injection profile (if required)
- Workover plan to sustain the hydrocarbon production during the field life cycle

Example: Reserves Estimation-Volumetric Method

Oil in place by the volumetric method is given by:

$$N(t) = \frac{V_b \phi(p(t)) \left(1 - S_w(t)\right)}{B_o(p(t))}$$

Where:

$N(t)$	= oil in place at time t, STB
V_b	= 7758 A h = bulk reservoir volume, bbl
7758	= bbl/acre-ft
A	= area, acres
h	= thickness, ft
$\varphi(p(t))$	= porosity at reservoir pressure p, fraction
$S_w(t)$	= water saturation at time t, fraction
$B_o(p(t))$	= oil formation volume factor at reservoir pressure p, bbl/STB
$p(t)$	= reservoir pressure at time t, psia

Areal Extent (productive limits of reservoir)

- Structure map
- Seismic
- Analogy

Net pay thickness

- Well logs

Porosity

- Well log and cores

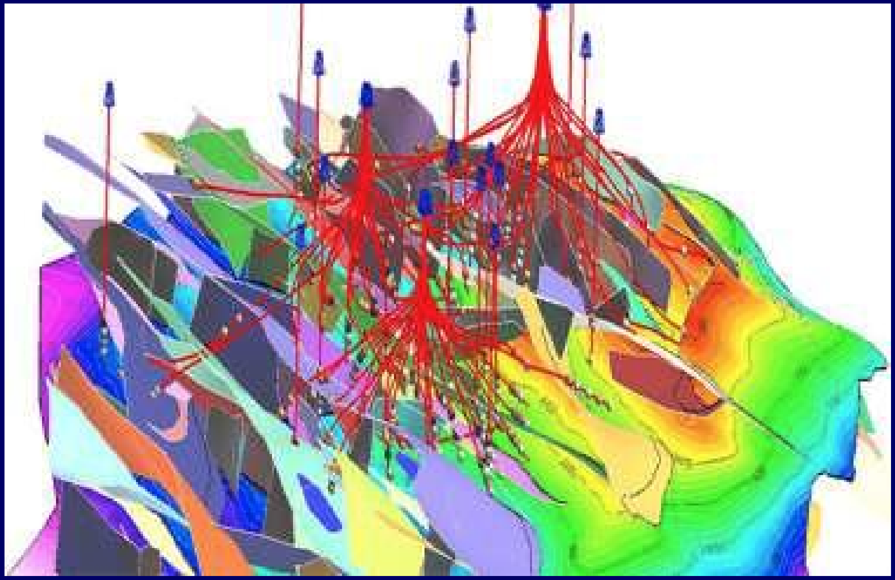
Water saturation

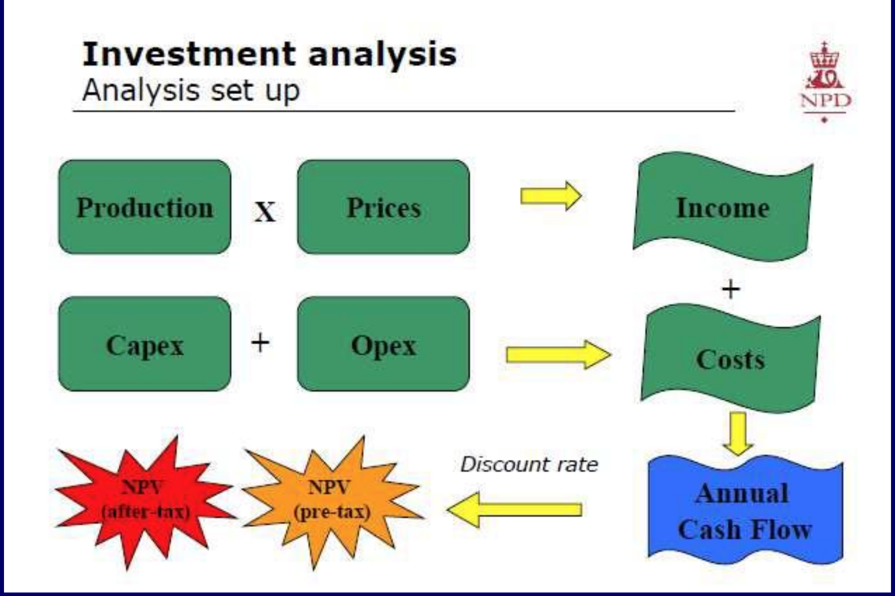
- Well logs and/or cores

Recovery efficiency

- Analogy
- Drive mechanism
- Reservoir characteristics

Development Planning





- Type of well:
  vertical, slanted, horizontal, multilateral
- Natural depletion or natural depletion augmented by fluid (water or gas) injections
- Well spacing – number of wells, platforms, reserves, and economics

Development Methods

- **Primary Recovery :**

Using the natural energy of the reservoir as a drive to depressure reservoir

- **Secondary Recovery:**

Water flooding , sometimes gas injection for gas drive

- **Tertiary Recovery :**

Enhanced Oil Recovery, EOR, injection of gas, chemicals, microorganism

- **Infill Recovery**

Determined by drive mechanism

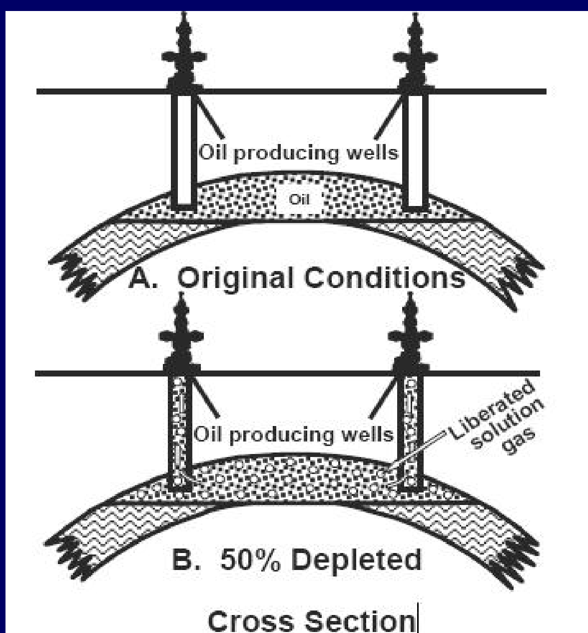
Reservoir Drive Mechanisms

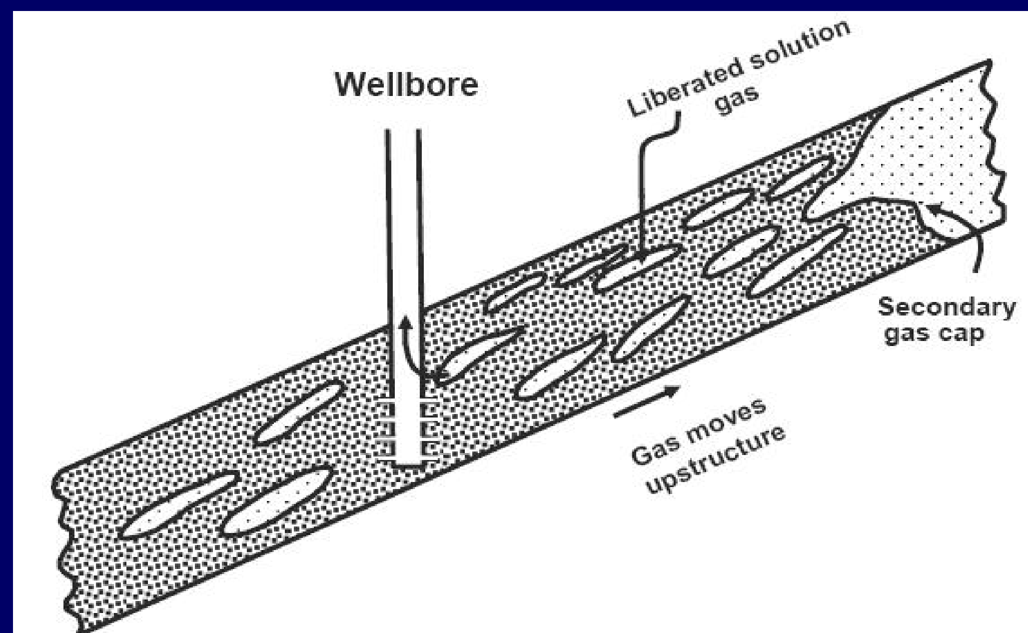
1. Solution-gas drive (Liberation, expansion of solution gas)
2. Gas-cap drive
3. Water drive (Influx of aquifer water)
4. Closed expansion drive (Expansion of reservoir rock and compression of pore volume, Expansion of original reservoir fluids)
5. Combination drive
6. Gravity-drainage drive (Gravitational forces)

Development Strategy for Depletion or Solution Gas Drive Reservoirs

- **Solution drive**

Occurs on a reservoir which contain no initial gas cap or underlying active aquifer to support the pressure and therefore oil is produced by the driving force due to the expansion of oil and connate water, plus any compaction drive.





- **Energy supply**

When the pressure in the vicinity of the wellbore drops below the bubble point pressure, gas will escape from the oil inside the reservoir and begin to expand.

The gas expansion will displace an increasing quantity of oil from the pore space in the rock.

When the pressure of the whole reservoir falls below saturation pressure, it is possible to form a “secondary gas cap” .

Development Strategy for Solution Gas Drive Reservoirs

- In a steeply dipping field, wells would be located down-dip. However, in a field with low dip, the wells must be perforated as low as possible.

Question:

Why wells are in down-dip and perforated at lower interval?

- There are three distinct production phases, defined by looking at the oil production rate.

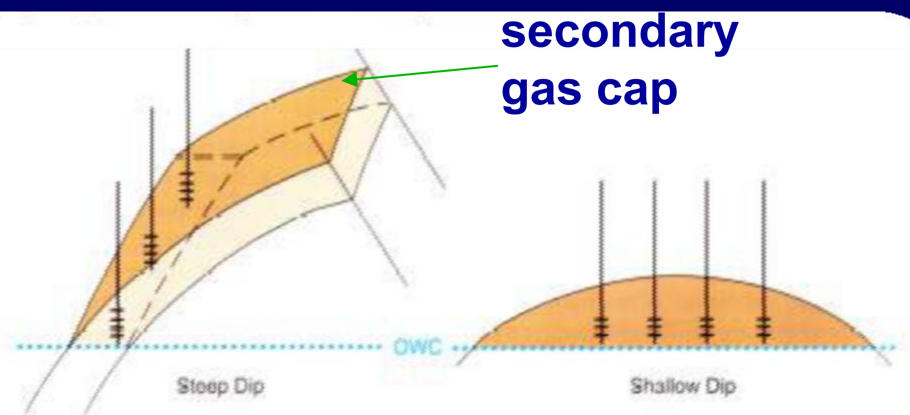


Figure 9.2 Location of wells for solution gas drive.

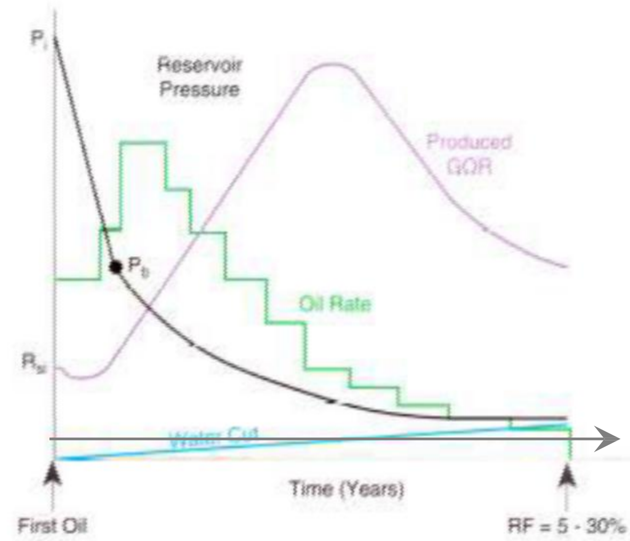


Figure 9.3 Production profile for solution gas drive reservoir.

Optimized Strategy for Solution Gas Drive Reservoirs

- Recovery factor is low (5-30%)
- Technical considerations would be the external supply of gas, and the feasibility of injecting the fluids into the reservoir.
- Multiple reservoir simulation runs, combined with an adequate economic analysis, are require to define the problem

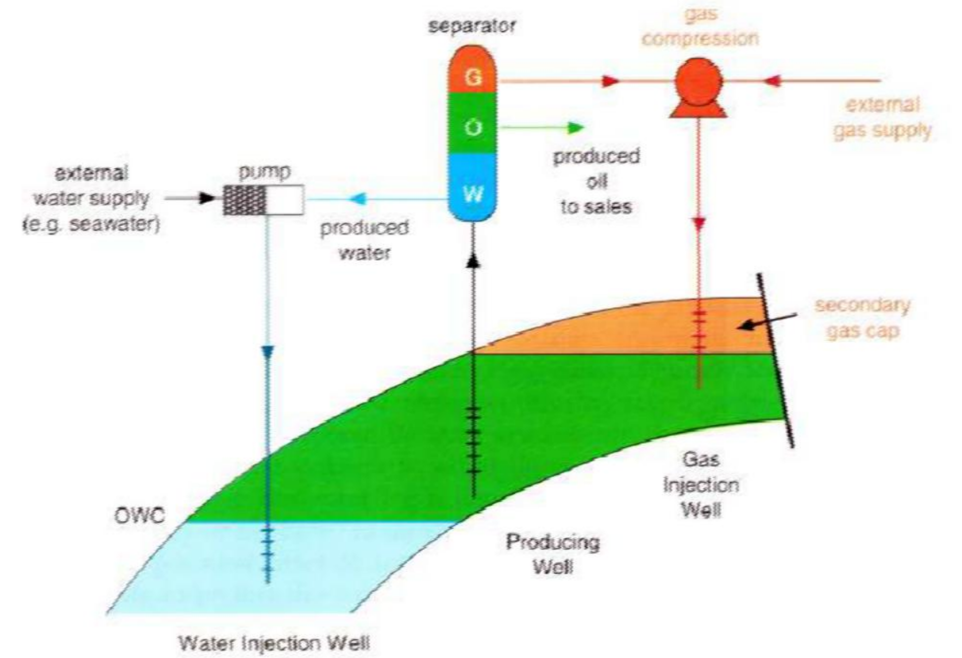
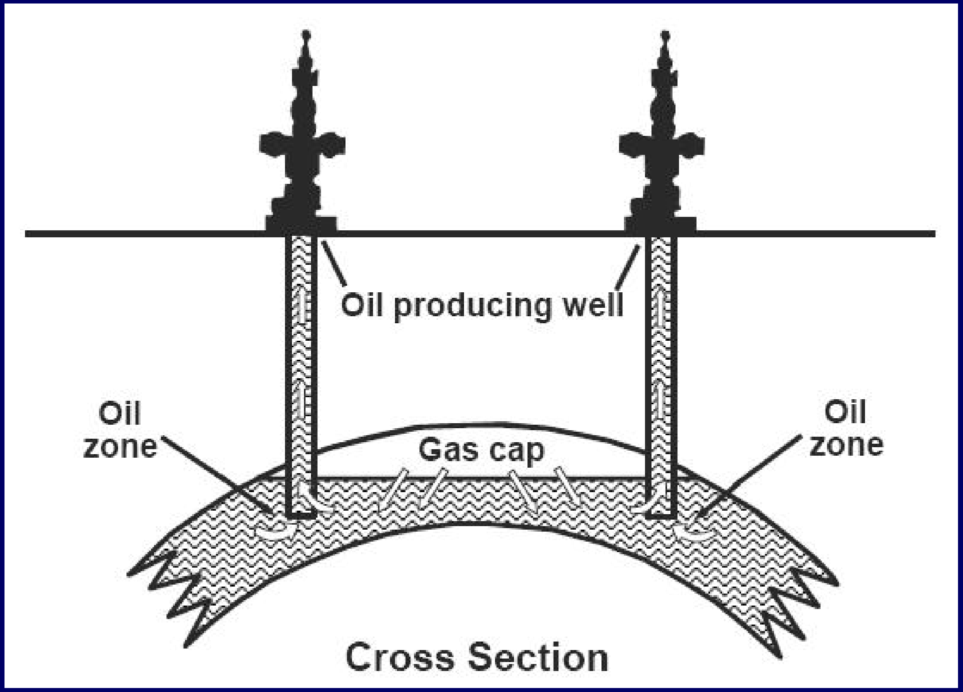


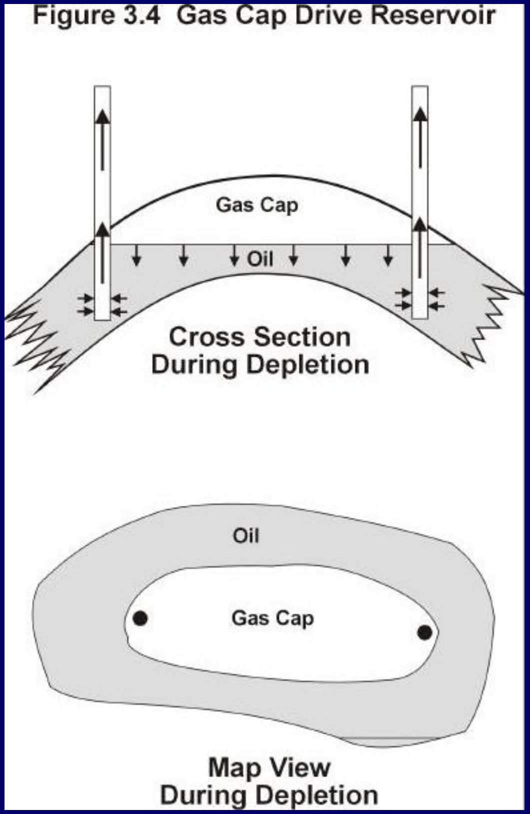
Figure 9.4 Secondary recovery: gas or water injection schemes.

F. Jahn , M. Cook & M. Grahm 2008

Development Strategy for Gas Cap Drive Reservoir

- The initial condition for gas cap drive is an **initial gas cap**. The high compressibility of gas provide drive energy for production, and the larger the gas cap, the more energy is available





Energy supply

The gas cap expands to fill the pore space formerly occupied by the oil, and thus displaces oil downwards towards the producing well.

Development Strategy for Gas Cap Drive Reservoir

- Prolonged and slower decline due to highly compressible gas cap
- RF-20-60%
- Abandonment conditions are caused by very high producing GORs, or lack of reservoir pressure to maintain production
- The gas injection well would be located in the crest of the structure, injecting produced gas into the existing gas cap.

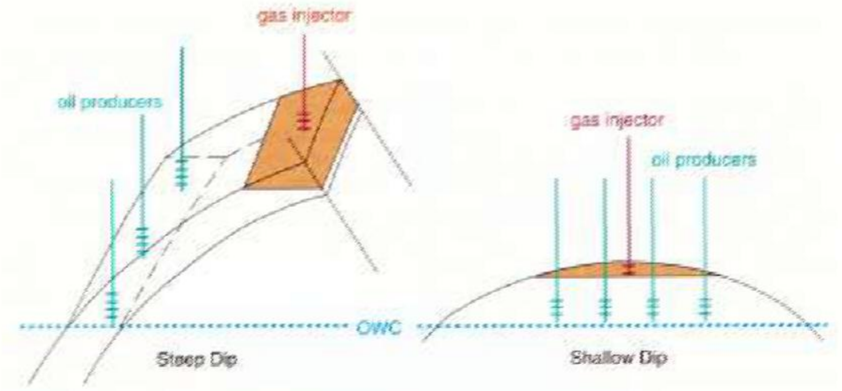


Figure 9.5 Location of wells for gas cap drive.

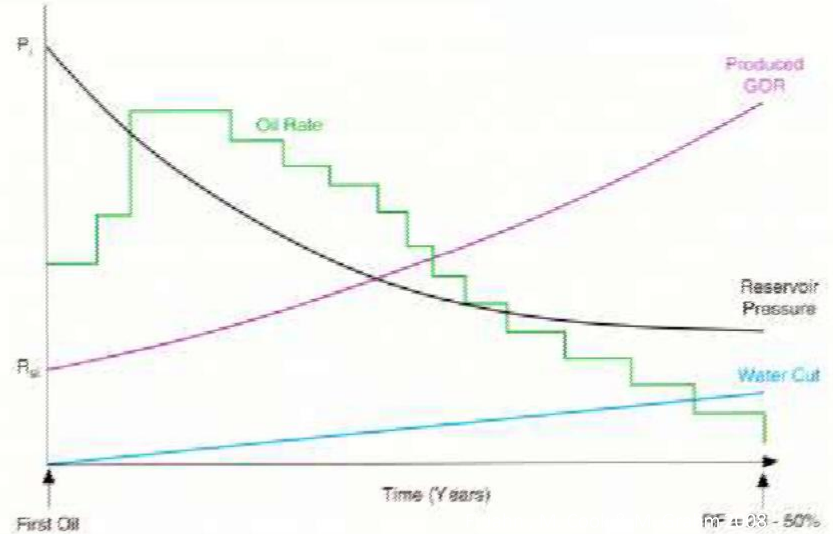
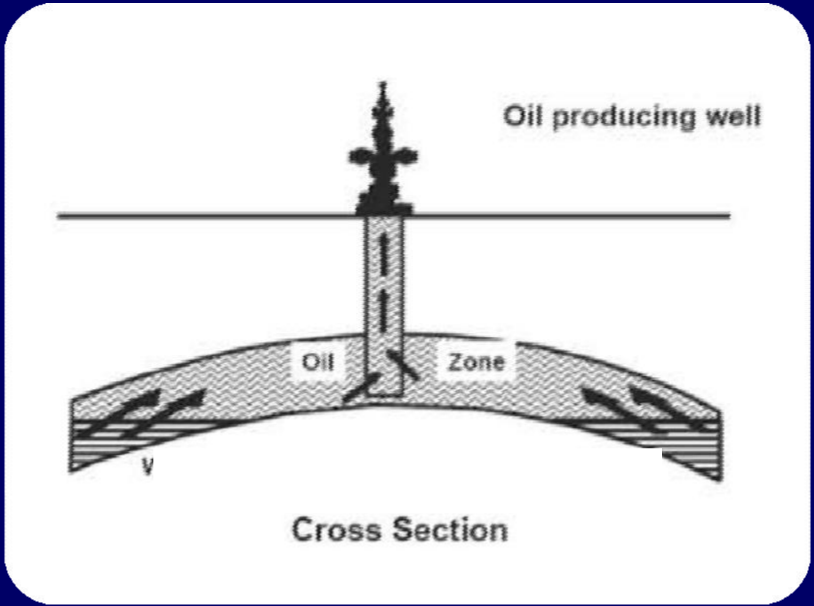


Figure 9.6 Characteristic production profile: gas cap drive.

Development Strategy for Water Drive Reservoir

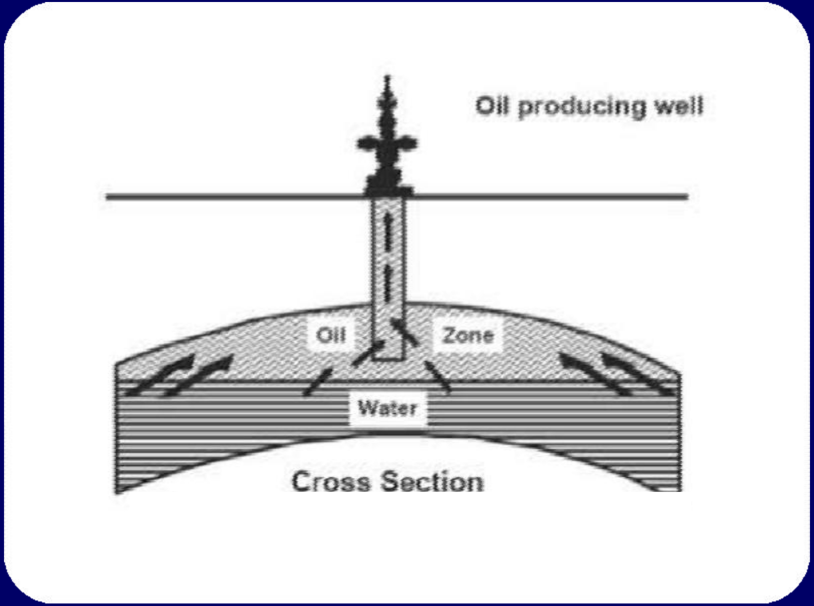
- According to the location of the aquifer relative to the reservoir, they are classified as :

  - **Peripheral water drive** - the aquifer areally encircles the reservoir, either partially or wholly



- Edgewater drive - the aquifer exclusively feeds one side or flank of the reservoir

- Bottomwater drive - the aquifer underlays the reservoir and feeds it from beneath



Development Strategy for Water Drive Reservoir

- Injecting into the water column to avoid by-passing down-dip oil.
- If the permeability in the water leg is significantly reduced due to compaction or diagenesis, it may be necessary to inject into the oil column.
- Initially produce the reservoir using natural depletion, and to install water injection facilities in the event of little aquifer support
- Large increase in water cut over the life of the field, which is usually the main reason for abandonment.

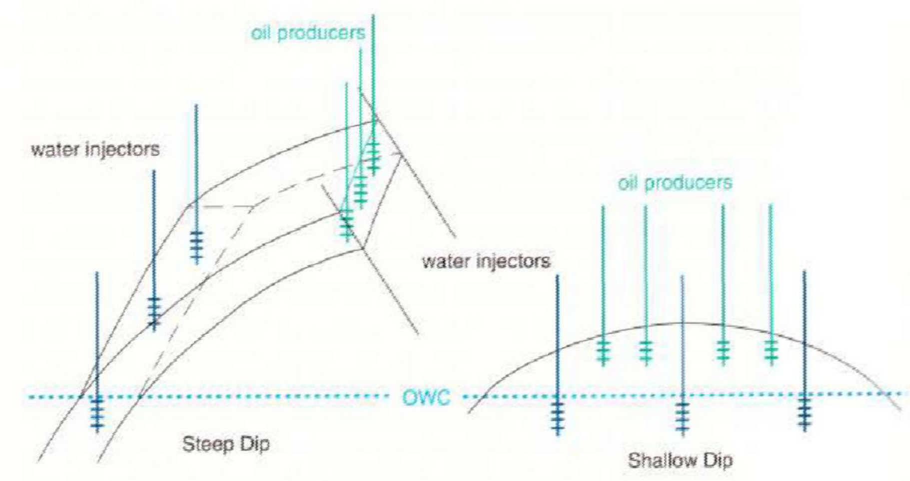


Figure 9.7 Location of wells for water drive.

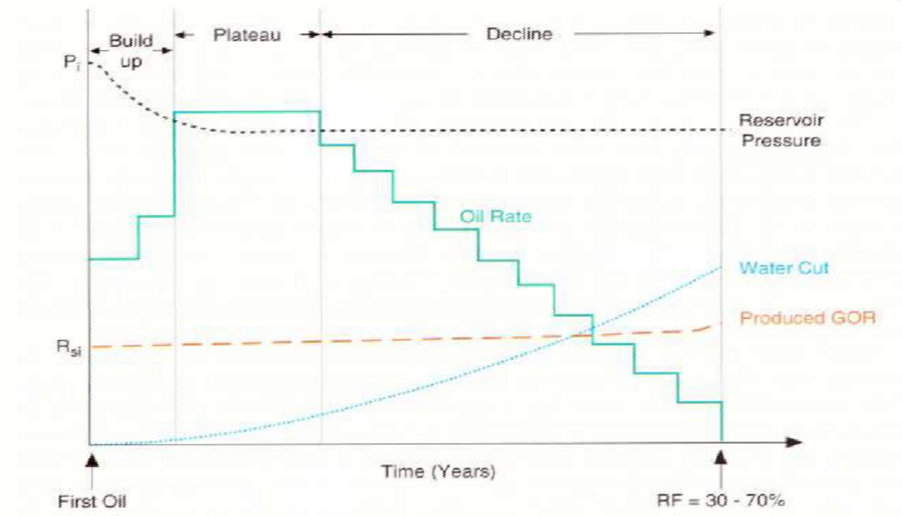
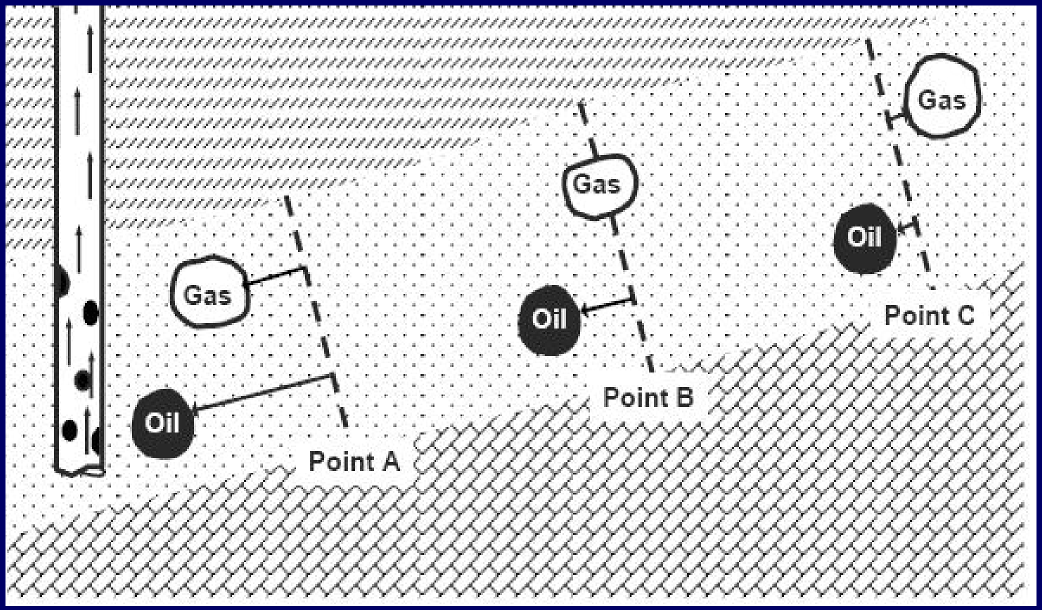
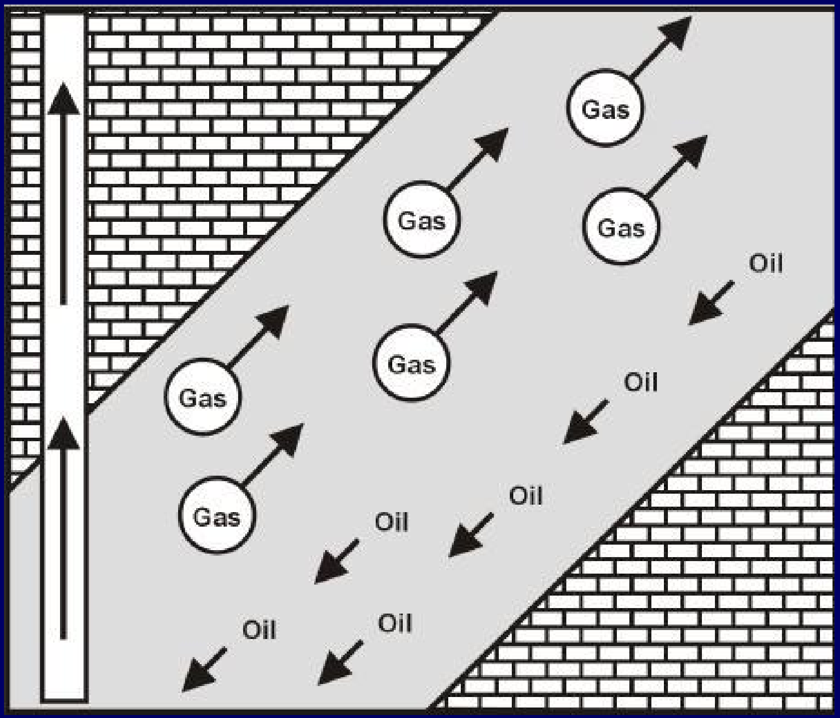


Figure 9.8 Characteristic production profile: water drive.

F. Jahn , M. Cook & M. Grahm 2008

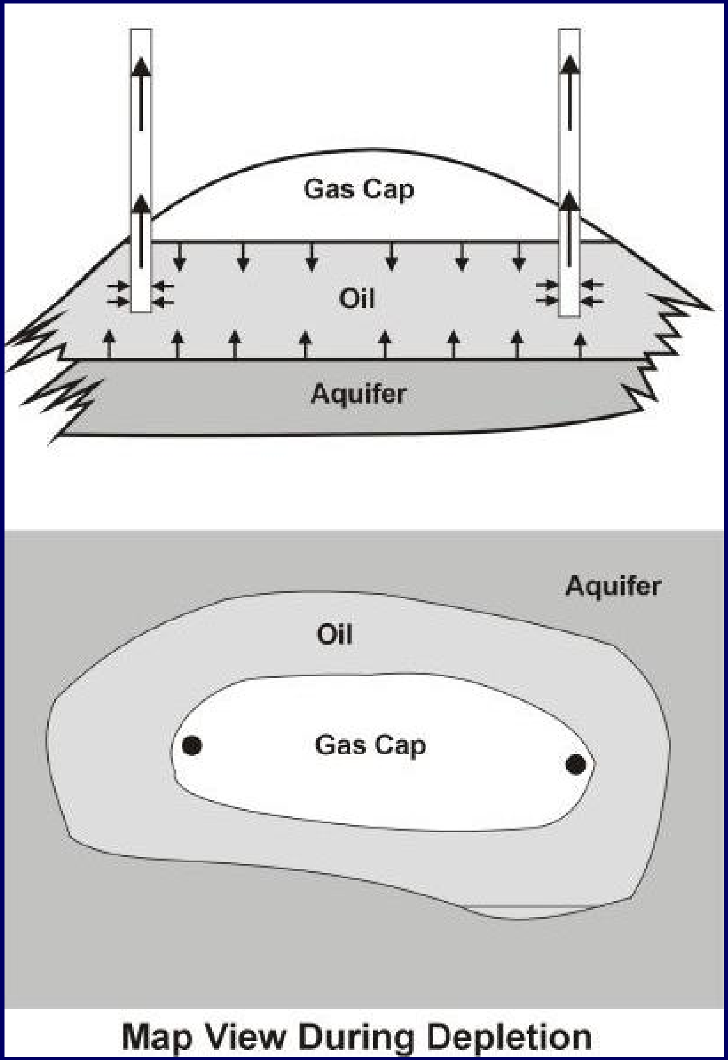
Gravity Drainage in Oil Reservoirs



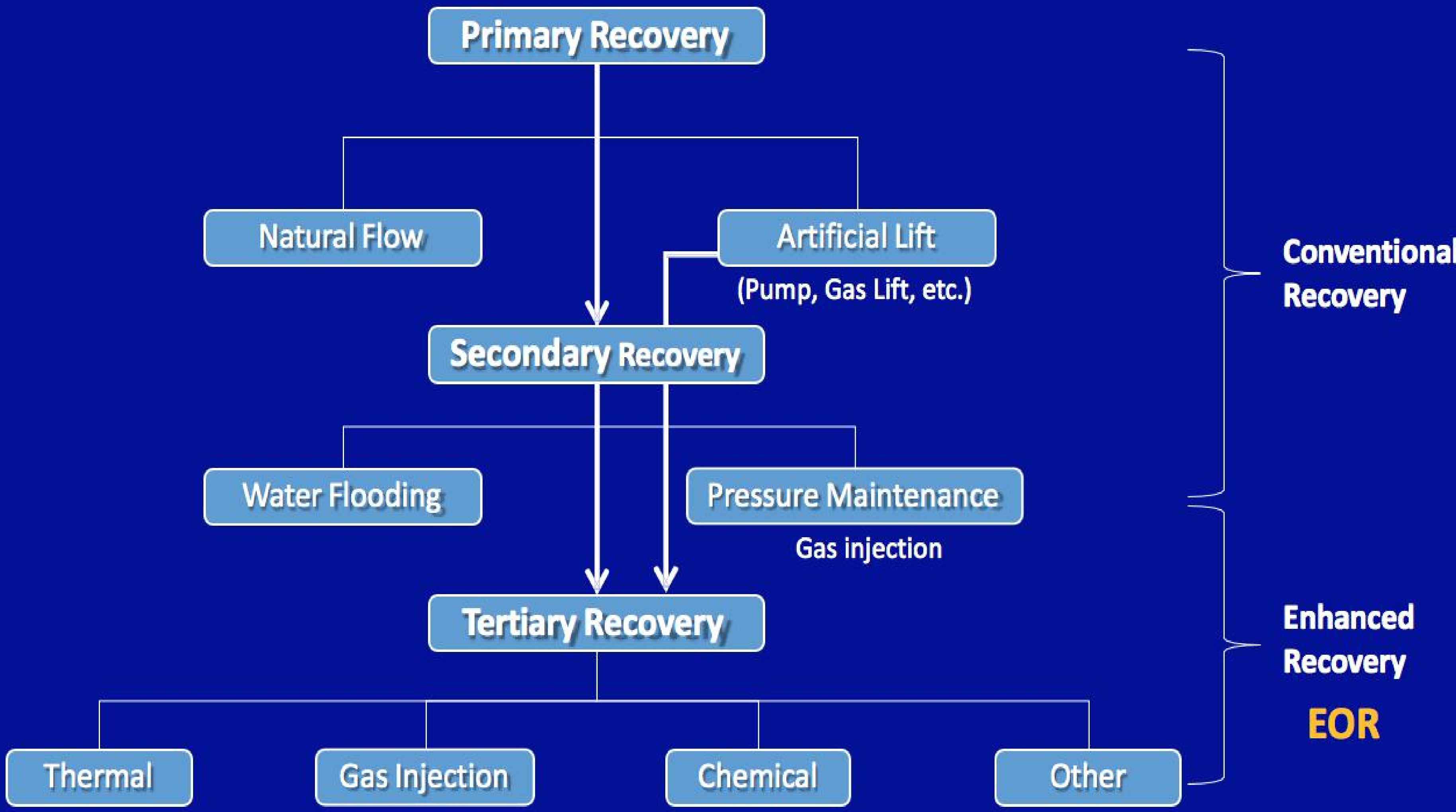


Combination Drive in Oil Reservoirs

- At least two main drive mechanisms
- This compromise must take into account the strength of each drive present, the size of the gas cap, and the size/permeability of the aquifer.

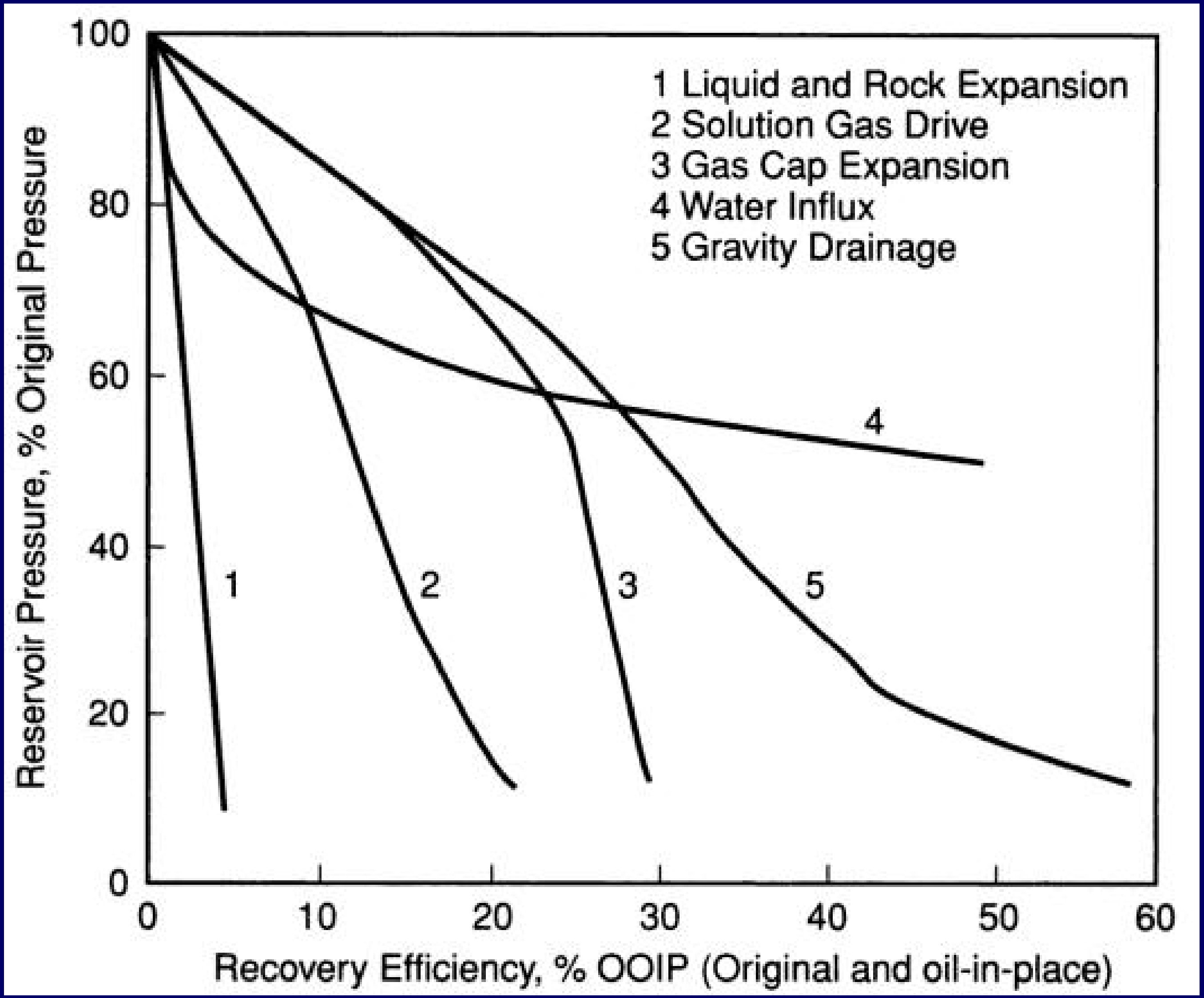


Development details of the Oil Recovery Scheme


Primary Recovery
Natural Flow
Artificial Lift
(Pump, Gas Lift, etc.)
Secondary Recovery
Water Flooding
Pressure Maintenance
Gas injection
Tertiary Recovery
Thermal
Gas Injection
Chemical
Other
Conventional Recovery
Enhanced Recovery
EOR

Recovery factors for different drive types mechanism

Drive mechanism	Percent ultimate recovery [%]	
	Gas	Oil
Strong water	30–40	45–60
Partial water	40–50	30–45
Gas expansion	50–70	20–30
Solution gas	N/A	15–25
Rock	60–80	10–60
Gravity drainage	N/A	50–70



1 Liquid and Rock Expansion
2 Solution Gas Drive
3 Gas Cap Expansion
4 Water Influx
5 Gravity Drainage
Reservoir Pressure, % Original Pressure
Recovery Efficiency, % OOIP (Original and oil-in-place)
100
80
60
40
20
0
0
10
20
30
40
50
60
1
2
3
4
5

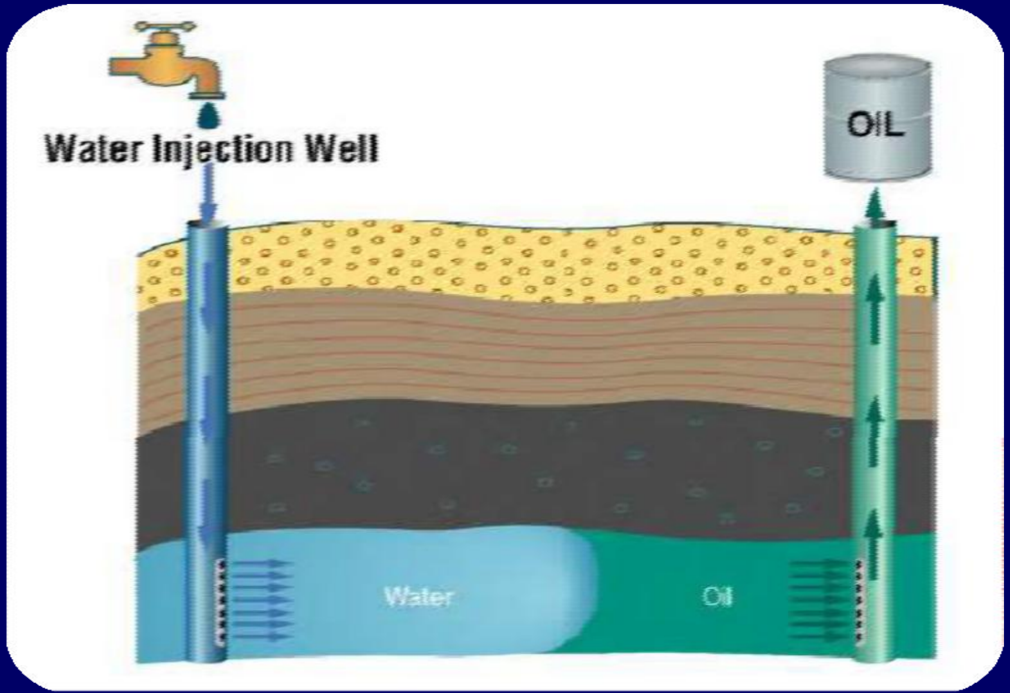
Secondary- Waterflooding

- ***Waterfooding is the injection of water into a wellbore for pressure maintenance as well as pushing, or "driving" oil to another well where it can be produced.*** The principal reason for waterflooding an oil reservoir is to increase the oil-production rate and, ultimately, the oil recovery.

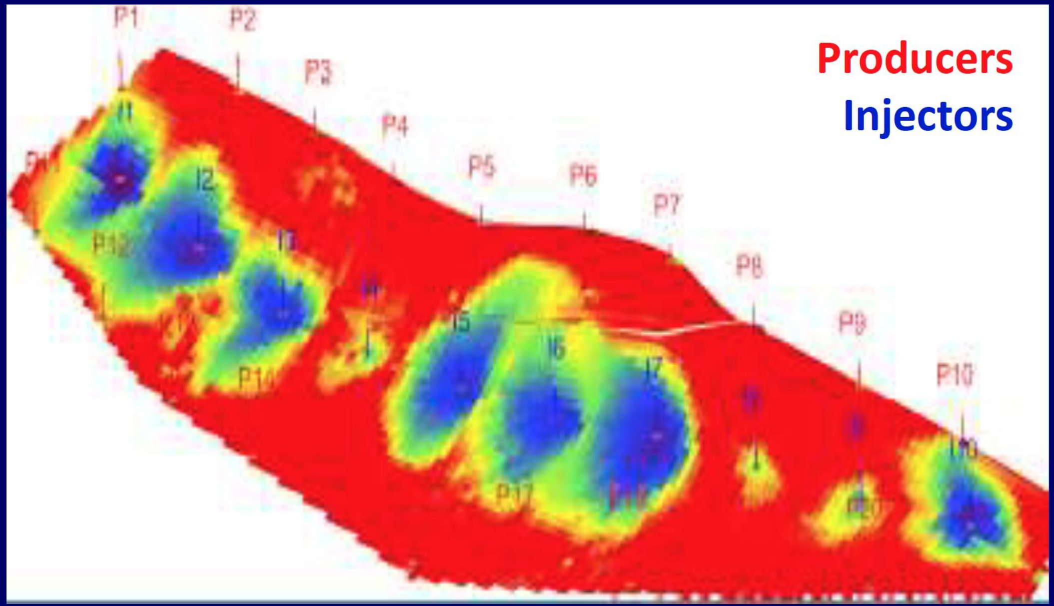
- This is accomplished by "voidage replacement"—injection of water ***to increase the reservoir pressure*** to its initial level and maintain it near that pressure.

- The water displaces oil from the pore spaces, but the efficiency of such displacement depends on many factors (e.g., oil viscosity and rock characteristics).

- Waterflooding is one of the most widely used post-primary recovery method. Reservoir engineers are responsible for waterfood design, performance prediction, and reserves estimation. They share responsibilities with production engineers for the implementation, operation.



William M. Cobb & Associates, Inc.



Wettability, Absolute Permeability, Relative Permeability and Critical Saturation

- **Wettability** is a fundamental property, being that it influences the fluid saturations and **relative permeability**.

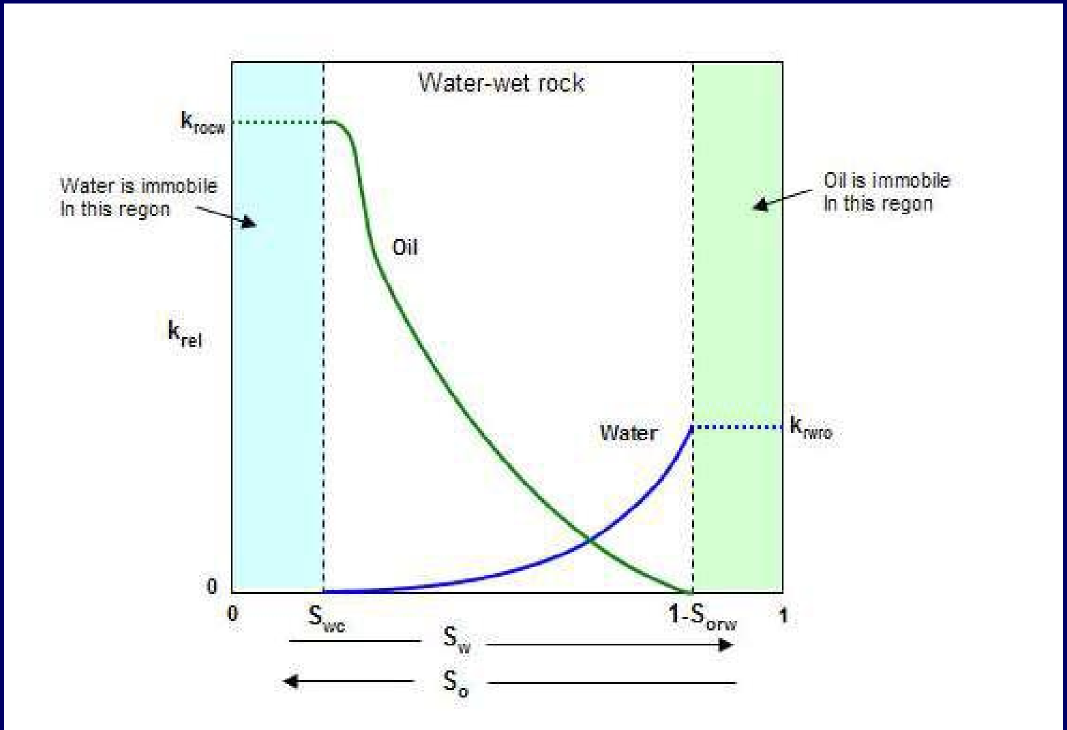
- **The relative permeability** to a fluid is defined as the ratio between the effective permeability to that fluid and the absolute permeability of the rock. **Absolute permeability** is an intrinsic property of reservoir rock, and defines the ease with which a fluid can flow through the interconnected pore spaces when the rock is saturated in a single fluid, whereas effective permeability defines a fluid's ability to do the same in the presence of other fluids (water, gas, oil).

- Therefore, **relative permeability is a property that is dependent on the fractions or saturation degree of the different fluids present in the porous medium**, and **by definition can vary between zero and one.** The greater the percentage of fluid present in the porous medium, the higher its relative permeability will be.

- On the other hand, every fluid has a saturation point, referred to as **critical saturation;** below this point, the fluid is no longer mobile, though still present within the porous medium; **at that point the relative permeability becomes zero.**

Relative Permeability Curve

- During the viscous displacement flood, the water saturation increases from its irreducible value (S_{wc}), at which it is immobile, to the maximum or flood-out saturation ($S_w = 1 - S_{orw}$) at which the oil ceases to flow.
- S_{orw} , is the residual oil saturation representing the unconnected oil droplets trapped in each pore space by surface tension forces at the end of the waterflood.



Consequently the maximum amount of oil than can be displaced (recovered) during a waterflood is:

$$MOV = PV\,(1 - S_{orw} - S_{wc})$$

Factors governing the waterflooding process

- Three are the factors **governing the oil recovery efficiency** achievable by the waterflooding process.

  They are:

  - **Mobility ratio**
  - **Heterogeneity**
  - **Gravity**

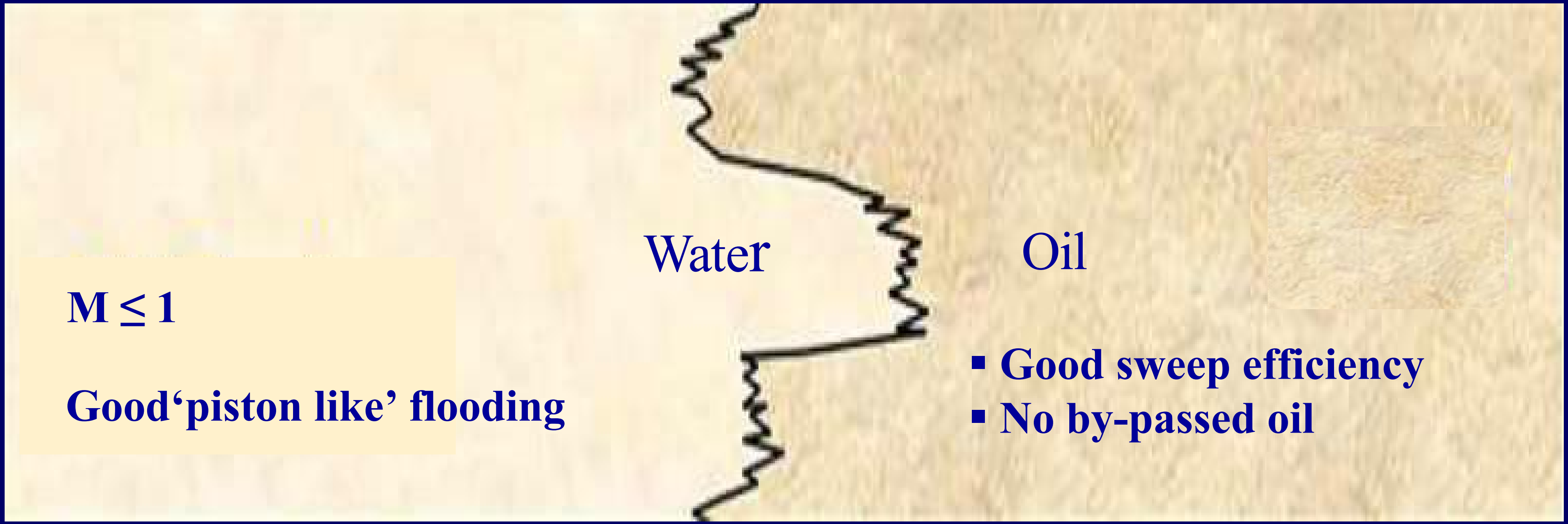
– Mobility ratio M

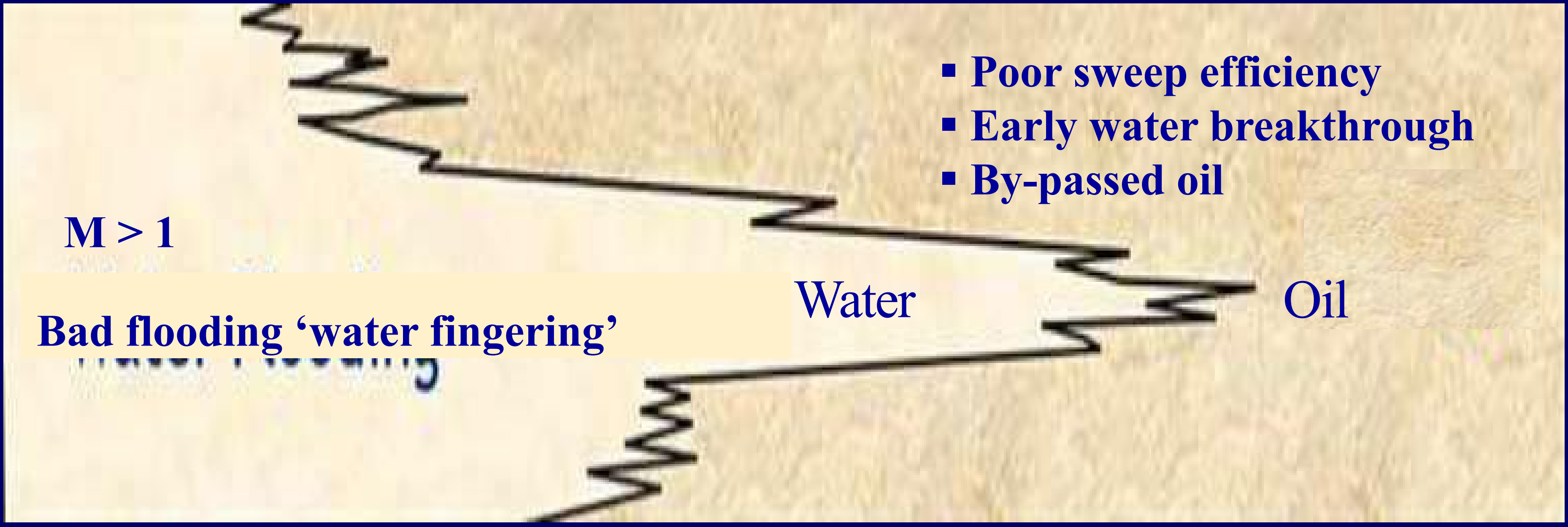
$M \le 1$ means that the injected water cannot travel faster than the oil and therefor displaces the oil in perfect piston-like manner.

$M \le 1$ Stable displacement (piston-like displacement)

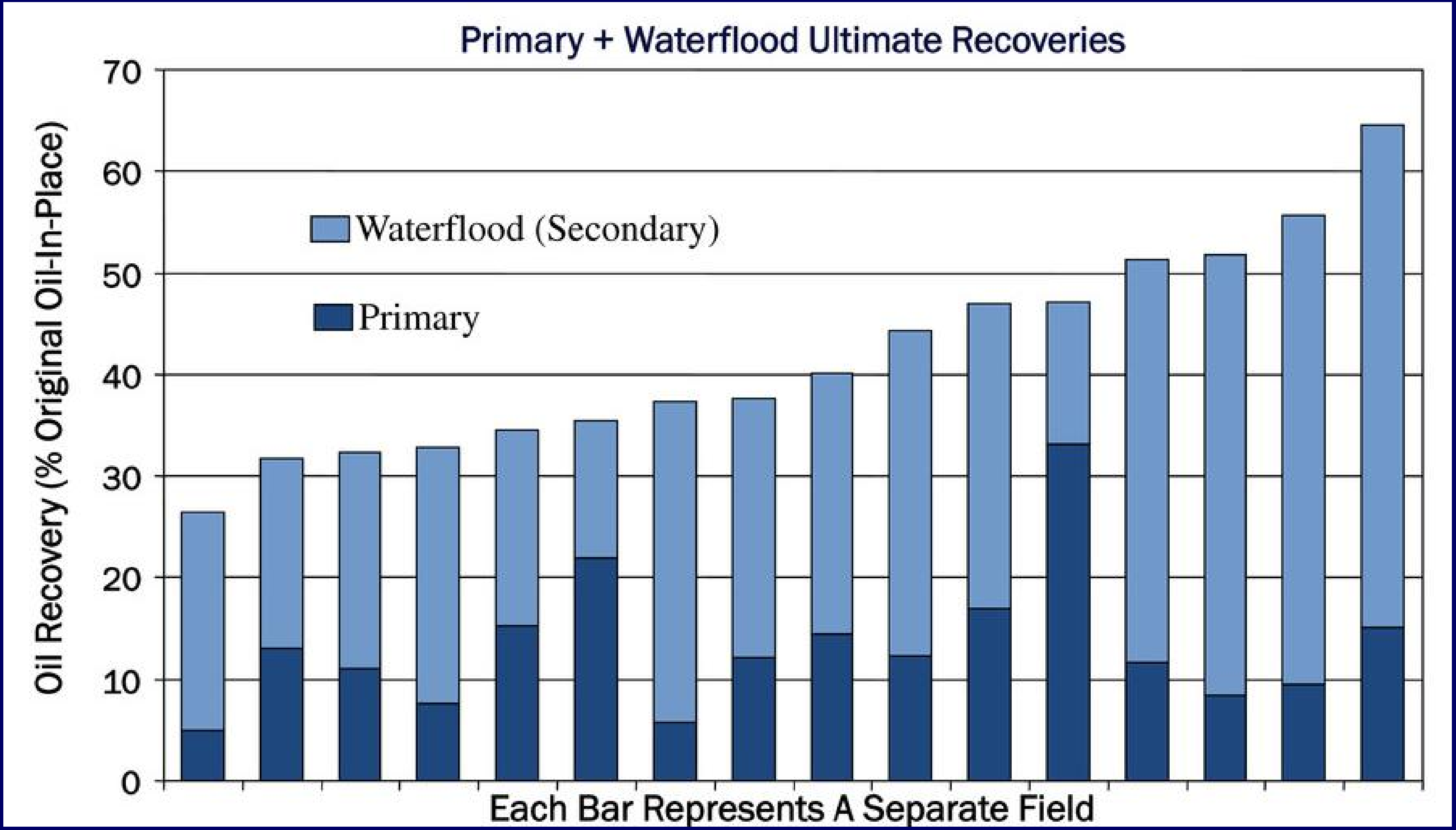
$M > 1$ Unstable displacement (water fingering, poor oil recovery)

Mobility ratio [M] impact on Sweep Efficiency





Waterflooding
-Proven Method to Increase Oil Recovery



Tertiary recovery (EOR)

- The objective of EOR is to economically increase displacement efficiency. The key factor is the mobility ratio, M:

$$M = \lambda_w / \lambda_o = [\ k_{rw}(S_w) / \mu_w\ ] / [\ k_{ro}(S_o) / \mu_o\ ]$$

Mobility ratio is a function of viscosity and relative permeability, which in turn depends on saturation.

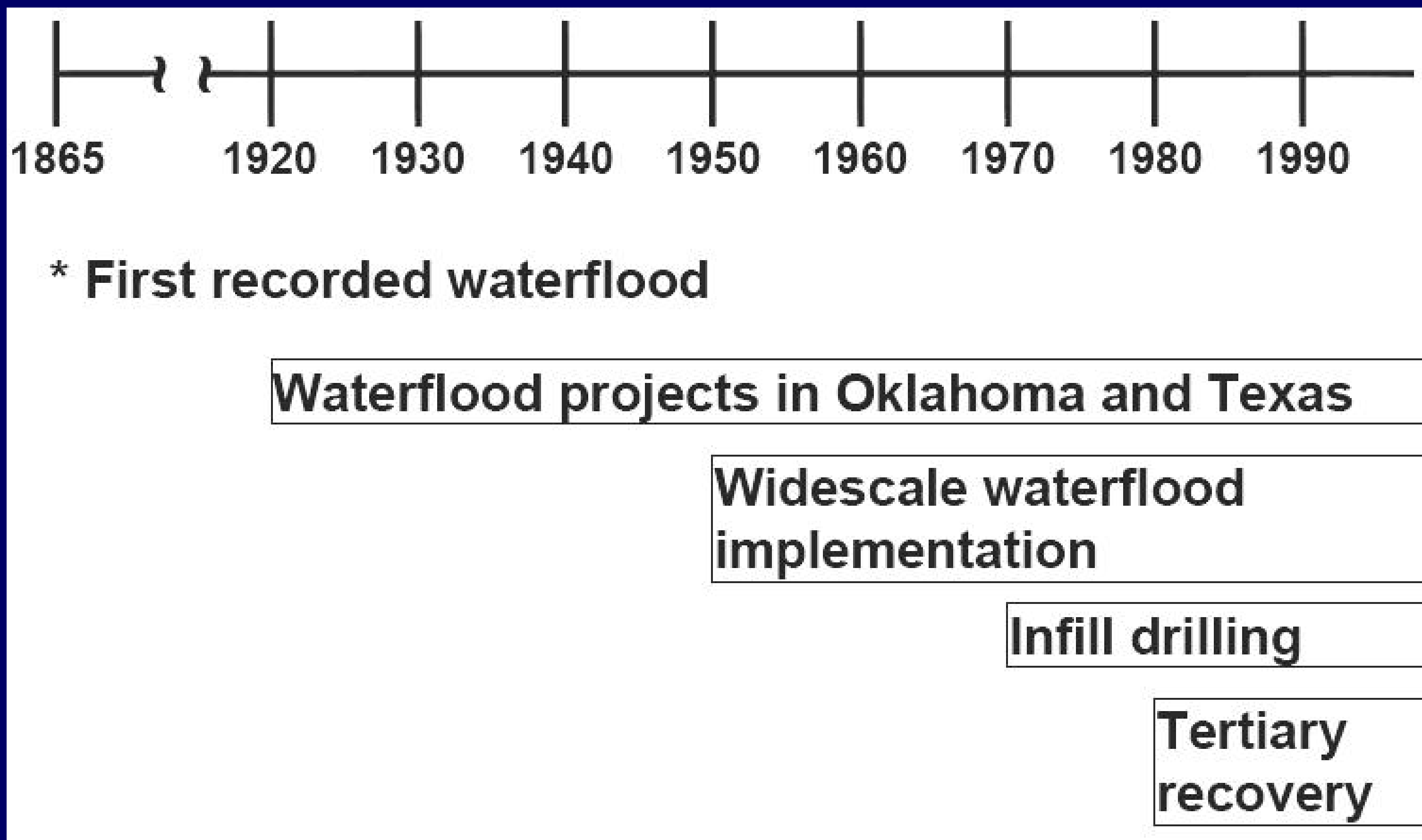
EOR involves mobility control of various kinds that can:

• change oil and water viscosities

• change interfacial tensions

• change oil and water saturations

History of Secondary and EOR Development Methods



Detailed EOR Technologies

EOR Technologies

Thermal

- Steam Hot Water
- In-situ Combustion
- Electric heat

Gas Injection

- CO2
- Hydrocarbon
- Nitrogen/inert gas
- Flue gas
- Miscible solvent

Chemical

- Alkali
- Surfactant
- Polymer
- Caustic
- Combination

Other

- Microbial
- Acoustic/vibration
- Electromagnetic

Thermal recovery

- Cyclic steam injection (huff and puff or steam soak)-high rate injection of slugs of steam and soak for 5-10 days, then production for 100-200 days
- Steamflood (steam drive, same pattern of injectors and producers as waterflood)
- Fireflood (in-situ combustion for high permeability, heat for reducing viscosity+steam drive+gas drive)
- microwave heating (EM wave to heat)

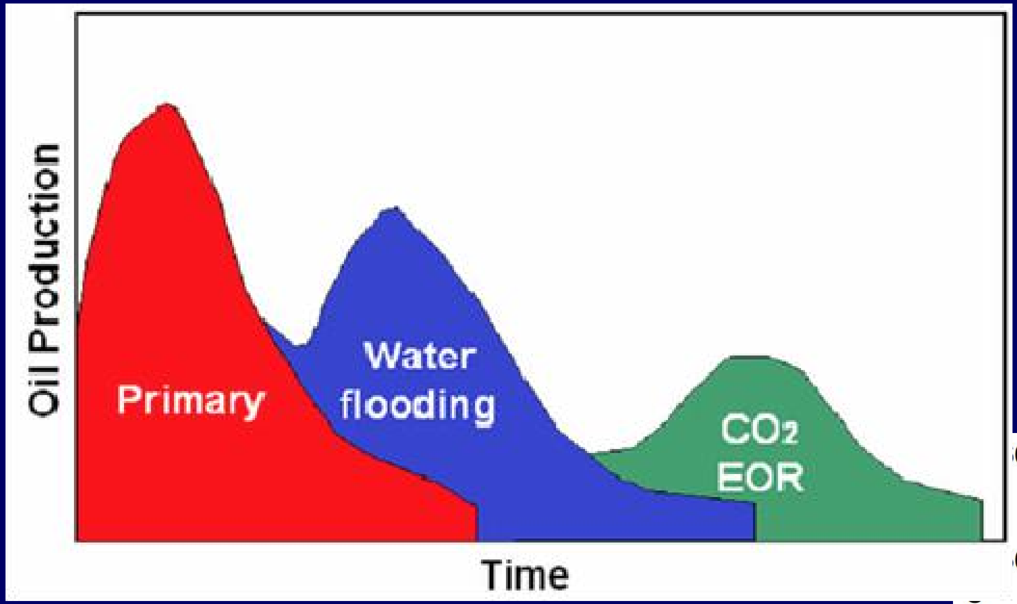
Miscible EOR
(only proven economically method)

- Principle: some fluids are miscible with crude oil (methane, ethane, CO_2 etc) and can be used to displace oil with no capillary resistance.
- The effect of adding a miscible fluid to the reservoir is to "swell" the oil and increase So and hence k_{ro}.
- An additional benefit of miscible hydrocarbon gases and CO_2 is that they dissolve in oil to lower its viscosity.

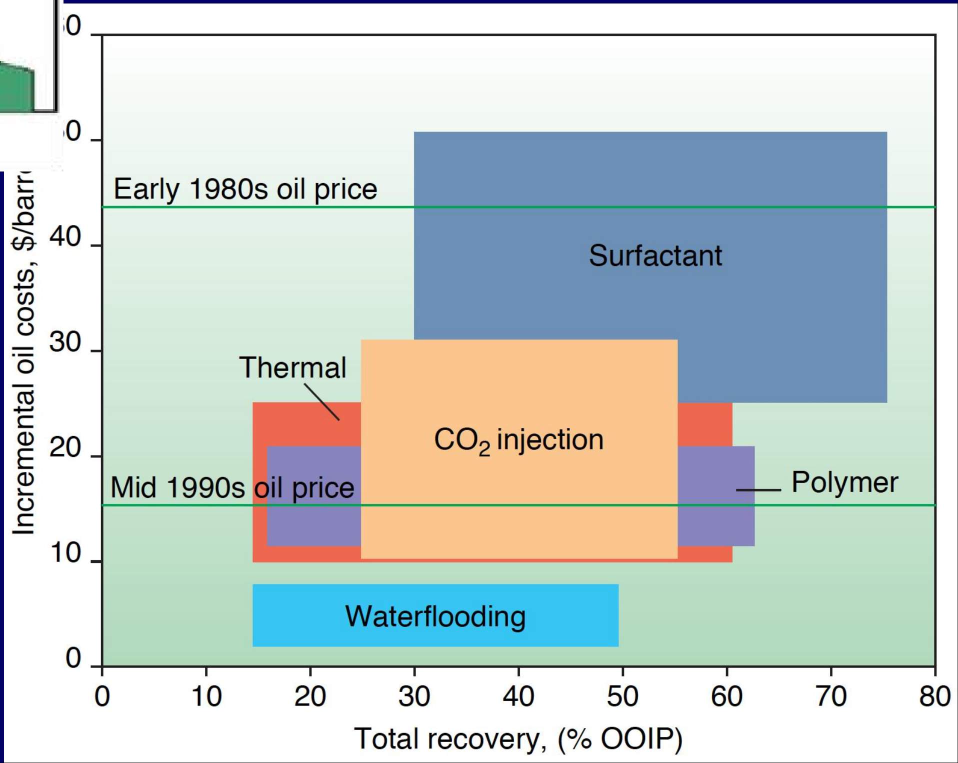
Infill Recovery

- Is carried out when recovery from the previous three phases have been completed. It involves drilling cheap production holes between existing boreholes to ensure that the whole reservoir has been fully depleted of its oil.

Expected Sequence of Oil Recovery Methods



Carr et al., 2005



Screening Criteria for Selecting Improved Recovery Methods

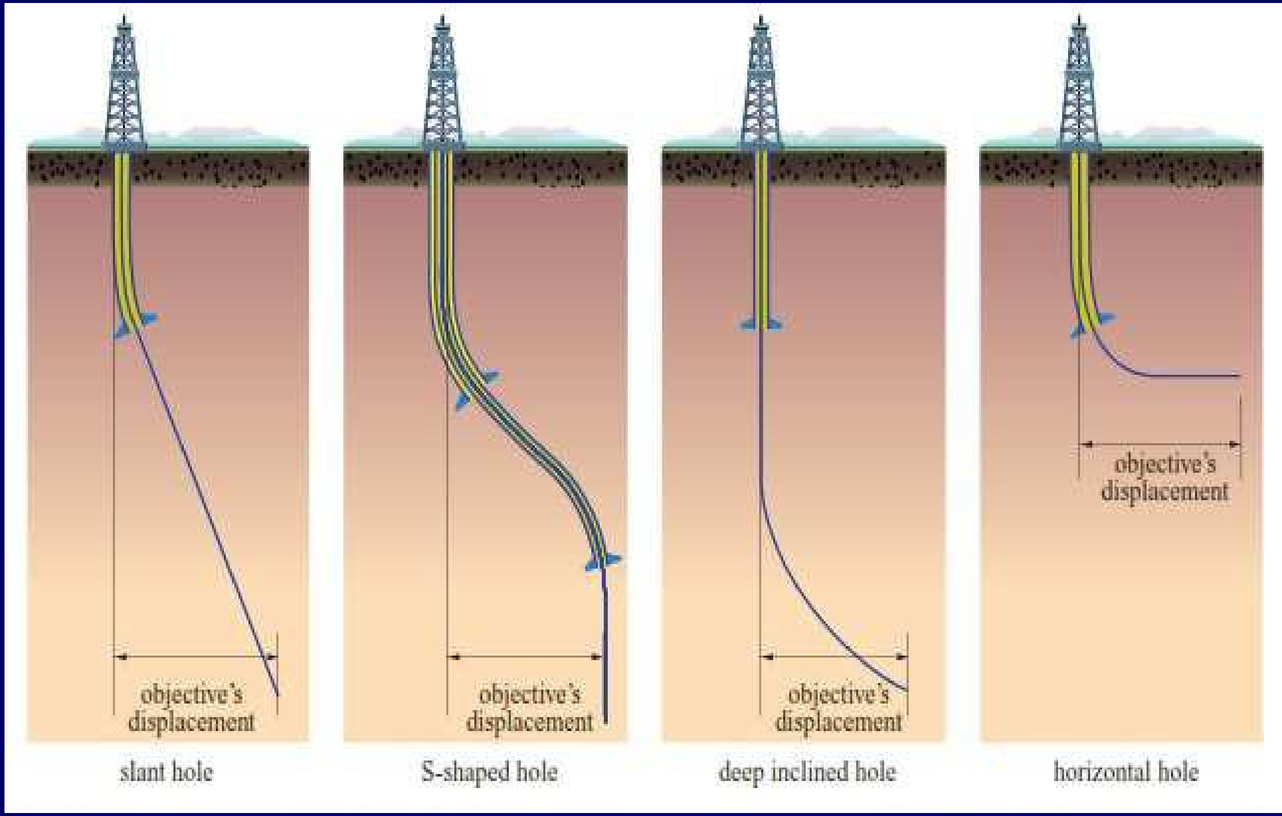
TABLE 20.1—SCREENING CRITERIA FOR SELECTING IMPROVED RECOVERY PROCESSES

Process	Rock Type	Average k md	Depth ft	Oil Viscosity cp	T_R ºF
Waterflood	Either	>5*	NR**	<100	NR**
Immiscible					
Hydrocarbon	Either	>1000	NR**	<20	NR**
CO_2, N_2	Either	>1000	NR**	<20	NR**
Miscible					
High-pressure hydrocarbon	Either	All	>5,000	<5	NR**
Enriched hydrocarbon	Either	All	>3,000	<5	NR**
CO_2	Either	All	>3,000	<10	NR**
N_2	Either	All	>6,000	<5	NR**
Thermal					
Steam	Either	†	200 to 5,000	>20	NR**
Combustion	Sandstone	†	>1,000	NR**	NR**
Chemical					
Polymer	Either	>100	NR**	<40	<200
Alkaline	Sandstone	>100	NR**	<40‡	<200

*Can be <1 md for carbonates; **NR = no restriction; †kh/μ >100; ‡acid number>0.2.

Well Architecture

- Vertical
- Slanted
- S-shape
- Horizontal
- Multilateral

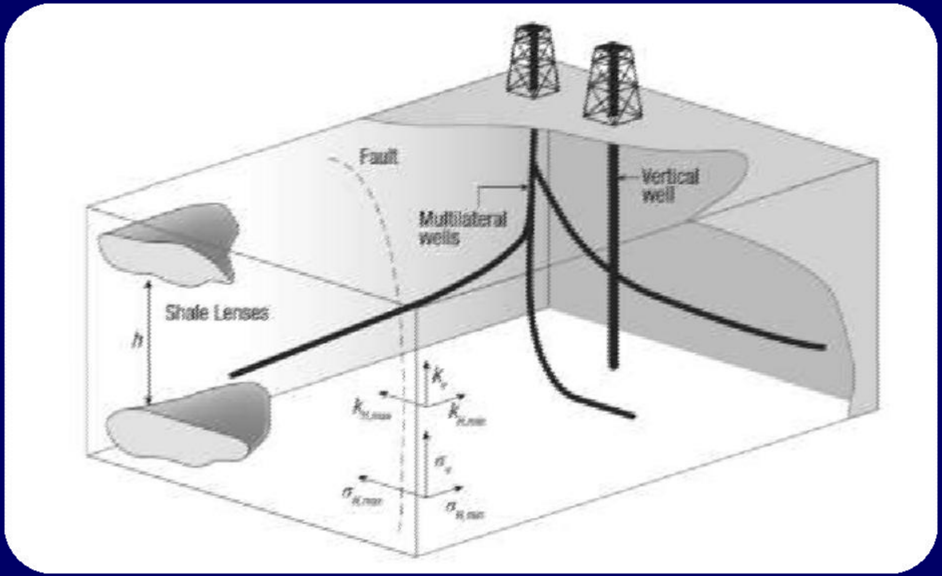


Well Type by Shape

- This gives us the flexibility to select the most appropriate, according to the production target and the subsurface formation characteristics.

Well Drilling and Completion Planning

- The drilling of a well involves **a major investment** ranging from a few million US$ for onshore well to 100 million US$ for a deepwater exploration well.
- Well engineering is aimed at maximizing the value of this investment by employing the most appropriate technology and business process, **to drill a ''fit for purpose''** well, at the minimum cost, without compromising safety or environmental standards
- **To optimize the design of a well it is desirable to have as accurate a picture as possible of the subsurface: identification of boundaries, heterogeneities, and anisotropies**.



The subsurface team will define optimum location and well architecture for the planned wells to penetrate the trajectory through the objective sequence.

Completion engineering, as part of is that part FDP integrated team, is responsible of well completion design aimed to maximize production (or injection) in a cost-effective manner.

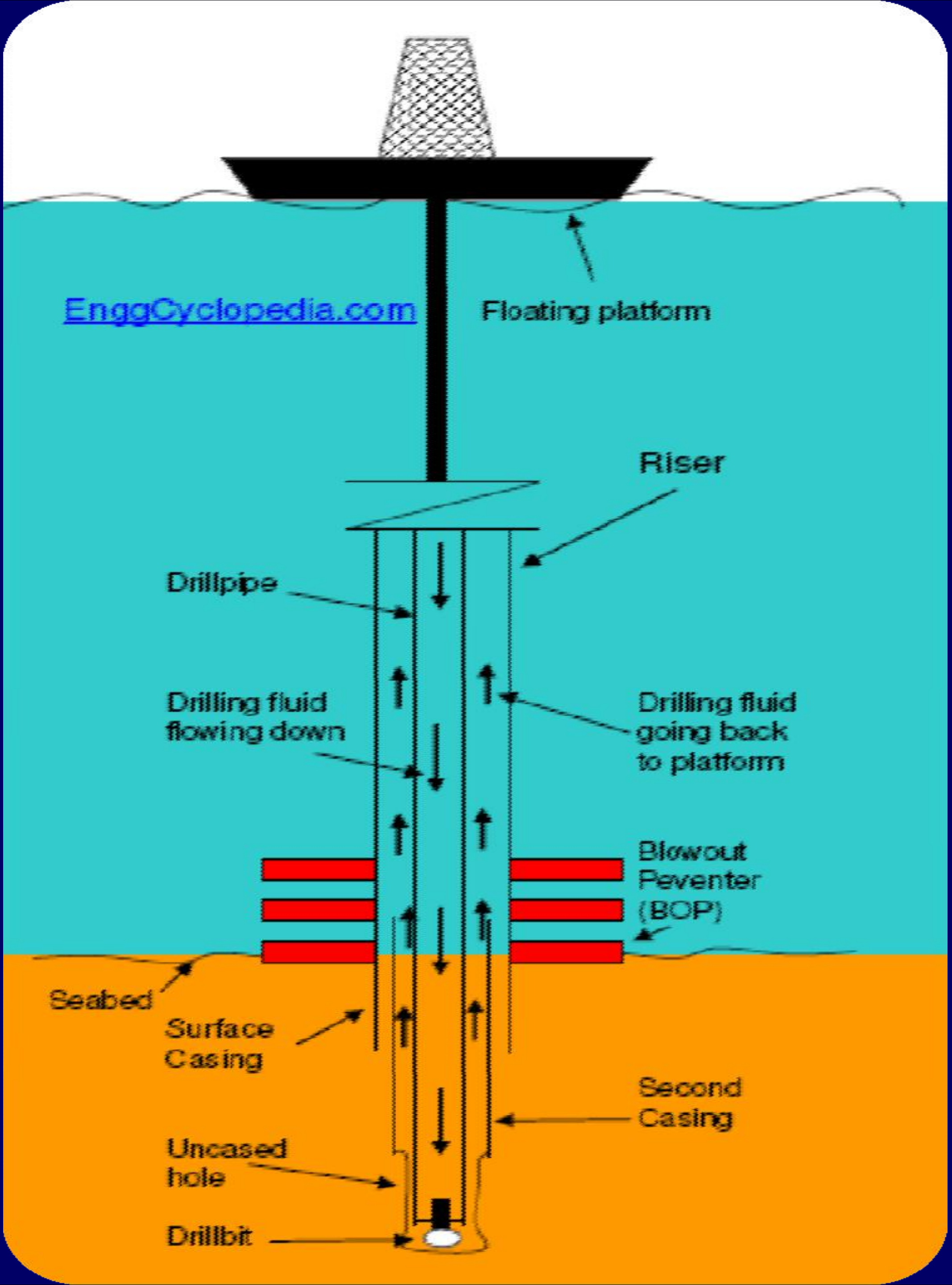
Vertical Well

- Vertical well is the ideal solution **to produce from a single flow unit having a large net pay or multiple flow units can be produced commingled.**

- Easy to be drilled.

- Very **good bottom hole accessibility.**

- Less expensive.

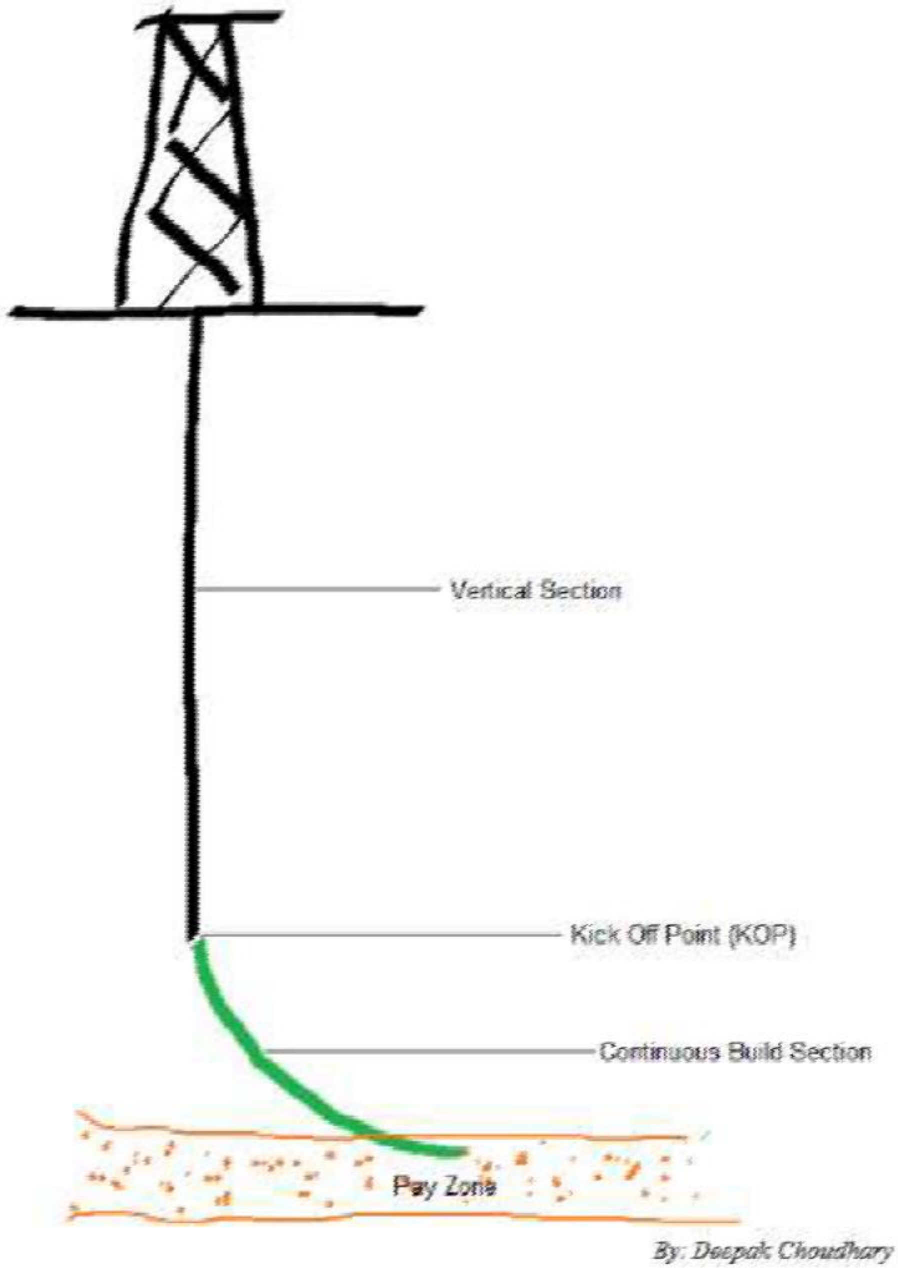

EnggCyclopedia.com
Floating platform
Riser
Drillpipe
Drilling fluid
flowing down
Drilling fluid
going back
to platform
Blowout
Peventer
(BOP)
Seabed
Surface
Casing
Second
Casing
Uncased
hole
Drillbit

J-shape

J-shape wells are made up of a vertical section, a deep kick off and a build up to target. They are also called Deep Kick off wells or J Profile wells (as they are J - shaped).

The well is deflected at the kickoff point, and inclination is continually built through the target interval (Build). The inclinations are usually high and the horizontal departure low.

This type of **well is generally used for multiple sand zones, fault drilling, salt dome drilling, and stratigraphic tests.**


Vertical Section
Kick Off Point (KOP)
Continuous Build Section
Pay Zone
By: Deepak Choudhary

Horizontal Well

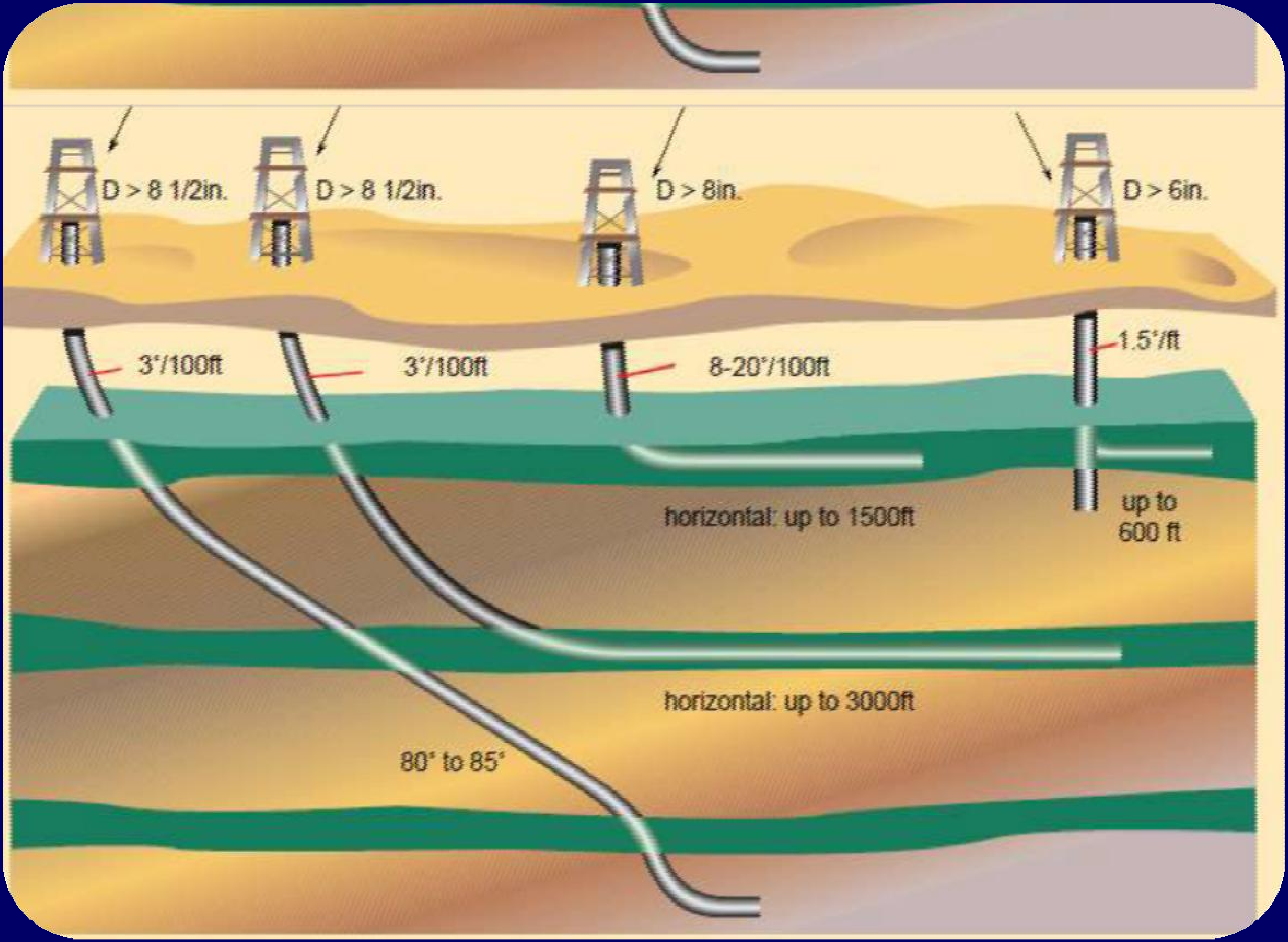
- Horizontal wells have ***been employed in a variety of reservoir applications***:
  - Thin zones
  - Naturally fractured reservoirs,
  - Reservoirs with water and gas coning problems
  - Low permeability reservoirs
  - Gas reservoirs
  - Heavy oil reservoirs
  - Waterflooding
  - EOR applications.

Disadvantages of horizontal wells are:

High cost as compared to a vertical well.

Generally only one zone at a time can be produced using a horizontal well.

If the reservoir has multiple pay-zones, especially with large differences in vertical depth, or large differences in permeability, it is not easy to drain all the layers using a single horizontal well.

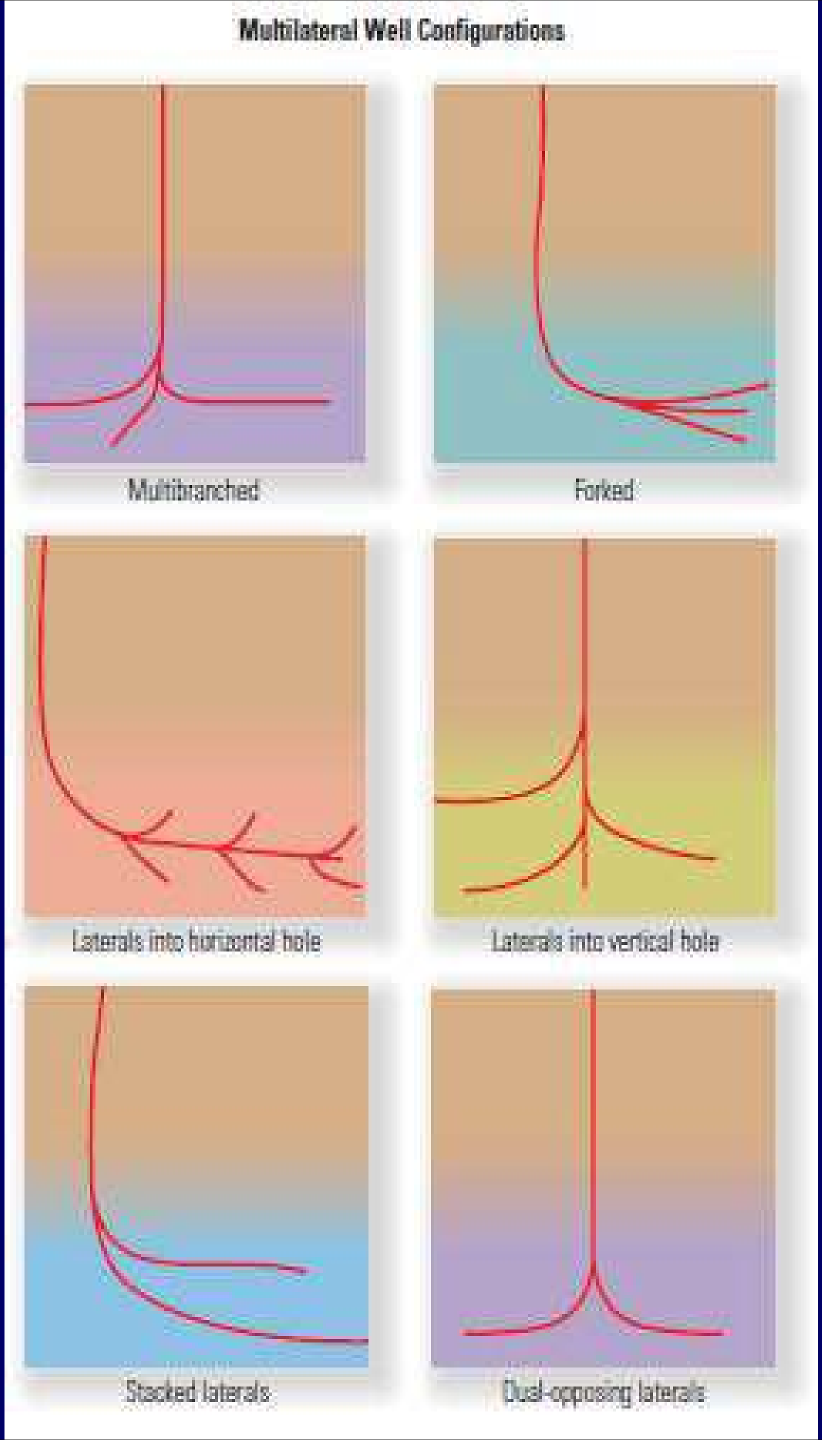

D > 8 1/2in.
D > 8 1/2in.
D > 8in.
D > 6in.
3°/100ft
3°/100ft
8-20°/100ft
1.5°/ft
horizontal: up to 1500ft
up to 600 ft
horizontal: up to 3000ft
80° to 85°

Multilateral well

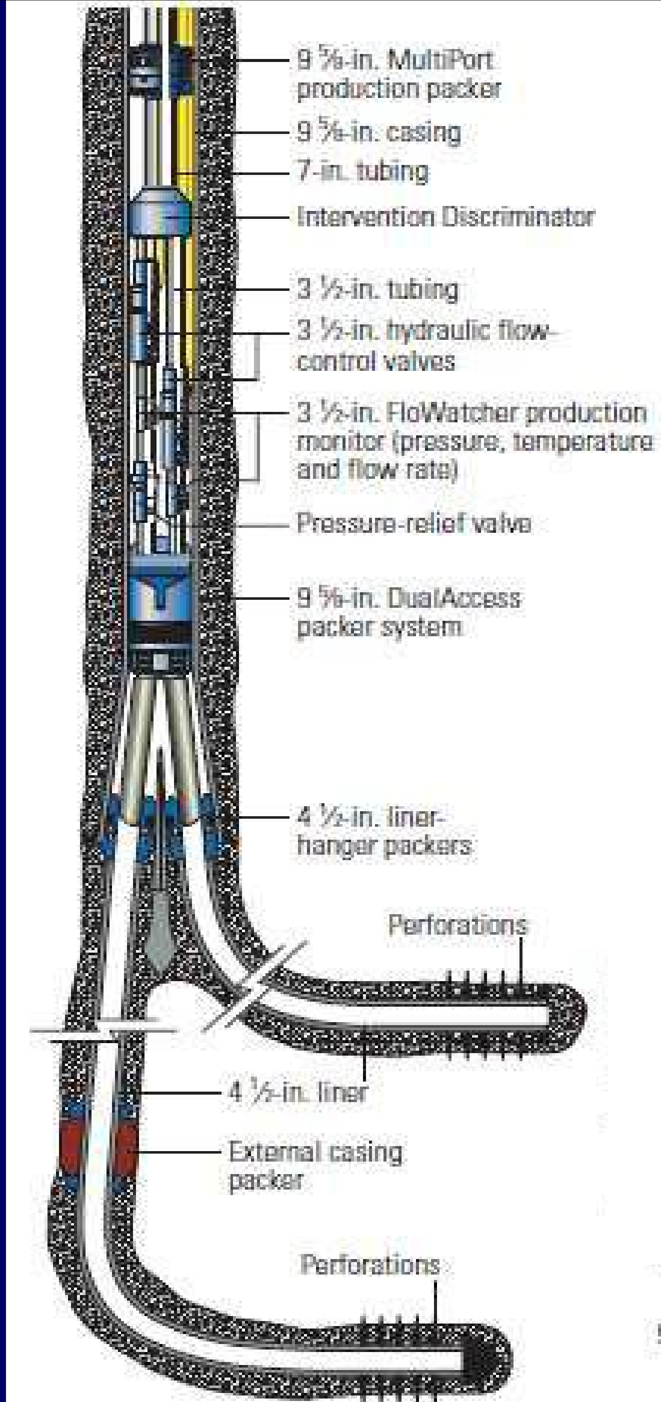
A multilateral is a well with more than one branch (lateral).

Multilaterals find wide applications:

—*Compartmentalized reservoirs*
— *Stacked intervals*
— *Increased reservoir drainage*
— *Reducing drawdown*
— *Slot constrained platforms or pads.*



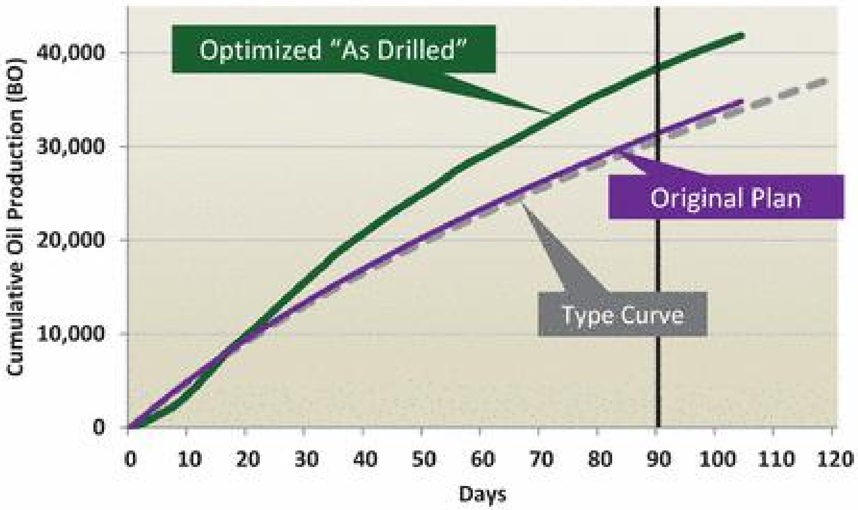
Multilateral Well Configurations
Multibranched
Forked
Laterals into horizontal hole
Laterals into vertical hole
Stacked laterals
Dual-opposing laterals

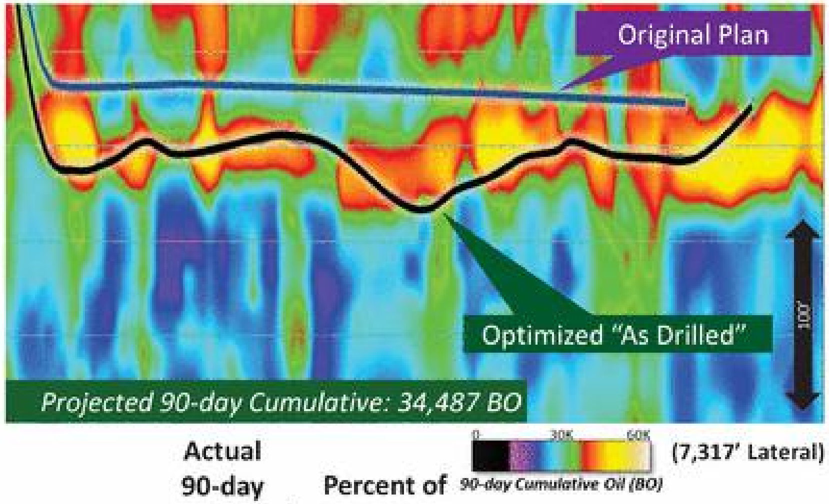


9 5/8-in. MultiPort production packer
9 5/8-in. casing
7-in. tubing
Intervention Discriminator
3 1/2-in. tubing
3 1/2-in. hydraulic flow-control valves
3 1/2-in. FloWatcher production monitor (pressure, temperature and flow rate)
Pressure-relief valve
9 5/8-in. DualAccess packer system
4 1/2-in. liner-hanger packers
Perforations
4 1/2-in. liner
External casing packer
Perforations

Well Planning Adjustment

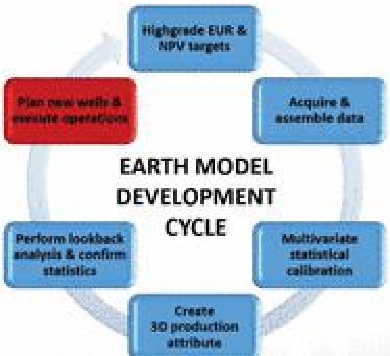
Middle Wolfcamp Targeting Uplift Example





Actual 90-day Production[1]	Percent of Type Curve
Actual: 38,430 BO	125%
Original: 31,453 BO	103%
Type Curve: 30,655 BO	100%

Optimized "as drilled" targeting results demonstrate 25% improvement in 90-day cumulative oil from type curve



Laredopetro

Well Completion Strategy

Figure 1.5 Economic influence of completions.

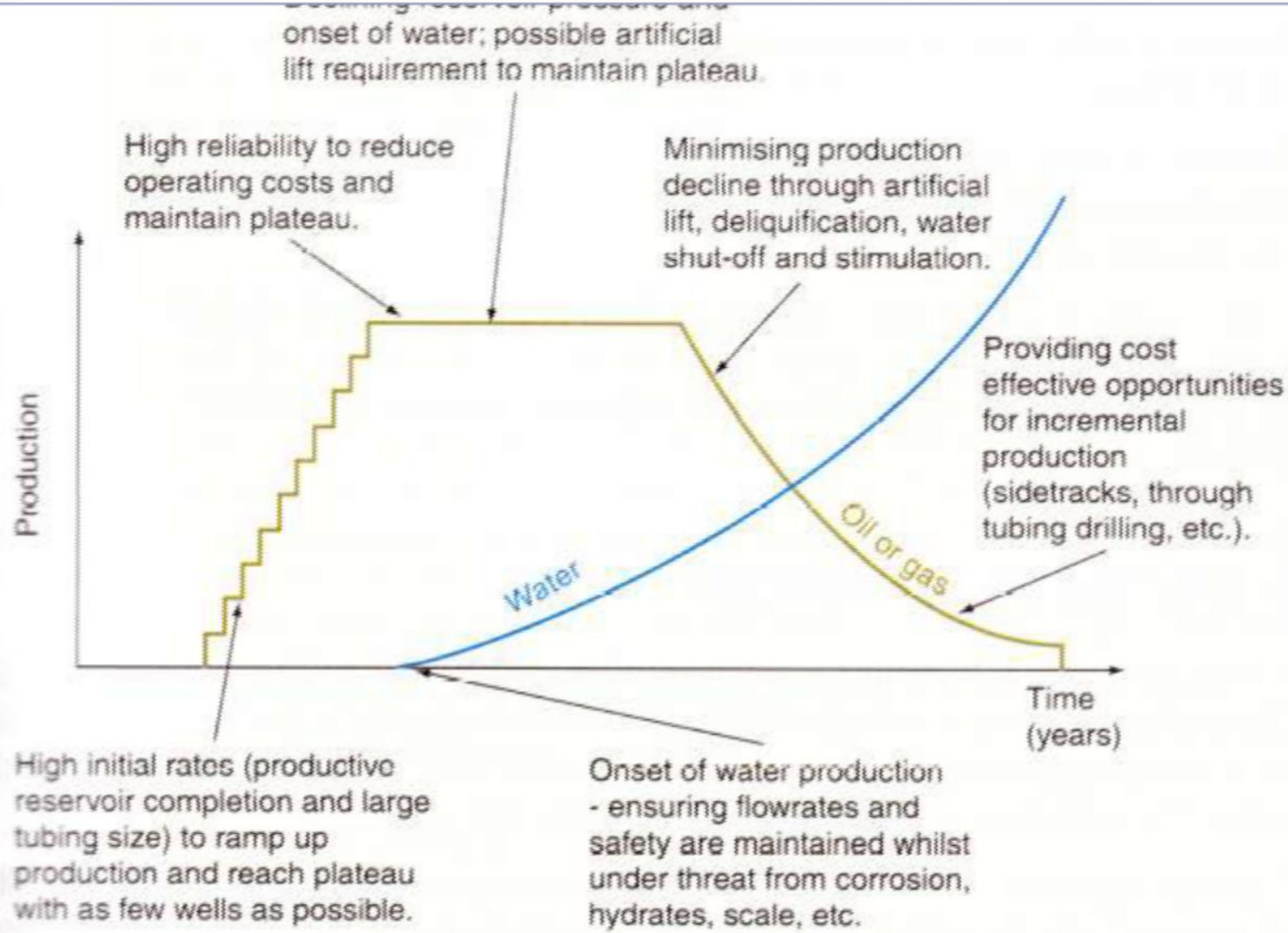


Figure 1.5 Economic influence of completions.

Completion Planning

- Wells to be completed can be **producers or injectors**.
  - A **producer** can be an oil or gas producer well.
  - An **injector** can be an water, gas (hydrocarbon gas or waste products such as carbon dioxide, Sulphur, hydrogen sulphide, etc.), steam well injector or disposal well.
- Completion planning of a producer, involves:
  - Defining the **well architecture**
  - Defining the mode of formation fluid production: **Natural flow or assisted flow by Artificial Lift system.**
  - Choosing the **equipment** to be used
  - Selecting **materials**
  - Defining operational guidelines

- The completion planning for **the injector** is the same of the producer but considering that the is in of “hydraulic injection flow condition” only.

- The completion design mast **take into account the evolution of the production/injection characteristics** (BHFP, WC, GOR) of the well along the field life time, according to the production/injection forecast.

Single Completion

- **Single zone** completion is one of the types of upper completion which allows producing only one zone. Production tubing is a flow path for fluid from a reservoir to flow to the surface so it protects the casing from corrosion and maximizes the efficiency of the flow.

- In a single tubing string completion, typically a packer is set on top of a reservoir so the reservoir fluid can flow up into the production tubing. Types of packers are based on several factors as temperature, pressure, reservoir fluid, etc. Additionally, complexity of tubing and packer installation is driven by objectives.

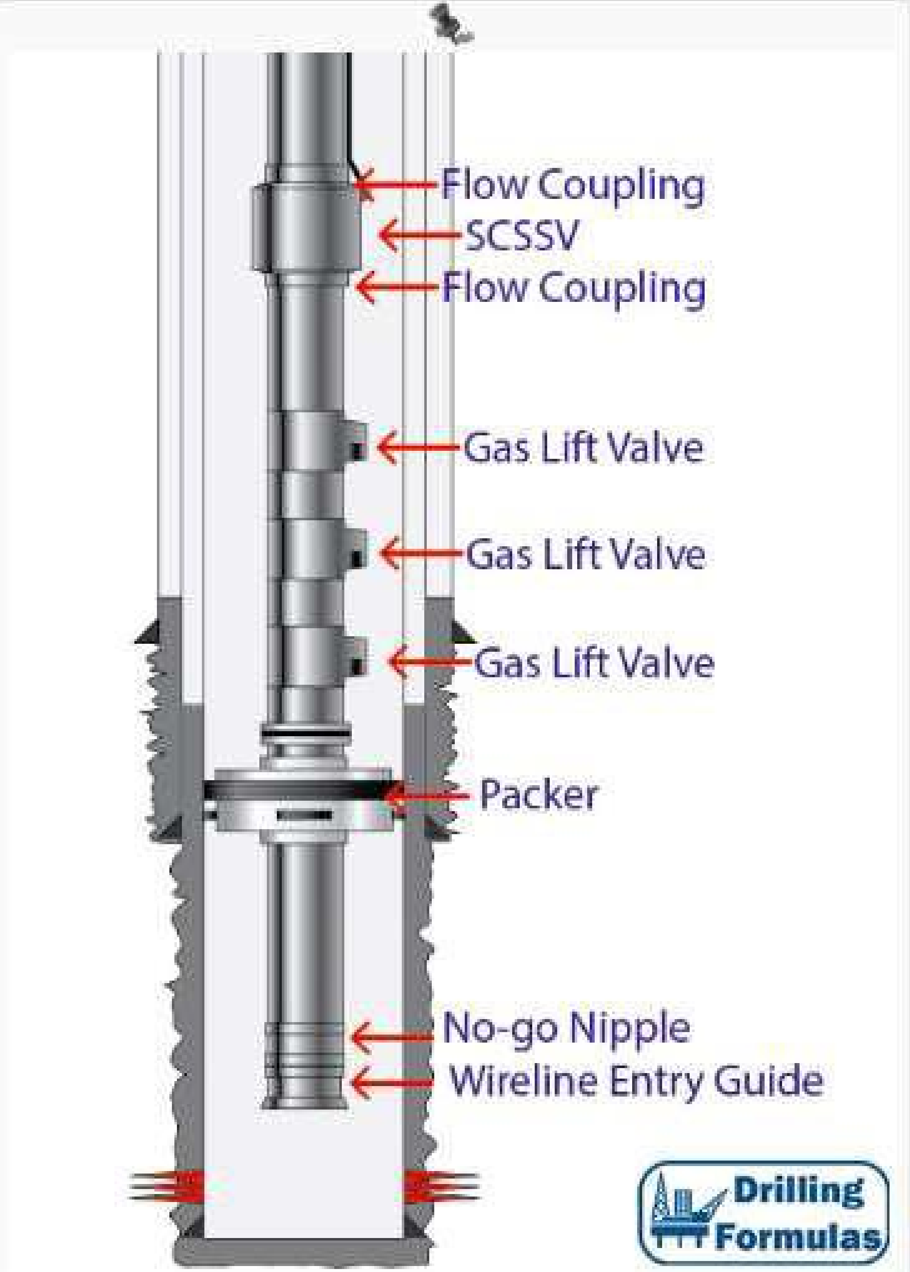


Figure 2 – Single Zone Completion with Gas Lift

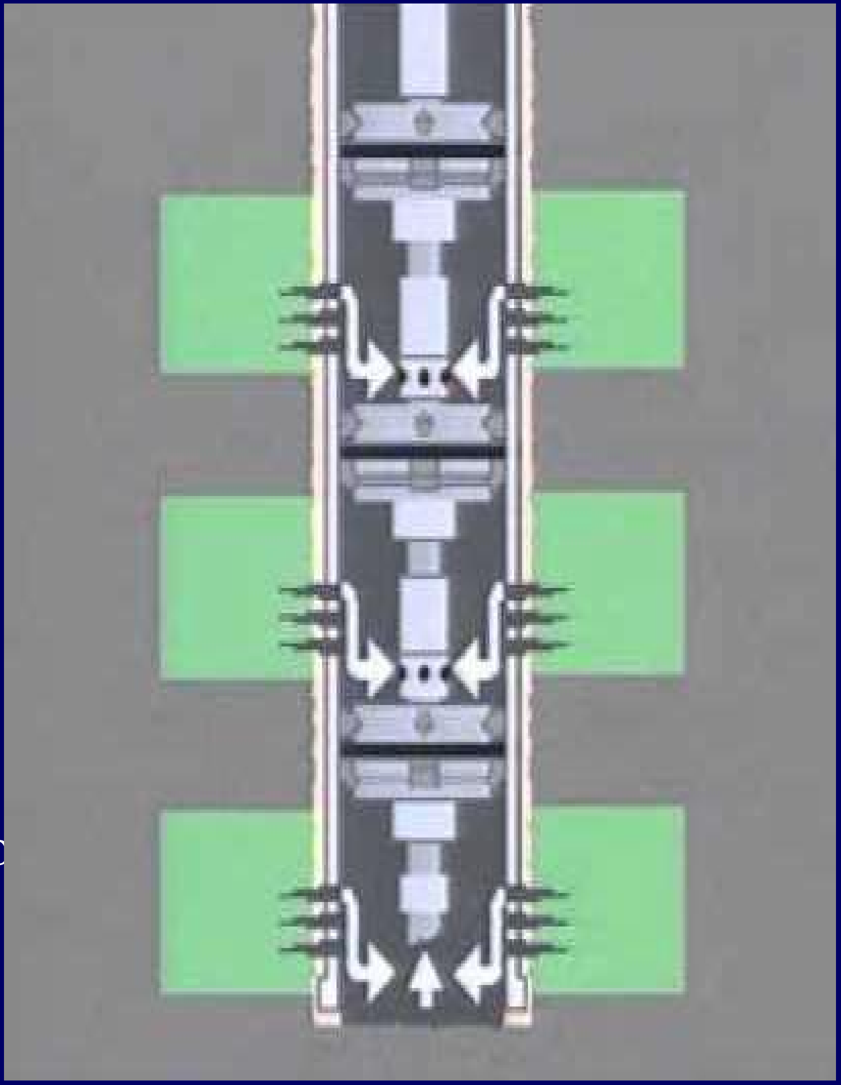
Multiple zone completion

Multiple zone completion is one type of completion which allows operators **to selectively produce or comingle reservoir fluid from different zones into one well.**

It is also possible **to workover the upper part of completion string without removing the next interval completion.**

Additionally, **through tubing perforation is can performed at the bottom zone.**

A multiple zone completion can be divided into two parts, which are **single string completion** and **multiple string completion.**



Single Multiple Zone Completion

- A multiple-string configuration **consists of two or more completion strings in one well.**

- This is more expensive and complicated to install than a single-string configuration. However, it has some advantages such as the ability to **simultaneous produce or inject into different zones in commingled.**

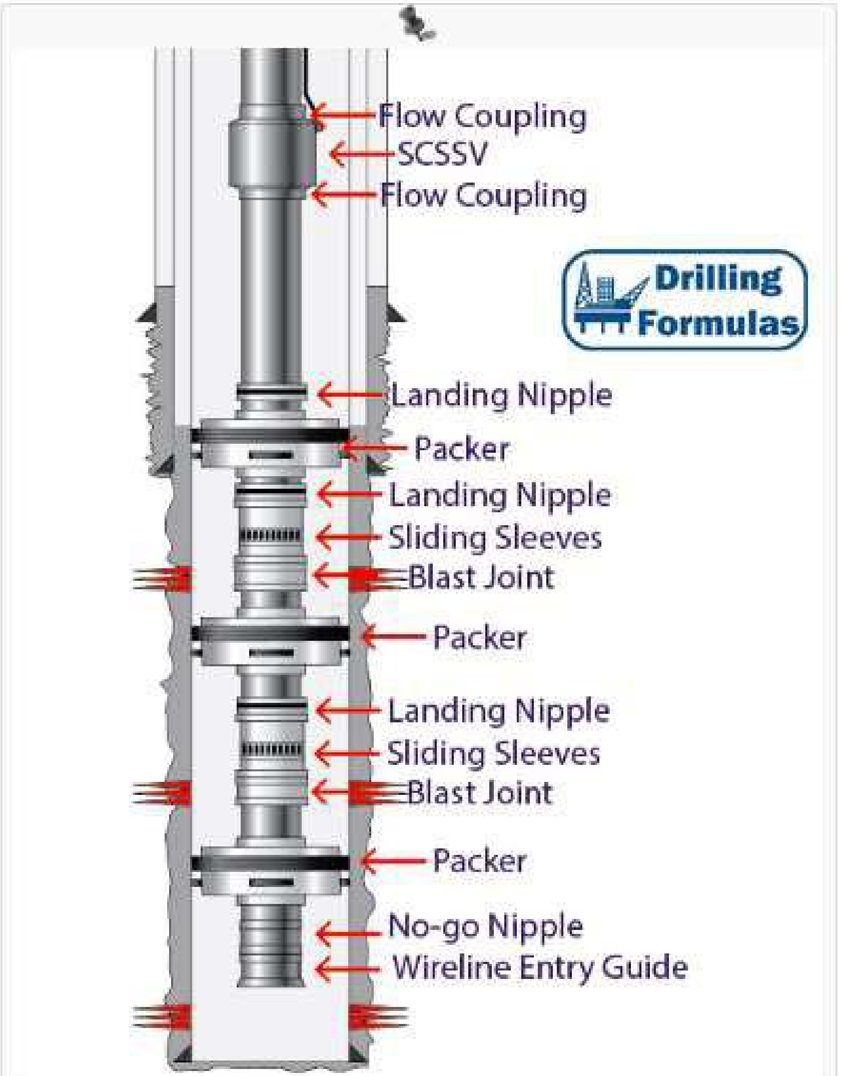


Figure 1 – Completion Equipment Arrangement for a Single String Configuration

Dual Multi zone Completion

- A multiple-string configuration **consists of two or more completion strings in one well.**

- This is more expensive and complicated to install than a single-string configuration. However, it has some advantages such as the ability **to simultaneous produce and inject into different zones and has a more accurate production allocation than a single string type.**

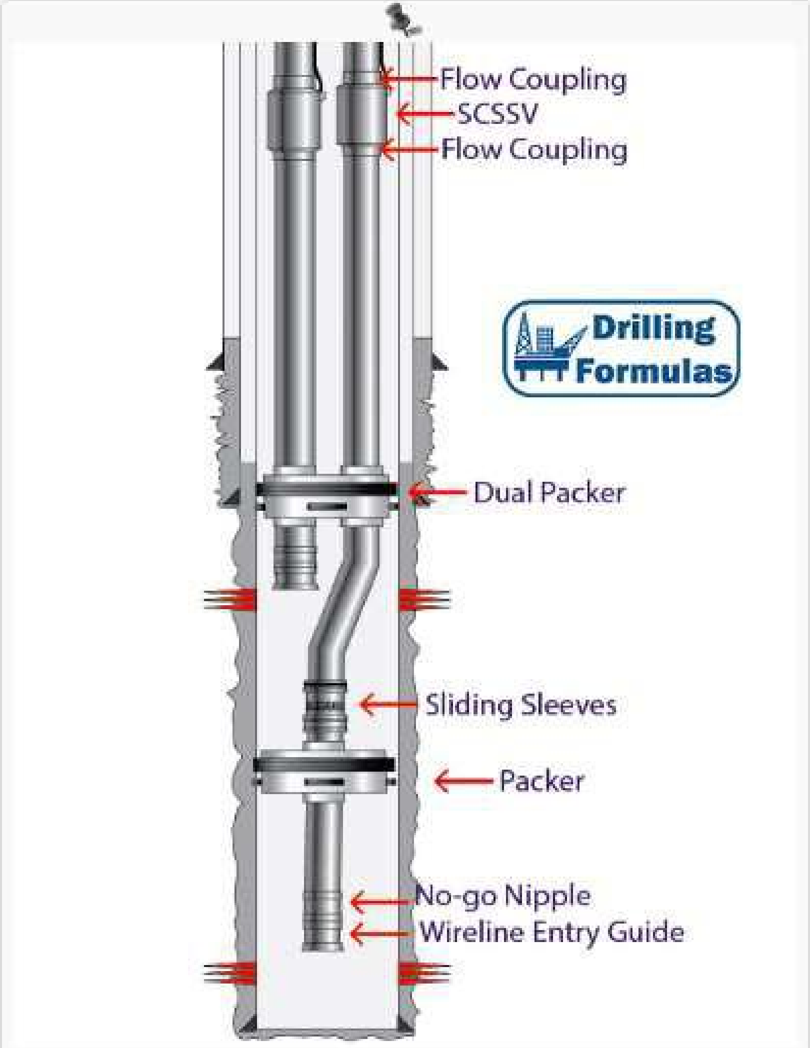
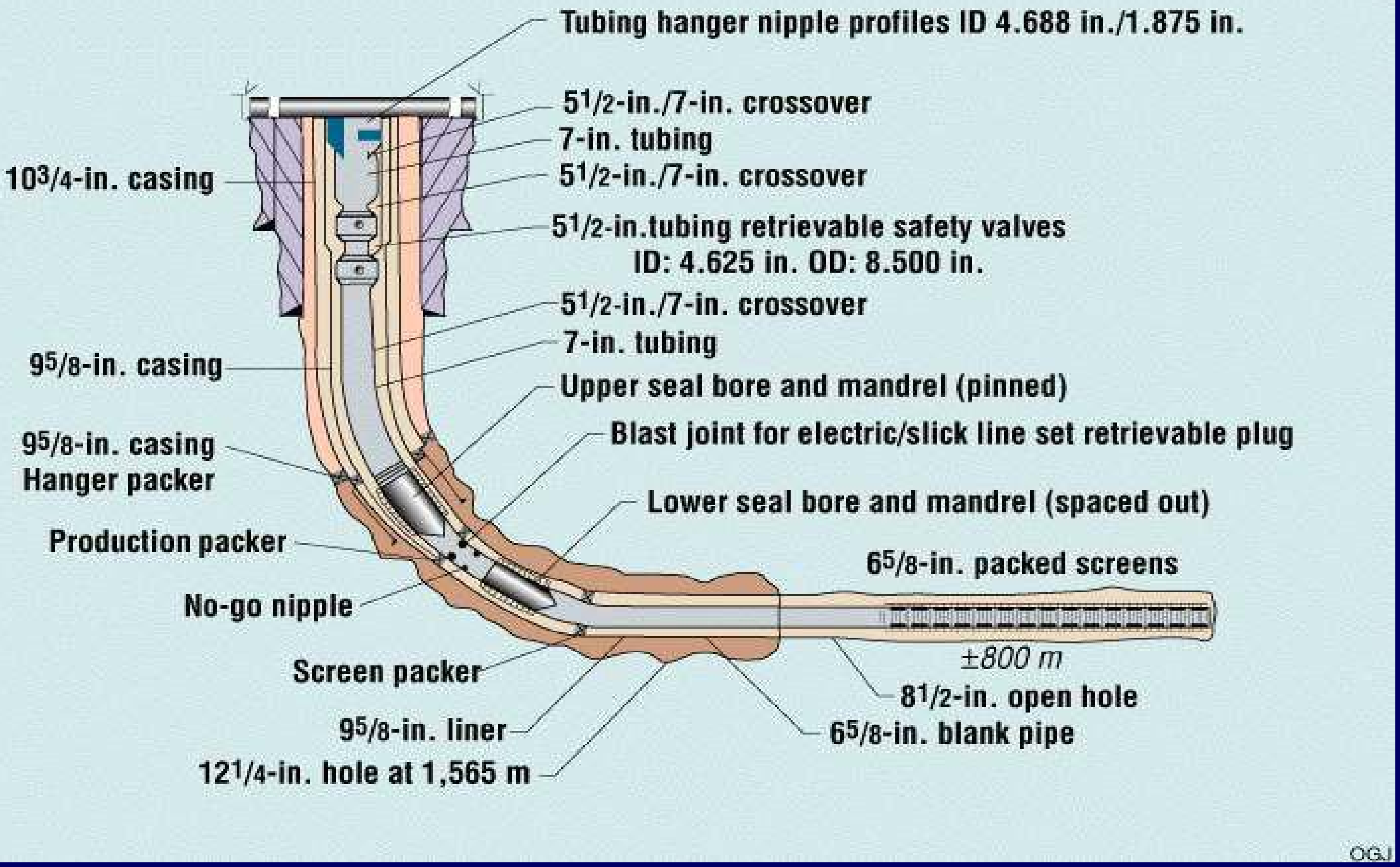


Figure 2 – Completion Equipment Arrangement for a Dual String Configuration

Horizontal well Typical Completion



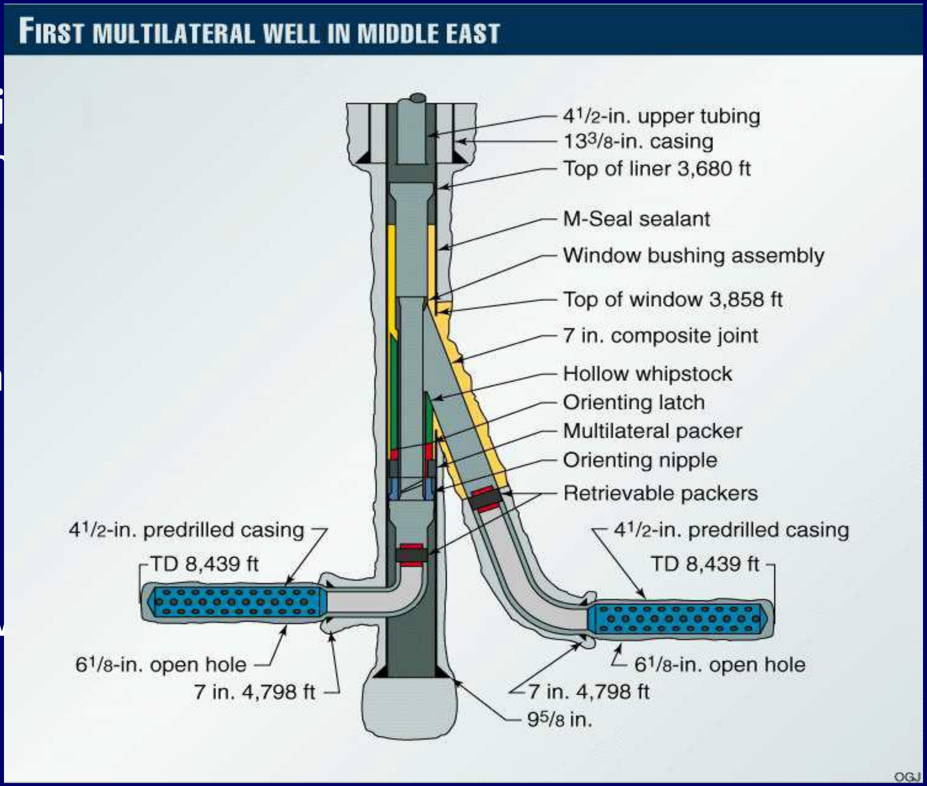
Multilateral Completion

- **Multilateral technology can be used in a variety of scenarios including:**
  - The development of in fill field programs with **limited slots.**
  - The **extension of field life by accessing new reserves.**
  - The development of **deepwater** plays.

- **Generally, multilaterals can be divided i**
  - **Re-entry** - Where an existing well is re-en
    the
    existing well bore.
  - **New development** -Where a new well is
    branches and various completion types a

- **Design concepts**

  In a multilateral completion, a unique system
  horizontal laterals to a parent well bore, allow
  be selectively produced or commingled.



Offshore Development

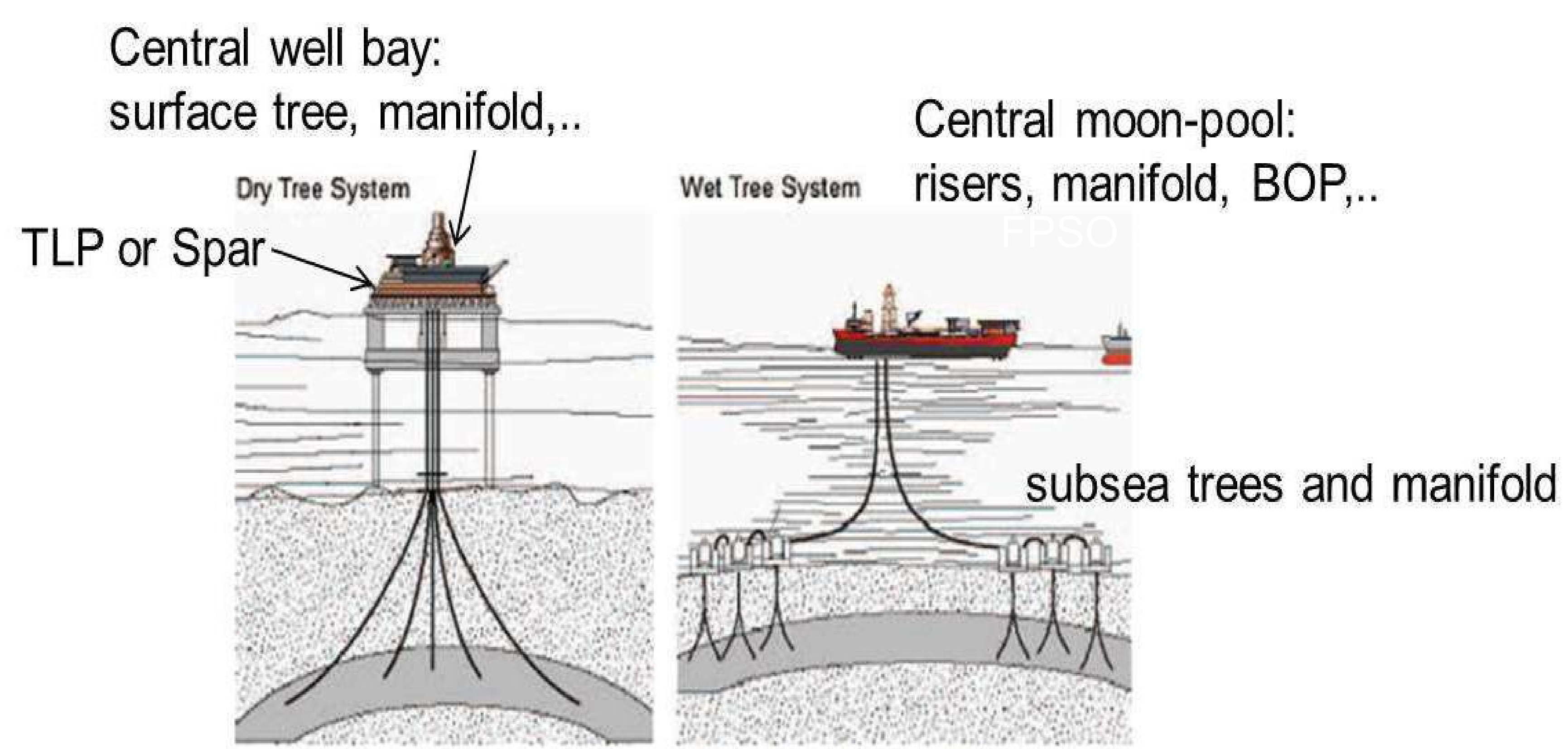


Figure 2-2 Dry Tree and Wet Tree Systems [1]

- For the dry tree system, trees are located on or close to the platform, whereas wet trees can be anywhere in a field in terms of cluster, template, or tie-back methods.
- Globally, more than 70% of the wells in deepwater developments that are either in service or committed are wet tree systems.

Chapter 7 Field Development Plan-
Development Well Pattern Design and Adjustment

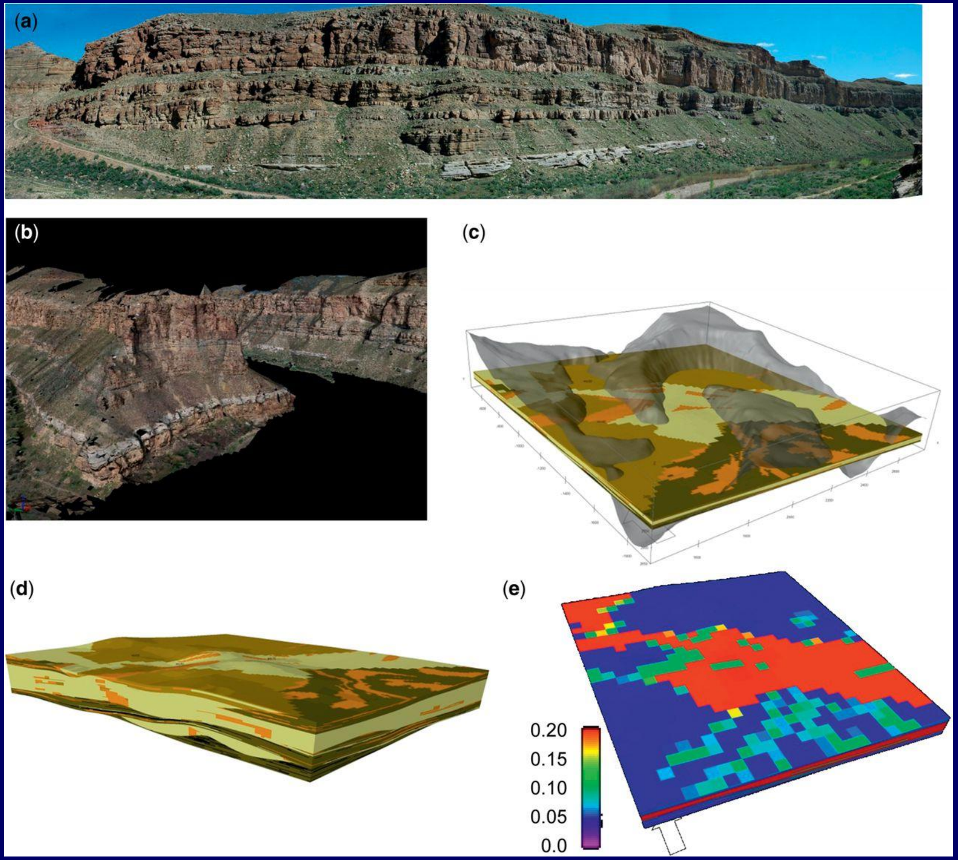
Section 1 Reservoir/Field Development Planning

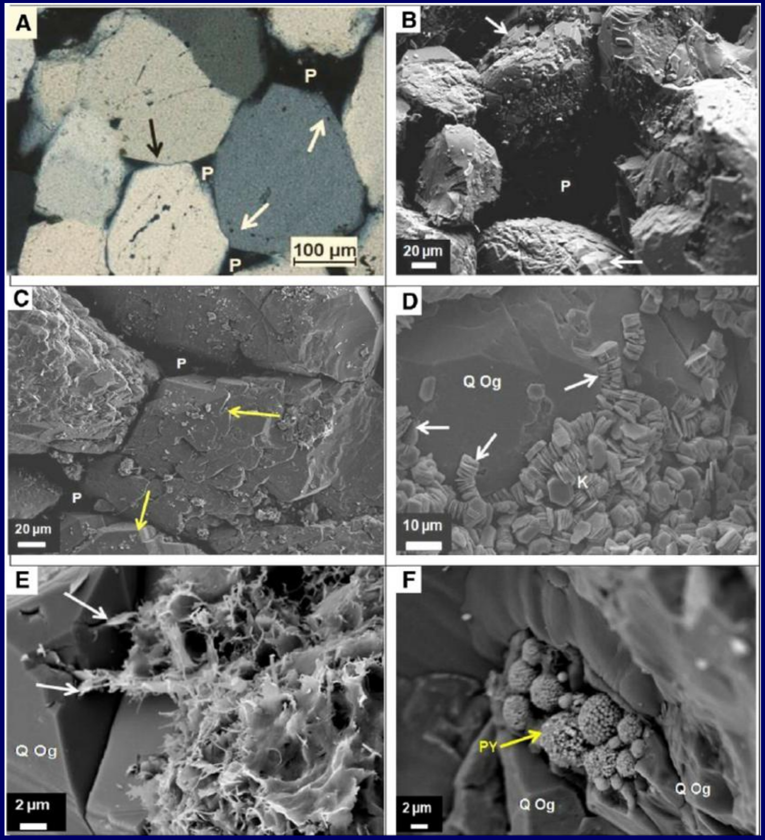
Section 2 Zonation for Multi-payzones Development and Well Pattern Design

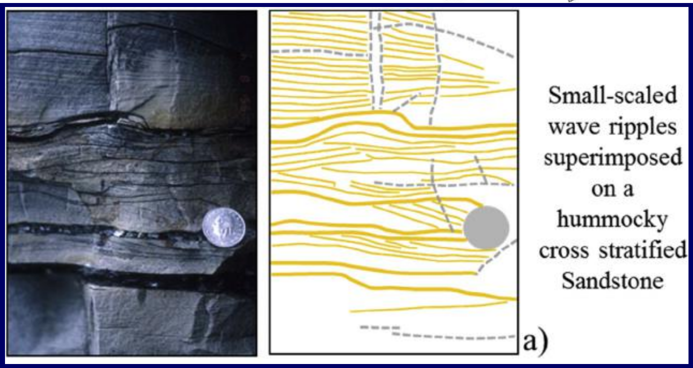
Section 3 Residual Oil/Bypassed Plays and Development System Adjustment

Section 2 Zonation for Multi-payzones Development and Well Pattern Design

Reservoir Heterogeneity

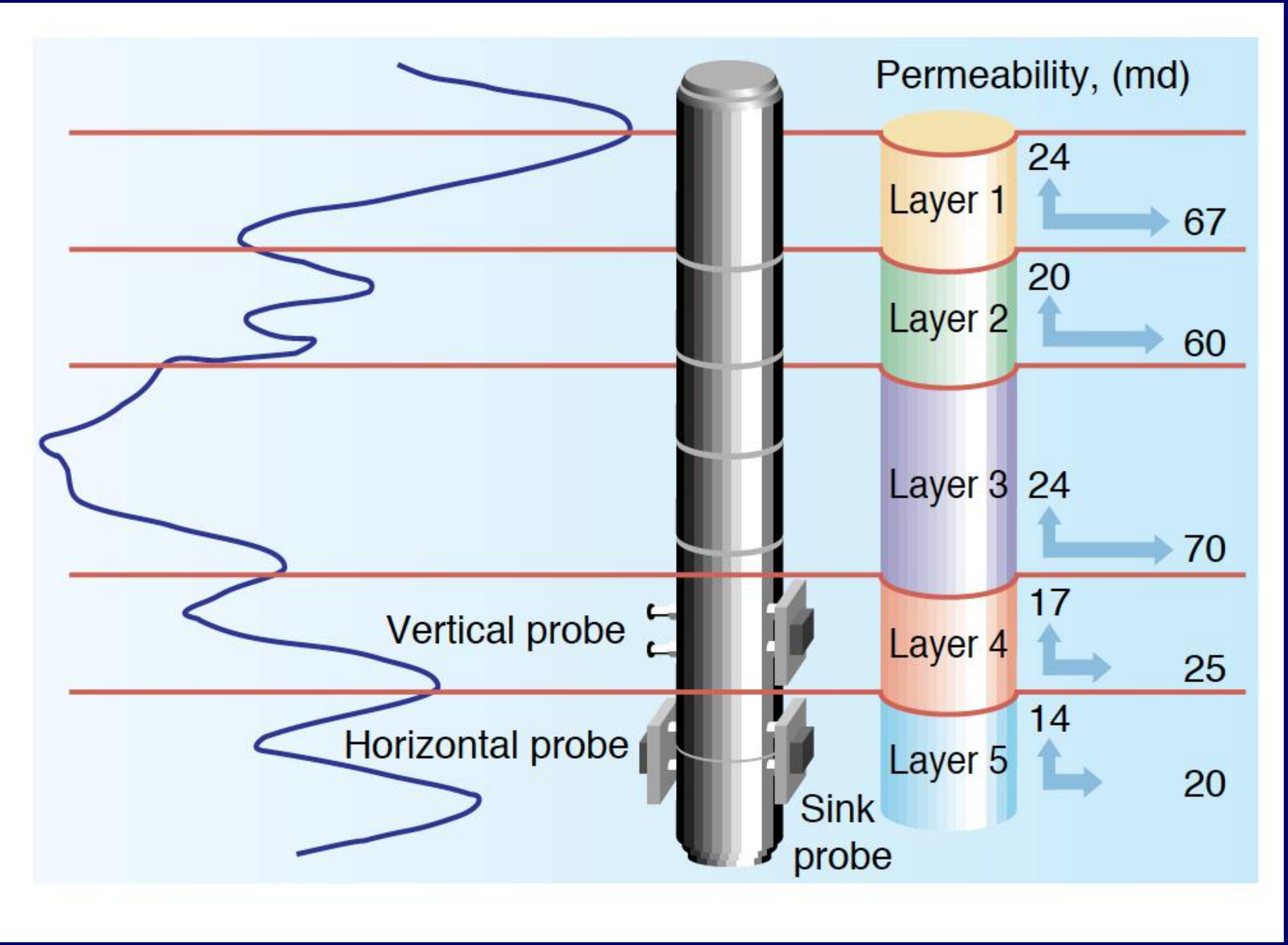






3D heterogeneity from regional scale to nano-scale

3D Heterogeneity



Reservoir Heterogeneity for Development

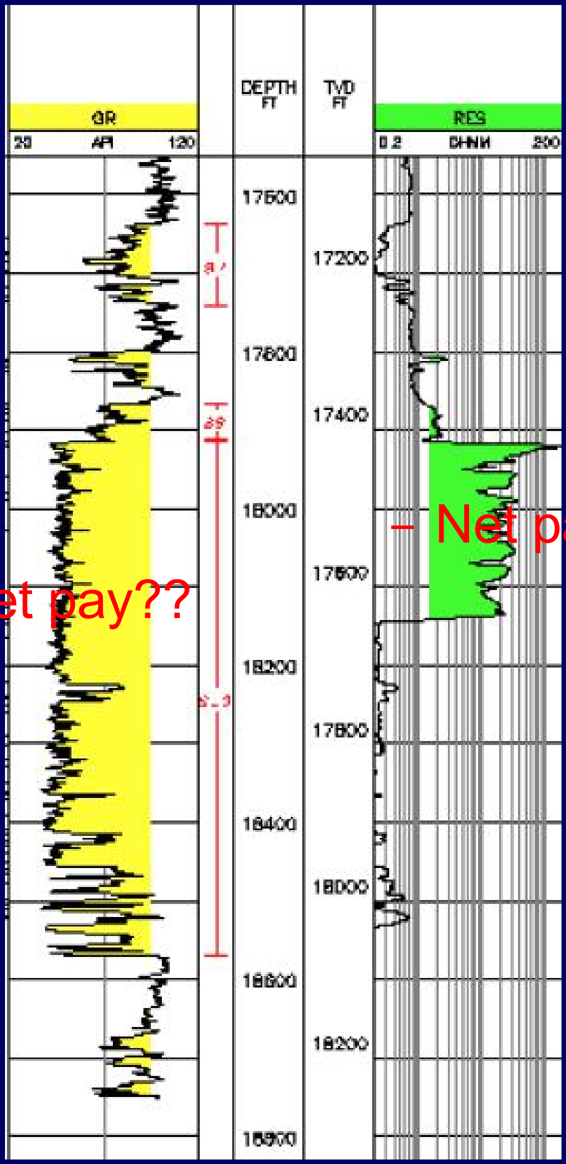
- **All oil reservoirs are heterogeneous rock formations.** The primary geological consideration for development is **to determine nature and degree of heterogeneities in a particular oil field.**

- Matrix permeability variation in the vertical direction causes displacing fluid to advance faster in zones of higher permeability **and results in earlier breakthrough in such layers.**

- To achieve a good recovery factor, the displacement fluid, whether of natural origin or induced by injection, **must efficiently sweep the hydrocarbons in the pore spaces and must also come into contact with the greatest possible volume of the reservoir.**

- The macroscopic displacement efficiency, in turn, is the product of two elements: **areal sweep efficiency and vertical invasion efficiency.**

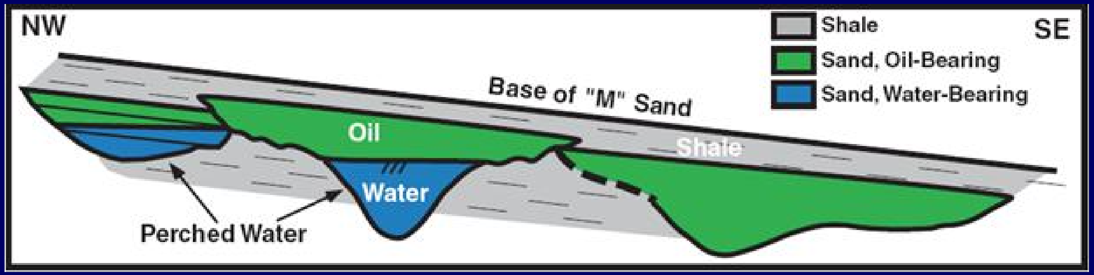
Pay zone identification



– Net pay??

– Net pay?

Oil Reservoir with perched water



Ram Powell N reservoir (Kendrick, 2000)

Porter, et al, SPE 58735 (2000)

Pay zone identification

$$V_{sh} = \frac{GR - GR_{min}}{GR_{max} - GR_{min}}$$

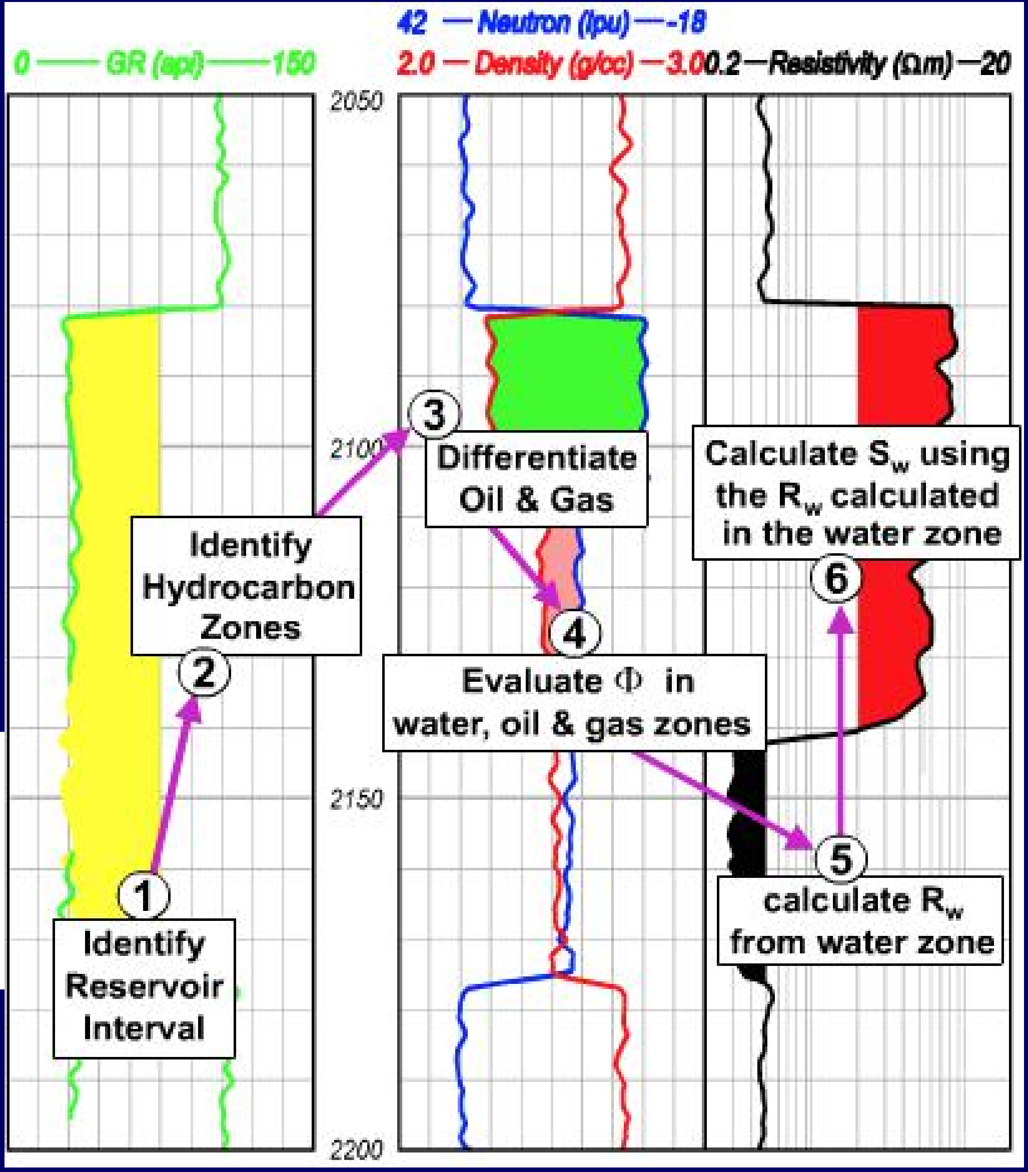
$$\Phi = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_{fl}}$$

$$S_w = \frac{1}{\Phi}\sqrt{\frac{R_w}{R_t}}$$

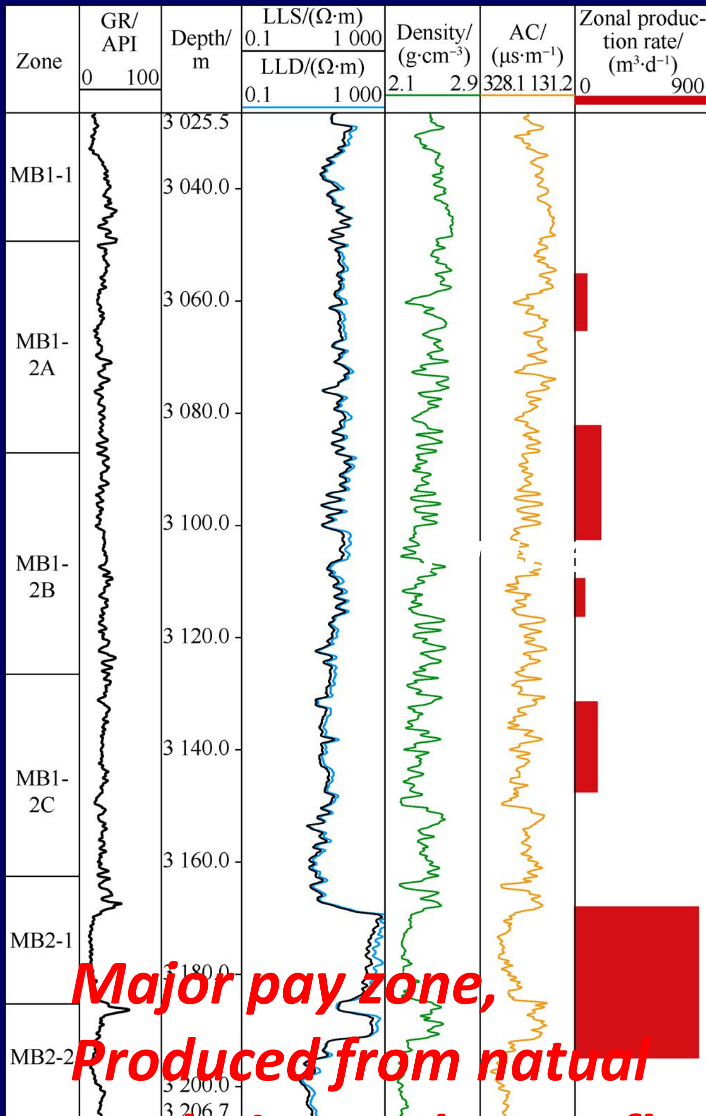
In clean water bearing formations (Sw = 1):

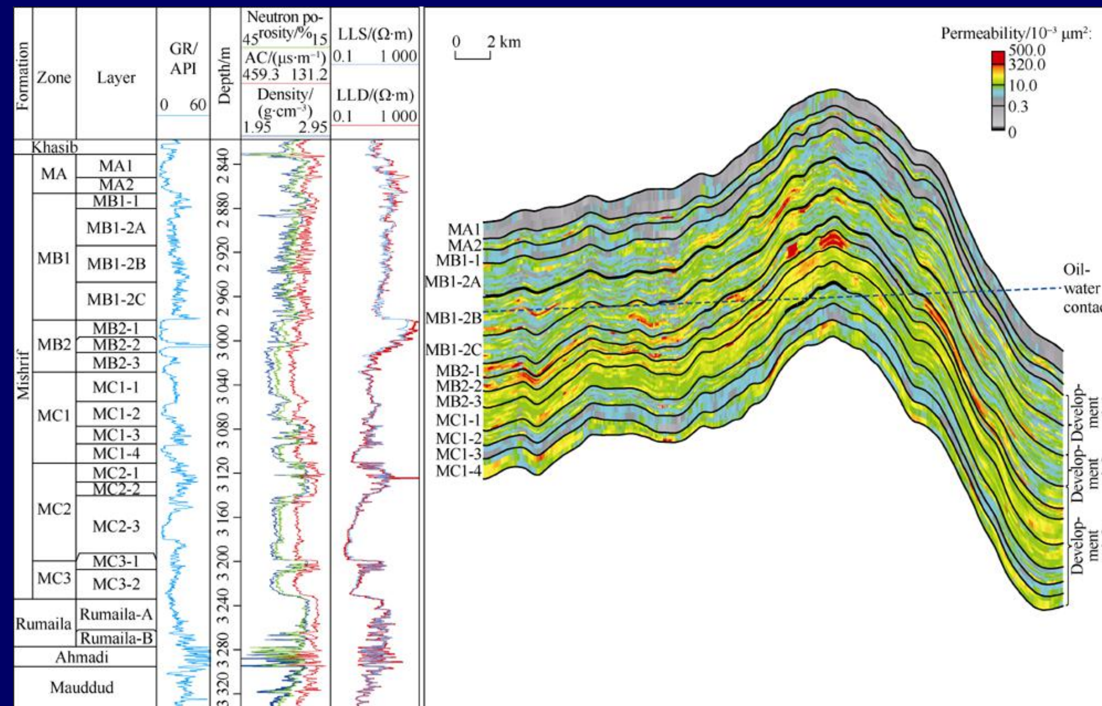
$$Rw = \phi^2 Rt$$

assuming a = 1, m = n = 2



Major Pay Zone Identification





(a) Well logging curve and zonation (b) The NW-SE trending section of Mishrif reservoir in Halfaya Oilfield

Song and Li, 2018

Production logging test profile of a producer in Mishrif Formation of Halfaya Oilfield.

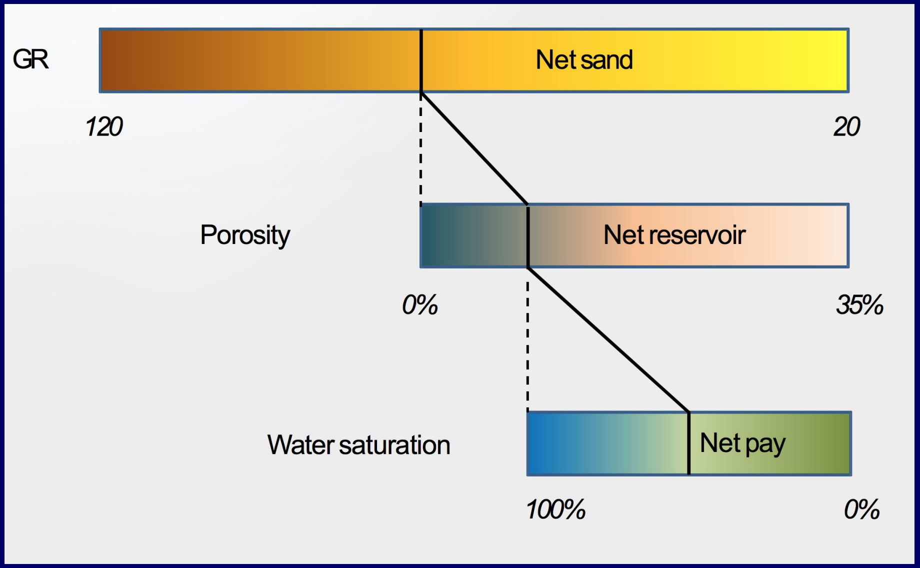
Major pay zone,
Produced from natual
Depletion and waterflooding

Net Pay

What is the different between net pay and gross thickness?

Net pay (net productive) thickness: It is the thickness of those intervals in which porosity and permeability are known or supposed to be high enough for the interval to be able to produce oil or gas, water and gas is not included to the net pay thickness.

Gross thickness: (also referred to reservoir thickness) It is the thickness of the stratigraphically defined interval in which the reservoir beds occur, including such non-productive intervals as may be interbedded between the productive intervals. In other words, it's the thickness of the whole reservoir.

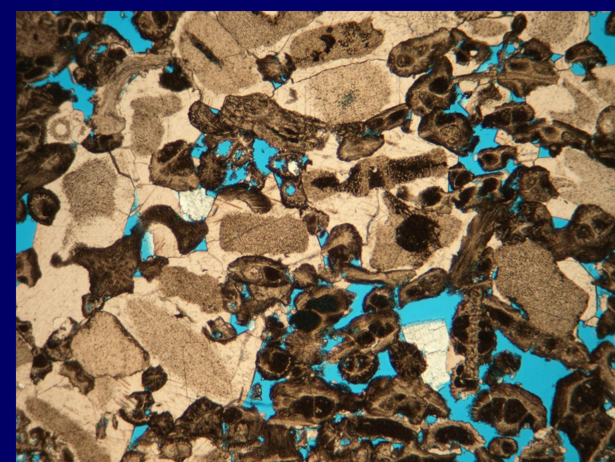


Heterogeneous reservoir

High quality to Low Quality Net Pay

Illinois Basin

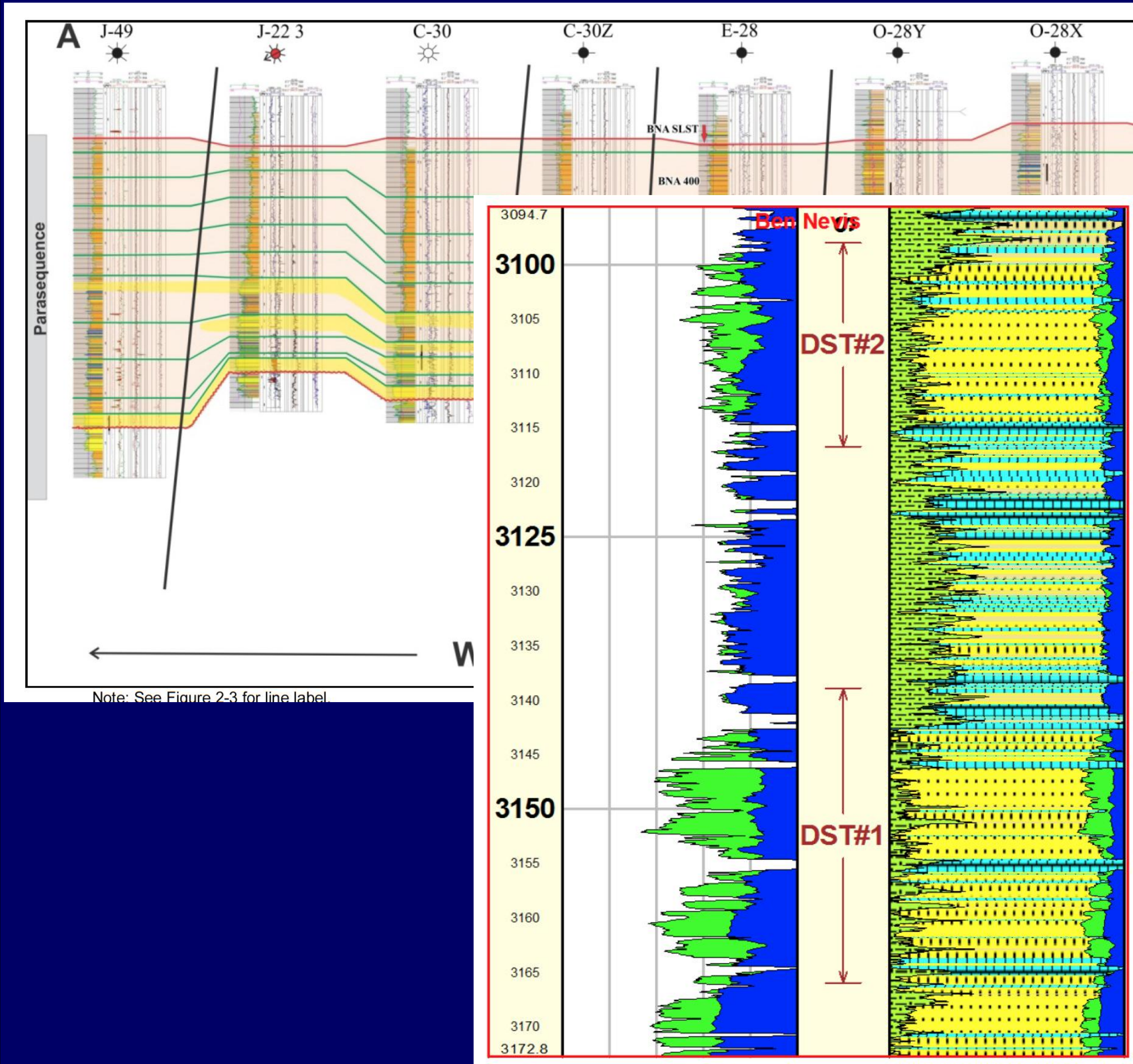
Only ~20% of net reservoir is over 7%φ ("conventional pay").
That means that~80% of the porous rock is below7%φ (potentially, "tight pay").



(dark purple)	> 7%
(light pink)	3% < x < 7%

12.0% φ, 47.3 mD, Swi 20.6%, Krg , Krg 0.993

Reservoir to Net Pay



Pay Cutoff:phi>10%, Sw<50%, k>3md

<u>DST#2 : 3098 – 3117 TVDSS</u>

Net Oil Pay	3.5m	
Gross	19m	
N/G	19%	
(Avg) Phi 12.2		Sw 39
Vsh 17		K 21 md

<u>DST#1: 3139 - 3166 TVDSS</u>

Net Oil Pay:	11.5m	
Gross	27m	
N/G	42%	
(Avg)Phi 15.2		Sw 35
Vsh 10		K 64 md

Reservoir Heterogeneity

- **Areal sweep efficiency.** Areal sweep efficiency, is defined as the ratio between the area of the reservoir with which the displacement fluid comes into contact and the reservoir's total area
- **Vertical sweep efficiency**. Vertical sweep efficiency is a parameter that expresses the degree of displacement of the oil by the displacement fluid along a vertical section of the reservoir at a specific moment in its productive life.

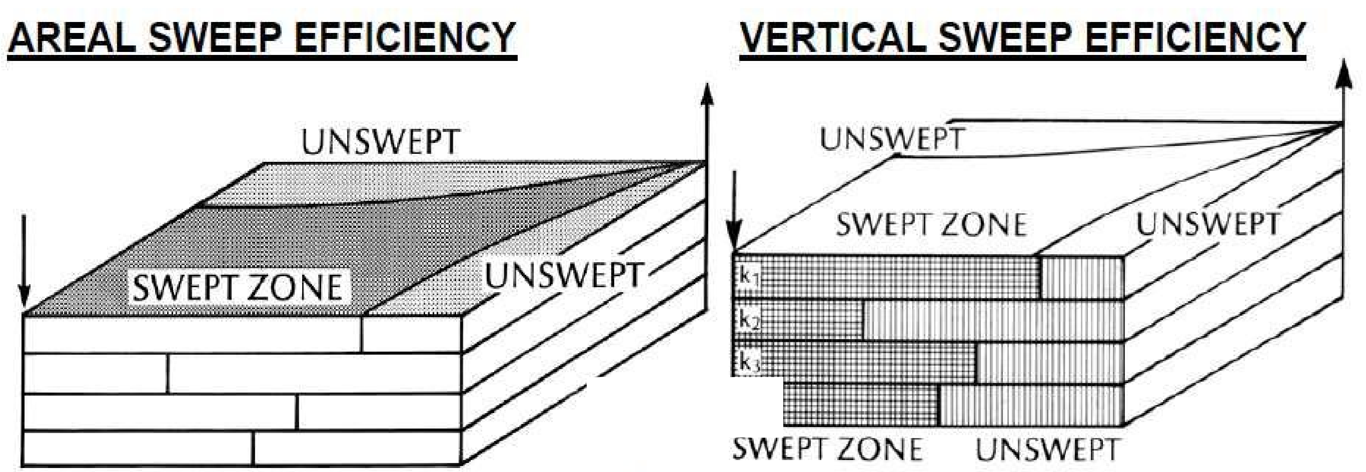
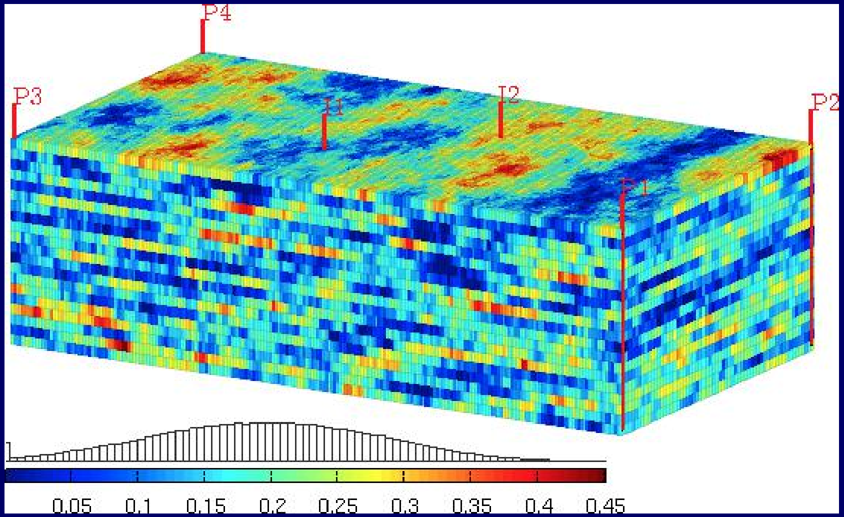
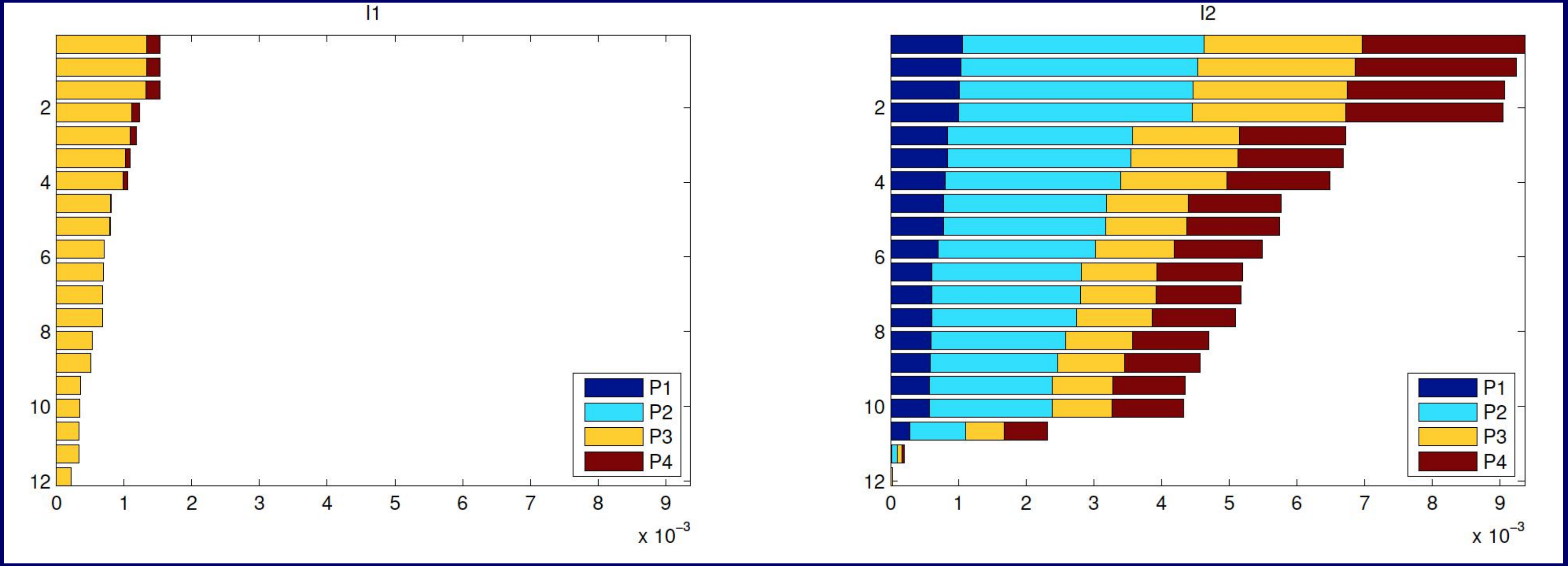


Figure 1

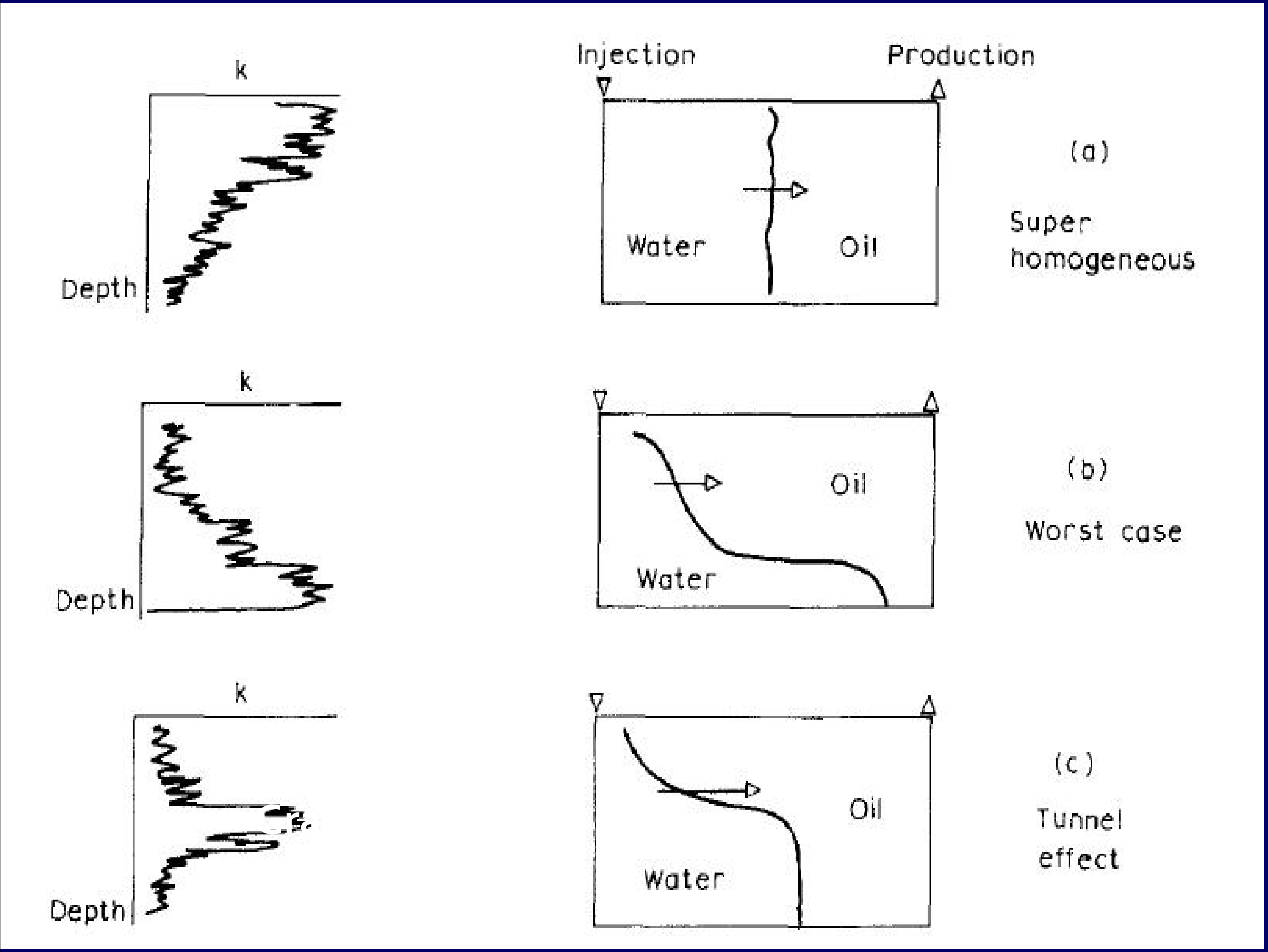
Well Injection and Production allocation factors



Porosity and well positions for a model consisting of subset of the Tarbert formation in Model 2 from the 10th SPE Comparative Solution Project



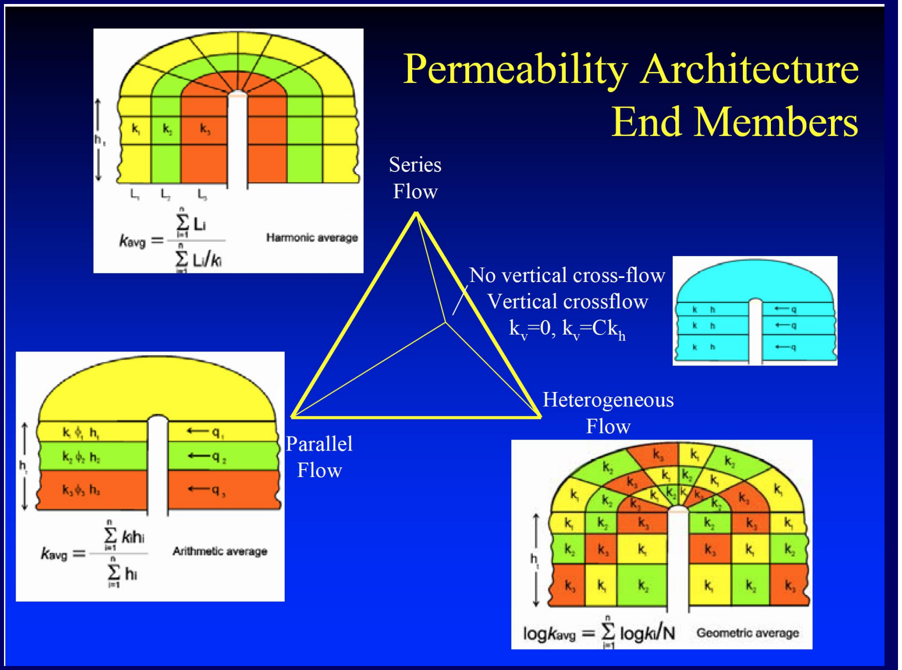
Impact of Permeability distribution across a continuous reservoir section on Displacement Efficiency

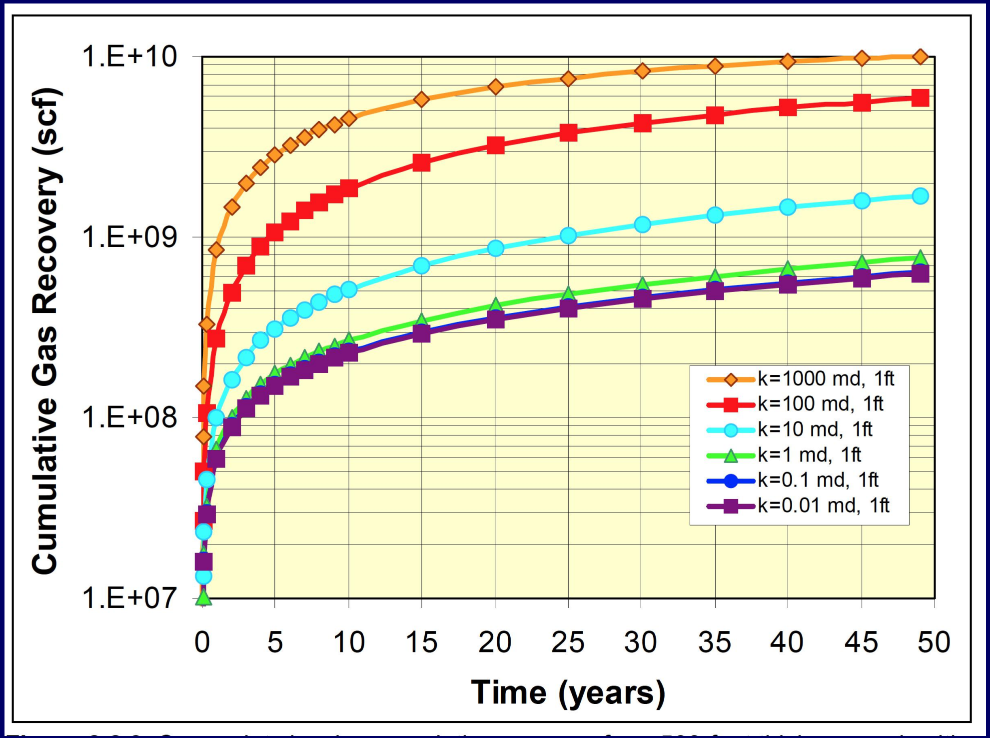


The majority of the injected water enters at the base, this leads to premature breakthrough.

The Practice of Reservoir Engineering – L. P. Dake - 2001

Heterogeneous K-Well Production allocation





A.P. Byrnes, et al

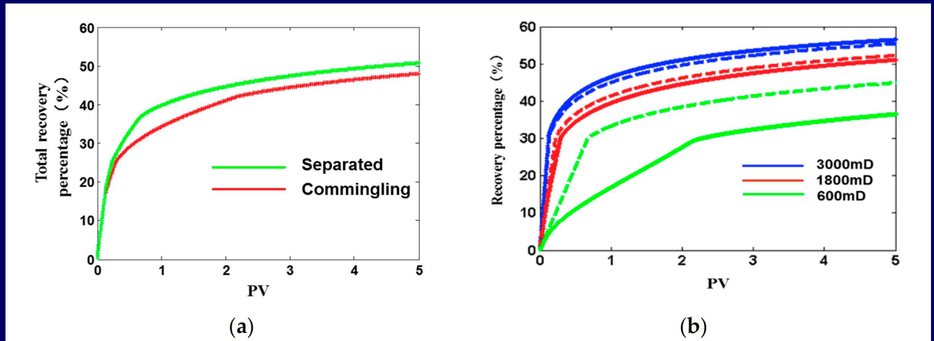


Figure 6. Comparison of recovery percentage in the reservoir ranging from 0 to 5 PV (**a**) separated and commingling production; (**b**) each different permeability layer (solid line, commingling production; dotted line, separated production).

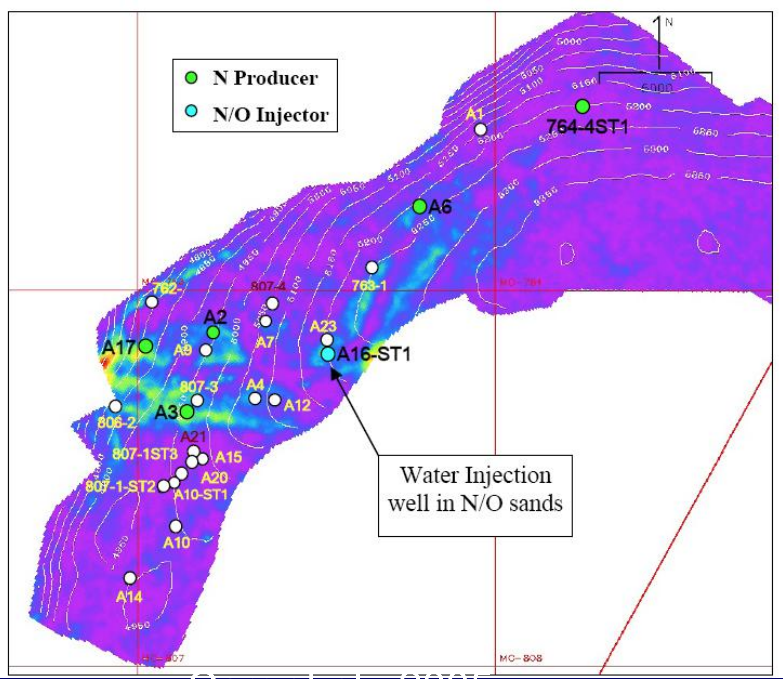
F. Shen, et al., 2018, Energies

Cross-plot showing the dependence of cumulative gas on the vertical permeability (k_v) for a reservoir with 0.01 md and a 1-ft thick bed of 100 md, $P_{initial}$ =450, BHP=50 psi.

Zonation for Development

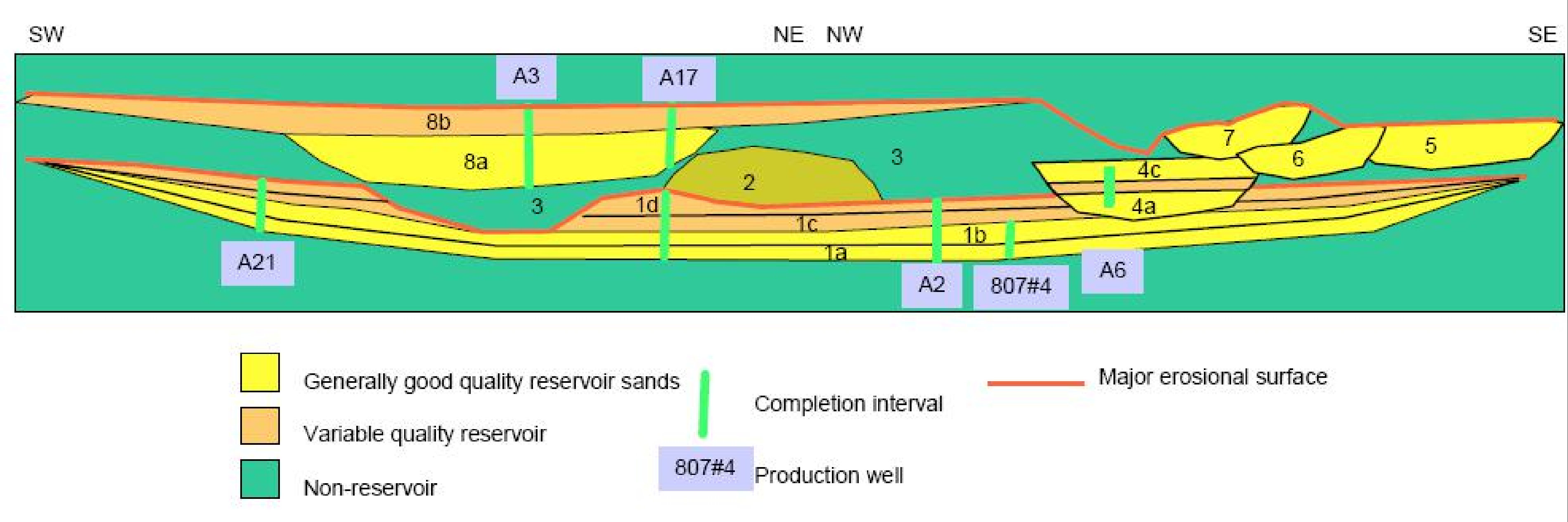
- Different injection patterns and well pattern for reservoirs with different properties
- The different layers in one development zone should have similar reservoir and fluid properties, e.g. similar permeability and pressure
- Each development zone should have good barriers above and below to prevent interference between different zones
- Injection and production allocation for different layers with different properties

Commingled or Separated Production

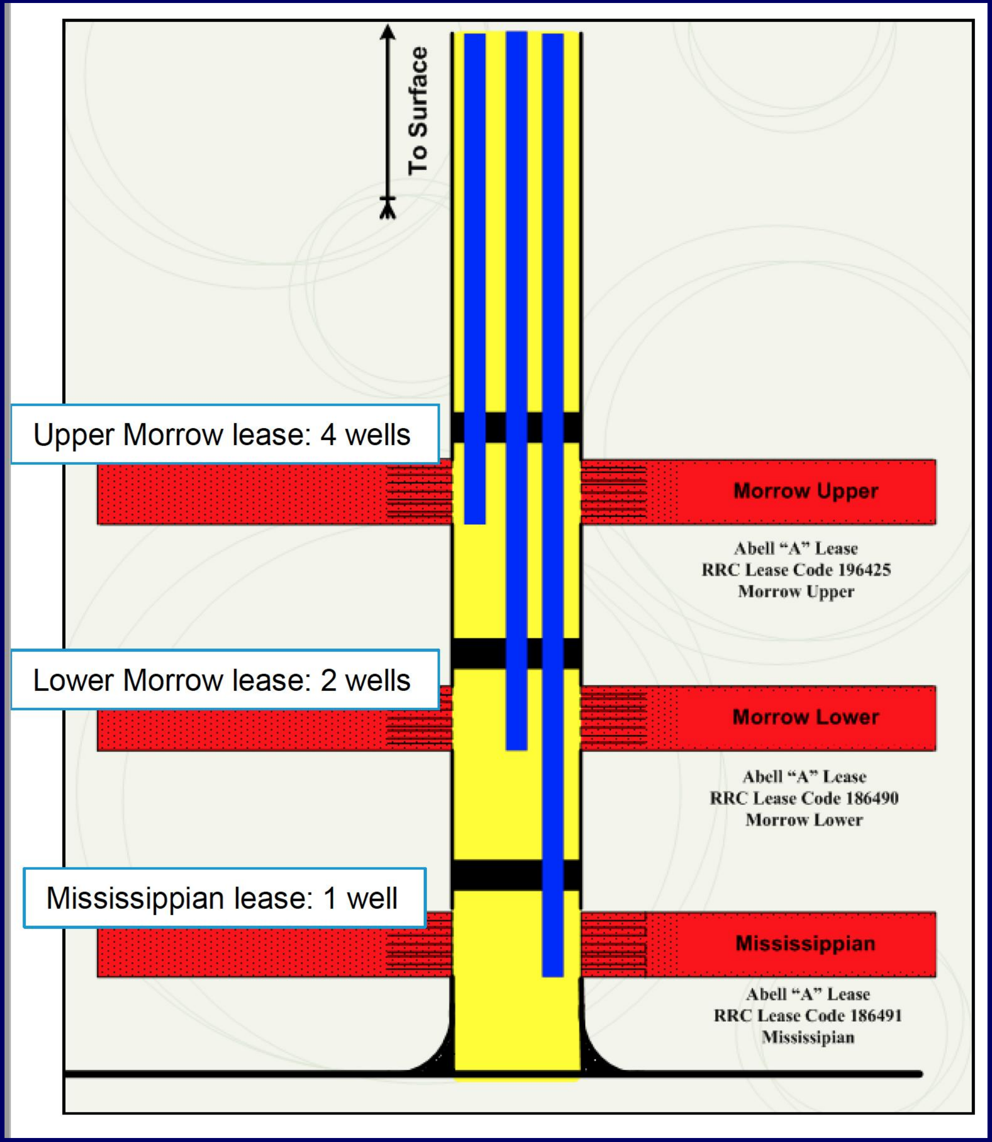


Carr et al., 2005

N/O sand structure map (Weiland, 2008) and cross-section (Reynolds, 2000)



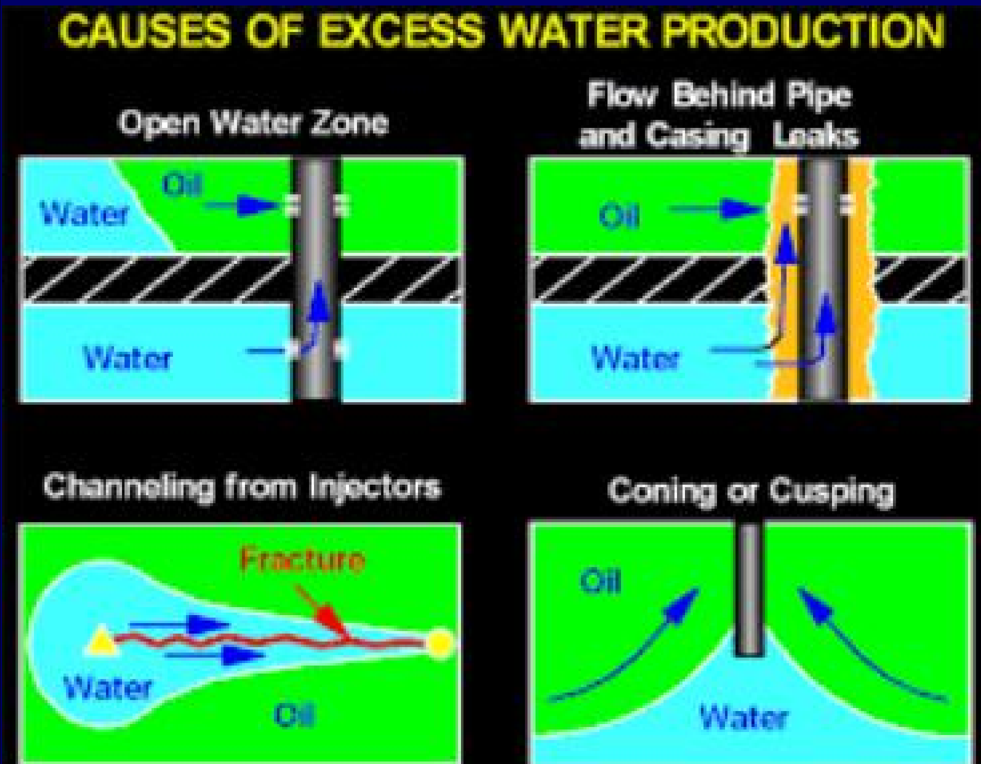
One Well – Three Reservoirs and Different Leases

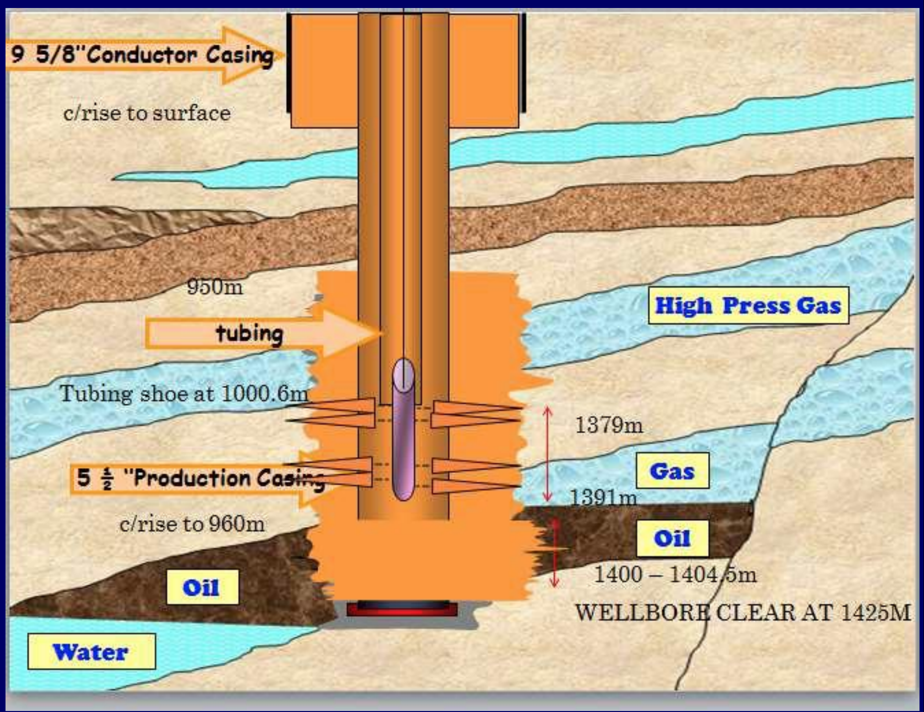


3 tubing strings producing from 3 different reservoirs:

•The Texas RRC requires operators to file production separately for each reservoir. The allocation is performed separately for each oil reservoir. There can be different wells associated with the lease-level production for each reservoir

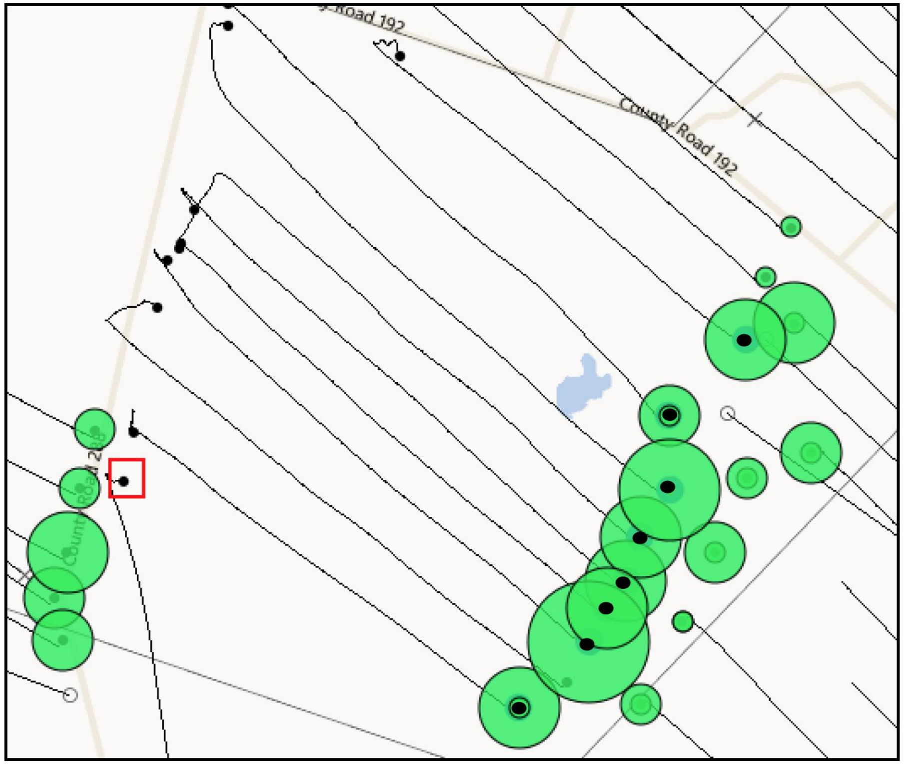
Commingled Production



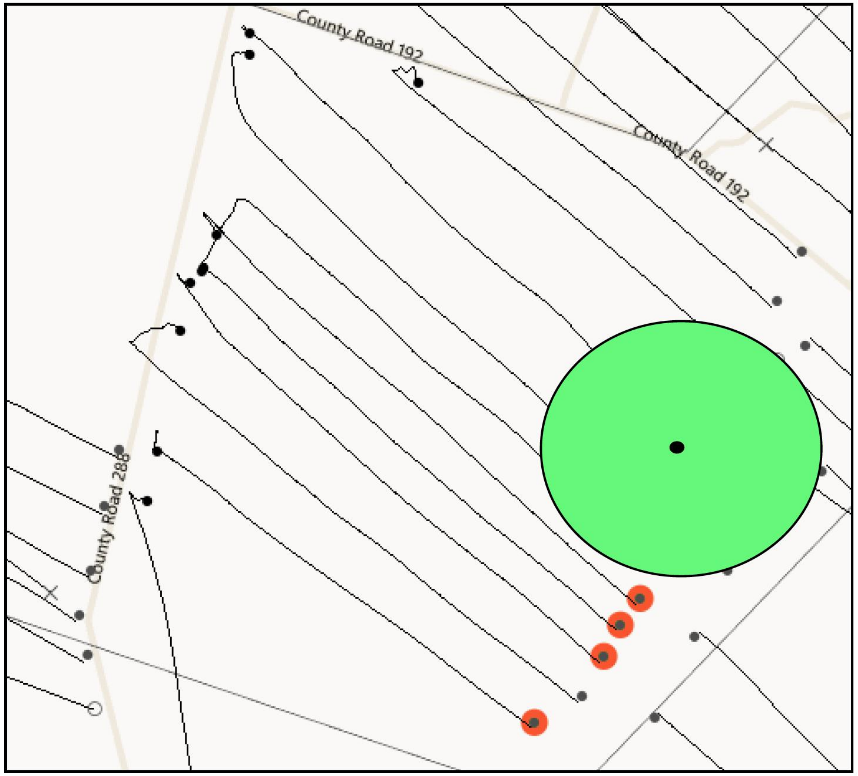


Map view of Allocated vs Unallocated Production

Allocated Production



Unallocated Production



The 9 Wells producing on the Cusack Ranch Lease have a green circle with black dot at the bottom hole location of each well. The allocated cumulative volume for each well is shown by the size of the circle. The total of the Allocated Volumes is 1,536,395 BO matching the total volume of the unallocated production.

All 1,536,395 BO reported for the Cusack Lease is reported to a single API number. Bubble mapping will assign all volume to the single "Primary API number" associated with the lease.

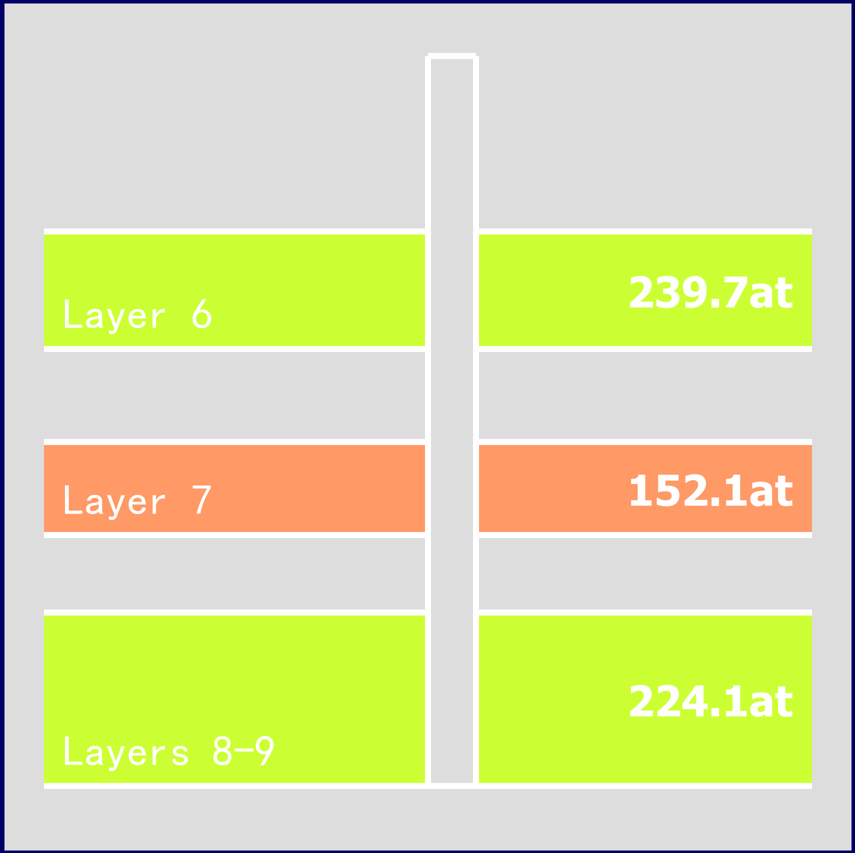
Development Zonation Adjustment

One development system in 1973

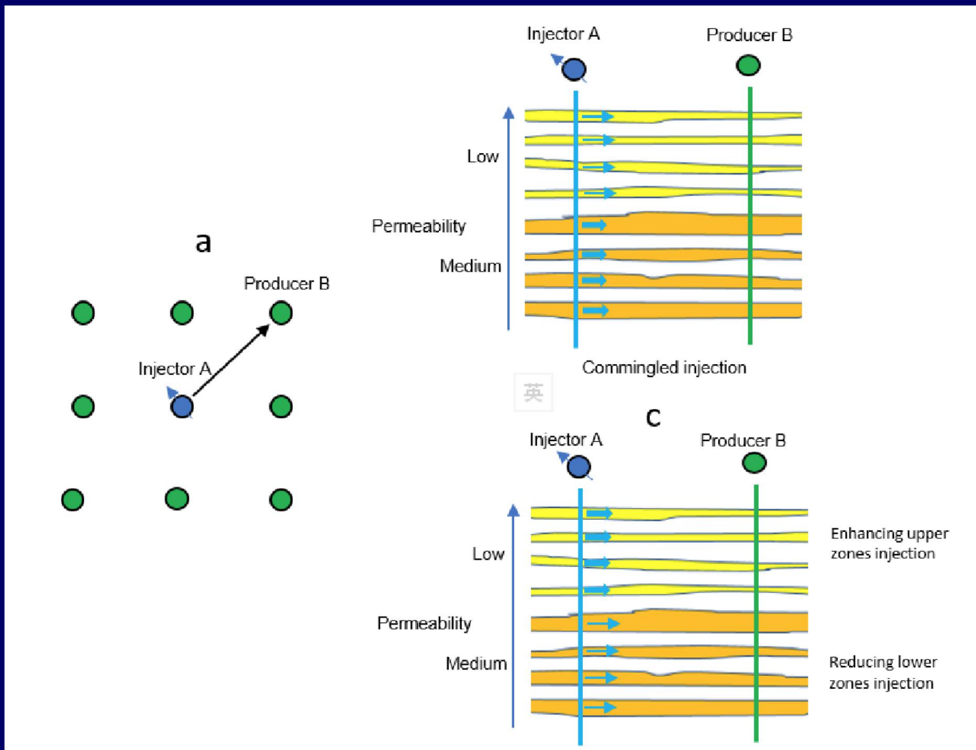
1980:
Oil production dropped 2t/d,
fw=95%, Pf:200 a t

Adjustment:
separation and producing
Oil production increased to 97.8t/d,
fw=2.2%

Question:
Which layer has the increased production?



Development Adjustment for Multilayer payzones



- a. Inverted nine-spot pattern;
- b. commingled water injection resulting in
- Nonuniform injection between upper and lower Intervals;
- c. zonal water injection resulting in enhanced injection in the upper interval and reduced injection in the lower interval

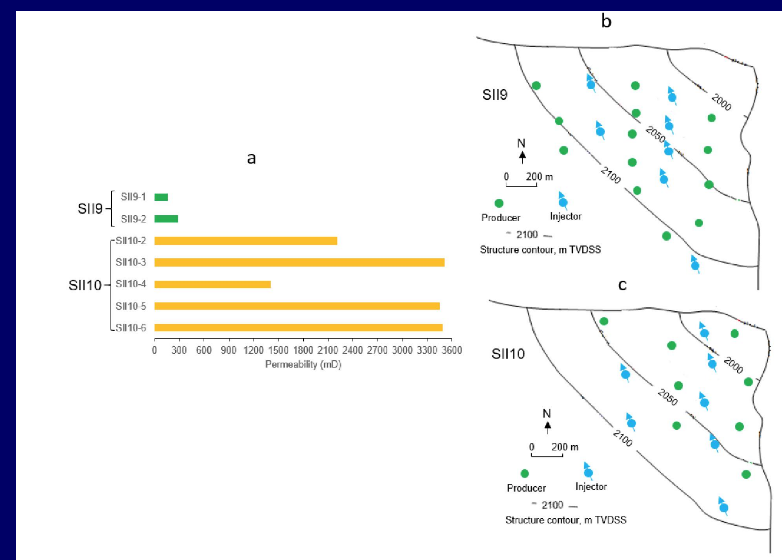


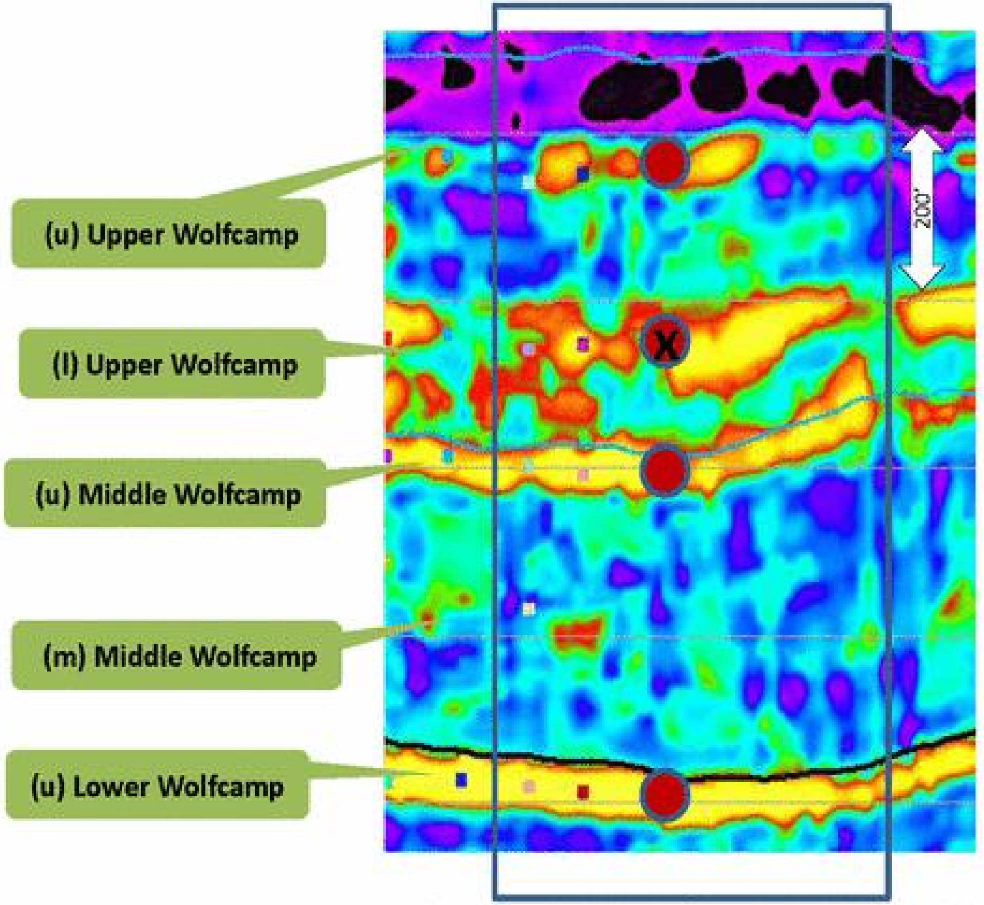
Figure 10—Diagram showing: a. permeability contrast among sub-units of SII9-10 reservoir; b. well pattern of SII9 after injection-production unit subdivision; and c. well pattern of SII10 after injection-production unit subdivision (Modified from Wang, 2011).

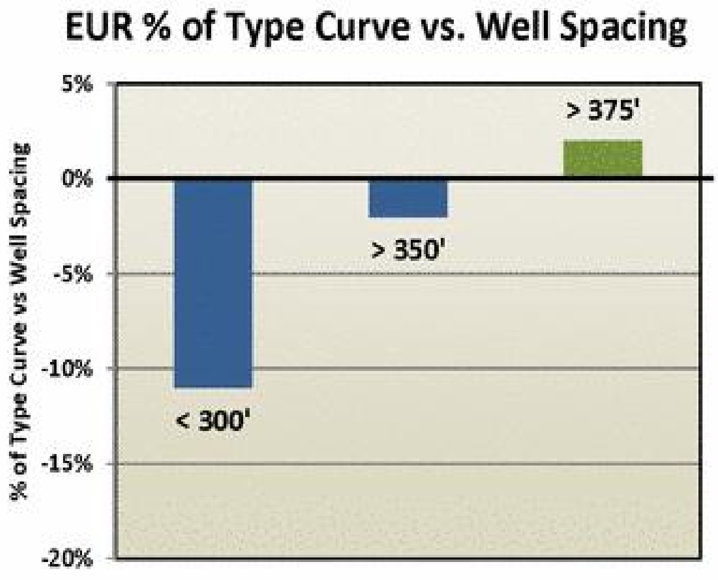
Lu and Xu, 2017, SPE-186431

Well Spacing Rules

Well Spacing for Horizontal Well

Vertical spacing of horizontal wells needs to be ≥400'

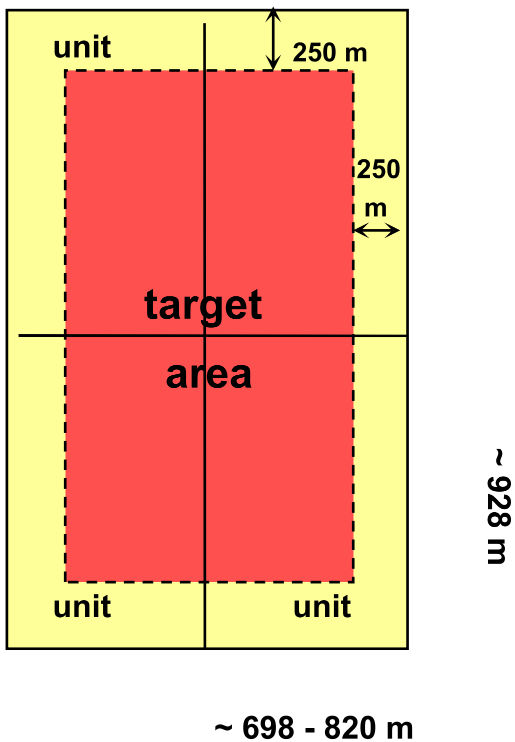




Laredopetro

Normal Well Spacing and Target Areas

GAS WELL SPACING AREA

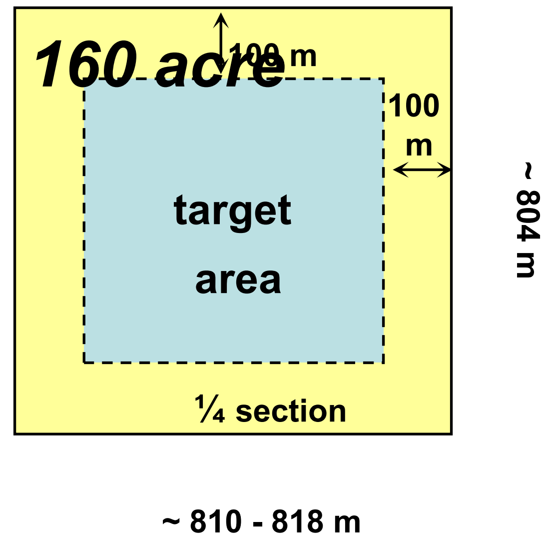


One gas well per pool per

4 units (NTS) or,

1 section (DLS)

OIL WELL SPACING AREA

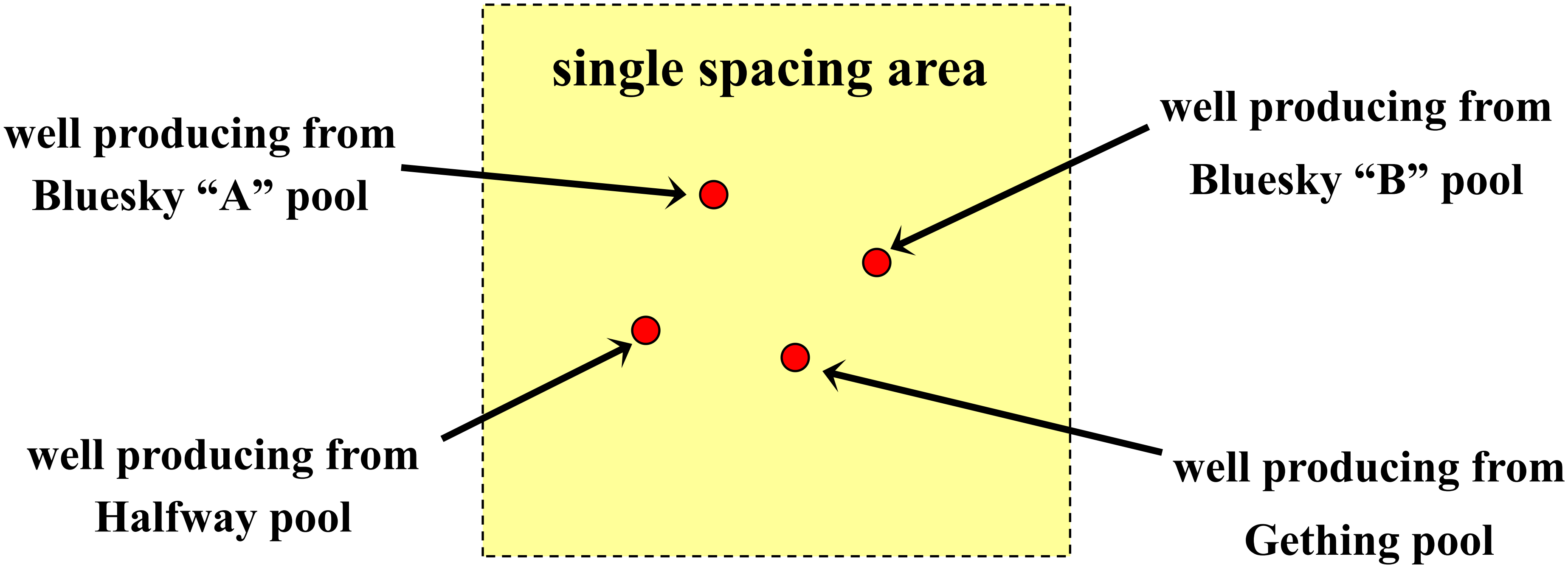


One oil well per pool per

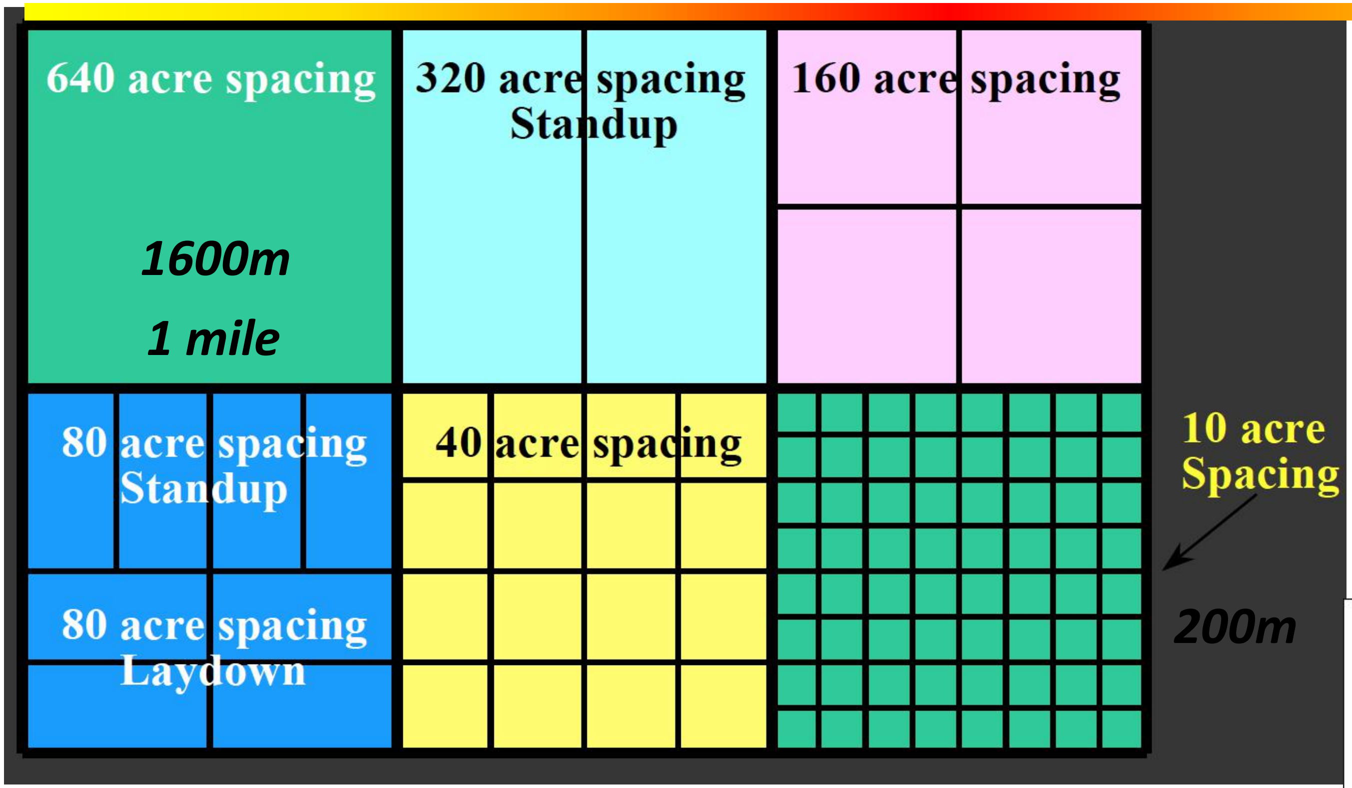
1 unit (NTS) or,

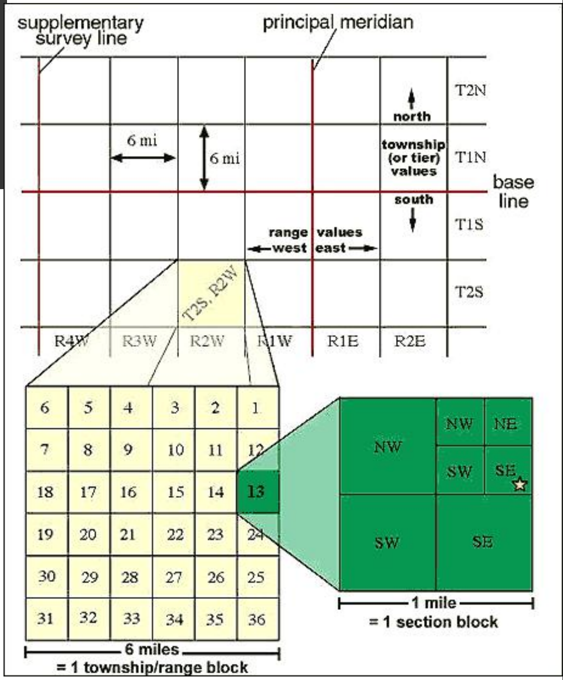
1/4 section (DLS)

Well Spacing is Pool Specific

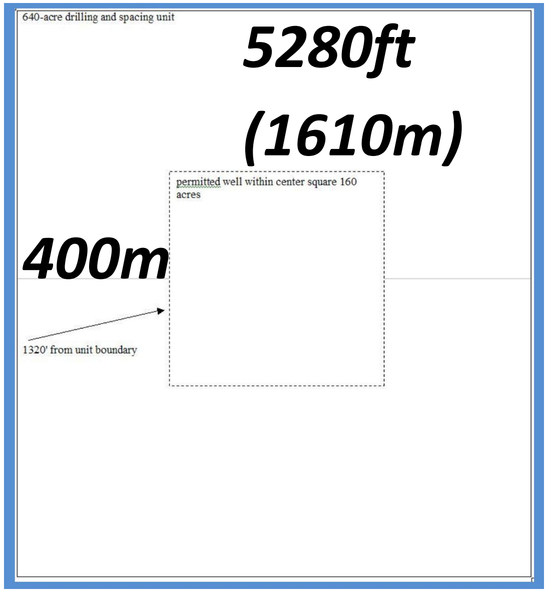


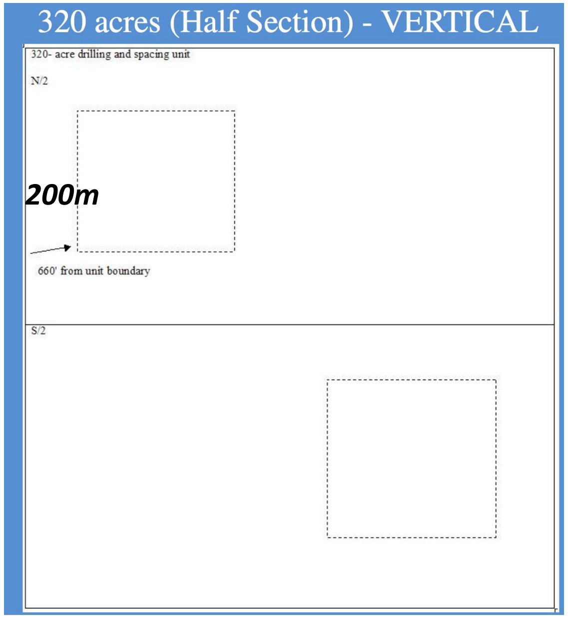
Spacing Patterns

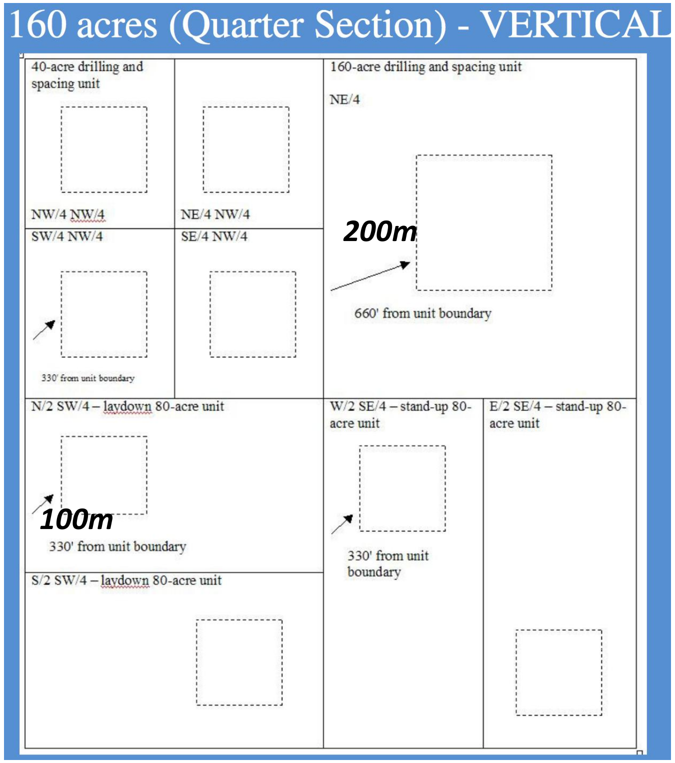




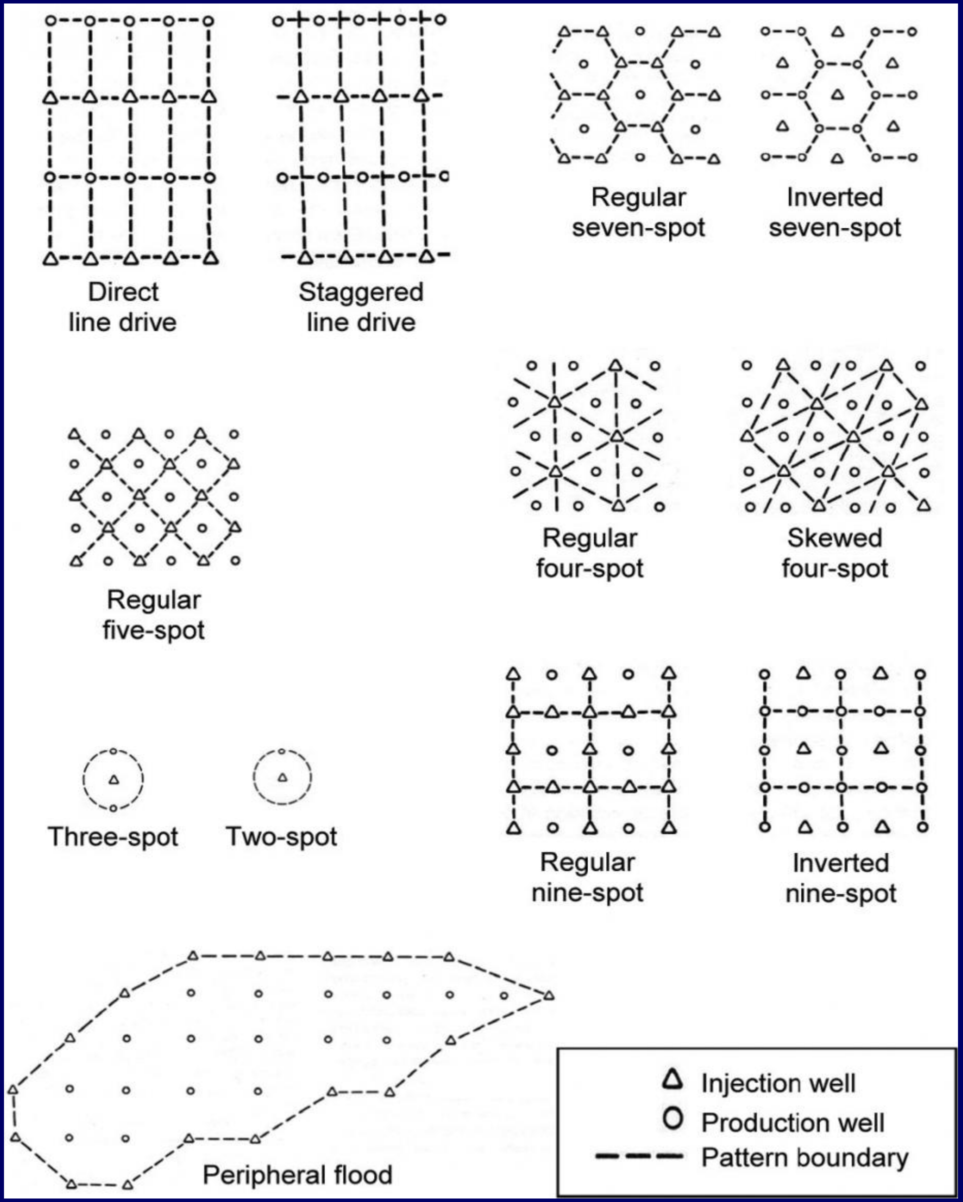
Parameters of Typical Spacing



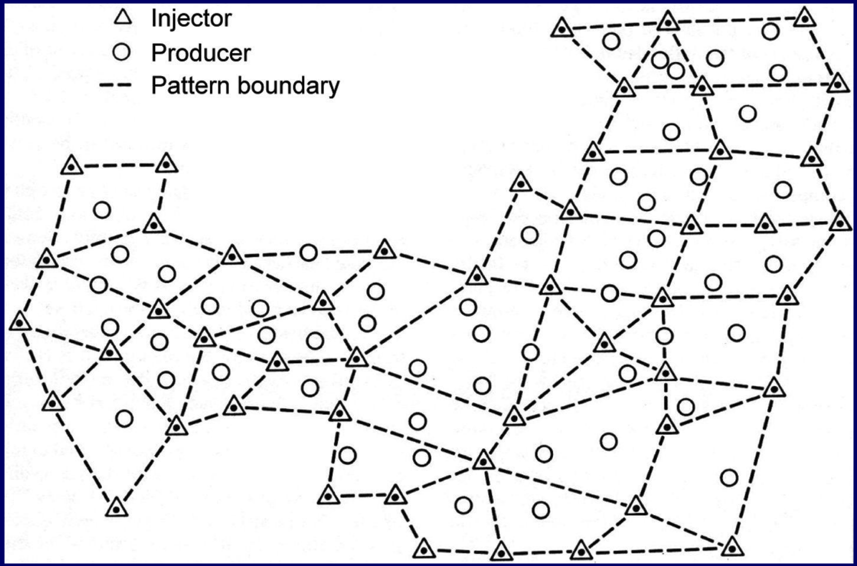




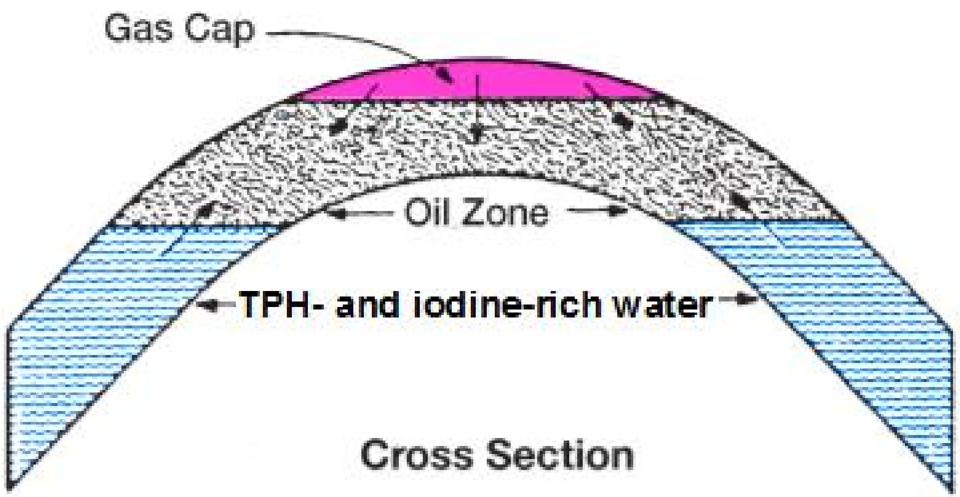
Injector/Producer Well Patterns for Waterflooding

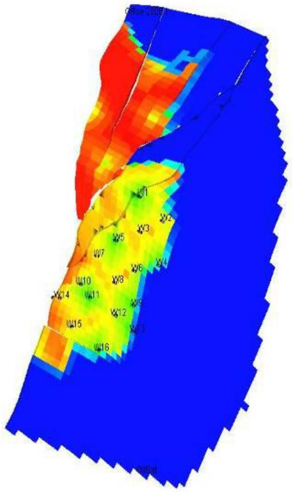


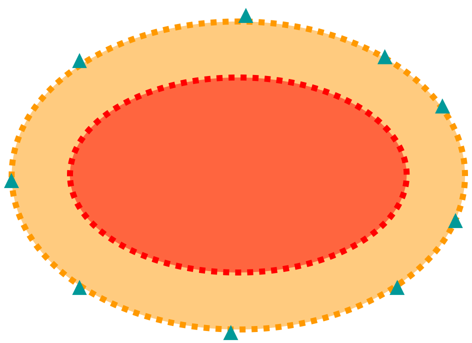
In waterflooding, water is injected into one or more injection wells while the oil is produced from surrounding producing wells spaced according to the desired patterns



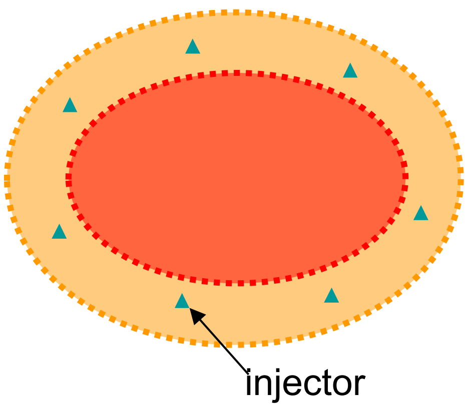
Example-peripheral injection pattern



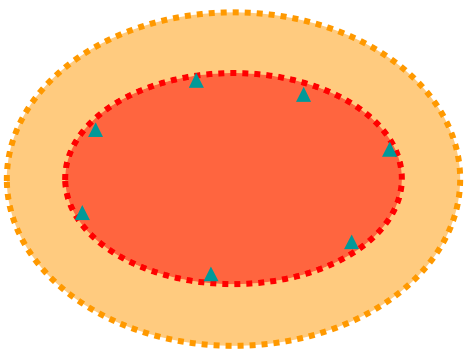




Outside water injection



peripheral water injection



Inner edge water injection

Even water drive, low water cut

No more than 3 line producers effected

Direct line drive

Well distance =a

$$m = 1:1$$

$$F = 2a^2$$

$$S = a^2$$

parameters：

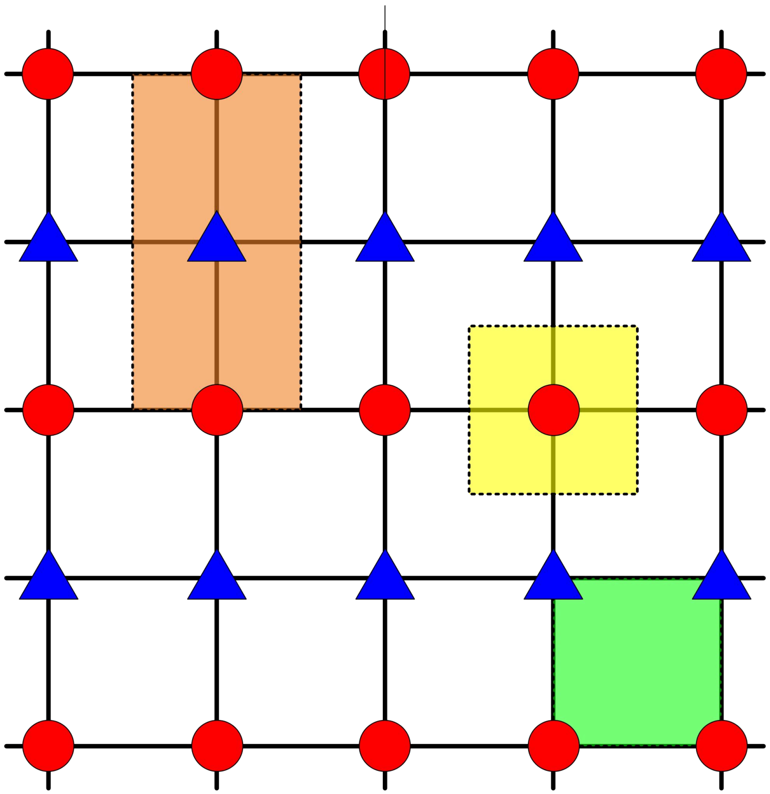
a: well distance

d: distance between lines of injectors and producers

m: producer injector ratio

F: area controlled per injector

S: well density(area per well)



Inverted nine spot

$m = 3:1$

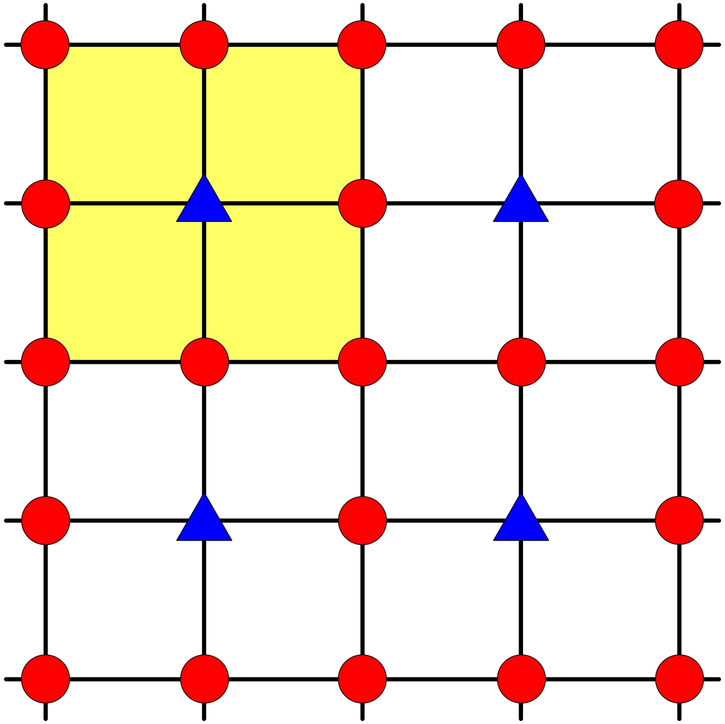
$F = 4a^2$

$S = a^2$

Applied in early period

Less injectors

Flexible to adjustment

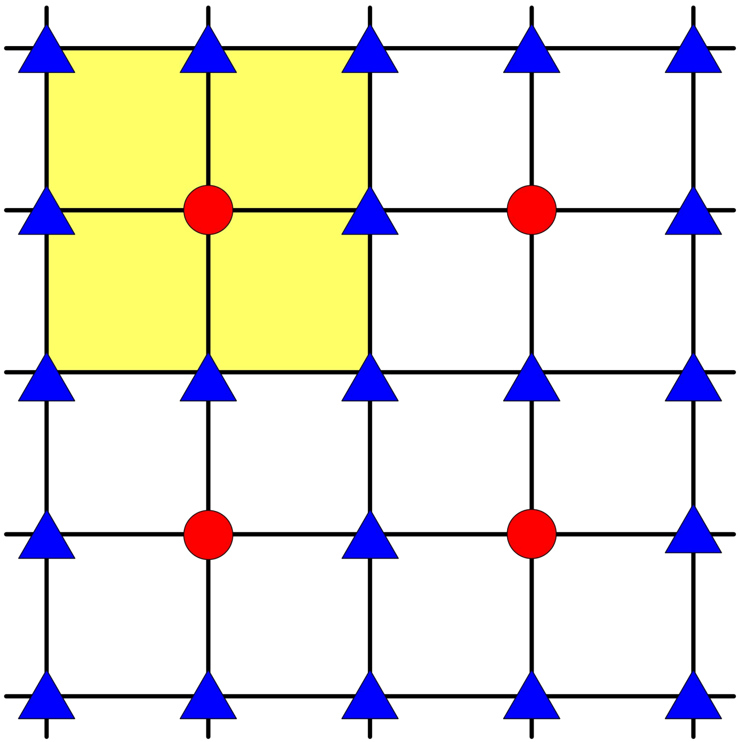


Nine spot:

$$m = 1:3$$

$$F = \frac{4}{3}a^2 = 1.333a^2$$

$$S = a^2$$



Applied in later period

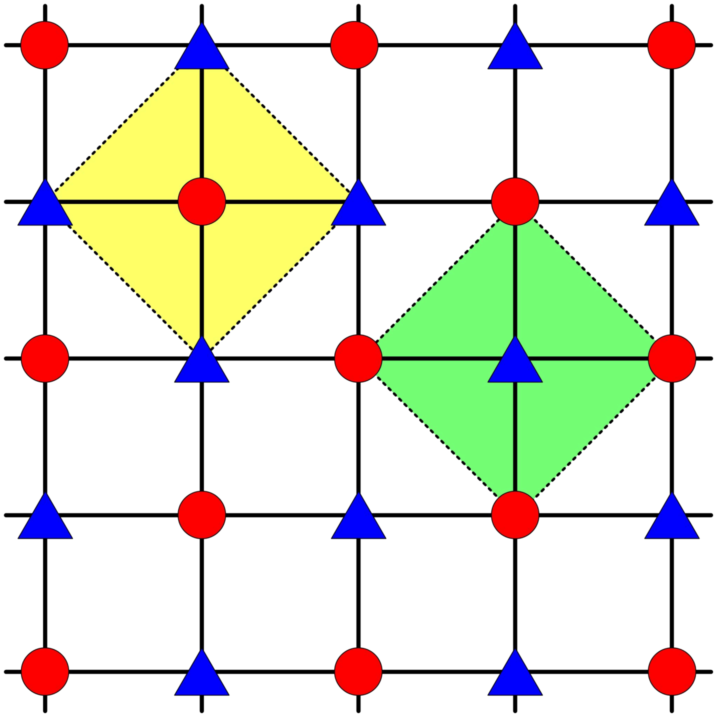
For reinforced liquid production

Five Spot

$$m = 1:1$$

$$F = 2a^2$$

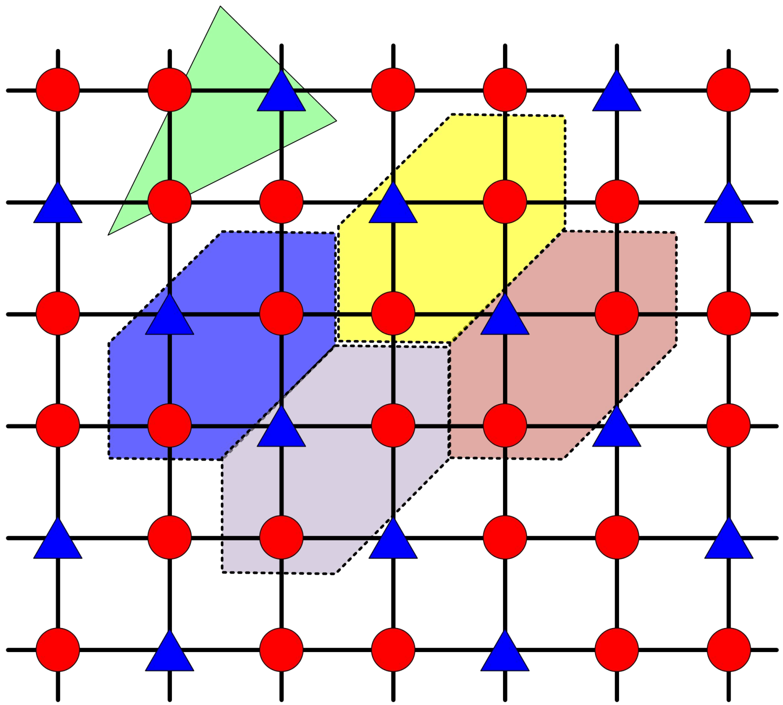
$$S = a^2$$



For five spot well pattern, normal and inverted well arrangements are the same.

For reinforced injection and production

Inverted square seven spot (skewed four spot)

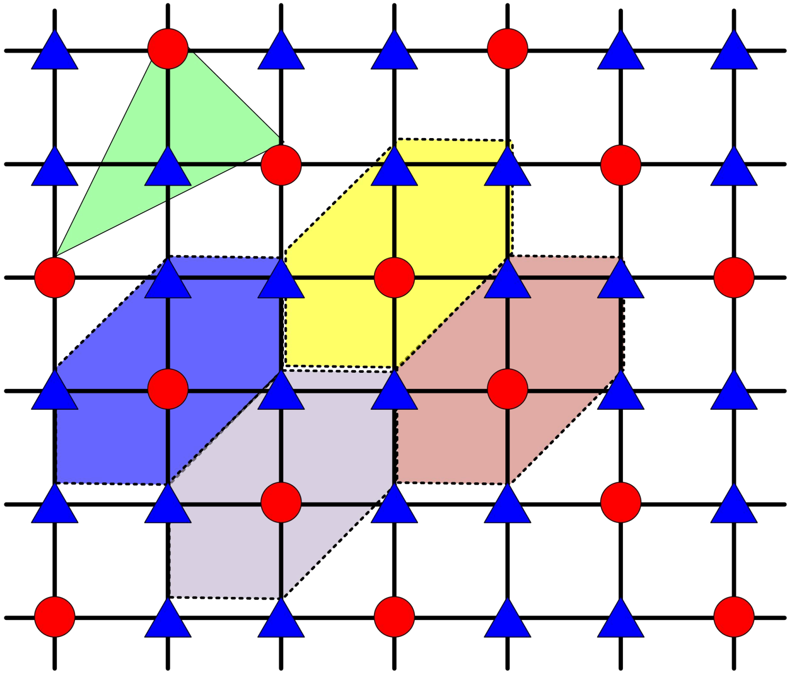


$$m = 2:1$$

$$F = 3a^2$$

$$S = a^2$$

Square seven spot（inverted skewed four spot）

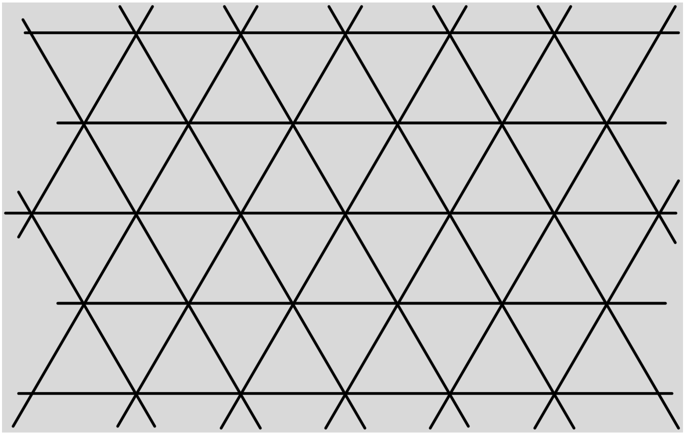


$$m = 1:2$$

$$F = 1.5a^2$$

$$S = a^2$$

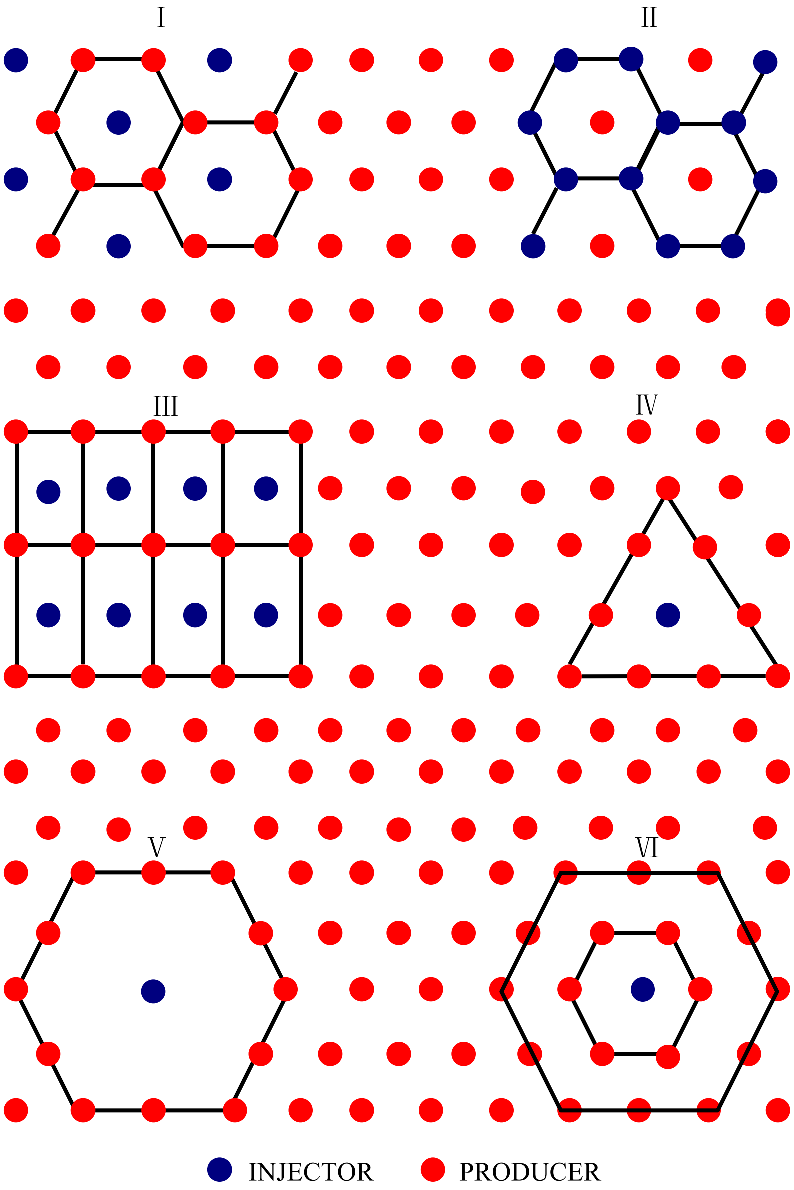
Triangular well pattern



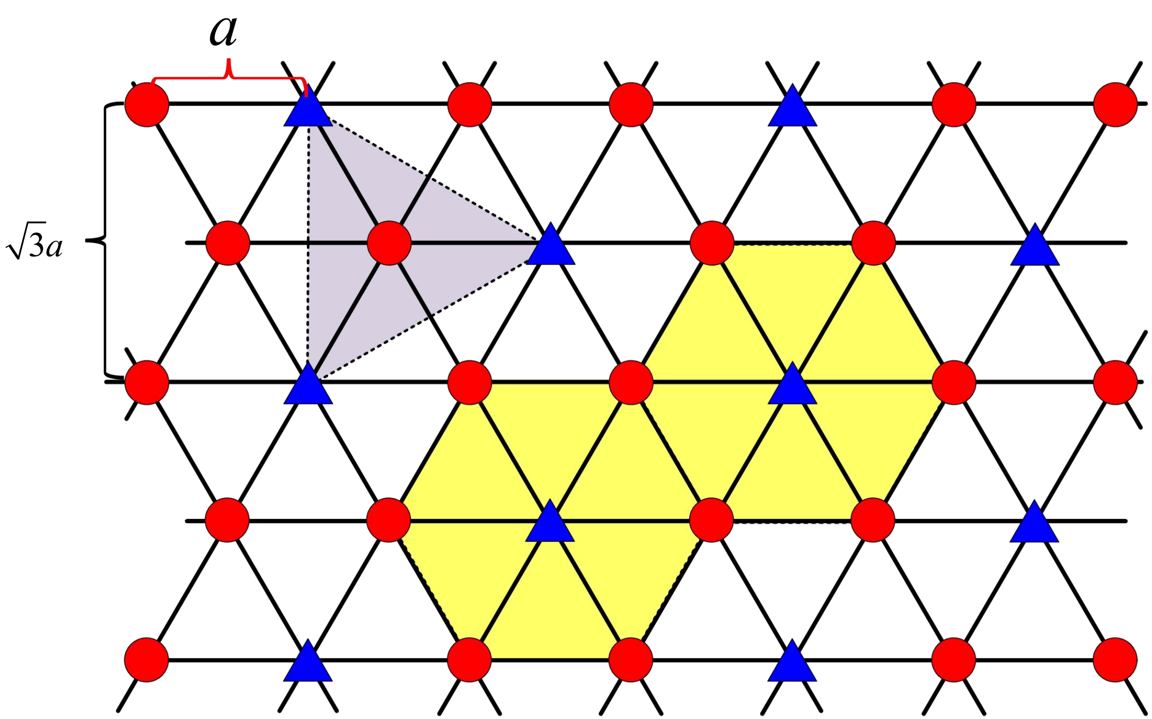
- I —Inverted seven spot
- II —Seven spot
- III —Staggered line drive
- IV, V, VI—Honeycomb well pattern

Question:

Alternative patterns for I and II?



Inverted seven spot（four spot）

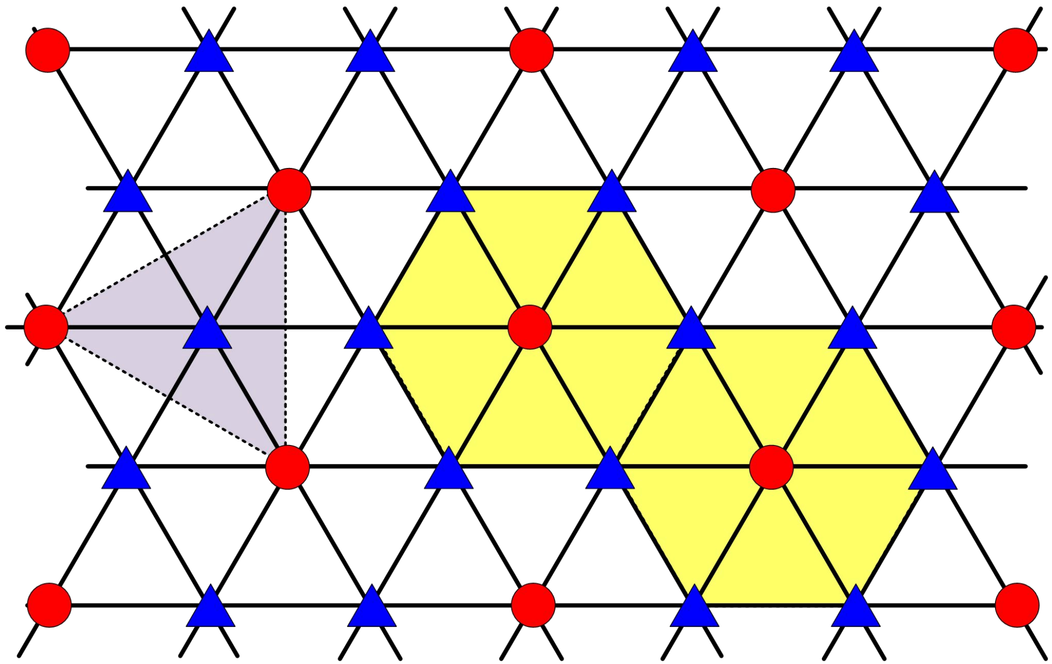


$$m = 2:1$$

$$F = \frac{3\sqrt{3}}{2}a^2 = 2.598a^2$$

$$S = \frac{\sqrt{3}}{2}a^2 = 0.866a^2$$

Seven spot(inverted four spot）

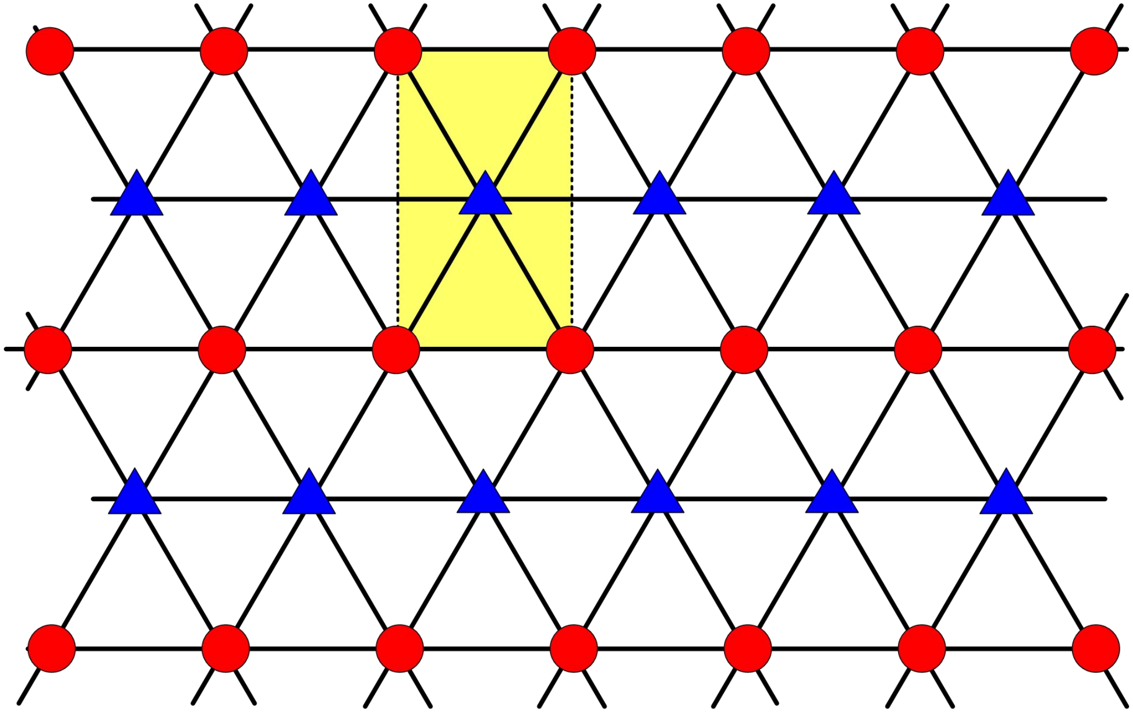


$$m = 1:2$$

$$F = \frac{3\sqrt{3}}{4}a^2 = 1.299a^2$$

$$S = \frac{\sqrt{3}}{2}a^2 = 0.866a^2$$

Staggered line drive well pattern

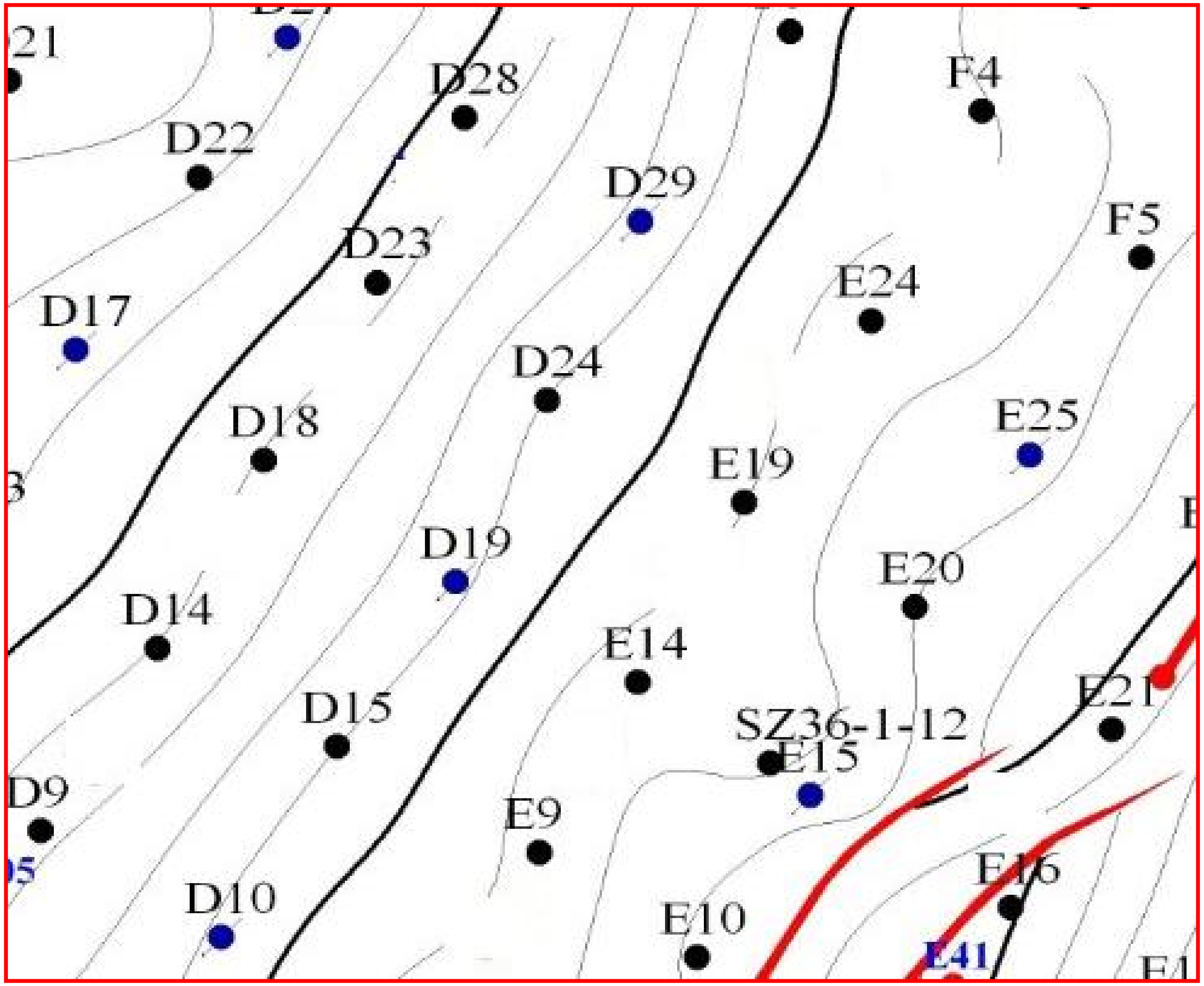


$m = 1:1$

$F = \sqrt{3}a^2 = 1.732a^2$

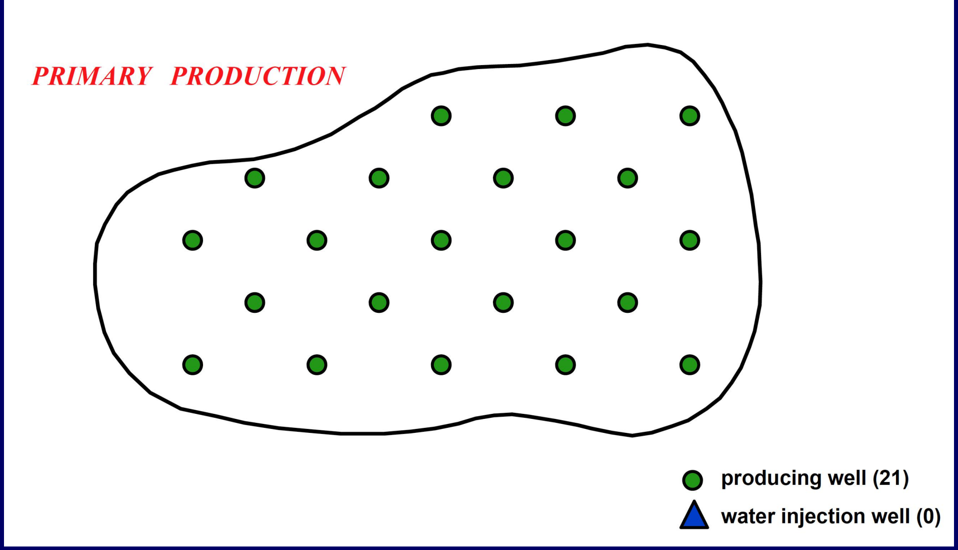
$S = \frac{\sqrt{3}}{2}a^2 = 0.866a^2$

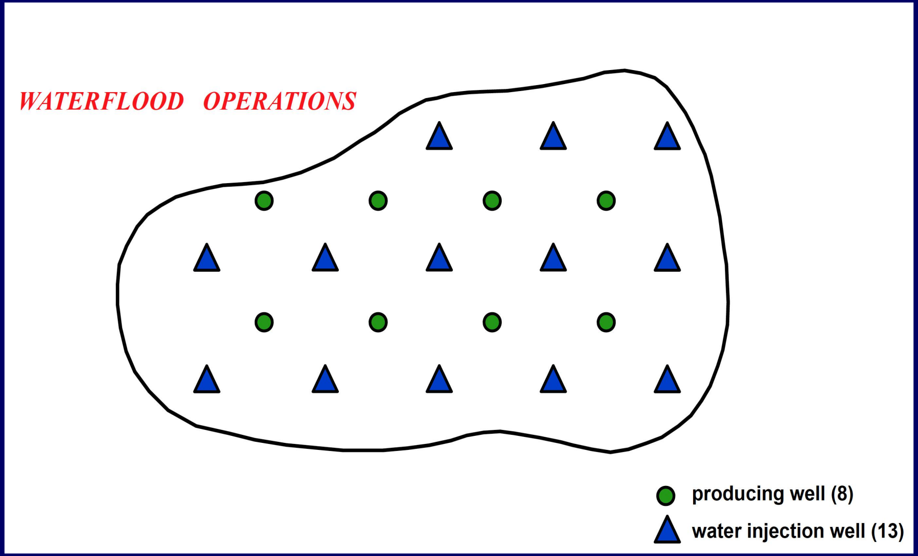
Question-Well Pattern?

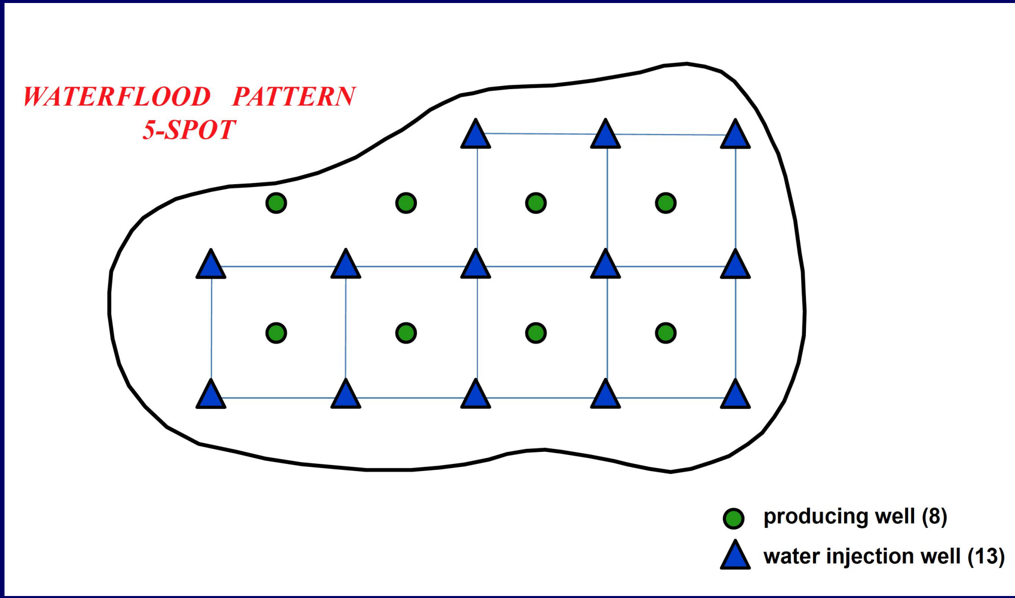


Black dot-production well; Blue dot-injection well

Waterflood Design



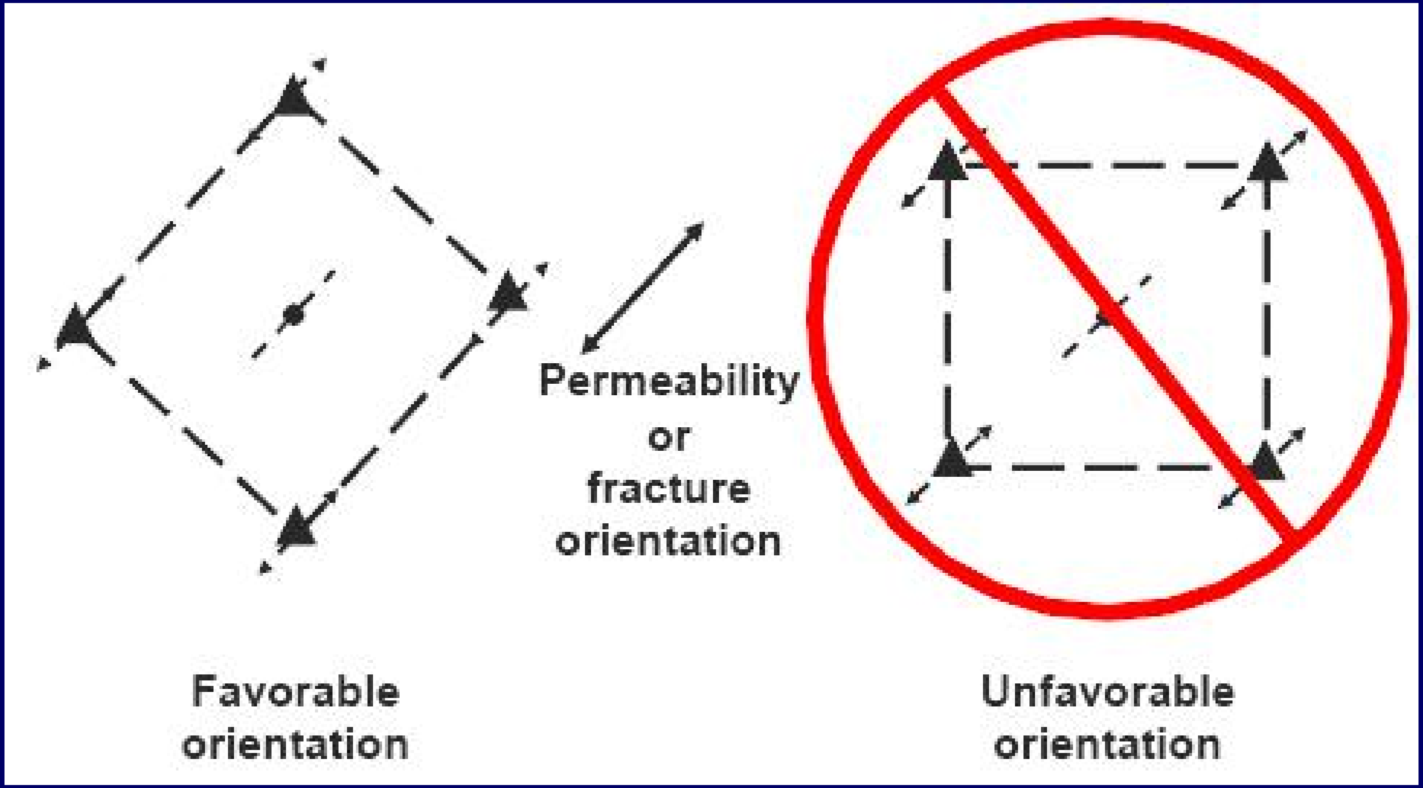


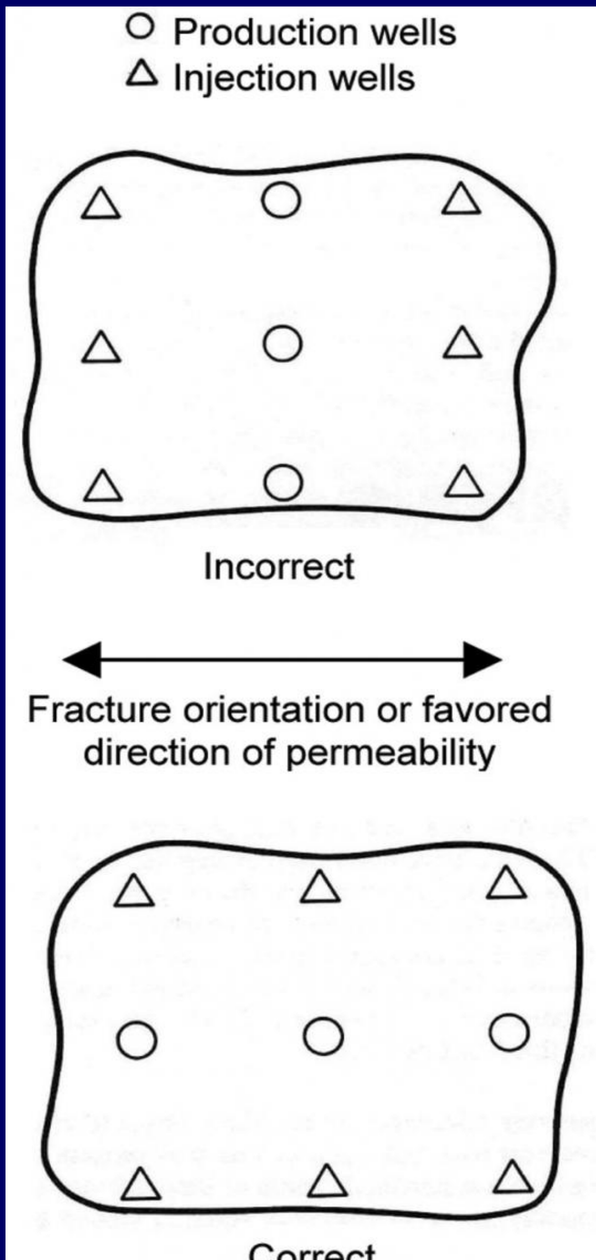


Factors Affecting Selection of Waterflood Pattern

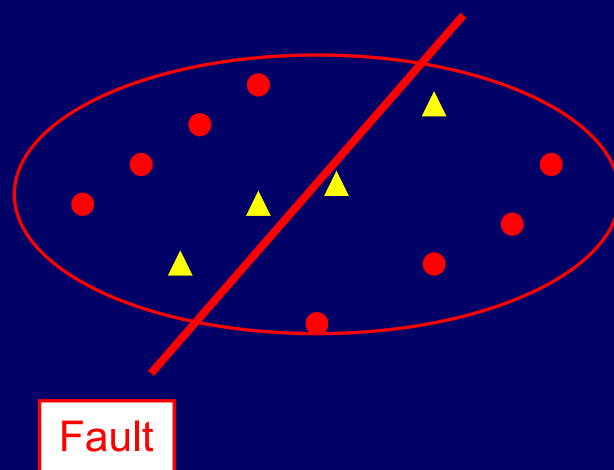
1. Know the geology,reservoir properties and drive mechanism first.
2. Provide desired oil production capacity.
3. Provide sufficient water injection rate to yield desired oil productivity.
4. Maximize oil recovery with a minimum of water production.
5. Take advantage of known reservoir nonuniformities - i.e., directional permeability, regional permeability differences, formation fractures, dip, etc.
6. Be compatible with the existing well pattern and require a minimum of new wells.
7. Be compatible with flooding operations of other operators on adjacent leases.
8. Consider the future adjustment at the beginning of design.

Pattern Orientation





the orientation of the rows of producers and injectors must take into account any permeability anisotropy and natural-fracture orientation



Correct?

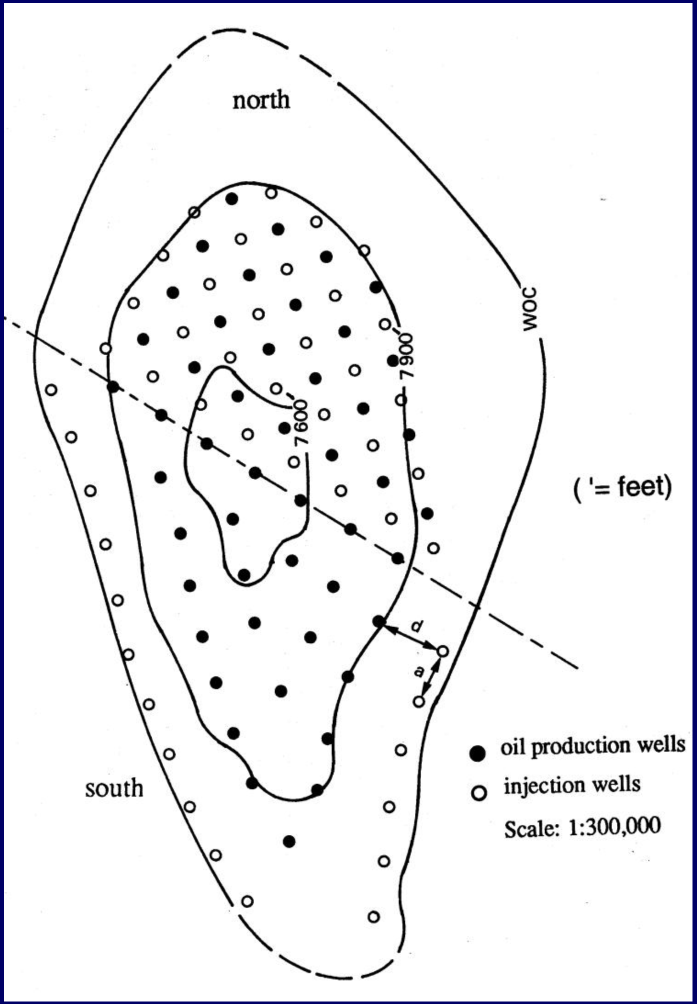
Example of Well Sites on a Field

- A large carbonate field in Abu Dhabi.
- Wide variation in petrophysical properties from the south to the north of the structure.
- South:

h = 90m, k = 400mD -> peripheral flood

- North:

h = 30m, k = 50mD -> five-spot pattern

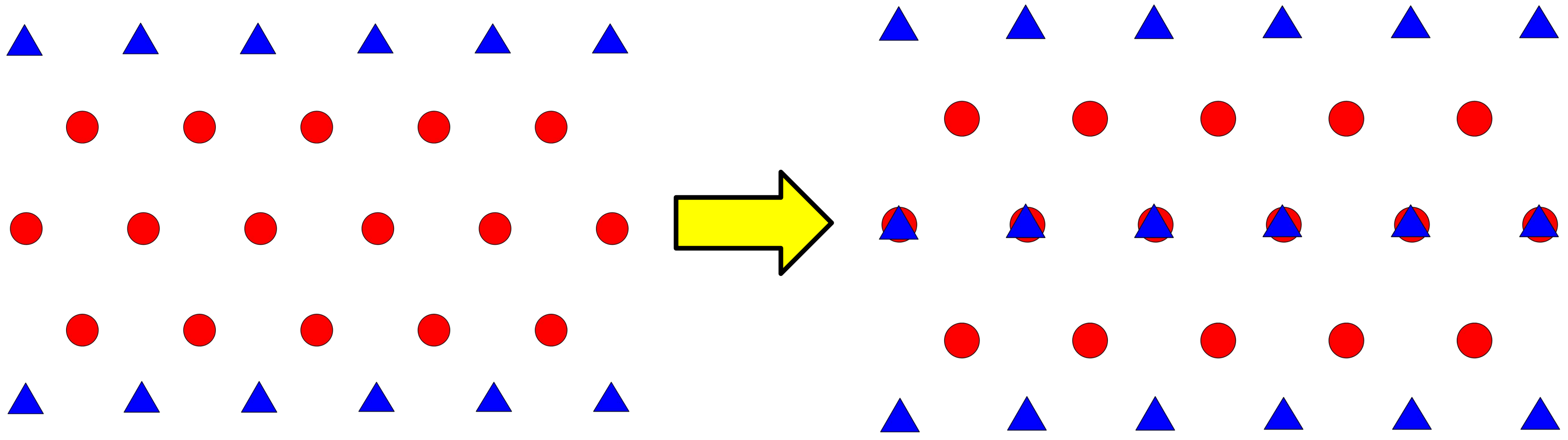


(Basics of Reservoir Engineering, R. Cosse)

Well Pattern Adjustment and Conversion

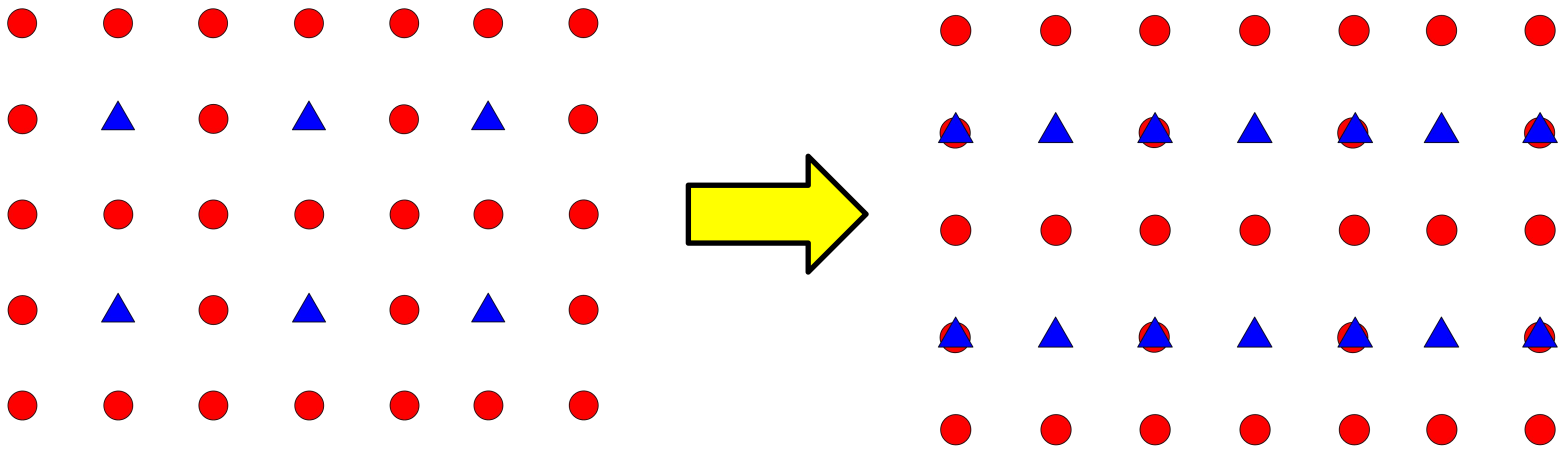
With the further development and recognition of reservoir heterogeneity , well pattern adjustment and reduced well space will be taken, with the recombining of oil layers.

Line drive changed to staggered line drive pattern

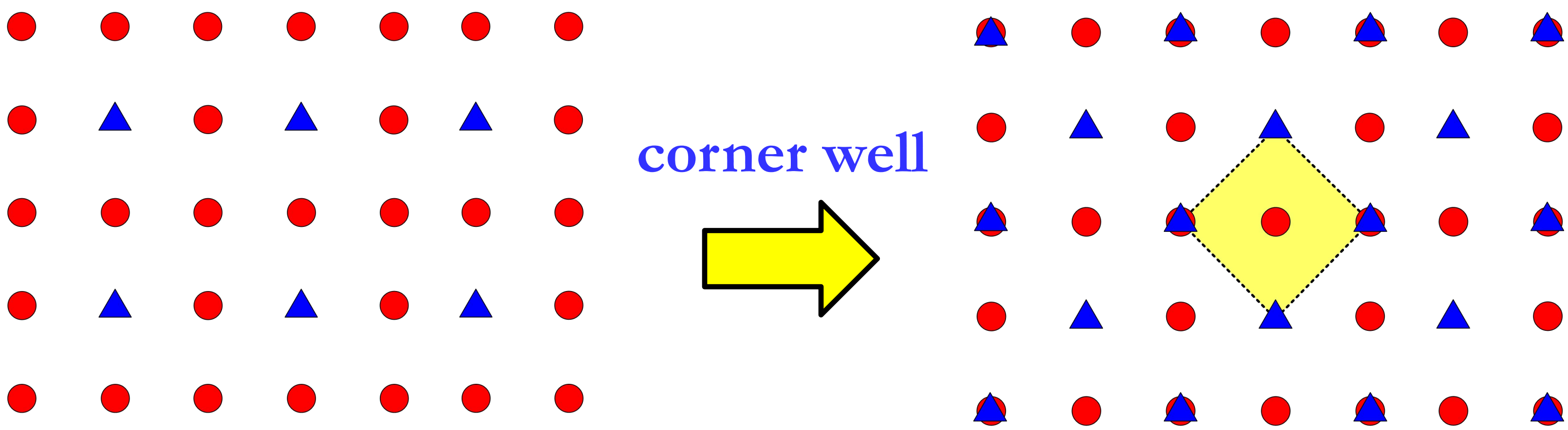


Well Pattern Adjustment and Conversion

Inverted nine spot changed to direct line drive

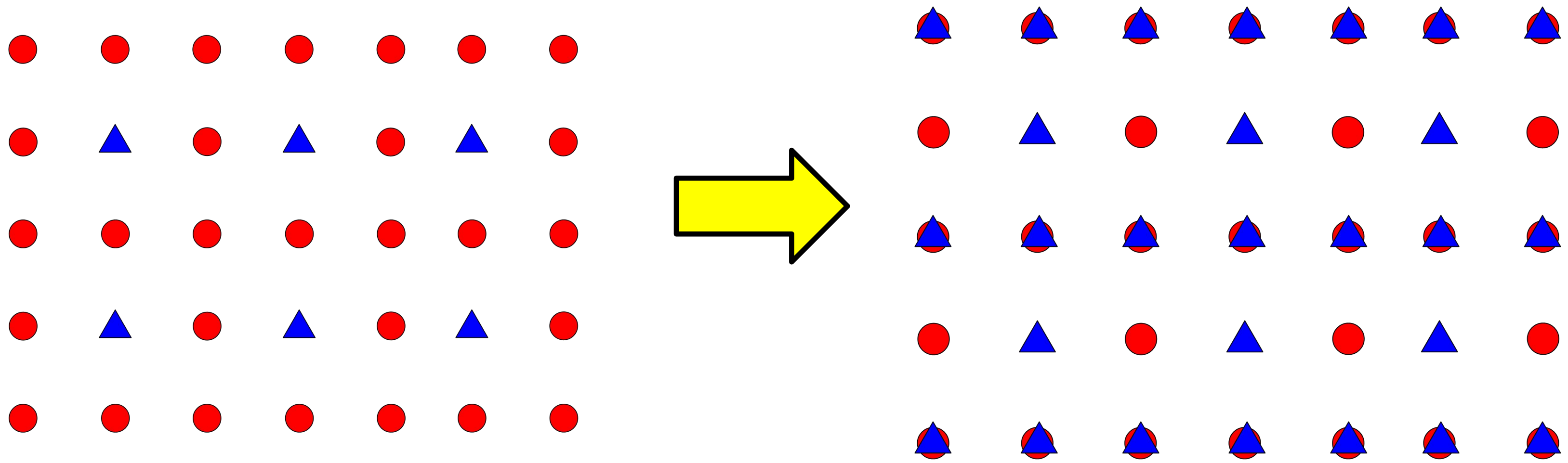


Inverted nine spot changed to five spot



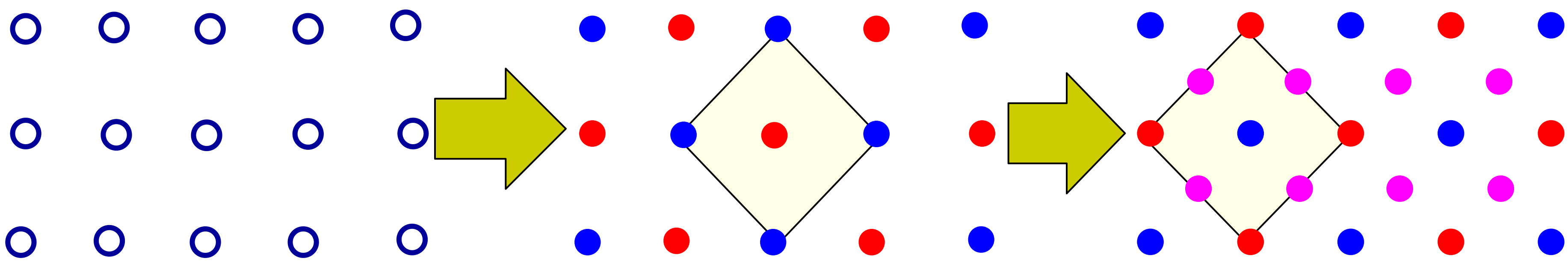
Well Pattern Adjustment and Conversion

Inverted nine spot changed to normal nine spot



Well Pattern Adjustment and Conversion

- Square well pattern



● Producer ● Injector ● infill producer

Cumulative Waterflood Recovery

$$Np \propto N * E_A * E_V * E_D$$

N_P = Cumulative Waterflood Recovery, BBL.

N = Oil in Place at Start of Injection, BBL.

E_A = Areal Sweep Efficiency, Fraction

E_V = Vertical Sweep Efficiency, Fraction

E_D = Displacement Efficiency, Fraction

Waterflood Recovery Factor

$$\frac{N_p}{N} = RF$$

$$RF \propto \underbrace{E_A * E_V}_{E_{VOL}} * E_D$$

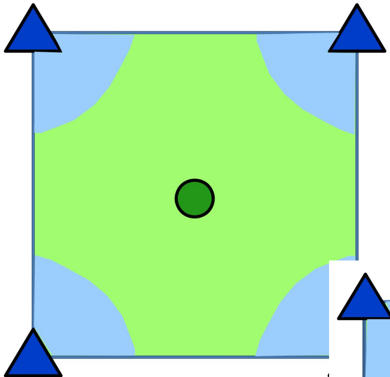
E_A = f (MR, Pattern, Directional Permeability, Pressure Distribution, Cumulative Injection & Operations)

E_V = f (Rock Property variation between different flow units, Cross-flow, MR)

E_{VOL} = Volumetric Sweep of the Reservoir by Injected Water

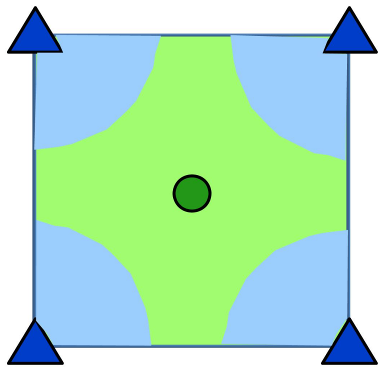
E_D = f (Primary Depletion, So, $\bar{S}o$, K_{rw} & K_{ro}, μ_o & μ_w)

Waterflood Progress-Areal



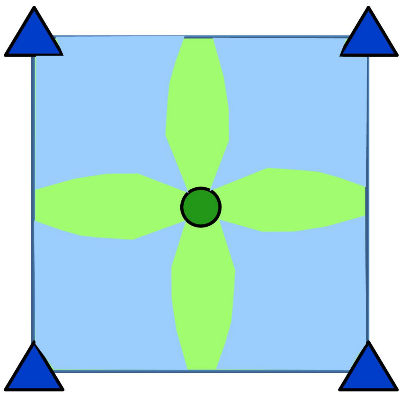
Time 1

Early in life of waterflood. Producer making 100% oil.



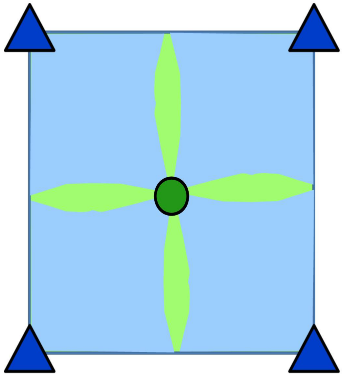
Time 2

Still relatively early in life of waterflood. Water banks expanding, but producer still making 100% oil.



Time 3

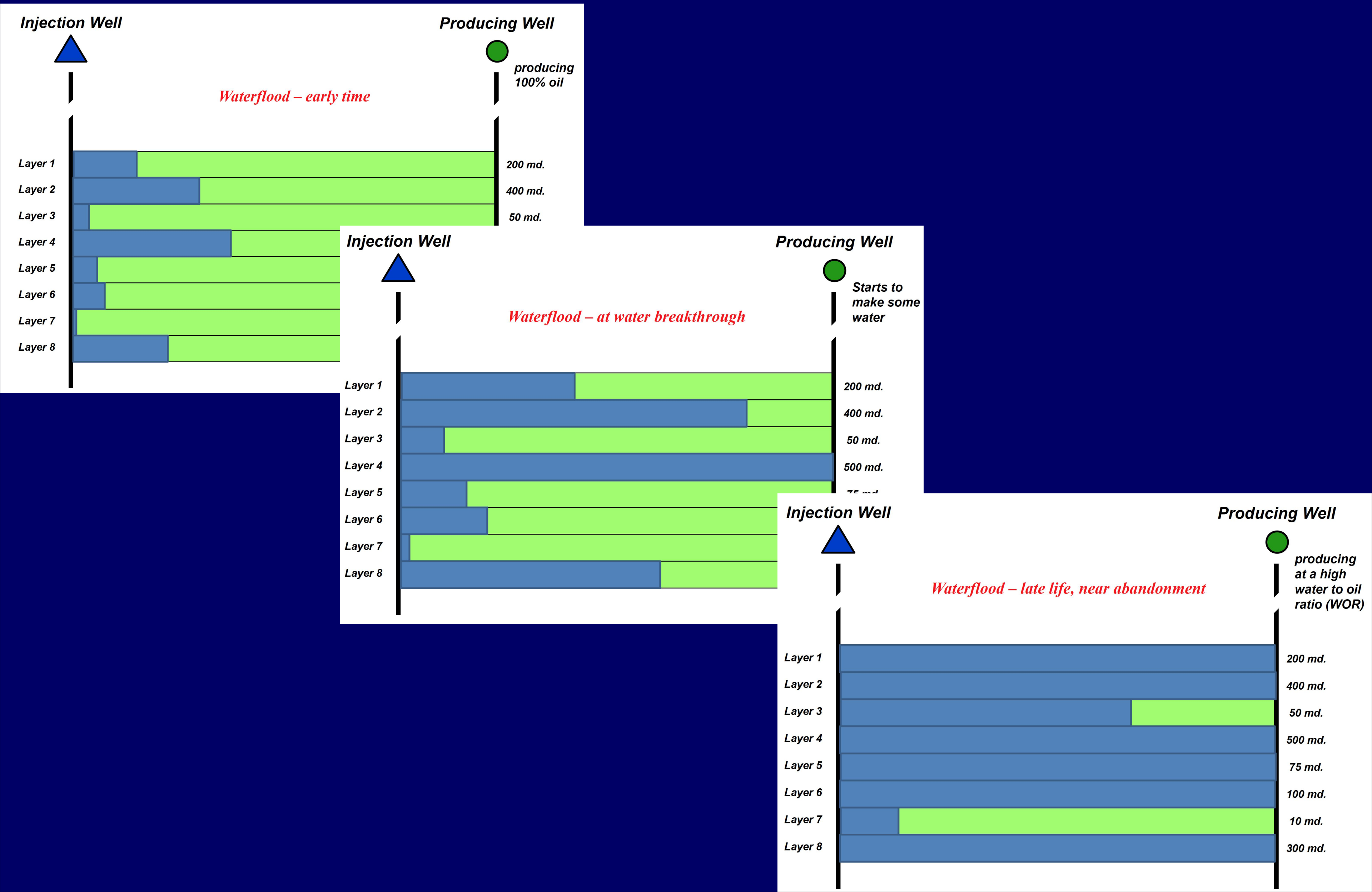
Mid-life of the waterflood. Water has reached the producing well. Producer now makes oil and water.



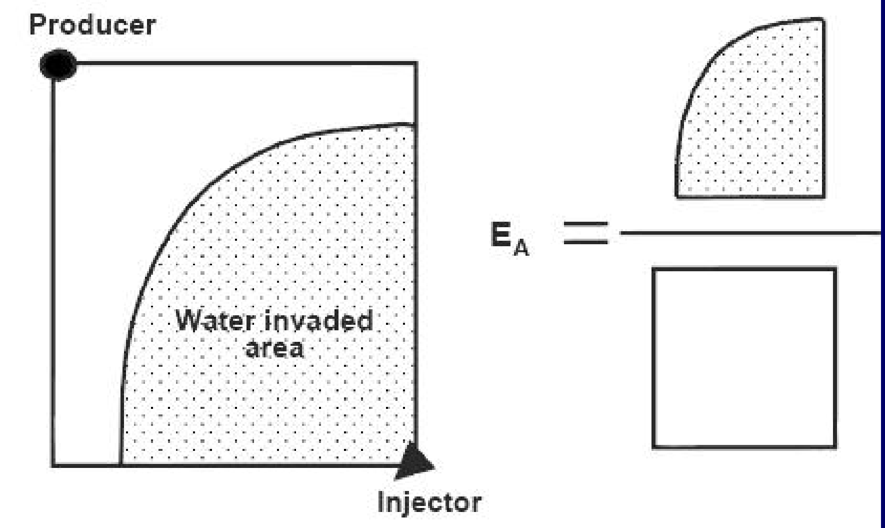
Time 4

Late in the life of the waterflood. Producer now making large volume of water compared to the oil volume.

Waterflood Progress-Vertical



Areal Sweep Efficiency [E_A]



- Fraction of the horizontal plane of the reservoir that is
- behind the flood front at a point in time.
- Factors affecting E_A:
  - Mobility ratio
  - Well spacing
  - Pattern geometry
  - Areal heterogeneity

Mobility Ratio

- Mobility = $\dfrac{\text{permeability of rock to fluid}}{\text{fluid viscosity}}$

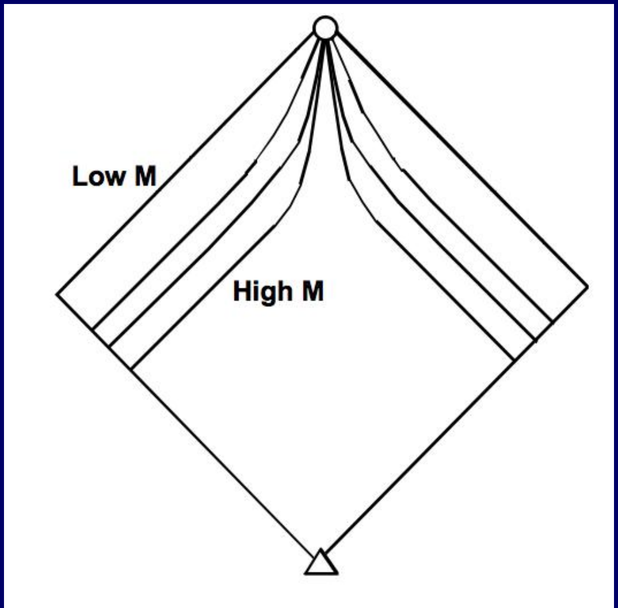
- Mobility ratio:

$$M = \frac{\text{Mobility of water}}{\text{Mobility of oil}} = \frac{\dfrac{k\,k_{rw}}{\mu_w}}{\dfrac{k\,k_{ro}}{\mu_o}} = \frac{k_{rw}\mu_o}{k_{ro}\mu_w}$$

Mobility Ratio Effects

M = 1	Neutral	Water and oil move equally well
M < 1	Favorable	Oil will move easier than water
M > 1	Unfavorable	Water will move easier than oil

For five-spot patterns, areal sweep efficiency (ASE) at breakthrough is over 95% for mobility ratios less than 0.2. At M = 1.0, ASE = 67% and at M =10, ASE = 50%.



Areal Sweep Efficiency [E_A]

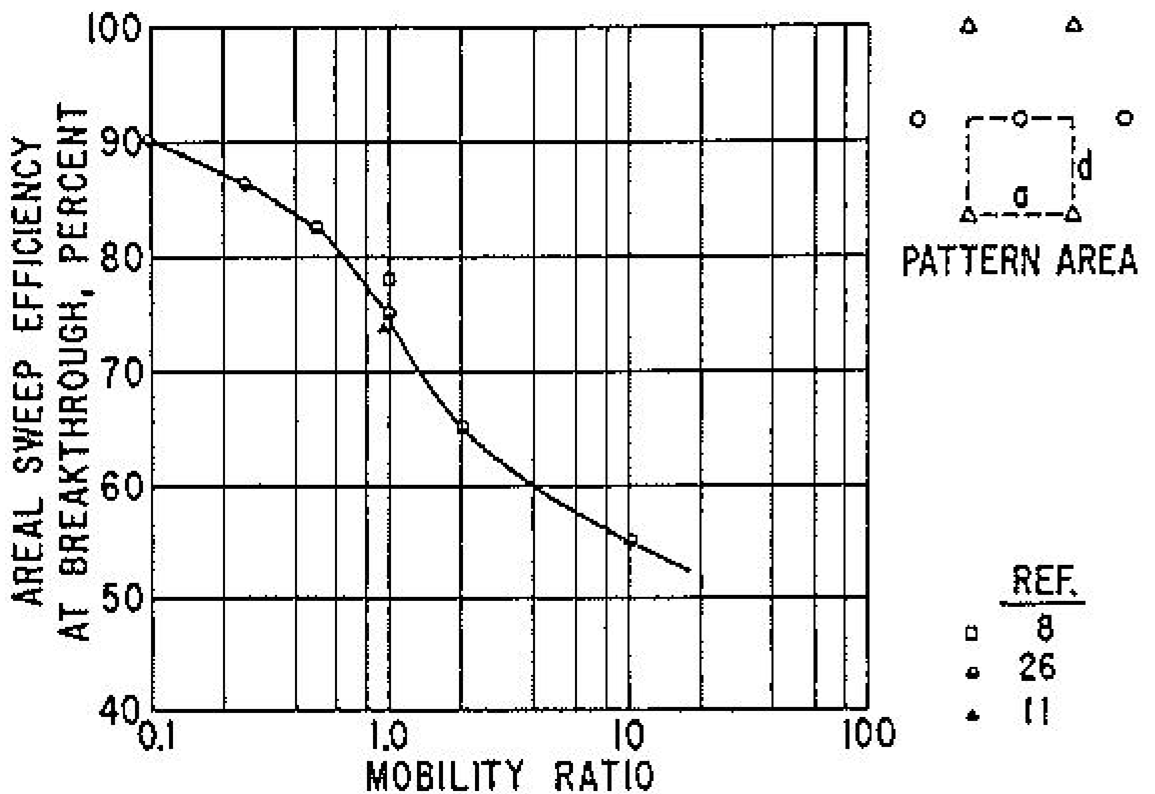
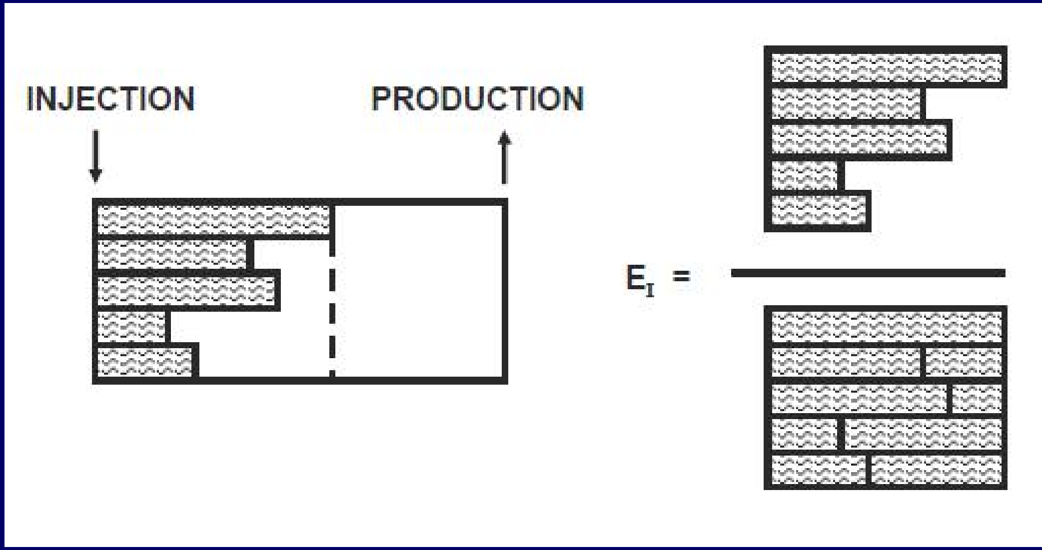


Fig. 5.12 Areal sweep efficiency at breakthrough, developed staggered line drive. $d/a = 1.0$.

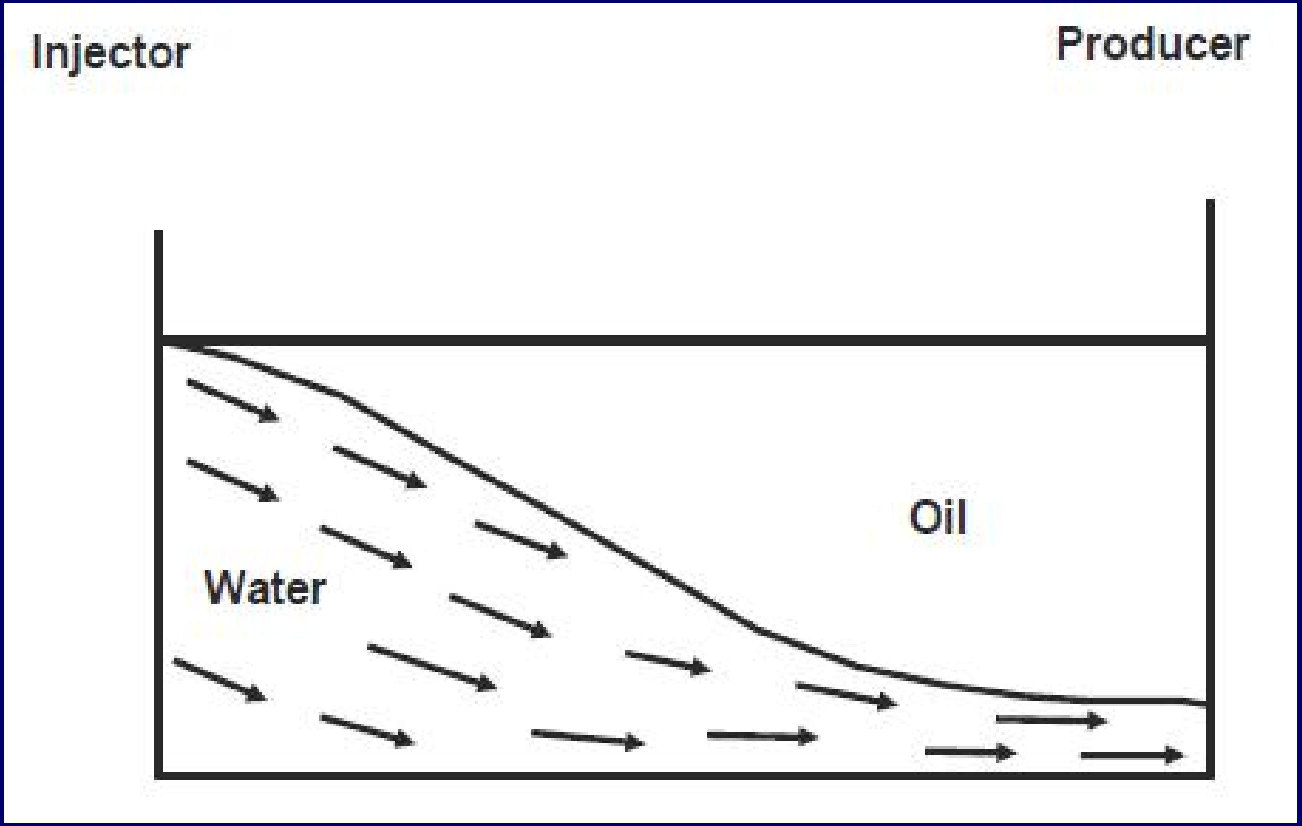
(The Reservoir Engineering Aspect of Waterflooding, Forrest F. Craig)

Vertical Sweep Efficiency

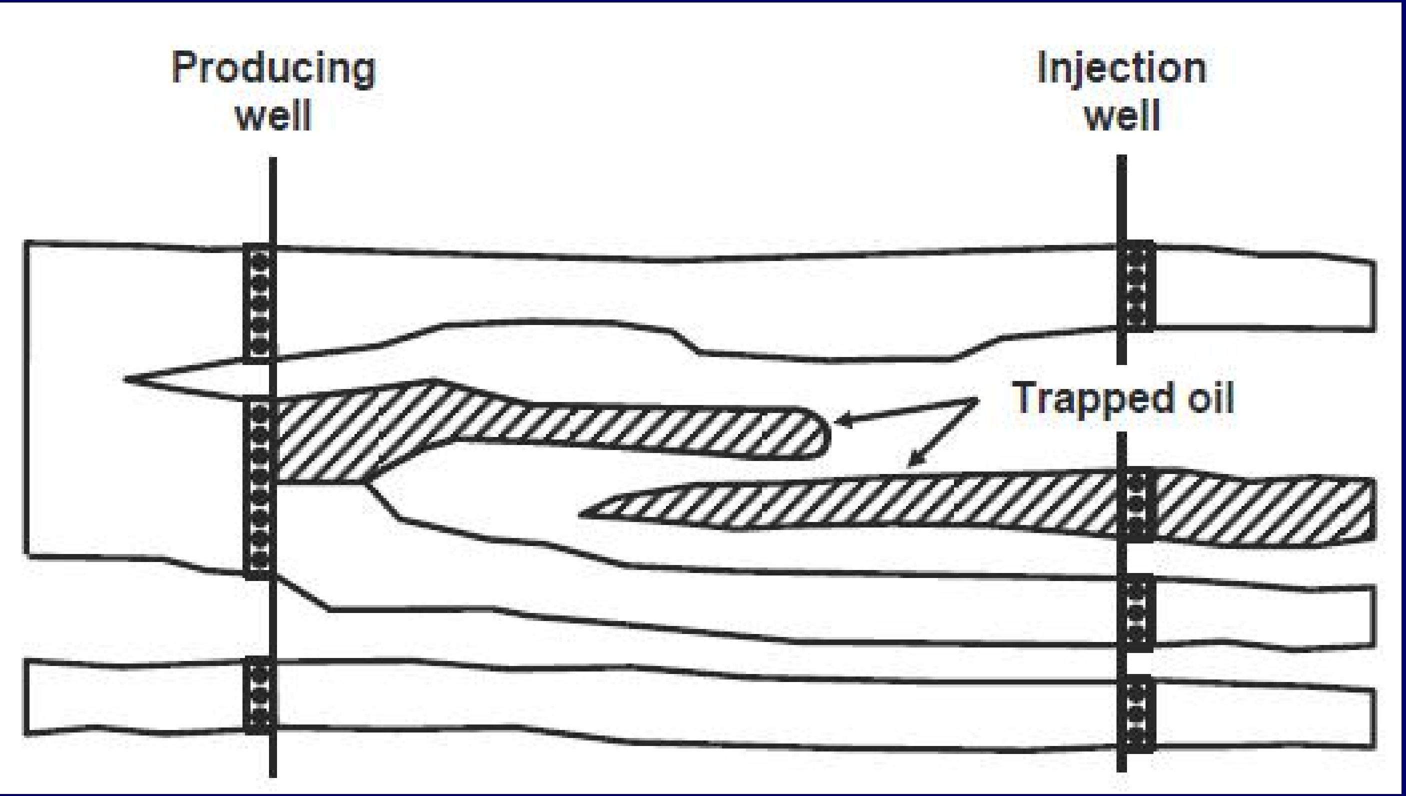


- **Factors affecting E_I:**
  - Gravity
  - Barriers to vertical flow
  - Lateral pay discontinuities
  - Completion interval inconsistencies

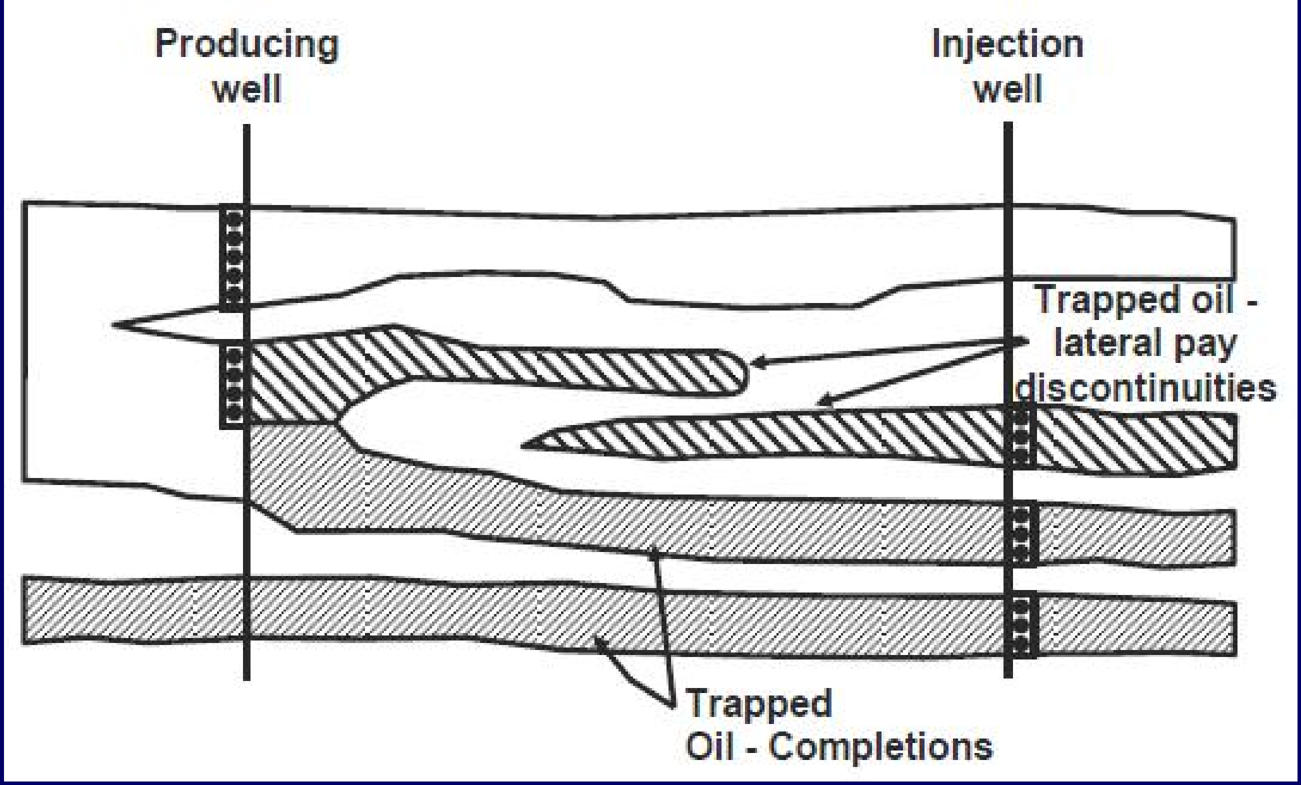
Effects of Gravity



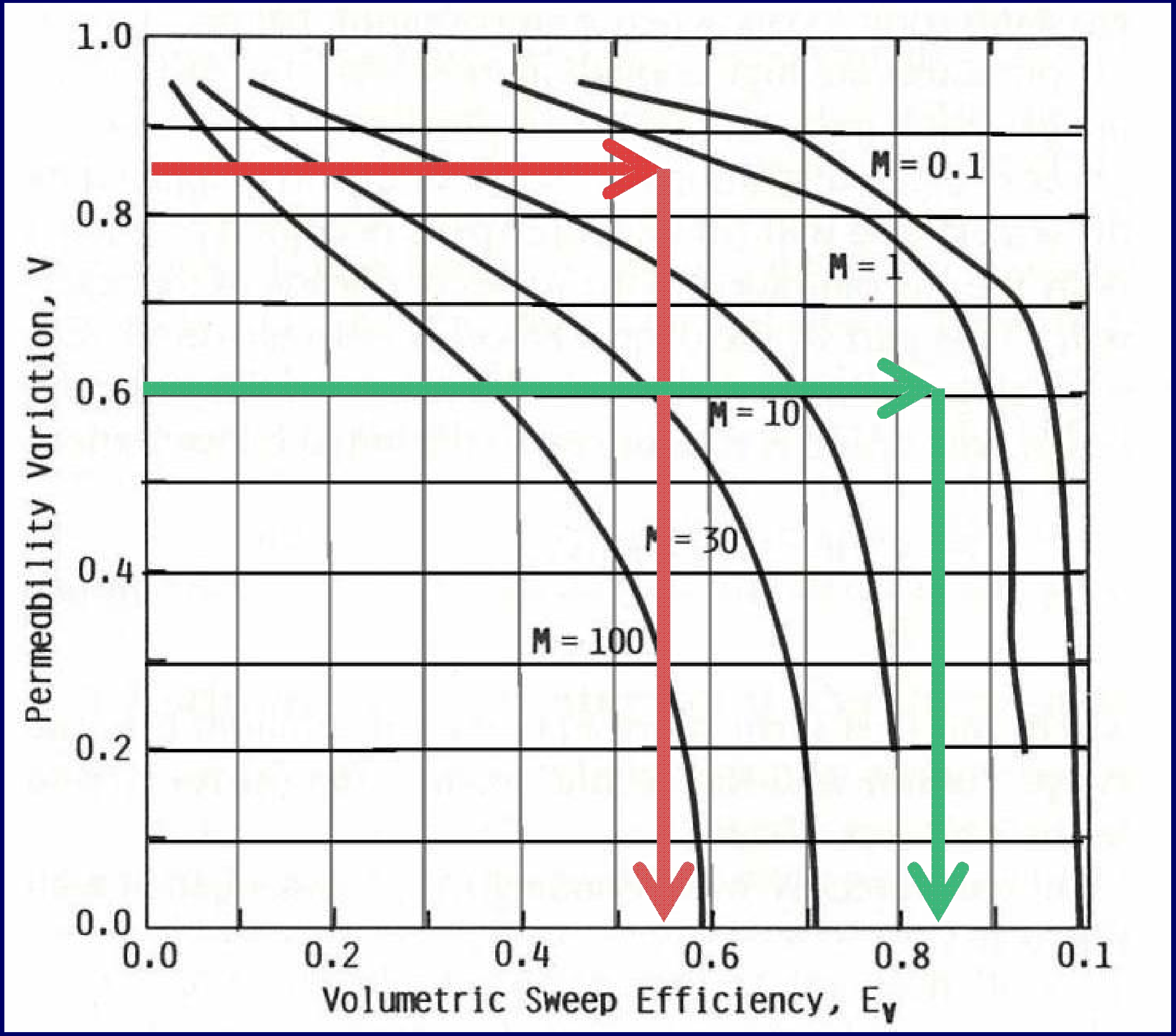
Lateral Pay Discontinuities



Completion Interval Inconsistencies



Willhite's Correlation for Five Spot Volumetric Sweep Efficiency with WOR = 50.



Chapter 7 Field Development Plan-Development Well Pattern Design and Adjustment

Section 1 Reservoir/Field Development Planning

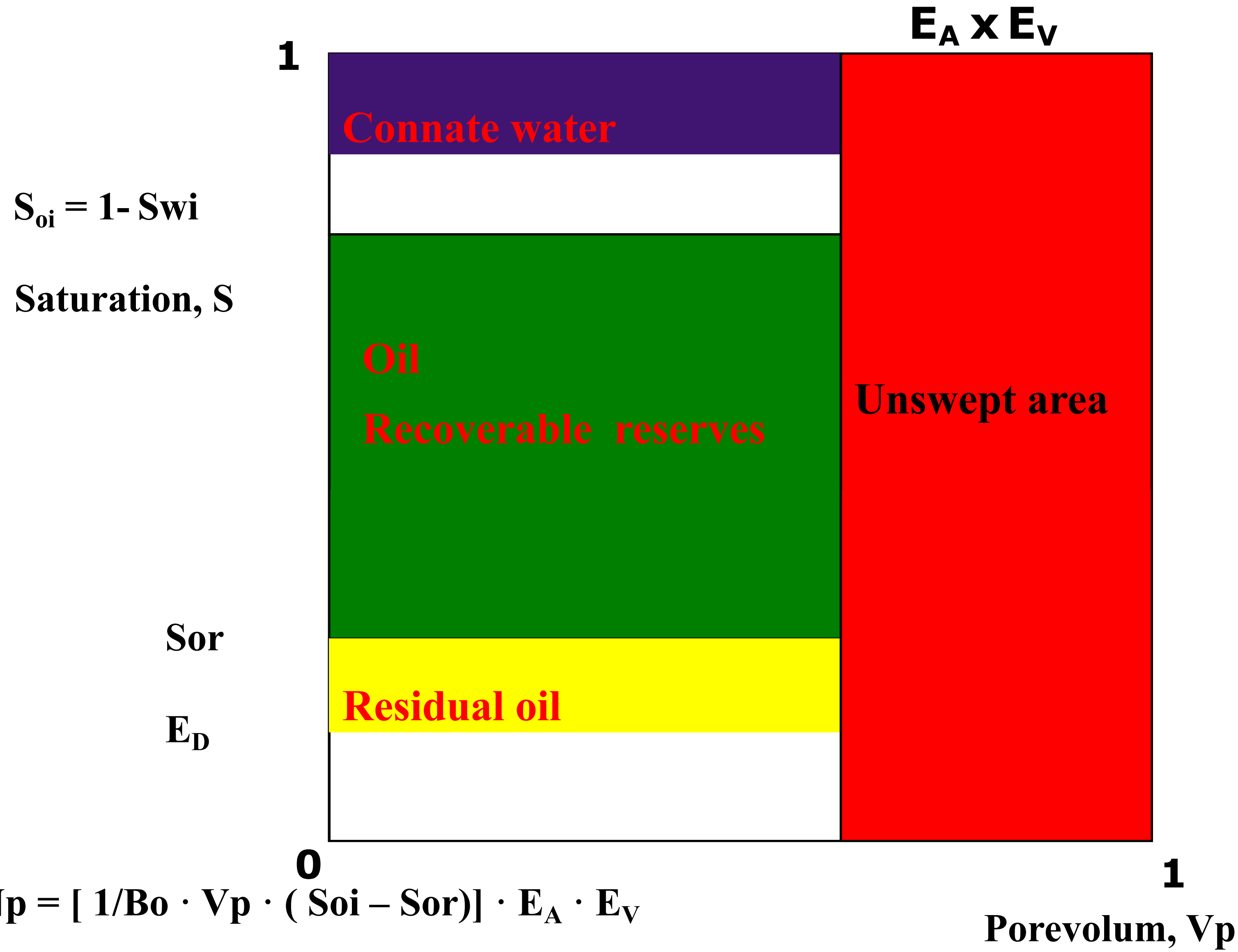
Section 2 Zonation for Multi-payzones Development and Well Pattern Design

Section 3 Residual Oil/Bypassed Plays and Development System Adjustment

Section 3 Residual Oil/Bypassed Plays and Development System Adjustment

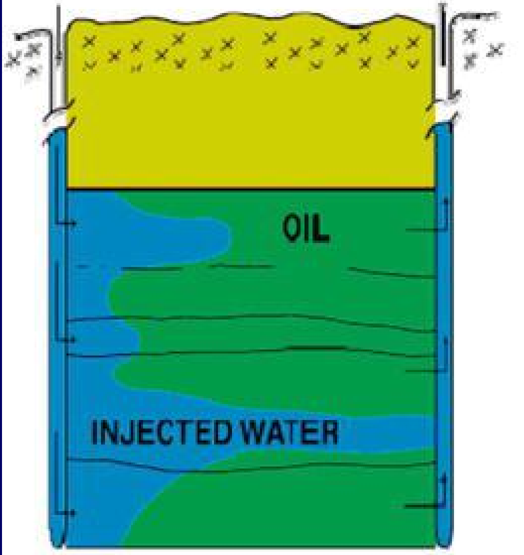
Oil Recovery Efficiency

Oil recovery efficiency = E_D x E_A x E_V



$$Np = [\,1/Bo \cdot Vp \cdot (Soi - Sor)] \cdot E_A \cdot E_V$$

Residual Oil or Bypassed Oil



Oil reservoir with conformance problems

breakthrough

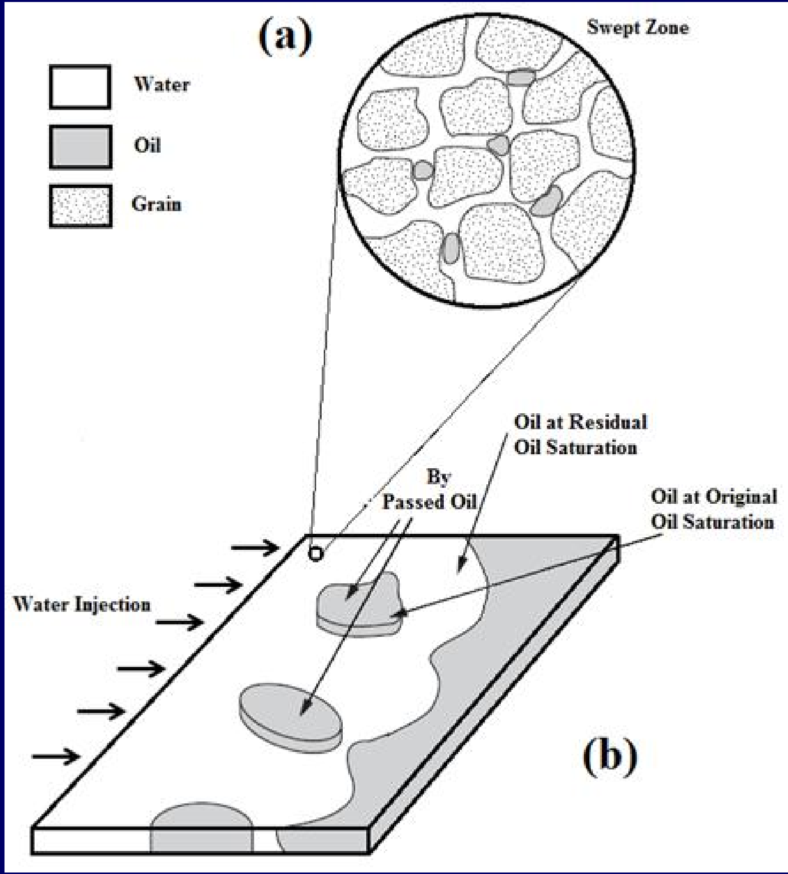
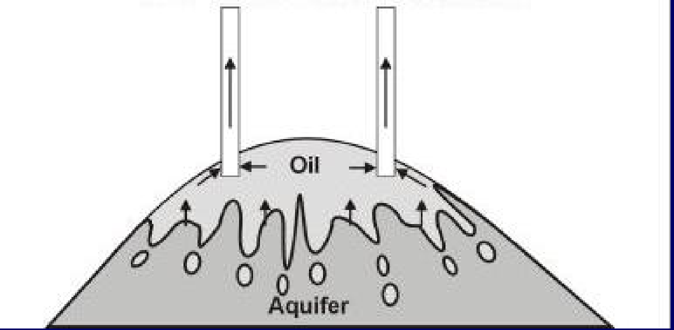
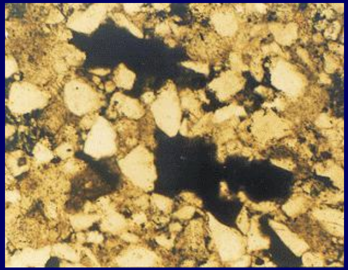


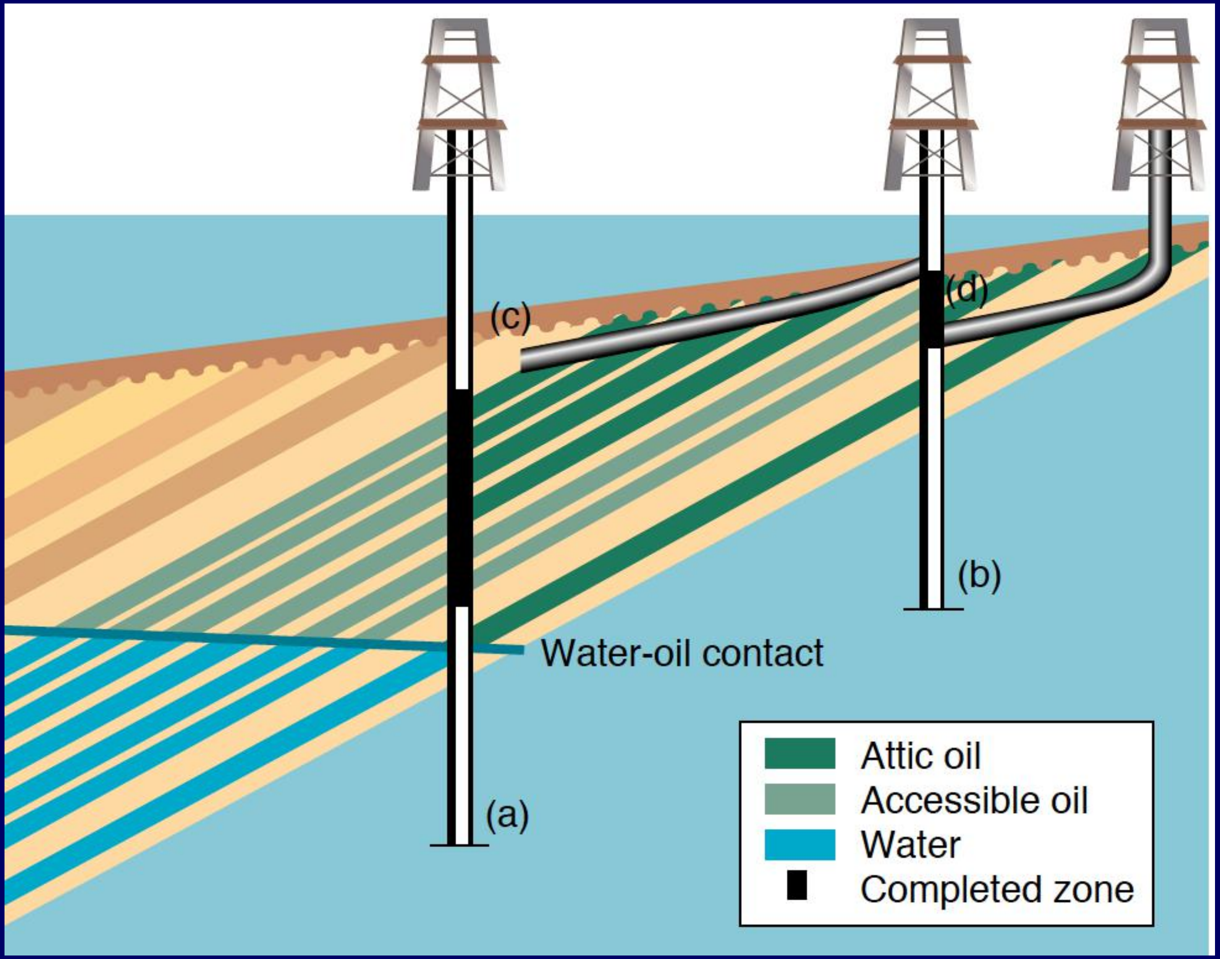
Figure 3.6 A Schematic Example of Fingering in a Water Drive Reservoir



Water fingering and coning



Attic Oil


(c)
(d)
(b)
Water-oil contact
(a)
Attic oil
Accessible oil
Water
Completed zone

Bypassed Play from Inappropriate Design

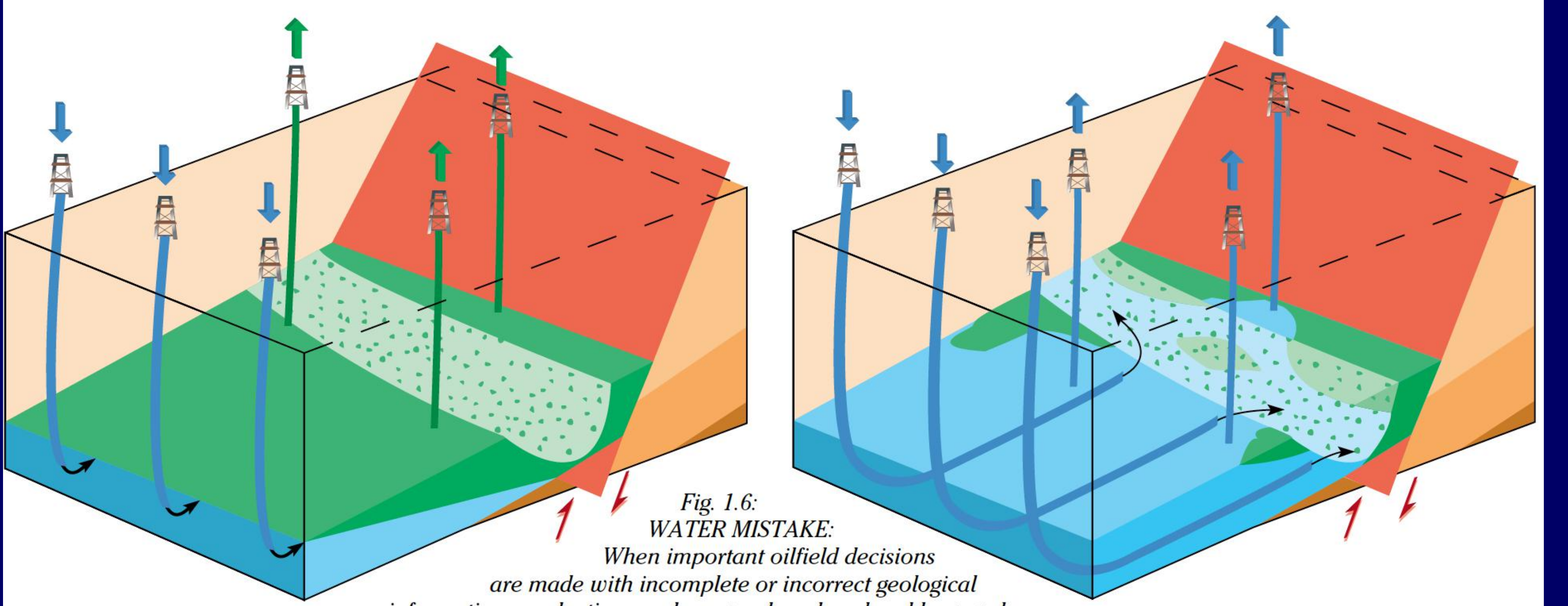
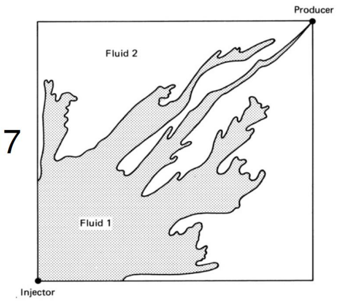


Fig. 1.6:
WATER MISTAKE:
When important oilfield decisions are made with incomplete or incorrect geological information, production can be severely reduced and large volumes of bypassed oil left behind. Here, a channel which had not been identified prior to waterflooding takes injection water away from the production wells.

Geological Control on Residual Pays

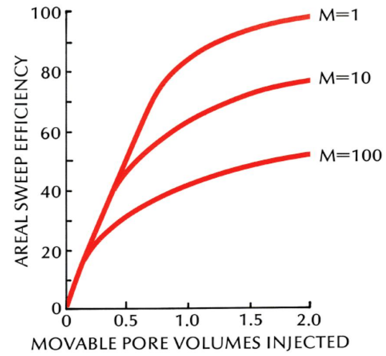
Areal sweep

M=17

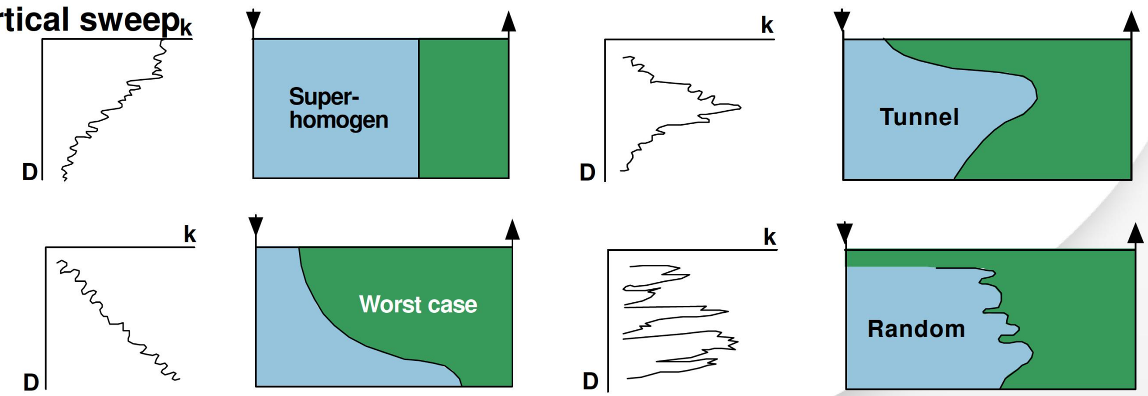


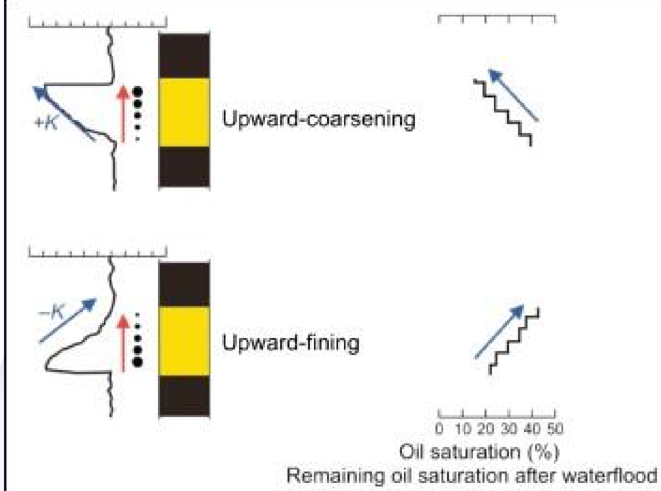
$$M = \frac{K'_{rw}/\mu_w}{K'_{ro}/\mu_o}$$

M < 1 stable front



Vertical sweep





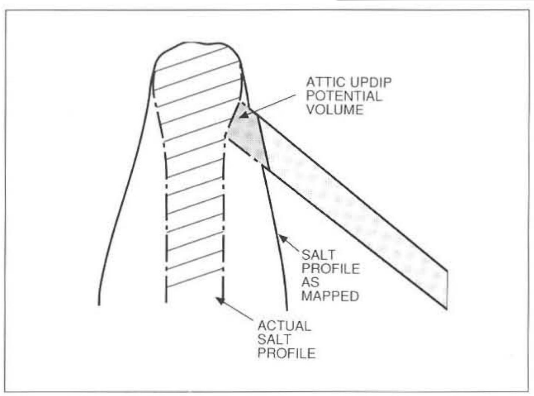


Fig. 3 Bypassed oil due inaccurate detection of salt boundary, after an ICF report (I.C.F., 1996).

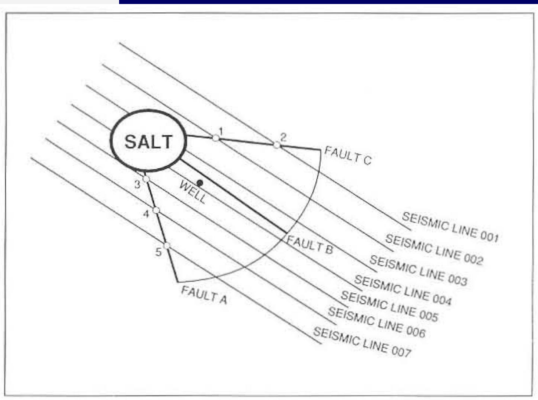
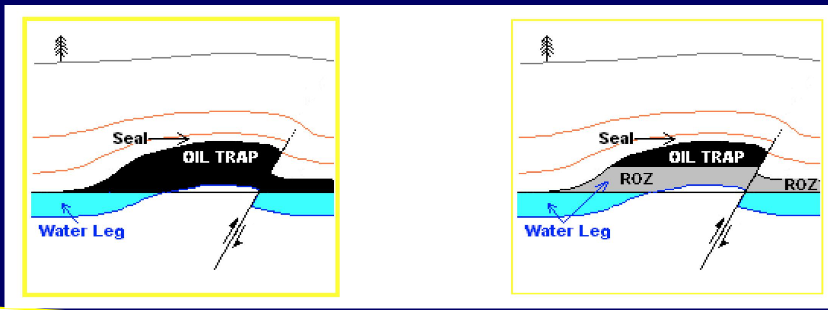
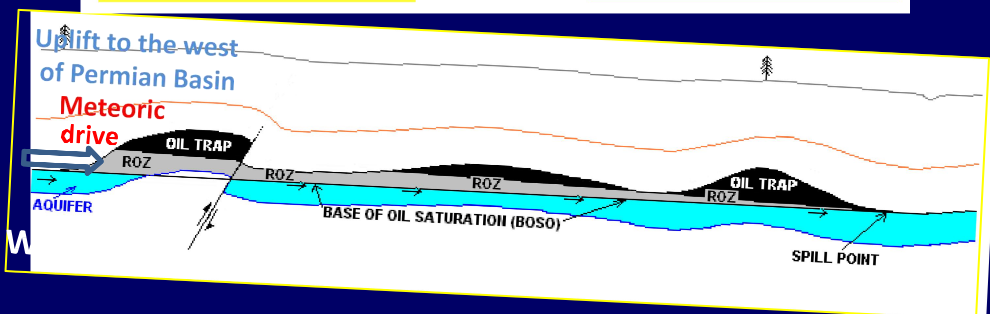


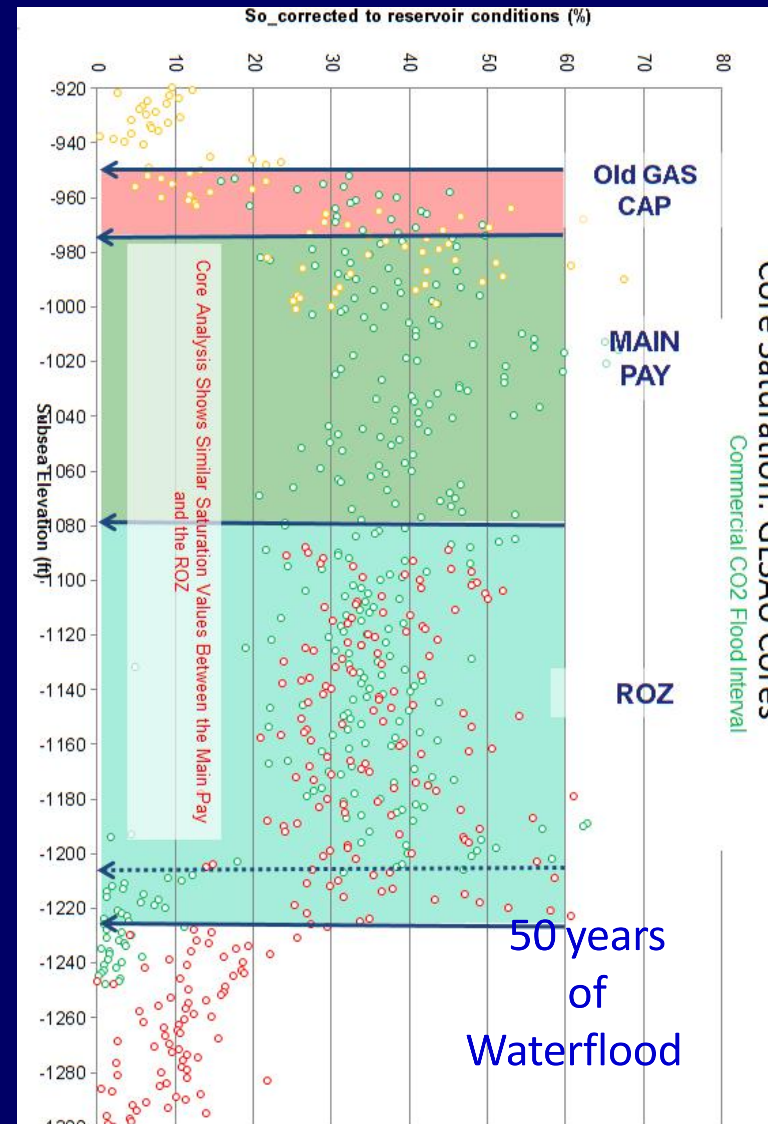
Fig. 4 Bypassed oil due to faulting, after an ICF report (I.C.F., 1996). The recently developed 3-D seismic technology can provide the necessary information to properly map the reservoir.

ROZ from Waterflood-Permian Basin Example



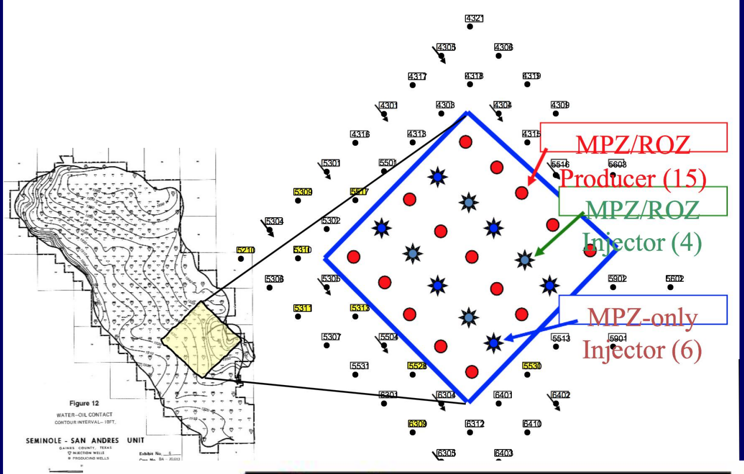


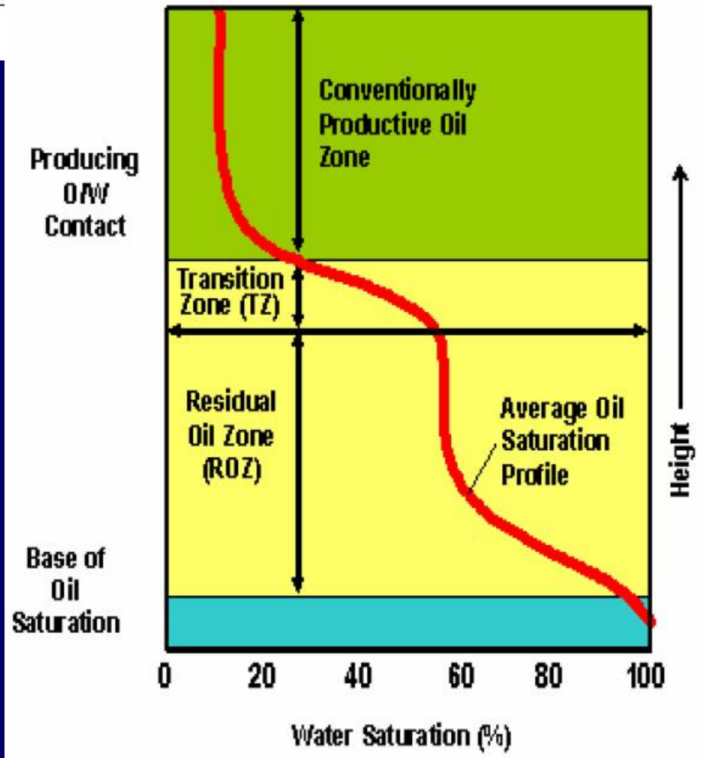
Spotty oil stain in tighter portion of burrowed open marine wackestone,



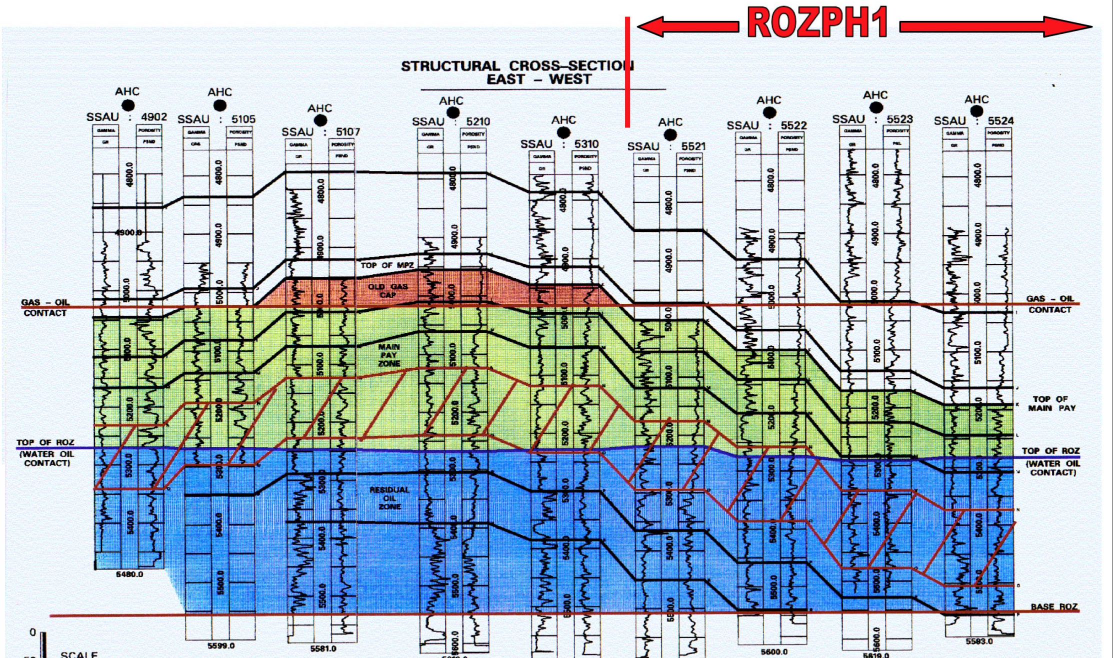
Seminole San Andres Unit – The Gold Standard for Brownfield ROZ's

Pilot Area for the SSAU ROZ Phase I Pilot





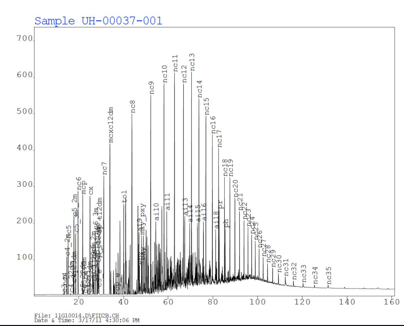
SSAU MPZ & ROZ Crossection and Zonal Attributes



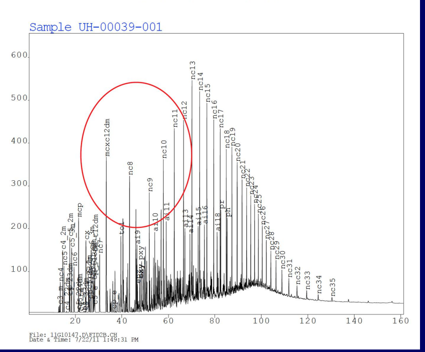
	Gross Thickness	Net Thickness	Porosity	Permeability Range	OOIP	Initial Oil Saturation
Main Pay Zone (MPZ):	160'	126'	12%	0.8-120 md	1 billion stbo	0.84
Residual Oil Zone (ROZ):	246'	197'	12.6%	0.5-270 md	0.4-1.1 billion stbo	0.32

Reference 2a

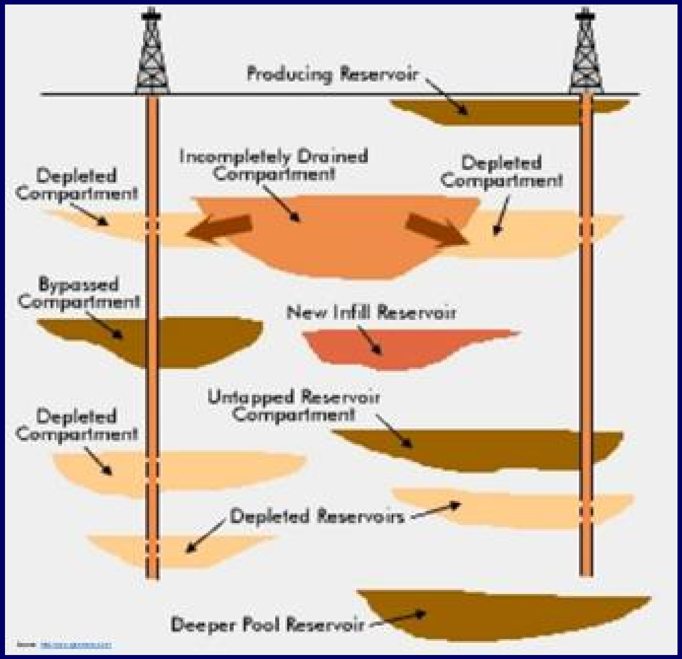
MPZ Reservoir Oil

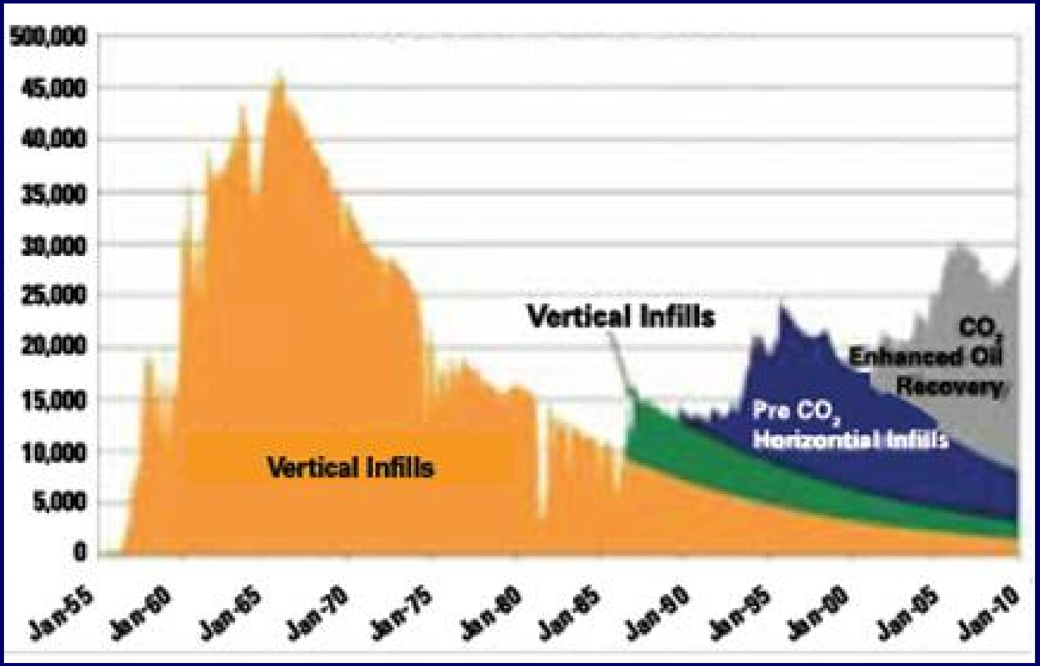


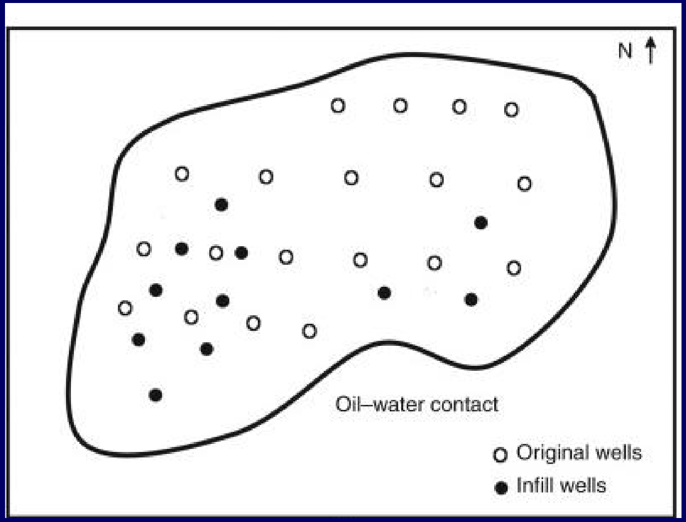
From ROZ Interval



Development of Residual Oil



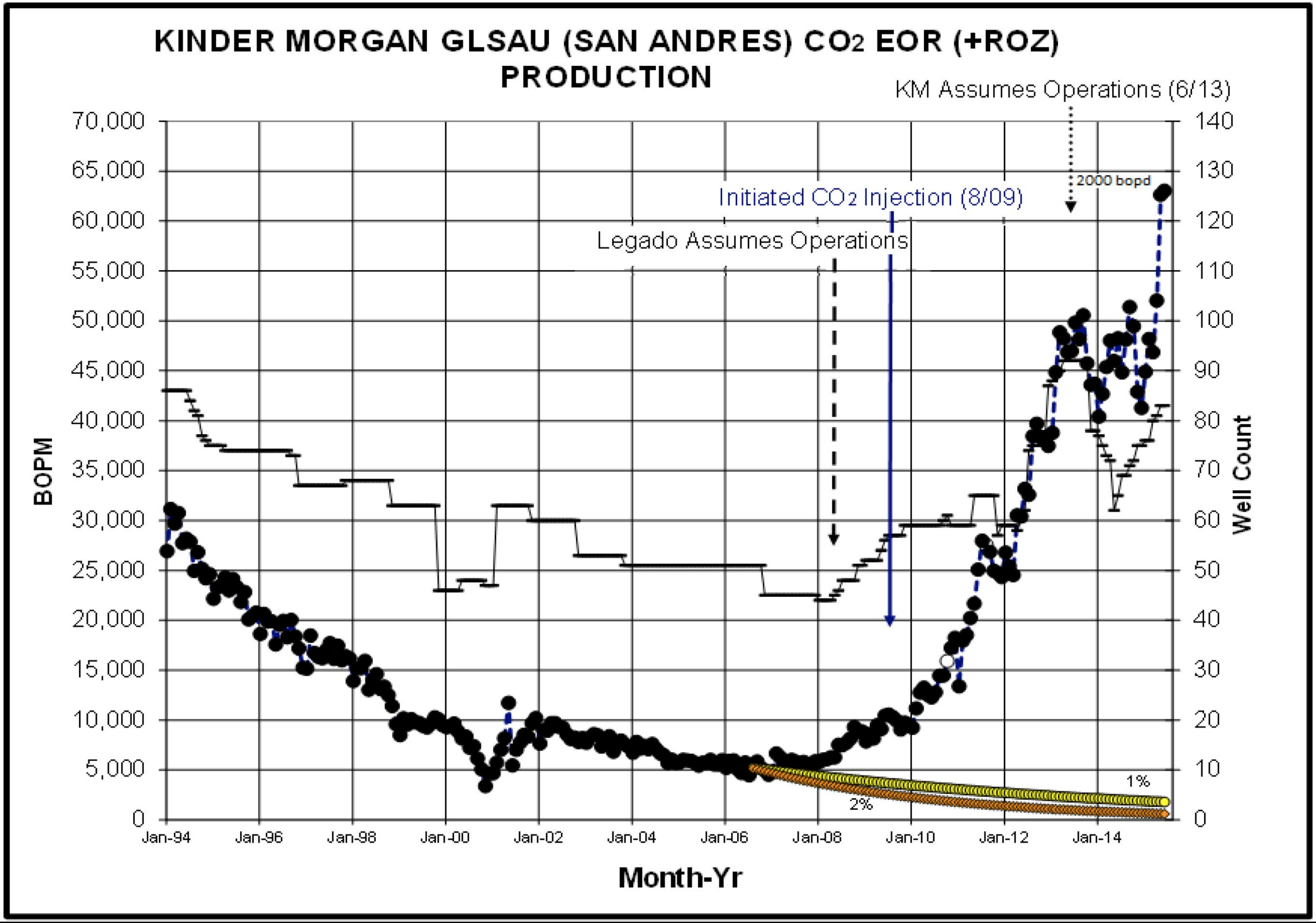




Infill Drilling to EOR

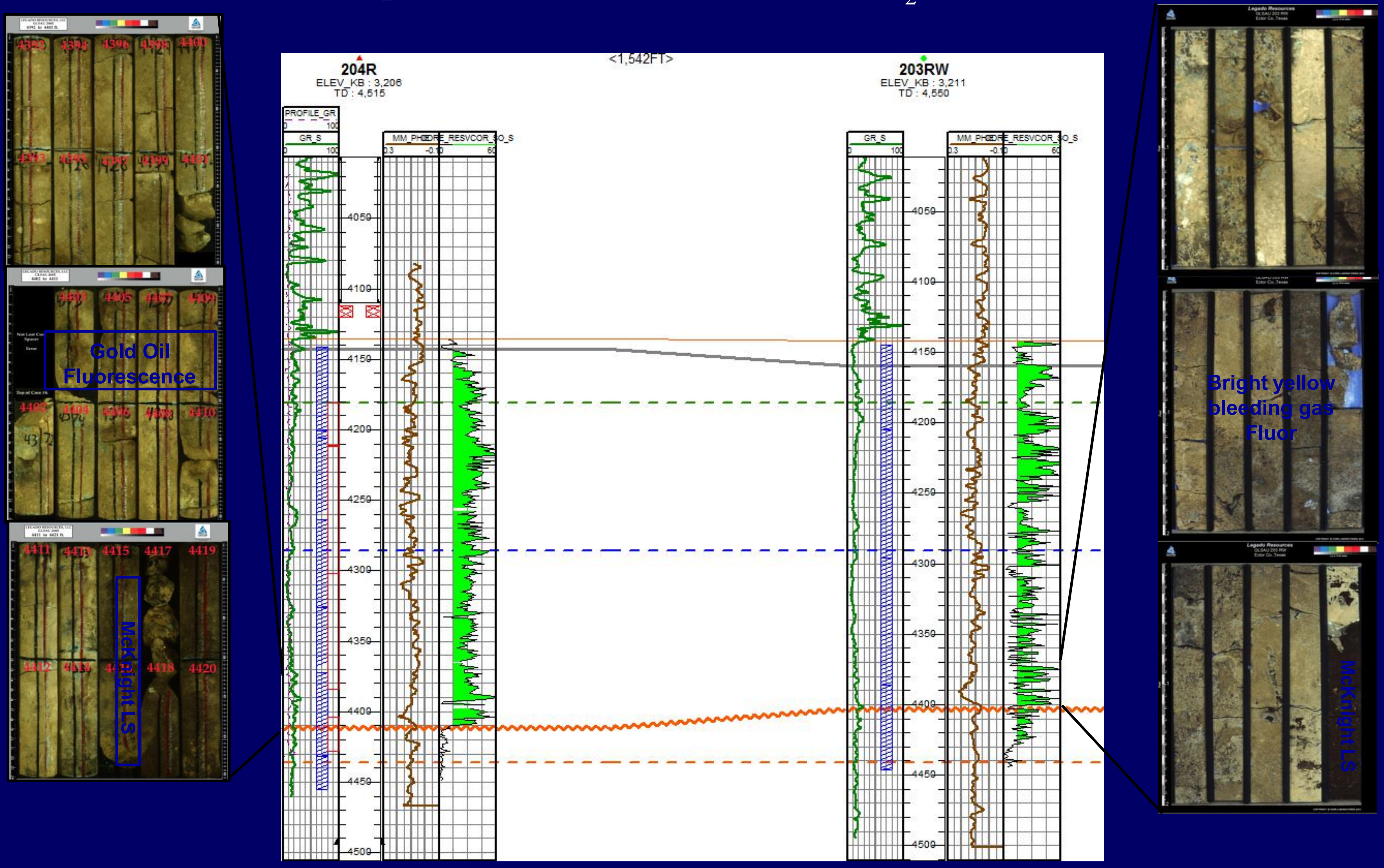
Also, development adjustment

Figure 1.4 – GLSAU Production History: Jan 94 – Jun 15



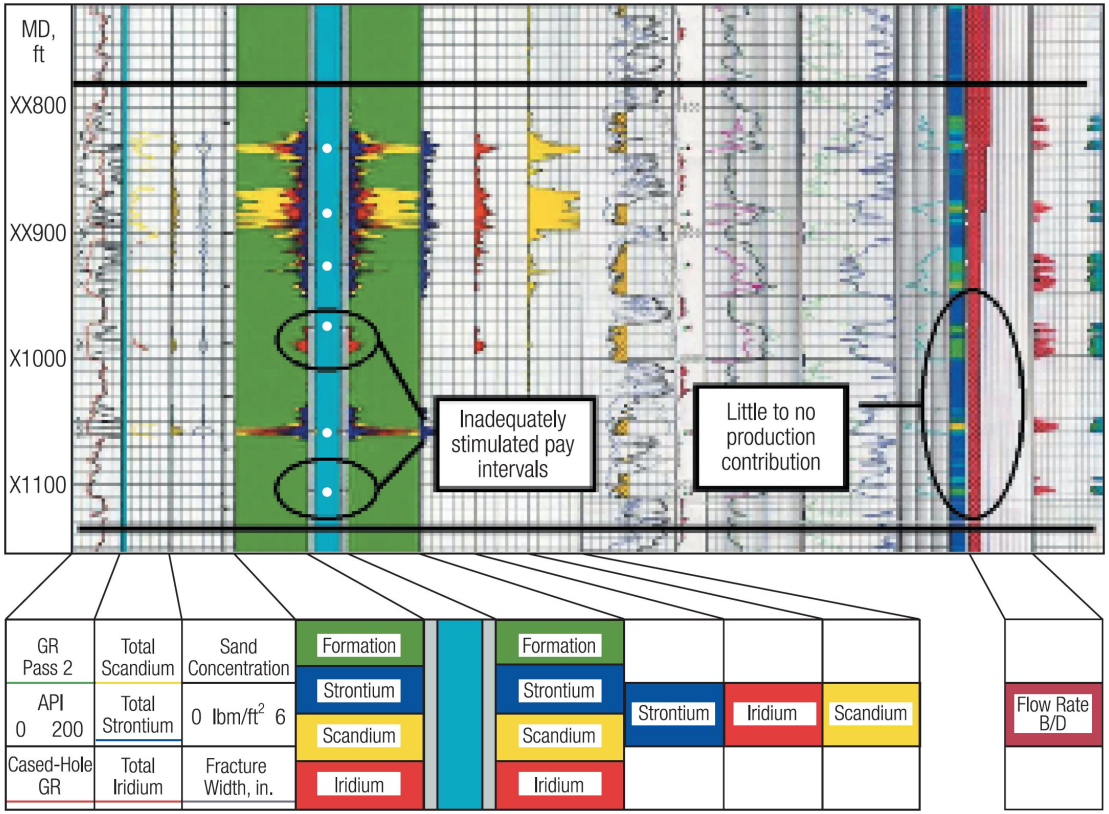
Pre-CO_2 Flood 2009

Post-CO_2 Flood 2013



Green > 15% Reservoir –corrected Sor

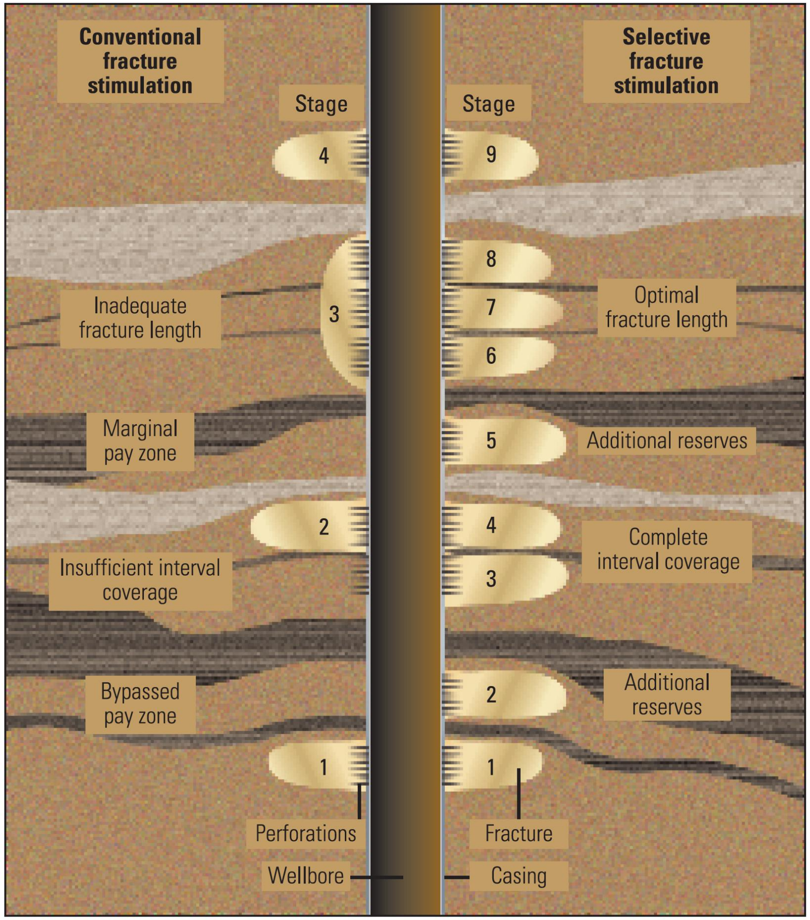
Development Adjustment



^ Single-stage treatment diversion: radioactive tracers and production logs. With limited-entry techniques, some zones are not stimulated effectively and others may remain untreated. In this example, six pay zones over a 300-ft [90-m] gross interval were fractured through 24 perforations. A radioactive-tracer survey shows that the three upper zones received most of the treatment fluids and proppant, while the three lower zones were not adequately stimulated (*left*). If an interval did not take fluid at the beginning of a treatment, perforation erosion in other sands eliminated the backpressure necessary for diversion. The lowest zone contributes no production; the other two contribute very little flow on the production log spinner survey (*right*).

Isolate and Stimulate Individual Intervals

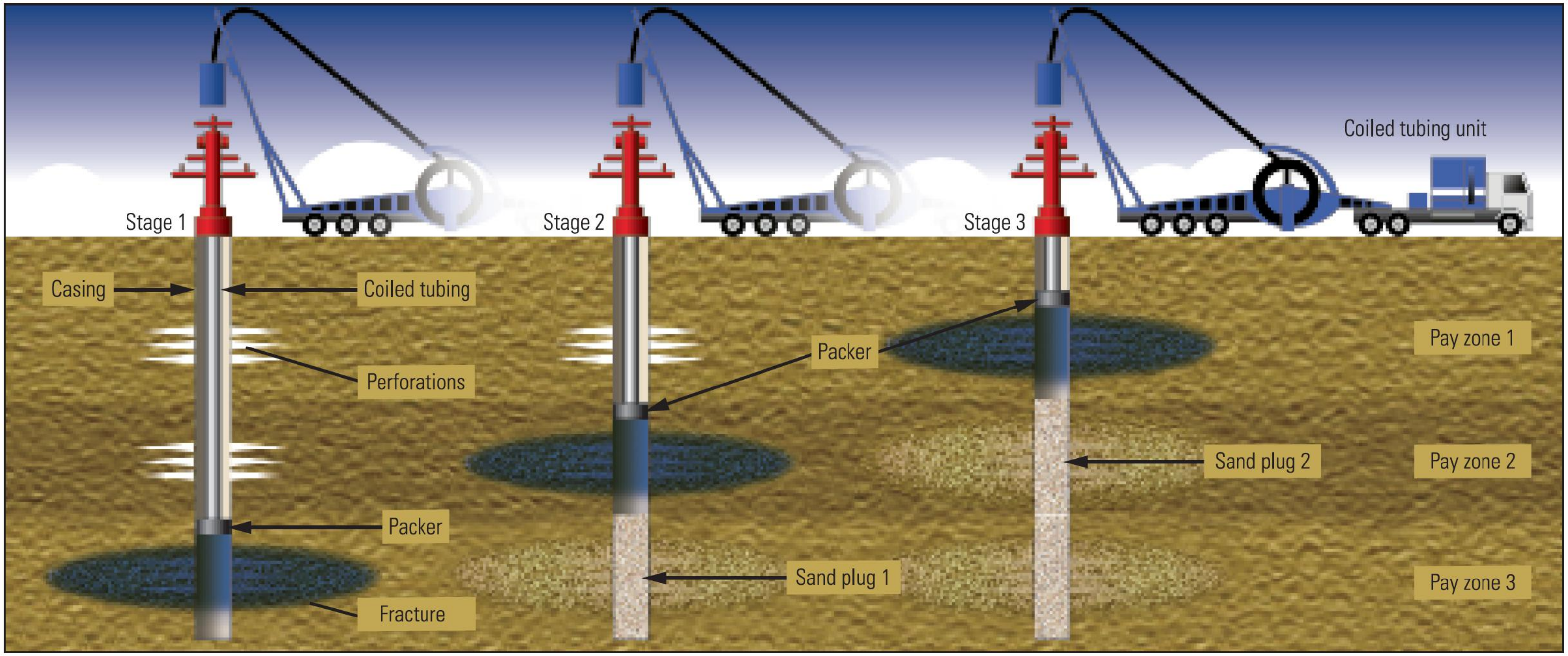
K.F.Degenhardt, et al.,2001, Oilfield Review



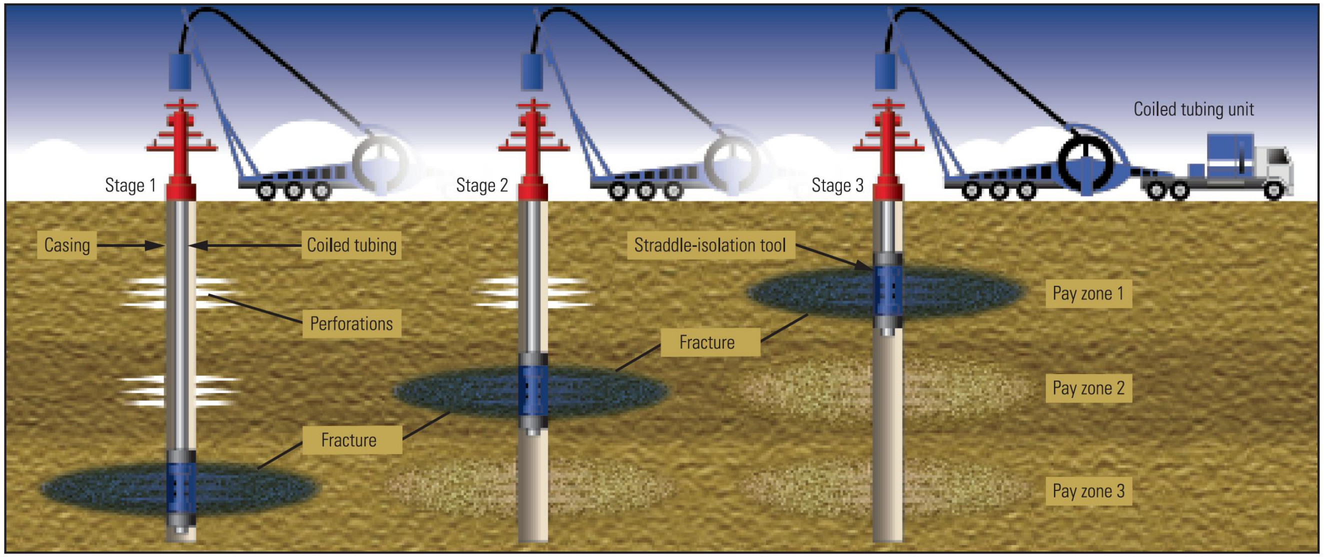
^ Conventional and selective stimulations. Fracturing several zones grouped in large intervals, or stages, is a widely used technique. However, fluid diversion and proppant placement are problematic in discontinuous and heterogeneous formations. Conventional treatments, like this four-stage example, maximize fracture height, often at the expense of fracture length and complete interval coverage (*left*). Some zones remain untreated or may not be stimulated adequately; others are bypassed intentionally to ensure effective treatment of more permeable zones. Selective isolation and stimulation with coiled tubing, in this case nine stages, overcome these limitations, allowing engineers to design optimal fractures for each pay zone of a productive interval (*right*).

Selective fracture stimulation to better develop previous pay zones and bypassed pay zones

K.F.Degenhardt, et al.,2001, Oilfield Review



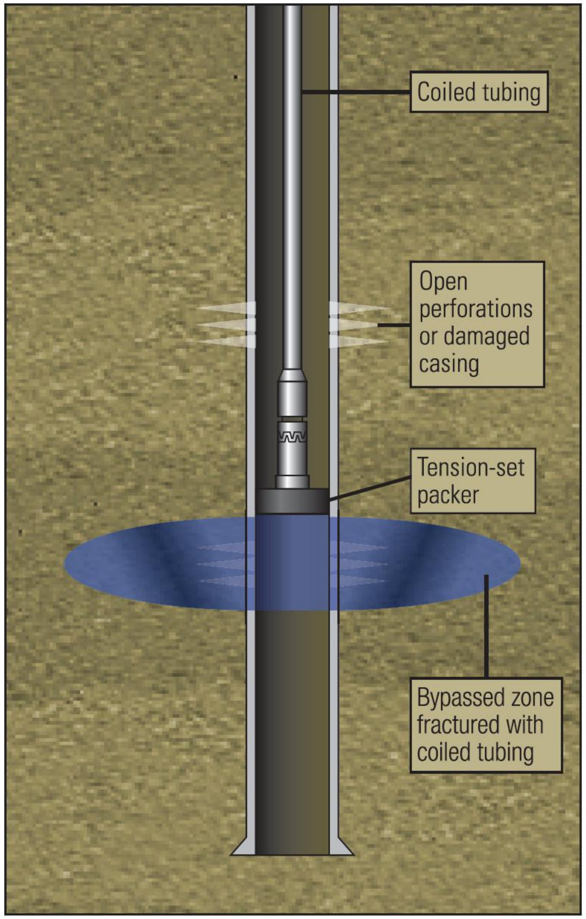
^ Coiled tubing-conveyed fracturing with a single tension-set packer and sand plugs.



^ Multistage coiled tubing-conveyed fracturing operation with early straddle-isolation tools.

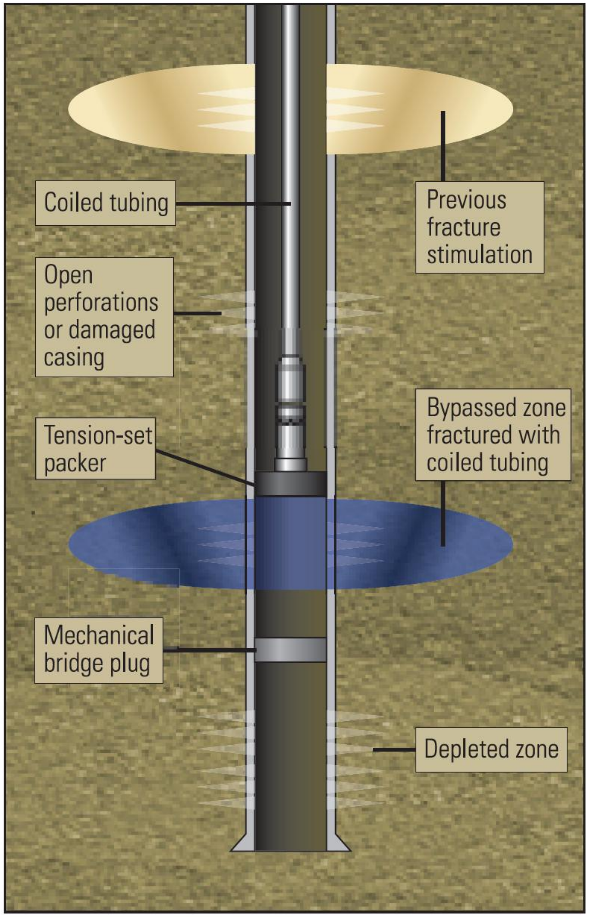
Coiled tubing- Conveyed fracturing

K.F.Degenhardt, et al.,2001, Oilfield Review

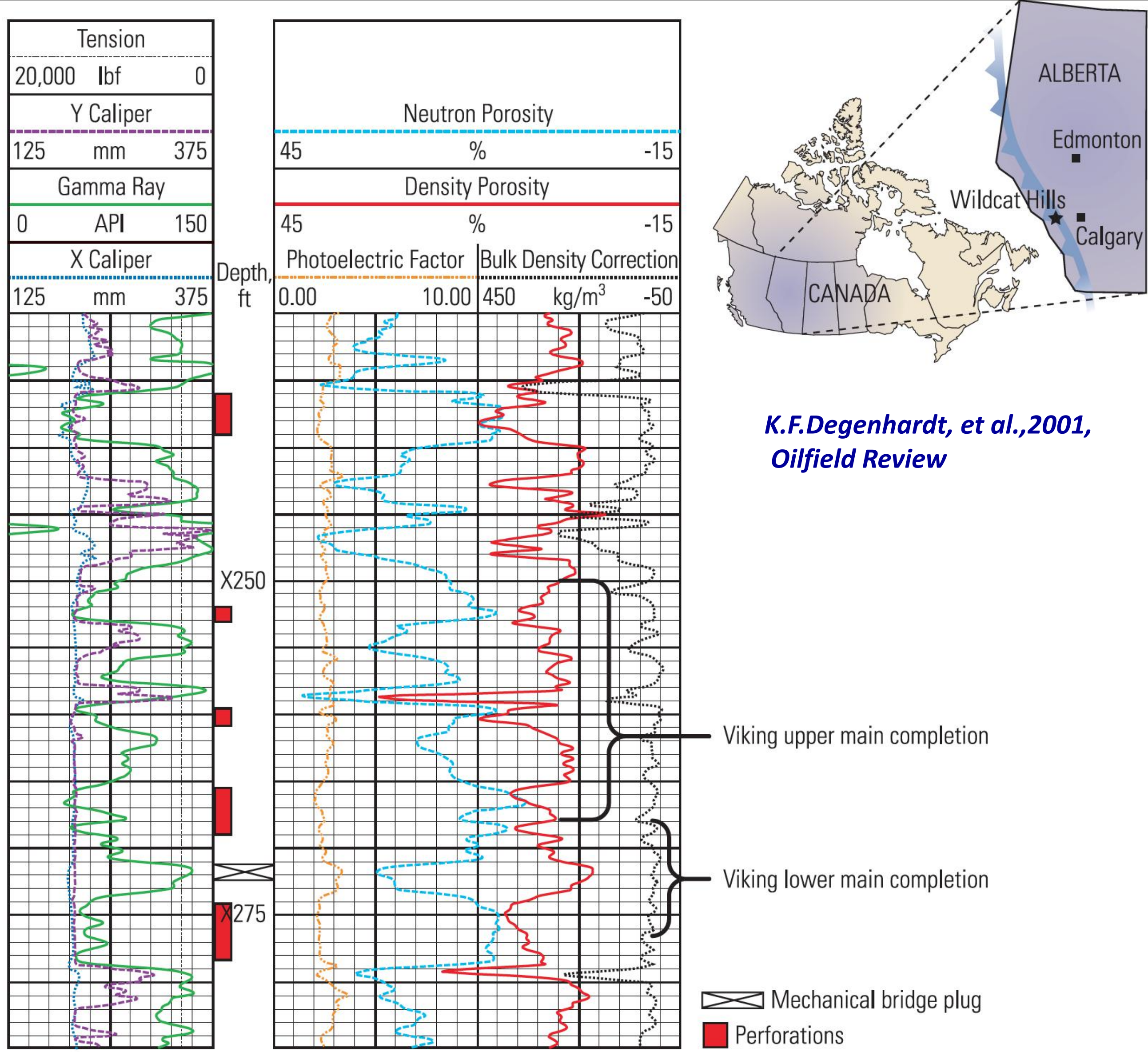


^ Coiled tubing-conveyed fracturing with a single tension-set packer for casing and tubing protection.

K.F.Degenhardt, et al.,2001, Oilfield Review

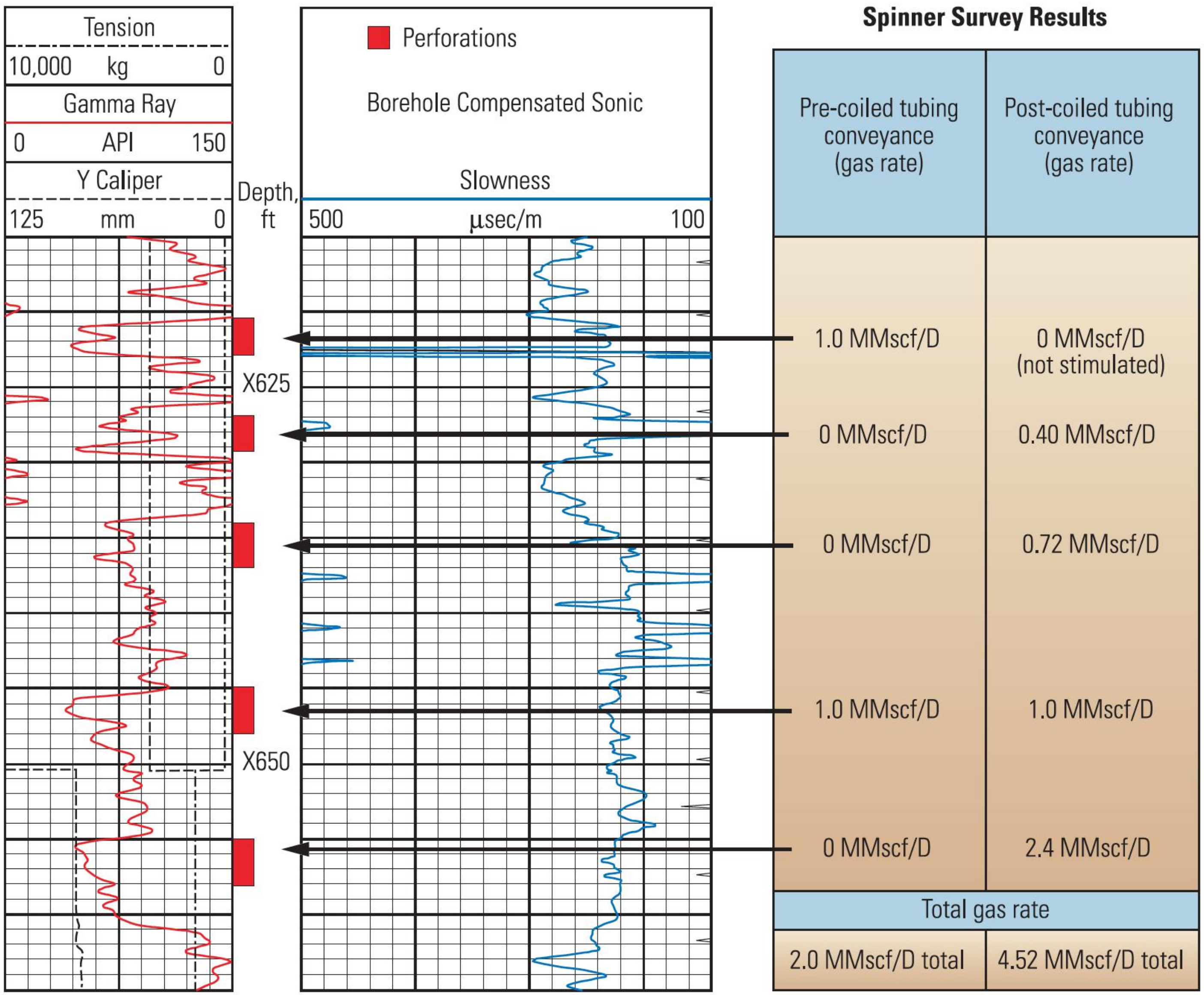


^ Coiled tubing-conveyed fracturing with a single packer and mechanical bridge plugs. In south Texas, a well with casing damage near the surface and a bypassed zone between existing open perforations was stimulated successfully with coiled tubing. The operator set a bridge plug to isolate the lower zone before running a tension-set packer on coiled tubing to isolate the upper zone and protect the casing. This technique eliminated a costly workover and remedial cement-squeeze operations.



^ Well 3-3-27-5W5M, Wildcat Hills field. Previous attempts to stimulate the Viking formation as a continuous interval were not successful because of difficulty in intersecting multiple zones with conventional single-stage fracture treatments. Closely spaced perforated intervals prohibited isolation with a packer and sand or bridge plugs. Selective CoilFRAC treatment placement simulated four zones individually to increase recovery by isolating and fracturing pay that often is bypassed or left untreated. Secondary goals were to simplify several days of completion operations into a single day and reduce cost.

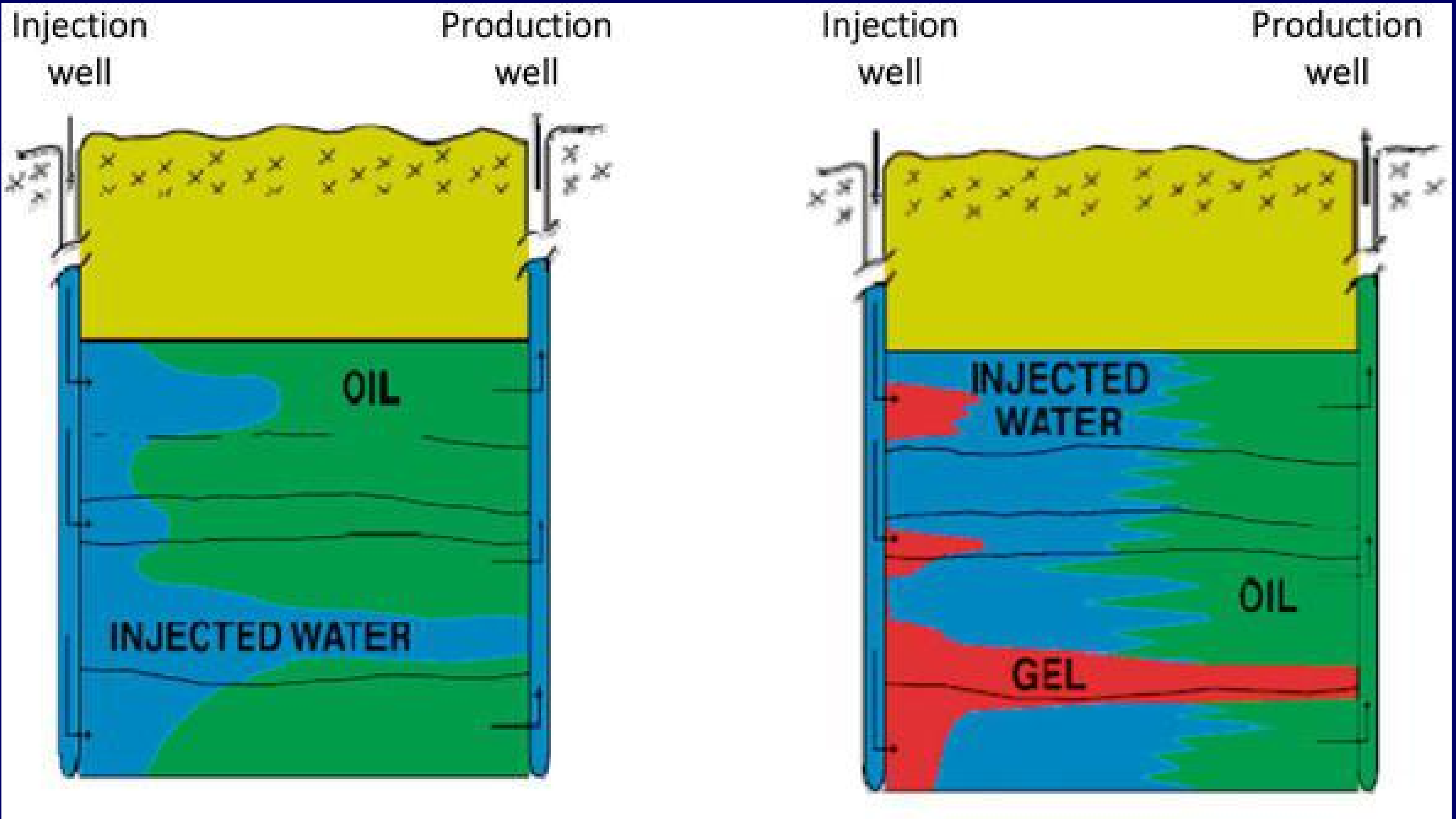
K.F.Degenhardt, et al.,2001, Oilfield Review



^ Pre- (*left*) and post-stimulation (*right*) evaluation. Production log spinner surveys in Viking Well 4-21-27-5W5M confirmed that CoilFRAC selective fracturing treatments in each Viking sand improved the production profile and total gas rate (*right*).

K.F.Degenhardt, et al.,2001, Oilfield Review

Development Adjustment-Gel

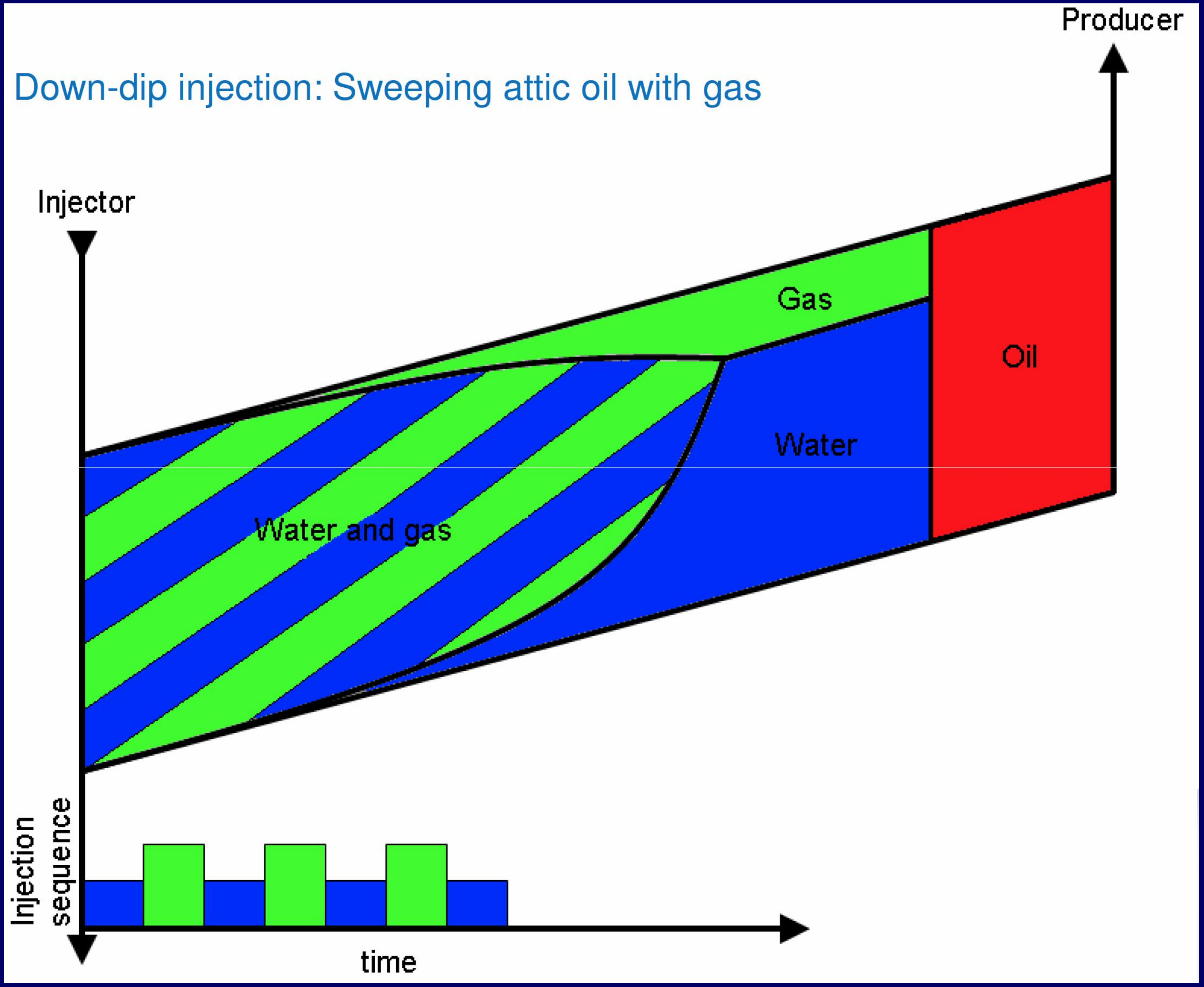


Oil reservoir with conformance problems

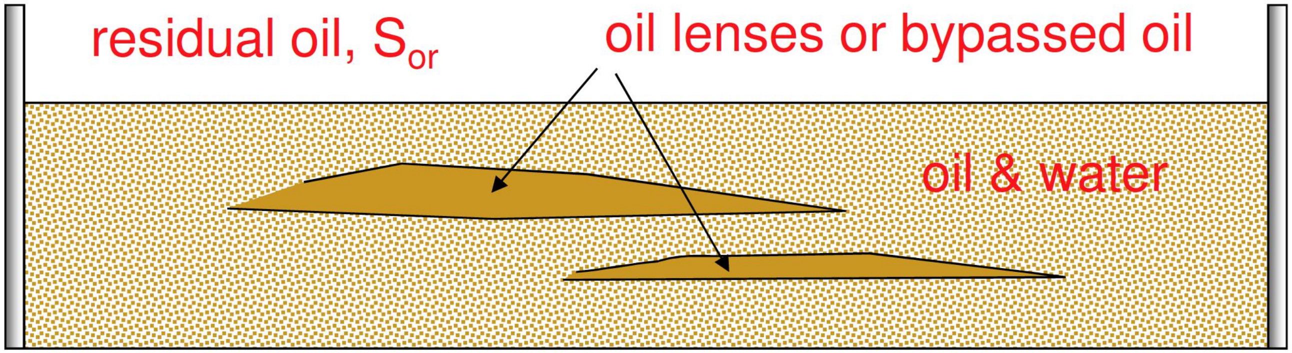
Oil reservoir after conformance-improvement treatment using hydrogel

Question: what is the role of GEL?

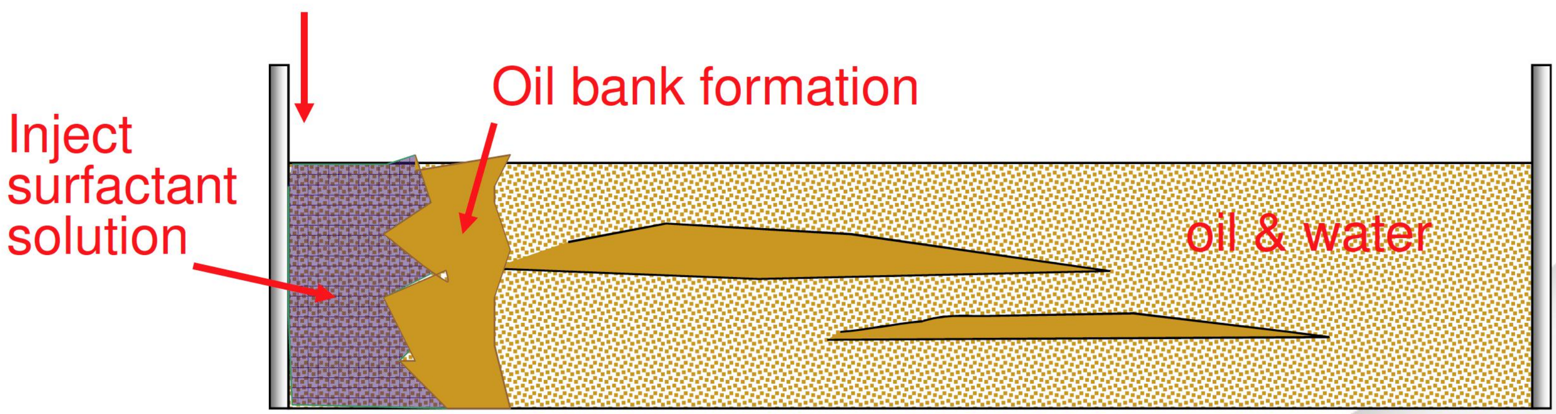
Development Adjustment-
Gas and water improving vertical sweep



Development Adjustment- surfactant floods are applied in the field



1. Situation after some time of waterflooding; S_{or} and bypassed oil



2. Inject aqueous surfactant solution - mobilise oil - form "oil bank"

Development Adjustment-Tracer

Table 4.16. Impact of Well Completion Design on CO_2 Profile

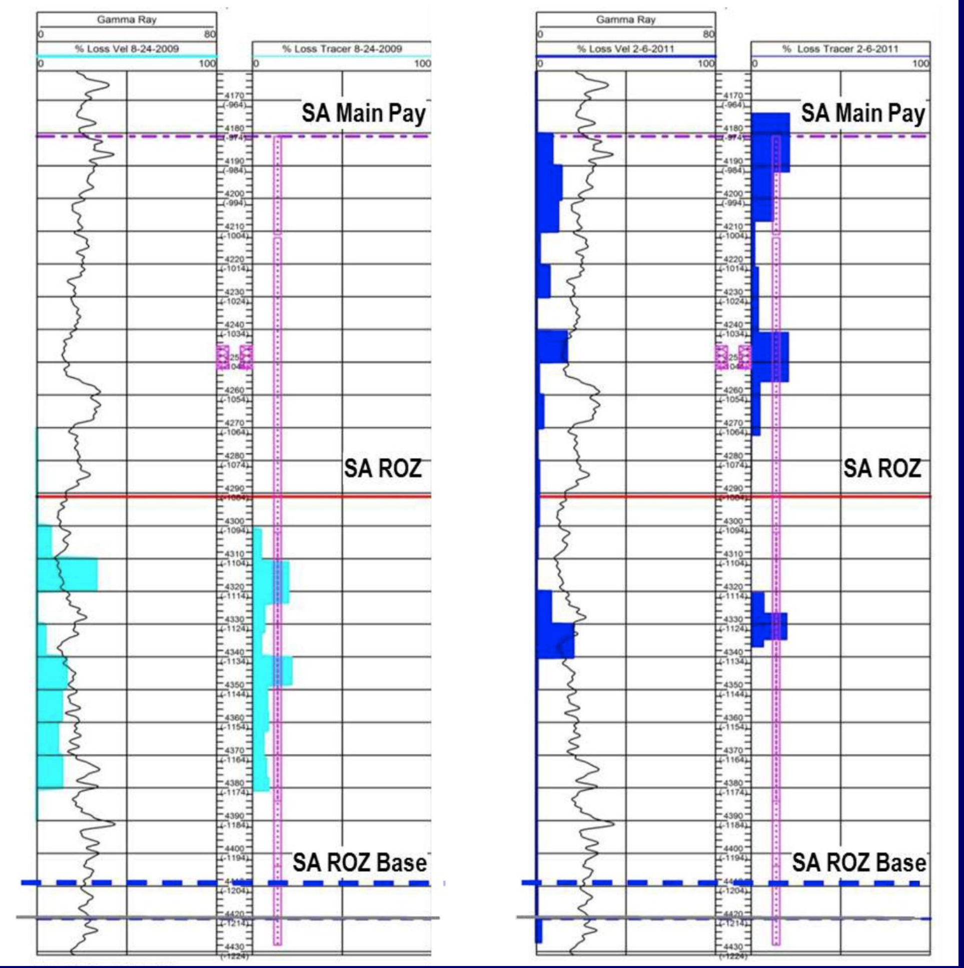
Reservoir Interval	Type of CO2 Injection Well Completion			
	OH	Partial Perf Plus OH	Dual MPZ/ROZ	ROZ Only
	(% CO_2)	(% CO_2)	(% CO_2)	(% CO_2)
Gas Cap	7%	25%	6%	0%
MPZ	72%	48%	77%	1%
ROZ	19%	20%	17%	99%
Other	2%	7%	0%	0%

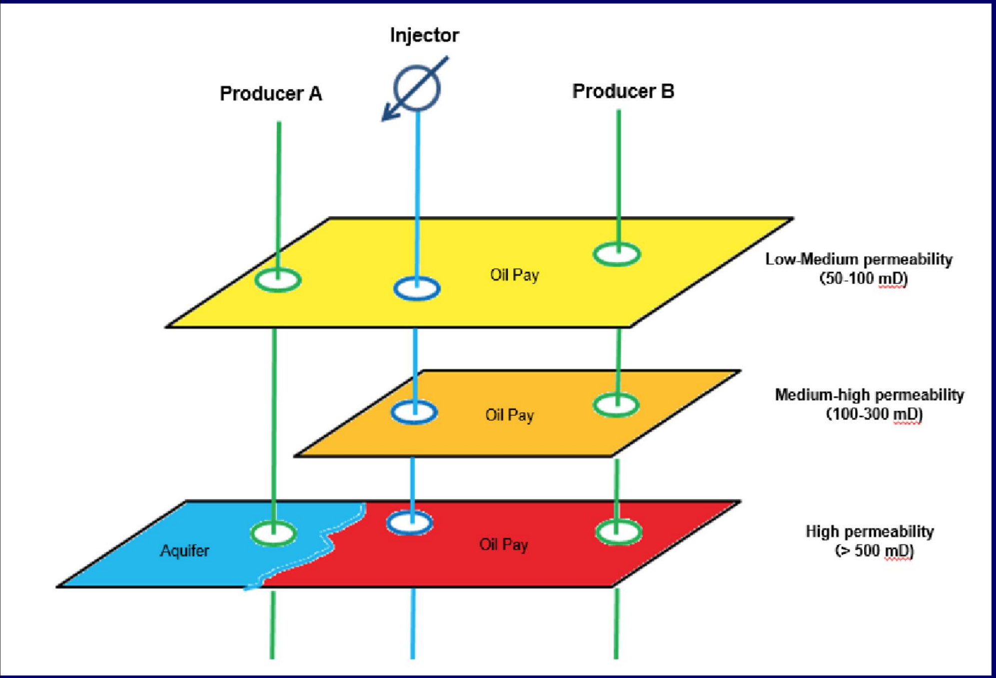
Question:

Which well is ROZ only completion?

What is Well B's completion?

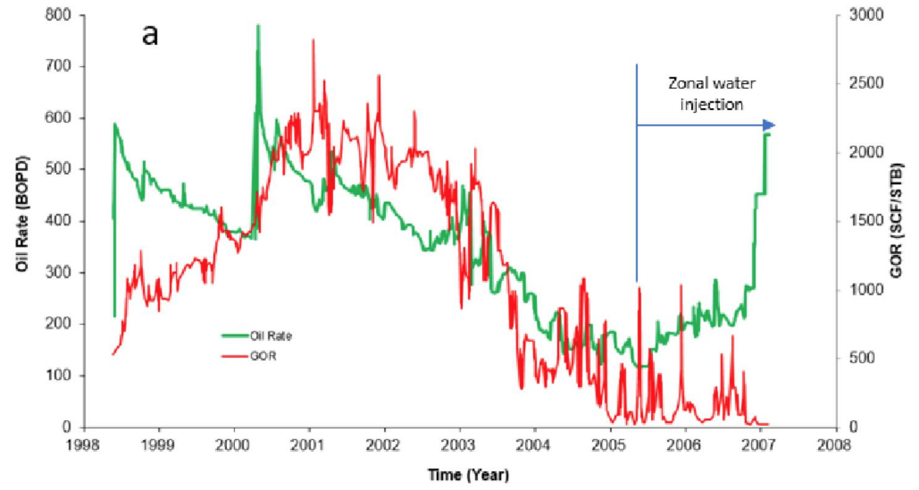
Well A　　　　Well B

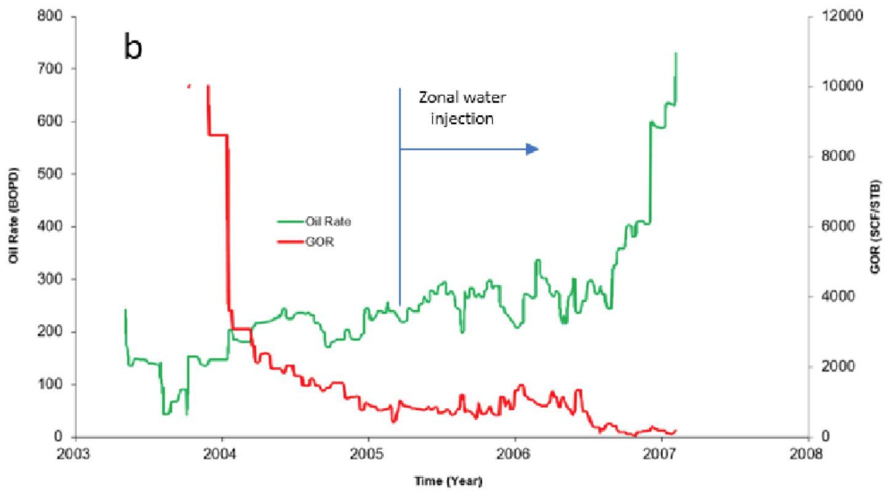




Waterflooding OPTIMIZATION- Injection Adjustment: Zonal water injection

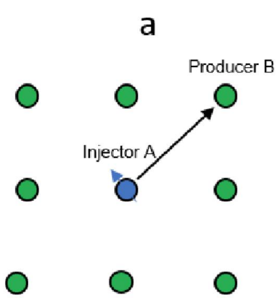
Lu and Xu, 2017, SPE-186431



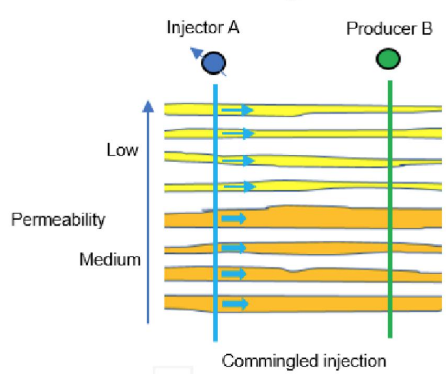


Well A **Well B**

Commingled Production for Multilayer payzones

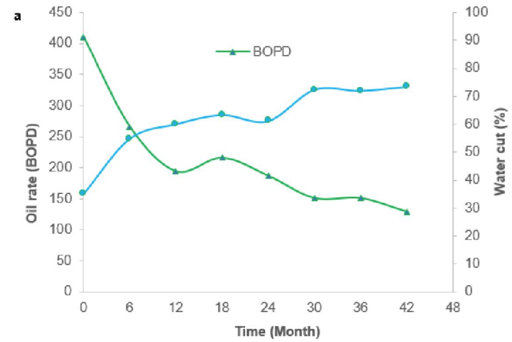


Inverted nine-spot pattern

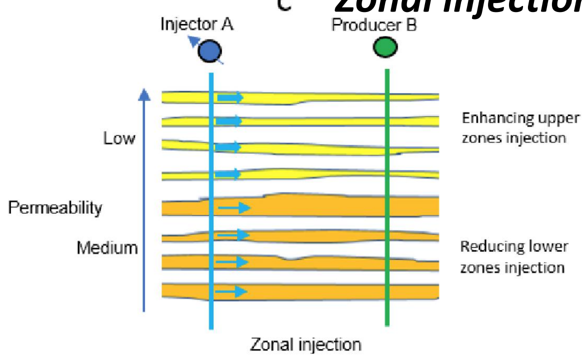


Bypassed

Commingled injection

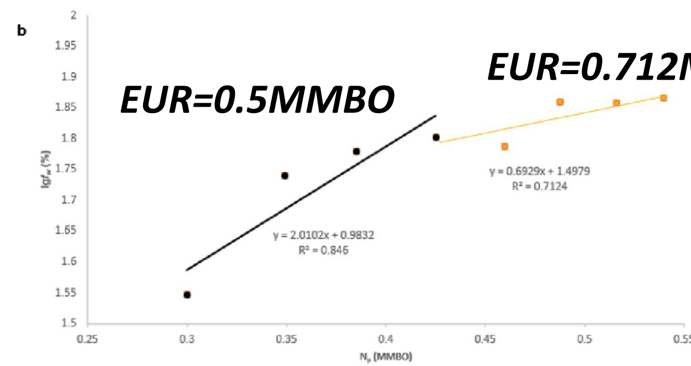


Zonal injection



EUR=0.5MMBO

EUR=0.712MMBO

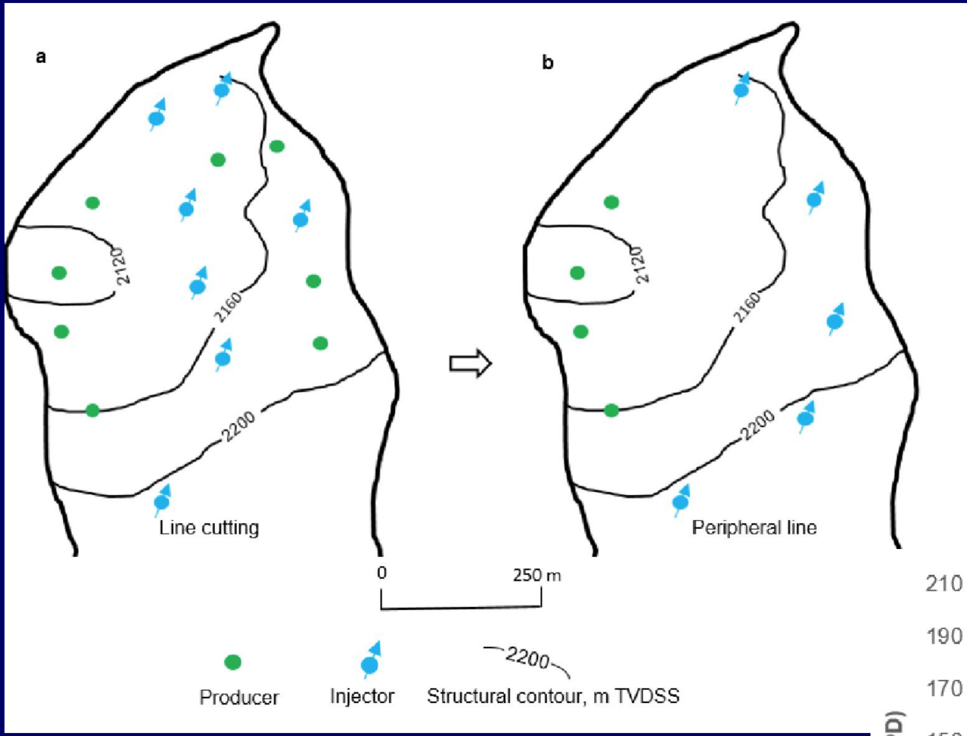


Lu and Xu, 2017, SPE-186431

commingled water injection resulting in water cut increase from 35% to 60%

zonal water injection resulting in enhanced injection in the upper interval and reduced injection in the lower interval

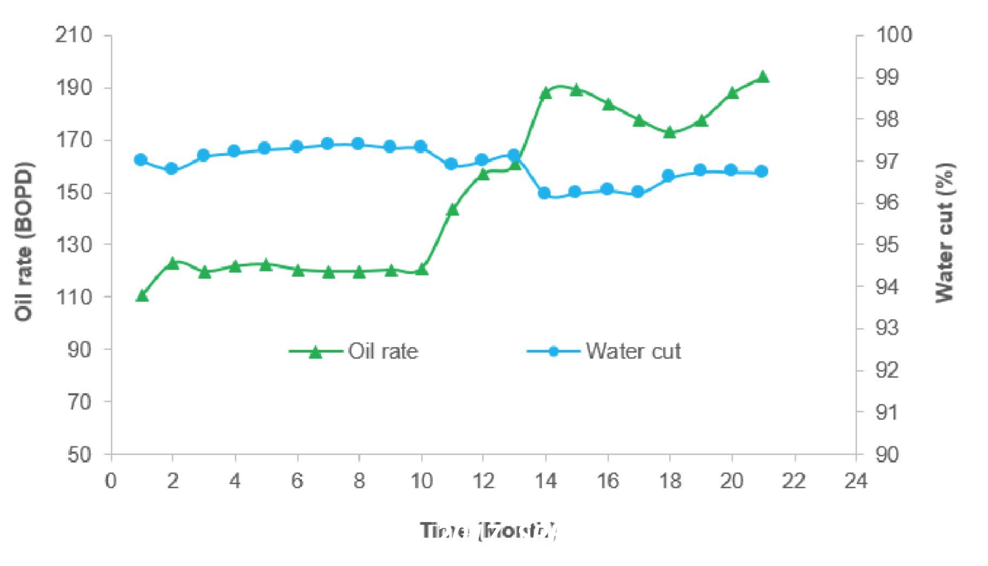
Changing pattern and injection direction



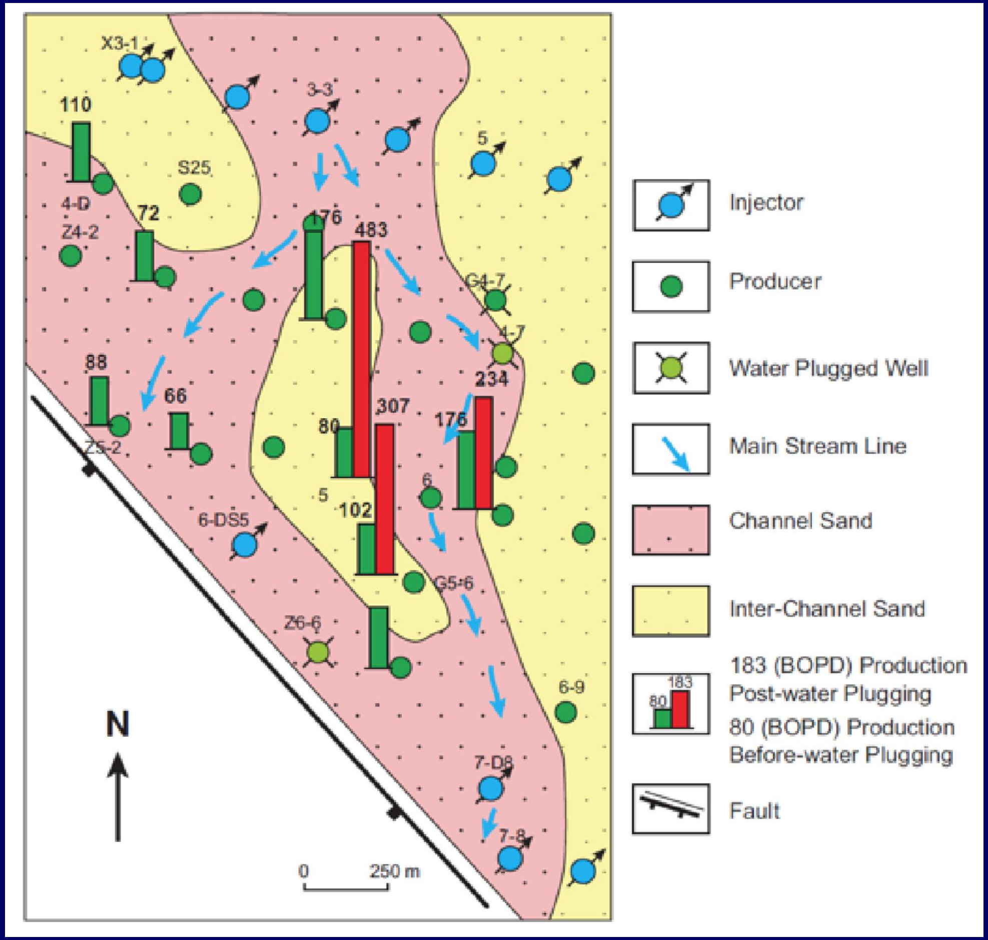
Line cutting

to

peripheral line injection



Water Shut-off to improve areal sweep efficiency



Question:

Why the areal sweep efficiency is improved?

Lu and Xu, 2017, SPE-186431

Subdividing the injection-production units

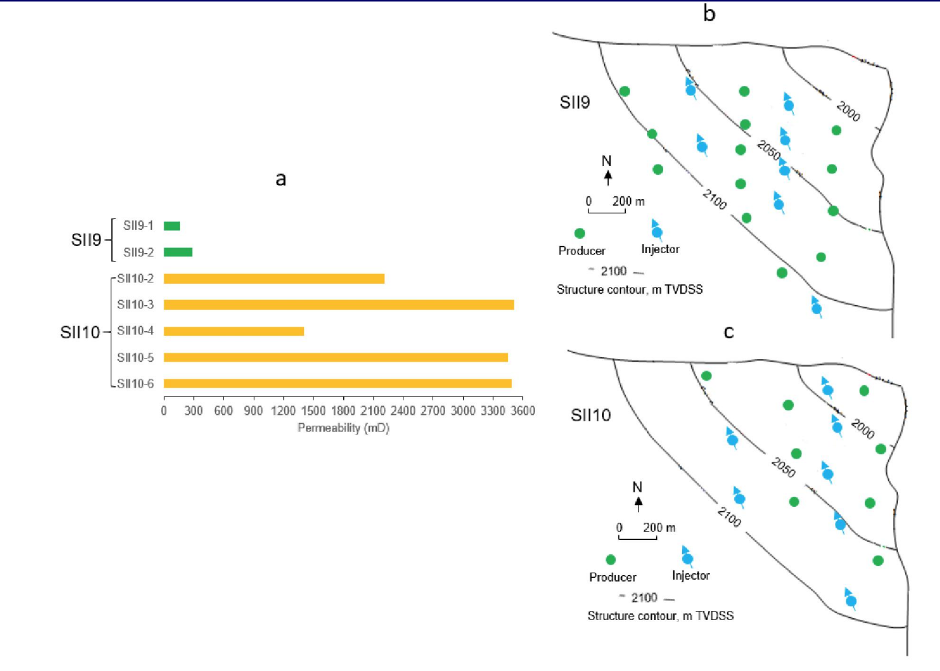


Figure 10—Diagram showing: a. permeability contrast among sub-units of SII9-10 reservoir; b. well pattern of SII9 after injection-production unit subdivision; and c. well pattern of SII10 after injection-production unit subdivision (Modified from Wang, 2011).

Spacing in SII9 was reduced from 300/260 m to 250/200 m with infill drilling

Spacing in SII9 was increased from 300/260 m to 480/300 m

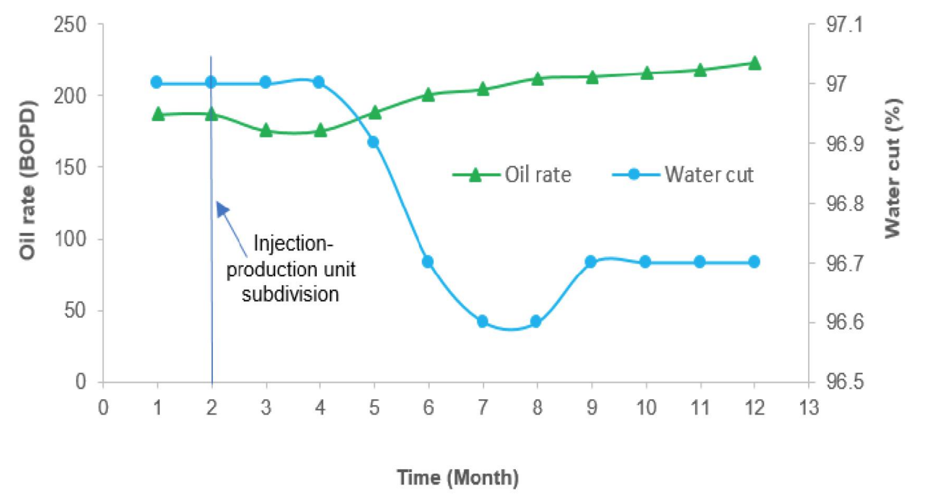
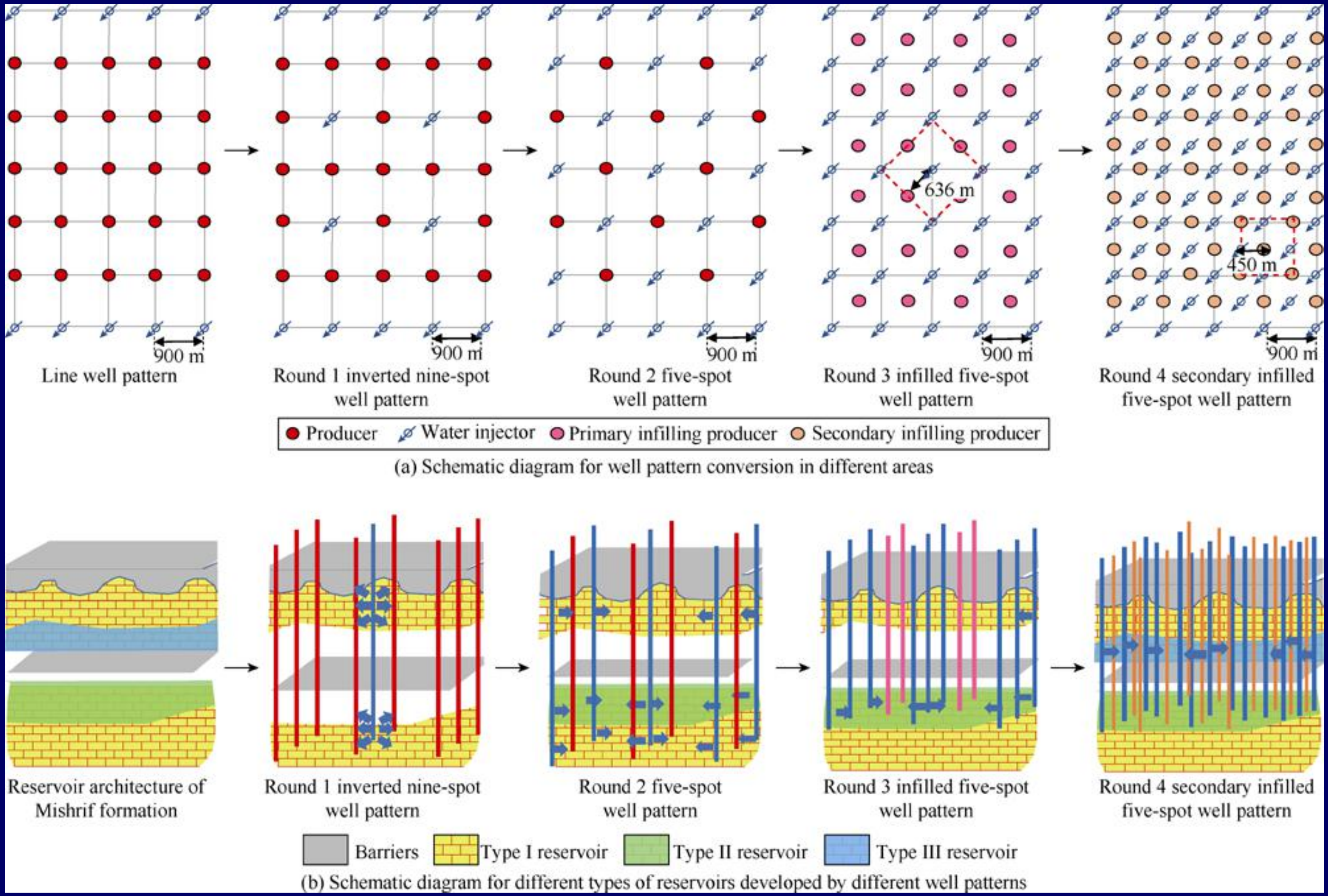


Figure 11—SII10 Unit production performance.

Lu and Xu, 2017, SPE-186431

Optimum development for MB1 layer of the Mishrif Formation of Halfaya

Schematic diagram of the areal waterflooding well pattern with " low injection rate for single well with uniform and stronger areal flooding efficiency" .



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