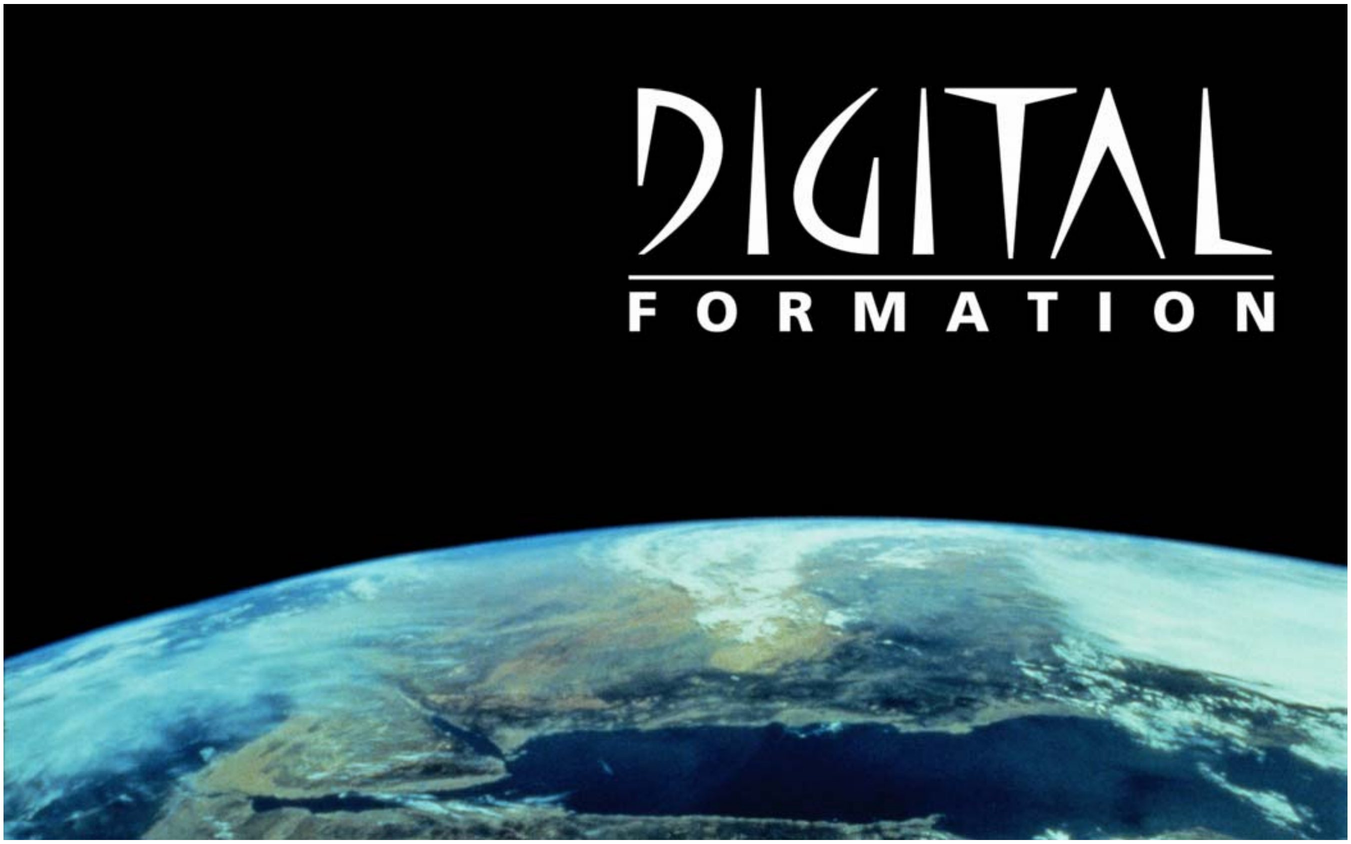

Capillary Pressure & Relative Permeability Petrophysical Reservoir Models

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May 2002

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Summary

Two novel approaches are discussed whereby capillary pressure and relative permeability measurements are combined with standard petrophysical analyses for an overall reservoir interpretation. Summaries of the techniques are:

Capillary Pressure Petrophysical Reservoir Model

What it does

- Identifies hydraulic units in pressure communication.
- Identifies hydrocarbon/water contacts.
- Highlights rock type differences.
- Distinguishes potential water sands in a gross hydrocarbon-bearing interval.

Requirements

- Representative capillary pressure measurements on the rock sequence — or from an analogue reservoir.
- Calculated petrophysical profiles of effective porosity and water saturation.

Relative Permeability Petrophysical Reservoir Model

What it does

- Quantifies effective permeabilities of water, oil and gas, level-by-level.
- Calculates cumulative permeabilities to each different fluid.
- Can be used to make quantitative estimates of formation damage.
- By combining with cumulative values of oil, gas and water pore volumes, can be used to define flow units of each fluid separately.
- Identifies overlapping flow units of different fluids.

Requirements

- Relative permeability measurements form the reservoir, or an analogue reservoir.
- Petrophysical analyses giving profiles of bulk volumes water, gas and oil. The ***LESA*** package from Digital Formation generates this output routinely.

Introduction

This report gives an overview, with examples, of two novel approaches to reservoir categorization by combining special core analyses with standard petrophysical analyses:

- The Capillary Pressure Model in which a theoretical water saturation profile, based on capillary pressure data, is compared with a routine petrophysical saturation profile. Comparisons yield a wide variety of reservoir interpretations including:

- ♦ Hydrocarbon/water contacts, even if below the total depth of the well.
- ♦ Hydraulic units in pressure communication and controlled by a single hydrocarbon/water contact.
- ♦ Differing rock types.
- ♦ Heights and locations of transition zones.
- ♦ Reservoirs that are isolated from their neighbors.
- ♦ Location and amount of mobile water.

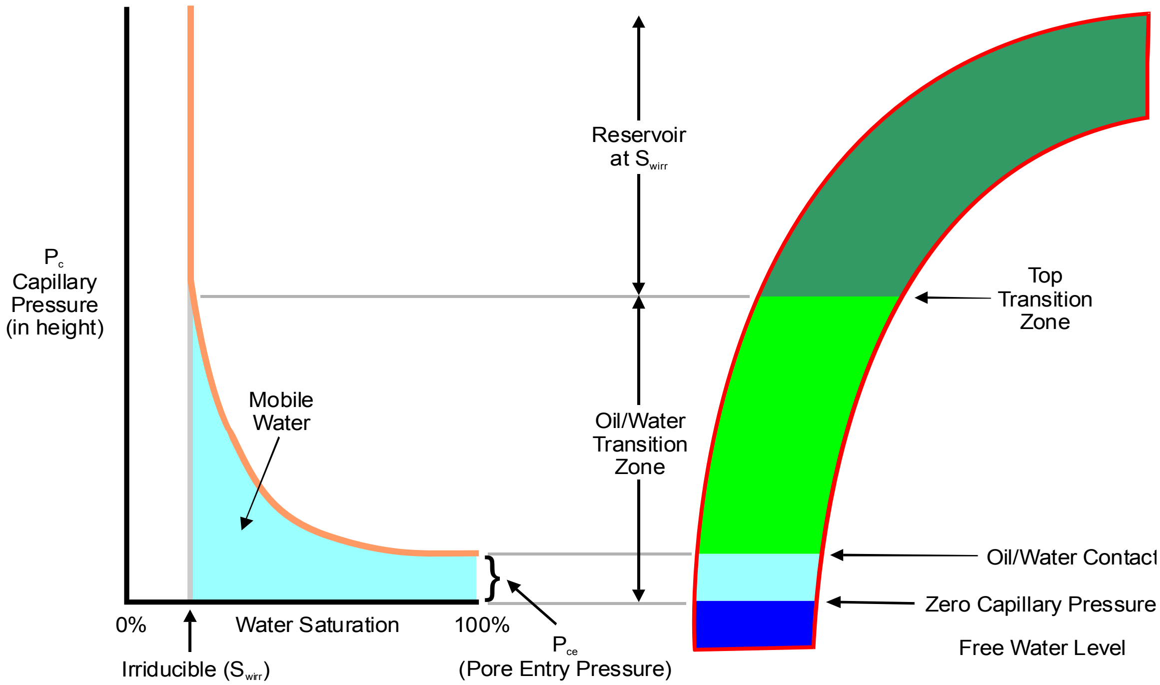
- The Relative Permeability Model, which defines, layer-by-layer, effective permeabilities of each fluid phase — oil, gas and water.
- The calculations allow:
  - ♦ Level-by-level definition of effective permeabilities to oil, water, gas.
  - ♦ Cumulative permeabilities for each fluid.
  - ♦ Definition of the degree of formation damage due to mud filtrate invasion if any, by determining effective permeabilities to oil and/or gas close to the wellbore.
  - ♦ By comparison with cumulative volumes of in-place oil, gas, and water, definition of flow units of each fluid separately.
  - ♦ Precise locations of overlapping flow units of each fluid — oil, gas, and water.

Capillary Pressure Petrophysical Reservoir Model

General

The figure below is a schematic relationship between a capillary pressure curve and oil accumulation.

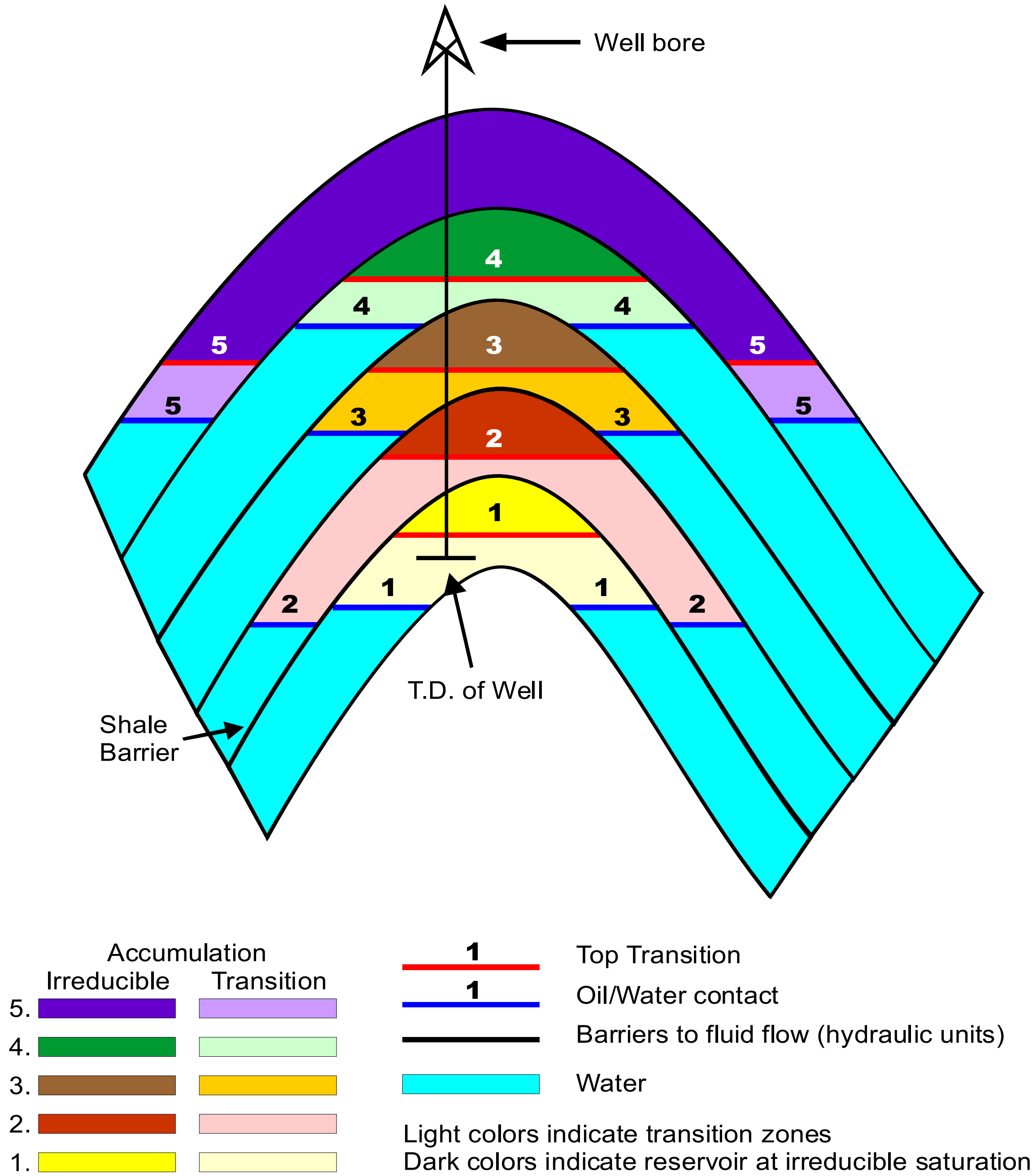
Relation of a single accumulation to capillary type curve



Terminology:

- Capillary Pressure (P_c) — converted from pressure to height above zero feet (or meters). Conversion depends on contact angles and interfacial tensions of laboratory and reservoir fluids.
- Irreducible water saturation (S_{wirr}) — water saturation of bound capillary water.
- Pore entry pressure (P_{ce}) — minimum pressure required before oil can begin to invade the pore structure.
- Transition zone — reservoir interval over which both oil and water will flow.

Schematic relations of multiple accumulations



In actual reservoirs, the fluid distributions are complicated by rock variation, as expressed by changing porosity and permeability both vertically and between wells. As a consequence of these changes, the water saturation/height functions are dependent upon the changing values of porosity from one depth to the next. The model presented here accounts for vertical reservoir variation within any single well bore.

Capillary Pressure Model

The deterministic method proposed here has, to our knowledge, no equivalents and is unique. It depends upon a suite of capillary pressure curves available that is experimentally reliable and representative of all (or most) reservoir rock types likely to be encountered. Fluid system(s) used to measure the capillary pressures are not critical, since all are converted into equivalent reservoir fluids.

For each capillary pressure curve, the following parameters are recorded:

- Porosity
- Permeability
- Pore entry pressure
- Irreducible water saturation
- Shape of the capillary pressure curve

These factors are combined with petrophysical calculations of the reservoir relating porosity to irreducible water saturation. A series of algorithms, which are specific to the reservoir examined, allow calculations to be made showing changes with depth of:

- Theoretical water saturation, specific to the particular porosity profile.
- Values of irreducible water saturation, again specific to the particular porosity profile.
- By difference the amount of potential mobile water at each level.

The level of zero capillarity (or free water level), that determines the theoretical saturation profile is the user's choice, and can be fixed by trial and error.

The theoretical saturation profile is compared with log-calculated water saturation. If there is divergence between the two curves, it is most often due to:

- An incorrect choice of the level of zero capillarity. However, any divergence might also be due to the incorrect log-calculated saturations (incorrect values of R_w, m, n, etc.).
- Changing rock type (changing bound water volumes)

Application of the Capillary Pressure Model to Reservoir Understanding

Information Available

The correspondence between theoretical and log-calculated saturation profiles can be used in a variety of ways:

- To identify, with precision, the level of free water, even if the well has not penetrated this level.
- To identify, again with precision, the hydrocarbon/water contact, even if the well has not penetrated this level.
- Height of the hydrocarbon/water transition zone, and, at any level, the potential bulk volume of the rock occupied by mobile water.
- Vertical intervals within the well that are in hydraulic continuity, with respect to any hydrocarbon/water system.
- Levels in the hydrocarbon column that might have been affected, at the time the well was logged, by offset production.
- Multiple free water levels in the same well, indicating multiple stacked accumulations.
- Changing rock types.
- Reservoirs in isolation from their neighbors.

The technique can be applied to wells that have no measured capillary pressure, so long as the same variation in rock type is represented on which the model is based. If the well has different rock types, not previously encountered, the model will not correlate.

Exploration and Geological Applications

For an exploration well that has an isolated accumulation, and/or the suggestions of a transition zone on the flanks of an accumulation the following data are available:

- Location of oil/water or gas/water contacts to help in estimates of volumetric reservoir content. These data can be compared with geological definitions of reservoir geometries having multiple wells.
- Structural elevation that has to be achieved so that porosity development is above the top of the transition zone. This would help in locating offset exploratory and/or stepout wells.
- Levels of the reservoir in hydraulic continuity. Any shales within each accumulation are likely to be laterally discontinuous; whereas, the shales (and/or other barriers) which separate accumulations are likely to be laterally continuous, at least over the area of the specific accumulation.
- Since the capillary pressure curves are characterized by a shape factor, there is information available concerning pore size distribution.

Production Engineering

Various potential applications are:

- Identification of intervals that, at least initially, should produce water-free hydrocarbons.
- Identification of intervals that, if completed, will produce hydrocarbons and water.
- Recognition of levels that have been affected by offset production (watered out).
- Identification of hydraulic units in pressure communication (stimulation design).

Reservoir Engineering

The main applications are:

- Definition of oil/water or gas/water contacts to calculate and map extent of the reservoir.
- An alternative to Leverett-J functions in describing saturation profiles through a single set of calculations, based only on the choice of zero capillarity depth.
- Recognition of different rock types with differing values of bound water volumes.

Relative Permeability Petrophysical Reservoir Model

General

Relative permeability measurements are made routinely on core samples, to define the relative amounts of fluids that will flow through the rocks, when more than one fluid phase is flowing. A typical example of an oil/water relative permeability measurement is attached.

Definitions are:

$k_{ro} = k_o/k_a$

$k_{rw} = k_w/k_a$

$k_{rg} = k_g/k_a$

o, w, g = oil, water, gas

k_r = relative permeability

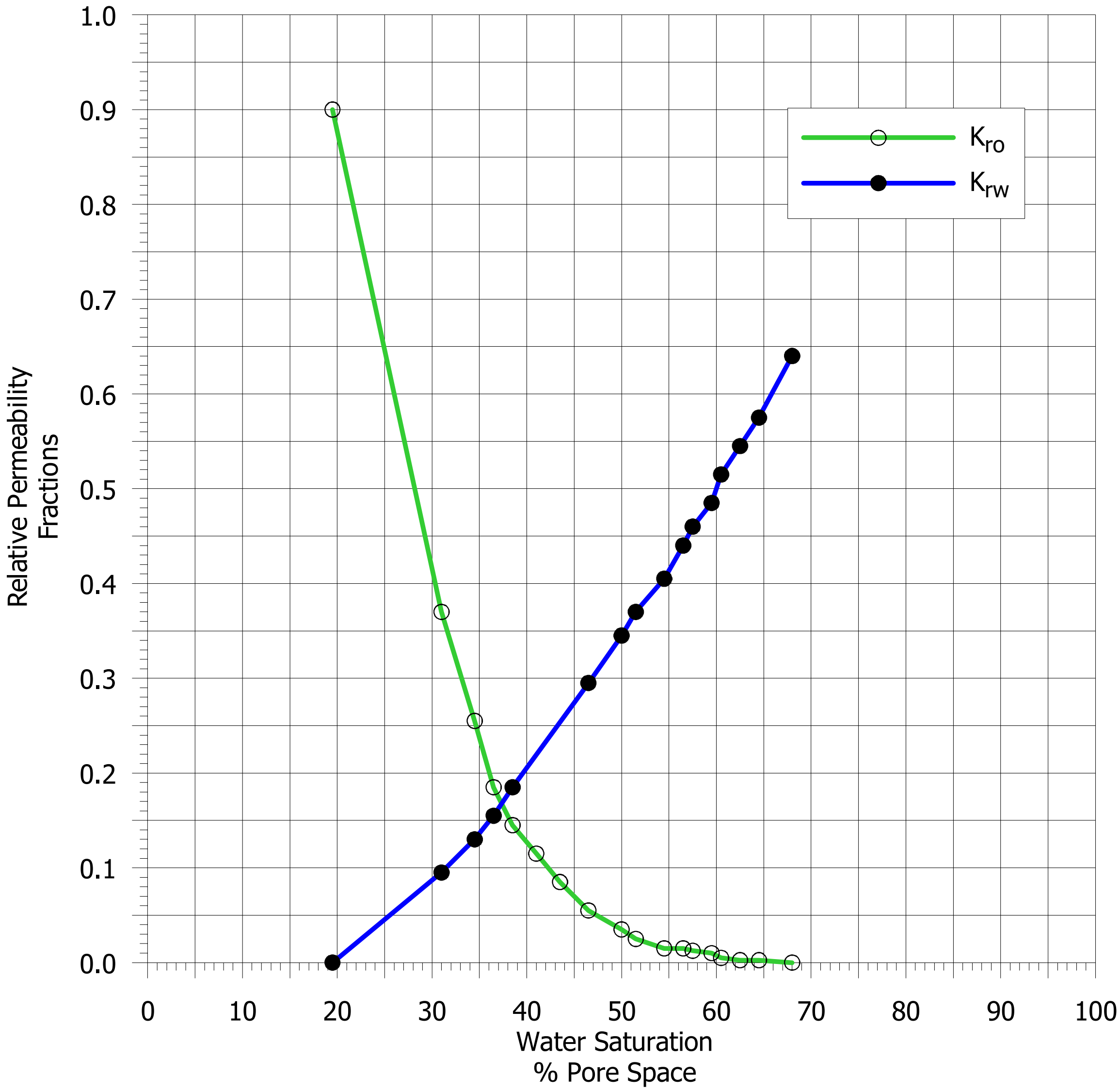
k = permeability to a specific fluid, o, w, or g

k_a = klinkenberg or theoretical "air" permeability

A description of relative permeability reservoir characteristics is essential to describing fluid flow. Often, because the experiments are costly and time-consuming, only a limited number are collected even in major reservoir studies.

The approach described here combines normalized relative permeability curves with petrophysical analyses of porosity and water saturations, to derive, level-by-level, the following parameters:

- Relative and effective permeabilities to oil, water, and gas in both uninvaded and invaded zones.
- Cumulative effective permeabilities to oil, water, gas.
- A quantitative estimate of wellbore damage caused by invasion of mud filtrate into the formation.



The petrophysical software essential to the interpretations - Digital Formation's ***LESA*** software has the unique capability of determining oil, gas, and water saturations both close to and remote from the wellbore. This is required information to make the necessary calculations described here. A density/neutron/resistivity log suite is essential. Additionally, ***LESA*** allows petrophysical modeling to estimate permeability from porosity/water saturation relationships. These calculations are best calibrated by comparing with core-measured values of porosity, and permeability.

Methodology

(1) From examination of all relative permeability curves available from the reservoir, general relationships are developed relating each saturation phase to its respective relative permeability:

- S_w and k_{rw}
- S_o and k_{ro}
- S_g and k_{rg}

These relations may be porosity dependent.

(2) Using an empirical transform, determine the permeability profile for the well under consideration. In the ***LESA*** software, one routine approach is to determine permeability from the equation:

$$k = \frac{62{,}500 \times Phie^{m}}{S_{wi}^{\;2}}$$

Where phie = effective porosity,

m = exponent - standard is 5, but dependent upon the rock type can vary from 4 to 7

S_{wi} = irreducible water saturation

In the ***LESA*** program, comparisons are made, level-by-level, between log calculated S_w and a theoretical S_{wi} based on a “bulk volume water at irreducible” (BVWI) — often 0.05 is used as a first estimate, but should be verified by the interpreter. The lower of S_w and theoretical S_{wi} is used to calculate permeability.

(3) For the uninvaded zone, level-by-level calculations of both relative and effective permeabilities are made, based on “far-wellbore” saturation calculations:

Water = S_w - from deep reading resistivity log

Oil [1] = S_{one} - using the neutron log depth of investigation

Gas [1] = S_{gne} - using the neutron log depth of investigation

(4) For the invaded zone, level-by-level calculations of both relative and effective permeabilities are made, based on “near wellbore” saturation calculations:

Water = S_{xo} - from shallow reading resistivity log

Oil [1] = S_{od} - using the density log depth of investigation

Gas [1] = S_{gd} - using the density log depth of investigation

---

[1] Methodology of calculations described in Holmes and Holloway “Oil, Gas, and Water Saturation Calculated as Separate Entities from Density, Neutron, and Resistivity Logs” SPWLA, Lafayette, June 1990.

Applications to Reservoir Description

- Level-by-level definition of effective permeabilities (and comparison between them) to gas, oil, water.
- Level-by-level definition of relative permeabilities of each fluid phase.
- Recognition of water-bearing levels, and magnitude of water effective permeability.
- From cumulative permeability curves, recognition of major levels of contribution to flow capacity of oil, gas, and water.
- By comparing invaded with uninvaded zone permeability calculations, a quantification estimate of near wellbore damage due to mud filtrate invasion is available, level-by-level.
- Cross plots of cumulative volumes and cumulative permeabilities of each fluid phase yield depth locations of intervals contributing to fluid flow (flow units).

Examples

Three examples are attached:

(1) T.P. Scott No. 5 Harrison County, Texas
Low permeability sandstone gas reservoir (Travis Peak Formation)

(2) S.F.O.T. No. 1 Nacogdoches County, Texas
Low permeability sandstone gas reservoir (Travis Peak Formation)

(3) Edenborn 19, Natchitoches Parish, Louisiana
High permeability limestone gas condensate/oil reservoir (Pettet Formation)

For the two low permeability gas reservoirs, information is presented (in Track 2) comparing theoretical water saturation from the capillary pressure model with petrophysically-defined water saturations. Mismatches are highlighted.

Yellow S_w theoretical > S_w petrophysics

Magenta S_w theoretical < S_w petrophysics

Track 3 shows bulk volume of water (blue) and gas (red). Core porosity and core permeability are compared with petrophysical estimates.

Track 4 shows the interpreted locations of each gas/water contact, and its companion hydraulic unit (color-coded).

Track 5 is a comparison between theoretical irreducible water saturations and petrophysically defined water saturation. Potential mobile water is highlighted in blue.

Track 6 is a calculation of effective permeability to water (blue) and gas (red).

Track 7 is a relative permeability ratio, gas: water.

Track 8 is the cumulative permeability to gas and water. For gas > water, color fill is red.

On the right side of the plot is a schematic representation of the hydraulic unit groupings and locations of each gas/water contact.

Coded on each plot are the essential features of the model interpretation:

1) Gas/water contacts
2) Hydraulic units
3) Levels of moveable water
4) Gas/water transition zones

5) Different rock types

6) Changing effective permeabilities with depth for each fluid

For the high permeability gas/condensate reservoir, information is presented (in Track 2) showing variations in bulk volume of oil (green) and gas (red) and water (blue).

Track 3 shows effective permeabilities to each fluid phase, for the uninvaded zone.

Track 4 presents cumulative permeabilities for oil, gas, and water.

Track 5 is the gas/oil and oil/water relative permeability calculation.

Track 6 shows effective permeabilities to each fluid phase for the invaded zone.

Track 7 shows potential damage to oil and gas permeability due to mud filtrate invasion.

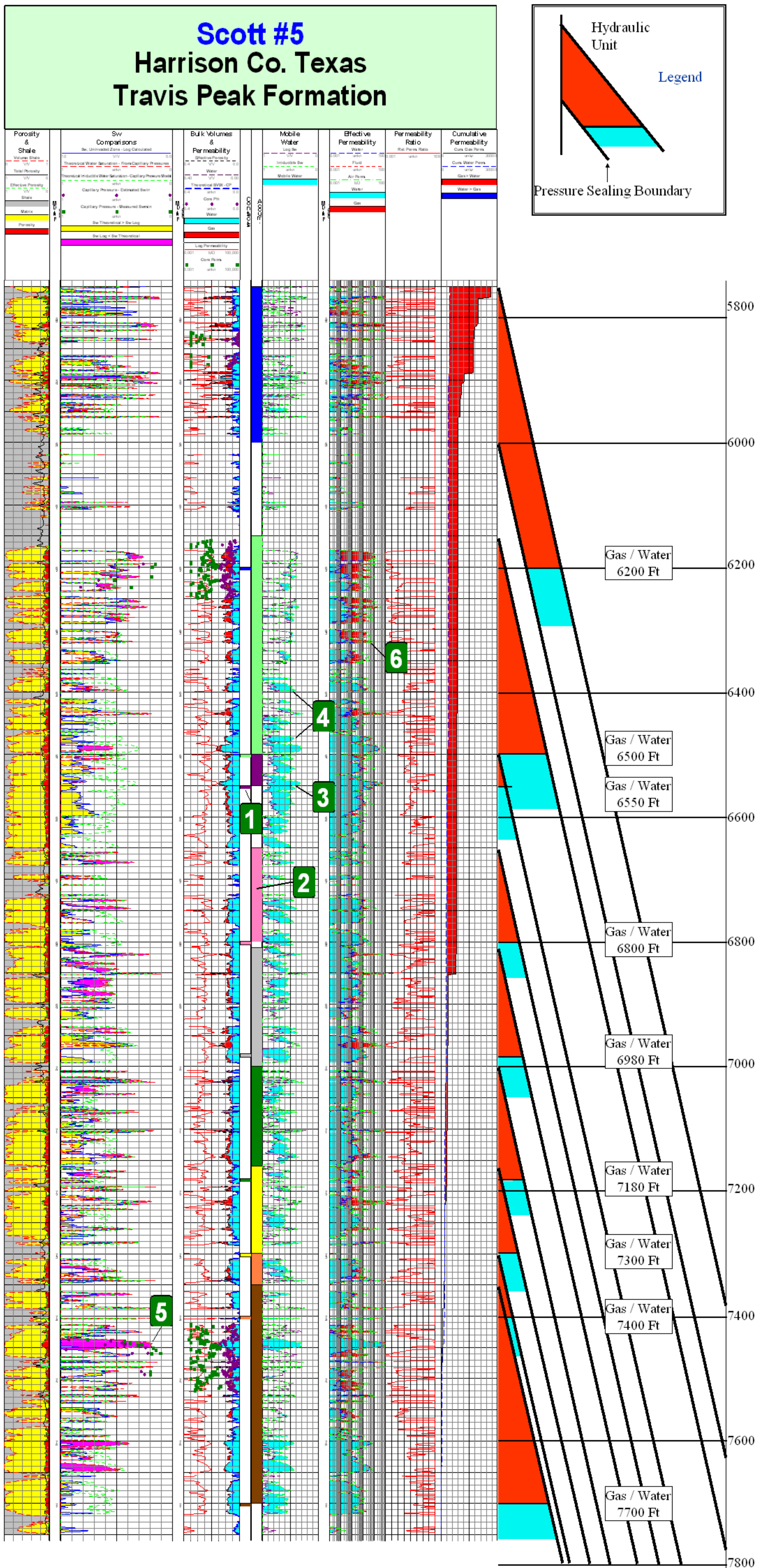
Track 8 shows location of flow units to water, oil, and gas.

T.P. Scott No. 5

Saturation comparisons (Track 2) show good comparisons over much of the gross interval (e.g. 7450 ft. to 7600 ft). Notable levels where the petrophysical calculations are much higher than theoretical are 7600 ft to 7610 ft. and 7435 ft. to 7450 ft. From independent geological studies these anomalous intervals are known to be a different rock type — clay lining, of the pores, leading to high capillary bound water volumes.

A good example of the gradually changing saturation gradient within a single hydraulic unit is 6150 ft. to 6500 ft. The amount of mobile water (Track 5) gradually decreases upwards. Top of the gas/water transition zone is at 6380 feet, indicating the thickness of the transition zone is 120 feet for this hydraulic unit.

From the cumulative effective permeability to gas curve, it is clear that most of the flow capacity to gas is concentrated above 6200 feet. It is also clear the mobile water might be associated with the gas (as at 5895 feet).



1 **Gas / water contacts**

2 **Hydraulic units**

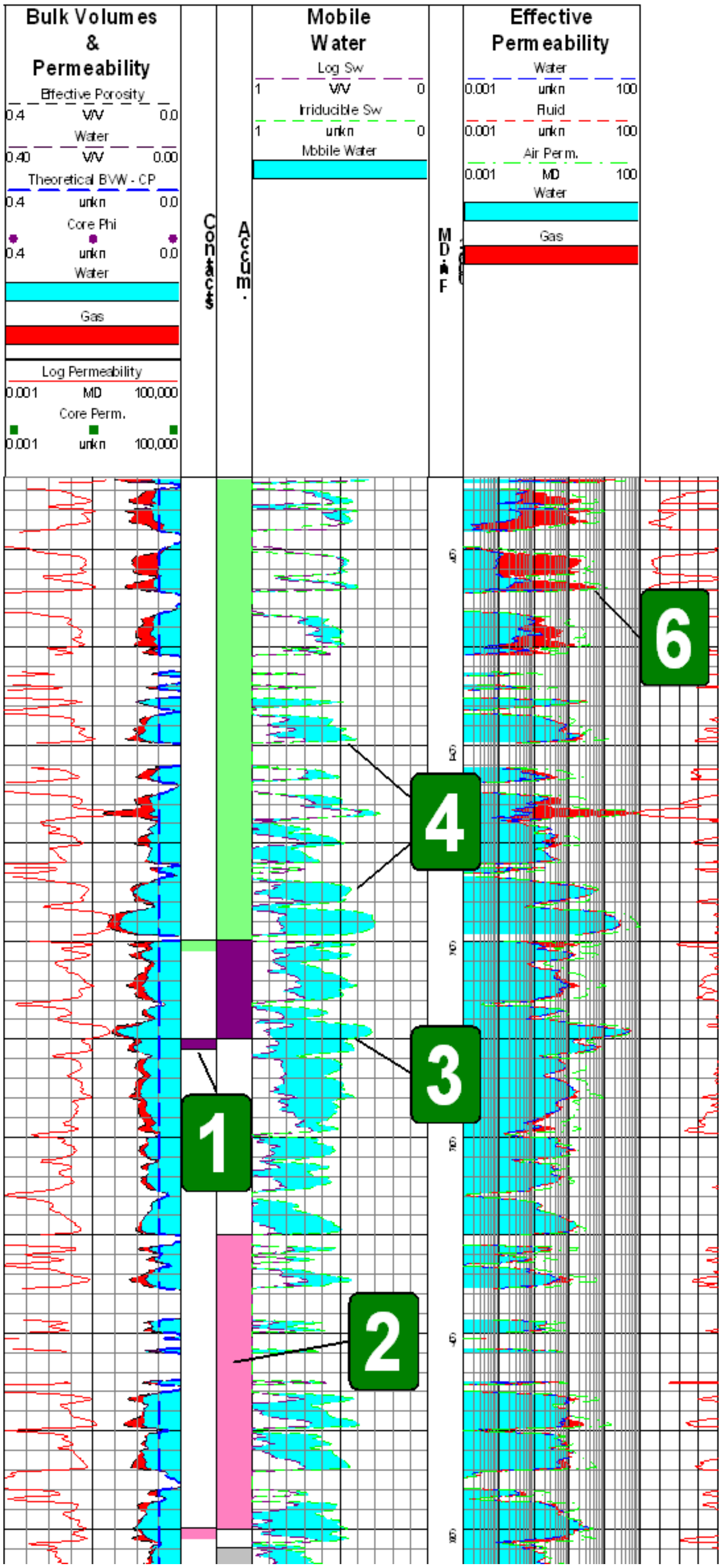
3 **Levels of moveable water**

4 **Transition zones**

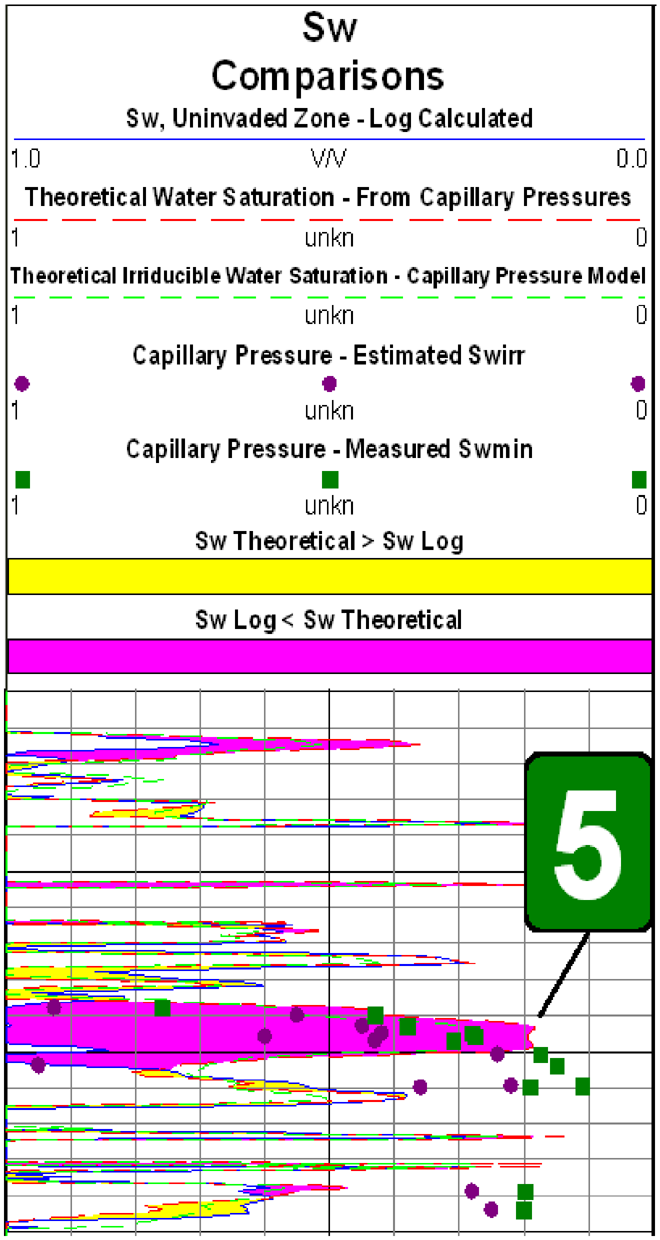
5 **Different rock types**

6 **Changing effective permeabilities with depth for each fluid**

Expanded View of Items #1, 2, 3, 4 & 6



Expanded View of Item #5

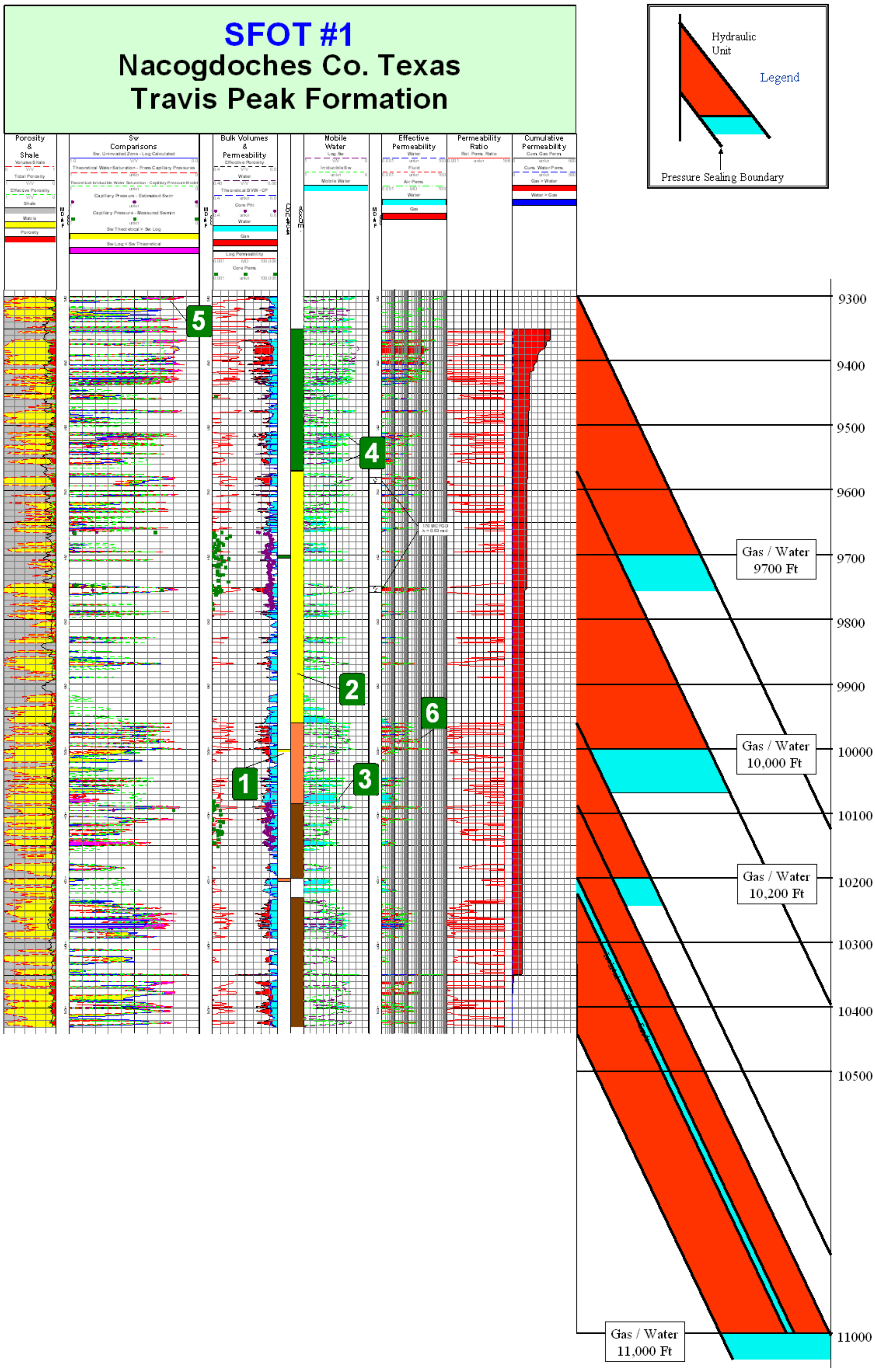


SFOT No. 1

As compared with Scott No. 5, there appears to be less rock type variation. Levels where there is discrepancy are mostly below 10090 feet. The level 10140 feet to 10150 feet is interpreted to have high capillary bound water, possibly in consequence of clay lining to the pore network.

Sands at 10200 feet to 10225 feet appear to be hydraulically isolated from sands both above and below. This might be a consequence of lateral termination (discontinuous sands).

There appears to be much less permeability to water than in the Scott No. 5 well. Most of the gas permeability is located in sands above 9450 feet.



1 Gas / water contacts

2 Hydraulic units

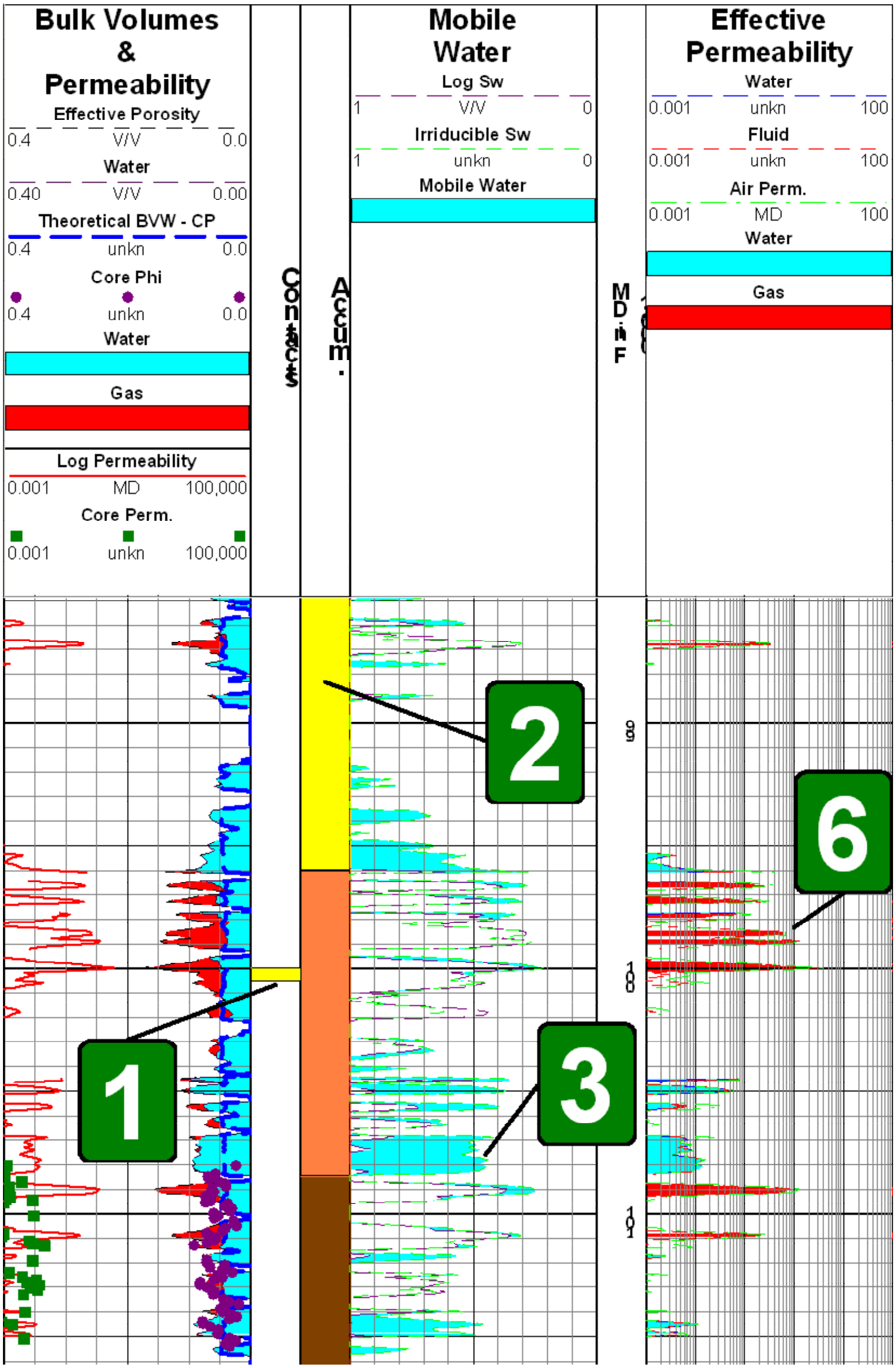
3 Levels of moveable water

4 Transition zones

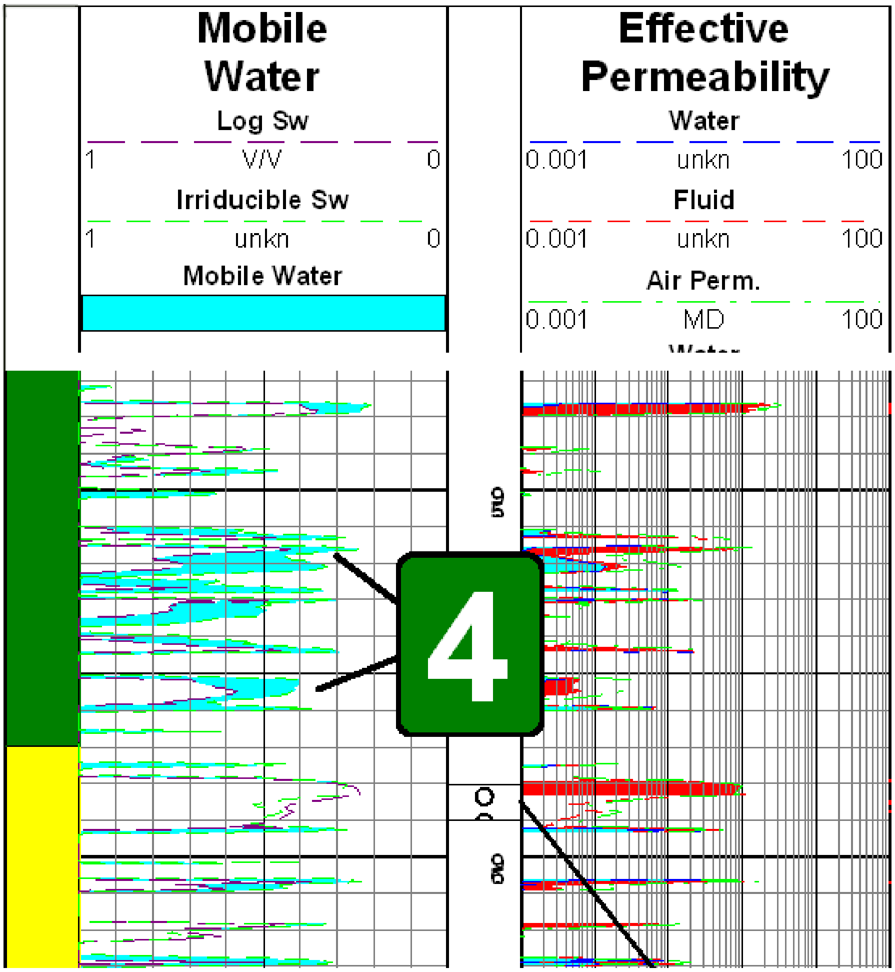
5 Different rock types

6 Changing effective permeabilities with depth for each fluid

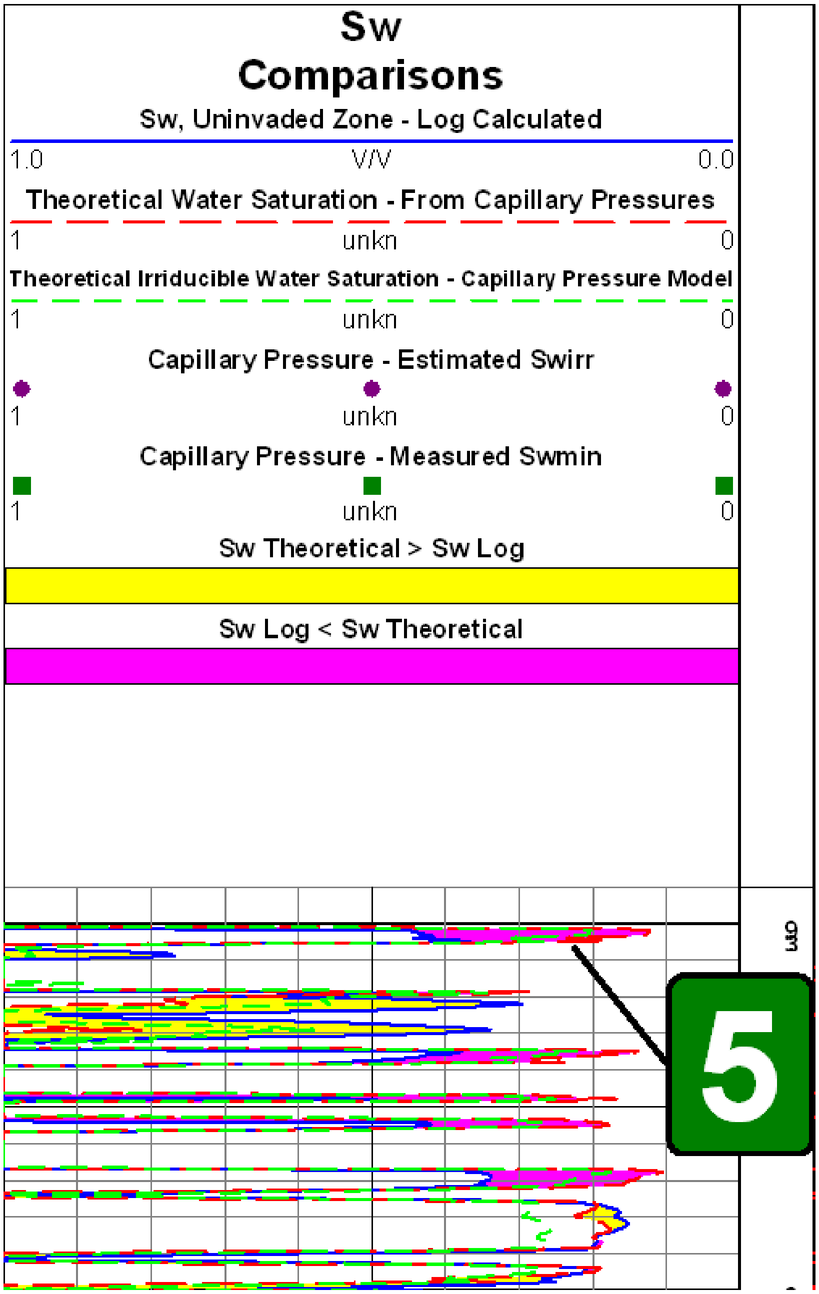
Expanded View of Items #1, 2, 3 & 6



Expanded View of Item #4



Expanded View of Item #5



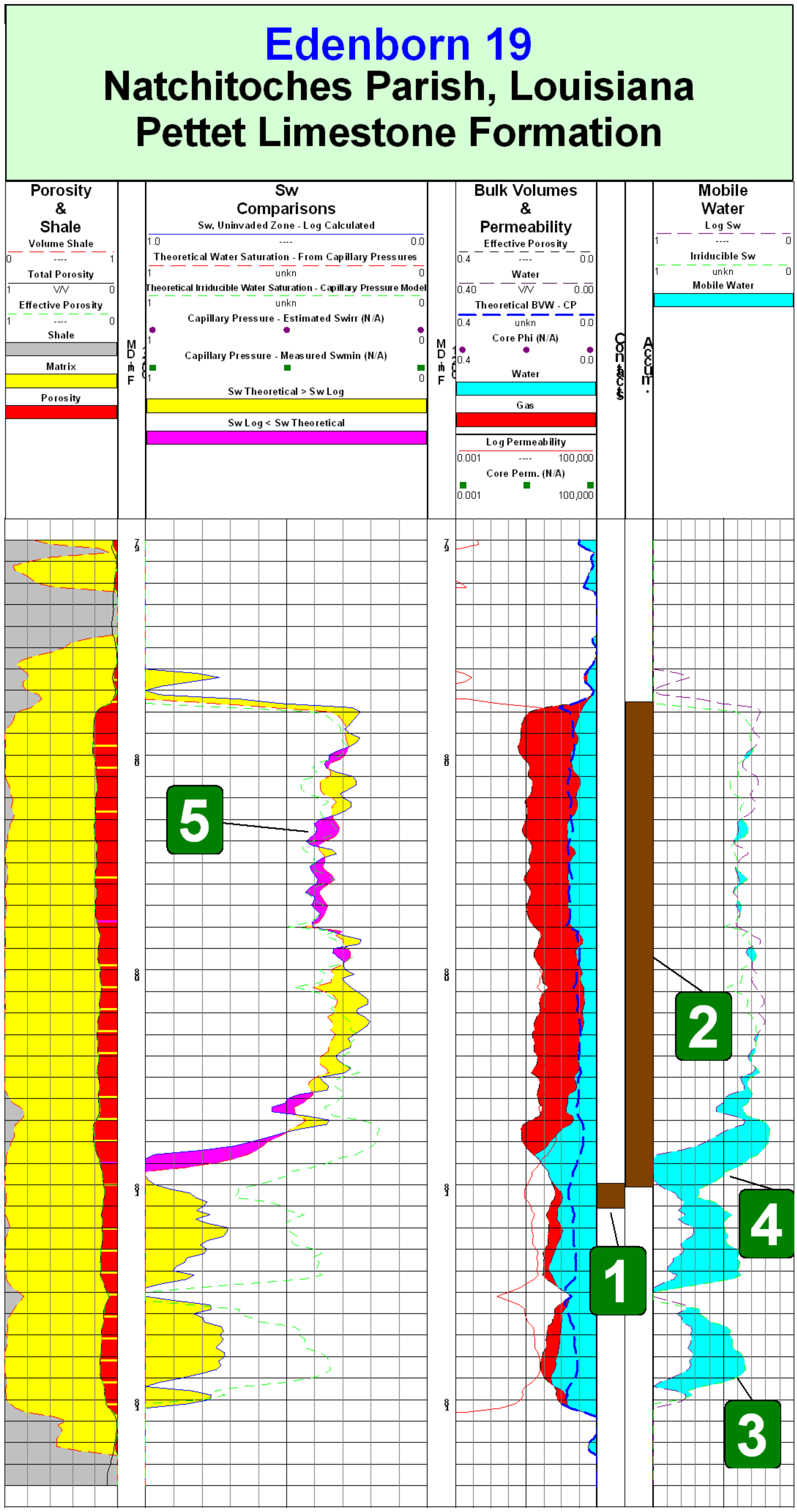
Edenborn 19

This limestone example is a gas/condensate reservoir with an oil zone at the base, and an oil/water contact at 8995 feet. A small amount of residual oil, with some free gas exists in the water zone. The well was drilled at depletion, and the small volumes of residual oil in the gas zone are a consequence of retrograde condensation.

A good suite of relative permeability measurements was used to calibrate the model. The profiles of changing effective permeabilities to each fluid show that the oil below the oil/water contact and in the gas zone is immobile. Levels showing permeability to water in the gas cap are probably erroneous, and a consequence of changing rock type. The accompanying capillary pressure analysis on Edenborn 19 shows changing rock type (higher capillary bound water) at the same levels.

Comparisons of the damaged zone permeabilities (Track 6) with undamaged (Track 3) suggest significant permeability reduction, particularly to oil. A quantification of damage is shown in Track 7.

Three cross plots show comparisons between cumulative permeability and cumulative volume for oil, gas, and water. These are similar to Lorenz plots, and can be interpreted to locate flow units — locations where there are rapid increases in permeability. Each of these intervals are recognized by color-coding on the cross plots, and the same data are included on the relative permeability depth plot. There is some overlap of flow units in the oil and water zones, at the depth levels 8077 feet to 8082 feet, and 8087 feet to 8091 feet, at the base of the oil/water transition zone.



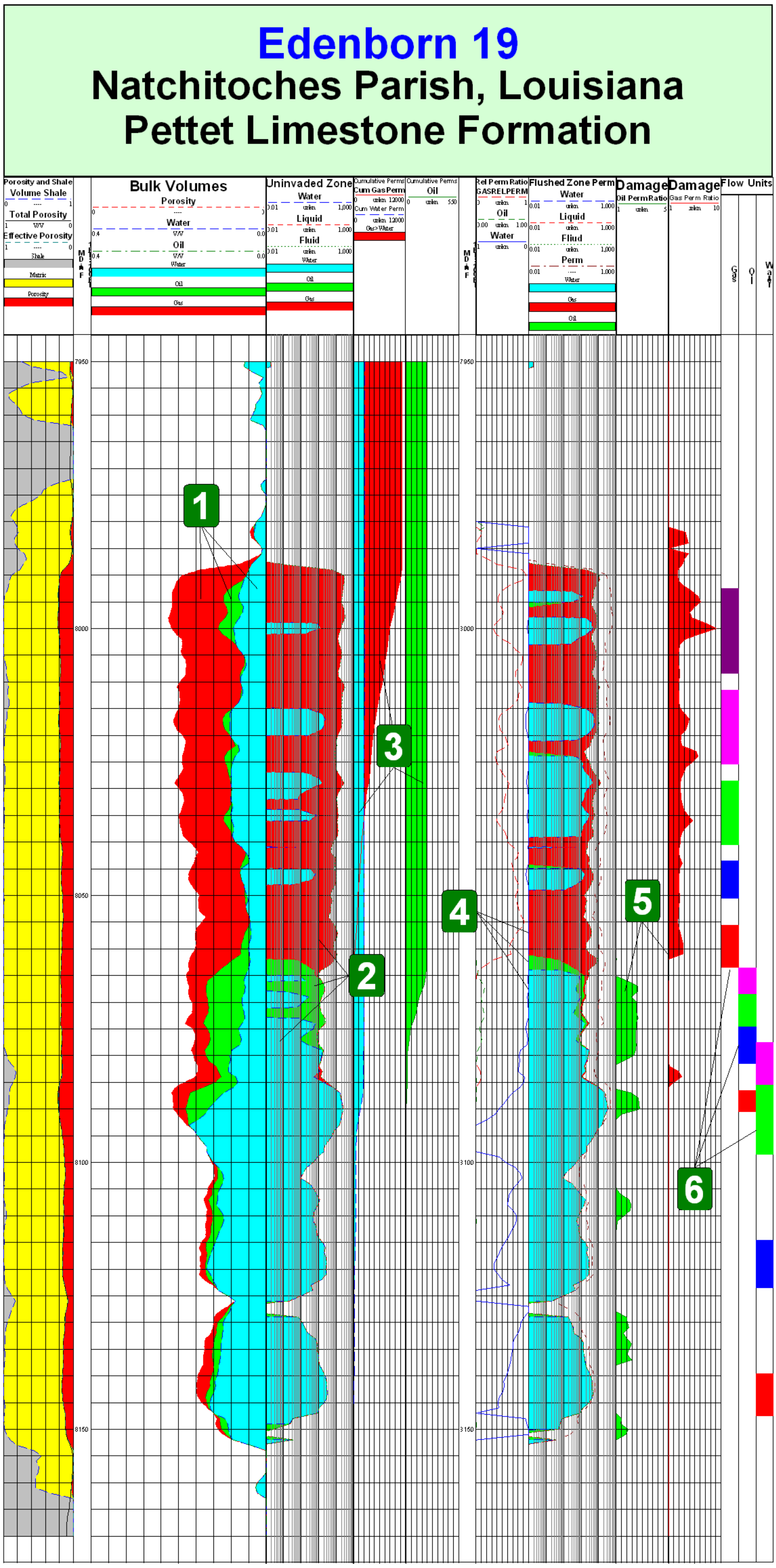
1 **Oil / water contacts**

2 **Hydraulic units**

3 **Levels of moveable water**

4 **Transition zones**

5 **Different rock types**



1 Bulk volumes

2 Effective permeabilities

3 Cumulative permeabilities

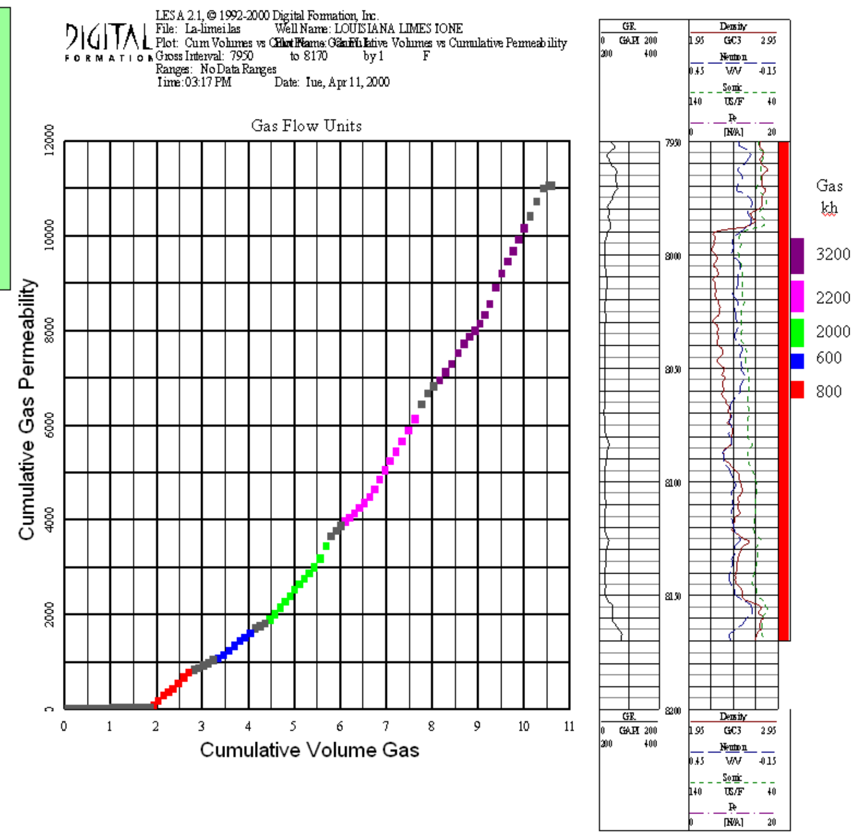
4 Effective permeabilities in damaged zones

5 Quantitative estimate of damage due to mud filtrate invasion

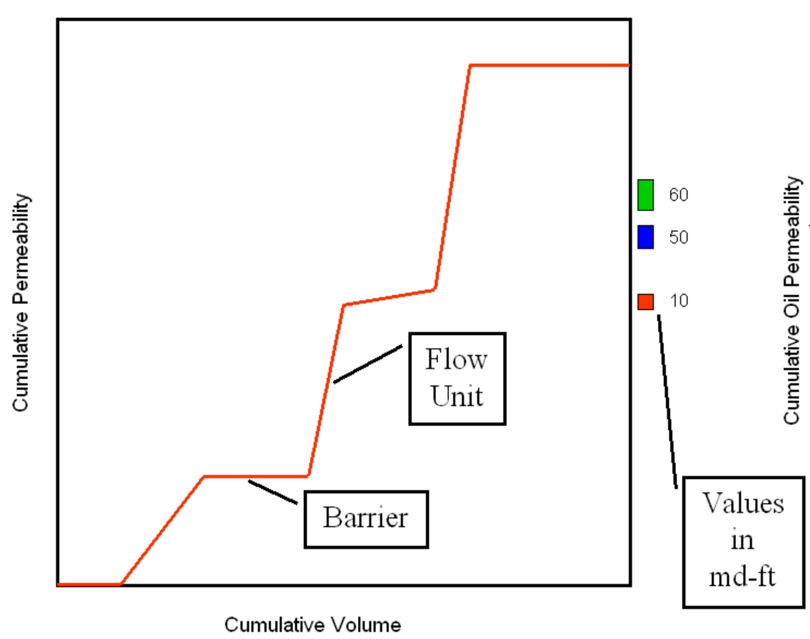
6 Location of flow units

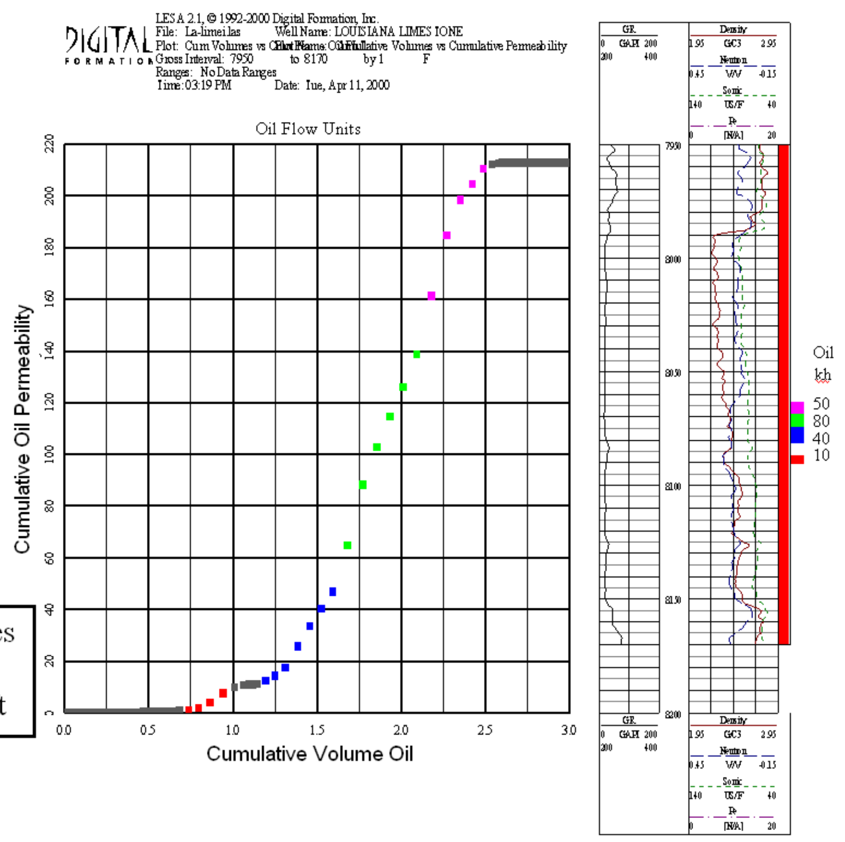
Edenborn 19

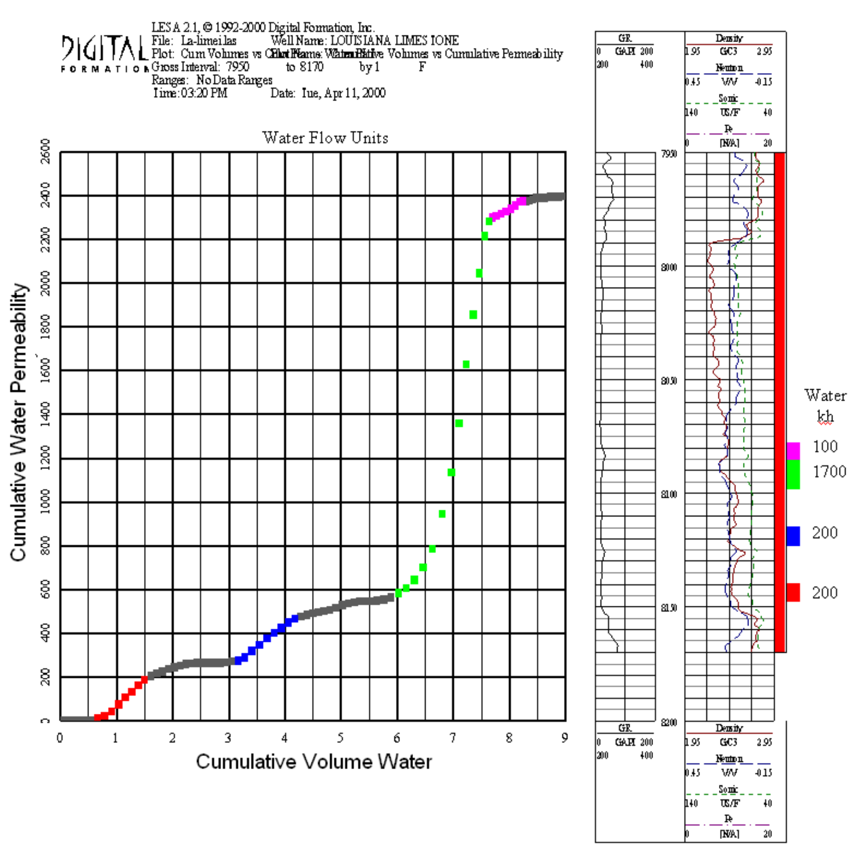
Natchitoches Parish, Louisiana
Pettet Limestone Formation



Flow Units for gas, oil and water







DIGITAL FORMATION

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