Lecture 9 summary:

Reservoir Management Modeling – Part 2

4.2. Rock Properties modeling:

The different parameters that must be digitized for use in a grid include elevations or structure tops, permeability in three directions, porosity, gross thickness, net-to-gross thickness, descriptions of faults, fractures, and aquifers.

The resulting maps are digitized by overlaying a grid on the maps and reading a value for each grid block. The digitizing process is sketched in Figures 24-1a through 24-1d.

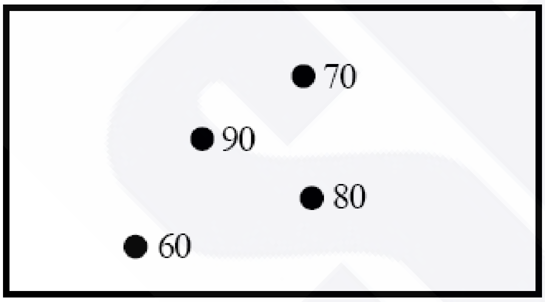

Figure 24-1a. Gather data

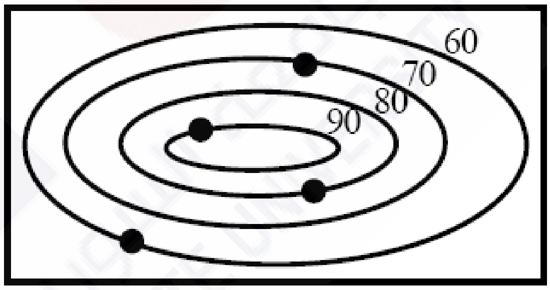

Figure 24-1b. Contour data

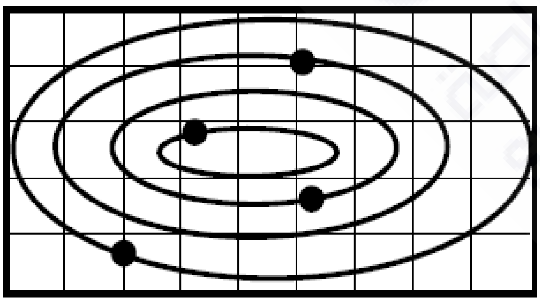

Figure 24-1c. Overlay grid

60	60	60	65	65	65	60	60	60
60	60	75	80	82	80	75	67	60
65	75	85	90	90	86	80	70	64
60	70	75	77	78	77	74	65	60
60	60	60	65	66	65	62	60	60

Figure 24-1d. Digitize data

There are two modern methods for distributing rock properties: reservoir geophysics and geostatistics.

Information obtained from reservoir geophysics is improving our ability to "see" between wells in a deterministic sense.

By contrast, geostatistics provides a reservoir characterization that is statistical. Many modelers view geostatistics as the method of choice for sophisticated reservoir flow modeling.

A deterministic model is a single representation of reservoir geology. The uncertainty associated with a deterministic model can be estimated by estimating the model sensitivity to uncertainties in available data.

A stochastic model is a set of realizations obtained from the probability distributions developed during the geostatistical analysis of data.

The process of preparing a geologic model requires the development of a structural and stratigraphic framework using available seismic and well data. Multiple realizations may be generated and used to quantify uncertainty in the geologic model. The process of translating point observations to a conceptual geologic model is a sequential process. It is also an iterative process if a match of time-dependent (dynamic) data is included in the preparation of the final reservoir model. Once the framework exists, a lithofacies model and petrophysical properties can be incorporated in the flow model.

4.3. Fluid Modeling

In general, fluid behavior is best modeled using an equation of state. Table 9 shows some cubic equations of state (EoS) used in commercial compositional simulators. In addition to pressure (P), volume (V), and temperature (T), the EoS contains the gas constant R and a set of adjustable parameters $\{a, b\}$ which may be functions of temperature. The EoS in Table 9 are called "cubic" because they yield a cubic equation for the compressibility factor $Z = PV/RT$. In the case of an ideal gas, $Z = 1$.

Table 9 Examples of Cubic Equations of State

Redlich-Kwong	$P = \frac{RT}{V-b} - \frac{a/T^{1/2}}{V(V+b)}$
Soave-Redlich-Kwong	$P = \frac{RT}{V-b} - \frac{a(t)}{V(V+b)}$
Peng-Robinson	$P = \frac{RT}{V-b} - \frac{a(t)}{V(V+b)+b(V-b)}$
Zudkevitch-Joffe	$P = \frac{RT}{V-b} - \frac{a(T)/T^{1/2}}{V[V+b(T)]}$

The two most common types of reservoir fluid models are black oil models and compositional models. Black oil models are based on the assumption that the saturated phase properties of two hydrocarbon phases (oil and gas) depend on pressure only.

Compositional models also assume two hydrocarbon phases, but they allow the definition of many hydrocarbon components.

Equations of state must be used to calculate equilibrium relations in a compositional model.

This entails tuning parameters such as EoS parameters {*a*, *b*} in Table 9. Several regression techniques exist for tuning an EoS. They usually differ in the choice of EoS parameters that are to be varied in an attempt to match lab data with the EoS.

Figure 25 shows typical property behavior of oil properties for a black oil model. Oil properties are oil formation volume factor (B_o), oil viscosity (μ_o), and solution GOR (R_{so}). Both saturated and undersaturated curves are included as functions of pressure only. Phase changes occur at the saturation pressures. Single-phase oil becomes two-phase gas-oil when pressure drops below the bubble point pressure (P_b).

Simulators run most efficiently when fluid property data are smooth curves. Any discontinuity in a curve can cause numerical difficulties.

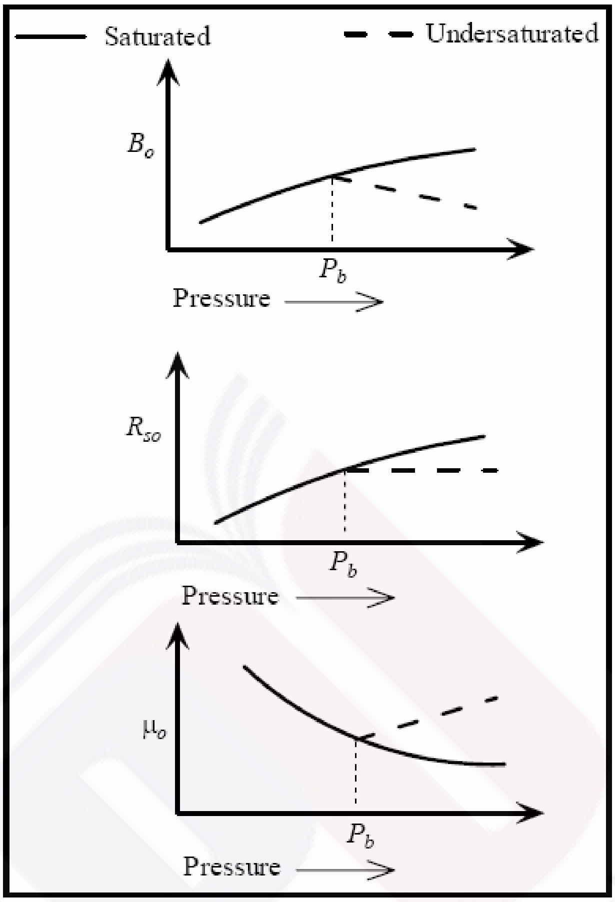

Figure 25. Oil Phase Properties

4.4. Capillary Pressure and Transition Zones modeling

Capillary pressure is often included in reservoir simulators to help establish the initial distribution of fluids.

The capillary pressure concept is also used to simplify the handling of the phase pressures and potentials in the flow equations. The differences in phase pressures: $P_{cow} = P_o - P_w$ and $P_{cgo} = P_g - P_o$ are the capillary pressures for oil-water and gas-oil systems, respectively. Experimentally P_{cow} and P_{cgo} have been observed to be functions of water and gas saturations, respectively.

Capillary pressure data is used for determining initial fluid contacts and transition zones.

The relationship between capillary pressure and elevation is used to establish the initial transition zone in the reservoir.

If capillary pressure is neglected, transition zones are not included in the model.

Figure 26 illustrates a dipping reservoir with fluid contacts and no transition zones. Figure 27 shows the effect of neglecting capillary pressure when a grid is used to represent the reservoir. The fluid content of the grid block is determined by the location of the grid block midpoint relative to a contact between two phases.

The grid block midpoint is shown as a dot in the center of the grid blocks in Figure 27. Figures 28 and 29 illustrate the initialization of a model containing a nonzero capillary pressure curve.

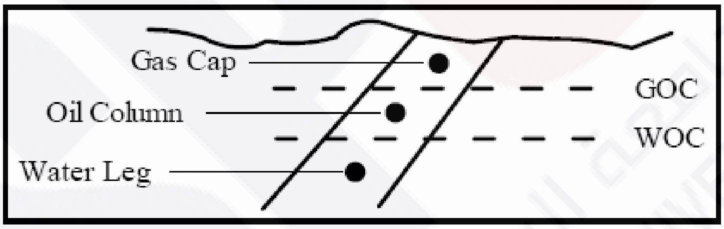

Figure 26. Case 1: Neglect Transition Zones

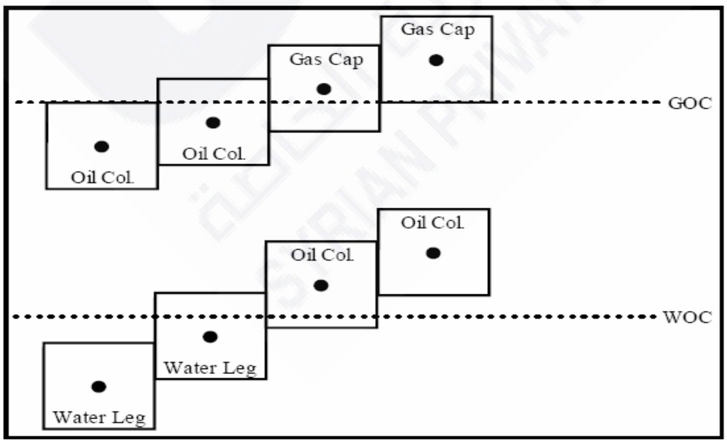

Figure 27. Initial Fluid Distribution without Transition Zone

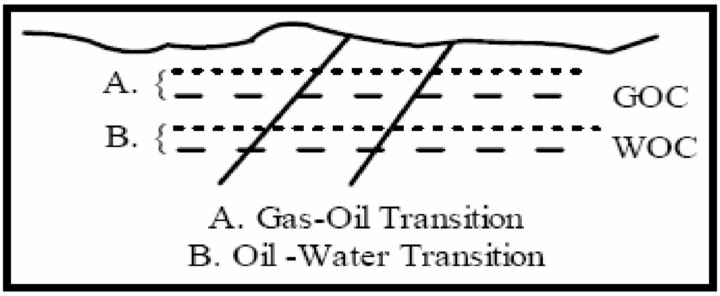

Figure 28. Case 2: Include Transition Zone in Model

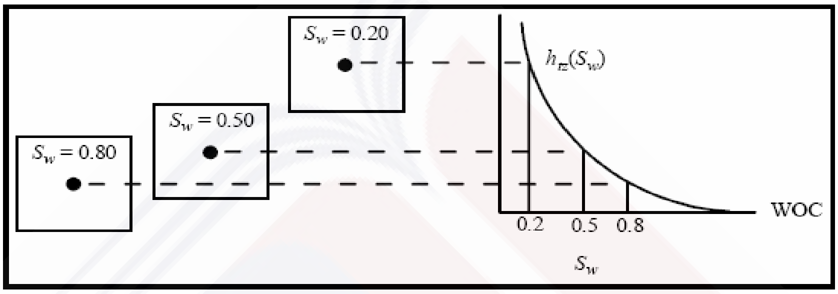

Figure 29. Initial Grid block Saturations with Transition Zone

Transition zones complicate the identification of fluid contacts because the definition of fluid contact is not universally accepted.

4.5. Upscaling

All of the information collected at various scales must be integrated into a single, comprehensive, and consistent representation of the reservoir.

The integration of data obtained at different scales is a difficult issue that is often referred to as the upscaling.

One way to integrate available data is to apply the flow unit concept.

A flow unit is defined as "a volume of rock subdivided according to geological and petrophysical properties that influence the flow of fluids through it". A reservoir is modeled by subdividing its volume into an array of representative elementary volumes (REV). The REV concept is not the same as the flow unit concept. A flow unit is a contiguous part of the reservoir that has similar flow properties as characterized by geological and petrophysical data.

Table 10 Properties Typically Needed to Define a Flow Unit

Geologic	Petrophysical
Texture Mineralogy Sedimentary Structure Bedding Contacts Permeability Barriers	Porosity Permeability Compressibility Fluid Saturations