Reservoir geology

An understanding of the geology of the reservoir is essential to its development, production, and management. This include both the external geology of the reservoir — what created the hydrocarbon trap — and the internal geology of the reservoir — the nature of the rocks in which the hydrocarbons exist. This article focuses on what an engineer needs to know about the external and internal geology to understand the reservoir from which he or she is planning to produce hydrocarbons.



**Contents**

* [1Need for understanding of geology](https://petrowiki.org/Reservoir_geology#Need_for_understanding_of_geology)
* [2External geometry-reservoir traps](https://petrowiki.org/Reservoir_geology#External_geometry-reservoir_traps)
	+ [2.1Traps](https://petrowiki.org/Reservoir_geology#Traps)
	+ [2.2Seals](https://petrowiki.org/Reservoir_geology#Seals)
* [3Reservoir base](https://petrowiki.org/Reservoir_geology#Reservoir_base)
* [4Internal geometry-reservoir architecture](https://petrowiki.org/Reservoir_geology#Internal_geometry-reservoir_architecture)
	+ [4.1Sequence stratigraphy](https://petrowiki.org/Reservoir_geology#Sequence_stratigraphy)
* [5Nomenclature](https://petrowiki.org/Reservoir_geology#Nomenclature)
* [6References](https://petrowiki.org/Reservoir_geology#References)
* [7Noteworthy papers in OnePetro](https://petrowiki.org/Reservoir_geology#Noteworthy_papers_in_OnePetro)
* [8External links](https://petrowiki.org/Reservoir_geology#External_links)
* [9See also](https://petrowiki.org/Reservoir_geology#See_also)

Need for understanding of geology

The efficient extraction of oil and gas requires that the reservoir be visualized in 3D space. Engineers need a conceptual model of reservoirs. Conceptual models are an integral part of the decision-making process, whether that process involves selecting perforations or forecasting future production. However, most engineering measurements made on reservoirs have little or no spatial information. For example, a core measurement has no dimensional information, wireline logs and continuous core measurements are 1D, and production data and pressure information are volumetric but with unconstrained spatial information. Geologic information, on the other hand, contains valuable spatial information that can be used to visualize the reservoir in 3D space. Therefore, engineers should understand the geologic data that can improve their conceptual model of the reservoir and, thus, their engineering decisions.

The most important geologic information is the external geometry of the reservoir, defined by seals or flow barriers that inhibit the migration of hydrocarbons, forming a hydrocarbon trap. The buoyancy force produced by the difference in density between water and hydrocarbons drives migration. Migration will cease, and a hydrocarbon reservoir will form, only where hydrocarbons encounter a trap. Traps are composed of the following types of seals:

* Top
* Lateral
* Bottom seals

The geometry of traps can have origins of the following types:

* Structural
* Sedimentary
* Diagenetic

The second most important geologic information is the internal reservoir architecture. A reservoir is composed of rock types of varying reservoir quality that are systematically stacked, according to stratigraphic and diagenetic principles. The lateral distribution of depositional textures is related to depositional environments, and the vertical stacking of textures is described by stratigraphy, which is the geological study of the following aspects of rock strata:

* Form
* Arrangement
* Geographic distribution
* Chronologic succession
* Classification
* Correlation

Diagenesis, changes that happen to the sediment after deposition, can also control the lateral continuity and vertical stacking of reservoir rock types. This fact is most important in carbonate reservoirs, in which the conversion of limestone to dolostone and the dissolution of carbonate have a large effect on internal reservoir architecture.

The basic concern for most engineers is the spatial distribution of petrophysical properties, such as:

* Porosity
* Permeability
* Water saturation
* Relative permeability

To visualize the reservoir in petrophysical terms, the engineer must be able to equate measurements (log, core, or production) with geologic models because the measurements themselves do not contain spatial information. Linking engineering measurements with geologic descriptions is best done at the rock-fabric level because rock fabric controls pore-size distribution, which, in turn, controls:

* Porosity
* Permeability
* Capillary properties

Rock fabrics can be tied directly to stratigraphic models and, thus, to 3D space.

External geometry-reservoir traps

Hydrocarbons are formed by [anaerobic](https://petrowiki.org/Glossary%3AAnaerobic) decomposition of organic matter that accumulates from the deposition of plankton in deep ocean basins. Oil and gas are generated as the sediments are buried and the temperature rises. Oil is the first hydrocarbon to be generated, followed by wet gas, and lastly by dry gas. Once generated, oil and gas flow vertically and laterally through overlying sediments because of the density difference between hydrocarbons and formation water and they migrate through permeable formations until they encounter a reservoir trap in which oil and gas accumulate. Oil will fill the traps first because it is first to be generated. Higher temperatures resulting from continued burial cause gas to be generated. Migrating gas will displace oil from the traps because gas has a lower density. The displaced oil will migrate further updip and fill any trap encountered.[[1]](https://petrowiki.org/Reservoir_geology#cite_note-r1-1)

Traps filled with hydrocarbons are often referred to as pools. However, engineers normally use the term reservoir instead of pool for an oil and gas accumulation. A field is composed of one or more reservoirs in a single area. A trap is defined by the geometry of its seals, which are formations with very low permeability and very small pores that will impede or stop the flow of hydrocarbons. To trap migrating hydrocarbons, seals must contain flow in 3D: the seals must form a closure. In the simplest terms, a trap is similar to a box with its bottom removed. The box is the seal composed of top and lateral seals. A trap may also contain a bottom seal. Imagine a smaller box inserted into the base of the original box. The smaller box is also a seal and confines the reservoir to a layer within the larger box.

Seals may be in the form of impermeable lithologies or faults. The simplest traps are convex structures in which the sealing layer dips in all directions from a central structural high, forming domes or doubly dipping anticlines. More complex structural traps are formed when convex structures are truncated by faults or when faulting occurs around a piercement structure. Many traps are combinations of structural uplift, faulting, and stratigraphy, such as an updip pinchout of a sand body into an impermeable shale. A purely stratigraphic trap may form when deposition creates a topographic high that is encased by impermeable lithology, such as shale or salt.

The volume of oil and gas that can accumulate is defined partly by the height of the trap because any additional hydrocarbons will spill out the bottom. The base of the trap is therefore called the spill point (see **Fig. 1**). The trap may not be full because the height of the oil column will be controlled by the capacity of the seal to impede flow and the volume of oil that migrates to the trap. In addition, oil/water contacts need not be horizontal because subsurface fluids are rarely static, and the flow can cause the oil/water contact to tilt in the direction of flow.

* 

**Fig. 1 – Diagram description of hyrdrocarbon traps.**

**Traps**

Geologists commonly describe traps on the basis of their origin. Structural traps are closures formed by structural movements within the Earth, and stratigraphic traps are closures formed by sedimentation and diagenesis, without the need for structural movements. Structural/stratigraphic traps are closures formed by patterns of reservoir rock that impinge upon a structure. This organization will be used hereafter, even though new groupings based on sealing surfaces were suggested by Milton and Bertram.[[2]](https://petrowiki.org/Reservoir_geology#cite_note-r2-2)

Structural traps are formed most commonly by structural uplift and differential compaction. Typical structural traps are structural domes and doubly plunging anticlines (see **Fig. 1**). These traps have a structural high and quaquaversal dips (the seal dips away from a structural high in all directions). The bulk of the world’s oil is found in these four-way-closure traps,[[3]](https://petrowiki.org/Reservoir_geology%22%20%5Cl%20%22cite_note-r3-3) which were the first type to be exploited by surface mapping. Many major oil fields in the world were discovered by using surface mapping to locate domal structures.

A more complex method of forming a structural trap is by faulting and structural uplift (see **Fig. 1**). Faulted structures can vary from a simple faulted anticline to complex faulting around piercement structures and domal uplifts. Faulted structures are very common and form some of the most complex reservoirs known. Types of faults include normal, listric, reverse, and thrust, which are related to the stress fields generated during structural movement. Piercement traps (diapirs) are formed typically by salt moving up through a stack of sediment driven by the density difference between salt and quartz or carbonate. Closure is achieved by the uplift of sediments juxtaposed to the piercement dome, by the top seal being an overlying impervious bed and the lateral seals being formed by structural dip, by sealing faults, or by the piercement salt. Faulted reservoirs commonly have a bottom seal formed by the lower contact of sand with shale. The bottom seal, along with the oil/water contact within the sand body, forms the base of the reservoir.

Structural/stratigraphic traps are formed by a combination of:

* Structure
* Deposition
* Diagenesis

The most common form, the updip pinchout of reservoir lithology into a sealing lithology (see **Fig. 1**), is found in the flanks of structures. The top and updip seal is normally an impervious rock type, and the lateral seals are formed by either structural dip or the lateral pinchout of reservoir rock into seal material. The base of the reservoir is defined by a bottom seal composed of impervious rock and by an oil/water contact. During relative sea-level fall, streams may erode deep valleys, thus forming lateral seals for fluvial sediments. Onlap of sand onto a paleotopographic high during relative sea-level rise can produce an updip seal for a sand body. Unconformity traps are formed by the truncation of dipping strata by overlying bedded sealing lithology. The reservoir rock may be found in the form of buried hills formed by erosion during the time of the unconformity. The oil/water contact forms the base of these reservoirs. A stratigraphic trap may be partly related to diagenetic processes; for example, the updip seal for the supergiant Coalinga field, California, is tar- and asphalt-filled sandstone and conglomerate. Many traps in the Permian reservoirs of west Texas, are formed by lateral changes related to stratigraphy from porous to dense dolomite in an updip direction.

Stratigraphic traps are formed by depositional processes that produce paleotopographic highs encased in impermeable material, such as evaporite or shale (**Fig. 1**). Closure occurs when there is contact between seal material and underlying sediment. The most common type is a carbonate buildup, usually erroneously called a "reef." Piles of sand deposited on the seafloor by density currents often form broad topographic highs that, in turn, form stratigraphic traps. Structure may also play a part in the geometry of stratigraphic traps, although the defining characteristic is that structure is not required to form the trap.

**Seals**

A seal is a low-permeable to impermeable rock or immobile fluid, such as tar, with a capillary entry pressure large enough to dam up or trap hydrocarbons.[[4]](https://petrowiki.org/Reservoir_geology#cite_note-r4-4) As shown in **Fig. 2**, typical seals include:

* Top
* Bottom
* Lateral
* Fault

Faults may be sealing or nonsealing, depending on whether the sand offsets another sand (nonsealing) or shale (sealing).[[5]](https://petrowiki.org/Reservoir_geology#cite_note-r5-5) Any lithology can be a seal or flow barrier. The requirement is that the minimum capillary displacement pressure of the seal or flow-barrier material be greater than the buoyancy pressure of the hydrocarbons in the accumulation. The continuous, small, pore-throat sizes create a barrier to moving hydrocarbons, causing them to dam up or become trapped. Therefore, the size of the continuous pore throats and the density of the hydrocarbons and water are critical elements in evaluating a seal or flow barrier.

* 

**Fig. 2 – Some typical seals; HCH is the hydrocarbon-column height that the weakest seal will hold. Figure courtesy of Sneider Exploration Inc.**

Porosity and permeability are not the best criteria for evaluating seal and flow-barrier behavior. The seal capacity of a rock can be best evaluated with a mercury porosimeter that can inject mercury into material using pressures as high as 60,000 psi. The key equation used in capillary pressure/saturation evaluation of reservoir rocks, seals, and flow barriers is:

 ....................(1)

in which

* *hc* = the maximum hydrocarbon column held
* *pc* = the capillary entry pressure
* *ρw* = the density of water
* *ρhc* = the density of the hydrocarbon

The capillary pressure used is usually not the capillary entry pressure but the capillary pressure at a mercury saturation of between 5 and 10% because of closure effects.

Effective hydrocarbon seals for exploration plays and reservoirs must be laterally continuous. Some typical seal lithologies, illustrated in **Fig. 3**, have entry pressures ranging from 14 to 20,000 psi. With data from more than 3,000 seals, we can group the data into Classes A through E to categorize the typical lithologies listed in **Fig. 3** from most to least ductile. **Fig. 3** also illustrates the hydrocarbon column that can be held, assuming that the fluid is 35°API oil and saline water.

* Very shaly siltstone and sandstone, anhydrite-filled dolostones, and cemented sandstone each have between 50 and 100 ft of capacity
* Sandy shales are ranked next, with a 100- to 500-ft capacity
* Clay-mineral-rich shale, silty shales, and dense mudstones can hold between 500 and 1,000 ft of oil column
* Evaporite and kerogen-rich shale can hold the greatest oil column—from 1,000 to more than 5,000 ft.

Immobile fluids, such as tar, bitumen, and asphalt, also can be effective seals and barriers. For example, the updip seal for the supergiant Coalinga field, California, is tar- and asphalt-filled sandstone and conglomerate.

* 

**Fig. 3 – (a) Air/mercury capillary pressure curves of seal lithologies. The ordinate is a log scale. (b) Typical seal lithologies. (c) Sneider *et al.***[[3]](https://petrowiki.org/Reservoir_geology#cite_note-r3-3)**classification of seals and flow barriers. The hydrocarbon column that can be held assumes that the fluids in the reservoirs are 35° API oil and saline water. Types are keyed to Figs. 3a and 3b. Figure courtesy of Sneider Exploration Inc.**

Reservoir base

Whereas structure and stratigraphy most often define the reservoir trap or top of the reservoir, factors controlling the base of a petroleum reservoir include:[[6]](https://petrowiki.org/Reservoir_geology%22%20%5Cl%20%22cite_note-r6-6)[[7]](https://petrowiki.org/Reservoir_geology#cite_note-r7-7)

* Seal capacity
* Spill point
* Capillary forces
* Hydrodynamics

The reservoir base is defined as the zero capillary pressure level, also referred to as the free-water level. Reservoir height is determined by the height from seal to spill point, if seal capacity is large enough. If the height is less than that from seal to spill point, seal capacity or hydrocarbon charge will determine the position of the reservoir base.

Subsurface groundwater is seldom static. The following factors combine to create a difference in hydrodynamic potentials that result in the movement of fluids in the subsurface:

* Differences in water density
* Structural tilting
* Tectonic forces
* Other factors

Fluid movement is controlled by the fluid potential as defined by Hubbert[[6]](https://petrowiki.org/Reservoir_geology%22%20%5Cl%20%22cite_note-r6-6) and illustrated by the following formula[[8]](https://petrowiki.org/Reservoir_geology#cite_note-r8-8):

....................(2)

in which

* *Z* = elevation relative to a datum (sea level)
* *P* = measured static pressure
* *ρ* = density of the fluid (water)

A potentiometric map is a map that connects points of equal fluid potential within an aquifer. If the potentiometric surface is not horizontal, the aquifer will flow in the direction of lowest potential. Calculating fluid potential requires accurate subsurface pressure measurements in the aquifer. The flow of water under a reservoir will cause the zero-capillary-pressure level to tilt, referred to as a tilted water table. The degree of tilt can be estimated from the following equation.

 ....................(3)

in which

*  change in reservoir height for distance *x* (tilt in water table)
* *ρw* = density of water in aquifer
* *ρo* = density of hydrocarbon
*  change in potentiometric surface for distance *x*

During primary development, the economic base of the reservoir is normally defined as the producing oil/water contact, or the level at which oil and water are first coproduced. This level is generally assumed to be at approximately 50% water saturation, according to relative permeability considerations. During tertiary development, the economic base of the reservoir may be defined as the level of zero oil saturation. However, because pore size can vary with stratigraphy, 50 or 100% water saturation may not occur at the same height throughout the reservoir. The economic base of the reservoir will not be horizontal.

Defining the base of a reservoir is often made difficult by the presence of residual-oil and tar zones below the producing oil/water contact. Residual-oil and tar zones can be as thick as 300 ft and are thought to form by a variety of processes, including:

* Biodegradation of hydrocarbons
* Flushing of part of the oil column as a result of hydrodynamic forces
* Remigrating of hydrocarbons because of leaky seals and structural tilting

The presence of this material may indicate that the reservoir is in an imbibition rather than a drainage mode. Estimates of the original oil in place will depend on which capillary pressure model is assumed. An incorrect model can lead to large errors in estimates of the original oil in place.

Internal geometry-reservoir architecture

Information that defines the external reservoir geometry is of primary importance during exploration and initial development of a reservoir. Such information includes:

* Trap configuration
* Seal capacity
* The base of the reservoir

As development continues, reservoir architecture becomes key to predicting the distribution of reservoir quality so that primary- and secondary-development programs can be planned. Reservoir architecture is important because it provides a basis for distributing petrophysical properties in 3D space. In most cases, this operation is done by relating lithofacies to petrophysical properties because lithofacies can be directly linked to depositional processes for prediction.

We commonly correlate lithofacies from one well to the next by assuming a degree of horizontality and continuity of similar facies. This approach leads to images with highly continuous lithofacies and porosity zones. Many depositional facies, however, are known to be highly discontinuous laterally and vertically, and correlating similar lithofacies from one well to the next can lead to unrealistic displays of reservoir architecture. Modern correlation methods rely more on the chronostratigraphic approach, one that uses time stratigraphy rather than lithostratigraphy to determine continuity between wells. This approach is referred to as sequence stratigraphy and provides a basis for correlating time surfaces between which lithofacies are distributed systematically in a predictable pattern.

**Sequence stratigraphy**

Sequence stratigraphy is a chronostratigraphic method of correlation. It groups lithofacies into time-stratigraphic units between chronostratigraphic surfaces, which are sometimes defined by unconformities and facies shifts. A key premise is that the surfaces are formed in response to eustatic sea-level changes of various scales and periodicity (eustatic refers to worldwide sea-level changes affecting all oceans). It is thought that eustatic sea-level changes can be linked to climatic changes and to eccentricities in the Earth’s orbit. The Russian astronomer Milanovitch defined cyclic variation in the shape of the Earth’s orbit and in the tilt and wobble of the axis. These Earth cycles are:

* Precession (19,000 to 23,000 years)
* Obliquity (41,000 years)
* Eccentricity (1,000,000 to 4,000,000 years)

These cycles are thought to cause changes in the Earth’s climate, resulting in more or less water trapped as ice at the poles. The trapping or release of water from the ice caps is thought to result in sea-level rise and fall, referred to as eustasy.

Sequence stratigraphy is important for reservoir modeling because a chronostratigraphic surface is present in every well in the reservoir. This fact provides geologists with a powerful tool for correlating packages of lithofacies between wells. A more realistic image of reservoir architecture can, therefore, be constructed by distributing lithofacies and petrophysical properties within a detailed sequence-stratigraphic framework.

The terminology of sequence stratigraphy, like most geologic terminology, is complex and constantly evolves as concepts and ideas change.[[9]](https://petrowiki.org/Reservoir_geology#cite_note-r9-9)[[10]](https://petrowiki.org/Reservoir_geology#cite_note-r10-10) It is the intent here to present a basic overview of the terminology to provide the reader with sufficient understanding to communicate with reservoir geologists. The classic Exxon model (see **Fig. 4**) shows the terminology used in siliciclastic stratigraphy. The terms used in carbonate stratigraphy, although similar, have important differences because carbonates are organic in origin and clastics are terrigenous in origin. The terminology used in carbonate stratigraphy is illustrated in **Fig. 5**.

* 

**Fig. 4 – Exxon idealized depositional-sequence cross-sectional model for siliciclastic sediments. Sequence boundary (SB), LST composed of basin-floor fan (bf), slope fan (sf), and lowstand prograding wedge (LSW), TST, HST, and shelf-margin wedge (SMW). Maximum flooding surface (mfs) separates the TST from the HST. Taken from Kerans and Tinker.**[[10]](https://petrowiki.org/Reservoir_geology#cite_note-r10-10)

* 

**Fig. 5 – Hierarchy of carbonate sequence-stratigraphic terminology in a cross-sectional view. An HFC is composed of a flooding event (transgression) and a shallowing event (prograding). HFSs are composed of a retrogradational cycle set that makes up the TST and prograding cycle set that makes up the HST. Composite sequences are composed of a basal retrogradational set of HFSs and an upper set of progradational HFSs/ The dark shading indicates transgressive units, and the light shading indicates progradational units. See Kerans and Tinker.**[[10]](https://petrowiki.org/Reservoir_geology#cite_note-r10-10)

The smallest time-stratigraphic unit is the high-frequency cycle (HFC), or parasequence, a unit composed of genetically related lithofacies deposited during one basic sea-level rise and fall. Assuming a constant rate of subsidence, each cycle begins with a flooding event as sea level rises. The flooding event is also referred to as transgression or retrogradation, the backward and landward movement or retreat of a shoreline or coastline. The sea transgresses the land, the shoreline retreats, and the space for sediment to accumulate increases. The space created by the transgression is referred to as accommodation space. Sea-level rise is followed by a stillstand, during which sediment completely or partly fills the accommodation space. The buildup of sediment by deposition is referred to as aggradation. The stillstand is followed by a relative sea-level fall during which accommodation space is reduced, forcing sediment to be transported into the basin and resulting in progradation of the sediment body. Progradation refers to the building forward and outward toward the sea of a shoreline or body of sediment. During sea-level fall, the most-landward sediment may become subaerially exposed, forming an unconformity. Farther basinward the water is deeper, and the shallowing event is identified by a facies shift in the vertical stacking of lithofacies. The next sea-level rise produces another flooding event, and the depositional cycle is repeated. Flooding events approximate chronostratigraphic surfaces and define the HFC as a time-stratigraphic unit.

Repeated eustatic sea-level cycles result in the vertical stacking of HFC. Cycles are stacked vertically into:

* Retrogradational cycles
* Aggradational cycles
* Progradational cycles

Retrogradational cycles are formed when the eustatic sea-level rise for each cycle is much more than the fall. The shoreline will move farther landward with each successive cycle, a pattern described as back stepping or transgression. The sediments are said to be deposited in the transgressive system’s track (TST). Aggradational cycles are formed when eustatic rise and fall are equal, and the resulting facies will stack vertically. These cycles are defined as part of the highstand system’s tract (HST). Progradational cycles form when the eustatic fall for each cycle is greater that the rise. The shoreline for each successive cycle will move seaward, a pattern described as progradation or regression, and the sediments are said to be deposited in the HST. Sediments deposited when relative sea level is lowest are said to be deposited in the lowstand system’s track (LST). The sequence from TST to HST to LST defines a larger-scale sea-level signal referred to as a high-frequency sequence (HFS). The turnaround from transgression to aggradation and progradation is termed the maximum flooding surface (MFS). HFSs can be packaged into longer-term signals called composite sequences on the basis of the observation that they tend to stack vertically into the following sequences:

* Transgressive
* Progradational
* Lowstand

The terminology and duration of the cycle hierarchies estimated by Goldhammer[[11]](https://petrowiki.org/Reservoir_geology%22%20%5Cl%20%22cite_note-r11-11) are shown in **Fig. 6**. HFC, HFS, and composite sequences are commonly referred to as fifth-, fourth-, and third-order cycles, respectively, with characteristic durations ranging from 0.01 to 10 million years (m.y.). First- and second-order cycles, or supersequences, have much longer durations, from 10 to more than 100 m.y., and are related more to structural movements than to eustasy. These major sequences are useful not only for regional but also for worldwide correlations. The durations of all these cycles and sequences are approximate and are based on radiogenic dates extrapolated to the numbers of cycles and sequences of various scales.

* 

**Fig. 6 – Terminology of cycle hierarchies and order of cylicity from Goldhammer.**[[11]](https://petrowiki.org/Reservoir_geology#cite_note-r11-11)

Nomenclature

|  |  |  |
| --- | --- | --- |
| *hc* | = | the maximum hydrocarbon column held |
| *pc* | = | the capillary entry pressure |
| *ρw* | = | the density of water |
| *ρhc* | = | the density of the hydrocarbon |
| *Z* | = | elevation relative to a datum (sea level) |
| *P* | = | measured static pressure |
| *ρ* | = | density of the fluid (water) |
| RTENOTITLE | = | change in reservoir height for distance *x* (tilt in water table) |
| *ρw* | = | density of water in aquifer |
| *ρo* | = | density of hydrocarbon |
| RTENOTITLE | = | change in potentiometric surface for distance *x* |

References

1. [↑](https://petrowiki.org/Reservoir_geology#cite_ref-r1_1-0) Hunt, J.M. 1979. Petroleum Geochemistry and Geology, 617. San Francisco: W.H. Freeman and Co.
2. [↑](https://petrowiki.org/Reservoir_geology#cite_ref-r2_2-0) Milton, N.J. and Bertram, G.T. 1992. Trap Styles—A New Classification Based on Sealing Surfaces. AAPG Bull. 76 (7): 983-999. <http://aapgbull.geoscienceworld.org/content/76/7/983.citation>.
3. ↑ [Jump up to:3.0](https://petrowiki.org/Reservoir_geology#cite_ref-r3_3-0) [3.1](https://petrowiki.org/Reservoir_geology#cite_ref-r3_3-1) Demaison, G. and Huizinga, B.J. 1991. Genetic Classification of Petroleum Systems. AAPG Bull. 75 (10): 1626-1643. <http://aapgbull.geoscienceworld.org/content/75/10/1626.citation>.
4. [↑](https://petrowiki.org/Reservoir_geology#cite_ref-r4_4-0) Sneider, R.M. et al. 1997. Comparison of Seal Capacity Determinations: Conventional Cores Versus Cuttings. Seals, Traps, and the Petroleum System, R.C. Surdam ed., 12. AAPG Memoir 67. <http://archives.datapages.com/data/specpubs/mem67/ch01/ch01.htm>.
5. [↑](https://petrowiki.org/Reservoir_geology#cite_ref-r5_5-0) Smith, D.A. 1966. Theoretical Considerations of Sealing and Non-Sealing Faults. AAPG Bull. 50 (2): 363-374. <http://archives.datapages.com/data/bulletns/1965-67/data/pg/0050/0002/0350/0363.htm>.
6. ↑ [Jump up to:6.0](https://petrowiki.org/Reservoir_geology#cite_ref-r6_6-0) [6.1](https://petrowiki.org/Reservoir_geology#cite_ref-r6_6-1) Hubbert, M.K.L. 1953. Entrapment of Petroleum under Hydrodynamic Conditions. AAPG Bull. 37 (8): 1954-2026. <http://archives.datapages.com/data/bulletns/1953-56/data/pg/0037/0008/1950/1954.htm>.
7. [↑](https://petrowiki.org/Reservoir_geology#cite_ref-r7_7-0) Schowater, T.T. 1979. Mechanics of Secondary Hydrocarbon Migration and Entrapment. AAPG Bull. 63 (5): 723-760 <http://aapgbull.geoscienceworld.org/content/63/5/723.citation>.
8. [↑](https://petrowiki.org/Reservoir_geology#cite_ref-r8_8-0) North, F.K. 1985. Petroleum Geology, 631. Boston, Massachusetts: Unwin Hyman Inc.
9. [↑](https://petrowiki.org/Reservoir_geology#cite_ref-r9_9-0) Von Wagoner, J.C. 1995. Overview of Sequence Stratigraphy of Foreland Basin Deposits: Terminology, Summary of Papers, and Glossary of Sequence Stratigraphy. In AAPG Memoir 64--Sequence Stratigraphy of Foreland Basin Deposits; Outcrop and Subsurface Examples from the Cretaceous of North America, J.C. Van Wagoner and G.T. Bertram ed. <http://archives.datapages.com/data/specpubs/memoir64/front/000i.htm>.
10. ↑ [Jump up to:10.0](https://petrowiki.org/Reservoir_geology#cite_ref-r10_10-0) [10.1](https://petrowiki.org/Reservoir_geology#cite_ref-r10_10-1) [10.2](https://petrowiki.org/Reservoir_geology#cite_ref-r10_10-2) Kerans, C. and Tinker, S.W. 1997. Sequence Stratigraphy and Characterization of Carbonate Reservoirs. SEPM Short Course Notes No. 40, 130.