1.0 PREREQUISITES FOR HYDROCARBON ACCUMULATION

The accumulation of hydrocarbons and formation of oil or gas deposit involve certain prerequisites. These are the following:

1. Source Rock
2. Reservoir Rock
3. Trap
4. Seal
5. Timing
6. Migration

Not all petroleum discoveries, however, are commercial or economic – that is they can all be developed and produced at a profit. Additional geological requirements for a petroleum deposit to be economic are:

1. Sufficient volume of accumulated hydrocarbon – in-place reserves
2. Producibility – recoverable reserves
   a. adequate reservoir drive
   b. concentration
   c. oil quality (e.g., API gravity or viscosity)
3. Preservation of the petroleum deposit, that is freedom from:
   a. flushing
   b. biodegradation
   c. diffusion
   d. overcooking

Non-geological factors affecting profitability of a petroleum discovery are:
   • Cost of development and production
   • Price of oil/gas
   • Fiscal terms

1.1 Source Rock

1.1.1 Definitions:

Source Rock
   -- Sedimentary rock containing organic material, which under heat, time, and pressure was transformed to liquid or gaseous hydrocarbons. Source rock is usually shale or limestone.
Some explorationists use a stricter definition -- that is requiring sufficient hydrocarbon generation and migration from the rock unit to form commercial accumulation(s) of oil and/or gas for it to be considered a source rock.

Possible source rock
-- any unit of rock, which by its general lithology and depositional environment, may generate hydrocarbons.

Potential source rock
-- contains adequate quantities of organic matter to generate oil or gas but has not yet done because of insufficient thermal maturation.

Effective source rock
-- is generating or has generated and expelled petroleum.

An effective source rock may further be classified into:

Active source rock – presently generating and expelling petroleum.

Quiescent potential source rock – previously active yet has stopped generating and expelling petroleum because of thermal cooling due to uplift or erosion but may become active again if reburied.

Spent source rock – has completed the process of oil or gas generation and expulsion.

It is apparent from the above definitions that a source rock to be effective has to attain a certain level of maturation so that hydrocarbons may be generated. However, before a source rock could be effective, it has first to be a good potential source rock – that is, it has to be sufficiently organically rich.

1.1.2 Organic Matter in Sediments

Remains of plants and animals deposited with the sediments comprise the organic matter, which if in sufficient quantity makes the sediments possible source rock.

The types of organisms that contribute organic matter to sediments changed through time.

<table>
<thead>
<tr>
<th>Time</th>
<th>Organism</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-Devonian</td>
<td>Bacteria, phytoplanktons and zooplanktons, algae</td>
</tr>
<tr>
<td>Late Devonian</td>
<td>Gymnosperms (non-flowering plants)</td>
</tr>
<tr>
<td>Cretaceous</td>
<td>Angiosperms (flowering plants)</td>
</tr>
</tbody>
</table>
This is quite important because the nature of hydrocarbon generated – whether oil or gas – by a source rock depends on the type of the organic matter it contains.

Figure 1-2. Change in organic material contribution through geologic time. (from Emery, 1996)

1.1.3 Organic Richness

Controls on organic richness and source potential of a possible source rock are:

- terrestrial organic productivity
- terrestrial organic matter supply
- primary productivity
- water depth
- oceanic circulation
- organic matter preservation – anoxic conditions
- sedimentation rate
Figure 1-1. Factors affecting the organic richness of a possible source rock. (from Emery, 1996)

Figure 1-3. Hydrocarbon source systems through geologic time. (from Emery, 1996)
Average composition of some biomolecules compared to petroleum

<table>
<thead>
<tr>
<th>Biomolecule</th>
<th>C</th>
<th>H</th>
<th>S</th>
<th>N</th>
<th>O</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbohydrates</td>
<td>44</td>
<td>6</td>
<td></td>
<td></td>
<td>50</td>
</tr>
<tr>
<td>Lignins</td>
<td>63</td>
<td>5</td>
<td>0.1</td>
<td>0.3</td>
<td>31.6</td>
</tr>
<tr>
<td>Proteins</td>
<td>53</td>
<td>7</td>
<td>1</td>
<td>17</td>
<td>22</td>
</tr>
<tr>
<td>Lipids</td>
<td>76</td>
<td>12</td>
<td></td>
<td></td>
<td>12</td>
</tr>
<tr>
<td>Petroleum</td>
<td>85</td>
<td>13</td>
<td>1</td>
<td>0.5</td>
<td>0.5</td>
</tr>
</tbody>
</table>

The biomolecules listed in the table are the principal structural components of living organisms. Lignins are exclusive to plants and with cellulose, form an important chemical constituent of wood.

Note that petroleum has higher C and H, about the same sulfur, and less nitrogen and oxygen. It is apparent from the table that lipids are the biomolecules closest in chemical composition to petroleum – needing only to lose a little oxygen to become hydrocarbon. Lipids include fats and waxes, particularly the waxy coatings of pollen grains, spores, and leaves.

It is apparent here that the hydrocarbon generated upon maturation of the source rock, whether oil or gas, depends on chemical composition – particularly hydrogen and carbon -- of the precursor organic matter.

1.1.4 Conversion of Organic Matter to Petroleum

The generation of petroleum from primary organic matter occurs in 3 stages.

Diagenesis

- burial of no more than 3-400 m
- low T and P
- mainly compaction and expulsion of water
- alteration due primarily to microbial action
- biogenic gas generation due to anaerobic decay
- change is basically progressive lost of acid groups
- end of diagenesis is when the organic matter becomes insoluble (in acid, base, or organic solvents)

This is attained when there are no more acid groups left, the organic matter has turned to kerogen. There is no fundamental chemical difference between a coal and terrestrial kerogen. It is simply that coals occur in massive deposits (ratio of organic matter to mineral matter is sufficiently high) while kerogen is dispersed in a mineral matrix. Kerogen or brown coal are the end products of diagenesis of organic matter.

Kerogen is defined as the organic material in sedimentary rocks that is insoluble in organic solvents.
Some of the original free lipids, including hydrocarbons, also remain. These compounds are relatively resistant to microbial degradation and they include the biochemical fossils referred to as biomarker.

Catagenesis
- burial to depths of several kilometers
- marked decrease in sediment porosity and permeability
- considerable increase in temperature and pressure
- temperature range is 50-180°C
- vitrinite reflectance increases from 0.5 to 2.0%
- principal zone of oil formation
- end of catagenesis is marked by the inability of the kerogen to produce hydrocarbons further

Metagenesis
- occurs at great depths
- vitrinite reflectance increases to >2%
- kerogen residue is converted to graphite
- expelled bitumen is further broken down to methane and a carbon residue
- coals are converted to anthracite

Figure 1-4. Transformation of organic matter to hydrocarbons. (from Murray, etal., 1992)
1.2 Reservoir Rock

In petroleum geology, a reservoir rock is any rock that has sufficient porosity and permeability to permit the storage and accumulation of crude oil or natural gas under adequate trap conditions, and to yield the hydrocarbons at satisfactory flow rate upon production. Sandstones, limestones, and dolomites are the most common reservoir rocks, but accumulation in fractured igneous and metamorphic rocks is not unknown.

1.2.1 Porosity

Porosity is defined as the ratio of the pore volume to the bulk volume of a material. It is usually expressed as a percentage.

\[ \varphi = \frac{Pore\ Volume}{Bulk\ Volume} \times 100 = \frac{Bulk\ Volume - Grain\ Volume}{Bulk\ Volume} \times 100 \]

Total Porosity – the ratio of the volume of all the pores to the bulk volume of a material, regardless of whether or not all of the pores are interconnected.

Effective Porosity -- the ratio of the interconnected pore volume to the bulk volume of a material.

Types of Porosity

Primary

Intergranular

Intraparticle
Porosity in reservoir rocks serves as storage space for the hydrocarbons, but for oil or gas to be able to move into the pores and flow out when produced requires something else…

1.2.2 Permeability

Permeability is the property of a porous medium to transmit fluids when a pressure gradient is imposed. An empirical correlation function, Darcy’s Law, relates permeability to pressure gradient, fluid flow velocity and viscosity.

Darcy’s Law

\[ v = \frac{k}{\mu} \frac{dP}{dL} \]

- \(v\) = apparent flow velocity, cm/s
- \(\mu\) = viscosity of the flowing fluid, centipoises
- \(dP/dL\) = pressure gradient in the direction of flow, atmosphere/cm
- \(k\) = permeability of the porous medium, darcies

Stated in terms of volume flow rate, Darcy’s Law is

\[ Q = \frac{k (P_1 - P_2) A}{\mu L} \]

- \(Q\) = rate of flow, cm\(^3\)/s
- \(k\) = permeability of the porous medium, darcies
- \((P_1 - P_2)\) = pressure drop across the sample, atmosphere
- \(A\) = cross-sectional area, cm\(^2\)
- \(\mu\) = viscosity of the flowing fluid, centipoise
- \(L\) = length of sample, cm
The basic and standard unit of permeability is darcy. It is equivalent to the passage of one cubic centimeter of fluid of one centipoise viscosity flowing in one second under a pressure differential of one atmosphere through a porous medium having a cross-sectional area of one square centimeter.

\[
1 \text{ darcy} = 9.869 \times 10^{-9} \text{ cm}^2
\]

Darcy’s Law assumes:
1. Laminar flow
2. No reaction between the fluid and the rock
3. One phase (fluid) is present at 100% saturation

Absolute Permeability \((k_a)\) – permeability of a rock to a fluid when the rock is 100% saturated with that fluid.

Effective Permeability \((k_e)\) – permeability of a rock to a particular fluid when that fluid has a pore saturation of less than 100%

Relative Permeability \((k_r)\) – the ratio of the effective permeability of a fluid at a given value of saturation to the effective permeability of that fluid at 100% saturation (absolute permeability), expressed as a fraction from 0 to 1.

![Figure 1-5. Graph of relative permeability and saturation. (from Corelab, 1973)](image-url)
Permeability is a vectorial property, that is, it varies depending on the direction of measurement (horizontal and vertical permeability).

### 1.3 Trap

Any barrier to upward movement of oil or gas, allowing either or both to accumulate. A trap includes a reservoir rock and an overlying or updip impermeable cap.

A trap is basically a geometry of reservoir rock.

- Crest or culmination – the highest point of the trap
- Spill point – the lowest point
- Vertical closure – vertical distance between the crest and the spill point
- Areal closure – area under the vertical closure
- Pay – thickness of productive reservoir
- Gross pay – total vertical interval of productive zone
- Net pay – thickness of actual productive intervals, excludes intervening non-productive layers.

Figure 1-6. Trap nomenclature using a simple anticline as an example.

Figure 1-7. Difference of gross pay and net pay.
Classification of Traps

Structural trap – formed due to folding, faulting, and other deformation
Stratigraphic trap – result of lithologic changes rather than structural deformation

porosity/permeability trap – formed by lateral variation in porosity/permeability of the reservoir rock, e.g., as a result of cementation, presence of clay minerals, or decrease in grain size

Combination trap – a trap that has both structural and stratigraphic elements
Hydrodynamic trap – due to flow of water

1.4 Seal

Effectiveness of a trap is not determined by its 4-way closure only. A seal is also required.

Seal is an impervious or impermeable bed capping the reservoir rocks in a trap.

Vertical seal

Lateral seal

Whenever two immiscible phases are present in a fine bore tube, there is a pressure drop across the curved liquid interface called capillary pressure.

Capillary pressure in a tube can be calculated if the fluid interfacial tension (T), rock-fluid contact angle (θ), and the tube radius are known (r).

\[ \text{Force Up} = 2\pi r T \cos \theta \]

Capillary pressure can also be expressed as a hydrostatic head. It is equal to the product of the height of the liquid rise (h), the density difference of the two liquids (D_w - D_h), and the gravitational constant (g).

\[ \text{Force Down} = \pi r^2 h (D_w - D_h) g \]

\[ \text{Capillary pressure, } P_c = \frac{\text{Force Up}}{\pi r^2} = \frac{\text{Force Down}}{\pi r^2} \]

Capillary pressure may be used to quantify the quality or effectiveness of a seal. The force down equation of capillary pressure may be used to estimate the height of the hydrocarbon column a trap may contain. This can be used in assessing trap fill.
The mere presence of the four prerequisites discussed above, namely source rock, reservoir rock, trap and seal in a basin is not enough for a petroleum deposit to form. They also have to be in a proper spatial and temporal relation, thus, the additional requisites timing and migration.

1.5 Migration
-- movement of generated hydrocarbons from the source rock to the reservoir rock in a trap through conduits such as permeable beds, fractures, and faults.

Primary Migration or Expulsion – movement of generated hydrocarbons out of the source rock into a more permeable conduit.

Secondary Migration – movement of petroleum through the conduit into a reservoir in a trap.

Accumulation is the end of migration -- that is the hydrocarbons have reached a trap and are stored in the reservoir.

1.6 Timing
-- relationship between the time of trap formation and time of hydrocarbon generation and migration.

Good timing is for the reservoir, trap and seal to be already in place before the source rock generates hydrocarbons and migration starts.