DETERMINING THE ORIGIN OF LIGHT OILS AND CONDENSATES

Hydrocarbon liquids which at surface conditions are high gravity (~45-60 °API), may be either a light oil (volatile oil) or a gas condensate. A true condensate is a hydrocarbon liquid at surface conditions that is a gas at reservoir conditions, while a volatile oil is a liquid at both surface and reservoir conditions.

Two general "rules of thumb" for distinguishing between a volatile oil and a gas condensate include:

- When the GOR of a produced petroleum is > 3,000 ft³ of gas/ barrel oil (cfg/bo), then the liquid is a condensate (i.e., exists as a gas in the reservoir; Kingston, 1990).
- Condensates typically contain < 12.5 mole %C₇+, while volatile oils typically contain > 12.5 mole% C₇+ (Danesh, 1998).

Those general rules of thumb are similar to the criteria employed by The Organization of Petroleum Exporting Countries (OPEC) in defining a condensate. Effective January 1, 1989, OPEC defined condensate as any hydrocarbon liquid with an API of 50° or higher, a gas:liquid ratio of 5,000:1 or higher, or a C₇+ fraction of 3.5 mole % or less. The OPEC criteria also allowed certain other liquids that fell outside these limits to be considered as condensates (depending on a variety of factors), but a lower limit of 45° API was set, as was a limit of not more than 8% C₇+ fraction (Kingston, 1990).

However, all of the "rules of thumb" listed above are only general, and do not allow one to know with certainty whether or not a given fluid is a gas condensate or a volatile oil. For example, although gas condensates typically consist almost entirely of C₅-C₁₀ range hydrocarbons, (Kingston, 1990), in deep accumulations, due to high pressure and temperature, relatively high-molecular-weight hydrocarbons may be part of a condensate. As a case-in-point, Hunt (1996) reports that the hydrocarbons C₁- C₁₈ are present in the gas phase at 20,000 feet in the Maloosa condensate field, Italy (reservoir pressure = 15,431 psi, temperature = 153 °C, reservoir = Triassic dolomite).

The concentration of condensate dissolved in a gas may vary from <10 to > 400 barrels condensate/MMCFG, (Kingston et al., 1990) and that concentration depends on a variety of factors. To know with certainty whether or not a high-gravity liquid at surface conditions was a gas or a liquid at reservoir conditions requires PVT calculations (i.e., the answer must be determined through Equation-of-State or Pressure-Volume-Temperature calculations; see Danesh, 1998; Meulbroek, 2002; Meulbroek and MacLeod, 2002), and the answer depends on:

1. The reservoir pressure
2. The reservoir temperature
3. The composition of the "dead" hydrocarbon liquid
4. The composition of the gas co-produced with the dead hydrocarbon liquid
5. The gas/oil ratio of the co-produced gas and dead oil.
The following is a discussion of the origin of volatile oils (i.e., their source and the geological processes responsible for their formation), and does NOT concern the origin of "true" condensates. However, for ease of discussion, we will refer to these volatile oils as "condensates".

Condensates (high gravity hydrocarbon liquids) can be formed by any of the following five geological processes:

1. **Generation from Type III, gas-prone organic matter** ("humic" material) THROUGHOUT the oil window range of maturities (EARLY to LATE oil window, e.g., see Snowden, 1982).

   Examples: Condensates in many fluvio-deltaic environments, since such environments commonly have higher-plant-rich source rocks. Specific examples include the Neocomian reservoirs of western Siberia, and the deltaic sands of the Mahakam, Niger, and US Gulf Coast Tertiary deltas.

   **Oil geochemistry indicators for this type of liquid:**
   - Very high pristane/phytane ratio (>2.5). The ABSOLUTE abundance of these compounds will be low (due simply to their high molecular weight), but the RATIO of these two compounds is high in this type of condensate.
   - Compared to other types of condensate, in this type there is a relative abundance of light aromatic compounds (benzene, toluene, xylenes, etc.), which are a component of woody higher plant material.
   - Although the ABSOLUTE abundance of biomarkers will be low (due simply to their high molecular weight), the RELATIVE abundance of certain biomarkers (RELATIVE to other biomarkers of similar molecular weight), will be high. Specifically, compared to other biomarkers of similar molecular weight, there is a relative abundance of higher-plant (angiosperm and/or conifer) diterpane and triterpane biomarkers in this type of condensate. Such compounds include saturated hydrocarbons (e.g., oleananes, lupanes, bicadinanes) and/or aromatic hydrocarbons (e.g., retene, cadalene, simonellite, etc).

2. **Generation at high maturity (late oil window) from oil-prone or oil/gas-gas source rocks.**

   **Oil geochemistry indicators for this type of liquid:**
   - Aromatic steroid maturity parameters suggest high maturity (e.g., MA1/(MAI+MAII) ~ 1.0; TAI/(TAI+TAII) ~ 1.0).
   - No abundance of higher plant biomarkers.

3. **Cracking of oil in high-temperature reservoirs** (>140-170 °C, depending on the reservoir lithology).

   Examples: Gas-condensate fields in the Interior Salt basin, southwestern Alabama, USA., and the Khuff Formation of the Persian Gulf Region.

   **Oil geochemistry indicators for this type of liquid:**
   - High diamondoid concentrations (e.g., Dahl et al., 1999). These compounds, which are present in all oils, are concentrated during the oil cracking process, since diamondoids are very stable and are not destroyed by oil cracking, while the other non-diamondoid compounds are destroyed by cracking.
   - Certain light hydrocarbon components are isotopically heavy (e.g., Rooney, 1995; Chung et al., 1981) in this type of condensate.
4. Evaporative fractionation (e.g., Thompson 1987, 1988):

A geologic process in which

i. a charge of gas (generally dry) enters an existing oil accumulation,
ii. the gas then equilibrates with the light components of the reservoired oil, and then
iii. the gas is vented from the accumulation, taking with it dissolved components that originally were part of the oil accumulation.

The migrating gas may then condense out a liquid (or "retrograde condensate") in a shallower reservoir. Therefore, this process is the cause of two new fluids:

- High-gravity retrograde condensate in a shallower reservoir, and
- Lower gravity, more aromatic residual oil (in the original reservoir) depleted in light paraffins and enriched in the other fractions. This process is common in deltaic stacked pay sands. Examples: Certain condensate fields in North Sumatra (Kingston, 1990).

Oil geochemistry indicators for this type of liquid:

- Depleted in light aromatic hydrocarbons relative to light saturated hydrocarbons (due to the higher vapor pressure of saturated hydrocarbons relative to aromatic hydrocarbons of similar molecular weight).
- Depleted in cyclic and branched compounds relative to straight chain compounds (due to the higher vapor pressure of straight chain saturated hydrocarbons relative to branched and cyclic hydrocarbons of similar molecular weight).
- Maturity indicators suggest that the liquid is NOT high maturity.
- No abundance of higher-plant biomarkers relative to other biomarkers of similar molecular weight.
- Under certain conditions, evaporative fractionation can also result in generation of very aromatic-hydrocarbon-rich condensates. This occurs when the parent oil undergoes repeated gas washing episodes, such that no saturated compounds are left to be stripped by migrating gas, and then a subsequent migrating gas is forced to pick up a very aromatic-rich residue from the parent oil, and delivers that material to a shallower reservoir where it condenses out as an aromatic-hydrocarbon-rich condensate (e.g., Thompson, 1987).
5. Generation from relatively lean (i.e., organic-matter-poor) source rocks (e.g., <1.0 % TOC) containing Type II or Type II organic matter where the gas/condensate is separated from higher molecular weight hydrocarbons during the primary migration out of the source rock. Oil geochemistry indicators for this type of liquid:

- Low average molecular weight, due to loss of heavier components during primary migration out of the source rock.
- Low diamondoid concentrations.

Significant exploration and development considerations for a basin can often hinge on an understanding of which of the processes discussed above is responsible for the formation of a given high-gravity hydrocarbon liquid. Understanding which of these processes is active in a basin is important because different processes will result in different vertical and lateral distributions of:

- hydrocarbon abundance,
- hydrocarbon GOR's, and
- condensate API gravity.

Therefore, it is important to recognize that oil geochemistry provides extremely useful tools for discerning the source and the geological processes.

For more information on the techniques described here, or to discuss a specific project, e-mail us at oiltracers@weatherfordlabs.com, or call us at U.S. (214) 584-9169.

References


