Evaluating Source Rocks

by

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Overview

Introduction

To evaluate a play or prospect in an undrilled area, we must first ask, "Is a source rock present?" But this is usually not enough. After determining that a source rock is present, we also need to know its richness, its quality, and its maturity. This chapter covers all of these topics.

In this chapter

This chapter contains the following topics.

Section A
Source Rock Basics

Introduction The first factor to be assessed in an exploration play in an area yet to be drilled is whether a source rock is present. If so, then we ask, "How good is it? Will it generate oil or gas? Has it generated hydrocarbons already?" To answer these questions, we must know the basics of what constitutes a source rock, how to classify source rocks, and how to estimate potential. This section provides a background in these fundamentals.

In this section This section contains the following topics.

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Types of Source Rocks

Definition of source rock

A source rock is a rock that is capable of generating or that has generated movable quantities of hydrocarbons.

Definitions of source rock types

Source rocks can be divided into at least four major categories:
- Potential
- Effective
- Relic effective
- Spent

These categories and their definitions are shown in the table below.

Type	Definition
Potential source rock	Rock which contains organic matter in sufficient quantity to generate and expel hydrocarbons if subjected to increased thermal maturation.
Effective source rock	Rock which contains organic matter and is presently generating and/or expelling hydrocarbons to form commercial accumulations.
Relic effective source rock	An effective source rock which has ceased generating and expelling hydrocarbons due to a thermal cooling event such as uplift or erosion before exhausting its organic matter supply.
Spent source rock	An active source rock which has exhausted its ability to generate and expel hydrocarbons either through lack of sufficient organic matter or due to reaching an overmature state.

Characterizing Source Rocks

Introduction

To be a source rock, a rock must have three features:

1. Quantity of organic matter
2. Quality capable of yielding moveable hydrocarbons
3. Thermal maturity

The first two components are products of the depositional setting. The third is a function of the structural and tectonic history of the province.

Determining source rock potential

The quantity of organic matter is commonly assessed by a measure of the total organic carbon (TOC) contained in a rock. Quality is measured by determining the types of kerogen contained in the organic matter. Thermal maturity is most often estimated by using vitrinite reflectance measurements and data from pyrolysis analyses.

The table below shows the most common methods used to determine the potential of a source rock.

To determine…	Measure…
Quantity of source rock	Total organic carbon (TOC) present in the source rock
Quality of source rock	• Proportions of individual kerogens • Prevalence of long-chain hydrocarbons
Thermal maturity of source rock	• Vitrinite reflectance • Pyrolysis T_{max}

Section B
Evaluating Source Rock Richness

Introduction

Source rock richness is determined by measuring the total organic carbon (TOC) present in a rock. The two most common techniques of analyzing a rock for TOC are Rock-Eval pyrolysis with TOC and the LECO method. Conventional well logs can also provide information for evaluating interval richness.

This section first discusses what TOC is and then describes these three techniques and the information they yield.

In this section

This section contains the following topics:

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Measuring a Rock's Ability to Generate Hydrocarbons

Introduction

How do we determine if an interval of strata can be categorized as a source rock? Measuring the total organic carbon (TOC) present in weight percent (wt %) is the most common method for making this determination. A TOC analysis is a screening analysis used to evaluate the overall organic richness of a rock unit. TOC serves as a guideline for assessing the hydrocarbon generating potential of a unit of rock.

Why use TOC?

Hydrocarbons are 75–95 wt % carbon by molecular weight (Jarvie, 1991) and average 83 wt %. The amount of organic carbon present in a rock is a determining factor in a rock's ability to generate hydrocarbons.

Effect of depositional environment

Depositional environment controls the amount of organic carbon contained in a rock. Source rocks are generally associated with areas where high organic productivity is combined with (1) deposition in poorly oxygenated environments (anoxic to dysaerobic), (2) upwelling, and (3) rapid sedimentation (Chinn, 1991). These processes preserve organic matter.

Average TOCs

The table below (from Chinn, 1991) shows average TOC values for different sedimentary rock types.

Rock Type	TOC Value, %
Average for all shales	0.8
Average for shale source rocks	2.2
Average for calcareous shale source rocks	1.8
Average for carbonate source rocks	0.7
Average for all source rocks	1.8

Caveat

Use the table above only as a guide. TOC average values in the real world are meaningless unless we know how the average was calculated. For example, suppose a potential source rock unit is 100 m thick. What was the average calculated from:

- 1 sample, 1 cm thick
- 10 samples, 10 cm thick, taken every 10 m
- 100 samples, 1 cm thick, taken every 1 m

Was the sampling high-graded, taking only the richest intervals? Without answers to these questions, TOC averages have no value.

Measuring a Rock's Ability to Generate Hydrocarbons, continued

Guidelines for assessing richness

The table below gives guidelines for assessing the richness of source rock intervals.

Generation Potential	Wt % TOC, Shales	Wt % TOC, Carbonates
Poor	0.0–0.5	0.0–0.2
Fair	0.5–1.0	0.2–0.5
Good	1.0–2.0	0.5–1.0
Very Good	2.0–5.0	1.0–2.0
Excellent	> 5.0	> 2.0

Caveat

If a sample being analyzed for richness is not in an immature state, then the present-day maturation level of the interval needs to be determined to establish an initial (prematuration) organic carbon value for the interval. The measured TOC value is not indicative of the sample's source potential.

Using Pyrolysis to Estimate Richness

What is pyrolysis?
Pyrolysis is the decomposition of organic matter by heating in the absence of oxygen. Organic geochemists use pyrolysis to measure richness and maturity of potential source rocks. In a pyrolysis analysis, the organic content is pyrolyzed in the absence of oxygen, then combusted. The amount of hydrocarbons and carbon dioxide released is measured. The most widely used pyrolysis technique is Rock-Eval.

Rock-Eval pyrolysis
In Rock-Eval pyrolysis, a sample is placed in a vessel and is progressively heated to 550°C under an inert atmosphere. During the analysis, the hydrocarbons already present in the sample are volatized at a moderate temperature. The amount of hydrocarbons are measured and recorded as a peak known as S_1. Next pyrolyzed is the kerogen present in the sample, which generates hydrocarbons and hydrocarbon-like compounds (recorded as the S_2 peak), CO_2, and water (Tissot and Welte, 1984). The CO_2 generated is recorded as the S_3 peak. Residual carbon is also measured and is recorded as S_4.

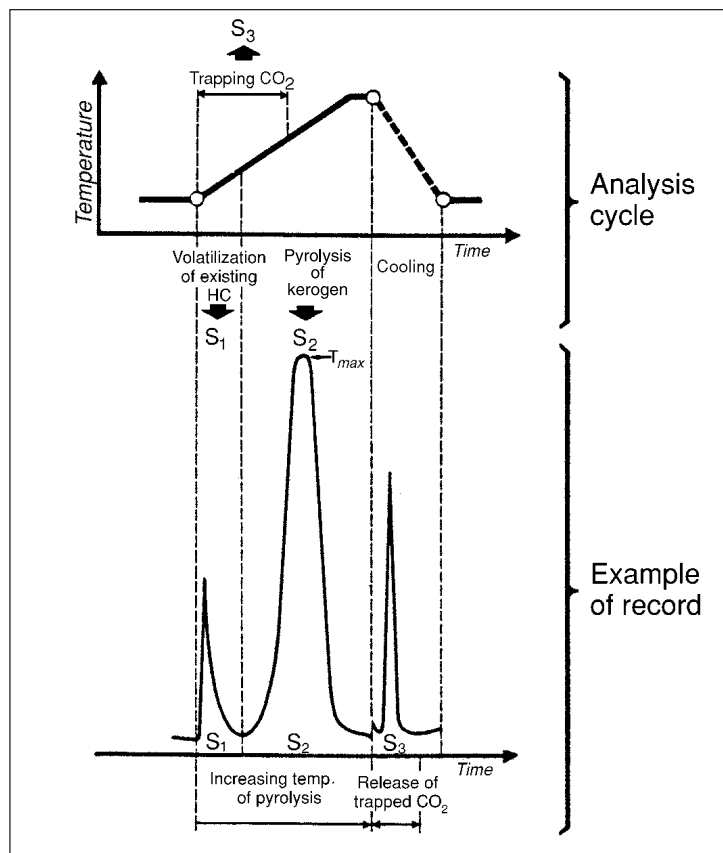The diagram below shows the cycle of analysis and the corresponding recording.

Figure 6–1. From Tissot and Welte, 1984; courtesy Springer-Verlag.

Using Pyrolysis to Estimate Richness, continued

Pyrolysis indices The table below lists the Rock-Eval pyrolysis peaks and explains what they represent.

Peak	Is a measurement of…	Comment
S_1 mg Hc/g rock	The free hydrocarbons present in the sample before the analysis	Can be thought of as a residual hydrocarbon phase. When S_1 is large relative to S_2, an alternative source such as migrated hydrocarbons or contamination should be suspected
S_2 mg Hc/g rock	The volume of hydrocarbons that formed during thermal pyrolysis of the sample	Used to estimate the remaining hydrocarbon generating potential of the sample
S_3 mg Co2/g rock	The CO_2 yield during thermal breakdown of kerogen	Most prevalent in calcareous source rocks.
S_4 mg carbon/g rock	The residual carbon content of the sample	Residual carbon content of sample has little or no potential to generate hydrocarbons due to a lack of hydrogen and the chemical structure of the molecule

Estimating TOC with pyrolysis The percent TOC is actually a value that is calculated, not measured directly, using the following formula:

$$\%TOC = [0.082(S_1 + S_2) + S_4]/10$$

Units are usually given as wt % organic carbon per weight of dry rock (milligrams hydrocarbon per gram of rock).

Using the LECO Method to Estimate Richness

Definition of LECO method

The LECO method of estimating TOC uses an instrument known as a LECO carbon analyzer to measure TOC values by combusting the organic carbon and measuring the resulting carbon dioxide produced. The LECO method has almost totally been replaced by Rock-Eval pyrolysis. However, data may still be available from prior analysis.

Measuring TOC with LECO

Samples are powdered, weighed, and chemically treated prior to analysis to remove the inorganic carbon (carbonate) from the rock. The sample is then combusted in the presence of excess oxygen, allowing carbon dioxide to form from the free (organic) carbon in the rock.

The amount of carbon dioxide is directly proportional to the amount of organic carbon or the TOC of the rock. However, the TOC value can be inflated due to the presence of sulfur compounds, water, and carbonate if they have not been removed prior to analysis.

Comparing TOC values

The TOC measured by the LECO method does not include a measurement of the free hydrocarbons present in the sample. The free hydrocarbons would be volatized when samples are dried after acid treatment is performed to remove the inorganic carbonate minerals. Thus, if a sample has a high free hydrocarbon content, the LECO TOC value will be smaller than a Rock-Eval TOC value, which includes free hydrocarbons (S_1) in the TOC calculation.

Using Conventional Well Logs to Estimate Richness

Introduction
Conventional well logs are useful for estimating source rock richness both qualitatively and quantitatively. Well logs allow a qualitative identification of organic-rich formations and a quantitative analysis of the amount of organic matter. The advantages of using well logs over cuttings are continuous sampling, more accurate depth control, and greater vertical resolution (Herron, 1991).

Using well logs
The use of conventional well logs to predict organic richness of a unit of rock requires calibrating well log intervals to samples measured for TOC using pyrolysis or another suitable measurement technique. Using the calibrated logs, we can extrapolate TOC values to uncalibrated logs to estimate source rock richness over large areas.

Note: Consider changes in depositional environment and maturity when applying these techniques.

Effects of organic matter on well logs
The increasing concentration of organic matter in a rock directly affects its properties by lowering density, slowing sonic velocity, increasing radioactivity, raising resistivity, and raising hydrogen and carbon contents. All of these attributes can be measured using density, sonic, neutron, gamma ray, and resistivity logs. The table below (from Herron, 1991) summarizes log responses to organic matter.

Log/Property	Response/Value for Organic Matter (OM)	Comments
Gamma ray (GR) or uranium (U)	High	High GR caused by U; can be linear with OM; U not always present
Density	Low (approx. 1 g/cm^3)	Similar to pore fluids
Neutron	High	Due to hydrogen in OM
Sonic	High transit time	Estimates vary from 150 to more than 200 μsec/ft
Resistivity	High	May not affect log response unless generated hydrocarbons occupy pores
Pulsed neutron	High carbon–oxygen ratio	Most direct measurement of carbon; needs inorganic correction

Using Conventional Well Logs to Estimate Richness, continued

Shale response example

The following composite log of Kimmeridge shale, North Sea, is a typical log response to a high concentration of organic matter in a shale section. The underlying Heather Formation is very silty. The source rock interval is indicated by dots with dashes through them. Note the high sonic and gamma ray readings and the low density readings. The resistivity log reads only slightly higher than the overlying shale section.
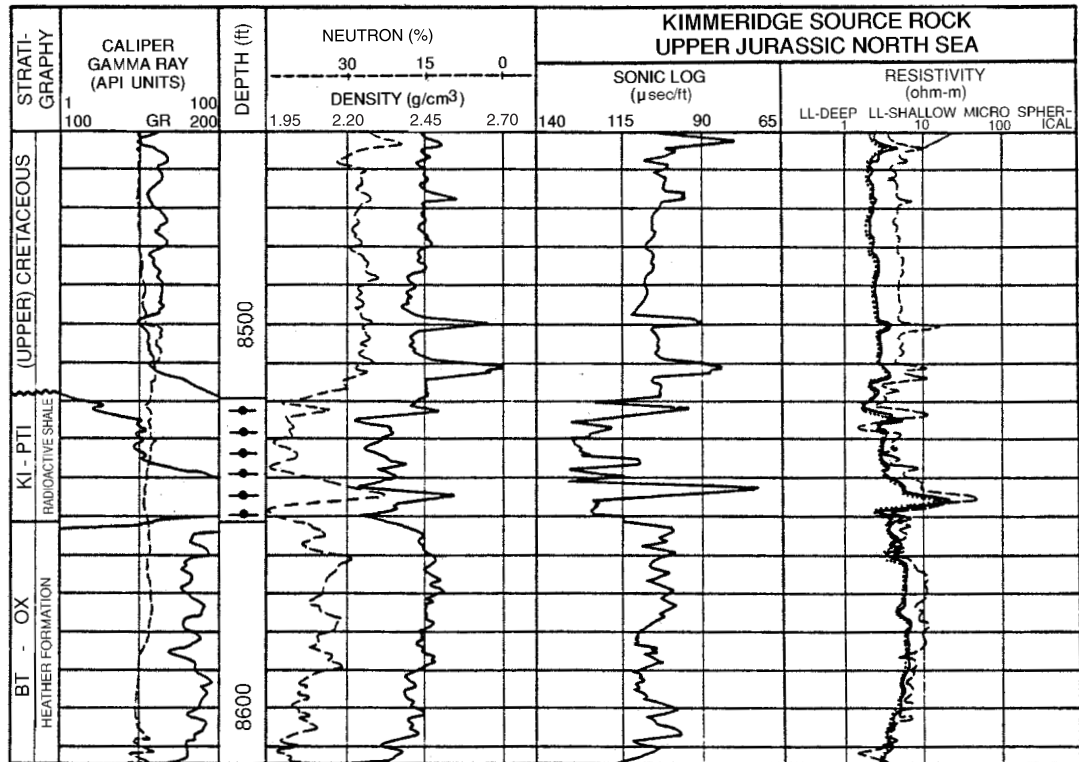

Figure 6–2. From Meyer and Nederlof, 1984; courtesy AAPG.

Using Conventional Well Logs to Estimate Richness, continued

Limestone response example

The following composite log of the Upper Jurassic Hanifa limestone in the Middle East displays a typical response of organic matter in a limestone section. No shale is present in this interval. Note the high gamma ray and resistivity readings. Core analysis of this well indicates the source rock (indicated by dots with dashes through them) is mature and generating oil.
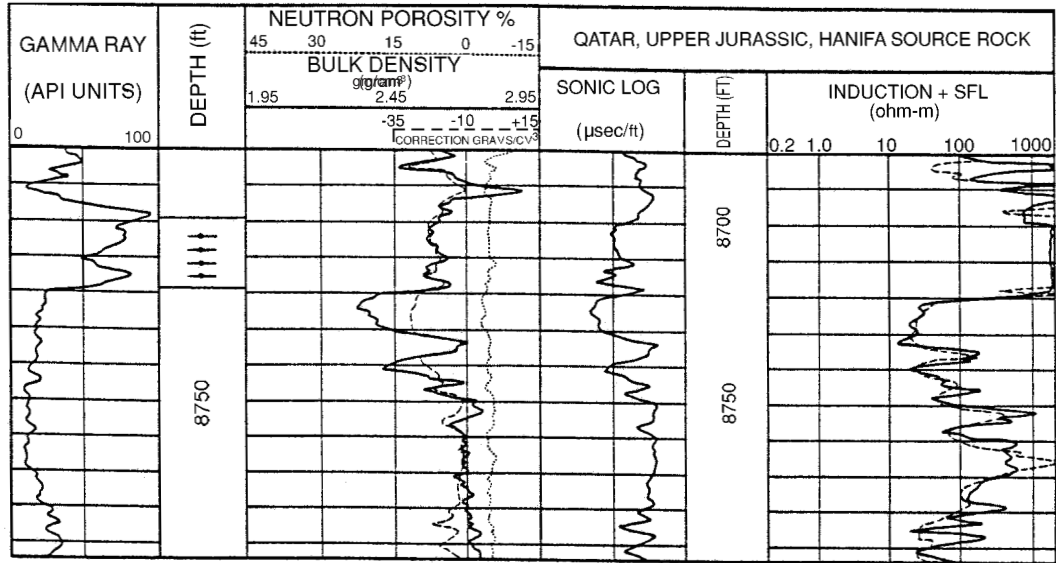

Figure 6–3. From Meyer and Nederlof, 1984; courtesy AAPG.

Limitations

Well-log signals are recorded for an interval thickness, which varies depending on the type of logging tool. Averaged values may not give a true picture of the richness of the source rock.

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Section C

Evaluating Source Rock Quality

</div>

Introduction   This section discusses types of kerogen and how to estimate the quality of source rocks.

In this section   This sections contains the following topics.

Kerogen Types

Introduction

Depositional environment is the dominant factor in determining the types of organic matter found in a rock. Only two types of organic matter are found in rocks: land derived and aquatic algae derived. Heat and pressure convert organic matter into a substance called **humin** and then into **kerogen**. Time and temperature convert kerogen into petroleum.

What is kerogen?

Geochemists (Durand, 1980; Tissot and Welte, 1984) define kerogen as the fraction of sedimentary organic constituent of sedimentary rocks that is insoluble in the usual organic solvents. Kerogens are composed of a variety of organic materials, including algae, pollen, wood, vitrinite, and structureless material. The types of kerogens present in a rock largely control the type of hydrocarbons generated in that rock. Different types of kerogen contain different amounts of hydrogen relative to carbon and oxygen. The hydrogen content of kerogen is the controlling factor for oil vs. gas yields from the primary hydrocarbon-generating reactions.

Kerogen quality

The type of kerogen present determines source rock quality. The more oil prone a kerogen, the higher its quality. Four basic types of kerogen are found in sedimentary rocks. A single type or a mixture of types may be present in a source rock. The table below lists and defines these four basic kerogen types.

Kerogen Type	Predominant Hydrocarbon Potential	Amount of Hydrogen	Typical Depositional Environment
I	Oil prone	Abundant	Lacustrine
II	Oil and gas prone	Moderate	Marine
III	Gas prone	Small	Terrestrial
IV	Neither (primarily composed of vitrinite) or inert material	None	Terrestrial(?)

Evaluating Quality Using Rock-Eval HI/OI

Introduction

Obviously, the two main elements of hydrocarbons are hydrogen and carbon. Therefore, once we know the amount of organic carbon present in a rock, we then need to know the amount of hydrogen present in order to assess overall source rock quality. The amount of oxygen and hydrogen present in the kerogen defines the kerogen as type I, II, or III and if the rock will be oil or gas prone.

Hydrogen index

The hydrogen index (HI) represents the amount of hydrogen relative to the amount of organic carbon present in a sample. The S_2 curve of a Rock-Eval analysis can help us determine the total amount of hydrogen in milligrams of hydrogen to grams of sample according to the following formula:

$$HI = S_2 \text{ (mg/g)}/\%TOC \times 100$$

Oxygen index

The oxygen index (OI) represents the amount of oxygen relative to the amount of organic carbon present in a sample. The S_3 curve of a Rock-Eval analysis can help us determine the total amount of oxygen present in a sample according to the following formula:

$$OI = S_3 \text{ (mg/g)}/\%TOC \times 100$$

Determining kerogen quality

The type of kerogen present in a rock determines its quality. Type I kerogen is the highest quality; type III is the lowest. Type I has the highest hydrogen content; type III, the lowest. To determine the kerogen type present in a source rock, plot the hydrogen and oxygen indices on a modified Van Krevlen diagram (at right).
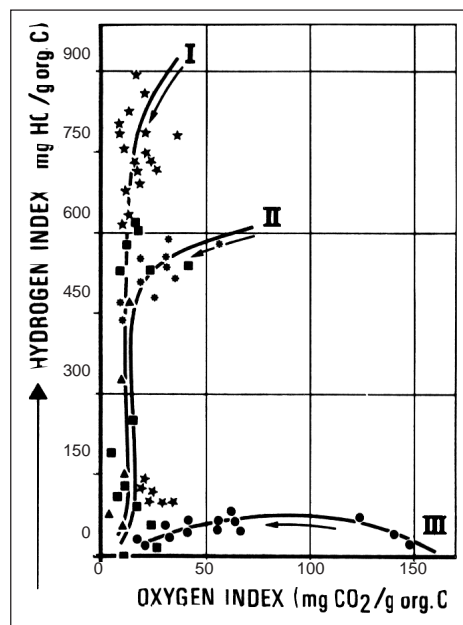

Figure 6–4. From Tissot and Welte, 1984; courtesy Springer-Verlag.

Caveat

Use the HI/OI technique only to determine source rock quality (kerogen type) of immature rocks. HI and OI change as a source rock matures (the amount of hydrogen and oxygen relative to carbon decreases and the HI/OI ratios converge toward the origin of the plot, leading one to a more gas-prone type III interpretation). Therefore, in mature rocks HI and OI are not indicative of the original kerogen quality.

Visually Assessing Quality

The method   To assess kerogen quality visually, we can separate it from the mineral matrix through acidification. We can then examine the kerogen using transmitted light through a microscope to determine its form (structured or amorphous) and origin. Structured kerogens include woody, herbaceous, vitrinite, and inertinite. Amorphous kerogens are by far the most prevalent and include most of the algal material.

Visual kerogen estimates are usually presented in terms of the percentage of each type of kerogen in a sample derived from cuttings composites or core (conventional or sidewall). For example, a visual estimate of kerogen type might be stated as 50% woody, 45% amorphous, 5% inertinite. In general, the more amorphous kerogen present, the more oil prone the rock is.

Visual kerogen types and quality   Visual kerogen types and quality are shown in the table below.

Visual Kerogen Type	Hydrocarbon Potential
Woody	Gas prone
Herbaceous	Oil and gas prone
Vitrinite	Gas prone
Inertinite	No potential
Amorphous (dominantly algal)	Oil and gas prone

Using Pyrolysis Gas Chromatography to Assess Quality

What is Py-GC?   Pyrolysis gas chromatography (Py-GC) is anhydrous thermal decomposition of a material that leads to the conversion of kerogen to hydrocarbon compounds. Py-GC can be conducted on whole rock or isolated kerogen samples to obtain a visual signature or "fingerprint" of the organic material present.

How to read gas chromatograms   Gas chromatography generally is a qualitative tool. It is not typically used as a quantitative measurement of hydrocarbon molecules. However, the patterns generated in the chromatograms can help us determine if a source rock will be oil or gas prone.

The X-axis of a gas chromatogram is retention time, and the Y-axis is the relative quantity of each compound. Each spike in the chromatogram represents a particular hydrocarbon compound, beginning with lowest number of carbon atoms in the compound on the left and going to higher chains of carbons to the right. The height of the spike represents the relative abundance of the compound pyrolized from the sample's kerogen. Typical gas chromatogram examples for types I, II, and III kerogen are shown below.
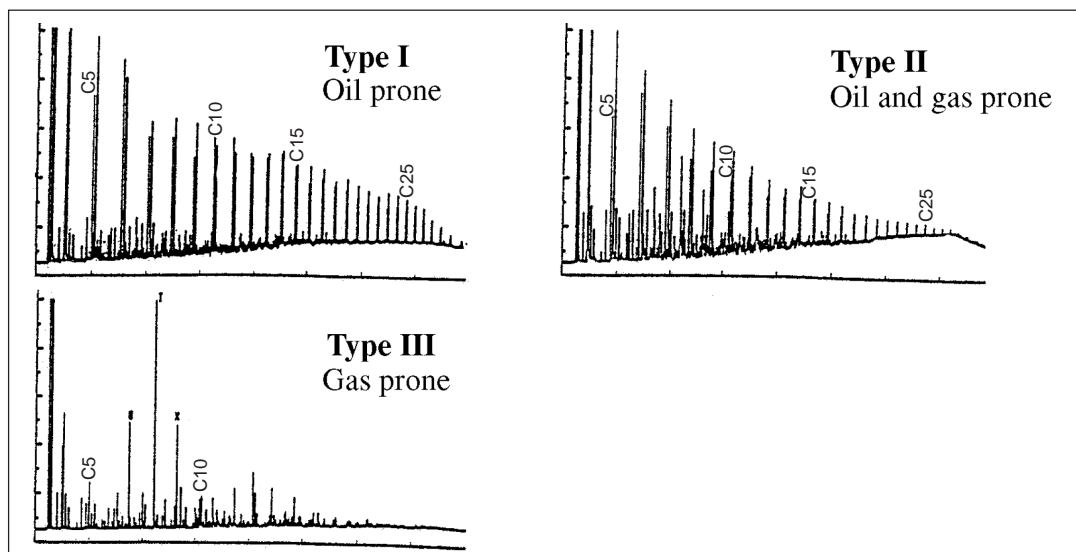

Figure 6–5.

Interpreting gas chromatograms   A gas chromatogram is evaluated qualitatively to determine the potential of a rock to generate oil vs. gas. The table below shows how chromatograms for oil- vs. gas-prone rocks are evaluated.

Chromatograms of oil-prone rock	Chromatograms of gas-prone rock
Dominated by long-chain carbon compounds (greater than C_{10})	Dominated by short-chain carbon compounds from C_1-C_4
Contain carbon compounds up to C_{25} or greater	Contain very few carbon compounds above C_{10}

Section D
Evaluating Source Rock Maturity

Introduction   Once the two questions "Is a source rock present?" and "What type of hydrocarbons will it generate?" have been answered to our satisfaction, we must ask, "Has it generated hydrocarbons?" In other words, what is its present-day maturity?

In this section   This section discusses the following topics.

Maturation

Introduction

The chemistry of organic matter contained within a sedimentary rock changes over time, reflecting its temperature and burial history. This change or maturation is measured and can be combined with quality and richness data to gauge the amount of hydrocarbon generated by the organic matter. The present-day maturity level is the product of a number of variables, such as tectonic setting, burial history, and thermal history. A number of variables such as paleolatitude, pressure, fluid flow, rock matrix chemistry, and pore fluid chemistry can affect the thermal history and thus a rock's rate of maturation.

Transformation rate

The rate at which hydrocarbons are generated from organic matter is called the **transformation rate**. Using source rock maturity, we can estimate the transformation rate. Different kerogen types (1) generate hydrocarbons at different maturity levels and (2) have different transformation rates. Maturity measurements can be made on several different components of a rock like vitrinite, kerogen, spores, apatite grains, and biomarkers; each has its own relationship to the kerogen transformation rate.

Caveat

Evaluating the maturation of a geologic section is based on a depth trend from samples in a well or basin. The level of maturity interpreted from most maturation indices is dependent on the type of organic matter or material being analyzed.

For example, T_{max} cutoffs for hydrocarbon-generation zones are greater for type III than for type II kerogen. Therefore, a trend is only valid if based on analysis of samples from a homogeneous organic sequence or if differences in chemistry are accounted for in the interpretation process.

T_{max}

Introduction

T_{max} is the temperature at which the maximum rate of hydrocarbon generation occurs in a kerogen sample during pyrolysis analysis. The S_2 peak represents the rate of hydrocarbon generation (the area under the curve represents the amount). The temperature at the time the S_2 peak is recorded during pyrolysis is T_{max}, given in °C. The diagram below shows output from a pyrolysis analysis and when T_{max} is recorded.
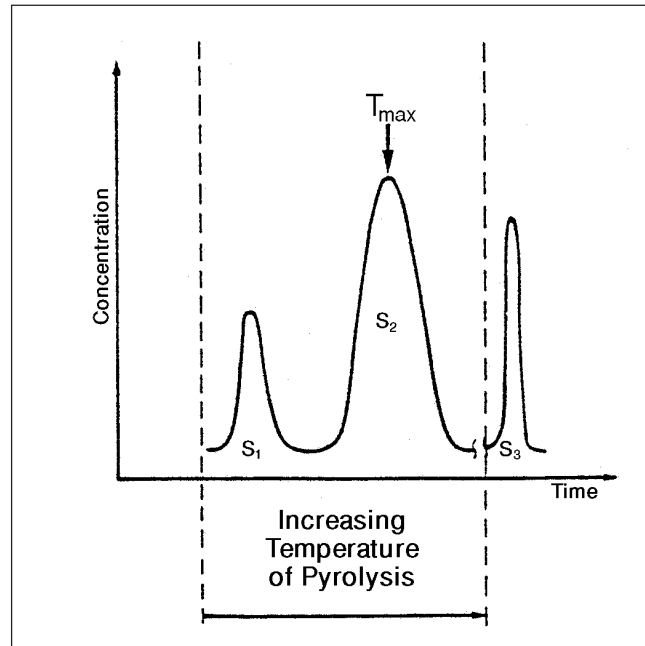

Figure 6–6.

Interpreting T_{max}

We can use the general guidelines for maturation levels given below for Rock-Eval pyrolysis T_{max} for types II and III kerogens. Different pyrolysis techniques have different cutoffs for pyrolysis oil and gas generation zone boundaries. Pyrolysis T_{max} can be significantly different for type I kerogen (Tissot et al., 1987) or kerogen containing high sulfur concentration and is not a reliable indicator of maturity for these kerogen types.

Hydrocarbon Generation Zone	Rock-Eval Pyrolysis T_{max}, °C
Immature	< 435
Oil (from type II kerogen)	435–455
Oil (from type III kerogen)	435–465
Gas (from type II kerogen)	> 455
Gas (from type III kerogen)	> 465

Vitrinite Reflectance

Introduction

Vitrinite reflectance is a measure of the percentage of incident light reflected from the surface of vitrinite particles in a sedimentary rock. It is referred to as $\%R_o$. Results are often presented as a mean R_o value based on all vitrinite particles measured in an individual sample.

Connection between vitrinite and kerogen

The maturation of vitrinite is a kinetic process. The relationship between $\%R_o$ and hydrocarbon generation is dependent on the chemistry of the vitrinite as well as the chemistry of the kerogen.

Oil and gas zones

Oil and gas zone boundaries can be established using vitrinite reflectance data. The boundaries are approximate and vary according to kerogen type. The figure below shows the approximate boundaries for kerogen types I, II, and III. Time–temperature relationships and mixing of various sources of organic matter may alter these boundaries.
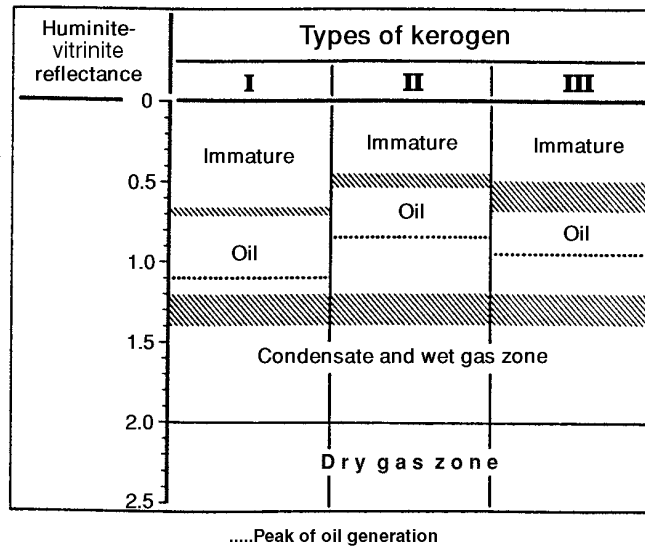

Figure 6–7. From Tissot and Welte, 1984; courtesy Springer-Verlag.

Vitrinite Reflectance, continued

Misleading data, cautions, and recommendations

A bimodal distribution or a large spread in the range of measured values produces a mean R_o value that does not accurately represent the maturity of the rock sample. Variations or errors in vitrinite reflectance measurements may be caused by the following:

- Vitrinite composition
- Incorrect identification of vitrinite particles
- Anisotropy
- Oxidation
- Staining
- Presence of caved vitrinite particles in borehole cuttings
- Reworking of vitrinite in the geologic section
- Drilling mud additives

Therefore, explorationists should always request and examine the raw data as well as the histograms and mean data.

The data below are a perfect example from a sample where the mean value reported is 1.27% R_o, based on 14 measurements. The interpretation of the mean value would place this sample past the oil generation zone. The true reflectance of the indigenous vitrinite in this sample is 0.7% R_o, providing an extremely different interpretation and placing the sample in the early stage of liquid hydrocarbon generation.

A bimodal distribution or a large spread in the range of measured values will produce a mean R_o that does not truly represent the maturity of a rock sample.
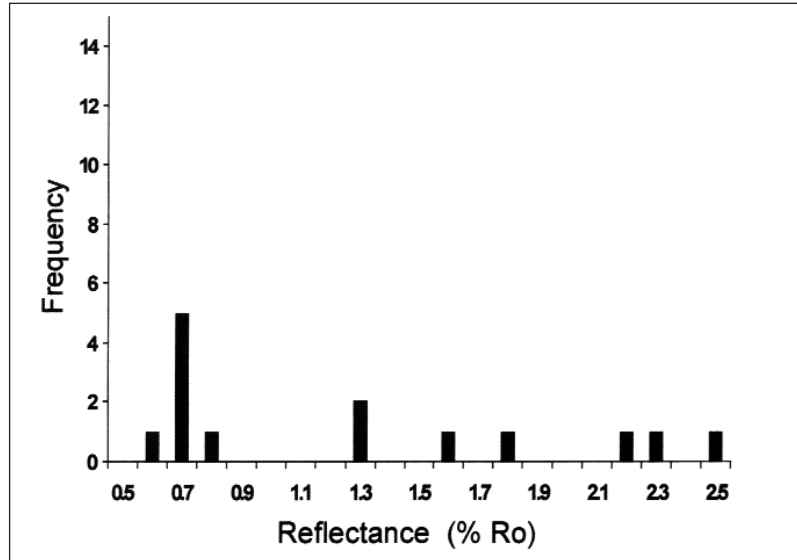

Figure 6–8.

Vitrinite Reflectance, continued

Recognizing good data

An excellent way to recognize high-quality vitrinite reflectance data is to plot it in a histogram. We can have high confidence in the data when a single mode in the distribution curve is tightly clustered about a mean value. The histogram below is a good example.
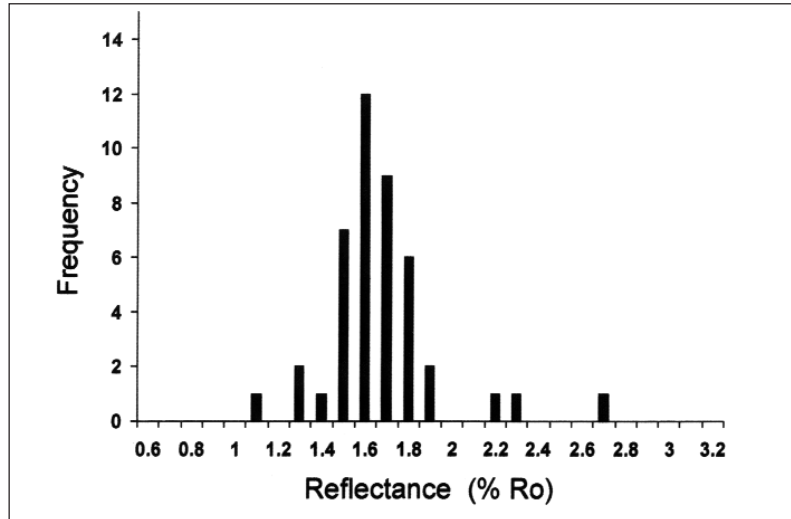

Figure 6–9.

Adequate number of measurements

A histogram profile of vitrinite reflectance used to estimate the maturity level of a sample must have an adequate number of measurements. Make as many reflectance measurements as possible for a valid R_o determination for a sample. The histogram below is an example of a poor profile due to a lack of data. We should not place a high degree of confidence in an R_o obtained from this sample. A rule of thumb is 40–50 vitrinite readings per sample.
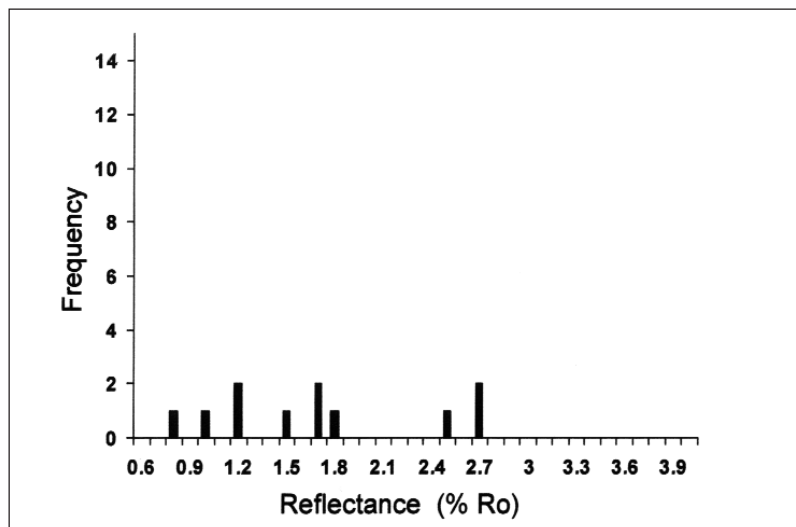

Figure 6–10.

Vitrinite Reflectance, continued

Data contaminated by caving

The histogram below represents poor-quality vitrinite reflectance data due to contamination by caving. As a result of the drilling process, immature kerogen caved into the borehole and mixed with drill cuttings originally containing sparse amounts of vitrinite. The indigenous vitrinite is about 2.5% R_o. Therefore, it is important to know the type of sample used for vitrinite analysis.
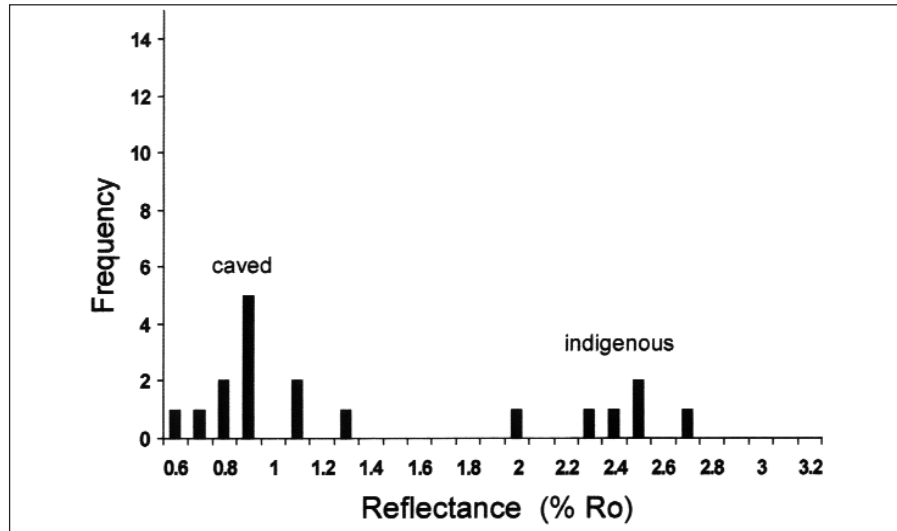

Figure 6–11.

Sample with reworked vitrinite

The bimodal distribution shown in the histogram below represents an indigenous and a reworked population of vitrinite measured in one sample. The reworked population would have been eroded from a more mature provenance and deposited with the indigenous organic matter of this sample.
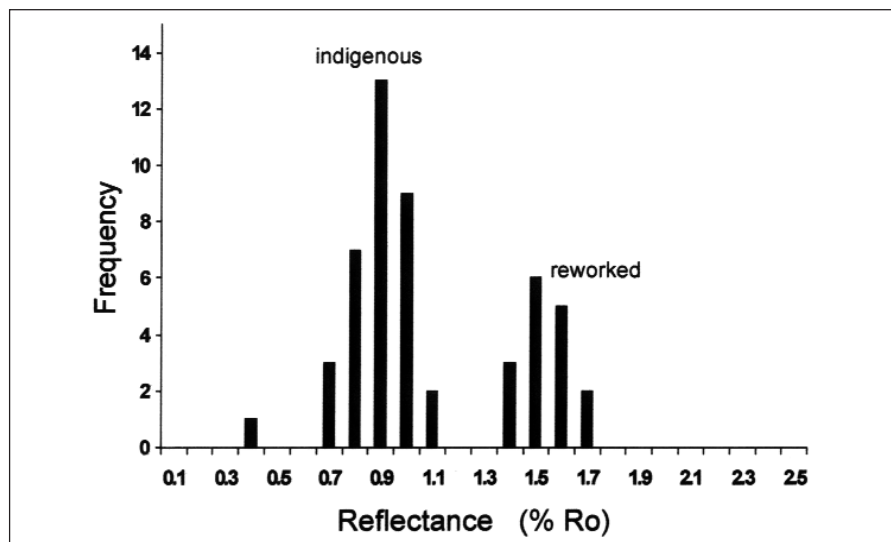

Figure 6–12.

Apatite Fission Track Analysis

What is apatite fission track analysis?

Apatite fission tracks are formed when charged particles are released by the spontaneous nuclear fission of uranium 238 in apatite crystals. The highly charged particles released by the fission reaction damage the lattice of apatite crystals. The damage appears as linear features referred to as **fission tracks**.

The rate of decay of uranium 238 is a time-dependent reaction; therefore, the number of fission tracks in a crystal can be used to measure the time since the formation of the apatite grains. This is the basis for apatite fission track analysis.

Measuring maturity with apatite fission tracks

The continued existence of apatite fission tracks is temperature dependent. At temperatures below 60°C the fission tracks exist as they were formed. However, as the temperature increases from 60–120°C, the length of the fission tracks in apatite crystals will decrease due to thermally induced "healing" of the crystal structure. This process is referred to as **annealing**.

The mean length of a fission track at the time of formation and up to 60°C is 15μ. Fission tracks will completely anneal and disappear at approximately 120°C. Therefore, the length of apatite fission tracks can be used as a measure of the maximum temperature that a rock has been subjected to and provides information related to thermal history.

Using analysis with R_o

Apatite grains are commonly found in sandstones. The amount of information provided from fission track analysis can be significant and is very complementary to vitrinite data in portions of the geologic section that are lean in organic matter. See Duddy et al., 1988, and Gleadow et al., 1986, for a general overview of the interpretation and application of apatite fission track data in petroleum exploration.

Caveat

The chemistry of apatite is variable and can be significant enough to have an effect on the rate of fission track annealing. One should consider this effect when interpreting apatite data. Also, one should make sure caved material has not contaminated a sample of drilling cuttings. This can be a source of erroneous data.

Getting a valid measurement

One reading of fission track length is not enough to make a valid determination of the thermal history of a sample. Instead, many readings need to be made to achieve a high confidence level. A service company's report cites the fission track length as a mean of the total population of fission track lengths measured. Overall, mean track length should decrease as depth and/or temperature increase. We should check the raw data in an apatite fission track analysis report against the known geologic history of an area (and its expected thermal history) to verify or refine a vendor's interpretation.

Apatite Fission Track Analysis, continued

Effect of uplift on AFTA data

If the mean age distribution of a sample as determined from apatite fission track analysis is less than the geologic age of that sample determined by other means, then that sample is interpreted to have been exposed to temperatures of > 120°C during its burial history. For example, a sample might have been buried to a depth where temperatures were > 120°C. At these high temperatures, all the fission tracks would have annealed. Then the sample might have been subsequently uplifted and exposed to temperatures < 120°C where new fission tracks formed. The number and length of the new fission tracks reflect the latest thermal environment.

This application of fission track data makes the technique extremely useful for evaluating the magnitude and timing of major unconformities in an area of interest.

Example of fission track length interpretation

The length data in itself may not be adequate to evaluate the thermal history. For example, the figure below shows a unimodal distribution of relatively long (unannealed) fission tracks. These data would need to be combined with the fission track age determination to derive thermal history information. If the fission track age of this sample was older than the depositional age, the implication would be that the sample had never been exposed to temperature in the annealing zone and most likely never experienced temperatures greater than 60–70°C. In contrast, if the fission track age was less than the depositional age, the sample would have been subjected to temperatures above 110–120°C, where all of the original tracks would have been annealed. The sample would then have been uplifted rapidly and all of the remaining tracks would have formed since the uplift to a temperature zone less than or equal to the 60–70°C. The fission track age date would provide information on the timing of this rapid uplift event.
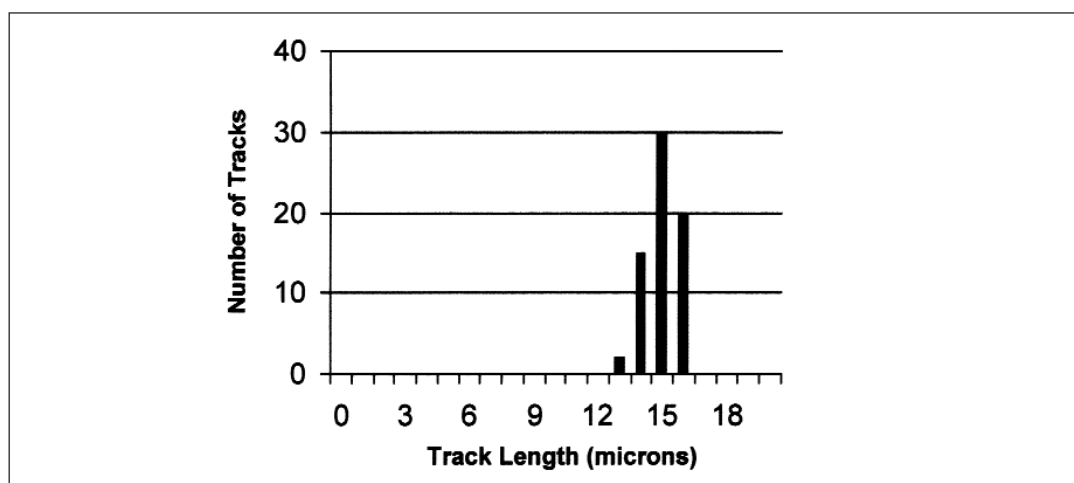

Figure 6–13.

Spore Coloration and Thermal Alteration Indices

How to use SCI and TAI

SCI (spore coloration index) and TAI (thermal alteration index) are maturation indicators that measure the color of palynomorphs. Color changes as a function of maturity.

There are a number of scales for both SCI and TAI within the exploration industry. The SCI and TAI scales have been "standardized" to the vitrinite reflectance maturity scale. Users of SCI and TAI data need to have access to the maturation relationship used by the lab supplying the data, and users should be aware of how the scales compare from one lab to another in order to apply the data correctly. These relationships should be available from the vendor performing the analysis.

Correlation of SCI & TAI with other parameters

The table below shows a very generalized correlation of kerogen maturity parameters with SCI and TAI (after Waples, 1985).

Vitrinite Reflectance (%R_o)	Spore Coloration Index (SCI)	Thermal Alteration Index (TAI)	Pyrolysis T_{max} (°C)	Generalized Hydrocarbon Zone
0.40	4.0	2.0	420	Immature
0.50	5.0	2.3	430	Immature
0.60	6.0	2.6	440	Oil
0.80	7.4	2.8	450	Oil
1.00	8.1	3.0	460	Oil
1.20	8.3	3.2	465	Oil & wet gas
1.35	8.5	3.4	470	Wet gas
1.50	8.7	3.5	480	Wet gas
2.00	9.2	3.8	500	Methane
3.00	10	4.0	500+	Methane
4.00	10+	4.0	500+	Overmature

Hydrogen Index (HI)

Introduction

Gross trends of hydrogen indices (HI) can be used as a maturation indicator. The hydrogen index is calculated from Rock-Eval data using the following formula:

$$HI = S_2 \text{ (mg/g)}/\%TOC \times 100$$

How to apply HI

Hydrocarbon generation zones can be indicated in the HI data for a uniform source section when HI decreases with depth. Inconsistencies due to changes in organic facies or the chemistry of the source rock can produce shifts in the HI data which are not indicative of maturation trends. Therefore, be sure the source is of uniform character when applying this concept.

The figure below shows a decreasing HI trend for a source rock beginning to generate hydrocarbons at a depth of approximately 2200 m.
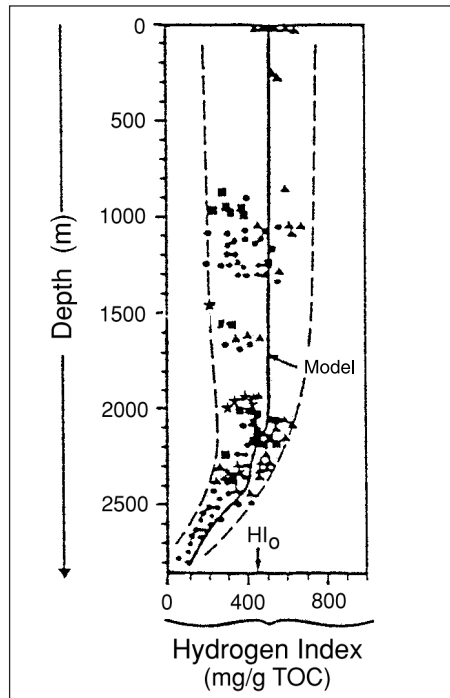

Figure 6–14. From Ungerer et al., 1991; courtesy John Wiley & Sons.

Production Index (PI)

Introduction Maturity of a homogeneous source section can be accessed from the production index (PI). PI is calculated from Rock-Eval data:

$$PI = S_1/(S_1 + S_2)$$

How to apply PI PI increases continuously through the oil window up to a value of 0.50. The following cut-offs can generally be applied.

Production Index	Generation Zone
< 0.10	Immature
0.10–0.30	Oil generation
> 0.30	Gas generation/oil cracking

Caveat PI data are misleading if the S_1 peak includes nonindigenous hydrocarbons, such as drilling additives or migrated hydrocarbons. Expulsion characteristics of a source rock are not considered when looking at PI numbers. If the expulsion saturation threshold of the source rock is high, the PI data will be overestimated. If the expulsion saturation threshold is low, the data will be underestimated.

A trend is valid only if developed over a uniform source internal. If the depositional environment changes significantly, establish a different PI trend for each unique source rock type.

Section E

Relationships Between Maturity and Hydrocarbon Generation

Introduction   Different types of kerogens convert to hydrocarbons at different rates, and they yield different quantities of various hydrocarbon phases. Therefore, one standard relationship between a measured maturity parameter and hydrocarbon generation does not exist. Values such as 0.6% R_o are generally associated with the onset of oil generation or indicate the top of the oil window. However, this generality applies only if a source rock is composed of pure type II organic matter (marine kerogen).

This section reviews some of the relationships between maturation indicators and hydrocarbon generation from standard kerogen types.

In this section   This section contains the following topics.

Kerogen Type and Hydrocarbon Generation

Introduction

Kerogen consists of many fractions, each converting to hydrocarbons at a specified rate. This rate of conversion to hydrocarbons is defined by a first-order rate equation known as the Arrhenius law:

$$K(+) \ = \ A_e^{-E/RT(t)}$$

where:

$A \ = \ $ Arrhenius factor
$E \ = \ $ activation energy

These are generally referred to as **kinetic parameters**. They can be measured using various pyrolysis techniques and are different for each distinct kerogen analyzed.

Hydrocarbon generation— depth and yield

The depth of hydrocarbon generation and the yield of individual hydrocarbon phases are primarily a function of the kinetics of the kerogen–hydrocarbon conversion. Burial history and catalytic effects, due to source rock matrix chemistry, affect the rate of generation, although these effects are secondary to the kinetic effects.

The following hydrocarbon generation vs. depth plots for types I (left) and III (right) kerogens are based on identical burial and thermal conditions. Thus, they depict the difference in the depth of hydrocarbon generation, based on kerogen type alone. Type I kerogen generally has a shallower liquid hydrocarbon zone and generates significantly larger amounts of hydrocarbons. The onset of generation is indicated by the change in the slope of the curves.
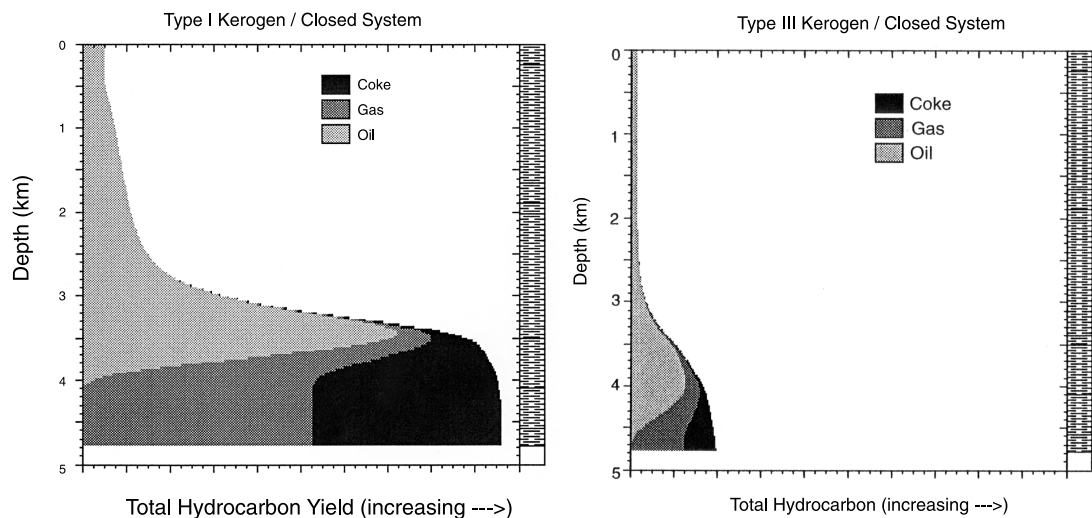

Figure 6–15. From results of Genex 1-D basin modeling software, courtesy Institute Français du Petrole.

Kerogen Type and Hydrocarbon Generation, continued

Timing hydrocarbon generation

Variations in the kinetic parameters affect predictions of the present-day distribution of hydrocarbon generation zones and also influence when, in geologic time, a potential source interval generates. The figures below compare the timing of hydrocarbon generation from type I kerogen (left) to type III (right). The onset of hydrocarbon generation is indicated by the dramatic change in slope of the curves: 110–100 Ma for type I and 90–80 Ma for type III. The difference in timing shown in this example is based only on the different kinetic parameters of the kerogen types.
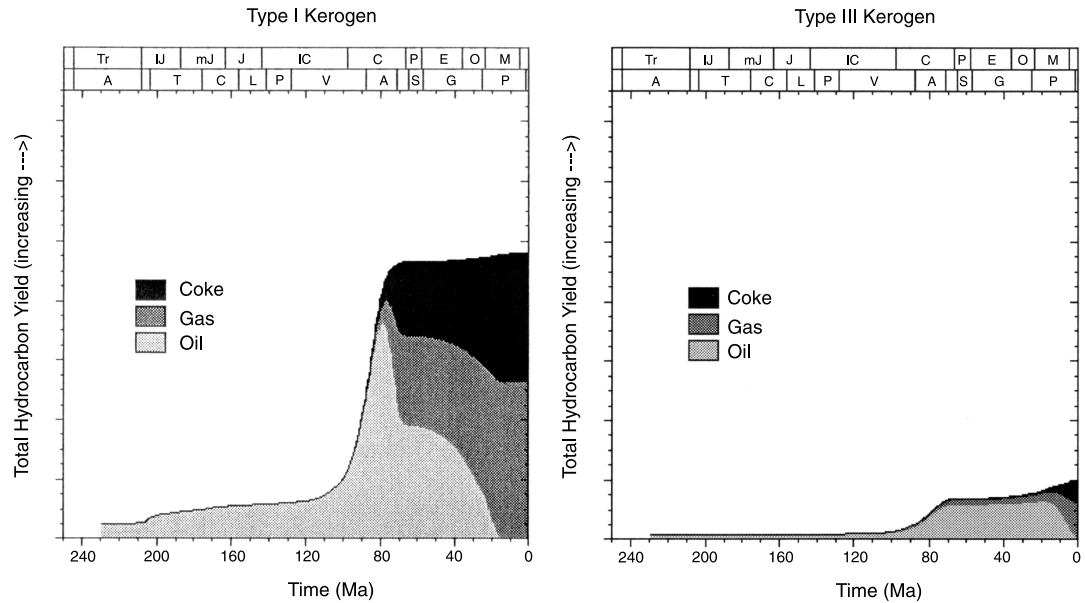

Figure 6–16.

Recommendations

Conduct kerogen kinetic analysis on samples from the basin being modeled. If samples are not available, standard values for types I–III are available from Burnham, 1989; Burnham and Sweeney, 1990; and Tissot and Espitalie, 1975. Apply these values after carefully classifying the kerogen type in terms of the depositional environment of the individual source intervals.

Kerogen Type and Maturity

Introduction

Each kerogen type has its own relationship to maturity parameters. Maturity measurements are made on materials other than kerogen; therefore, they are not a direct measure of the hydrocarbon generation stage of the source intervals. A relationship must be established between maturity of the geologic section and hydrocarbon generation for each kerogen type in a basin. This relationship can be derived using 1-D basin modeling techniques.

Hydrocarbon generation and maturity

The hydrocarbon generation–depth curve shown below indicates where various phases of hydrocarbons would be generated today in the geologic section if a uniform kerogen existed throughout. We would use the following steps to compare the relationships.

| Step	Action
1	Define the hydrocarbon generation stage for a calibrated well based on the depth vs. hydrocarbon yield plot (left figure). For example, the onset of oil generation occurs at approximately 2.1 km. Then transfer to the depth versus maturity plot (in this case vitrinite reflectance, right figure) and follow across at 2.1 km until you reach the maturity profile. This vitrinite reflectance value (0.55 %R_o) would indicate the onset of hydrocarbon generation in this well.
2	Apply this relationship to predict the generation zones for this specific kerogen in wells with similar thermal and burial histories in the basin for which maturity data are available.
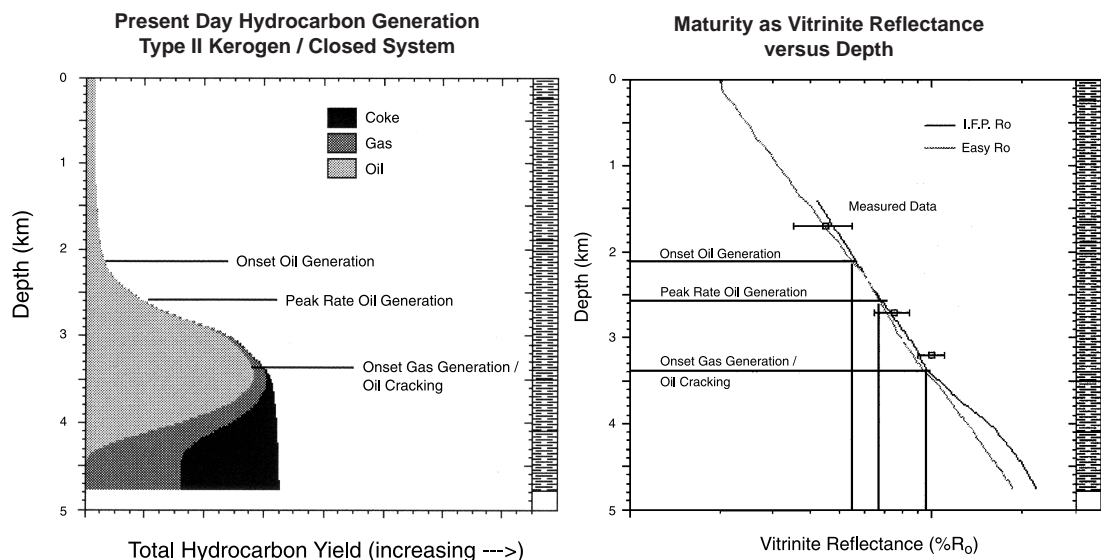
Figure 6–17. From results of Genex 1-D basin modeling software, courtesy Institute Français du Petrole.

Kerogen Type and Transformation Ratio

Introduction   When we compare hydrocarbon generation curves and transformation ratio curves from 1-D models, we can develop a relationship in a way similar to that for generation–maturity. If vitrinite reflectance data are available, the relationship between transformation ratio and maturity can be used to predict (1) percentage of kerogen that has generated hydrocarbons at a given depth and (2) hydrocarbon yields.

Example   Based on the figures below, we determine that at a depth of 2.6 km the modeled well is presently in the oil generation zone and approximately 25% of the kerogen in the source rocks at this depth has generated hydrocarbons. We know from the hydrocarbon generation–maturity relationship that at 2.6 km this well has a vitrinite reflectance of 0.7% R_o. If another well in the basin contains similar source rocks and has a maturity of 0.7% R_o at 3.7 km, then we can predict that the section at 3.7 km is mature for liquid generation and has generated a liquid hydrocarbons, converting approximately 25% of its kerogen to hydrocarbons.
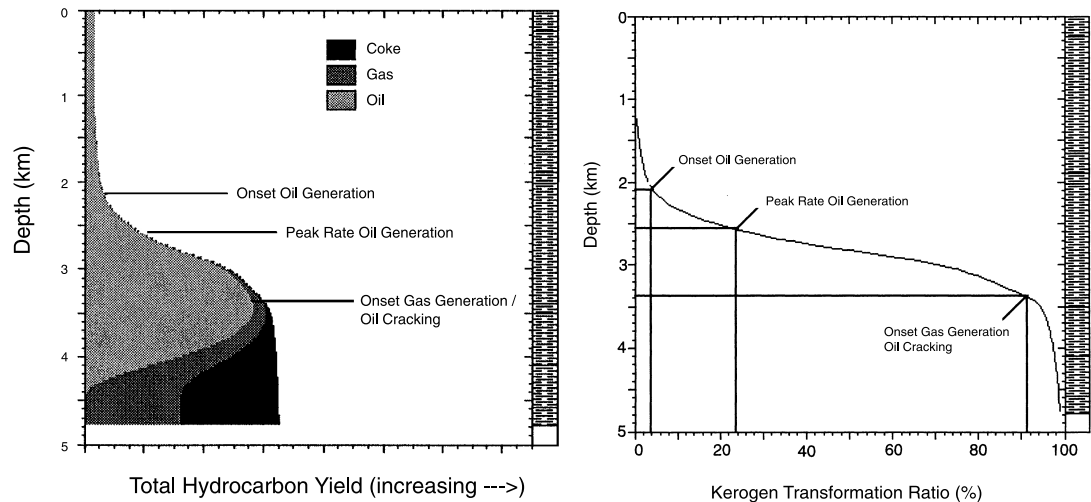

Figure 6–18. From results of Genex 1-D basin modeling software, courtesy Institute Français du Petrole.

Comparison of Kerogen Types

Parameter differences

The table below shows examples of the relationships between hydrocarbon generation zones, maturity, and transformation ratio for standard types II and III kerogens, based on a specific burial and thermal history model. The most significant difference is in the depth to the onset of oil generation, where 1000 m separates the top of the oil windows of these two kerogen types.

Hydrocarbon Generation Zone	Vitrinite Reflectance, % R_o		Transformation Ratio, %		Present-Day Depth, m	
	Type II	**Type III**	**Type II**	**Type III**	**Type II**	**Type III**
Onset oil	0.55	0.85	5	12	2200	3200
Onset peak rate generation	0.65	1.00	17	31	2600	3500
Onset gas/cracking liquids	0.95	1.35	88	64	3400	4050

Open- vs. Closed-System Generation Modeling

Introduction

Hydrocarbon generation results from computerized 1-D basin modeling software are typically presented as either open- or closed-system yields. **Open-system** models are based on the assumption that hydrocarbons have been expelled from the source rock, have been transported away, and are no longer subject to the thermal conditions of the 1-D model. **Closed-system** models assume the hydrocarbons have not been expelled from the source rock and that all generated hydrocarbon phases are subject to further cracking to lighter phases.

Implications for yield predictions

Below are examples of yield curves for the same well, based on both open- and closed-system modeling conditions. The open-system model is run with an expulsion efficiency of 70%, meaning 70% of the generated hydrocarbons were expelled before subsequent maturation and were not subjected to secondary cracking to lighter phases. The closed-system model does not incorporate an expulsion component; therefore, the hydrocarbons are subject to cracking to lighter phases. The closed-system model (right) predicts significantly greater quantities of gas at depth than the open-system model (left).
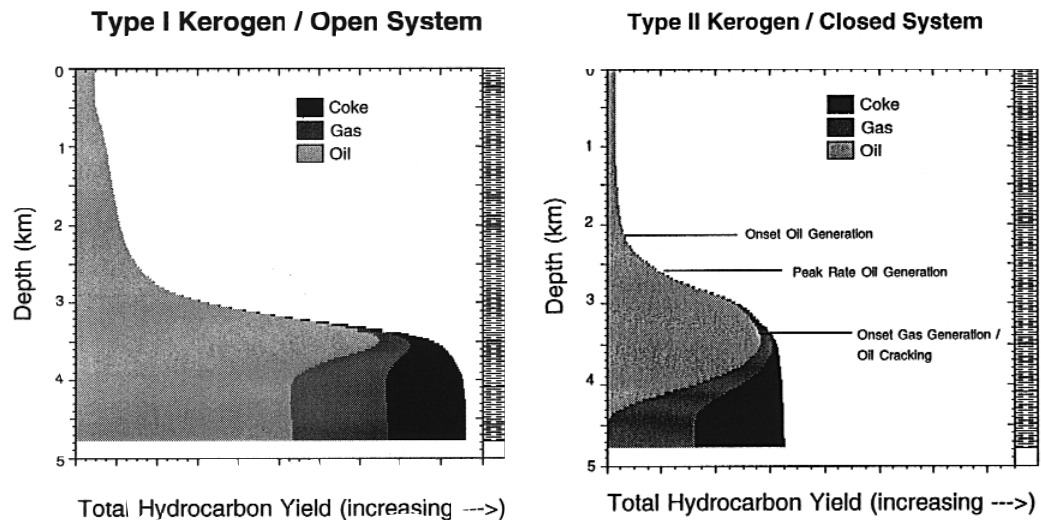

Figure 6–19. From results of Genex 1-D basin modeling software, courtesy Institute Français du Petrole.

Note: In general, open-system models overestimate the quantities of liquids present in a system. Closed-system models overestimate the amount of gas present in the system and are pessimistic in terms of predicting quantities of liquids. Closed-system models typically are not run any more. However, when evaluating older models, consider this effect.

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Annotated Bibliography

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