TRABAJO PRÁCTICO N°1

UNIDAD 1: Generalidades sobre métodos exploratorios. Objeto de la exploración petrolera. Revisión del sistema petrolero. El proceso exploratorio y el dominio del subsuelo. Métodos geológicos. Prospección Geoquímica. Métodos sísmicos y potenciales.

UNIDAD 2: Evolución de las Cuencas Sedimentarias. Clasificaciones de cuencas. Etapas de evolución. Evolución espacial y temporal de las fallas. Dataciones. Velocidad de sedimentación. Subsidencia, medidas, tipos de subsidencia, relación entre el depósito y la subsidencia. Naturaleza, forma y dimensiones de las unidades litoestratigráficas. Relaciones laterales y verticales. Tipos de discordancias. Correlaciones y Mapas.

RECURSOS PROPORCIONADOS

Leer y analizar a partir de la siguiente guía el artículo ***"Basin and Petroleum System Modeling".***

Actividad

1. Analizar la importancia de la prospección geoquímica en el modelado de cuencas y sistemas petroleros: Explicar cómo el análisis geoquímico de las rocas madre, como la determinación del COT, el IH y los parámetros cinéticos, es fundamental para el modelado del proceso de generación de hidrocarburos. Se puede usar el ejemplo del estudio de Mobil en Indonesia, donde el análisis de biomarcadores en muestras de petróleo permitió reevaluar el potencial de la zona.

2. Comparar la información que se puede obtener de los métodos sísmicos con la que se obtiene de el modelado de cuencas: Identificar las limitaciones de la interpretación sísmica para predecir el contenido de las trampas y la importancia del modelado para determinar la presencia, tipos y volúmenes de hidrocarburos. Describir cómo el modelado de cuencas puede mejorar los resultados de la imagen sísmica, como en el caso del estudio del Golfo de México por BP.

3. Describir el proceso exploratorio en el contexto del modelado de cuencas: Explicar cómo el modelado se integra en las diferentes etapas del proceso exploratorio, desde la evaluación inicial de una cuenca hasta la toma de decisiones sobre la perforación de pozos. Resaltar la importancia del modelado para reducir el riesgo de inversión y aumentar la probabilidad de éxito en la exploración.

4. Discutir la importancia del dominio del subsuelo en el modelado de cuencas: Explicar cómo la construcción de un modelo preciso del subsuelo, incluyendo la geometría, estratigrafía y propiedades de las rocas, es crucial para la precisión del

modelado. Se puede mencionar el caso del estudio en Kuwait, donde se combinaron modelos de cuenca y de yacimiento con un refinamiento de la malla local para entender la distribución del petróleo pesado.

5. Identificar los diferentes métodos geológicos y geofísicos utilizados para obtener los datos necesarios para el modelado de cuencas: Describir las diferentes fuentes de datos, como estudios de afloramientos, datos de teledetección, sondeos electromagnéticos y levantamientos gravimétricos. Enfatizar la importancia de integrar diferentes tipos de datos para construir un modelo completo y preciso.

6. Analizar la evolución de las cuencas sedimentarias en el contexto del modelado de sistemas petroleros: Describir cómo el modelado permite reconstruir la historia de la cuenca, incluyendo la subsidencia, la deposición de sedimentos, la formación de trampas y la generación de hidrocarburos a lo largo del tiempo geológico. Se puede usar el ejemplo del estudio del margen atlántico noruego, donde se modeló la generación de petróleo a partir de la Formación Spekk durante millones de años.

7. Explicar cómo el modelado de cuencas puede ayudar a determinar la velocidad de sedimentación y los diferentes tipos de subsidencia: Describir la relación entre la subsidencia y la deposición de sedimentos. Mencionar cómo el modelado puede ayudar a identificar las diferentes etapas de evolución de la cuenca y a comprender la influencia de la tectónica en la subsidencia y la sedimentación.

8. Identificar las diferentes unidades litoestratigráficas presentes en un modelo de cuenca y describir sus relaciones laterales y verticales: Explicar cómo el modelado permite analizar la distribución espacial de las diferentes unidades litoestratigráficas, sus espesores y sus propiedades. Discutir la importancia de identificar los tipos de discordancias presentes en la cuenca para entender la historia de la deposición y la erosión.

9. Utilizar la información proporcionada por el modelado de cuencas para realizar correlaciones estratigráficas entre diferentes pozos y áreas: Explicar cómo el modelado puede ayudar a establecer la cronología de los eventos geológicos y a correlacionar las unidades litoestratigráficas a través de la cuenca. Se puede mencionar el uso de la reflectancia de la vitrinita como parámetro de calibración para correlacionar la madurez de la roca madre en diferentes puntos de la cuenca.

10. Analizar mapas temáticos (isopacos, facies, madurez de la roca madre) derivados de los resultados del modelado de cuencas. Describir cómo el modelado ayuda a la prospección petrolera.

Basin and Petroleum System Modeling

The success of any exploration campaign depends on the convergence of crucial geologic elements and processes. Basin and petroleum system modeling allows geoscientists to examine the dynamics of sedimentary basins and their associated fluids to determine if past conditions were suitable for hydrocarbons to fill potential reservoirs and be preserved there.

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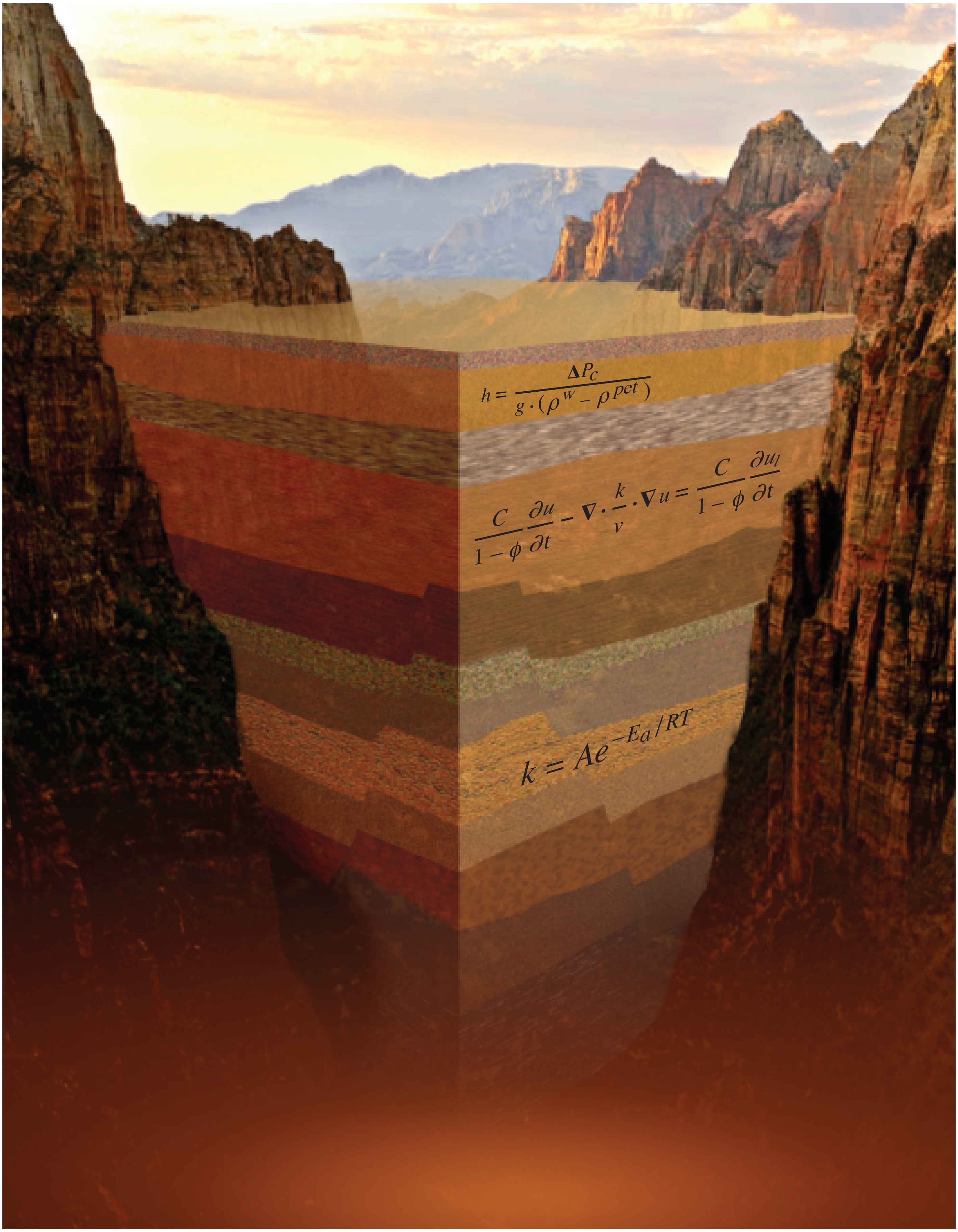
The best way to reduce investment risk in oil and gas exploration is to ascertain the presence, types and volumes of hydrocarbons in a prospective structure before drilling. Seismic interpretation can delineate closed structures and identify potential subsurface traps, but it does not reliably predict trap content. Drilling on a closed structure, even near a producing oil or gas field, holds no guarantee that similar fluids will be found. Profitable exploration requires a methodology to predict the likelihood of success given the available data and associated uncertainties.

More than 50 years ago, geologists began building the foundation for a concept that has since evolved into such a predictive methodology. The concept connects the past—a basin, the sediments and fluids that fill it, and the dynamic processes acting on them—to the present: hydrocarbon discoveries. Early endeavors sought to describe how basins form, fill and deform, focusing mainly on compacting sediments and the resulting rock structures.[1] Subsequent efforts concentrated on developing methods to model these processes quantitatively. This area of study, which has become known as basin modeling, applies mathematical algorithms to seismic, stratigraphic, paleontologic, petrophysical, well log and other geologic data to reconstruct the evolution of sedimentary basins.

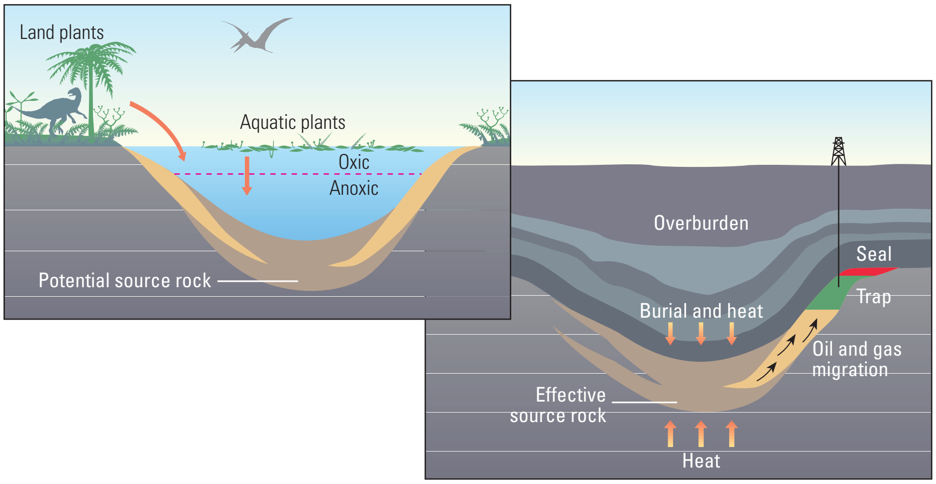
In the early 1970s, geochemists developed methods for the prediction of the petroleum-generation potential of a lithologic unit in quantitative terms.[2] Soon after, they began to use sedimentary basin models as structural frameworks for geochemical genetic correlations between hydrocarbons and source rocks.[3] A number of scientists worked on the notion independently, so several names were given to the idea, including oil system, hydrocarbon machine, petroleum system and independent petroliferous system; each approach emphasized different aspects of this multifaceted problem. The term "petroleum system" is now commonly used within the industry, and the concept it describes synthesizes many features of the collective work.[4]

A petroleum system comprises a pod of active source rock and the oil and gas derived from it as established by geochemical correlation. The concept embodies all of the geologic elements and processes needed for oil and gas to accumulate. The essential elements are an effective source rock, reservoir, seal and overburden rock; the last

1. Weeks LG: "Factors of Sedimentary Basin Development That Control Oil Occurrence," *Bulletin of the AAPG* 36, no. 11 (November 1952): 2071–2124.
   Knebel GM and Rodriguez-Eraso G: "Habitat of Some Oil," *Bulletin of the AAPG* 40, no. 4 (April 1956): 547–561.
2. Welte DH: "Petroleum Exploration and Organic Geochemistry," *Journal of Geochemical Exploration* 1, no. 1 (July 1972): 117–136.
3. Dow WG: "Application of Oil-Correlation and Source-Rock Data to Exploration in Williston Basin," *AAPG Bulletin* 58, no. 7 (July 1974): 1253–1262.
4. Magoon LB and Dow WG: "The Petroleum System," in Magoon LB and Dow WG (eds): *The Petroleum System—From Source to Trap, AAPG Memoir 60*. Tulsa: AAPG (1994): 3–24.



$h = \frac{\Delta P_c}{g \cdot (\rho^{w} - \rho^{pet})}$
$\frac{C}{1-\phi}\frac{\partial u}{\partial t} - \nabla \cdot \frac{k}{v} \cdot \nabla u = \frac{C}{1-\phi}\frac{\partial u_l}{\partial t}$
$k = Ae^{-E_a/RT}$



^ Simulating geologic, thermal and fluid-flow processes in sedimentary basins over time. Basin and petroleum system modeling (BPSM) reconstructs the deposition of source, reservoir, seal and overburden rocks and the processes of trap formation and hydrocarbon generation, migration and accumulation from past (*left*) to present (*right*).

facilitates the burial of the others. The processes include trap formation and the generation, migration and accumulation of petroleum.[5] These elements and processes must occur in the proper order for the organic matter in a source rock to be converted into petroleum and then to be stored and preserved. If a single element or process is missing or occurs out of the required sequence, a prospect loses viability.

A failure to adequately characterize a petroleum system occurred in the Mukluk prospect offshore the North Slope of Alaska, USA. The area is characterized by multiple effective source rocks, proven reservoir rocks and effective seals. The Mukluk structure is positioned on the same regional feature—the Barrow Arch—as the nearby Prudhoe Bay field that contains 25 billion bbl [4 billion m^3] of oil. Seismic data indicated Mukluk was a giant structure, 20 mi long by 9 mi wide [32 km by 14 km]. Although structural dip on the western side of the feature was uncertain because of difficulties in assessing seismic velocity effects through permafrost, the prospect was estimated to contain up to 1.5 billion bbl [240 million m^3] of recoverable oil.[6]

In 1982, oil companies spent more than US $1.5 billion on lease rights on the outer US Continental Shelf over the Mukluk prospect.[7] A partnership led by Sohio Alaska Petroleum spent more than US $120 million constructing an artificial gravel island in Arctic waters and from there, drilling the wildcat well. Drillbit cuttings showed extensive oil stain in the target formation, but the well tested water with noncommercial amounts of oil. It was referred to at the time as the most expensive dry hole in the world. Subsequent evaluation of the Mukluk reservoir formations indicated oil had once been in the structure but had since migrated. A crucial element or process of the petroleum system was missing. After debating causes of the failure, geologists determined that either the seal was ineffective or the oil had leaked out after the structure had tilted at some late stage.

In the years since the Mukluk well was drilled, companies have become more sensitive to risk, demanding better information before committing to increasingly expensive projects (see "Modeling and Risk Management," *page 1*.) This article reviews one of the tools they rely upon, basin and petroleum system modeling. The method, which combines geologic, geophysical, geochemical, hydrodynamic and thermodynamic data, was first envisioned in the early 1980s.[8] Comprehensive modeling software, the result of 25 years of development, incorporates these data to simulate the interrelated effects of deposition and erosion of sediments and organic matter, compaction, pressure, heat flow, petroleum generation and multiphase fluid flow. Examples from the Middle East, North America and the Norwegian Atlantic margin demonstrate the use of this modeling technique to assess whether appropriate conditions for hydrocarbon generation, migration, accumulation and preservation have occurred.

Modeling over Millions of Years

In essence, basin and petroleum system modeling (BPSM) tracks the evolution of a basin through time as it fills with fluids and sediments that may eventually generate or contain hydrocarbons (left). In concept, BPSM is analogous to a reservoir simulation, but with important differences. Reservoir simulators model fluid flow during petroleum drainage to predict production and provide information for its optimization. The distance scale is meters to kilometers, and the time scale is months to years. Although the flow is dynamic, the model geometry is static, remaining unchanged during the simulation. On the other hand, BPSM simulates the hydrocarbon-generation process to calculate the charge, or the volume of hydrocarbons available for entrapment, as well as the fluid flow, to predict the volumes and locations of accumulations and their properties. The distance scale typically is tens to hundreds of kilometers, and the periods covered may reach hundreds of millions of years. The model geometry is dynamic and often changes significantly during simulation.

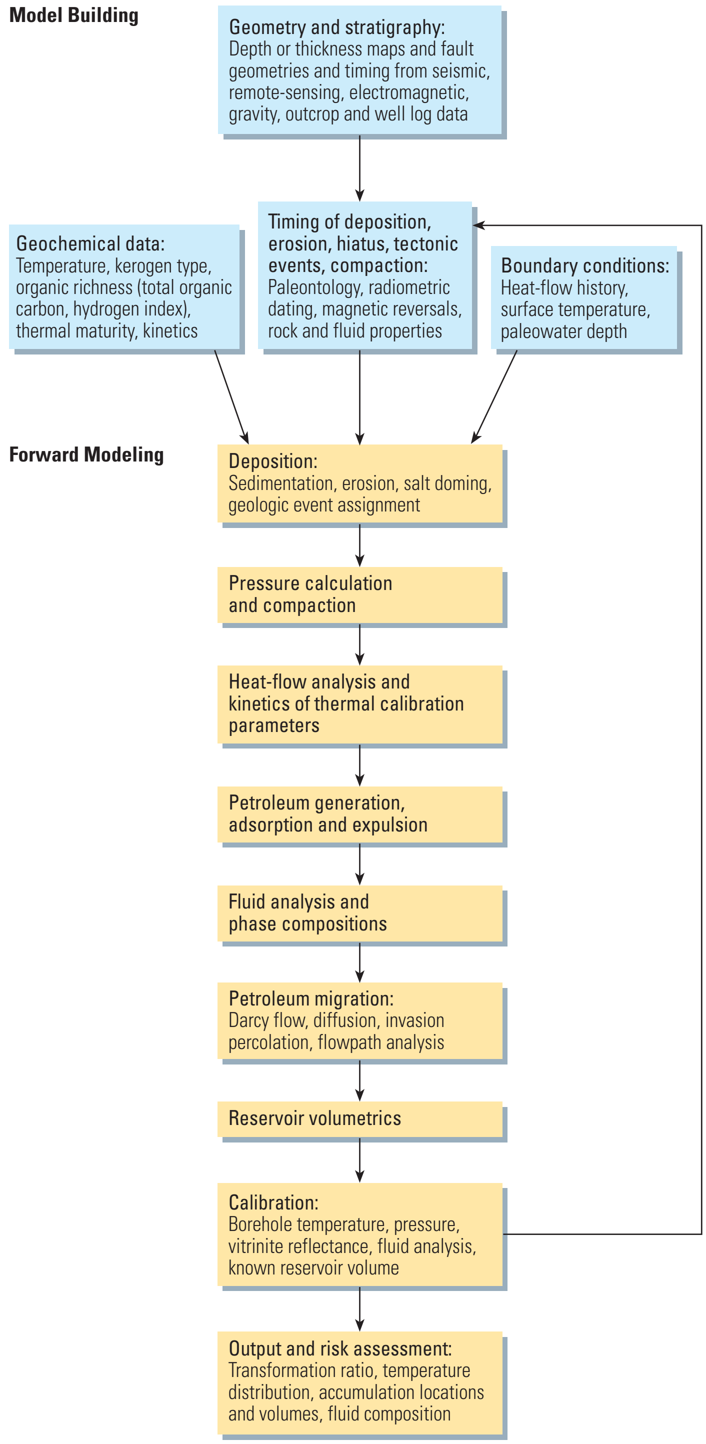
Basin and petroleum system modeling brings together several dynamic processes, including sediment deposition, faulting, burial, kerogen maturation kinetics and multiphase fluid flow.[9] These processes may be examined at several levels, and complexity typically increases with spatial dimensionality; the simplest, 1D modeling, examines burial history at a point location. Two-dimensional modeling, either in map or cross section, can be used to reconstruct oil and gas generation, migration and accumulation along a cross section. Three-dimensional modeling reconstructs petroleum systems at reservoir and basin scales and has the ability to display the output in 1D, 2D or 3D, and through time.[10] Most of the following discussion and examples pertain to 3D modeling; if the time dimension is included, the modeling can be considered 4D.

5. Magoon and Dow, reference 4.
6. Hohler JJ and Bischoff WE: "Alaska: Potential for Giant Fields," in Halbouty MT (ed): *Future Petroleum Provinces of the World, AAPG Memoir 40*. Tulsa: AAPG (1986): 131–142.
7. Gallaway BJ: "Appendix D: Historical Overview of North Slope Petroleum Development," Environmental Report for Trans Alaska Pipeline System Right-of-Way Renewal, 2001, http://tapseis.anl.gov/documents/docs/I_App_D_May2.pdf (accessed May 13, 2009).
8. Welte DH and Yukler MA: "Petroleum Origin and Accumulation in Basin Evolution—A Quantitative Model," *AAPG Bulletin* 65, no. 8 (August 1981): 1387–1396.
9. Kerogen is insoluble particulate organic matter. It is either directly inherited from biopolymers in living organisms or formed during diagenesis. Kerogen represents more than 90% of all organic matter in sediments.
10. Higley DK, Lewan M, Roberts LNR and Henry ME: "Petroleum System Modeling Capabilities for Use in Oil and Gas Resource Assessments," USGS Open-File Report 2006–1024.
11. Vitrinite reflectance, R_o, is a measurement by microscope of optical properties of vitrinite, a form of organic matter, contained in rock samples. The measurement is expressed in terms of the percentage of incident light reflected from a vitrinite sample. Larger measured values indicate higher levels of thermal maturity.
12. Magoon and Dow, reference 4.

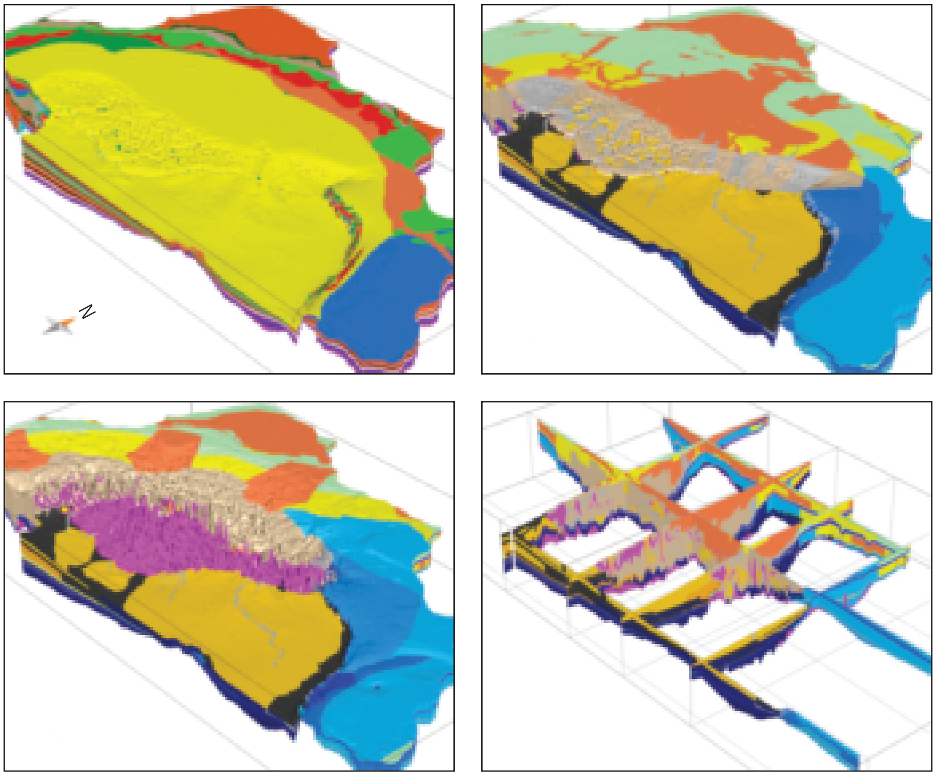
For any spatial dimensionality, BPSM performs deterministic computations to simulate the history of a sedimentary basin and its associated fluids. The computations require a model, or a discretized numerical representation of layers containing sediments, organic matter and fluids with assigned properties. A model is constructed from geophysical, geologic and geochemical data. The layers are subdivided into grid cells within which properties are uniform. Computer programs simulate physical processes that act on each cell, starting with initial conditions and progressing by a selected time increment to the present. Model outputs, such as porosity, temperature, pressure, vitrinite reflectance, accumulation volume or fluid composition, can be compared with independent calibration information, and the model can be adjusted to improve the match.[11]

Basin and petroleum system modeling is an iterative process with many interrelated steps, each of which is a scientific discipline in itself (right). Assembling these steps in a single workflow is a daunting task. A few major oil companies and a handful of contractor companies have developed systems that perform these calculations in one way or another. The Schlumberger approach combines Petrel seismic-to-simulation software for building the basin model with PetroMod petroleum system modeling software for simulating the generation, migration and accumulation of hydrocarbons. The following explanation of BPSM describes aspects of the general process along with a few features particular to PetroMod software.

In general, a preparation step before modeling defines the petroleum system to be modeled. Formally, the name of a petroleum system consists of the name of the active source rock, followed by a hyphen and the name of the reservoir rock that contains the largest volumes of petroleum from the source rock. The name ends with a punctuation symbol in parentheses that expresses the level of certainty—known, hypothetical or speculative—that a particular pod of active source rock has generated the hydrocarbons in an accumulation.[12] In a known petroleum system, the active source rock has a clear geochemical match with trapped hydrocarbons. For example, in the Shublik-Ivishak (!) petroleum system of the North Slope of Alaska, geochemical analysis has determined the Triassic Shublik Formation source rock is the source of hydrocarbons in the Triassic Ivishak reservoir. The (!) indicates it is a known petroleum system. In a hypothetical petroleum system, designated by the (.) symbol, the source rock has been characterized by geochemical



^ The multiple and interrelated steps of BPSM. Basin and petroleum system modeling consists of two main stages: model building and forward modeling. Model building involves constructing a structural model and identifying the chronology of deposition and physical properties of each layer. Forward modeling performs calculations on the model to simulate sediment burial, pressure and temperature changes, kerogen maturation and hydrocarbon expulsion, migration and accumulation. Calibration compares model results with independent measurements to allow refinement of the model.



^ A regional-scale structural model of the entire northern Gulf of Mexico. BP combined local and regional maps of salt and sediment horizons to construct a regional model covering approximately 1.1 million km^2 [400,000 mi^2] that accounts for complex salt movement. Each colored layer (*top left*) represents a stratigraphic interval of specified age. Colors in the top right correspond to different sedimentary depositional settings and mixtures of rock types. The bottom left image displays the model with shallow horizons removed to expose the allochthonous salt (magenta). The fence diagram (*bottom right*) shows the internal detail of the model, including multiple salt layers. All images represent the present-day geology. (Courtesy of Rich Gibson, BP).

analysis, but no match has yet been made with a hydrocarbon accumulation. In a speculative petroleum system, labeled with (?), the correlation of a source rock to petroleum is merely postulated based on geologic inference.

The first step is to create a depth-based structural model of the area of interest, which may encompass a single petroleum system in a small basin or multiple petroleum systems in one basin or many basins across a region (above). Input is typically in the form of formation tops and layer thicknesses and can be imported from a separate model-building program. Data sources might include seismic surveys, well logs, outcrop studies, remote-sensing data, electromagnetic soundings and gravity surveys. This model of present-day architecture represents the final result of all the processes acting on the basin throughout geologic time.[13]

The modeler must then analyze the present-day geometric model to describe the deposition chronology and physical properties of the basin-fill materials and to identify postdepositional processes—an undertaking that will enable reconstruction of the basin and its layers and fluids throughout geologic time. This analysis establishes a basin history that is subdivided into an uninterrupted series of stratigraphic events of specified age and duration. These events are summarized in a petroleum system events chart (next page). Each event represents a span of time during which deposition, nondeposition or erosion occurred. This summary describes the chronology of the geologic elements in a petroleum system. Syn- and postdepositional episodes of folding, faulting, salt tectonics, igneous intrusion, diagenetic alteration and hydrothermal activity can be included to explain the model. Determining the timing of trap formation and of the remaining processes—generation, migration and accumulation of hydrocarbons—is one of the main goals of BPSM.

An important concept in process timing is the "critical moment." This is the time of generation, migration and accumulation of most of the hydrocarbons in a petroleum system.[14] The critical moment occurs in the range of 50 to 90% transformation ratio (TR), which is the relative conversion of source-rock organic matter to hydrocarbons. The selection of the time within this range is at the discretion of the modeler.

The absolute age of each layer in the basin and petroleum system model is an important parameter for determining the timing of the processes that generate, move and trap petroleum. Age information may be available from paleontologic data, radiometric dating, fission-track dates and magnetic-reversal tracking.[15] In many basins, known petroleum source rocks have been assigned to global geologic periods based on geochemical and biostratigraphic determinations.[16]

Identification of the lithology and depositional environment of each stratigraphic unit is crucial. For example, classifying the depositional environment, and thus properties, such as porosity and permeability, of coarse-grained sediments helps identify their potential as reservoir or carrier rocks that facilitate migration of petroleum from source rock to reservoir. Characterizing the source-rock depositional environment helps predict the probable petroleum product generated through kerogen maturation. Fine-grained sediments deposited in deep marine basins, on continental shelves and in anoxic lakes all contain different types of kerogen, leading to different petroleum outputs.[17]

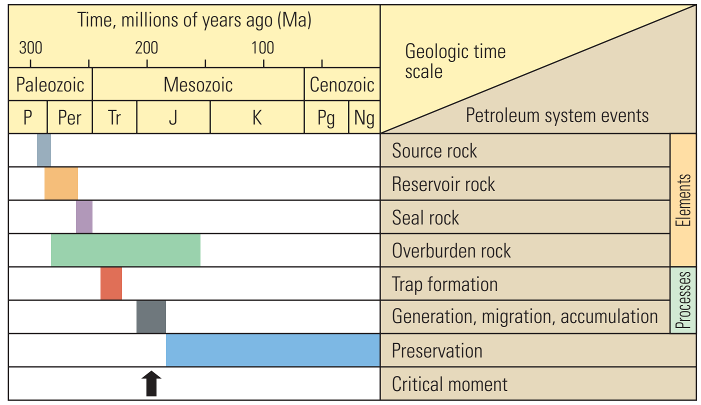
Source-rock properties are needed as inputs to simulate the reactions that govern the degradation of organic material to produce hydrocarbons. These essential properties are the total organic carbon (TOC) measured by combustion of rock samples and the hydrogen index (HI) obtained through pyrolysis of rock samples for petroleum-generation potential.[18] Also required are kinetic parameters for the thermal conversion of the source-rock kerogen to petroleum. Another measure of kerogen maturity is vitrinite reflectance. As an independent measurement that is not a PetroMod input, it provides a means to calibrate the model output. Simulation of the burial history can be used to predict the expected vitrinite reflectance at any depth or time in the model. Calibration entails adjusting the model so that the simulated vitrinite reflectance matches that measured in samples at varying depths in the well.

Several other physical properties must also be specified for each layer. Porosity and permeability in reservoir and carrier layers are important for fluid-flow computations and reservoir volumetric estimates. Permeability of source rocks affects the efficiency with which generated hydrocarbons can be expelled. Heat capacity and thermal conductivity, usually inferred from lithology and mineralogy, are needed for the thermal calculations that model kerogen maturation and petroleum generation. In addition, density and compressibility data are required inputs to model compaction and burial.

The burial history of basin sediments contains information about burial depth and preservation of organic material, which are related to the temperatures and pressures the sediments were exposed to and the durations of exposure. Temperature is the primary variable in conversion of kerogen to petroleum, and pressure is important for migration of fluids. Key inputs for building a burial history include sedimentation rate, compaction, uplift, erosion and depositional environment.

The thermal history of a basin is linked to the history of the crust in which it formed. Crustal behavior determines basin subsidence, uplift and heat flow. Modeling the petroleum potential of a basin requires reconstruction of the temperature over geologic time and across the basin. Therefore, in addition to model properties, some specific past conditions must be evaluated. These conditions, treated as boundary conditions by the modeling software, include paleobathymetry, which determines the location and type of deposition. Other boundary conditions are sediment/water interface temperatures throughout geologic time which, along with paleoheat-flow estimates, are required to calculate the temperature history of the basin.

Generic Events Chart



^ An events chart depicting timing of a petroleum system. Each of the colored horizontal bars represents the time span of an event. For this system, all the essential elements and processes are present and the timing is favorable; source-rock deposition was followed by deposition of reservoir, seal and overburden rock. Also, the trap formed before hydrocarbon generation, migration and accumulation. Because the reservoir was filled before the end of Jurassic time, its hydrocarbons must be preserved for more than 180 million years to remain a viable prospect. The critical moment (black arrow) was chosen to be approximately half-way through the period of hydrocarbon generation, migration and accumulation.

Fast Forward

After the boundary conditions and ages and properties of all layers have been defined, the simulation can be run forward, starting with sedimentation of the oldest layer and progressing to the present. The following steps summarize the workflow of the PetroMod modeling software.[19]

Deposition—Layers are created on the upper surface during sedimentation or are removed during erosion. Depositional thickness, which may have been greater than current thickness, can be calculated by several methods: porosity-controlled backstripping starting with present-day thickness, importation from structural-restoration programs, and estimation from sedimentation rate and depositional environment.

Pressure calculation and compaction—The pressure calculation treats dewatering as a one-phase flow problem driven by changes in overburden weight caused by sedimentation. In addition, internal pressure-building processes such as gas generation, quartz cementation and mineral conversions can be taken into account. Compaction causes changes in many rock properties, including porosity, and to a lesser extent, density, elastic moduli, conductivity and heat capacity. Therefore, pressure and compaction calculations must be performed before heat-flow analysis in each time step.

Heat-flow analysis—The goal of heat-flow analysis is temperature calculation, a prerequisite for determining geochemical reaction rates. Heat conduction and convection from below as well as heat generation by emissions from naturally occurring radioactive minerals must be considered. Incorporating the effects of igneous intrusions requires the inclusion of thermal phase transitions in sediments. Thermal boundary conditions with inflow of heat at the base of sediments must also be formulated. These basal heat-flow values are often predicted using crustal models in separate preprocessing programs or are interactively calculated from crustal models for each geologic event.

An example of the level of complexity involved in heat-flow analysis is seen in a study of petroleum systems in the San Joaquin basin in California, USA.[20] The process begins with the present-day latitude of the basin. A PetroMod option recreates the plate tectonic locations of

13. Poelchau HS, Baker DR, Hantschel T, Horsfield B and Wygrala B: "Basin Simulation and the Design of the Conceptual Basin Model," in Welte DH, Horsfield B and Baker DR (eds): *Petroleum and Basin Evolution: Insights from Petroleum Geochemistry, Geology and Basin Modeling.* Berlin: Springer-Verlag (1997): 3–70.
14. Magoon and Dow, reference 4.
15. Faure G and Mensing TM: *Isotopes: Principles and Applications, 3rd Edition.* Hoboken, New Jersey, USA: John Wiley & Sons, Inc., 2005.
    Tagami T and O'Sullivan PB: "Fundamentals of Fission-Track Thermochronology," *Reviews in Mineralogy and Geochemistry* 58, no. 1 (January 2005): 19–47.
16. Peters KE, Walters CC and Moldowan JM: *The Biomarker Guide.* Cambridge, England: Cambridge University Press, 2005.
17. Peters et al, reference 16.
18. Pyrolysis is the thermal decomposition of organic materials in the absence of oxygen. Laboratory pyrolysis typically occurs at temperatures above those at which hydrocarbons are generated in nature. Hydrogen index is expressed as mg of hydrocarbon/gram of total organic carbon.
19. Hantschel T and Kauerauf AI: *Fundamentals of Basin and Petroleum Systems Modeling*. Heidelberg, Germany: Springer, 2009.
20. Peters KE, Magoon LB, Lampe C, Hosford-Scheirer A, Lillis PG and Gautier DL: "A Four-Dimensional Petroleum Systems Model for the San Joaquin Basin Province, California," in Hosford-Scheirer A (ed): *Petroleum Systems and Geologic Assessment of Oil and Gas in the San Joaquin Basin Province, California.* USGS Professional Paper 1713 (2008): Chapter 12.

the basin through time and calculates the corresponding temperatures of the sediment/water interface (below). These surface temperatures are then corrected for water depth to give past sediment/water interface temperatures. These constrain the paleoheat-flow profiles.

Present-day heat-flow values were estimated using temperature and thermal-conductivity data from wells and aqueduct tunnels in the San Joaquin basin. The temperatures—measured as functions of depth—were used to determine the geothermal gradient. Contemporary heat flow was calculated by multiplying the geothermal gradient by the thermal conductivity. The resulting map of surface heat flow was an input to the PetroMod software, which delivered source-rock maturity values that matched available maturity measurements.

Petroleum generation—The generation of petroleum from kerogen in source rocks, called primary cracking, and the subsequent breakdown of oil to gas in source or reservoir rocks, called secondary cracking, can be described by the decomposition kinetics of sets of parallel reactions. The number of chemical components produced in most models can vary between 2 (oil and gas) and 20. The cracking schemes may be quite complex when many components and secondary cracking are taken into account. PetroMod software uses a database of reaction kinetics to predict the phases and properties of hydrocarbons generated from source rocks of various types.[21] In addition, adsorption models describe the release of generated hydrocarbons into the free pore space of the source rock.

Fluid analysis—The generated hydrocarbons are mixtures of chemical components. Fluid-flow models deal with fluid phases that are typically liquid, vapor and supercritical or undersaturated phases. The fluid-analysis step examines temperature- and pressure-dependent dissolution of hydrocarbon components in the fluid phases to determine fluid properties, such as density and viscosity, for input to fluid-flow calculations. These properties are also essential for subsequent migration modeling and calculation of reservoir volumetrics. Fluids may be modeled using a black-oil model, which has two components or phases, or a multicomponent model.

Fluid-flow calculations—There are several fluid-flow approaches to model migration of generated hydrocarbons from source rock to trap. Darcy flow describes multicomponent three-phase flow based on the relative-permeability and capillary-pressure concept. With this method, migration velocities and accumulation saturations are calculated in one step. Describing fluid migration across faults requires special algorithms.

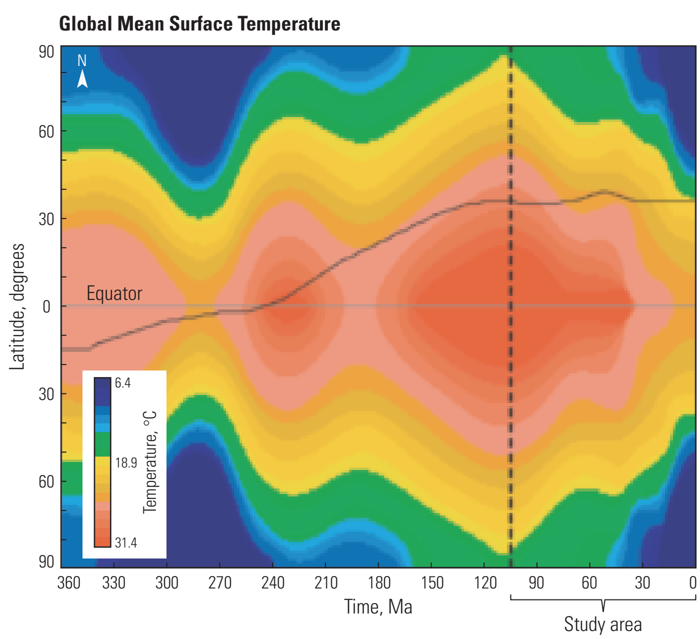
A simplified fluid-flow calculation is made by flowpath analysis. In high-permeability layers, known as carriers, lateral petroleum flow occurs instantaneously on geologic time scales. It can be modeled with geometrically constructed flowpaths to predict the locations and compositions of accumulations. Spilling between and merging of drainage areas must be taken into account. In a hybrid method, flowpath analysis in high-permeability zones may be combined with Darcy flow in low-permeability regions.

Alternatively, migration and accumulation can be modeled by invasion percolation in the PetroMod software. This calculation assumes that on geologic time scales petroleum moves instantaneously through the basin driven by buoyancy and capillary pressure. Any timing constraint is neglected, and the petroleum volume is subdivided into small finite amounts. Invasion percolation is convenient for modeling fluid flow in faults. The method is especially efficient for one-phase flow consisting of only a few hydrocarbon components and for the introduction of higher-resolution migration.

Reservoir volumetrics—The height of a petroleum accumulation is limited by the capillary entry pressure of the overlying seal and the spill point at the base of the structure. Loss at the spill point and leakage through the seal reduce the trapped volume. Other processes, such as secondary cracking or biodegradation, can also impact the quality and quantity of accumulated petroleum.

Calibration parameters—It is possible to predict rock temperature, vitrinite reflectance values and concentration ratios of molecular fossils (biomarkers) using models based on Arrhenius-type reaction rates and simple conversion equations.[22] These temperature-sensitive predictions can be compared with measured data to calibrate uncertain thermal input data, such as paleoheat-flow values.

Risk—Numerical models, including basin and petroleum system models, provide scenarios for what might happen given various constraints on the input data.[23] The impact of uncertain data can be studied by multiple simulation runs with varying model parameters. Assignment of varying



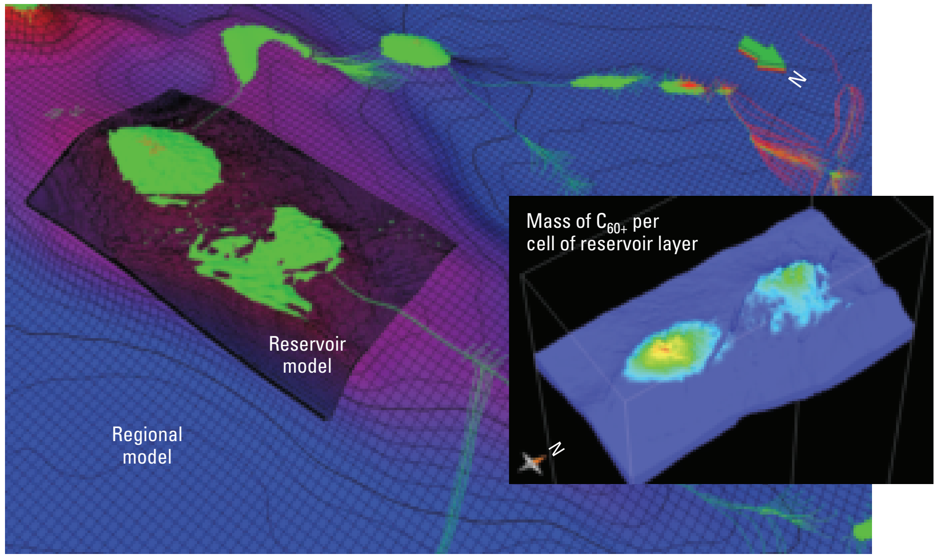
^ Estimated global mean surface temperature throughout geologic time. Variations of this chart can be used to calculate the paleotemperature of the sediment/water interface for sediments deposited at any latitude and any age. The solid black line shows the variation in latitude with time for the San Joaquin basin study area. The dashed line represents the beginning of deposition of the sediments studied. The portion of the solid black line to the right of the dashed line tracks the temperature of the sediment/water interface during the study period. A PetroMod calculation corrects these temperatures for subsequent water depth. (Adapted from Peters et al, reference 20.)

parameters and the corresponding impact on the model can be performed with statistical methods, such as Monte Carlo simulations. These simulations do not provide a unique answer, but rather a range of possible outcomes with estimates of uncertainty. Increased computing power combined with multiple simulations allows the user to compare the effects of various scenarios and identify which variables exert the most control on the computed results. Final outcomes are mainly scenario probabilities and confidence intervals—for example, percentiles limiting in situ petroleum volumes.

Because of the highly sensitive nature of petroleum system modeling results, many companies keep BPSM success stories to themselves. An example from Indonesia was released because the operator sought drilling partners after a study showed that deepwater acreage on the Mahakam Delta and Makassar Slope off Kalimantan would likely produce oil, contrary to belief at the time that source rocks were gas-prone and thermally postmature.[24] The generally accepted geochemical-stratigraphic model for the area restricted the effective and oil-prone coaly source rocks to updip shelfal areas. Age-equivalent rocks on the outer shelf were also thought to be buried too deeply to preserve good reservoir quality.

Before the deadline to relinquish the blocks, Mobil conducted a study of 61 oil samples provided by the principal operators in the area. Using biomarkers in the oil samples, reinterpreted sequence stratigraphy and proprietary kinetic parameters, Mobil geologists performed BPSM, which predicted that most of the Miocene source rock in the area of interest would be within the present-day oil window and would be currently generating hydrocarbons. Use of the model resulted in major oil discoveries by Mobil and its partner Unocal in the deepwater Makassar Straits, with some wells producing 10,000 bbl/d [1,600 m^3/d] of oil from areas previously considered nonprospective. The study also changed the way the industry views deepwater deltaic petroleum systems worldwide.[25]

Historically, BPSM has been applied to basin-scale studies to assess uncertainties in hydrocarbon charge, migration and trap formation. Increasingly, it is being applied to understand the origins of fluid complexities in producing fields. The next two examples demonstrate how PetroMod simulations help explain fluid distributions that pose challenges to production.



^ Linking models of different scales. A portion of the 3D regional PetroMod model of a petroleum system in Kuwait was constructed on a coarse grid of 1,200 by 1,200 m [3,900 by 3,900 ft]. Depth to the reservoir is color-coded, with depth increasing from red to blue. Contour interval is 50 m [164 ft]. The 100- by 100-m [330- by 330-ft] grid cells from a Petrel reservoir model were included in the PetroMod model by means of local grid refinement. Green indicates oil accumulations and red indicates gas. Thin green and red lines show the multiple migration paths taken by the fluids to the traps. The inset depicts results of modeling the present-day distribution of the reservoir's dissolved heavy-oil (C_{60+}) components. The color scale (not shown) is in megatons and ranges from 0 (blue) through yellow to 0.04 (red). The current distribution of heavy-oil components in each reservoir can be fully explained as a function of the generation, expulsion and migration history.

Petroleum System Modeling to Understand Production

Three-dimensional fluid-flow modeling can provide a competitive advantage at different times in the life of a field. Basin-scale petroleum system modeling is designed for use during exploration, and field-scale reservoir modeling is performed during production. Until recently, however, the vastly different scales of petroleum system and reservoir models have impeded progress toward linking these powerful methods. Working with the Kuwait Oil Company (KOC), Schlumberger used local grid refinement (LGR) to combine basin- and reservoir-scale models. While LGR is well-established in reservoir simulators, this was its first use in 3D fluid-migration simulation. Applied to an oil field in Kuwait, the technology improved understanding of the origin and distribution of heavy oil within the field and helped to assess the impact of these heavy-oil deposits on development strategies.

A PetroMod model on a regional scale helped quantify the location and timing of petroleum expulsion from source rock, volumes and composition of the products, and migration pathways. This exercise revealed that two effective post-salt source rocks, the Cretaceous Makul Formation and the Cretaceous Kazhdumi Formation, produced fluids that migrated along different pathways to the trap at different times, resulting in a complex filling history.

The PetroMod model incorporated high-resolution grids from a Petrel reservoir model by means of the new local grid refinement option in PetroMod software (above). The linked models helped engineers investigate the influence of

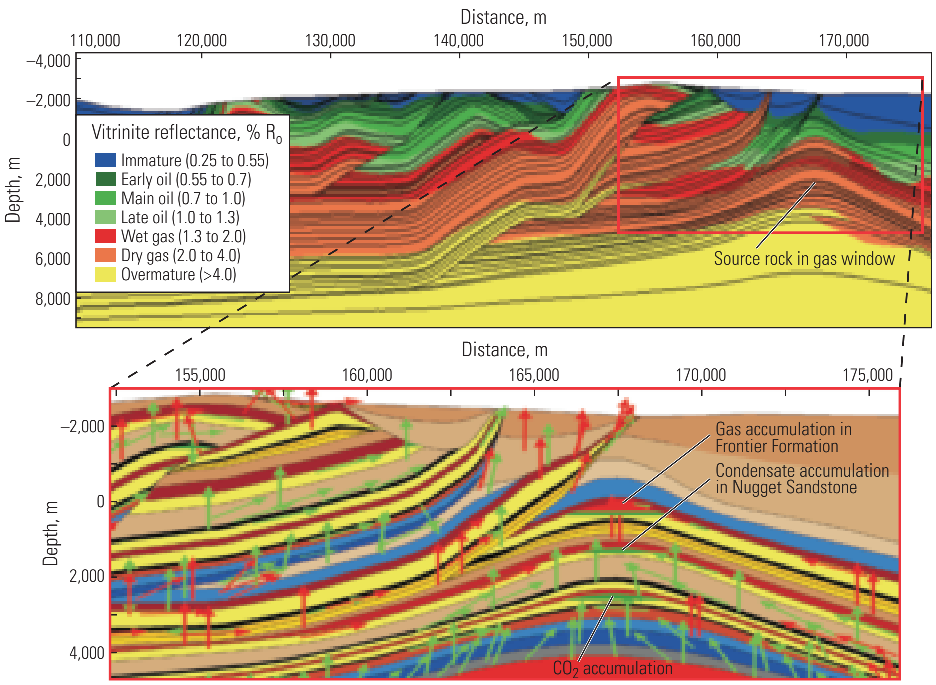
21. "Phase Kinetics Wizard," http://www.petromod.com/files/public/brochures/English/PhaseKineticsWizard.pdf (accessed June 12, 2009).

22. The Arrhenius equation is a simple formula that describes the temperature dependence of the rate of a chemical reaction.

23. Peters KE: *Basin and Petroleum System Modeling, AAPG Getting Started Series No. 16*. Tulsa: AAPG/Datapages, 2009.

24. Peters K, Snedden JW, Sulaeman A, Sarg JF and Enrico RJ: "A New Geochemical-Sequence Stratigraphic Model for the Mahakam Delta and Makassar Slope, Kalimantan, Indonesia," *AAPG Bulletin* 84, no. 1 (January 2000): 12–44.

25. Saller A, Lin R and Dunham J: "Leaves in Turbidite Sands: The Main Source of Oil and Gas in the Deep-Water Kutei Basin, Indonesia," *AAPG Bulletin* 90, no. 10 (October 2006): 1585–1608.



^ Modeling maturity and migration. PetroMod software modeled the products of maturation from multiple source rocks in a complex thrust zone (*top*). Migration calculations over a portion of the section (*bottom*) predicted accumulation of CO_2 in a deep Paleozoic reservoir, condensate in the Nugget Sandstone and gas in the Frontier Formation. Green and red arrows represent flowpaths taken by liquid and vapor phases, respectively. Results matched published fluid data from the field. (Adapted from Kemna et al, reference 26.)

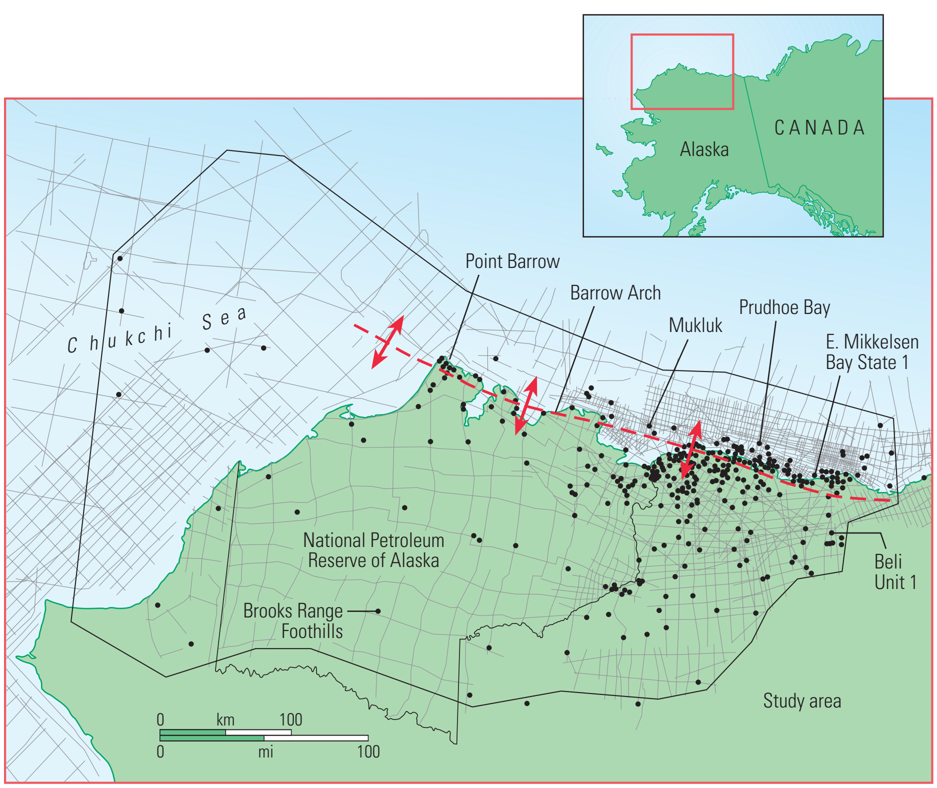
pressure-volume-temperature changes on discontinuous deposits of heavy oil throughout basin history—including multiple charging episodes and periods of uplift and erosion that led to tilting of traps and ancient oil/water contacts. The results from linking the models provided KOC with testable hypotheses on the mechanisms of heavy-oil formation, which should prove useful for predicting the distribution of these low-permeability barriers for input to ECLIPSE reservoir simulation of field production.

Modeling Gas Migration in a Thrust Belt

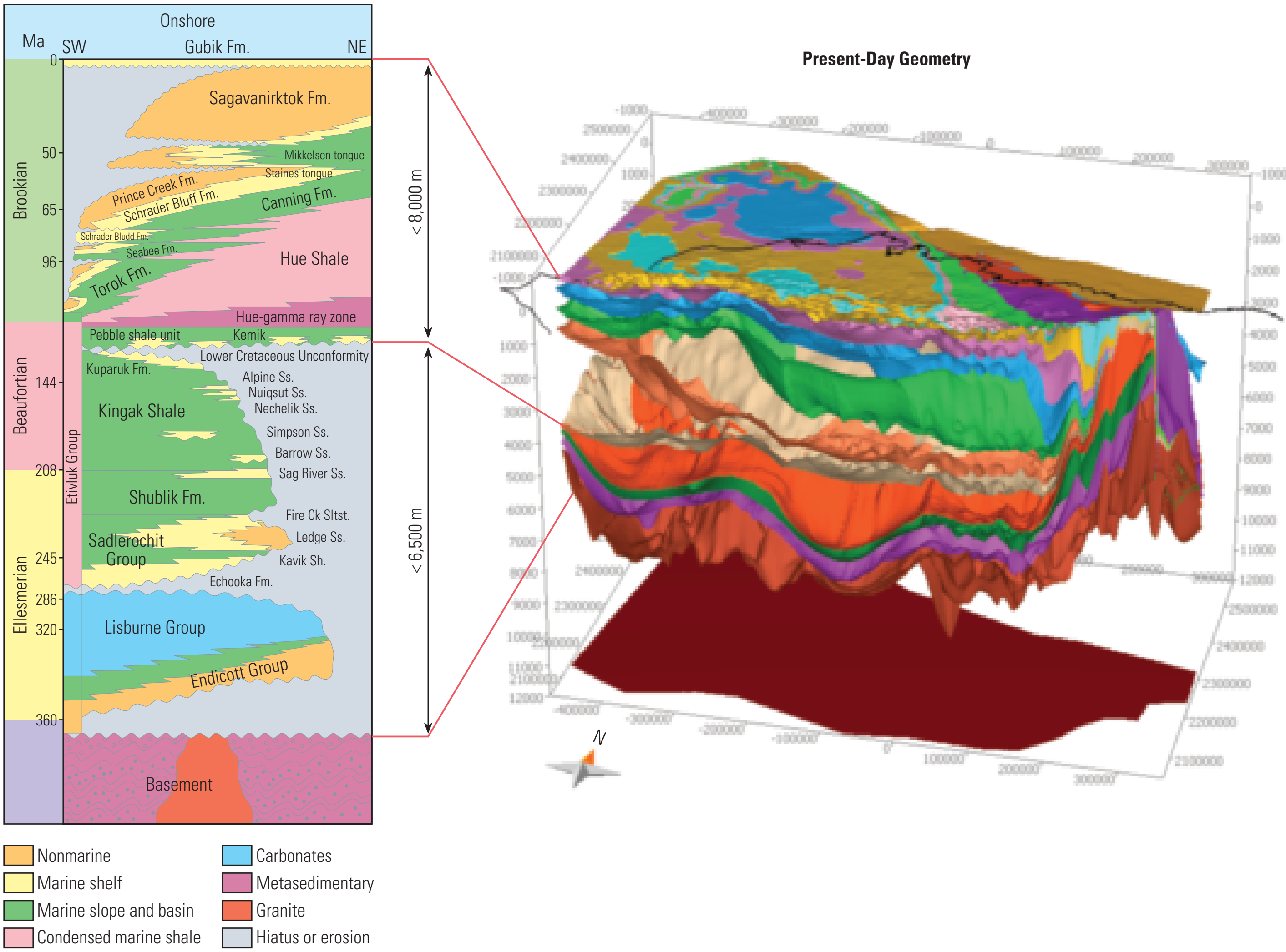
Tectonically complex, compressional environments pose challenges to BPSM. Analysis of a petroleum system in such an area—a thrust belt in western Wyoming, USA—used public data and structural-restoration software to determine the distribution of gas, gas condensate and CO_2 in wells in the La Barge field.[26]

Two overlapping tectonic phases, the Late Jurassic to Early Tertiary Sevier orogeny, and the Late Cretaceous to Early Neogene Laramide orogeny, contributed to structural complexity in the geology seen today.[27] Geologists reconstructed the 90 million-year history of the basin using third-party software and input the resulting model into PetroMod software. The modeled present-day source-rock maturity was calibrated using temperature data from wells in the distant Wind River basin (above left).

Petroleum migration simulated using a combination of Darcy flow and flowpath modeling tracked the movement of fluids to present-day accumulations. Predicted petroleum properties, such as API gravity and gas/oil ratio (GOR), match published data on fluids produced from the La Barge field.



< North Slope regional BPSM study. The study area covered most of the National Petroleum Reserve of Alaska and the central North Slope, and extended over the eastern part of the Chukchi Sea. The red dashed line indicates the trace of the Barrow Arch. The red arrows point in the direction of the plunge.



^ Alaska structural model. The stratigraphy (*left*) catalogs the source rocks (Kekiktuk coals of the Endicott Group, Shublik Formation, Kingak Shale, Hue Shale, Hue-GRZ) and reservoir rocks (Kemik, Kuparuk Formation, Sag River Sandstone, Ledge Sandstone) of the North Slope petroleum systems. Stratigraphic reconstruction accounted for more than 4,000 m [13,000 ft] of eroded overburden, which significantly affected burial and maturation. The structural model (*right*) contains 44 layers and was constructed from well and seismic data. The black line near the top of the model is the present-day coastline. The Lower Cretaceous Unconformity (LCU) is a major structural feature that strongly influenced the migration and accumulation of petroleum.

North Alaska Petroleum Systems

In addition to improving the understanding of complex fluid distributions, basin and petroleum system modeling can be applied both to frontier provinces and to well-understood areas. An example from the North Slope unites these approaches by combining BPSM on a regional scale with prospect-scale modeling to help geoscientists understand the petroleum systems in a region spanning vast underexplored areas and those containing significant known reserves.

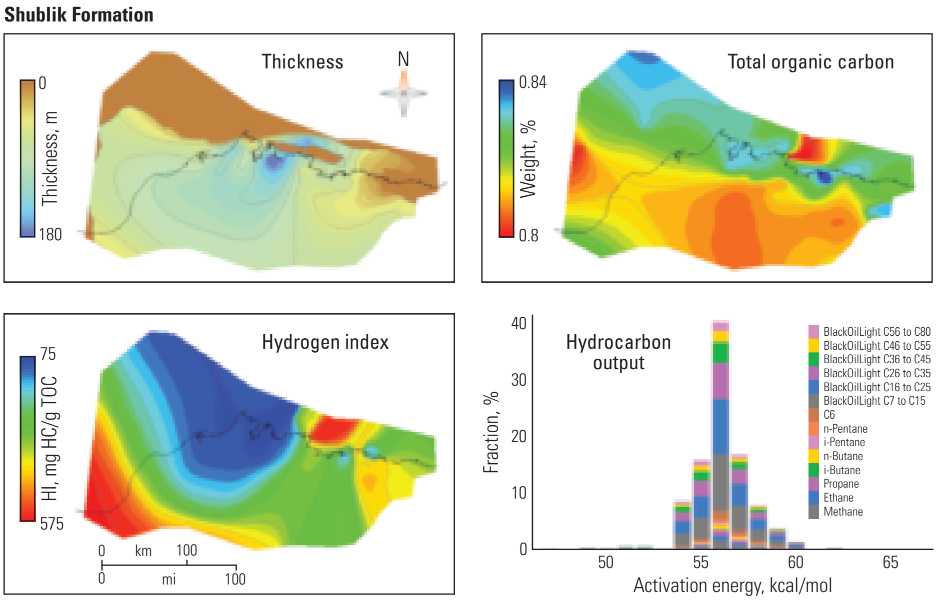
The study, undertaken by Schlumberger and the US Geological Survey (USGS), had multiple objectives: to use public geophysical, geologic and log data to develop a comprehensive model of depositional units and rock properties; to better define the timing of basin filling, source-rock maturation and petroleum migration and accumulation; and to quantify the volumes, compositions and phases of generated hydrocarbons.

The study area covers 275,000 km^2 [106,000 mi^2] and includes data from more than 400 wells (previous page, bottom). The model, built from logs and 2D seismic data, featured a grid with 1- by 1-km [0.6- by 0.6-mi] resolution. In the western portion of the study area, in the Chukchi Sea, data are relatively sparse, whereas the eastern part of the study area is well-explored and contains several productive fields, including Prudhoe Bay, the largest field in North America.

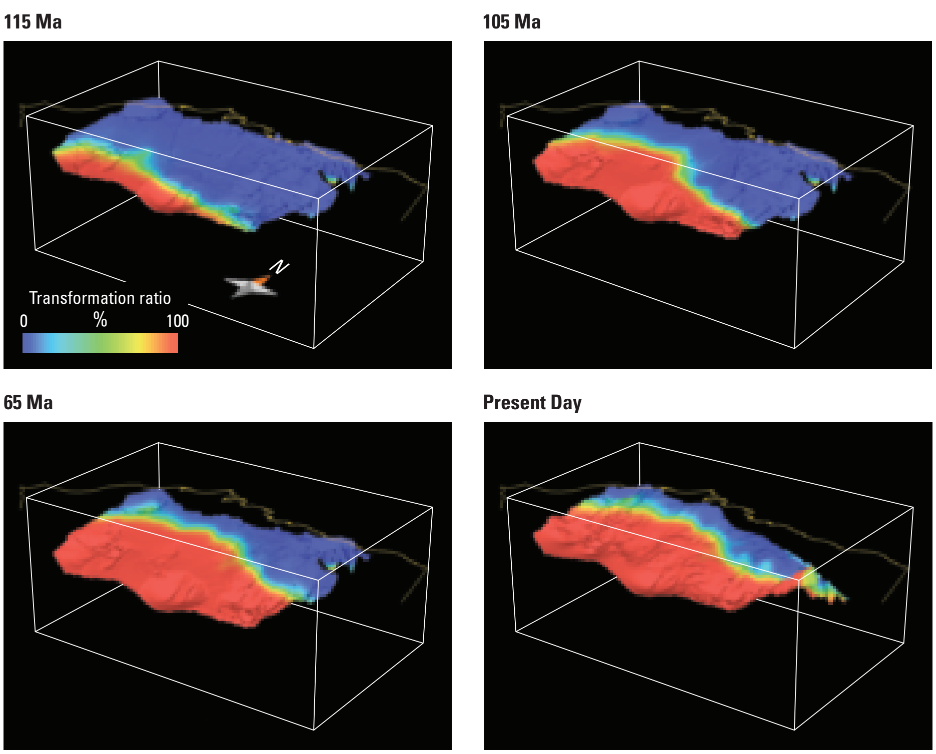
The present-day subsurface geometry shows complex stratigraphy (above). Hydrocarbons from five source rocks have accumulated in several reservoir formations, creating multiple petroleum

26. Kemna HA, Kornpihl K, Majewska-Bell M, Borracini F and Mahon K: "Structural Restoration and Petroleum Systems Modeling of the Wyoming-Utah Thrust Belt," presented at the AAPG Annual Convention, San Antonio, Texas, April 20–23, 2008.

27. Orogeny refers to geologic periods of mountain building.



^ Shublik Formation source-rock properties. Model input included source-rock thickness (*top left*), total organic carbon (*top right*), hydrogen index (*bottom left*) and expected hydrocarbon output based on reaction kinetics measured from an immature equivalent of the source rock in the Phoenix 1 well (*bottom right*). Similar input data were created for each of the oil-generating source rocks.



^ Snapshots of the source-rock transformation ratio of the Shublik Formation. Kerogen in this source rock undergoes increasing transformation to petroleum as the layer is buried. The transformation ratio is color-coded from blue (0%) to red (100%). By 65 Ma, more than half the mapped Shublik Formation kerogen had undergone 100% transformation. The updip portion to the north along the Barrow Arch remained immature. The present-day plot shows that the formation is currently undergoing transformation as it is buried in the northeast.

systems. Important source rocks lie beneath a prominent stratigraphic boundary: the Lower Cretaceous Unconformity (LCU). Tracking the deposition of the overburden rocks, called the Brookian foresets, facilitates an understanding of the burial history and helps determine the maturation of source rock. Snapshots of PetroMod models through geologic time show the burial of the Triassic, Jurassic and Cretaceous source rocks and the progradation of the Brookian foresets from southwest to northeast and their eventual erosion (next page, left). This dynamic model formed the structural input to the PetroMod model.

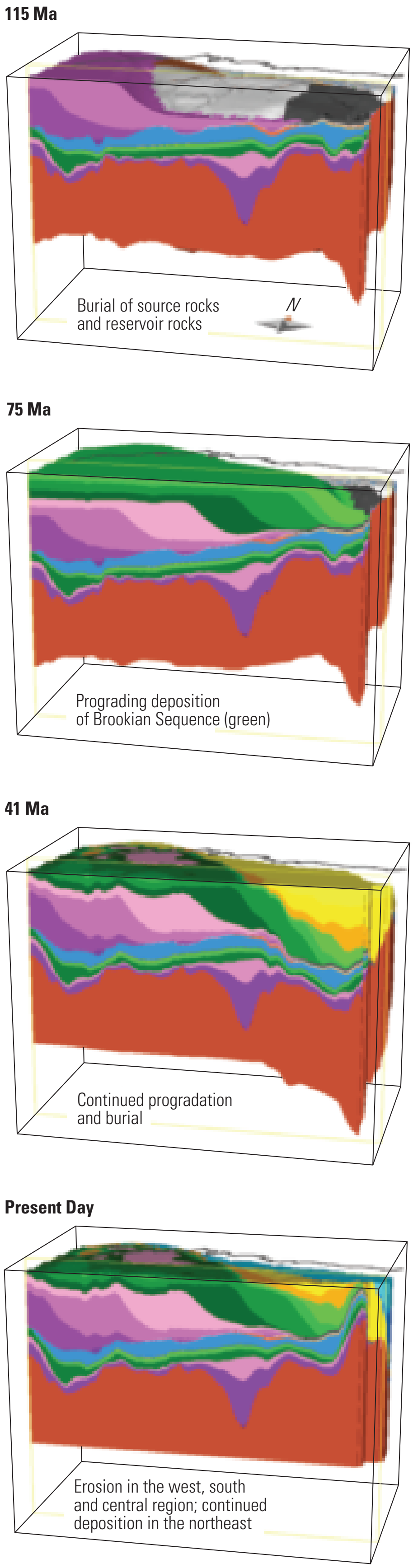
For each of the source rocks, input included maps of layer thickness, original TOC and original HI, and expected hydrocarbon output based on kinetic measurements from thermally immature source-rock samples at different well locations (left).

Among the results of PetroMod modeling are time-lapse maps of the transformation ratio, or percentage of kerogen transformed into petroleum, for each source rock (below left). In general, as burial depth increases, more of the source rock passes through the oil-generation window, allowing more-complete maturation of the organic matter. Most of the kerogen in the Shublik Formation outside the Barrow Arch has already undergone 100% transformation to petroleum.

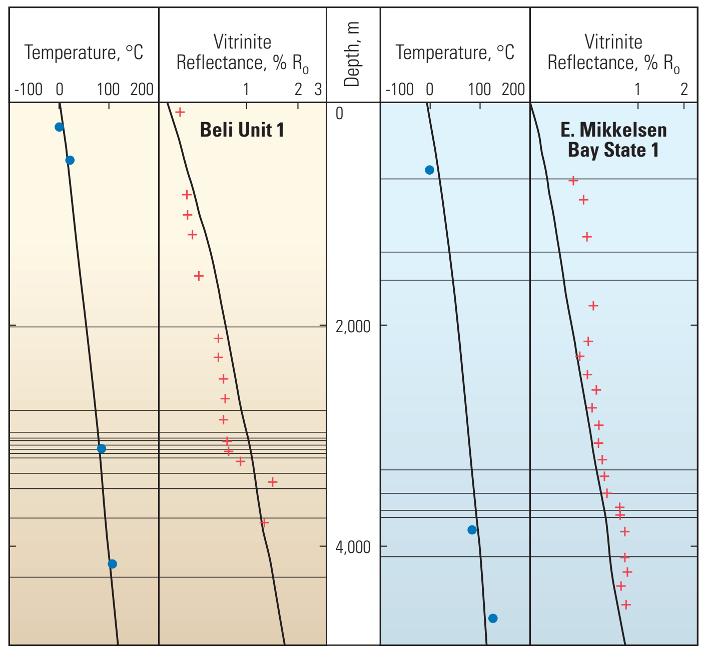
The results of BPSM can be calibrated by comparison with independent information on basin history and kerogen maturation. Two key calibration parameters are temperature and vitrinite reflectance measured in boreholes and from borehole samples, respectively (next page, top right).

Incorporating burial pressure, heat-flow calculations, kinetics of thermal maturation and multiphase flow simulations, PetroMod software modeled the expulsion of liquid and vapor hydrocarbons from the many source rocks and the migration of these fluids to trapping structures. Tracking fluid migration to the present indicates areas where hydrocarbons have accumulated (next page, bottom right).

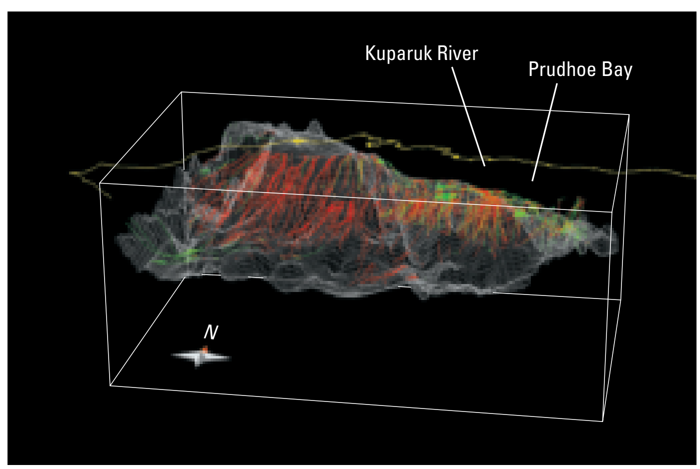
Simulation results show that hydrocarbon charging occurs quickly—instantaneously on a geologic time scale. If traps are not formed as soon as or before hydrocarbons are ready to move, there is a high risk the fluids will not be trapped. Events charts for two different areas overlying the thermally mature Shublik source



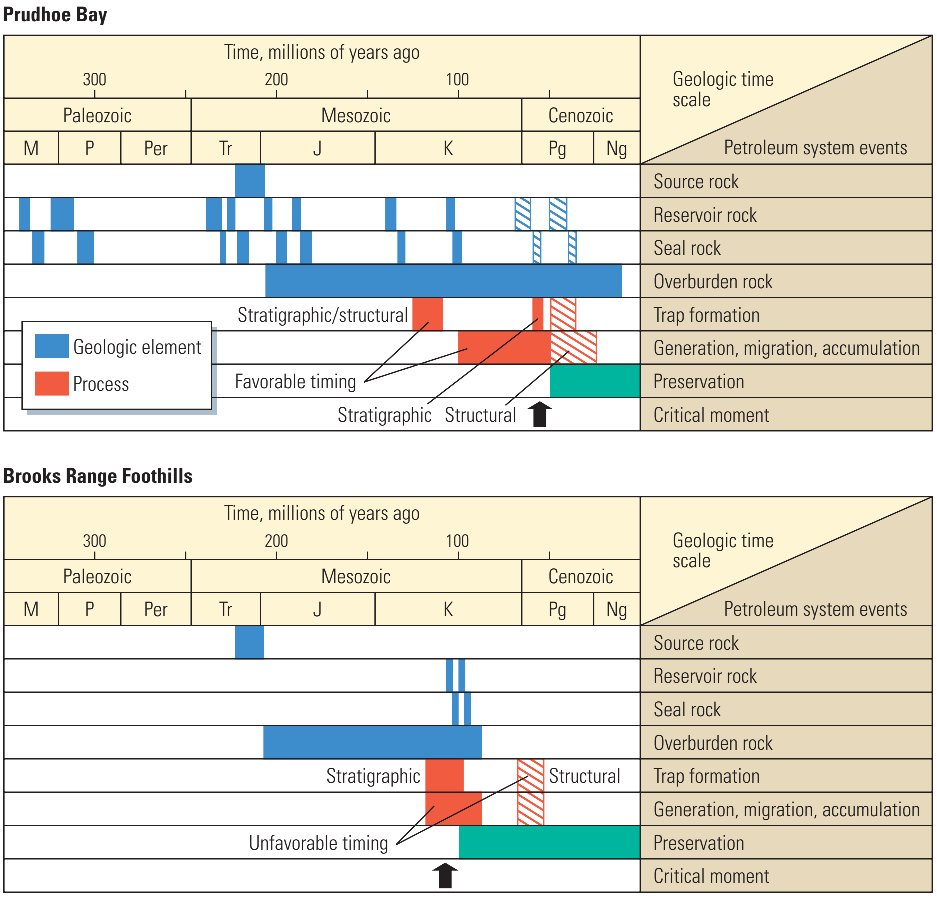
< Time-lapse basin models. Forward modeling begins prior to 115 million years ago (Ma) and proceeds to the present day. The snapshots show southwest to northeast progradation of the Brookian Sequence that significantly influenced the timing of petroleum generation and migration from the underlying source rocks. The study area was subsequently affected by multiple events of uplift and erosion. Four panels out of the 148 modeled time steps are shown.



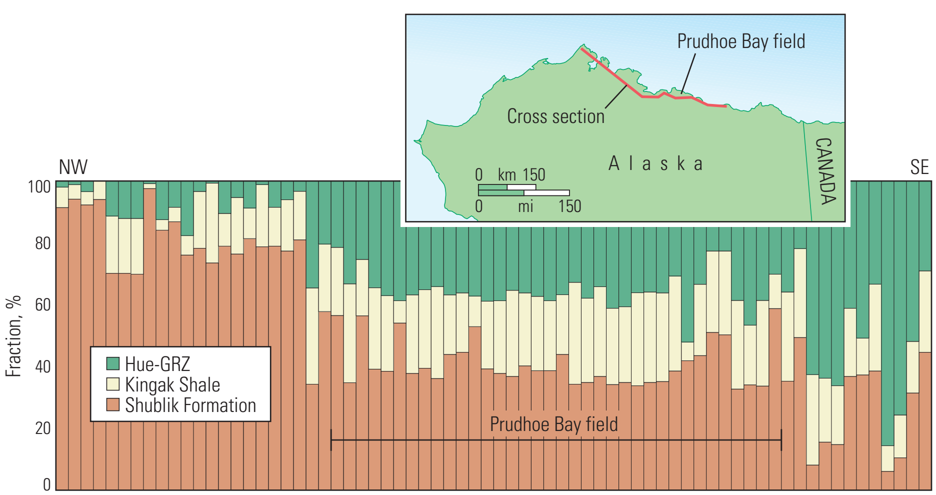
^ Calibrating modeling results. Independent information such as subsurface temperature and vitrinite reflectance helps to check the quality of BPSM. Data from two wells show a good fit with model calculations. Recycled vitrinite probably accounts for the elevated reflectance values in rocks shallower than 2,000 m in the E. Mikkelsen Bay State 1 well.



^ Modeled North Slope accumulations. PetroMod software calculates the paths along which liquid (green) and vapor (red) hydrocarbon phases migrated from areas where they were generated to their accumulation locations.



^ Comparing events charts. The event chronology for Prudhoe Bay (*top*) indicates favorable timing for accumulation of hydrocarbons generated from the Shublik source rock. By the time hydrocarbons were migrating in the middle of the Cretaceous (K), many traps had formed and were available to capture fluids. To the south, in the foothills of the Brooks Range (*bottom*), events were not as favorably timed. Although traps may have formed too late to contain oil and gas generated in the Cretaceous, they might have formed in time to hold remigrating fluids, or those displaced from other areas (hatched).



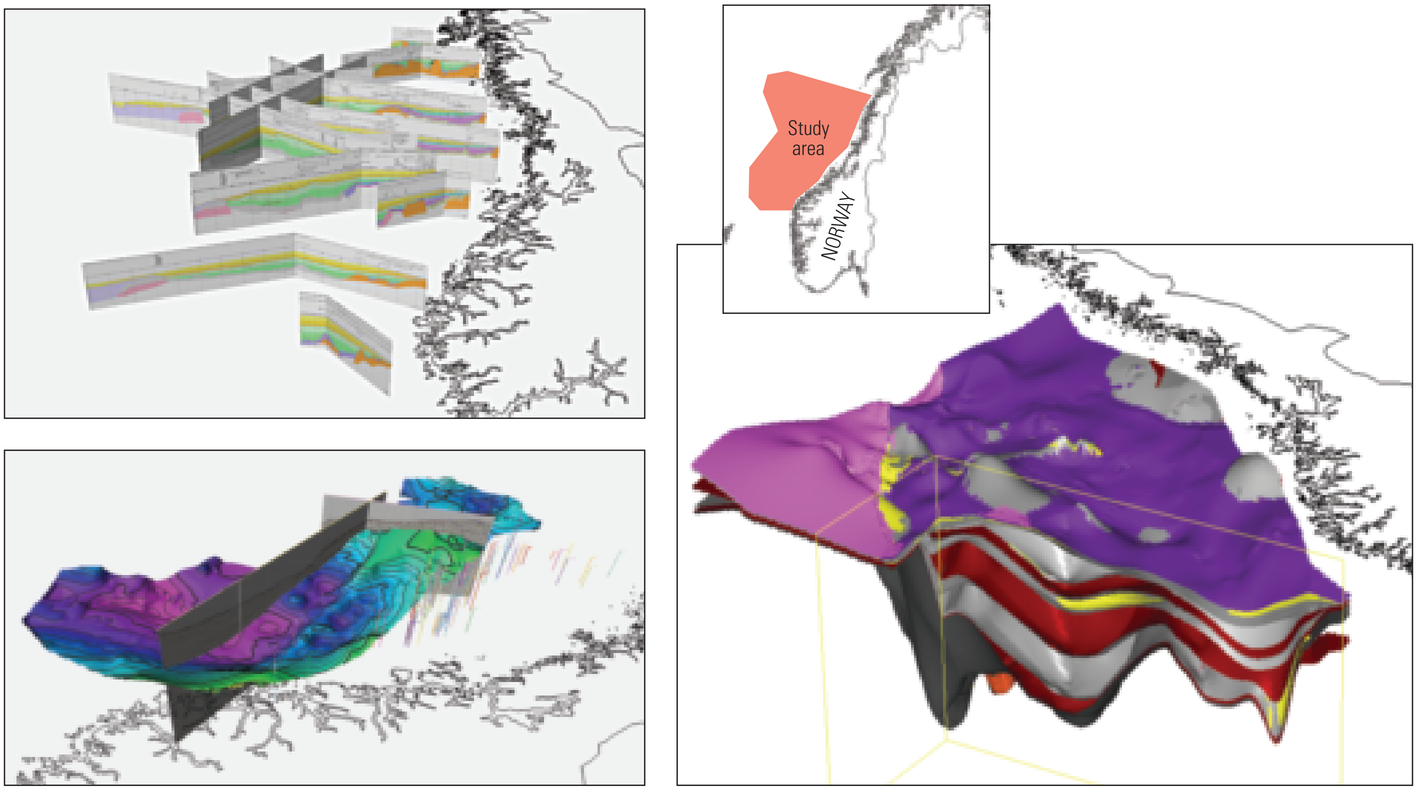
^ Mixed crude oils. Geochemical analysis of 70 oils from wells along the Barrow Arch shows variation in source-rock contributions. These data are consistent with the chronology of generation, migration and accumulation modeled by PetroMod software. The three most prolific source rocks matured and expelled petroleum at different times and places, charging reservoirs with a mixture of crude oils. (Adapted from Peters et al, reference 29.)

rock show how relative timing between trap formation and source-rock maturation can impact risk (left). At Prudhoe Bay and elsewhere on the Barrow Arch, trap formation preceded generation, migration and accumulation by several million years, resulting in major oil accumulations.[28] However, the events chart at a well in the foothills of the Brooks Range shows that location has significant timing risks for stratigraphic traps, which formed at about the same time as generation and migration of fluids from the Shublik Formation. In addition, risk is high for the structural traps because they can be filled only by remigration of petroleum from older stratigraphic traps.

The various North Slope source rocks matured and expelled petroleum at different times and places, charging reservoirs with a mixture of crude oils. Analysis of biomarkers and stable carbon isotope ratios for oils recovered from wells on the Barrow Arch shows a geographic variation in contributing source rocks (below left).[29] Reservoirs in the west produce oil generated predominately from the Shublik Formation, while those to the east produce oil generated mainly from the Hue-gamma ray zone (Hue-GRZ). The Prudhoe Bay field is intermediate in position and produces oil that is more evenly mixed, containing oil from the Shublik Formation and Hue-GRZ, with lesser input from the Kingak Shale. These findings are consistent with the multiple charging episodes depicted in the 3D PetroMod model, in which the Shublik and Kingak source rocks started to generate and expel petroleum during the Cretaceous, and the Hue-GRZ contributed oil later—and continues to do so today.

Modeling Norwegian Accumulations

Modelers have conducted a similar study of petroleum systems in the Norwegian Atlantic margin. The Upper Jurassic Spekk Formation, a marine shale, has proved to be a regionally effective source rock, having charged Jurassic sandstone reservoirs—producing fields in the Halten Terrace area—with oil and gas. However, neighboring areas remain unexplored, such as deepwater regions and prospects close to existing fields. Their assessment will benefit from minimizing uncertainties in our understanding of the timing and locations of the generation, expulsion, migration, accumulation and preservation of hydrocarbons. Basin and petroleum system modeling can provide greater insight and risk analysis of the chronology of the geologic elements and processes occurring in this region.



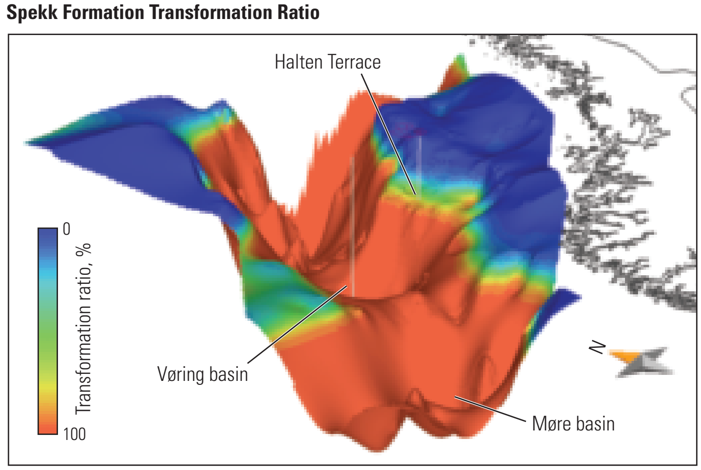
^ A regional BPSM study of the Norwegian Atlantic margin. A regional-scale model covering a large area offshore Norway (*top right*) was built using 2D seismic data and logs from approximately 200 wells (*bottom left*). The depth to the top Cretaceous horizon is color-coded from shallow (green) to deep (purple). Two 2D seismic lines intersect in the northwest portion of the model. Wells are depicted as vertical lines. Interpreted cross sections (*top left*) were taken from the literature. The resulting Petrel model (*bottom right*), containing 24 layers, was filled with facies information for PetroMod petroleum system modeling.

The initial regional-scale model covers an area 700 by 400 km [435 by 250 mi]. Constructed in Petrel software on a 3- by 3-km [2- by 2-mi] grid, the model incorporates information from 188 two-dimensional seismic lines and 198 wells. Data from the Norwegian Petroleum Directorate and published interpreted cross sections enhanced the model (above).[30]

Depth maps of each formation were loaded into the PetroMod software as stratigraphic input for regional-scale petroleum system modeling. Lithology and age information and source-rock potential completed the input. Using boundary conditions, PetroMod software simulated regional burial effects, such as changes in pressure, porosity and permeability caused by compaction, thermal history, and hydrocarbon generation, migration and accumulation throughout geologic time.

Modeling indicates petroleum generation in the deepest portions of the Spekk source rock occurred in the Early Cretaceous, between 140 and 110 million years ago. These deepest source rocks have undergone complete transformation of kerogen to petroleum (right).

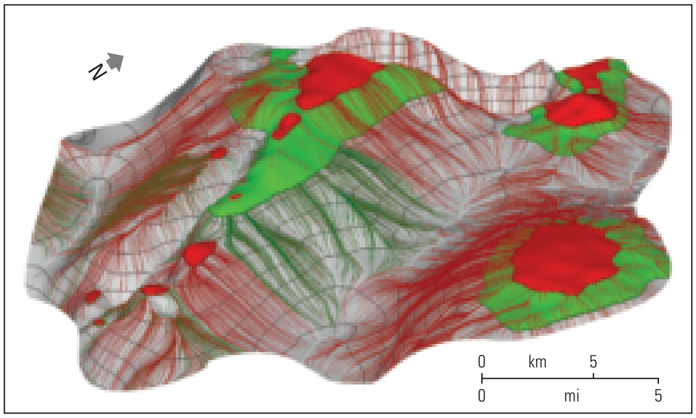
Spekk Formation Transformation Ratio



^ Transformation of organic matter in the Spekk Formation to petroleum. PetroMod modeling of present-day conditions indicates that shallow, immature source rock (blue) exists on the east and west margins of the deep basins offshore Norway. Within the basins, source-rock transformation is overmature; 100% of its kerogen has been converted into oil and gas.

28. Bird KJ: "Ellesmerian(!) Petroleum System, North Slope, Alaska, U.S.A.," in Magoon LB and Dow WG (eds): *The Petroleum System—From Source to Trap, AAPG Memoir 60*. Tulsa: AAPG (1994): 339–358.
29. Peters KE, Ramos LS, Zumberge JE, Valin ZC and Bird KJ: "De-Convoluting Mixed Crude Oil in Prudhoe Bay Field, North Slope, Alaska," *Organic Geochemistry* 39, no. 6 (June 2008): 623–645.
30. Brekke H, Dahlgren S, Nyland B and Magnus C: "The Prospectivity of the Vøring and the Møre Basins on the Norwegian Sea Continental Margin," in Fleet AJ and Boldy SAR (eds): *Petroleum Geology of Northwestern Europe: Proceedings of the 5th Conference*. London: Geological Society (1999): 261–274.

Modeled Accumulations



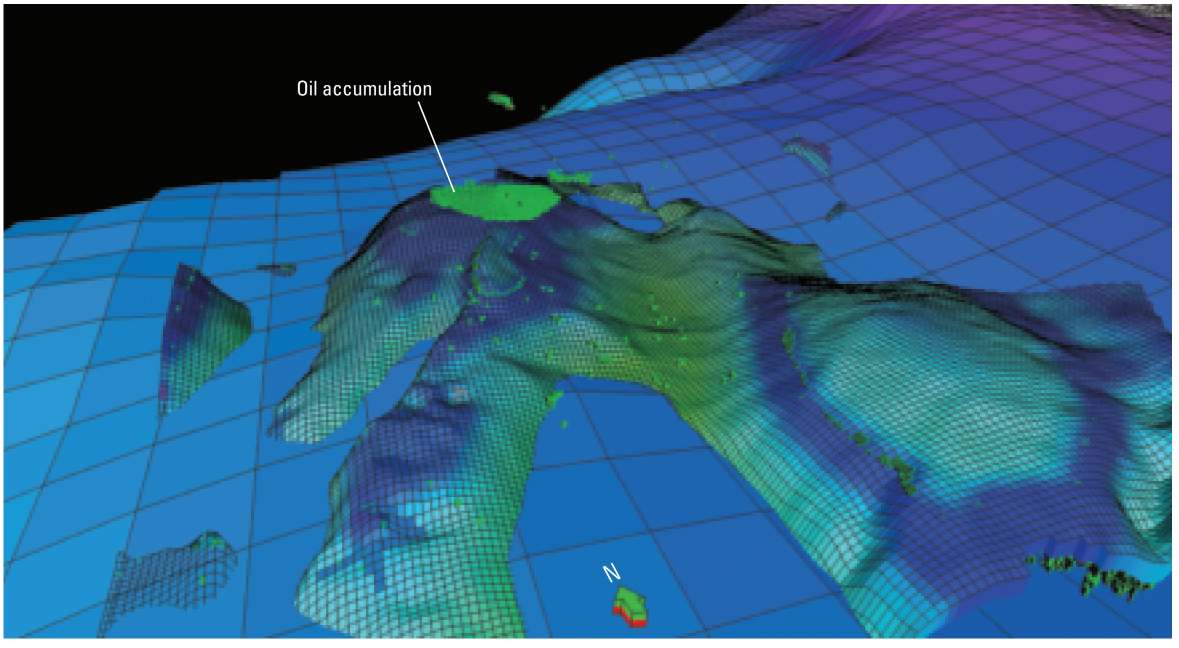
^ Modeled oil and gas accumulations. According to BPSM, oil (green) and gas (red) have migrated from multiple source rocks and accumulated in reservoirs offshore Norway. Many of these modeled accumulations correspond to known reservoirs. White lines are drainage-area boundaries. Visualizing accumulations and drainage-area boundaries helps interpreters understand the potential for fluids to leak and spill.

On the Halten Terrace, on the eastern flank of the basins, transformation is incomplete and still on-going; little hydrocarbon generation from the Spekk Formation has occurred to date. On the other hand, the locally present Åre source rock—a deeper and discontinuous Early Jurassic coaly clastic formation—began generating hydrocarbon during Eocene times, around 40 million years ago. Thus, it was expected that the Åre Formation was the main source of hydrocarbon charge to the producing reservoirs on the basin flanks.

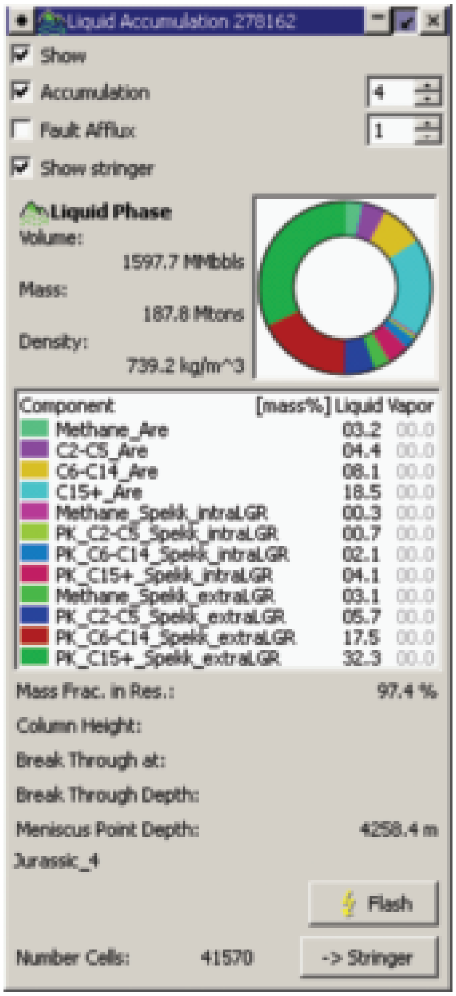
After modeling hydrocarbon generation from the Spekk and Åre Formations, PetroMod software modeled the migration and accumulations of expelled oil and gas (above). According to the maps, the simulated hydrocarbon accumulations match known producing fields within the area, in terms of extent and composition, building confidence in the application of the results to investigate new prospects.

To examine possible satellite prospects around existing fields, modelers constructed a refined local model with a 200-m [656-ft] square cell size over the field area using 3D seismic data for detailed and continuous horizon geometry. Log-calibrated inversion of the seismic data for lithofacies delivered improved estimates of porosity and permeability in the field area. The high-resolution geometry was populated with the seismically derived properties by recently developed PetroMod seismic facies refinement technology. These updated petrophysical parameters enhanced the locally refined model, leading to more-accurate simulation of hydrocarbon migration from source to reservoir. Simulations using the local model were coupled to the regional model by local grid refinement. The result is a much finer 3D distribution of the hydrocarbons and a better understanding of processes such as leakage and spilling (below).

Furthermore, modeling fluid provenance, composition and properties supplied a definitive answer to the question about the source of the hydrocarbons produced from Halten Terrace fields. The in situ composition of modeled accumulated hydrocarbons shows greater contribution from the Spekk Formation than expected from its



^ Accumulations on a field scale. Two surfaces (large grid and small grid) from the PetroMod model demonstrate the capabilities of local grid refinement. Oil accumulations (green cubes) initially modeled on the large grid (3,000 by 3,000 m) can be examined in more detail when displayed on the smaller grid (200 by 200 m).



^ Properties of a modeled liquid accumulation. PetroMod software outputs fluid properties at specified conditions. This example shows volume, mass, density, composition and phase at reservoir conditions. Properties at other PVT conditions, such as at the surface, can be modeled by the flash calculator (*bottom right*). The colored ring (*top right*) is a graphical representation of the composition given in the table (*center*). When vapor phases are present (not in this accumulation), their composition is shown in the center of the ring. The table quantifies composition in terms of methane, C_2 to C_5, C_6 to C_{14}, and C_{15+}. This accumulation has contributions from three source rocks: the Åre Formation, the Spekk Formation within the locally refined grid (intraLGR) and outside the locally refined grid (extraLGR). At least 60% of the accumulation came from the Spekk Formation outside the LGR (Spekk_extraLGR).

local degree of transformation and limited thickness (left). Approximately 60% of the hydrocarbons originate from beyond the local area. Simply modeling the volume surrounding the reservoir block would have incorrectly simulated the accumulation volume and composition. Incorporating regional- and field-scale information provides a better understanding of the petroleum systems and their impact on reservoir fluids.

Fluid composition is a major factor to be considered in investigating satellite fields. This and other results from PetroMod simulation can be imported into Petrel software by way of the PetroMod-Petrel Data Exchange Plug-in, allowing integration and viewing of all available reservoir data. For the producing fields on the Halten Terrace, this will facilitate investigations into the possibility of tiebacks to existing field infrastructure.

Modeling More

Basin and petroleum system modeling can do more than indicate hydrocarbon accumulations. With a view to improving the results of seismic imaging, geoscientists at BP have used PetroMod software to model effective stresses in subsalt formations in the central Gulf of Mexico.[31] Effective stresses derived from the modeling were converted into seismic velocities that were used to remigrate the 3D seismic data. Applying the enhanced velocity model improved the illumination of the subsalt volume and delivered an updated model of the reservoir layers and the underlying source rock. The new imaging results also have major implications for insight into the petroleum system, revising the interpreted depth, and thus maturity, of the source rock, and increasing the areal extent of mature source rock. The prospect, when drilled, proved to be a large discovery that is now undergoing appraisal.

Geoscientists are working on advances to the PetroMod system to improve its ability to deliver enhanced BPSM. For example, seismic data are now interpreted to determine layer boundaries that are used to build a geometric model. With the proper constraints, however, seismic data can be inverted to yield lithology and fluid properties that can be incorporated directly into PetroMod property grids.

Another important link is being forged between PetroMod software and VISAGE software for modeling reservoir geomechanics. Such a combination will enable prediction of stress fields and pore pressure through geologic time, helping companies evaluate the risk of seal failures that cause traps to leak. Including the geomechanical capabilities of the VISAGE package with PetroMod software also has the potential to enhance well planning and directional-drilling activities.

Schlumberger scientists are also developing methods to model additional types of petroleum systems, such as those related to coalbed methane, shale gas and methane hydrate. The ability to model such accumulations will improve local and global assessments of these resources.

Vast regional studies such as those presented in this article require input—large-scale 3D seismic surveys, for instance—that may be too costly for individual companies to commission. Including data from multiclient seismic and electromagnetic surveys will allow companies accessing these large-scale BPSM projects to predict and validate prospective structures prior to licensing rounds.

Today, basin and petroleum system modeling is poised for a change. In the not-so-distant past, building 3D geologic models was the domain of expert geologists working with cumbersome hardware and software. The availability of 3D model-building utilities on personal computers has allowed a greater number of less-specialized geoscientists to participate in this activity. Similarly, the realm of BPSM was once that of advanced exploration experts who assessed basin-scale risks as a part of frontier prospecting. The capabilities of the PetroMod system will allow geologists to incorporate some aspects of BPSM into their standard geoscience workflows. Instead of running a petroleum system model once before a discovery is made, the model can be updated with information about the discovered fluids and serve as a development tool throughout the life of the field.

Predicting the present by modeling the past is a powerful tool for oil and gas industry professionals. Although BPSM may not be able to predict every oil and gas accumulation, it is designed to help companies find more hydrocarbons and avoid costly drilling mistakes in the future. —LS

31. Petmecky RS, Albertin ML and Burke N: "Improving Sub-Salt Imaging Using 3D Basin Model-Derived Velocities," *Marine and Petroleum Geology* 26, no. 4 (April 2009): 457–463.