Rock/Fluid Characterization and Their Integration—Implications on Reservoir Management

M.M. Honarpour, SPE, N.R. Nagarajan, SPE, and K. Sampath, SPE, ExxonMobil Upstream Research Co.

Abstract

The flow performance of hydrocarbon reservoirs is controlled largely by rock and fluid properties, their variation, and rock/fluid interactions. In this paper, we highlight the rock- and fluid-data needs for various production processes with an emphasis on quality control (QC) and efficient data management. We stress the need for an integrated and a multidisciplinary approach to rock and fluid characterization to minimize measurement uncertainty. Such an approach will ensure reliable rock and fluid data that are required for the determination of accurate volumes in place, reliable recovery factors, and realistic development plans, thus minimizing technical risks and maximizing the economic value of the hydrocarbon assets. Also discussed are the effects of uncertainties in rock and fluid properties on reservoir-performance prediction. The importance of reservoir surveillance through periodic coring, fluid sampling, and testing as well as reservoir simulation for data validation and refinement is further emphasized. Finally, worldwide field examples of sandstone and carbonate reservoirs containing black oil, volatile oil, and gas/condensates are presented to highlight these points.

Introduction

The performance of hydrocarbon reservoirs is controlled largely by the rock and fluid properties, their spatial and temporal variations, and rock/fluid interactions (Al-Hussainy and Humphreys 1996). High-quality rock and fluid data are critical for reliable geological modeling, reservoir-engineering calculations, and performance predictions by use of reservoir simulators and for subsequent economic analysis. Many pressure-maintenance and secondary- and tertiary-recovery projects have failed because of inadequate geologic description and lack of reliable rock and fluid data. In the absence of good-quality data in adequate quantity, simulation models with multimillion gridblocks, and sophisticated scaleup methodology, do not add any economic value to the resource. In short, the value of rock and fluid data lies in their potential to guide the selection of the most suitable recovery process and its effect on project economics.

__Mehdi Matt Honarpour,__ SPE, is a senior engineering adviser with ExxonMobil Upstream Research Co. in Houston. He holds BS, MS, and PhD degrees in petroleum engineering from the U. of Missouri. Honarpour serves as the Chairperson of SPEREE Review Committee and has served as the chairperson of the SPE Special Series Committee. __N.R. Nagarajan,__ SPE, is an engineering associate at ExxonMobil Upstream Research Co. with 22 years of experience in the oil industry. He holds a PhD degree in physics and has served on program committees and the Forum Series for SPE. __Krishnaswamy Sampath,__ SPE, is the Reservoir Div. Manager at ExxonMobil Upstream Research Co. in Houston. He has served on program committees for the SPE Annual Technical Conference and Exhibition and as a technical editor for SPE journals.

Rock characterization involves quantification of porosity, permeability, capillary pressure, and relative permeability associated with various recovery processes. Similarly, fluid characterization quantifies the reservoir phase behavior, fluid compositional changes throughout the reservoir, and changes in fluid properties as a result of production and injection processes. The process of data gathering begins with exploration and continues through the life of the reservoir.

Reliable data acquisition requires a multidisciplined approach with experts to ensure rigorous QC during sampling and measurement stages while making use of company or industry databases as resources.

This paper discusses the rock- and fluid-data needs for a few important production scenarios from a primary-depletion process through more-complex gas-injection and miscible processes. In addition, the best practices for data-gathering process, QC strategies, and data-management techniques are presented. Finally, sensitivities of performance prediction to various fluid and rock properties are illustrated through a series of field examples.

Role of Rock and Fluid Data

Rock and fluid properties provide vital information for geoscience and engineering applications. They are obtained from direct measurements on reservoir core and fluid samples to quantify reservoir physical and flow properties. Well testing and petrophysics, on the other hand, infer the physical and dynamic properties of the reservoir through the interpretation of formation response to an applied perturbation by use of selected models. These models must be calibrated with rock and fluid data for validation.

Core description and analysis play a major role in geoscience activities, such as determination of environment of deposition, sequence stratigraphy, framework, compartmen-

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talization, and determination of reservoir quality. Similarly, fluid properties are used for determining reservoir continuity. Special-core-analysis laboratory (SCAL) data are used for rock-typing and flow-unit classification. Together with fluid data, these analyses provide input for well-deliverability calculations, rock/fluid compatibility studies, stimulation design, reservoir-engineering calculations, reservoir simulation, production optimization, and design of improved-recovery processes.

Table 1 provides a comprehensive list of fluid pressure/volume/temperature (PVT) and SCAL requirements for a variety of reservoir fluids and rock types. Depending on whether the reservoir contains a dry gas; condensate; or volatile, black, or heavy oil, the sampling method varies from simple wellhead sampling to more-complex bottomhole sampling techniques. The required fluid data also depend on the fluid type, ranging from simple compressibility-factor estimation for dry gas to more-complex phase-behavior changes for near-critical fluids. The rock-type-based relative permeability and capillary pressure data are essential for all reservoir and fluid types. Sample size will depend on the nature and scale of heterogeneity (Honarpour et al. 2003).

Data Collection

A road map for rock and fluid characterization for reservoir management is shown in **Fig. 1.** The program involves a set of clear objectives, a comprehensive data-collection and testing plan, experimental protocols, rigorous QC/quality-assurance (QA) procedures, and a sound data-management

TABLE 1—SCAL AND FLUID-ANALYSIS-DATA REQUIREMENTS AND CRITICAL CONSIDERATIONS

Reservoir Fluid	Fluid Sampling and PVT Requirements	Reservoir Rock	SCAL Requirements	Critical Considerations
Dry gas or wet gas	Dry gas—wellhead samples, Z-Factor Wet gas—separator samples, CGR and Z-Factor	All rock types and tight gas sand	P_c, k_{gswi}, k_{rg}–k_{rw}, and S_{gt}	S_{wi} and distribution trapped-gas saturation, and k_{rg}–k_{rw}
Gas condensate	DST and formation-tester samples Isokinetic samples for rich condensate	All rock types	k_{ro}–k_{rg}, k_{rg}–k_{rw}, S_{gt}, and S_{cc}	Reservoir-condition SCAL tests with reservoir fluids, B_o and GOR, nonhydrocarbon composition, and OBM contamination
Near-critical fluid	Formation-tester samples solution GOR, oil shrinkage below saturation pressure	All rock types	P_c, k_{ro}–k_{rw}, remaining-oil saturation	Critical gas saturation, PVT properties, and OBM contamination
Volatile oil	Formation-tester or DST samples, PVT data for gas-injection processes	All rock types	P_c, k_{ro}–k_{rw}, remaining-oil saturation	Accurate GOR, compositional PVT, IFT, and OBM contamination
Black oil	Surface samples, standard black-oil PVT	All rock types	P_c, k_{ro}–k_{rw}, k_{ro}–k_{rg}, hysteresis, S_{gc}, remaining-oil saturation	B_o, GOR, viscosity, IFT, and OBM contamination
Viscous or heavy oil	Formation-tester sampling, viscosity, density, and emulsion	Mainly clastic rocks and unconsolidated sand	P_c, k_{ro}–k_{rw}, k_{rw}–k_{rg}, hysteresis, S_{gc}, remaining-oil saturation	Viscosity, fluid contamination, sand production, S_{gc}, k_{rw}, k_{ro}, k_{rg}, and emulsion
All fluid types	Sampling and PVT corresponding to fluid types listed above	Clay-rich sandstone	SCAL on preserved cores or with properly cleaned cores and wettability restoration using compatible brine	Formation damage because of clay swelling/fines migration, unrepresentative SCAL if incompatible brine is used
All fluid types	Sampling and PVT corresponding to fluid types listed above; avoid sand production	Unconsolidated sand	SCAL with minimum change to mechanical properties	Grain reorientation, sample disintegration, clay swelling/fines migration and unrepresentative SCAL
All fluid types	Sampling and PVT corresponding to fluid types listed above	Heterogeneous rocks, vugular and naturally fractured	SCAL on whole core	Scale of measurement to capture the effect of heterogeneity, mud solids contamination
Fluids with compositional variation	Formation-tester sampling and depth-dependent PVT	All rock types	Compositional-dependent SCAL	Depth-dependent fluid variation and the effect on relative permeability

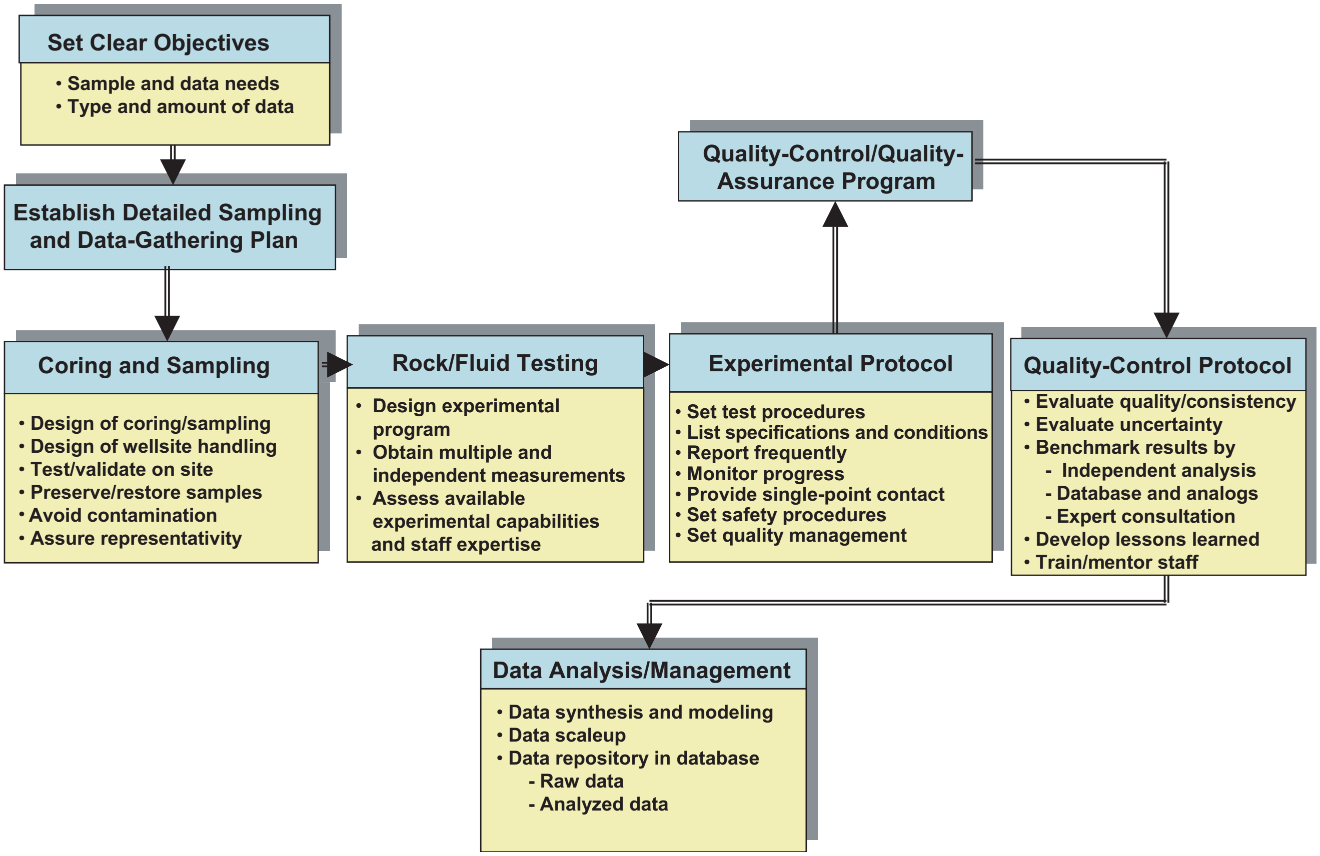


Fig. 1—Road map of rock-fluid characterization for reservoir management.

system. The process starts with the collection of representative rock and fluid samples, sample preservation/restoration, and testing procedures. The validated data are organized into a data repository and managed digitally for retrieval and further analysis (e.g., synthesis and modeling).

Critical Rock and Fluid Data

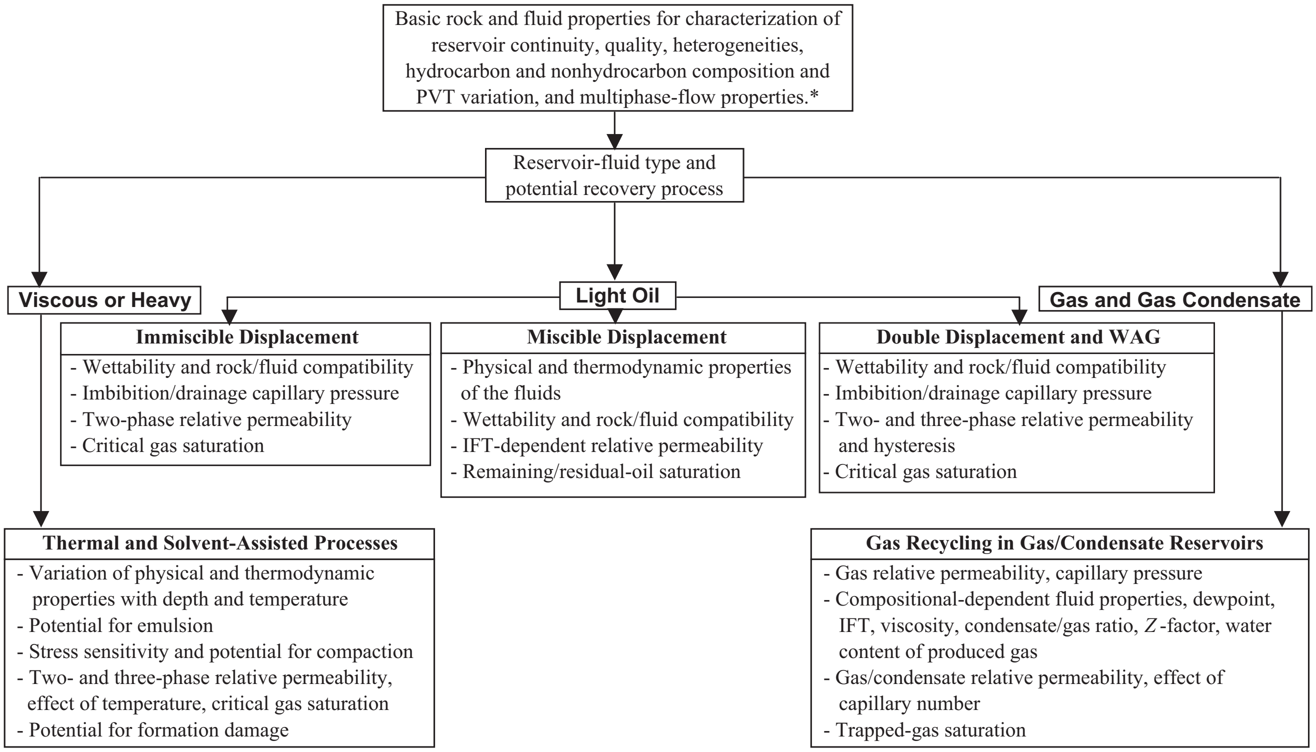
The basic and critical rock and fluid data required for evaluation of various reservoir-depletion strategies are shown in **Fig. 2.** Rock, fluid, and rock/fluid data form the basis for the design of any recovery process, calibration of wireline logs, and evaluation of potential compaction and subsidence. The specific rock-/fluid-data requirements are further classified under three major reservoir-fluid classes: viscous or heavy oils, light oils, or gas and gas condensates. The recovery processes involving light oils are grouped into three processes: immiscible, miscible, and tertiary gas injection, including water-alternating-gas (WAG) injection. Other recovery processes, such as thermal methods, will require customized rock/fluid characterization as well.

Acquiring representative rock and fluid samples is challenging and requires expertise. Major challenges in obtaining fluid samples include avoiding liquid dropout in gas condensates and gas evolution in heavy oils during sampling. Potential fluid contamination by oil-based mud (OBM) should be minimized for obtaining representative bottomhole samples. Special coring techniques are used to maximize core recovery while obtaining low-invasion core samples to avoid unnecessary cleaning and wettability restoration.

Fig. 3 exhibits typical uncertainties observed in rock- and fluid-property measurements and the resulting effect on hydrocarbon-in-place (HCIP) values, production/injection rates, fractional flow, and recovery factors. The magnitude of the effect is related to the rock and fluid types, their properties, wettability, and the balance of capillary, viscous, and gravitational forces. The largest effect on HCIP is caused by uncertainties in porosity, particularly for low-quality rocks, and by uncertainties in the formation volume factor (FVF) for volatile oils. The uncertainties in permeability, relative permeability, viscosity, and FVF have similar effects on rates and fractional flow. Quantifying the effect of rock/fluid uncertainties on the recovery factor is not straightforward because of heterogeneity, wettability, and the combined effect of viscous, capillary, and gravitational forces. However, the wettability, endpoint saturation, corresponding relative permeability, and permeability contrast are critical parameters that affect the recovery factor significantly. The recovery factor in heavy-oil reservoirs is highly influenced by uncertainties in the live-oil viscosity.

QC Program

High-quality rock and fluid data add significant value by reducing uncertainty, especially when the initial investment



* Includes the effect of factors such as net-/gross-pay ratio and interwell connectivity.

Fig. 2—Rock- and fluid-data collection for evaluation of depletion strategies.

is substantial, such as in deepwater operations and production strategies for giant reservoirs. The evaluation of coring fluid, coring parameters, core handling, and wellsite-wettability preservations should be the first step in the QC process (Bulau and Honarpour 1997). In case of contaminated core samples, cleaning and wettability restoration should be custom designed. Special tools and methods should be adopted to minimize fluid contamination by OBM.

The laboratory QC program consists of prequalification of the laboratories and subsequent consistency checks. The prequalification involves evaluation of laboratories on the basis of routine property measurements on a set of standard rock and fluid samples and an on-site inspection. This step provides information on the laboratories' technical capabilities including wellsite operation, rock and fluid handling, screening, analysis, and safety practices. It also includes information about the company's QC practices, communication, documentation, and reporting on previous projects. Strength and weaknesses of each laboratory in various categories should be documented and used to select qualified laboratories. The consistency check of routine-core-analysis data from prequalified laboratories is conducted by repeating measurements on a subset of samples at another qualified laboratory. Special-core- and fluid-analysis data need to be compared against a database on similar core samples or fluids analyzed under similar conditions. In summary, reliable core- and fluid-analysis data require a qualified laboratory, supervision by experienced staff, and coordinated effort on the parts of both the service providers and the clients to ensure quality data.

Data Management

Millions of dollars are spent to gather, analyze, and interpret the rock and fluid data for use in various reservoir-engineering and -simulation studies. However, if these data are not managed efficiently, the value of the data may not be fully realized. Often, the data gathered on rocks and fluids from different sources must be archived for retrieval, then displayed graphically for data comparison and integration. Key components of a data-management system should include a comprehensive data repository and a set of analysis tools to guide in proper interpretation, modeling, and systematic data integration. The data-repository system should include a database of both raw and interpreted data in a well-organized format. The raw data must be grouped on the basis of regional and geological information. Further grouping may be organized on the basis of individual reservoir, well, and rock/fluid type. The data also are classified under different formations, petrophysical properties, and fluid types, then ranked for quality by use of standard QC/QA procedures.

Examples: Effect of Rock and Fluid Properties

Three examples listed in **Table 2** show the effect of rock and fluid data on reservoir-performance prediction. The examples include volatile oil, black oil, and gas/condensate fluid systems from both sandstone and carbonate reser-

Production/Injection Rates

$$Q = \frac{k\,k_r h \Delta P}{\mu\,\beta \ln(r_e / r_w)}$$

Property	Fluid/ Rock Type	Typical Uncertainty	Effect on Rates
k	High quality	15%	15%
k	Low quality	>15%	>15%
k_r(S)	Light oil/gas Condensate	15%	15%
k_r(S)	Heavy oil	>15%	>15%
μ_o	Light oil	10%	10%
μ_o	Heavy oil	>15%	>15%
β_o	Black oil	5%	5%
β_o	Volatile oil	10%	10%

Original Hydrocarbon in Place

$$\text{OHCIP} = Ah\phi(1 - S_{wi})\beta_{hc}$$

Property	Fluid/ Rock Type	Typical Uncertainty	Effect on OHCIP
β_o	Black oil	5%	5%
β_o	Volatile oil	10%	10%
ϕ	High quality	0.5 PU	2–4%
ϕ	Low quality	0.65 PU	10–20%
S_{wi}	High quality	2.0 SU	2%
S_{wi}	low quality	10.0 SU	10%

Fractional Flow

$$F_w = \frac{1}{1 + (k_{ro} / k_{rw})(\mu_w \beta_w / \mu_o \beta_o)}$$

Property	Fluid/ Rock Type	Typical Uncertainty	Effect on Rates
k_r(S)	Light oil/gas Condensate	15%	15%
k_r(S)	Heavy oil	>15%	>15%
μ_o	Light oil	10%	10%
μ_o	Heavy oil	>15%	>15%
β_o	Black oil	5%	5%
β_o	Volatile oil	10%	10%

Recovery Factor

$$\text{RF} = \frac{1 - S_{wi} - S_{orw}}{1 - S_{wi}} E_A\,(k, \mu, \rho) E_V\,(k, \mu, \rho)$$

Property	Fluid/ Rock Type	Typical Uncertainty	Effect on RF
S_{wi}		2.0 SU	10%
S_{orw}		6.0 SU	20%
k_r(S)	Light oil/gas Condensate	15%	15%
k_r(S)	Heavy oil	>15%	>15%
μ_o	Light oil	10%	10%
μ_o	Heavy oil	>15%	>15%

Fig. 3—Effects of rock/fluid-property uncertainties on reservoir-engineering calculations.

voirs. In Anschutz Ranch (volatile oil), reliable predictions were achieved by use of a representative-fluid model and a deterministic geologic model honoring the rock and fluid data. In Ubit (black oil), a correct gas/oil relative permeability curve representing the gravity-dominated process improved reserves estimates and the economics significantly. In Arun (gas/condensate), characterization of water vaporization and gas/condensate relative permeability provided improved performance prediction, leading to efficient reservoir management.

Effect of Fluid Gradients on Recovery and Reservoir Management—Anschutz Ranch Field. The first example is a near-critical fluid in an Aeolian Nugget sandstone reservoir, Anschutz Ranch field, on the Wyoming/Utah border, in the U.S. The initial reservoir pressure was 5,320 psi at 5,314 ft subsea, and the reservoir temperature was 220°F. The 100-ft-thick formation has a relief of 2,400 ft with a 24° dip. Porosity ranges from 2 to 22%, and the interpreted matrix permeability ranges from 0.01 to 400 md. Oriented whole cores showed the presence of filled and open fractures and the heterogeneous nature of the matrix. Measurements taken with a minipermeameter on the slabbed face of whole cores showed a permeability contrast of more than two orders of magnitude. The hydrocarbon fluid varied from a rich-gas condensate at the top to a volatile oil down the structure. As a result, a strong compositional gradient existed with depth, induced by gravitational forces, as shown in **Fig. 4** for the methane and C_{7+} fraction, respectively. The saturation pressures varied between 4,800 and 5,300 psia, the gas/oil ratio (GOR) between 4,000 and 5,400 scf/STB, and the stock-tank oil gravity between 42 and 50°API. A compositional-fluid model based on an equation of state was developed through detailed characterization of 18 PVT analyses. However, initially, the compositional-gradient model was based on an assumed linear correlation (Metcalfe et al. 1988) of observed data. The linear correlation predictions for methane and C_{7+} are also shown in Fig. 4.

Among several pressure-maintenance schemes by gas injection, nitrogen injection was selected because of its lower cost, its availability, and possible near miscibility. However, miscibility was presumed on the basis of an incorrect fluid gradient. The disadvantages of nitrogen injection were accelerated liquid dropout in the gas/condensate region because of an elevated dewpoint and immiscibility of nitrogen with the volatile oil at the bottom.

TABLE 2—KEY ROCK AND FLUID PROPERTIES AND THEIR EFFECT ON PERFORMANCE PREDICTIONS

Field	Critical Fluid Properties	Critical Rock Properties	Data Acquisition	Data Modeling	Effect
Anschultz Ranch (Sandstone)	Depth-dependent compositional gradient	Rock-property variation and heterogeneity	Multiple core and fluid samples to capture variability over the entire reservoir	EOS-based GCE model and deterministic permeability model	Sweep efficiency, gas breakthrough, GOR, and liquid recovery
Ubit (Sandstone)	Areally different PVT regions	Representative gas/oil relative permeability	Areal fluid PVT and gravity-drainage gas/oil relative permeability	Black-oil model and facies-based SCAL	Displacement efficiency, reserves
Arun (Carbonate)	Water vaporization and CO_2 effect on PVT	Gas/condensate relative permeability whole core	Water vaporization and gas/condensate relative permeability and whole-core measurements	Three-phase compositional EOS facies-based SCAL	Water production, condensate recovery, and well deliverability

The initial compositional-simulation model was set up with permeability maps that were generated with stochastic modeling because of a lack of basic rock data at appropriate measurement scale. Analog relative permeability data were used to simulate gas/oil fractional flow. Simulation studies were performed to history match the production data. A comparison of the produced GOR with simulation predictions in **Fig. 5** shows a poor match. To overcome this difficulty, the geological model was altered significantly by introducing high-permeability streaks at selected locations. The result was a forced history match that honored neither the rock nor the fluid data. The reservoir-performance prediction based on this simulation model was unreliable, as indicated by the actual field performance encountered in the later life of the field, with very low sweep efficiency, earlier gas breakthrough, and a significantly lower liquid recovery.

A new simulation model was set up honoring all the rock and fluid data. The geologic model was based on a determin-

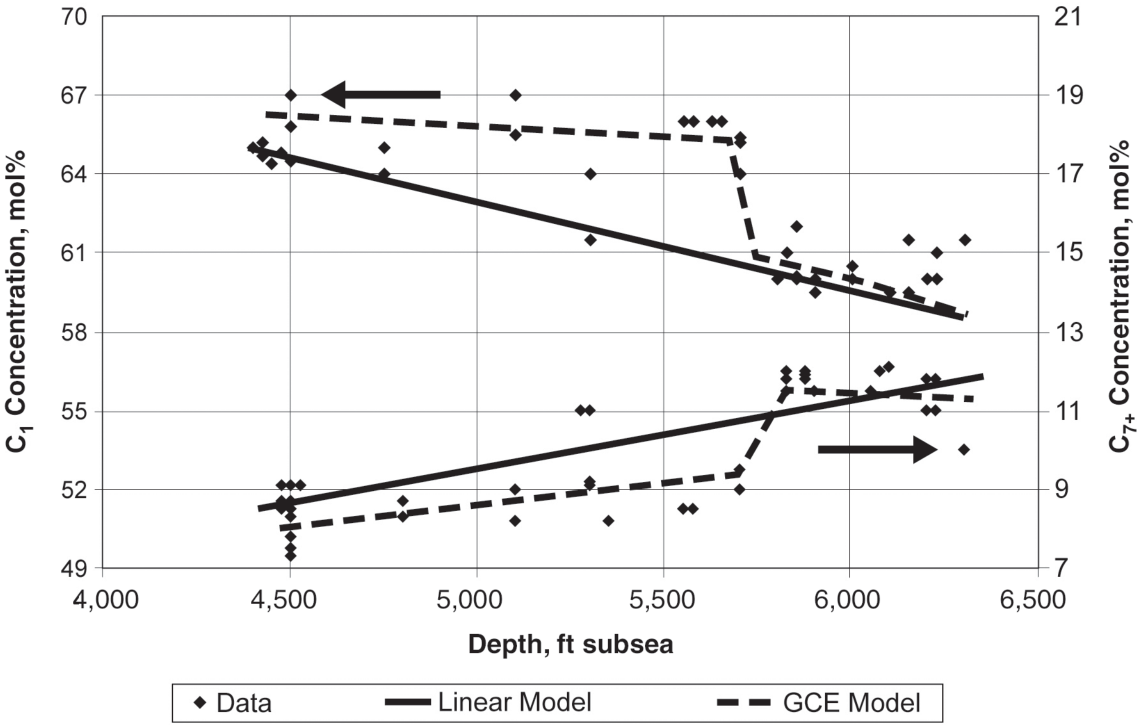


Fig. 4—Compositional gradients in Aschutz Ranch reservoir for C_1 and C_{7+}.

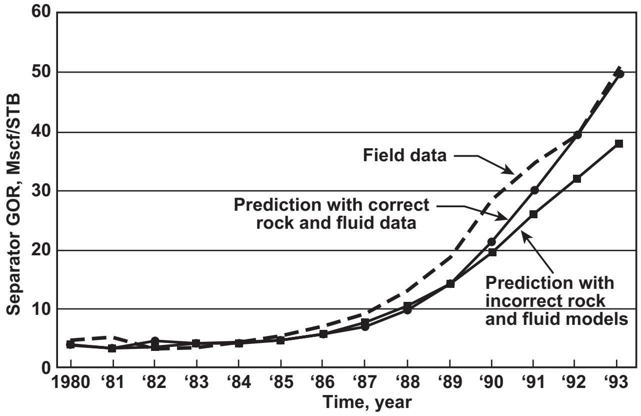


Fig. 5—Separator GOR profile: prediction vs. field data.

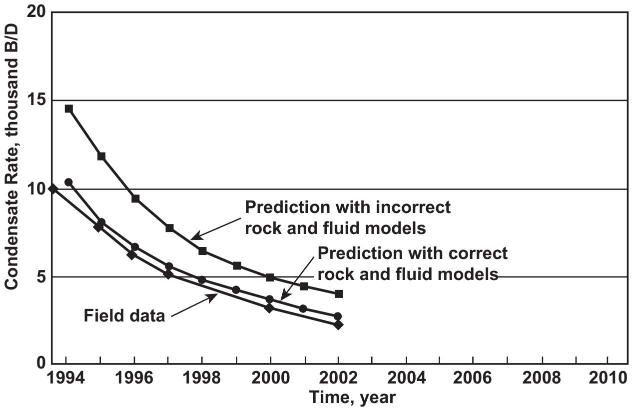


Fig. 6—Condensate rate as a function of time.

istic model for porosity and permeability. A fluid gradient model based on gravity/chemical equilibrium (GCE) was used to match the observed compositional gradient, correctly predicting a thin volatile-oil leg at the base and a large gas/condensate fluid above it. The GCE-model predictions for methane and C_{7+} also are shown in Fig. 4. An improved history match was obtained, as shown in Fig. 5 for the produced high-pressure-separator GOR. Even though the nitrogen-breakthrough time was not matched, the late-life performance was accurately captured. The condensate rate as a function of time from the two simulation runs along with field data are compared in **Fig. 6.** The simulation model that honored rock and fluid data with the correct compositional gradient matched the field performance more closely.

Effect of Gas/Oil Relative Permeability on Reserves and Recovery—Ubit Field. The Ubit field is one of the largest producing light-oil reservoirs in Nigeria, with more than 2 billion STB oil in place. The reservoir has an areal extent of 15,000 acres, with an oil column of 160 ft and a dip of 2.5°. The reservoir energy was provided by natural gas-cap expansion and solution-gas drive with little aquifer support. Gravity drainage was recognized as the main recovery mechanism because of adequate gas-/oil-density contrast, excellent vertical and horizontal permeability (1,000 and 3,000 md, respectively), a large oil column, and fieldwide pressure communication. In the gravity-drainage process, oil-bypassing and -trapping events are minimized because of the stable gas front displacing the oil. The oil maintains hydraulic continuity and drains to very low residual-oil saturation because of positive spreading coefficient.

The gravity-drainage process was characterized in the laboratory with several types of drainage gas/oil relative permeability and capillary pressure tests at reservoir conditions using live oil (Edwards et al. 1998). The relevant tests included gravity-drainage experiments with X-ray for in-situ saturation monitoring on 1- to 5-ft-long vertically oriented whole cores to determine oil relative permeability, k_{ro}, residual-oil saturation, and endpoint gas permeability; steady-state-drainage gas/oil relative permeability tests to obtain gas and oil relative permeabilities; primary-drainage gas/oil

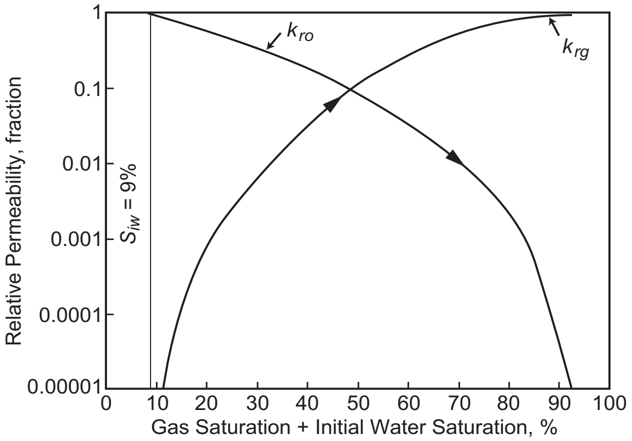


Fig. 7—Typical gas/oil relative permeabilities for high-quality geologic facies.

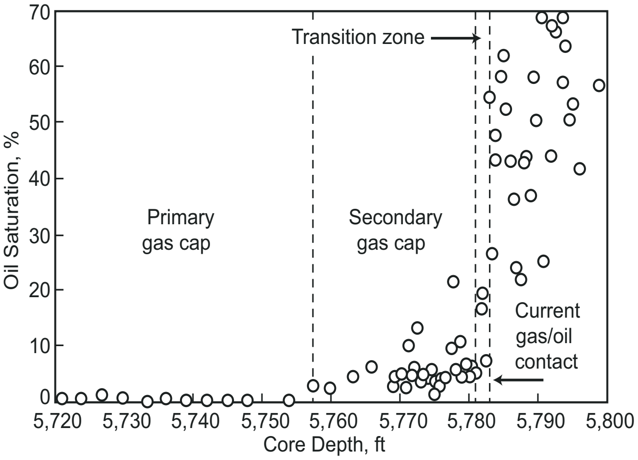


Fig. 8—Residual-oil saturations in gas cap, secondary gas cap, and oil zone.

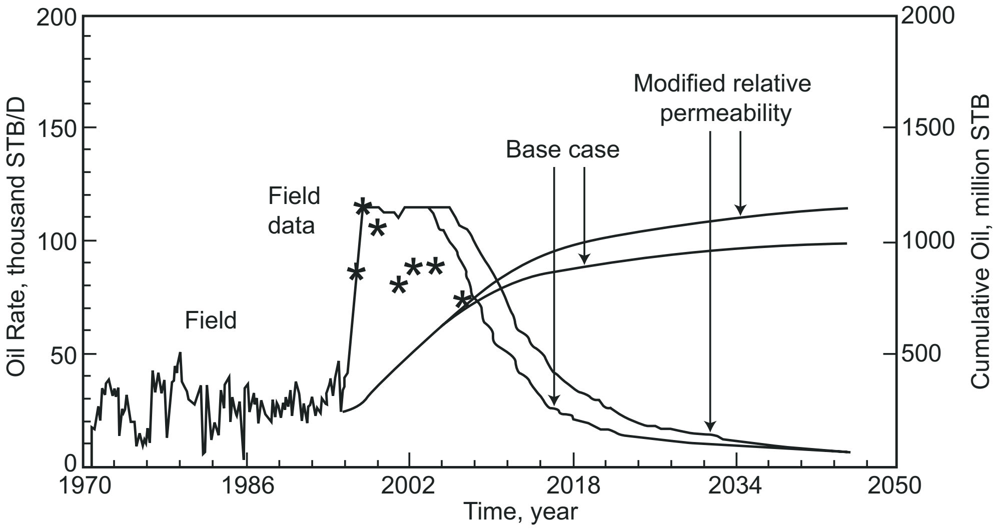


Fig. 9—Comparison of oil rate and cumulative oil production for cases with conventional relative permeability and gravity-drainage relative permeability.

relative permeability with the centrifuge technique under confining stress to determine k_{ro} at very low oil saturation; and primary-drainage gas/oil capillary pressure on core plugs by use of the centrifuge technique under confining stress to determine minimum residual-oil saturation. A typical gas/oil relative permeability curve for high-quality facies is shown in **Fig. 7.** Residual-oil saturation for major reservoir facies was low, in the range of 6.5% ±5%. Laboratory residual-oil-saturation measurements were validated with a low-invasion coring program using water-based mud in a zone in which the gas cap expanded approximately 25 ft over a 25-year production period. The residual-oil saturation measured on the cored interval, in the secondary gas cap, was approximately 6%, as shown in **Fig. 8.**

The simulation model used black-oil PVT properties and comprised 18 layers, mostly in the oil zone to capture oil displacement by advancing gas cap. The history-match parameters were primarily the pressure, GOR, and water/oil ratio (WOR). The residual-oil saturation and the gas/oil relative permeability for the gravity-drainage process played a significant role in the history match. Initially, only centrifuge relative permeability measurements with stock-tank oil without correction for capillary end effect were used in the simulation. Even when the correct residual-oil saturation of 6% was used, the simulation model calculated remaining oil saturations as high as 20% in the secondary gas cap after 25 years of production. This error was caused by adverse oil relative permeability near residual-oil saturation. After using the correct gas/oil relative permeability curves, residual-oil saturation in the range of 4.0 to 6.5% was predicted in the reservoir-simulation model in the actual production time span. The difference in the shape of the oil relative permeability curve for the gravity-drainage process had a major effect on the reserves and the plateau production, adding 150 million STB of incremental oil recovery. **Fig. 9** compares the base case with a case that used correct gas/oil relative permeability, resulting in a 3-year increase in plateau production and a corresponding increase in cumulative recovery. Actual performance was not as good as the prediction because of changes to the development plan, mainly a reduction in the number of new wells because of capital-spending constraints.

Effect of Relative Permeability, Water Vaporization, and Measurement Scale on Performance—Arun Field. Arun field is a gas/condensate field off the northern coast of Aceh Province, North Sumatra, Indonesia. The initial reservoir pressure and temperature were 7,100 psia and 352°F, respectively, at a datum of 10,050 ft subsea. The gas-bearing formation had an areal extent of 23,000 acres and formation thickness of 1,000 ft (Pathak et al. 2004). The extensive core analysis identified vuggy (reef facies), moldic (lagoonal facies), and intercrystalline porosities. The reservoir fluid was a retrograde-gas condensate containing 15 mol% CO_2 with a liquid yield of 65 separator bbl/MMscf at 1,250 psia and 68°F. The dewpoint pressure was 4,400 psi at 352°F. The connate-water saturation in the gas zone was in the range of 5 to 20% for reef facies and higher for lagoonal facies. Pressure maintenance by peripheral gas injection (mainly methane and CO_2) was implemented to delay condensate dropout. Although the gas injection helped to displace rich gas toward the central clusters of producers, it also resulted in CO_2-rich gas production in later stages of the reservoir life. The focus of the reservoir-rock and -fluid characterization and modeling was an accurate account of the reduction in gas deliverability caused by condensate dropout, water vaporization, and increased CO_2 content of produced gas.

Core Characterization—Measurement Scale. The effect of measurement scale on both routine and special core analysis was captured though measurements on whole cores and core plugs. Permeability was measured on whole cores and core plugs taken at high- and low-permeability locations identified by minipermeametry. **Fig. 10** shows significant

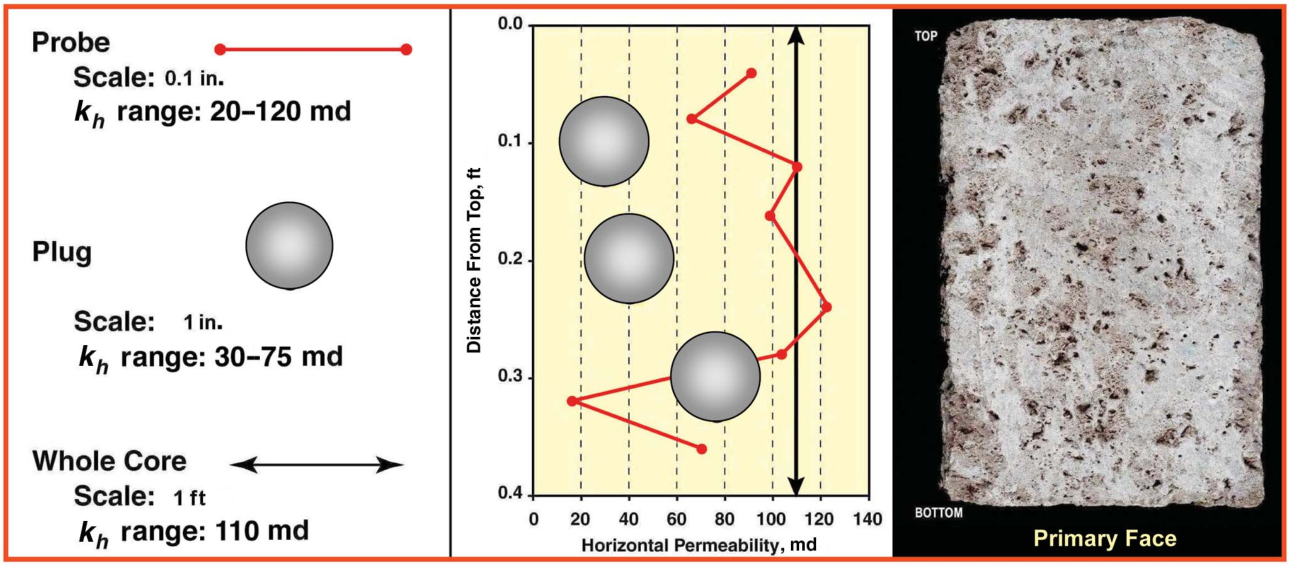


Fig. 10—Comparison of permeabililty measurements on whole core, plugs, and minipermeametry (probe): reef facies of Arun field.

differences in absolute permeabilities between the whole core and core plugs as a result of the presence of small-scale heterogeneities (Honarpour et al. 2003). Whole-core data provided the most representative values because they correctly averaged the high- and low-permeability zones into the overall volume, whereas the plug measurements were significantly lower because they did not capture the 3D connectivity of the pore system. Ignoring this scale effect can lead to unnecessary adjustment of relative permeability or other data. Capillary pressure and electrical-property measurements on whole cores showed the characteristics of a dual vugular/matrix-pore system for reef facies (Honarpour et al. 2003). The whole-core pore-volume compressibility measured from reef facies showed 20 to 100 microsips, compared with 5 to 16 microsips measured on core plugs.

Water Vaporization. Water vaporization was recognized as the main source of water production in the field. Increasing water vaporization during depletion was characterized by a nine-component equation-of-state (EOS) model and validated with laboratory measurements ranging from 4 mol% at the initial reservoir pressure to 16 mol% at 1,000 psia. **Fig. 11** shows good agreement between field water production and predicted values by use of accurate fluid characterization.

Gas/Condensate Relative Permeability. Well-deliverability and liquid-recovery predictions in the Arun field over the life of the reservoir were key parameters in planning the number of wells, completion strategy, and the surface-facility sizing. Well-deliverability and liquid-recovery calculations required accurate knowledge of gas/condensate relative permeability data. Measurements were conducted on 1-ft-long core samples at representative initial water saturation. The critical condensate saturation was determined by a depletion test (Afidick et al. 1994; Nagarajan et al. 2004). At the critical condensate saturation, the gas relative permeability dropped by 80% for the vugular reef facies and by 50% for the lagoonal facies. The drop in productivity index caused by liquid accumulation in the near-wellbore region, predicted by a radial single-well compositional model using measured relative permeability data, showed an excellent match with field data.

Conclusions

Reliable rock and fluid characterization require a set of well-defined objectives, a clear road map, and a multidisciplinary approach. A systematic and integrated procedure, involving well-designed coring and sampling procedures, best-practice laboratory tests, rigorous QC, data integration, and validation, should be followed to reduce measurement uncertainty and increase data reliability for accurate reservoir-performance prediction. Rock and fluid data are important company assets; therefore, they require

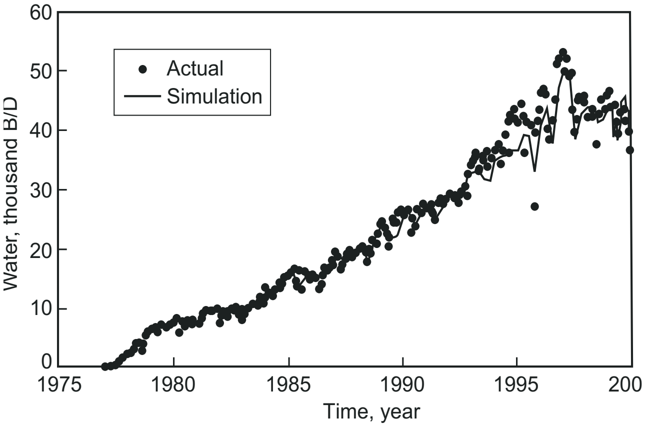


Fig. 11—Water-production history match.

a well-designed data-management system for future access and application.

Rock and fluid characterization strongly affect in-place volumes, recovery factors, injectivity/productivity, and deliverability. Therefore, accurate rock and fluid characterization are key for minimizing technical risks and maximizing the asset value.

Acronyms

CGR = condensate/gas ratio
EOS = equation-of-state
FVF = formation volume factor
IFT = interfacial tension
OBM = oil-based mud
OHCIP = original hydrocarbon in place
PU = porosity unit
PVT = pressure/volume/temperature
QA = quality assurance
QC = quality control
RF = recovery factor
SU = saturation unit
WAG = water-alternating-gas

Nomenclature

A = cross-sectional area
B_o = oil formation volume factor
E_A = areal-sweep efficiency
E_V = vertical-sweep efficiency
F_w = fractional flow
h = formation thickness
k = permeability
k_{gswi} = gas permeability at initial water saturation
k_{rg} = gas relative permeability
k_{ro} = oil relative permeability
k_{rw} = water relative permeability
$k_r(S)$ = relative permeability as a function of saturation
P_c = capillary pressure
Q = flow rate
r_e = drainage radius
r_w = well radius
S_{cc} = critical condensate saturation
S_{gc} = critical gas saturation
S_{gt} = trapped gas saturation
S_{orw} = residual oil saturation in displaced zone
S_{wi} = initial water saturation
Z = gas deviation factor
β_{hc} = hydrocarbon formation volume factor
β_o = oil formation volume factor
β_ω = water formation volume factor
ϕ = porosity
ρ = density
μ = viscosity
μ_o = oil viscosity
μ_w = water viscosity
ΔP = pressure drop

Acknowledgments

We gratefully acknowledge the support and encouragement of ExxonMobil Upstream Research Co., ExxonMobil Exploration Co., ExxonMobil Oil Indonesia, Mobil Producing Nigeria, and ExxonMobil Production Co.

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