Investigating Clastic Reservoir Sedimentology

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Geoscientists use a robust arsenal of tools to expand their knowledge of reservoir characteristics and to model reservoir behavior. Borehole imaging offers geologists the high-resolution data needed to investigate detailed aspects of reservoir sedimentology. Optimal exploitation of oil and gas assets is more likely when geologists understand the geologic processes that dictated the character of sedimentary reservoirs.

For hundreds of years, geologists have sought to understand the origin of sedimentary rocks and the depositional processes that formed them, and to develop clear methods to describe and classify them. This discipline, called sedimentology, has a clearly established economic value. The petroleum geologist must study sedimentological factors across a range of spatial scales, from grain size to reservoir continuity. While individual sediment grains are small and seemingly insignificant, sediment-transport distances can be huge, and the rock formations created through sedimentation vary tremendously in size and properties. These factors are used to create reservoir models from which reservoir experts predict and assess production behavior in response to field-development and enhanced-recovery steps.

Within each of the many recognized depositional environments there are subdivisions—subenvironments and depositional facies.[1] Some facies are recognizable because sedimentary features observed on surface outcrops, fullbore cores and borehole images indicate a given environment. However, many facies are less distinct. The depositional setting influences the thickness, distribution and internal architecture of siliciclastic or carbonate formations during deposition, and strongly affects the eventual reservoir characteristics.

This article highlights borehole imaging and interpretation techniques that help define clastic reservoir sedimentology. Case studies demonstrate the significance of borehole images in developing depositional analogs and reservoir models, and for making field-development decisions with more certainty.

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1. Facies reflect the overall characteristics and origin of a rock unit that differentiate the unit from others around it. Mineralogy and sedimentary source, fossil content, sedimentary structures and texture distinguish one facies from another.
2. Alsos T, Eide A, Astratti D, Pickering S, Benabentos M, Dutta N, Mallick S, Schultz G, den Boer L, Livingstone M, Nickel M, Sønneland L, Schlaf J, Schoepfer P, Sigismondi M, Soldo JC and Strønen LK: "Seismic Applications Throughout the Life of the Reservoir," *Oilfield Review* 14, no. 2 (Summer 2002): 48–65.

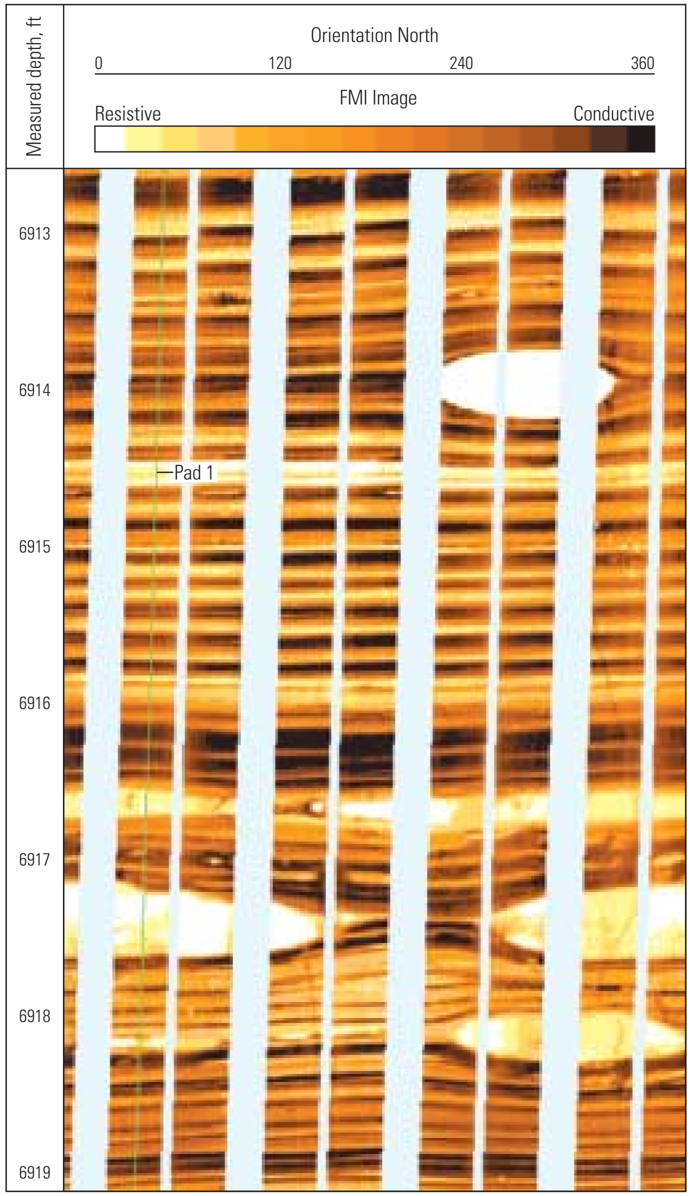
   Frorup M, Jenkins C, McGuckin J, Meredith J and Suellentrop G: "Capturing and Preserving Sandbody Connectivity for Reservoir Simulation: Insights from Studies in the Dación Field, Eastern Venezuela," paper SPE 77593, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, September 29–October 2, 2002.

Significance in Sedimentation

Understanding the sedimentary history of a reservoir offers many advantages to specialists involved in every stage of the life of a field, from exploration to field abandonment. A basin's architecture and sediment sourcing influence exploration strategy. Once field development begins, reservoir sedimentology can be described at several scales from a variety of sources. Surface seismic images, wellbore data—including borehole seismic data and borehole images—and core data are crucial for succesful reservoir exploitation (see "Superior Seismic Data from the Borehole," *page 2*). Sedimentological information from wellbore data can be especially helpful when defining broader reservoir stratigraphy for planning offset wells and trajectories for kickoff, horizontal and multilateral wells. Interpretations of borehole images obtained from devices such as the FMI Fullbore Formation MicroImager and OBMI Oil-Base MicroImager tools commonly provide detailed descriptions of sedimentary features, especially bedding. This helps geologists predict the architecture and local distribution of productive reservoir rock.

Geologists and engineers studying mature fields have consistently seen that initial field models describing connectivity of the reservoir—both lateral and vertical—tend to be simplistic. Underestimating reservoir complexity may have significant financial implications, because initial drainage strategies might not produce the predicted recoverable hydrocarbon reserves. Conversely, overestimating complexity may lead to drilling too many wells in well-connected reservoirs, wasting valuable resources. Reservoir-modeling and time-lapse (4D) seismic imaging capabilities have significantly reduced the uncertainty in reservoir development, but those models are only as good as the data on which they are built.[2]

High-resolution measurements are essential when assessing small-scale reservoir heterogeneity.[3] Although standard logs may not be sufficient to identify these complexities, borehole images can provide details on internal bedding and bounding surfaces that help characterize the strata exposed in the borehole (right). Engineers formulate completion and stimulation strategies based on reservoir heterogeneity and bedding, factors directly related to sedimentary processes.[4] Quantitative analysis of thin beds using borehole image data can potentially identify productive-pay sections previously bypassed because they appeared too shaly or too wet. In a sand-count analysis example from western India, thin, silty sand beds are clearly resolved on processed FMI images. Using cutoffs on the sharpened synthetic resistivity (SRES) output from calibrated image data, a comparison of high, medium and low net-pay scenarios can be made in highly laminated sequences (next page, top).[5]



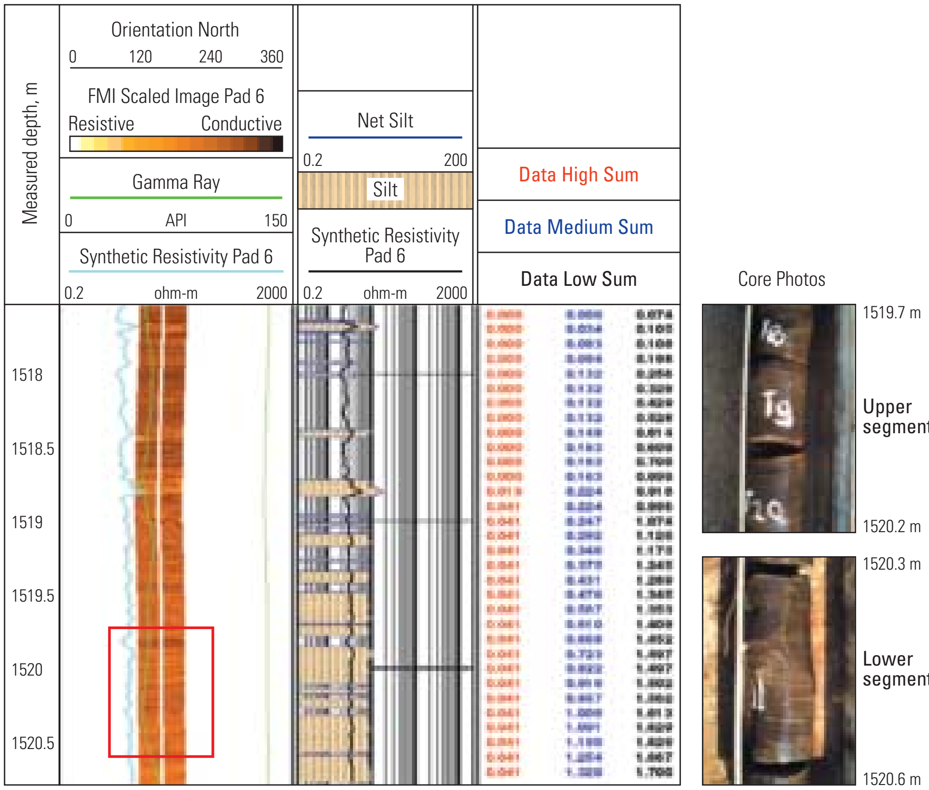
^ Identifying sedimentary features. High-resolution borehole images, from tools like the FMI device, allow geologists to locate and identify features at or near the borehole wall that are rarely observed using standard well logs. Certain diagnostic features can help geologists reconstruct the depositional environment in which sedimentation occurred. This image shows resistive nodules—white on the image—interpreted to be concretions that might indicate periodic flooding. The bedding around the concretions has undergone postdepositional compaction as indicated by the compression of the bedding above and below the concretions.

Tools of the Trade

Many tools are available to geoscientists to describe and model reservoir geology. Prominent among them are borehole imaging tools, which have experienced several technological breakthroughs since the 1950s; these tools now deliver high-resolution data across a broad range of challenging operating environments.[6] Borehole imaging technology was extended to logging-while-drilling (LWD) operations in 1994, allowing operators to optimize placement of wells in the reservoir (see "Wellbore Imaging Goes Live," *page 24*).

New tools are not restricted to downhole acquisition; software tools also play a major role in the successful application of borehole imaging to reservoir sedimentology. The GeoFrame borehole geology software includes an integrated suite of tools that enables geoscientists and petrophysicists to thoroughly analyze borehole data. GeoFrame software provides experts with an integrated set of applications to process and analyze formation-dip data, interpret sedimentological features such as paleocurrent bedding,

3. Sovich JP and Newberry B: "Quantitative Applications of Borehole Imaging," *Transactions of the SPWLA 34th Annual Logging Symposium*, Calgary, Alberta, Canada, June 13–16, 1993, paper FFF.
   Anderson B, Bryant I, Lüling M, Spies B and Helbig K: "Oilfield Anisotropy: Its Origins and Electrical Characteristics," *Oilfield Review* 6, no. 4 (October 1994): 48–56.
   Delhomme JP: "A Quantitative Characterization of Formation Heterogeneities Based on Borehole Image Analysis," *Transactions of the SPWLA 33rd Annual Logging Symposium*, Oklahoma City, Oklahoma, USA, June 14–17, 1992, paper T.
4. Behrmann L, Brooks JE, Farrant S, Fayard A, Venkitaraman A, Brown A, Michel C, Noordermeer A, Smith P and Underdown D: "Perforating Practices That Optimize Productivity," *Oilfield Review* 12, no. 1 (Spring 2000): 52–74.
   Cosad C: "Choosing a Perforation Strategy," *Oilfield Review* 4, no. 4 (October 1992): 54–69.
5. Cheung P, Hayman A, Laronga R, Cook G, Flournoy G, Goetz P, Marshall M, Hansen S, Lamb M, Li B, Larsen M, Orgren M and Redden J: "A Clear Picture in Oil-Base Muds," *Oilfield Review* 13, no. 4 (Winter 2001/2002): 2–27.
   Shray F and Borbas T: "Evaluation of Laminated Formations Using Nuclear Magnetic Resonance and Resistivity Anisotropy Measurements," paper SPE 72370, presented at the SPE Eastern Regional Meeting, Canton, Ohio, USA, October 17–19, 2001.
   Ray S and Singh C: "Quantitative Evaluation of Net Pay Thickness from Clastics of Western India Using High Resolution Response from Electrical Images," presented at the Fifth SPWLA Well Logging Symposium, Makuhari, Chiba, Japan, September 29–30, 1999.
   Boyd A, Darling H, Tabanou J, Davis B, Lyon B, Flaum C, Klein J, Sneider RM, Sibbit A and Singer J: "The Lowdown on Low-Resistivity Pay," *Oilfield Review* 7, no. 3 (Autumn 1995): 4–18.
6. Cheung et al, reference 5.
   For more on the applications of borehole imaging tools: Luthi S: *Geological Well Logs: Their Use in Reservoir Modeling*. Berlin, Germany: Springer-Verlag, 2001.

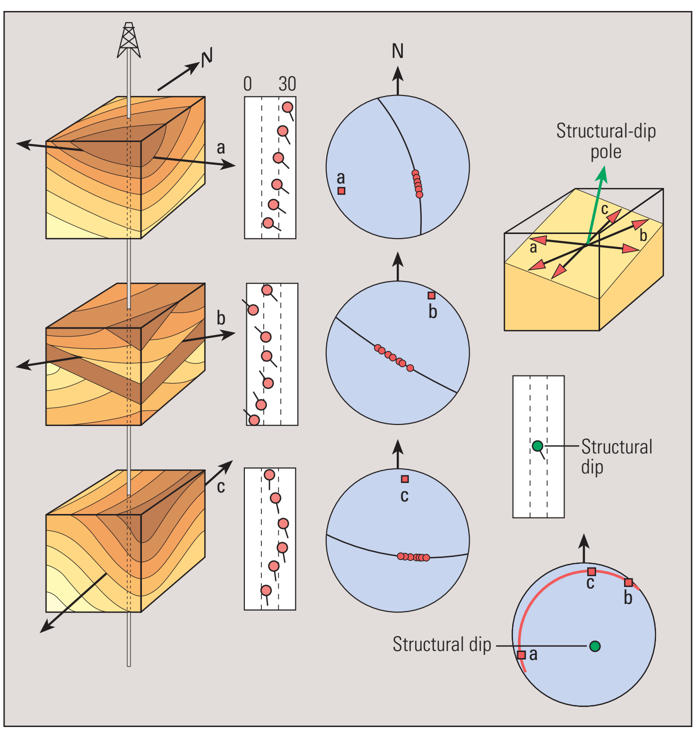


^ Sand-count analysis for thin-bed evaluation. A silty sand interval in western India was processed for net-pay percentage using the high-resolution sand-count analysis. Standard logging measurements lack the resolution to properly characterize thinly laminated sequences. With various resistivity cutoffs, SRES outputs from FMI data (Tracks 1 and 2) can be used to define high, medium and low net-pay scenarios. In this case, using a medium-resistivity cutoff of 3.0 ohm-m, 46% of the 3.3-m [10.8-ft] gross interval was determined to be pay, allowing more precise reserves predictions. The red box indicates the interval covered by the core photographs (*right*).

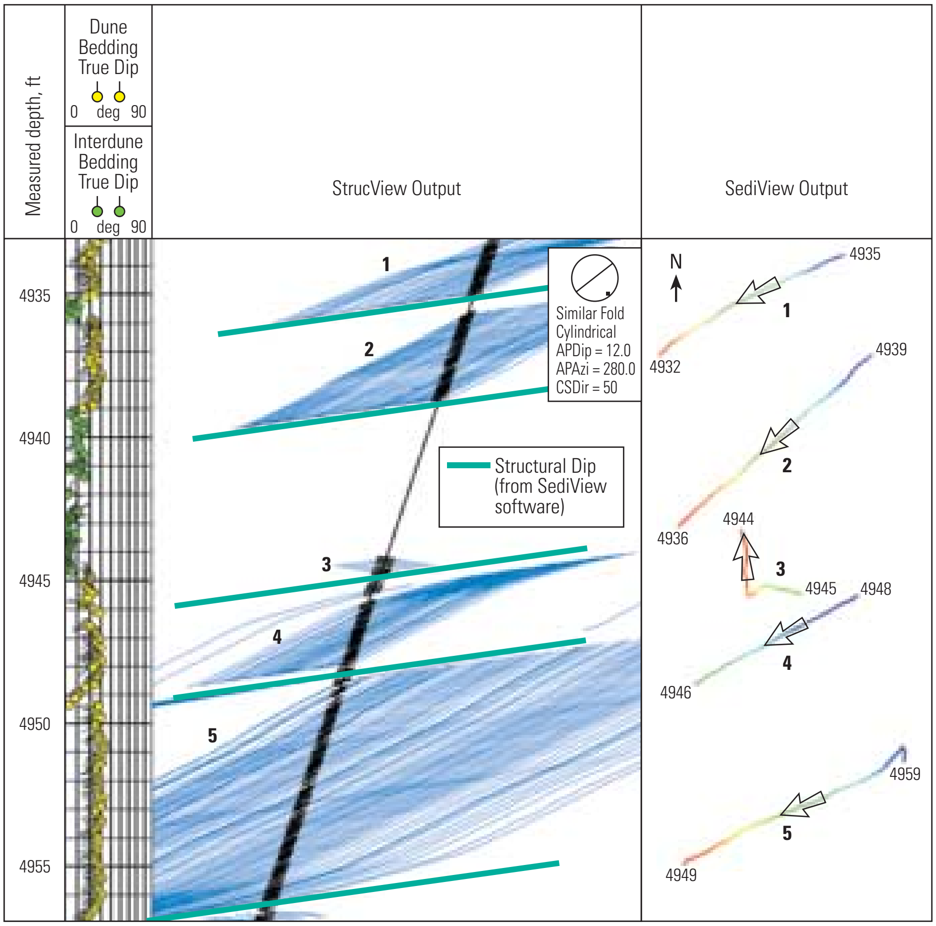
assess rock textures and lithologies to differentiate facies, interpret structural features like faults, and characterize natural fractures to estimate their productive potential.

After field data are processed to create borehole images, the BorView borehole imaging application allows geoscientists to examine image data in various formats and scales. Detailed and interactive dip-plane selection produces extremely accurate formation-dip information that can be used in other applications to further refine the analysis. For example, the SediView application within GeoFrame system software helps geologists determine and correct for structural dip. Commonly, shales produce the best representation of structural dip in a wellbore because they typically are deposited in low-energy environments and exhibit flat bedding, or zero dip. Subsequent tilting of the strata produces structural dip and alters the true orientation and dip magnitude of stratigraphic bedding.

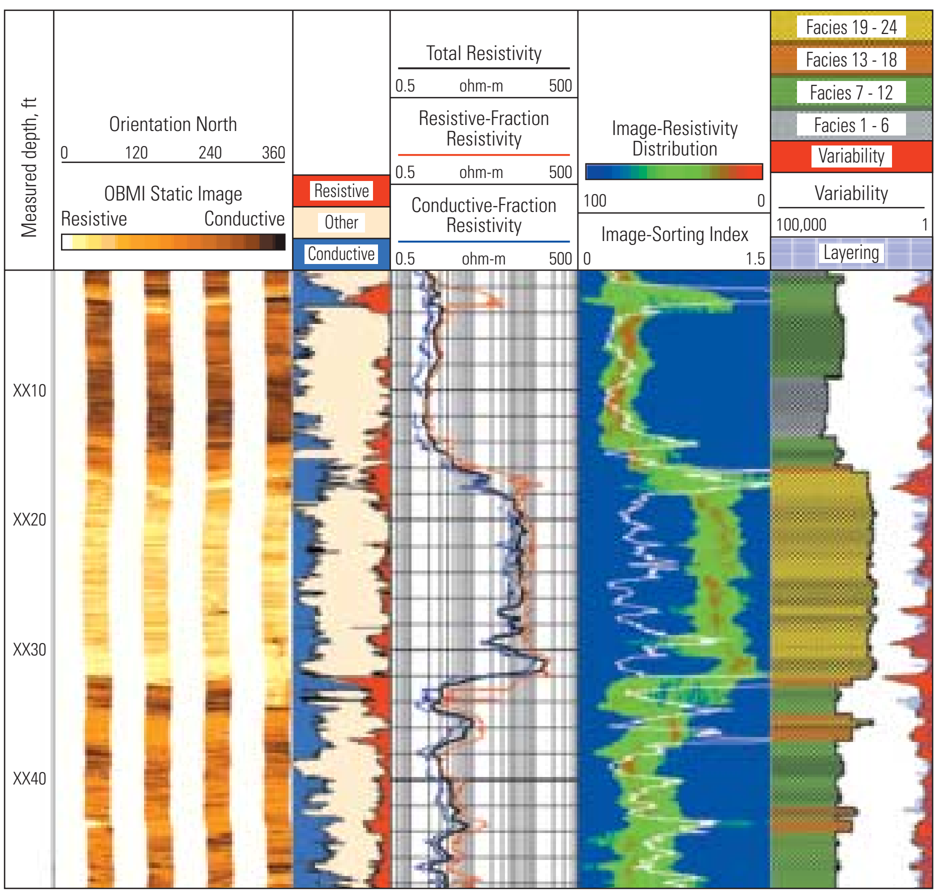
SediView software uses the principle of the local curvature axis (LCA) technique and great circle analysis to determine an accurate and representative structural dip. That dip is then removed to determine what the internal bedding or crossbedding was before being structurally altered (below).



< Principle of the local curvature axis (LCA) method. Sedimentary structures and their axes are depicted along with their corresponding dipmeter response (*left*). All are affected by the same structural-dip component. Bedding surfaces in each structure are plotted on a Schmidt net and poles of each surface are determined (*middle*). When these poles fit a great circle, a local curvature axis is computed for each sedimentary structure—*a*, *b* and *c*. The structural dip can then be determined by plotting the LCAs on a Schmidt plot (*bottom right*); if the LCAs follow a great circle, this great circle corresponds to the structural dip (*middle right*). The upper right diagram depicts the structural dip, and shows the three sedimentary axes and the pole of the structural-dip component (green arrow).



< Sedimentological representation using the StrucView tool. StrucView software (Track 2) shows the internal bedding (blue) within an ancient sand-dune complex. Dip data were acquired using the FMI tool (Track 1). SediView software was used to determine and remove the structural dip (green), and compute vector plots for each dune (Track 3). The vector plots are color-coded according to depth within each of the five dune intervals. The analysis of these eolian, or wind-blown, sands clearly shows that the dominant prevailing wind direction was from the northeast.

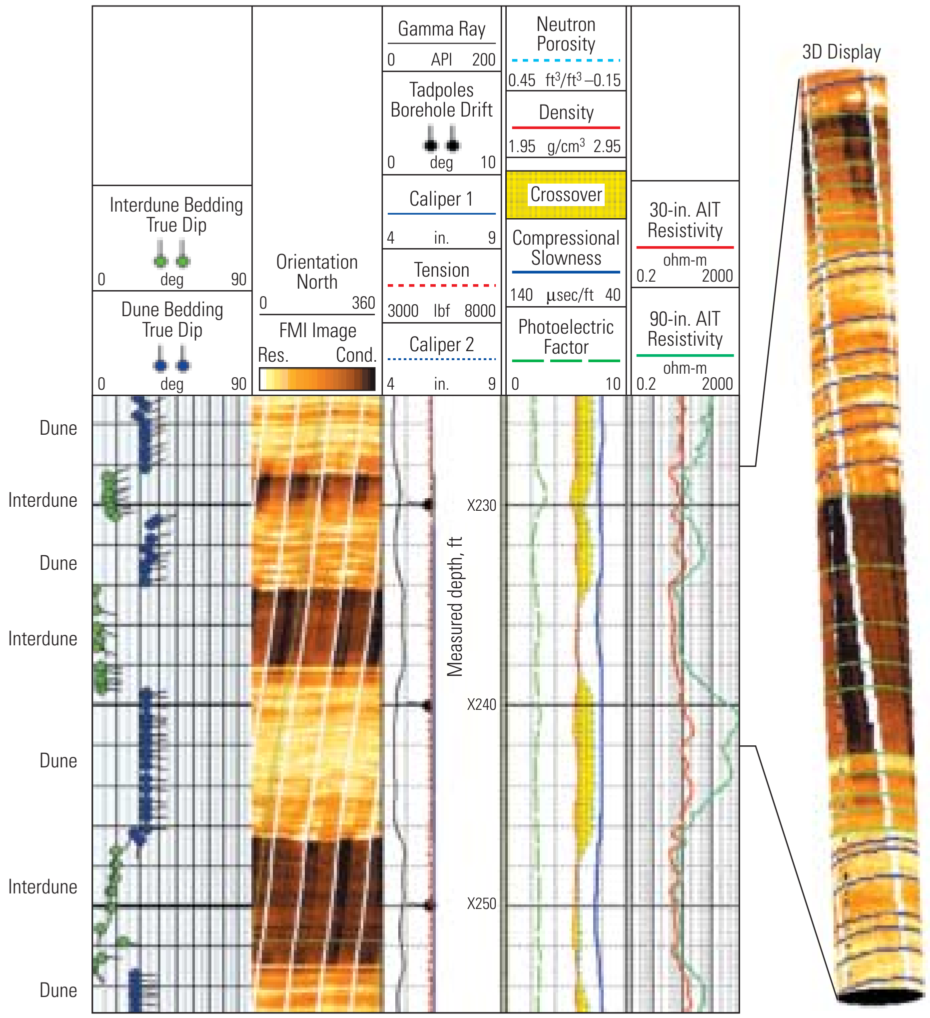


< Facies differentiation by evaluating grain-size sorting. SandTex software calculates an image-resistivity spectrum every 1 in. [2.5 cm], in this case, from OBMI data (Track 1). An image-sorting index is calculated from the percentile distribution of the spectrum. Locally, any points more or less resistive than a well-sorted sand are counted as part of the resistive or conductive fractions, respectively (Track 2). Although within short intervals, silt within sand would show up as part of the conductive fraction, its resistivity would normally be quite different from that of shale. For this reason, the resistivities of the fractions are calculated (Track 3). Track 4 displays the image-resistivity distribution and a calculated sorting index—a low value meaning more well-sorted. Openhole logs then are combined with the high-resolution image data to generate a facies description that captures much of the textural content of the images (Track 5). Local image variability and layering are also computed and shown on Track 5.

Some environments lack shales, making the structural dip of the reservoir difficult to determine. For example, in fluvial and eolian environments, the SediView method often resolves structural dip, enabling interpreters to remove the structural-dip component for an improved representation using StrucView GeoFrame structural cross section software. The strike of a channel can be determined from the paleocurrent direction, or the orientation of a dune can be revealed from the prevailing wind direction (previous page, top). Vector plots of sediment-transport indicators from SediView software supply geologists with prevailing water and wind directions during the time of deposition, which greatly influence the shape, continuity and trend of sand bodies (right). Additionally, sand-body characteristics directly impact reservoir size, anisotropy and compartmentalization.

When analyzing reservoir sedimentology, geologists must differentiate individual stratigraphic layers within the sedimentary sequence. Boundaries between sets or packages of internal bedding can represent abrupt changes, for example, changes in depositional energy, sediment-transport direction or sediment supply. The GeoFrame Sequence stratigraphic boundaries tool detects boundaries using log-curve shape analysis and helps characterize grain-size trends within each sediment package. Understanding these trends and their vertical successions helps geologists define facies relationships. This, in turn, assists in correlation and mapping, sand-quality assessment and the determination of specific depositional environments.

Another GeoFrame tool, BorTex texture classification software, also works to discriminate facies by classifying textures derived from borehole image data. BorTex software is used to characterize carbonate porosity and distinguish facies.[7] Schlumberger experts recently developed new sand-texture analysis software for use in sand-shale sequences. Taking advantage of high-resolution data from FMI, Formation MicroScanner or OBMI tools as well as standard log data, the SandTex tool computes the image-resistivity distribution across the reservoir-sand intervals. The distribution relates directly to grain size, enabling the SandTex software to characterize grain-size sorting, an important factor in defining reservoir facies (previous page, bottom). The character of a specific facies influences the eventual reservoir architecture on a local scale, while spatial relationships between different facies impact larger-scale issues, such as reservoir continuity and connectivity.



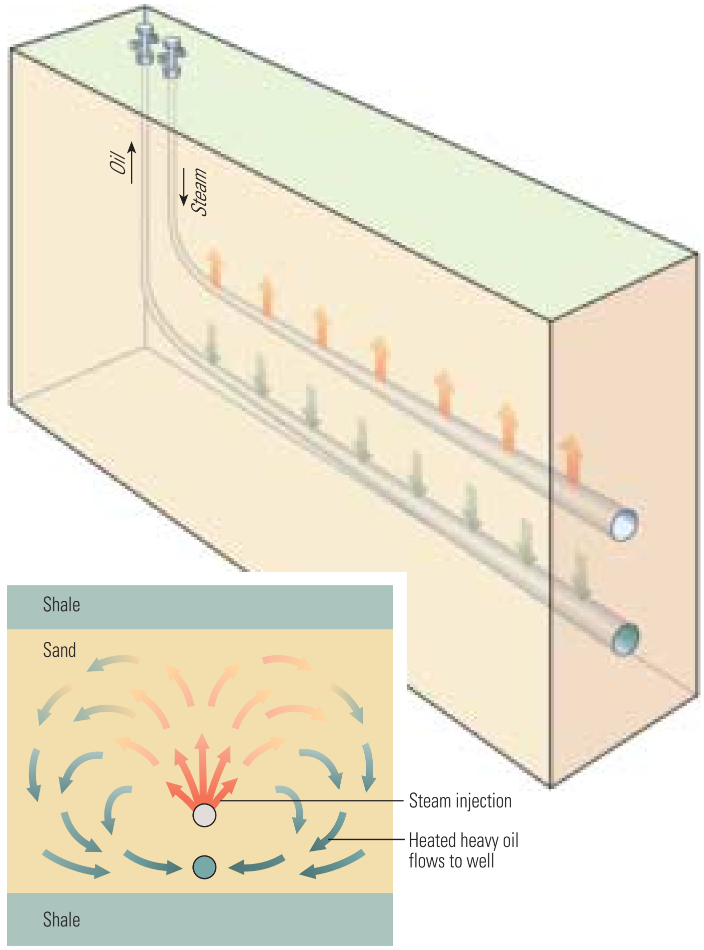
^ Eolian sand dune and interdune facies. A detailed analysis in BorView software helps characterize the different facies associated with eolian sand deposition. The dominant wind direction during deposition is shown by the blue dips and exhibits the consistency commonly found in barchan or transverse dune deposition (Track 1). The lower angle green dips represent the interdune facies. The FMI borehole image in Track 2 clearly shows sharp contacts between the two main facies in this section. Track 3 displays caliper and borehole-orientation data, Track 4 contains porosity and lithology information, and Track 5 shows AIT Array Induction Imager Tool resistivity data. A 3D representation of the wellbore aids visualization (*right*).

Characterizing Facies for Enhanced-Oil Recovery

Reservoir architecture affects well tests and production-decline behavior.[8] Stratigraphic boundaries, such as unconformities, pinchouts and amalgamation surfaces, can drastically reduce hydrocarbon recovery during primary production and enhanced-recovery stages. Impermeable clay-rich or shale layers in and around reservoir facies, and even stratification or crossbedding within a sand body, influence the effectiveness of

7. Akbar M, Vissapragada B, Alghamdi AH, Allen D, Herron M, Carnegie A, Dutta D, Olesen J-R, Chourasiya RD, Logan D, Stief D, Netherwood R, Russell SD and Saxena K: "A Snapshot of Carbonate Reservoir Evaluation," *Oilfield Review* 12, no. 4 (Winter 2000/2001): 20–41.
   Russell SD, Akbar M, Vissapragada B and Walkden GM: "Rock Types and Permeability Prediction from Dipmeter and Image Logs: Shuaiba Reservoir (Aptian), Abu Dhabi," *Bulletin of the American Association of Petroleum Geologists* 86, no. 10 (October 2002): 1709–1732.
8. Deruyck B, Ehlig-Economides C and Joseph J: "Testing Design and Analysis," *Oilfield Review* 4, no. 2 (April 1992): 28–45.

^ Athabasca oil-sands deposit. Alberta's oil sands, also called tar sands, contain more than 400 billion m^3 [2.5 trillion barrels] of bitumen in place, giving Canada the largest reserves of ultraheavy oil and bitumen in the world. The Athabasca deposit holds the vast majority of Canada's bitumen reserves.



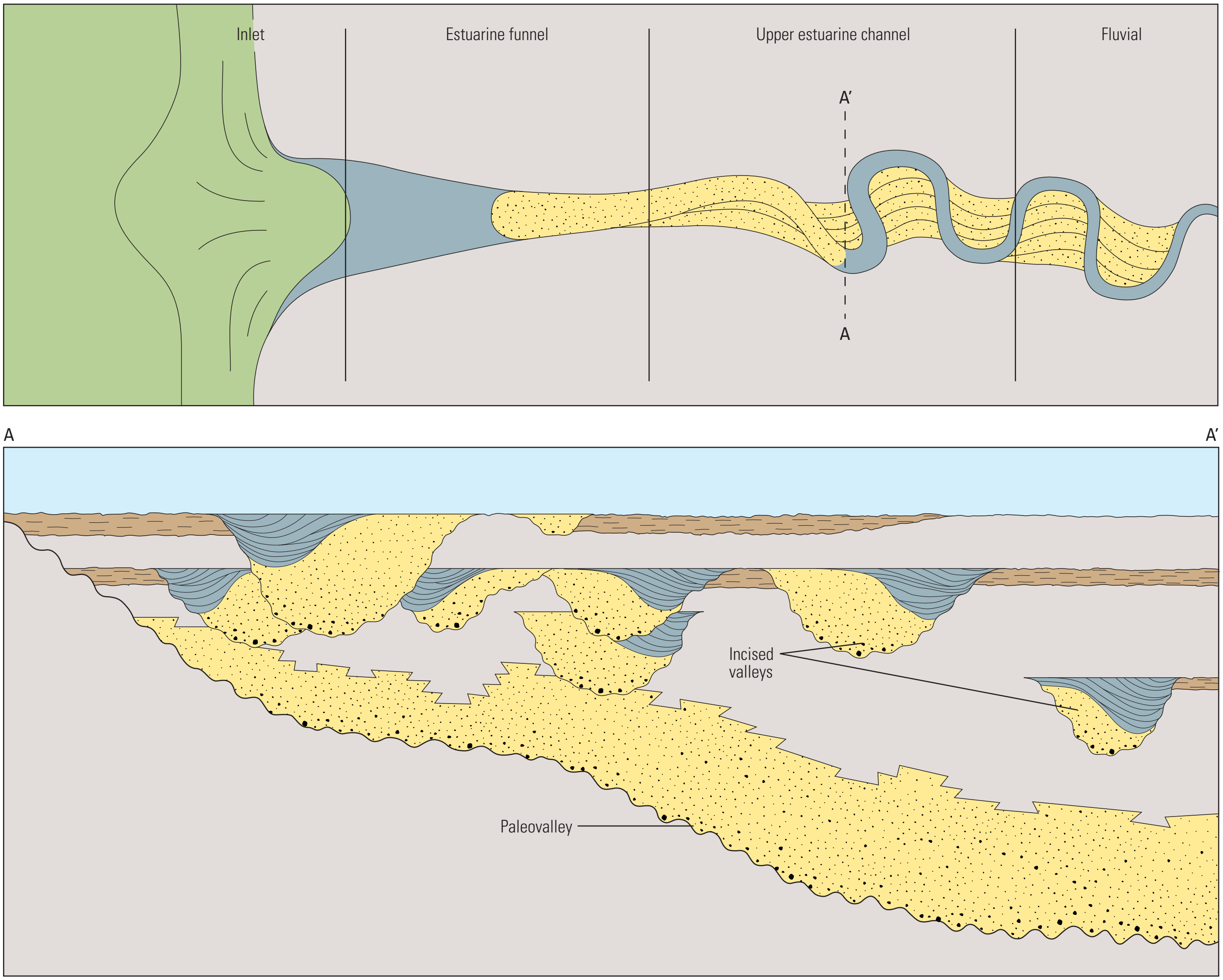
^ In-situ steam assisted gravity drainage (SAGD) design. Steam is injected into the upper steam-injection well. The steam heats the surrounding bitumen-saturated sand and mobilizes the oil. The mobilized hydrocarbons, under the force of gravity, migrate to the production well. When permeability barriers hinder this process, oil-production rates decline, steam/oil ratios increase, and reserves are left behind. The optimal SAGD design is achieved when the volume of steam coverage is unimpeded by impermeable layers of shale or clay, also called lateral accretions, associated with meandering fluvial systems. Careful well placement also minimizes steam requirements.

enhanced-recovery techniques.[9] When developing steam-injection strategies to enhance heavy-oil recovery, high-resolution borehole images are crucial to characterize the reservoir and surrounding facies.

Alberta, Canada, is estimated to have the largest volume of crude bitumen in place, about 400 billion m^3 [2.5 trillion bbl].[10] The bitumen-rich deposits, also called oil sands or tar sands, occur in three areas: Athabasca, Cold Lake and Carbonate Triangle (above left). These deposits, located in northeastern Alberta, comprise the Wabiskaw and McMurray formations. Open-pit mining is the most common technique used to extract the sand and bitumen from shallow depths. However, when these formations are deeper than 75 m [245 ft], in-situ extraction technology called steam-assisted gravity drainage (SAGD) is proving to be a more viable technique.[11]

The SAGD oil-recovery technique requires two horizontal wells: an upper well for injection and a lower well for producing the oil mobilized by the steam. This technique works effectively when steam from the injection well flows unimpeded into the strata above, and when the heated oil flows unimpeded to the production well below (above right). When permeability barriers hinder this process, oil-production rates decline, steam/oil ratios increase and reserves are left behind.

Petro-Canada has been characterizing the McMurray formation to optimize SAGD performance in its oil-sands projects. The McMurray formation, which contains most of the bitumen in the Athabasca sands, was deposited during an early Cretaceous period transgression in a paleovalley 200 km [120 miles] wide.[12] A dynamic transgressive phase interrupted the McMurray sand deposition several times, resulting in a rapidly varying depositional history. The most significant sedimentation for hydrocarbon accumulation occurred in low-stand fluvial-estuarine incised valleys, where a meandering river system deposited reservoir-quality point-bar sands, containing several distinct facies, each with



^ McMurray formation depositional model. A significant portion of the McMurray formation was deposited in an upper estuarine-channel environment within a drowned incised valley (*top*). The internal architecture of the McMurray strata is also shown (*bottom*). The dominance of lateral accretions—shale and clay beds—at the top of most of the channels and the presence of intensive bioturbation suggest that tidal-estuarine influences existed.

different reservoir properties (above).[13] The McMurray sands range from 20 to 58 m [65 to 190 ft] thick, maintain high porosities from 30 to 35% and are extremely permeable, with permeabilities commonly from 3 to 10 darcies.

This sedimentary sequence is complex. Despite the immense quantity of data, including well log and core data from closely spaced wells, it is difficult to correlate zones, even over short distances. To properly assess the bitumen resources and sedimentology of the oil sands, fullbore coring is standard practice. This practice consumes 10 to 15 hours of rig time per well, plus other costs associated with coring and core handling.

9. Corbett PWM, Ringrose PS, Jensen JL and Sorbie KS: "Laminated Clastic Reservoirs: The Interplay of Capillary Pressure and Sedimentary Architecture," paper SPE 24699, presented at the 67th SPE Annual Technical Conference and Exhibition, Washington DC, USA, October 4–7, 1992.

   Weber KJ and van Geuns LC: "Framework for Constructing Clastic Reservoir Simulation Models," *Journal of Petroleum Technology* 42, no. 10 (October 1990): 1248–1297.

   Weber KJ: "How Heterogeneity Affects Oil Recovery," in Lake LW and Carroll HB Jr (eds): *Reservoir Characterization*. Orlando, Florida, USA: Academic Press (1986): 487–544.

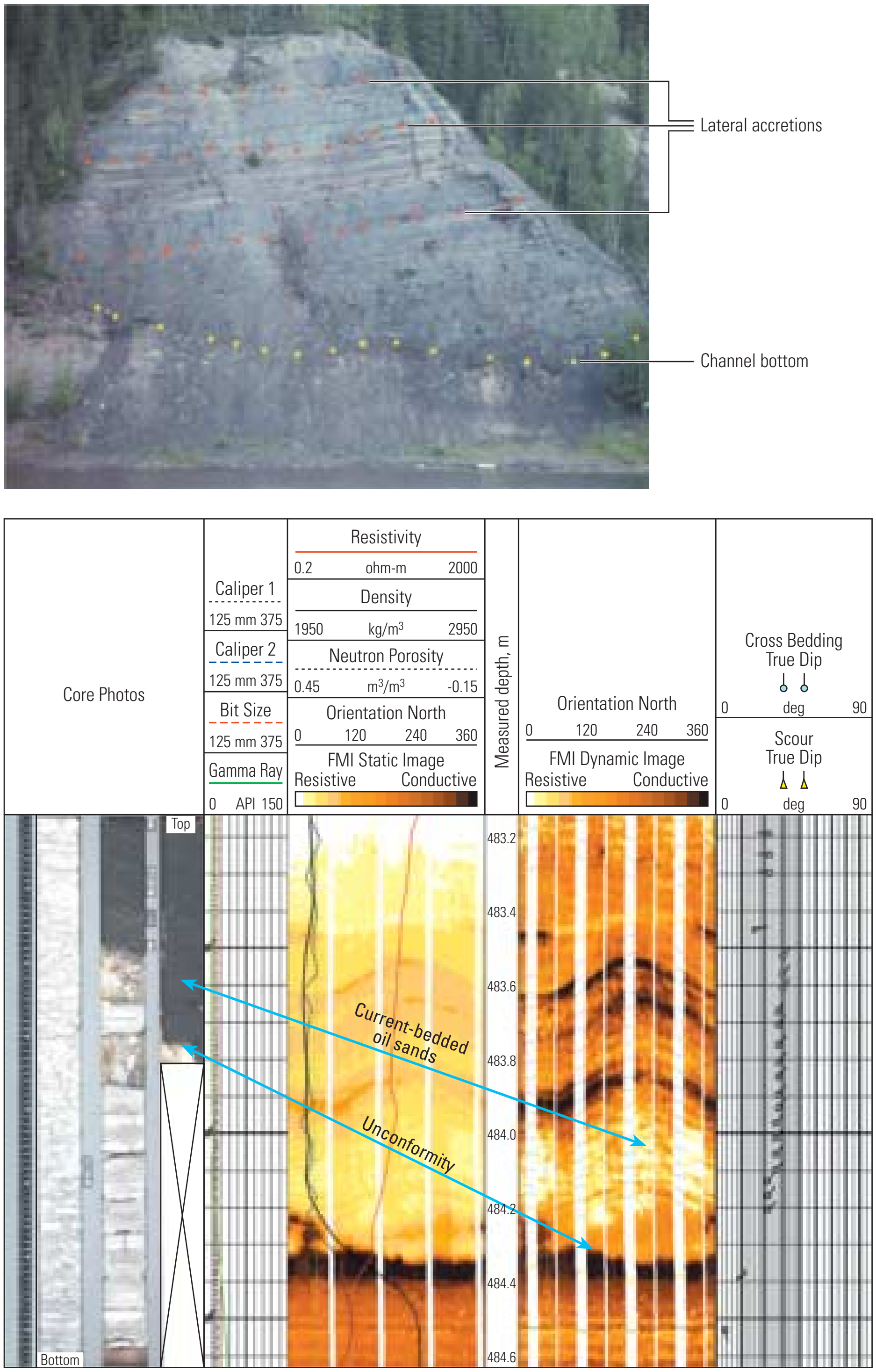
10. Bitumen is a naturally-occurring, inflammable organic matter formed from kerogen in the process of petroleum generation that is soluble in carbon bisulfide. Bitumen includes hydrocarbons such as asphalt and mineral wax. Typically solid or nearly so, and brown or black, bitumen has a distinctive petroliferous odor. Laboratory dissolution with organic solvents allows determination of the amount of bitumen in samples, an assessment of source-rock richness.

    Hein FJ, Langenberg CW, Kidston C, Berhane H, Berezniuk T and Cotterill DK: *A Comprehensive Field Guide for Facies Characterization of the Athabasca Oil Sands, Northeast Alberta*. Alberta Energy and Utilities Board and Alberta Geological Survey (2001): 422.

11. For more on exploiting heavy-oil reservoirs: Curtis C, Kopper R, Decoster E, Guzmán-Garcia A, Huggins C, Knauer L, Minner M, Kupsch N, Linares LM, Rough H and Waite M: "Heavy Oil Reservoirs," *Oilfield Review* 14, no. 3 (Autumn 2002): 30–51.

12. Transgression refers to the migration of a shoreline out of a basin and onto land during the accumulation of sequences through deposition, in which beds are deposited successively landward because sediment supply is limited and cannot fill the available accommodation space. A transgression can result in sediments characteristic of shallow water being overlain by deeper-water sediments.

13. Hu YG and Lee DG: "Incised Valleys Versus Channels: Implications for McMurray Formation Bitumen Mapping and Exploration," presented at the Annual Meeting of the Canadian Society of Petroleum Geologists, Calgary, Alberta, Canada, June 3–7, 2002.



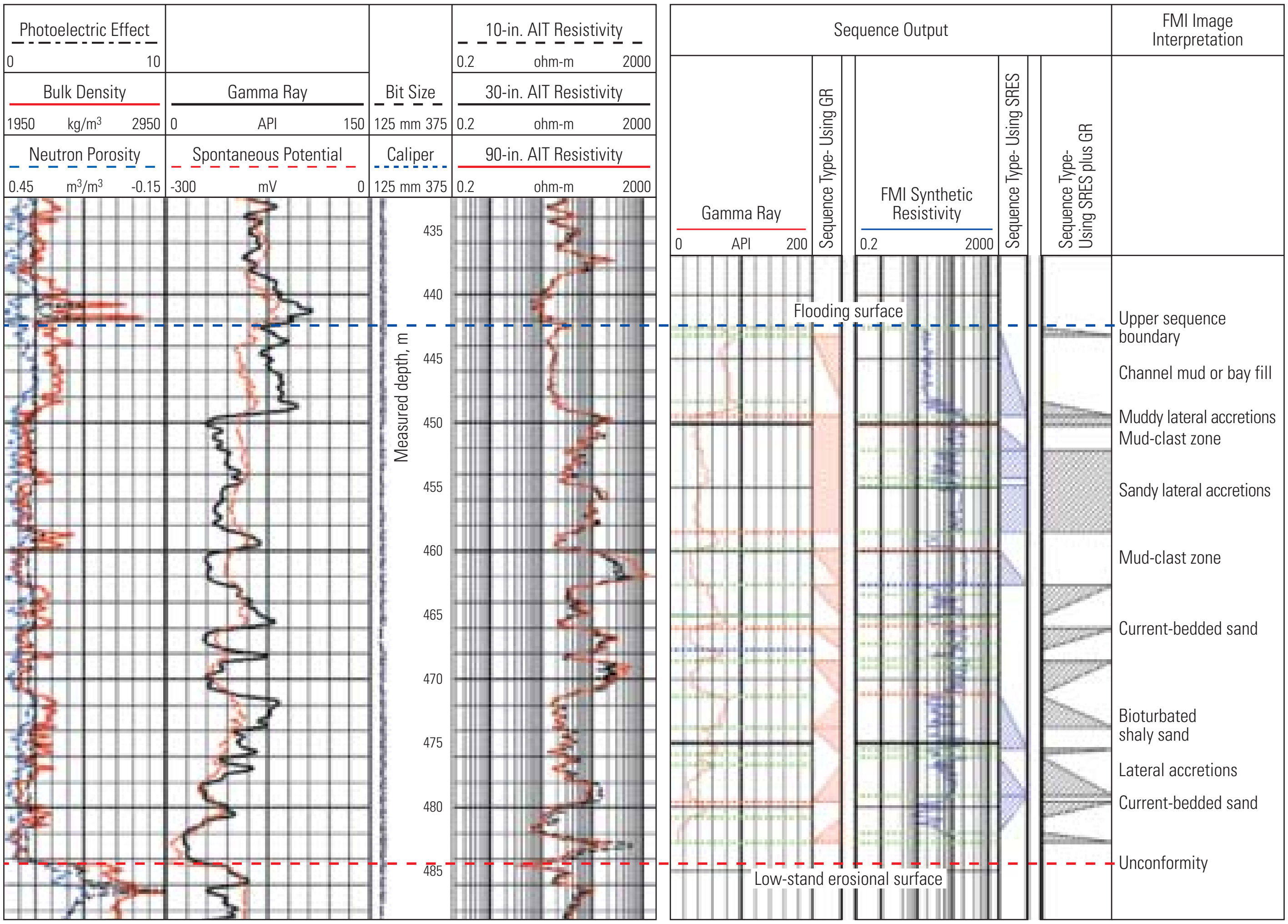
^ A McMurray formation outcrop near the town of Fort McMurray, Alberta, Canada. The outcrop, about 50 m [165 ft] in height, shows at least five fining-upward point-bar sequences (*top*). The base of this channel is indicated by yellow dots. Each succession has massive cross-stratified, bitumen-saturated sandstone in the lower part, which is darker on the outcrop, and inclined discontinuous stratifications, which are lighter on the outcrop. These stratifications are interpreted as lateral accretions (red dots). Core photographs and an FMI image 1.4 m [4.6 ft] in height shows the unconformable contact between the McMurray oil sand above and the Paleozoic carbonate rocks below (*bottom*). This unconformity cannot be observed in the outcrop shown because it is slightly below the water surface at the bottom of photograph.

Borehole images from the FMI tool identify and determine the orientation of stratigraphic boundaries within the McMurray oil-sand deposit (left).[14] The stacked channel sands of the McMurray Formation are bounded on the bottom by an erosional surface, or unconformity, on the Paleozoic carbonate rocks. It is bounded on the top by a transgressive flooding surface upon which the Wabiskaw marine sediments were deposited.

The interpretation and integration of FMI data with other log-derived information, along with fullbore core data from vertical wells and rock outcrops, are providing insights into critical sedimentological factors that directly affect SAGD effectiveness. This detailed comparison between outcrop, cores and FMI images allows Petro-Canada and Schlumberger geologists to identify different facies within the McMurray formation and to infer paleocurrent directions. Using the FMI tool potentially reduces the number of cored wells and the costs associated with fullbore coring. In some cases, borehole imaging techniques acquire data across high-porosity sand intervals that may be missed when coring, if core recovery is poor.

Determining grain-size relationships, such as fining or coarsening upward, within sand layers aids the identification of facies. In the subsurface, this is usually accomplished using standard log data, such as gamma ray or neutron. Geologists examine the grain-size trends to identify successions of facies that exist within the sediment sequences, learning more about the depositional processes that shaped the reservoir. Conventional curve-shape analysis methods, for example using gamma ray only, are sometimes unreliable because they do not describe the depositional history. In the McMurray interval, higher resolution measurements are required to recognize the depositional complexity. Using the high-resolution synthetic resistivity (SRES) data from the FMI tool, the Sequence application can automatically identify intervals as fining upward, coarsening upward or as having a blocky character. This analysis is combined with an integrated interpretation of the FMI images and cores to produce an advanced sedimentological analysis that gives geologists a more accurate depiction of the significant facies to consider when drilling SAGD wells (next page).

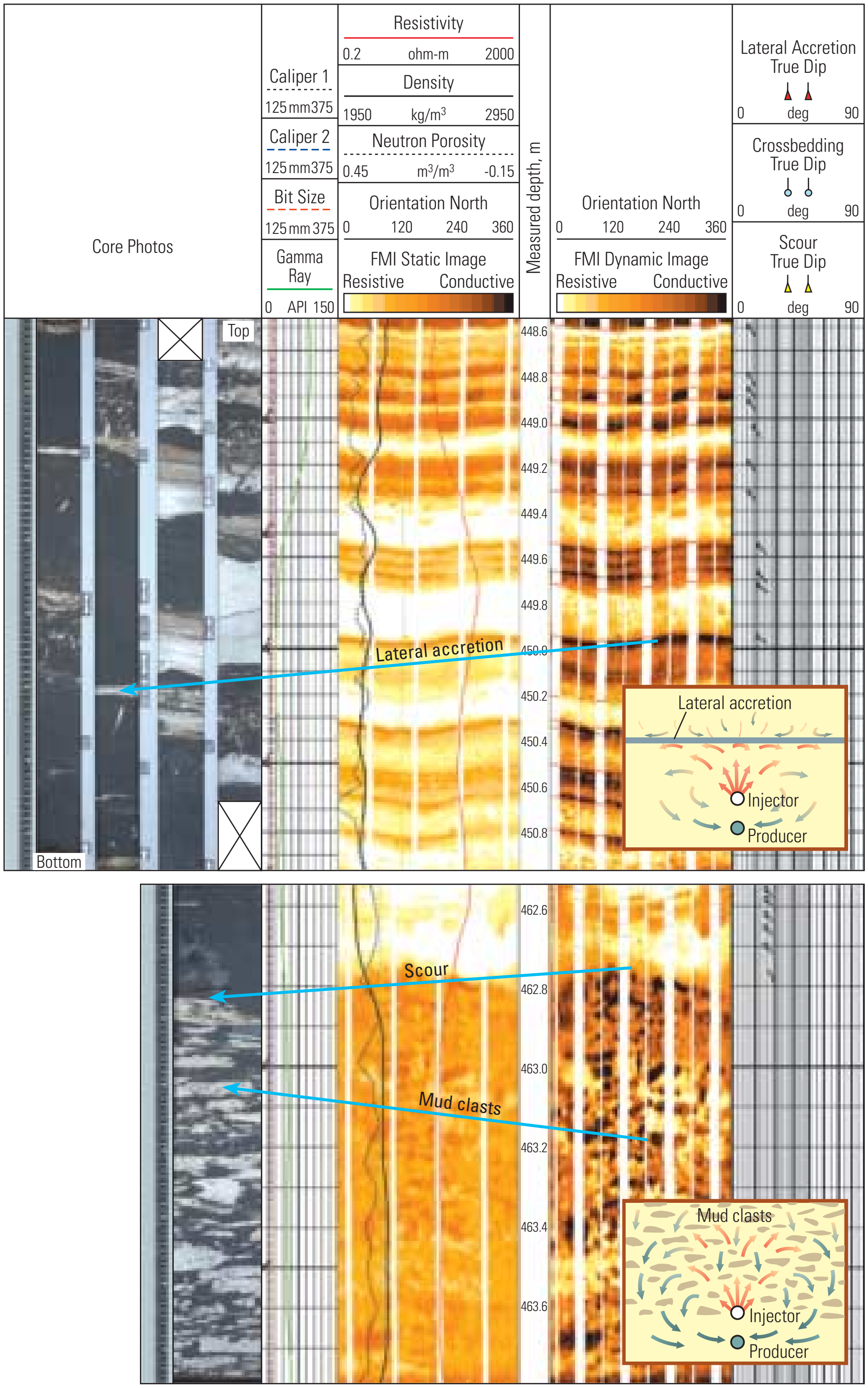
14. Hein et al, reference 10.



^ Using the Sequence tool for facies definition. At first, the Sequence program used only the input from the gamma ray log to define three curve-shape trends, or sequence types—coarsening upward, fining upward, and blocky or relatively constant grain size (Track 4). This analysis did not provide an adequate solution to capture the stratigraphic complexity, so the high-resolution synthetic resistivity (SRES) FMI output was scaled to the AIT tool 30-in. response and used to improve the trend analysis (Track 5). Lastly, both SRES and gamma ray were used to generate an improved sequence-type description (last track on right, or Track 6). Comparing the sequence types with the image sedimentology analysis, geologists can authenticate the curve-based sequence stratigraphy analysis. Significantly, blank sections in the analysis correspond to mud-clast zones. Also, flooding surfaces and low-stand erosional surfaces can be clearly seen on the image. Porosity and lithology data are shown in Track 1, gamma ray and spontaneous potential are shown in Track 2, caliper is shown in the depth track and resistivity data are shown in Track 3.

Advanced sedimentological analysis is helping to differentiate certain facies that have similar appearances on standard logs, but affect SAGD oil recovery in drastically different ways. Meandering estuarine systems produce point-bar sand deposits that commonly contain lateral accretions, or low-permeability clay layers, deposited in the top portion of the fining-upward point-bar sands during periods of flooding or slack water. Although lateral accretions may have limited lateral extent, their top, shaly portions are detrimental to the SAGD process because they can hinder the steam-chamber growth locally into the bitumen-rich point-bar sands above them. These low-permeability layers appear to prevent mobilized oil from migrating down to the production wellbore.

Another facies, identified as mud-clast zones, looks similar to shaly sand on standard logs. Shaly intervals are not considered pay, but mud-clast zones are, since the clast zones' matrix is clean bitumen-saturated sand. Clast zones allow



^ Lateral accretions versus mud-clast zones. The top of these point-bar sequences can become mud-dominated. The presence of lateral accretions reduces the total producible hydrocarbons because accretions hinder the SAGD process (*top*). However, mud-clast zones can be considered pay and can add to reserves since SAGD steam will rise up through them, effectively treating and draining these intervals (*bottom*).

steam to penetrate and migrate upward. The FMI images easily differentiate mud-clast zones from the shaly sands that are frequently seen disrupting the upper part of lateral accretions (left).

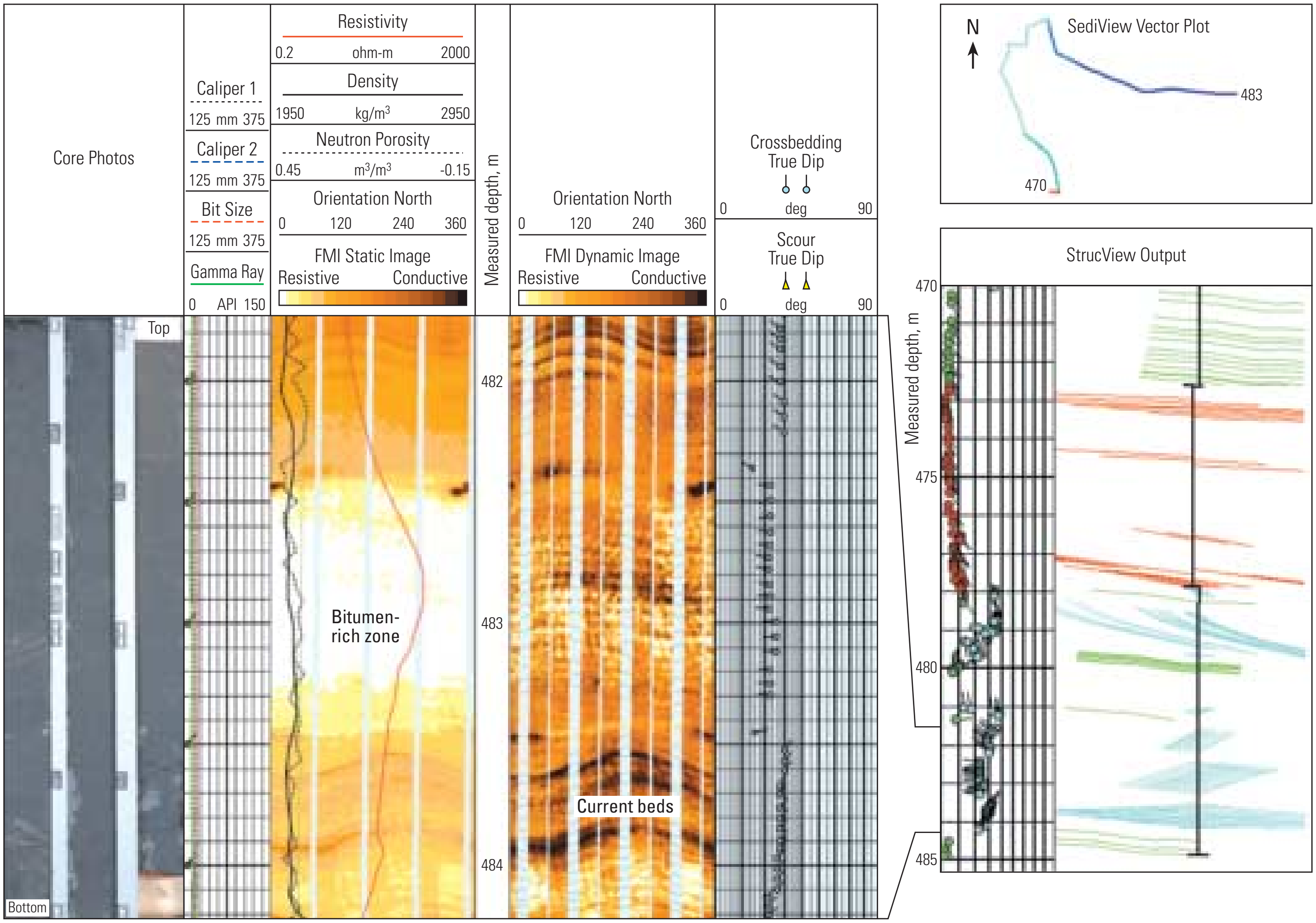
The FMI tool has proved useful in analyzing sand-body orientation and geometry. Sedimentological features may be difficult to see on the core because of dark bitumen staining but are easily observed on the FMI images. Current bedding on the borehole images shows that the direction of river flow was approximately north during the McMurray sand deposition, but varies throughout the sequence. Interpreting tidal influences on sand deposition helps construct a more accurate geologic model. Current bedding associated with fluvial-estuarine processes also reflects the trend of the sand body; this is important information for effective development of bitumen fields for Petro-Canada.

With this directional information, a sand-trend analysis can be performed using the SediView tool (next page). Image data also provide operators with relative bitumen content between zones of similar characteristics—a lighter static image indicates higher bitumen content. This relationship has been established by numerous core comparisons. Another sedimentological feature identified on borehole images is bioturbation, commonly associated with estuarine environments. Aside from providing facies information, bioturbation can drastically affect eventual rock characteristics, most prominently reservoir permeability.

In Petro-Canada's efforts to characterize the McMurray formation, FMI images have been useful in resolving facies because they mimic core-facies data. These images enable geologists to differentiate those facies that impede SAGD from those that do not. Viewed as a good way to optimize coring, borehole imaging offers cost benefits, complete data across poor core-recovery intervals, information about bitumen content, sand trend and sand geometry.

The Deepwater Challenge

Submarine fans, commonly composed of accumulations of sand, are some of the world's most prolific sand-rich reservoirs. Many are located in deepwater environments. The enormous cost of finding and producing hydrocarbon reserves makes deepwater reservoir-development strategies much different from those of typical fields. Ideally, time to first oil must be minimized for prospect viability, fewer wells tend to be drilled for reservoir evaluation, and increasing use of subsea installations means that well interventions are extremely costly and difficult.[15] As a result,



^ Typical stacked, incised channels separated by scour surfaces. The StrucView tool graphically depicts the major types of bedding found within the upper estuarine-channel environment of the McMurray oil sands; they include paleocurrent bedding (blue), accretionary bedding (red) and low-angle and low-energy bedding reflecting structural dip to the south-southeast (green) (*bottom right*). This is a north-northwest to south-southeast cross section and shows the paleocurrent direction to be dominantly to the north in the lower section, but a west-to-northwest direction in the midsection. The upper part of the point bar, above 480 m [1570 ft], indicates a sediment-transport direction change to the southeast. The StrucView cross section direction was selected to enhance the current bedding. The FMI images from a small section in this interval show the appearance of current bedding in the dynamically processed image to the right and a bright bitumen-rich zone on the static image to the left (*left*). Bedding is difficult to see on cores, but is clearly observed on the FMI image. The dip-vector analysis from SediView software tracks the paleocurrent direction as this interval was deposited and indicates a meandering point-bar environment, probably tidally influenced (*top right*). This analysis suggests that more sand development can be expected to the north of this well position.

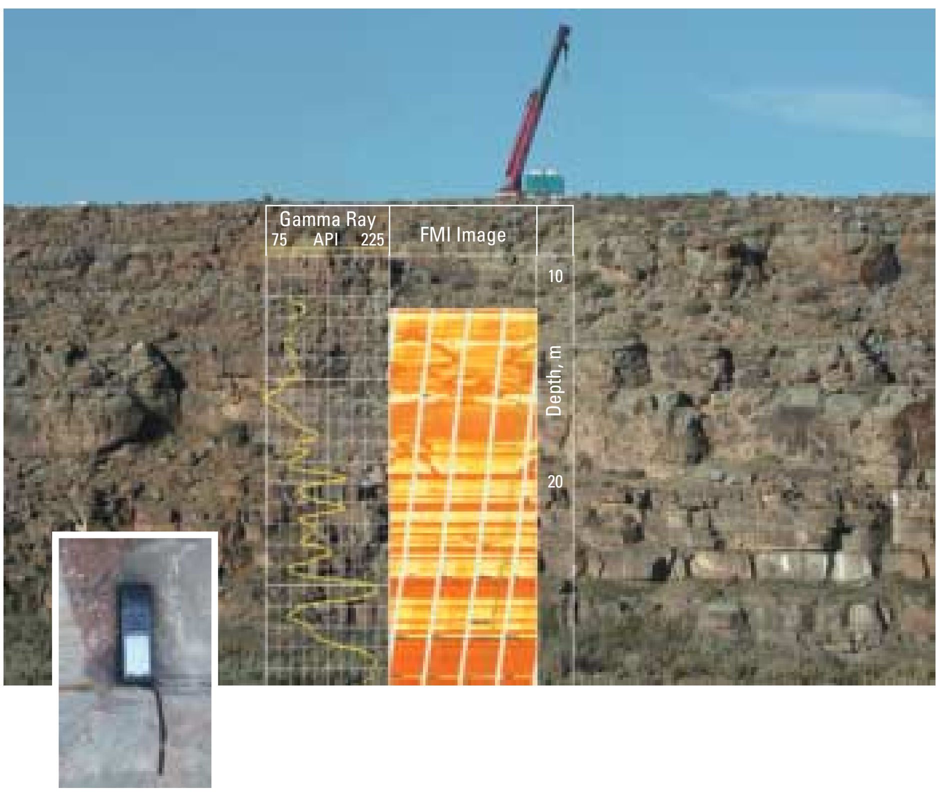
geologists must understand and model these reservoirs with significantly less well-log data, borehole images and cores. This scarcity of field-specific information has led to the increased study of exploration- and reservoir-scale submarine-fan and turbidite analogs to help geologists model the complex distribution and architecture of these reservoirs.[16]

A recent global study of the industry's use of depositional analogs shows that two-thirds of the companies surveyed not only use analogs but also believe that their use reduces risk and uncertainty. It also found that both geologists and engineers benefit from detailed analog studies, because these analogs bolster confidence in exploration and field-development modeling and subsequent decision-making.[17] Given the difficulty of studying recent modern deepwater sedimentary systems, researchers study ancient outcrop analogs.[18]

The Novel Modeled Analog Data for more efficient exploitation of deepwater hydrocarbon reservoirs (NOMAD) research project, launched in 2001, aims to reduce development costs associated with deepwater reservoirs. Sponsored by the European Union, NOMAD is a joint project of industry and academia. The participants

15. Carré G, Pradié E, Christie A, Delabroy L, Greeson B, Watson G, Fett D, Piedras J, Jenkins R, Schmidt D, Kolstad E, Stimatz G and Taylor G: "High Expectations from Deepwater Wells," *Oilfield Review* 14, no. 4 (Winter 2002/2003): 36–64.
16. Turbidites are sedimentary deposits formed by turbidity currents in deep water at the base of the continental slope and on the abyssal plain. Turbidites commonly show predictable changes in bedding from coarse layers at the bottom to finer laminations at the top, known as Bouma sequences, that result from different settling velocities of the particle sizes present. The high energy associated with turbidite deposition can result in destruction of earlier deposited layers by subsequent turbidity currents.
Dromgoole P, Bowman M, Leonard A, Weimer P and Slatt RM: "Developing and Managing Turbidite Reservoirs—Case Histories and Experiences: Results of the 1998 EAGE/AAPG Research Conference," *Petroleum Geoscience* 6, no. 2 (2000): 97–105.
17. Sun SQ and Wan JC: "Geological Analog Usage Rates High in Global Survey," *Oil and Gas Journal* 100, no. 46 (November 11, 2002): 49–50.
18. Purvis K, Kao J, Flanagan K, Henderson J and Duranti D: "Complex Reservoir Geometries in a Deep Water Clastic Sequence, Gryphon Field, UKCS: Injection Structures, Geological Modelling and Reservoir Simulation," *Marine and Petroleum Geology* 19 (2002): 161–179.

^ The Karoo basin study area. Within the Karoo basin lies the Tanqua fan complex and more than 640 km^2 [250 sq miles] of exposed strata.



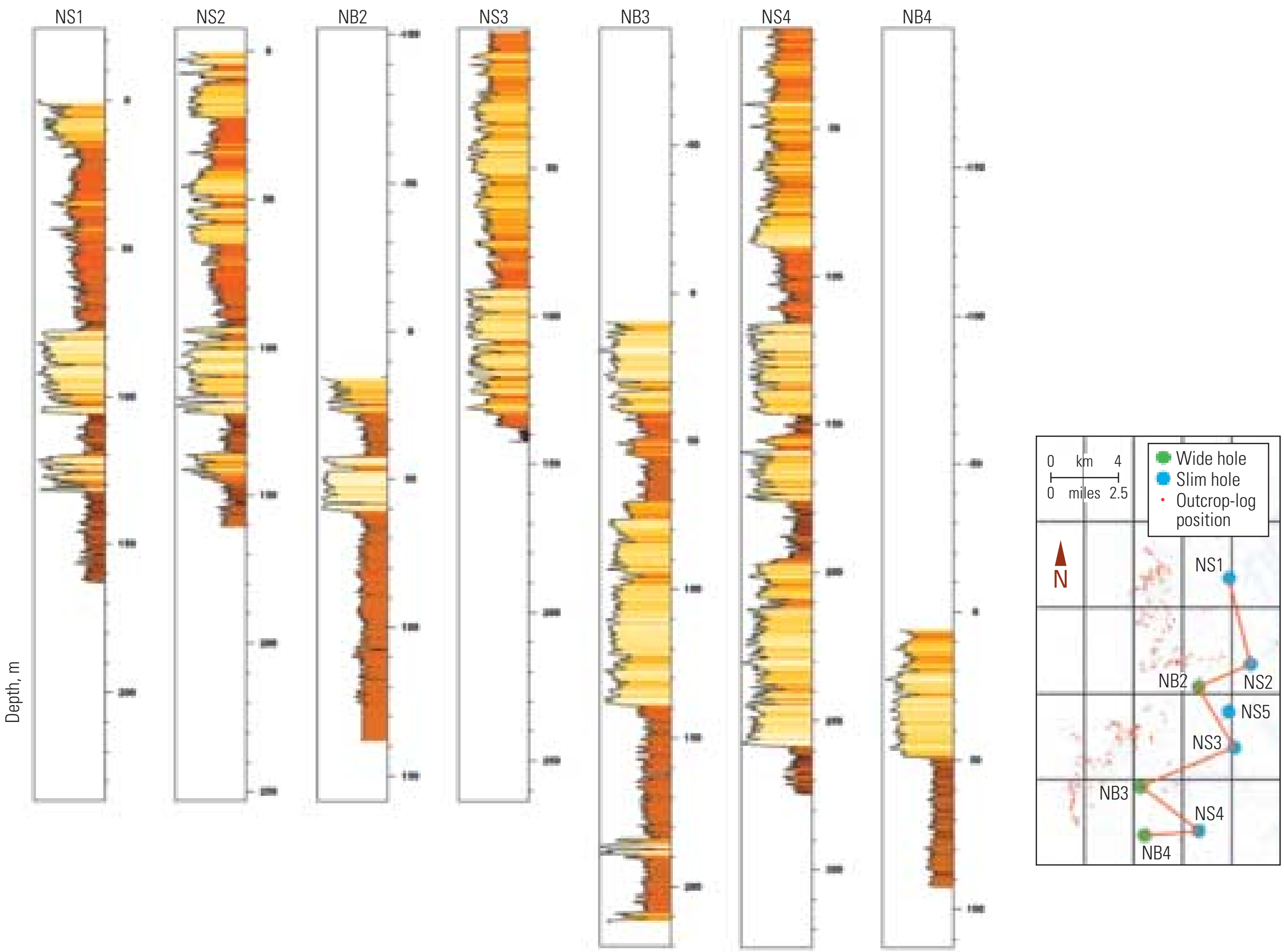
^ Mapping the outcrops. High-quality outcrops, such as this one exposing Fan 4 below the NB2 well location, enabled the NOMAD team of geologists to map the sedimentological details of the fan complex. Accurate mapping was facilitated by global positioning systems (GPS) and geographic information systems (GIS) (*inset*). The FMI image and gamma ray log from the well immediately adjacent to the outcrop are overlaid and compare directly with the outcrop.

include Statoil; Schlumberger; Delft University of Technology, The Netherlands; University of Liverpool, England; and the University of Stellenbosch, South Africa. The goal of the project is to improve the industry's ability to characterize deepwater reservoirs through the development of a detailed three-dimensional (3D) geological model using a vast supply of surface-outcrop data from the Tanqua subbasin submarine fan complex in South Africa.

The project area is southwest of the Karoo foreland basin (left). A Paleozoic clastic wedge of sediments—the Cape Supergroup—within the basin reaches a thickness of 8000 m [26,250 ft]. Two subbasins were formed during the Permian and Triassic periods, the Tanqua subbasin being one of them. The five Permian Tanqua fans have been studied extensively during the last ten years, laying solid technical groundwork for the NOMAD project.[19] The correlation of facies across the region from mapped exposed strata enhanced the modeling of the broad distribution of the fans. This led to an improved understanding of the depositional settings of five deepwater turbidite fan systems.[20]

From oldest to youngest, Fan 1 represents the most distal basin-floor position; Fans 2 and 3 are more proximal in a depositional dip sense, while Fan 4 represents a well-exposed depositional strike section. The lowest four fans are from a basin-floor environment, while Fan 5, the uppermost fan, appears to have been deposited on a submarine slope. Within each fan sequence, the architecture of sand bodies varies principally from channels to sheet sands.

Geological data from a variety of sources have been acquired on the submarine fans in the Tanqua subbasin, including the examination and mapping of rock outcrops at unprecedented levels of detail and accuracy using global positioning system (GPS) and geographic information system (GIS) technology. Additionally, seven shallow wellbores—four 4-in. diameter wells and three 6-in. diameter wells—were drilled. A total of 1186 m [3891 ft] of fullbore core has been extracted, and comprehensive suites of wireline logs were acquired on the 6-in. diameter wells, including Platform Express, ECS Elemental Capture Spectroscopy, NGS Natural Gamma Ray Spectrometry logs and FMI images. The wellbore locations were strategically placed with respect to the available outcrops, surface mapping and local subsurface geology (left). Cores from the seven wells were of excellent quality and underwent thorough analysis, including sedimentological core logging and digital core photography.



^ Correlating the fans in the Tanqua subbasin study area. Correlating the deepwater fans in the study area was challenging. Generally, the fan complex thins as mud content increases to the north, supporting a northerly downstream or basinward direction. The fan names and boundaries have been removed, as have the crosswell correlation markers. A plan view of the well locations is also shown (*right*).

The wireline logs also were of excellent quality, were crucial for correlating key surfaces, sand bodies and sedimentary facies across the project area, assessing rock properties and defining mineralogy (above).

Because of erosion and limited exposure, outcrops often do not allow precise assessment of stratigraphic thickness and subtle sedimentological features. Wellbore data helped determine the true stratigraphic thickness from observed thickness at outcrops, allowing more precise correlation of key flow units within submarine fans across the project area. This was especially important in the less resistant, silt- and mud-rich interfan deposits because of their relatively poor outcrop exposure. Additionally, it was particularly difficult to assess a narrow range of grain sizes, the amount of bioturbation and subtle bed boundaries—bed-thickness indicators—from the outcrops alone. In contrast, detailed core studies provided valuable additional information on all these parameters and allowed accurate description and quantification of the full facies variation. Cores and logs proved crucial for proper correlation of fans, depositional features and facies, leading to the construction of more robust 3D geological models.

Detailed outcrop logs and photographs are now being correlated with log, image and core data to expand the model beyond outcrops and wells to assist modeling of the interwell volumes, and also to provide a link to common well data acquired in exploration and production. Eventually, when the depositional analog is used to develop reservoir models, field data will be input to provide the dynamic information—for example, pressure and fluid type—necessary for successful simulation.

19. Wickens HdeV: "Basin Floor Fan Building Turbidites of the Southwestern Karoo Basin, Permian Ecca Group, South Africa," Unpublished PhD thesis, University of Port Elizabeth, Cape Town, South Africa, 1994.

Bouma AH and Wickens HdeV: "Permian Passive Margin Submarine Fan Complex, Karoo Basin, South Africa: Possible Model to Gulf of Mexico," *Transactions of the Gulf Coast Association of Geological Sciences* 41 (1991): 30–42.

Rozman DJ: "Characterisation of a Fine-Grained Outer Submarine Fan Deposit, Tanqua-Karoo Basin, South Africa," in Bouma AH and Stone J: *Fine-Grained Turbidite Systems.* American Association of Petroleum Geologists, Memoir 72 / SEPM Special Publication 68. Tulsa, Oklahoma, USA: American Association of Petroleum Geologists (2000): 292–298.

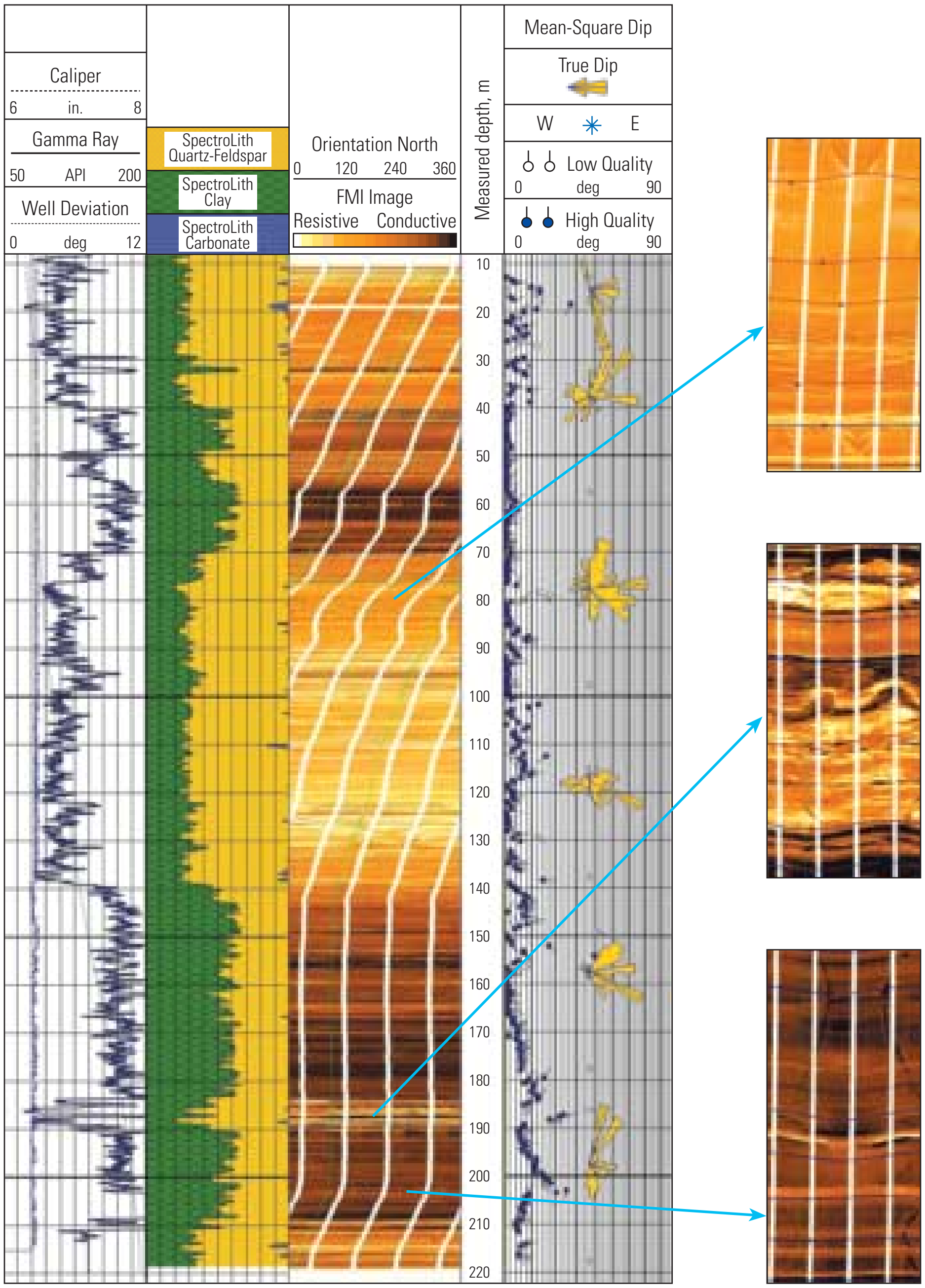
Bouma AH and Wickens HdeV: "Tanqua Karoo, Ancient Analog for Fine-grained Submarine Fans," in Weimer P, Bouma AH and Perkins BF (eds): *Submarine Fans and Turbidite Systems: Sequence Stratigraphy, Reservoir Architecture, and Production Characteristics, Proceedings of the Gulf of Mexico and International Gulf Coast Section, Society of Economic Paleontologists and Mineralogists Foundation 15th Research Conference* (1994): 23–34.

20. Johnson SD, Flint S, Hinds D and Wickens HdeV: "Anatomy of Basin Floor to Slope Turbidite Systems, Tanqua Karoo, South Africa: Sedimentology, Sequence Stratigraphy and Implications for Subsurface Prediction," *Sedimentology* 48 (2001): 987–1023.

The high-quality FMI images from the NOMAD project wellbores have identified and established the orientation of important sedimentological and structural features (below). For example, paleocurrent direction from borehole images will be input as trend maps to condition deepwater-fan reservoir models, facilitating the population of reservoir-feature geometry, porosity and permeability data. Sedimentary features observed on borehole images help geologists discern which portion of the fan has been penetrated and whether the well is in a confined channel or unconfined sheet-sand deposit—critical information when modeling deepwater fans. Seemingly insignificant features also can provide valuable clues about the sequence stratigraphy of deepwater systems. In the Tanqua fans, for example, concretions seen in outcrops and observed on the FMI images within some mudstone facies correlate with periodic flooding surfaces.[21]

Modeling and simulation tools allow geoscientists and engineers to exploit data from many different sources, including borehole images. The power of modern modeling and simulation software is exemplified in Petrel workflow tools, a PC-based platform that supports all disciplines of reservoir expertise. Petrel software handles two-dimensional (2D) and 3D seismic data interpretation and visualization; structural, stratigraphic and petrophysical modeling and mapping; well correlation; data analysis and model-volume population; reserve-volume calculation; and well design. Petrel software functionalities have enabled the visualization and modeling of the depositional zones of each of the Tanqua fan systems throughout the NOMAD project (next page, top). The ability to model deepwater-fan reservoir properties in detail offers multidisciplinary asset teams clear advantages in reservoir optimization during all stages of field development.

Borehole images are a small but important element within an enormous collection of data used in the modeling of reservoirs. However, specific data types change according to area, availability and the operating environment. While the FMI tool was used in the NOMAD wells drilled using conductive wellbore fluids, many deepwater wells are drilled with nonconductive drilling muds, thereby excluding the use of some formation-evaluation techniques. The OBMI tool, designed to run in oil-base and synthetic-base mud systems, provides high-resolution borehole images for sedimentological analysis.[22] For example, the OBMI tool can assist in the identification of slump features that reduce sand continuity and tend to reduce potential reservoir thickness and connectivity. Slumps observed at the wellbore should be considered when calculating total sand count or when estimating reservoir properties such as permeability. In addition, the examination of sedimentary features—such as crossbedding—on OBMI images has given geologists valuable insight into the orientation of sand bodies in a variety of depositional environments.



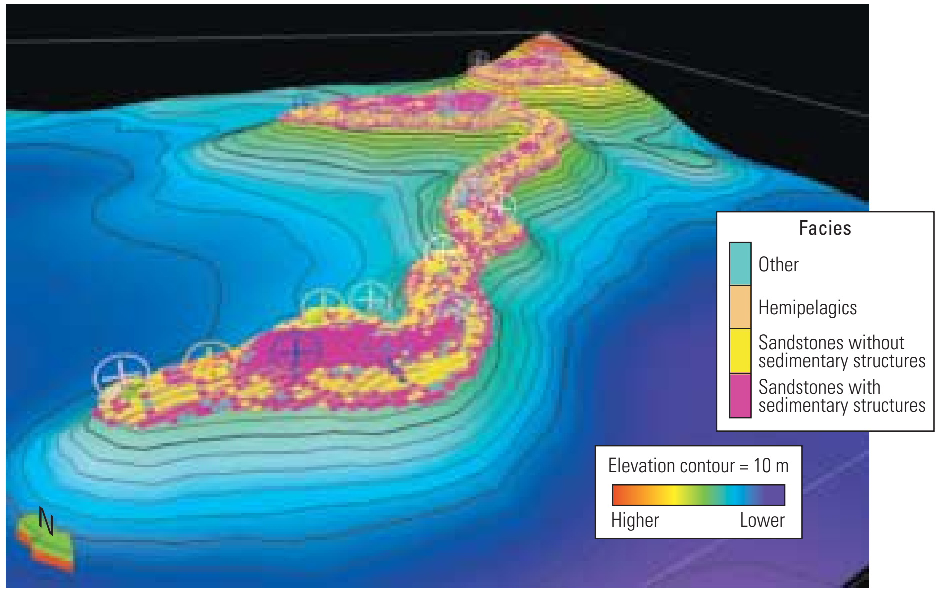
^ FMI images on NOMAD Well NB3. The FMI tool was run on the larger diameter wellbores to provide a high-resolution analysis of sedimentary and structural features. Track 1 contains gamma ray, caliper and borehole-deviation information. Track 2 shows the computed lithology from the ECS data. Track 3 displays a static image from the FMI tool, and Track 4 shows the computed true dips from the FMI data. Several key features are highlighted in this shallow wellbore. A significant thrust fault was identified at a depth of 203 m [666 ft] (*bottom right*). Contorted bedding was identified from 185 m to 190 m [607 to 623 ft] (*middle right*). Possible climbing ripple faces were identified at 80 m [262 ft] and show a south orientation, which is consistent with a northerly paleocurrent flow (*top right*). Fractures were also identified and oriented, although most are healed with quartz cement (*top right*).

Thin Beds in Deepwater Fans

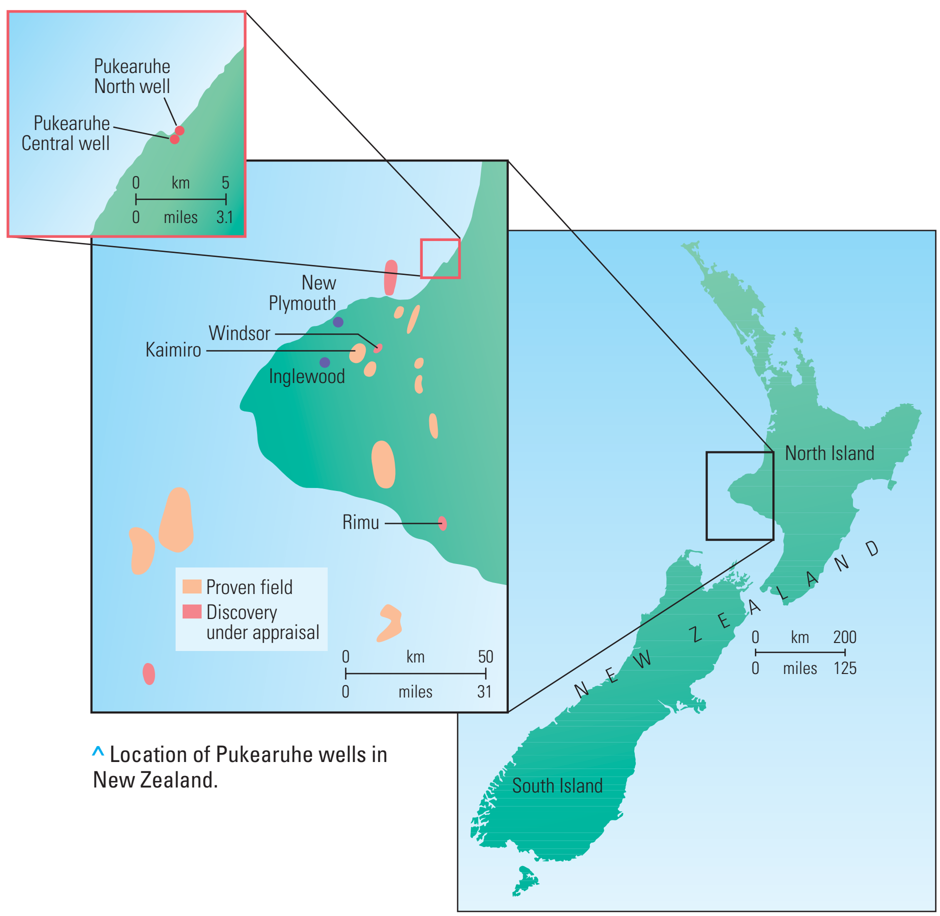
The Taranaki basin is one of the most explored and commercially successful hydrocarbon provinces of New Zealand. The main reservoir sands, of Miocene age and younger, were deposited in a deepwater slope and basin-floor fan setting. Oil was discovered in the Mt. Messenger formation in the Kaimiro field in 1991. Continued exploration led to oil discoveries in Rimu, South Taranaki, and a gas discovery in Windsor, North Taranaki. Thin-bedded sediments are the main reservoir facies, so identification of these sediments has been essential to successful exploration. The formation comprises predominantly very fine-grained sandstones, siltstones and mudstones, and geologists have interpreted this formation as deposited in a slope-fan setting.

The Mt. Messenger formation is found on the North Island of New Zealand, in both outcrop and subsurface. Borehole image data and wireline logs were collected from two adjacent wells, drilled about 450 ft [137 m] apart. The Pukearuhe North and Pukearuhe Central wells were drilled to depths of 236 ft [72 m] and 292 ft [89 m], respectively and were positioned approximately 300 ft [91 m] from the outcrop cliff. The boreholes were drilled into the Mt. Messenger formation in 1996, inland of Pukearuhe Beach, 50 km [31 miles] northeast of New Plymouth on the west coast of North Island (right). The outcrops have been interpreted as vertically stacked levee and overbank deposits comprising thin-bedded, typically planar-laminated sandstones and siltstones, and climbing ripple-laminated sandstones and siltstones.[23]

Detailed facies identified from the images were characteristic of a deep marine environment. A lithological log was defined from the gamma ray log and the SRES curve derived from stacking the 192 resistivity curves acquired by the FMI tool. The lithological log identified thin beds—minimum thickness of 2 in. [5.1 cm]—enabling a more accurate determination of sand count, mean bed thickness, lithological proportions, and thinning- and thickening-up cycles. Clearly identifiable dip domains defined these thinning- and thickening-up cycles. These dip



^ Modeling the Tanqua fans. A high-resolution lithofacies model constructed using Petrel software shows the variability of sheet-like sands in Fan 3. Grid cells represent 10 m by 10 m by 0.25 m [33 ft by 33 ft by 0.8 ft] volume—265 by 206 by 282 cells, equaling 15,394,380 cells in total—and are color-coded according to the mapped lithofacies type. The sinuous outcrop geometry is a result of erosion and is not related to sedimentation in a channel. The circled 'plus' symbols mark the top of each measured sedimentary section taken on the outcrop. Structureless sands are present in the areas of high amalgamation, or high energy, such as the center of a poorly confined channel, and structured sands are dominant in the less amalgamated areas, or lower energy areas. Hemipelagic sedimentation represents shutdown periods in the turbidite system. Hemipelagic sediments are deep-sea, muddy sediments formed close to continental margins, containing biogenic material and terrigenous silt.

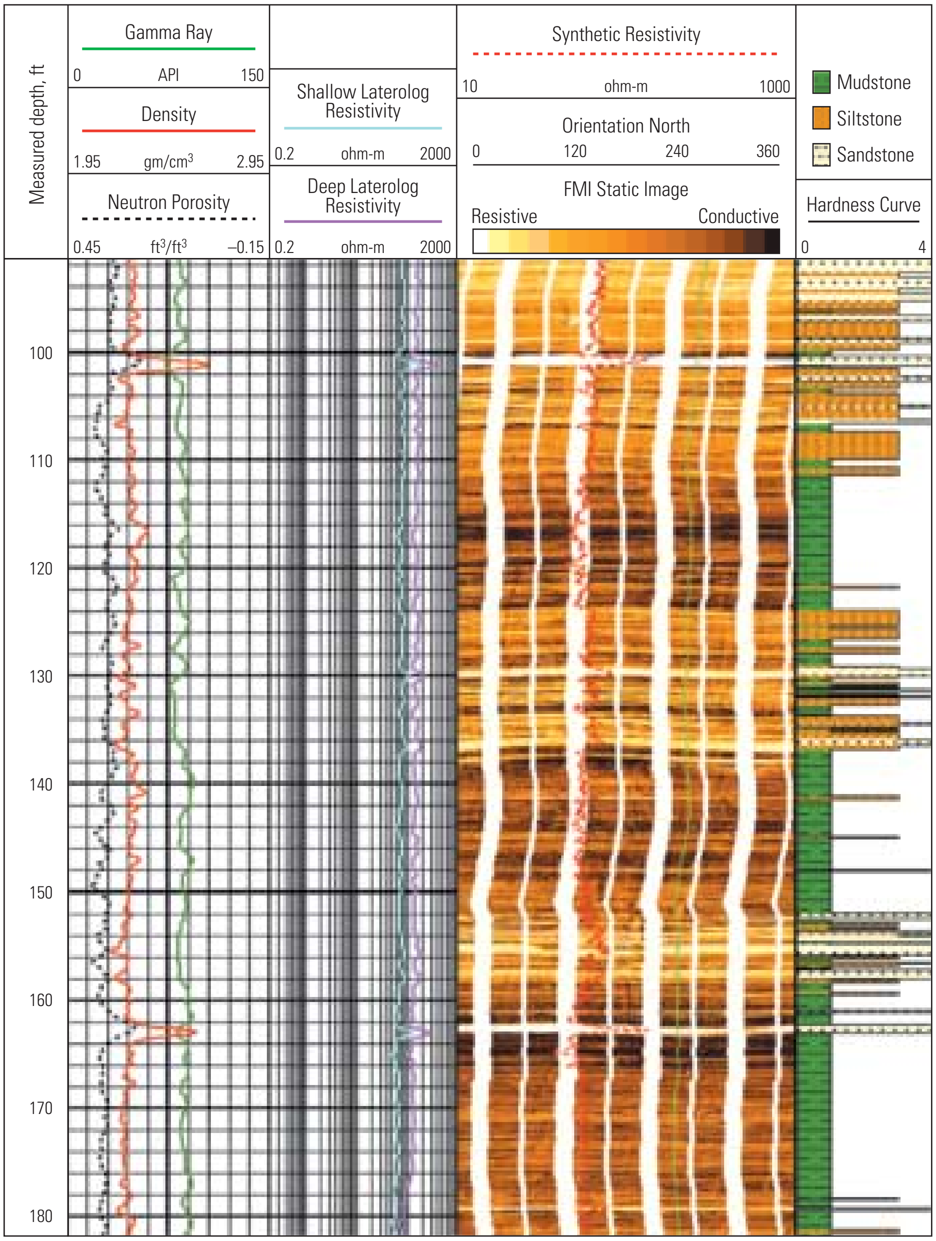


^ Location of Pukearuhe wells in New Zealand.

21. Johnson et al, reference 20.
22. Cheung et al, reference 5.
Cheung P, Pittman D, Hayman A, Laronga R, Vessereau P, Ounadjela A, Desport O, Hansen S, Kear R, Lamb M, Borbas T and Wendt B: "Field Test Results of a New Oil-Base Mud Formation Imager Tool," *Transactions of the SPWLA 42nd Annual Logging Symposium*, Houston, Texas, USA, June 17–20, 2001, paper XX.
23. Browne GH and Slatt RM: "Outcrop and Behind-Outcrop Characterization of a Late Miocene Slope Fan System, Mt. Messenger Formation, New Zealand," *AAPG Bulletin* 86, no. 5 (2002): 841–862.

domains were generally bounded at their base by a distinctive scour surface and overlain by a succession of dips that are similarly oriented but declining in magnitude upwards through the dip succession. Bed-to-bed correlation between the two wells proved difficult because of localized scouring and amalgamation of the sandstone beds. However, dip domains observed between wells suggested that facies packages could be correlated. These cycles were interpreted to represent individual lobes deposited on the basin plain.

Thin-bed analysis is critical to achieve accurate estimation of reserves, particularly during the early appraisal process. Although thin beds can now be identified from high-resolution openhole logs—2-in. resolution—sedimentological information from borehole images, with resolution as low as 0.2 in. [0.5 cm], helps assess reservoir continuity and reservoir potential.



^ Lithology log from the Pukearuhe North well. High-resolution lithology analysis helped resolve bed-thickness relationships in both the Pukearuhe North and Pukearuhe Central wells. Lithological logs, displaying beds as thin as 2 in., comprised three lithologies: sandstones, siltstones and mudstones (Track 4). Bed-thickness curves, derived from conductivity measurements, show thickening-up cycles in the Pukearuhe North well that coincided with the dip domains found in both wells.

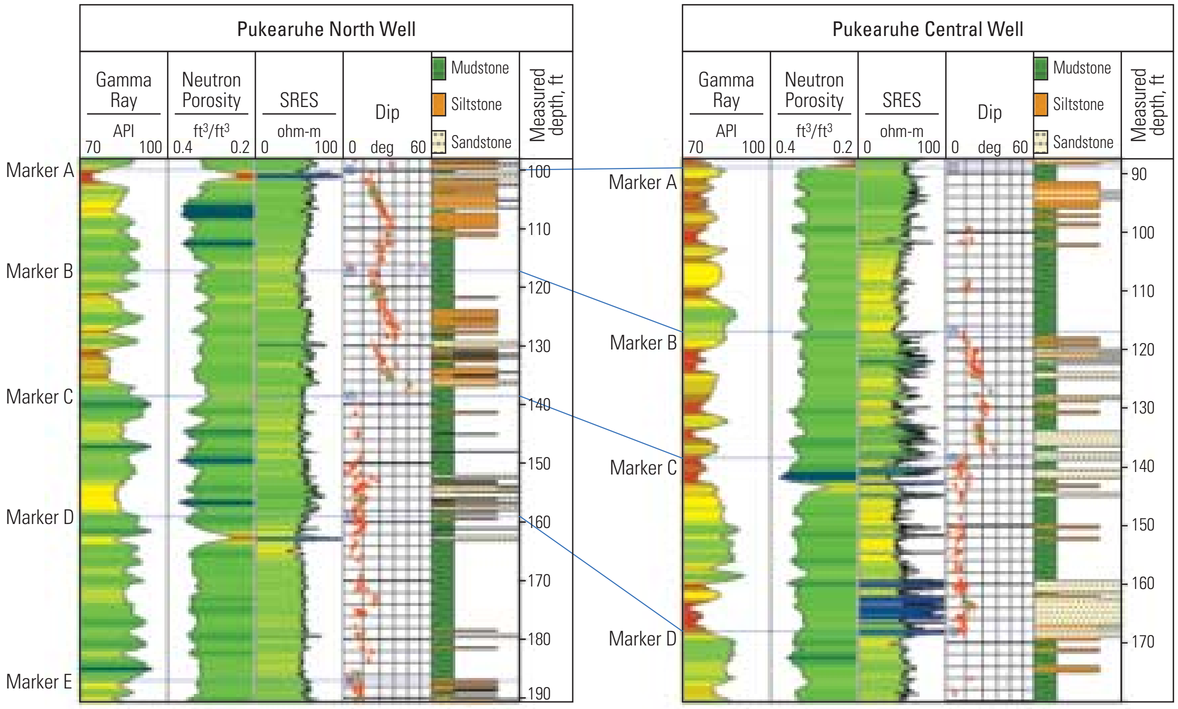
The FMI images showed the characteristics of a slope system, ranging from mudstone, then becoming interbedded with fine sands and growing increasingly sand-rich, and eventually forming thicker sandstones beds of approximately 2 ft [0.6 m] in thickness. Lithological logs comprised three lithologies: sandstones, siltstones and mudstones. The analysis displayed beds as thin as 2 in. (left). Bed-thickness block curves derived from conductivity measurements in the Pukearuhe North well exhibited thickening-up cycles that coincided with the dip domains. The dip domains were also observed in the Pukearuhe Central well, although the beds appeared much thinner and displayed much smaller cycles. The positions of the lithological markers were determined using the dip data and enabled a reasonably confident correlation across the two wells. The distinctive dip data within key zones allowed correlation between the two wells; without the dip data, correlation would have been difficult (next page, top). There were few other sedimentary features that could be correlated between the wells because of the repetitive nature of the sedimentation. As a result of the correlation, the proportion of sandstone was observed to increase towards the Pukearuhe Central well, indicating the greater potential for a channel margin towards the south.

The FMI tool was critical for proper thin-bed analysis. The identification and quantification of these thin beds would not have been possible with conventional wireline logs alone. The lithological log generated from the FMI data helped define the petrophysical parameters for each lithology and helped determine cutoffs, which could then be propagated throughout the field.

Improving Reservoir Models and Field Development

Continental-onshore and shallow-marine depositional environments may be more complex than submarine environments. Drilling in continental or transitional settings typically occurs at greater well densities, generating more subsurface data. Also, it is easier to observe active deposition in onshore environments. Transitional environments present special challenges because of the interplay of deposition and erosion under the combined and often opposing forces of land and sea, which leads to complex reservoir architecture.

Teikoku Oil de Sanvi-Güere has characterized the sedimentology of a complex series of reservoir sands in the Guarico 13 field of eastern



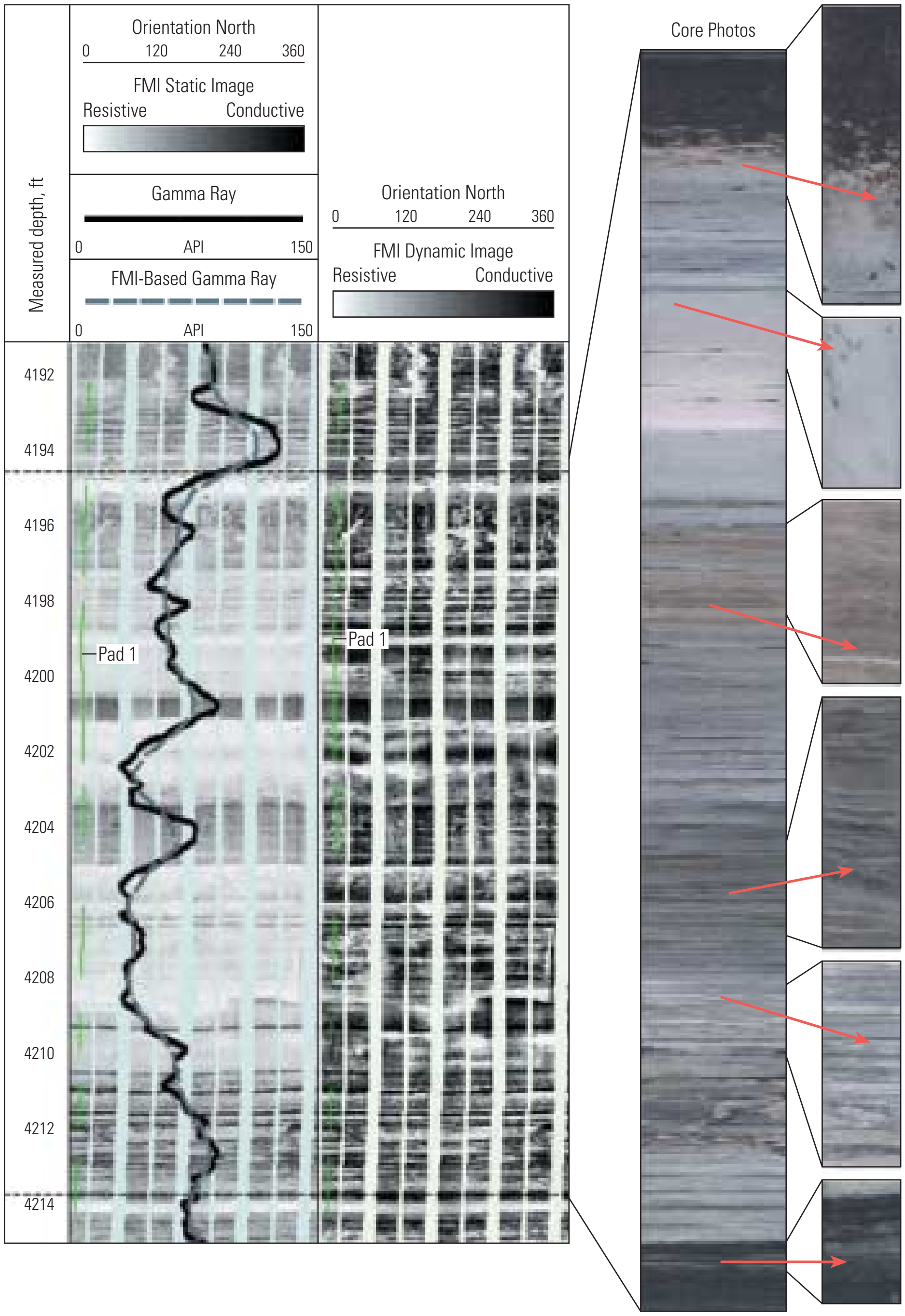
^ Correlation with dip data. The positions of the lithological markers were determined using the dip data from the FMI tool, enabling correlation across the two wells. A lack of sedimentary features and the repetitive nature of the sedimentation made correlation between the wells extremely difficult. This correlation allowed assessment of the relative proportions of sand in each zone. The Pukearuhe Central well contained the greater percentage of sand, suggesting the direction towards the channel and improved reservoir potential was south.

Venezuela (right). One of the main hydrocarbon-bearing intervals within this field, the upper Merecure formation, was deposited during the lower Miocene in a coastal-plain environment associated with a fluvial-deltaic system.[24] It is characterized by thin, very fine- to medium-grained sandstones, with typical gross-sand thicknesses of 10 to 30 ft [3 to 9 m]. Subenvironments include meander channels, floodplain channels, crevasse splays and channels, delta-front mouth bars, swamps and lakes.[25] Sediments within this environment are dominantly fine-grained but can be coarse- to medium-grained when deposited in higher energy channel subenvironments. Coal beds within the upper Merecure interval make laterally extensive correlation markers, but even with these markers, productive sand intervals can be elusive when drilling for maximum production and optimal recovery.

24. Gamero H, Contreras C, Pestman P and Mizobe A: "Borehole Electrical Images as a Reservoir Characterization Tool in the Merecure Formation, Guarico 13 Field, Eastern Venezuela," *Memorias del VII Simposio Bolivariano*, Caracas, Venezuela, (September 10–13, 2000): 620–641.

25. For more on fluvial and deltaic depositional environments: Scholle PA and Spearing D: *Sandstone Depositional Environments, Memoir 31.* Tulsa, Oklahoma, USA: The American Association of Petroleum Geologists, 1982.

^ Location of the Guarico 13 field, eastern Venezuela.

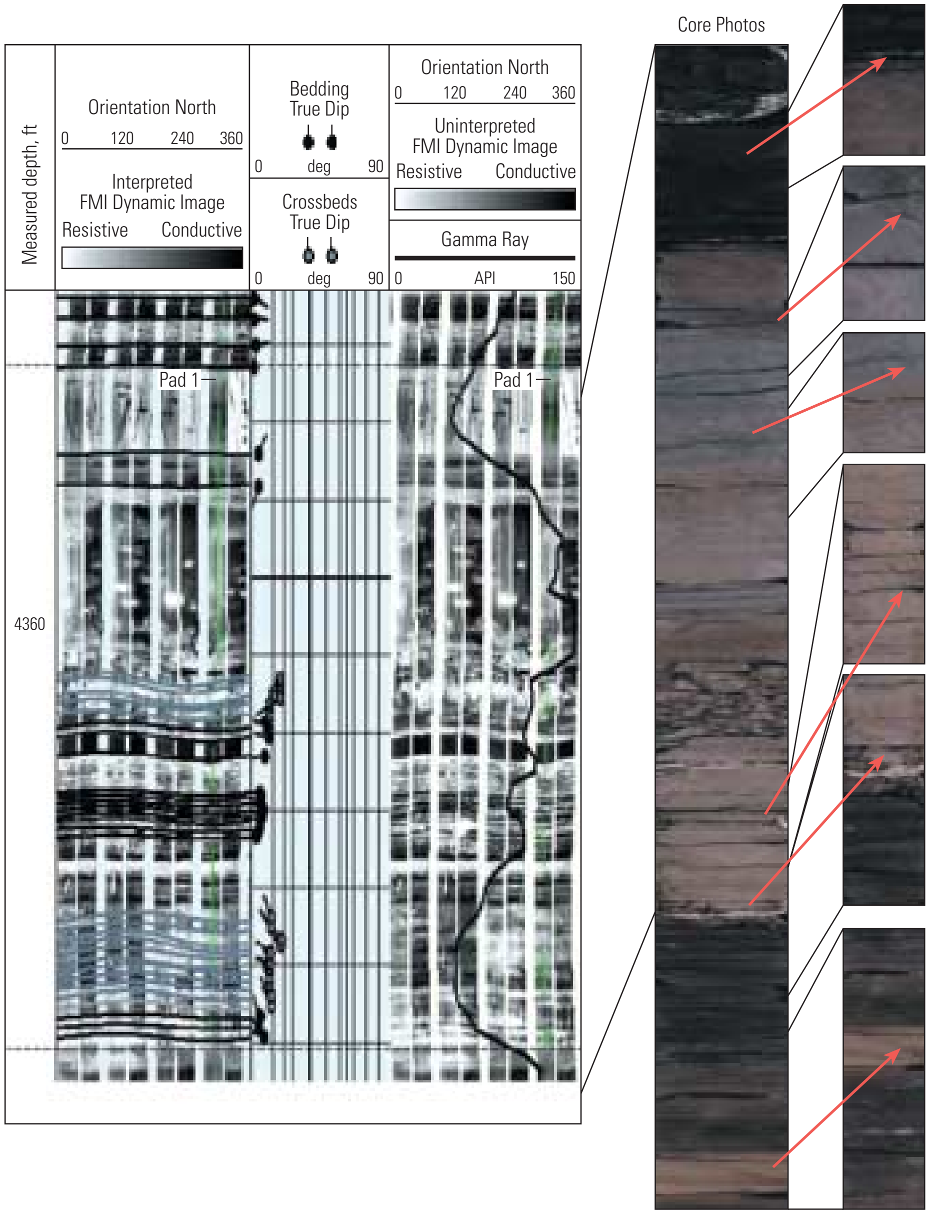


^ Crevasse-splay and lacustrine-sand facies. The core photographs show thinly laminated shales and siltstones, followed by sharp-based, parallel to crosslaminated sandstone that grades upward into a massive sandstone with plant-root traces (*right*). This is capped by a coal bed less than 1 ft thick. The FMI images match the core data over the crevasse-splay succession (*left*).

Borehole imaging tools, such as the FMI tool, have been invaluable to Teikoku Oil geologists. They have used the FMI data to develop sedimentological models for each reservoir sand within the Merecure formation. Using BorView tools in GeoFrame system software, Schlumberger and Teikoku geologists characterized the different sands by analyzing the sedimentary features on FMI images, thereby improving sedimentological models.

The determination of reservoir trends, continuity and connectivity could not have been accomplished using the available seismic data in the Guarico 13 field. In this area, most of the sand thicknesses and structural features—like faults—fall below the limits of the seismic data resolution. Borehole images help resolve the orientation of both productive and nonproductive lithofacies used in model and field development.

Extensive core and image analysis led to the recognition of eight facies within the Merecure formation. All eight facies are distinguishable on the FMI images and are verifiable by modern

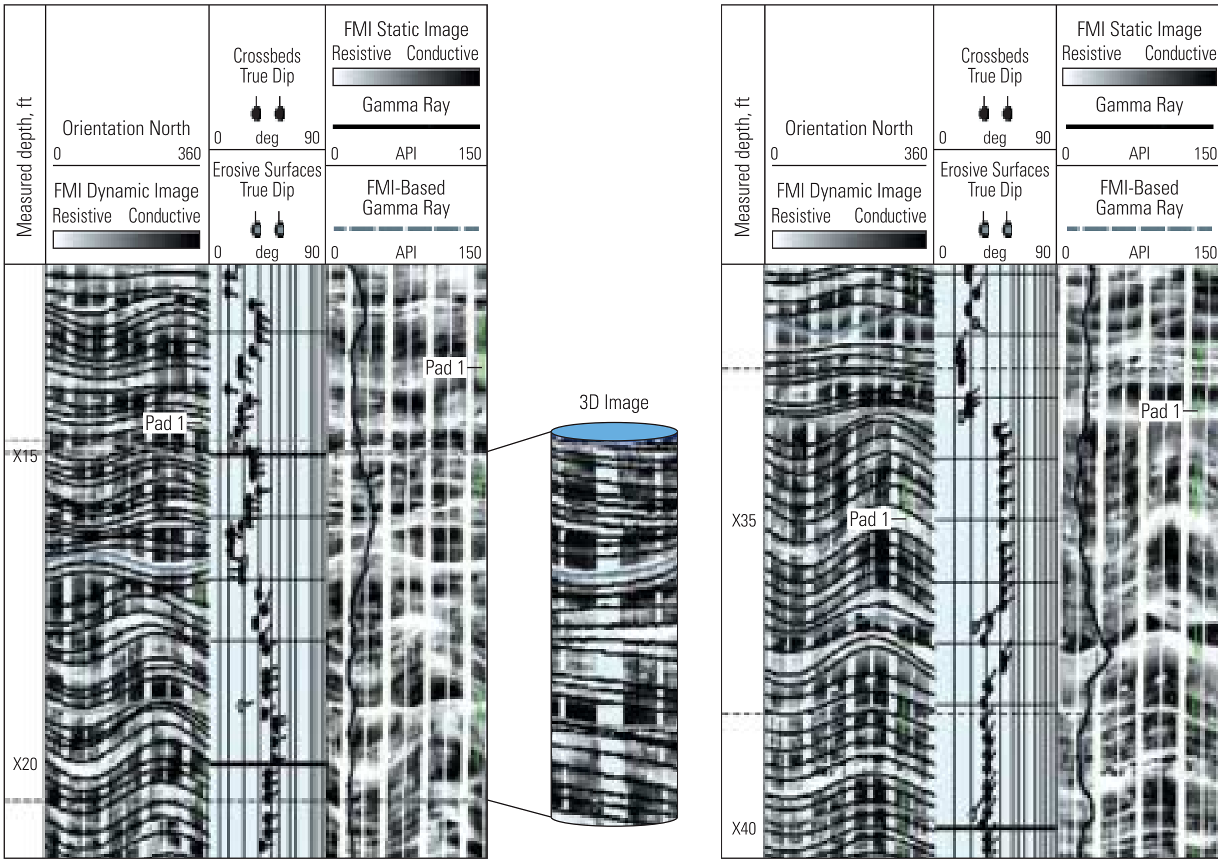


^ Crevasse-channel facies. The core data show sharp- or erosive-based, fine- to medium-grained sandstone (*right*). In some cases, the sandstones are crosslaminated or cross-stratified, but usually the facies appear massive. This interval is capped by abandoned channel facies. The FMI images match the core data over the crevasse channel-fill succession, and show sharp-based crosslaminated sandstone, overlain by fine-grained river-floodplain facies (*left*).

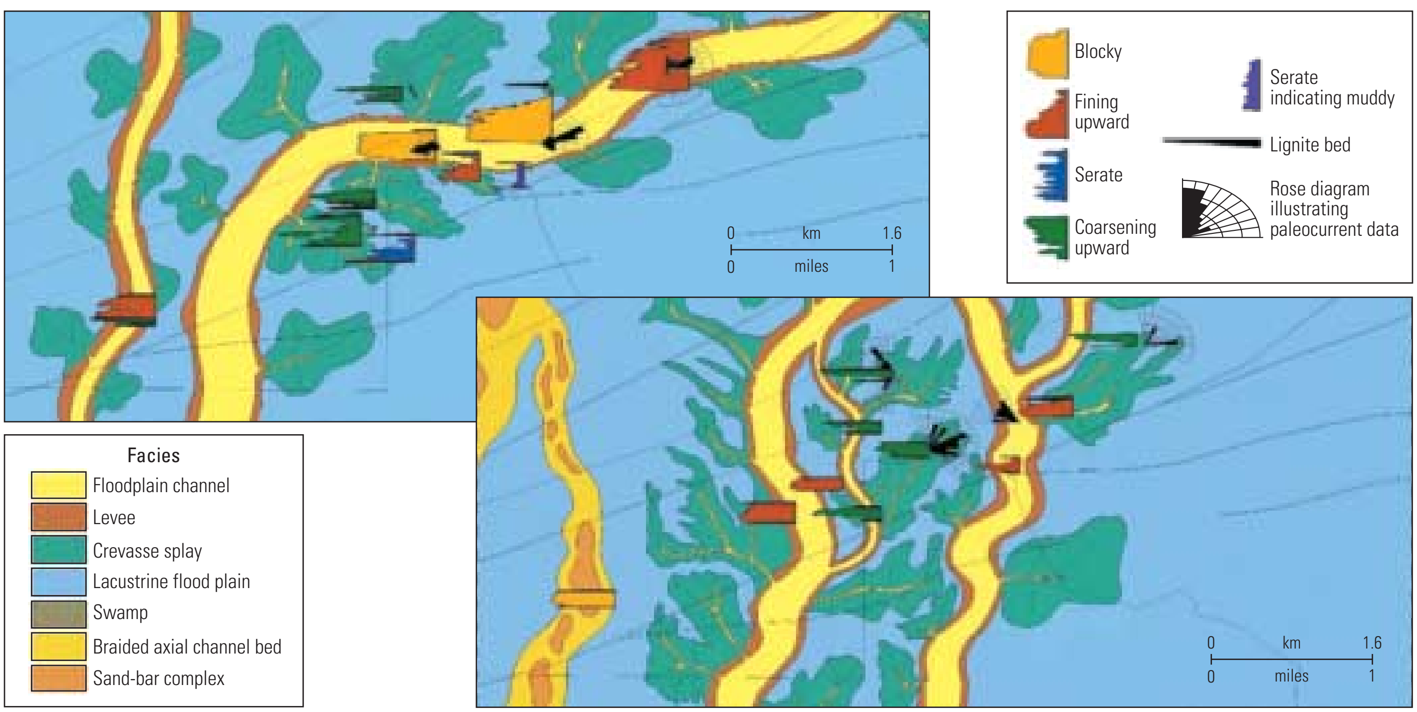
depositional analogs.[26] Crevasse channels and crevasse splays are important facies in the upper Merecure formation because of their high-quality reservoir characteristics. Crevasse splays are very fine- to medium-grained sand bodies that generally coarsen upward. They display abrupt lower contacts, parallel to crosslaminations and often show root traces in the top portion of the sand (previous page). This facies overlies thinly laminated shales and siltstones and is overlain by a thin coal bed. Characteristically, crevasse channels have sharp erosive bases, are fine- to medium-grained fining-upward successions, and can exhibit crossbedding but usually have a more massive internal structure. Both crevasse splays and crevasse channels display crossbedding that indicates paleocurrent direction, often representative of reservoir trends (above).

Four other significant facies that were identified are the meander-belt/braided-channel facies, which is found in the lower and middle

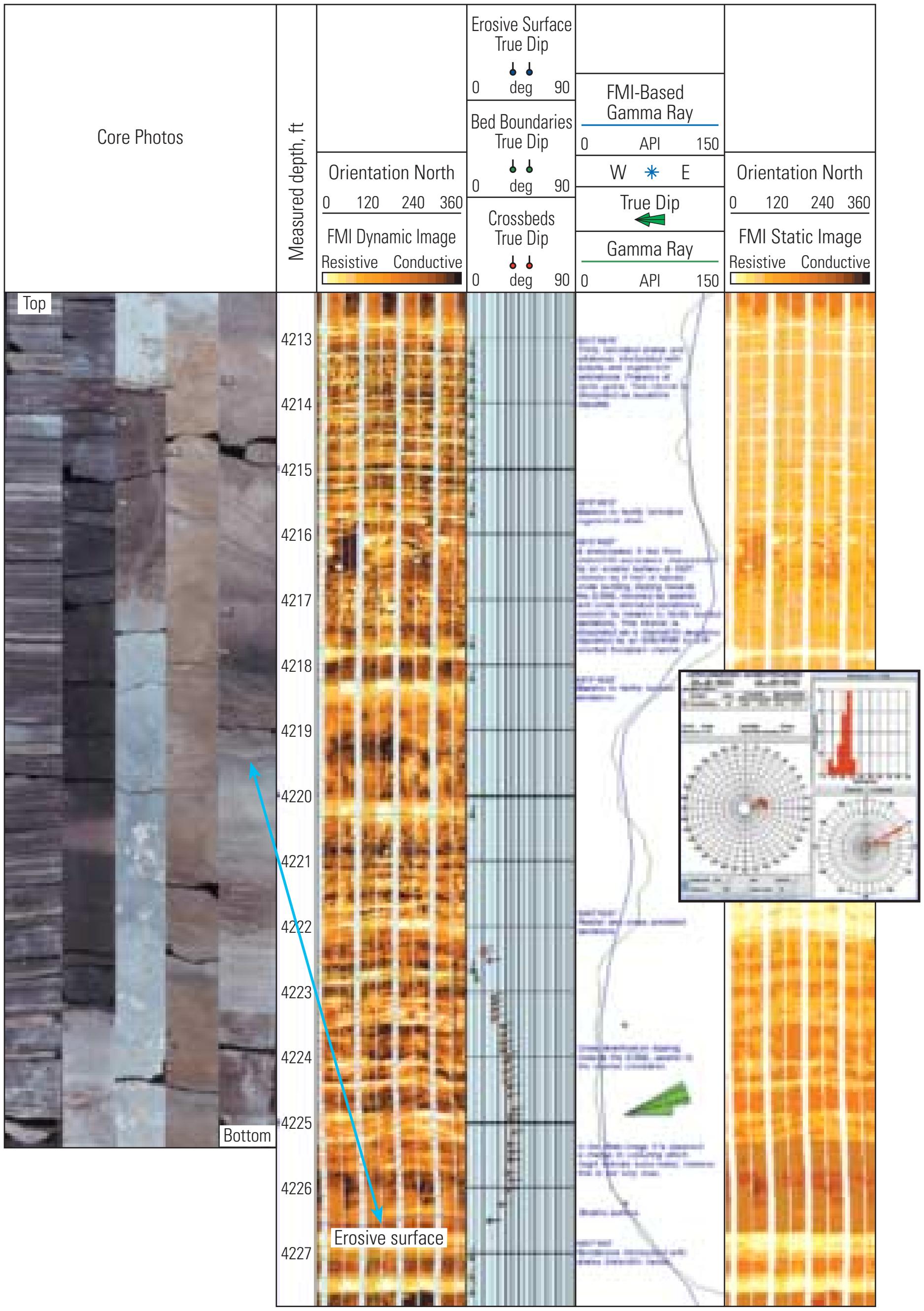
26. Gamero et al, reference 24.



^ Meander-belt/braided-channel facies. The FMI images show multiple erosive surfaces, separating units of 1-ft to 1.5-ft [0.3-m to 0.5-m] thick planar-crossbed sets dipping towards the north-northeast, east-northeast and northeast. This facies was not cored.



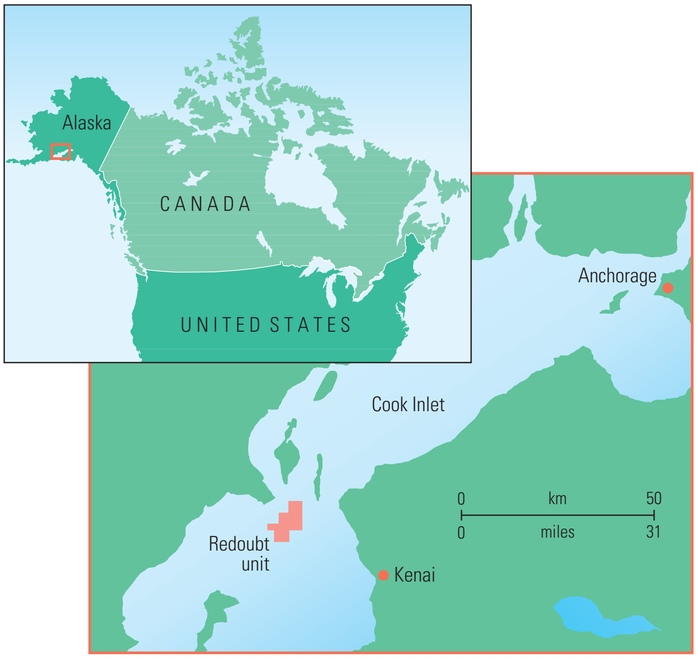
^ Sedimentological models incorporating the information derived from log, borehole image and fullbore core data. Models of two of the reservoir sands in the Guarico 13 field are displayed along with paleocurrent direction from the FMI analysis. Productive facies include the floodplain-channel facies (yellow), crevasse-splay (green), and the braided-channel facies (gold and orange). [Adapted from Hamilton DS, Ambrose WA, Barba RE, De Angelo M, Tyler N, Yeh JS, Dunlap DB and Laubach SE: "Hydrocarbon Production Opportunities Defined by Integrated Reservoir Characterization, Guarico 13/10 Area, Eastern Venezuela," Internal Teikoku Oil de Sanvi-Güere Report (1999).]



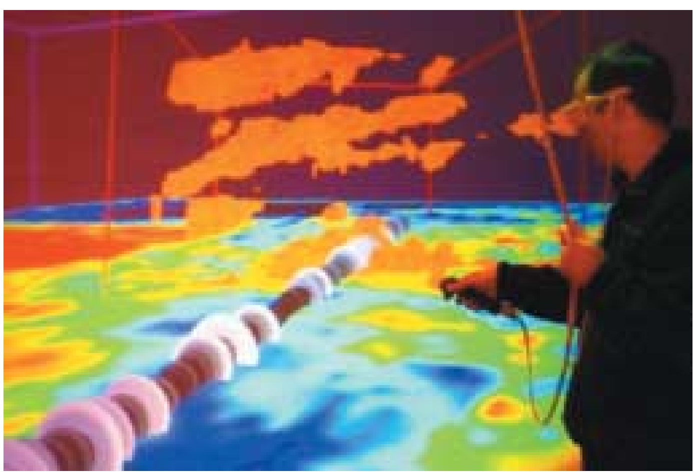
< Floodplain-channel facies. The borehole electrical images, integrated with the core data (4214.5 to 4222.6 ft, core depth), over the fining-upward succession (4219 to 4227 ft) show, from base to top, an erosive surface at 4227 ft (4222.6 ft, core depth) with an associated coarse-grained channel lag, overlain by a medium-grained sandstone with high-angle cross-stratification dipping towards the east and east-northeast. The cross-bedded sets are bounded by truncation surfaces, are inches thick and indicate an east-northeast sediment-transport direction. This interval is interpreted as a channel-fill succession deposited by a fluvial channel oriented east-northeast to west-southwest.

Merecure formation; the floodplain-channel facies in the lower part of the upper Merecure formation; and the shallow-marine shale and marine-bar facies, both at the top of the upper Merecure formation. The channel facies exhibit higher energy sedimentary structures such as planar and trough crossbedding as well as basal scour surfaces (previous page, top).

High-energy environments produce particularly strong directional indicators and typically represent the most productive reservoir section—highest porosity and permeability. In many cases, consistent paleocurrent indicators represent the channel-sand orientation. One of the main reservoirs in the Guarico 13 field, the U2M sand, is interpreted as a floodplain-channel facies. These facies are fining-upward successions of medium- to coarse-grained sandstones between 7 and 35 feet [2 and 11 m] thick, with tabular and trough cross-stratification and characterized by erosive basal contacts (above). This sedimentological information benefits the asset team's reservoir-modeling and field-development efforts (previous page, bottom).



^ The Redoubt Shoal field, Cook Inlet, Alaska, USA.



^ Understanding reservoir geometry using immersive visualization. In many fields, development economics dictates drilling of a minimum number of wells, each having maximum contact with the reservoir. Knowing more about reservoir sedimentology helps reduce the risk of failure or problems in these important wells, improving project economics. Using Inside Reality immersive technology, well-planning teams may be able to plan more complex wells that take detailed sedimentology into account, leading to greater success during drilling and geosteering operations.

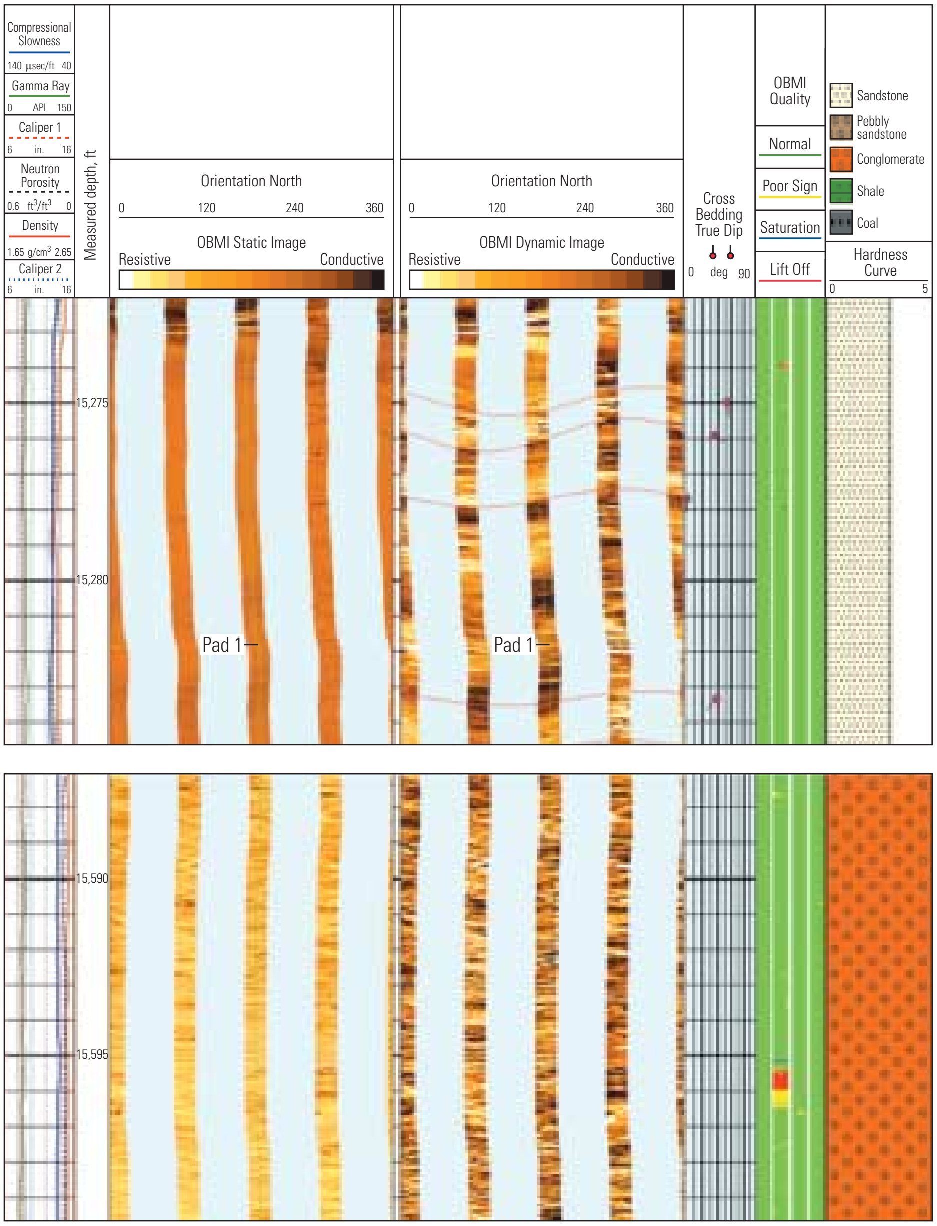
Facies Determination in Complex Rocks

Forest Oil Corporation is a key operator in the Cook Inlet, Alaska, USA, and has maintained an aggressive exploration program in the Redoubt Shoal field by using advanced technology to improve reservoir characterization. OBMI images acquired in March 2003 marked the first use of the tool by Forest in Alaska. There is substantial evidence from early results that the OBMI tool will have a considerable positive impact on facies determination and correlation in this area.

The Cook Inlet is a major oil and gas province located south-southwest of Anchorage, Alaska (left). It is located in a forearc-basin setting, which developed as a result of the subduction of the Pacific Plate margin. The hydrocarbon is trapped in compressional structures related to the convergent tectonics. Complex borehole-stress regimes create difficult drilling conditions that require the use of oil-base muds. Until the arrival of the OBMI tool in Alaska, acquisition of resistivity image data had not been feasible in the Hemlock formation within Redoubt Shoal field.

The central part of the Cook Inlet is filled in with 26,000 ft [7925 m] of nonmarine Tertiary rocks. The Hemlock conglomerates are upper Oligocene in age and consist of interbedded conglomeratic sandstone and conglomerates. They have been classified as lithic feldarenites, feldspathic litharenites, or lithoarenites. From core results, the Hemlock formation at Redoubt Shoal has been interpreted as low-sinuosity braided-stream deposits. The sandstones and conglomerate beds are often stacked to form large, homogeneous, sedimentary units that can reach thicknesses of greater than 50 ft [15 m]. OBMI images now provide important stratigraphic information that was previously unavailable, and a more robust structural-dip calculation than previously derived from the UBI Ultrasonic Borehole Imager tool.[27] Also, because of complex lithologies, the log character of these conglomeratic sediments makes facies determination and correlation difficult. However, OBMI images show clear differences between productive sandstone facies and less productive conglomerate and nonproductive mudstone facies (next page).

27. Johansson M and Saltmarsh A: "The Geological Application of Acoustic Images in Homogeneous Clastic Sediments; Examples from the Tertiary Hemlock Formation, Cook Inlet, Alaska," paper SPE 77995, presented at the SPE Western Regional/AAPG Pacific Section Joint Meeting, Anchorage, Alaska, USA, May 20–22, 2002.



< Facies determination with OBMI images. The use of oil-base mud systems in the Redoubt Shoal field has limited Forest Oil Corporation's ability to differentiate facies. There is now good evidence that the sandstone facies (*top*) can be distinguished from conglomeratic facies (*bottom*) within the Hemlock conglomerates using textural differences in the OBMI image data. The OBMI data were first acquired in the Cook Inlet in March 2003.

Knowing the Reservoir

To understand sedimentology is to understand the foundation on which a reservoir was built. Different depositional environments give rise to a variety of facies that influence reservoir characteristics. Reservoir models that incorporate detailed aspects of depositional processes often are more useful for predicting reservoir performance because of this relationship between environments, facies and the reservoir. Today, high-resolution seismic images and reservoir-visualization and immersion tools give asset teams the ability to more fully account for complexities, such as discontinuous or unconnected reservoirs. The GeoViz 3D visualization tool within GeoFrame software and the Inside Reality 3D virtual-reality system, a technology acquired by Schlumberger from Norsk Hydro, bring interactive well and field planning to the next level (previous page, bottom). As the industry moves ahead, borehole images will join a growing list of functional data types for these reservoir-visualization tools. Real-time and detailed visualization of LWD borehole images for geosteering holds significant promise.

The industry will continue to see the capabilities and applications of borehole imaging tools expand in both wireline and LWD systems. For example, in oil-base and synthetic-base muds, the new OBMI2 Integrated Dual Oil-Base MicroImager tool offers twice the borehole coverage of the original OBMI tool. As technologies advance and improve, the capacity of asset teams to assess, quantify, model and predict the sedimentological effects on reservoir development and performance will continue to multiply. Consequently, the value of borehole imaging in geology and asset management will be more fully realized. —MG