Geological Mapping and Reservoir Characterization of Oil Sands Reservoir by Integrating 3D Seismic, Dipmeter, Core Descriptions, and Analogs in the McMurray Formation, NE Alberta*

By

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Search and Discovery Article #40281 (2008)

Posted February 15, 2008

*Adapted from extended abstract prepared for AAPG Hedberg Conference, "Heavy Oil and Bitumen in Foreland Basins – From Processes to Products," September 30 - October 3, 2007 – Banff, Alberta, Canada

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Introduction

NEXEN Inc. and OPTI Canada Inc. formed a 50/50 joint venture to develop the Long Lake property located about 40 km southeast of Fort McMurray in the Athabasca Oil Sands Region (AOSR) of northeastern Alberta (Figure 1). The project will be developed in several phases. Phase 1 development aims to produce approximately 70,000 barrels per day (b/d) of bitumen. Production will use Steam Assisted Gravity Drainage (SAGD) bitumen recovery technology that uses steam to transfer heat and mobilize extremely viscous bitumen. This technology is applied virtually in all existing and planned in-situ projects in the AOSR.

Optimal positioning of injection and production horizontal wells (well pairs) is a must for project success. However, due to reservoir and bitumen heterogeneity encountered in the AOSR, this is not an easy task. The major challenges for optimal positioning of well pairs include finding, characterizing, and mapping the extent of thick, continuous, bitumen-saturated sands; permeability barriers; water and gas saturated zones; and viscosity changes. Mapping these properties requires the acquisition and processing of a variety of subsurface information and their full integration into geological context. In the Long Lake project, subsurface information includes:

- high resolution 3D seismic
- drill hole data (densely drilled stratigraphic wells commonly cored through the entire zone of interest and logged with conventional suite of geophysical logs including dipmeter)
- laboratory measurements of bitumen content and its physical properties

The purpose of this article is to demonstrate how a multidisciplinary team integrates a variety of measured rock and fluid characteristics in order to interpret and map reservoir heterogeneities impacting SAGD operation; and to illustrate that data integration unavoidably leads to non-uniqueness of interpretation that requires evaluation of different geological concepts by active participation of many team members. A comprehensive integration of data is fundamental to achieve efficient engineering development of the multibillion-dollar oil sands project.

Geological Background

The Lower Cretaceous McMurray Formation forms the most volumetrically significant portion of the Athabasca Oil Sands Deposit (AOSD), the largest petroleum deposit in the world. Since the McMurray Formation has never been buried to significant depths (Williams, 1963) and since early charged petroleum "lubricated" hosting rocks, diagenesis has been minimal, inferring that the reservoir quality directly reflects the depositional history (Wightman and Pemberton, 1997). However, due to restricted accommodation space (Hein, 2007) and multiple transgressive-regressive events, depositional history is very complex. Although regionally the McMurray Formation comprises fluvial, open estuarine, and estuarine-channel complex (ECC) deposits, within the project area bitumen-hosting rocks are identified as ECC deposits. ECC deposits comprise complex networks of interfingered and multiple-stacked, tidally influenced point bar (PB) and associated abandoned channel (AC) fill deposits of an ancient estuary. Genetically associated tidal flat (TF) deposits are rarely preserved in the subsurface, likely due to erosion in this low accommodation setting. Reservoir complexity is further enhanced by a range of channel sizes and their unique geometries as well as internal heterogeneities within each of PB and AC-fill deposits.

Many authors have discussed the geometry of McMurray Formation channel deposits. Mossop and Flach (1983) suggested that thickness of the individual PB deposit might be up to 45 m, as documented at the Steepbank River outcrop. This outcrop may have a modern analog in Han River in Korea as reported by Choi and others (2004). Recent case studies by Brekke and Evoy (2003) and Fustic (2007), have documented individual point bar deposits with lateral extents (width) of > 4km, and ~ 1.5 km, respectively. These dimensions are in line with inferred geometry of the channel meander revealed on the time slice seismic image (Figure 2a) from one of NEXEN Inc. / OPTI Canada's leases. While the above-mentioned dimensions are impressive, studies of modern and ancient analogs suggest that the presence of preserved channel deposits with thickness in all ranges, from the above-suggested 45 meters to as thin as 2 meters (tidal creeks), should not be discounted in subsurface studies. Also, considering that constant re-working of sediments by meandering rivers and tide currents create very complex interfingered channel deposits, the preservation of any entire channel deposit is rather a rare phenomenon.

Internal architecture of both PB and AC-fill deposits appears to be very heterogeneous too. Generally, PB deposits of the McMurray Formation comprise trough cross-bedded sand unit at the base of the channel and Inclined Heterolithic Strata (IHS) unit in its upper portions (Thomas et al., 1986; Smith, 1988; Wightman and Pemberton, 1997). Based on their stratigraphic relationship they are also classified as Lower Point Bar (LPB) and Upper Point Bar (UPB) deposits. In case of McMurray Formation the proportion of UPB to LPB deposits increases as the meander develops, until the UPB extend to the base of the deposit (Wightman and Pemberton, 1997) (Figure 2c and d). However, among other processes, changes in flow hydrodynamics including occasional floods (Thomas and others, 1986; Strobl and others 1997) and changes in position of the point bar within the estuary (Lettley and Pemberton, 2003) affects the idealized geometry of PB (Figure 2c) deposits in terms of reorienting direction of lateral accretion beds and changing lithologies, respectively. The latter is particularly common within maximum turbidity zones where huge amounts of mud may be deposited forming muddy IHS-dominated PB deposits.

As a higher energy deposit, LPB deposit contains coarser sand and is commonly characterized by excellent porosity and permeability associated with high bitumen saturation. On another side, the interbedded nature of sand and mud encountered in UPB deposits makes porosity and permeability and associated bitumen saturation highly variable over short distances. When those properties are upscaled to the entire unit they show that UPB deposits have quite poorer reservoir properties than LPB deposits. Consequently, LPB and UPB may be classified as Type I (Figure 3g) and Type II (Figure 3f) reservoir, respectively, with Type I being the most desirable for oil sands developments. AC-fill deposits are predominantly mud filled and as such are not considered as reservoir, but as a permeability barrier.

Methodology

The purpose of geological mapping is to find and delineate thick and continuous Type 1 reservoirs as the primary target and Type 2 reservoirs as secondary targets for developments. Due to the generic association and spatial, proximities these two reservoir types commonly have to be developed simultaneously. Their finding, delineation and visualization involve several steps.

First, acquired data are processed, analyzed, and grouped to the level suitable for well-to-well correlation. At this step everyone exercises expertise in his/her own discipline or specialty. Geologists make detailed stratigraphic interpretation of each well (1D interpretation). The process involves integrating information from core images, geophysical logs including dipmeter, bitumen-grade distributions, petrophysical analysis, etc. with an aim to group previously described lithofacies into mappable facies assemblages based on their generic depositional associations (i.e., LPB, UPB, AC), determine the vertical continuity of each of the identified channels and the number of stacked channel deposits in examined well, recognize other possibly preserved depositional features (i.e., tie channel deposits), and particularly characterize the type and nature of encountered mud and lean zones. Geophysicists, using both conventional processing and advanced pre-stack processing methods (AVO/LMR and multi-attribute analysis) for reservoir characterization, generate the high quality seismic volumes from which seismic time slices and cross-sections may be easily created. It allows recognizing and tracing not only major lithological changes (breaks), but, also in some instances, estimation of Shale Volume (Vsh) (Gray et al., 2006), distinguishing water, bitumen- and gas-saturated intervals, as well as overall lithology (Bellman, 2007).

Second, interpreted geological data and processed seismic from the first step are integrated to create a realistic 3D visual reservoir model. The process of the data integration for interpreting subsurface information means constant comparison of all available information. Interpretation starts with recognizing geologically large-scale and then smaller, but still mappable features. The large-scale feature, such as the lateral extent of major meandering channels, is commonly detected and delineated on seismic time slices (Figure 2a). Interpretation continues by making a set of geological cross-sections tied to drill-hole locations. Here the major geological information from each hole is correlated from well to well. Seismic reflector traces and LMR facies posted behind the cross-section allow for confident correlation of contacts between sand units and thick shale beds, shale plugs (AC-fill deposits), and muddy IHS deposits. At this stage, seismic resolution reaches its limit. Due to the frequency ‘band-limited’ nature of the seismic method, we are not fully able to image finer detail features such as sand-dominated IHS bedding packages, precise vertical continuity of individual channel deposits, erosional contacts between similar lithologies, etc. These have been achieved using traditional sedimentological approaches supplemented by dipmeter data. Generally, dips with the same and/or similar orientation over a certain depth interval commonly indicate that IHS packages belong to the same channel and that those with opposite and/or oblique orientations belong to different channel deposits. This information allows not only for distinguishing different channel deposits, but also for predicting in which direction reservoir quality might improve (Figure 2c and d). When a set of parallel or semi-parallel cross-sections is created, comparison of geology between them allows for 3D reservoir visualization.

Finally, with the depositional facies framework created, additional information of importance to operations (i.e., bitumen grade, lean zones, viscosity, etc.) may be posted and analyzed within the framework, and the framework can then be modified or, if necessary, reworked to honor all data.

Case Study

The study area extends over 9 sections (9 square miles). Visual inspection of seismic time slices within the study area allows for delineation of at least two meandering channel deposits (A and B) as well as a major Quaternary channel deposit (Q) to the east (Fig 2a). The geometry of the delineated meandering channels very much resembles the geometry of modern meandering channels of the Fly River in Papua New Guinea (Fig 2b). After investigating the seismic time slices from different depths, it appears hard to distinguish whether channel "A" or "B" is younger and stratigraphically higher. This dilemma becomes resolved after inspecting core and dipmeter information. For instance, well "X" (Figure 3c) from depth of 176 to 185 meters shows dips pointing towards the northwest and from 185 to 192 towards the southeast. The contact between those oppositely oriented dips marks an erosional surface between two separate but stacked channels (Fig 2c). The well location suggests that this well penetrates the cutting edge of the AC-fill deposit of "A" channel that is expected to dip into this direction. Underlying lateral accretion beds of the "B" channel are expected to dip in the direction in which meanders developed which is towards the southeast. Lithology confirms both interpretations (Figure 3e and f). Seismic traces show relatively strong contrast between two lithologies allowing tracing of the AC-fill deposit contact towards the north. Tracing suggests that the "A" channel thickens to the north from "X" and that true channel thickness is about 20 m (Figure 3d.). This interpretation is supported by the presence of channel lag breccia along this elevation in nearby wells. Apparent discrepancy between dipmeter data in "X" with data from other wells and seismic traces is logical, considering that this well penetrated only the marginal portion of AC-fill deposit along its cutting edge (Fig 2d.). Dipmeter data supplemented with seismic also suggests that many erosional surfaces observed in cores are actually reactivation surfaces at points where PB deposits were reoriented, perhaps due to floods. This information suggests that observed erosional surfaces are not disconformities. The mud dominated nature of a majority of laterally accreting beds in channel "B" may be explained as a function of the sinuosity of the "B" channel that indicates low-current energy. Analyzed internal architectures and mapped geometries, placed in view of the concept of increased proportion of UPB to LPB deposits as meander develops, suggests that LPB deposits for both channel "A" and channel "B" has to be predominant in the north and northeastern corner of the study area (Figure 2a). Finding stacked LPB deposits means finding thick and continuous Type I reservoir that allows for commercial development. The absence of geological reflectors on seismic indicates consistent lithology, perhaps supporting the interpretation of thick stacked LPB deposits. However, other direct subsurface information confirms this suggestion (typical core image from that area - Figure 3f). More detailed characterization for placing horizontal developmental wells will be focused in that area in order to predict the actual recoverable reserves in context of reservoir heterogeneities and SAGD technology limitations.

The above interpretation was not straightforward. Two instances of non-uniqueness between data presented challenges for integration of interpretation. In the first instance, seismic time slices seem to image scroll bars of channel "A" that extend in depth below the interpreted base of the channel. Detailed analysis suggested that it is possibly due to multiple reflection events propagating within the formation, a common issue with surface seismic imaging. In the second case, seismic interpretation highlighted the presence of a 4-5-meter thick set of laterally accreting beds close to the upper portion of the reservoir. Dipmeter data from two wells that have penetrated this interval do not support that suggestion; however, review of the core data showed the likelihood of seismic being more reliable, and seismic information was honored in mapping the extent of this channel deposit.

Future Work

The next step is to use interpreted information as a frame for reservoir simulation. In these terms, upscaled geological facies are converted into facies assemblages (depositional architectural elements - LPB, UPB, AC, etc.) that were used for well-to-well correlation on each of geological cross sections should be connected to form 3D objects. Those objects will posses similar reservoir properties for each individual channel and, if populated by empirically derived averaged values for properties of interest, may be directly transformed into distinct reservoir flow units – huge cells. Such a model will provide a realistic 3D framework for reservoir simulations.

Conclusions

Although complex, subsurface reservoir geology of the McMurray Formation is mappable in subsurface. However, only full utilization and integration of all available geological data and geophysical data allow for a realistic geological interpretation and model for oil sands developments purposes. It requires the teamwork of many geologists, geophysicists, and engineers.

Acknowledgments

We are thankful to NEXEN Inc. for allowing us to present data and interpretation for this case study. We are also thankful to Adam Yakabuskie and Shin Ma for assisting in creating figures accompanying this paper.

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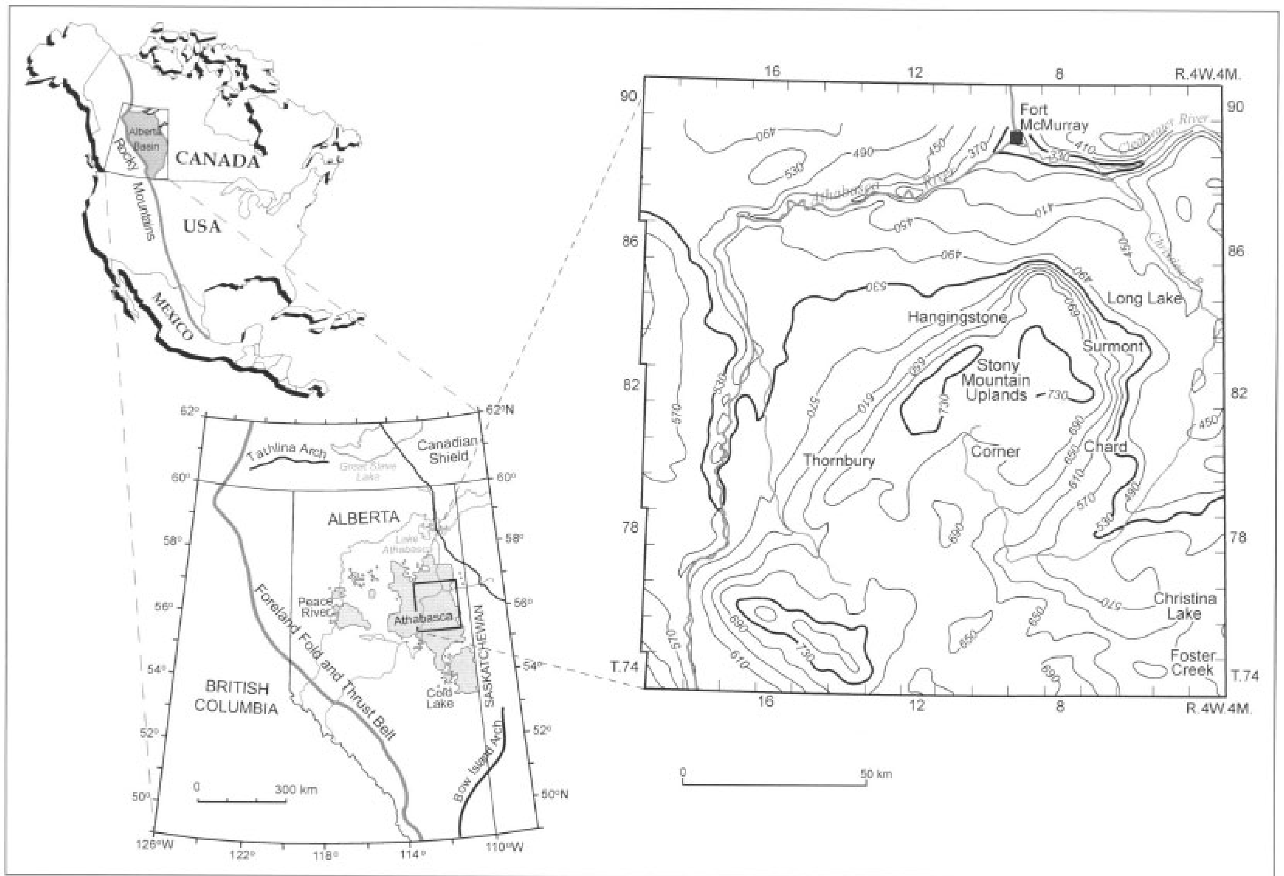

Figure 1. Location map for Long Lake property in Athabasca Oil Sands Region, northeastern Alberta (from Barson et al., 2001).

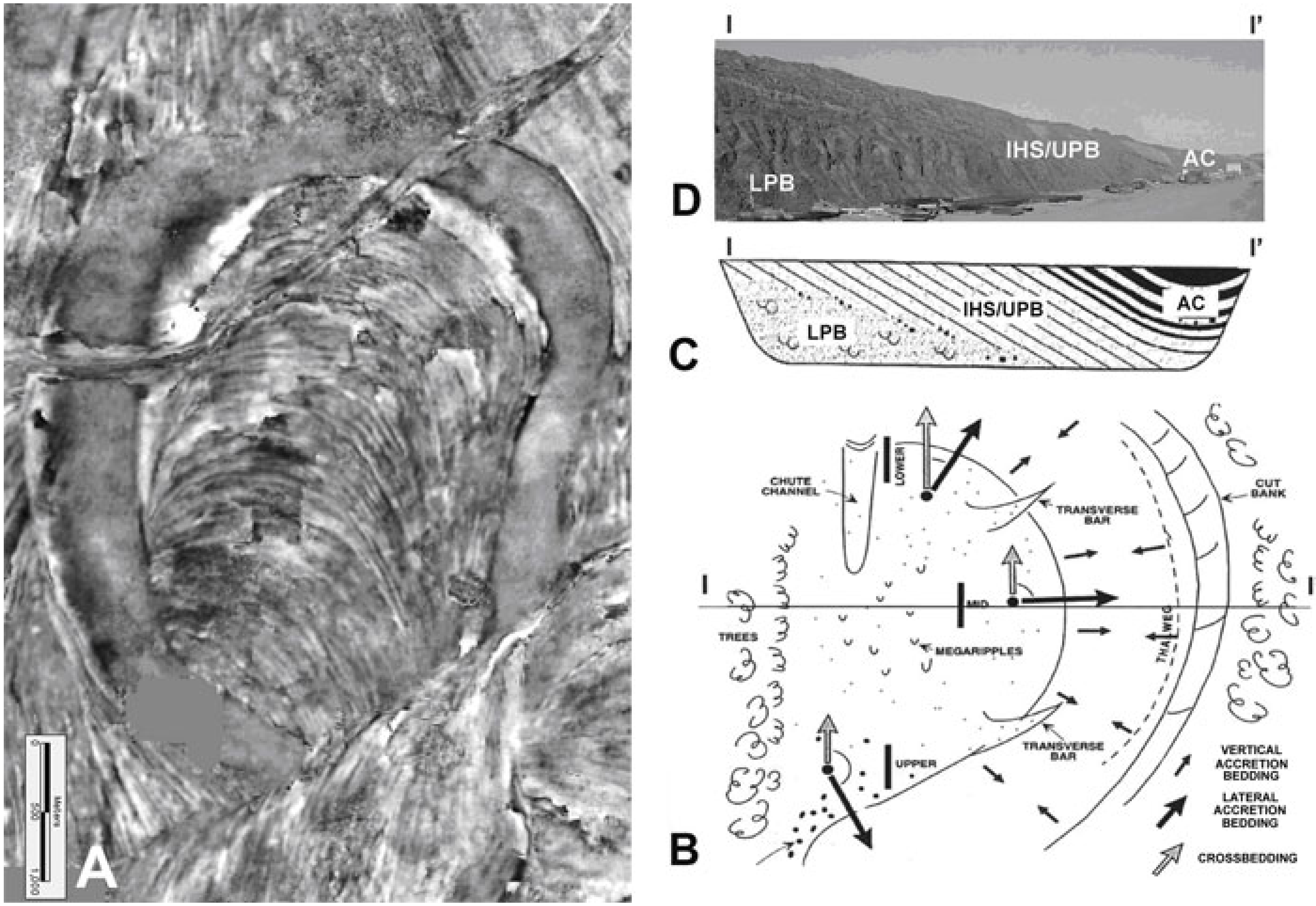

Figure 2. McMurray Formation – geometry and architecture of tidally influenced channel deposits. **A.** Seismic time slice from one of NEXEN Inc. / OPTI leases shows the lateral extent of a single point bar deposit extending beyond 4 km. **B.** Dip orientation within a point bar depositional setting: lateral accretion (black arrows) vs. cross-bedding (gray arrows) are juxtaposed on point bar surface. Short gray arrows within the channel suggest the direction of vertical accretion of bedding that would develop after channel abandonment. I-I' is the position of a cross-sectional line for Figure 2C and D. (Modified after Hayes, 2002.) **C.** Schematic diagram of a point bar deposit illustrating its constituent elements: lower point bar (LPB), upper point bar (UPB) and abandoned channel-fill (AC). The ratio of UPB to LPB increases as the meander migrates until UPB deposit beds extend to the base of the deposit. (Modified after Wightman and Pemberton, 1997.) **D.** Image of an exposure at Muskeg River Mine displaying the lateral and vertical changes of reservoir properties as suggested in Figure 2C. Bitumen grade of 15 mass % encountered in LPB zones decreases laterally (to right) to 0 mass % in abandoned channel-fill deposit (light colored exposure at right end). Length of the exposure is about 500 m; height of the face is 15 m. (Modified after Fustic, 2007.)

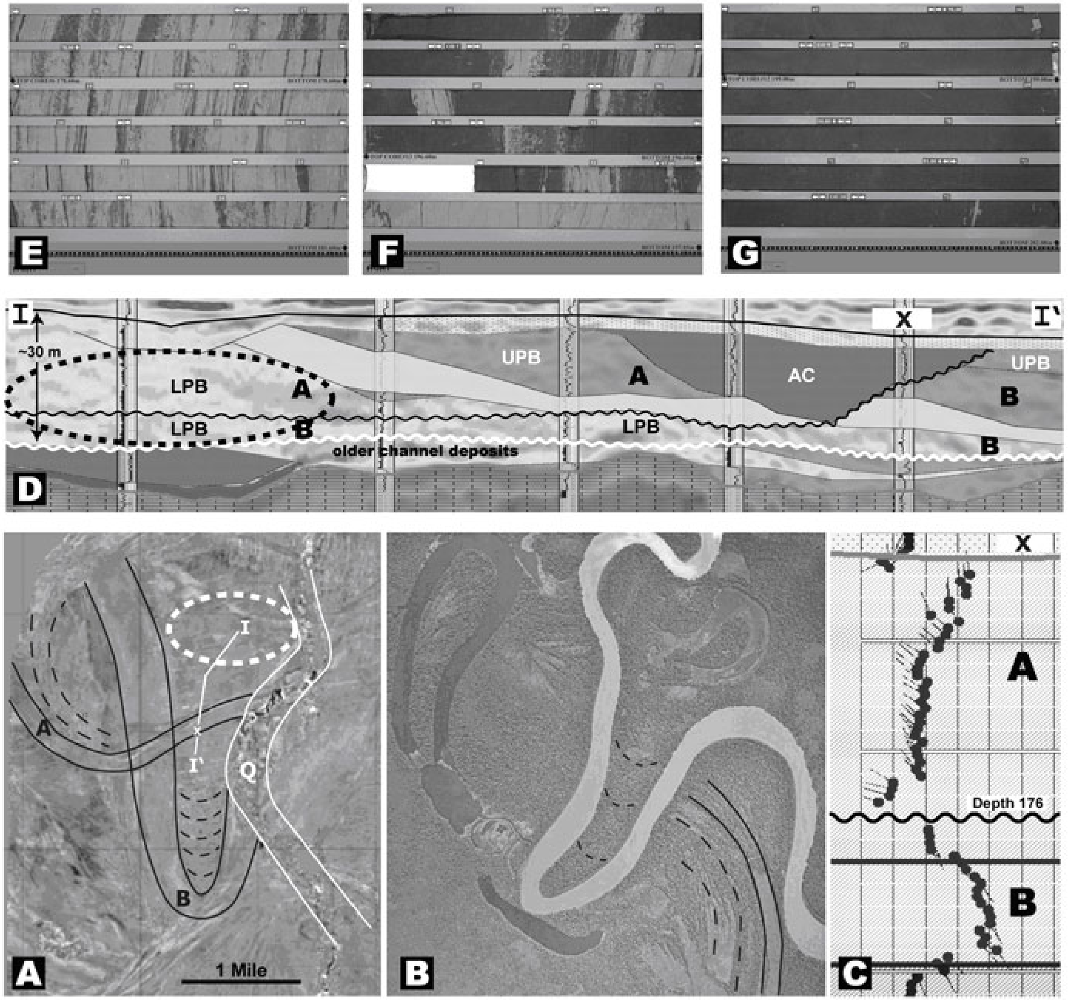

Figure 3. Reservoir geometry and characterization. **A.** Seismic time slice over the study area. Highlighted are two meanders labeled as "A" and "B" channels. Scroll bars are highlighted by black dashed lines and terminal portions (abandoned channel-fill deposits) with black solid lines. A Quaternary channel deposit that has incised into the McMurray Formation is outlined and labeled "Q". White line (I-I') shows the position of the geological section presented in Figure 3D. Vertical well "X" (see Figure 3C) is marked by a small white cross (x). A big oval (white dashed lines) encircles an area with the best reservoir sands. **B.** Aerial photo of Fly River in Papua New Guinea shows similar geometries to those revealed by seismic in Figure 3A. **C.** Dipmeter data from well "X". Dip orientation determines the stratigraphic order of stacked channels A and B. **D.** Geological cross-section showing the relationship of stacked point bar "A" and "B" deposits. Black wavy line shows the bottom of the channel "A" whilst white wavy line indicates the bottom of the channel "B". Note that lower point bar (LPB) portions of channels "A" and "B" are stacked in the northern portion and that only channel "B" exists in the southern portion of the section. Areas not shaded represents thick continuous sands and bottom channel breccia deposits – expected reservoir type I quality. Light shaded areas are sandy HIS deposits of the upper point bar (UPB) deposit – expected reservoir type II quality. Darker shaded areas are mud dominated IHS within the UPB and solid dark grey-color-filled areas are muddy IHS of the abandoned channel-fill deposit (AC). The last two are non-reservoir facies. The dashed sphere indicates the best position for future SAGD development where two LPB deposits are stacked yielding approximately 30 meters vertically continuous sand pay. Note remnants of some older deposits below channel A and B deposits. **E, F, and G**. Core images of abandoned channel-fill, sandy IHS (UPB deposit), and apparently "massive" clean sand from LPB deposit, respectively. They represent non-reservoir, reservoir type 2 and reservoir type 1 deposit, respectively.