Research Article

Quantitative Characterization of Tidal Couplets in Oil Sands Reservoir, the Upper McMurray Formation, Northeastern Alberta, Canada

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The McMurray Formation, NE Alberta, Canada, is one of the most significant bitumen bearing deposits worldwide. This formation deposited and reworked in fluvial, tidal, or estuarine environments results in a huge number of tidal couplets (TCs) which is consisted of mm-cm scale sandy and muddy interlayers. These couplets not only increase the geologic heterogeneity of the oil sand reservoir but also make it hard to predict the performance of in situ thermal processes. In this paper, based on literatures, lab analysis, core photos, logging, and drilling data, a quantitative characterization procedure for mm-cm scale tidal couplets was proposed. This procedure, which includes identification, classification, quantitative description, and spatial distribution prediction, was presented. Five parameters, thickness, mud volume, laminae frequency, spatial scale, and effective petrophysical properties, were selected to describe the TCs quantitatively. To show the procedure practically, TCs in the oil sand reservoir of McMurray Formation, Mackay River Project, and CNPC, were selected to demonstrate this procedure. The results indicate that the TCs are in mm-cm thickness, densely clustered, and in a variety of geometries. Based on geologic origins, these couplets were divided into four types: tidal bar couplets (TBCs), sand bar couplets (SBCs), mix flat couplets (MFCs), and tidal channel couplets (TCCs). The thickness, mud volume, and frequency were calculated by mathematical morphological processed core photos. The spatial scale of TCs was estimated by high-density well correlations. The effective petrophysical properties were estimated by bedding scale modeling and property modeling via REV. Finally, the spatial distribution of TCs was predicted by object-based modeling.

1. Introduction

The oil sands or tar sands, which play an important role in the world energy market, are one typical unconventional hydrocarbon resource [1, 2]. Large amount of oil sand reservoirs is found and in production in Athabasca, Cold Lake, and Peace River, northeastern Alberta, Canada [3, 4]. The bitumen in these reservoirs below 75 m only can be extracted commercially by in situ thermal methods, steam drive, and steam-assisted gravity drainage (SAGD) etc. [5, 6]. SAGD utilizes an 800-1000 m long horizontal well pair, with the two horizontal wells vertically aligned and placed at a vertical distance of approximately 5 m apart. The upper well is used to inject steam in the reservoir zone, thereby slowly heating and mobilizing the bitumen. The heated bitumen, now liquid, flows via gravity down the margins of the developing steam chamber and into the production well below [7]. Although the recovery ratio of SAGD is high, it is badly influenced by strong reservoir heterogeneity, especially in the McMurray Formation which bears plenty of tidal couplets [8, 9].

The tidal couplets deposited and reworked in tidal, fluvial, or estuarine environments are mm-cm scale sandy and muddy laminae interlayers [10, 11]. It is necessary to understand the origins, characteristics, and spatial distributions of the tidal couplets to enhance SAGD well performance. Numerous studies have been done to characterize these tidal couplets.
couplets. Six parameters, laminae types, thickness, sandy volume, the ability allowing steam to go through, vertical permeability, and spatial scale, were proposed [12], but some of these parameters are so ideal that it is not easy to get in the oilfield. However, most specialists pay great attention on estimating the vertical permeability because of the SAGD production mechanism. To do so, based on deposition process-based bedding-scale geomodeling strategy [13] and 2D stream-line method [14], the representative elementary volume (REV) to estimate effective petrophysical properties of tidal couplets was calculated under the criterion of variation coefficient $(Cv) < 0.5$ [15, 16]. Further, a vertical permeability estimation workflow for the McMurray Formation was proposed [17, 18], and an effective permeability estimation workflow for the upper McMurray Formation was presented [19].

However, effective permeability estimation is not enough to demonstrate the influence resulted from tidal couplets on SAGD production. The spatial distribution of tidal couplets between these SAGD well pairs must be taken into consideration, either. Therefore, this paper differs from previous studies in (1) the origin-based classification of TCs that was discussed via core photos, logging, and literatures; (2) five practical and easy-to-get parameters were proposed to characterize TCs; and (3) the spatial distribution of TCs was predicted by object-based modeling. The aim of this paper is to propose a quantitative characterization process for mm-cm scale couplets and to clarify the tidal couplets’ influences on SAGD production.

2. Geologic Background

The bitumen bearing formations in Athabasca were developed in Alberta subbasin of Western Canadian Basin [20]. The McMurray Formation is a member of the Manville Group that was deposited as fluvial-estuarine-marginal successions due to the Boreal sea level rising during the middle to late Cretaceous. It is bounded unconformably below by Carboniferous and above by the Wabiskaw Member, Cretaceous (Figure 1).

The study area, Mackay River Project (MRP), is located c. 30 km northwest of Fort McMurray, Alberta. The initial development area (IDA) of the MRP covers townships 90 and ranges 13 to 14 W4M. The McMurray Formation in Alberta is roughly subdivided into lower, middle, and upper intervals [21]. Although there are three intervals in the McMurray Formation, the lower counterparts is missing in MRP because of erosion. The middle and upper McMurray intervals characterized by a series of clean, linear tidal sand bars contain most of the exploitable bitumen resources

![Figure 1: Location maps showing (a) regional and (b) detailed study area. (c) A typical well (marked the red spot in (b)). Mackay River Project is located northwest of Fort McMurray, Alberta. Grey numbers in boxes indicate section of the LSD.](image-url)
Our focus was the TCs in the middle and upper intervals. The middle and upper McMurray Formation in the Mackay River Project, CNPC, is dominated by six estuary-originated microfacies (Figure 2). The tidal channel, salt marsh, sand bar, and tidal bar are deposited in the middle McMurray Formation [23]. Meanwhile, the mixed flat, sand bar, and tidal bar are dominated in the upper McMurray Formation. The features and distributions of TCs are controlled by the geometry and scale of these microfacies.

3. Methods

The quantitative characterization of mm-cm scale TCs includes following aspects: identification, classification, quantitative description, and spatial distribution prediction. Fortunately, previous literatures and some practical methods can be applied to accomplish these tasks. To begin with, the identification and classification of TCs could be done by core photos and logging. Next, for quantitative description, firstly, the mathematical morphology process (MMP) [25] was applied to calculate the interlayers’ thickness, mud volume, and frequency. Then, based on the origins of TCs, a deposition process-based modeling strategy was utilized to build the bedding-scale model. Further, according to REV, the effective petrophysical properties were estimated under the criterion of $C_V < 0.5$ [15]. Besides, the spatial scale of each type of couplets was estimated by high-density well correlations. Finally, the spatial distribution of these couplets was predicted by object-based modeling.

3.1. Mathematical Morphology Process. MMP was applied to quantify the features of TCs in core photos because of its simplicity and reliability [26]. The MMP uses a certain shape of structure element to analyze, measure, and extract the information of images. In MMP, the binary value image, regarded as a data set, was handled by a structure element which is a data set, either. A series of calculation was conducted when the structure element was moving through the image. The information remained in image depends on the shape of the structure element.

3.2. Modeling Strategies. The characterization and spatial prediction of TCs require different modeling strategies. For

![Sedimentary model of the McMurray Formation, MRP](image-url)
Figure 3: Core images in McMurray (left) and GR vs. RT crossplot (right) (blue: sands, orange: TCs). (a) 0803089, 181.9 m. (b) 0227090, 178.6 m. (c) 0413090, 186.3 m. (d) 0812090, 196.15 m. (e) 0605091, 182.9 m. (f) 0614090, 187.8 m.

Figure 4: The TCs’ classification in middle and upper McMurray Formation, Mackay River Project.
the effective petrophysical property estimation, a bedding scale model is essential [13]. We recommend the process-based method for two reasons. First, the origins and features of each type of tidal couplet are analyzed through sedimentary interpretation and description. Secondly, process-based modeling strategy has been applied successfully in the similar reservoir conditions.

As for the prediction of spatial distribution, two methods, object-based one and surface-based one, are both important and useful [27, 28]. The geobody in the model built by the object-based method can be in a variety of geometries and spatial scales, while the surface-based method that utilizes the surfaces and boundaries in each level, bedding, lithofacies, lithofacies associations, intervals etc., seems to be less flexible and variable. So, in this paper, the object-based method was used to predict the spatial distribution of TCs.

3.3. REV Theory. The representative elementary volume (REV) is adopted to estimate the effective petrophysical properties. The intrinsic variability in rock properties and geological characteristics at all scales is commonly referred to as “heterogeneity” [29]. Replacing a heterogeneous property field with a hypothetical homogeneous one is the notion referred to as REV. It denotes a volume of the rock property that is large enough to capture a representative amount of the heterogeneity [30]. The determination of this volume is
associated with the length scale. When the sample volume is small compared to the length scale of heterogeneity, the measured property will vary with small changes in the sample volume. At some volume, namely, the REV, the fluctuations are minimized, and a representative amount of heterogeneity can be confidently averaged in the measurement. Nordahl & Ringrose [16] have shown that a lithofacies-scale REV can be achieved at the c. 0.3 m length scale for models of tidal heterolithic bedding deposits.

4. Results

Based on core photos, lab analysis, logging, and drilling data, the identification, classification, characterization, and distribution prediction of TCs were done through mathematic morphology process, bedding-scale modeling, REV, and object-based modeling. The details of each step were demonstrated as follows.

4.1. Identification. The 88 core wells in IDA or nearby provide a solid foundation for TC observation and description. The identification of TCs largely depends on high resolution core photos and logging.

In core photos, TCs offer the following characteristics: (1) they are in mm-cm scale thickness with great variation. The thinnest mud laminae can be 2 mm, while the thickest one can be 5 cm (Figures 3(a)–3(d)); (2) they are in a variety of shapes and geometries because of different deposition micro-environments and the degree of bioturbation (Figures 3(b) and 3(e)); and (3) they are densely clustered with high frequency sandy and muddy interlayers (Figure 3(f)).

In logging, TCs were identified by GR and RT crossplot because of their thickness and oil saturations. TCs identified in logging are in high GR (40-120 API) and low RT (10-50 Ω·m), while for the bitumen bearing sand intervals, generally, the value of GR is less than 40 API, and RT is more than 50 Ω·m (Figure 3 right).

4.2. Classification. Many classification schemes were proposed for TCs from different point of views, such as mud volume, frequency, thickness of mud laminae, and the degree of bioturbation [31]. In the literatures, the classification scheme of mud volume is widely accepted. In our point of view, although the mud volume reflects lots of information, like the sedimentary supply and hydrodynamic condition, it is not representative because the TCs originated from different environments may have the same mud volume [32]. Therefore, according to sedimentary microfacies analysis, this paper proposed a geologic origin-related classification scheme for TCs. In the origin-based classification scheme,
TCs can be divided into four types. They are tidal bar couplets (TBCs), sand bar couplets (SBCs), mixed flat couplets (MFCs), and tidal channel couplets (TCCs). Each type of TCs offers the following features (Figure 4).

4.2.1. Tidal Bar Couplets (TBCs). TCs in tidal bars were named tidal bar couplets (TBCs). The mud volume of TBCs is low. The dispersed mud laminae in TBCs are in mm-scale thickness and low frequency with few bioturbations. The bioturbation index (BI) \[33\] ranges from 0 to 1. The sedimentary supply of sand is abundant, and the bedding structures well preserved indicate a strong hydrodynamic condition.

4.2.2. Sand Bar Couplets (SBCs). The SBCs are TCs developed in the sand bars. The mud volume of SBCs is moderate. The mud laminae are in varied thickness and clustered with few bioturbations. The thinnest laminae can be 2 mm, while the thickest one can be 42 mm. The BI ranges from 1 to 2. The fine sediments supply increased, and there are wavy bedforms in surrounding deposits with subtle slope.

4.2.3. Mixed Flat Couplets (MFCs). The laminae of MFCs existed in mixed flat are easily recognized because of their mud volume, high frequency, and strong rhythmic. The mud volume of MFCs is high with moderate bioturbations. The BI ranges from 2 to 4. The most obvious feature is the strong rhythmic sandy and muddy interlayers which indicate a rhythmic deposition process and abundant deposition supply.

4.2.4. Tidal Channel Couplets (TCCs). TCCs are found in tidal channels. Its mud volume is high with clustered thick mud laminae and high degree bioturbation. The thickness of mud laminae in TCCs can be up to 63 mm. The BI can be 3-5. The structures of thick mud reworked by bioturbation form lots of irregular pores and holes. The mud volume and remained structures indicated a sedimentary environment with low hydrodynamic condition.

Based on logging identification of TCs and classification scheme, four types of TCs can be identified by GR and RT crossplot. The results indicate that TBCs are in low GR (20-30 API) and high RT (40-50Ω·m); SBCs are in moderate-high GR (84-110 API) with moderate RT (25-35Ω·m); MFCs are in moderate-high GR (85-115 API) and low RT (15-25Ω·m); TCCs are in high GR (90-120 API) and low RT (10-15Ω·m) (Figure 5).
4.3. Quantitative Description. Five parameters, i.e., thickness, mud volume, frequency, spatial scale, and effective properties, are used to describe each type of couplets quantitatively. Thickness, mud volume, and frequency are calculated by core photos. The spatial scale of each couplets is estimated by high-density well correlations. As for the petrophysical properties, the porosity and permeability are estimated by the bedding scale model and REV. The details of results are as follows.

4.3.1. Thickness, Mud Volume, and Frequency. The thickness, mud volume, and frequency of each type of TCs are calculated by core images processed by five steps. There are two prerequisites of the MMP application in the study area. First, it is assumed that only two kinds of deposits, i.e., sandy intervals and muddy laminae, are in the target formation, while the dark pixel represents sand and the white pixel represents mud. Secondly, to ensure the accuracy, we only count the mud layers which go across the vertical axis of the core photo.

Take SBCs as an example, (1) obtaining the pixels matrix of depth-corrected core images by gray processing and (2) using a local pixel threshold to gain binary images. Pixels above the threshold are set to be sand, while others are set to be mud. The dark pixels denote sand while white one denotes mud; (3) erasing the noise pixels by erosion algorithm via a rectangular structure element; (4) using expansion algorithm by the same structure element and for image restoration; and (5) counting the thickness and numbers of the white pixels in yellow box. Further, the mud volume and frequency can be calculated by the total pixels and the length of the core images. Additionally, the mud volume of TBCs and SBCs was calculated in every 50 cm intervals, while MFCs and TCCs are in 30 cm. The frequency was calculated by every 50 cm (Figure 6).
4.3.2. Thickness. Results indicate that thickness of each type of TCs varies. The thickness of TBCs ranges from 1 to 12 mm with the average value of 3 mm. For SBCs, the thickness ranges from 2 to 42 mm with the average value of 11 mm. The thickness of MFCs ranges from 1 to 16 mm with the average value of 2 mm. As for TCCs, its thickness ranges from 8 to 63 mm with average value of 18 mm (Figure 7).

4.3.3. Mud Volume. Similarly, the mud volume of different types of TCs changes. The mud volume of TBCs ranges from 1% to 12.13% with the average value of 9.57%. For SBCs, the value ranges from 13.24% to 31.02% with the average of 26.54%. The thickness of MFCs ranges from 43.97% to 52.13% with the average of 51.06%. As for TCCs, its thickness ranges from 36.47% to 49.17% with average of 45.29%. Meanwhile, mud volume logs of 1 cm, 5 cm, and 10 cm intervals can be calculated by changing moving windows through the whole well (Figure 8).

4.3.4. Frequency. The frequency changes greatly. The frequency of TBCs is relatively low, ranging from 1 to 5 No./m with the average of 3. For SBCs, the frequency ranges from 5 to 10 No./m with the average of 25. The thickness of MFCs ranges from 32 to 66 No./m with the average of 64. As for TCCs, its thickness ranges from 3 to 10 No./m with the average of 8 (Figure 8).

Figure 11: Bedding scale models of MFCs (mud volume = 36.44%). (a) Core images. (b) Geometry model. (c) Permeability. (d) Porosity realization. All models are presented in core view.
Figure 12: Petrophysical properties from the bedding model. (a) Kv/Kh histograms (blue: Kv/Kh of core plugs with mean value 0.74; range: effective Kv/Kh with mean value 0.36. (b) KE and mud volume crossplot.

Figure 13: Estimated horizontal and vertical permeability on a log scale, 1AA141209014 well. Gamma ray (track 1), RT (track 2), and depth in MD (track 3); facies division (track 4); core images (track 5); V shale for 1 cm (track 6); V shale for 5 cm (track 7); V shale for 10 cm (track 8); binary sand-mud division (track 9); Kve log (track 10, purple dots denote core plug Kv) at a vertical resolution of 5 cm; Khe at a vertical resolution of 5 cm (track 11, red dots denote core plug Kh); and core plug porosity (track 12).
(1) Spatial Scale Estimation. The spatial scale estimation of TCs is mainly based on high-density well correlations (Figure 9). The distance between wells in IDA ranges from 250 to 1500 m. Two section profiles were selected carefully. The results are in Table 1.

(2) Effective Property Estimation. To populate the bedding scale models, the lab analysis data of core plugs from the 13 wells were assembled. In Figure 10, the relationships between core-based horizontal and vertical permeability and between the permeability and porosity are presented (328 samples). Because the tidal deposits in the McMurray Formation are unconsolidated and the core plugs are often taken in pure sand intervals, the measured Kv, Kh, and Kv/Kh are commonly biased to higher values. The Kv and Kh range from 10 to 14000 mD with a mean value of 4500 mD while Kv/Kh ranges from 0.1 to 1.3 with a mean value of 0.74 (Figure 10). Besides, there is no linearity between porosity and permeability. High permeability and the lack of a direct relationship between porosity and permeability mean that estimations are necessary before property modeling.

Therefore, to prepare the bedding scale modeling, a mean input porosity value for sand is 0.32, while for mud, it sets as 0.1. A mean permeability value of 4500 mD, with standard deviation of 20 mD, was assigned to the sand laminae. The permeability of mud laminae was assigned a mean input value of 100 mD, with standard deviation of 20 mD. Besides, the quantitative description data of each type of TCs were also set in the model. Additionally, the size of the bedding scale model was in 10 × 10 × 50 cm³. Figure 11 gives an example of the MFC bedding scale model.

Finally, based on REV, the bedding scale modeling and property modeling process were done by SBED®. The property models in this process are upscaled by single phase flow-based simulation and fixed boundary condition to obtain effective properties for a given bedding structure. The criterion for REV is C_w < 0.5. To ensure the accuracy and reliability, 50 realizations of each TC bedding scale model were done. The results show that the TCs reduce the effective petrophysical properties greatly (Figure 12). The TBCs, SBCs, MFCs, and TCCs reduce 9%, 25%, 47%, and 44% of the porosity; 10%, 27%, 51%, and 45% of the Kh; and 64%, 84%, 96%, and 94% of the Kv of the reservoir.

Kv/Kh is corrected from 0.74 to 0.38. Further, the mud volume log with a 10 cm moving window was used to estimate the horizontal and vertical permeability from the bedding scale model results. The upscaled permeability in each interval is much lower than core-based permeability (Figure 13). This is generally true when we take small scale bedding structures and mud volume into consideration.

4.4. Spatial Distribution Prediction. According to the thickness, mud volume, frequency, and spatial scale of each TCs, an object-based geomodeling strategy was applied to forecast the spatial distribution of TCs. Take the SBCs for instance, firstly, the fraction of SBCs (1.89%) is set according to the upscaled well data. Secondly, the body shape, orientation, minor width, Maj/Min ratio, and thickness of SBCs are set based on the spatial scales estimated by high-density well correlations. Finally, SBCs can only be inserted in sand bars. Similarly, the models for the other types of TCs can be built (Figure 14).

Spatial prediction results indicate that TCs are developed in the middle-bottom parts of the target formation. TBCs are in the middle of the formation. SBCs are mainly in the southern area, and MFCs are in the eastern area. Further, the spatial distribution of TCs in 8 production pads can be predicted (Figure 15).

5. Conclusions

In this paper, a quantitative characterization procedure for mm-cm scale tidal couplets (TCs) was proposed. Details of this procedure, which includes identification, classification, quantitative description, and spatial distribution prediction, are presented in the case study of the oil sands reservoir of the McMurray Formation, Mackay River Project, and CNPC. TCs in photos and logging are in mm-cm thickness, densely clustered, and in a variety of geometries. There are four types of tidal couplets in the target formation. They are named tidal bar couplets (TBCs), sand bar couplets (SBCs), mix flat couplets (MFCs), and tidal channel couplets (TCCs), respectively, according to surrounding microfacies. Five parameters were selected to describe TCs. Thickness, mud volume, and frequency were calculated by MMP core photos. Spatial scale was predicted by high-density well correlations, and the effective properties were estimated by a
Figure 15: Distribution of TCs in 8 pads of IDA (purple: TBCs; green: SBCs; blue: MFCs; black: TCCs).
combined modeling method. The reductions of petrophysical properties, especially the Kh, caused by TCs and the spatial distribution of TCs in each well pad explain why the SAGD production performance in the target formation is not so ideal.

Obviously, other sources of data, like Formation Micro-resistivity Images (FMI) [34], can be used in the process of quantitative description of TCs. Besides, the bedding-scale model could also be done by surface-based modeling strategy [27, 28]. The results of effective petrophysical properties can further be upscaled for reservoir simulation which is not mentioned here. Therefore, more work needs to be done for better understanding of the TCs in the McMurray Formation and its influence on SAGD production.

Data Availability

The data comes from the Mackay River Oil Sands Project, CNPC.

Conflicts of Interest

The authors declare that they have no conflicts of interest.

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