DOI 10.1007/s12182-013-0246-9

Evaluation of oil sands resources —A case study in the Athabasca Oil Sands, NE Alberta, Canada

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Abstract: Oil sands are the most important of the oil and gas resources in Canada. So the distribution and evaluation of oil sands form a critical basis for risk investment in Canada. Distribution of oil sands resources is severely controlled by the reservoir heterogeneity. Deterministic modeling is commonly used to solve the heterogeneity problems in the reservoir, but rarely used to evaluate hydrocarbon resources. In this paper, a lithofacies based deterministic method is employed to assess the oil sands resources for a part of a mining project in northern Alberta. The statistical analysis of Dean Stark water and oil saturation data and study of the core description data, regional geology and geophysical logs reveal that the lithofacies in the study area can be classified into reservoir facies, possible reservoir facies and non-reservoir facies. The indicator krigging method is used to build a 3D lithofacies model based on the classification of sedimentary facies and the ordinary krigging method is applied to petrophysical property modeling. The results show that the krigging estimation is one of the good choices in oil sand resources modeling in Alberta. Lithofacies-grade based modeling may have advantages over the grade-only based modeling.

Key words: Athabasca oil sands, deterministic method, krigging method, 3D lithofacies model

1 Introduction

Oil sands are the most important of the oil and gas resources in Canada (Carrigy and Kramers, 1973; Flach, 1984; Hein and Cotterill, 2006a, 2006b; Mossop, 1980; Ranger, 1994; Vigrass, 1968; Wightman et al, 1995). According to the Alberta Energy Department in 2009, the oil sands resources in situ are 1.7 trillion barrels of bitumen and the proven reserves are 170.4 billion barrels in northern Alberta. About 20% of bitumen resources occur in the surface mineable area[①]. Oil sands are produced from the lower Cretaceous McMurray Formation, in which the depositional environments were typical delta plains (Flach and Mossop, 1985; Ranger and Gingras, 2003). The timing of oil accumulated was earlier than oil sands resource forming (Riediger et al, 2001; Bekele et al, 2002), and biodegradation of pre-existing petroleum created the oil sands resource (Allan and Creaney, 1991; Brooks et al, 1988; Hein and Langenberg, 2003; Moshier and Waples, 1985; Mossop and Flach, 1983; Riediger et al, 2001; Rubinstein and Strausz, 1979). The distribution of the oil sands resources is severely controlled by the reservoir heterogeneity (Brekke and Evoy, 2004; MacGillivray et al, 1992; Langenberg et al, 2002; Smith, 1989). Understanding of the spatial distribution of ore and waste is the key to the mining engineering plan and design and 3D oil sands resource modeling can help understand the distribution[②] (Langenbergetal et al, 2001). Various types of modeling methods have been proposed for bitumen resource mining assessment. The modeling method we used here is a deterministic interpolation method by integrating lithofacies and bitumen grade (porosity and oil saturation). We chose a small area of about 15 sections in the Northern Lights Partnership Property for this study. This paper summarizes the method and geological analysis of oil sands resources in the study area. The hard data available for this study include core description data, Dean Stark data and geophysical log data[③]. The Northern Lights project area is located about 110 kilometers northeast of Fort McMurray in Township 98 and 99, Ranges 5 to 7 W4M (west of the Fourth Meridian) and the study area is situated in the west lease of the project area[④] (Fig. 1).

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Received September 29, 2011

① http://www.energy.alberta.ca/OilSands/791.asp
② Alberta Energy and Utilities Board. Phase 3 final proceeding under bitumen conservation requirements in the Athabasca Wabiskaw-McMurray. Decision 2005-B(122): 32
③ Paulen R, Rice R and Gingras M. Geology of the Fort McMurray area, northeast Alberta. Edmonton Geol. Society (Edmonton). 2004: 67
④ http://www.cspg.org/conventions/abstracts/2005Core/kimball_e_despositional_environments. pdf

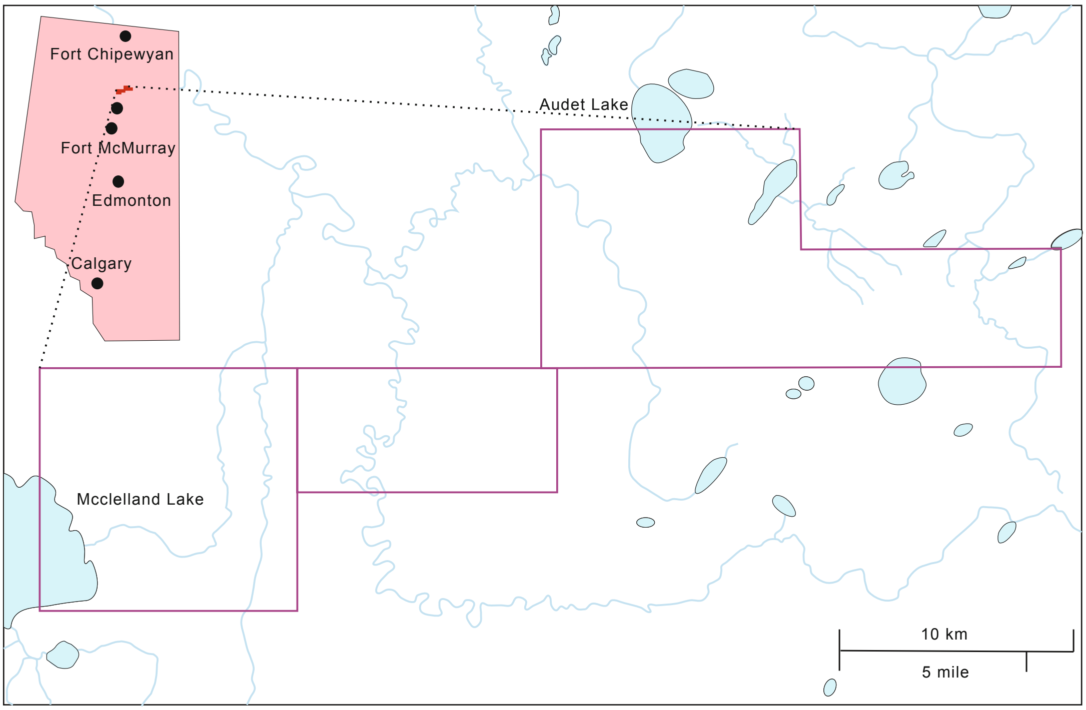

Fig. 1 Location of the study area
(Modified from http://environment.alberta.ca/documents/Synenco_Energy_Northern-Lights-Oil-Sands-Mine_PDD.pdf)

2 Oil sands geology in Northern Lights Project Leases

In the study area, oil sands occur dominantly in the Middle and Lower McMurray Formations, which were deposited in estuarine-tidal-fluvial depositional systems (Alberta Energy and Utilities Board, 2003; Flach and Hein, 2001; Hein and Cotterill, 2006a; 2006b). The estuarine channel sand, tidal channel sand, tidal flat sand, and fluvial channel sand serve as the major oil sands reservoirs. Typically Middle McMurray's upper estuarine sands are well sorted thickly bedded fine to medium grained sheet sand and sand beds are generally on a meter scale. Lower estuarine sands are composed of well sorted fine-medium grained sands with interbedded tidal muds. Tidal flat deposits consist of thin well sorted, fine grained flat sand, flat muds and mixture of fine grained flat sand and muds. Mud breccia was deposited in association with the Middle McMurray estuarine and tidal channel sands. Early fluvial sands are coarse sands deposited in a high energy environment. Late fluvial deposits consist of moderately sorted, fine-medium grained sands. Marsh muds and the associated coal swamp low energy clays, silts and coaly deposits are also developed in Lower McMurray (Hein and Dolby, 2001; Hein et al, 2000).

3 Classification of lithofacies

Based on the study of depositional environments, core data, statistical analysis of Dean Stark data, geophysical log data and the facies associations in cross-sections, the sedimentary facies can be categorized into differenst facies groups in the Middle and Lower McMurray Formations (Table 1).

The reservoir facies group is chiefly composed of sand lithofacies deposited in the tidal/estuarine channel (the Middle McMurray Formation) and the continental fluvial channel (the Lower McMurray Formation). The possible reservoir facies group consists of sand dominated, sand/mud mixed facies and sand/mud breccia mixed facies deposited in the tidal flat or the continental overbank; while the non-reservoir facies group includes the mud/coal dominated facies, the sand facies deposited in the marsh, coal swamp, overbank and tidal flats. Fine-medium grained channel sand (Fig. 2) and tidal/estuarine channel sand (Fig. 3) are the best and typical oil-sands reservoirs in Northern Lights Partnership leases.

4 Data analysis

Statistical analysis of Dean Stark data indicates that the lithofacies classification of reservoirs, possible reservoirs, and non-reservoirs is well reflected by the bitumen content (Table 2). The average content of bitumen in reservoirs is generally well above cut-off grade (6%). That of the possible reservoirs is around the cut-off grade and that of the non-reservoir is well below the cut-off grade. The bitumen contents are generally high in reservoir facies (Fig. 4). For this modeling, we should determine the distribution of the reservoir facies and the possible reservoir facies, of which the bitumen grade is above the cut-off grade (Hein and Cotterill, 2006a; 2006b; Hein et al, 2006).

Table 1 Classification of facies groups in the Lower and Middle McMurray Formations

Member	Facies group	Facies	Brief description	Depositional environment	Bitumen content
Middle McMurray Formation	Reservoir facies	Estuarine channel sand	Fine-medium grained, well sorted sand with low-angle cross beddings	Estuarine	>6%
		Tidal channel sand	Dominantly fine grained, well sorted sand with low-angle cross beddings, and few burrows	Tidal channel	>6%
	Possible reservoir facies	Silt/sand flat	Silt/very fine-fine grained sand with interbedded/ interlaminated mud, moderately bioturbated	Tidal flat	5%-8%
		Channel breccia	Fine-medium grained sand with greater than 10% mud breccia, chaotic	Tidal/estuarine channel	6%-10%
	Non-reservoir facies	Mud flat	Thick mud with interlaminated very fine-fine grained sand/silt	Tidal flat	<4%
		Mixed flat	Interbedded/interlaminated very fine-fine grained sand and mud, intensively bioturbated		
		Abandoned channel mud	Thick mud with interbedded thin fine grained sand		
		Estuarine channel sand	Fine-medium grained, well sorted sand with low-angle cross beddings	Estuarine channel	<6%
		Tidal channel sand	Dominantly fine grained, well sorted sand with low-angle cross beddings, and few burrows	Tidal channel	<6%
Lower McMurray Formation	Reservoir facies	Fluvial channel coarse sand	Medium-very coarse grained, moderately sorted sand with high-angle cross beddings	Fluvial channel	>6%
		Fluvial channel fine sand	Fine-medium-grained, moderately sorted sand with high-angle cross beddings	Fluvial channel	>6%
	Possible reservoir facies	Overbank sand/silt	Silty sand with mud layers	Overbank	4-7%
	Non-reservoir facies	Overbank mixed	Interbedded fine grained sand and mud		<3%
		Pond mud	Thin bedded mud and silt mud	Pond	<1%
		Marsh mud	Mud and silty mud, bedding disturbed by plant roots	Marsh	<1%
		Coal swamp-coal	Coal, may include thin bedded mud	Coal swamp	<1%
		Coal swamp margin	Coal, dark/dark brown carbonaceous mud		<1%
		Fluvial channel sand	Fine to very coarse grained, moderately sorted sand with high-angle cross beddings	Fluvial channel	<6%
		Post-depositional slump	Mixed McMurray sediments, folded, faulted by post-depositional slumping	Post-depositional slump	<4%

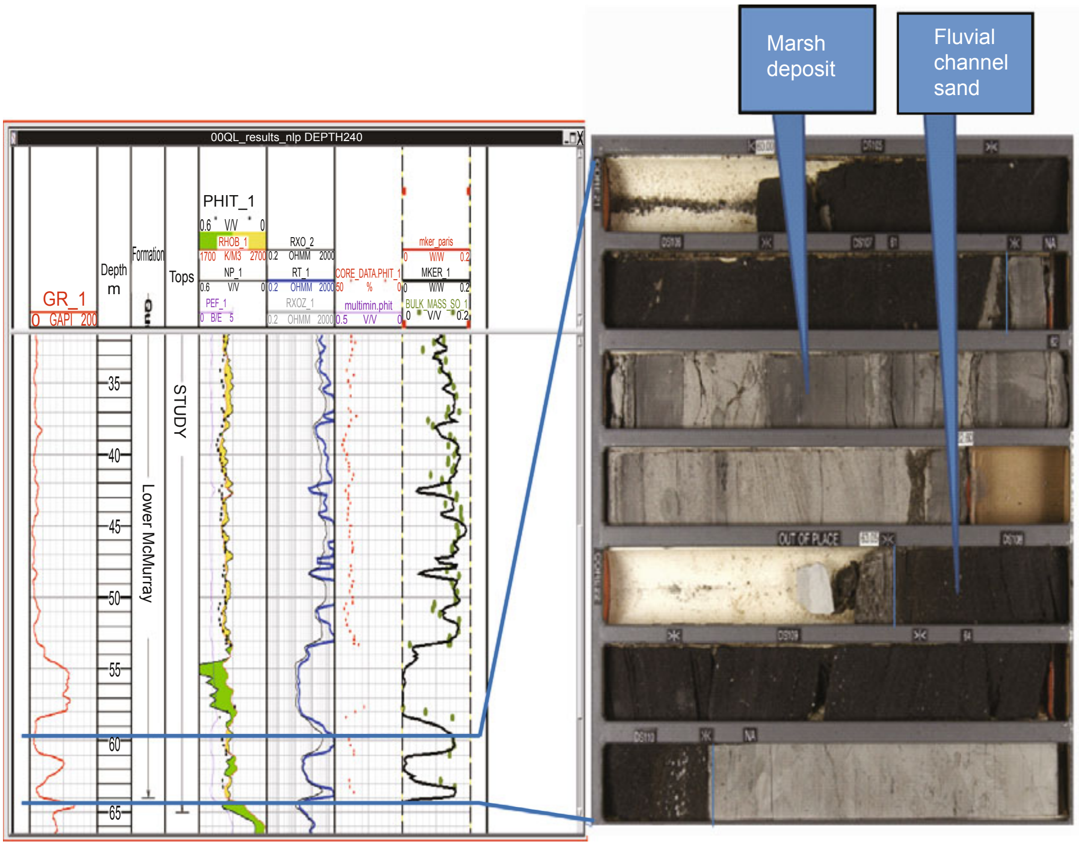

Fig. 2 Typical fluvial channel sand with high resistivity and low Gamma ray

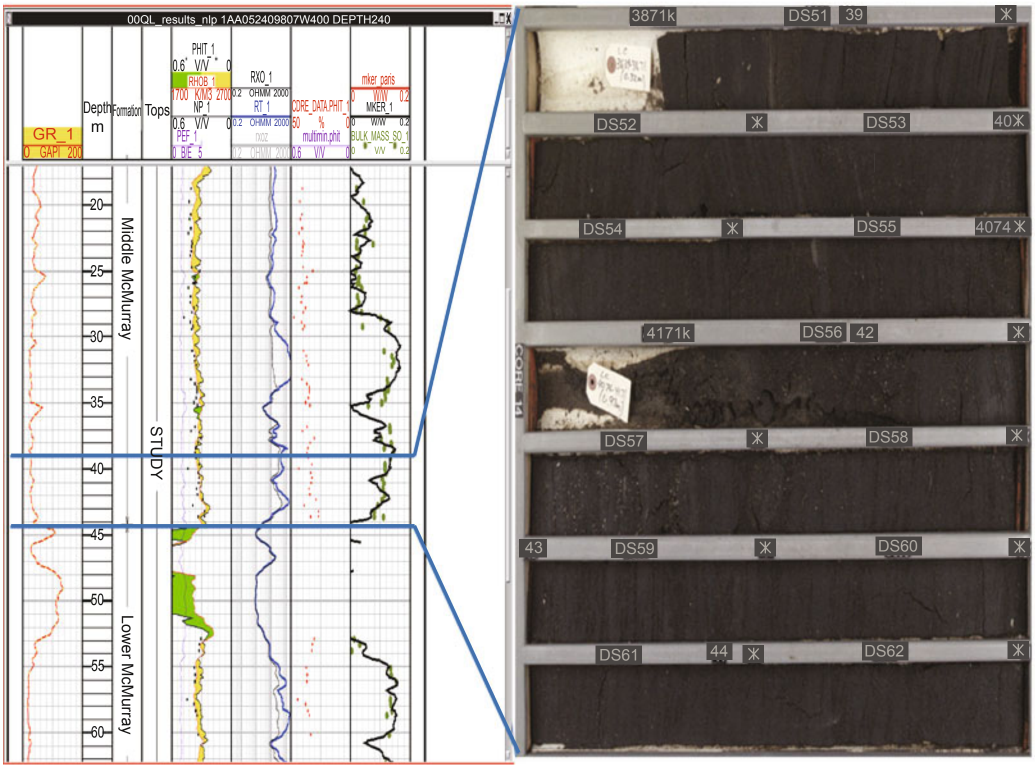

Fig. 3 Tidal and estuarine channel sand

Table 2 Statistics on bitumen content

Facies	Bitumen content, %		
	Min.	Max.	Average
Estuarine channel	5.03	18.24	12.03
Estuarine channel sand	0.27	4.92	2.74
Tidal channel sand	5.00	19.59	12.81
Tidal channel sand	0	4.98	3.09
Tidal/estuarine channel breccia	0	17.65	6.49
Abandoned tidal channel	0.01	3.02	0.69
Tidal flat sand	0.24	17.95	7.87
Tidal flat sand	1.35	2.93	2.25
Tidal flat mixed	0	8.98	3.32
Tidal flat mud	0	4.90	1.09
Fluvial channel coarse sand	5.02	17.98	11.07
Fluvial channel coarse sand	0.02	12.66	2.86
Fluvial channel fine sand	5.00	18.61	11.36
Fluvial channel fine sand	0	7.26	2.82
Overbank sand	0	17.29	5.75
Flood plain	0	8.89	2.50
Marsh	0.01	2.60	0.57
Coal swamp	0	4.18	0.94

In the Middle McMurray Formation, the average reservoir accounts for more than 50% of the total rocks; while the reservoirs occur mainly at the top and the bottom in the Lower McMurray Formation (Fig. 5).

5 Resources modeling method

Deterministic methods and stochastic methods are generally used in oil and gas resources and reservoir modeling depending on the data available. The stochastic methods, such as sequential Gaussian simulation, are employed in the areas with sparse data. However, the deterministic methods are generally considered in the areas with plenty of data available for modeling. In our study area, the well spacing is less than 100 meters in some parts and more than 260 holes were drilled. In this case, it is believed that the deterministic method is a good choice for resources modeling. For facies modeling, the indicator kriging method is used and the ordinary kriging estimator is employed to interpolate the bitumen grade on the basis of facies modeling.

5.1 The method

In the indicator kriging interpolation of lithofacies and the ordinary kriging estimation of reservoir petrophysical properties, semivariograms, functions indicating the spatial correlation in observations measured at sample locations, should be calculated and the appropriate semivariogram model should be selected for modeling both lithofacies and reservoir petrophysical properties.

5.1.1 Semivariogram

Semivariogram is defined as (Clark, 2001):

$$\gamma(h)=\frac{1}{2N(h)}\sum_{i}^{N(h)}(Z(x_i)-Z(x_{i+h}))^2$$

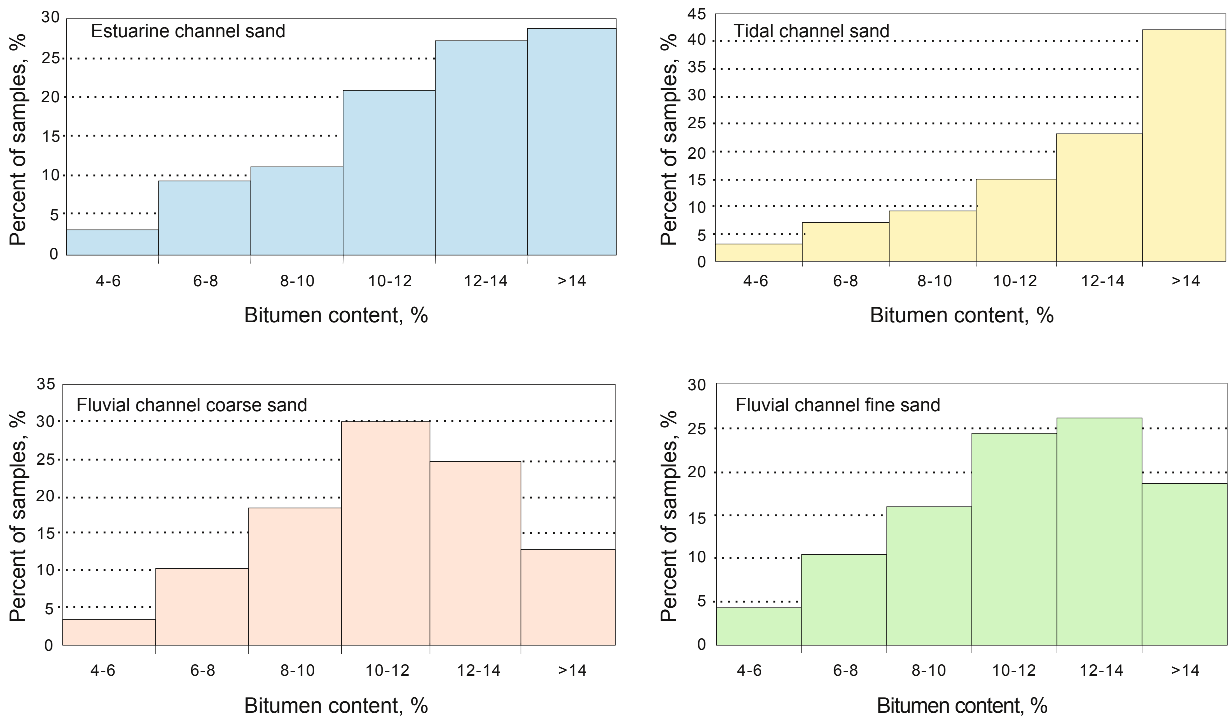

Fig. 4 Bitumen content distribution in reservoir samples

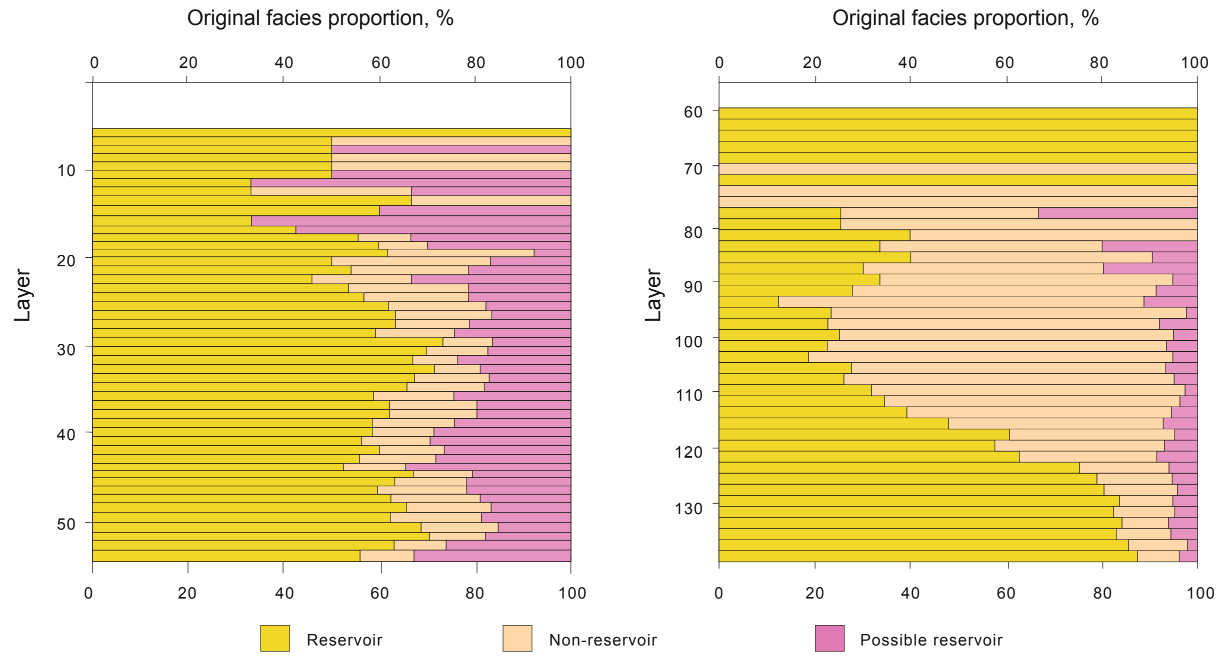

Fig. 5 Vertical distribution of the reservoirs in the Middle (left) and Lower (right) McMurray Formation

where $\gamma(x_i, x_j)$ is the semivariogram; $N(h)$ is the number of data pairs separated by distance of h; $Z(x_i)$ is the value at the start or "tail" of the pair and $Z(x_i+h)$ is the variable at the end or "head" of the pair. The formula above can be used for continuous data and discrete data. However, it is called an indicator semivariogram, where the indicator is used instead of the property values in the formula above.

5.1.2 Semivariogram models

There are many semivariogram models in practice. However, the most common ones are spherical, exponential and straight line models. Nugget, range and sill parameters are important for semivariogram models. However, the straight line model does not have sill and range (Clark, 2001).

5.1.3 Indicator semivariogram

An indicator is used in the calculation of indicator semivariograms and is defined as follows:

$$I(x_i, s_k) = \begin{cases} 1 & Z(x_i) = s_k \\ 0 & \text{otherwise} \end{cases} \qquad k = 1, 2, \cdots, K$$

where x_i is a vector representing a particular facies location; k is the presence of a particular facies.

If the particular facies is present at location x_i, its indicator is assigned to 1; otherwise, it is 0. For the indicator semivariogram, $Z(x_i)$ and $Z(x_i+h)$ are replaced by $I(x_i, s_k)$ and $I(x_i+h, s_k)$ in the semivariogram formula above.

5.1.4 Ordinary kriging method

Ordinary kriging estimation is one of the methods in the kriging estimation family and it uses the local average value to estimate the particular property. The formula is defined as:

$$\hat{Z}(x^*) = \begin{bmatrix} \lambda_1 \\ \cdot \\ \cdot \\ \cdot \\ \lambda_n \end{bmatrix} \cdot \begin{bmatrix} Z(x_i) \\ \cdot \\ \cdot \\ \cdot \\ Z(x_n) \end{bmatrix}$$

$\hat{Z}(x^*)$ is the kriging estimator, $Z(x_i)$ ($i = 1, 2, \cdot\cdot, n$) is grade value at location x_i. The weight vector (λ) is determined as follows:

$$\begin{bmatrix} \lambda_1 \\ \cdot \\ \cdot \\ \lambda_n \\ \mu \end{bmatrix} = \begin{bmatrix} \gamma(x_1, x_2) & \cdots & \cdots & \gamma(x_1, x_n) & 1 \\ \vdots & \vdots & \vdots & \vdots & \vdots \\ \vdots & \vdots & \vdots & \vdots & \vdots \\ \gamma(x_n, x_1) & \cdots & \cdots & \gamma(x_n, x_n) & 1 \\ 1 & \cdots & \cdots & 1 & 0 \end{bmatrix}^{-1} \begin{bmatrix} \gamma(x_1, x^*) \\ \vdots \\ \vdots \\ \gamma(x_n, x^*) \\ 1 \end{bmatrix}$$

where $\gamma(x_i, x_j)$ is the semivariogram of the property Z, which is separated by the distance between locations x_i and x_j. The sum of λ_i (i=1, 1, 2, $\cdot\cdot$, n) should be 1.

$$\sum_{i=1}^{n} \lambda_i = 1$$

5.2 Lithofacies modeling

Indicator kriging is used to interpolate facies. An indicator semivariogram is calculated for reservoir facies, possible reservoir facies and non-reservoir facies in the Middle McMurray and Lower McMurray Formation. The variograms match the spherical variogram model. For the indicator variograms, they match the spherical model very well (Table 3 and Fig. 6 upper).

The nuggets are generally high for the reservoir facies in the study area, indicating high variability of reservoir facies in the study area. The ranges in the major and minor directions are quite different in both the Middle and Lower McMurray Formations, implying the fluvial channel, estuarine and tidal channel depositional environments of the reservoir. After the semivariogram is computed, indicator kriging is employed to interpolate lithofacies.

5.3 Reservoir property modeling

The semivariogram of bitumen content is calculated

Table 3 Calculated variogram parameters for the Middle McMurray and Lower McMurray reservoirs

Property	Middle McMurray reservoir facies	Lower McMurray reservoir facies	Bitumen content in the Middle McMurray reservoir facies	Bitumen content in the Lower McMurray reservoir facies
Variogram model	Spherical	Spherical	Spherical	Spherical
Search radius, m	2000	2000	2000	2000
Lag distance, m	266.7	266.7	266.7	266.7
Tolerance angle, °	15	15	15	15
Tolerance distance, %	50	50	50	50
Nugget	0.726	0.468	0.517	0.554
Major range, m	627.5	1096.7	876.2	1029.4
Minor range, m	302.3	767.9	793.3	774.2
Vertical range, m	29.2	26	29.9	54.1

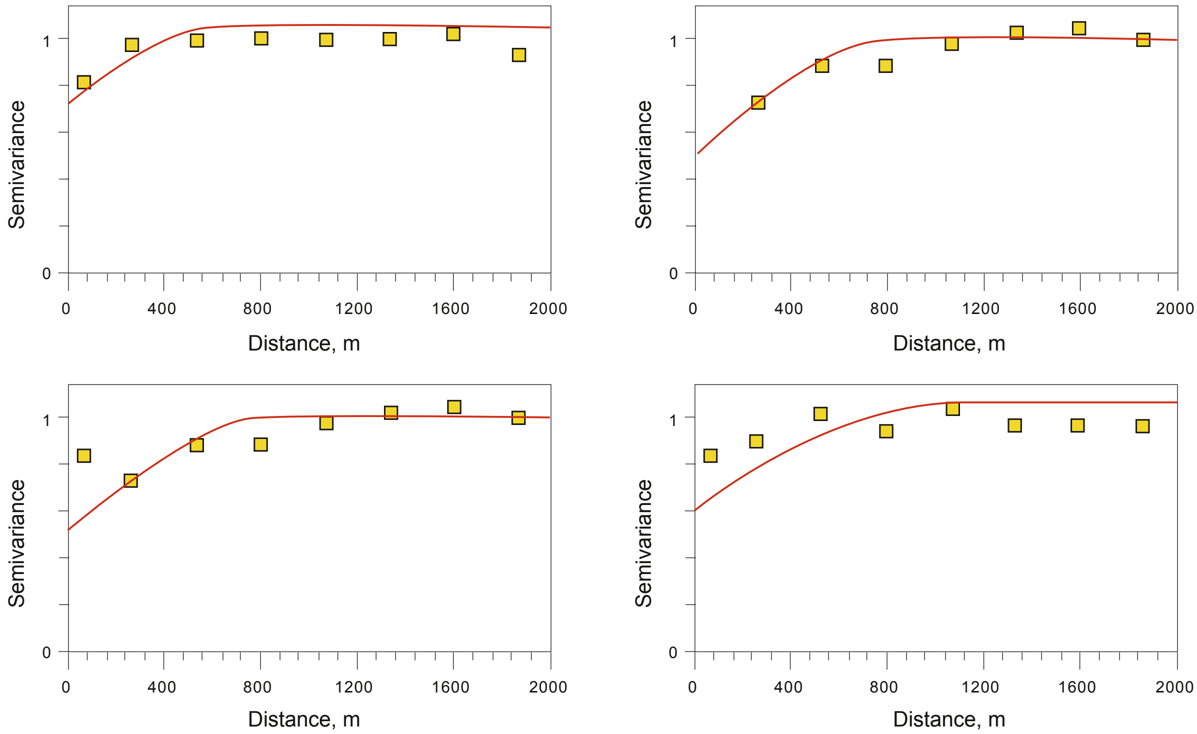

Fig. 6 Indicator variogram of reservoir facies (Upper left: Middle McMurray, Upper right: Lower McMurray), and bitumen content of the reservoirs (Bottom left: Middle McMurray, Bottom right: Lower McMurray)

for reservoirs, non-reservoirs and possible reservoirs in the Middle and Lower McMurray Formations. The spherical model seems to fit the semivariogram of the bitumen grade. Table 3 and Fig. 6 (bottom) show the semivariogram models of bitumen grade in the reservoir facies in the Middle and Lower McMurray Formations respectively. Again the nuggets are high, implying high variability in bitumen grade. The ordinary kriging method is used to interpolate the bitumen grade based on the semivariogram model.

Some modelers also use the inverse distance squared method in their resources modeling. They believe that kriging estimation may produce a more reasonable result if a lot of hard data are available. In addition, the Middle McMurray Formation and the Lower McMurray Formation is treated as two separate zones in both facies modeling and petrophysical modeling.

6 Quality control of modeling results

The facies distribution histogram (Fig. 7) and probability curves are calculated before and after modeling and a comparison between them shows a very good match before and after modeling.

7 Discussion

The kriging estimation is one of the good choices in oil sand resources modeling if the well space in the modeling area is small and lot of hard data (core logging, Dean Stark and geophysical log data) are available though the inverse distance squared method is extensively accepted as one of

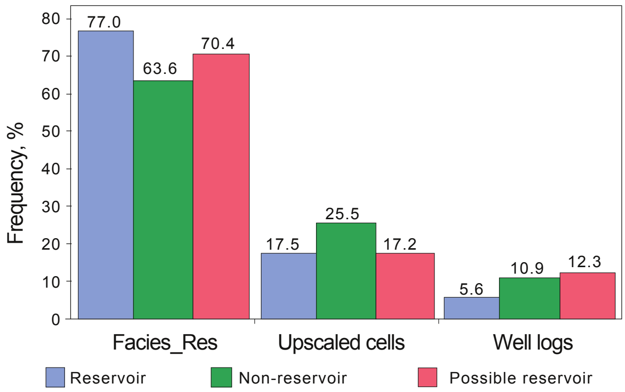

Fig. 7 Distribution histogram of facies after modeling

oil sands resources modeling method in Alberta. Lithofacies-grade based modeling may have advantages over the grade-only based modeling since the data used for estimation are sourced from the same or the similar sedimentary facies in lithofacies-grade based modeling.

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(Edited by Sun Yanhua)