NZEC WP Reports

WP4 Report: Site assessment of carbon dioxide storage potential in the Honggang and Xinli oilfields

Site assessment of the Songliao Basin, report of the Near Zero Emissions Coal (NZEC) Project, Work Package 4

Report to the Department of Energy and Climate Change

Restricted Commercial
ED 02413
Issue Number
Date

Title	Site assessment of carbon dioxide storage potential in the Honggang and Xinli oilfields
Customer	The Department of Energy and Climate Change (DECC)
Customer reference	
Confidentiality, copyright and reproduction	China University of Petroleum, Enhanced Oil Recovery Research Center
File reference	
Reference number	ED02413–

China University of Petroleum
Enhanced Oil Recovery Research Center,
18 Fuxue Road,
Changping District,
Beijing, P. R. China

t: 0086 10 89733266

Author	Name	**Mingyuan Li, Bo Peng, Meiqin Lin and Hua Zhou,** Reviewed by Ceri Vincent, Karen Kirk and Jonathan Pearce, British Geological Survey and NZEC advisors; Paul Freund, consultant and Andrew Minchener, DEVELOPMENT Solutions Europe Ltd.
Approved by	Name	Simon Hayles
	Signature	
	Date	

Executive summary

The Honggang and Xinli oilfields, located within the Jilin oilfield complex, were chosen for detailed site assessment based on the previous study for CO_2 storage potential of oil–bearing reservoirs in the Songliao Basin (Li et al, 2009). The storage potential of the Jilin oilfield complex was assessed using geological data, rock properties, and crude oil and formation water data. Two scenarios have been used to estimate storage capacities within this assessment:

1. Storage potential with enhanced oil recovery by CO_2 flooding.
2. CO_2 storage in depleted oil/gas reservoirs.

The main oil and gas bearing strata are in the Nenjiang, Yaojia, Qingshankou and Quantou formations. The regional caprocks are the Nen I and Nen II members of the Nenjiang Formation and mudstones in the Qingshankou Formation.

The storage capacity of the Xinli Oilfield was estimated to be 3 $MtCO_2$ (CUPB methodology) to 11 $MtCO_2$ (CSLF-based methodology). The storage potential of the Honggang Oilfield was estimated to be 8 $MtCO_2$ (CUPB methodology) to 4$MtCO_2$ (CSLF-based methodology). When depleted, the capacity of the oilfields was estimated to be 6$MtCO_2$ and 51 $MtCO_2$ for the Xinli and Honggang oilfields respectively.

If an EOR recovery rate of 10% could be achieved, an estimated 0.7 and 0.2 million barrels of additional oil could be recovered from the Xinli and Honggang oilfields.

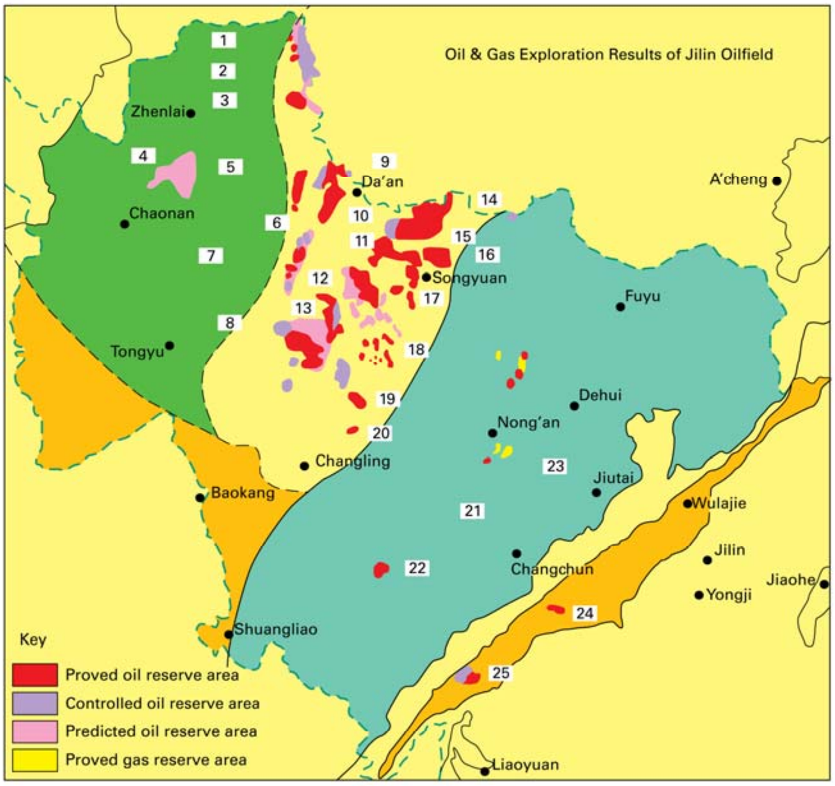
Table of contents

Appendices

1 Introduction

The Honggang and Xinli oilfields, located within the Jilin oilfield complex (Figure 1), have been chosen for detailed site assessment based on the previous study for CO_2 storage potential of oil–bearing reservoirs in the Songliao Basin (Li et al, 2009). The storage potential of the Jilin oilfield complex was assessed using geological data, rock properties, and crude oil and formation water data. Two scenarios have been used to estimate storage capacities within this assessment:

1. Storage potential with enhanced oil recovery by CO_2 flooding.
2. CO_2 storage in depleted oil/gas reservoirs.



1	Yikeshu Oilfield	10	Xinbei Oilfield	19	Dalaoyefu Oilfield
2	Sifangtuozi Oilfield	11	Xinli Oilfield	20	Shuangtuozi Oilfield
3	Yingtai Oilfield	12	Liangjing Oilfield	21	Xiaohelong gas field
4	Taobao Oilfield	13	Qian'an Oilfield	22	Siwujiazi Oilfield
5	Honggang Oilfield	14	Xinmin Oilfield	23	Buhai Gasfield
6	Da'an Oilfield	15	Xinmiao Oilfield	24	Changchun Oilfield
7	Haituozi Oilfield	16	Fuyu Oilfield	25	Moliqing Oilfield
8	Daqingzijing Oilfield	17	Mutou Oilfield		
9	Da'anbei Oilfield	18	Gudian Oilfield		

Figure 1: Location of the Honggang and Xinli oilfields in the Jilin oilfield complex

The main oil and gas bearing strata are in the Nenjiang, Yaojia, Qingshankou and Quantou formations. The regional caprocks are the Nen I and Nen II members of the Nenjiang Formation and mudstones in the Qingshankou Formation. The thickness of these black mudstones and shales in the Nen I and Nen II layers is 200 – 300 m. The thickness of these sealing black mudstones and shales in the Qingshankou Formation is 100 – 400m (Figure 2). These mudstones are widely distributed, thick,

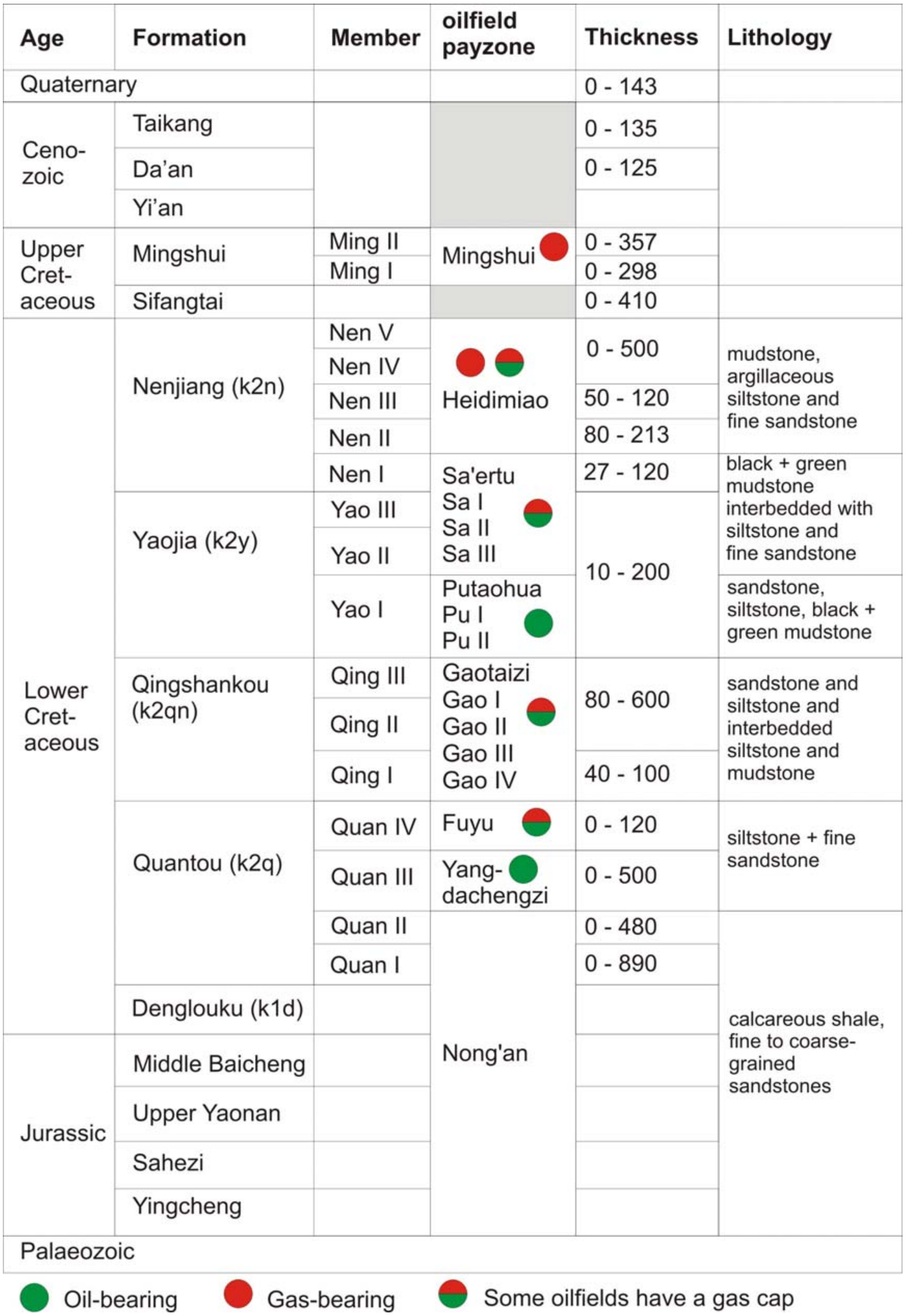


Figure 2: Summary of stratigraphy in the Jilin oilfield complex

with high stabilization, strong plasticity, small pore size, high driving pressure (related to the breakthrough pressure) and therefore are likely to form effective seals to trap CO_2.

2 Honggang Oilfield

2.1 Introduction

The Honggang Oilfield is located in Da'an County of the Jilin Province (Zhai 1993). Exploitation of the Honggang Oilfield began in 1975 with production capacity of 0.5 Mt/year crude oil. The proven oil–bearing area of the Honggang Oilfield covers 49.4km^2 and the proven gas–bearing area is 32.1 km^2. In 2005, the proven original oil in place (OOIP) was estimated at 58.38 Mt and the ultimately recoverable reserves (URR) of oil was approximately 19.44 Mt, the initial gas in place (IGIP) was 37.38×10^{8}m^3 with URR of gas estimated at 21.68×10^{8}m^3.

The trap structure lies in the south of the Honggang Terrace in the Central depression region of the Songliao Basin. The Honggang Oilfield is a structural reservoir comprising the Mingshui gas stratum, and the Heidimiao, Sa'ertu, Gaotaizi and Fuyu strata (Figure 2). The most exploited reservoir is the Sa'ertu stratum in the upper Yaojia Formation (Yao II and Yao III member) and Nenjiang Formation (Nen I member). It belongs to the Honggang–Da'an upper oil–gas accumulation zone of the western reservoir region in the Songliao Basin.

2.2 Geological characteristics of the Honggang oilfield

2.2.1 Formation of the reservoir

The oilfield is located in the Central depression of the Songliao Basin which is near the centre of a multi–layered oil–forming depression. There are six oil and gas bearing strata in the Honggang oilfield (Wang et al., 2007) within which the Sa'ertu, Putaohua and Gaotaizi strata which comprise the main exploited reservoirs. Oil and gas were generated from the hydrocarbon source rocks of the Qingshankou and Nenjiang formations. Most of the oil and gas reservoirs comprise fluvial fan delta and sandstones. Hydrocarbons are formed and stored in the multi–layered reservoir; the source rocks are above the storage layer. The Qing I and Nen I members are the stable seal of this structure, which made it possible to form oil and gas reservoirs within the closure of the anticline.

2.2.2 Structure

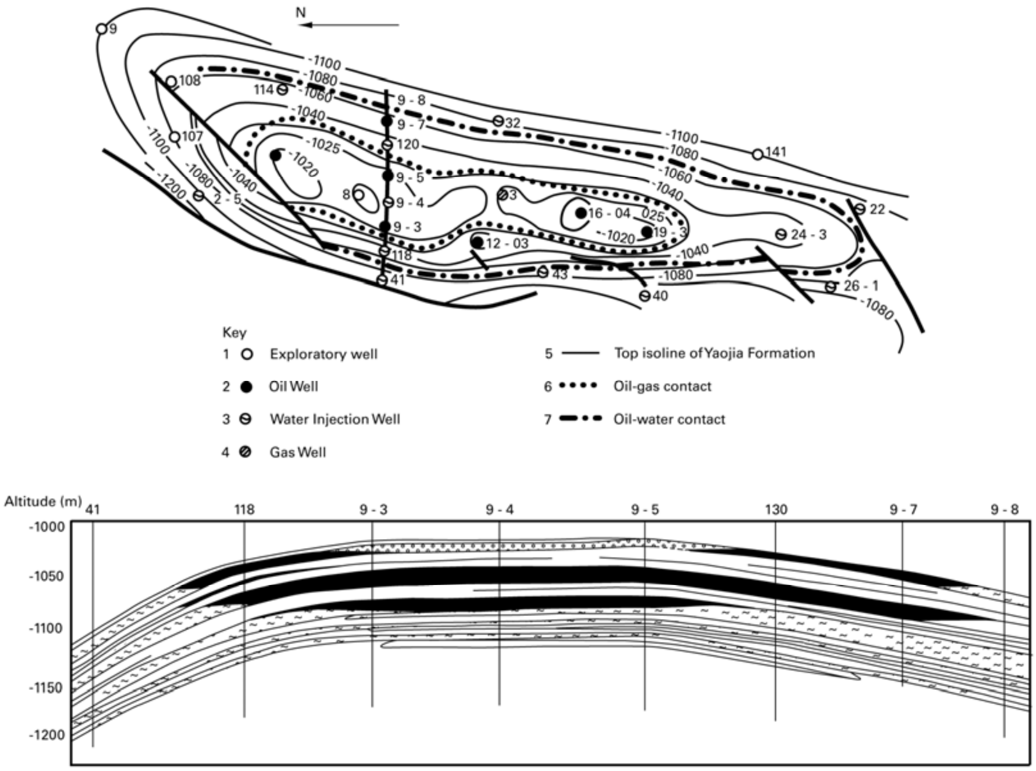
The Honggang structure is a part of the Honggang–Da'an antithetic drag anticline belt located in the south of the Da'an Terrace in the central depression of the Songliao Basin (Li et al., 2009). The overall structural form is an elongate anticline. The western fault was an east–dipping sedimentary normal fault developed at the end of deposition of the Nenjiang Formation which altered to an antithetic fault as a result of developing compressive stress from east to west; this fault formed the rudimentary beginnings of the anticline at the end of the Upper Cretaceous.

The oil–bearing area in Honggang Oilfield is about 49.4 km^2. The structure is located in the Honggang terrace of the Central depression. The structure is a long–axis anticline which is steeper in the western limb, gently sloping in the eastern limb, and flat and wide in the axis (Figure 3).

The long axis is orientated north–north–east (Figure 3), the length of the long axis is 16 km while the short axis is 1.5 – 3.5 km. The closure line is –1070 m (below mean sea level) and the height of the closure is 54 m. There is no evidence of faulting in the structure, which combined with the hydrocarbon reserves, suggests the integrity of this structure may be high. The antithetic fault in the west extends for 50 km and the throw is 250 – 350 m.

The oil and gas reservoirs in the Sa'ertu stratum are the most important in the Honggang Oilfield, they contain crude oil reserves of 32.45 Mt and the centre of the reservoir is –1200 m (below mean sea level). The Sa'ertu stratum is divided into two sub–strata, Sa I and Sa II. The top surfaces of Sa I and Sa II lie along the long–axis anticline, the Sa I closure lies 1065 m below ground level. The Sa II closure lies 1085 m below ground level and there are no faults within the stratum. There are three structural highs in the Sa II sub–stratum and the closure tightens from north to south. The top of the structure slopes gently, the limb angle is gentle in the east and steep in the west. The area of the closure is small in the top and larger in the bottom. The thickness of the Sa I and Sa II sub–stratum is 50 m and 53 m (Table 1) respectively and the closure area of Sa I and Sa II is 46.3 km^2 and 38.2 km^2 respectively. The area of the gas cap is 15.7 km^2 in Sa I sub–stratum and the area of interlayer gas in

Sa II sub–stratum is 5.28 km^2. The natural gas reserves are 50 million cubic metres in Sa I and 18 million cubic metres in Sa II sub–stratum.



Age	Formation	Member	Depth(m)
Lower Cretaceous	Yaojia	Yao III	1160
			1180
			1200
		Yao II	1220
			1240
		Yao I	
			1260
	Qingshankou	Qing III	
			1280
		Qing II	1300

Figure 3: Stratigraphy and structure of the Honggang Oilfield

Table 1: The structural data of the Sa'ertu stratum

Stratum	Thickness(m)	Top point		Axis length(km)		Dip angle		Axis direction
		Depth (m)	Well No.	Long axis	Short axis	West wing	East wing	
Sa I	50	–1015	16–04	16	3.42–1.47	8°–10°	3°	NE 11°
Sa II	53	–1032	Hong16	15.69	3.3–1.4			

2.2.3 Faults

There are almost no faults in the Honggang Oilfield, only one east–dipping antithetic fault located on the west limb of the structure which trends in an approximately north–south direction. The length of this fault is 12.8 km and the width is 115 – 300 m. The fault acts as a boundary to lateral hydrocarbon movement.

2.3 Characteristics of the oil–bearing strata in the Honggang Oilfield

2.3.1 Sa'ertu stratum of the Honggang Oilfield

2.3.1.1 Lithology

The Sa'ertu stratum (payzone) lies in the Yao II and Yao III members of the Yaojia Formation and the Nen I member of the Nenjiang Formation (Figure 2). The burial depth of the Sa'ertu stratum is 1150 – 1230 m, and the lithology of the reservoirs is a combination of sandstone and mudstone which comprises predominantly siltstone and argillaceous siltstone.

2.3.1.2 Division of the oil–bearing layers

The Sa'ertu stratum is divided into two oil–bearing sub–stratum, Sa I and Sa II. These two layers are separated by a 12 m thick sage green mudstone layer with argillaceous siltstone of which 1 – 2 lenses were found in several wells. There are 26 thin layers in the Sa I and II sub–stratum in total. A gas cap is found in Sa I and Sa II and these are also the main oil–bearing layers.

There are three marker beds in the Sa I sub–stratum. The first marker bed is a three metre thick limestone which is about 11–15 m above the Sa I sub–stratum. The second marker bed is a 0.2 – 0.5 m thick calcareous sandstone, which lies on the top of the Sa I sub–stratum. The third marker bed is a 1.5 – 2.0 m thick grey mudstone layer which lies 20 m above the base of the Sa I sub–stratum. In the Sa II sub–stratum there are eight marker beds which are thinly laminated. There are 22 thin layers grouped into eight sandstone–rich layers in the Sa II sub–stratum, 19 of which are oil–bearing.

2.3.1.3 Distribution of oil–bearing stratum and characteristics of the sandstone

The Sa I stratum is a thick sedimentary sandstone layer deposited before a large–scale transgression, the sandstone of the west limb is massive while the sandstone on the east limb is laminated. The Sa II sub–strata layer is a laminated sandstone with a thickness of less than 2 m interlayered with mudstone or sandy mudstone separations which are less than 0.5 m thick.

The distribution of sedimentary layers varies vertically. With the exception of the three sandstone layers in Sa I sub–stratum which are about 10 m thick, most layers are less than 2 m in thickness. The majority of the sandstone layers are successive and horizontally homogeneous. Mudstone layers between the sandstone are generally 0.6 – 0.8 m thick. The mudstone layers have good sealing properties, as demonstrated by natural gas trapped as a gas cap in the sandstone reservoirs.

2.3.1.4 Physical characteristics of the oil–bearing sandstones

The main oil–bearing layers are distributed successively with good physical properties. The average effective thickness of the oil–bearing layer is 5.1 m, the porosity of the oil–bearing layers is about 24% and the permeability is 165 mD. About 22 – 24 % of the reservoir material is cement, which is mainly argillaceous and calcareous; the type of cementation is contact–pore.

2.3.2 Gaotaizi stratum of the Honggang Oilfield

The Gaotaizi stratum is located in the Qing I, II and III members of the Qingshankou Formation. Lithologically, it comprises grey siltstone, fine sandstone and calcareous siltstone. At a depth of 1250 – 1650 m the thickness of the stratum is 10.6 m. The type of cementation is mainly pore–filling with pore–contact. The average porosity of the stratum is 17.9 % and the permeability is 16 mD.

2.3.3 Heidimiao stratum of the Honggang Oilfield

The Heidimiao stratum is located in the Nen II, III, IV and V members of the Nenjiang Formation (Figure 2). The buried depth of the Heidimiao stratum is 900 m and the lithology is siltstone. The porosity of the stratum is about 24 % and the permeability is 73 mD.

2.4 Reservoir characteristics of the Honggang oilfields

2.4.1 Distribution of oil, gas, water and type of reservoir

2.4.1.1 Sa'ertu stratum

The distribution of oil and gas in the Sa'ertu stratum is successive; the oil is situated in the upper part and the water in the lower part of the stratum. The water is inactive because there is insufficient natural water drive. There are clear interfaces between gas, oil and water in the reservoir (Zhong 1997).

There is a gas cap in both the Sa I and Sa II sub–stratum, the oil–water contact in the Sa II sub–stratum is 1084 m below ground level. The oil–gas contact in Sa I sub–stratum is 1030 m below ground level while the oil–water contact is between 1064 m and 1070 m below ground level.

2.4.1.2 Distribution characteristics of oil, gas and water are as follows:

A. There are small gas caps in every sandstone layer of the Sa II sub–stratum.

B. The interfaces between gas, oil and water in every stratum are controlled by the structure. The oil–water contact in the middle and northern highs of Sa I and Sa II strata are at the same depth. The oil–water contact is symmetrically distributed in two limbs of the structure.

C. The gas–oil contact decreases in depth from south to north, the height difference of the interface between gas and oil in the Sa I sub–stratum is about 30 m.

2.4.1.3 Gaotaizi stratum

The distribution of oil, gas and water is complex in the Gaotaizi stratum; it is controlled mainly by the structure and partly by the lithology. There are 40 thin layers containing a 350 m oil and gas. There are clear contacts between gas, oil and water in every sandstone layer. There are gas caps in the majority of the oil–bearing layers, oil and gas lie in the upper part of the layers and water is in the lower part of the layers. There are clear contacts between gas, oil and water in all of the highs of the structure. The southern high is mainly gas–bearing, the central high contains mainly oil and gas and the northern high contains mainly oil.

The Gao I and Gao III sub–stratum form lamellar structural reservoirs with oil and gas located in the top part underlain by water in the lower part of the reservoirs. The Gao II sub–stratum layer forms lamellar lithological–structural reservoirs with gas in the higher part and water in the lower part of the reservoir. This sandstone–rich layer thins from west to east, pinching out in the axis of the anticline.

2.4.1.4 Heidimiao stratum

The Heidimiao stratum forms lithological–structural reservoirs and contacts between gas, oil and water are controlled by both the lithology and structure. Gas is present in the top part of the reservoir, but the oil–gas contact is unclear.

2.4.1.5 Mingshui gas stratum

The Mingshui stratum forms anticlinal gas reservoirs mainly controlled by structure with a distinguishable gas–water contact, the pressure system in the reservoir is stable.

2.4.2 Temperature and pressure

The original reservoir pressure of the Sa'ertu stratum was 12.25 MPa with a pressure gradient of 1.02 MPa/100m. The temperature of the reservoir is 55°C, and the temperature gradient is 5°C/100m. The original saturated pressure was 10.94 MPa, the difference between formation and saturation press is 1.3 MPa (Table 2).

Table 2: Temperature and pressure of the oil–bearing stratum

	Original Reservoir Pressure (Mpa)	Pressure Gradient (Mpa/100m)	Original saturation Pressure (Mpa)	Pressure Coefficient	Difference between formation and saturation pressure (Mpa)	Reservoir Temperature (°C)	Temperature gradient (°C/100m)
Sa'ertu	12.25	1.02	10.94		1.3	55	5
Gaotaizi			13.37–15.97 (middle of stratum pressure is 13.78)	0.99		40–73, (64 in middle of stratum)	4.43
Heidimiao		0.92	8.09			38	4.0

The temperature of the Gaotaizi stratum is 40 – 73 °C, the average temperature gradient is 4.43°C/100m, and the temperature of the middle part in the stratum is 64°C. The pressure ranges from 13.37 – 15.97 MPa, the pressure of the middle part in the stratum is 13.78 MPa; the pressure coefficient is 0.99 on average and the stratum has a normal pressure system.

The reservoir pressure of the Heidimiao stratum is 8.09 MPa with a temperature of 38°C. Average pressure gradient is 0.92 MPa/100m, temperature gradient is 4.0°C/100m.

2.4.3 Properties of crude oil, gas and water in the Honggang Oilfield

2.4.3.1 Crude oil properties

A. Sa'ertu stratum

The density of crude oil in the Sa'ertu stratum is 0.821g/cm^3 under reservoir conditions, the average viscosity of the crude oil at reservoir condition is 12.9 mPa·s. The pour point of the crude is 19°C and the original ratio of gas to oil is 38.839 m^3/m^3. The resin content in the crude is 14.1%, the content of asphaltene is 1.9 – 2.9% and the wax content is 20% with a sulphur content of 0.09% (Table 3).

Table 3: The properties of crude oil in the Honggang Oilfield

Properties / Stratum	Density (g/cm^3)	Viscosity (mPa·s)	Pour Point (°C)	Resin content (%)	Asphaltene content (%)	Wax content (%)	Sulphur content (%)	Original gas to oil ratio (m^3/m^3)
Sa'ertu	0.821	12.9	19	14.1	1.9 – 2.9	20	0.09	38.839
Gaotaizi	0.8627–0.8960 Average 0.8725	42.10–106.29	12.7–37.8	10–20 average 15.93		14.32–32.97 Average 24.7	/	46.08
Heidimiao	0.8769	33.83	19	/	/	19.05	/	39

B. Gaotaizi stratum

The density of crude oil in the Gaotazi stratum is 0.8627 – 0.8960 g/cm^3 and the average density of the crude is 0.8725 g/cm^3 under reservoir conditions. The viscosity of the crude is 42.10 – 106.29 mPa·s, the pour point of the crude is 12.7 – 37.8°C. The resin and asphaltene content of the crude oil is 10%–20% with an average of 15.93%. The wax content is 14.32 – 32.97% with an average of 24.7%. The formation volume factor (B_0) of the crude oil under reservoir conditions is 1.088, the original gas to oil ratio was 46.08 m^3/m^3, the original saturated pressure was 9.05 MPa and the difference between the formation and saturation pressure is 5.4MPa (Table 3).

C. Heidimiao stratum

The density of crude oil in the Heidimiao stratum under reservoir conditions is 0.8769 g/cm^3, viscosity is 33.83 mPa·s, the average pour point is 19°C, original gas to oil ratio is 39 m^3/m^3 and the wax content in the crude oil is 19.05% (Table 3).

2.4.3.2 Natural gas properties

The methane (CH_4) content of natural gas in the Sa'ertu stratum is over 90%, the relative density is 0.603. The carbon dioxide (CO_2) content of the gas is less than 4% and the nitrogen (N_2) content in the gas is 0.40 – 0.64% (Table 4).

There are gas caps and interlayered gas in the Gaotaizi stratum, the relative density of natural gas is 0.7118, the average CH_4 (methane) content in the gas is 81.38%, the CO_2 content in the gas is 1.25 – 25.90% (Table 4).

The relative density of natural gas in the Heidimiao stratum is 0.590, the CH_4 content of the gas is 94.2%, the content of heavy hydrocarbons, N_2, CO_2 and H_2S in the gas is 1.76%, 3.02%, 1.18% and 0.60% respectively.

The natural gas in the Mingshui gas reservoir is mainly CH_4 (92–95%) and the N_2 content in the gas is 3.8 – 6.9%. The relative density of natural gas is 0.5776.

Table 4: The properties of natural gas in the Honggang Oilfield

Stratum \ Properties	Relative density	CH_4 content (%)	CO_2 content (%)	N_2 content (%)	Other
Sa'ertu	0.603	>90	<4	0.40–0.64	–
Gaotaizi	0.7118	81.38	1.25–25.90	–	–
Heidimiao	0.590	94.2	1.18	3.02	Heavy hydrocarbons:1.76% H_2S:0.60%
Mingshui	0.5776	92–95	–	3.8–6.9	–

2.4.3.3 Formation water properties

The total salinity of formation water in the Sa'ertu stratum is 10000 – 14000 mg/L, Chlorine (Cl^-) content in the water is 5600 – 5800 mg/L and the water type is sodium bicarbonate ($NaHCO_3$) (Table 5).

The average salinity of formation water in the Gaotaizi stratum is 31270.58 mg/L, the relative density is 1.0097 and the water type is $NaHCO_3$.

The total salinity of formation water in the Heidimiao stratum is 6537 – 8710 mg/L, and the water type is $NaHCO_3$.

Table 5: The properties of formation water in the Honggang Oilfield

Stratum \ Properties	Total salinity (mg/L)	Cl^- content (mg/L)	Water type
Sa'ertu	10000 – 14000	5600 – 5800	$NaHCO_3$
Gaotaizi	average 31270.58	–	$NaHCO_3$
Heidimiao	6537 – 8710	–	$NaHCO_3$

3 Xinli Oilfield

3.1 Introduction

The Xinli Oilfield is located in Qianguo County of the Jilin Province. The structure lies in the west of the Fuyu–Xinli anticline belt. It belongs to the Fuyu–Xinli lower oil–gas accumulation zone of the Central depression in the Songliao Basin (Figure 1). The oil–bearing reservoirs are in the Fuyu–Yangdachengzi (abbreviated to Fu–Yang stratum) and Putaohua strata. The Xinli Oilfield has the second largest reserves and production of oil and gas in the Jilin oilfield complex. The most exploited reservoir in the Xinli Oilfield produces from the Fuyu–Yang stratum which is buried at a depth of 1000 – 1800 m and has oil–bearing layers with total thickness of 300 m.

3.2 Geological characteristics of the Xinli Oilfield

3.2.1 Reservoir formation conditions

The Fuyu, Yangdachengzi and Putaohua strata are the main producing reservoirs near the Gulong–Sanzhao and Da'an oil–forming sub–basins. The oil and gas source rock is in the Qingshankou Formation. Most of the oil and gas reservoir strata are fluvial fan deltas and debouchure dam sandstones. Hydrocarbons were generated in the upper part and stored in the lower part of the Qingshankou Formation. The mudstone in the upper part of the Qingshankou Formation forms a stable cap rock cover in this region.

3.2.2 Structure

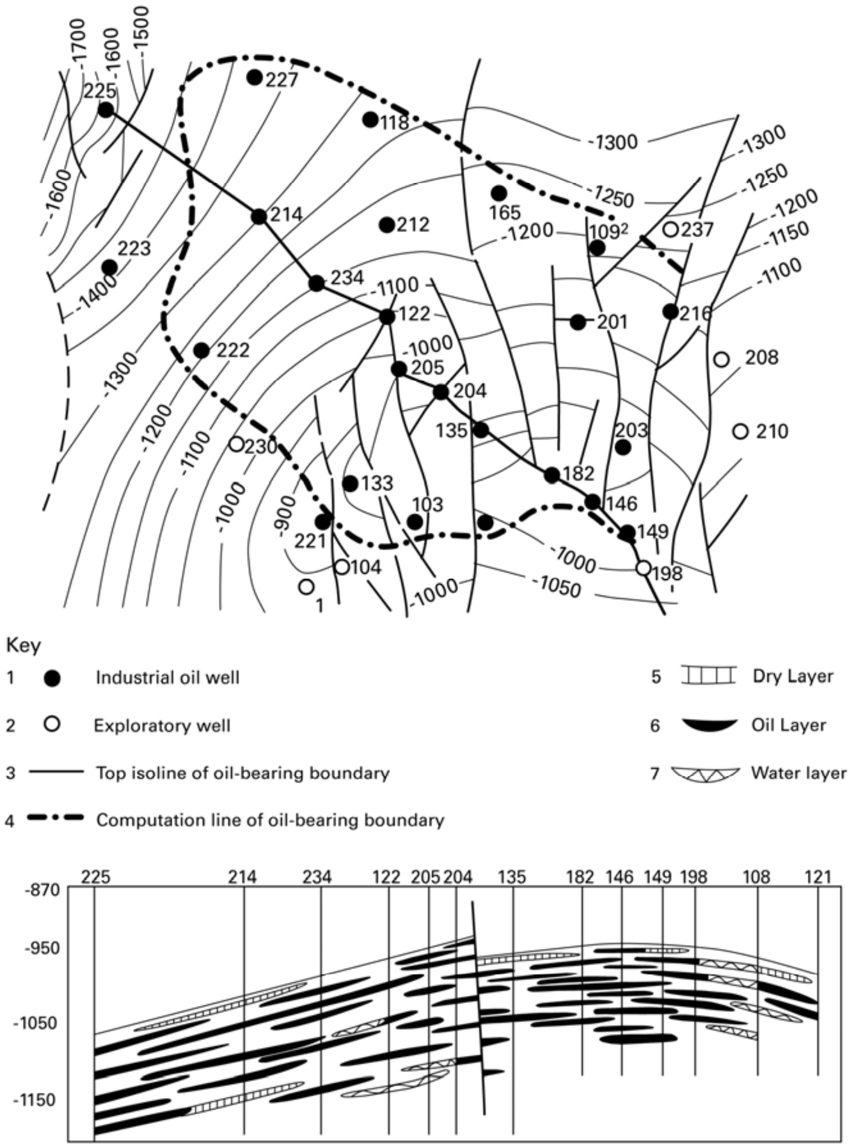
The Xinli structure is located in the west of Fuyu–Xinli structural belt which pinches out between the Changling and Gulong sub–basins. The basement is a west–dipping fault nose; the depth from the ground level to the top of the basement is between 5000 m and 7000 m. The structure is a dome–shaped uplift (T_{04}, T_1, T_2, Table 6), the specific configuration and element of each layer is different. The area of the upper part of the closure is larger than the lower part of the closure. There are many faults and fractures in the structure.

3.2.2.1 Structural characteristics of the Quan IV Member

The main oil–bearing reservoirs are located in the Quan IV member of Quantou Formation (Figure 4) in Xinli Oilfield. The structure in Quan IV member is an east–west trending dome anticline which is cut by faults. The surface expression is gentle and the axis trends in an east–west direction. The west part of the structure deflects to the south; the overall structure is like an arc with convexity to the north. The dip angle of the north limb is 2° while the dip angle of south wing is 2.5°. The length of the long and short axes is 12 km and 6 km, respectively. The top of the structure is 865 m below ground level in Xin221 well which is located in the north part of the structure. North–north–east and north–north–west trending normal faults are found in the main part of structure creating a complicated stair–like feature from west to east. The closure area is 55 km^2 and the thickness is 136 m.

Table 6: Structural elements of the Xinli Oilfield

Elements / Stratum	Closure altitude (m)	Area (km^2)	Thickness (m)	Dip angle		Long axis (km)	Short axis (km)	Structure type	Method of exploration
				East wing	West wing				
T_{04}	–250	210	190	2°	1°48'	24.5	11.5	Long axis	Seismic
T_1	–600	162	207	2°	2°	16	11	Dome	Drilling
T_2	–1000	55	136	2°	2°30'	12	6	Dome	Drilling
*T_{04} is the surface of Nen III member, T_1 is the surface of Yaojia formation, T_2 is the surface of Quan IV member									



Age	Formation	Member	Depth(m)
Lower Cretaceous	Quantou	Quan IV	1100
			1140
			1180
		Quan III	1220
			1260
			1300
			1340

Figure 4: Stratigraphy and structure of the Xinli Oilfield

3.2.3 Faults

Faults are found in the Xinli structure, especially in the surface of the Quan IV member. There are 15 faults in the oil–bearing area and 22 large faults in the structure with a throw of 20–30 m; the largest throw is 80m. Fault lengths are generally about 7 km and the longest fault is greater than 10 km.

3.2.3.1 Fault configuration

The majority of faults trend in a north–north–east direction, though some faults trend in a north–west direction. These two fault belts form in the axis of the structure, the western faults mostly dip to the east and the eastern faults dip to the east or west. All are normal faults with dip angles of around 45°.

3.2.3.2 Fault distribution and characteristics

There are more faults in the lower part of the structure. The faults are found mainly in the Qing II and III members (Table 7), and the faults do not extend through the caprocks which are in the upper part of the Qingshankou Formation.

The throw of the faults in the lower part of the structure is larger than in the upper part of the structure. The average of the largest throw is 46 m in the Quan IV member and diminishes upwards.

Table 7: Faults in the Xinli structure

Stratum	Quan IV	Qing I	QingII + III	YaoII + III	Nen II	Nen III	Nen IV
Break point	11	9	25	3	11	9	2
Throw (m)	46	22	24	21	13	12	31

3.3 Characteristics of the oil–bearing strata in the Xinli Oilfield

The oil–bearing strata in Xinli Oilfield are the Fu–Yang, Putaohua and Heidimiao strata, and the Fu–Yang stratum is the most important reservoir. The Qing I and Nen I members which cover the Quan IV member (Fu–Yang oil–bearing stratum) and Yao I member (Putaohua stratum) comprise black mudstone. The Qing I and Nen I members are not only good oil–source rocks but also provide a stable regional seal. The Qing I, Nen I, Quan IV and Yao I members form an effective sequence of generation–storage–seal rocks. Oil and gas are generated in the upper part of the reservoir and trapped in the lower part of the reservoir.

3.3.1 Fu–Yang stratum of the Xinli Oilfield

3.3.1.1 Lithology

The Fu–Yang stratum is in the Quan IV and upper Quan III members, the buried depth of the Fu–Yang stratum is 1000 – 1800 m and the thickness of the oil–bearing layer is about 150 – 170 m (Figure 4). The oil–bearing reservoir is mainly fine sandstone and siltstone, with minor argillaceous siltstone. The thickness ratio of sandstone to mudstone is 5:43.

3.3.1.2 Division of the oil–bearing layers

The Fu–Yang stratum is divided into nine oil–bearing layers with 26 sub–layers. Among these sub–layers 1, 8, 14, 16 and 26 are distributed in main region of the oilfield and the others are distributed as bars or lenses.

3.3.1.3 Distribution and characteristics of the oil–bearing layers

The number of oil–bearing layers is small and the thickness of the layers is thin and variable. The average thickness of a single layer is 2 – 5 m and the effective reservoir thickness of one layer is 1 – 3 m. The thickest layer is 11.2 m and the thickest effective reservoir layer is 10.2 m. Typically there are five to seven oil–bearing layers encountered in a production well. The total effective thickness of the oil–bearing layers is 5 – 8 m and the greatest total effective thickness encountered in a well is 34.4 m.

Oil–bearing layers have a small area and are distributed in lenses or bars. There are 53 sandstone layers in the exploration area with the distance between wells generally around 300m. Only seven wells encountered more than nine sandstone layers. Twenty–nine sandstone layers are distributed as bars and 18 as sandstone layers which trend in a north–east direction. The reserves of each layer are limited because the layers are deposited as lenses or bars which are small and divided by faults.

The mudstone layers between the oil–bearing sandstone layers in the Fu–Yang stratum are stable and thick. Mudstone layers more than 10m thick are found in 47 wells, which is about 80% of all the wells in the area.

3.3.1.4 Fractures in oil–bearing strata

The oil–bearing strata contain many natural fractures in the Xinli Oilfield and the fractures can be divided into two types: 1) tensional 2) shearing. The longest of the fractures is about 2 m. The fractures are densely distributed at the base of Qing I and the top of the Quan IV members (Table 8). The characteristics of fractures are as follows:

(1) The fractures are grouped in the oil–bearing stratum. Most fractures are parallel and divide the stratum into slices. Some of the fractures cross over one another forming X–shaped fractures.

(2) The fractures are long, 45% of the fractures are more than 20 cm in length.

(3) Open fractures comprise up to 16% of the total fractures.

(4) 19% of total fractures are filled with mud.

The distribution of vertical and oblique crossing fractures adjacent to and in oil–bearing layers was studied. The result shows that these two types of fractures are mostly located at the base of the Qingshankou Formation, or in the Quan IV or Quan III members which have a fracture density of 0.48, 0.27 and 0.15 fractures per metre, respectively.

There are more fractures in the eastern part of the structure than in the western part and near the top, axis line and faults of the structure. There are fewer fractures in the limbs of the anticlinal structure.

Table 8: Fractures in eastern and western of the Xinli Oilfield

Lithology	Mudstone		Sandstone		Calcareous sandstone		Average	
Position	E	W	E	W	E	W	E	W
Density of fractures(piece/m)	0.12	0.10	0.35	0.20	0.84	0.69	0.27	0.19

*E: eastern, W: western

3.3.1.5 Physical characteristics of oil–bearing layers

The porosity and permeability of oil–bearing strata are very low. However, the Fu–Yang stratum is homogeneous with little change in porosity. The porosity of the main oil–bearing layers is 8 – 16 % and the average is 12.2 %. The permeability is 1 – 101 mD, the average permeability of main oil–bearing stratum is 7 mD. The pore type of the oil–bearing layers is inter–granular pore and the cementation type of the sandstone is contact–pore or pore–contact.

3.3.2 Putaohua stratum of the Xinli Oilfield

The Putaohua stratum comprises the Yao I member in the middle and lower part of the Yaojia Formation. The thickness of the Yao I member is 38 – 45 m. The depth of burial of the Putaohua stratum is 600 – 900 m and sandstone layers have thickness of 2 – 6 m. The stratum is distributed as intermittent lenses. The Putaohua oil–bearing stratum is mainly siltstone and argillaceous siltstone loosely cemented with argillaceous material. The main porosity type is inter–granular pores. The reservoir quality of the stratum changes according to the thickness and position of sandstone layers; the reservoir qualities are higher in the thicker sandstone layers and worsen towards the edges of the sandstone–rich layers. For example, the porosity and permeability of well Xin301 in the centre of the sandstone layer is 24.6 % and 14 mD, respectively. The porosity and permeability of well Xin302 located near the border of sandstone layer is 16.6 % and 0.2 mD, respectively (Table 9).

Table 9: Change of physical properties of sandstone layers in the Putaohua stratum

Sandstone layer	Well No.	Porosity (%)	Permeability (mD)	Cement (%)	Cementation type
Centre	Xin301	24.6	14	15.6	Pore–Contact
	Ji3–4	18.7	6	12.5	Contact
Border	Ji4–14	18.5	3	19.5	Contact–Pore
	Xin302	16.6	0.2	16.0	Contact–Pore

3.4 Reservoir characteristics of the Xinli Oilfield

3.4.1 Type of reservoirs and distribution of oil and water

3.4.1.1 Fu–Yang stratum; Quan IV and III members of the Quantou Formation

The Fu–Yang stratum is a thick layer distributed across the whole region of the Xinli Oilfield which thins at its edges. The reservoir is controlled by faults and trends structurally east–west and lithologically north–south. The reservoir is a lithological–structural reservoir.

3.4.1.2 Distribution of oil and water

The effect of fluid density is evident; crude oil is situated in the upper part and water in the lower part of the stratum. There is no water at the top or interlayer water in the stratum. The contact between crude oil and water is not at a consistent level across the reservoir; it is higher in the west and south and lower in the east and north indicating compartmentalisation of the reservoir. The thickness of the oil–bearing stratum is greater than that of the reservoir closure.

3.4.1.3 Putaohua stratum in Yao I member of the Yaojia Formation

The Putaohua stratum is in the Yao I member in the middle and lower parts of the Yaojia Formation. There are one to two thin oil–bearing layers in the stratum; the distribution of these layers is dependant on the lithology. The oil–bearing area is dependant on the shape and the physical properties of the sandstone layers. Crude production is by natural water drive, elasticity drive and dissolved gas drive.

3.4.2 Temperature and pressure

The original pressure of the Fu–Yang stratum was 11.75 – 12.70 MPa with an average pressure of 12.2 MPa. The saturated pressure in the stratum is 9.5 MPa, the difference between formation and saturation pressure is 2.6 – 2.8 MPa. The original pressure in the middle of the Fu–Yang stratum was 12.32 MPa at a depth of 1220 m. The temperature generally ranges from 62.5 – 70^{o}C with an average of 66^{o}C, the temperature gradient is 5.1^{o}C/100m (Table 10).

Table 10: Temperature and pressure of the Fu–Yang stratum

Temperature, Pressure / Stratum	Original Reservoir Pressure (Mpa)	Original Pressure in the middle stratum (Mpa)	Original saturation Pressure (Mpa)	Difference between formation and saturation pressure (Mpa)	Reservoir Temperature (^{o}C)	Temperature gradient (^{o}C/100m)
Fu–Yang	11.75 – 12.70 Average 12.2	12.32 (1220m)	9.5	2.6–2.8	62.5 – 70 average 66	5.1

3.4.3 Properties of crude oil, gas and water

3.4.3.1 Crude oil properties

The crude oil in the Fu–Yang stratum is of good quality. The density of crude oil is 0.8624 g/cm^3, the viscosity is 23.56 mPa·s at 50 ^{o}C, the pour point of the crude is 33.1 ^{o}C, the sulphur content in the crude is 0.08% and the primary boiling point of the crude is 111.2 °C. The ratio of gas to oil is 37m^3/t, the formation volume factor (B_0) of the crude is 1.111 (Table 11).

Table 11: The properties of crude oil in the Xinli Oilfield

Properties / Stratum	Density (g/cm³)	Viscosity (mPa·s)	Pour Point (°C)	Primary boiling point (°C)	Sulphur content (%)	Original gas to oil ratio (m³/t)
Fu–Yang	0.8624	23.56(50°C)	33.1	111.2	0.08	37
Putaohua	0.85 – 0.86	16 – 23	24 – 30	69 – 131	–	–

The density, viscosity, pour point, sulphur content and primary boiling point of the crude oil in the Putaohua stratum are lower than that of the crude in the Fu–Yang stratum. Table 12 summarises the properties of crude oil for the Putaohua stratum.

Table 12: Properties of the crude oil in the Putaohua stratum

Well No.	Well section(m)	Relative density d_4^{20}	Viscosity 50°C (mPa·s)	Pour point (°C)	Water content (%)	Primary boiling point (°C)
Xin150	692.8 – 698.6	0.8579	18.926	25	0	69
Xin 155	690.4 – 693.4 705.2 – 708.0	0.8580	16.82	26	0.2	109
Xin 208	658.0 – 665.0	0.8631	22.15	30	3.7	110
Xin 301	717.2 – 722.2	0.8612	23.47	24	Trace	131
Xin 305	657.0 – 660.4	0.8556	17.09	28	0	83
Xin 306	762.0 – 766.6	0.8597	23.73	24	6.0	125
Xin 309	680.0 – 686.2	0.8583	19.51	30	0.9	108
Xin 307	733.6 – 738.6	0.8558	22.15	28	0	106

3.4.3.2 Natural gas properties

The content of hydrocarbon of the gas is high and the relative density of the gas is 0.7038. The content of methane (CH_4), ethylate (C_2H_5), propane (C_3H_8), butane (C_4H_{10}), nitrogen (N_2) and CO_2 in the gas is 81.02%, 4.91%, 5.04%, 2.37%, 5.55% and 0.16%, respectively (Table 13).

Table 13: The properties of natural gas in the Xinli Oilfield

Properties / Stratum	Relative density	CH_4 content (%)	CO_2 content (%)	N_2 content (%)	Other
Fu–Yang Putaohua	0.7038	81.02	0.16	5.55	C_2H_5:4.91%;C_3H_8:5.04%; C_4H_{10}:2.37%

3.4.3.3 Formation water properties

The salinity of the water in the Fu–Yang stratum is fairly consistent, around 6000 – 9000 mg/L and salinity is higher in the southern part than in the northern part of the stratum. The water type is mainly $NaHCO_3$ (sodium bicarbonate) with some areas having a composition of sodium sulphate (Na_2SO_4) or calcium chloride ($CaCl_2$). The chlorine (Cl^-) content in the water ranges between 2500 – 4200 mg/L with a pH of 6–9.

The salinity of the water in Putaohua stratum is 10787.5 mg/L, the Cl^- content in the water is 3071.0 mg/L and the type of water is $NaHCO_3$. The water properties of the Putaohua stratum are summarised in Table 14.

Table 14: The properties of water in the Xinli Oilfield

Properties / Stratum	Total salinity (mg/L)	Cl^- content (mg/L)	pH	Water type
Fu–Yang	6000–9000	2500–4200	6–9	$NaHCO_3$ (some Na_2SO_4 or $CaCl_2$)
Putaohua	10787.5	3071.0	13	$NaHCO_3$

4 CO_2 storage potential in the Honggang and Xinli oilfields

4.1 CO_2 storage potential in the Honggang Oilfield

4.1.1 Calculation model of CO_2 storage capacity

A typical structure of the oil and water–bearing reservoirs is shown in Figure 5.

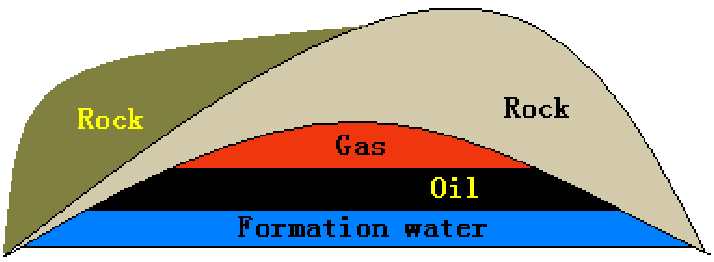


Figure 5: Structure of oil–bearing reservoir and water formation

The calculation model of CO_2 storage capacity has been developed based on the geological conditions, rock properties, crude oil and formation water of the Jilin oilfield complex. The equation used for calculating CO_2 storage capacity in oil–bearing reservoirs and water formations based on Tanaka et al., 1995 is as follows:

$$M_{(CO2)}=M_1+M_2+M_3+M_4 \quad \text{(Equation 3–1)}$$

Where

$M_{(CO2)}$ – total storage capacity of CO_2 (m^3)

M_1 – storage capacity of CO_2 dissolved in the oil and formation water of the oil bearing reservoir

M_2 – storage capacity of CO_2 dissolved in the underlying water–bearing aquifer

M_3 – storage capacity of CO_2 replacing oil in the oil bearing reservoir during CO_2 flooding

M_4 – storage capacity of CO_2 through long–term chemical reactions with reservoir rocks

Information about CO_2 reaction with the rock and the underlying aquifers is not available for the reservoirs in Jilin oilfield complex. Therefore the assumption has been made that the volume and porosity of the water formation is as same as the volume and porosity of the oil–bearing reservoir, equation 3–1 is modified as follows:

$$M_{(CO2)}=E_f\times A\times h\times \varphi\times[S_o\times R_{o(CO2)}+(1-S_o)\times R_{w(CO2)}]+h\times A\times \varphi\times S_w+(M_p\times 4\%/\rho_f) \quad \text{(Equation 3–2)}$$

Where

E_f–overall sweep efficiency (fraction), E_f=5%–25%, assume E_f=18%;

A–area of oil–bearing reservoir (m^2)

h–thickness of reservoir (m)

φ–porosity of reservoir (fraction)

S_o–oil saturation in reservoir (fraction), assume S_o=65%

$R_{o\,(CO2)}$–CO_2 solubility in oil (fraction)

$R_{w(CO2)}$–CO_2 solubility in water(fraction)

S_w–CO_2 solubility in formation water (fraction)

M_p–residual oil in reservoir (10^4t)

ρ_f–oil density in formation (kg/m^3)

The storage capacity potential of the oilfields was also estimated using a Carbon Sequestration Leadership Forum (CSLF) based methodology (Bachu et al 2007). This calculation assumes that the volume of recoverable reserves of the oil can be largely replaced with CO_2. This is generally valid for pressure–depleted reservoirs that are not subject to water drive from surrounding aquifers, or where water–flooding has not been applied. Where water has invaded the reservoir, it is assumed that CO_2 can displace some but not all of this fluid, and so the estimated storage capacity is reduced. Though it can be assumed that CO_2 will be injected into depleted reservoirs until the initial reservoir pressure is restored, in some cases, it may be safe to increase the pressure beyond the initial reservoir pressure. Alternatively, depletion may have damaged the reservoir and it may not be possible to inject CO_2 until the initial reservoir pressure is reached. For the simple calculations performed for this report, it was assumed that the reservoir pressure could be returned to the initial pressure. The formula used here, including a discount to allow for irreversible water invasion, was as follows:

$$M_{CO2} = (V_{OIL}\ (stp).B_o)\ .\ \rho_{CO2}\ .\ S_{coeff} \qquad \text{(Equation 3–3)}$$

Where

M_{CO2} = estimated storage capacity (Mt)

V_{OIL} (stp) = Volume of oil at standard temperature and pressure (Mt converted to m^3 using API of oil which is typically 33API in the Jilin oilfield complex)

B_o = Formation volume factor (Assumed to be 1.1)

ρ_{CO2} = Density of CO_2 in the reservoir (0.6 t/m^3)

S_{coeff} = storage coefficient to discount for water invasion etc (0.4)

4.1.2 CO_2 storage potential in the Honggang Oilfield

CO_2 storage potential in the Honggang Oilfield has been assessed in two ways; 1) CO_2 stored during the process of enhanced oil recovery (EOR) by CO_2 injection and 2) CO_2 injected and stored when the oil field is depleted.

4.1.2.1 CO_2 storage potential using EOR during CO_2 injection

There is a gas cap on the top of Sa I member and three oil bearing strata which are the Sa'ertu, Gaotaizi and Heidimiao strata in the Honggang Oilfield. The gas reservoir covers an area of 15.7 km^2 with natural gas reserves of 50 million cubic metres. The Honggang Oilfield has been exploited using water flooding for more than 40 years and the natural gas has been completely produced. Assuming the space originally occupied by natural gas is full of water due to flooding, equation 3–1 can be modified as follows:

$$M_{(CO2)}=M_0+M_1+M_2+M_3 \qquad \text{(Equation 3–4)}$$

Where

M_0 – storage capacity of CO_2 dissolved in the water which is in the gas reservoir

And in this case, equation 3–2 can be modified as follows:

$$M_{(CO2)}=\rho_g\times V_g/\rho_w\times S_w+E_f\times A\times h\times\varphi\times[S_o\times R_{o(CO2)}+(1-S_o)\times R_{w(CO2)}]+ h\times A\times\varphi\times S_w+(Mp\times 4\%/\rho_f) \qquad \text{(Equation 3–5)}$$

ρ_g—density of natural gas

V_g—volume of natural gas in reservoir

ρ_w—density of water

This equation assumes immediate dissolution of available CO_2 into the formation water and does not take into account the kinetics of this dissolution.

For the Honggang Oilfield, E_f is 18%, CO_2 solubility in water ($R_{w(CO2)}$) is 5% (weight), CO_2 solubility in the Jilin oil ($R_{o(CO2)}$) is 15% (weight)[2], the density of CO_2 in its highly dense phase is 600 kg/m^3. CO_2 solubility in formation water (S_w) is taken to be the same as CO_2 solubility in water $R_{w(CO2).}$ Density of the natural gas ρ_g is 603 kg/m^3 and volume of natural gas in the reservoir V_g is 5.0×10^{7}m^3. The residual oil in the reservoir (Mp) in 2000 and other basic reservoir and oil properties and are shown in Table 15 and the average oil recovery rate by CO_2 flooding from the pilot test in Daqing oilfield complex is taken to be 4% (Xigui et al., 1999).

Table 15: Basic parameters of the Honggang Oilfield

Oil field	Stratum	*A*/ km^2	*h*/m	*φ*/%	*M*p/(Mtt)	ρ_f/(Kg/m^3)	*T*/°C	*P*/MPa
Hongang	Sa'ertu	49.4	5.1	24	11.69	885	55	12
	Gaotaizi	20	10.6	17.9	5.85	872.5	64	13.78
	Heidimiao	/	/	/	/	876.9	38	8.09

As data of the area, thickness and porosity of reservoirs in the Heidimiao stratum are not available it is impossible to calculate the storage potential of CO_2 in this stratum. The Sa'ertu and Gaotaizi strata in the Honggang Oilfield have high pressure and so may be suitable for storage of CO_2.

Using the calculations described above, the available storage capacity that could potentially be utilised during CO_2 flooding in the Honggang Oilfield is shown in Table 16. The storage capacity of CO_2 dissolved in the formation water of the gas cap of the reservoir (M_0) is about 18% of the total storage capacity is provided by migration of CO_2 and about 17% of the total storage capacity would be provided dissolution of CO_2 in the oil and water contained within the reservoir (M_1). The storage capacity of CO_2 that could be dissolved in water–bearing reservoir below the oilfield (M_2) is about 59%, and CO_2 retained in an oil–bearing reservoir during flooding (M_3) is about 6% of the total CO_2 storage capacity. The oilfield has large volumes of formation water with the potential to store the greatest amount of CO_2.

The total storage capacity of CO_2 in the Honggang Oilfield is 8.3 Mt (13.78×10^{6}m^3) under supercritical conditions, among which the storage capacity in Sa'ertu stratum is the largest (Table 16).

The storage capacity potential of CO_2 in the Honggang Oilfield estimated using Carbon Sequestration Leadership Forum (CSLF) method is also shown in Table 16. The total storage capacity of CO_2 in the Honggang Oilfield is 4.0 Mt under supercritical conditions. The CSLF methodology assumes simple displacement of the native pore fluids in the reservoir. The CUPB methodology incorporates displacement of native pore fluids and dissolution into the native pore fluids in the reservoir and the aquifers in contact with the reservoir.

Table 16: CO_2 storage capacity in the Honggang Oilfield (2000) (assuming CO_2 density 600 kg/m^3)

Stratum	M_0 (Mt)	M_0/M (%)	M_1 (Mt)	M_1/M (%)	M_2 (Mt)	M_2/M (%)	M_3 (Mt)	M_3/M (%)	Total (Mt)	Capacity using CSLF based methodology
Sa'ertu	1.5	26.4	0.9	15	3.0	53	0.3	5.6	5.7	2.7
Gaotaizi	/	0	0.5	20.6	1.9	73.1	0.2	6.3	2.6	1.3
Total	1.5	18.1	1.4	16.8	4.9	59.3	0.5	5.8	8.3	4.0

As production continues, the oil saturation (S_o) in the reservoir will decrease. As the latest available oil reserve figures are from 2000, in order to assess how remaining oil saturation would affect the CO_2 storage, capacity was calculated with different oil saturations in the Honggang Oilfield as shown in Table 17. The data shows that as the theoretical oil saturation was decreased from 65% to 25% when the oil is produced by water flooding the potential CO_2 storage capacity decreased by about 11.1% in the Honggang Oilfield.

The results obtained using the CSLF formula are smaller than those obtained using the CUP (Beijing) methodology as the former assumes that CO_2 is stored by only replacing the oil in the reservoir, thus the estimate is related to the estimated recoverable reserves. The CUP (Beijing) method assumes that CO_2 is rapidly dissolved into the oil and water in the reservoir and the pore water in the underlying aquifer, during the period in which EOR is undertaken.

Table 17: CO_2 storage capacity with different S_o in the Honggang Oilfield (Mt)

Stratum	S_o=65%	S_o=50%	S_o=40%	S_o=30%	S_o=25%
Sa'ertu	6.1	5.8	9.47	5.5	5.4
Gaotaizi	2.8	2.7	4.31	2.5	2.5
Total	8.9	8.5	13.78	8.0	7.9

4.1.2.2 CO_2 storage potential of the Honggang Oilfield after depletion

When the Honggang Oilfield is depleted the CO_2 storage potential in the field can be calculated as follows:

$$M_{(CO2)}=M_0'+M_1+M_2 \quad \text{(Equation 3–6)}$$

M_0'– storage capacity of CO_2 in the gas reservoir

When the Honggang Oilfield is depleted and all of the wells are closed, it is assumed that the injection of CO_2 will cause the reservoir to recover to its original pressure, the gas reservoir will be filled with CO_2 instead of natural gas and the volume of formation water will be three times that of oil (for the earlier calculation of CO_2 storage capacity during EOR, it was assumed that the water volume in the underlying aquifer is equal to the oil volume). Thus, the CO_2 storage potential could be calculated by using the following equation:

$$M_{(CO2)}= \rho_g\times V_g/\rho_{CO2} +A\times h\times\varphi\times[S_o\times R_{o(CO2)}+(1-S_o)\times R_{w(CO2)}]+3\times h\times A\times\varphi\times S_w \quad \text{(Equation 3–7)}$$

If it is assumed that when the oilfield is depleted that the remaining unrecoverable oil saturation will be 25%, the total CO_2 storage capacity in Honggang Oilfield is 51.5 Mt (Table 18). The CO_2 storage capacity in the gas reservoir (M_0') is about 58.6% of the total CO_2 storage capacity, the storage capacity of CO_2 dissolved in the oil and water of the oil–bearing reservoir (M_1) is about 12.9% of the total storage capacity, again assuming perfect and rapid mixing and maximum solution of the CO_2. The amount of CO_2 dissolved in the underlying water–bearing reservoir (M_2) is about 28.6% of the total capacity. Calculated storage potential of the Honggang Oilfield when depleted is up to 51.5 Mt ($85.82\times10^6 m^3$).

Due to the low oil saturation in the depleted oil field, the CO_2 storage capacity in the oil is reduced and the estimated storage capacity in the oil is reduced compared to the CO_2 which can be stored during EOR operations. The gas reservoir provides the largest potential when the field is depleted at 50.25 Mt CO_2.

Table 18: CO_2 storage capacity in the Honggang Oilfield (assuming CO_2 density 600 kg/m^3)

Stratum	M_0' (Mt)	M_0'/M (%)	M_1 (Mt)	M_1/M (%)	M_2 (Mt)	M_2/M (%)	Total (Mt)
Sa'ertu	30.2	69.7	4.1	9.4	9.0	20.9	43.3
Gaotaizi	/	0	2.5	31.2	5.7	68.8	8.2
Total	30.2	58.6	6.6	12.9	14.7	28.6	51.5

4.2 CO_2 storage potential of the Xinli Oilfield

There are two oil–bearing strata, Fu–Yang and Putaohua, but there is no gas cap or underlying aquifer/bottom water present in the Xinli Oilfield. The enhanced oil recovery and the CO_2 storage potential are calculated by the following equations:

$$M_{(CO2)}= M_1 +M_3 \quad \text{(Equation 3–8)}$$

$$M_{(CO2)}= E_f\times A\times h\times\varphi\times[S_o\times R_{o(CO2)}+(1-S_o)\times R_{w(CO2)}] +(Mp\times4\%/\rho_f) \quad \text{(Equation 3–9)}$$

The basic parameters of the Xinli Oilfield are shown in Table 19.

Table 19: Basic parameters of the Xinli Oilfield

Oil field	Stratum	A/ km^2	h/m	φ/%	Mp/(Mt)	ρ_f/(Kg/m^3)	T/°C	P/MPa
Xinli	Fu–Yang	42.3	6.5	12.2	20.566	863	66	12.2
	Putaohua	82.06	3	19.6	28.7923	858.7	40	5.1

The storage capacity during CO_2 flooding in the Xinli Oilfield is shown in Table 20. The storage capacity of CO_2 dissolved in the oil and water of the oil–bearing reservoir (M_1) is about 48.5% of the total storage capacity. The storage capacity from replacing oil in the oil–bearing reservoir during CO_2 flooding (M_3) is about 51.5% of the total. The total storage capacity of CO_2 in the Xinli Oilfield is 2.7 Mt ($4.47\times10^6 m^3$) in its highly dense phase, the Putaohua stratum has the largest potential storage capacity.

The CO_2storage capacity potential in the Xinli Oilfield estimated using Carbon Sequestration Leadership Forum (CSLF) method (Bachu et al., 2007) is also shown in Table 20. The total CO_2 storage capacity in the Xinli Oilfield is 11.2 Mt under supercritical conditions.

The remaining reserves figures are from the year 2000 (the most recently published data available). As exploitation of the field has continued, CO_2 storage capacity was calculated with decreasing oil saturation to depletion (here taken as 25% capacity). The storage capacity of CO_2 with different oil saturations in the Xinli Oilfield is shown in Table 21. When the oil saturation in the oilfield was decreased from the 2000 reserves to 25% the potential of total CO_2 storage capacity is reduced by about 45% in the Xinli Oilfield.

Table 20: CO_2 storage capacity in the Xinli Oilfield (using oil reserves published in 2000) (assuming CO_2 density 600 kg/m^3)

Stratum	M1 (Mt)	M1/M (%)	M3 (Mt)	M3/M (%)	Total (Mt)	Capacity using CSLF based methodology
Fu–Yang	0.5	48.1	0.6	51.9	1.1	4.7
Putaohua	0.8	48.9	0.8	51.1	1.6	6.6
Total	1.3	48.5	1.4	51.5	2.7	11.2

Here, the CSLF–based methodology results in a larger estimate than the CUPB methodology because there is no aquifer connected with the Xinli Oilfield, so for the CUPB methodology, M2 = 0, so the dissolution into the underlying aquifer is discounted for the CUPB calculation.

Table 21: CO_2 storage capacity with different oil saturations in the Xinli Oilfield (Mt) (assuming CO_2 density 600 kg/m^3)

Stratum	So=65%	So=50%	So=40%	So=30%	So=25%
Fu–Yang	1.3	1.0	0.9	0.7	0.7
Putaohua	1.8	1.5	1.3	1.1	1.0
Total/(×106m3)	3.0	2.5	2.2	1.8	1.6

Theoretical storage capacity when the oilfield is depleted is calculated using the following equation:

$$M_{(CO2)} = M_1 \qquad \text{(Equation 3–10)}$$

$$M_{(CO2)} = A \times h \times \varphi \times [S_o \times R_{o(CO2)} + (1 - S_o) \times R_{w(CO2)}] \qquad \text{(Equation 3–11)}$$

If the oil field is depleted with a remaining oil saturation of 25%, the CO_2 storage potential is 5.5 Mt (Table 22).

Table 22: CO_2 storage capacity in the Xinli Oilfield

Stratum	M_1 (Mt)
Fu–Yang	2.3
Putaohua	3.3
Total	5.5

5 EOR potential in the Honggang and Xinli oilfields

The Honggang and Xinli oilfields are considered suitable for enhanced oil recovery (EOR) using available data on geological and reservoir conditions and the properties of the crude oil. The potential additional oil which could be recovered using EOR assuming different recovery percentages of the reserves is summarised in Table 23. If oil production could be increased by 10% of the residual oil in reservoir (using reserves from the year 2000) the additional potential oil production would be 0.3 million barrels and 0.7 million barrels in the Honggang and Xinli oilfields respectively.

Table 23: Enhanced oil recovery through CO_2 flooding in the Honggang and Xinli oilfields

Oil field	Stratum	Mp (million barrels)	Additional oil produced (barrels) for each EOR recovery factor (%)				
			2	4	6	8	10
Hongang	Sa'ertu	1.73	34500	69000	103500	138000	172500
	Gaotaizi	0.90	18000	36000	54000	72000	90000
	Total	**2.63**	**52500**	**105000**	**157500**	**210000**	**262500**
Xinli	Fu–Yang	3.08	61500	123000	184500	246000	307500
	Putaohua	4.35	87000	174000	261000	348000	435000
	Total	**7.43**	**148500**	**297000**	**445500**	**594000**	**742500**
NB: Mp is residual oil in the reservoir in 2000							

6 Conclusions

In the Jilin oilfield complex, the Honggang field shows more potential as a CO_2 storage demonstration site than the Xinli field. This is based on the geological conditions, reservoir conditions and the crude oil properties. The storage capacity of the Xinli Oilfield was estimated to be 3 $MtCO_2$ (CUPB methodology) to 11 $MtCO_2$ (CSLF-based methodology). The storage potential of the Honggang Oilfield was estimated to be 8 $MtCO_2$ (CUPB methodology) to 4$MtCO_2$ (CSLF-based methodology). The greatest potential for the Honggang field lies within the Sa'ertu stratum. As part of the CUPB methodology, storage through CO_2 dissolution in formation waters (M_2) was estimated to represent about 59% of the total storage capacity, though this would be expected to be utilised over a period of 10's to 1000's of years, as the dissolution rate is assumed to be rapid. The CSLF-based estimate is expected to be available during the CO_2 injection period due to displacement of pore fluids.

When depleted, the capacity of the oilfields was estimated to be 6$MtCO_2$ and 51 $MtCO_2$ for the Xinli and Honggang oilfields respectively. These capacities are small compared to the typical emissions from a 600MW power station. The storage capacity of CO_2 in the gas in the Honggang Oilfield (M_0') and CO_2 dissolved in formation water (M_2) amounts to 58.6% and 28.6% of the total storage capacity respectively.

If the amount of oil recovered could be increased by 10% of the residual oil in reservoir in 2000 using CO_2–EOR, the additional recoverable oil reserves would be 0.7 and 0.2 million barrels in the Xinli and Honggang oilfields respectively.

References

LI, M., PENG, B., LIN, M., WANG, M. AND ZHOU, H. 2009. Assessment of CO_2 storage potential in oil–bearing reservoirs of the Songliao Basin.

ZHA, G. 1993. Petroleum geology of China, Vol.2. Petroleum Industry Press. 371–387,402–408 (in Chinese)

WANG, Y., KANG, W. AND MAO, C. 2007. Exploration theory and practice of oil and gas in Jilin exploration area. Petroleum Industry Press. 293–296,306–307 (in Chinese)

ZHONG, X. 1997. Low permeability sandstone reservoir of Sa'ertu stratum in Honggang oil field. Petroleum Industry Press. 141–142 (in Chinese)

BACHU, S., BONIJOLY, D., BRADSHAW, J., BURRUSS, R., CHRISTENSEN, N. P., HOLLOWAY, S. AND MATHIASSEN. O–M. 2007, Phase II Final Report from the Task Force for Review and Identification of Standards for CO_2 Storage Capacity Estimation: Estimation of CO_2 storage capacity in geological media – phase 2

DONG, X., HAN, P. AND YANG, Z. 1999. Pilot test of CO_2 flooding in Daqing oil field. Petroleum Industry Press. 166 (in Chinese)

TANAKA, S., KOIDE, H. AND SASAGAWA, A. 1995. Possibility of underground CO_2 sequestration in Japan. Energy Conversion and Management **36**(6–9) 527–530.