Attachment 4

INFORMATION MEMORANDUM

THAILAND
PETROLEUM BIDDING
ROUND 2018
FOR OFFSHORE BLOCK
G1/61&G2/61

กระทรวงพลังงาน
MINISTRY OF ENERGY

Information Memorandum

Thailand Petroleum Bidding Round 2018 for Offshore Block G1/61 and G2/61

กระทรวงพลังงาน
MINISTRY OF ENERGY

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Introduction

DMF, under Ministry of Energy, Thailand, provides the Information Memorandum for the Bidding Process of exploration blocks no. G1/61 and G2/61 in GoT under the PSC system to provide information under the Ministry of Energy Announcement Annex: Subject “Rules, procedures and conditions for submission and consideration to acquire Production Sharing Contract (PSC) in Exploration Blocks offshore the Gulf of Thailand No. G1/61 and G2/61”

The purpose of the Bidding Process is to select an operator, joint venture or consortium to acquire the right to explore and produce petroleum in the Gulf of Thailand. The Bidding Process will be undertaken in an objective manner and in accordance with the Government of Thailand's objective to enhance the continuity and efficiency of petroleum production for Thailand's energy security.

Table of Content

Thailand Upstream Overview

Thailand's primary energy consumption in 2016 was 2.09 million barrels of oil equivalent per day, an increase of 0.7% from the previous year. Primary energy consumption increased at an annual rate of 1.3% between 2012 and 2016.

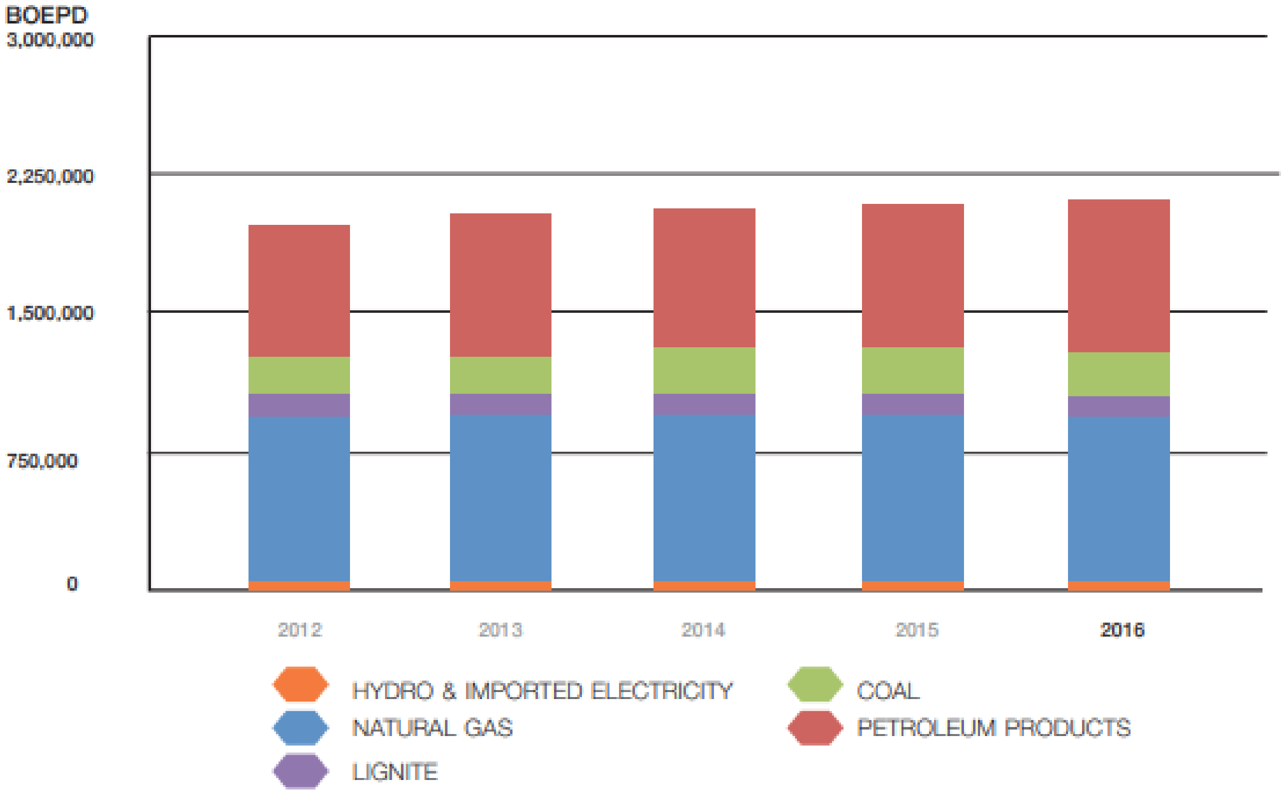

Figure 1 Thailand's primary commercial energy consumption, 2012-2016
Source: Energy Policy and Planning Office (EPPO)

In 2016, 81% of primary energy demand was from petroleum (comprising 43% natural gas and 38% petroleum products). 17% of primary energy demand was from coal and lignite, and 2% hydropower and imported electricity.

In 2016, Thailand's domestic supply accounted for 43% of domestic demand whereas the remaining 57% was imported. Domestic production was approximately 0.879 million barrels of oil equivalent per day, an increase of 0.5% from 2015. Domestic production consisted of 3 types of petroleum; 19% crude oil (163,680 barrels per day), 11% condensates (97,185 barrels of oil equivalent per day), and 70% natural gas (3,544 mmscfd).

Thailand's upstream oil and gas production is predominately sourced from two offshore areas in the GoT, namely the Pattani Basin and the Malay Basin. Due to the fractured nature of the offshore geology, Thailand's reserves and production is provided by many separate, but relatively homogenous, reservoirs spread across the two basins. Gas accounts for 75% of Thailand's remaining hydrocarbon reserves.

Recent exploration activities have focused on step-out exploration and appraisal drilling of non-vertical wells. Even though overall success rates have been low, a number of small discoveries have been made in recent years, both onshore and in the Gulf of Thailand.

Growing gas demand in Thailand has placed a greater emphasis on maintaining domestic gas supply and securing new imports. Pipeline gas import supply is sourced from Myanmar and the Malaysia-Thailand JDA; LNG is also imported to meet domestic gas demand.

Current Concessions

There are 39 petroleum concessions currently under operation in Thailand and 49 exploration blocks. 22 of the petroleum producing concessions and 29 exploration blocks are located offshore, whereas 17 petroleum producing conessions and 20 exploration blocks are located onshore. Details of these petroleum concessions are provided in Table 1.

Table 1 Petroleum Concessions in Thailand (as of 1 January 2018)

Concess. No. Date Issued	Concessionaire(s)	Share (%)	Block	Concession Area (sq.km.)		
				Exploration	Production	Reserves
Gulf of Thailand						
1/1/2514	Thailand-Cambodia Overlapping Area					
26-Nov-71	Mitsui Oil Exploration Co., Ltd.	20.00	5	4,645.0000	–	–
	Idemitsu Kosan Co., Ltd.	50.00	6	5,510.0000	–	–
	**Chevron Thailand Exploration and Production Ltd.	20.00				
	* Chevron Blocks 5 and 6, Ltd.	10.00				
1/2515/5	Gas Sale Agreement No.2 (Unit Area I)					
1-Mar-72	* Chevron Thailand Exploration and Production Ltd.	70.00				
	**Mitsui Oil Exploration Co., Ltd.	30.00				
	Gas Sale Agreement No.2 (Supplementary) (Unit Area II)		10	–	744.1295	123.0800
			11	–	1,154.8318	–
	* Chevron Thailand Exploration and Production Ltd.	71.25				
	**Mitsui Oil Exploration Co., Ltd.	23.75				
	**PTT Exploration and Production Public Co., Ltd.	5.00				
23-Apr-75	Thailand-Cambodia Overlapping Area					
Sup.No 2	* Chevron Thailand Exploration and Production Ltd.	60.00	10	1,382.9000	–	–
	**Mitsui Oil Exploration Co., Ltd.	40.00	11	1,401.4900	–	–
17-Dec-97	* Chevron Thailand Exploration and Production Ltd.	60.00	10A	–	166.0000	–
Sup.No 9	**Mitsui Oil Exploration Co., Ltd.	40.00	11A	–	88.0000	–
2/2515/6	Gas Sale Agreement No.1					
1-Mar-72	* Chevron Thailand Exploration and Production Ltd.	80.00				
	**Mitsui Oil Exploration Co., Ltd.	20.00				
	Gas Sale Agreement No.2 (Unit Area I)					
	* Chevron Thailand Exploration and Production Ltd.	70.00	12	–	1,295.1646	–
	**Mitsui Oil Exploration Co., Ltd.	30.00	13	–	1,175.7716	–
	Gas Sale Agreement No.2 (Supplementary) (Unit Area II)					
	* Chevron Thailand Exploration and Production Ltd.	71.25				
	**Mitsui Oil Exploration Co., Ltd.	23.75				
	**PTT Exploration and Production Public Co., Ltd.	5.00				

Concess. No. Date Issued	Concessionaire(s)	Share (%)	Block	Concession Area (sq.km.)		
				Exploration	Production	Reserves
8-Jun-99 Sup.No.6	<u>Thailand-Cambodia Overlapping Area</u> * Chevron Thailand Exploration and Production Ltd. **Mitsui Oil Exploration Co., Ltd.	 80.00 20.00	12A 12B 13	294.0000 125.0000 471.0000	– – –	– – –
3/2515/7 8-Mar-72	* PTT Exploration and Production Public Co., Ltd. Total E&P Thailand Shell Integrated Gas Thailand Pte Limited	44.45 33.33 22.22	16 17	– –	1,403.1090 518.3800	– –
1-Jun-98 Sup.No.11	* PTT Exploration and Production Public Co., Ltd. Chevron Thailand Exploration and Production Ltd. Moeco Thailand Co., Ltd.	80.00 16.00 4.00	16A	–	719.8457	–
4/2515/8 9-Mar-72	<u>Thailand-Cambodia Overlapping Area</u> * BG Asia Inc. Chevron Overseas Petroleum (Thailand) Ltd. Petroleum Resources (Thailand) Pty., Ltd.	 50.00 33.33 16.67	 7 8 9	 4,760.0000 3,400.0000 2,260.0000	 – – –	 – – –
17-Jul-03 Sup.No.9	* Chevron Offshore (Thailand) Ltd. Orange Energy Limited Chevron Block B 8/32 (Thailand) Ltd. Palang Sophon Limited	44.34 46.34 7.32 2.00	9A	–	80.0276	–
5/2515/9 10-Mar-72	* PTT Exploration and Production Public Co., Ltd. Total E&P Thailand Shell Integrated Gas Thailand Pte Limited	44.45 33.33 22.22	15	–	1,279.0000	–
27-Feb-98 Sup.No.11	* PTT Exploration and Production Public Co., Ltd. Chevron Thailand Exploration and Production Ltd. Moeco Thailand Co., Ltd.	80.00 16.00 4.00	14A	–	1,373.1890	–
	<u>Thailand-Cambodia Overlapping Area</u> * PTT Exploration and Production Public Co., Ltd. Chevron Thailand Exploration and Production Ltd. Moeco Thailand Co., Ltd.	 80.00 16.00 4.00	14A	133.0000	–	–
27-Feb-98 Sup.No.11	* PTT Exploration and Production Public Co., Ltd. Chevron Thailand Exploration and Production Ltd. Moeco Thailand Co., Ltd.	80.00 16.00 4.00	15A	–	1,466.0516	–
3/2528/28 6-Feb-85	* PTTEP Siam Ltd.	100.00	B6/27	–	9.6375	1,296.9625
1/2529/33 15-Jan-86	* Chevron Thailand Exploration and Production Ltd. PTT Exploration and Production Public Co., Ltd. PTTEP SP Limited MOECO Thai Oil Development Co., Ltd.	35.00 45.00 15.00 5.00	B12/27	–	2,565.9630	554.0800

Concess. No. Date Issued	Concessionaire(s)	Share (%)	Block	Concession Area (sq.km.)		
				Exploration	Production	Reserves
1/2532/35 9-Aug-89	MP B5 (Thailand) Limited	100.00	B5/27	–	75.8988	1,855.3412
1/2534/36 1-Aug-91	Tantawan Production Area * Chevron Offshore (Thailand) Ltd. Orange Energy Limited **Chevron Block B 8/32 (Thailand) Ltd. Palang Sophon Limited	 44.34 46.34 7.32 2.00	B8/32	–	274.6670	–
	Outside Tantawan Production Area * Chevron Offshore (Thailand) Ltd. Orange Energy Limited B8/32 Partners Ltd. **Chevron Block B 8/32 (Thailand) Ltd. Palang Sophon Limited	 29.67 31.67 31.67 5.00 2.00	B8/32	–	1,717.4300	–
3/2539/50 24-Oct-96	* Ophir Thailand (Bualuang) Limited Ophir Thailand (E&P) Limited	60.00 40.00	B8/38	–	376.5626	–
4/2546/61 17-Jul-03	* Chevron Offshore (Thailand) Ltd. PTTEP International Ltd. **Siam Moeco Ltd. Palang Sophon Limited	51.000 21.375 21.250 6.375	G4/43	–	454.8500	–
7/2546/64 17-Jul-03	CEC International Ltd. (Thailand Branch)	100.00	G5/43	–	357.3241	–
8/2546/65 17-Jul-03	Thailand-Cambodia Overlapping Area PTTEP International Ltd.	 100.00	G9/43	2,619.0000	–	–
1/2549/69 15-Mar-06	* Chevron Pattani, Ltd. Siam Moeco Ltd. PTTEP International Ltd.	71.25 23.75 5.00	G4/48	–	70.8300	–
3/2549/71 15-Mar-06	* PTTEP International Ltd. Total E&P Thailand Thai Energy Co., Ltd	44.45 33.33 22.22	G12/48	–	37.0500	–
7/2549/75 8-Dec-06	* MP G1 (Thailand) Limited Northern Gulf Petroleum Pte. Ltd. Tap Energy (Thailand) Pty. Ltd.	60.00 10.00 30.00	G1/48	–	161.1400	484.2300
8/2549/76 8-Dec-06	* KrisEnergy (Gulf of Thailand) Limited KrisEnergy G10 (Thailand) Limited Palang Sophon Limited	25.00 64.00 11.00	G10/48	–	132.2000	1,392.3000
4/2550/80 8-Jan-07	* KrisEnergy (Gulf of Thailand) Limited MP G6 (Thailand) Limited Northern Gulf Petroleum Pte. Ltd.	30.00 30.00 40.00	G6/48	–	87.7400	283.6300
5/2550/81 13-Feb-07	* MP G11 (Thailand) Limited KrisEnergy (Gulf of Thailand) Limited Palang Sophon Limited	67.50 22.50 10.00	G11/48	–	23.1800	991.6800

Concess. No. Date Issued	Concessionaire(s)	Share (%)	Block	Concession Area (sq.km.)		
				Exploration	Production	Reserves
11/2550/87 19-Dec-07	* Chevron Pattani, Ltd. PTTEP International Limited PTTEP G7 Limited **Siam Moeco Ltd.	35.00 45.00 15.00 5.00	G7/50	–	45.4400	29.5900
12/2550/88 19-Dec-07	* PTTEP International Limited Chevron Petroleum (Thailand), Ltd. **Siam Moeco Ltd.	80.00 16.00 4.00	G8/50	–	121.9400	–
Total	**22 concessions**		**29 blocks**	**27,001.3900**	**17,975.3534**	**7,010.8937**

Concess. No. Date Issued	Concessionaire(s)	Share (%)	Block	Concession Area (sq.km.)		
				Exploration	Production	Reserves
Onshore						
1/2522/16 15-Mar-79	* PTTEP Siam, Ltd. **PTT Exploration and Production Public Company Limited	75.00 25.00	S1	–	870.5149	454.9500
2/2522/17 16-Mar-79	Namphong Area * ExxonMobil Exploration and Production Khorat Inc. **PTT Exploration and Production Public Co., Ltd.	80.00 20.00	E5	–	34.4000	34.5400
	Phu Horm Area * PTTEP SP Limited Apico LLC **PTT Exploration and Production Public Co., Ltd. ExxonMobil Exploration and Production Khorat Inc.	35.00 35.00 20.00 10.00	E5	–	39.3100	–
1/2524/19 3-Jun-81	* PTTEP SP Limited Apico LLC **PTTEP Siam Ltd. ExxonMobil Exploration and Production Khorat Inc.	35.00 35.00 20.00 10.00	EU1	–	192.8900	–
1/2526/23 12-Apr-83	* Sino-U.S. Petroleum Inc. Central Place Company Ltd. Thai Offshore Petroleum Ltd. Sino Thai Energy Ltd.	33.33 33.33 16.67 16.67	NC	–	11.2439	–
1/2527/24 24-Jul-84	Eco Orient Energy (Thailand) Ltd.	100.00	SW1	–	14.4611	–
2/2528/27 5-Feb-85	PTTEP International Ltd.	100.00	PTTEP1	–	9.0400	–
1/2546/58 17-Jul-03	CNPCHK (Thailand) Ltd.	100.00	L21/43	–	43.3460	–
2/2546/59 17-Jul-03	PTTEP International Ltd.	100.00	L22/43	–	16.4800	–
3/2546/60 17-Jul-03	Eco Orient Resources (Thailand) Ltd.	100.00	L44/43	–	94.4800	–

Concess. No. Date Issued	Concessionaire(s)	Share (%)	Block	Concession Area (sq.km.)		
				Exploration	Production	Reserves
5/2546/62 17-Jul-03	Eco Orient Resources (Thailand) Ltd.	100.00	L33/43	–	11.9400	–
9/2546/66 25-Sep-03	Apico (Khorat) Limited	100.00	L15/43 L27/43	– –	70.1500 31.9100	34.0100 –
1/2547/67 22-Jan-04	* Siam Moeco Ltd.	100.00	L10/43 L11/43		77.6600 47.4200	– –
2/2547/68 22-Jan-04	PTTEP International Ltd.	100.00	L53/43 L54/43	– –	1.9800 10.8300	– –
1/2550/77 8-Jan-07	Pan Orient Energy (Siam) Ltd.	100.00	L53/48	–	22.2200	213.9100
13/2550/89 19-Dec-07	* Twinza Oil Limited Twinza Oil (Thailand) Limited	50.00 50.00	L7/50	1,256.7600	–	–
6/2553/108 25-Feb-10	Yanchang Petroleum (Thailand) Co., Ltd	100.00	L31/50	920.5400	–	–
2/2554/110 8-Feb-11	TPI Refinery (1997) Company Limited	100.00	L29/50	982.8600	–	–
Total	**17 concessions**		**20 blocks**	**3,160.1600**	**1,600.2759**	**737.4100**
Grand Total	**39 concessions**		**49 blocks**	**30,161.5500**	**19,575.6293**	**7,748.3037**

Note

* Operator

** Co-venturer

Source: Department of Mineral Fuels

Figure 2 Current Petroleum Concession Map of Thailand

Geology of the Gulf of Thailand

The Gulf of Thailand (GoT) is located in Southeast Asia between approximately latitudes 06 00 and 14 00 N and longitudes 99 00 and 103 00 E, covering an area of about 300,000 square kilometers. The West of the GoT borders the Thai-Malay Peninsula, the East borders Cambodia and Vietnam, and the South borders Malaysia (as shown in Figure 3). Petroleum exploration in the GoT began in 1968 under special conditions of the Mineral Act BE 2510 (1967). Subsequent to the promulgation of the Petroleum Act BE 2514 (1971), the exploration rights were transferred from being under the Mineral Law to the Petroleum Law. In 1981, the Erawan field, the first exploration and production area in the Gulf of Thailand, began production.

GoT has since experienced continuous exploration and production activity. Currently, there are 22 petroleum concessions, 29 exploration blocks and 136 production areas in the GoT, supporting the fact of a proven petroleum system in the GoT. At the end of 2016, the cumulative production of natural gas, crude oil and condensate in the GoT was approximately 4,944 MMBOE, covering 90.5% of total domestic production. Therefore, the GoT is considered as the area with highest potential in terms of petroleum production. According to the reserve estimation at the end of 2016, the amount of Proved Reserves (P1) in the GoT was 6.60 tcf of natural gas, 122.7 million barrels of crude oil, and 170.68 million barrels of oil equivalent of condensate.

The GoT consists of Cenozoic sedimentary basins formed by normal fault. As a result, these basins formed graben and half-graben geometries oriented in the north-south direction (as shown in Figure 3 and Figure 4) which can be categorized into 2 groups, using the Ko Kra Ridge as a natural borderline. The first group of basins, located on the west of the Ko Kra Ridge, contains about 11 small basins. The active basins include the Chumphon Basin, Songkhla Basin, Western Kra Basin, and Kra Basin. On the other side of Ko Kra Ridge, the eastern part is the most successful area for petroleum exploration and production in the country, comprising two major basins; the Pattani Basin and the North Malay Basin. The production of both basins accounts for 73.4% of the total production in the GoT and 68.6% of the total production in the country (as of the end of 2016).

The formation of petroleum in the GoT originates from the Main Petroleum Source Rock Layer, a shale and coal layer containing a high amount of organic content. This source rock formed in the Late Eocene-Miocene, in flood plain, alluvial plain and lacustrine environments. The sandstone reservoir rock was deposited in a Fluvial and Fluvio-Lacustrine environment and has an average porosity of 10 – 30%. Most of the reservoirs correlate with the fault. Petroleum usually migrates through these faults and rock layers to the structural trap. While the petroleum seal, which is the rock layer that has relatively low porosity and permeability, usually consists of shale, mudstone, siltstone, and coal layers interbedded with the sandstone reservoir (as shown in Figure 5).

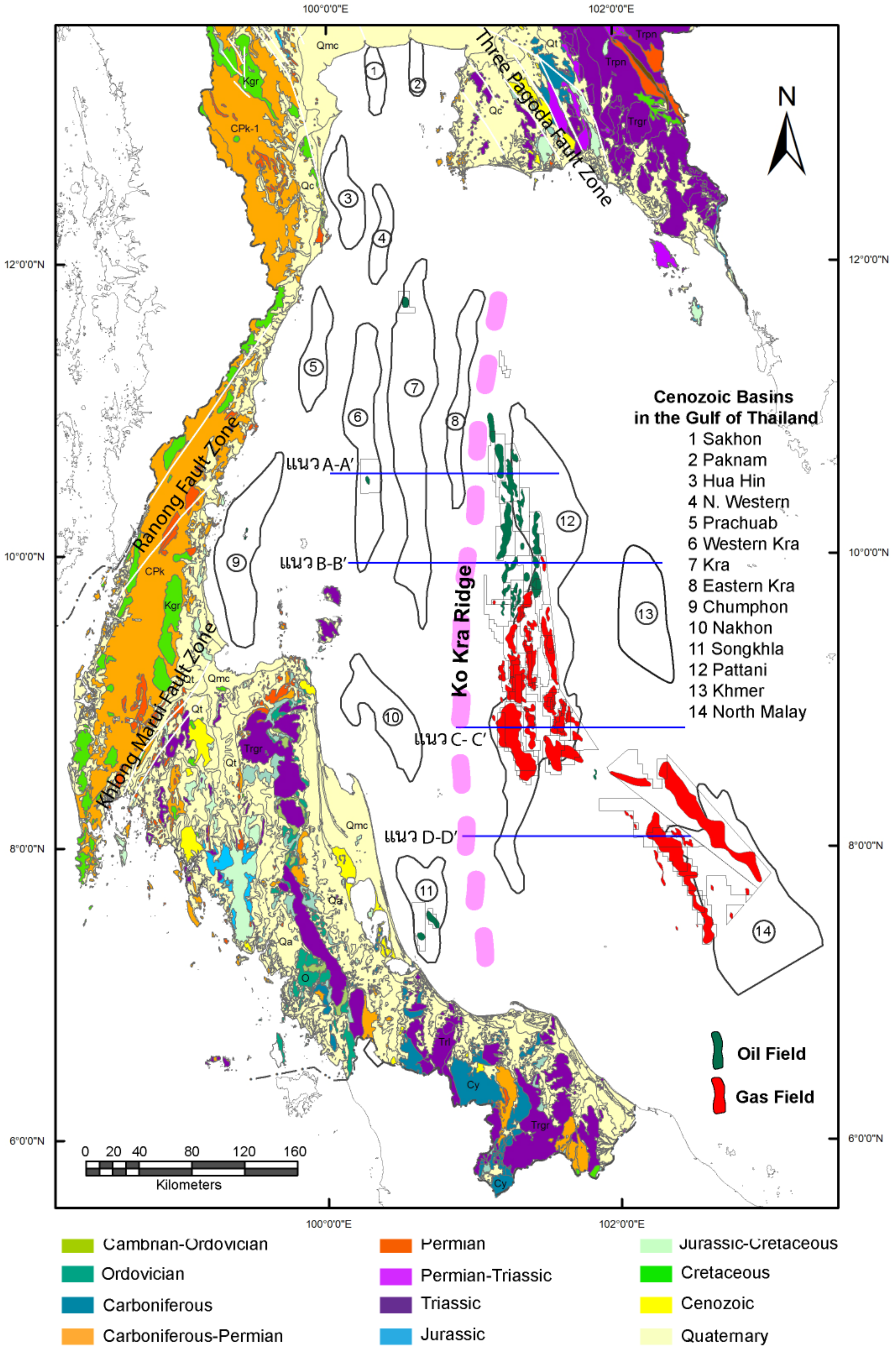

Figure 3 Map of Thailand's sedimentary basins and petroleum fields in the Gulf of Thailand

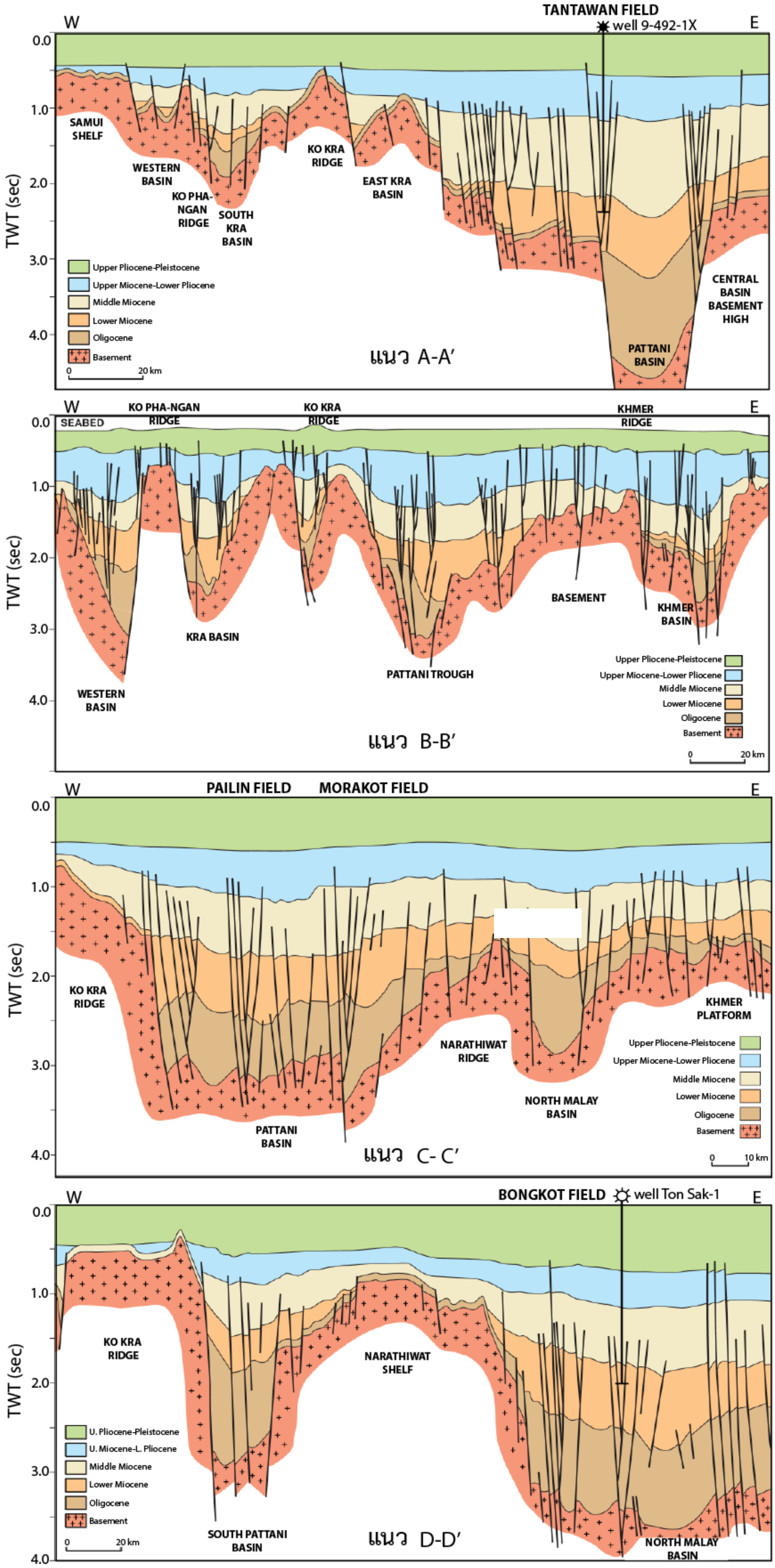

Figure 4 Cross sectional model showing the basins (modified from Racey 2011) following the pink line shown in Figure 3

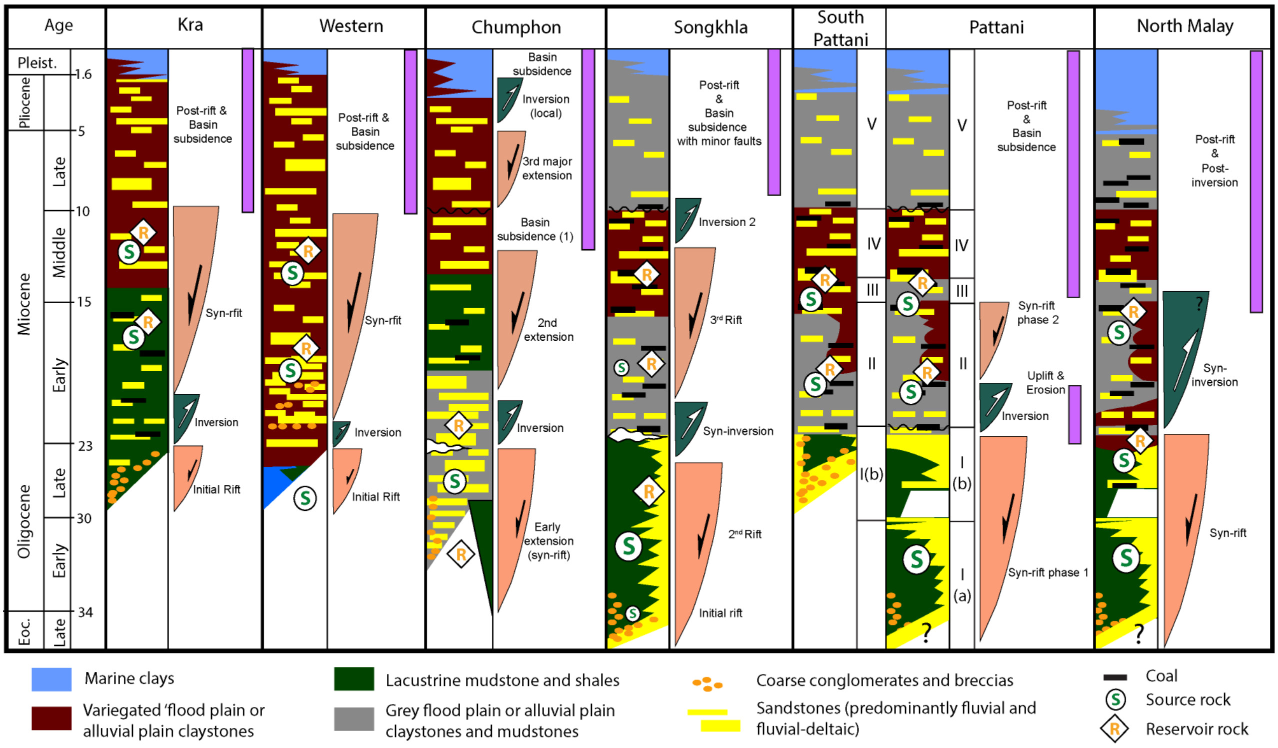

Figure 5 Model of petroleum system in the Gulf of Thailand (collected and modified information from Chantaraprasert 2000, Intawong 2006, Kaewkor 2018, Morley and Racey 2011, Racey 2011, Chevron 2016, PTTEP 2015).

1. Geology of Block G1/61

Block G1/61 is located in the Pattani Basin which is approximately 270 km long and 100 km wide, oriented in the north-south direction. The Pattani Basin has the highest total production rate of gas, oil and condensate in the GoT.

The Pattani Basin rifted during the Late Eocene to Late Oligocene, followed by post-rift and thermal sag since the Early Miocene to the recent era. The main structure consists of normal faults which are oriented in the north-south direction, forming graben and half-graben geometries.

The stratigraphy of the Pattani Basin can be divided into 5 sequences, shown in Figure 6

Sequence 1 is the rock layer formed in the Late Eocene-Oligocene, with sedimentation occuring concurrently with the Syn-Rift Sediment. This sequence consists principally of shale, sandstone, and conglomerate. Shale in this sequence contains a high amount of organic content and usually resides in the lacustrine deposition. The sandstone and conglomerate are usually deposited in the fluvio-deltaic and alluvial fan environments respectively.

Sequence 2 is the rock layer formed in the Early-Mid Miocene period, primarily consisting of sandstone, mudstone, and coal. The sedimentation of sequence 2 occurred during the Post-Rift Phase. The sandstone in this sequence resides only in the fluvial deposition, while the mudstone resides in both the delta plain and intertidal deposition.

Sequence 3 is the rock layer formed in the Mid Miocene period, consisting of carbonaceous shale interbedded with sandstone, siltstone, and coal which reside in the lagoon, fluvial, and shallow marine depositions.

Sequence 4 is the rock layer formed in the Mid-Late Miocene period, consisting of mudstone interbedded with sandstone and coal which resides in the fluvio-deltaic deposition. The top surface of this sequence contains the Mid Miocene Unconformity (MMU).

Sequence 5 is the rock layer formed in the Late Miocene-Recent period, consisting of mudstone interbedded with sandstone, shale and coal which resides in the fluvial and shallow marine depositions.

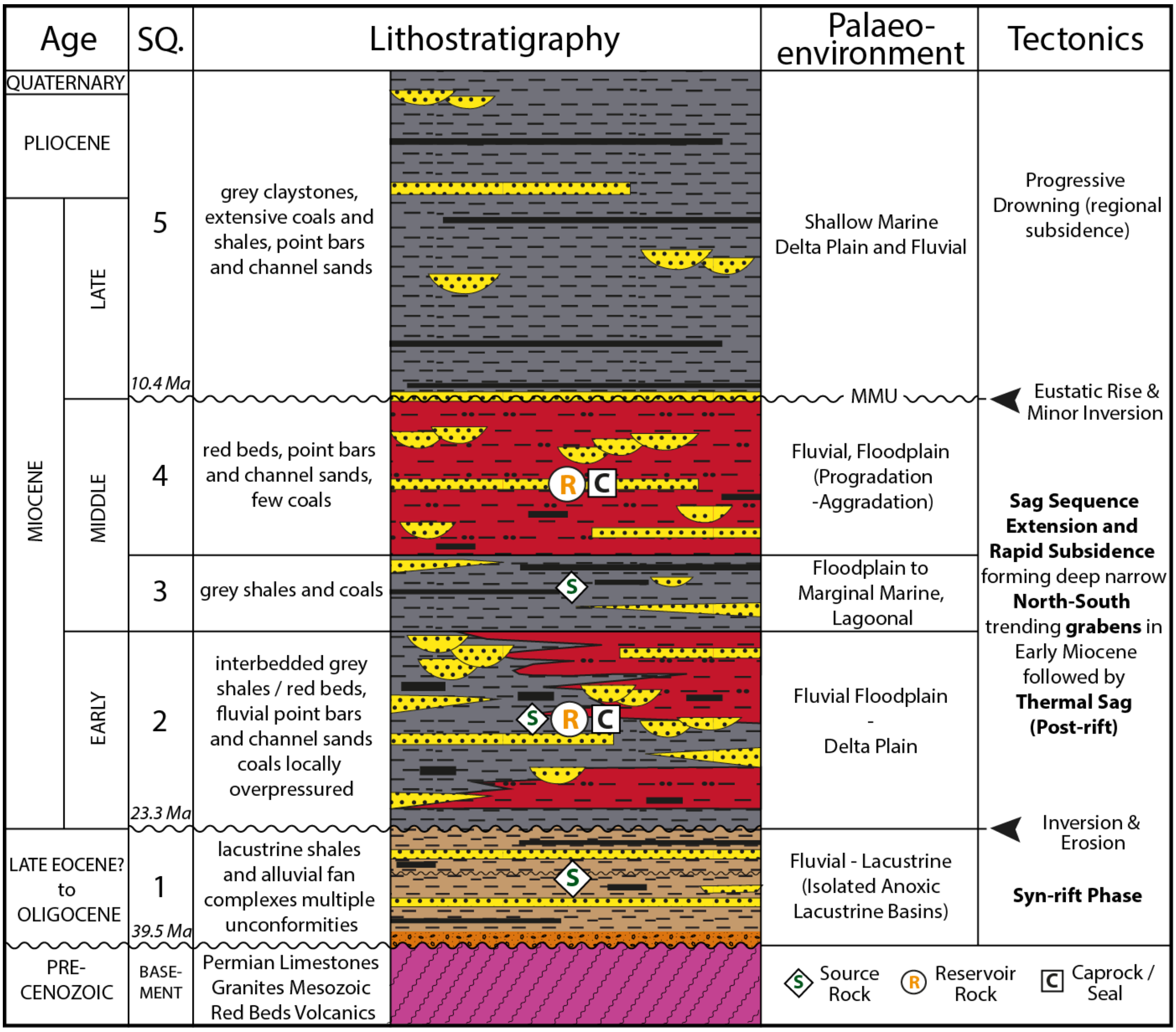

Figure 6 The stratigraphy of the Pattani Basin (compiled and modified from Chantaraprasert, 2000; Chevron, 2016; Jardine, 1997; Morley & Racey, 2011; Racey, 2011)

2. Petroleum System of Block G1/61

The northern part of block G1/61 consists of Plamuk, Platong, Surat, Yala, and Kaphong petroleum fields etc. (Fig 7) which produce gas, oil and condensate. The central and southern parts of the block (Fig 8 and 9) are mainly composed of gas fields such as Pakarang, Satun, Erawan, Trat, Funan, and Gomin etc. The Top Oil Window occurs from depths of 2,000 meters, while the Top Gas Window occurs from depths of 2,900 meters. The petroleum basin's formation system (as shown in Figure 10) can be described as follows:

1) Source Rock: The main source rock is the Oligocene lacustrine shale with high organic content in sequence 1 (oil prone). In addition, sequences 2, 3 and lowermost sequence 4 may also be potential source rocks (gas-condensate prone).

2) The generation-migration-accumulation (G-M-A): The G-M-A of sequence 1 was likely to have occured during the late Oligocene to Mid Miocene until the basin margin uplift occurred, leading to structural inversion (Jardine, 1997). The migration of petroleum from the source rock in sequences 2, 3, and 4 started since the Mid Miocene to Recent (Chevron, 2011).

3) Reservoir rock: The main reservoir rocks are fluvio-deltaic sandstones in sequences 2 and 3. The minor reservoir rocks are also sandstones found in the sequences 1 and 4. The sandstone layer thickness ranges from 2 – 25 meters.

4) Trap and Seal: Both structural and stratigraphic traps are found in the area. The seals are low porosity and permeability layers (e.g. shale, claystone, siltstone and coal) interbedded with reservoir rocks, coupled by faults.

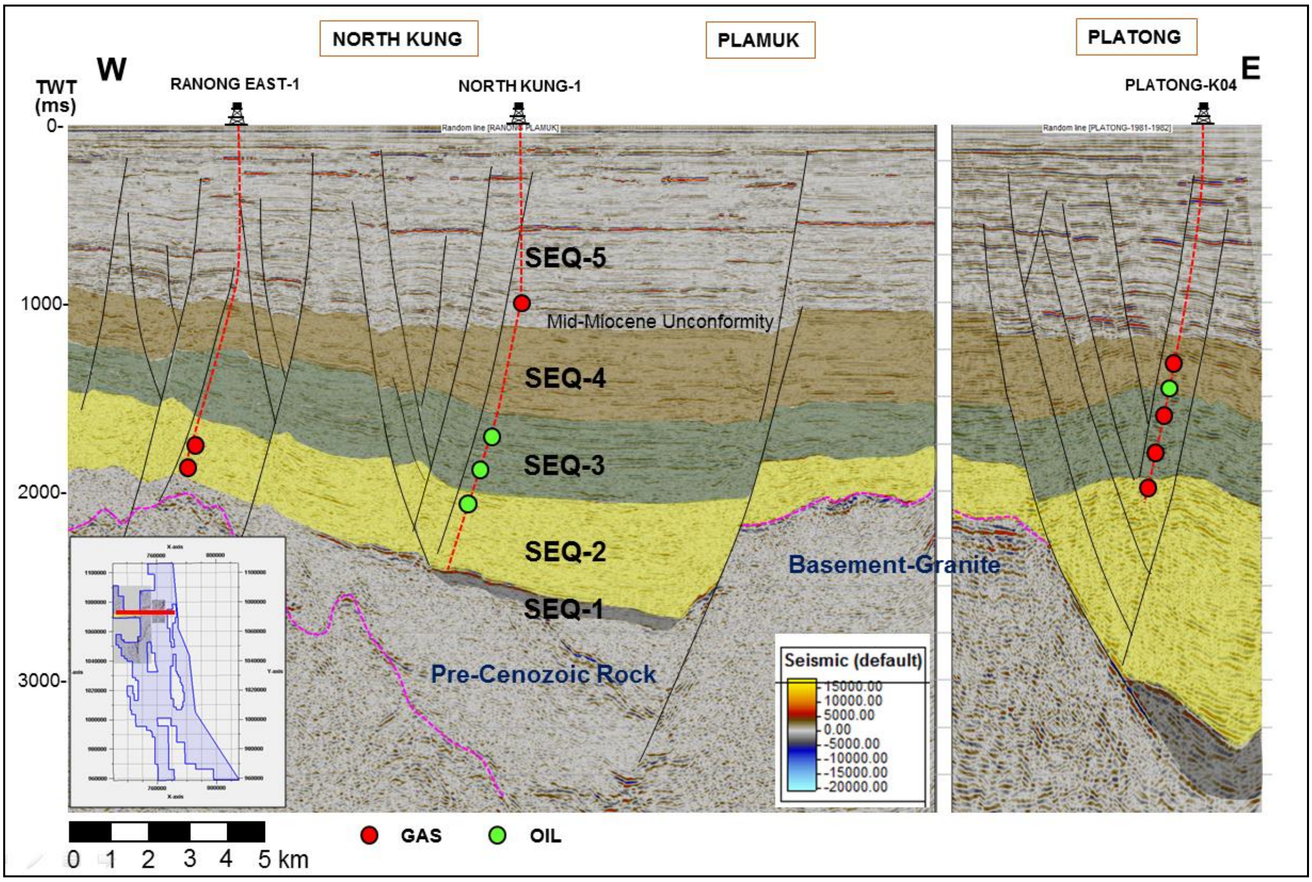

Figure 7 Cross sectional seismic data in the East-West Trending Northern Region of block G1/61 which passes through North Kung, Plamuk, and Platong fields. The figure also shows Ranong East-1, North Kung-1, and Platong-K04 well trendlines.

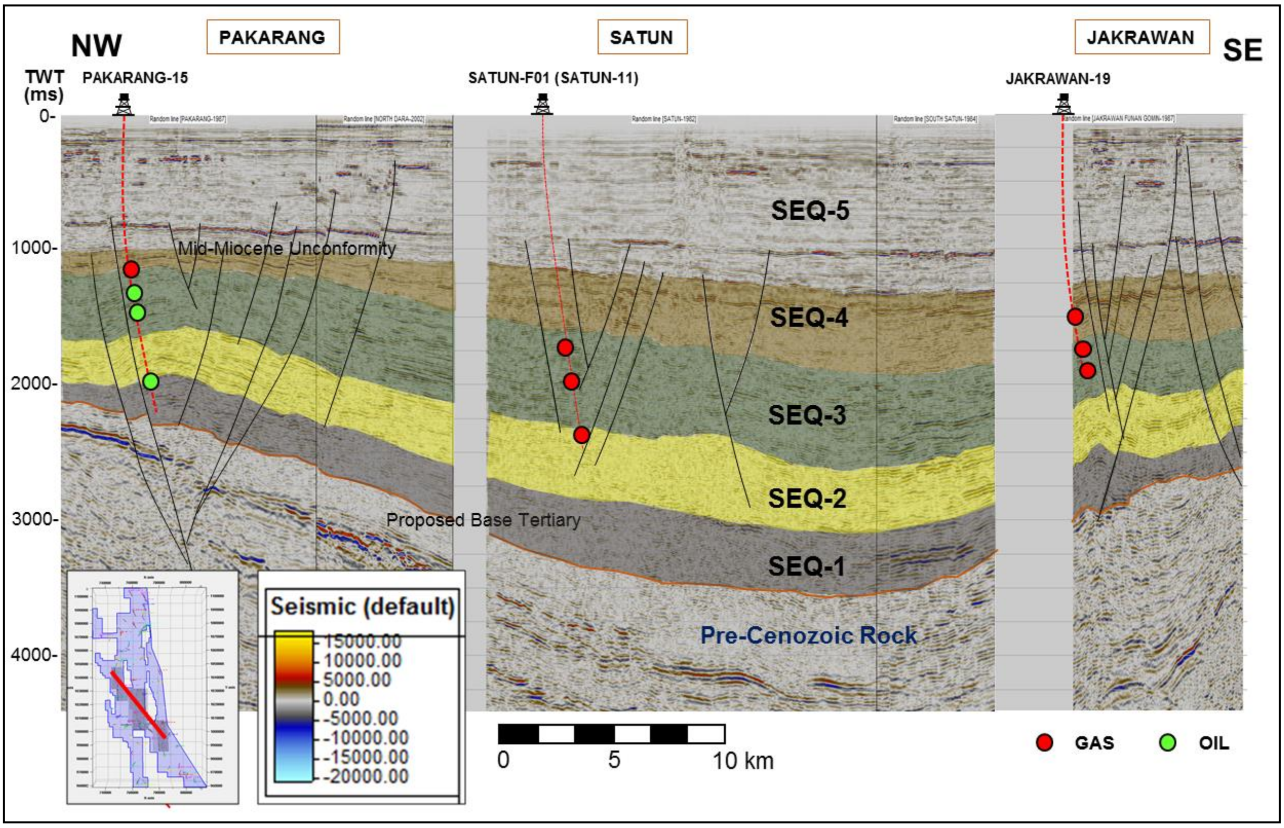

Figure 8 Cross sectional seismic data in the SE-NW Trending Central Region of block G1/61 which passes through Pakarang, Satun, and Jakrawan fields. The figure also shows the Pakarang-15, Satun-F01, and Jakrawan-19 well trendlines.

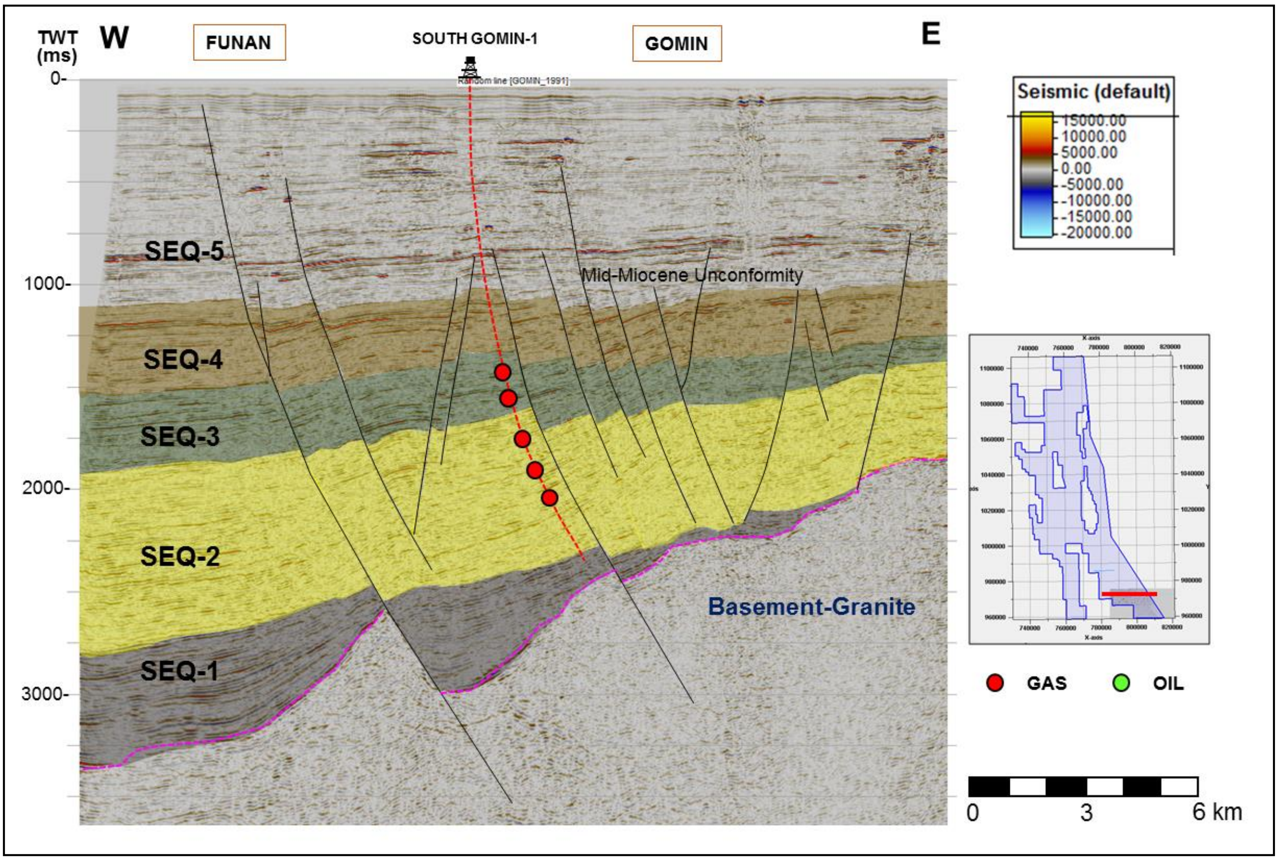

Figure 9 Cross sectional seismic data in the East-West Trending Southern Region of block G1/61 which passes through Funan and Gomin fields. The figure also shows the South Gomin-1 well trendlines.

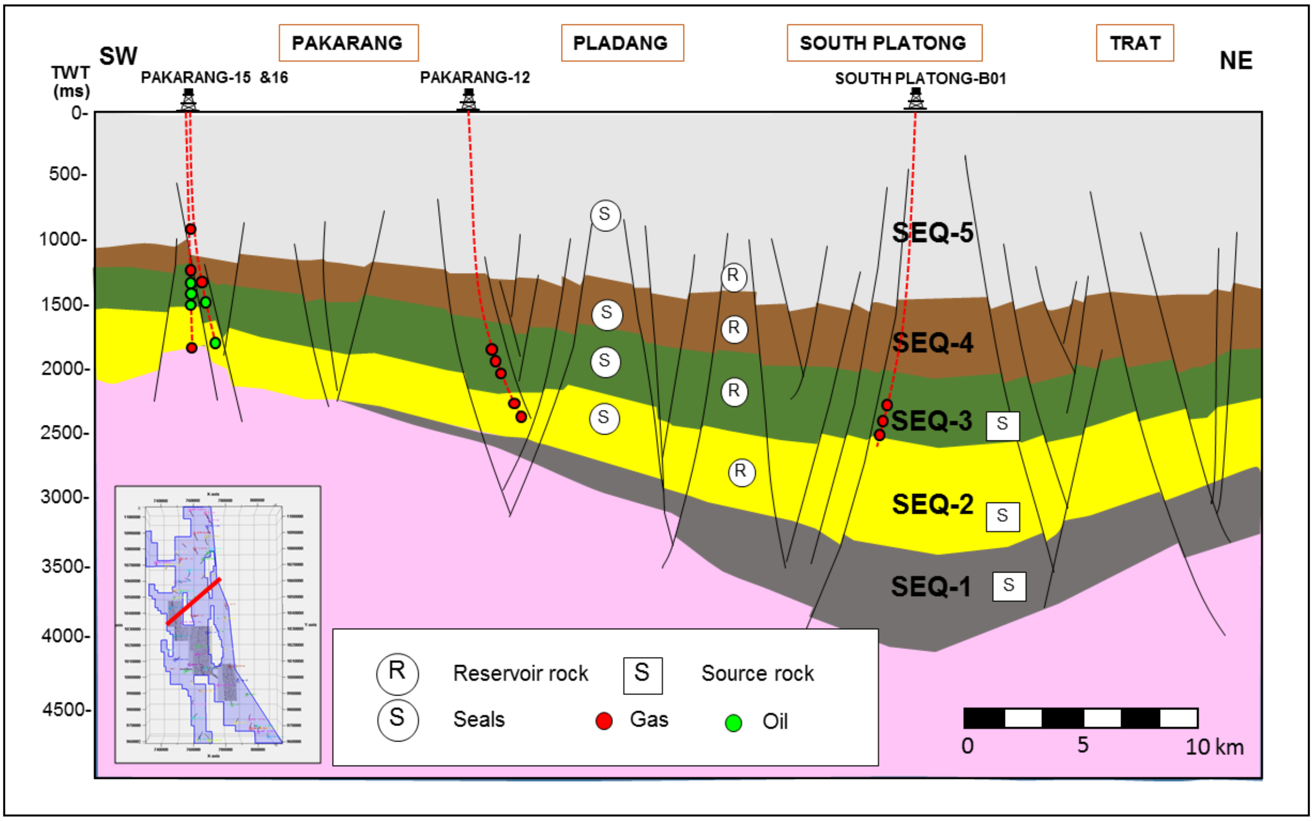

Figure 10 The SW-NE schematic cross section passes through Pakarang, Pladang, South Platong, and Trat fields showing the relationship between stratigraphy and petroleum system in the Pattani Basin.

3. Geology of Block G2/61

Block G2/61 is located in the North Malay Basin which is the Southeastern extent of the Pattani Basin. The North Malay Basin is a large sedimentary basin that contains Cenozoic sediments, with a layer thickness of 9 kilometers. The North Malay Basin covers an area of approximately 18,000 square kilometres. The major gas fields in the basin are Bongkot (Block G2/61) and Arthit.

The rifting phase in the North Malay Basin started in Late Eocene and ended during the Late Oligocene, followed by a post-rift and thermal sag from the Early Miocene to the recent era. The main fault pattern is the set of normal faults which are oriented in the north-south and northwest-southeast directions, forming graben and half-graben geometries.

The Stratigraphy of the North Malay Basin can be divided into 4 formations which are shown in Figure 11.

FM-0 is the rock layer formed in the Late Eocene-Oligocen, with concurrent sedimentation with the Syn-Rift Sediment. FM-0 consists principally of lacustrine shale and fluvial sandstone with more sandstone at the top of the formation.

FM-1 is the rock layer formed in the Late Oligocene-Early Miocene period, with sedimentation occurring during the Post-Rift Phase. FM-1 consists principally of coarse-grained sandstone residing in the fluvial deposition and interbedded with shale or mudstone layers.

FM-2 is the rock layer formed in the Early-Mid Miocene period, consisting of sandstone that resides in the Fluvial, Fluvio-Deltaic, and Flood Plain depostition. The alternation of coal and shale layers is commonly found in FM-2. The top surface of FM-2 is marine shale.

FM-3 is the rock layer formed in the Late Miocene-Pliocene period, consisting principally of shale, with some permeation of thin layers of sandstone. The FM-3 is resided in a Marine deposition.

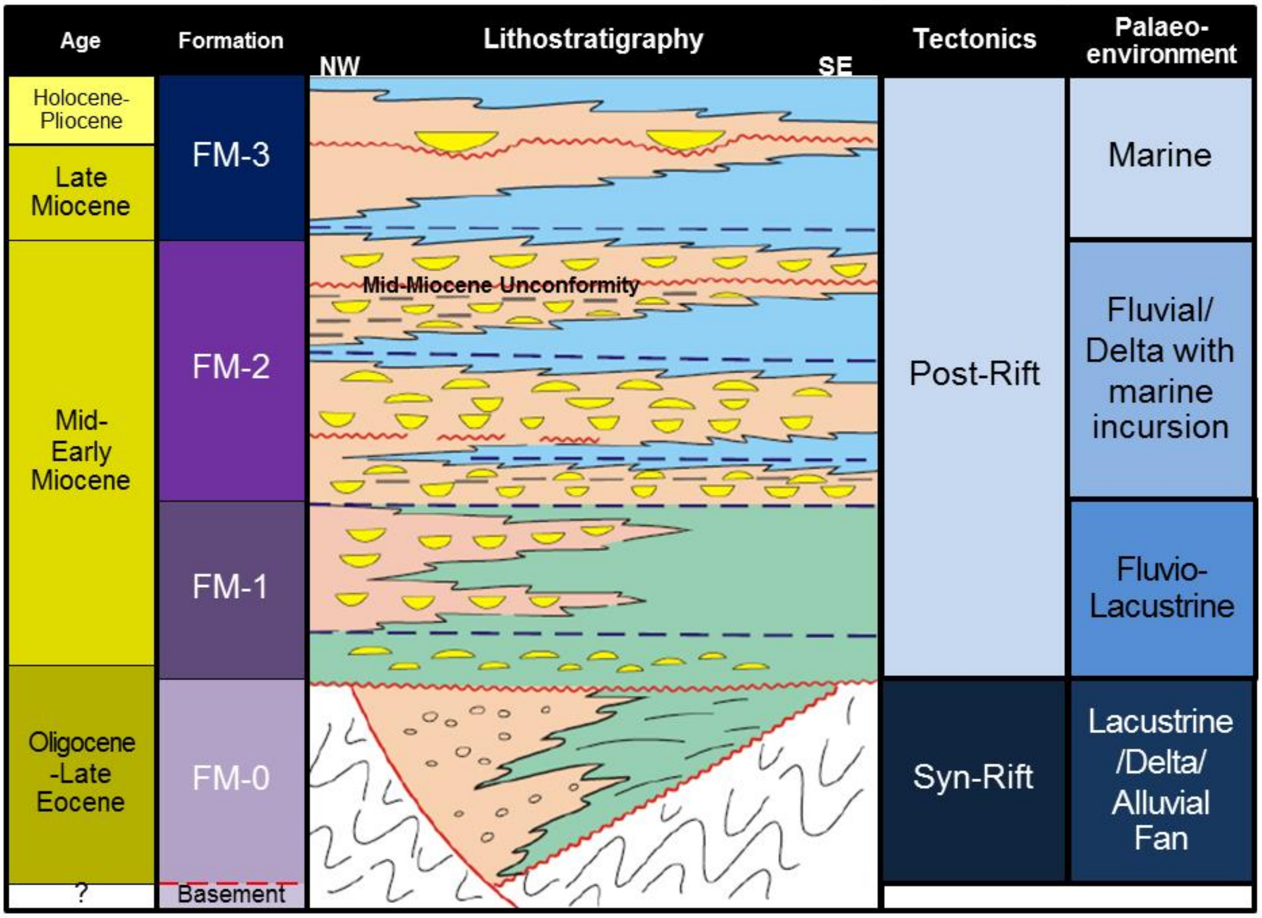

Figure 11 The stratigraphy, Tectonics and Palaeo-environment of the North Malay Basin

4. Petroleum System of Block G2/61

Block G2/61 (Bongkot field) is a major gas field in the GoT and can be divided into Greater Bongkot North (GBN) and Greater Bongkot South (GBS) as shown in figure 12. The major gas production from this block occurs in a reservoir rock layer, the sandstone layer of FM-2. The main source rock is the shale in FM-1 and FM-2 which contains high amount of organic content. The petroleum system (Figure 13) can be described as follows:

1) Source rock: The source rocks are coal and organic shale in the FM-2 which contain 53% and 11% of total organic content (TOC), respectively. The other potential source rocks are lacustrine shale in the FM-0, FM-1 and marine shale in the FM-3. These source rocks are gas-prone.

2) The generation-migration-accumulation (G-M-A): GBS is the main kitchen area of the block G2/61. Hydrocarbons have partly migrated upward in the NW direction to GBN. The G-M-A likely occurred during the late Miocene to Pliocene.

3) Reservoir rock: The main reservoir is sandstone in the FM-2, deposited in distributary channels, deltaic bars, delta front and crevasse splays. Moreover, sandstone in the FM-0 and FM-1, deposited in fluvio-lacustrine environment may be alternative potential reservoirs as shown in figure 14 and 15.

4) Trap and Seal: Both structural traps (e.g. fault trap and 4-way dip closure) and stratigraphic traps are found in the area. The seals are low porosity and permeability layers (e.g. shale, claystone, siltstone and coal) interbedded with reservoir rocks.

One significant challenge facing petroleum production in this area is derived from the greater than average Geothermal Gradient. With every additional 100 meters of depth, the temperature rises by approximately 5-8 degree celcius. Moreover, large quantities of CO_2 are found in the gas produced from this area.

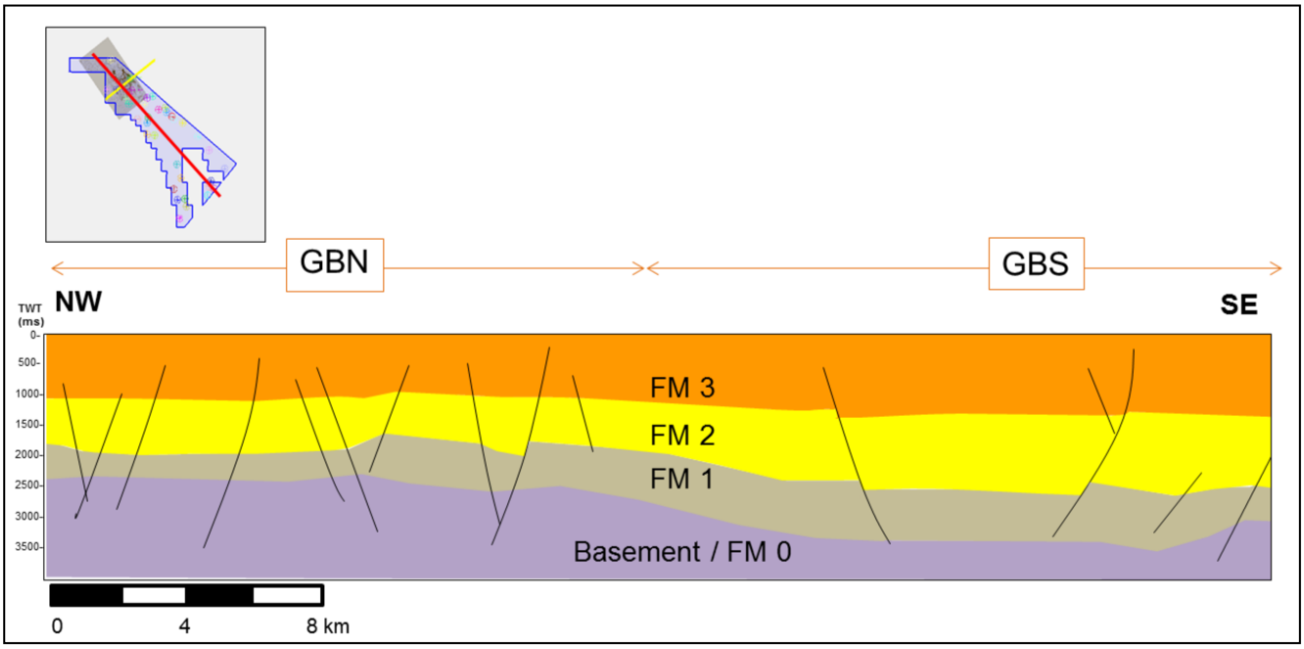

Figure 12 A NW-SE schematic cross section passing through the Greater Bongkot North (GBN) and Greater Bongkot South (GBS) fields showing the stratigraphy; thickness and depth levels increase in GBS.

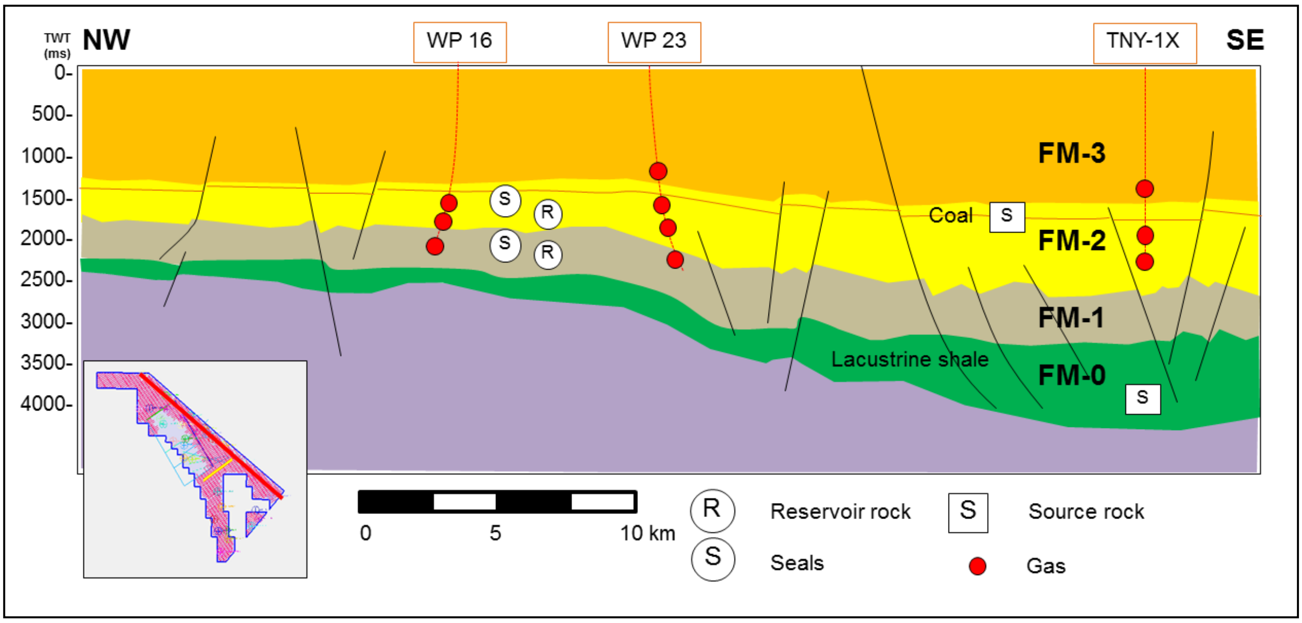

Figure 13 A NW-SE schematic cross section passing through wellhead platforms WP 16 and WP 23 and well TNY-1X, showing the relationship between stratigraphy and petroleum system in the North Malay Basin. The main producing gas reservoir is the FM-2.

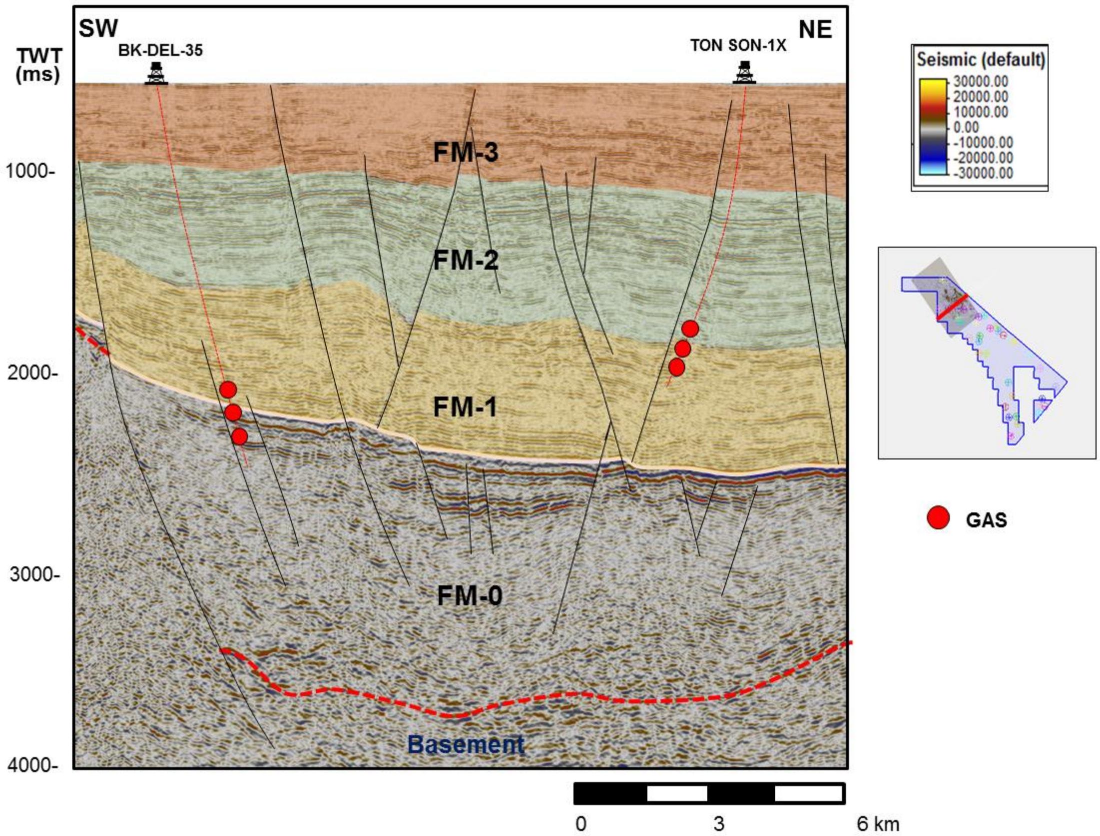

Figure 14 The cross sectional seismic data in the SW-NE trending Northern Region of block G2/61 passing through well number BK-DEL-35 and Ton Son-1X, where the gas produced from FM-0, FM-1, and FM-2 was found.

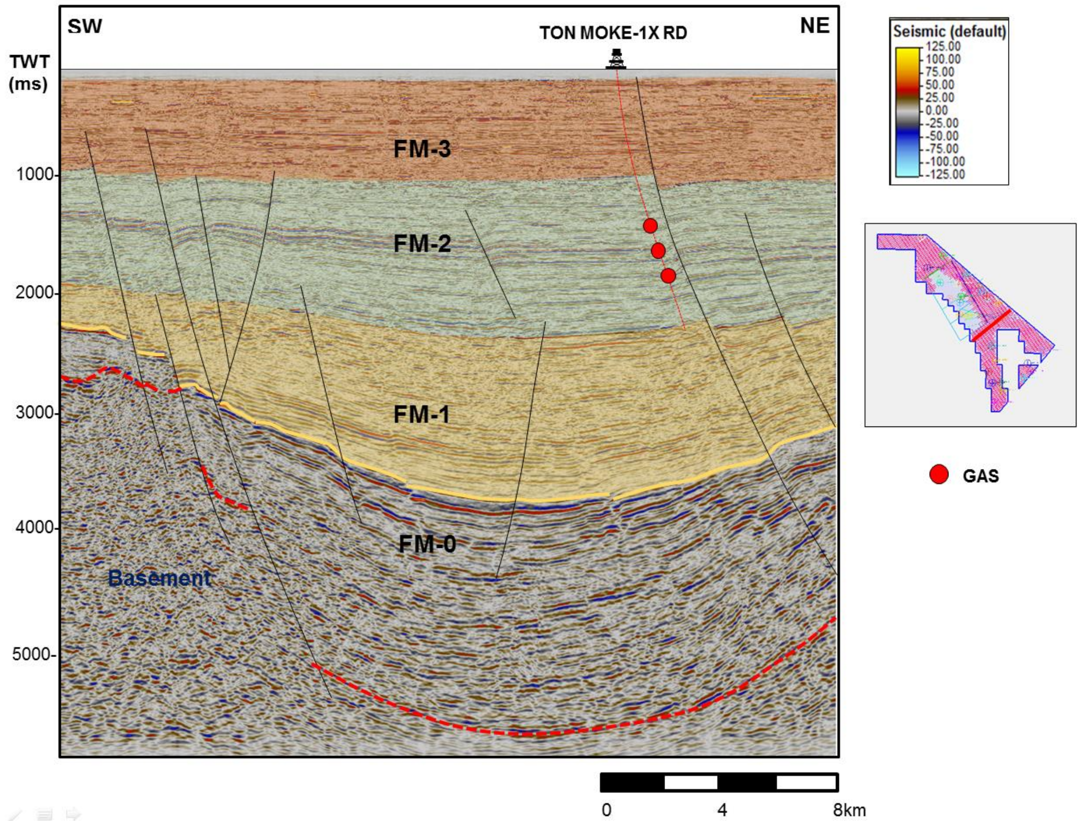

Figure 15 The cross sectional seismic data in the SW-NE trending Southern Region of block G2/61 which passes through well Ton Moke-1XRD (where the gas produced from FM-2 was found).

Petroleum Reserves

Petroleum reserves in the G1/61 and G2/61 blocks have been certified by DMF. The proved reserves of gas, condensate and oil at the end of 2016 are listed as follows:

Table 2 Petroleum reserves in Blocks G1/61 and G2/61

Block	Cumulative Production			Proved Reserves		
	Gas (Bcf)	Condensate (MMbbl)	Oil (MMbbl)	Gas (Bcf)	Condensate (MMbbl)	Oil (MMbbl)
G1/61	10,378.06	321.87	167.46	2,435.58	72.35	36.35
G2/61	5,004.72	148.09	-	1,375.51	31.27	-

Petroleum Production

Liquids

The Defence Energy Department began oil production in Thailand in the late-1950s. However, production remained at relatively low levels until Shell brought the Sirikit field onstream in 1983. Thailand's other main source of indigenous liquid production has been condensate from Chevron's gas fields in the Gulf of Thailand, the first being produced from Erawan in 1981. Liquids production increased steadily during the 2000s, as a result of the "Big Oil" project, which produces from fields including Plamuk and Yala in the Chevron-operated areas. Higher production from the Bongkot area has also added to Thailand's liquid output.

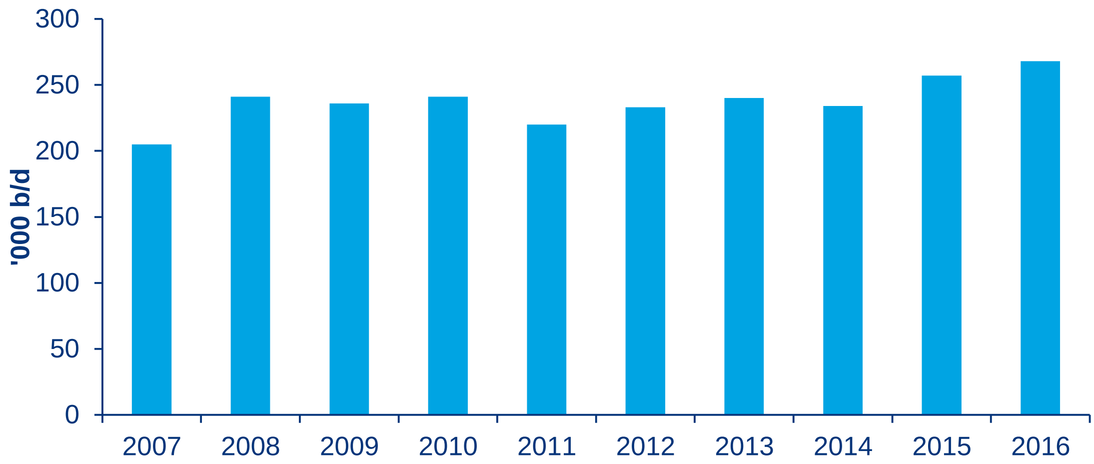

Figure 16 Thai Liquids Production
Source: Wood Mackenzie

In the near to medium-term, the largest liquids producer in Thailand will continue to be Chevron, from the contract areas, the B8/32 concession and PTTEP's S1 (Sirikit Area) concessions. In 2015, KrisEnergy's G10/48 (Wassana field) and Mubadala's G11/48 (Nong Yao field) blocks started production.

Table 3 Liquids production ('000 b/d)

Location	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Arthit	-	-	15	18	18	16	11	9	9	9	10
B12/27 (Palin)	19	18	18	19	19	16	15	16	18	14	15
B5/27 (Jasmine)	9	19	20	20	18	17	14	13	14	12	13
B6/27 (Nang Nuan)	1	1	-	-	-	-	-	-	-	-	-
B8/32 (Benchamas)	59	51	61	61	49	40	41	32	35	33	37
B8/38 (Bualuang)	-	-	3	5	9	7	8	12	12	11	8
Bongkot	18	18	19	18	20	21	28	32	29	28	27
Contract 1 Area	11	11	11	13	11	11	9	6	7	6	6
Contract 2 Area	9	12	10	7	11	11	14	14	15	27	26
Contract 3 Area	39	47	43	36	45	41	36	44	39	38	44
E5 & EU1 (Sinphuhorm)	-	0	0	0	0	0	0	0	0	0	0
G1/48 (Manora)	-	-	-	-	-	-	-	-	1	14	11
G10/48 (Wassana)	-	-	-	-	-	-	-	-	-	3	7
G11/48 (Nong Yao)	-	-	-	-	-	-	-	-	-	3	9
G5/43 (Songkhla)	-	-	-	5	8	10	20	20	14	13	12
L11/43 (Burapa)	-	-	-	-	0	0	1	1	1	1	1
L44/43, L33/43 & SW1A and L53/48	0	2	14	7	6	3	2	2	6	10	10
Military Operated Area (MOA)	1	1	1	1	1	1	1	1	1	1	1
NC (Bung Ya) & L21/43 (Nong Sa)	1	1	2	2	1	1	2	2	2	2	1
PTTEP1 (Suphan Buri Area)	1	0	1	0	0	1	0	0	0	0	0
S1 (Sirikit Area)	22	23	23	23	24	25	31	36	31	32	30
Total Liquids Production	**190**	**204**	**241**	**235**	**240**	**221**	**233**	**240**	**234**	**257**	**268**

Source: Wood Mackenzie

Natural Gas

To date, the vast majority of Thailand's gas output has come from the Gulf of Thailand, where production started in 1981 from Unocal's Erawan field. Chevron acquired Unocal in August 2005 and became Thailand's premier gas producer.

As a result of the Asian economic crisis, growth in gas demand was stifled in the late-1990s and Thailand was confronted with an oversupply of contracted gas. An increase in contracted supply from Myanmar in the early-2000s meant limited opportunities for increased domestic supply.

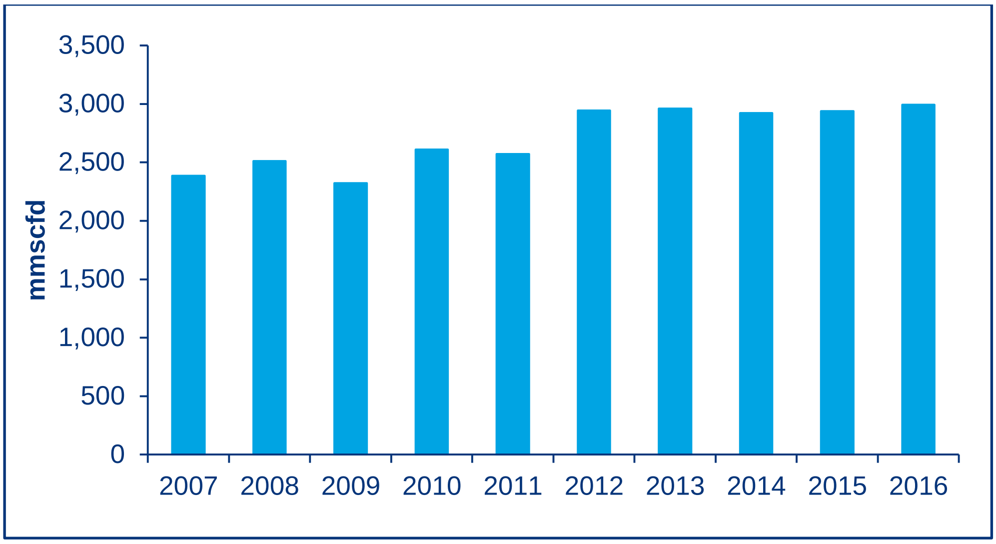

Figure 17 Thai gas production
Source: Wood Mackenzie

However, in the last decade Thailand's domestic gas demand has grown strongly; in 2003, a number of sales agreements for the supply of domestic gas were signed. Incremental supply was secured from existing suppliers such as Unocal's B12/27 concession, and in January 2004, a Gas Sales Agreement was signed for the supply of gas from PTTEP's Arthit fields. This was the first new source of gas to be contracted to the Thai market since early-2000. In addition, a GSA and a 10-year extension to the Chevron-operated concession agreements were secured in 2007. Supply from Arthit started in April 2008, via the third Gulf of Thailand gas trunk line.

Thailand is also supplied with gas from the Malaysia-Thailand JDA, from both the CPOC-operated B-17 block and the CTOC-operated A-18 block. A-18 and B-17 are expected to supply 400 mmscfd and 270 mmscfd, respectively. The sales agreements for A-18 and B-17 have an option to increase supply if demand and reserves allow. First production from the Malaysia-Thailand JDA was achieved in 2008.

In recent years, two major projects have been brought onstream to increase the supply of gas to Thailand's domestic market. Chevron's Platong project began commercial production in October 2011, whilst PTTEP's Bongkot South development began production in April 2012. These projects will increase gas production by 420 mmscfd and 320 mmscfd respectively.

Table 4 Gas sales (mmscfd)

Location	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Arthit	-	-	235	329	427	351	238	223	218	213	221
B12/27 (Palin)	388	399	391	364	362	407	392	376	375	305	325
B8/32 (Benchamas)	198	192	167	181	175	156	125	111	96	100	129
Bongkot	599	607	589	516	586	591	773	889	871	905	890
Contract 1 Area	243	266	253	235	245	230	247	190	217	196	220
Contract 2 Area	197	234	238	182	223	260	470	411	378	486	454
Contract 3 Area	466	548	506	399	472	458	568	633	622	575	605
E5 & EU1 (Sinphuhorm)	6	86	83	85	87	83	93	88	105	121	116
E5 (Nam Phong)	31	26	23	19	18	16	14	13	12	12	11
S1 (Sirikit Area)	36	29	26	13	15	20	24	26	28	26	22
Total Gas Production	**2,164**	**2,387**	**2,511**	**2,323**	**2,610**	**2,572**	**2,944**	**2,960**	**2,922**	**2,939**	**2,993**

Source: Wood Mackenzie

Petroleum Exploration and Production Investment Overview

In 2016, investment in exploration and production of petroleum in Thailand for both onshore and offshore petroleum concessions amounted to 141,244 Million Baht, the breakdown of which is as follows: 1,560 Million Baht (1%) for petroleum exploration, 91,811 Million Baht (65%) for field development, 44,703 Million Baht (32%) for production and sales and 3,170 Million Baht (2%) for administration.

Most of the investment in 2016 was attributed to the development cost including wellhead platform installations, processing platform installations and drilling of exploration and development wells, in the petroleum concessions detailed below:

- Erawan, Satun , Kaphong, Platong, Plamuk, Yala, Pakarang, Trat, North Trat, Jakrawan, Funan, Gomin and South Gomin, Bannpot and Pailin fields which are operated by Chevron Thailand Exploration and Production, Ltd.
- Bongkot and Arthit fields which are operated by PTT Exploration and Production Public Co., Ltd.
- Tantawan, Benchamas, Rajpruek and Lanta fields which are operated by Chevron Offshore (Thailand) Ltd.
- Songkhla field which is operated by CEC International Ltd.
- Sirikit field which is operated by PTTEP Siam, Ltd.

The total investment for petroleum exploration and production by company is shown in the figure below:

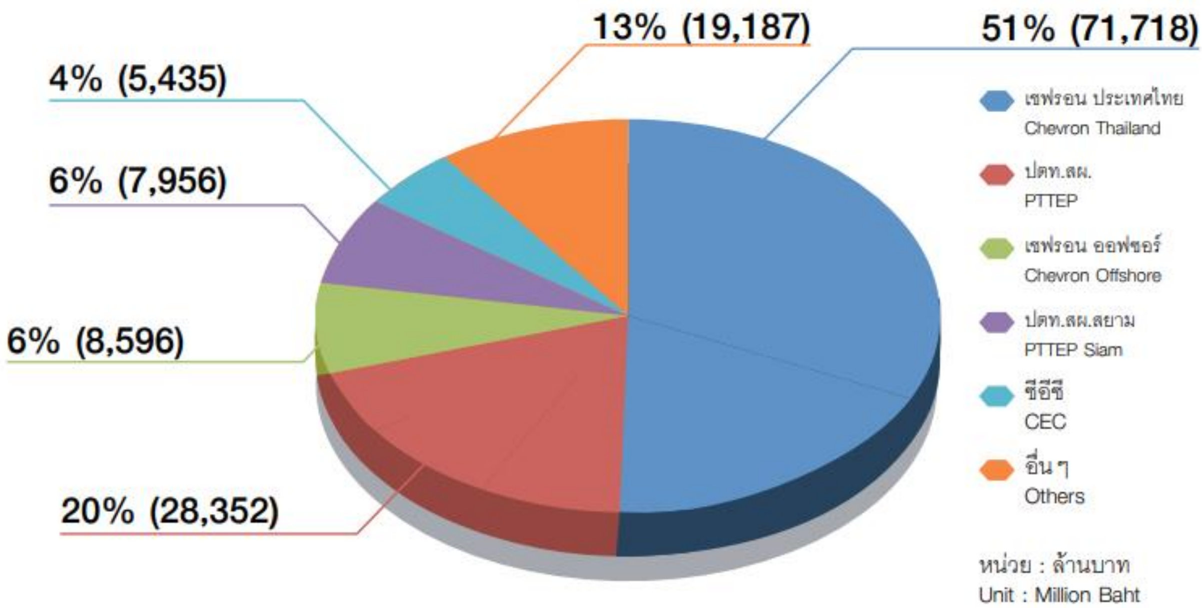

Figure 18 Petroleum Exploration and Production Investment by companies
Source: Annual report Year 2016, Department of Mineral Fuels

Erawan Key Facts

The Erawan complex covers an area of exploration blocks (no. 10, 11, 12 and 13) in the Gulf of Thailand which are currently operated by Chevron Thailand Exploration and Production, Ltd. Blocks no. 10 and 11 were awarded under Petroleum Concession No. 1/2515/5 and blocks no. 12 and 13 were awarded under Petroleum Concession No. 2/2515/6. Natural gas production from these blocks is supplied under gas sales contracts of around 1,240 mmscfd. Under the concessions, 86 areas were granted production approval amounting to 4,487.41 square kilometers and a reserved area amounting to 123.08 square kilometers. All contracts will terminate on 23 April 2022.

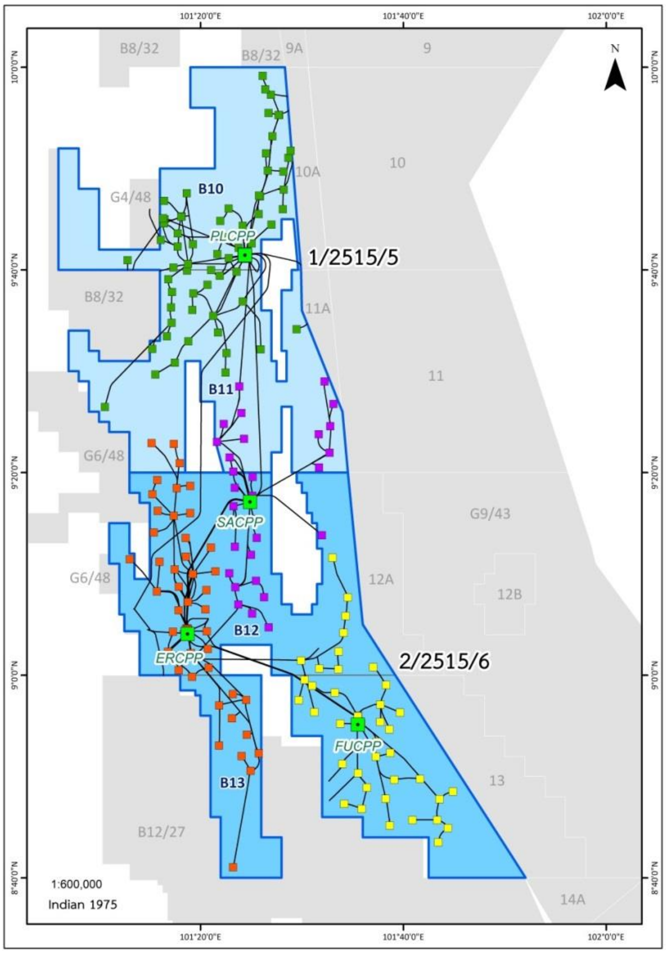

Figure 19 Exploration Blocks in the Gulf of Thailand No.10, 11, 12, and 13 (Erawan Complex)

Erawan, a large and complex gas field, was brought onstream in 1981 and has been developed via a central five-platform complex and more than 25 wellhead platforms. Gas is transported north to a terminal at Map Ta Phut through PTT's pipeline and onto southwestern Thailand, via a pipeline to Khnom. Following this, more natural gas fields have been developed including Baanpot, Platong, Satun, South Satun, Kaphong and Pladang in 1983.

Ongoing exploration and appraisal drilling in the area led to the discoveries of the South West Platong and South Platong fields in 1996 and 1999 respectively. In 2008, Chevron began the development of Platong II, a natural gas expansion project of the existing Platong complex in the Gulf of Thailand. The project would see combined production capacity for the three contract areas increase by 420 mmscfd and 22,000 b/d.

In addition to the development of the area's gas reserves, the oil legs of the Kaphong and Platong fields have been developed as part of the Thai Oil Development 1 (TOD1) project, previously known as the "Big Oil" project. Crude production started from the Plamuk field in July 2001 and was supplemented from the Yala field in May 2002. A second phase of development was implemented, involving the development of the East Yala field in 2005.

Gas production from the three contract areas has been consistently higher than the Daily Contracted Quantity (DCQ) due to strong Thai gas demand. In early 2007, the third Gulf of Thailand trunk line was commissioned to allow an increase in production from the contract areas. In December 2007, the Thai Government granted a 10-year extension to the Unocal 3 contract, from 2012 to 2022. Following the extension, Chevron converted a Heads of Agreement to a Gas Sales Agreement (GSA) for the supply of additional gas through this pipeline. The new GSA allows for a combined DCQ of 1,240 mmscfd and a similar gas price across all three contract areas.

Production during 2013/14 in the Contract 2 Area fell due to a lack of available drilling rigs during the period. It is understood that in 2015, production levels improved as additional rigs have been contracted by the operator. The Dara field was brought onstream in 2015, helping to maintain total output above 200 mmscfd until 2022. However, activity levels are expected to fall from the peak in 2015 due to the low oil price environment.

First production from the Platong 2 development began in October 2011. The project also involved the development of South Platong and South West Platong, whilst the Pakarang, South Baanpot and North Trat fields were brought onstream during 2011/2012 as part of the Platong 2 project. The project will increase production capacity by 420 mmscfd and 22,000 b/d. Total costs for the Platong 2 project are estimated at US$3.1 billion.

1. Concession Holder

Table 5 Concession Holder for Exploration Blocks 10,11,12 and 13

Concess. No. Date Issued	Exploration Blocks	Concession(s)	Share (%)
1/2515/5 1 March 1972	10 and 11	<u>Gas Sale Agreement No.22 (Unit Area I)</u>	
		* Chevron Thailand Exploration and Production Ltd.	70.00%
		**Mitsui Oil Exploration Co., Ltd.	30.00%
		<u>Gas Sale Agreement No.2 (Supplementary) (Unit Area 2)</u>	
		* Chevron Thailand Exploration and Production Ltd.	71.25%
		**Mitsui Oil Exploration Co., Ltd.	23.75%
		**PTT Exploration and Production Public Co., Ltd.	5.00%
2/2515/6 1 March 1971	12 and 13	<u>Gas Sale Agreement No.1</u>	
		* Chevron Thailand Exploration and Production Ltd.	80.00%
		**Mitsui Oil Exploration Co., Ltd.	20.00%
		<u>Gas Sale Agreement No.2 (Unit Area I)</u>	
		* Chevron Thailand Exploration and Production Ltd.	70.00%
		**Mitsui Oil Exploration Co., Ltd.	30.00%
		<u>Gas Sale Agreement No.2 (Supplementary) (Unit Area 2)</u>	
		* Chevron Thailand Exploration and Production Ltd.	71.25%
		**Mitsui Oil Exploration Co., Ltd.	23.75%
		**PTT Exploration and Production Public Co., Ltd.	5.00%

<u>Note</u>

* Operator

** Co-venturer

Source: Department of Mineral Fuels

2. Petroleum Production

Natural Gas

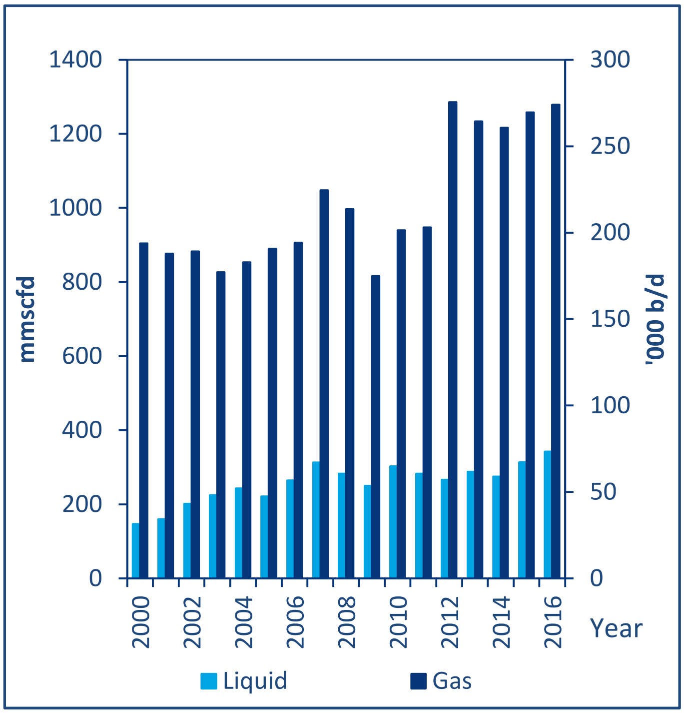

Figure 20 Contract Areas production profile
Source: Wood Mackenzie

Production from Erawan started in August 1981. The field was initially contracted to produce 200 mmscfd, rising to 250 mmscfd by mid-1983. However, initial deliveries were restricted by high downhole temperatures which affected equipment, requiring the production wells to be re-completed. It also became clear from initial production experience that the reservoir structures were more complex than had been first envisaged. As a result, a maximum production level of only 160 mmscfd had been achieved by the end of 1982.

Unocal subsequently worked to raise production levels and during 1984-85, four additional platforms (I, J, K and L) were installed, boosting output to around 185 mmscfd in 1985.

With continued development work, a production peak of 298 mmscfd was reached in 1999. As Thai gas demand grew strongly in the last decade, supply from the Gulf of Thailand fields was constrained by trunk line capacity. Production from Erawan was restricted to around 250 mmscfd in 2003 and 2004, increasing to around 265 mmscfd in 2005.

The Unocal 1 sales contract had initially been expected to expire in 2006, but an extension was granted until April 2012. From May 2012, gas sales from the Erawan field have been included in a new combined GSA for the Contract 1, 2 and 3 Area fields. It is assumed that production from Contract 1 Area will be maintained above 200 mmscfd until 2022.

The Contract 2 Area fields were originally scheduled to start production in 1985. However, the development of a single production platform at Baanpot was brought forward to cover a shortfall of supply from Erawan. Baanpot came onstream in November 1983 and output quickly built up to a plateau level of just over 30 mmscfd.

Satun and Platong were developed as originally proposed. Satun came onstream in January 1985, Platong in March 1985 and Kaphong in July 1989. The latest field to come onstream before the Platong 2 development was Pladang in April 1998.

The Contract 3 Area fields have been brought onstream in a phased manner to replace declining output from the first and second contract areas, and to boost overall production from the Gulf of Thailand.

Production from Funan and Surat started in 1992, with Jakrawan following in 1993 and Gomin in 1995. In January 1998, Plamuk came onstream, followed by Trat in September 1999.

The second Erawan-Map Ta Phut trunk line was commissioned in 1996 and increased the pipeline capacity from the Gulf of Thailand to Rayong to between 1,750 mmscfd and 1,800 mmscfd (including compression). This removed previous infrastructure constraints, allowing an increase in overall production from all three sales contract areas to around 1,000 mmscfd in 1998.

DCQ levels

Following development work on the Contract 2 and 3 Areas, Unocal supplied above the combined DCQ level of 510 mmscfd for a number of years. However, supply from the fields in the Gulf of Thailand was constrained by trunk line capacity. Two trunk lines were debottlenecked in 2004, to allow for small incremental amounts of gas to be supplied above the total capacity of 1,800 mmscfd. Due to growing demand in Thailand, production from the Contract 2 and 3 areas is expected to continue to be higher than DCQ levels.

The split of production between the Contract 2 and Contract 3 Areas has been weighted towards Contract 3 Area since 2000. Production volumes for each contract area will vary as production from existing fields decline and new fields come onstream, with Contract 2 Area expected to supply less than 40% of the overall sales.

Platong 2

Chevron embarked on the Platong 2 development in 2008 to raise production capacity by 420 mmscfd and 22,000 b/d. Following some initial commissioning volumes, production from the Platong 2 phase began in October 2011, with first gas from the South Platong field, followed by South West Platong in February 2012.

A third trunk line from the Gulf of Thailand was commissioned in March 2007, removing the infrastructure constraints on production from the area. In readiness for this increase in pipeline capacity, Unocal (now Chevron) signed a Heads of Agreement (HoA) for the supply of additional gas post-2006. Under the terms of the HoA, some of this additional gas has been supplied from the Contract 1 Area, allowing previously uncontracted reserves to be developed.

Oil

The oil leg of the Kaphong field is being developed as part of the Thai Oil Development (TOD) project (previously known as the "Big Oil" project) and first oil was produced from the field in July 2001. The Platong field has also produced oil, but at minimal levels.

Although Unocal produced a small amount of oil from the Surat field in the early 1990s, oil production effectively started in July 2001, when the Plamuk field was brought onstream at an initial rate of 2,500-3,000 b/d. Oil production from Yala began in May 2002, taking total average oil production from the area to around 9,000 b/d.

Due to reserve upgrades and the discovery of oil in the East Yala field, the operator implemented a second phase oil project, TOD2. In addition to further development of Yala and Plamuk, oil production has been supplemented by the development of the Surat field oil leg.

3. Infrastructure

Natural Gas

Contract 1 Area

Erawan-Khnom

Some gas from Erawan field is transported to southwestern Thailand via a 161-kilometer, 500 mmscfd capacity, 24-inches pipeline to Khnom. This gas supplies the 674 MW Khnom combined cycle power plant. However, with the plant consuming only around 160 mmscfd, the line is under-utilised. It is believed that the pipeline costed in the region of US$200 million in 1993.

Erawan - Map Ta Phut 1

The majority of gas is transported from the Erawan Central Processing Platform to the Gas Seperation Plant at Map Ta Phut, 125 kilometers southeast of Bangkok. The pipeline and terminal facilities are owned and operated by PTT. Construction of the offshore section of the pipeline began in June 1980. The whole system was commissioned in September 1981, at a cost of around US$450 million.

The pipeline was originally designed for a capacity of 550 mmscfd. However, in October 1989, Unocal and PTT reached an agreement to install an offshore compressor platform to increase pipeline capacity to a maximum of 800 mmscfd. The cost of this installation, US$28.5 million, was shared equally between Unocal and PTT. The installation and commissioning of these new facilities was completed in August 1990.

Erawan - Map Ta Phut 2

In April 1992, PTT announced its intention to commission a new pipeline running parallel to the existing Erawan-Map Ta Phut (Rayong) trunk line, allowing capacity to almost double to 1,450 mmscfd, without compression. The 36-inches line was commissioned in 1996, with gas coming from two main sources - fields operated by Unocal's Erawan and PTTEP's Bongkot field. As part of this project, a new 110 kilometers, 28-inches onshore pipeline was completed in 1997, running from Rayong on the northern coast of Thailand to the Bang Pakong power station. The project is thought to have cost around US$700 million to complete.

Having considered a number of options for increasing the gas flow rate, including the possibility of a third pipeline, PTT installed additional compression facilities for the 36-inches trunk line in 1998. This is believed to have boosted combined capacity to around 1,800 mmscfd. It is understood that debottlenecking of the pipeline took place in 2004 to allow for small incremental amounts of gas to be supplied above the 1,800 mmscfd capacity.

Erawan - Map Ta Phut 3

In 2004, PTT awarded Hyundai the EPC contract for the third Gulf of Thailand trunkline (wholly-owned and operated by PTT) connecting the fifth onshore gas processing plant (also owned and operated by PTT) and was completed in 2005. The pipeline was commissioned in March 2007 and follows the same route as the existing lines, extending from a new, PTT-funded, riser platform at the Erawan field (PTT Riser Platform or PRP).

<u>Contract 2 Area</u>

Wet gas from Baanpot and South Satun is piped to the Erawan C processing platform, where it is compressed and transported on to the Erawan CPP. Pladang production is routed via the Satun CPP. Gas from Platong goes directly into the Erawan-Map Ta Phut pipeline after processing at Platong CPP. Production from Kaphong is piped, via a 15-kilometer spur line, to the Platong CPP.

<u>Contract 3 Area</u>

A 24-inches diameter pipeline, 36 kilometers in length, transports processed gas from Funan to the Erawan complex. Production from Plamuk is transported via Surat, where it is combined with Surat gas and piped through a 16-inches, 9-kilometer pipeline to the central processing platform at the Platong gas field. Gas from Platong goes directly into the Erawan-Map Ta Phut pipeline.

Jakrawan output is fed either via the Funan CPP or (in the case of those platforms in the north) directly to the Erawan field. Gomin production is routed via Funan, while Trat's output is piped via the Satun CPP. Production from Yala, as a liquids-rich gas stream, is routed to Kaphong and on to the processing facilities on the PLOCPP and the PLCPP at Platong. At this point, the gas, condensate and crude from Yala and Kaphong are separated, with the gas piped into the Erawan-Map Ta Phut pipeline.

Liquids

Condensate production is stored in the 1,080,000-barrels capacity FSO Erawan 2, permanently moored at the Erawan field. The original FSO, Erawan, with a capacity of 660,000 was replaced in 2012 with the Erawan 2, a new build from IHI in Japan. A pipeline connects the Platong and Satun CPP's, thereby enabling a single condensate collection point. Liquids are then periodically exported by tanker.

Oil from the Kaphong field, together with that from the Contract 3 Area fields Yala, Plamuk and Surat, is piped to the TOD1 PLOCPP and onwards, via a 3.5-kilometer pipeline, to the Pattani Spirit FSO.

The original FSO, the Sibeia, was replaced with the Pattani Spirit in 2004. Teekay Shipping Corporation was awarded the contract for provision of the leased vessel, which is a conversion of the Namsan Spirit tanker. The new vessel accommodates the proposed ramp-up in oil production from the fields and has a storage capacity of 850,000 barrels of oil equivalent. The Pattani Spirit will be leased for 10 years, with a five-year extension option, and was installed in Q2 2004.

Production from the Yala, Plamuk and Surat fields is processed at the Platong central processing platform complex (which comprises the original PLCPP and the new oil the PLOCPP). The hydrocarbons arrive at the processing complex as an oily, liquids-rich gas stream which is processed so that oil can then be transported, via a 3.5-kilometer pipeline, to the Pattani Spirit FSO.

Condensate from the Plamuk, Surat and Yala fields is transported by pipeline to the Erawan FSO facility via Satun. Liquids from Jakrawan, Funan and Gomin are collected at the Funan central processing platform and transported to Erawan for export.

Table 6 Contract Area gas pipeline summary

Pipeline	Type	From	To	Length (km)	Diameter (in)	Capacity (mmscfd)
Erawan to Khnom	Gas	Erawan	Khnom	161	24	500
Erawan to Platong Spur	Gas	Erawan	Platong Spur	75	34	860
Platong Spur to Map Ta Phut	Gas	Platong Spur	Map Ta Phut (1st TL)	339	34	860
Erawan (PRP) to Rayong	Gas	Erawan	Rayong (3rd TL)	414	42	1,900
Erawan to Tantawan Spur	Gas	Erawan	Tantawan Spur	112	36	1,150
Tantawan Spur to Map Ta Phut	Gas	Tantawan Spur	Map Ta Phut (2nd TL)	300	36	1,180
Baanpot to Erawan 1	Gas	Baanpot	Erawan	9		
Pladang to Satun	Gas	Pladang	Satun	23		
Satun to Erawan	Gas	Satun	Erawan	29	16	240
Kaphong to Platong	Gas	Kaphong	Platong	15	16	
Platong to Erawan Trunkline	Gas	Platong	Erawan Trunkline	34	24	170
Trat to Satun	Gas	Trat	Satun	17	18	145
Plamuk to Surat	Gas	Plamuk	Surat	9	16	125
Surat to Platong	Gas	Surat	Platong	12	16	125
Yala to Kaphong	Gas	Yala	Kaphong	18	16	

Pipeline	Type	From	To	Length (km)	Diameter (in)	Capacity (mmscfd)
Jakrawan to Erawan	Gas	Jakrawan	Erawan	30	16	
Jakrawan to Funan (Gas)	Gas	Jakrawan	Funan	6	16	125
Gomin to Funan	Gas	Gomin	Funan	3	10	75
Funan to Erawan (Gas)	Gas	Funan	Erawan	36	24	200

Source: Wood Mackenzie

Condensate

Historically, around 80% of the condensate produced was exported (mainly to the US West Coast). However, in August 1992, PTT issued a new directive stating that all gas liquids production should be refined locally.

With the commissioning of the Thai aromatics plant, PTT/Mitsui signed an agreement, effective from 1 September 1998, with Unocal and its partners to supply around 35,000 b/d for 15 years from the Unocal Contract Areas and B12/27. Pricing is based on an average of a basket of five condensates and crudes (Berri, Murbau, Seria Light, North West Shelf, Tapis) posted in Singapore, at a discount of between 4.5% and 8.5%. Prices are adjusted monthly.

4. Gas Sale Contracts

Natual Gas

1978 agreement

Unocal signed an agreement with PTT in September 1978, covering a total supply of 1.7 tcf of gas from the Erawan structure. The contract was negotiated on a daily contract quantity (DCQ) of 250 mmscfd. However, the DCQ was reduced to 105 mmscfd following poor initial production performance. Subsequently, the DCQ was increased to 160 mmscfd.

1994 upgrade to DCQ

In late 1994, Unocal reached agreement with PTT to increase its DCQ for Unocal Contract Areas 1 to 3, from 500 mmscfd to 740 mmscfd (on a take-or-pay basis) with a swing factor of up to 15%, on completion of the 36-inches Erawan-Rayong pipeline in 1996. Of this 740 mmscfd, the DCQ attributable to Contract 1 Area is 230 mmscfd. This agreement contracted Unocal 1 reserves until 2006.

Gas pricing

The price received for gas, ex-platform, is based on a formula incorporating the following indices:

- a basket of medium fuel oils from Singapore,
- the U.S. Index of Export Prices,
- the Producer Price of Oilfield Machinery and Tools Index and
- the Baht/US$ Exchange Rate.

Historically, the gas price attributable to each contract area differed according to its weighting on individual indices. The Unocal 1 GSA is understood to have been less weighted to the fuel oil price than the Unocal 2/3 GSA.

The Unocal 1 gas price was adjusted annually, at the end of June, and the indices to which the price was tied did not all use June as a reference point. Consequently, the price paid would occasionally appear out of step with prevailing market conditions. In 1992, Unocal was forced to offer what was in effect a 5.3% discount on the wellhead price of natural gas due to a fall in demand from EGAT, which chose to switch from gas to fuel oil at its power stations because gas became a more expensive energy source.

2001 agreement

In October 2001, Unocal signed an agreement with PTT to effectively discount the price of gas supplied over and above the contracted volumes. Unocal and its partners paid US$15 million to PTT as an incentive to take gas above the quantity contracted from the Gulf of Thailand. The agreement was valid for supply of up to 100 mmscfd above the DCQ, from the beginning of July 2001 through to the end of September 2002, and effectively decreased the incremental gas price by around 33%. Around nine (9) bcf of gas above DCQ was supplied from Unocal 1 during this period. This agreement was a forerunner to a price change which affected the whole of the contracted volume.

2002 agreement

This second agreement was signed in April 2002 and not only included a discount on the final price of gas contracted, but also allowed for a change in the gas pricing formula and an extension of the contract duration. For the remainder of the contract, it was agreed that the price would be discounted by 2%, effective at the beginning of July 2002. The contract was extended by six years from its original expiry date of end June 2006 to the end of April 2012. The gas price for the period of the extension was reduced by 7% from the original price. The agreement effectively contracted a further 462 bcf of gas from the Contract 1 Area. All other terms of the agreement, such as DCQ, take or pay level and swing factor, were unchanged.

A modification to the gas pricing formula was also made in April 2002. Whereas the original pricing formula incorporated the Wholesale Price Index in Thailand, following modification, and retroactive to January 2000, the formula is indexed to the Producer Price Index. No adjustment to the base price was made.

2003 HoA and 2007 GSA

In October 2003, Unocal signed a HoA with PTT for the supply of an additional 500 mmscfd of gas. This gas was to be supplied from the start-up of the third Gulf of Thailand trunk line, originally planned for 2006, but delayed until March 2007. It is understood that the initial increase would take the combined DCQ from the three contract areas from 740 mmscfd to 850 mmscfd in 2006, and eventually up to a total of 1,240 mmscfd, in line with the increasing gas demand.

It is understood that for the conversion of the HoA to a full GSA, PTT - the gas buyer - required the government to grant Unocal a 10-years extension to the current concession agreement. This was granted in December 2007 (further information on the GSA can be found in the Thailand Gas Market Overview section). Under the terms of the new GSA, gas prices from all three contract areas will converge to a similar price. This has in effect increased the price received from the Contract 1 Area.

5. Concession Regime

All blocks in the Contract Areas are licensed under the modified Thailand I concession agreement, as part of the contract extensions signed in 2007. In addition, the partners are required to pay a lump-sum extension bonus every quarter until contract expiry in 2022.

Bongkot Key Facts

The Bongkot complex covers areas including exploration blocks (no. 15, 16 and 17) in the Gulf of Thailand currently operated by PTT Exploration and Production Public Co., Ltd. Block no. 15 was awarded under Petroleum Concession No. 5/2515/9 and blocks. No. 16 and 17 were awarded under Petroleum Concession No. 3/2515/7. Natural gas produced from these blocks is sold under sales contract totaling around 870 mmscfd. Petroleum Concession No. 5/2515/9 will terminate on 23 April 2022, whereas Petroleum Concession No. 3/2515/7 will terminate on 7 March 2023.

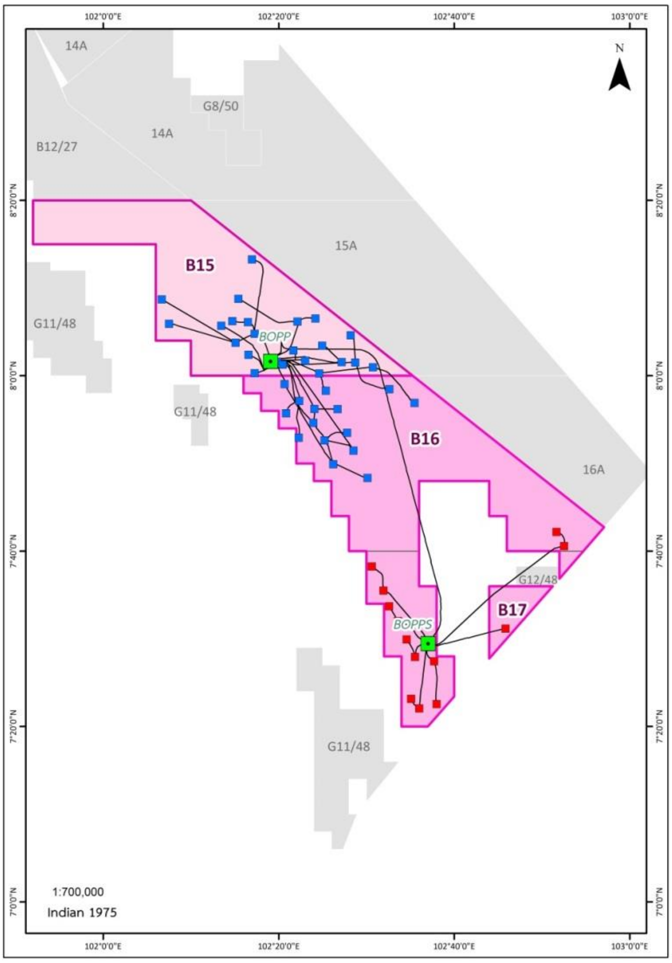

Figure 21 Exploration Blocks in the Gulf of Thailand No. 15, 16 and 17 (Bongkot Complex)

The Bongkot area consists of a collection of several compartmentalised gas reservoirs situated in the Malay Basin in the Gulf of Thailand. The main Bongkot field was brought onstream in 1993 and is one of the primary suppliers of domestic gas to Bangkok. The initial development focused on the central and northern accumulations (Greater Bongkot North) and incorporated three wellhead platforms, a central processing platform, accommodation platform and an FSO for liquids handling.

A development phase, incorporating further wellhead platforms and a riser platform, was completed in 1996.

A third phase has been ongoing since 1997-1998 and the joint venture is now engaged in Phase 3N development, which involves the installation of four 16-slot wellhead platforms respectively to maintain plateau production from the Greater Bongkot North fields.

A fourth development phase, targeting the southern accumulations of South Bongkot, Ton Koon and Ton Nok Yoong (Greater Bongkot South), was brought onstream in April 2012. The development of the Greater Bongkot South fields has involved the installation of a new central processing platform, an accommodation platform and to date 13 wellhead platforms across Phase 4A-4D. The Greater Bongkot South development will add about 300 mmscfd of gas production to the Bongkot area

1. **Concession Holder**

Table 7 Concession Holders for Block 15, 16 and 17

Concess. No. Date Issued	Exploration Blocks	Concession(s)	Share (%)
5/2515/9 10 March 1972	15	* PTT Exploration and Production Public Co., Ltd.	44.45%
		Total E&P Thailand	33.33%
		Shell Integrated Gas Thailand Pte Limited	22.22%
3/2515/7 8 March 1972	16 and 17	* PTT Exploration and Production Public Co., Ltd.	44.45%
		Total E&P Thailand	33.33%
		Shell Integrated Gas Thailand Pte Limited	22.22%

<u>Note</u>

* Operator

Source: Department of Mineral Fuels

Blocks B15, B16 and B17 were originally awarded to Tenneco (B15) and BP (B16 and B17) in 1972. Tenneco and BP drilled seven wildcats before relinquishing the blocks in 1976. Texas Pacific subsequently acquired Block 15 in 1976 and Blocks 16 and 17 in 1978.

Texas Pacific, along with its partners, sold its entire B15, B16 and B17 interests in July 1988 to the Petroleum Authority of Thailand's (PTT) exploration subsidiary, PTTEP. This followed almost 10 years of negotiations over development proposals and gas pricing for the 'B' structure (named as the Bongkot field in August 1990). The sale price was US$83.75 million.

PTTEP

In August 1988, PTTEP invited 14 oil companies and institutions to participate in the development of the 'B' structure. Of the five companies originally invited to submit bids (Exxon, Shell, BP, Unocal and Statoil), four withdrew from the discussions. In March 1989, an agreement was signed between PTTEP and Total to develop the 'B' structure. Under the terms of the contract, PTTEP retained a 40% stake, while Total acquired a 30% interest and operatorship of the project. The remaining interest was farmed out to British Gas (20%) and Statoil (10%). Statoil is reported to have paid US$10 million for its stake. In August 1990, the 'B' structure was officially named the Bongkot field.

The current concession was carved out of the original B15/B16/B17 licenses and was originally split into two distinct operational sectors: the development area and the exploration area. The former covered the Bongkot structure - an area of 986 km^2. Costs in this area are shared equally amongst the partners. The exploration area covered about 2,214 km^2 of prospective acreage adjacent to the field. PTTEP was carried through the exploration phase in this area. In July 2005, an amendment was made to the original GSA to incorporate the whole of the Bongkot concession area (3,200 km^2) as a development area.

PTTEP assumed operatorship of the development and exploration acreage in July 1998. In December 1998, it was announced that Statoil had sold its 10% stake in the field to the remaining partners PTTEP, Total and BG. The deal was effective from 18 December 1998 and led PTTEP a 44.45% holding, Total 33.33% and BG 22.22%.

In 2001, the production areas of Arthit and Bongkot were given the title "Navamindra Petroleum Area" by the King of Thailand to commemorate PTTEP's 15th anniversary.

In 2006, the same partners of Bongkot, were awarded an exploration Block G12/48.

In 2007, a 10-years extension to the production license was granted. The extension allows for gas and condensate production from Block B15 until 2022, and Blocks B16 and B17 until 2023.

BG

In April 2015, Shell and BG agreed the terms of a cash-and-share offer to be made by Shell for the entire share capital of BG. The deal was approved by shareholders of both companies and was completed in February 2016. Bongkot was a disposal candidate as part of Shell's US$30 billion non-core asset divestment program between 2016-2018 and was initially reached an agreement with KUFPEC. However the deal fell through and Shell eventually sold it's stake in Bongkot to PTTEP in January 2018.

2. Petroleum Production

The Bongkot field started production on 16 July 1993 at an initial rate of 150 mmscfd; this increased to around 350 mmscfd in 1997. In April 1998, the field was temporarily shut down for 20 days in order to install additional facilities, following which, output climbed to around 550 mmscfd. In addition to produced condensate, some oil rim accumulations are being exploited through horizontal wells. The Ton Sak field was brought onstream in 2003 and supplements Bongkot North production.

Table 8 Historical Production at Bongkot production

	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Oil ('000 b/d)										
Bongkot	2.8	2.6	2.4	2.4	2.6	2.8	2.0	1.5	1.5	0.8
Condensate ('000 b/d)										
Greater Bongkot North	15.2	16.0	15.8	17.3	18.0	18.0	19.6	15.8	15.9	15.5
Greater Bongkot South	-	-	-	-	-	7.6	10.9	11.6	10.7	10.5
Total Liquid ('000 b/d)	**18.0**	**18.6**	**18.2**	**19.7**	**20.6**	**28.4**	**32.5**	**28.9**	**28.1**	**26.8**
Sales Gas (mmscfd)										
Greater Bongkot North	607.3	589.3	516.3	586.4	591.0	580.7	587.2	567.8	593.1	590.0
Greater Bongkot South	-	-	-	-	-	192.8	301.9	302.8	311.6	300.0
Total Sales Gas (mmscfd)	**607.3**	**589.3**	**516.3**	**586.4**	**591.0**	**773.5**	**889.1**	**870.6**	**904.7**	**890.0**

Source: Wood Mackenzie

In July 2005, the Bongkot partners agreed to supply an additional 61 bcf of gas (48 mmscfd) between the period 1 April 2005 and 1 October 2008. As a result, production exceeded the DCQ and reached around 592 mmscfd in 2005. During April 2005, production from the Bongkot field was shut down for a 13-day period to allow the new sour gas processing platform to be tied in to the existing facilities. This shut-down did not affect the total average yearly production from the field. Greater Bongkot North produced at an average rate of 589 mmscfd in 2008.

Ton Rang was brought onstream in March 2009 and was followed by Ton Chan later in the year. Production from the Bongkot fields increased above the DCQ level of 550 mmscfd in 2010 due to strong domestic demand which is expected to continue.

It is forecasted that additional phases of development drilling will help maintain sales volumes at/above DCQ level of 550 mmscfd from Greater Bongkot North until 2020, after which production from the northern accumulations is expected to decline.

First production from the Greater Bongkot South fields, including the Ton Koon and Ton Nok Yoong fields, was achieved in April 2012. Output from Greater Bongkot South is expected to maintain production at DCQ level of 320 mmscfd from 2016 to 2020.

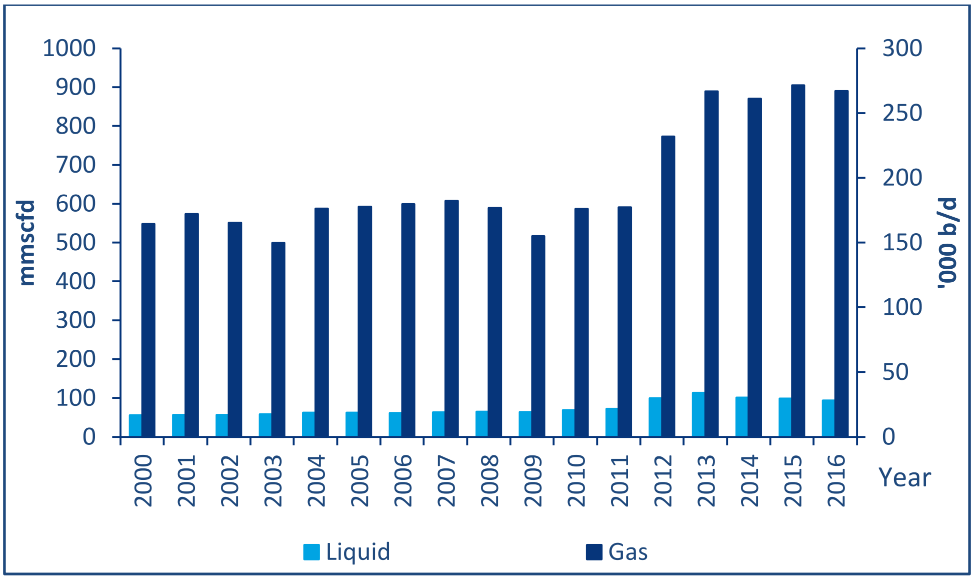

Figure 22 Bongkot production profile (Source: Wood Mackenzie)

3. Development

The Bongkot area has been developed on a phased basis as follows:

Phase 1

The initial phase started in 1992 and focused on the northern area. This was to be the centre for production facilities. Phase I incorporated:

- an eight-legged central processing platform (CPP) with a capacity of around 300 mmscfd
- a 125-man quarters platform (QP)
- three, 12-slot, four-legged wellhead platforms (WP-1, WP-2 and WP-3), installed in June 1992
- a 30,000-dwt floating condensate storage & offloading vessel (FSO) with a capacity of 180,000 barrels of oil equivalent.
- 29 production wells drilled.

The design, fabrication and installation of all five platforms was undertaken by McDermott. Gas collected on the central processing platform undergoes condensate separation/stabilisation, compression and dehydration before being exported to the Erawan field, via a 32-inches export line. A separate 6-inch condensate line ran from the Bongkot CPP to the attendant FSO 1. Phase I was completed in 1993. Four booster compressors were added to the Phase 1 platforms in 2009.

Phase 2

The second phase of the Bongkot development, to raise DCQ levels to 350 mmscfd, incorporated:

- five, four-legged, 12-slot wellhead platforms, each tied into the CPP via 14 or 18-inches subsea flowlines

• development drilling started in March 1995

• a new riser platform and flare, both bridge-linked to the CPP, were installed in late 1995

• 48 development wells were drilled, including the field's first horizontal well, BK-4-M

These developments increased the field's production capacity to 420 mmscfd of gas and 10,000 b/d of condensate. Moreover, during the second phase of development, several oil rims were identified beneath the producing gas accumulations. These were exploited via WP-4 and WP-7. Phase 2 was completed in April 1996.

Between 1997 and 1998, the Bongkot joint venture invested US$10 million (nominal terms) on a scheme to inject all produced water and contaminants, including mercury produced naturally in association with the gas and condensate, into a depleted gas well.

Phase 3

The first part of the third phase of development was completed in July 1998. The expansion increased the production capacity to 630 mmscfd of gas and 21,000 b/d of condensate, enabling the field to meet the increased DCQ (550 mmscfd) from mid-1998. Phase 3 comprises a number of sub-phases.

• Phase 3A was completed in July 1998. This entailed the installation of two wellhead platforms, WP-9 and WP-10, and a further series of modifications to the CPP, including a third gas processing train. 39 development wells were drilled.

• Phase 3B began in Q1 2001 and involved the installation of the WP-11 and WP-12 platforms and the initial development of Ton Sak. Around 50 slimhole development wells were drilled from new and existing platforms. This phase also included debottlenecking of liquids processing facilities. The WP-11 platform was installed on Ton Sak East.

• Under Phase 3C and 3D, a further two wellhead platforms were installed. WP-13 and WP-14 are four-legged conventional platforms with 12 slots. The work scope included modifications to WP-9 and WP-10, completed in early 2003. WHP-14 is located at the Ton Sak-6X well location, on the western flank of the Ton Sak field. Phase 3C also included the installation of a new gas processing platform to treat sour gas from reservoirs in the central portion of the Bongkot field. Sembcorp Marine was awarded the EPIC contract for the eight-legged sour gas production platform, which was installed at the field in April 2005.

• Phase 3E involved the installation of three, seven-slot wellhead platforms, each with a 60 mmscfd capacity. Thailand Nippon Steel was awarded the EPC contract for the three wellhead platforms and associated flowlines. The first wellhead platform of Phase 3E, WP-17, was commissioned in September 2006. The other two, WP-15 and WP-16, were brought onstream at the end of 2006. Drilling started from WP-17 on the G structure, followed by drilling from WP-15 and WP-16 on the Ton Sak structure. Three infill wells were completed on WP17 in Q3 2010.

• Phase 3F focused on the Greater Bongkot North area and included the development of Ton Rang. PTTEP issued the EPIC tender for Phase 3F in May 2006. This included three wellhead platforms, WP-18, WP-19 and WP-20, with a minimal jacket size and associated flowlines. The three platforms and the tie-in lines were onstream in early 2009.

• Phase 3G involved two more wellhead platforms (WP-21 and WP-22) with inter-platform flowlines, to be sited on Tong Rang-2X and Tong Chan-1X. Each platform has 16 slots and installation was completed in Q1 2011.

• Phase 3H was launched in 2009 and includes the installation of three platforms and 25 development wells. Platforms WP-23, WP-24 and WP-25 are located at Ton Chan-2, Ton Sak-7, and Ton Sak-8. Installation was completed Q2 2011.

• Development phases 3J, 3K and 3L comprised the installation of eight additional platforms. Phases 3J and 3K were completed in Q4 2012 and Q3 2013 respectively, whilst Phase 3L was completed in mid-2014. Phase 3M, comprising five WHPs and 39 development wells, was sanctioned in February 2013 and completed in mid-2016. Phase 3N (comprise 4 WHPs and 30 wells) was sanctioned in 2015 and is expected to complete in 2017.

• There are also plans for Phase 3P, 3Q and 3R but these phases would utilise slimmer WHPs that are more cost effective. Each of these phases will comprise 3 WHPs and 24 wells.

Bongkot FSO

Although the Bongkot FSO was expected to have a design life of 15 years, corrosion of the ballast tanks rendered it unsafe and required its replacement in 2000. In September 2000, PTTEP secured a 250,000-barrels temporary FSO under a US$20 million contract with an alliance of Technip, Coflexip Stena and Italian Thai Development. The contract included the installation of two 6-inches flowlines, a new pipeline-end manifold and temporary mooring system and the towing and hook-up of the mooring buoy to the FSO. Under the terms of the agreement, the vessel was to be leased for either 100 or 180 days. However, a condensate leak from the hose connecting the CALM buoy to the FSO prompted PTTEP to bring forward a tender for a permanent storage vessel. A submerged concrete storage vessel was considered, however in July 2001, PTTEP awarded an EPC contract to Modec for a new-build FSO, the Pathumabaha, with 400,000 barrels of oil equivalent storage and accommodation facilities. Installation of the new vessel was completed in early 2003.

Bongkot Optimisation System

In July 2006, PTTEP selected Aspen Technology to implement a system to optimise production from the Bongkot field.

<u>Phase 4</u>

Pre-project and basic engineering plans for the Greater Bongkot South development, incorporating Bongkot South, Ton Koon and Ton Nok Yoong, began in June 2005. The project was sanctioned in 2007, and construction began in 2009. The development includes the installation of:

• a 22,000 tonne CPP with CO_2 treatment facilities, required due to higher levels of CO_2 in the southern Bongkot reservoirs

• a new accommodation platform

• a new 82-kilometer, 8-inches condensate pipeline from the Greater Bongkot South facilities to the Pathumabaha FSO

• Phase 4A-B included 10 WHPs and 120 wells. These two phases were completed between 2011-2015

• Thai Nippon Steel was awarded the EPC contract for Phase 4B which was completed in 2014.

• Phase 4C includes 3 WHPs and 22 wells. First gas was achieved in 2015 and drilling was completed in 2016.

• Phase 4D was sanctioned in July 2015 and first gas was in 2016. It will include 2 WHPs and 14 wells.

• These processing platforms will be equipped to remove carbon dioxide, mercury and hydrogen sulphide to produce purer and cleaner natural gas.

It is understood there are also plans for Phase 4E and 4F which would utilise slimmer WHPs that are more cost effective. The Ton Koon extension in Block G12/48 is expected to be developed as part of Phase 4E. Gas is exported via a tie-in to the Arthit Pipeline End Manifold (PLEM) to Erawan pipeline, and then via the third trunkline in the Gulf of Thailand.

Installation of the 350 mmscfd gas and 15,000 b/d condensate capacity CPP, and accommodation platform was completed in Q3 2011. Commissioning took place during late-2011 and early 2012. First production from the Greater Bongkot South development was achieved in April 2012.

4. Infrastructure

Gas

In March 1993, the first stage of PTT's US$360 million pipeline project to bring natural gas onshore from the Bongkot field was completed. This consisted of the laying of a 172 kilometer, 32-inches pipeline from Bongkot to Chevron's Erawan gas field, as well as the installation of a riser platform at Erawan, which serves as a distribution centre for the offshore gas, and then transmitted via trunklines to the Rayong gas separation plant 125 kilometers southeast of Bangkok. The Bongkot to Erawan pipeline currently has a capacity of around 1,100 mmscfd.

In Greater Bongkot South, processed gas from the CPP on the South Bongkot field is transported to the third trunk line via a tie-in to the Arthit PLEM to Erawan pipeline.

Liquids

Initial Bongkot North condensate production was pumped via 6-inches diameter pipelines to an attendant 180,000-barrel FSO vessel, moored three kilometers away. The FSO incorporated an internal turret mooring system, and was used to receive and store condensate, which was then periodically offloaded onto shuttle tankers. The installation of a new, 400,000-barrel capacity FSO and 8-inches pipeline was completed in early 2003. See development section for further details.

Produced condensate from the Greater Bongkot South is sent to the Bongkot FSO via a new 82-kilometer, 8-inches pipeline.

Table 9 Bongkot pipeline summary

Pipeline	Type	From	To	Length (km)	Diameter (in)	Capacity (mmscfd)
Bongkot to Erawan Riser Platform	Gas	Bongkot Area	Erawan Riser Platform	172	32″	1,100
Bongkot South Spur	Gas	South Bongkot	Bongkot South Tee	38	24″	200
Bongkot South Condensate	Condensate	Bongkot South CPP	Bongkot FSO	82	8″	

5. Gas Sale Contracts

Greater Bongkot North

The Bongkot Gas Sales Agreement (GSA) was officially concluded in March 1990. Under the terms of the contract, gas is sold to PTT at the entrance to the Bongkot/Erawan pipeline. The contract called for an initial minimum delivery of 150 mmscfd, increasing to 250 mmscfd by 1995 and later amended to 350 mmscfd by 1996. A further amendment to the GSA in August 1996 allowed an increase in DCQ of 200 mmscfd to 550 mmscfd of gas from mid-1998.

The contract term, tied to the Greater Bongkot North reserves, is currently estimated at 31 years, and there is a swing factor of up to 15% (615 mmscfd) on the DCQ level.

Gas pricing

Pricing for gas was based on a formula incorporating the following indices:

- A basket of medium fuel oils from Singapore
- The Wholesale Price Index in Thailand
- The US Index of Export Prices
- The Producer Price of Oil field Machinery and Tools Index
- The Baht/US$ Exchange Rate

The gas price is adjusted every six months. A modification to the gas pricing formula was made in April 2002. Whereas the original pricing formula incorporated the Wholesale Price Index in

Thailand, following modification, and retroactive to January 2000, the formula is now indexed to the Producer Price Index. No adjustment to the base price was made.

Other gas sales arrangements

Under the sales agreement, if gas is supplied above the contracted volume in any one year, PTT as gas buyer, has the right to decrease future gas offtake by such quantity (Carry Forward Gas). On 31st July 2001, the Bongkot partners signed an agreement with PTT to effectively compensate PTT for waiving the right to exercise the outstanding Carry Forward Gas of 19.54 bcf that had been produced over the contractual volume. This would enable gas production to be maintained at the contracted 550 mmscfd of sales gas. A further agreement was reached in relation to the 11.6 bcf additional sales gas which was produced from the field between 5 August 2001 and 1 June 2002. PTT agreed to purchase this gas in return for a one-off payment. The Bongkot partners compensated PTT with US$19.61 million on 31 August 2001, for the combined amount of 31.14 bcf.

In 2003, Greater Bongkot North production was below the 550 mmscfd DCQ level. Increased average production, above the DCQ level, was seen in 2004 to compensate for previous undersupply.

2005 Agreement

On 13 July 2005, the Bongkot partners signed a supplementary agreement to supply an additional 61 bcf of gas between 1 April 2005 and 1 October 2008. As part of the agreement, the partners agreed to make a one-off payment of 1,000 million Baht (US$25 million) to PTT, on the date of signing.

Greater Bongkot South

Under the Phase 4 development, the southern accumulations are estimated to hold around 1.8 tcf of gas and are capable of producing at a plateau rate of around 300-320 mmscfd. These reserves have been contracted under a separate gas sales agreement signed in August 2009, with an agreed DCQ of 320 mmscfd with a swing factor of up to 10% (350mmscfd). It is understood that the gas price at Bongkot South achieves a premium due to the additional costs needed for CO_2 removal from the recovered gas.

Condensate

All condensate produced is sold to PTT in Thailand, ex-FSO. Pricing is based on the arithmetic average of a basket of one condensate and three crudes posted in Singapore, less an 8.5% discount. Prices are adjusted monthly.

6. Concession Regime

The Bongkot area is taxed under Thai I terms and Block G12/48 is taxed under Thai III terms.

As part of the contract extensions signed in 2008, the partners are required to pay a lump-sum extension bonus every quarter until contract expiry.

Key Legislation

Key Legislation of Thailand’s petroleum exploration and production comprises two main acts: The Petroleum Act, BE 2514 (1971), and its revisions, and The Petroleum Income Tax Act, BE 2514 (1971), and its revisions

Production Sharing Contract (PSC)

The contract of exploration blocks opened for bidding the right to explore and produce petroleum is a Production Sharing Contract which contains the following key terms:

Contract Term

Table 10 Contract Terms

Contract Type	Production Sharing Contract
Contract period (years)	
• Exploration	3 (with 3 years extendable).
• Production	20 (with 10 years extendable) starting immediately after the end of the exploration period.
Contract Area	
• Exploration Block	As defined in the bid announcement. Area relinquishment at the end of exploration period: ▪ <u>Exploration period extended</u> 25% of remaining area (excluding production area) ▪ <u>Exploration period not extended</u> All of remaining area (excluding production area)
• Production Area	Upon commercial discovery, a production area can be delineated. Once the production area is delineated, the production may be started even during petroleum exploration period.

Table 11 Fiscal Terms

Bonuses and Rentals	**Requirement** — **Detail** Signature Bonus — as designated by government Production Bonus — as designated by government Other Bonuses — as designated by government *Note: Bonuses are not cost recoverable but are tax deductible*
Royalty	Royalty is levied at 10% of total petroleum production required by law
PSC Cost Recovery	The cost of petroleum business can be deducted in accordance with plan and approved budget, which is not more than 50% of total annual petroleum production. If the cost of petroleum production is more than 50% of total in any year, an excess can be deducted in the following years, but not more than at the aforementioned rate and not longer than the contact period.

Percentage of Contractors' Share of Profit Petroleum	The percentage of Contractors' Share of Profit Petroleum shall be not more than 50% as stipulated in Section 53/3 (2) (c) of the Petroleum Act B.E. 2514 (1971) which is amended by the Petroleum Act (No. 7) B.E. 2560 (2017).
Corporate Income Tax	Corporate Income Tax is levied at 20% of net profit as stipulated in Chapter 7 of the Petroleum Income Tax Act B.E. 2514 (1971) which is amended by the Petroleum Act (No. 7) B.E. 2560 (2017).
Product Pricing	The price of oil is the market price - the f.o.b price realised by the Contractor on arm's length terms. The gas price will be that stipulated under the terms of discrete gas sales agreements.

Please refer to Ministerial Regulation Prescribing Form of Production Sharing Contract B.E. 2561 for a copy of the model of the Production Sharing Contract.