Field Evaluation Report

– Far East –

Sirikit Field
Phitsanulok Basin, Thailand
Executive Summary

The Sirikit Field is located in the Phitsanulok Basin, ~400 km north of Bangkok (Fig. 1). It was discovered in 1981 and brought onstream in 1982. The field has a STOIIP of 800 MMB (this may include satellites) and ultimate recoverable reserves for the Greater Sirikit Area are 148 MMBO and 250 BCFG (2001). It is the largest oilfield onshore Thailand, holding close to one third of oil reserves in the country. The field produces sweet light waxy oil (39-40 °API, 15-20% wax), termed the ‘Phet crude’. The oil and gas are trapped in a heavily faulted, north-trending anticline by a combination of fault and dip closure and there are numerous, separate fault compartments. The reservoirs in the main field are predominantly lacustrine-delta sandstones of the Miocene Lan Krabu Formation. Lacustrine claystones form the source and seal in the basin and are arranged in cyclical sequences with the reservoir sandstones. Small accumulations to the west and north of the main field are hosted by younger fluvial sandstones. Development of Sirikit commenced in 1982 and has continued to the present (2008). Water injection supplements weak solution-gas and gas-cap expansion natural drives. The water injection programme was implemented in 1995 to provide pressure support and improve overall recovery rates. The application of the latest exploration and production technology has resulted in an increase in recoverable reserves from 30 MMBO to 148 MMBO in less than twenty years. By 2000, 128 MMBO and 276 BCFG had been produced. It was hoped to maintain a production rate of ~24,000 BOPD from the Greater Sirikit Area until 2010 but in 2004 and 2005 average daily production had declined to ~17,000 BOPD.

Exploration History

The Phitsanulok Basin contains the Sirikit Field and several smaller fields, including West Sirikit, Pru Krathiarn and Thap Raet (Figs. 1 and 2), in structural traps within fluvial and lacustrine delta reservoirs (Polahan, 1986). The basin, which covers over 6000 km², was defined in the late 1970s through fieldwork and aeromagnetic surveys. Shell was granted the S1 concession in the centre of the basin in 1979. Shell acquired and interpreted >2000 km of 2-D seismic data over the block in 1980 and 1981 and 4000 km in 1982 (Fletcher, 1982, 1983; Fletcher and Soeparjadi, 1984). Two well locations were selected, based on the results of the seismic surveys, and the second well, LKU AO1, discovered the field at the end of 1981. The discovery well was very encouraging; it tested at rates up to 4400-4600 BOPD, RFT tests suggested a long oil column and the STOIIP was initially estimated to be ~1 BBO (Brooks, 1987). A decision was made to develop the field and an early production scheme was implemented. The time from discovery to initial production was just twelve months. Development drilling commenced in 1982, five producers were completed and the field was brought onstream by the end of the year. The field, initially known as Lan Krabu, was officially inaugurated in 1983 and renamed the Sirikit Field (Shell, 2001).

Five wells were drilled as part of the initial appraisal programme. Four of the wells in the north of the field indicated: (1) a deeper GOC (1555 m TVDSS) than that found in the discovery well (1435 m TVDSS); (2) hydrocarbons were in separate reservoir sands; and (3) flow rates that were lower than in the discovery well. Consequently, further appraisal wells were drilled and a 3-D seismic
survey was acquired over the field in 1983-84. The northeast of the field is structurally simple and so was developed first. After the 3-D seismic interpretation was completed, appraisal and development were focused on the eastern and central parts of the field. In 1985 an appraisal well on the western flank and a well at the southern end of the field both found GWCs at the same level, thus downgrading expectations of oil in those areas (Brooks, 1987). The western portion of the field, which is structurally complex, was appraised and developed last.

Once Sirikit production was established, exploration focused on satellite accumulations and on deeper objectives in the main field. Sirikit West was discovered in 1983, has a STOIIP of 34 MMB, partly in younger fluvial reservoirs, and came onstream in 1985. Over 50 exploration wells have been drilled on the block (OGJ, 1999a). Additional STOIIP has been found in deeper reservoirs (Brooks, 1987), in the Pru Krathiam and the West and East Sirikit satellites and gas reserves have been added on the west flank of the field. An active exploration programme continues on the block.

**Basin Evolution and Petroleum Systems**

The Sirikit Field lies on a basement-cored high in the southwest of the Phitsanulok Basin in north-central Thailand (Fig. 1). It is one of a series of elongate north trending extensional basins found onshore and offshore Thailand (Fig. 3). The basin was initiated in the Late Oligocene in response to regional strike-slip movement in the Thai-Malay Mobile Belt which represents a Permo-Triassic collision zone between the Shan-Thai and Indochina continental blocks (Fig. 4) (Polachan et al., 1991). The tectonic activity and basin development during the Tertiary in SE Asia are related to the collision of the Indian and South Asian Plates however the details of this process are complex and controversial, for example with regard to the amount and sense of displacement on the main strike-slip faults (Polachan et al., 1991).

Seven major Cenozoic basins are found in central Thailand, within the mobile belt: the Phitsanulok, Phetchabun, Nang Bua, Suphan Buri, Mae Sod, Kamphaeng Saen and Ayutthaya basins. They are half grabens, bounded by north trending, low-angle (30-45°) extensional faults that formed in response to movement on the regional NE-trending strike-slip faults. The most significant strike-slip faults are the NW trending Mae Ping and Three Pagoda Faults and the conjugate, NE trending Uttaradit and Ranong Faults (Fig. 4). The NE-trending faults are terminated by the principal NW-trending strike-slip faults (Fig. 4). Phitsanulok, formed at the intersection of the Uttaradit and Mae Ping Faults, is the largest and deepest of the Cenozoic basins (Fig. 5). It is 100 km long and 40 km wide and is deepest adjacent to the western boundary fault where up to 8 km of sediments have accumulated (Flint et al., 1989). The north trending western boundary fault dips at an unusually shallow angle of 35-45° (Flint et al., 1988). The basin is floored by Mesozoic to Paleozoic sedimentary, igneous and metamorphic rocks and is surrounded by highly deformed Mesozoic and Paleozoic sedimentary rocks.

Major tectonic activity commenced in the Late Oligocene and the main phase of strike-slip tectonics occurred at this time (Polachan et al., 1991). The intracratonic basins formed by extension or pull-apart, followed by rim uplift, rapid asymmetric basin subsidence and sedimentation. By Early Miocene time, lacustrine conditions were established in the onshore basins. Local inversion and uplift occurred in the Late Miocene. The Late Miocene unconformity is capped by basaltic lavas dated at 10.3 Ma (Polachan et al., 1991) in the Phitsanulok Basin. Subsidence recommenced in the Late Miocene and continued to Recent time.

The Phitsanulok Basin contains the Cham Saeng petroleum system. There is a cyclic repetition of organic-rich claystones that formed during phases of lake expansion with progradational fluvio-deltaic sandstones. The former provide the source rocks.
and the seals whereas the latter are the reservoirs. The source rocks are up to 400 m thick (Sladen, 1997) and belong to the Lower-Middle Miocene Chum Saeng Formation. Coals are also present locally. Freshwater and terrestrial palynofacies and freshwater gastropod fossils confirm the lacustrine origin of the source rock. The source rocks have a high content of Type I kerogen derived from freshwater algae and Type III kerogen from higher plants. Source kitchens occur in the deepest part of the basin, north of the field. The oils are relatively immature, have not been biodegraded and are low in aromatics. Variations in isotopic ratios between different oil pools may reflect sourcing at different stages of source rock maturation, while similarities in chromatograms indicate common source and migration histories (Lawwongngam and Philp, 1991). Oil generation may have commenced in the Pliocene in the west of the basin, where heat flow is high. Generation and expulsion may have taken place at a depth >4 km (Knox and Wakefield, 1983).

Structure and Trap Definition

The main Sirikit Field is a north-trending faulted anticline, developed over a basement high with the same trend in the southern part of the Phitsanulok Basin. The anticline developed as part of an extensional or pull-apart fault complex in the Oligocene in response to transtensional sinistral shear on the Mae Ping and Uttaradit fault systems (Fig. 6). Basement faulting continued during the deposition of the main reservoir (Lan Krabu) and ceased in late Middle Miocene times (Brooks, 1987). The main faults have listric geometries, trend roughly north and have been reactivated and modified by sinistral strike-slip (Flint et al., 1988, 1989). The strike-slip has produced synthetic and antithetic faults and Reidel shears which have a characteristic sigmoidal shape and a ~NW orientation (Flint et al., 1988). Oil and gas are structurally trapped in multiple pools on the faulted anticline.

The main Sirikit Field is ~8 km long by ~6 km wide and covers an area of ~12,000 ac. The main structure plunges to the NNW and is dip and fault closed to the west by a complex extensional fault system. It is fault and dip closed to the north and east (Figs. 7, 8 and 9). The reservoirs typically dip at 10° to the ENE.

The main reservoir in the main Sirikit Field is the K Member of the Lan Krabu Formation, which contains both oil and free gas, but there are several deeper oil reservoirs, including the L and M Members of the same formation (Fig. 10). The crest of the main Sirikit Field is at 1350 m TVDSS (top K Member) and the crest of the L Member is at 1550 m TVDSS. The main field has a widespread GOC at 1555 m TVDSS in the K Member and OWCs at 1641 m and 1930 m TVDSS in the K and L Members, respectively (Brooks, 1987). The bulk of the recoverable oil lies within the K Member where the oil rim is 86 m thick (Brooks, 1987). There is no gas cap in the L Member. Deeper ODTs and OWCs are recorded at 2005, 2050, 2250 and 2400 m TVDSS, in the M and P Members. Fluid contacts are variable on the highly faulted western margin of the field. Extensive normal and strike-slip fault systems compartmentalize the reservoir and some fault blocks have never been charged with hydrocarbons.

Open lacustrine claystones of the Cham Saeng Formation that interleave with the Lan Krabu sandstones form the seals to the main reservoirs (Figs. 11-13). The ‘Main Clay’ overlies the K Member. It is ~200 m thick on the crest and eastern side of the field. An intermediate seal, termed the ‘Upper Intermediate Seal’ or UIS, is 20-50 m thick, separates the K and L reservoirs. The top seal to the M Member is the ‘Lower Clay’ or LIS which is 80-300 m thick. The bottom seal to the M Member and Lan Krabu Formation and top seal to deeper Sarabop Formation reservoirs is the ‘BS’ or bottom seal member.

The main Sirikit Field is fault- and dip-separated from the West and East Sirikit and Thap Raet Fields by NW and NE trending faults (Figs. 1 and 2). Sirikit-D block is a north trending fault block, with
fault closure to the W and dip closure to the N, S and E. It is 3500 m long and 250 m wide. **Thap Raet Field** consists of four fault blocks, with most of the production coming from two in the SW, which together extend for ~2 x 2 km. **Sirikit West Field** occurs at the triangular intersection of two major strike-slip faults (Fig. 14) and consists of several tilted, down-faulted blocks associated with westward dipping faults (Chuenbunchom et al., 2003).

Amplitude maps have been used to identify and rapidly map small structural disturbances and sigmoidal anomalies that resemble Riedel shears. The mapping of these small faults is important because of the thinly interbedded nature of the reservoirs (Flint et al., 1988). A ~16 m-thick deltaic wedge within the Upper Intermediate Seal (UIS) has been mapped in the NW of the field (E block) based on its high amplitude response (Fig. 15) but the application of this method for facies mapping is restricted because of the thinness of the reservoirs relative to the resolution of the 3-D seismic.

**Stratigraphy and Depositional Facies**

In the main **Sirikit Field** hydrocarbons occur in members K, L and M of the Early-Middle Miocene Lan Krabu Formation which is ~540 m thick (Figs. 8 and 12) and in deeper reservoirs beneath the M Member. The Lan Krabu Formation represents the basal part of the postrift sag sequence. It unconformably overlies the Kom, Sarabop and Nong Bua Formations, which are Oligocene synrift, coarse-grained siliciclastic sediments. Minor amounts of oil also occur in the P Member of the diachronous Sarabop Formation and in so-called ‘basement’ which consists of fractured, metamorphosed, clastic red beds (Smit, 1999). The Lan Krabu Formation is overlain by Middle-Upper Miocene Pradu (or Pratu) Tao and Yom Formations (Fig. 16) and these are oil bearing in satellite fields (see below for more details).

The **Lan Krabu Formation** is 500-2200 m thick and consists mainly of lacustrine-delta sediments. It grades into lacustrine mudstones of the Chum Saeng Formation to the south and into alluvial and delta plain sediments to the north (Fig. 13). Fluvial and alluvial fan deposits of the Prato Tao Formation conformally overlie the Lan Krabu Formation. The Lan Krabu Formation has been divided into reservoir members or sequences, named from top to base: K, L and M (Fig. 11). These sandy members are separated by lacustrine shales. The sequences have been subdivided into submembers and parasequences (Ainsworth et al., 1999). The Lan Krabu Formation thickens off-structure and in Sirikit West an additional sequence, the D Member, occurs above K (Fig. 11) (Ainsworth and Sankosik, 1998).

Sands of the Lan Krabu Formation were deposited on lobate, river-dominated deltas that advanced repeatedly into a shallow, extensive, perennial lake in a humid, subtropical climate. The thicker sandstones accumulated on prograding mouthbars and to a lesser extent in fluvial distributary channels (Fig. 17). The progradational sequences are up to ~15 m thick and are capped by floodplain and/or lacustrine mudstones and claystones (Flint et al., 1989). Individual distributary channels and mouthbars are identifiable on wireline logs (Fig. 18).

A detailed core based sedimentological study (Flint et al., 1989) of the Lan Krabu Formation found that the commonest sedimentary sequence starts with (1) open lacustrine claystones, passing up into (2) thinly interbedded fine sandstones, mudstones and siltstones (termed heterolithics) deposited on the delta front, then (3) cross-bedded fine- to coarse-grained sandstones deposited both on mouthbars and in channels, and finally (4) either argillaceous, aggradational floodplain deposits or abandoned channel-fill sediments. The main reservoirs occur in regressive cycles typically 4-8 m thick, representing progradation of deltas into the main body of the lake. Smaller, 1-3 m thick regressive sequences, commonly containing little or no sandstone, are interpreted as either distal equivalents of the thick, sandy sequences or the deposits of crevasse deltas formed in interdistributary bays. Regressive, sandy
sequences are thickest and are best developed in the middle L and lower K Members. In the model of Flint et al. (1989), progradation was predominantly from the ENE (Fig. 19) and in a previous paper (Flint et al., 1988) progradation from the NW (intra-UIS delta), from the E (K30/K20) and from the SE (K20) were proposed, whereas more recent papers (e.g., Ainsworth et al., 1999) have favored progradation from the N.

Unusually thick (up to 30 m) intervals dominated by argillaceous floodplain deposits occur in the middle of the K Member and in the lower part of the L Member. These may have been related to localized areas of differential subsidence that allowed thick delta-top sediments to accumulate or to rapid rises in lake level that led to sediments being trapped on the flood plain (Flint et al., 1988).

Sirikit-D block, Sirikit West and Thap Raet Fields contain oil and minor gas in fluvial sandstones of the Middle-Upper Miocene Pradu Tao and Yom Formations (Fig. 15) (Chuenbunchom et al., 2003) that overlie lacustrine shales of the Chum Saeng Formation. The Pradu Tao Formation is ~300 m thick and a shale divides it into two units termed UPTO and LPTO. Similarly, the Yom Formation is ~250 m thick and a 5-30 m-thick shale divides it into two units named UYOM and LYOM.

Sirikit West also has oil in the D and K Members of the Lan Krabu Formation. Stratigraphic units are up to three times thicker in Sirikit West than in the main field, indicating synsedimentary movement on the major fault that separates them (Fig. 14). The additional thickness in Sirikit West is mainly represented by shale (Ainsworth and Sankosik, 1998; Ainsworth et al., 1999).

Reservoir Architecture

The Lan Krabu Formation in the main Sirikit Field is divided into the K, L and M Members or sequences, which have been further divided into parasequences (Table 1), each 10-20 m thick. The K Member, the uppermost and main reservoir unit, is up to 320 m thick and has been divided into submembers, K1-K4, and seismically defined sequences, K10, K20, K30 and K40 that occur above reflectors E10, E20 etc. (Figs. 19 and 20A). The main reservoirs are mouthbar and fluvial-channel sandstones with variable reservoir quality. The K20 interval contains a reasonably continuous seismic facies corresponding to progradational deltaic cycles. K20 sandstones become thinner and less numerous towards the S of the field (Flint et al., 1988). Sandstones in K30 are more numerous in the S of the field and mark the maximum progradation of the delta systems. The Upper Intermediate Seal which occurs above the L Member (Fig. 20A) is characterized by continuous high amplitude reflections, however, towards the north reflections disappear and amplitudes change as a result of the appearance of sandy deltaic wedges within the shales. The L Member is 190 m thick and reservoirs are predominantly channel sandstones. On seismic it produces continuous, high amplitude reflections though these converge and disappear towards the N, W and E of the dataset (Flint et al., 1988). It is subdivided into parasequences L1-L6, with moderate reservoir quality. The M Member is 70 m thick and comprises eight submembers M1-M8, with poor to moderate reservoir quality.

Sands were sourced from the north of the basin and the N:G ratio and net thickness decreases towards the south of the field (Flint et al., 1988; Finley et al., 1996).

Fieldwide claystones seal the reservoirs and can be easily recognised on downhole logs because they have low sonic velocities and high GR responses (Figs. 12, 18 and 20A). Flooding surfaces at the bases of the transgressive claystones are used for correlating the reservoirs and seals between the wells (Figs. 19 and 21). The correlations developed in the 1980s emphasized the lateral continuity of reservoir sandstones and Flint et al. (1989) reported that the mouthbars have an extensive lateral
continuity based on well data and detailed log correlations (Fig. 19) and that production data suggest that many of these sands are interconnected, forming drainage areas of up to 20 km².

The initial reservoir architecture model was based on these lithostratigraphic correlations in which petrophysically defined sandstones were correlated if they occurred at the same stratigraphic level relative to a flooding surface datum (Fig. 21). However, several important discrepancies were found during the 1990s: (1) full-scale waterflood on the eastern flank of the field arrested production decline in some wells but in others failed to support pressure and in seven wells water broke through prematurely; (2) Kh derived from core data were two to five times higher than those derived from well tests; (3) connected STOIIP was less than the calculated STOIIP, suggesting that significant volumes of oil may have been bypassed; and (4) some wells produced far more oil than their calculated connected STOIIP whereas others produced far less, suggesting the original connectivity model was wrong (Ainsworth et al., 1999).

Therefore, a new model was developed for the D Member of the Lan Krabu in Sirikit West using a chronostratigraphic correlation (Figs. 21 and 22) based on observations on analogous modern and ancient mouthbar deposits and incorporating new well and 3-D seismic data. In the correlation good quality, petrophysically defined sandstones deposited on the upper parts of the mouthbar were considered to grade down the depositional dip (estimated to be 0.5°) into thinly (2-15 cm) interbedded sandstones and shales, known as heterolithics, that represent the toe sets of the advancing mouthbars (Ainsworth et al., 1999) (Fig. 22). Sandstones in the heterolithics are too thin to be properly resolved using low-resolution, conventional, downhole logs but can be seen in cores and their presence in wells can be inferred from small inflections on GR, CFD and CNL logs. The grid cells used in the model were 25 x 25 x 0.2 m; their low height was selected to preserve the depositional dips of discrete mouthbar sands. Petrophysical parameters were derived from logs and stochastically sampled core data. The model was scaled up to represent a single mouthbar parasequence. The flow model assumed an oil-filled reservoir with solution gas expansion as the natural drive mechanism. Results of the simulation showed that the lithostratigraphic-based model has a 2.6% higher recovery factor than a chronostratigraphic model, in both cases with only petrophysically defined sandstones being perforated. If the heterolithic sections were perforated using the chronostratigraphic model, the absolute recovery factor was increased by 1.7% relative to the same model without perforated heterolithics.

Fractured basement reservoir in main Sirikit has been successfully modeled using three faults, the top pre-Tertiary seismic horizon and FMS logs from three wells (Smit 1999).

The typical thickness of stacked, fluvial channel sandstone bodies in the Lower Pradu Tao in Sirikit-D block, Sirikit West and Thap Raet Fields is in the range 10-30 m. In the Upper Pradu Tao the bodies are less well connected and are 5-10 m thick. Sandstone bodies in the Lower Yom are typically 2-5 m thick and isolated. Thap Raet and Sirikit West have more complex architectures and fluid distributions, with multiple stacked oil columns, than Sirikit-D (Chuenbunchom et al., 2003).

The reservoirs in Sirikit West and Thap Raet are compartmentalized by faults that are both sealing and partly sealing. Downhole logs and pressure tests indicate that there are multiple hydrocarbon columns with multiple, stacked fluid contacts (Walsh et al., 2001).

Reservoir Properties

Sandstones in the Lan Krabu Formation are very fine-grained to coarse and pebbly (Flint et al., 1989) and are compositionally immature, containing

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common feldspar and metamorphic rock fragments. Reservoir quality declines with increasing burial depth in all reservoirs and economic basement is at ~2500 m (Brooks, 1987). Secondary porosity has been formed by dissolution of feldspar and lithic fragments. Other diagenetic modifications included the formation of calcite, siderite and kaolinite cements. Variations in reservoir quality are largely controlled by differences in grain size because both channel and mouth-bar sands have similar mineralogy, other textural characteristics and diagenetic history (Flint et al., 1988).

Reservoir quality is very variable in the Lan Krabu throughout the main Sirikit Field (e.g., Fig. 23). A porosity versus permeability cross-plot for three wells in the main field (Fig. 24) shows: (A) an overlap between the values from the mouthbar/continuous sandstones and the channel/discontinuous sandstones; (B) values from the channel sandstones are closely clustered at the high end of the range whereas those from the mouthbar sandstones show a wider range to lower values, reflecting the presence of finer grained and more argillaceous rock types in the latter; (C) a relatively high porosity cut-off (e.g., 17.5%, Walsh et al., 2001) for net sand definition, if a conventional 1 mD permeability cut-off is employed; and (D) net sands typically have porosities in the range 21-30% and permeabilities in the range 30-2000 mD.

The N:G ratio of the reservoir members varies from 0.05 to 0.37 (Fig. 23, Table 1), across the main Sirikit Field, depending on depth and reservoir facies. The K Member, the most productive in the field, has N:G ratios of 0.25 in deltaic sands and 0.05-0.15 in thin-bedded mouth-bar and floodplain sands (Flint et al., 1989).

Hydrocarbon saturations have been derived mainly from capillary pressures rather than from resistivity logs. This is because it is difficult to derive reliable saturations from resistivity logs run through intervals of thinly interbedded sandstones and shales, as found in the Lan Krabu (Walsh et al., 2001). Reservoir properties for the Yom and Pradu Tao Formations in the Sirikit-D block, Sirikit West and Thap Raet Fields (Table 2) and core analysis data from Sirikit West (Fig. 25) indicate that: (A) average porosities range from 16% to 28% and the maximum porosity is ~33%; (B) permeabilities are typically in the range from 10 mD to several hundred millidarcies and maximum values are >1 D; and (C) N:G ratios are very variable (0.15-0.7). In addition the best-fit line for reservoir D (Fig. 25) shows the potential for using a lower porosity cut-off (~13%) for net sand definition locally. Sirikit-D has the best reservoir quality and the least complicated geology of these three areas (Chuenbunchom et al., 2003). The analysis of NMR logs has confirmed the irreducible water saturations derived from core analyses and has increased the operator’s confidence in the maximum hydrocarbon saturations that have been assumed for the reservoirs in Sirikit West (Walsh et al., 2001).

Production Engineering Analysis

Volumetric figures are somewhat confused because authors do not always make clear whether they are referring to the main Sirikit Field alone or to the Greater Sirikit Area which includes satellite fields. On discovery it was thought that the main Sirikit Field may have a STOIIP as high as 1 BBO (Brooks, 1987). As the field’s complexity was recognised and became better understood, volumetric estimates were reduced to 312 MMBO in place and 34 MMBO recoverable (Brooks, 1987) and 350 MMBO in place and 41 MMBO recoverable (Flint et al., 1988). These figures indicate recovery factors of 11-12%. In the late 1990s significantly higher STOIIPs and URRs were reported but these may include satellite fields, e.g., 791 MMBO in place, 133 MMBO recoverable (SchAAFsm and Phuthithammakul, 1997) and 800 MMBO in place (for the ‘Sirkit oil field’, Ainsworth et al., 1999). Sirikit West has a STOIIP of 34 MMBO (Ainsworth et al., 1998). Shell (2001) reported proved reserves of 126 MMBO for the S1 concession. The most recent URRs, for the Greater Sirikit Area, are 148 MMBO and 250 BCFG (OGJ, 2001a).
The oil has an API gravity of 36-40° and its high (15-20%) wax content, low GOR and lack of sulphur are typical of oils derived from lacustrine source rocks (Sladen, 1997). Gas-cap expansion, weak solution-gas drive and weak aquifer support are the primary production mechanisms; aquifer support is weak due to reservoir compartmentalization and low permeability in the water leg.

Field development and pilot production commenced in 1982, following testing of the discovery well. Five appraisal wells were drilled during 1982, which highlighted the complex nature of the reservoir. Field development took place in stages and additional areas were exploited, as the field was better understood. Shortly after production commenced, reservoir pressure dropped from an initial value of 2760 psi to below the bubble point (2360 psi) and as a result GORs increased and oil production fell. GOR limits were set for each reservoir sequence and high GOR wells were shut-in. An intensive drilling campaign boosted production rate until it reached a plateau rate of ~20,000 BOPD was achieved in 1985, despite some setbacks (Brooks, 1987), and this was maintained until 1993 (Fig. 26).

A pilot water injection programme was initiated in the late 1980s. This was successful and a full-scale waterflood was implemented in the main field in 1995 (Ainsworth et al., 1999) at a cost of US$33M and this helped to reverse the decline in production (Fig. 26). Initially 11 wells injected 40,000 BWPD into the reservoir, primarily in the relatively unfaulted areas of the field. A direct injection method was adopted, with water being sourced from and injected within the same well. Water is drawn from the Pratu Tao Formation aquifer at wellhead pressures of 800-1200 psi, using electric submersible pumps (ESPs) and injected directly into the Lan Krabu Formation in the same wells (Finley et al., 1996).

By 1998 >130 wells had been drilled (Ainsworth et al., 1998) and the well spacing was 400-650 m in 1999 (Ainsworth et al., 1999). In 2001, the field suffered a rapid drop in pressure and the average production from the Greater Sirikit field fell to 21,760 BOPD from an expected 24,900 BOPD (OGJ, 2001b) and in the same year Shell announced a plan to redevelop the field and explore the S1 licence, at a cost of US$ 360M. Shell planned to drill 132 infill wells on Sirikit, together with over 50 exploration, appraisal, gas production and satellite development wells by 2007. Satellite field tie-backs and developments include the Nang Makham satellite NW of Sirikit producing 1500-2000 BOPD and waterflood programs at the Thap Raet and West Sirikit satellite fields (OGJ, 2001a).

Production from the Yom and Tao Pradu Formations in Sirikit-D, Sirikit West and Thap Raet Fields started in 1997, and in 2003 8500 BOPD was being produced. The oil is mostly undersaturated and has API gravities of 36-40° (Chuenbunchom et al., 2003). Initial production from Sirikit-D (Fig. 27) was from three wells and the primary recovery factor was expected to be 22%. Water injection started in January 2000 from an injector (LKU-CC02) located in the south of the field (Fig. 28A). Well LKU-D14 located to the north of the crest benefitted most, with oil production increasing from ~353 to ~663 BOPD (Fig. 29). Well LKU-CC01 on the crest of the structure began production in April 2002 after pressure support had built up and led to a substantial increase in production for the field from ~844 to ~2677 BOPD (Fig. 27). With careful monitoring, modeling and recompletions the ultimate recovery factor is expected to be 40% (Chuenbunchom et al., 2003).

In Thap Raet Field, which is more complex than Sirikit-D, water injection was commissioned in 2001 (Fig. 30). However a rapid decline in injectivity was observed and this was eventually tackled by artificially fracturing the reservoir. Water injection was responsible for 85% of oil production in the first half of 2003 and it is expected to increase the ultimate recovery factor from 14% to 36% (Chuenbunchom et al., 2003).
Production started in *Sirikit West* in 1985 and by 1998 the field was producing 800 BOPD from four wells (Ainsworth and Sankosik, 1998). Water injection under fracturing conditions was initiated following comprehensive modeling and simulation studies that were necessary because of the complexity of the reservoir and uncertainties regarding the connectivity of the sand bodies, for example (Chuenbunchom et al., 2003). The ultimate recovery factor is expected to increase from 15% to 31%, i.e., rather less than in Sirikit-D and Thap Raet. The success of waterflood projects in Sirikit West and Thap Raet was partly responsible for an 8.8% increase in oil reserves for the Greater Sirikit Area to 148 MMBO at the end of 2000 (OGJ, 2001a). It was hoped that the waterflood programme together with new discoveries in satellite fields could maintain production at 24,000 BOPD and 60 MMCFGPD until 2010 (Alexander’s Gas and Oil Connections, 1999b), however, in 2004 and 2005, average production had declined to just over 17,000 BOPD (Fig. 26).

As a result of detailed reservoir modeling, zones of bypassed oil have been identified together with oil bearing thin-bedded sands below seismic and log resolution. Wells are being recompleted to tap these oil reserves. Reperforation and recompletion have increased recovery factors to 28% in some reservoir compartments and raised daily production by 5% (Ainsworth et al., 1999b) above the base case.

Production from *fractured basement* has been attempted from three wells. The most successful, on the Central Sirikit High in the main Sirikit Field, has been in production since 1991 but another well watered out rapidly so was shut-in and a third only produced water (Smit, 1999).

Oil is transported from the field in a fleet of road tankers to the railway terminal at Bung Phra, 55 km away (Brooks, 1987). From there it is taken to the Bangchak refinery near Bangkok. A gas separation and processing plant was built in 1990, close to the field at Kamphaeng Phet. It handles 40 MMCFGPD and 700 BCPD and feeds gas to a local electricity power station. LPG is extracted from the associated gas and in early 1999 average production was 310 tons per day (OGJ, 1999a).
KEY REFERENCES


KEY REFERENCES
(continued)


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# Table of Field Parameters

<table>
<thead>
<tr>
<th>1 - GENERAL</th>
<th></th>
</tr>
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<tbody>
<tr>
<td>Field name</td>
<td>SIRIKIT</td>
</tr>
<tr>
<td>Location</td>
<td>Onshore Thailand</td>
</tr>
<tr>
<td>Basin name</td>
<td>Phitsanulok Basin</td>
</tr>
<tr>
<td>Basin type</td>
<td>Bally: 3122; Klemme: IIIB</td>
</tr>
<tr>
<td>Operator</td>
<td>Thai Shell Exploration and Production Ltd</td>
</tr>
<tr>
<td>Hydrocarbon type</td>
<td>Light oil and gas</td>
</tr>
<tr>
<td>Discovery year (well)</td>
<td>1981 (Lan Krabu LKU AOL 1)</td>
</tr>
<tr>
<td>Discovery well flow rate</td>
<td>4400-4600 BOPD</td>
</tr>
<tr>
<td>First production</td>
<td>1982</td>
</tr>
<tr>
<td>Current status</td>
<td>On production</td>
</tr>
<tr>
<td>No. exploration and appraisal wells</td>
<td>7</td>
</tr>
<tr>
<td>No. production wells (year)</td>
<td>127 (2005)</td>
</tr>
<tr>
<td>No. injection wells (year)</td>
<td>NA</td>
</tr>
<tr>
<td>Platforms/production centres</td>
<td>8 clusters</td>
</tr>
<tr>
<td>Elevation or water depth</td>
<td>Elevation: 59 m</td>
</tr>
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<table>
<thead>
<tr>
<th>2 - TRAP</th>
<th></th>
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<tbody>
<tr>
<td>Structural setting</td>
<td>Rift basin</td>
</tr>
<tr>
<td>Trap type</td>
<td>Miocene</td>
</tr>
<tr>
<td>Timing of trap formation</td>
<td>Dip-closed and fault-closed</td>
</tr>
<tr>
<td>Closure mechanisms</td>
<td>Dip-closed and fault-closed</td>
</tr>
<tr>
<td>Basis for discovery</td>
<td>Regional studies, potential field data and seismic grid</td>
</tr>
<tr>
<td>Seismic database</td>
<td>3-D seismic data 1983-84</td>
</tr>
<tr>
<td>Direct hydrocarbon indicators (DHI)</td>
<td>NA</td>
</tr>
<tr>
<td>Depth to top pay</td>
<td>1350 m TVDSS (Main field, K Member)</td>
</tr>
<tr>
<td>Reservoir dip</td>
<td>10°</td>
</tr>
<tr>
<td>No. of vertically separate HC pools</td>
<td>Multiple</td>
</tr>
<tr>
<td>No. of structural compartments</td>
<td>Multiple</td>
</tr>
<tr>
<td>Vertical closure to spill point</td>
<td>NA</td>
</tr>
<tr>
<td>Original hydrocarbon column height</td>
<td>Oil: 86 m (K Member, main field); &gt;200 m (L Member, main field)</td>
</tr>
<tr>
<td>Areal closure to spill point</td>
<td>12,000 ac (48.6 km²)</td>
</tr>
<tr>
<td>Field area</td>
<td>14,000 ac (56.7 km²)</td>
</tr>
<tr>
<td>Original fluid contact</td>
<td>Main field: widespread GOC: 1555 m TVDSS; K Mb OWC: 1641 m TVDSS; other ODTs and OWCs between 1930 and 2400 m TVDSS</td>
</tr>
<tr>
<td>Current fluid contacts (date)</td>
<td>NA</td>
</tr>
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<table>
<thead>
<tr>
<th>3 - RESERVOIR</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Producing formation (age)</td>
<td>Main reservoir in main field: Lan Krabu Fm (Miocene)</td>
</tr>
<tr>
<td>Depositional system</td>
<td>Lacustrine, shoreface</td>
</tr>
<tr>
<td>Sandbody type (dominant)</td>
<td>Mouth bar sands</td>
</tr>
<tr>
<td>Sandbody type (secondary)</td>
<td>Channel sands</td>
</tr>
<tr>
<td>Sandbody type (tertiary)</td>
<td>NA</td>
</tr>
<tr>
<td>Reservoir architecture/geometry</td>
<td>Wedge-shaped siliciclastic lobes</td>
</tr>
<tr>
<td>Fluid flow restrictions: macro-scale</td>
<td>Sealing faults</td>
</tr>
<tr>
<td>Fluid flow restrictions: meso-scale</td>
<td>Shale interbeds, lateral facies changes</td>
</tr>
<tr>
<td>Fluid flow restrictions: micro-scale</td>
<td>Cementation, compaction</td>
</tr>
<tr>
<td>No. reservoir stratigraphic layers</td>
<td>Main field: 5 minimum</td>
</tr>
<tr>
<td>Gross reservoir thickness</td>
<td>Main field: 540 m; 320 m (K); 190 m (L); 70 m (M)</td>
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<tr>
<td>Net reservoir thickness</td>
<td>NA</td>
</tr>
<tr>
<td>N/G ratio</td>
<td>0.05-0.25 (K Member, main field)</td>
</tr>
<tr>
<td>Net pay</td>
<td>NA</td>
</tr>
<tr>
<td>Lithology</td>
<td>Sandstone</td>
</tr>
<tr>
<td>Porosity types</td>
<td>Primary intergranular mainly, secondary dissolution</td>
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<tr>
<td>Core porosity</td>
<td>21-30% (net sand, main field)</td>
</tr>
<tr>
<td>Air permeability</td>
<td>30-2000 mD (net sand, main field)</td>
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<tr>
<td>Production-derived permeability</td>
<td>NA</td>
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<tr>
<td>Initial water saturation</td>
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# TABLE OF FIELD PARAMETERS (continued)

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<tr>
<th>4 - SOURCE</th>
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<tr>
<td>Formation and age</td>
<td>Chum Saeng Fm (Miocene)</td>
</tr>
<tr>
<td>Lithology</td>
<td>Bituminous claystone and possibly coals</td>
</tr>
<tr>
<td>Depositional system</td>
<td>Lacustrine</td>
</tr>
<tr>
<td>TOC</td>
<td>Typically 1-2%; up to 17-40% in thin beds</td>
</tr>
<tr>
<td>Kerogen type</td>
<td>Type I &amp; III</td>
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<tr>
<td>Time of hydrocarbon expulsion</td>
<td>Possibly started in Pliocene</td>
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<table>
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<th>5 - SEAL</th>
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<tr>
<td>Formation and age</td>
<td>Lan Krabu &amp; Chum Saeng Fm (Miocene)</td>
</tr>
<tr>
<td>Lithology</td>
<td>Siltstone and claystone</td>
</tr>
<tr>
<td>Depositional system</td>
<td>Lacustrine</td>
</tr>
<tr>
<td>Thickness</td>
<td>Main seal, for K reservoir: 200 m, others 300 m and 20-50 m</td>
</tr>
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</table>

<table>
<thead>
<tr>
<th>6 - RESERVES AND PRODUCTION</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Original volume in-place</td>
<td>800 MMBO (1999, may include satellites)</td>
</tr>
<tr>
<td>Ultimate recoverable</td>
<td>Whole S1 area: 148 MMBO; 250 BCFG (2001)</td>
</tr>
<tr>
<td>Cumulative production (date)</td>
<td>128 MMBO; 276 BCFG (2000)</td>
</tr>
<tr>
<td>Initial production rate (date)</td>
<td>3,800 BOPD (1983)</td>
</tr>
<tr>
<td>Max production rate (date)</td>
<td>24,650 BOPD (1999)</td>
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<tr>
<td>Current production rate (date)</td>
<td>17,129 BOPD (2005), 60 MMCFD (2001)</td>
</tr>
<tr>
<td>Current water-cut (date)</td>
<td>NA</td>
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<tr>
<td>Max prod rate per well</td>
<td>780 BOPD (1984)</td>
</tr>
<tr>
<td>Typical prod rate per well</td>
<td>311 BOPD (avg. 1983-2005)</td>
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<tr>
<td>Productivity index</td>
<td>NA</td>
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<tr>
<th>7 - HYDROCARBON COMPOSITION</th>
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<tbody>
<tr>
<td>API gravity</td>
<td>Main field: 39-40°; Sirikit-D, W, Thap Raet: 36-40°</td>
</tr>
<tr>
<td>Viscosity</td>
<td>Sirikit-D, W, Thap Raet: 0.4-2.0 cp at reservoir conditions</td>
</tr>
<tr>
<td>Sulphur content</td>
<td>Nil</td>
</tr>
<tr>
<td>Wax content</td>
<td>15-20 wt.%</td>
</tr>
<tr>
<td>Gas gravity</td>
<td>NA</td>
</tr>
<tr>
<td>Gas content</td>
<td>NA</td>
</tr>
<tr>
<td>Condensate yield</td>
<td>NA</td>
</tr>
<tr>
<td>Initial GOR</td>
<td>Low</td>
</tr>
<tr>
<td>FVF</td>
<td>NA</td>
</tr>
<tr>
<td>Saturation pressure</td>
<td>Main field: bubble point: 2360 psi @ 1830 m TVDSS</td>
</tr>
<tr>
<td>Pour point</td>
<td>Main field: 95 °F</td>
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</tbody>
</table>

<table>
<thead>
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<th>8 - FIELD CHARACTERISTICS</th>
<th></th>
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</thead>
<tbody>
<tr>
<td>Reservoir temperature</td>
<td>Main field: 160 °F @ 1830 m TVDSS</td>
</tr>
<tr>
<td>Original reservoir pressure</td>
<td>Main field: 2760 psi @ 1830 m TVDSS</td>
</tr>
<tr>
<td>Current pressure (date)</td>
<td>NA</td>
</tr>
<tr>
<td>Pressure gradient</td>
<td>Main field: 0.445 psi/ft</td>
</tr>
<tr>
<td>Water salinity</td>
<td>NA</td>
</tr>
<tr>
<td>Natural drive mechanism</td>
<td>Solution gas expansion, local gas cap expansion, limited aquifer support</td>
</tr>
<tr>
<td>Secondary recovery method</td>
<td>Water injection: main field (1995); Sirikit D (2000); Thap Raet (2001, with frac); Sirikit West (2003, with frac)</td>
</tr>
<tr>
<td>Tertiary recovery method</td>
<td>None</td>
</tr>
<tr>
<td>Improved recovery method</td>
<td>Infill drilling</td>
</tr>
<tr>
<td>Recovery factor</td>
<td>Oil: main field: 19%; Sirikit D: 40%; Thap Raet: 36%; Sirikit West: 31%</td>
</tr>
<tr>
<td>Production well spacing</td>
<td>Main field well spacing: 40-140 ac (400-650 m) (1999)</td>
</tr>
<tr>
<td>Injection rate (date)</td>
<td>Main field: 40,000 BWPD (1996); Sirikit D: ~7600 BWPD (2002); Thap Raet: ~4400 BWPD (early 2003)</td>
</tr>
</tbody>
</table>
### TABLE OF FIELD PARAMETERS
(continued)

<table>
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<tr>
<th>9 - COMPLETION PRACTICE</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Type of completion</strong></td>
</tr>
<tr>
<td>Perforated casing; most wells completed in 2 or more reservoirs, with dual string</td>
</tr>
<tr>
<td><strong>Interval perforated</strong></td>
</tr>
<tr>
<td>Main field: Lan Krabu Zones K, L, M, basement; Sirikit-D, W, Thap Raet: Pradu Tao and Lower Yom</td>
</tr>
<tr>
<td><strong>Well treatment</strong></td>
</tr>
<tr>
<td>NA</td>
</tr>
<tr>
<td>Seismic Stratigraphy</td>
</tr>
<tr>
<td>----------------------</td>
</tr>
<tr>
<td>K10 E10</td>
</tr>
<tr>
<td>K20 E20</td>
</tr>
<tr>
<td>K30 E30</td>
</tr>
<tr>
<td>K40 E40</td>
</tr>
<tr>
<td>E40-L</td>
</tr>
<tr>
<td>L RSVR</td>
</tr>
<tr>
<td>M RSVR</td>
</tr>
</tbody>
</table>

Table 1 - Reservoir stratigraphy, lithologies, thickness, net:gross ratios and reservoir quality, Sirikit Field (Flint et al., 1988).
Table 2 - Reservoir properties of the Pradu Tao and Yom Formations in Sirikit D, Thap Raet and Sirikit West Fields (Chuenbunchom et al., 2003).

<table>
<thead>
<tr>
<th>Reservoir</th>
<th>Property</th>
<th>Sirikit D</th>
<th>Thap Raet</th>
<th>Sirikit West</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>HC</td>
<td>HC</td>
<td>HC</td>
</tr>
<tr>
<td>Lower Yom</td>
<td>Thickness (m)</td>
<td>170-190</td>
<td>150-160</td>
<td>160-220</td>
</tr>
<tr>
<td></td>
<td>Net to gross ratio</td>
<td>0.22-0.36</td>
<td>0.25-0.38</td>
<td>0.15-0.30</td>
</tr>
<tr>
<td></td>
<td>Avg. porosity</td>
<td>0.26-0.28</td>
<td>0.20-0.22</td>
<td>0.16-0.25</td>
</tr>
<tr>
<td>Upper Pradu Tao</td>
<td>Thickness (m)</td>
<td>90-120</td>
<td>170-220</td>
<td>170-260</td>
</tr>
<tr>
<td></td>
<td>Net to gross ratio</td>
<td>0.35-0.70</td>
<td>0.23-0.43</td>
<td>0.13-0.47</td>
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<tr>
<td></td>
<td>Avg. porosity</td>
<td>0.26-0.28</td>
<td>0.19-0.22</td>
<td>0.19-0.24</td>
</tr>
<tr>
<td>Lower Pradu Tao</td>
<td>Thickness (m)</td>
<td>100-120</td>
<td>120-180</td>
<td>230-350</td>
</tr>
<tr>
<td></td>
<td>Net to gross ratio</td>
<td>0.15-0.30</td>
<td>0.33-0.60</td>
<td>0.36-0.70</td>
</tr>
<tr>
<td></td>
<td>Avg. porosity</td>
<td>0.19-0.25</td>
<td>0.19-0.23</td>
<td>0.21-0.26</td>
</tr>
</tbody>
</table>
Figure 1 – Location map of the Sirikit Field, Phitsanulok Basin, Thailand (STPC 1999).
Figure 2 – Map showing location of satellite fields relative to the main Sirikit Field and faults (Chuenbunchom et al., 2003). For location, see Figure 1.
Figure 3 – Cenozoic basins in Thailand (Polachan et al., 1989). Basins formed in the Oligocene and are predominantly north-south trending half grabens. See Figure 5 for cross-section A-A’.
Figure 4 – Location of the Phitsanulok Basin relative to major strike-slip faults and other regional tectonic elements (Polachan et al., 1991).
Figure 5 – W-E cross-section through the Phitsanulok Basin, showing the asymmetric half graben, Western Boundary Fault and eastwards pinch-out of sedimentary units (Flint et al., 1988). See Figure 3 for the location of section.

Figure 6 – Location of the Phitsanulok Basin relative to the Uttaradit and Mae Ping fault zones (Flint et al., 1988).

Figure 7 – Top L Member depth-structure map for main Sirikit Field (Flint et al., 1988).

Figure 8 – W-E 3-D line 346 used for interpretation in Figure 9 (Brooks, 1987). See Figure 7 for location of the section.
Figure 9 – Geoseismic section based on W-E 3-D seismic line 346 shown in Figure 8, showing main reservoirs, pools, fluid contacts, seals and faults within the main Sirikit Field (Brooks, 1987). See Figure 7 for location of the section.
<table>
<thead>
<tr>
<th>AGE</th>
<th>FORMATION</th>
<th>THICKNESS (UP TO)</th>
<th>LITHOLOGY</th>
<th>DESCRIPTION</th>
<th>ENVIRONMENT</th>
</tr>
</thead>
<tbody>
<tr>
<td>LATE Miocene - Recent</td>
<td>PNG</td>
<td>1,300 m</td>
<td>SANDS/GRAVELS WITH ASSOCIATED CLAYS</td>
<td>Sands, clear, white, coarse grained, occasionally gravel.</td>
<td>Alluvial Fan &amp; Alluvial Plain</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Gravels, variegated, lithic</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Clays, varicoloured, sandy, silty</td>
<td></td>
</tr>
<tr>
<td>MIDDLE Miocene - LATE Miocene</td>
<td>YOM</td>
<td>1,600 m</td>
<td>SANDS/CLAYS</td>
<td>Sands, clear, white, coarse grained, occasionally gravel.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Clays, varicoloured, sandy, silty</td>
<td></td>
</tr>
<tr>
<td>EARLY Miocene - MIDDLE Miocene</td>
<td>PRATU TAO</td>
<td>2,200 m</td>
<td>SAND (STONES)/CLAY (STONES)</td>
<td>Sand (stones), clear, white, fine-coarse grained</td>
<td>Ephemeral Lacustrine &amp; Fluvial</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Clay (stones), redbrown, varicoloured, sandy, silty</td>
<td></td>
</tr>
<tr>
<td>EARLY Miocene - EARLY Miocene</td>
<td>LAN KRABU - NONG BUA</td>
<td>2,200 m</td>
<td>CLAYSTONES AND SILTSTONES/SANDSTONES</td>
<td>Claystones and siltstones, grey, silty, occasionally gastropod-bearing and</td>
<td>Lacustrine &amp; Fluvialacustrine</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>carbonaceous</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Sandstones, clear, white, grey, fine-medium grained, thinly bedded</td>
<td></td>
</tr>
<tr>
<td>OLIGOCENE - EARLY Miocene</td>
<td>SARABOP - NONG BUA</td>
<td>1,200 m</td>
<td>CLAYSTONES</td>
<td>Claystones, redbrown, occasionally grey to varicoloured, with minor coarse-fine lithic sandstones</td>
<td>Fluvial &amp; Ephemeral Lacustrine</td>
</tr>
<tr>
<td>PRE-TERTIARY BASEMENT</td>
<td></td>
<td></td>
<td>MESOZOIC - PALEOZOIC CLASTIC, CARBONATE, VOLCANICLASTIC IGNEOUS, AND METAMORPHIC ROCKS</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Figure 10 – Stratigraphy of the Phitsanulok Basin (Knox and Wakefield, 1983).
Figure 11 – Reservoir stratigraphy of the Lan Krabu and Sarabop Formations, Sirikit Field (Ainsworth et al., 1999), showing seals, sequences and parasequences.
<table>
<thead>
<tr>
<th>FORMATION</th>
<th>MEMBER</th>
<th>RESERVOIR SUBDIVISION</th>
<th>GAMMA RAY</th>
<th>Depth (m)</th>
<th>SONIC</th>
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</thead>
<tbody>
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<td>L K1</td>
<td>L1</td>
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<td>L2</td>
<td>L2</td>
<td>M</td>
<td></td>
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<td>L6</td>
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</tr>
<tr>
<td>M K1</td>
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<td>M</td>
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<td>K2</td>
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**Figure 12** – Typical log for Sirikit Field (Brooks 1987), showing GR, DT, reservoir units, seals and oil and gas zones.
Figure 13 – Summary of the stratigraphy of the Phitsanulok Basin along a S-N section, including the Sirikit Field (Ainsworth et al., 1999).

Note the interfingering of the source rocks of the Chum Saeng and reservoirs of the Lan Krabu Formations.

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Figure 14 – Structure map for Sirikit West. Depths and contour interval are not stated but the crest is at ~1980 m TVDSS. The eastern fault was active during deposition of the reservoir intervals and is referred to as the main boundary fault or W60 fault complex (Chuenbunchom et al., 2003).
Figure 15 – Seismic amplitude map of Sirikit for an horizon 36 msec TWT above the top of member L of the Lan Krabu Formation. The high amplitudes (orange) indicate the presence of a ~16 m-thick sandstone wedge in the Upper Intermediate Seal (UIS) in the NW of the main field (Flint et al., 1988). © 1988 American Association of Petroleum Geologists. All rights reserved. Reprinted with permission of American Association of Petroleum Geologists.
<table>
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Figure 16 – Summary of the occurrence of oil and gas in the Yom and Pradu Tao Formations in Sirikit and satellite fields and in older formations (Chuenbunchom et al., 2003).
Levee on upper part of simple midchannel bar

Composite mid-channel bar

Overbank channels

Major channel

Top underlying delta cycle

Coalescent (dissected) mouth bars

Prodelta

Note: no implied lateral scale

Figure 17 – 3-D depositional model for Lan Krub Formation: a highly constructive, lobate, lacustrine delta (Flint et al., 1988).

Figure 18 – Reservoir facies and environmental interpretation in the K Member of Sirikit Field based on log and core analyses of well LKUE-07 (Flint et al., 1988).
Figure 19 – Correlation of sandstone bodies in the L Member across part of Sirikit Field using GR, DT and synthetic seismograms (Flint et al., 1988). © 1988 American Association of Petroleum Geologists. All rights reserved. Reprinted with permission of American Association of Petroleum Geologists.
Figure 20 – (A) Gamma ray and sonic logs, synthetic seismogram, seismic horizons and sequences for the K and upper L Members in well LKU E-03 (Flint et al., 1988). (B) E10-E20 seismic isochron map for main Sirikit Field extracted from 3-D seismic survey, showing the thinning of the main K20 reservoir interval towards the N and NW (Flint et al., 1988). Map covers the same area as Figure 7.

Figure 21 – Comparison of (A) lithostratigraphic with (B) chronostratigraphic correlations showing also the consequent differences in sweep efficiencies (C & D), the potential need for infill wells and the potential benefit of perforating the heterolithics (Ainsworth et al., 1999).

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Figure 22 – Vertical sections from a 3-D reservoir simulation model, Sirikit Field, showing (A) the lithostratigraphic model facies and lithology; (B) the chronostratigraphic model facies and lithology; and (C) the chronostratigraphic model with stochastically derived porosity from core plugs (Ainsworth et al., 1999). © 1999 American Association of Petroleum Geologists. All rights reserved. Reprinted with permission of American Association of Petroleum Geologists.
Figure 23 – Core and average porosity and net to gross ratio, K Member, well AO4-A, Sirikit Field, (Ainsworth and Sankosik, 1998).
Continuous Sands ~ Mouth Bar Sands
- Large drainage area
- Poorer reservoir quality
- Lower decline rate

Discontinuous Sands ~ Channel Sands
- Smaller drainage area
- Good reservoir quality
- Higher decline rate

Figure 24 – Porosity versus permeability cross-plot, with mouthbar and channel sandstones indicated, for three wells (A-01, E-02 and F-01) in the main Sirikit Field (Flint et al., 1988).

Figure 25 – Porosity versus permeability cross-plot for reservoirs B, C and D in the Yom and Pradu Tao Formations in Sirikit West Field (Walsh et al., 2001). Highlighted data (A): data from Reservoir D seems to lie on a different trend relative to the other reservoirs; (B): some anomalously high permeabilities in Reservoir B may be due to poor sample preparation.
Figure 26 – Production profile for Sirikit Field and satellites (OGJ, 1981-2005).
Figure 27 – Production profile for Sirikit-D block (Chuenbunchom et al., 2003).
Figure 28 – (A) cartoon map of Sirikit-D showing well locations relative to OWC, (B) cartoon cross-section showing perforated intervals (Chuenbunchom et al., 2003).
Figure 29 – Production profile for well LKU-D14 in Sirikit-D (Chuenbunchom et al., 2003).
Figure 30 – Production profile for Thap Raet Field (Chuenbunchom et al., 2003).