## 7.4 Resources Beyond the 2P and 2C Categories - Australia Assets

### 7.4.1 Brief Geology of Bonaparte Basin

The Bonaparte Basin (adapted from Geoscience Australia) represents the easternmost offshore province of Australia's North West Shelf comprising also the Browse, Roebuck, Offshore Canning, and Northern Carnarvon basins. Located offshore, the Bonaparte Basin contains a Paleozoic, Mesozoic and Cenozoic sedimentary succession that exceeds 15,000 m in thickness in the southern portion ("Petrel Sub-basin") and a Mesozoic-Cenozoic basin fill in the northern part (Figure 5-1, Figure 5-2 and Figure 7-59). The basin has been an established oil and gas province since the development of the Bayu-Undan and Blacktip gas discoveries (1995 and 2001 respectively) and first oil discoveries in the Vulcan Sub-basin (Jabiru in 1986; Challis and Cassini in 1989).

#### 7.4.1.1 Basin Outline

The Bonaparte Basin belongs to a series of extensional basins, which formed during late Paleozoic-early Mesozoic rifting in the context of Gondwana break-up. In the northeast, beyond the limits of the Darwin Shelf, the Bonaparte Basin adjoins the Money Shoal Basin and to the southwest it is contiguous with the Browse Basin. The basin's northwestern border is the Timor Trough (Figure 7-59), which defines the tectonic boundary between the Australian plate and Banda orogen.

#### 7.4.1.2 Basin Evolution

The Bonaparte Basin developed during two phases of Paleozoic extension, followed by Middle–Late Triassic compression and further extension in the Mesozoic that culminated in the breakup of Gondwana in the Middle Jurassic (O'Brien et al, 1993). Thermal subsidence in the Early Cretaceous developed a thick, prograding wedge of siliciclastic and carbonate sediment. Preliminary post-survey analysis and modelling of the WestraliaSPAN seismic data suggest that rifting in the Bonaparte Basin has been more extreme than previously reported (Pryer et al, 2014, 2015).

Convergence of the Australia-India Plate and Southeast Asian microplates in the Neogene resulted in lithospheric flexural downwarp of the Timor Trough and widespread fault reactivation across the Bonaparte Basin, which is particularly evident in the northwest. The convergence and associated uplift and erosion has created thick sedimentary deposits in the Cartier and Nancar troughs and Malita Graben (Keep et al, 2002, 2007; Langhi et al, 2011).

The Bonaparte Basin contains several sub-basins and regional structural elements (Figure 7-59) each of which represents a distinct geologic domain. Within the held permits of AC/P68 and AC/P69 the geological areas are represented by the Vulcan Sub-basin and Londonderry High of the greater Bonaparte Basin described below.

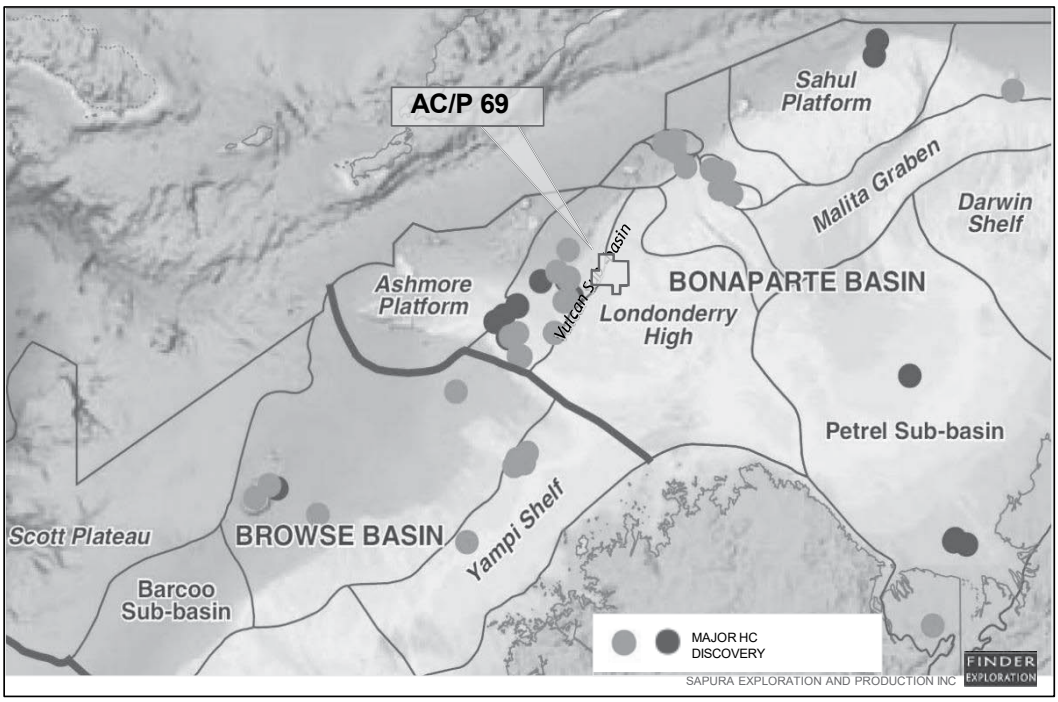


***Figure 7-59: The General Tectonic Setting in Relation To AC/P-61 Block (after Finder).***

### 7.4.1.3 Vulcan Sub-basin

The Vulcan Sub-basin is a major northeast-trending Late Jurassic extensional depocenter in the western Bonaparte Basin. The sub-basin comprises a complex series of horsts, graben and marginal terrace sand is flanked by the Permo-Triassic platforms of the Londonderry High and the Ashmore Platform to the southeast and northwest, respectively (Figure 5-2 and Figure 7-59). The proven hydrocarbon provinces of the Swan Graben and Paqualin Graben terminate in the northeast beneath the Neogene Cartier Trough. The Montara Terrace flanks the Swan Graben to the east, while the Jabiru Terrace borders the eastern margin of the Paqualin Graben and Cartier Trough. The boundary between the southern Vulcan Sub-basin and the northern Browse Basin (Caswell Sub-basin) is poorly defined. O'Brien et al (1999) considered the boundary to be a fault relay zone that overlies a major northwest-trending Proterozoic fracture system. The suggested abutting Abalone Sub-basin, in the north of the Caswell Sub-basin, is based on Proterozoic and Paleozoic structural trends identified in gravity and seismic data (Lawrence et al, 2014), and may have implications for sediment transport pathways in the area.

Structural evolution, O'Brien (1993) described the Vulcan Sub-basin as forming part of a single upper plate rift margin. This margin comprises orthogonal to northeast-trending normal faults linked by northwest-trending accommodation zones (Etheridge and O'Brien, 1994; O'Brien et al, 1996; O'Brien et al, 1999). Deposition during the basin's thermal sag phase continued until the late Neogene and resulted in the accumulation of over 10000 m of sediments in the deeper graben, such as the Swan Graben (Baxter et al, 1997). Mesozoic extension in the Vulcan Sub-basin commenced in the late Callovian, coincident with the onset of seafloor spreading in the Argo Abyssal Plain to the southwest, and continued through to the Tithonian (Pattillo and Nicholls, 1990; O'Brien et al, 1996a). Initial extension in the late Callovian–early Oxfordian created a broad graben. During the mid-Oxfordian to early Kimmeridgian, faulting was focused on the western portion of the sub-basin, forming the deep, narrow Swan and Paqualin graben where thick Oxfordian marine source rocks accumulated. The Jabiru, Challis and other intra-basinal horsts were semi-emergent to emergent at this time. Early Kimmeridgian–early Tithonian marine sediments are presently restricted to the main graben

depocenters, but probably extended across the adjoining terraces to the east, prior to uplift and erosion in the Tithonian.

Mid-Tithonian structuring resulted in uplift and erosion of the flanking eastern terraces and central horst blocks, whereas marine deposition continued in the Swan and Paqualin graben. The dominant northeast-southwest oriented fault trend was overprinted in the northern portion of the sub-basin by east-trending faults at this time, which resulted in the development of 'hourglass' horsts and graben (Woods, 1992). Fitall and Cowley (1992) and Woods (1992) suggested that this Tithonian structuring was extensional in nature, whereas O'Brien et al (1993) argued for a more transpressive intra-plate stress origin.

Post-rift regional thermal subsidence commenced in response to Valanginian breakup, and was marked by the deposition of a thick Cretaceous–Cenozoic succession. A condensed Valanginian–Barremian section is confined largely to the graben and adjoining terraces, but with continuing subsidence during the Aptian–Albian, marine sediments transgressed the adjacent, previously emergent, areas of the Londonderry High and Ashmore Platform. Upper Cretaceous marine carbonates are widespread across the region, and their progradation marks the termination of the transgressive peak of the post-rift succession. The Cenozoic succession was characterised by the establishment of a sub-tropical carbonate platform, and as the Australian Plate continued to move northward, culminated in the development of tropical carbonates, banks, and reefs.

The late Miocene–Pliocene was characterised by the convergence of the Australian and Eurasian plates to the northwest. This resulted in flexural downwarp of the Australian margin at the Timor Trough and widespread reactivation of the previous extensional fault systems (Woods, 1992; Shuster et al, 1998).

The presence of salt in the Vulcan Sub-basin was established with the drilling of Paqualin-1 (1989). The well intersected a pre-Permian salt layer at considerable depth, indicating that the Vulcan Sub-basin has an affinity with the Petrel Sub-basin to the east where salt diapirs are more widespread (Woods, 1994). Structural analysis indicates that the salt at Paqualin began to move and form salt pillows in the Late Jurassic, while

salt diapirism occurred towards the end of the Miocene. The timing of these two main phases of salt movement coincided with the two major tectonic events in the region: the breakup of the Australian northwest continental margin, and the collision between the Australian and South East Asian plates.

The margins of the depocenter are characterised by northeast-striking faults. The impact of repeated episodes of fault reactivation on the preservation of petroleum accumulations varies widely. Trap breach, vertical and lateral water migration, secondary migration of oil and gas flushing all occur in parts of the sub-basin (O'Brien et al, 2003).

#### 7.4.1.4 Stratigraphy

The stratigraphy of the Vulcan Sub-basin has been compiled from Mory (1988), Osborne (1990), Pattillo and Nicholls (1990), and Gorter et al (2009) and has recently been updated to the geological timescale after Ogg et al (2016). The Kinmore Group (Mory, 1988, 1991; Gorter, 1998) marks the top of 'uneconomic basement' in the Vulcan Sub-basin (Figure 7-63). A continuous high-amplitude seismic reflector produced by a limestone bed near the top of the Hyland Bay Sub-group is a key marker for the top of the Permian, and as a signature for deep-basinal architecture over much of the Bonaparte Basin. The uppermost claystone unit of the Kinmore Group, the Mt Goodwin Sub-group straddles the Permo-Triassic boundary (Gorter et al, 2009) and passes vertically into the Middle-Upper Triassic Sahul Group. The Sahul Group comprises the Osprey, Pollard, Challis, and Nome formations. The Osprey Formation consists predominantly of turbidites that grade upwards into deltaic sediments. The overlying Pollard Formation consists of shallow marine sandstones. Clastic and carbonate sediments of the Challis Formation succeed the Pollard Formation, and represent a shoreline sequence with complex lateral facies relationships. The Challis Formation is petroleum-bearing at the Challis–Cassini and Talbot accumulations. The overlying Nome Formation comprises delta front to delta plain sediments, which resulted from the progradation of a major deltaic lobe across the platform during the Late Triassic.

The Sahul Group is unconformably overlain by the thick Lower–Middle Jurassic Plover Formation (Troughton Group), which was deposited following Late Triassic uplift and erosion. The Plover Formation comprises deltaic and barrier bar sandstones, siltstones, shales, and coals. The top of the Plover Formation sandstone facies, as intersected by wells in the northern and western Bonaparte Basin, represents a widespread transgressive surface. This surface marks the termination of deltaic sedimentation and the onset of shallow marine shelf deposition. Regionally, this is interpreted to mark a phase of increased rifting leading into the breakup event along the Argo margin in the Callovian. The Upper Jurassic–Lower Cretaceous Swan Group overlies the Callovian Unconformity and comprises the Montara and lower and upper Vulcan formations. The Swan Group contains organic-rich source rocks which have been correlated with a significant proportion of the hydrocarbons found in the offshore Bonaparte Basin (Edwards et al, 2004). The Montara Formation comprises prograding fan-delta sandstones that fringe the southeast flanks of the Vulcan Sub-basin. Laterally equivalent to these sediments are low-energy marine deposits that represent major source rock accumulations. Continued extension and faulting through the Oxfordian to the Tithonian resulted in widespread marine conditions in the Vulcan Sub-basin, and the deposition of restricted marine shales and more localised fan systems of the Vulcan Formation.

Post-rift thermal subsidence resulted in widespread flooding of the continental margin and deposition of the Valanginian–Maastrichtian Bathurst Island Group. The basal unit of this group, the Valanginian–Aptian Echuca Shoals Formation, comprises largely glauconitic claystones and minor sandstones. From the Aptian to the Campanian, fine-grained clastic sediments and carbonates were deposited as part of a shelf-to-slope facies assemblage. In the late Campanian, a sea-level lowstand resulted in the development of a channel-fed submarine fan system (Puffin Formation) in the southern Vulcan Sub-basin.

Subtropical and tropical carbonates accumulated in the Paleogene and Neogene (Woodbine Group). Sedimentation was interrupted by a major Oligocene hiatus that is recognised throughout the North West Shelf. Sea-level lowstands during the early Eocene and Miocene resulted in prograding sand-prone shoreline facies and localised submarine fans (Grebe Sandstone Member and the Oliver Formation, respectively).

### 7.4.1.5 Londonderry High

The Londonderry High is a submerged basement block separating the Petrel Sub-basin in the east from the Vulcan Sub-basin in the west (Figure 2 and Figure 3). Its northern boundary is abutted by the Sahul Syncline. Basement rocks are onlapped by upper Paleozoic and Mesozoic sediments which are preserved as part of a strongly faulted horst and graben complex. Uplift during the Late Jurassic rifting provided the sediment source for adjacent depocenters (Whibley and Jacobsen, 1990; de Ruig et al, 2000).

The stratigraphy of the Londonderry High is essentially similar to that in the Vulcan Sub-basin, however deposition was interrupted during the Fitzroy Movement in the Late Triassic which led to inversion and deep erosion of previously accumulated basin fill sequences. Subsequent to tectonic inversion, the large deltaic system represented by the Plover Formation covered much of the Londonderry High during the Jurassic. This succession is overlain by a relatively unfaulted Upper Jurassic and younger sediments. There is evidence of fault reactivation in the Miocene.

### 7.4.1.6 Regional Petroleum Systems

Numerous petroleum systems of Paleozoic and Mesozoic age have been mapped within the Bonaparte Basin by combining geochemical studies of hydrocarbon families with their postulated source rocks, interpreted from geological and palaeogeographic studies. Bradshaw (1993) and Bradshaw et al (1994, 1997, 1998) developed petroleum systems and supersystems framework linking together Australian basins of similar age, facies, structural history, and generated hydrocarbons. Each petroleum system within a supersystem is defined by a combination of play elements separated by either tectonic and/or climatic events. The Oils of Western Australia studies (AGSO and GeoMark, 1996; Edwards and Zumberge, 2005) put the geochemically defined oil families from the Bonaparte, Browse, Canning, Carnarvon, and Perth basins into this framework. The following petroleum systems are recognised in the Bonaparte Basin:

- Lower Cretaceous-sourced petroleum system (Westralian 3)
- Upper Jurassic-sourced petroleum system (Westralian 2)
- Lower–Middle Jurassic-sourced petroleum system (Westralian 1)

- Permian-sourced petroleum system (Gondwanan 1)
- Lower Carboniferous (Mississippian)-sourced petroleum system (Larapintine 4)
- Upper Devonian-sourced petroleum system (Larapintine 3).

Revisions and remapping of all systems are required as new data from the basin becomes available. In particular, numerous hydrocarbon charges have been expelled from the Permo-Carboniferous system in the southern Petrel Sub-basin, as exemplified by gas at Blacktip and Penguin, and significant oil and gas shows at the Turtle and Barnett accumulations, and Marina 1 and Torrens 1. However, the source potential of the Carboniferous to Permian Langfield, Weaber, Kulshill and Kinmore groups is not well understood and the source potential of older Paleozoic rocks needs more analysis.

Geochemical analysis of the palaeo-oil column in the Permian Hyland Bay Subgroup at Torrens 1 (Londonderry High), gas/condensate in the Hyland Bay Subgroup at the Petrel-Tern fields (Petrel Sub-basin) and dry gas in the same unit at Kelp Deep 1 (Sahul Platform) suggests a land-plant-rich source in the Permian (Kennard et al, 2000).

### 7.4.2 AC/P69 (Birdwing)

Petroleum Exploration Permit AC/P69 is situated in relatively shallow waters within the Vulcan Sub-basin of the Bonaparte Basin, offshore northern Western Australia. The area covers 1,430.6 km$^2$ and consists of 16 full graticular blocks and one partial block. It is located in water depths of between 120 to 340 m in the Vulcan Sub- basin, Western Bonaparte Basin in the Timor Sea, approximately 250 km offshore and 650 km from Darwin off the Northwest coast of Western Australia.

The permit area is surrounded by oil discoveries, i.e. the Tenacious oil field (yet to be developed) to the West, the depleted Jabiru oil field to the south (which produced 120 MMstb of oil) and the yet-to be-developed Audacious oil field to the east. The Oliver gas/oil discovery is located to the North and the Cash/Maple gas field complex is approximately 30 km to the west. Figure 7-60 shows the location of the permit and the surrounding discoveries.

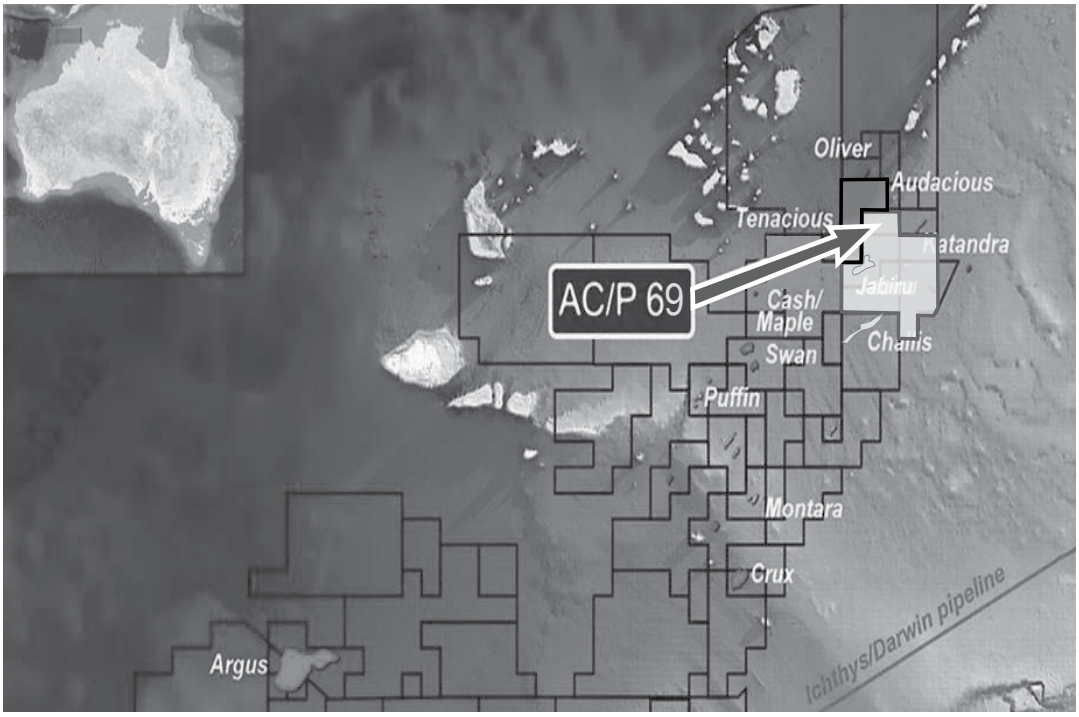


***Figure 7-60: AC/P69 Location Map (Source: SOMV).***

The block is located northeast of the Londonderry High at the eastern edge of the Vulcan Sub-basin (Figure 5-2, Figure 7-59 and Figure 7-60). The permit contains the intra-graben Jabiru horst block depleted field and currently no reported mapped prospects, and if presence is likely, the Jabiru or Challis horst block look-a-like features of Jurassic Oxfordian. The permit is fully covered by the Onnia 3D seismic survey. A broadband pre-Stack Depth Migration reprocessing effort will include the adjacent offset well ties from the Oliver, Tenacious to Audacious oil and gas fields for full permit coverage (Figure 7-61).

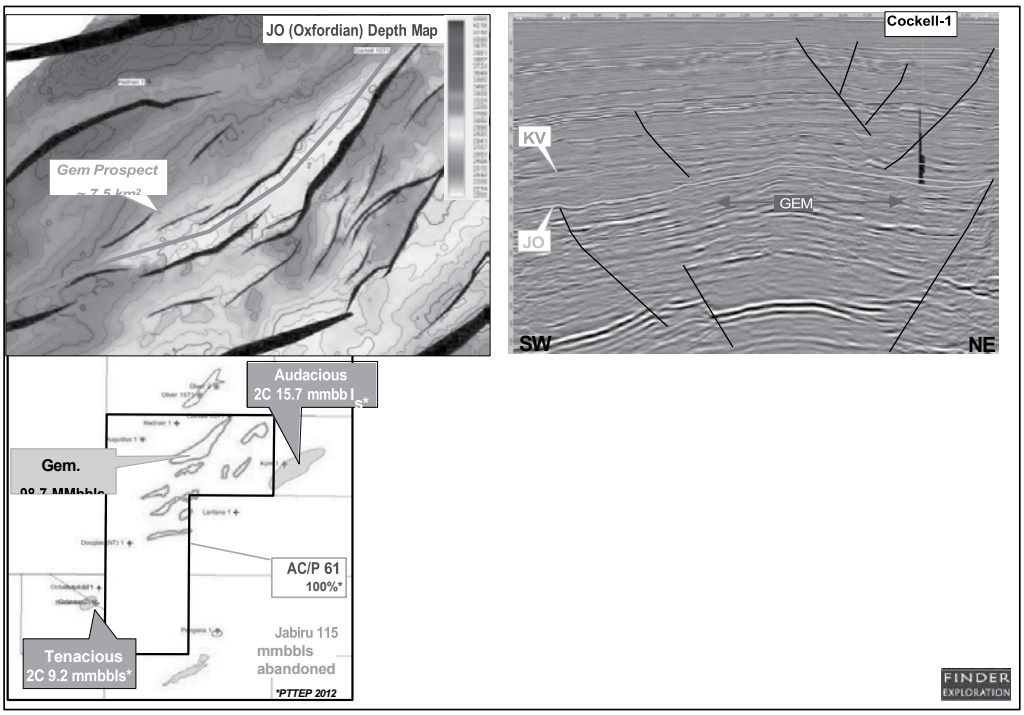


***Figure 7-61: AC/P69 – Look-A-Like Of AC/P61 Gem Prospect Structure and Seismic Section (after Finder).***

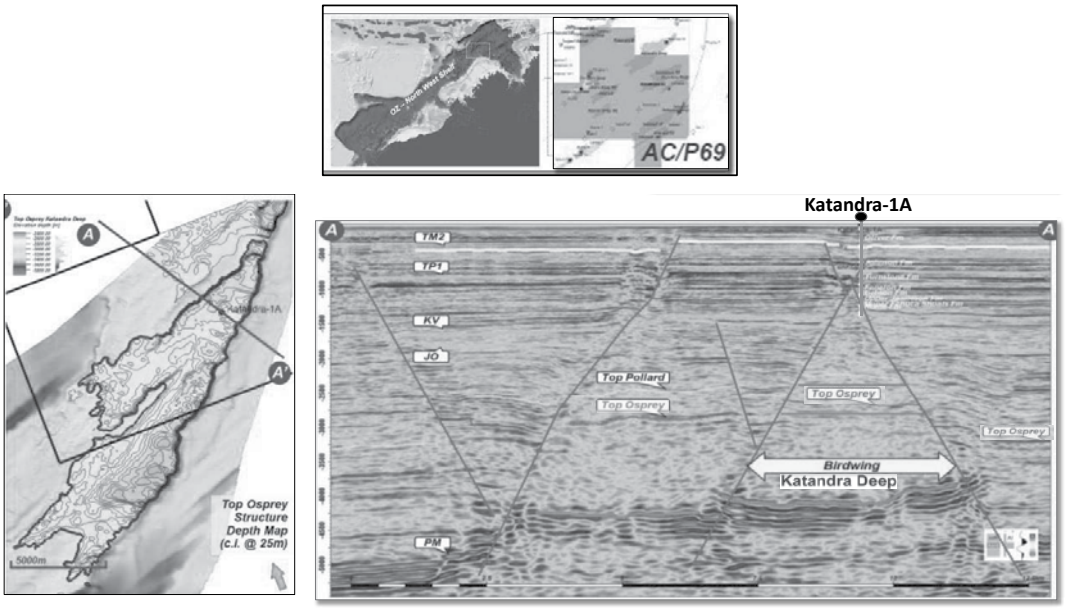


***Figure 7-62: AC Birdwing Lead (Katandra Deep) structure mapped below Top Osprey horizon in AC/P69 (after SOMV).***

AC/P69 main reservoir system is Plover fluvio-deltaic sealed by upper Jurassic basin claystone. Upper Vulcan Tithonian reservoirs (i.e., Tenacious, Octavius etc.) not present over Gem prospect (look-a-like), and basinal claystone rich facies is interpreted in the area. Reservoir and trap play elements are interpreted to be low risks (Figure 7-62 and Figure 7-63).

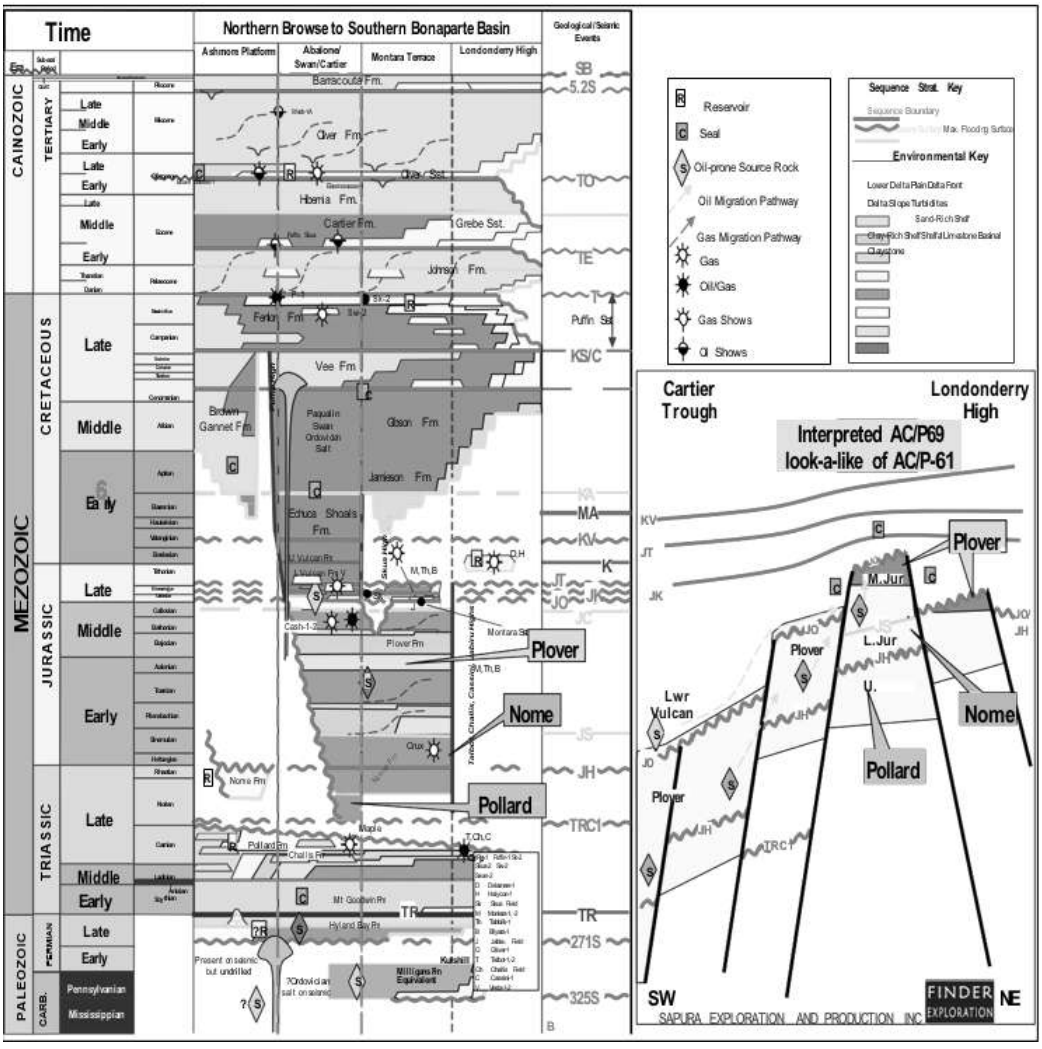


***Figure 7-63: AC/P69 Stratigraphy and Schematic interpreted similar to AC/P61 - Proposed Gem Prospect Play Types (after Finder).***

Most of the identified traps are primarily fault dependent (occasionally at fault junction, e.g., Gem), and anticlinal closures for the relatively smaller traps. The key

play element risks are trap/seal and charge in the $P_g$ (geological chance of success) estimation.

The Petroleum Exploration Permit was granted as "Release Area AC19-3" for a period of six years, with scheduled work commitments shown in Table 7-20. Permit Years 1 – 3 included full licensing of NOVAR MC3D seismic data, geotechnical studies and acquisition or licencing of new 3D seismic data. Permit Years 4 – 6 comprised various geotechnical studies, well planning and drilling of one exploration well including post well studies. In March 2023, the joint venture was to issue a 12-month suspension and extension to the OCR (Operating Committee Resolution) to the permit to manage the permit work obligations in view of the difficulty to secure approvals for Environmental Plan following Barossa/Tiwi Island Federal Court case. For WPB 2023, G&G work was included to complete the minimum work obligations which were not carried out in 2022. As an update, the operator confirmed that the letter for extension of PSC commitment or application for suspension and extension was under preparation (update in September 2023). There is a commitment by the joint venture to carry out 3D seismic on an area of 1,362 $km^2$ by June 2024. Based on the information available, EQ has placed the classification of resources for the Birdwing prospect in the Prospective category.

| Year | Start Date | End Date | Activity Description | Remarks |
|---|---|---|---|---|
| 1 | 16/6/2021 | 15/6/2024 | 1408$km^2$ Full JV Licencing of Novar MC3D seismic data. Phase 1 geotechnical studies including seismic interpretation of Novar MC3D seismic data, fault seal analysis, planning new 3D seismic survey, offset well analysis and petroleum modelling | |
| 2 | 16/6/2021 | 15/6/2024 | 1,362 $km^2$ acquire or licence new 3D seismic data | Extension of 12 months to cater for uncompleted work in 2022. Application ongoing |
| 3 | 16/6/2021 | 15/6/2024 | Phase 2 geotechnical studies including seismic interpretation of new 3D seismic data, prospect and lead generation and play analysis | |
| 4 | 16/6/2024 | 15/6/2025 | Geotechnical studies including well planning | |
| 5 | 16/6/2025 | 15/6/2026 | Drill one exploration well | |
| 6 | 16/6/2026 | 15/6/2027 | Geotechnical studies, including post-well studies | |

***Table 7-20: AC/P69 Exploration Work Commitments (Source: SOMV).***

## 7.5 Resources Beyond the 2P and 2C Categories – Production Flowstreams (Toutouwai and Kan)

From the information available, the flowstream for Kan was extracted from a preliminary MBAL model generated (from TCM May 2023), whilst the flowstream for Toutouwai was based on the profiles generated using Type Curve analysis based on offset field Maari which is under depletion drive (from Annex 1: PAS/PAN Review support pack Oct 2020). For the purpose of valuation, these production flowstreams are associated with the potential developments from Toutouwai (New Zealand) and Kan (Mexico) assets which may be included, incorporating a risked value to reflect the chance of development. The production flowstreams for Toutouwai and Kan are depicted in Figure 7-64 and Figure 7-65 , respectively. Note that the figures shown for Toutouwai are on Working Interest (WI) basis, i.e., at 30% of gross, to reflect the equity owned by SOMV.

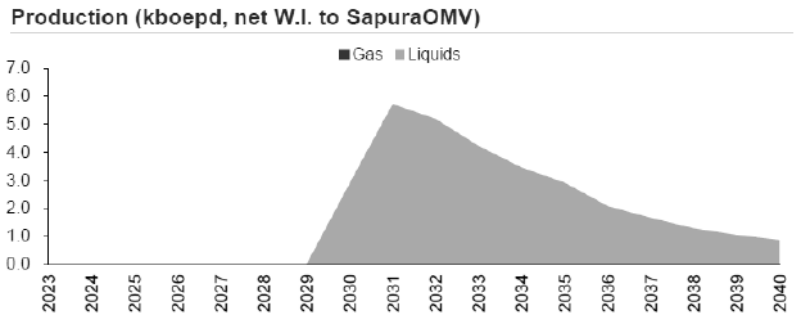


***Figure 7-64: Production forecast for Toutouwai (Source: SOMV).***

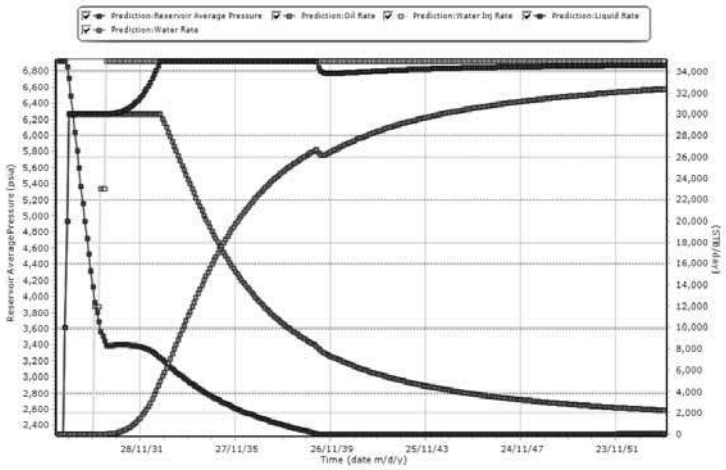


***Figure 7-65: Production forecast for Kan (Source: TCM 2023).***

## 8 Summary

This Competent Person's Report (CPR) provides an independent technical review of the geological, geophysical, petrophysical and engineering data of SOMV's assets under various contracts, comprising a list of fields across several countries (Malaysia, New Zealand, Mexico, and Australia). A separate Competent Valuer's Report (CVR) is also prepared to present the commercial valuation for the assets. The purpose of the CPR and CVR is to prepare an independent technical expert report and independent valuation report in respect of SapuraOMV Group's Oil and Gas (O&G) reserves and resources for the proposed disposal by Sapura Upstream Assets Sdn. Bhd., a wholly-owned subsidiary of the SEB, of its entire 50% in SapuraOMV Upstream Sdn. Bhd. (SapuraOMV or SOMV). SapuraOMV is a 50:50 joint venture between SEB and OMV Aktiengesellschaft.

The assets include four gas fields which have been put on production in Malaysia PSC Blocks SK408 (Larak, Bakong and Gorek, i.e., LaBaGo fields) and SK310 (B15 field), one gas field currently under development in SK408 (Jerun field), two gas fields planned for development in SK408 (Teja and Pepulut fields), and also discoveries and potential exploration prospects in Malaysia, New Zealand, Mexico, and Australia. As of end December 2023, the estimated cumulative gas production (sales and non-sales) from the SK408 and SK310 is around 526 Bscf and 253 Bscf, delivering an average production of around 437 MMscfd and 133 MMscfd of gas sales in December 2023, respectively.

Standard geological and engineering techniques generally accepted by the petroleum industry were used in estimating the Petroleum Initially-in-place (PIIP) and recoverable hydrocarbons, in accordance with the fundamental principles for the evaluation and classification of petroleum reserves and resources provided in the 2018 Petroleum Resources Management System (PRMS).

The effective date of this CPR is 1st January 2024, and the recoverable volumes are expressed as estimated gross and net resources, reported as of end December 2023. Gross resources are defined as the total estimated hydrocarbon to be produced in the event of exploration and/or production success, subject to economic limit. In this CPR,

the Gross reserves and resources reported post Economic Limit Test (ELT) i.e., 2040 for SK408 (end of PSC period) and 2027 for SK310 (facilities decommissioning planned in the same year). Net Working Interest is defined as that portion of gross resources attributable to SEB's working interest of those produced quantities. Net Entitlement is tabulated by PSC, and the figures are extracted from the work conducted by Energy Quest Sdn. Bhd., documented in the "Competent Valuer's Report (CVR) on SapuraOMV Upstream Sdn Bhd ("SapuraOMV") Assets and Hydrocarbon Resources prepared for the Proposed Divestment of Sapura Energy Berhad ("SEB") 50% Equity in SapuraOMV", of which the effective date is consistent with this CPR.

.

2P Reserves comprise Developed Reserves from the existing producing wells at Larak, Bakong, Gorek and B15 fields, and Undeveloped Reserves from producing gas fields resulting from production enhancement initiatives i.e., the planned Bakong Phase-II development project, and recoveries associated with the ongoing Jerun gas field development. As of end December 2023, the gross Reserves (2P) from the gas fields in SK408 (LaBaGo and Jerun) and SK310 (B15) are assessed to be 3,386 Bscf (891 Bscf Developed and 2,495 Bscf Undeveloped) and 43 Bscf (all Developed), respectively. For the purpose of valuation, the Best Estimate (2P i.e., P50) is utilized, whilst the Low (1P i.e., P90) and High (3P i.e., P10) estimates are only run as sensitivities.

2C Contingent Resources are from the planned gas development projects in Malaysia PSC Block SK408 (Teja and Pepulut fields), based on the assessment of SOMV's ongoing work to mature the FDPs and secure the GSA approval from the governing authorities. As of end December 2023, the gross 2C Contingent Resources from PSC Block SK408 (Teja and Pepulut fields) is assessed to be 455 Bscf.

As of end December 2023, the estimated Gross and Net Reserves and Resources are summarized in Table 8-1 (Gas, Bscf), Table 8-2 (Condensate, MMstb), Table 8-3 (Plant Liquid Return, PLR, MMstb) and Table 8-4 (Total, MMboe).

For Teja field, the calculated net figures reflect 40% Working Interest (WI) and 80% of the gross total field volume (i.e., the SK408 portion of the field area by applying the

agreed 80%/20% split between SK408 and SK316). Note that the conversion used to convert Bscf to MMboe is 6 Bscf = 1 MMboe.

Less information was available for the opportunities, discoveries and exploration potential and less focus was given. Potentials identified in the assessment include the followings, and are summarized by their respective resource category in Table 8-5:

- Opportunities identified from notional projects (e.g., Bakong Study which assumes the availability of additional sweet gas for blending, reserves acceleration from Jerun Optimization project, and viability of Jerun Talus development (currently pending Jerun appraisal post-drill evaluation)
- Discovered resources categorized as Contingent Resources with a lower sub-class category, where the development is deemed to be either "On Hold" or "Unclarified" (i.e., resources that are potentially recoverable but require further appraisal and maturation to be considered viable for development commercially, e.g., discoveries in Malaysia PSC Block SK408 (Jarak, Legundi and Jeremin), New Zealand (Toutouwai) and Mexico (Kan).
- Prospective Resources from undrilled exploration opportunities i.e., resources that are potentially recoverable from exploration blocks in New Zealand, Mexico, and Australia, and also from the recently signed PSC for exploration block SB412 offshore Sabah, in Malaysia.

| | | Gross* | | | | | | | | Net Working Interest (SEB) | | | | | | | Net Entitlement (SEB) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Malaysia, PSC Block** | **Fields** | **Cumulative (Sales + Non-Sales)** | **1P** | **2P** | | **3P** | **1C** | **2C** | **3C** | **1P** | **2P** | | **3P** | **1C** | **2C** | **3C** | **1P** | **2P** | **3P** | **1C** | **2C** | **3C** |
| | | | | **Dev** | **Undev** | | | | | | **Dev** | **Undev** | | | | | | | | | | | |
| SK408 | Larak | 150.9 | 229.0 | 280.1 | 0.0 | 335.5 | 0.0 | 0.0 | 0.0 | 45.8 | 56.0 | 0.0 | 67.1 | 0.0 | 0.0 | 0.0 | 349.3 | 386.0 | 395.3 | 33.0 | 56.8 | 75.0 |
| | Bakong | 235.6 | 623.5 | 427.0 | 289.3 | 873.1 | 0.0 | 0.0 | 0.0 | 124.7 | 85.4 | 57.9 | 174.6 | 0.0 | 0.0 | 0.0 | | | | | | |
| | Gorek | 140.0 | 129.3 | 183.7 | 40.0 | 294.2 | 0.0 | 0.0 | 0.0 | 25.9 | 36.7 | 8.0 | 58.8 | 0.0 | 0.0 | 0.0 | | | | | | |
| | Jerun | 0.0 | 1861.6 | 0.0 | 2166.1 | 2228.8 | 0.0 | 0.0 | 0.0 | 372.3 | 0.0 | 433.2 | 445.8 | 0.0 | 0.0 | 0.0 | | | | | | |
| | Teja | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 34.2 | 175.1 | 415.8 | 0.0 | 0.0 | 0.0 | 0.0 | 5.5 | 28.0 | 66.5 | | | | | | |
| | Pepulut | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 98.2 | 280.0 | 465.0 | 0.0 | 0.0 | 0.0 | 0.0 | 19.6 | 56.0 | 93.0 | | | | | | |
| SK310 | B15 | 252.7 | 27.2 | 43.2 | 0.0 | 63.2 | 0.0 | 0.0 | 0.0 | 4.1 | 6.5 | 0.0 | 9.5 | 0.0 | 0.0 | 0.0 | 2.7 | 4.2 | 6.2 | 0.0 | 0.0 | 0.0 |
| **TOTAL, Bscf** | | **779** | **2870.5** | **934.0** | **2495.4** | **3794.8** | **132.3** | **455.1** | **880.9** | **572.7** | **184.6** | **499.1** | **755.8** | **25.1** | **84.0** | **159.5** | **352.0** | **390.2** | **401.5** | **33.0** | **56.8** | **75.0** |

***Table 8-1: Estimated Gross and Net Reserves and Resources for Gas, Bscf (as of end December 2023).***

**Gross reserves and resources reported reflect post Economic Limit Test (ELT).*

| | | Gross* | | | | | | | Net Working Interest (SEB) | | | | | | | Net Entitlement (SEB) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Malaysia, PSC Block** | **Fields** | **1P** | **2P** | | **3P** | **1C** | **2C** | **3C** | **1P** | **2P** | | **3P** | **1C** | **2C** | **3C** | **1P** | **2P** | **3P** | **1C** | **2C** | **3C** |
| | | | **Dev** | **Undev** | | | | | | **Dev** | **Undev** | | | | | | | | | | | |
| SK408 | Larak | 2.3 | 3.8 | 0.0 | 5.6 | 0.0 | 0.0 | 0.0 | 0.5 | 0.8 | 0.0 | 1.1 | 0.0 | 0.0 | 0.0 | 3.0 | 3.5 | 3.8 | 0.1 | 0.3 | 0.4 |
| | Bakong | 3.1 | 3.6 | 2.1 | 9.7 | 0.0 | 0.0 | 0.0 | 0.6 | 0.7 | 0.4 | 1.9 | 0.0 | 0.0 | 0.0 | | | | | | |
| | Gorek | 1.3 | 1.8 | 0.4 | 2.9 | 0.0 | 0.0 | 0.0 | 0.3 | 0.4 | 0.1 | 0.6 | 0.0 | 0.0 | 0.0 | | | | | | |
| | Jerun | 37.7 | 0.0 | 51.7 | 61.5 | 0.0 | 0.0 | 0.0 | 7.5 | 0.0 | 10.3 | 12.3 | 0.0 | 0.0 | 0.0 | | | | | | |
| | Teja | 0.0 | 0.0 | 0.0 | 0.0 | 0.6 | 2.9 | 6.9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.5 | 1.1 | | | | | | |
| | Pepulut | 0.0 | 0.0 | 0.0 | 0.0 | 1.6 | 4.6 | 7.7 | 0.0 | 0.0 | 0.0 | 0.0 | 0.3 | 0.9 | 1.5 | | | | | | |
| SK310 | B15 | 0.2 | 0.3 | 0.0 | 0.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **TOTAL, MMstb** | | **44.6** | **9.5** | **54.2** | **80.2** | **2.2** | **7.6** | **14.6** | **8.9** | **1.9** | **10.8** | **16.0** | **0.4** | **1.4** | **2.6** | **3.0** | **3.5** | **3.8** | **0.1** | **0.3** | **0.4** |

***Table 8-2: Estimated Gross and Net Reserves and Resources for Condensate, MMstb (as of end December 2023).***

**Gross reserves and resources reported reflect post Economic Limit Test (ELT).*

| Malaysia, PSC Block | Fields | Gross* | | | | | | | Net Working Interest (SEB) | | | | | | | Net Entitlement (SEB) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1P | 2P | | 3P | 1C | 2C | 3C | 1P | 2P | | 3P | 1C | 2C | 3C | 1P | 2P | 3P | 1C | 2C | 3C |
| | | | Dev | Undev | | | | | | Dev | Undev | | | | | | | | | | |
| SK408 | Larak | 1.1 | 1.4 | 0.0 | 1.7 | 0.0 | 0.0 | 0.0 | 0.2 | 0.3 | 0.0 | 0.3 | 0.0 | 0.0 | 0.0 | 0.7 | 0.7 | 0.7 | 0.1 | 0.1 | 0.1 |
| | Bakong | 2.4 | 1.7 | 1.1 | 3.4 | 0.0 | 0.0 | 0.0 | 0.5 | 0.3 | 0.2 | 0.7 | 0.0 | 0.0 | 0.0 | | | | | | |
| | Gorek | 0.5 | 0.6 | 0.1 | 1.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.0 | 0.2 | 0.0 | 0.0 | 0.0 | | | | | | |
| | Jerun | 7.4 | 0.0 | 8.7 | 8.9 | 0.0 | 0.0 | 0.0 | 1.5 | 0.0 | 1.8 | 1.8 | 0.0 | 0.0 | 0.0 | | | | | | |
| | Teja | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | | | | | | |
| | Pepulut | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | | | | | | |
| SK310 | B15 | 0.1 | 0.2 | 0.0 | 0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **TOTAL, MMstb** | | **11.6** | **3.8** | **9.9** | **15.2** | **0.0** | **0.0** | **0.0** | **2.3** | **0.8** | **2.0** | **3.0** | **0.0** | **0.0** | **0.0** | **0.7** | **0.7** | **0.7** | **0.1** | **0.1** | **0.1** |

***Table 8-3: Estimated Gross and Net Reserves and Resources for PLR, MMstb (as of end December 2023).***

**Gross reserves and resources reported reflect post Economic Limit Test (ELT).*

| Malaysia, PSC Block | Fields | Gross* | | | | | | | Net Working Interest (SEB) | | | | | | | Net Entitlement (SEB) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1P | 2P | | 3P | 1C | 2C | 3C | 1P | 2P | | 3P | 1C | 2C | 3C | 1P | 2P | 3P | 1C | 2C | 3C |
| | | | Dev | Undev | | | | | | Dev | Undev | | | | | | | | | | |
| SK408 | Larak | 41.6 | 51.8 | 0.0 | 63.2 | 0.0 | 0.0 | 0.0 | 8.3 | 10.4 | 0.0 | 12.6 | 0.0 | 0.0 | 0.0 | 61.9 | 68.5 | 70.4 | 5.6 | 9.8 | 12.9 |
| | Bakong | 109.5 | 76.5 | 51.5 | 158.6 | 0.0 | 0.0 | 0.0 | 21.9 | 15.3 | 10.3 | 31.7 | 0.0 | 0.0 | 0.0 | | | | | | |
| | Gorek | 23.3 | 33.1 | 7.2 | 53.0 | 0.0 | 0.0 | 0.0 | 4.7 | 6.6 | 1.4 | 10.6 | 0.0 | 0.0 | 0.0 | | | | | | |
| | Jerun | 355.4 | 0.0 | 421.4 | 441.9 | 0.0 | 0.0 | 0.0 | 71.1 | 0.0 | 84.3 | 88.4 | 0.0 | 0.0 | 0.0 | | | | | | |
| | Teja | 0.0 | 0.0 | 0.0 | 0.0 | 6.3 | 32.1 | 76.2 | 0.0 | 0.0 | 0.0 | 0.0 | 1.0 | 5.1 | 12.2 | | | | | | |
| | Pepulut | 0.0 | 0.0 | 0.0 | 0.0 | 18.0 | 51.3 | 85.2 | 0.0 | 0.0 | 0.0 | 0.0 | 3.6 | 10.3 | 17.0 | | | | | | |
| SK310 | B15 | 4.8 | 7.7 | 0.0 | 11.2 | 0.0 | 0.0 | 0.0 | 0.7 | 1.2 | 0.0 | 1.7 | 0.0 | 0.0 | 0.0 | 0.5 | 0.7 | 1.1 | 0.0 | 0.0 | 0.0 |
| **TOTAL, MMboe** | | **534.6** | **169.0** | **480.1** | **727.8** | **24.3** | **83.4** | **161.4** | **106.7** | **33.5** | **96.0** | **145.0** | **4.6** | **15.4** | **29.2** | **62.4** | **69.2** | **71.5** | **5.6** | **9.8** | **12.9** |

***Table 8-4: Estimated Total Gross and Net Reserves and Resources, MMboe (as of end December 2023).***

**Gross reserves and resources reported reflect post Economic Limit Test (ELT).*

| Country | Block/ Permit | Assets | Category | Exploration Well | Remarks |
|---|---|---|---|---|---|
| Malaysia | SK408 | Bakong Study | Contingent Resources (Development On Hold/ Unclarified) | N/A | Gas |
| | | Jerun Optimization Project | | | Gas; reserves acceleration |
| | | Jerun Talus | | | Gas; pending Jerun appraisal results |
| | | Jarak | | Jarak-1 | Gas |
| | | Legundi | | Legundi-1 | Gas |
| | | Jeremin | | Jeremin-1 | Gas |
| | SB412 | Maligan South | Prospective Resources | N/A | Pending G&G Studies results |
| | | Kokohitan North | | | |
| | | Gajah Hitam NE | | | |
| New Zealand | PEP60093 | Toutouwai | Contingent Resources (Development On Hold/ Unclarified) | Toutouwai-1 | Oil |
| | | Karoro | Prospective Resources | N/A | Oil |
| | | Riroriro | | | Oil |
| | | Riroriro Iti | | | Oil |
| | PEP60092 | Longridge | | | Gas |
| | | Sandy Point SW | | | Gas |
| | | Gladstone Updip SW | | | Gas |
| | | Gladstone Updip Moki | | | Gas |
| | | Shag | | | Oil |
| | | Pihipihi | | | Oil |
| | PEP57075 | Cloudy Bay | | | Gas |
| | | Brackenridge | | | Gas |
| | | Stonyridge | | | Oil |
| | | Mensa | | | Oil & Gas |
| Mexico | Block 30 | Kan | Contingent Resources (Development On Hold/ Unclarified) | Kan-1 | Oil |
| | | Ix | Prospective Resources | Ix-1 | Oil |
| | | Cabrilla | Prospective Resources | N/A | Oil |
| Australia | AC/P69 | Birdwing | Prospective Resources | N/A | Oil; pending extension |

***Table 8-5: Summary of Resources Beyond the 2P and 2C Categories.***

## 9 References

1. "Petroleum Resources Management System", Sponsored by Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), Society of Petroleum Evaluation Engineers (SPEE), Society of Exploration Geophysicists (SEG), Society of Petrophysicists and Well Log Analysts (SPWLA), European Association of Geoscientists & Engineers (EAGE), published June 2018; SPE website (www.spe.org).

2. API Bulletin D14: "A Statistical Study of Recovery Efficiency", First Edition, October 1967.

3. "Dynamic Material Balance (Oil or Gas-In-Place Without Shut-Ins)", Mattar, L. and Anderson, D., CIPC paper 2005-113, presented at the Canadian International Conference, Calgary, Alberta, 7-9 June 2005.

4. "Pushing the Boundaries of Exploration in East Malaysia: Building on Early Success", Mark Jones, Stuart Burley, Neil Sharp and Nick Wilson, Murphy Exploration and Production Co., presented at the AAPG International Conference and Exhibition, Melbourne, Australia, September 13-16, 2015.

5. "The Petroleum Geology and Resources of Malaysia", PETRONAS, 1999.

6. "Estimation of Primary Oil Reserves", J.J. Arps, published in Petroleum Transactions, AIME, 1956.

7. Securities Commission Malaysia's Prospectus Guidelines, Chapter 17, "Specific Requirements for a Corporation with MOG Exploration or Extraction Assets".

8. Bursa Malaysia Main Market Listing Requirement, Practice Note 32 (PN 32), "Additional Requirements for Listed Issuers Involved in MOG Activities".

## 10 Nomenclature

| Term | Definition |
|---|---|
| 1C | Low estimate of Contingent Resources |
| 1P | Low estimate of Reserves (i.e., Proved Reserves). Equal to P1. |
| 2C | Best estimate of Contingent Resources |
| 2D | Two dimensional referring to seismic data |
| 2P | Best estimate of Reserves. The sum of Proved plus Probable Reserves. |
| 3C | High estimate of Contingent Resources |
| 3D | Three dimensional, referring to seismic data |
| 3P | High estimate of reserves. The sum of Proved plus Probable plus Possible Reserves. |
| AAPG | American Association of Petroleum Geologists |
| ACQ | Annual Contract Quantity |
| ADP | Area Development Plan |
| AGRU | Acid Gas Removal Unit |
| AMiR | Asset Management Integrated Review |
| Aquifer | Water-bearing formation |
| ARPR | Annual Review of Petroleum Resources |
| barg | bar gauge, metric unit of pressure |
| Basin | A large low-lying area or depression in the crust of the Earth, caused by plate tectonic activity and subsidence, in which sediments accumulate |
| bbl | Barrel |
| BCO | Behind casing opportunity |
| Best Estimate (P50) | With respect to resources categorization, the most realistic assessment of recoverable quantities if only a single result were reported. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate. |
| BIM | Brownfield Integrated Module |
| BOE | Barrel of Oil Equivalent i.e., The term allows for a single value to represent the sum of all the hydrocarbon products that are forecast as resources. Typically, condensate, oil, bitumen, and synthetic crude barrels are taken to be equal (1 bbl = 1 BOE). Gas and NGL quantities are converted to an oil equivalent based on a conversion factor that is recommended to be based on a nominal heating content or calorific value equivalent to a barrel of oil. |
| Bscf | Billion (standard) cubic feet of gas |
| BSTAB | Bintulu Stabilization Plant conditions |
| CAPEX | Capital Expenditure |
| CGR | Condensate Gas Ratio |
| CNH | Comisión Nacional de Hidrocarburos, the regulator of Mexico |
| $CO_2$ | Carbon dioxide |
| CoC | Change of Conditions |
| CoP | Cease of Production |
| CPP | Central Processing Platform |
| CPR | Competent Person's Report |
| CVR | Competent Valuer's Report |
| DES | Diamond Energy Sarawak |
| DMB | Dynamic Material Balance |
| DoD | Drill or Drop |
| DPR | Daily Production Report |
| DRU | Deep Regional Unconformity |
| DST | Drill stem test |
| DWR | Daily Well Report |
| E | East |
| E&P | Exploration and Production |
| EAGE | European Association of Geoscientists & Engineers |
| ELT | Economic Limit Test |
| ENI | ENI (Ente Nazionale Idrocarburi) is an Italian multinational energy company. |
| EOR | Enhanced Oil Recovery |
| EQ | Energy Quest Sdn. Bhd. |
| EQ-AIMS | EQ - Asset Integrated Monetization System |
| EQAST | EQ's proprietary in-house system for Production Forecasting |
| ERD | Extended reach drilling |
| ESP | Electrical Submersible Pump |
| EUR | Estimated Ultimate Recovery i.e., Those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities that have been already produced.<br>PETRONAS defines Gas EUR in ARPR as Gas EUR = Gp Sales + Gp Non-sales (Fuel) + Gp Non-sales (Flare/Vent) + Gi (Donor) - Gi (Receiver) + P50 Developed + P50 Undeveloped + P50 CR + P50 Fuel +P50 Flare/Vent + P50 Gas Reinjection (Donor) - Gas Reinjection (Receiver). EUR includes P50 Fuel + P50 Flare/Vent. |

| Term | Definition |
|---|---|
| FAEP | First Additional Exploration Period |
| FBHP | Flowing bottomhole pressure |
| FDP | Field Development Plan |
| FFR | Full Field Review |
| FFT | Fuel Flare Tracking |
| FGD | First Gas Date |
| FID | Final Investment Decision i.e., Project approval stage when the participating companies have firmly agreed to the project and the required capital funding. |
| FPSO | Floating Production Storage and Offtake |
| FSA | Facilities Sharing Agreement |
| ft | feet |
| FWL | Free Water Level |
| FWS | Full Well Stream |
| G&G | Geological and Geophysical |
| GHA | Gas Holding Area |
| GIIP | Gas Initially In-place |
| Gp | Cumulative gas produced |
| GR | Gamma Ray |
| Gross | Gross resources are defined as the total estimated hydrocarbon to be produced in the event of exploration and/or production success, subject to economic limit. |
| GRV | Gross Rock Volume |
| GSA | Gas Supply Agreement |
| GWC | Gas-water Contact |
| $H_2S$ | Hydrogen sulfide |
| High Estimate (P10) | With respect to resources categorization, this is considered to be an optimistic estimate of the quantity that will actually be recovered from an accumulation by a project. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate. |
| HIIP | Hydrocarbon Initially In-place |
| HP | High Pressure |
| HPHT | High Pressure High Temperature |
| IOR | Improved Oil Recovery |
| JV | Joint Venture |
| km | kilometres |
| $km^2$ | Square kilometre, sqkm |
| LaBaGo | Larak, Bakong and Gorek fields. Also referred to as GoLaBa |
| LAT | Lowest Astronomical Tide |
| Lead | A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect. A project maturity sub-class of Prospective Resources. |
| LCC | Lowest Closing Contours |
| LLB | Lang Lebah |
| Low Estimate (P90) | With respect to resources categorization, this is a conservative estimate of the quantity that will actually be recovered from the accumulation by a project. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate. |
| LP | Low Pressure |
| LWD | Logging while Drilling |
| m | meters |
| Ma | Mega-annum, Million years ago |
| MC3D | Multi-client 3D |
| mD | millidarcy, unit for permeability |
| MD | Measured Depth |
| MEFS | Minimum Economic Field Size |
| MLNG | Malaysia Liquefied Natural Gas |
| MMboe | Million barrels of oil equivalent |
| MMscfd | Million (standard) cubic feet of gas per day |
| MMstb | Million (standard) barrels of oil or condensate |
| Mstb | Thousand (standard) barrels of oil or condensate |
| Mstbd | Thousand (standard) barrels of oil or condensate per day |
| MMU | Middle Miocene Unconformity |
| MODU | Mobile Offshore Drilling Unit |
| MOG | Mineral, Oil and Gas |
| MOM | Minutes of Meeting |
| MP | Medium Pressure |
| MPM | Malaysia Petroleum Management acts for and on behalf of PETRONAS in the overall management of Malaysia's petroleum resources throughout the lifecycle of upstream oil and gas assets and is the governing body for Malaysia's petroleum development. |

| Term | Definition |
|---|---|
| MR | Milestone Review with PETRONAS; usually followed by a number to denote the stage of the review process |
| mRT | meter (Rotary Table) |
| MRU | Mercury Removal Unit |
| Mscfd | Thousand (standard) cubic feet of gas per day |
| MWC | Minimum Work Commitment |
| NAG | Non-associated gas |
| NE | Northeast |
| Net Entitlement | That portion of future production (and thus Resources) legally accruing to an entity under the terms of the development and production contract or license. Under the term of PSCs, the producers have an entitlement to a portion of the production. This entitlement, often referred to as "net entitlement" or "net economic interest", is estimated using a formula based on the contract terms incorporating costs and profits. |
| Net Working Interest | That portion of Gross Resources attributable to the Working Interest of those produced quantities |
| NFA | No Further Action |
| NNE | North Northeast |
| NOPTA | National Offshore Petroleum Titles Administrator |
| NTG | Net to Gross ratio |
| NW | Northwest |
| O&G | Oil and Gas |
| OGP | Onshore Gas Plant |
| OMV | Österreichische Mineralölverwaltung (English: Austrian Mineral Oil Administration), an Austrian integrated oil and gas company |
| OOIP | Original Oil In-place |
| Operator | The company responsible for the exploration, development, and production of an oil or gas well or block |
| ORLI | Overall Resource Life Index.<br>PETRONAS definition in ARPR, for 2P+2C reserves and resources, ORLI (years) = (P50 Dev + P50 Undev + P50 CR) / Production. |
| OWC | Oil-water Contact |
| P&A | Plug & Abandoned |
| P10 | Refer definition for "High Estimate" |
| P50 | Refer definition for "Best Estimate" |
| P90 | Refer definition for "Low Estimate" |
| PCSB | PETRONAS Carigali Sdn. Bhd. |
| PDG | Permanent downhole gauge |
| PETRONAS | Petroliam Nasional Berhad |
| $P_g$ | Probability of Geological Success |
| PIIP | Petroleum Initially In-place i.e., The total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs, as of a given date, discovered and undiscovered, before production. |
| PLR | Plant Liquid Return |
| PMCD | Pressurised Mud Cap Drilling |
| ppm | Parts per million |
| PRG | PETRONAS Reserves Group |
| PRMS | Petroleum Resources Management System |
| Project | A defined activity or set of activities that provides the link between the petroleum accumulation's resources sub-class and the decision-making process, including budget allocation. A project may, for example, constitute the development of a single reservoir or field, an incremental development in a larger producing field, or the integrated development of a group of several fields and associated facilities (e.g. compression) with a common ownership. In general, an individual project will represent a specific maturity level (sub-class) at which a decision is made on whether or not to proceed (i.e., spend money), suspend, or remove. There should be an associated range of estimated recoverable resources for that project. (See also Development Plan.) |
| Prospect | A project associated with an undrilled potential accumulation that is sufficiently well defined to represent a viable drilling target. A project maturity sub-class of Prospective Resources |
| PRrMS | PETRONAS Reserves & Resources Management System |
| PSC | Production Sharing Contract i.e., A contract between a contractor and a host government in which the contractor typically bears the risk and costs for exploration, development, and production. In return, if exploration is successful, the contractor is given the opportunity to recover the incurred investment from production, subject to specific limits and terms. Ownership of petroleum in the ground is retained by the host government; however, the contractor normally receives title to the prescribed share of the quantities as they are produced. (Also termed production-sharing agreement (PSA). |
| PSDM | Pre-Stack Depth Migration |
| PSTM | Pre-Stack Time Migration |
| psi | pounds per square inch |
| psia | pounds per square inch absolute, common unit of pressure |
| psig | pounds per square inch gauge, common unit of pressure |

| Term | Definition |
|---|---|
| PTTEP | PTT Exploration and Production Company Limited, a national petroleum exploration and production company based in Thailand |
| PVT | Pressure, Volume, Temperature |
| QAA | Quarterly Audit Accounts |
| R/P | Reserves to Production ratio |
| RA | Resource Assessment |
| RF | Recovery Factor |
| RLI | Reserves Life Index.<br>PETRONAS definition in ARPR, for 2P reserves, RLI (years) = (P50 Dev + P50 Undev) / Production |
| RQI | Rock Quality Index |
| scf | Standard cubic feet of gas |
| SE | Southeast |
| SEB | Sapura Energy Berhad |
| SEG | Society of Exploration Geophysicists |
| SI | Shut-in |
| SISGES | Sarawak Integrated Sour Gas Evacuation System |
| SOCM | Strategic Operations Committee Meeting |
| SOMV | SapuraOMV Upstream Sdn. Bhd. |
| SPE | Society of Petroleum Engineers |
| SPEE | Society of Petroleum Evaluation Engineers |
| SPWLA | Society of Petrophysicists and Well Log Analysts |
| sqkm | Square kilometre, $km^2$ |
| SRU | Shallow Regional Unconformity |
| SSB | Sarawak Shell Berhad |
| SSW | South Southwest |
| stb | Standard barrel of oil |
| STOIIP | Oil In-place Volume (Stock Tank Conditions) |
| SW | Southwest |
| TCM | Technical Committee Meeting |
| TD | total depth |
| TDR | Turndown Rate |
| TG | Trip Gas |
| THP | Tubinghead pressure |
| TOC | Top of Carbonate |
| TOC | Total Organic Content |
| Tscf | Trillion (standard) cubic feet of gas |
| TVD | True Vertical Depth |
| TVDSS | True Vertical Depth (Subsea) |
| VDR | Virtual Data Room |
| VLAP | Very Low Abandonment Pressure |
| VR | Vitrinite Reflectance |
| WHP | Wellhead Platform |
| WI | Working Interest |
| Working Interest | An entity's equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms. |
| WPB | Work Program and Budget |
| WPC | World Petroleum Council |

## Appendix 1: Energy Quest Track Record

| No | Year | Contract Title / Description | Client / Project Location |
|---|---|---|---|
| 1. | June-23 | Asset evaluation of 2 oil and gas fields in Indonesia | PJBUMI / Hess<br><br>Indonesia |
| 2. | Jan-23 | East Sabah geological fieldwork. | Repsol / Petronas.<br><br>Malaysia |
| 3. | Sept-22 | Block SK334 Prospectivity Study | PETROS / Big Oil<br><br>Malaysia |
| 4. | July-22 | Petrophysical study of production fields | Deleum Berhad<br><br>Malaysia |
| 5. | Feb-21 | Competent Person's Report and CVR for the Independent Technical Evaluation of Samarang PSC Asset, Offshore Sabah | Sabah International Petroleum E&P Sdn Bhd<br><br>Malaysia |
| 6. | Feb-21 | Tembungo Late Life Asset Evaluation, CPR and CVR | MTC and Partners.<br><br>Malaysia |
| 7. | Feb-21 | MASA Late Life Asset Evaluation, CPR and CVR | MTC and Partners.<br><br>Malaysia |
| 8. | Dec-21 | Phase-2 field work and outcrop scouting on onshore peninsular basin. | Salamander Energy (Malaysia) Limited<br><br>Malaysia |
| 9. | Dec-20 | Block Evaluation, Conceptual FDP and Competent Person's Report of Sinamar Field, South West Bukit Barisan Block, West Sumatra & Riau, Sumatra. | Kulim (Malaysia) Berhad<br><br>Indonesia |
| 10. | Mac-20 | Provision of Fieldworks and Outcrops Scouting on Peninsular Malaysia Onshore Basins | Salamander Energy (Malaysia) Limited / Ophir a MEDCOENERGI Company<br><br>Malaysia |
| 11. | Mac-20 | East Sabah Integrated Geological and Geophysical (G&G) Study – Extension-Pinangah CBM works | PETRONAS Malaysia Petroleum Management (MPM) / PETRONAS Carigali Sdn. Bhd.<br><br>Malaysia |
| 12. | Dec-19 | Block Evaluation, Conceptual FDP and Competent Person's Report of Sinamar Field, South West Bukit Barisan Block, West Sumatra & Riau, Sumatra | KULIM (Malaysia) Berhad.<br><br>Indonesia |
| 13. | Mar-19 | East Sabah Integrated Geological and Geophysical (G&G) Study | PETRONAS Malaysia Petroleum Management (MPM) / PETRONAS Carigali Sdn. Bhd.<br><br>Malaysia |
| 14. | Feb-19 | Umbrella Contract for the Provision of Subsurface Consultancy Service for PM8E | Enquest Petroleum Production Malaysia Ltd.<br><br>Malaysia |
| 15. | Feb-19 | Umbrella Contract for the Provision of Subsurface Consultancy Service for Tanjong Baram | Enquest Petroleum Production Malaysia Ltd.<br><br>Malaysia |
| 16. | Jan-19 | Sarawak Deep Water 2A Block Evaluation | Coro Energy Plc.<br><br>Malaysia |

| No | Year | Contract Title / Description | Client / Project Location |
|---|---|---|---|
| 17. | Jan-19 | Provision of 1 Reservoir Engineer for Larut Project for Vestigo (Extension) | UZMA Engineering Sdn. Bhd. / VESTIGO Petroleum Sdn. Bhd.<br><br>Malaysia |
| 18. | Oct-18 | Independent Technical Expert including Valuation Report on the Asset Review and Evaluation of Hydrocarbon Resources of Sapura Exploration & Production's Malaysian and international assets – IVR & ITR | SAPURA Energy Berhad.<br><br>Malaysia, Australia, New Zealand, Mexico |
| 19. | Oct-18 | Provision of a Reservoir Engineer for Larut FDP | UZMA Engineering Sdn. Bhd. / VESTIGO Petroleum Sdn. Bhd.<br><br>Malaysia |
| 20. | Jul-18 | Provision of a Reservoir Engineer for Jitang FDP | UZMA Engineering Sdn. Bhd. / VESTIGO Petroleum Sdn. Bhd.<br><br>Malaysia |
| 21. | Jul-18 | Provision of a team of Reservoir Engineers to conduct study, analysis and develop suitable solutions for Intelligent Gas Forecasting and Optimization (IGFO) System for Petronas Carigali Sdn Bhd (PCSB) | ILAUNCH Sdn. Bhd.<br><br>Malaysia |
| 22. | Jan-18 | Provision of a Reservoir Simulation, a Production Engineer and a Geophysicist for Berantai Full Field Review | UZMA Engineering Sdn. Bhd. / VESTIGO Petroleum Sdn. Bhd.<br><br>Malaysia |
| 23. | Jan-18 | Provision of a Reservoir Simulation Engineer for Tg Baram FDP | UZMA Engineering Sdn. Bhd. / ENQUEST Petroleum Sdn. Bhd.<br><br>Malaysia |
| 24. | Jan-18 | Provision of Basement Fieldwork Service for Block M12, M13, M14 in Myanmar for PCML | PETRONAS Carigali Myanmar (PCML) Limited<br><br>Myanmar |
| 25. | Jan-18 | Asset Evaluation, Conceptual FDP and Economics - Lirik II for Barakah Offshore Petroleum. | BARAKAH Offshore Petroleum Sdn. Bhd.<br><br>Indonesia |
| 26. | May-17 | Production Engineering Studies – Desktop Analysis of Lengo & Camar Field Offshore East Java | Private Investor<br><br>Indonesia |
| 27. | July-17 | Resource Assessment – Resource & Remaining Reserve Assessment for Galapagos | Private Investor<br><br>United Kingdom |
| 28. | Mar-17 | Provision of an integrated team for Comprehensive & Integrated Third Party Geological & Geophysical Block Evaluation for SK331 | RHP (Mukah) Pte Ltd<br><br>Malaysia |
| 29. | Jul-16 | Appointment Of Panel Contractors For The Provision Of Subsurface Studies For Routine And Enhanced Oil Recovery (EOR) Services | PETRONAS Malaysia Petroleum Management (MPM)<br><br>Malaysia |
| 30. | Jul-16 | Provision of an integrated for the Petrophysical Analysis of offshore Sarawak block evaluation | UZMA Engineering Sdn. Bhd.<br><br>Malaysia |
| 31. | Apr-16 | Provision of a seismic interpreter and Geomodeler for Seismic Interpretation and Geomodeling Works | UZMA Engineering Sdn. Bhd.<br><br>Malaysia |
| 32. | Apr-16 | Independent Technical Review of the RPS Independent Technical Expert Report and RPS Independent Valuation Report of Emir-Oil Concession Block, Onshore Kazakhstan | Reach Energy Berhad.<br><br>Kazakhstan |

| No | Year | Contract Title / Description | Client / Project Location |
|---|---|---|---|
| 33. | Aug-15 | Provision of technical services and solutions for the Geophysical Services (Umbrella Contract) for Mubadala. | MDC Oil & Gas (SK320) Limited.<br><br>Malaysia |
| 34. | Aug-15 | Prospectivity of Limbang-Klias & Kudat (a) Regional geology and Stuctural analysis (b) Petroleum System analysis ( c) Fieldwork Analysis | PETRONAS Carigali Sdn. Bhd.<br><br>Malaysia |
| 35. | Jun-15 | Subsurface Studies For Routine And Enhanced Oil Recovery (EOR) Services including developing RMS Framework and Technical Potential Guidelines for PETRONAS | Orogenic Resources Sdn. Bhd. / PETRONAS Malaysia Petroleum Management (MPM)<br><br>Malaysia |
| 36. | Dec-14 | Asset Evaluation of Pinnacle Energy Gulf of Mexico Assets - LS21484 & BS001 Fields | BARAKAH Offshore Petroleum Sdn. Bhd.<br><br>Mexico |
| 37. | Oct-14 | Technical support for execution of Field Development Plan for KPOC Fields | Kebabangan Petroelum Operating Company (KPOC)<br><br>Malaysia |
| 38. | Aug-14 | Sabah Geological Field Trip KK, Kudat | PETRONAS Malaysia Petroleum Management (MPM)<br><br>Malaysia |
| 39. | Aug-14 | Asset Evaluation of TAQA North Sea Assets (19 Producing Fields, 2 discovered fields & 2 Green fields) | Private Investor<br><br>United Kingdom |
| 40. | Aug-14 | Well Rejuvenation PTT, PTB, KSB fields (a) Decline Curve Analysis (b) KSB seismic revisit interpretation | SAPURA KENCANA Petroleum Berhad.<br><br>Indonesia |
| 41. | Aug-14 | Validated recoverable based on existing dynamic model of the brown field offshore Thailand | SAPURA KENCANA Petroleum Berhad.<br><br>Thailand |
| 42. | Jul-14 | (a) Production Enhancement (Kikeh, D-35) (b) Network Modeling (Betty, Baronia) (c) RMP Study (Baram, St Joseph GI, D35, J4) (d) TP Guidelines (e) Data Management (Dulang Field) | Orogenic Resources Sdn. Bhd. / PETRONAS Malaysia Petroleum Management (MPM)<br><br>Malaysia |
| 43. | Jun-14 | Pulau Redang Geological Field Trip | PETRONAS Malaysia Petroleum Management (MPM)<br><br>Malaysia |
| 44. | May-14 | Data Review At BHP Biliton | ADECO Exploration Limited.<br><br>Malaysia |
| 45. | Apr-14 | Sabah Basin Study (a)Regional structural framework analysis (b)regional petroleum system analysis in relation to CBM Resources (c) Regional Geology Mapping (d) Coal Sampling | PETRONAS Carigali Sdn. Bhd.<br><br>Malaysia |
| 46. | Apr-14 | Asset Evaluation of SB305 Fields | M3NERGY Berhad.<br><br>Malaysia |
| 47. | Mar-14 | Provision of Geological Evaluation Of Prospectivity On Tinjar Province | PETRONAS Malaysia Petroleum Management (MPM)<br><br>Malaysia |
| 48. | Mar-14 | Data Review of Exploration Block SK408 (short review) | SAPURA KENCANA Petroleum Berhad.<br><br>Malaysia |
| 49. | Feb-14 | Technical evaluation for Exploration Block DW 2C (Sarawak) | SAPURA KENCANA Petroleum Berhad.<br><br>Malaysia |

| No | Year | Contract Title / Description | Client / Project Location |
|---|---|---|---|
| 50. | Feb-14 | Asset Evaluation of Perlak Field (Indonesia) including Production Enhancement Opportunities | SAPURA KENCANA Petroleum Berhad.<br><br>Indonesia |
| 51. | Feb-14 | Asset Evaluation of Kendal Field (Indonesia) including Production Enhancement Opportunities | SAPURA KENCANA Petroleum Berhad.<br><br>Indonesia |
| 52. | Feb-14 | Asset Evaluation of Newfield China Asset (Bohai Bay 3 Fields & Lu Feng 1 Field ) | SAPURA KENCANA Petroleum Berhad.<br><br>China |
| 53. | Feb-14 | Desktop Analysis To Verify Volumes & Recoveries Of Vietnam Block 102 & 106 | SAPURA KENCANA Petroleum Berhad.<br><br>Vietnam |
| 54. | Feb-14 | Block Review And Technical Evaluation Of Block OPL 2010 | SAPURA KENCANA Petroleum Berhad.<br><br>Nigeria |
| 55. | Feb-14 | Revision And Reconciliation Of Final Reserves Numbers for Carigali Hess Thailand Asset | SAPURA KENCANA Petroleum Berhad.<br><br>Thailand |
| 56. | Jan-14 | Bubu Diwangsa FDP Phase 1 | SAPURA KENCANA Petroleum Berhad.<br><br>Malaysia |
| 57. | Nov-13 | Provision Of Petrophysicist For Vestigo | UZMA Engineering Sdn. Bhd. / VESTIGO Petroleum Sdn. Bhd.<br><br>Malaysia |
| 58. | Nov-13 | Resource Evaluation and Certification of Newfield Assets for SapuraKencana Asset Acquisition/Security Commission Malaysia Submission. | SAPURA KENCANA Petroleum Berhad.<br><br>Malaysia |
| 59. | Oct-13 | Technical Service For INPEX - Basin Modeling Work | UZMA Engineering Sdn. Bhd.<br><br>Malaysia |
| 60. | Oct-13 | Technical Service For INPEX -Petrophysical Evaluation | UZMA Engineering Sdn. Bhd.<br><br>Malaysia |
| 61. | Oct-13 | Hess Asset Technical Sub-Surface Review of Thailand On-shore Asset | SAPURA KENCANA Petroleum Berhad.<br><br>Thailand |
| 62. | Oct-13 | Asset Evaluation of Seruway PSC Farm Out | SAPURA KENCANA Petroleum Berhad.<br><br>Indonesia |
| 63. | Sept-13 | Regional Geological Mapping – Block CA1 Brunei Deepwater | PETRONAS Carigali Brunei Limited<br><br>Brunei |
| 64. | Sep-13 | MEO Asset Evaluation - Marina Field, Breakwater And Other Prospect Within WA-45 | SAPURA KENCANA Petroleum Berhad.<br><br>Malaysia |
| 65. | Sep-13 | Economics Evaluation of Russian Asset | SILVERSAND Sdn. Bhd.<br><br>Russia |
| 66. | Sept-13 | Sepat Gas FDP – Static & dynamic Modeling Sepat Gas Field & FDP | UZMA Engineering Sdn. Bhd. / PETRONAS Malaysia Petroleum Management (MPM)<br><br>Malaysia |
| 67. | Sept-13 | Nosong Bongawan FDP – Static & Dynamic Modeling Nosong & Bongawan Fields and FDP | UZMA Engineering Sdn. Bhd. / PETRONAS Malaysia Petroleum Management (MPM)<br><br>Malaysia |
| 68. | Jul-13 | Asset Evaluation of Newfield China Asset (Bohai Bay 3 Fields & Lu Feng 1 Field ) | SAPURA KENCANA Petroleum Berhad.<br><br>China |

| No | Year | Contract Title / Description | Client / Project Location |
|---|---|---|---|
| 69. | July-13 | Well Sample Analysis For Kerupang Fields | PETRONAS Malaysia Petroleum Management (MPM)<br><br>Malaysia |
| 70. | Jul-13 | Asset Evaluation of Newfield Malaysia Asset (4 Exploration Blocks & 13 Producing Fields) | SAPURA KENCANA Petroleum Berhad.<br><br>Malaysia |
| 71. | July-13 | Provision of Reservoir Engineer – Dynamic Modeling for Samudera Field | Carigali HESS Operating Company Sdn. Bhd.<br><br>Malaysia |
| 72. | Jun-13 | Cadlao Brown Field FDP For Asset Evaluation | SAPURA KENCANA Petroleum Berhad.<br><br>Phillipines |
| 73. | Jun-13 | Data Review of Exploration Block SK317 | JAPEX Asia & Ocenia Project Division.<br><br>Malaysia |
| 74. | Apr-13 | Technical Evaluation of Tg Baram Field (2 months) | SAPURA KENCANA Petroleum Berhad.<br><br>Malaysia |
| 75. | Apr-13 | Pre LOI Technical Support for Tg Baram Field | SAPURA KENCANA Petroleum Berhad.<br><br>Malaysia |
| 76. | Apr-13 | (a) Dulang EOR (b) Baram Delta Regional Study | OROGENIC Resources Sdn. Bhd./EPTD<br><br>Malaysia |
| 77. | Apr-13 | PCPP Field Trip - Basement Study Fieldtrip for Block SK305 Sarawak / Malaysia | PCPP Operating Company Sdn. Bhd.<br><br>Malaysia |
| 78. | Apr-13 | Brunei Block L - Asset Evaluation | SAPURA KENCANA Petroleum Berhad.<br><br>Brunei |
| 79. | Apr-13 | Brunei Block L - Asset Evaluation | UZMA Engineering Sdn. Bhd.<br><br>Brunei |
| 80. | Mar-13 | Dynamic Modeling - Samudera Field | Carigali HESS Operating Company Sdn. Bhd.<br><br>Malaysia |
| 81. | Mar-13 | Well Sample Analysis | PETRONAS Malaysia Petroleum Management (MPM)<br><br>Malaysia |
| 82. | Sep-12 | Russia Exploration Block - Asset Evaluation | SAPURA Kencana Petroleum Berhad.<br><br>Russia |
| 83. | Sep-12 | Prospectivity of Tinjar Province (a) Petroleum System Analysis( b) Regional Structure geology (construct regional structure element map) (c). Fieldwork, sampling (site coring), and lab analysis | PETRONAS Carigali Sdn. Bhd.<br><br>Malaysia |
| 84. | Sep-12 | Technical Evaluation For Semangkok Timur, Laba And Laba Barat Fields | PETRONAS Carigali Sdn. Bhd.<br><br>Malaysia |
| 85. | Sep-12 | PMU Field Trip-Limbang/Klias/Kota Kinabalu | PETRONAS Management Unit<br><br>Malaysia |
| 86. | Sep-12 | Fast Track Desktop Screening And Data Room Review Sabah Basin | MMC Petroleum & Resources Sdn. Bhd.<br><br>Malaysia |
| 87. | Jul-12 | Resource Assessment of Sabah Fields | ROC Oil (Malaysia) Pty Limited<br><br>Malaysia |

| No | Year | Contract Title / Description | Client / Project Location |
|---|---|---|---|
| 88. | Jun-12 | Resource Assessment of Sabah Fields | ROC Oil (Malaysia) Pty Limited<br><br>Malaysia |
| 89. | May-12 | Sabah Geological Field Trip | MDC Oil & Gas (SK320) Ltd.<br><br>Malaysia |
| 90. | May-12 | Aceh Exploration Block - Asset Evaluation | SAPURA Kencana Petroleum Berhad.<br><br>Indonesia |
| 91. | Apr-12 | Asset Evaluation -Exxon Mobil Block B | Casa Straits Sdn Bhd<br><br>Malaysia |
| 92. | Mar-12 | Data Room Review And Fast Track Evaluation - Exploration Block SK314A | SAPURA Kencana Petroleum Berhad.<br><br>Malaysia |
| 93. | Feb-12 | Technical Evaluation Balai Cluster Field Development | BC Petroleum Sdn. Bhd.<br><br>Malaysia |
| 94. | Jan-12 | Data Review For Cue Energy At PMU | CUE Energy (M) Sdn. Bhd.<br><br>Malaysia |
| 95. | Dec-11 | Kudat Field Trip 21-23 May 2013 | Malaysia Petroleum Management PETRONAS (MPM)<br><br>Malaysia |
| 96. | Nov-11 | Small Field Data Review For Petrofac At Petronas | SAPURA Kencana Petroleum Berhad.<br><br>Malaysia |
| 97. | Oct-11 | Data Room Review And Fast Track Evaluation - Exploration Block PM316 And PM 331 | MMC Petroleum & Resources Sdn. Bhd.<br><br>Malaysia |
| 98. | Aug-11 | Asset Evaluation Ketapang And Muriah PSC | M3NERGY Berhad.<br><br>Indonesia |
| 99. | Jul-11 | Data Review For Petronas 21 Small Fields | ROC Oil (Malaysia) PTY LIMITED<br><br>Malaysia |
| 100. | Jun-11 | Ngudal Field Subsurface Evaluation and monitoring | Petrosolve Energy (M) Sdn. Bhd.<br><br>Indonesia |
| 101. | Jan-11 | Provision For Geological Studies For Block SK320 MDC Oil And Gas Ltd | Orogenic Resources Sdn. Bhd. / MDC<br><br>Malaysia |
| 102. | Jan-11 | Block PM305/314 Data Review-Evaluation | Handal Resources Bhd.<br><br>Malaysia |
| 103. | Sep-10 | Geological Study -MDC Oil And Gas Ltd | Orogenic Resources Sdn. Bhd. / MDC<br><br>Malaysia |
| 104. | Sep-10 | The Provision Of Resource Assessment For Petrofac Malaysia (Malaysia PM-304) Ltd | OROGENIC RESOURCES SDN BHD / Petrofac<br><br>Malaysia |
| 105. | April-10 | Sabah Geological Field Trip | LUNDIN Malaysia<br><br>Malaysia |
| 106. | Sep-09 | Conducted D35 Field Enhanced Oil Recovery (EOR) Study | PETRONAS Carigali Sdn. Bhd.<br><br>Malaysia |
| 107. | Aug-09 | Geological Study For Angsi Field Development | PETRONAS Carigali Sdn. Bhd.<br><br>Malaysia |

| No | Year | Contract Title / Description | Client / Project Location |
|---|---|---|---|
| 108. | Jul-09 | Iran Gas Field Development Subsurface Study (Golshan And Firdowsi) | PETROFIELD/SKS<br><br>Iran |
| 109. | July-09 | Iran Oil Field Pre-Development Review (Resalat Field) | AMONA International<br><br>Iran |
| 110. | Oct-08 | Complete Geophysical, Geological And Reservoir Engineering Study For Jonkyang Field FDP | WNPOC<br><br>Sudan |
| 111. | Aug-08 | Southern East Coast Peninsular Geological Field Trip | PETRONAS Petroleum Management Unit (PMU)<br><br>Malaysia |
| 112. | Aug-08 | Southern East Coast Peninsular Geological Study | PETRONAS Petroleum Management Unit (PMU)<br><br>Malaysia |
| 113. | Aug-08 | Petrophysical Study For Low Resistivity Low Contrast (LRLC) | PETRONAS Research & Scientific Sdn. Bhd (PRSSB)<br><br>Malaysia |
| 114. | Jul-08 | Geophysical Study For Kinabalu Field Development | PETRONAS Carigali Sdn. Bhd.<br><br>Malaysia |
| 115. | Jul-08 | Geophysical Study For Vietnam Exploration Block | PARADIGM / KNOC<br><br>Vietnam |
| 116. | May-08 | Geophysical Study For Malaysia Basin Fluvial System | PETRONAS Research & Scientific Sdn. Bhd (PRSSB)<br><br>Malaysia |
| 117. | May-08 | Seismic Interpretation Professional Services For Malaysia Basin Migration System | PETRONAS Research & Scientific Sdn. Bhd (PRSSB)<br><br>Malaysia |
| 118. | April-08 | Carbonate Field Study-Cuba | PETRONAS Carigali Cuba Pty.Ltd.<br><br>Cuba |
| 119. | Mar-08 | Geological Evaluation Of Nigeria Fields And Blocks | EERS<br><br>London |
| 120. | Nov-06 | Reservoir Management Project For 14 Gas Fields, Bangladesh | PETROBANGLA<br><br>Bangladesh |
| 121. | Sep-06 | Mahanadi, India Block Study | PARADIGM / ONGC<br><br>India |
| 122. | Aug-06 | D-35 FDP And FFR Study Conducted Full Field Review and formulated Field Development Plan for Infill Program at D35 Field FDP And FFR Study | PETRONAS Carigali Sdn. Bhd.<br><br>Malaysia |
| 123. | Aug-06 | The Development Of New Models, Analogs & Tools For Better Prediction Of Miocene Carbonates Reservoirs (Detailed Petrophysical Study) | PETRONAS Carigali Sdn. Bhd./ PETRONAS Research & Scientific Sdn. Bhd (PRSSB)<br><br>Malaysia |
| 124. | Jun-06 | Luconia Regional Study For Co2 Sequestration | PETRONAS Petroleum Management Unit (PMU)<br><br>Malaysia |
| 125. | May-06 | Nymphe-Nymphe North Resource Assessment | PETRONAS Carigali Sdn. Bhd.<br><br>Malaysia |

| No | Year | Contract Title / Description | Client / Project Location |
|---|---|---|---|
| 126. | May-06 | Benrinnes Field Resource Assessment | PETRONAS Carigali Sdn. Bhd.<br><br>Malaysia |
| 127. | May-06 | Tangga Barat Core & Sedimentological Study, Irong Core & Sedimentological Study | PETRONAS Carigali Sdn. Bhd./ PETRONAS Research & Scientific Sdn. Bhd (PRSSB)<br><br>Malaysia |
| 128. | Mar-06 | Guling-2 Core & Sedimentological Study | PETRONAS Carigali Sdn. Bhd./ PETRONAS Research & Scientific Sdn. Bhd (PRSSB)<br><br>Malaysia |
| 129. | Jan-06 | K5 Field Resource Assessment | PETRONAS Petroleum Management Unit (PMU) / PETRONAS Research & Scientific Sdn. Bhd (PRSSB)<br><br>Malaysia |
| 130. | Jan-06 | J5 Field Resource Assessment | PETRONAS Petroleum Management Unit (PMU)<br><br>Malaysia |
| 131. | Nov-05 | SE Collins Field Resource Assessment | PETRONAS Carigali Sdn. Bhd.<br><br>Malaysia |
| 132. | Nov-05 | Geophysical Study And Block Assessment Of Semboja Area, Indonesia | SCHLUMBERGER<br><br>Indonesia |
| 133. | Sep-05 | Lokan Field Resource Assessment | PETRONAS Carigali Sdn. Bhd.<br><br>Malaysia |
| 134. | Sep-05 | Piatu-East Piatu 3D Seismic Interpretation & H80 Volumetric Re-Assessment | PETRONAS Petroleum Management Unit (PMU)<br><br>Malaysia |
| 135. | Feb-05 | India Nelp-V Blocks Evaluation And Resource Assessment (5 Blocks) | PETRONAS Carigali Sdn. Bhd.<br><br>India |
| 136. | Feb-05 | Yemen Block Review And Assessment (2 Blocks) | M3NERGY Berhad.<br><br>Yemen |
| 137. | Jan-05 | Mutiara Hitam Field Resource Assessment | PETRONAS Carigali Sdn. Bhd./ PETRONAS Research & Scientific Sdn. Bhd (PRSSB)<br><br>Malaysia |
| 138. | Jan-05 | Kuda Terbang Field Resource Assessment | PETRONAS Carigali Sdn. Bhd./ PETRONAS Research & Scientific Sdn. Bhd (PRSSB)<br><br>Malaysia |
| 139. | Dec-04 | Regional Expert For Regional Study Of Malaysia Basin | PETRONAS Carigali Sdn. Bhd./ PETRONAS Research & Scientific Sdn. Bhd (PRSSB)<br><br>Malaysia |
| 140. | Sep-04 | Guling Deep Core & Sedimentological Study | PETRONAS Petroleum Management Unit (PMU) / PETRONAS Research & Scientific Sdn. Bhd (PRSSB)<br><br>Malaysia |
| 141. | Sept-04 | Heglig Field, Sudan Structural Mapping | PETRONAS Research & Scientific Sdn Bhd (PRSSB)<br><br>Sudan |
| 142. | Aug-04 | Reservoir Characterization Study Of Temana Field | UZMA Engineering Sdn. Bhd. / PETRONAS Carigali Sdn. Bhd.<br><br>Malaysia |

| No | Year | Contract Title / Description | Client / Project Location |
|---|---|---|---|
| 143. | Jul-04 | Laba-laba Barat Resource Assessment | PETRONAS Petroleum Management Unit (PMU) / PETRONAS Research & Scientific Sdn. Bhd (PRSSB)<br><br>Malaysia |
| 144. | July-04 | Serok Field Resource Assessment | PETRONAS Petroleum Management Unit (PMU) / PETRONAS Research & Scientific Sdn. Bhd (PRSSB)<br><br>Malaysia |
| 145. | Mar-04 | Piatu-East Piatu Fdp Study (Geology And Reservoir Engineering Portion) | PETRONAS Petroleum Management Unit (PMU) / PETRONAS Research & Scientific Sdn. Bhd (PRSSB)<br><br>Malaysia |

## Appendix 2: PRMS Reserves & Resources Definitions

The following figures and tables have been extracted from the 2018 Petroleum Resources Management System (PRMS), prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), the Society of Petroleum Evaluation Engineers (SPEE), the Society of Exploration Geophysicists (SEG), the Society of Petrophysicists and Well Log Analysts (SPWLA) and the European Association of Geoscientists & Engineers (EAGE). The complete document is available from www.spe.org.

The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

Figure A2-1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Petroleum.

Figure A2-2 illustrates the Project Maturity Sub-Classes, where development projects and associated recoverable quantities may be sub-classified according to project maturity levels and the associated actions (i.e., business decisions) required to move a project toward commercial production. The maturity terminology and definitions for each project maturity class and sub-class are provided in Table A2-1.

Once projects satisfy commercial maturity (criteria given in Table A2-1), the associated quantities are classified as Reserves. These quantities may be allocated to sub-divisions provided in Table A2-2, based on the funding and operational status of wells and associated facilities within the reservoir development plan. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will

then move to the appropriate resources sub-class. Table A2-3 provides criteria for the Reserves categories determination.

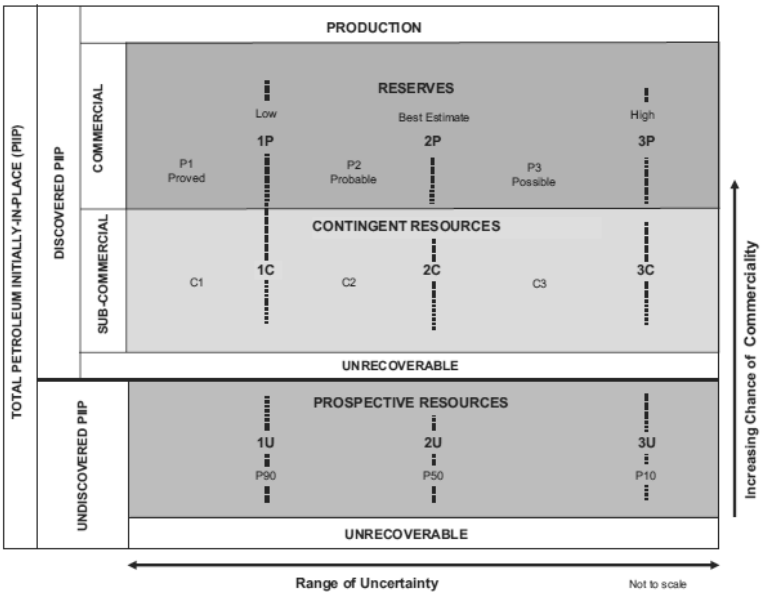


***Figure A2- 1: Petroleum Resources Classification Framework***

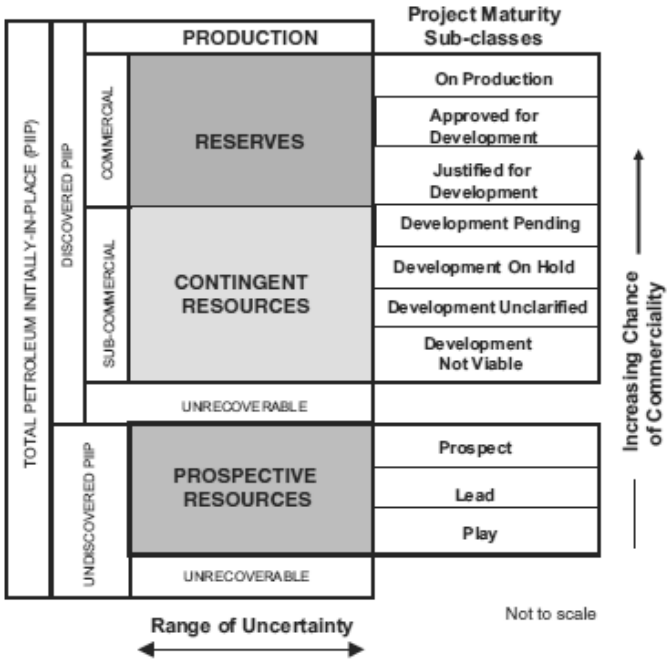


***Figure A2- 2: Sub-Classes Based on Project Maturity***

| Class/Sub-Class | Definition | Guidelines |
|---|---|---|
| **Reserves** | Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. | Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status.<br><br>To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame.<br><br>A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.<br><br>To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests. |
| **On Production** | The development project is currently producing or capable of producing and selling petroleum to market. | The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves.<br><br>The project decision gate is the decision to initiate or continue economic production from the project. |
| **Approved for Development** | All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way. | At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget.<br><br>The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells. |
| **Justified for Development** | Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained. | To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame}) There must be no known contingencies that could preclude the development from proceeding (see Reserves class).<br><br>The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time. |
| **Contingent Resources** | Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies. | Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist.<br><br>Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status. |
| **Development Pending** | A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. | The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. |

| Class/Sub-Class | Definition | Guidelines |
|---|---|---|
| | | The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production. |
| **Development on Hold** | A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. | The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status.<br><br>The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies. |
| **Development Unclarified** | A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information. | The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development.<br><br>This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production. |
| **Development Not Viable** | A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential. | The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions.<br><br>The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future. |
| **Prospective Resources** | Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations. | Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration. |
| **Prospect** | A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target. | Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program. |
| **Lead** | A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect. | Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect.<br>Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios. |
| **Play** | A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects. | Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios. |

***Table A2- 1: Recoverable Resources Classes and Sub-Classes***

| Status | Definition | Guidelines |
|---|---|---|
| **Developed Reserves** | Expected quantities to be recovered from existing wells and facilities. | Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing. |
| **Developed Producing Reserves** | Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. | Improved recovery Reserves are considered producing only after the improved recovery project is in operation. |
| **Developed Non-Producing** | Shut-in and behind-pipe Reserves. | Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet |

| | | |
|---|---|---|
| **Reserves** | | started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.<br><br>In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well. |
| **Undeveloped Reserves** | Quantities expected to be recovered through future significant investments. | Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects. |

***Table A2- 2: Reserves Status Definitions and Guidelines***

| **Category** | **Definition** | **Guidelines** |
|---|---|---|
| **Proved Reserves** | Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations. | If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate.<br><br>The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.<br><br>In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved.<br><br>Reserves in undeveloped locations may be classified as Proved provided that:<br>A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive.<br>B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations.<br><br>For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program. |
| **Probable Reserves** | Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. | It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.<br><br>Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria.<br><br>Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved. |
| **Possible Reserves** | Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves. | The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate.<br><br>Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are |

| Category | Definition | Guidelines |
|---|---|---|
| | | progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project.<br><br>Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable. |
| **Probable and Possible Reserves** | See above for separate criteria for Probable Reserves and Possible Reserves. | The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects.<br><br>In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area.<br><br>Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources.<br><br>In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations. |

***Table A2- 3: Reserves Category Definitions and Guidelines***

## Appendix 3: Competent Valuer

| | |
|---|---|
| Name | Jawati Abu Naim |
| Address | Energy Quest Sdn Bhd (602734-A)<br>Unit 3A-13-09,<br>Menara Paragon @ Pan'gaea,<br>Persiaran Bestari, Cyberjaya,<br>63000 Cyberjaya,Selangor. |
| Qualifications | Bachelor (Hons) Geology, University Of Malaya, Malaysia. |
| Years of relevant experience | Oil & Gas (44+ years):<br>● 1980-1986: Esso Production Malaysia INC (EPMI)<br>● 1986-1987 / 2003 – 2012: Esso Australia Pty Ltd (EAL)<br>● 2012 – 2013: ExxonMobil Exploration & Production (Malaysia) Inc<br>● 20014 – Present: Energy Quest Sdn Bhd, an Upstream Oil & Gas Consulting Company<br>Resource Certification (10 years), for example:<br>● SapuraKencana acquisition of Newfield Asset (2013)<br>● Reach Energy Berhad – Emir Oil Concession Acquisition (2016)<br>● Sapura Energy Berhad & OMV acquisition– Independent Technical Expert Report (2018)<br>● Kulim Energy Indonesian Asset Acquisition (2020) |
| Professional Membership | Member of Institute of Geology Malaysia (IGM) Member ID: IGM710<br>Board of Geologist Malaysia (BoG): P421<br>Geological Society of Malaysia (GSM): Full Member |
| Details of the recognised professional organization of the competent valuer. | <u>Recognized Professional Organization: Institute of Geology Malaysia (IGM)</u><br>Officially registered with the Malaysian Registrar of Societies in 1989 (PPM-003-14-11031989). Its establishment was in response to the urgent need for a single body to regulate the profession of geology in Malaysia. The seal of IGM portrays a hammer flanked by silhouette maps of Peninsular Malaysia and East Malaysia. The seal depicts the basic tool of the field geologist and thus symbolizes the role of the geologist in Malaysia. The objectives of IGM are as follows:<br>● To provide a central organisation for geologists in the form of a learned and scientific institute for geology and to provide for the definition of, and qualification for, the various branches of the profession of the geological sciences.<br>● To promote friendly interaction amongst geologists and to hold meetings for readings and discussions of matters relating to geology and their various arts and sciences connected therewith. |

| | |
|---|---|
| | ● To regulate and uphold the dignity, standing and reputation of the profession of geology.<br>● To promote and advance the knowledge, study and practice of geology and the various arts and sciences connected therewith.<br>● To assist, advise and cooperate with government departments and other private or public bodies in an honorary capacity on questions relating to the science of geology and policy in respect of land and earth resource utilisation and all other matters connected therewith.<br><br><u>Recognized Professional Organization: Board of Geologist Malaysia (BoG)</u><br><br>The Board was established in November 2014 under the Geologists Act 2008, Act 689 Laws of Malaysia. The Board's mandate is for the registration of geologists, the regulations of geological practice and for related matters.<br><br>It was until late 2015, after the regulations cited as Geologists (Registration of Geologists) Regulations 2015 was approved and in force, the Board began its due process of registration. As it is at its infancy stage, the registration process was rather slow because of problems and challenges encountered that affect the administrative process.<br><br>Applications for various categories of geologists' registrations reached just above 2000 applications. However, at end of May 2016, the number of applicants registered was 625 and the number keeps growing. Hopefully, all geologists are aware of the requirements as they are duty bound to register with the Board of Geologists.<br><br>The Board is established under Section 3 of Geologists act 2008, Act 689 Laws of Malaysia. It is a body corporate and shall have perpetual succession. It consists of fourteen (14) members who shall be Malaysian citizens and shall be appointed by the Minister. The Board is headed by a Chairman, and other members include five (5) from public services, five (5) from private practice, two (2) persons who, in the opinion of the Minister can contribute to the development of the profession, and one (1) representative from Institute of Geology Malaysia (IGM). The Board appoints a Registrar of Geologists, in adherence to Section 29 of Geologists Act 2008. The Registrar duty is to ensure that a register is kept of every person who is suitably qualified to be registered as a geologist. This involves recording all entries of registration, suspension, revocation, removal and reinstatement in the Register. The Registrar shall be under the general control and direction of the Board, is charged with the duty of running the secretariat.<br><br>The Board appoints Committees in accordance to Section 14 of the Geologist Act 2008. Currently the Board has three (3) Committees namely:<br><br>1. Corporate Services and Finance (JHKK)<br>2. Legal, Ethics and Discipline (JPED)<br>3. Development and Professional Program (JPPP)<br><br>An elected Board Member respectively chairs each Committee and the Board may appoint any person to be a member of any committee established.<br><br>The Committee deals with all legal matters to determine and regulate the professional conduct and ethics of the geological profession. They investigate and recommend actions to be taken by the Board on matters pertaining to disputes or ethics and disciplinary matters. It advices the Board to consider and recommend reforms to the law relating to geological surveying, and reviewing on Acts and Regulations. |

| | |
|---|---|
| | The Committee is established in order to execute the scheme and curriculum for examination for admission to the geological profession. To undertake continuous professional development programmes for geologists and practitioners to further enhance their knowledge in the latest developments relating to the geological profession. To establish linkages with institutions such as universities, colleges, organisations and agencies with the Board for training courses and benefits of the profession.<br><br>Recognized Professional Organization: Geological Society of Malaysia (GSM)<br><br>The society was founded in 1967 with the aim of promoting the advancement of the earth sciences in Malaysia and the Southeast Asian (S.E.A) region. Currently, it has a membership of more than 600 earth scientists worldwide of various disciplines and expertise.<br><br>The society is active in organizing conferences such as the GEOSEA and National Geoscience Conference (NGC). The society also organize technical talks, field trips and forums for our members. |

## Appendix 4: Key elements of SK310 and SK408 PSCs

### SK408 PSC

Equity Parties

SOMV owns a 40% working interest in SK408 PSC and is the operator of Larak and Bakong fields. Sarawak Shell Berhad owns 30% working interest and is the operator of Gorek field. PETRONAS Carigali Sdn. Bhd. holds the remaining 30% working interest.

Contract Duration

This PSC was effective on December 12, 2012, with First Commercial Production (FCP) achieved on February 17, 2020. The PSC will expire on February 16, 2040.

Cash Payment

Cash Payment to the government is assessed at 10% of gross oil and/or gas sales volumes.

Research Cess

Research cess is assessed at 0.5% of the sum of Cost Oil and/or Cost Gas and contractors' portion of Profit Oil and/or Profit Gas as set by the PSC.

Recovery of Costs and Division of Profit

The percentage of gross production that shall be applicable for cost recovery and sharing of Profit Oil and/or Profit Gas shall be determined based on contractors' Revenue-Over-Cost (R/C) ratios and the specified threshold volumes of cumulative gas and liquid production.

Export Duty

Export duty is only applicable on the contractors' portion of Profit Oil on oil exported internationally based on the prevailing customs and excise regulations.

Supplemental Payments

If the prevailing cumulative R/C ratio exceeds one, the contractors are obligated to pay PETRONAS a Supplemental Payment which is an amount that is equal to 70% (for oil) and 60% (for gas) of the excess difference between the realised oil or gas price and prevailing base price on the Profit Oil or Profit Gas portion, less the export duties.

Abandonment Cess Payment

The contractors are required to pay to PETRONAS an abandonment cess payment on the first anniversary of production. The quantum of the annual payments is based on the abandonment estimates distributed over the remaining life of the PSC. The amounts paid to PETRONAS are cost recoverable under Cost Oil or Cost Gas. For

SK408, the abandonment cess payment covers both the facilities decommissioning costs and the well plug and abandonment costs.

Petroleum Income Tax (PITA)

Petroleum Income Tax is assessed at 38% of taxable income as per the 1967 Petroleum (Income Tax) Act. For marginal fields, the Income Tax is reduced to 25% of taxable income.

Capital Allowances

Capital allowances are allowed in determination of taxable income as per Malaysian tax guidelines provided by the Malaysian Inland Revenue Board.

Training Commitment

Training commitment that is agreeable by the parties is used for training of PETRONAS' personnel in respect of petroleum operations. Costs related to training commitment are recoverable.

**SK310 PSC**

Equity Parties

SOMV owns a 30% working interest in SK310 PSC and is the current operator of the PSC. Diamond Energy Sarawak Sdn. Bhd. owns 30% working interest and PETRONAS Carigali Sdn. Bhd. holds the remaining 40% working interest.

Contract Duration

This PSC was effective on June 17, 2008 and currently expires on June 16, 2037.

Cash Payment

Cash Payment to the government is assessed at 10% of gross oil and/or gas sales volumes.

Recovery of Costs and Division of Profit

The percentage of gross production that shall be applicable for cost recovery and sharing of Profit Oil and/or Profit Gas shall be determined based on contractors' Revenue-Over-Cost (R/C) ratios and the specified threshold volumes (THV) of cumulative gas and liquid production.

Export Duty

Export duty is only applicable on the contractors' portion of Profit Oil on oil exported internationally based on the prevailing customs and excise regulations.

Supplemental Payments

If the prevailing cumulative R/C ratio exceeds one, the contractors are obligated to pay PETRONAS a Supplemental Payment which is an amount that is equal to 70% (for oil) and 60% (for gas) of the excess difference between the realised oil or gas price and prevailing base price on the Profit Oil or Profit Gas portion, less the export duties.

Research Cess

Research cess is assessed at 0.5% of the sum of Cost Oil and/or Cost Gas and contractors' portion of Profit Oil and/or Profit Gas as set by the PSC.

Abandonment Cess Payment

The contractors are required to pay to PETRONAS an abandonment cess payment on the first anniversary of production. The quantum of the annual payments is based on the abandonment estimates distributed over the remaining life of the PSC using unit of production basis. The amounts paid to PETRONAS are cost recoverable under Cost Oil or Cost Gas. For SK310, the abandonment cess payment covers only the facilities decommissioning costs and does not include the well plug and abandonment costs.

Petroleum Income Tax (PITA)

Petroleum Income Tax is assessed at 38% of taxable income as per the 1967 Petroleum (Income Tax) Act. For marginal fields, the Income Tax is reduced to 25% of taxable income.

Capital Allowances

Capital allowances are allowed in determination of taxable income as per Malaysian tax guidelines provided by the Malaysian Inland Revenue Board.

Training Commitment

Training commitment that is agreeable by the parties is used for training of PETRONAS personnel in respect of petroleum operations. Costs related to training commitment are recoverable.

**Appendix 5: Production forecast by field, by category (P90 and P10).**

The production forecasts by field, for P90 (1P) and P10 (3P) categories based on ARPR 1.1.2024 are presented in the tables below.

The inclusion of these tables is to synchronize with the valuation done in CVR on the Low and High cases.

- P90 Production forecast:
  - Gas sales by PSC, field, and category (MMscfd).
  - Condensate by PSC, field, and category (Mstbd).
  - PLR by PSC and category (Mstbd).
- P10 Production forecast:
  - Gas sales by PSC, field, and category (MMscfd).
  - Condensate by PSC, field, and category (Mstbd).
  - PLR by PSC and category (Mstbd).

## P90 Production forecast – Gas sales by PSC, field, and category (MMscfd):

| PSC | SK408 | | | | SK310 |
|---|---|---|---|---|---|
| Field | Larak | Bakong | Gorek | Jerun | B15 |
| Category / Year | 1P | 1P | 1P | 1P | 1P |
| 2024 | 102.67 | 130.59 | 109.98 | 151.71 | 74.20 |
| 2025 | 68.68 | 130.99 | 67.54 | 500.00 | 0.00 |
| 2026 | 51.70 | 177.92 | 60.62 | 500.00 | 0.00 |
| 2027 | 60.37 | 142.69 | 36.37 | 460.90 | 0.00 |
| 2028 | 66.28 | 139.08 | 28.58 | 500.00 | 0.00 |
| 2029 | 66.24 | 138.71 | 24.25 | 500.00 | 0.00 |
| 2030 | 65.16 | 155.55 | 26.84 | 486.78 | 0.00 |
| 2031 | 52.63 | 161.87 | 0.00 | 411.91 | 0.00 |
| 2032 | 42.39 | 135.00 | 0.00 | 341.50 | 0.00 |
| 2033 | 33.52 | 117.05 | 0.00 | 283.12 | 0.00 |
| 2034 | 17.12 | 86.43 | 0.00 | 237.44 | 0.00 |
| 2035 | 0.00 | 57.36 | 0.00 | 197.32 | 0.00 |
| 2036 | 0.00 | 46.29 | 0.00 | 164.06 | 0.00 |
| 2037 | 0.00 | 45.11 | 0.00 | 136.48 | 0.00 |
| 2038 | 0.00 | 42.40 | 0.00 | 113.64 | 0.00 |
| 2039 | 0.00 | 0.00 | 0.00 | 91.94 | 0.00 |
| 2040 | 0.00 | 0.00 | 0.00 | 20.14 | 0.00 |
| 2041 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2042 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2043 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2044 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2045 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2046 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Total, Bscf** | **228.77** | **623.07** | **129.28** | **1860.38** | **27.08** |

## P90 Production forecast – Condensate by PSC, field, and category (Mstbd):

| PSC | SK408 | | | | SK310 |
|---|---|---|---|---|---|
| Field | Larak | Bakong | Gorek | Jerun | B15 |
| Category / Year | 1P | 1P | 1P | 1P | 1P |
| 2024 | 1.23 | 0.83 | 1.08 | 3.50 | 0.56 |
| 2025 | 0.75 | 0.80 | 0.66 | 11.53 | 0.00 |
| 2026 | 0.54 | 1.02 | 0.60 | 11.53 | 0.00 |
| 2027 | 0.61 | 0.78 | 0.36 | 10.64 | 0.00 |
| 2028 | 0.64 | 0.73 | 0.28 | 11.47 | 0.00 |
| 2029 | 0.62 | 0.69 | 0.24 | 10.57 | 0.00 |
| 2030 | 0.59 | 0.73 | 0.26 | 9.48 | 0.00 |
| 2031 | 0.48 | 0.73 | 0.00 | 7.44 | 0.00 |
| 2032 | 0.39 | 0.58 | 0.00 | 5.92 | 0.00 |
| 2033 | 0.31 | 0.49 | 0.00 | 4.84 | 0.00 |
| 2034 | 0.16 | 0.35 | 0.00 | 4.02 | 0.00 |
| 2035 | 0.00 | 0.23 | 0.00 | 3.33 | 0.00 |
| 2036 | 0.00 | 0.19 | 0.00 | 2.76 | 0.00 |
| 2037 | 0.00 | 0.18 | 0.00 | 2.29 | 0.00 |
| 2038 | 0.00 | 0.17 | 0.00 | 1.90 | 0.00 |
| 2039 | 0.00 | 0.00 | 0.00 | 1.57 | 0.00 |
| 2040 | 0.00 | 0.00 | 0.00 | 0.34 | 0.00 |
| 2041 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2042 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2043 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2044 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2045 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2046 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Total, MMstb** | **2.31** | **3.10** | **1.27** | **37.64** | **0.20** |

## P90 Production forecast – PLR by PSC, field, and category (Mstbd):

| PSC | SK408 | | | | SK310 |
|---|---|---|---|---|---|
| Field | Larak | Bakong | Gorek | Jerun | B15 |
| Category / Year | 1P | 1P | 1P | 1P | 1P |
| 2024 | 0.51 | 0.50 | 0.41 | 0.61 | 0.26 |
| 2025 | 0.34 | 0.50 | 0.25 | 2.00 | 0.00 |
| 2026 | 0.25 | 0.68 | 0.22 | 2.00 | 0.00 |
| 2027 | 0.30 | 0.55 | 0.13 | 1.84 | 0.00 |
| 2028 | 0.33 | 0.54 | 0.11 | 2.00 | 0.00 |
| 2029 | 0.33 | 0.54 | 0.09 | 2.00 | 0.00 |
| 2030 | 0.33 | 0.60 | 0.10 | 1.95 | 0.00 |
| 2031 | 0.26 | 0.63 | 0.00 | 1.65 | 0.00 |
| 2032 | 0.21 | 0.53 | 0.00 | 1.37 | 0.00 |
| 2033 | 0.17 | 0.46 | 0.00 | 1.13 | 0.00 |
| 2034 | 0.09 | 0.34 | 0.00 | 0.95 | 0.00 |
| 2035 | 0.00 | 0.23 | 0.00 | 0.79 | 0.00 |
| 2036 | 0.00 | 0.19 | 0.00 | 0.66 | 0.00 |
| 2037 | 0.00 | 0.19 | 0.00 | 0.55 | 0.00 |
| 2038 | 0.00 | 0.18 | 0.00 | 0.45 | 0.00 |
| 2039 | 0.00 | 0.00 | 0.00 | 0.37 | 0.00 |
| 2040 | 0.00 | 0.00 | 0.00 | 0.08 | 0.00 |
| 2041 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2042 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2043 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2044 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2045 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2046 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Total, MMstb** | **1.14** | **2.43** | **0.48** | **7.45** | **0.09** |

## P10 Production forecast – Gas sales by PSC, field, and category (MMscfd):

| PSC | SK408 | | | | SK310 |
|---|---|---|---|---|---|
| Field | Larak | Bakong | Gorek | Jerun | B15 |
| Category / Year | 3P | 3P | 3P | 3P | 3P |
| 2024 | 89.71 | 191.65 | 106.28 | 151.71 | 125.45 |
| 2025 | 82.07 | 147.63 | 96.77 | 500.00 | 47.25 |
| 2026 | 70.17 | 167.64 | 78.63 | 500.00 | 0.00 |
| 2027 | 54.86 | 142.41 | 57.03 | 500.00 | 0.00 |
| 2028 | 48.04 | 130.09 | 44.07 | 500.00 | 0.00 |
| 2029 | 59.10 | 133.15 | 30.24 | 500.00 | 0.00 |
| 2030 | 74.23 | 154.99 | 36.29 | 500.00 | 0.00 |
| 2031 | 74.22 | 155.00 | 36.29 | 500.00 | 0.00 |
| 2032 | 64.96 | 146.77 | 41.47 | 500.00 | 0.00 |
| 2033 | 59.00 | 142.61 | 60.48 | 491.11 | 0.00 |
| 2034 | 51.22 | 129.10 | 69.12 | 401.11 | 0.00 |
| 2035 | 45.25 | 117.35 | 57.89 | 308.65 | 0.00 |
| 2036 | 41.36 | 110.00 | 51.84 | 237.67 | 0.00 |
| 2037 | 32.95 | 98.50 | 38.02 | 183.19 | 0.00 |
| 2038 | 23.93 | 84.29 | 1.73 | 141.41 | 0.00 |
| 2039 | 24.29 | 77.74 | 0.00 | 106.02 | 0.00 |
| 2040 | 20.84 | 69.56 | 0.00 | 81.38 | 0.00 |
| 2041 | 2.23 | 55.14 | 0.00 | 0.00 | 0.00 |
| 2042 | 0.00 | 46.69 | 0.00 | 0.00 | 0.00 |
| 2043 | 0.00 | 43.86 | 0.00 | 0.00 | 0.00 |
| 2044 | 0.00 | 40.03 | 0.00 | 0.00 | 0.00 |
| 2045 | 0.00 | 5.86 | 0.00 | 0.00 | 0.00 |
| 2046 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Total, Bscf** | **335.23** | **872.37** | **294.24** | **2227.32** | **63.04** |

## P10 Production forecast – Condensate by PSC, field, and category (Mstbd):

| PSC | SK408 | | | | SK310 |
|---|---|---|---|---|---|
| Field | Larak | Bakong | Gorek | Jerun | B15 |
| Category / Year | 3P | 3P | 3P | 3P | 3P |
| 2024 | 1.79 | 2.42 | 1.05 | 4.47 | 0.94 |
| 2025 | 1.54 | 1.81 | 0.95 | 14.72 | 0.36 |
| 2026 | 1.27 | 2.01 | 0.77 | 14.72 | 0.00 |
| 2027 | 0.96 | 1.67 | 0.56 | 14.72 | 0.00 |
| 2028 | 0.82 | 1.49 | 0.43 | 14.72 | 0.00 |
| 2029 | 1.00 | 1.52 | 0.30 | 14.80 | 0.00 |
| 2030 | 1.22 | 1.74 | 0.36 | 14.45 | 0.00 |
| 2031 | 1.19 | 1.70 | 0.36 | 13.87 | 0.00 |
| 2032 | 1.02 | 1.58 | 0.41 | 13.34 | 0.00 |
| 2033 | 0.91 | 1.51 | 0.60 | 12.66 | 0.00 |
| 2034 | 0.78 | 1.35 | 0.68 | 10.09 | 0.00 |
| 2035 | 0.69 | 1.21 | 0.57 | 7.59 | 0.00 |
| 2036 | 0.63 | 1.13 | 0.51 | 5.77 | 0.00 |
| 2037 | 0.50 | 1.00 | 0.37 | 4.42 | 0.00 |
| 2038 | 0.37 | 0.86 | 0.02 | 3.40 | 0.00 |
| 2039 | 0.38 | 0.79 | 0.00 | 2.55 | 0.00 |
| 2040 | 0.33 | 0.71 | 0.00 | 2.01 | 0.00 |
| 2041 | 0.04 | 0.57 | 0.00 | 0.00 | 0.00 |
| 2042 | 0.00 | 0.49 | 0.00 | 0.00 | 0.00 |
| 2043 | 0.00 | 0.46 | 0.00 | 0.00 | 0.00 |
| 2044 | 0.00 | 0.42 | 0.00 | 0.00 | 0.00 |
| 2045 | 0.00 | 0.06 | 0.00 | 0.00 | 0.00 |
| 2046 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Total, MMstb** | **5.64** | **9.67** | **2.90** | **61.43** | **0.47** |

## P10 Production forecast – PLR by PSC, field, and category (Mstbd):

| PSC | SK408 | | | | SK310 |
|---|---|---|---|---|---|
| Field | Larak | Bakong | Gorek | Jerun | B15 |
| Category / Year | 3P | 3P | 3P | 3P | 3P |
| 2024 | 0.44 | 0.73 | 0.37 | 0.61 | 0.44 |
| 2025 | 0.40 | 0.56 | 0.34 | 2.00 | 0.17 |
| 2026 | 0.34 | 0.64 | 0.27 | 2.00 | 0.00 |
| 2027 | 0.27 | 0.54 | 0.20 | 2.00 | 0.00 |
| 2028 | 0.24 | 0.50 | 0.15 | 2.00 | 0.00 |
| 2029 | 0.29 | 0.51 | 0.11 | 2.00 | 0.00 |
| 2030 | 0.37 | 0.60 | 0.13 | 2.00 | 0.00 |
| 2031 | 0.37 | 0.60 | 0.13 | 2.00 | 0.00 |
| 2032 | 0.32 | 0.57 | 0.14 | 2.00 | 0.00 |
| 2033 | 0.29 | 0.55 | 0.21 | 1.96 | 0.00 |
| 2034 | 0.26 | 0.50 | 0.24 | 1.60 | 0.00 |
| 2035 | 0.23 | 0.46 | 0.20 | 1.23 | 0.00 |
| 2036 | 0.21 | 0.43 | 0.18 | 0.95 | 0.00 |
| 2037 | 0.17 | 0.39 | 0.13 | 0.73 | 0.00 |
| 2038 | 0.12 | 0.33 | 0.01 | 0.57 | 0.00 |
| 2039 | 0.12 | 0.31 | 0.00 | 0.42 | 0.00 |
| 2040 | 0.11 | 0.28 | 0.00 | 0.33 | 0.00 |
| 2041 | 0.01 | 0.22 | 0.00 | 0.00 | 0.00 |
| 2042 | 0.00 | 0.19 | 0.00 | 0.00 | 0.00 |
| 2043 | 0.00 | 0.18 | 0.00 | 0.00 | 0.00 |
| 2044 | 0.00 | 0.17 | 0.00 | 0.00 | 0.00 |
| 2045 | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 |
| 2046 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Total, MMstb** | **1.66** | **3.39** | **1.03** | **8.91** | **0.22** |

**Appendix 6: Contingent Resources for P90(1C), P50(2C) and P10(3C) for Teja and Pepulut for Assessment of Net Entitlement Resources.**

**Teja and Pepulut Production Forecast for Gas sales, MMscfd**

| PSC | SK408 | | | | | |
|---|---|---|---|---|---|---|
| Field | Teja | Pepulut | Teja | Pepulut | Teja | Pepulut |
| Category / Year | 1C | 1C | 2C | 2C | 3C | 3C |
| 2024 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 33.08 | 41.35 | 21.04 | 26.31 | 0.00 | 0.00 |
| 2028 | 53.82 | 81.70 | 53.26 | 66.57 | 0.00 | 0.00 |
| 2029 | 6.59 | 60.32 | 65.69 | 82.12 | 21.04 | 26.30 |
| 2030 | 0.00 | 38.08 | 65.65 | 82.06 | 39.44 | 49.31 |
| 2031 | 0.00 | 28.15 | 73.46 | 91.82 | 61.85 | 77.32 |
| 2032 | 0.00 | 19.07 | 73.43 | 91.79 | 73.63 | 92.04 |
| 2033 | 0.00 | 0.00 | 68.14 | 91.70 | 73.60 | 92.00 |
| 2034 | 0.00 | 0.00 | 43.35 | 83.99 | 73.15 | 91.44 |
| 2035 | 0.00 | 0.00 | 15.32 | 65.65 | 73.56 | 91.95 |
| 2036 | 0.00 | 0.00 | 0.00 | 50.86 | 73.51 | 91.89 |
| 2037 | 0.00 | 0.00 | 0.00 | 31.65 | 70.16 | 87.70 |
| 2038 | 0.00 | 0.00 | 0.00 | 2.11 | 73.43 | 91.79 |
| 2039 | 0.00 | 0.00 | 0.00 | 0.00 | 73.36 | 91.70 |
| 2040 | 0.00 | 0.00 | 0.00 | 0.00 | 73.24 | 91.55 |
| 2041 | 0.00 | 0.00 | 0.00 | 0.00 | 69.63 | 81.03 |
| 2042 | 0.00 | 0.00 | 0.00 | 0.00 | 69.48 | 67.61 |
| 2043 | 0.00 | 0.00 | 0.00 | 0.00 | 69.38 | 56.08 |
| 2044 | 0.00 | 0.00 | 0.00 | 0.00 | 69.29 | 45.98 |
| 2045 | 0.00 | 0.00 | 0.00 | 0.00 | 64.20 | 37.12 |
| 2046 | 0.00 | 0.00 | 0.00 | 0.00 | 16.51 | 10.40 |
| **Total, Bscf** | **34.12** | **98.06** | **174.96** | **279.82** | **415.54** | **464.72** |

## Teja and Pepulut Production Forecast for Condensate, Mstbd

| PSC | SK408 | | | | | |
|---|---|---|---|---|---|---|
| Field | Teja | Pepulut | Teja | Pepulut | Teja | Pepulut |
| Category / Year | 1C | 1C | 2C | 2C | 3C | 3C |
| 2024 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.55 | 0.69 | 0.35 | 0.44 | 0.00 | 0.00 |
| 2028 | 0.89 | 1.36 | 0.88 | 1.11 | 0.00 | 0.00 |
| 2029 | 0.11 | 1.00 | 1.09 | 1.36 | 0.35 | 0.44 |
| 2030 | 0.00 | 0.63 | 1.09 | 1.36 | 0.65 | 0.82 |
| 2031 | 0.00 | 0.47 | 1.22 | 1.52 | 1.03 | 1.28 |
| 2032 | 0.00 | 0.32 | 1.22 | 1.52 | 1.22 | 1.53 |
| 2033 | 0.00 | 0.00 | 1.13 | 1.52 | 1.22 | 1.53 |
| 2034 | 0.00 | 0.00 | 0.72 | 1.39 | 1.21 | 1.52 |
| 2035 | 0.00 | 0.00 | 0.25 | 1.09 | 1.22 | 1.53 |
| 2036 | 0.00 | 0.00 | 0.00 | 0.84 | 1.22 | 1.53 |
| 2037 | 0.00 | 0.00 | 0.00 | 0.53 | 1.16 | 1.46 |
| 2038 | 0.00 | 0.00 | 0.00 | 0.04 | 1.22 | 1.52 |
| 2039 | 0.00 | 0.00 | 0.00 | 0.00 | 1.22 | 1.52 |
| 2040 | 0.00 | 0.00 | 0.00 | 0.00 | 1.22 | 1.52 |
| 2041 | 0.00 | 0.00 | 0.00 | 0.00 | 1.16 | 1.35 |
| 2042 | 0.00 | 0.00 | 0.00 | 0.00 | 1.15 | 1.12 |
| 2043 | 0.00 | 0.00 | 0.00 | 0.00 | 1.15 | 0.93 |
| 2044 | 0.00 | 0.00 | 0.00 | 0.00 | 1.15 | 0.76 |
| 2045 | 0.00 | 0.00 | 0.00 | 0.00 | 1.07 | 0.62 |
| 2046 | 0.00 | 0.00 | 0.00 | 0.00 | 0.27 | 0.17 |
| **Total, MMstb** | **0.57** | **1.63** | **2.90** | **4.65** | **6.89** | **7.72** |

## Teja and Pepulut Production Forecast for PLR, Mstbd

| PSC | SK408 | | | | | |
|---|---|---|---|---|---|---|
| Field | Teja | Pepulut | Teja | Pepulut | Teja | Pepulut |
| Category / Year | 1C | 1C | 2C | 2C | 3C | 3C |
| 2024 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2035 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2036 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2037 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2038 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2039 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2040 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2041 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2042 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2043 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2044 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2045 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2046 | 0.00 | 0.00 | **0.00** | **0.00** | 0.00 | 0.00 |
| **Total, MMstb** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** |

# SapuraOMV Upstream Sdn. Bhd.

(Registration 201801040231(1302262-U))
(Incorporated in Malaysia)

## Financial statements for the year ended 31 December 2023

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**Contents** **Page**

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

## Directors' report

The directors have pleasure in submitting their report together with the audited financial statements of the Group and of the Company for the financial year ended 31 December 2023.

## Principal activities

The principal activity of the Company is investment holding and the principal activities of its subsidiaries are as described in Note 38 to the financial statements.

## Results

| | Group RM'000 | Company RM'000 |
|---|---|---|
| Profit for the year | 9,155 | 257,491 |

There were no material transfers to or from reserves or provisions during the financial year in the financial statements.

In the opinion of the directors, the results of the operations of the Group and of the Company during the financial year were not substantially affected by any item, transaction or event of a material and unusual nature.

## Dividend

No dividend has been paid or declared by the Company since the end of the previous financial year. The directors do not recommend any dividend payment in respect of the current financial year.

## Directors

The names of the directors of the Company in office since the beginning of the financial year to the date of this report are:

Peter Rudolf Zeilinger
Tan Sri Ibrahim Bin Menudin
Datuk Mohd Anuar Bin Taib
Berislav Gaso (appointed on 8 March 2023)
Reinhard Oswald (appointed on 1 March 2024)
Chew Seng Heng (appointed on 9 April 2024)
Reinhard Florey (appointed on 1 January 2023 and resigned on 8 March 2023)
Gabriel Selischi (resigned on 29 February 2024)
Tan Sri Dato' Seri Shahril Bin Shamsuddin (resigned on 5 February 2024)

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**Directors (cont'd.)**

The names of the directors of the Company's subsidiaries in office since the beginning of the financial year to the date of this report, excluding the directors already listed above are:

Wolfgang Stock
Muhammad Zamri Jusoh
Erwin Kroell
Giselle Patricia

**Directors' benefits**

Neither at the end of the financial year, nor at any time during that year, did there subsist any arrangement to which the Company was a party, whereby the directors might acquire benefits by means of the acquisition of shares in or debentures of the Company or any other body corporate.

Since the end of the previous financial year, no director has received or become entitled to receive a benefit (other than those shown below) by reason of a contract made by the Company or related corporations with any director or with a firm of which he is a member, or with a company in which he has a substantial financial interest.

The Directors benefits paid to or receivable by Directors in respect of the financial year ended 31 December 2023 are as follows:

| | RM'000 |
|---|---|
| Directors of the Company: | |
| Fees | 120 |

The Company maintains a Directors & Officers Management Liability insurance for the directors and officers of the Group. The total amount of sum insured for directors and officers of the Group and of the Company for the financial year amounted to RM50 million. No payment has been made to indemnify the directors and officers for the financial year ended 31 December 2023.

**Directors' interests**

According to the register of directors' shareholdings, none of the directors in office at the end of the financial year had interest in shares in the Company during the financial year and interests of the directors in related corporations were disclosed by related corporations.

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**Holding companies**

The immediate and ultimate holding companies of the Company are OMV Exploration & Production GmbH ("OMV EP") and OMV Aktiengesellschaft ("OMV AG"), both of which are incorporated in Austria.

**Other statutory information**

(a) Before the statements of comprehensive income and statements of financial position of the Group and of the Company were made out, the directors took reasonable steps:

(i) to ascertain that proper action had been taken in relation to the writing off of bad debts and the making of provision for doubtful debts and satisfied themselves that all known bad debts had been written off and that adequate provision for doubtful debts had been made; and

(ii) to ensure that any current assets which were unlikely to realise their value as shown in the accounting records in the ordinary course of business had been written down to an amount which they might be expected so to realise.

(b) At the date of this report, the directors are not aware of any circumstances which would render:

(i) the amount written off for bad debts or the amount of the provision for doubtful debts in the financial statements of the Group and of the Company inadequate to any substantial extent; and

(ii) the values attributed to the current assets in the financial statements of the Group and of the Company misleading.

(c) At the date of this report, the directors are not aware of any circumstances which have arisen which would render adherence to the existing method of valuation of assets or liabilities of the Group and of the Company misleading or inappropriate.

(d) At the date of this report, the directors are not aware of any circumstances not otherwise dealt with in this report or financial statements of the Group and of the Company which would render any amount stated in the financial statements misleading.

(e) At the date of this report, there does not exist:

(i) any charge on the assets of the Group or of the Company which has arisen since the end of the financial year which secures the liabilities of any other person; or

(ii) any contingent liability of the Group or of the Company which has arisen since the end of the financial year.

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**Other statutory information (cont'd.)**

(f) In the opinion of the directors:

(i) no contingent or other liability has become enforceable or is likely to become enforceable within the period of twelve months after the end of the financial year which will or may affect the ability of the Group or of the Company to meet their obligations when they fall due; and

(ii) no item, transaction or event of a material and unusual nature has arisen in the interval between the end of the financial year and the date of this report which is likely to affect substantially the results of the operations of the Group or of the Company for the financial year in which this report is made.

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**Auditors**

The auditors, KPMG PLT, have expressed their willingness to continue in office.

Auditors' remunerations at the Group and the Company during the year is RM553,000 and RM105,000 respectively.

There was no indemnify given or insurance effected for auditors of the Company.

Signed on behalf of the Board in accordance with a resolution of the directors dated 30 April 2024.

Datuk Mohd Anuar Bin Taib

Berislav Gaso

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**Statement by directors**
**Pursuant to Section 251(2) of the Companies Act 2016**

We, Datuk Mohd Anuar Bin Taib and Berislav Gaso, being two of the directors of SapuraOMV Upstream Sdn. Bhd., do hereby state that, in the opinion of the directors, the accompanying financial statements set out on pages 7 to 76 are drawn up in accordance with Malaysian Financial Reporting Standards, IFRS Accounting Standards as issued by the International Accounting Standards Board and the requirements of the Companies Act 2016 in Malaysia so as to give a true and fair view of the financial position of the Group and of the Company as at 31 December 2023 and of their financial performance and cash flows for the year then ended.

Signed on behalf of the Board in accordance with a resolution of the directors dated 30 April 2024.

Datuk Mohd Anuar Bin Taib

Berislav Gaso

**Statutory declaration**
**Pursuant to section 251(1)(b) of the Companies Act 2016**

I, Wolfgang Stock, being the officer primarily responsible for the financial management of SapuraOMV Upstream Sdn. Bhd., do solemnly and sincerely declare that the accompanying financial statements set out on pages 7 to 76 are, to the best of my knowledge and belief, correct, and I make this solemn declaration conscientiously believing the same to be true and by virtue of the provisions of the Statutory Declarations Act, 1960.

Subscribed and solemnly declared by
the abovenamed Wolfgang Stock
at Kuala Lumpur in the Federal Territory
on 30 April 2024

Wolfgang Stock

Before me,

PESURUHJAYA SUMPAH
No. PJS: W933
MOHD JAMIZAL BIN ZAINOL
1.2.2022 - 31.12.2024
MALAYSIA

Pesuruhjaya Sumpah-Level 53
Petronas Twin Towers 2,
Kuala Lumpur City Centre,
50250 Kuala Lumpur

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**Consolidated statement of comprehensive income**
**For the financial year ended 31 December 2023**

| | Note | Group 2023 RM'000 | Group 2022 RM'000 (restated) |
|---|---|---|---|
| Sales revenues | 3 | 1,328,964 | 1,402,070 |
| Other operating income | | 45,039 | 55,507 |
| **Total revenues and other income** | | 1,374,003 | 1,457,577 |
| Purchases (net of inventory variation) | 17 | (830) | (962) |
| Production and operating expenses | 17 | (87,849) | (72,292) |
| Production and similar taxes | | (51,694) | (99,277) |
| Selling and distribution expenses | | (87,416) | (77,570) |
| Administrative expenses | | (34,451) | (35,280) |
| Depreciation, amortisation and impairment charges | | (383,569) | (1,079,945) |
| Exploration expenses | | (507,724) | (180,651) |
| Other operating expenses | | (16,747) | (48,364) |
| **Operating result** | | 203,723 | (136,764) |
| Interest income | | 12,799 | 666 |
| Interest expenses | 4 | (146,641) | (79,232) |
| Other financial expenses | 5 | (27,554) | (25,665) |
| **Profit/(loss) before taxation** | 6 | 42,327 | (240,995) |
| Income tax expense | 8 | (33,172) | (290,944) |
| **Profit/(loss) for the year** | | 9,155 | (531,939) |
| **Other comprehensive income:** | | | |
| *Items that may be reclassified (subsequently to profit or loss)* | | | |
| Foreign currency translation differences, representing other comprehensive income, net of tax | | 193,604 | 174,406 |
| **Total comprehensive income/(loss) for the year** | | 202,759 | (357,533) |

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**Company statement of comprehensive income**
**For the financial year ended 31 December 2023**

| | Note | Company 2023 RM'000 | 2022 RM'000 |
|---|---|---|---|
| Dividend income | | 421,571 | 87,883 |
| Other operating income | | 1,183 | 13,644 |
| Administrative expenses | | (213) | (1,054) |
| Reversal of consulting expenses | | 2,279 | - |
| Allowance for impairment on investment in a subsidiary company | 30 | - | (566,632) |
| Allowance for impairment on amount due from a subsidiary company | 31 | (4,311) | (153,940) |
| Other operating expenses | | (980) | (1,244) |
| **Operating result** | | 419,529 | (621,343) |
| Interest income | | 220 | 75 |
| Interest expenses | 4 | (142,624) | (79,977) |
| Other financial expenses | 5 | (19,550) | (14,205) |
| **Profit/(loss) before taxation** | 6 | 257,575 | (715,450) |
| Income tax expense | 8 | (84) | (63) |
| **Profit/(loss) for the year** | | 257,491 | (715,513) |
| **Other comprehensive income:** | | | |
| *Items that may be reclassified (subsequently to profit or loss)* | | | |
| Foreign currency translation differences, representing other comprehensive income, net of tax | | 181,352 | 168,075 |
| **Total comprehensive profit/(loss) for the year** | | 438,843 | (547,438) |

The accompanying accounting policies and explanatory notes form an integral part of the financial statements.

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**Consolidated statement of financial position**
**As at 31 December 2023**

| | Note | Group 31.12.2023 RM'000 | 31.12.2022 RM'000 (restated) | 01.01.2022 RM'000 (restated) |
|---|---|---|---|---|
| **Assets** | | | | |
| **Non-current assets** | | | | |
| Plant and equipment | 9 | 159 | 96 | 396 |
| Intangible assets | 10 | 357,440 | 668,773 | 600,826 |
| Oil and gas assets | 11 | 5,413,284 | 4,764,820 | 4,475,223 |
| Assets under construction | 11 | 21,362 | 12,493 | 26,217 |
| Right-of-use assets | 12 | 10,033 | 21,435 | 319 |
| Goodwill on acquisition | 14 | 994,139 | 941,472 | 1,533,222 |
| Long-term receivable | 15 | 45,430 | 37,676 | 23,972 |
| Deferred tax assets | 16 | 15,739 | 37,996 | 28,021 |
| | | 6,857,586 | 6,484,761 | 6,688,196 |
| **Current assets** | | | | |
| Inventories | 17 | 4,756 | 1,824 | 2,937 |
| Trade receivables | 18 | 154,725 | 169,893 | 97,262 |
| Other financial assets | 18 | 682,138 | 565,668 | 346,261 |
| Other non-financial assets | 19 | 97,664 | 87,892 | 27,746 |
| Tax recoverable | | 20,456 | 20,985 | 28,680 |
| Cash and cash equivalents | 20 | 456,947 | 510,130 | 261,663 |
| | | 1,416,686 | 1,356,392 | 764,549 |
| **Total assets** | | 8,274,272 | 7,841,153 | 7,452,745 |
| **Equity and liabilities** | | | | |
| **Equity attributable to equity holders of the Company** | | | | |
| Share capital | 21 | 4,443,120 | 4,443,120 | 4,443,120 |
| Foreign currency translation reserve | 22 | 485,817 | 292,213 | 117,807 |
| Accumulated losses | | (1,278,243) | (1,287,398) | (755,459) |
| | | 3,650,694 | 3,447,935 | 3,805,468 |

201801040231 (1302262-U)

SapuraOMV Upstream Sdn. Bhd.
(Incorporated in Malaysia)

**Consolidated statement of financial position (cont'd.)**
**As at 31 December 2023**

| | Note | Group 31.12.2023 RM'000 | 31.12.2022 RM'000 (restated) | 01.01.2022 RM'000 (restated) |
|---|---|---|---|---|
| **Non-current liabilities** | | | | |
| Amount due to immediate holding company | 23 | 1,638,539 | 1,551,736 | 1,481,211 |
| Borrowings | | - | - | 52,900 |
| Provision for asset retirement obligations | 24 | 84,366 | 83,441 | 81,711 |
| Deferred tax liabilities | 16 | 1,561,682 | 1,593,287 | 1,461,745 |
| Lease liabilities | 13 | 1,788 | 11,332 | - |
| | | 3,286,375 | 3,239,796 | 3,077,567 |
| **Current liabilities** | | | | |
| Amount due to a corporate shareholder | 25 | 19,794 | 18,668 | 17,983 |
| Amount due to ultimate holding company | 26 | 1,732 | 1,618 | - |
| Amount due to immediate holding company | 23 | 75,153 | 55,871 | 29,183 |
| Lease liabilities | 13 | 9,377 | 11,282 | 413 |
| Trade payables | 27 | 1,075,720 | 859,897 | 425,193 |
| Other financial liabilities | 27 | 56,942 | 66,975 | 27,803 |
| Other non-financial liabilities | 28 | 18,113 | 24,746 | 9,242 |
| Other provisions | 29 | 16,764 | 14,237 | 22,608 |
| Taxation | | 63,608 | 100,128 | 37,285 |
| | | 1,337,203 | 1,153,422 | 569,710 |
| **Total liabilities** | | 4,623,578 | 4,393,218 | 3,647,277 |
| **Total equity and liabilities** | | 8,274,272 | 7,841,153 | 7,452,745 |

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**Company statement of financial position**
**As at 31 December 2023**

| | Note | Company 2023 RM'000 | 2022 RM'000 |
|---|---|---|---|
| **Non-current asset** | | | |
| Investment in a subsidiary company | 30 | 5,274,408 | 4,994,990 |
| **Current assets** | | | |
| Amounts due from subsidiary companies | 31 | 46,041 | 32,918 |
| Other financial asset | 18 | 14,528 | 33,210 |
| Other non-financial asset | 19 | 2,535 | 57 |
| Tax recoverable | | 139 | 663 |
| Cash and cash equivalents | 20 | 4,898 | 5,518 |
| | | 68,141 | 72,366 |
| **Total assets** | | 5,342,549 | 5,067,356 |
| **Equity and liabilities** | | | |
| **Equity attributable to equity holders of the Company** | | | |
| Share capital | 21 | 4,443,120 | 4,443,120 |
| Foreign currency translation reserve | 22 | 461,453 | 280,101 |
| Accumulated losses | | (1,348,381) | (1,605,872) |
| | | 3,556,192 | 3,117,349 |
| **Non-current liabilities** | | | |
| Amount due to immediate holding company | 23 | 1,638,539 | 1,551,736 |
| **Current liabilities** | | | |
| Amount due to a corporate shareholder | 25 | 18,918 | 17,916 |
| Amount due to ultimate holding company | 26 | 1,732 | 1,618 |
| Amount due to immediate holding company | 23 | 75,153 | 55,871 |
| Amount due to subsidiary company | 32 | 39,312 | 304,565 |
| Other financial liabilities | 27 | 3,200 | 11,815 |
| Other non-financial liabilities | 28 | 9,342 | 6,348 |
| Other provisions | 29 | 161 | 138 |
| | | 147,818 | 398,271 |
| **Total liabilities** | | 1,786,357 | 1,950,007 |
| **Total equity and liabilities** | | 5,342,549 | 5,067,356 |

The accompanying accounting policies and explanatory notes form an integral part of the financial statements.

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**Consolidated statement of changes in equity**
**For the financial year ended 31 December 2023**

| | <---------- Non-distributable ----------> | | | |
|---|---|---|---|---|
| | Share capital RM'000 | Foreign currency translation reserve RM'000 | Accumulated losses RM'000 | Total RM'000 |
| **Group** | | | | |
| **At 1 January 2022** | 4,443,120 | 117,807 | (755,459) | 3,805,468 |
| Loss for the year | - | - | (531,939) | (531,939) |
| Other comprehensive income for the year | - | 174,406 | - | 174,406 |
| Total comprehensive loss for the year | - | 174,406 | (531,939) | (357,533) |
| **At 31 December 2022** | 4,443,120 | 292,213 | (1,287,398) | 3,447,935 |
| **At 1 January 2023** | 4,443,120 | 292,213 | (1,287,398) | 3,447,935 |
| Profit for the year | - | - | 9,155 | 9,155 |
| Other comprehensive income for the year | - | 193,604 | - | 193,604 |
| Total comprehensive income for the year | - | 193,604 | 9,155 | 202,759 |
| **At 31 December 2023** | 4,443,120 | 485,817 | (1,278,243) | 3,650,694 |

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**Company statement of changes in equity**
**For the financial year ended 31 December 2023**

| | <---------- Non-distributable ----------> | | | |
|---|---|---|---|---|
| | Share capital RM'000 | Foreign currency translation reserve RM'000 | Accumulated losses RM'000 | Total RM'000 |
| **Company** | | | | |
| **At 1 January 2022** | 4,443,120 | 112,026 | (890,359) | 3,664,787 |
| Loss for the year | - | - | (715,513) | (715,513) |
| Other comprehensive income for the year | - | 168,075 | - | 168,075 |
| Total comprehensive loss for the year | - | 168,075 | (715,513) | (547,438) |
| **At 31 December 2022** | 4,443,120 | 280,101 | (1,605,872) | 3,117,349 |
| **At 1 January 2023** | 4,443,120 | 280,101 | (1,605,872) | 3,117,349 |
| Profit for the year | - | - | 257,491 | 257,491 |
| Other comprehensive income for the year | - | 181,352 | - | 181,352 |
| Total comprehensive income for the year | - | 181,352 | 257,491 | 438,843 |
| **At 31 December 2023** | 4,443,120 | 461,453 | (1,348,381) | 3,556,192 |

The accompanying accounting policies and explanatory notes form an integral part of the financial statements.

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**Consolidated statement of cash flows**
**For the financial year ended 31 December 2023**

| | 2023 RM'000 | 2022 RM'000 |
|---|---|---|
| **Cash flows from operating activities** | | |
| Profit/(loss) before taxation | 42,327 | (240,995) |
| Adjustments for: | | |
| Amortisation of computer software | 354 | 230 |
| Depreciation of plant and equipment | 71 | 394 |
| Depreciation of oil and gas assets | 370,861 | 403,649 |
| Write off of intangible assets | 388,794 | 130,393 |
| Write off of assets under construction | 12 | 10,316 |
| Depreciation of right-of-use assets | 12,271 | 6,512 |
| Accretion of discount on lease liabilities | 538 | 384 |
| Accretion of discount on asset retirement obligations | 3,479 | 2,243 |
| Net unrealised foreign exchange loss | 9,784 | 20,009 |
| Impairment on oil and gas assets with unproved reserves | 60,260 | 7,252 |
| Impairment on goodwill on acquisition | - | 658,843 |
| (Reversal of)/provision for obsolete stock | (1,030) | 299 |
| Revision of decommissioning liabilities | (1,110) | - |
| Loss on disposal of plant and equipment | - | 64 |
| Interest income | (12,799) | (666) |
| Interest expense on amount due to immediate holding company | 134,067 | 72,740 |
| Commitment fee | 8,557 | 3,684 |
| Interest expense on a borrowing | - | 181 |
| Operating profit before working capital changes | 1,016,436 | 1,075,532 |
| (Increase)/decrease in inventories | (1,728) | 945 |
| Increase in financial and non-financial assets | (63,299) | (317,834) |
| Increase in financial and non-financial liabilities | 44,460 | 280,069 |
| Payment for asset retirement obligations | (8,029) | (13,635) |
| Net changes in balance with related parties | (1,404) | 3,913 |
| Cash generated from operating activities | 986,436 | 1,028,990 |
| Tax refund | 3,344 | - |
| Tax paid | (143,322) | (168,249) |
| Net cash generated from operating activities | 846,458 | 860,741 |

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**Consolidated statement of cash flows (cont'd.)**
**For the financial year ended 31 December 2023**

| | 2023 RM'000 | 2022 RM'000 |
|---|---|---|
| **Cash flows from investing activities** | | |
| Purchase of plant and equipment | (125) | (114) |
| Purchase of oil and gas assets | (683,177) | (339,178) |
| Purchase of intangible assets | (110,057) | (173,406) |
| Purchase of assets under construction | (7,968) | (70) |
| Interest received | 12,799 | 666 |
| Net cash used in investing activities | (788,528) | (512,102) |
| **Cash flows from financing activities** | | |
| Payment for lease liabilities | (12,033) | (5,763) |
| Repayment of borrowing | - | (54,927) |
| Payment for commitment fee | (8,533) | (2,078) |
| Interest paid | (116,935) | (51,959) |
| Net cash used in financing activities (Note A) | (137,501) | (114,727) |
| **Net (decrease)/increase in cash and cash equivalents** | (79,571) | 233,912 |
| **Effect of exchange rate changes** | 26,388 | 14,555 |
| **Cash and cash equivalents at beginning of year** | 510,130 | 261,663 |
| **Cash and cash equivalents at end of year** | 456,947 | 510,130 |

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**Consolidated statement of cash flows (cont'd.)**
**For the financial year ended 31 December 2023**

**Note A:**

A reconciliation of liabilities arising from financing activities is as follows:

**Group**

| | Lease liabilities RM'000 | Borrowing RM'000 | Amount due from ultimate holding company RM'000 | Loan from immediate holding company RM'000 | Total RM'000 |
|---|---|---|---|---|---|
| At 1 January 2023 | 22,614 | - | 1,618 | 1,594,023 | 1,618,255 |
| Net cash changes | (12,033) | - | (8,533) | (116,935) | (137,501) |
| Accretion of discount on lease liabilities | 538 | - | - | - | 538 |
| Commitment fee charged | - | - | 8,557 | - | 8,557 |
| Amortisation of borrowing cost | - | - | - | 134,067 | 134,067 |
| Foreign exchange movement | 46 | - | 90 | 89,635 | 89,771 |
| At 31 December 2023 | 11,165 | - | 1,732 | 1,700,790 | 1,713,687 |
| At 1 January 2022 | 413 | 53,091 | - | 1,501,196 | 1,554,700 |
| Net cash changes | (5,763) | (55,307) | (2,078) | (51,579) | (114,727) |
| Accretion of discount on lease liabilities | 384 | - | - | - | 384 |
| New leases during the year | 27,426 | - | - | - | 27,426 |
| Commitment fee charged | - | - | 3,684 | - | 3,684 |
| Amortisation of borrowing cost | - | 181 | - | 72,740 | 72,921 |
| Foreign exchange movement | 154 | 2,035 | 12 | 71,666 | 73,867 |
| At 31 December 2022 | 22,614 | - | 1,618 | 1,594,023 | 1,618,255 |

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**Company statement of cash flows**
**For the financial year ended 31 December 2023**

| | 2023 RM'000 | 2022 RM'000 |
|---|---|---|
| **Cash flows from operating activities** | | |
| Profit/(loss) before taxation | 257,575 | (715,450) |
| Adjustments for: | | |
| Interest expense on amount due to immediate holding company | 134,067 | 72,740 |
| Commitment fee | 8,557 | 3,684 |
| Interest expense on amount due to subsidiary company | - | 3,372 |
| Interest expense on a borrowing | - | 181 |
| Allowance for impairment loss on investment in a subsidiary company | - | 566,632 |
| Allowance for impairment loss on amount due from a subsidiary company | 4,311 | 153,940 |
| Net unrealised foreign exchange loss | 1,221 | 401 |
| Interest income | (220) | (75) |
| Operating profit before working capital changes | 405,511 | 85,425 |
| Decrease in financial and non-financial assets | 17,586 | 9,429 |
| Decrease in financial and non-financial liabilities | (6,449) | (35) |
| Waiver of amounts due from subsidiary companies | - | (69,344) |
| Net changes in balance with related parties | (292,773) | 83,777 |
| Cash generated from operating activities | 123,875 | 109,252 |
| Tax refund | 479 | - |
| Tax paid | (22) | (57) |
| Net cash generated from operating activities | 124,332 | 109,195 |
| **Cash flows from investing activity** | | |
| Interest received, representing net cash generated from investing activities | 220 | 75 |
| **Cash flows from financing activities** | | |
| Repayment of borrowing | - | (54,927) |
| Payment for commitment fee | (8,533) | (2,078) |
| Interest paid | (116,935) | (51,959) |
| Net cash used in financing activities (Note A) | (125,468) | (108,964) |
| **Net (decrease)/increase in cash and cash equivalents** | (916) | 306 |
| **Effect of exchange rate changes** | 296 | 241 |
| **Cash and cash equivalents at beginning of year** | 5,518 | 4,971 |
| **Cash and cash equivalents at end of year** | 4,898 | 5,518 |

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**Company statement of cash flows (cont'd.)**
**For the financial year ended 31 December 2023**

**Note A:**

A reconciliation of liabilities arising from financing activities is as follows: (cont'd.)

**Company**

| | Borrowing RM'000 | Amount due from ultimate holding company RM'000 | Loan from immediate holding company RM'000 | Total RM'000 |
|---|---|---|---|---|
| At 1 January 2023 | - | 1,618 | 1,594,023 | 1,595,641 |
| Net cash changes | - | (8,533) | (116,935) | (125,468) |
| Amortisation of borrowing cost | - | - | 134,067 | 134,067 |
| Commitment fee charged | - | 8,557 | - | 8,557 |
| Foreign exchange movement | - | 90 | 89,635 | 89,725 |
| At 31 December 2023 | - | 1,732 | 1,700,790 | 1,702,522 |
| At 1 January 2022 | 53,091 | - | 1,501,196 | 1,554,287 |
| Net cash changes | (55,307) | (2,078) | (51,579) | (108,964) |
| Amortisation of borrowing cost | 181 | - | 72,740 | 72,921 |
| Commitment fee charged | - | 3,684 | - | 3,684 |
| Foreign exchange movement | 2,035 | 12 | 71,666 | 73,713 |
| At 31 December 2022 | - | 1,618 | 1,594,023 | 1,595,641 |

The accompanying accounting policies and explanatory notes form an integral part of the financial statements.

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**Notes to the financial statements - 31 December 2023**

## 1. Corporate information

SapuraOMV Upstream Sdn. Bhd. ("the Company") is incorporated on 2 November 2018 and domiciled in Malaysia. The registered office and principal place of business of the Company is located at Level 53, Tower 2, PETRONAS Twin Towers, Kuala Lumpur City Centre, 50088 Kuala Lumpur.

The Company regards OMV EP as the immediate holding company and OMV AG, a company listed on Vienna Stock Exchange as the ultimate holding company, both of which are incorporated and domiciled in Austria. Sapura Energy Berhad ("SEB") is a corporate shareholder of the Company and the Company regards the subsidiary companies of SEB as related parties.

The principal activity of the Company is investment holding and the principal activities of its subsidiaries are as described in Note 38.

The financial statements were authorised for issue by the Board of Directors in accordance with a resolution of the directors on 30 April 2024.

## 2. Basis of preparation and material accounting policies

### 2.1 Basis of preparation

### 2.1.1 Basis of measurement

The financial statements of the Group and of the Company have been prepared in accordance with Malaysian Financial Reporting Standards ("MFRS"), IFRS Accounting Standards as issued by the International Accounting Standards Board ("IFRS Accounting Standards") and the requirements of the Companies Act, 2016 in Malaysia.

The financial statements have been prepared on historical cost basis unless otherwise disclosed in the accounting policies below.

The financial statements are presented in Ringgit Malaysia ("RM") and all values are rounded to the nearest thousand (RM'000), except when otherwise indicated.

**2. Basis of preparation and material accounting policies (cont'd.)**

**2.2 Statement of compliance**

**2.2.1 Adoption of new and revised pronouncements**

The Group and the Company adopted the following pronouncements mandatory for annual periods beginning on or after 1 January 2023.

On 1 January 2023, the Group and the Company adopted the following new and amended MFRSs:

| Description | Effective for annual periods beginning on or after |
|---|---|
| Amendments to MFRS 101 Presentation of Financial Statements - Disclosure of Accounting Policies | 1 January 2023 |
| Amendments to MFRS 108 Accounting Policies, Changes in Accounting Estimates and Errors: Definition of Accounting Estimates | 1 January 2023 |
| MFRS 17 Insurance Contracts | 1 January 2023 |
| Amendments to MFRS 17 Insurance Contracts: Initial Application of MFRS 17 and MFRS 9 - Comparative Information | 1 January 2023 |
| Amendments to MFRS 112 Income Taxes: Deferred Tax related to Assets and Liabilities arising from a Single Transaction and International Tax Reform - Pillar Two Model Rules | 1 January 2023 |

**2.2.2 Standards issued but not yet effective**

The standards that are issued but not yet effective up to the date of issuance of the Group's and of the Company's financial statements are disclosed below. The Group and the Company intend to adopt these standards, if applicable, when they become effective.

| Description | Effective for annual periods beginning on or after |
|---|---|
| Amendments to MFRS 107, Statement of Cash Flows and MFRS 7, Financial Instruments: Disclosures - Supplier Finance Arrangements | 1 January 2024 |
| Amendments to MFRS 16 Leases: Lease Liability in a Sale and Leaseback | 1 January 2024 |
| Amendments to MFRS 101, Presentation of Financial Statements - Non-current Liabilities with Covenants and Classification of Liabilities as Current or Non-current | 1 January 2024 |
| Amendments to MFRS 121 The Effects of Changes in Foreign Exchange Rates: Lack of Exchangeability | 1 January 2025 |

**2. Basis of preparation and material accounting policies (cont'd.)**

**2.2 Statement of compliance (cont'd.)**

**2.2.2 Standards issued but not yet effective (cont'd.)**

| Description | Effective for annual periods beginning on or after |
|---|---|
| Amendments to MFRS 10, Consolidated Financial Statements and MFRS 128, Investments in Associates and Joint Ventures - Sale or Contribution of Assets between an Investor and its Associate of Joint Venture | Deferred |

The adoption of the above standards are not expected to have any material impact on the financial statements of the Group and of the Company.

**2.3 Material accounting policies**

The Group and the Company adopted amendments to MFRS 101 Presentation of Financial Statements and MFRS Practice Statement 2 - Disclosures of Accounting Policies from 1 January 2023. The amendments require the disclosure of "material", rather than "significant", accounting policies. The amendments did not result in any changes to the accounting policy information disclosed in the financial statements.

The accounting policies set out below have been applied consistently to all periods presented in these financial statements and have been applied consistently by the Group and the Company, unless otherwise stated.

**2.3.1 Subsidiary and basis of consolidation**

The consolidated financial statements comprise the financial statements of the Company and its subsidiaries as at the reporting date. The financial statements of the subsidiaries used in the preparation of the consolidated financial statements are prepared for the same reporting date as the Company. Consistent accounting policies are applied for like transactions and events in similar circumstances.

The Company controls an investee if and only if the Company has all the following:

(i) Power over the investee (i.e. existing rights that give it the current ability to direct the relevant activities of the investee);

(ii) Exposure, or rights, to variable returns from its investment with the investee; and

(iii) The ability to use its power over the investee to affect its returns.

**2. Basis of preparation and material accounting policies (cont'd.)**

**2.3 Material accounting policies (cont'd.)**

**2.3.1 Subsidiary and basis of consolidation (cont'd.)**

When the Company has less than a majority of the voting rights of an investee, the Company considers the following in assessing whether or not the Company's voting rights in an investee are sufficient to give it power over the investee:

(i) The size of the Company's holding of voting rights relative to the size and dispersion of holdings of the other vote holders;

(ii) Potential voting rights held by the Company, other vote holders or other parties;

(iii) Rights arising from other contractual arrangements; and

(iv) Any additional facts and circumstances that indicate that the Company has, or does not have, the current ability to direct the relevant activities at the time that decisions need to be made, including voting patterns at previous shareholders' meetings.

Subsidiaries are consolidated when the Company obtains control over the subsidiary and ceases when the Company loses control of the subsidiary. All intra-group balances, income and expenses and unrealised gains and losses resulting from intra-group transactions are eliminated in full.

Losses within a subsidiary are attributed to the non-controlling interests even if that results in a deficit balance.

Changes in the Company's ownership interests in subsidiaries that do not result in the Company losing control over the subsidiaries are accounted for as equity transactions. The carrying amounts of the Group's interest and the non-controlling interests are adjusted to reflect the changes in their relative interests in the subsidiaries. The resulting difference is recognised directly in equity and attributed to owners of the Company.

When the Group loses control of a subsidiary, a gain or loss calculated as the difference between:

(i) the aggregate of the fair value of the consideration received and the fair value of any retained interest; and

(ii) the previous carrying amount of the assets and liabilities of the subsidiary and any non-controlling interest, are recognised in statement of comprehensive income.

The subsidiary's cumulative gain or loss which has been recognised in other comprehensive income and accumulated in equity are reclassified to statement of comprehensive income or where applicable, transferred directly to retained profit. The fair value of any investment retained in the former subsidiary at the date control is lost is regarded as the cost on initial recognition of an investment.

**2. Basis of preparation and material accounting policies (cont'd.)**

**2.3 Material accounting policies (cont'd.)**

**2.3.1 Subsidiary and basis of consolidation (cont'd.)**

Acquisitions of subsidiaries are accounted for using the acquisition method. The cost of an acquisition is measured as the aggregate of the consideration transferred, which is measured at acquisition date fair value, and the amount of any non-controlling interest in the acquiree. The Group elects on a transaction-by-transaction basis whether to measure the non-controlling interests in the acquiree either at fair value or at the proportionate share of the acquiree's identifiable net assets. Transaction costs incurred are expensed and included in administrative expenses.

***Business combinations***

Any contingent consideration to be transferred by the acquirer will be recognised at fair value at the acquisition date. Subsequent changes in the fair value of the contingent consideration which is deemed to be an asset or liability, will be recognised in accordance with MFRS 9: *Financial Instruments* either in statement of comprehensive income or a change to other comprehensive income. If the contingent consideration is classified as equity, it will not be remeasured. Subsequent settlement is accounted for within equity. In instances where the contingent consideration does not fall within the scope of MFRS 9, it is measured in accordance with the appropriate MFRS.

When the Group acquires a business, it assesses the financial assets and liabilities assumed for appropriate classification and designation in accordance with the contractual terms, economic circumstances and pertinent conditions as at the acquisition date. This includes the separation of embedded derivatives in host contracts by the acquiree.

If the business combination is achieved in stages, the Group remeasures its previously held equity interest in the acquiree at its acquisition-date fair value and recognise the resulting gain or loss, if any, in profit or loss or other comprehensive income, as appropriate.

Goodwill is initially measured as the excess of the aggregate of the consideration transferred and the amount recognised for non-controlling interests over the net identifiable assets acquired and liabilities assumed. If the fair value of the net assets acquired is in excess of the aggregate consideration transferred, the Group re-assesses whether it has correctly identified all of the assets acquired and all of the liabilities assumed and reviews the procedures used to measure the amounts to be recognised at the acquisition date. If the reassessment still results in an excess of the fair value of net assets acquired over the aggregate consideration transferred, then the gain is recognised in the statement of comprehensive income.

**2. Basis of preparation and material accounting policies (cont'd.)**

**2.3 Material accounting policies (cont'd.)**

**2.3.2 Subsidiaries**

In the Company's separate financial statements, investments in subsidiaries are accounted for at cost less impairment losses. On disposal of such investments, the difference between net disposal proceeds and their carrying amounts is included in the profit or loss.

**2.3.3 Joint arrangements**

Significant joint exploration and production activities in the Group are conducted through joint operations which are not structured through a separate vehicle. For these joint operations, the Group recognises in the consolidated financial statements its share of the assets held and liabilities and expenses incurred jointly with the other partners, as well as the Group's income from the sale of its share of the output and any liabilities and expenses that the Group has incurred in relation to the joint operation. Acquisitions of interests in a joint operation, in which the activity of the joint operation constitutes a business, are accounted for according to the relevant MFRS 3: *Business Combinations* principles for business combination accounting.

There are contractual arrangements similar to joint operations in the Group which are not jointly controlled and therefore do not meet the definition of a joint operation according to MFRS 11: *Joint Arrangements*. This is the case when the main decisions can be taken by more than one combination of affirmative votes of the involved parties or where one other party has control. The Group assesses whether such arrangements are within or out of scope of MFRS 11 on the basis of the relevant legal arrangements such as concession, license or joint operating agreements which define how and by whom the relevant decisions for these activities are taken. For these joint operations, the Group recognises in the consolidated financial statements its share of the assets held and liabilities and expenses incurred jointly with the other partners, as well as the group's income from the sale of its share of the output and any liabilities and expenses that the Group has incurred in relation to the joint operation. As acquisitions of interests in such arrangements are not within the scope of MFRS 3, the Group's accounting policy is to treat such transactions as asset acquisitions.

**2.3.4 Foreign currency**

**(a) Functional and presentation currency**

The individual financial statements of each entity in the Group are measured using the currency of the primary economic environment in which the entity operates ("the functional currency"). The functional currency of the Company is United State Dollar ("USD") and the consolidated and separate financial statements are presented in RM.

**2. Basis of preparation and material accounting policies (cont'd.)**

**2.3 Material accounting policies (cont'd.)**

**2.3.4 Foreign currency (cont'd.)**

**(b) Foreign currency transactions**

Monetary foreign currency balances are measured at closing rates, and exchange gains and losses accrued at statement of financial position date are recognised in the statement of comprehensive income.

The financial statements of Group companies with functional currencies different from the Group's presentation currency are translated using the closing rate method. Differences arising from statement of financial position items translated at closing rates are disclosed in other comprehensive income. Income statement items are translated at average rates for the period. The use of average rates for the income statement creates additional differences compared to the application of the closing rates in the statement of financial position which are directly adjusted in other comprehensive income.

**(c) Foreign operations**

The assets and liabilities of foreign operations are translated into RM at the rate of exchange ruling at the reporting date and income and expenses are translated at exchange rates at the dates of the transactions. The exchange differences arising on the translation are taken directly to other comprehensive income. On disposal of a foreign operation, the cumulative amount recognised in other comprehensive income and accumulated in equity under foreign currency translation reserve relating to that particular foreign operation is recognised in the profit or loss.

Goodwill and fair value adjustments arising on the acquisition of foreign operations are treated as assets and liabilities of the foreign operations and are recorded in the functional currency of the foreign operations and translated at the closing rate at the reporting date.

**2.3.5 Intangible assets, plant and equipment and assets under construction**

Intangible assets, plant and equipment and assets under construction are recognised at costs of acquisition or construction (including costs of major inspection and general overhauls). Costs for replacements of components are capitalised and carrying values of the replaced parts are derecognised. Costs relating to minor maintenance and repairs are treated as expenses in the year in which they are incurred.

**2. Basis of preparation and material accounting policies (cont'd.)**

**2.3 Material accounting policies (cont'd.)**

**2.3.5 Intangible assets, plant and equipment and assets under construction (cont'd.)**

Intangible assets and depreciable plant and equipment (except for oil and gas assets with unproved reserves) are amortised or depreciated on a straight-line basis over the useful economic life as follows:

| | |
|---|---|
| Furniture and fittings | 14% |
| Office equipment | 33% |
| Computer software | 33% |

**2.3.6 Oil and gas assets**

Oil and gas assets are recorded using the successful efforts method. The acquisition costs of geological and geophysical studies before the discovery of proved reserves form part of expenses for the period. The costs of wells are capitalised and reported as intangible assets until the existence or absence of potentially commercially viable oil or gas reserves is determined. Wells which are not commercially viable are expensed. The costs of exploration wells whose commercial viability has not yet been determined continue to be capitalised as long as the following conditions are satisfied:

- Sufficient oil and gas reserves have been discovered that would justify completion as a production well.

- Sufficient progress is being made in assessing the economic and technical feasibility to justify beginning field development in the near future.

- The period for which the entity has the right to explore in the specific area has not expired.

License acquisition costs and capitalised exploration and appraisal activities are generally not amortised as long as they are related to unproved reserves, but tested for impairment. Once the reserves are proved and commercial viability is established, the related assets are reclassified into tangible assets. Development expenditure on the construction, installation or completion of infrastructure facilities such as platforms and pipelines and drilling development wells is capitalised within oil and gas assets. Once production starts, depreciation commences. Capitalised exploration and development costs and support equipment are generally depreciated based on proved development reserves by applying the unit-of-production method; only capitalised exploration rights and acquired reserves are amortised on the basis of total proved reserves, unless a different reserves basis is more adequate.

**2. Basis of preparation and material accounting policies (cont'd.)**

**2.3 Material accounting policies (cont'd.)**

**2.3.7 Goodwill on acquisition**

Goodwill is calculated as the excess of the aggregate of the consideration transferred and the fair value of the equity previously held by the Group in the acquired entity over the net identifiable assets acquired and liabilities assumed. Goodwill is recorded as an asset and tested for impairment at least yearly. Impairments are recorded immediately through profit or loss, subsequent write-ups are not possible.

**2.3.8 Impairment of non-financial assets**

Intangible assets, plant and equipment, oil and gas assets and assets under construction are tested for impairment whenever events or changes in circumstances indicate that an asset may be impaired. Impairment tests are performed on the level of the asset or the smallest group of assets that generates cash inflows that are largely independent of those from other assets or groups of assets, called cash-generating units ("CGU").

If assets are determined to be impaired, the carrying amounts are written down to their recoverable amount, which is the higher of fair value less costs of disposal or value in use.

In assessing value in use, the estimated future cash flows are discounted to their present value using a post-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset or CGU. The pre-tax discount rate is determined by way of iteration. The cash flows are generally derived from the recent budgets and planning calculations, which are prepared separately for each of the Group's CGU to which the individual assets are allocated.

The fair value less costs of disposal is determined on the basis of the recent market transactions, if available. If no such transactions can be identified, an appropriate valuation model is used.

If the reasons for impairment no longer apply in a subsequent period, a reversal is recognised in profit or loss. The increased carrying amount related to the reversal of an impairment loss shall not exceed the carrying amount that would have been determined (net of amortisation and depreciation) had no impairment loss been recognised in prior years.

**2. Basis of preparation and material accounting policies (cont'd.)**

**2.3 Material accounting policies (cont'd.)**

**2.3.9 Non-derivative financial assets**

At initial recognition, the Group and the Company classify their financial assets as subsequently measured at amortised cost, fair value through other comprehensive income ("OCI") or fair value through profit or loss. The classification depends both on the Group's and the Company's business model for managing the financial assets and the contractual cash flow characteristics of the financial assets. All regular way trades are recognised and derecognised on the trade date, i.e., the date that the Group and the Company commit to purchase or sell the asset.

The Group and the Company classify all their financial assets as at amortised cost.

Debt instruments are measured at amortised cost if both of the following conditions are met:

- the asset is held within the business model whose objective is to hold assets in order to collect contractual cash flows; and

- the contractual terms of the financial asset give rise on specific dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

These assets are subsequently measured at amortised cost using the effective interest method less any impairment losses. Interest income, impairment losses and gains or losses on derecognition are recognised in profit or loss.

The Group and the Company recognise allowances for expected credit losses ("ECLs") for all financial assets measured at amortised costs. The ECL calculation is based on external or internal credit ratings of the counterparty and associated probabilities of default. Available forward-looking information is taken into account, if it has a material impact on the amount of valuation allowance recognised.

ECLs are recognised in two stages. Where there has not been a significant increase in the credit risk since initial recognition, credit losses are measured at 12 month ECLs. The 12 month ECL is the credit loss which results from default events that are possible within the next 12 months. The Group and the Company consider a financial asset to have low credit risk when its credit risk rating is equivalent to the definition of 'investment grade'.

**2. Basis of preparation and material accounting policies (cont'd.)**

**2.3 Material accounting policies (cont'd.)**

**2.3.9 Non-derivative financial assets (cont'd.)**

Where there has been a significant increase in the credit risk since initial recognition, a loss allowance is required for the lifetime ECL, i.e. the expected credit losses resulting from possible default events over the expected life of a financial asset. For this assessment, the Group and the Company consider all reasonable and supportable information that is available without undue cost or effort. Furthermore, the Group and the Company assume that the credit risk on a financial asset has significantly increased if it is more than 30 days past due. If the credit quality improves for a lifetime ECL asset, the Group and the Company revert to recognising allowances on a 12 month ECL basis. A financial asset is considered to be in default when the financial asset is 90 days past due unless there is reasonable and supportable information that demonstrate that a more lagging default criterion is appropriate. A financial asset is written off when there is no reasonable expectation that the contractual cash flows will be recovered.

For trade receivables from contracts with customers a simplified approach is adopted, where the impairment losses are recognised at an amount equal to lifetime expected credit losses. In case there are credit insurances or securities held against the balances outstanding, the ECL calculation is based on the probability of default of the insurer/securer for the insured/secured element of the outstanding balance and the remaining amount will take the probability of default of the counterparty.

The Group and the Company derecognise a financial asset when the contractual rights to the cash flows from the asset expire, or when it transfers the financial asset and substantially all the risks and rewards of ownership of the asset to another party.

**2.3.10 Cash and cash equivalents**

Cash and cash equivalents comprise cash at bank and on hand, which are subject to an insignificant risk of change in value.

**2.3.11 Inventories**

The value of the crude oil inventory is determined by the weighted average cost of production basis and is stated at the lower of cost or net realisable value at the reporting date. Costs of production comprise directly attributable costs as well as fixed and variable indirect material and production overhead costs. Production-related administrative costs are also included.

Inventories of consumable, materials and supplies are stated at the lower of cost and net realisable value. Cost is determined using the weighted average cost method. Net realisable value is the estimate of the selling price in the ordinary course of business, less the estimated costs necessary to make the sale.

**2. Basis of preparation and material accounting policies (cont'd.)**

**2.3 Material accounting policies (cont'd.)**

**2.3.12 Provisions**

**(a) Provision for asset retirement obligations**

Decommissioning and restoration costs are recognised when the Group has the obligation to dismantle and remove a facility or an item of oil and gas assets and to restore the site on which it is located, and when a reasonable estimate of that liability can be made. The amount recognised is the present value of the estimated future expenditure determined in accordance with local conditions and requirements.

A corresponding item of oil and gas assets of an amount equivalent to the provision is also created. The change in the present value of the provision for the expected costs due to the passage of time is included within finance costs.

Any change in the expected future cost, interest rate and inflation rate is reflected as an adjustment to the provision and the corresponding oil and gas assets.

**(b) Other provisions**

A provision is recorded for present obligations against third parties when it is probable that an obligation will occur and the settlement amount can be estimated reliably. Provisions for individual obligations are based on the best estimate of the amount necessary to settle the obligation, discounted to the present value in the case of long-term obligations.

**2.3.13 Non-derivative financial liabilities**

Liabilities are carried at amortised cost. Long-term liabilities are discounted using the effective interest rate method.

The Group and the Company derecognise a financial liability when the obligation specified in the contract is discharged, cancelled or expires.

**2.3.14 Borrowing costs**

Borrowing costs directly attributable to the acquisition, construction or production of qualified assets are capitalised until these assets are substantially ready for their intended use or sale. All other costs of borrowing are expensed in the period in which they are incurred.

**2. Basis of preparation and material accounting policies (cont'd.)**

**2.3 Material accounting policies (cont'd.)**

**2.3.15 Employee benefits**

**(a) Short term benefit**

Wages, salaries and bonuses and social security contributions are recognised as an expense in the period in which the associated services are rendered by employees. Short term accumulating compensated absences such as paid annual leave are recognised when services are rendered by employees that increase their entitlement to future compensated leave. Short term non-accumulating compensated leave such as sick leave are recognised when the absences occur.

**(b) Defined contribution plans**

In terms of defined contribution plans, the Group has no obligations beyond payment of the agreed premiums, and no provision is therefore recognised. The reported expenses corresponds to the contributions payable for the period. As required by law, companies in Malaysia make such contributions to the Employees Provident Fund ("EPF"). Some of the Group's foreign subsidiaries also make contributions to their respective countries' statutory pension schemes.

Employee benefits expenses are to be capitalised when directly attributable to oil and gas assets of proved and unproved reserves.

**2.3.16 Leases**

The Group as a lessee recognises lease liabilities and right-of-use assets for lease contracts according to MFRS 16 *Leases*. It applies the recognition exemption for short-term leases and leases in which the underlying asset is of low value and therefore does not recognise right-of-use assets and lease liabilities for such leases. Leases to explore for and use oil and natural gas, which comprise mainly land leases used for such activities, are not in the scope of MFRS 16. The rent for these contracts is recognised as expense on a straight-line basis over the lease term.

Non-lease components are separated from the lease components for the measurement of right-of-use assets and lease liabilities. Lease liabilities are recognised at the present value of fixed lease payments and lease payments which depend on an index or rate over the determined lease term with the applicable discount rate. Right-of-use assets are recognised at the value of the lease liability plus prepayments and initial direct costs.

**2. Basis of preparation and material accounting policies (cont'd.)**

**2.3 Material accounting policies (cont'd.)**

**2.3.16 Leases (cont'd.)**

The lease liability is measured at amortised cost using the effective interest method. It is remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a revision of in-substance fixed lease payments, or if there is a change in the Group's estimate of the amount expected to be payable under a residual value guarantee, or if the Group changes its assessment of whether it will exercise a purchase, extension or termination option. The Group will reassess whether it is reasonably certain to exercise the extension option if there is a significant change in circumstances within its control.

When the lease liability is remeasured as described in the above paragraph, a corresponding adjustment is made to the carrying amount of the right-of-use asset or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

**2.3.17 Sales revenues**

**Sale of crude oil and gas and its related products**

The Group's contracts with a customer for the sale of crude oil and gas generally include one performance obligation. Revenue from sale of crude oil and gas and its related by-products are recognised in at a point in time when control of the asset is transferred to the customer, generally on delivery of goods.

**2.3.18 Other revenues**

Other revenues include revenue from recharging of lease and rental costs to joint arrangement partners.

**2.3.19 Interest income**

Interest income is recognised on accrual basis using effective interest method.

**2.3.20 Dividend income**

Dividend income is recognised when the Company's right to receive payment is established.

**2. Basis of preparation and material accounting policies (cont'd.)**

**2.3 Material accounting policies (cont'd.)**

**2.3.21 Income taxes**

Current tax assets and liabilities are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted by the reporting date.

Current taxes are recognised in statement of profit or loss except to the extent that the tax relates to items recognised outside statements of profit or loss, either in other comprehensive income or directly in equity.

Deferred tax is provided using the liability method on temporary differences at the reporting date between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes.

Deferred tax liabilities are recognised for all temporary differences, except:

- where the deferred tax liability arises from the initial recognition of goodwill or of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss; and

- in respect of taxable temporary differences associated with investments in subsidiaries, associates and interests in joint arrangements, where the timing of the reversal of the temporary differences can be controlled and it is probable that the temporary differences will not reverse in the foreseeable future.

Deferred tax assets are recognised for all deductible temporary differences, carry forward of unused tax credits and unused tax losses, to the extent that it is probable that taxable profit will be available against which the deductible temporary differences, and the carry forward of unused tax credits and unused tax losses can be utilised except:

- where the deferred tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss; and

- in respect of deductible temporary differences associated with investments in subsidiaries, deferred tax assets are recognised only to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available against which the temporary differences can be utilised.

**2. Basis of preparation and material accounting policies (cont'd.)**

**2.3 Material accounting policies (cont'd.)**

**2.3.21 Income taxes (cont'd.)**

The carrying amount of deferred tax assets is reviewed at each reporting date and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all or part of the deferred tax asset to be utilised. Unrecognised deferred tax assets are reassessed at each reporting date and are recognised to the extent that it has become probable that future taxable profit will allow the deferred tax assets to be utilised.

When assessing whether taxable profits will be available against which it can utilise a deductible temporary differences, the Group has taken into account the restrictions in the tax laws on certain sources of taxable profits which may not be available against the deductions on the reversal of that deductible temporary differences. If the law imposes no such restrictions, the Group assesses a deductible temporary difference in combination with all of its other deductible temporary differences. However, if law restricts the utilisation of losses to deduction against income of a specific type, a deductible temporary difference is assessed in combination only with other deductible temporary differences of the appropriate type.

Deferred tax relating to items recognised outside statement of profit or loss is recognised outside statements of comprehensive income. Deferred tax items are recognised in correlation to the underlying transaction either in other comprehensive income or directly in equity and deferred tax arising from a business combination is adjusted against goodwill on acquisition.

Deferred tax assets and deferred tax liabilities are offset, if a legally enforceable right exists to set off current tax assets against current tax liabilities and the deferred taxes relate to the same taxable entity and the same taxation authority.

The assessment of the potential exposure to Pillar Two income taxes is based on the most recent tax filings, country-by-country reporting and financial statements available for the constituent entities in the Group. Based on the initial assessment carried out as at 31 December 2023, the Pillar Two effective tax rate in all jurisdiction in which the Group operates is above 15%. Therefore, the Group does not expect a potential exposure to Pillar Two top-up taxes.

**2.3.22 Share capital**

An equity instrument is any contract that evidences a residual interest in the assets of the Company after deducting all of its liabilities. Ordinary shares are equity instruments.

Ordinary shares are recorded at the proceeds received, net of directly attributable incremental transaction costs. Ordinary shares are classified as equity. Dividends on ordinary shares are recognised in equity in the period in which they are declared.

**2. Basis of preparation and material accounting policies (cont'd.)**

**2.3 Material accounting policies (cont'd.)**

**2.3.23 Segmental reporting**

Operating segment is reported in a manner consistent with the internal reporting provided for the chief operating decision-makers. The chief operating decision-makers are responsible for allocating resources, assessing performance of the operating segments and making strategic decisions. The single reportable segment of the Group is exploration, development and production of crude oil and natural gas.

The types of product sold, geographical area of operations, and major customers of the operating segment are disclosed in Notes 3, 11 and 35 (c) respectively.

**2.3.24 Exploration expenses**

Exploration expenses relate to costs associated with unproved reserves. These include geological and geophysical costs for the identification and investigation of areas with possible oil and gas reserves and administrative, legal and consulting costs in connection with exploration. They also include all impairments on exploration wells where no proved reserves could be demonstrated. Depreciation of economically successful exploration wells is reported as depreciation, amortisation and impairment charges.

**2.3.25 Significant accounting judgements and estimates**

The preparation of the Group's and of the Company's financial statements requires management to make judgements, estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities at the reporting date. However, uncertainty about these assumptions and estimates could result in outcomes that could require a material adjustment to the carrying amount of the asset or liability affected in the future. The judgements made in applying accounting policies and key sources of estimation uncertainty are discussed below:

**Key sources of estimation uncertainty**

The key assumptions concerning the future and other key sources of estimation uncertainty at the statement of financial position date, that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below:

**(a) Recoverability of intangible assets (oil and gas assets with unproved reserves), oil and gas assets and assets under construction**

Evaluating whether assets or CGUs are impaired or whether past impairments should be reversed, require the use of different estimates and assumptions such as price developments, production volumes and discount rates.

**2. Basis of preparation and material accounting policies (cont'd.)**

**2.3 Material accounting policies (cont'd.)**

**2.3.25 Significant accounting judgements and estimates (cont'd.)**

**(a) Recoverability of intangible assets (oil and gas assets with unproved reserves), oil and gas assets and assets under construction (cont'd.)**

The key estimates and assumptions used bear the risk of change due to the inherent volatile nature of the various macro-economic factors and the uncertainty in asset or CGU specific factors like reserve volumes and production profiles, which can impact the recoverable amount of assets and/or CGUs.

The key valuation assumptions for the recoverable amounts of oil and gas assets are the oil and natural gas prices, production volumes and discount rates. The production profiles were estimated based on reserve estimates and represent management's best estimate of future production. The cash flow projections for the first five years are based on the mid-term plan ("MTP") and thereafter on a "life of field" planning and therefore cover the whole life term of the field.

The nominal oil price assumptions are listed below:

**2023**

| | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|
| Brent oil price (USD/bbl) | 80.00 | 75.00 | 70.00 | 70.00 | 66.21 |
| Gas price (USD/boe) | 22.53 | 21.45 | 20.26 | 20.17 | 20.8 |

For the years 2029 until 2031, the Group and the Company assumed a Brent oil price of USD 68/bbl which is expected to gradually increase to USD 69/bbl until 2035. From 2035 onwards, the Branch applied a Brent oil price of USD 69/bbl. All before mentioned assumptions for the years after 2028 are based on 2028 real terms. Gas prices are assumed to remain stable in real terms after 2028.

The price and margin assumptions used in impairment testing are reviewed annually by management and approved by the Supervisory Board within the MTP. They are based on management's best estimate and were consistent with external sources. Whereas prices in the near term are anchored in recent forward prices and market developments, long-term price assumptions are developed using a variety of long-term forecasts by reputable experts and consultants and consider long-term views of global supply and demand. The Group and the Company's long-term assumptions take into consideration the impacts of the climate change and the energy transition to lower-carbon energy sources.

**2. Basis of preparation and material accounting policies (cont'd.)**

**2.3 Material accounting policies (cont'd.)**

**2.3.25 Significant accounting judgements and estimates (cont'd.)**

**(b) Goodwill**

The Group determines whether goodwill is impaired at least on an annual basis. This requires an estimation of the value-in-use of the CGU to which goodwill is allocated. Estimating a value-in-use amount requires management to make an estimate of the expected future cash flows from the CGU and also to choose a suitable discount rate in order to calculate the present value of those cash flows.

While the group belives that the assumptions are appropriate and reasonable, significant changes in the assumptions may materially affect the assessment of recoverable amounts and may lead to future impairment losses.

The key assumptions made in relation to the goodwill on consolidation are disclosed in Note 14 to the financial statements.

**(c) Estimation of oil and gas reserves**

The Group's oil and gas reserves are estimated by the Group's petroleum engineers in accordance with industry standards and reassessed at least once per year. In addition, external reviews are performed regularly.

Proved reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time at which the contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain.

Proved oil and gas reserves were estimated based on a 12-month average price, unless prices are defined by contractual arrangements.

The reserves are reassessed by the Group at least once per year. Changes to the estimates of proved oil and gas reserves impact prospectively the amount of depletion charged.

Oil and gas reserve estimates have a significant impact on the assessment of recoverability of carrying amounts of oil and gas assets of the Group. Downward revisions of these estimates could lead to impairment of the asset's carrying value and to reduced depreciation expense in the next period.

**2. Basis of preparation and material accounting policies (cont'd.)**

**2.3 Material accounting policies (cont'd.)**

**2.3.25 Significant accounting judgements and estimates (cont'd.)**

**(d) Recoverability of unproved oil and gas assets**

There may be cases when costs related to unproved oil and gas assets remain capitalised over longer periods while various appraisal and seismic activities continue in order to assess the size of the reservoir and its commerciality.

Further decisions on the optimum timing of such developments are made from a resource and portfolio point of view. As soon as there is no further intention to develop the discovery, the assets are immediately impaired.

**(e) Provision for asset retirement obligations**

The most significant asset retirement obligations of the Group are related to the plugging of wells, the abandonment of facilities and the removal and disposal of offshore installations. The majority of these activities are planned to occur many years into the future, while decommissioning technologies, costs, regulations and public expectations are constantly changing. Estimates of future restoration costs are based on reports prepared by Group engineers and on past experience. Any significant downward changes in the expected future costs or postponement in the future affect both the provision and the related asset, to the extent that there is sufficient carrying amount, otherwise the provision is reversed to income. Significant upward revisions trigger the assessment of the recoverability of the underlying asset.

Provisions for decommissioning and restoration costs require estimates of discount rates, which have material effects on the amounts of the provision. The real discount rates applied for calculating the provision for decommissioning and restoration costs were between 3.75% and 4.61% (2022: 3.88% and 4.15%). Further details are disclosed in Note 24 to the financial statements.

**(f) Incremental borrowing rate for lease liabilities**

The Group cannot readily determine the interest rate implicit in the lease, therefore, it uses its incremental borrowing rate ("IBR") to measure lease liabilities. The IBR is the rate of interest that the Group would have to pay to borrow over a similar term, and with a similar security, the funds necessary to obtain an asset of a similar value to the right-of-use asset in a similar economic environment. The Group first determines the closest available borrowing rates before using significant judgement to determine the adjustments required to reflect the term, security, value or economic environment of the respective leases. Further details of lease liabilities are disclosed in Note 13 to the financial statements.

**2. Basis of preparation and material accounting policies (cont'd.)**

**2.3 Material accounting policies (cont'd.)**

**2.3.25 Significant accounting judgements and estimates (cont'd.)**

**(g) Deferred tax assets**

The recognition of deferred tax assets requires an assessment of when those assets are likely to reverse, and a judgement as to whether or not there will be sufficient taxable profits available to offset the assets when they reverse. This assessment of recoverability requires assumptions regarding future profits and is therefore uncertain. In the Group, this assessment is based on detailed tax plannings which covers the whole life of field and a five year period in the other entities.

Changes in the assumptions regarding future profits can lead to an increase or decrease of the amount of deferred tax assets recognised which has an impact on the net income in the period in which the change occurs.

**3. Sales revenues**

| | Group | |
|---|---|---|
| | **2023** | **2022** |
| | **RM'000** | **RM'000** |
| Revenue from crude oil sales | 223,382 | 261,428 |
| Revenue from non-associated gas sales | 1,097,965 | 1,137,250 |
| Revenue from other sources | 7,617 | 3,392 |
| | 1,328,964 | 1,402,070 |

The type of goods sold by the Group are crude oil and non-associated gas.

Crude oil sales are made to PETCO Trading Labuan Company Limited ("PTLCL") (a subsidiary of Petroliam Nasional Berhad ("PETRONAS") trading in crude oil and petroleum products) and PETRONAS in Malaysia.

Non-associated gas sales are made solely to PETRONAS in Malaysia.

The goods transferred and the associated performance obligations are satisfied at a point in time. Variable elements obligation for returns and warranty are not applicable. The nominal payment term is disclosed in Note 18 to the financial statements.

Revenue from other sources relates to revenue from recharging of lease and rental costs to joint arrangement partners.

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

## 4. Interest expenses

| | Group | | Company | |
|---|---|---|---|---|
| | 2023 RM'000 | 2022 RM'000 | 2023 RM'000 | 2022 RM'000 |
| Interest expense on amount due to immediate holding company | 134,067 | 72,740 | 134,067 | 72,740 |
| Commitment fee | 8,557 | 3,684 | 8,557 | 3,684 |
| Interest expense on amount due to subsidiary company | - | - | - | 3,372 |
| Accretion of discount on lease liabilities | 538 | 384 | - | - |
| Accretion of discount on asset retirement obligations | 3,479 | 2,243 | - | - |
| Interest expense on borrowing | - | 181 | - | 181 |
| | 146,641 | 79,232 | 142,624 | 79,977 |

## 5. Other financial income and expenses

| | Group | | Company | |
|---|---|---|---|---|
| | 2023 RM'000 | 2022 RM'000 | 2023 RM'000 | 2022 RM'000 |
| Net realised foreign exchange gain from financing activities | 1,769 | 87 | 378 | 5 |
| Net unrealised foreign exchange (loss)/gain from financing activities | (10,283) | (11,363) | (888) | 179 |
| Withholding tax on interest expense | (20,161) | (10,938) | (20,161) | (10,938) |
| Revolving credit funds fees | - | (3,451) | - | (3,451) |
| Others | 1,121 | - | 1,121 | - |
| | (27,554) | (25,665) | (19,550) | (14,205) |

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

## 6. Profit/(loss) before taxation

| | Group | | Company | |
|---|---|---|---|---|
| | 2023 RM'000 | 2022 RM'000 | 2023 RM'000 | 2022 RM'000 |
| This is arrived at after charging/(crediting): | | | | |
| Auditors' remuneration | | | | |
| - Statutory audits | 553 | 436 | 105 | 87 |
| - Other services | - | 172 | - | - |
| Other auditors | 172 | - | - | - |
| Employee benefits expense (Note 7) | 34,432 | 37,534 | 133 | 255 |
| Net unrealised foreign exchange (gain)/loss from operating activities | (499) | 8,646 | 328 | 580 |
| Net realised foreign exchange (gain)/loss from operating activities | (3,729) | (3,429) | 310 | 132 |
| Rental expense for short term leases | 2,364 | 610 | - | - |
| Depreciation on plant and equipment (Note 9) | 71 | 394 | - | - |
| Depreciation on intangible assets (Note 10) | 354 | 230 | - | - |
| Write off of oil and gas assets with unproved reserves (Note 10) | 388,794 | 130,393 | - | - |
| Impairment on oil and gas assets with unproved reserves (Note 10) | 60,260 | 7,252 | - | - |
| Depreciation of oil and gas assets (Note 11) | 370,861 | 403,649 | - | - |
| Write off of assets under construction (Note 11) | 12 | 10,316 | - | - |
| Depreciation of right-of-use assets (Note 12) | 12,271 | 6,512 | - | - |
| Impairment loss on goodwill on acquisition (Note 14) | - | 658,843 | - | - |
| (Reversal of)/provision for obsolete stock (note 17) | (1,030) | 299 | - | - |
| Allowance for impairment loss on investment in a subsidiary company (Note 30) | - | - | - | 566,632 |
| Allowance for expected credit loss on amount due from a subsidiary company (Note 31) | - | - | 4,311 | 153,940 |
| Interest income from subsidiary companies | - | - | - | 14 |

## 7. Employee benefits expense

| | Group | | Company | |
|---|---|---|---|---|
| | 2023 RM'000 | 2022 RM'000 | 2023 RM'000 | 2022 RM'000 |
| Wages and salaries | 87,565 | 65,094 | - | - |
| Director fees | 120 | 120 | 120 | 120 |
| Social security contributions and taxes | 7,984 | 17,042 | - | - |
| Contributions to defined contribution plan | 11,383 | 10,313 | - | - |
| Other benefits | 9,566 | 10,229 | 13 | 135 |
| | 116,618 | 102,798 | 133 | 255 |
| Less: Billed to joint arrangement partners | (67,354) | (52,501) | - | - |
| Less: Capitalised in expenditure in oil and gas assets | (14,832) | (12,763) | - | - |
| | 34,432 | 37,534 | 133 | 255 |

Costs of employee benefits arising directly from the technical employees' timewriting to the oil and gas construction projects are capitalised in expenditure in oil and gas assets.

## 8. Income tax expense

| | Group | | Company | |
|---|---|---|---|---|
| | 2023 RM'000 | 2022 RM'000 (restated) | 2023 RM'000 | 2022 RM'000 |
| **Income tax:** | | | | |
| Current year | 157,785 | 228,204 | 83 | 51 |
| (Over)/under provision in prior year | (30,837) | 9,543 | 1 | 12 |
| | 126,948 | 237,747 | 84 | 63 |
| **Deferred tax (Note 16):** | | | | |
| Origination and reversal of temporary differences | (99,684) | 45,752 | - | - |
| Under provision in prior year | 5,908 | 7,445 | - | - |
| | (93,776) | 53,197 | - | - |
| Income tax expense | 33,172 | 290,944 | 84 | 63 |

Domestic income tax is calculated at the Malaysian and Bahamas statutory tax rate of 24% and 0% (2022: 24% and 0%) of the estimated assessable loss for the year, respectively.

**8. Income tax expense (cont'd.)**

Income from petroleum operation is calculated at the petroleum income tax rate of 38% in Malaysia (2022: 38%), 30% in Mexico (2022: 30%), 28% in New Zealand (2022: 28%) and 30% in Australia (2022: 30%).

Income from Malaysia's marginal field is calculated at the marginal field tax incentive rate of 25% (2022: 25%).

Reconciliations of income tax applicable to loss before taxation at the statutory income tax rate to income tax at the effective income tax rate of the Group and of the Company are as follows:

| | Group | |
|---|---|---|
| | **2023 RM'000** | **2022 RM'000 (restated)** |
| Profit/(loss) before taxation | 42,327 | (240,995) |
| Taxation at Malaysian petroleum income tax rate of 38% (2022: 38%) | 16,084 | (91,578) |
| Effect of operating expenses taxed at statutory income tax rate of 24% (2022: 24%) | 24,868 | 106,555 |
| Effect of different tax rate of marginal field tax incentive rate at 25% (2022: 25%) | (67,003) | (61,869) |
| Effect of different tax rate of Mexico petroleum income tax rate at 30% (2022: 30%) | 7,694 | 1,346 |
| Effect of different tax rate of New Zealand petroleum income tax rate at 28% (2022: 28%) | 182 | 179 |
| Effect of different tax rate of Australia petroleum income tax rate at 30% (2022: 30%) | 443 | 12,480 |
| Effect of expenses not deductible for tax purposes | 7,478 | 234,838 |
| Effect of currency translation on tax base | 10,447 | 11,101 |
| Effect of unrecognised deferred tax assets | 57,908 | 60,904 |
| Under provision of deferred tax in prior year | 5,908 | 7,445 |
| (Over)/under provision of income tax in prior year | (30,837) | 9,543 |
| Income tax expense during the year | 33,172 | 290,944 |

| | Company | |
|---|---|---|
| | **2023 RM'000** | **2022 RM'000** |
| Profit/(loss) before taxation | 257,575 | (715,450) |
| Taxation at Malaysian statutory income tax rate of 24% (2022: 24%) | 61,818 | (171,708) |
| Effect of income not subject to tax | (101,177) | (21,092) |
| Effect of expenses not deductible for tax purposes | 39,442 | 192,851 |
| Under provision of income tax in prior year | 1 | 12 |
| Income tax expense during the year | 84 | 63 |

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**9. Plant and equipment**

| Group | Furniture and fittings RM'000 | Office equipment RM'000 | Total RM'000 |
|---|---|---|---|
| **2023** | | | |
| **Cost** | | | |
| At 1 January 2023 | 677 | 1,334 | 2,011 |
| Addition | 18 | 107 | 125 |
| Foreign currency translation differences | 37 | 79 | 116 |
| At 31 December 2023 | 732 | 1,520 | 2,252 |
| **Accumulated depreciation** | | | |
| At 1 January 2023 | 673 | 1,242 | 1,915 |
| Depreciation during the year | 21 | 50 | 71 |
| Foreign currency translation differences | 38 | 69 | 107 |
| At 31 December 2023 | 732 | 1,361 | 2,093 |
| **Net carrying amount** | | | |
| At 31 December 2023 | - | 159 | 159 |
| **2022** | | | |
| **Cost** | | | |
| At 1 January 2022 | 630 | 1,282 | 1,912 |
| Addition | 30 | 84 | 114 |
| Disposal | (14) | (92) | (106) |
| Transfer to intangible assets | - | (1) | (1) |
| Foreign currency translation differences | 31 | 61 | 92 |
| At 31 December 2022 | 677 | 1,334 | 2,011 |
| **Accumulated depreciation** | | | |
| At 1 January 2022 | 630 | 886 | 1,516 |
| Depreciation during the year | 11 | 383 | 394 |
| Disposal | - | (69) | (69) |
| Transfer to intangible assets | - | (1) | (1) |
| Foreign currency translation differences | 32 | 43 | 75 |
| At 31 December 2022 | 673 | 1,242 | 1,915 |
| **Net carrying amount** | | | |
| At 31 December 2022 | 4 | 92 | 96 |

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**10. Intangible assets**

| Group | | Computer software RM'000 | Oil and gas assets with unproved reserves RM'000 | Total RM'000 |
|---|---|---|---|---|
| **2023** | | | | |
| **Cost** | | | | |
| At 1 January 2023 | | 2,201 | 761,594 | 763,795 |
| Additions | | 658 | 109,343 | 110,001 |
| Write off | (a) (i) | - | (388,794) | (388,794) |
| Foreign currency translation differences | | 140 | 34,814 | 34,954 |
| At 31 December 2023 | | 2,999 | 516,957 | 519,956 |
| **Accumulated depreciation, amortisation and impairment** | | | | |
| At 1 January 2023 | | 1,379 | 93,643 | 95,022 |
| Depreciation during the year | | 354 | - | 354 |
| Impairment | (b) (i) | - | 60,260 | 60,260 |
| Foreign currency translation differences | | 89 | 6,791 | 6,880 |
| At 31 December 2023 | | 1,822 | 160,694 | 162,516 |
| **Net carrying amount** | | | | |
| At 31 December 2023 | | 1,177 | 356,263 | 357,440 |

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**10. Intangible assets (cont'd.)**

| Group (cont'd.) | | Computer software RM'000 | Oil and gas assets with unproved reserves RM'000 | Total RM'000 |
|---|---|---|---|---|
| **2022** | | | | |
| **Cost** | | | | |
| At 1 January 2022 | | 1,251 | 683,756 | 685,007 |
| Additions | | 927 | 173,034 | 173,961 |
| Write off | (a) (ii) | - | (130,393) | (130,393) |
| Disposal | | (46) | - | (46) |
| Transfer from plant and equipment | | 1 | - | 1 |
| Transfer from assets under construction | | - | 4,214 | 4,214 |
| Foreign currency translation differences | | 68 | 30,983 | 31,051 |
| At 31 December 2022 | | 2,201 | 761,594 | 763,795 |
| **Accumulated depreciation and amortisation** | | | | |
| At 1 January 2022 | | 1,111 | 83,070 | 84,181 |
| Depreciation during the year | | 230 | - | 230 |
| Disposal | | (18) | - | (18) |
| Impairment | (b) (ii) | - | 7,252 | 7,252 |
| Transfer from plant and equipment | | 1 | - | 1 |
| Foreign currency translation differences | | 55 | 3,321 | 3,376 |
| At 31 December 2022 | | 1,379 | 93,643 | 95,022 |
| **Net carrying amount** | | | | |
| At 31 December 2022 | | 822 | 667,951 | 668,773 |

**10. Intangible assets (cont'd.)**

**(a) Write off**

**(i)** In the financial year, there had been a write off of one exploration wells of B14, amounting to RM388,794,000 due to license expired on 15 October 2023 and deemed relinquished to PETRONAS.

**(ii)** In the previous financial year, there had been a write off of one exploration wells of Australia, namely Kanga, amounting to RM130,392,000 as well had been found dry as a result of exploration drilling.

**(b) Impairment**

**(i)** There had been impairment loss on exploration and appraisal assets related to asset in Mexico, namely Ix-1, amounting to RM 60,260,000, due to delays and technical issues, hence plug and abandon programme has taken place. Recoverable amount is RM Nil and hence the asset is fully impaired.

**(ii)** In the previous financial year, there had been impairment loss on exploration and appraisal assets related to asset in Australia, namely Stairway, amounting to RM 7,252,000, due to no justification to support entry into Permit Year 5 with an exploration well commitment and the Group has elected to exit the permit and surrendered on 20 February 2023. Recoverable amount is RM Nil and hence the asset is fully impaired.

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

## 11. Oil and gas assets and assets under construction

| Group | | Oil and gas assets RM'000 | Assets under construction RM'000 | Total RM'000 |
|---|---|---|---|---|
| **2023** | | | | |
| **Cost** | | | | |
| At 1 January 2023 | | 6,210,217 | 12,493 | 6,222,710 |
| Additions | | 748,730 | 7,968 | 756,698 |
| Write off | (a) (i) | - | (12) | (12) |
| Change in decommissioning liabilities (Note 24) | | (7,124) | - | (7,124) |
| Revision of decommissioning liabilities | | 1,110 | - | 1,110 |
| Foreign currency translation differences | | 367,500 | 913 | 368,413 |
| At 31 December 2023 | | 7,320,433 | 21,362 | 7,341,795 |
| **Accumulated depletion, depreciation and amortisation/impairment** | | | | |
| At 1 January 2023 | | 1,445,397 | - | 1,445,397 |
| Depreciation during the year | | 370,861 | - | 370,861 |
| Foreign currency translation differences | | 90,891 | - | 90,891 |
| At 31 December 2023 | | 1,907,149 | - | 1,907,149 |
| **Net carrying amount** | | | | |
| At 31 December 2023 | | 5,413,284 | 21,362 | 5,434,646 |

201801040231 (1302262-U)

SapuraOMV Upstream Sdn. Bhd.
(Incorporated in Malaysia)

11. Oil and gas assets and assets under construction (cont'd.)

| Group (cont'd.) | | Oil and gas assets RM'000 | Assets under construction RM'000 | Total RM'000 |
|---|---|---|---|---|
| **2022** | | | | |
| **Cost** | | | | |
| At 1 January 2022 | | 5,466,171 | 26,217 | 5,492,388 |
| Additions | | 483,488 | 66 | 483,554 |
| Transfers | | 377 | (377) | - |
| Transfer to intagible assets | | | (4,214) | (4,214) |
| Write off | (a) (ii) | - | (10,316) | (10,316) |
| Change in decommissioning liabilities (Note 24) | | (4,385) | - | (4,385) |
| Foreign currency translation differences | | 264,566 | 1,117 | 265,683 |
| At 31 December 2022 | | 6,210,217 | 12,493 | 6,222,710 |
| **Accumulated depletion, depreciation and amortisation/impairment** | | | | |
| At 1 January 2022 | | 990,948 | - | 990,948 |
| Depreciation during the year | | 403,649 | - | 403,649 |
| Foreign currency translation differences | | 50,800 | - | 50,800 |
| At 31 December 2022 | | 1,445,397 | - | 1,445,397 |
| **Net carrying amount** | | | | |
| At 31 December 2022 | | 4,764,820 | 12,493 | 4,777,313 |

**11. Oil and gas assets and assets under construction (cont'd.)**

**(a) Write off**

**(i)** Write off during the year included mainly unsuccessful workovers and obsolete assets relating to blocks SK408.

**(ii)** In the previous financial year, write off included mainly unsuccessful workovers and obsolete assets relating to blocks SK310 and SK408, amounting to RM5,313,000 and RM5,001,000 respectively.

Included in oil and gas assets is development expenditures amounting to RM4,163 million (2022: RM3,213 million) which are not depreciated.

Included in the additions of oil and gas assets are employee benefits expense capitalised amounting to RM14.8 million (2022: RM12.8 million) as disclosed in Note 7.

**Production Sharing Contracts**

In Malaysia, the Group secures the rights to carry out exploitation of petroleum resource activities via various Production Sharing Contracts ("PSCs") with PETRONAS.

Under the terms of the various PSCs that the Group has entered into as PSC contractor, the PSC contractors bear all costs. The PSC contractors fund the work outlined in the approved work programme and budget and may recover their costs in barrels of crude oil or gas equivalent, in accordance with the terms of the respective PSCs. Remaining unrecovered costs in any quarter can be carried forward for recovery against production of crude oil in subsequent quarter/quarters. The contractors' share of production also includes an element of profit.

Title to all equipment and other assets purchased or acquired by PSC contractors exclusively for the purpose of petroleum operations, and which costs are recoverable in barrels of cost oil are vested with the host authority. The contractors retain the right to use those assets for the duration of the relevant PSCs.

Details of the participating interest of the respective joint arrangements within and outside Malaysia are disclosed in Note 39.

## 12. Right-of-use assets

| Group | Buildings RM'000 | Vessel RM'000 | Total RM'000 |
|---|---|---|---|
| **2023** | | | |
| **Cost** | | | |
| At 1 January 2023 | 36,901 | 7,235 | 44,136 |
| Foreign currency translation differences | 2,065 | 405 | 2,470 |
| At 31 December 2023 | 38,966 | 7,640 | 46,606 |
| **Accumulated depreciation** | | | |
| At 1 January 2023 | 21,093 | 1,608 | 22,701 |
| Depreciation during the year | 7,312 | 4,959 | 12,271 |
| Foreign currency translation differences | 1,377 | 224 | 1,601 |
| At 31 December 2023 | 29,782 | 6,791 | 36,573 |
| **Net carrying amount** | | | |
| At 31 December 2023 | 9,184 | 849 | 10,033 |
| **2022** | | | |
| **Cost** | | | |
| At 1 January 2022 | 15,716 | - | 15,716 |
| Additions | 20,255 | 7,171 | 27,426 |
| Foreign currency translation differences | 930 | 64 | 994 |
| At 31 December 2022 | 36,901 | 7,235 | 44,136 |
| **Accumulated depreciation** | | | |
| At 1 January 2022 | 15,397 | - | 15,397 |
| Depreciation during the year | 4,918 | 1,594 | 6,512 |
| Foreign currency translation differences | 778 | 14 | 792 |
| At 31 December 2022 | 21,093 | 1,608 | 22,701 |
| **Net carrying amount** | | | |
| At 31 December 2022 | 15,808 | 5,627 | 21,435 |

## 13. Lease liabilities

| | Group | |
|---|---|---|
| | 2023 RM'000 | 2022 RM'000 |
| At 1 January | 22,614 | 413 |
| Additions | - | 27,426 |
| Accretion of discount | 538 | 384 |
| Payments | (12,033) | (5,763) |
| Foreign currency translation differences | 46 | 154 |
| At 31 December | 11,165 | 22,614 |
| | | |
| Current | 9,377 | 11,282 |
| Non-current | 1,788 | 11,332 |
| | 11,165 | 22,614 |

The maturity analysis of lease liabilities are disclosed in Note 35(b).

The following are the amounts of leases recognised in statement of comprehensive income:

| | Group | |
|---|---|---|
| | 2023 RM'000 | 2022 RM'000 |
| Depreciation of right-of-use assets | 12,271 | 6,512 |
| Accretion of discount on lease liabilities | 538 | 384 |
| Rental expense for short term leases | 2,364 | 610 |
| Total amount recognised in profit or loss | 15,173 | 7,506 |

## 14. Goodwill on acquisition

| | Group | |
|---|---|---|
| | 2023 | 2022 |
| | RM'000 | RM'000 |
| At 1 January | 941,472 | 1,533,222 |
| Allowance for impairment loss during the year | - | (658,843) |
| Foreign currency translation differences | 52,667 | 67,093 |
| At 31 December | 994,139 | 941,472 |

The goodwill is arising from the acquisition of a subsidiary company, SapuraOMV Upstream (Holding) Sdn. Bhd. ("SEUPMY").

**Key assumptions used in value in use calculations**

The recoverable amount of the CGU has been determined based on value in use calculation using discounted cash flow projections. The cash flow projections cover the whole life term of the field.

The following describes each key assumption on which management has based its cash flow projections to undertake impairment testing of goodwill:

**(i) Discount rate**

The discount rate used by the Group for impairment test of the goodwill is a pre-tax discount rate of 14.11% (2022: 14.48%).

**(ii) Oil and natural gas prices**

The assumptions used for oil and gas prices for short and medium term are consistent with external sources. The nominal oil and gas price assumptions are further disclosed in Note 2.28(a).

**(iii) Production volume**

The production profiles were estimated based on reserves estimates (see Note 2.28(c)) and represent management's best estimate of future production.

**(iv) Production cost and capital expenditure**

The production cost and capital expenditure were estimated based on real time data and existing contract with yearly inflation rate of 2.43% (2022: 2.47%) which represent management's best estimation.

With regard to the assessment of value in use, a pre-tax discount rate increase of 5% would lead to an post-tax impairment of approximately RM24.4 million of the goodwill.

## 15. Long-term receivable

Included in the Group's long term receivable is abandonment cess contribution to the Abandonment Cess Fund, which is reimbursable to the Group upon execution of the abandonment of the oil and gas properties in accordance with the terms of the PSCs. The PSC Contractors have the right to request PETRONAS to reimburse the abandonment cess up to the cumulative amount paid upon the execution of the abandonment activities.

## 16. Deferred tax (assets)/liabilities

| | Group | |
|---|---|---|
| | 2023 RM'000 | 2022 RM'000 (restated) |
| At 1 January | 1,555,291 | 1,433,724 |
| Recognised in statement of comprehensive income (Note 8) | (93,776) | 53,197 |
| Foreign currency translation differences | 84,428 | 68,370 |
| At 31 December | 1,545,943 | 1,555,291 |

Presented after appropriate offsetting as follows:

| | Group | |
|---|---|---|
| | 2023 RM'000 | 2022 RM'000 (restated) |
| Deferred tax liabilities | 1,561,682 | 1,593,287 |
| Deferred tax assets | (15,739) | (37,996) |
| | 1,545,943 | 1,555,291 |

Presented prior to offsetting as follows:

| | Group | |
|---|---|---|
| | 2023 RM'000 | 2022 RM'000 (restated) |
| Deferred tax liabilities | 1,597,459 | 1,637,155 |
| Deferred tax assets | (51,516) | (81,864) |
| | 1,545,943 | 1,555,291 |

**16. Deferred tax (assets)/liabilities (cont'd.)**

The components and movements of deferred tax liabilities and assets during the financial year prior to offsetting are as follows:

**Deferred tax liabilities of the Group:**

| | 2023 RM'000 | 2022 RM'000 (restated) |
|---|---|---|
| **Accelerated capital allowances** | | |
| At 1 January | 1,631,796 | 1,558,168 |
| Recognised in statement of comprehensive income | (124,697) | (188) |
| Foreign currency translation differences | 87,852 | 73,816 |
| At 31 December | 1,594,951 | 1,631,796 |
| **Right-of-use assets** | | |
| At 1 January | 5,359 | 13 |
| Recognised in statement of comprehensive income | (3,067) | 5,297 |
| Foreign currency translation differences | 216 | 49 |
| At 31 December | 2,508 | 5,359 |

**Deferred tax assets of the Group:**

| | 2023 RM'000 | 2022 RM'000 (restated) |
|---|---|---|
| **Provisions** | | |
| At 1 January | (17,140) | (18,377) |
| Recognised in statement of comprehensive income | 6,481 | 2,092 |
| Foreign currency translation differences | (764) | (855) |
| At 31 December | (11,423) | (17,140) |
| **Lease liabilities** | | |
| At 1 January | (5,653) | (38) |
| Recognised in statement of comprehensive income | 3,093 | (5,563) |
| Foreign currency translation differences | (233) | (52) |
| At 31 December | (2,793) | (5,653) |
| **Unabsorbed losses and capital allowances** | | |
| At 1 January | (59,071) | (106,042) |
| Recognised in statement of comprehensive income | 24,414 | 51,559 |
| Foreign currency translation differences | (2,643) | (4,588) |
| At 31 December | (37,300) | (59,071) |

**16. Deferred tax (assets)/liabilities (cont'd.)**

Deferred tax assets have not been recognised in respect of the following items:

| | Group | |
|---|---|---|
| | 2023 | 2022 |
| | RM'000 | RM'000 |
| Unabsorbed capital allowances | 49,977 | - |
| Unutilised tax losses | 946,678 | 748,081 |
| | 996,655 | 748,081 |

Deferred tax assets have not been recognised due to uncertainty of its recoverability as they may not be used to offset against any future profits of other entities in the Group.

**17. Inventories**

| | Group | |
|---|---|---|
| | 2023 | 2022 |
| | RM'000 | RM'000 |
| **At cost** | | |
| Consumable, materials and spares | 4,564 | 1,039 |
| Crude oil | 192 | 785 |
| | 4,756 | 1,824 |
| **Expenses with inventories** | | |
| Inventories recognised as an expense during the year | (87,849) | (72,292) |
| Changes in inventories during the year | (1,860) | (663) |
| (Reversal of)/provision for obsolete stock | 1,030 | (299) |

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

## 18. Trade receivables and other financial assets

| | Note | Group 2023 RM'000 | Group 2022 RM'000 | Company 2023 RM'000 | Company 2022 RM'000 |
|---|---|---|---|---|---|
| **Trade receivables** | | | | | |
| Third parties | (a) | 154,725 | 169,893 | - | - |
| **Other financial assets** | (b) | | | | |
| Amount due from joint arrangement partners | | 657,220 | 504,362 | - | - |
| Deposits | | 3,607 | 3,512 | - | - |
| Sundry receivables | | 21,311 | 57,794 | 14,528 | 33,210 |
| | | 682,138 | 565,668 | 14,528 | 33,210 |
| Total financial assets at amortised cost | | 836,863 | 735,561 | 14,528 | 33,210 |

### (a) Trade receivables

Trade receivables are non-interest bearing. The Group's normal trade credit term is 30 (2022: 30) days. Overdue balances are reviewed regularly by senior management. Trade receivables are recognised at original invoice amounts which represent their fair values on initial recognition.

Ageing analysis of trade receivables

The ageing analysis of the Group's trade receivables is as follows:

| | Group 2023 RM'000 | Group 2022 RM'000 |
|---|---|---|
| Neither past due nor impaired | 154,725 | 169,893 |

Receivables that is neither past due nor impaired

Trade receivables that are neither past due nor impaired are creditworthy debtors with good payment records with the Group. Most of the Group's trade receivables arise from customers with many years of experience with the Group and losses have occurred infrequently.

None of the Group's trade receivables that are neither past due nor impaired have been renegotiated during the financial year.

**18. Trade receivables and other financial assets (cont'd.)**

**(b) Other financial assets**

Other financial assets are non-trade, unsecured, interest free and repayable on demand.

The amount due from joint arrangement partners represents cash call receivable from joint arrangement partners, net of joint arrangement expenditures, which are unsecured, interest free and repayable on demand.

Included in sundry receivable is income tax receivable and contingent payment from the acquirer of the discontinued operations, amounting to RM14.1 million (2022: RM32.8 million) which is unsecured, interest free and repayable on demand.

**19. Other non-financial assets**

| | Group | | Company | |
|---|---|---|---|---|
| | 2023 RM'000 | 2022 RM'000 | 2023 RM'000 | 2022 RM'000 |
| Goods and service tax receivable | 34,219 | 8,394 | - | - |
| Prepayments | 63,188 | 79,363 | 2,535 | 57 |
| Others | 257 | 135 | - | - |
| | 97,664 | 87,892 | 2,535 | 57 |

Included in prepayments are the amounts paid upfront to the suppliers for the services rendered for transportation and installation of offshore facilities.

**20. Cash and cash equivalents**

Other information on foreign currency risks of cash and cash equivalents are disclosed in Note 35 (a).

**21. Share capital**

| | Amount | | Number of shares | |
|---|---|---|---|---|
| | 2023 RM'000 | 2022 RM'000 | 2023 | 2022 |
| **Issued and fully paid** | | | | |
| **Ordinary shares** | | | | |
| At 1 January/31 December | 4,443,120 | 4,443,120 | 4,443,120 | 4,443,120 |

The holders of ordinary shares are entitled to receive dividends as and when declared by the Company. All ordinary shares rank equally with regards to the Company's residual assets.

## 22. Foreign currency translation reserve

The foreign currency translation reserve represents the exchange differences arising from the translation of the financial statements of the Group companies whose functional currencies are different from that of the Group's and of the Company's presentation currency.

## 23. Amount due to immediate holding company

| | Note | Group and Company 2023 RM'000 | Group and Company 2022 RM'000 (restated) |
|---|---|---|---|
| **Non-current** | | | |
| Loan from immediate holding company | (a) | 1,638,539 | 1,551,736 |
| **Current** | | | |
| Interest payable on loan from immediate holding company | (a) | 62,251 | 42,287 |
| Others | | 12,902 | 13,584 |
| | | 75,153 | 55,871 |
| | | 1,713,692 | 1,607,607 |

### (a) Loan from immediate holding company

Non-current amount due to immediate holding company relates to drawdown of USD350 million (2022: USD350 million) from a facility agreement entered into by OMV EP with a financial institution whereby the loan was extended to the Company. This forms part of the share subscription agreement and restructuring exercise between SEB, OMV EP, the Company and Sapura Upstream Assets Sdn. Bhd. ("SUA") on 31 January 2019.

The repayment date of the loan is 31 January 2025.

Current amount due to immediate holding company relates to interest payable to OMV EP on the loan. The interest charged is based on Secured Overnight Financing Rate ("SOFR") + 3% margin per annum, with an interest period repayable either 3 or 6 months period.

## 24. Provision for asset retirement obligations

| | Group | |
|---|---|---|
| | **2023 RM'000** | **2022 RM'000 (restated)** |
| At 1 January | 83,441 | 81,711 |
| Revision during the year* | (7,124) | (4,385) |
| Accretion of discount | 3,479 | 2,243 |
| Foreign currency translation differences | 4,570 | 3,872 |
| At 31 December | 84,366 | 83,441 |

* Included in the revision is the change in decommissioning liabilities in the accompanying oil and gas assets, amounting to RM7.1 million (2022: RM4.4 million) and the decommissioning income arising from the reversal of the provision amounting to RM1.1 million (2022: RMNil) as the accompanying oil and gas assets have been fully depreciated.

The Group revises its estimated future cost of decommissioning of oil and gas assets as a result of changes in inflation rate ranging from 2.00% to 2.51% and discounted using a discount rate of 3.75% to 4.61% over the period till the date when abandonment operation is expected to be carried out.

The unwinding of the discount rate is recognised in the interest expenses (Note 4) line of the statement of comprehensive income.

While the provision are based on the best estimate of future costs and the economic lives of the production facilities, there is uncertainty regarding the amount as the decommissioning activities will be carried out in the future and dependent to changes of various factors such as laws and regulation, advancement of technology, economy and political climate. Annual reviews are performed by management on the key assumptions applied for measurement of the provision such as the estimated abandonment costs, discount and inflation rate.

## 25. Amount due to a corporate shareholder

Amount due to a corporate shareholder are unsecured, interest free and repayable on demand.

## 26. Amount due to ultimate holding company

On 21 July 2022, the Company has entered into a USD200 million revolving credit facility agreement with the ultimate holding company.

The principal amount of the new facility is repayable within the facility and interest period up till the last day of the interest period i.e. the termination date of 31 July 2027. The interest charged is based on SOFR + 2.645% margin ("Margin") per annum, with an interest period repayable either 1, 3 or 6 months period.

The Company shall pay to the ultimate holding company a fee computed at the rate of 35% of the Margin on the available facility. The amount drawdown by the Company during the year was RMNil.

## 27. Trade payables and other financial liabilities

| | | Group | | Company | |
|---|---|---|---|---|---|
| | Note | 2023 RM'000 | 2022 RM'000 | 2023 RM'000 | 2022 RM'000 |
| **Trade payables** | (a) | | | | |
| Third parties | | 140,028 | 147,852 | - | - |
| Trade accruals | | 935,692 | 712,045 | - | - |
| | | 1,075,720 | 859,897 | - | - |
| **Other financial liabilities** | (b) | | | | |
| Amount due to joint arrangement partners | | 11,349 | 43,985 | - | - |
| Sundry payables | | 45,593 | 22,990 | 3,200 | 11,815 |
| | | 56,942 | 66,975 | 3,200 | 11,815 |
| Total trade payables and other financial liabilities at amortised cost | | 1,132,662 | 926,872 | 3,200 | 11,815 |

### (a) Trade payables

Trade payables are non-interest bearing and the normal trade credit terms granted to the Group and the Company range from 30 to 90 (2022: 30 to 90) days.

**27. Trade payables and other financial liabilities (cont'd.)**

**(b) Other financial liabilities**

The amount due to joint arrangement partners represents cash call payable to joint arrangement partners, net of joint arrangement expenditures, which are unsecured, interest free and repayable on demand.

Included in sundry payables are amount due to related parties of which are subsidiary companies of SEB amounting to RM3.1 million (2022: RM2.7 million), amount due to a joint arrangement partner for the utilisation of the joint arrangement partner's tax losses for block SK408 amounting to RM39.5 million (2022: RM11.5 million) and income tax accruals relating to a disposed subsidiary amounting to RMNil million (2022: RM5.7 million).

**28. Other non-financial liabilities**

| | Group | | Company | |
|---|---|---|---|---|
| | 2023 RM'000 | 2022 RM'000 | 2023 RM'000 | 2022 RM'000 |
| Withholding tax payable | 9,342 | 6,348 | 9,342 | 6,348 |
| Export duty payable | 56 | 35 | - | - |
| Production taxes payable | 2,525 | 13,128 | - | - |
| Others | 6,190 | 5,235 | - | - |
| | 18,113 | 24,746 | 9,342 | 6,348 |

Included in others is mainly relating to Sarawak sales tax and research cess payable.

**29. Other provisions**

| | Group | | Company | |
|---|---|---|---|---|
| | 2023 RM'000 | 2022 RM'000 | 2023 RM'000 | 2022 RM'000 |
| Provision for audit fees | 681 | 454 | 108 | 88 |
| Provision for employee bonus | 16,035 | 13,473 | - | - |
| Others | 48 | 310 | 53 | 50 |
| | 16,764 | 14,237 | 161 | 138 |
| At 1 January | 14,237 | 22,608 | 138 | 247 |
| Addition | 16,077 | 13,770 | 109 | 83 |
| Over provision in prior year | (326) | (12,050) | - | - |
| Payment during the year | (14,063) | (11,080) | (95) | (203) |
| Foreign currency translation differences | 839 | 989 | 9 | 11 |
| At 31 December | 16,764 | 14,237 | 161 | 138 |

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

## 30. Investment in a subsidiary company

| | Company | |
|---|---|---|
| | 2023 | 2022 |
| | RM'000 | RM'000 |
| At 1 January | 4,994,990 | 5,246,918 |
| Subscription of new ordinary shares issued | - | 75,686 |
| Allowance for impairment loss during the year | - | (566,632) |
| Foreign currency translation differences | 279,418 | 239,018 |
| At 31 December | 5,274,408 | 4,994,990 |
| Unquoted shares, at cost in SEUPMY | 7,082,566 | 6,707,359 |

As at 31 December 2023, management had estimated the recoverable amount of investment at higher of fair value less costs of disposal ("FVLCD") or value in use ("VIU").

The key assumptions used are disclosed in Note 14 to the financial statements.

Movement in allowance for impairment loss:

| | Company | |
|---|---|---|
| | 2023 | 2022 |
| | RM'000 | RM'000 |
| At 1 January | 1,712,369 | 1,092,128 |
| Additions | - | 566,632 |
| Foreign currency translation differences | 95,789 | 53,609 |
| At 31 December | 1,808,158 | 1,712,369 |

## 31. Amounts due from subsidiary companies

| | Company | |
|---|---|---|
| | 2023 | 2022 |
| | RM'000 | RM'000 |
| **Current** | | |
| Amounts due from subsidiary companies | 214,477 | 188,240 |
| Less: Allowance for expected credit loss | (168,436) | (155,322) |
| | 46,041 | 32,918 |

Amounts due from subsidiary companies are unsecured, interest free and repayable on demand.

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**31. Amounts due from subsidiary companies (cont'd.)**

The Company has performed impairment assessment on the amount due from the subsidiaries in accordance with MFRS 9: Financial Instruments The Company assessed the cash flows availability based on its cash flow projections and assessed the reasonableness of the expected timing and amount of repayment made by the subsidiary campanies.

Movement in allowance for impairment on amount due from a subsidirary company:

| | Company | |
|---|---|---|
| | 2023 | 2022 |
| | RM'000 | RM'000 |
| At 31 January | 155,322 | - |
| Charge for the year | 4,311 | 153,940 |
| Foreign currency translation differences | 8,803 | 1,382 |
| At 31 December | 168,436 | 155,322 |

**32. Amounts due to subsidiary companies**

Amounts due to subsidiary companies are unsecured, interest free and repayable on demand.

**33. Commitments**

| | Group | |
|---|---|---|
| | 2023 | 2022 |
| | RM'000 | RM'000 |
| **Capital expenditure for oil and gas assets** | | |
| Approved and contracted for | 155,901 | 739,576 |
| Approved but not contracted for | - | 154 |
| | 155,901 | 739,730 |

## 34. Related party disclosures

### (a) Related party transactions

Significant transactions with related parties are disclosed in Notes 4, 6, 23, 25, 26, 27, 30, 31 and 32 to the financial statements.

### (b) Compensation of key management personnel

The remuneration of members of key management are as follows:

| | Group | |
|---|---|---|
| | 2023 | 2022 |
| | RM'000 | RM'000 |
| Salaries | 4,743 | 4,324 |
| Others | 6,181 | 3,854 |
| | 10,924 | 8,178 |

Key management personnel comprise the Executive Management Committee of the Group, having authority and responsibility for planning, directing and controlling the activities of the Group entities either directly or indirectly. Compensations of key management personnel of the Group are paid or payable by the Group and related corporations.

## 35. Financial risk management objectives and policies

The Group and the Company are exposed to financial risks arising from its operations and the use of financial instruments. The key financial risks include foreign currency risk, liquidity risk, credit risk and interest rate risk.

The Group's and the Company's financial risk management policy seeks to ensure that adequate financial resources are available for the development of the Group's and the Company's businesses whilst managing its interest rate, foreign currencies, liquidity and credit risks. The Group and the Company operate within clearly defined guidelines approved by the Board and the Group's and the Company's policy is not to engage in speculative transactions.

It is, and has been throughout the financial year, the Group's and the Company's policy that no derivatives shall be undertaken except for the use as hedging instruments where appropriate and cost-efficient.

The following sections provide details regarding the Group's and the Company's exposure to the above-mentioned financial risks and the objectives, policies and processes for the management of these risks.

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**35. Financial risk management objectives and policies (cont'd.)**

**(a) Foreign currency risk**

Foreign currency (a currency which is other than the functional currency of the Group entities) risk is the risk that the fair value or future cash flows of the Group's financial instrument will fluctuate because of the changes in foreign exchange rates.

The Group has transactional currency exposures arising mainly from revenue or costs and advances that are denominated in a currency other than the respective functional currencies of Group entities, primarily USD. The foreign currencies in which these transactions are denominated are mainly RM.

The Group maintains a natural hedge, whenever possible, by borrowing in the currency of the country in which the property or investment is located or by borrowing in the currencies that match the future revenue stream to be generated from its investments.

As at 31 December 2023, approximately 21% (2022: 21%) of the Group's financial and non-financial liabilities and 0% (2022: 0%) of the Company's non-financial liabilities and 51% (2022: 48%) of the Group's financial and non-financial assets and 56% (2022: 73%) of the Company's financial and non-financial assets are denominated in foreign currencies.

The Group and the Company also hold cash and cash equivalents denominated in foreign currency for working capital purposes. At the reporting date, such foreign currency balances amount to RM69.9 million (2022: RM327.0 million).

Sensitivity analysis for foreign currency risk

The following table demonstrates the sensitivity of the loss net of tax of the Group and of the Company to a reasonably possible change in the RM exchange rates against the respective functional currencies of the Group entities, with all other variables held constant.

| | Group | | Company | |
|---|---|---|---|---|
| | 2023 Effect on loss net of tax Increase/ (decrease) RM'000 | 2022 Effect on loss net of tax Increase/ (decrease) RM'000 | 2023 Effect on loss net of tax Increase/ (decrease) RM'000 | 2022 Effect on loss net of tax Increase/ (decrease) RM'000 |
| RM/USD | | | | |
| - strengthened 5% | 6,194 | 3,637 | 1,061 | 763 |
| - weakened 5% | (6,194) | (3,637) | (1,061) | (763) |

**35. Financial risk management objectives and policies (cont'd.)**

**(b) Liquidity risk**

Liquidity risk is the risk that the Group and the Company may encounter difficulty in meeting financial obligations due to shortage of funds. The Group's and the Company's exposure to liquidity risk arises primarily from mismatches of the maturities of financial assets and liabilities.

The Group and the Company actively manage its debt maturity profile, operating cash flows and the availability of funding so as to ensure that all refinancing, repayment and funding needs are met.

The Group and the Company raise committed funding from its immediate holding company and ultimate holding company and prudently balances its portfolio. The loan from immediate holding company accounted for 59% (2022: 62%) and 96% (2022: 82%) of the total financial liabilities of the Group and of the Company respectively, based on the carrying amount reflected in the Group's and the Company's financial statements.

**Analysis of financial instruments by remaining contractual maturities**

The table below summarises the maturity profile of the Group's and the Company's liabilities at the reporting date based on contractual undiscounted repayment obligations.

| | On demand or within one year RM'000 | One to five years RM'000 | Total RM'000 |
|---|---|---|---|
| **Group** | | | |
| **2023** | | | |
| Financial liabilities: | | | |
| Lease liabilities | 9,820 | 1,879 | 11,699 |
| Amount due to a corporate shareholder | 19,794 | - | 19,794 |
| Amount due to ultimate holding company | 10,401 | 22,392 | 32,793 |
| Amount due to immediate holding company | 201,327 | 1,650,124 | 1,851,451 |
| Trade payables | 1,075,720 | - | 1,075,720 |
| Other financial liabilities | 56,942 | - | 56,942 |
| Total undiscounted financial liabilities | 1,374,004 | 1,674,395 | 3,048,399 |

**35. Financial risk management objectives and policies (cont'd.)**

**(b) Liquidity risk (cont'd.)**

**Analysis of financial instruments by remaining contractual maturities (cont'd.)**

The table below summarises the maturity profile of the Group's and the Company's liabilities at the reporting date based on contractual undiscounted repayment obligations. (cont'd.)

| | On demand or within one year RM'000 | One to five years RM'000 | Total RM'000 |
|---|---|---|---|
| **Group** | | | |
| **2022** | | | |
| Financial liabilities: | | | |
| Lease liabilities | 11,101 | 11,698 | 22,799 |
| Amount due to a corporate shareholder | 18,668 | - | 18,668 |
| Amount due to ultimate holding company | 9,828 | 29,414 | 39,242 |
| Amount due to immediate holding company | 170,102 | 1,697,067 | 1,867,169 |
| Trade payables | 859,897 | - | 859,897 |
| Other financial liabilities | 66,975 | - | 66,975 |
| Total undiscounted financial liabilities | 1,136,571 | 1,738,179 | 2,874,750 |
| **Company** | | | |
| **2023** | | | |
| Financial liabilities: | | | |
| Amount due to a corporate shareholder | 18,918 | - | 18,918 |
| Amount due to immediate holding company | 201,327 | 1,650,124 | 1,851,451 |
| Other financial liabilities | 3,200 | - | 3,200 |
| Total undiscounted financial liabilities | 223,445 | 1,650,124 | 1,873,569 |
| **2022** | | | |
| Financial liabilities: | | | |
| Amount due to a corporate shareholder | 17,916 | - | 17,916 |
| Amount due to immediate holding company | 171,720 | 1,697,067 | 1,868,787 |
| Other financial liabilities | 11,815 | - | 11,815 |
| Total undiscounted financial liabilities | 201,451 | 1,697,067 | 1,898,518 |

**35. Financial risk management objectives and policies (cont'd.)**

**(c) Credit risk**

Credit risk is the risk of loss that may arise on outstanding financial instruments should a counterparty default on its obligations. The Group's exposure to credit risk arises primarily from trade receivables.

Credit risks are minimised and monitored via strictly limiting the Group's associations to business partners with high creditworthiness. Credit approvals are performed in accordance with approved Limits of Authority. Trade receivables are monitored on an ongoing basis via Group management reporting procedures.

For other financial assets (including cash and bank balances), the Group minimises credit risk by dealing exclusively with high credit rating counterparties.

Exposure to credit risk

At the reporting date, the Group's maximum exposure to credit risk is represented by the carrying amount of each class of financial assets recognised in the consolidated statements of financial position.

As at 31 December 2023, the Group has a significant concentration of credit risk arising amount due from PETRONAS and its related companies PTLCL that accounted for approximately 100% (2022: 100%) of total trade receivables.

Financial assets that are neither past due nor impaired

Information regarding trade and other financial assets that are neither past due nor impaired is disclosed in Note 18.

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

## 35. Financial risk management objectives and policies (cont'd.)

### (d) Interest rate risk

Interest rate risk is the risk that the fair value or future cash flows of the Group and the Company will fluctuate because of changes in market interest rates.

The Group's and the Company's earnings are affected by changes in interest rates due to the changes in interest bearing financial liabilities. The Group's and the Company's exposure to interest rate risk arises primarily from its loan from their immediate holding company and borrowing from financial institution.

The Group's and the Company's loan and borrowing are at floating interest rates. The Group and the Company actively reviewed its debt portfolio, taking into account the investment holding period and nature of its assets. This strategy allows it to capitalise on cheaper funding in a low interest rate environment and achieve a certain level of protection against rate hikes.

Sensitivity analysis for interest rate risk

The following table demonstrates the sensitivity to a reasonably possible change in interest rates with all other variables held constant, of the Group and of the Company's loss net of tax (through the impact on interest expense on floating rate loan from its immediate holding company and financial institution).

| | Group and Company | | | |
|---|---|---|---|---|
| | 2023 | | 2022 | |
| | Increase/ (decrease) in basis points | Effect on loss net of tax Increase/ (decrease) RM'000 | Increase/ (decrease) in basis points | Effect on loss net of tax Increase/ (decrease) RM'000 |
| **Group** | | | | |
| - RM | + 25 | 3,031 | + 25 | 2,922 |
| - RM | - 25 | (3,031) | - 25 | (2,922) |

## 36. Financial instruments

### (a) Classification of financial instruments

The accounting policies in Note 2.3.9 and Note 2.3.13 describe how the categories of financial instruments are measured, and how income and expenses, including changes in fair value, are recognised.

The respective financial assets and liabilities as well as other instruments are classified in the statement of financial position and in the notes to financial statements.

### (b) Financial instruments that are not carried at fair value and whose carrying amounts are reasonable approximation of fair value

The following are classes of financial instruments that are not carried at fair value and whose carrying amounts are reasonable approximation of fair value:

| | Note |
|---|---|
| Trade receivables and other financial assets | 18 |
| Cash and cash equivalents | 20 |
| Amount due to immediate holding company | 23 |
| Amount due to a corporate shareholder | 25 |
| Amount due to ultimate holding company | 26 |
| Trade payables and other financial liabilities | 27 |
| Amounts due from subsidiary companies | 31 |
| Amounts due to subsidiary companies | 32 |

The carrying amounts of these financial assets and liabilities are reasonable approximation of fair values, either due to their short-term nature or that they are floating rate instruments that are re-priced to market interest rates on or near the reporting date.

### (c) Net gains and losses arising from financial instruments

| | 2023<br>RM'000 | 2022<br>RM'000 |
|---|---|---|
| **Group** | | |
| Net losses/(gains) on: | | |
| - Financial assets measured at amortised cost | 43,027 | (18,682) |
| - Financial liabilities measured at amortised cost | (38,741) | 35,175 |
| | 4,286 | 16,493 |
| **Company** | | |
| Net losses/(gains) on: | | |
| - Financial assets measured at amortised cost | 177 | 1,025 |
| - Financial liabilities measured at amortised cost | 971 | (497) |
| | 1,148 | 528 |

## 37. Capital management

The board of directors reviews and agrees policies and procedures for the management of liquidity risk and credit risk which influence the primary objective of the Group's capital management.

The Group's policies and procedures also include, where necessary, obtaining funding from its ultimate holding company to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due.

## 38. Subsidiaries and activities

Details of the subsidiaries are as follows:

| Name of subsidiaries | Principal place of business | Principal activities | Proportion of ownership interest 2023 % | Proportion of ownership interest 2022 % |
|---|---|---|---|---|
| **(a) Held by the Company** | | | | |
| SapuraOMV Upstream (Holding) Sdn. Bhd. | Malaysia | Investment holding | 100 | 100 |
| **(b) Held by SapuraOMV Upstream (Holding) Sdn. Bhd.** | | | | |
| SapuraOMV Upstream (Americas) Sdn. Bhd. | Malaysia | Investment holding | 100 | 100 |
| SapuraOMV Upstream (Oceania) Sdn. Bhd. | Malaysia | Investment holding | 100 | 100 |
| SapuraOMV Upstream (Sarawak) Inc. * | Malaysia | Exploration, development and production of crude oil and natural gas | 100 | 100 |
| SapuraOMV Upstream (Malaysia) Sdn. Bhd. | Malaysia | Exploration, development and production of crude oil and natural gas | 100 | 100 |
| SapuraOMV Block 30 S. de R. L. de C.V. * | Mexico | Exploration, development and production of crude oil and natural gas | 99 | 99 |

201801040231 (1302262-U)

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

**38. Subsidiaries and activities (cont'd.)**

Details of the subsidiaries are as follows: (cont'd.)

| Name of subsidiaries | Principal place of business | Principal activities | Proportion of ownership interest 2023 % | 2022 % |
|---|---|---|---|---|
| **(c) Held through SapuraOMV Upstream (Americas) Sdn. Bhd.** | | | | |
| SapuraOMV Upstream (Mexico) Sdn. Bhd. | Malaysia | Investment holding | 100 | 100 |
| **(d) Held through SapuraOMV Upstream (Oceania) Sdn. Bhd.** | | | | |
| SapuraOMV Upstream (NZ) Sdn. Bhd. | Malaysia | Investment holding | 100 | 100 |
| SapuraOMV Upstream (Australia) Sdn. Bhd. | Malaysia | Investment holding | 100 | 100 |
| **(e) Held through SapuraOMV Upstream (Mexico) Sdn. Bhd.** | | | | |
| SapuraOMV Block 30 S. de R. L. de C.V. * | Mexico | Exploration, development and production of crude oil and natural gas | 1 | 1 |
| **(f) Held through SapuraOMV Upstream (NZ) Sdn. Bhd.** | | | | |
| SapuraOMV Upstream JV Sdn. Bhd. | Malaysia | Production of crude gaseous hydrocarbon (natural gas), draining and separation of liquid hydrocarbon fractions and mining of hydrocarbon liquids, obtain through liquefaction or pyrolysis | 100 | 100 |
| **(g) Held through SapuraOMV Upstream (Australia) Sdn. Bhd.** | | | | |
| SapuraOMV Upstream (Western Australia) Pty. Ltd. * | Australia | Exploration, development and production of crude oil and natural gas | 100 | 100 |

\# Incorporated in Bahamas
* Audited by member firms of KPMG Global in the respective countries.

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

## 39. Joint arrangements

Details of the joint arrangements are as follows:

| | | Group Participating interest | |
|---|---|---|---|
| | | 2023 % | 2022 % |
| **(a) Malaysia** | | | |
| SK408 | | 40.0 | 40.0 |
| SK310 | | 30.0 | 30.0 |
| SB412 | | 40.0 | 40.0 |
| **(b) New Zealand** | | | |
| PEP 57075 | | 30.0 | 30.0 |
| PEP 60092 | | 30.0 | 30.0 |
| PEP 60093 | | 30.0 | 30.0 |
| **(c) Mexico** | | | |
| Block 30 | | 30.0 | 30.0 |
| **(d) Western Australia** | | | |
| WA-412-P # | (i) | - | 100.0 |
| AC/P 50 | (ii) | - | 40.0 |
| AC/P 67 | | 33.3 | 33.3 |
| AC/P 68 | | 33.3 | 33.3 |
| AC/P 69 | | 33.3 | 33.3 |

\# Participating interest presented is up and until the farm-in well is drilled.
(i) The surrender of Kanga-1 title took effect on 14 February 2023.
(ii) The surrender of AC/P50 title took effect on 20 February 2023.

**201801040231 (1302262-U)**

**SapuraOMV Upstream Sdn. Bhd.**
**(Incorporated in Malaysia)**

## 40. Restatement

The following comparative amounts of the Group and the Company for the financial year ended 31 December 2021 and 31 December 2022 have been restated in accordance with the requirements of *MFRS 108 Accounting Policies, Changes in Accounting Estimates and Errors*, to conform to current presentation and correct the error. The effects are disclosed below:

| | Note | As previously reported RM'000 | Adjustment RM'000 | As restated RM'000 |
|---|---|---|---|---|
| **31 December 2022** | | | | |
| **Statement of financial position** | | | | |
| **Non-current assets** | | | | |
| Long-term receivable | (a) | - | 37,676 | 37,676 |
| Deferred tax assets | (b) | - | 37,996 | 37,996 |
| **Non-current liabilities** | | | | |
| Deferred tax liabilities | (b) | 1,473,475 | 119,812 | 1,593,287 |
| Provision for asset retirement obligations | (a) | 38,872 | 44,569 | 83,441 |
| **Current liabilities** | | | | |
| Provision for asset retirement obligations | (a) | 6,893 | (6,893) | - |
| **Statement of comprehensive income** | | | | |
| Deferred tax (credit)/expenses | (b) | (27,896) | 81,093 | 53,197 |
| **Statement of change in equity** | | | | |
| Accumulated losses | (b) | (1,206,305) | (81,093) | (1,287,398) |
| Foreign currency translation reserve | (b) | 292,936 | (723) | 292,213 |

201801040231 (1302262-U)

SapuraOMV Upstream Sdn. Bhd.
(Incorporated in Malaysia)

**40. Restatement (cont'd.)**

| | Note | As previously reported RM'000 | Adjustment RM'000 | As restated RM'000 |
|---|---|---|---|---|
| **1 January 2022** | | | | |
| **Statement of financial position** | | | | |
| **Non-current assets** | | | | |
| Long-term receivable | (a) | - | 23,972 | 23,972 |
| Deferred tax assets | (b) | - | 28,021 | 28,021 |
| **Non-current liabilities** | | | | |
| Deferred tax liabilities | (b) | 1,433,724 | 28,021 | 1,461,745 |
| Provision for asset retirement obligations | (a) | 44,135 | 37,576 | 81,711 |
| **Current liabilities** | | | | |
| Provision for asset retirement obligations | (a) | 13,604 | (13,604) | - |

**(a)** In previous financial years, abandonment cess contribution to the Abandonment Cess Fund was offsetting against provision for asset retirement obligations. The abandonment cess contribution was reclassified to long term receivables to conform to current presentation.

**(b)** In previous financial year, capital expenditure incurred on the development project was partially claimed as deductable expenses under exisiting producing field in the final tax submission. The timing difference was not recognised as deferred tax liability.