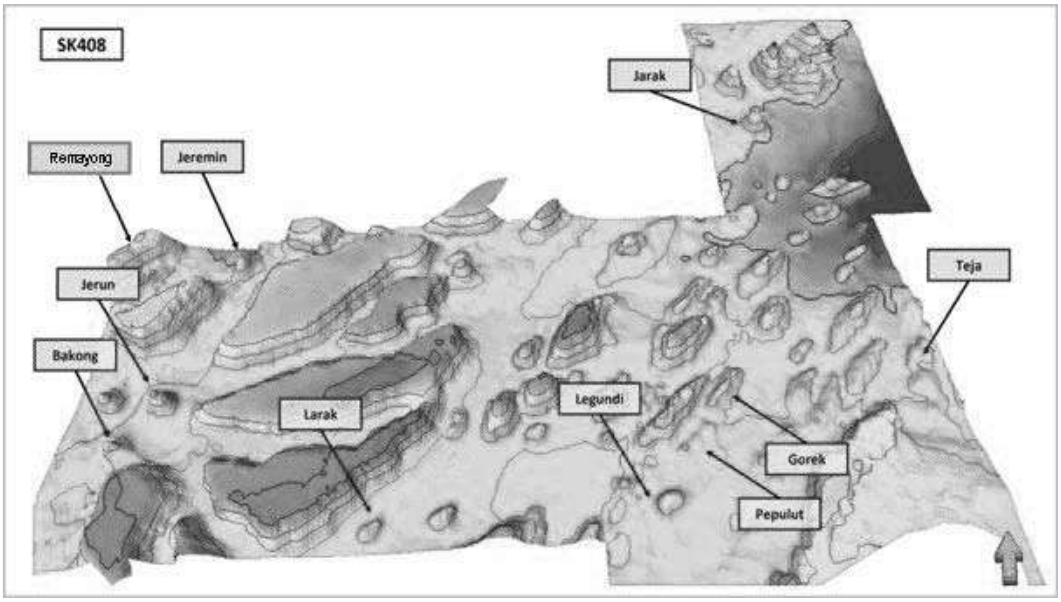

Figure 2-10: SK408 top carbonate pinnacle reef structures and the 10 discoveries (after SOMV).

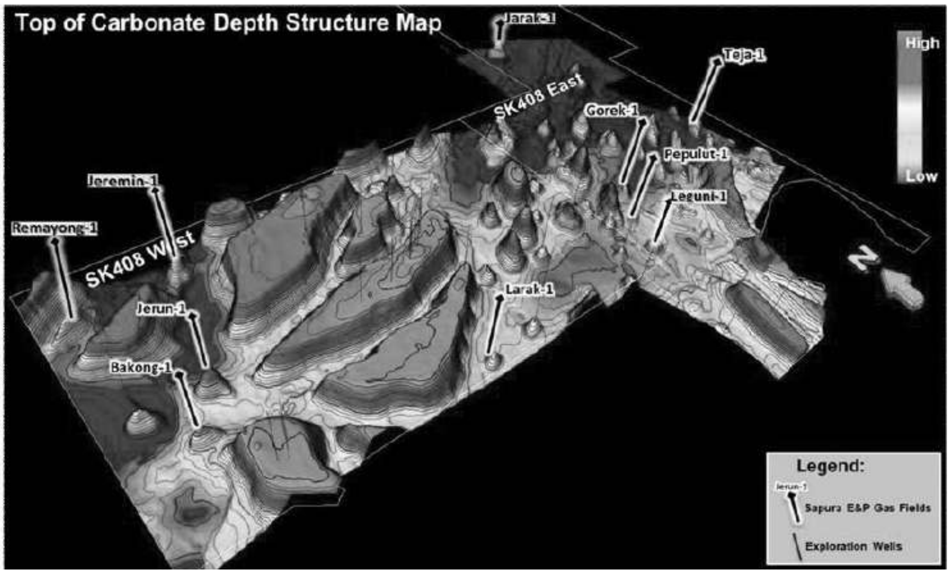

Figure 2-11: SK408 Gas Fields – Top Carbonate Depth Structure Map (Source: Sapura).

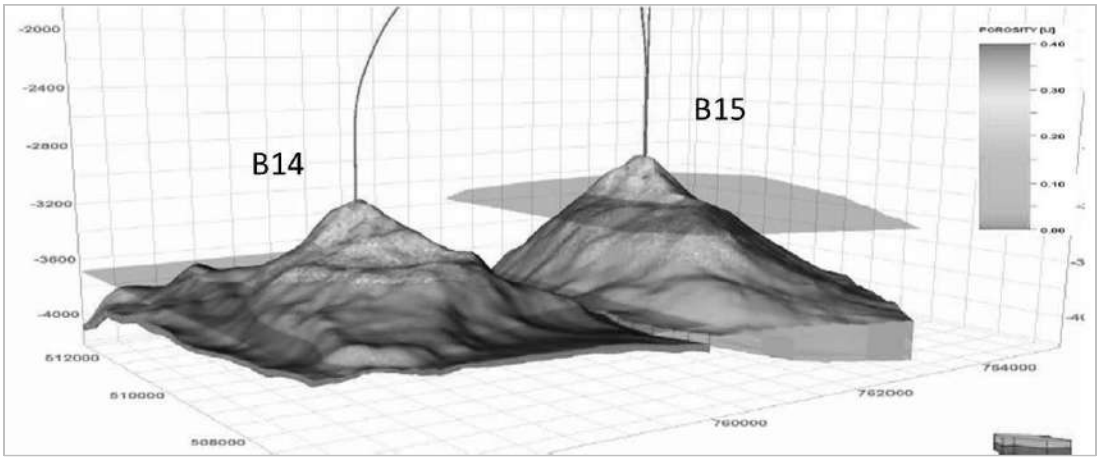

Figure 2-12: SK310 pinnacle reef carbonates (Source: SOMV).

SOMV has a good success history in Sarawak post-SK408 and SK310 PSC acquisitions. The technical successes in the blocks were attributed to the application of blocks acquisition geological exploration play concept for the resource exploration, evaluation and development activities. The B15 field in SK310 is currently being produced. In the SK408, Sapura anticipated a high Geologic Chance of Success (GCOS) or Pg (Prospect Chance of Success) as expected, and improved the understanding of the sub-plays as discoveries were made.

The focus of the carbonate play is the relative high chance (low risk) Type 1 Pinnacle reefs sub-play and based on ranked risked volumes also tested the risker Type 3 and Type-2 sub-plays. One of the key risks in this play is 'what controls the trap volume', i.e. what bridged the trap and hence, the hydrocarbon column height. The presence of porous sandstone "thief beds" and faults leaked to the surface (mapped using seismic) are key issues addressed, and predicted statistically from discoveries and post-drilled analysis in the pinnacle reefs sub- plays. This is true when obvious factors controlling the trapped hydrocarbon column become less apparent in the remaining prospects.

2.1.2 Sabah Basin

The Northwest (NW) Sabah Basin existed during early Middle Miocene overlying the Oligocene-Early Miocene West Crocker Formation rocks which are related to the younger Rajang Group in western and northern Sabah. The Crocker Fold-Thrust Belt comprises deeper marine turbidites that crop out along strike of the Rajang Fold-Thrust Belt of Sarawak. This belt of deep marine turbidites structured the shore-parallel Crocker Range (Mazlan et. al., 2001), and is marginally younger than the Rajang Fold-Thrust Belt itself, interpreted to be Late Cretaceous-Late Eocene (Hutchison, 1996). The equivalents of the older Rajang Group in Sabah incorporate the East Crocker, Trusmadi, and Sapulut formations. A larger part of the Sabah Basin particularly lies on the northwest offshore areas compared to the onshore (Figure 2-13).

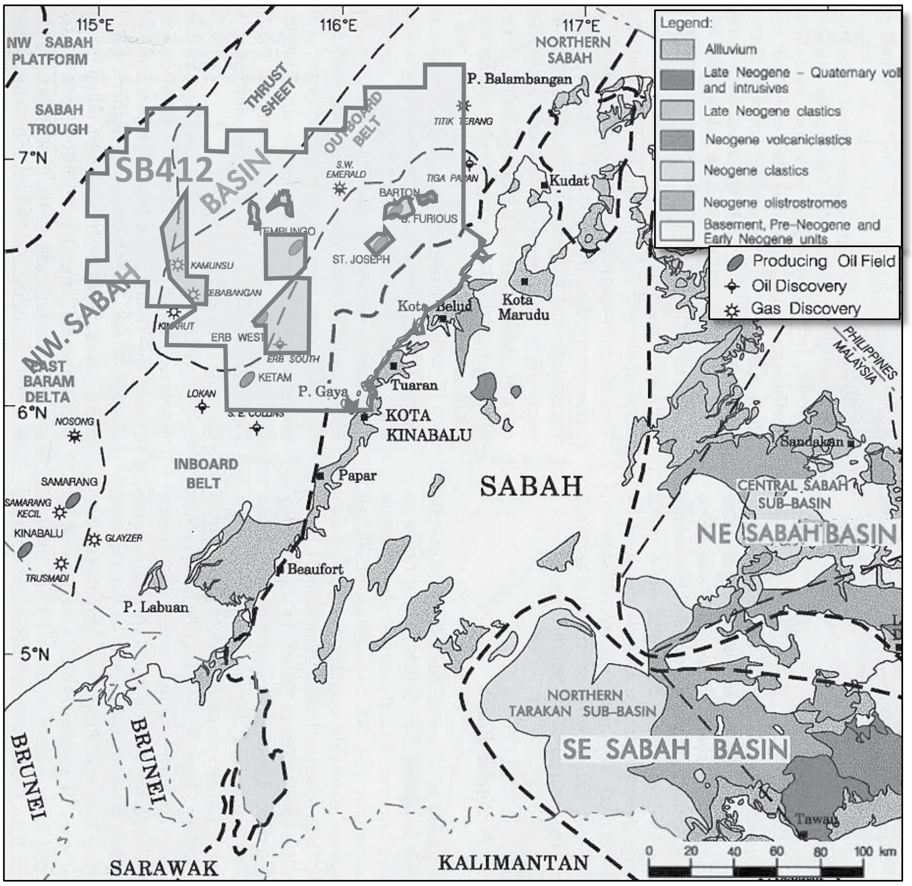

Figure 2-13: Location of SB412 and NW Sabah Basin (after PETRONAS, 1999).

The depositional successions of the Sabah Basin during Middle Miocene were separated by a major regional unconformity which was called Deep Regional Unconformity (DRU) which indicated the major changes in terms of siliciclastic sedimentation of the Northwest Sabah Basin with the phase of the progradation slope deposits (Figure 2-14 and Figure 2-15).

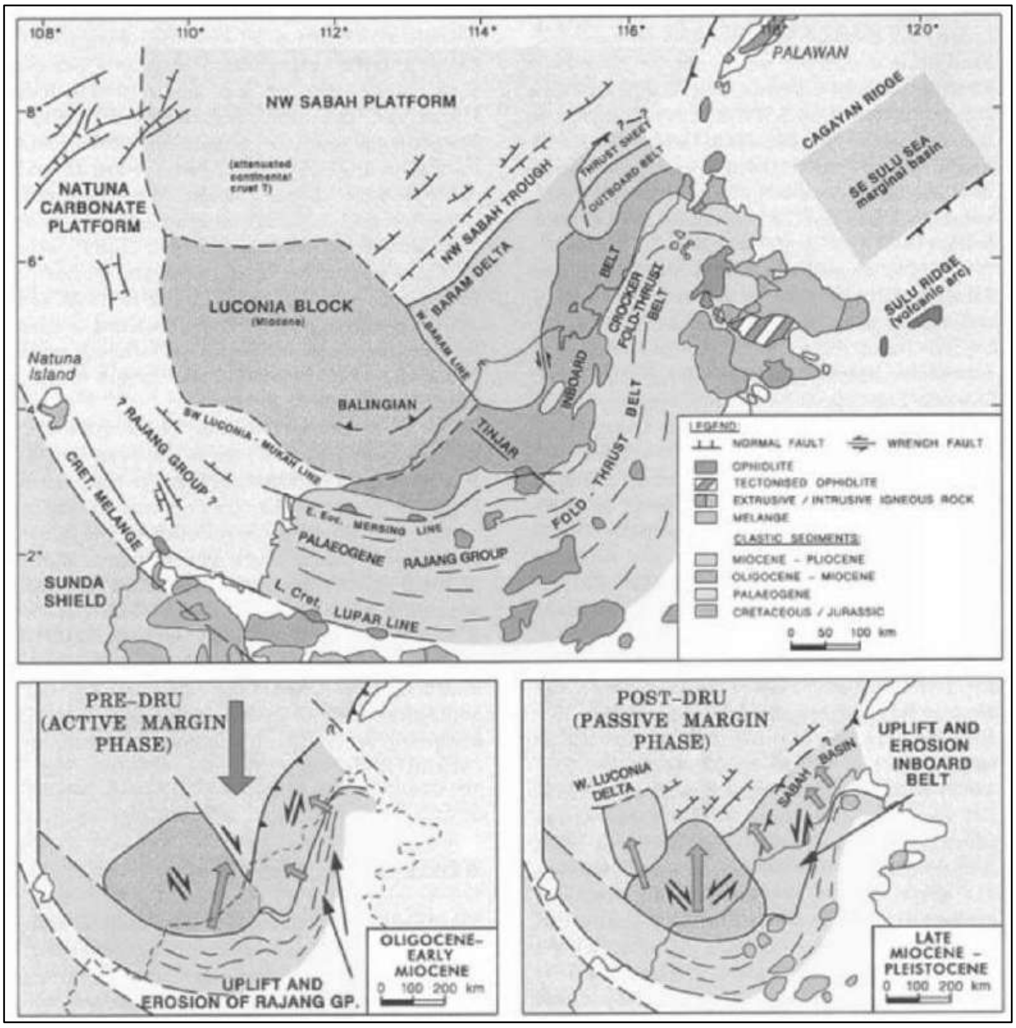

Figure 2-14: Post Deep Regional Unconformities of Sabah Basin (Source: PETRONAS, 1999).

<table>
<tr><th>EVENTS</th><th>EPOCH</th><th colspan="3">STAGES</th><th>SETTINGS</th><th>FORMATION</th></tr>
<tr><td rowspan="3">POST DRU</td><td rowspan="6">MIOCENE</td><td rowspan="3">Late</td><td rowspan="5">IV</td><td>E</td><td rowspan="3">Widespread of clastic shelf/slope deposition</td><td>Uplift forming Inboard Belt</td></tr>
<tr><td>D</td><td rowspan="4">Sediments primarily deposited which providing the sources and the reservoirs of Hydrocarbon.</td></tr>
<tr><td>C</td></tr>
<tr><td rowspan="2">DRU</td><td rowspan="2">Middle</td><td>B</td><td rowspan="2">Subsequent uplift resulted in regional erosional surface known as Deep Regional Unconformity (DRU)</td></tr>
<tr><td>A</td></tr>
<tr><td>PRE DRU</td><td>Early</td><td colspan="2">III</td><td>Thick layer overlain the older/previous carbonate layer</td><td>Minor oil and gas were 'reservoired'</td></tr>
</table>

Figure 2-15: Summary of Sabah Basin Formation and the tectonic evolution of the continental margin since Late Eocene (Source: PETRONAS, 1999).

The initiation of DRU started during the Oligocene to Early Miocene when Sungai Rajang Crust subducted beneath Sabah, during which when the subduction process Crocker Fold-Thrust Belt ended, which resulted in uplift and the regional eroded surfaces. During Middle Miocene to Recent, Sabah Basin sedimentation progradation across the continental margin which sourced the sediments from the uplifted Rajang Group. Although Northwest Sabah lacked large inland rivers feeding sediments to the offshore basin, several structural events of upliftment and erosion caused by diaprism and deformation preceding by major unconformities (Inboard Belt), produced complex depositional systems as numerous sediment 'point source' for offshore sediments provenance influencing the paleoenvironments of the area (Figure 2-16).

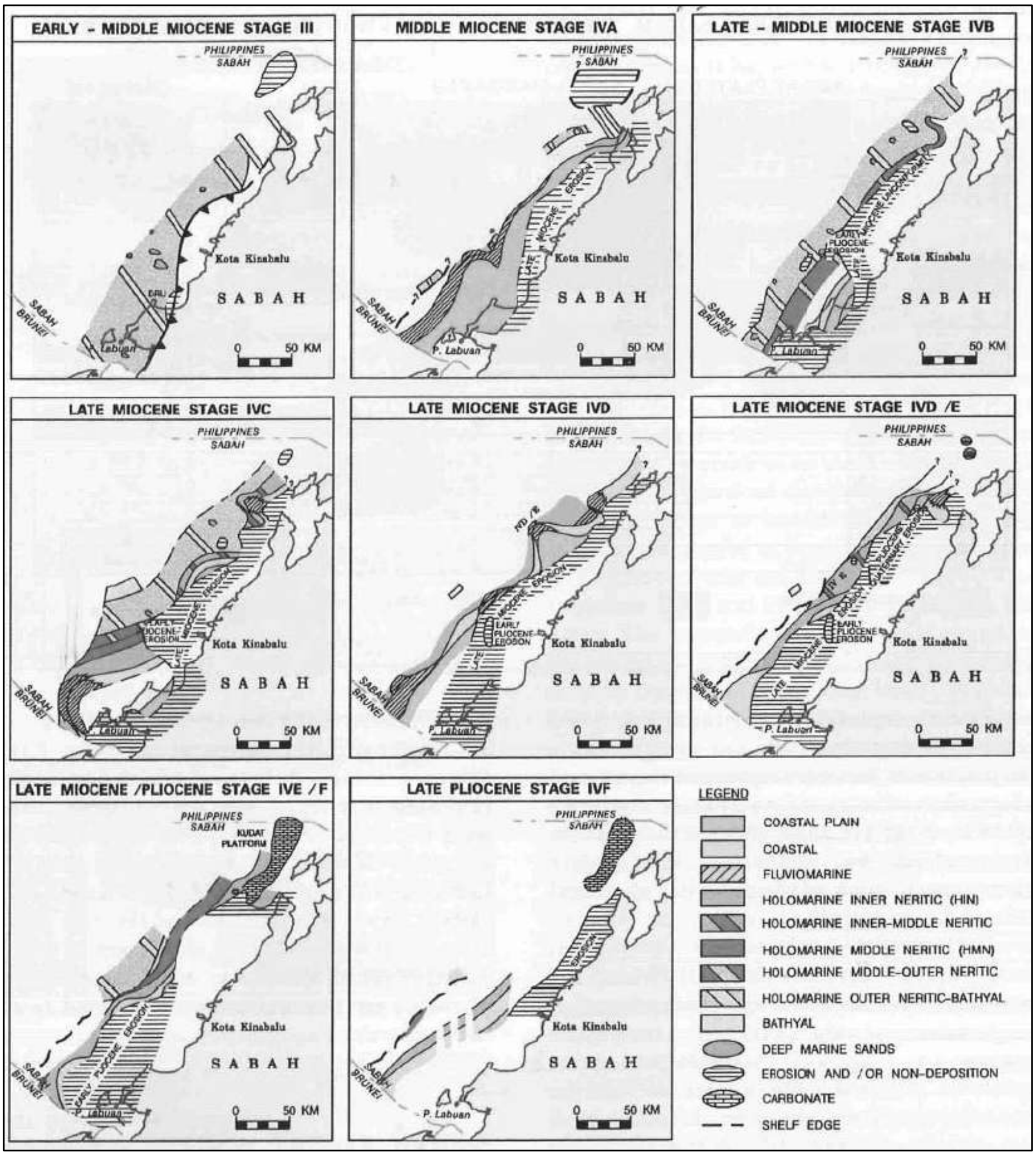

Figure 2-16: Interpreted Northwest Sabah Paleogeographic maps from Early-Mid Miocene Stage III to Late Pliocene Stage IVF (Source: PETRONAS, 1999).

From wells and seismic interpretation, the coastal plain area is known to be closer to shore. Transported sediments (including source rock) towards basin center could have been by 'point source' along strike of the coast during occurrences of upliftment as indicated by unconformities. This is evidenced by the lack of evidence of known large Baram-like rivers from onshore of NW Sabah.

Geophysical evidence shows the paleo-slope during the Stage IVA - IVD had relatively minor shift along the strike, and is interpreted to control the basin shale top seal. Over the slope available sediment feeders will feed sediments towards the relatively deeper vicinities as slope channels, ponded deposits and fans (Figure 2-17). The source rock would be preserved if the sediment deposition is rapid and under non-oxidizing conditions e.g., turbiditic environment. Evidence from studies indicated the offshore deepwater hydrocarbon discoveries are mainly sourced from disseminated terrestrial and coastal source deposits, apart from little known of marine in-origin. The paleogeography model which captures the reservoir, seal and source distribution, and basin modelling (temperature gradient/heat flow) to predict maturation, timing and couple by migration model will provide a reasonable de-risking of the SB412 block. The wells and fields will audit the overall interpretation of the undiscovered hydrocarbon potential.

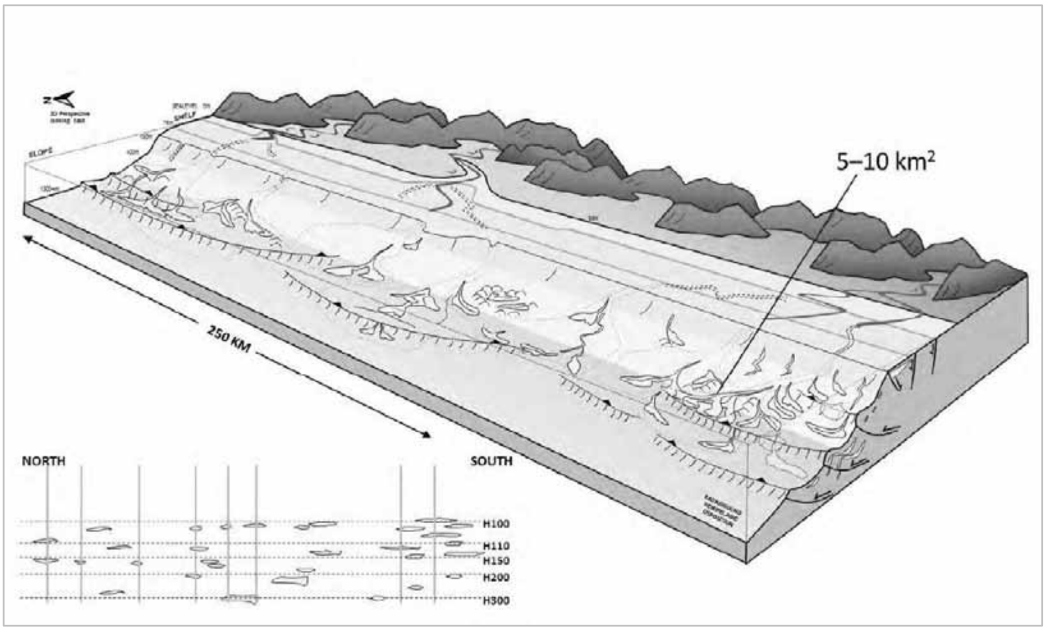

Figure 2-17: NW Sabah Basin – Exploration Model (Source: Murphy Oil, AAPG 2015).

Based on differences in structural styles and sedimentation cycles (Hans P. Hazebroek, Denis Tan, Shell, 1992 and PETRONAS,1999), the offshore NW Sabah (Figure 2-13) where the SB412 PSC straddles can be subdivided into the following main provinces:

- The Inboard Belt was subjected to strong compressional deformation, probably associated with deep-seated major north-south shear zones. Transtensional tectonics at the western margin of the belt resulted in the formation of two major depocenter provinces, i.e., the Outboard Belt and the East Baram Delta. The Inboard Belt area was strongly folded, uplifted and eroded resulting in the Shallow Regional Unconformity (SRU). From the late Miocene to Holocene, the Inboard Belt remained a shallow stable area, which was continuously eroded till Stage IVF times. The Inboard Belt (Figure 2-13 and Figure 2-14) trends broadly parallel to the Fold-Thrust Belt (Figure 2-14), and extends from offshore NW Sabah on to the onshore in a southward direction. Structurally, the Inboard Belt consists of broadly NNE-SSW oriented, tight, broken anticlines (Sabah Ridges), separated by wide synclines. The anticlines show a variety of structural features indicative of wrench-related compression, such as flower structures, and reverse faults steepening with depth (Bol and van Hoorn, 1980). In the northern part of the Inboard Belt, the orientation of the anticlines deviates to NE, E and SE. The bending of this trend occurs near the axial plane of the sharp inflection as observed in the Rajang Group Fold-Thrust Belt (NW Borneo Trend to Sulu Trend). Timing of deformation in the Inboard Belt is based on well and seismic data, indicating a major Late Miocene/Early Pliocene phase and a more locally developed Late Pliocene - Pleistocene phase. An indication for the sense of strike-slip movement and the magnitude of offset has been derived from the offset in the pattern of Middle Miocene shelf margins (dated on pollen). Sinistral strike-slip movement with a cumulative offset of some 100 km has been estimated for the southern part of the Inboard Belt. The sedimentation history in the Southern and Central parts of the Belt consist of an early Middle Miocene regression (Stage IVA), a late Middle Miocene transgression (mainly Stage IVB) and a Late Miocene to Pliocene regression (Stages IVC and IVF/G; Stages IVD and IVE are thin or absent). Further to the north, the main difference in sedimentation history is a prolonged Late Miocene to Pliocene regression marked by well-developed Stages IVC, IVD and IVE sediments.

- The Outboard Belt is represented by thick prograding wedge built out toward the northwest from Late Miocene to Holocene. A late Pliocene phase of deformation affected mainly the Outboard Belt and East Baram Delta and gentle anticlinal features with numerous crestal faults were formed. The Outboard Belt occurs west of the northern part of the Inboard Belt and is an elongated Late Miocene Pliocene depocenter that lies roughly along strike of the East Baram Delta. It is structurally complex with features indicating both extensional and compressional phases of deformation. The former deformation is marked by large, NE-SW trending down-to-basin normal fault systems, whereas the latter is indicated by wrench induced features in the Tembungo and Kinarut areas and by clay diapirism along the western margin of this Belt. The province represents an elongated Late Miocene-Pliocene depocenter comprising Stages IVD, E, F and G deltaic and shelf (topset) sequence of sediments prograding north-westward over Stage IVC and older deep marine sediments. The slumping of the shelf edge along the once-active Bunbury-St Joseph Ridge, provides large volumes of sediments, eroded from Stage IV and IVB, into the Outboard Belt. Outboard Belt discoveries and production demonstrate the petroliferous nature of this basin where commercial hydrocarbon accumulations are reservoirs within shallow marine to deep marine reservoir deposits. Traps were also formed by extensional and growth faulted anticlinal structures that are in-places deeper seated by thrust faults.

- The East Baram Delta province is characterised by typical delta tectonics, and can be subdivided into a proximal part, dominated by extensional growth-faulting, a transitional area formed by the delta slope, and a distal part, dominated by over-thrusted anticlines representing the toe-thrust zone of the delta. In the proximal part of the delta large down-to-basin growth-faults and corresponding counter regional faults define the NNE-SSW trending Champion-Padas megastructure. In Sabah, this megastructure is made up of several macrostructures, each bounded by its main growth fault on the landward side. (e.g., Timbalai, Samarang and Padas macrostructures). The topsets of the prograding wedge of deltaic sediments are largely confined to the Champion-Padas megastructure. These macrostructures merge downdip into a large expanding flank, bounded on the seaward side by an important counter-regional fault system, which trends broadly parallel to the present coastline. The toe-thrust zone of the delta is 50 to 80 km in width in the main part of the delta, but narrows towards the northern fringe of the delta. About six NE-SW trending elongated, broadly parallel, over-thrusted anticlines are present in this zone. The anticlines form ridges on the sea floor, that increase in amplitude towards the delta toe. Between the anticlines are mini-basins, that have been partly or entirely filled with draping hemipelagic, and to a minor extent with onlapping turbidites. The fill of the mini-basins is less complete towards the delta toe. These observations strongly suggest recent tectonic activity of the delta toe. Such toe-thrust features may be regarded as an integral part of gravitational delta tectonics, and are analogous to those observed in the Niger Delta, which has a passive margin setting. On the delta slope (as well as closer ashore), older anticlines become associated with clay-diapiric ridges and may represent an advanced stage of development of the thrusted anticlines, with the thrust-planes steepening as the delta builds out. The toe-thrust, deepwater fans, slope channels and ponded mini basins are new deepwater exploration plays in NW Sabah (Figure 2-17).

- The 'Thrust Sheet'; Hinz et al. (1989) proposed the term 'Thrust Sheet' for a block of chaotic seismic facies, which is bounded to the NW and Southwest (SW) by steep thrust faults and to the Southeast (SE) by normal faults, separating it from the Outboard Belt. The chaotic seismic facies are overlain by gently folded sediments of possibly early Middle Miocene age. Beneath the chaotic seismic facies, a coherent reflection can be seen dipping in a landward direction, which is inferred to correlate to the Oligo-Miocene carbonates dredged from the Dangerous Grounds area (Kudrass et al., 1986). The tentatively interpreted allochthonous mass making up the 'Thrust Sheet' defines the northeastern margin of the NW Sabah Trough, and exceeds 40 km in width. It protrudes up to 150 km offshore and is located at the axial plane of the sharp inflection of the Fold-Thrust Belt (NW Borneo Trend/Sulu Trend). The 'Thrust Sheet' has a similar seismic response as the deep marine sediments of the Fold-Thrust Belt. The 'Thrust Sheet' may therefore represent a nappe, consisting of Rajang Group rocks, that resulted from gravity sliding associated with the uplift of the Fold-Thrust Belt.

- The NW Sabah Trough is a NE-SW linear bathymetric feature with a water depth of up to 2,800 m, extends over a length of over 300 km, and reaches an average width of some 80 km. To the SW, the Trough terminates abruptly against the Luconia Block. The Trough becomes less well-expressed northwards towards Palawan Island, where it is referred to as the Palawan Trough. The Trough is observed on seismic to be a down-faulted part of the NW Sabah Platform which extends beneath the Baram Delta front. An Upper Tertiary fill of some 2 seconds seismic two-way time thickness overlies the Lower Tertiary platform within the Trough. This fill consists largely of pelagic clays with some turbidite intercalations. The Baram Delta toe thrust zone, which is Late Miocene to Recent in age, is an important element in the morphology of the Trough, bounding it to SE. These factors suggest that the present NW Sabah Trough is a relatively young feature, and that if an older, Palaeogene, trench is present, it would occur landward of, and with a different orientation to the NW Sabah Trough. The Palaeogene trench would no longer have a surface expression.

2.2 SK408

PSC Block SK408 is located offshore within the Central Luconia Province, approximately 150 km North of Bintulu, Sarawak, in water depths ranging from around 70 m in the south to 120 m in the north (Figure 2-18).

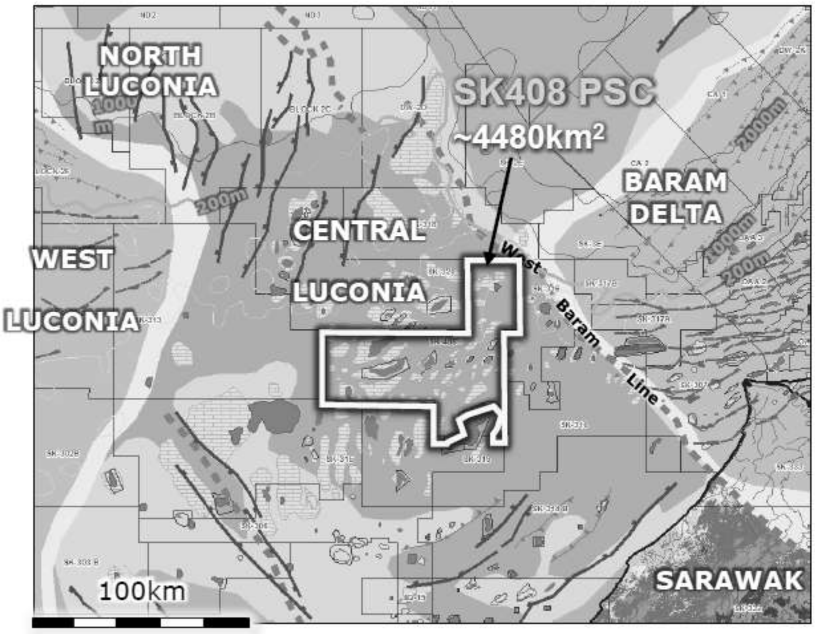

Figure 2-18: SK408 location and size of contract area (Source: SOCM 2023).

The Central Luconia area predominantly comprises gas-prone, platform and pinnacle carbonate reservoirs. Block SK408 contains a series of pinnacle-reef carbonate gas discoveries made in 2014 and 2015, which encountered non-associated gas reservoirs at depths of around 2,300 to 2,700 mTVDSS (Figure 2-19). The reservoir drive mechanism is pressure depletion, with weak to moderate aquifer support, characteristic of localized carbonate-pinnacle reef gas reservoirs, which may not be well connected with bigger and wider aquifers compared to carbonate-platform type and large reef type of gas reservoirs.

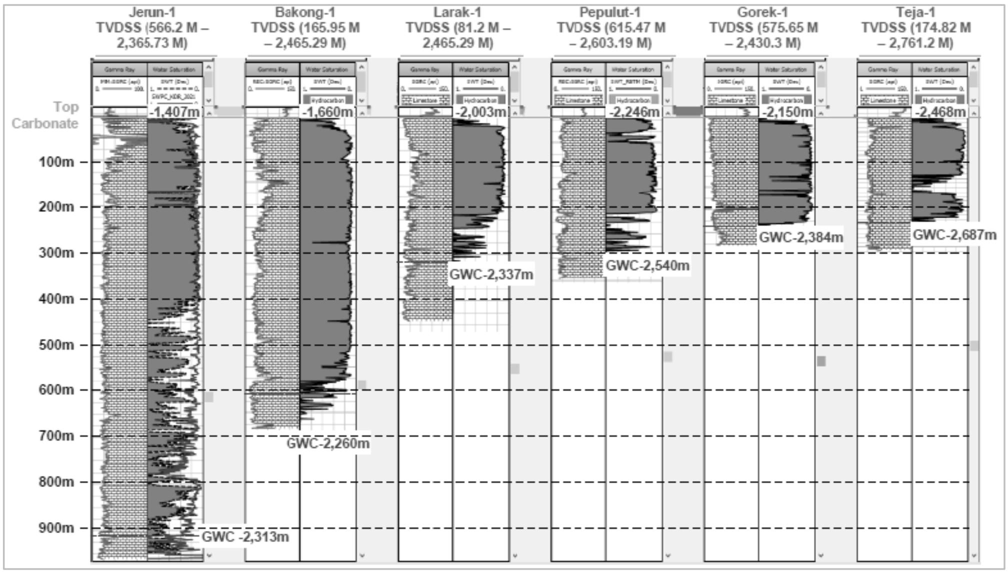

Figure 2-19: Overview of the commercially discovered wells (Source: SOMV).

The first production SK408 Larak, Bakong and Gorek (LaBaGo) fields was from Larak field in December 2019, followed by Gorek and Bakong fields in May 2020 and June 2020, respectively. The historical gas production for SK408 shown in Figure 2-20. The FGD for Block SK408 was reported to be on the 9th January 2020 (upon verification of Larak field metered gas into the SK408 facilities).

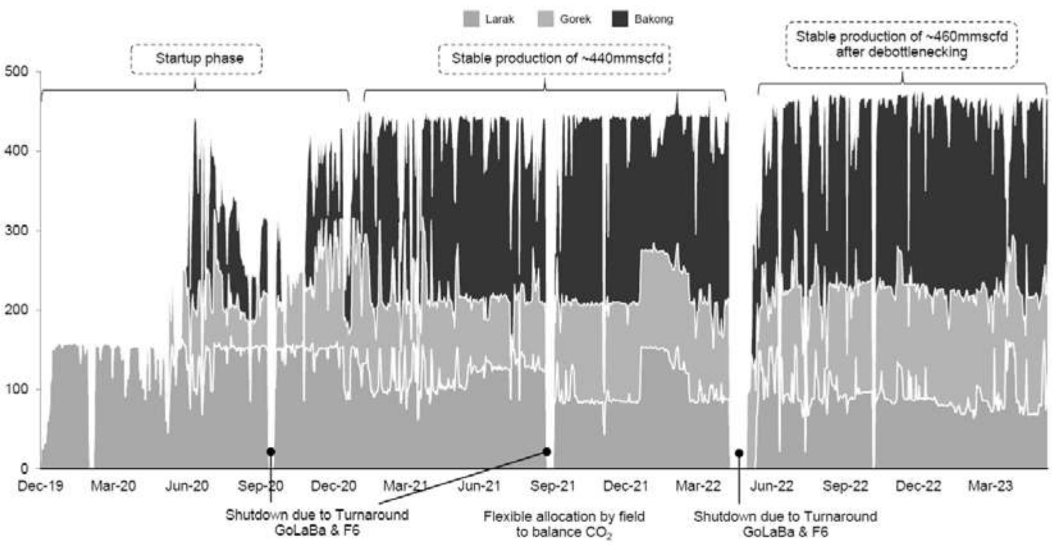

Figure 2-20: SK408 historical (gross) gas production, MMscfd (Source: SOMV).

Two development wells were drilled and completed in each field, i.e., wells LRK-A1 and A2 at Larak, BKG-A1 and A2 at Bakong, and GRK-101 and 104 at Gorek, with wet gas meters installed at the wellheads of all the wells. The LaBaGo fields are developed as three separate 4-legged unmanned Wellhead Platforms (WHP) with three slots each, tied back to the existing SSB operated F6 Brownfield Integrated Module (BIM) processing facility, then to the E11 Riser A (E-11R-A), and finally via trunkline to MLNG. The full well stream (FWS) production from these fields flows through gas and condensate allocation meters installed downstream of the production separator in the BIM processing hub. The gas is then mixed with F6 and F28 gas, dehydrated, and transferred to the E11 Riser A (E-11R-A), and finally to the MLNG via trunkline. The combined LaBaGo gas production is constrained by BIM capacity at the F6 hub and contaminants limits i.e., 6.5 mol% CO_2 and approximately 28 ppm or 2.9 mbara H_2S partial pressure. LaBaGo condensate is commingled with F6 and F28 condensate before export. Produced water from LaBaGo, along with F6 and F28, is treated and flowed to water disposal wells. The simplified integrated production network and process overview are depicted in Figure 2-21, Figure 2-22 and Figure 2-23.

For SK408 ongoing and planned developments, Jerun field will be developed via a Central Processing Platform (CPP) which ties back to E11R-B, whilst the current plan for the future WHPs for Teja and Pepulut fields is to tie-back to the F23 hub (Figure 2-4).

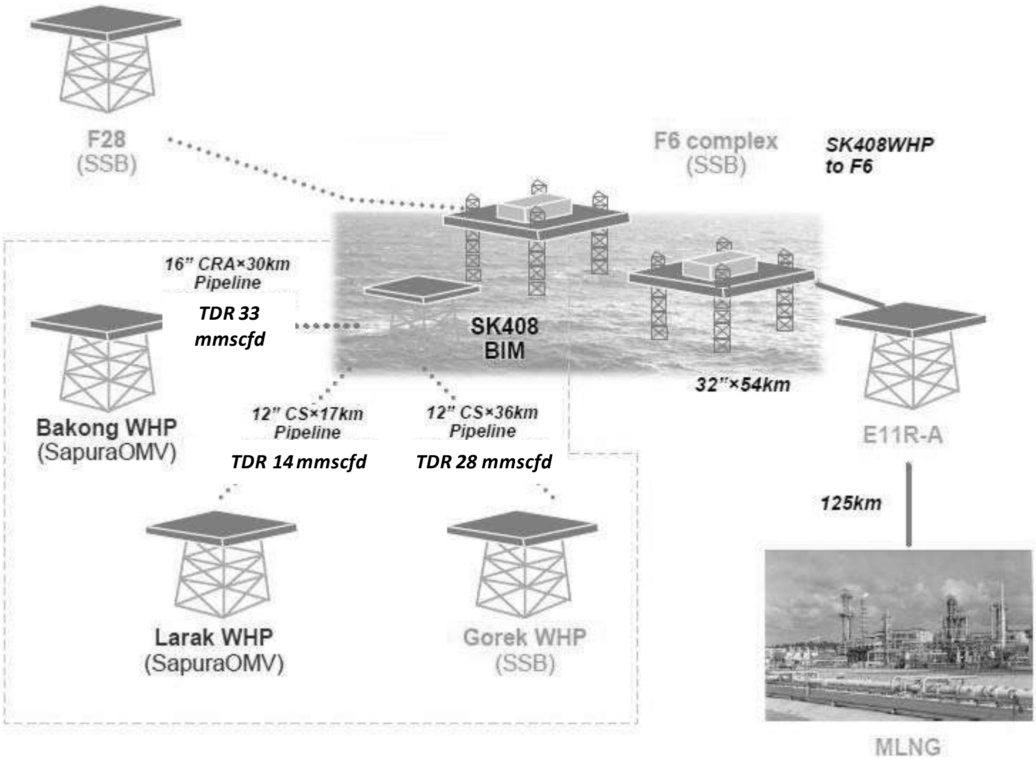

Figure 2-21: SK408 LaBaGo overview of infrastructure (Source: SOMV, updated for Larak, Bakong and Gorek TDRs per ARPR 1.1.2024).

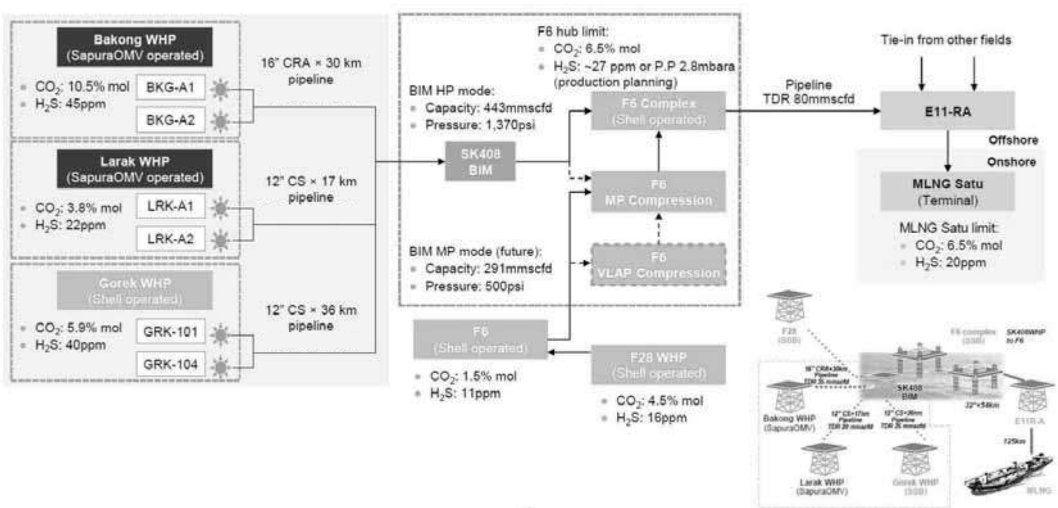

Figure 2-22: SK408 LaBaGo integrated production network (modified from SOMV).

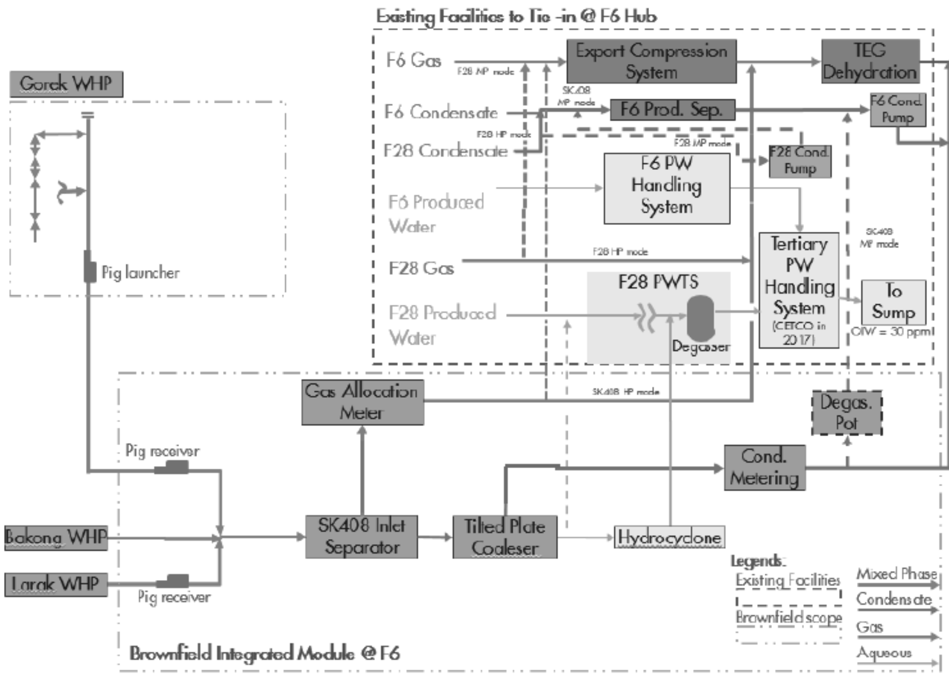

Figure 2-23: Simplified LaBaGo process overview (Source: ARPR 1.1.2024).

LaBaGo gas production is maximized within the F6 BIM capacity limit (i.e., at 460 MMscfd after debottlenecking in Q4 2022, and at 291 MMscfd in Medium Pressure (MP) mode) and meets the SK408 GSA ACQ at 400 MMscfd. The production split by field is optimized based on the availability of sweet gas to blend with at the F6 hub to meet the export line H_2S partial pressure limit of around 2.9 Mbara and CO_2 sales specification limit of 6.5 mol%. The historical gas sales profile split by field for LaBaGo is shown in Figure 2-24. In December 2023, the average gross sales from Larak, Bakong and Gorek was approximately 87, 212 and 139 MMscfd of gas, respectively, giving a total of 437 MMscfd of gas for SK408. As of end December 2023, the cumulative gas (sales and non-sales) recorded for Larak, Bakong and Gorek was approximately 151, 236 and 140, respectively, giving a total of 526 Bscf for SK408.

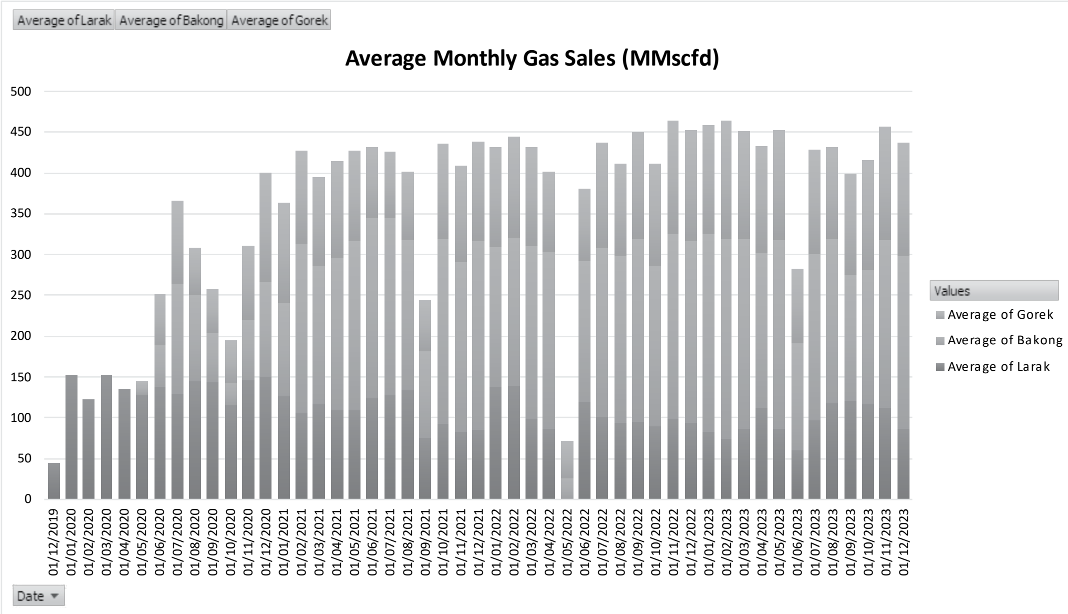

Figure 2-24: LaBaGo gas sales profile (gross), MMscfd.

Defined opportunities with approved FDPs for SK408 are the Jerun gas development and Bakong Phase-II projects, which are expected to add production from 2024 onwards. Teja and Pepulut developments are expected to be developed in the medium-term, with first gas expected in 2027.

The SK408 fields and opportunities are further discussed in the following sections of this report.

2.2.1 Larak

The Larak gas field is a circular pinnacle reef carbonate structure of Middle Miocene age, located in Block SK408, in the Central Luconia province offshore Sarawak, in water depth of approximately 81 m (Figure 2-25). The field was discovered with the drilling of the Larak-1 exploration well in June 2014. Larak field depth structure map and cross-section are shown in Figure 2-26.

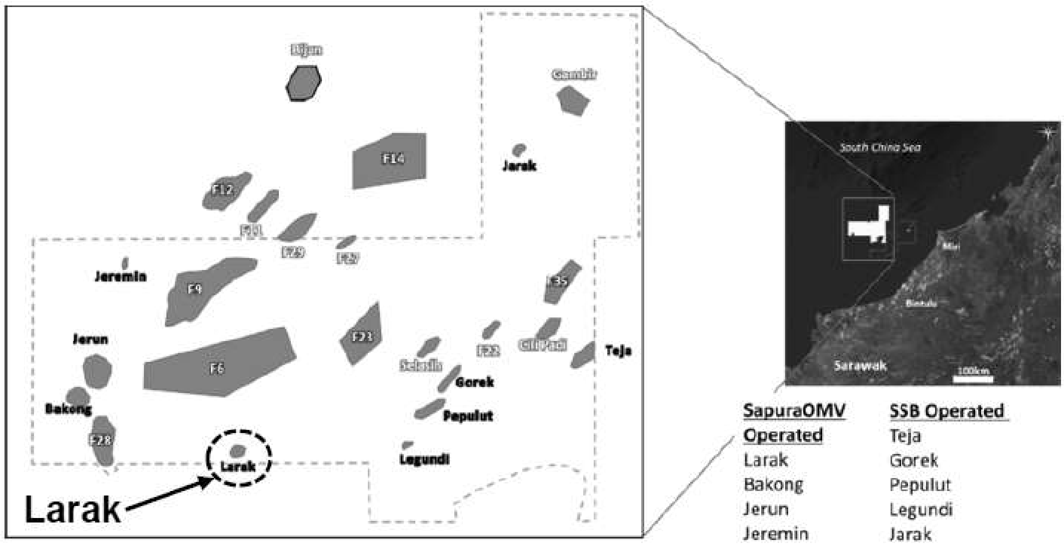

Figure 2-25: Larak field location (Source: ARPR 1.1.2024).

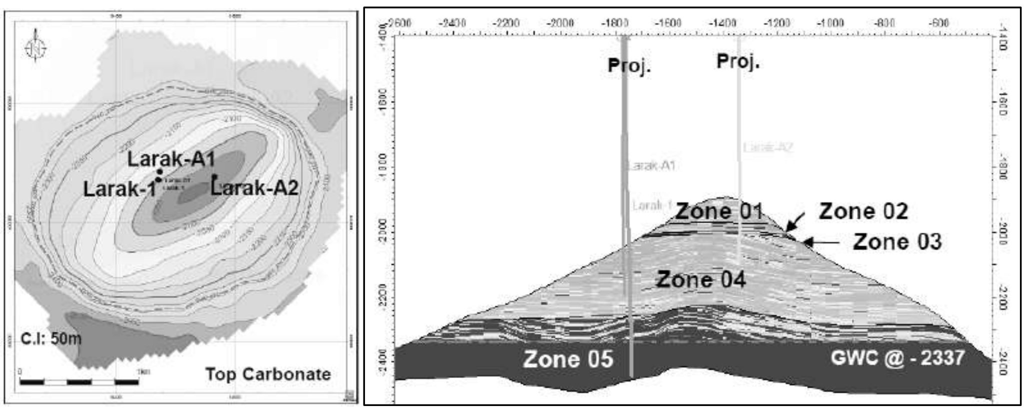

Figure 2-26: Larak field top carbonate map and cross-section (Source: ARPR 1.1.2024).

Larak was developed as a WHP tie-in to F6 BIM processing hub, and first gas from the field was reported in December 2019. Two gas producing wells (each with a 7-inch tubing string installed with a permanent downhole gauge, PDG) were drilled and completed in the field (both are currently active). Larak field and reservoir properties are summarized in Table 2-2. The average porosity and permeability are estimated to be approximately 18% and 50 mD, respectively. The reservoir drive mechanism is pressure depletion, with weak aquifer support and no secondary recovery. The estimated in-place and recoverable volumes for Larak based on ARPR 1.1.2024 submission are shown in Table 2-3. Note that the Estimated Ultimate Recovery (EUR) comprises cumulative production (sales and non-sales), P50 reserves (Developed and Undeveloped), P50 Contingent Resources, as well as fuel and flare/vent volume estimates.

Property/ parameter	Unit	Value/ Remarks
No. of wells	-	2
No. of well slots	-	3
Gas column	m	424
GWC	mTVDSS	2,337
Area at GWC	km^2	3.8
Porosity	%	18
Permeability	mD	50
Reservoir pressure	psi	3,526
Reservoir temperature	degF	262
Gas s.g.	-	0.72
CO_2	mol%	3.8
H_2S	ppm	22
CGR	bbl/MMscf	18

Table 2-2: Larak field and reservoir properties (Sources: SOMV, ARPR 1.1.2024, AMiR 2023).

	Low (P90)	Base (P50)	High (P10)
GIIP (Bscf)	476	553	639
EUR (Bscf)	385	436	491

Table 2-3: Larak GIIP and EUR (Source: ARPR 1.1.2024).

Static and dynamic modelling for Larak field was updated in 2022, and the reservoir tank model has been updated and matched with latest static downhole pressure from June 2023 shutdown. The results have been incorporated in ARPR 1.1.2024. Larak reserves are all Developed (P50 Developed, 280 Bscf), and there are no ongoing studies and no plans for future projects for the field.

The GIIP volume was further validated via Dynamic Material Balance (DMB) analysis, utilizing the Larak A-1 and Larak A-2 well production and PDG-measured flowing bottomhole pressure (FBHP) data. The results shown in Figure 2-27, Figure 2-28 and Table 2-4 indicate that the GIIP obtained from DMB are comparable to ARPR 1.1.2024 Best Case (P50).

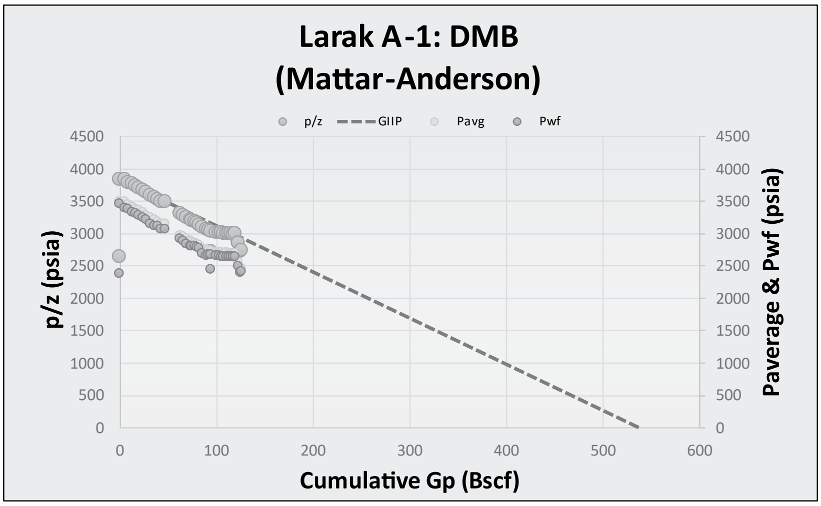

Figure 2-27: Larak A-1 DMB analysis.

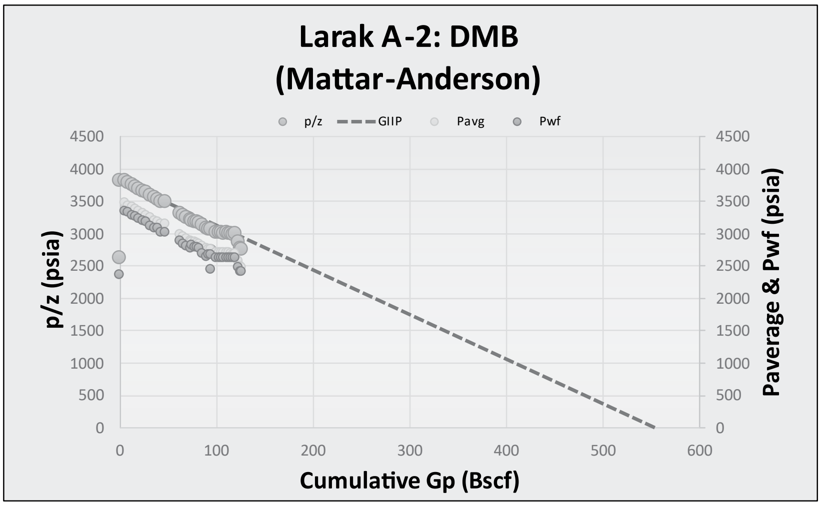

Figure 2-28: Larak A-2 DMB analysis.

GIIP (Bscf)	ARPR 1.1.2024 (Best)	DMB	%Diff
LaA-1	553	538	-3%
LaA-2	553	554	0%
Average	553	546	-1%

Table 2-4: Larak DMB analysis results.

The Key Resource Indicators for Larak Non-associated gas (NAG) resources summarized in Table 2-5 indicate that the recoveries are optimized and reasonable, and also within the ranges observed in Central Luconia gas fields, for reservoirs with pressure depletion and weak to moderate aquifers (Figure 1-2).

P90 (Dev+ Undev) (Bscf)	P50 (Dev+ Undev) (Bscf)	P50 CR (Bscf)	2023 Prod (Bscf)	P50 RF (%)	1P RLI (Years)	2P RLI (Years)	2P+2C ORLI (Years)
228.97	280.09	0.00	31.81	79	7.20	8.80	8.80

Table 2-5: Larak Key Resource Indicators (Source: ARPR 1.1.2024).

In December 2023, the average gross sales from the field was approximately 87 MMscfd of gas. As of end December 2023, a total of 151 Bscf cumulative gas production (sales and non-sales) was recorded. The historical field production is shown in Figure 2-29.

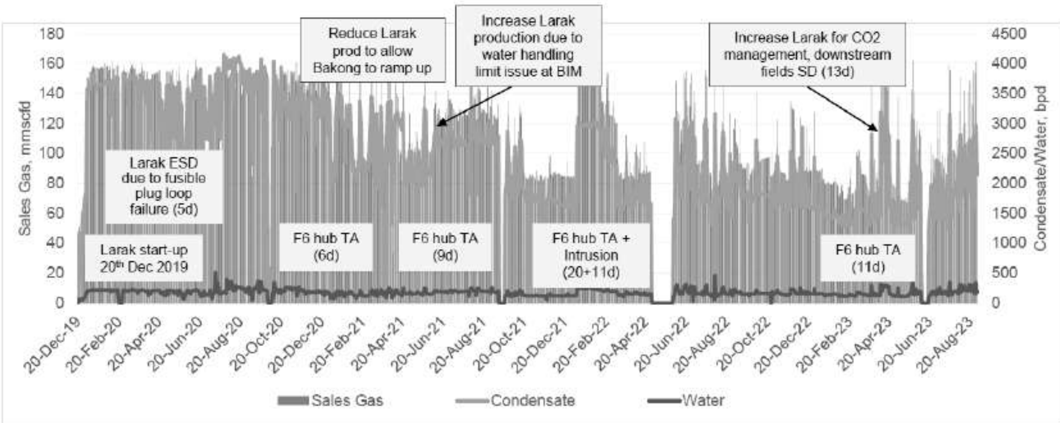

Figure 2-29: Larak field production (Source: ARPR 1.1.2024).

Sweet gas from Larak has been proactively minimized and conserved for blending with Bakong and Gorek gas (with higher CO_2 and H_2S contents), to meet the current contaminant constraints and for long term contaminant management, together with sweet gas from other fields from the F6 hub i.e., F6 and F28. Downtime at Larak is mostly contributed by external downtime e.g., from F6 unavailability and curtailment from downstream.

2.2.2 Bakong

The Bakong gas field is a circular pinnacle reef carbonate structure of Middle Miocene age, located in Block SK408, in the Central Luconia province offshore Sarawak, approximately 150 km North of Bintulu in water depth of around 85 m (Figure 2-30. The field was discovered with the drilling of the Bakong-1 exploration well in July 2014. Bakong field depth structure map and cross-section are shown in Figure 2-31.

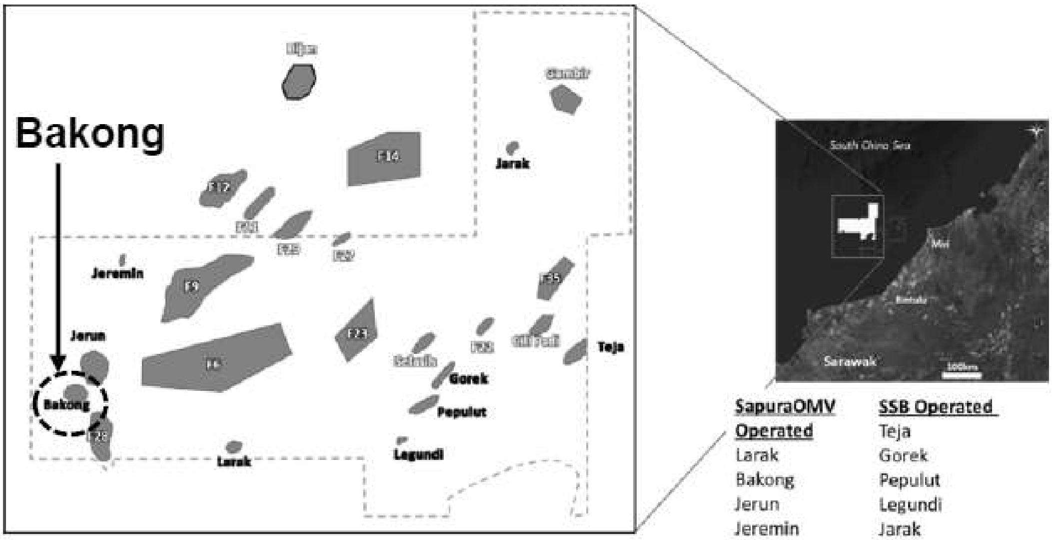

Figure 2-30: Bakong field location (Source: ARPR 1.1.2024).

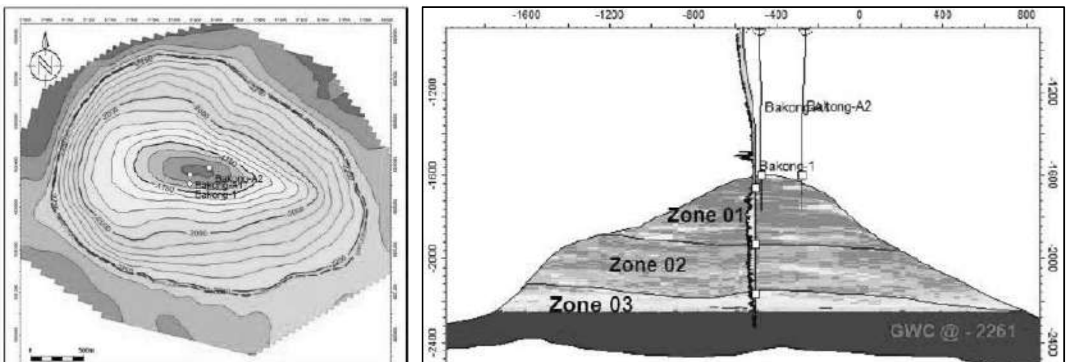

Figure 2-31: Bakong field top carbonate map and cross-section (Source: ARPR 1.1.2024).

Bakong field adopts a two-phased development strategy, targeted for early gas sales opportunity. Bakong Phase-I development was a WHP tie-in to F6 BIM processing hub, and first gas from the field was reported in June 2020. Bakong Phase-II development (refer Section 2.2.2.1 below) is an extension of Phase-I production, with an additional supply of sweet gas from F6 complex to blend down Bakong CO_2, via the F6 VLAP (Very Low Abandonment Pressure) project.

Bakong Phase-I development comprised drilling of two gas producing wells (each completed with a 7-inch tubing string), and both wells are currently active. Bakong field and reservoir properties are summarized in Table 2-6. The average porosity and permeability are estimated to be approximately 24% and 100 mD, respectively. The reservoir drive mechanism is pressure depletion, with weak aquifer support and no secondary recovery. The estimated in-place volumes for Bakong based on ARPR 1.1.2024 submission is shown in Table 2-7.

Property/ parameter	Unit	Value/ Remarks
No. of wells	-	2
No. of well slots	-	3
Gas column	m	664
GWC	mTVDSS	2,261
Area at GWC	km^2	4.1
Porosity	%	24
Permeability	mD	100
Reservoir pressure	psi	3,244
Reservoir temperature	degF	277
Gas s.g.	-	0.72
CO_2	mol%	10.5
H_2S	ppm	45
CGR	bbl/MMscf	11

Table 2-6: Bakong field and reservoir properties (Source: SOMV, ARPR 1.1.2024, AMiR 2023).

	Low (P90)	Base (P50)	High (P10)
GIIP (Bscf)	1,232	1,353	1,479
EUR (Bscf)	1,000	1,105	1,274

Table 2-7: Bakong GIIP and EUR (Source: ARPR 1.1.2024).

Static and dynamic modelling for Bakong field was updated in 2022, and the results have been incorporated in ARPR 1.1.2024. H_2S sampling and isotope analysis are listed as ongoing studies for the field, designed to achieve higher accuracy in H_2S measurement. Bakong reserves comprise both Developed (P50 Developed, 427 Bscf) reserves from the existing base production, and Undeveloped (P50 Undeveloped, 289 Bscf) reserves from Bakong Phase-II development (F6 VLAP) project, where additional gas production from Bakong is expected as a result of having additional sweet gas produced by F6 and F28 fields available for blending. Having a higher GIIP compared to Larak and Gorek, it is expected that Bakong gas with the highest H_2S and CO_2 contents is prioritized and maximized when the additional sweet gas is available for blending to meet the contaminant constraints.

The GIIP volume was further validated via Dynamic Material Balance (DMB) analysis, utilizing the Bakong A-1 well production and PDG-measured flowing bottomhole pressure (FBHP) data. The results shown in Figure 2-32 and Table 2-8 indicate that the GIIP obtained from DMB are comparable to ARPR 1.1.2024 Best Case (P50).

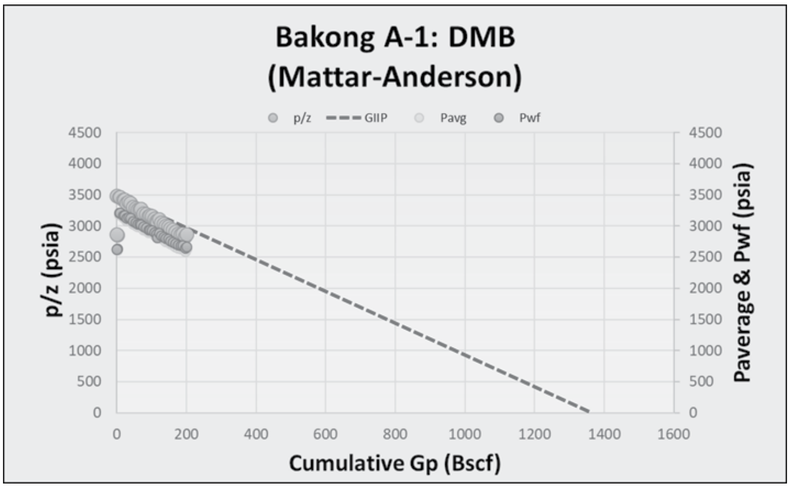

Figure 2-32: Bakong A-1 DMB analysis.

GIIP (Bscf)	ARPR 1.1.2024 (Best)	DMB	%Diff
BaA-1	1,353	1,363	1%

Table 2-8: Bakong DMB analysis results.

The Key Resource Indicators for Bakong Non-associated gas (NAG) resources summarized in Table 2-9 indicate that the recoveries are optimized and reasonable, and also within the ranges observed in Central Luconia gas fields, for reservoirs with pressure depletion and weak to moderate aquifers (Figure 1-2).

P90 (Dev+ Undev) (Bscf)	P50 (Dev+ Undev) (Bscf)	P50 CR (Bscf)	2023 Prod (Bscf)	P50 RF (%)	1P RLI (Years)	2P RLI (Years)	2P+2C ORLI (Years)
623.51	716.27	131.18	76.71	82	8.13	9.34	11.05

Table 2-9: Bakong Key Resource Indicators (Source: ARPR 1.1.2024).

In December 2023, the average gross sales from the field was approximately 212 MMscfd of gas. As of end December 2023, a total of 236 Bscf cumulative gas production (sales and non-sales) was recorded. The historical field production is shown in Figure 2-33.

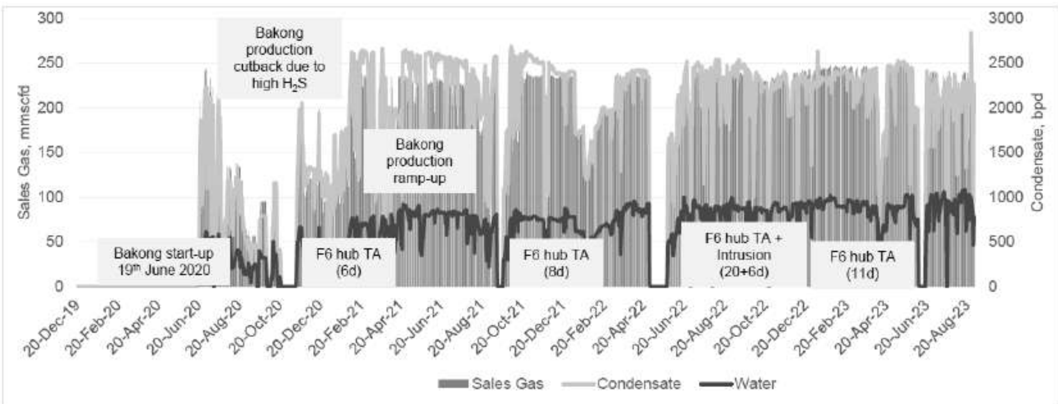

Figure 2-33: Bakong field production (Source: ARPR 1.1.2024).

Bakong gas with high CO_2 and H_2S requires blending with sweet gas producing fields in F6 hub i.e., Larak, F6 and F28. Similar to Larak, the facilities downtime at Bakong is mostly contributed by external downtime e.g., from F6 unavailability and curtailment from downstream. Any decrease in production of sweet gas available for blending would result in choking back of Bakong wells production to meet the contaminant constraints, and would result in lower recoverable reserves.

2.2.2.1 Bakong Phase-II Development Project

Bakong gas which contains 10.5 mol% CO_2 is constrained by the contaminant export limit (MLNG's specification of 6.5 mol%) at the F6 hub. Blending Bakong gas production with sweet gas from F6 complex is therefore required to ensure that the gas is on-spec upon arrival at MLNG.

A VLAP compressor is planned to be installed at F6 hub to reduce the backpressure of wells at F6 complex, thus increasing the supply of sweet gas. It is expected that the additional sweet gas available for blending would result in an increase in Bakong field's gas production and ultimate recovery, as the recovery factor is expected to increase from approximately 46% (based on the FDP targeted recoverable reserves of 675 Bscf) to 82% (based on current reserves estimates). The project is considered a firm project under SSB and is operated by SSB outside of SK408 PSC. The FDP for F6 VLAP was approved by PETRONAS on 26th January 2023, and tendering of the Engineering, Procurement and Construction (EPC) and (Transportation and Installation) T&I contracts are reported to be ongoing. The volumes associated with the F6 VLAP in Bakong Phase-II Development Project to recover 289 Bscf reserves from Bakong is classified under the Undeveloped reserves category in ARPR 1.1.2024 (FDP SK408 Bakong Fac). The incremental sweet gas from F6 VLAP project (First Gas Date, FGD) is expected in April 2026.

The notional incremental recovery associated with Bakong Study is categorized as Contingent Resources (Development On Hold/ Unclarified) Unclarified presented in Section 7 of this report.

2.2.3 Gorek

The Gorek gas field is an elongated pinnacle carbonate structure located in Block SK408, in the Central Luconia province offshore Sarawak, approximately 120 km Northwest of Miri in water depth of around 89 m (Figure 2-34). The field was discovered with the drilling of the Gorek-1 exploration well in April 2014. Gorek field depth structure map, well logs and field cross-section depicted in Figure 2-35 show that gas is primarily contained within Zones 0, 1 and 2, whereas Zone 3 is described as consisting of a tight layer.

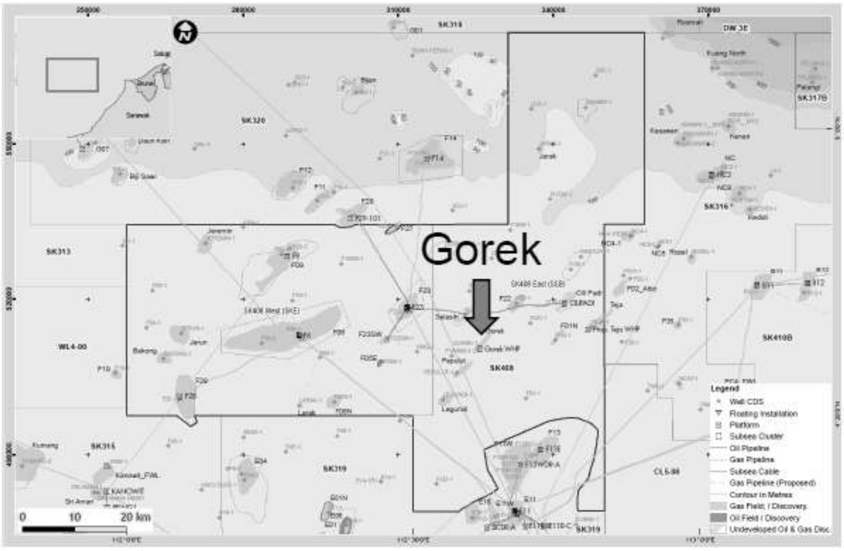

Figure 2-34: Gorek field location (Source: ARPR 1.1.2024).

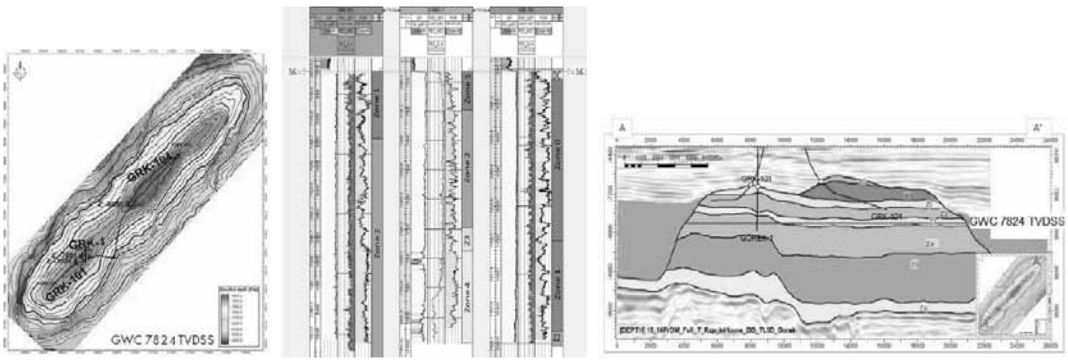

Figure 2-35: Gorek field depth structure map, well logs and field cross-section (Source: ARPR 1.1.2024).

Gorek was developed as a WHP tie-in to F6 BIM processing hub, and first gas from the field was reported in May 2020. Two gas producing wells (each with a 7-inch tubing string installed with a permanent downhole gauge, PDG) were drilled and completed in the field (both are currently active). Gorek field and reservoir properties are summarized in Table 2-10. The average porosity and permeability are estimated to be approximately 18% and 50 mD, respectively. The reservoir drive mechanism is pressure depletion, with weak aquifer support and no secondary recovery. The estimated in-place volumes for Gorek based on ARPR 1.1.2024 submission is shown in Table 2-11.

Property/ parameter	Unit	Value/ Remarks
No. of wells	-	2
No. of well slots	-	3
Gas column	m	255
GWC	mTVDSS	2,385
Area at GWC	km^2	5.0
Porosity	%	18
Permeability	mD	50
Reservoir pressure	psi	3,585
Reservoir temperature	degF	257
Gas s.g.	-	0.67
CO_2	mol%	5.9
H_2S	ppm	40
CGR	bbl/MMscf	9

Table 2-10: Gorek field and reservoir properties (Source: SOMV, ARPR 1.1.2024).

	Low (P90)	Base (P50)	High (P10)
GIIP (Bscf)	359	475	570
EUR (Bscf)	272	367	437

Table 2-11: Gorek GIIP and EUR (Source: ARPR 1.1.2024).

Static and dynamic modelling for Gorek field was updated in 2022, and the results have been incorporated in ARPR 1.1.2024. The GIIP ranges correspond to the dynamic model cases which assume different aquifer drives providing pressure support i.e., Low Case (P90) with strong aquifer, Base Case (P50) with moderate aquifer, and High Case (P10) with no aquifer support (pure depletion). The P/z plot for the different dynamic model cases is shown in Figure 2-36.

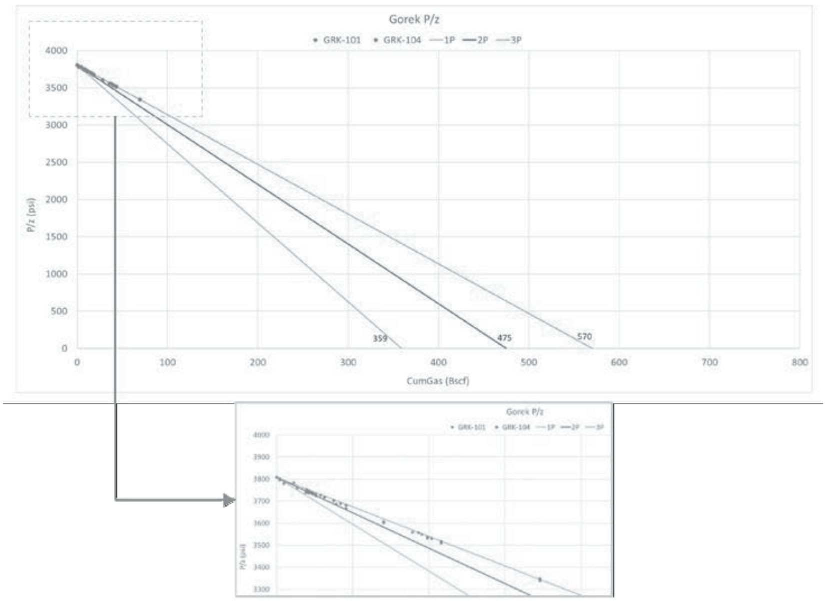

Figure 2-36: Gorek P/z plot and the corresponding 1P (low case), 2P (base case) and 3P (high case) GIIP from dynamic model cases (Source: ARPR 1.1.2024).

The GIIP volume was further validated via Dynamic Material Balance (DMB) analysis, utilizing the Gorek-101 and Gorek-104 well production and PDG-measured flowing bottomhole pressure (FBHP) data. The results shown in Figure 2-37, Figure 2-38 and Table 2-12 indicate that the GIIP obtained from DMB are comparable to ARPR 1.1.2024 High Case (P10), which corresponds to the reservoir model associated with pure depletion drive mechanism i.e., no aquifer support. Weak aquifer is also observed from offset fields such as Cili Padi, F23 and F23SW, and as such, the same (weak vs no aquifer) is expected at Gorek. Therefore, the Base Case (P50) model was utilized in the 2P (P50) production forecast.

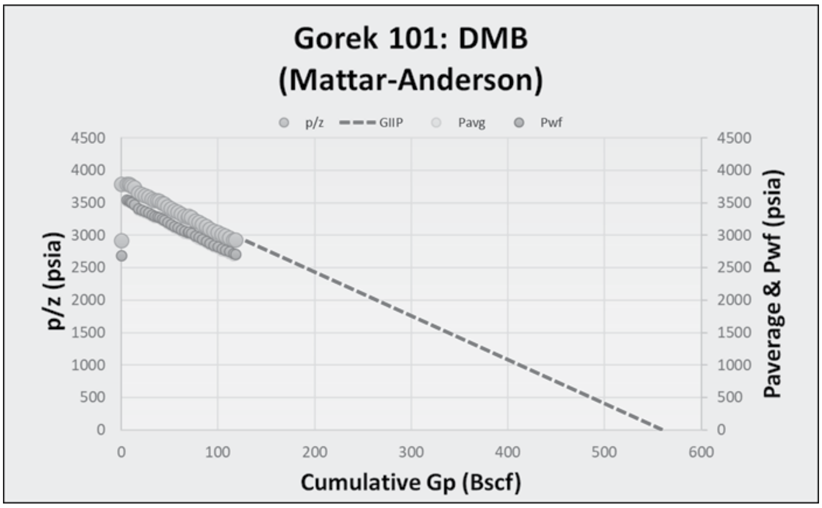

Figure 2-37: Gorek-101 DMB analysis.

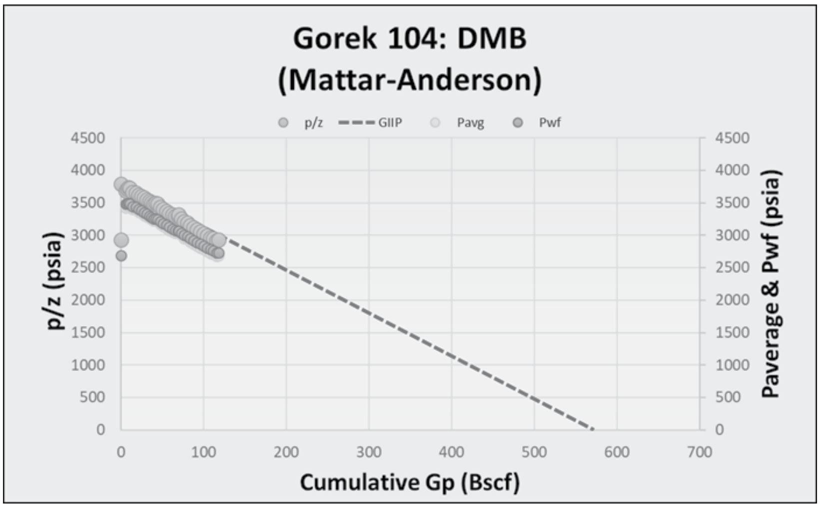

Figure 2-38: Gorek-104 DMB analysis.

GIIP (Bscf)	ARPR 1.1.2024 (Best)	ARPR 1.1.2024 (High)	DMB	%Diff (Best)	%Diff (High)
Gorek 101	475	570	560	18%	-2%
Gorek 104	475	570	572	20%	0%
Average	475	570	566	19%	-1%

Table 2-12: Gorek DMB analysis results.

The Key Resource Indicators for Gorek Non-associated gas (NAG) resources summarized in Table 2-13 indicate that the recoveries are optimized and reasonable, and also within the ranges observed in Central Luconia gas fields, for reservoirs with pressure depletion and weak to moderate aquifers (Figure 1-2).

P90 (Dev+ Undev) (Bscf)	P50 (Dev+ Undev) (Bscf)	P50 CR (Bscf)	2023 Prod (Bscf)	P50 RF (%)	1P RLI (Years)	2P RLI (Years)	2P+2C ORLI (Years)
129.28	223.70	0	40.22	77	3.21	5.56	5.56

Table 2-13: Gorek Key Resource Indicators (Source: ARPR 1.1.2024).

In December 2023, the average gross sales from the field was approximately 139 MMscfd of gas. As of end December 2023, a total of 140 Bscf cumulative gas production (sales and non-sales) was recorded. The historical field production is shown in Figure 2-39.

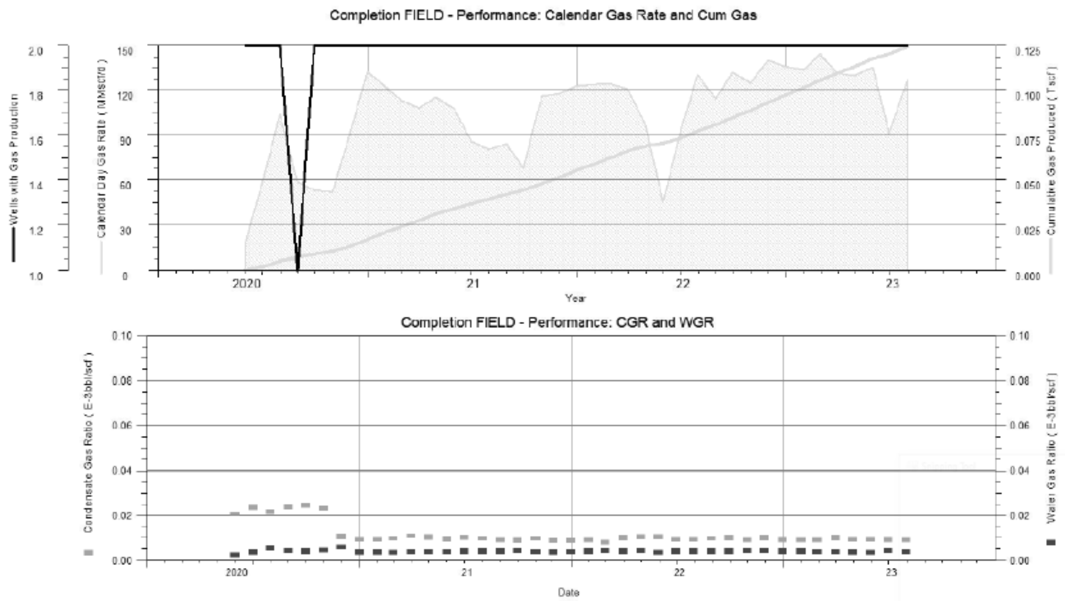

Figure 2-39: Gorek field production (Source: ARPR 1.1.2024).

The current production policy prioritizes and maximizes Bakong gas production over Gorek (Bakong has a higher GIIP and higher H_2S and CO_2 contents). As such, Gorek gas production is only ramped up when there is ullage from Bakong's decline. The additional sweet gas available for blending from the F6 VLAP in Bakong Phase-II development project is expected to also benefit Gorek.

Gorek reserves comprise both Developed (P50 Developed, 184 Bscf) reserves from the existing base production, and Undeveloped (P50 Undeveloped, 40 Bscf) reserves associated with the Bakong Phase-II development (F6 VLAP) project (FS SK408 Gorek Fac). A plan to execute FFR activities for Gorek in 2026 was also indicated.

2.2.4 Jerun

Jerun gas field is located in the Central Luconia province offshore Sarawak, approximately 160 kilometers Northwest from Bintulu, in water depth of approximately 87 m (Figure 2-40). The field is a Cycle IV/V circular pinnacle carbonate build-up of Middle to Late Miocene age, located in the western part of Block SK408. The field was discovered with the drilling of the Jerun-1 exploration well in October 2015. Jerun top of carbonate depth structure map and field cross-section are shown in Figure 2-41.

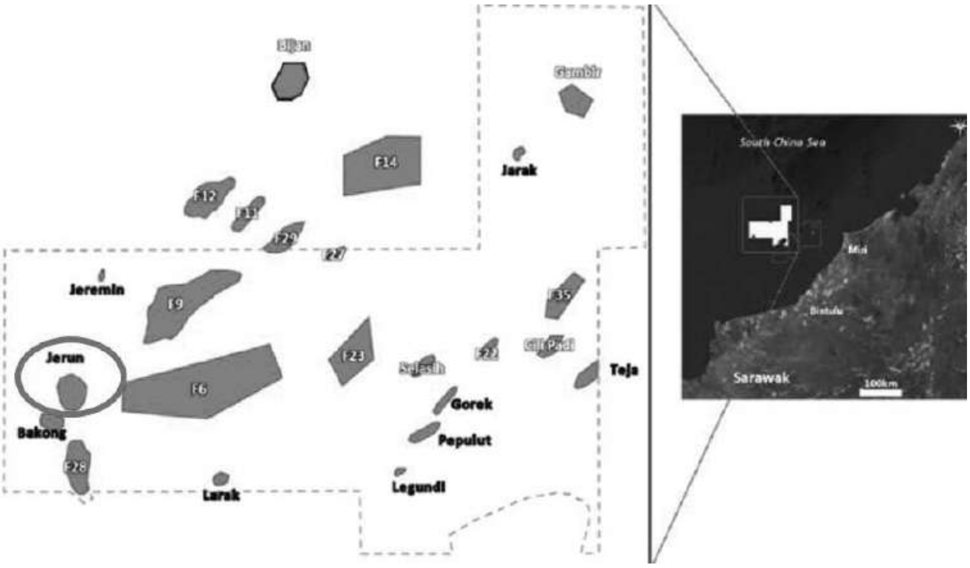

Figure 2-40: Jerun field location (Source: ARPR 1.1.2024).

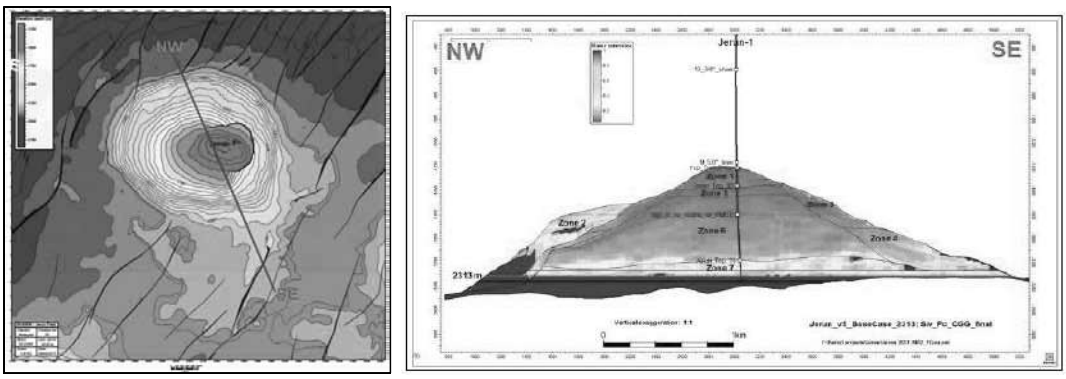

Figure 2-41: Jerun top of carbonate depth structure map and field cross-section (Source: ARPR 1.1.2024).

Jerun field and reservoir properties are summarized in Table 2-14. The field structure is a circular pinnacle carbonate of good reservoir quality throughout the gas zone, with a slight porosity degradation near the estimated gas-water contact (GWC). The average porosity and permeability are estimated to be approximately 23% and 50 mD, respectively. The reservoir drive mechanism is expected to be pressure depletion with weak aquifer support. The estimated in-place volumes for Jerun based on ARPR 1.1.2024 submission is shown in Table 2-15.

Property/ parameter	Unit	Value/ Remarks
No. of wells	-	6 (planned)
No. of well slots	-	8
Gas column	m	907
GWC	mTVDSS	2,313
Area at GWC	km^2	8.5
Porosity	%	23
Permeability	mD	50
Reservoir pressure	psi	3,639
Reservoir temperature	degF	289
Gas s.g.	-	0.765
CO_2	mol%	7.1
H_2S	ppm	20 - 30
CGR	bbl/MMscf	25

Table 2-14: Jerun field and reservoir properties (Source: SOMV, ARPR 1.1.2024).

	Low (P90)	Base (P50)	High (P10)
GIIP (Bscf)	2,437	2,884	3,336
EUR (Bscf)	1,933	2,238	2,301

Table 2-15: Jerun GIIP and EUR (Source: ARPR 1.1.2024).

In ARPR 1.1.2024, the volumes associated with the six well development of NAG pinnacle carbonate reservoir without compression (FDP SK408 Gas Jerun GFD), and the benefit from the compression project (FDP SK408 Jerun Fac) from 2028 onwards as per the approved FDP/FID, are classified as Undeveloped reserves (P50) estimated to be at 1,148 Bscf and 1,018 Bscf, respectively, giving a total of 2,166 Bscf for the project.

Jerun FDP that was approved in February 2022 comprised the plan to develop the field via six gas producers i.e., development wells i.e., Jerun-A1, A2, A3, A4, A5 and A6, which consist of vertical and deviated single gas producers completed with pre-drilled liners and 7-inch tubing strings (Figure 2-42).

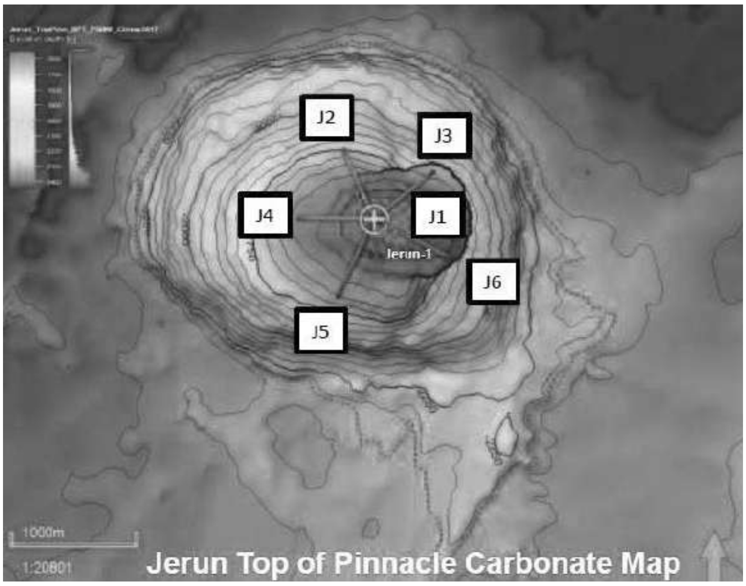

Figure 2-42: Jerun planned well locations (Source: Jerun MR5).

Figure 2-43 illustrates the Jerun gas development project which comprises an integrated CPP (iCPP) JRN-A 8-legged jacket platform, with a Wellhead Deck (WHD) and processing platform equipped with gas treatment facilities and living quarters, and an export pipeline that ties back to the existing riser platform E11R-B. The platform facility is designed for 600 MMscfd to meet the expected target gas sales of 500 MMscfd from the field.

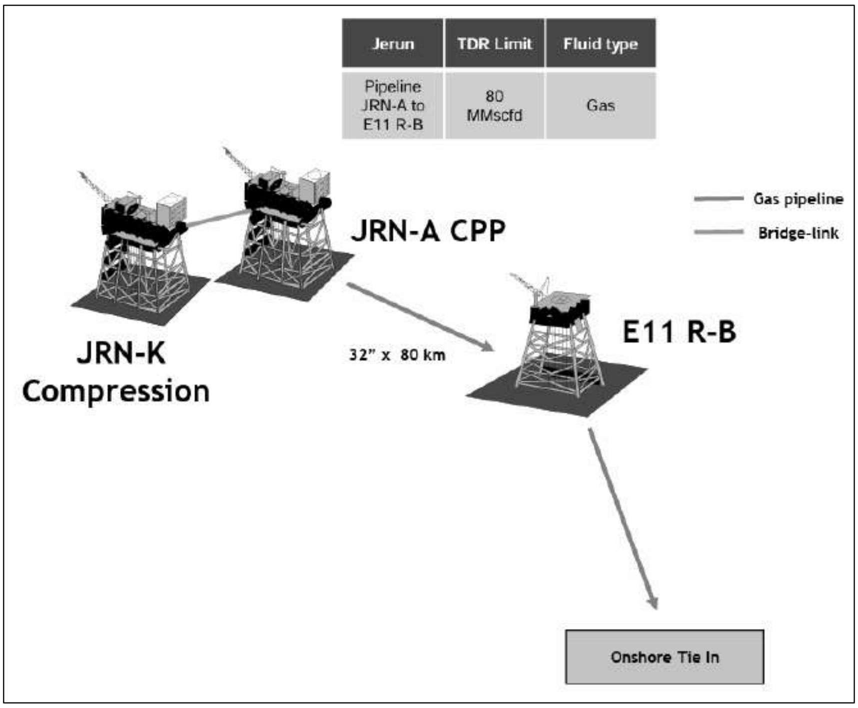

Figure 2-43: Jerun gas development project (Source: ARPR 1.1.2024).

As the reservoir pressure declines, a future gas compression facility i.e., JRN-K will be installed on a separate platform structure to sustain the gas plateau at 500 MMscfd annual average. The JRN-K platform is bridge-connected to JRN-A platform, and is equipped with two compression trains anticipated for optimal facility uptime. The minimum well tubing head pressure (THP) limit assumed pre-compression is at 1,700 psi, and at 500 psi post-compression.

From the gas sales profile and compression timing shown in Figure 2-44, it is estimated the Medium Pressure (MP) compression mode will be required around four years after first production (estimated first gas post-compression in 2028), followed by the Low Pressure (LP) mode around three years later. The forecasted gas sales from Jerun shown indicates a seven-year plateau production of 500 MMscfd gas to meet ACQ, to be sold to the MLNG in Bintulu.

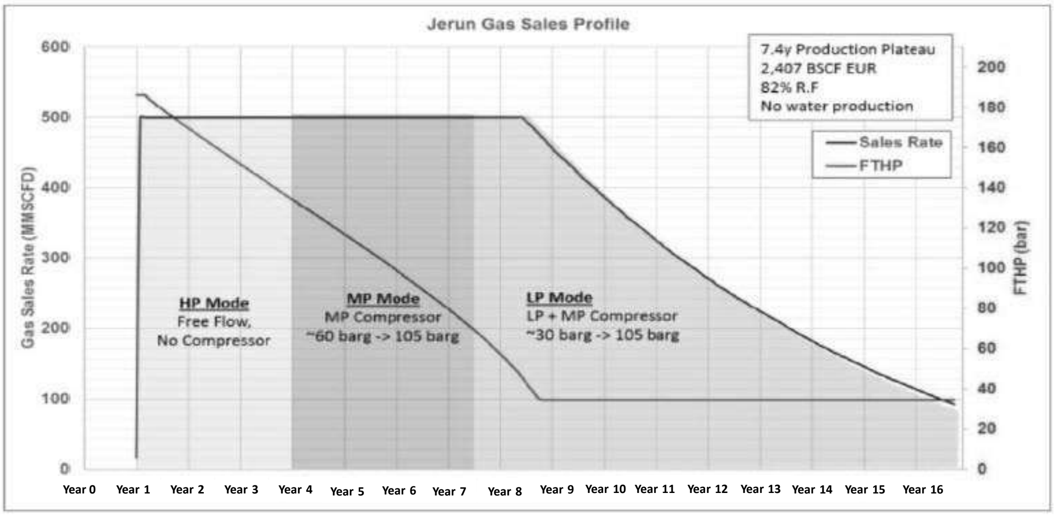

Figure 2-44: Jerun gas sales and compression timing (Source: ADP 2021, adjusted for FGD).

Jerun gas contains 7.1 mol% CO_2, which is slightly higher than the MLNG's specification of 6.5 mol%. Ensuring that the gas is on-spec upon arrival at MLNG would require blending with sweet gas within the Sarawak Gas Network during the early production years, estimated to be sufficient until year 2030 (per MR5 Minutes of Meeting (MOM) referenced in Jerun FDP and PETRONAS's "Blend Gas Letter" dated 27th February 2020). To mitigate the risk of gas off-spec as the sweet gas available for blending diminishes, the Jerun development has a provision for an Acid Gas Removal Unit (AGRU) to be installed on JRN-K in the future, for the removal of CO_2 if necessary. The AGRU installation timing is dependent on the blend gas outlook which shall be periodically reviewed, taking into consideration the lead time required to decide for the AGRU installation (typically three to four years for a brownfield project).

The key uncertainties for the project are gas compositions, tank volume and the availability of sweet gas for blending. It was reported that 117 µg /m^3 of mercury was detected during exploration drilling; however, due to the possible trace contamination from barite used in drilling mud, it is inconclusive whether the mercury detected was from the drilling mud or reservoir fluid. In the event of off-spec mercury levels discovered during development drilling, installation of Mercury Removal Unit (MRU) at JRN-A for both gas-phase and condensate-phase were also considered as part of the FDP.

Drilling commenced in Q3 2023, and based on the development drilling update in December 2023, carbonate reef pinnacles were encountered in Jerun-A1, A2, A3, A4 and A5 (previously Jerun-J1, J2, J3, J4 and J5) wells. The preliminary log analysis results from these wells are summarized in Table 2-16, which describes intervals of gas bearing reservoirs with water saturation ranging from 9% to 32%. Post-drilling analysis is currently ongoing, and it is expected that the GIIP and EUR for Jerun will be updated based on the post-drill results.

Well	Completion Interval (mMD)	Description	Gross thickness (m)	Average porosity (%)		Average water saturation (%)	
				Log	Prognosed	Log	Prognosed
Jerun-A1	1466.3 – 1672.0	Gas bearing	205.7	35	30	9	11
Jerun-A2	1971.0 – 2012.0	Gas bearing (moderate RQI)	41.0	7	37	23	8
	2012.0 – 2186.0	Gas bearing (good RQI)	173.8	24	30	10	11
Jerun-A3	2160.8 – 2308.1	Gas bearing	147.0	20	21	21	20
Jerun-A4	1805.7 – 2005.0	Gas bearing	199.3	30	32	10	9
Jerun-A5	1902.5 – 1945.3	Gas bearing	42.7	11	33	32	11
	1945.3 – 2160.0	Gas bearing	214.4	25	29	12	11

Table 2-16: Jerun preliminary log analysis results (Source: Jerun wells drilling subsurface update December 2023).

Also indicated was the presence of 5 mol% to 7 mol% CO_2, 19 ppm to 23 ppm H_2S and 1 µg /m^3 to 128 µg /m^3 mercury, from onsite gas sampling conducted on Jerun-A1, A2, A3 and A4 (previously Jerun-J1, J2, J3 and J4), as summarized in Table 2-17.

Well	CO_2 (mol%)	H_2S (ppm)	Hg ($\mu g/m^3$)
Jerun-A1	5 - 7	19 - 21	11 - 128
Jerun-A2	6 - 7	21 - 23	6 - 9
Jerun-A3	5 - 7	19 - 20	2 - 10
Jerun-A4	5 - 7	20 - 22	1 - 20

Table 2-17: Jerun onsite gas sampling results (Source: Jerun wells drilling subsurface update December 2023).

It is expected that the plan for AGRU and MRU will be revisited, based on the contaminant compositions from the final post-drill well analysis results, along with the latest blend gas outlook (refer plan for AGRU and MRU installations depicted in Figure 2-45). As of October 2023, the overall project progress for JRN-A facilities was reported to be at around 84%, and on track for the JRN-A platform, export pipeline and host tie-in into the riser platform to be onstream and achieve first gas in August 2024 to meet MLNG demand. The JRN-K platform is expected to be onstream in Q3 2028.

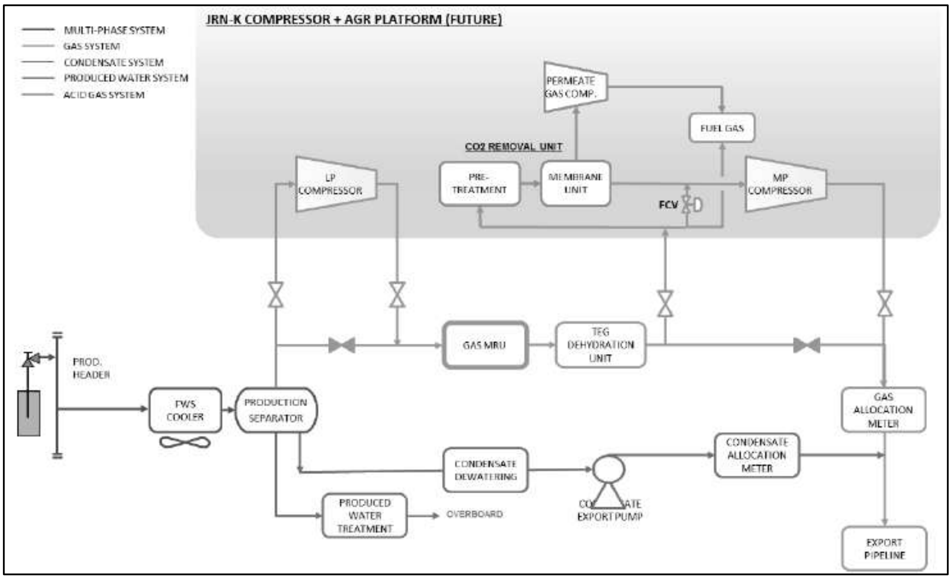

Figure 2-45: Overview of Jerun process diagram (Source: ARPR 1.1.2024).

Opportunities associated with Jerun Optimization project and Jerun Talus potential are categorized as Contingent Resources (Development On Hold/ Unclarified) and presented in Section 7 of this report.

2.2.5 Teja

The Teja gas field is an elongated carbonate pinnacle build-up structure located in the eastern region of Block SK408, in the Central Luconia province offshore Sarawak, in water depth of approximately 89 m. The field straddles across two different PSC blocks (refer Figure 2-46) i.e., SK408, and SK316 held by PCSB, with an equity split between the PSC Blocks assumed to be at 80% and 20%, based on the Teja unitization close-out in August 2022. The field was discovered in 2014 with the drilling of Teja-1 exploration well. The field top structure map and seismic cross-section are shown in Figure 2-47.

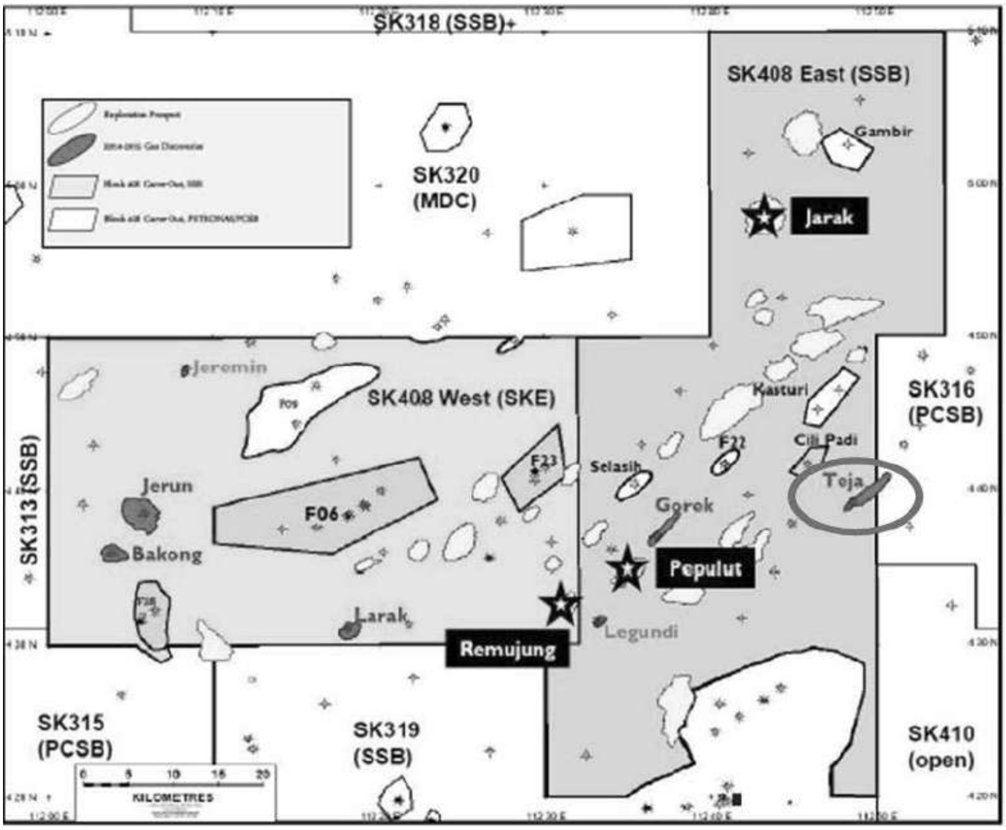

Figure 2-46: Teja field location (Source: ARPR 1.1.2024).

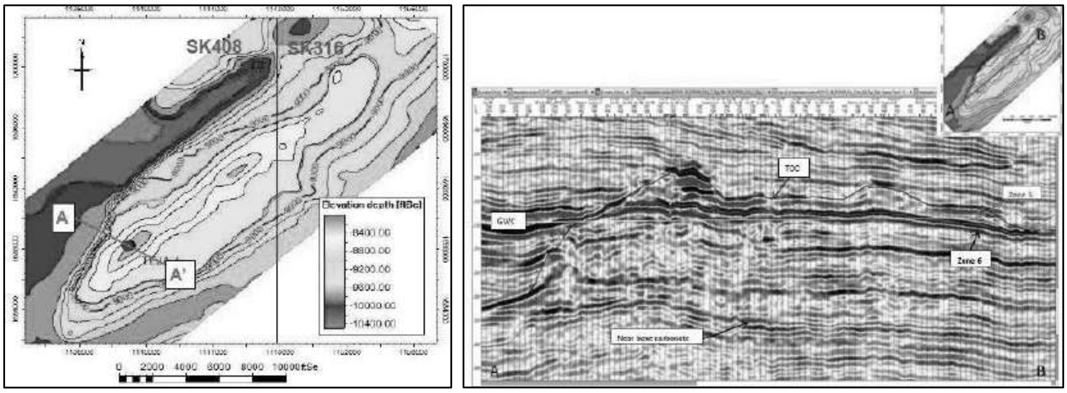

Figure 2-47: Teja field top structure map and seismic cross-section (Source: ARPR 1.1.2024).

Teja field and reservoir properties are summarized in Table 2-18. The average porosity and permeability are estimated to be approximately 10% to 20% and 60 mD, respectively. Presence of around 8 mol% CO_2 and 40 to 60 ppm H_2S are indicated for this field. The estimated in-place volumes for Teja based on ARPR 1.1.2024 submission is shown in Table 2-19.

Property/ parameter	Unit	Value/ Remarks
No. of wells	-	1 (planned)
No. of well slots	-	4
Gas column	m	219
GWC	mTVDSS	2,688
Area at GWC	km^2	4.0
Porosity	%	13.8
Permeability	mD	60
Reservoir pressure	psi	3,760
Reservoir temperature	degF	280
Gas s.g.	-	0.74
CO_2	mol%	7.3 – 8.2
H_2S	ppm	40 - 60
CGR	bbl/MMscf	17

Table 2-18: Teja field and reservoir properties (Source: SOMV, ARPR 1.1.2024, Teja MR3 2015, Teja model updates review 2021).

	PSC	Low (P90)	Base (P50)	High (P10)
GIIP (Bscf)	SK408 (80%)	117	283	637
	SK316 (20%)	29	71	159
	Total field	146	354	796
EUR (Bscf)	SK408 (80%)	28	141	334
	SK316 (20%)	7	35	83
	Total field	35	176	417

Table 2-19: Teja GIIP and EUR (Source: ARPR 1.1.2024).

The reservoir drive mechanism is expected to be pressure depletion, with weak aquifer support and no secondary recovery. The tight porosity zone identified in Teja related to geological exposure and flooding zones (Zone 5) is likely to act as a baffle to delay any water encroachment. Similar porosity trend is observed from offset fields in Central Luconia such as Bakong, Larak and Pepulut (Figure 2-48).

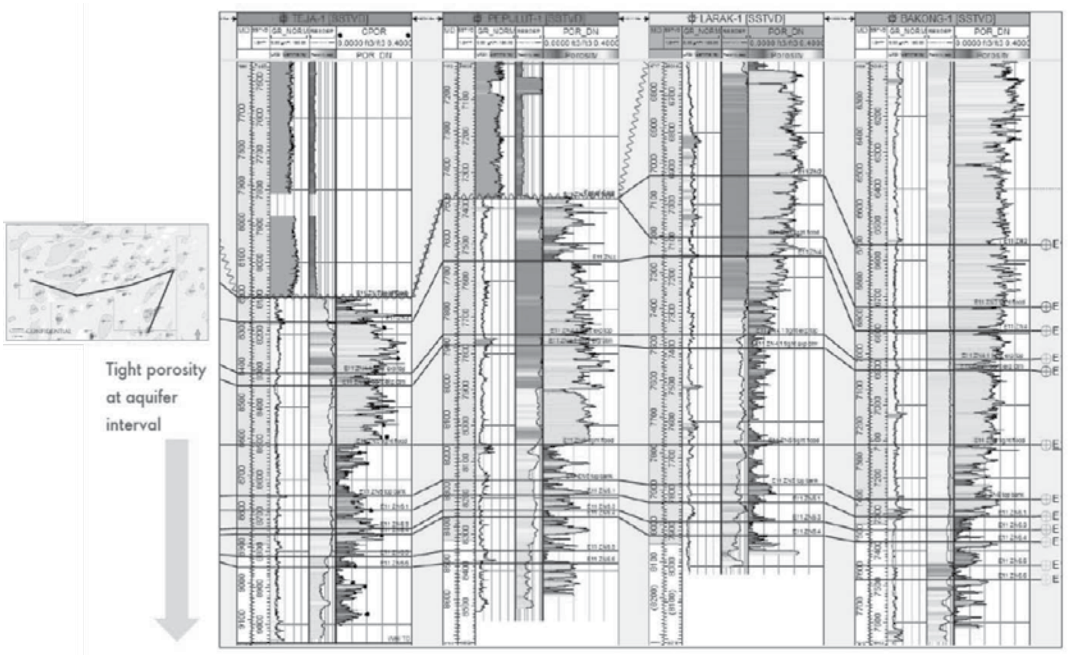

Figure 2-48: Teja regional aquifer properties (Source: Teja model updates review 2021).

A new WHP is planned to be installed for Teja to tie-in to the F23 processing hub, to rely on the sweet gas available at the hub for blending. Conceptually, the tie-in would be via a co-development with Pepulut WHP (daisy chain via a new 12-inch, 30 km carbon steel, sour rated pipeline), as shown in Figure 2-49. Teja FWS is sent to Pepulut WHP, is commingled with Pepulut FWS and then sent to F23 hub via a 14-inch, carbon steel, sour rated pipeline. The conceptual development assumes that a new BIM may be required for F23 hub, equipped with inlet separator, pig receiver, and gas and condensate metering skids. In this scenario, F23 hub will undergo a rejuvenation campaign from 2027 to 2030, during which the offshore Hook-up and Commissioning (HUC) activities for Teja and Pepulut fields to F23 hub are also carried out in 2H 2027. The rejuvenation cost is to be allocated to Teja and Pepulut based on their share of the hub's forward-looking Long Term Production Forecast (LTPF). It is also assumed that the development sites for Teja and Pepulut are Jack Up rig and WHP friendly (subject to site survey and soil boring results), and that both Teja and Pepulut fields will operate in HP mode from day one of production.

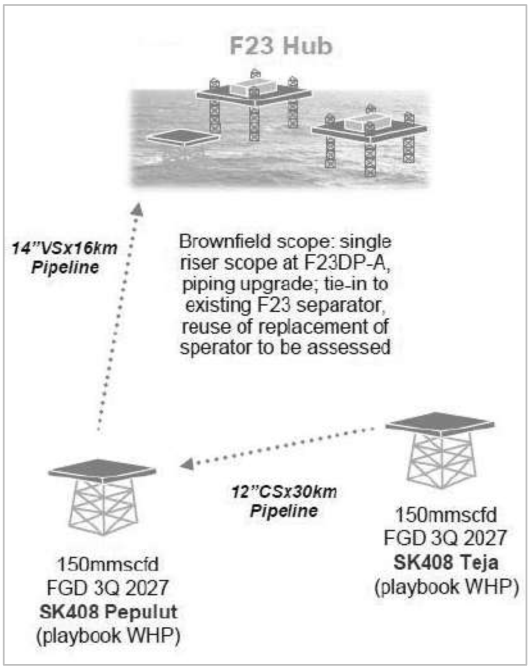

Figure 2-49: Teja and Pepulut planned development concept (Source: SOMV).

The SK408 Area Development Plan (ADP) which included the different development options for Teja was prepared and submitted in September 2021. Static and dynamic modelling for Teja field was updated in 2020 and approved in MR2/3 in April 2021. Considerations on possible surface network effects, constraints and interaction with other fields tied to the F23 hub were also captured in further fine tuning and optimization of the surface network, and the results have been incorporated in ARPR 1.1.2024. The volumes associated with Teja field development are classified under CR1 potential recoverable resource category in ARPR 1.1.2024 (FDP SK408 Gas Teja GFD and FDP SK316 Gas Teja GFD).

One gas well is planned for the field, and the WHP capacity is at 150 MMscfd. The recoverable volume for the entire Teja field is estimated to be at 175 Bscf (P50 Contingent Resource), based on the F23-E11RA pipeline turndown rate (TDR) truncation of 100 MMscfd and also incorporating uptime assumptions at F23 hub. The development concept and FGD timing will be revisited during MR4 planned in May 2024, along with the latest gas demand outlook by MPM. FDP approval is targeted in April 2025 to meet the planned FID approval by June 2025 per the GHA, and the expected first gas is in September 2027.

2.2.6 Pepulut

The Pepulut gas field is a low-relief carbonate pinnacle build-up structure located in the central region of Block SK408, in the Central Luconia province offshore Sarawak, in water depths of approximately 85 m to 90 m (Figure 2-50). The field was discovered with the drilling of the Pepulut-1 exploration well in 2018. The top carbonate map and seismic cross-section of Pepulut field is shown in Figure 2-51.

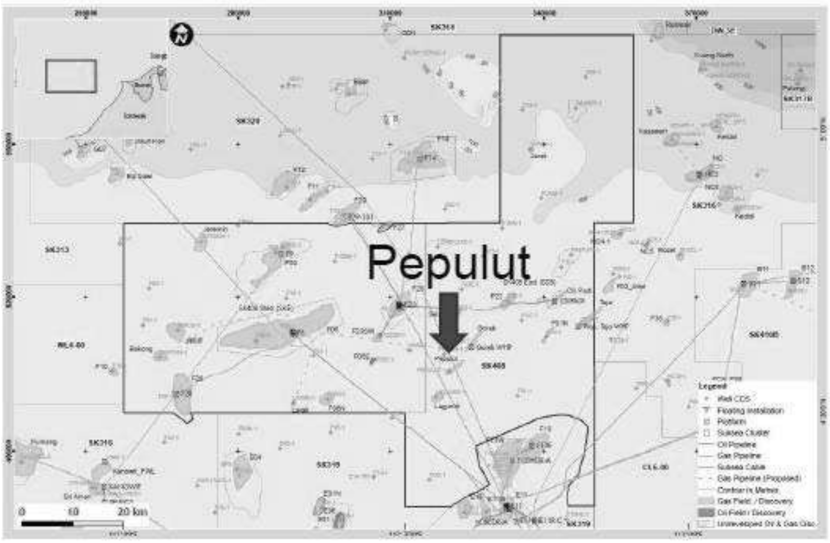

Figure 2-50: Pepulut field location (Source: ARPR 1.1.2024).

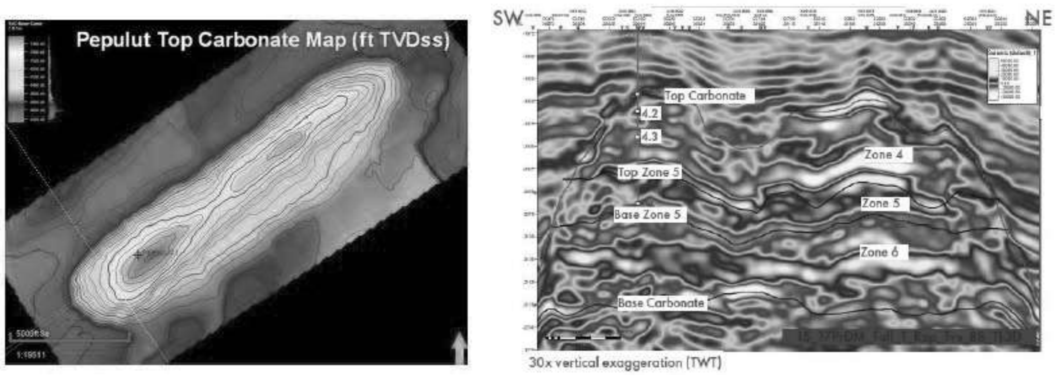

Figure 2-51: Pepulut field top carbonate map and seismic cross-section (Source: ARPR 1.1.2024).

Pepulut field and reservoir properties are summarized in Table 2-20. The average porosity and permeability are estimated to be approximately 16% and 55 mD, respectively. Presence of 5 mol% CO_2 and 20 to 45 ppm H_2S are indicated for this field. The estimated in-place volumes for Pepulut based on ARPR 1.1.2024 submission is shown in Table 2-21.

Property/ parameter	Unit	Value/ Remarks
No. of wells	-	1 (planned)
No. of well slots	-	4
Gas column	m	315
GWC	mTVDSS	2,540
Porosity	%	16
Permeability	mD	55
Reservoir pressure	psi	3,781
Reservoir temperature	degF	279
CO_2	mol%	5
H_2S	ppm	20 - 45
CGR	bbl/MMscf	20

Table 2-20: Pepulut field and reservoir properties (Source: SOMV, ARPR 1.1.2024, Pepulut MR2/3 2023).

	Low (P90)	Base (P50)	High (P10)
GIIP (Bscf)	274	447	649
EUR (Bscf)	101	283	468

Table 2-21: Pepulut GIIP and EUR (Source: ARPR 1.1.2024).

The reservoir drive mechanism is expected to be pressure depletion, with weak aquifer support and no secondary recovery. Weak aquifer is also observed from offset fields such as Cili Padi, F23 and F23SW, and the connectivity with the surrounding structures i.e., Gorek and F01 WNW is deemed unlikely.

A new WHP is planned to be installed for Pepulut to tie-back to the F23 processing hub and a co-development with Teja WHP via a daisy chain pipeline setup is assumed, as shown in Figure 2-49. The conceptual development plan is as described in Section 2.2.5.

The SK408 Area Development Plan (ADP) which included the different development options for Pepulut was prepared and submitted in September 2021. The static model for Pepulut field was updated to reflect Gross Rock Volume (GRV) changes resulting from utilizing the updated 2017 Terumbu Luconia Pre-Stack Depth Migration (PSDM) seismic data. The updated subsurface model (static and dynamic) was approved in the MR2/3 in March 2023. Considerations on possible surface network effects, constraints and interaction with other fields tied to the F23 hub were also captured in further fine tuning and optimization of the surface network, and the results have been incorporated in ARPR 1.1.2024. The volumes associated with Pepulut field development are classified under CR1 potential recoverable resource category in ARPR 1.1.2024 (FDP SK408 Gas Pepulut).

One gas well is planned for the field, placed in Southwest pinnacle to have maximum standoff from the GWC, at a target interval above the tight zone (Zone 5) to benefit from the natural baffle to the aquifer. The WHP capacity is at 150 MMscfd. The recoverable volume for Pepulut is estimated to be at 280 Bscf (P50 Contingent Resources), based on the F23-E11RA pipeline turndown rate (TDR) truncation of 100 MMscfd and also incorporating uptime assumptions at F23 hub. Similar to Teja, the development concept and FGD timing will be revisited during MR4 planned in May 2024, along with the latest gas demand outlook by MPM. FDP approval is targeted in April 2025 to meet the planned FID approval by June 2025 per the GHA, and the expected first gas is in September 2027.

2.3 SK310

PSC Block SK310 is located in water depth of around 80 m offshore Sarawak in the Central Luconia province, an area which predominantly comprises gas-prone, carbonate reservoirs. (Figure 2-52).

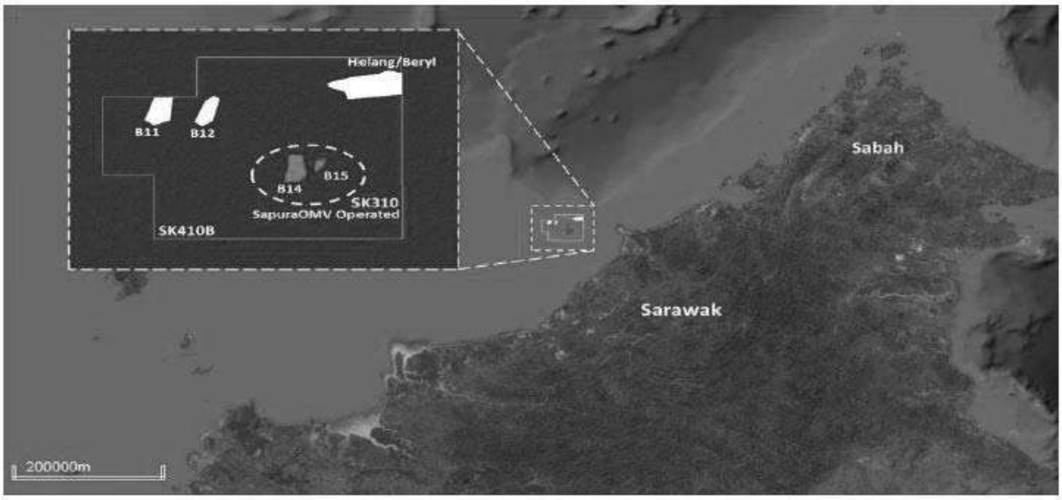

Figure 2-52: SK310 field location map (Source: SOMV).

The top carbonate depth structure map and seismic cross-section for Block SK310 are shown in Figure 2-53 and Figure 2-54, which show a series of highly over-pressured, Northwest-Southeast (NW-SE) oriented Late Miocene pinnacle reef carbonate structures that include B15 and B14 gas discoveries, at depths of around 3,000 mTVDSS. The reservoir geometry depicted in Figure 2-55 shows four geological zones that have been defined based on reservoir properties, i.e., Upper Pinnacle, Zone 4, Lower Pinnacle A and Lower Pinnacle B. Below the gas-water contact (GWC) in B15, the Upper Pinnacle carbonate section is separated from a platform section by a regional tight layer designated as Zone 4, which is not penetrated by the B15-1 well in the B15 pinnacle, but was encountered in the adjacent B14 pinnacle by the B14-ST1 exploration well drilled in 2013.

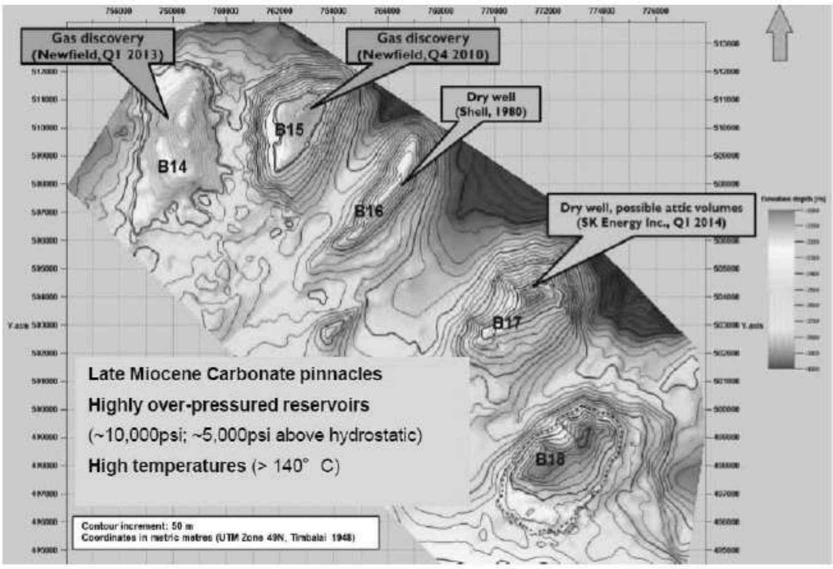

Figure 2-53: Overview of Northeast area of SK310 top of carbonate (Source: SOMV).

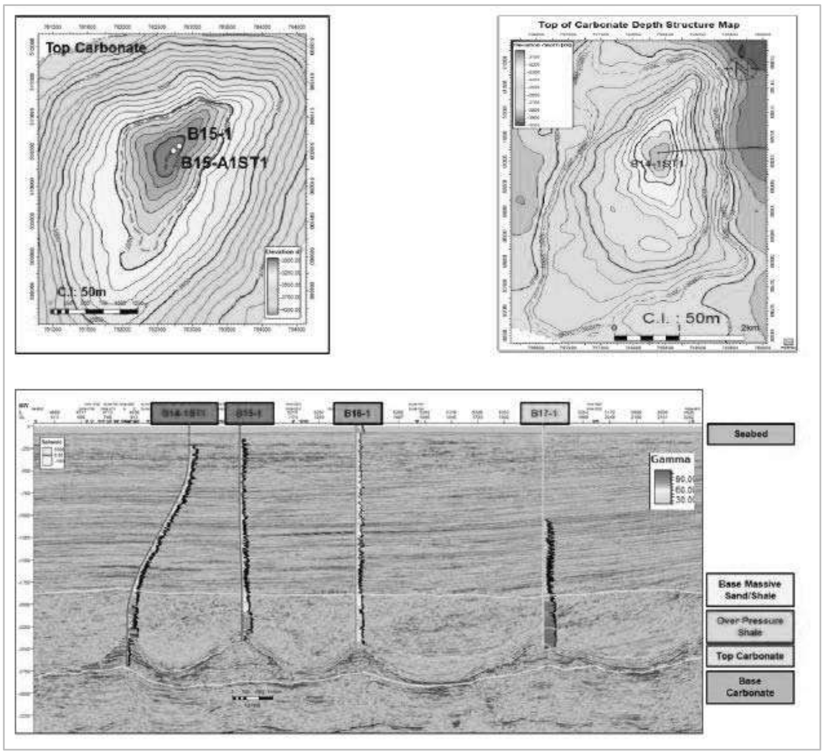

Figure 2-54: SK310 top carbonate depth structures and seismic cross-section (Source: SOMV).

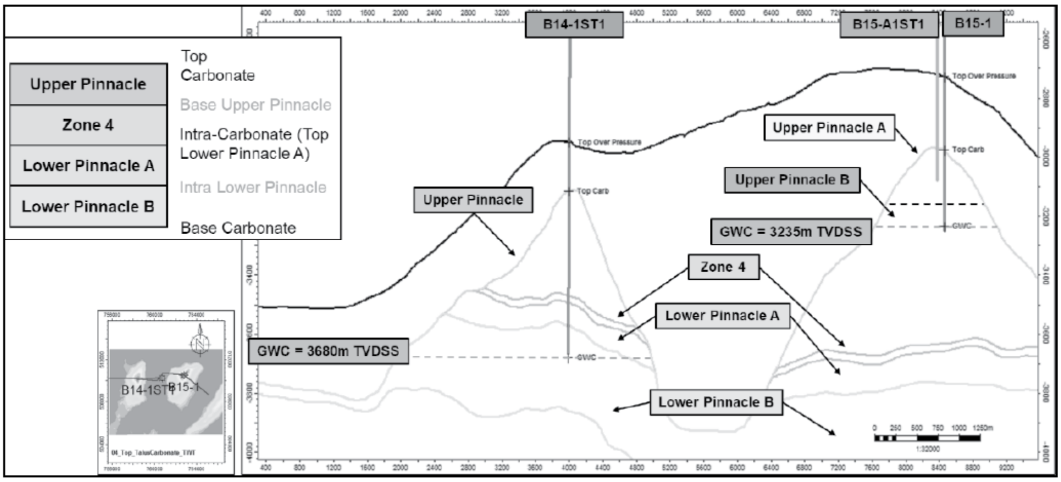

Figure 2-55: B15 – B14 reservoir geometry (Source: FFR 2022).

The simplified overview of the facilities and infrastructure at SK310 is depicted in Figure 2-56 and Figure 2-57. For SK310 producing field, production from the B15 Central Processing Platform (CPP) flows via pipeline to the B11 Complex; it does not flow into the B11 process systems but joins the B11-E11 export line downstream of the B11 main process systems into E11 Riser B (E11R-B), and then via trunkline to the Malaysia Liquefied Natural Gas (MLNG) plant in Bintulu, Sarawak.

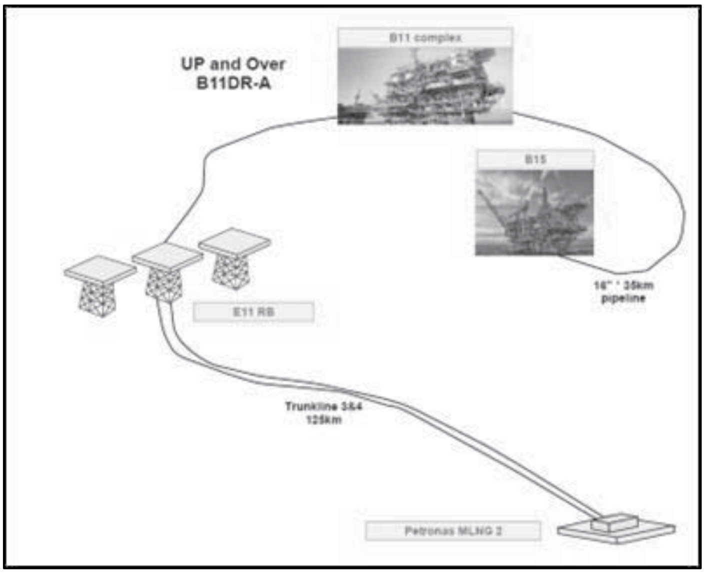

Figure 2-56: SK310 facilities and infrastructure overview (Source: SOMV).

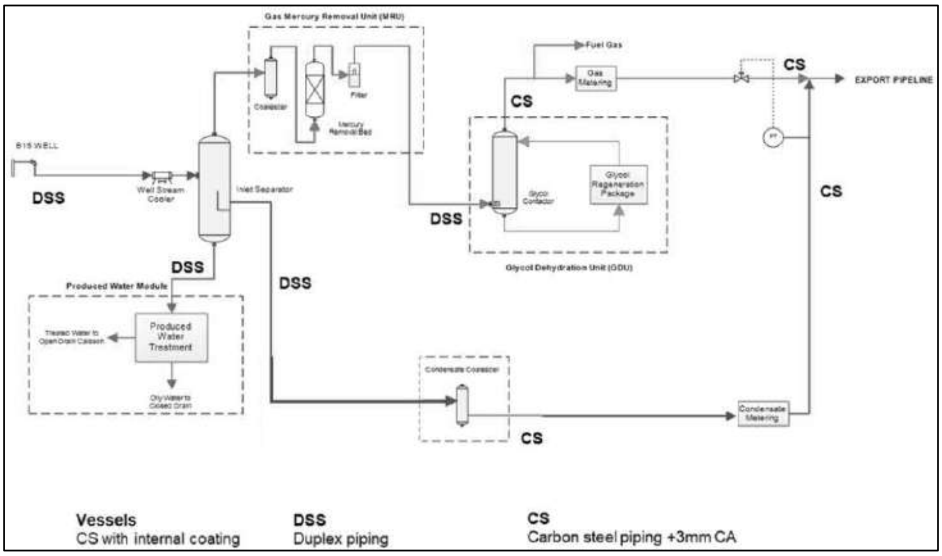

Figure 2-57: Simplified B15A process overview (Source: ARPR 1.1.2024).

Production from SK310 is from B15A-1ST1 development well, which commenced in October 2017 but was intermittent initially due to various downstream issues not related to B15 facilities. The historical gas production is shown in Figure 2-58, which indicate a relatively stable production rate of around 135 MMscfd from 2019 to 2022, and nomination rates of 100 MMscfd and 135 MMscfd, in Q1 2023 and from Q2 2023 onwards, respectively.

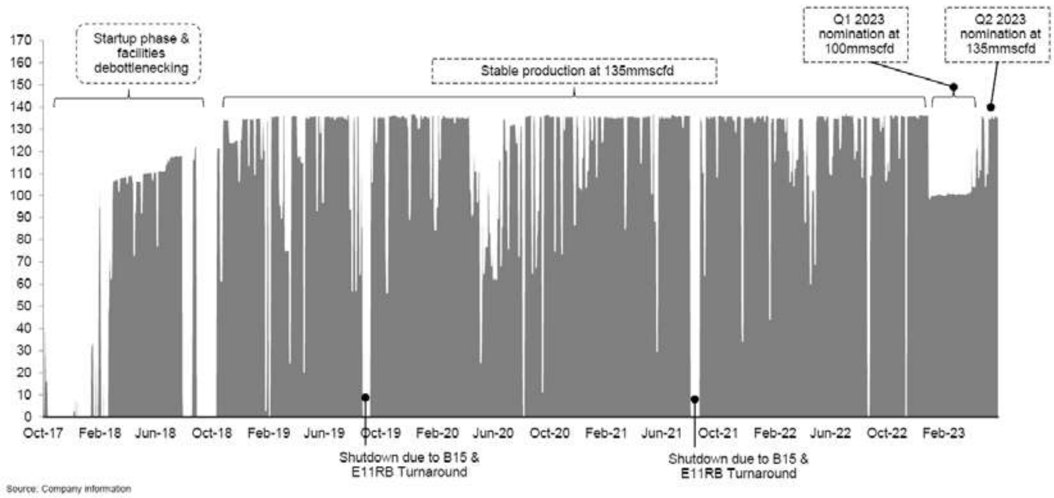

Figure 2-58: B15 field historical daily gross production (Source: SOMV).

2.3.1 B15

The B15 non-associated gas field is a Cycle V pinnacle reef carbonate structure located in the eastern part of Block SK310, in the Central Luconia province offshore Sarawak. This marginal gas field is located around 75 km West of Miri and 150 km North-Northeast of Bintulu, in water depth of approximately 80 m (Figure 2-59). The field was discovered by B15-1 exploration well in 2010, which encountered a log-observed GWC at 3,271 mMD i.e., 3,235 mTVDSS (Figure 2-60). The B15 field top carbonate map and cross-section are shown in Figure 2-61.

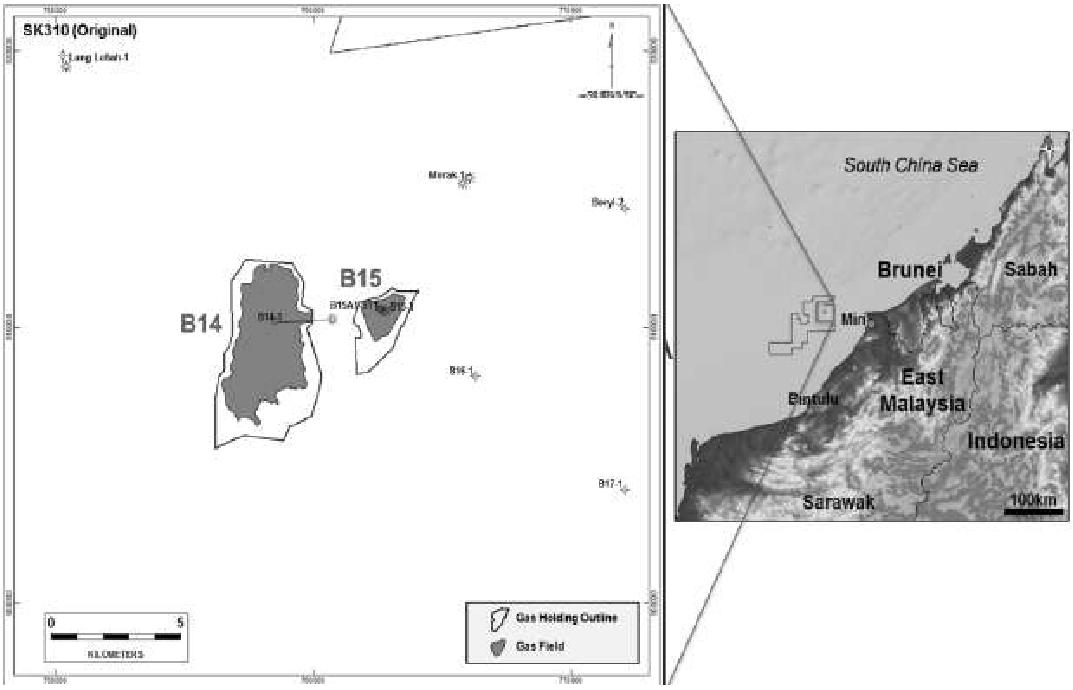

Figure 2-59: B15 field location (Source: ARPR 1.1.2024).

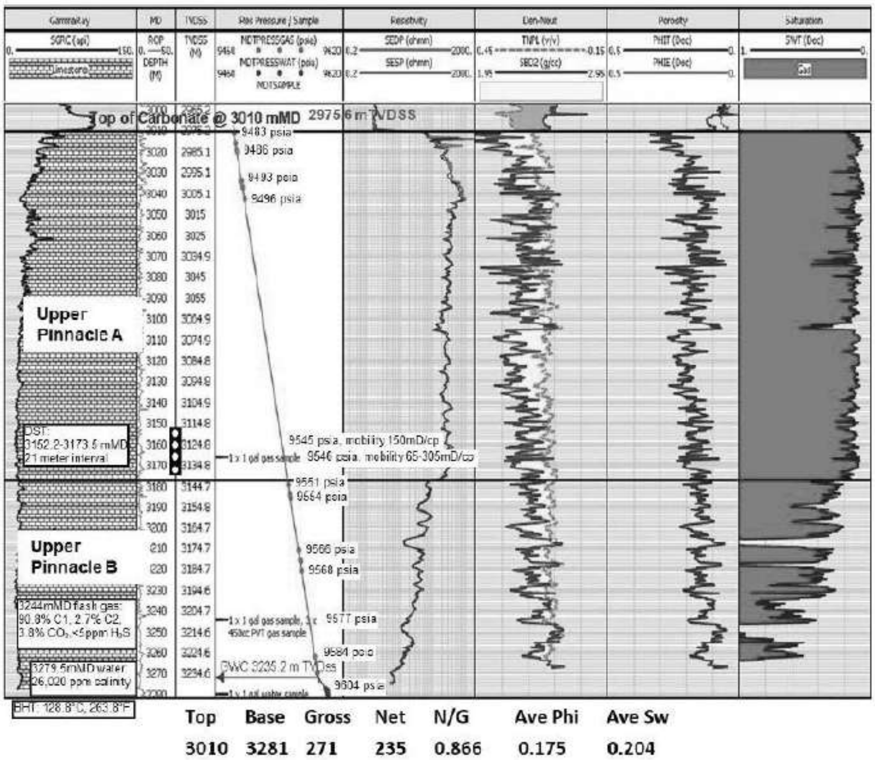

Figure 2-60: B15-1 exploration well log (Source: FFR 2022).

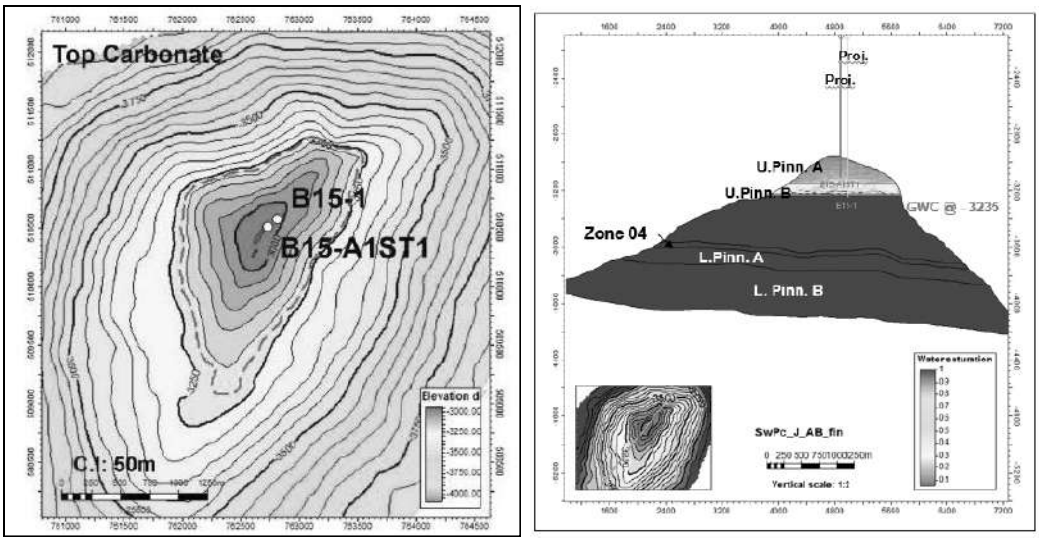

Figure 2-61: B15 top carbonate map and cross-section (Source: ARPR 1.1.2024, FFR 2022).

B15 field is a single gas well development (B15-A1ST1), drilled at the crest of the pinnacle structure. To avoid early water breakthrough, only 41 m was perforated at the top of the well, giving about 236 m standoff from the original GWC. The well was completed in August 2017, and first gas was reported in October 2017. The field and reservoir properties are summarized in Table 2-22. B15 field is a High-Pressure High-Temperature (HPHT) carbonate reservoir, over-pressured by approximately 5,000 psi above hydrostatic. The field contains sweet gas with 3.8 mol%, CO_2 and low H_2S. The average porosity is around 17% to 20%, and permeability ranges are estimated to be approximately 200 mD to 500 mD. The field has been producing under natural depletion, with rock expansion drive and weak to moderate aquifer.

Property/ parameter	Unit	Value/ Remarks
No. of wells	-	1
No. of well slots	-	2
Gas column	m	279
GWC	mTVDSS	3,235
Area at GWC	km^2	2.08
Porosity	%	21
Permeability	mD	200 - 500
Reservoir pressure	psi	9,587
Reservoir temperature	degF	272
Gas s.g.	-	0.66
CO_2	mol%	3.8
H_2S	ppm	20
CGR	bbl/MMscf	11.5

Table 2-22: B15 field and reservoir properties (Source: SOMV, FFR 2022, ARPR 1.1.2024).

When estimating the GIIP for B15, the conventional material balance plot of P/z vs Gp (cumulative gas produced) indicated that the reservoir pressure decline has not reached the inflection point of the over-pressured regime, yielding a highly optimistic GIIP compared to the static model results (Figure 2-62). Correcting the P/z vs Gp plot for rock and fluid compressibilities via the method proposed by Ramagost and Farshad still resulted in a high GIIP, which is not justified by seismic and well data. The P/z vs Gp plot is therefore deemed not applicable for B15, as the pressure still remains in its over-pressured regime.

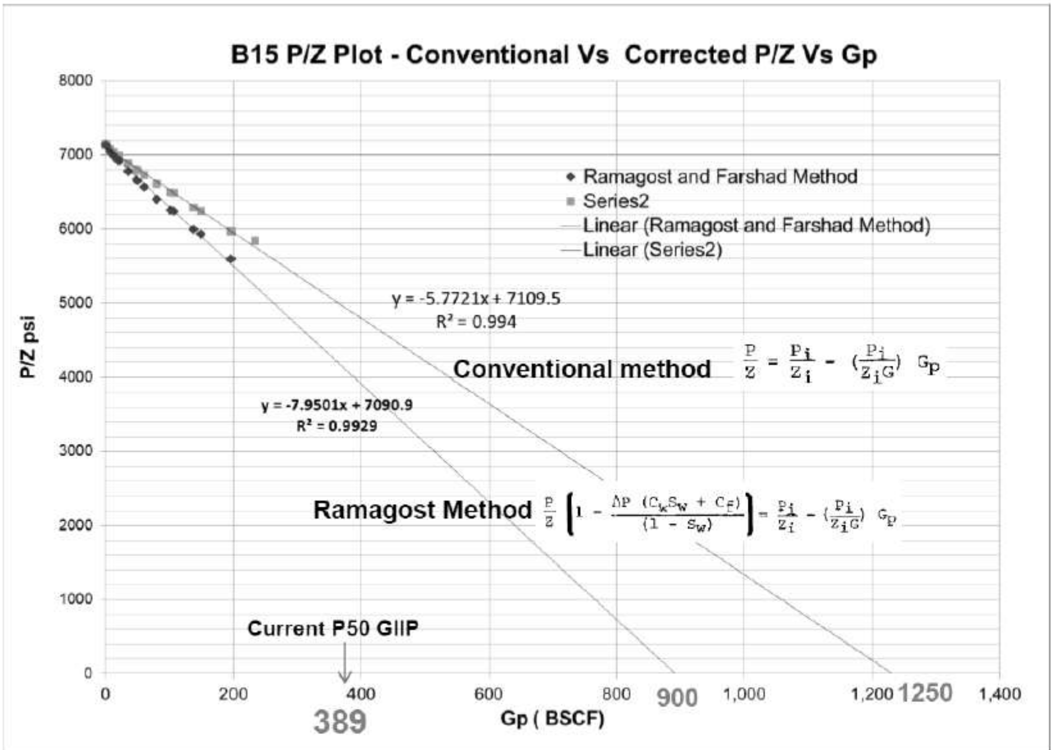

Figure 2-62: P/z vs Gp plot for B15 (Source: ARPR 1.1.2024).

The Full Field Review (FFR) study conducted in 2022 provided an updated GIIP for the field, based on static and dynamic modelling and subsurface technical assessment incorporating new field data such as seismic reprocessing results, and also pressure and production data from the well B15-A1ST1. The history matched model was calibrated to incorporate additional observed production and pressure data, which suggested a higher recoverable volume, driven by the slower reservoir pressure decline observed (Figure 2-63).

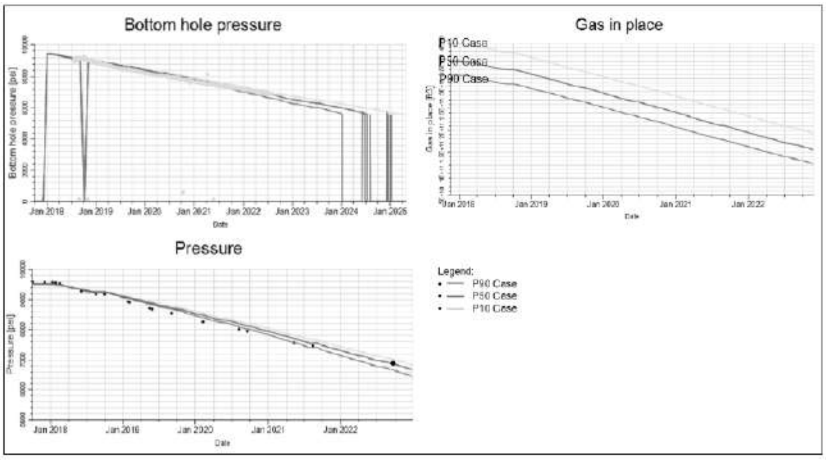

Figure 2-63: History matched model updated and calibrated against actual observed data (Source: FFR 2022, ARPR 1.1.2023).

In Q2 2023, the simulation model was updated to incorporate the latest measured production and pressure data, as well as enhancing the aquifer model description to improve history matching. Pressure trend analysis showed a slower decline after each shut-in (SI), which indicated possible charging from aquifer influx into the reservoir system (Figure 2-64). The results suggested a higher recoverable volume, and the changes have been incorporated in ARPR 1.1.2024 submission, as shown in Table 2-23.

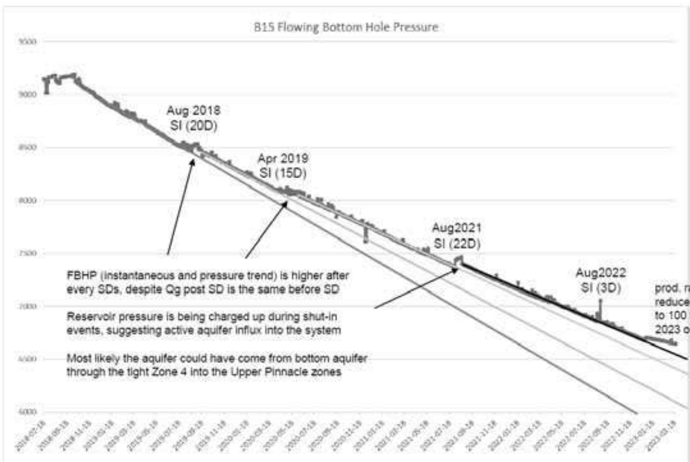

Figure 2-64: Model updated to incorporate enhanced aquifer model description and calibrated against actual observed data (Source: ARPR 1.1.2024).

	Low (P90)	Base (P50)	High (P10)
GIIP (Bscf)	371	389	416
EUR (Bscf)	280	296	316

Table 2-23: B15 GIIP and EUR (Source: ARPR 1.1.2024).

The Key Resource Indicators for B15 Non-associated gas (NAG) resources summarized in Table 2-24 indicate that the recoveries are optimized and reasonable, and also within the ranges observed in Central Luconia gas fields, for reservoirs with pressure depletion and weak to moderate aquifers (Figure 1-2).

P90 (Dev+ Undev) (Bscf)	P50 (Dev+ Undev) (Bscf)	P50 CR (Bscf)	2023 Prod (Bscf)	P50 RF (%)	1P RLI (Years)	2P RLI (Years)	2P+2C ORLI (Years)
27.16	43.16	0	41.61	76	0.65	1.04	1.04

Table 2-24: B15 Key Resource Indicators (Source: ARPR 1.1.2024).

In December 2023, the average gross sales from the field was approximately 133 MMscfd of gas. As of end December 2023, a total of 253 Bscf cumulative gas production (sales and non-sales) was recorded. The historical field production is shown in Figure 2-65, and the gas sales profile is shown in Figure 2-66.

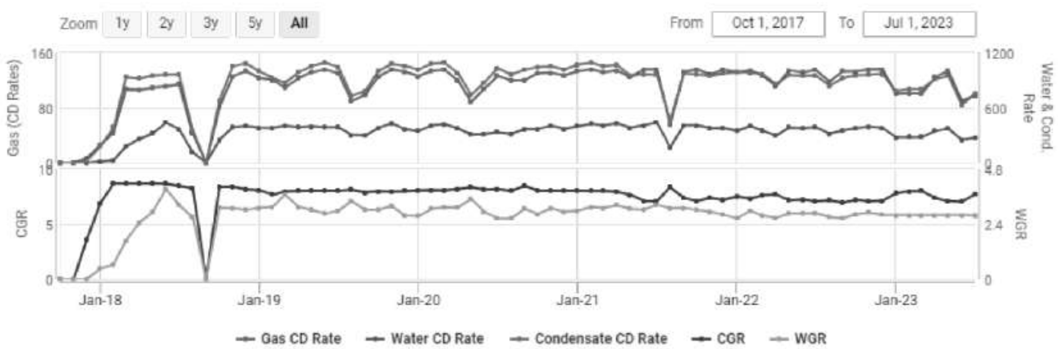

Figure 2-65: B15 field production (Source: AMiR 2023).

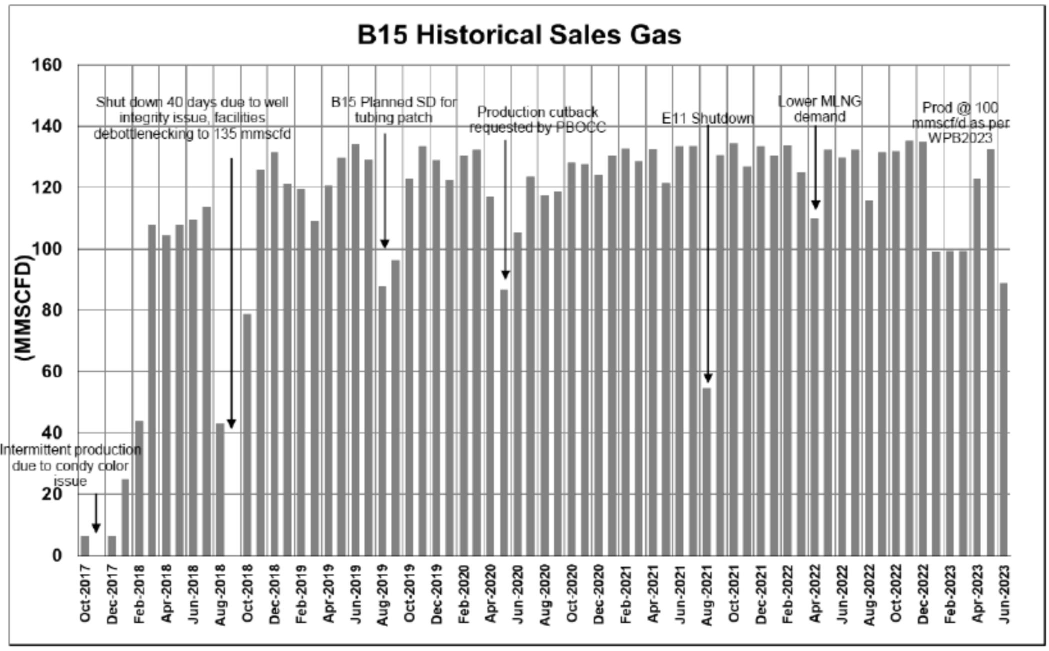

Figure 2-66: B15 gas sales profile (gross), MMscfd (Source: ARPR 1.1.2024).

The findings from the FRR concluded that no additional opportunities (e.g., Behind Casing Opportunities (BCO), infill drilling) were found, and no further development is required for the field. The reserves is expected to be recovered from the existing well, supported by the uniform pressure depletion trend showing no isolated compartments. A slower decline is observed (vs FDP 2015 and FFR 2022), and continuous monitoring of both gas and liquid production, bottomhole pressure, as well as temperature, is conducted in the field. To date, no significant production of formation water is indicated. This may be due to localized reservoir heterogeneities, the presence of the tight Zone 4 and tight layers observed near the GWC, which resulted in a slower GWC movement in the middle section of the carbonate reservoir. Furthermore, with the B15-A1ST1 positioned at the crest of the structure, water breakthrough is not expected until at the very end of field life. The main issue highlighted for the field is B15-A1ST1 tubing leak, resulting in pressure communication between the 7-inch tubing and the production casing annulus. Permanent dispensation to continue producing the well was obtained from MPM on October 23, 2020 until end of well life, with continuous monitoring of the iron count soluble in water.

B15 field is approaching end of field life, and the Cease of Production (CoP) is expected to be by December 2024 per ARPR 1.1.2024 (P50 case), subject to gas sales rates and overall field performance. Key uncertainties include the true GIIP for the field, CoP timing, aquifer strength and the sealing effect of the tight Zone 4. The estimated GIIP and expected recoverable volumes are continually updated by incorporating new observed field data (i.e., production and bottomhole pressure) to calibrate the model via history matching; it is expected that an increase would lead to an extension of the CoP for B15.

3 New Zealand Assets

SOMV's assets in New Zealand comprise discoveries and exploration opportunities located in three exploration permits in the Taranaki Basin, i.e., PEP60093 (Toutouwai), 60092 (Ridgeline) and 57075 (Cloudy Bay), as shown in Figure 3-1. The permits are currently jointly held by SOMV and OMV New Zealand (OMV) at 30% and 70% equity, respectively, with OMV as the operator (Table 3-1).

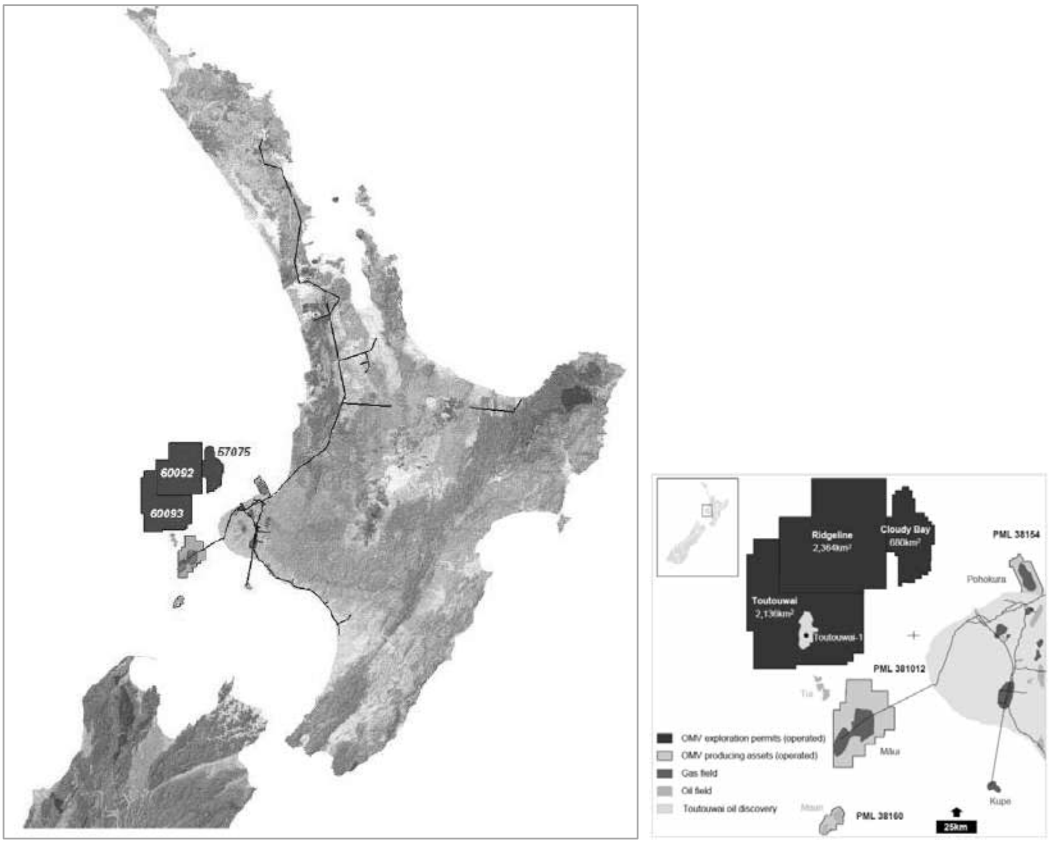

Figure 3-1: Location of SOMV exploration permits in New Zealand (Source: OCM 2023, SOMV).

Block / Permit Number	Permit Name	Effective Start Date Permit	End of Permit Term	Coverage Area (km²)	Discoveries / Prospects
PEP60093	Toutouwai	1st April 2016	31st March 2028	Original = 2,136 Area of retention as of 31st March 2023 (50%) = 1,068	Toutouwai
					Karoro
					Riroriro
					Riroriro Iti
PEP60092	Ridgeline	1st April 2016	31st March 2028	2,364	Longridge
					Sandy Point SW
					Gladstone Updip SW
					Gladstone Updip (Moki)
					Shag
					Pihipihi
PEP57075	Cloudy Bay	1st April 2015	31st March 2027	Original = 1,365 Area of retention as of 20th June 2020 (50%) = 680	Cloudy Bay
					Brackenridge
					Stonyridge
					Mensa

Table 3-1: SOMV New Zealand Assets (Source: SOMV, OCM 2023).

Exploration wells within the contract areas include Gladstone-1 drilled in PEP57075 in 2019 and Toutouwai-1 drilled in PEP60093 in 2020. Gladstone-1 was classified as a dry well with hydrocarbon shows, shifting the focus from Miocene to Cretaceous play. The Toutouwai-1 oil discovery confirmed a working petroleum system and opened up the Cretaceous play within the Taranaki Basin, proving the presence of hydrocarbons at several stratigraphic levels within the Cretaceous and Paleocene, with additional opportunities in the Miocene that can be intersected when chasing the deeper plays.

Toutouwai discovery, Karoro prospect and other Prospective Resources within PEP60093, PEP60092 and PEP57075 which comprise exploration prospects primarily within the Cretaceous and Miocene, are categorized as Contingent Resources (Development On Hold/ Unclarified)and are further discussed in Section 7 of this report.

On 31st March 2023, all due commitments for the existing PEP60093 Work Programme have been satisfied, and the proposed 50% relinquishment area was submitted for approval. The remaining 50% of the area for retention has been selected to capture as much of the identified prospectivity.

For PEP60092 and PEP57075, a CoC (Change of Conditions; a change of permit conditions process, used to alter the terms, duration, or minerals of a permit) application was submitted on 30th November 2022, to delay the commitment to drill one exploration well each at PEP60092 and PEP57075, from 31st March 2024 to 31st March 2026. The CoC was granted on 16th April 2023, and all due commitments for the existing PEP60092 and PEP57075 Work Programmes have been satisfied.

On 2nd June 2023, an application was submitted for the amalgamation of PEP60092 and PEP60093, with the assumption that the proposed relinquishment area for PEP60093 is accepted (Figure 3-2). It is expected that having an amalgamated permit (where the commitments of PEP60092 are consolidated with, and become part of PEP60093) would allow for a unified work program that would lead to a more effective exploration strategy and an efficient drilling campaign.

Figure 3-2: Proposed PEP60093 retention area outlined in red (left); Outline of the merged PEP60093 and PEP60092 (right) (Source: OMV Letters 31st March 2023, 2nd June 2023).

In the next stage of planning, is the application for permit extension to cover the leads within Karoro North and Shag areas, prior to the start of drilling campaign (Figure 3-3). If successful, the remaining commitment shall comprise four wells i.e., Toutouwai-2, Karoro-1, Toutouwai- 3 (contingent on Toutouwai-2), and another must-drill well in the extension area. Options for the acquisition of 3D seismic shall also be explored, to aid in refining prospectivity and generate the prospect inventory for the area, for the selection of drilling candidate(s).

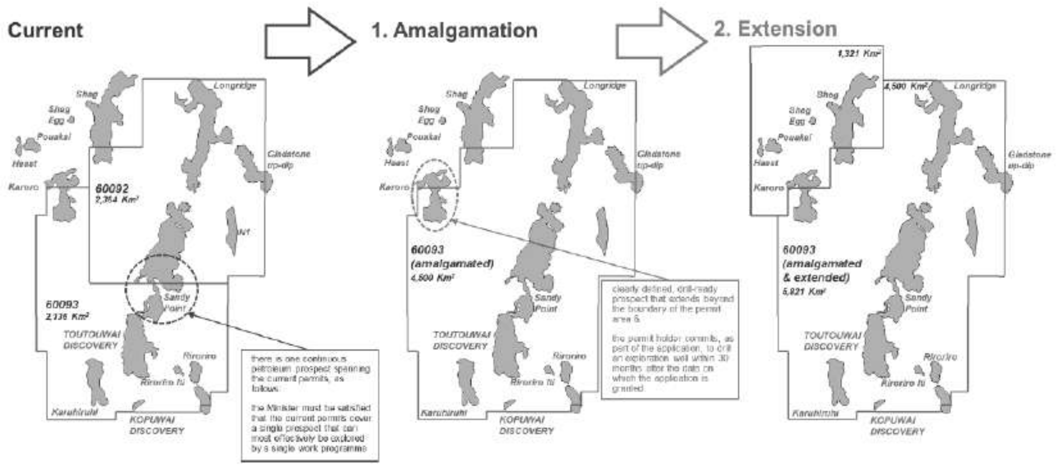

Figure 3-3: Proposed amalgamation and extension of PEP60093 and PEP60092 (Source: TCM 2023).

Note that the drilling and discharge consents for the Taranaki Exploration and Appraisal Drilling (EAD) Programme are only available for specific sites, and shall expire on 31st December 2025. The consented sites currently covered by the existing consents are for Toutouwai-2 (G), Toutouwai-3 (E), Karoro-1 (D), Riroriro Iti-1 (H) and Riroriro-1 (I) in PEP60093, Longridge (A) in PEP60092, and Cloudy Bay (B), as shown in Figure 3-4. Any post-drill environment monitoring and drilling activity post 2025 would require new drilling and discharge consents, or an extension of the expiry date by CoC. Rig availability is noted as an uncertainty; it is indicated that there is currently no capable rig forecasted to be in the country, at least until 2025 at the earliest.

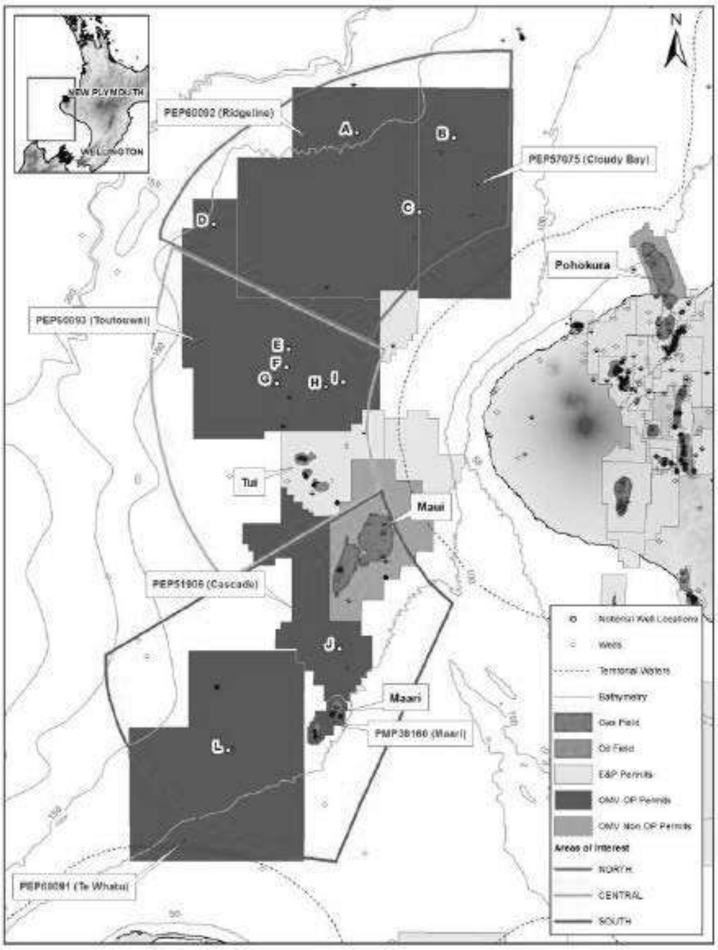

Figure 3-4: PEP60093 proposed exploration wells (Source: SOMV).

Also included in the current outlook is OMV's plan to farm out up to 30% equity across all three of its Taranaki exploration permits i.e., PEP60093, 60092 and 57075. Advent Energy Ltd. had earlier signed the intent to farm in for 30% equity, subject to achieving all regulatory approvals. However, after a lapse of more than six months since the submission of the application to the New Zealand Petroleum and Minerals (NZP&M) and the condition for the farminee to obtain the approval from the Minister for the transfer of equity remained unsatisfied, and the agreement was terminated. At the time of writing this CPR, both partners OMV and SOMV remain at their current existing equity levels.

4 Mexico Assets

In March 2018, SOMV and its joint venture (JV) consortium partners, Deutsche Erdoel Mexico (Dea) and Premier Oil signed a PSC for Contract Area AS CS-14 (i.e., Block 30) with Comisión Nacional de Hidrocarburos (CNH), the regulator of Mexico (Figure 4-1). Dea (now Wintershall Dea) is the operator for the block, and the equity split between Wintershall Dea, Premier Oil (now Harbour Energy) and SOMV is at 40%, 30% and 30%, respectively (Table 4-1).

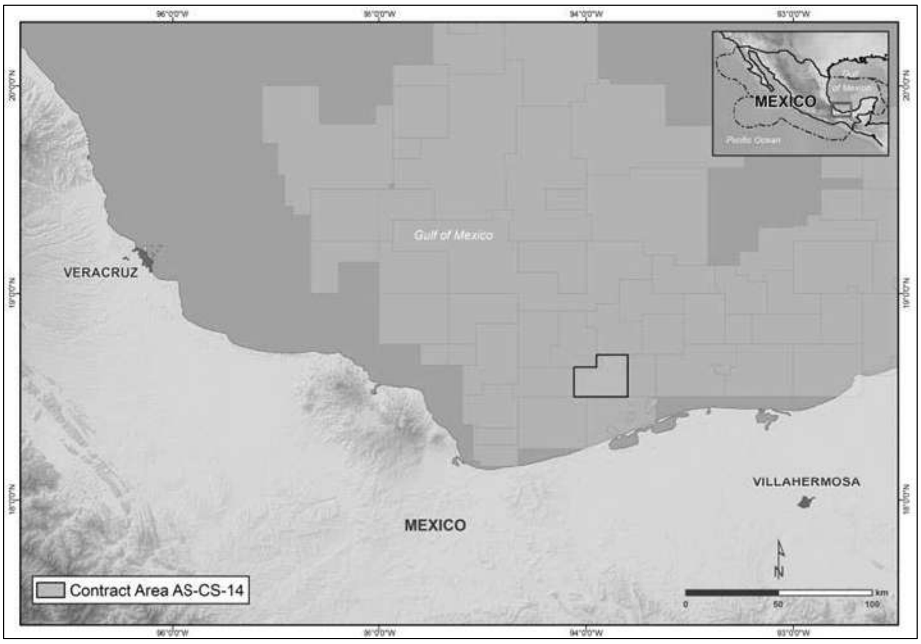

Figure 4-1: Location of Contract Area AS CS-14 (Source: 2019 Exploration Plan).

Concession and Block	Percentage Interests	Operator	Concession Commencement and Expiry
PSC Block 30, Southeast Basin	Wintershall Dea (40%), Harbour Energy (30%), SOMV (30%).	Wintershall Dea	PSC awarded on 27th March 2018; Contract executed on 27th June 2018 (effective date) for a period of 30 years, expiring on 26th June 2048.

Table 4-1: Overview of the Block 30 PSC (Source: Factbook July 2023).

The contract area of around 528 km² is located in shallow water depth ranging between 40 m to 120 m in the Salina sub-basin, an oil-prone part of the Sureste Basin in the Gulf of Mexico (Figure 4-2). Block 30 is situated in a proven and prolific hydrocarbon province, surrounded by large oil discoveries i.e., Zama oil discovery directly to the northeast, and Amoca oil field to the south, through wells Zama-1 by Talos and Amoca-1 by ENI (Figure 4-3). The hydrocarbon type identified within the Pliocene and Miocene sandstones in the nearby discoveries was oil, with API ranging from 28 to 37 degrees.

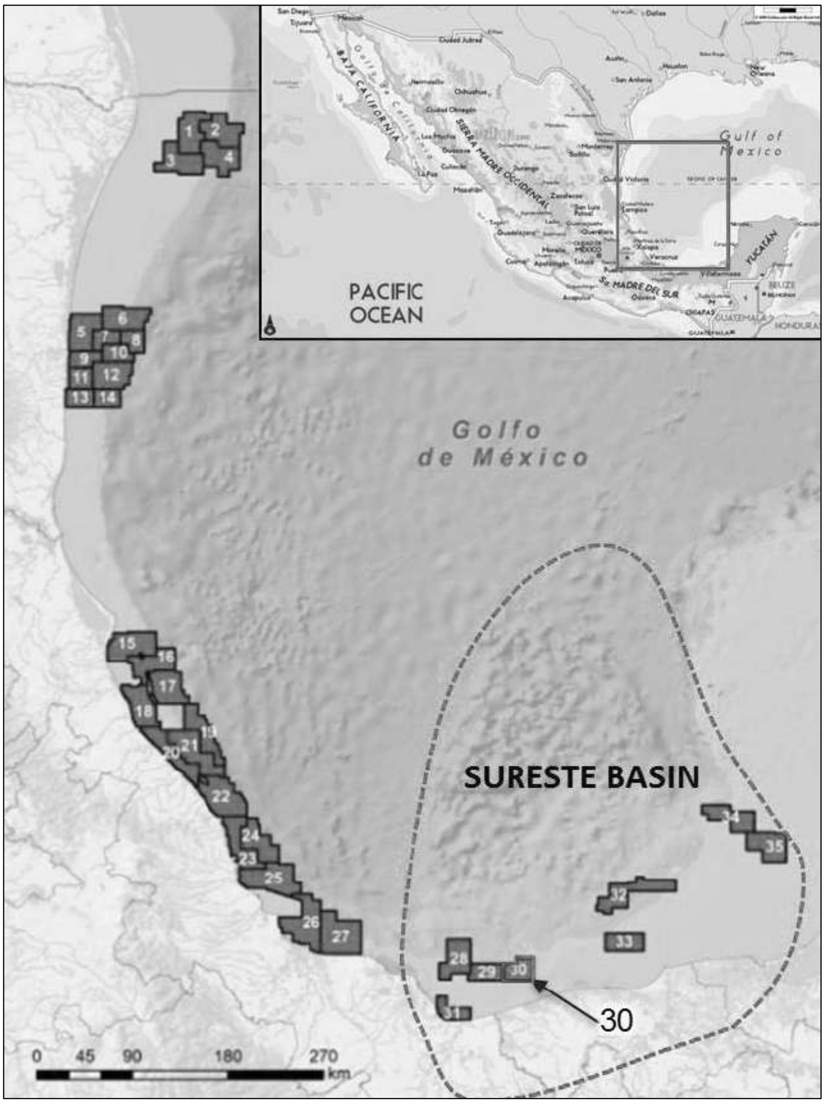

Figure 4-2: Block 30 Location Map (Source: Sapura).

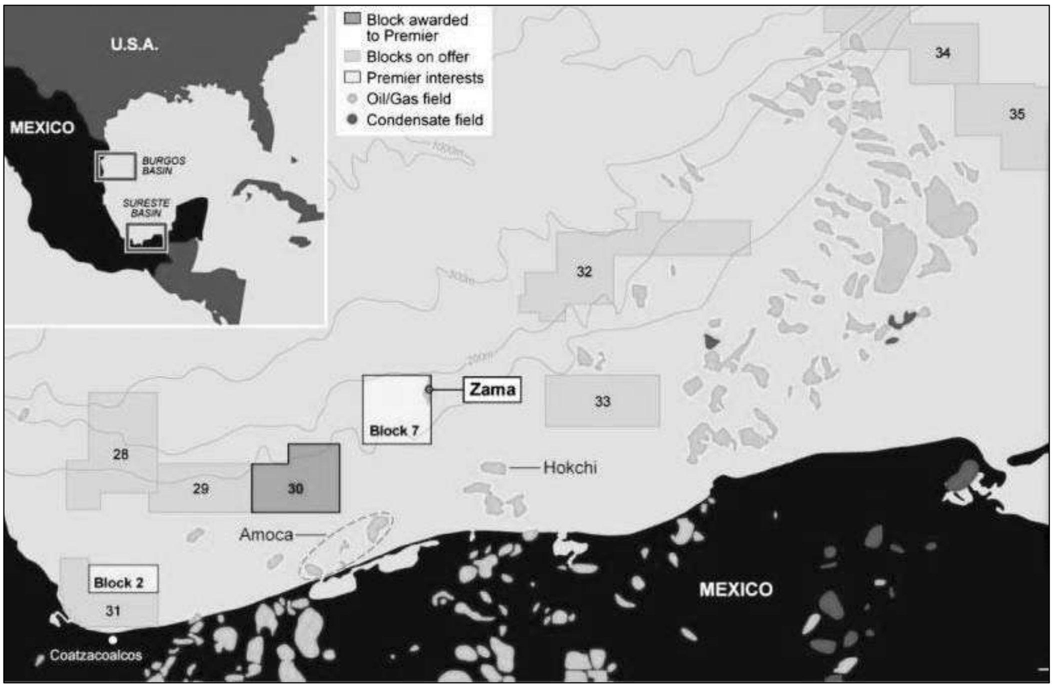

Figure 4-3: Block 30 and Surrounding Fields (Source: www.epmag.com).

The objective of the exploration consortium was to provide CNH with sufficient information to evaluate the technical and operational aspects for Block 30. The current contract term has a validity of 30 years, and the Contractors may request for up to two additional terms, each with up to five years extension, for a fraction or the entirety of the development areas, provided that all the obligations have been met. The duration of the "Initial Exploration Period" phase is four years from the approval of the exploration plan, where the Minimum Work Commitments (MWC) to be fulfilled are expressed in work units (WU), and the specified work program comprises drilling two exploration wells. The Contractors may request for extensions via the "First Additional Exploration Period" and the "Second Additional Exploration Period" phases, that last for two years for each of the phase, subject to CNH approval that all specified conditions under the contract have been satisfied. The initial exploration phase has been fulfilled after the drilling of the two exploration wells i.e., Kan-1 and Ix-1 have been drilled in April and May 2023, respectively.

Block evaluation was initially conducted using 2D seismic data and 3D data that partly covered the Southwest corner, acquired by the operator in the adjacent southern block.

Another 3D seismic survey 'Kanxok' was acquired by the JV in 2019 to cover the entire Block 30, prior to drilling of the first exploration well within the block, i.e. Kan-1. The well was drilled to evaluate the Upper Miocene, and a significant oil discovery was reported. With the discovery of well Kan-1, CNH's approval on the work plan for drilling the appraisal well Kan-2 is targeted in early 2024. The work plan is expected to be executed within two years until the expiry in December 2025. There are currently four target locations under evaluation for the appraisal drilling, where a similar data acquisition plan to Kan-1 well will be executed.

The initial exploration period for Ix will expire in the first quarter of 2024 and if there is interest to proceed into FAEP (First Additional Exploration Period), the decision has to be made before that date. The FAEP spans for two years and expires in March 2026. The Figure 4-4 below illustrates the forward plan for Kan discovery and Ix prospect until 2026.

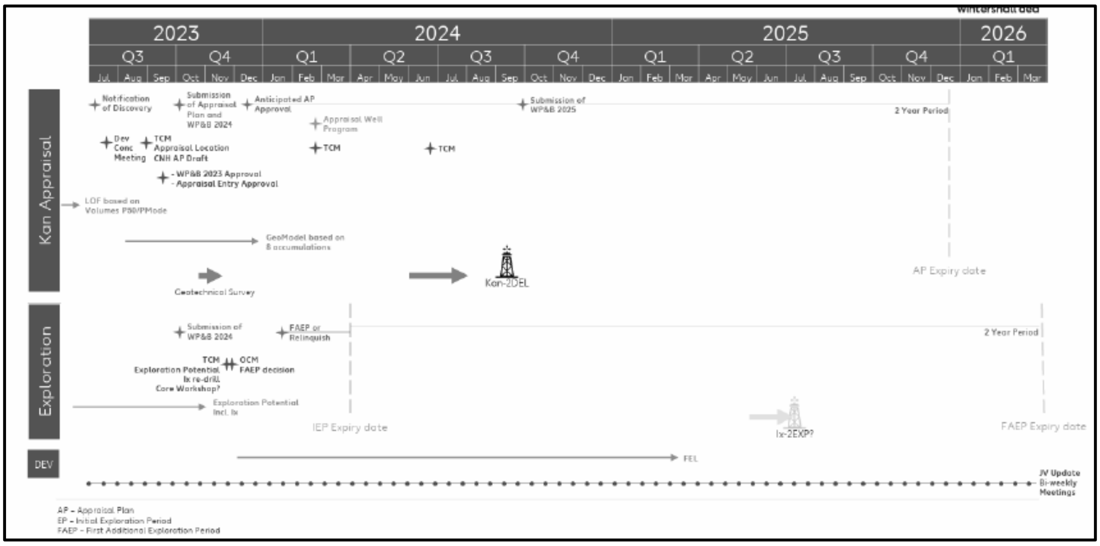

Figure 4-4: Appraisal Plan Project Overview (Source: TCM 2023).

Kan discovery is categorized as Contingent Resources (Unclarified/On-hold), whereas Ix and Cabrilla are maintained as Prospective Resources and discussed in Section 7 of this report.

5 Australia Assets

As of September 2023, only AC/P69 was reported to be under suspension and extension application to the local authority, whilst all of the remaining licenses in Australia have either been approved for surrender (AC/P50, AC/P68, WA-412-P) or submitted to be surrendered (AC/P67). The current status for the five licences held by SOMV via SOMV Upstream (Western Australia) Pty Ltd in Australia is shown in Table 5-1. All the status and permit locations are shown in Figure 5-1 and Figure 5-2 below. This asset is classified as Prospective Resources, and discussed in Section 7 of this report.

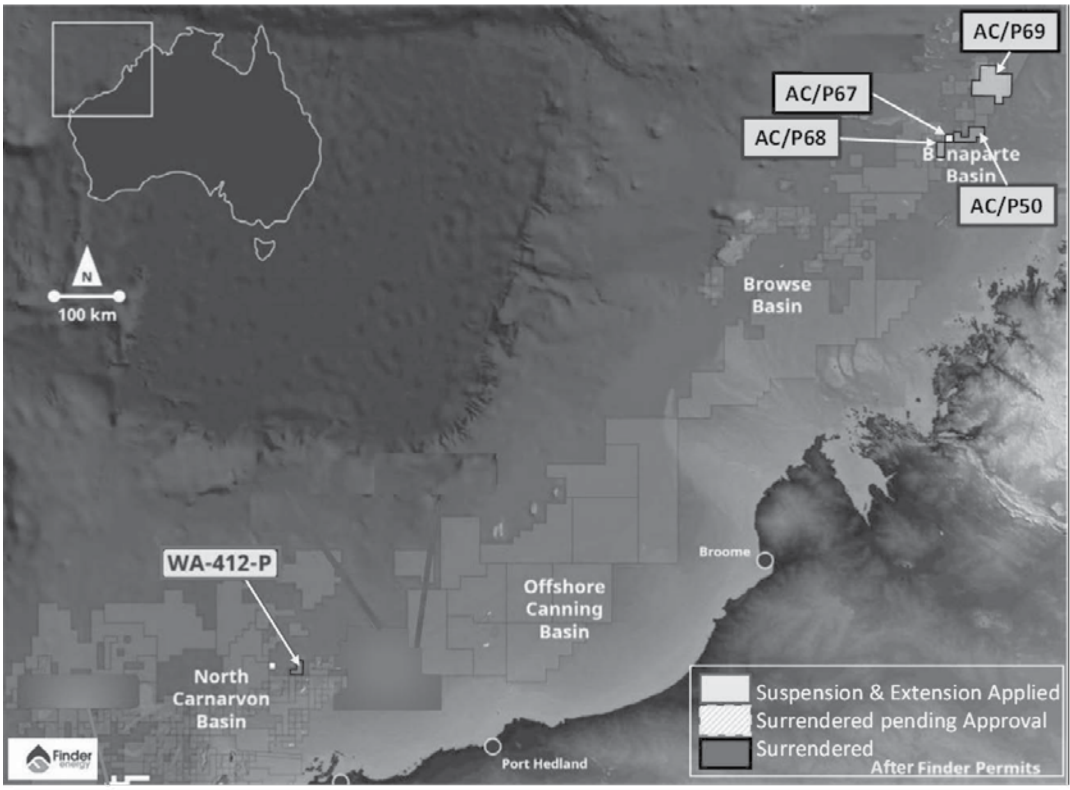

Figure 5-1: SOMV Exploration Permits Locations and Status (after Finder, Geoscience Australia).

Concession and Block / License	Participating Interests	Concession Granted	Concession Expiry	Prospect Name	Status
AC/P67 JOA Exploration Permit AC/P67, SD51 Block 0489)	Santos Offshore Pty Ltd (33.4%, Operator), SOMV (33.3%), ENI (33.3%)	3rd November 2020	2nd November 2026	Magnolia	Surrender of permit submitted to National Offshore Petroleum Titles Administrator (NOPTA) in September 2023. Pending gazette of surrender from Australian authority
AC/P68 JOA Exploration Permit AC/P68, SD51 Blocks 0560, 0632		3rd November 2020	2nd November 2026	Leeuwin	Surrender granted in Jan 2024
AC/P69 JOA Exploration Permit AC/P69, SD51 Blocks 0060, 0061, 0062, 0063, 0064, 0135. SC51 Blocks 3301, 3302, 3373, 3374, 3375, 3376, 3444, 3445, 3446, 3447, 3448		16th June 2021	15th June 2027	Birdwing	Preparing for suspension and extension (as of September 2023 update)
AC/P50	Santos (60%, Operator), SOMV (40%)	19th May 2025 (permit title transferred to Santos and SOMV on 7th April 2021)	18th November 2023	Stairway	Surrendered (Relinquished to Australian Authority prior to entering Year 4 exploration phase – no exploration drilling)
WA-412-P	SOMV (70%, Operator), Finder Exploration (15%), Fugro Exploration (15%)	10th September 2014	9th June 2023	Kanga	Surrendered permit post drilling analysis (Drilled Kanga-1 exploration well, non-prospective)

Table 5-1: Participating Interests and Status of SOMV Assets In Australia (Source: Factbook July 2023).

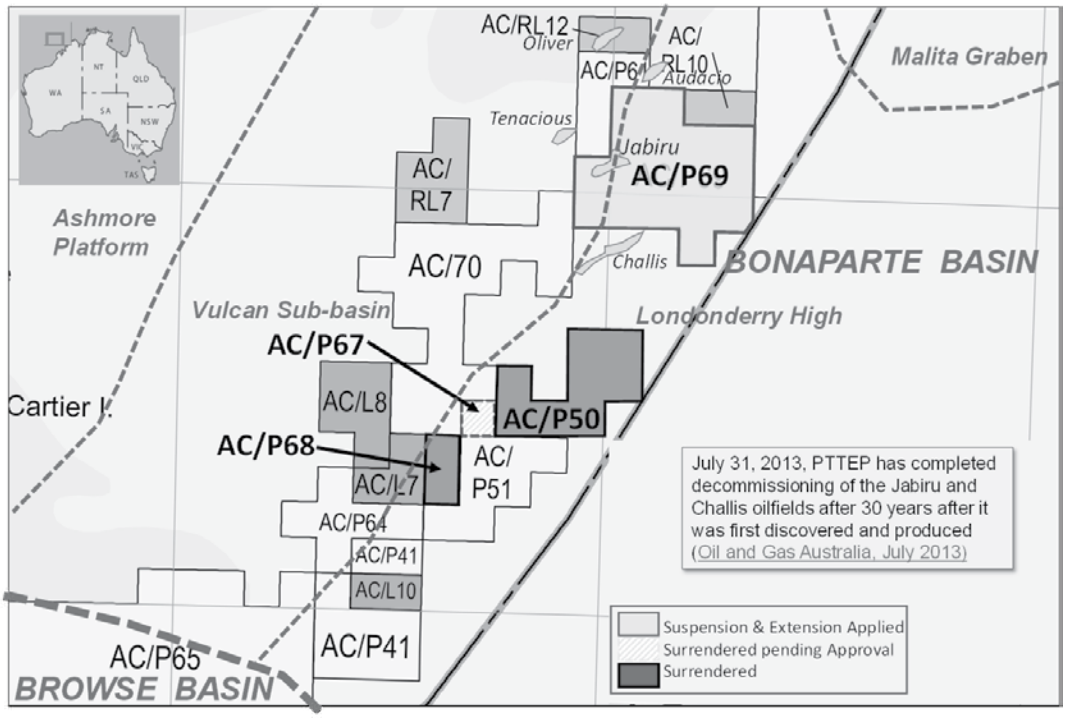

Figure 5-2: SOMV Exploration Permits Locations and Status in The Bonaparte Basin (after Geoscience Australia).