6 Production Forecast

The production forecast methodology is described in Section 1.3.2 of this CPR. The production flowstreams presented below is the Base Case, which comprises 2P reserves associated with recoveries attained from existing operations i.e., No Further Action (NFA) production from the currently producing fields (2P Developed), and also Undeveloped reserves potentially recovered based on approved FDPs (2P Undeveloped).

The production forecasts by field, for P90 (1P) and P10 (3P) reserves and resource categories for gas, condensate and PLR, based on ARPR 1.1.2024, are included in Appendix 5 of this report. In assessing the net entitlement for Contingent Resources P90(1C), P50(2C) and P10(3C) based on the commercial valuation in the CVR, the production flowstreams are included in Appendix 6.

As mentioned in Section 1.1, the static, dynamic simulation, material balance (MBAL), well and surface network models were not provided in the dataset. For the production profiles presented in the tables below, please note the following bases and assumptions:

- "Gas" denotes gas sales.
- The annual volumes for the year 2024 reflect the estimated production from January until December 2024.
- The ARPR 1.1.2024 flowstreams are indicated to be based on surface network optimization which have incorporated uptime and shrinkage assumptions and considerations on possible surface network effects, constraints and interaction with other fields tied to the processing hub, if any.
- The production profile for pre and post Economic Limit Test (ELT) are similar as the end of PSC period (SK408) and the year when facilities decommissioning is planned (SK310 B15) are the same year when the cumulative net cash flow becomes negative based on the post-tax undiscounted Net Cash Flow Money of the Day (MOD).
- The composition profiles for each field is considered constant until the end of field life.

- For Gorek field, the split between NFA and VLAP flowstreams is inferred from ARPR 1.1.2023 production flowstreams, calibrated against ARPR 1.1.2024 estimated reserves.
- Contingent Resources associated with the notional additional recovery from Bakong Study project is classified as Contingent Resource (Development On Hold/ Unclarified), and as such not included in the Base Case.
- BIM facilities assumed F6 and F28 flowstreams forecast from ARPR 1.1.2023 to meet blending and TDR requirements (Figure 6-1and Figure 6-2).
    - LaBaGo production is optimized to meet the required contaminant limits at F6 facilities (6.5 mol% CO_2, and approximately 28 ppm or 2.9 mbara H_2S partial pressure).
    - Larak gas is minimized and conserved for blending with Bakong and Gorek gas with higher CO_2 and H_2S contents.
    - Bakong gas production is prioritized over Gorek gas for blending with the sweet gas available.
- Production is validated to be within the TDR Limits i.e., Larak (14 MMscfd), Bakong (33 MMscfd), Gorek (28 MMscfd), BIM (80 MMscfd), Jerun (80 MMscfd), and B15 (70 MMscfd).
- Jerun production is maintained at 500 MMscfd for seven years to meet ACQ.
- The gross flowstreams shown for Teja is for the total field i.e., include both SK408 and SK316.
- B15-A1ST1 tubing leak is manageable, and the well is able to continue producing until CoP for B15, expected to be in December 2024.

Uncertainties in flowstreams prediction include the following:

- The availability of sweet gas for blending, and changes in production and reservoir behavior from fields supplying sweet gas for blending e.g., in view of delayed F28 water breakthough (more sweet gas available for blending), Larak production is conserved.
- F6 and F28 forecasted production.
- True GIIP for B15 field and CoP timing.
- External downtime e.g., from F6 unavailability and curtailment from downstream,

- Uncertainties surrounding the new development projects i.e., fluid compositions, project timing and execution, and gas sales targets, which need to be synergized with the overall gas demand outlook.

The forecasted gas sales production by PSC, field and category (2P Developed and 2P Undeveloped) are shown in Figure 6-3, Figure 6-4, Figure 6-5, Table 6-1 and Table 6-2. The corresponding production forecast for condensate is shown in Figure 6-6, Figure 6-7, Figure 6-8, Table 6-3 and Table 6-4. For PLR, the production forecast is shown in Figure 6-9, Figure 6-10, Figure 6-11, Table 6-5 and Table 6-6.

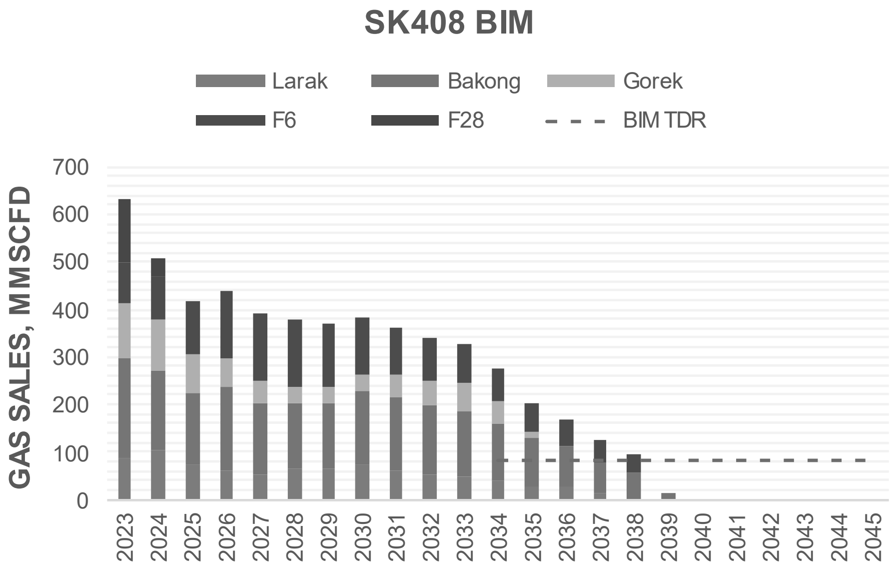


Figure 6-1: Total BIM gas forecast (MMscfd).

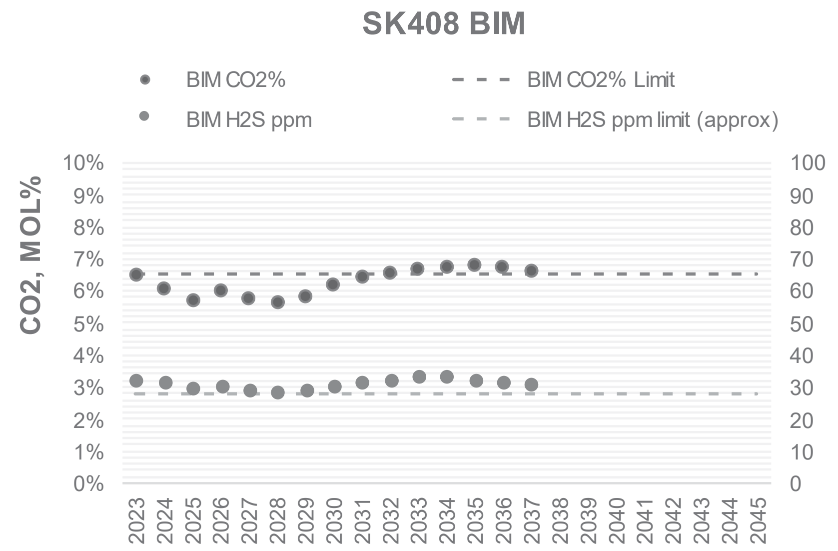


Figure 6-2: Calculated CO_2 (mol%) and H_2S (ppm) estimated at BIM.

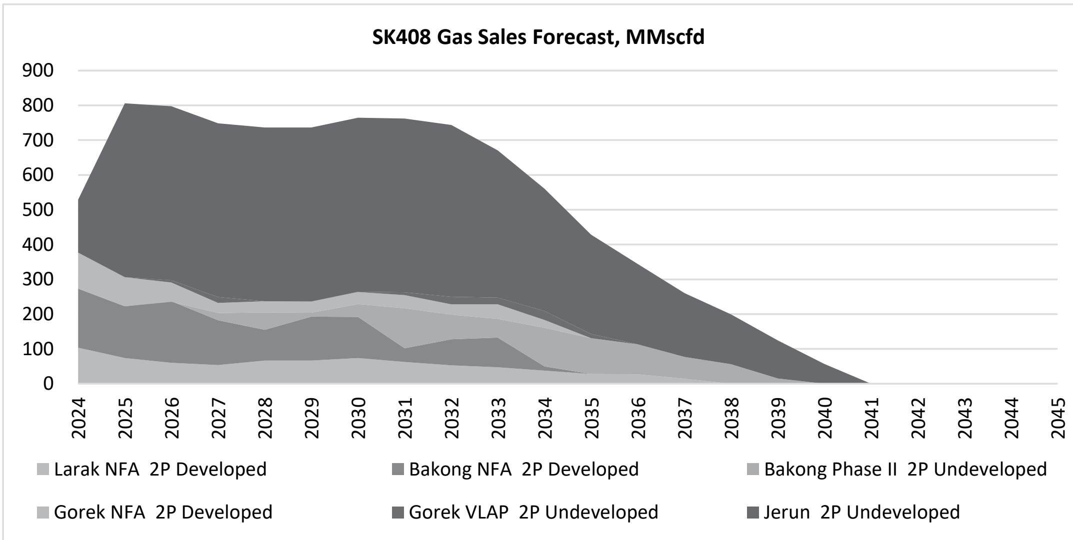


Figure 6-3: SK408 gas sales forecast by field and category (MMscfd).

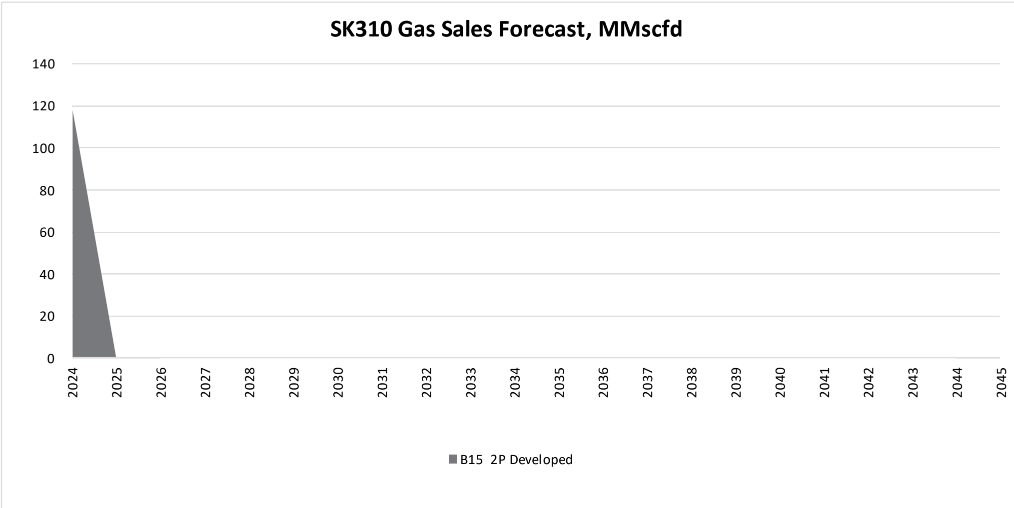


Figure 6-4: SK310 gas sales forecast by field and category (MMscfd).

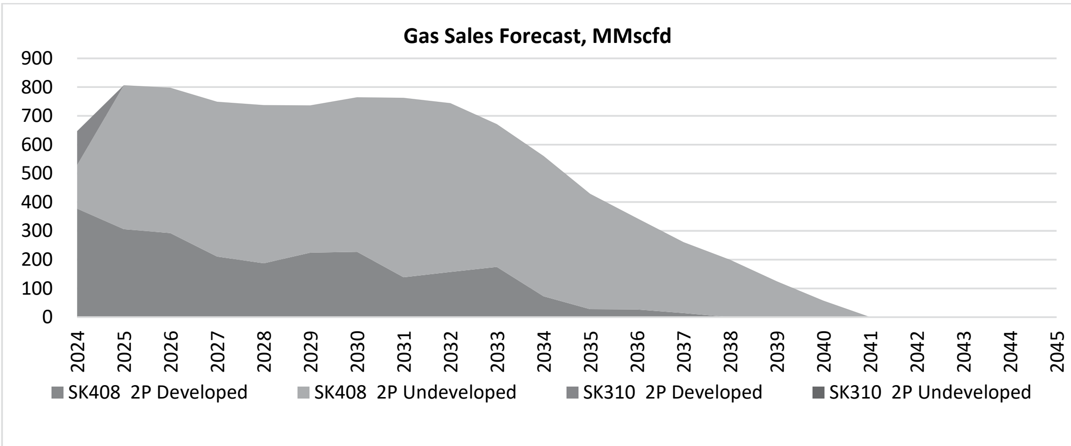


Figure 6-5: Gas sales forecast by PSC and category (MMscfd).

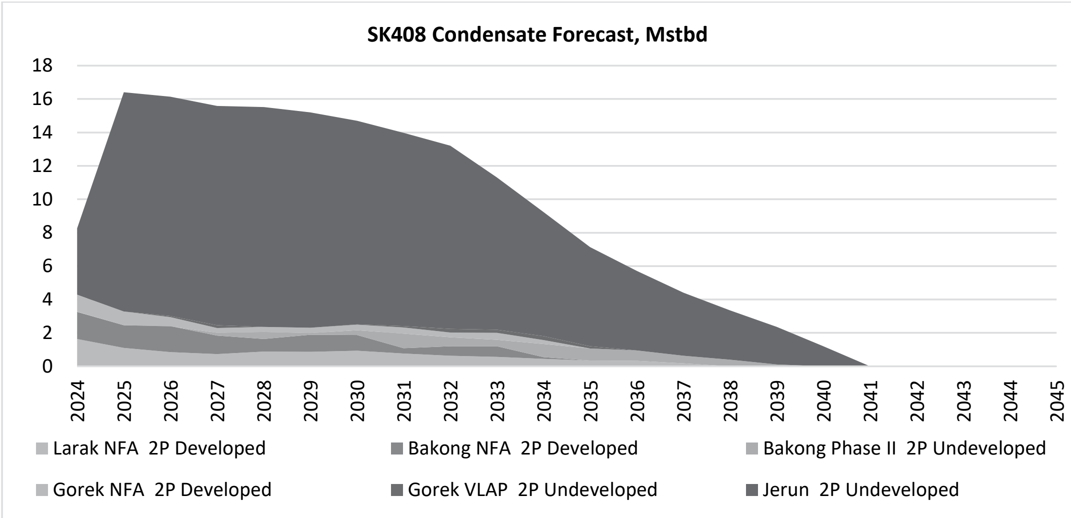


Figure 6-6: SK408 condensate forecast by field and category (Mstbd).

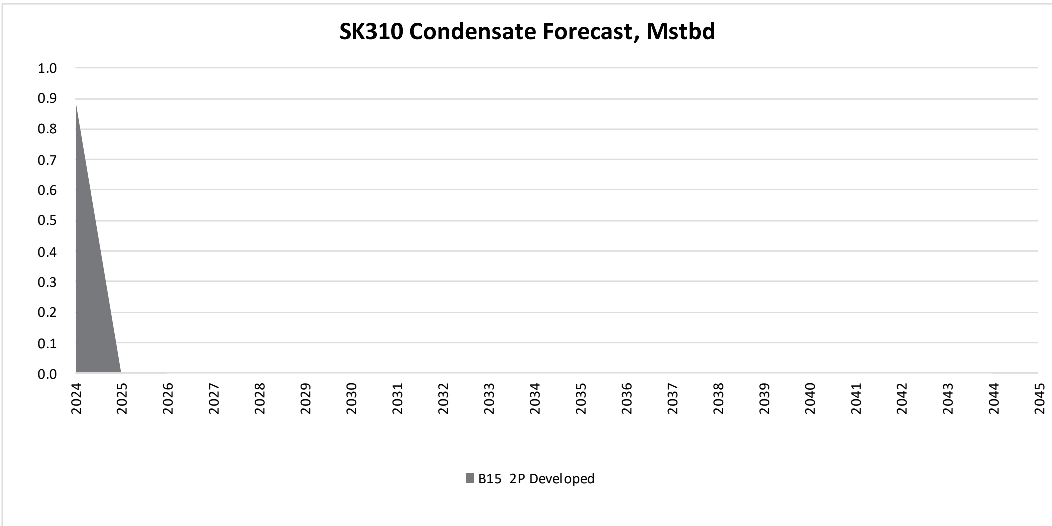


Figure 6-7: SK310 condensate forecast by field and category (Mstbd).

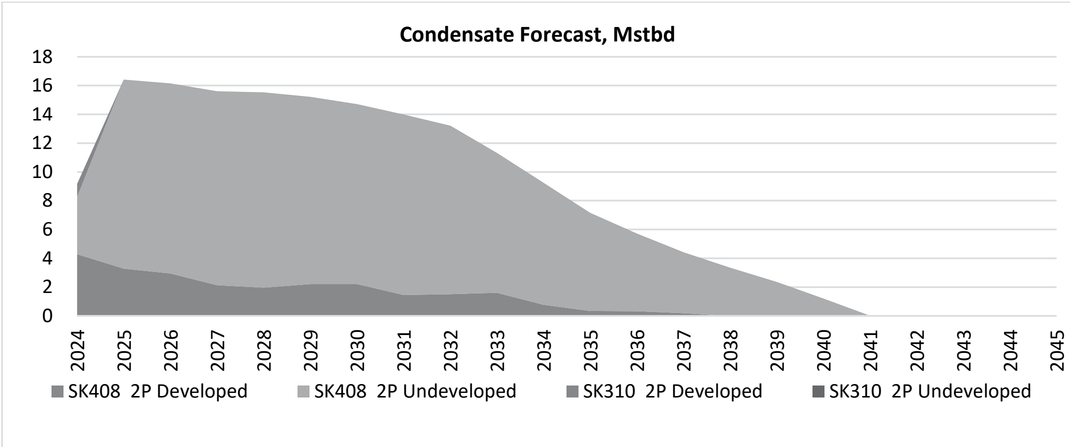


Figure 6-8: Condensate forecast by PSC and category (Mstbd).

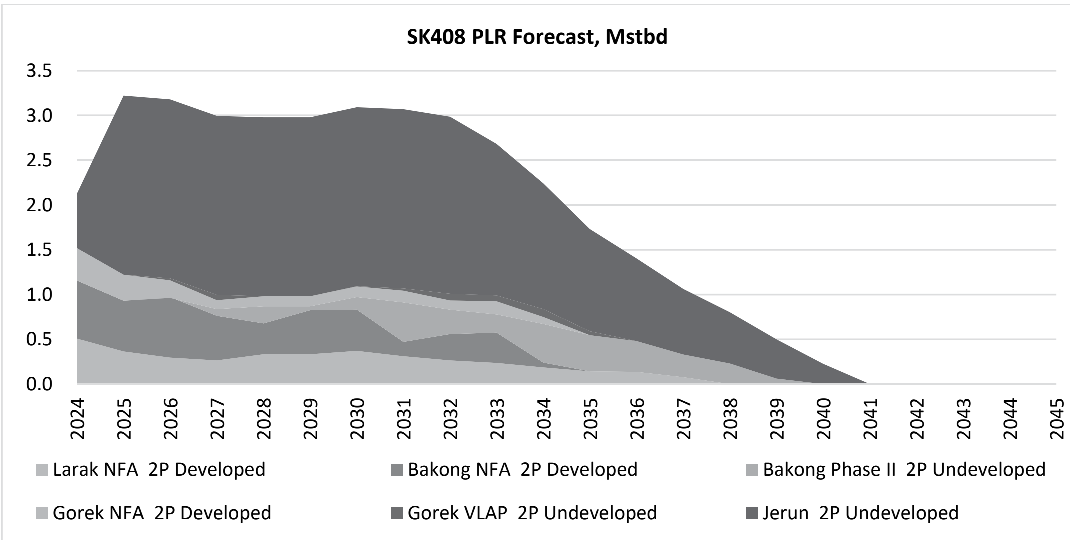


Figure 6-9: SK408 PLR forecast by field and category (Mstbd).

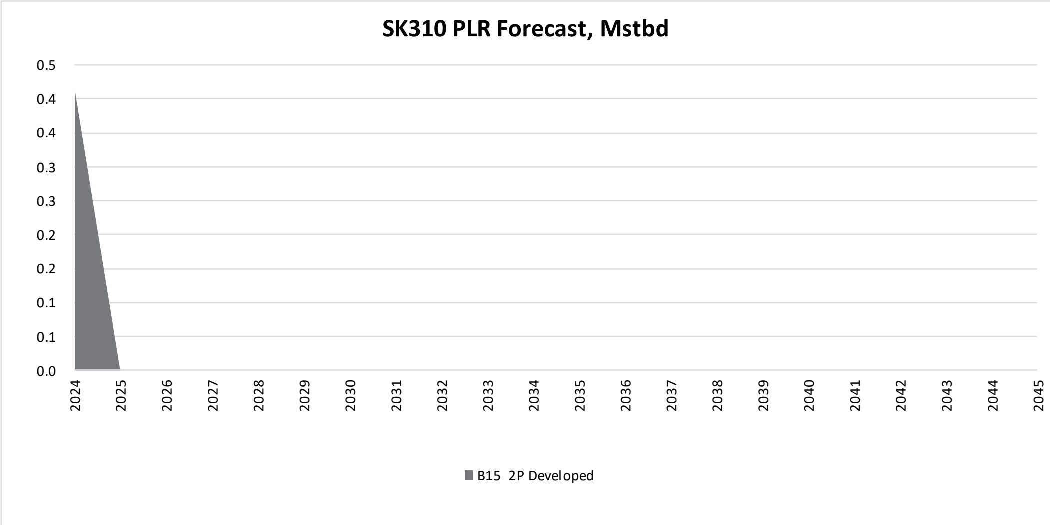


Figure 6-10: SK310 PLR forecast by field and category (Mstbd).

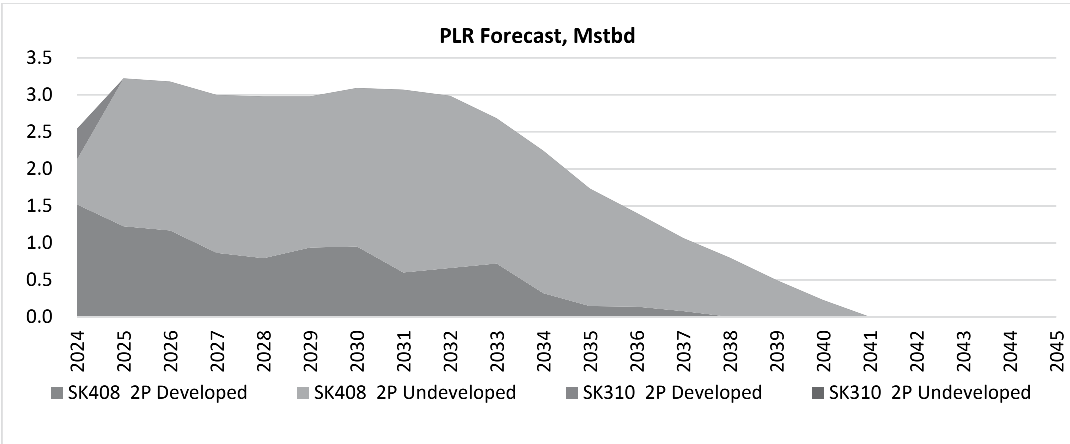


Figure 6-11: PLR forecast by PSC and category (Mstbd).

PSC	SK408						SK310
Field	**Larak NFA**	**Bakong NFA**	**Bakong Phase II**	**Gorek NFA**	**Gorek VLAP**	**Jerun**	**B15**
Category / Year	**2P Developed**	**2P Developed**	**2P Undeveloped**	**2P Developed**	**2P Undeveloped**	**2P Undeveloped**	**2P Developed**
2024	103.31	169.93	0.00	104.17	0.00	151.71	117.92
2025	74.06	148.75	0.00	83.34	0.00	500.00	0.00
2026	60.37	176.58	0.00	55.96	6.54	500.00	0.00
2027	53.63	128.38	20.85	29.07	16.94	500.00	0.00
2028	66.24	88.69	49.63	32.12	0.00	500.00	0.00
2029	66.25	126.35	11.83	32.12	0.00	500.00	0.00
2030	74.03	118.05	36.95	34.73	0.86	500.00	0.00
2031	62.48	39.31	115.53	37.40	7.74	500.00	0.00
2032	52.49	74.83	70.99	29.95	21.27	494.49	0.00
2033	47.22	85.43	53.91	41.84	18.93	423.52	0.00
2034	37.19	12.73	110.97	22.62	25.12	351.73	0.00
2035	28.19	0.00	102.30	0.00	12.15	286.07	0.00
2036	26.70	0.00	86.77	0.00	0.00	230.76	0.00
2037	14.54	0.00	62.77	0.00	0.00	183.35	0.00
2038	0.00	0.00	56.38	0.00	0.00	142.93	0.00
2039	0.00	0.00	14.73	0.00	0.00	109.53	0.00
2040	0.00	0.00	0.00	0.00	0.00	56.57	0.00
2041	0.00	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	0.00
2043	0.00	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	0.00
2045	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total, Bscf	**279.84**	**426.69**	**289.04**	**183.71**	**39.99**	**2,164.69**	**43.04**

Table 6-1: Production forecast – Gas sales by field, and category (MMscfd).

PSC	SK408			SK310			Total		
Category / Year	**2P Developed**	**2P Undeveloped**	**2P (Dev + Undev)**	**2P Developed**	**2P Undeveloped**	**2P (Dev + Undev)**	**2P Developed**	**2P Undeveloped**	**2P (Dev + Undev)**
2024	377.40	151.71	529.11	117.92	0.00	117.92	495.32	151.71	647.03
2025	306.14	500.00	806.14	0.00	0.00	0.00	306.14	500.00	806.14
2026	292.91	504.83	797.73	0.00	0.00	0.00	292.91	504.83	797.73
2027	211.08	537.79	748.87	0.00	0.00	0.00	211.08	537.79	748.87
2028	187.04	549.63	736.67	0.00	0.00	0.00	187.04	549.63	736.67
2029	224.72	511.83	736.55	0.00	0.00	0.00	224.72	511.83	736.55
2030	226.81	537.82	764.62	0.00	0.00	0.00	226.81	537.82	764.62
2031	139.18	623.27	762.45	0.00	0.00	0.00	139.18	623.27	762.45
2032	157.28	586.74	744.02	0.00	0.00	0.00	157.28	586.74	744.02
2033	174.48	496.36	670.84	0.00	0.00	0.00	174.48	496.36	670.84
2034	72.54	487.82	560.36	0.00	0.00	0.00	72.54	487.82	560.36
2035	28.19	400.52	428.72	0.00	0.00	0.00	28.19	400.52	428.72
2036	26.70	317.53	344.23	0.00	0.00	0.00	26.70	317.53	344.23
2037	14.54	246.13	260.67	0.00	0.00	0.00	14.54	246.13	260.67
2038	0.00	199.31	199.31	0.00	0.00	0.00	0.00	199.31	199.31
2039	0.00	124.25	124.25	0.00	0.00	0.00	0.00	124.25	124.25
2040	0.00	56.57	56.57	0.00	0.00	0.00	0.00	56.57	56.57
2041	0.00	0.00	0.00	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	0.00	0.00	0.00
2043	0.00	0.00	0.00	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	0.00	0.00	0.00
2045	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total, Bscf	**890.23**	**2,493.72**	**3,383.96**	**43.04**	**0.00**	**43.04**	**933.27**	**2,493.72**	**3,426.99**

Table 6-2: Production forecast – Gas sales by PSC and category (MMscfd).

PSC	SK408						SK310
Field	**Larak NFA**	**Bakong NFA**	**Bakong Phase II**	**Gorek NFA**	**Gorek VLAP**	**Jerun**	**B15**
Category / Year	**2P Developed**	**2P Developed**	**2P Undeveloped**	**2P Developed**	**2P Undeveloped**	**2P Undeveloped**	**2P Developed**
2024	1.64	1.61	0.00	1.03	0.00	3.98	0.89
2025	1.10	1.36	0.00	0.82	0.00	13.13	0.00
2026	0.85	1.55	0.00	0.55	0.06	13.13	0.00
2027	0.74	1.10	0.17	0.29	0.17	13.13	0.00
2028	0.89	0.75	0.41	0.32	0.00	13.15	0.00
2029	0.86	1.03	0.09	0.32	0.00	12.90	0.00
2030	0.93	0.94	0.29	0.34	0.01	12.19	0.00
2031	0.77	0.31	0.88	0.37	0.08	11.58	0.00
2032	0.64	0.57	0.53	0.29	0.21	10.96	0.00
2033	0.57	0.63	0.39	0.41	0.19	9.12	0.00
2034	0.45	0.09	0.79	0.22	0.25	7.42	0.00
2035	0.35	0.00	0.73	0.00	0.12	5.95	0.00
2036	0.33	0.00	0.62	0.00	0.00	4.76	0.00
2037	0.18	0.00	0.45	0.00	0.00	3.77	0.00
2038	0.00	0.00	0.40	0.00	0.00	2.94	0.00
2039	0.00	0.00	0.10	0.00	0.00	2.25	0.00
2040	0.00	0.00	0.00	0.00	0.00	1.20	0.00
2041	0.00	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	0.00
2043	0.00	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	0.00
2045	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total, MMstb	**3.76**	**3.64**	**2.13**	**1.81**	**0.39**	**51.67**	**0.32**

Table 6-3: Production forecast – Condensate by field, and category (Mstbd).

PSC	SK408			SK310			Total		
Category / Year	**2P Developed**	**2P Undeveloped**	**2P (Dev + Undev)**	**2P Developed**	**2P Undeveloped**	**2P (Dev + Undev)**	**2P Developed**	**2P Undeveloped**	**2P (Dev + Undev)**
2024	4.28	3.98	8.27	0.89	0.00	0.89	5.17	3.98	9.15
2025	3.28	13.13	16.41	0.00	0.00	0.00	3.28	13.13	16.41
2026	2.96	13.18	16.14	0.00	0.00	0.00	2.96	13.18	16.14
2027	2.13	13.46	15.59	0.00	0.00	0.00	2.13	13.46	15.59
2028	1.95	13.56	15.51	0.00	0.00	0.00	1.95	13.56	15.51
2029	2.21	12.99	15.20	0.00	0.00	0.00	2.21	12.99	15.20
2030	2.21	12.48	14.69	0.00	0.00	0.00	2.21	12.48	14.69
2031	1.45	12.54	13.99	0.00	0.00	0.00	1.45	12.54	13.99
2032	1.50	11.70	13.20	0.00	0.00	0.00	1.50	11.70	13.20
2033	1.62	9.69	11.31	0.00	0.00	0.00	1.62	9.69	11.31
2034	0.77	8.46	9.23	0.00	0.00	0.00	0.77	8.46	9.23
2035	0.35	6.80	7.15	0.00	0.00	0.00	0.35	6.80	7.15
2036	0.33	5.38	5.71	0.00	0.00	0.00	0.33	5.38	5.71
2037	0.18	4.22	4.41	0.00	0.00	0.00	0.18	4.22	4.41
2038	0.00	3.34	3.34	0.00	0.00	0.00	0.00	3.34	3.34
2039	0.00	2.35	2.35	0.00	0.00	0.00	0.00	2.35	2.35
2040	0.00	1.20	1.20	0.00	0.00	0.00	0.00	1.20	1.20
2041	0.00	0.00	0.00	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	0.00	0.00	0.00
2043	0.00	0.00	0.00	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	0.00	0.00	0.00
2045	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total, MMstb	**9.21**	**54.19**	**63.40**	**0.32**	**0.00**	**0.32**	**9.53**	**54.19**	**63.72**

Table 6-4: Production forecast – Condensate by PSC and category (Mstbd).

PSC	**SK408**						**SK310**
Field	**Larak NFA**	**Bakong NFA**	**Bakong Phase II**	**Gorek NFA**	**Gorek VLAP**	**Jerun**	**B15**
Category / Year	**2P Developed**	**2P Developed**	**2P Undeveloped**	**2P Developed**	**2P Undeveloped**	**2P Undeveloped**	**2P Developed**
2024	0.51	0.65	0.00	0.36	0.00	0.61	0.41
2025	0.36	0.57	0.00	0.29	0.00	2.00	0.00
2026	0.30	0.67	0.00	0.19	0.02	2.00	0.00
2027	0.26	0.50	0.08	0.10	0.06	2.00	0.00
2028	0.33	0.35	0.19	0.11	0.00	2.00	0.00
2029	0.33	0.49	0.04	0.11	0.00	2.00	0.00
2030	0.37	0.46	0.14	0.12	0.00	2.00	0.00
2031	0.31	0.16	0.44	0.13	0.03	2.00	0.00
2032	0.26	0.29	0.27	0.10	0.07	1.98	0.00
2033	0.24	0.34	0.20	0.15	0.07	1.69	0.00
2034	0.19	0.05	0.43	0.08	0.09	1.41	0.00
2035	0.14	0.00	0.40	0.00	0.04	1.14	0.00
2036	0.14	0.00	0.34	0.00	0.00	0.92	0.00
2037	0.08	0.00	0.25	0.00	0.00	0.73	0.00
2038	0.00	0.00	0.23	0.00	0.00	0.57	0.00
2039	0.00	0.00	0.06	0.00	0.00	0.44	0.00
2040	0.00	0.00	0.00	0.00	0.00	0.23	0.00
2041	0.00	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	0.00
2043	0.00	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	0.00
2045	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total, MMstb	**1.39**	**1.65**	**1.13**	**0.64**	**0.14**	**8.66**	**0.15**

Table 6-5: Production forecast – PLR by field, and category (Mstbd).

PSC	SK408			SK310			Total		
Category / Year	**2P Developed**	**2P Undeveloped**	**2P (Dev + Undev)**	**2P Developed**	**2P Undeveloped**	**2P (Dev + Undev)**	**2P Developed**	**2P Undeveloped**	**2P (Dev + Undev)**
2024	1.52	0.61	2.12	0.41	0.00	0.41	1.93	0.61	2.54
2025	1.22	2.00	3.22	0.00	0.00	0.00	1.22	2.00	3.22
2026	1.16	2.02	3.18	0.00	0.00	0.00	1.16	2.02	3.18
2027	0.86	2.13	3.00	0.00	0.00	0.00	0.86	2.13	3.00
2028	0.79	2.19	2.98	0.00	0.00	0.00	0.79	2.19	2.98
2029	0.94	2.04	2.98	0.00	0.00	0.00	0.94	2.04	2.98
2030	0.95	2.14	3.09	0.00	0.00	0.00	0.95	2.14	3.09
2031	0.60	2.47	3.07	0.00	0.00	0.00	0.60	2.47	3.07
2032	0.66	2.32	2.99	0.00	0.00	0.00	0.66	2.32	2.99
2033	0.72	1.96	2.68	0.00	0.00	0.00	0.72	1.96	2.68
2034	0.32	1.93	2.24	0.00	0.00	0.00	0.32	1.93	2.24
2035	0.14	1.59	1.73	0.00	0.00	0.00	0.14	1.59	1.73
2036	0.14	1.27	1.40	0.00	0.00	0.00	0.14	1.27	1.40
2037	0.08	0.99	1.06	0.00	0.00	0.00	0.08	0.99	1.06
2038	0.00	0.80	0.80	0.00	0.00	0.00	0.00	0.80	0.80
2039	0.00	0.50	0.50	0.00	0.00	0.00	0.00	0.50	0.50
2040	0.00	0.23	0.23	0.00	0.00	0.00	0.00	0.23	0.23
2041	0.00	0.00	0.00	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	0.00	0.00	0.00
2043	0.00	0.00	0.00	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	0.00	0.00	0.00
2045	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total, MMstb	**3.68**	**9.92**	**13.61**	**0.15**	**0.00**	**0.15**	**3.83**	**9.92**	**13.76**

Table 6-6: Production forecast – PLR by PSC and category (Mstbd).

7 Resources Beyond the 2P and 2C Categories

Resources identified in the assessment include the followings, and are summarized by their respective resource category in Table 7-1. Note that less information was available for the opportunities, discoveries and exploration potentials and therefore, less focus was given.

(i) Opportunities identified from notional projects, which include 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). These potentials are classified as Contingent Resources with a lower sub-class category, where the development is deemed to be either "On Hold" or "Unclarified".

(ii) Discovered resources that are potentially recoverable but require further appraisal and maturation to be considered viable for development commercially, categorized as Contingent Resources with a lower sub-class category, where the development is deemed to be either "On Hold" or "Unclarified". These include the discovered opportunities in Malaysia PSC Block SK408 (Jarak, Legundi and Jeremin), New Zealand (Toutouwai) and Mexico (Kan).

(iii) Prospective Resources from exploration opportunities, defined in PRMS as Resources as resources that are potentially recoverable from undiscovered accumulations by application of future development projects. For Prospective Resources, potential accumulations may mature from Play, to Lead and then to Prospect based on the ability to identify potentially commercially viable exploration projects. These include identified Leads and Prospects located in several exploration blocks in New Zealand, Mexico and Australia and also from the recently signed PSC for exploration block SB412 offshore Sabah, in Malaysia.

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 7-1: Summary of Resources Beyond the 2P and 2C Categories.

7.1 Resources Beyond the 2P and 2C Categories. – Malaysia Assets

7.1.1 SK408 Potential Opportunities

7.1.1.1 Bakong Study

In ARPR 1.1.2024, additional volumes are indicated to be potentially recoverable, associated with a better F6 VLAP performance or the additional blending availability via future sweet gas tie-in projects to meet the H_2S & CO_2 limits at F6 Hub. This notional project is currently estimated to recover 131 Bscf from Bakong, where the notional first gas is assumed to be in January 2034. These volumes are not included in the production forecast in this CPR, as no additional sweet gas has yet been identified for blending.

7.1.1.2 Jerun Optimization Project

Jerun optimization project presents the opportunity to accelerate gas production via the debottlenecking of JRN-A facilities in 2025, i.e., post start-up and stabilisation phase. This notional project is expected to uplift the annual production prior to compression in 2028. This project is considered notional at this stage, and as such not included in the production forecast in this CPR and is classified as Contingent Resources under the category Development Unclarified sub-category.

7.1.1.3 Jerun Talus

In ARPR 1.1.2022, Jerun Talus is classified as an undiscovered resource, not penetrated by Jerun-1 exploration well (Figure 7-1), and comprises three prospects i.e., Jerun Talus SH (Upper Accretionary Talus, AT), Jerun Talus D (Lower Accretionary Talus, AT) and Jerun Talus (Stringer-Talus, ST), as depicted in Figure 7-2.

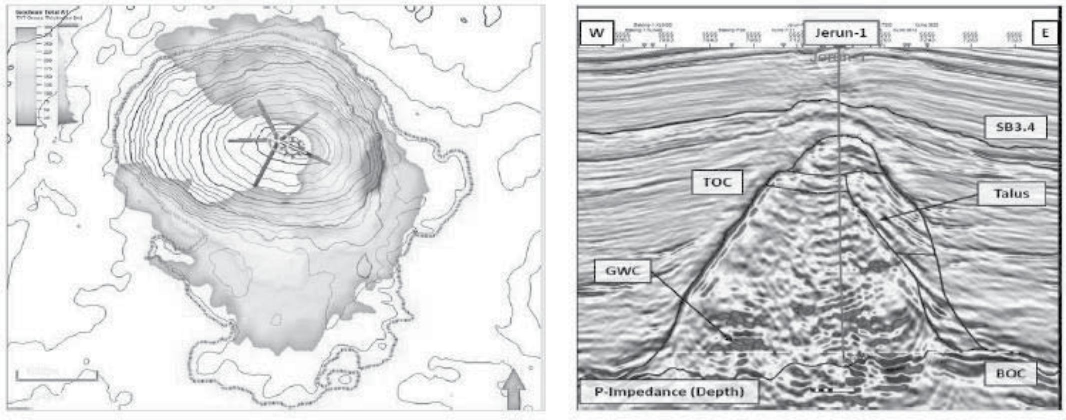
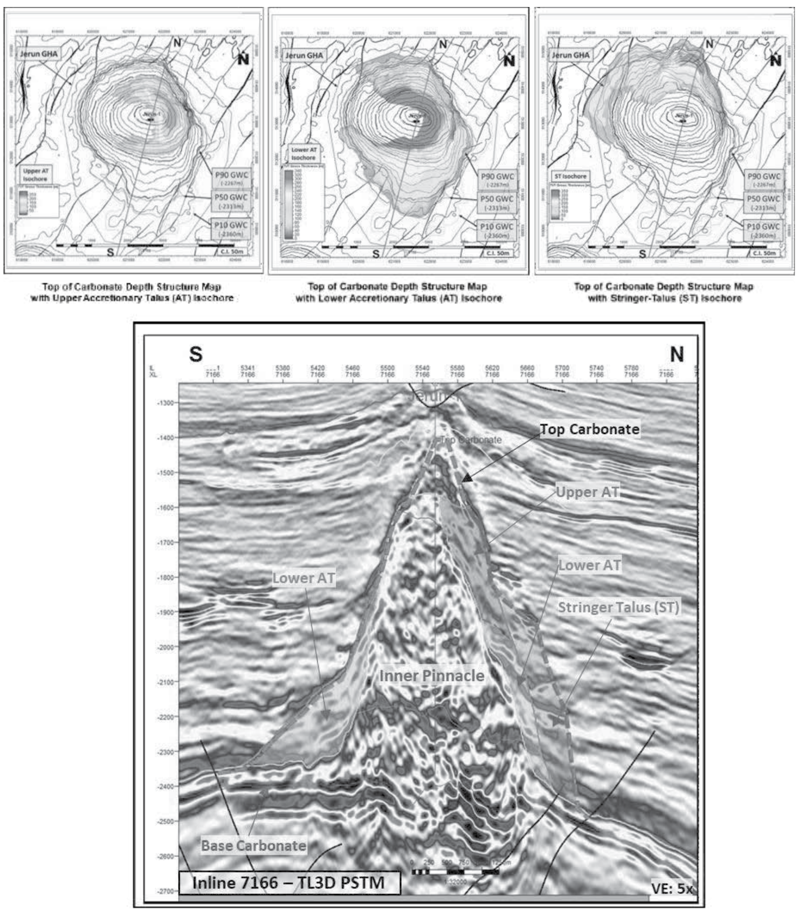


Figure 7-1: Jerun Talus thickness map and seismic cross-section (Source: SOMV).



Inline 7166 – TL3D PSTM

Figure 7-2: Jerun Talus prospects (Source: ARPR 1.1.2022).

Jerun field development drilling campaign included the plan to appraise the Talus potential by one of the development wells i.e., Jerun-J3 well (Figure 7-3). Jerun-J3 data acquisition plan was designed to allow for validation of the current reservoir characterization, both in terms of reservoir quality and Talus productivity. The appraisal program comprised acquiring LWD quad-combo logs and pressure data to confirm communication between Talus and the reef pinnacle, fluid samples to confirm the level of contaminants in Talus and the core pinnacle, and also conventional and sidewall cores (SWC) for petrophysical and static / dynamic model calibration. Jerun-J2 and Jerun-J6 wells are also expected to encounter Talus; however, the data acquisition program was focused only on Jerun-J3. In the case of a successful appraisal, the potential incremental GIIP of around 1,200 Bscf (P50 estimate, unrisked) could be firmed up. In the planning phase, one notional well is assumed, to unlock the Talus potential. The potentials from the incremental volumes from Talus development may also extend the Jerun gas sales plateau, and may also delay the timing for compression requirement.

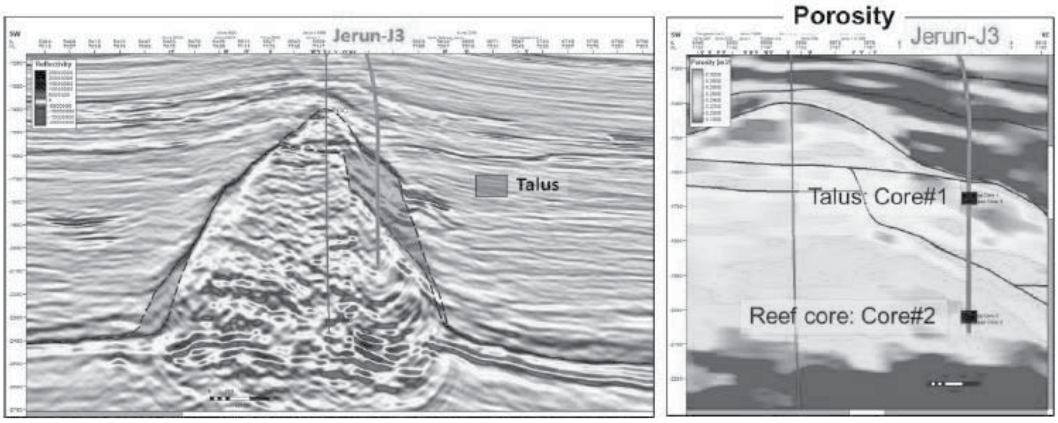


Figure 7-3: Jerun Talus seismic and porosity cross-sections (Source: SOMV).

Based on the development drilling update in December 2023, Jerun Talus was encountered in Jerun-A3, A2 and A5 (previously Jerun-J3, J2 and J5). Log analysis from the report indicated poorer porosity vs. prognosed, and the presence of higher water saturation, in the range of 56% to 100% in the wells, as summarized in Table 7-2.

Well	**Interval (mMD)**	**Description**	**Gross thickness (m)**	**Average porosity (%)**		**Average water saturation (%)**	
				Log	**Prognosed**	**Log**	**Prognosed**
Jerun-A3	1787.3 – 1987.3	Gas bearing	200	12	29	56	12
	1987.3 – 2088.5	Perched water	101.2	11	26	100	12
	2088.5 – 2160.8	Gas bearing	72.2	11	28	76	9
Jerun-A2	1850.0 – 1971.0	Mainly tight carbonate	121.0	11	N/A	88	N/A
Jerun-A5	1864.3 – 1902.5	Tight carbonate	38.3	10	N/A	100	N/A

Table 7-2: Jerun preliminary log analysis results (Source: Jerun wells drilling subsurface update December 2023).

The unrisked estimated in-place volumes for each prospect in Jerun Talus based on ARPR 1.1.2022 is shown in Table 7-3. It is expected that the GIIP for Jerun Talus will be reduced significantly based on the post-drill results, likely to be revised by Q1 2024. Recovery Factors are estimated to be based on gas reservoirs with pressure depletion and weak to moderate aquifers i.e., ranging from 65% to 75%. Jerun Talus is considered an additional potential, pending post-drilling analyses which is not available at the time of writing this CPR.

Prospect	**Volume**	**Low (P90)**	**Base (P50)**	**High (P10)**
Jerun Talus SH (Upper AT)	Unrisked GIIP (Bscf)	426	488	557
	Unrisked Recoverable (Bscf)	277	342	418
Jerun Talus D (Lower AT)	Unrisked GIIP (Bscf)	393	551	746
	Unrisked Recoverable (Bscf)	256	386	560
Jerun Talus (Stringer-Talus, ST)	Unrisked GIIP (Bscf)	64	127	217
	Unrisked Recoverable (Bscf)	42	89	163
Total	**Unrisked GIIP (Bscf)**	**883**	**1,166**	**1,520**
	Unrisked Recoverable (Bscf)	**574**	**816**	**1,140**

Table 7-3: Jerun Talus estimated GIIP, unrisked (Source: ARPR 1.1.2022).

7.1.2 SK408 Discovered Opportunities (Jarak, Legundi, Jeremin)

Other additional structures discovered within SK408 are the Jarak, Legundi and Jeremin gas discoveries, which provide potential opportunities for increasing future production within the block (Figure 7-4).

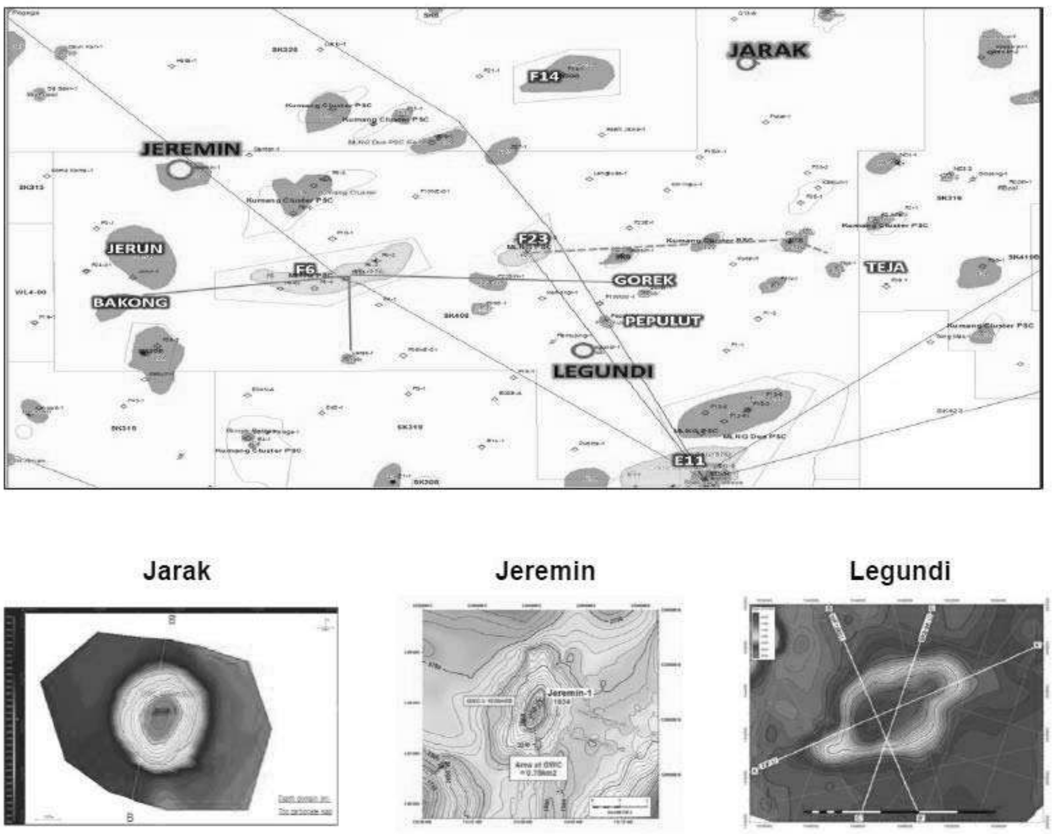


Figure 7-4: SK408 other discovered opportunities (Source: SOMV).

Based on the screening of potential development concepts conducted in the SK408 ADP 2021 however, these discoveries were deemed to have very low likelihood of commercial development primarily due to their marginal volumes. Furthermore, as there were no fluid samples collected from these fields, the uncertainty with regards to the gas contaminants (especially in H_2S gas composition and the risk associated with the integrity of potential tie-in facilities) will likely impact development viability.

The viability of these projects may potentially be improved by the re-use of topside equipment (e.g., from B15 when it has reached end of field life), implementing extended reach drilling (ERD) for fields located near an existing WHP (e.g., Legundi and Gorek), and synergizing with potential new discoveries in the area, in addition to a combination of competitive commercial/fiscal enablers such as uplifting the gas price and commercial terms (e.g., tax incentives for marginal fields). However, for the purpose of this CPR, these discoveries are categorized as Contingent Resources with a lower Sub-class category, where the development is either "On Hold" or "Unclarified", due to their likelihood of commercial development. These discoveries are further discussed below.

7.1.2.1 Jarak

Jarak field is a post-MMU (Cycle IV/V) pinnacle carbonate build-up located in the Northeast direction of Block SK408, in water depth of approximately 97 m. The field was discovered with the drilling of the Jarak-1 exploration well in 2017. The field top carbonate map and seismic cross-section are shown in Figure 7-5.

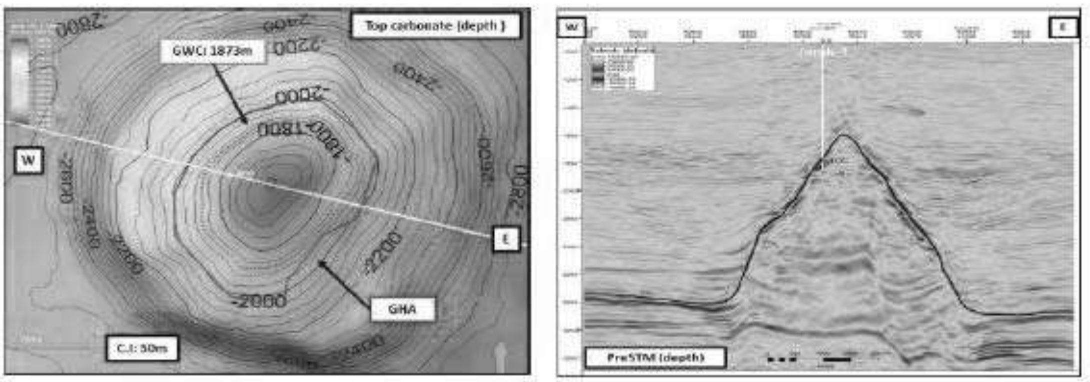


Figure 7-5: Jarak field top carbonate map seismic cross-section and (Source: SOMV).

Jarak field and reservoir properties are summarized in Table 7-4. The average porosity and gas saturation is estimated to be approximately 25% and 80%, respectively. No fluid sample was collected from Jarak-1 well, and as such, no information is available to define the H_2S uncertainty which will have an impact on gas blending options with potential tie-ins. The contaminant ranges shown are based on information from nearby offset fields (e.g., F14, and Kasawari), whilst CGR is estimated based on pre-drill assessment and CGR trend observed in Central Luconia. The estimated in-place volumes for Jarak based on ARPR 1.1.2022 submission is shown in Table 7-5.

Property/ parameter	Unit	Value/ Remarks
Gas column	m	119
GWC	mTVDSS	1,842
Area at GWC	km^2	0.73
Porosity	%	25
Gas saturation	%	80
Reservoir pressure	psi	4,626
Reservoir temperature	degF	176 - 185
CO_2	mol%	2 – 10 - 22
H_2S	ppm	25 – 50 - 100
CGR	bbl/MMscf	16

Table 7-4: Jarak field and reservoir properties (Source: ADP 2021).

	Low (P90)	Base (P50)	High (P10)
GIIP (Bscf)	109	153	211
EUR (Bscf)	77	107	148

Table 7-5: Jarak GIIP and EUR (Source: ADP 2021).

Jarak field is considered marginal in size, and is relatively far from the existing producing facilities. As a standalone development concept with processing facilities may be uneconomic, the SK408 ADP 2021 investigated three different tie-back development options to available tie-in points within 50 km of the field, i.e., to F23 hub via SK8 Cili Padi or F14, or tie-back to SK316 NC3 platform (Figure 7-6). The development concept, timing and feasibility will be revisited based on the gas demand outlook by MPM and Jarak MR4 is targeted no later than 31st March 2024, to fulfill the condition as per GHA.

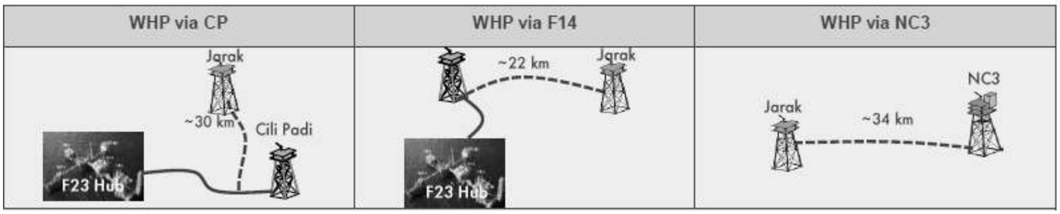


Figure 7-6: Jarak development concepts (Source: ADP 2021).

7.1.2.2 Legundi

Legundi field is a post-MMU (Cycle IV/V) pinnacle carbonate build-up located in the center region of Block SK408, in water depth of approximately 84 m. The field was discovered with the drilling of the Legundi-1 exploration well in 2014. The field top carbonate map and seismic cross-section is shown in Figure 7-7.

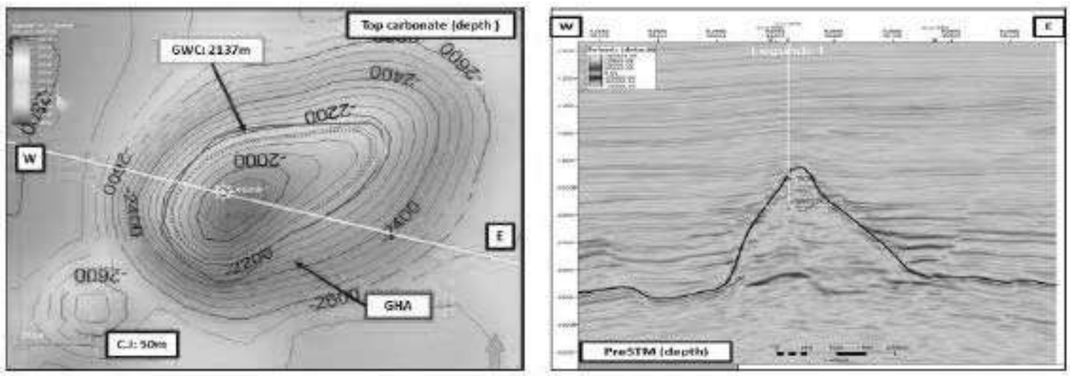


Figure 7-7: Legundi field top carbonate map and seismic cross-section (Source: SOMV).

Legundi field and reservoir properties are summarized in Table 7-6. The average porosity and gas saturation is estimated to be approximately 14% and 69%, respectively. No fluid sample was collected from Legundi-1 well, and as such, no information is available to define the H_2S uncertainty which will have an impact on gas blending options with potential tie-ins. The contaminant ranges shown are based on information from nearby offset fields (e.g., Pepulut and Gorek), whilst CGR is estimated based on pre-drill assessment and CGR trend observed in Central Luconia. The estimated in-place volumes for Legundi based on ARPR 1.1.2022 submission is shown in Table 7-7.

Property/ parameter	Unit	Value/ Remarks
Gas column	m	137
GWC	mTVDSS	2,101
Area at GWC	km^2	
Porosity	%	14
Gas saturation	%	69
Reservoir pressure	psi	None
Reservoir temperature	degF	200
CO_2	mol%	3 - 5 - 7
H_2S	ppm	20 - 45
CGR	bbl/MMscf	10

Table 7-6: Legundi field and reservoir properties (Source: ADP 2021).

	Low (P90)	Base (P50)	High (P10)
GIIP (Bscf)	45	77	114
EUR (Bscf)	27	48	75

Table 7-7: Legundi GIIP and EUR (Source: ADP 2021).

Legundi field is considered marginal in size, and a standalone development concept with processing facilities may be uneconomic. Three tie-back development concepts for available tie-in points were investigated in the SK408 ADP 2021, i.e., to F6 hub via Gorek or Larak platform, or tie-back to F23 hub via SK8 Cili Padi (Figure 7-8). The development concept, timing and feasibility will be revisited based on the gas demand outlook by MPM and Legundi MR4 is targeted no later than 31st March 2024, to fulfill the condition as per GHA.

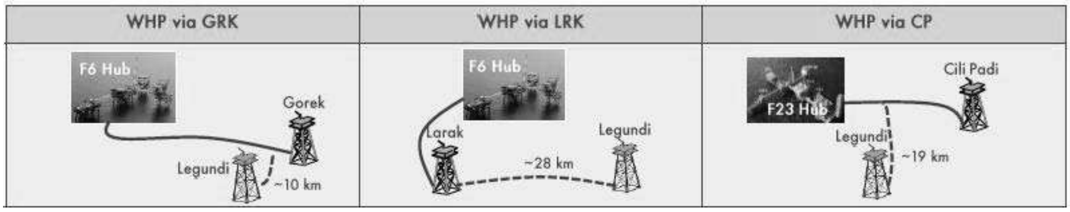


Figure 7-8: Legundi development concepts (Source: ADP 2021).

7.1.2.3 Jeremin

Jeremin field is a post-MMU (Cycle IV/V) circular pinnacle carbonate build-up located around 18 km North of the Jerun field, in water depth of approximately 96 m. The field was discovered with the drilling of the Jeremin-1 exploration well in November 2016. The field top carbonate map and seismic cross-section are shown in Figure 7-9.

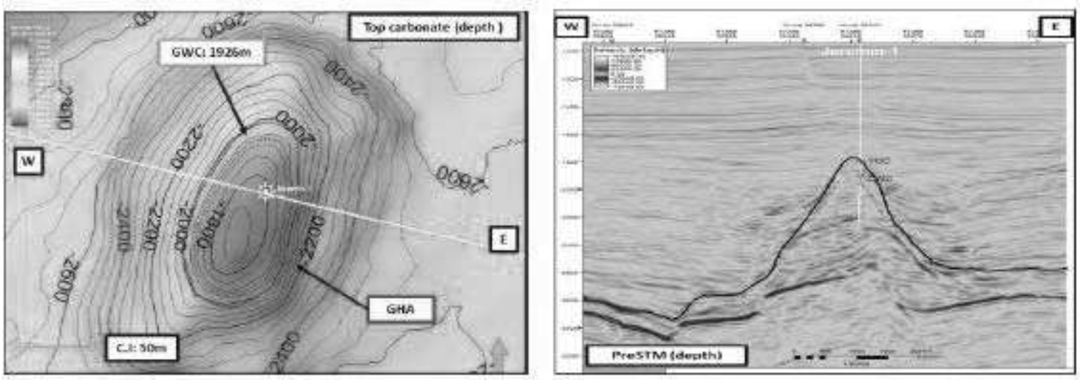


Figure 7-9: Jeremin field top carbonate map and seismic cross-section (Source: SOMV).

Jeremin field and reservoir properties are summarized in Table 7-8. The average porosity and gas saturation is estimated to be approximately 21% and 82%, respectively. Presence of 4.9 mol% CO_2 and H_2S ranging from 20 to 40 ppm are indicated based on MDT samples from Jeremin-1. The estimated in-place volumes for Jeremin based on ARPR 1.1.2022 submission is shown in Table 7-9.

Property/ parameter	Unit	Value/ Remarks
Gas column	m	178
GWC	mTVDSS	1,928
Area at GWC	km^2	0.75
Porosity	%	21
Gas saturation	%	82
Reservoir pressure	psi	3,010
Reservoir temperature	degF	257
CO_2	mol%	4.9
H_2S	ppm	20 - 40
CGR	bbl/MMscf	40

Table 7-8: Jeremin field and reservoir properties (Source: ADP 2021).

	Low (P90)	Base (P50)	High (P10)
GIIP (Bscf)	45	64	90
EUR (Bscf)	27	42	63

Table 7-9: Jeremin GIIP and EUR (Source: ADP 2021).

Jeremin field is considered marginal in size, and a standalone development concept with processing facilities may be uneconomic. A WHP tie-back development concept to the nearby Jerun CPP located around 18 km away was investigated in the SK408 ADP 2021. The results indicate that although this option may be feasible as Jerun CPP is expected to have ullage post 2030, the costs to develop the marginal reserves may deem the Jeremin development to be uneconomic.

7.1.3 SB412 Prospective Resources

PSC Block SB412 covers an area of approximately 16,000 km^2 offshore Sabah, in water depths ranging from 50 m to 2,000 m (Figure 7-10). Northwest Sabah basin is known to have an effective proven petroleum system as documented by oil and gas discoveries. In proving the play concept, ability to predict key play elements for a successful venture is critical, since the large and easy to find prospective areas have already been drilled and tested. An integrated geological, geophysical and geochemical analysis is one of the approaches that industries are investing in, to evaluate and locate the remaining undiscovered hydrocarbon potential. PSC Block SB412 offshore NW Sabah basin is no exception, given the number of wells drilled and known discoveries to demarcate and map the proven hydrocarbon occurrences, low to high hydrocarbon risk areas, the unknown gas versus oil distribution incorporating geological control for the main play elements prediction, extending the petroleum play concept further offshore (Figure 7-11). Data availability and quality addressed the chance of hydrocarbon (risky) particularly in the frontier areas.

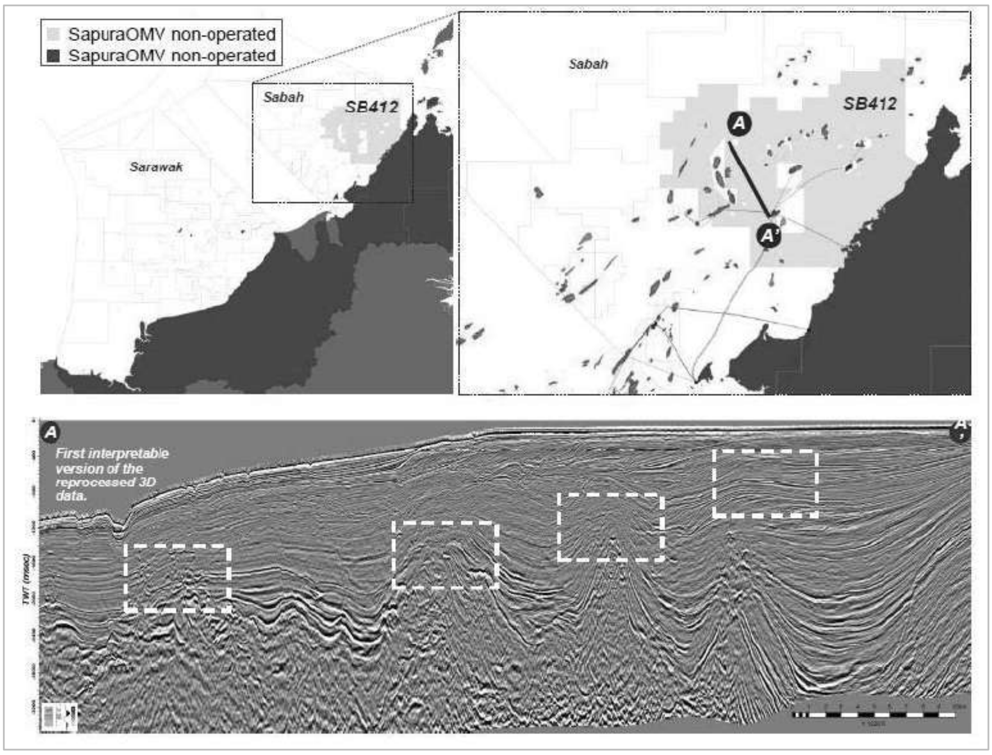


Figure 7-10: SB412 location map (Source: SOMV).

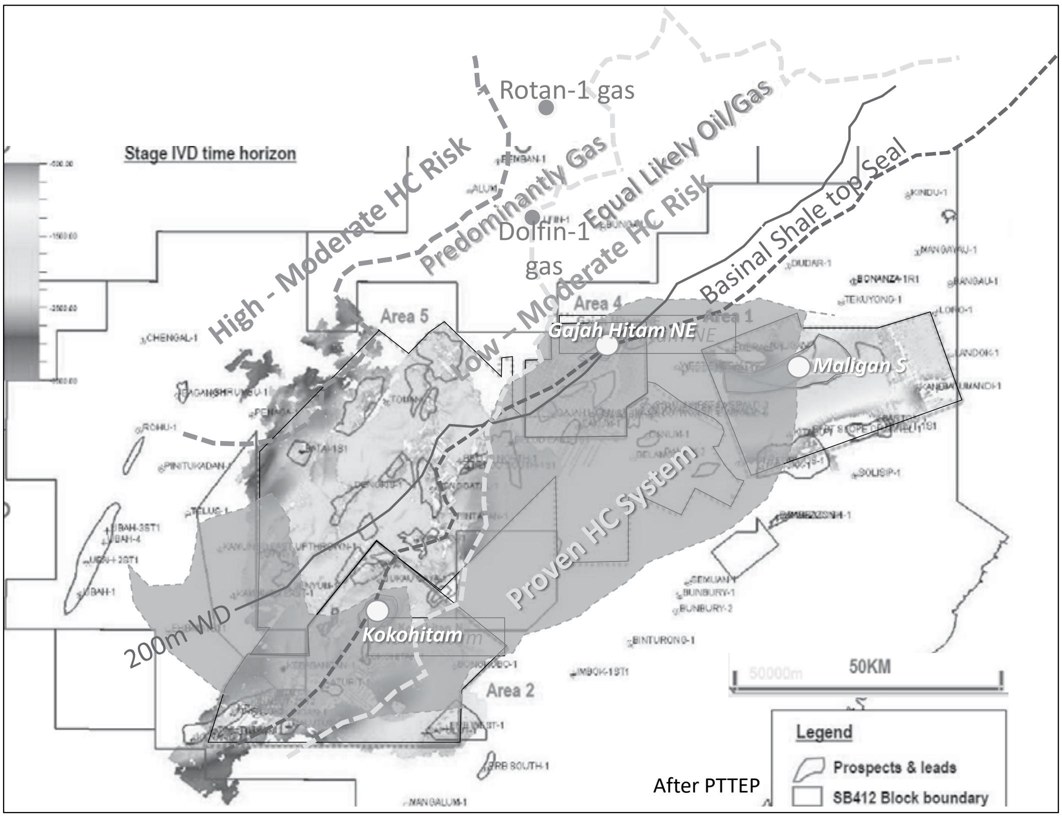


Figure 7-11: NW Sabah Basin – Proposed Petroleum System Play Map Model (after TCM 2023 and EQ, 2012).

In general, NW Sabah SB412 block frontier offshore area is interpreted to be dominantly gas and higher risk of hydrocarbon occurrence, and this could also be attributed to amount of data. The identified Areas 1 to 4 are within the proven and relatively more favourable for chance of HC as documented by well shows and discoveries (Figure 7-11). Failures in the area are location specific, since one or more of the other key petroleum play elements were absent.

Regional study is performed to gain better understanding of the petroleum system and regional geology of the area and develop a prospect inventory based on the 3D Mega Merge seismic reprocessing, covering the total area of 5,000 km^2 in Block SB412.

In February 2023, three key prospects were identified within Block SB412 for further analysis, i.e., Maligan South (Area 1), Kokohitan North (Area 2) and Gajah Hitam NE

(Area 4), as shown in Figure 7-12. These prospects are located in water depths less than 200 m, within the relatively favourable hydrocarbon occurrences and along the paleo-slope of basinal shale top seal (Figure 7-11). Based on this finding, the 3D seismic reprocessing for the purpose of prospect evaluation is focused on the targeted Areas 1, 2 and 4. As of August 2023, it was reported that the seismic reprocessing and G&G studies are currently ongoing.

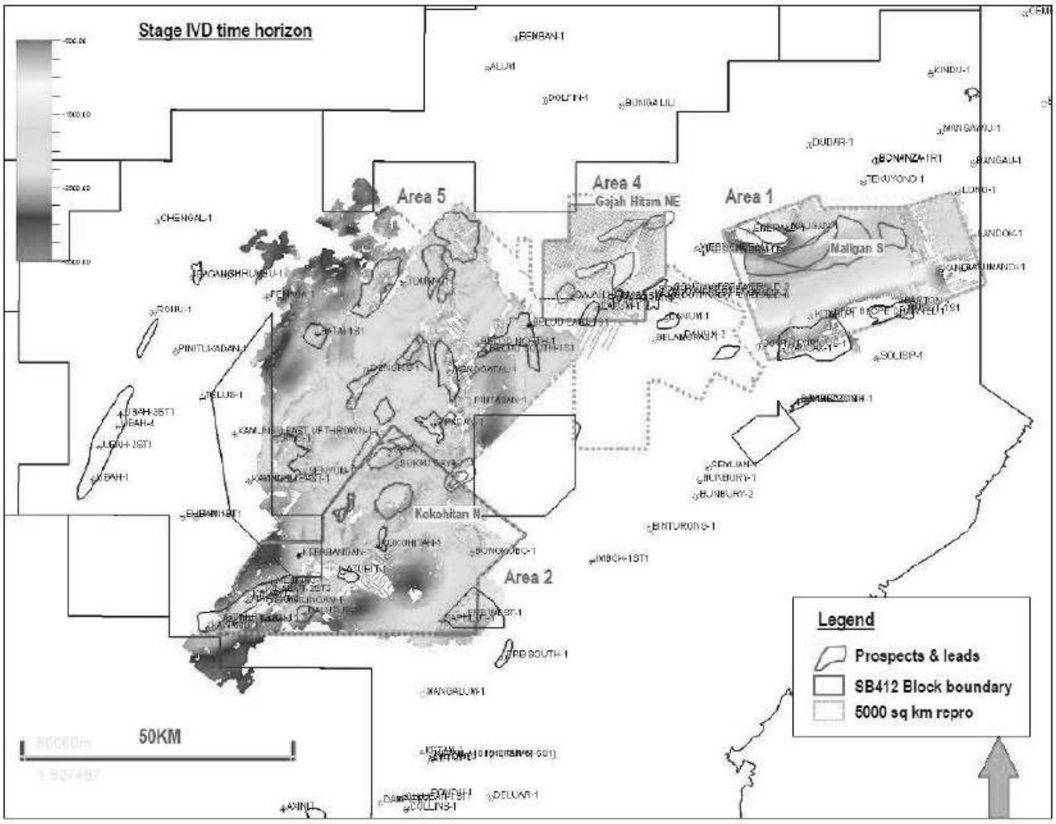


Figure 7-12: SB412 highlighted prospects (Source: TCM 2023).

Uncertainties include key petroleum play elements i.e., reservoir, source, timing and trap, type and risk of hydrocarbon (oil vs gas), as depicted in Figure 7-11. EQ has placed the classification of resources for Block SB412 in the Prospective category.

7.2 Resources Beyond the 2P and 2C Categories– New Zealand Asset

The Toutouwai-1 oil discovery assists with the assessment of remaining prospectivity within PEP60093, and provides a step-off point for the Western Platform development hub, with Karoro identified as the next prospect to be drilled.

Prospective Resources within PEP60093, PEP60092 and PEP57075 which comprise exploration prospects primarily within the Cretaceous and Miocene, are shown in Figure 7-13 and summarized in Table 7-10.

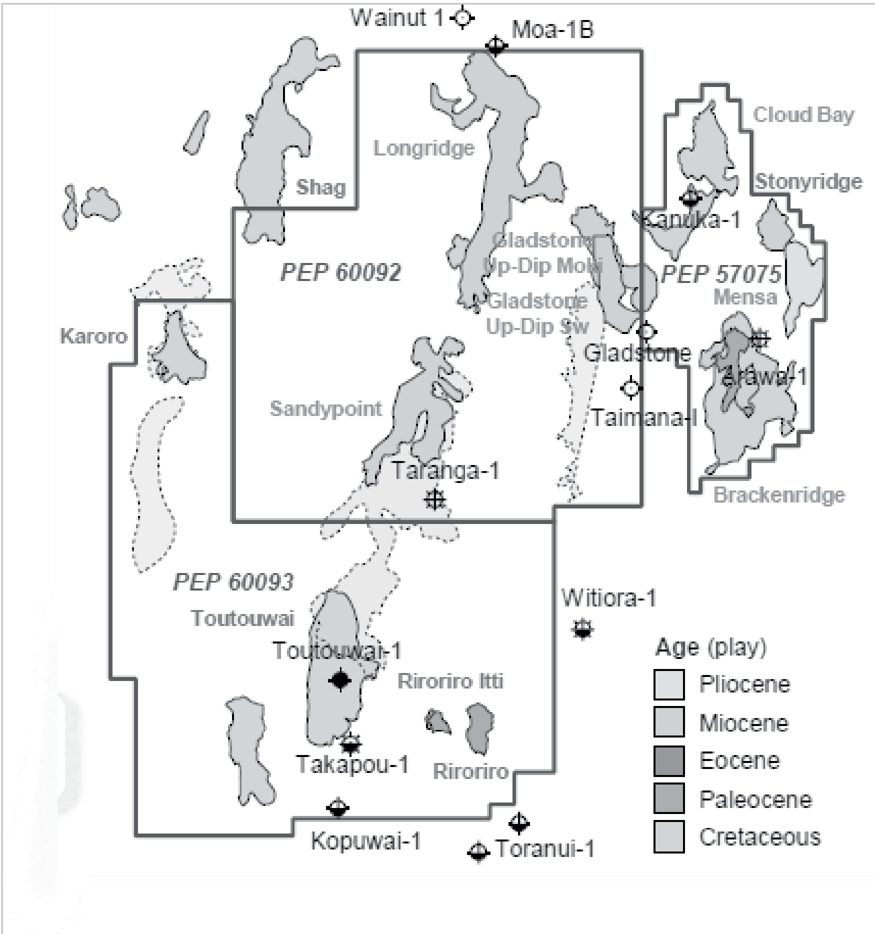


Figure 7-13: Location of SOMV exploration permits and Prospective Resources in New Zealand by age (play) (Source: SOMV).

Permit	Prospect	Predicted phase	Gross recoverable		Pg (%)
			P50	P_{mean}	
PEP60093	Karoro	Oil (MMstb)	37	47	49
	Riroriro	Oil (MMstb)	4	5	30
	Riroriro Iti	Oil (MMstb)	3	3	15 - 36
PEP60092	Longridge	Gas (Bscf)	120	206	9
	Sandy Point SW	Gas (Bscf)	48	111	5
	Gladstone Updip SW	Gas (Bscf)	106	132	4
	Gladstone Updip (Moki)	Gas (Bscf)	16	17	14
	Shag	Oil (MMstb)	133	171	27
	Pihipihi	Oil (MMstb)	6	7	32
PEP57075	Cloudy Bay	Gas (Bscf)	40	67	29
	Brackenridge	Gas (Bscf)	154	233	15
	Stonyridge	Oil (MMstb)	1	3	<15
	Mensa	Oil & Gas (MMboe)	3	4	8.5

Table 7-10: Summary of New Zealand Prospective Resources.

7.2.1 Brief Geology of South Taranaki Basin

The majority of the discovered hydrocarbons within New Zealand is found within the Taranaki Basin, which contains a thick sequence of Late Cretaceous-Recent sediments that overlie Paleozoic and early Mesozoic basement rocks. Economically important hydrocarbon discoveries have been made solely in Paleogene and Neogene. Prospectivity was difficult in the Late Cretaceous syn-rift sediment (Pakawau Group) which is directly linked and influenced by tectonic activity.

The tectonic history of the Southern Taranaki Basin is characterized by two distinct rift episodes within a single rift mechanic, separated by tectonic quiescence stages. Extension was initiated on NE-SW trending faults during Santonian time and sequentially dip-slip movement-controlled syn-rift depositions infill as the Pakawau Group. The group comprises the oldest sedimentary rocks known in Taranaki Basin, recognized in this evaluation as the entire sequence, bundled up from the (seismic) top of basement marker to the top K90 marker (or in short, the K90 group), as shown in the seismic cross-section highlighting the Toutouwai prospect in Figure 7-14. The syn-rift bundle (Pakawau/K90 to basement top group), which includes the Rakopi Formation, Lower North Cape Formation, Upper North Cape Formation, and Wainui Formation, consist of Cretaceous-Paleocene conglomerate, sandstone, and coal measure sequences. These rocks crop out in the northwest of the South Island, and were also encountered in offshore wells such as Cook-1, Fresne-1, North Tasman-1, Maui Field, Maui-4, Pukeko-1, Kopuwai-1, Takapou-1, Taranui-1, Cape Farewell-1, Wainui-1, Witiora-1, Taranga-1, Wainui-1, Moa-1B, Hoki-1, Tane-1, and the recent Toutouwai-1.

Some of these syn-rift deposits (K80 to top basement) contain thick coaly intervals within coastal to fluvial plain environments forming excellent source rocks for significant hydrocarbon fields and discoveries in the younger formations of the Cenozoic in South Taranaki, only until the recent geologically successful drilling of the Toutouwai-1 well in 2020.

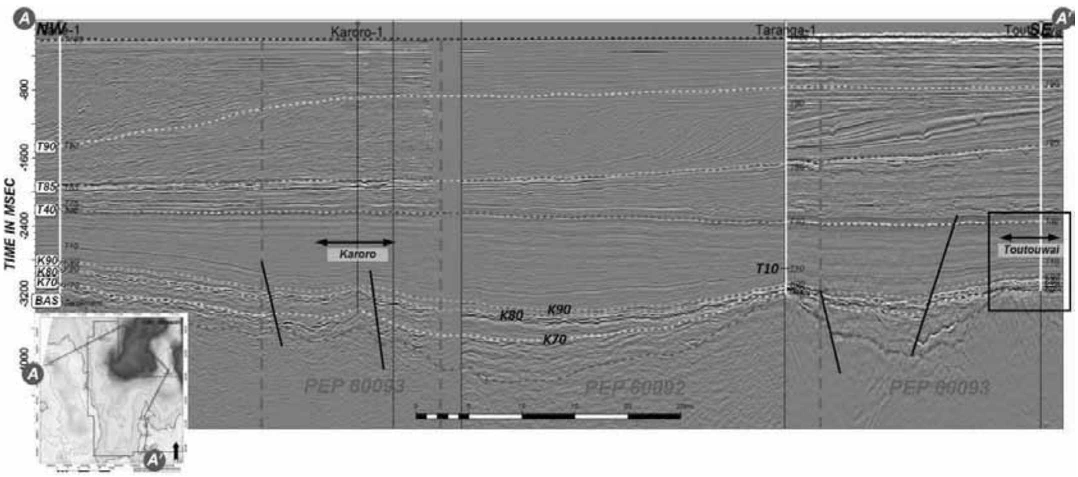


Figure 7-14: Seismic section highlighting Toutouwai prospect.

7.2.2 PEP60093

7.2.2.1 Toutouwai Discovery

Permit PEP60093 contains the Toutouwai discovery and three other prospects, namely Karoro, Riroriro and Riroriro Iti. Two seismic surveys are available, i.e., Kokako 3D in 2013 and multi-client Western Platform 3D (WPMC3D) in 2018. The Toutouwai discovery and Karoro prospect are discussed in more detail in the following sections. In 2021, it was reported that the acquisition of site survey data over Toutouwai appraisal and Karoro well locations was completed, to confirm jack-up rig suitability for drilling preparations. Drilling of the Toutouwai-2 appraisal well is planned in 2025, in combination with the exploration well for Karoro and Riroriro prospects, all of which would immediately de-risk the remaining opportunities within the block. In the other blocks, the prospect key risks are trap, reservoir and source with wider range in the P10 and P90.

The Toutouwai discovery is located approximately 50 km offshore in the Taranaki Basin, in PEP60093 (Figure 7-15). The Toutouwai-1 well is a play opening oil discovery within Cretaceous-Paleocene (near basement) reservoirs, aiding in the assessment of remaining prospectivity within PEP60093, especially in terms of derisking reservoir, seal and hydrocarbon charge uncertainties. Toutouwai-1 well that was drilled in March 2020 encountered elevated C_1 to C_5 readings and oil shows. The targeted formations were reached at depths of around 4,000 mMD (in the 12 1/4" hole section), where LWD data (GR, Resistivity, Neutron, Density and Sonic) was acquired (Figure 7-16).

The plan to complete wireline logging (which was initially discontinued after experiencing deteriorating hole conditions and borehole stability issues), and drill a short-offset side-track to acquire core data and perform Drill Stem Testing (DST) however was not achieved, as well operations were impacted by the Covid-19 pandemic, and the well was plugged and abandoned.

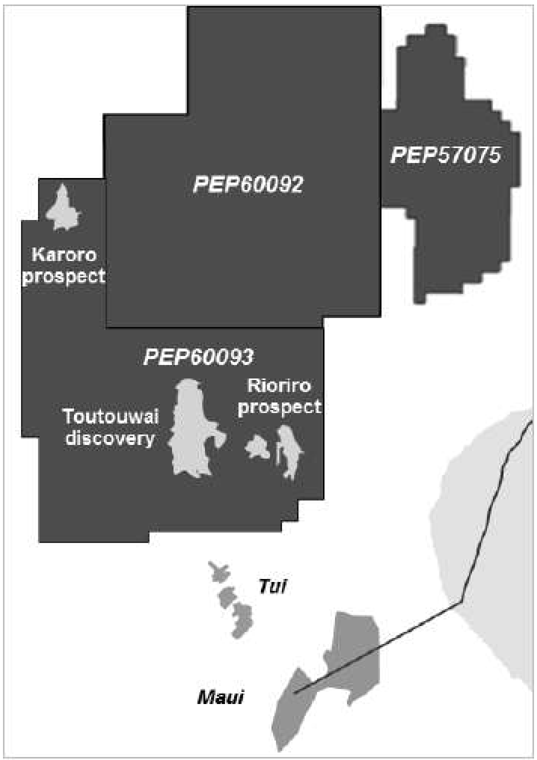


Figure 7-15: Location of Toutouwai discovery (Source: SOMV).

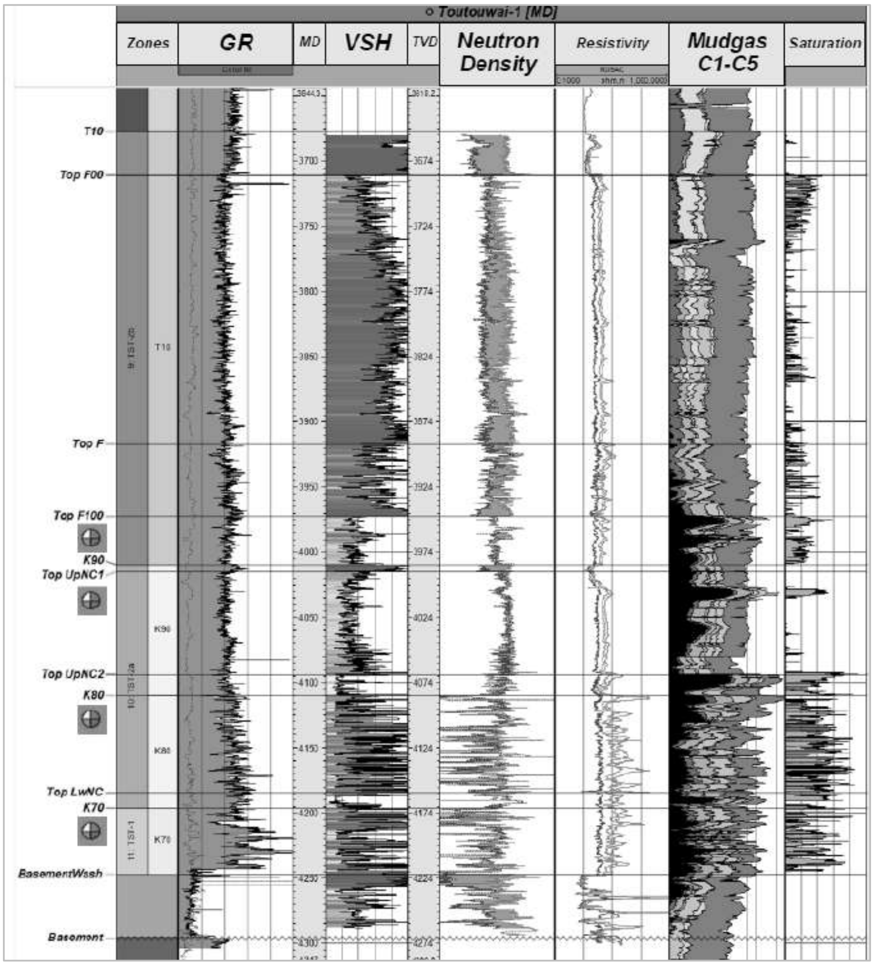


Figure 7-16: Toutouwai-1 well log and stratigraphic column (Source: TCM 2023).

The reservoirs comprise lower coastal plain sandstone intervals in K70 and K80, and shallow marine sandstone intervals in the upper zones (K90 and younger), with thinner sealing shale atop the reservoirs. Well data indicated reservoir presence and effectiveness at deeper targets of the Paleogene and older in the Taranaki Basin, as the well penetrated multiple shallow marine and lower coastal plain hydrocarbon bearing intervals. T10 and K90 to K70 intervals are depicted in Figure 7-17, which shows Toutouwai-1 hydrocarbon reservoir bearing zones of Cretaceous-Paleogene intervals from measured depth of 3,968 m to near basement (T10 – K70), with average porosity of 15% to 16%. The encouraging post-well analysis results highlighted the potential prospectivity of nearby areas (e.g., Karoro and other leads in PEP60092 and PEP57075 further northeast).

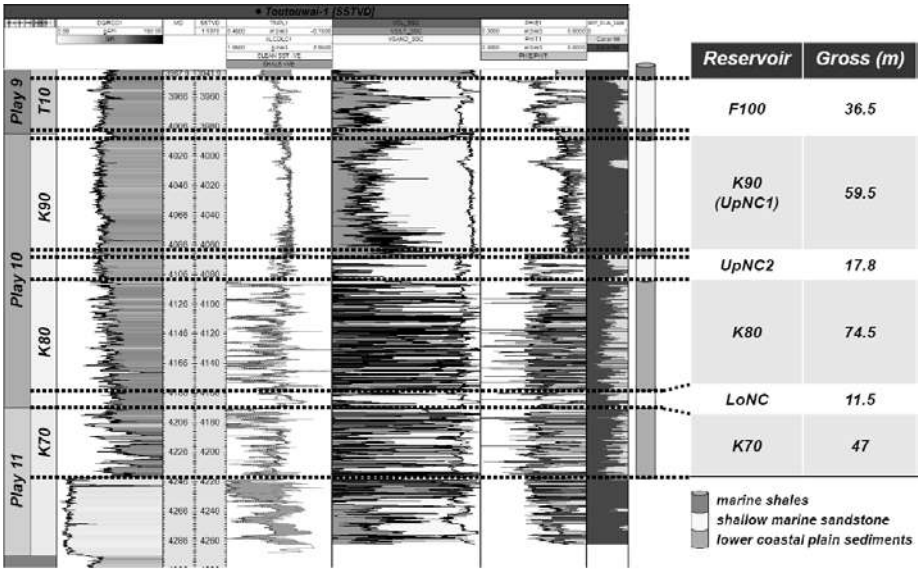


Figure 7-17: Toutouwai-1 HC reservoir bearing zones (Source: PAS/PAN Review October 2020).

Figure 7-18 shows the seismic-derived subsurface schematic section penetrated by the Toutouwai-1 well. Toutouwai prospectivity by its respective reservoir zones are shown in Figure 7-19 (F100), Figure 7-20 (K90 UpNC1), Figure 7-21 (K90 UpNC2), Figure 7-22 (K80), Figure 7-23 (K80 LoNC) and Figure 7-24 (K70), and summarized in Table 7-11.

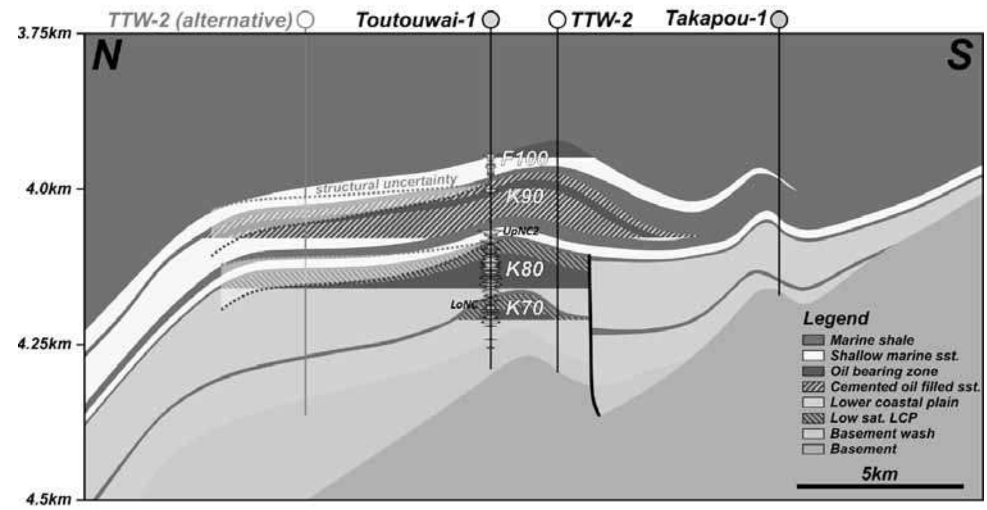


Figure 7-18: Seismic adapted schematic N-S structural cross-section of prospect drilled by Toutouwai-1 (Source: PAS/PAN Review October 2020).

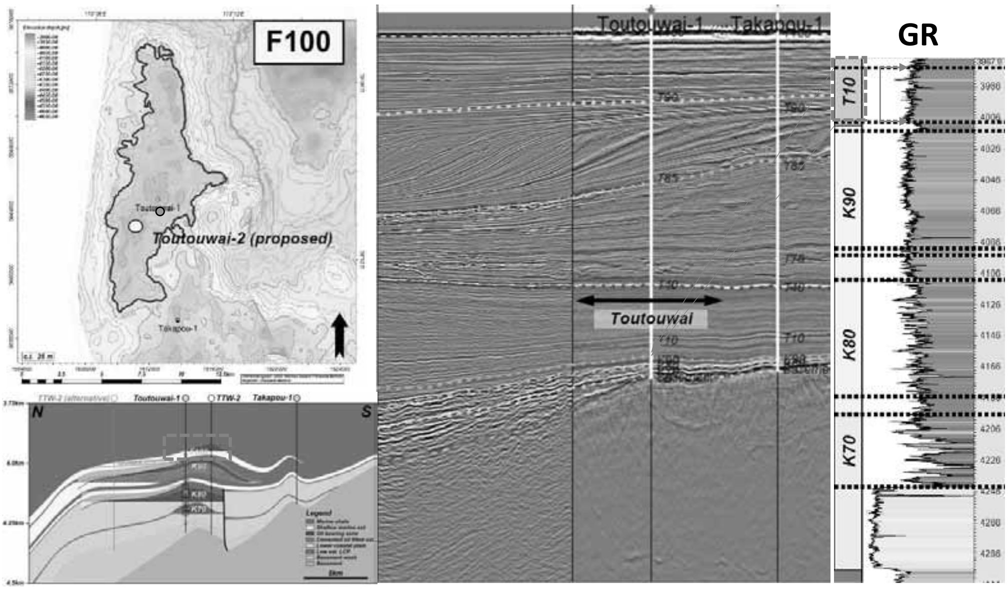


Figure 7-19: F100 reservoir at lower T10 seismic package.

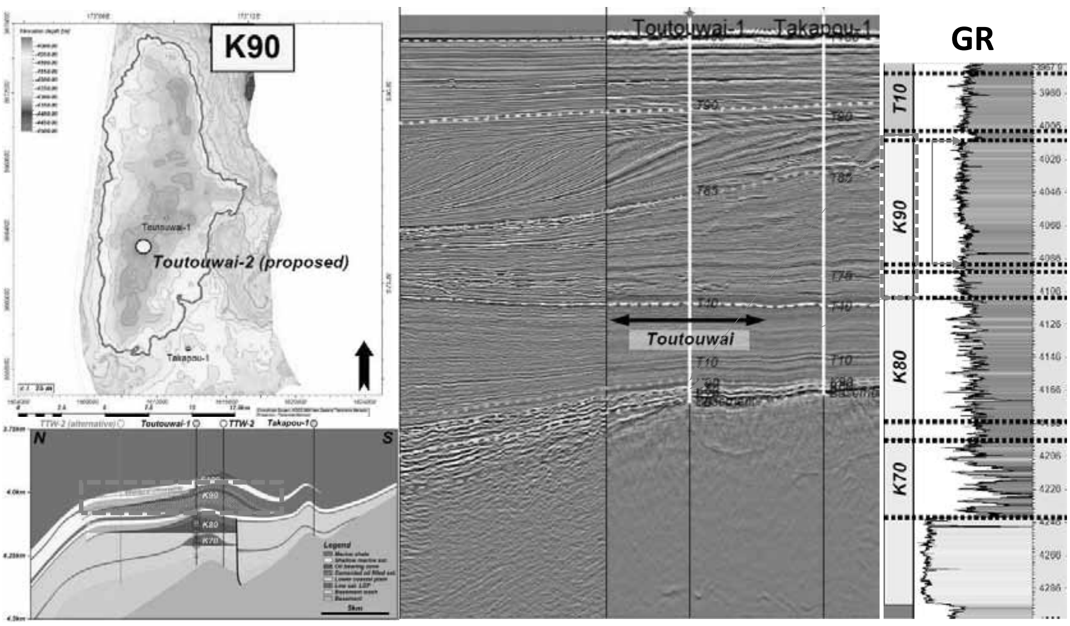


Figure 7-20: UpNC1 reservoir at main K90 seismic package.

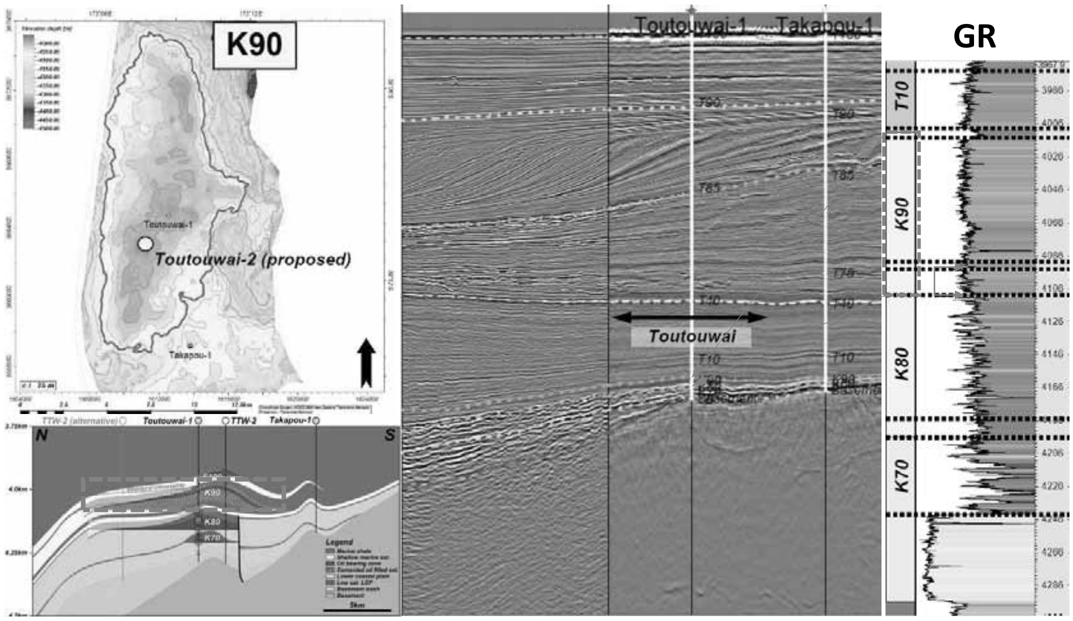


Figure 7-21: UpNC2 reservoir at near base K90 seismic package.

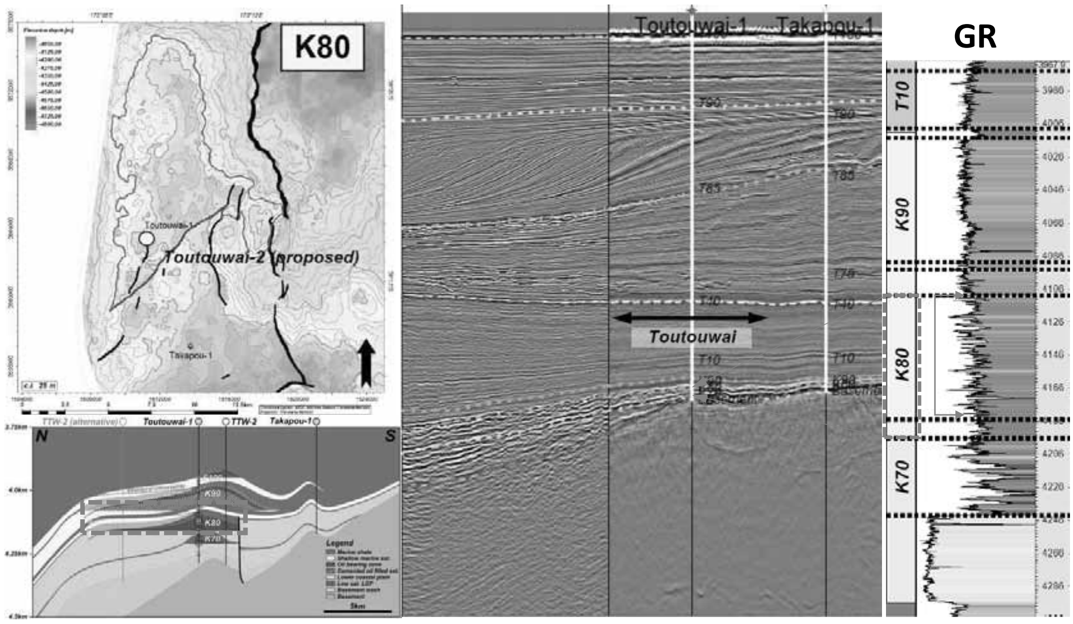


Figure 7-22: K80 reservoir seismic package.

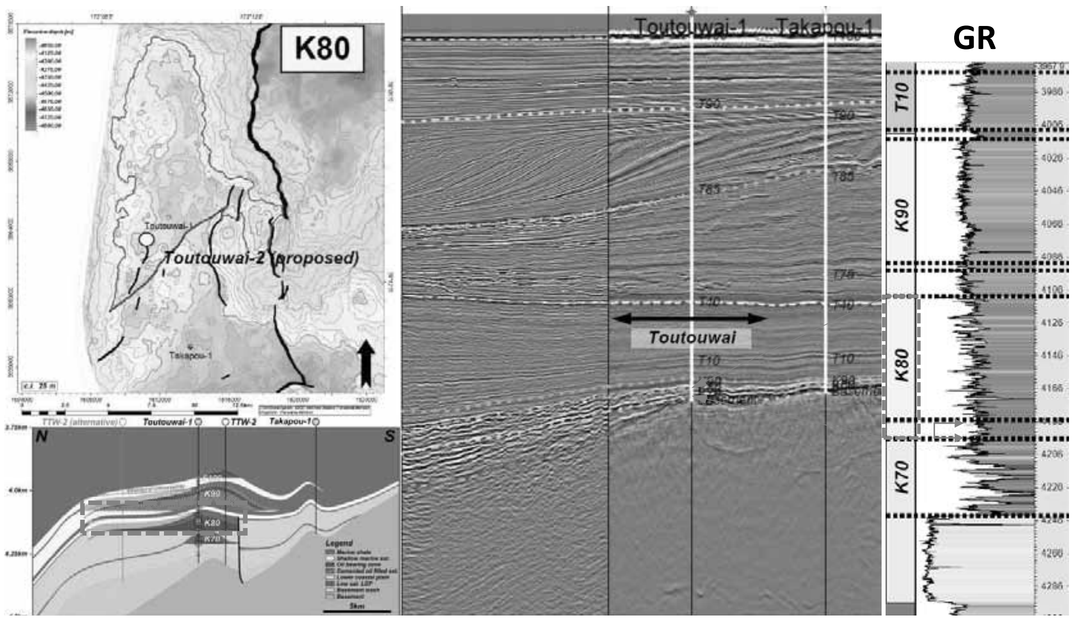


Figure 7-23: LoNC reservoir at near base K80 seismic package.

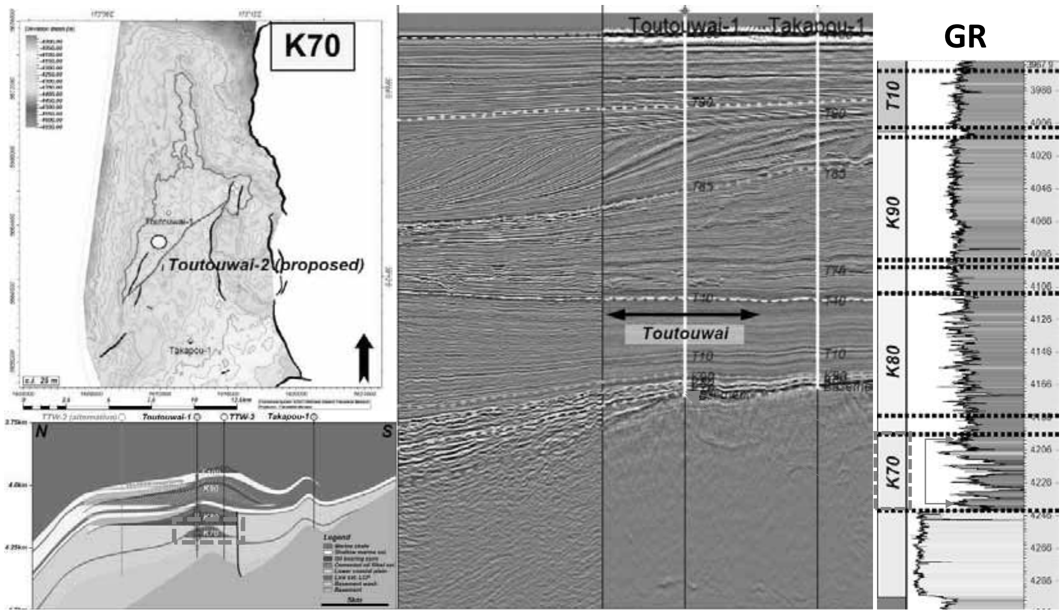


Figure 7-24: K70 reservoir seismic package.

Reservoir	F100	K90 UpNC1	K90 UpNC2	K80	K80 LoNC	K70
Area (km^2)	54	96	96	70	70	26
WD (m)	131	131	131	131	131	131
Reservoir Thickness (m)	36.5	59.5	17.8	74.5	11.5	47
N/G (%)	80	9	77	36	58	43
Average Porosity (%)	14	12	15	16	15	17
Soil (%)	24	38	39	47	45	56
Description	four-way dip closure of sandy shallow marine strata	four-way dip closure of sandy shallow marine strata	four-way dip closure of overall coarsening upwards sandy coastal plain strata	three-way dip closure of overall coarsening upwards sand-shale of lower coastal plain strata	three-way dip closure of overall coarsening upwards sand of lower coastal plain strata	three-way dip closure of stacking of overall coarsening upwards sand-shale para-sequences of lower coastal plain strata

Table 7-11: Toutouwai discovery - summary by zone.

Independent evaluation methodologies for petroleum geochemistry analyses on Toutouwai-1 i.e., mud gas interpretation, petrophysical analysis, petroleum system modelling and gas chromatography analysis, suggest the presence of oil phase accumulation within the prospect. Furthermore, the analogue offset fields nearby i.e., the Tui and Amokura fields, are undersaturated oil fields, with low viscosity, high quality oil.

The petrophysical assessment that was conducted was limited to the acquired LWD well log data (with acceptable quality), which shows that several sandstone reservoirs with hydrocarbon indications were encountered. Based on the log analysis estimate of between 10 m and 83 m of net pay, the estimated recoverable resource (Table 7-12) was found to be within the range of Minimum Economic Field Size (MEFS), with STOIIP of 324 MMbbl (P50) and recoverable resource of 50 MMbbl (P50). For Toutouwai discovery the inputs parameters and in-place volume are acceptable and within the range of EQ estimation. EQ considers the volumes reported to be preliminary, due to the limitations on data availability, and as further appraisal is required. The P90, P50 and P10 size distribution is positive log normal as expected since additional field data is needed to address the uncertainties.

Recovery Factor estimates are noted as an uncertainty for the field (the calculated RFs for the individual reservoirs at Toutouwai ranging from around 9% to 21% are reasonable for depletion drive reservoirs, based on Arps API correlations on the statistical performance for reservoir drive mechanisms, that indicate the RF for sandstone oil reservoirs of ranging from around 8.4% to 35.6% for API between 30-50 deg and GOR around 600 scf/bbl).

Layer	Resource	P90	P50	P_{mean}	P10
F100	In-place, Oil, MMstb	11.4	20.3	22.0	34.9
	Recoverable, MMstb	1.07	2.3	2.7	4.8
K90 (UpNC)	In-place, Oil, MMstb	58.4	149.2	177.2	332.4
	Recoverable, MMstb	4.9	17.0	23.5	50.5
K80	In-place, Oil, MMstb	25.7	111.1	124.7	241.9
	Recoverable, MMstb	4.4	19.7	24.4	50.8
K70	In-place, Oil, MMstb	9.2	30.3	33.9	63.9
	Recoverable, MMstb	1.6	5.4	6.6	13.3
Total	**In-place, Oil, MMstb**	**150.4**	**323.9**	**356.5**	**598.3**
	Recoverable, MMstb	**20.0**	**50.1**	**57.2**	**102.6**

Table 7-12: Toutouwai Discovery In-place and Recoverables Resources by Stochastic Method (Source: PAS/PAN Review October 2020, TCM 2023).

Toutouwai-1 is classified as a potentially commercial oil discovery that requires further appraisal. Retention of the area surrounding Toutouwai discovery would enable further exploration and appraisal of the structure. The drilling of Toutouwai-2 approximately 1.4 km southwest of Toutouwai-1 is planned, to appraise hydrocarbon bearing formations encountered in Toutouwai-1, by targeting the southern crest of the Toutouwai structure. The Pg, GCOS (Geological Chance of Success) for Toutouwai-2 is estimated to be at 95% (per the Design Rationale Document, January 2021). The planned data acquisition program for Toutouwai-2 appraisal well include wireline logging, collecting rock and fluid samples, and conducting DSTs to determine reservoir deliverability and productivity over the Paleocene and Late Cretaceous section, that could not be acquired in the Toutouwai-1 discovery well.

Figure 7-25 shows the nearby fields and facilities surrounding Toutouwai. The current development concept for Toutouwai comprises drilling 10 development wells and producing via a WHP and FPSO (Figure 7-26), and the notional first oil is in 2030. The notional well count consists of eight oil producers, one gas injector and one water disposal well. Figure 7-27 depicts the notional reservoir development concept which comprises drilling horizontal wells in the upper reservoirs (F100 and K90), and vertical wells for the K80 and K70 reservoirs. It is expected that artificial lift i.e., gas lift or ESPs will also be required, along with the application of smart completions for multi-reservoir wells. Segmented selective completions in the K80/K70 producers will likely be necessary in an attempt to control water production from the different layers. Multilaterals could also be considered for the upper reservoir development with horizontal wells; however, these may come with significant production disadvantages, e.g., absence of pressure integrity at the junction, and the inability to control water production.

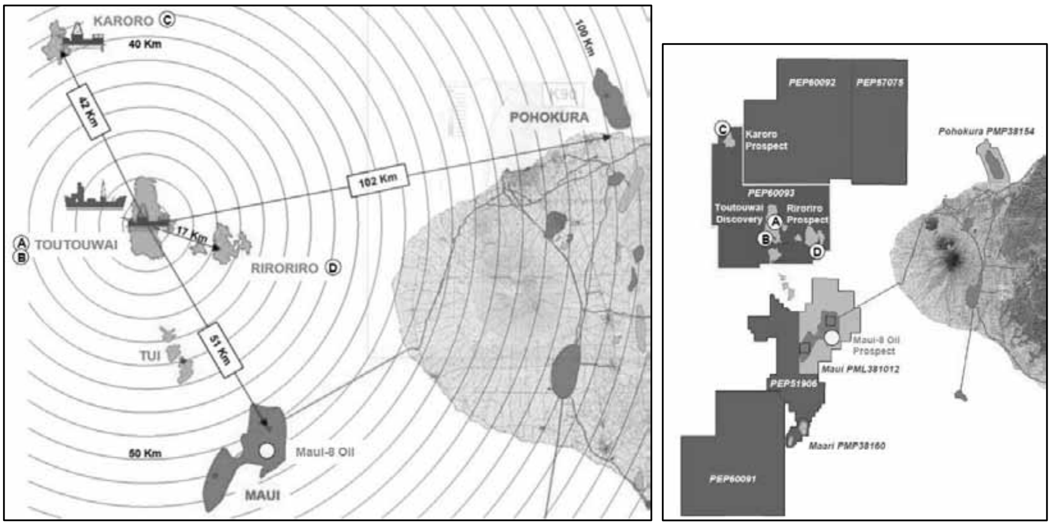


Figure 7-25: Toutouwai nearby fields and facilities (Source: PAS/PAN Review October 2020).

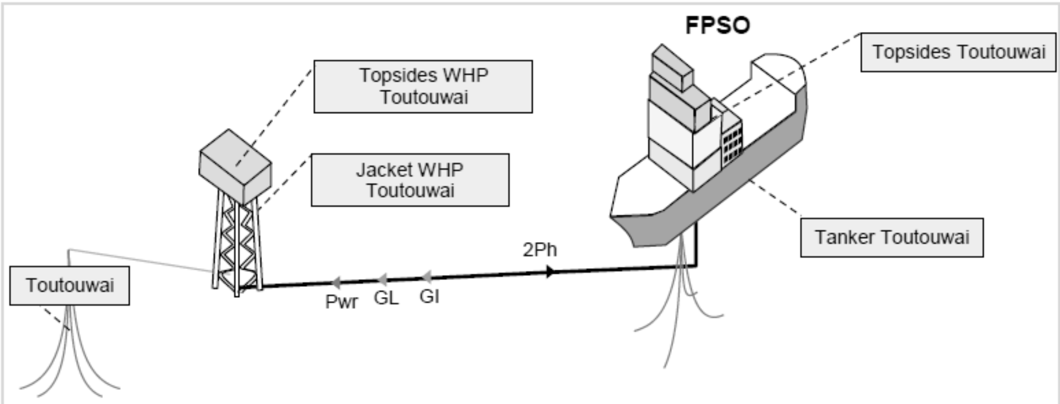


Figure 7-26: Toutouwai development concept (Source: SOMV).

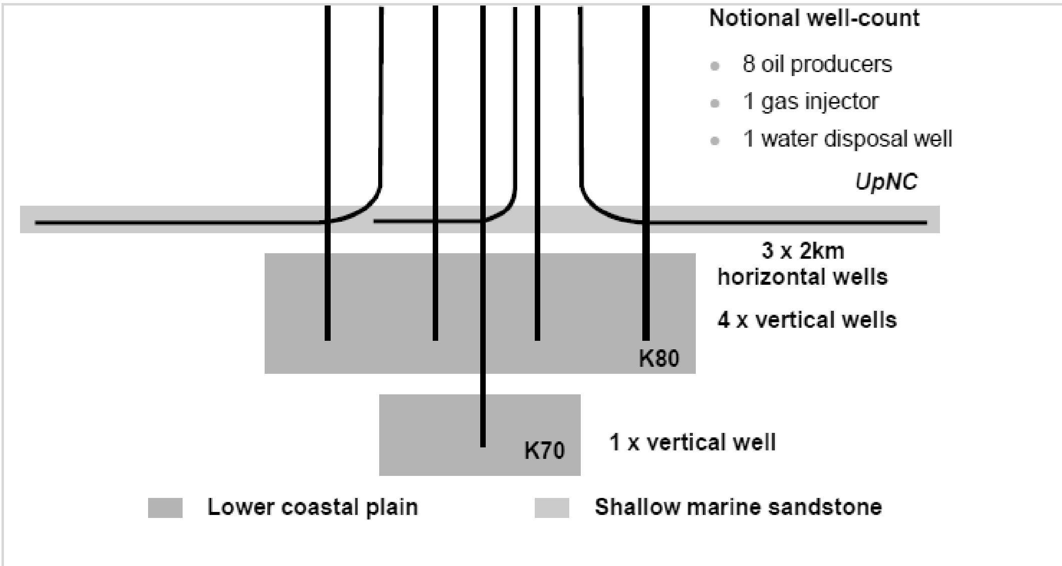


Figure 7-27: Toutouwai notional reservoir development (Source: SOMV).

Key uncertainties for the field include tank volume, rock and fluid properties, aquifer strength, reservoir deliverability and well productivity, and recovery factor estimates. Sedimentological aspects of the reservoir intervals and the extent of reservoir continuity away from Toutouwai-1 are also a geological uncertainty.

Based on the information available, Toutouwai-1 well did not flow any hydrocarbons to surface, and whether the Toutouwai discovery is able to meet the economic thresholds for future development is subject to the results from the appraisal program. As such, EQ has placed the classification of resources for Toutouwai discovery as Contingent Resources with a lower Sub-class category, where the development is either "On Hold" or "Unclarified", due to its current technical uncertainty.

7.2.2.2 Karoro Prospect

Retention of the Karoro structure would enable future exploration within tie-back distance of Toutouwai. Figure 7-28 shows the K90 top structure map for Karoro, and Figure 7-29 shows the geology and structural overview of the prospect, relative to Toutouwai-1. A 3D seismic survey that was acquired in 2013 covers an area of 308 km^2 over Karoro prospect. The seismic cross-section and depth structure map highlighting the K90 and K80 reservoirs in Karoro prospect is shown in Figure 7-30.

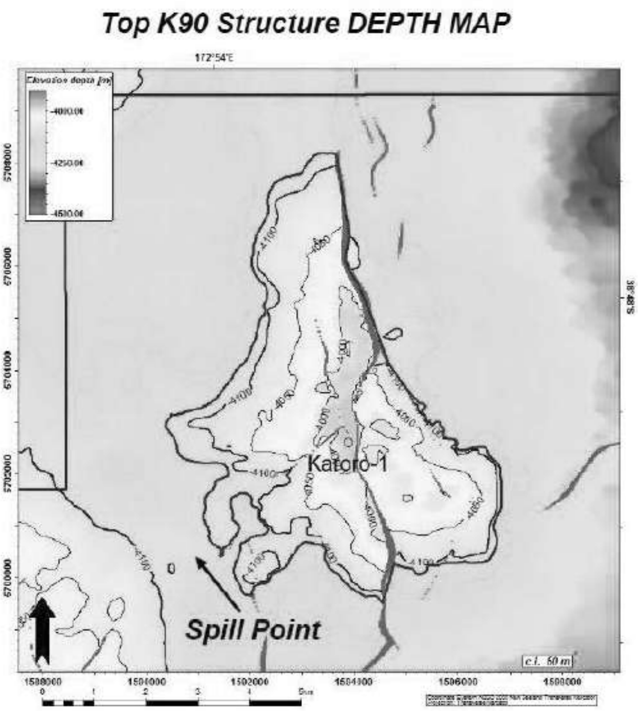


Figure 7-28: Karoro Top K90 structure map (Source: TCM 2020).

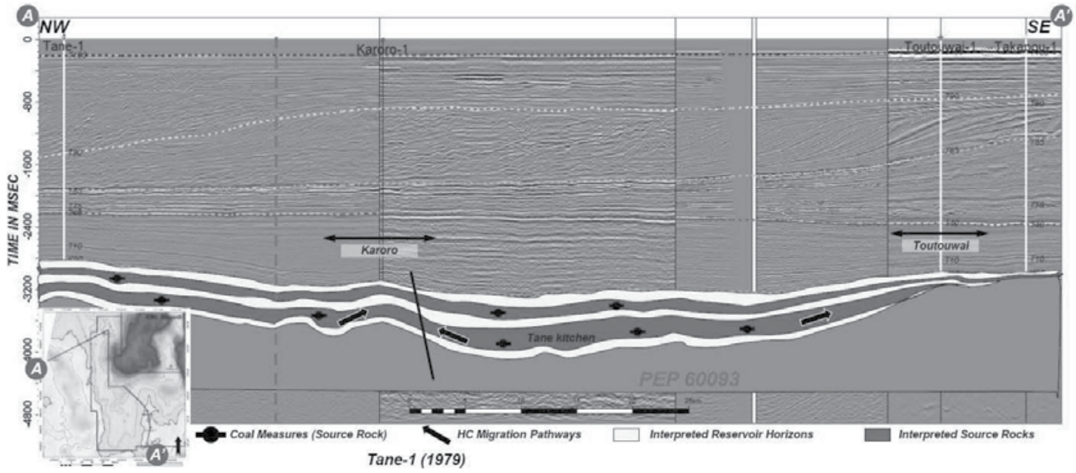


Figure 7-29: Geology and structural overview of Karoro (Source: TCM 2020).

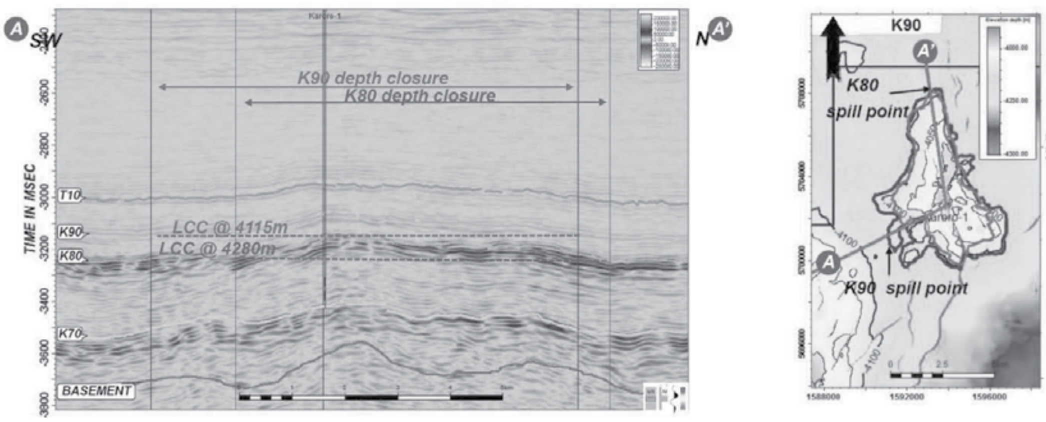


Figure 7-30: Seismic cross-section and depth structure map of Karoro prospect (Source: TCM 2021).

The source, migration and reservoir presence of Karoro has been de-risked by the success of Toutouwai-1, and is now considered a ready-to-drill prospect with Pg (i.e., Prospect Geological Chance of Success) of 49%. An exploration well is planned in 2025 i.e., in the same drilling campaign as Toutouwai appraisal well, to acquire core and fluid samples to delineate reservoir properties and characteristics. The reprocessing of Karoro 3D seismic is also planned, post drilling of Karoro-1. The current estimated volumes (P50) are 178 MMstb STOIIP, with 37 MMstb recoverable oil (Table 7-13).

Layer	Resource	P90	P50	Pmean	P10
K90 (UpNC)	In-place, Oil, MMstb	63.2	166.8	186.1	335.4
	Recoverable, Oil, MMstb	10.4	36.5	45.9	92.7
	In-place, Associated Gas, Bscf	57.2	173.9	205.7	395.3
	Recoverable, Associated Gas, Bscf	14.0	45.4	55.7	109.7
K80	In-place, Oil, MMstb	4.96	52.1	72.6	173.6
	Recoverable, Oil, MMstb	0.876	9.07	14.3	35.1
	In-place, Associated Gas, Bscf	5.1	51.9	79.8	198.6
	Recoverable, Associated Gas, Bscf	1.12	11.6	18.3	45.5
Total	**In-place, Oil, MMstb**	**42.0**	**178.3**	**201.1**	**384.9**
	Recoverable, Oil, MMstb	**6.99**	**37.3**	**47.2**	**99.7**
	In-place, Associated Gas, Bscf	**39.7**	**182.8**	**220.1**	**448.7**
	Recoverable, Associated Gas, Bscf	**9.34**	**45.6**	**57.3**	**120.1**

Table 7-13: Karoro prospect In-Place and Recoverable resource estimate (Source: TCM 2020, TCM 2021).

The development concept for Karoro comprises drilling five development wells, produced via tie-back to Toutouwai FPSO with a 42 km connection (Figure 7-31).

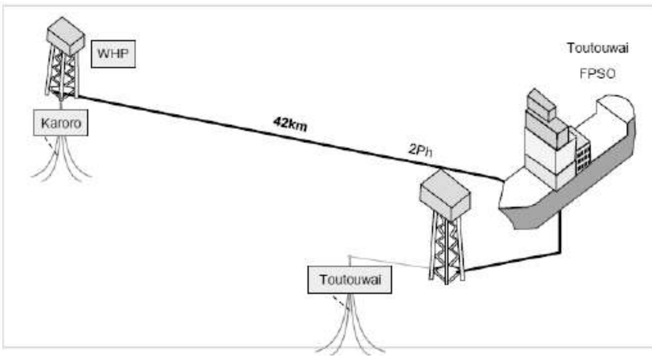


Figure 7-31: Karoro development concept (Source: SOMV).

Key uncertainties for the field include fluid contacts, aquifer strength, reservoir thickness and porosity, hydrocarbon saturation, gas oil ratio, as well as recovery factor estimates. Based on the information available, EQ has placed the classification of resources for Karoro in the Prospective category.

7.2.2.3 PEP60093 Additional Leads/Prospects

The retained area within PEP60093 would also include additional leads that have been identified i.e., the Paleocene prospectivity identified in the Riroriro and Riroriro Iti prospects, the Crestaceous prospectivity identified in the Titipounamu (formerly named Karuhiruhi) to the west of Toutouwai, and the Pliocene/Miocene channel prospectivity extending from eastern PEP60093 into Sandy Point Lead in PEP60092 to the north (Figure 7-13 and Figure 3-3). Information on these leads and prospects is however, limited. The recoverable resource estimates for Riroriro and Riroriro Iti are shown in Table 7-14. Based on the information available, EQ has placed the classification of these resources in the Prospective category. For the purpose of this CPR, EQ did not evaluate the volumes directly but observed that the prospect range for recoverables is associated with in-place volumes that reflect positive log normal distribution and the key risks associated with the prospects will be de-risked by drilling of Toutouwai-2 planned in 2025.

Prospect	Layer/ Resource	P90	P50	Pmean	P10	Pg (%)
Riroriro	F00 Recoverable, Oil, MMstb	0.88	3.68	5.15	11.4	30.3
Riroriro Iti	F00 Recoverable, Oil, MMstb	1.03	2.23	2.59	4.67	36
	K90 Recoverable, Oil, MMstb	0.08	0.30	0.45	1.0	15.2
	Total Recoverable, Oil, MMstb	**1.11**	**2.53**	**3.04**	**5.67**	

Table 7-14: Riroriro and Riroriro Iti recoverable resource estimate (Source: TCM 2020).

7.2.3 PEP60092

Permit PEP60092 contains two Cretaceous oil leads at Shag and Pihipihi (Figure 7-32), and four Miocene gas prospects at Longridge, Sandy Point SW, Gladstone Updip SW and Gladstone Updip Moki (Figure 7-33). Information on these leads and prospects are limited, and uncertainties that have been identified include trap, reservoir and seal. The estimated recoverable volumes and Pg for each prospect are shown in Table 7-15.

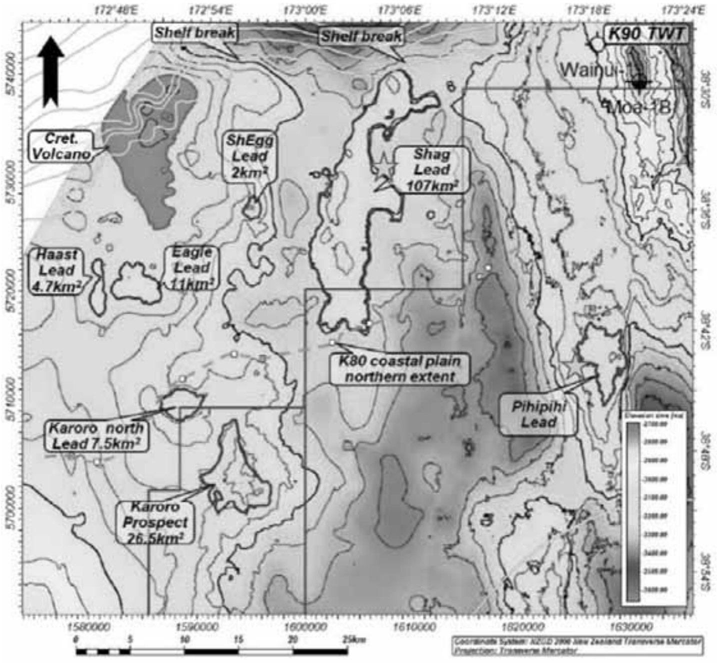


Figure 7-32: PEP60092 oil leads (Source: TCM 2023).

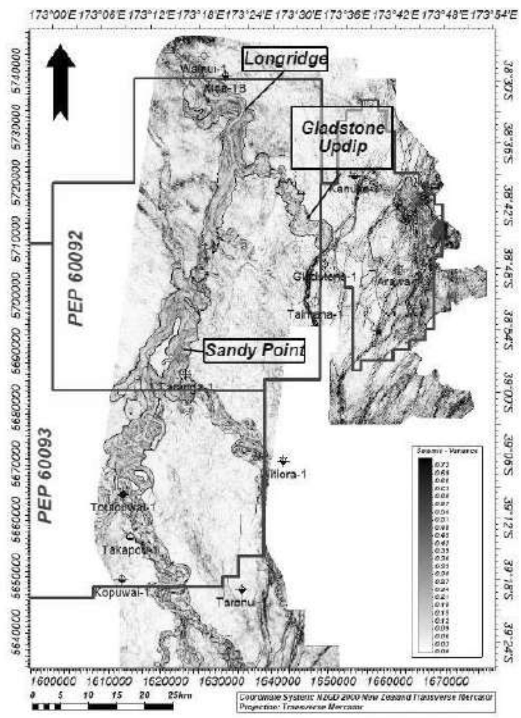


Figure 7-33: PEP60092 gas prospects (Source: TCM 2023).

Prospect/Lead	Phase	P90	P50	Mean	P10	Pg (%)
Longridge	Gas (Bscf)	9	120	206	529	9
Sandy Point SW	Gas (Bscf)	12	48	111	287	5
Gladstone Updip SW	Gas (Bscf)	13	106	132	285	4
Gladstone Updip (Moki)	Gas (Bscf)	5	16	17	32	14
Shag	Oil (MMbbl)	31	133	171	357	27
Pihipihi	Oil (MMbbl)	2	6	7	12	32

Table 7-15: Estimated Prospective Recoverable Volumes (Source: TCM 2023).

Based on the information available, EQ has placed the classification of resources for the PEP60092 prospects and leads in the Prospective category. For the purpose of this CPR, EQ did not evaluate the volumes directly but observed that the prospect range for recoverables are associated with in-place volumes that reflect positive log normal distribution and the key risks associated with the undrilled fault blocks are trap, reservoir and source with wider range in the P10 and P90.

7.2.4 PEP57075

Gladstone-1 well in PEP57075 was drilled in December 2019, targeting the Mid-Miocene deep marine turbidites (Moki Formation). The well was classified as a dry well with hydrocarbon shows (no indications of moveable hydrocarbon based on LWD, cuttings and gas chromatograph response). The main failure for the prospect was the lack of sufficient seal, with all other geological elements present. The results provided a valuable control point for assessing the remaining prospectivity within the Taranaki permits.

Permit PEP57075 contains two potential gas prospects at Cloudy Bay and Brackenridge, one oil prospect at Stonyridge, and one multiphase prospect at Mensa (Figure 7-34). Information on these leads and prospects are limited, and uncertainties that have been identified include trap, reservoir and seal. The estimated recoverable volumes and Pg for each prospect are shown in Table 7-16. It is expected that additional drilling in PEP60093 will further de-risk these prospects.

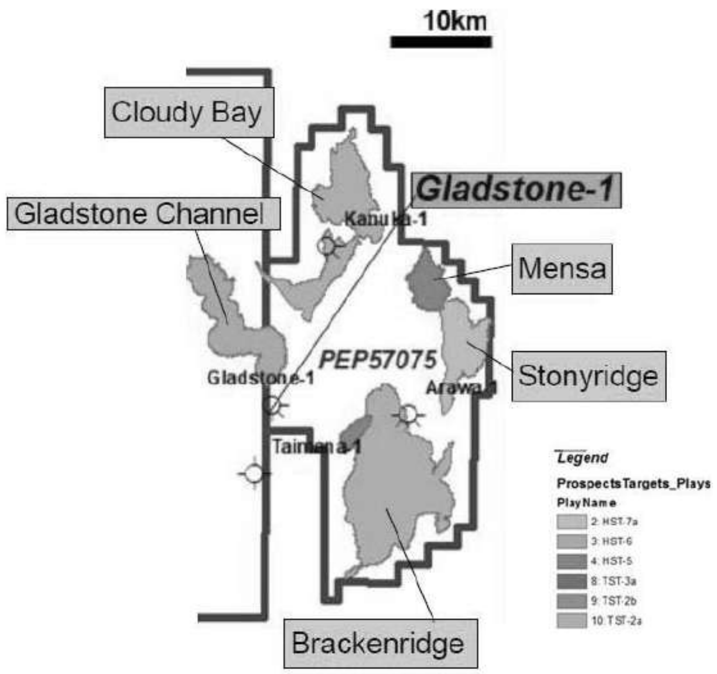


Figure 7-34: PEP57075 prospects (Source: TCM 2023).

Prospect/Lead	Phase	P90	P50	Mean	P10	Pg (%)
Cloudy Bay (K90)	Gas (Bscf)	5	40	67	168	29
Brackenridge (K90)	Gas (Bscf)	26	154	233	553	15
Stonyridge (T70)	Oil (MMbbl)	0.5	1	3	8	<15
Mensa (T85)	Oil & Gas (MMboe)	0.4	2.6	3.8	8.9	8.5

Table 7-16: Estimated Prospective Recoverable Volumes (Source: TCM 2023, Joint Venture Workshop July 2020).

Based on the information available, EQ has placed the classification of resources for the PEP57075 prospects and leads in the Prospective category. For the purpose of this CPR, EQ did not evaluate the volumes directly but observed that the prospect range for recoverables is associated with in-place volumes that reflect positive log normal distribution and the key risks associated with the undrilled fault blocks are trap, reservoir and source with wider range in the P10 and P90.

7.3 Resources Beyond the 2P and 2C Categories - Mexico Assets

7.3.1 Brief Geology of Sureste Basin

Sureste Basin lies the Bay of Campeche that is located about 25 km north of the coastline of Tabasco and Veracruz states. It contains some of the biggest fields discovered in Mexico (i.e., Zama by Talos, Amoca by ENI and Hokchi by Pan American), encompassing onshore and offshore petroleum provinces that are geologically subdivided into four distinct sub-basins, based on the regional geological tectonic events, as follows:

(i) Salina sub-basin - extensional and salt tectonic domain (Figure 7-35).
(i) Comalcalco sub-basin - extensional and salt tectonic domain.
(ii) Reforma-Akal sub-basin - contractional system.
(iii) Macuspana sub-basin – extensional system.

Apart from the Macuspana sub-basin which is gas prone, the other sub-basins are oil prone sub-basins.

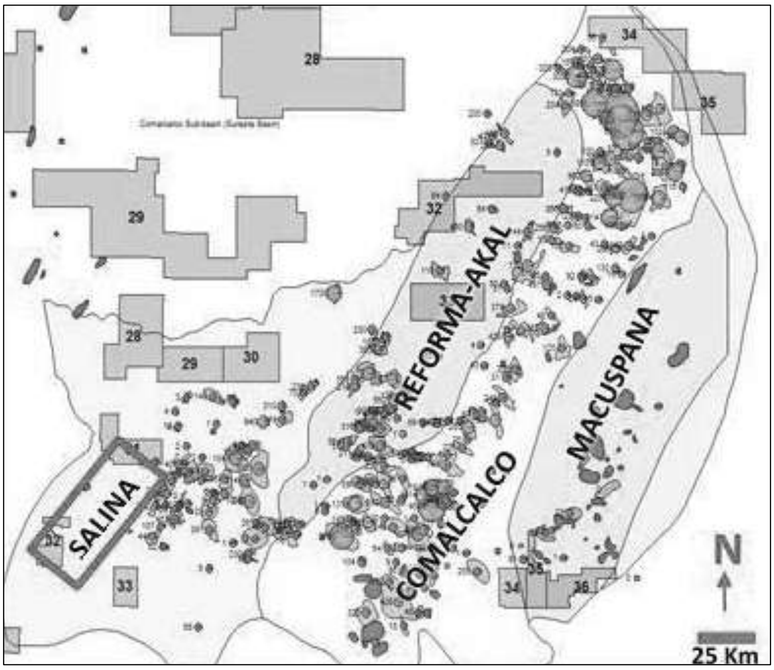


Figure 7-35: Sureste Sub-basins, Block 30 in Salina Sub-Basin (Source: Sapura).

Block 30 is located in the shallow water depth in the Salina sub-basin (Salina del Istmo) within Sureste basin. Exploration activities within the block are related to Pliocene post-gradational systems in the mature thermal Tithonian source rock that is rich with oil. The extensional tectonic setting provides trap opportunity and reservoir potential that has been shown by the nearby discoveries. Seismic and well data within the block indicate Middle to Late Pliocene Orca formation, which is a classic post-gradational sequence with reservoir potential. The formation has interbedded sandstone and shale, deposited in local mini basins that were formed by extensional faulting.

7.3.1.1 Stratigraphy

The Salina sub-basin a Jurassic-Pliocene basin made up of older Jurassic-Cretaceous carbonates and Paleogene-Neogene clastic, punctured by Collovian salt dykes and sills up to Pliocene at the near surface. Figure 7-36 illustrates the stratigraphy of Sureste Basin, Mid-Jurassic to Pliocene. Mesozoic is made up of carbonates formation, while Paleogene-Neogene is clastic formation.

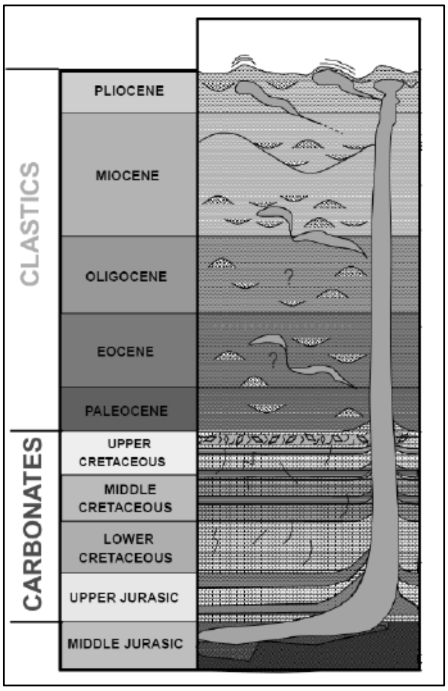


Figure 7-36: Stratigraphy of Sureste Basin, Mid Jurassic to Pliocene (Source: Sapura).

7.3.1.2 Tectonic

Gravitational tectonics resulted in large sediment input into the basin, and locally filled the Pescadores trough Figure 7-37. The mobilisation of salt volumes through extension-contraction formed a depocenter of Pliocene sediment.

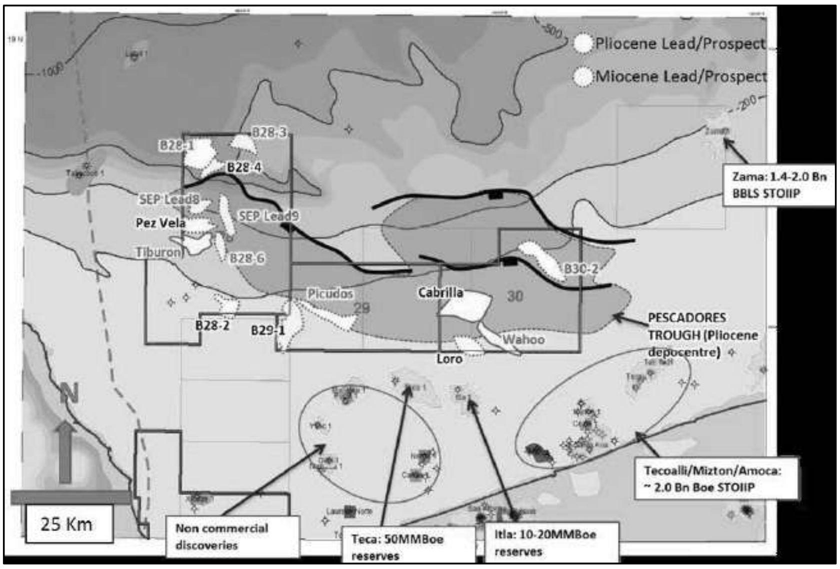


Figure 7-37: Block 30 location North and West of existing oil fields (Source: Sapura).

7.3.1.3 Reservoir

The reservoirs in the area are made up of Miocene/Pliocene clastic reservoirs of basin floor and turbiditic sheet sandstones interpreted to be the likely reservoirs in Block 30 as encountered by wells drilled in the adjacent area; however, a more complex setting and interpretation inclusive of shallower environments also need to be considered. Figure 7-38 illustrates that Block 30 is located in the depocenter of Pliocene sediments. This predominantly turbiditic reservoir was encountered by Kan-1 well (Figure 7-39), along with additional discoveries in the Mesozoic Upper Jurassic Kimmeridgian and Middle Cretaceous.

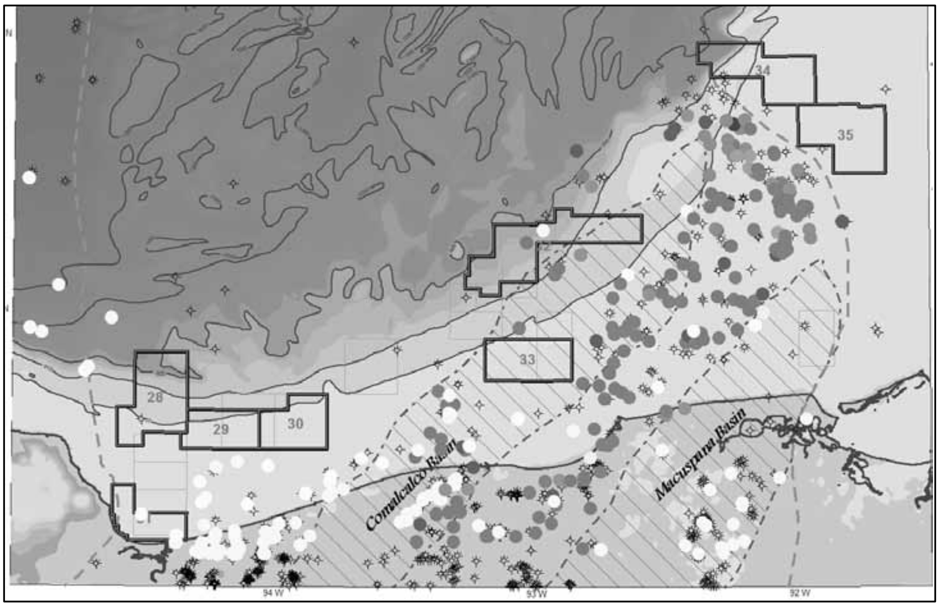


Figure 7-38: Block 30 location in depocenter of Pliocene sediments (Source: Sapura).

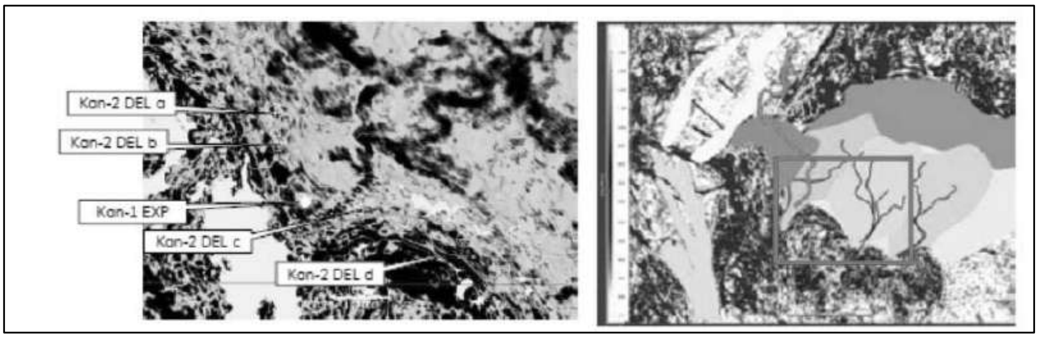


Figure 7-39: Turbiditic Reservoir Based On The Current Observations of Kan-1 Well (Source: TCM 2023).

7.3.1.4 Source

The basin is sourced by matured Tithonian Sureste rich source rocks. This Mesozoic basin source rock is widely distributed, with thickness ranging between 100 m to 400 m. The source rock is rich in Total Organic Content (TOC), which was prognosed to be around 4% of Type II. Source rock samples from Kan-1 well indicated lower TOC, averaging around 0.57 %. At the well location, the calculated vitrinite reflectance (VR) value is in the onset of maturation, i.e., approximately 0.6 % VR at a depth of 3,000 m.

Commercial and non-commercial oil discoveries were made around the Block 30 area. The discovered reserves range from 10 MMboe to 50 MMboe as seen at Itla-Teca field, with the billion-barrel Tecoalli field located 10 km to the southeast (Figure 7-37). Recent discoveries around Block 30 are shown in Figure 7-40, which include the following:

- Hok-1, Octli-1 and Suuk-1 (2018)
- Mulach-1, Cibix-1 and Saasken-1 (2019)
- Chinwol-1, Tlamatini-1, Itta-1 and Tema-1 (2020)
- Sayulita-1, Camatl-1, Xolotl-1, Paki-1 and Niquita-1 (2021)

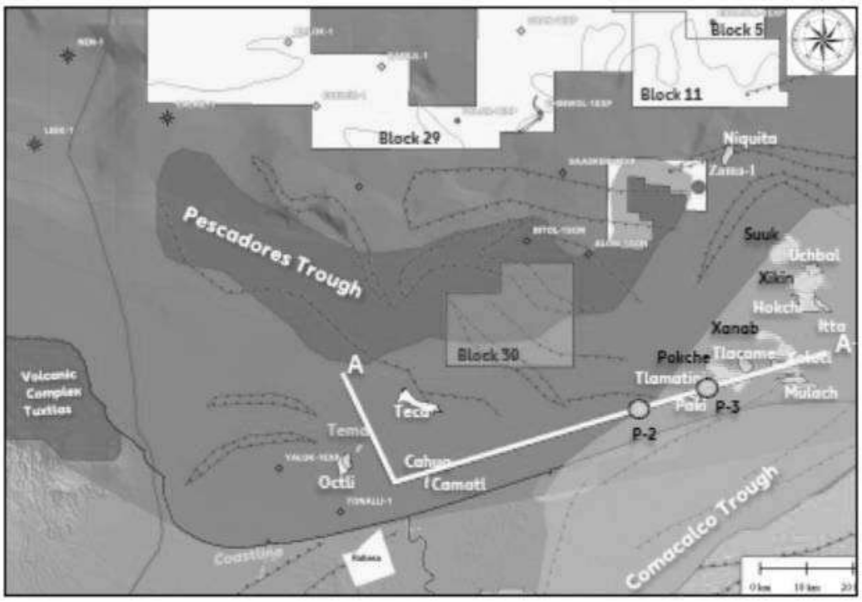


Figure 7-40: Recent Discoveries around Block 30 (TCM 2023).

7.3.2 Block 30

Three selected prospects (Figure 7-41 and Figure 7-42) identified in Block 30 evaluation post 3D data acquisition i.e., Kan (formerly Wahoo), Ix (formerly Pike) and Cabrilla are briefly discussed in the sections below. Exploration wells Kan-1 drilled in April 2023 discovered oil, and Ix-1 drilled in May 2023 was plugged and abandoned prior to reaching the intended reservoir targets due to low formation strength and overpressure experienced during drilling.

Figure 7-41: Location of Wahoo (now Kan), Pike (now Ix) and Cabrilla Prospects (Source: 2019 Exploration Plan).

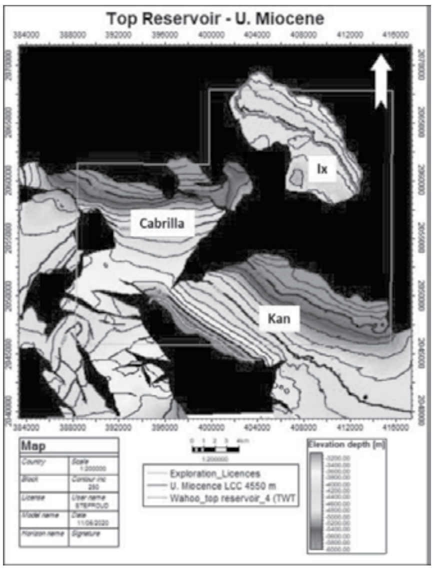


Figure 7-42: Kan, Ix and Cabrilla Prospects in Block 30 (TCM 2023).

A list of potential exploration leads and prospects for Block 30 was developed based on Kan-1 and Ix-1 post-drill results. Table 7-17 summarizes the prospects and leads identified in Block 30, along with the status of each exploration potential as of August 2023. However, EQ considers the volumes reported to be very much preliminary, as limited information was available for these identified leads and prospects.

Prospect / Lead	Top Target Depth (TVDss)	Estimated Recoverable (MMstb)			Maturation Status	Way Forward
		P90	Pmean	P10		
Kan (Upper Miocene)	2,500	8	113	292	High	Update ongoing
Ix (MioPliocene)	2,940	9	91	200	Low	Further maturation
Ix (Mid Miocene)	4,420	5	95	234	Low	Further maturation
Ix (Lower Miocene)	4,820	5	57	139	Low	Further maturation
Kan (Lower Miocene)	3,000	2	23	55	Low	Further maturation
Cabrilla Stacked 1 (Pliocene)	2,900	2	3	4	Low	No further maturation
Cabrilla Stacked 3 (Pliocene)	3,440	5	8	11	Low	No further maturation
Pliocene South (UPPER)	1,540	2	7	13	Low	No further maturation
Pliocene South (MID)	1,860	5	17	31	Low	No further maturation
Pliocene South (DEEP)	1,980	0.2	1	2	Low	No further maturation
Flounder Channel (Pliocene)	2,990	3	6	8	Mid	Pending approval
Flounder Fan (Pliocene)	3,100	3	8	13	Mid	Pending approval
Long Channel (Pleitocene)	1,010	1	5	8	Low	No further maturation
NN1-NN3 (Lower Miocene)	4,500-5,000	n/a	n/a	n/a	Low	Maturation and volumes
Cahuac (Pleistocene)*Updated	1,880	1.35	14.7	34.5	Mid/High	Dismissed, too small
Ix (Pleistocene)	1,200-2000	-	-	-		No further maturation
Itzamma (Mesozaic)	7,300	n/a	n/a	n/a	Low	No further maturation
Coba (Mesozaic)	6,800	n/a	n/a	n/a	Low	No further maturation
Balam (Mesozaic)	7,800	n/a	n/a	n/a	Low	No further maturation
Tintal (Mesozaic)	7,720	n/a	n/a	n/a	Low	No further maturation
Edzna (Mesozaic)	6,700	n/a	n/a	n/a	Low	No further maturation
Kabah (Mesozaic)	6,540	n/a	n/a	n/a	Low	No further maturation

Table 7-17: Block 30 Exploration Potential Status (Source: TCM 2023).

7.3.2.1 Kan Discovery

Kan is located at the southern boundary of the contract area and extends to the southeast (Figure 7-43). Initially, the prospect was identified 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 was acquired prior to drilling of the exploration well Kan-1. Amplitude map generated from the 3D data indicates conformable amplitudes to Kan structural closures (Figure 7-44) of approximately 3.5 km^2. An area of 8 km^2 to 10 km^2 is estimated to close the projected amplitude to the North. Kan structure is bounded by two large normal faults trending Northeast-Southwest, and the fault throw is more than 1,000 m. Kan is a fault dependent structure, and is the largest among the identified prospects prior to exploration drilling. Kan has a maximum closure of 18 km^2. Figure 7-45 illustrates the 3D and 2D displayed depth map of Top Tecoalli Oil Equivalent, the billion-barrel oil field reservoir penetrated by Tecoalli-1 well, correlated as the analogue of reservoir attributes for the Kan potential.

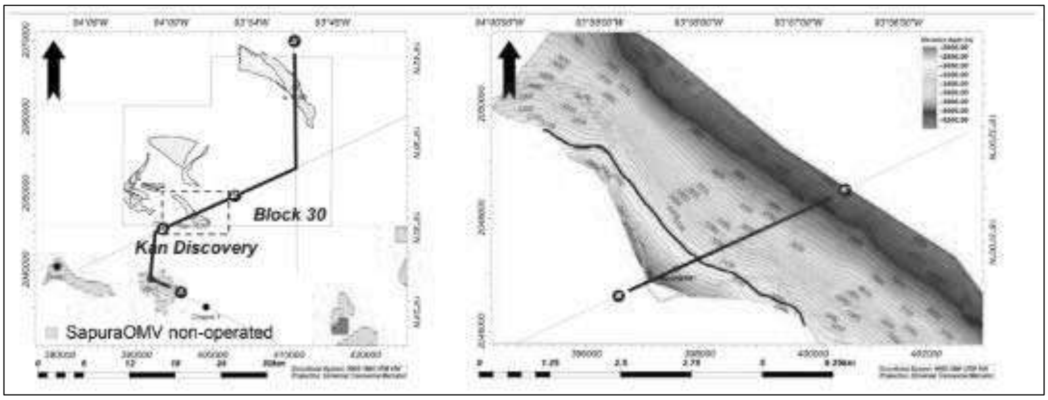


Figure 7-43: Location Map of Kan (Source: SOMV).

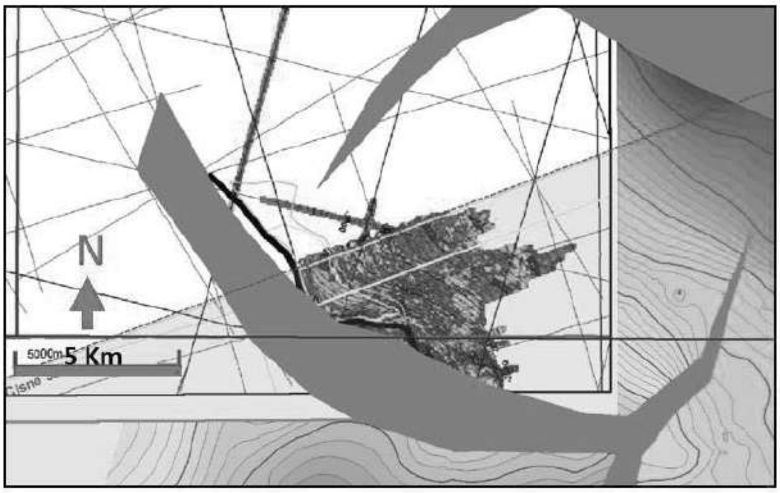


Figure 7-44: Initial 3D Seismic Coverage Of The Block, Amplitude Map Showing Amplitudes That Conform To The Structure (Source: Sapura).

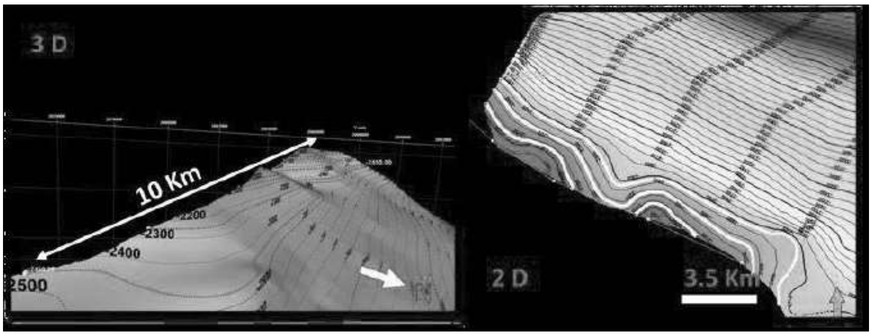


Figure 7-45: Kan Field (Formerly Wahoo) Identified Prior To Drilling (Source: Sapura).

In April 2023, exploration well Kan-1 was drilled to evaluate the Upper Miocene, and a significant oil discovery was reported. The original hole drilled encountered shale only zone with sand stringers, and samples taken in the 6-1/2" hole confirmed the Middle Miocene Unconformity (MMU) at 3,295 mMD. The well was subsequently sidetracked via an 8-1/2" hole and drilled to a TD of 3,237 mTVDSS (3,317 mMDSS). The well logs for Kan-1 original (main) hole and sidetrack are shown in Figure 7-46.

The well penetrated the biggest possible pay section in the Upper Miocene (UM) and proved the presence of oil-bearing reservoir sandstone below the main amplitude package down to MMU (Middle Miocene Unconformity) regional key marker. Most of its planned objectives were achieved, which include well logging, conventional coring for both routine and special core analyses, and fluid sampling. Data was acquired to confirm the geological and petrophysical concepts and parameters for the in-place volume calculations, except for confirming the seismic flat-spot Free Water Level (FWL) and the Oil-Water Contact (OWC), as no water sand was encountered. Fluid sampling was conducted in both hole sections, and the results of the analysis confirmed the expected oil density, ranging from 0.78 (50 °API) to 0.87 g/cc (31 °API), consistent with the light oil description in offset wells in the surrounding block.

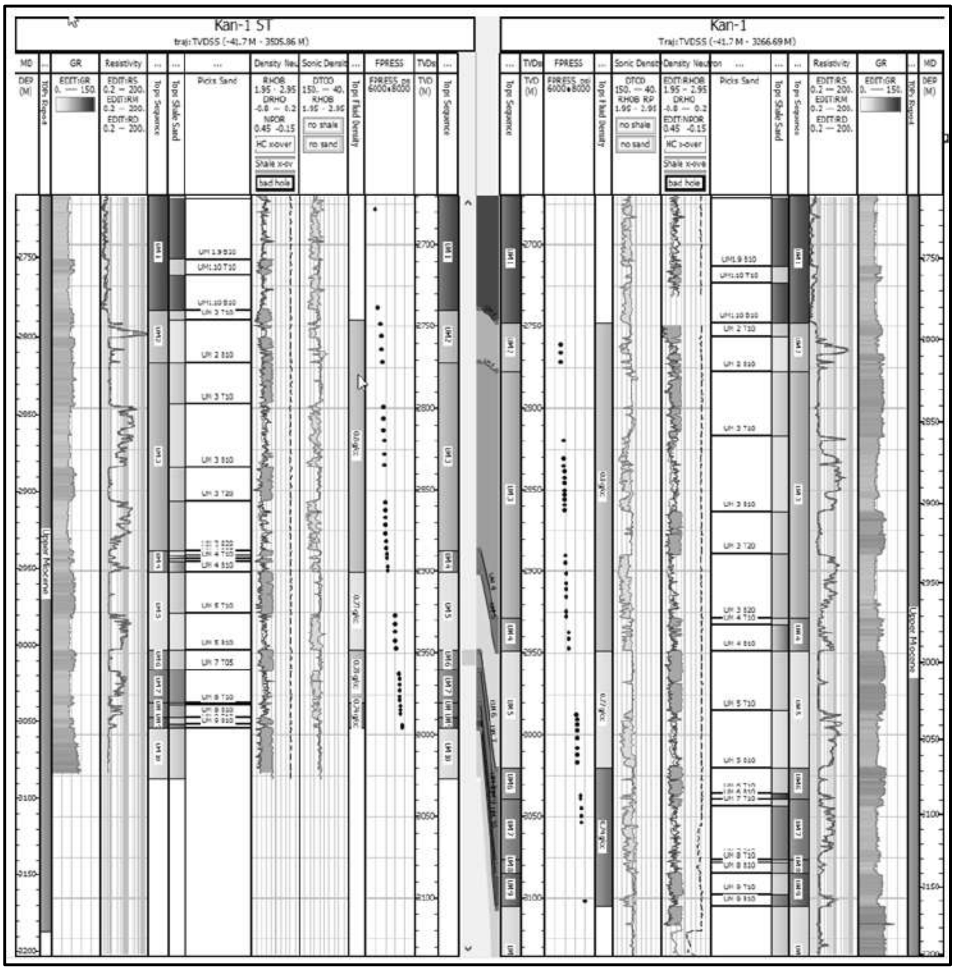


Figure 7-46: Kan-1 Well Log (Main Hole and Sidetrack) (Source: TCM 2023).

The presence of two reservoir systems i.e., Tank 1 and Tank 2, were indicated in Kan, characterized by reservoir properties, geochemistry, pressures, and seismic mapping. Tank 1 represents the UM2 – UM4 also identified as the "Upper System", whilst Tank 2 represents UM5 – UM9 or the "Lower System". The reservoir quality ranges from good to excellent, with some overpressure of around 2,500 psi was reported during drilling. The reservoir drive mechanism assumed is pressure depletion with weak aquifer drive, and secondary recovery via water injection is considered in the proposed conceptual development plan.

Several studies were reported to be in progress to update the model for each individual sand for Tank 1 and Tank 2, of which due to lack of data and geophysical evidence, had utilised ODT and spill points as the maximum distribution. Table 7-18 shows the in-place volumes that were updated post-drilling of well Kan-1. EQ considers the volumes reported to be very much preliminary, due to the limitations on data availability and quality, and as further appraisal is required in the following Kan well. EQ validated the field resource volumes based on the reported key volumetric parameters and ranges. It is noted that this validation is on the preliminary volumes, given the seismic interpretation work is ongoing.

	Tank	Mode	Mean	P90	P50	P10
In-place Volumes, MMbbl	Tank 1	153.9	161.3	115.8	156.9	213.2
	Tank 2	320	350	209	333	511

Table 7-18: Kan In-place Volumes Estimation (Source: TCM 2023).

The preliminary development concept for Kan comprises drilling ten development wells (seven oil producers and three water injectors, where first oil is expected with the completion of the first three oil wells), via three possible facilities processing options i.e., offshore processing, onshore processing and tie-back to ENI FPSO. The development concepts are described below, and the notional first oil is in October 2028. Water injection is required approximately 14 months after drilling all the producers, following first oil. However, it is expected that further optimization for an earlier injection timing will be explored, to minimize potential compaction or rapid pressure decline. From

Material Balance studies conducted (TCM 2023), five producers and two injectors are planned for Tank 1, with two producers and one water injector in Tank 2, to yield RFs of 31% and 35%, respectively. No artificial lift was considered in the initial development concept; for further consideration, gas lift or electrical submersible pumps are possible options to further improve the production. It was also noted that sand production is anticipated, and fracturing and gravel packing (frac-pack) completion strategy is planned for the producers, as an option to manage unconsolidated sand reservoirs.

In the offshore processing option (Figure 7-47), one 4-legged PUQ (Production Utility Quarters) will be installed with one bridge connecting to a 3-legged WHP (wellhead platform). Equipped with 10 slots, the wellhead platform is designed to hold dry trees. For export route to shore, there are two independent oil and gas pipelines spanning 34 km each to San Ramon flow station.

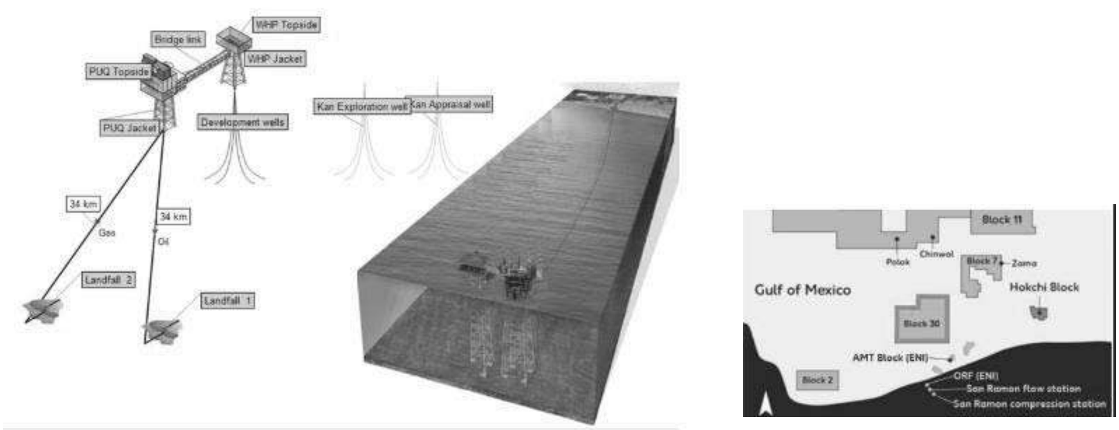


Figure 7-47: Kan Development Concept Offshore Processing (Source: TCM May 2023).

In the onshore processing concept, a 28 km multiphase export pipeline is installed from the 3-legged WHP to the landfall, followed by another 5 km before arriving at the new Kan Onshore Facility (Figure 7-48). There are power cables, gas lift and water injection lines from the onshore facility to the WHP to cater for the production optimization. Subsequently, the production is sent to La Venta Processing Complex that is situated 1 km away.

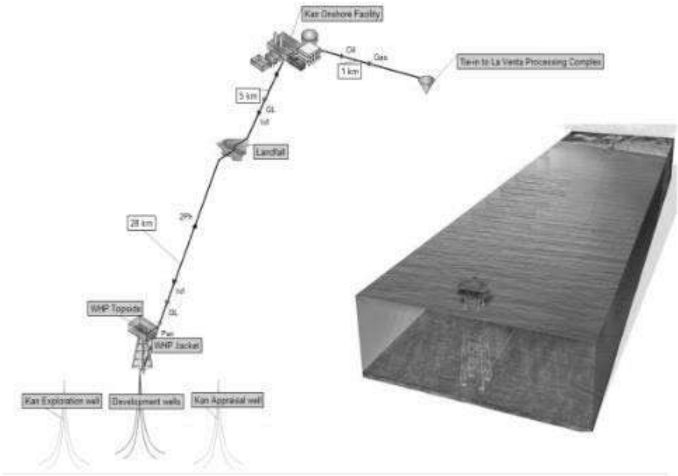


Figure 7-48 : Kan Development Concept Onshore Processing (Source: TCM May 2023).

In the ENI tie-back concept, a 3-legged WHP with 10 slots for dry trees will be tied back to the AMT (Amoca-Mizton-Tecoalli) FPSO owned by ENI via a 30 km multiphase export pipeline (Figure 7-49). Similarly, there are power cable, gas lift and water injection lines connecting the WHP and FPSO.

Figure 7-49: Kan Facilities Concept 3 (Source: TCM May 2023).

The conceptual development plans presented above require further optimization and maturation e.g., conducting geomechanical studies to evaluate the potential compaction effects, injection requirements (and timing), and considerations for artificial lift requirements. The estimated Recovery Factor reported was in the range of 31% to 35% (with water injection), which is comparable to the surrounding field such as Hoch, and validated to be reasonable for water drive reservoirs based on Arps API correlations on the statistical performance for reservoir drive mechanisms, that indicate the RF for sandstone oil reservoirs of ranging from around 32% to 36% for API around 30 deg and GOR around 300 scf/bbl).

Uncertainties also include reservoir continuity, aquifer strength, well productivity and deliverability, recovery factor estimates, and sand control requirements to manage and mitigate sand production issues.

Based on the information available, Kan-1 well did not flow any hydrocarbons to surface, and whether the Kan discovery is able to meet the economic thresholds for future development is subject to the results from the appraisal program. Based on the information available, the Kan discovery is categorized as Contingent Resources with a lower Sub-class category, where the development is either "On Hold" or "Unclarified", due to its current technical uncertainty.

7.3.2.2 Ix Prospect

Ix is located in water depth of approximately 100 m in the northeast corner of the Block 30, 17 km NNE of Kan-1 discovery. It is a multi-target opportunity with potential stacked pay, evaluated for its hydrocarbon potential from three sequences i.e., Pliocene, Upper Miocene, and Lower Miocene. The prospect targeted was a salt diaper related to the horst block with fault-dependent closure, located within the Pescadores Trough. Ix-1 was the second exploration well drilled in May 2023 to evaluate the prospect in Block 30 (Figure 7-50).

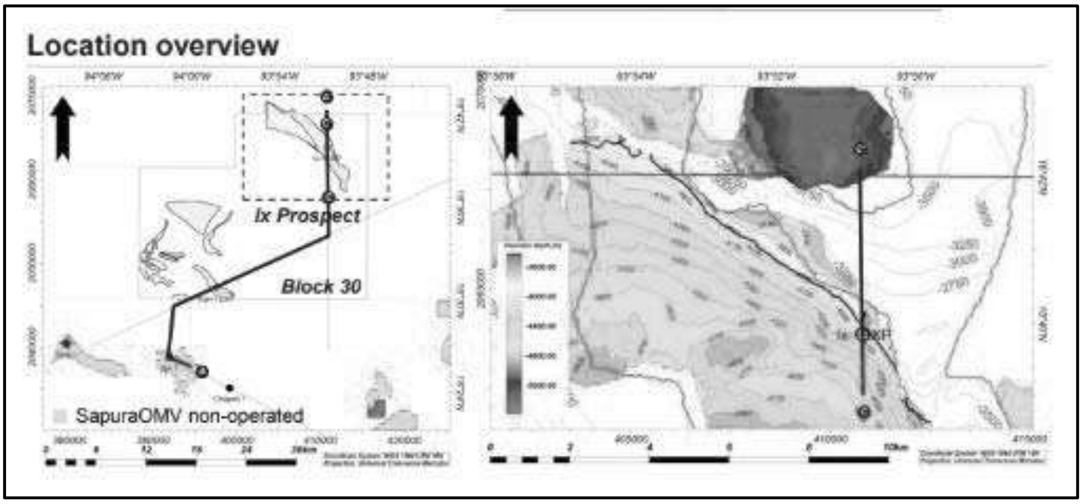


Figure 7-50: Ix-1 Location Overview (Source: SOMV).

Figure 7-51 shows that well Ix-1 reached the Upper Miocene sand, and the well was plugged and abandoned in July the same year due to low formation strength and high overpressure. Hydrocarbons encountered in the overburden have proven charge to the structure, and made the well remain as a valid target for potential re-drill. The well results exhibited the same Upper Miocene play as the Kan-1 discovery, which is similar in structural size.

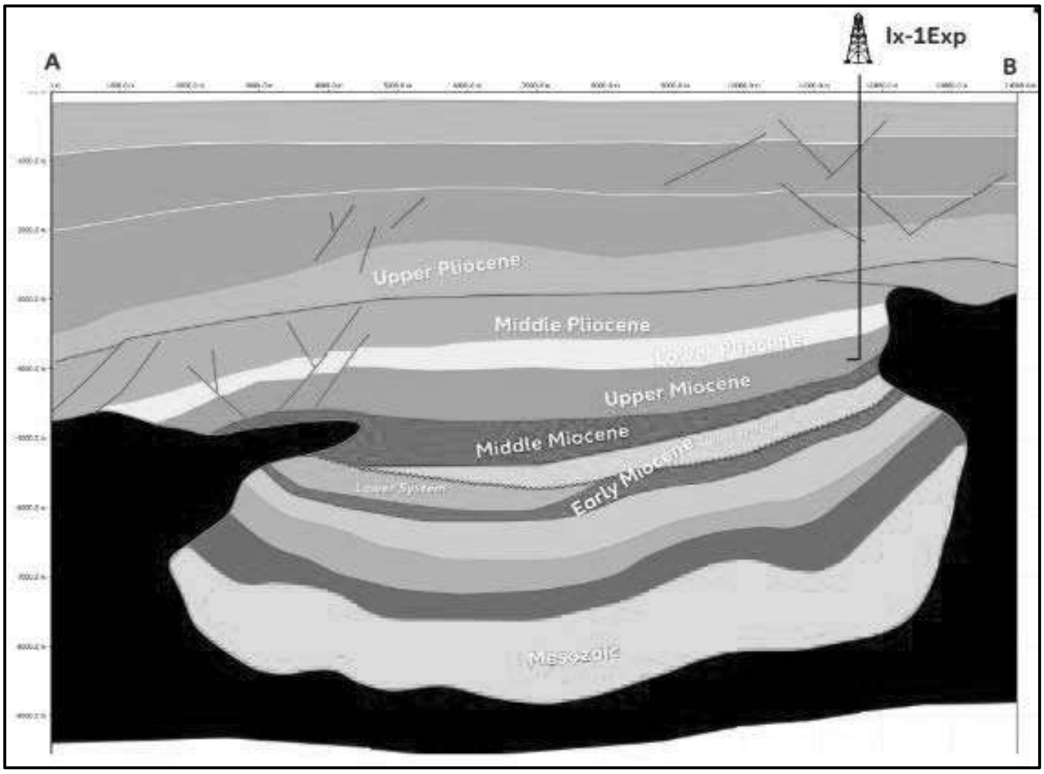


Figure 7-51: Well Ix-1 Sand Penetration (Source: TCM 2023).

Top Pliocene (Figure 7-52) is made up of NW-SE trending channel systems fitting the regional model, where sediment is driven off the shelf from the south to the north, identified by amplitude studies as a high amplitude event showing thin amalgamated channel systems network. The main target has been identified in the Middle Pliocene in a structurally complex area north of a large listric normal fault.

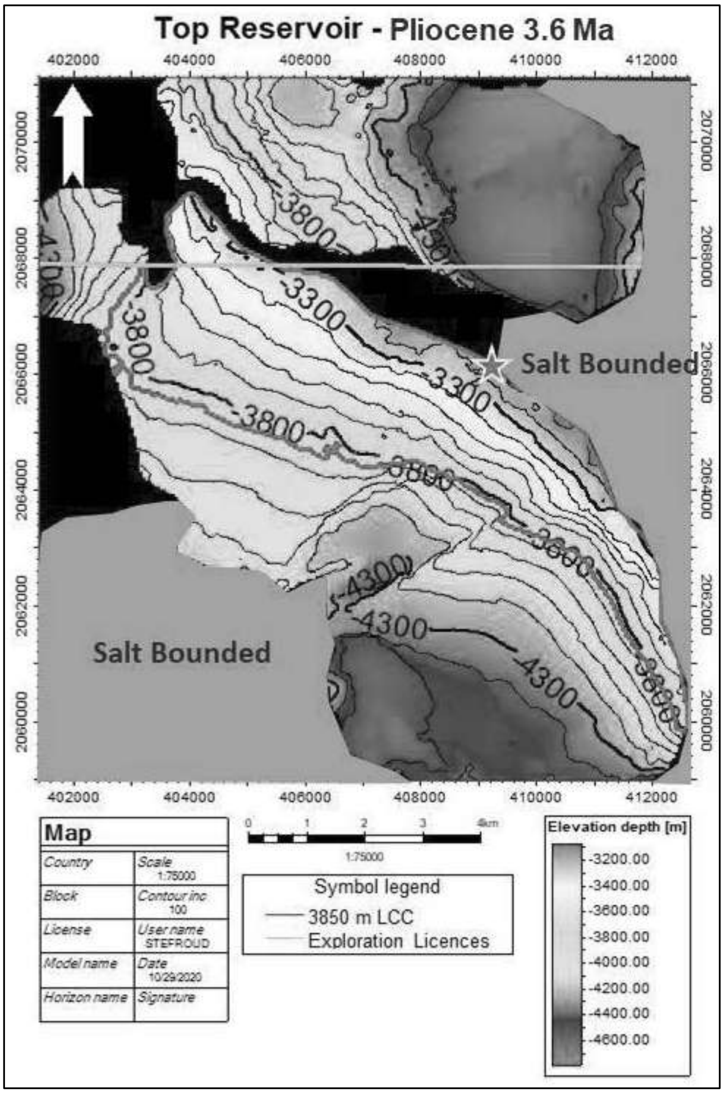


Figure 7-52: Ix Top Pliocene Depth Map (Source: TCM 2023).

The Upper Miocene sequence (Figure 7-53) is sealed by salt in the south and a fault in the north, and is a time-equivalent level to Kan. Amplitude studies indicated consistent channelised NW-SE trending features throughout the entire Upper Miocene section. Stacking of all interpreted layers in the Upper Miocene shows a dense channel system throughout the sequence. However, due to poor seismic imaging, attributes and Paleoscan™ geomodel struggled to image the crestal part of Ix.

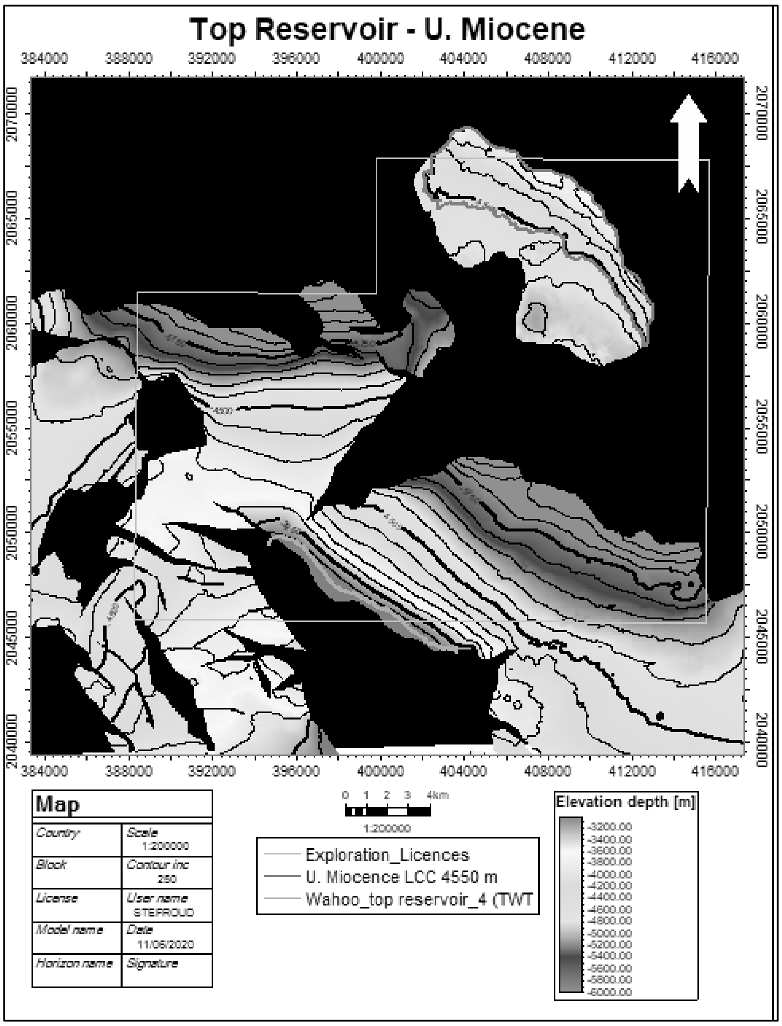


Figure 7-53: Ix Top Upper Miocene Depth Map (Source: TCM 2023).

The Lower Miocene sequence (Figure 7-54) is sealed by salt in the south and a fault in the north. It is made up of two different trending channel axes which appear in this level, which suggest the existence of two mini depositional centres i.e., NW-SE channels in the northern half and NE-SW channels in the southern domain. The channel systems are indicated to comprise a high net to gross, based on the nature of high amalgamated amplitudes.

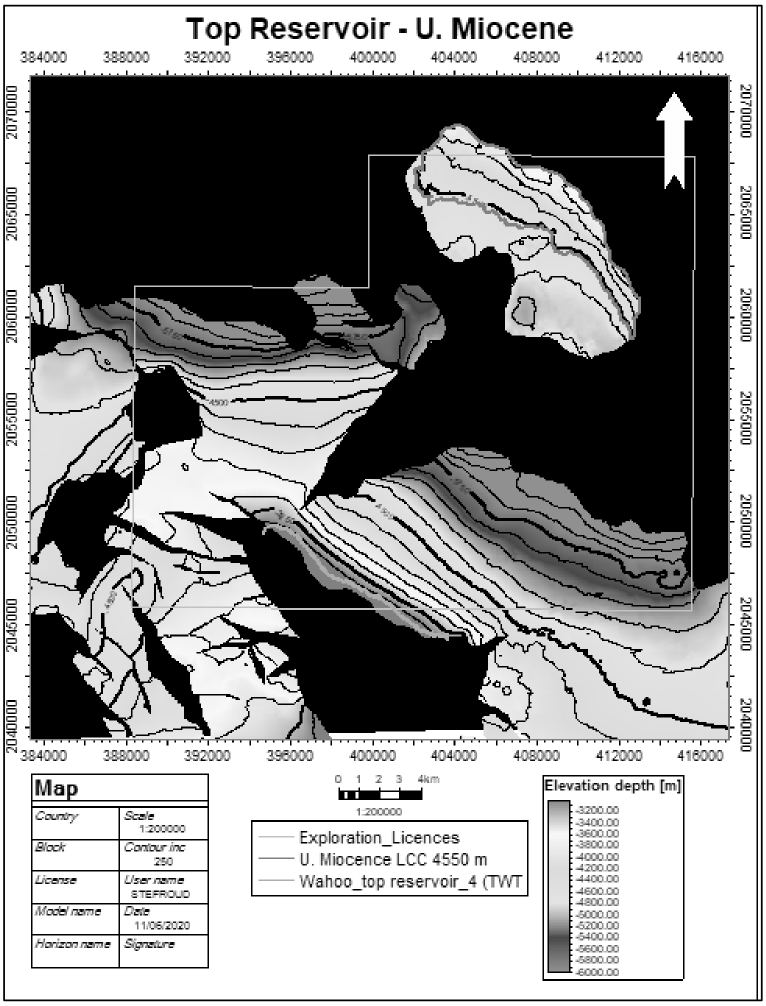


Figure 7-54: Ix Top Lower Miocene Depth Map (Source: TCM 2023).

Due to the absence of the Ix post-drill volumetric assessment, despite reported positive to be a redrill, EQ did not conduct any further evaluation for this well. As such, EQ maintains this asset as a prospect.

7.3.2.3 Cabrilla Prospect

The Cabrilla prospect is located in water depth of 70 m directly northwest of Kan, separated by a North-East trending fault (Figure 7-55). It is reported to be a relatively shallow, small, single target fault dependent closure relying on a working fault seal, as sand to sand juxtaposition is expected. The prospect is a two-way fault bounded dip closure, with an amplitude driven area of approximately 13 km^2 (Figure 7-56).

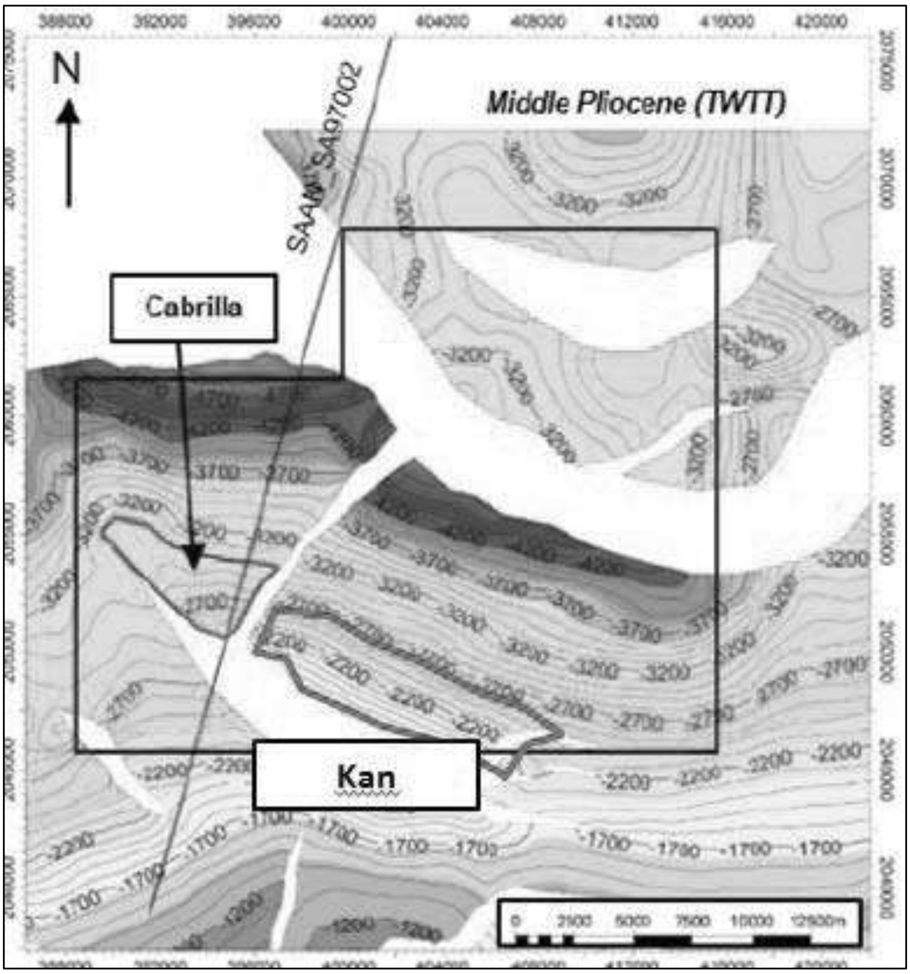


Figure 7-55: Cabrilla Prospect Location (Source: TCM 2023, modified).

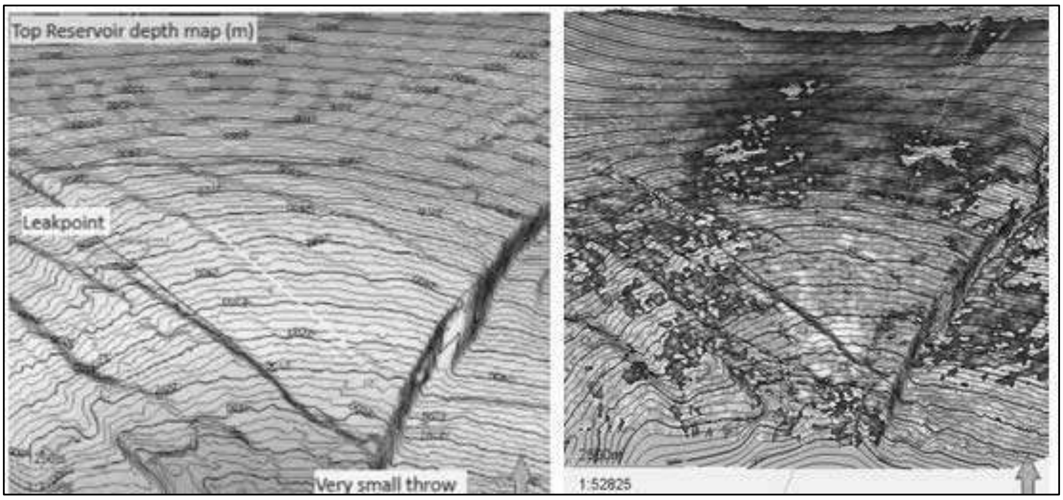


Figure 7-56: Top Lower Pleistocene Reservoir Depth Map (left), Top reservoir RMS Amplitude TWT (right) (Source: TCM 2023).

The main target for the prospect is the Pliocene turbiditic sandstones with top of structure located at 2,340 m depth and the spill point at 3,000 m depth (Figure 7-57). The targeted reservoir for Cabrilla is the shallow Lower Pleistocene, expected to have a poor net to gross, based on the depositional model evaluated. The depositional model proposes a delta front/pro-delta shallow deposit within Cabrilla on a relatively narrow shelf and a proximal shoreface with strand plain. The reservoir is expected to be very heterogeneous (Figure 7-58), given the burial history scenario, and assuming a late trap timing (at 2 Ma) charge into the trap is available. However, uncertainties exist in terms of trap fill which is dependent on fault and top seal. Furthermore, minor biodegradation risk cannot be ruled out due to its shallowness. Amplitude studies concluded that the amplitude standout is moderate to strong; although conformance is obscured by faults, sharp amplitude cut-offs at the faults are typically good fluid indicators. Lack of visible flat spot or phase distortion and patchy response is probably due to low net to gross, a negative factor for the prospect.

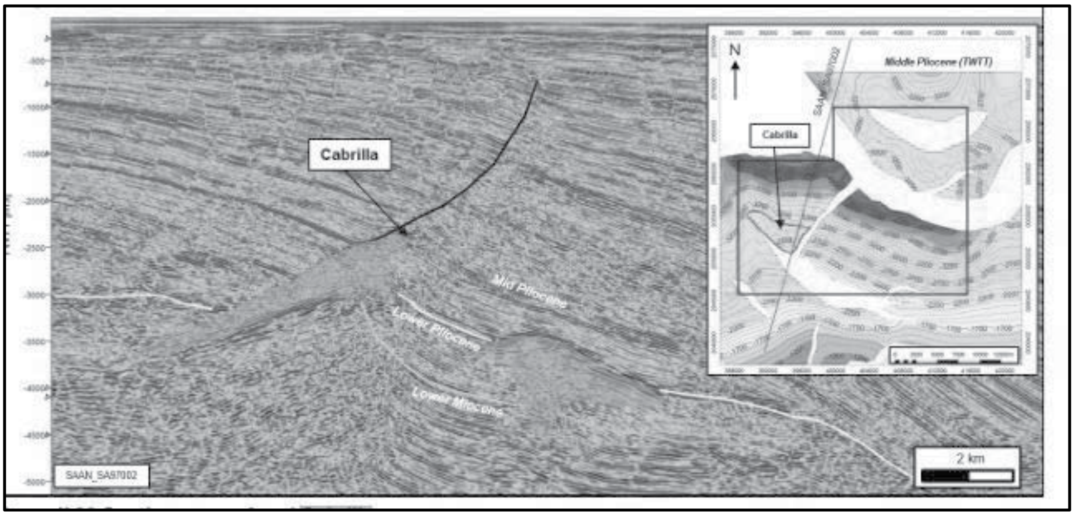


Figure 7-57: Cabrilla (Source: 2019 Exploration Plan).

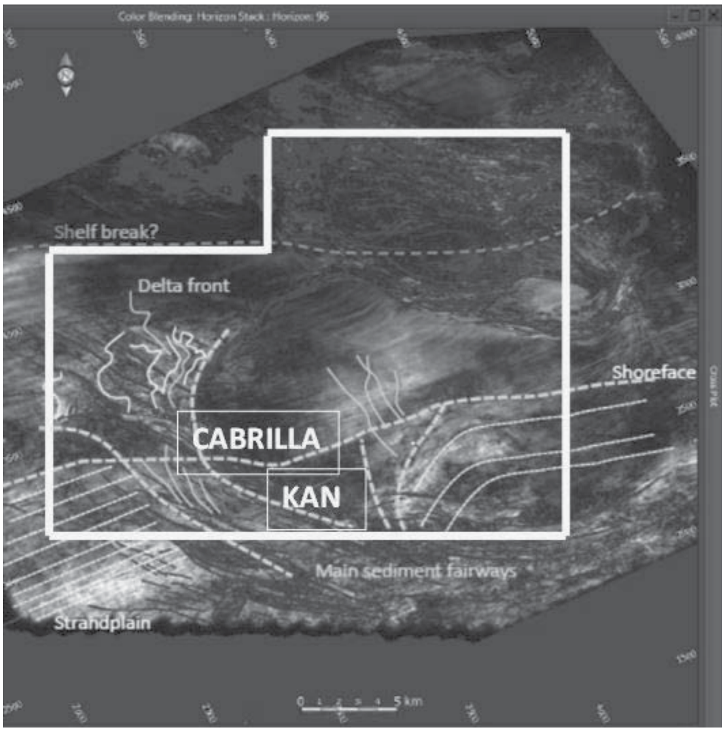


Figure 7-58: Proposed Block 30 depositional model for Lower Pleistocene (TCM 2023).

Volumetric estimation for Cabrilla prospect was conducted in December 2020 based on the parameters shown in Table 7-19, which indicate poor NTG as well as structural compartmentalisation observed from the depositional model. The estimated in-place volumes stand at 119 MMstb (Pmean) with 30 MMstb recoverable (Pmean). It is expected that Cabrilla development may not be viable on a standalone basis, but its adjacent location to Kan discovery has made it a feasible exploration drilling candidate.

Parameter	**Value**		
Column Height	640		
Porosity %	24		
NTG%	4		
Oil saturation%	65		
Bo bbl/stb	1.2		
GOR	700		
RF%	25		
Volume Estimates	**P90**	**Pmean**	**P10**
In-place (MMbbl)	26	119	227
Recoverable (MMbbl)	6	30	57

Table 7-19: Volumetric parameters and estimated In-place and recovery for Cabrilla Lower Pleistocene reservoir (Source: SOMV Dec 2020).

Based on the information available, EQ has placed the classification of resources for the Cabrilla prospect in the Prospective category. For the purpose of this CPR, EQ did not evaluate the volumes directly but observed that the prospect range of in-place volumes reflect positive log normal distribution and the key risks associated with the undrilled fault block are trap, reservoir and source with wider range in the P10 and P90.