Peninsula Hibiscus Evaluation

Block PM3 CAA in Malaysia-Vietnam Commercial Arrangement Area

Short Form Competent Person's Report

Prepared for:

Hibiscus Petroleum Berhad

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23th May 2025
FINAL SHORT FORM

REPORT

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Date: 23th May 2025

Hibiscus Petroleum Berhad
2nd Floor Syed Kechik Foundation Building
Jalan Kapas
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59100 Kuala Lumpur
Malaysia

Dear Sirs,

EVALUATION OF RESERVES AND CONTINGENT REOSURCS IN CERTAIN ASSTES OFFSHORE MALAYSIA AND VIETNAM

In response to a request by Hibiscus Petroleum Berhad ("Hibiscus"), and the Letter of Engagement dated 04 December 2024 with Hibiscus (the "Agreement"), Tetra Tech RPS Energy Ltd ("TTRPSE") has completed an independent evaluation of the following Asset:

- 35% working interest in the PM3 CAA block located within the Commercial Arrangement Area ("CAA") between Malaysia and Vietnam

This Short Form Competent Person's Report is issued by Tetra Tech RPS Energy under the appointment by Hibiscus and is produced as part of the Services detailed therein and subject to the terms and conditions of the Agreement. A full CPR has been issued to Hibiscus separately.

We have estimated Proved, Probable and Possible Reserves and estimated 1C, 2C and 3C Contingent Resources as of 01 January 2025. All Reserves and Resources definitions and estimates shown in this report are based on the 2018 SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Resource Management System ("PRMS") v1.03 and are reported to the Bursa Malaysia Securities Berhad requirements for reporting oil and gas activities as specified in Practice Note 32.

The work was undertaken by a team of petroleum engineers, geoscientists and economists and is based on data made available by Hibiscus.

TTRPSE has reviewed available data and evaluated forecasts for existing production and additional projects presented by Hibiscus' technical team.

A set of kick-off meetings were held between 13th and 21st November 2024 and full set of data was made available to TTRPSE on 26th December 2024. This contained technical and commercial information pertinent to the project. A number of progress meetings were also held during the course of the project with the Hibiscus team during which any queries or clarifications were resolved.

In estimating Reserves, we have used standard geoscience and petroleum engineering techniques. We have estimated the degree of uncertainty inherent in the measurements and interpretation of the data and have calculated a range of recoverable volumes, based on predicted field performance and contracted gas sales.

Due to the types of data available, our methodology has been restricted to reviewing estimates of hydrocarbons in place and evaluating production forecasts by decline curve analysis for existing production, type curves based on analogue wells for planned interventions and the existing developments based on audit of dynamic models. TTRPSE has also reviewed estimated Capital (CAPEX), Operating (OPEX) and abandonment (ABEX) costs provided in various documents and used our experience of similar projects in the region to evaluate the proposed costs for reasonableness.

We have taken the working interest that Hibiscus has in the Fields as presented by Hibiscus. We have not investigated, nor do we make any warranty as to Hibiscus interest in the Assets.

No site visit has been conducted as part of our evaluation.

For each Asset, Hibiscus has presented a “No Further Activity (NFA)” case and a number of planned well interventions and development projects. Some of the planned activity is classed as Contingent Resources. Prospective Resources volumes have not been evaluated by TTRPSE as they are outside the scope of this report.

The Net Entitlement Reserves as of 01 January 2025 assuming the current PSC expiry are summarised in Table 1-2 to Table 1-4 for oil, gas and condensate. Table 1-5 gives the Net Entitlement Reserves in oil-equivalent barrels. The Net Entitlement Reserves as of 01 January 2025 assuming a PSC extension of 20 years are summarised in Table 1-6 to Table 1-8 for oil, gas and condensate. Table 1-9 gives the Net Entitlement Reserves in oil-equivalent barrels.

The Net Entitlement Contingent Resources as of 01 January 2025 assuming a PSC extension of 20 years are summarised in Table 1-10 to Table 1-12 for oil, gas and condensate. Table 1-13 gives the Net Entitlement Contingent Resources in oil-equivalent barrels.

QUALIFICATIONS

TTRPSE is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. The provision of professional services has been solely on a fee basis. Mr Gordon Taylor, Technical Director, has reviewed this report. Mr Taylor is a Chartered Geologist with over 40 of years’ experience in upstream oil and gas. The project has been managed by Adam Turner who has over 13 years of experience in upstream oil and gas. Other TTRPSE employees involved in this work hold at least a Master’s degree in geology, geophysics, petroleum engineering or a related subject or have at least five years of relevant experience in the practice of geology, geophysics or petroleum engineering.

BASIS OF OPINION

The evaluation presented in this report reflects our informed judgment, based on accepted standards of professional investigation, but is subject to generally recognized uncertainties associated with the interpretation of geological, geophysical and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, Tetra Tech RPS Energy is not in a position to attest to the property title, financial interest relationships or encumbrances related to the property. Our estimates of Reserves are based on data provided by Hibiscus. We have accepted, without independent verification, the accuracy and completeness of this data.

The report represents Tetra Tech RPS Energy’s best professional judgment and should not be considered a guarantee or prediction of results. It should be understood that any evaluation, particularly one involving future performance and development activities may be subject to significant variations over short periods of time as new information becomes available. This report relates specifically and solely to the subject assets and is conditional upon various assumptions that are described herein. This report must, therefore, be read in its entirety. This report was provided for the sole use of Hibiscus and their corporate advisors on a fee basis.

This report may be reproduced in its entirety. However, excerpts may only be reproduced or published (as required for regulated securities reporting purposes) with the express written permission of Tetra Tech RPS Energy.

Yours sincerely,
for Tetra Tech RPS Energy Ltd

Gordon Taylor C.Eng, C.Geol
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Name	Role	Signature
Gordon Taylor	Project Supervisor	
Adam Turner	Project Manager, Principal Reservoir Engineer	
Clare Wilson	Principal Advisor Geoscience	
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Joseph Tan	Petroleum Economist	
David Walker	Principal Costs/Development Engineer	

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1 EXECUTIVE SUMMARY

In response to a request by Hibiscus Petroleum Berhad ("Hibiscus"), and the Letter of Engagement dated 04 December 2024 with Hibiscus (the "Agreement"), Tetra Tech RPS Energy Ltd ("TTRPSE") has completed an independent evaluation of the following Asset:

- 35% working interest in the PM3 CAA block located within the Commercial Arrangement Area ("CAA") between Malaysia and Vietnam

This Short Form Competent Person's Report (CPR) is issued by Tetra Tech RPS Energy under the appointment by Hibiscus and is produced as part of the Services detailed therein and subject to the terms and conditions of the Agreement.

1.1 Overview of Company or Asset(s) that is the subject of report

The Assets are located in the Malay Basin, offshore Malaysia (Figure 1-1).

Block PM3 CAA is located in the Northeast Malay basin, close to the Vietnamese median line. The block contains a total of 16 accumulations in eight fields, developed around two hubs (North and South). The neighbouring Block 46 is in Vietnamese waters and contains the Cai Nuoc field, an extension of the East Bunga Kekwa field in the PM3 CAA block. A unitisation agreement was signed in 2000 forming the East Bunga Kekwa – Cai Nuoc unit. The field is tied back to PM3 CAA facilities. The undeveloped Hoa Mai field also lies primarily in Block 46, outside of the East Bunga Kekwa – Cai Nuoc unit but straddles the Malaysia/Vietnam maritime border into PM3 CAA. These assets were previously owned and operated by Repsol before purchase by Hibiscus in 2021.

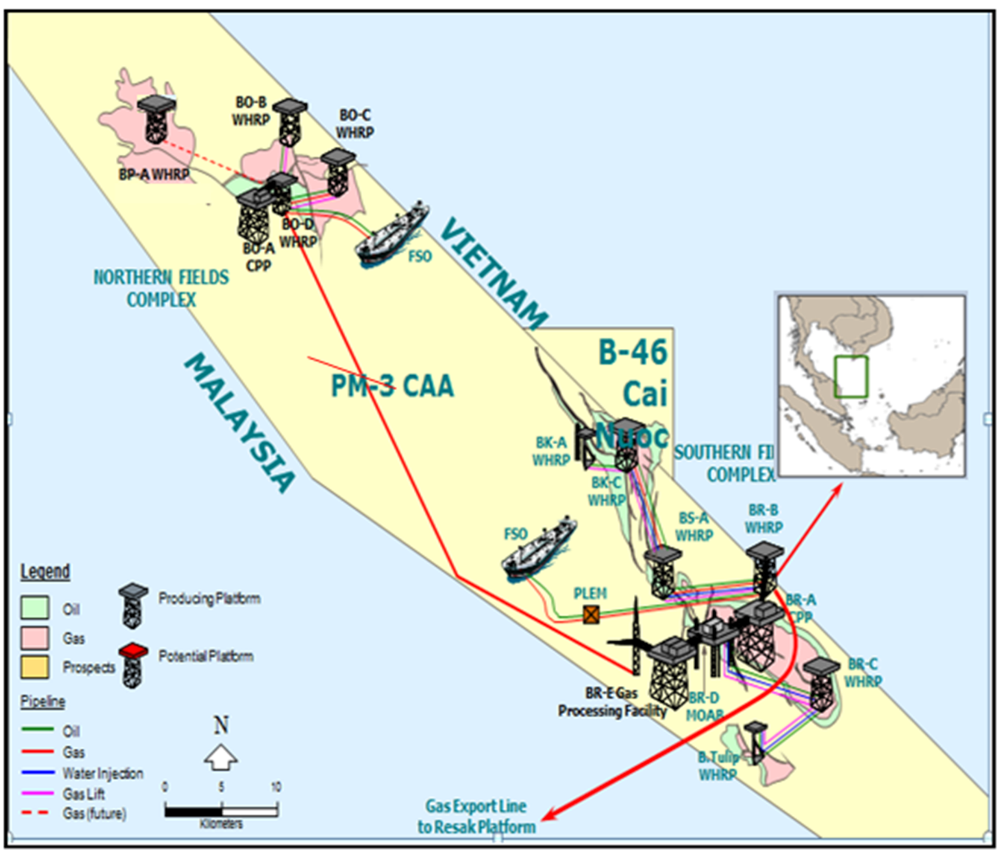

Figure 1-1: Map showing Location of Assets

1.2 Health, Safety, Security and Environment (“HSSE”)

As a PSC holder, Hibiscus is subjected to the Laws of Malaysia and the terms and condition of the contract entered with PETRONAS. This includes the use of PETRONAS’ definition on HSSE management, the adoption of PETRONAS established procedures, reporting of agreed parameters and access by local authorities/PETRONAS to conduct site inspections and audits.

Three of the important HSSE systems established by PETRONAS and in use by Hibiscus are:

- PGS – PETRONAS Governing Standards
- OSRMS – Offshore Self-Regulatory Management System
- HSEMS – Health Safety Environment Management System

The above three form the operational basis for the conduct of operations and for PETRONAS to inspect and audit upstream operations. Compliance check to OSRMS (at Tier 3 level) is conducted by a joint team of PETRONAS and DOSH (Department of Occupational Safety and Health, Malaysia), while PGS compliance check is conducted by PETRONAS through the IOAIA (Integrated Operation Asset Integrity Assurance) and HSEMS audits.

1.3 Malay Basin Geology

The Malay basin has three recorded phases of tectonic history; an extension/ rift phase in the Late Cretaceous to Late Oligocene, followed by compression in the Middle to Late Miocene, which caused structural uplift and inversion and formed the dominant anticlinal structure seen in the fields, followed by, more recently, a mild extension which can be seen in faults that extend to surface and which have been re-activated.

Thick fault bounded sediments associated with the early phase of extension were compressed into structural highs, that occurred approximately 22 -10 MYA and is shown by thinning of the F, G, H, I and J Groups (Figure 3-5). The result is a basin containing a thick central section of approximately 14km, characterised by steeply dipping faults that have been mapped to basement. Upper reservoir sections are characterised by fault dip-anticlinal structures. Towards the flanks of the basin the strata is relatively gently dipping with a few major normal faults and half grabens.

The Assets comprise Lower – Upper Miocene age sands from the L-D Groups, as shown on the regional stratigraphic column. The deepest L sands are typically braided plain facies, comprises laterally extensive lacustrine and fluvial sands, that thin towards the south of the PM3 CAA block, where basement/Mesozoic horst blocks are more prominent.

The reservoirs in the assets have a variety of trapping types ranging from structural, stratigraphic or combination traps. This results in stacked pay within many fields. Sand quality and distribution varies depending on the depositional setting, although typically good quality reservoir sands show high porosity (20-30%) and up to 10’s of metres thickness. Thin bed sands also contribute to pay; these exhibit a low resistivity response in hydrocarbons.

Seal comprises intra-formational shales within the fluvial delta plain, with good lateral seal provided by the tidal muds, estuarine muds or mud filled abandoned channels. This is particularly important in the PM3 CAA region, which contains a high concentration of CO_2 in certain deeper reservoirs.

All fields are covered by 3D seismic of varying vintage, ranging from 1995 over the Kekwa field through to a new 2020 acquisition over the PM3 area, with the hope it will help unlock additional reservoir potential.

1.4 Subsurface and Resource Evaluation

A series of meetings and new data was shared with TTRPSE by Hibiscus, including presentations, models, subsurface data, costs and economics data. TTRPSE has audited the data provided and adjusted the models where necessary to define forecast produced volumes and estimate Reserves and Contingent Resources.

TTRPSE has focussed on auditing existing production, planned commitments and defined future developments that will come to fruition within the next five years. A summary of the activities presented by Hibiscus and TTRPSE' review status is shown in Table 1-1.

With the exception of Bunga Aster Phase 1, the currently producing fields have been assessed based on production data only, and TTRPSE has not independently estimated the in-place volumes. In-place volumes for development projects outside of a 5-year development window have not been independently estimated by TTRPSE.

Status	Block/Permit	Field	Reviewed by TTRPSE?	Methodology	TTRPSE Resource Classification
Existing Production	**PM3 CAA**	Bunga Orkid	Y	DCA	Reserves – Developed Producing
		North Bunga Orkid			
		West Bunga Orkid			
		East Bunga Orkid			
		North Bunga Pakma			
		Bunga Pakma			
		Bunga Lavatera			
		East Bunga Kekwa			
		West Bunga Kekwa			
		East Bunga Raya			
		West Bunga Raya			
		Bunga Seroja			
		North Bunga Raya			
		North West Bunga Raya			
		West Bunga Tulip			
		Bunga Aster Phase 1		Review and rescale operator profile to TTRPSE STOIIP	
Well Interventions	**PM3 CAA**	Bunga Orkid	Y	Operator type curve audit	Reserves – Developed Non-producing
		North Bunga Orkid			
		West Bunga Orkid			
		North Bunga Pakma			
		Bunga Pakma			
		East Bunga Kekwa			
		North West Bunga Raya			
		West Bunga Kekwa			

Status	Block/Permit	Field	Reviewed by TTRPSE?	Methodology	TTRPSE Resource Classification
Low Investment Case (Sanctioned Projects)	**PM3 CAA**	Gas Cap Blowdown Phase 1	Y	Hibiscus model audit	Reserves – Approved for Development
		North Bunga Pakma Nose			
		LP Gas (BOD-22 and BOD-2)			
		Bunga Raya Infill			
Defined Developments (within 5-year development window)	**PM3 CAA**	Bunga Saffron	Y	Hibiscus model audit	Contingent Resources – Development Pending
		Bunga Aster Phase 2		Hibiscus model audit	Contingent Resources – Development Unclarified
		Gas Cap Blowdown Phase 2		Hibiscus model audit	Contingent Resources – Development Unclarified
		LP Gas (within 5 years)		Hibiscus model audit	Contingent Resources – Development Unclarified
Defined Developments (outside 5-year development window)	**PM3 CAA**	Gas Cap Blowdown Phase 3	N	No review - Operator profiles reported	Contingent Resources – Development Unclarified
		Bunga Matahari			
		LP Gas (after 5 years)			
Immature Developments (outside 5-year development window)	**PM3 CAA**	Sliver	N	No review - Operator profiles reported	Not classified

Table 1-1: Summary of TTRPSE Review

1.5 Economic Analysis

The Economic Limit Test ("ELT") performed for the determination of Reserves is based on TTRPSE's estimates of recoverable volumes, a review of the Company's estimates of Capex and Opex, and inclusion of other financial information and assumptions, as outlined in Capex, Opex and Abex sections.

The PSC is assumed to reach its economic limit when the cumulative value of its undiscounted net cash flow before tax ceases to increase. All projects to be classified as Reserves must be economic under defined conditions[1]. RPS has therefore assessed the future economic viability of each case on the basis of its pre-tax undiscounted Net Cash Flow MOD.

An annual inflation rate of 2 per cent has been built into the ELT.

The effective date of this report is 1st January 2025 and this has been used as the discount date for the valuation.

[1] *PRMS 2018: 3.1.2.1 Economic determination of a project is tested assuming a zero percent discount rate (i.e., undiscounted). A project with a positive undiscounted cumulative net cash flow is considered economic.*

1.6 Reserves Summary

Hibiscus Net Entitlement Reserves for the PSC with current expiry in December 2027 are presented in Table 1-2 to Table 1-5.

SUMMARY OF OIL RESERVES
As of 01 January 2025
To current PSC expiry (December 2027)
BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Reserves[1,2] (MMstb)		
	1P	**2P**	**3P**
PM3 CAA	2.2	2.7	2.9

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2027 for 1P, 2P, and 3P.

Table 1-2: Oil Reserves as of 01 January 2025 to Current PSC Expiry (December 2027)

SUMMARY OF GAS RESERVES
As of 01 January 2025
To current PSC expiry (December 2027)
BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Reserves[1,2] (Bscf)		
	1P	**2P**	**3P**
PM3 CAA	41.1	52.3	64.1

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2027 for 1P, 2P, and 3P.

Table 1-3: Gas Reserves as of 01 January 2025 to Current PSC Expiry (December 2027)

SUMMARY OF CONDENSATE RESERVES
As of 01 January 2025
To current PSC expiry (December 2027)
BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Reserves[1,2] (MMstb)		
	1P	**2P**	**3P**
PM3 CAA	0.6	0.7	0.7

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2027 for 1P, 2P, and 3P.

Table 1-4: Condensate Reserves as of 01 January 2025 to Current PSC Expiry (December 2027)

SUMMARY OF RESERVES (BOE)
As of 01 January 2025
To current PSC expiry (December 2027)
BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Reserves[1,2] (MMboe)[3]		
	1P	**2P**	**3P**
PM3 CAA	9.6	12.0	14.3

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2027 for 1P, 2P, and 3P.

[3] Conversion rate of 6,000 standard cubic feet per boe

Table 1-5: Summary of Reserves in Oil Equivalent Barrels as of 01 January 2025 to Current PSC Expiry (December 2027)

Hibiscus Net Entitlement Reserves for current PSC expiry with a 20 years extension to December 2047 are presented in Table 1-6 to Table 1-9.

SUMMARY OF OIL RESERVES
As of 01 January 2025
To PSC expiry with 20-year extension (December 2047)
BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Reserves[1,2] (MMstb)		
	1P	**2P**	**3P**
PM3 CAA	3.7	6.4	10.4

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2030,2032, 2038 for 1P, 2P, and 3P, respectively.

Table 1-6: Oil Reserves as of 01 January 2025 to PSC Expiry with 20-year Extension (December 2047)

SUMMARY OF GAS RESERVES
As of 01 January 2025
To PSC expiry with 20-year extension (December 2047)
BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Reserves[1,2] (Bscf)		
	1P	**2P**	**3P**
PM3 CAA	60.1	101.9	174.3

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2030,2032, 2038 for 1P, 2P, and 3P, respectively.

Table 1-7: Gas Reserves as of 01 January 2025 to PSC Expiry with 20-year Extension (December 2047)

SUMMARY OF CONDENSATE RESERVES
As of 01 January 2025
To PSC expiry with 20-year extension (December 2047)
BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Reserves[1,2] (MMstb)		
	1P	**2P**	**3P**
PM3 CAA	0.8	1.3	2.0

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2030,2032, 2038 for 1P, 2P, and 3P, respectively.

Table 1-8: Condensate Reserves as of 01 January 2025 to PSC Expiry with 20-year Extension (December 2047)

SUMMARY OF RESERVES (BOE)
As of 01 January 2025
To PSC expiry with 20-year extension (December 2047)
BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Reserves[1,2] (MMboe)[3]		
	1P	**2P**	**3P**
PM3 CAA	14.5	24.6	41.4

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2030,2032, 2038 for 1P, 2P, and 3P, respectively.

[3] Conversion rate of 6,000 standard cubic feet per boe

Table 1-9: Summary of Reserves in Oil Equivalent Barrels as of 01 January 2025 to PSC Expiry with 20-year extension (December 2047)

1.7 Contingent Resources Summary

Hibiscus Net Entitlement Contingent Resources, comprising subcategories Development Pending and Development Unclarified, for current PSC expiry with a 20 years extension to December 2047 are presented in Table 1-10 to Table 1-13.

SUMMARY OF OIL CONTINGENT RESOURCES
As of 01 January 2025
To PSC expiry with 20-year extension (December 2047)
BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Contingent Resources[1,2] (MMstb)		
	1C	2C	3C
PM3 CAA	2.7	4.5	5.5

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2032, 2035, and 2040 for 1C, 2C, and 3C, respectively.

Table 1-10: Oil Contingent Resources as of 01 January 2025 to PSC Expiry with 20-year Extension (December 2047)

SUMMARY OF GAS CONTINGENT RESOURCES
As of 01 January 2025
To PSC expiry with 20-year extension (December 2047)
BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Contingent Resources[1,2] (Bscf)		
	1C	2C	3C
PM3 CAA	26.3	49.4	56.0

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2032, 2035, and 2040 for 1C, 2C, and 3C, respectively.

Table 1-11: Gas Contingent Resources as of 01 January 2025 to PSC Expiry with 20-year Extension (December 2047)

SUMMARY OF CONDENSATE CONTINGENT RESOURCES

As of 01 January 2025

To PSC expiry with 20-year extension (December 2047)

BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Contingent Resources[1,2] (MMstb)		
	1C	**2C**	**3C**
PM3 CAA	0.4	0.7	0.8

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2032, 2035, and 2040 for 1C, 2C, and 3C, respectively.

Table 1-12: Condensate Contingent Resources as of 01 January 2025 to PSC Expiry with 20-year Extension (December 2047)

SUMMARY OF CONTINGENT RESOURCES (BOE)

As of 01 January 2025

To PSC expiry with 20-year extension (December 2047)

BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Contingent Resources[1,2] (MMboe)[3]		
	1C	**2C**	**3C**
PM3 CAA	7.4	13.4	15.6

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2032, 2035, and 2040 for 1C, 2C, and 3C, respectively.

[3] Conversion rate of 6,000 standard cubic feet per boe

Table 1-13: Summary of Contingent Resources in Oil Equivalent Barrels as of 01 January 2025 to PSC Expiry with 20-year Extension (December 2047)

2 INTRODUCTION

In response to a request by Hibiscus Petroleum Berhad (“Hibiscus”), and the Letter of Engagement dated 04 December 2024 with Hibiscus (the “Agreement”), Tetra Tech RPS Energy Ltd (“TTRPSE”) has completed an independent evaluation of the following Assets:

- 35% working interest in the PM3 CAA block located within the Commercial Arrangement Area (“CAA”) between Malaysia and Vietnam

This Short Form CPR is issued by Tetra Tech RPS Energy under the appointment by Hibiscus and is produced as part of the Services detailed therein and subject to the terms and conditions of the Agreement. A full CPR has been issued to Hibiscus separately.

A glossary of terms used in the report is presented in Appendix A. A summary of PRMS reporting guidelines in included in Appendix B.

2.1 The Assets

The Assets are located in the Malay Basin offshore Malaysia (Figure 1-1).

Block PM3 CAA is located in the Northeast Malay basin, close to the Vietnamese median line. The block contains a total of 16 accumulations in eight fields, developed around two hubs (North and South). Fields are generally comprised of low relief anticline structures with multiple stacked fluvial/shallow marine deltaic sandstones. Fluids are a combination of oil, condensate and gas, with highly variable CO2 content (5-70%).

The neighbouring Block 46 is in Vietnamese waters and contains the Cai Nuoc field, an extension of the East Bunga Kekwa field in the PM3 CAA block. A unitisation agreement was signed in 2000 forming the East Bunga Kekwa – Cai Nuoc unit. The field is tied back to PM3 CAA facilities. The undeveloped Hoa Mai field also lies primarily in Block 46, outside of the East Bunga Kekwa – Cai Nuoc unit but straddles the Malaysia/Vietnam maritime border into PM3 CAA.

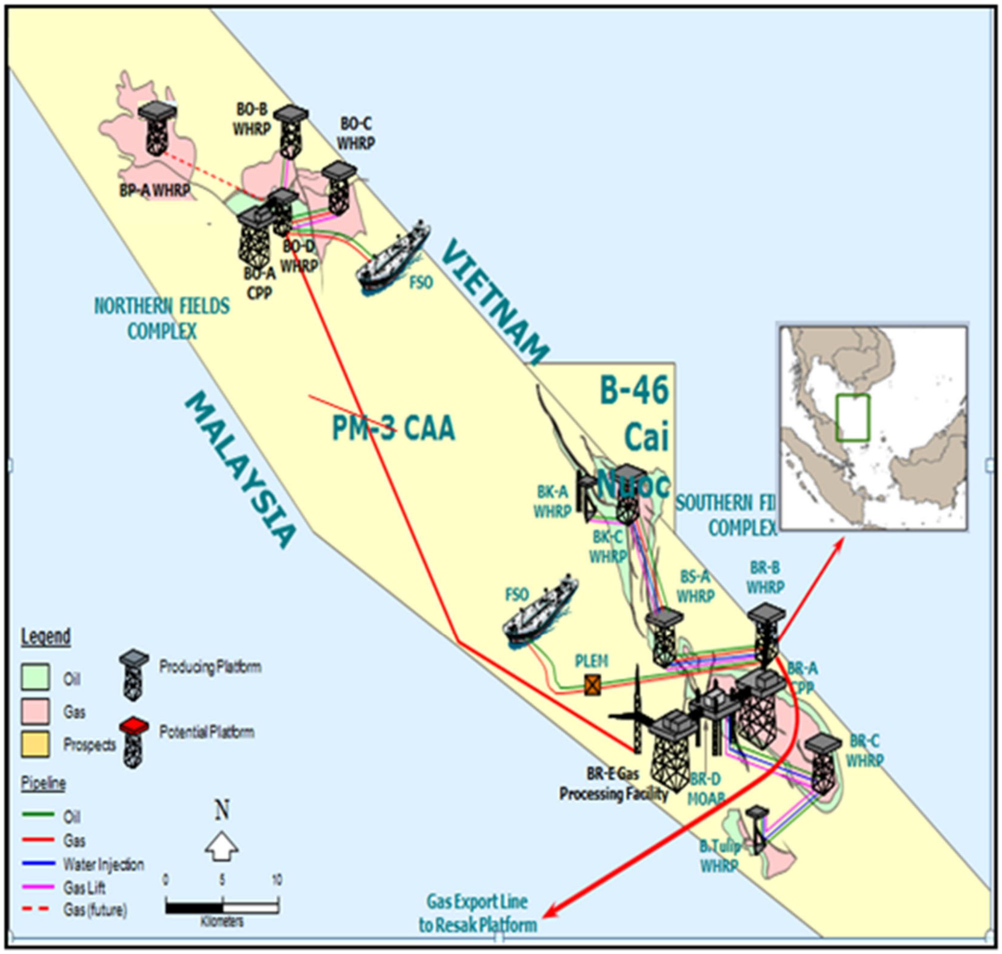

Figure 2-1: Map showing Location of Assets

2.2 Basis Of Opinion

The evaluation presented in this report reflects our informed judgment, based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, TTRPSE is not in a position to attest to the property title, financial interest relationships or encumbrances related to the property. Our estimates of Reserves and Resources are based on data provided by Hibiscus. We have accepted, without independent verification, the accuracy of the data and Vitol have confirmed in their letter of representation that the data are complete.

The report represents TTRPSE' best professional judgment and should not be considered a guarantee or prediction of results. It should be understood that any evaluation, particularly one involving future performance and development activities may be subject to significant variations over short periods of time as new information becomes available.

All Reserves and Resources definitions and estimates shown in this report are based on the 2018 SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Resource Management System ("PRMS") v1.03. A summary of PRMS is presented in Appendix B

2.3 Site Visit

No Site Visit was undertaken as part of the study. A review of operational HSE was beyond the scope of this study.

3 PM3 CAA BACKGROUND

The PM3 CAA is subdivided into northern and southern regions, which in total contains eight fields. The northern area consists of Bunga Orkid, Bunga Pakma, Bunga Aster and Bunga Lavatera, while the southern area consists of Bunga Kekwa, Bunga Raya, Bunga Seroja and Bunga Tulip.

The northern area is developed by the Bunga Orkid-A (BO-A) central production platform, which processes and exports the produced oil and condensate via pipeline to the FSO and gas to the Bunga Raya-E (BRE) platform (Figure 3-1).

Some 45 development wells (39 in Bunga Orkid and 6 in Bunga Pakma) have been drilled from four well head riser platforms (BP-A, BO-B, BO-C and BO-D) to exploit the hydrocarbon accumulations. First oil was achieved on 25th of March 2009.

The southern area is developed by a central production complex comprised of Bunga Raya-A (BR-A), Bunga Raya-D (BR-D) and Bunga Raya-E (BR-E) bridge linked platforms which process and export oil, gas and condensate from the Bunga Raya, Bunga Kekwa, Bunga Seroja and Bunga Tulip fields along with the gas and condensate from the northern Fields.. Development wells are drilled from six wellhead riser platforms, Bunga Raya-B (BR-B), Bunga Raya-C (BR-C), Bunga Kekwa-A (BK-A), Bunga Kekwa-C (BK-C), Bunga Seroja-A (BS-A) and Bunga Tulip-A (BT-A).

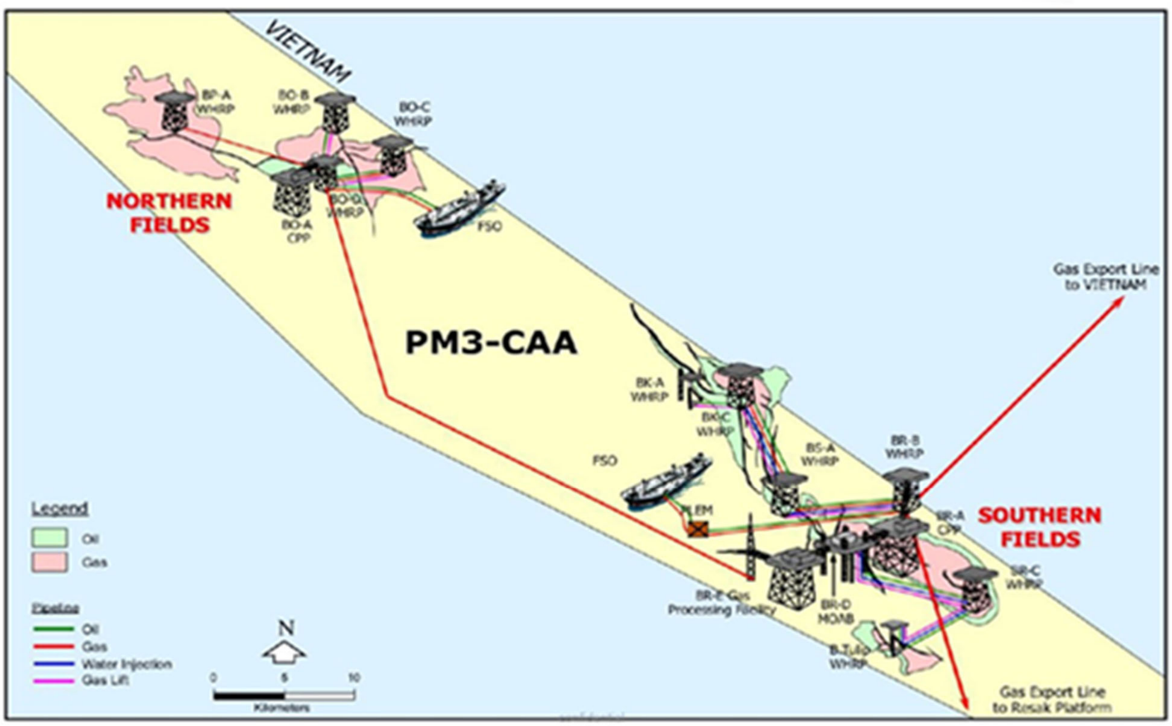

Figure 3-1: PM3 CAA Infrastructure[2]

Block 46 is located in Vietnamese waters adjacent to PM-3 CAA and contains the producing Cai Nuoc field and the Hoa Mai discovery. Cai Nuoc is an extension of the East Bunga Kekwa field and was unitised with East Bunga Kekwa in 2000, forming the East Bunga Kekwa – Cai Nuoc Unit field. Under the terms of the unitisation agreement, 24% of Unit Reserves are deemed to lie in Block 46. Fluids from the Unit field are produced via PM-3 facilities.

All gas is sold to PETRONAS and PetroVietnam.

[2] *VDR_Management Presentation 2020.12vF.pdf - Repsol*

3.1 Block History

Exploration in PM3 CAA started in the 1990's, when Hamilton Oil drilled the Bunga Orkid discovery well, Bunga Orkid-1 (BO-1) and the PSC was extended to the end of 2027 in 2016. Vintage seismic over the area shows modestly sized structures, which are often accompanied by a strong amplitude change associated with the presence of oil and gas in the stacked sand reservoirs.

The Bunga Orkid area originally consisted of four adjacent fault block accumulations (Bunga Orkid, North Bunga Orkid, East Bunga Orkid and West Bunga Orkid). Bunga Orkid was the first discovery in the PM3 CAA area with the successful drilling of Bunga Orkid-1 in 1991 followed by Bunga Orkid-2 in 1992. North Bunga Orkid and East Bunga Orkid were discovered in 2003 followed by West Bunga Orkid in 2004. The complex is developed by three wellhead platforms (BO-B, BO-C & BO-D) all tied back to a central processing platform (BO-A). Development drilling commenced in 2007, with first gas production in July 2008 and first oil in March 2009. In 2024 Bunga Aster G40SS10 was drilled and completed with a single oil producer via the BO-D platform, with first oil in May 2024.

Bunga Pakma was discovered in 1991 with the drilling of Bunga Pakma-1. Bunga Pakma North, situated in the adjacent, northern, fault block was discovered in 1998. Six gas producers were drilled from April 2018 to August 2018 and successfully delivered first gas on 21st May 2018. A new single wellhead riser platform called Bunga Pakma-A (BP-A) was installed and tied-back to the BO-D platform, which is approximately 9 km to the south. In 2023 the BPA-7 (formerly Bunga Lavatera-1) well was drilled from the BP-A platform to exploit the reservoirs in the North Bunga Pakma Nose structure.

Bunga Seroja was discovered in 1997 with the drilling of Bunga Seroja-1. The field is developed by a single wellhead platform (BS-A) which is tied back to the Bunga Raya Complex via the BR-B WHP which is bridge Linked to the BR-A Central Processing Platform.. A total of five development wells have been drilled. First production was in December 2003.

Bunga Tulip was discovered in 2003 with the drilling of Bunga Tulip -1 and three subsequent side-track wells drilled in 2004 (Bunga Tulip-1ST1, -1ST2, and -1ST3). The field is developed by two oil producers and two water injectors drilled from the BT-A wellhead platform. First oil production was delivered in October 2006.

The Bunga Kekwa area consists of two adjacent fault block accumulations: East Bunga Kekwa and West Bunga Kekwa. Bunga Kekwa was discovered in 1994 with the drilling of Bunga Kekwa-1 and subsequently defined in 1996 with Bunga Kekwa A1, A2, A3, and A4 wells and sidetracks. East Bunga Kekwa extends into Block 46 in Vietnamese waters and is part of the East Bunga Kekwa – Cai Nuoc Unit field, having been unitised in 2000. Bunga Kekwa is developed by a single wellhead platform (BK-C) and the BK-A LWS, a light wellhead stack, tied back via the Bunga Seroja platform to the Bunga Raya platform. First oil was achieved in July 1997.

The Bunga Raya area is composed a number of adjacent accumulations separated by faults: North Bunga Raya, Northwest Bunga Raya, East Bunga Raya and West Bunga Raya. Complex facilities are based around a central processing platform (BR-A), a bridge linked gas compression mobile offshore application barge or MOAB (BR-D) and a single wellhead platform (BR-C) which is connected to the BD-D Compression Platform via a 3km pipeline. A Gas Processing Facility BR-E is bridge-linked to the BR-D Compression Platform and receives gas from the Northern Fields BOD platform via a 54km/24" pipeline. The complex commenced production in late 2003, with water injection commencing in early 2004. A total of 34 wells have been drilled in the Bunga Ray Complex to date. North Bunga Raya has ceased production since May 2018 with no further production anticipated.

Since the last evaluation undertaken by TTRPSE, NBO H4 development drilling of two oil producers and four water injectors has been completed, with first oil in Q2 2022. BRB-LL and BOC infill drilling was completed with first oil in Q4 2022 and Q1 2023 respectively. The Bunga Lavatera-1 well discovered the G50SS10 reservoir and North Bunga Pakma Nose gas in Q2 2023. Bunga Aster G40SS10 was drilled and completed with a single oil producer with first oil in May 2024.

CO_2 content varies by field and the sales gas has a CO_2 content specification, these CO_2 contents have been provided by Hibiscus as vol% and applied to each field individually for the NFA and development projects.

Historical production plots for combined oil and condensate, and for sales gas and are shown in Figure 3-3 & Figure 3-4 respectively.

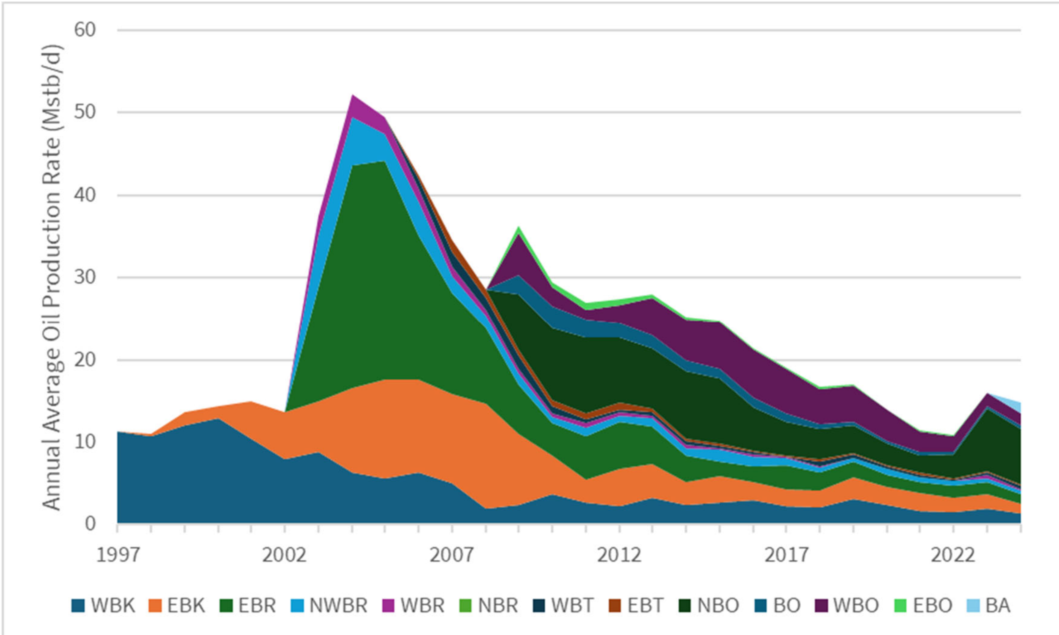

Figure 3-2: **PM3 CAA Historical Oil Production**

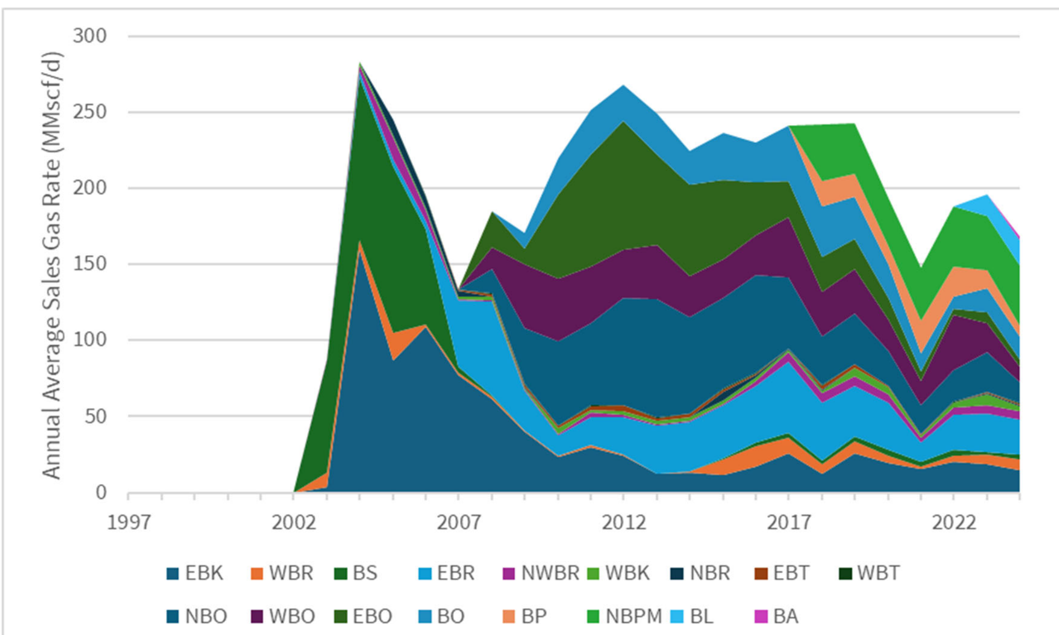

Figure 3-3: **PM3 CAA Historical Sales Gas Production**

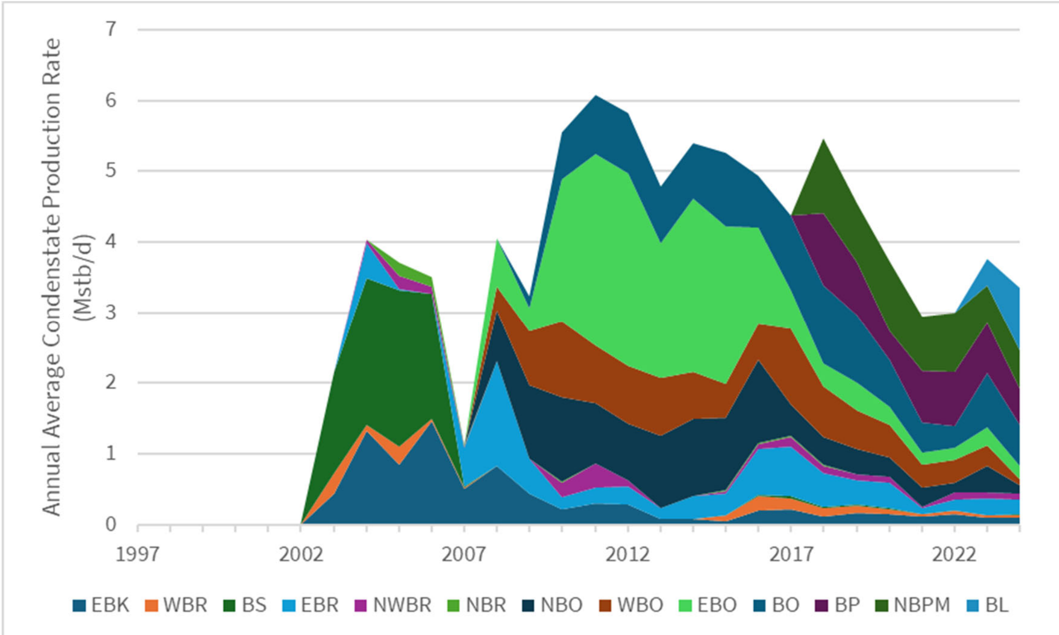

Figure 3-4: PM3 CAA Historical Condensate Production

3.2 Malay Basin Geology

The Malay basin has three recorded phases of tectonic history; An extension/ rift phase in the Late Cretaceous to Late Oligocene, followed by compression in the Middle to Late Miocene, which caused structural uplift and inversion and formed the dominant anticlinal structure seen in the fields, followed by, more recently, a mild extension which can be seen in faults that extend to surface and which have been re-activated.

Thick fault bounded sediments associated with the early phase of extension were compressed into structural highs, that occurred approximately 22 -10 MYA and is shown by thinning of the F, G, H, I and J Groups (Figure 3-5). The result is a basin containing a thick central tertiary section of approximately 14km, characterised by steeply dipping faults that have been mapped to basement. Upper reservoir sections are characterised by fault dip-anticlinal structures. Towards the flanks of the basin the strata is relatively gently dipping with a few major normal faults and half grabens.

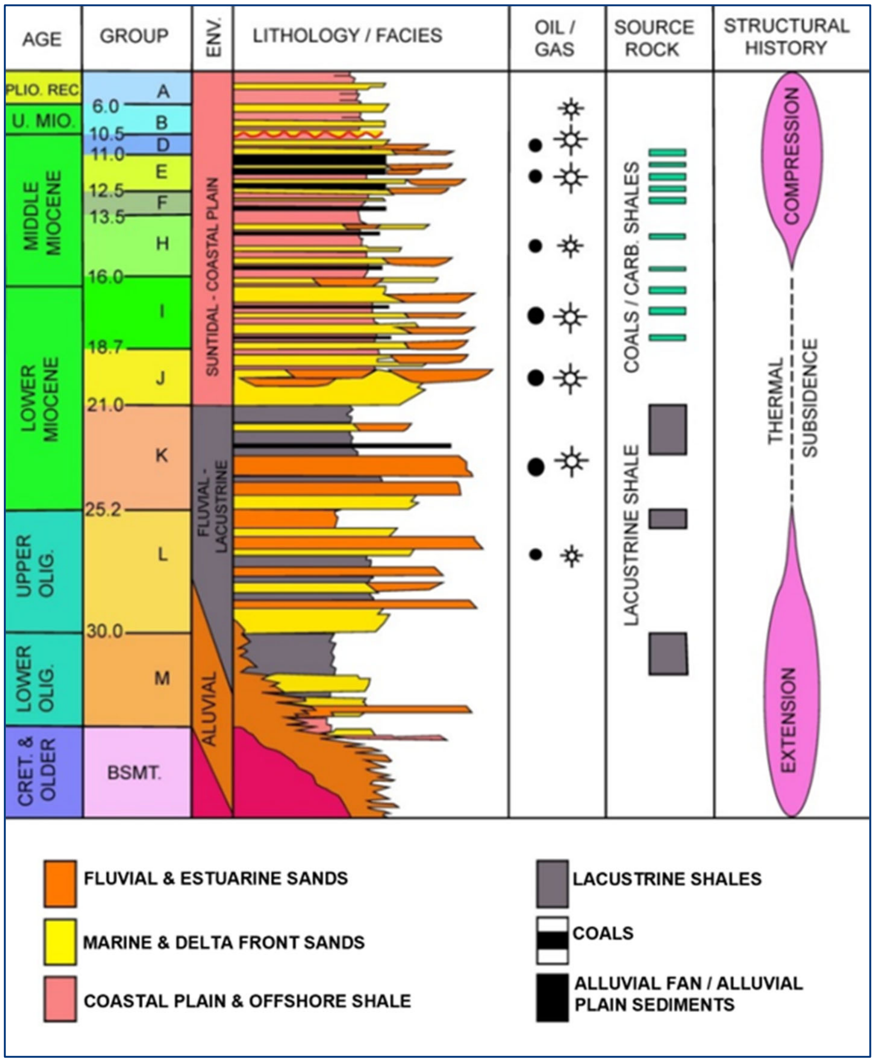

Figure 3-5: Stratigraphy of the Malay Basin[3]

The Assets comprise Lower – Upper Miocene age sands from the L-D Groups, as shown on the regional stratigraphic column (Figure 3-5).

The deepest L sands are typically braided plain facies, comprises laterally extensive lacustrine and fluvial sands, that thin towards the south of the PM3 CAA block, where basement/Mesozoic horst blocks are more prominent.

[3] *Hassann. M, Bhattacharya. S.K, Mathew. M.J, Siddiqui. N. A, (2015): Understanding Basin Evolution through Sediment Accumulations Modelling: A case study from Malay Basin. Research Journal of Applied Sciences, Engineering and Technology 11(4): 388-395*

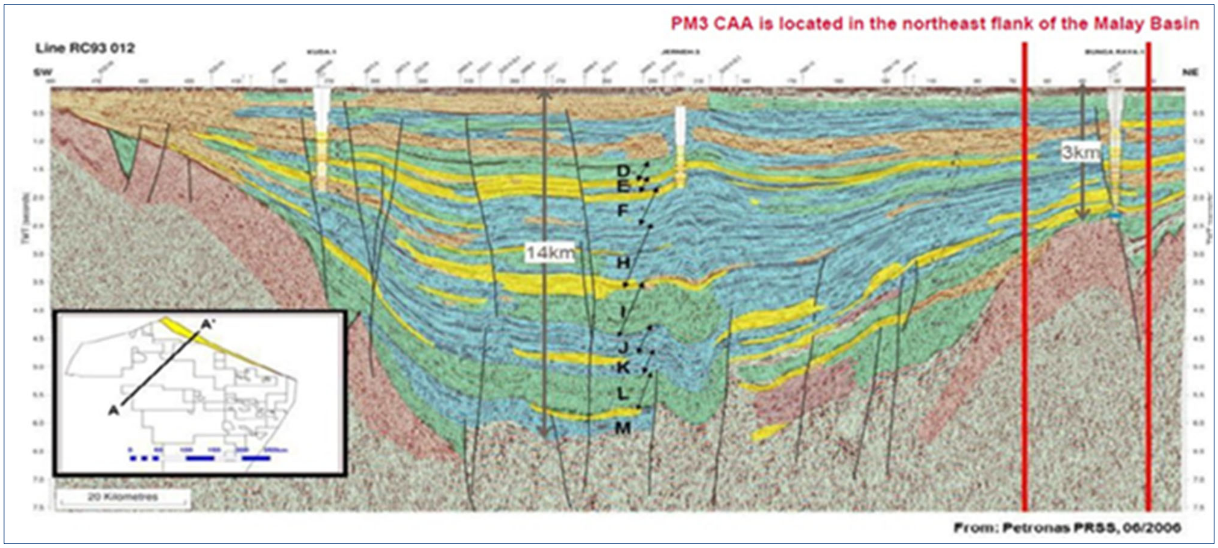

Figure 3-6: Seismic Section through Malay Basin[4]

A large transgressive episode caused an abrupt change from continental / lacustrine to marine depositional environment, the basal K group is dominated by lacustrine shales, which are considered the primary hydrocarbon source, especially in the centre of the basin. The K group was then followed by a more regressive sequence for the J group, which are predominantly sub-tidal bars becoming coastal plain and tidal shelf deposits in the younger I-D sands. It should be noted that Hibiscus defined a G group, within the upper part of the H group. This is not present in the stratigraphic scheme originally described by ExxonMobil and used by PETRONAS for the Malay Basin.

The change in depositional setting leads to a series of different trapping styles with many of the fields comprising a series of trapping ranging from structural, stratigraphic or combination traps (Figure 3-7). This results in stacked pay within the field often trapped by different mechanisms.

Sand quality and distribution varies depending on the depositional setting, although typically good quality reservoir sands show high porosity (20-30%) and up to 10's of metres thickness. Thin bed sands also contribute to pay; these exhibit a low resistivity response in hydrocarbons.

Seal comprises intra-formational shales within the fluvial delta plain, with good lateral seal provided by the tidal muds, estuarine muds or mud filled abandoned channels. This is particularly important in the PM3 CAA region, which contains a high concentration of CO_2 in the lower reservoir sands (L-H). Above the seal in the H group CO_2 concentrations are much lower[5].

All fields are covered by 3D seismic of varying vintage, ranging from 1995 over the Kekwa field through to a new 2020 acquisition over the PM3 area, with the hope it will help unlock additional reservoir potential.

[4] VDR Management Presentation, December 2020, Repsol

[5] PM 02_34_NBO_H4_FDP.pdf, Repsol

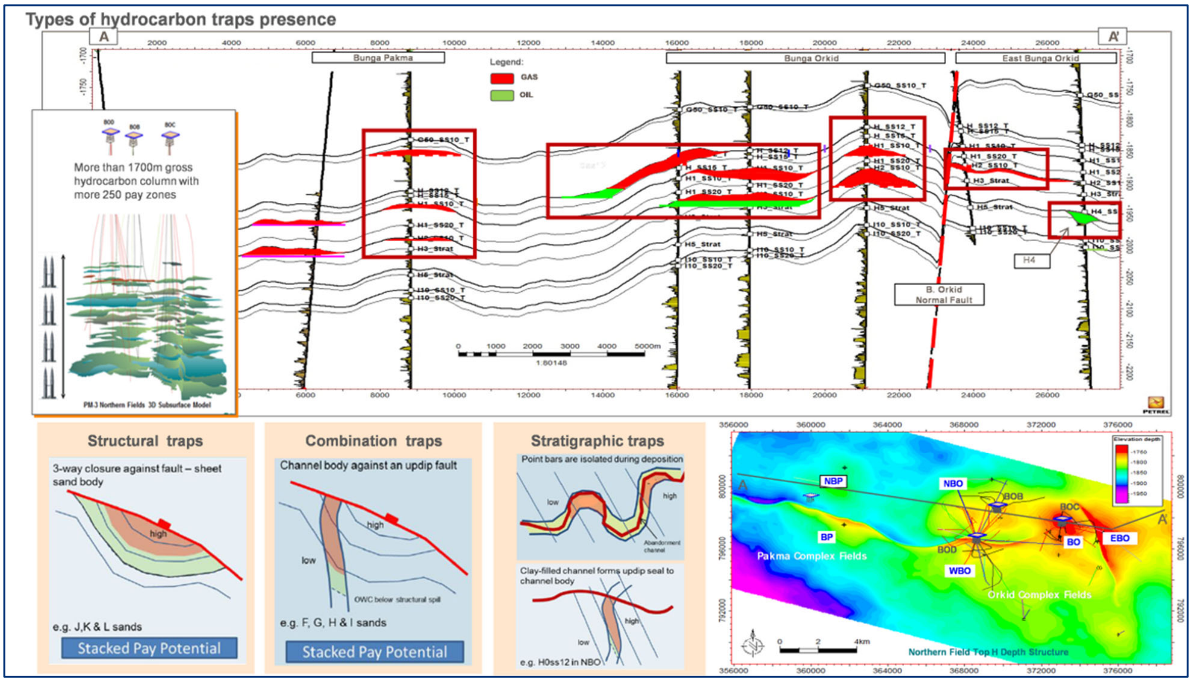

Figure 3-7: Illustration of PM3 Trapping Styles

4 HIBISCUS DEVELOPMENT CASE

Hibiscus has presented its planned well interventions program and development projects as outlined below (and detailed in Table 1-1):

- Existing Production (Developed Producing)
- Planned Interventions - Plug & Perforate (Developed Non-producing)
- Sanctioned Development Projects (Undeveloped)
  - Gas Cap Blowdown Phase 1
  - North Bunga Pakma Nose
  - Low Pressure Gas Project (BOD-2 and BOD-22)
  - Bunga Raya Infill
    - North West Bunga Raya
    - East Bunga Raya
- Defined Developments within 5-year development window (Contingent Resources)
  - Bunga Saffron
  - Bunga Aster Phase 2
  - Gas Cap Blowdown Phase 2
  - Low Pressure Gas Project (within 5 years)
- Defined Developments outside 5-year development window (Contingent Resources)
  - Bunga Matahari
  - Hoa Mai
  - Gas Cap Blowdown Phase 3
  - Low Pressure Gas Project (after 5 years)
  - Sliver

4.1 Existing Production & Planned Interventions

Existing production in the block is from a total of 16 accumulations, in eight fields, developed around two hubs (North and South), with Bunga Orkid and Bunga Pakma, Bunga Aster & Bunga Lavatera to the north, and Bunga Kekwa, Bunga Raya, Bunga Seroja & Bunga Tulip to the south. The fields contain a mixture of oil, associated gas, non-associated gas and condensate, as outlined in Table 4-1.

Development Area	Complex	Field	Oil	Associated Gas	Non-Associated Gas	Condensate
North	Bunga Orkid	Bunga Orkid	Y	Y	Y	Y
		North Bunga Orkid	Y	Y	Y	Y
		East Bunga Orkid	Y	Y	Y	Y
		West Bunga Orkid	Y	Y	Y	Y
	Bunga Pakma	Bunga Pakma[1]	N	N	Y	Y
		North Bunga Pakma[1]	N	N	Y	Y
	Bunga Aster	Bunga Aster	Y	Y	N	N
	Bunga Lavatera	Bunga Lavatera	N	N	Y	Y
South	Bunga Seroja	Bunga Seroja	N	N	Y	N
	Bunga Tulip	Bunga Tulip	Y	Y	N	N
	Bunga Kekwa	East Bunga Kekwa[2]	Y	Y	Y	Y
		West Bunga Kekwa	Y	Y	N	N
	Bunga Raya	North Bunga Raya	N	N	Y	Y
		East Bunga Raya	Y	Y	Y	Y
		West Bunga Raya	Y	Y	Y	Y
		Northwest Bunga Raya	Y	Y	Y	Y

1 Bunga Pakma & North Bunga Pakma reported together.

2 East Bunga Kekwa and Cai Nuoc are unitised forming the East Bunga Kekwa-Cai Nuoc Unit Field. 24% of Reserves are deemed to lie in Cai Nuoc under the terms of the unit agreement.

Table 4-1: PM3 CAA Assets & Fluids Summary

5 PRODUCTION FORECASTS

5.1 Existing Production (NFA Case)

The No Further Activity (NFA) production forecast case has been assessed for all producing fields in PM3 CAA by Decline Curve Analysis (DCA) at the field level based on production data supplied by Hibiscus in OFM to October 2024.

For each producing field, primary phases (oil and non-associated gas) have been forecasted where appropriate, with secondary phases (associated gas and condensate) forecast separately.

Gas forecasts were estimated using DCA on the basis of produced gas rate vs time or cumulative gas production for all cases. Proved (1P), Proved plus Probable (2P) and Proved plus Probable plus Possible (3P) forecasts were based on a hyperbolic curve fit, with coefficients and decline rates tuned to match existing production trends.

The OFM database contained both produced gas and sales gas data, which was used to estimate a sales gas conversion factor, primarily related to the removal of CO_2, fuel and flare, and efficiency loses. This shrinkage is typically in the range of 45-50%. Hibiscus has advised that a turn-down rate cutoff of 100 MMscf/d is applied to the base NFA gross gas production profile where there is no longer sufficient gas for export and the remaining gas will be used for fuel to support the other development activities.

Condensate production has been estimated on the basis of gas production using the condensate gas ratios for each field based on OFM production data.

This methodology is consistent for all assets in PM3 CAA except Bunga Aster which was brought on-stream in May 2024 and therefore has insufficient production data for DCA. For Bunga Aster, TTRPSE has performed an independent review of the in-place volumes and rescaled the Operator forecast profiles accordingly (see Section 5.2).

Oil forecasts were estimated based on an exponential fit of oil rate vs. time or cumulative production for the Proved (1P) case and Proved plus Probable plus Possible (3P) based on Log Water-Oil Ratio vs. cumulative production, with Proved plus Probable (2P) forecasts taken as the arithmetic average of 1P and 3P.

5.2 Bunga Aster Phase 1

Bunga Aster was discovered by the Bunga Aster-1 well which encountered approximately 20 m (gross) of oil-bearing sandstone, with 2.7% CO_2, in the G40SS10 sand. The Bunga Aster-1 well was drilled from the existing BO-D platform and completed as a single oil producer and renamed as BOD-27. First oil started on 4th May 2024.

The Bunga Aster Field is a linear NW-SE dipping erosional fluvial channel that has been picked by Hibiscus using seismic attribute data derived from the 2017 Pakma 3D PSDM survey. Structurally the G40SS10 reservoir has a small saddle, situated approximately halfway along the structure. Depending on the depth of the contact, the saddle could bifurcate the structure and result in some compartmentalisation of the oil.

Hibiscus plan to drill another well, Bunga Aster 2, to appraise the area downdip of the Bunga Aster 1 well. If results are favourable, Hibiscus propose to execute Phase 2 of the development with a further eight wells, comprising five producers and three water injectors, from a new platform in 2029.

5.2.1 Petrophysical Assessment

TTRPSE did not independently evaluate Hibiscus' petrophysical evaluation of the Bunga Aster-1 well. However, comparison of the derived values with the average reservoir values of porosity and permeability from the Malay basin indicated that the Bunga Aster-1 petrophysical estimation was within the expected regional average.

TTRPSE then compared the petrophysically-derived NTG for the Bunga Aster-1 well to those estimated from the nearby Bunga Saffron field and found them to be within the expected range (80-95% NTG).

TTRPSE therefore accepts the Hibiscus petrophysical evaluation of the Bunga Aster-1 well and has based the range applied in its independent volumetric estimation upon this.

5.2.2 Geological Assessment

No Petrel™ modelling project exists for the Bunga Aster Field, though there is a project containing all the surfaces, well data and seismic extracts, including Far and near Angle stack extracts, and AVO for the G40SS10[6]. Communication with Hibiscus confirmed that map-based volumes have been estimated with reservoir parameters derived from the Bunga Aster -1 well.

TTRPSE reviewed the supplied tops for G40_SS10 in the Bunga Aster-1 well and agree that they look correct. However, the Petrel™ seismic project only contained one well and therefore the Bunga Aster-1 well top interpretation could not be directly cross checked with any other regional well.

Hydrocarbons are trapped within a channelised section of the G group and as such are constrained by a series of seismic attribute derived polygons. TTRPSE reviewed the seismic extract data from the Petrel™ model, along with some explanatory slides. TTRPSE accepts that the near and far extraction data shows potential sand presence. However, TTRPSE did not see any evidence that the supplied AVO response shows hydrocarbons rather than other fluids, such as water.

TTRPSE used Hibiscus' Top G40SS10 sand surface from the Petrel project[7] to generate a series of area-depths. Gross reservoir thickness was estimated using both the Bunga Aster-1 well and thicknesses for the G40SS10 from the Bunga Saffron Field, which is situated to the north of Bunga Aster.

Hibiscus volumes use a single set of gas and oil hydrocarbon contacts estimated from data gathered by the Bunga Aster-1 well and structural mapping, to cover the entire Bunga Aster structure.

The Bunga Aster-1 well intersected hydrocarbons but did not find either a gas or and oil contact. Therefore, Hibiscus has derived the contacts using a mixture of structural spill depths and Hydrocarbons-Up-To or Down-To.

Gas-oil contacts (GOC) have been estimated by Hibiscus using the depth of the mapped crest as the shallowest contact, the Oil-Up-To as the deepest contact and assuming a midpoint between these depths for the P50 contact.

Oil-water contacts (OWC) have been estimated by Hibiscus based on the Oil-Down-To in the Bunga Aster-1 well, the deepest structural spill of the entire Bunga Aster structure as the deepest contact and a midpoint between these depths as the P50 contact.

TTRPSE considers that this is an acceptable approach at this point in the field's life cycle.

For its independent volumetric estimation, TTRPSE used the same gas contacts as Hibiscus. However, TTPSE created two volumetric models based on the saddle point that intersects the field at the expected mid-point oil contact, the oil contacts used differ slightly.

For the Full area model TTRPSE uses the same contacts as Hibiscus. However, for the partial area model TTRPSE uses the same ODT as Hibiscus for the P99 case, but instead of the spill point for the entire structure, as used by Hibiscus and the TTRPSE Full area model for the P10 case, TTRPSE uses the deepest point of the saddle. The P50 is then estimated between these.

5.2.3 Reservoir Engineering Assessment

TTRPSE has rescaled the Hibiscus NFA profile in proportion to the relative differences in GIIP estimation.

[6] Bunga Aster Post Drill Volume.pet

[7] '*G40SS10_SandTop_phantom_Vertical_Tie_only_to_Bunga Aster-1*'

5.3 Planned Well Interventions

Hibiscus has provided an updated summary of planned well interventions and estimated incremental recovery for each activity.

Workovers and production enhancement activities are carried out by Hibiscus on a regular basis. Insufficient time was available to fully review each potential intervention, so incremental production associated with these activities were based on type curves.

TTRPSE reviewed individual well production performance and generated Low, Mid and High type curves based on produced gas for each field. These were used to determine the incremental production for the planned interventions in each field.

5.4 Sanctioned Development Projects

Four fully sanctioned developments have been presented to TTRPSE by Hibiscus:

- North Bunga Pakma Nose
- Gas Cap Blowdown Phase 1
- LP Gas Project BOD-2 and BOD-22
- Bunga Raya Infill
  - North West Bunga Raya
  - East Bunga Raya

These projects have been reviewed by TTRPSE. These projects are classed as Reserves.

In order to generate production forecasts for these projects, TTRPSE has reviewed data provided by Hibiscus such as maps, petrophysical interpretations, seismic interpretations, material balance models. Where appropriate, TTRPSE has generated independent estimates of volume-in-place and developed a range of production profiles.

5.4.1 North Bunga Pakma Nose

North Bunga Pakma Nose is part of the Bunga Pakma development from the BP-A platform. The I23SS10 and I40SS10 sands were penetrated by the BPA-7 well (Bunga Lavatera-1) in 2023. The extent of sands is identified from amplitude anomalies on seismic data, the anomalies are correlated to sands rather than hydrocarbon filled sands. Both layers contain gas with 26% and 57% CO_2 in I23SS10 and I40SS10 respectively. No logged contacts were encountered so a range of contacts is inferred from structural mapping and for I40SS10 pressure data from nearby wells.

5.4.2 Gas Cap Blowdown Phase 1

The Gas Cap Blowdown project (GCBD) aims to produce the remaining gas cap of a series of currently or previously produced oil reservoirs. It is composed of three phases:

- Phase 1: North Bunga Orkid (NBO) I68SS20 Reservoir – First Gas is planned for Q2 2026.
- Phase 2: East Bunga Kekwa (EBK) I-90 Reservoir – First Gas is planned for Q1 2027.
- Phase 3: NBO I10SS20, NBO I36SS10, EBK I-60, EBR I-115U/L and EBR I-40L. – First Gas is planned for 2030.

TTRPSE notes that the three phases for the Gas Cap Blowdown are at different levels of maturity, and so has completed an independent technical evaluation of Phase 1 and Phase 2 (Section 5.5.3) only.

5.4.3 Low Pressure Gas Project (BOD-2 and BOD-22)

Hibiscus has presented profiles for a Low Pressure Gas project, which involves reactivation or workover of existing wells and flowing them through the low pressure system. Studies are still ongoing to identify the final full list of targets with BOD-2 and BOD-22 identified as firm targets for October/November 2025.

5.4.4 Bunga Raya Infill

Bunga Raya comprises a series of stacked channel and tidal sand reservoirs that produce both gas and oil from a series of accumulations bisected into by a northwest – southeast trending fault.

The Bunga Raya Infill project is comprised of infill wells in two reservoirs – North West Bunga Raya and East Bunga Raya. Due to decreasing production from other reservoirs in the Bunga Raya complex, Hibiscus is now looking to drill two new infills into the I-50L reservoir to drain two areas of the Bunga Raya field (NWBR and EBR) that are thought to have only been partially swept.

5.5 Defined Developments (within 5-year development Window)

A number of development projects have been presented to TTRPSE which do not have a firm commitment and are therefore categorised as Contingent Resources.

In order to generate production forecasts for these projects, TTRPSE has reviewed data provided by Hibiscus such as maps, petrophysical interpretations, seismic interpretations, material balance models. Where appropriate, TTRPSE has generated independent estimates of volume-in-place and developed a range of production profiles.

5.5.1 Bunga Saffron (Previously Bunga Saffron Point Bar B)

Bunga Saffron (Previously Bunga Saffron Point Bar B) was discovered by the NBP-3 (Bunga Saffron-1 and -ST1) well in May 2019.

5.5.2 Bunga Aster Phase 2

As described in Section 5.2, Bunga Aster is currently producing through a single well which commenced production of oil in May 2024. Hibiscus plans to further develop this field with eight infill wells (five producers and three water injectors).

5.5.3 Gas Cap Blowdown Phase 2

Gas Cap Blowdown (GCBD) Phase 2 comprises gas production from the EBK I-90 reservoir and comprises a large braided costal channel and point bar system that curves from the northwest to the south. Two structures have been identified within the Bunga Kekwa area, separated by a large fault zone; The western (WBK), downthrown trap which contained oil and the larger eastern (EBK) 4-way dip closed structure, that contained a large free gas cap and an associated oil rim.

GCBD Phase 2 is focussed on the development and production of only the gas in the EBK structure

5.5.4 Low Pressure Gas Project

Hibiscus has presented profiles for a Low Pressure Gas project, which involves reactivation or workover of existing wells and flowing them through the low pressure system. Studies are still ongoing to identify the final list of targets with at least two wells planned to start production in 2025. Profiles have been created by Hibiscus on a well-by-well basis up to end 2028, after which a type well curve approach has been used to generate a profile for a notion list of future wells. TTRPSE has reviewed the inputs and used scaling factors to account for variations in GIIP and a portfolio-based chance of success to give a range of profiles.

5.6 Defined Developments (outside 5-year development window)

A number of development projects have been presented to TTRPSE which either do not have a firm commitment or fall outside a five-year development window and are therefore categorised as Contingent Resources – Development Unclarified.

TTRPSE has not independently reviewed these plans and instead Hibiscus forecast profiles for the purposes of this evaluation.

5.6.1 Bunga Matahari

Bunga Matahari is a small structure at the southern extension of Bunga Orkid which was discovered and tested gas via the Bunga Matahari-1 well in 2006. Development is planned in 2030 via a single gas producer. As this project falls outside of the 5-year development window, TTRPSE has not independently evaluated the plan and uses the profiles as provided by Hibiscus for this evaluation.

5.6.2 Gas Cap Blowdown Phase 3

GCBD Phase 3 current candidates presented by Hibiscus are NBO I10SS20, NBO I36SS10, EBK I-60, EBR I-115U/L and EBR I-40L which are planned for development starting in 2031. As this project falls outside of the 5-year development window, TTRPSE has not independently evaluated the plan and uses the P50 profile as provided by Hibiscus for this evaluation, with the Low and High cases generated using scaling factors of 0.7 and 1.3 respectively.

5.7 Immature Developments (outside 5-year development window)

5.7.1 Sliver

Sliver was discovered in 2007 with well Sliver-1 in the southeast of the PM3 block. Subsequently, in 2010, Sliver-2 was drilled and tested the downdip potential of the I-90, K-10 and lower K sands. Development of the Sliver I-40U and I-90 reservoirs are currently planned for 2031. As this project falls outside of the 5-year development window, TTRPSE has not independently evaluated the plan nor classified as Reserves/Contingent Resources and used the profiles as provided by Hibiscus for completeness.

6 FACILITIES

PM3 CAA fields are grouped around a North and South hub.

The North consist of Bunga Orkid and Bunga Pakma. Bunga Orkid comprises three well head riser platforms (WHRP's) (BO-B, BO-C, BO-D) linked back to the Bunga Orkid central processing platform (BO-A). Bunga Pakma is produced through a single well head platform (BP-A) linked back to BO-A.

There are 46 active producing wells in the North fields.

Oil from the northern fields is piped to an FSO near BO-A and is exported by shuttle tanker. Gas from the North hub is piped to Bunga Raya in the South hub through a PETRONAS owned 24" pipe, where it is exported onwards via the Resak field facility in PM6 to Kerteh.

The South consists of Bunga Raya, Bunga Kekwa, Bunga Tulip and Bunga Seroja. Bunga Raya comprises five WHRP's (BR-B, BR-C, BT-A, BS-A, BK-C) and one Light Weight Structure platform (BK-A) linked back to Bunga Raya Complex processing platform (BR-A). BR-A is also bridge linked to a gas compression MOAB (BR-D) which is bridge-linked to the BR-E Gas Processing Platform.

Oil from the southern fields is piped from BR-B to an FSO and is exported via shuttle tanker. Malaysian gas from the South fields is exported from BR-B through a PETRONAS owned 24" pipe, where it is exported onwards via the Resak field facility in PM6 to Kerteh. Vietnam gas produced at BK-C is exported from BR-B to Vietnam via a separate 18" pipeline.

7 COST ENGINEERING

Based on the NFA and development project production profiles for each asset, Hibiscus has provided TTRPSE with its associated cost profiles. TTRPSE has reviewed the Capex, Opex, and Abex provided by Hibiscus and accepted the estimates.

It is noted that the projected Capex predictions includes an allowance for a Carbon Capture and Storage (CCS) project. TTRPSE has not been provided any details of the CCS project so are unable to offer comment on the suitability of the costs allowed for by the operator.

Hibiscus have presented details of an Opex reduction scheme that will significantly reduce Opex from 2033 onwards. RPS have accepted the proposed savings in operating costs.

Abandonment costs will be paid over the economic field life rather than incurred following cessation of production. Costs are based on unit production.

8 ECONOMIC EVALUATION

8.1 Contractual Rights Overview

PM3 CAA PSC overview and its fiscal terms, as used to conduct commercial evaluation; Unitisation Agreement its Tract participation and Unit Participation are presented in Table 8-1 to Table 8-3.

	PM3 CAA PSC	PM3 CAA PSC Extension
Contractors / Participating Interest	PETRONAS Carigali (35.0%) Hibiscus Malaysia Oil and Gas Limited (22.3%) Hibiscus Malaysia Oil and Gas (PM3) Limited (12.7%) PVEP (30.0%)	PETRONAS Carigali (35.0%) Hibiscus Malaysia Oil and Gas Limited (22.3%) Hibiscus Malaysia Oil and Gas (PM3) Limited (12.7%) PVEP (30.0%)
Scope	Governs the exploration, development activities, and production of liquids and natural gas in PM3 CAA Sets out each Contractor's responsibilities and commitments as well as terms on allocation of output (for royalty and profit crude oil / natural gas) and cost recovery mechanism.	Governs the exploration, development activities, and production of liquids and natural gas in PM3 CAA Sets out each Contractor's responsibilities and commitments as well as terms on allocation of output (for royalty and profit crude oil / natural gas) and cost recovery mechanism.
Effective Date and Duration	Effective as of 16th February, 1989 PSC extension has been granted for a further term ending on 31st December 2027	Effective January 1, 2028. PSC extension has been granted for a further 20-year term ending on 31st December 2047
Royalty	As per PSC terms	As per PSC terms
Cost Liquids / Gas	As per PSC terms	As per PSC terms
Unused Liquids / Gas and Available Profit Liquids / Gas	As per PSC terms	As per PSC terms
Research Cess	As per PSC terms	As per PSC terms
Export Duty	As per PSC terms	As per PSC terms
Supplementary Payment:	As per PSC terms	As per PSC terms
Petroleum Income Tax rate	38%	38%
Extension bonus payment	As per PSC terms	As per PSC terms
Abandonment Cess	Facilities abandonment costs are deposited in an escrow account according to the ratio of production to remaining reserves. Wells abandonment costs are recovered as paid.	Facilities and wells abandonment costs are deposited in an escrow account according to the ratio of production to remaining reserves.

Table 8-1: PM3 CAA PSC Fiscal Terms

Unitisation Agreement of PM3 CAA	
Counterparties	PETRONAS PetroVietnam
Scope	Establishes the creation of East Bunga Kekwa – Cai Nuoc unitised field that overlaps the boundary lines between Peninsular Malaysia and Vietnam Provides for the joint administration and management of as well as for the sharing of hydrocarbons in the unitised field
Effective Date	Effective as of 10 February 2000
Tract participation and Unit Participation	As presented in Table 8-3

Table 8-2: PM3 CAA Unitisation Agreement

Petroleum Contract	Group Interest	Tract Participation	Unit Participation
PM3 CAA		75.9508%	
Hibiscus Oil & Gas Malaysia Limited	22.33%		16.96%
Hibiscus Oil & Gas Malaysia (PM3)	12.67%		9.62%
PETRONAS Carigali	35.00%		26.58%
PVEP	30.00%		22.79%
Block 46 (Cai Nuoc)		24.0492%	
Hibiscus	70.00%		16.83%
PVEP	30.00%		7.21%
Total		100.00%	100.00%

Table 8-3: PM3 CAA Unitisation Agreement Tract participation and Unit Participation

Summaries of Gas Sales and Purchase Agreement key glossaries and terms are presented in Table 8-4.

Upstream Gas Sales Agreements (UGSA)	
Signing Date	10th February, 2000
Term	Initial term was for a period of 10 years and was initially extended until end of the existing PSC term (31 December 2027), and then a further 20-years until December 2047 consistent with the recent PSC extension
Counterparty	PETRONAS PetroVietnam PM3 CAA contractors: PETRONAS Carigali (35%), Hibiscus Malaysia Oil and Gas Limited (22.33%), Hibiscus Malaysia Oil and Gas (PM3) Limited (12.67%), PVEP (30%)
Scope	The contract lays down the obligations of both the Hibiscus, the PM3 CAA contractors, and the buyers, PETRONAS and PetroVietnam The contract defines the quality, quantity and price of the gas sold from the field

Delivery	The PM3 CAA contractors have to deliver the contracted gas capacity to PETRONAS or PetroVietnam delivery points, where the ownership of the gas will be transferred to PETRONAS or PetroVietnam respectively In case the PM3 CAA contractors fails to deliver the contracted daily quantity to either PETRNAS or PetroVietnam, they have to deliver the "Penalty Quantity" in the following year Penalty Quantity is the difference between the contracted daily quantity and quantity delivered at delivery point The first delivery of gas in any year will be deemed to be the Penalty Quantity accrued in preceding year
Pricing	As per UGSA terms

Table 8-4: Upstream Gas Sales Agreements (UGSA) Key Terms

Hibiscus has advised TTRPSE that the Key Principles Agreement (KPA) for the further extension of the current PM 3 PSC and UGSA to December 2047 was signed in March 2025. RPS has not seen this agreement. However, Hibiscus has advised TTRPSE that the KPA obliges Hibiscus to undertake projects categorised under Minimum Exploration Work Commitment (MEWC), Minimum Development Work Commitment (MDWC) and Minimum Production Work Commitment (MPWC). Hibiscus advise that the MEWC, MDWC and MPWC projects will be undertaken and executed, and that Hibiscus will be considered to have fulfilled its obligations and will not be required to incur further expenditure in carrying out those activities, nor be subjected to any penalties.

All MDWC and MPWC activities that have yet to be sanctioned which come with production have been included in TTRPSE's economic evaluation of the respective Contingent Resource. The cost associated with the CCS project which has no associated production and exploration wells (which are assumed to be not successful in the base case) are included as costs incurred in TTPRSE's valuation of the PSC Reserves case.

8.2 Petroleum Pricing Basis

The valuation has been based on the TTRPSE Q2 2025 long term forecast for Brent (forward curve between 2025 and 2033; long term price of US$ 70 per barrel flat real at 2 per cent per annum thereafter) as shown in Table 8-5.

Based on the historical Tapis crude oil and condensate prices provided by Hibiscus, PM3 CAA crude oil and condensate were traded at a 5% premium to Brent. A summary of PM3 CAA crude oil price (less offtake fee of US$ 0.25 per barrel), PM3 CAA condensate price, and the implied gas price based on the gas pricing formula in UGSA is presented in Table 8-5.

Year	TTRPSE Brent	PM3 CAA Crude Oil and Condensate	PM3 CAA gas price
	US$/bbl	US$/bbl	US$/Mscf
2025	65.0	68.0	4.3
2026	65.0	68.0	4.3
2027	70.0	73.3	4.7
2028	70.0	73.3	5.2
2029	70.0	73.3	5.2
2030	73.0	76.4	5.4
2031	73.0	76.4	5.4
2032	75.0	78.5	5.6
2033	78.0	81.7	5.8
2034	84.5	88.5	6.3
2035	+2%	+2%	+2%

Table 8-5: TTRPSE Price Forecast; PM3 CAA Crude and Condensate Realised Price Forecast, and Implied Gas Price Forecast

8.3 Cashflow Analysis

The Economic Limit Test ("ELT") performed for the determination of Reserves is based on TTRPSE's estimates of recoverable volumes, a review of the Company's estimates of Capex and Opex, and inclusion of other financial information and assumptions, as outlined in Capex, Opex and Abex sections.

The PSC is assumed to reach its economic limit when the cumulative value of its undiscounted net cash flow before tax ceases to increase. All projects to be classified as Reserves must be economic under defined conditions[8]. RPS has therefore assessed the future economic viability of each case on the basis of its pre-tax undiscounted Net Cash Flow MOD.

An annual inflation rate of 2 per cent has been built into the ELT.

The effective date of this report is 1st January 2025 and this has been used as the discount date for the valuation.

[8] *PRMS 2018: 3.1.2.1 Economic determination of a project is tested assuming a zero percent discount rate (i.e., undiscounted). A project with a positive undiscounted cumulative net cash flow is considered economic.*

9 Reserves and Resources

9.1 Reserves

Hibiscus Net Entitlement Reserves for the PSC with current expiry in December 2027 are presented in Table 9-1 to Table 9-4.

SUMMARY OF OIL RESERVES
As of 01 January 2025
To current PSC expiry (December 2027)
BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Reserves[1,2] (MMstb)		
	1P	2P	3P
PM3 CAA	2.2	2.7	2.9

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2027 for 1P, 2P, and 3P.

Table 9-1: Oil Reserves as of 01 January 2025 to Current PSC Expiry (December 2027)

SUMMARY OF GAS RESERVES
As of 01 January 2025
To current PSC expiry (December 2027)
BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Reserves[1,2] (Bscf)		
	1P	2P	3P
PM3 CAA	41.1	52.3	64.1

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2027 for 1P, 2P, and 3P.

Table 9-2: Gas Reserves as of 01 January 2025 to Current PSC Expiry (December 2027)

SUMMARY OF CONDENSATE RESERVES
As of 01 January 2025
To current PSC expiry (December 2027)
BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Reserves[1,2] (MMstb)		
	1P	**2P**	**3P**
PM3 CAA	0.6	0.7	0.7

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2027 for 1P, 2P, and 3P.

Table 9-3: Condensate Reserves as of 01 January 2025 to Current PSC Expiry (December 2027)

SUMMARY OF RESERVES (BOE)
As of 01 January 2025
To current PSC expiry (December 2027)
BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Reserves[1,2] (MMboe)[3]		
	1P	**2P**	**3P**
PM3 CAA	9.6	12.0	14.3

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2027 for 1P, 2P, and 3P.

[3] Conversion rate of 6,000 standard cubic feet per boe

Table 9-4: Summary of Reserves in Oil Equivalent Barrels as of 01 January 2025 to Current PSC Expiry (December 2027)

Hibiscus Net Entitlement Reserves for current PSC expiry with a 20 years extension to December 2047 are presented in Table 9-5 to Table 9-8.

SUMMARY OF OIL RESERVES
As of 01 January 2025
To PSC expiry with 20-year extension (December 2047)
BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Reserves[1,2] (MMstb)		
	1P	**2P**	**3P**
PM3 CAA	3.7	6.4	10.4

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2030,2032, 2038 for 1P, 2P, and 3P, respectively.

Table 9-5: Oil Reserves as of 01 January 2025 to PSC Expiry with 20-year Extension (December 2047)

SUMMARY OF GAS RESERVES
As of 01 January 2025
To PSC expiry with 20-year extension (December 2047)
BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Reserves[1,2] (Bscf)		
	1P	**2P**	**3P**
PM3 CAA	60.1	101.9	174.3

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2030,2032, 2038 for 1P, 2P, and 3P, respectively.

Table 9-6: Gas Reserves as of 01 January 2025 to PSC Expiry with 20-year Extension (December 2047)

SUMMARY OF CONDENSATE RESERVES
As of 01 January 2025
To PSC expiry with 20-year extension (December 2047)
BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Reserves[1,2] (MMstb)		
	1P	**2P**	**3P**
PM3 CAA	0.8	1.3	2.0

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2030,2032, 2038 for 1P, 2P, and 3P, respectively.

Table 9-7: Condensate Reserves as of 01 January 2025 to PSC Expiry with 20-year Extension (December 2047)

SUMMARY OF RESERVES (BOE)

As of 01 January 2025

To PSC expiry with 20-year extension (December 2047)

BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Reserves[1, 2] (MMboe)[3]		
	1P	**2P**	**3P**
PM3 CAA	14.5	24.6	41.4

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2030,2032, 2038 for 1P, 2P, and 3P, respectively.

[3] Conversion rate of 6,000 standard cubic feet per boe

Table 9-8: Summary of Reserves in Oil Equivalent Barrels as of 01 January 2025 to PSC Expiry with 20-year extension (December 2047)

9.2 Contingent Resources

Hibiscus Net Entitlement Contingent Resources, comprising subcategories Development Pending and Development Unclarified, for current PSC expiry with a 20 years extension to December 2047 are presented in Table 9-9 to Table 9-12.

SUMMARY OF OIL CONTINGENT RESOURCES
As of 01 January 2025
To PSC expiry with 20-year extension (December 2047)
BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Contingent Resources[1,2] (MMstb)		
	1C	**2C**	**3C**
PM3 CAA	2.7	4.5	5.5

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2032, 2035, and 2040 for 1C, 2C, and 3C, respectively.

Table 9-9: Oil Contingent Resources as of 01 January 2025 to PSC Expiry with 20-year Extension (December 2047)

SUMMARY OF GAS CONTINGENT RESOURCES
As of 01 January 2025
To PSC expiry with 20-year extension (December 2047)
BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Contingent Resources[1,2] (Bscf)		
	1C	**2C**	**3C**
PM3 CAA	26.3	49.4	56.0

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2032, 2035, and 2040 for 1C, 2C, and 3C, respectively.

Table 9-10: Gas Contingent Resources as of 01 January 2025 to PSC Expiry with 20-year Extension (December 2047)

SUMMARY OF CONDENSATE CONTINGENT RESOURCES
As of 01 January 2025
To PSC expiry with 20-year extension (December 2047)
BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Contingent Resources[1,2] (MMstb)		
	1C	**2C**	**3C**
PM3 CAA	0.4	0.7	0.8

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2032, 2035, and 2040 for 1C, 2C, and 3C, respectively.

Table 9-11: Condensate Contingent Resources as of 01 January 2025 to PSC Expiry with 20-year Extension (December 2047)

SUMMARY OF CONTINGENT RESOURCES (BOE)
As of 01 January 2025
To PSC expiry with 20-year extension (December 2047)
BASE CASE PRICES AND COSTS

	Hibiscus Net Entitlement Contingent Resources[1,2] (MMboe)[3]		
	1C	**2C**	**3C**
PM3 CAA	7.4	13.4	15.6

Notes:

[1] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[2] Economic limit in year 2032, 2035, and 2040 for 1C, 2C, and 3C, respectively.

[3] Conversion rate of 6,000 standard cubic feet per boe

Table 9-12: Summary of Contingent Resources in Oil Equivalent Barrels as of 01 January 2025 to PSC Expiry with 20-year Extension (December 2047)

10 CONSULTANT'S INFORMATION

TTRPSE is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. The evaluation presented in this report reflects our informed judgment, based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, TTRPSE is not in a position to attest to the property title, financial interest relationships or encumbrances related to the property. Our estimates of Reserves and Resources are based on data provided by Hibiscus. We have accepted, without independent verification, the accuracy and completeness of this data.

The report represents TTRPSE' best professional judgment and should not be considered a guarantee or prediction of results. It should be understood that any evaluation, particularly one involving future performance and development activities may be subject to significant variations over short periods of time as new information becomes available. This report relates specifically and solely to the subject assets and is conditional upon various assumptions that are described herein. This report must, therefore, be read in its entirety. This report was provided for the sole use of Hibiscus. The provision of professional services has been solely on a fee basis.

To the best of our knowledge, no conflict of interest has existed in the work conducted as part of this report. Furthermore, TTRPSE nor any of the management and employees involved in the work have any interest in the assets evaluated or related to the analysis carried out as part of this report.

Mr Gordon Taylor, Technical Director, has reviewed this report. Mr Taylor is a Chartered Geologist and Chartered Engineer with over 40 of years' experience in upstream oil and gas. The project has been managed by Adam Turner who has over 13 years of experience in upstream oil and gas. Other TTRPSE employees involved in this work hold at least a Master's degree in geology, geophysics, petroleum engineering or a related subject or have at least five years of relevant experience in the practice of geology, geophysics or petroleum engineering.

Table 10-1 provides a summary of staff involved in this evaluation, their level of experience and professional qualifications.

Name	Role	Years of Experience	Qualifications	Professional Memberships
Gordon Taylor	Competent Person	>40	BSc. Geological Science Birmingham University MSc Foundation Engineering Birmingham University	Chartered Geologist Fellow, Geological Society Chartered Engineer Member, IMMM Certified Geologist Division Professional Affairs, AAPG Member, SPE
Adam Turner	Project Manager, Principal Reservoir Engineer	10+	MSc Petroleum Engineering BSc Chemical Engineering	Member, SPE
Clare Wilson	Principal Advisor Geoscience	>25	BSc. Geophysics (Geological), University of Leicester MBA, University of Hull,	Chartered Geologist, Fellow, Geological Society. Member, PESGB

David Offer	Principal Geoscientist	>25	QT – Her Majesty's Government of UK and Northern Ireland BSc (hons). Exploration and Mining Geology, University of Wales MSc. Industrial Mineralogy, University of Leicester	Fellow, Geological Society Member, PESGB formerly Vice-President
Shoaib Memon	Senior Reservoir Engineer	17	B.E Petroleum and Gas Engineering , Mehran University MSc Petroleum Engineering, Heriot-Watt University, Edinburgh, UK, 2010	Member of Society of Petroleum Engineer
David Walker	Principal Costs/Development Engineer	>20	MEng Hons, Chemical Process Eng, University of Sheffield	
Joseph Tan	Petroleum Economist	24	BEng (Hons.) Petroleum Engineering, Universiti Teknologi Malaysia, 2001	Member – SPE Member – South East Asia Petroleum Exploration Society (SEAPEX) Member – Association of International Energy Negotiators (AIEN)

Table 10-1: Summary of Consultant Personnel

Appendix A: Glossary

1C	The low estimate of Contingent Resources. There is estimated to be a 90% probability that the quantities actually recovered could equal or exceed this estimate
2C	The best estimate of Contingent Resources. There is estimated to be a 50% probability that the quantities actually recovered could equal or exceed this estimate
3C	The high estimate of Contingent Resources. There is estimated to be a 10% probability that the quantities actually recovered could equal or exceed this estimate
1P	The low estimate of Reserves (proved). There is estimated to be a 90% probability that the quantities remaining to be recovered will equal or exceed this estimate
2P	The best estimate of Reserves (proved+probable). There is estimated to be a 50% probability that the quantities remaining to be recovered will equal or exceed this estimate
3P	The high estimate of Reserves (proved+probable+possible). There is estimated to be a 10% probability that the quantities remaining to be recovered will equal or exceed this estimate
1U	The unrisked low estimate of Prospective Resources
2U	The unrisked best estimate of Prospective Resources
3U	The unrisked high estimate of Prospective Resources
AVO	Amplitude versus Offset
B	Billion
bbl(s)	Barrels
bbls/d	Barrels per day
Bcm	Billion cubic metres
B_g	Gas formation volume factor
B_{gi}	Gas formation volume factor (initial)
B_o	Oil formation volume factor
B_{oi}	Oil formation volume factor (initial)
B_w	Water volume factor
boe	Barrels of oil equivalent
stb/d	Barrels of oil per day
BHP	Bottom hole pressure
Bscf	Billions of standard cubic feet
bwpd	Barrels of water per day
condensate	A mixture of hydrocarbons which exist in gaseous phase at reservoir conditions but are produced as a liquid at surface conditions
cP	Centipoise
Eclipse	A reservoir modelling software package
E_{gi}	Gas Expansion Factor
EMV	Expected Monetary Value
EUR	Estimated Ultimate Recovery
FBHP	Flowing bottom hole pressure
FTHP	Flowing tubing head pressure
ft	Feet
FWHP	Flowing well head pressure
FWL	Free Water Level

GDT	Gas Down To
GIIP	Gas Initially in Place
GOC	Gas oil Contact
GOR	Gas/oil ratio
GRV	Gross rock volume
GWC	Gas water contact
IPR	Inflow performance relationship
IRR	Internal rate of return
KB	Kelly Bushing
k_a	Absolute permeability
k_h	Horizontal permeability
km	Kilometres
LPG	Liquefied Petroleum Gases
m	Metres
m^3	Cubic metres
m^3/d	Cubic metres per day
ma	Million years
M	Thousand
M$	Thousand US dollars
MBAL	Material balance software
Mbbls	Thousand barrels
mD	Permeability in millidarcies
MD	Measured depth
MDT	Modular formation dynamics tester tool
MM	Million
MMbbls	Million barrels
MMscf/d	Millions of standard cubic feet per day
MMstb	Million stock tank barrels (at 14.7 psi and 60° F)
MMt	Millions of tonnes
MM$	Million US dollars
MPa	Mega pascals
m/s	Metres per second
msec	Milliseconds
Mt	Thousands of tonnes
mV	Millivolts
NTG or N:G	Net to gross ratio
NGL	Natural Gas Liquids
NPV	Net Present Value
OWC	Oil water contact
P90	There is estimated to be at least a 90% probability (P_{90}) that this quantity will equal or exceed this low estimate
P50	There is estimated to be at least a 50% probability (P_{50}) that this quantity will equal or exceed this best estimate

P10	There is estimated to be at least a 10% probability (P_{10}) that this quantity will equal or exceed this high estimate
PDR	Physical data room
Petrel	A geoscience and reservoir engineering software package
petroleum	Naturally occurring mixtures of hydrocarbons which are found beneath the Earth's surface in liquid, solid or gaseous form
phi	Porosity
p_i	Initial reservoir pressure
PI	Productivity index
ppm	Parts per million
psi	Pounds per square inch
psia	Pounds per square inch (absolute)
psig	Pounds per square inch (gauge)
p_{wf}	Flowing bottom hole pressure
PSDM	Pre-stack depth migrated seismic data
PSTM	Pre-stack time migrated seismic data
PVT	Pressure volume temperature
rb	Barrel(s) at reservoir conditions
rcf	Reservoir cubic feet
REP™	A Monte Carlo simulation software package
RF	Recovery factor
RFT	Repeat formation tester
RKB	Relative to kelly bushing
rm^3	Reservoir cubic metres
SCADA	Supervisory control and data acquisition
SCAL	Special Core Analysis
scf	Standard cubic feet measured at 14.7 pounds per square inch and 60° F
scf/d	Standard cubic feet per day
scf/stb	Standard cubic feet per stock tank barrel
SGS	Sequential Gaussion Simulation
SIBHP	Shut in bottom hole pressure
SIS	Sequential Indicator Simulation
sm^3	Standard cubic metres
S_o	Oil saturation
S_{oi}	Initial oil saturation
S_{or}	Residual oil saturation
S_{orw}	Residual oil saturation relative to water
sq. km	Square kilometers
stb	Stock tank barrels measured at 14.7 pounds per square inch and 60° F
stb/d	Stock tank barrels per day
STOIIP	Stock tank oil initially in place
S_w	Water saturation
S_{wc}	Vonnate water saturation
$	United States Dollars

t	Tonnes
THP	Tubing head pressure
Tscf	Trillion standard cubic feet
TVDSS	True vertical depth (sub-sea)
TVT	True vertical thickness
TWT	Two-way time
US$	United States Dollar
VDR	Virtual data room
VLP	Vertical lift performance
V_{sh}	Shale volume
VSP	Vertical Seismic Profile
W/m/K	Watts/metre/° K
WC	Water cut
WUT	Water Up To
Z	A measure of the "non-idealness" of gas
ϕ	Porosity
μ	Viscosity
μ_g	Viscosity of gas
μ_o	Viscosity of oil
μ_w	Viscosity of water

Appendix B: Summary of Reporting Guidelines

PRMS is a fully integrated system that provides the basis for classification and categorization of all petroleum reserves and resources.

B.1 Basic Principles and Definitions

A classification system of petroleum resources is a fundamental element that provides a common language for communicating both the confidence of a project's resources maturation status and the range of potential outcomes to the various entities. The PRMS provides transparency by requiring the assessment of various criteria that allow for the classification and categorization of a project's resources. The evaluation elements consider the risk of geologic discovery and the technical uncertainties together with a determination of the chance of achieving the commercial maturation status of a petroleum project.

The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. Quantities of petroleum and associated products can be reported in terms of volumes (e.g., barrels or cubic meters), mass (e.g., metric tonnes) or energy (e.g., Btu or Joule). These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

B.1.1 Petroleum Resources Classification Framework

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid state. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content can be greater than 50%.

The term resources as used herein is intended to encompass all quantities of petroleum naturally occurring within the Earth's crust, both discovered and undiscovered (whether recoverable or unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered as conventional or unconventional resources.

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

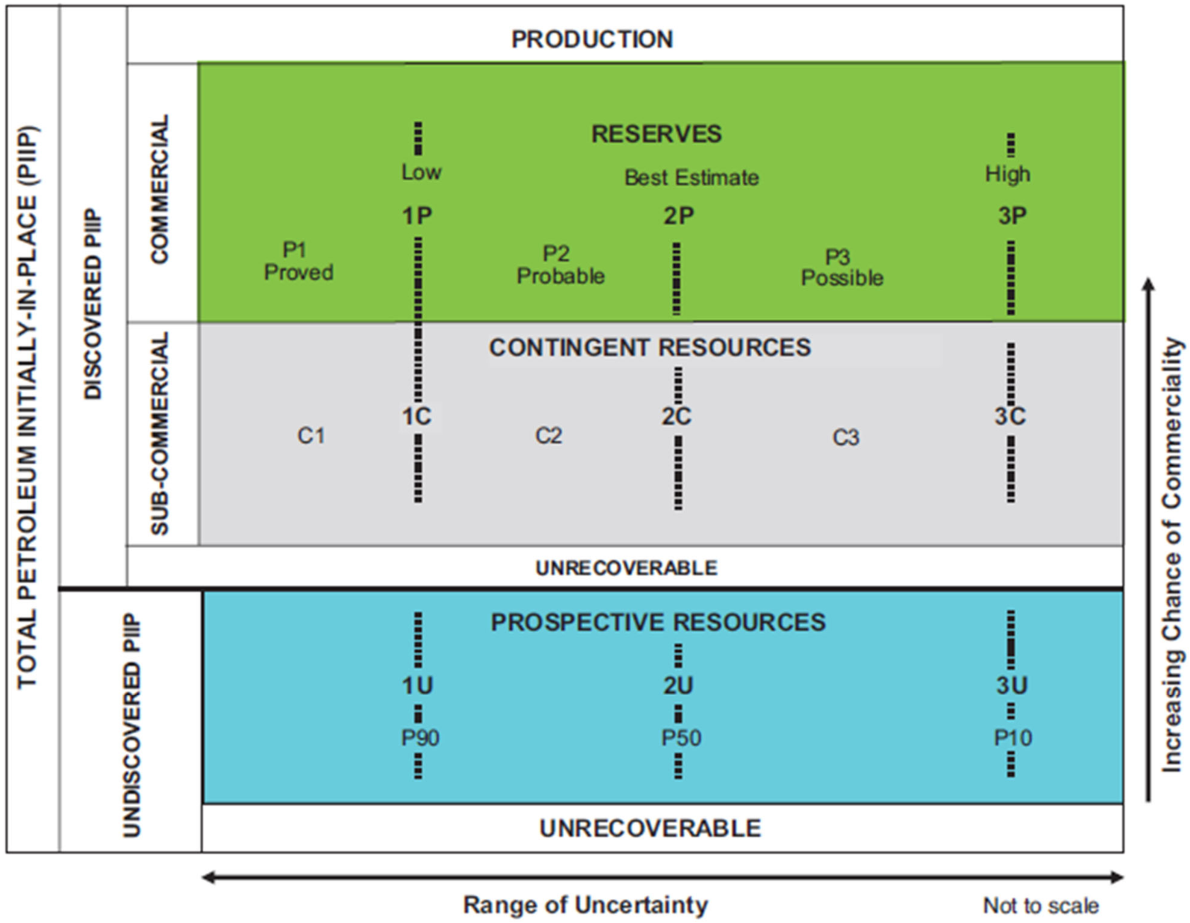

Figure B. 1: Resources classification framework

The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, P_c, which is the chance that a project will be committed for development and reach commercial producing status.

The following definitions apply to the major subdivisions within the resources classification:

- **Total Petroleum Initially-In-Place (PIIP)** is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.
- **Discovered PIIP** is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.
- **Production** is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see PRMS 2018 Section 3.2, Production Measurement).

Multiple development projects may be applied to each known or unknown accumulation, and each project will be forecast to recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into commercial, sub-commercial, and undiscovered, with the estimated recoverable quantities being classified as Reserves, Contingent Resources, or Prospective Resources respectively, as defined below.

- **Reserves** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see PRMS 2018 Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

Reserves are further categorized in accordance with the range of uncertainty and should be sub- classified based on project maturity and/or characterized by development and production status.

- **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be sub- classified based on project maturity and/or economic status.
- **Undiscovered PIIP** is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.
- **Prospective Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.
- **Unrecoverable Resources** are that portion of either discovered or undiscovered PIIP evaluated, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided.

Other terms used in resource assessments include the following:

- **Estimated Ultimate Recovery (EUR)** is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities already produced from the accumulation or group of accumulations. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.
- **Technically Recoverable Resources (TRR)** are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. TRR may be used for specific Projects or for groups of Projects, or, can be an undifferentiated estimate within an area (often basin-wide) of recovery potential.

Whenever these terms are used, the conditions associated with their usage must be clearly noted and documented.

B.1.2 Project Based Resource Evaluations

The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure A.2).

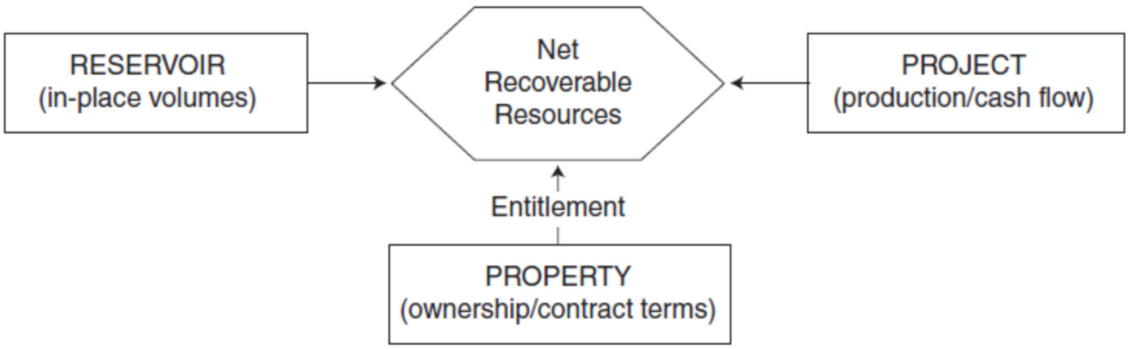

Figure B. 2: Resources Evaluation

The reservoir (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

The project: A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty.

The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

The property (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See PRMS 2018 Section 2.1.3.5, Project Maturity Sub-Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See PRMS 2018 Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

An accumulation or potential accumulation of petroleum is often subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resources classes simultaneously. When multiple options for development exist early in project maturity, these options should be reflected as competing project alternatives to avoid double counting until decisions further refine the project scope and timing. Once the scope is described and the timing of decisions on future activities established, the decision steps will generally align with the project's classification. To assign recoverable resources of any class, a project's development plan, with detail that supports the resource commercial classification claimed, is needed.

The estimates of recoverable quantities must be stated in terms of the production derived from the potential development program even for Prospective Resources. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be based largely on analogous projects. In-place quantities for which a feasible project cannot be defined using current or reasonably forecast improvements in technology are classified as Unrecoverable.

Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see PRMS 2018 Section 3.1, Assessment of Commerciality).

Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see PRMS 2018 Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see PRMS 2018 Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see PRMS 2018 Section 3.1.1, Net Cash-Flow Evaluation).

The supporting data, analytical processes, and assumptions describing the technical and commercial basis used in an evaluation must be documented in sufficient detail to allow, as needed, a qualified reserves evaluator or qualified reserves auditor to clearly understand each project's basis for the estimation, categorization, and classification of recoverable resources quantities and, if appropriate, associated commercial assessment.

B.1.3 Classification and Categorization Guidelines

To consistently characterize petroleum projects, evaluations of all resources should be conducted in the context of the full classification system shown in Figure A.1. These guidelines reference this classification system and support an evaluation in which projects are "classified" based on their chance of commerciality, P_c (the vertical axis labeled Chance of Commerciality), and estimates of recoverable and marketable quantities associated with each project are "categorized" to reflect uncertainty (the horizontal axis). The actual workflow of classification versus categorization varies with individual projects and is often an iterative analysis leading to a final report. Report here refers to the presentation of evaluation results within the entity conducting the assessment and should not be construed as replacing requirements for public disclosures under guidelines established by regulatory and/or other government agencies.

B.1.4 Resources Classification

The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project's recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

B.1.4.1 Determination of Discovery Status

A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see PRMS 2018 Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

Where a discovery has identified recoverable hydrocarbons, but is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

B.1.4.2 Determination of Commerciality

Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity's commitment to the project and all of the following criteria:

- Evidence of a technically mature, feasible development plan.
- Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
- Evidence to support a reasonable time-frame for development.
- A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see PRMS 2018 Section 3.1.1, Net Cash-Flow Evaluation).
- A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, CO_2) can be sold, stored, re-injected, or otherwise appropriately disposed.
- Evidence that the necessary production and transportation facilities are available or can be made available.
- Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the *2P* Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see PRMS 2018 Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section A.2.1.2. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves. However, this may be another external reporting requirement. In many cases, financing is conditional upon the same criteria as above. In general, if there is not a reasonable expectation that financing or other forms of commitment (e.g., farm-outs) can be arranged so that the development will be initiated within a reasonable time-frame, then the project should be classified as Contingent Resources. If financing is reasonably expected to be in place at the time of the final investment decision (FID), the project's resources may be classified as Reserves.

B.1.4.3 Project Status and Chance of Commerciality

Evaluators have the option to establish a more detailed resources classification reporting system that can also provide the basis for portfolio management by subdividing the chance of commerciality axis according to project maturity. Such sub-classes may be characterized qualitatively by the project maturity level descriptions and associated quantitative chance of reaching commercial status and being placed on production.

As a project moves to a higher level of commercial maturity in the classification (see Figure A.1 vertical axis), there will be an increasing chance that the accumulation will be commercially developed and the project quantities move to Reserves. For Contingent and Prospective Resources, this is further expressed as a chance of commerciality, P_c, which incorporates the following underlying chance component(s):

- The chance that the potential accumulation will result in the discovery of a significant quantity of petroleum, which is called the "chance of geologic discovery," P_g.
- Once discovered, the chance that the known accumulation will be commercially developed is called the "chance of development," P_d.

There must be a high degree of certainty in the chance of commerciality, P_c, for Reserves to be assigned; for Contingent Resources, $P_c = P_d$; and for Prospective Resources, P_c is the product of P_g and P_d.

Contingent and Prospective Resources can have different project scopes (e.g., well count, development spacing, and facility size) as development uncertainties and project definition mature.

Project Maturity Sub-classes

As Figure A.3 illustrates, development projects and associated recoverable quantities may be sub- classified according to project maturity levels and the associated actions (i.e., business decisions) required to move a project toward commercial production.

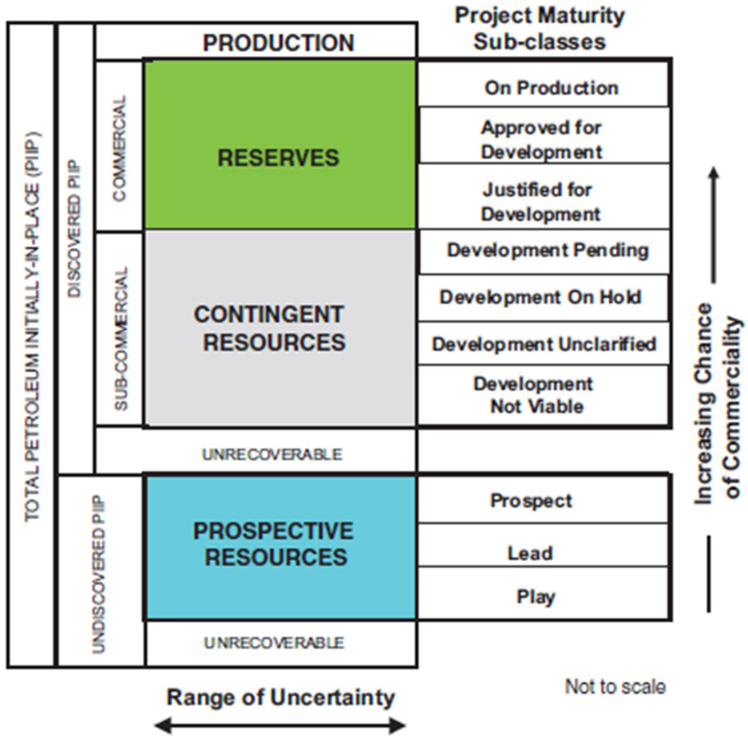

Figure B. 3: Sub-classes based on project maturity

Maturity terminology and definitions for each project maturity class and sub-class are provided in PRMS 2018 Table I. This approach supports the management of portfolios of opportunities at various stages of exploration, appraisal, and development. Reserve sub-classes must achieve commerciality while Contingent and Prospective Resources sub-classes may be supplemented by associated quantitative estimates of chance of commerciality to mature.

Resources sub-class maturation is based on those actions that progress a project through final approvals to implementation and initiation of production and product sales. The boundaries between different levels of project maturity are frequently referred to as project "decision gates."

Projects that are classified as Reserves must meet the criteria as listed in Section A.2.1.2, Determination of Commerciality. Projects sub-classified as Justified for Development are agreed upon by the managing entity and partners as commercially viable and have support to advance the project, which includes a firm intent to proceed with development. All participating entities have agreed to the project and there are no known contingencies to the project from any official entity that will have to formally approve the project.

Justified for Development Reserves are reclassified to Approved for Development after a FID has been made. Projects should not remain in the Justified for Development sub-class for extended time periods without positive indications that all required approvals are expected to be obtained without undue delay. If there is no longer the reasonable expectation of project execution (i.e., historical track record of execution, project progress), the project shall be reclassified as Contingent Resources.

Projects classified as Contingent Resources have their sub-classes aligned with the entity's plan to manage its portfolio of projects. Thus, projects on known accumulations that are actively being studied, undergoing feasibility review, and have planned near-term operations (e.g., drilling) are placed in Contingent Resources Development Pending, while those that do not meet this test are placed into either Contingent Resources On Hold, Unclarified, or Not Viable.

Where commercial factors change and there is a significant risk that a project with Reserves will no longer proceed, the project shall be reclassified as Contingent Resources.

For Contingent Resources, evaluators should focus on gathering data and performing analyses to clarify and then mitigate those key conditions or contingencies that prevent commercial development. Note that the Contingent Resources sub-classes described above and shown in Figure A.3 are recommended; however, entities are at liberty to introduce additional sub-classes that align with project management goals.

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. The Prospective Resources are evaluated according to chance of geologic discovery, P_g, and chance of development, P_d, which together determine the chance of commerciality, P_c. Commercially recoverable quantities under appropriate development projects are then estimated. The decision at each exploration phase is whether to undertake further data acquisition and/or studies designed to move the Play through to a drillable Prospect with a project description range commensurate with the Prospective Resources sub-class.

Reserves Status

Once projects satisfy commercial maturity (criteria given in PRMS 2018 Table 1), the associated quantities are classified as Reserves. These quantities may be allocated to the following subdivisions based on the funding and operational status of wells and associated facilities within the reservoir development plan (PRMS 2018 Table 2 provides detailed definitions and guidelines):

- **Developed Reserves** are quantities expected to be recovered from existing wells and facilities.
  - **Developed Producing Reserves** are expected to be recovered from completion intervals that are open and producing at the time of the estimate.
  - **Developed Non-Producing Reserves** include shut-in and behind-pipe reserves with minor costs to access.
- **Undeveloped Reserves** are quantities expected to be recovered through future significant investments.

The distinction between the “minor costs to access” Developed Non-Producing Reserves and the “significant investment” needed to develop Undeveloped Reserves requires the judgment of the evaluator taking into account the cost environment. A significant investment would be a relatively large expenditure when compared to the cost of drilling and completing a new well. A minor cost would be a lower expenditure when compared to the cost of drilling and completing a new well.

Once a project passes the commercial assessment and achieves Reserves status, it is then included with all other Reserves projects of the same category in the same field for estimating combined future production and applying the economic limit test (see PRMS 2018 Section 3.1, Assessment of Commerciality).

Where Reserves remain Undeveloped beyond a reasonable time-frame or have remained Undeveloped owing to postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and to justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay (see Section A.2.1.2, Determination of Commerciality) is justified, a reasonable time-frame to commence the project is generally considered to be less than five years from the initial classification date.

Development and Production status are of significant importance for project portfolio management and financials. The Reserves status concept of Developed and Undeveloped status is based on the funding and operational status of wells and producing facilities within the development project. These status designations are applicable throughout the full range of Reserves uncertainty categories (1P, 2P, and 3P or Proved, Probable, and Possible). Even those projects that are Developed and On Production should have remaining uncertainty in recoverable quantities.

Economic Status

Projects may be further characterized by economic status. All projects classified as Reserves must be commercial under defined conditions (see PRMS 2018 Section 3.1, Assessment of Commerciality Assessment). Based on assumptions regarding future conditions and the impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into two groups:

- **Economically Viable Contingent Resources** are those quantities associated with technically feasible projects where cash flows are positive under reasonably forecasted conditions but are not Reserves because it does not meet the commercial criteria defined in Section A.2.1.2.
- **Economically Not Viable Contingent Resources** are those quantities for which development projects are not expected to yield positive cash flows under reasonable forecast conditions.

The best estimate (or P50) production forecast is typically used for the economic evaluation for the commercial assessment of the project. The low case, when used as the primary case for a project decision, may be used to determine project economics. The economic evaluation of the project high case alone is not permitted to be used in the determination of the project's commerciality.

For Reserves, the best estimate production forecast reflects a specific development scenario recovery process, a certain number and type of wells, facilities, and infrastructure.

The project's low-case scenario is tested to ensure it is economic, which is required for Proved Reserves to exist (see Section A.2.2.2, Category Definitions and Guidelines). It is recommended to evaluate the low case and the high case (which will quantify the 3P Reserves) to convey the project downside risk and upside potential. The project development scenarios may vary in the number and type of wells, facilities, and infrastructure in Contingent Resources, but to recognize Reserves, there must exist the reasonable expectation to develop the project for the best estimate case.

The economic status may be identified independently of, or applied in combination with, project maturity sub-classification to more completely describe the project. Economic status is not the only qualifier that allows defining Contingent or Prospective Resources sub-classes. Within Contingent Resources, applying the project status to decision gates (and/or incorporating them in a plan to execute) more appropriately defines whether the project is placed into the sub-class of either Development Pending versus On Hold, Not Viable, or Unclarified.

Where evaluations are incomplete and it is premature to clearly define the associated cash flows, it is acceptable to note that the project economic status is "undetermined."

B.1.5 Resources Categorization

The horizontal axis in the resources classification in Figure A.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

- The total petroleum remaining within the accumulation (in-place resources).
- The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).
- Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3), 1C, 2C, 3C, C1, C2, and C3; or 1U, 2U, and 3U resources categories. The commercial chance of success is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

There must be a single set of defined conditions applied for resource categorization. Use of different commercial assumptions for categorizing quantities is referred to as "split conditions" and are not allowed. Frequently, an entity will conduct project evaluation sensitivities to understand potential implications when making project selection decisions. Such sensitivities may be fully aligned to resource categories or may use single parameters, groups of parameters, or variances in the defined conditions.

Moreover, a single project is uniquely assigned to a sub-class along with its uncertainty range. For example, a project cannot have quantities classified in both Contingent Resources and Reserves, for instance as 1C, 2P, and 3P. This is referred to as “split classification.”

B.1.5.1 Range of Uncertainty

Uncertainty is inherent in a project’s resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see PRMS 2018 Section 4.2, Resources Assessment Methods).

When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see Section A.2.2.2, Category Definitions and Guidelines).

Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

While there may be significant chance that sub-commercial and undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable quantities independent of such likelihood when considering what resources class to assign the project quantities.

B.1.5.2 Category Definitions and Guidelines

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see PRMS 2018 Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

Use of consistent terminology (Figure A.1 and Figure A.3) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P1), Probable (P2) and Possible

(P3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. PRMS 2018 Table 3 provides criteria for the Reserves categories determination.

For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see PRMS 2018 Section 4.2.1, Aggregating Resources Classes).

Without new technical information, there should be no change in the distribution of technically recoverable resources and the categorization boundaries when conditions are satisfied to reclassify a project from Contingent Resources to Reserves.

All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see PRMS 2018 Section 3.1, Assessment of Commerciality).

PRMS 2018 Tables 1, 2, and 3 present category definitions and provide guidelines designed to promote consistency in resources assessments. The following summarize the definitions for each Reserves category in terms of both the deterministic incremental method and the deterministic scenario method, and also provides the criteria if probabilistic methods are applied. For all methods (incremental, scenario, or probabilistic), low, best and high estimate technical forecasts are prepared at an effective date (unless justified otherwise), then tested to validate the commercial criteria, and truncated as applicable for determination of Reserves quantities.

- Proved Reserves are those quantities of Petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from known reservoirs and under defined technical and commercial conditions. If deterministic methods are used, the term “reasonable certainty” is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.
- Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.
- Possible Reserves are those additional Reserves that analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves, which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves that are located outside of the 2P area (not upside quantities to the 2P scenario) may exist only when the commercial and technical maturity criteria have been met (that incorporate the Possible development scope). Stand- alone Possible Reserves must reference a commercial 2P project (e.g., a lease adjacent to the commercial project that may be owned by a separate entity), otherwise stand-alone Possible is not permitted.

One, but not the sole, criterion for qualifying discovered resources and to categorize the project's range of its low/best/high or P90/P50/P10 estimates to either 1C/2C/3C or 1P/2P/3P is the distance away from known productive area(s) defined by the geoscience confidence in the subsurface.

A conservative (low-case) estimate may be required to support financing. However, for project justification, it is generally the best-estimate Reserves or Resources quantity that passes qualification because it is considered the most realistic assessment of a project's recoverable quantities. The best estimate is generally considered to represent the sum of Proved and Probable estimates (2P) for Reserves, or 2C when Contingent Resources are cited, when aggregating a field, multiple fields, or an entity's resources.

It should be noted that under the deterministic incremental method, discrete estimates are made for each category and should not be aggregated without due consideration of associated confidence. Results from the deterministic scenario, deterministic incremental, geostatistical and probabilistic methods applied to the same project should give comparable results (see PRMS 2018 Section 4.2, Resources Assessment Methods).

If material differences exist between the results of different methods, the evaluator should be prepared to explain these differences.

B.1.6 Incremental Projects

The initial resources assessment is based on application of a defined initial development project, even extending into Prospective Resources. Incremental projects are designed to either increase recovery efficiency, reduce costs, or accelerate production through either maintenance of or changes to wells, completions, or facilities or through infill drilling or by means of improved recovery. Such projects are classified according to the resources classification framework (Figure A.1), with preference for applying project maturity sub-classes (Figure A.3). Related incremental quantities are similarly categorized on the range of uncertainty of recovery. The projected recovery change can be included in Reserves if the degree of commitment is such that the project has achieved commercial maturity (See Section A.2.1.2, Determination of Commerciality). The quantity of such incremental recovery must be supported by technical evidence to justify the relative confidence in the resources category assigned.

An incremental project must have a defined development plan. A development plan may include projects targeting the entire field (or even multiple, linked fields), reservoirs, or single wells. Each incremental project will have its own planned timing for execution and resource quantities attributed to the project. Development plans may also include appraisal projects that will lead to subsequent project decisions based on appraisal outcomes.

Circumstances when development will be significantly delayed and where it is considered that Reserves are still justified should be clearly documented. If there is no longer the reasonable expectation of project execution (i.e., historical track record of execution, project progress), forecast project incremental recoveries are to be reclassified as Contingent Resources (see PRMS 2018 Section 2.1.2, Determination of Commerciality).

B.1.6.1 Workovers, Treatments and Changes of Equipment

Incremental recovery associated with a future workover, treatment (including hydraulic fracturing stimulation), re-treatment, changes to existing equipment, or other mechanical procedures where such projects have routinely been successful in analogous reservoirs may be classified as Developed Reserves, Undeveloped Reserves, or Contingent Resources, depending on the associated costs required (see Section A.2.1.3.2, Reserves Status) and the status of the project's commercial maturity elements.

Facilities that are either beyond their operational life, placed out of service, or removed from service cannot be associated with Reserves recognition. When required facilities become unavailable or out of service for longer than a year, it may be necessary to reclassify the Developed Reserves to either Undeveloped Reserves or Contingent Resources. A project that includes facility replacement or restoration of operational usefulness must be identified, commensurate with the resources classification.

B.1.6.2 Compression

Reduction in the backpressure through compression can increase the portion of in-place gas that can be commercially produced and thus included in resources estimates. If the eventual installation of compression meets commercial maturity requirements, the incremental recovery is included in either Undeveloped Reserves or Developed Reserves, depending on the investment on meeting the Developed or Undeveloped classification criteria. However, if the cost to implement compression is not significant, relative to the cost of one new well in the field, or there is reasonable expectation that compression will be implemented by a third party in a common sales line beyond the reference point, the incremental quantities may be classified as Developed Reserves. If compression facilities were not part of the original approved development plan and such costs are significant, it should be treated as a separate project subject to normal project maturity criteria.

B.1.6.3 Infill Drilling

Technical and commercial analyses may support drilling additional producing wells to reduce the wells spacing of the initial development plan, subject to government regulations. Infill drilling may have the combined effect of increasing recovery and acceleration production. Only the incremental recovery (i.e. recovery from infill wells less the recovery difference in earlier wells) can be considered as additional Reserves for the project; this incremental recovery may need to be reallocated.

B.1.6.4 Improved Recovery

Improved recovery is the additional petroleum obtained, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural reservoir energy. It includes secondary recovery (e.g., waterflooding and pressure maintenance), tertiary recovery processes (thermal, miscible gas injection, chemical injection, and other types), and any other means of supplementing natural reservoir recovery processes.

Improved recovery projects must meet the same Reserves technical and commercial maturity criteria as primary recovery projects.

The judgment on commerciality is based on pilot project results within the subject reservoir or by comparison to a reservoir with analogous rock and fluid properties and where a similar established improved recovery project has been successfully applied.

Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed portion of the project, where the response provides support for the analysis on which the project is based. The improved recovery project's resources will remain classified as Contingent Resources Development Pending until the pilot has demonstrated both technical and commercial feasibility and the full project passes the Justified for Development "decision gate."

B.1.7 Unconventional Resources

The types of in-place petroleum resources defined as conventional and unconventional may require different evaluation approaches and/or extraction methods. However, the PRMS resources definitions, together with the classification system, apply to all types of petroleum accumulations regardless of the in- place characteristics, extraction method applied, or degree of processing required.

- Conventional resources exist in porous and permeable rock with pressure equilibrium. The PIIP is trapped in discrete accumulations related to a local geological structure feature and/or stratigraphic condition. Each conventional accumulation is typically bounded by a down dip contact with an aquifer, as its position is controlled by hydrodynamic interactions between buoyancy of petroleum in water versus capillary force. The petroleum is recovered through wellbores and typically requires minimal processing before sale.

- Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and are not significantly affected by hydrodynamic influences (also called "continuous-type deposit"). Usually there is not an obvious structural or stratigraphic trap. Examples include coalbed methane (CBM), basin-centered gas (low permeability), tight gas and tight oil (low permeability), gas hydrates, natural bitumen (very high viscosity oil), and oil shale (kerogen) deposits. Note that shale gas and shale oil are sub-types of tight gas and tight oil where the lithologies are predominantly shales or siltstones. These accumulations lack the porosity and permeability of conventional reservoirs required to flow without stimulation at economic rates. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, hydraulic fracturing stimulation for tight gas and tight oil, steam and/or solvents to mobilize natural bitumen for in-situ recovery, and in some cases, surface mining of oil sands). Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders).

For unconventional petroleum accumulations, reliance on continuous water contacts and pressure gradient analysis to interpret the extent of recoverable petroleum is not possible. Thus, there is typically a need for increased spatial sampling density to define uncertainty of in-place quantities, variations in reservoir and hydrocarbon quality, and to support design of specialized mining or in-situ extraction programs. In addition, unconventional resources typically require different evaluation techniques than conventional resources.

Extrapolation of reservoir presence or productivity beyond a control point within a resources accumulation must not be assumed unless there is technical evidence to support it. Therefore, extrapolation beyond the immediate vicinity of a control point should be limited unless there is clear engineering and/or geoscience evidence to show otherwise.

The extent of the discovery within a pervasive accumulation is based on the evaluator's reasonable confidence based on distances from existing experience, otherwise quantities remain as undiscovered. Where log and core data and nearby producing analogs provide evidence of potential economic viability, a successful well test may not be required to assign Contingent Resources. Pilot projects may be needed to define Reserves, which requires further evaluation of technical and commercial viability.

A fundamental characteristic of engagement in a repetitive task is that it may improve performance over time. Attempts to quantify this improvement gave rise to the concept of the manufacturing progress function commonly called the "learning curve." The learning curve is characterized by a decrease in time and/or costs, usually in the early stages of a project when processes are being optimized. At that time, each new improvement may be significant. As the project matures, further improvements in time or cost savings are typically less substantial. In oil and gas developments with high well counts and a continuous program of activity (multi-year), the use of a learning curve within a resources evaluation may be justified to predict improvements in either the time taken to carry out the activity, the cost to do so, or both. While each development project is unique, review of analogs can provide guidance on such predictions and the range of associated uncertainty in the resulting recoverable resources estimates (see also PRMS 2018 Section 3.1.2 Economic Criteria).

Source: Petroleum Resources Management System (revised June 2018), Version 1.01, Society of Petroleum Engineers