THIS CIRCULAR TO SHAREHOLDERS OF HIBISCUS PETROLEUM BERHAD IS IMPORTANT AND REQUIRES YOUR IMMEDIATE ATTENTION.

If you are in any doubt as to the course of action to be taken, please consult your stockbroker, bank manager, solicitor, accountant or other professional adviser immediately.

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HIBISCUS PETROLEUM BERHAD

Registration Number: 200701040290 (798322-P)
(Incorporated in Malaysia)

CIRCULAR TO SHAREHOLDERS

IN RELATION TO THE

PROPOSED ACQUISITION BY SIMPOR HIBISCUS SDN BHD, AN INDIRECT WHOLLY-OWNED SUBSIDIARY OF HIBISCUS PETROLEUM BERHAD, OF THE ENTIRE EQUITY INTEREST IN TOTALENERGIES EP (BRUNEI) B.V., A WHOLLY-OWNED SUBSIDIARY OF TOTALENERGIES HOLDINGS INTERNATIONAL B.V. FOR A CASH CONSIDERATION OF APPROXIMATELY USD259.4 MILLION (OR EQUIVALENT TO APPROXIMATELY RM1,087.8 MILLION)

AND

NOTICE OF EXTRAORDINARY GENERAL MEETING

Principal Adviser

AmInvestment Bank Berhad
(Registration No. 197501002220 (23742-V))
(A Participating Organisation of Bursa Malaysia Securities Berhad)

The Notice of Extraordinary General Meeting of Hibiscus Petroleum Berhad ("**EGM**") together with the Form of Proxy are enclosed in this Circular. The EGM will be held on a virtual basis, the details of which are as follows:

Date and time of the virtual EGM	:	Thursday, 10 October 2024 at 9.30 a.m., or at any adjournment of the EGM
Broadcast Venue of the virtual EGM	:	Tricor Business Centre, Gemilang Room, Unit 29-01, Level 29, Tower A, Vertical Business Suite, Avenue 3, Bangsar South, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur, Malaysia.
Last day and time for lodging the Form of Proxy	:	Tuesday, 8 October 2024 at 9.30 a.m.

This Circular is dated 25 September 2024

DEFINITIONS

Except where the context otherwise requires, the following definitions shall apply throughout this Circular:

2P NPV10	:	NPV of the Asset cash flows at 10% discount rate based on RPS Energy 2P Reserves case production and cost profile
2C NPV12	:	NPV of the Asset cash flows at 12% discount rate based on RPS Energy 2C Resources case
Act	:	Companies Act, 2016
Agreed Interest Rate	:	Interest at SOFR plus six percentage points (6%). The Agreed Interest Rate shall be applied to the relevant amount on a compounded basis in respect of each day for which the Agreed Interest Rate must be paid divided by 360. Where, in respect of any day, SOFR: (i) is negative, SOFR shall be deemed to be zero; or (ii) cannot be ascertained due to such day being a non-business day in New York, SOFR from the immediately preceding business day in New York shall apply to such day. If the resulting Agreed Interest Rate is contrary to any applicable usury law, then the amount of interest to be applied shall be the maximum amount permitted by Applicable Law
AmInvestment Bank	:	AmInvestment Bank Berhad
Asset	:	Maharajalela Jamalulalam (MLJ) field within Block B
BBJV Partners	:	Collectively, Shell Deepwater, Brunei Energy and the TargetCo
Board	:	Board of Directors
BLNG	:	Brunei LNG Sendirian Berhad
Block B	:	Block B offshore Brunei which contains the MLJ field
BNM	:	Bank Negara Malaysia
Branch	:	The branch office of the TargetCo registered in Brunei
Brunei	:	Brunei Darussalam
Brunei Act	:	Brunei Darussalam Companies Act
Brunei Energy	:	Brunei Energy Exploration Sdn Bhd
Bursa Securities	:	Bursa Malaysia Securities Berhad
Closing	:	Completion of the sale and purchase of the TargetCo Shares in accordance with the terms and conditions of the SPA
Closing Amount	:	Balance payment set forth and calculated pursuant to Section 2.1 of this Circular
Closing Date	:	The date on which Closing occurs

Competent Person's Report	:	Competent Person's Report dated 13 June 2024 prepared by RPS Energy
Competent Valuer's Report	:	Competent Valuer's Report dated 13 June 2024 prepared by RPS Energy
Condition Precedent	:	Condition precedent to the Closing
CY	:	Calendar year
Deposit	:	USD49.0 million (or equivalent to approximately RM205.5 million)
Director(s)	:	The director(s) of Hibiscus Petroleum and shall have the same meaning as given in Section 2(1) of the Capital Markets and Services Act 2007 and for the purpose of the Proposed Acquisition, includes any person who is or was within the preceding six (6) months of the date on which the terms of the transaction were agreed upon, a director or a Chief Executive Officer of Hibiscus Petroleum, our subsidiary or holding company
DCC	:	Dutch Civil Code
E&P	:	Exploration and production
Effective Date	:	31 December 2022
EGM	:	Extraordinary general meeting of Hibiscus Petroleum
EMDEs	:	Emerging market and developing economies
EPS	:	Earnings per share
ESG	:	Environmental, social and governance
FHCA	:	FHMH Corporate Advisory Sdn Bhd, the Corporate Advisory arm of Baker Tilly Malaysia
FYE	:	Financial year ended / ending, as the case may be
GDP	:	Gross domestic product
GSA	:	Gas supply agreement dated 16 December 2013 between BLNG and the BBJV Partners
Hibiscus Petroleum Group or Group	:	Hibiscus Petroleum and its subsidiaries
Hibiscus Petroleum or Company	:	Hibiscus Petroleum Berhad
Hibiscus Petroleum Share(s) or Share(s)	:	Ordinary share(s) of Hibiscus Petroleum
IFRS	:	International Financial Reporting Standards

Jaspet	:	Jasra International Petroleum Sendirian Berhad
JOA	:	Joint Operating Agreement initially entered into between Jaspet, Pengiran Dato Paduka Haji Abdul Rahman Bin Pengiran Haji Abdul Rahim and ELF Petroleum Asia B.V. dated 10 December 1986 as amended, supplemented and novated from time to time. The BBJV Partners are the current JOA parties
LAT	:	Loss after taxation
LATAMI	:	Loss after taxation and minority interest
LBT	:	Loss before taxation
Leakage	:	As defined under Section 1.5 of Appendix I of this Circular
Listing Requirements	:	Main Market Listing Requirements of Bursa Securities
LNG	:	Liquefied natural gas
Long Stop Date	:	The date falling nine (9) months after the date of the SPA or as may be agreed to by the parties to the SPA
LPD	:	The latest practicable date prior to the date of this Circular, being 20 September 2024
LPS	:	Loss per share
Major Shareholder	:	A person who has an interest or interests in one (1) or more voting shares in our Company and the number or aggregate number of those shares, is: a) ten percent (10%) or more of the total number of voting shares in our Company; or b) five percent (5%) or more of the total number of voting shares in our Company where such person is the largest shareholder of our Company For the purpose of this definition, "interests" shall have the meaning of "interests in shares" given in Section 8 of the Act and for the purpose of the Proposed Acquisition, "Major Shareholder" includes any person who is or was within the preceding six (6) months of the date on which the terms of the transaction were agreed upon, a major shareholder of our Company or any other corporation which is our Company's subsidiary or holding company
MLJ	:	Maharajalela Jamalulalam
NA	:	Net assets
Net Purchase Price	:	Net purchase price of USD178 million (being the Purchase Price of USD245 million less the value of the Third Party Gas ascribed by RPS Energy of USD67 million)

NPV	:	Net present value
O&G	:	Oil and gas
OPEC	:	Organisation of the Petroleum Exporting Countries
PAT	:	Profit after taxation
PATAMI	:	Profit after taxation and minority interest
Parent Company Guarantee	:	Parent Company Guarantee dated 13 June 2024 furnished by our Company in favour of TotalEnergies Holdings to guarantee the Purchaser's performance under the SPA
PBT	:	Profit before taxation
PMA	:	Block B Petroleum Mining Agreement dated 23 November 1989 initially entered into between the government of Brunei and Jaspet
Pre-Closing Dividend	:	A dividend or other distribution to be declared by the TargetCo to the Vendor based on the principles set out in the SPA before Closing
Proposed Acquisition	:	Proposed Acquisition by Simpor Hibiscus of the entire equity interest of TargetCo for the Purchase Consideration
Purchase Consideration	:	Cash consideration of approximately USD259.4 million (or equivalent to approximately RM1,087.8 million) comprising the Purchase Price and net working capital of USD14.4 million (or equivalent to approximately RM60.4 million), subject to the adjustments mechanism as set out in Section 2.1 of this Circular
Purchase Price	:	USD245.0 million (or equivalent to approximately RM1,027.4 million)
RPS Energy	:	RPS Energy Limited, the independent competent expert and competent valuer appointed by our Company. RPS Energy (Company No. 1465554), is a company duly registered in England and is a 100% owned subsidiary of RPS Group Limited (Company No. 02087786), a company duly registered in England. RPS Group Limited is a subsidiary of Tetra Tech UK Holdings Limited and is ultimately owned by Tetra Tech Inc, a company registered in the US and listed on the NASDAQ market
Share Buyback	:	Share buy-back of 22,809,300 Shares (and retained as Hibiscus treasury shares) up to the LPD
Share Consolidation	:	Share consolidation of every five (5) Shares into two (2) consolidated Shares, which was completed on 20 October 2023
Shell Deepwater	:	Shell Deepwater Borneo BV (formerly known as Shell Deepwater Borneo Limited)
Simpor Hibiscus or Purchaser	:	Simpor Hibiscus Sdn Bhd, our indirect wholly-owned subsidiary
SOFR	:	Secured overnight financing rate

SPA	:	The sale and purchase agreement dated 13 June 2024 entered into between Simpor Hibiscus and TotalEnergies Holdings in relation to the Proposed Acquisition
SSAR	:	Specific Scope Assessment Report dated 19 September 2024 prepared by FHCA
TargetCo	:	TotalEnergies EP (Brunei) B.V., the wholly-owned subsidiary of TotalEnergies Holdings
TargetCo Shares	:	Entire issued share capital of the TargetCo, which is registered in the name of the Vendor
Third Party Gas	:	Gas and associated condensate for which the BBJV has been licensed by third parties, subject to payment of a licence fee thereto, to produce, process and sell
TotalEnergies Holdings or Vendor	:	TotalEnergies Holdings International B.V.
Transition Services Agreement or TSA	:	The transition services agreement dated 23 September 2024 entered into between Simpor Hibiscus and TotalEnergies Holdings
US	:	United States of America

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1C or 1C Resources	:	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 or 2C Resources	:	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 or 3C Resources	:	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 or 1P Reserves	:	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 or 2P Reserves	:	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 or 3P Reserves	:	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
bpd	:	Barrels per day
boe	:	Barrels of oil equivalent
Bscf	:	Billion standard cubic feet
Condensate	:	A mixture of hydrocarbons which exist in gaseous phase at reservoir conditions but are produced as a liquid at surface conditions
CO_2	:	Carbon dioxide
hydrocarbon	:	An organic compound consisting only of carbon and hydrogen. The majority of hydrocarbons are found to form naturally in crude oil, natural gas, and coal
km	:	Kilometres
$ktCO_2e$	:	Kilo tonnes carbon dioxide equivalent
MMboe	:	Million barrels of oil equivalent
MMscf	:	Million standard cubic feet
MMstb	:	Million stock tank barrels

CURRENCIES

RM	:	Ringgit Malaysia
USD	:	US Dollar

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All references to "**our Company**" in this Circular are to Hibiscus Petroleum and references to "**our Group**" collectively refers to our Company and our subsidiaries. References to "**we**", "**us**", "**our**" and "**ourselves**" are to our Company, and where the context otherwise requires, shall include our Company and subsidiaries.

All references to "**you**" and "**your**" in this Circular are to our shareholders who are entitled to attend and vote at our forthcoming EGM, unless the context otherwise requires.

Words denoting the singular shall, where applicable, include the plural and vice versa and words denoting the masculine gender shall, where applicable, include the feminine and neuter genders and vice versa. References to persons shall include corporations, unless otherwise specified.

All references to any enactment in this Circular are references to that enactment as for the time being amended or re-enacted. Any reference to a time of day in this Circular shall be a reference to Malaysian time, unless otherwise specified.

Any discrepancy in the figures included in this Circular between the amounts listed, actual figures and the totals thereof are due to rounding adjustments.

Unless otherwise stated and wherever applicable, the exchange rate of USD1: RM4.1935, being the middle rate for USD to RM quoted by BNM at 5.00 p.m. as at LPD, is used throughout this Circular.

Certain statements in this Circular may be forward-looking in nature, which are subject to uncertainties and contingencies. Forward-looking statements may contain estimates and assumptions made by our Board after due enquiry, which are nevertheless subject to known and unknown risks, uncertainties and other factors which may cause the actual results, performance and achievements to differ materially from the anticipated results, performance and achievements expressed or implied in such forward-looking statements. In light of these and other uncertainties, the inclusion of a forward-looking statement in this Circular should not be regarded as a representation or warranty that our Group's plans and objectives will be achieved.

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This Executive Summary highlights only the salient information of the Proposed Acquisition in this Circular. You are advised to read and carefully consider the contents of this Circular and the appendices contained herein in its entirety for further details and not to rely solely on this Executive Summary in forming a decision on the Proposed Acquisition before voting at the forthcoming EGM.

Salient information	Description	Reference to Circular
Summary of the Proposed Acquisition	Simpor Hibiscus, had on 13 June 2024, entered into a conditional SPA with TotalEnergies Holdings for the proposed acquisition of the entire equity interest of TargetCo for a cash consideration of approximately USD259.4 million (or equivalent to approximately RM1,087.8 million), subject to the adjustments mechanism as set out in Section 2.1 of this Circular. A Parent Company Guarantee dated 13 June 2024 was furnished by our Company in favour of TotalEnergies Holdings to guarantee Simpor Hibiscus' performance under the SPA. In addition, a Transition Services Agreement was executed between Simpor Hibiscus and TotalEnergies Holdings on 23 September 2024 for the provision of various services by TotalEnergies Holdings to Simpor Hibiscus in order to facilitate a smooth handover of the business and operations of the TargetCo. The TargetCo was incorporated in the Netherlands, which via its Branch is operating in Brunei. The principal activity of the Branch is hydrocarbon exploration and production. The TargetCo through its Branch in Brunei owns a 37.5% operated interest in the Asset.	Sections 1 and 2
Basis and justification for the Purchase Consideration	The Purchase Consideration was arrived at on a 'willing-buyer willing-seller' basis and after taking into account, amongst others, the following: (i) Net Entitlement 2P Reserves of 24.2 MMboe and Net Entitlement 2C Resources of 6.8 MMboe as at 1 January 2023 based on the Competent Valuer's Report; (ii) the discounted cash flow valuation as of 1 January 2023 of USD250.0 million (or equivalent to approximately RM1,048.4 million), derived from the expected remaining ultimate recovery of hydrocarbons from the Asset (net to the TargetCo). The Net Purchase Price translates to USD7.4/boe (based on 2P Reserves) and USD5.7/boe (based on 2P Reserves and 2C Resources);	Section 2.2

Salient information	Description	Reference to Circular
	(iii) the working capital and net cash of the TargetCo as at the Effective Date as stated in Section 2.1 of this Circular; and (iv) the prospects of the O&G sector as well as the prospects, earnings and cash flow potential of the Asset as set out in Section 4 of this Circular. The Net Purchase Price is also viewed as competitive based on similar past deals, as indicated in Section 2.2 of this Circular and the Competent Valuer's Report.	
Rationale and benefits of the Proposed Acquisition	(i) In line with the growth strategy of our Group of acquiring producing assets in well-established regions with operatorship role; (ii) Expected increase in gas composition in our Group's portfolio and decarbonisation opportunities; (iii) Identified plans and projects to enhance reserves and production (iv) Retention of the TargetCo's experienced team to maintain continuity; (v) Entry into the global LNG market & long-term contracts underpin future growth; (vi) Capitalises on our Group's successful track record of significantly improving the performance of acquired assets; and (vii) Politically stable and well-established O&G jurisdiction.	Section 3
Prospects of the Asset and the TargetCo	Our Board believes that the future prospects of the enlarged Hibiscus Group are expected to be positive in view of the following: (i) the rationale and benefits of the Proposed Acquisition as set out in Section 3 of this Circular; (ii) the improvement to our Group's projected total net cash flows (based on the RPS Energy 2P and 2C estimated cash flows); and (iii) the expected enhancement of future earnings.	Section 4.4
Risk factors in relation to the Proposed Acquisition	There are certain risks specifically associated with the Proposed Acquisition as well as relating to the business of the TargetCo, which include the following:	Section 5

Salient information	Description	Reference to Circular
	• Risks relating to the Proposed Acquisition (i) Non-completion risk; (ii) Acquisition risk; (iii) Reliance on current estimated reserves; and (iv) Valuation based on projected cash flows depends on assumptions that may not materialise. • Risks relating to the business of the TargetCo (i) Potential fluctuation in revenue and profits due to the changes in O&G prices and cost of services; (ii) Exposure to development and production risks; (iii) Political, economic, market, regulatory and environmental considerations; (iv) Dependence on skilled professionals and experienced staff; (v) Non-renewal of the concession and other related agreements; (vi) Foreign exchange risk; and (vii) Goodwill and impairment risk.	
Approvals required	The Proposed Acquisition is subject to the approval of the shareholders of our Company at an EGM to be convened. The Undertaking Shareholders (as defined in Section 8 of this Circular) have provided undertakings to vote in favour of the resolution pertaining to the Proposed Acquisition to be tabled at the forthcoming EGM in accordance with the recommendations of the Board. As at the LPD, the Undertaking Shareholders have approximately 12.3% shareholdings in our Company.	Section 8
Interests of Directors, Major Shareholder, chief executive and/or persons connected with them	None of our Directors, Major Shareholder, chief executive of our Company and/or persons connected with them has any interest, whether direct or indirect, in the Proposed Acquisition.	Section 11

Salient information	Description	Reference to Circular
Directors' statement and recommendation	Our Board, after having considered all aspects of the Proposed Acquisition, including but not limited to the basis and justifications for the Purchase Consideration, terms of the SPA, rationale and benefits of the Proposed Acquisition, effects of the Proposed Acquisition as well as the prospects of the TargetCo and the risks involved, is of the opinion that the Proposed Acquisition is in the best interests of our Group. Accordingly, our Board recommends that you **VOTE IN FAVOUR** of the ordinary resolution pertaining to the Proposed Acquisition to be tabled at the forthcoming EGM.	Section 12

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HIBISCUS PETROLEUM BERHAD
Registration Number: 200701040290 (798322-P)
(Incorporated in Malaysia)

Registered Office:
Unit 521, 5th Floor, Lobby 6
Block A, Damansara Intan
No. 1, Jalan SS 20/27
47400 Petaling Jaya
Selangor Darul Ehsan

25 September 2024

Board of Directors:
Zainul Rahim bin Mohd Zain *(Non-Independent Non-Executive Chairman)*
Dr Kenneth Gerard Pereira *(Managing Director)*
Dato' Sri Roushan Arumugam *(Non-Independent Non-Executive Director)*
Thomas Michael Taylor *(Senior Independent Non-Executive Director)*
Dato' Dr Zaha Rina Zahari *(Independent Non-Executive Director)*
Emeliana Dallan Rice-Oxley *(Independent Non-Executive Director)*
Zaidah binti Ibrahim *(Independent Non-Executive Director)*

To: Our shareholders

Dear Sir/Madam,

PROPOSED ACQUISITION

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1. INTRODUCTION

On 14 June 2024, AmInvestment Bank had on behalf of our Company, announced that Simpor Hibiscus, had on 13 June 2024, entered into a conditional SPA with TotalEnergies Holdings for the Proposed Acquisition.

In conjunction with the Proposed Acquisition, a Parent Company Guarantee dated 13 June 2024 was furnished by our Company in favour of TotalEnergies Holdings to guarantee Simpor Hibiscus' performance under the SPA.

In addition, a Transition Services Agreement was executed between Simpor Hibiscus and TotalEnergies Holdings on 23 September 2024 for the provision of various services by TotalEnergies Holdings to Simpor Hibiscus in order to facilitate a smooth handover of the business and operations of the TargetCo.

Further information on the salient terms of the SPA, Parent Company Guarantee and the Transition Services Agreement are set out in Appendix I of this Circular.

THE PURPOSE OF THIS CIRCULAR IS TO PROVIDE YOU WITH RELEVANT INFORMATION ON THE PROPOSED ACQUISITION AND TO SET OUT THE VIEWS AND RECOMMENDATION OF OUR BOARD AS WELL AS TO SEEK YOUR APPROVAL FOR THE RESOLUTION PERTAINING TO THE PROPOSED ACQUISITION WHICH WILL BE TABLED AT THE FORTHCOMING EGM OF OUR COMPANY. THE NOTICE OF THE EGM AND THE FORM OF PROXY ARE ENCLOSED IN THIS CIRCULAR.

YOU ARE ADVISED TO READ AND CAREFULLY CONSIDER THE CONTENTS OF THIS CIRCULAR TOGETHER WITH THE APPENDICES BEFORE VOTING ON THE RESOLUTION TO GIVE EFFECT TO THE PROPOSED ACQUISITION AT OUR FORTHCOMING EGM.

2. DETAILS OF THE PROPOSED ACQUSITION

The Proposed Acquisition is in relation to the acquisition by Simpor Hibiscus of the TargetCo Shares, subject to the terms and conditions of the SPA.

The TargetCo was incorporated in the Netherlands, which via its Branch, is operating in Brunei. The principal activity of the Branch is hydrocarbon exploration and production. The TargetCo through its Branch in Brunei owns a 37.5% operated interest in the Asset.

The parties holding the remaining participating interests in the Asset are Shell Deepwater which holds 35.0% and Brunei Energy which holds 27.5%. Brunei Energy is owned by Brunei Energy Holdings Sdn Bhd which in turn is owned by the Brunei Minister for Finance Corporation.

The concession was awarded on 23 November 1989 with an expiry date of 23 November 2029, with the option for the BBJV Partners to extend the concession until 23 November 2039. Post extension, the BBJV Partners shall assume a best-efforts obligation to ensure continued commercial exploitation of the contract area for the period remaining after 1 April 2033 (being the expiry of the BBJV Partners' existing gas supply commitment to BLNG). Please refer to Section 2.2 and Section 3.5 of this Circular for the extension terms of the key related agreements i.e. Third Party Gas agreement, GSA and services agreement.

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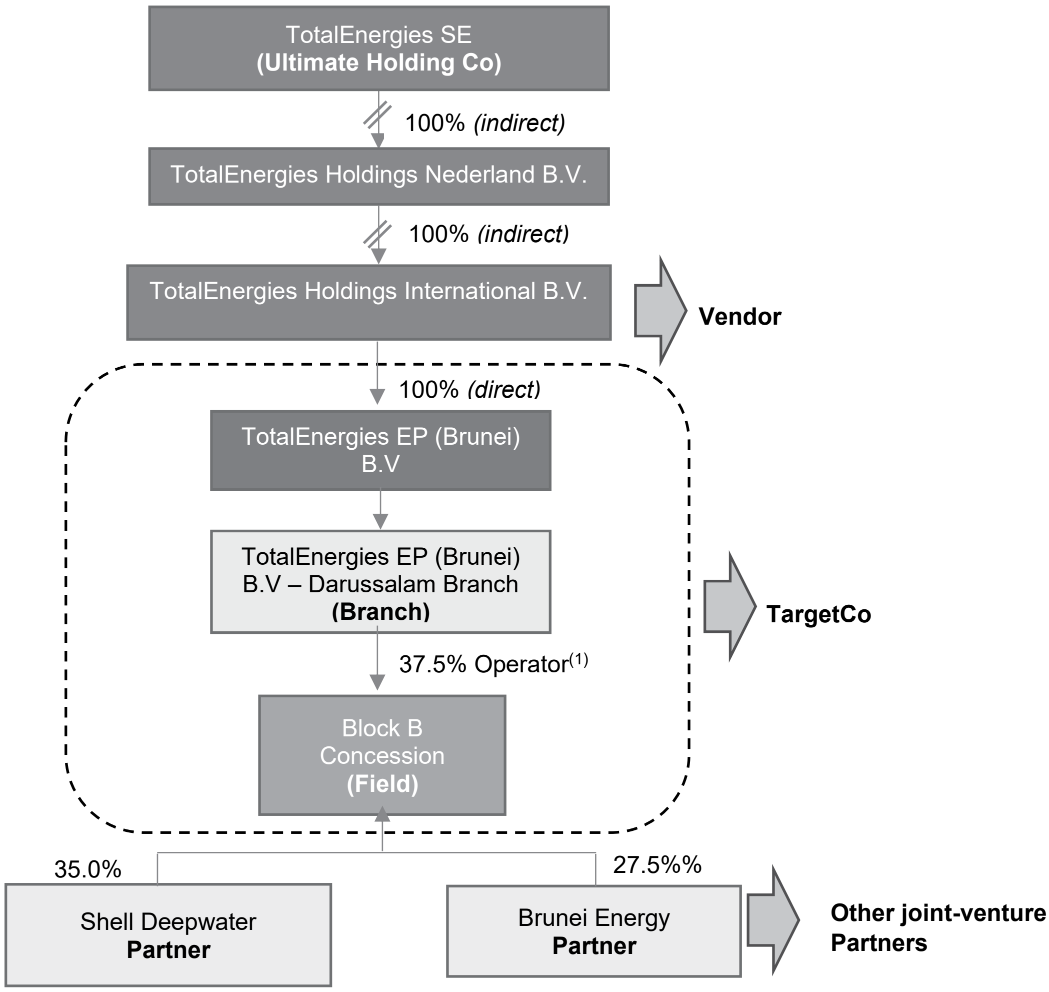

Note:

(1) 37.5% Operator means that apart from holding a 37.5% participating interest, the TargetCo also operates the Asset on behalf of the BBJV Partners under the JOA. Additionally, under the GSA and the Third Party Gas agreement, the TargetCo acts as the BBJV Partners' operator in operating and managing the respective agreements.

For further information on the TargetCo and the Asset, please refer to Appendix II and Appendix III of this Circular, respectively. For further details on the salient features of the PMA, JOA, JVA and Cash Investors Agreement, please refer to Appendix III of this Circular.

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The summary of the key unaudited condensed consolidated financial information of the TargetCo for FYE 31 December 2021, FYE 31 December 2022 and FYE 31 December 2023 based on the SSAR is as follows:

	FYE 31 December 2021		FYE 31 December 2022		FYE 31 December 2023	
	USD'million	**Equivalent to RM'million**	**USD'million**	**Equivalent to RM'million**	**USD'million**	**Equivalent to RM'million**
Revenue	113.1	471.1	159.6	700.6	151.0	693.1
PBT	41.1	171.1	86.3	378.8	64.3	295.3
PAT	11.0	45.6	33.7	148.0	32.8	150.4
PAT and non-controlling interests / Net profits attributable to the TargetCo	11.0	45.6	33.7	148.0	32.8	150.4
Share capital	100	416.5	100	439.0	100	459.0
No. of shares ('000)	1,000	1,000	1,000	1,000	1,000	1,000
Net earnings per share(iv) (RM or USD)	11.0	45.6	33.7	148.0	32.8	150.4
NA / Shareholders' funds	177.4	738.7	141.1	619.3	158.8	729.1
NA per share(v) (RM or USD)	177.4	738.7	141.1	619.3	158.8	729.1
Current ratio(vi) (times)	1.38	1.38	1.10	1.10	1.18	1.18
Total borrowings	-	-	-	-	-	-
Gearing (times)	-	-	-	-	-	-

The USD currency rates in the table above were converted to RM on the basis of the following Bank Negara middle rates:

(i) For FYE 31 December 2021, USD1.00:RM4.1650.
(ii) For FYE 31 December 2022, USD1.00:RM4.3900;
(iii) For FYE 31 December 2023, USD1.00:RM4.5900;
(iv) Computed based on net earnings divided by the number of shares;
(v) Computed based on NA divided by the number of shares; and
(vi) Computed based on current assets divided by current liabilities.

Please refer to Appendix II for further details on the historical financial information of the TargetCo.

2.1 Purchase Consideration

The Purchase Consideration comprises the following and is subject to adjustments to be calculated in accordance with the SPA:

		USD' million	RM' million
(a)	Purchase Price	245.0	1,027.4
(b)	(plus) Net cash as at 31 December 2022	44.9	188.3
(c)	(less) Working capital as at 31 December 2022	(30.5)	(127.9)
	Purchase Consideration	**259.4**	**1,087.8**

The consideration structure is based on a "locked-box" concept, whereby the economic risks and benefits after the Effective Date accrue to the Purchaser which means all net cash flows from such date will be to the account of the Purchaser. This is the basis of the Purchase Price. Also, as this is a company acquisition, the working capital and net cash as at the Effective Date also accrue to the Purchaser and are adjusted in the Purchase Consideration. The "locked-box" concept is generally seen in O&G transactions to provide purchase price certainty and avoid post-closing disputes, all of which are crucial in an industry where financials may be impacted by external factors such as commodity prices and operational risks.

The agreed adjustments to derive the Closing Amount at the Closing Date are as follows:

(i) (plus) a fixed USD17.0 million (or equivalent to approximately RM71.3 million), being the time value amount from the Effective Date to and including 14 October 2024, provided that (a) there should be no adjustment to this if Closing occurs on or prior to 14 October 2024 and (b) there shall be no other Leakage from the cut-off date (i.e. 5:00 p.m. local time in Paris, France on 10 June 2024) up to the Closing Date. Such sum is based on an effective interest rate of approximately 5.0% per annum. Leakages are essentially outflows which are not in the ordinary course of business such as dividends. Accordingly, any Leakages will be deducted from the Closing Amount. The estimated Leakage during the relevant period is shown in the table below, in this Section.

Note:
The time value amount compensates the Vendor for the opportunity cost of not receiving the full consideration on the Effective Date. This cost is calculated from the Effective Date to the Closing Date, reflecting the foregone interest or returns the Vendor could have earned during such period. Such rate is typically based on a market-aligned rate. The effective interest rate of approximately 5.0% per annum is reflective of the USD fixed deposit rate at the time of SPA signing;

(ii) (plus) interest at the Agreed Interest Rate (i.e. interest at SOFR plus 6%) from 15 October 2024 to and including the Closing Date (should the Closing Date be postponed after 14 October 2024) on the Purchase Price less the amount of the Deposit and less any Leakage amount from the date when such Leakage was actually incurred;

Note:
The interest, reflects the additional opportunity cost incurred by the Vendor for not having received the full consideration by 14 October 2024. This opportunity cost is calculated from 15 October 2024 until the Closing Date when the remaining consideration is received. The Agreed Interest Rate is mutually agreed between the Vendor and Hibiscus Petroleum;

(iii) (less) Pre-Closing Dividend;

(iv) (less) the Deposit; and

(v) (less) an amount equal to the estimated Leakage amount (if any).

Upon execution of the SPA, the Purchaser has paid the Deposit to the Vendor. The balance of the Purchase Consideration after the relevant adjustments shall be paid by the Purchaser on the Closing Date.

For illustrative purposes, assuming the Proposed Acquisition is completed on 14 October 2024, the estimated Closing Amount would be as follows:

	USD' million	RM' million
Purchase Consideration	**259.4**	**1,087.8**
Agreed adjustments:		
Add: Estimated time value amount	17.0	71.3
(Less): Estimated pre-closing dividend	(65.0)	(272.6)
(Less): Estimated Leakage	(15.6)	(65.4)
(Less): Deposit	(49.0)	(205.5)
Estimated Closing Amount	**146.8**	**615.6**

The estimated Closing Amount provided above is indicative and will be finalised by the Closing Date. The final Closing Amount will depend on factors such as the TargetCo's cash reserves and actual adjustments. Our Company will issue an announcement regarding the final Closing Amount, which will include details and basis of any adjustments made to the Purchase Consideration on the Closing Date.

2.2 Basis and justification for the Purchase Consideration

The Purchase Consideration was arrived at on a 'willing-buyer willing-seller' basis and after taking into account, amongst others, the following:

(i) Net Entitlement* 2P Reserves of 24.2 MMboe and Net Entitlement 2C Resources of 6.8 MMboe as at 1 January 2023 based on the Competent Valuer's Report;

Note:
* *"Net Entitlement" means the TargetCo share of 37.5%.*

(ii) the discounted cash flow valuation as of 1 January 2023 of USD250.0 million (or equivalent to approximately RM1,048.4 million), derived from the expected remaining ultimate recovery of hydrocarbons from the Asset (net to the TargetCo*)

Note:
* *"net to the TargetCo" means the TargetCo share of 37.5%.*

The breakdown of the USD250.0 million valuation as estimated by RPS Energy based on RPS Energy's 2P Reserves and 2C Resources is set out below:

Block B (net to the TargetCo)	**USD' million**
<u>2P NPV10</u>	
2P Reserves	169
Present value of future cash flows from Third Party Gas[(1)]	67
<u>2C NPV12</u>	
2C Resources	14
Valuation	**250**

Note:

(1) Under the Third Party Gas agreement, the third party owners have licensed the BBJV Partners to produce, process and take title to its gas and associated condensate, in consideration of payment of a licence fee to the third party owners. The terms and conditions of the agreement include payment of the licence fee and the parties' ability to mutually agree to extend the term of the agreement from 2025 accordingly as long as there are gas volumes remaining in the reservoir.

The valuation above has assumed that the Asset will be producing up to 2039. As mentioned above, the concession was awarded on 23 November 1989 with an expiry date of 23 November 2029, with the option for the BBJV Partners to extend the concession until 23 November 2039. In the event the concession is not extended by the BBJV Partners, we estimate the expected fair market value of the Assets as at 1 January 2023 to be approximately USD177 million (or equivalent to approximately RM742.2 million) based on RPS Energy inputs.

The present value of future cash flows from Third Party Gas is based on the assumption that the Third Party Gas will continue being produced and processed until the end of 2039. The Third Party Gas is included in the cash flow projections and contributes to the total fair value. Further details are set out in Section 6.4 and Appendix C of the Competent Valuer's Report.

The other key valuation assumptions used by RPS Energy in arriving at the discounted cash flow valuation of the Asset (net to the TargetCo) of USD250.0 million based on its report dated 13 June 2024, are set out in Section 2 of Appendix III of this Circular.

The valuation of USD250 million is compared against the Purchase Price of USD245 million as this represents the value of the Asset based on the Effective Date. As we are acquiring the TargetCo (i.e. the company itself as opposed to just the Asset), the net cash less net working capital of the TargetCo as at the Effective Date has also been added to the Purchase Price to derive the Purchase Consideration of USD259.4 million.

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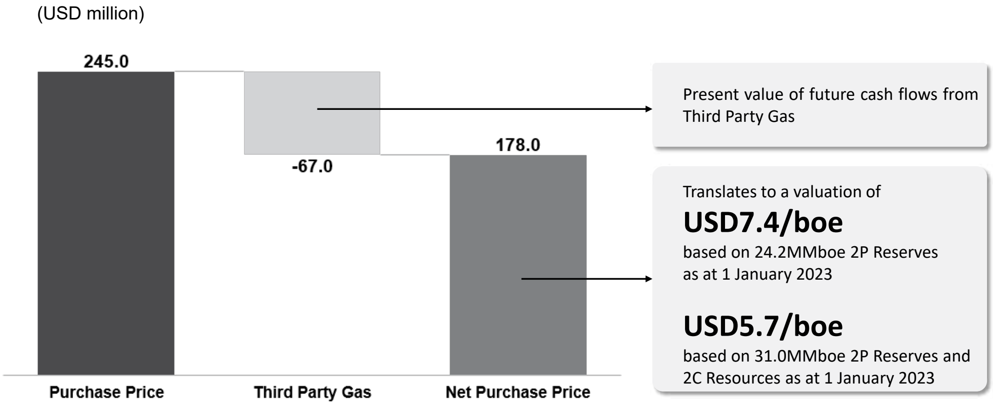
The Net Purchase Price translates to USD7.4/boe (based on 2P Reserves) and USD5.7/boe (based on 2P Reserves and 2C Resources) as depicted in the chart below:



(iii) the working capital and net cash of the TargetCo as at the Effective Date as stated in Section 2.1 of this Circular; and

(iv) the prospects of the O&G sector as well as the prospects, earnings and cash flow potential of the Asset as set out in Section 4 of this Circular.

The quantum of the Deposit takes into account the competitive process for the TargetCo as well as the other commercially negotiated terms of the Proposed Acquisition acceptable to both parties on a "willing buyer, willing seller" basis.

The Net Purchase Price is also viewed as competitive based on similar past deals as extracted from the Competent Valuer's Report reproduced below:

SPA Date	Asset	Buyer	Seller	2P Reserves (MMboe)	2P Price (USD/ boe)	2P + 2C (MMboe)	2P + 2C Price (USD/ boe)	Avg. Yearly Brent Price [(1)] (USD/bbl)
June 2021	Acquisition of Repsol Assets in Malaysia & Block 46, Vietnam	Peninsula Hibiscus Sdn Bhd	Repsol Malaysia	34.5	6.2	35.8	5.9	71
June 2024	Proposed Acquisition of TotalEnergies Asset in Brunei	Simpor Hibiscus	TotalEnergies Holdings	24.2	7.4	31.0	5.7	84
Jan 2019	Acquisition of Ophir Energy plc	PT Medco Energi Internasional Tbk	Ophir Energy plc	70.1	7.4	-	-	64
June 2022	Concession L53/48	Dialog Systems (Asia) Pte Ltd	Pan Orient Energy Corp	4.6	8.4	-	-	101

SPA Date	Asset	Buyer	Seller	2P Reserves (MMboe)	2P Price (USD/ boe)	2P + 2C (MMboe)	2P + 2C Price (USD/ boe)	Avg. Yearly Brent Price (1) (USD/bbl)
May 2018	Acquisition of Santos's Southeast Asian production licences	Ophir Energy Plc	Santos Limited	23.3	8.8	-	-	71
Mar 2019	Murphy Oil Corporation's interests in Malaysia	PTTEP Limited	Murphy Oil Corporation	169.3	12.6	-	-	64
Nov 2018	50 per cent interest in SEB Upstream Sdn Bhd (SUP)	OMV Exploration and Production GmbH	Sapura Energy Berhad	46.1	17.3	74.7	10.7	71

(Source: Competent Valuer's Report)

Note:
The Net Purchase Price is used for comparison above as it refers to the value of the Asset similar to the above mentioned transactions which is based on the Reserves and excludes any balance sheet adjustments.

(1) This represents the average yearly Brent price in the year of SPA execution.

Based on the historical similar past deals, the price transacted was between USD6.2/boe and USD17.3/boe for 2P Reserves and USD5.9/boe and USD10.7/boe for the 2P Reserves and 2C Resources. The Net Purchase Price, which translates to USD7.4/boe (for 2P Reserves) is within the range of the historical similar past deals. Based on 2P Reserves and 2C Resources, the Net Purchase Price translates to USD5.7/boe, which is lower than historical similar past deals.

The TargetCo Shares will be acquired with full title guarantee free from any encumbrances together with all benefits and rights attaching or accruing thereto on the Closing Date, including all dividends and distributions declared, paid or made by the TargetCo after the Closing Date.

There are no material developments (outside the ordinary course of business) in the TargetCo since the Effective Date which would affect the assets and liabilities of the TargetCo.

2.3 Sources of funding for the Proposed Acquisition

The funding of the Purchase Consideration will include a combination of the following:

(i) deduction from the Purchase Consideration of an amount equivalent to any Pre-Closing Dividend from the TargetCo to the Vendor. Please refer to Section 2.1 of this Circular for further details; and

(ii) internally generated funds of our Group; and/or

(iii) existing debt/other facilities.

Our Group does not intend to propose any equity issuances as a source of funding as we believe that other available sources of funding are sufficient to fund the Purchase Consideration.

The actual breakdown of the source of funding will only be finalised nearer to Closing and will depend on, amongst others, the TargetCo's available funds as well as our Group's cash reserves. Assuming our Group funds part of the Purchase Consideration of USD100.0 million by way of existing debt/other financing facilities, the interest expense is estimated to be approximately USD8 million per annum which is expected to reduce in line with repayment and lower interest rate.

Under the Transition Services Agreement, the total fees payable for transition services to be provided by TotalEnergies Holdings is estimated to be between USD5 million to USD8 million and shall be funded from our Group's internally generated funds.

2.4 Estimated capital and operating expenditure for the Asset

We anticipate that the capital and operating expenditures for the Asset (net to the TargetCo*) will be approximately USD497.7 million (or equivalent to approximately RM2,087.1 million) up to 2039. The capital and operating expenditures for the Asset are expected to be funded via operating cash flow available from the Asset and/or internally generated funds of our Group.

Note:

* *"net to the TargetCo" means the TargetCo share of 37.5%.*

The annual capital and operating expenditures (based on RPS 2P and 2C case) of the Asset (net to the TargetCo) are set out in the table below:

	Capital Expenditure[1]	**Operating Expenditure**
Year	**USD' million**	
2023	25.2	14.5
2024	33.6	16.8
2025	8.6	19.0
2026	0.4	20.7
2027	0.4	19.5
2028	6.4	20.2
2029	51.7[2]	21.6
2030	8.7	19.0
2031	0.1	18.3
2032	9.1	19.1
2033	0.1	26.6
2034	9.5	19.2
2035	0.1	16.9
2036	9.8	16.7
2037	0.1	18.6
2038	10.2	18.7
2039	0.1	18.2
Total	**174.1**	**323.6**

(Source: Competent Valuer's Report)

Notes:

(1) The capital expenditure tabulated above does not include decommissioning cost. In the event the PMA is extended to November 2039, the TargetCo is expected to incur an estimated decommissioning cost of approximately USD72 million (or equivalent to approximately RM301.9 million) in the year 2040.

(2) The capital expenditure for year 2029-2030 reflects investment associated with maturing 2C Resources via the identified investment for a new high pressure well and a well deepening workover.

For further details on the cash flow projections of the Asset, please refer to Appendix C of the Competent Valuer's Report in Appendix IV of this Circular.

2.5 Liabilities and guarantees

Other than pursuant to the Parent Company Guarantee and customary operational liabilities such as the requirement to continue to pay the on-going cost of operations and maintenance including licence fees, other potential liabilities including decommissioning, health, safety and environmental liabilities as well as the loss or damage to facilities and pollution, there are no other anticipated liabilities, including contingent liabilities and guarantees, to be assumed by our Company pursuant to the Proposed Acquisition.

2.6 Additional financial commitment

Upon completion of the Proposed Acquisition, there is no additional financial commitment expected to be incurred by our Group as the TargetCo is already in operations and the Asset is producing and cash flow generating. As such, any foreseeable additional financial commitments, including capital expenditure required by the TargetCo in the future for further project development and production maintenance of its existing facilities are expected to be funded using funds generated from its own operations.

2.7 Background information of TotalEnergies Holdings (Vendor)

TotalEnergies Holdings was incorporated in Netherlands on 30 December 2011 as a private limited company. The principal activity of TotalEnergies Holdings is financial holdings and through its subsidiaries, hydrocarbon exploration and production.

TotalEnergies Holdings is a wholly-owned subsidiary of TotalEnergies Holdings Nederland B.V. and an indirect wholly-owned subsidiary of Total Energies SE incorporated in France. Total Energies SE is a global integrated energy company that produces and markets energies: oil and biofuels, natural gas and green gases, renewables and electricity, and is active in about 120 countries.

Total Energies SE is listed on Euronext Paris, Euronext Brussels, London Stock Exchange and New York Stock Exchange.

As at 30 August 2024, TotalEnergies Holdings has a sole managing director being TotalEnergies Management BV, itself represented by 4 individuals (i.e. Bernardus Klein Swormink, Mr. Benoit Sibout, Viestarts Rutenbergs and Marcus Kloppenburg), each of them having authority to represent the company solely/independently.

(Source: TotalEnergies Holdings)

2.8 Competent person and competent valuer

Gordon Taylor, the Technical Director of RPS Energy, has supervised both the Competent Person's Report and Competent Valuer's Report for the purposes of the evaluation therein. He is a Chartered Geologist and Chartered Engineer with over 40 years' experience in upstream O&G.

(Source: RPS Energy)

3. RATIONALE AND BENEFITS OF THE PROPOSED ACQUISITION

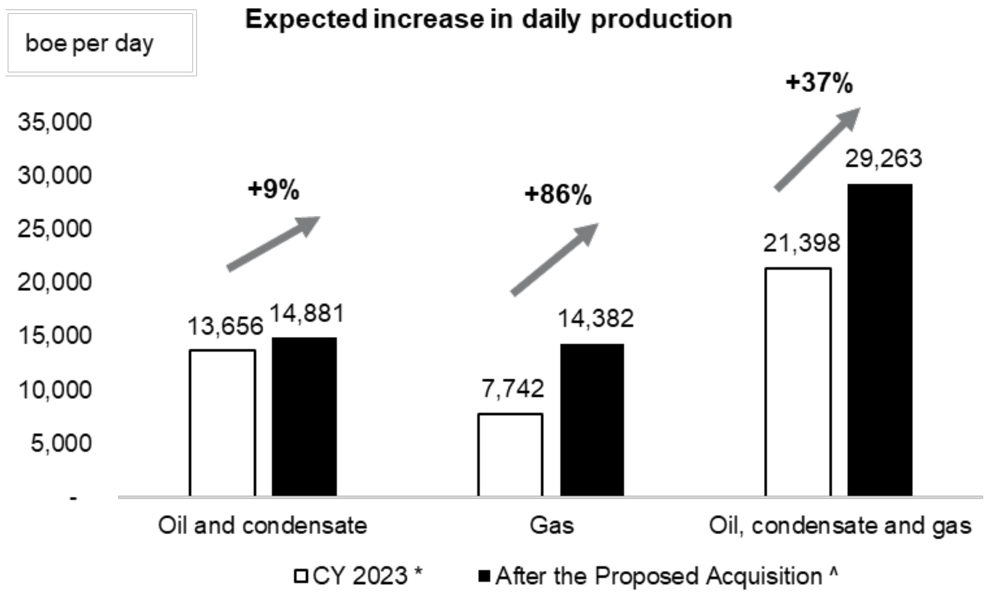
3.1 In line with the growth strategy of our Group of acquiring producing assets in well-established regions with operatorship role

The Proposed Acquisition presents an opportunity for our Group to acquire a well-established gas asset in Brunei and assume the TargetCo's role as operator in the Asset. This Asset, situated near our Group's home country, Malaysia, will enable our Group to further strengthen its position as a significant independent E&P company in the region.

Located in a prolific hydrocarbon-bearing region, the Asset in Brunei has delivered reliable gas and condensate production since its start-up in 1999. It has long-term production rights until 23 November 2029, with an option for a 10-year extension until 23 November 2039, subject to agreement of the BBJV Partners.

Based on the Competent Valuer's Report, the average daily O&G production rate is projected to be 7,865 boe per day (net to the TargetCo) in CY 2024. With our Group's existing production and identified future development opportunities, the Asset is expected to add approximately 24.2 MMboe of 2P Reserves and 6.8 MMboe of 2C Resources as at 1 January 2023. Accordingly with the Proposed Acquisition, our Group is expecting increases in:

(i) daily oil, condensate and gas production from 21,398* boe per day to 29,263^ boe per day as follows:

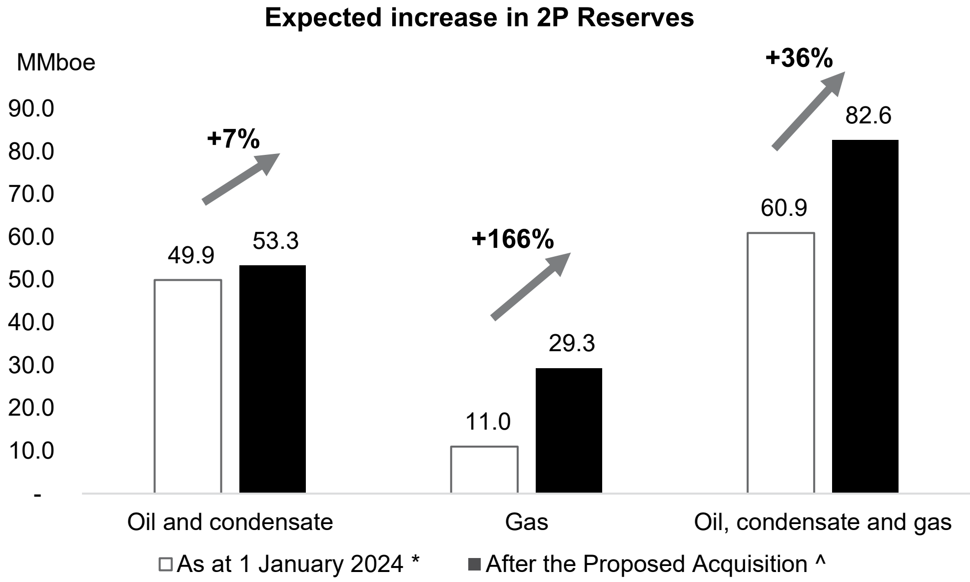


Notes:

* *Based on our Group's CY2023 actual production rates.*

^ *Based on our Group's CY2023 actual production rates and CY2024 2P Reserves case estimates by RPS Energy for the Asset (net to the TargetCo).*

(ii) 2P Oil, Condensate and Gas Net Entitlement Reserves from 60.9 MMboe* to 82.6 MMboe^ as follows:



Notes:

* *Based on our Group's reserves as at 1 January 2024.*

^ *Based on our Group's reserves as at 1 January 2024 and the Asset's reserves (net to the TargetCo) as at 1 January 2024, adjusted for CY2023 production of 2.5 MMboe from the 24.2 MMboe 2P Reserves stated in the Competent Valuer's Report.*

Based on RPS Energy's valuation, the total NPV of the Asset is USD250.0 million (or equivalent to RM1,048.4 million) as of 1 January 2023 for 2P Reserves and 2C Resources, at discount rates of 10% and 12% respectively, and includes the present value of future cash flows at a 10% discount rate from Third Party Gas. The valuation is based on RPS Energy Brent price and gas price forecasts. For information, the total net undiscounted cash flows is approximately USD329.0 million (or equivalent to RM1,379.7 million), expected to be generated over approximately 17 years from 2023 to 2039.

The key valuation assumptions by RPS Energy in arriving at the discounted cash flow valuation of the Asset (net to the TargetCo) are set out in Section 2 of Appendix III of this Circular.

(Source: Competent Person's Report and Competent Valuer's Report)

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The RPS Energy's valuation has assumed that the Asset will be producing up to 2039. As mentioned in Section 2 of this Circular, the concession was awarded on 23 November 1989 with an expiry date of 23 November 2029, with the option for the BBJV Partners to extend the concession until 23 November 2039. In the event the concession is not extended by the BBJV Partners, we estimate the expected fair market value of the Assets as at 1 January 2023 to be approximately USD177 million (or equivalent to approximately RM742.2 million) based on RPS Energy inputs. In the event that the concession and/or the related agreements are not extended beyond their respective expiry dates, there is no legal recourse available to our Group and we may face a potential asset impairment due to the reduction in gas and condensate reserves.

The projected cash flows will allow our Group to reinvest into existing assets and potentially acquire new assets to further expand our Group's asset portfolio. It will also provide additional funds enhancing our Group's financial position and ability to meet its commitments.

The Proposed Acquisition represents an opportunity of a considerable size that fits well with the strategic objectives and plans of our Group.

3.2 Expected increase in gas composition in our Group's portfolio and decarbonisation opportunities

The Proposed Acquisition is in line with our Group's energy transition strategy of increasing the composition of gas assets in its portfolio as transition fuel. Gas is widely viewed as an energy transition fuel as it emits significantly lesser air pollutants and CO_2.

Almost 84% of the Asset's production consists of gas, hence this will increase our Group's gas portfolio from 36% (CY2023) to 49%, as shown below. In addition to that, the Asset's low greenhouse gas intensity of 11kg CO_2/boe will further reduce the overall Group's greenhouse gas intensity.

This signals our Group's commitment towards ESG considerations and in taking solid steps in reaching its net zero goal by 2050. Such increase in gas composition is also expected to present a better balance to our Group's asset portfolio by offering greater price stability (against oil price volatility), lower emissions and growing demand in energy transition. It diversifies revenue streams, ensures more predictable cashflows through longer-term contracts and helps meet environmental goals.

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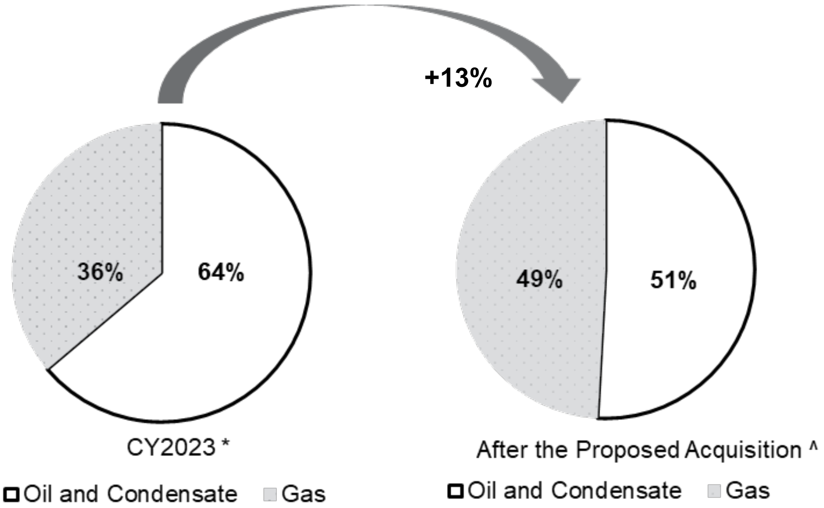
Expected increase in gas composition in our Group's production volume



Notes:

* *Based on our Group's CY2023 actual production rates.*

^ *Based on our Group's CY2023 actual production rates and CY2024 2P Reserves case estimates by RPS Energy for the Asset (net to the TargetCo).*

The TargetCo is exploring ways to reduce methane emissions and use solar power (as elaborated in Section 3.3 of this Circular) for own consumption and is currently under evaluation.

One plan involves replacing hydrocarbon gas used in instruments (valves and pneumatic control systems) and hydrocarbon storage tanks with nitrogen that functions as a safety feature and to stabilize the pressure in the system. This initiative is estimated to reduce emissions by 150 ktCO_2e.

These opportunities are subject to further evaluation by Hibiscus Petroleum after the completion of the Proposed Acquisition.

If these opportunities are realised, they will constitute a further part of our Group's commitment towards ESG considerations.

3.3 Identified plans and projects to enhance reserves and production

In order to enhance production and extend field life, the TargetCo is currently undertaking a low-pressure compression project, which is expected to come on stream in the second half of 2025. As a measure to reduce carbon emissions from the low-pressure compression project, a 12.688 megawatt solar facility is being planned for installation in Lumut, Brunei. The solar facility will occupy 22.41 acres and is projected to be operational between 2025 and 2027. It is anticipated to offset about 11,500 tonnes of CO_2 annually and generate about 18,000 megawatt hour of electricity per year. This is pending further evaluation by Hibiscus Petroleum.

Regular low-cost well intervention and workover campaigns have been planned in the year 2024 to increase monetisation of the 2P Reserves. All gas is sold under the GSA to BLNG which operates a LNG plant.

With regard to the 2C Resources, the TargetCo has planned for a new high pressure well and a well deepening workover. Additionally, regular well production enhancement activities of existing well stock beyond 2024 are also expected to monetise the 2C Resources.

3.4 Retention of the TargetCo's experienced team to maintain continuity

The Proposed Acquisition involves the retention of employees from the TargetCo, bringing on board a highly qualified team with in-depth knowledge of the Asset. The continued employment of the TargetCo's experienced team will be valuable in providing continuity, and in managing the operations of the Asset.

In addition, this team will be complemented by the knowledge and experience that our Company has built up over the last decade. By combining the strengths of both teams, our Company will be well-positioned to maintain operational efficiency, leverage local knowledge, and drive successful asset development. This strategic move reiterates our Group's commitment to strengthening its operational capabilities and delivering long-term growth in the region.

3.5 Entry into the global LNG market & long-term contracts underpin future growth

The Proposed Acquisition will increase our Group's access to a gas weighted asset and the fast growing global LNG market through BLNG. Gas from BBJV is processed before being sold to BLNG under the GSA between BLNG (as buyer) and the BBJV Partners (as sellers) with 100% Take-or-Pay and a gas price linked to LNG price (which is linked to Japan Crude Cocktail price). The current GSA term expires on 31 March 2033 and is subject to any extension as may be mutually agreed by the parties. The TargetCo's share of condensates are sold by TOTSA TotalEnergies Trading SA on behalf of the TargetCo to TotalEnergies Trading Asia Pte Ltd. The services agreement in relation to such arrangement was entered into in 2023 and has an initial 5-year term with an automatic 1-year extension on the same terms and conditions (unless otherwise terminated). Any further extension will be subject to the mutual agreement of the parties.

3.6 Capitalises on our Group's successful track record of significantly improving the performance of acquired assets

Since its inception, our Group has steadily developed its capabilities to acquire, operate and extract value from mature mid-to late-life assets.

Our Group's strategies are based on implementing "fit-for-purpose" methods and pursuing projects that extend field life safely and sustainably. Our Group prioritises projects through smart allocation of capital into economically viable endeavors, with a keen focus on cost control.

Based on these strategies, our Group arrested production declines and increased daily production for assets such as the Anasuria Cluster, North Sabah and Peninsula Hibiscus, while also enhancing reliability and uptime of our Group's assets. In order to achieve this result, our Group, in addition to its day-to-day operational capabilities, had undertaken several capital projects to enhance production.

Average facility uptimes in Anasuria Cluster, North Sabah and Peninsula Hibiscus are also relatively high at approximately 91%, 91%, and 86% respectively for the 12 months ended 31 December 2023 (each being top quartile performance for its respective asset class).

Based on the above, should Simpor Hibiscus successfully complete the Proposed Acquisition, it anticipates that it may be in a position to introduce plans to improve the Asset's performance and reduce the operating costs per barrel.

3.7 Politically stable and well-established O&G jurisdiction

The Asset is located in Brunei, which is considered a politically stable country and situated in a well-established O&G jurisdiction. Our Group's existing assets are located in other stable, well-established jurisdictions in Malaysia, the United Kingdom, Vietnam and Australia. From a risk perspective, the Proposed Acquisition will offer geographical diversity in addition to enhancing our Group's assets.

4. INDUSTRY OVERVIEW, OUTLOOK AND PROSPECTS

The TargetCo is principally involved in hydrocarbon exploration and production in Brunei. Accordingly, the prospects of the Asset are largely linked to the prospects of global economic factors as well as the O&G industry in Brunei.

4.1 Overview and outlook of the global economy

Global growth is projected to expand at 3% due to the slow post-pandemic global recovery, prolonged geopolitical tension and the increase in interest rates by various economies to manage inflation. The GDP growth in advanced economies is expected to moderate at 1.5% due to subdued manufacturing activities in advanced economies despite strong services sector.

The EMDEs economic growth is expected to register 4%, which is stronger than advanced economies. However, the growth rate among EMDEs varies across regions. Despite subdued investment in the real estate sector, China’s economy is anticipated to expand at 5.2%, contributed by higher net exports following relaxation of lockdown policies. Meanwhile, India’s economy is projected to grow 6.1% buoyed by stronger domestic investment. Similarly, the GDP growth of ASEAN-5 is envisaged to expand at 4.6%.

(Source: Economic Outlook 2024, Ministry of Finance)

Global trade recovery is also expected to continue in second half 2024. The global economy is expected to be sustained in the second half of this year. This is supported by positive labour market conditions and moderating inflation. The monetary policy easing by the advanced economies will further support growth in the short-to-medium term. China’s growth is expected to expand albeit at a slower pace, as fiscal support will be offset by weak property market and consumer sentiments. Global trade growth is expected to recover further, as global technology upcycle gains momentum.

(Source: Second Quarter 2024 Bulletin, Bank Negara Malaysia)

4.2 Overview and outlook of the O&G industry

Despite a drop in the Brent crude oil spot price to USD73 per barrel (b) on September 6, Energy Information Administration ("**EIA**") expects ongoing withdrawals from global oil inventories will push prices back above USD80/b this month. More oil will be taken out of inventories in the fourth quarter of 2024 (4Q24) that EIA previously expected because OPEC+ announced that they will delay production increases until December. Those increases had been set to start in October. Although market concerns over economic and oil demand growth, particularly in China, have increased, causing oil prices to fall, OPEC+ production cuts mean less oil is being produced globally than is being consumed. EIA expects the Brent crude oil spot price to average USD82/b in 4Q24 and average USD84/b in 2025.

Persistent economic concerns have reduced market expectations around global oil demand growth. Slowing global economic activity and reduced fuel demand in China, one of the leading sources of global oil demand growth, as well as signs of slowing US job growth in recent months, have limited any upward price momentum in recent months.

However, EIA still expects oil prices will rise in the coming months, driven by ongoing withdrawals from global oil inventories as a result of OPEC+ production cuts. The OPEC+ production cuts continue to cause less oil to be produced globally than is being consumed. Even before OPEC+ announced that it will delay production increases until December, EIA expected a significant reduction in global oil inventories through the end of this year. EIA now expects more oil will be taken out of inventories than EIA previously expected.

(Source: Short-Term Energy Outlook, September 2024, Energy Information Administration)

4.3 Overview and outlook of the Brunei economy and O&G industry

The Brunei economy grew in 2023 where its GDP expanded by an impressive 1.4% in 2023, the second fastest annual growth rate in the past decade.

GDP saw a strong growth of 6.8% in Q4 of 2023. The full global reopening amidst the fading effects of the COVID-19 pandemic has helped boost private consumption and the services sector, especially air travel.

Significantly, the non-O&G sector (which includes the downstream activities) continued its expansion relative to the O&G sector (in terms of contribution to nominal gross value added) in 2023 whereby its contribution climbed to 53% which is the largest relative difference observed in recent data. This reflects the structural transition that the economy is undergoing which is expected to increase further in the coming years.

Assuming the O&G sector and the downstream segments maintain their output close to the levels seen in Q4 of 2023, the Brunei economy is forecasted to grow by a stronger 2.7% in 2024.

(Source: Brunei Economic Outlook 2024, Centre for Strategic and Policy Studies of Brunei Darussalam)

Brunei is the 51st largest producer of O&G in the world with an average production of around 258 thousand boe per day for the last three years. Gas dominates output, representing about 58% of cumulative production, with the remainder being liquids. Currently, 33 fields are under production, in addition to 3 fields which are presently being developed and 29 discoveries. Shell, the government of Brunei and TotalEnergies are among the top producers in the country contributing almost all of the country's total production in 2023. The explorers in the country have spent about USD226 million on exploration over the last 5 years and have unearthed around 20 million barrels of new resources.

There are significant remaining resources in Brunei yet to be exploited, as shown in the table below. These resources are primarily dominated by oil majors and the government of Brunei. As of the end of 2023, the country's remaining resources are estimated at approximately 2.6 billion boe.

Hydrocarbons (MMboe)	1P	Remaining
Crude Oil	179	1,076
Condensate	27	145
Gas	345	1,334
Total	**551**	**2,555**

(Source: Upstream Country Report, June 2024, Rystad Energy)

Brunei has long been a cornerstone of upstream activities in Southeast Asia, a key LNG exporter, and participating in OPEC cuts as part of the non-member countries group. Although the pace of the activity has been slower over the past decade, there has been a noticeable recovery and intensification of efforts since 2021. Given the focus of International Oil Companies on Southeast Asia ranging from exploration to mature field opportunities, this could well be the decade with improved performance and improved player landscape for Brunei's O&G sector.

New oil developments are underway that could help stabilise and slightly reverse the declining trend in oil production. The Ministry of Energy of Brunei projects that workover and infill drilling activities could boost production by approximately 30% year-over-year in 2024 and 2025. Rystad Energy forecasts a 28.5% increase in oil production in 2024 and an 11% rise in 2025, with condensate production following a similar trend.

(Source: Brunei Upstream Outlook, Rystad Energy)

4.4 Prospects of the Asset and the TargetCo

Our Group is committed to creating value for its stakeholders via growth through development of its existing assets as well as value accretive acquisitions in well-established and well-regulated O&G jurisdictions within its geographical areas of focus.

The TargetCo has been operating in Brunei since 1986 and has a proven track record in operating the Asset in Brunei and with no lost time injury for over the last 24 years. Leveraging on the TargetCo's team's strong experience in E&P operations and the associated health, safety and environment aspects, coupled with oversight by our Company in-house team, the Asset is expected to contribute favourably to our Group.

Our Board believes that the future prospects of the enlarged Hibiscus Group are expected to be positive in view of the following:

(i) the rationale and benefits of the Proposed Acquisition as set out in Section 3 of this Circular;

(ii) the improvement to our Group's projected total net cash flows (based on the RPS Energy 2P and 2C estimated cash flows); and

(iii) the expected enhancement of future earnings.

5. RISK FACTORS

The Proposed Acquisition is not expected to materially change the risk profile of our Group as our Group operates in the same industry segment as the TargetCo. As such, the enlarged Hibiscus Group would be exposed to similar risks inherent in the industry upon the completion of the Proposed Acquisition. There are certain risks specifically associated with the Proposed Acquisition as well as relating to the business of the TargetCo, which include the following:

5.1 Risks relating to the Proposed Acquisition

(i) Non-completion risk

Completion of the Proposed Acquisition is conditional upon, amongst others, the fulfillment of the Condition Precedent and the performance by the relevant parties of their respective obligations under the SPA.

The Condition Precedent is the receipt by our Company of our shareholders' approval. Should this Condition Precedent fail to be satisfied, the SPA will not close and the Deposit will be subject to forfeiture. In this connection, our Company has used all reasonable efforts to ensure that this Circular meets the requisite disclosure standards to present a clear and balanced view of the merits of the Proposed Acquisition to enable our shareholders to make an informed decision.

In addition, the SPA may be terminated and fail to close in the event any party exercises their termination rights pursuant to the terms of the SPA. Should any such termination occur as a result of the Purchaser not fulfilling its obligations set out in the SPA, the Deposit will be subject to forfeiture.

Our Company cannot provide assurances that it will be able to successfully complete the Proposed Acquisition on the terms or within the timeline expected, or at all. Our Company's failure to complete the Proposed Acquisition on terms and within a time frame acceptable to it may have an adverse effect on its business, financial condition, results of operations and prospects. In addition, if certain conditions are not met or the Purchaser is in breach of certain obligations under the SPA, TotalEnergies Holdings would be entitled to terminate the SPA and the Deposit will be subject to forfeiture.

(ii) Acquisition risk

The Proposed Acquisition is expected to enhance the earnings of the enlarged Hibiscus Group. However, there is no assurance that the anticipated benefits of the Proposed Acquisition will be realised or that the enlarged Hibiscus Group will be able to generate sufficient revenues from the Proposed Acquisition to offset the associated acquisition costs incurred and potential expenditures. Under the SPA, the parties are only entitled to terminate the SPA under limited circumstances.

Please refer to the identified plans and projects to enhance reserves and productions under Section 3.3 of this Circular.

(iii) Reliance on current estimated reserves

The reserves of the TargetCo, as is with other E&P assets, have a finite lifespan which is inherent to the E&P industry. Hence, upon completion of the Proposed Acquisition, the continued development of new reserves to replace those produced and sold is key to ensure the long-term growth and sustainability of the business of the TargetCo. If attempts at locating and developing or acquiring new reserves are unsuccessful, existing reserves will decline over time. The ability to achieve this objective depends, in part, on the level of success in discovering or acquiring additional O&G reserves, and further development of existing contingent resources base.

While our Group seeks to enhance recoveries and/or replenish reserves through initiatives including but not limited to various production enhancements initiatives such as infill drilling opportunities and undertaking development appraisal programmes, there can be no assurance that any such initiatives implemented by our Group would be successful.

(iv) Valuation based on projected cash flows depends on assumptions that may not materialise

Our Company has engaged the services of RPS Energy to undertake an independent assessment of the reserves and resource estimation of the TargetCo's assets. Please refer to Section 2.8 of this Circular for details of the competent person and competent valuer of RPS Energy.

The process of estimating hydrocarbon reserves is complex, requiring interpretation of available technical data and assumptions made in a particular hydrocarbon price environment. Understanding of the subsurface conditions is based on the interpretation of the best data available but due to the uncertainty of such interpretation, the conclusion may be incorrect. Any significant deviations from these interpretations, prices or assumptions (including extensions of relevant agreements) could materially affect the estimated quantities of hydrocarbons reported and the valuations.

Payments of expenditure are based on best estimates based on known factors and may be subject to change due to unforeseeable events. Projected O&G prices are also subject to volatility.

There is no assurance that the estimates by RPS Energy will be accurate due to the above factors.

In this regard, should there be a significant adverse change in the estimates, our Company's financial performance will be affected.

5.2 Risks relating to the business of the TargetCo

(i) Potential fluctuation in revenue and profits due to the changes in O&G prices and cost of services

The business, revenues and profit generated by the TargetCo will be substantially dependent upon the prevailing prices of, and demand for and supply of, O&G. The markets for O&G are volatile in nature and this is expected to continue in the future. Any potential fluctuations in the price of O&G and cost of services may adversely affect the business, revenues and profits of the TargetCo. The price received for any condensate and/or gas produced will depend on changes in the supply of, and demand for, O&G in the global markets, market uncertainty and a variety of additional factors that are beyond the TargetCo's control, including, inter alia:

(a) the ability of OPEC and other petroleum producing nations to set and maintain production levels and prices;
(b) the level of global O&G E&P activity;
(c) technological advances affecting energy consumption;
(d) the price and availability of alternative fuels;
(e) weather conditions and natural disasters;
(f) global economic growth; and
(g) geopolitical uncertainty.

Hence, there can be no assurance that any fluctuations in the prices of O&G and cost of services will not materially affect the business, revenues and profits generated by the TargetCo.

As operator of the Asset, the TargetCo is in a position to plan and manage the work programmes and budgets, to the extent reasonably practicable, so as to re-phase non-critical expenditure during low oil price cycles to preserve cashflows.

(ii) Exposure to development and production risks

The result of further development drilling is uncertain and may involve unprofitable efforts, which may arise from dry or unproductive wells. There is also the risk of cost overruns in operating the Asset due to factors such as unexpected drilling conditions, adverse weather (such as monsoon seasons) or equipment failures, which may result in operational downtime and an increase in the overall cost of operations. Moreover, there is no assurance that additional O&G can be accessed via development drilling at the sites of the Asset.

The development operations are subject to operational risks such as fire, natural disasters, explosions, pipeline ruptures and spills. In more severe circumstances, these could result in loss of human life or serious injury, environmental pollution, damage to equipment and machinery as well as damage to the enlarged Hibiscus Group's reputation.

Production risks could arise from factors such as delays in obtaining relevant governmental approvals or consents, inadequate or insufficient storage or transportation capacity or equipment failure as a result of exposure to weather and natural hazards.

There can be no assurance that the above adverse operational factors will not materially and adversely affect the business and financial performance of the TargetCo.

Furthermore, pursuant to the terms of the Proposed Acquisition in accordance with normal industry practice, in relation to the decommissioning, environmental, health and safety obligations, the enlarged Hibiscus Group will be responsible for such obligations arising before, on or after the Effective Date insofar as they are not a result of any breach of warranty or the terms of the SPA by TotalEnergies Holdings. There can be no assurance that the abovementioned obligations, if they arise, will not cause a material and adverse impact to the financial position of the enlarged Hibiscus Group. However, we have undertaken due diligence reviews and will also be relying on the Vendor's warranties.

Notwithstanding the above, our Group will take the necessary steps to monitor and ensure proper operating procedures are in place to mitigate such risks, including ensuring that the TargetCo is adequately insured (where possible and to the extent practicable).

(iii) Political, economic, market, regulatory and environmental considerations

The TargetCo could be adversely affected by changes in political, economic, market and regulatory conditions in both Malaysia and Brunei. These uncertainties include, amongst others, risk of war, terrorism, riot, expropriation, changes in political leadership, nationalism, termination or nullification of existing contracts, changes in interest rates and methods of taxation, and exchange control policy or rules.

In addition, the Dutch, Malaysian and Brunei governments could amend their existing laws, policies and regulations or invoke new ones. Any adverse developments or uncertainties in the political, economic, market and regulatory conditions may adversely affect the financial performance of the TargetCo.

The O&G industry is also subject to the laws and regulations relating to environmental and safety matters in the exploration for and development and production of hydrocarbons. The discharge of condensate, gas or other pollutants into the air, soil or water may give rise to liabilities and may require the TargetCo to incur costs to remedy such discharge. There is no assurance that environmental laws and regulations will not in the future result in a curtailment of production or a material increase in the cost of production, or development activities which will adversely affect the results and operations of the TargetCo.

To mitigate the above risk, our Group adopts a proactive approach in keeping abreast with political, economic, market and regulatory developments of the countries in which our Group operates or intends to operate.

(iv) Dependence on skilled professionals and experienced staff

The business and activities conducted by the TargetCo require highly skilled personnel. The pool of qualified personnel is limited and competition for the employment of such personnel is high. Accordingly, the loss and/or failure to retain, attract or recruit, on a timely basis, qualified and skilled personnel may have an adverse impact on the results and operations of the TargetCo.

Notwithstanding the above, our Group will continuously adopt appropriate measures to attract, employ and retain key personnel to manage the O&G operations of the TargetCo.

(v) Non-renewal of the concession and other related agreements

The non-renewal of the concession will have an adverse impact on our financials. In the event that the concession is not renewed after 2029, we will not have access to the field and will have to cease operation. The non-renewal of the Third Party Gas agreement will stop our access to the Third Party Gas which means we will no longer have any revenues attributable to the said gas.

Currently all the gas is sold under GSA to BLNG. The non-renewal of the GSA will affect our ability to sell the gas if we are unable to find an alternative buyer.

As mentioned in Section 3.5 of this Circular, the TargetCo's share of condensates are sold by TOTSA TotalEnergies Trading SA on behalf of TargetCo to TotalEnergies Trading Asia Pte Ltd. The services agreement was entered into to govern such arrangement. The non-renewal of the services agreement will result in the TargetCo having to procure a new buyer for the condensates on similar terms.

Notwithstanding this, our Group will take all necessary steps to engage with the relevant authorities and other parties to secure a renewal for the concession and the relevant agreements on similar terms.

(vi) Foreign exchange risk

The financial results of the TargetCo are denominated in USD. As the financial results of the TargetCo will be consolidated with the financial results of the enlarged Hibiscus Group which is reported in RM upon completion of the Proposed Acquisition, fluctuations of USD against the RM will impact the enlarged Hibiscus Group's financial performance.

Notwithstanding the above, the exchange translation on consolidation is only an accounting entry for the purpose of consolidating the enlarged Hibiscus Group's financial results as at a particular date.

(vii) Goodwill and impairment risk

Our Group may recognise goodwill arising from the Proposed Acquisition, the amount of which depends on a purchase price allocation exercise that will be carried out as at the Closing Date. The purchase price allocation exercise will include any adjustments which may be necessary to align to the accounting policies of our Group. The identifiable assets of the TargetCo include the present value of the 2P Reserves and 2C Resources expected to be generated from Closing Date up to 2039 and other assets of the TargetCo. Any difference between the Purchase Consideration and the fair value of the net identifiable assets and liabilities is recognised as goodwill. The outcome of this exercise cannot be ascertained at this juncture.

Per our Group's accounting policy, the carrying amounts of the acquired assets of the TargetCo, where relevant, would be assessed for indicators of impairment at the appropriate intervals and reviewed for possible impairment when indicators of impairment exist. If a provision for impairment is identified post assessment, such impairment loss shall be recognised in profit or loss immediately.

6. EFFECTS OF THE PROPOSED ACQUISITION

The effects of the Proposed Acquisition set out below are computed based on the TargetCo's unaudited condensed financial statements for FYE 31 December 2023.

6.1 Issued share capital

The Proposed Acquisition will not have any effect on the issued share capital of our Company.

6.2 Consolidated NA and consolidated gearing

For illustration purposes only, the pro forma effects of the Proposed Acquisition on the consolidated NA and consolidated gearing of our Company subject to the completion adjustments in accordance with the SPA and the finalisation of the purchase price allocation and expenses in relation to the Proposed Acquisition, based on the audited consolidated statement of financial position of our Company as at 30 June 2023 and assuming that the Proposed Acquisition was completed on 30 June 2023 and based on the exchange rate of USD1.00:RM4.6650 as at 30 June 2023 are as follows:

		(I)	**(II)**
	Audited as at 30 June 2023 (RM'000)	**After the subsequent events[(1)] (RM'000)**	**After (I) and the Proposed Acquisition (RM'000)**
Share capital	166,014	166,014	166,014
Treasury shares	-	(51,017)	(51,017)
Other reserves	308,930	308,930	308,930
Retained earnings	2,214,815	2,214,155	2,207,091[(2)]
Total equity / Shareholders' funds / NA	**2,689,759**	**2,638,082**	**2,631,018**
No. of Shares in issue (excluding Hibiscus treasury shares) ('000)	2,012,419	782,158[(1)]	782,158[(1)]
NA per Share (RM)	1.34	3.37	3.36
Total borrowings[(3)]	456,840	456,840	915,840[(4)]
Gearing (times)	0.17	0.17	0.35

Notes:

(1) After adjusting for Share Consolidation and Share Buyback.

(2) After taking into consideration the estimated expenses of approximately RM7.1 million relating to the Proposed Acquisition.

(3) Comprises interest-bearing borrowings and excludes lease liabilities.

(4) Assumes part of the Purchase Consideration of USD100.0 million is funded through existing debt/other financing facilities, of which the estimated cost of the debt/other financing facilities is computed based on an interest rate of about 8% per annum.

(5) *A purchase price allocation exercise to determine the fair value of the identifiable assets and liabilities of the TargetCo will be performed as at the Closing Date. The exercise will include any adjustments which may be necessary to align to the accounting policies of our Group. The identifiable assets of the TargetCo include the present value of the 2P Reserves and 2C Resources expected to be generated from Closing Date up to 2039 and other assets of the TargetCo.*

Any difference between the Purchase Consideration and the fair value of the net identifiable assets and liabilities is recognised as goodwill. The outcome of this exercise cannot be ascertained at this juncture.

For the purposes of the financial effects above, the fair value of the identifiable assets and liabilities based on our Group's preliminary valuation are assumed to approximate the carrying amount of the assets and liabilities of the TargetCo shown in the unaudited condensed financial statements for FYE 31 December 2023 and the present value of the cash flows from the 2P Reserves and 2C Resources expected to be generated up to 2039.

6.3 Consolidated earnings and EPS

Upon completion of the Proposed Acquisition, our Company will consolidate the results of the TargetCo. The Proposed Acquisition is expected to have a positive impact on the consolidated earnings and EPS of our Company in the future. Such impact will depend on, amongst others, market and industry conditions, Asset performance and the successful integration of the Asset and operations into our Group.

For illustration purposes, assuming the Proposed Acquisition was completed on 1 July 2022, the pro forma PAT attributable to owners of our Group for FYE 30 June 2023 after taking into consideration the unaudited results of the TargetCo for FYE 31 December 2023 *(translated at the exchange rate of USD1.00:RM4.5900 as at 31 December 2023)* is set out below:

	(RM'000)
PAT attributable to owners of our Company for FYE 30 June 2023	400,518[(1)]
PAT of TargetCo for FYE 31 December 2023	150,362[(2)]
Expenses incurred for Share Consolidation (which was completed on 20 October 2023)	(518)
Estimated expenses for the Proposed Acquisition	(7,064)
Interest expenses	(38,189)[(3)]
PAT attributable to owners of our Company after the Proposed Acquisition	**505,109**
No. of Shares in issue (excluding Hibiscus treasury shares) ('000)	782,158[(4)]
EPS (sen) – before the Proposed Acquisition	51.14[(5)]
EPS (sen) – after the Proposed Acquisition	64.58[(5)]

Notes:

(1) *Based on the audited consolidated financial statements of our Company for FYE 30 June 2023.*
(2) *Based on the unaudited financial statements of TargetCo for FYE 31 December 2023.*
(3) *Assumes part of the Purchase Consideration of USD100.0 million is funded through existing debt/other financing facilities, of which the estimated cost of the debt/other financing facilities is computed based on an interest rate of about 8% per annum.*
(4) *After adjusting for Share Consolidation and Share Buyback.*
(5) *After taking into account expenses incurred for Share Consolidation.*

At this juncture, our Company has not finalised the breakdown of the source(s) of funding for the Proposed Acquisition, which will be a combination of funding sources as set out in Section 2.3 of this Circular. As such, the effects shown above are for illustration purposes only.

6.4 Substantial shareholders’ shareholdings

The Proposed Acquisition will not have any effect on the substantial shareholders’ shareholdings of our Company.

6.5 Convertible securities

As at the LPD, our Company does not have any convertible securities.

7. SSAR

Purpose

The Vendor has informed our Company that the TargetCo has never filed its audited statutory accounts with the Dutch Trade Register since its incorporation based on an exemption under Section 2:403 of the DCC, which provides an exemption to Dutch private companies from the requirement to prepare and file audited accounts provided that certain criteria are met.

The Vendor has stated that TotalEnergies Holdings Netherland B.V has filed a 403-statement relating to its subsidiaries incorporated in the Netherlands, which include the TargetCo, and that under Section 2:403 of DCC, a subsidiary belonging to a group of companies may be exempted from the requirement to prepare and publish its full annual audited accounts provided that, inter alia, the annual accounts of the parent company and the subsidiary are presented on a consolidated basis and the consolidating parent company issues (and files with the Dutch Trade Register) a statement pursuant to Section 2:403 of the DCC in respect of such subsidiary (a so-called 403-statement).

In any case, the Branch’s financial statements for FYE 31 December 2021, FYE 31 December 2022 and FYE 31 December 2023 (where the Asset’s results of operations are recorded) had been audited. The Branch’s financial statements had been prepared based on the Branch’s Accounting Policies (“**BAP**”) and in accordance with the provisions of the Brunei Act whereas the TargetCo’s unaudited financial statements had been prepared based on the IFRS.

In view of the absence of the audited financial statements of the TargetCo as detailed above, our Company has engaged FHCA, to conduct a special scope assessment review on the statement of financial position and statement of comprehensive income of the TargetCo for FYE 31 December 2021, FYE 31 December 2022 and FYE 31 December 2023, as set out in Appendix X of this Circular.

Findings and conclusion

FHCA has stated in the SSAR that there were no adverse findings in the accompanying combined financial statements contained in the SSAR for the FYE 31 December 2021, 2022 and 2023 based on the information provided to them as detailed in Section 2.2 of the SSAR.

The adjustments from Branch to TargetCo have been disclosed in Section 4 of the SSAR.

Additionally, FHCA observes that certain line items differ in the statement of financial position and statement of comprehensive income to those unaudited condensed financial statements appended in this Circular due to differences in classification and categorisation. However, it is noted that these differences in classification and categorisation do not affect the net assets and net profit reported by the TargetCo during the review period (being FYE 31 December 2021, 2022 and 2023) ("**Review Period**"). A reconciliation between both is detailed in Annexure 1 of the SSAR.

8. APPROVALS REQUIRED

The Proposed Acquisition is subject to the approval of the shareholders of our Company at an EGM to be convened.

The following shareholders ("**Undertaking Shareholders**") have provided undertakings to vote in favour of the resolution pertaining to the Proposed Acquisition to be tabled at the forthcoming EGM in accordance with the recommendations of the Board:

		Direct		Indirect	
Shareholder	**Details**	**No. of shares**	**(1) %**	**No. of shares**	**(1) %**
Hibiscus Upstream Sdn Bhd	Substantial Shareholder	43,509,040	5.56	-	-
Hibiscus Energy Sdn Bhd	Shareholder	5,700,000	0.73	-	-
Dr Kenneth Gerard Pereira	Director and Substantial Shareholder	29,914,000	3.82	49,209,040	(2) 6.29
Littleton Holdings Pte Ltd	Shareholder	14,992,280	1.92	-	-
Dato' Sri Roushan Arumugam	Director and shareholder	498,000	0.06	14,992,280	(3) 1.92
Dato' Dr Zaha Rina Zahari	Director and shareholder	1,800,000	0.23	-	-

Notes:

(1) Computed based on 782,158,128 shares (issued share capital of 804,967,428 shares less treasury share of 22,809,300).

(2) Deemed interest by virtue of his interest in Hibiscus Upstream Sdn Bhd and Hibiscus Energy Sdn Bhd pursuant to Section 8 of the Act.

(3) Deemed interest by virtue of his interest in Littleton Holdings Pte Ltd pursuant to Section 8 of the Act.

As at the LPD, the Undertaking Shareholders have approximately 12.3% shareholdings in our Company.

The Proposed Acquisition is not conditional upon any other corporate exercise undertaken or to be undertaken by our Company.

9. CORPORATE EXERCISES ANNOUNCED BUT PENDING COMPLETION

Save for the Proposed Acquisition (being the subject matter of this Circular), there are no other corporate exercises which have been announced by our Company but are pending completion as at the date of this Circular.

10. PERCENTAGE RATIO

Pursuant to Paragraph 10.02(g) of the Listing Requirements, the highest percentage ratio applicable to the Proposed Acquisition is 45.4% based on the Purchase Consideration of approximately USD259.4 million (or equivalent to approximately RM1,087.8 million) compared with the audited consolidated net assets of our Company for the FYE 30 June 2023.

11. INTERESTS OF DIRECTORS, MAJOR SHAREHOLDER, CHIEF EXECUTIVE AND/OR PERSONS CONNECTED WITH THEM

None of our Directors, Major Shareholder, chief executive of our Company and/or persons connected with them has any interest, whether direct or indirect, in the Proposed Acquisition.

12. DIRECTORS' STATEMENT AND RECOMMENDATION

Our Board, after having considered all aspects of the Proposed Acquisition, including but not limited to the basis and justifications for the Purchase Consideration, terms and conditions of the SPA, rationale and benefits of the Proposed Acquisition, effects of the Proposed Acquisition as well as the prospects of the TargetCo and the risks involved, is of the opinion that the Proposed Acquisition is in the best interests of our Group.

Accordingly, our Board recommends that you **VOTE IN FAVOUR** of the ordinary resolution pertaining to the Proposed Acquisition to be tabled at the forthcoming EGM.

13. ESTIMATED TIMEFRAME FOR COMPLETION AND TENTATIVE TIMELINE FOR IMPLEMENTATION

Barring any unforeseen circumstances, the Proposed Acquisition is expected to be completed by the fourth quarter of calendar year 2024.

The tentative timeline of events leading to the completion of the Proposed Acquisition is as follows:

Event	Tentative timeline
EGM for the Proposed Acquisition	10 October 2024
Fulfilment of the Condition Precedent	10 October 2024
Closing	By end of October 2024

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14. EGM

We will hold a virtual EGM, the notice of which is enclosed in this Circular at the broadcast venue at Tricor Business Centre, Gemilang Room, Unit 29-01, Level 29, Tower A, Vertical Business Suite, Avenue 3, Bangsar South, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur, Malaysia on Thursday, 10 October 2024 at 9.30 a.m. or at any adjournment thereof, for the purpose of considering and if thought fit, passing with or without modifications, the resolution set out in the Notice of EGM.

If you are unable to attend and vote at the virtual EGM, please complete and return the enclosed Form of Proxy for the EGM to the office of our Share Registrar, Tricor Investor & Issuing House Services Sdn Bhd at Unit 32-01, Level 32, Tower A, Vertical Business Suite, Avenue 3, Bangsar South, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur or its Customer Service Centre at Unit G-3, Ground Floor, Vertical Podium, Avenue 3, Bangsar South, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur, not later than forty-eight (48) hours before the time set for the EGM or at any adjournment thereof. The Form of Proxy should be completed strictly in accordance with the instructions contained therein. The Form of Proxy may also be electronically submitted via TIIH Online at https://tiih.online. Please refer to the Administrative Guide on the conduct of this EGM for further details. The completion and the return of the Form of Proxy will not preclude you from attending and voting at the virtual EGM should you subsequently decide to do so.

15. FURTHER INFORMATION

You are requested to refer to the enclosed appendices for further information.

Yours faithfully
for and on behalf of the Board of
HIBISCUS PETROLEUM BERHAD

ZAINUL RAHIM BIN MOHD ZAIN
Non-Independent Non-Executive Chairman

1. SALIENT TERMS OF THE SPA

The salient terms of the SPA, amongst others, are as follows:

1.1 Sale and Purchase of Shares

The TargetCo Shares will be acquired with full title guarantee free and clear of any encumbrances and with all benefit and rights attaching or accruing thereto on the Closing Date, including all dividends and distributions declared, paid or made by the TargetCo after the Closing Date.

1.2 Condition Precedent

The Condition Precedent is the receipt of our shareholders' approval within the Long Stop Date.

1.3 Purchase Consideration

(i) The Purchase Consideration for the sale and purchase of the TargetCo Shares is approximately USD259.4 million (or equivalent to approximately RM1,087.8 million), subject to certain agreed adjustments at Closing.

(ii) The Deposit of USD49.0 million (or equivalent to approximately RM205.5 million) (20% of the Purchase Price) is payable by the Purchaser upon execution of the SPA and does not bear any interest.

Note:
In the event shareholders' approval at the EGM is not obtained, the Deposit will be forfeited and will not be refundable to us. The quantum of the Deposit takes into account the competitive process for the TargetCo as well as the commercially negotiated terms of the Proposed Acquisition acceptable to both parties on a "willing buyer, willing seller" basis.

(iii) The Deposit will be non-refundable to the Purchaser except where the SPA is terminated by:

(a) either party where the parties are unable to mutually agree on a joint approach to resolve any (1) written request from any of the parties to the Cash Investors Agreement (as defined in Section 3(iv) of Appendix III of this Circular), to tender the TargetCo's resignation as an Operator (as defined in the Cash Investors Agreement); or (2) objection or disagreement to the Proposed Acquisition and potential change in control with respect of the TargetCo received from the Petroleum Authority of Brunei (collectively, "**Objections**") or the required changes to the SPA and other transaction documents as may be necessary to address such Objections and the parties have not resolved or waived the Objections by the Long Stop Date (but only where such party has complied with its respective obligations under the relevant provisions of the SPA);

(b) the Purchaser, where the Vendor fails to comply with its Closing obligations and deliverables, where it is not a sanctioned person or was prevented by a sanctions event from performance of its obligations where the other party is in violation of its obligations to be compliant with certain sanctions law, or where the Vendor is in breach of its obligation to comply with certain anti-corruption and anti-bribery laws;

(c) the Purchaser, where the SPA is terminated as a result of fraud or willful misconduct by the Vendor group or the TargetCo; or

(d) mutual written consent of each party at any time prior to the Closing Date.

1.4 Termination of Intercompany Service Agreements

Effective at Closing, the Vendor shall, and shall procure that the TargetCo shall:

(a) provided that the Transition Services Agreement has been entered into by the relevant parties and to the extent not required under the Transition Services Agreement, terminate the intercompany service agreements in respect of the TargetCo as identified in the SPA ("**Intercompany Service Agreements**"), without any party having any continuing liabilities to the other, other than for payment in respect of the provision of goods or services up to and including the Closing Date;

(b) settle, pay, forgive or otherwise release all amounts due under the Intercompany Service Agreements (for the avoidance of doubt, any receivables under the Intercompany Service Agreements shall be paid on or prior to Closing);

(c) settle any intercompany receivables owing by any member of the Vendor's group of companies ("**Vendor's Group**") to the TargetCo and any intercompany payables owing by the TargetCo to the Vendor's Group; and

(d) procure that any net amount owed by the Vendor's Group to the TargetCo, or due to the Vendor's Group by the TargetCo, shall be settled.

1.5 Closing Adjustments

The SPA provides for the Purchase Consideration to be paid at closing after having been adjusted for (a) a fixed USD17.0 million, being a time value amount from the Effective Date to and including 14 October 2024, provided that (i) there should be no adjustment to this amount if closing occurs on or prior to 14 October 2024 and (ii) there shall be no other Leakage from the cut-off date up to the Closing Date; (b) interest at Agreed Interest Rate from 15 October 2024 to and including the Closing Date (should the Closing Date be postponed after 14 October 2024) on the Purchase Price less Deposit and less any Leakage amount from the date when such Leakage was actually incurred, (c) an agreed Pre-Closing Dividend to be paid by the TargetCo, (d) the Deposit amount, and (e) the amount of any estimated Leakages.

Note:
"Leakage" means (without double counting) any of the following made by the TargetCo:

(a) the payment of any dividend (including interim dividends) or other distribution or return of income declared, paid, or made (whether in cash or in kind) or payments in lieu of any dividend or distribution, or any purchase, repurchase, redemption, repayment or return of any loans or share capital (or any other relevant securities) by the TargetCo to or for the benefit of any member of the Vendor's Group other than the Pre-Closing Dividend;

(b) the payment of any sum (including bonuses and management, monitoring and service fees) to or for the benefit of any member of the Vendor's Group, or on behalf of any member of the Vendor's Group, other than on an arm's length basis and in the ordinary course of business;

(c) the sale, purchase, transfer, or disposal of any asset, right or other benefit to any member of the Vendor's Group that is made at less than the fair market value, to the extent the actual amount received by the TargetCo in respect of such sale, purchase, transfer, or disposal is less than the fair market value in which case the amount of such Leakage shall be the difference between the fair market value and the actual amount received by the TargetCo in respect of such sale, purchase, transfer, or disposal;

(d) the forgiveness, release, deferral, discount or waiver by the TargetCo of any amount, economic benefit, liability or obligation owed to the TargetCo by the Vendor or any member of the Vendor's Group the assumption or incurring any liabilities by the TargetCo for the benefit of, any member of the Vendor's Group;

(e) the payment of any professional fees or bonuses to or for the benefit of any employee of the TargetCo or any member of' the Vendor's Group made in relation to the sale of the Shares;

(f) the entry into any binding agreement (whether conditional or not) to do or procure the doing of any of the foregoing; or

(g) the payment of any fees, costs or tax by the TargetCo as a consequence of any matter referred to in paragraphs (a) through (f) (inclusive) above (but, in each case, excluding VAT (other than any irrecoverable VAT)),

occurring, in each case, during the Leakage period but excluding permitted Leakage.

1.6 Termination

The SPA may only be terminated, save in the case of fraud, in the following circumstances:

(i) at any time prior to closing by mutual written consent of each of the parties;

(ii) by the Vendor if the Purchaser fails to pay the Deposit or becomes insolvent;

(iii) by either party if the condition precedent has not been satisfied or waived by the Long Stop Date;

(iv) by either party where the parties are unable to agree on a joint approach to address any objections to the Proposed Acquisition received from the government of Brunei or a joint venture partner or the required changes to the SPA and other transaction documents as may be necessary to address such Objections and the parties have not resolved or waived the Objections by the Long Stop Date;

(v) by the non-defaulting party where the other party has failed to satisfy its closing obligations and/or make its closing deliveries;

(vi) by either party that is not a sanctioned person which was prevented by a sanctions event from performance of its obligations where the other party is in violation of its obligations to be compliant with certain sanctions law;

(vii) by the non-breaching party where the other party is in breach of its obligation to comply with certain anti-corruption and anti-bribery laws; or

(viii) by either party, if the other party, through no fault of the party terminating the SPA, fails, refuses, or is unable for any reason not permitted by the SPA to achieve closing under the terms and conditions of the SPA.

1.7 Governing Law and Dispute Resolution

The SPA will be governed and be construed in accordance with English law. Any dispute shall be settled by final and binding arbitration under the Rules of Arbitration of the International Chamber of Commerce in London.

2. SALIENT TERMS OF THE TRANSITION SERVICES AGREEMENT

The salient terms of the TSA, amongst others, are as follows:

(a) Vendor agrees to provide certain agreed information technology, data migration, project management and other services in respect of the operations of the TargetCo and the Asset to Purchaser ("**Services**") from the date of the TSA, for a period of nine (9) months (which may be extended by mutual agreement), in consideration of the agreed fee to be paid by Purchaser per service.

(b) The term of the TSA shall end nine (9) months after the Closing Date (subject to any extension by mutual agreement or any early termination).

(c) The Purchaser may terminate the TSA at any time by giving to the Vendor at least fifteen (15) business days advance written notice of such termination. The Purchaser shall indemnify and keep harmless the Vendor for any documented costs incurred by the Vendor in relation to the services to be provided as a consequence of the Purchaser's decision to terminate the TSA before expiration of its term (unless the termination by the Purchaser is due to a material breach by the Vendor).

(d) A party may terminate the TSA with immediate effect by written notice to the other party if the breaching party is in material breach of its obligations under the TSA and if the breach is capable of remedy, fails to remedy the breach within the agreed grace period.

(e) The TSA may also be terminated with seven (7) days written notice from the non-affected party to the affected party in the event of force majeure lasting more than one (1) month after the affected party uses all reasonable diligence to remove or overcome the force majeure event as quickly as possible in a commercially reasonable manner.

(f) The TSA will be governed by and construed in accordance with English law.

(g) Any dispute shall be settled by final and binding arbitration under the Rules of Arbitration of the International Chamber of Commerce in London.

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3. SALIENT TERMS OF THE PARENT COMPANY GUARANTEE

The salient terms of the Parent Company Guarantee, amongst others, are as follows:

3.1 Hibiscus Petroleum guarantees, as a primary obligation for the benefit of the Vendor (as beneficiary), the Purchaser's due and punctual performance and observance of all the Purchaser's obligations, warranties, duties and undertakings under the SPA ("Guaranteed Obligations") at its own costs and expenses.

3.2 Hibiscus Petroleum undertakes that whenever the Purchaser does not perform any Guaranteed Obligations, or pay any amount when due, under or in connection with the SPA, Hibiscus Petroleum shall be liable immediately on demand and shall pay, within seven (7) business days of any such demand, that amount as if it was the principal obligor or take whatever steps may be necessary to procure performance of the obligations of the Purchaser under the SPA.

3.3 Hibiscus Petroleum agrees with the Vendor that if any Guaranteed Obligation is or becomes unenforceable, invalid or illegal, it will, as an independent and primary obligation, indemnify and hold the Vendor harmless and shall be liable immediately on demand (with payment of any amount due to be made within seven (7) business days of such demand) against any cost, loss or liability it incurs as a result of the Purchaser not paying any amount that would, but for such unenforceability, invalidity or illegality, have been payable by it under the SPA or such other transaction documents.

3.4 In the event of any breach by the Purchaser of any term, condition and/or obligation under the SPA or any of the documents entered into or delivered by the Vendor or the Purchaser (together with their respective affiliates), in connection with the SPA and such other transaction documents, Hibiscus Petroleum shall (as a separate and independent obligation and liability from its obligations and liabilities under Sections 3.1, 3.2 and 3.3 above) indemnify the Vendor from and against any and all claims, losses, damages, liens, debts, costs (including legal costs) and expenses, liabilities and causes of action of whatever nature, and shall on receipt of first written notice, pay such sums to the Vendor, without any deduction or set-off.

3.5 In addition to any liabilities arising under Sections 3.1, 3.2 and 3.3 above, Hibiscus Petroleum agrees that is shall be liable on demand, and shall pay the Vendor, within seven (7) business days of any such demand, reasonable legal and other costs, charges and expenses (on a full and unqualified indemnity basis) incurred by the Vendor whether before or after the date of demand on Hibiscus Petroleum for payment in enforcing or reasonably endeavouring to enforce the payment of any money due under the Parent Company Guarantee or otherwise in relation to the Parent Company Guarantee.

3.6 Hibiscus Petroleum shall promptly indemnify and hold the Vendor harmless against any cost (including reasonable legal costs), loss or liability save for any indirect and/or consequential losses incurred by it as a result of:

(a) any default or delay by Hibiscus Petroleum in the performance of any of the obligations expressed to be assumed by it in the Parent Company Guarantee;

(b) the taking, holding, protection or enforcement of the Parent Company Guarantee; and/or

(c) the exercise of any of the rights, powers, discretions and remedies vested in the Vendor by the Parent Company Guarantee.

3.7 The Parent Company Guarantee is a continuing guarantee for so long as the obligations of the TargetCo under the SPA remain undischarged.

3.8 The Parent Company Guarantee will be governed by and construed in accordance with the laws of England and Wales.

3.9 Any dispute shall be settled by final and binding arbitration under the Rules of Arbitration of the International Chamber of Commerce in London.

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1. HISTORY AND BUSINESS

The TargetCo was incorporated as a private limited liability company in Netherlands on 18 August 1986 under the Laws of Netherlands. It commenced its operation in 1989. Subsequently, on 19 October 2021, its name was changed to TotalEnergies EP (Brunei) BV.

The TargetCo is principally engaged in support activities for petroleum and natural gas extraction. Through its Branch, it operates in Brunei and owns a 37.5% participating interest in the Asset. The principal products of the TargetCo are natural gas and condensate. The gas is sold to BLNG where it is liquified and exported from Brunei. Apart from the Branch, there are no other business activities in the TargetCo.

The annual gross and net Condensate and Gas Production for the past 3 years of the TargetCo were as follows:

	Annual production volume (1)					
	FYE 31 December 2021		FYE 31 December 2022		FYE 31 December 2023	
	Gross[2]	Net[3]	Gross[2]	Net[3]	Gross[2]	Net[3]
Gas (Bscf)	52.7	19.8	45.9	17.2	37.8	14.2
Condensate (MMstb)	1.0	0.4	0.8	0.3	0.9	0.3
Condensate and Gas (MMboe)	10.4	3.9	9.0	3.4	7.6	3.1

Notes:
(1) Excluding Third Party Gas. The Third Party Gas gross annual production volume of condensate and gas was 0.7 MMboe in FYE 31 December 2022 and 3.2 MMboe in FYE 31 December 2023.
(2) Gross refers to entitlement to all BBJV Partners (including the TargetCo).
(3) Net refers to TargetCo's entitlement of 37.5%.

Based on the unaudited financial statements for the FYE 31 December 2023, the TargetCo has not incurred any research and development expenses.

The total capital expenditure incurred from the Effective Date up to 30 August 2024 by the TargetCo is as follows:

	TargetCo	
	USD'million	Equivalent to RM'million
Net investments excluding acquisitions and disposals	42.39	182.96

Notes:
(1) Net investments relate to capital expenditure incurred in the ordinary course of business. There have been no acquisitions or disposals from Effective Date.
(2) The USD currency in the table above has been converted to RM on the basis of the following Bank Negara middle rate as at 30 August 2024, USD1:RM4.3160.

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2. SHARE CAPITAL

As at 30 August 2024, the issued share capital of the TargetCo is USD100 million comprising 1,000,000 common shares.

3. DIRECTORS

As at 30 August 2024, the TargetCo has a sole managing director being TotalEnergies Management BV, itself represented by 4 individuals (i.e. Bernardus Klein Swormink, Mr. Benoit Sibout, Viestarts Rutenbergs and Marcus Kloppenburg), each of them having authority to represent the company solely/independently.

As at 30 August 2024, TotalEnergies Management BV and representatives do not hold any direct or indirect shareholdings in the TargetCo.

4. SHAREHOLDER

As at 30 August 2024, TotalEnergies Holdings holds 100% of the equity interest in TargetCo.

5. SUBSIDIARIES AND ASSOCIATED COMPANIES

As at 30 August 2024, apart from the Branch, the TargetCo does not have any subsidiary and/or associated company.

6. SUMMARY OF FINANCIAL INFORMATION

The summary of the key unaudited condensed consolidated financial information of the TargetCo for FYE 31 December 2021, FYE 31 December 2022 and FYE 31 December 2023 based on the SSAR are as follows:

	FYE 31 December 2021		**FYE 31 December 2022**		**FYE 31 December 2023**	
	USD'million	**Equivalent to RM'million**	**USD'million**	**Equivalent to RM'million**	**USD'million**	**Equivalent to RM'million**
Revenue	113.1	471.1	159.6	700.6	151.0	693.1
PBT	41.1	171.1	86.3	378.8	64.3	295.3
PAT	11.0	45.6	33.7	148.0	32.8	150.4
PAT and non-controlling interests / Net profits attributable to the TargetCo	11.0	45.6	33.7	148.0	32.8	150.4
Share capital	100	416.5	100	439.0	100	459.0
No. of shares ('000)	1,000	1,000	1,000	1,000	1,000	1,000

	FYE 31 December 2021		FYE 31 December 2022		FYE 31 December 2023	
	USD'million	Equivalent to RM'million	USD'million	Equivalent to RM'million	USD'million	Equivalent to RM'million
Net earnings per share [(iv)] (RM or USD)	11.0	45.6	33.7	148.0	32.8	150.4
NA / Shareholders' funds	177.4	738.7	141.1	619.3	158.8	729.1
NA per share[(v)] (RM or USD)	177.4	738.7	141.1	619.3	158.8	729.1
Current ratio [(vi)] (times)	1.38	1.38	1.10	1.10	1.18	1.18
Total borrowings	-	-	-	-	-	-
Gearing (times)	-	-	-	-	-	-

The USD currency rates in the table above were converted to RM on the basis of the following Bank Negara middle rates:

(i) For FYE 31 December 2021, USD1.00:RM4.1650.
(ii) For FYE 31 December 2022, USD1.00:RM4.3900;
(iii) For FYE 31 December 2023, USD1.00:RM4.5900;
(iv) Computed based on net earnings divided by the number of shares;
(v) Computed based on NA divided by the number of shares; and
(vi) Computed based on current assets divided by current liabilities.

The summary of the key audited financial information of the Branch for FYE 31 December 2021, FYE 31 December 2022 and FYE 31 December 2023 based on the audited financial statements of the Branch are as follows:

	FYE 31 December 2021		FYE 31 December 2022		FYE 31 December 2023	
	USD'million	Equivalent to RM'million	USD'million	Equivalent to RM'million	USD'million	Equivalent to RM'million
Income	112.2	467.3	157.2	690.1	144.7	664.2
PBT	52.9	220.1	94.8	416.3	66.7	306.3
PAT	22.3	93.0	42.4	186.1	35.2	161.6
PAT and non-controlling interests / Net profits attributable to the Branch	22.3	93.0	42.4	186.1	35.2	161.6
Share capital	*	*	*	*	*	*
No. of shares ('000)	*	*	*	*	*	*

	FYE 31 December 2021		FYE 31 December 2022		FYE 31 December 2023	
	USD'million	Equivalent to RM'million	USD'million	Equivalent to RM'million	USD'million	Equivalent to RM'million
Net earnings/ (loss) per share(iv) (RM or USD)	*	*	*	*	*	*
NA / Shareholders' funds	303.1	1,262.4	275.4	1,209.0	295.6	1,356.8
NA per share(v) (RM or USD)	*	*	*	*	*	*
Current ratio(vi) (times)	1.37	1.37	1.10	1.10	1.20	1.20
Total borrowings	-	-	-	-	-	-
Gearing (times)	-	-	-	-	-	-

** Not applicable*

The USD currency rates in the tables above were converted to RM on the basis of the following Bank Negara middle rates:
(i) For FYE 31 December 2021, USD1.00:RM4.1650.
(ii) For FYE 31 December 2022, USD1.00:RM4.3900;
(iii) For FYE 31 December 2023, USD1.00:RM4.5900;
(iv) Computed based on net earnings divided by the number of shares;
(v) Computed based on NA divided by the number of shares; and
(vi) Computed based on current assets divided by the number of current liabilities.

The Vendor has informed our Company that the TargetCo has never filed its audited statutory accounts with the Dutch Trade Register since its incorporation based on an exemption under Section 2:403 of the DCC, which provides an exemption to Dutch private companies from the requirement to prepare and file audited accounts provided that certain criteria are met.

The Vendor has stated that TotalEnergies Holdings Netherland B.V has filed a 403-statement relating to its subsidiaries incorporated in the Netherlands, which include the TargetCo, and that under Section 2:403 of DCC, a subsidiary belonging to a group of companies may be exempted from the requirement to prepare and publish its full annual audited accounts provided that, inter alia, the annual accounts of the parent company and the subsidiary are presented on a consolidated basis and the consolidating parent company issues (and files with the Dutch Trade Register) a statement pursuant to Section 2:403 of the DCC in respect of such subsidiary (a so-called 403-statement).

In any case, the Branch's financial statements for FYE 31 December 2021, FYE 31 December 2022 and FYE 31 December 2023 (where the Asset's results of operations are recorded) had been audited. The Branch's financial statements had been prepared based on the Branch's Accounting Policies ("**BAP**") and in accordance with the provisions of the Brunei Act whereas the TargetCo's unaudited financial statements had been prepared based on the IFRS.

In view of the absence of the audited financial statements of the TargetCo as detailed above, our Company has engaged FHCA, the Corporate Advisory arm of Baker Tilly Malaysia, to conduct a special scope assessment review on the statement of financial position and statement of comprehensive income of the TargetCo for FYE 31 December 2021, FYE 31 December 2022 and FYE 31 December 2023, as set out in Appendix X of this Circular.

Please refer to the adjustments from Branch to TargetCo under Section 4 of the SSAR for further details on the adjustments. Additionally, FHCA observes that certain line items differ in the statement of financial position and statement of comprehensive income from those appended in this Circular due to differences in classification and categorisation. However, it is noted that these differences in classification and categorisation do not affect the net assets and net profit reported by the TargetCo during the review period. A reconciliation between both is detailed in Annexure 1 of the SSAR. As such, the summary of the financial information of the TargetCo above has included financial information based on the SSAR.

FHCA also has stated in the SSAR that there were no adverse findings in the accompanying combined financial statements contained in the SSAR for the FYE 31 December 2021, 2022 and 2023 based on the information provided to them as detailed in Section 2.2 of the SSAR.

Commentary on material fluctuations in the financial performance of the TargetCo:

FYE 31 December 2022 vs FYE 31 December 2021

The total revenue increased by RM229.5 million or 48.7% to RM700.6 million in FYE 31 December 2022 (FYE 31 December 2021: RM471.1 million). On top of the market-driven increase in selling prices, revenue has also been impacted by additional gas sales of USD9.8 million *(or equivalent to approximately RM43.0 million)* in FYE 31 December 2022.

The total PAT increased by RM102.4 million or 224.6% to RM148.0 million in FYE 31 December 2022 (FYE 31 December 2021: RM45.6 million) primarily due to the increase in revenue as explained above.

FYE 31 December 2023 vs FYE 31 December 2022

Both total revenue and total PAT in FYE 31 December 2023 as compared with FYE 31 December 2022 were fairly consistent.

There are (i) no accounting policies adopted by the TargetCo which are peculiar to the TargetCo and its business, as well as the effects of such policies on the determination of income or financial position and (ii) no audit qualifications reported in the financial statements of the Branch for the FYE 31 December 2021, FYE 31 December 2022 and FYE 31 December 2023.

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7. ADJUSTMENTS FROM BRANCH TO TARGETCO (BASED ON SSAR)

The adjustments made from Branch to TargetCo based on FYE 31 December 2021 to 2023 are as follows:

Statement of Financial Position

FYE 2021

	Note	AFS Branch	Adjustments		Adjusted Branch	Head Office	TargetCo
		(BAP)	Interest (1)	Branch(2)	(IFRS)	(IFRS)	(IFRS)
		USD'000					
Non-current Assets							
Development Costs	(i)	153,316	45,783	-	199,099	-	199,099
Exploration Costs	(ii)	214,384	11,716	-	226,100	(183,493)	42,607
Fixed Assets	(iii)	1,388	-	(111)	1,277	-	1,277
Others		12,750	-	-	12,750	-	12,750
Total Non-current Assets		**381,838**	**57,499**	**(111)**	**439,226**	**(183,493)**	**255,733**
Current Assets							
Cash and Cash Equivalents		97,527	-	-	97,527	16	97,543
Trade and Other Debtors	(iv)	30,058	-	(764)	29,294	-	29,294
Amounts due From Partners	(i)	2,277	342	-	2,619	-	2,619
Stocks	(i)	1,507	381	-	1,888	-	1,888
Total Current Assets		**131,369**	**723**	**(764)**	**131,328**	**16**	**131,344**
Total Assets		**513,207**	**58,222**	**(875)**	**570,554**	**(183,477)**	**387,077**
Current Liabilities							
Trade and Other Creditors	(iv), (v)	46,255	-	(452)	45,803	-	45,803
Other current liabilities		49,307	-	-	49,307	-	49,307
Total Current Liabilities		**95,562**	**-**	**(452)**	**95,110**	**-**	**95,110**
Total Non-current Liabilities		**114,592**	**-**	**-**	**114,592**	**-**	**114,592**
Total Liabilities		**210,154**	**-**	**(452)**	**209,702**	**-**	**209,702**
Net Asset		**303,053**	**58,222**	**(423)**	**360,852**	**(183,477)**	**177,375**

FYE 2022

	Note	AFS Branch	Adjustments		Adjusted Branch	Head Office	TargetCo
		(BAP)	Interest [1]	Branch [2]	(IFRS)	(IFRS)	(IFRS)
				USD'000			
Non-current Assets							
Development Costs	(i)	140,504	39,389	-	179,893	-	179,893
Exploration Costs	(ii)	210,385	10,200	-	220,585	(183,491)	37,094
Fixed Assets	(iii)	1,206		(109)	1,097	-	1,097
Others		10,820	-	-	10,820	-	10,820
Total Non-current Assets		**362,915**	**49,589**	**(109)**	**412,395**	**(183,491)**	**228,904**
Current Assets							
Cash and Cash Equivalents		110,937	-	-	110,937	97	111,034
Trade and Other Debtors	(iv)	34,132	-	(511)	33,621	-	33,621
Amounts due From Partners	(i)	9,439	(630)	-	8,809	-	8,809
Stocks	(i)	1,364	395	-	1,759	-	1,759
Total Current Assets		**155,872**	**(235)**	**(511)**	**155,126**	**97**	**155,223**
Total Asset		**518,787**	**49,354**	**(620)**	**567,521**	**(183,394)**	**384,127**
Current Liabilities							
Trade and Other Creditors	(iv, v)	68,983	-	(304)	68,679	-	68,679
Other current liabilities		72,896	-	-	72,896	-	72,896
Total Current Liabilities		**141,879**	**-**	**(304)**	**141,575**	**-**	**141,575**
Total Non-current Liabilities		**101,471**	**-**	**-**	**101,471**	**-**	**101,471**
Total Liability		**243,350**	**-**	**(304)**	**243,046**	**-**	**243,046**
Net Asset		**275,437**	**49,354**	**(316)**	**324,475**	**(183,394)**	**141,081**

FYE 2023

	Note	AFS Branch (BAP)	Adjustments Interest [(1)]	Adjustments Branch [(2)]	Adjusted Branch (IFRS)	Head Office (IFRS)	TargetCo (IFRS)
		USD'000					
Non-current Assets							
Development Costs	(i)	135,324	38,881	-	174,205	-	174,205
Exploration Costs	(ii)	207,076	8,946	-	216,023	(183,490)	32,533
Fixed Assets	(iii)	2,261	-	(110)	2,151	-	2,151
Others		5,329	-	-	5,329	-	5,329
Total Non-current Assets		**349,991**	**47,827**	**(110)**	**397,708**	**(183,490)**	**214,218**
Current Assets							
Cash and Cash Equivalents		114,225	-	-	114,225	101	114,326
Trade and Other Debtors	(iv)	27,767	-	(436)	27,331	-	27,331
Amounts due from Partners	(i)	18,014	(1,350)	-	16,664	-	16,664
Stocks	(i)	2,510	396	-	2,906	-	2,906
Total Current Assets		**162,516**	**(954)**	**(436)**	**161,126**	**101**	**161,227**
Total Assets		**512,507**	**46,873**	**(546)**	**558,833**	**(183,389)**	**375,444**
Current Liabilities							
Trade and Other Creditors	(iv), (v)	89,238	-	(260)	88,978	-	88,978
Other current liabilities		46,652	-	-	46,652	-	46,652
Total Current Liabilities		**135,890**	**-**	**(260)**	**135,630**	**-**	**135,630**
Total Non-current Liabilities		**80,974**	**-**	**-**	**80,974**	**-**	**80,974**
Total Liabilities		**216,864**	**-**	**(260)**	**216,604**	**-**	**216,604**
Net Asset		**295,641**	**46,873**	**(286)**	**342,229**	**(183,389)**	**158,840**

Notes:
(1) This refers to the adjustments in relation to the Carry Arrangement (as described below).
(2) This refers to the manual adjustments made on the management accounts of the Branch.

Based on the above table, the adjustments are as follows:

(i) The adjustment made to reflect the Carry Arrangement. Carry Arrangement refers to the arrangement pursuant to a Cash Investors Agreement (as defined in Section 3(iv) of Appendix III of this Circular), whereby the TargetCo and Shell Deepwater shall carry Brunei Energy's participating interest of capital expenditure in the BBJV. In accordance with the Cash Investor Agreement, the TargetCo shall then recoup the carried capital expenditure monthly by taking a share from the joint venture partner's base gas sales. Please refer to the Section 3(iv) of Appendix III of this Circular for further details on the Cash Investor Agreement and the participating interest of the TargetCo and Shell Deepwater.

(ii) Prior to 2009, the exploration costs were fully capitalised at the Branch level, but was substantially written-off at the Head Office accounts due to the lack of commercial viability. This adjustment was made to accurately reflect the net book value of exploration costs and account for the Carry Arrangement.

(iii) Adjustment made to eliminate unidentified amounts carried forward from previous years to reflect the actual carrying value of fixed assets held by the TargetCo.

(iv) FYE 2021 and FYE 2022

Based on the GSA, the BBJV Partners are required to make up any gas shortfall between the daily contract quantity and the actual delivery ("**Shortfall Gas**"). A provision for this shortfall was recorded in the TargetCo's books for FYE 2020, 2021, and 2022, pending final negotiation of the adjustment with the customer.

(v) FYE 2023

Similar to the description for FYE 2021 and FYE 2022, this refers to an adjustment made to provide for the Shortfall Gas during the FYE 2020 and FYE 2021 as a credit note for the FYE 2022 Shortfall Gas have been issued to the customer during the FYE 2023.

(vi) Adjustment made to reflect the provisional reduction in royalty and tax payable due to the adjustment in revenue resulting from the Shortfall Gas for the relevant financial years.

(vii) Adjustment made to reflect the Carry Arrangement in relation to stocks carried the TargetCo.

(viii) Adjustment made to reflect the provisional reduction in royalty and tax payable due to the adjustment in revenue resulting from the Shortfall Gas for the relevant financial years.

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Statement of Profit or Loss and Other Comprehensive Income

FYE 2021

	Note	AFS Branch	Adjustments		Adjusted Branch	Head Office	TargetCo
		(BAP)	Interest (1)	Branch (2)	(IFRS)	(IFRS)	(IFRS)
				USD'000			
Sales	(i)	112,246	880	(8)	113,118	-	113,118
Interest Income		-	-	-	-	-	-
Total Income		**112,246**	**880**	**(8)**	**113,118**	**-**	**113,118**
Depreciation and Amortisation	(ii)	(31,709)	(12,502)	-	(44,211)		(44,211)
Production Cost		(14,642)	-	-	(14,642)	-	(14,642)
Royalties		(9,027)	-	-	(9,027)	-	(9,027)
Other Costs	(ii)	(2,707)	(203)	-	(2,909)	2	(2,907)
Value Compensation		(362)	-	-	(362)	-	(362)
Accretion Expense		(1,221)	-	-	(1,221)	-	(1,221)
Condensate Stock Variation		324	-	-	324	-	324
Profit Before Tax ("PBT")		**52,902**	**(11,824)**	**(8)**	**41,070**	**2**	**41,072**
Taxation	(iii)	(30,578)	-	455	(30,124)	-	(30,124)
Profit After Tax ("PAT")		**22,324**	**(11,824)**	**447**	**10,946**	**2**	**10,948**

FYE 2022

	Note	AFS Branch	Adjustments		Adjusted Branch	Head Office	TargetCo
		(BAP)	Interest (1)	Branch (2)	(IFRS)	(IFRS)	(IFRS)
				USD'000			
Sales	(i)	157,218	2,135	253	159,606	-	159,606
Interest Income		1,866	-	-	1,866	91	1,957
Total Income		**159,084**	**2,135**	**253**	**161,472**	**91**	**161,563**
License Fees		(7,385)	-	-	(7,385)	-	(7,385)
Depreciation and Amortisation	(ii)	(27,595)	(11,006)	-	(38,601)	-	(38,601)
Production Cost		(12,723)	-	-	(12,723)	-	(12,723)

	Note	AFS Branch	Adjustments		Adjusted Branch	Head Office	TargetCo
		(BAP)	Interest (1)	Branch (2)	(IFRS)	(IFRS)	(IFRS)
		USD'000					
Royalties		(11,480)	-	-	(11,480)	-	(11,480)
Other Costs	(ii)	(2,153)	7	-	(2,147)	(5)	(2,152)
Value Compensation		(1,480)	-	-	(1,480)	-	(1,480)
Accretion Expense		(1,258)	-	-	(1,258)	-	(1,258)
Condensate Stock Variation		(182)	-	-	(182)	-	(182)
PBT		**94,828**	**(8,864)**	**253**	**86,217**	**86**	**86,303**
Taxation	(iii)	(52,443)	-	(150)	(52,594)	(3)	(52,597)
PAT		**42,385**	**(8,864)**	**102**	**33,623**	**83**	**33,706**

FYE 2023

	Note	AFS Branch	Adjustments		Adjusted Branch	Head Office	TargetCo
		(BAP)	Interest(1)	Branch (2)	(IFRS)	(IFRS)	(IFRS)
		USD'000					
Sales	(i)	144,661	6,311	75	151,046	-	151,046
Interest Income		4,944	-	-	4,944	-	4,944
Total Income		**149,605**	**6,311**	**75**	**155,990**	**-**	**155,990**
License Fees		(36,365)	-	-	(36,365)	-	(36,365)
Depreciation and Amortisation	(ii)	(22,489)	(8,781)	-	(31,270)	-	(31,270)
Production Cost		(12,856)	-	-	(12,856)	-	(12,856)
Royalties		(7,639)	-	-	(7,639)	-	(7,639)
Other Costs	(ii)	(3,146)	(11)	-	(3,157)	5	(3,153)
Value Compensation		(1,533)	-	-	(1,533)	-	(1,533)
Condensate Stock Variation		1,151	-	-	1,151	-	1,151
PBT		**66,728**	**(2,482)**	**75**	**64,321**	**5**	**64,325**
Taxation	(iii)	(31,523)	-	(45)	(31,567)	-	(31,567)
PAT		**35,205**	**(2,482)**	**30**	**32,754**	**5**	**32,758**

Notes:

(1) This refers to the adjustments in relation to the Carry Arrangement (as described below)

(2) This refers to the manual adjustments made on the management accounts of the Branch

Based on the above table, FHCA notes the following:-

(i) This comprises the following adjustments:

- Interest Adjustments: Refers to an adjustment for capital expenditure recoupment arising from the Carry Arrangement. Further, the commencement of a Low Pressure Compressor ("**LPC**") Project in January 2022 resulted in higher capital expenditure during the FYE 2022 and 2023.

- Branch Adjustments: This adjustment reflects the year-on-year differences in Shortfall Gas recorded for the FYE 2020, 2021 and 2022, with variances arising from over- or under-estimations of Shortfall Gas across the respective financial years.

(ii) Refers to an adjustment to reflect the Carry Arrangement.

(iii) Refers to the tax impact arising from over- or under-estimations of Shortfall Gas for the FYE 2020, 2021 and 2022.

8. MATERIAL COMMITMENTS

Save as disclosed below, as at 30 August 2024, there are no material commitments incurred or known to be incurred by the TargetCo that have not been provided for which, upon becoming enforceable, may have a material impact on the TargetCo's financial results/position:

Approved and Contracted for	**Total (USD'000)**	**Total (Equivalent to RM'000)**
Capital commitment	29,800	128,617
Total	**29,800**	**128,617**

Note:
(1) The USD currency in the table above has been converted to RM on the basis of the following Bank Negara middle rate as at 30 August 2024, USD1:RM4.3160.

9. CONTINGENT LIABILITIES

As at 30 August 2024, there are no contingent liabilities incurred or known to be incurred by the TargetCo which, upon becoming enforceable, may have a material impact on the TargetCo's financial results/ position.

10. MATERIAL CONTRACTS

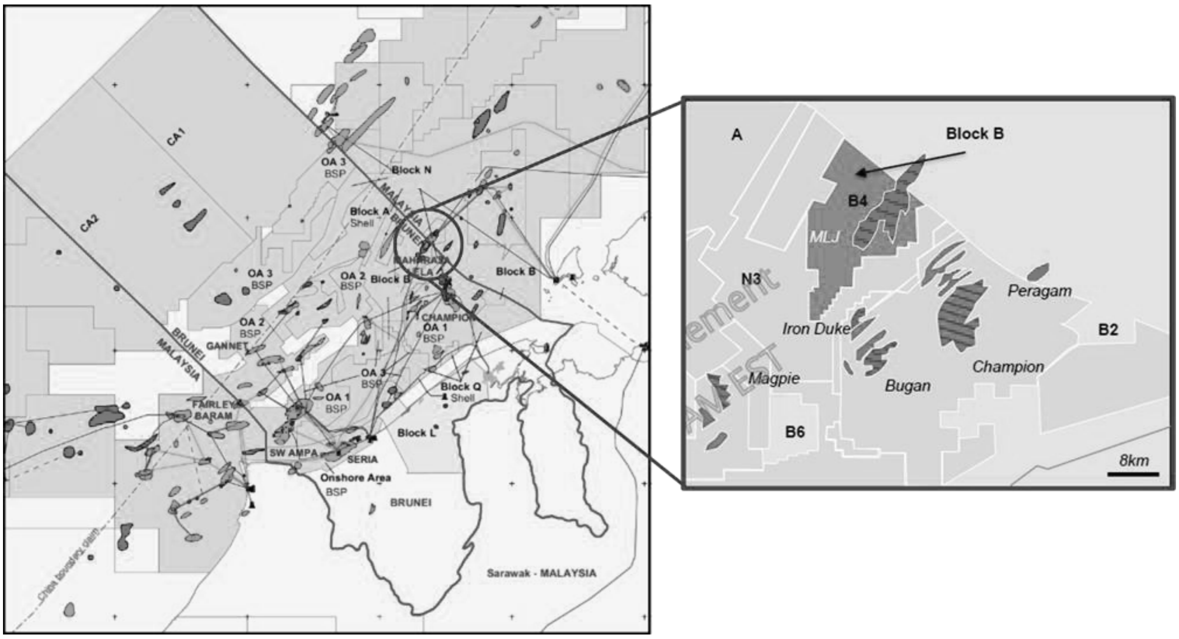
The TargetCo has not entered into any material contract (not being contracts entered into in the ordinary course of business) within the past two years preceding the date of this Circular.

11. MATERIAL LITIGATION, CLAIMS OR ARBITRATION

As at 30 August 2024, the TargetCo is not engaged in any material litigation, claim and/or arbitration either as plaintiff or defendant, which may materially and adversely affect its financial position or business, and there is no proceeding, pending or threatened, or of any fact likely to give rise to a proceeding which may materially and adversely affect the financial position or business of the TargetCo.

1. Overview of the Asset

Block B offshore Brunei contains MLJ field which was discovered in 1989 by the Maharajalela North well and which was appraised and developed during the 1990s with first gas in 1999. It has a total area of 276km^2 and is approximately 50km offshore Brunei. Since 1999, the field has been producing gas and condensate from three unmanned platforms in relatively shallow, less than 100m water depths. The location of Block B is shown below:



The MLJ field comprises a complex faulted system that is divided into elongated structural compartments (panels), limited by major sealing normal faults. Hydrocarbons have been found in eight dynamically independent panels, each subdivided into tens of different reservoir levels. There are three unmanned production platforms - MLJ1, MLJ2 and MLJ3 which are operated by the TargetCo. No processing occurs offshore and multiphase production is exported to an onshore processing plant at Lumut. At Lumut, gas and liquids are separated, and condensate and water stabilised at 60 barg and gas is processed to remove mercury and traces of H_2S. Gas is sent to BLNG, and condensate and water exported to Seria Crude Oil Terminal (SCOT). The maximum gas handling rate is 201 MMscf/d and liquid rate is 18 thousand stock tank barrels per day.

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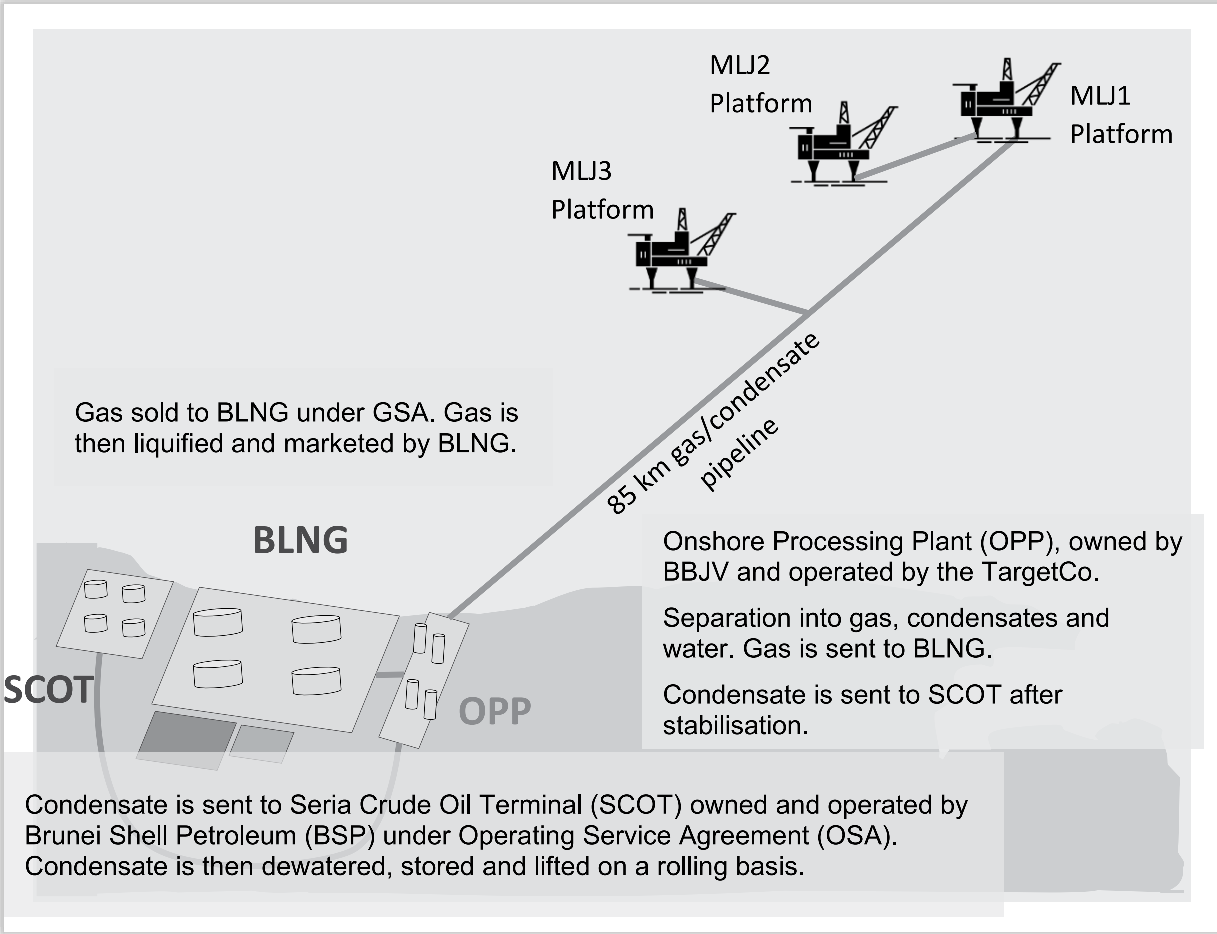
Block B Facilities Diagram



A total of 22 exploration, appraisal and development wells have been drilled. As of end 2022, there were 15 active gas producers (four wells on MLJ1 platform, five wells on MLJ2 platform and six wells on the MLJ3 platform).

(Source: Competent Person's Report)

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2. O&G reserves, valuation and valuation assumptions of the Asset

A summary of the condensate and gas reserves and contingent resources of the Asset in Bscf, MMstb and MMboe as at 1 January 2023 estimated by RPS Energy are set out below:

(i) Summary of Condensate and Gas Reserves as at 1 January 2023

Below is a summary of the Net Entitlement 1P, 2P and 3P Reserves of the Asset to the TargetCo:

	Net Entitlement Reserves(1)		
	1P	2P	3P
Gas (Bscf)	80	123	162
Condensate (MMstb)	1.7	3.7	6.4
Condensate and Gas (MMboe)(2)	15.0	24.2	33.4

Notes:

(1) Net Entitlement Reserves computed based on the TargetCo's participating interest of 37.5%. Royalties are paid in cash and treated as production tax and is therefore not deducted from the TargetCo's Net Entitlement.

(2) Conversion rate of 6,000 standard cubic feet per boe.

(ii) Summary of Contingent Resources as at 1 January 2023

Below is a summary of the Net Entitlement 1C, 2C and 3C Contingent Resources of the Asset to the TargetCo:

	Net Entitlement Contingent Resources(1)		
	1C	2C	3C
Gas (Bscf)	11.6	34.6	32.9
Condensate (MMstb)	0.2	1.1	1.4
Condensate and Gas (MMboe)(2)	2.2	6.8	6.8

Notes:

(1) Net Entitlement Reserves computed based on the TargetCo's participating interest of 37.5%. Royalties are paid in cash and treated as production tax and is therefore not deducted from the TargetCo's Net Entitlement.

(2) Conversion rate of 6,000 standard cubic feet per boe.

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(iii) Summary of valuation of the Asset

RPS Energy has conducted a valuation of the Asset as at 1 January 2023, being the valuation date, using two valuation methods:

(i) Discounted cash flow / Income-based approach; and
(ii) Market-based approach

Summary of the two valuation methods stated above:

Discounted cash flow / Income-based approach

The key valuation assumptions by RPS Energy in arriving at the discounted cash flow valuation of the Asset are set out below:

No.	Key input	Assumptions
1.	Production and cost profiles	RPS Energy 2P and 2C case RPS Energy uses the 2P and 2C case for the valuation of the Asset on the basis of industry practice as the 2P case represents the best estimate case for Reserves (proved+probable) and 2C represents the best estimate of Contingent Resources in the fair market valuation of producing O&G assets.
2.	O&G prices	RPS Energy Brent price and gas price forecast
3.	Average premiums to dated Brent	2% for MLJ condensate
4.	Effective date	1 January 2023
5.	Annual inflation rate	2% per annum from for prices and costs
6.	PMA period	Assumed to be automatically extended from 2029 until November 2039 on the basis that the Asset continues to be economically viable for the BBJV Partners
7.	Tenure of underlying agreements [1]	Assumed to be extended up to expiry of the extended PMA period

Note:
(1) The underlying agreements comprise the GSA, Third Party Gas agreement and service agreement (as referred to under Section 3.5 of this Circular).

The total NPV of the Asset is USD250.0 million (or equivalent to RM1,048.4 million) as of 1 January 2023 for 2P Reserves and 2C Resources, at discount rates of 10% and 12% respectively, and includes the present value of future cash flows at a 10% discount rate for Third Party Gas. The valuation is based on RPS Brent price and gas price forecasts.

The discount rates of 10% and 12% used for 2P Reserves and 2C Resources respectively, as opined by RPS Energy, are fair rates for the purpose of valuing the Asset after taking into consideration the range of Hibiscus Petroleum's weighted average cost of capital of between 7.8% and 10.9%.

The reasonable range applying this Income-based Approach together with net working capital and cash of USD14.4 million (or equivalent to approximately RM60.4 million) would be between **USD250.4 million** (or equivalent to approximately RM1,050.1 million) for Reserves and **USD264.4 million** (or equivalent to approximately RM1,108.8 million) for 2P Reserves plus 2C Resources**.**

The Purchase Consideration is within this estimated range based on Income-based Approach.

Market-based Approach *(Alternative valuation method)*

For the alternative valuation method, in this case the Market-based approach, by comparison to similar market transactions, RPS Energy has reviewed the information of recent transactions in Malaysia, Indonesia and Thailand that are available in the public domains and considered those deals relating to producing fields for comparison with the current valuation as set out in Section 2.2 of this Circular ("**Similar Market Transactions**").

Based on the Competent Valuer's Report, RPS Energy determined the range of implied USD per barrel valuations in these Similar Market Transactions to be between USD 7.2/boe and USD 12.7/boe, after adjusting for the average Brent crude oil price differences to account for the timings of these various transactions. Accordingly, the reasonable range of valuation for the TargetCo would be between USD242 million *(or equivalent to approximately RM1,014.8 million)* and USD461 million *(or equivalent to approximately RM1,933.2 million)*.

The Purchase Consideration of USD259.4 million (or equivalent to approximately RM1,087.8 million) is within this estimated range based on Market-based Approach.

(Source: RPS Energy)

For further details on the methodology of estimates of reserves and resources and the valuation assumptions made by RPS Energy, please refer to the Competent Valuer's Report in Appendix IV of this Circular.

3. Information on key contractual arrangements entered into by the TargetCo in respect of the Asset

(i) PMA

The primary concession document in respect of the Asset is the PMA. The PMA was amended by two amendments titled "Amendment Agreement to Block B Petroleum Mining Agreement dated 23 November 1989" entered into between (1) Brunei National Petroleum Company Sendirian Berhad ("**PetroleumBRUNEI**"), (2) TargetCo, (3) Shell Deepwater and (4) Brunei Energy on 12 February 2014 ("**First Amendment**") and 10 July 2014 ("**Second Amendment**").

The summary of salient features of the PMA is as follows:

(a) The term of the PMA is thirty (30) years from 23 November 1989. By virtue of the First Amendment, the initial expiry date of 23 November 2019 of the PMA was extended for a first ten (10) year period, to 23 November 2029. The BBJV Partners have the option to extend the PMA for another ten (10) year period (with an expiry date of 23 November 2039) upon one year's prior notice. Post extension, the BBJV Partners will assume a best-efforts obligation to ensure continued commercial exploitation of the contract area for the period remaining after 1 April 2033 (being the expiry of the BBJV Partners' existing gas supply commitment to BLNG).

(b) Following discovery of technically and commercially exploitable deposits of petroleum, the government of Brunei shall have the right to participate up to fifty percent (50%) share in the development and exploitation by the BBJV Partners.

(c) The government of Brunei shall have the first option to purchase, for consumption in Brunei, certain amounts of surplus natural gas.

(d) The BBJV Partners undertake to make available to PetroleumBRUNEI for domestic use or consumption within Brunei ten percent (10%) of natural gas produced in Block B in accordance with the GSA.

(e) The BBJV Partners are obligated to make available for consumption within Brunei petroleum (except natural gas produced within Brunei) to the extent of such proportion of the total demand in Brunei for such petroleum as is equal to the proportion which the Block B joint venture's production bears to the total production in Brunei. To the extent such petroleum takes the form of refined products, such petroleum is to be made available at prices to be agreed between the government of Brunei and the BBJV Partners.

(f) The government of Brunei shall be entitled, upon giving reasonable notice to the BBJV Partners, to undertake any act which it considers necessary to ensure compliance with the obligations of the parties and to recover the costs and expenses of so doing.

(g) A BBJV Partner cannot transfer its interest under the PMA without first obtaining written consent from the government of Brunei.

(ii) JOA

Operations of the TargetCo in respect of the Asset are governed by the JOA.

The summary of salient features of the JOA is as follows:

(a) The JOA was entered into for the purposes of governing the PMA from the time when the PMA became effective. It establishes the principles, terms and conditions under which the BBJV Partners will carry out operations under the PMA and shall remain in effect during the subsistence of the PMA or until the JOA is terminated.

(b) The JOA defines the individual participating interests of the participants. All costs and expenses and liabilities are shared, and the individual entitlements are determined, among the participants on the basis of these participating interests.

(c) The TargetCo is the current operator of the Asset. The operator may be removed by unanimous vote of the non-operators after six months' prior notice where: (i) it becomes subject to an insolvency event; (ii) it is in breach of its duties/obligations and rectification has not been commenced within sixty days of notification of all non-operators; (iii) it used to be and ceases to be an affiliate of any party to the JOA; (iv) it retains less than thirty percent (30%) participating interest; or (v) it has failed in a material manner to perform its duties and obligations under the JOA and such default remains unrectified.

(d) There is an operating committee comprising three representatives from the TargetCo and two representatives from Shell Deepwater. The chairman shall be one of the operator's representatives. Matters are resolved by an affirmative vote of two or more parties constituting more than seventy two and a half percent (72.5%) of the total participating interest of all parties. Operator's opinion shall prevail over certain enumerated matters.

(e) The operator is responsible for preparing the annual programme and budget for submission to the operating committee for review and approval.

(f) There is a permanent management committee to ensure that the government of Brunei's interests in the operation are fully represented in the daily management.

(g) Each participant shall have the obligation to lift and dispose separately its participating share of hydrocarbons at the specified delivery point. Each party shall have the right to take in kind its participating interest share in the production capacity of petroleum.

(h) A participant may at any time assign all or a part of its participating interest so long as such assignment is in accordance with the JOA and provided that no assignment shall be made which has the effect of leaving the assignor or the assignee with less than five percent (5%) participating interest.

(iii) Joint Venture Agreement

Operations in respect of the Asset are governed by the Joint Venture Agreement initially entered into between (1) Jaspet, (2) Pengiran Dato Paduka Haji Abdul Rahman Bin Pengiran Haji Abdul Rahim ("**Pengiran**") and (3) TargetCo dated 20 November 1986 as amended, supplemented and novated from time to time ("**JVA**"). The current parties to the JVA are the BBJV Partners.

The summary of salient features of the JVA is as follows:

(a) Pursuant to the JVA, the Block B joint venture partners (being the current BBJV Partners) have set up an unincorporated joint venture where each of the partners manage their respective rights and obligations with each other as independent entities with separate legal personalities. The BBJV Partners agreed to contribute to the financing of any and all expenditure, costs and expenses associated with or in relation to exploration, appraisal, development and production activities.

(b) By signing the JVA, the parties are bound by the JOA (unless specifically provided otherwise in the JVA).

(c) Under the JOA, the TargetCo is obligated to fund the cash calls sent to Jaspet and the Pengiran ("**Advances**"), and interest shall run on such Advances until the date of recoupment. The JVA further provides that if the exploration and/or appraisal activities lead to the determination to develop a given project (i.e. a commercial development to produce oil and gas from one or more fields), then the TargetCo shall be able to recoup such Advances (and interest) from the production which Jaspet and the Pengiran are entitled to by way of their participating interests.

Note:
Jaspet's and Pengiran's interest were revoked by, and such interest reverted to, the government of Brunei. The government of Brunei then transferred such interest to PetroleumBRUNEI, and PetroleumBRUNEI subsequently assigned its interest to Brunei Energy.

(d) The TargetCo and Shell Deepwater are entitled to freely assign and transfer their rights and obligations to their affiliates upon giving (whether pre-transfer or post-transfer) written notice to the other parties.

(e) The TargetCo is the current operator of the Asset.

(iv) Cash Investors Agreement

The TargetCo initially held 72.5% interest in the PMA. The TargetCo assigned 35% undivided interest in the PMA to Fletcher Challenge Energy Borneo Limited (formerly known as Fletcher Challenge Petroleum Borneo Ltd) ("**FCPB**") upon fulfilment of certain conditions set out in the farmout agreement initially entered into between (1) TargetCo and (2) FCPB dated 13 December 1995, as amended, supplemented and novated from time to time. Following such assignment, FCPB became a "Cash Investor" under the JVA and the JOA assuming (with respect to Block B and in proportion to the undivided interest assigned to it) all the rights, obligations and commitments of the TargetCo as Cash Investor under the said agreements. The TargetCo and FCPB entered into the Cash Investors Agreement dated 13 December 1995 to set out their respective rights and obligations as Cash Investors under the JVA and the JOA ("**Cash Investors Agreement**"). Shell Deepwater is the successor of FCPB.

The summary of salient features of the Cash Investors Agreement is as follows:

(a) The parties have set up a committee ("**Cash Investors Committee**") in order to define the cash investors' common position to be adopted generally in respect of the joint operations including in the meetings of the Operating Committee with respect to any decisions involving directly or indirectly the disbursement or recoupment of funds. Decisions of the Cash Investors Committee shall be binding upon and between the TargetCo and Shell Deepwater, and the TargetCo and Shell Deepwater shall cast their votes in the Operating Committee in accordance with the decisions of the Cash Investors Committee.

(b) Each of TargetCo and Shell Deepwater shall designate two representatives to the Cash Investors Committee. One representative of each party shall have the full authority to represent, bind and vote on behalf of such parties at each Cash Investors Committee meeting. The Chairman shall be a representative or alternate representative of the Operator (currently, being the TargetCo).

(c) Decisions are to be made by simple majority (i.e. more than 50% of the Cash Investors' participating interests), save in respect of the following important matters which require the affirmative votes of both parties: (i) works or expenditures in excess of PMA obligations, save for sole risk operations; (ii) surrender of all or part of the Block B acreage; (iii) amendment to or voluntary termination of the PMA; (iv) any material unitisation decision; (v) approval of programmes and revisions thereto; (vi) budget items and revisions exceeding 10% of the original approval item; (vii) approval of non-budgeted items in excess of USD100,000; and (viii) bid selections relating to third party contracts requiring expenditure of more than USD500,000 or affiliate contracts requiring expenditure of more than USD50,000.

(d) TargetCo and Shell Deepwater, each in proportion to their respective participating interest, shall contribute to all expenditures, costs, obligations and liabilities incurred for the joint operations. In addition, TargetCo and Shell Deepwater, each in the proportion that their respective participating interests bear to the sum of their participating interests, shall be responsible for the Advances as prescribed under paragraph (iii)(c) of JVA above. Any party that fails to pay when due its cash participating obligation share of any cash call made shall be considered in default.

(e) The TargetCo's share of recoupment of Advances is higher than its participating interest to allow accelerated recovery of Advances made prior to the effective date of the abovementioned assignment of interest as a priority. After the TargetCo has fully recouped the relevant sums equivalent to the Advances and accrued interest prior to the effective date of the abovementioned assignment of interest, the obligation to pay Advances and the right to recoup such Advances (and interest thereon) shall be apportioned between the TargetCo and Shell Deepwater (in accordance with their respective participating interests) on an approximately 51.72:48.28 basis, as computed below.

All in %	**Original Working Interest**	**Split of Brunei Energy share**	**Financing Interest (i.e. Interest with Carry)**
TargetCo	37.50	14.22	51.72
Shell Deepwater	35.00	13.28	48.28
Brunei Energy	27.50	-	-
TOTAL	**100.00**	**27.50**	**100.00**

(f) No participating interest under the PMA, the JVA and the JOA may be assigned to a non-affiliate unless the non-assigning party consents in writing (consent may only be withheld on grounds of lack of technical capabilities and financial resources of the proposed assignee to fulfil its obligations under the JVA, the JOA or the Cash Investors Agreement by notification within 30 days). If an assigning party wishes to transfer its participating interest under the Cash Investors Agreement to a third party (other than an affiliate), it shall first offer such participating interest to the non-assigning party by notice in writing. The non-assigning party has the right, exercisable within 30 days from the date of receipt of such notice to accept such offer. Where an assigning party assigns its participating interest to an affiliate, it shall remain jointly and severally liable with the assignee.

(g) A Cash Investor shall not withdraw from the Cash Investors Agreement unless such withdrawal results from a valid and effect withdrawal from the PMA, the JVA and the JOA.

(h) If there is a change in control in the Operator's company, other than to: (i) another affiliate or (ii) an entity with the technical and financial capability to carry out joint operations in accordance with the JOA, then the Operator will tender its resignation under the JOA.

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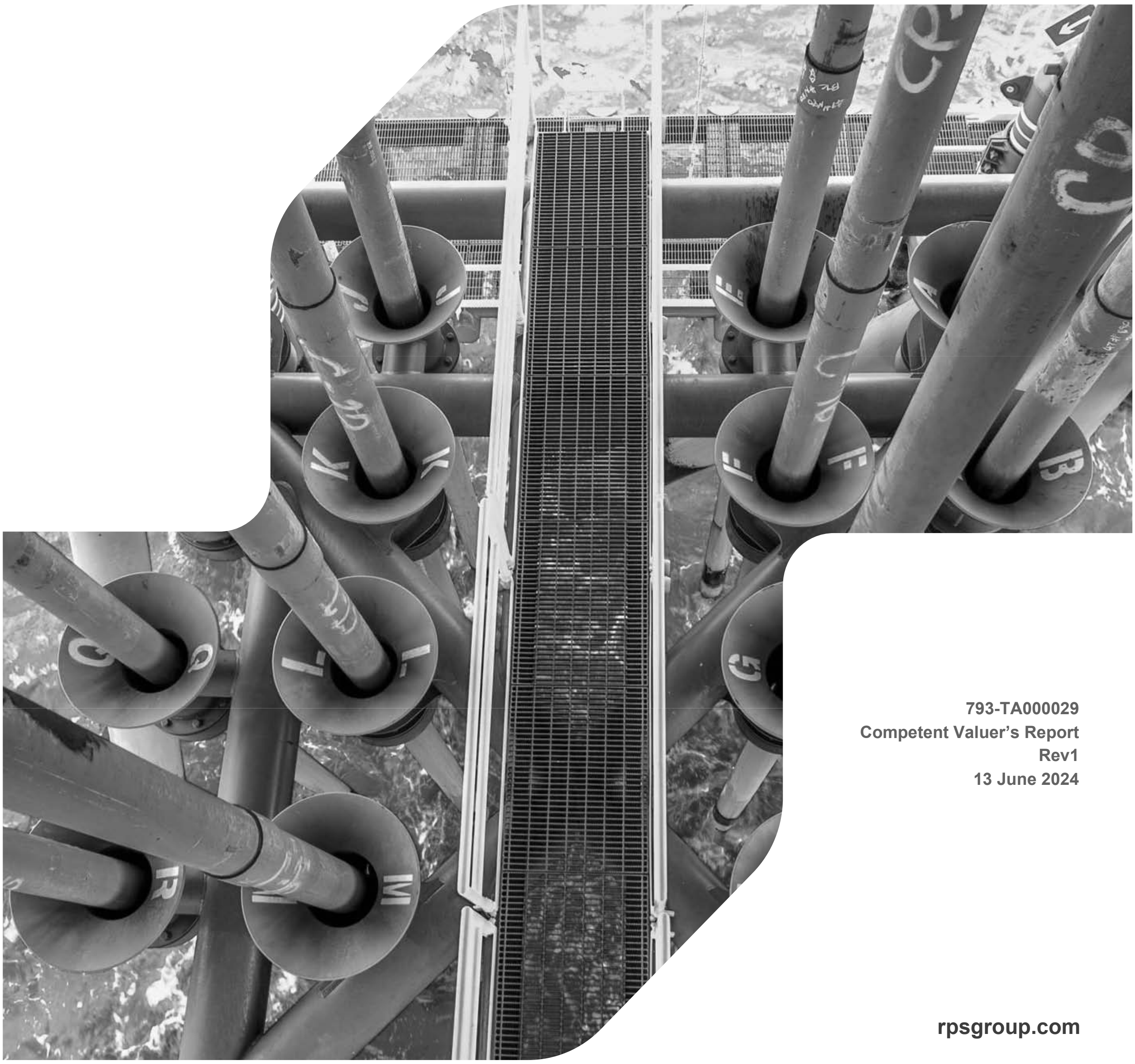
A TETRA TECH COMPANY

COMPETENT VALUER'S REPORT ON MAHARAJALELA JAMALULALAM FIELD

BLOCK B, OFFSHORE BRUNEI



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Competent Valuer's Report
Rev1
13 June 2024

rpsgroup.com

COMPETENT VALUER'S REPORT

Document status

Version	Purpose of document	Authored by	Reviewed by	Approved by	Review date
Rev0	Final Draft	GT, JT	GT	GT	27/05/2024
Rev1	Final Draft	GT, JT	GT	GT	13/06/2024

Approval for issue

Gordon Taylor		13 June 2024

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Date: 13 June 2024

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Dear Sirs,

EVALUATION OF MAHARAJALELA JAMALULALAM FIELD, OFFSHORE BRUNEI

In response to a request by Hibiscus Petroleum Berhad ("Hibiscus"), and the Letter of Engagement dated 2nd January 2024 with Hibiscus (the "Agreement"), RPS Energy Limited ("RPS") has completed an independent evaluation of the Maharajalela Jamalulalam (MLJ) Field, in Block B offshore Brunei. The field is currently operated by TotalEnergies EP (Brunei) B.V. ("TargetCo"). TotalEnergies Holdings International B.V. ("Total" or "Vendor"), being the holding company of the TargetCo, is seeking to divest TargetCo.

The potential transaction encompasses a 100% of the issued shares of the TargetCo offered by Total. The TargetCo holds and operates 37.5% working interest in the Block B Concession located offshore Brunei.

This report is issued by RPS under the appointment by Hibiscus to conduct an independent valuation of the Assets to satisfy Paragraph 11, Part III of Practice Note 32 of the Main Market Listing Requirements of Bursa Malaysia Securities Berhad ("Bursa Securities"); and is produced as part of the Services detailed therein and subject to the terms and conditions of the Agreement. This Competent Valuer's Report has been prepared solely for the use of Hibiscus, its other advisors and Bursa Securities as well as for inclusion in Hibiscus' circular to shareholders.

We have estimated Proved, Probable and Possible Reserves as of 1 January 2023. All Reserves and Resources definitions and estimates shown in this report are based on the 2018 Petroleum Resource Management System of SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE ("PRMS"). This Competent Valuer's Report has been prepared in compliance with the requirements for reporting oil and gas activities as specified in Practice Note 32 of the Main Market Listing Requirements of Bursa Securities and the disclosure requirements and contents of reports as prescribed in Chapter 17, Division 1, Part II of the Prospectus Guidelines issued by the Securities Commission Malaysia's ("SC") in relation to Specific Requirements For A Corporation with MOG Exploration or Extraction Assets.

The work was undertaken by a team of petroleum engineers, geoscientists and economists and is based on data supplied by Hibiscus made available by Total. Our approach has been to audit data made available in a virtual dataroom ("VDR") by Total.

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.

We have taken the working interest that Total holds in the MLJ Field as presented by Total in the VDR. We have not investigated, nor do we make any warranty as to Hibiscus' interest in the asset.

A site visit was not conducted.

Prospective Resources volumes have not been evaluated by RPS as they are outside the scope of this report.

RPS estimates of Reserves and Contingent Resources are provided in the Executive Summary and in Section 6.5.

QUALIFICATIONS

RPS is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. The provision of professional services has been solely on a fee basis. Gordon Taylor, Technical Director, has supervised this evaluation. Gordon is a Chartered Geologist and Chartered Engineer with over 40 years' experience] in upstream oil and gas. The project has been managed on a day-to-day basis by James Hodson who has 12 years' experience in upstream oil and gas. Other RPS 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, RPS 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 RPS'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.

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Yours sincerely,
for RPS Energy Ltd

Gordon Taylor
Technical Director

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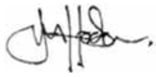
Name	Role	Signature
James Hodson	Project Manager and Geoscience Lead	
Adolfo Perez	Reservoir Engineering Lead	
David Walker	Facilities and Costs Lead	
Joseph Tan	Economics Lead	

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APPENDICES

1 EXECUTIVE SUMMARY

In response to a request by Hibiscus Petroleum Berhad ("Hibiscus"), and the Letter of Engagement dated 2 January 2024 with Hibiscus (the "Agreement"), RPS Energy Limited ("RPS") has completed an independent evaluation of the Maharajalela Jamalulalam (MLJ) Field, in Block B offshore Brunei. The field is currently operated by TotalEnergies EP (Brunei) B.V. ("TargetCo"). TotalEnergies Holdings International B.V. ("Total" or "Vendor"), being the holding company of the TargetCo, is seeking to divest TargetCo. The report is based on an audit of material made available by Total in a virtual dataroom ("VDR").

1.1 Overview of Maharajalela Jamalulalam (MLJ) Field

Total is looking to dispose of its business in Brunei which is focused on offshore Block B.

Block B offshore Brunei contains the MLJ field which was discovered in 1989 by the Maharajalela North well and which was appraised and developed in the 1990s with first gas in 1999. Since 1999 the field has been producing gas and condensate from three unmanned platforms in relatively shallow (less than 100 m) water depths. The field consists of a complex faulted system that is divided into elongated structural compartments. The northern panel (MLJ North) extends into a third party's licensed area.

The block has some remaining prospectivity according to the Vendors but a review of prospectivity was not within the scope of this project.

Given the nature of this audit a site visit was not undertaken.

For the purposes of this Report, Third Party Gas is gas and associated condensate for which the Block B Joint Venture ("BBJV") has been licensed by a third party, subject to payment of a Licence Fee thereto, to produce, process and sell.

All Reserves and Contingent Resource estimate herein are reported to PRMS 2018 standards. This report fulfils the requirements stipulated in Chapter 17, Part II, Division1 of the Securities Commission Malaysia's Prospectus Guidelines for a Competent Person's Report.

1.2 Health, Safety, Security and Environment ("HSSE")

Total claims to have an experienced team with in-depth knowledge of the assets and region, and RPS understand that much of this team will be retained as part of the transaction.

RPS remit was to focus on the production and cost forecast of the Vendor and, therefore, we have not reviewed the Total technical team or safety record.

Total is an international operator that adheres to stringent HSSE standards as indicated in their health-hygiene, safety, security, societal, environment & quality policy which it emphasizes the following industry standard commitment:

- Protect the health, safety and security of personnel
- Protect the environment
- Safeguard our production facilities and assets
- Contribute to the sustainable development of neighbouring communities and addressing stakeholder expectations

1.3 Surface Review

There are three unmanned production platforms - MLJ1, MLJ2 and MLJ3. No processing occurs offshore, and multiphase production is exported to onshore processing plant ("OPP") at Lumut. At Lumut, gas and liquids are separated, and condensate and water stabilised at 60 barg and gas is processed to remove mercury and traces of H_2S. Gas is sent to Brunei LNG Sendirian Berhad ("BLNG") plant at 43 barg, and condensate and water exported to Seria Crude Oil Terminal ("SCOT") at 20 barg.

A total of 22 exploration, appraisal and development wells have been drilled. In the final month of 2022, there were 15 wells producing gas from the MLJ field (four wells on the MLJ1 platform, five wells on the MLJ2 platform and six wells on the MLJ3 platform)[1].

1.4 Third Party Arrangement

The northern panel (MLJ North) extends into a third party's licensed area. Two reservoir layers (Layers 1 and 2) have been on production on agreed terms with the third party and future production from Layer 3 (via one of the existing wells) could be on the same terms.

RPS is not in a position to opine on the terms of the third party arrangement, and it was not part of the scope of this report.

1.5 Subsurface and Resource Evaluation

The field comprises a complex faulted system that is divided into elongated structural compartments ("panels"), limited by major sealing normal faults. Hydrocarbons have been found in eight dynamically independent panels, each subdivided into tens of different reservoir levels of Late Miocene age. Pressure regimes vary with depth and age with highest pressures in the deepest reservoir in the northwesternmost panels.

During December 2022, production was from the following panels:

- MLJ North panel production from wells MLJ1-06 and MLJ1-07
- JAM panel production from well MLJ1-02
- JMB panel production from perforations in MLJ1-01
- West panel production from wells MLJ1-01, MLJ2-01, MLJ2-02, MLJ2-03
- B1 panel production from well MLJ2-06
- A panel production from wells MLJ2-07, MLJ3-02 and MLJ3-06
- C1/C2 panel production from wells MLJ3-01 and MLJ3-03
- B2 panel production from wells MLJ3-04 and MLJ3-05:

RPS estimates of Reserves are provided in Table 1.1 to Table 1.3 and RPS estimates of Contingent Resources in Table 1.4 to Table 1.6.

[1] At the end of 2023 (Dec 2023) there are 11 wells producing gas. Two wells in the MLJ1 platform (MLJ1-06 and MLJ1-07), four wells in the MLJ2 platform (MLJ2-01, MLJ2-02, MLJ2-06 and MLJ2-07) and five wells in the MLJ3 platform (MLJ3-01, MLJ3-02, MLJ3-04, MLJ3-05 and MLJ3-06, with MLJ3-03 shut in due to intervention).

1.6 Economic Analysis

The Economic Limit Test ("ELT") performed for the determination of Reserves is based on RPS's estimates of recoverable volumes, a review of the company's estimates of Capex, Opex, and Abex; and inclusion of other financial information and assumptions, as outlined in Section 5.

The licences are assumed to reach its economic limit when the cumulative value of its net cash flow (excluding Abex) before tax ceases to increase. All projects to be classified as Reserves must be economic under defined conditions[2]. RPS has therefore assessed the future economic viability of each case on the basis of its pre-tax undiscounted Net Cash Flow Money Of the Day ("MOD").

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

The effective date of this report is 1 January 2023.

1.7 Reserves and Contingent Resources Summary & Estimated Net Present Value

A summary of Reserves is provided in Table 1.1 to Table 1.3 for Gas, Condensate, and Barrels of Oil Equivalent, respectively. The Net Present Value of the asset as of the effective date for the transaction based on Total's working interest is presented in Table 1.4.

Third Party Gas which is produced, processed and sold by BBJV (and is net to the TargetCo) is included in the production and cost profiles and impacts economics, but is not included as Reserves or Contingent Resources by RPS in this Report.

SUMMARY OF GAS RESERVES
As of 1 January 2023
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (Bscf)			Net Entitlement Reserves[2] (Bscf)		
	1P	2P	3P	1P	2P	3P
MLJ	213	328	432	80	123	162

Notes:

*[1] Gross field Reserves (100% basis) **after** economic limit test. Economic limit in year 2030 for 1P; 2036 for 2P and 2039 3P.*

[2] Total's net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Total's Net Entitlement.

Table 1.1: Gas Reserves in MLJ Field as of 1 January 2023

[2] *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.*

SUMMARY OF CONDENSATE RESERVES
As of 1 January 2023
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMstb)			Net Entitlement Reserves[2] (MMstb)		
	1P	2P	3P	1P	2P	3P
MLJ	4.5	9.9	17.2	1.7	3.7	6.4

Notes:

[1] Gross field Reserves (100% basis) ***after*** *economic limit test. Economic limit in year 2030 for 1P; 2036 for 2P and 2039 3P.*

[2] Total's net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Total's Net Entitlement.

Table 1.2: Condensate Reserves in MLJ Field as of 1 January 2023

SUMMARY OF RESERVES (BOE)
As of 1 January 2023
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMboe)[3]			Net Entitlement Reserves[2] (MMboe)[3]		
	1P	2P	3P	1P	2P	3P
MLJ	40.0	64.5	89.2	15.0	24.2	33.4

Notes:

[1] Gross field Reserves (100% basis) ***after*** *economic limit test. Economic limit in year 2030 for 1P; 2036 for 2P and 2039 3P.*

[2] Total's net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Total's Net Entitlement.

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

Table 1.3: Oil Equivalent Reserves in MLJ Field as of 1 January 2023

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1P	2030	140	140	139	137
2P	2036	283	246	236	227
3P	2039	476	356	333	313

Table 1.4: Block B Post-Tax Valuation at RPS Base Case Price Scenario

A summary of Contingent Resources is presented in Table 1.5 to Table 1.7.

SUMMARY OF GAS CONTINGENT RESOURCES
As of 1 January 2023
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (Bscf)			Net Entitlement Contingent Resources[2] (Bscf)		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**Resources Post EL**	3.4	0.0[5]	0.0[5]	1.3	0.0[5]	0.0[5]
MLJ	**Workover**	2.2	3.2	4.4	0.8	1.2	1.7
MLJ	**Layer 3**	9.2	27.9	25.3	3.4	10.5	9.5
MLJ	**B1-15K**	10.9	36.9	40.4	4.1	13.8	15.2
MLJ	**Hibiscus Workover Plan**	5.4	24.3	17.7	2.0	9.1	6.6
Total[3, 4]		**31.0**	**92.3**	**87.8**	**11.6**	**34.6**	**32.9**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2031 for 1P; 2039 for 2P and 3P.

[2] Total's net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Total's Net Entitlement.

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, RPS' totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

4 It should be noted that all RPS forecasts are cut off at 2039. Contingent projects are assumed to be added to the NFA production when is required. However, total production is constrained by compressor capacity limits. Certain contingent projects are delayed in the RPS forecasts until there is compressor capacity available. In the high case, the NFA forecasts are sufficiently high that a smaller volume of contingent production is required than in the base case before the compressor capacity is reached. This means the high case contingent volume is smaller than the base case volume. If, however, the forecasts are extended beyond 2039 the 3C volumes are always higher than the 2C volumes as capacity becomes available. Table 6-7 of the Competent Person's Report dated 13th June 2024 shows the technically recoverable low, best, and high case volumes if production extends to 2059.

[5] Pre economic limit production forecast for 2P and 3P ends in year 2036 and 2039, respectively.

Table 1.5: Gas Contingent Resources in MLJ Field as of 1 January 2023

SUMMARY OF CONDENSATE CONTINGENT RESOURCES
As of 1 January 2023
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (MMstb)			Net Entitlement Contingent Resources[2] (MMstb)		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**Resources Post EL**	0.1	0.0[4]	0.0[4]	0.0	0.0[4]	0.0[4]
MLJ	**Workover**	0.0	0.1	0.2	0.0	0.0	0.1
MLJ	**Layer 3**	0.2	0.9	1.0	0.1	0.3	0.4
MLJ	**B1-15K**	0.2	1.1	1.7	0.1	0.4	0.6
MLJ	**Hibiscus Workover Plan**	0.1	0.7	0.7	0.0	0.3	0.3
Total[3]		**0.6**	**2.8**	**3.6**	**0.2**	**1.1**	**1.4**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2031 for 1P; 2039 for 2P and 3P.

[2] Total's net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Total's Net Entitlement.

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, RPS' totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

[4] Pre economic limit production forecast for 2P and 3P ends in year 2036 and 2039, respectively.

Table 1.6: Condensate Contingent Resources in MLJ Field as of 1 January 2023

SUMMARY OF CONTINGENT RESOURCES (BOE)
As of 1 January 2023
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (MMboe)[3]			Net Entitlement Contingent Resources[2] (MMboe)[3]		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**Resources Post EL**	0.6	0.0[5]	0.0[5]	0.2	0.0[5]	0.0[5]
MLJ	**Workover**	0.4	0.6	0.9	0.2	0.2	0.3
MLJ	**Layer 3**	1.7	5.5	5.3	0.6	2.1	2.0
MLJ	**B1-15K**	2.0	7.3	8.4	0.8	2.7	3.1
MLJ	**Hibiscus Workover Plan**	1.0	4.8	3.7	0.4	1.8	1.4
Total[4]		**5.8**	**18.2**	**18.2**	**2.2**	**6.8**	**6.8**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2031 for 1P; 2039 for 2P and 3P.

[2] Total's net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Total's Net Entitlement.

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

[4] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, RPS' totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

[5] Pre economic limit production forecast for 2P and 3P ends in year 2036 and 2039, respectively.

Table 1.7: Summary of Oil Equivalent Contingent Resources in MLJ Field as of 1 January 2023

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	**8%**	**10%**	**12%**
1P+1C	2031	136	136	135	133
2P+2C	2039	329	267	254	241
3P+3C	2039	556	388	359	334

Table 1.8: Block B Reserves and Contingent Resources Post-Tax Valuation at RPS Base Case Price Scenario

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1C	2031	(4)	(4)	(4)	(4)
2C	2039	46	21	17	14
3C	2039	80	32	25	20

Table 1.9: Block B Contingent Resources Post-Tax Valuation at RPS Base Case Price Scenario

As the Asset is already in production phase, we opine it is reasonable not to add additional premium over the WACC. Therefore, RPS opine a discount rate of 10 per cent is a fair rate to be applied for the purpose of current valuation for the Reserves. As summarized in Table 6.5, the asset 2P NPV discounted at 10 per cent is **US$ 236 million**.

For the valuation of Contingent Resources, RPS opine a discount rate of 12 per cent to be reasonable. As summarized in Table 6.10, the Asset 2C NPV discounted at 12 per cent is **US$ 14 million**. Therefore, total NPV for 2P Reserves and 2C Contingent Resources at discount rate of 10 per cent and 12 per cent, respectively, is **US$ 250 million**.

1.8 Fair Market Value

Based on the two Common Valuation Approaches recommended by VALMIN Code, namely the Income-based Approach and Market-based Approach, RPS opine the Fair Market Value of the Asset ranges between **US$ 242 million** and **US$ 461 million**.

Hibiscus proposed purchase price of of **US$ 245 million** plus the net working capital **US$ 14.4 million**, which summed up to a total of **US$ 259.4 million**, is within this estimated range.

2 INTRODUCTION

In response to a request by Hibiscus Petroleum Berhad ("Hibiscus"), and the Letter of Engagement dated 2 January 2024 with Hibiscus RPS Energy Limited ("RPS") has completed an independent evaluation of the Maharajalela Jamalulalam (MLJ) Field, Block B, offshore Brunei.

Block B is currently operated by Total (via TargetCo) who is seeking to divest the asset by selling TargetCo. The report is based on an audit of material made available by Total in a VDR which has been undertaken by RPS. Given the nature of the audit a site visit was not undertaken. The block has some remaining prospectivity according to the Vendor but a review of prospectivity was not in the scope of this project.

All Reserves and Contingent Resource estimate herein are reported to PRMS 2018 standards. This report fulfils the requirements stipulated in Chapter 17, Part II, Division1 of the Securities Commission Malaysia's Prospectus Guidelines for a Competent Person's Report.

For the purposes of this Report, Third Party Gas is gas and associated condensate for which the Block B Joint Venture ("BBJV") has been licensed by a third party, subject to payment of a Licence Fee thereto, to produce, process and sell. These volumes are included in the production and cost profiles, and impact field economics, but are not included as Reserves or Contingent Resources by RPS in this Report.

The effective date of this evaluation is 1 January 2023.

2.1 Brunei Block B

Block B offshore Brunei contains MLJ field which was discovered in 1989 by the Maharajalela North well and which was appraised and developed during the 1990s with first gas in 1999. It has total area of 276 km^2 and is approximately 50 km offshore Brunei. Since 1999, the field has been producing gas and condensate from three unmanned platforms in relatively shallow (less than 100 m) water depths. The field consists of a complex faulted system that is divided into elongated structural compartments. The northern panel (MLJ North) extends into a third party's licensed area. The location of the block is shown in Figure 2.1.

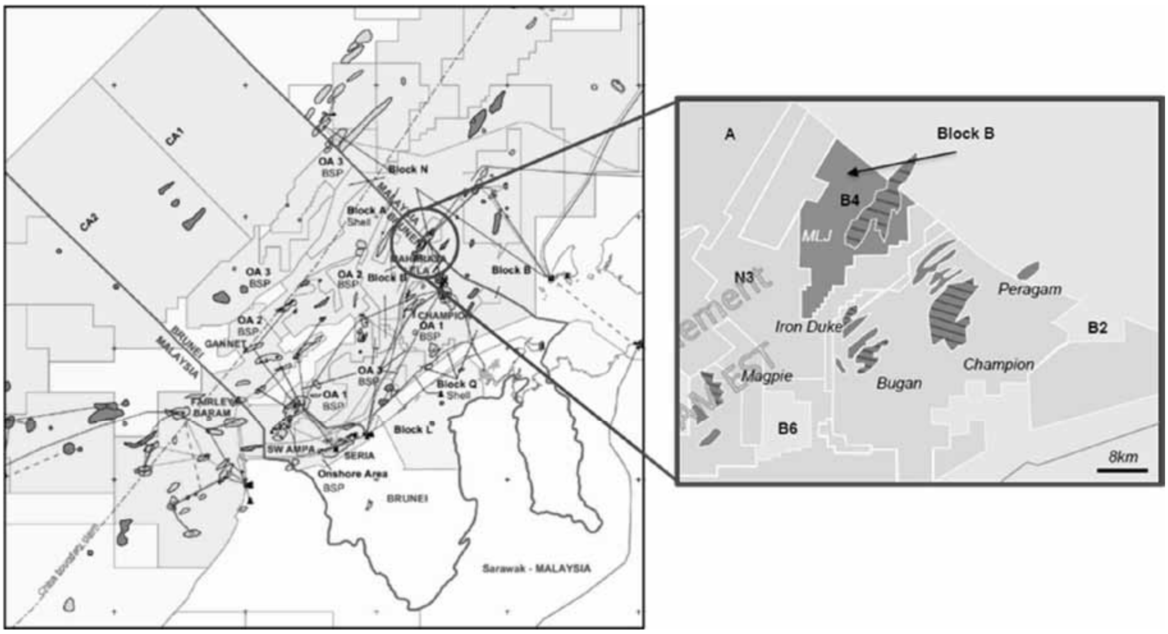

Figure 2.1: Location Map

The MLJ field has been producing since 1999 under a Petroleum Mining Agreement ("PMA"), with the gas delivered to the BLNG plant. On 12 February 2014, the PMA, originally planned to end in November 2019, was extended for 10 years to 23 November 2029 with an option to extend for a further 10 years to 23 November 2039.

Gas is sold to BLNG under a Gas Sale Agreement ("GSA"). The first GSA ran from 1999 to 2013. In December 2013, a new GSA was signed for a period of 20 years to 1 April 2033. The first Annual Contract Quantity ("ACQ") period ends in March 2023 and the second ACQ period starts in April 2023 and lasts until March 2032.

Produced liquids are handled and managed at the terminal operated by Brunei Shell Petroleum ("BSP") via the Operating Services Agreement ("OSA"). Liquids are exported to the Seria Crude Oil Terminal ("SCOT") for processing under the OSA. An OSA was signed in March 2017 and a subsequent amendment agreed in March 2023 to update the Nomination and Allocation Procedure.

Total has been present in Brunei since 1986 and claims to have an experienced team with in-depth knowledge of the assets and region. RPS remit was to focus on the production and cost forecast of Total and has therefore not reviewed the Total technical team or safety record.

Country	Licence Type	Operator	Total Interest	Development Status	Licence Expiry Date	Partners
Brunei	PMA	Total	37.5%	Producing	November 2029 (option to extend to November 2039)	Shell Deepwater Borneo BV (37.5%) Brunei Energy Exploration (27.5%)

Table 2.1: Summary of MLJ Field

2.1 Third Party Arrangement

The northern panel (MLJ North) extends into a third party's licensed area. Two reservoir layers (Layers 1 and 2) have been on production on agreed terms with the third party and future production from Layer 3 (via one of the existing wells) could be on the same terms.

RPS is not in a position to opine on the terms of the third party arrangement, and it was not part of the scope of this report.

3 BASIS OF OPINION

This report was prepared in response to a request by Hibiscus, and the Letter of Engagement dated 2 January 2024 with Hibiscus. This report is issued by RPS under this appointment and is produced as part of the Services detailed therein and subject to the terms and conditions of the Agreement.

All volume and resource definitions and estimates shown in this report are based on the 2018 Petroleum Resource Management System ("PRMS") of SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE. This report fulfils the requirements stipulated in Chapter 17, Part II, Division1 of the Securities Commission Malaysia's Prospectus Guidelines for a Competent Person's Report.

In preparing forecasts, we have used standard 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.

The work is based solely on data supplied by the Vendors, Total, to Hibiscus in a Virtual Data Room (VDR). Our estimates of recoverable volumes and associated costs are based on the data provided and we have accepted, without independent verification, the accuracy of these data.

The evaluation presented herein reflects our informed judgment, based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests.

RPS is not in a position to attest to the property title, financial interest relationships or encumbrances related to the properties.

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.

3.1 Methodology

Our approach has been to review production history and provide low, base and high case production forecasts for the existing well stock and the planned additional activity described in the Vendor's Information Memorandum (IM). The capital and operating cost forecasts have been reviewed for the planned activities.

A detailed review of the condition of the facilities, the environmental and safety performance of the facilities and site visits to the facilities was not within the scope of this project.

3.2 Database

The effective date of the Reserves and Contingent Resource estimates and valuation is 1 January 2023. However, data in the VDR included historic produced volumes to year end 2023. Reserves quoted in this report as of 1 January 2023 include actual produced volumes in 2023 plus forecast production from 1 January 2024 which was based on RPS decline analysis ("DCA").

Similarly, actual 2023 costs and forecast future costs from 2024 onwards, based on information received as of January 2024, were used in the evaluation. The evaluation used Q2 2024 price forecasts as stated in Section 8.3.

3.3 Site Visit

A detailed review of the condition of the facilities, the environmental and safety performance of the facilities and site visits to the facilities was not within the scope of this project.

4 MLJ FIELD FACILITIES

The MLJ Field comprises a complex faulted system that is divided into elongated structural compartments ("panels"), limited by major sealing normal faults. Hydrocarbons have been found in eight dynamically independent panels, each subdivided into tens of different reservoir levels. There are three unmanned production platforms - MLJ1, MLJ2 and MLJ3. No processing occurs offshore, and multiphase production is exported to onshore processing plant ("OPP") at Lumut. At Lumut, gas and liquids are separated, and condensate and water stabilised at 60 barg and gas is processed to remove mercury and traces of H_2S. Gas is sent to BLNG at 43 barg, and condensate and water exported to SCOT at 20 barg (Figure 4.1). The maximum gas handling rate is 201 MMscf/d and liquid rate is 18 Mstb/d.

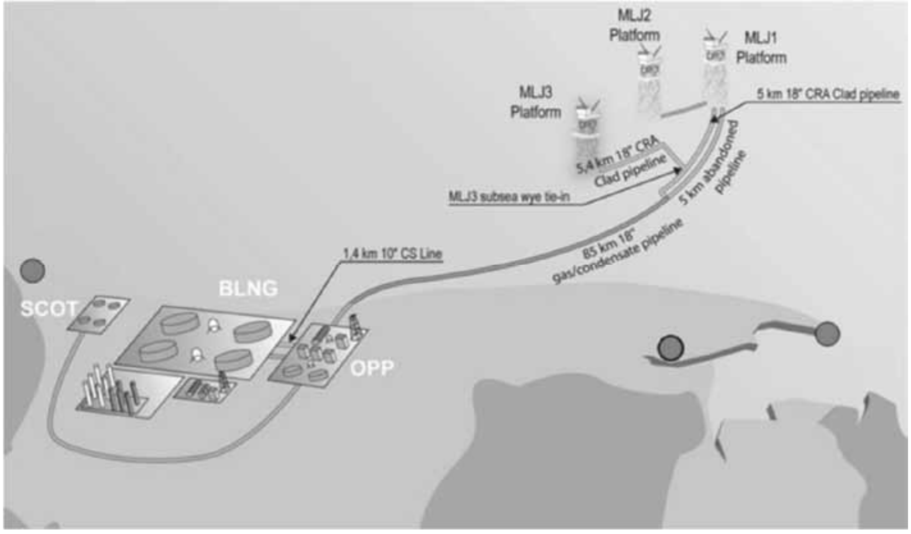

Figure 4.1: Block B Facilities Diagram

A total of 22 exploration, appraisal and development wells have been drilled. As of end 2022, there were 15 active gas producers (four wells on MLJ1 platform, five wells on MLJ2 platform and six wells on the MLJ3 platform).

The original MLJ development produced gas, condensate, and condensation water from the MLJ1 and MLJ2 wellhead platforms that are interconnected by a 12" 2.5 km inter-field pipeline. In 2015/16, a redevelopment project, called the MLJ South Project, consisted of debottlenecking of the OPP to increase export in high pressure mode (from 4.1 Mscm/d to 5.0 Mscm/d) and installation of a third HPHT platform MLJ3 with 12 slots. First gas from MLJ3 platform was in July 2016.

The panels with wells producing during December 2022 are shown in Table 4.1.

Panel	Platform	Producing Wells
MLJ North	MLJ1	MLJ1-06, MLJ1-07
JMB	MLJ1	Perforations in MLJ1-01
JAM	MLJ1	MLJ1-02
West	MLJ1	MLJ1-01
	MLJ2	MLJ2-01, MLJ2-02, MLJ2-03
B1	MLJ2	MLJ2-06
A	MLJ2	MLJ2-07
	MLJ3	MLJ3-02, MLJ3-06
C1/C2	MLJ3	MLJ3-01, MLJ3-03
B2	MLJ3	MLJ2-04, MLJ3-05

Table 4.1: December 2022 Producing Wells

During recent years, there have been a number well interventions. In 2019, perforations of four wells, in 2021 perforations on six wells, and in 2022 perforations and well clean-up on two wells. In 2023 to Q1 of 2024 a campaign to perforate three wells was planned.

Review of facilities integrity, operational performance, maintenance status and safety performance is beyond the scope of the RPS remit.

4.1 Planned Activities

A planned project to increase field life by decreasing OPP arrival pressure was sanctioned in 2023. Work is ongoing and the project is expected to be completed by 2025. The project is designed to modify the current 3.5 Msm^3/d plateau rates at 57 bar to deliver approximately 4.0 Mscm/d rates operating initially at 27 bar. This should enable field life extension to at least 2039 and is included in the Vendor's Reserves forecast.

Further well intervention work is planned. The Vendor forecast includes the following as Contingent Resources in their forecasts: -

- Three reperforation workovers (no additional sands accessed)
- MLJ North Layer 3 additional sand perforation
- B1-15k well to be drilled from the MLJ3 platform (the target is in the 2013 FDP) which will produce reservoirs proven by MLJ2-06 and appraise the 15k reservoirs in the B1panel.

5 COST FORECASTS

RPS reviewed the costs presented by the Vendor in the economic model and in other documents located in the VDR. Actual cost data and predicted future costs information in the VDR were valid as of 1 January 2024. RPS has reviewed and opined these costs are reasonable when benchmarked against cost estimates for similar operation in the region.

All costs discussed are 2023 Real and not Money of the Day[3] i.e., do not include any assumptions for inflation.

RPS has produced cost forecasts for two scenarios with a Low/Mid/High case for each. The first scenario is the Developed Producing along with the firm developments and developments in progress (the LP Compression and two workovers). A second scenario includes the contingent development activities. In total, there are six RPS produced cost and production forecasts used for valuation purposes.

5.1 Operating Costs (Opex)

RPS has received an economic model from the Vendor containing some high level Opex forecasts. These have been split by the Vendor into the following categories:

- Opex
- Supervision & Base Costs
- Other Opex Accounting Standards Codification ("ASC") & non-ASC 932; excluding Total's General and Administration ("G&A") and overheads
- Transportation Costs

The "Opex" category appears to consist of fixed operating costs and have been accepted by RPS.

The Supervision & Base Costs appear to contain the incremental LP Compressor operating costs, but these are not differentiated in the economic model. Following a request from RPS, the Vendor has supplied an incremental LP Compression Opex forecast separated out into the following sub-categories:

- Electricity costs
- Routine and non-routine Opex
- Compressor re-bundling costs

RPS has removed these costs from the Supervision and Base Costs to generate effectively a NFA cost and has produced an additional Opex line for the three sub-categories above under the LP incremental Opex.

RPS has accepted the Routine and non-routine Opex and the compressor re-bundling costs. The compressor re-bundling cost timing has been adjusted by RPS to suit the RPS generated forecasts. As RPS currently understands the new LP compressor will require re-bundling when the production drops below 1.7 Msm^3/d (60 MMscfd).

RPS has generated electricity cost forecasts based on the RPS production forecasts combined with data on the LP Compressor taken from the LP Compressor technical datasheet from the VDR. RPS has taken the LP Compressor data and have generated a relationship between gas flow and absorbed power and has utilised this to calculate the absorbed compressor power on an annualised basis against the RPS production

[3] RPS uses the term "Money of the Day" to prices which incorporate the effects of annual inflation and reflect the time value of money.

forecasts. The electricity import cost was supplied by the Vendor at a rate of $100/MWh. The compressor flow vs absorbed power taken from the compressor datasheet is shown in Figure 5.1.

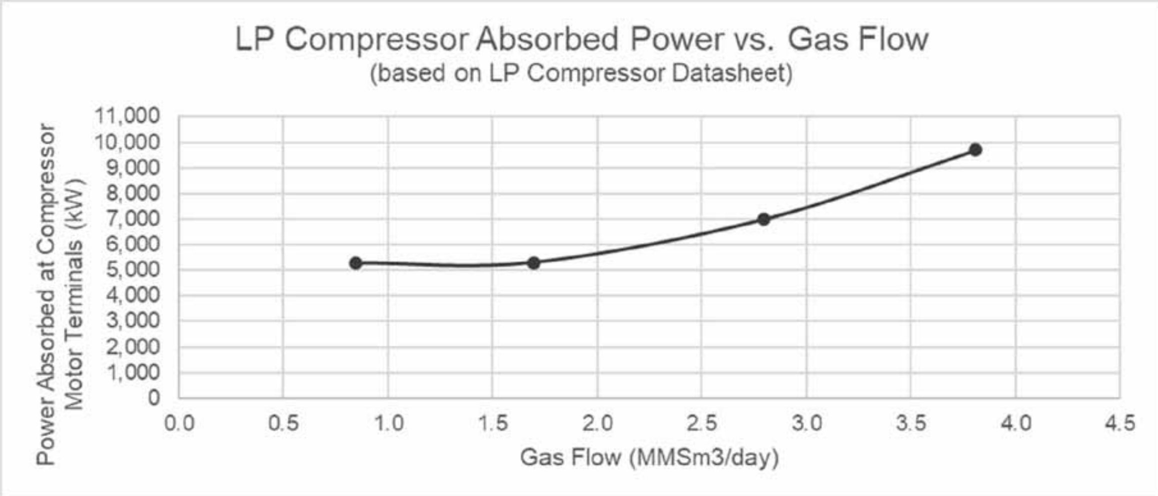

Figure 5.1. Compressor absorbed power vs gas flow

RPS has accepted the 'Other Opex Asc & non ASC932 (excluding TTE G&A and overheads)' operating costs. RPS has queried the G&A Costs and received confirmation from the Vendor that they are included in the provided Opex estimates with the exception of costs related such items as R&D, Strategy etc.

The transportation costs in the Vendor model are based on the condensate rates at a unit rate of $2.6/bbl. RPS has maintained this unit cost and calculated the transportation costs against the RPS generated condensate forecasts.

The tariff appears high for transportation only but no granularity on rates was available in the VDR, and a request from RPS for clarity on what is included in this rate solicited no response from the Vendor.

RPS has not applied a carbon tax in the valuation.

5.2 Capital Expenditure (Capex)

The Vendor model includes a Capex estimate of $312m. This figure covers the following development activities that are either in development or have been moved to firm commitment:

- GSR Studies, Structure Costs and Overhead
- CFR
- LP Compression
- Well Intervention 23
- Well Intervention 24

And it covers the following contingent activities:

- Light Workover (WO) - (3 wells)
- Layer 3 - MLJ1-07 Deepening
- B1-15k - MLJ3-07

The Vendor's model also includes an additional cost for Prospective wells, but the costs of Prospective activity have been excluded from the RPS estimates as they are not part of this study.

The Vendor's Capex estimates have been accepted by RPS. The contingent activities timing has been adjusted by RPS to align with the RPS production forecasts and are adjusted to coincide when capacity becomes available in the facilities due to natural decline.

RPS has added an additional 5% contingency on the currently in development and firm commitment activity Capex costs. The major Capex activity is the LP compression project which is due for start-up in 2025 and as RPS understands the major long lead items and equipment have been ordered.

6 ECONOMIC EVALUATION

6.1 Contractual Rights Overview

A Petroleum Mining Agreement (PMA) was signed in November 1989, followed by an Amendment Agreement signed in February 2014; and extended until November 2029.

PMA is assumed to be automatically extended from 2029 until November 2039, with renewal being subject to BBJV partners discretion.

6.2 Fiscal Overview

Block B PMA fiscal terms as provided in the management presentation and applied in the economic model are summarised in Figure 6.1.

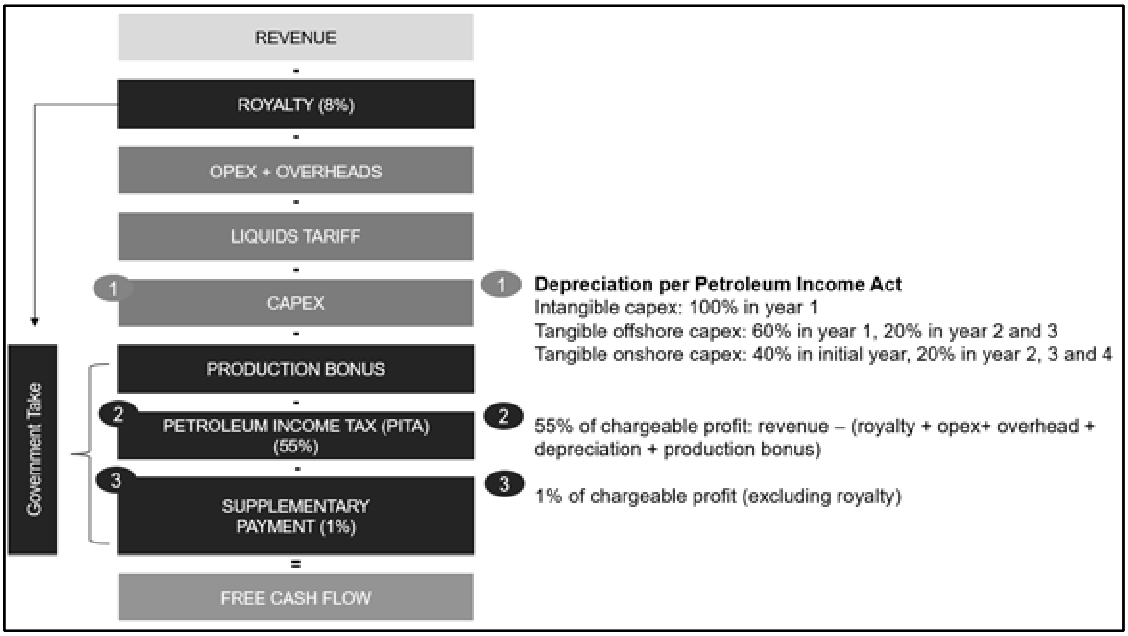

Figure 6.1: Block B PMA Fiscal Terms Summary

6.3 Petroleum Pricing Basis

Based on the data provided in Total's dataroom management presentation and economic model:

- MLJ condensate has average premiums to dated Brent of 2%;
- Into Plant Price (IPP) to BLNG gas price formula as per the GSA:
- Inflation: 2% per annum from 2024 for prices and costs.
- USD10/MMBtu JKM LNG prices with 2% annual inflation and JCC premium over Brent of $1.6/bbl assumed to forecast gas prices
- Domestic Market Obligation ("DMO") gas price of USD 0.33/MMBtu assumed (DMO price is applicable on 10% of the gas sold)

These price assumptions are applied in RPS commercial evaluation, and the annual forecasts are summarised in Table 6.1.

Year	RPS Q2 2024 Brent Oil Price (US$/bbl) MOD	Realised Condensate Price (US$/bbl) MOD	Realised Gas Price (US$/Mscf) MOD
2023	82.4	84.1	4.7
2024	82.0	83.6	4.9
2025	80.0	81.6	4.7
2026	78.0	79.6	4.6
2027	75.0	76.5	4.6
2028	75.0	76.5	4.6
2029	75.0	76.5	4.6
2030	77.0	78.5	4.7
2031	79.0	80.6	4.9
2032	81.0	82.6	5.0
2033	84.5	86.2	5.1
2034	86.2	87.9	5.2
2035	87.9	89.6	5.3
2036	89.6	91.4	5.4
2037	91.4	93.3	5.5
2038	93.3	95.1	5.6
2039	95.1	97.0	5.8

Table 6.1: Oil and Gas Price Assumptions

6.4 Cashflow Analysis

The Economic Limit Test ("ELT") performed for the determination of Reserves is based on RPS's estimates of recoverable volumes, a review of the Total's estimates of Capex, Opex, and Abex; and inclusion of other financial information and assumptions, as outlined in Section 5.

The licence is assumed to reach its economic limit when the cumulative value of its net cash flow (excluding Abex) before tax ceases to increase. All projects to be classified as Reserves must be economic under defined conditions[4]. 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 1 January 2023.

[4] *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.*

6.5 Reserves and Contingent Resources Summary & Estimated Net Present Value

A summary of Reserves is provided in Table 6.2 to Table 6.4 for gas, condensate, and barrels of oil equivalent, respectively. The Net Present Value ("NPV") of the asset as of the effective date for the transaction based on Total's working interest is presented in Table 6.5.

SUMMARY OF GAS RESERVES
As of 1 January 2023
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (Bscf)			Net Entitlement Reserves[2] (Bscf)		
	1P	2P	3P	1P	2P	3P
MLJ	213	328	432	80	123	162

Notes:

[1] *Gross field Reserves (100% basis) **after** economic limit test. Economic limit in year 2030 for 1P; 2036 for 2P and 2039 3P.*

[2] *Total's net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Total's Net Entitlement.*

Table 6.2: Gas Reserves as of 1 January 2023

SUMMARY OF CONDENSATE RESERVES
As of 1 January 2023
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMstb)			Net Entitlement Reserves[2] (MMstb)		
	1P	2P	3P	1P	2P	3P
MLJ	4.5	9.9	17.2	1.7	3.7	6.4

Notes:

[1] *Gross field Reserves (100% basis) **after** economic limit test. Economic limit in year 2030 for 1P; 2036 for 2P and 2039 3P.*

[2] *Total's net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Total's Net Entitlement.*

Table 6.3: Condensate Reserves in MLJ Field as of 1 January 2023

SUMMARY OF RESERVES (BOE)
As of 1 January 2023
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMboe)[3]			Net Entitlement Reserves[2] (MMboe)[3]		
	1P	2P	3P	1P	2P	3P
MLJ	40.0	64.5	89.2	15.0	24.2	33.4

Notes:

[1] *Gross field Reserves (100% basis) **after** economic limit test. Economic limit in year 2030 for 1P; 2036 for 2P and 2039 3P.*

[2] *Total's net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Total's Net Entitlement.*

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

Table 6.4: Oil Equivalent Reserves in MLJ Field as of 1 January 2023

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1P	2030	140	140	139	137
2P	2036	283	246	236	227
3P	2039	476	356	333	313

Table 6.5: Block B Reserves Post-Tax Valuation at RPS Base Case Price Scenario

A summary of Contingent Resources is presented in Table 6.6 to Table 6.8. The Contingent Resources NPV of the asset as of the effective date for the transaction based on Total's working interest is presented in Table 6.9 and Table 6.10.

SUMMARY OF GAS CONTINGENT RESOURCES
As of 1 January 2023
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (Bscf)			Net Entitlement Contingent Resources[2] (Bscf)		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**Resources Post EL**	3.4	0.0[5]	0.0[5]	1.3	0.0[5]	0.0[5]
MLJ	**Workover**	2.2	3.2	4.4	0.8	1.2	1.7
MLJ	**Layer 3**	9.2	27.9	25.3	3.4	10.5	9.5
MLJ	**B1-15K**	10.9	36.9	40.4	4.1	13.8	15.2
MLJ	**Hibiscus Workover Plan**	5.4	24.3	17.7	2.0	9.1	6.6
Total[3, 4]		**31.0**	**92.3**	**87.8**	**11.6**	**34.6**	**32.9**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2031 for 1P; 2039 for 2P and 3P.

[2] Total's net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Total's Net Entitlement.

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, RPS' totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

4 It should be noted that all RPS forecasts are cut off at 2039. Contingent projects are assumed to be added to the NFA production when is required. However, total production is constrained by compressor capacity limits. Certain contingent projects are delayed in the RPS forecasts until there is compressor capacity available. In the high case, the NFA forecasts are sufficiently high that a smaller volume of contingent production is required than in the base case before the compressor capacity is reached. This means the high case contingent volume is smaller than the base case volume. If, however, the forecasts are extended beyond 2039 the 3C volumes are always higher than the 2C volumes as capacity becomes available. Table 6-7 of the Competent Person's Report dated 13th June 2024 shows the technically recoverable low, best, and high case volumes if production extends to 2059.

[5] Pre economic limit production forecast for 2P and 3P ends in year 2036 and 2039, respectively.

Table 6.6: Gas Contingent Resources in MLJ Field as of 1 January 2023

SUMMARY OF CONDENSATE CONTINGENT RESOURCES
As of 1 January 2023
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (MMstb)			Net Entitlement Contingent Resources[2] (MMstb)		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**Resources Post EL**	0.1	0.0[4]	0.0[4]	0.0	0.0[4]	0.0[4]
MLJ	**Workover**	0.0	0.1	0.2	0.0	0.0	0.1
MLJ	**Layer 3**	0.2	0.9	1.0	0.1	0.3	0.4
MLJ	**B1-15K**	0.2	1.1	1.7	0.1	0.4	0.6
MLJ	**Hibiscus Workover Plan**	0.1	0.7	0.7	0.0	0.3	0.3
Total[3]		**0.6**	**2.8**	**3.6**	**0.2**	**1.1**	**1.4**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2031 for 1P; 2039 for 2P and 3P.

[2] Total's net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Total's Net Entitlement.

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, RPS' totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

[4] Pre economic limit production forecast for 2P and 3P ends in year 2036 and 2039, respectively.

Table 6.7: Condensate Contingent Resources in MLJ Field as of 1 January 2023

SUMMARY OF CONTINGENT RESOURCES (BOE)
As of 1 January 2023
BASE CASE PRICES AND COSTS

Block B		Full Field Gross Contingent Resources[1] (MMboe)[3]			Net Entitlement Contingent Resources[2] (MMboe)[3]		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**Resources Post EL**	0.6	0.0[5]	0.0[5]	0.2	0.0[5]	0.0[5]
MLJ	**Workover**	0.4	0.6	0.9	0.2	0.2	0.3
MLJ	**Layer 3**	1.7	5.5	5.3	0.6	2.1	2.0
MLJ	**B1-15K**	2.0	7.3	8.4	0.8	2.7	3.1
MLJ	**Hibiscus Workover Plan**	1.0	4.8	3.7	0.4	1.8	1.4
Total[4]		**5.8**	**18.2**	**18.2**	**2.2**	**6.8**	**6.8**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2031 for 1P; 2039 for 2P and 3P.

[2] Total's net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Total's Net Entitlement.

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

[4] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, RPS' totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

[5] Pre economic limit production forecast for 2P and 3P ends in year 2036 and 2039, respectively.

Table 6.8: Summary of Oil Equivalent Contingent Resources in MLJ Field as of 1 January 2023

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	**8%**	**10%**	**12%**
1P+1C	2031	136	136	135	133
2P+2C	2039	329	267	254	241
3P+3C	2039	556	388	359	334

Table 6.9: Block B Reserves and Contingent Resources Post-Tax Valuation at RPS Base Case Price Scenario

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1C	2031	(4)	(4)	(4)	(4)
2C	2039	46	21	17	14
3C	2039	80	32	25	20

Table 6.10: Block B Contingent Resources Post-Tax Valuation at RPS Base Case Price Scenario

6.6 Sensitivity Analysis

A Low Price Case and High Price Case are also shown in Figure 6.2 in Money of the Day (MOD) and have been used for price sensitivity purposes on the RPS 2P case.

RPS has also analysed sensitivity of 2P NPV to discount rate (Figure 6.3). Sensitivity of 2P NPV or other key parameters is presented in Figure 6.4. In this analysis, the sensitivity to the key parameters is based on plus and minus of 20 per cent (except for oil price).

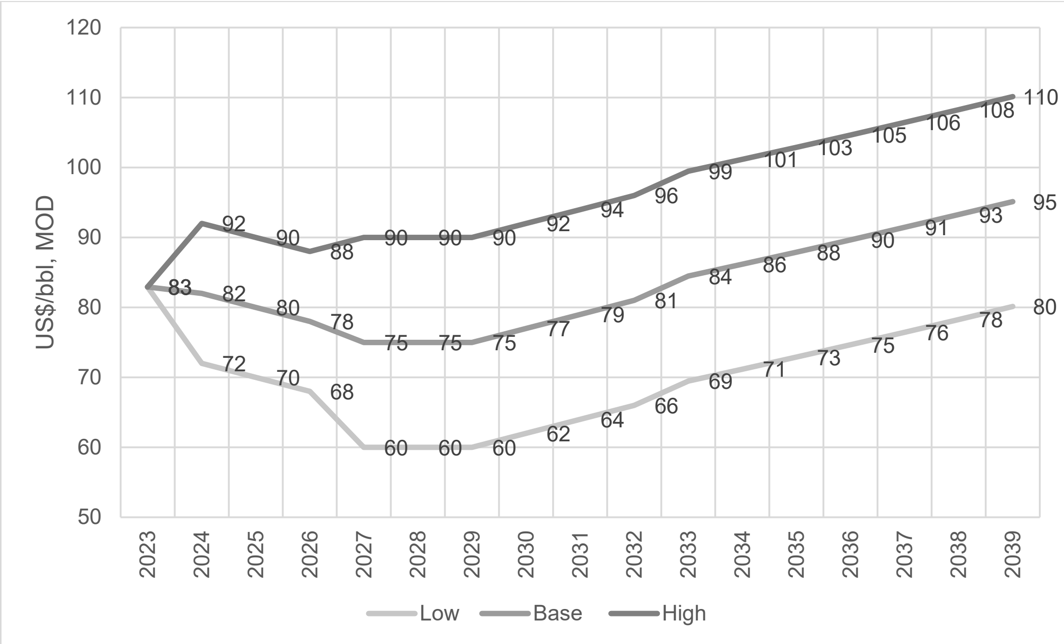

Figure 6.2: RPS Brent Price Forecasts (Q2 2024)

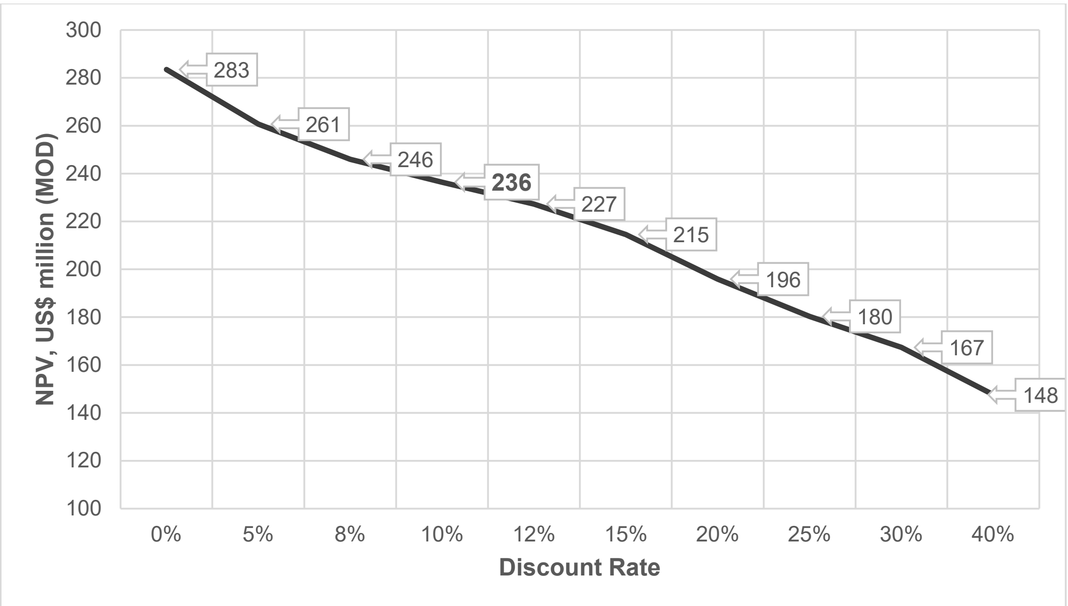

Figure 6.3: Summary of NPV of 2P Reserves as of 1 January 2023 (Sensitivity Analysis of Discount Rate)

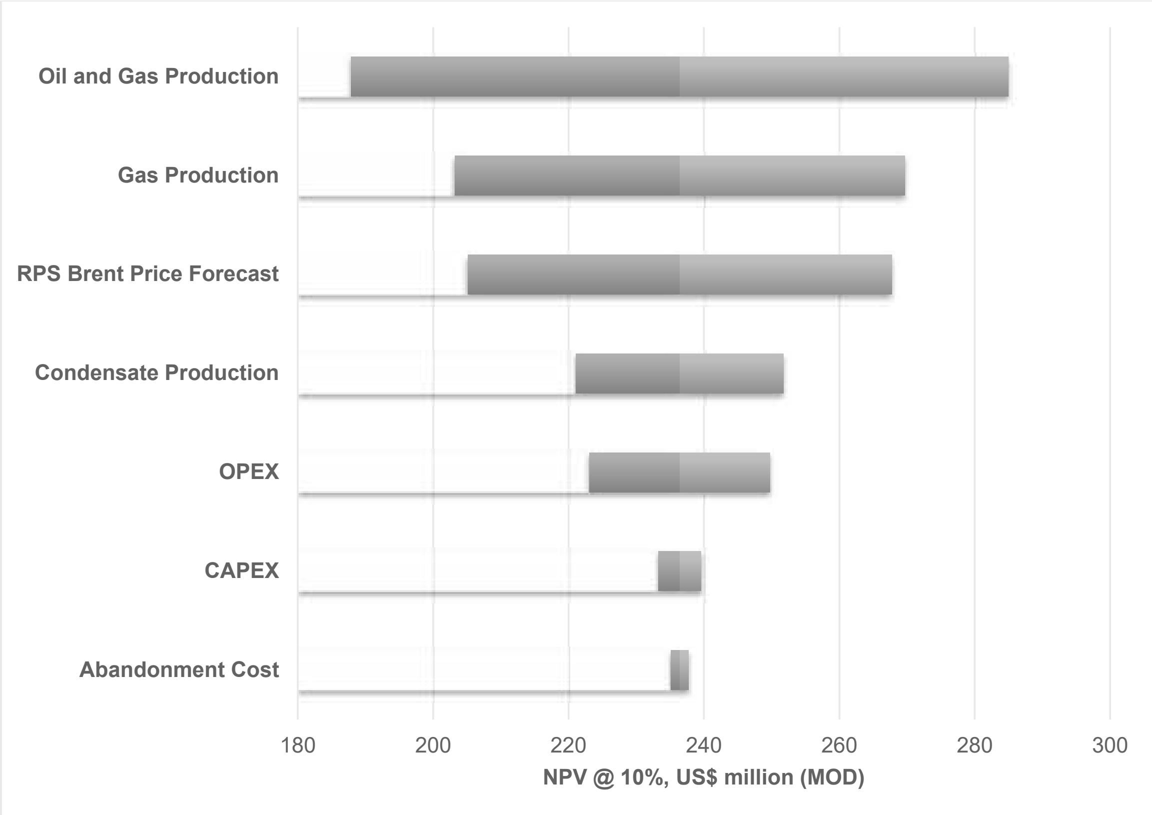

Figure 6.4: Summary of NPV of 2P Reserves as of 1 January 2023 (Sensitivity Analysis of Key Parameters, +/-20%; RPS Low and High Brent price forecast as per Figure 6.2)

6.7 Alternative Market Valuation

There are three Common Valuation Approaches recommended by The Australasian Code for the Public Reporting of Technical Assessments and Valuations of Mineral Assets (VALMIN Code) 2015 Edition[5]; namely the Income-based, Market-based, and Cost-based. Each valuation approach is defined in Section 8 of the VALMIN Code[6]. As outlined in Section 8.3 Appropriate Valuation Approach, VALMIN Code recommends Market and Income approach for Production Projects.

6.7.1 Income-based Approach

The valuation of the Asset, as presented in Section 6.4, was undertaken using Discounted Cash Flow (DCF) method, consistent with the industry standard of valuing Reserves and Resource according to the PRMS guidelines. This DCF method has similar principle with the Income-based approach defined by the VALMIN Code.

In order to determine the fair range of valuation based on this Income-based Approach, RPS has reviewed the range of discount rates to be applied to the valuation cash flow based on Hibiscus's Weighted Average Cost of Capital ("WACC") presented in Table 6.11. RPS has verified the WACC computation input and confirm these are consistent with information available in the public domain.

	D/E: 0.3x	D/E: 0.4x	D/E: 0.5x	D/E: 0.6x
Average Cost of Equity[1]	13.9%	13.9%	13.9%	13.9%
Pre-Tax Cost of Debt[2]	6.14%	6.14%	6.14%	6.14%
Petroleum Income Tax (PITA)	38%	38%	38%	38%
Post-Tax Cost of Debt	3.81%	3.81%	3.81%	3.81%
Target Debt/Equity	0.3	0.4	0.5	0.6
WACC	10.87%	9.86%	8.85%	7.84%

Notes:

[1] Based on 5 Year Average Cost of Equity (source: Hibiscus, Bloomberg as at 9 May 2024)

[2] Based on weighted average cost of debt as at end Feb 2024 and 5 Year Average Secured Overnight Financing Rate (SOFR) provided by Hibiscus

Table 6.11: Range of Hibiscus's Weighted Average Cost of Capital (WACC)

As the Asset is already in production phase, RPS believes it is reasonable not to add additional premium over the WACC. Therefore, RPS opines that a discount rate of 10 per cent is a fair rate to be applied for the purpose of current valuation for the Reserves. As summarized in Table 6.5, the Asset 2P NPV discounted at 10 per cent is **US$ 236 million**.

For the valuation of Contingent Resources, RPS opines that a discount rate of 12 per cent to be reasonable. As summarized in Table 6.10, the Asset 2C NPV discounted at 12 per cent is **US$ 14 million**. Therefore, total NPV for 2P and 2C at discount rate of 10 per cent and 12 per cent, respectively, is **US$ 250 million**.

[5] http://www.valmin.org/docs/VALMIN_Code_2015_final.pdf

[6] Market-based, which is based primarily on the notion of substitution. In this Valuation Approach the Mineral Asset being valued is compared with the transaction value of similar Mineral Assets under similar time and circumstance on an open market.

Income-based, which is based on the notion of cashflow generation. In this Valuation Approach the anticipated benefits of the potential income or cash flow of a Mineral Asset are analysed.

Cost-based, which is based on the notion of cost contribution to Value. In this Valuation Approach the costs incurred on the Mineral Asset are the basis of analysis.

Therefore, the reasonable range applying this Income-based Approach without net working capital and cash of US$ 14.4 million would be between US$ 236 million for Reserves and US$ 250 million for Reserves plus Contingent Resources.

The reasonable range applying this Income-based Approach together with net working capital and cash of US$ 14.4 million would be between **US$ 250.4 million** for Reserves and **US$ 264.4 million** for Reserves plus Contingent Resources**.**

The proposed acquisition of the entire equity interest of the TargetCo by Hibiscus for a cash consideration of **US$ 259.4 millio**n (including net working capital and cash of US$14.4 million, as at 31 December 2022), subject to the adjustments set out in share purchase agreement ("Purchase Consideration"), is within this estimated range based on Income-based Approach.

6.7.2 Market-based Approach

RPS' estimate of 2P Net Entitlement Reserves as of 1 January 2023 is 123 Bscf of gas, 3.7 MMstb of condensate and, assuming 6,000 scf/boe for the gas Reserves, translate to a total barrel of equivalent of 24.2 MMboe.

The valuation of the 2P Reserves at RPS Base Brent price and applying a 10% discount rate as of 1 January 2023 but excluding cash flow from Third Party Gas, is US$ 169 Million. The implied dollar per 2P barrel is therefore US$ 7.0/boe.

The valuation of 2C at RPS Base Brent price and applying a 12% discount rate as of 1 January 2023 but excluding cash flow from Third Party Gas, is US$ 14 Million. Total NPV for 2P plus 2C is therefore US$ 183 million and translates an implied dollar per 2P plus 2C barrel of 5.9/boe.

For the alternative valuation method, in this case the Market-based approach, by comparison to similar market transactions, we have reviewed the information of recent transactions in Malaysia, Indonesia and Thailand that are available in the public domains and considered those deals relating to producing fields for comparison with the current valuation.

A summary of the limited number of transactions in Malaysia, Indonesia, and Thailand, which completed in year 2018 and 2022 is presented in Table 6.12. Clearly, the market transactions tabulated would have been made under different price environments, as well as being concluded at different discount rates according to the respective buyers' investment strategy at the time the acquisitions were made.

Based on the information summarised in Table 6.12, the implied dollar per 2P barrel ranges between US$ 6.2/boe and US$ 17.3/boe. The current valuation with its implied dollar per 2P barrel of US$ 7.0/boe falls within this range. RPS opines that it would not be accurate to assume 100 per cent of the reported 2C Contingent Resources to derive the implied dollar per 2P plus 2C barrel, it is probably not unreasonable to assume a third of the 2C in deriving the deal metric based on information sourced from public domain. Based on this assumption, the implied dollar per 2P plus 2C barrel ranges between US$ 5.9/boe and US$10.7/boe. The current valuation with its implied dollar per 2P plus 2C barrel of US$ 5.9/boe falls within this range.

During the current commercial evaluation period between December 2023 and April 2024 in which the acquisition price of Total's asset was finalised, average Brent crude oil price is US$ 83 per barrel, which is approximately 18% more than when Repsol assets in Malaysia were acquired by Hibiscus. The implied dollar per 2P barrel price of US$ 6.2/boe for that transaction is the lowest of the transactions analysed in Table 6.12. If an 18% adjustment was applied to the Repsol transaction, the implied dollar per 2P barrel is US$ 7.2/boe.

The highest implied dollar per 2P plus 2C barrel of US$ 10.7/bbl is related to OMV Exploration and Production GmbH (OMV) acquisition of 50 per cent interest in Sapura Energy Berhad (SEB) Upstream Sdn Bhd (SUP) in January 2019. Brent crude oil price during current evaluation is approximately 19% more compared to when Sapura OMV transaction was completed. If we are to apply this 19% adjustment to Sapura OMW transaction, the implied dollar per 2P plus 2C barrel is US$ 12.7/boe

Therefore, applying these implied dollars per barrel to 2P and 2P plus 2C, the reasonable range of valuation would be between **US$ 242 million** and **US$ 461 million.**

The Purchase Consideration of USD 259.4 million is within this estimated range based on Market-based Approach.

No.	SPA Date	Asset name	Buyer(s)	Seller	Price (US$MM)	2P Reserves (MM boe)	2P Price (US$/boe)	2P+2C[1] (MM boe)	2P+2C Price (US$/boe)
1	June 2022	Concession L53/48[7]	Dialog Systems (Asia) Pte Ltd (DSAPL)	Pan Orient Energy Corp	38.7	4.6	8.4	-	-
2.	June 2021	Acquisition of Repsol Assets in Malaysia & Block 46, Vietnam	Peninsula Hibiscus Sdn Bhd	Repsol Malaysia	212.5	34.5	6.2	35.8	5.9
3.	January 2019	Acquisition of Ophir Energy plc[8]	PT Medco Energi Internasional Tbk	Ophir Energy plc	517[2]	70.1	7.4	-	-
4.	March 2019	Murphy Oil Corporation's Interests in Malaysia[9]	PTTEP Limited	Murphy Oil Corporation	2,127	169.3[3]	12.6	-	-
5.	November 2018	50 per cent interest in SEB Upstream Sdn Bhd (SUP)[10]	OMV Exploration and Production GmbH	Sapura Energy Berhad	800	46.1	17.3[3]	74.7	10.7
6.	May 2018	Acquisition of Santos's Southeast Asian production licences[11]	Ophir Energy plc	Santos Limited	205	23.3	8.8	-	-

Notes:

[1] 100% 2P plus a third of 2C

[2] Medco completed the acquisition of Ophir Energy plc in a recommended all cash offer valued at £408.4 million. GBP = 1.2663 US$ (Source: Bank of England)

[3] 2P of approximately 274 million boe, according to working interest. RPS has applied an average 61.8% factor to convert the working interest Reserves to 2P Net Entitlement Reserves. 2C Resources was not disclosed.

Table 6.12: Summary of Several Recent Transactions in Malaysia, Thailand and Indonesia

[7] https://www.nst.com.my/business/2022/06/802987/dialog-group-acquires-pan-orient-energy-rm170mil

[8] https://www.medcoenergi.com/en/subpagelist/view/12/2941

[9] https://www.pttep.com/en/Investorrelations/Regulatorfilings/Setnotification/Theacquisitionofmurphyoilcorporationsinterestsinmalaysia.aspx

[10] http://ir.chartnexus.com/sapuraenergy/onenew.php?id=2920472&type=Announcement

[11] https://www.ophir-energy.com/wp-content/uploads/2019/03/2018-Full-Year-Results.pdf

6.7.3 Fair Market Value

Based on the two Common Valuation Approaches recommended by VALMIN Code, namely the Income-based Approach and Market-based Approach, RPS opine the Fair Market Value of the Asset ranges between **US$ 242 million** and **US$ 461 million**.

The Purchase Consideration of USD 259.4 million is within this estimated range.

7 CONSULTANT'S INFORMATION

RPS Energy Limited confirms the following:

- 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, RPS 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 Total to Hibiscus. We have accepted, without independent verification, the accuracy and completeness of this data.

- The report represents RPS'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.

- RPS Energy Limited has been remunerated on a fee basis, not connected to asset or client financial performance, past or future, in any way.

- RPS Energy Limited confirms that there is no conflict of interest related to this work. Furthermore, the management and employees of RPS Energy Limited have no interest in any of these assets evaluated nor related with the analysis carried out as part of this report.

- RPS Energy Limited confirms also that neither it nor its management and employees have any interest in either the Vendor, Total, nor the potential Purchaser, Hibiscus Petroleum Berhad.

- All staff and associates working on this evaluation meet the professional qualifications requirements of a Qualified Reserves Auditor as specified in the SPE Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (June 2019):

  – A minimum of 10 years practical experience in petroleum engineering or petroleum geology or similar;

  – Have at least a bachelor's or advanced degree in Petroleum Engineering, Geology or other discipline of engineering or physical science;

  – Has received and is maintaining in good standing, a registered or certified professional licence or equivalent thereof from an appropriate governmental authority or professional organisation.

A summary of experience and relevant qualifications is provided in Table 7.1.

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
James Hodson	Project Manager and Geoscience Lead	15	PhD Sedimentology, University of East Anglia MSc Petroleum Geoscience and Management, University of Manchester BSc (Hons) Geology, University of Manchester	Fellow, Geological Society of London
Adolfo Perez	Reservoir Engineering Lead	>20	MSc Reservoir Evaluation and Management, Heriot Watt University MSc Geotechnical Engineering, University of Barcelona BSc (Hons) Geology, University of Barcelona	SPE AMEI
David Walker	Costs/Facilities Lead	>20	MEng Chemical Process Engineering University of Sheffield	
Joseph Tan	Economics Lead	>20	BEng (Hons.) Petroleum Engineering, Universiti Teknologi Malaysia, 2001	Member – SPE Member – South East Asia Petroleum Exploration Society (SEAPEX) Member and Malaysia Section Lead – Association of International Energy Negotiators (AIEN)

Table 7.1: 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.

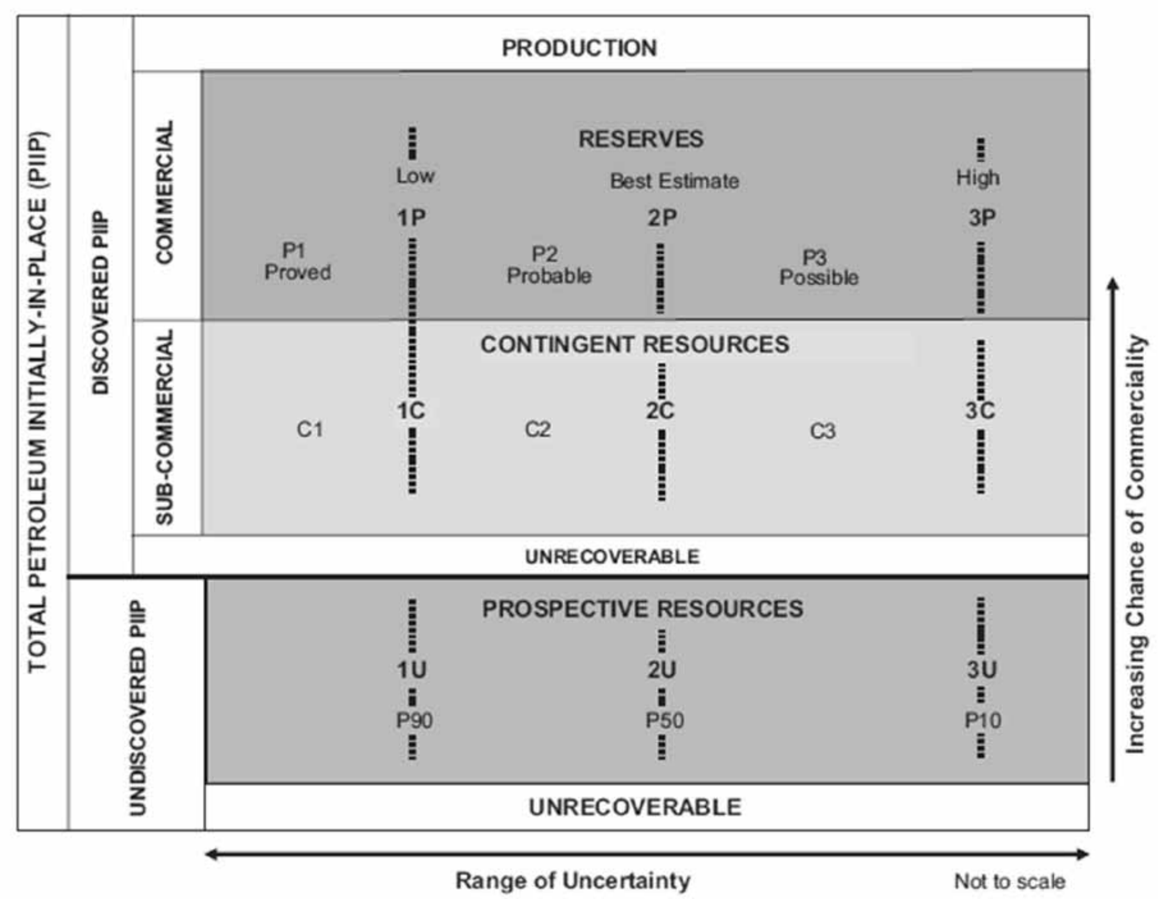

Figure A.1: Resources classification framework

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).

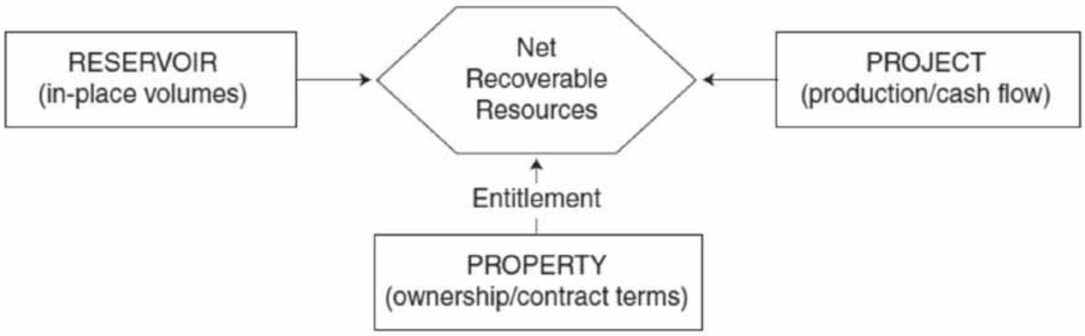

Figure A.2: Resources Evaluation

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.2 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.2.1 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.2.1.1 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.2.1.2 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.2.1.3 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.

B.2.1.3.1 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.

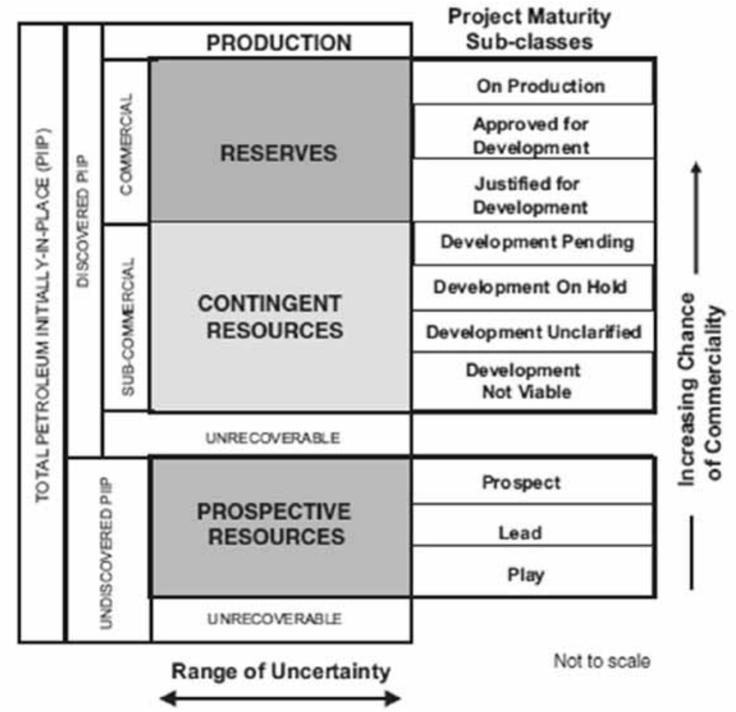

Figure A.3: Sub-classes based on project maturity

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.

B.2.1.3.2 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.

B.2.1.3.3 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.2.2 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.2.2.1 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.2.2.2 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.2.3 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.2.3.1 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.2.3.2 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.2.3.3 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.2.3.4 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.2.4 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

Appendix C
Cashflow Forecasts

1P		Total	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Block B (37.5%)		**Total**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Gross Daily Gas Production Rate	MMscfd	213 Bscf	96.7	97.6	73.4	81.4	81.4	73.4	47.9	30.8	-	-
Gross Daily Third Party Gas Rate	MMscfd	76 Bscf	40.7	33.7	28.1	27.1	27.1	24.5	16.0	10.3	-	-
Total Gross Daily Gas rate processed	MMscfd	288 Bscf	137.5	131.3	101.4	108.5	108.5	97.8	63.9	41.0	-	-
Net Daily Gas Sales	MMscfd	**80 Bscf**	36.3	36.6	27.5	30.5	30.5	27.5	18.0	11.5	-	-
Net Daily Condensate Production	Bcpd	**2 MMstb**	913.1	750.0	563.9	625.7	625.7	564.0	368.6	236.6	-	-
Net Condensate and Gas Production	**Boe/day**	**15 MMboe**	**6,958**	**6,848**	**5,149**	**5,713**	**5,713**	**5,150**	**3,365**	**2,161**	**-**	**-**
Brent Price	**$/bbl**		**82.4**	**82.0**	**80.0**	**78.0**	**75.0**	**75.0**	**75.0**	**77.0**	**-**	**-**
JKM LNG Price	**$/MMbtu**		**15.0**	**10.2**	**10.4**	**10.6**	**10.8**	**11.0**	**11.3**	**11.5**	**-**	**-**
Realized Gas Price	$/kscf		4.7	4.9	4.7	4.6	4.6	4.6	4.6	4.7	-	-
Realized Condensate Price	$/bbl		84.1	83.6	81.6	79.6	76.5	76.5	76.5	78.5	-	-
Total Revenue	**USD mm**	558	**98.3**	**96.9**	**70.2**	**76.4**	**74.7**	**67.7**	**44.5**	**29.3**	**-**	**-**
Royalty	**USD mm**	(45)	(7.9)	(7.7)	(5.6)	(6.1)	(6.0)	(5.4)	(3.6)	(2.3)	-	-
Opex	**USD mm**	(145)	(14.5)	(16.2)	(18.3)	(20.1)	(18.8)	(19.2)	(19.8)	(18.1)	-	-
Capex	**USD mm**	(69)	(25.2)	(33.6)	(8.6)	(0.4)	(0.4)	(0.1)	(0.1)	(0.1)	-	-
Abex	**USD mm**	(60)	-	-	-	-	-	-	-	-	(60.3)	-
Supplementary Payment	**USD mm**	(3)	(0.4)	(0.2)	(0.3)	(0.5)	(0.5)	(0.5)	(0.2)	(0.1)	0.0	-
Petroleum Income Tax	**USD mm**	(159)	-	(27.7)	(23.0)	(17.6)	(24.8)	(26.7)	(23.1)	(11.3)	(4.5)	-
Free Cash Flows from Third Party Gas	**USD mm**	62	**12.6**	**10.1**	**8.0**	**8.0**	**8.3**	**7.4**	**4.5**	**2.9**	**0.5**	**(0.2)**
Free Cash Flows to Total	**USD mm**	**140**	**63.0**	**21.6**	**22.4**	**39.6**	**32.4**	**23.3**	**2.2**	**0.2**	**(64.3)**	**(0.2)**

Table C.1: Production and Cashflow Forecast for Block B MLJ Field – 1P

2P																
Block B (37.5%)		**Total**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Gross Daily Gas Production Rate	MMscfd	328 Bscf	96.7	106.2	81.6	85.0	85.0	85.2	84.8	70.8	54.1	42.8	34.6	28.5	24.0	18.9	-
Gross Daily Third Party Gas Rate	MMscfd	113 Bscf	40.7	35.2	29.4	28.3	28.3	28.4	28.3	23.6	18.0	14.3	11.5	9.5	8.0	6.3	-
Total Gross Daily Gas rate processed	MMscfd	441 Bscf	137.5	141.5	111.0	113.3	113.3	113.7	113.1	94.4	72.2	57.1	46.1	38.1	32.0	25.1	-
Net Daily Gas Sales	MMscfd	**123 Bscf**	36.3	39.8	30.6	31.9	31.9	32.0	31.8	26.6	20.3	16.1	13.0	10.7	9.0	7.1	-
Net Daily Condensate Production	Bcpd	**4 MMstb**	913.1	1,225.0	940.9	980.3	980.3	983.0	978.1	816.6	624.2	493.9	398.6	329.2	276.5	217.5	-
Net Condensate and Gas Production	**Boe/day**	**24.2 MMboe**	**6,958**	**7,865**	**6,041**	**6,294**	**6,294**	**6,311**	**6,280**	**5,243**	**4,008**	**3,171**	**2,559**	**2,114**	**1,775**	**1,396**	**-**
Brent Price	**$/bbl**		**82.4**	**82.0**	**80.0**	**78.0**	**75.0**	**75.0**	**75.0**	**77.0**	**79.0**	**81.0**	**84.5**	**86.2**	**87.9**	**89.6**	**-**
JKM LNG Price	**$/MMbtu**		**15.0**	**10.2**	**10.4**	**10.6**	**10.8**	**11.0**	**11.3**	**11.5**	**11.7**	**12.0**	**12.2**	**12.4**	**12.7**	**12.9**	**-**
Realized Gas Price	$/kscf		4.7	4.9	4.7	4.6	4.6	4.6	4.6	4.7	4.9	5.0	5.1	5.2	5.3	5.4	-
Realized Condensate Price	$/bbl		84.1	83.6	81.6	79.6	76.5	76.5	76.5	78.5	80.6	82.6	86.2	87.9	89.6	91.4	-
Total Revenue	**USD mm**	962	**98.3**	**117.9**	**87.4**	**89.2**	**87.1**	**87.8**	**87.9**	**75.1**	**58.8**	**47.6**	**39.8**	**33.5**	**28.7**	**23.0**	**-**
Royalty	**USD mm**	(77)	(7.9)	(9.4)	(7.0)	(7.1)	(7.0)	(7.0)	(7.0)	(6.0)	(4.7)	(3.8)	(3.2)	(2.7)	(2.3)	(1.8)	-
Opex	**USD mm**	(262)	(14.5)	(16.8)	(19.0)	(20.7)	(19.5)	(20.2)	(21.6)	(18.2)	(17.3)	(19.8)	(26.0)	(17.6)	(16.6)	(14.3)	-
Capex	**USD mm**	(69)	(25.2)	(33.6)	(8.6)	(0.4)	(0.4)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.1)	(0.1)	-	-
Abex	**USD mm**	(68)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67.9)
Supplementary Payment	**USD mm**	(6)	(0.4)	(0.4)	(0.5)	(0.6)	(0.7)	(0.7)	(0.7)	(0.6)	(0.4)	(0.3)	(0.1)	(0.2)	(0.1)	(0.1)	-
Petroleum Income Tax	**USD mm**	(297)	-	(27.7)	(33.4)	(25.9)	(31.0)	(32.6)	(32.7)	(32.2)	(27.7)	(19.9)	(12.8)	(5.5)	(6.9)	(5.0)	(3.5)
Free Cash Flows from Third Party Gas	**USD mm**	100	**12.6**	**11.4**	**8.9**	**8.9**	**9.2**	**9.4**	**9.5**	**7.7**	**5.8**	**4.8**	**3.9**	**3.3**	**2.9**	**2.2**	**(0.5)**
Free Cash Flows to Total	**USD mm**	**283**	**63.0**	**41.4**	**27.9**	**43.3**	**37.8**	**36.6**	**35.2**	**25.7**	**14.4**	**8.4**	**1.3**	**10.8**	**5.5**	**4.1**	**(72.0)**

Table C.2: Production and Cashflow Forecast for Block B MLJ Field – 2P

3P																				
Block B (37.5%)		**Total**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Gross Daily Gas Production Rate	MMscfd	432 Bscf	96.7	113.9	88.8	87.7	87.7	88.0	87.7	87.7	84.8	70.3	58.6	50.4	44.2	39.5	35.5	32	30	-
Gross Daily Third Party Gas Rate	MMscfd	147 Bscf	40.7	36.7	30.6	29.2	29.2	29.3	29.2	29.2	28.3	23.4	19.5	16.8	14.7	13.2	11.8	11	10	-
Total Gross Daily Gas rate processed	MMscfd	579 Bscf	137.5	150.7	119.4	117.0	117.0	117.3	117.0	117.0	113.1	93.7	78.2	67.2	59.0	52.6	47.3	43	40	-
Net Daily Gas Sales	MMscfd	**162 Bscf**	36.3	42.7	33.3	32.9	32.9	33.0	32.9	32.9	31.8	26.4	22.0	18.9	16.6	14.8	13.3	12	11	
Net Daily Condensate Production	Bcpd	**6 MMstb**	913.1	1,751.8	1,365.4	1,348.8	1,348.8	1,352.5	1,348.8	1,348.8	1,304.0	1,080.9	901.7	775.2	679.9	607.0	545.6	497	456	
Net Condensate and Gas Production	**Boe/day**	**33.4 MMboe**	**6,958.3**	**8,873.0**	**6,915.9**	**6,831.6**	**6,831.6**	**6,850.3**	**6,831.6**	**6,831.6**	**6,604.7**	**5,475.0**	**4,567.2**	**3,926.5**	**3,443.6**	**3,074.5**	**2,763.3**	2,515	2,308	
Brent Price	**$/bbl**		**82.4**	**82.0**	**80.0**	**78.0**	**75.0**	**75.0**	**75.0**	**77.0**	**79.0**	**81.0**	**84.5**	**86.2**	**87.9**	**89.6**	**91.4**	93	95	
JKM LNG Price	**$/MMbtu**		**15.0**	**10.2**	**10.4**	**10.6**	**10.8**	**11.0**	**11.3**	**11.5**	**11.7**	**12.0**	**12.2**	**12.4**	**12.7**	**12.9**	**13.2**	13	14	
Realized Gas Price	$/kscf		4.7	4.9	4.7	4.6	4.6	4.6	4.6	4.7	4.9	5.0	5.1	5.2	5.3	5.4	5.5	6	6	
Realized Condensate Price	$/bbl		84.1	83.6	81.6	79.6	76.5	76.5	76.5	78.5	80.6	82.6	86.2	87.9	89.6	91.4	93.3	95	97	
Total Revenue	**USD mm**	1,424	**98.3**	**139.8**	**105.3**	**101.9**	**99.3**	**100.1**	**100.3**	**102.7**	**101.7**	**86.3**	**74.7**	**65.5**	**58.5**	**53.3**	**48.8**	45	42	
Royalty	**USD mm**	(114)	(7.9)	(11.2)	(8.4)	(8.2)	(7.9)	(8.0)	(8.0)	(8.2)	(8.1)	(6.9)	(6.0)	(5.2)	(4.7)	(4.3)	(3.9)	(4)	(3)	-
Opex	**USD mm**	(333)	(14.5)	(17.5)	(19.8)	(21.3)	(20.1)	(20.8)	(22.2)	(19.6)	(19.2)	(20.0)	(27.1)	(18.4)	(18.7)	(17.1)	(18.9)	(19)	(19)	
Capex	**USD mm**	(70)	(25.2)	(33.6)	(8.6)	(0.4)	(0.4)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)	(0)	(0)	
Abex	**USD mm**	(72)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(72)
Supplementary Payment	**USD mm**	(9)	(0.4)	(0.6)	(0.6)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.7)	(0.5)	(0.5)	(0.4)	(0.4)	(0.3)	(0)	(0)	
Petroleum Income Tax	**USD mm**	(491)	-	(27.7)	(44.1)	(34.5)	(37.1)	(38.5)	(38.6)	(38.2)	(40.9)	(40.6)	(32.4)	(22.5)	(22.6)	(19.0)	(17.2)	(14)	(12)	(11)
Free Cash Flows from Third Party Gas	**USD mm**	141	**12.6**	**12.7**	**9.8**	**9.6**	**10.0**	**10.2**	**10.3**	**10.5**	**10.3**	**8.3**	**7.1**	**6.3**	**5.6**	**5.1**	**4.7**	4	4	(1)
Free Cash Flows to Total	**USD mm**	**476**	**63.0**	**62.1**	**33.6**	**46.4**	**43.0**	**42.1**	**40.9**	**46.3**	**42.8**	**26.4**	**15.6**	**24.9**	**17.6**	**17.5**	**13.1**	**12.6**	**11.8**	**(84.2)**

Table C.3: Production and Cashflow Forecast for Block B MLJ Field – 3P

1P + 1C													
Block B (37.5%)		**Total**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Gross Daily Gas Production Rate	MMscfd	244 Bscf	96.7	97.6	73.4	81.4	81.4	84.1	69.1	44.1	39.9	-	-
Gross Daily Third Party Gas Rate	MMscfd	77 Bscf	40.7	33.7	28.1	27.1	27.1	24.5	16.0	10.3	3.1	-	-
Total Gross Daily Gas rate processed	MMscfd	321 Bscf	137.5	131.3	101.4	108.5	108.5	108.5	85.1	54.3	43.0	-	-
Net Daily Gas Sales	MMscfd	**91 Bscf**	36.3	36.6	27.5	30.5	30.5	31.5	25.9	16.5	15.0	-	-
Net Daily Condensate Production	Bcpd	**2 MMstb**	913.1	750.0	563.9	625.7	625.7	646.2	531.5	338.6	306.6	-	-
Net Condensate and Gas Production	**Boe/day**	**17 MMboe**	**6,958.3**	**6,847.8**	**5,148.7**	**5,712.9**	**5,712.9**	**5,899.4**	**4,852.2**	**3,091.9**	**2,799.7**	**-**	**-**
Brent Price	**$/bbl**		**82.4**	**82.0**	**80.0**	**78.0**	**75.0**	**75.0**	**75.0**	**77.0**	**79.0**	**-**	**-**
JKM LNG Price	**$/MMbtu**		**15.0**	**10.2**	**10.4**	**10.6**	**10.8**	**11.0**	**11.3**	**11.5**	**11.7**	**-**	**-**
Realized Gas Price	$/kscf		4.7	4.9	4.7	4.6	4.6	4.6	4.6	4.7	4.9	-	-
Realized Condensate Price	$/bbl		84.1	83.6	81.6	79.6	76.5	76.5	76.5	78.5	80.6	-	-
Total Revenue	**USD mm**	639	**98.3**	**96.9**	**70.2**	**76.4**	**74.7**	**77.6**	**64.2**	**41.9**	**38.8**	**-**	**-**
Royalty	**USD mm**	(51)	(7.9)	(7.7)	(5.6)	(6.1)	(6.0)	(6.2)	(5.1)	(3.4)	(3.1)	-	-
Opex	**USD mm**	(163)	(14.5)	(16.2)	(18.3)	(20.1)	(18.8)	(19.6)	(20.3)	(18.2)	(16.6)	-	-
Capex	**USD mm**	(142)	(25.2)	(33.6)	(8.6)	(0.4)	(28.5)	(36.6)	(0.1)	(8.7)	(0.1)	-	-
Abex	**USD mm**	(62)	-	-	-	-	-	-	-	-	-	(61.5)	-
Supplementary Payment	**USD mm**	(2)	(0.4)	(0.2)	(0.3)	(0.5)	(0.0)	0.1	(0.4)	(0.1)	(0.2)	0.1	0.0
Petroleum Income Tax	**USD mm**	(146)	-	(27.7)	(23.0)	(17.6)	(24.8)	(12.4)	(8.3)	(17.7)	(4.9)	(9.8)	-
Free Cash Flows from Third Party Gas	**USD mm**	62	**12.6**	**10.1**	**8.0**	**8.0**	**8.3**	**7.4**	**4.5**	**2.9**	**0.5**	**(0.2)**	**-**
Free Cash Flows to Total	**USD mm**	**136**	**63.0**	**21.6**	**22.4**	**39.6**	**4.8**	**10.3**	**34.5**	**(3.3)**	**14.4**	**(71.5)**	**0.0**

Table C.4: Production and Cashflow Forecast for Block B MLJ Field – 1P + 1C

2P + 2C																				
Block B (37.5%)		**Total**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Gross Daily Gas Production Rate	MMscfd	420 Bscf	96.7	106.2	81.6	85.0	85.0	85.2	85.1	89.7	86.2	65.1	59.3	45.5	43.9	34.2	39.9	30.8	31.8	-
Gross Daily Third Party Gas Rate	MMscfd	113 Bscf	40.7	35.2	29.4	28.3	28.3	28.4	28.3	23.6	18.0	14.3	11.5	9.5	8.0	6.3	-	-	-	-
Total Gross Daily Gas rate processed	MMscfd	533 Bscf	137.5	141.5	111.0	113.3	113.3	113.7	113.3	113.3	104.2	79.4	70.8	55.0	51.9	40.5	39.9	30.8	31.8	-
Net Daily Gas Sales	MMscfd	**158 Bscf**	36.3	39.8	30.6	31.9	31.9	32.0	31.9	33.7	32.3	24.4	22.2	17.1	16.5	12.8	15.0	11.5	11.9	
Net Daily Condensate Production	Bcpd	**5 MMstb**	913.1	1,225.0	940.9	980.3	980.3	983.0	981.0	1,034.9	993.7	750.6	683.3	524.6	506.7	394.3	460.2	354.8	366.2	
Net Condensate and Gas Production	**Boe/day**	**31 MMboe**	**6,958.3**	**7,864.5**	**6,040.9**	**6,293.5**	**6,293.5**	**6,310.8**	**6,298.2**	**6,643.9**	**6,379.9**	**4,818.7**	**4,387.0**	**3,368.0**	**3,253.2**	**2,531.2**	**2,954.7**	**2,278.0**	**2,351.3**	
Brent Price	**$/bbl**		**82.4**	**82.0**	**80.0**	**78.0**	**75.0**	**75.0**	**75.0**	**77.0**	**79.0**	**81.0**	**84.5**	**86.2**	**87.9**	**89.6**	**91.4**	**93.3**	**95.1**	
JKM LNG Price	**$/MMbtu**		**15.0**	**10.2**	**10.4**	**10.6**	**10.8**	**11.0**	**11.3**	**11.5**	**11.7**	**12.0**	**12.2**	**12.4**	**12.7**	**12.9**	**13.2**	**13.5**	**13.7**	
Realized Gas Price	$/kscf		4.7	4.9	4.7	4.6	4.6	4.6	4.6	4.7	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.8	
Realized Condensate Price	$/bbl		84.1	83.6	81.6	79.6	76.5	76.5	76.5	78.5	80.6	82.6	86.2	87.9	89.6	91.4	93.3	95.1	97.0	
Total Revenue	**USD mm**	1,263	**98.3**	**117.9**	**87.4**	**89.2**	**87.1**	**87.8**	**88.1**	**95.2**	**93.6**	**72.4**	**68.3**	**53.5**	**52.6**	**41.8**	**49.7**	**39.1**	**41.1**	
Royalty	**USD mm**	(101)	(7.9)	(9.4)	(7.0)	(7.1)	(7.0)	(7.0)	(7.0)	(7.6)	(7.5)	(5.8)	(5.5)	(4.3)	(4.2)	(3.3)	(4.0)	(3.1)	(3.3)	-
Opex	**USD mm**	(324)	(14.5)	(16.8)	(19.0)	(20.7)	(19.5)	(20.2)	(21.6)	(19.0)	(18.3)	(19.1)	(26.6)	(19.2)	(16.9)	(16.7)	(18.6)	(18.7)	(18.2)	
Capex	**USD mm**	(174)	(25.2)	(33.6)	(8.6)	(0.4)	(0.4)	(6.4)	(51.7)	(8.7)	(0.1)	(9.1)	(0.1)	(9.5)	(0.1)	(9.8)	(0.1)	(10.2)	(0.1)	
Abex	**USD mm**	(72)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(72.1)
Supplementary Payment	**USD mm**	(6)	(0.4)	(0.4)	(0.5)	(0.6)	(0.7)	(0.6)	0.2	(0.6)	(0.7)	(0.4)	(0.4)	(0.2)	(0.3)	(0.1)	(0.3)	(0.1)	(0.2)	
Petroleum Income Tax	**USD mm**	(357)	-	(27.7)	(33.4)	(25.9)	(31.0)	(32.6)	(29.6)	(6.9)	(30.5)	(34.0)	(21.2)	(19.2)	(11.6)	(16.6)	(7.1)	(14.2)	(4.9)	(10.3)
Free Cash Flows from Third Party Gas	**USD mm**	100	**12.6**	**11.4**	**8.9**	**8.9**	**9.2**	**9.4**	**9.5**	**7.7**	**5.8**	**4.8**	**3.9**	**3.3**	**2.9**	**2.2**	**(0.5)**	**-**	**-**	**-**
Free Cash Flows to Total	**USD mm**	**329**	**63.0**	**41.4**	**27.9**	**43.3**	**37.8**	**30.4**	**(12.1)**	**60.2**	**42.3**	**8.7**	**18.4**	**4.4**	**22.3**	**(2.6)**	**19.1**	**(7.2)**	**14.4**	**(82.4)**

Table C.5: Production and Cashflow Forecast for Block B MLJ Field – 2P + 2C

3P + 3C																			
Block B (37.5%)		**Total**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Gross Daily Gas Production Rate	MMscfd	520 Bscf	96.7	113.9	88.8	87.7	87.7	88.0	87.7	87.7	88.7	93.9	97.2	90.3	77.4	70.6	61.2	56.9	49.9	-
Gross Daily Third Party Gas Rate	MMscfd	147 Bscf	40.7	36.7	30.6	29.2	29.2	29.3	29.2	29.2	28.3	23.4	19.5	16.8	14.7	13.2	11.8	10.8	9.9	-
Total Gross Daily Gas rate processed	MMscfd	667 Bscf	137.5	150.7	119.4	117.0	117.0	117.3	117.0	117.0	117.0	117.3	116.8	107.1	92.1	83.7	73.0	67.6	59.8	-
Net Daily Gas Sales	MMscfd	**195 Bscf**	36.3	42.7	33.3	32.9	32.9	33.0	32.9	32.9	33.3	35.2	36.5	33.9	29.0	26.5	22.9	21.3	18.7	
Net Daily Condensate Production	Bcpd	**8 MMstb**	913.1	1,751.8	1,365.4	1,348.8	1,348.8	1,352.5	1,348.8	1,348.8	1,363.7	1,443.0	1,495.2	1,388.0	1,189.5	1,085.2	940.3	874.1	766.9	
Net Condensate and Gas Production	**Boe/day**	**40 MMboe**	**6,958.3**	**8,873.0**	**6,915.9**	**6,831.6**	**6,831.6**	**6,850.3**	**6,831.6**	**6,831.6**	**6,907.2**	**7,308.7**	**7,573.3**	**7,030.4**	**6,025.0**	**5,496.4**	**4,762.6**	**4,427.6**	**3,884.6**	
Brent Price	**$/bbl**		**82.4**	**82.0**	**80.0**	**78.0**	**75.0**	**75.0**	**75.0**	**77.0**	**79.0**	**81.0**	**84.5**	**86.2**	**87.9**	**89.6**	**91.4**	**93.3**	**95.1**	
JKM LNG Price	**$/MMbtu**		**15.0**	**10.2**	**10.4**	**10.6**	**10.8**	**11.0**	**11.3**	**11.5**	**11.7**	**12.0**	**12.2**	**12.4**	**12.7**	**12.9**	**13.2**	**13.5**	**13.7**	
Realized Gas Price	$/kscf		4.7	4.9	4.7	4.6	4.6	4.6	4.6	4.7	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.8	
Realized Condensate Price	$/bbl		84.1	83.6	81.6	79.6	76.5	76.5	76.5	78.5	80.6	82.6	86.2	87.9	89.6	91.4	93.3	95.1	97.0	
Total Revenue	**USD mm**	1,744	**98.3**	**139.8**	**105.3**	**101.9**	**99.3**	**100.1**	**100.3**	**102.7**	**106.4**	**115.2**	**123.8**	**117.2**	**102.4**	**95.3**	**84.2**	**79.8**	**71.4**	
Royalty	**USD mm**	(139)	(7.9)	(11.2)	(8.4)	(8.2)	(7.9)	(8.0)	(8.0)	(8.2)	(8.5)	(9.2)	(9.9)	(9.4)	(8.2)	(7.6)	(6.7)	(6.4)	(5.7)	-
Opex	**USD mm**	(340)	(14.5)	(17.5)	(19.8)	(21.3)	(20.1)	(20.8)	(22.2)	(19.6)	(19.4)	(21.0)	(28.7)	(19.8)	(18.4)	(18.0)	(19.5)	(21.1)	(18.8)	
Capex	**USD mm**	(170)	(25.2)	(33.6)	(8.6)	(0.4)	(0.4)	(0.1)	(0.1)	(0.1)	(6.8)	(54.8)	(9.3)	(0.1)	(9.6)	(0.1)	(10.0)	(0.1)	(10.4)	
Abex	**USD mm**	(72)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(72.1)
Supplementary Payment	**USD mm**	(11)	(0.4)	(0.6)	(0.6)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.1)	(0.8)	(0.9)	(0.7)	(0.8)	(0.5)	(0.6)	(0.4)	
Petroleum Income Tax	**USD mm**	(596)	-	(27.7)	(44.1)	(34.5)	(37.1)	(38.5)	(38.6)	(38.2)	(40.9)	(39.7)	(20.9)	(39.6)	(45.1)	(36.9)	(37.6)	(27.0)	(28.3)	(21.2)
Free Cash Flows from Third Party Gas	**USD mm**	141	**12.6**	**12.7**	**9.8**	**9.6**	**10.0**	**10.2**	**10.3**	**10.5**	**10.3**	**8.3**	**7.1**	**6.3**	**5.6**	**5.1**	**4.7**	**4.4**	**4.1**	**(0.9)**
Free Cash Flows to Total	**USD mm**	**556**	**63.0**	**62.1**	**33.6**	**46.4**	**43.0**	**42.1**	**40.9**	**46.3**	**40.3**	**(1.3)**	**61.4**	**53.6**	**26.0**	**37.0**	**14.6**	**29.0**	**11.9**	**(94.2)**

Table C.6: Production and Cashflow Forecast for Block B MLJ Field – 3P + 3C

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MAKING COMPLEX EASY
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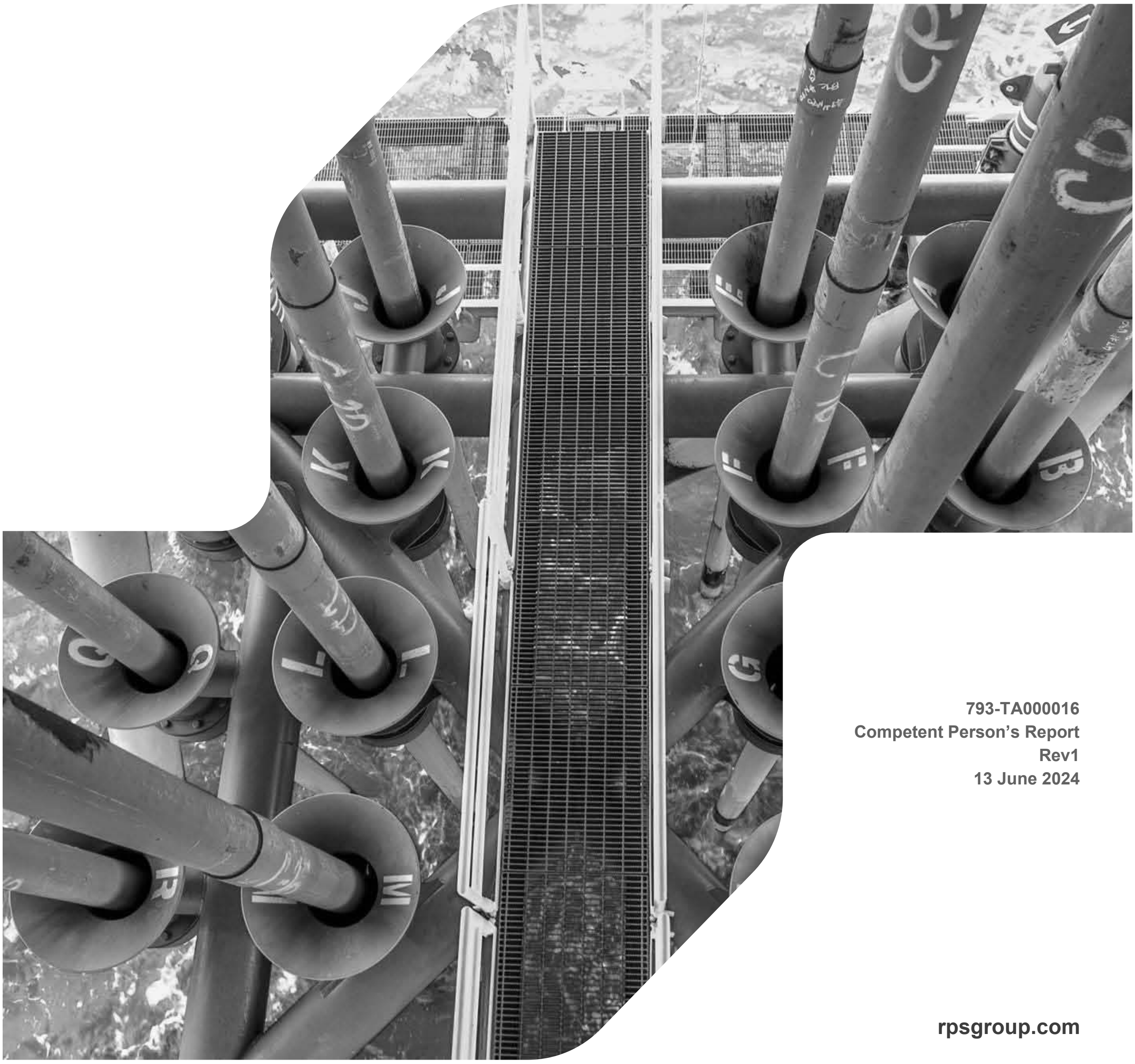
COMPETENT PERSON'S REPORT ON MAHARAJALELA JAMALULALAM FIELD

BLOCK B, OFFSHORE BRUNEI



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Rev1
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Version	Purpose of document	Authored by	Reviewed by	Approved by	Review date
Rev0	Final draft	GT, JH, AP, DE, DW, JT	GT	GT	27/05/2024
Rev1	Final	GT, JH, AP, DE, DW, JT	GT	GT	13/06/2024

Approval for issue

Gordon Taylor		13 June 2024

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Dear Sirs,

COMPETENT PERSON'S REPORT ON MAHARAJALELA JAMALULALAM FIELD, OFFSHORE BRUNEI

In response to a request by Hibiscus Petroleum Berhad ("Hibiscus"), and the Letter of Engagement dated 2nd January 2024 with Hibiscus (the "Agreement"), RPS Energy Limited ("RPS") has completed an independent evaluation of the Maharajalela Jamalulalam (MLJ) Field, in Block B offshore Brunei. The field is currently operated by TotalEnergies EP (Brunei) B.V. ("TargetCo"). TotalEnergies Holdings International B.V. ("Total" or "Vendor") being the holding company of the TargetCo, is seeking to divest TargetCo.

This report is issued by RPS 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.

We have estimated Proved, Probable and Possible Reserves and 1C, 2C and 3C Contingent Resources as of 1 January 2023. All Reserves and Resources definitions and estimates shown in this report are based on the PRMS and reported to the Securities Commission of Malaysia regulations. The work was undertaken by a team of petroleum engineers, geoscientists and economists and is based on data supplied by Hibiscus. Our approach has been to audit data made available in a virtual dataroom ("VDR") by Total who are looking to dispose of the asset.

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.

We have taken the working interest in the MLJ Field as presented by Total in the VDR. We have not investigated, nor do we make any warranty as to Hibiscus interest in the asset.

A site visit was not conducted.

Prospective Resources volumes have not been evaluated by RPS as they are outside the scope of this report.

RPS estimates of Reserves and Contingent Resources are provided in the Executive Summary and in Section 8.5.

QUALIFICATIONS

RPS is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. The provision of professional services has been solely on a fee basis. Gordon Taylor, Technical Director, has supervised this evaluation. Gordon is a Chartered Geologist and Chartered Engineer with over 40 years' experience] in upstream oil and gas. The project has been managed on a day-to-day basis by James Hodson who has 12 years' experience in upstream oil and gas. Other RPS 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, RPS 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 RPS'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 RPS.

Yours sincerely,
for RPS Energy Ltd

Gordon Taylor
Technical Director

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Name	Role	Signature
James Hodson	Project Manager and Geoscience Lead	
Adolfo Perez	Reservoir Engineering Lead	
David Walker	Facilities and Costs Lead	
Joseph Tan	Economics Lead	

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APPENDICES

1 EXECUTIVE SUMMARY

In response to a request by Hibiscus Petroleum Berhad ("Hibiscus"), and the Letter of Engagement dated 2 January 2024 with Hibiscus (the "Agreement"), RPS Energy Limited ("RPS") has completed an independent evaluation of the Maharajalela Jamalulalam ("MLJ") Field, in Block B offshore Brunei. The field is currently operated by TotalEnergies EP (Brunei) BV ("TargetCo"), TotalEnergies Holdings International B.V. ("Total" or "Vendor") being the holding company of the TargetCo, is seeking to divest TargetCo. The report is based on an audit of material made available by Total in a virtual dataroom (VDR).

1.1 Overview of Maharajalela Jamalulalam (MLJ) Field

Total is looking to dispose of its business in Brunei which is focused on offshore Block B. Block B offshore Brunei contains the MLJ field which was discovered in 1989 by the Maharajalela North well and which was appraised and developed in the 1990s with first gas in 1999. Since 1999 the field has been producing gas and condensate from three unmanned platforms in relatively shallow (less than 100 m) water depths. The field consists of a complex faulted system that is divided into elongated structural compartments. The northern panel (MLJ North) extends into a third party's licensed area.

The block has some remaining prospectivity according to the Vendor but a review of prospectivity was not within the scope of this project.

Given the nature of this audit a site visit was not undertaken.

For the purposes of this Report, Third Party Gas is gas and associated condensate for which the Block B Joint Venture ("BBJV") has been licensed by a third party, subject to payment of a Licence Fee thereto, to produce, process and sell.

All Reserves and Contingent Resource estimate herein are reported to PRMS 2018 standards. This report fulfils the requirements stipulated in Chapter 17, Part II, Division1 of the Securities Commission Malaysia's Prospectus Guidelines for a Competent Person's Report.

1.2 Health, Safety, Security and Environment ("HSSE")

Total claims to have an experienced team with in-depth knowledge of the assets and region and RPS understand much of this team will be retained as part of the transaction.

RPS remit was to focus on the production and cost forecast of the Vendor and, therefore, we have not reviewed the Total technical team or safety record.

Total is an international operator that adheres to stringent HSSE standards as indicated in their health-hygiene, safety, security, societal, environment & quality policy which it emphasises the following industry standard commitment:

- Protect the health, safety and security of personnel
- Protect the environment
- Safeguard our production facilities and assets
- Contribute to the sustainable development of neighbouring communities and addressing stakeholder expectations

1.3 Surface Review

There are three unmanned production platforms - MLJ1, MLJ2 and MLJ3. No processing occurs offshore, and multiphase production is exported to onshore processing plant ("OPP") at Lumut. At Lumut, gas and liquids are separated, and condensate and water stabilised at 60 barg and gas is processed to remove mercury and traces of H_2S. Gas is sent to Brunei LNG Sendirian Berhad ("BLNG") plant at 43 barg, and condensate and water exported to the Seria Crude Oil Terminal ("SCOT") at 20 barg.

A total of 22 exploration, appraisal and development wells have been drilled. In the final month of 2022, there were 15 wells producing gas from the MLJ field (four wells on the MLJ1 platform, five wells on the MLJ2 platform and six wells on the MLJ3 platform)[1].

1.4 Third Party Arrangement

The northern panel (MLJ North) extends into a third party's licensed area. Two reservoir layers (Layers 1 and 2) have been on production on agreed terms with the third party and future production from Layer 3 (via one of the existing wells) could be on the same terms.

RPS is not in a position to opine on the terms of the third-party arrangement, and it was not part of the scope of this report.

1.5 Subsurface and Resource Evaluation

The field comprises a complex faulted system that is divided into elongated structural compartments ("panels"), limited by major sealing normal faults. Hydrocarbons have been found in eight dynamically independent panels, each subdivided into tens of different reservoir levels of Late Miocene age. Pressure regimes vary with depth and age with highest pressures in the deepest reservoir in the northwesternmost panels.

During December 2022, production was from the following wells and panels:

- MLJ North panel production from wells MLJ1-06 and MLJ1-07
- JAM panel production from well MLJ1-02
- JMB panel production from perforations in MLJ1-01
- West panel production from wells MLJ1-01, MLJ2-01, MLJ2-02, MLJ2-03
- B1 panel production from well MLJ2-06
- A panel production from wells MLJ2-07, MLJ3-02 and MLJ3-06
- C1/C2 panel production from wells MLJ3-01 and MLJ3-03
- B2 panel production from wells MLJ3-04 and MLJ3-05:

RPS estimates of Reserves are provided in Table 1.1 to Table 1.3 and RPS estimates of Contingent Resources in Table 1.4 to Table 1.6.

1.6 Economic Analysis

The Economic Limit Test ("ELT") performed for the determination of Reserves is based on RPS's estimates of recoverable volumes, a review of the Company's estimates of Capex, Opex, and Abex; and inclusion of other financial information and assumptions, as outlined in Section 7.

The licences are assumed to reach its economic limit when the cumulative value of its net cash flow (excluding Abex) before tax ceases to increase. All projects to be classified as Reserves must be economic

[1] At the end of 2023 (Dec 2023) there are 11 wells producing gas. Two wells in the MLJ1 platform (MLJ1-06 and MLJ1-07), four wells in the MLJ2 platform (MLJ2-01, MLJ2-02, MLJ2-06 and MLJ2-07) and five wells in the MLJ3 platform (MLJ3-01, MLJ3-02, MLJ3-04, MLJ3-05 and MLJ3-06, with MLJ3-03 shut in due to intervention).

under defined conditions[2]. RPS has therefore assessed the future economic viability of each case on the basis of its pre-tax undiscounted Net Cash Flow Money Of the Day ("MOD").

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

The effective date of this report is 1 January 2023.

1.7 Reserves and Contingent Resources Summary

A summary of Reserves is provided in Table 1.1 to Table 1.3 for Gas, Condensate, and Barrels of Oil Equivalent, respectively.

Third Party Gas which is produced, processed and sold by BBJV (and is net to the TargetCo) is included in the production and cost profiles, and impacts economics, but is not included as Reserves or Contingent Resources by RPS in this Report.

SUMMARY OF GAS RESERVES
As of 1 January 2023
BASE CASE PRICES AND COSTS

	Full Field Gross Resources[1] (Bscf)			Net Entitlement Reserves[2] (Bscf)		
	1P	2P	3P	1P	2P	3P
MLJ	213	328	432	80	123	162

Notes:
*[1] Gross field Reserves (100% basis) **after** economic limit test. Economic limit in year 2030 for 1P; 2036 for 2P and 2039 3P.*
[2] Total's net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Total's Net Entitlement.

Table 1.1: Gas Reserves in MLJ Field as of 1 January 2023

SUMMARY OF CONDENSATE RESERVES
As of 1 January 2023
BASE CASE PRICES AND COSTS

	Full Field Gross Resources[1] (MMstb)			Net Entitlement Reserves[2] (MMstb)		
	1P	2P	3P	1P	2P	3P
MLJ	4.5	9.9	17.2	1.7	3.7	6.4

Notes:
*[1] Gross field Reserves (100% basis) **after** economic limit test. Economic limit in year 2030 for 1P; 2036 for 2P and 2039 3P.*
[2] Total's net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Total's Net Entitlement.

Table 1.2: Condensate Reserves in MLJ Field as of 1 January 2023

[2] 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.

SUMMARY OF RESERVES (BOE)
As of 1 January 2023
BASE CASE PRICES AND COSTS

	Full Field Gross Resources[1] (MMboe)[3]			Net Entitlement Reserves[2] (MMboe)[3]		
	1P	2P	3P	1P	2P	3P
MLJ	40.0	64.5	89.2	15.0	24.2	33.4

Notes:

*[1] Gross field Reserves (100% basis) **after** economic limit test. Economic limit in year 2030 for 1P; 2036 for 2P and 2039 3P.*

[2] Total's net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Total's Net Entitlement.

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

Table 1.3: Oil Equivalent Reserves in MLJ Field as of 1 January 2023

A summary of Contingent Resources is presented in Table 1.4 to Table 1.6.

SUMMARY OF GAS CONTINGENT RESOURCES
As of 1 January 2023
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (Bscf)			Net Entitlement Contingent Resources[2] (Bscf)		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**Resources Post EL**	3.4	0.0[5]	0.0[5]	1.3	0.0[5]	0.0[5]
MLJ	**Workover**	2.2	3.2	4.4	0.8	1.2	1.7
MLJ	**Layer 3**	9.2	27.9	25.3	3.4	10.5	9.5
MLJ	**B1-15K**	10.9	36.9	40.4	4.1	13.8	15.2
MLJ	**Hibiscus Workover Plan**	5.4	24.3	17.7	2.0	9.1	6.6
Total[3, 4]		**31.0**	**92.3**	**87.8**	**11.6**	**34.6**	**32.9**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2031 for 1P; 2039 for 2P and 3P.

[2] Total's net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore is not deducted from Total's Net Entitlement.

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, RPS' totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

[4] It should be noted that all RPS forecasts are cut off at 2039. Contingent projects are assumed to be added to the NFA production when is required. However, total production is constrained by compressor capacity limits. Certain contingent projects are delayed in the RPS forecasts until there is compressor capacity available. In the high case, the NFA forecasts are sufficiently high that a smaller volume of contingent production is required than in the base case before the compressor capacity is reached. This means the high case contingent volume is smaller than the base case volume. If, however, the forecasts are extended beyond 2039 the 3C volumes are always higher than the 2C volumes as capacity becomes available. Table 6.7 shows the technically recoverable low, best, and high case volumes if production extends to 2059.

[5] Pre-economic limit production forecast for 2P and 3P ends in year 2036 and 2039, respectively.

Table 1.4: Gas Contingent Resources in MLJ Field as of 1 January 2023

SUMMARY OF CONDENSATE CONTINGENT RESOURCES
As of 1 January 2023
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (MMstb)			Net Entitlement Contingent Resources[2] (MMstb)		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**Resources Post EL**	0.1	0.0[4]	0.0[4]	0.0	0.0[4]	0.0[4]
MLJ	**Workover**	0.0	0.1	0.2	0.0	0.0	0.1
MLJ	**Layer 3**	0.2	0.9	1.0	0.1	0.3	0.4
MLJ	**B1-15K**	0.2	1.1	1.7	0.1	0.4	0.6
MLJ	**Hibiscus Workover Plan**	0.1	0.7	0.7	0.0	0.3	0.3
Total[3]		**0.6**	**2.8**	**3.6**	**0.2**	**1.1**	**1.4**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2031 for 1P; 2039 for 2P and 3P.

[2] Total's net entitlement based on its 37.5% working interest after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Total's Net Entitlement.

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, RPS' totals were summed arithmetically and, as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

[4] Pre-economic limit production forecast for 2P and 3P ends in year 2036 and 2039, respectively.

Table 1.5: Condensate Contingent Resources in MLJ Field as of 1 January 2023

SUMMARY OF CONTINGENT RESOURCES (BOE)
As of 1 January 2023
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (MMboe)[3]			Net Entitlement Contingent Resources[2] (MMboe)[3]		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**Resources Post EL**	0.6	0.0[5]	0.0[5]	0.2	0.0[5]	0.0[5]
MLJ	**Workover**	0.4	0.6	0.9	0.2	0.2	0.3
MLJ	**Layer 3**	1.7	5.5	5.3	0.6	2.1	2.0
MLJ	**B1-15K**	2.0	7.3	8.4	0.8	2.7	3.1
MLJ	**Hibiscus Workover Plan**	1.0	4.8	3.7	0.4	1.8	1.4
Total[4]		**5.8**	**18.2**	**18.2**	**2.2**	**6.8**	**6.8**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2031 for 1P; 2039 for 2P and 3P.

[2] Total's net entitlement based on its 37.5% working interest after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Total's Net Entitlement.

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

[4] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, RPS' totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

[5] Pre-economic limit production forecast for 2P and 3P ends in year 2036 and 2039, respectively.

Table 1.6: Summary of Oil Equivalent Contingent Resources in MLJ Field as of 1 January 2023

2 INTRODUCTION

In response to a request by Hibiscus Petroleum Berhad ("Hibiscus"), and the Letter of Engagement dated 2 January 2024 with Hibiscus RPS Energy Limited ("RPS") has completed an independent evaluation of the Maharajalela Jamalulalam (MLJ) Field, Block B, offshore Brunei.

Block B is currently operated by Total (via TargetCo) who is seeking to divest the asset by selling TargetCo. The report is based on an audit of material made available by Total in a VDR which has been undertaken by RPS. Given the nature of the audit a site visit was not undertaken. The block has some remaining prospectivity according to the Vendor but a review of prospectivity was not in the scope of this project.

All Reserves and Contingent Resource estimate herein are reported to PRMS 2018 standards. This report fulfils the requirements stipulated in Chapter 17, Part II, Division1 of the Securities Commission Malaysia's Prospectus Guidelines for a Competent Person's Report.

For the purposes of this Report, Third Party Gas is gas and associated condensate for which the Block B Joint Venture ("BBJV") has been licensed by a third party, subject to payment of a Licence Fee thereto, to produce, process and sell. These volumes are included in the production and cost profiles, and impact field economics, but are not included as Reserves or Contingent Resources by RPS in this Report.

The effective date of this evaluation is 1 January 2023.

2.1 Brunei Block B

Block B offshore Brunei contains MLJ field which was discovered in 1989 by the Maharajalela North well and which was appraised and developed during the 1990s with first gas in 1999. It has total area of 276 km^2 and is approximately 50 km offshore Brunei. Since 1999, the field has been producing gas and condensate from three unmanned platforms in relatively shallow (less than 100 m) water depths. The field consists of a complex faulted system that is divided into elongated structural compartments. The northern panel (MLJ North) extends into a third party's licensed area. The location of the block is shown in Figure 2.1.

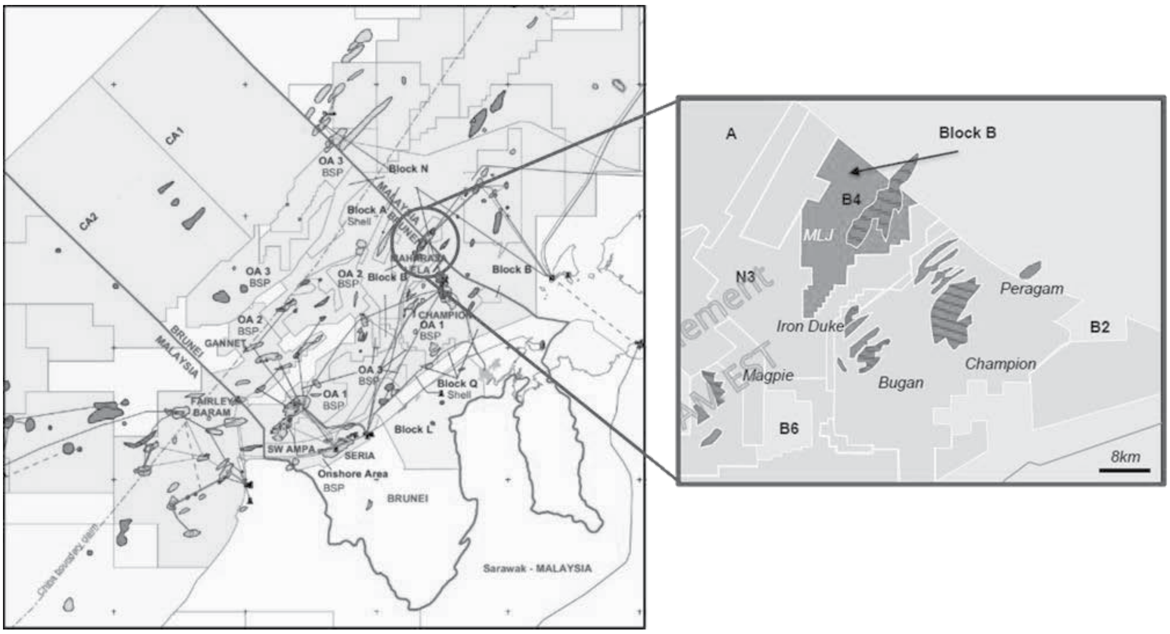

Figure 2.1: Location map

The MLJ field has been producing since 1999 under a Petroleum Mining Agreement ("PMA"), with the gas delivered to the BLNG plant. On 12 February 2014, the PMA, originally planned to end in November 2019, was extended for 10 years to 23 November 2029 with an option to extend for a further 10 years to 23 November 2039.

Gas is sold to BLNG under a Gas Sale Agreement ("GSA"). The first GSA ran from 1999 to 2013. In December 2013, a new GSA was signed for a period of 20 years to 1 April 2033. The first Annual Contract Quantity ("ACQ") period ends in March 2023 and the second ACQ period starts in April 2023 and lasts until March 2032.

Produced liquids are handled and managed at the terminal operated by Brunei Shell Petroleum ("BSP") via the Operating Services Agreement ("OSA"). Liquids are exported to the SCOT for processing under the OSA. An OSA was signed in March 2017 and a subsequent amendment agreed in March 2023 to update the Nomination and Allocation Procedure.

Total has been present in Brunei since 1986 and claims to have an experienced team with in-depth knowledge of the assets and region. RPS remit was to focus on the production and cost forecast of Total and has therefore not reviewed the Total technical team or safety record.

Country	Licence Type	Operator	Total Interest	Development Status	Licence Expiry Date	Partners
Brunei	PMA	Total	37.5%	Producing	November 2029 (option to extend to November 2039)	Shell Deepwater Borneo BV (35.0%) Brunei Energy Exploration (27.5%)

Table 2.1: Summary of MLJ Field

2.2 Third Party Arrangement

The northern panel (MLJ North) extends into a third party's licensed area. Two reservoir layers (Layers 1 and 2) have been on production on agreed terms with the third party and future production from Layer 3 (via one of the existing wells) could be on the same terms.

RPS is not in a position to opine on the terms of the third-party arrangement, and it was not part of the scope of this report.

3 BASIS OF OPINION

This report was prepared in response to a request by Hibiscus and the Letter of Engagement dated 2 January 2024 with Hibiscus, This report is issued by RPS under this appointment and is produced as part of the Services detailed therein and subject to the terms and conditions of the Agreement.

All volume and resource definitions and estimates shown in this report are based on the 2018 Petroleum Resource Management System ("PRMS") of SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE. This report fulfils the requirements stipulated in Chapter 17, Part II, Division1 of the Securities Commission Malaysia's Prospectus Guidelines for a Competent Person's Report.

In preparing forecasts, we have used standard 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.

The work is based solely on data supplied by Total to Hibiscus in a Virtual Data Room (VDR). Our estimates of recoverable volumes and associated costs are based on the data provided and we have accepted, without independent verification, the accuracy of these data.

The evaluation presented herein reflects our informed judgment, based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests.

RPS is not in a position to attest to the property title, financial interest relationships or encumbrances related to the properties.

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.

3.1 Methodology

Our approach has been to review production history and provide low, base, and high case production forecasts for the existing well stock and the planned additional activity described in the Vendor's Information Memorandum (IM). The capital and operating cost forecasts have been reviewed for the planned activities.

A detailed review of the condition of the facilities, the environmental and safety performance of the facilities and site visits to the facilities was not within the scope of this project.

3.2 Database

The effective date of the Reserves and Contingent Resource estimates and valuation is 1 January 2023. However, data in the VDR included historic produced volumes to year end 2023. Reserves quoted in this report as of 1 January 2023 include actual produced volumes in 2023 plus forecast production from 1 January 2024 which was based on RPS decline analysis ("DCA"). RPS did not receive Q1 2024 production data, so we have not been able to verify our forecast for this period.

Similarly, actual 2023 costs and forecast future costs from 2024 onwards, based on information received as of January 2024, were used in the evaluation. The evaluation used Q2 2024 price forecasts as stated in Section 8.3.

3.1 Site Visit

A detailed review of the condition of the facilities, the environmental and safety performance of the facilities and site visits to the facilities was not within the scope of this project.

4 MLJ FIELD FACILITIES

The MLJ Field comprises a complex faulted system that is divided into elongated structural compartments ("panels"), limited by major sealing normal faults. Hydrocarbons have been found in eight dynamically independent panels, each subdivided into tens of different reservoir levels. There are three unmanned production platforms - MLJ1, MLJ2 and MLJ3. No processing occurs offshore, and multiphase production is exported to onshore processing plant ("OPP") at Lumut. At Lumut, gas and liquids are separated, and condensate and water stabilised at 60 barg and gas is processed to remove mercury and traces of H_2S. Gas is sent to BLNG at 43 barg, and condensate and water exported to SCOT at 20 barg (Figure 4.1). The maximum gas handling rate is 201 MMscf/d and liquid rate is 18 Mstb/d.

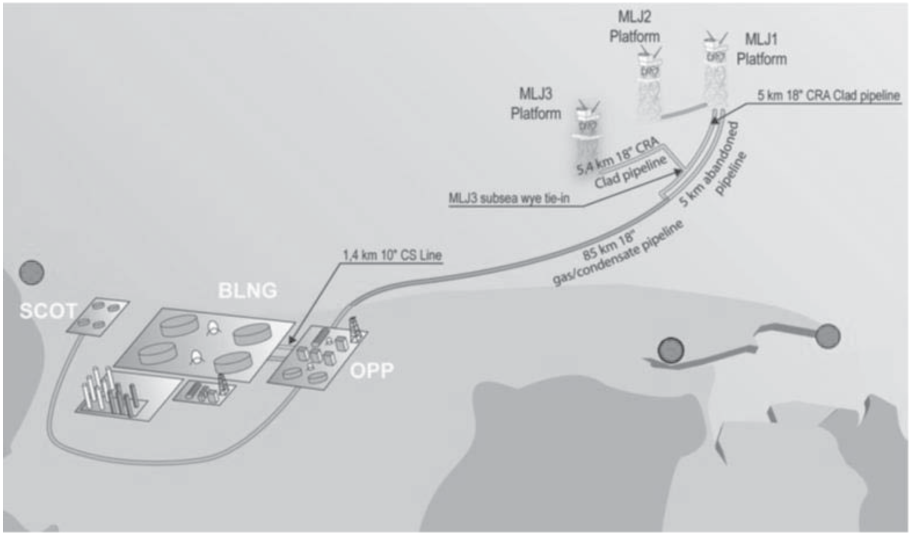

Figure 4.1: Block B Facilities Diagram

A total of 22 exploration, appraisal and development wells have been drilled. As of end 2022 there were 15 active gas producers (four wells on MLJ1 platform, five wells on MLJ2 platform and six wells on the MLJ3 platform).

The original MLJ development produced gas, condensate, and condensation water from the MLJ1 and MLJ2 wellhead platforms that are interconnected by a 12" 2.5 km inter-field pipeline. In 2015/16, a redevelopment project, called the MLJ South Project, consisted of debottlenecking of the OPP to increase export in high pressure mode (from 4.1 Mscm/d to 5.0 Mscm/d) and installation of a third HPHT platform MLJ3 with 12 slots. First gas from MLJ3 platform was in July 2016.

The panels with wells producing during December 2022 are shown in Table 4.1.

Panel	Platform	Producing Wells
MLJ North	MLJ1	MLJ1-06, MLJ1-07
JMB	MLJ1	Perforations in MLJ1-01
JAM	MLJ1	MLJ1-02
West	MLJ1	MLJ1-01
	MLJ2	MLJ2-01, MLJ2-02, MLJ2-03
B1	MLJ2	MLJ2-06
A	MLJ2	MLJ2-07
	MLJ3	MLJ3-02, MLJ3-06
C1/C2	MLJ3	MLJ3-01, MLJ3-03
B2	MLJ3	MLJ3-04, MLJ3-05

Table 4.1: December 2022 Producing Wells

During recent years, there have been a number well interventions. In 2019 perforations of four wells, in 2021 perforations on six wells, and in 2022 perforations and well clean-up on two wells. In 2023 to Q1 of 2024 a campaign to perforate three wells was planned.

Review of facilities integrity, operational performance, maintenance status and safety performance is beyond the scope of the RPS remit.

4.1 Planned Activities

A planned project to increase field life by decreasing OPP arrival pressure was sanctioned in 2023. Work is ongoing and the project is expected to be completed by 2025. The project is designed to modify the current 3.5 Msm^3/d plateau rates at 57 bar to deliver approximately 4.0 Mscm/d rates operating initially at 27 bar. This should enable field life extension to at least 2039 and is included in the Vendor's Reserves forecast.

Further well intervention work is planned. The Vendor forecast includes the following as Contingent Resources in their forecasts: -

- Three reperforation workovers (no additional sands accessed)
- MLJ North Layer 3 additional sand perforation
- B1-15k well to be drilled from the MLJ3 platform (the target is in the 2013 FDP) which will produce reservoirs proven by MLJ2-06 and appraise the 15k reservoirs in the B1panel.

5 GEOLOGICAL EVALUATION

Block B is located in a structurally complex zone within a highly subsiding part of the shelf constrained to the east by the regional listric fault of the Champion Field and to the west by the major counter regional Frigate-Perdana fault (located deep bellow Pelican structure). Within this sub-basin, the FK-01/FMS-01 fault is an important NNE-SSW, NW-dipping normal fault probably connected at depth with the Frigate-Perdana fault. These listric and counter regional faults create important accommodation space for prograding Upper Miocene deltaic and shallow marine sediments.

Depositional sequences are predominantly sandy (fine to very fine sand) and bound above and below by transgressive surfaces and thin shales with excellent sealing properties. The resulting reservoir interval in each panel comprises several tens of individual reservoir layers of good quality sandstones generally dynamically sealed from each other by thin shale layers. Little variation of this depositional setting is seen for the whole reservoir interval of in excess of 2,000 m. Panels have different pressure regimes with deeper, higher-pressure panels being towards the northwest.

5.1 Geological Assessment

5.1.1 Geophysics

The field is covered by 1,243 sq km of 3D seismic acquired in five surveys between 1989 to 2004. The data sets have been merged and reprocessed with a reference PreStack Time Migration (PreSTM) dataset (BB06) used for the latest interpretation.

The 3D seismic was not available in the VDR or in the supplied Petrel static models, so RPS was unable to audit the seismic interpretation or depth conversion.

5.1.2 Geology

Total's static geological models were provided in the VDR. Given the maturity of the asset and the limited time available RPS has not reviewed the models in detail apart from the areas around planned new wells.

The supplied static models included:

- 2022_MLJ_SOUTH_WORK_CP.pet
- 2022_MLJ_WEST_WORK_HRL_CP.pet
- 2022_MLJ_NORTH_PV2015_3_CP.pet

These are clearly working Petrel projects and contain multiple iterations of structural grid and modelled reservoir and fluid properties (NTG, Porosity, fluid contacts and Sw). They also contain multiple volumetric cases. No documentation for the model builds or the volumetric cases was available in the VDR. It was noted that the most recent drill wells were incorporated in the model builds for the appropriate areas.

The 2022_MLJ_SOUTH_WORK_CP.pet model incorporated the ML4, ML5, ML6 Exploration wells and the MLJ2-06st1, MLJ2-07, MLJ2-07, MLJ3-06, MLJ3-02, MLJ3-01, MLJ3-03, MLJ3-04, MLJ3-05 Development wells in the model build.

The 2022_MLJ_WEST_WORK_HRL_CP.pet model incorporated the ML2, ML3 Exploration wells and the MLJ1-01DB, MLJ1-03, MLJ2-02, MLJ2-02, MLJ2-03, MLJ2-04, MLJ2-05 Development wells in the model build.

The 2022_MLJ_NORTH_PV2015_3_CP.pet included the ML-1, MLJ1-06, MLJ1-06T, MLJ1-07b, MLJ2-06, and MLJ2-06T1 wells.

From our brief review, RPS believes the models are probably reasonable for estimation of in-place volume. However, we make some observations.

NTG and PHIT properties appear to have been distributed in the grid using kriging[3]. Total states that this approach was used as there is "lateral continuity and good well data coverage within gas pool support". They also state that a kriging-based model was used for the MLJ North third-party arrangement, and that the "history match proved that kriging can be considered with confidence". It is not clear if kriging was adopted as part of the third-party arrangement procedures and has propagated into the subsequent model builds or if other approaches have been tried. However, Total indicate it was used in the 2006/07 model builds. The kriged properties use a spherical variogram with long axis of 4000 m and short axis of 1500 m. The NTG and PHIE logs were upscaled using arithmetic averaging.

The result of this approach is that the NTG and PHIE properties are quite smoothly distributed both laterally and vertically through the field and there are places where the connectivity could be overestimated (Figure 5.1 and Figure 5.2). Therefore, we would caution against using the static models as a basis for simulation. No dynamic models were available for review in the VDR.

There is no variation in reservoir properties between low, mid, and high case models. Total only appears to have varied the input fluid contacts in the panels included in the volumetric cases. However, given the maturity of the asset with distribution of well control, a range of in-place volumes is probably not critical.

Sw has been modelled using a saturation-height function. The 2022_MLJ_SOUTH_WORK_CP.pet model appears to use a Sw-ht function consistent with Document 4.2.3.1.2.1[3], which uses three porosity-permeability transforms for given porosity classes.

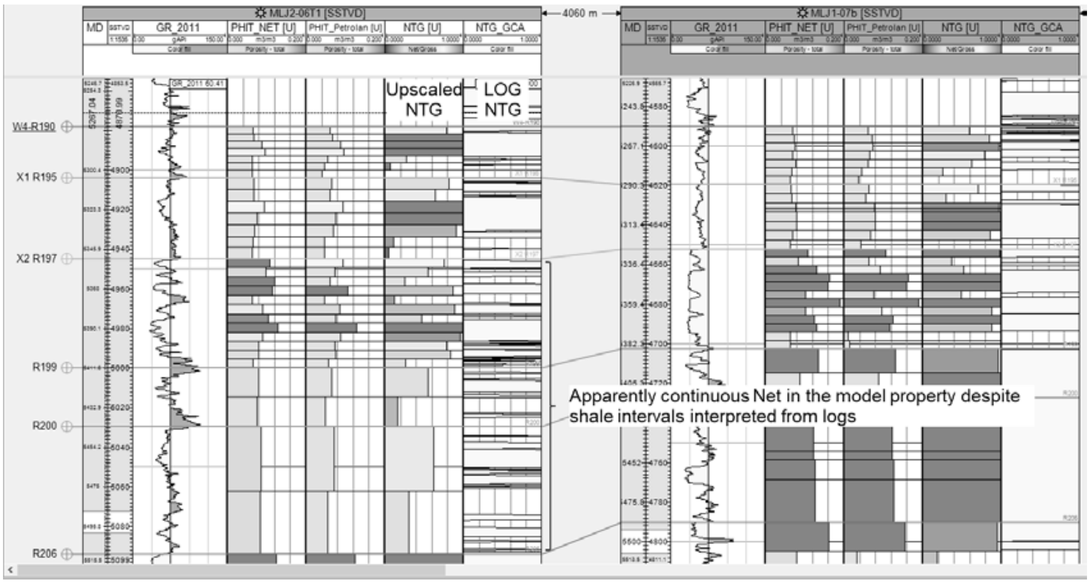

Figure 5.1: Comparison of upscaled and log-derived NTG.

[3] VDR Document No. 4.2.3.1.2.1 – 2019-03-06 BBJV Technical Workshop Static Model.pdf

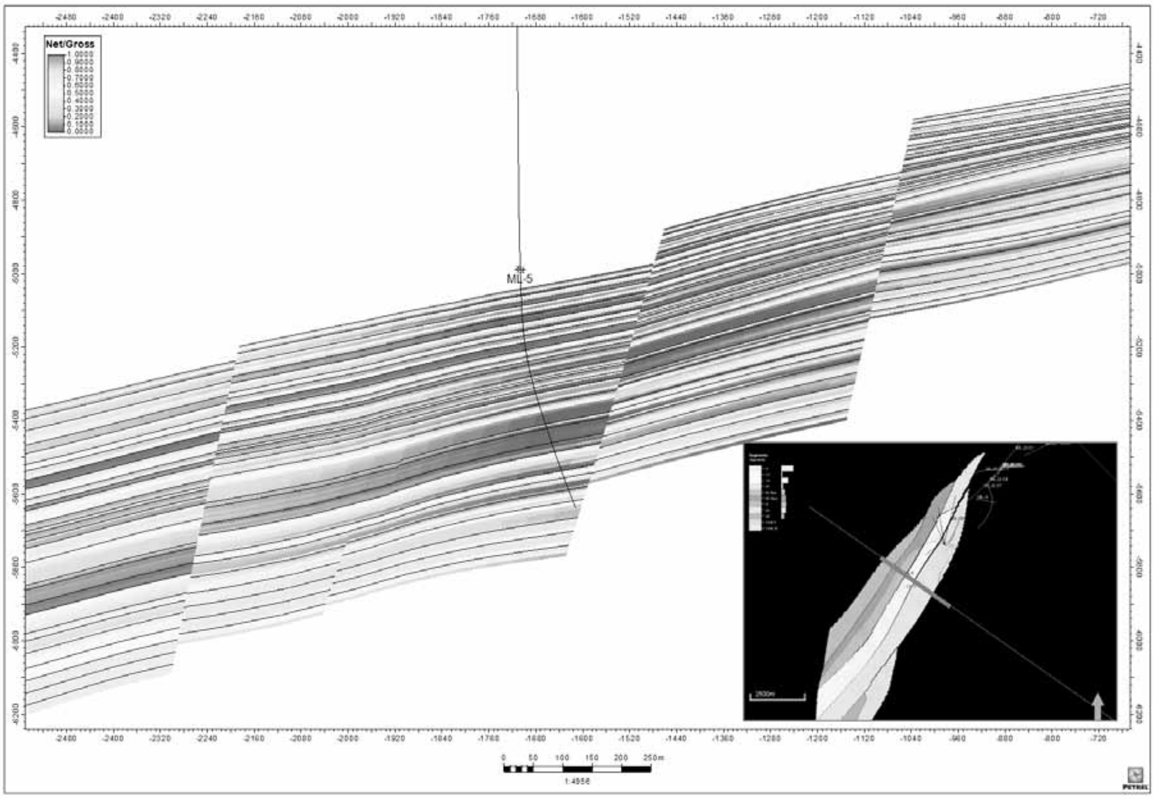

Figure 5.2: Cross-section through NTG property.

5.1.2.1 Contingent Resources – Planned Wells

Total provided some detail for two planned wells: MLJ1-07 deepening and well B1-15k. RPS reviewed Technical Workshop presentations provided in the VDR, which give some geological and in-place background to the planned wells.

5.1.2.1.1 B1-15k well

B1-15k is planned to target the R190 to Qb54 reservoirs in the B1 Panel (Figure 5.3). The R190 to R214 reservoirs were penetrated by the MLJ2-06T1 well and are gas-bearing, and Total call these "development/infill targets" for B1-15k. Total call the deeper R220 to Qb54 reservoirs "appraisal targets". However, MLJ2-06T1 penetrated the FMS22 bounding fault of the B1 Panel before reaching these deeper 15k reservoirs. Total's approach is to use offset wells as analogues and assume that the R220-Qb54 reservoirs will be gas-bearing in B1-15k (e.g., by comparison to MLJ3-05). In RPS' opinion, given the interpretation that the bounding faults are sealing, these deeper reservoirs remain prospective in the B1 Panel. There appears to have been some discussion to this effect amongst the partners based on the material supplied in the VDR from the infill drilling Technical Workshops, with the uncertainty of the fault tip on the main bounding faults being one issue. As seismic data were unavailable, RPS was unable review the fault interpretation.

The in-place volume results derived from the static model are consistent with the base case quoted by Total in their Technical Workshop presentations. Therefore, RPS used the volumetric range quoted by Total for our evaluation of Contingent Resources in the R190 to R214 reservoirs. RPS interpret the R220-Qb54 reservoirs as prospective, and they are consequently excluded from our evaluation. Total's quoted volumes were adopted for evaluation of the Contingent Resources associated with well B1-15k.

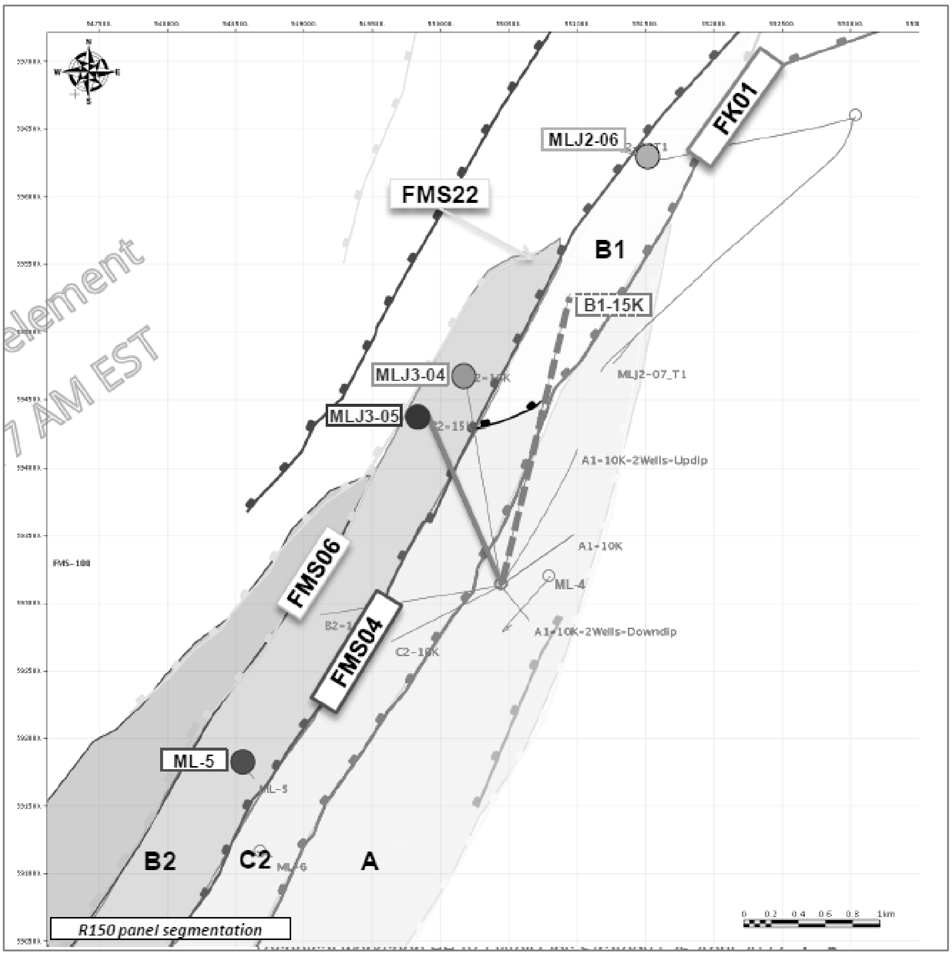

Figure 5.3: Location of proposed B1-15k well in Panel B1.

5.1.2.1.2 Deepening Well MLJ1-07

Total plans to "deepen" the existing MLJ1-07 well drilled on MLJ-North to produce the Layer 3 reservoirs as described in Section 1.4. The operation is a perforation through casing of MLJ1-07 as the well has already penetrated Layer 3 and the R190-197 reservoirs are cased above the 7" liner shoe.

There are risks associated with the project that Total have recognised:

- 15k reservoirs are expected in Layer 3, which may pose challenges for the existing downhole and surface facilities design.

RPS reviewed the static models for MLJ North and the volumes for the Layer 3 reservoirs. The model volumes are consistent with the base case volumes quoted by Total in their Technical Workshop presentation[4], so Total's quoted volumes were adopted for evaluation of Contingent Resources associated with the planned MLJ1-07 deepening project.

[4] VDR Document No. 4.2.3.3.2 – 20220426 Layer 3 MLJ1-07 Deepening.pdf

5.1.3 Petrophysics

RPS undertook a brief review of the petrophysical interpretation for MLJ2-06T1 and MLJ3-05 wells that were included in the Petrel project. The interpretations looked reasonable. RPS stresses that this was not an in-depth or comprehensive review of Total's petrophysical interpretation.

5.2 In-Place Volumes

Given the maturity of the asset and the limited time available, RPS did not review the in-place volumes in detail, but best case volumes were extracted from Total's static models presented in the virtual dataroom. Where volumes are quoted by the Vendor they are a reasonable match to those extracted from the best case models. None of the model volumes were carried forward into our resource evaluation. As stated in Sections 5.1.2.1.1 and 5.1.2.1.2, our evaluation of Contingent Resources in the B1-15k and Layer 3 reservoirs used the Vendor quoted GIIP ranges, which were considered reasonable.

6 RESERVOIR ENGINEERING ASSESSMENT

6.1 Fluid Properties

The fluid is considered gas-condensate, but compositions vary from one reservoir to another, which gives variations in condensate richness. Fluid modelling is complex since the field comprises stacked reservoirs in several structural panels with depth variations of more than 2000 m.

A sample composition is shown in Table 6.1.

Reservoir fluid composition	% mole
N2	0.186
CO2	1.765
C1	85.646
C2	4.852
C3	2.673
IC4	0.505
NC4	0.600
IC5	0.277
NC5	0.178
C6	0.423
C7	0.379
C8	0.259
C9	0.143
C10	0.126
C11+	1.988

Table 6.1: Sample gas composition

The historical CGR evolution versus gas cumulative production is presented in Figure 6.1.

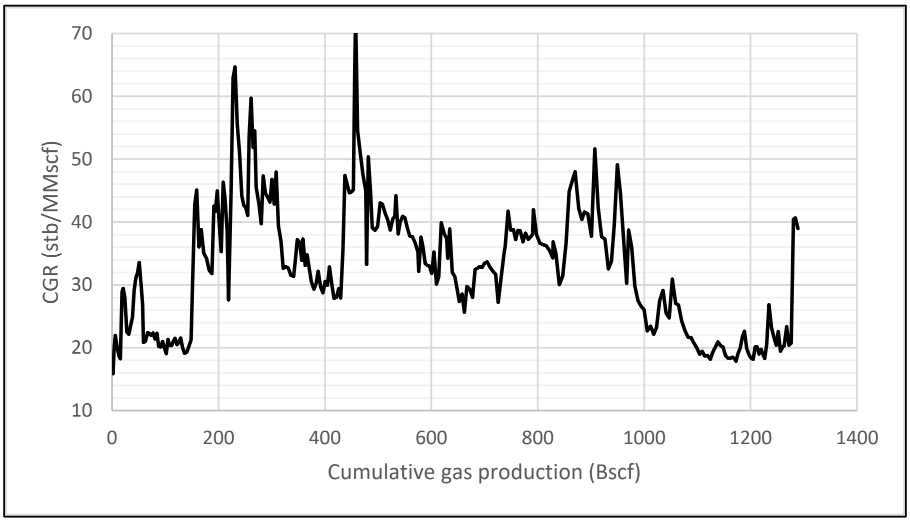

Figure 6.1: CGR versus cumulative gas production.

The average CGR has been approximately 30 stb/MMscf. This decreased to 20 stb/MMscf before the last work over campaign following which condensate production increased back to around 40 stb/MMscf.

6.2 Production History

Historic gas, condensate and water production rates are shown in Figure 6.2. The increase in production after implementation of the MLJ South Redevelopment Project with first production in 2016 is clearly seen. Since 2016, the field was in decline until wells MLJ1-06 and MLJ1-07 were brought back online in October 2022.

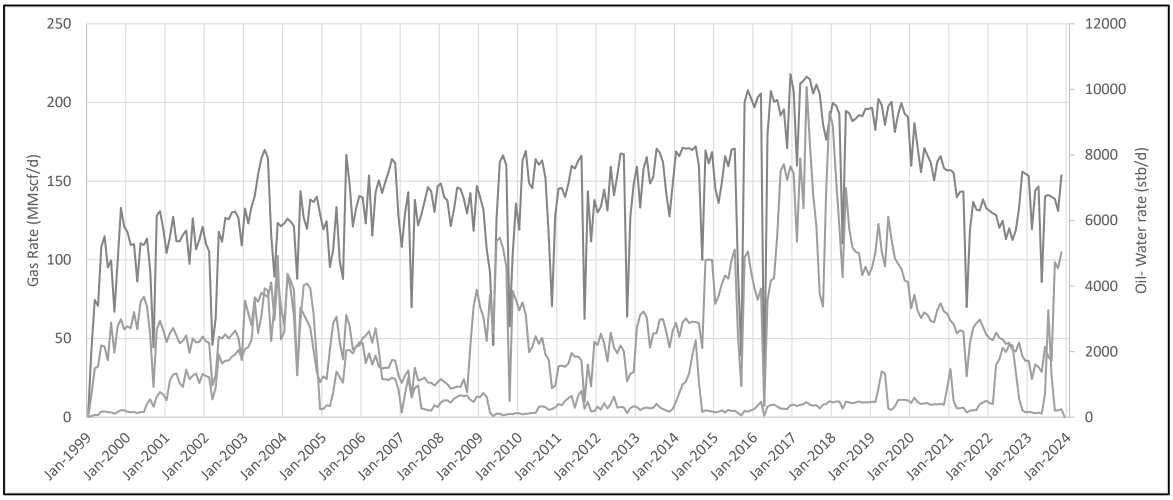

Figure 6.2: Historic Production Rates

Currently, all wells are producing free flow. Only 12 wells have been produced continuously during 2023 (two of them being MLJ1-06 and 07) and well MLJ2-03 produced only for 5 months with insignificant volumes. Wells MLJ1-05 and MLJ2-04 are plugged and abandoned, and wells MLJ1-01, MLJ1-02, MLJ1-03 and MLJ2-05 have not produced during 2023.

A total of 1,289 Bscf of gas and 42 MMstb of condensate has been produced of which 307 Bscf and 15 MMstb has been produced from the MLJ1-06 and MLJ1-07 wells.

The wells suffer from calcite deposition over time, which decreases the productivity index (PI). In recent years, some efforts have focused on maintaining the PI of the MLJ3 platform wells by reperforating the producing intervals. This resulted in production increases over several months, which potentially indicates that periodic reperforations could maintain the PI of these wells.

6.3 Production Forecasts

Historic production data to 31 December 2023, were available in the VDR.

6.3.1 NFA Production Forecast

Historical monthly production data and periodic well test data have been collated and analysed to establish well-by-well decline. Exponential, hyperbolic (with b=0.5) and harmonic declines have been chosen for the low, base, and high cases, respectively.

Historical workovers have been identified based on documentation available from 2019 in order to identify the reasons for historical gas rate increases. An example of the collated data is shown in Figure 6.3 and Figure 6.4 for well MLJ3-03. Some discrepancies between the reported and tested condensate were identified which will require further clarification from the Vendor. RPS used the reported official figures for our analysis. The decline chosen for this well is presented in Figure 6.5.

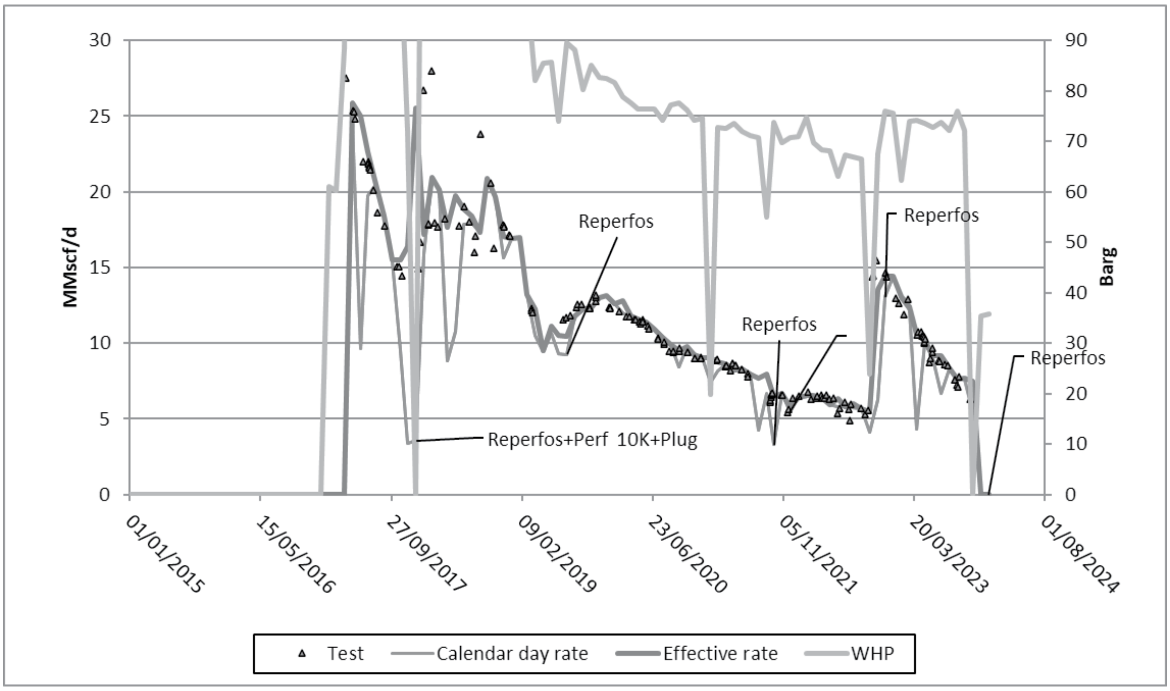

Figure 6.3: Gas production, WHP and WO identification.

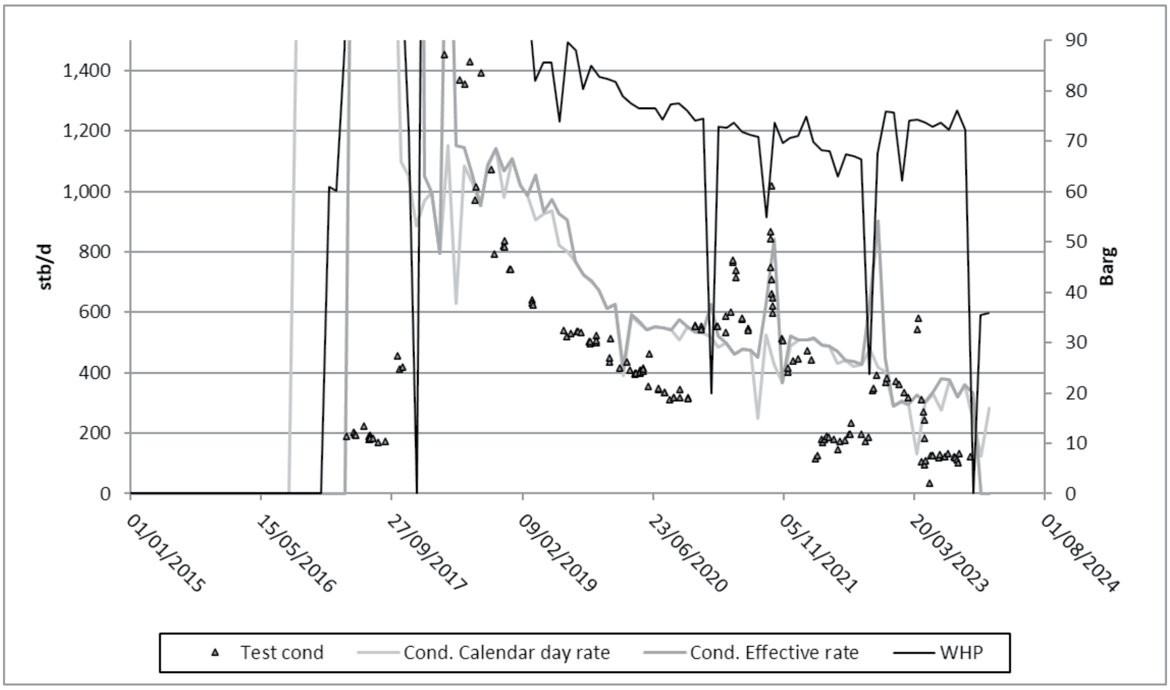

Figure 6.4: Condensate production and WHP well MLJ3-03

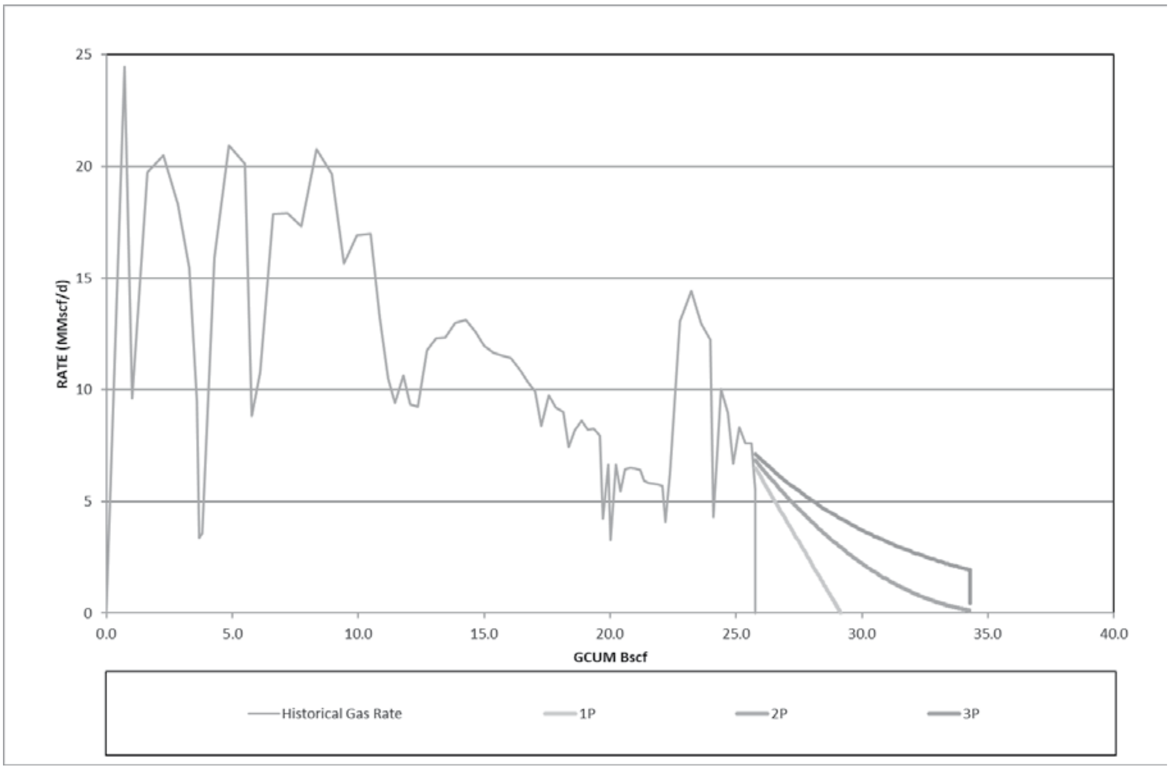

Figure 6.5: Well MLJ3-03 forecast gas production

The resulting NFA forecast is showed in Figure 6.6. Notice that a minimum pipeline hydraulic turndown well head rate of approximately 63 MMscf/d (1.8 Mscm/d) is expected pre-compression. For this reason, the forecasts include the mention cut of rate (at total production level i.e., including Third Party Gas).

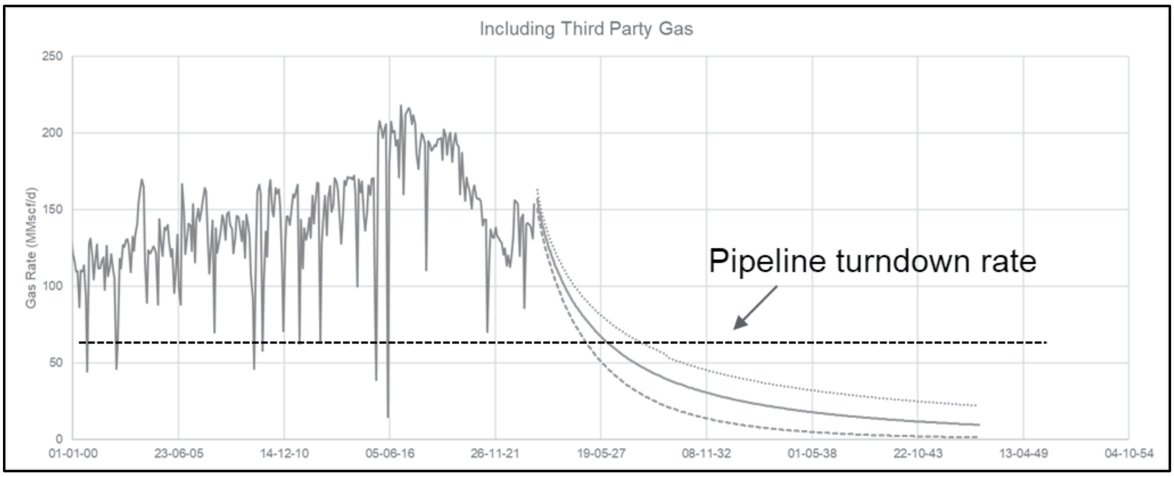

Figure 6.6: NFA production forecast (Third Party Gas included)

Figure 6.7 shows the NFA forecast without the Third Party Gas.

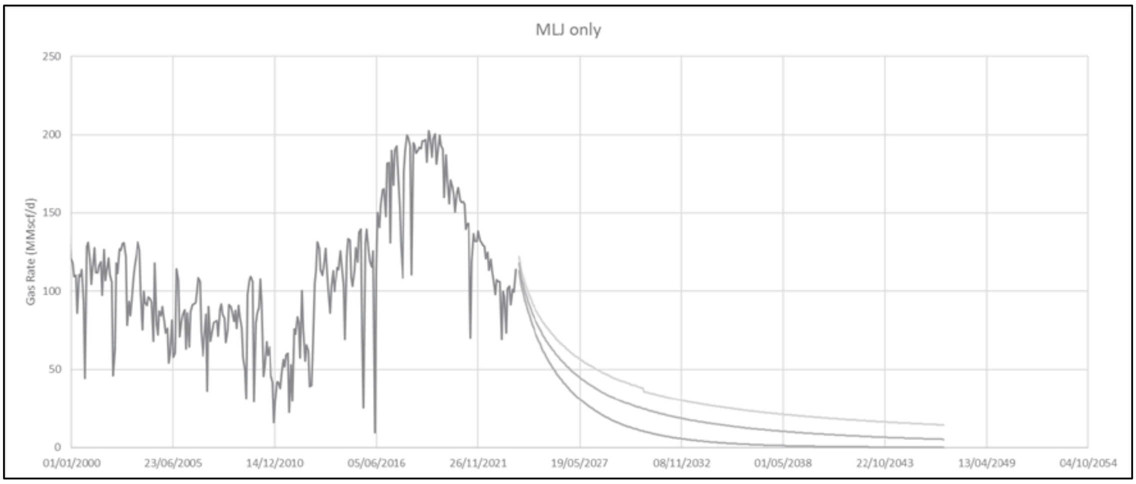

Figure 6.7: NFA production forecast (Third Party Gas not included)

6.3.2 Well Interventions

As discussed in the previous sections, during the last five years the MLJ3 wells have enjoyed several work-over campaigns to maintain or increase deliverability. In most cases, the interventions consisted of reperforation of existing producing intervals to maintain the PI of the wells which had decreased mainly due to mineral deposition. However, RPS notes that additional sands have been perforated in certain wells with a resulting production increase.

Historical analysis revealed that the workovers provide a clear rate increase. However, in most of the cases, this increase only lasted for a few months.

RPS has analysed the incremental production and developed type curves for the workovers that included only reperforation and type curves for workovers that include perforation of additional sands (Figure 6.8).

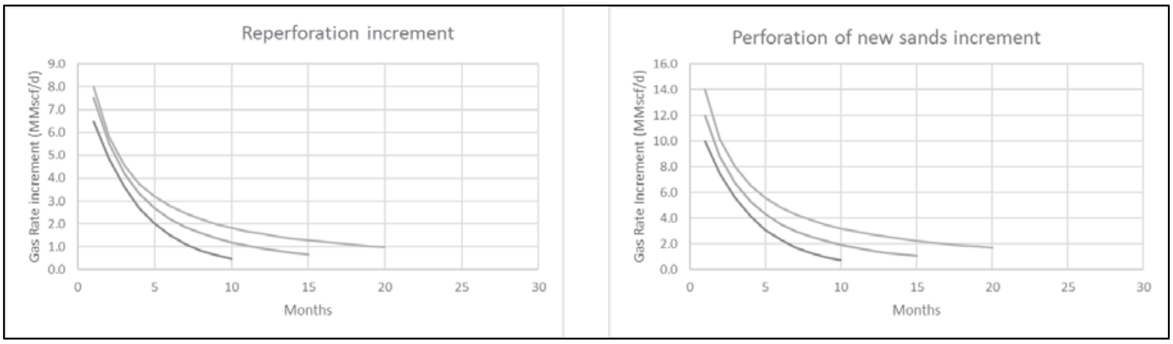

Figure 6.8: Type Curves for Workovers

RPS' Reserves forecast include two workovers delayed from 2023 and two additional workovers in 2024.

6.3.3 LP Project Forecast

The LP compression project is expected to come on stream in the second half of 2025. Based on the documentation provided by the Vendor, compression will decrease the arrival pressure to 17 barg and will limit the production rate to approximately 124 MMscf/d (3.5 Msm^3/d).

The current WHP of the wells is in the range 70 to 80 barg (all flowing at free flow). After compression, this pressure is expected to decrease to 40 barg (at the 124 MMscf/d limit rate). At the end of the forecast, it is expected a minimum WHP of 25 barg.

The compressor efficiency chosen for the compressor is 90% - 94% - 97% for the low, base, and high cases, respectively.

In absence of any models, RPS used WHP and rate historical performance to establish a potential rate. WHP vs rate plots were generated by well (examples are shown in Figure 6.9 and Figure 6.10) to establish the operational envelope for each well and define windows of expected rate after WHP decreases to the expected minimum of 22 bar WHP. This potential rate was then used to establish recovery after compression. To generate the compressor-constrained forecast a volume balance was used maintaining the same recovery as the potential unconstrained rate. Based on the compressor efficiency, the plateau limits used were 111-116-120 MMscf/d for the low, base, and high cases, respectively.

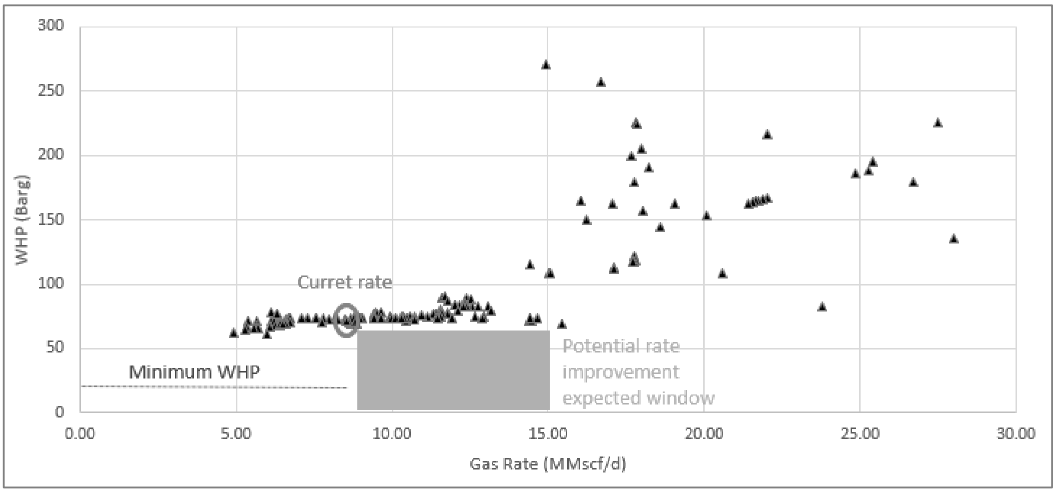

Figure 6.9: MLJ3-03 well WHP vs gas rate

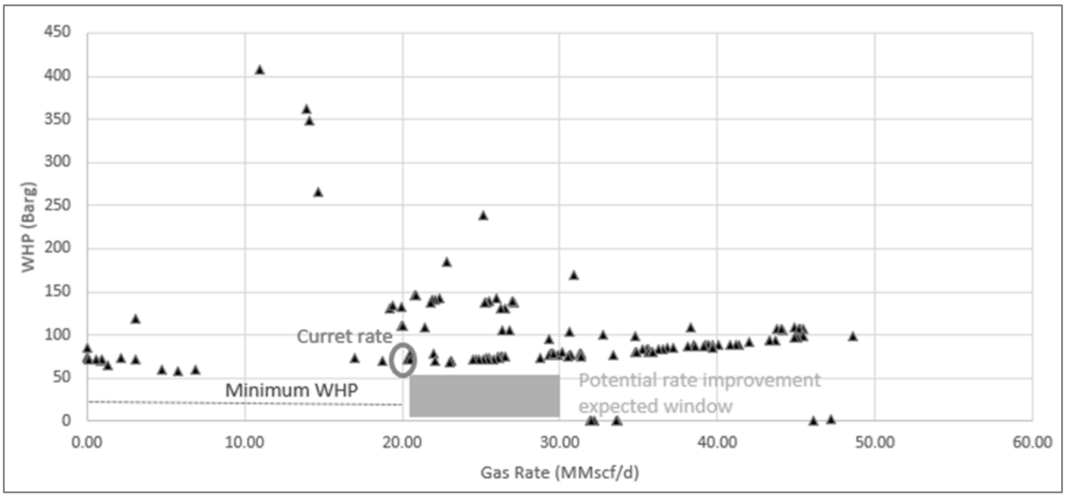

Figure 6.10: MLJ3-06 well WHP vs gas rate

The RPS forecast after compression is shown in Figure 6.11. This figure compares the NFA case, the unconstrained potential and the compressor-constrained forecast.

According to the documentation available, the minimum pipeline hydraulic turndown rate after compression will be approximately 28 MMscf/d (0.8 Mscm/d). Therefore, RPS has used this cut-off rate when developing the forecasts.

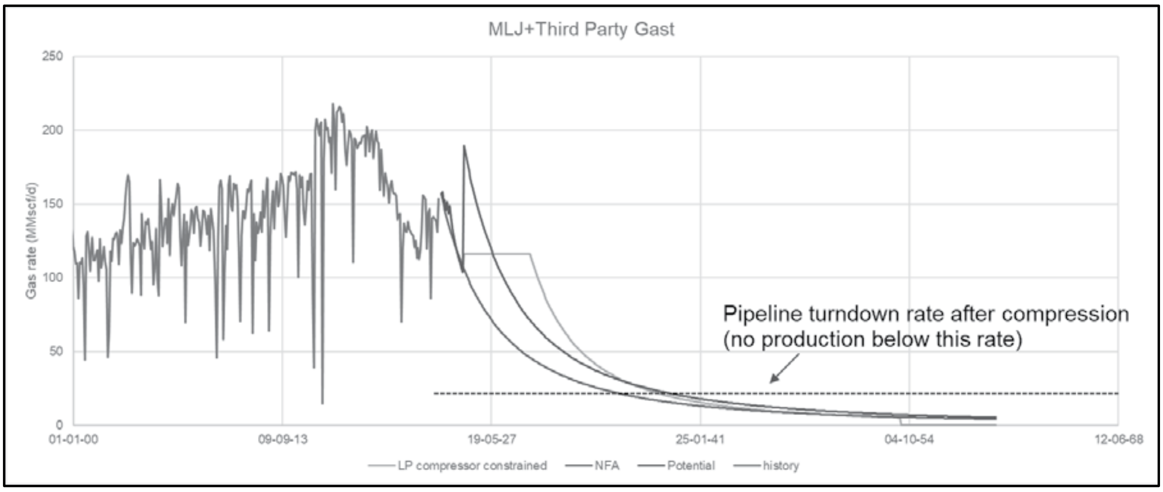

Figure 6.11: Base case production forecast after compression.

It is important to highlight that RPS assumes the Third Party Gas will continue producing in line with historical trends and therefore it will also be constrained by the compressor limit rate.

6.3.4 Contingent Projects

The operator is considering three additional projects classified as Contingent Resources:

- Three unspecified workovers (reperforation without accessing extra sands)
- Additional MLJ North workover to perforate Layer 3
- New well B1-15k

There is an additional project outside the current Operator's plan and considered by Hibiscus also, which is classified as Contingent Resources:

- Six campaigns every two years with four workovers per campaign.

To build our forecasts, RPS has assumed that the projects will come online as soon as there is availability given the compressor limit rate. According to the documentation supplied by the Vendor the three workovers will start first, then the additional Layer 3 sand, followed by the B1-15k new well and the Hibiscus proposed workover campaigns thereafter.

For the workovers, the same type curves as defined for the Undeveloped Reserves form the imminent workovers were used. For the Additional MLJ North Layer 3 workover and the new B1-15k well, a recovery factor of 50-60-70% for the low-best-high cases were assumed and applied to the estimated GIIP.

The GIIP and the potential recoverable volumes for these two wells are presented in Table 6.2.

Well	Case	GIIP (Bscf)	RF (%)	EUR (Bscf)
MLJ North Layer 3 workover	Low	30	50	15
	Base	48	60	29
	High	60	70	42
B1-15k new well	Low	49	50	25
	Base	56	60	34
	High	78	70	55

Table 6.2: Potential EUR per Well based on RF.

Low, base, and high case forecast used the type curves based on historical well performance (Section 6.3.2) to honour the recovery shown in Table 6.2.

It is important to highlight that the full field production based on remaining rate from compressor constrain and minimum turndown rates decreases the potential recovery stated above.

6.3.5 Full RPS Reserves Forecast

The full RPS pre-ELT production forecast for the committed plans (mid case including Third Party Gas) is presented in Figure 6.12 and the mid case pre-ELT forecast (without including Third Party Gas) in Figure 6.13.

Given the complexity of the fluid and the lack of models supplied by the Vendor, condensate production has been calculated based on a flat CGR of 20-30-40 stb/MMscf for the low, base, and high cases. These figures are supported by historical CGR (Figure 6.14) and also by the "Process Simulation Report & HMB" document number "4.1.8.13 BN-OPP-30-DOR1-353001" supplied by the Vendor, which forecasted a CGR of approximately 30 stb/MMscf from 2025 to 2039. Figure 6.15 shows the condensate forecast.

Pre-ELT EUR volumes up to 2039 for the committed plans are presented in Table 6.3 and Table 6.4.

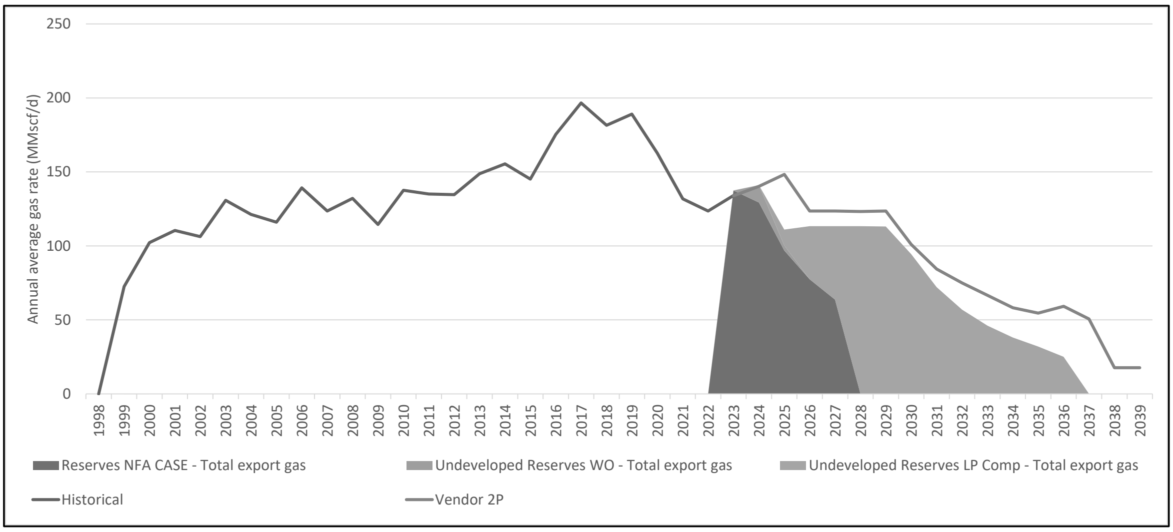

Figure 6.12: Production forecast including Third Party Gas (note that Third Party Gas does not contribute to Reserves in this Report)

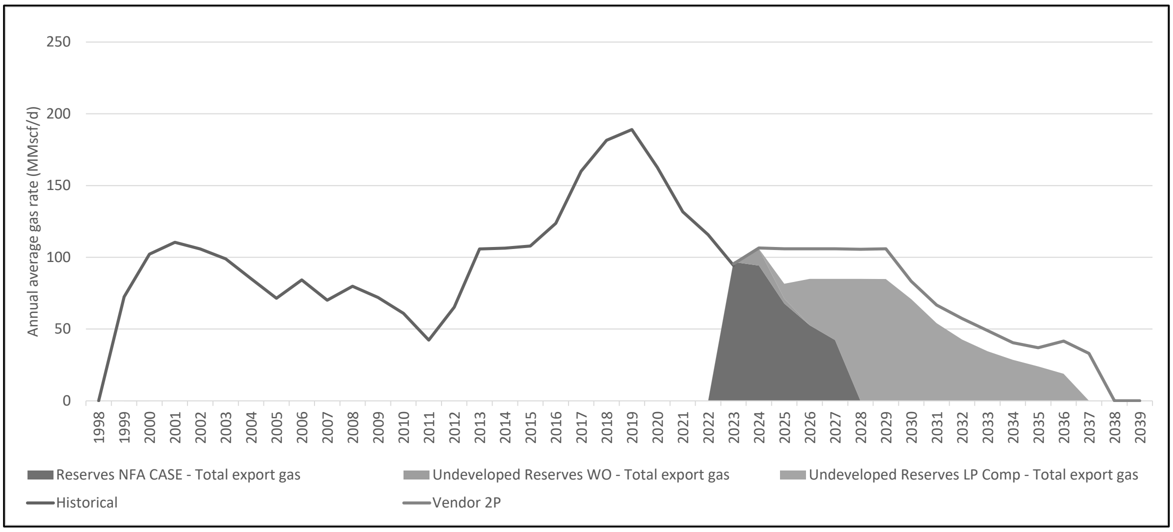

Figure 6.13: Gas production forecast (Third Party Gas not included)

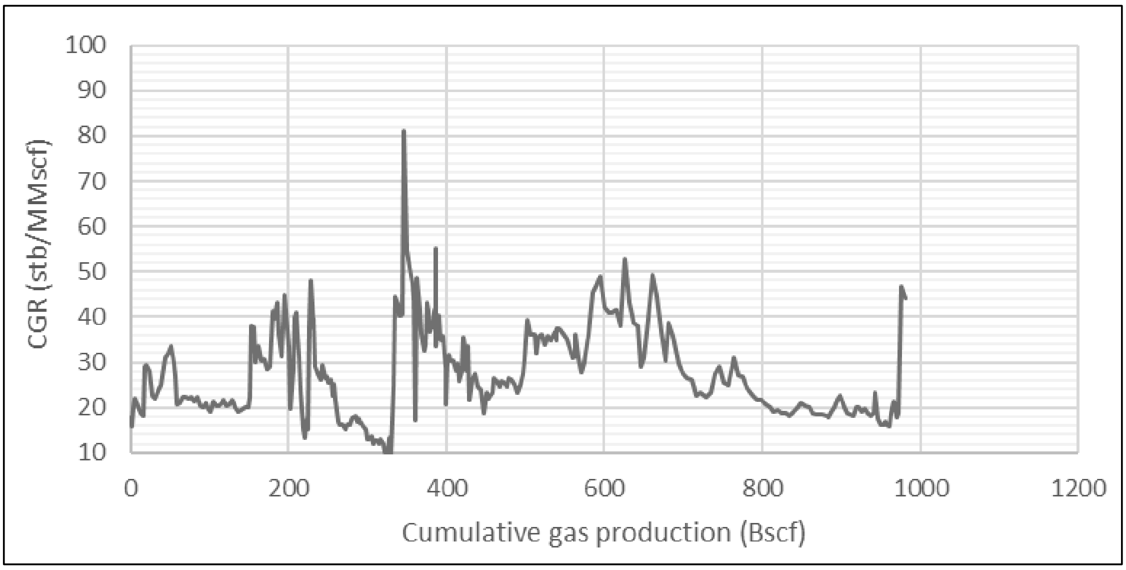

Figure 6.14: Historical field CGR (CGR v Cumulative Gas)

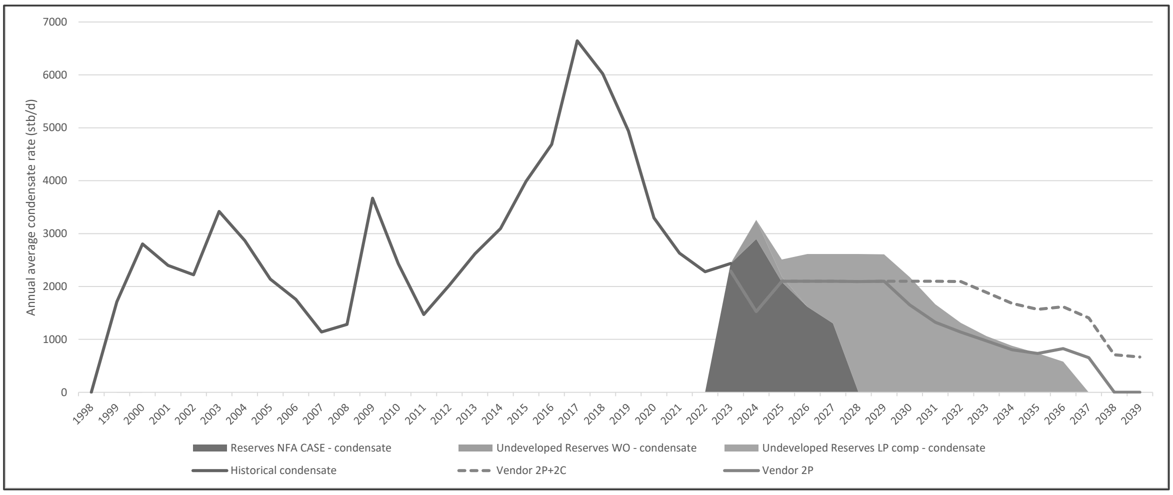

Figure 6.15: Condensate production forecast (Third Party Gas not included)

		Gas EUR (Bscf)		
		Low	Best	High
Developed	**NFA**	97.9	129.2	182.0
Undeveloped	**Well Interventions**	3.7	5.5	8.1
	LP Project	114.5	193.2	241.9
Total[1]		**216.0**	**327.9**	**432.0**

[1] Arithmetic summation of pre-ELT volumes

Table 6.3: Gas EUR (committed plans, Third Party Gas not included)

		Condensate EUR (MMstb)		
		Low	Best	High
Developed	**NFA**	2.2	3.8	6.9
Undeveloped	**Well Interventions**	0.1	0.2	0.3
	LP Project	2.3	5.9	9.9
Total[1]		**4.6**	**9.9**	**17.2**

[1] Arithmetic summation of pre-ELT volumes

Table 6.4: Condensate EUR (committed plans, Third Party Gas not included)

6.3.6 Contingent Resources Forecasts

The full RPS production forecast (mid-case including Third Party Gas and including committed plans and contingent plans) is presented in Figure 6.16. Reserves plus Contingent Resources are presented in Figure 6.17 for gas and Figure 6.18 for condensate.

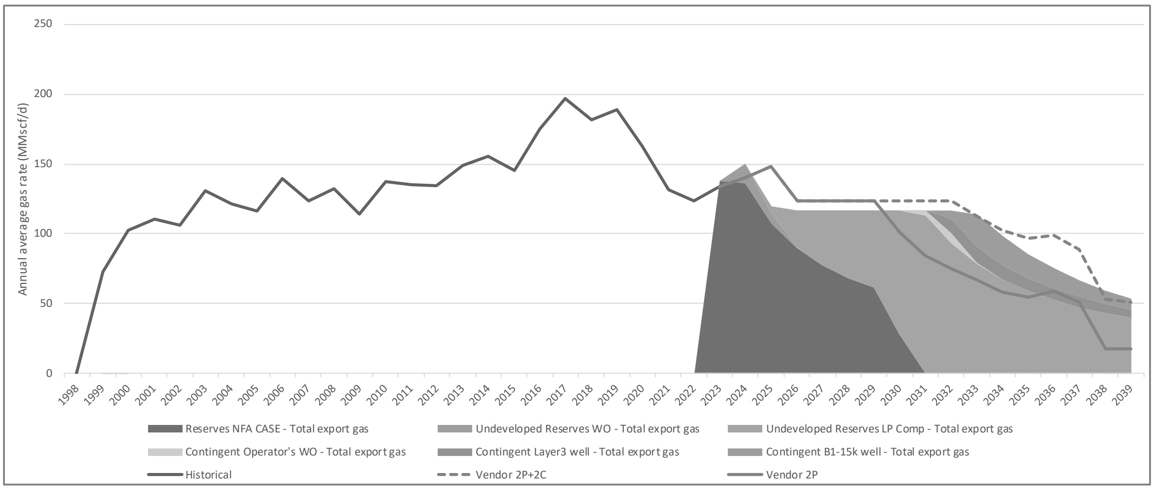

Figure 6.16: Committed plus Uncommitted plans (including Third Party Gas) mid case gas production forecast.

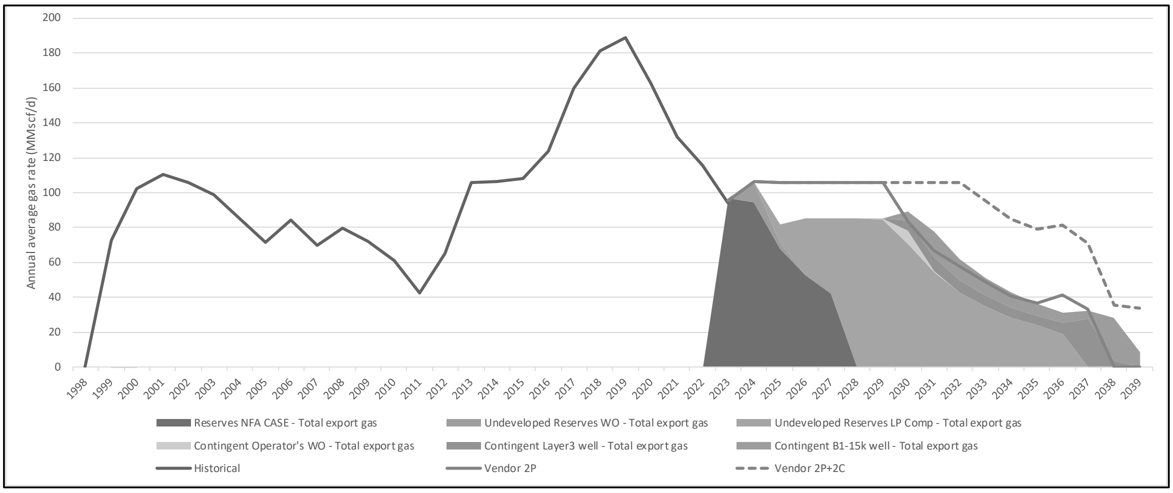

Figure 6.17: Reserves plus Contingent Resources mid case gas production forecast (Third Party Gas not included)

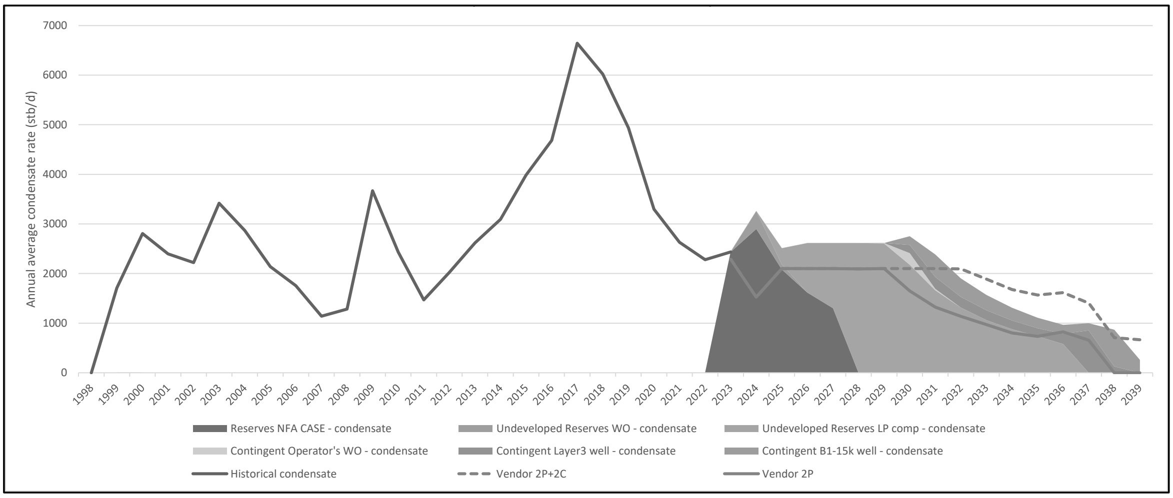

Figure 6.18: Reserves plus Contingent Resources condensate mid case production forecast (Third Party Gas volume not included)

Pre-ELT EUR contingent volumes up to 2039 are presented in Table 6.5 and Table 6.6. Notice that numbers only reflect recoveries until 2039 for comparisons with Hibiscus numbers. Some of the forecasts extend further that is part of the reason some high cases recovery is lower than the base case.

		Gas EUR (Bscf)		
		Low	**Best**	**High**
Contingent	**Workover**	2.2	3.2	4.4
	Layer 3	9.2	27.9	25.3
	B1-15k new well	14.4	36.9	40.4
	Hibiscus Workover Plan	9.8	24.3	17.7
	Total[1]	**35.6**	**92.3**	**87.8**

[1] Arithmetic summation of pre-ELT volumes

Table 6.5: Pre ELT contingent EUR gas volumes

		Condensate EUR (Bscf)		
		Low	**Best**	**High**
Contingent	**Workover**	0.0	0.1	0.2
	Layer 3	0.2	0.9	1.0
	B1-15k new well	0.3	1.1	1.7
	Hibiscus Workover Plan	0.2	0.7	0.7
	Total[1]	**0.7**	**2.8**	**3.6**

[1] Arithmetic summation of pre-ELT volumes

Table 6.6: Pre ELT contingent EUR condensate volumes

It is important to highlight that cases are limited by the compressor limit rates, so additional projects need to be integrated when there is enough availability. This causes the additional incremental to be delayed in time and is the reason why some of the high cases are lower than the base cases since the numbers only reflect volume until 2039. If extended, all the high cases are higher than the base cases except in the Hibiscus workover project (Table 6.7).

		Gas EUR (up to 2059) (Bscf)		
		Low	Best	High
Contingent	Workover	2.2	3.2	4.4
	Layer 3	9.2	27.9	54.6
	B1-15k new well	14.4	36.9	60.3
	Hibiscus Workover Plan	9.8	32.6	30.5
Total[1]		**35.6**	**100.6**	**149.7**

[1] Arithmetic summation of pre-ELT volumes

Table 6.7: Pre ELT contingent EUR gas volumes (up to 2059)

The Hibiscus workover project is limited by both the compressor maximum limit rate and the minimum hydraulic rate so, for the low case only three Workover (WO) campaigns are possible before the minimum rate is achieved, as opposed to the base and high cases for which all six campaigns are.

Notice that the volumes reflect incremental recoveries. In some cases, these increments can be higher than the sole production of the project. The additional rate can extend the field rate above the hydraulic limit for longer. Therefore, the incremental volume accounts for the extra production from previous projects that are able to flow after the rate increase in addition to the sole production from the new project (see an example in Figure 6.19 and Figure 6.20).

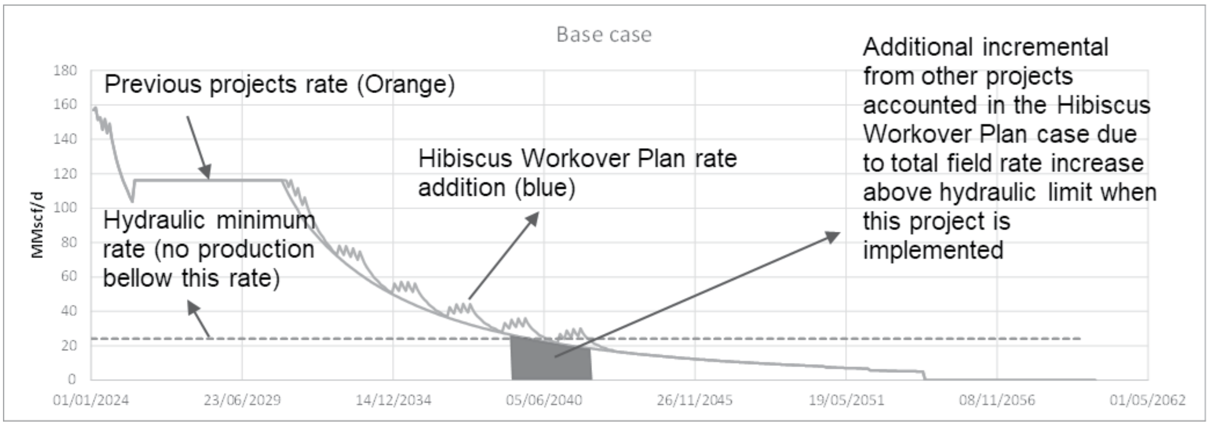

Figure 6.19: Base case Hibiscus workover production forecast.

For the high case, the Hibiscus Workover (WO) project comes on stream earlier than the minimum hydraulic limit is reached and therefore does not have the same incremental benefit than in the base case. For this reason, the base case incremental is larger than the high case incremental for this particular project.

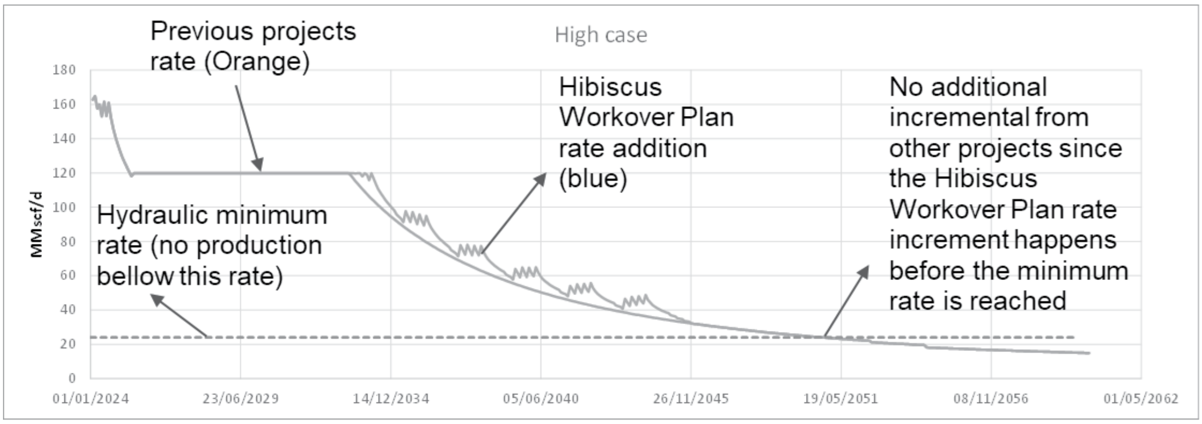

Figure 6.20: High case Hibiscus workover production forecast.

7 COST FORECASTS

RPS reviewed the costs presented by the Vendor in the economic model and in other documents located in the VDR. Actual cost data and predicted future costs information in the VDR were valid as of 1 January 2024. RPS has reviewed and opined these costs are reasonable when benchmarked against cost estimates for similar operation in the region.

All costs discussed are 2023 Real and not Money of the Day[5] i.e. do not include any assumptions for inflation.

RPS has produced cost forecasts for two scenarios with a Low/Mid/High case for each. The first scenario is the Developed Producing along with the firm developments and developments in progress (the LP Compression and two workovers). A second scenario includes the contingent development activities. In total, there are six RPS produced cost and production forecasts used for valuation purposes.

7.1 Operating Costs (Opex)

RPS has received an economic model from the Vendor containing some high level Opex forecasts. These have been split by the Vendor into the following categories:

- Opex
- Supervision & Base Costs
- Other Opex Accounting Standards Codification ("ASC") & non ASC 932; excluding Total's General and Administration ("G&A") and overheads
- Transportation Costs

The "Opex" category appears to consist of fixed operating costs and have been accepted by RPS.

The Supervision & Base Costs appear to contain the incremental LP Compressor operating costs, but these are not differentiated in the economic model. Following a request from RPS, the Vendor has supplied an incremental LP Compression Opex forecast separated out into the following sub-categories:

- Electricity costs
- Routine and non-routine Opex
- Compressor re-bundling costs

RPS has removed these costs from the Supervision and Base Costs to generate effectively a NFA cost and has produced an additional Opex line for the three sub-categories above under the LP incremental Opex.

RPS has accepted the Routine and non-routine Opex and the compressor re-bundling costs. The compressor re-bundling cost timing has been adjusted by RPS to suit the RPS production forecasts. As RPS currently understands the new LP compressor will require re-bundling when the production drops below 1.7 Msm^3/d (60 MMscfd).

RPS has generated electricity cost forecasts based on the RPS production forecasts combined with data on the LP Compressor taken from the LP Compressor technical datasheet from the VDR. RPS has taken the LP Compressor data and have generated a relationship between gas flow and absorbed power and has utilised this to calculate the absorbed compressor power on an annualised basis against the RPS production forecasts. The electricity import cost was supplied by the Vendor at a rate of $100/MWh. RPS used this rate in our evaluation although we acknowledge that lower rates are quoted by the Brunei Department of

[5] RPS uses the term "Money of the Day" to prices which incorporate the effects of annual inflation and reflect the time value of money.

Electrical Services. The compressor flow vs absorbed power taken from the compressor datasheet is shown in Figure 7.1:

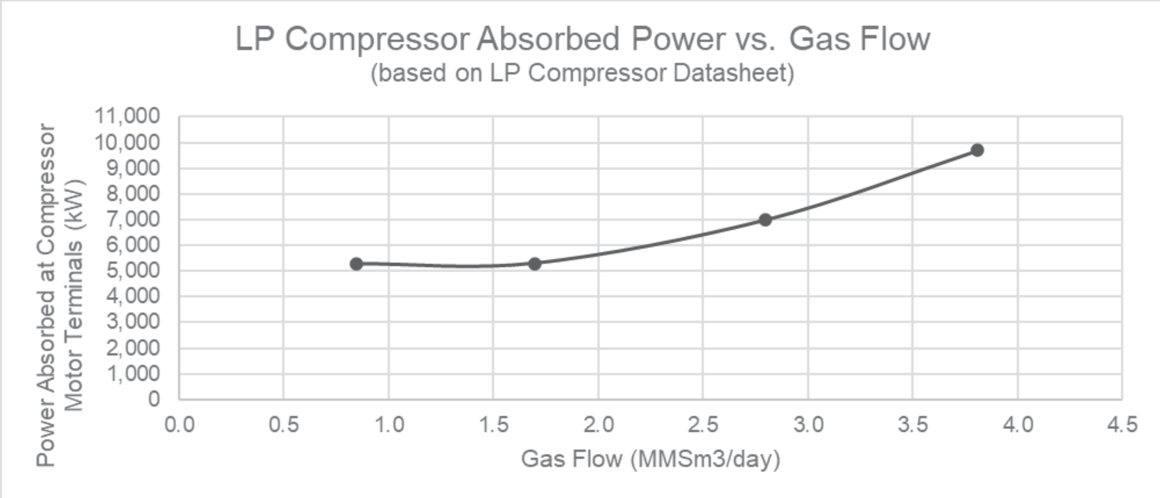

Figure 7.1. Compressor absorbed power vs gas flow.

RPS has accepted the 'Other Opex Asc & non ASC932 (excluding TTE G&A and overheads)' operating costs. RPS has queried the G&A Costs and received confirmation from the Vendor that they are included in the provided Opex estimates with the exception of costs related to such items as R&D, Strategy etc.

The transportation costs in the Vendor model are based on the condensate rates at a unit rate of $2.6/bbl. RPS has maintained this unit cost and calculated the transportation costs against the RPS generated condensate production forecasts. The tariff appears high for transportation only but no granularity on rates was available in the VDR, and a request from RPS for clarity on what is included in this rate solicited no response from the Vendor.

RPS has not applied a carbon tax in the valuation.

7.2 Capital Expenditure (Capex)

The Vendor model includes a Capex estimate of $312m. This figure covers the following development activities that are either already in development or have been moved to firm commitment:

- GSR Studies, Structure Costs and Overhead
- CFR
- LP Compression
- Well Intervention 23
- Well Intervention 24

And it covers the following contingent activities:

- Light Workover (WO) -3 wells
- Layer 3 - MLJ1-07 Deepening
- B1-15k - MLJ3-07

The Vendor's model also includes an additional cost for Prospective wells, but the costs of Prospective activity have been excluded from the RPS estimates as they are not part of this study.

The Vendor's Capex estimates have been accepted by RPS. The contingent activities timing has been adjusted by RPS to align with the RPS production forecasts and are adjusted to coincide when capacity becomes available in the facilities due to natural decline.

RPS has added an additional 5% contingency on the currently in development and firm commitment activity Capex costs. The major Capex activity is the LP compression project which is due for start-up in 2025 and as RPS understands the major long lead items and equipment have been ordered.

8 ECONOMIC EVALUATION

8.1 Contractual Rights Overview

A Petroleum Mining Agreement (PMA) was signed in November 1989, followed by an Amendment Agreement signed in February 2014; and extended until November 2029.

PMA is assumed to be automatically extended from 2029 until November 2039, with renewal being subject to BBJV partners discretion.

8.2 Fiscal Overview

Block B PMA fiscal terms as provided in the management presentation and applied in the economic model are summarised in Figure 8.1.

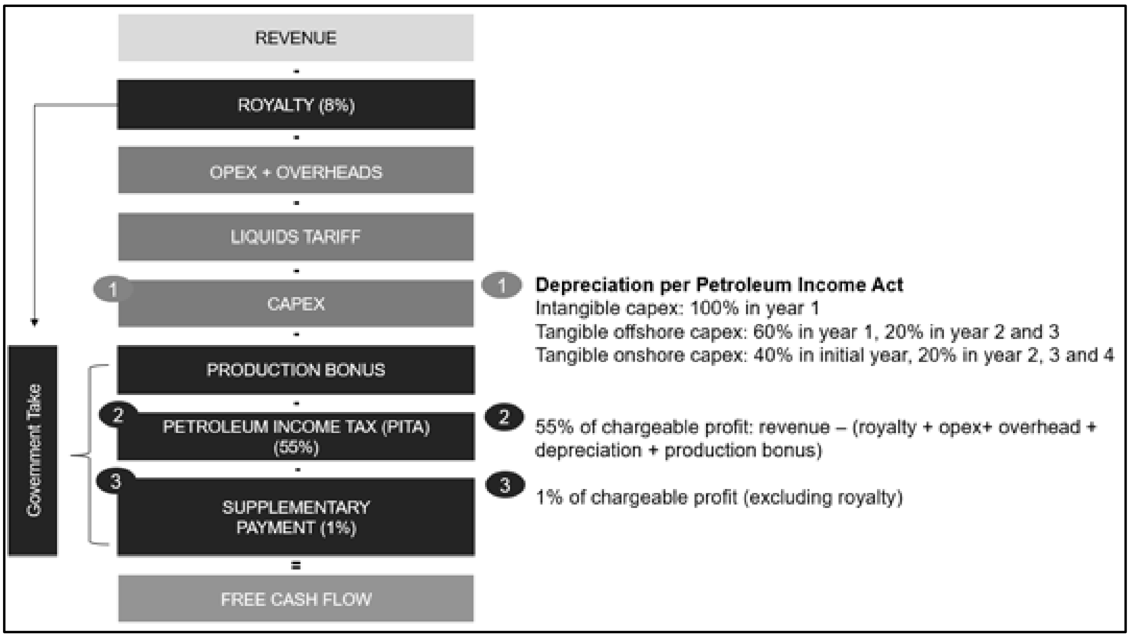

Figure 8.1: Block B PMA Fiscal Terms Summary

8.3 Petroleum Pricing Basis

Based on the data provided in Total's dataroom management presentation and economic model:

- MLJ condensate has average premiums to dated Brent of 2%.
- Into Plant Price (IPP) to BLNG gas price formula as per the GSA:
- Inflation: 2% per annum from 2024 for prices and costs.
- USD10/MMBtu JKM LNG prices with 2% annual inflation and JCC premium over Brent of $1.6/bbl assumed to forecast gas prices
- Domestic Market Obligation ("DMO") gas price of USD 0.33/MMBtu assumed (DMO price is applicable on 10% of the gas sold)

These price assumptions are applied in RPS commercial evaluation, and the annual forecasts are summarised in Table 8.1.

Year	RPS Q2 2024 Brent Oil Price (US$/bbl) MOD	Realised Condensate Price (US$/bbl) MOD	Realised Gas Price (US$/Mscf) MOD
2023	82.4	84.1	4.7
2024	82.0	83.6	4.9
2025	80.0	81.6	4.7
2026	78.0	79.6	4.6
2027	75.0	76.5	4.6
2028	75.0	76.5	4.6
2029	75.0	76.5	4.6
2030	77.0	78.5	4.7
2031	79.0	80.6	4.9
2032	81.0	82.6	5.0
2033	84.5	86.2	5.1
2034	86.2	87.9	5.2
2035	87.9	89.6	5.3
2036	89.6	91.4	5.4
2037	91.4	93.3	5.5
2038	93.3	95.1	5.6
2039	95.1	97.0	5.8

Table 8.1: Oil and Gas Price Assumptions

8.4 Cashflow Analysis

The Economic Limit Test ("ELT") performed for the determination of Reserves is based on RPS's estimates of recoverable volumes, a review of the Total's estimates of Capex, Opex, and Abex; and inclusion of other financial information and assumptions, as outlined in Section 7.

The licences are assumed to reach its economic limit when the cumulative value of its net cash flow (excluding Abex) before tax ceases to increase. All projects to be classified as Reserves must be economic under defined conditions[6]. 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 1 January 2023.

[6] *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.*

8.5 Reserves and Resources

A summary of Reserves is provided in Table 8.2 to Table 8.4 for gas, condensate, and barrels of oil equivalent, respectively.

SUMMARY OF GAS RESERVES
As of 1 January 2023
BASE CASE PRICES AND COSTS

	Full Field Gross Resources[1] (Bscf)			Net Entitlement Reserves[2] (Bscf)		
	1P	2P	3P	1P	2P	3P
MLJ	213	328	432	80	123	162

Notes:

*[1] Gross field Reserves (100% basis) **after** economic limit test. Economic limit in year 2030 for 1P; 2036 for 2P and 2039 3P.*

[2] Total's net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Total's Net Entitlement.

Table 8.2: Gas Reserves as of 1 January 2023

SUMMARY OF CONDENSATE RESERVES
As of 1 January 2023
BASE CASE PRICES AND COSTS

	Full Field Gross Resources[1] (MMstb)			Net Entitlement Reserves[2] (MMstb)		
	1P	2P	3P	1P	2P	3P
MLJ	4.5	9.9	17.2	1.7	3.7	6.4

Notes:

*[1] Gross field Reserves (100% basis) **after** economic limit test. Economic limit in year 2030 for 1P; 2036 for 2P and 2039 3P.*

[2] Total's net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Total's Net Entitlement.

Table 8.3: Condensate Reserves in MLJ Field as of 1 January 2023

SUMMARY OF RESERVES (BOE)
As of 1 January 2023
BASE CASE PRICES AND COSTS

	Full Field Gross Resources[1] (MMboe)[3]			Net Entitlement Reserves[2] (MMboe)[3]		
	1P	2P	3P	1P	2P	3P
MLJ	40.0	64.5	89.2	15.0	24.2	33.4

Notes:

*[1] Gross field Reserves (100% basis) **after** economic limit test. Economic limit in year 2030 for 1P; 2036 for 2P and 2039 3P.*

[2] Total's net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Total's Net Entitlement.

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

Table 8.4: Oil Equivalent Reserves in MLJ Field as of 1 January 2023

A summary of Contingent Resources is presented in Table 8.5 to Table 8.7.

SUMMARY OF GAS CONTINGENT RESOURCES
As of 1 January 2023
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (Bscf)			Net Entitlement Contingent Resources[2] (Bscf)		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**Resources Post EL**	3.4	0.0[5]	0.0[5]	1.3	0.0[5]	0.0[5]
MLJ	**Workover**	2.2	3.2	4.4	0.8	1.2	1.7
MLJ	**Layer 3**	9.2	27.9	25.3	3.4	10.5	9.5
MLJ	**B1-15K**	10.9	36.9	40.4	4.1	13.8	15.2
MLJ	**Hibiscus Workover Plan**	5.4	24.3	17.7	2.0	9.1	6.6
Total[3, 4]		**31.0**	**92.3**	**87.8**	**11.6**	**34.6**	**32.9**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2031 for 1P; 2039 for 2P and 3P.

[2] Total's net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Total's Net Entitlement.

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, RPS' totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

[4] It should be noted that all RPS forecasts are cut off at 2039. Contingent projects are assumed to be added to the NFA production when is required. However, total production is constrained by compressor capacity limits. Certain contingent projects are delayed in the RPS forecasts until there is compressor capacity available. In the high case, the NFA forecasts are sufficiently high that a smaller volume of contingent production is required than in the base case before the compressor capacity is reached. This means the high case contingent volume is smaller than the base case volume. If, however, the forecasts are extended beyond 2039 the 3C volumes are always higher than the 2C volumes as capacity becomes available. Table 6.7 shows the technically recoverable low, best, and high case volumes if production extends to 2059.

[5] Pre-economic limit production forecast for 2P and 3P ends in year 2036 and 2039, respectively.

Table 8.5: Gas Contingent Resources in MLJ Field as of 1 January 2023

SUMMARY OF CONDENSATE CONTINGENT RESOURCES
As of 1 January 2023
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (MMstb)			Net Entitlement Contingent Resources[2] (MMstb)		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**Resourcres Post EL**	0.1	0.0[4]	0.0[4]	0.0	0.0[4]	0.0[4]
MLJ	**Workover**	0.0	0.1	0.2	0.0	0.0	0.1
MLJ	**Layer 3**	0.2	0.9	1.0	0.1	0.3	0.4
MLJ	**B1-15K**	0.2	1.1	1.7	0.1	0.4	0.6
MLJ	**Hibiscus Workover Plan**	0.1	0.7	0.7	0.0	0.3	0.3
Total[3]		**0.6**	**2.8**	**3.6**	**0.2**	**1.1**	**1.4**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2031 for 1P; 2039 for 2P and 3P.

[2] Total's net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Total's Net Entitlement.

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, RPS' totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

[4] Pre-economic limit production forecast for 2P and 3P ends in year 2036 and 2039, respectively.

Table 8.6: Condensate Contingent Resources in MLJ Field as of 1 January 2023

SUMMARY OF CONTINGENT RESOURCES (BOE)
As of 1 January 2023
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (MMboe)[3]			Net Entitlement Contingent Resources[2] (MMboe)[3]		
Field	**Project**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
MLJ	**Resources Post EL**	0.6	0.0[5]	0.0[5]	0.2	0.0[5]	0.0[5]
MLJ	**Workover**	0.4	0.6	0.9	0.2	0.2	0.3
MLJ	**Layer 3**	1.7	5.5	5.3	0.6	2.1	2.0
MLJ	**B1-15K**	2.0	7.3	8.4	0.8	2.7	3.1
MLJ	**Hibiscus Workover Plan**	1.0	4.8	3.7	0.4	1.8	1.4
Total[4]		**5.8**	**18.2**	**18.2**	**2.2**	**6.8**	**6.8**

Notes:

[1] Gross field Contingent Resources (100% basis). Economic limit in year 2031 for 1P; 2039 for 2P and 3P.

[2] Total's net entitlement based on its 37.5% working interest; after economic limit test. Royalties are paid in cash and treated as production tax. Therefore, is not deducted from Total's Net Entitlement.

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

[4] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. As such, RPS' totals were summed arithmetically and as a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

[5] Pre-economic limit production forecast for 2P and 3P ends in year 2036 and 2039, respectively.

Table 8.7: Summary of Oil Equivalent Contingent Resources in MLJ Field as of 1 January 2023

9 CONSULTANT'S INFORMATION

RPS Energy Limited confirms the following:

- 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, RPS 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 Total to Hibiscus. We have accepted, without independent verification, the accuracy and completeness of this data.

- The report represents RPS'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.

- RPS Energy Limited has been remunerated on a fee basis, not connected to asset or client financial performance, past or future, in any way.

- RPS Energy Limited confirms that there is no conflict of interest related to this work. Furthermore, the management and employees of RPS Energy Limited have no interest in any of these assets evaluated nor related with the analysis carried out as part of this report.

- RPS Energy Limited confirms also that neither it nor its management and employees have any interest in either the Vendor, Total Energies, or the potential Purchaser, Hibiscus Petroleum Berhad.

- All staff and associates working on this evaluation meet the professional qualifications requirements of a Qualified Reserves Auditor as specified in the SPE Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (June 2019):

  - A minimum of 10 years practical experience in petroleum engineering or petroleum geology or similar.

  - Have at least a bachelor's or advanced degree in Petroleum Engineering, Geology, or other discipline of engineering or physical science.

  - Has received and is maintaining in good standing, a registered or certified professional licence or equivalent thereof from an appropriate governmental authority or professional organisation.

A summary of experience and relevant qualifications is provided in Table 9.1.

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
James Hodson	Project Manager and Geoscience Lead	15	PhD Sedimentology, University of East Anglia MSc Petroleum Geoscience and Management, University of Manchester BSc (Hons) Geology, University of Manchester	Fellow, Geological Society of London
Adolfo Perez	Reservoir Engineering Lead	>20	MSc Reservoir Evaluation and Management, Heriot Watt University MSc Geotechnical Engineering, University of Barcelona BSc (Hons) Geology, University of Barcelona	SPE AMEI
David Walker	Costs/Facilities Lead	>20	MEng Chemical Process Engineering University of Sheffield	
Joseph Tan	Economics Lead	>20	BEng (Hons.) Petroleum Engineering, Universiti Teknologi Malaysia, 2001	Member – SPE Member – South East Asia Petroleum Exploration Society (SEAPEX) Member and Malaysia Section Lead – Association of International Energy Negotiators (AIEN)

Table 9.1: 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 Gaussian 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}	Connate 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 sulphide, and sulphur. 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.

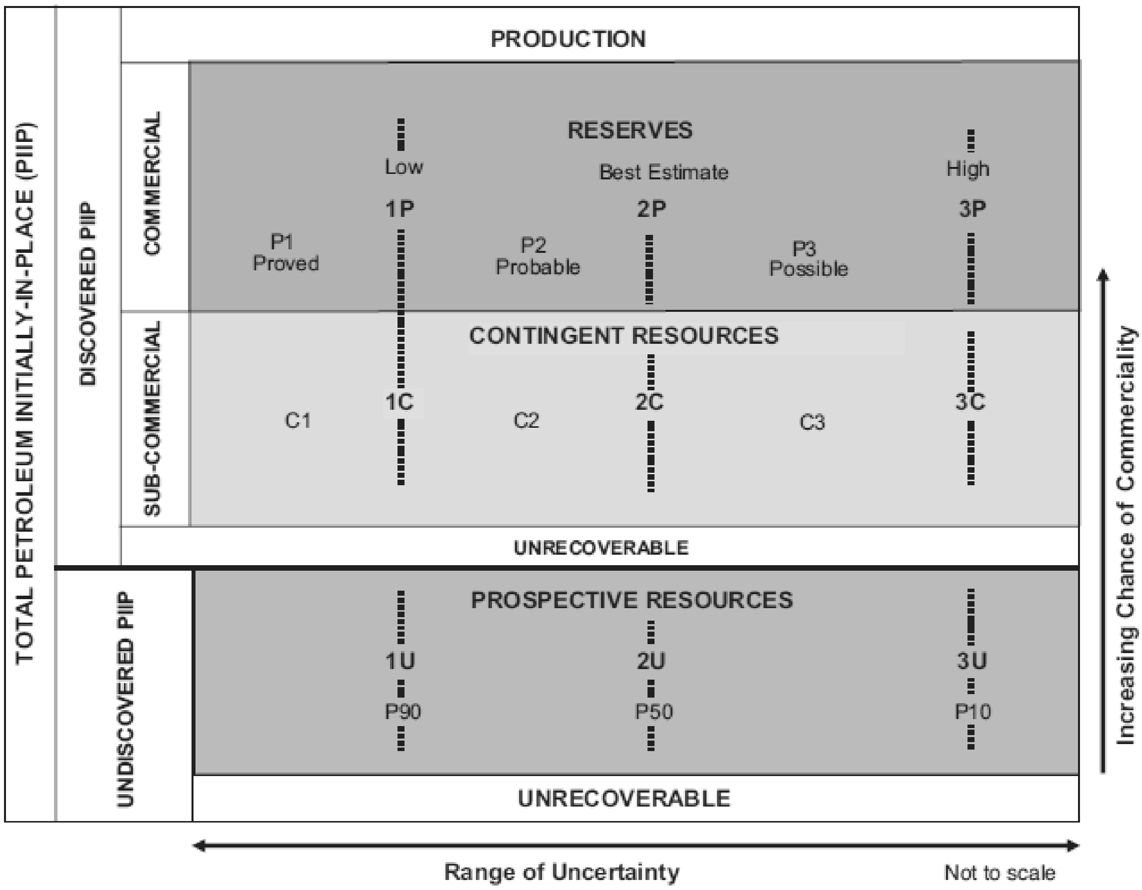

Figure A.1: Resources classification framework

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).

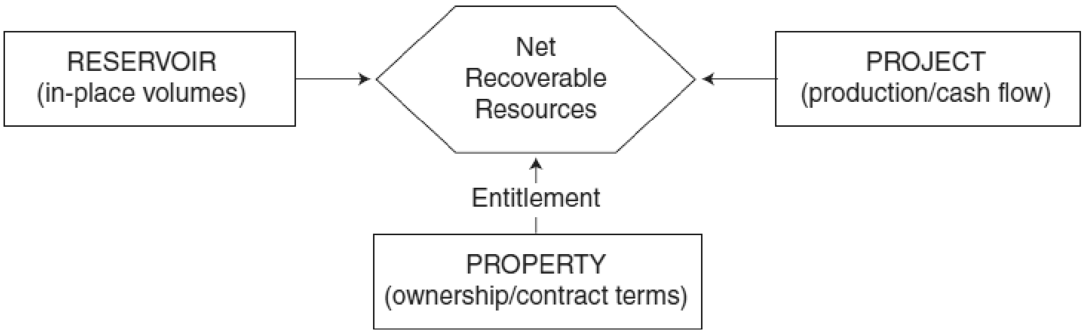

Figure A.2: Resources Evaluation

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.2 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 labelled 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.2.1 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.2.1.1 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.2.1.2 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.2.1.3 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.

B.2.1.3.1 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.

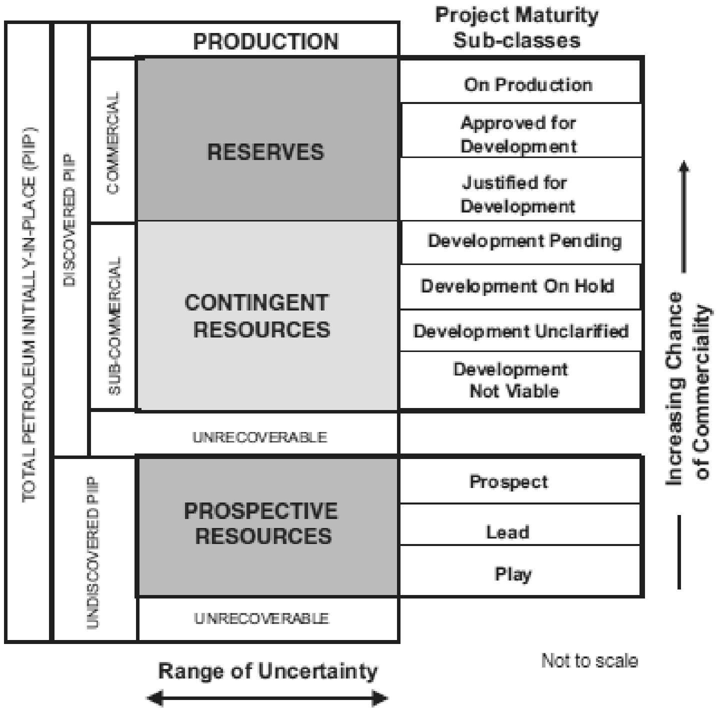

Figure A.3: Sub-classes based on project maturity.

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.

B.2.1.3.2 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.

B.2.1.3.3 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 describe the project more completely. 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.2.2 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.2.2.1 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.2.2.2 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.2.3 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.2.3.1 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.2.3.2 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.2.3.3 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.2.3.4 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 favourable 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.2.4 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-centred 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

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FAIRNESS OPINION REPORT ON MAHARAJALELA JAMALULALAM FIELD

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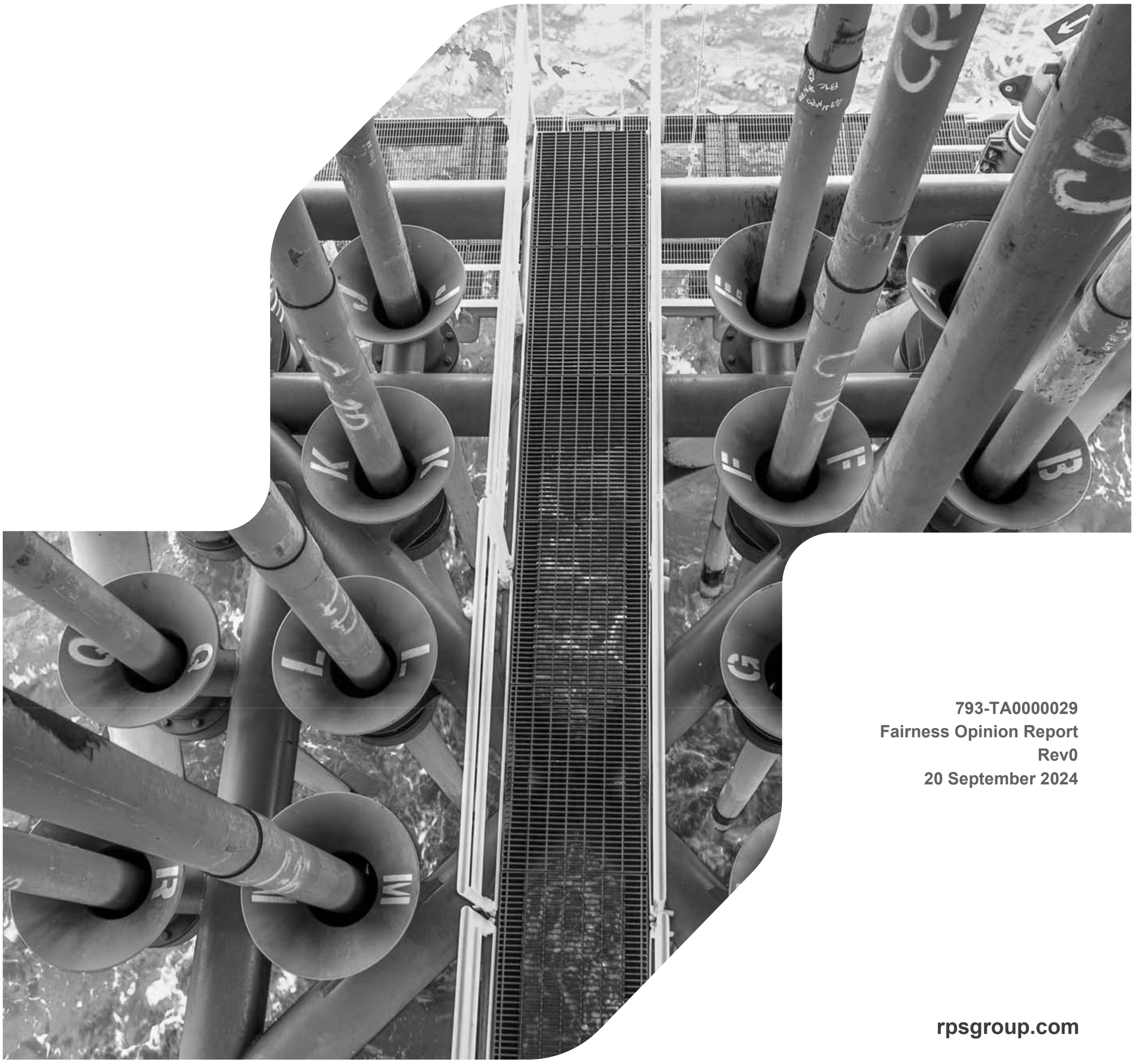

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FAIRNESS OPINION REPORT

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Date: 20 September 2024

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Attn: The Board of Directors

Dear Sirs,

HIBISCUS PETROLEUM BERHAD ("HIBISCUS" OR "COMPANY") EXPERT'S REPORT ON THE FAIRNESS OF THE PURCHASE CONSIDERATION FOR UPSTREAM ASSET HELD BY TOTALENERGIES EP (BRUNEI) B.V. (THE "TARGETCO")

In response to a request by Hibiscus Petroleum Berhad ("Hibiscus"), and the Letter of Engagement dated 30th April 2024 with Hibiscus, RPS Energy Limited ("RPS") has completed a report on the fairness of the purchase consideration of the Maharajalela Jamalulalam (MLJ) Field, in Block B offshore Brunei ("Asset"). The field is currently operated by TotalEnergies EP (Brunei) B.V. ("TargetCo"). TotalEnergies Holdings International B.V. ("Total" or "Vendor"), being the holding company of the TargetCo, is seeking to divest the TargetCo.

The potential transaction encompasses a 100% of the issued shares of the TargetCo offered by Total. The TargetCo holds and operates 37.5% working interest in the Block B Concession located offshore Brunei.

1.1 Brief particulars of the Proposed Acquisition

The Proposed Acquisition entails the acquisition by Simpor Hibiscus Sdn Bhd (an indirect wholly-owned subsidiary of Hibiscus) of the entire equity interest of TargetCo for a cash consideration of approximately USD259.4 million, subject to the terms and conditions of the sale and purchase agreement dated 13 June 2024 ("SPA").

On 14 June 2024, the Company announced that Simpor Hibiscus Sdn Bhd, had on 13 June 2024, entered into the conditional SPA with Total for the Proposed Acquisition.

1.2 Review of Information

In arriving at a discounted cashflow ("DCF") valuation of the proposed transaction, RPS has relied on information from Hibiscus via a Vendor's Virtual Data Room ("VDR"). RPS has reviewed available data and evaluated forecasts for existing production and additional projects confirmed by RPS as being reported by the Vendor.

VDR access was made available to RPS on 3rd January 2024. This contained process documentation, presentations, minutes from key meetings, field development plans, legal and regulatory information and finance and tax information as well as subsurface technical data and historical production data.

The alternative valuation method adopted, the market comparison/market-based approach, required the use of public domain information from company press releases of comparable transactions.

In arriving at the Fairness Opinion, RPS has assumed and relied upon the accuracy and completeness of the data provided by Hibiscus, and certain publicly available information.

1.3 Valuation Methodology

All Reserves and Resources definitions and estimates performed are based on the Petroleum Resources Management System (PRMS). Concurrent with this, RPS performed a DCF valuation of the Asset. In addition, RPS undertook a market comparison/market-based approach with a number of published similar transactions.

1.3.1 Discounted Cash Flow Valuation

The key valuation assumptions by RPS Energy in arriving at the discounted cash flow valuation of the Asset are set out below:-

No.	Key input	Assumptions
1.	Production and cost profiles	RPS Energy 2P and 2C case
2.	O&G prices	RPS Energy Brent price and gas price forecasts
3.	Average premiums to dated Brent	2% for MLJ condensate
4.	Effective date	1 January 2023
5.	Annual inflation rate	2% per annum from for prices and costs
6.	Petroleum Mining Agreement (PMA) period	Assumed to be automatically extended from 2029 until November 2039 on the basis that the Asset continues to be economically viable for the BBJV Partners
7.	Tenure of underlying agreements[1]	Assumed to be extended up to expiry of the extended PMA period

Note:

1. The underlying agreements comprise the Gas Sales Agreement, Third Party Gas agreement and service agreement.

The RPS Reserves cases are truncated at the economic limit, a point in time that defines the economic life of the project. The Petroleum Mining Agreement is assumed to reach its economic limit when the cumulative value of its net cash flow (excluding Abex) 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 post-tax undiscounted Net Cash Flow Money-of-the-Day (MOD).

1.4 Alternative Market Valuation

There are three Common Valuation Approaches recommended by The Australasian Code for the Public Reporting of Technical Assessments and Valuations of Mineral Assets (VALMIN Code) 2015 Edition[2]; namely the Income-based, Market-based, and Cost-based. Each valuation approach is defined in Section 8 of the

[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.

[2] http://www.valmin.org/docs/VALMIN_Code_2015_final.pdf

VALMIN Code[3]. As outlined in Section 8.3 Appropriate Valuation Approach, VALMIN Code recommends Market and Income approach for Production Projects.

1.4.1 Income-based Approach

The valuation of the Asset was undertaken using Discounted Cash Flow (DCF) method, consistent with the industry standard of valuing Reserves and Resource according to the PRMS guidelines. This DCF method has similar principle with the Income-based approach defined by the VALMIN Code.

In order to determine the fair range of valuation based on this Income-based Approach, RPS has reviewed the range of discount rates to be applied to the valuation cash flow based on Hibiscus's Weighted Average Cost of Capital ("WACC") presented in Table 1. RPS has verified the WACC computation input and confirm these are consistent with information available in the public domain.

	D/E: 0.3x	D/E: 0.4x	D/E: 0.5x	D/E: 0.6x
Average Cost of Equity[1]	13.9%	13.9%	13.9%	13.9%
Pre-Tax Cost of Debt[2]	6.14%	6.14%	6.14%	6.14%
Petroleum Income Tax (PITA)	38%	38%	38%	38%
Post-Tax Cost of Debt	3.81%	3.81%	3.81%	3.81%
Target Debt/Equity	0.3	0.4	0.5	0.6
WACC	10.87%	9.86%	8.85%	7.84%

Notes:
[1] Based on 5 Year Average Cost of Equity (source: Hibiscus, Bloomberg as at 9 May 2024)
[2] Based on weighted average cost of debt as at end Feb 2024 and 5 Year Average Secured Overnight Financing Rate (SOFR) provided by Hibiscus

Table 1: Range of Hibiscus's Weighted Average Cost of Capital (WACC)

As the Asset is already in the production phase, we believes it is reasonable not to add additional premium over the WACC. Therefore, RPS opines that a discount rate of 10 per cent is a fair rate to be applied for the purpose of current valuation for the Reserves. The Asset 2P NPV discounted at 10 per cent is **US$ 236 million**.

For the valuation of Contingent Resources, RPS opines that a discount rate of 12 per cent is reasonable. The Asset 2C NPV discounted at 12 per cent is **US$ 14 million**. Therefore, total NPV for 2P and 2C at discount rate of 10 per cent and 12 per cent, respectively, is **US$ 250 million**.

Therefore, the reasonable range applying this Income-based Approach without net working capital and cash of US$ 14.4 million would be between US$ 236 million for Reserves and US$ 250 million for Reserves plus Contingent Resources.

The reasonable range applying this Income-based Approach together with net working capital and cash of US$ 14.4 million would be between **US$ 250.4 million** for Reserves and **US$ 264.4 million** for Reserves plus Contingent Resources**.**

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[3] Market-based, which is based primarily on the notion of substitution. In this Valuation Approach the Mineral Asset being valued is compared with the transaction value of similar Mineral Assets under similar time and circumstance on an open market.

Income-based, which is based on the notion of cashflow generation. In this Valuation Approach the anticipated benefits of the potential income or cash flow of a Mineral Asset are analysed.

Cost-based, which is based on the notion of cost contribution to Value. In this Valuation Approach the costs incurred on the Mineral Asset are the basis of analysis.

The proposed acquisition of the entire equity interest of the TargetCo by Hibiscus for a cash consideration of **US$ 259.4 millio**n (including net working capital and cash of US$14.4 million, as at 31 December 2022), subject to the adjustments set out in share purchase agreement ("Purchase Consideration"), is within this estimated range based on Income-based Approach.

1.4.2 Market-based Approach

RPS's estimate of 2P Net Entitlement Reserves as of 1st January 2023 is 123 Bscf of gas 3.7 MMstb of condensate, and; assuming 6,000 scf/boe for the gas Reserves, translate to a total barrel of equivalent of 24.2 MMboe.

The valuation of the 2P Reserves at RPS Base Brent price and applying a 10% discount rate as of 1 January 2023 but excluding cash flow from Third Party Gas, is US$ 169 Million. The implied dollar per 2P barrel is therefore US$ 7.0/boe.

The valuation of 2C at RPS Base Brent price and applying a 12% discount rate as of 1st January 2023 but excluding cash flow from Third Party Gas, is US$ 14 Million. Total NPV for 2P plus 2C is therefore US$ 183 million and translates an implied dollar per 2P plus 2C barrel of 5.9/boe.

For the alternative valuation method, in this case the Market-based approach, by comparison to similar market transactions, we have reviewed the information of recent transactions in Malaysia, Indonesia and Thailand that are available in the public domains and considered those deals relating to producing fields for comparison with the current valuation.

A summary of the limited number of transactions in Malaysia, Indonesia and Thailand, which completed in year 2018 and 2022 is presented in Table 2. Clearly, the market transactions tabulated would have been made under different price environments, as well as being concluded at different discount rates according to the respective buyers' investment strategy at the point of the acquisitions made.

Based on the information summarised in Table 2, the implied dollar per 2P barrel ranges between US$ 6.2/boe and US$ 17.3/boe. The current valuation with its implied dollar per 2P barrel of US$ 7.0/boe falls within this range. RPS opines it would not be accurate to assume 100 per cent of the reported 2C Contingent Resources to derive the implied dollar per 2P plus 2C barrel, it is probably not unreasonable to assume a third of the 2C in deriving the deal metric based on information sourced from public domain. Based on this assumption, the implied dollar per 2P plus 2C barrel ranges between US$ 5.9/boe and US$10.7/boe. The current valuation with its implied dollar per 2P plus 2C barrel of US$ 5.9/boe falls within this range.

During current commercial evaluation period between December 2023 and April 2024 in which the acquisition price of Total's asset was finalised, average Brent crude oil price is US$ 83 per barrel, which is approximately 18% more than when Repsol assets in Malaysia were acquired by Hibiscus. The implied dollar per 2P barrel price of US$ 6.2/boe for that transaction is the lowest of the transactions analysed in Table 2. If an 18% adjustment was applied to the Repsol transaction, the implied dollar per 2P barrel is US$ 7.2/boe.

The highest implied dollar per 2P plus 2C barrel of US$ 10.7/bbl is related to OMV Exploration and Production GmbH (OMV) acquisition of 50 per cent interest in Sapura Energy Berhad (SEB) Upstream Sdn Bhd (SUP) in January 2019. Brent crude oil price during current evaluation is approximately 19% more compared to when Sapura OMV transaction was completed. If we are to apply this 19% adjustment to Sapura OMW transaction, the implied dollar per 2P plus 2C barrel is US$ 12.7/boe.

Therefore, applying these implied dollars per barrel to 2P and 2P plus 2C, the reasonable range of valuation would be between **US$ 242 million** and **US$ 461 million.**

The Purchase Consideration of USD 259.4 million is within this estimated range based on Market-based Approach.

No.	SPA Date	Asset name	Buyer(s)	Seller	Price (US$MM)	2P Reserves (MM boe)	2P Price (US$/boe)	2P+2C[1] (MM boe)	2P+2C Price (US$/boe)
1	June 2022	Concession L53/48[4]	Dialog Systems (Asia) Pte Ltd (DSAPL)	Pan Orient Energy Corp	38.7	4.6	8.4	-	-
2.	June 2021	Acquisition of Repsol Assets in Malaysia & Block 46, Vietnam	Peninsula Hibiscus Sdn Bhd	Repsol Malaysia	212.5	34.5	6.2	35.8	5.9
3.	January 2019	Acquisition of Ophir Energy plc[5]	PT Medco Energi Internasional Tbk	Ophir Energy plc	517[2]	70.1	7.4	-	-
4.	March 2019	Murphy Oil Corporation's Interests in Malaysia[6]	PTTEP Limited	Murphy Oil Corporation	2,127	169.3[3]	12.6	-	-
5.	November 2018	50 per cent interest in SEB Upstream Sdn Bhd (SUP)[7]	OMV Exploration and Production GmbH	Sapura Energy Berhad	800	46.1	17.3[3]	74.7	10.7
6.	May 2018	Acquisition of Santos's Southeast Asian production licences[8]	Ophir Energy plc	Santos Limited	205	23.3	8.8	-	-

Notes:

[1] 100% 2P plus a third of 2C

[2] Medco completed the acquisition of Ophir Energy plc in a recommended all cash offer valued at £408.4 million. GBP = 1.2663 US$ (Source: Bank of England)

[3] 2P of approximately 274 million boe, according to working interest. RPS has applied an average 61.8% factor to convert the working interest Reserves to 2P Net Entitlement Reserves. 2C Resources was not disclosed.

Table 2: Summary of Several Recent Transactions in Malaysia, Thailand and Indonesia

[4] https://www.nst.com.my/business/2022/06/802987/dialog-group-acquires-pan-orient-energy-rm170mil

[5] https://www.medcoenergi.com/en/subpagelist/view/12/2941

[6] https://www.pttep.com/en/Investorrelations/Regulatorfilings/Setnotification/Theacquisitionofmurphyoilcorporationsinterestsinmalaysia.aspx

[7] http://ir.chartnexus.com/sapuraenergy/onenew.php?id=2920472&type=Announcement

[8] https://www.ophir-energy.com/wp-content/uploads/2019/03/2018-Full-Year-Results.pdf

1.4.3 Fair Market Value

Based on the two Common Valuation Approaches recommended by VALMIN Code, namely the Income-based Approach and Market-based Approach, RPS opine the Fair Market Value of the Asset ranges between **US$ 242 million** and **US$ 461 million**.

The Purchase Consideration of USD 259.4 million is within this estimated range.

QUALIFICATIONS

RPS is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. The provision of professional services has been solely on a fee basis. Gordon Taylor, Technical Director, has supervised this evaluation. Gordon is a Chartered Geologist and Chartered Engineer with over 40 years' experience in upstream oil and gas. The project has been managed on a day-to-day basis by James Hodson who has 12 years' experience in upstream oil and gas. Other RPS 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, RPS 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 RPS'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 RPS.

Yours sincerely,
for RPS Energy Ltd

Gordon Taylor
Technical Director

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Building a better working world

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20 September 2024

Dear Sirs,

LETTER OF POLICIES ON FOREIGN INVESTMENTS, TAXATION AND REPATRIATION OF PROFITS OF THE NETHERLANDS AND BRUNEI DARUSSALAM

We have been requested to provide our professional statement, containing a summary information of policies on foreign investments, taxation and repatriation of profits in the Netherlands and Brunei Darussalam, as may be applicable (the “Professional Statement”) in connection with the proposed acquisition by Simpor Hibiscus Sdn Bhd (an indirect wholly-owned subsidiary of Hibiscus Petroleum Berhad) of the entire equity interest in TotalEnergies EP (Brunei) B.V., a company incorporated in the Netherlands (including its branch which is operating in Brunei (the “Branch”)) (collectively referred to as “TEPB”). TEPB holds a 37.5% participating interest in the Maharajalela Jamalulalam (MLJ) field within Block B.

The Professional Statement has been prepared on the basis of laws and policies that are in force in the Netherlands and Brunei Darussalam, as applicable, at the date of this letter. The laws are subject to change and any change may impact our statement materially. The text below is a brief summary and therefore, limited to a general overview. It does not cover every aspect of investments and cannot provide information regarding individual circumstances. The information given in this memorandum is limited to the tax regulations and does not constitute legal advice.

(Please note that Ernst & Young Tax Consultants Sdn. Bhd. does not provide legal services and legal advice, and therefore our comments below on the policies on foreign investment and repatriation of profits of the Netherlands and Brunei, as applicable, are general comments only.)

Building a better working world

LETTER OF POLICIES ON FOREIGN INVESTMENTS, TAXATION AND REPATRIATION OF PROFITS OF THE NETHERLANDS AND BRUNEI
20 September 2024

A. The Netherlands

The information set out below is a general non-exhaustive summary of the relevant Dutch tax legislation. This summary does not purport to be a comprehensive or complete description of all Dutch tax legislation that may be relevant in relation to the proposed transaction.

All references in this letter to the Netherlands and Dutch tax law are to the European part of the Kingdom of the Netherlands and its laws. Unless explicitly stated otherwise, this summary is based on the tax laws of the Netherlands in effect on the date of this letter, which are subject to changes that could prospectively or retrospectively affect the Dutch tax legislation.

PART I – Corporate Income Tax ("CIT")

1.1 Requirements for tax residency

Whether a company is resident in the Netherlands in principle is determined on the basis of the facts and circumstances, the place of effective management being the most relevant fact/circumstance.

An entity that has been incorporated in the Netherlands is considered Dutch resident by virtue of law based on the Dutch Corporate Income Tax Act 1969 ("CITA"). However, to claim certain specific benefits under Dutch tax law or under tax treaties concluded between the Netherlands and another jurisdiction, companies are typically required to have their *place of effective management* in the Netherlands. The place of effective management is the place where key management and commercial decisions that are necessary for the conduct of the entity's business are made. In this respect substance prevails over form.

The place where the management is carried out would generally be considered the place where the management board takes its decisions. The place where the directors of the company actually reside is not decisive, however it can be used as indication of the place of effective management.

In order to determine the place of effective management of a company, the quantity/size/frequency of the activities of a company that are undertaken by that company is not relevant. What is relevant is the place where the activities of the company have been decided upon, i.e. effectively managed.

The place of effective management is the jurisdiction wherein its directors are (tax) residents, where they hold the (board) meetings and where the key decision regarding the company are taken. Apart from the place of effective management, also other facts/circumstances could play a role in determining the residency of a company, although they typically play a (very) minor role. Relevant criteria could be amongst others:

- The jurisdiction where the administration is performed and the annual accounts are prepared and from where the bank accounts are managed;
- The corporate law under which the respective company was incorporated; and
- The registration in the Chamber of Commerce.

The above are just examples and these criteria are not exhaustive, but as said, they only play a very minor role.

1.2 Application of CIT rates

Pursuant to article 22 of the CITA, a Dutch resident entity regularly subject to Dutch CIT is taxed based on its worldwide taxable income at the following rates:

Bracket (EUR) – Taxable amount	Rate (in 2024)
0 – 200,000	19.0%
In excess of 200,000	25.8%

1.3 Foreign income

1.3.1 Application of Dutch object (branch) exemption

A Dutch besloten vennootschap ("BV") is taxable in the Netherlands on its worldwide income. However, income derived through a foreign permanent establishment ("PE") is in principle exempt from Dutch corporate income tax. Double taxation is in principle avoided through a so-called object exemption. In the calculation of the taxable amount of the BV, the PE results (both positive and negative) are in principle exempt and excluded from the taxable basis (i.e. non-taxable or non-deductible). However, if the currency used for tax purposes in the PE country differs from the currency used to determine the profit of the BV (reference is made to section 2), also (translation) differences could occur, and they are not eliminated.

The question of whether a foreign PE is recognized is firstly a question of whether a PE is recognized under Dutch domestic law that – in case a treaty is applicable – also refers to the definition of a PE under the relevant applicable treaty. In this respect, most tax treaties use the same or similar language as included in the OECD Model Tax Convention ("MTC") and hence the explanatory notes to the OECD MTC are a useful tool in determining whether a PE should be recognized.

The definition of a PE for Dutch CIT purposes has been amended in line with the definition as included in the OECD recommendations in the context of the Base Erosion and Profit Shifting ("BEPS") project, as these will be implemented over time via the Multilateral Instrument ("MLI") in (amongst others) the Dutch network of double tax treaties. Pursuant to article 3, paragraph 4 Dutch CITA, the question whether a PE is recognized under Dutch domestic law should be based on the definition included in the relevant treaty at hand (as mentioned above). In non-treaty situations, reference is made to the most recent OECD definition.

1.4 Foreign currency election

The default currency of a Dutch BV upon incorporation is Euro that is used as the currency for preparing and filing the annual CIT return in the Netherlands. However, it is possible to apply a different functional currency (such as USD) for CIT purposes. In order to apply a different functional currency a request should be filed with the Dutch tax authorities. In this respect the following is relevant:

- The currency for statutory (accounting) purposes must be the same currency as well. The use of another currency has to be justified by the activity of the legal entity or the international activities of the group.
- The functional currency of a Dutch BV can be applied retroactively upon incorporation by filing a request in the first financial year of the entity.
- To calculate the CIT payable, the amount should be converted from the functional currency to EUR at the average exchange rate of the (accounting) year.
- The functional currency of the Dutch BV is in principle applied for a period of 10 years.

1.5 Tax losses and change of control rules

As from 1 January 2022, the annual utilization of tax loss carryforwards is limited to the first EUR 1 million of taxable profit, plus 50% of the taxable profit exceeding EUR 1 million. In addition, losses can be carried back one year and carried forward indefinitely.

This rule applies to all tax losses arising as of 1 January 2022, as well as any tax loss carryforwards still available at that date. These old losses may in principle be set off against taxable profits for financial years commencing on or after 1 January 2022. Losses incurred before 2013 that have not been offset against taxable profits up to and including 2021, are expired and can therefore no longer be carried forward. In principle, losses as of 2013 can be offset indefinitely over time. However, the losses are subject to the aforementioned '50% rule'. Under Dutch tax law, the carry forward and/or carry back of losses may be limited for certain holding and/or group financing companies.

<u>*Change of control*</u>
Dutch tax law provides anti abuse rules in relation to the utilization of tax losses carried forward (and certain other tax attributes such as interest carry forwards) after a change of control. These rules aim to combat the trade in loss-making companies.

The general rule is that a Dutch taxpayer's tax loss may not be offset against its future taxable profits if the ultimate interest in the Dutch taxpayer has substantially changed (i.e., 30% or more) compared to the oldest loss year, unless the following cumulative requirements are met:

i. The assets of the Dutch taxpayer do not, for more than 50%, consist of portfolio investments during a period of at least 9 months in the year the tax losses were incurred (portfolio investments test);
ii. Directly prior to the change of control, the activities of the Dutch taxpayer have not decreased to less than 30% in comparison to its activities at the beginning of the oldest year in which the tax losses were incurred (activity test);
iii. At the moment of the change of control there is no intention to decrease the activities of the Dutch taxpayer within the next 3 years, to less than 30% in comparison to the activities at the beginning of the oldest year in which the tax carry forward losses were incurred (intention test).

Furthermore, the tax losses can only be offset against taxable profits during a tax book year in which, for a period of at least 9 months during said tax year, the assets do not consist for more than 50% of passive portfolio investments.

Limitation of loss set-off for holding and group financing companies
Under Dutch tax law, the carry forward and/or carry back of losses may be limited for holding companies and/or group financing companies (on top of the aforementioned change of control rules and 50% rules). The restrictions apply to companies at least 90% of whose activities, during 90% or more of the financial year, consisted of holding activities and/or the direct or indirect financing of related parties.

The limitation of loss setoff for holding and financing companies was abolished per 1 January 2019. Transitional measures (article 34i CITA) apply to losses incurred prior to the first fiscal year starting on or after 1 January 2019 and which were subject to the limitation of loss setoff for holding and group financing companies. In case a loss qualified as 'holding and/or group financing loss' in 2018 or earlier years, the limitation of loss setoff for holding and group financing companies continues to apply as long as these losses are available for offset. Such companies can only set off losses of any financial year against profits of another financial year, if the activities of these companies in both financial years consisted for 90% or more of holding activities or the direct or indirect financing of related parties.

PART II – Withholding Taxes and other taxes

2.1 (Conditional) withholding taxes

2.1.1. Dividends (description of the Dutch domestic dividend withholding tax exemption)

The Netherlands in principle levies a 15% statutory dividend withholding tax ("DWHT") on proceeds (such as dividends) distributed by a Dutch BV. Proceeds within the meaning of the Dutch Dividend Withholding Tax Act 1965 ("DWTA") should be broadly interpretated and amongst others includes both formal and informal dividend distributions of any kind, including liquidation distribution proceeds, partial repayment of share capital if and to the extent there are embedded profits, redemption of share capital above the average paid in share capital. The proceeds also include amounts distributed on profit-sharing certificates and/or profit participating loans. Please note that the above is not exhaustive.

However, in case the conditions of article 4 of the DWTA are applicable then an exemption from DWHT applies. The exemption is applicable if regarding the recipient of the proceeds from the shares the following conditions are met:

A. if the Dutch participation exemption as defined in article 13 CITA or the Dutch participation credit regime is applicable on the proceeds received by the recipient and the share interest held in the Dutch BV is part of its business enterprise in the Netherlands; or
B. if both the recipient and the withholding agent (e.g., the distributing entity) are part of the same fiscal unity as defined in article 15 CITA, and the share interest is part of the business enterprise of the recipient in the Netherlands; or
C. is established in a European Union ("EU") / European Economic Area ("EEA") Member State or is established in another jurisdiction with which the Netherlands has concluded a tax treaty that includes an article covering dividends and according to a tax treaty concluded by its state of establishment, not considered to be established in

a state which has not concluded a tax treaty with the Netherlands including an article covering dividends, not being an EU / EEA Member State; and

D. has an interest in the company distributing the dividend to which the Dutch participation exemption or the Dutch participation credit regime would apply at the time of the dividend distribution if the company receiving the dividend would be a tax resident in the Netherlands; and

E. does not fulfill a function similar to an investment (fund) institution in the meaning of article 6a or article 28a CITA; and

F. is considered the beneficial owner of the proceeds (and the anti-dividend stripping rules do not apply); and

G. the recipient does not hold the interest in the distributing company via a so-called reverse hybrid entity, i.e., an entity that from a Dutch perspective is not treated as the beneficiary of the dividend income as from a Dutch tax perspective its partners, owners or shareholders are treated as such, while according to the laws of its state of residency of those partners, owners or shareholders, that entity is treated as the beneficiary; and

H. is not considered 'abusive' as a result of the domestic implementation of the Principal Purpose Test under the MLI, meaning that the recipient:
   a. does not hold the interest in the distributing company with the main purpose or one of the main purposes to avoid the levy of Dutch DWHT of the (in)direct owner of the recipient (individual or company) ("Subjective test"); or
   b. the arrangement or transaction, or series of arrangements or transactions are not considered artificial. An arrangement or transaction, or series of arrangements or transactions is not considered to be artificial if it is put into place based on valid commercial reasons that reflect economic reality ("Objective test").

If an entity qualifies as non-transparent according to Dutch tax standards but is not treated as a resident according to the laws of its state of residency (e.g., because it is transparent under the local legislation), condition C will not be met and therefore the domestic DWHT exemption is in principle not applicable.

However, article 4, paragraph 9 DWTA determines that if the recipient of the income (for Dutch tax purposes) is not treated as the recipient of the income for its domestic tax purposes according to the law of the country in which the entity is incorporated, because the recipient is not treated as established in such country for the applicable domestic tax purposes as it is treated as transparent by that jurisdiction, the participants in such recipient will be treated as the recipients for purposes of Dutch DWHT provided that all of the participants in the recipient are regarded as the recipients of the income (for their domestic tax purposes) in the state in which they are resident. The Dutch domestic DWHT exemption shall not apply if the Dutch domestic DWHT exemption would not have been applicable to all indirect recipients if such recipient held the interest directly instead of indirectly.

Following article 4, paragraph 4 of the DWTA, the domestic exemption cannot be applied if the recipient of the dividends is not considered to be the beneficial owner of the dividends. This is, for example, the case if the anti-dividend stripping provisions of article 4, paragraphs 7 and 8 of the DWTA apply. Dividend stripping includes transactions in which a DWHT claim is either reduced or completely avoided while the economic interest in the shares on which the dividend is paid is (barely) altered.

The recipient is not considered the ultimate beneficial owner of the proceeds (including dividends) in case, in conjunction with the proceeds a compensation/consideration has been provided as part of a series of transactions whereby it is plausible that:

A. The proceeds in whole or in part, directly or indirectly, have benefitted:
   a. a natural person or legal entity with regard to whom withholding may not be omitted, while in respect of the party that provided the compensation/ consideration such withholding would be permitted; or
   b. a natural person or legal entity who cannot fully benefit from a reduction or refund of DWHT than the party that provided the compensation/ consideration (i.e. the party that provided the compensation/consideration is in a better DHWT position than the ultimate beneficiary of the compensation/ consideration) and

B. the natural person or legal entity that benefited from the compensation/ consideration, directly or indirectly, maintains or acquires a position in shares, profit-sharing certificates or profit participating loans that is comparable to the position it held prior to the time that the series of transactions took place.

The domestic DWHT exemption does not impose a minimum holding period. If the domestic DWHT exemption applies, a notification must be submitted to the Dutch tax authorities within 30 days from the day that the dividend was made available to the beneficiaries of the dividend proceeds. In the situation that no domestic or treaty based Dutch DWHT exemption applies, a DWHT return must be filed and any DWHT due must be paid, within one month following any distribution.

As of 1 January 2024, a conditional anti-abuse WHT on dividend payments entered into force. This WHT co-exists with the regular DWHT. Although an anti-cumulation rule will apply, the total tax burden on dividends to low-taxed jurisdictions, hybrid entities and abusive situations should be equal to 25.8% (highest CIT rate). As the conditional WHT on dividends is applied similarly to the Dutch conditional WHT on interest and royalties, we refer to the general summary below for further details.

2.1.2. Conditional WHT on interest, royalties and dividends.
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As of 1 January 2021, a WHT against a rate equal to the headline CIT rate (25.8% in 2024) has come into effect on intragroup interest and royalties (deemed) paid or accrued by a Dutch corporate taxpayer (entity or permanent establishment). As of 1 January 2024, the conditional WHT was extended to dividend payments. The WHT is due in case payments are made to a related entity resident in:

i. a jurisdiction with no tax or a statutory tax rate lower than 9%; or
ii. a jurisdiction that is included on the European Union (EU) list of non-cooperative jurisdictions for tax purposes; or
iii. other jurisdictions if the entity allocates the interest, royalties or dividends to a permanent establishment in a jurisdiction with no tax or a statutory tax rate lower than 9% or in a jurisdiction that is included on the EU list of non-cooperative jurisdictions; or
iv. certain situations in which the recipient is a hybrid entity; or
v. certain abusive situations.

We note that conditional WHT is also due on deemed dividends. Also we note that in case interest or royalties are not determined on an at arm's length basis, the conditional withholding tax will be due on the at arm's length amount.

Definitions
The beneficiary or its related party needs to hold a 'qualifying interest' in the Dutch payor. An interest is a 'qualifying interest' when a holder of such interest can exercise decisive control over decisions of the entity. This should be determined based on the relevant facts and circumstances. An interest representing 50% or more of the statutory voting rights will in any case qualify as a qualifying interest. An interest is also considered a 'qualifying interest' in case a group of shareholders act together whereby none or not all of the shareholders has on a standalone basis decisive control over decisions of the entity. Whether a group of shareholders qualify as a "collaborating group" (which may also fall under the definition of holding a qualifying interest) of shareholders depends on the facts and circumstances, such as coordinated group decisions.

The conditional WHT is due on (deemed) payments/accruals of interest, royalties and/or dividends. Interest is defined as consideration of any kind – including costs – for debt. The definition of royalties follows the OECD model treaty definition and includes consideration for the right to use any patents, trademarks, designs or models. The conditional WHT on dividends is due on any proceeds as defined under the 'regular' Dutch DWTA as noted in section 2.1 above. The conditional interest WHT is due on accrued, imputed or paid considerations. Upward corrections if the interest or royalty payment is not at arm's length (e.g., imputed expenses) including secondary adjustments (deemed dividends), are also in scope of the conditional interest WHT.

Moment of enjoyment
The conditional WHT is due at the moment of enjoyment of the interest, or royalty or dividend payment by the recipient. The moment of enjoyment is defined as:

i. The time the amount has been paid or settled, made available to the beneficiary or becomes interest bearing.
ii. The time the amount has become claimable and collectible.
iii. If interest or royalties have accrued and remained outstanding during a calendar year: on 31 December of that year.

Both the payor and recipient of the relevant payment are liable for the conditional interest WHT. The payor must report and withhold the conditional WHT within thirty days after termination of the calendar year in which WHT on interest, or royalties or dividends were due. Non-compliance with these obligations may result in administrative penalties.

The dividend is enjoyed at the time that the dividend was made available to the beneficiaries of the dividend proceeds.

2.2 Foreign substantial interest taxpayer rules

Based on article 3 CITA, legal persons (e.g., foreign corporate bodies) residing abroad may be subject to Dutch corporate income tax as non-resident taxpayers to the extent they earn Dutch income. Pursuant to article 17, paragraph 3, subparagraph b CITA, this includes the taxable income from a so-called substantial interest (as defined by chapter 4 of the Dutch

Personal Income Tax Act 2001 ("PITA"), in an entity, not being an exempt investment entity within the meaning of article 6a CITA that is a tax resident in the Netherlands, in case the substantial interest is held with the main purpose or one of the main purposes to avoid personal income tax at the level of another entity and the arrangement or transaction, or series of arrangements or transactions are considered artificial. An arrangement or transaction, or series of arrangements or transactions is considered to be artificial if it is not based on valid commercial reasons that reflect economic reality.

Pursuant to article 4.6 PITA, a taxpayer, together with his or her spouse or spousal equivalent, holds a substantial interest if he/she directly or indirectly owns at least 5% of the issued share capital of a Dutch BV or has an entitlement to acquire, directly or indirectly, at least 5% of the share capital.

In Netherlands, dividends and interests (under certain conditions) paid to non-resident shareholders are subject to withholding tax. However, domestic law in the Netherlands provides for exemptions, under certain conditions, on payments made to Malaysian tax residents.

PART III – Anti-abuse Rules

3.1 Principal purpose test under tax treaties

As a result of the implementation of the MLI, a Principal Purpose Test ("PPT") is included in so-called Covered Tax Agreements ("CTA") whereby both contracting states have implemented the MLI resulting in the PPT to apply. The PPT is defined as follows (art. 7 MLI):

"A benefit under the Covered Tax Agreement shall not be granted in respect of an item of income or capital if it is reasonable to conclude, having regard to all relevant facts and circumstances, that obtaining that benefit was one of the principal purposes of any arrangement or transaction that resulted directly or indirectly in that benefit, unless it is established that granting that benefit in these circumstances would be in accordance with the object and purpose of the relevant provisions of the Covered Tax Agreement."

The PPT is the implementation of BEPS action plan 6. Whether the PPT would be applicable should be assessed based on the following decision framework:

1. Identify and quantify the objective treaty benefit, e.g. is there a reduced withholding tax rate pursuant to the interposition of a treaty partner in the shareholder chain?
2. Identify the non-tax business reasons for the existence of a (holding) entity within the corporate structure. Genuine substance should normally provide for such reason.
3. Identify the non-tax and non-treaty reasons for the choice of location of a holding/financing company.
4. Weigh up the evidence to assess the weight of different purposes.
5. Determine whether granting the benefit of the tax treaty is contrary to the object and purpose of the relevant provisions within the tax treaty.

As the Netherlands have implemented the MLI per 1 July 2019, the Dutch Government has published an overview of the CTAs per 1 April 2024 on its website.

3.2 ATAD3 brief explanation and status

On 22 December 2021, the European Commission published a legislative proposal for a Directive setting ("UNSHELL" or "ATAD 3"). In short, the draft directive aims at introducing an EU-wide "'substance-test", including a reporting obligation for taxpayers to identify group companies that are engaged in an economic activity but which do not have minimal substance.

In February 2023, the Dutch State Secretary of Finance published a letter in which the Dutch approach regarding shell companies was addressed as well. In this letter it was again stressed (in line with previous publications) that the Dutch government prefers a uniform international approach.

As the proposal of the Directive has to be discussed by the meeting of the Economic and Financial Affairs ("ECOFIN"), it is unclear whether the adoption of UNSHELL will take place at a later stage or whether the proposal will be dropped.

One of the objectives of the current Belgian Presidency (until July 1, 2024) of the EU is to achieve a compromise on Unshell. However, after several rounds of negotiations, Member States' positions continue to lay far apart.

PART IV - Repatriation of Profits

4.1 Repatriation of profits

As noted in section 2.1, the Netherlands levies dividend WHT on proceeds distributed by a Dutch BV, unless the Dutch domestic dividend WHT exemption can be applied or a reduced rate may be applied based on the applicable double tax treaty. In the Netherlands, the repayment of nominal share capital that is recognized as capital for Dutch tax purposes should in principle not fall under the scope of the DWHT, if certain formal conditions are met. The Netherlands does not levy stamp duty.

The Netherlands do not impose exchange control regulations on the repatriation of profits, allowing foreign investors to freely transfer their earnings out of the country without specific governmental restrictions. Both EU and non-EU investors benefit from the principle of free movement of capital under Dutch and EU law. However, it is important to consider that other regulations, such as trade sanctions, may impact the repatriation of profits in certain situations.

PART V – Foreign Investment

Generally, there are no restrictions on foreign investment in Netherlands. The Netherlands have adopted legislation that requires the prior approval from the Dutch government of any merger or acquisition of, or a significant investment entity in, a Dutch company that engages in one or more activities that are considered vital to Dutch national security (Act on the security screening of investments, mergers and acquisitions or Wet veiligheidstoets investeringen, fusies en overnames ('Vifo Act')). Whilst the transport, distribution, production and storage of gas on land and sea, as well as the storage, transport, refinery and treatment of crude oil and petroleum products are considered vital to Dutch national security, the Vifo Act only applies if and in so far as these activities (i) take place in The Netherlands and/or (ii) are in fact managed from The Netherlands. Absent such nexus to The Netherlands, the Vifo Act does not apply.

B. Brunei

PART I – Corporate Income Tax

1.1 Overview of CIT and PIT

Corporate Income Tax

Limited companies, regardless of whether they are incorporated overseas or locally or are registered as a branch, are subject to a tax on income accruing in, derived from or received in Brunei Darussalam except for petroleum operations. Income derived from petroleum operations is covered under Petroleum income tax section. The chargeable income is determined by taking income and deducting costs, expenses and capital allowances in respect of qualifying capital expenditure. Under the Income Tax Act ("ITA"), deductions allowed are those outgoings and expenses wholly and exclusively incurred for the purpose of revenue generating activities.

Rate of corporate income tax
The income tax rate is 18.5% for resident and non-resident companies. The first BND100,000 of chargeable income is taxed at a reduced rate of one quarter of the full rate, while the next BND150,000 is taxed at half the full rate. The balance of chargeable income is taxed at the full rate. For a new entity, the first BND100,000 of chargeable income is exempt from tax. This exemption applies for an entity's first three consecutive years of assessment.

Certain enterprises and industries may be exempted from taxation if they are considered essential for the development of the country. Please see further below comments on Petroleum Income Tax.

Entities that have gross sales or turnover of BND1 million or less are exempted from corporate income tax or charged with a 0% corporate income tax.

Administration
The tax year is the calendar year. Tax returns must be filed by electronic means.

Timeline on the filing of tax return
Entities must file an estimated chargeable income ("ECI") return within three months after their accounting year-end if they are unable to file their annual tax return within this period. Any tax due under an ECI return must be paid by the due date for filing the ECI return. If tax is paid under an ECI return, the tax is adjusted accordingly in the annual tax return. In general, extensions of time are not granted. Entities must file an annual tax return by 30 June of each year in respect of the previous financial year and pay any tax due by the same date.

Petroleum Income Tax

Brunei tax law defines petroleum operations as searching for and winning or obtaining of petroleum including mineral oil or hydrocarbon and natural gas in its natural condition in Brunei Darussalam by or on behalf of a company, excluding any transportation or refining petroleum or any dealing with refined products. There are two methods of calculating income tax under Income Tax Petroleum Act ("ITPA"):

- For a production sharing agreement ("PSA") mining arrangement, the income tax rate of 55% is applied on chargeable profit which is determined by taking oil and gas income and deducting all costs, expenses and capital expenditure as are prescribed in and allowed under the relevant PSA.
- For non-production sharing agreement mining arrangement, the income tax rate of 55% is applied on chargeable profit which is determined by taking oil and gas income and deducting costs, expenses and capital allowances in respect of qualifying capital expenditure. Under the ITPA, deductions allowed are those outgoings and expenses wholly and exclusively incurred for the purpose of petroleum operations.

Administration
The tax year is the calendar year. Tax returns must be filed by electronic means.

Timeline on the filing of tax return
Entities must file an annual tax return by 30 June of each year in respect of the previous financial year and pay any tax due by the same date.

Groups of companies
No special rules or reliefs apply to groups of companies; each company is taxed on its own income as appropriate.

1.2 Utilising prior tax year losses

Corporate income tax
Losses may be carried forward for up to six years to offset future profits. Continuity of trade or ownership is not required to carry forward losses. Losses in one trade or business may be set off against other sources of income for the same year of assessment.

Petroleum income tax
For PSA mining arrangement, the carry forward of losses is subject to the terms of the relevant PSA.

For non-production sharing agreement mining arrangement, the number of years when losses may be carried forward is not defined in the ITPA.

1.3 Branch income

Branches of foreign companies are taxed on their profits arising in Brunei Darussalam at the same rates as corporations.

1.4 Transfer pricing

Brunei does not have a formal legislation or rules on transfer pricing. The tax authorities can review and raise queries on related party transactions. It is recommended that there is sufficient documentation to support such transactions. A typical tax review could cover requests for supporting documents (e.g. invoices, agreements, etc); transfer pricing studies, a description of the goods supplied or services rendered; the method and rationale for allocating expenses; the basis of determining prices; etc.

1.5 Statute of Limitations

The tax authorities have up to 6 years to re-assess an ITA tax return and 12 years to re-assess an ITPA tax return. Under the ITA and ITPA legislation, the above limitation periods do not apply when there is a willful default or fraud.

PART II – Withholding Taxes, other taxes and repatriation of profits

2.1 Withholding tax

Withholding tax rates
A resident company or permanent establishment that makes payment of the following nature to non-resident companies or directors, is required to withhold taxes at the rates specified as follows:

Interest	2.5%
Royalties	10%
Payment for the use or right to use scientific, technical, industrial or commercial knowledge or information	10%
Technical assistance and service fees	10%
Management fees	10%
Rent or other payment for the use of movable properties	10%
Non-resident directors' remuneration	10%

Withholding tax return filing
Withholding tax returns are required to be filed by electronic means. Withholding tax is due and payable within 14 days of payment or deemed payment failing which penalties apply. Deemed payment can include situations whereby actual payment is not made but applied as a set-off or credited to any account.

Branches of foreign companies are subject to the same withholding tax regulations as a private limited company.

Since Branches are generally regarded as non-resident companies, payments received by a Branch from Brunei companies may be subject to withholding tax if the payments fall within the scope of withholding tax. Any taxes withheld may be applied as corporate income tax when the Branch files its income tax return.

The repatriation of branch profits after taxation to its headquarter is not subject to any Bruneian withholding tax.

In Brunei, remittance of branch profits after tax to Head Office (Netherlands) is not subject to withholding tax. Other types of remittances such as interests, royalties, management fees and technical fees paid out of Brunei to non-residents will be subject to withholding tax.

2.2 Double tax treaty overview

Brunei Darussalam has entered into double tax treaties with Bahrain, Cambodia, China Mainland, the Hong Kong SAR, Indonesia, Japan, Korea (South), Kuwait, Laos, Luxembourg, Malaysia, Oman, Pakistan, Qatar, Singapore, the United Arab Emirates, the United Kingdom and Vietnam. The above withholding tax rates may be reduced under tax treaties.

2.3 Capital gains tax

Capital gains are not taxed. Capital losses are not deductible. However, if assets have been acquired for resale rather than for a company's use, any profit from the sale is regarded as taxable income.

2.4 Other taxes (i.e., stamp duty and customs duty / excise duty)

Stamp duty
Stamp duty in Brunei is imposed on instruments such as property sales, leases, share transfers etc. The rates vary by instruments type and value, and payment is required for the document to be legally valid. There may be exemptions or reliefs for certain instruments. Non-compliance can lead to penalties, including fines. The Ministry of Finance and Economy, particularly its Revenue Division, oversees stamp duty regulations and enforcement.

Customs duty/excise duty
In Brunei, customs duty is a tax on imported goods managed by the Royal Customs and Excise Department (RCED) as per the Customs Order, 2006. The duty rate varies based on the item type and value, with some goods eligible for exemptions or reduced rates. Excise duty is a tax on specific domestic or imported goods, particularly on items like tobacco and alcohol, aimed at reducing consumption and is governed by the Excise Order, 2006. Non-compliance to both duties can lead to penalties.

Other taxes
There are no personal income taxes, Value Added Tax ("VAT") or Goods and Services Tax ("GST") imposed in Brunei. Refer above for withholding tax.

2.5 Repatriation of profits

Generally, Brunei does not impose exchange control rules on repatriation of profits after taxation in the oil and gas industry.

PART III – Foreign Investment

Generally, there are no restrictions on foreign investment in Brunei Darussalam.

Depending on the nature and type of business activity, approvals (including for the transfer of interest in a mining arrangement), permits, licenses or clearances from the relevant authority may be required.

Building a better working world

LETTER OF POLICIES ON FOREIGN INVESTMENTS, TAXATION AND REPATRIATION OF PROFITS OF THE NETHERLANDS AND BRUNEI
20 September 2024

Limitations

You should note that our Professional Statement represents our views on the Netherlands and Brunei taxes based on our analysis at the date of this letter. This advice is not binding on the local tax or regulatory authorities. Our advice on taxes is based on, amongst other provisions, the applicable provisions of the following (all at the date of this letter):

i. Netherlands

Requirements for tax residency
- Article 2 CITA
- Article 3 CITA
- Article 4 General Tax Act

Application of CIT rates
- Article 22 CITA

Foreign income
- Application of Dutch object (branch) exemption
  - Article 3, CITA
  - Article 15e CITA

Foreign currency election
- Article 7 CITA

Tax losses and change of control rules
- Article 20 CITA
- Article 20a CITA

(Conditional) withholding taxes
- Dividends (description of the Dutch domestic dividend withholding tax exemption)
  - Article 1 DWTA
  - Article 3 DWTA
  - Article 4 DWTA (Dividend domestic DWHT exemption)
- Interest, royalties and dividends
  - Article 2.1 Conditional WHT Act 2021
  - Article 3.1 Conditional WHT Act 2021
  - Article 3.5 Conditional WHT Act 2021

Principal purpose test under tax treaties
- Article 7 MLI

ATAD3 brief explanation and status
- COM (2021) 565 final – Unshell proposal
- Directorate-General Taxation and Customs Union – management plan 2024.

Repatriation of profits
- Article 4 DWTA

ii. Brunei

- Income Tax Act, Chapter 35
- Income Tax Petroleum Act, Chapter 119
- Stamp Act, Chapter 34
- Custom Order, 2006
- Excise Order, 2006

Any changes to these and other relevant statutes may or may not be retroactive with respect to the proposed transaction and could affect the advice expressed in this Professional Statement.

Notes to this Professional Statement

This Professional Statement is based on the completeness and accuracy of the facts and / or representation provided by you. If any of the aforementioned facts, representations or assumptions is not entirely complete or accurate, it is imperative that we be informed immediately, as inaccuracy and incompleteness could have a material effect on the validity of this Professional Statement.

This Professional Statement reflects our interpretation of the applicable laws and the corresponding jurisprudence.

This Professional Statement is prepared based on the current tax laws in the Netherlands and Brunei and is subject to changes in such laws, or on the interpretation thereof. Such changes may be retrospective. While the comments are considered to be a correct interpretation of existing laws in force as at the latest practicable date, no assurance can be given that courts or fiscal authorities responsible for the administration of such laws will agree with this interpretation or that changes in such laws will not occur.

Please note that Ernst & Young Tax Consultants Sdn. Bhd. does not provide legal services and legal advice, and therefore our comments above on the policies on foreign investment and repatriation of profits of the Netherlands and Brunei, as applicable, are general comments only.

We have no obligation to update the contents of this Professional Statement as laws or practices change, unless specifically requested to do so.

No inference beyond their normal meaning should be drawn from the is of the words "will", "should", etc as they relate to the relative strengths of a particular position outlined in the document.

This Professional Statement, which would be included in the circular and to be distributed to the shareholders of Hibiscus Petroleum Berhad, was prepared solely for Hibiscus Petroleum Berhad on the basis of the engagement letter concluded between Hibiscus Petroleum Berhad and ourselves. Third parties' notice of its content is entirely at their own risk.

We have no obligation, responsibility, or duty of care towards third parties (reliance restricted), unless otherwise confirmed to a third party in advance in writing.

Yours faithfully
Ernst & Young Tax Consultants Sdn Bhd

DocuSigned by:
11AB8699BB9840C...

Sharon Yong
Partner

HERBERT SMITH FREEHILLS

To: Hibiscus Petroleum Berhad
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Date
24 September 2024

Dear Sir/Madam

English law opinion:

Share Purchase Agreement dated 13 June 2024 and made between TotalEnergies Holdings International B.V. and Simpor Hibiscus Sdn. Bhd.

Transition Services Agreement dated 23 September 2024 and made between TotalEnergies Holdings International B.V. and Simpor Hibiscus Sdn. Bhd.

Deed of Guarantee and Indemnity dated 13 June 2024 and made between Hibiscus Petroleum Berhad and TotalEnergies Holdings International B.V.

1. INTRODUCTION

1.1 We have been asked to provide an English law legal opinion to Hibiscus Petroleum Berhad ("**Hibiscus**") in connection with:

1.1.1 an English law governed Share Purchase Agreement dated 13 June 2024 (the "**SPA**") made between TotalEnergies Holdings International B.V. (the "**Seller**") and Simpor Hibiscus Sdn. Bhd. (the "**Buyer**") for the proposed acquisition by the Buyer of the entire equity interest of TotalEnergies EP (Brunei) B.V. (the "**Company**") from the Seller (the "**Proposed Acquisition**");

1.1.2 an English law governed Transition Services Agreement dated 23 September 2024 (the "**TSA**") and made between the Seller, as supplier and the Buyer, as purchaser; and

1.1.3 an English law governed Deed of Guarantee and Indemnity (the "**PCG**") dated 13 June 2024 and made between Hibiscus, as guarantor and the Seller, as beneficiary,

HERBERT SMITH FREEHILLS

Date
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each of the agreements above as more particularly described in the circular distributed to the shareholders of Hibiscus in relation to the Proposed Acquisition, to which a copy of this letter will be attached.

1.2 In this opinion, the SPA, the TSA and the PCG are together referred to as the "**Agreements**" and are individually referred to as an "**Agreement**".

1.3 Save as otherwise specified or as the context may otherwise require, expressions defined in the Agreements, as at the date of this opinion, shall have the same meanings when used in this opinion.

2. SCOPE OF THIS OPINION

2.1 We are solicitors qualified in England and Wales. We express no opinion as to any law other than English law as applied by English courts and reported and in effect on the date of this opinion.

2.2 No opinion is expressed as to matters of fact.

2.3 We have advised Hibiscus in respect of certain matters of English law in respect of the SPA and the PCG.

2.4 This opinion addresses only the validity and enforceability of the Agreements and does not address the type, adequacy, nature and appropriateness of the interests, rights, obligations or remedies which may arise under the Agreements.

2.5 Without limiting paragraph 2.4, we have not received instructions from any of the parties to the TSA in connection with the TSA nor advised any of the parties in connection the TSA. In particular, we have not advised any of the parties on the type, adequacy, nature and appropriateness of the interests, rights, obligations or remedies which may arise under the TSA.

2.6 This opinion and any non-contractual obligations arising out of or in connection with it are governed by and shall be construed in accordance with English law. This opinion is given on the condition that the courts of England have exclusive jurisdiction to settle any dispute or claim arising out of or in connection herewith (including any non-contractual disputes or claims).

2.7 This opinion is not designed to and is not likely to reveal fraud, misrepresentation, bribery or corruption by any person.

3. DOCUMENTS WE HAVE EXAMINED AND ENQUIRIES WE HAVE MADE

3.1 We have examined the following documents for the purposes of giving this opinion:

3.1.1 a scanned and emailed version of the signed SPA dated 13 June 2024;

3.1.2 a scanned and emailed version of the signed TSA dated 23 September 2024; and

3.1.3 a scanned and emailed version of the signed PCG dated 13 June 2024.

3.2 Except as stated above, we have not for the purpose of this opinion, examined any agreements, documents or corporate records entered into by or affecting the parties to the Agreements (together, the "**Parties**", and individually, a "**Party**") or made any other enquiries concerning the Parties.

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Date
24 September 2024
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4. **ASSUMPTIONS**

4.1 This opinion is based upon the assumption (which may or may not be the case) that:

4.1.1 **Due incorporation:** each Party is a company duly incorporated under its law of incorporation;

4.1.2 **Authenticity:** all documents (including scanned, emailed, electronic and copy documents) examined by us are authentic, complete and accurate and all signatures and seals (if any) thereon are genuine;

4.1.3 **Documents up-to-date etc:** all documents which we have reviewed are and remain up-to-date, and have not been amended, superseded, terminated or rescinded;

4.1.4 **Parties – capacity and authority etc:** each Party has the power and legal capacity to enter into, perform and exercise its rights under each of the Agreements to which it is a party and each of the Agreements has been duly authorised, executed and, where applicable, delivered by all of the Parties thereto in accordance with all applicable laws;

4.1.5 **Solvency:** each Party was solvent at the time of the execution and delivery of each of the Agreements to which it is a party and did not become insolvent as a result of entering into the arrangements contained in the Agreements to which it is a party, and no Party has entered into any composition, compromise or arrangement with its creditors (or any class of them);

4.1.6 **Administration etc:** no step has been taken to obtain a moratorium in relation to any Party or to wind up any Party or to place any Party into administration, and no receiver has been appointed over or in respect of the assets of any Party, nor has any analogous procedure or step been taken in any jurisdiction;

4.1.7 **Overseas insolvency:** no foreign main insolvency proceeding has been recognised in Great Britain under the Cross-Border Insolvency Regulations 2006 (and it is not possible to conduct a central search in Great Britain in relation to any such proceedings) which would entitle actions in respect of any assets of any Party the subject of those foreign proceedings to be taken in Great Britain;

4.1.8 **Validity/enforceable obligations:** the Agreements constitute legal, valid, binding and enforceable obligations of all of the parties thereto under all applicable laws (other than, in the case of the Seller, English law) and to the extent that the laws or regulations of any jurisdiction other than England may be relevant to (i) the obligations or rights of any Party under the Agreements to which it is a party, or (ii) any of the transactions contemplated by the Agreements, such laws and regulations do not prohibit, and are not inconsistent with, the entering into and performance of any such obligations, rights or transactions;

4.1.9 **No breach:** no Party will, by reason of the transactions contemplated by the Agreements to which it is a party, be in breach of any of its obligations under any agreement, licence, authorisation, consent or similar document;

4.1.10 **Misconduct etc:** no party to an Agreement (and no individual employed by or acting on behalf of any such party) is, or will be, engaging in criminal, misleading, deceptive or unconscionable conduct or seeking to conduct any relevant transaction or any associated activity in a manner or for a purpose not evident on the face of the Agreement which might render the Agreement (or any part thereof) or any transaction contemplated thereby or any associated activity illegal, unlawful, void or unenforceable;

4.1.11 **Entry into Agreements:** each Party has entered into the Agreements (to which it is a party) in pursuance of a commercial activity and the terms of the Agreements have been freely negotiated by the parties thereto;

4.1.12 **Entry into Agreements outside the UK:** the Agreements were executed outside the United Kingdom and do not relate to any things done, or to be done, in the United Kingdom, or to any property situated in the United Kingdom; and

4.1.13 **No UK share register etc:** none of the shares in the Company are (i) registered on a register kept by or on behalf of the Company in the United Kingdom, or (ii) paired with shares of a body corporate incorporated in the United Kingdom.

5. **OPINION**

5.1 Based on the Agreements, and subject to the assumptions contained in paragraph 4, the qualifications contained in paragraph 6 and matters not disclosed to us, it is our opinion that:

5.1.1 **Validity:** the obligations of the Seller under each Agreement constitute legal, valid, binding and enforceable obligations of the Seller;

5.1.2 **Registration:** it is not necessary to file, register or record any Agreement in any register maintained by any public or statutory body in England or Wales for the purposes of ensuring the validity, binding effect or enforceability of the obligations of the Seller under any Agreement; and

5.1.3 **Stamp duty:** no stamp, registration or similar duties are payable in England or Wales in respect of the execution and delivery of any Agreement.

6. **QUALIFICATIONS**

6.1 This opinion is subject to the qualifications contained in this section.

6.2 **Insolvency etc:** This opinion is subject to all insolvency and other laws affecting the rights of creditors (whether secured or unsecured) generally.

6.3 **Validity:** The opinion that the obligations of the Seller under each Agreement constitute legal, valid, binding and enforceable obligations of the Seller means that the obligations are of a type and form generally found to be legal, valid, binding and enforceable by the English courts or arbitral tribunals applying English law. It is not, however, certain that those obligations will necessarily be legal, valid or binding or will be enforced in all circumstances in accordance with their terms, since the existence, effect and enforcement of legal obligations is subject to principles of law, equity, court or the arbitral tribunal's discretion, issues of public policy and procedure of general application. Nor is it the case that English law will apply in all circumstances nor that an English court or arbitral tribunal will have jurisdiction in all circumstances. In particular:

6.3.1 equitable remedies, such as specific performance and injunctions, are within the discretion of the court or arbitral tribunal, and may be subject to the power to award such remedies being available to the arbitral tribunal. An English court or arbitral tribunal may make an award of damages if it considers this an adequate remedy for breach of legal obligations and not grant an equitable remedy in such circumstances;

6.3.2 claims may become time-barred;

6.3.3 pursuant to section 12 of the Arbitration Act 1996, where an agreement which is subject to arbitration provides that a claim shall be barred, or the claimant's rights extinguished, unless the claimant takes within a time fixed by the agreement some step to begin proceedings or to exhaust another process before taking arbitral proceedings, a court may by order extend the time for taking such step;

6.3.4 enforcement of rights and obligations may become frustrated;

6.3.5 claims may be subject to defences of set-off or counterclaim;

6.3.6 a failure or delay to exercise a right may constitute a waiver of that right;

6.3.7 any indemnity obligations imposed under any of the Agreements may not be effective insofar as they relate to fines and penalties arising out of matters of civil or criminal liability and an indemnity for costs of litigation may not be effective;

6.3.8 an agreement whereby a party is to pay the whole or part of the costs of the arbitration in any event will not be valid if made before the dispute in question has arisen;

6.3.9 any terms excluding or limiting the duties owed by or the liability of any person may be void if and to the extent they do not satisfy the relevant tests of reasonableness or fairness imposed by law and will be construed strictly;

6.3.10 an obligation to negotiate or enter into further agreements may not be enforceable;

6.3.11 an English court or arbitral tribunal may choose not to treat any certificate or determination as being conclusive;

6.3.12 the severance of any invalid or illegal provision and the continued effect of any other obligations will be determined by an English court or arbitral tribunal, at its discretion;

6.3.13 any discretion or determination may be required to be exercised or made in a timely manner, reasonably or in good faith, and not arbitrarily, capriciously, perversely or irrationally, whether or not there is any express obligation to do so;

6.3.14 any provision in a contract which requires payment of additional amounts by any party as a result of breach of its contractual obligations (whether expressed by way of fee, additional interest (whether described as penalty or default interest or implemented by margin ratchet), or specified or liquidated damages or otherwise), or which results in the loss of a right to a future payment or a requirement to transfer assets at an undervalue, may be unenforceable as a penalty;

6.3.15 notwithstanding any contractual provision that requires a variation to be made in writing or to comply with some other formality, a party may in some circumstances be prevented from enforcing the original terms where a variation was agreed orally or by conduct of the parties;

6.3.16 a contract may not be binding if the consideration given for the benefit of a promise is not valuable consideration or is past consideration;

6.3.17 if a provision lacks certainty it may not be contractually binding;

6.3.18 an English court or any arbitral tribunal applying English law may choose not to enforce or recognise as binding obligations which are incompatible with English public policy or which purport to override mandatory rules of English law;

6.3.19 any right to apply payments in a specific order may not be effective if a Party, in making payment, specifies a contrary order of application;

6.3.20 an indemnity in respect of or other undertaking or other arrangements to pay United Kingdom stamp duty may be void by virtue of section 117 of the Stamp Act 1891;

6.3.21 a contract may be void if the parties are mistaken as to some matter that is essential to the contract;

6.3.22 any provision in an agreement between a company and a third party which purports to restrict a company's choice of auditor to particular lists or categories will be void;

6.3.23 by virtue of the Business Contract Terms (Assignment of Receivables) Regulations 2018 (2018/1254), a term in a contract may have no effect to the extent that it prohibits or imposes a condition, or other restriction, on the assignment of a receivable as defined under those Regulations in circumstances where an exemption does not apply at the time of the relevant assignment;

6.3.24 by virtue of section 233B of the Insolvency Act 1986, a provision of a contract for the supply of goods or services to a company ceases to have effect when the company becomes subject to a relevant insolvency procedure if and to the extent that, under the provision (a) the contract or the supply would terminate, or any other thing would take place, because the company becomes subject to the relevant insolvency procedure, or (b) the supplier would be entitled to terminate the contract or the supply, or to do any other thing, because the company becomes subject to the relevant insolvency procedure.

6.4 **Unlawful communications:** An agreement which is entered into in consequence of an unlawful communication may be unenforceable pursuant to the Financial Services and Markets Act 2000.

6.5 **Stay of English court proceedings for arbitration**: An English court may refuse to stay its own proceedings in relation to a matter which, under the Agreements, is referred to arbitration if it considers that:

6.5.1 the arbitration agreement is null and void, inoperative or incapable of being performed or is contrary to English public policy or mandatory law;

6.5.2 the dispute falls outside the scope of the provisions for arbitration contained in clause 22.2 of the SPA, clause 28 of the TSA or clause 23 of the PCG;

6.5.3 the dispute is not capable of being arbitrated;

6.5.4 the respondent has taken steps in the proceedings before the English courts;

6.5.5 it is exercising its supervisory jurisdiction or powers under the Arbitration Act 1996; or

6.5.6 section 9 of the Arbitration Act 1996 does not apply to the court proceedings.

6.6 **Recognition of arbitration by the English courts**: the submission of disputes to arbitration will be recognised by the English courts subject to the exceptions and provisions of the Arbitration Act 1996, other relevant principles of English law, and any other mandatory statute.

6.7 **Sanctions:**

6.7.1 Where a party to the Agreements is the subject of targeted financial sanctions or restrictive measures implemented or effective in England and Wales, or is owned or controlled (directly or indirectly) by, or is acting on behalf of, a person subject to such sanctions (a **"Sanctioned Person"**), then the obligations and rights of the parties under the Agreements may be unenforceable or void. Where the performance of any obligations under the Agreements would otherwise involve the provision of any funds or assets (directly or indirectly) to a Sanctioned Person or a use of or dealing with funds or assets belonging to, or owned, held or controlled by, a Sanctioned Person, then such obligations may be unenforceable or void. Where any Party is the subject of other restrictive measures (including trade sanctions or embargoes, financing restrictions and investment restrictions) implemented or effective in England and Wales which affect the provision of finance or credit to, or payments to or from, such persons (as a result of being resident in, incorporated in or constituted under the laws of a country which is subject to such measures, or being part of a class of persons of a generic description subject to such measures, or being named as subject to such measures), or where the proceeds of any loan made available under any Agreement are to be used for activities which are contrary to such measures, then the obligations and rights of the parties under the Agreements may be unenforceable or void.

6.7.2 We express no opinion on the legality or enforceability of clauses 14.1(f) and 15 of the SPA, paragraph 66 of exhibit C to the SPA and clause 12.2 of the TSA, or on any other provision of any Agreement related to sanctions or the use of proceeds, or whether they violate English law, to the extent they have an effect of contravening EU Council Regulation (EC) No. 2271/96 (to the extent applicable), and/or its equivalent in UK law (including having regard to (the UK law equivalent of) Commission Implementing Regulation (EU) 2018/1101, the Extraterritorial US Legislation (Sanctions against Cuba, Iran and Libya) Protection of Trading Interests Order 1996 and the Protecting against the Effects of the Extraterritorial Application of Third Country Legislation) (Amendment) (EU Exit) Regulations 2020).

6.8 **Tax:** Save as expressly set out in paragraph 5.1.3, we express no opinion as to the tax treatment of any Agreement or the transactions contemplated thereby.

6.9 **Consents:** No opinion is given in relation to the need for any authorisations or consents in connection with the entry into or performance of any Agreement (including the undertaking of any transaction, or the doing of any other thing, under any Agreement).

7. ADDRESSEES AND RESPONSIBILITY

7.1 This opinion is addressed to you personally, is given solely for the benefit of Hibiscus and is provided solely in connection with the Proposed Acquisition. It may not be relied upon by (or disclosed to) any other entity or person without our prior written consent, save that this opinion may be disclosed without such consent in the following manner:

7.1.1 to the extent required by any order of any court of competent jurisdiction or any competent judicial, governmental, regulatory or supervisory body;

7.1.2 to the extent required by the rules of any listing authority, stock exchange or any regulatory or supervisory body with which you are legally bound to comply;

7.1.3 to your affiliates and the officers, employees, auditors and professional advisers of either you or your affiliates;

HERBERT
SMITH
FREEHILLS

Date
24 September 2024
Letter to
Hibiscus Petroleum Berhad

7.1.4 a copy of this opinion will be attached to a circular to shareholders of Hibiscus in relation to the Proposed Acquisition, which will be a publicly available document (including on the website of Bursa Malaysia Securities Berhad);

7.1.5 a copy of this opinion may be submitted to Bursa Malaysia Securities Berhad as part of the relevant regulatory approval process in relation to the Proposed Transaction; and

7.1.6 to the extent required by the laws or regulations of any country with jurisdiction over your affairs,

provided that, in each case:

(A) such disclosure is made for information purposes only and not for the purposes of reliance; and

(B) we do not assume any duty or liability to any person to whom such disclosure is made and no such person to whom this opinion is disclosed may rely on it without our prior written consent.

7.2 This opinion is given by Herbert Smith Freehills LLP which assumes liability for and is solely responsible for it.

Yours faithfully

Herbert Smith Freehills

Herbert Smith Freehills LLP

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To: Each party (**Opinion Addressee**) listed in Schedule 1 (Opinion addressees)

RE	**Dutch law legal opinion – SPA - TotalEnergies Holdings International B.V.**
REFERENCE	54824632
DATE	23 September 2024

1 INTRODUCTION

We have acted as special counsel on certain matters of Dutch law to the Opinion Addressee.

2 DEFINITIONS

2.1 Capitalised terms used but not defined herein are used as defined in the Schedules to this opinion letter.

2.2 In this opinion letter:

Articles means the articles of association listed in paragraph 2.2 (Constitutional documents) of Schedule 3 (Reviewed documents).

Board Resolutions means the document listed in paragraph 2.3 (Board resolutions) of Schedule 3 (Reviewed documents).

Deed of Incorporation means any deed of incorporation listed in paragraph 2.2 (Constitutional documents) of Schedule 3 (Reviewed documents).

Director means TotalEnergies Management B.V., registered with the Trade Register under number 56543719.

Excerpt means any document listed in paragraph 2.1 (Excerpts) of Schedule 3 (Reviewed documents).

Opinion Document means any document listed in paragraph 1 (Opinion documents) of Schedule 3 (Reviewed documents).

Opinion Party means the entity listed in Schedule 2 (Opinion parties).

Relevant Date means the date of the Board Resolutions, the date of the Opinion Documents or the date of this opinion letter.

Shareholders' Register means the document listed in paragraph 2.4 (Shareholders' register) of Schedule 3 (Reviewed documents).

Shares means 100,000 ordinary shares in the capital of the Target Company, with a nominal value of USD 100 each, numbered 1 up to and including 100,000,000.

Target Company means TotalEnergies EP (Brunei) B.V., registered with the Trade Register under number 27116219.

Trade Register means the trade register of the Chamber of Commerce in the Netherlands.

3 SCOPE OF INQUIRY

3.1 For the purpose of rendering this opinion letter, we have only examined and relied upon electronically transmitted copies of the executed Opinion Documents and the other documents listed in Schedule 3 (Reviewed documents).

3.2 We have not reviewed and express no opinion on any document incorporated by reference or referred to in the Opinion Documents other than the documents referred to in paragraph 3.1.

3.3 We have undertaken the following checks (the **Checks**) at the date of this opinion letter:

(a) an inquiry at the Trade Register, confirming that no relevant changes were registered compared to the contents of the Excerpts;

(b) an inquiry at the Central Insolvency Register (*Centraal Insolventieregister*) confirming that the Opinion Party and the Director are not listed with the Central Insolvency Register and not listed on the EU Registrations list with the Central Insolvency Register; and

(c) an inquiry at EUR-Lex relating to the list referred to in article 2 (3) of Council regulation (EC) No 2580/2001, Annex I of Council regulation (EC) No 881/2002 and the Annex to Council Common Position 2001/931 relating to measures to combat terrorism, confirming that the Opinion Party and the Director are not listed on such annexes.

4 NATURE OF OPINION

4.1 We only express an opinion on matters of Dutch law and the law of the European Union, to the extent directly applicable in the Netherlands, in force on the date of this opinion letter, excluding unpublished case law, all as interpreted by Dutch courts and the European Court of Justice. We do not express an opinion on tax law, competition law, sanction laws and financial assistance. The terms "the Netherlands" and "Dutch" in this opinion letter refer solely to the European part of the Kingdom of the Netherlands.

4.2 Our opinion is strictly limited to the matters stated herein. We do not express any opinion on matters of fact, on the commercial and other non-legal aspects of the transactions contemplated by the Opinion Documents and on any representations, warranties or other information included in the Opinion Documents and any other document examined in connection with this opinion letter, except as expressly stated in this opinion letter.

4.3 In this opinion letter Dutch legal concepts are sometimes expressed in English terms and not in their original Dutch terms. The concepts concerned may not be identical to the concepts described by the same English term as they exist under the laws of other jurisdictions. For the purpose of tax law a term may have a different meaning than for the purpose of other areas of Dutch law.

4.4 This opinion letter may only be relied upon under the express condition that any issue of interpretation or liability arising hereunder will be governed by Dutch law and be brought exclusively before the competent court in Rotterdam, the Netherlands.

4.5 This opinion letter is issued by Loyens & Loeff N.V. and may only be relied upon under the express condition that any liability of Loyens & Loeff N.V. is limited to the amount paid out under its professional liability insurance policies. Individuals or legal entities that are involved in the services provided by or on behalf of Loyens & Loeff N.V. cannot be held liable in any manner whatsoever.

5 OPINIONS

The opinions expressed in this paragraph 5 (Opinions) should be read in conjunction with the assumptions set out in Schedule 4 (Assumptions) and the qualifications set out in Schedule 5 (Qualifications). On the basis of these assumptions and subject to these qualifications and any factual matters or information not disclosed to us in the course of our investigation, we are of the opinion that as at the date of this opinion letter:

5.1 **Corporate status**

The Opinion Party has been duly incorporated and is validly existing as a *besloten vennootschap met beperkte aansprakelijkheid* (private limited liability company) under Dutch law.

5.2 **Corporate power**

The Opinion Party has the corporate power to execute the Opinion Documents and to perform its obligations thereunder.

5.3 **Due authorisation**

The Opinion Party has duly authorised with all requisite corporate action the execution of the Opinion Documents.

5.4 **Due execution**

The Opinion Party has duly executed the Opinion Documents.

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5.5 **No violation of Articles and law**

The execution by the Opinion Party of the Opinion Documents and the performance of its obligations thereunder do not result in a violation of its Articles or of the provisions of any published law, rule or regulation of general application of the Netherlands which would affect the validity or enforceability of the Opinion Documents.

5.6 **Choice of law**

The choice of law as contained in the Opinion Documents is valid and binding under Dutch law.

5.7 **Enforceability**

Dutch law does not restrict the validity and binding effect on and enforceability of the contractual obligations contained in the Opinion Documents against the Opinion Party.

5.8 **Submission to arbitration**

The submission to arbitration as contained in the Opinion Documents, is recognised under Dutch law.

5.9 **Enforcement of arbitral award**

An arbitral award rendered in London, England will be recognised and enforced in the Netherlands subject to the provisions of for example: the Convention on the Recognition and Enforcement of Foreign Arbitral Awards of New York, 1958 in conjunction with Section 1075 of the Dutch Code of Civil Procedure.

5.10 **Consents**

No approval, authorisation or other action by, or filing with, any Dutch governmental, regulatory or supervisory authority or body, is required in connection with the execution by the Opinion Party of the relevant Opinion Document and the performance of its obligations thereunder.

5.11 **Issued share capital of the Target Company**

5.11.1 The Shares have been duly authorised, validly issued, fully paid and are validly outstanding.

5.11.2 The Target Company's issued share capital (*geplaatst kapitaal*) consists of the Shares.

5.12 **Shareholdings of Target Company**

Based solely on the Excerpt of the Target Company and the Shareholders' Register, the Opinion Party holds title to the Shares in the Target Company, free and clear of any pledge (*pand*), right of usufruct (*vruchtgebruik*) or attachment (*beslag*).

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6 ADDRESSEES

6.1 This opinion letter is addressed to you and may only be relied upon by you in connection with the Opinion Documents and may not be disclosed to and relied upon by any other person without our prior written consent.

6.2 To the extent reasonably required, this opinion letter may be disclosed without our prior written consent to:

(a) any person to whom disclosure is required to be made by applicable law or court order or any ratings agency, supervisor, regulator or other government body or agency or in connection with any judicial proceedings;

(b) the officers, employees, auditors, affiliates, officers, directors and professional advisers of the Opinion Addressee;

(c) any transferees or assignees or any potential assignee or transferee and to their officers, employees, auditors, affiliates, officers, directors and professional advisers;

(d) any shareholders of the Opinion Addressee, and may be included in any publications or circulars of such shareholders, including as an attachment to any publicly available circular in relation to the transaction contemplated pursuant to the Opinion Documents, including on the website of Bursa Malaysia Securities Berhad; and

(e) Bursa Malaysia Securities Berhad as part of the relevant regulatory approval process in relation to the transaction contemplated pursuant to the Opinion Documents,

in each case, on the basis that:

(i) such disclosure is made solely to enable any such person to be informed that an opinion letter has been given and to be made aware of its terms but not for the purposes of reliance;

(ii) we do not assume any duty or liability to any person to whom such disclosure is made; and

(iii) (other than in relation to disclosure under paragraph (a)) such person agrees not to further disclose this opinion letter or its contents to any other person, other than as permitted above.

Yours faithfully,
Loyens & Loeff N.V.

P.P. Mary Jane Spiteri   P.P. Mary Jane Spiteri

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Schedule 1

OPINION ADDRESSEES

(1) Hibiscus Petroleum Berhad.

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Schedule 2

OPINION PARTIES

(1) TotalEnergies Holdings International B.V., registered with the Trade Register under number 54265258.

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Schedule 3

REVIEWED DOCUMENTS

1 OPINION DOCUMENTS

1.1.1 The English and Welsh law share purchase agreement dated 13 June 2024 between the Opinion Party as seller and Simpor Hibiscus Sdn. Bhd as buyer.

1.1.2 The English law deed of guarantee and indemnity dated 13 June 2024 between Hibiscus Petroleum Berhad as guarantor and the Opinion Party as beneficiary.

1.1.3 The English and Welsh law transition services agreement dated 23 September 2024 between the Opinion Party as supplier and Simpor Hibiscus Sdn Bhd as purchaser.

2 ORGANISATIONAL DOCUMENTS

2.1 **Excerpts**

2.1.1 An excerpt of the registration of the Opinion Party in the Trade Register dated 2 July 2024.

2.1.2 An excerpt of the registration of the Target Company in the Trade Register dated 2 July 2024.

2.1.3 An excerpt of the registration of the Director in the Trade Register dated 2 July 2024.

2.2 **Constitutional documents**

2.2.1 The deed of incorporation of the Opinion Party dated 29 December 2011.

2.2.2 The articles of association of the Opinion Party dated 30 June 2021.

2.2.3 The deed of incorporation of the Target Company dated 18 August 1986.

2.2.4 The articles of association of the Target Company dated 19 October 2021.

2.3 **Board resolutions**

The resolutions of the management board of the Opinion Party dated 23 May 2024.

2.4 **Shareholders' register**

The shareholders' register of the Target Company.

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Schedule 4

ASSUMPTIONS

The opinions in this opinion letter are subject to the following assumptions:

1 Documents

1.1 All original documents are authentic, all signatures (whether handwritten or electronic) are genuine and were inserted or agreed to be inserted by the relevant individual, and all copies are complete and conform to the originals.

1.2 The information recorded in each Excerpt is true, accurate and complete on each Relevant Date (although not constituting conclusive evidence thereof, this assumption is supported by the Checks).

1.3 The information recorded in the Shareholders' Register is true, accurate and complete on the date of this opinion letter.

2 Incorporation, existence and corporate power

2.1 Each Deed of Incorporation is a valid notarial deed (*notariële authentieke akte*), the contents thereof are correct and complete and there were no defects in the incorporation process (not appearing on the face thereof) for which a court might dissolve the Opinion Party or the Target Company.

2.2 The Opinion Party, the Director and the Target Company have not been dissolved, merged involving the Opinion Party, Director and the Target Company as disappearing entity, demerged, converted, granted a suspension of payments, declared bankrupt or subjected to any other insolvency proceedings listed in Annex A of Regulation (EU) 2015/848 on insolvency proceedings (recast), listed on the list referred to in article 2 (3) of Council Regulation (EC) 2580/2001, listed in Annex I to Council Regulation (EC) 881/2002 or listed and marked with an asterisk in the Annex to Council Common Position 2001/931 relating to measures to combat terrorism (although not constituting conclusive evidence thereof, this assumption is supported by the contents of the Excerpts and the Checks).

2.3 The Articles are the articles of association (*statuten*) of the Opinion Party and the Target Company in force on each Relevant Date (although not constituting conclusive evidence thereof, this assumption is supported by the contents of its Excerpt).

3 Corporate authorisations

3.1 The Board Resolutions (a) correctly reflect the resolutions made by the relevant corporate body of the Opinion Party, (b) have been made with due observance of the relevant Articles and any applicable board regulations and (c) are in full force and effect.

3.2 No member of the management board of the Opinion Party has a direct or indirect personal interest which conflicts with the interest of the Opinion Party or its business in respect of the transactions contemplated by the Opinion Documents.

3.3 The general meeting of the Opinion Party has not subjected any resolutions of its management board to its approval pursuant to its Articles and its Board Resolutions do not conflict with any instruction given by the general meeting to its management board which precludes it from entering into the Opinion Documents.

3.4 The Opinion Party has not established, not been requested to establish, nor is in the process of establishing any works council (*ondernemingsraad*) and there is no works council, which has jurisdiction over the transactions contemplated by the Opinion Documents.

4 Other parties

4.1 Each party to the Opinion Documents, other than the Opinion Party, is validly existing under the laws by which it is purported to be governed.

4.2 Each party to the Opinion Documents, other than the Opinion Party, has all requisite power and capacity (corporate and otherwise) to execute and to perform its obligations under the Opinion Documents and each Opinion Document has been duly authorised, executed and delivered by or on behalf of the parties thereto other than the Opinion Party.

5 Validity

Under any applicable laws (other than Dutch law):

(a) each Opinion Document constitutes the legal, valid and binding obligations of the parties thereto, which are enforceable against those parties in accordance with their terms; and

(b) the choice of law and submission to jurisdiction made in each Opinion Document are valid and binding.

6 Share capital

6.1 The Shares (a) have been duly authorised and validly issued and have not been repurchased (*ingekocht*), cancelled (*ingetrokken*), reduced (*afgestempeld*), split, or combined, (b) are fully paid up, and (c) are free and clear of any pledge (*pand*), right of usufruct (*vruchtgebruik*) or attachment (*beslag*) (although not constituting conclusive evidence thereof, this assumption is supported by the contents of the Shareholders' Register and the Excerpt).

6.2 The Shares have been validly transferred to the Opinion Party and such transfer has not been rescinded, nullified or declared null and void.

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Schedule 5

QUALIFICATIONS

The opinions in this opinion letter are subject to the following qualifications:

1 Insolvency

The opinions expressed herein may be affected or limited by the provisions of any applicable bankruptcy, suspension of payments, statutory composition proceeding, any intervention, recovery or resolution measure, other insolvency proceedings and fraudulent conveyance (*actio Pauliana*) and other laws of general application now or hereafter in effect, relating to or affecting the enforcement or protection of creditors' rights.

2 Enforceability

2.1 The applicable law of an agreement governs the legality, validity and enforceability of an agreement. Subject to the legality, validity and enforceability under the applicable law, as a result of the due execution of an agreement by a Dutch person, the obligations contained in such agreement become binding upon and enforceable against such Dutch person.

2.2 A Dutch legal entity may invoke the nullity of a transaction if the transaction is not within the objects of such legal entity and the other parties to the transaction knew, or without independent investigation, should have known, that such objects were exceeded. In determining whether a transaction is within the objects of a legal entity all relevant circumstances should be taken into account, including the wording of the objects clause of the articles of association and the level of (direct or indirect) benefit derived by the legal entity.

3 Accuracy of information

3.1 A Trade Register excerpt does not provide conclusive evidence that the facts set out therein are correct and complete. However, subject to limited exceptions, a company cannot invoke the incorrectness or incompleteness of its trade register registration against third parties who were unaware thereof.

3.2 A shareholders' register does not provide conclusive evidence that the facts set out therein are correct and complete. However, the management board of a Dutch private or public limited liability company is obliged to regularly update the shareholders' register.

4 Dutch court proceedings

4.1 A Dutch court may apply provisions of law other than the law chosen by the parties, pursuant to and subject to the limitations under the EC Regulation (593/2008) on the law applicable to contractual obligations (Rome I) and the EC Regulation (864/2007) on the law applicable to non-contractual obligations (Rome II).

4.2 Notwithstanding any provision to the contrary, a Dutch competent court may assume jurisdiction in summary proceedings (*kort geding*) if provisional measures are required in view of the interest of the parties. A Dutch court has the power or obligation to stay proceedings or decline jurisdiction if prior concurrent proceedings have been brought elsewhere.

4.3 Specific performance may not always be available.

4.4 Any provision in an agreement permitting concurrent proceedings to be brought in different jurisdictions may not be enforceable.

4.5 If an action is instituted in the Netherlands for payment of a sum of money expressed in a non-Dutch currency, the claimant has the option to request a Dutch court to render judgment either in the lawful currency of the Netherlands or such non-Dutch currency. An enforceable judgment in a non-Dutch currency may be enforced in the Netherlands either in such non-Dutch currency or, if enforcement purposes would so require, in the lawful currency of the Netherlands. In either case, the applicable rate of exchange is the rate of exchange at which the claimant can purchase the sum payable in the non-Dutch currency without delay.

4.6 An arbitral award rendered in England will in principle be recognised and enforced in the Netherlands pursuant to Section V of the Convention on the Recognition and Enforcement of Foreign Arbitral Awards of New York, 1958 and Section 1075 of the Dutch Code of Civil Procedure, unless:

(a) the party against whom recognition or enforcement is sought proves that:

(i) the parties to the submission to arbitration were under some incapacity or the submission to arbitration is invalid under the chosen law;

(ii) the party against whom the award is invoked was not given proper notice of the appointment of the arbitrator or the arbitral proceedings or was otherwise unable to present his case;

(iii) the award deals with a difference not contemplated by the submission to arbitration or it contains decisions on matters beyond the scope of the submission to arbitration;

(iv) the arbitral tribunal that rendered the award was constituted in violation of the law of the country where the arbitration took place;

(v) the arbitral award has not yet become binding on the parties, or has been set aside or suspended by a competent authority of the country in which or under the law of which it was rendered; or

(b) the Dutch court finds that:

(i) the subject matter of the dispute is not capable of settlement by arbitration under Dutch law; or

(ii) recognition or enforcement of the arbitral award would be contrary to public policy (*openbare orde*) of the Netherlands.

5 Trust

A trust created in accordance with the governing law, is recognised under Dutch law, provided that the governing law provides for trusts and the trust has been created voluntarily and is evidenced in writing. The courts in the Netherlands will, however, not be bound to recognise a trust of which the significant elements are more closely connected with states which do not provide for the institution of the trust.

6 Share capital

An attachment (*beslag*) on registered shares in a Dutch private or public limited liability company should be recorded in the shareholders' register by the bailiff and the management board of such company. However, a transfer of shares cannot be invoked against a prior judgment creditor (*beslaglegger*) even if the attachment on such shares has not been recorded in the shareholders' register.

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Project OG

Special Scope Assessment Review

19 September 2024

THIRD-PARTIES OR ANY BUYERS AND/OR INVESTORS ARE ADVISED TO SEEK THEIR RELEVANT PROFESSIONAL OPINION PRIOR TO MAKING DECISIONS BASED ON FINDINGS IN THIS REPORT.

PRIVATE AND CONFIDENTIAL

Now, for tomorrow

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19 September 2024

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

Dear Sirs,

Special Scope Assessment Review ("SSAR") on TotalEnergies EP (Brunei) B.V. and its branch office in Brunei Darussalam ("Branch") (Collectively referred to as "TEPB" or the "Entity")

FHMH Corporate Advisory Sdn Bhd ("**FHCA**") was engaged by Hibiscus Petroleum Berhad (the "**Company**" or "**HPB**") to perform a SSAR on the Entity in connection with the proposed acquisition of the entire equity interest in TEPB ("**Proposed Corporate Exercise**").

FHCA has prepared this report (the "**Report**") in accordance with the terms of reference as set out in our engagement letter dated 11 June 2024 (the "**Engagement Letter**").

This Report has been prepared exclusively for the specific purpose mentioned in the above paragraphs. Other than inclusion in the Company's circular to shareholders for the purpose of the Proposed Corporate Exercise, this Report is not for general circulation, publication or to be reproduced in whole or in part for any other purpose without the prior written consent of FHCA. FHCA does not assume any responsibility or liability as a result of the unauthorised circulation, publication, reproduction or use of this Report, or any part hereof.

Please do not hesitate to contact Ms Michelle Cheah or Ms Ho Jia Xin of this office, if you have any queries in relation to this Report.

For and on behalf of
FHMH CORPORATE ADVISORY SDN BHD

DING SU-LYNN	**ANDREW HENG**
Director	Director

ABBREVIATION

Entities

Term		**Definition**
"BBJV" or the "BBJV Partners"	:	TEPB and two (2) other Joint Venture Partners
"Branch"	:	TEPB's branch office in Brunei Darussalam
"Company" or "HPB"	:	Hibiscus Petroleum Berhad
"TEPB" or the "Entity"	:	TotalEnergies EP (Brunei) B.V.'s Head Office including the Branch
"FHCA"	:	FHMH Corporate Advisory Sdn Bhd
"Head Office"	:	TEPB's Head Office in Netherlands

Agreements

Term		**Definition**
"CIA"	:	Cash Investors Agreement
"JVA"	:	Joint Venture Agreement

General

Term		**Definition**
"AFS"	:	Audited Financial Statements
"ARO"	:	Asset Retirement Obligation
"BAP"	:	Branch's Accounting Policies
"Block B"		Block B offshore Brunei which contains the Maharaja Lela Jamulalam field
"Branch Adjustments"	:	Manual adjustments made on the management accounts of the Branch
"Carry Arrangement"	:	One (1) of the Joint Venture Partner's participating interest of capital expenditure in BBJV carried by TEPB
"EBITDA"	:	Earnings Before Interest, Tax, Depreciation and Amortisation
"Engagement Letter"	:	Engagement letter dated 11 June 2024
"FOB"	:	Free on Board
"FYE"	:	Financial Year End
"GP"	:	Gross Profit
"IFRS"	:	International Financial Reporting Standards
"Indemnified Persons"	:	FHCA, its directors and officers
"Interest Adjustments"	:	Adjustments in relation to the Carry Arrangement
"LPC"	:	Low Pressure Compressor
"Management"	:	Management of the Entity
"NBV"	:	Net Book Value
"PAT"	:	Profit After Tax
"PBT"	:	Profit Before Tax
"Proposed Corporate Exercise"	:	Proposed acquisition of the entire equity interest in TEPB
"Report"	:	Special Scope Assessment Review dated 19 September 2024
"Review Period"	:	FYE 31 December 2021, 2022 and 2023
"ROU"	:	Right-of-use
"Shortfall Gas"	:	Shortfall between the gas delivered and contractual quantity by BBJV
"SLEB"	:	Seria Light Export Blend
"SSAR"	:	Special Scope Assessment Review
"2nd Floor, RBA Plaza"	:	2nd Floor, RBA Plaza, Jalan Sultan, Bandar Seri Begawan BS8811, Negara Brunei Darussalam

Currency

Term		**Definition**
"BND"	:	Brunei Dollars
"USD"	:	United States Dollars

Note: Some figures in the Report may not be exactly added or computed due to rounding.

TABLE OF CONTENTS

1 INTRODUCTION

1.1 Scope of Engagement

1.1.1 Overview

- FHCA understands that the Company is undertaking a proposed acquisition of the entire equity interest in the Entity.

- FHCA was made to understand that the Entity's unaudited financial statements was prepared based on the International Financial Reporting Standards ("**IFRS**") whereas the Audited Financial Statements ("AFS") of the Branch was prepared based on the Branch's Accounting Policies ("**BAP**").

- As the AFS of the Entity was not available, the Company had appointed FHCA to conduct a SSAR on the Entity.

- The purpose of this SSAR primarily consists of the review and report of findings on the following:

  a) The AFS of the Branch for the Financial Year Ended 31 December ("**FYE**") 2021, 2022 and 2023 (collectively referred to as the **"Review Period**"); and

  b) The consolidated management accounts of the Entity for the FYE 31 December 2021, 2022 and 2023, as well as to clarify on the financial statement adjustments made from Branch to Entity.

- This review does not encompass any legal due diligence review and / or operational review of the Entity and any mention of any legal and / or operational matters, if any, within this Report shall not be taken as an opinion provided by FHCA and/or taken as a conclusion to the subject matter mentioned but only serve the purpose for providing additional information for consideration by the Company.

- FHCA will also not specifically assess and review the accounting and internal control procedures and practices adopted by the Entity or its compliances with the relevant statutory requirements other than to the extent deemed necessary to enable FHCA to perform our review.

- Furthermore, the procedures that FHCA will be performing will be substantially less than an audit performed in accordance with generally accepted international auditing standards. As a result, FHCA will not express an opinion on the financial statements of the Entity or give "negative assurance" with respect thereto.

- Moreover, this work cannot provide assurance that all matters of significance to the financial information of the Entity will be disclosed.

1.2 Reliance on Information and Explanation

- As part of our SSAR, where in the absence of particular concerns, FHCA placed reliance upon information from sources provided by the Management unless expressly stated. In the absence of concerns about the matters being included in FHCA's SSAR, it is assumed that the information provided to FHCA have been carefully and honestly prepared for the purpose for which it has been prepared.

- The information was restricted to specified documents made available to FHCA. FHCA has not independently verified and shall not assume responsibility for the accuracy and completeness of the information provided to FHCA. Any significant errors in, or omissions from, the information supplied to FHCA will have a corresponding effect on FHCA's analyses and conclusions.

- The directors of the Entity are responsible for the preparation of the combined financial statements contained in the Report, so as to give a true and fair view. The directors are also responsible for such internal control as the directors determine is necessary to enable the preparation of the combined financial statements of the Entity that are free from material misstatement, whether due to fraud or error.

1.3 Confidentiality, Disclaimer and Restriction

- FHCA understands that the scope of work stated in FHCA's letter of engagement is sufficient for your purpose in connection with the Proposed Corporate Exercise. However, FHCA makes no representations regarding the sufficiency of the scope of work that FHCA has carried out for any other purposes.

- The scope of work does not constitute an audit review and, consequently, no assurance is expressed. FHCA has not specifically assessed and reviewed the accounting and internal control procedures and practices adopted by the Entity other than to the extent deemed necessary to enable FHCA to perform this assignment.

1.3.1 Disclaimer of Liability to Third Party

- This Report is prepared for the use of the Company in connection with the Proposed Corporate Exercise and should not be used or relied upon for any other purposes. FHCA assumes no responsibility howsoever or whatsoever for any loss or damage arising out of or in connection with the contents of this Report to parties other than the Company.

1.3.2 Restriction on Use and Distribution

- FHCA's report on the SSAR in connection with the Proposed Corporate Exercise is given in confidence and is provided for the sole use of the Company and should not be used or relied upon for any other purpose. Other than inclusion in the Company's circular for the purpose of the Proposed Corporate Exercise, no part of any of FHCA's report may be disclosed to third parties or copied, reproduced, extracted, quoted or included in any other document to third parties without FHCA's prior written consent.

- No reliance should be placed on any draft copies of FHCA's report issued for discussion and FHCA shall not be responsible to any parties who have place reliance on such draft copies of the report.

2 TRANSACTION SUMMARY

2.1 FHCA's Approach

- In the course of FHCA's work, FHCA have liaised with the Management to provide FHCA with the necessary information and accessibility to the financial records of the Entity in conducting this assignment.

- FHCA's objective is to ascertain and report on any adverse findings in relation to the combined financial statements of the Entity as of 31 December 2021, 2022 and 2023.

- FHCA has conducted FHCA's work based on the documents provided via electronic mails / virtual data room / physical copies obtained from the Management. FHCA have conducted visits to the business location of the Entity located at 2nd Floor, RBA Plaza, Jalan Sultan, Bandar Seri Begawan BS8811, Negara Brunei Darussalam ("**2nd Floor, RBA Plaza**").

- FHCA has not reviewed events subsequent to 31 December 2023.

2.2 Source of Information

- For the purpose of this SSAR, FHCA have relied upon, in part or in whole on the information contained within the following documents and sources of information:

  (i) AFS of the Branch for the FYE 31 December 2021, 2022 and 2023;

  (ii) Consolidated management accounts of the Entity for the FYE 31 December 2021, 2022 and 2023;

  (iii) All relevant documents relating to accounting transactions that were maintained by the Entity that are pertinent for our review;

  (iv) All documents provided to FHCA via electronic mail / virtual data room / physical copies by the management of Entity;

  (v) Statutory records kept and maintained by the Entity; and

  (vi) Information, explanation and representations given by the management of the Entity ("**Management**").

- This Report only covers matters which are known to FHCA of 31 December 2023. FHCA accepts no responsibility for updating our Report or for informing any addressees of this Report in relation to events becoming known to FHCA or occurring after this date.

- FHCA notes that there are no adverse findings in the accompanying combined financial statements contained in the SSAR as of 31 December 2021, 2022 and 2023 based on the information provided to us as detailed in **Section 1.2** of this Report.

3 BACKGROUND OF ENTITY

- TEPB is part of the subsidiaries of TotalEnergies SE, a global integrated energy company that produces and markets energy. TEPB was incorporated in the Netherlands and has been involved in gas and condensate production activities in Brunei since April 1999.

- TEPB and two (2) other parties (collectively referred to as the "**BBJV**" or the "**BBJV Partners**") have been granted the mining rights of Block B offshore Brunei which contains the Maharaja Lela Jamulalam field ("**Block B**") that will expire on 23 November 2029. It was further noted that it can be automatically extended for another ten (10) years subject to agreement of the BBJV Partners.

  A Joint Venture Agreement ("**JVA**") was entered between the BBJV partners in relation to the abovementioned arrangement.

- There have been no significant changes in the nature of these principal activities during the FYE under review.

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4 **Adjustments from Branch to Entity**

- The AFS of the Branch are prepared in accordance with BAP. The AFS reflects / records transactions related to TEPB’s participating interest in BBJV only and is the basis used to compute Chapter 119 Income tax (Petroleum) Act and Chapter 35 Income tax payable in Brunei.
- Pursuant to a Cash Investors Agreement (“**CIA**”) entered among the BBJV Partners, TEPB and one (1) of the joint venture partners shall carry the other remaining joint venture partner’s participating interest of capital expenditure in the BBJV (“**Carry Arrangement**”). In accordance with the CIA, the Entity shall then recoup the carried capital expenditure monthly by taking a share from the joint venture partner’s base gas sales.
- IFRS 11 Joint Arrangements states that entities involved in joint operations recognise their share of assets, liabilities, revenue and expenses based on their rights and obligations within the arrangement. Accordingly, the Entity included adjustments to reflect the Carry Arrangement as well as manual adjustments when consolidating its Branch and Head Office financial statements

These adjustments for the FYE 2021, FYE 2022 and FYE 2023 are summarised and described as follows:

4.1. Statement of Financial Position

FYE 2021

	Note	AFS Branch (BAP)	Adjustments Interest [1]	Branch [2]	Adjusted Branch (IFRS)	Head Office (IFRS)	Entity (IFRS)
					USD'000		
Non-current Assets							
Development Costs	(i)	153,316	45,783	-	199,099	-	199,099
Exploration Costs	(ii)	214,384	11,716	-	226,100	(183,493)	42,607
Retirement Obligation Asset		12,308	-	-	12,308	-	12,308
Fixed Assets	(iii)	1,388	-	(111)	1,277	-	1,277
ROU Assets		442	-	-	442	-	442
Total Non-current Assets		**381,838**	**57,499**	**(111)**	**439,226**	**(183,493)**	**255,733**
Current Assets							
Cash and Cash Equivalents		97,527	-	-	97,527	16	97,543
Trade and Other Debtors	(iv)	30,058	-	(764)	29,294	-	29,294
Amounts due From Partners	(v)	2,277	342	-	2,619	-	2,619
Stocks	(vi)	1,507	381	-	1,888	-	1,888
Total Current Assets		**131,369**	**723**	**(764)**	**131,328**	**16**	**131,344**
Total Assets		**513,207**	**58,222**	**(875)**	**570,554**	**(183,477)**	**387,077**

4

	Note	AFS Branch (BAP)	Adjustments Interest [1]	Adjustments Branch [2]	Adjusted Branch (IFRS)	Head Office (IFRS)	Entity (IFRS)
				USD'000			
Current Liabilities							
Trade and Other Creditors	(iv), (vii)	46,255	-	(452)	45,803	-	45,803
Taxation		47,086	-	-	47,086	-	47,086
Amounts due to Related Companies		1,952	-	-	1,952	-	1,952
Finance Lease Liabilities		269	-	-	269	-	269
Total Current Liabilities		**95,562**	**-**	**(452)**	**95,110**	**-**	**95,110**
Non-current Liabilities							
Deferred Taxation		72,240	-	-	72,240	-	72,240
Provision for Asset Retirement Obligation ("**ARO**")		41,934	-	-	41,934	-	41,934
Finance Lease Liability		418	-	-	418	-	418
Total Non-current Liabilities		**114,592**	**-**	**-**	**114,592**	**-**	**114,592**
Total Liabilities		**210,154**	**-**	**(452)**	**209,702**	**-**	**209,702**
Net Asset		**303,053**	**58,222**	**(423)**	**360,852**	**(183,477)**	**177,375**

FYE 2022

	Note	AFS Branch (BAP)	Adjustments Interest [1]	Adjustments Branch [2]	Adjusted Branch (IFRS)	Head Office (IFRS)	Entity (IFRS)
				USD'000			
Non-current Assets							
Development Costs	(i)	140,504	39,389	-	179,893	-	179,893
Exploration Costs	(ii)	210,385	10,200	-	220,585	(183,491)	37,094
Retirement Obligation Asset		10,595	-	-	10,595	-	10,595
Fixed Assets	(iii)	1,206		(109)	1,097	-	1,097
ROU Assets		225	-	-	225	-	225
Total Non-current Assets		**362,915**	**49,589**	**(109)**	**412,395**	**(183,491)**	**228,904**
Current Assets							
Cash and Cash Equivalents		110,937	-	-	110,937	97	111,034
Trade and Other Debtors	(iv)	34,132	-	(511)	33,621	-	33,621
Amounts due From Partners	(v)	9,439	(630)	-	8,809	-	8,809

	Note	AFS Branch (BAP)	Adjustments Interest [1]	Adjustments Branch [2]	Adjusted Branch (IFRS)	Head Office (IFRS)	Entity (IFRS)
		USD'000					
Stocks	(vi)	1,364	395	-	1,759	-	1,759
Total Current Assets		**155,872**	**(235)**	**(511)**	**155,126**	**97**	**155,223**
Total Asset		**518,787**	**49,354**	**(620)**	**567,521**	**(183,394)**	**384,127**
Current Liabilities							
Trade and Other Creditors	(iv, vii)	68,983	-	(304)	68,679	-	68,679
Taxation		66,429	-	-	66,429	-	66,429
Amounts due to Related Companies		6,156	-	-	6,156	-	6,156
Finance Lease Liability		311	-	-	311	-	311
Total Current Liabilities		**141,879**	**-**	**(304)**	**141,575**	**-**	**141,575**
Non-current Liabilities							
Deferred Taxation		58,170	-	-	58,170	-	58,170
Provision for ARO		43,192	-	-	43,192	-	43,192
Finance Lease Liabilities		109	-	-	109	-	109
Total Non-current Liabilities		**101,471**	**-**	**-**	**101,471**	**-**	**101,471**
Total Liability		**243,350**	**-**	**(304)**	**243,046**	**-**	**243,046**
Net Asset		**275,437**	**49,354**	**(316)**	**324,475**	**(183,394)**	**141,081**

FYE 2023

	Note	AFS Branch (BAP)	Adjustments Interest [1]	Adjustments Branch [2]	Adjusted Branch (IFRS)	Head Office (IFRS)	Entity (IFRS)
		USD'000					
Non-current Assets							
Development Costs	(i)	135,324	38,881	-	174,205	-	174,205
Exploration Costs	(ii)	207,076	8,946	-	216,023	(183,490)	32,533
Retirement Obligation Asset		5,112	-	-	5,112	-	5,112
Fixed Assets	(iii)	2,261	-	(110)	2,151	-	2,151
Right-of-Use ("**ROU**")		217	-	-	217	-	217
Total Non-current Assets		**349,991**	**47,827**	**(110)**	**397,708**	**(183,490)**	**214,218**

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	Note	AFS Branch (BAP)	Adjustments Interest [1]	Branch [2]	Adjusted Branch (IFRS) USD'000	Head Office (IFRS)	Entity (IFRS)
Current Assets							
Cash and Cash Equivalents		114,225	-	-	114,225	101	114,326
Trade and Other Debtors	(iv)	27,767	-	(436)	27,331	-	27,331
Amounts due from Partners	(v)	18,014	(1,350)	-	16,664	-	16,664
Stocks	(vi)	2,510	396	-	2,906	-	2,906
Total Current Assets		**162,516**	**(954)**	**(436)**	**161,126**	**101**	**161,227**
Total Assets		**512,507**	**46,873**	**(546)**	**558,833**	**(183,389)**	**375,444**
Current Liabilities							
Trade and Other Creditors	(iv), (vii)	89,238	-	(260)	88,978	-	88,978
Taxation		40,946	-	-	40,946	-	40,946
Amounts due to Related Companies		5,431	-	-	5,431	-	5,431
Finance Lease Liability		275	-	-	275	-	275
Total Current Liabilities		**135,890**	**-**	**(260)**	**135,630**	**-**	**135,630**
Non-current Liabilities							
Deferred Taxation		48,750	-	-	48,750	-	48,750
Provision for ARO		32,224	-	-	32,224	-	32,224
Total Non-current Liabilities		**80,974**	**-**	**-**	**80,974**	**-**	**80,974**
Total Liabilities		**216,864**	**-**	**(260)**	**216,604**	**-**	**216,604**
Net Asset		**295,641**	**46,873**	**(286)**	**342,229**	**(183,389)**	**158,840**

Note:

[1] This refers to adjustments in relation to the Carry Arrangement.

[2] This refers to manual adjustments made on the management accounts of the Branch.

Based on the above table, FHCA notes the following:

(i) This refers to an adjustment made to reflect the Carry Arrangement in relation to development costs shared by the BBJV.

(ii) FHCA understands that prior to 2009, the exploration costs were fully capitalised at the Branch level, but was substantially written-off at the Head Office accounts as hydrocarbon volumes seen in these exploration wells will not achieve commercial viability. Hence, the adjustments made in the Head Office accounts (representing exploration costs capitalised for these wells) was made to include the written-off amounts of the exploration costs prior to 2009 to accurately reflect the net book value of the exploration costs as of the respective financial years as well as to reflect the Carry Arrangement.

(iii) This refers to an adjustment to eliminate unidentified amounts carried forward from previous years to reflect the actual carrying value of fixed assets held by the Entity.

(iv) **FYE 2021 and FYE 2022**

Based on a gas supply agreement entered by the BBJV in relation to the sale of gas, the BBJV is obliged to make up any under delivery of gas arising from the difference between the daily contract quantity and quantity made available for delivery ("**Shortfall Gas**"). This refers to an adjustment made to provide for the Shortfall Gas during the FYE 2020, FYE 2021 and FYE 2022. As the final adjustment figure is to be negotiated between the Entity and the customer, the abovementioned provision was made only for the purpose of the Entity books.

FYE 2023

Similar to the description for FYE 2021 and FYE 2022, this refers to an adjustment made to provide for the Shortfall Gas during the FYE 2020 and FYE 2021 as a credit note for the FYE 2022 Shortfall Gas have been issued to the customer during the FYE 2023.

(v) This refers to an adjustment made to reflect the net amount due from the BBJV partners arising from the JVA after taking into account the Carry Arrangement.

(vi) This refers to an adjustment made to reflect the Carry Arrangement in relation to stocks carried by the Entity.

(vii) This refers to an adjustment made to reflect the provisional reduction in royalty and tax payable due to the adjustment in revenue resulting from the Shortfall Gas for the relevant financial years, as explained in **Section 4.1 (iv)** of this Report.

4.2. Statement of Profit or Loss and Other Comprehensive Income

FYE 2021

	Note	AFS Branch (BAP)	Adjustments Interest [1]	Adjustments Branch [2]	Adjusted Branch (IFRS)	Head Office (IFRS)	Entity (IFRS)
		USD'000					
Sales	(i)	112,246	880	(8)	113,118	-	113,118
Interest Income		-	-	-	-	-	-
Total Income		**112,246**	**880**	**(8)**	**113,118**	**-**	**113,118**
Depreciation and Amortisation	(ii)	(31,709)	(12,502)	-	(44,211)		(44,211)
Production Cost		(14,642)	-	-	(14,642)	-	(14,642)
Royalties		(9,027)	-	-	(9,027)	-	(9,027)
Other Costs	(iii)	(2,707)	(203)	-	(2,909)	2	(2,907)

	Note	AFS Branch (BAP)	Adjustments Interest [1]	Adjustments Branch [2]	Adjusted Branch (IFRS)	Head Office (IFRS)	Entity (IFRS)
		USD'000					
Value Compensation		(362)	-	-	(362)	-	(362)
Accretion Expense		(1,221)	-	-	(1,221)	-	(1,221)
Condensate Stock Variation		324	-	-	324	-	324
Profit Before Tax ("PBT")		**52,902**	**(11,824)**	**(8)**	**41,070**	**2**	**41,072**
Taxation	(iv)	(30,578)	-	455	(30,124)	-	(30,124)
Profit After Tax ("PAT")		**22,324**	**(11,824)**	**447**	**10,946**	**2**	**10,948**

FYE 2022

	Note	AFS Branch (BAP)	Adjustments Interest [1]	Adjustments Branch [2]	Adjusted Branch (IFRS)	Head Office (IFRS)	Entity (IFRS)
		USD'000					
Sales	(i)	157,218	2,135	253	159,606	-	159,606
Interest Income		1,866	-	-	1,866	91	1,957
Total Income		**159,084**	**2,135**	**253**	**161,472**	**91**	**161,563**
License Fees		(7,385)	-	-	(7,385)	-	(7,385)
Depreciation and Amortisation	(ii)	(27,595)	(11,006)	-	(38,601)	-	(38,601)
Production Cost		(12,723)	-	-	(12,723)	-	(12,723)
Royalties		(11,480)	-	-	(11,480)	-	(11,480)
Other Costs	(iii)	(2,153)	7	-	(2,147)	(5)	(2,152)
Value Compensation		(1,480)	-	-	(1,480)	-	(1,480)
Accretion Expense		(1,258)	-	-	(1,258)	-	(1,258)
Condensate Stock Variation		(182)	-	-	(182)	-	(182)
PBT		**94,828**	**(8,864)**	**253**	**86,217**	**86**	**86,303**
Taxation	(iv)	(52,443)	-	(150)	(52,594)	(3)	(52,597)
PAT		**42,385**	**(8,864)**	**102**	**33,623**	**83**	**33,706**

FYE 2023

	Note	AFS Branch (BAP)	Adjustments Interest [1]	Adjustments Branch [2]	Adjusted Branch (IFRS)	Head Office (IFRS)	Entity (IFRS)
		USD'000					
Sales	(i)	144,661	6,311	75	151,046	-	151,046
Interest Income		4,944	-	-	4,944	-	4,944
Total Income		**149,605**	**6,311**	**75**	**155,990**	**-**	**155,990**
License Fees		(36,365)	-	-	(36,365)	-	(36,365)

	Note	AFS Branch (BAP)	Adjustments Interest [1]	Branch [2]	Adjusted Branch (IFRS)	Head Office (IFRS)	Entity (IFRS)
				USD'000			
Depreciation and Amortisation	(ii)	(22,489)	(8,781)	-	(31,270)	-	(31,270)
Production Cost		(12,856)	-	-	(12,856)	-	(12,856)
Royalties		(7,639)	-	-	(7,639)	-	(7,639)
Other Costs	(iii)	(3,146)	(11)	-	(3,157)	5	(3,153)
Value Compensation		(1,533)	-	-	(1,533)	-	(1,533)
Condensate Stock Variation		1,151	-	-	1,151	-	1,151
PBT		**66,728**	**(2,482)**	**75**	**64,321**	**5**	**64,325**
Taxation	(iv)	(31,523)	-	(45)	(31,567)	-	(31,567)
PAT		**35,205**	**(2,482)**	**30**	**32,754**	**5**	**32,758**

Note:

[1] This refers to adjustments in relation to the Carry Arrangement.

[2] This refers to manual adjustments made on the management accounts of the Branch.

Based on the above table, FHCA notes the following:

(i) This comprises of the following adjustments:

- Interest Adjustments: This refers to an adjustment for capital expenditure recoupment arising from the Carry Arrangement. The Management explained that the rise in capital expenditure recoupment from FYE 2021 to FYE 2023 was due to the commencement of a Low Pressure Compressor ("**LPC**") Project in January 2022, resulting in higher capital expenditure during the FYE 2022 and 2023.

- Branch Adjustments: This adjustment reflects the year-on-year differences in Shortfall Gas recorded for the FYE 2020, 2021 and 2022, with variances arising from over- or under-estimations of Shortfall Gas across the respective financial years.

(ii) This refers to an adjustment to reflect the Carry Arrangement in relation to the depreciation and amortisation expenses solely on assets shared among the BBJV carried by the Entity.

(iii) This refers to an adjustment to reflect the Carry Arrangement in relation to the increase in provision for consumable stock carried by the Entity.

(iv) This refers to the tax impact arising from over- or under-estimations of Shortfall Gas for the FYE 2020, 2021 and 2022 as described in **Section 4.2 (i)** of this Report.

FHCA observes that certain line items differ in the statement of financial position and statement of comprehensive income between the Entity (IFRS) and those appended in the Circular due to differences in classification and categorization. However, it is noted that these differences in classification and categorization do not affect the net assets and net profit reported by the Entity during the Review Period. A reconciliation between both is detailed in **Annexure 1** of this Report.

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5 SUPPORTING ANALYSIS ON FINANCIAL POSITION OF THE ENTITY

5.1 Historical Financial Position Overview

	Note	FYE 2021	FYE 2022 USD'000	FYE 2023
Non-current Assets				
Development Costs	*5.2*	199,099	179,893	174,205
Exploration Costs	*5.3*	42,607	37,094	32,533
Retirement Obligation Assets	*5.4*	12,308	10,595	5,112
Fixed Assets	*5.5*	1,277	1,097	2,151
ROU Assets	*5.6*	442	225	217
Total Non-current Assets		**255,733**	**228,904**	**214,218**
Current Assets				
Cash and Cash Equivalents		97,543	111,034	114,326
Trade and Other Debtors	*5.7*	29,294	33,621	27,331
Amounts due from Partners	*5.8*	2,619	8,809	16,664
Stocks	*5.9*	1,888	1,759	2,906
Total Current Assets		**131,344**	**155,223**	**161,227**
Total Assets		**387,077**	**384,127**	**375,444**
Current Liabilities				
Trade and Other Creditors	*5.10*	45,803	68,679	88,978
Taxation		47,086	66,429	40,946
Amounts due to Related Companies	*5.11*	1,952	6,156	5,431
Finance Lease Liability	*5.6*	269	311	275
Total Current Liabilities		**95,110**	**141,575**	**135,630**
Non-current Liabilities				
Deferred Taxation		72,240	58,170	48,750
Provision for ARO	*5.4*	41,934	43,192	32,224
Finance Lease Liability	*5.6*	418	109	-
Total Non-current Liabilities		**114,592**	**101,471**	**80,974**
Total Liabilities		**209,702**	**243,046**	**216,604**
Net Asset		**177,375**	**141,081**	**158,840**

- Based on the AFS and an impairment indicator questionnaire prepared by the auditors of the Branch, it was concluded that there is no indication of impairment on the assets of the Entity for the Review Period.

5.2 Development Costs

- Development costs capitalised comprise of development studies, acquisition of assets, drilling of development wells as well as construction of onshore and offshore production facilities associated with the development of Block B, inclusive of those classified as work in progress pending completion.

  Capitalised development costs are amortised using the unit-of-production method, representing the ratio of oil and gas produced for the financial period to total proved reserve of Block B.

- Details in relation to development costs are tabled as follows:

Development Cost	Note	FYE 2021	FYE 2022 USD'000	FYE 2023
As of 1 January		610,331	613,031	621,202
Addition	(i)	2,700	8,171	18,504
Changes in Assumption	(ii)	-	-	(6,165)
As of 31 December		613,031	621,202	633,541
Amortisation		(459,715)	(480,698)	(498,217)
Net Book Value ("NBV")		**153,316**	**140,504**	**135,324**
Interest Adjustments	(iii)	45,783	39,389	38,881
Adjusted NBV		**199,099**	**179,893**	**174,205**

Based on the table above, FHCA notes the following:

(i) This refers to addition in relation to the LPC project that commenced during the FYE 2021.

(ii) Changes in assumption relating to the retirement obligation assets where the discount and inflation rate adopted in FYE 2023 was 5.0% and 2.0% as compared to 4.0% and 2.0% respectively in FYE 2022.

(iii) This refers to adjustments made to reflect the Carry Arrangement.

5.3 Exploration Costs

- Initial exploration drilling costs are capitalised until it is determined whether proved reserves have been discovered. Exploration costs will remain capitalised upon any confirmed discovery and shall be amortised adopting the unit-of-production method. In the event where the hydrocarbon volumes seen in these exploration wells is deemed to not achieve commercial viability, the entire costs in relation to these exploration wells are entirely expensed.

- The carrying balance of exploration costs are summarised as follows:

Exploration Costs	FYE 2021	FYE 2022 USD'000	FYE 2023
Exploration Drilling	215,372	215,372	215,372
Exploration Studies	38,347	38,347	38,347
Seismic	22,412	22,412	22,411
General Studies	7,835	7,835	7,835
Accumulated Amortisation	(69,582)	(73,581)	(76,888)
Head Office and Interest Adjustments [1]	(171,777)	(173,291)	(174,544)
NBV	**42,607**	**37,094**	**32,533**

Note:

*[1] This refer to the expensing of exploration costs for dry wells that was capitalised prior to 2009 as well as to reflect the Carry Arrangement, please refer to **Section 4.1 (ii)** of this Report for further information regarding the same.*

5.4 Retirement Obligation Assets

- Retirement obligation asset represents the initial recognition of the cost of an ARO that is capitalized as part of the carrying amount of facilities and operations as well as development wells situated in Block B. Amounts capitalised are depreciated under the unit-of-production method.

- Details regarding the Entity's retirement obligation assets for the FYE 2023 are tabled as follows:

	Facilities and Operations	Development Wells USD'000	Total
Cost	28,626	2,353	30,979
Changes in Assumption	(3,385)	(1,418)	(4,803)
Accumulated Depreciation	(20,129)	(935)	(21,064)
NBV	**5,112**	**-**	**5,112**

As described in **Section 5.2 (ii)** of this Report, changes in assumption refers to changes in discount rate adopted when computing the retirement obligation assets.

<u>**Provision for ARO**</u>

- A provision for ARO is recognized in the statement of financial position of the Entity as a liability representing the present value of the estimated future costs to retire the assets.

  The carrying amount of the provision for ARO changes over time as the Entity recognises accretion expenses that are measured by applying a risk-free discount rate to the amount of the liability. Changes in the estimated liability resulting from revisions to estimated timing or future asset retirement cost estimates are recognised as a change in the provision for asset retirement obligation and the related asset retirement obligation assets.

5.5 Fixed Assets

- Fixed assets held by the Entity are detailed as follows:

	Cost as of 1 January	Addition / (Disposal)	Depreciation Expenses USD'000	NBV as of 31 December
<u>**FYE 2021**</u>				
Leasehold Improvement	32	6	(37)	1
Data Processing, Technical Equipment and Software	1,631	(595)	(13)	1,023

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	Cost as of 1 January	Addition / (Disposal)	Depreciation Expenses	NBV as of 31 December
			USD'000	
Furniture and Equipment	325	194	(155)	364
Total FYE 2021	**1,988**	**(395)**	**(205)**	**1,388**
Branch Adjustments [1]				(111)
Adjusted Total				**1,277**
FYE 2022				
Leasehold Improvement	1	(1)	-	-
Data Processing, Technical Equipment and Software	1,023	249	(540)	733
Furniture and Equipment	364	258	(149)	473
Total FYE 2022	**1,388**	**506**	**(689)**	**1,206**
Branch Adjustments [1]				(109)
Adjusted Total				**1,097**
FYE2023				
Data Processing, Technical Equipment and Software	732	415	(574)	573
Furniture and Equipment	473	1,389	(174)	1,688
Total	**1,205**	**1,804**	**(748)**	**2,261**
Branch Adjustments [1]				(110)
Adjusted Total				**2,151**

Note:

[1] This refers to adjustments made to eliminate an unidentified balance carried forward from previous years. Please refer to ***Section 4.1 (iii)*** *of this Report for further information regarding the same.*

- Fixed assets of the Entity are depreciated using the straight-line method over their estimated useful lives.

5.6 ROU

- The ROU of the Entity arose from a lease agreement pursuant to the charter hire of a crew boat vessel that will expire in July 2024.
- The carrying value of the ROU and its corresponding lease liability is recorded at the present value of lease payments, discounted using the incremental borrowing rate of 3.7% as stipulated in the AFS of the Branch for the FYE 2023. The ROU asset shall be depreciated using the straight-line method over the lease term upon the lease commencement date.

5.7 Trade and Other Debtors

- Trade and other debtors of the Entity are analysed as follows:

Trade and Other Debtors	Note	FYE 2021	FYE 2022	FYE 2023
			USD'000	
Trade Receivables	(i)	29,063	33,149	22,679
Advance Payment	(ii)	447	441	4,467
Others	(iii)	548	542	621
Total		**30,058**	**34,132**	**27,767**
Branch Adjustments [1]		(764)	(511)	(436)
Adjusted Total		**29,294**	**33,621**	**27,331**

Note:

[1] This refers to a provision in relation to the Shortfall Gas. Please refer to ***Section 4.1 (iv)*** *of this Report for further information.*

With reference to the above table, FHCA notes the following:

(i) FHCA notes that trade receivables of the Entity are current and is within the ten (10) days credit terms offered by the Entity. FHCA notes that there was no provision made in relation to bad or doubtful debts made by the Entity. FHCA have sighted to the trade receivables breakdown of subsequent periods and noted that the balance receivable at every FYEs is settled in the subsequent period.

(ii) Advance payments recorded for the FYE 2021 and 2022 mainly refer to an advance payment in relation to the general maintenance and operation services. The larger advance payment recorded during FYE 2023 was due to an amount paid to trade creditors of the Entity, FHCA have further verified that the amount was off set against the relevant trade creditor in the subsequent period based on the management accounts as of 30 June 2024.

(iii) Others refer mainly to prepayments, deposits, staff loan as well as staff advances. Staff loan offered by the Entity are interest-free.

5.8 Amounts due from Partners

- Amounts due from partners refer to net receivables (nett of sales with the partners' respective share in working capital and capital expenditures) and from the BBJV Partners arising from the BBJV operations.

5.9 Stocks

- The stocks held by the Entity consist of condensate stock and consumable stock. The breakdown of condensate stock and consumable stock held by the Entity are as follows:

	FYE 2021	FYE 2022 USD'000	FYE 2023
Condensate stock	504	322	1,473
Consumable stock	1,003	1,042	1,037
Total Stock at Branch	**1,507**	**1,364**	**2,510**
Interest Adjustments [1]	381	395	396
Adjusted Total Stock at Entity	**1,888**	**1,759**	**2,906**

Note:

*[1] This refers to an adjustment made to reflect the Carry Arrangement. Please refer to **Section 4.1 (vi)** of this Report for further information regarding the same.*

5.10 Trade and Other Creditors

- Trade and other creditors of the Entity are summarised as follows:

Trade and Other Creditors	Note	FYE 2021	FYE 2022 USD'000	FYE 2023
Accruals		30,164	57,218	69,779
Royalty and Tax Payable		7,692	6,992	6,377
Trade Creditors	(i)	6,646	3,264	6,194
Others		1,753	1,509	6,888
Total		**46,255**	**68,983**	**89,238**
Branch Adjustments [1]		(452)	(304)	(260)
Adjusted Total		**45,803**	**68,679**	**88,978**

Note:

*[1] This refers to adjustments to reflect the provision of Shortfall Gas and reduction in royal and tax payable resulting from the adjustment in revenue as described in **Section 4.1 (iv), (vii)** and **Section 5.7** of this Report.*

Based on the above table, FHCA notes the following:

(i) Normal trade credit term granted to the Entity ranges from thirty (30) to sixty (60) days.

5.11 Amounts due to Related Companies

- Amounts due to and from related companies are unsecured, interest free and are repayable upon demand.

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6 SUPPORTING ANALYSIS ON FINANCIAL PERFORMANCE OF THE ENTITY

6.1 Historical Operating Result Overview

	Note	FYE 2021	FYE 2022 USD'000	FYE 2023
Sales	*6.2*	113,118	159,606	151,046
Interest income	*6.3*	-	1,957	4,944
Total Income		**113,118**	**161,563**	**155,990**
Condensate Stock Variation		324	(182)	1,151
License Fees	*6.4*	-	(7,385)	(36,365)
Depreciation and Amortisation	*6.5*	(44,211)	(38,601)	(31,270)
Production Cost	*6.6*	(14,642)	(12,723)	(12,856)
Royalties	*6.7*	(9,027)	(11,480)	(7,639)
Other Costs		(2,907)	(2,152)	(3,153)
Value Compensation	*6.8*	(362)	(1,480)	(1,533)
Accretion Expense		(1,221)	(1,258)	-
PBT		**41,072**	**86,303**	**64,325**
Taxation [1]		(30,124)	(52,597)	(31,567)
PAT		**10,948**	**33,706**	**32,758**

Note:

[1] Taxation includes a 55% Petroleum Income Tax on taxable income from gas and condensate (excluding the field involving third-party arrangement), an 18.5% Corporate Income Tax on taxable income from interest, gas and condensate produced from the field involving third-party arrangement, as well as supplementary payments.

6.2 Sales

- The Entity's sales by product for the Review Period are as follows:

	FYE 2021	FYE 2022 USD'000	FYE 2023
Gas Sales	88,043	122,624	112,887
Condensate Sales	25,075	36,982	38,159
Total Sales	**113,118**	**159,606**	**151,046**

6.3 Interest Income

- Interest income refers to the interest earned from deposits placed with a related party.

6.4 License Fees

- The BBJV shall pay a license fee for producing and selling raw gas from a third party.

6.5 Depreciation and Amortisation

- This refers to the depreciation and amortisation for fixed assets, exploration costs, retirement obligation asset, development cost, and right-of-use assets.

6.6 Production Cost

- Production costs primarily consist of expenses for maintaining and operating the production facilities (onshore and offshore), including personnel, logistics, general maintenance, insurance premiums, and repairs.

6.7 Royalties

- In accordance with a petroleum mining agreement entered by the BBJV, a royalty of 8.0% shall be paid by the BBJV to the Government of Brunei on all gas and condensate (excluding gas and condensate extracted from the field involving third-party arrangement) obtained and sold.

6.8 Value Compensation

- Under an operating services agreement between the BBJV and a service provider, BBJV's hydrocarbon liquids are processed, stored, and loaded at the provider's terminal. The value compensation represents the payment BBJV makes for the change in value due to mixing with the provider's liquids.

6.9 Gross Profit ("GP"), Earnings Before Interest, Tax, Depreciation and Amortisation ("EBITDA"), and PAT

GP Margin, EBITDA Margin and PAT Margin

	FYE 2021	FYE 2022 USD'000	FYE 2023
GP [1]	**42,929**	**86,127**	**60,521**
GP Margin	*38.0%*	*54.0%*	*40.1%*
EBITDA	**85,635**	**123,206**	**90,895**
EBITDA Margin	*75.7%*	*77.2%*	*60.2%*
PAT	**10,948**	**33,706**	**32,758**
PAT Margin	*9.7%*	*21.1%*	*21.7%*

Note:

[1] Computed using the following formula: Sales - Value Compensation - Cost of sales. Cost of sales consists of license fees, royalties, production cost, depreciation and amortisation, transportation costs, loss/(gain) on disposal of stocks, provision for stock/(obsolete stock written back), condensate stock variation and other costs after upstream separation point.

- The Management explained that the higher GP margin in FYE 2022 compared to FYE 2021 and FYE 2023 was due to the elevated gas selling prices and condensate selling prices during FYE 2022.

- The EBITDA margin rose from FYE 2021 to FYE 2022 due to higher sales revenue but declined in FYE 2023 as sales decreased and cost of sales increased.

- The PAT margin increased from FYE 2021 to FYE 2022 due to a substantial increase in EBITDA and increased interest income. Despite the drop in EBITDA margin in FYE 2023, the PAT margin still rose slightly to 21.7%, indicating that gains in interest income helped offset the decline in operational performance.

7 CONTINGENT LIABILITIES, CAPITAL AND OFF-BALANCE SHEET COMMITMENTS

7.1 Contingent Liabilities, Capital and Off-Balance Sheet Commitments

Contingent Liabilities

- The Management represented that there are no ongoing / potential proceedings which may materially affect the position and business of the Entity as of 31 December 2023.

7.2 Capital and Off-Balance Sheet Commitments

- Capital and off-balance sheet commitments of the Entity as of 31 December 2023 is identified as follows:

Type	Description	USD'million
Capital Commitment	LPC Project	20
Off-Balance Sheet Commitment	Lease liabilities below threshold [1]	3
Total		**23**

Note:

[1] FHCA notes that the Entity's financial statements are prepared for consolidation purposes. This refers to the aggregate lease contracts, each below the ultimate holding company's threshold of USD1.0 million.

About Baker Tilly

Baker Tilly ranks among the largest accounting and business advisory firms in Malaysia, with 50 Partners and Directors, 8 offices across Malaysia and an office in Phnom Penh, Cambodia, and a staff force of over 800 professionals.

With more than 40 years of experience in Malaysia, strengthened by our access to an international network of professionals and specialists spanning across 145 countries, we have the edge and capacity to provide high quality audit & assurance, tax, financial advisory services to multinational corporations, publicly listed corporations, organisations in the public sector, and small and medium-size corporations, across all industries.

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Annexure 1 – Reconciliation between the Entity (IFRS) and accounts appended in the Circular

FHCA observes that certain line items differ in the statement of financial position and statement of comprehensive income between the Entity (IFRS) and those appended in the Circular due to differences in classification and categorization. However, it is noted that these differences in classification and categorization do not affect the net assets and net profit reported by the Entity during the Review Period. A reconciliation between both is detailed as follows:

(A) Statement of Financial Position for the Review Period

	Note	FYE 2021 Entity (IFRS) [1]	FYE 2021 As appended in the Circular [2]	FYE 2021 Variance	FYE 2022 Entity (IFRS) [1]	FYE 2022 As appended in the Circular [2]	FYE 2022 Variance	FYE 2023 Entity (IFRS) [1]	FYE 2023 As appended in the Circular [2]	FYE 2023 Variance
		USD'million								
Non-current Assets	A.1	256	257	(1)	229	229	*	214	220	(6)
Current Assets	A.1, A.2	131	134	(3)	155	157	(2)	161	165	(4)
Total Assets		**387**	**390**	**(4)**	**384**	**386**	**(2)**	**375**	**385**	**(10)**
Current Liabilities	A.2	95	98	(3)	142	144	(2)	136	145	(9)
Non-current Liabilities		115	115	*	101	101	*	81	81	*
Total Liabilities		**210**	**213**	**(3)**	**243**	**245**	**(2)**	**217**	**226**	**(9)**
Net Assets		**177**	**177**	**-**	**141**	**141**	**-**	**159**	**159**	**-**

Note:

**negligible*

[1] Figures presented in the SSAR.

[2] Figures appended as part of the circular by the Company dated [date].

Notes:

Note	Description
A.1	FYE 2021, FYE 2022 - Reclassification of deposits and employee loans from other debtors in non-current assets to current assets. FYE 2023 - Removal of accruals for an expected jacket repair from total assets and liabilities as repair works have not been commenced as of 31 December 2023

Note	Description
A.2	FYE 2021, FYE 2022 and FYE 2023 - Reclassification of trade and other debtors to trade and other creditors due to netting of balance between debtors who are also creditors of the Entity.

(B) Statement of Comprehensive Income for the Review Period

	Note	FYE 2021 Entity (IFRS) [1]	FYE 2021 As appended in the Circular [2]	FYE 2021 Variance	FYE 2022 Entity (IFRS) [1]	FYE 2022 As appended in the Circular [2]	FYE 2022 Variance	FYE 2023 Entity (IFRS) [1]	FYE 2023 As appended in the Circular [2]	FYE 2023 Variance
		USD'million								
Revenue	B.1	113	113	*	160	158	2	151	150	1
Profit before Taxation		41	41	-	86	86	-	64	64	-
Profit after Taxation		11	11	-	34	34	-	33	33	-

Note:

**negligible*

[1] Figures presented in the SSAR.

[2] Figures appended as part of the circular announced by the Company dated [date].

Note	Description
B.1	FYE 2021, FYE 2022 and FYE 2023 - Reclassification of value compensation cost from revenue to operating costs

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TotalEnergies EP (Brunei) B.V.

(Incorporated in the Netherlands)
Brunei Darussalam Branch

Financial Statements
As at and for the year ended 31 December 2022
(with comparative figures and notes as at and for the year ended 31 December 2021)

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TotalEnergies EP (Brunei) B.V.
(Incorporated in the Netherlands)
Brunei Darussalam Branch

As at and for the year ended 31 December 2022
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TotalEnergies EP (Brunei) B.V.
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Brunei Darussalam Branch

Report on the Audit of the Financial Statements

Our Opinion

In our opinion, the financial statements of TotalEnergies EP (Brunei) B.V. - Brunei Darussalam Branch (the Branch) gives a true and fair view of the financial position as at 31 December 2022, and its financial performance and its cash flows for the year then ended in accordance with the accounting policies as described in Note 2 to the financial statements and the provisions of the Brunei Darussalam Companies Act, Chapter 39 (the Act).

What we have audited

The financial statements of the Branch comprise:

- the balance sheet as at 31 December 2022
- the profit and loss account for the year ended 31 December 2022
- the statement of cash flows for the year ended 31 December 2022; and
- the notes to the financial statements, which include a summary of significant accounting policies.

Basis for Opinion

We conducted our audit in accordance with International Standards on Auditing (ISA). Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence

We are independent of the Branch in accordance with the International Code of Ethics for Professional Accountants issued by the International Ethics Standards Board for Accountants (the Code), together with the ethical requirements that are relevant to our audit of the financial statements in Brunei Darussalam, and we have fulfilled our other ethical responsibilities in accordance with these requirements and the Code.

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Other matter

The financial statements of the Branch as at and for the year ended 31 December 2021 were audited by another firm of auditors whose report dated 17 June 2022 expressed an unmodified opinion on those statements. We were not engaged to audit, review or apply any procedures to the financial statements as at and for the year ended 31 December 2021, accordingly, we do not express an opinion or any other form of assurance on the financial statements as at and for the year ended 31 December 2021 taken as a whole.

Responsibilities of Directors and Those Charged with Governance for the Financial Statements

The Directors are responsible for the preparation and fair presentation of the financial statements in accordance with the accounting policies described in Note 2 of the financial statements and the provisions of the Act, and for such internal control as the Directors determine is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, the Directors are responsible for assessing the Branch's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the Directors either intend to liquidate the Branch or to cease operations, or have no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Branch's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISA will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with ISA, we exercise professional judgement and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

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- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Branch's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by the Directors.

- Conclude on the appropriateness of the Directors' use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Branch's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Report on Other Legal and Regulatory Requirements

In our opinion, the accounting and other records required by the Act to be kept by the Branch have been properly kept in accordance with the provisions of the Act. We have obtained all the information and explanations that we required.

PricewaterhouseCoopers Services

Chai Xiang Yuin
Partner

Brunei Darussalam
10 July 2023

TotalEnergies EP (Brunei) B.V.
(Incorporated in the Netherlands)
Brunei Darussalam Branch

Balance Sheet
31 December 2022
(with comparative figures as at 31 December2021)
(All amounts in US Dollars)

	Notes	2022	2021
ASSETS			
Non-current assets			
Fixed assets, net	3	1,205,650	1,387,706
Exploration costs, net	4	210,384,780	214,383,841
Retirement obligation asset, net	5	10,595,164	12,307,845
Development costs, net	6	140,503,895	153,316,250
Right of use asset, net	7	225,172	441,916
Total non-current assets		362,914,661	381,837,558
Current assets			
Stocks, net	8	1,364,114	1,507,080
Trade and other receivables	9	34,132,473	30,058,032
Amounts due from partners	10	9,439,292	2,277,609
Cash and cash equivalents	12	110,936,867	97,526,484
Total current assets		155,872,746	131,369,205
Total assets		518,787,407	513,206,763
LIABILITIES AND HEAD OFFICE ACCOUNT			
Current liabilities			
Trade and other payables	13	68,982,576	46,255,468
Amounts due to related companies	11	6,156,575	1,951,923
Income tax payable		66,429,037	47,086,000
Finance lease liabilities	7	310,632	269,322
Total current liabilities		141,878,820	95,562,713
Non-current liabilities			
Deferred income tax liabilities	15	58,170,200	72,240,200
Provision for asset retirement obligation	14	43,192,051	41,934,030
Finance lease liabilities	7	109,254	417,825
Total non-current liabilities		101,471,505	114,592,055
Total liabilities		243,350,325	210,154,768
Head office account			
Head office account	16	(681,772,675)	(611,772,675)
Retained earnings	16	957,209,757	914,824,670
Total head office account		275,437,082	303,051,995
Total liabilities and head office account		518,787,407	513,206,763

The notes are integral part of these financial statements.

Jerome SANIEZ
General Manager & Country Chair

TotalEnergies EP (Brunei) B.V.
(Incorporated in the Netherlands)
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Profit and Loss Account
For the year ended 31 December 2022
(With comparative figures for the year ended 31 December 2021)
(All amounts in US Dollars)

	Notes	2022	2021
Income			
Sales	17	157,218,332	112,245,705
Interest income	12	1,865,977	36
		159,084,309	112,245,741
Cost and expenses			
Depreciation and amortisation	3,4,5,6,7	27,595,147	31,709,230
Production costs		12,722,864	14,642,034
Royalties		11,479,912	9,087,736
License fee		7,384,735	-
Cost of value compensation		1,480,138	362,042
Accretion expense	14	1,258,021	1,221,379
Other costs (after upstream separation point)		1,095,755	1,115,203
Transportation costs	19	563,561	563,112
Interest on finance leases	7	258,566	352,227
Stock variation loss (gain)	18	181,624	(323,983)
Foreign exchange loss		135,343	57,264
Other costs (up to upstream separation point)		124,005	195,913
Gain on disposal of stocks	8	(6,345)	(62,435)
Loss on disposal of fixed assets	3	-	9,997
Provision for (reversal of) stock obsolescence	8	(17,508)	475,224
		64,255,818	59,404,943
Profit before income tax		94,828,491	52,840,798
Income tax expense	15	(52,443,404)	(30,517,172)
Net profit for the year		42,385,087	22,323,626

The notes are integral part of these financial statements.

TotalEnergies EP (Brunei) B.V.
(Incorporated in the Netherlands)
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Statement of Cash Flows
For the year ended 31 December 2022
(With comparative figures for the year ended 31 December 2021)
(All amounts in US Dollars)

	Notes	2022	2021
Cash flows from operating activities			
Profit before income tax		94,828,491	52,840,798
Adjustments for:			
Depreciation and amortisation	3,4,5,6,7	27,595,147	31,709,230
Accretion expense	14	1,258,021	1,221,379
Interest on finance leases	7	258,566	352,227
Loss on disposal of fixed assets	3	-	9,997
Gain on disposal of stocks	8	-	(62,435)
Provision for (reversal of) stock obsolescence	8	(17,508)	475,224
Interest income	2	(1,865,977)	(36)
Operating cash flows before working capital		122,056,740	86,546,384
Changes in working capital			
Stock		160,471	(245,246)
Trade and other receivables		(4,074,438)	(6,020,244)
Amount due from partners		(7,161,683)	6,708,391
Trade and other payables		22,727,108	8,309,212
Amount due to related companies		4,204,652	2,264,907
Cash generated from operations		137,912,850	97,563,404
Tax paid		(47,170,367)	(39,237,244)
Net cash generated from operating activities		90,742,483	58,326,160
Cash flows from investing activities			
Interest received		1,865,977	36
Purchase of fixed assets	3	(501,006)	(521,830)
Payment of development costs		(8,171,244)	(2,699,690)
Net cash used in investing activities		(6,806,273)	(3,221,484)
Cash flows from financing activities			
Remittances to Head office	16	(70,000,000)	(20,000,000)
Payment of lease liabilities - principal	7	(267,261)	(173,600)
Payment of lease liabilities - interest	7	(258,566)	(352,227)
Net cash used in financing activities		(70,525,827)	(20,525,827)
Net increase in cash and cash equivalents		13,410,383	34,578,849
Cash and cash equivalents at 1 January		97,526,484	62,947,635
Cash and cash equivalents at 31 December	12	110,936,867	97,526,484

The notes are integral part of these financial statements.

TotalEnergies EP (Brunei) B.V.
Brunei Darussalam Branch
(Registered in Brunei Darussalam)

Notes to the Financial Statements
As at and for the year ended 31 December 2022
(with comparative figures and notes as at and for the year ended 31 December 2021)
(In the notes, all amounts are shown in US Dollar unless otherwise stated)

Note 1 - General information

TotalEnergies EP (Brunei) B.V. - Brunei Darussalam Branch (the Branch), whose Head Office and immediate parent company is TotalEnergies EP (Brunei) B.V., a company incorporated in the Netherlands. Its ultimate parent company is TotalEnergies SE, a company incorporated in France. The principal activity of the Branch is that relating to hydrocarbon exploration and production.

The Branch, in consortium with the other entities, is the operator of Block B Joint Venture (BBJV) for the exploration, development and exploitation of oil and gas in its contract area situated offshore in Brunei Darussalam. The Branch's interest share in BBJV is 37.5% together with Shell Deepwater Borneo B.V. (35%) and Brunei Energy Exploration Sdn Bhd (27.5%), both entities incorporated in Brunei Darussalam.

In October 2022, the Gas Production Agreement was signed between the BBJV partners, Petroliam Nasional Berhad and Petronas Carigali Sdn Bhd for the BBJV to produce Malaysia's entitlement of hydrocarbons in the MLJ North-KN West NAG Unitised Fields.

The Branch's registered office address, which is also its principal place of business, is 2nd Floor, RBA Plaza, Jalan Sultan, Locked Bag 15, Bandar Seri Begawan, BS8811, Negara Brunei Darussalam.

The financial statements were approved to be issued by the General Manager, as authorised by the Head Office's Board of Directors, on 10 July 2023.

Note 2 - Summary of significant accounting policies

The principal accounting policies applied in the preparation of these financial statements are set out below. The accounting policies used have been consistently applied to all the years presented, unless otherwise stated.

2.1 Basis of preparation

The non-statutory financial statements of the Branch are prepared in accordance with the accounting policies of the Branch. The financial statements have been prepared from the records of the Branch and reflect only transactions recorded locally based on the Branch's equity share in the joint venture at 37.5%.

2.2 Accounting convention

The financial statements, expressed in United States Dollars, are prepared in accordance with the historical cost convention.

2.3 Fixed assets

Items of fixed assets are measured at cost less accumulated depreciation and impairment loss, if any. The initial cost of property and equipment consists of its purchase price, including import duties and nonrefundable purchase taxes and any directly attributable costs of bringing the asset to its working condition and location for its intended use. Subsequent expenditure is capitalised only if it is probable that the future economic benefits associated with the expenditure will flow to the Branch.

Depreciation is calculated to write off the cost of items of fixed assets less their estimated residual values using the straight-line method over their estimated useful lives and is recognised in profit or loss. The estimated useful lives of fixed assets for current and comparative periods are as follows:

	Useful life
Leasehold improvements	5 years
Data processing equipment and software	3 years
Technical equipment	5 years
Office and house furniture and equipment	5 years

Fully depreciated assets are retained in the financial statements until they are no longer in use.

Leasehold improvements are amortised over the term of the lease or the estimated useful life, whichever is shorter. Major renovations are depreciated over the remaining useful life of the related asset or to the date of the next major renovation, whichever is sooner.

The assets' residual values, estimated useful lives and depreciation and amortisation method are reviewed periodically, and adjusted if appropriate, at each reporting date to ensure that the method and period of depreciation are consistent with the expected pattern of economic benefits from items of the fixed assets.

An asset's carrying amount is written down immediately to its recoverable amount if the asset's carrying amount is greater than its estimated recoverable amount. The recoverable amount is the higher of an asset's fair value less costs to sell and value in use. Value in use requires entities to make estimates of future cash flows to be derived from the particular asset, and discount them using a pre-tax market rate that reflects current assessments of the time value of money and the risks specific to the asset. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows (cash-generating units).

The carrying amount of an item of fixed asset is derecognised on disposal, sale or when no future economic benefits are expected from its use or disposal at which time the cost and the related accumulated depreciation are removed from the accounts. Any gains and losses on disposals are determined by comparing proceeds with carrying amount and are included in profit or loss.

2.4 Exploration costs

Exploration costs consist of the Branch's share of general studies, exploration drilling, exploration studies and seismic costs. Except for exploration drilling costs, all other exploration costs are directly expensed when incurred. Initial exploration drilling costs are capitalised until a determination is made as to whether proved reserves have been discovered. If a discovery is confirmed, the exploration well costs remain capitalised (and depreciated according to the units of production method when the discovered field has been brought into production by reference to prove developed reserves) and proved reserves are recognised. If the exploration well is determined to be dry, the entire costs are expensed off. All unproved and work in progress exploration costs are not depleted nor impaired.

Prior to 2009, the exploration costs were fully capitalised at the Branch level due to the financing nature of the joint-venture agreement but substantially written off at Head Office. Thereafter, all exploration costs except successful wells are directly expensed at the Branch.

Exploration costs are tested for impairment whenever facts and circumstances indicate impairment. An impairment loss is recognised unless (a) proved reserves are booked, or (b) (i) they have found commercially producible quantities of reserves and (ii) they are subject to further exploration or appraisal activity in that either drilling of additional exploratory wells is under way or firmly planned for the near future or other activities are being undertaken to sufficiently progress the assessing of reserves and the economic and operating viability of the project.

2.5 Development costs

Development costs incurred for the drilling of development wells and for the construction of production facilities are capitalised which consist of development studies, assets associated with the development of the Maharaja Lela/Jamalulalam field and those classified as work in progress pending completion. The capitalised development costs are depleted using the unit-of-production method, which is the ratio of oil and gas production for the period to proved developed reserves (development wells) or total proved reserves (production facilities). The depletion for capitalised work in progress costs commence only after completion is ascertained.

Any gains or losses from the divestiture of development costs are recognised in profit or loss.

Development costs are assessed for impairment at least annually or when the facts and circumstances suggest that the carrying amount of the development costs may exceed its recoverable amount. Recoverable amount is determined as the greater of an asset's or cash generating unit's (CGU) value in use (VIU) and fair value less costs to sell (FVLCS). VIU is estimated as the discounted present value of the future cash flows expected to arise from the continuing use of a CGU or asset. FVLCS is determined based on reference to market prices for similar or identical assets. The impairment test is performed at the CGU level. Impairment losses are recognised in profit or loss.

2.6 Depletion, depreciation and amortisation of retirement obligation asset, development and successful exploration well costs

Retirement obligation asset, development costs and successful exploration well costs are depleted, depreciated or amortised by the unit of production method by reference to either proved developed reserves or total proved reserves. The depletion, depreciation and amortisation method are reviewed periodically to ensure that it is consistent with the expected pattern of economic benefits from wells, platforms and other facilities.

2.7 Provisions

A provision is recognised if, as a result of a past event, the Branch has a present obligation, legal or constructive, that can be estimated reliably, and it is more likely than not that an outflow of economic benefits will be required to settle the obligation. The Branch does not recognise a provision for future operating losses.

Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognised as a finance expense in profit or loss.

Provisions are derecognised when the obligation is settled, cancelled or has expired.

2.8 Provision for asset retirement obligations

Asset retirement obligations are recognised based on a reasonable estimate in the period in which the obligation arises. The associated asset retirement costs such as dismantlement, restoration and abandonment costs are capitalised as part of the carrying amount of the underlying asset. The amount capitalised in asset retirement obligation assets are depreciated under the unit-of-production (UOP) method.

Changes in the liability for an asset retirement obligation due to the passage of time (accretion) are measured by applying a risk-free discount rate to the amount of the liability. Changes in the estimated liability resulting from revisions to estimated timing or future asset retirement cost estimates are recognised as a change in the provision for asset retirement obligation and the related asset retirement obligation assets.

Actual expenditures incurred are charged against the accumulated liability.

2.9 Leases

The Branch recognises lease as a right-of-use asset and a corresponding liability at the date which the leased asset is available for use.

The lease payments are discounted using the lessee's incremental borrowing rate, being the rate that the individual lessee would have to pay to borrow the funds necessary to obtain an asset of similar value to the right-of-use asset in a similar economic environment with similar terms, security and conditions.

Lease payments are allocated between principal and interest expense. The interest expense is charged to profit or loss over the lease period so as to produce a constant periodic rate of interest on the remaining balance of the liability for each period.

Right-of-use asset measured at cost comprises the amount of the initial measurement of lease liability.

Right-of-use assets are generally depreciated over the shorter of the asset's useful life and the lease term on a straight-line basis. If the Branch is reasonably certain to exercise a purchase option, the right-of-use asset is depreciated over the underlying asset's useful life.

2.10 Joint arrangements

Investments in joint arrangements are classified as either joint operations or joint ventures. The classification depends on the contractual rights and obligations of each investor, rather than the legal structure of the joint arrangement. The Branch only has joint operations.

Joint operations

A joint operation is a type of joint arrangement whereby parties that have joint control of the arrangement have rights to the assets and obligations for the liabilities, relating to the arrangement.

In relation to its interests in joint operations, the Branch recognise share of assets held jointly, share of any liabilities incurred jointly, revenue from the sale of its share of the output arising from the joint operation, share of the revenue from the sale of the output by the joint operation including its share of any expenses incurred jointly.

2.11 Interest in joint operation

The Branch entered into an arrangement with the joint venture partners for the joint exploration, development and production activities in the field under contractual arrangement. Accordingly, the Branch continues to account only for its share of assets, liabilities, revenues and expenses, classified in the appropriate balance sheet and profit and loss account based on the contractual terms of the joint operations and the individual accounting policies applicable to each category of asset, liability, revenue and expense.

The Branch, as the primary contractor and operator, has direct legal liability for certain obligations to suppliers of the joint operation. The Branch recognises these liabilities at 100% and the corresponding cash calls received or receivable from partners under amounts due from partners. The members of the consortium share in the expenditures of the field for both production and development expenditure of the field according to their participating interest. The Branch's share in the expenditures is at 37.5%.

2.12 Stocks

Stocks consist of consumable stocks, stocks of liquid hydrocarbons and stocks in transit.

Consumable stocks are stated at the lower of cost, determined on a weighted average method, or net realisable value. Provision for stock obsolescence on consumable stock is made for slow moving (at 66.67%) and dead consumable stocks (at 100%).

Stocks of liquid hydrocarbons are valued at cost or net realisable value, whichever is the lower.

Cost comprises attributable cost of production plus overhead charges. Net realisable value is the estimated selling price in the ordinary course of business, less applicable variable selling expenses.

Stocks are derecognised either when sold or written-off. When stocks are sold, the carrying amount of those stock is recognised as an expense (under production costs) in the period in which the related revenue is recognised.

Provisions for stock obsolescence are set-up, if necessary, based on a review of the movements and current condition of each inventory item. Stocks are periodically reviewed and evaluated for obsolescence. Provisions for inventory obsolescence are made to reduce all slow-moving, obsolete, or unusable stocks to their estimated useful or scrap values.

The amount of any write-down of inventories to net realisable value and all losses of inventories is recognised as an expense in the period the write-down or loss occurs. The amount of any reversal of any write-down of inventories, arising from an increase in net realisable value is recognised as income in the period in which the reversal occurs.

2.13 Trade and other receivables

Trade and other receivables are stated at estimated realisable value after each debt has been considered individually. Where the payment of a debt becomes doubtful a provision is made and charged to the profit or loss.

This is derecognised when collected or cancelled.

2.14 Advances

Advances to suppliers, which are carried at cost, are cash advances for goods and services and recorded as assets upon payment. These are derecognised as either an asset or expense upon receipts of the goods or service rendition.

Advances to employees consist of various cash advances made for business purpose. These kinds of advances are being collected through salary deduction.

2.15 Deposits

Refundable deposits include rental deposits on leased properties by the Branch which are refundable at the end of the lease term. These are presented in the balance sheet as non-current assets if the related lease term extends beyond 12 months from the reporting date.

2.16 Cash and cash equivalents

Cash includes cash on hand, deposits held at call with banks and other short-term, highly liquid investments with original maturities of three (3) months or less. It is carried in the balance sheet at face amount or nominal amount.

Deposits placed with a related party include cash transferred to a cash pooling arrangement with its related party. It is carried in the balance sheet at face amount.

2.17 Trade and other payables

Trade and other payables represent liabilities for goods and services provided to the Branch in the normal course of business which are unpaid. They are classified as current liabilities if payment is due within one year or less (or in the normal operating cycle of the business if longer). Otherwise, they are presented as non-current liabilities.

Trade and other payables are derecognised when extinguished, i.e., when the obligation is discharged or is cancelled, expires, or paid.

2.18 Taxation

2.18.1 Current income tax

Current income tax comprises of the expected tax payable or receivable on the taxable income or loss for the year and any adjustment to the tax payable or receivable in respect of previous years. The amount of current income tax payable or receivable is the best estimate of the tax amount expected to be paid or received and reflects the uncertainty related to income taxes, if any. It is measured using tax rates enacted or substantively enacted at the reporting date. Current income tax assets and liabilities are offset only if certain criteria are met.

2.18.2 Deferred income tax

Deferred income tax is recognised in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred income tax assets are recognised for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable profits will be available against which they can be used. Future taxable profits are determined based on the reversal of relevant taxable temporary differences. If the amount of taxable temporary differences is insufficient to recognise a deferred income tax asset in full, then future taxable profits, adjusted for reversals of existing temporary differences, are considered based on the business plans for the Branch. Deferred income tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realised; such reductions are reversed when the probability of future taxable profits improves.

Unrecognised deferred income tax assets are reassessed at each reporting date and recognised to the extent that it has become probable that future taxable profits will be available against which they can be used. Deferred income tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted at the reporting date, and reflects uncertainty related to income taxes, if any.

The measurement of deferred income tax reflects the tax consequences that would follow from the manner in which the Branch expects, at the reporting date, to recover or settle the carrying amount of its assets and liabilities.

Deferred income tax assets and liabilities are offset only if certain criteria are met.

2.19 Head office account

Head office account represents inward and outward remittance from and to the Head Office, consisting mainly of advances and payment made on behalf of the Branch.

2.20 Retained earnings

Retained earnings include all current and prior years' results of operations.

2.21 Revenue and cost recognition

a. Sale of hydrocarbons

Sale of hydrocarbons are recognised when the control has been transferred to the buyer and the amount can be reasonably measured. The Branch's share of the sale of hydrocarbons are recorded upon transfer of title, according to the terms of the sales contracts.

Commencing from 1st January 2021, the Block B Joint Venture (BBJV) is required to undertake the Domestic Gas Supply Obligation ("DGSO"), that is to make available 10% of all-natural gas produced and processed from Block B to domestic market within Brunei. In the DGSO context, BBJV will pay to the Government of Brunei the DGSO volume multiplied by the difference between final gas selling price and prevailing DGSO price.

b. Interest income

Interest income is recognised when earned and measured on a time-proportion basis using effective interest method.

c. Other income

Other income are recognised in profit or loss when earned.

d. Cost recognition

Costs and expenses are charged to operations when incurred.

2.22 Foreign currency transactions and translations

(a) Functional and presentation currency

Items included in the financial statements of the Branch are measured using the currency of the primary economic environment in which the Branch operates (the 'functional currency'). The financial statements are presented in US Dollar, which is the Branch's functional and presentation currency.

(b) Foreign currency transactions

Foreign currency transactions are translated into US Dollars using the exchange rates prevailing at the dates of the transactions. Outstanding foreign currency denominated financial assets and liabilities are translated at the exchange rate prevailing at reporting date. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at year-end exchange rates of financial assets and liabilities denominated in foreign currencies are recognised in profit or loss.

2.23 Related party relationships and transactions

Related party relationship exists when one party has the ability to control, directly, or indirectly through one or more intermediaries, the other party or exercise significant influence over the other party in making financial and operating decisions.
Such relationship also exists between and/or among entities which are under common control with the reporting enterprise, or between and/or among the reporting enterprise and its key management personnel, directors, or its shareholder. In considering each possible related party relationship, attention is directed to the substance of the relationship, and not merely the legal form.

2.24 Subsequent events

Post year-end events that provide additional information about the Branch's position at the reporting date (adjusting events) are reflected in the financial statements. Post year-end events that are not adjusting events are disclosed in the notes to financial statements when material.

Note 3 - Fixed assets, net

The compositions and movements of the account as at and for the years ended 31 December consist of:

	Leasehold improvement	Data processing equipment and software	Technical equipment	Office/house furniture and equipment	Total
Cost					
At 1 January 2022	967,035	6,601,648	29,270	2,169,207	9,767,160
Additions	(7,320)	249,959	-	258,367	501,006
At 31 December 2022	959,715	6,851,607	29,270	2,427,574	10,268,166
Accumulated depreciation					
At 1 January 2022	965,652	5,579,024	29,270	1,805,508	8,379,454
Charges for the year	(5,937)	540,356	-	148,643	683,062
At 31 December 2022	959,715	6,119,380	29,270	1,954,151	9,062,516
Net book values					
At 31 December 2022	-	732,227	-	473,423	1,205,650
Cost					
At 1 January 2021	960,963	7,196,864	29,270	1,976,016	10,163,113
Additions	6,072	263,069	-	252,689	521,830
Disposals	-	(858,285)	-	(59,498)	(917,783
At 31 December 2021	967,035	6,601,648	29,270	2,169,207	9,767,160
Accumulated depreciation					
At 1 January 2021	928,261	5,594,865	29,270	1,650,576	8,202,972
Charges for the year	37,391	832,447	-	214,430	1,084,268
Disposals	-	(848,288)	-	(59,498)	(907,786
At 31 December 2021	965,652	5,579,024	29,270	1,805,508	8,379,454
Net book values					
At 31 December 2021	1,383	1,022,624	-	363,699	1,387,706

In 2022, the Branch has disposed off assets with net book value amounting to US$13,798 for the same value.

In 2021, the Branch disposed off assets with net book value amounting to US$9,997 for nil consideration resulting to a loss.

There were no conditions that would indicate impairment of fixed assets at 31 December 2022 and 2021.

Note 4 - Exploration costs, net

The compositions and movements of the account as at and for the years ended 31 December consist of:

	2022	2021
General studies	7,834,826	7,834,826
Exploration drilling	215,372,484	215,372,484
Exploration studies	38,346,618	38,346,618
Seismic	22,411,586	22,411,586
	283,965,514	283,965,514
Provision for amortisation	(73,580,734)	(69,581,673)
	210,384,780	214,383,841

Movements of the provision for amortisation for the years ended 31 December follow:

	2022	2021
At 1 January	69,581,673	65,034,823
Charges during the year	3,999,061	4,546,850
At 31 December	73,580,734	69,581,673

Note 5 - Retirement obligation asset, net

This account as at 31 December consists of:

	2022	2021
Cost		
Facilities and operations	28,626,296	28,626,296
Development wells	2,353,407	2,353,407
	30,979,703	30,979,703
Accumulated depreciation		
Facilities and operations	(19,449,180)	(18,163,185)
Development wells	(935,359)	(508,673)
	(20,384,539)	(18,671,858)
Net book values	10,595,164	12,307,845

Movements of the accumulated depreciation for the years ended 31 December follow:

	2022	2021
At 1 January	18,671,858	16,708,609
Charges during the year	1,712,681	1,963,249
At 31 December	20,384,539	18,671,858

Note 6 - Development costs, net

This account as at 31 December consists of:

	2022	2021
Development related costs	621,202,507	613,031,263
Provision for depletion, depreciation and amortisation	(480,698,612)	(459,715,013)
	140,503,895	153,316,250

Movements of the provision for depletion, depreciation and amortisation for the years ended 31 December follow:

	2022	2021
At 1 January	459,715,013	435,816,892
Charges during the year	20,983,599	23,898,121
At 31 December	480,698,612	459,715,013

Note 7 - Right-of-use of assets, net

The Branch recognised the charter hire of a crew boat vessel, having met the necessary criteria of lease term longer than 12 months and high value asset. A right-of-use asset and a corresponding liability is recorded at the present value of lease payments, discounted using the incremental borrowing rate of 3.73%. The asset is depreciated using the straight line method over the lease term, starting from the lease commencement date. Lease payments consist of two components - principal and interest, of which the lease liability is reduced by the principal amount paid.

Right-of-use assets are presented as a separate line item in the balance sheet. The following amounts relating to leases as at 31 December:

	2022	2021
Cost		
At 1 January and 31 December	1,083,717	1,083,717
Accumulated amortisation		
At 1 January	(641,801)	(425,059)
Charges during the year	(216,744)	(216,742)
At 31 December	(858,545)	(641,801)
Net book value	225,172	441,916

Finance lease liabilities as at 31 December are presented follow:

	2022	2021
Current	310,632	269,322
Non-current	109,254	417,825
	419,886	687,147

Movements of lease liabilities for the years ended 31 December follow:

	2022	2021
At 1 January	687,147	860,747
Payment of principal	(267,261	(173,600
Payment of interest	(258,566	(352,227
Interest charged	258,566	352,227
At 31 December	419,886	687,147

The following were charged to profit or loss relating to leases for the year ended 31 December:

	2022	2021
Amortisation	216,744	216,742
Interest on finance leases	258,566	352,227

Total cash outflows for the leases for the years ended 31 December 2022 and 2021 amounted to US$525,827.

Note 8 - Stocks, net

This account as at 31 December consists of:

	2022	2021
Consumable stocks	5,181,392	5,159,732
Consumable stocks in transit	3,679	4,189
Less: Provision for stock obsolescence	(4,143,182)	(4,160,690)
	1,041,889	1,003,231
Stock of liquid hydrocarbon	322,225	503,849
	1,364,114	1,507,080

Movements of the provision for stock obsolescence for the years ended 31 December follow:

	2022	2021
At 1 January	4,160,690	3,685,466
Provision (reversal)	(17,508)	475,224
At 31 December	4,143,182	4,160,690

In 2021, the Branch has sold scrap inventories for US$70,433 resulting to gain of US$62,435.

Note 9 - Trade and other receivables

This account as at 31 December consists of:

	2022	2021
Trade receivables	33,148,783	29,062,836
Advances to suppliers	448,453	448,231
Advances to employees	324,061	309,105
Deposits	211,176	237,860
	34,132,473	30,058,032

Note 10 - Amounts due from partners

The account represents net position of its cash calls and receipts from its joint operation partners and their respective share in the working capital assets of the joint operation amounting to B$9,439,292 as at 31 December 2022 (2021 - B$2,277,609). The accounts are billed and settled within 30 days.

Note 11 - Related party transactions and balances

Related parties in these financial statements refer to members of the ultimate parent company's group of companies. Some of the Branch's transactions and arrangements are with related parties and the effect of these transactions on the basis determined between the parties are reflected in these financial statements.

The related party balances as at 31 December follow:

	Note	2022	2021
Company under common control			
Cash deposits	12	109,791,375	96,514,561
Amount due to		(6,156,575)	(1,951,923)

Transactions with companies under common control

The amounts due to/from related companies are trade and non-trade in nature. They are unsecured, interest free and have no fixed term of repayment.

Transaction with key management personnel

There were no payments made to key management personnel for the years ended 31 December 2022 and 2021.

Note 12 - Cash and cash equivalents

This account as at 31 December consists of:

	Note	2022	2021
Cash on hand		9,860	9,236
Cash in bank		1,135,632	1,002,687
Deposits placed with a related party	11	109,791,375	96,514,561
		110,936,867	97,526,484

Deposit placed with a related party earn interest at the prevailing bank deposit rate. Total interest income earned in 2022 amounted to US$1,865,977 (2021 - US$36).

Note 13 - Trade and other payables

This account as at 31 December consists of:

	2022	2021
Trade payables	60,177,835	36,810,197
Accruals	8,804,741	9,445,271
	68,982,576	46,255,468

Note 14 - Provision for asset retirement obligation

The compositions and movements of the account as at and for the years ended 31 December follow:

	2022	2021
At 1 January		
Facilities and transportation	27,522,899	26,721,261
Development wells	14,411,131	13,991,390
	41,934,030	40,712,651
Accretion expense		
Facilities and transportation	825,687	801,638
Development wells	432,334	419,741
	1,258,021	1,221,379
At 31 December		
Facilities and transportation	28,348,586	27,522,899
Development wells	14,843,465	14,411,131
	43,192,051	41,934,030

As at 31 December 2022 and 2021, the discount and inflation rates used were 4.0% and 2.0%, respectively.

Note 15 - Taxation

This account as at 31 December consists of:

	2022	2021
Current	66,513,404	47,088,172
Deferred	(14,070,000)	(16,571,000)
	52,443,404	30,517,172

Current income taxes are comprised of charges from petroleum operations and non-petroleum operations, and supplemental payment under the consortium's mining agreement totaling US$66.5 million for the years ended 31 December 2022 (2021 - US$47.1 million).

Deferred income tax liabilities, net are comprised of excess of net book value over tax written down value, asset retirement obligation, provision for stock obsolescence, net right-of-use liabilities and unrealised translation loss totaling US$58.2 million as at 31 December 2022 (2021 - US$72.2 million). The net movement for the year ended 31 December 2022 amounting to US$14.1 million (2021 - US$16.6 million) is charged to profit or loss. These are taxed at the Branch's effective tax rate of 56%.

Note 16 - Head office account; Retained earnings

The movements of the accounts for the years ended 31 December follow:

	2022	2021
Head office account		
At 1 January	(611,772,675)	(591,772,675)
Remittances to	(70,000,000)	(20,000,000)
At 31 December	(681,772,675)	(611,772,675)
Retained earnings		
At 1 January	914,824,670	892,501,044
Net profit for the year	42,385,087	22,323,626
At 31 December	957,209,757	914,824,670
Total head office account	275,437,082	303,051,995

Note 17 - Revenue

Revenue for years ended 31 December follow:

	BBJV	Unit GPA	Total
For the year ended 31 December 2022			
Gas	110,411,840	9,824,779	120,236,619
Condensate	36,981,713	-	36,981,713
	147,393,553	9,824,779	157,218,332
For the year ended 31 December 2021			
Gas	87,170,868	-	87,170,868
Condensate	25,074,837	-	25,074,837
	112,245,705	-	112,245,705

Note 18 - Stock Variation - Liquid (arising from Gas Production Agreement "GPA")

Stock variation gain (loss) arising from the GPA for the years ended 31 December follows:

	2022	2021
BBJV	(256,850)	323,983
Unit GPA	75,226	-
	(181,624)	323,983

Note 19 - Transportation costs (arising from GPA)

Transportation costs arising from the GPA for years ended 31 December follow:

	2022	2021
BBJV	488,668	563,112
Unit GPA	74,893	-
	563,561	563,112

TotalEnergies EP (Brunei) B.V.

(Incorporated in the Netherlands)
Brunei Darussalam Branch

Financial Statements
As at and for the years ended 31 December 2023 and 2022

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TotalEnergies EP (Brunei) B.V.
(Incorporated in the Netherlands)
Brunei Darussalam Branch

As at and for the years ended 31 December 2023 and 2022

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Independent Auditor's Report

To the Board of Directors of
TotalEnergies EP (Brunei) B.V.
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Brunei Darussalam Branch

Report on the Audits of the Financial Statements

Our Opinion

In our opinion, the financial statements of TotalEnergies EP (Brunei) B.V. - Brunei Darussalam Branch (the Branch) give a true and fair view of the financial positions as at 31 December 2023 and 2022, and its financial performances and its cash flows for the years then ended in accordance with the accounting policies as described in Note 2 to the financial statements and the provisions of the Brunei Darussalam Companies Act, Chapter 39 (the Act).

What we have audited

The financial statements of the Branch comprise:

- the balance sheets as at 31 December 2023 and 2022;
- the profit and loss accounts for the years ended 31 December 2023 and 2022;
- the statements of cash flows for the years ended 31 December 2023 and 2022; and
- the notes to the financial statements, which include a summary of significant accounting policies.

Basis for Opinion

We conducted our audits in accordance with International Standards on Auditing (ISA). Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence

We are independent of the Branch in accordance with the International Code of Ethics for Professional Accountants issued by the International Ethics Standards Board for Accountants (the Code), together with the ethical requirements that are relevant to our audit of the financial statements in Brunei Darussalam, and we have fulfilled our other ethical responsibilities in accordance with these requirements and the Code.

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Independent Auditor's Report
To the Board of Directors of
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Responsibilities of Directors and Those Charged with Governance for the Financial Statements

The Directors are responsible for the preparation and fair presentation of the financial statements in accordance with the accounting policies described in Note 2 of the financial statements and the provisions of the Act, and for such internal control as Directors determine is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, the Directors are responsible for assessing the Branch's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the Directors either intend to liquidate the Branch or to cease operations, or have no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Branch's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISA will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with ISA, we exercise professional judgement and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Branch's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by the Directors.

- Conclude on the appropriateness of the Directors' use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Branch's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Branch to cease to continue as a going concern.

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- Conclude on the appropriateness of the Directors' use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Branch's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Branch to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Report on Other Legal and Regulatory Requirements

In our opinion, the accounting and other records required by the Act to be kept by the Branch have been properly kept in accordance with the provisions of the Act. We have obtained all the information and explanations that we required.

PricewaterhouseCoopers Services

Chai Xiang Yuin
Partner

Brunei Darussalam
24 May 2024

TotalEnergies EP (Brunei) B.V.
(Incorporated in the Netherlands)
Brunei Darussalam Branch

Balance Sheets
31 December 2023 and 2022
(All amounts in US Dollars)

	Notes	2023	2022
Assets			
Non-current assets			
Fixed assets, net	3	2,260,954	1,205,650
Exploration costs, net	4	207,076,678	210,384,780
Retirement obligation asset, net	5	5,111,780	10,595,164
Development costs, net	6	135,323,759	140,503,895
Right of use asset, net	7	217,385	225,172
Total non-current assets		349,990,556	362,914,661
Current assets			
Stocks, net	8	2,510,534	1,364,114
Trade and other receivables	9	27,766,529	34,132,473
Amounts due from partners	10	18,014,149	9,439,292
Cash and cash equivalents	12	114,224,855	110,936,867
Total current assets		162,516,067	155,872,746
Total assets		512,506,623	518,787,407
Liabilities and Head Office Account			
Current liabilities			
Trade and other payables	13	89,237,748	68,982,576
Amounts due to related companies	11	5,430,940	6,156,575
Income tax payable		40,946,000	66,429,037
Finance lease liabilities	7	275,575	310,632
Total current liabilities		135,890,263	141,878,820
Non-current liabilities			
Deferred income tax liabilities	15	48,750,200	58,170,200
Provision for asset retirement obligation	14	32,224,068	43,192,051
Finance lease liabilities	7	-	109,254
Total non-current liabilities		80,974,268	101,471,505
Total liabilities		216,864,531	243,350,325
Head office account			
Head office account	16	(696,772,675)	(681,772,675)
Retained earnings	16	992,414,767	957,209,757
Total head office account		295,642,092	275,437,082
Total liabilities and head office account		512,506,623	518,787,407

The notes are integral part of these financial statements.

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Jerome SANIEZ
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Jerome SANIEZ
General Manager & Country Chair

TotalEnergies EP (Brunei) B.V.
(Incorporated in the Netherlands)
Brunei Darussalam Branch

Profit and Loss Accounts
For the years ended 31 December 2023 and 2022
(All amounts in US Dollars)

	Notes	2023	2022
Income			
Sales	17	144,660,501	157,218,332
Interest income	12	4,944,265	1,865,977
		149,604,766	159,084,309
Cost and expenses			
License fee		36,365,276	7,384,735
Depreciation and amortisation	3,4,5,6,7	22,489,062	27,595,147
Production costs		12,855,564	12,722,864
Royalties		7,639,237	11,479,912
Cost of value compensation		1,533,336	1,480,138
Other costs (after upstream separation point)		1,032,775	1,095,755
Other costs (up to upstream separation point)		880,197	124,005
Transportation costs	19	844,268	563,561
Interest on finance leases	7	243,750	258,566
Loss (gain) on disposal of stocks	8	89,715	(6,345)
Provision for (reversal of) stock obsolescence	8	35,168	(17,508)
Foreign exchange loss		19,674	135,343
Accretion expense	14	-	1,258,021
Stock variation loss (gain)	18	(1,150,867)	181,624
		82,877,155	64,255,818
Profit before income tax		66,727,611	94,828,491
Income tax expense	15	(31,522,601)	(52,443,404)
Net profit for the year		35,205,010	42,385,087

The notes are integral part of these financial statements.

TotalEnergies EP (Brunei) B.V.
(Incorporated in the Netherlands)
Brunei Darussalam Branch

Statements of Cash Flows
For the years ended 31 December 2023 and 2022
(All amounts in US Dollars)

	Notes	2023	2022
Cash flows from operating activities			
Profit before income tax		66,727,611	94,828,491
Adjustments for:			
Depreciation and amortisation	3,4,5,6,7	22,489,062	27,595,147
Interest on finance leases	7	243,750	258,566
Loss (gain) on disposal of stocks	8	89,715	(6,345)
Provision for (reversal of) stock obsolescence	8	35,168	(17,508)
Accretion expense	14	-	1,258,021
Interest income	12	(4,944,265)	(1,865,977)
Operating cash flows before working capital		84,641,041	122,050,395
Changes in working capital			
Stock		(1,271,303)	166,816
Trade and other receivables		6,365,944	(4,074,438)
Amount due from partners		(8,574,857)	(7,161,683)
Trade and other payables		20,255,172	22,727,108
Amount due to related companies		(725,635)	4,204,652
Cash generated from operations		100,690,362	137,912,850
Tax paid		(66,425,638)	(47,170,367)
Net cash generated from operating activities		34,264,724	90,742,483
Cash flows from investing activities			
Interest received		4,944,265	1,865,977
Purchase of fixed assets	3	(1,804,443)	(501,006)
Payment of development costs	6	(18,504,329)	(8,171,244)
Net cash used in investing activities		(15,364,507)	(6,806,273)
Cash flows from financing activities			
Remittances to Head office	16	(15,000,000)	(70,000,000)
Payment of lease liabilities - principal	7	(368,479)	(267,261)
Payment of lease liabilities - interest	7	(243,750)	(258,566)
Net cash used in financing activities		(15,612,229)	(70,525,827)
Net increase in cash and cash equivalents		3,287,988	13,410,383
Cash and cash equivalents at 1 January		110,936,867	97,526,484
Cash and cash equivalents at 31 December	12	114,224,855	110,936,867

The notes are integral part of these financial statements.

TotalEnergies EP (Brunei) B.V.
(Incorporated in the Netherlands)
Brunei Darussalam Branch

Notes to the Financial Statements
As at and for the years ended 31 December 2023 and 2022
(In the notes, all amounts are shown in US Dollar unless otherwise stated)

1 General information

TotalEnergies EP (Brunei) B.V. - Brunei Darussalam Branch (the Branch), whose Head Office and immediate parent company is TotalEnergies EP (Brunei) B.V., a company incorporated in the Netherlands. Its ultimate parent company is TotalEnergies SE, a company incorporated in France. The principal activity of the Branch is that relating to hydrocarbon exploration and production.

The Branch, in consortium with the other entities, is the operator of Block B Joint Venture (BBJV) for the exploration, development and exploitation of oil and gas in its contract area situated offshore in Brunei Darussalam. The Branch's interest share in BBJV is 37.5% together with Shell Deepwater Borneo B.V. (35%) and Brunei Energy Exploration Sdn Bhd (27.5%), both entities incorporated in Brunei Darussalam.

In October 2022, the Gas Production Agreement was signed between the BBJV partners, Petroliam Nasional Berhad and Petronas Carigali Sdn Bhd for the BBJV to produce Malaysia's entitlement of hydrocarbons in the MLJ North-KN West NAG Unitised Fields.

The Branch's registered office address, which is also its principal place of business, is 2nd Floor, RBA Plaza, Jalan Sultan, Locked Bag 15, Bandar Seri Begawan, BS8811, Negara Brunei Darussalam.

The financial statements were approved to be issued by the General Manager, as authorised by the Head Office's Board of Directors on 23 May 2024.

2 Summary of significant accounting policies

The principal accounting policies applied in the preparation of these financial statements are set out below. The accounting policies used have been consistently applied to all the years presented, unless otherwise stated.

2.1 Basis of preparation

The non-statutory financial statements of the Branch are prepared in accordance with the accounting policies of the Branch. The financial statements have been prepared from the records of the Branch and reflect only transactions recorded locally based on the Branch's equity share in the joint venture at 37.5%.

2.2 Accounting convention

The financial statements, expressed in United States Dollars, are prepared in accordance with the historical cost convention.

2.3 Fixed assets

Items of fixed assets are measured at cost less accumulated depreciation and impairment loss, if any. The initial cost of property and equipment consists of its purchase price, including import duties and nonrefundable purchase taxes and any directly attributable costs of bringing the asset to its working condition and location for its intended use. Subsequent expenditure is capitalised only if it is probable that the future economic benefits associated with the expenditure will flow to the Branch.

Depreciation is calculated to write off the cost of items of fixed assets less their estimated residual values using the straight-line method over their estimated useful lives and is recognised in profit or loss. The estimated useful lives of fixed assets for current and comparative periods are as follows:

	Useful life
Leasehold improvements	5 years
Data processing equipment and software	3 years
Technical equipment	5 years
Office and house furniture and equipment	5 years

Fully depreciated assets are retained in the financial statements until they are no longer in use.

Leasehold improvements are amortised over the term of the lease or the estimated useful life, whichever is shorter. Major renovations are depreciated over the remaining useful life of the related asset or to the date of the next major renovation, whichever is sooner.

The assets' residual values, estimated useful lives and depreciation and amortisation method are reviewed periodically, and adjusted if appropriate, at each reporting date to ensure that the method and period of depreciation are consistent with the expected pattern of economic benefits from items of the fixed assets.

An asset's carrying amount is written down immediately to its recoverable amount if the asset's carrying amount is greater than its estimated recoverable amount. The recoverable amount is the higher of an asset's fair value less costs to sell and value in use. Value in use requires entities to make estimates of future cash flows to be derived from the particular asset, and discount them using a pre-tax market rate that reflects current assessments of the time value of money and the risks specific to the asset. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows (cash-generating units).

The carrying amount of an item of fixed asset is derecognised on disposal, sale or when no future economic benefits are expected from its use or disposal at which time the cost and the related accumulated depreciation are removed from the accounts. Any gains and losses on disposals are determined by comparing proceeds with carrying amount and are included in profit or loss.

2.4 Exploration costs

Exploration costs consist of the Branch's share of general studies, exploration drilling, exploration studies and seismic costs. Except for exploration drilling costs, all other exploration costs are directly expensed when incurred. Initial exploration drilling costs are capitalised until a determination is made as to whether proved reserves have been discovered. If a discovery is confirmed, the exploration well costs remain capitalised (and depreciated according to the units of production method when the discovered field has been brought into production by reference to prove developed reserves) and proved reserves are recognised. If the exploration well is determined to be dry, the entire costs are expensed off. All unproved and work in progress exploration costs are not depleted nor impaired.

Prior to 2009, the exploration costs were fully capitalised at the Branch level due to the financing nature of the joint-venture agreement but substantially written off at Head Office. Thereafter, all exploration costs except successful wells are directly expensed at the Branch.

Exploration costs are tested for impairment whenever facts and circumstances indicate impairment. An impairment loss is recognised unless (a) proved reserves are booked, or (b) (i) they have found commercially producible quantities of reserves and (ii) they are subject to further exploration or appraisal activity in that either drilling of additional exploratory wells is under way or firmly planned for the near future or other activities are being undertaken to sufficiently progress the assessing of reserves and the economic and operating viability of the project.

2.5 Development costs

Development costs incurred for the drilling of development wells and for the construction of production facilities are capitalised which consist of development studies, assets associated with the development of the Maharaja Lela/Jamalulalam field and those classified as work in progress pending completion. The capitalised development costs are depleted using the unit-of-production method, which is the ratio of oil and gas production for the period to proved developed reserves (development wells) or total proved reserves (production facilities). The depletion for capitalised work in progress costs commence only after completion is ascertained.

Any gains or losses from the divestiture of development costs are recognised in profit or loss.

Development costs are assessed for impairment at least annually or when the facts and circumstances suggest that the carrying amount of the development costs may exceed its recoverable amount. Recoverable amount is determined as the greater of an asset's or cash generating unit's (CGU) value in use (VIU) and fair value less costs to sell (FVLCS). VIU is estimated as the discounted present value of the future cash flows expected to arise from the continuing use of a CGU or asset. FVLCS is determined based on reference to market prices for similar or identical assets. The impairment test is performed at the CGU level. Impairment losses are recognised in profit or loss.

2.6 Depletion, depreciation and amortisation of retirement obligation asset, development and successful exploration well costs

Retirement obligation asset, development costs and successful exploration well costs are depleted, depreciated or amortised by the unit of production method by reference to either proved developed reserves or total proved reserves. The depletion, depreciation and amortisation method are reviewed periodically to ensure that it is consistent with the expected pattern of economic benefits from wells, platforms and other facilities.

2.7 Provisions

A provision is recognised if, as a result of a past event, the Branch has a present obligation, legal or constructive, that can be estimated reliably, and it is more likely than not that an outflow of economic benefits will be required to settle the obligation. The Branch does not recognise a provision for future operating losses.

Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognised as a finance expense in profit or loss.

Provisions are derecognised when the obligation is settled, cancelled or has expired.

2.8 Provision for asset retirement obligations

Asset retirement obligations are recognised based on a reasonable estimate in the period in which the obligation arises. The associated asset retirement costs such as dismantlement, restoration and abandonment costs are capitalised as part of the carrying amount of the underlying asset. The amount capitalised in asset retirement obligation assets are depreciated under the unit-of- production (UOP) method.

Changes in the liability for an asset retirement obligation due to the passage of time (accretion) are measured by applying a risk-free discount rate to the amount of the liability. Changes in the estimated liability resulting from revisions to estimated timing or future asset retirement cost estimates are recognised as a change in the provision for asset retirement obligation and the related asset retirement obligation assets.

Actual expenditures incurred are charged against the accumulated liability.

2.9 Leases

The Branch recognises lease as a right-of-use asset and a corresponding liability at the date which the leased asset is available for use.

The lease payments are discounted using the lessee's incremental borrowing rate, being the rate that the individual lessee would have to pay to borrow the funds necessary to obtain an asset of similar value to the right-of-use asset in a similar economic environment with similar terms, security and conditions.

Lease payments are allocated between principal and interest expense. The interest expense is charged to profit or loss over the lease period so as to produce a constant periodic rate of interest on the remaining balance of the liability for each period.

Right-of-use asset measured at cost comprises the amount of the initial measurement of lease liability.

Right-of-use assets are generally depreciated over the shorter of the asset's useful life and the lease term on a straight-line basis. If the Branch is reasonably certain to exercise a purchase option, the right-of-use asset is depreciated over the underlying asset's useful life.

2.10 Joint arrangements

Investments in joint arrangements are classified as either joint operations or joint ventures. The classification depends on the contractual rights and obligations of each investor, rather than the legal structure of the joint arrangement. The Branch only has joint operations.

Joint operations

A joint operation is a type of joint arrangement whereby parties that have joint control of the arrangement have rights to the assets and obligations for the liabilities, relating to the arrangement.

In relation to its interests in joint operations, the Branch recognise share of assets held jointly, share of any liabilities incurred jointly, revenue from the sale of its share of the output arising from the joint operation, share of the revenue from the sale of the output by the joint operation including its share of any expenses incurred jointly.

2.11 Interest in joint operation

The Branch entered into an arrangement with the joint venture partners for the joint exploration, development and production activities in the field under contractual arrangement. Accordingly, the Branch continues to account only for its share of assets, liabilities, revenues and expenses, classified in the appropriate balance sheet and profit and loss account based on the contractual terms of the joint operations and the individual accounting policies applicable to each category of asset, liability, revenue and expense.

The Branch, as the primary contractor and operator, has direct legal liability for certain obligations to suppliers of the joint operation. The Branch recognises these liabilities at 100% and the corresponding cash calls received or receivable from partners under amounts due from partners.

The members of the consortium share in the expenditures of the field for both production and development expenditure of the field according to their participating interest. The Branch's share in the expenditures is at 37.5%.

2.12 Stocks

Stocks consist of consumable stocks, stocks of liquid hydrocarbons and stocks in transit.

Consumable stocks are stated at the lower of cost, determined on a weighted average method, or net realisable value. Provision for stock obsolescence on consumable stock is made for slow moving (at 66.67%) and dead consumable stocks (at 100%).

Stocks of liquid hydrocarbons are valued at cost or net realisable value, whichever is the lower.

Cost comprises attributable cost of production plus overhead charges. Net realisable value is the estimated selling price in the ordinary course of business, less applicable variable selling expenses.

Stocks are derecognised either when sold or written-off. When stocks are sold, the carrying amount of those stock is recognised as an expense (under production costs) in the period in which the related revenue is recognised.

Provisions for stock obsolescence are set-up, if necessary, based on a review of the movements and current condition of each inventory item. Stocks are periodically reviewed and evaluated for obsolescence. Provisions for inventory obsolescence are made to reduce all slow-moving, obsolete, or unusable stocks to their estimated useful or scrap values.

The amount of any write-down of inventories to net realisable value and all losses of inventories is recognised as an expense in the period the write-down or loss occurs. The amount of any reversal of any write-down of inventories, arising from an increase in net realisable value is recognised as income in the period in which the reversal occurs.

2.13 Trade and other receivables

Trade and other receivables are stated at estimated realisable value after each debt has been considered individually. Where the payment of a debt becomes doubtful a provision is made and charged to the profit or loss.

This is derecognised when collected or cancelled.

2.14 Advances

Advances to suppliers, which are carried at cost, are cash advances for goods and services and recorded as assets upon payment. These are derecognised as either an asset or expense upon receipts of the goods or service rendition.

Advances to employees consist of various cash advances made for business purpose. These kinds of advances are being collected through salary deduction.

2.15 Deposits

Refundable deposits include rental deposits on leased properties by the Branch which are refundable at the end of the lease term. These are presented in the balance sheet as non-current assets if the related lease term extends beyond 12 months from the reporting date.

2.16 Cash and cash equivalents

Cash includes cash on hand, deposits held at call with banks and other short-term, highly liquid investments with original maturities of three (3) months or less. It is carried in the balance sheet at face amount or nominal amount.

Deposits placed with a related party include cash transferred to a cash pooling arrangement with its related party. It is carried in the balance sheet at face amount.

2.17 Trade and other payables

Trade and other payables represent liabilities for goods and services provided to the Branch in the normal course of business which are unpaid. They are classified as current liabilities if payment is due within one year or less (or in the normal operating cycle of the business if longer). Otherwise, they are presented as non-current liabilities.

Trade and other payables are derecognised when extinguished, i.e., when the obligation is discharged or is cancelled, expires, or paid.

2.18 Taxation

2.18.1 Current income tax

Current income tax comprises of the expected tax payable or receivable on the taxable income or loss for the year and any adjustment to the tax payable or receivable in respect of previous years. The amount of current income tax payable or receivable is the best estimate of the tax amount expected to be paid or received and reflects the uncertainty related to income taxes, if any. It is measured using tax rates enacted or substantively enacted at the reporting date. Current income tax assets and liabilities are offset only if certain criteria are met.

2.18.2 Deferred income tax

Deferred income tax is recognised in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred income tax assets are recognised for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable profits will be available against which they can be used. Future taxable profits are determined based on the reversal of relevant taxable temporary differences. If the amount of taxable temporary differences is insufficient to recognise a deferred income tax asset in full, then future taxable profits, adjusted for reversals of existing temporary differences, are considered based on the business plans for the Branch. Deferred income tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realised; such reductions are reversed when the probability of future taxable profits improves.

Unrecognised deferred income tax assets are reassessed at each reporting date and recognised to the extent that it has become probable that future taxable profits will be available against which they can be used. Deferred income tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted at the reporting date, and reflects uncertainty related to income taxes, if any.

The measurement of deferred income tax reflects the tax consequences that would follow from the manner in which the Branch expects, at the reporting date, to recover or settle the carrying amount of its assets and liabilities.

Deferred income tax assets and liabilities are offset only if certain criteria are met.

2.19 Head office account

Head office account represents inward and outward remittance from and to the Head Office, consisting mainly of advances and payment made on behalf of the Branch.

2.20 Retained earnings

Retained earnings include all current and prior years' results of operations.

2.21 Revenue and cost recognition

a. *Sale of hydrocarbons*

Sale of hydrocarbons are recognised when the control has been transferred to the buyer and the amount can be reasonably measured. The Branch's share of the sale of hydrocarbons are recorded upon transfer of title, according to the terms of the sales contracts.

Commencing from 1st January 2021, the Block B Joint Venture (BBJV) is required to undertake the Domestic Gas Supply Obligation ("DGSO"), that is to make available 10% of all-natural gas produced and processed from Block B to domestic market within Brunei. In the DGSO context, BBJV will pay to the Government of Brunei the DGSO volume multiplied by the difference between final gas selling price and prevailing DGSO price.

b. Interest income

Interest income is recognised when earned and measured on a time-proportion basis using effective interest method.

c. Other income

Other income are recognised in profit or loss when earned.

d. Cost recognition

Costs and expenses are charged to operations when incurred.

2.22 Employee cost

(a) Retirement benefits obligation

Defined contribution plan

Payments to defined contribution retirement benefit plans are charged as an expense when employees have rendered the services entitling them to the contributions. Payments made to state-managed retirement benefit schemes such as Tabung Amanah Pekerja ("TAP") and Supplemental Contributory Pensions Trust Fund ("SCP") are dealt with as payments to defined contribution plans where the Branch's obligations under the plans are equivalent to those arising in a defined contribution retirement benefit plan. The Branch has no further payment obligations once the contributions have been paid. The contributions are recognised as employee benefits when they are due.

In July 2023, the new retirement scheme "Skim Persaraan Kebangsaan (SPK) or National Retirement Scheme" has come into effect. There is no change in the employee's contribution rates. The new scheme provides for new prescribe rates for employer contribution ranging from 8.5% to 10.5% based on the basic salary range with a stipulated minimum contribution threshold of BND57.50.

(b) Bonus plans

The Branch recognises a liability and an expense for bonuses and based on a formula that takes into consideration the profit after certain adjustments. The Branch recognises a provision where contractually obliged or where there is a past practice that has created a constructive obligation.

(c) Short-term employee benefits

Wages, salaries, paid annual vacation and sick leave credits and other non-monetary benefits are accrued during the period in which the related services are rendered by employees of the Branch. Short-term employee benefit obligations are measured on an undiscounted basis.

Employee entitlements to annual leave are recognised when they accrue to employees. A provision is made for the estimated liability for annual leave as a result of services rendered by employees up to the end of the reporting period.

2.23 Foreign currency transactions and translations

(a) Functional and presentation currency

Items included in the financial statements of the Branch are measured using the currency of the primary economic environment in which the Branch operates (the 'functional currency'). The financial statements are presented in US Dollar, which is the Branch's functional and presentation currency.

(b) Foreign currency transactions

Foreign currency transactions are translated into US Dollars using the exchange rates prevailing at the dates of the transactions. Outstanding foreign currency denominated financial assets and liabilities are translated at the exchange rate prevailing at reporting date. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at year-end exchange rates of financial assets and liabilities denominated in foreign currencies are recognised in profit or loss.

2.24 Related party relationships and transactions

Related party relationship exists when one party has the ability to control, directly, or indirectly through one or more intermediaries, the other party or exercise significant influence over the other party in making financial and operating decisions.

Such relationship also exists between and/or among entities which are under common control with the reporting enterprise, or between and/or among the reporting enterprise and its key management personnel, directors, or its shareholder. In considering each possible related party relationship, attention is directed to the substance of the relationship, and not merely the legal form.

2.25 Subsequent events

Post year-end events that provide additional information about the Branch's position at the reporting date (adjusting events) are reflected in the financial statements. Post year-end events that are not adjusting events are disclosed in the notes to financial statements when material.

3 Fixed assets, net

The compositions and movements of the account as at and for the years ended 31 December consist of:

	Leasehold improvement	Data processing equipment and software	Technical equipment	Office/house furniture and equipment	Total
Cost					
At 1 January 2023	959,715	6,851,607	29,270	2,427,574	10,268,166
Additions	-	415,042	-	1,389,401	1,804,443
At 31 December 2023	959,715	7,266,649	29,270	3,816,975	12,072,609
Accumulated depreciation					
At 1 January 2023	959,715	6,119,380	29,270	1,954,151	9,062,516
Charges for the year	-	574,261	-	174,878	749,139
At 31 December 2023	959,715	6,693,641	29,270	2,129,029	9,811,655
Net book values					
At 31 December 2023	-	573,008	-	1,687,946	2,260,954
Cost					
At 1 January 2022	967,035	6,601,648	29,270	2,169,207	9,767,160
Additions	-	249,959	-	258,367	508,326
Disposals	(7,320)	-	-	-	(7,320)
At 31 December 2022	959,715	6,851,607	29,270	2,427,574	10,268,166
Accumulated depreciation					
At 1 January 2022	965,652	5,579,024	29,270	1,805,508	8,379,454
Charges for the year	-	540,356	-	148,643	688,999
Disposals	(5,937)	-	-	-	(5,937)
At 31 December 2022	959,715	6,119,380	29,270	1,954,151	9,062,516
Net book values					
At 31 December 2022	-	732,227	-	473,423	1,205,650

In 2022, the Branch has disposed off assets with net book value amounting to US$1,383 for the same value.

There were no conditions that would indicate impairment of fixed assets at 31 December 2023 and 2022.

4 Exploration costs, net

The compositions and movements of the account as at and for the years ended 31 December consist of:

	2023	2022
General studies	7,834,826	7,834,826
Exploration drilling	215,372,484	215,372,484
Exploration studies	38,346,618	38,346,618
Seismic	22,411,586	22,411,586
	283,965,514	283,965,514
Accumulated depletion, depreciation and amortisation	(76,888,836)	(73,580,734)
	207,076,678	210,384,780

Movements of the accumulated depletion, depreciation and amortisation for the years ended 31 December follow:

	2023	2022
At 1 January	73,580,734	69,581,673
Charges during the year	3,308,102	3,999,061
At 31 December	76,888,836	73,580,734

5 Retirement obligation asset, net

This account as at 31 December consists of:

	Facilities and operations	Development wells	Total
Cost			
At 1 January 2023	28,626,296	2,353,407	30,979,703
Changes in assumptions (note 14)	(3,384,796)	(2,353,407)	(5,738,203)
At 31 December 2023	25,241,500	-	25,241,500
Accumulated depreciation			
At 1 January 2023	19,449,180	935,359	20,384,539
Charges for the year	680,540	-	680,540
Changes in assumptions (note 14)	-	(935,359)	(935,359)
At 31 December 2023	20,129,720	-	20,129,720
Net book values			
At 31 December 2023	5,111,780	-	5,111,780
Cost			
At 31 December 2022 and 1 January 2022	28,626,296	2,353,407	30,979,703
Accumulated amortisation			
At 1 January 2022	18,163,185	508,673	18,671,858
Charges for the year	1,285,995	426,686	1,712,681
At 31 December 2022	19,449,180	935,359	20,384,539
Net book values			
At 31 December 2022	9,177,116	1,418,048	10,595,164

6 Development costs, net

This account as at 31 December consists of:

	Note	2023	2022
Cost			
At 1 January		621,202,507	613,031,263
Additions		18,504,329	8,171,244
Changes in assumptions	14	(6,165,139)	-
At 31 December		633,541,697	621,202,507
Allowance for depletion, depreciation and amortisation			
At 1 January		480,698,612	459,715,013
Charges during the year		17,519,326	20,983,599
At 31 December		498,217,938	480,698,612
Net book values		135,323,759	140,503,895

7 Right-of-use of assets, net

The Branch recognised the charter hire of a crew boat vessel, having met the necessary criteria of lease term longer than 12 months and high value asset. A right-of-use asset and a corresponding liability is recorded at the present value of lease payments, discounted using the incremental borrowing rate of 3.73%. The asset is depreciated using the straight line method over the lease term, starting from the lease commencement date. Lease payments consist of two components - principal and interest, of which the lease liability is reduced by the principal amount paid.

In 2023, the charter hire of a crew boat vessel contract was extended 6 months with the same rental rate.

Right-of-use assets are presented as a separate line item in the balance sheet. The following amounts relating to leases as at 31 December:

	2023	2022
Cost		
At 1 January	1,083,717	1,083,717
Additions	224,168	-
At 31 December	1,307,885	1,083,717
Accumulated amortisation		
At 1 January	858,545	641,801
Charges during the year	231,955	216,744
At 31 December	1,090,500	858,545
Net book value	217,385	225,172

Finance lease liabilities as at 31 December are presented follow:

	2023	2022
Current	275,575	310,632
Non-current	-	109,254
	275,575	419,886

Movements of lease liabilities for the years ended 31 December follow:

	2023	2022
At 1 January	419,886	687,147
Additions	224,168	-
Payment of principal	(368,479)	(267,261)
Payment of interest	(243,750)	(258,566)
Interest charged	243,750	258,566
At 31 December	275,575	419,886

The following were charged to profit or loss relating to leases for the year ended 31 December:

	2023	2022
Amortisation	231,955	216,744
Interest on finance leases	243,750	258,566

Total cash outflows for the leases for the years ended 31 December 2023 and 2022 amounted to US$612,229 and US$525,827, respectively.

8 Stocks, net

This account as at 31 December consists of:

	2023	2022
Consumable stocks	5,176,835	5,181,392
Consumable stocks in transit	38,957	3,679
Less: Provision for stock obsolescence	(4,178,350)	(4,143,182)
	1,037,442	1,041,889
Stock of liquid hydrocarbon	1,473,092	322,225
	2,510,534	1,364,114

Movements of the provision for stock obsolescence for the years ended 31 December follow:

	2023	2022
At 1 January	4,143,182	4,160,690
Provision (reversal)	35,168	(17,508)
At 31 December	4,178,350	4,143,182

In 2023, the Branch has sold scrap inventories resulting to a loss of US$89,715 (2022 - US$6,345 gain).

9 Trade and other receivables

This account as at 31 December consists of:

	2023	2022
Trade receivables	22,678,861	33,148,783
Advances to suppliers	4,479,778	448,453
Advances to employees	363,949	324,061
Deposits	243,941	211,176
	27,766,529	34,132,473

10 Amounts due from partners

The account represents net position of its cash calls and receipts from its joint operation partners and their respective share in the working capital assets of the joint operation amounting to US$18,014,149 as at 31 December 2023 (2022 - US$9,439,292). The accounts are billed and settled within 30 days.

11 Related party transactions and balances

Related parties in these financial statements refer to members of the ultimate parent company's group of companies. Some of the Branch's transactions and arrangements are with related parties and the effect of these transactions on the basis determined between the parties are reflected in these financial statements.

The related party balances as at 31 December follow:

	Note	2023	2022
Company under common control			
Cash deposits	12	101,652,247	109,791,375
Amount due to		(5,430,940)	(6,156,575)

Transactions with companies under common control

The amounts due to/from related companies are trade and non-trade in nature. They are unsecured, interest free and have no fixed term of repayment.

Transaction with key management personnel

There were no payments made to key management personnel for the years ended 31 December 2023 and 2022.

12 Cash and cash equivalents

This account as at 31 December consists of:

	Note	2023	2022
Cash on hand		123,808	9,860
Cash in bank		12,448,800	1,135,632
Deposits placed with a related party	11	101,652,247	109,791,375
		114,224,855	110,936,867

Deposit placed with a related party earn interest at the prevailing bank deposit rate. Total interest income earned in 2023 amounted to US$4,944,265 (2022 - US$1,865,977).

13 Trade and other payables

This account as at 31 December consists of:

	2023	2022
Trade payables	75,972,807	60,177,835
Accruals	13,264,941	8,804,741
	89,237,748	68,982,576

14 Provision for asset retirement obligation

The compositions and movements of the account as at and for the years ended 31 December follow:

		2023	2022
At 1 January			
Facilities and transportation		28,348,586	27,522,899
Development wells		14,843,465	14,411,131
		43,192,051	41,934,030
Accretion expense			
Facilities and transportation		-	825,687
Development wells		-	432,334
		-	1,258,021
Changes in assumptions			
Facilities and transportation	5	(3,384,796)	-
Development wells	5,6	(7,583,187)	-
		(10,967,983)	-
At 31 December			
Facilities and transportation		24,963,790	28,348,586
Development wells		7,260,278	14,843,465
		32,224,068	43,192,051

As at 31 December 2023, the discount and inflation rates used were 5.0% and 2.0%, respectively (2022: 4% and 2%).

15 Taxation

This account as at 31 December consists of:

	2023	2022
Current	40,942,601	66,513,404
Deferred	(9,420,000)	(14,070,000)
	31,522,601	52,443,404

Current income taxes are comprised of charges from petroleum operations and non-petroleum operations, and supplemental payment under the consortium's mining agreement totaling US$40.9 million for the years ended 31 December 2023 (2022 - US$66.5 million).

Deferred income tax liabilities, net are comprised of excess of net book value over tax written down value, asset retirement obligation, provision for stock obsolescence, net right-of-use liabilities and unrealised translation loss totalling US$48.8 million as at 31 December 2023 (2022 - US$58.2 million). The net movement for the year ended 31 December 2023 amounting to US$ 9.4 million (2022 - US$14.1 million) is charged to profit or loss. These are taxed at the Branch's effective tax rate of 56%.

16 Head office account; Retained earnings

The movements of the accounts for the years ended 31 December follow:

	2023	2022
Head office account		
At 1 January	(681,772,675)	(611,772,675)
Remittances to	(15,000,000)	(70,000,000)
At 31 December	(696,772,675)	(681,772,675)
Retained earnings		
At 1 January	957,209,757	914,824,670
Net profit for the year	35,205,010	42,385,087
At 31 December	992,414,767	957,209,757
Total head office account	295,642,092	275,437,082

17 Revenue

Revenue for years ended 31 December follow:

	BBJV	Unit GPA	Total
For the year ended 31 December 2023			
Gas	67,770,763	38,730,798	106,501,561
Condensate	29,431,668	8,727,272	38,158,940
	97,202,431	47,458,070	144,660,501
For the year ended 31 December 2022			
Gas	110,411,840	9,824,779	120,236,619
Condensate	36,981,713	-	36,981,713
	147,393,553	9,824,779	157,218,332

18 Stock variation - Liquid (arising from Gas Production Agreement "GPA")

Stock variation gain (loss) arising from the GPA for the years ended 31 December follow:

	2023	2022
BBJV	(68,835)	(256,850)
Unit GPA	1,219,702	75,226
	1,150,867	(181,624)

19 Transportation costs (arising from GPA)

Transportation costs arising from the GPA for years ended 31 December follow:

	2023	2022
BBJV	625,628	488,668
Unit GPA	218,640	74,893
	844,268	563,561

TotalEnergies EP (Brunei) B.V. (fka Total E&P Borneo B.V.)
STATEMENT OF FINANCIAL POSITION
CURRENCY: USD

	2022	2021
Goodwill	-	-
Intangible assets	502,165	816,329
Property, plant and equipment	228,401,476	254,916,504
Subsidiaries & investment in associated companies	-	-
Other financial assets	182,074	696,375
Loans receivable	272,373	293,750
Deferred tax asset	-	-
Non-current assets	**229,358,088**	**256,722,958**
Inventories	1,759,311	1,887,615
Trade and other receivables	44,624,115	34,509,661
Current income tax assets	-	-
Cash and cash equivalents	111,033,857	97,542,766
Current assets other than non-current assets held for sale	**157,417,283**	**133,940,042**
Non-current assets or disposal groups classified as held for sale	-	-
Current assets	**157,417,283**	**133,940,042**
Total assets	**386,775,371**	**390,663,000**
Issued capital	100,000,000	100,000,000
Share premium	2,674,020	2,674,020
Treasury shares	-	-
Currency translation reserve	-	-
Remeasurements of defined benefit plans	-	-
Revaluation reserves	-	-
Retained earnings	4,700,557	63,752,377
Result of the year	33,706,413	10,948,180
Equity attributable to owners of parent	**141,080,990**	**177,374,577**
Non-controlling interests	-	-
Total equity	**141,080,990**	**177,374,577**
Pension liabilities	-	-
Provisions	43,192,051	41,934,030
Non-current payables	-	-
Deferred tax liabilities	58,170,200	72,240,200
Loans and borrowings	-	-
Long term lease liability	291,328	1,114,201
Non-current liabilities	**101,653,579**	**115,288,431**
Trade and other payables	77,046,690	50,589,282
Current tax liabilities	66,165,742	46,692,518
Current loans and borrowings	-	-
Current lease liability	828,370	718,192
Other current liabilities	-	-
Current liabilities other than liabilities included in disposal groups	**144,040,802**	**97,999,992**
Liabilities included in disposal groups classified as held for sale	-	-
Current liabilities	**144,040,802**	**97,999,992**
Total liabilities	**245,694,381**	**213,288,423**
Total equity and liabilities	**386,775,371**	**390,663,000**

TotalEnergies EP (Brunei) B.V. (fka Total E&P Borneo B.V.)
INCOME STATEMENT

	2022	2021
Net sale of products	158,126,048	112,755,876
Cost of sales	(72,019,052)	(69,826,834)
Gross profit	**86,106,996**	**42,929,042**
Exploration costs	-	-
General and administration expenses	(263,446)	(272,601)
Other operating income	-	-
Other operating expenses	-	-
Other gains (losses)	-	(9,997)
Operating profit	**85,843,550**	**42,646,444**
Finance income	2,387,483	587,081
Finance expenses	(1,948,286)	(2,161,655)
Financial result	**439,197**	**(1,574,574)**
Share of profit (loss) of subsidiaries and other associated companies	-	-
Profit (loss) before tax	**86,282,747**	**41,071,870**
Income tax expense	(52,576,334)	(30,123,690)
Profit (loss) from continuing operations	**33,706,413**	**10,948,180**
Profit (loss) from discontinued operations	-	-
Net income (loss)	**33,706,413**	**10,948,180**
Retained earnings - Net profit (loss) for the period	**33,706,413**	**10,948,180**

TotalEnergies EP (Brunei) B.V. (fka Total E&P Borneo B.V.)
CASH FLOW STATEMENT

	2022	2021
Cash flow from operating activities		
Profit (loss) before income tax from continuing operations	86,282,747	41,071,870
Profit (loss) before income tax for discontinued operations	-	-
Profit (loss) before income tax	86,282,747	41,071,870
Adjustments to reconcile profit to net cash flows		
Depreciation, depletion and amortisation	38,600,880	44,210,785
Impairment of intangible assets and property. plant and equipment	-	-
Impairment of goodwill	-	-
(Gains)/ losses on disposal of assets	-	9,997
Reimbursement of exploration expenditures previously expensed out	-	-
Movement in provisions	-	-
Exploration costs written off	-	-
Profit on sale of subsidiaries	-	-
Result of associated companies	-	-
Dividends from a non-group company	-	-
Finance expenses	689,543	939,272
Allowance for RES Provision - Accretion	1,258,021	1,221,379
Finance income	(2,387,483)	(587,081)
Impairment non-group company	-	-
Gain on extinguishment of debt	-	-
Gain on disposal of subsidiary	-	-
Net cash flow from operating activities before changes in working capital	124,443,708	86,866,222
Working capital adjustments		
Decrease/ (increase) in inventories	128,304	353,984
Decrease/ (increase) in trade and other receivables	(10,990,831)	(378,941)
Increase/ (decrease) in trade and other payables	26,457,408	10,688,605
Interest received	2,387,483	587,081
Interest paid	(34)	-
Income taxes (paid) received	(47,173,110)	(39,237,243)
Withholding tax paid	-	-
Net cash flow from operating activities	**95,252,928**	**58,879,708**
Cash flow from investing activities		
Exploration investments	-	-
Development investments	(11,771,688)	(4,218,947)
Proceeds from disposal of intangible assets and property, plant and equipment	-	-
Dividend received from a non-group company	-	-
Capital increase or decrease existing subsidiairies/ dividend received from subsidiaries	-	-
Proceeds from disposal of subsidiaires/ participating interest	-	-
Investment in subsidiaires/ participating interest	-	-
Reimbursement of investment in associates	-	-
Dividend received from associate	-	-
Draw down of loans receivable	(20,385)	(49,501)
Sale of loans receivable	-	
Reimbursement of loans receivable	41,762	47,026
Net cash flow from investing activities	**(11,750,311)**	**(4,221,422)**
Cash flow from financing activities		
Proceeds from issuing shares	-	-
Proceeds from issuing shares to noncontrolling interests	-	
Share premium repaid to noncontrolling interests	-	
Payments to acquire or redeem entity's shares	-	-
Proceeds from sale of entity's shares	-	-
Draw down of loans payable	-	-
Reimbursement of loans payable	-	-
Payment of finance lease liability	-	-
Dividends paid to parent company	(70,000,000)	(20,000,000)
Dividends paid to noncontrolling interests	-	
Net cash flow from financing activities	**(70,011,526)**	**(20,076,957)**
Net increase (decrease) in cash and cash equivalents	13,491,091	34,581,329
Cash and cash equivalents at beginning of period	97,542,766	62,961,437
Cash and cash equivalents at end of period	**111,033,857**	**97,542,766**

Date: 26-10-2023

Name: TotalEnergies Management B.V.
Title: Managing Director, represented by Aurélie Abiad
its solely authorised board member

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TotalEnergies EP (Brunei) B.V. (fka Total E&P Borneo B.V.)

STATEMENT OF FINANCIAL POSITION

CURRENCY: USD

	2023 Total	2022 Total
Goodwill	-	-
Intangible assets	213 211	502 165
Property, plant and equipment	219 504 058	228 401 476
Subsidiaries & investment in associated companies	-	-
Other financial assets	-	182 074
Loans receivable	325 097	272 373
Deferred tax asset	-	-
Non-current assets	**220 042 366**	**229 358 088**
Inventories	2 906 276	1 759 311
Trade and other receivables	47 934 987	44 624 115
Current income tax assets	-	-
Cash and cash equivalents	114 326 452	111 033 857
Current assets other than non-current assets held for sale	**165 167 715**	**157 417 283**
Non-current assets or disposal groups classified as held for sale	-	-
Current assets	**165 167 715**	**157 417 283**
Total assets	**385 210 081**	**386 775 371**
Issued capital	100 000 000	100 000 000
Share premium	2 674 020	2 674 020
Treasury shares	-	-
Currency translation reserve	-	-
Remeasurements of defined benefit plans	-	-
Revaluation reserves	-	-
Retained earnings	23 406 970	4 700 557
Result of the year	32 758 511	33 706 413
Equity attributable to owners of parent	**158 839 501**	**141 080 990**
Non-controlling interests	-	-
Total equity	**158 839 501**	**141 080 990**
Pension liabilities	-	-
Provisions	32 224 068	43 192 051
Non-current payables	-	-
Deferred tax liabilities	48 750 200	58 170 200
Loans and borrowings	-	-
Long term lease liability	-	291 328
Non-current liabilities	**80 974 268**	**101 653 579**
Trade and other payables	103 940 047	77 046 690
Current tax liabilities	40 721 398	66 165 742
Current loans and borrowings	-	-
Current lease liability	734 867	828 370
Other current liabilities	-	-
Current liabilities other than liabilities included in disposal groups	**145 396 312**	**144 040 802**
Liabilities included in disposal groups classified as held for sale	-	-
Current liabilities	**145 396 312**	**144 040 802**
Total liabilities	**226 370 580**	**245 694 381**
Total equity and liabilities	**385 210 081**	**386 775 371**

TotalEnergies EP (Brunei) B.V. (fka Total E&P Borneo B.V.)

INCOME STATEMENT

	2023	2022
	Total	**Total**
Net sale of products	149 513 010	112 755 876
Cost of sales	(88 992 442)	(69 826 834)
Gross profit	**60 520 568**	**42 929 042**
Exploration costs	-	-
General and administration expenses	(899 872)	(272 601)
Other operating income	-	-
Other operating expenses	-	-
Other gains (losses)	-	(9 997)
Operating profit	**(899 872)**	**42 646 444**
Finance income	5 211 269	587 081
Finance expenses	(506 152)	(2 161 655)
Financial result	**4 705 117**	**(1 574 574)**
Share of profit (loss) of subsidiaries and other associated companies	-	-
Profit (loss) before tax	**64 325 813**	**41 071 870**
Income tax expense	(31 567 302)	(30 123 690)
Profit (loss) from continuing operations	**32 758 511**	**10 948 180**
Profit (loss) from discontinued operations	-	-
Net income (loss)	**32 758 511**	**10 948 180**
Retained earnings - Net profit (loss) for the period	**32 758 511**	**10 948 180**

TotalEnergies EP (Brunei) B.V. (fka Total E&P Borneo B.V.)
CASH FLOW STATEMENT

	2023	2022
Cash flow from operating activities		
Profit (loss) before income tax from continuing operations	64.325.813	86.282.747
Profit (loss) before income tax for discontinued operations	-	-
Profit (loss) before income tax	64.325.813	86.282.747
Adjustments to reconcile profit to net cash flows		
Depreciation, depletion and amortisation	31.270.195	38.600.880
Impairment of intangible assets and property. plant and equipment	-	-
Impairment of goodwill	-	-
(Gains)/ losses on disposal of assets	-	-
Reimbursement of exploration expenditures previously expensed out	-	-
Movement in provisions	-	-
Exploration costs written off	-	-
Profit on sale of subsidiaries	-	-
Result of associated companies	-	-
Dividends from a non-group company	-	-
Finance expenses	506.152	689.543
Allowance for RES Provision - Accretion	-	1.258.021
Finance income	(5.211.117)	(2.387.483)
Impairment non-group company	-	-
Gain on extinguishment of debt	-	-
Gain on disposal of subsidiary	-	-
Net cash flow from operating activities before changes in working capital	90.891.043	124.443.708
Working capital adjustments		
Decrease/ (increase) in inventories	(1.146.965)	128.304
Decrease/ (increase) in trade and other receivables	(3.369.317)	(10.990.831)
Increase/ (decrease) in trade and other payables	26.182.167	26.457.408
Interest received	5.211.117	2.387.483
Interest paid	(506.152)	(34)
Income taxes (paid) received	(66.431.646)	(47.173.110)
Withholding tax paid	-	-
Net cash flow from operating activities	**50.830.247**	**95.252.928**
Cash flow from investing activities		
Exploration investments	-	-
Development investments	(32.116.448)	(11.771.688)
Proceeds from disposal of intangible assets and property, plant and equipment	-	-
Dividend received from a non-group company	-	-
Capital increase or decrease existing subsidiairies/ dividend received from subsidiaries	-	-
Proceeds from disposal of subsidiaires/ participating interest	-	-
Investment in subsidiaires/ participating interest	-	-
Reimbursement of investment in associates	-	-
Dividend received from associate	-	-
Draw down of loans receivable	(52.724)	(20.385)
Sale of loans receivable	-	-
Reimbursement of loans receivable	41.762	41.762
Net cash flow from investing activities	**(32.127.410)**	**(11.750.311)**
Cash flow from financing activities		
Proceeds from issuing shares	-	-
Proceeds from issuing shares to noncontrolling interests	-	-
Share premium repaid to noncontrolling interests	-	-
Payments to acquire or redeem entity's shares	-	-
Proceeds from sale of entity's shares	-	-
Draw down of loans payable	-	-
Reimbursement of loans payable	-	-
Payment of finance lease liability	(368.480)	-
Dividends paid to parent company	(15.000.000)	(70.000.000)
Dividends paid to noncontrolling interests	-	-
Net cash flow from financing activities	**(15.368.480)**	**(70.011.526)**
Net increase (decrease) in cash and cash equivalents	3.292.595	13.491.091
Cash and cash equivalents at beginning of period	111.033.857	97.542.766
Cash and cash equivalents at end of period	**114.326.452**	**111.033.857**

Date: 30-07-2024

Name: TotalEnergies Management B.V.
Title: Managing Director represented by
Mr. Marcus Kloppenburg
its solely authorised board member

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1. DIRECTORS' RESPONSIBILITY STATEMENT

Our Board has seen and approved this Circular and they collectively and individually accept full responsibility for the accuracy of the information given in this Circular. They confirm that after making all reasonable enquiries and to the best of their knowledge and belief, there are no false or misleading statements or other facts, the omission of which would make any statement in this Circular misleading.

The information on the Vendor, the TargetCo and the Asset was obtained from the Vendor or based on public and other available information, and the responsibility of our Board is limited to ensuring that this information is correctly extracted and reproduced in this Circular.

2. CONSENTS AND CONFLICTS OF INTEREST

2.1 AmInvestment Bank

AmInvestment Bank, being the Principal Adviser for the Proposed Acquisition, has given and has not subsequently withdrawn its written consent for the inclusion in this Circular of their names, reports and/or letters (where applicable) and all references thereto in the form and context in which they appear in this Circular.

AmInvestment Bank confirms that there is no conflict of interest which exists or is likely to exist in its capacity as the Principal Adviser in respect of the Proposed Acquisition.

AmInvestment Bank, its related and associated companies, as well as its holding company, AMMB Holdings Berhad and the subsidiaries and associated companies of its holding company ("**AmBank Group**") form a diversified financial group and are engaged in a wide range of investment and commercial banking, brokerage, securities trading, asset and funds management and credit transaction service businesses.

In the ordinary course of their businesses, any member of AmBank Group may at any time extend services to any company as well as hold long or short positions, and trade or otherwise effect transactions, for its own account or the account of its other clients, in debt or equity securities or senior loans of any company. Accordingly, there may be situations where parts of the AmBank Group and/or its clients now have or in the future, may have interests or take actions that may conflict with the interests of our Group. As at the LPD, the AmBank Group has not extended credit facilities to our Group.

AmInvestment Bank is of the view that its role as the Principal Adviser for the Proposed Acquisition is not likely to result in a conflict of interest or potential conflict of interest situation for the following reasons:

(i) AmInvestment Bank's role in the Proposed Acquisition is undertaken in the ordinary course of business; and

(ii) AmInvestment Bank undertakes each of its roles on an arm's length basis and its conduct is regulated by Bank Negara Malaysia and the Securities Commission Malaysia and governed under, inter alia, the Financial Services Act 2013, the Capital Markets and Services 2007, and AmBank Group's Chinese Wall policy and internal controls and checks.

2.2 RPS Energy

RPS Energy has given and has not subsequently withdrawn its written consent to the inclusion in this Circular of its name, the Competent Valuer's Report, Competent Person's Report and the fairness opinion report on the fairness of the Purchase Consideration for the TargetCo and all references thereto in the form and context in which they appear.

RPS Energy confirms that, it is also not aware of any possible conflict of interest which exists or is likely to exist in its capacities as the independent valuer in respect of the Assets, as the expert providing the Competent Valuer's Report, Competent Person's Report and the fairness opinion report on the fairness of the Purchase Consideration for the TargetCo.

2.3 Ernst & Young Tax Consultants Sdn Bhd ("EY")

EY has given and has not subsequently withdrawn its written consent to the inclusion in this Circular of its name, the letter of policies in relation to foreign investments, taxation and repatriation of profits of the Netherlands and Brunei Darussalam and all references thereto in the form and context in which they appear.

EY confirms that, it is not aware of any possible conflict of interest which exists or is likely to exist in its capacity as the expert providing the letter of policies in relation to to foreign investments, taxation and repatriation of profits of the Netherlands and Brunei Darussalam.

2.4 Herbert Smith Freehills LLP ("HSF")

HSF has given and has not subsequently withdrawn its written consent to the inclusion in this Circular of its name, the legal opinion on the enforceability of agreements, representations and undertakings given by TotalEnergies Holdings International B.V. under English law and all references thereto in the form and context in which they appear.

HSF confirms that, it is not aware of any possible conflict of interest which exists or is likely to exist in its capacity as our foreign legal counsel in providing the legal opinion on the enforceability of agreements, representations and undertakings given by TotalEnergies Holdings International B.V. under English law.

2.5 FHMH Corporate Advisory Sdn Bhd ("FHMH")

FHMH has given and has not subsequently withdrawn its written consent to the inclusion in this Circular of its name, the SSAR and all references thereto in the form and context in which they appear.

FHMH confirms that, it is not aware of any possible conflict of interest which exists or is likely to exist in its capacity as our financial adviser in providing the SSAR.

2.6 Loyens & Loeff N.V. ("L&L")

L&L has given and has not subsequently withdrawn its written consent to the inclusion in this Circular of its name, the legal opinion on the ownership of title to the securities or assets in the foreign jurisdiction and the enforceability of agreements, representations and undertakings given by foreign counter-parties under Dutch law and all references thereto in the form and context in which they appear.

L&L confirms that, it is not aware of any possible conflict of interest which exists or is likely to exist in its capacity as our foreign legal counsel in providing the legal opinion on the ownership of title to the securities or assets in the foreign jurisdiction and the enforceability of agreements, representations and undertakings given by foreign counter-parties under Dutch law.

3. MATERIAL COMMITMENTS

Save as disclosed below, as at 30 June 2024, being the date of the latest unaudited quarterly financial report of our Group, our Group does not have any other material commitments incurred or known to be incurred by our Group which, upon becoming enforceable, may have a material impact on the financial position of our Group:

	RM'000
Approved and contracted for:	
▪ Group's capital commitments	229,441
▪ Share of a joint operation's capital commitments	15,940
Total capital commitments approved and contracted for	245,381
▪ Share of a joint operation's other material commitments	33,593
	278,974

4. CONTINGENT LIABILITIES

As at 30 June 2024, being the date of the latest unaudited quarterly financial report of our Group, there are no contingent liabilities incurred or known to be incurred by our Group which, upon becoming enforceable, may have a material impact on the financial position of our Group.

5. DOCUMENTS AVAILABLE FOR INSPECTION

The following documents or copies of them are available for inspection during normal business hours at the registered office of our Company at Unit 521, 5th Floor, Lobby 6, Block A, Damansara Intan, No. 1, Jalan SS 20/27, 47400 Petaling Jaya, Selangor Darul Ehsan, Malaysia, from Mondays to Fridays (except public holidays) from the date of this Circular up to the time stipulated for the holding of the EGM:

(i) our constitution and the constitution of TargetCo;

(ii) our audited consolidated financial statements for the FYE 30 June 2022 and the FYE 30 June 2023 and our latest unaudited quarterly financial statements for the FYE 30 June 2024;

(iii) the SPA;

(iv) the Parent Company Guarantee;

(v) the Transition Services Agreement;

(vi) the Competent Valuer's Report as set out in Appendix IV of this Circular;

(vii) the Competent Person's Report as set out in Appendix V of this Circular;

(viii) the expert's report on the fairness of the Purchase Consideration for the TargetCo as set out in Appendix VI of this Circular;

(ix) the letter of policies on foreign investments, taxation and repatriation of profits of Netherlands and Brunei as set out in Appendix VII of this Circular;

(x) the legal opinion on the enforceability of agreements, representations and undertakings given by foreign counter-parties under the English law as set out in Appendix VIII of this Circular;

(xi) the legal opinion on the ownership of title to the securities or assets in the foreign jurisdiction and enforceability of agreements, representations and undertakings given by foreign counter-parties under the Dutch law as set out in Appendix IX of this Circular;

(xii) SSAR as set out in Appendix X of this Circular;

(xiii) the audited financial statements of the Branch for the FYE 31 December 2022 and FYE 31 December 2023;

(xiv) the unaudited condensed financial statements of the TargetCo for the FYE 31 December 2022 and FYE 31 December 2023;

(xv) letters of undertaking from the Undertaking Shareholders referred to in Section 8 of this Circular; and

(xvi) the letters of consent and declaration of conflict of interest referred to in Section 2 of this Appendix.

HIBISCUS PETROLEUM BERHAD

Registration Number: 200701040290 (798322-P)
(Incorporated in Malaysia)

NOTICE OF EXTRAORDINARY GENERAL MEETING

NOTICE IS HEREBY GIVEN THAT an Extraordinary General Meeting ("**EGM**") of Hibiscus Petroleum Berhad will be held via a virtual platform at the broadcast venue at Tricor Business Centre, Gemilang Room, Unit 29-01, Level 29, Tower A, Vertical Business Suite, Avenue 3, Bangsar South, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur, Malaysia ("**Broadcast Venue**") on Thursday, 10 October 2024 at 9.30 a.m. or at any adjournment thereof, whichever is later, for the purpose of considering and if thought fit, to pass the following resolution (with or without modifications):

ORDINARY RESOLUTION

PROPOSED ACQUISITION BY SIMPOR HIBISCUS SDN BHD ("SIMPOR HIBISCUS"), AN INDIRECT WHOLLY-OWNED SUBSIDIARY OF HIBISCUS PETROLEUM BERHAD ("HIBISCUS PETROLEUM" OR "COMPANY"), OF THE ENTIRE EQUITY INTEREST IN TOTALENERGIES EP (BRUNEI) B.V. ("TARGETCO"), A WHOLLY-OWNED SUBSIDIARY OF TOTALENERGIES HOLDINGS INTERNATIONAL B.V. FOR A CASH CONSIDERATION OF APPROXIMATELY USD259.4 MILLION (OR EQUIVALENT TO APPROXIMATELY RM1,087.8 MILLION) ("PROPOSED ACQUISITION")

"**THAT** approval be and is hereby given for Simpor Hibiscus, an indirect wholly-owned subsidiary of Hibiscus Petroleum, to acquire the entire equity interest in the TargetCo for a cash consideration of approximately USD259.4 million (or equivalent to approximately RM1,087.8 million), subject to adjustments, pursuant to and in accordance with the terms and conditions of the Sale and Purchase Agreement dated 13 June 2024 in relation to the Proposed Acquisition, as further elaborated in the Company's circular to shareholders dated 25 September 2024.

AND THAT the Directors of the Company, be and are hereby empowered and authorised to do all acts, deeds and things and to execute, sign, deliver and cause to be delivered on behalf of the Company all such documents and/or agreements (including, without limitation, the affixing of the Company's common seal, where applicable) as the Directors may consider necessary, expedient or relevant to give effect to and complete the Proposed Acquisition and with full power to assent to any conditions, terms, modifications, variations and/or amendments in any manner as may be required by the relevant authorities or as the Directors may deem necessary, expedient or relevant in the best interest of the Company and to take such steps as they may deem necessary, expedient or relevant in order to implement, finalise and give full effect to the Proposed Acquisition."

BY ORDER OF THE BOARD

Khoo Ming Siang (MAICSA No. 7034037) (SSM PC No. 202208000150)
Law Wei Leng (MAICSA No. 7064862) (SSM PC No. 202108000506)
Secretaries

Selangor Darul Ehsan
25 September 2024

IMPORTANT NOTICE

The Broadcast Venue is strictly for the purpose of complying with Section 327(2) of the Companies Act 2016 which requires the Chair of the meeting to be present at the main venue of the meeting.

Shareholders or proxies are **NOT** to be physically present at the Broadcast Venue on the meeting day.

Shareholders are to attend, participate, speak (in the form of real-time submission through typed texts) and vote (collectively referred to as 'participate') remotely at the EGM via the Remote Participation and Voting facilities (RPV) provided by Tricor Investor & Issuing House Services Sdn Bhd (Tricor) as the Poll Administrator of the Company via its TIIH Online website at https://tiih.online.

Notes:

1. *For purposes of determining a member who shall be entitled to attend and vote at this EGM in accordance with Clauses 72(b) and 72(c) of the Company's Constitution and Section 34(1) of the Securities Industry (Central Depositories) Act, 1991, the Company shall be requesting Bursa Malaysia Depository Sdn Bhd to issue a General Meeting Record of Depositors as at 3 October 2024. Only a Depositor whose name appears on such Record of Depositors shall be entitled to attend, participate, speak and vote via RPV at this EGM as well as for appointment of proxy(ies) to attend, participate, speak and vote on his/her stead.*

2. *A member of the Company who is entitled to participate at the EGM may appoint up to two (2) proxies to attend and vote at the EGM via RPV. Where a member appoints more than one (1) proxy, the appointments shall be invalid unless he specifies the proportions of his holdings to be represented by each proxy. A proxy appointed to attend and vote at the EGM via RPV shall have the same right as a member to speak at the EGM.*

3. *A proxy or attorney or a duly authorised representative may, but need not be a member of the Company. There shall be no restriction as to the qualification of the proxy.*

4. *Where a member is an authorised nominee as defined under the Securities Industry (Central Depositories) Act, 1991 which is exempted from compliance with the provisions of subsection 25A(1) of the Securities Industry (Central Depositories) Act, 1991 (Exempt Authorised Nominee) which holds Ordinary Shares in the Company for multiple beneficial owners in one (1) securities account (Omnibus Account), there is no limit to the number of proxies which the Exempt Authorised Nominee may appoint in respect of each Omnibus Account it holds. Where the Exempt Authorised Nominee appoints more than one (1) proxy, the proportion of shareholdings to be represented by each proxy must be specified in the instrument appointing the proxies.*

5. *A member who has appointed a proxy or attorney or authorised representative to attend and vote at this EGM via RPV* ***must request his/her proxy or attorney or authorised representative to register himself/herself for RPV*** *at TIIH Online website at https://tiih.online. The procedures for RPV can be found in the Administrative Guide for the EGM.*

6. *Members who wish to appoint a proxy may do so either by using a hard copy form or through electronic means, following the procedure outlined below. The proxy appointment must be deposited with Tricor not less than forty-eight (48) hours before the time appointed for holding the EGM or any adjourned meeting. In the event the member(s) duly executes the Form of Proxy but does not name any proxy, such member(s) shall be deemed to have appointed the Chair of the meeting as his/her proxy, provided always that the rest of the Form of Proxy, other than the particulars of the proxy has been duly completed by the member(s).*

To facilitate the proxy appointment process, kindly follow the guidelines provided below:

(a) In hard copy form:

In the case of an appointment made in hard copy form, the completed Form of Proxy must be deposited with:

(i) Tricor Investor & Issuing House Services Sdn Bhd
Unit 32-01, Level 32, Tower A, Vertical Business Suite,
Avenue 3, Bangsar South, No. 8, Jalan Kerinchi,
59200 Kuala Lumpur, Malaysia.

or alternatively

***Tricor's Customer Service Centre** at:*

Unit G-3, Ground Floor, Vertical Podium,
Avenue 3, Bangsar South, No. 8, Jalan Kerinchi,
59200 Kuala Lumpur, Malaysia.

(ii) By fax at 03-2783 9222.

(b) By electronic means:

The Form of Proxy can be electronically submitted with Tricor via TIIH Online at https://tiih.online.

Kindly refer to the Administrative Guide for the EGM on the procedures for the electronic lodgement via TIIH Online.

7. Please ensure ALL particulars required in the Form of Proxy are completed and the Form of Proxy is signed and dated accordingly.

8. The last date and time for submitting the Form of Proxy is on Tuesday, 8 October 2024 at 9.30 a.m.

9. If the Form of Proxy is signed under the hands of an appointor or his attorney duly authorised (or if the appointor is a corporation, the Form of Proxy must be executed under its common seal or under the hands of an officer or attorney duly authorised), it should be accompanied by a statement reading "signed as authorised officer under Authorisation Document which is still in force, no notice of revocation having been received". If the Form of Proxy is signed under the attorney duly appointed under a power of attorney, it should be accompanied by a statement reading "signed under Power of Attorney which is still in force, no notice of revocation having been received". A copy of the Authorisation Document or the Power of Attorney, which should be valid in accordance with the laws of the jurisdiction in which it was created and is exercised, should be enclosed in the Form of Proxy.

10. Any authority pursuant to which such an appointment is made by a power of attorney must be deposited with Tricor or alternatively the Customer Service Centre at the address stated under item (6)(a)(i) not less than forty-eight (48) hours before the time appointed for holding the EGM or adjourned general meeting at which the person named in the appointment proposes to vote. A copy of the power of attorney may be accepted provided that it is certified notarially and/or in accordance with the applicable legal requirements in the relevant jurisdiction in which it is executed.

11. By submitting the duly executed Form of Proxy, the member and his/her proxy(ies) consent to the Company (and/or its agents/service providers) collecting, using and disclosing the personal data therein in accordance with Personal Data Protection Act 2010 for the purpose of the EGM or any adjournment thereof.

12. Pursuant to paragraph 8.29A of the Main Market Listing Requirements of Bursa Malaysia Securities Berhad, the resolution set out in the Notice of this EGM will be put to vote by way of poll. An Independent Scrutineer will be appointed to verify the poll results.

PERSONAL DATA POLICY

By submitting an instrument appointing proxy(ies) and/or representative(s) to attend, participate and vote at the EGM and/or any adjournment thereof, a member of the Company (i) consents to the collection, use and disclosure of the member's personal data by the Company (or its agents) for the purpose of the processing and administration by the Company (or its agents) of proxies and representatives appointed for the EGM (including any adjournment thereof) and the preparation and compilation of the attendance lists, minutes and other documents relating to the EGM (including any adjournment thereof) and in order for the Company (or its agents) to comply with any applicable laws, listing rules, regulations and/or guidelines (collectively, the "Purposes"), (ii) warrants that where the member discloses the personal data of the member's proxy(ies) and/or representative(s) to the Company (or its agents), the member has obtained the prior consent of such proxy(ies) and/or representative(s) for the collection, use and disclosure by the Company (or its agents) of the personal data of such proxy(ies) and/or representative(s) for the Purposes, and (iii) agrees that the member will indemnify the Company in respect of any penalties, liabilities, claims, demands, losses and damages as a result of the member's breach of warranty.

Hibiscus Petroleum Berhad
Registration Number: 200701040290 (798322-P)

FORM OF PROXY

FOR THE EXTRAORDINARY GENERAL MEETING

No. of Ordinary Shares Held	
CDS Account Number	

*I/We____

(Full Name In Block Letters)

NRIC/Passport/Registration/Company No.:

of ____

(Full Address)

Mobile No.:____

Email Address:____

being a member of **HIBISCUS PETROLEUM BERHAD** ("**HIBISCUS PETROLEUM**" or "**Company**")

hereby appoint:

<table>
<tr><th>Full Name (In Block Letters)</th><th>NRIC/Passport No.</th><th>Mobile No.</th><th colspan="2">Proportion of Shareholdings</th></tr>
<tr><td></td><td></td><td></td><th>No. of Shares</th><th>%</th></tr>
<tr><th colspan="2">Full Address</th><th>Email Address</th><td rowspan="2"></td><td rowspan="2"></td></tr>
<tr><td colspan="2"></td><td></td></tr>
</table>

and/or (delete as appropriate)

<table>
<tr><th>Full Name (In Block Letters)</th><th>NRIC/Passport No.</th><th>Mobile No.</th><th colspan="2">Proportion of Shareholdings</th></tr>
<tr><td></td><td></td><td></td><th>No. of Shares</th><th>%</th></tr>
<tr><th colspan="2">Full Address</th><th>Email Address</th><td rowspan="2"></td><td rowspan="2"></td></tr>
<tr><td colspan="2"></td><td></td></tr>
</table>

or failing him/her, the CHAIR OF THE MEETING as my/our proxy, to vote for me/us on my/our behalf at the Extraordinary General Meeting ("**EGM**") of the Company to be held via a virtual platform at the broadcast venue at Tricor Business Centre, Gemilang Room, Unit 29-01, Level 29, Tower A, Vertical Business Suite, Avenue 3, Bangsar South, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur, Malaysia ("**Broadcast Venue**") on Thursday, 10 October 2024 at 9.30 a.m. or at any adjournment thereof, whichever is later, on the following resolution (with or without modifications) referred to in the Notice of the EGM by indicating an "X" in the space provided below:

RESOLUTION	FOR	AGAINST
Ordinary Resolution - Proposed Acquisition		

Dated this ______ day of ______________________________ 2024

____
Signature/Common Seal of Shareholder(s)

Please refer to the Notice of the EGM for full details of the proposed Ordinary Resolution.

(Please indicate with an "X" in the spaces provided whether you wish your vote to be cast for or against the Ordinary Resolution. In the absence of specific directions, your proxy will vote or abstain as he/she thinks fit).

Notes:

1. *For purposes of determining a member who shall be entitled to attend and vote at this EGM in accordance with Clauses 72(b) and 72(c) of the Company's Constitution and Section 34(1) of the Securities Industry (Central Depositories) Act, 1991, the Company shall be requesting Bursa Malaysia Depository Sdn Bhd to issue a General Meeting Record of Depositors as at 3 October 2024. Only Depositor whose name appear on such Record of Depositors shall be entitled to attend, participate, speak and vote via RPV on his/ her stead.*

2. *A member of the Company who is entitled to participate at the meeting may appoint up to two (2) proxies to attend and vote at the EGM via RPV. Where a member appoints more than one (1) proxy, the appointments shall be invalid unless he specifies the proportions of his holdings to be represented by each proxy. A proxy appointed to attend and vote at the EGM via RPV shall have the same right as a member to speak at the EGM.*

3. *A proxy or attorney or a duly authorized representative may, but need not be a member of the Company. There shall be no restriction as to the qualification of the proxy.*

4. *Where a member is an authorized nominee as defined under the Securities Industry (Central Depositories) Act, 1991 which is exempted from compliance with the provisions of subsection 25A(1) of the Securities Industry (Central Depositories) Act, 1991 (Exempt Authorised Nominee) which holds Ordinary Shares in the Company for multiple beneficial owners in one (1) securities account (Omnibus Account), there is no limit to the number of proxies which the Exempt Authorised Nominee may appoint in respect of each Omnibus Account it holds. Where the Exempt Authorised Nominee appoints more than one (1) proxy, the proportion of shareholdings to be represented by each proxy must be specified in the instrument appointing the proxies.*

5. *A member who has appointed a proxy or attorney or authorized representative to attend and vote at this EGM via RPV* ***must request his/her proxy or attorney or authorised representative to register himself/herself for RPV*** *at TIIH Online website at https://tiih.online. The procedures for RPV can be found in the Administrative Guide for this EGM.*

6. *Members who wish to appoint a proxy may do so either by using a hard copy form or through electronic means, following the procedure outlined below. The proxy appointment must be deposited with Tricor not less than forty-eight (48) hours before the time appointed for holding the EGM or any adjourned meeting. In the event the member(s) duly executes the Form of Proxy but does not name any proxy, such member(s) shall be deemed to have appointed the Chair of the meeting as his/her proxy, provided always that the rest of the Form of Proxy, other than the particulars of the proxy has been duly completed by the member(s).*

   To facilitate the proxy appointment process, kindly follow the guidelines provided below:

   (a) *In hard copy form:*

   In the case of an appointment made in hard copy form, the completed Form of Proxy must be deposited with:

   (i) ***Tricor Investor & Issuing House Services Sdn Bhd (Tricor)**:*

   Unit 32-01, Level 32, Tower A, Vertical Business Suite,
   Avenue 3, Bangsar South, No. 8, Jalan Kerinchi,
   59200 Kuala Lumpur, Malaysia.

   Or alternatively

   ***Tricor's Customer Service Centre** at:*

   Unit G-3, Ground Floor, Vertical Podium,
   Avenue 3, Bangsar South, No. 8, Jalan Kerinchi,
   59200 Kuala Lumpur, Malaysia

   (ii) ***By fax at 03-2783 9222.***

   (b) *By electronic means:*

   The Form of Proxy can be electronically submitted with Tricor via TIIH Online at https://tiih.online.

   Kindly refer to the Administrative Guide for this EGM on the procedures for the electronic lodgement via TIIH Online.

7. *Please ensure ALL the particulars required in the Form of Proxy are completed and the Form of Proxy is signed and dated accordingly.*

8. *The last date and time for lodging the Form of Proxy is on Tuesday, 8 October 2024 at 9.30 a.m.*

9. *If the Form of Proxy is signed under the hands of an appointor or his attorney duly authorised (or if the appointor is a corporation, the Form of Proxy must be executed under its common seal or under the hands of an officer or attorney duly authorised), it should be accompanied by a statement reading "signed as authorised officer under Authorisation Document which is still in force, no notice of revocation having been received". If the Form of Proxy is signed under the attorney duly appointed under a power of attorney, it should be accompanied by a statement reading "signed under Power of Attorney which is still in force, no notice of revocation having been received". A copy of the Authorisation Document or the Power of Attorney, which should be valid in accordance with the laws of the jurisdiction in which it was created and is exercised, should be enclosed in the Form of Proxy.*

10. *Any authority pursuant to which such an appointment is made by a power of attorney must be deposited with Tricor or alternatively the Customer Service Centre at the address stated under item (6)(a)(i) not less than forty-eight (48) hours before the time appointed for holding this EGM or adjourned general meeting at which the person named in the appointment proposes to vote. A copy of the power of attorney may be accepted provided that it is certified notarially and/or in accordance with the applicable legal requirements in the relevant jurisdiction in which it is executed.*

11. *By submitting the duly executed Form of Proxy, the member and his/her proxy(ies) consent to the Company (and/or its agents/service providers) collecting, using and disclosing the personal data therein in accordance with the Personal Data Protection Act 2010 for the purpose of this EGM or any adjournment thereof.*

12. *Pursuant to Paragraph 8.29A of the Main Market Listing Requirements of Bursa Malaysia Securities Berhad, the resolution set out in the Notice of this EGM will be put to vote by way of poll. An Independent Scrutineer will be appointed to verify the poll results.*

PERSONAL DATA POLICY

By submitting an instrument appointing a proxy(ies) and/or representative(s), the member accepts and agrees to the personal data privacy terms set out in the Notice of EGM dated 25 September 2024.

Fold this flap for sealing

Then fold here

AFFIX
STAMP

Share Registrar

TRICOR INVESTOR & ISSUING HOUSE SERVICES SDN BHD
Unit 32-01, Level 32, Tower A
Vertical Business Suite, Avenue 3
Bangsar South
No. 8, Jalan Kerinchi
59200 Kuala Lumpur
Malaysia

1st fold here