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.

HIBISCUS Petroleum

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

CIRCULAR TO SHAREHOLDERS

IN RELATION TO THE

PROPOSED ACQUISITION BY PENINSULA HIBISCUS SDN BHD, AN INDIRECT WHOLLY-OWNED SUBSIDIARY OF HIBISCUS PETROLEUM BERHAD, OF THE ENTIRE ISSUED SHARE CAPITAL OF FORTUNA INTERNATIONAL PETROLEUM CORPORATION FOR A CASH CONSIDERATION OF USD212.5 MILLION (OR EQUIVALENT TO APPROXIMATELY RM879.5 MILLION)

AND

NOTICE OF EXTRAORDINARY GENERAL MEETING

Principal Adviser

CIMB

CIMB Investment Bank Berhad
Registration No. 197401001266 (18417-M)

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	:	Tuesday, 28 December 2021 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	:	Sunday, 26 December 2021 at 9.30 a.m.

This Circular is dated 13 December 2021

DEFINITIONS

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

2012 Kinabalu Oil	:	2012 Kinabalu Oil block located in Sabah, offshore Malaysia
2012 Kinabalu Oil JOA	:	The joint operating agreement between RML and PCSB originally entered into on 23 May 2012 and as amended from time to time in relation to operations under the 2012 Kinabalu Oil PSC
2012 Kinabalu Oil PSC	:	The production sharing contract between PETRONAS, RML and PCSB dated 23 May 2012 in relation to operations in respect of the Kinabalu fields, offshore Sabah
2P NPV10	:	Net present value of the asset cash flows at 10% discount rate based on RPS Energy 2P case production and cost profile
Affiliates	:	In relation to either Repsol or Peninsula Hibiscus ("**Party**"), any subsidiary undertaking or parent undertaking of that Party and any subsidiary undertaking of any such parent undertaking, in each case from time to time
Anasuria Cluster	:	Our Group's 50% interest in the License No. P013 containing the Guillemot A, Teal and Teal South producing fields, 19.3% interest in the License No. P185 containing the Cook producing field and 50% interest in the Anasuria floating production storage and offloading vessel. Our Group jointly operates the producing fields under License No. P013 and the Anasuria floating production storage and offloading vessel via Anasuria Operating Company Limited
Assets	:	Collectively, the 2012 Kinabalu Oil, PM3 CAA, PM305 and PM314 and Block 46
Block 46	:	Block 46, located geologically in the Northeast Malay Basin, Vietnamese waters
Block 46 JOA or Vietnamese JOA	:	The joint operating agreement dated 26 August 2002 between TVL and PVEP in relation to operations under the Block 46 PSC, as amended
Block 46 PSC or Vietnamese PSC	:	The production sharing contract dated 8 August 1990 between PetroVietnam, TVL and PVEP in relation to operations in respect of Block 46, as amended
BNM	:	Bank Negara Malaysia
Board	:	Board of Directors
Bursa Securities	:	Bursa Malaysia Securities Berhad
CAA	:	Commercial Arrangement Area
CIMB	:	CIMB Investment Bank Berhad
Closing	:	Completion of the SPA

Closing Date	:	The date on which the closing meeting between the parties to the SPA takes place (after the fulfilment or waiver of the conditions precedent under the SPA) for the delivery and performance of various closing obligations as provided under the SPA, prior to Closing
Covid-19	:	Coronavirus disease 2019
CRPS	:	Islamic Convertible Redeemable Preference Shares
CRPS Placement	:	Placement of up to 2,000,000,000 new CRPS in our Company at an issue price of RM1.00 by way of a private placement. As at the LPD, our Company has issued 2 tranches of CRPS, namely CRPS-T1 and CRPS-T2
CRPS-T1	:	First tranche of CRPS, amounting to 6,600 CRPS
CRPS-T2	:	Second tranche of CRPS, amounting to 203,604,500 CRPS
Deposit	:	USD15.0 million
E&P	:	Exploration and production
Effective Date	:	00:00:01 hours, 1 January 2021
EGM	:	Extraordinary general meeting
EMDEs	:	Emerging market and developing economies
EPS	:	Earnings per share
ESG	:	Environmental, social and governance
FIPC	:	Fortuna International Petroleum Corporation
FIPC Group	:	FIPC and its wholly-owned subsidiaries, namely RML, RMPM3 and TVL
FIPC Shares	:	Entire issued share capital of FIPC, which is registered in the name of the Seller
FPE	:	Financial period ended/ending, as the case may be
FYE	:	Financial year ended/ending, as the case may be
GDP	:	Gross domestic product
Hibiscus Group or Group	:	Hibiscus Petroleum and its subsidiaries
Hibiscus Petroleum or Company	:	Hibiscus Petroleum Berhad
Hibiscus Petroleum Shares	:	Ordinary shares of Hibiscus Petroleum
IFRS	:	International Financial Reporting Standards

JOAs	:	Joint operating agreements in relation to the PSCs namely: (i) the Block 46 JOA; (ii) the 2012 Kinabalu Oil JOA; (iii) the PM3 CAA JOA; (iv) the PM305 JOA; and (v) the PM314 JOA
LAT	:	Loss after taxation
LATAMI	:	Loss after taxation and minority interest
LBT	:	Loss before taxation
Listing Requirements	:	Main Market Listing Requirements of Bursa Securities
LPD	:	The latest practicable date prior to the date of this Circular, being 24 November 2021
LPS	:	Loss per share
Malaysian JOAs	:	JOAs namely: (i) 2012 Kinabalu Oil JOA; (ii) PM3 CAA JOA; (iii) PM305 JOA; and (iv) PM314 JOA
Malaysian PSCs	:	PSCs namely: (i) 2012 Kinabalu Oil PSC; (ii) PM3 CAA PSC; (iii) PM305 PSC; and (iv) PM314 PSC
MFRS	:	Malaysian Financial Reporting Standards
NA	:	Net assets
North Sabah PSC	:	2011 North Sabah Enhanced Oil Recovery PSC
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 1 June 2021 furnished by our Company in favour of Repsol to guarantee the Purchaser's performance under the SPA
Parent undertaking	:	Shall have the meaning ascribed in the Companies Act 2006 of the United Kingdom
PBT	:	Profit before taxation
PCSB	:	PETRONAS Carigali Sdn Bhd, a wholly-owned subsidiary of PETRONAS

Peninsula Hibiscus or Purchaser	:	Peninsula Hibiscus Sdn Bhd, our indirect wholly-owned subsidiary
PETRONAS	:	Petroliam Nasional Berhad (PETRONAS)
PetroVietnam	:	Vietnam Oil and Gas Group
PITA	:	Petroleum (Income Tax) Act 1967
PM3 CAA	:	PM3 CAA block located geologically in Northeast Malay Basin, within the CAA between Malaysia and Vietnam for exploration and development of oil and gas fields therein
PM3 CAA JOA	:	The joint operating agreement between RML, RMPM3, PVEP and PCSB originally entered into on 16 February 1989 and as amended from time to time in relation to operations under the PM3 CAA PSC
PM3 CAA PSC	:	The production sharing contract between PETRONAS, RMPM3 and PCSB dated 16 February 1989 in relation to operations in respect of PM3 CAA
PM305	:	PM305 block located geologically in the Southwest Malay Basin, offshore Peninsular Malaysia
PM305 JOA	:	The joint operating agreement between RML and PCSB originally entered into on 27 November 2000 and as amended from time to time in relation to operations under the PM305 PSC
PM305 PSC	:	The production sharing contract between PETRONAS, RML and PCSB dated 27 November 2000 in relation to operations in respect of PM305
PM314	:	PM314 block located geologically in the Southwest Malay Basin, offshore Peninsular Malaysia
PM314 JOA	:	The joint operating agreement between RML and PCSB originally entered into on 31 March 2004 and as amended from time to time in relation to operations under the PM314 PSC
PM314 PSC	:	The production sharing contract between PETRONAS, RML and PCSB dated 31 March 2004 in relation to operations in respect of PM314
PPA	:	Purchase price allocation
PRMS	:	2018 Petroleum Resource Management System of *SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE*
Proposed Acquisition	:	Proposed Acquisition by Peninsula Hibiscus of the entire issued share capital of FIPC for a cash consideration of USD212.5 million (or equivalent to approximately RM879.5 million), subject to adjustments pursuant to the SPA
PSC(s)	:	Production sharing contract(s)
Purchase Price	:	Purchase price of USD212.5 million (or equivalent to approximately RM879.5 million), subject to the adjustments mechanism as set out in Section 2.2 of this Circular

PVEP	:	PetroVietnam Exploration Production Corporation, a wholly-owned subsidiary of PetroVietnam
RCPS	:	Redeemable convertible preference shares
Repsol or Seller	:	Repsol Exploración, S.A.
RML	:	Repsol Oil & Gas Malaysia Limited
RMPM3	:	Repsol Oil & Gas Malaysia (PM3) Limited
RPS Energy	:	RPS Energy Consultants Limited, the competent person and competent valuer appointed by our Company
RPS Energy Brent Price Forecast	:	RPS Energy Brent Price Forecast (Q2 2021) presented in Figure 10-1 of the Competent Valuer's Report
SEA Hibiscus	:	SEA Hibiscus Sdn Bhd, our indirect wholly-owned subsidiary
Seller Group	:	The Seller and each of its Affiliates from time to time but excluding the FIPC Group
SPA	:	The sale and purchase agreement dated 1 June 2021 entered into between Peninsula Hibiscus and Repsol in relation to the Proposed Acquisition
Subsidiary undertaking	:	Shall have the meaning ascribed in the Companies Act 2006 of the United Kingdom
Transition Services Agreement	:	The transition services agreement dated 11 November 2021 entered into between Peninsula Hibiscus and Repsol
TVL	:	Talisman Vietnam Limited
YA	:	Year of Assessment

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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(1)
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(1)
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(1)
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(1)
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(1)
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(1)
bbl	:	Barrels of oil
Block	:	Term commonly used to describe areas over which there is a petroleum or production licence
boe	:	Barrels of oil equivalent
Bscf	:	Billion standard cubic feet
Contingent Resources	:	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(1)
Exploration	:	The phase of operations which covers the search for O&G by carrying out detailed geological and geophysical surveys followed up where appropriate by exploratory drilling
Field	:	A geographical area under which either a single oil or gas reservoir or multiple oil or gas reservoir lie, all grouped on or related to the same individual geological structure feature and/or stratigraphic condition
Hydrocarbon	:	An organic compound consisting only of carbon and hydrogen. The majority of hydrocarbons found naturally in crude oil and natural gas where decomposed organic matter provides an abundance of carbon and hydrogen
kbbl(s)	:	Kilobarrel(s)
km	:	Kilometres
kscf	:	Thousand standard cubic feet

mbbl	:	Thousand barrels
MMbbl	:	Million barrels
MMboe	:	Million barrels of oil equivalent
MMscf	:	Million standard cubic feet
MMstb	:	Million stock tank barrels (at 14.7 psi and 60° F)
Operator	:	The operator(s) appointed in accordance with and under a JOA
Reserves	:	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[1]

CURRENCIES

RM	:	Ringgit Malaysia
USD	:	United States of America Dollar

Note:

(1) As defined in the Competent Valuer's Report.

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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:RM4.1390, being the middle rate for USD to RM quoted by BNM at 5.00 p.m. as at 27 May 2021, being the latest practicable date prior to the announcement of the Proposed Acquisition, 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.

CONTENTS

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	Peninsula Hibiscus, had on 1 June 2021, entered into a conditional SPA with Repsol for the Proposed Acquisition. A Parent Company Guarantee dated 1 June 2021 was also furnished by our Company to Repsol to guarantee Peninsula Hibiscus' performance under the SPA. In addition, a Transition Services Agreement dated 11 November 2021 was entered into between the Purchaser and the Seller for the provision of certain services by the Seller to the Purchaser and FIPC and its subsidiaries in order to facilitate a smooth handover between the parties. FIPC through its wholly-owned subsidiaries, namely, RML, RMPM3 and TVL, owns participating interests in the following PSCs: (i) 60% interest in the 2012 Kinabalu Oil PSC, currently held by RML; (ii) 35% interest in the PM3 CAA PSC, currently held by RMPM3 (12.7%) and RML (22.3%); (iii) 60% interest in each of the PM305 PSC and PM314 PSC, currently held by RML; and (iv) 70% interest in the Block 46 PSC, currently held by TVL.	Sections 1 and 2
Basis and justification of arriving of the Purchase Price	The Purchase Price was arrived at on a 'willing-buyer willing-seller' basis and after the Board has taken into account, amongst others, the following: (i) the Reserves of the Assets as assessed by RPS Energy; ***Note:*** *All definitions and estimates of Reserves are based on the PRMS;* (ii) the discounted cash flow valuation from the expected recovery of hydrocarbons (2P NPV10) from the Assets from the Effective Date, used for purposes of valuation until the end of respective PSCs, of USD285 million (or equivalent to RM1,179.6 million); (iii) the net working capital of the FIPC Group as at 31 December 2020; and (iv) the prospects of the O&G sector as well as the prospects and earnings potential of the Assets as set out in Section 4 of this Circular.	Section 2.3

Salient information	Description	Reference to Circular
Rationale and benefits of the Proposed Acquisition	(i) Represents a transformational acquisition for our Group; (ii) Immediate access to proven and probable O&G Reserves and future potential upside; (iii) Diversification into gas; (iv) Key opportunities for cost savings; (v) Stable partners with established track records; and (vi) Capitalise on Hibiscus Petroleum's successful track record of significantly improving the performance of assets acquired in Malaysia.	Section 3
Prospects of the Assets and the future prospects of the enlarged Hibiscus Group	Our Board believes that the future prospects of the enlarged Hibiscus Group will be positive in view of the following: (i) the significant increases in daily O&G production; (ii) the substantial increase in the enlarged Hibiscus Group's 2P Reserves with long-term production rights expiring between 2027 and 2033 coupled with identified future development opportunities; (iii) the improvement to the expected total net cash flow (based on the RPS Energy 2P estimated cash flows); (iv) with almost 50% of the production comprising gas from the Assets, the addition of gas production will present a better balance to the enlarged Hibiscus Group's asset portfolio; and (v) significant synergy potential to be realised resulting from the integration of the operations of the Assets with our Group's existing North Sabah asset.	Section 4.3

Salient information	Description	Reference to Circular
Risk factors in relation to the Proposed Acquisition	The Proposed Acquisition is subject to the following risks: • Risks relating to the Proposed Acquisition (i) Non-completion risk; (ii) The expected benefits of the Proposed Acquisition as well as our future prospects will depend on our ability to integrate and manage other challenges; (iii) Reliance on current estimated Reserves; (iv) Our Group expects to incur significant transaction costs in connection with the Proposed Acquisition; (v) Valuation based on projected cash flows depend on assumptions that may turn out to be incorrect; (vi) Foreign exchange risk; (vii) The pro forma financial information included in this Circular may not be representative of our position and results as a group in the future; and (viii) The due diligence undertaken in connection with the Proposed Acquisition may not have revealed all relevant considerations or liabilities of the FIPC Group, and the Proposed Acquisition also generally subjects us to the liabilities of the FIPC Group, and such liabilities could have a material adverse effect on our financial condition or results of operations. • Risks relating to the business of the FIPC Group (i) Potential fluctuation in revenue and profits due to the changes in O&G prices; (ii) Exposure to development and production risks; (iii) Political, economic, market and regulatory considerations; (iv) Exposure to weather and natural hazards; (v) Environmental risk; (vi) Insurance coverage risk; (vii) Dependence on skilled professionals and experienced staff; and (viii) Risk of changes in taxation laws and interpretations.	Section 5

Salient information	Description	Reference to Circular
Approvals required	The Proposed Acquisition is subject to the following being obtained: (i) the approval from each of PETRONAS and PetroVietnam for the sale of the FIPC Shares to Peninsula Hibiscus for the relevant PSCs. In this regard, Repsol has received the approval from PETRONAS dated 6 December 2021 for the change of control of Repsol's rights, interests and obligations under the 2012 Kinabalu Oil PSC, PM3 CAA PSC, PM305 PSC and PM314 PSC, with effect from 1 January 2021; (ii) the receipt by the Seller of written waivers by each of PCSB and PVEP of its pre-emption rights or expiry of the pre-emption period under the relevant pre-emption notices issued by the Seller to PCSB and PVEP, under each of the relevant JOAs, which was satisfied on 9 July 2021; (iii) the approval from the Barbados Exchange Control Authority for the sale of FIPC Shares to Peninsula Hibiscus, which was obtained by Repsol on 29 June 2021; (iv) the approval of the shareholders of Hibiscus Petroleum at an EGM to be convened; and (v) the approval from BNM, which was obtained on 21 June 2021 subject to conditions imposed.	Section 7
Interests of Directors, major shareholder and/or persons connected with them	None of our Directors, major shareholder of our Company and/or persons connected with them has any interest, whether direct or indirect, in the Proposed Acquisition.	Section 10
Directors' statement and recommendation	• Our Board, after having considered all aspects of the Proposed Acquisition, including but not limited to the terms of the SPA, basis and justification for the Purchase Price, rationale and benefits of the Proposed Acquisition, risk factors in relation to the Proposed Acquisition, effects of the Proposed Acquisition as well as the prospects of the FIPC Group and the risks involved, is of the opinion that the Proposed Acquisition is in the best interest of our Company. • 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 11

HIBISCUS PETROLEUM BERHAD

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

Registered Office:
12th Floor, Menara Symphony
No. 5, Jalan Prof. Khoo Kay Kim
Seksyen 13
46200 Petaling Jaya
Selangor Darul Ehsan

13 December 2021

Board of Directors:

Zainul Rahim bin Mohd Zain *(Non-Independent Non-Executive Chairman)*
Dr Kenneth Gerard Pereira *(Managing Director)*
Dato' Sri Roushan Arumugam *(Independent Non-Executive Director)*
Thomas Michael Taylor *(Senior Independent Non-Executive Director)*
Dato' Dr Zaha Rina Zahari *(Independent Non-Executive Director)*

To: Our shareholders

Dear Sir/Madam,

PROPOSED ACQUISITION

1. INTRODUCTION

On 2 June 2021 and 4 June 2021, CIMB had on behalf of our Company, announced that Peninsula Hibiscus, had on 1 June 2021, entered into a conditional SPA with Repsol for the Proposed Acquisition.

In conjunction with the Proposed Acquisition, a Parent Company Guarantee dated 1 June 2021 was furnished by our Company in favour of Repsol to guarantee Peninsula Hibiscus' performance under the SPA.

In addition, a Transition Services Agreement was executed between Peninsula Hibiscus and Repsol on 11 November 2021 for the provision of certain services by Repsol to Peninsula Hibiscus and FIPC and its subsidiaries in order to facilitate a smooth handover between the parties.

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

2.1 Proposed Acquisition

The Proposed Acquisition entails the acquisition by Peninsula Hibiscus of the entire issued share capital of FIPC, subject to the terms and conditions of the SPA.

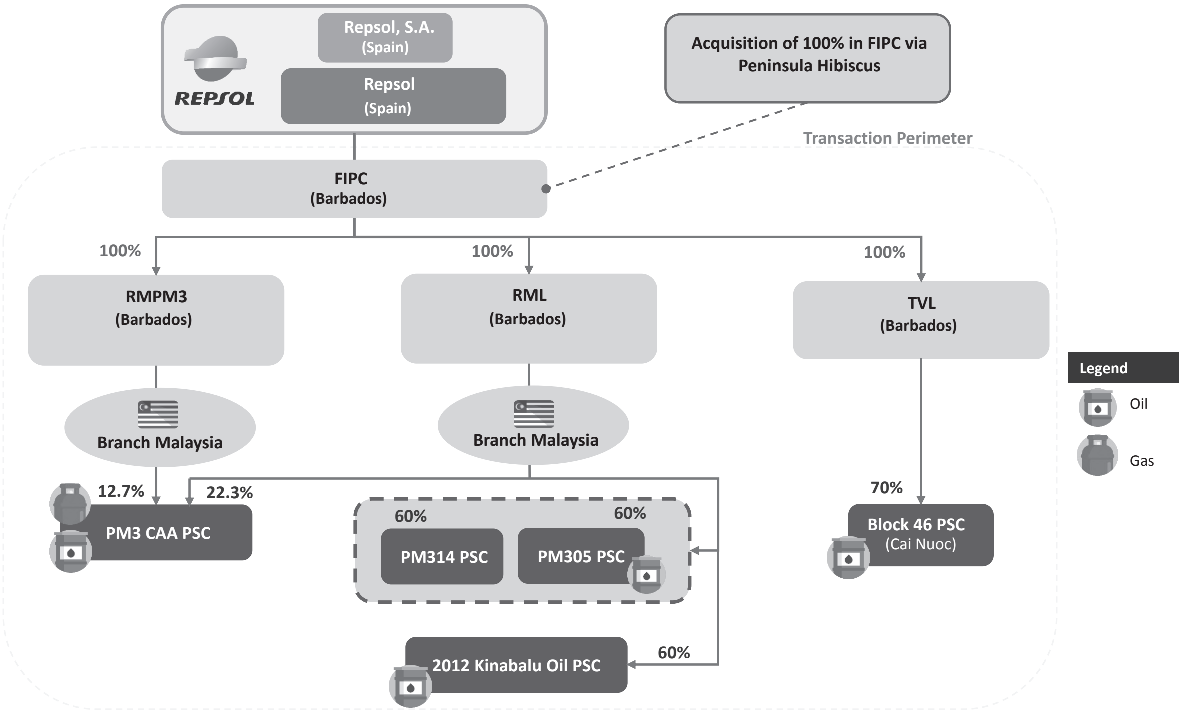
FIPC through its wholly-owned subsidiaries, namely, RML, RMPM3 and TVL, owns participating interests in the following PSCs:

(i) 60% interest in the 2012 Kinabalu Oil PSC, currently held by RML;

(ii) 35% interest in the PM3 CAA PSC, currently held by RMPM3 (12.7%) and RML (22.3%);

(iii) 60% interest in each of the PM305 PSC and PM314 PSC, currently held by RML; and

(iv) 70% interest in the Block 46 PSC, currently held by TVL.



The parties holding the remaining participating interests in the PSCs are as follows:

(i) PCSB, in the 2012 Kinabalu Oil PSC, PM305 PSC and PM314 PSC;

(ii) PCSB and PVEP, in the PM3 CAA PSC; and

(iii) PVEP, in the Block 46 PSC.

For further information on the FIPC Group and the Assets, please refer to Appendix III and Appendix IV of this Circular, respectively.

2.2 The Purchase Price and mode of satisfaction

The Purchase Price of USD212.5 million (or equivalent to approximately RM879.5 million) under the SPA, takes into account a base purchase price ("**Base Purchase Price**") and a working capital adjustment of the FIPC Group as at 31 December 2020 and is subject to adjustments to be calculated in accordance with the SPA.

The Proposed Acquisition is structured such that the net economic benefits arising from ownership of the FIPC Group will accrue to the Purchaser from the Effective Date. The Base Purchase Price was arrived at after considering, amongst others, the discounted cash flow valuation from the expected recovery of hydrocarbons (2P NPV10) from the Assets from the Effective Date. The working capital adjustment of the FIPC Group as at 31 December 2020 is also taken into account by the parties as the transaction is a corporate acquisition and, accordingly, opening cash balances as at the Effective Date also benefits the Purchaser through its ownership of the FIPC Group.

The agreed adjustments to the Purchase Price are as follows:

(i) **(plus) Time value amount**: generally, an amount equal to three percent (3%) per annum accruing daily and compounding monthly on the balance of the base purchase price less the Deposit, calculated for the period from, and including the Effective Date to, and including, the Closing Date;

The time value amount imputes the opportunity cost of the Seller not having received the full consideration on the Effective Date. Such opportunity cost is computed from the Effective Date to the Closing Date when the balance consideration is fully received. The rate of three percent (3%) was arrived at after considering market rates of debt instruments. The estimated time value amount to be paid has been factored into our overall projected internal rate of return of the Assets.

(ii) **(less) Pre-closing dividend**: the contemplated dividend/distribution payment from FIPC to Repsol based on cash balances available in the FIPC Group, subject to the agreement of the Purchaser, prior to Closing; and

(iii) **(less) Leakage adjustment amount** (estimated, if any): the amount of estimated Seller-related payouts (being any relevant payment/matter to, or on behalf of, or for the benefit of the Seller or any member of Seller Group for the period from and including the Effective Date to and including the day immediately prior to the Closing Date, subject to the agreement of the Purchaser. Seller-related payments generally relate to payments made to the Seller Group and/or their nominees/representatives which are not to the benefit of the operations of the Assets per se, and therefore should be excluded from the Purchase Price. Such payments do not affect the valuation of the Assets or economic benefits to the Purchaser as these are deducted from the Purchase Price.

Accordingly, our Company will make an announcement on the final Purchase Price including the relevant details of the adjustments to the Purchase Price on Closing.

The Deposit of USD15.0 million (or RM61.8 million, based on actual RM equivalent) has been paid by Peninsula Hibiscus to Repsol in the following manner:

(i) a partial deposit of USD7.5 million has been paid upon the execution of the SPA; and

(ii) the balance deposit of USD7.5 million has been paid following the receipt of the approval from BNM for the Proposed Acquisition on 21 June 2021.

The balance of the Purchase Price after the above adjustments shall be paid by Peninsula Hibiscus on Closing.

2.3 Basis and justification of the Purchase Price

The Purchase Price was arrived at on a 'willing-buyer willing-seller' basis and after the Board has taken into account, amongst others, the following:

(i) the Reserves of the Assets as assessed by RPS Energy;

Note: *All definitions and estimates of Reserves are based on the PRMS;*

(ii) the discounted cash flow valuation from the expected recovery of hydrocarbons (2P NPV10) from the Assets from the Effective Date, used for purposes of the valuation until the end of respective PSCs, of USD285 million (or equivalent to RM1,179.6 million);

(iii) the net working capital of the FIPC Group as at 31 December 2020; and

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

The FIPC Shares will be acquired free from third party interests (save for any right of assignment, any right to create a security or any similar right under the PSCs, JOAs and other material contracts, or arising under or by operation of applicable law), liens, charges and with all rights attaching to the FIPC Shares including the right to receive all distributions and dividends declared, paid or made in respect of the FIPC Shares upon Closing.

2.3.1 The breakdown of the USD285 million valuation as estimated by RPS Energy based on the 2P case is set out below:

	Post-tax 2P NPV10(1)
	USD million
2012 Kinabalu Oil PSC	150
PM3 CAA PSC	142
PM305 PSC and PM314 PSC	(10)
Block 46 PSC	3
Total	**285**

Note:

(1) Based on a discount rate of 10% as opined by RPS Energy to be a fair rate for the purpose of valuing the Assets after taking into consideration the range of Hibiscus Petroleum's weighted average cost of capital of between 9.4% and 10.5%.

RPS Energy uses the 2P case for the valuation of the Assets on the basis of industry practice as the 2P case represents the best estimate case for oil, condensate and gas production profile in the fair market valuation of producing O&G assets.

Based on the assessments conducted by RPS Energy, there are no identifiable Reserves in PM305 and PM314. However, there are still expenditures to be incurred for PM305 and PM314 mainly relating to net abandonment costs resulting in a negative net present value. The Proposed Acquisition involves the acquisition of the entire issued share capital of FIPC which comprise all the Assets.

Based on the projected free cash flows to be generated from the Assets using RPS Energy 2P case production profile and RPS Energy Brent Price Forecast as set out in Section 2.3.2 below, we expect to achieve a projected internal rate of return ("**IRR**") of about 46%. The projected IRR of about 46% represents an opportunity for our Group to further expand its assets portfolio through the Proposed Acquisition at an affordable Purchase Price.

2.3.2 The key valuation assumptions used by RPS Energy in arriving at the discounted cash flow valuation of the Assets of USD285 million based on its report dated 25 June 2021 are set out below:

No.	Key input	Assumptions
1.	O&G prices	RPS Energy Brent Price Forecast Base Case
2.	Realised oil price	Brent price with 5% premium
3.	PSC terms	Terms as per the respective PSCs
4.	PSC extension	No PSC extension assumed
5.	Effective date	1 January 2021
6.	PITA	38%

In applying the abovementioned assumptions, the projected free cash flows to be generated from the Assets (based on 2P Oil, Condensate and Gas Reserves of the Assets estimated by RPS Energy as set out in Section 2.3.3(i) below) from the Effective Date to 2032 are as follows:

	Projected free cash flows from the Assets
	USD million
2021	77
2022	45
2023	81
2024	54
2025	41
2026	32
2027	10
2028	9
2029	5
2030	5
2031	(1)
2032	(8)

(Source: Competent Valuer's Report)

2.3.3 A summary of the 1P, 2P and 3P Oil, Condensate and Gas Reserves and the 1C, 2C and 3C Contingent Resources of the Assets in MMstb, Bscf and MMboe as at 1 January 2021 estimated by RPS Energy are set out below:

(i) Summary of Oil, Condensate and Gas Reserves as at 1 January 2021

Below is a summary of the Net Entitlement 1P, 2P and 3P Reserves of the Assets to Peninsula Hibiscus. The 2P case Oil, Condensate and Gas Reserves of the Assets as estimated by RPS Energy in the tables below form the basis for the projected free cash flows to be generated from the Assets and the USD285 million valuation as set out in Sections 2.3.1 and 2.3.2 above.

Net Entitlement Reserves[(1)(2)]

	Oil Reserves			**Condensate Reserves**			**Gas Reserves**		
	1P MMstb	**2P MMstb**	**3P MMstb**	**1P MMstb**	**2P MMstb**	**3P MMstb**	**1P Bscf**	**2P Bscf**	**3P Bscf**
2012 Kinabalu Oil	6.4	10.8	14.1	-	-	-	-	-	-
PM3 CAA	4.0	6.6	7.9	1.5	2.7	3.4	49.0	83.6	112.5
PM305 and PM314	0.0	0.0	0.0	-	-	-	-	-	-
Block 46	0.0	0.4	0.6	-	-	-	-	-	-
Total	**10.4**	**17.9**	**22.6**	**1.5**	**2.7**	**3.4**	**49.0**	**83.6**	**112.5**

Notes:

(1) Company's net entitlement, which exclude the Malaysian Government's share under the PSC after economic limit test.

(2) Estimates based on the PRMS.

Below is a summary of the Net Entitlement 1P, 2P and 3P Reserves of the Assets to Peninsula Hibiscus in boe as at 1 January 2021.

	Oil, Condensate and Gas Net Entitlement Reserves[(1)(2)]		
	1P [(3)]MMboe	**2P [(3)]MMboe**	**3P [(3)]MMboe**
2012 Kinabalu Oil	6.4	10.8	14.1
PM3 CAA	13.7	23.3	30.1
PM305 and PM314	0.0	0.0	0.0
Block 46	0.0	0.4	0.6
Total	**20.1**	**34.5**	**44.8**

Notes:

(1) Company's net entitlement, which exclude the Malaysian Government's share under the PSC after economic limit test.

(2) Estimates based on the PRMS.

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

(Source: RPS Energy)

Based on the above, the 2P Oil, Condensate and Gas Net Entitlement Reserves of the Assets are expected to increase our Group's daily production and Reserves by 34.5 MMboe, representing about 70.8% increase from our Group's reserves as at 1 July 2021 of 48.7 MMboe, comprising:

(a) an increase in 2P Oil and Condensate Net Entitlement Reserves by 20.6 MMstb, representing about 43.7% increase from our Group's reserves as at 1 July 2021 of 47.1 MMstb; and

(b) an increase in 2P Gas Net Entitlement Reserves by 83.6 Bscf, representing about 853.1% increase from our Group's reserves as at 1 July 2021 of 9.8 Bscf.

(ii) Summary of Contingent Resources as at 1 January 2021

Below is a summary of the Net Entitlement 1C, 2C and 3C Contingent Resources of the Assets to Peninsula Hibiscus. For the avoidance of doubt, the Purchase Price and valuation of the Assets by RPS Energy did not include Contingent Resources. Accordingly, the Contingent Resources represent an upside to the valuation of the Assets.

		Net Entitlement Contingent Resources[(1)(2)]					
		Oil			**Gas**		
	Project	**1C MMstb**	**2C MMstb**	**3C MMstb**	**1C Bscf**	**2C Bscf**	**3C Bscf**
PM3 CAA	Raya post Seismic	1.4	2.3	2.6	1.8	3.1	3.8
PM3 CAA	NW BR Infill	0.3	0.5	0.6	0.1	0.2	0.3
PM3 CAA	Production Efficiency	0.1	0.1	0.1	0.9	1.5	1.8
2012 Kinabalu Oil	Production Efficiency	0.1	0.1	0.2	-	-	-
Total[(3)]		**1.9**	**3.1**	**3.4**	**2.8**	**4.8**	**5.9**

Notes:

(1) Company's net entitlement, which excludes the Malaysia Government's share under the PSC after economic limit test.

(2) All values are rounded to one decimal place.

(3) Estimates based on PRMS.

	Project	Oil, Condensate and Gas Net Entitlement Contingent Resources as at 1 January 2021[1][2] 1C [3]MMboe	2C [3]MMboe	3C [3]MMboe
PM3 CAA	Raya post Seismic	1.7	2.9	3.2
PM3 CAA	NW BR Infill	0.3	0.6	0.6
PM3 CAA	Production Efficiency	0.2	0.3	0.4
2012 Kinabalu Oil	Production Efficiency	0.1	0.1	0.2
Total[4]		**2.3**	**3.9**	**4.4**

Notes:

(1) Company's net entitlement, which excludes the Malaysia Government's share under the PSC after economic limit test.

(2) All values are rounded to one decimal place.

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

(4) Estimates based on PRMS.

(Source: RPS Energy)

For further details on the Reserves and resources classifications, methodology of estimates of Reserves and resources, and the assumptions, please refer to the Competent Valuer's Report in Appendix V of this Circular and Competent Person's Report in relation to the Reserves and resources evaluation of the Assets in Appendix VII of this Circular.

As at the LPD, no material changes have occurred since the Effective Date which has or will have any material effect on the content, validity or accuracy of the Competent Valuer's Report and the Competent Person's Report.

2.3.4 Additional information on the competent person and competent valuer from RPS Energy is set out below:

Mr. Jim Bradly, the Operations Director at RPS Energy, has supervised both the Competent Person's Report and Competent Valuer's Report for the purpose of the valuation of the Assets. He has over 20 years of experience in upstream O&G of which over 15 years were in auditing and evaluating O&G Reserves and resources. He is a Chartered Engineer and Chartered Petroleum Engineer. He holds a BEng in Electronic and Electrical Engineering and a MSc in Petroleum Engineering.

(Source: RPS Energy)

For further details on the valuation of the Assets and the expert's report on the fairness of the purchase price issued by RPS Energy, please see Appendix V and Appendix VI of this Circular, respectively.

2.4 Sources of funding for the Proposed Acquisition

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

(i) deduction from the Purchase Price of an amount equivalent to any pre-closing dividend or distribution payment from FIPC to Repsol. Please refer to Section 2.2 (ii) of this Circular for further details;

(ii) the remaining net proceeds raised from the CRPS Placement of about RM134.7 million as at 30 November 2021 (after taking account the payment of Deposit of USD15.0 million (or RM61.8 million, based on actual RM equivalent) in the custodian account); and

(iii) internally generated funds and available facilities of Hibiscus Group.

Our Group does not intend to propose a rights issue as a source of funding as our Group believes that other available sources of funding are sufficient to fund the Purchase Price.

The actual breakdown of the source of funding will only be finalised nearer to Closing and will depend on, amongst others, the FIPC Group's funds available as well as our Group's cash reserves.

2.5 Estimated capital and operating expenditure for the Assets

We anticipate that the capital and operating expenditures for the Assets will be approximately USD995 million (or equivalent to approximately RM4.1 billion). The capital and operating expenditures for the Assets are estimated to be funded via operating cash flow available from the Assets and/or internally generated funds of our Group.

The annual capital and operating expenditures (based on best estimate (2P)) of the Assets are set out in the table below:

	Capital Expenditure	**Operating Expenditure**
Year	**USD million**	
2021	20	99
2022	82	113
2023	13	108
2024	4	105
2025	4	103
2026	4	103
2027	4	101
2028	1	25
2029	1	25
2030	1	25
2031	1	25
2032	1	25
Total	**138**	**857**

(Source: Competent Valuer's Report)

For further details on the cash flow projections of the Assets, please refer to Appendix E of the Competent Valuer's Report in Appendix V of this Circular.

2.6 Liabilities to be assumed

Other than the Parent Company Guarantee and the 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, tax liabilities (which may include potential tax liabilities as disclosed in Section 10 of Appendix III of this Circular) as well as conditions (if any) imposed by the respective host authority pursuant to the PSCs to effect the change in control, there are no other known liabilities, including contingent liabilities and guarantees to be assumed by our Company pursuant to the Proposed Acquisition.

2.7 Additional financial commitment

Upon completion of the Proposed Acquisition, there is no additional financial commitment expected to be incurred by our Group as the FIPC Group is currently in operations and the Assets are producing. As such, any additional financial commitments, including capital expenditure required by the FIPC Group in the future for further O&G project development and production maintenance of its existing facilities, are expected to be funded using its internally generated funds from its operations and/or internally generated funds of our Group.

2.8 Background information of Repsol

Repsol was incorporated in Spain under the Spanish Corporations Act on 5 May 1965 as a private limited company. The principal activity of Repsol is the investigation, operation, industrialisation, transport and marketing of hydrocarbons and through its subsidiaries, explores for, produces and markets hydrocarbons.

The existing directors of Repsol as at the LPD are Manuel Tomás García Blanco and José Ángel Murillas Angoiti.

As at the LPD, Repsol S.A. holds more than 99.99% equity interest in Repsol while the remaining equity interest is held by Repsol Petróleo, S.A..

(Source: Repsol)

Based on publicly available information, the existing directors of Repsol S.A. are Antonio Brufau Niubó, Manuel Manrique Cecilia, Josu Jon Imaz San Miguel, Aurora Catá Sala, Aránzazu Estefanía Larrañaga, Carmina Ganyet i Cirera, Teresa García-Milà Lloveras, Emiliano López Achurra, Ignacio Martín San Vicente, Mariano Marzo Carpio, Henri Philippe Reichstul, Isabel Torremocha Ferrezuelo, J. Robinson West and Luis Suárez de Lezo Mantilla.

Further, Respol S.A.'s major shareholders as at 29 November 2021 are JP Morgan Chase & Co., BlackRock Inc., Amundi Asset Management, S.A., Sacyr, S.A and Banco Santander, and Norges Bank, which hold about 5.4%, 5.1%, 4.5%, 4.0%, 3.8%, and 3.0% of total voting rights, respectively.

For further details, please refer to Repsol's website at *www.repsol.com/en/index.cshtml*.

3. RATIONALE AND BENEFITS OF THE PROPOSED ACQUISITION

3.1 Represents a transformational acquisition for our Group

One of our Group's key strategies is to invest in producing assets on a selective basis in areas of its geographical focus.

The Proposed Acquisition is a unique opportunity for our Group to acquire a high-quality portfolio of five PSCs in Malaysia and Vietnam and to operate through RML and TVL in all of the PSCs under the JOAs:

PSC	Location	Operator	PSC expiry
PM314	Geologically in the Southwest Malay Basin, offshore Peninsular Malaysia	RML	30.03.2033
PM305	Geologically in the Southwest Malay Basin, offshore Peninsular Malaysia	RML	26.11.2029
2012 Kinabalu Oil	Sabah, offshore Malaysia	RML	25.12.2032
PM3 CAA	Geologically in the Northeast Malay Basin, within the CAA between Malaysia and Vietnam	RML	31.12.2027
Block 46	Geologically in the Northeast Malay Basin, Vietnamese waters	TVL	31.12.2027

Based on the Competent Person's Report, the average daily O&G production levels is projected to be 17,364 boe per day (net to Peninsula Hibiscus) in calendar year 2022. Accordingly with the Proposed Acquisition, our Group's daily production and Reserves are expected to increase as follows:

(i) daily Oil, Condensate and Gas production by almost 3 times from 9,107 boe per day (average for FY2021) to 26,471* boe per day which comprises:

(a) daily oil and condensate production by more than double from 8,780 bbl per day (average for FY2021) to 18,291* bbl per day; and

(b) daily gas production from 2 MMscf per day (average for FY 2021) to 49* MMscf per day;

Note:

* *Based on calendar year 2022 2P case estimates by RPS Energy for the Assets and the Group's FY2021 actual production rates.*

(ii) 2P Oil, Condensate and Gas Net Entitlement Reserves by more than 1.5 times from 48.7 MMboe to 83.2* MMboe which comprises:

(a) 2P Oil and Condensate Net Entitlement Reserves by 1.5 times from 47.1* MMstb to 67.7* MMstb; and

(b) 2P Gas Net Entitlement Reserves by almost 10 times from 9.8* Bscf to 93.4* Bscf.

Note:

* *Based on the Group's reserves as at 1 July 2021 and the Assets' reserves (net to Peninsula Hibiscus) as at 1 January 2021.*

Based on the RPS Energy 2P case cash flows (2P NPV10):

(i) the 2P oil, condensate and gas Reserves are valued at an estimated USD285 million (or equivalent to RM1,179.6 million);

(ii) the total net undiscounted cash flows expected to be generated over the next 5 years from 2021 to 2025 is approximately USD255 million (or equivalent to RM1,055.4 million) (adjusted for potential third-party liabilities);

The key bases and assumptions used are as follows:

(a) production and cost profiles based on RPS Energy 2P case;

(b) O&G prices based on RPS Energy Brent Price Forecast;

(c) PSC terms as per the respective PSCs with no extensions; and

(d) estimates of third party liabilities based on information provided by the Seller and reviewed by the management of our Group.

The projected cash flows will allow our Group to reinvest into existing assets and potentially acquire new assets to further expand our Group's assets portfolio. It will also provide additional funds to optimise our Group's ability to meet our commitments. If the balance surplus is sufficiently healthy, it will also enhance Hibiscus Petroleum's ability to continue to pay dividends to its shareholders.

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

3.2 Immediate access to proven and probable O&G Reserves and future potential upside

The producing fields are located in key hydrocarbon provinces in Malaysia and Vietnam. These fields have been delivering reliable production since coming onstream in 1997. With long-term production rights expiring between 2027 and 2033, and identified future development opportunities expected to add incremental 2P Reserves as estimated by RPS Energy of up to 34.5 million boe, this bodes well for the increased trajectory of our Group into its next milestone of growth.

Please refer to the table on Oil, Condensate and Gas Entitlement Reserves in Section 2.3.3 of this Circular for further details on the breakdown of 2P Reserves of 34.5 million boe derived by RPS Energy. For further details on the basis and assumptions used by RPS Energy in estimating the Reserves, please refer to the Competent Valuer's Report in Appendix V of this Circular and Competent Person's Report in relation to the Reserves and resources evaluation of the Assets in Appendix VII of this Circular.

Some of the enhanced production activities identified include but are not limited to:

(i) update remaining hydrocarbon inventories through subsurface studies;

(ii) rejuvenate idle wells;

(iii) identify in-fill opportunities; and

(iv) maximise recovery from the PM3 CAA and 2012 Kinabalu Oil fields.

3.3 Diversification into gas

Almost 50% of the FIPC Group's production comprises gas. The addition of gas production is expected to present a better balance to our Group's asset portfolio in terms of price stability, markets and operations. Gas prices are linked to the prices of high sulfur fuel oil. Gas is directly and continuously delivered to the offtakers via a pipeline with proceeds from the sale of gas received monthly. In contrast, oil offtakes only occur after a minimum volume threshold is attained which may not take place monthly. Further, gas production operations are separate from crude oil operations which balances risks of downtime or disruption.

In addition, such diversification represents a key aspect of our energy transition strategy as natural gas is viewed as more environmentally friendly because it produces fewer undesirable by-products per unit energy than petroleum and other fossil fuels.

3.4 Key opportunities for cost savings

Our Company has identified several key opportunities for an efficient, lean and safe mode of operations, which encompass processes and procurement, while taking advantage of lower corporate overheads. As Peninsula Hibiscus will be assuming the role of operator, it will be responsible for the day-to-day operations and management of the work activities of the PSCs and under the JOAs, thereby providing it with a significant level of financial control and decision-making in the operational management and timing of the conduct of work activities under the JOAs.

Furthermore, our Group has the opportunity to integrate operations of the new producing Malaysian assets with its existing operations in Sabah. In particular, for the 2012 Kinabalu Oil asset, there is significant synergy potential as Kinabalu crude flows to the Labuan Crude Oil Terminal is being operated by our Group.

3.5 Stable partners with established track records

The other stakeholders in the PSCs are currently PCSB and PVEP. PCSB is a wholly-owned subsidiary of PETRONAS which is the national oil company of Malaysia. PETRONAS is a fully integrated O&G multinational ranked among the largest corporations on FORTUNE Global 500®. PVEP is a wholly-owned subsidiary of PetroVietnam, the national oil company of Vietnam.

3.6 Capitalise on Hibiscus Petroleum's successful track record of significantly improving the performance of assets acquired in Malaysia

In March 2018, SEA Hibiscus, acquired a 50% participating interest in the North Sabah PSC from Sabah Shell Petroleum Company Limited and Shell Sabah Selatan Sdn Bhd. The remaining 50% interest is held by PCSB.

As operator, SEA Hibiscus successfully increased the daily production levels and reduced operating costs per bbl by approximately 30% from the previous operator.

SEA Hibiscus' key achievements as an operator include:

(i) first well drilled within 14 months of operatorship transfer;

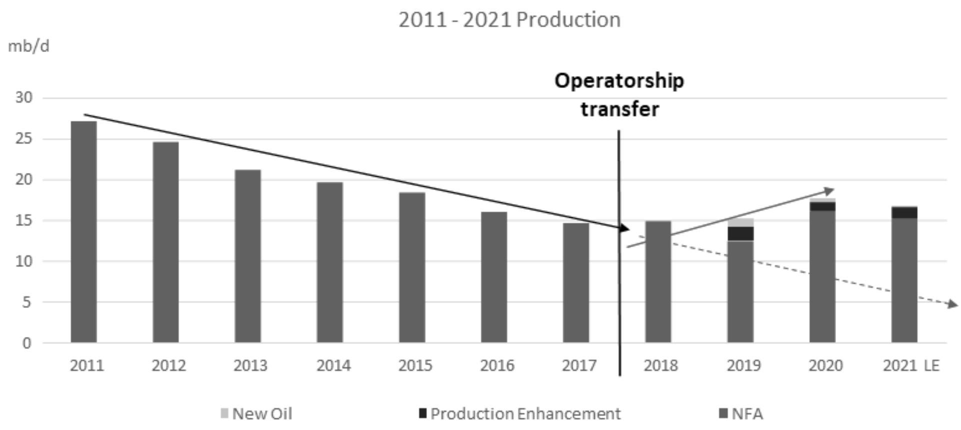
(ii) 10 oil producers and 1 water injector wells successfully drilled in 2019/2020;

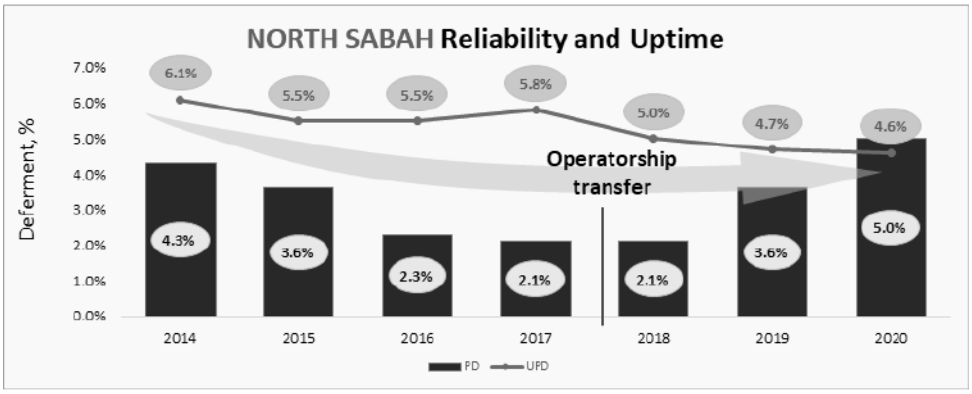
(iii) approximately 8,000 bbl/day of incremental capacity added through developments;

(iv) active production enhancement campaigns to mitigate base decline;

(v) strong reliability performance improvements; and

(vi) prioritisation in safety and integrity maintenance investments, in line with projected extensions in facilities life end.





Note: *PD denotes Planned Downtime while UPD denotes Unplanned Downtime*

Should Peninsula Hibiscus successfully complete the Proposed Acquisition, it anticipates that it will be able to improve the Assets' performance and reduce the operating costs per bbl.

4. INDUSTRY OVERVIEW AND PROSPECTS

The FIPC Group is principally involved in the production and development of O&G in Malaysia. Accordingly, the prospects of the Assets are largely linked to the prospects of the O&G industry in Malaysia.

4.1 Overview and outlook of the global economy

The global economy is projected to expand by 5.9% in 2021. Growth is anticipated to be underpinned by widespread vaccine rollouts, accommodative policy support, and rising commodity prices. Nevertheless, higher infection rates and new variants of the Covid-19 virus are expected to be the headwinds to economic improvement. The GDP in advanced economies ("**AEs**") is expected to grow by 5.2% in 2021, driven by the easing of pandemic restrictions, speedy vaccine rollouts and large-scale fiscal support. Growth in the EMDEs is projected to turn around by 6.4%, supported by elevated commodity prices and improved external demand.

The global economy is projected to expand by 4.9% in 2022, following the expected gradual improvement in both advanced economics as well as EMDEs. In 2022, GDP in the advanced economies is forecast to moderate to 4.5% but remain robust, led by the normalisation of economic activities. Growth in the EMDEs is projected to moderate to 5.1% in 2022, owing to the gradual unwinding of fiscal support and subdued investment.

(Source: Economic Outlook 2022, Ministry of Finance)

The global economy continued to recover but moderated in the third quarter of 2021. This follows a strong recovery in the previous quarter, due mainly to a low base from the second quarter of 2020, when Covid-19 related lockdowns were widespread. In most AEs, growth was broad-based across manufacturing and services as containment measures were eased further amid higher vaccination rates. In contrast, many emerging market economies ("**EMEs**") experienced a softer recovery in domestic demand due to localised lockdowns to curb resurgences amid lower vaccination rates. Nevertheless, trade activity remained strong, especially among commodity exporters.

In their October World Economic Outlook ("**WEO**") publication, the International Monetary Fund revised its projection of global growth marginally downwards from 6.0% to 5.9% for 2021, compared to their July WEO.

This reflected weaker prospects in AEs, due partly to resurgences in Covid-19 cases which dampened domestic demand as well as ongoing supply disruptions in the manufacturing sector. The growth outlook for several EMEs were revised upwards, reflecting improving demand conditions and commodity exporters benefitting from a rebound in demand and higher prices. The progress of vaccine rollout remains a key determinant of the growth recovery. The higher vaccination rates in AEs, compared to EMEs excluding China, accords AEs more flexibility to reopen the economy and resume economic activity earlier. Many AEs have also introduced booster vaccines especially for at-risk groups amid rising cases due to highly infectious strains. This, along with ongoing fiscal support, underpin expectations for a recovery in AEs for the rest of the year.

In EMEs, growth is expected to be supported by continued trade activity and recovery in domestic demand. However, growth could continue to be affected by localised containment measures and some production restrictions as healthcare capacity remained strained due to persistently high cases of severe infections amid slower rollout of vaccines relative to AEs. The growth prospects in China are projected to be further weighed by ongoing energy disruptions and lower-than-expected public investment.

The balance of risks remains tilted to the downside. Covid-19 is a key source of downside risks. Other risks include more severe and persistent global supply disruptions leading to higher price pressures and faster-than-expected policy normalisation. In contrast, upside risks to growth could come from faster vaccination progress in EMEs.

(Source: Quarterly Bulletin Third Quarter 2021, BNM)

4.2 Overview and outlook of the O&G industry

<u>Global</u>

According to the International Energy Agency ("**IEA**"), global oil demand is strengthening due to robust gasoline consumption and increasing international travel as more countries re-open their borders. In October 2021, total oil supplies leapt by 1.4 MMbbl per day to 97.7 MMbbl per day, with the US post-hurricane recovery accounting for half the increase. A further boost of 1.5 MMbbl per day is expected over November 2021 and December 2021 even as OPEC+ disregarded pleas from major consumers to ramp up beyond a monthly allocated 400 kbbl per day to cool prices. Over this period, the US is now poised to provide the largest increase in supply of any individual country. Even so, the US will not return to pre-Covid rates until the end of 2022.

That increase will go some way to meet rising demand, still recovering from the 2020 Covid slump, with the IEA forecasting oil demand growth at 5.5 MMbbl per day for 2021 and 3.4 MMbbl per day in 2022.

(Source: Oil Market Report November 2021, International Energy Agency)

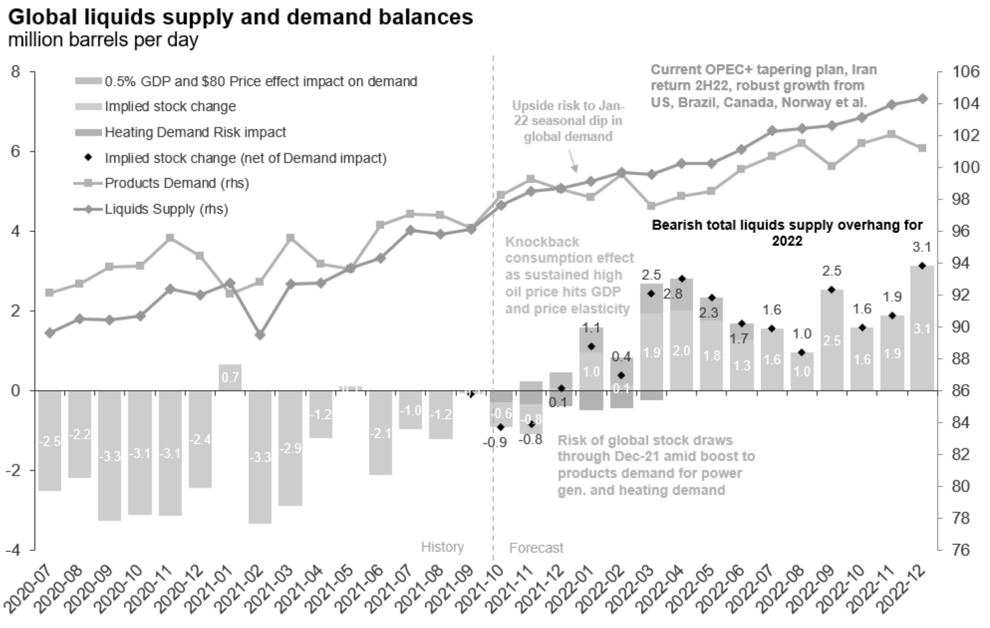


Figure 1: Global liquids supply and demand, as of 5 November 2021

Figure 1 by Rystad Energy above shows energy crunch-induced upside to demand from power generation from gas-to-oil switching and direct heating-demand for liquified petroleum gas and gasoil.

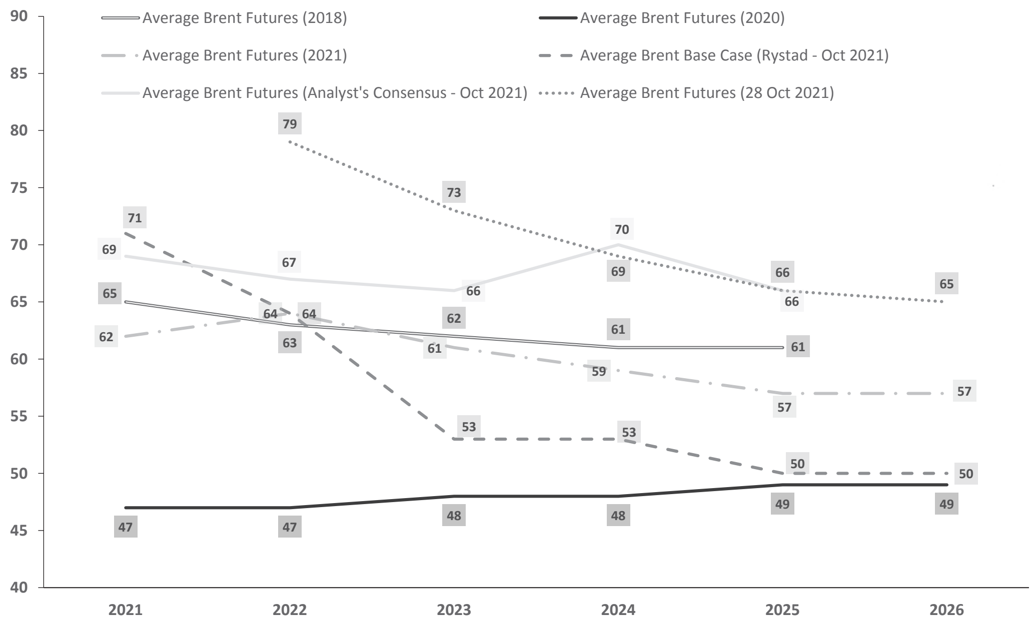


Figure 2: Analysis of Brent Oil Price Outlook, as of 10 November 2021

Based on our Group's analysis, Figure 2 shows a compilation of average Brent futures curves and oil price outlooks from various sources, demonstrating the volatility of oil prices and that oil prices were not predicted to develop in this positive manner before.

Beyond the high oil prices of today, more recent outlooks such as the latest available projections by analysts as well as the Brent futures as of 28 October 2021 indicate that oil prices will be structurally higher, and higher for longer.

The current strong outlook in oil prices is influenced by the tightening of supply from climate change pressures and underinvestment in the industry as well as an increase in demand as part of the post-pandemic economic recovery.

(Source: "Corporate and Business Update" 10 November 2021, Hibiscus Petroleum)

<u>Southeast Asia</u>

Based on research by Rystad Energy, an independent energy research and business intelligence company, around 300 million boe of resources have been discovered in 10 fields as of the end of the third quarter of 2021. Volumes discovered thus far in 2021 have exceeded the total volume discovered in 2020 by 6.5%. In 2021, about 84% of the total discovered resources in the region are gas whilst only 16% are liquids. About 78% of total volumes were discovered in Malaysia, in shallow water, followed by 11% in Myanmar in ultra-deep water, 10% in Indonesia, both onshore and in shallow water offshore, and 1% in Brunei's deep water. In summary, 82% of the volume was discovered offshore, in shallow waters.

Upstream developments with over 650 million boe of reserves and around USD3 billion of greenfield investments are also likely to be sanctioned in 2021, with almost 100% of the projects being gas or gas-condensate developments.

Thus far, committed investments in 2021 reflect a recovery of around 35% year-on-year but are still marginally behind the committed investments of 2019. Sanctioning of activities are likely to continue with over 1 billion boe of resources and over USD6 billion worth of committed investments likely in 2022. The regional independents and NOC-operated projects are likely to hold over 65% of the commitments on projects reaching Final Investment Decision ("**FID**") in 2021, with over 90% of these projects primarily from offshore areas in Indonesia and Malaysia.

(Source: "Southeast Asia E&P Report – 3Q" October 2021, Rystad Energy)

According to Rystad Energy, international oil and gas companies ("**IOC**") continue to exit projects in Southeast Asia, allowing national oil companies ("**NOC**") to capitalise on the opportunity and acquire additional interests in top producing blocks. As such, the share of resources held by oil and gas majors in the region has dropped from around 30% in 2015 to 19% in 2021 and is likely to fall further to around 16% in 2022.

Concerns have also been raised about PSCs due to expire. It is estimated that over 100 blocks are covered by PSCs that are due to expire by 2030. Whilst efforts are being made to progress discovered opportunities to FID and host country governments are also establishing more favorable exploration policies and fiscal revisions to promote international investments, over 6 billion bbl are at risk if PSCs are not extended in a timely manner.

PSC renewals often bring along the potential for revised fiscal terms, higher government participation, as well as higher production and investments targets. As such, if progressed, these PSC extensions might be an opportunity for majors, E&Ps industrial and regional players to negotiate more favorable terms, expand regional portfolios and look for partnership opportunities with regional NOCs.

(Source: "Expiring PSC wave, a concern for upstream activities in Southeast Asia" October 2021, Rystad Energy)

4.3 Prospects of the Assets and the future prospects of the enlarged Hibiscus Group

In summary, our Group is cognisant of various uncertainties caused by the ongoing Covid-19 pandemic. However, we will remain focused on delivering optimal operational performance in an improving oil price environment. Additionally, in pursuit of business growth, Hibiscus Group is continuously working on potential merger and acquisition opportunities, focusing on producing assets in the Southeast Asia region.

The Proposed Acquisition is expected to create new opportunities within the enlarged Hibiscus Group given the access to the Assets via the Proposed Acquisition.

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

(i) the significant increases in daily O&G production;

(ii) the substantial increase in the enlarged Hibiscus Group's 2P Reserves with long-term production rights expiring between 2027 and 2033 coupled with identified future development opportunities;

(iii) the improvement to the expected total net cash flow (based on the RPS Energy 2P estimated cash flows);

(iv) with almost 50% of the production comprising gas from the Assets, the addition of gas production will present a better balance to the enlarged Hibiscus Group's asset portfolio; and

(v) significant synergy potential to be realised resulting from the integration of the operations of the Assets with our Group's existing North Sabah asset.

5. RISK FACTORS IN RELATION TO THE PROPOSED ACQUISITION

The Proposed Acquisition will not materially change the risk profile of our Group as our Group operates in the same industry segment as the FIPC Group. As such, the enlarged Hibiscus Group will be exposed to similar risks inherent in the industry upon the completion of the Proposed Acquisition. These risks include:

(i) the nature and perception of the O&G industry exposes our Group to negative publicity associated with ESG-related concerns; and

(ii) unforeseen circumstances such as the prolonged Covid-19 pandemic which will suppress economic activity and thus lead to a decline in global consumption of crude oil and natural gas.

In addition to the industry risks above, there are certain risks specifically associated with the Proposed Acquisition and certain risks relating to the business of the FIPC Group, as follows:

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 conditions precedent to the SPA, the performance of the relevant parties of their respective obligations under the SPA and the approvals from the relevant authorities and/or parties being obtained.

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 precedent are not met or our Company is in breach of certain obligations under the SPA, Repsol is entitled to terminate the SPA and forfeit the Deposit.

Other than obtaining the approval of the shareholders of Hibiscus Petroleum, the condition precedent relating to PETRONAS/PetroVietnam approvals is still pending satisfaction. In this regard, Repsol has received the approval from PETRONAS dated 6 December 2021 for the change of control of Repsol's rights, interests and obligations under the 2012 Kinabalu Oil PSC, PM3 CAA PSC, PM305 PSC and PM314 PSC, with effect from 1 January 2021. Our Company continues to engage with the relevant parties to facilitate the decision-making process.

(ii) The expected benefits of the Proposed Acquisition as well as our future prospects will depend on our ability to integrate and manage other challenges

The success of the Proposed Acquisition and our future prospects will depend, in part, on our Group's ability to integrate the FIPC Group's business and operations with the Group's existing businesses. The integration process may be complex, costly and time consuming. The difficulties of integrating the business include, amongst others:

(a) failure to implement our Group's business plan for the combined business;

(b) unanticipated issues in integrating our logistics, information, accounting, communications and other systems;

(c) possible inconsistencies in standards, controls, procedures and policies between the FIPC Group's and our Group's business;

(d) unanticipated changes in applicable laws and regulations;

(e) failure to integrate, motivate and retain as well as ability to attract or recruit, on a timely basis, key employees;

(f) operating risks inherent in the FIPC Group's business and in the Group's business; and

(g) other unanticipated issues, expenses and liabilities.

Our Group may not be able to maintain the levels of revenue, earnings or operating efficiency that our Group and the FIPC Group, respectively, have achieved or might achieve separately. In addition, our Group may not accomplish the integration of our Group's business smoothly, successfully or within the anticipated costs or timeframe or achieve the projected revenue and costs synergies related to the Proposed Acquisition. If our Group experiences difficulties with the integration process, the anticipated benefits of the Proposed Acquisition may not be realised fully, or at all, or may take longer to realise than expected.

While our Group seeks to enhance its earnings from the Proposed Acquisition, there can be no assurance that the anticipated benefits of the Proposed Acquisition will be realised or that our Group (following completion of the Proposed Acquisition) will be able to generate sufficient revenues from the Proposed Acquisition to offset the associated acquisition costs incurred and potential expenditures.

Our Group has an inter-disciplinary team comprising experienced employees and advisers which has been working on a smooth transition and integration plan. Our Group also has experience in successfully integrating assets acquired namely the Anasuria Cluster in 2016 and North Sabah PSC in 2018 (as illustrated in Section 3.6 of this Circular). In addition, our Group manages risks via a structured process, whereby the corporate and the respective asset risk registers are updated monthly and quarterly Executive Risk Management Committee meetings are held. During these meetings, key risks and mitigations are identified, assessed, deliberated and agreed among the members of the said committee.

(iii) Reliance on current estimated Reserves

The Reserves of the FIPC Group, as is with other E&P upstream players, have a finite lifespan which is inherent to the E&P segment. Hence, upon completion of the Proposed Acquisition, the continued acquisition and/or the development of new Reserves to replace those produced and sold is crucial to ensure sustainability of the business of the FIPC Group. If attempts at locating and developing or acquiring new Reserves are unsuccessful, existing Reserves (and hence production) will decline over time. However, 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 Reserves 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) Our Group expects to incur significant transaction costs in connection with the Proposed Acquisition

Our Group expects to incur non-recurring costs associated with the Proposed Acquisition. These costs are likely to cover areas including financial advisory, legal, accounting, consulting and other advisory fees and expenses, reorganisation and restructuring costs, funding costs, severance/employee benefit-related expenses, regulatory expenses, printing expenses and other related charges.

(v) Valuation based on projected cash flows depend on assumptions that may turn out to be incorrect

The process of estimating hydrocarbon Reserves is complex, requiring interpretation of available technical data and assumptions made in a particular hydrocarbon price environment. Any significant deviations from these interpretations, prices or assumptions could materially affect the estimated quantities of hydrocarbons reported. Understanding 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.

Our Company has engaged the services of RPS Energy, a wholly-owned subsidiary of RPS Group Plc, a multi-national energy consultancy company listed on the London Stock Exchange to undertake an independent assessment of the Reserves and resource estimation of FIPC's assets.

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 as further described under Section 5.2(i) of this Circular.

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 Group's financial performance will be affected.

(vi) Foreign exchange risk

The financial results of the FIPC Group are denominated in USD. As the financial results of the FIPC Group 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) The pro forma financial information included in this Circular may not be representative of our position and results as a group in the future

The pro forma financial information included in this Circular is based upon the historical audited financial statements of FIPC and its subsidiaries for the FYE 31 December 2020 and the audited consolidated financial statements of our Company as at 30 June 2021, adjusted for effects of the Proposed Acquisition ("**Pro Forma Consolidated Financial Information**").

The Pro Forma Consolidated Financial Information included in this Circular has been prepared to illustrate the effects of, among other things, consummation of the Proposed Acquisition and is based in part on certain assumptions regarding FIPC, the Proposed Acquisition and intercompany eliminations. We cannot assure you that our assumptions will prove to be accurate over time. The Pro Forma Consolidated Financial Information included in this Circular is not necessarily indicative of the financial position that we would have achieved had we actually completed the Proposed Acquisition on the assumed date of completion.

(viii) The due diligence undertaken in connection with the Proposed Acquisition may not have revealed all relevant considerations or liabilities of the FIPC Group, and the Proposed Acquisition also generally subjects us to the liabilities of the FIPC Group, and such liabilities could have a material adverse effect on our financial condition or results of operations

There can be no assurance that the due diligence undertaken by us in connection with the Proposed Acquisition has revealed all relevant facts that may be necessary to evaluate the Proposed Acquisition. Furthermore, the information provided during due diligence may have been incomplete or inadequate. As part of the due diligence process, we have also made subjective judgments regarding the results of operations, financial condition and prospects of the FIPC Group. If the due diligence investigation has failed to correctly identify material issues and liabilities that may be present in the FIPC Group, or if we consider any identified material risks to be commercially acceptable relative to the opportunity, we may incur substantial impairment charges or other losses following the Proposed Acquisition.

As part of the Proposed Acquisition, we will acquire the FIPC Group and assume all of its assets and liabilities. Additional information about the FIPC Group that we are currently not aware of (including previously undisclosed liabilities of FIPC Group that were not identified during due diligence) and that could adversely affect us, such as unknown or contingent liabilities and issues relating to compliance with applicable laws, could increase our costs and expenses due to exposure to such unanticipated liabilities and therefore could materially and adversely affect our or our investments' business, prospects, financial condition and results of operations.

Furthermore, the FIPC Group is involved in various litigation (as set out under Section 10 of Appendix III of this Circular). Following completion of the Proposed Acquisition, we could be subject to liabilities or disputes with respect to such activities which could adversely affect our financial position and require management attention.

5.2 Risks relating to the business of the FIPC Group

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

The FIPC Group's financial results are affected by international O&G prices, which have historically fluctuated widely. The market prices of crude oil and natural gas are expected to continue to be volatile and are subject to a variety of factors beyond the FIPC Group's control. These factors include:

(a) global and regional supply and demand for O&G and related products;

(b) competition from other energy sources, including new and emerging sources;

(c) domestic and foreign government regulations with respect to O&G and the energy industry in general;

(d) weather conditions and seasonality;

(e) global conflicts or acts of terrorism;

(f) political instability;

(g) overall domestic and international economic conditions;

(h) inflation outlook; actions of commodity market participants; outbreaks of viruses or other communicable diseases; and

(i) other factors over which the FIPC Group has no control.

In early March 2020, oil prices experienced a precipitous decline in response to oil demand concerns due to the economic impact of the Covid-19 outbreak as well as anticipated increases in supply from Russia and the OPEC, particularly Saudi Arabia. This precipitous decline, following a more general decline beginning in January 2020, followed the Covid-19 outbreak and fear of its further spread, which caused significant disruptions in international economies and international financial and oil markets.

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

(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 Assets due to factors such as unexpected drilling conditions, adverse weather or equipment failures, which may result in an increase in the overall cost of operations. Moreover, there is no assurance that additional oil can be accessed via development drilling at the sites of the Assets.

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 FIPC Group.

Furthermore, 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 Repsol[(1)]. 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.

Note:

(1) It is a normal industry practice for transactions of this nature for the Purchaser to assume decommissioning, environmental, health and safety obligations once the transaction is completed. The Purchaser has undertaken a due diligence review and will also be relying on the Seller'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 operations of the FIPC Group are adequately insured (where possible and to the extent practicable).

(iii) Political, economic, market and regulatory considerations

The FIPC Group could be adversely affected by changes in political, economic, market and regulatory conditions in both Malaysia and Vietnam. 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 Malaysian and Vietnamese 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 FIPC Group.

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) Exposure to weather and natural hazards

Adverse changes in weather such as monsoon seasons may affect the FIPC Group's ability to carry out offshore operations in whole or in part. In addition, natural hazards such as earthquakes in the areas where the FIPC Group operates may cause damage to equipment, leading to operational downtime. This may have a material adverse impact on the FIPC Group's revenues and profits.

(v) Environmental risk

The O&G industry is 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 oil, gas or other pollutants into the air, soil or water may give rise to liabilities and may require the FIPC Group 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 FIPC Group.

However, it is noted that in 2021, Hibiscus Petroleum participated in the drafting of BNM's Value-based Intermediation Financing and Investment Impact Assessment Framework (VBIAF) Sectoral Guide on O&G. This participation has afforded Hibiscus Petroleum opportunities to focus on critical metrics faced by the O&G sector under the environment component which is on climate change. Subsequent to this knowledge, Hibiscus Petroleum has developed a climate change framework which addresses both transition and physical climate-related risks and the framework includes our action plan and baseline status which demonstrates our implemented measures as of FY2021.

(vi) Insurance coverage risk

O&G operations are subject to various risks inherent in development and production operations, many of which concern recklessness and negligence in operations and may cause personal injury, loss of life, severe damage to or destruction of property and environmental pollution. This may even result in suspension of operations and the imposition of civil or criminal penalties. Further, insurance policies may not cover, and insurance may not be commercially available, to cover all potential risks which the FIPC Group is or may be exposed.

Nevertheless, our Group will, from time to time, review its insurance policies and take the necessary action to ensure that the O&G operations of the FIPC Group are adequately insured (where possible and to the extent practicable).

(vii) Dependence on skilled professionals and experienced staff

The business activities conducted by the FIPC Group 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 FIPC Group.

Notwithstanding the above, our Group, together with FIPC, will continuously adopt appropriate measures to attract, employ and retain key personnel to manage the O&G operations of the FIPC Group. In order to retain existing key management personnel and attract new talent, our Group intends to implement human resource strategies which include competitive remuneration packages, career development and training.

(viii) Risk of changes in taxation laws and interpretations

The FIPC Group's O&G operations are subject to taxation which could increase substantially as a result of changes in, or new interpretations of, taxation laws, which could have a material adverse effect on our liquidity and results of operations.

In addition, the taxation authorities could review and question our tax returns leading to additional taxes and penalties.

To mitigate this risk, our Group will, from time to time, engage external tax advisers to advise on, amongst others, taxation laws and requirements as well as preparation and/or submission of tax returns to the relevant authorities.

6. EFFECTS OF THE PROPOSED ACQUISITION

6.1 Issued share capital

The Proposed Acquisition will not have any effect on the issued share capital of Hibiscus Petroleum.

6.2 NA and gearing

For illustration purposes only, the pro forma effects of the Proposed Acquisition on the consolidated NA and gearing of our Company subject to the completion adjustments in accordance with the SPA, finalisation of the PPA and expenses in relation to the Proposed Acquisition based on the audited consolidated statement of financial position of our Company as at 30 June 2021 and assuming that the Proposed Acquisition was completed on 30 June 2021 and based on the exchange rate of USD1.00:RM4.1546 as at 30 June 2021 are as follows:

	Audited as at 30 June 2021	After the Proposed Acquisition
	RM 000	**RM 000**
Share capital	959,892	959,892
Other reserves	62,165	62,165
Retained earnings	451,865	(1),(2)480,583
Shareholders' funds/NA	1,473,922	1,502,640
No. of Hibiscus Petroleum Shares in issue ('000)	2,000,137	2,000,137
NA per Hibiscus Petroleum Share (sen)	0.74	0.75
Total borrowings(1)	-	-
Gearing (times)	-	-

Notes:

(1) Excludes lease liabilities arising from, amongst others, the rental of offices, warehouses and vessels of the Hibiscus Group and FIPC Group amounting to RM26.8 million and RM205.0 million, respectively.

(2) After deducting estimated expenses of RM7.1 million to be incurred in relation to the Proposed Acquisition.

(3) A PPA exercise will be performed as at the acquisition date. For illustration purposes, the fair value of the O&G Reserves is based on our Company's preliminary valuation and the fair value of other identifiable assets and liabilities are assumed to approximate the carrying amount of the assets and liabilities of the FIPC Group shown in the audited financial statements for the FYE 31 December 2020 after adjustments to align to the accounting policies of our Group. The difference between the fair value of the purchase consideration and the higher fair value of the net identifiable assets and liabilities is recognised as negative goodwill.

6.3 Earnings and EPS

Upon completion of the Proposed Acquisition, Hibiscus Petroleum will consolidate the results of the FIPC Group. For illustration purposes, assuming the Proposed Acquisition was completed on 1 July 2020, the pro forma LAT attributable to owners of our Company for the FYE 30 June 2021 after taking into consideration the results of the FIPC Group in its audited financial statements for the FYE 31 December 2020 translated at the average exchange rate of USD1.00:RM4.1227 for the period 1 July 2020 to 30 June 2021, and elimination of intercompany adjustments, subject to the completion adjustments in accordance with the SPA, finalisation of the PPA and expenses in relation to the Proposed Acquisition, is set out below:

	Audited for the FYE 30 June 2021	**After the Proposed Acquisition**
	RM '000	**RM '000**
PAT/(LAT) attributable to owners of our Company	103,676	(614,721)
Weighted average no. of Hibiscus Petroleum Shares for basic EPS computation ('000)	1,754,277	1,754,277
Effects of dilution of CRPS ('000)	94,273	-
Weighted average no. of Hibiscus Petroleum Shares for diluted EPS computation ('000)	1,848,550	1,754,277
Basic EPS/(LPS) (sen)	5.91	(35.04)
Diluted EPS/(LPS) (sen)	5.61	(35.04)

The pro forma LAT and pro forma LPS were arrived at after recognising impairment of O&G assets of RM610.8 million in relation to RML and RMPM3 for the FYE 31 December 2020. These impairments were recognised due to the adverse situation in the commodity markets and social and economic consequences of the Covid-19 pandemic when the impairment assessments on the O&G assets were carried out. Excluding these impairment amounts, the pro forma LAT as reported above would be RM3.9 million instead. Pro forma basic LPS and pro forma diluted LPS would be 0.22 sen instead. CRPS is not included in the calculation of the pro forma diluted LPS because they are antidilutive.

The Proposed Acquisition is expected to have a positive impact on the consolidated earnings and EPS of Hibiscus Petroleum for the FYE 30 June 2022. Such impact will depend on, amongst others, market and industry conditions and the successful integration of the Assets and operations into our Group.

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, save as disclosed below, our Company does not have any other existing convertible securities:

(i) 2,193,880 outstanding RCPS in our Company. These RCPS are no longer convertible into new Hibiscus Petroleum Shares as the conversion events in relation to the pre-listing events of our Company have lapsed and are no longer applicable. However, these RCPS remain to be redeemable at the option of the holder on any date after 25 July 2011, being the date of listing of our Company; and

(ii) 2,404,769 outstanding CRPS-T2, which have a conversion price of RM0.48 each and are expiring on 18 November 2022.

In accordance with the terms of the CRPS as stipulated in the Constitution of our Company, the Proposed Acquisition will not result in any adjustment to the conversion price and number of the outstanding CRPS-T2.

7. APPROVALS REQUIRED

The Proposed Acquisition is subject to the conditions precedent as set out in Appendix I of this Circular, including the following approvals/clearance being obtained:

(i) the approval from each of PETRONAS and PetroVietnam for the sale of the FIPC Shares to Peninsula Hibiscus for the relevant PSCs. In this regard, Repsol has received the approval from PETRONAS dated 6 December 2021 for the change of control of Repsol's rights, interests and obligations under the 2012 Kinabalu Oil PSC, PM3 CAA PSC, PM305 PSC and PM314 PSC, with effect from 1 January 2021;

(ii) the receipt by the Seller of written waivers by each of PCSB and PVEP of its pre-emption rights or expiry of the pre-emption period under the relevant pre-emption notices issued by the Seller to PCSB and PVEP, under each of the relevant JOAs, which was satisfied on 9 July 2021;

(iii) the approval from the Barbados Exchange Control Authority for the sale of FIPC Shares to Peninsula Hibiscus, which was obtained by Repsol on 29 June 2021;

(iv) the approval of the shareholders of Hibiscus Petroleum at an EGM to be convened; and

(v) the approval from BNM, which was obtained on 21 June 2021, is subject to the following conditions that Peninsula Hibiscus, amongst others:

	Conditions imposed	**Status of Compliance**
(a)	obtains the prior approval of BNM for any changes in the information relating to the investment which has been provided to BNM, including any borrowing in foreign currency from a non-resident, if exceeding the approved limit under Notice 2: Borrowing, Lending and Guarantee;	Noted
(b)	informs BNM after the completion of the transfer of the assets to a resident entity; and	To be complied
(c)	informs BNM of the termination of the Proposed Acquisition, if applicable.	Noted

8. PERCENTAGE RATIO

On 4 June 2021, CIMB had on behalf of our Company, announced that pursuant to Paragraph 10.02(g) of the Listing Requirements of Bursa Securities, the highest percentage ratio applicable to the Proposed Acquisition is 154.1% based on the aggregate total assets of FIPC and its subsidiaries, namely RML, RMPM3 and TVL as at 31 December 2020, compared with the audited consolidated total assets of Hibiscus Petroleum as at 30 June 2020.

In this regard, the Proposed Acquisition is deemed as a very substantial transaction pursuant to paragraph 10.02(n) of the Listing Requirements.

9. CORPORATE EXERCISES ANNOUNCED BUT PENDING COMPLETION

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

(i) On 9 September 2020, Hong Leong Investment Bank Berhad ("**HLIB**") and CIMB had on behalf of our Board, announced that our Company proposes to undertake the CRPS Placement. The CRPS Placement was approved by Bursa Securities on 22 September 2020 and approved by our shareholders on 3 November 2020.

On 20 November 2020, HLIB and CIMB had on behalf of our Board, announced that the placement of the CRPS-T1 has been completed on 18 November 2020 with the allotment and issuance of 6,600 CRPS-T1 solely to Dr Kenneth Gerard Pereira, being the Managing Director of our Company. Our Company had on 23 November 2020 announced that the placement of the CRPS-T2 has been completed following the listing of and quotation for the 203,604,500 CRPS-T2 on the Main Market of Bursa Securities on the same day.

On 4 March 2021, HLIB and CIMB had on behalf of our Board announced that Bursa Securities has resolved to grant an extension of time of 6 months from 22 March 2021 until 21 September 2021 for our Company to complete the implementation of the CRPS Placement.

On 15 September 2021, HLIB and CIMB had on behalf of our Board announced that Bursa Securities has resolved to approve a further extension of time of 6 months from 22 September 2021 until 21 March 2022 for our Company to complete the implementation of the CRPS Placement.

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

10. INTERESTS OF DIRECTORS, MAJOR SHAREHOLDER, AND/OR PERSONS CONNECTED WITH THEM

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

11. DIRECTORS' STATEMENT AND RECOMMENDATION

Our Board, after having considered all aspects of the Proposed Acquisition, including but not limited to the terms of the SPA, basis and justification for the Purchase Price, rationale and benefits of the Proposed Acquisition, risk factors in relation to the Proposed Acquisition, effects of the Proposed Acquisition as well as the prospects of the FIPC Group and the risks involved, is of the opinion that the Proposed Acquisition is in the best interest of our Company.

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.

12. ESTIMATED TIMEFRAME FOR COMPLETION AND TENTATIVE TIMELINE FOR IMPLEMENTATION

Barring any unforeseen circumstances and subject to all relevant approvals being obtained from the relevant authorities and/or parties, the Proposed Acquisition is expected to be completed by the fourth quarter of calendar year 2021 or first quarter of calendar year 2022.

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

Event	Tentative timeline
EGM for the Proposed Acquisition	28 December 2021
Fulfilment of all conditions precedent to the SPA	[(1)]By December 2021 / January 2022
Completion of the Proposed Acquisition	By December 2021 / January 2022

Note:

(1) The timeline which is indicative as this juncture, may vary depending on amongst others, the date of fulfilment of all conditions precedent to the SPA.

13. 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 Tuesday, 28 December 2021 at 9.30 a.m. or at any adjournment of the EGM, 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 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 in person at the EGM should you subsequently decide to do so.

14. 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

SALIENT TERMS OF THE SPA

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

1. Sale and purchase of the Shares

1.1 The FIPC Shares shall be sold and purchased free from third party interest (save for permitted encumbrances under the PSCs, JOAs and other material contracts, or arising under or by operation of applicable law) with effect from Closing and with all rights attaching to them including the right to receive all distributions and dividends declared, paid or made in respect of the FIPC Shares after Closing.

2. Conditions precedent to Closing

2.1 The conditions precedent to the Closing of the SPA are as follows:

(i) the Seller's receipt of written approval from each of PETRONAS and PetroVietnam of the sale of the FIPC Shares to the Purchaser;

(ii) the:

(a) receipt by the Seller of written waivers from each of PCSB and PVEP (collectively, "**Co-Venturers**") of its pre-emption rights under each of the relevant JOAs; or

(b) expiry of the pre-emption period under the relevant pre-emption notices issued by the Seller to each of the Co-Venturers under each of the relevant JOAs;

(iii) the receipt by the Seller of written approval from the Barbados Exchange Control Authority of the sale of the FIPC Shares to the Purchaser;

(iv) no Material Adverse Event[(1)] is continuing and subsisting; and

(v) receipt by the Purchaser of:

(a) consent of BNM; and

(b) all necessary shareholders' approval or consents, and Bursa Securities' clearance of the circular to shareholders, on the part of the Purchaser and our Company (for the purposes of the Listing Requirements and all other purposes);

in relation to the Proposed Acquisition.

Note:

(1) ***Material Adverse Event*** *means any event or circumstance occurring before Closing and not fairly disclosed to the Purchaser before the date of the SPA, which:*

(a) has resulted in physical loss of, or damage or destruction to, assets or facilities owned or leased by the FIPC Group for the conduct of the relevant operations; and

(b) has had, or is reasonably likely to have, a material adverse effect on the financial condition, assets, liabilities, operations, profitability or prospects of any of the FIPC Group, the Seller's indirect participating interests in the rights and obligations in and under the PSCs and JOAs or the relevant operations resulting in a reduction in the value of FIPC by an amount equal to or exceeding thirty per cent. (30%) of the Purchase Price.

SALIENT TERMS OF THE SPA (CONT'D)

2.2 The parties shall, within 12 months (or such other period as may be agreed) from the signing of the SPA ("**Longstop Date**"), procure the satisfaction of the conditions precedent.

2.3 Clause 4.2 of the SPA provides, inter alia, for each party to use reasonable endeavours to procure fulfilment of the conditions precedent, provide all reasonably requested assistance and information in connection with the satisfaction of the conditions precedent and to notify the other party of progress with any counter-party in connection with the satisfaction of the conditions precedent.

2.4 Clause 4.3 of the SPA provides, inter alia, for the provision of relevant commitments if so required for purposes of satisfying the stated conditions precedent.

2.5 Clause 4.8 of the SPA provides, inter alia, that each party shall use their reasonable endeavours to notify the other party upon becoming aware that any of the conditions precedent has been fulfilled.

2.6 Clause 4.10 of the SPA provides, inter alia, that each party warrants and undertakes to the other party that all relevant actions taken will be in compliance with applicable anti-bribery, anti-corruption, anti-money laundering and fraud laws.

2.7 Clause 8.3 of the SPA provides, inter alia, that if either party fails to comply with their closing obligations, the other party shall be entitled to various rights and remedies.

3. Purchase Price

3.1 The consideration for the sale and purchase of the FIPC Shares is USD212.5 million, subject to certain agreed adjustments at Closing.

3.2 The Deposit, comprising the partial deposit of USD7.5 million, is payable by the Purchaser upon execution of the SPA and the balance deposit of USD7.5 million is payable by the Purchaser upon receipt of the requisite approval from BNM. The Deposit will be subject to forfeiture by the Seller if the SPA is terminated prior to Closing due to the Purchaser's breach of its specified obligations(1) under the SPA or if the conditions precedent relating to BNM's and Hibiscus Petroleum's shareholders' approvals are not duly satisfied (or waived by the written agreement of the parties) on or before the Longstop Date. The Deposit shall be refunded if the SPA terminates prior to Closing for any other reason.

Note:

(1) The specified obligations are set out in Clause 3.2 of the SPA, and relate to obligations and the warranty/undertaking on the part of the Purchaser under (or contained in) Clauses 4.2, 4.3, 4.8, 4.10 and/or 8.3 of the SPA (as elaborated in Sections 2.3 to 2.7 above).

4. Closing adjustments

4.1 The SPA provides for the balance of the Purchase Price to be paid at Closing after having been adjusted for:

(i) an amount equal to 3% per annum on the base purchase price, net of the Deposit, calculated from the Effective Date to Closing Date;

(ii) an agreed dividend payout by FIPC; and

(iii) adjustment for payouts, if any, to the Seller or any member of the Seller Group(1), other than certain permitted payouts, from the Effective Date to Closing Date.

SALIENT TERMS OF THE SPA (CONT'D)

Note:

(1) Refers to the Seller and any subsidiary undertaking or parent undertaking from time to time, excluding the FIPC Group.

5. Parent Company Guarantee

5.1 Hibiscus Petroleum (or any other replacement party reasonably acceptable to the Seller for this purpose) shall enter into the Parent Company Guarantee to guarantee the performance of the Purchaser's obligations under the SPA.

6. Termination

6.1 Save for the following, neither the Seller nor the Purchaser shall be entitled to rescind or terminate the SPA in any circumstances whatsoever (whether before, at or after Closing):

(i) if, on or after the date of the SPA, but before Closing, the Purchaser or the Seller agree (or where the parties are unable to agree, as determined by an independent expert) that a Material Adverse Event has occurred;

(ii) the conditions precedent to the Closing of the SPA are not fulfilled (or waived) by the Longstop Date or where the Purchaser and the Seller reasonably agree that any of the conditions precedent can no longer be fulfilled (and should not be waived);

(iii) if the Seller or the Purchaser (or any of their respective Affiliates) fails to ensure that all actions taken by the respective party in connection with the fulfilment of the conditions precedent or the Closing of the SPA are in compliance with the applicable anti-bribery, anti-corruption, anti-money laundering and fraud laws;

(iv) if a party fails to comply with any of its closing obligations and after being notified, fails to remedy such default within the agreed grace period, the non-defaulting shall have the right to terminate the SPA; or

(v) in the event the Seller becomes aware of any matter which constitutes a material breach of any of the fundamental warranties provided by the Seller, which would result in a material reduction in the value of FIPC and where such breach is capable of remedy, the Seller fails to remedy such breach within the agreed timeframe.

6.2 If the SPA is terminated pursuant to the events set out in Section 6.1(i) - (v) above, no party (nor any of its Affiliates) shall have any claim under the SPA or the Transaction Documents (as defined in the SPA) of any nature whatsoever against any other party (or any of its Affiliates) except in respect of any rights and liabilities which have accrued before terminated or under any of the Surviving Provisions (as defined in the SPA).

7. Governing law and dispute resolution

7.1 The SPA shall be governed by and interpreted in accordance with English law.

7.2 Any dispute, controversy or claim arising out of or in connection with the SPA shall be resolved by arbitration under the arbitration rules of the Singapore International Arbitration Centre, and the dispute resolution clause shall be governed by and construed in accordance with Singapore law.

SALIENT TERMS OF THE PARENT COMPANY GURANTEE AND TRANSITION SERVICES AGREEMENT

1. Salient terms of the Parent Company Guarantee

The Parent Company Guarantee has been executed by Hibiscus Petroleum in favour of the Seller.

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

(i) under the Parent Company Guarantee, Hibiscus Petroleum guarantees, for the benefit of the Seller (as beneficiary), the Purchaser's punctual performance and observance of all the Purchaser's obligations, warranties, duties and undertakings under the SPA;

(ii) Hibiscus Petroleum undertakes that whenever the Purchaser does not perform any obligation, 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;

(iii) in the event of any breach by the Purchaser of any term, condition and/or obligation under the SPA, Hibiscus Petroleum shall (as a separate and independent obligation and liability from its obligations and liabilities under Clauses 2.1 and 2.2 of the Parent Company Guarantee) indemnify the Seller 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, save for any indirect and/or consequential losses which the Seller may incur as a result of or arising in connection with any breach by the Purchaser of any term, condition and/or obligation under the SPA and shall on receipt of first written notice, pay such sums to the Seller, without any deduction or set-off;

(iv) in addition to any liabilities arising under Clause 2 of the Parent Company Guarantee, Hibiscus Petroleum agrees that it shall be liable on demand, and shall pay the Seller, 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 Seller 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;

(v) Hibiscus Petroleum shall promptly indemnify and hold the Seller 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 Seller by the Parent Company Guarantee.

(vi) the Parent Company Guarantee is a continuing guarantee and is not subject to any express expiry or termination provision;

SALIENT TERMS OF THE PARENT COMPANY GURANTEE AND TRANSITION SERVICES AGREEMENT (CONT'D)

(vii) the maximum liability of Hibiscus Petroleum under the Parent Company Guarantee is the sum total of all its obligations and liabilities, in accordance with the terms of the Parent Company Guarantee;

(viii) the Parent Company Guarantee will be governed by and construed in accordance with English law; and

(ix) any disputes, controversy or claim arising out of or in connection with the Parent Company Guarantee shall be resolved by arbitration under the arbitration rules of the Singapore International Arbitration Centre, and the dispute resolution clause shall be governed by and construed in accordance with Singapore law.

2. Salient terms of the Transition Services Agreement

The salient terms of the Transition Services Agreement, amongst others, are as follows:

(i) Repsol agrees to provide certain agreed information technology services to Peninsula Hibiscus and FIPC and its subsidiaries from the date of the Transition Services Agreement, in consideration of the agreed fee to be paid by Peninsula Hibiscus per service;

(ii) invoicing and payment of the fees shall be on a monthly basis;

(iii) the services shall be provided by Repsol in a manner that is consistent with past practice in the ordinary course of business, and in accordance with standard market practice and applicable legislation, regulations, decrees and/or official government decisions;

(iv) the term of the Transition Services Agreement shall end nine (9) months after the Closing Date (subject to any extension by mutual agreement or any early termination);

(v) Peninsula Hibiscus may terminate the Transition Services Agreement by giving at least 15 business days' advance written notice to Repsol;

(vi) a party to the Transition Services Agreement may terminate the Transition Services Agreement with immediate effect by written notice to the other party if such party commits material breach(es) of the terms of the Transition Services Agreement;

(vii) the Transition Services Agreement shall be governed by and interpreted in accordance with English law; and

(viii) any dispute, controversy or claim arising out of or in connection with the Transition Services Agreement shall be resolved by arbitration under the arbitration rules of the Singapore International Arbitration Centre, and the dispute resolution clause shall be governed by and construed in accordance with Singapore law.

INFORMATION ON THE FIPC GROUP

1. HISTORY AND BUSINESS

FIPC was incorporated under the laws of Barbados on 21 November 2001 under the Barbados Companies Act Cap. 308. The principal activity of FIPC is investment holding and it commenced operations since 31 December 2001. Through its subsidiaries, it holds participating interests and operates producing O&G fields in Malaysia and Vietnam.

Details of the organisational and assets structure of the FIPC Group are as set out in Section 2.1 of this Circular.

As at the LPD, Repsol holds 100% of the equity interest in FIPC.

The principal markets of the FIPC Group are in Malaysia. Based on the audited financial statements for the FYE 31 December 2020, approximately 89% and 11% of the total revenue of the FIPC Group were generated from Malaysia and international markets, respectively.

The annual gross and net O&G production volume for the past 3 years and for the six months FPE 30 June 2021 of each PSC are as follows:

	Annual gross production volume attributable to parties to the PSC (boe)							
	FYE 31 December 2018		FYE 31 December 2019		FYE 31 December 2020		FPE 30 June 2021	
	Crude Oil	Gas	Crude Oil	Gas	Crude Oil	Gas	Crude Oil	Gas
PM3 CAA	7,597,845	15,734,493	7,717,188	15,867,492	6,378,948	12,659,348	2,885,550	5,889,405
Block 46	194,764	-	260,225	-	202,722	-	104,620	-
PM305	613,176	-	454,854	-	159,346	-	62,526	-
PM314	68,326	-	48,564	-	-	-	-	-
2012 Kinabalu Oil	6,224,398	-	5,407,408	-	5,985,622	-	2,211,102	-
Total	**14,698,509**	**15,734,493**	**13,888,239**	**15,867,492**	**12,726,638**	**12,659,348**	**5,263,798**	**5,889,405**

	Annual net production volume attributable to the FIPC Group (boe)							
	FYE 31 December 2018		FYE 31 December 2019		FYE 31 December 2020		FPE 30 June 2021	
	Crude Oil	Gas	Crude Oil	Gas	Crude Oil	Gas	Crude Oil	Gas
PM3 CAA	1,263,517	4,397,302	1,703,882	3,183,133	1,360,801	3,190,994	485,931	1,524,313
Block 46	64,992	-	110,117	-	86,504	-	56,941	-
PM305	272,252	-	194,743	-	149,634	-	27,570	-
PM314	28,289	-	25,787	-	5,420	-	-	-
2012 Kinabalu Oil	2,142,893	-	1,653,669	-	2,452,702	-	790,345	-
Total	**3,771,943**	**4,397,302**	**3,688,198**	**3,183,133**	**4,055,061**	**3,190,994**	**1,360,787**	**1,524,313**

Based on the audited financial statements for the FYE 31 December 2020, the FIPC Group has not incurred any research and development expenses.

INFORMATION ON THE FIPC GROUP (CONT'D)

The total capital expenditure incurred from the Effective Date up to 30 September 2021 by the FIPC Group is as follows:

	FIPC		RML		RMPM3		TVL	
Details	**USD'000**	**[(1)]RM'000**	**USD'000**	**[(1)]RM'000**	**USD'000**	**[(1)]RM'000**	**USD'000**	**[(1)]RM'000**
Exploration expenditure	-	-	55	230	34	134	-	-
Development expenditure	-	-	1,017	4,258	211	883	(23)	(96)

Note:

(1) Based on the exchange rate of USD1:RM4.187, being the middle rate quoted by BNM at 5.00 p.m. as at 30 September 2021.

2. SHARE CAPITAL

As at the LPD, the issued share capital of FIPC is USD182,094,000 comprising 313,736,062 class A common shares.

3. DIRECTORS

As at the LPD, the directors of FIPC are as follows:

Name	Nationality	Designation
Sir Trevor Carmichael	Barbados	Director
W. Peter Douglas	Barbados	Director
J. Andrew Marryshow	Barbados	Director

As at the LPD, the directors of FIPC do not have any direct/indirect shareholdings in FIPC.

4. SHAREHOLDER

As at the LPD, Repsol holds 100% of the equity interest in FIPC.

5. SUBSIDIARIES AND ASSOCIATED COMPANIES

As at the LPD, the details of the subsidiaries of FIPC are as follows:

Name of company	Date and place of incorporation	Issued share capital	Effective equity interest	Principal activities
Repsol Oil & Gas Malaysia (PM3) Ltd.	10 December 2001 / Barbados	USD11,668,000	100%	Exploration, development, production and marketing of crude oil, natural gas and natural gas liquids.

INFORMATION ON THE FIPC GROUP (CONT'D)

Name of company	Date and place of incorporation	Issued share capital	Effective equity interest	Principal activities
Repsol Oil & Gas Malaysia Ltd.	6 April 1992 / Barbados	USD12,000	100%	Exploration, development, production and marketing of crude oil, natural gas and natural gas liquids.
Talisman Vietnam Ltd	20 February 1992 / Barbados	USD12,000	100%	Exploration, development, production and marketing of crude oil, natural gas and natural gas liquids.

As at the LPD, FIPC does not have any associated companies.

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INFORMATION ON THE FIPC GROUP (CONT'D)

6. SUMMARY OF FINANCIAL INFORMATION

6.1 FIPC is exempted from the preparation of consolidated financial statements in accordance with MFRS 10/IFRS 10 'Consolidated Financial Statements' as FIPC is a wholly-owned subsidiary of Respol. Hence, FIPC did not prepare any consolidated information for the past three FYE 31 December 2020 and the six months FPE 30 June 2021. Accordingly, a summary of the historical financial information of FIPC, RML, RMPM3 and TVL for the past three FYE 31 December 2020 and the unaudited and reviewed financial information of FIPC, RML, RMPM3 and TVL as at and for the six months FPE 30 June 2021 which have been derived from the unaudited interim financial statements of FIPC, RML, RMPM3 and TVL as at and for the six months FPE 30 June 2021, prepared in accordance with MFRS and IFRS are set out below:

FIPC

	Audited FYE 31 December						**Unaudited FPE 30 June**	
	2018		**2019**		**2020**		**2021**	
	USD'000	**[1]RM'000**	**USD'000**	**[1]RM'000**	**USD'000**	**[1]RM'000**	**USD'000**	**[1]RM'000**
Revenue	7,425	**30,710**	7,928	**32,449**	12,931	**51,944**	-	-
PBT	7,320	**30,276**	7,881	**32,257**	12,877	**51,727**	(33)	**(137)**
PATAMI	10,671	**44,135**	7,763	**31,774**	11,531	**46,320**	(33)	**(137)**
No. of shares in issue ('000)	779,322	**779,322**	779,322	**779,322**	313,736	**313,736**	313,736	**313,736**
Net earnings/(loss) per share (USD/RM)	0.01	**0.06**	0.01	**0.04**	0.04	**0.15**	(0.00)	**(0.00)**
Issued share capital	452,322	**1,870,804**	452,322	**1,851,354**	182,094	**731,472**	182,094	**756,473**
NA	529,933	**2,191,803**	537,696	**2,200,790**	182,227	**732,006**	182,194	**756,889**
NA per share (USD/RM)	0.68	**2.81**	0.69	**2.82**	0.58	**2.33**	0.58	**2.41**
Cash and cash equivalents	72	**298**	18	**74**	12	**48**	10	**42**
Current ratio (times)	13,902.20	**13,902.20**	17,771.55	**17,771.55**	47.12	**47.12**	59.95	**59.95**
Total borrowings including all interest-bearing debt	-	**-**	-	**-**	-	**-**	-	-
Gearing (times)	-	**-**	-	**-**	-	**-**	-	-

INFORMATION ON THE FIPC GROUP (CONT'D)

RML

	Audited FYE 31 December						Unaudited FPE 30 June	
	2018		2019		2020		2021	
	USD'000	[(1)]RM'000	USD'000	[(1)]RM'000	USD'000	[(1)]RM'000	USD'000	[(1)]RM'000
Revenue	316,151	**1,307,601**	252,712	**1,034,350**	192,029	**771,380**	87,267	**362,533**
PBT/(LBT)	70,887	**293,189**	68,250	**279,347**	(86,609)	**(347,908)**	31,828	**132,223**
PATAMI/(LATAMI)	83,470	**345,232**	23,475	**96,083**	(121,386)	**(487,608)**	17,708	**73,564**
No. of shares in issue ('000)	12	**12**	12	**12**	12	**12**	12	**12**
Net earnings/(loss) per share (USD/RM)	6,955.83	**28,769.33**	1,956.25	**8,006.92**	(10,115.50)	**(40,634.00)**	1,475.67	**6,130.36**
Issued share capital	12	**50**	12	**49**	12	**48**	12	**50**
NA	304,299	**1,258,581**	327,340	**1,339,803**	205,954	**827,317**	223,662	**929,159**
NA per share (USD/RM)	25,358.25	**104,881.75**	27,278.33	**111,650.25**	17,162.83	**68,943.08**	18,638.50	**77,429.92**
Cash and cash equivalents	81,283	**336,186**	68,885	**281,946**	48,090	**193,178**	44,632	**185,415**
Current ratio (times)	0.95	**0.95**	1.11	**1.11**	0.97	**0.97**	1.3	**1.3**
Total borrowings including all interest-bearing debt	10,968	**45,364**	-	**-**	-	**-**	-	-
Gearing (times)	0.04	**0.04**	-	**-**	**-**	**-**	-	-

INFORMATION ON THE FIPC GROUP (CONT'D)

RMPM3

	Audited FYE 31 December						Unaudited FPE 30 June	
	2018		2019		2020		2021	
	USD'000	[(1)]RM'000	USD'000	[(1)]RM'000	USD'000	[(1)]RM'000	USD'000	[(1)]RM'000
Revenue	68,450	**283,109**	65,592	**268,468**	43,938	**176,499**	26,167	**108,706**
PBT/(LBT)	21,837	**90,318**	19,455	**79,629**	(59,091)	**(237,369)**	9,820	**40,795**
PATAMI/(LATAMI)	10,877	**44,987**	4,372	**17,895**	(53,161)	**(213,548)**	5,989	**24,880**
No. of shares in issue ('000)	1	**1**	1	**1**	1	**1**	1	1
Net earnings/(loss) per share (USD/RM)	10,877.00	**44,987.27**	4,372.00	**17,894.60**	(53,161.00)	**(213,547.74)**	5,989.00	**24,880.10**
Issued share capital	11,668	**48,259**	11,668	**47,757**	11,668	**46,870**	11,668	**48,472**
NA/(net loss)	32,171	**133,059**	36,347	**148,768**	(16,814)	**(67,542)**	(10,825)	**(44,970)**
NA/(net loss) per share (USD/RM)	32,171.00	**133,059.26**	36,347.00	**148,768.27**	(16,814.00)	**(67,541.84)**	(10,825.00)	**(44,970.30)**
Cash and cash equivalents	4,660	**19,274**	5,790	**23,698**	939	**3,772**	3,094	**12,853**
Current ratio (times)	0.41	**0.41**	0.44	**0.44**	0.24	**0.24**	0.35	**0.35**
Total borrowings including all interest-bearing debt	41,385	**171,168**	16,637	**68,095**	18,216	**73,174**	15,556	**64,624**
Gearing (times)	1.29	**1.29**	0.46	**0.46**	*N/A	***N/A**	*N/A	***N/A**

Note:

* *Gearing is not applicable due to negative NA in the FYE 31 December 2020 and FPE 30 June 2021.*

INFORMATION ON THE FIPC GROUP (CONT'D)

TVL

	Audited FYE 31 December						Unaudited FPE 30 June	
	2018		2019		2020		2021	
	USD'000	[(1)]RM'000	USD'000	[(1)]RM'000	USD'000	[(1)]RM'000	USD'000	[(1)]RM'000
Revenue	15,224	**62,966**	5,334	**21,832**	-	**-**	11,555	**48,003**
PBT	11,003	**45,508**	1,595	**6,528**	985	**3,957**	6,945	**28,852**
PATAMI/(LATAMI)	6,395	**26,450**	1,204	**4,928**	(444)	**(1,784)**	4,899	**20,352**
No. of shares in issue ('000)	12	**12**	12	**12**	12	**12**	12	**12**
Net earnings/(loss) per share (USD/RM)	532.92	**2,204.17**	100.33	**410.67**	(37.00)	**(148.63)**	408.25	**1,695.99**
Issued share capital	12	**50**	12	**49**	12	**48**	12	**50**
NA	18,279	**75,602**	19,483	**79,744**	9,039	**36,310**	13,938	**57,903**
NA per share (USD/RM)	1,523.25	**6,300.17**	1,623.58	**6,645.33**	753.25	**3,025.81**	1,161.50	**4,825.22**
Cash and cash equivalents	1,372	**5,675**	1,000	**4,093**	949	**3,812**	9,733	**40,434**
Current ratio (times)	6.74	**6.74**	5.98	**5.98**	4.88	**4.88**	5.57	**5.57**
Total borrowings including all interest-bearing debt	-	**-**	-	**-**	-	**-**	-	**-**
Gearing (times)	-	**-**	-	**-**	-	**-**	-	**-**

Note:

(1) The USD currency rates in the tables above were converted to RM based on the following middle rates quoted by BNM at 5.00 p.m.:

(i) For the FYE 31 December 2018, on 31 December 2018, USD1.00:RM4.136.

(ii) For the FYE 31 December 2019, on 31 December 2019, USD1.00:RM4.093.

(iii) For the FYE 31 December 2020, on 31 December 2020, USD1.00:RM4.017.

(iv) For the FPE 30 June 2021, USD1.00:RM4.154.

There are no unusual accounting policies adopted by the FIPC Group and no audit qualifications reported in the audited financial statements of the FIPC Group for the FYE 31 December 2018 to the FYE 31 December 2020.

INFORMATION ON THE FIPC GROUP (CONT'D)

Commentaries on financial performance:

For the past three FYE 31 December 2020 and the six months FPE 30 June 2021, FIPC Group's revenue was derived from the sale of crude oil and natural gas, representing 70%-77% and 23%-30% of their total revenue, respectively. The major customers for FIPC and its subsidiaries for crude oil and natural gas include PETCO Trading Labuan Company Ltd and PetroVietnam.

The cost of sales of FIPC Group mainly comprise the cost of operations, marketing and transportation costs and the depletion, depreciation and amortisation charges. The said cost of operations relates to operating expenses incurred under the Assets, and is computed based on contracted rate/ price and charged to profit or loss when an uplift occurs. The gross profit margin of FIPC and its subsidiaries is generally aligned with the fluctuation in crude oil and natural gas prices.

For purposes of commentary analysis, a summary of the crude oil and natural gas production as well as the average selling prices for the years/period indicated are as follows:

	2018			2019			2020			Six months FPE 30 June 2021		
	Oil	Gas	Total	Oil	Gas	Total	Oil	Gas	Total	Oil	Gas	Total
	MMbbl	Bscf	MMboe	MMbbl	Bscf	MMboe	MMbbl	Bscf	MMboe	MMbbl	Bscf	MMboe
Net Production	3.8	24.7	8.2	3.7	17.9	6.9	4.1	17.9	7.2	1.4	8.6	2.9
Net Sales volume	3.8	24.7	8.2	3.4	17.9	6.6	4.2	17.9	7.4	1.3	8.6	2.8
	USD/bbl	USD/kscf	USD/boe	USD/bbl	USD/kscf	USD/boe	USD/bbl	USD/kscf	USD/boe	USD/bbl	USD/kscf	USD/boe
Average sales price	74.01	4.81	48.79	70.27	4.72	49.13	43.60	3.02	32.04	68.65	4.22	43.97

(i) FPE 30 June 2021

FIPC

Minimal interest income in FPE 30 June 2021 due to lower intercompany loan due from a related company subsequent to a dividend payment made in December 2020.

RML

RML recorded a revenue of USD87.3 million for the FPE 30 June 2021. This is primarily attributable to oil sales of USD64.3 million at price of USD68.7/bbl and gas sales of USD23.0 million at USD4.2/kscf.

RML recorded a PBT of USD31.8 million for the FPE 30 June 2021, primarily due to (i) revenue from oil and gas sales of USD87.3 million as mentioned above, (ii) other operating expense of USD42.4 million in relation to PSC operating activities, and (iii) depletion, depreciation and amortisation of USD20.7 million of O&G properties.

RML recorded a PAT of USD 17.7 million for the FPE 30 June 2021. In addition to the abovementioned points, a current income tax expense of USD6.4 million and a deferred income tax expenses of USD 7.7 million were recognised for the same period.

RMPM3

RMPM3 recorded a revenue of USD26.2 million for the FPE 30 June 2021. This is primarily attributable to oil sales of USD13.1 million at price of USD68.7/bbl and gas sales of USD13.1 million at USD4.2/kscf.

RMPM3 recorded a PBT of USD9.8 million for the FPE 30 June 2021, primarily due to (i) revenue from oil and gas sales of USD26.2 million as mentioned above, (ii) other operating expense of USD10.2 million in relation to PSC operating activities, and (iii) depletion, depreciation and amortisation of USD5.3 million of O&G properties.

RMPM3 recorded a PAT of USD6.0 million for the FPE 30 June 2021. In addition to the abovementioned points, a current income tax expense of USD4.5 million was recognised for the same period.

TVL

TVL recorded a revenue of USD11.6 million for the FPE 30 June 2021 attributable to oil sales of 125 kbbl at price of USD68.7/bbl.

TVL recorded a PBT of USD6.9 million for the FPE 30 June 2021, primarily due to (i) revenue from oil sales of USD 11.6 million as mentioned above, (ii) changes in crude oil inventory of USD3.0 million, (iii) other operating expense of USD0.9 million mainly relates to facilities processing fees, and (iv) depletion, depreciation and amortisation of USD0.7 million of O&G properties.

TVL recorded a PAT of USD4.9 million for the FPE 30 June 2021. In addition to the abovementioned points, a current income tax expense of USD2.9 million and a deferred tax recovery of USD0.9 million were recognised for the same period.

(ii) FYE 31 December 2020 vs. FYE 31 December 2019

FIPC

FIPC recorded a revenue of USD12.9 million for the FYE 31 December 2020, which represents an increase of 63.3% or USD5.0 million as compared to USD7.9 million for the FYE 31 December 2019. This is primarily attributable to the USD10.0 million dividend income received from TVL, offset by a lower interest income of USD2.9 million received in the FYE 31 December 2020 vis-à-vis the USD7.9 million received in the FYE 31 December 2019.

FIPC recorded a PBT of USD12.9 million for the FYE 31 December 2020, which represents an increase of 63.3% or USD5.0 million as compared to USD7.9 million for the FYE 31 December 2019. The improvement in PBT was driven by higher revenue recorded for the financial year.

FIPC recorded a PATAMI of USD11.5 million for the FYE 31 December 2020, which represents an increase of 47.4% or USD3.7 million as compared to USD7.8 million for the FYE 31 December 2019. This increase is attributable to the abovementioned points and is partly offset by a USD1.2 million derecognition of deferred tax assets due to changes in the forecasted taxable income.

FIPC's share capital as at the FYE 31 December 2020 is lower than FYE 31 December 2019 due to a USD270.2 million return of common shares to Repsol.

RML

RML recorded a revenue of USD192.0 million for the FYE 31 December 2020, which represents a decrease of 24.0% or USD60.7 million as compared to USD252.7 million for the FYE 31 December 2019. This is primarily attributable to lower market prices for its oil by 38.0% (USD43.6/bbl vs USD70.3/bbl) and gas by 36.0% (USD3.0/kscf vs USD4.7/kscf) as a result of the Covid-19 pandemic. The decrease in selling prices was offset by higher sales volumes of 791 mbbl and 30 MMscf of O&G, respectively, for the FYE 31 December 2020 vis-à-vis the FYE 31 December 2019.

RML recorded a LBT of USD86.6 million for the FYE 31 December 2020, which represents a decrease of USD154.9 million as compared to the PBT of USD68.3 million for the FYE 31 December 2019. A LBT was recorded for the FYE 31 December 2020 primarily due to (i) a one-off impairment loss of USD90.8 million being charged to the O&G properties, (ii) a one-off impairment loss of USD10.4 million being charged to right-of-use assets, (iii) USD15.1 million additional provisions for potential tax liabilities related to YA2014 to YA2016, (iv) a USD14.4 million increase in depreciation, depletion and amortisation charges vis-à-vis FYE 31 December 2019 resulting from higher production during the financial year, (v) a USD12.3 million decrease in other operating income primarily arising from lower partners' recovery for personnel expense, (vi) a USD20.0 million increase in change in underlift expense vis-à-vis the FYE 31 December 2019, (vii) the absence of a USD2.7 million foreign exchange gain previously recorded in the FYE 31 December 2019, and (viii) lower revenue recorded for the financial year. However, this LBT was offset by (i) a USD39.0 million reduction in operating expenses (excluding tax liabilities) arising from cost optimisation and continuous improvements on offshore logistic arrangements, (ii) a USD11.9 million decrease in personnel cost resulting from a reduction in employee headcount from 392 in the FYE 31 December 2019 to 359 in the FYE 31 December 2020, (iii) a USD5.7 million decrease in supplies expenses, and (iv) a USD14.1 million decrease in finance expenses mainly attributable to lower accretion expense arising from the sinking fund.

RML recorded a LATAMI of USD121.4 million for the FYE 31 December 2020, representing a decrease of USD144.9 million as compared to a PATAMI of USD23.5 million in the FYE 31 December 2019. In addition to the abovementioned points, this decrease was also attributable to a USD22.7 million tax provision being made for potential tax liabilities related to YA2015 to YA2016.

<u>RMPM3</u>

RMPM3 recorded a revenue of USD43.9 million for the FYE 31 December 2020, which represents a decrease of 33.1% or USD21.7 million as compared to USD65.6 million for the FYE 31 December 2019. This is primarily attributable to lower market prices for its oil by 38.0% (USD43.6/bbl vs USD70.3/bbl) and gas by 36.0% (USD3.0/kscf vs USD4.7/kscf) as a result of the Covid-19 pandemic. The decrease in selling prices was offset by higher sales volumes of 57 mbbl and 13 MMscf of O&G, respectively, for the FYE 31 December 2020 vis-à-vis the FYE 31 December 2019.

RMPM3 recorded a LBT of USD59.1 million for the FYE 31 December 2020, which represents a decrease of USD78.6 million as compared to the PBT of USD19.5 million for the FYE 31 December 2019. A LBT was recorded for the FYE 31 December 2020 primarily due to (i) a one-off impairment loss of USD41.4 million being charged to the O&G properties, (ii) a one-off impairment loss of USD6.0 million being charged to right-of-use assets, (iii) a USD4.5 million increase in depreciation, depletion and amortisation charge vis-à-vis the FYE 31 December 2019 resulting from higher production during the financial year, (iv) USD9.7 million additional provisions for potential tax liabilities related to YA2014 to YA2016 and (v) lower revenue recorded for the financial year. However, this LBT was partially offset by (i) a USD7.1 million decrease in accretion expenses arising from the sinking fund (ii) a USD1.8 million decrease in supplies expenses.

RMPM3 recorded a LATAMI of USD53.2 million for the FYE 31 December 2020, representing a decrease of USD57.6 million as compared to a PATAMI of USD4.4 million in the FYE 31 December 2019. In addition to the abovementioned points, this decrease was also attributable to an additional USD15.8 million tax provision being made for potential tax liabilities related to YA2015 to YA2016, which was offset by a USD1.9 million overprovision of prior year's tax.

<u>TVL</u>

TVL recorded no revenue for the FYE 31 December 2020 as the accumulated production in Block 46 since the last lifting in November 2019 was below the typical cargo size of 300 kbbl. In contrast, TVL recorded a revenue of USD5.3 million and sold 81 kbbl of oil for the FYE 31 December 2019.

TVL recorded a PBT of USD1.0 million for the FYE 31 December 2020, a decrease of 38.2% or USD0.6 million as compared to USD1.6 million for the FYE 31 December 2019. This is primarily attributable to the absence of revenue recorded for the financial year, partially offset by (i) an increase in the underlift of crude oil by USD2.7 million resulting from the production of 86 kbbl at USD51.4/bbl in 2020 and (ii) the absence of a USD1.9 million a receivable write-off previously recorded in the FYE 31 December 2019.

TVL recorded a LATAMI of USD0.4 million for the FYE 31 December 2020, a decrease of USD1.6 million as compared to a PATAMI of USD1.2 million for the FYE 31 December 2019. In addition to the abovementioned points, this decrease is also attributable to a USD1.3 million increase in tax rates differential for the PSC.

(iii) FYE 31 December 2019 vs. FYE 31 December 2018

FIPC

FIPC recorded a revenue of USD7.9 million for the FYE 31 December 2019, an increase of 6.8% or USD0.5 million, as compared to USD7.4 million in the FYE 31 December 2018. This increase is entirely attributable to an increase in interest income received from intercompany loans due to USD0.5 million.

FIPC recorded a PBT of USD7.9 million for the FYE 31 December 2019, an increase of 8.2% or USD0.6 million, as compared to USD7.3 million in FYE 31 December 2018. This increase is primarily due higher revenue recorded for the financial year.

FIPC recorded a PATAMI of USD7.8 million for the FYE 31 December 2019, a decrease of 27.1% or USD2.9 million as compared to USD10.7 million for the FYE 31 December 2018. This decrease is attributable to the abovementioned points as well as a USD2.2 million derecognition of deferred tax liabilities previously recorded in the FYE 31 December 2018.

RML

RML recorded a revenue of USD252.7 million for the FYE 31 December 2019, which represents a decrease of 20.1% or USD63.5 million as compared to USD316.2 million for the FYE 31 December 2018. This is primarily attributable to lower market prices for its oil by 5.1% (USD70.3/bbl vs USD74.0/bbl) and gas by 1.9% (USD4.7/kscf vs USD4.8/kscf). In addition to decreases in selling prices, RML also recorded lower sales volumes of 480 mbbl and 4,351 MMscf of O&G, respectively, for the FYE 31 December 2019 vis-à-vis the FYE 31 December 2018.

RML recorded a PBT of USD68.3 million for the FYE 31 December 2019, which represents a decrease of 3.7% or USD2.6 million as compared to USD70.9 million for the FYE 31 December 2018. This decrease is primarily due to (i) USD3.7 million additional provisions for potential tax liabilities relating to YA2014, (ii) a USD8.3m decrease in other operating income primarily arising from lower partners' recovery for personnel expense, and (iii) lower revenue recorded for the financial year. However, this decrease was offset by (i) a USD27.9 million reduction in operating expenses (excluding tax liabilities) arising from the introduction of cost efficiency initiatives and programmes to reduce logistic and maintenance costs, (ii) a USD11.1 million decrease in personnel cost resulting from a reduction in employee headcount from 483 in the FYE 31 December 2018 to 392 in the FYE 31 December 2019, (iii) a lower loss allowance on trade and other receivables of USD0.8m vis-à-vis the USD7.2 million recorded in the FYE 31 December 2018, (iv) a USD24.6 million reduction in depreciation, depletion and amortisation charges of non-current assets as a result of lower production during the financial year, and (v) a USD2.7m foreign exchange gain in the FYE 31 December 2019 vis-à-vis a USD0.6m foreign exchange loss recorded in the FYE 31 December 2018.

RML recorded a PATAMI of USD23.5 million for the FYE 31 December 2019, representing a decrease of 71.9% or USD60.0 million as compared to USD83.5 million in the FYE 31 December 2018. In addition to the abovementioned points, this decrease was also attributable to (i) an additional USD8.2 million tax provision for previous years and (ii) a USD49.5 million increase in deferred tax movement vis-à-vis the FYE 31 December 2018.

INFORMATION ON THE FIPC GROUP (CONT'D)

RMPM3

RMPM3 recorded a revenue of USD65.6 million for the FYE 31 December 2019, which represents a decrease of 4.2% or USD2.9 million as compared to USD68.5 million for the FYE 31 December 2018. This is primarily attributable to lower market prices for its oil by 5.1% (USD70.3/bbl vs USD74.0/bbl) and gas by 1.9% (USD4.7/kscf vs USD4.8/kscf). In addition to decrease in selling prices, RMPM3 also recorded lower gas sales volumes of 2,465 MMscf, which is offset by higher oil sales of 156 mbbl for the FYE 31 December 2019 vis-à-vis the FYE 31 December 2018.

RMPM3 recorded a PBT of USD19.5 million for the FYE 31 December 2019, which represents a decrease of 10.6% or USD2.3 million as compared to USD21.8 million for the FYE 31 December 2018. This decrease is primarily due to (i) USD2.3 million additional provisions for potential tax liabilities related to YA2014, (ii) a USD5.1 million increase in accretion expenses for sinking fund, (iii) the absence of a USD4.3 million other exceptional income arising from the revision in the estimate of asset retirement obligations ("**ARO**") previously recorded in FYE 31 December 2018, and (iv) lower revenue recorded for the financial year. However, this decrease was offset by (i) a USD7.6 million reduction in depreciation, depletion and amortisation charges as a result of the lower sales volume during the financial year and (ii) a USD4.3 million reversal of impairment losses previously recorded as the annual impairment review showed that the recoverable amount is in excess of the carrying amount.

RMPM3 recorded a PATAMI of USD4.4 million for the FYE 31 December 2019, representing a decrease of 59.6% or USD6.5 million as compared to USD10.9 million in the FYE 31 December 2018. In addition to the abovementioned points, this decrease was also attributable to an additional USD5.1 million tax provision for previous years.

TVL

TVL recorded a revenue of USD5.3 million for the FYE 31 December 2019, which represents a decrease of 65.1% or USD9.9 million as compared to USD15.2 million for the FYE 31 December 2018. This is primarily attributable to (i) lower market prices for its oil by 5.1% (USD70.3/bbl vs USD74.0/bbl) and (ii) lower oil sales volumes by 66 mbbl for the FYE 31 December 2019 vis-à-vis the FYE 31 December 2018.

TVL recorded an PBT of USD1.6 million for the FYE 31 December 2019, which represents a decrease of 85.5% USD9.4 million as compared to USD11.0 million for the FYE 31 December 2018. This decrease is primarily due to (i) a one-off intercompany receivable write-off amounting to USD1.9 million arising from Talisman Vietnam (15-2/01) Ltd. and (ii) lower revenue recorded for the financial year. The decrease is partially offset by an increase in underlift of crude oil by USD2.9 million resulting from the production of 110 kbbl at USD70.3/bbl in 2019.

TVL recorded a PATAMI of USD1.2 million for the FYE 31 December 2019, representing a decrease of 81.3% or USD5.2 million as compared to USD6.4 million in the FYE 31 December 2018. This decrease is attributable to the abovementioned points and is partly offset by lower foreign tax paid by USD3.8 million vis-à-vis the FYE 31 December 2018. TVL paid less foreign tax in the FYE 31 December 2019 as a result of lower revenue recorded for the financial year.

(iv) FYE 31 December 2018 vs. FYE 31 December 2017

FIPC

FIPC recorded a revenue of USD7.4 million for the FYE 31 December 2018, which represents a decrease of 96.2% or USD189.0 million as compared to USD196.4 million for the FYE 31 December 2017. This decrease is primarily attributable to the absence of dividend income from subsidiaries amounting to USD176.3 million.

FIPC recorded a PBT of USD7.3 million for the FYE 31 December 2018, which represents a decrease of 96.0% or USD177.3 million as compared to USD184.6 million for the FYE 31 December 2017. This decrease is mainly due to the lower revenue recorded for the financial year.

FIPC recorded a PATAMI of USD10.7 million for the FYE 31 December 2018, which represents a decrease of 94.2% or USD172.3 million as compared to USD183.0 million for the FYE 31 December 2017. This decrease is in tandem with the decrease in revenue and is partly offset by a USD2.2 million tax recovery arising from the derecognition of deferred tax liabilities.

FIPC's share capital as at the FYE 31 December 2018 is lower than the FYE 31 December 2017 due to the reissuance of common shares to Repsol amounting to USD186.0 million, which is partly offset by the return of share capital to Repsol Oil & Gas Canada Inc. amounting to USD190.0 million.

RML

RML recorded a revenue of USD316.2 million for the FYE 31 December 2018, which represents an increase of 39.4% or USD89.4 million as compared to USD226.8 million for the FYE 31 December 2017. This is primarily attributable to higher market prices for our oil by 31.9% (USD74.0/bbl vs USD56.1/bbl) and gas by 23.0% (USD4.8/kscf vs USD3.9/kscf) as a result of OPEC's decision to extend oil production cuts for the entirety of 2018. In contrast to the FYE 31 December 2017, RML recorded higher oil sales volume by 517 mbbl but lower gas sales volume by 2,929 MMscf.

RML recorded a PBT of USD70.9 million for the FYE 31 December 2018, which represents an increase of 55.8% or USD25.4 million as compared to USD45.5 million for the FYE 31 December 2017. This increase is primarily due to higher revenue recorded for the financial year, which was offset by (i) a USD34.1 million increase in other operating expenses, (ii) a USD18.2 million increase in personnel cost resulting from an increase in employee headcount from 601 in the FYE 31 December 2017 to 707 in the FYE 31 December 2018 and (iii) a USD0.7 million foreign exchange loss in the FYE 31 December 2018 vis-à-vis a USD11.2 million foreign exchange gain recorded in the FYE 31 December 2017.

RML recorded a PATAMI of USD83.5 million for the FYE 31 December 2018, representing a decrease of 28.3% or USD33.0 million as compared to a PATAMI of USD116.5 million in the FYE 31 December 2017. In addition to the abovementioned points, this decrease was also attributable to a USD58.1 million deferred tax movement arising from temporary differences in relation to initial recognition of deferred tax arising from first time GAAP conversion.

RMPM3

RMPM3 recorded a revenue of USD68.5 million for the FYE 31 December 2018, which represents a decrease of 8.4% or USD6.3 million as compared to USD74.8 million for the FYE 31 December 2017. This is attributable to lower O&G sales volumes by 231 mbbl and 1,721 MMscf respectively, against the FYE 31 December 2017, which is partly offset by higher market prices for its oil by 31.9% (USD74.0/bbl vs USD56.1/bbl) and gas by 23.0% (USD4.8/kscf vs USD3.9/kscf) as a result of OPEC's decision to extend oil production cuts for the entirety of 2018.

RMPM3 recorded a PBT of USD21.8 million for the FYE 31 December 2018, which represents an increase of 139.6% or USD12.7 million as compared to USD9.1 million for the FYE 31 December 2017. This increase is due to (i) a USD12.3 million decrease in depletion, depreciation and amortisation charges resulting from the lower production volume, (ii) an increase in other exceptional income of USD4.3 million arising from the revision in the estimate of ARO, (iii) a USD3.2 million decrease in finance expenses, and (iv) a USD12.5 million decrease in supplies expenses. However, this increase was offset by (i) lower recorded revenue for the financial year, (ii) a lower one-off impairment loss reversal amounting to USD1.2 million vis-à-vis the USD8.2 million previously recorded for the FYE 31 December 2017, and (iii) the absence of interest income from loan to related parties amounting to USD7.4 million previously recorded in the FYE 31 December 2017.

RMPM3 recorded a PATAMI of USD10.9 million for the FYE 31 December 2018, representing a decrease of 33.5% or USD5.5 million as compared to a PATAMI of USD16.4 million in the FYE 31 December 2017. In addition to the abovementioned points, this decrease was also attributable to a USD18.5 million increase in deferred tax movement arising from temporary differences vis-à-vis the FYE 31 December 2017.

TVL

TVL recorded a revenue of USD15.2 million for the FYE 31 December 2018, which represents an increase of 300.0% or USD11.4 million as compared to USD3.8 million for the FYE 31 December 2017. This is primarily attributable to higher market prices of oil by 31.9% (USD74.0/bbl vs USD56.1/bbl) and gas by 23.0% (USD4.8/kscf vs USD3.9/kscf) as a result of OPEC's decision to extend oil production cuts for the entirety of 2018. In contrast to the FYE 31 December 2017, TVL recorded higher oil sales volume by 92 kbbl but lower gas sales volume by 150 MMscf.

TVL recorded a PBT of USD11.0 million for the FYE 31 December 2018, which represents an increase of 35.8% or USD2.9 million as compared to USD8.1 million for the FYE 31 December 2017. This increase is primarily due attributable to higher revenue recorded for the financial year, which was offset by the absence of a USD9.9 million non-recurring income arising from the recalculation of sales entitlements from the acquisition of additional working interest from PVEP that was previously recorded for the FYE 31 December 2017.

TVL recorded a PATAMI of USD6.4 million for the FYE 31 December 2018, representing a decrease of 23.8% or USD2.0 million as compared to a PATAMI of USD8.4 million in the FYE 31 December 2017. In addition to the abovementioned points, this increase was partly offset by a USD3.9 million increase in current tax as a result of the higher revenue recorded for the financial year.

7. MATERIAL COMMITMENTS

Save as disclosed below, as at 30 September 2021, there are no material commitments incurred or known to be incurred by FIPC Group that have not been provided for which, upon becoming enforceable, may have a material impact on FIPC Group's financial results/position:

Approved and Contracted for	Total (USD'000)	(1)Total (RM'000)
PM3 CAA PSC minimum financial commitment	48,585	203,425
Floating, Storage, Offloading unit ("**FSO**") operations and maintenance (Bunga Orkid)	22,853	95,686
FSO PM-3 CAA operations and maintenance	3,626	15,182
2012 Kinabalu Oil PSC training commitment	1,715	7,181
Block 46 PSC training commitment	919	3,848
PM3 CAA PSC training commitment	199	833
Total	**77,897**	**326,155**

Note:

(1) Based on the exchange rate of USD1:RM4.187, being the middle rate quoted by BNM at 5.00 p.m. as at 30 September 2021.

8. CONTINGENT LIABILITIES

Save as disclosed in Section 10 below, as at 30 September 2021, there are no other contingent liabilities incurred or known to be incurred by the FIPC Group which, upon becoming enforceable, may have a material impact on the FIPC Group's financial results/ position.

9. MATERIAL CONTRACTS

FIPC and its subsidiaries have 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.

10. MATERIAL LITIGATION, CLAIMS OR ARBITRATION

Save as disclosed below, as at LPD, the FIPC Group 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 FIPC Group:

(i) On 27 December 2019, the Inland Revenue Board of Malaysia ("**IRB**") issued a Notice of Additional Assessment to RML, PCSB, RMPM3 and PVEP ("**PM3 CAA Partners**") for additional tax and penalty amounting to RM95,641,365.08 for PITA YA2014 ("**Notice of Additional Assessment for YA2014**"), disallowing several PSC costs and sole costs of RML. Of this total amount, the portion potentially attributable to RML and RMPM3 is estimated to be an amount of up to RM79,168,229.90.

On 9 January 2020, RML (on behalf of the PM3 CAA Partners) filed a notice of appeal with the Special Commissioners of Petroleum Income Tax ("**SCPIT**") against the Notice of Additional Assessment for YA2014. The next case mention for this appeal is scheduled for 21 January 2022.

On 17 January 2020, RML (as operator on behalf of the PM3 CAA Partners) also filed with the High Court in Kuala Terengganu an application for judicial review and stay of proceedings. The applications were heard by the High Court on 5 February 2020 and both the leave for judicial review and stay of proceedings were granted. The hearing on the merits of the judicial review proceeded on 14 December 2020. On 20 January 2021, the High Court delivered its decision in relation to the judicial review. The High Court did not quash/invalidate the Notice of Additional Assessment for YA2014 or declare it as being invalid but had instead granted an Order of Prohibition ("**Prohibition Order**") to prohibit the IRB from, among other things, taking steps to collect the additional tax and penalties in respect of the Notice of Additional Assessment for YA2014, until the case is resolved before the SCPIT.

Therefore, no payment is required to be made in respect of YA2014 yet.

IRB has subsequently filed an appeal to the Court of Appeal ("**CA**") against the grant of Prohibition Order by the High Court while the PM3 CAA Partners have filed a corresponding appeal with the CA against the High Court's refusal to quash/invalidate the Notice of Additional Assessment for YA2014. The next case management for both appeals is scheduled for 29 December 2021.

(ii) On 31 December 2020, the IRB issued a Notice of Assessment for additional taxes and penalties for PITA YA2015 and YA2016, for a total amount of RM166,282,868.93 (including penalties), against the PM3 CAA Partners with regard to the PSC as a whole ("**Notices of Assessment for YA2015 and YA2016**"), disallowing several PSC costs and sole costs of RML. Of this total amount, the portion potentially attributable to RML and RMPM3 is estimated to be an amount of up to RM16,446,882.48.

On 31 December 2020, RML (as operator on behalf of the PM3 CAA Partners) filed with the High Court in Kuala Terengganu an application for judicial review and stay of proceedings.

On 12 January 2021, RML (on behalf of the PM3 CAA Partners) filed a notice of appeal with the SCPIT against the Notices of Assessment for YA2015 and YA2016.

On 9 February 2021, the High Court delivered its decision. The High Court did not quash/invalidate the Notices of Assessment for YA2015 and YA2016 or declare those Notices as being invalid but had instead granted a Prohibition Order to prohibit the IRB from, among other things, taking steps to collect the additional tax and penalties in respect of the Notices of Assessment for YA2015 and YA2016, until the case is resolved before the SCPIT.

Therefore, no payment is required to be made in respect of YA2015 and YA2016 yet.

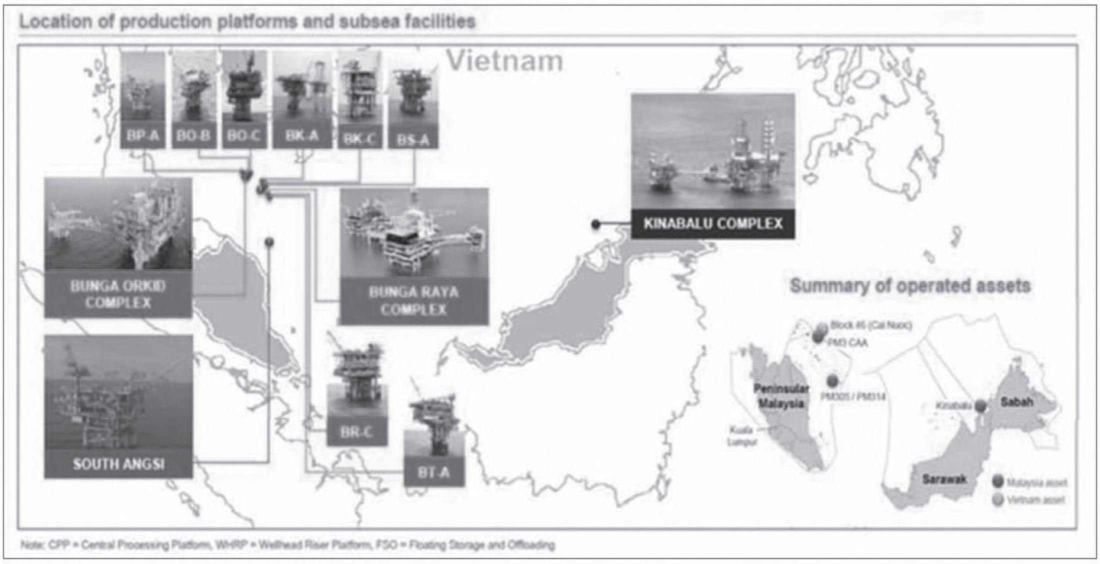
IRB has subsequently filed an appeal to the CA against the grant of Prohibition Order by the High Court while the PM3 CAA Partners have filed a corresponding appeal with the CA against the High Court's refusal to quash/invalidate the Notices of Assessment for YA2015 and YA2016. The next case management for both appeals is scheduled for 29 December 2021.

There are limited rights of recourse against the Seller in relation to the above legal proceedings based on the terms of the SPA. The Purchaser has conducted a due diligence exercise using the services of external professional tax advisers, and has taken into account the above proceedings when evaluating the transaction.

INFORMATION ON THE ASSETS

1. Overview of the Assets

The Assets are located in the Malay and Sabah Basins, offshore Malaysia and Vietnam as applicable and as shown below.



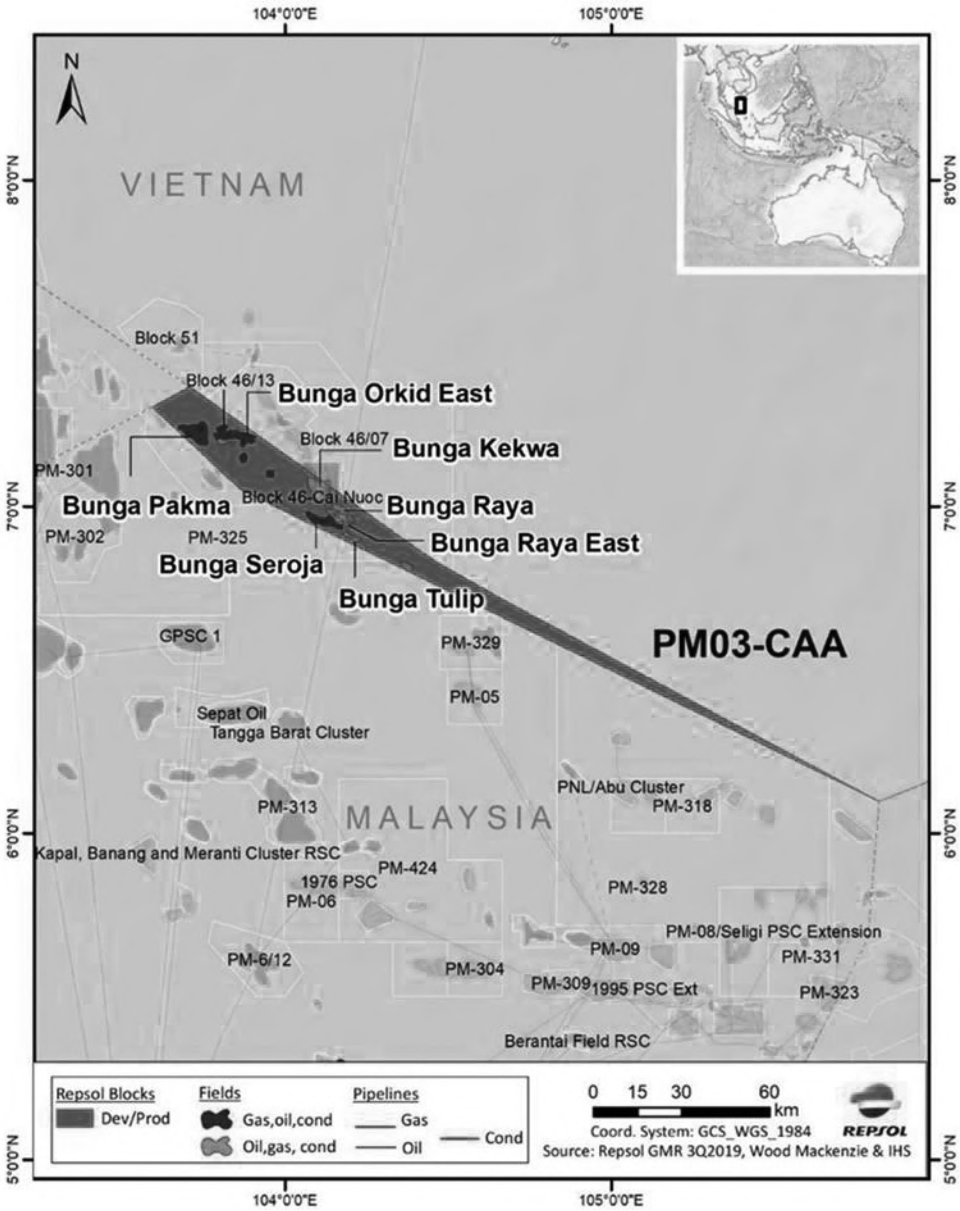
(Source: Repsol)

216mmboe Gross reserves	46% / 54% Liquids / Gas (by gross reserves)	73kboed Gross 2020E production
100% Operatorship	~963km² Net acreage	17 Platforms
2 FSOs	14 Support vessels	>650km Pipelines
165[1] Active strings	76 Gas lift strings	~355 Local employees

(Source: Repsol and Management of the Company)

1.1 PM3 CAA

PM3 CAA which is located geologically in the Northeast Malay basin, lies in the Commercial Arrangement Area between Malaysia and Vietnam for exploration and development of oil and gas fields therein, with a project area of 1,995km², as illustrated in the diagram below. The block contains a total of 14 accumulations in six fields, developed around two hubs (North and South). PM3 CAA is subdivided into Northern and Southern Regions, which in total contains six fields: Bunga Orkid, Bunga Pakma in the North and Bunga Kekwa, Bunga Raya, Bunga Seroja and Bunga Tulip in the South. First gas production was in October 2003 and first oil produced in July 1997.



(Source: Repsol, Management of our Company)

INFORMATION ON THE ASSETS (CONT'D)

As at 30 September 2021, there are five remaining commitments from the PM3 CAA PSC as detailed below:

(i) one exploration commitment: acquisition of new 3D high quality seismic data;

(ii) two development commitments:

(a) undertake an Enhanced Oil Recovery (EOR) study;

(b) develop undeveloped commercial discovery(ies) to address production decline;

(iii) one minimum financial commitment: improve hydrocarbon recovery within the extended term at existing and/or producing fields; and

(iv) one training commitment: training commitment to be completed before expiry of the PSC.

RML as operator, is responsible for ensuring the commitments are met. RMPM3 as a partner in the JOA, as with all JOA partners, is required to fund its share of commitments.

Further details on the material commitments are disclosed under Section 7, Appendix III of this Circular.

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INFORMATION ON THE ASSETS (CONT'D)

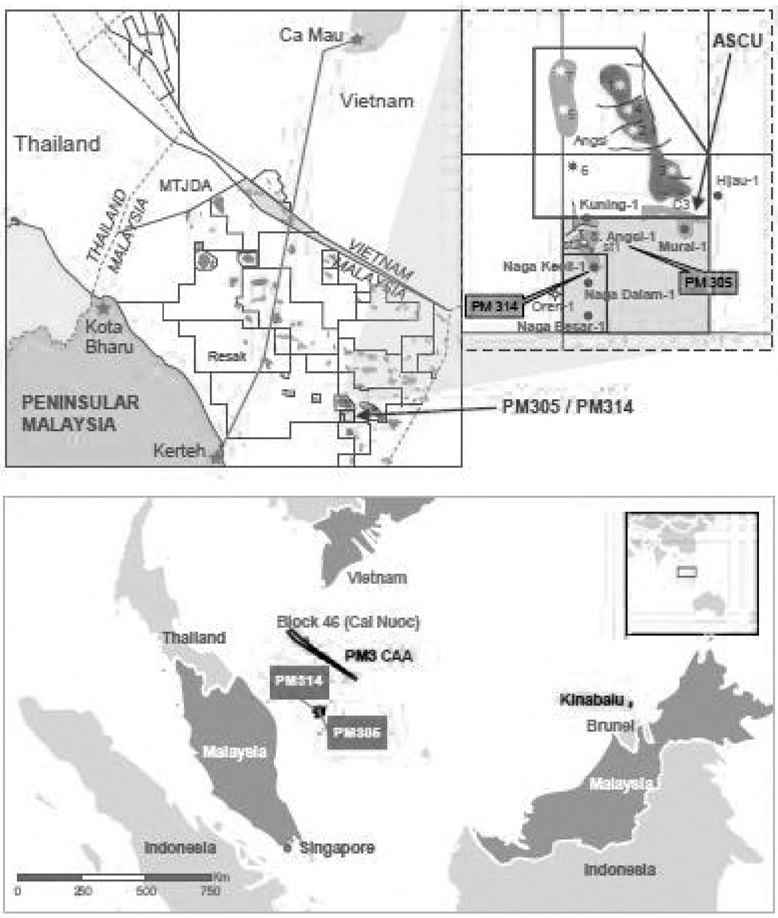
1.2 Block 46

Block 46, which is located geologically in the Northeast Malay Basin, with a project area of 82km^2, lies in Vietnamese waters adjacent to PM3 CAA, as illustrated in the diagram below, and contains the producing Cai Nuoc field and the undeveloped Hoa Mai field. Cai Nuoc is an extension of the East Bunga Kekwa field and was unitised with East Bunga Kekwa in 2000, forming the East Bunga Kekwa – Cai Nuoc unit field. The field is tied back to PM3 CAA's facilities. The undeveloped Hoa Mai field also lies primarily in Block 46, outside of the East Bunga Kekwa – Cai Nuoc unit but straddles the Malaysia/Vietnam maritime border into PM3 CAA. First oil was produced in 2003.

(Source: Repsol, Management of our Company)

1.3 PM305 and PM314

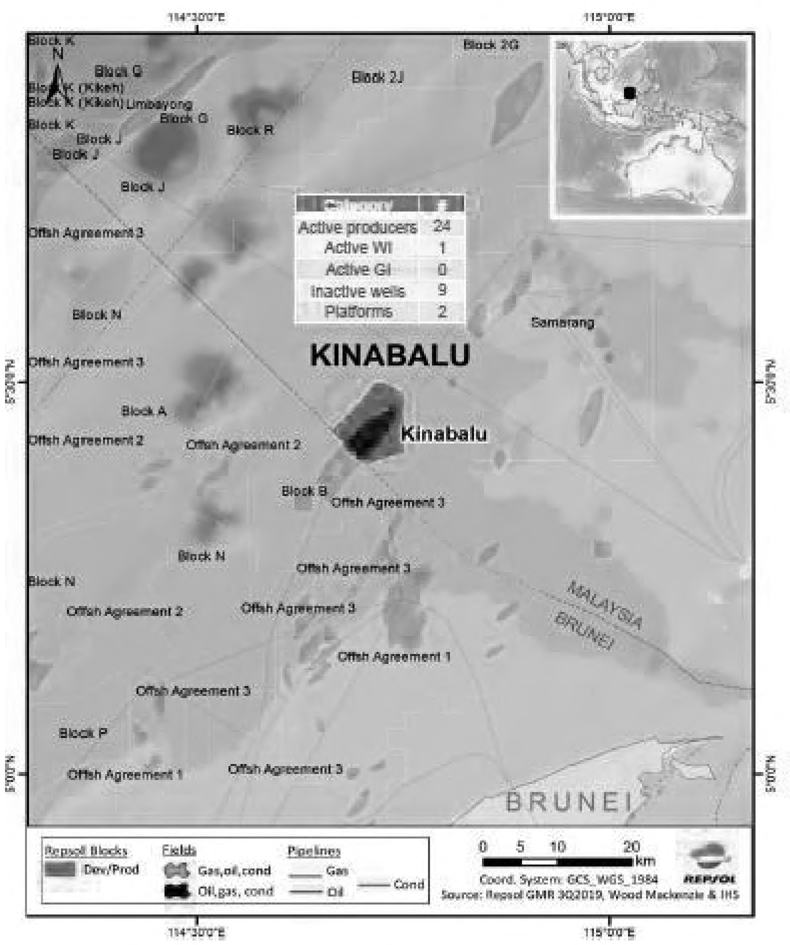
PM305, with a project area of 175km^2, and PM314, with a project area of 46km^2, both of which are located geologically in the Southwest Malay Basin, lie in offshore Peninsular Malaysia, as illustrated in the diagram below, comprising four fields which are South Angsi, Kuning, Murai and Naga Kecil. South Angsi, Kuning and Naga Kecil have ceased production on 30 September 2019 and currently undergoing remaining commitment to decommission. Murai field (unitised with Angsi Southern Channel/Murai) is still producing O&G where the production evacuates via Angsi C (non-operated facilities and infrastructure). The field was developed with four oil producers (three active) with first oil produced in March 2004. Water injection via two water injectors (both active) was added in May 2007.



(Source: Repsol, Management of our Company)

1.4 2012 Kinabalu Oil

2012 Kinabalu Oil, with a project area of approximately 71km², is located in Sabah, offshore Malaysia, near the Malaysia-Brunei maritime border in the Sabah Basin, as illustrated in the diagram below. The PSC contains the Kinabalu field, which is separated by Northeast-Southwest trending extensional faults, into three fault blocks: Kinabalu Main, Kinabalu East and Kinabalu Far East. It was discovered by Sabah Shell Petroleum in 1989 with the KN-1 exploration well in a water depth of approximately 54m. First oil was produced in 1997 and the current partnership consists of RML (60%) and PCSB (40%). The 2012 Kinabalu Oil PSC expires in 2032.



(Source: Repsol, Management of our Company)

As at 30 September 2021, there is one outstanding training commitment for 2012 Kinabalu Oil PSC.

1.5 Summary of each PSC and permits as at 30 September 2021 is as follows:

Block	Active Fields	Asset type	Status	Operator	Working interest of participants	Estimated year of expiry
PM3 CAA	Bunga Orkid	Oil, gas and condensate	Producing	RML	RML (22.3%) RMPM3 (12.7%) PCSB[1] (35.0%) PVEP[2] (30.0%)	2027
	Bunga Pakma					
	Bunga Raya					
	Bunga Seroja					
	Bunga Kekwa					
	Bunga Tulip					
	Greater Central Area		Exploration			
	Greater Silver Area					
Block 46	Cai Nuoc	Oil and condensate	Producing	TVL	TVL (70.0%) PVEP[2] (30.0%)	2027
PM305 and PM314	Murai/Angsi Southern Channel Unit	Oil and condensate	Producing	RML	RML (60.0%) PCSB[1] (40.0%)	2029 (PM305) & 2033 (PM314)
2012 Kinabalu Oil	Kinabalu Main	Oil and condensate	Producing	RML	RML (60.0%) PCSB[1] (40.0%)	2032
	Kinabalu East					
	Kinabalu Far East					

Notes:

(1) PCSB is a wholly-owned subsidiary of PETRONAS, the national oil company of Malaysia. PCSB's principal activities are petroleum exploration, development and production. (Source: PETRONAS Annual Report)

(2) PVEP is a wholly-owned subsidiary of PetroVietnam, the national oil company of Vietnam, conducting the core business of exploration and production. (Source: http://pvep.com.vn/en/gioi-thieu-76/tong-quan-83)

1.6 SALIENT FEATURES OF THE CONTRACTUAL AGREEMENTS ENTERED BY THE FIPC GROUP FOR ITS O&G ASSETS

1.6.1 PSCs

1.6.1.1 Malaysian PSCs

(i) The FIPC Group's acreages in Malaysia are governed under PSCs, which were entered into with PETRONAS, which owns and has the exclusive rights and powers over hydrocarbon resources in Malaysia.

While the specific terms of each of the Malaysian PSCs vary, a summary of the salient features of the Malaysian PSCs is as follows:

(a) a PSC is entered into between (a) PETRONAS and (b) the relevant subsidiary of the FIPC Group, together with other PSC participants, as contractors ("**PSC participants**"). The PSC grants the PSC participants the rights to conduct petroleum operations comprising exploration and/or development and production activities in the contract area. All the PSC participants would then enter into a joint operating agreement ("**JOA**") under which one of the participants will assume the role as operator, which is responsible for carrying out all petroleum operations on behalf of the PSC participants;

(b) each PSC has a specific tenure and is subject to early termination of the PSC (e.g. a relinquishment of the contract area as a result of a failure (i) to make a commercial recovery during the exploration period, or (ii) unless otherwise excused under the PSC, to produce crude oil commercially from any producing field exceeding one year). In addition, PETRONAS may terminate the PSC with respect to any of the participants upon occurrence of certain events, such as material breaches of the PSC by that contractor, insolvency, winding-up or appointment of receivers of that contractor and change in control or ownership of the contractor without PETRONAS' prior consent;

(c) each PSC has an exploration period and/or development and production period during which the PSC participants must fulfil certain minimum work and financial commitments. In the case where PETRONAS is not reasonably satisfied with the minimum work performed by the PSC participants, there will be a financial penalty imposed for the remaining financial commitment relating to the amount of the remaining work;

(d) in the case of the PM3 CAA PSC for PM3 CAA which lies within the CAA between Malaysia and Vietnam, PETRONAS and PetroVietnam are recognised as co-host authorities under that PSC, and PETRONAS is responsible for the management of petroleum operations contemplated under that PSC as agreed by PETRONAS and PetroVietnam;

(e) any assignment of all or part of any PSC participant's interests, rights or obligations under the PSC requires the prior written approval of PETRONAS, and in the case of the PM3 CAA PSC, the approval of PetroVietnam as well; and

(f) as at the first quarter of 2021, most minimum work commitments under the PM3 CAA PSC and the 2012 Kinabalu Oil PSC have been completed and fulfilled, with remaining commitments on track to be committed. All minimum work commitments under the PM305 PSC and PM314 PSC have been fulfilled, with minimal net decommissioning exposure.

(ii) The fiscal terms of the PM3 CAA PSC and the 2012 Kinabalu Oil PSC provide that:

(a) a maximum of 10.0% of any oil or natural gas produced (not utilised for operations, in the case of natural gas) under the PSC to be allocated by the PSC participants as royalty payments to PETRONAS;

(b) a portion of the remaining oil and natural gas is allocated to the PSC participants to reimburse the petroleum operations expenditures of the PSC participants through cost recovery by the PSC participants on a quarterly basis, excluding non-recoverable costs. This amount is known as "**Cost Oil**" or "**Cost Gas**". Cost Oil and Cost Gas are subject to variable caps that are negotiated and agreed with PETRONAS; and

(c) after the allocation of the Cost Oil or Cost Gas as described above, all remaining oil or gas is designated as "**Profit Oil**" or "**Profit Gas**". The PSC participants' share of the Profit Oil or Profit Gas is within a range that is specified under the PSC, depending on whether the cumulative production of oil or natural gas is above or below a specified cumulative production threshold, and PETRONAS is allocated the remaining Profit Oil or Profit Gas.

(iii) The fiscal terms of the PM305 PSC and the PM314 PSC provide that:

(a) a maximum of 10.0% of any oil or gas produced (not utilised for operations, in the case of natural gas) under the PSC to be allocated as royalty payments to PETRONAS by the PSC participants;

(b) after the allocation of the royalties, a portion of the remaining oil and natural gas is allocated to the PSC participants to reimburse the petroleum operations expenditures of the PSC participants through cost recovery by the PSC participants on a quarterly basis, excluding non-recoverable costs. This amount, subject to variable caps that are negotiated and agreed with PETRONAS, is computed based on the revenue-to-cost ratio of the PSC participants' cumulative revenue and cumulative PSC costs;

(c) the PSC participants are allocated a share equal to a percentage of the Profit Oil or Profit Gas in each quarter depending on:

(1) the revenue-to-cost ratio for the immediately preceding quarter; and

(2) whether cumulative O&G production for that quarter exceeds a specified cumulative production threshold.

The PSC participants' allocation of the Profit Oil or Profit Gas is within a range that is negotiated and agreed with PETRONAS, and PETRONAS is allocated the remaining Profit Oil or Profit Gas; and

(d) if the actual petroleum operations expenditures are lower than the Cost Oil or Cost Gas cap described above during any quarter, the unused portion of Cost Oil or Cost Gas is included as part of the Profit Oil or Profit Gas, and the PSC participants are allocated such portion of the Profit Oil or Profit Gas in a more favourable apportionment. The PSC participants' allocation of the unused portion of the Cost Oil or Cost Gas is within a range that is negotiated and agreed with PETRONAS.

(iv) The Malaysian PSCs further provide that:

(a) the PSC participants share their allocated Profit Oil or Profit Gas, as calculated based on the formulae described in items (ii) and (iii) above, among themselves in proportion to their respective Working Interests;

(b) the PSC participants are required to comply with the Malaysian national objective of maximising Malaysian participants through the use of local equipment, facilities, goods, materials, suppliers and services;

(c) the PSC participants are required to pay PETRONAS research cess in an amount which is computed as a small percentage of Cost Oil and/or Cost Gas and the PSC participants' share of Profit Oil and/or Profit Gas;

(d) the PSC participants are required to pay to PETRONAS abandonment cess beginning on the first anniversary of production, the quantum of which is based on abandonment estimates distributed over the remaining life of the PSC. The amount paid to PETRONAS are cost recoverable under Cost Oil or Cost Gas, as the case may be. If abandonment takes place during tenure of PSC, contractors are responsible for undertaking abandonment work and if cost exceeds abandonment cess fund, contractors will bear the excess. If a PSC is terminated early, the PSC participants are liable for any outstanding abandonment cess payments in full within three months of notice of early termination except that in the case of the PM3 CAA PSC, the abandonment cess only became payable during the second extension of that PSC. Contractors are not responsible for abandonment which is undertaken after the expiry of PSC save for abandonment work which has been approved by PETRONAS and PetroVietnam but has yet to be completed;

(e) in any month, where the monthly average realised price exceeds a stipulated base price, which is escalated annually at a certain percentage stipulated in the PSC ("**the Excess**"), the PSC participants are required to pay a supplementary payment for the PSC participants' share of Profit Oil (less export duty paid)/Profit Gas in that month an amount equivalent to a specified percentage of the Difference, except that in the case of the PM3 CAA PSC, any such supplementary payment is levied on a quarterly basis and for oil only; and

(f) petroleum income tax is assessed at 38% of taxable income under the PITA. PSC participants are subjected to normal corporate income tax in respect of their non-petroleum operations.

1.6.1.2 Vietnamese PSC

(i) A summary of the salient features of the Vietnamese PSC is as follows:

(a) the Vietnamese PSC was entered into between PetroVietnam, with the approval by the Government of the Socialist Republic of Vietnam, and the relevant subsidiary of the FIPC Group, together with other PSC participants, as contractors. The PSC grants the PSC participants the rights to conduct petroleum operations comprising exploration and/or development and production activities in the contract area. All the PSC participants have entered into a JOA under which TVL assumes the role as operator, which is responsible for carrying out all petroleum operations on behalf of the PSC participants;

(b) the PSC has an exploration period, a development period and a production period, as extended, during which the PSC participants must fulfil certain minimum work commitments;

(c) PetroVietnam may terminate the PSC if the PSC participants essentially infringe the PSC or grossly and repeatedly violate the same;

(d) Any assignment of all or part of any PSC participant's interests, rights or obligations under the PSC requires the prior written approval of PetroVietnam; and

(e) As at the first quarter of 2021, all work commitments under the PSC have been fulfilled.

(ii) The fiscal terms of the Vietnamese PSC provide that:

(a) no royalty is payable under this PSC.

(b) Cost Oil or Cost Gas is allocated to the PSC participants is within a range that is negotiated and agreed with PVEP according to specified tranches of daily production of oil or gas, as applicable;

(c) Profit Oil or Profit Gas is allocated to the PSC participants within a range that is negotiated and agreed with PetroVietnam according to specified tranches of daily production of oil or gas, as applicable;

(d) an annual production bonus is payable by the PSC participants within a range negotiated and agreed with PetroVietnam when the daily oil production level first hits specified daily production levels in ascending order;

(e) an annual agreed training fee is payable by the PSC participants during the production phase;

(f) for the setting up of an abandonment fund in accordance with applicable Vietnamese laws, and in respect of the Unit Area wells located in Block 46, the abandonment terms shall be synchronised with the abandonment terms for the PM3 CAA PSC as last extended; and

(g) corporate income tax of 50% is paid on behalf of the PSC participants by PVEP and will be reimbursed by TVL.

1.6.2 Malaysian JOAs and Vietnamese JOA

The salient features of the Malaysian JOAs and the Vietnamese JOA are very similar and are as follows:

(i) it establishes the principles, terms and conditions under which the PSC participants will carry out petroleum operations under the PSC, including the production programming and disposition of their individual oil entitlements, and if commercial gas production occurs, the PSC participants will agree on the handling and disposition of their individual natural gas entitlements in a manner consistent with the JOA. However, under the PSC, individual natural gas entitlements are to be sold on a joint dedicated basis;

(ii) it defines the individual participating interests ("**PIs**") of the PSC participants. All costs and expenses and liabilities are shared, and the individual oil entitlements are determined, among the PSC participants on the basis of these PIs;

(iii) one of the PSC participants is appointed as the operator. RML and TVL are appointed the respective operators under the Malaysian JOAs and the Vietnamese JOA;

(iv) there is a management committee (operating committee, under the Vietnamese JOA) which comprises equal number of representatives from each PSC participant. The voting rights of the representatives are proportionate to their PIs. A representative of the operator is the chairman of the management committee;

(v) the operator is responsible for preparing the annual work programme and budget ("**WBP**") and, if applicable, the abandonment WPB for submission to the management committee for review and approval before the WPB is submitted to the relevant approving authority under respective PSC; and

(vi) any assignment of all or part of any PSC participant's PI to a third party requires the prior written consent of all the other PSC participants. Also, the other PSC participants have pre-emptive rights to acquire the PI to be assigned on the same terms and conditions agreed between the assigning PSC participant and the third party.

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

2.1 Classification of reserves and resources

Figure 3 below 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.

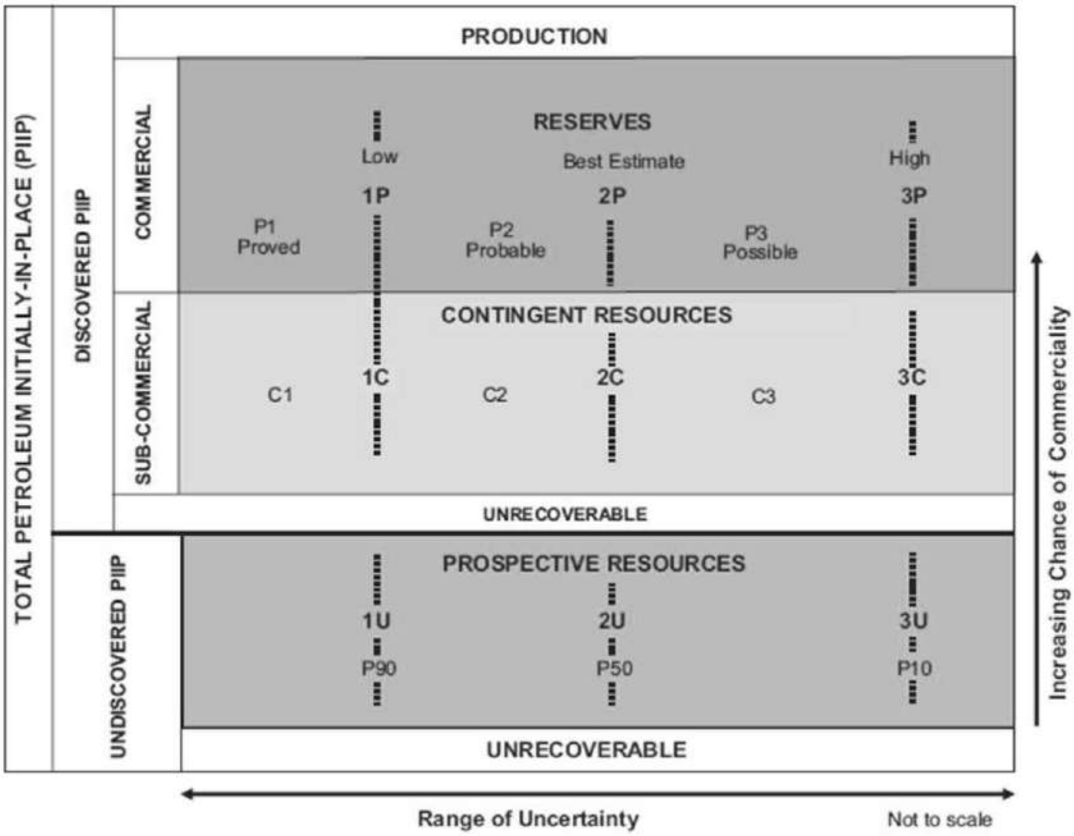


Figure 3: Resources classification framework based on PRMS

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, *Pc*, 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 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 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 nonhydrocarbon is separated before sales, it is excluded from Reserves.

  Reserves are further categorized in accordance with the range of uncertainty and should be subclassified 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.

(Source: Competent Valuers' Report)

For further details on the reserves and resources classifications, methodology of estimates of reserves and resources, and the assumptions, please refer to the Competent Valuer's Report in Appendix V of this Circular and Competent Person's Report in relation to the reserves and resources evaluation of the Assets in Appendix VII of this Circular.

2.2 Oil, Condensate and Gas Reserves and Contingent Resources

Oil, Condensate and Gas Reserves

A summary of 1P, 2P and 3P Oil, Condensate and Gas Reserves of the Assets in MMstb, Bscf and MMboe as at 1 January 2021 estimated by RPS Energy are set out in Section 2.3.3(i) of the main section of this Circular.

Contingent Resources

A summary of Contingent Resources for the Assets is provided in the tables set out in Section 2.3.1(ii) of the main section of this Circular for oil, gas, and barrels of oil equivalent, respectively. RPS Energy did not conduct any independent review of Repsol's estimates of these activities. The purchase price and valuation of the Assets did not include Contingent Resources. Accordingly, the Contingent Resources represent an upside to the valuation of the Assets.

The full field gross best estimate for both O&G are sourced directly from Repsol's economic model. In order to derive the full field gross Low Estimate and High Estimate, RPS Energy has applied the ratio of full field gross 1P over full field gross 2P and the ratio of full field gross 3P over full field gross 2P respectively to the Best Estimate. Net Entitlement Contingent Resources for 1C, 2C and 3C are derived based on the ratio of net entitlement over full field gross reserves.

2.3 The valuation of the 2P case Oil, Condensate and Gas Reserves using RPS Energy's base case price scenario ("**RPS Base Case**") at 10% discount rate as at 1 January 2021 estimated by RPS Energy is set out in Section 2.3.1 of the main section of this Circular.

2.4 The key valuation assumptions by RPS Energy in arriving at the discounted cash flow valuation of the Assets are set out in Section 2.3.2 of the main section of this Circular.

For further details on the valuation of the Assets and the expert's report on the fairness of the purchase price issued by RPS Energy, please see Appendix V and Appendix VI of this Circular, respectively.

COMPETENT VALUER'S REPORT

Hibiscus Petroleum Berhad

ECV2405
Competent Valuer's Report
Rev 2
25th June 2021

rpsgroup.com

COMPETENT VALUER'S REPORT ON THE ASSETS (CONT'D)

COMPETENT VALUER'S REPORT

Document status					
Version	**Purpose of document**	**Authored by**	**Reviewed by**	**Approved by**	**Review date**
Rev 0	Draft Report	JT	GJB	GJB	19/6/21
Rev 1	Final Report	JT	GJB	GJB	21/6/21
Rev 2	Final Report	JT	GJB	GJB	25/6/21

Approval for issue		
Jim Bradly		25/6/2021

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Date: 25th June 2021

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Dear Sirs,

EVALUATION OF ASSET RESERVES

In response to a request by Hibiscus Petroleum Berhad ("Hibiscus"), and the Letter of Engagement dated 12th December 2020 with Hibiscus (the "Agreement"), RPS Energy Consultants Ltd ("RPS") has completed an independent evaluation of the Repsol S.A. ("Repsol") assets, for sale as part of a proposal, administered by J.P. Morgan Securities plc, which Hibiscus is interested in acquiring.

The potential transaction encompasses a 100% working interest in each of the following entities:

- Repsol Oil & Gas Malaysia Limited;
- Repsol Oil & Gas Malaysia (PM3) Limited; and
- Talisman Vietnam Limited.

These entities in turn hold and operate Repsol's business in Malaysia, comprising the following interests, collectively, the "Assets":

- 60% working interest in the Kinabalu block located in Sabah, Malaysia
- 35% working interest in the PM3 CAA block located within the Commercial Arrangement Area ("CAA") between Malaysia and Vietnam
- 60% working interest in each of the PM305 and PM314 blocks located off the eastern coast of Peninsular Malaysia in the Malay Basin; and
- 70% working interest in Block 46 (Cai Nuoc), a tie-back asset to the PM3 CAA block located in Vietnamese waters.

Hibiscus had, on 2nd June 2021 and 4th June 2021 announced that its indirect wholly-owned subsidiary, Peninsula Hibiscus Sdn Bhd has on 1st June 2021 entered into a conditional sale and purchase agreement ("SPA") with Repsol for the proposed acquisition of the entire equity interest in Fortuna International Petroleum Corporation for a cash consideration of US$ 212.5 million ("Proposed Acquisition").

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 1st January 2021. 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 made available by J.P. Morgan Securities plc and Repsol via Virtual (VDR) and Physical (PDR) Datarooms.

RPS has reviewed available data and evaluated forecasts for existing production and additional projects confirmed by RPS as being reported by Repsol in the latest Work Plan and Budget (2021 WP&B) or equivalent.

VDR access was made available to RPS on 8th December 2020. This contained Process documentation, Presentations and Minutes from key meetings, Field Development plans, Legal and Regulatory Information and Finance and Tax information as well as historical production data for each of the Assets. RPS staff attended the PDR conducted via MS Teams between 14th and 17th December 2020. The PDR contained static and dynamic models of certain fields in the asset base.

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

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

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

No site visit has been conducted as part of our evaluation as it is usually conducted when a SPA is signed or during the transition period in which personnel specialises in Health Safety Environment would be allowed to conduct limited site visit.

For each Asset, Repsol has presented a Business Case consisting of a Low Investment Case, Defined Developments and Future Developments.

- Low Investment case consists of existing production plus some ongoing, fully sanctioned development projects and can typically be classified as Reserves;
- Defined Developments include a range of projects at different stages of definition, but can be considered a mixture of Contingent and Prospective Resources;
- Future Developments include additional potential projects which typically would be classified as Prospective Resources.

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

The Full Field Gross Reserves and Net Entitlement Reserves as of 1st January 2021 are summarised in Table 1.2 to Table 1.5 for oil, gas, condensate, and total production in barrels of oil equivalent volumes, respectively.

Net Present Value at 0%, 8%, 10%, and 12% discount rates as of 1st January 2021 for PM3 CAA and Kinabalu PSC are presented in Table 1.6 and Table 1.7, respectively.

COMPETENT VALUER'S REPORT ON THE ASSETS (CONT'D)

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. Jim Bradly, Operations Director has supervised this evaluation.

Mr Bradly holds a BEng in Electronic & Electrical Engineering from the University of Manchester in the UK and an MSc in Petroleum Engineering from Imperial College, London. He is a Member and Chartered Petroleum Engineer in good standing of the Energy Institute in the UK and is a Chartered Engineer registered with the Engineering Council UK (Registration # 569021) with over 20 years of experience in upstream oil and gas of which over 15 years' experience in auditing and evaluating oil and gas Reserves and Resources.

The project has been managed by Joseph Tan, a Petroleum Economist with over 20 years of experience in upstream oil and gas. Other RPS employees involved in this work hold at least a Batchelor'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

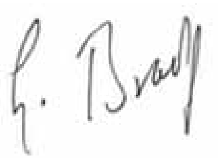
The evaluation presented in this report reflects our informed judgment, based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data. The evaluation has been conducted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

This 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 Consultants Ltd



Jim Bradly CEng, MEI, Chartered Petroleum Engineer
Operations Director – EAME
RPS Energy Technical & Advisory

Name	Role	Signature
Joseph Tan	Project Manager	Not available due to home working
David Offer	Geoscience Lead	
Jim Bradly	Reservoir Engineering Lead	
Gordon Fraser	Cost Engineering Lead	

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1 EXECUTIVE SUMMARY

In response to a request by Hibiscus Petroleum Berhad (“Hibiscus”), and the Letter of Engagement dated 18th December 2020 with Hibiscus (the “Agreement”), RPS Energy Consultants Ltd (“RPS”) has completed an independent evaluation of the Repsol S.A. (“Repsol”) assets, for sale as part of a proposal, administered by J.P. Morgan Securities plc, which Hibiscus is interested in acquiring.

The potential transaction encompasses a 100% working interest in each of the following entities:

- Repsol Oil & Gas Malaysia Limited;
- Repsol Oil & Gas Malaysia (PM3) Limited; and
- Talisman Vietnam Limited.

These entities in turn hold and operate Repsol’s business in Malaysia, comprising the following interests, collectively, the “Assets”:

- 60% working interest in the Kinabalu block located in Sabah, Malaysia
- 35% working interest in the PM3 CAA block located within the Commercial Arrangement Area (“CAA”) between Malaysia and Vietnam
- 60% working interest in each of the PM305 and PM314 blocks located off the eastern coast of Peninsular Malaysia in the Malay Basin; and
- 70% working interest in Block 46 (Cai Nuoc), a tie-back asset to the PM3 CAA block located in Vietnamese waters.

1.1 Overview of Assets

Repsol’s interests are located in the Malay and West Natuna Basins, offshore Malaysia (Figure 1-1)[1]

Block PM3-CAA is located in the Northeast Malay basin, close to the Vietnamese median line. The block contains a total of 14 accumulations in six fields, developed around two hubs (North and South). Fields are generally comprised of low relief anticline structures with multiple stacked fluvial/shallow marine deltaic sandstones. Fluids are a combination of oil, condensate and gas, with highly variable CO_2 content (5-70%).

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

Blocks PM305 and PM314 are located in the Southwest Malay Basin and are partially abandoned, with only the Angsi Southern Channel/Murai unitised field still producing.

The Kinabalu PSC is located on the Sabah side of the Malaysia-Brunei maritime border in the Natuna Basin. The block contains the Kinabalu field, which is separated by Northeast-Southwest trending extensional faults, into three fault blocks: Kinabalu Main, Kinabalu East and Kinabalu Far East.

[1] *Source: Repsol*

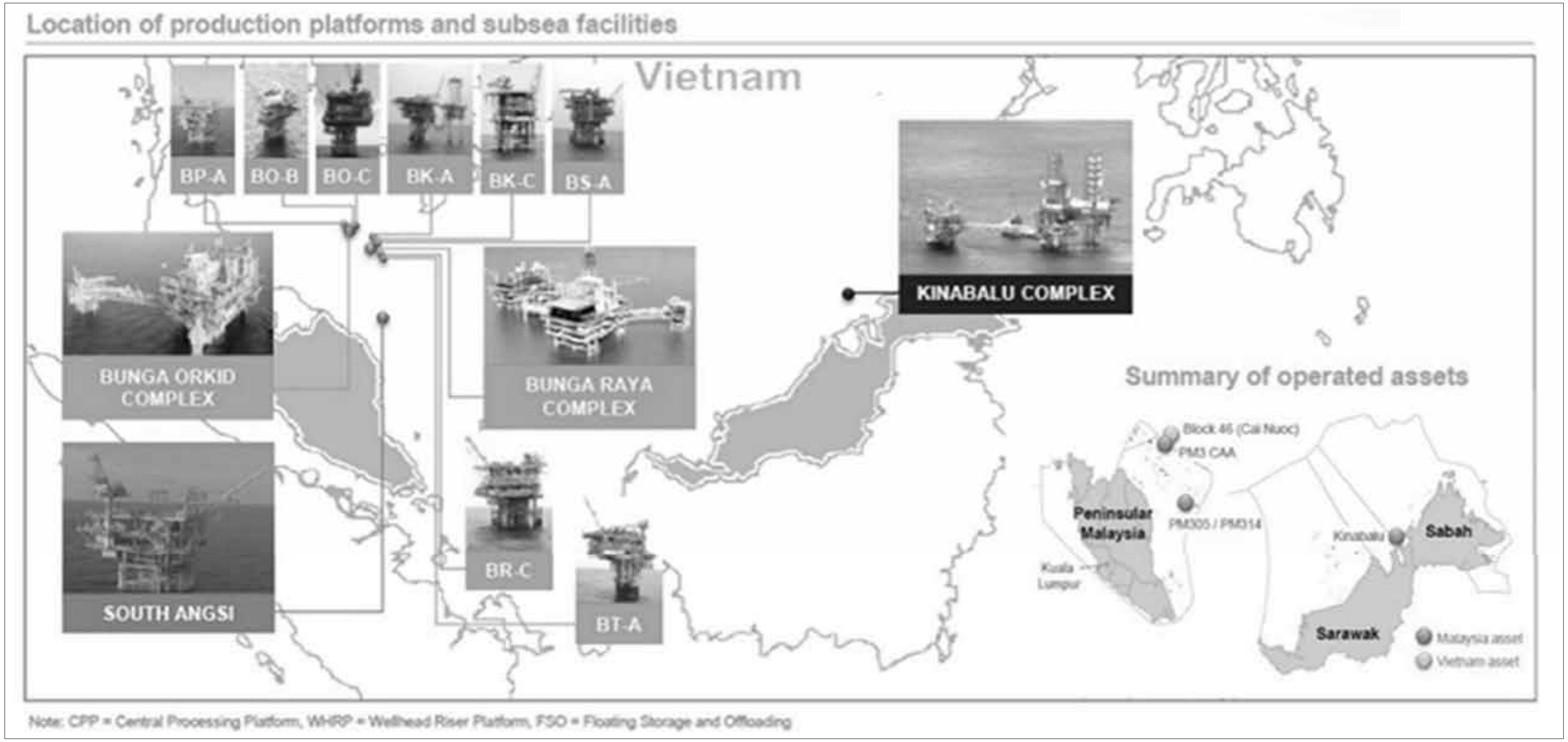

Figure 1-1: Map showing Transaction Assets

1.2 Subsurface and Resource Evaluation

Repsol has placed a large amount of field data, within reports and presentations, in the Virtual Data Room (VDR). A Physical Data Room (PDR) was also available in Repsol's Malaysia offices between the 14th and 17th of December 2020. Due to current travel restrictions, remote access to one computer, inside the PDR was made available to RPS staff, using Microsoft Teams, and the time shared between the geology and engineering disciplines.

Given the reduced access time, RPS has focussed on auditing a limited subset of existing production, planned commitments and defined future developments. A summary of the activities presented by Repsol's Business Case and RPS' review status is shown in Table 1.1.

The focus has been on existing production and planned interventions in the two major assets (PM3-CAA & Kinabalu), sanctioned development projects and near term mature development projects.

Certain assets present mature production with remaining reserves which are minor components of the overall portfolio valuation (e.g. PM305/314 existing production). As a result of the limited time available, these were not reviewed, with Repsol's reserves estimates accepted.

Of the remaining proposed projects, where possible, RPS has independently estimated in-place volumetrics (e.g. Saffron B Discovery, NW Raya Infill). Where this was not possible, RPS has reviewed the basis for Repsol's estimates and accepted them where appropriate on the basis of the information provided.

Other activities proposed by Repsol are not considered sufficiently mature to allow RPS to review them in any meaningful way (e.g. Kekwa post-seismic, Raya post-seismic).

COMPETENT VALUER'S REPORT ON THE ASSETS (CONT'D)

Status	Block/Permit	Field	Reviewed by RPS?	Methodology	RPS Resource Classification
Existing Production	**PM3-CAA**	Bunga Orkid	Y	DCA	Reserves – Developed Producing
		North Bunga Orkid			
		East Bunga Orkid			
		West Bunga Orkid			
		Bunga Pakma			
		North Bunga Pakma			
		East Bunga Kekwa			
		West Bunga Kekwa			
		North Bunga Raya			
		East Bunga Raya			
		West Bunga Raya			
		North West Bunga Raya			
		Bunga Seroja			
		Bunga Tulip			
	Block 46	Cai Nuoc	Y	DCA*	Reserves - Developed Producing
	PM305/314	Murai/Angsi Southern Channel Unit ("ASCU")	N	-	Reserves - Developed Producing
	Kinabalu	Kinabalu Main	Y	DCA	Reserves – Developed Producing
		Kinabalu East			
		Kinabalu Far East			
Well Interventions	**PM3-CAA**	Bunga Orkid	Y	Type Curves	Reserves – Developed Non-producing
		North Bunga Orkid			
		East Bunga Orkid			
		West Bunga Orkid			
		Bunga Pakma			
		North Bunga Pakma			
		East Bunga Kekwa			
		East Bunga Raya			
		North West Bunga Raya			
Low Investment Case (Sanctioned Projects)	**PM3-CAA**	North Bunga Orkid H4 Area Development (NBO-H4)	Y	Vendor Model Audit	Reserves – Approved for Development
		East Bunga Raya BR-LL Infill Well			

Status	Block/Permit	Field	Reviewed by RPS?	Methodology	RPS Resource Classification
Defined Developments	PM3-CAA	Pakma Infill	Y	Vendor Model Audit	Contingent Resources – Development Pending
		Saffron B Discovery	Y	Volumetrics Only	Contingent Resources – Development Pending
		2022 Infill (Bunga Orkid)	Y	Vendor Model Audit	Reserves – Approved for Development
		Kekwa Post-seismic	N	-	Prospective Resources
		Raya Post-seismic	N	-	Contingent Resources – Development Unclarified
		NW Raya Infill	Y	Volumetrics Only	Contingent Resources – Development Unclarified
		Hoa Mai Development	Y	Vendor Model Audit	Contingent Resources – Development Pending
		Water Injection	N	-	Contingent Resources – Development Unclarified
		Production Efficiency	N	-	Contingent Resources – Development Unclarified
		Gas Blowdown	N	-	Contingent Resources – Development Unclarified
		Low Low Pressure	N	-	Contingent Resources – Development Unclarified
		ESPs (East Bunga Raya & West Bunga Orkid)	Y	Vendor Model Audit	Reserves - Justified for Development (Pilot only)
	Kinabalu	Production Efficiency	N	-	Contingent Resources – Development Unclarified
		D18 Infill	Y	Vendor Model Audit	Reserves – Approved for Development
		Undrained Volumes	Y	Vendor Model Audit	Reserves – Approved for Development
		ESPs	Y	Vendor Model Audit	Reserves – Justified for Development (Pilot only)
Future Developments	PM3-CAA	Saffron A Prospect	N	-	Prospective Resources
		Saffron C Prospect	N	-	
		Greater Matahari Area	N	-	
		Greater Central Area	N	-	
		Raya I40U Leads	N	-	
		Greater Sliver Area	N	-	
	Kinabalu	2022 Infill Campaign	N	-	Contingent Resources – Development Unclarified
		CC Far East Development	N	-	Prospective Resources

Table 1.1: Summary of RPS Review

** Block 46 (Cai Nuoc) remaining production has been assessed as part of East Bunga Kekwa DCA*

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1.3 Economic Analysis

RPS has reviewed all pertinent fiscal terms related to both the all PSCs and confirmed they are correctly interpreted within the economic model presented by Repsol/J.P. Morgan and Hibiscus. These models have then been used to perform the economic analysis of the fields/assets.

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 and Opex, and inclusion of other financial information and assumptions, as outlined in Capex, Opex and Abex sections.

The PSC is assumed to reach its economic limit when the cumulative value of its operating cash flow 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 post-tax undiscounted Net Cash Flow Money-of-the-Day ("MOD").

An annual inflation rate of 2 per cent has been built into the ELT. This inflation rate has also been applied to all cost estimates to adjust them from 2021 dollars to MOD.

The effective date of this report is 1st January, 2021 and this has been used as the discount date for the valuation.

1.4 Reserves Summary & Estimated Net Present Value

A summary of Reserves for the assets is provided in Table 1.2 to Table 1.5 below for Oil, Gas, Condensate and Barrels of Oil Equivalent respectively. Table 1.6 to Table 1.7 provide Net Present Value estimates for PM3-CAA, Kinabalu PSC, B46 PSC and PM305/314 PSC, respectively. Table 1.10 summarises the consolidated (PM3 CAA PSC, Kinabalu PSC, B46 PSC, PM305/314 PSC) Net Present Value estimates.

SUMMARY OF OIL RESERVES
As of 1 January 2021
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMstb)						Hibiscus Net Entitlement Reserves[2] (MMstb)					
	1PD	**1P**	**2PD**	**2P**	**3PD**	**3P**	**1PD**	**1P**	**2PD**	**2P**	**3PD**	**3P**
PM3 CAA	14.0	17.7	21.1	29.8	25.6	39.0	3.2	4.0	4.6	6.6	5.4	7.9
B46[3]	0.0	0.0	1.0	1.0	1.3	1.3	0.0	0.0	0.4	0.4	0.6	0.6
Kinabalu	12.6	16.1	24.2	28.1	34.1	39.2	5.0	6.4	9.4	10.8	12.4	14.1
PM305/314[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total[3]	**26.6**	**33.7**	**46.3**	**58.9**	**61.1**	**79.5**	**8.2**	**10.4**	**14.5**	**17.9**	**18.4**	**22.6**

Notes:

*[1] Gross field Reserves (100% basis) **after** economic limit test*

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

[3] Zero 1PD and 1P as B46 Low Estimate does not pass economic limit test

[4] Zero Reserves for Low, Best, and High Estimate do not pass economic limit test

[5] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Reserves are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1P Reserves may be a very conservative assessment and the total 3P Reserves a very optimistic assessment.

Table 1.2: Oil Reserves as of 1 January 2021

[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.

COMPETENT VALUER'S REPORT ON THE ASSETS (CONT'D)

SUMMARY OF GAS RESERVES
As of 1 January 2021
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (Bscf)						Hibiscus Net Entitlement Reserves[2] (Bscf)					
	1PD	1P	2PD	2P	3PD	3P	1PD	1P	2PD	2P	3PD	3P
PM3 CAA	214.3	217.3	368.5	377.5	535.2	549.2	48.5	49.0	80.8	83.6	112.9	112.5
Block 46												
Kinabalu												
PM305/314												
Total[3]	**214.3**	**217.3**	**368.5**	**377.5**	**535.2**	**549.2**	**48.5**	**49.0**	**80.8**	**83.6**	**112.9**	**112.5**

Notes:

[1] *Gross field Reserves (100% basis)* ***after*** *economic limit test*

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

[3] *PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Reserves are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1P Reserves may be a very conservative assessment and the total 3P Reserves a very optimistic assessment.*

Table 1.3: Gas Reserves as of 1 January 2021

SUMMARY OF CONDENSATE RESERVES
As of 1 January 2021
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMstb)						Hibiscus Net Entitlement Reserves[2] (MMstb)					
	1PD	1P	2PD	2P	3PD	3P	1PD	1P	2PD	2P	3PD	3P
PM3 CAA	6.6	6.8	11.5	12.1	15.6	16.6	1.5	1.5	2.5	2.7	3.3	3.4
Block 46												
Kinabalu												
PM305/314												
Total[3]	**6.6**	**6.8**	**11.5**	**12.1**	**15.6**	**16.6**	**1.5**	**1.5**	**2.5**	**2.7**	**3.3**	**3.4**

Notes:

[1] *Gross field Reserves (100% basis)* ***after*** *economic limit test*

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

[3] *PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Reserves are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1P Reserves may be a very conservative assessment and the total 3P Reserves a very optimistic assessment.*

Table 1.4: Condensate Reserves as of 1 January 2021

SUMMARY OF RESERVES (BOE)
As of 1 January 2021
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMboe)						Hibiscus Net Entitlement Reserves[2] (MMboe)					
	1PD	1P	2PD	2P	3PD	3P	1PD	1P	2PD	2P	3PD	3P
PM3 CAA	56.4	60.7	94.0	104.8	130.4	147.1	12.8	13.7	20.7	23.3	27.5	30.1
Block 46	0.0	0.0	1.0	1.0	1.3	1.3	0.0	0.0	0.4	0.4	0.6	0.6
Kinabalu	12.6	16.1	24.2	28.1	34.1	39.2	5.0	6.4	9.4	10.8	12.4	14.1
PM305/314	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total[3]	**68.9**	**76.8**	**119.2**	**134.0**	**165.9**	**187.6**	**17.7**	**20.1**	**30.5**	**34.5**	**40.5**	**44.8**

Notes:
*[1] Gross field Reserves (100% basis) **after** economic limit test*
[2] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.
[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Reserves are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1P Reserves may be a very conservative assessment and the total 3P Reserves a very optimistic assessment.

Table 1.5: Summary of Reserves in Oil Equivalent Barrels as of 1 January 2021

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1PD	2025	46	53	54	56
1P	**2025**	**38**	**41**	**41**	**42**
2PD	2027	120	113	111	110
2P	**2027**	**170**	**146**	**142**	**137**
3PD	2027	241	203	196	189
3P	**2027**	**284**	**234**	**224**	**215**

Table 1.6: PM3 CAA PSC – Post-Tax Valuation at RPS Base Case Price Scenario

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1PD	2026	53	54	54	54
1P	**2027**	**77**	**74**	**73**	**72**
2PD	2032	147	128	123	120
2P	**2032**	**188**	**157**	**150**	**145**
3PD	2032	259	202	191	182
3P	**2032**	**293**	**227**	**215**	**204**

Table 1.7: Kinabalu PSC – Post-Tax Valuation at RPS Base Case Price Scenario

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1PD	2025	(5)	(3)	(3)	(3)
1P	**2025**	**(5)**	**(3)**	**(3)**	**(3)**
2PD	2027	2	3	3	3
2P	**2027**	**2**	**3**	**3**	**3**
3PD	2027	10	9	9	9
3P	**2027**	**10**	**9**	**9**	**9**

Table 1.8: B46 PSC – Post-Tax Valuation at RPS Base Case Price Scenario

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1PD	2025	(9)	(10)	(10)	(10)
1P	**2025**	**(9)**	**(10)**	**(10)**	**(10)**
2PD	2027	(10)	(10)	(10)	(10)
2P	**2027**	**(10)**	**(10)**	**(10)**	**(10)**
3PD	2027	(9)	(10)	(10)	(10)
3P	**2027**	**(9)**	**(10)**	**(10)**	**(10)**

Table 1.9: PM305/PM314 PSC – Post-Tax Valuation at RPS Base Case Price Scenario

	Post-Tax Net Present Value (US$ Million, MOD)			
	0%	8%	10%	12%
1PD	84	94	96	97
1P	**102**	**102**	**102**	**101**
2PD	259	233	228	222
2P	**351**	**296**	**285**	**275**
3PD	500	404	386	370
3P	**578**	**460**	**438**	**418**

Table 1.10: Consolidated (PM3 CAA PSC, Kinabalu PSC, B46 PSC, and PM305/314 PSC) – Post-Tax Valuation at RPS Base Case Price Scenario

COMPETENT VALUER'S REPORT ON THE ASSETS (CONT'D)

Table 1-11 and Table 1-12 summarise the incremental projects' recoverable volumes (until PSC expiry prior to economic limit test) for PM3 CAA PSC and Kinabalu PSC, respectively.

PM3 CAA PSC	Low	Best	High
Project Description	**MMstb**	**MMstb**	**MMstb**
North Bunga Orkid H4 Area Development (NBO-H4)	3.96	7.43	11.49
BRB-LL Development	0.49	0.95	1.41
East Bunga Raya ESP I-120 Reservoir	0.19	0.29	0.39
West Bunga Orkid ESP H0ss12 Reservoir	0.16	0.26	0.47
Bunga Orkid Infill Well	0.18	0.37	0.61

Table 1-11: PM3 CAA PSC Incremental Project Recoverable Oil and Condensate Volumes

Kinabalu PSC	Low	Best	High
Project Description	**MMstb**	**MMstb**	**MMstb**
D18 Infill Well	0.45	0.57	0.79
ESP	2.20	2.54	3.24
Undrained Volume Project	0.71	0.83	1.05

Table 1-12: Kinabalu PSC Incremental Project Recoverable Oil Volumes

1.5 Contingent Resources Summary

A summary of Contingent Resources for the Assets is provided in Table 1.13 to Table 1.15 below for Oil, Gas, and Barrels of Oil Equivalent, respectively. RPS did not conduct any independent review of Repsol's estimates of these activities.

The full field gross Best Estimate for both oil and gas are sourced directly from Repsol's economic model. In order to derive the full field gross Low Estimate and High Estimate, RPS has applied the ratio of full field gross 1P over full field gross 2P and the ratio of full field gross 3P over full field gross 2P respectively to the Best Estimate. Net Entitlement Contingent Resources for Low Estimate, Best Estimate, and High Estimate are derived based on the ratio of Net Entitlement over full field gross Reserves.

SUMMARY OF OIL CONTINGENT RESOURCES
As of 1 January 2021
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (MMstb)			Hibiscus Net Entitlement Contingent Resources[2] (MMstb)		
	Project	1C	2C	3C	1C	2C	3C
PM3 CAA	Raya post Seismic	6.2	10.5	12.6	1.4	2.3	2.6
PM3 CAA	NW BR Infill	1.4	2.4	2.8	0.3	0.5	0.6
PM3 CAA	Production Efficiency	0.3	0.4	0.5	0.1	0.1	0.1
Kinabalu	Production Efficiency	0.2	0.4	0.5	0.1	0.1	0.2
Total[3]		**8.1**	**13.7**	**16.4**	**1.9**	**3.1**	**3.4**

Notes:

[1] Gross field Contingent Resources (100% basis) until the current expiry of the PSC.

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

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Resources are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

Table 1.13: Oil Contingent Resources as of 1 January 2021

SUMMARY OF GAS CONTINGENT RESOURCES
As of 1 January 2021
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (Bscf)			Hibiscus Net Entitlement Contingent Resources[2] (Bscf)		
	Project	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
PM3 CAA	Raya post Seismic	8.0	13.9	18.7	1.8	3.1	3.8
PM3 CAA	NW BR Infill	0.6	1.0	1.3	0.1	0.2	0.3
PM3 CAA	Production Efficiency	3.8	6.6	8.9	0.9	1.5	1.8
Total[3]		**12.4**	**21.5**	**29.0**	**2.8**	**4.8**	**5.9**

Notes:

[1] Gross field Contingent Resources (100% basis) until the current expiry of the PSC

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

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Resources are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

Table 1.14: Gas Contingent Resources as of 1 January 2021

SUMMARY OF CONTINGENT RESOURCES (BOE)
As of 1 January 2021
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (MMboe)			Hibiscus Net Entitlement Contingent Resources[2] (MMboe)		
	Project	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
PM3 CAA	Raya post Seismic	7.6	12.9	15.7	1.7	2.9	3.2
PM3 CAA	NW BR Infill	1.5	2.5	3.1	0.3	0.6	0.6
PM3 CAA	Production Efficiency	0.9	1.5	2.0	0.2	0.3	0.4
Kinabalu	Production Efficiency	0.2	0.4	0.5	0.1	0.1	0.2
Total[3]		**10.2**	**17.3**	**21.3**	**2.3**	**3.9**	**4.4**

Notes:

[1] Gross field Contingent Resources (100% basis) until the current expiry of the PSC

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

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Resources are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

Table 1.15: Summary of Contingent Resources in Oil Equivalent Barrels as of 1 January 2021

RPS did not perform commercial evaluation on Contingent Resources.

2 INTRODUCTION

RPS Energy Consultants Ltd ("RPS") has completed an independent evaluation of the Repsol S.A. ("Repsol") assets, for sale as part of a proposal, administered by J.P. Morgan Securities plc, which Hibiscus is interested in acquiring.

The potential transaction encompasses a 100% working interest in each of the following entities:

- Repsol Oil & Gas Malaysia Limited;
- Repsol Oil & Gas Malaysia (PM3) Limited; and
- Talisman Vietnam Limited.

These entities in turn hold and operate Repsol's business in Malaysia, comprising the following interests, collectively, the "Assets":

- 60% working interest in the Kinabalu block located in Sabah, Malaysia
- 35% working interest in the PM3 CAA block located within the Commercial Arrangement Area ("CAA" between Malaysia and Vietnam
- 60% working interest in each of the PM305 and PM314 blocks located off the eastern coast of Peninsular Malaysia in the Malay Basin; and
- 70% working interest in Block 46 (Cai Nuoc), a tie-back asset to the PM3 CAA block located in Vietnamese waters.

3 BASIS OF OPINION

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

This report represents RPS' 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.

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 valuation 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.

4 PM3 CAA & BLOCK 46

The PM3-CAA is subdivided into Northern and Southern Regions, which in total contains six fields: Bunga Orkid, Bunga Pakma in the North and Bunga Kekwa, Bunga Raya, Bunga Seroja and Bunga Tulip in the South.

The Northern area is developed by the Bunga Orkid (BO-A) central production platform, which processes and exports the produced oil and condensate via pipeline to the FSO and gas to the Bunga Raya East (BRE) field (Figure 4-1).

45 development wells (39 in Bunga Orkid and 6 in Bunga Pakma) have been drilled from three well head riser platforms (BO-B, BO-C and BO-D) to exploit the hydrocarbon accumulations. First Oil was produced on the 25th March 2009.

The Southern area is developed by a central production complex comprised of Bunga Raya – A (BR-A), BR-D and BR-E bridge linked platforms which process and export oil, gas and condensate from the Bunga Raya, Bunga Kekwa, Bunga Seroja and Bunga Tulip fields. Development wells are drilled from 6 wellhead riser platforms, Bunga Raya-Beta (BR-B), Bunga Raya-Charlie (BR-C), Bunga Kekwa-Alpha (BR-A), Bunga Kekwa-Charlie (BK-C), Bunga Seroja-Alpha (BS-A) and Bunga Tulip-Alpha (BT-A).

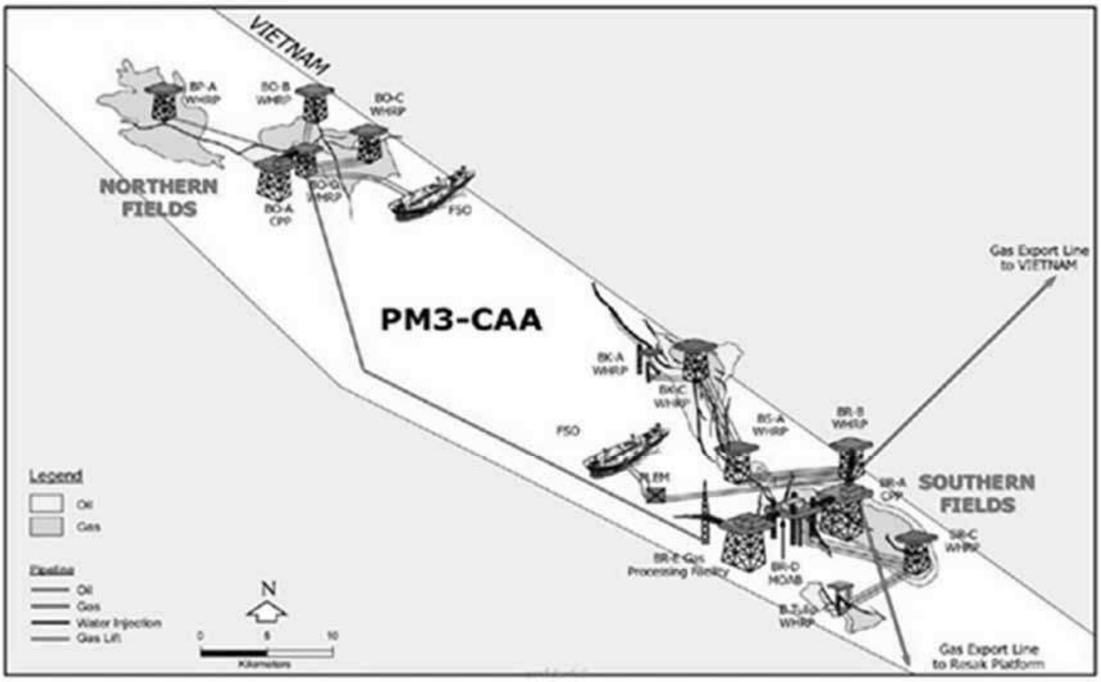

Figure 4-1: PM3-CAA Infrastructure[3]

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

All gas is sold to PETRONAS and PetroVietnam and PM3CAA is the only source of gas to southwest Vietnam.

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[3] *Source: Repsol*

4.1 Block History

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

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

Bunga Pakma was discovered in 1991 with the drilling of Bunga Pakma-1. Bunga Pakma North-1, in the immediately adjacent fault block to the north, was discovered in 1998. Six gas producers were drilled from April 2018 to August 2018 and successfully delivered first gas on 21st May 2018. A new single wellhead riser platform called Bunga Pakma-A (BP-A) was installed and tied-back to the BO-D platform, which is approximately 9 km to the south.

Bunga Seroja was discovered in 1997 with the drilling of Bunga Seroja-1. The field is developed by a single wellhead platform (BS-A) which is tied into Bunga Kekwa and tied back to Bunga Raya. A total of five development wells have been drilled. First production was in December 2003.

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

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

The Bunga Raya Complex is composed a number of adjacent accumulations separated by faults; North Bunga Raya, Northwest Bunga Raya, East Bunga Raya and West Bunga Raya. Complex facilities are based around a central processing platform (BR-A), with a gas compression mobile offshore application barge or MOAB (BR-D) and a single wellhead platform (BR-C). The complex commenced production in late 2003, with water injection commencing in early 2004. A total of 34 wells have been drilled in the Bunga Ray Complex to date. North Bunga Raya has been shut in since May 2018 with no further production anticipated.

Historical production plots for sales gas and combined oil & condensate are shown in Figure 4-2 & Figure 4-3 respectively.

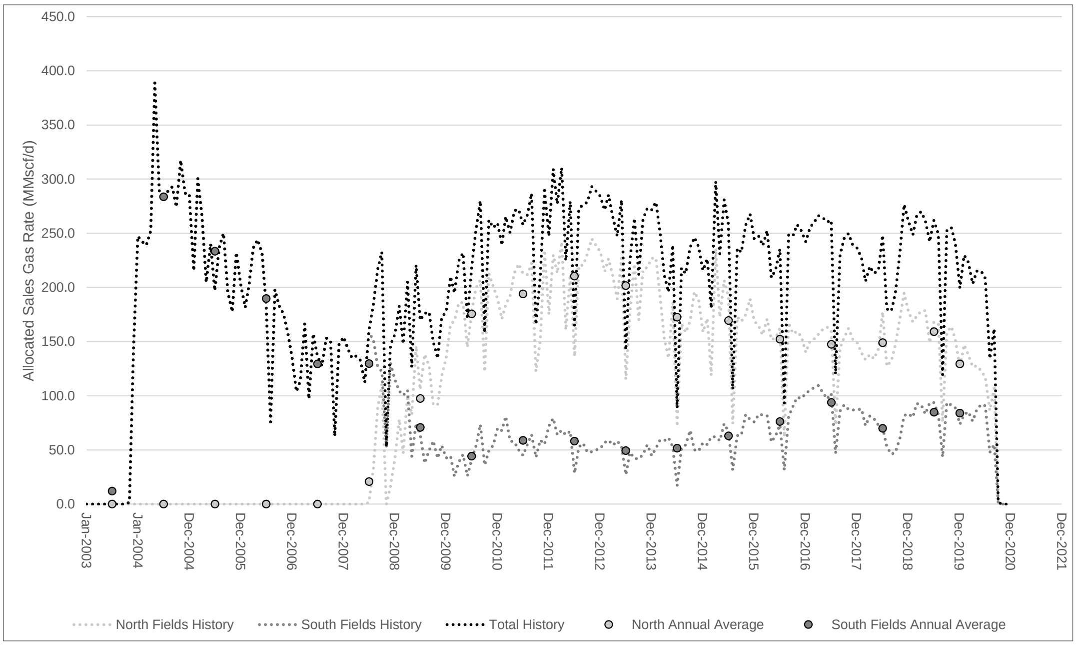

Figure 4-2: PM3-CAA Historical Sales Gas Production

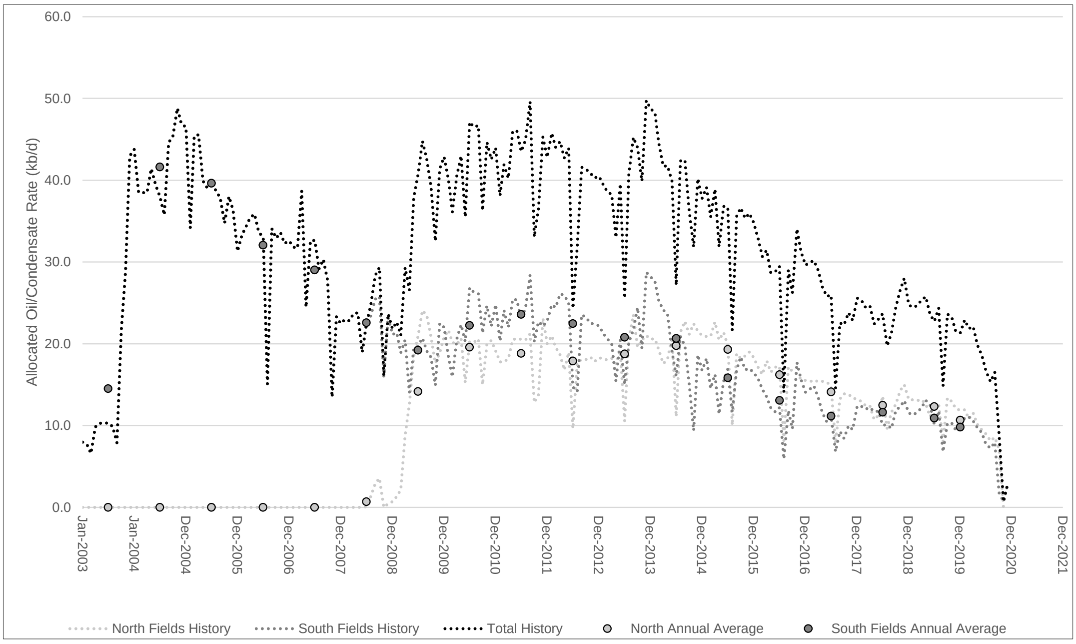

Figure 4-3: PM3-CAA Historical Combined Oil & Condensate Production[4]

[4] *Oil and Condensate are reported combined in the OFM database provided by Repsol.*

5 KINABALU

The Kinabalu field is located in the Eastern Baram Delta Province, 55km WNW of Labuan Island, Sabah and lies on the Western Flank of the Timbalai anticline in Block SB1 Kinabalu. It was discovered by Sabah Shell Petroleum in 1989 with the KN-1 exploration well in a water depth of approximately 54m. 3D seismic was acquired in Q4 1989, which lead to the drilling of three appraisal wells and the submission of the initial FDP in 1991. An additional 3D survey was acquired in 2004 and reprocessed in 2015. First oil was in December 1997 and the current partnership consists of Repsol (TLM) 60% and PETRONAS Carigali (40%). The current Oil PSC expires in 2032.

The field consists of three separate fault blocks split by 2 NE-SW trending syn-sedimentary extensional faults. These can be further divided into 4 separate accumulations: Kinabalu Main, Kinabalu Deep, Kinabalu East and Kinabalu Far East.

Hydrocarbons are produced by 2 well head platforms (KNDW-D WHP and KNDP-A) which have drilled over 50 development wells, 27 of which are currently active. Once at surface, hydrocarbons are then evacuated from the KNDP-A platform to the Semarang complex, 27 km to the northeast, where they are processes prior to transportation to the Labuan Crude Oil Terminal for storage and export (Figure 5-1).

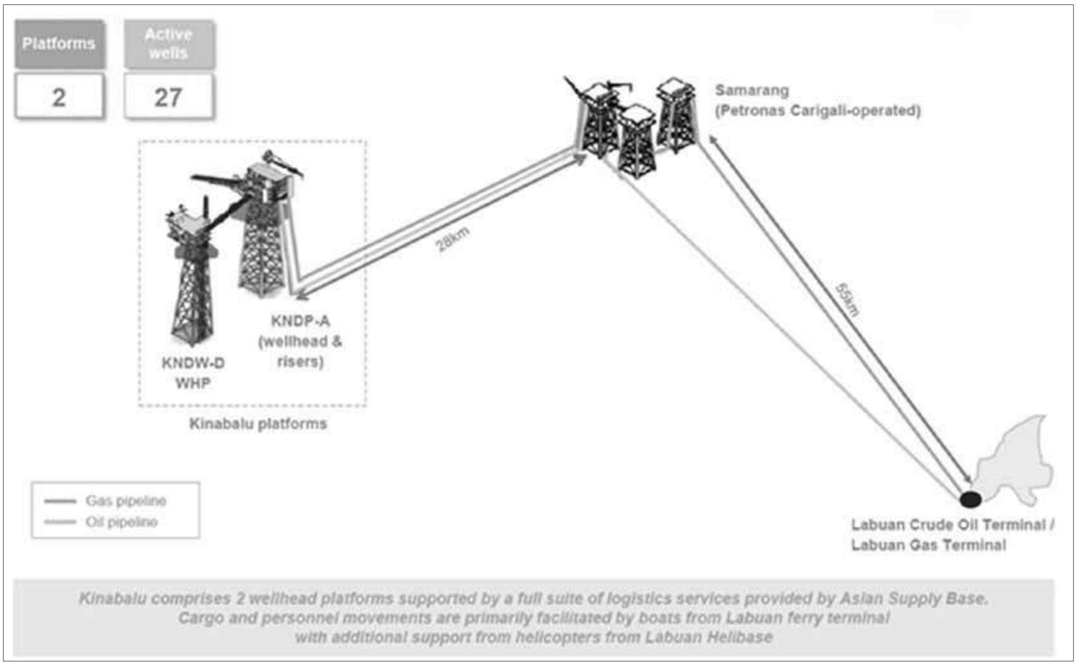

Figure 5-1: Diagram of Kinabalu Facilities[5]

5.1 Block History

The Kinabalu field was discovered in 1989 by drilling the KN-1 exploration well. The appraisal well KN-2 was drilled in 1990 confirmed the presence of considerable hydrocarbons volumes in the Main accumulation, known as Kinabalu Main. A second appraisal well KN-3 discovered the Kinabalu East accumulation. The Kinabalu Main and deep accumulations are dip-closed against a major SW-NE trending growth fault, whereas the Kinabalu East accumulation is dip closed in a similar was but against a smaller fault east of the major growth fault. KNFE-1 well proved the existence of the low relief 4-way dip closure associated with paleo-high structural play at Kinabalu Far East which works for O, R and S oil-bearing intervals

[5] Source: *Repsol*

COMPETENT VALUER'S REPORT ON THE ASSETS (CONT'D)

The field development plan was put in place in 1995 by the previous operator through KNDP-A platform with first oil in 26th December 1997. Further development wells were drilled during 2000 to 2009 whereby all the 20 slots on KNDP-A were fully utilised. Current operator, Repsol Oil and Gas Malaysia Limited (60%) has executed to increase the field oil production and achieved approximately 20,000 bopd in 2017-2018. In 2019, Kinabalu Redevelopment Plan Addendum Update 1 was proposed (comprise of 7 infill wells) with the intention to improve the overall reservoir recovery providing an additional 7 MMstb of gross reserves.

Oil is located in over 30 reservoirs with the majority of the reserves held in the F, J, K, L, M and O reservoirs in Kinabalu Main.

Reservoirs comprise of laterally continuous multiple stacked sandstones deposited in lower to upper shore face settings. Average reservoir porosities are 23% in the clean sands and 12% in the sand dominated heteroliths of the L group. Average hydrocarbon heights are approximately 50m and a maximum column height of 137m has been observed.

Structurally, the Kinabalu Main and Deep reservoirs are hanging wall monoclines. Hydrocarbons being trapped in a 3-way dip closure, which is fault closed by the NE-SW Kinabalu Main fault to the East an SE. The Kinabalu Main accumulation is separated by approximately 500m of shales from the Kinabalu Deep reservoir, which are filled with a condensate rich gas and at least one oil rim (S1-S2).

Kinabalu East is mainly gas bearing, with 2 oil rims, reservoirs are trapped in a tilted block fault closed to the West by the Kinabalu Main fault and to the East by the smaller Kinabalu East fault, whilst Kinabalu Far East is a small 4-way dip closure, which Repsol report as currently under appraised[6].

Historical production plots oil & are shown in Figure 5-2.

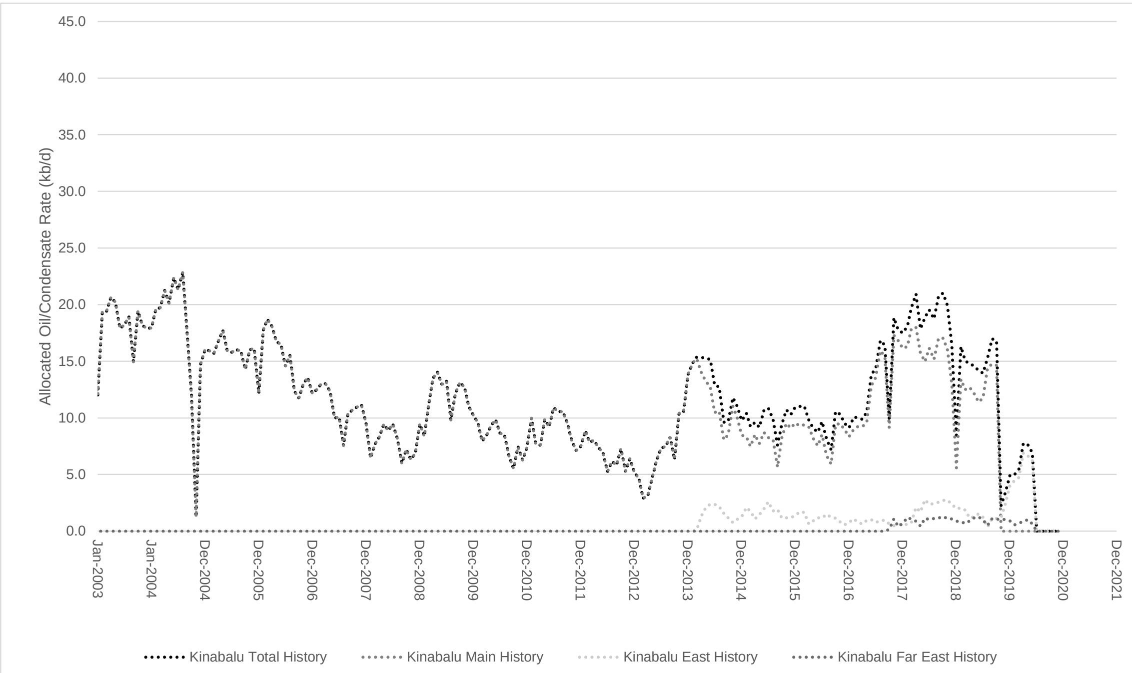

Figure 5-2: Kinabalu Historical Oil Production

[6] *3.3.2.1.1.1 2020 Kinabalu Oil FDP Addendum Update 2-K1 Main FB Additional Development - Repsol*

6 PM305/314

PM305/314 is a late life asset currently undergoing decommissioning. The only remaining production on the blocks comes from the Angsi South Channel unitised field ("ASCU"). As of September 2019, all other fields on the blocks, including South Angsi, Kuning and Naga Kecil have expired.

Production from the unitised ASCU field is via non-operated facilities and infrastructure, with all other operated facilities and infrastructure on the block currently undergoing decommissioning.

Decommissioning will be carried out in three phases:

- Phase 1 includes well suspension work and FSO decommissioning;
- Phase 2 includes plugging and abandoning (P&A) of wells; and
- Phase 3 includes removal of the MOAB.

All phases are anticipated to be completed by the end of 2023. A total exposure of approximately US$ 15 million remains (P&A costs). All other facilities abandonment costs and PSC commitments have been fulfilled.

6.1 Angsi South Channel Unit (ASCU)

The ASCU straddles the block boundary between PM-305 (Murai discovery) and the neighbouring non-operated Angsi GSPC, as shown in Figure 6-1.

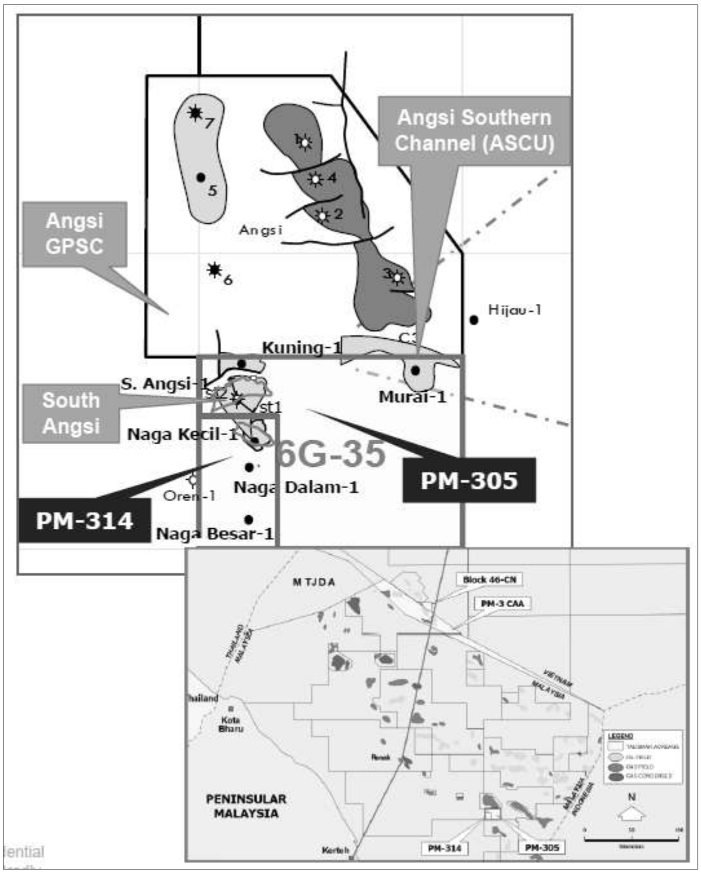

Figure 6-1: PM305 ASCU Location

The field was developed with four oil producers (three active) with first oil in March 2004. Water injection via two water injectors (both active) was added in 2007.

The field currently produces at approximately 500 bopd net to Repsol (based on a tract participation of 28.6%) with 77% water cut and has produced approximately 4.8 MMstb to date (June 2020) net to Repsol.

Repsol's WP&B 2021 estimate of remaining recoverable oil is approximately 0.6 MMstb net to Repsol.

Due to time constraints, the maturity of the production and relatively small volume of oil remaining in the asset based on Repsol's numbers, RPS has not reviewed Repsol's assessment and has accepted the 2021 WP&B numbers in the 1P, 2P and 3P cases.

7 FACILITIES

7.1 PM3-CAA

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

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

There are 46 active producing wells and 7 active producers in the North fields.

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

Figure 7-1 shows an outline of the North hub processing facilities.

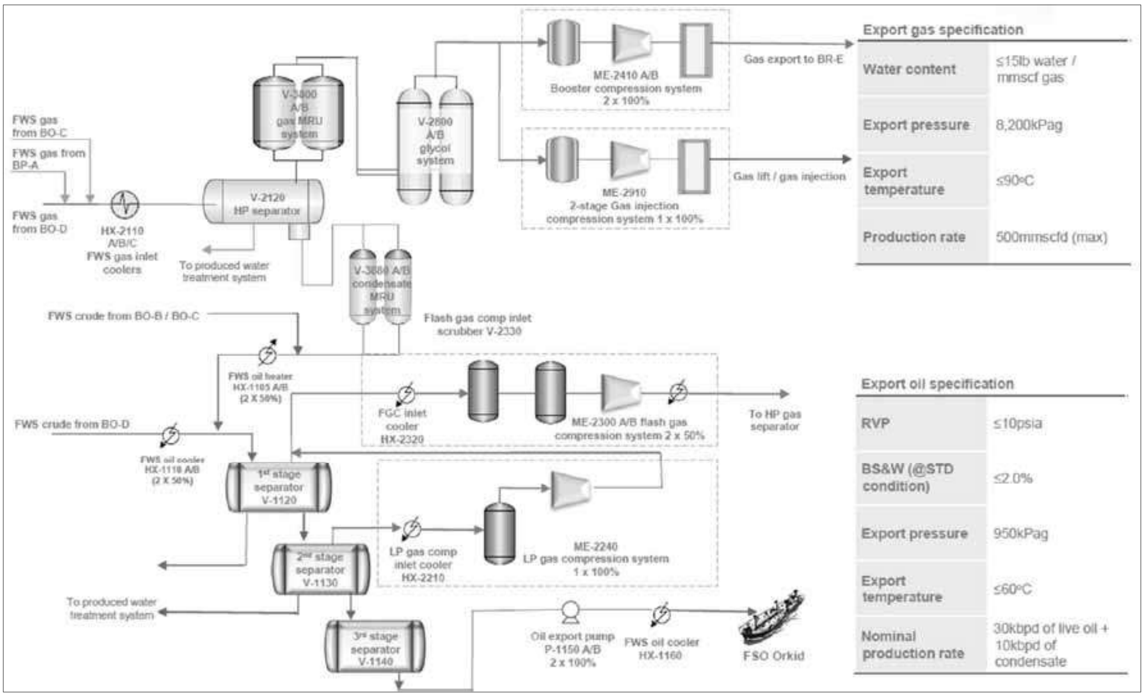

Figure 7-1: PM3-CAA North Fields Processing Facilities Schematic

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

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

Figure 7-2 & Figure 7-3 summarise the South hub processing facilities.

COMPETENT VALUER'S REPORT ON THE ASSETS (CONT'D)

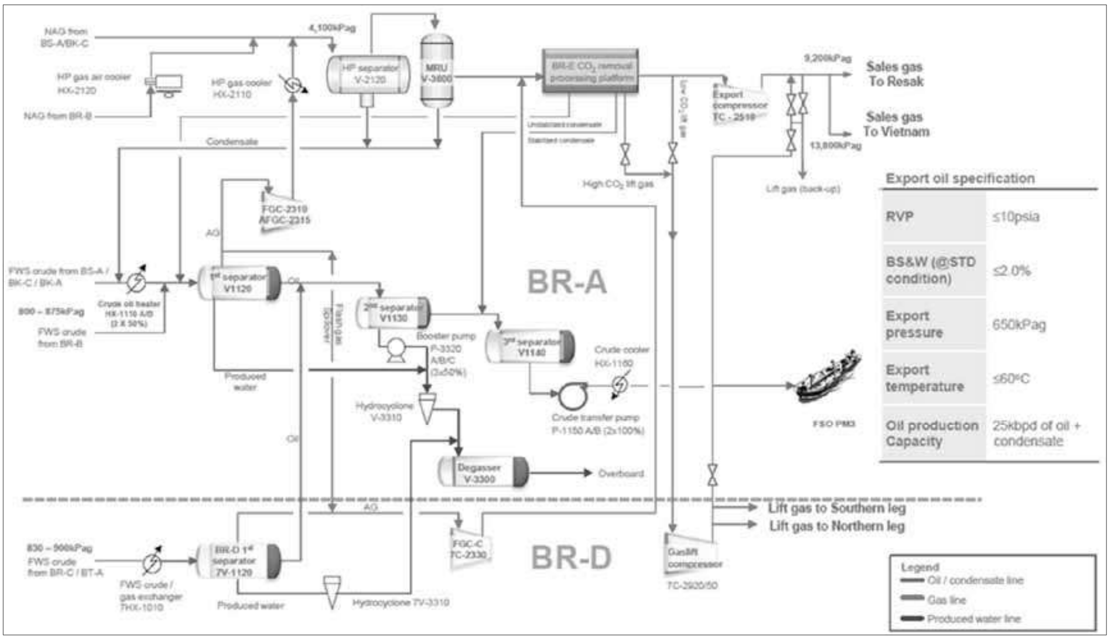

Figure 7-2: PM3-CAA South Fields Processing Facilities Schematic (BR-A & BR-D)

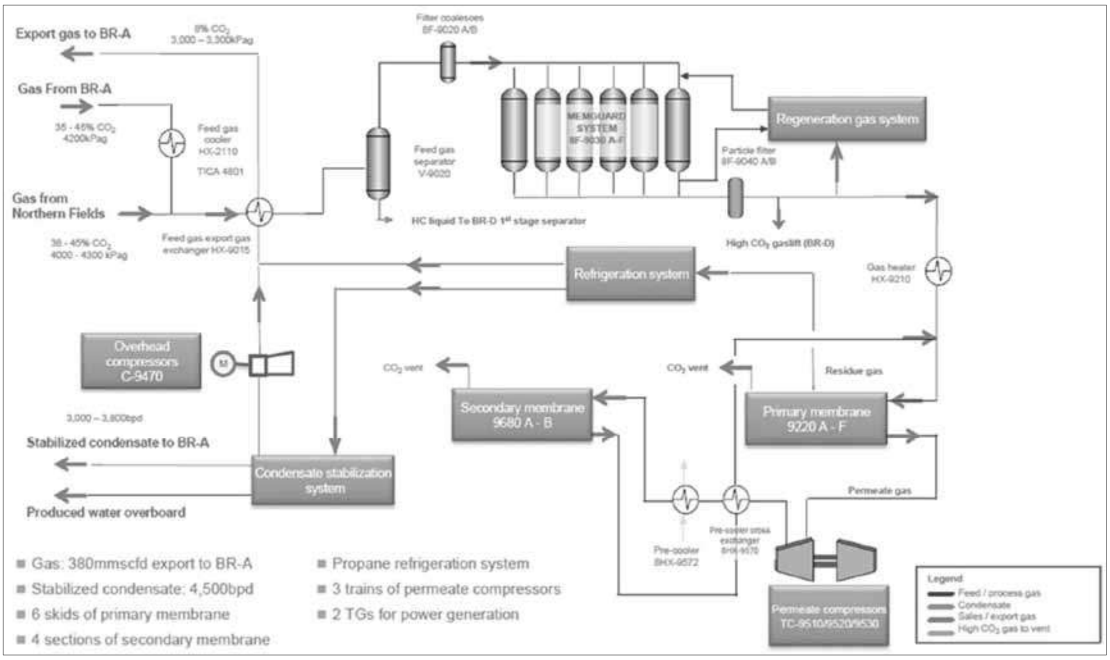

Figure 7-3: PM3-CAA South Fields Processing Facilities Schematic (BR-E)

7.2 Block 46 (Cai Nuoc)

Block 46 production is an extension of the East Bunga Kekwa field and subject to a unitisation agreement. Production is through the BK-C platform which is then routed to the BR-B CPP platform.

Oil and condensate are co-mingled and piped to an FSO for export via shuttle tanker. Gas is exported to Vietnam via pipeline.

7.3 Kinabalu PSC

Kinabalu facilities consist of 2 platforms (KNDP-A and KNDP-D). KNDP-A is a 20 slot well head platform with processing facilities for all Kinabalu production. KNDP-D is a 20 slot platform bridge linked to KNDP-A.

Oil is exported to the PETRONAS Carigali operated Semarang field and from there to Labuan Oil Terminal (LCOT) terminal on Labuan Island. Gas is exported to Semarang and on to Labuan Gas Terminal (LGAST) via pipeline.

Figure 7-4 shows the processing schematic for the block.

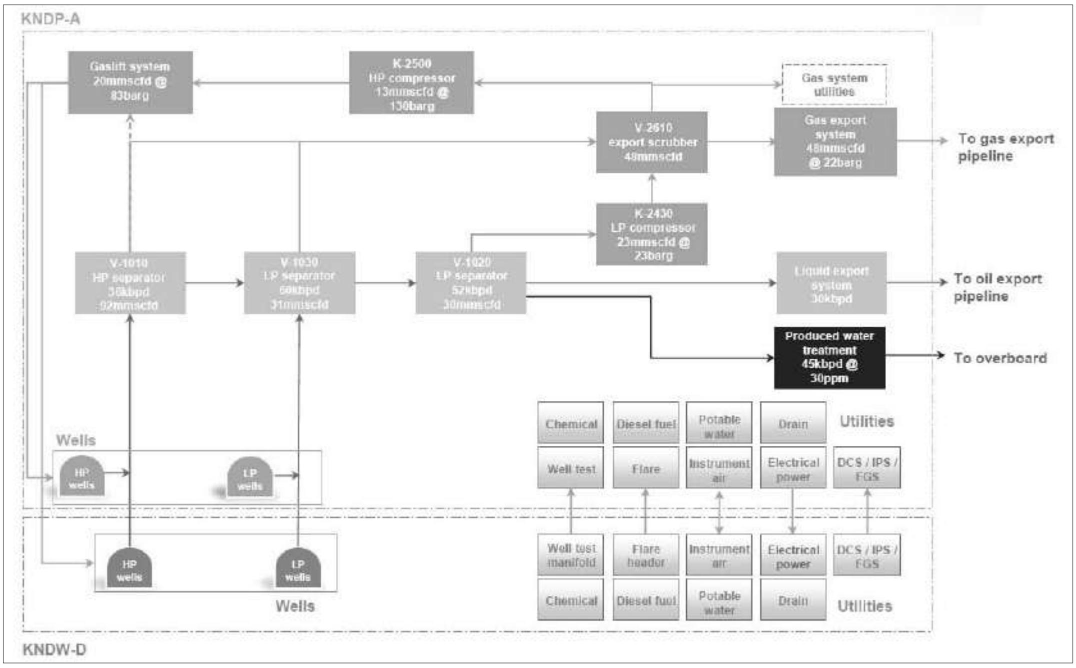

Figure 7-4: Kinabalu Processing Facilities Schematic

7.4 PM305/PM314

The only remaining producing field is the Angsi Southern Channel Unitised (ASCU) and is produced through Angsi C (AnDP-C) platform and piped to AnDR-A a drilling/riser platform and on to a bridge linked Angsi A CPP (AnPG-A). Oil is exported through Tapis field facilities and on to TCOT. Compressed gas is evacuated to an onshore slug catcher. Angsi hosts and process gas from the Besar field. Angsi C has 3 active producers, 2 active injectors and 1 idle well.

Southern Angsi facilities consisting of the SAA MOAB platform with 13 inactive wells currently undergoing decommissioning. The FSO has completed decommissioning in 2020.

8 COST ENGINEERING

Data pertaining to costs that RPS has used to independently generate its cost forecasts is largely based on the 2021 US$ Work Program and Budget (WP&B) documents which forecasts costs out to 2025 for all the PSC licenses and which Repsol submitted to PETRONAS's Malaysia Petroleum Management ("MPM") for approval. The MPM has now approved the WP&B's with some cost adjustment. RPS has incorporated the MPM adjustments in the forecast costs. RPS has reviewed the WP&B costs and unless otherwise stated believes the costs to be reasonable.

All costs presented in this Section are Real Term 2021.

8.1 Capital Expenditure (Capex)

Capex is categorised into 3 separate groups – Exploration, Development and Production Maintenance.

- Exploration Capex includes for a US$ 0.3 million spend in 2021 for seismic processing with no further spend scheduled after 2021.
- Development Capex consists of the following projects which are included in the 2021 WP&B and RPS has determined suitable for the base NFA case:
- PM3 North Bunga Orkid H4 (NBO-H4) project which is currently being developed and includes for 6 infill wells (2 oil producers and 4 water injector wells). First water is scheduled for September 2021 and first oil for December 2021
- PM3 Bunga Raya Infill (BRB-LL) project which includes for 1 oil producing well. Completion of drilling and first oil is scheduled for 4Q 2022
- PM3 Bunga Orkid Infill (BOC Infill) project which includes for 1 oil producing well. Completion of drilling and first oil scheduled for 1Q 202.
- PM3 ESP Pilot Project which includes installation and trial of 2 ESP's. One from the BRB and one from the BOD platform scheduled for 3Q 2022.
- Kinabalu Debottlenecking Project 2.0 address's flaring and debottlenecking will increase well production capacity. Includes installation of LP and HP compressors in 2023.
- Kinabalu D18 project which includes 1 oil producing well scheduled for drilling in 2022.
- Kinabalu ESP Pilot project which includes the workover of 2 existing wells to install ESP's. Scheduled for first oil 2022.
- Kinabalu Undrained Volumes project includes drilling of 1 oil producing well scheduled for 2022.

All the above projects are categorised as undeveloped with the exception of the Kinabalu Debottlenecking project which has been included in the developed costs. This project is largely complete apart from the installation of the compressors which serve to reduce flaring.

Table 8.1 details the project development CAPEX included in the NFA case.

Expenditure Item	Oil/Gas	2021	2022	2023
			US$ million	
PM3 Drilling H4 Wells	Oil	37.5	82.4	
PM3 Drilling BRB-LL Infill Well	Oil		15.6	
PM3 Drilling Indirects	Oil	1.2	1.0	1.2
PM3 Facilities H4	Oil	3.5	1.3	
PM3 ESP Pilot	Oil		9.0	
PM3 Indirects	Oil	0.5	0.5	
PM3 Total	**Oil**	**42.7**	**109.8**	**1.2**
KNB Debottlenecking Project 2.0		2.5	12.5	15.0
KNB D18	Oil		12.9	
KNB ESP Pilot	Oil		15.4	
KNB Undrained Volumes	Oil		13.7	
Kinabalu Total	**Oil**	**2.5**	**54.5**	**15.0**

Table 8.1: NFA Project Development Capex

Production Maintenance Capex includes operations maintenance and well workovers. Detailed operations maintenance budgets have been costed for 2021 and 2022. RPS has used these estimates together with previous years to estimate an average Production Maintenance Capex charge going forward post 2022. Table 8.2 details the annual costs included for production maintenance capex.

Asset	Oil/Gas	Annual Production Maintenance Capex (US$ million)
PM3	Oil	5.5
PM3	Gas	1.5
KNB	Oil	2.0

Table 8.2: Production Maintenance Capex

There is no difference in scope over the Low, Best and High cases.

8.2 Operating Costs (Opex)

Opex is based on the Operator's 2021 US$ WP&B which forecasts costs out to 2025. These costs were checked with previous 2020 US$ WP&B and were judged to be consistent. The US$ WP&B numbers were stated on a nominal basis and found to be using an increasing MYR/US$ exchange rate. RPS has adjusted the WP&B costs to real 2021 values and rebased MYR costs to a constant exchange rate of 4.13 MYR/US$.

RPS has adjusted the Total Platform cost element of the Surface Routine Operations included in the Inspection & Maintenance costs directly with annual production. All other costs are assumed to independent of production volumes.

Table 8.3, Table 8.4 and Table 8.5 detail the Opex cost breakdown for each asset.

PM3 Oil	US$ million				
	2021	2022	2023	2024	2025
Operating Personnel	6	8	8	7	7
Inspection & Maintenance	128	134	128	115	109
Well Costs	7	8	9	10	11
Transport	22	28	28	30	30
Others	33	37	37	35	34
Total	**196**	**215**	**210**	**197**	**191**

Table 8.3: PM3 2P Combined Oil & Gas Opex

KNB	US$ million				
	2021	2022	2023	2024	2025
Operating Personnel	2	2	2	2	2
Inspection & Maintenance	15	13	13	13	13
Well Costs	2	8	2	3	3
Transport	6	6	6	6	7
Others	18	23	19	17	14
Total	**43**	**52**	**42**	**41**	**39**

Table 8.4: KNB 2P Opex

Block 46	US$ million				
	2021	2022	2023	2024	2025
Operating Personnel	0.02	0.01	0.01	0.01	0.01
Inspection & Maintenance	3.1	2.4	2.4	2.2	2.1
Well Costs	0.5				
Transport	0.2	0.2	0.2	0.2	0.2
Others	0.2	0.1	0.1	0.1	0.1
Total	**4.0**	**2.7**	**2.7**	**2.6**	**2.4**

Table 8.5: Block 46 2P Opex

Opex costs for the remaining small production volumes from PM305/314 asset are minimal.

Full Life of Field costs have not been provided. RPS has extrapolated costs out to the end of the existing PSC and the end of the possible PSC extension term adjusting using the above methodology for declining production.

RPS has tapered production costs towards the end of field life reducing total annual Opex by 5% seven years from the end of forecast field life increasing to 10% reduction for the last two years.

8.2.1 Asset Integrity

RPS has reviewed asset integrity costs and has seen evidence of a comprehensive asset integrity program with scheduled future inspections and expected budgeted work to be carried out over the WP&B forecast period. After discussion with Hibiscus RPS considers the current maintenance budgets to be sufficient to maintain the current asset integrity standards for the remaining life of field. Details of the Hibiscus Asset Integrity Review are included in Section 10 of the Competent Person's Report.

8.3 Abandonment Costs (Abex)

Well abandonment costs and remaining facility decommissioning and abandonment cess payments are included in the life of field cost estimate. Facility abandonment costs are assumed to occur at the end of the field life and paid for out of the cess account which must cover the full facility abandonment cost by the end of the current PSC term. Well abandonment costs are scheduled for when the well ceases production and are at the operator's expense. Costs for well abandonments that occur during the term of the existing PSC's are included in the current PSC costs. Well abandonment costs that are scheduled to occur after the existing PSC term are assumed to be picked up by the future operator.

RPS has reviewed the operators 2020 abandonment cost estimates working file which details costs and schedule for well abandonment together with the remaining amount of cess payments needed to cover the full facilities abandonment cost. These schedules and costs have been compared against the abandonment costs in 2021 WP&B. The PM3 2021 WP&B shows no well abandonment having occurred in 2020 and no well abandonment expenditure forecast for 2021. The working file shows US$8 and US$17 million respectively for these 2 years. RPS has rescheduled the 2020-21 US$25 million well abandonment costs and includes these costs in the 2022, 2023 and 2024 abandonment costs.

Table 8.6 details the respective PSC's gross abandonment costs and cess payments, which in total is estimated to be US$ 218.5 million, is included in the cost input model.

RPS has estimated future well abandonment costs beyond the current PSC term using average costs of US$2 million per well for Kinabalu asset and $1.8 million per well for the PM3 asset.

Asset	Current PSC Well Abex	Outstanding Cess Payments
	US$ million	US$ million
PM3	88.2	71.2
Kinabalu	24.3	0.6[7]
Block 46 Unit	9.4	-
PM305/314	25.0	-
Total	**146.9**	**71.7**

Table 8.6: Abex Costs

[7] *Remaining US$ 557,000 Kinabalu Cess payment made in 2020.*

9 OVERVIEW AND OUTLOOK OF THE OIL AND GAS INDUSTRY

Overview and outlook of the oil and gas industry is presented in Appendix D.

10 ECONOMIC EVALUATION

10.1.1 Contractual Rights Overview

PM3 CAA PSC overview and its fiscal terms, as used to conduct commercial evaluation; Unitisation Agreement its Tract participation and Unit Participation are presented in Table 10.1 to Table 10.3.

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

Table 10.1: PM3 CAA PSC Fiscal Terms

Unitisation Agreement of PM3 CAA	
Counterparties	PETRONAS PetroVietnam
Scope	Establishes the creation of East Bunga Kekwa – Cai Nuoc unitised field that overlaps the boundary lines between Peninsular Malaysia and Vietnam Provides for the joint administration and management of as well as for the sharing of hydrocarbons in the unitised field
Effective Date	Effective as of 10 February 2000
Tract participation and Unit Participation	As presented in Table 10.3

Table 10.2: PM3 CAA Unitisation Agreement

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

Table 10.3: PM3 CAA Unitisation Agreement Tract participation and Unit Participation

Summaries of Gas Sales and Purchase Agreement key glossaries and terms are presented in Table 10.4 and Table 10.5.

Upstream Gas Sales Agreements (UGSA)	
Singing Date	10th February, 2000
Term	Initial term was for a period of 10 years and was extended until end of the existing PSC term (31 December 2027)
Counterparty	PETRONAS PetroVietnam PM3 CAA contractors: PETRONAS Carigali (35%), Repsol Malaysia Oil and Gas Limited (22.33%), Repsol Malaysia Oil and Gas (PM3) Limited (12.67%), PVEP (30%)
Scope	The contract lays down the obligations of both the Repsol, the PM3 CAA contractors, and the buyers, PETRONAS and PetroVietnam The contract defines the quality, quantity and price of the gas sold from the field
Delivery	The PM3 CAA contractors have to deliver the contracted gas capacity to PETRONAS or PetroVietnam delivery points, where the ownership of the gas will be transferred to PETRONAS or PetroVietnam respectively In case the PM3 CAA contractors fails to deliver the contracted daily quantity to either PETRNAS or PetroVietnam, they have to deliver the "Penalty Quantity" in the following year Penalty Quantity is the difference between the contracted daily quantity and quantity delivered at delivery point The first delivery of gas in any year will be deemed to be the Penalty Quantity accrued in preceding year
Pricing	As per UGSA terms

Table 10.4: Upstream Gas Sales Agreements (UGSA) Key Terms

Annual Delivery Quantity (ADQ) and Daily Average						
Year	**Total ADQ (Bscf)**	**PETRONAS ADQ (Bscf)**	**PetroVietnam ADQ (Bscf)**	**Total daily average (MMscfd)**	**PETRONAS daily average (MMscfd)**	**PetroVietnam daily average (MMscfd)**
2021	74.8	37.4	37.4	205.0	102.5	102.5
2022	74.8	37.4	37.4	205.0	102.5	102.5
2023	74.8	37.4	37.4	205.0	102.5	102.5
2024	63.5	31.8	31.8	174.0	87.0	87.0
2025	58.4	29.2	29.2	160.0	80.0	80.0

Table 10.5: Annual Delivery Quantity (ADQ) and Daily Average

Block 46 PSC overview and its fiscal terms, as used to conduct commercial are presented in Table 10.6.

Block 46 (Cai Nuoc)	
Contractors / Participating Interest	Repsol[1)] (70%) PVEP (30%)
Scope	Governs the redevelopment activities and production of liquids and natural gas in Block 46 (Cai Nuoc) Sets out each Contractor's responsibilities and commitments as well as terms on allocation of output (for royalty and profit crude oil / natural gas) and cost recovery mechanism
Effective Date and Duration	Effective as of 8 August 1990; valid for 25 years until 2015 PSC was first extended until 15 Feb 2017 for crude oil and 13 Dec 2018 for natural gas A second extension was subsequently granted until 31 Dec 2027 for both crude oil and natural gas
Cost Liquids / Gas	As per PSC terms
Profit Liquids / Gas	As per PSC terms
Export Duty	As per PSC terms
Training Fee	As per PSC terms
Corporate Income Tax rate	Paid on behalf of Contractor by Government (Corporate Tax Rate of 50%)
Production Bonus	As per PSC terms

1) Denotes operator

Table 10.6: Block 46 (Cai Nuoc) PSC Fiscal Terms

Block 46 PSC overview and its fiscal terms, as used to conduct commercial are presented in Table 10.7.

Kinabalu PSC	
Contractors / Participating Interest	Repsol 60%[1)] PETRONAS Carigali 40%
Scope	Governs the redevelopment activities and production of liquids and natural gas in Kinabalu. Sets out each Contractor's responsibilities and commitments as well as terms on allocation of output (for royalty and profit crude oil / natural gas) and cost recovery mechanism.
Effective Date and Duration	Effective as of 26th December, 2012 Contract valid for 20 years until 25th December, 2032
Royalty	As per PSC terms
Cost Liquids / Gas	As per PSC terms
Unused Liquids / Gas:	As per PSC terms
Available Profit Liquids / Gas:	As per PSC terms
Research Cess	As per PSC terms
Export Duty	As per PSC terms
Sabah Sales Tax[2)]	As per PSC terms
Supplementary Payment:	As per PSC terms
Petroleum Income Tax rate	38%
Abandonment Cess	Facilities abandonment costs are deposited in an escrow account according to the ratio of production to remaining reserves. Wells abandonment costs are recovered as paid.

1) Denotes operator; Repsol relinquished its associated gas rights effective from April 2015
2) The Sabah state government has implemented a 5% state sales tax on all petroleum products, mainly crude petroleum oil, natural gas (except for the natural gas used for the purpose of processing into LNG and natural gas sold o Sabah Energy Corporation Sdn Bhd), and liquefied gas, under Section 10 (1) of the State Sales Tax Enactment 1988, effective from 1 Apr 2020. Crude oil is exported from Labuan; therefore, Sabah Sales Tax is not be applicable in the valuation.

Table 10.7: Kinabalu PSC Fiscal Terms

PM305 / PM314 PSC overview and its fiscal terms, as used to conduct commercial evaluation; Unitisation Agreement its Tract participation and Unit Participation are presented in Table 10.8 to Table 10.12.

PM305 / PM314 PSC	
Contractors / Participating Interest	Repsol 60%[1)] PETRONAS Carigali 40%
Scope	Governs the exploration, development activities and production of liquids and natural gas in PM305. Sets out the Contractor's responsibilities and commitments as well as terms on allocation of output (for royalty and profit crude oil / natural gas) and cost recovery mechanism.
Effective Date and Duration	Effective as of 27th November, 2000 (PM305) / 31st March, 2004 (PM314) Contract valid for 29 years until 27th November, 2029 (PM305) / 31st March, 2033 (PM314)
Royalty	As per PSC terms
R/C Factor	As per PSC terms
Research Cess	As per PSC terms
Export Duty	As per PSC terms
Supplementary Payment:	As per PSC terms
Petroleum Income Tax rate	38%
Abandonment Cess	Facilities abandonment costs are deposited in an escrow account according to the ratio of production to remaining reserves. Wells abandonment costs are recovered as paid.

*1) Note: * Denotes operator; separate agreements exist each for PM305 / PM314*

Table 10.8: PM305 / PM314 PSC Fiscal Terms

Unitisation Agreement of PM305 and PM314	
Contractors / Participating Interest	PM305 – Repsol (60%), PETRONAS Carigali (40%) PM314 – Repsol (60%), PETRONAS Carigali (40%)
Scope	Establishes the creation of a unitised field combining the PM305 and PM314 tracts Provides for the joint administration and management of as well as for the sharing of hydrocarbons in the unitised field
Effective Date	Effective as of 14 August 2005
Tract participation and Unit Participation	As presented in Table 10.10

Table 10.9: Unitisation Agreement of PM305 and PM314

Petroleum Contract	Group Interest	Tract Participation	Unit Participation
PM 305		92.90%	
Repsol	60.00%		55.74%
PETRONAS Carigali	40.00%		37.16%
PM 314		7.10%	
Repsol	60.00%		4.26%
PETRONAS Carigali	40.00%		2.84%
Total		**100.00%**	**100.00%**

Table 10.10: PM305 and PM314 Unitisation Agreement Tract Participation and Unit Participation

Unitisation Agreement of PM305 and GPSC	
Contractors / Participating Interest	PM305 – Repsol (60%), PETRONAS Carigali (40%) GPSC – PETRONAS Carigali (50%), ExxonMobil (50%)
Scope	Establishes the creation of Angsi Southern Channel unitised field combining parts of PM305 and GPSC fields Provides for the joint administration and management of as well as for the sharing of hydrocarbons in the unitised field
Effective Date	Effective as of 18th March 2004
Tract participation and Unit Participation	As presented in Table 10.12

Table 10.11: Unitisation Agreement of PM305 and GPSC

Petroleum Contract	Group Interest	Tract Participation	Unit Participation
GPSC		71.40%	
PETRONAS Carigali	50.00%		35.70%
ExxonMobil	50.00%		35.70%
PM 305		28.60%	
Repsol	60.00%		17.20%
PETRONAS Carigali	40.00%		11.40%
Total		**100.00%**	**100.00%**

Table 10.12: Unitisation Agreement of PM305 and GPSC Tract Participation and Unit Participation

10.1.2 Petroleum Pricing Basis

The valuation has been based on the RPS Q2 2021 long term forecast for Brent (forward curve between 2021 and 2029; long term price of US$ 60 per barrel flat real at 2 per cent per annum thereafter) as shown in Table 10.13.

Based on the historical Tapis crude oil and condensate prices provided by Repsol, PM3 CAA crude oil and condensate, PM305 / PM314 crude oil, as well as Kinabalu crude oil were traded at a 5% premium to Brent, respectively. A summary of PM3 CAA, PM305, and Kinabalu crude oil price, PM3 CAA condensate price, and the implied gas price based on the gas pricing formula in UGSA is presented in Table 10.4.

Year	RPS Brent US$/bbl	PM3 CAA Crude Oil US$/bbl	PM305/PM314 Crude Oil US$/bbl	Kinabalu Crude Oil US$/bbl	PM3 CAA Condensate US$/bbl	PM3 CAA gas price US$/Mscf
2021	60.0	62.9	62.9	62.9	62.9	3.9
2022	57.0	59.7	59.7	59.7	59.7	3.7
2023	55.0	57.6	57.6	57.6	57.6	3.6
2024	53.0	55.5	55.5	55.5	55.5	3.5
2025	55.0	57.6	57.6	57.6	57.6	3.6
2026	58.0	60.8	60.8	60.8	60.8	3.9
2027	60.0	62.9	62.9	62.9	62.9	4.0
2028	63.0	66.0	66.0	66.0	66.0	4.2
2029	68.0	71.3	71.3	71.3	71.3	4.5
2030	71.7	75.1	75.1	75.1	75.1	4.8
2031	73.1	76.6	76.6	76.6	76.6	4.9
2032	74.6	78.2	78.2	78.2	78.2	5.0

Table 10.13: RPS Price Forecast; PM3 CAA and Kinabalu Crude and Condensate Realised Price Forecast, and Implied Gas Price Forecast

10.1.3 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 Company's estimates of Capex and Opex, and inclusion of other financial information and assumptions, as outlined in Capex, Opex and Abex sections.

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

An annual inflation rate of 2 per cent has been built into the ELT. This inflation rate has also been applied to all cost estimates to adjust them from 2021 dollars to MOD.

The effective date of this report is 1st January, 2021 and this has been used as the discount date for the valuation.

The net present values at various discount rates attributed to Repsol for PM3 CAA PSC, Kinabalu PSC, B46 PSC, and PM305/PM314 PSC are presented in Table 10.14 to Table 10.15. Table 10.18 summarises the consolidated net present values at various discount rates attributed to Repsol.

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1PD	2025	46	53	54	56
1P	**2025**	**38**	**41**	**41**	**42**
2PD	2027	120	113	111	110
2P	**2027**	**170**	**146**	**142**	**137**
3PD	2027	241	203	196	189
3P	**2027**	**284**	**234**	**224**	**215**

Table 10.14: PM3 CAA PSC Post-Tax Valuation at RPS Base Case Price Scenario

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

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1PD	2026	53	54	54	54
1P	**2027**	**77**	**74**	**73**	**72**
2PD	2032	147	128	123	120
2P	**2032**	**188**	**157**	**150**	**145**
3PD	2032	259	202	191	182
3P	**2032**	**293**	**227**	**215**	**204**

Table 10.15: Kinabalu PSC Post-Tax Valuation at RPS Base Case Price Scenario

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1PD	2025	(5)	(3)	(3)	(3)
1P	**2025**	**(5)**	**(3)**	**(3)**	**(3)**
2PD	2027	2	3	3	3
2P	**2027**	**2**	**3**	**3**	**3**
3PD	2027	10	9	9	9
3P	**2027**	**10**	**9**	**9**	**9**

Table 10.16: B46 PSC – Post-Tax Valuation at RPS Base Case Price Scenario

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1PD	2024	(9)	(10)	(10)	(10)
1P	**2024**	**(9)**	**(10)**	**(10)**	**(10)**
2PD	2024	(10)	(10)	(10)	(10)
2P	**2024**	**(10)**	**(10)**	**(10)**	**(10)**
3PD	2024	(9)	(10)	(10)	(10)
3P	**2024**	**(9)**	**(10)**	**(10)**	**(10)**

Table 10.17: PM305/PM314 PSC – Post-Tax Valuation at RPS Base Case Price Scenario

COMPETENT VALUER'S REPORT ON THE ASSETS (CONT'D)

	Post-Tax Net Present Value (US$ Million, MOD)			
	0%	**8%**	**10%**	**12%**
1PD	84	94	96	97
1P	**102**	**102**	**102**	**101**
2PD	259	233	228	222
2P	**351**	**296**	**285**	**275**
3PD	500	404	386	370
3P	**578**	**460**	**438**	**418**

Table 10.18: Consolidated (PM3 CAA PSC, Kinabalu PSC, B46 PSC, and PM305/PM314 PSC) Post-Tax Valuation at RPS Base Case Price Scenario

10.2 Reserves and Resources

Full Field Gross Reserves by field and Hibiscus Net Entitlement Reserves are presented in Table 10.19 to Table 10.22.

SUMMARY OF OIL RESERVES
As of 1 January 2021
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMstb)						Hibiscus Net Entitlement Reserves[2] (MMstb)					
	1PD	1P	2PD	2P	3PD	3P	1PD	1P	2PD	2P	3PD	3P
PM3 CAA	14.0	17.7	21.1	29.8	25.6	39.0	3.2	4.0	4.6	6.6	5.4	7.9
B46[3]	0.0	0.0	1.0	1.0	1.3	1.3	0.0	0.0	0.4	0.4	0.6	0.6
Kinabalu	12.6	16.1	24.2	28.1	34.1	39.2	5.0	6.4	9.4	10.8	12.4	14.1
PM305/314[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total[3]	**26.6**	**33.7**	**46.3**	**58.9**	**61.1**	**79.5**	**8.2**	**10.4**	**14.5**	**17.9**	**18.4**	**22.6**

Notes:

*[1] Gross field Reserves (100% basis) **after** economic limit test*

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

[3] Zero 1PD and 1P as B46 Low Estimate does not pass economic limit test

[4] Zero Reserves as Low, Best, and High Estimate do not pass economic limit test

[5] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Reserves are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1P Reserves may be a very conservative assessment and the total 3P Reserves a very optimistic assessment.

Table 10.19: Oil Reserves as of 1 January 2021

SUMMARY OF GAS RESERVES
As of 1 January 2021
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (Bscf)						Hibiscus Net Entitlement Reserves[2] (Bscf)					
	1PD	1P	2PD	2P	3PD	3P	1PD	1P	2PD	2P	3PD	3P
PM3 CAA	214.3	217.3	368.5	377.5	535.2	549.2	48.5	49.0	80.8	83.6	112.9	112.5
B46												
Kinabalu												
PM305/314												
Total[3]	**214.3**	**217.3**	**368.5**	**377.5**	**535.2**	**549.2**	**48.5**	**49.0**	**80.8**	**83.6**	**112.9**	**112.5**

Notes:

*[1] Gross field Reserves (100% basis) **after** economic limit test*

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

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Reserves are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1P Reserves may be a very conservative assessment and the total 3P Reserves a very optimistic assessment.

Table 10.20: Gas Reserves as of 1 January 2021

SUMMARY OF CONDENSATE RESERVES
As of 1 January 2021
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMstb)						Hibiscus Net Entitlement Reserves[2] (MMstb)					
	1PD	1P	2PD	2P	3PD	3P	1PD	1P	2PD	2P	3PD	3P
PM3 CAA	6.6	6.8	11.5	12.1	15.6	16.6	1.5	1.5	2.5	2.7	3.3	3.4
B46												
Kinabalu												
PM305/314												
Total[3]	**6.6**	**6.8**	**11.5**	**12.1**	**15.6**	**16.6**	**1.5**	**1.5**	**2.5**	**2.7**	**3.3**	**3.4**

Notes:

*[1] Gross field Reserves (100% basis) **after** economic limit test*

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

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Reserves are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1P Reserves may be a very conservative assessment and the total 3P Reserves a very optimistic assessment.

Table 10.21: Condensate Reserves as of 1 January 2021

SUMMARY OF RESERVES
As of 1 January 2021
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMboe)						Hibiscus Net Entitlement Reserves[2] (MMboe)					
	1PD	1P	2PD	2P	3PD	3P	1PD	1P	2PD	2P	3PD	3P
PM3 CAA	56.4	60.7	94.0	104.8	130.4	147.1	12.8	13.7	20.7	23.3	27.5	30.1
B46	0.0	0.0	1.0	1.0	1.3	1.3	0.0	0.0	0.4	0.4	0.6	0.6
Kinabalu	12.6	16.1	24.2	28.1	34.1	39.2	5.0	6.4	9.4	10.8	12.4	14.1
PM305/314	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total[3]	**68.9**	**76.8**	**119.2**	**134.0**	**165.9**	**187.6**	**17.7**	**20.1**	**30.5**	**34.5**	**40.5**	**44.8**

Notes:

*[1] Gross field Reserves (100% basis) **after** economic limit test*

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

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Reserves are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1P Reserves may be a very conservative assessment and the total 3P Reserves a very optimistic assessment.

Table 10.22: Summary of Reserves in Oil Equivalent Barrels as of 1 January 2021

10.3 Contingent Resources Summary

A summary of Contingent Resources for the Assets is provided in Table 1.13 to Table 1.15 below for Oil, Gas, and Barrels of Oil Equivalent, respectively. RPS did not conduct any independent review of Repsol's estimates of these activities.

The full field gross Best Estimate for both oil and gas are sourced directly from Repsol's economic model. In order to derive the full field gross Low Estimate and High Estimate, RPS has applied the ratio of full field gross 1P over full field gross 2P and the ratio of full field gross 3P over full field gross 2P respectively to the Best Estimate. Net Entitlement Contingent Resources for Low Estimate, Best Estimate, and High Estimate are derived based on the ratio of Net Entitlement over full field gross Reserves.

SUMMARY OF OIL CONTINGENT RESOURCES
As of 1 January 2021
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (MMstb)			Hibiscus Net Entitlement Contingent Resources[2] (MMstb)		
	Project	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
PM3 CAA	Raya post Seismic	6.2	10.5	12.6	1.4	2.3	2.6
PM3 CAA	NW BR Infill	1.4	2.4	2.8	0.3	0.5	0.6
PM3 CAA	Production Efficiency	0.3	0.4	0.5	0.1	0.1	0.1
Kinabalu	Production Efficiency	0.2	0.4	0.5	0.1	0.1	0.2
Total[3]		**8.1**	**13.7**	**16.4**	**1.9**	**3.1**	**3.4**

Notes:

[1] Gross field Contingent Resources (100% basis) until the current expiry of the PSC.

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

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Reserves are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

Table 10.23: Oil Contingent Resources as of 1 January 2021

SUMMARY OF GAS CONTINGENT RESOURCES As of 1 January 2021 BASE CASE PRICES AND COSTS							
		Full Field Gross Contingent Resources[1] (Bscf)			Hibiscus Net Entitlement Contingent Resources[2] (Bscf)		
	Project	1C	2C	3C	1C	2C	3C
PM3 CAA	Raya post Seismic	8.0	13.9	18.7	1.8	3.1	3.8
PM3 CAA	NW BR Infill	0.6	1.0	1.3	0.1	0.2	0.3
PM3 CAA	Production Efficiency	3.8	6.6	8.9	0.9	1.5	1.8
Total[3]		**12.4**	**21.5**	**29.0**	**2.8**	**4.8**	**5.9**

Notes:

[1] Gross field Contingent Resources (100% basis) until the current expiry of the PSC

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

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Reserves are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

Table 10.24: Gas Contingent Resources as of 1 January 2021

SUMMARY OF CONTINGENT RESOURCES (BOE) As of 1 January 2021 BASE CASE PRICES AND COSTS							
		Full Field Gross Contingent Resources[1] (MMstb)			Hibiscus Net Entitlement Contingent Resources[2] (MMstb)		
	Project	1C	2C	3C	1C	2C	3C
PM3 CAA	Raya post Seismic	7.6	12.9	15.7	1.7	2.9	3.2
PM3 CAA	NW BR Infill	1.5	2.5	3.1	0.3	0.6	0.6
PM3 CAA	Production Efficiency	0.9	1.5	2.0	0.2	0.3	0.4
Kinabalu	Production Efficiency	0.2	0.4	0.5	0.1	0.1	0.2
Total[3]		**10.2**	**17.3**	**21.3**	**2.3**	**3.9**	**4.4**

Notes:

[1] Gross field Contingent Resources (100% basis) until the current expiry of the PSC

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

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Reserves are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

Table 10.25: Summary of Contingent Resources in Oil Equivalent Barrels as of 1 January 2021

RPS did not perform commercial evaluation on Contingent Resources.

10.4 Sensitivity Analysis

A Low Price Case and High Price Case are also shown in Figure 10-1 in Money of the Day (MOD) and have been used for price sensitivity purposes.

RPS has also conducted sensitivity analysis on some other key parameters and the results are presented in Figure 10-2 and Figure 10-3. Except for the RPS Brent Price Forecast, the sensitivity analysis of all other key parameters is based on plus and minus of 20 per cent.

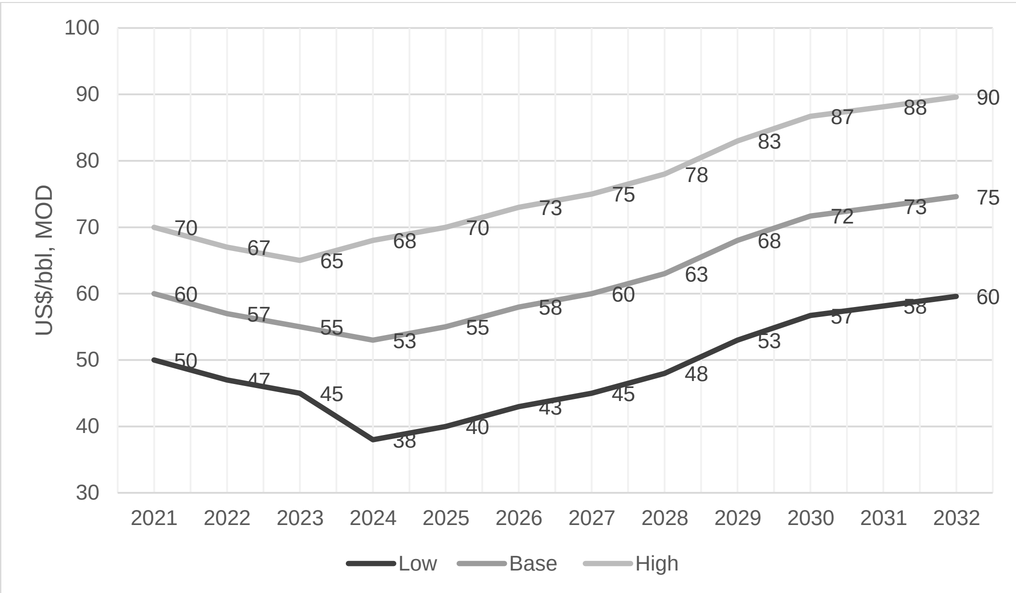

Figure 10-1: RPS Brent Price Forecasts (Q2 2021)

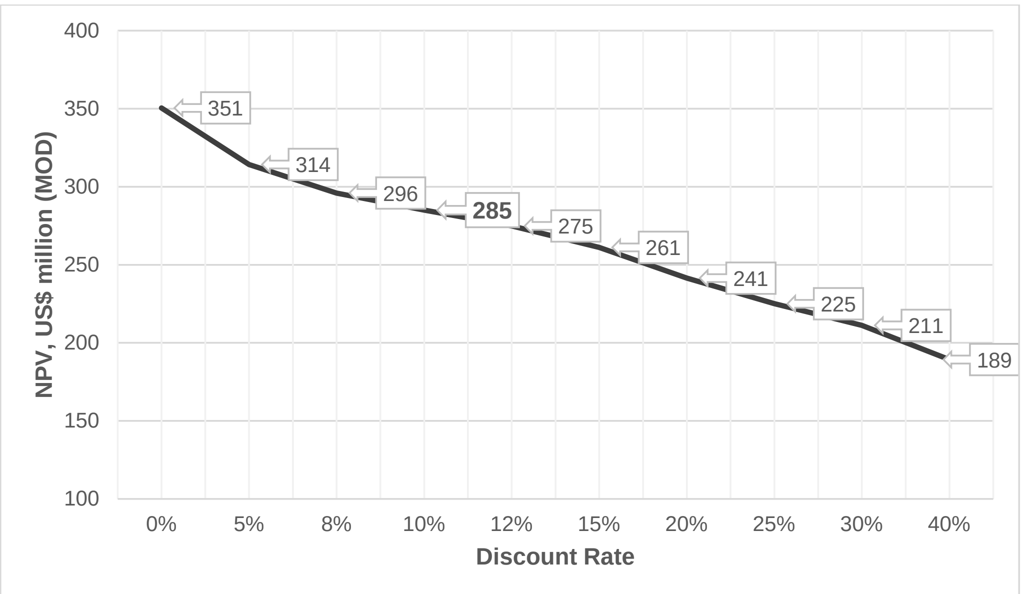

Figure 10-2: Summary of NPV of Reserves as of 1st January, 2021 (Sensitivity Analysis of Discount Rate)

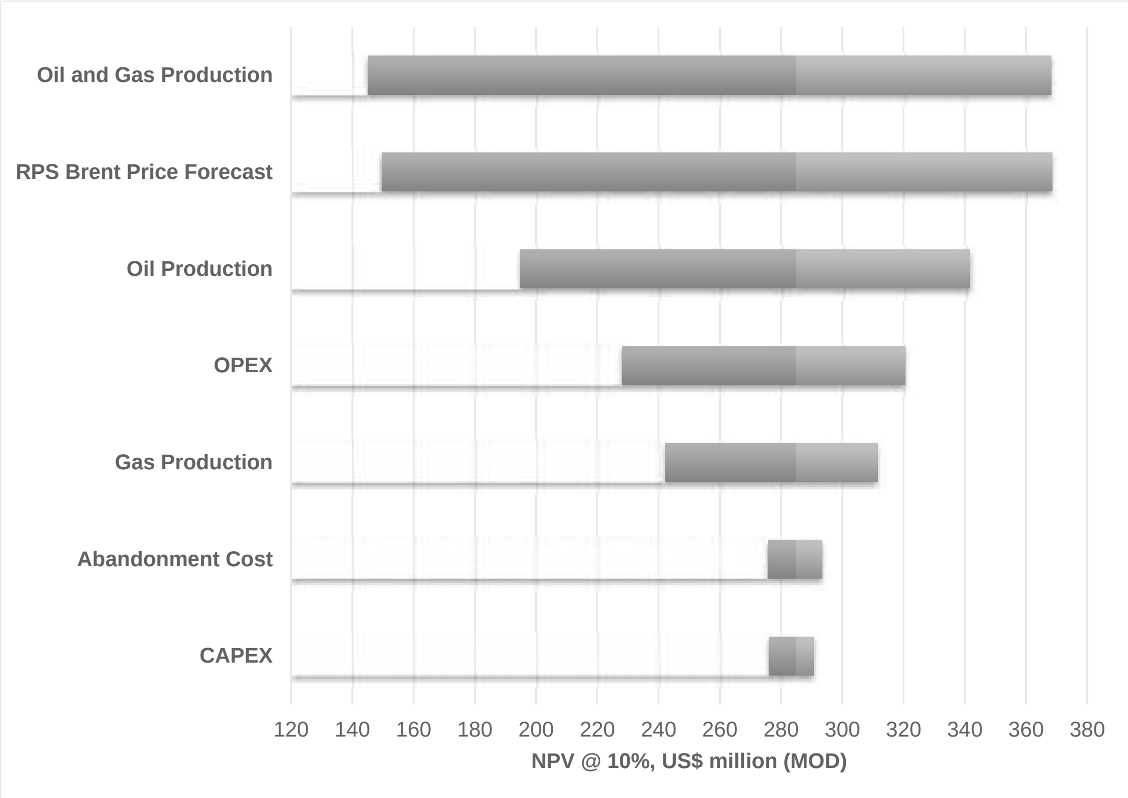

Figure 10-3: Summary of NPV of Reserves as of 1st January, 2021 (Sensitivity Analysis of Key Parameters)

10.5 Alternative Market Valuation

There are three (3) Common Valuation Approaches recommended by The Australasian Code for the Public Reporting of Technical Assessments and Valuations of Mineral Assets (VALMIN Code) 2015 Edition[9]; namely the Market-based, Income-based, and Cost-based. Each valuation approach is defined in Section 8 of the VALMIN Code[10]. As outlined in Section 8.3 Appropriate Valuation Approach, VALMIN Code recommends Market and Income approach for Production Projects.

10.5.1 Market-based Approach

RPS's estimate of 2P Reserves as of 1st January 2021 is 17.9 MMstb of crude oil, 2.7 MMstb of condensate, and 83.6 Bscf of gas; assuming 6,000 scf/boe for the gas Reserves, translate to a total barrel of equivalent of 34.5 MMboe. The valuation of the 2P Reserves at RPS Base Brent price and applying a 10% discount rate as of 1st January 2021 is US$ 285 Million. The implied dollar per 2P barrel is therefore US$ 8.3/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 and Indonesia that are available in the public domains, and considered those deals relating to producing fields for comparison with the current valuation. Both Malaysia and Indonesia apply production sharing contract fiscal regime.

A summary of the transactions in Malaysia and Indonesia which completed in year 2018 and 2019 is presented in Table 10.26. The market transactions tabulated would have been made under different price environments, as well as at different discount rates according to the respective buyers' investment strategy at the point of the acquisitions made. During the period between 2018 and 2019 which these transactions were conducted and closed; average Brent crude oil price is approximately US$ 67.7/bbl. During the commercial evaluation period between March and May 2021 in which the acquisition price of Repsol Asset was finalised, average Brent crude oil price is approximately US$ 66.3/bbl. Therefore, adjustment to the current valuation against the reported previous transacted values according to Brent crude oil price forecasts for the period between 2018 and 2019 is not necessary.

Based on the information summarised in Table 10.26, the implied dollar per 2P barrel ranges between US$ 7.4/boe and US$ 17.3/boe. Current valuation with its implied dollar per 2P barrel of US$ 8.3/boe falls within this range. The upper range of implied dollar per 2P of US$ 17.3/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. Whilst it is not accurate to assume 100 per cent of the reported 2C Contingent Resources of 173 MMboe (87 MMboe net to SEB) to derive the implied dollar per 2P plus 2C, it is probably not unreasonable to assume 33% of the 2C in deriving the deal metric based on information sourced in public domain. Based on this assumption, the implied dollar per 2P plus 2C becomes US$ 10.7/boe.

PTTEP Limited acquisition of Murphy Oil Corporation's Interests in Malaysia back in March 2019 also yielded relatively higher dollar per 2P barrel at US$ 12.6/boe. However, we are not able to source any information related to its 2C Contingent Resources from the public domain although there are news of discovered but yet to be developed fields. Therefore, the deal metric could potentially be lower but without the supporting information RPS is not able to make the adjustment.

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

[10] 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.

RPS determines the range of implied dollar per barrel valuations in these transactions to be between US$ 7.4/boe and US$ 10.7/bbl. Using these dollar per barrel values a fair market value of the Repsol net 2P of 34.5 MMboe would be between US$ 255 and US$ 368 million.

In October 2016, Hibiscus via its indirect wholly-owned subsidiary, SEA Hibiscus Sdn Bhd (SEA Hibiscus) entered into a conditional Sale and Purchase Agreement (SPA) with Sabah Shell Petroleum Company Limited and Shell Sabah Selatan Sdn Bhd to acquire Shell's entire 50 per cent participating interests in the 2011 North Sabah Enhanced Oil Recovery PSC for a purchase consideration of US$ 25 million. It is reported the PSC has gross 2P Reserves of 40.9 MMstb which translate to implied dollar per 2P barrel of only US$ 1.2/bbl. RPS does not consider this transaction metric to be suitable to determine the fair market value due to the following possible reason that prompted Shell to relinquish its interests in the PSC at below market value:

- The average Brent crude oil price in the beginning of 2016 until the conditional SPA signed in October 2016 was only US$ 42.5/bbl;
- The PSC was at its late production life and might not be commercially viable at low oil price environment; and,
- Shell might probably had been keen to divest its non-core asset as part of its global portfolio optimisation.

No.	Effective Date	Asset name	Buyer(s)	Seller	Price (US$MM)	2P Reserves (MM boe)	Price (US$/boe)
1.	May 2019	Acquisition of Ophir Energy plc[11]	PT Medco Energi Internasional Tbk	Ophir Energy plc	517[1]	70.1	7.4
2.	March 2019	Murphy Oil Corporation's Interests in Malaysia[12]	PTTEP Limited	Murphy Oil Corporation	2,127	169.3[2]	12.6
3.	January 2019	50 per cent interest in SEB Upstream Sdn Bhd (SUP)[13]	OMV Exploration and Production GmbH	Sapura Energy Berhad	800	46.1	17.3[3]
4.	September 2018	Acquisition of Santos's Southeast Asian production licences[14]	Ophir Energy plc	Santos Limited	205	23.3	8.8

Notes:

[1] 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)

[2] 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.

[3] The implied US$/boe reduces to US$6/boe if 2C of 86.6 million boe net to SEB is considered.

Table 10.26: Summary of Several Recent Transactions in Malaysia and Indonesia

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

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

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

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

10.5.2 Income-based Approach

The valuation of the Asset, as presented in Section 10, 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.

According to the Competent Valuer's Report disclosed by Sapura Energy Berhad (SEB) for the purpose of OMV acquisition of SEB's 50 per cent interest in SUP, the Competent Valuer had applied a discount rate of 8 per cent for the valuation of SEB's Malaysian upstream assets. Based on RPS previous commercial evaluation experiences for upstream assets in Malaysia and Indonesia, discount rate between 8 and 12 per cent is considered reasonable for fields already in production or in development phase.

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 10.19. RPS has verified the WACC computation input and confirm there 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]	12.4%	12.4%	12.4%	12.4%
Pre-Tax Cost of Debt[2]	7%	7%	7%	7%
Tax Rate (PITA)	38%	38%	38%	38%
Post-Tax Cost of Debt	4.3%	4.3%	4.3%	4.3%
Target Debt/Equity	0.3	0.4	0.5	0.6
WACC	10.5%	10.1%	9.7%	9.4%

Notes:

[1] Average cost of Equity provided by Hibiscus (source: Bloomberg)

[2] Provided by Hibiscus (source: Bloomberg)

Table 10.27: Range of Hibiscus's Weighted Average Cost of Capital (WACC)

As the Assets are 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.

As summarized in Table 10.18, the Assets NPV discounted at 10 per cent is **US$ 285 million**.

10.5.3 Fair Market Value

Based on the two Common Valuation Approaches recommended by VALMIN Code, namely the Market-based Approach and Income-based Approach, RPS opine the Fair Market Value of the Assets ranges between **US$ 255 and US$ 368 million**.

RPS opine that despite the Proposed Acquisition of the entire equity interest in FIPC for a cash consideration of US$ 212.5 million falls below the Fair Market Value range, it is fair value based on the fact that:

- Repsol Malaysia upstream portfolio only represent about 2 per cent of its current net output globally; and;
- Repsol aims to focus on the geographic areas that have the most competitive advantages as well as new low-carbon initiatives under the 2021-2025 Strategic Plan.

11 CONSULTANT'S INFORMATION

RPS is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. The evaluation presented in this report reflects our informed judgment, based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, 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 and Resources are based on data provided by Repsol and J.P. Morgan. We have accepted, without independent verification, the accuracy and completeness of this data.

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

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

Mr Jim Bradly, Operations Director - EAME, has supervised this evaluation. Mr Bradly is a Chartered Engineer, Chartered Petroleum Engineer and member of the Energy Institute in the UK with over 20 years' experience in upstream oil and gas and 15 years' experience in the evaluation of oil and gas Reserves and Resources.

Table 11.1 provides a summary of staff involved in this evaluation, their level of experience and professional qualifications.

Name	Role	Years of Experience	Qualifications	Professional Memberships
Jim Bradly	Supervisor and Reservoir Engineering Lead	>20	MSc. Petroleum Engineering, Imperial College, London, 2004 BEng Electronic and Electrical Engineering, Manchester University (1993-1996)	CEng MEI Chartered Petroleum Engineer (Registration # 569021) Member, Energy Institute Member, AIPN Member, SPE Member, SPWLA
David Offer	Geology Lead	26	2018 Qualified Teacher Status: Department of Education, Her Majesty's Government of the United Kingdom of Great Britain and Northern Ireland. • 1995 M.Sc. Industrial Minerology, University of Leicester • 1994 B.Sc. (Hons). Exploration and Mining Geology. University of Wales, College of Cardiff.	Fellow Geological Society of London Vice President of the Petroleum Exploration Society of Great Britain (PESGB)
Gordon Fraser	Cost Engineering Lead	>35	MBA, University of Glasgow BSc, Fuel and Energy Engineering, University of Leeds	
Joseph Tan	Project Manager/Economics Lead	20	B.Eng. (Hons.) Petroleum Engineering, Universiti Teknologi Malaysia, 2001	Member – Society of Petroleum Engineers (SPE) Member – South East Asia Petroleum Exploration Society (SEAPEX) Member – Association of International Petroleum Negotiators (AIPN)

Table 11.1: Summary of Summary of Lead Consultant Personnel

12 DATA SOURCES

The data for this report was provided in both virtual data room and physical data rooms hosted by Repsol in their Malaysian offices, accessible via MS Teams or Intralinks web portals.

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.

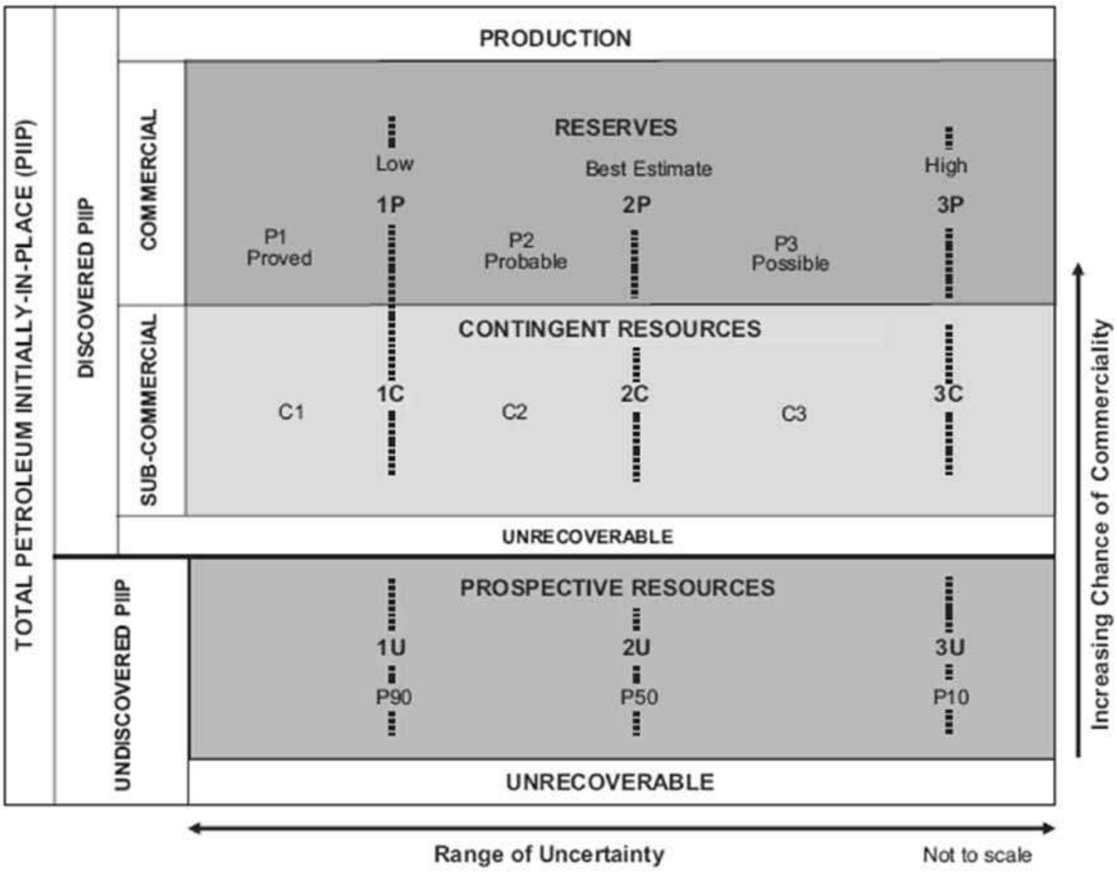

Figure A.1: Resources classification framework

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).

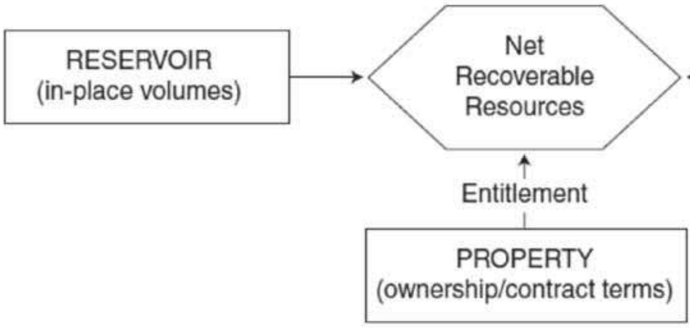

Figure A.2: Resources Evaluation

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.

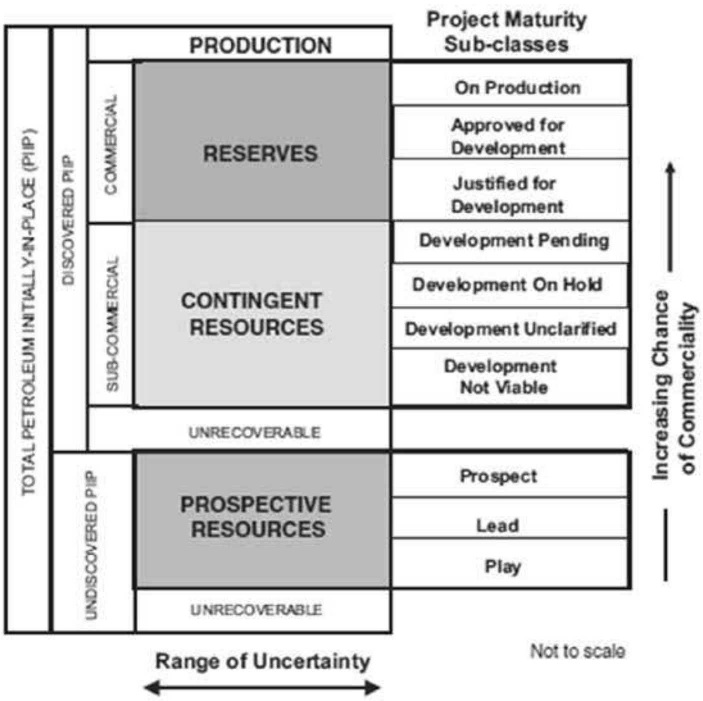

Figure A.3: Sub-classes based on project maturity

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
Site Visit Report

No site visit has been conducted as part of our evaluation as it is usually conducted when a SPA is signed or during the transition period in which personnel specialises in Health Safety Environment would be allowed to conduct limited site visit.

Appendix D
Overview and outlook of the O&G industry

Based on research by Rystad Energy, an independent energy research and business intelligence company, looking at production forecasts for some significant countries in the Southeast Asia region, most of the countries are likely to start the recovery cycle post-2025, excluding Malaysia which is expected to start recovery early as a result of new development start-ups and additional volumes from some top producing assets.

The share of volumes from new development is likely to be significant for all countries across Southeast Asia. With higher decline from its major producing assets, Indonesia is likely to see volumes fall until the start-up of production from significant developments such as Abadi, IDD and Kaliberau Dalam which are due for approval around 2024.

Vietnam has a long list of assets to be sanctioned in the next five years including the Blue Whale, Ken Bau and Block B projects which are likely to aid the production recovery from the country.

(Source: "Regional Trends Report – South East Asia" March 2021, Rystad Energy)

According to Rystad Energy, Southeast Asia was defined last year by historically low upstream activity levels, with less than five projects sanctioned. Looking forward however, activity in the region is expected to witness a significant recovery this year with around 15 projects lined up for approval and a similar number of fields likely to reach first production.

Rystad Energy expects a surge in sanctioning levels of nearly 300% year-on-year, with total commitments likely to cross the USD6 billion mark, reflecting increases in both onshore and offshore activity. Rystad Energy also expects offshore developments to dominate the scene, encompassing around 80% of discoveries to reach final investment decisions ("FIDs") in 2021.

More than 1 billion boe of recoverable resources are at stake, with development concepts ranging from floating liquefied natural gas ("FLNG"), subsea tiebacks and platform-based developments. Indonesia, with around 10 discoveries, is poised to dominate the region's sanctioning activity and is the only country in Southeast Asia with onshore discoveries expected to reach FID in 2021. Malaysia follows with around five new developments.

(Source: "Southeast Asia upstream recovery to be led by new startups and sanctioning" February 2021, Rystad Energy)

According to Rystad Energy, fiscal terms in Southeast Asian countries are a vital consideration amid efforts to revamp O&G exploration, which has been sluggish for years. Modifying and improving systems could boost investments and deliver more taxes to national budgets – as the governments of Indonesia and Malaysia have experienced already.

(Source: "Can Southeast Asia boost its upstream sector with updated fiscal terms?" May 2021, Rystad Energy)

Appendix E
Cashflow Forecasts

1PD – PM3 CAA PSC

PM3CAA PSC (35%) - PSC Expiry 2027	Unit	Total	2021	2022	2023	2024	2025
Gross Gas Production	MMscfd		162	156	124	85	60
Gross Condensate Production	Bcpd		3,342	5,157	4,469	3,033	2,131
Gross Oil Production	Bopd		11,092	9,026	7,360	6,032	4,925
Gross Annual Gas Production	**Bscf**	**214.3**	**59**	**57**	**45**	**31**	**22**
Gross Annual Condensate Production	**MMstb**	**6.6**	**1**	**2**	**2**	**1**	**1**
Gross Annual Oil Production	**MMstb**	**14.0**	**4**	**3**	**3**	**2**	**2**
Realized Gas Price	US$/MMBtu		4	4	4	3	4
Realized Condensate Price	US$/bbl		63	60	58	56	58
Realized Oil Price	US$/bbl		63	60	58	56	58
Cost Recovery to Repsol	MMUS$	347	87	87	76	55	42
Profit & Unused Oil + Gas + Con share to Repsol	MMUS$	108	35	29	20	13	10
Net Entitlement to Repsol			22%	22%	23%	23%	23%
Net Gas Production to Repsol	MMscfd		35	35	29	20	14
Net Condensate Production to Repsol	Bcpd		725	1,156	1,040	709	496
Net Oil Production to Repsol	Bopd		2,407	2,023	1,713	1,410	1,146
Net Annual Gas Production to Repsol	**Bscf**	**48.5**	**13**	**13**	**11**	**7**	**5**
Net Annual Condensate Production to Repsol	**MMstb**	**1.5**	**0**	**0**	**0**	**0**	**0**
Net Annual Oil Production to Repsol	**MMstb**	**3.2**	**1**	**1**	**1**	**1**	**0**
Net Revenue to Repsol	MMUS$	455	122	117	96	68	53
Net Opex to Repsol	MMUS$	(341)	(65)	(72)	(71)	(67)	(66)
Net Capex to Repsol	MMUS$	(12)	(2)	(3)	(2)	(2)	(2)
Net Abex (Wells + Facilities) to Repsol	MMUS$	(58)	(5)	(11)	(10)	(13)	(19)
Net Supplementary Payment- Repsol	MMUS$	0	0	0	0	0	0
Net Research Cess payment-Repsol	MMUS$	(2)	(1)	(1)	(0)	(0)	(0)
Overhead Payment from Partner	MMUS$	14	3	3	3	3	3
Net Export Duty-Repsol	MMUS$	(5)	(1)	(1)	(1)	(1)	(1)
Net PITA-Repsol	MMUS$	(7)	0	(6)	(1)	0	0
One-time extension bonus payment	MMUS$	2	0	1	1	0	0
Free Cash Flows to Repsol (PM3CAA)	**MMUS$**	**46**	**51**	**26**	**13**	**(12)**	**(33)**
NPV @ 10% Net to Repsol	**MMUS$**	**54**					

1PD – KINABALU PSC

Kinabalu PSC (60%) - PSC expiry 2032	Unit	Total	2021	2022	2023	2024	2025	2026
Gross Oil Production Rate	Bopd		11,108	7,994	5,792	4,234	3,092	2,252
Gross Annual Oil Production	**MMstb**	**12.6**	**4**	**3**	**2**	**2**	**1**	**1**
Realized Oil Price	US$/bbl		63	60	58	56	58	61
Cost Recovery to Repsol	MMUS$	177	29	43	37	27	23	18
Repsol's Share of Unused & Profit Oil	MMUS$	119	58	27	14	10	6	4
Net Entitlement to Repsol			34%	40%	43%	43%	45%	45%
Net Oil Production to Repsol	Bopd	5	3,761	3,186	2,470	1,818	1,391	1,013
Net Annual Oil Production to repsol	**MMstb**	**5.0**	**1**	**1**	**1**	**1**	**1**	**0**
Net Revenue to Repsol	MMUS$	296	86	69	52	37	29	22
Net Opex to Repsol	MMUS$	(158)	(25)	(32)	(26)	(25)	(25)	(24)
Net Capex to Repsol	MMUS$	(26)	(3)	(9)	(11)	(1)	(1)	(1)
Net Abex (Wells + facilities) to Repsol	MMUS$	(17)	0	(2)	0	0	0	(16)
Net Supplementary Payment	MMUS$	(26)	(15)	(6)	(3)	(1)	(1)	(1)
Net Research Cess payment	MMUS$	(1)	(0)	(0)	(0)	(0)	(0)	(0)
Sabah Sales Tax	MMUS$	(4)	(4)	0	0	0	0	0
Net Export Duty	MMUS$	(12)	(6)	(3)	(1)	(1)	(1)	(0)
Overhead Payment from partner	MMUS$	2	0	0	0	0	0	0
Net PITA	MMUS$	0	0	0	0	0	0	0
Free Cash Flows to Repsol (Kinabalu)	**MMUS$**	**53**	**33**	**19**	**11**	**8**	**2**	**(20)**
NPV @ 10% Net to Repsol	**MMUS$**	**54**						

1PD – B46 PSC

Block 46 PSC (70%) - PSC expiry 2027	Unit	Total	2021	2022	2023	2024	2025
Gross Oil & Condensate Production Rate	Bopd		383	394	315	253	203
Gross Annual Oil & Condensate Production	MMstb	**0.6**	**0**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56	58
Cost Recovery to Repsol	MMUS$	9	2	2	2	1	1
Repsol's Share of Profit Oil	MMUS$	5	1	1	1	1	1
Net Entitlement to Repsol			43%	43%	43%	43%	43%
Net Oil Production to Repsol	Bopd	0	163	168	134	108	86
Net Annual Oil Production to repsol	MMstb	**0.2**	**0**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	14	4	4	3	2	2
Net Opex to Repsol	MMUS$	(12)	(3)	(2)	(2)	(2)	(2)
Net Capex to Repsol	MMUS$	(0)	(0)	0	0	0	0
Net Abex (Wells + facilities) to Repsol	MMUS$	(7)	0	0	(1)	(1)	(5)
Net Export Duty	MMUS$	0	0	0	0	0	0
Overhead Payment from partner	MMUS$	0	0	0	0	0	0
Net Corporate Income Tax	MMUS$	0	0	0	0	0	0
Free Cash Flows to Repsol (Block 46)	**MMUS$**	**(5)**	**1**	**1**	**(0)**	**(1)**	**(5)**
NPV @ 10% Net to Repsol	**MMUS$**	**(3)**					

1PD – PM305/PM314 PSC

PM305/PM314 PSC (60%) - PSC expiry 2024	Unit	Total	2021	2022	2023	2024
Gross Oil Production Rate	Bopd		380	300	270	240
Gross Annual Oil Production	**MMstb**	**0.4**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56
Cost Recovery to Repsol	MMUS$	8	3	2	2	1
Repsol's Share of Profit Oil	MMUS$	4	1	1	1	1
Net Entitlement to Repsol			44%	44%	44%	44%
Net Oil Production to Repsol	Bopd	0	169	133	120	107
Net Annual Oil Production to Repsol	**MMstb**	**0.2**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	11	4	3	3	2
Net Opex to Repsol	MMUS$	(5)	(1)	(1)	(1)	(1)
Net Capex to Repsol	MMUS$	(1)	(0)	(0)	(0)	(0)
Net Abex (Wells + facilities) to Repsol	MMUS$	(15)	(13)	(2)	0	0
Supplementary Payment	MMUS$	(0)	(0)	(0)	(0)	0
Research Cess	MMUS$	(0)	(0)	(0)	(0)	(0)
Net Export Duty	MMUS$	(0)	(0)	(0)	(0)	(0)
Overhead Payment from partner	MMUS$	0	0	0	0	0
PITA	MMUS$	0	0	0	0	0
Free Cash Flows to Repsol (PM305)	**MMUS$**	**(9)**	**(10)**	**(1)**	**1**	**1**
NPV @ 10% Net to Repsol	**MMUS$**	**(10)**				

1P – PM3 CAA PSC

PM3CAA PSC (35%) - PSC Expiry 2027	Unit	Total	2021	2022	2023	2024	2025
Gross Gas Production	MMscfd		162	159	128	87	61
Gross Condensate Production	Bcpd		3,342	5,320	4,649	3,152	2,245
Gross Oil Production	Bopd		11,090	10,256	10,484	8,771	7,762
Gross Annual Gas Production	**Bscf**	**217.3**	**59**	**58**	**47**	**32**	**22**
Gross Annual Condensate Production	**MMstb**	**6.8**	**1**	**2**	**2**	**1**	**1**
Gross Annual Oil Production	**MMstb**	**17.7**	**4**	**4**	**4**	**3**	**3**
Realized Gas Price	US$/MMBtu		4	4	4	3	4
Realized Condensate Price	US$/bbl		63	60	58	56	58
Realized Oil Price	US$/bbl		63	60	58	56	58
Cost Recovery to Repsol	MMUS$	387	90	94	85	65	54
Profit & Unused Oil + Gas + Con share to Repsol	MMUS$	119	34	31	25	16	13
Net Entitlement to Repsol			22%	22%	23%	23%	23%
Net Gas Production to Repsol	MMscfd		36	36	29	20	14
Net Condensate Production to Repsol	Bcpd		738	1,196	1,053	729	515
Net Oil Production to Repsol	Bopd		2,448	2,307	2,374	2,027	1,781
Net Annual Gas Production to Repsol	**Bscf**	**49.0**	**13**	**13**	**11**	**7**	**5**
Net Annual Condensate Production to Repsol	**MMstb**	**1.5**	**0**	**0**	**0**	**0**	**0**
Net Annual Oil Production to Repsol	**MMstb**	**4.0**	**1**	**1**	**1**	**1**	**1**
Net Revenue to Repsol	MMUS$	506	124	125	110	81	67
Net Opex to Repsol	MMUS$	(346)	(65)	(72)	(73)	(69)	(67)
Net Capex to Repsol	MMUS$	(72)	(17)	(48)	(2)	(2)	(2)
Net Abex (Wells + Facilities) to Repsol	MMUS$	(59)	(5)	(11)	(10)	(13)	(20)
Net Supplementary Payment- Repsol	MMUS$	0	0	0	0	0	0
Net Research Cess payment-Repsol	MMUS$	(3)	(1)	(1)	(1)	(0)	(0)
Overhead Payment from Partner	MMUS$	17	3	5	3	3	3
Net Export Duty-Repsol	MMUS$	(6)	(1)	(1)	(1)	(1)	(1)
Net PITA-Repsol	MMUS$	0	0	0	0	0	0
One-time extension bonus payment	MMUS$	0	0	0	0	0	0
Free Cash Flows to Repsol (PM3CAA)	**MMUS$**	**38**	**38**	**(4)**	**26**	**(1)**	**(21)**
NPV @ 10% Net to Repsol	**MMUS$**	**41**					

1P – KINABALU PSC

Kinabalu PSC (60%) - PSC expiry 2032	Unit	Total	2021	2022	2023	2024	2025	2026	2027
Gross Oil Production Rate	Bopd		11,108	9,604	8,186	5,810	4,172	3,008	2,130
Gross Annual Oil Production	**MMstb**	**16.1**	**4**	**4**	**3**	**2**	**2**	**1**	**1**
Realized Oil Price	US$/bbl		63	60	58	56	58	61	63
Cost Recovery to Repsol	MMUS$	231	29	69	38	27	27	24	18
Repsol's Share of Unused & Profit Oil	MMUS$	148	58	22	29	19	11	6	4
Net Entitlement to Repsol			34%	44%	39%	39%	43%	45%	45%
Net Oil Production to Repsol	Bopd	6	3,761	4,193	3,167	2,280	1,774	1,354	958
Net Annual Oil Production to repsol	**MMstb**	**6.4**	**1**	**2**	**1**	**1**	**1**	**0**	**0**
Net Revenue to Repsol	MMUS$	380	86	91	67	46	37	30	22
Net Opex to Repsol	MMUS$	(183)	(25)	(32)	(27)	(26)	(25)	(25)	(23)
Net Capex to Repsol	MMUS$	(53)	(3)	(35)	(11)	(1)	(1)	(1)	(1)
Net Abex (Wells + facilities) to Repsol	MMUS$	(17)	0	(2)	0	0	0	(1)	(14)
Net Supplementary Payment	MMUS$	(31)	(15)	(5)	(5)	(3)	(1)	(1)	(1)
Net Research Cess payment	MMUS$	(2)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Sabah Sales Tax	MMUS$	(4)	(4)	0	0	0	0	0	0
Net Export Duty	MMUS$	(15)	(6)	(2)	(3)	(2)	(1)	(1)	(0)
Overhead Payment from partner	MMUS$	2	0	1	0	0	0	0	0
Net PITA	MMUS$	0	0	0	0	0	0	0	0
Free Cash Flows to Repsol (Kinabalu)	**MMUS$**	**77**	**33**	**16**	**21**	**15**	**8**	**1**	**(18)**
NPV @ 10% Net to Repsol	**MMUS$**	**73**							

1P – B46 PSC

Block 46 PSC (70%) - PSC expiry 2027	Unit	Total	2021	2022	2023	2024	2025
Gross Oil & Condensate Production Rate	Bopd		383	394	315	253	203
Gross Annual Oil & Condensate Production	MMstb	**0.6**	**0**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56	58
Cost Recovery to Repsol	MMUS$	9	2	2	2	1	1
Repsol's Share of Profit Oil	MMUS$	5	1	1	1	1	1
Net Entitlement to Repsol			43%	43%	43%	43%	43%
Net Oil Production to Repsol	Bopd	0	163	168	134	108	86
Net Annual Oil Production to repsol	MMstb	**0.2**	**0**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	14	4	4	3	2	2
Net Opex to Repsol	MMUS$	(12)	(3)	(2)	(2)	(2)	(2)
Net Capex to Repsol	MMUS$	(0)	(0)	0	0	0	0
Net Abex (Wells + facilities) to Repsol	MMUS$	(7)	0	0	(1)	(1)	(5)
Net Export Duty	MMUS$	0	0	0	0	0	0
Overhead Payment from partner	MMUS$	0	0	0	0	0	0
Net Corporate Income Tax	MMUS$	0	0	0	0	0	0
Free Cash Flows to Repsol (Block 46)	**MMUS$**	**(5)**	**1**	**1**	**(0)**	**(1)**	**(5)**
NPV @ 10% Net to Repsol	**MMUS$**	**(3)**					

1P – PM305/PM314 PSC

PM305/PM314 PSC (60%) - PSC expiry 2024	Unit	Total	2021	2022	2023	2024
Gross Oil Production Rate	Bopd		380	300	270	240
Gross Annual Oil Production	**MMstb**	**0.4**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56
Cost Recovery to Repsol	MMUS$	8	3	2	2	1
Repsol's Share of Profit Oil	MMUS$	4	1	1	1	1
Net Entitlement to Repsol			44%	44%	44%	44%
Net Oil Production to Repsol	Bopd	0	169	133	120	107
Net Annual Oil Production to Repsol	**MMstb**	**0.2**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	11	4	3	3	2
Net Opex to Repsol	MMUS$	(5)	(1)	(1)	(1)	(1)
Net Capex to Repsol	MMUS$	(1)	(0)	(0)	(0)	(0)
Net Abex (Wells + facilities) to Repsol	MMUS$	(15)	(13)	(2)	0	0
Supplementary Payment	MMUS$	(0)	(0)	(0)	(0)	0
Research Cess	MMUS$	(0)	(0)	(0)	(0)	(0)
Net Export Duty	MMUS$	(0)	(0)	(0)	(0)	(0)
Overhead Payment from partner	MMUS$	0	0	0	0	0
PITA	MMUS$	0	0	0	0	0
Free Cash Flows to Repsol (PM305)	**MMUS$**	**(9)**	**(10)**	**(1)**	**1**	**1**
NPV @ 10% Net to Repsol	**MMUS$**	**(10)**				

2PD – PM3 CAA PSC

PM3CAA PSC (35%) - PSC Expiry 2027	Unit	Total	2021	2022	2023	2024	2025	2026	2027
Gross Gas Production	MMscfd		198	209	184	143	113	90	73
Gross Condensate Production	Bcpd		4,091	6,447	6,261	4,922	3,934	3,201	2,598
Gross Oil Production	Bopd		12,067	10,429	9,059	7,932	6,941	6,121	5,383
Gross Annual Gas Production	**Bscf**	**368.5**	**72**	**76**	**67**	**52**	**41**	**33**	**27**
Gross Annual Condensate Production	**MMstb**	**11.5**	**1**	**2**	**2**	**2**	**1**	**1**	**1**
Gross Annual Oil Production	**MMstb**	**21.1**	**4**	**4**	**3**	**3**	**3**	**2**	**2**
Realized Gas Price	US$/MMBtu		4	4	4	3	4	4	4
Realized Condensate Price	US$/bbl		63	60	58	56	58	61	63
Realized Oil Price	US$/bbl		63	60	58	56	58	61	63
Cost Recovery to Repsol	MMUS$	532	80	93	91	81	71	63	54
Profit & Unused Oil + Gas + Con share to Repsol	MMUS$	194	49	44	34	21	17	15	13
Net Entitlement to Repsol			20%	21%	22%	23%	23%	23%	23%
Net Gas Production to Repsol	MMscfd		39	44	41	33	26	21	17
Net Condensate Production to Repsol	Bcpd		805	1,349	1,384	1,148	924	750	607
Net Oil Production to Repsol	Bopd		2,373	2,183	2,002	1,850	1,630	1,435	1,258
Net Annual Gas Production to Repsol	**Bscf**	**80.8**	**14**	**16**	**15**	**12**	**10**	**8**	**6**
Net Annual Condensate Production to Repsol	**MMstb**	**2.5**	**0**	**0**	**1**	**0**	**0**	**0**	**0**
Net Annual Oil Production to Repsol	**MMstb**	**4.6**	**1**	**1**	**1**	**1**	**1**	**1**	**0**
Net Revenue to Repsol	MMUS$	726	129	136	124	103	88	78	68
Net Opex to Repsol	MMUS$	(512)	(69)	(77)	(77)	(73)	(72)	(73)	(72)
Net Capex to Repsol	MMUS$	(17)	(2)	(3)	(2)	(2)	(2)	(3)	(3)
Net Abex (Wells + Facilities) to Repsol	MMUS$	(58)	(5)	(11)	(10)	(13)	(8)	(6)	(6)
Net Supplementary Payment- Repsol	MMUS$	0	0	0	0	0	0	0	0
Net Research Cess payment-Repsol	MMUS$	(4)	(1)	(1)	(1)	(1)	(0)	(0)	(0)
Overhead Payment from Partner	MMUS$	19	2	2	2	3	3	3	3
Net Export Duty-Repsol	MMUS$	(8)	(2)	(2)	(1)	(1)	(1)	(1)	(1)
Net PITA-Repsol	MMUS$	(30)	(6)	(13)	(9)	(2)	0	0	0
One-time extension bonus payment	MMUS$	4	1	1	1	1	0	0	0
Free Cash Flows to Repsol (PM3CAA)	**MMUS$**	**120**	**49**	**33**	**27**	**14**	**7**	**(1)**	**(10)**
NPV @ 10% Net to Repsol	**MMUS$**	**111**							

2PD – KINABALU PSC

Kinabalu PSC (60%) - PSC expiry 2032	Unit	Total	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gross Oil Production Rate	Bopd		12,983	10,360	8,394	6,917	5,737	4,816	4,055	3,469	2,976	2,577	2,161	1,787
Gross Annual Oil Production	**MMstb**	**24.2**	**5**	**4**	**3**	**3**	**2**	**2**	**1**	**1**	**1**	**1**	**1**	**1**
Realized Oil Price	US$/bbl		63	60	58	56	58	61	63	66	71	75	77	78
Cost Recovery to Repsol	MMUS$	342	29	44	38	28	27	29	27	27	28	25	22	18
Repsol's Share of Unused & Profit Oil	MMUS$	245	70	41	30	25	20	15	12	9	7	6	5	5
Net Entitlement to Repsol			33%	37%	39%	38%	39%	41%	42%	43%	45%	45%	45%	45%
Net Oil Production to Repsol	Bopd	9	4,314	3,885	3,236	2,609	2,239	1,966	1,694	1,498	1,339	1,160	973	804
Net Annual Oil Production to repsol	**MMstb**	**9.4**	**2**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	587	99	85	68	53	47	44	39	36	35	32	27	23
Net Opex to Repsol	MMUS$	(312)	(26)	(33)	(27)	(26)	(26)	(25)	(25)	(25)	(25)	(25)	(25)	(25)
Net Capex to Repsol	MMUS$	(35)	(3)	(9)	(11)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Net Abex (Wells + facilities) to Repsol	MMUS$	(17)	0	(2)	0	0	0	(1)	0	0	(5)	0	(3)	(6)
Net Supplementary Payment	MMUS$	(47)	(18)	(9)	(6)	(4)	(3)	(2)	(2)	(1)	(1)	(1)	(1)	(1)
Net Research Cess payment	MMUS$	(3)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Sabah Sales Tax	MMUS$	(5)	(5)	0	0	0	0	0	0	0	0	0	0	0
Net Export Duty	MMUS$	(25)	(7)	(4)	(3)	(3)	(2)	(2)	(1)	(1)	(1)	(1)	(1)	(0)
Overhead Payment from partner	MMUS$	4	0	0	0	0	0	0	0	0	0	0	0	0
Net PITA	MMUS$	0	0	0	0	0	0	0	0	0	0	0	0	0
Free Cash Flows to Repsol (Kinabalu)	**MMUS$**	**147**	**40**	**29**	**22**	**19**	**15**	**12**	**10**	**8**	**2**	**4**	**(3)**	**(10)**
NPV @ 10% Net to Repsol	**MMUS$**	**123**												

2PD – B46 PSC

Block 46 PSC (70%) - PSC expiry 2027	Unit	Total	2021	2022	2023	2024	2025	2026	2027
Gross Oil & Condensate Production Rate	Bopd		519	497	432	379	335	298	267
Gross Annual Oil & Condensate Production	MMstb	**1.0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56	58	61	63
Cost Recovery to Repsol	MMUS$	17	3	3	3	2	2	2	2
Repsol's Share of Profit Oil	MMUS$	9	2	2	1	1	1	1	1
Net Entitlement to Repsol			43%	43%	43%	43%	43%	43%	43%
Net Oil Production to Repsol	Bopd	0	222	212	184	162	143	127	114
Net Annual Oil Production to repsol	MMstb	**0.4**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	25	5	5	4	3	3	3	3
Net Opex to Repsol	MMUS$	(16)	(3)	(2)	(2)	(2)	(2)	(2)	(2)
Net Capex to Repsol	MMUS$	(0)	(0)	0	0	0	0	0	0
Net Abex (Wells + facilities) to Repsol	MMUS$	(7)	0	0	(1)	(1)	(3)	0	(2)
Net Export Duty	MMUS$	0	0	0	0	0	0	0	0
Overhead Payment from partner	MMUS$	0	0	0	0	0	0	0	0
Net Corporate Income Tax	MMUS$	0	0	0	0	0	0	0	0
Free Cash Flows to Repsol (Block 46)	**MMUS$**	**2**	**2**	**2**	**1**	**(0)**	**(2)**	**1**	**(1)**
NPV @ 10% Net to Repsol	**MMUS$**	**3**							

2PD – PM305/PM314 PSC

PM305/PM314 PSC (60%) - PSC expiry 2024	Unit	Total	2021	2022	2023	2024
Gross Oil Production Rate	Bopd		380	300	270	240
Gross Annual Oil Production	**MMstb**	**0.4**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56
Cost Recovery to Repsol	MMUS$	8	3	2	2	1
Repsol's Share of Profit Oil	MMUS$	4	1	1	1	1
Net Entitlement to Repsol			44%	44%	44%	44%
Net Oil Production to Repsol	Bopd	0	169	133	120	107
Net Annual Oil Production to Repsol	**MMstb**	**0.2**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	11	4	3	3	2
Net Opex to Repsol	MMUS$	(5)	(1)	(1)	(1)	(1)
Net Capex to Repsol	MMUS$	(1)	(0)	(0)	(0)	(0)
Net Abex (Wells + facilities) to Repsol	MMUS$	(15)	(13)	(2)	0	0
Supplementary Payment	MMUS$	(0)	(0)	(0)	(0)	0
Research Cess	MMUS$	(0)	(0)	(0)	(0)	(0)
Net Export Duty	MMUS$	(0)	(0)	(0)	(0)	(0)
Overhead Payment from partner	MMUS$	0	0	0	0	0
PITA	MMUS$	0	0	0	0	0
Free Cash Flows to Repsol (PM305)	**MMUS$**	**(10)**	**(10)**	**(1)**	**1**	**1**
NPV @ 10% Net to Repsol	**MMUS$**	**(10)**				

2P – PM3 CAA PSC

PM3CAA PSC (35%) - PSC Expiry 2027	Unit	Total	2021	2022	2023	2024	2025	2026	2027
Gross Gas Production	MMscfd		198	215	191	146	115	93	76
Gross Condensate Production	Bcpd		4,091	6,767	6,744	5,221	4,222	3,399	2,732
Gross Oil Production	Bopd		12,067	12,342	15,038	13,019	12,239	9,539	7,443
Gross Annual Gas Production	**Bscf**	**377.5**	**72**	**78**	**70**	**53**	**42**	**34**	**28**
Gross Annual Condensate Production	**MMstb**	**12.1**	**1**	**2**	**2**	**2**	**2**	**1**	**1**
Gross Annual Oil Production	**MMstb**	**29.8**	**4**	**5**	**5**	**5**	**4**	**3**	**3**
Realized Gas Price	US$/MMBtu		4	4	4	3	4	4	4
Realized Condensate Price	US$/bbl		63	60	58	56	58	61	63
Realized Oil Price	US$/bbl		63	60	58	56	58	61	63
Cost Recovery to Repsol	MMUS$	643	95	111	112	96	88	78	64
Profit & Unused Oil + Gas + Con share to Repsol	MMUS$	220	44	44	43	29	25	19	16
Net Entitlement to Repsol			21%	22%	22%	23%	23%	23%	23%
Net Gas Production to Repsol	MMscfd		42	47	42	33	26	22	18
Net Condensate Production to Repsol	Bcpd		873	1,484	1,471	1,176	957	785	633
Net Oil Production to Repsol	Bopd		2,574	2,707	3,281	2,932	2,774	2,204	1,724
Net Annual Gas Production to Repsol	**Bscf**	**83.6**	**15**	**17**	**15**	**12**	**10**	**8**	**6**
Net Annual Condensate Production to Repsol	**MMstb**	**2.7**	**0**	**1**	**1**	**0**	**0**	**0**	**0**
Net Annual Oil Production to Repsol	**MMstb**	**6.6**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Net Revenue to Repsol	MMUS$	863	139	155	154	125	113	97	80
Net Opex to Repsol	MMUS$	(522)	(69)	(77)	(77)	(76)	(75)	(75)	(74)
Net Capex to Repsol	MMUS$	(77)	(17)	(48)	(2)	(2)	(2)	(3)	(3)
Net Abex (Wells + Facilities) to Repsol	MMUS$	(59)	(5)	(11)	(10)	(13)	(8)	(6)	(6)
Net Supplementary Payment- Repsol	MMUS$	0	0	0	0	0	0	0	0
Net Research Cess payment-Repsol	MMUS$	(4)	(1)	(1)	(1)	(1)	(1)	(0)	(0)
Overhead Payment from Partner	MMUS$	21	3	5	2	3	2	3	3
Net Export Duty-Repsol	MMUS$	(9)	(1)	(2)	(2)	(1)	(1)	(1)	(1)
Net PITA-Repsol	MMUS$	(49)	(6)	(6)	(20)	(9)	(7)	(2)	0
One-time extension bonus payment	MMUS$	8	1	1	1	1	1	4	0
Free Cash Flows to Repsol (PM3CAA)	**MMUS$**	**170**	**46**	**16**	**45**	**26**	**22**	**16**	**(1)**
NPV @ 10% Net to Repsol	**MMUS$**	**142**							

2P – KINABALU PSC

Kinabalu PSC (60%) - PSC expiry 2032	Unit	Total	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gross Oil Production Rate	Bopd		12,983	12,254	11,209	8,771	7,002	5,698	4,685	3,964	3,336	2,842	2,361	1,942
Gross Annual Oil Production	**MMstb**	**28.1**	**5**	**4**	**4**	**3**	**3**	**2**	**2**	**1**	**1**	**1**	**1**	**1**
Realized Oil Price	US$/bbl		63	60	58	56	58	61	63	66	71	75	77	78
Cost Recovery to Repsol	MMUS$	379	29	70	39	28	28	29	27	27	31	28	24	20
Repsol's Share of Unused & Profit Oil	MMUS$	293	70	38	47	36	27	21	16	13	8	7	6	5
Net Entitlement to Repsol			33%	41%	36%	36%	37%	39%	40%	41%	45%	45%	45%	45%
Net Oil Production to Repsol	Bopd	11	4,314	4,974	4,054	3,152	2,610	2,225	1,879	1,642	1,501	1,274	1,062	874
Net Annual Oil Production to repsol	**MMstb**	**10.8**	**2**	**2**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	672	99	108	85	64	55	49	43	40	39	35	30	25
Net Opex to Repsol	MMUS$	(314)	(26)	(33)	(27)	(26)	(26)	(26)	(25)	(25)	(25)	(25)	(25)	(25)
Net Capex to Repsol	MMUS$	(60)	(3)	(35)	(11)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Net Abex (Wells + facilities) to Repsol	MMUS$	(17)	0	(2)	0	0	0	(1)	0	0	(5)	0	(3)	(6)
Net Supplementary Payment	MMUS$	(55)	(18)	(8)	(9)	(5)	(4)	(3)	(2)	(2)	(1)	(1)	(1)	(1)
Net Research Cess payment	MMUS$	(3)	(0)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Sabah Sales Tax	MMUS$	(5)	(5)	0	0	0	0	0	0	0	0	0	0	0
Net Export Duty	MMUS$	(29)	(7)	(4)	(5)	(4)	(3)	(2)	(2)	(1)	(1)	(1)	(1)	(0)
Overhead Payment from partner	MMUS$	4	0	1	0	0	0	0	0	0	0	0	0	0
Net PITA	MMUS$	(4)	0	0	0	0	0	0	(1)	(2)	(0)	(2)	0	0
Free Cash Flows to Repsol (Kinabalu)	**MMUS$**	**188**	**40**	**27**	**34**	**27**	**21**	**16**	**12**	**9**	**5**	**5**	**(1)**	**(8)**
NPV @ 10% Net to Repsol	**MMUS$**	**150**												

2P – B46 PSC

Block 46 PSC (70%) - PSC expiry 2027	Unit	Total	2021	2022	2023	2024	2025	2026	2027
Gross Oil & Condensate Production Rate	Bopd		519	497	432	379	335	298	267
Gross Annual Oil & Condensate Production	MMstb	**1.0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56	58	61	63
Cost Recovery to Repsol	MMUS$	17	3	3	3	2	2	2	2
Repsol's Share of Profit Oil	MMUS$	9	2	2	1	1	1	1	1
Net Entitlement to Repsol			43%	43%	43%	43%	43%	43%	43%
Net Oil Production to Repsol	Bopd	0	222	212	184	162	143	127	114
Net Annual Oil Production to repsol	MMstb	**0.4**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	25	5	5	4	3	3	3	3
Net Opex to Repsol	MMUS$	(16)	(3)	(2)	(2)	(2)	(2)	(2)	(2)
Net Capex to Repsol	MMUS$	(0)	(0)	0	0	0	0	0	0
Net Abex (Wells + facilities) to Repsol	MMUS$	(7)	0	0	(1)	(1)	(3)	0	(2)
Net Export Duty	MMUS$	0	0	0	0	0	0	0	0
Overhead Payment from partner	MMUS$	0	0	0	0	0	0	0	0
Net Corporate Income Tax	MMUS$	0	0	0	0	0	0	0	0
Free Cash Flows to Repsol (Block 46)	**MMUS$**	**2**	**2**	**2**	**1**	**(0)**	**(2)**	**1**	**(1)**
NPV @ 10% Net to Repsol	**MMUS$**	**3**							

2P – PM305/PM314 PSC

PM305/PM314 PSC (60%) - PSC expiry 2024	Unit	Total	2021	2022	2023	2024
Gross Oil Production Rate	Bopd		380	300	270	240
Gross Annual Oil Production	**MMstb**	**0.4**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56
Cost Recovery to Repsol	MMUS$	8	3	2	2	1
Repsol's Share of Profit Oil	MMUS$	4	1	1	1	1
Net Entitlement to Repsol			44%	44%	44%	44%
Net Oil Production to Repsol	Bopd	0	169	133	120	107
Net Annual Oil Production to Repsol	**MMstb**	**0.2**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	11	4	3	3	2
Net Opex to Repsol	MMUS$	(5)	(1)	(1)	(1)	(1)
Net Capex to Repsol	MMUS$	(1)	(0)	(0)	(0)	(0)
Net Abex (Wells + facilities) to Repsol	MMUS$	(15)	(13)	(2)	0	0
Supplementary Payment	MMUS$	(0)	(0)	(0)	(0)	0
Research Cess	MMUS$	(0)	(0)	(0)	(0)	(0)
Net Export Duty	MMUS$	(0)	(0)	(0)	(0)	(0)
Overhead Payment from partner	MMUS$	0	0	0	0	0
PITA	MMUS$	0	0	0	0	0
Free Cash Flows to Repsol (PM305)	**MMUS$**	**(10)**	**(10)**	**(1)**	**1**	**1**
NPV @ 10% Net to Repsol	**MMUS$**	**(10)**				

COMPETENT VALUER'S REPORT ON THE ASSETS (CONT'D)

3PD – PM3 CAA PSC

PM3CAA PSC (35%) - PSC Expiry 2027	Unit	Total	2021	2022	2023	2024	2025	2026	2027
Gross Gas Production	MMscfd		244	278	260	215	181	154	133
Gross Condensate Production	Bcpd		4,722	7,907	8,108	6,834	5,812	5,002	4,340
Gross Oil Production	Bopd		13,106	11,873	10,782	9,843	8,957	8,193	7,512
Gross Annual Gas Production	**Bscf**	**535.2**	**89**	**101**	**95**	**79**	**66**	**56**	**49**
Gross Annual Condensate Production	**MMstb**	**15.6**	**2**	**3**	**3**	**2**	**2**	**2**	**2**
Gross Annual Oil Production	**MMstb**	**25.6**	**5**	**4**	**4**	**4**	**3**	**3**	**3**
Realized Gas Price	US$/MMBtu		4	4	4	3	4	4	4
Realized Condensate Price	US$/bbl		63	60	58	56	58	61	63
Realized Oil Price	US$/bbl		63	60	58	56	58	61	63
Cost Recovery to Repsol	MMUS$	641	86	99	97	97	93	87	81
Profit & Unused Oil + Gas + Con share to Repsol	MMUS$	297	60	61	53	37	31	29	25
Net Entitlement to Repsol			19%	20%	20%	22%	23%	23%	23%
Net Gas Production to Repsol	MMscfd		47	55	53	48	41	35	30
Net Condensate Production to Repsol	Bcpd		910	1,570	1,658	1,508	1,315	1,130	991
Net Oil Production to Repsol	Bopd		2,527	2,358	2,205	2,172	2,026	1,850	1,716
Net Annual Gas Production to Repsol	**Bscf**	**112.9**	**17**	**20**	**19**	**17**	**15**	**13**	**11**
Net Annual Condensate Production to Repsol	**MMstb**	**3.3**	**0**	**1**	**1**	**1**	**0**	**0**	**0**
Net Annual Oil Production to Repsol	**MMstb**	**5.4**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Net Revenue to Repsol	MMUS$	937	146	160	151	134	124	115	107
Net Opex to Repsol	MMUS$	(554)	(73)	(83)	(83)	(81)	(81)	(77)	(76)
Net Capex to Repsol	MMUS$	(17)	(2)	(3)	(2)	(2)	(2)	(3)	(3)
Net Abex (Wells + Facilities) to Repsol	MMUS$	(58)	(5)	(11)	(10)	(13)	(8)	(6)	(6)
Net Supplementary Payment- Repsol	MMUS$	0	0	0	0	0	0	0	0
Net Research Cess payment-Repsol	MMUS$	(5)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Overhead Payment from Partner	MMUS$	18	2	2	2	3	2	2	3
Net Export Duty-Repsol	MMUS$	(11)	(2)	(2)	(2)	(1)	(1)	(1)	(1)
Net PITA-Repsol	MMUS$	(77)	(11)	(19)	(17)	(11)	(9)	(9)	(1)
One-time extension bonus payment	MMUS$	8	1	1	1	1	1	4	0
Free Cash Flows to Repsol (PM3CAA)	**MMUS$**	**241**	**57**	**44**	**39**	**29**	**24**	**25**	**22**
NPV @ 10% Net to Repsol	**MMUS$**	**196**							

COMPETENT VALUER'S REPORT ON THE ASSETS (CONT'D)

3PD – KINABALU PSC

Kinabalu PSC (60%) - PSC expiry 2032	Unit	Total	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gross Oil Production Rate	Bopd		14,859	12,726	10,996	9,599	8,383	7,380	6,525	5,805	5,107	4,519	3,990	3,574
Gross Annual Oil Production	**MMstb**	**34.1**	**5**	**5**	**4**	**4**	**3**	**3**	**2**	**2**	**2**	**2**	**1**	**1**
Realized Oil Price	US$/bbl		63	60	58	56	58	61	63	66	71	75	77	78
Cost Recovery to Repsol	MMUS$	368	29	43	38	28	27	28	27	27	32	27	30	32
Repsol's Share of Unused & Profit Oil	MMUS$	415	82	56	46	41	36	31	28	26	21	21	16	12
Net Entitlement to Repsol			33%	36%	36%	35%	36%	37%	37%	37%	40%	38%	41%	43%
Net Oil Production to Repsol	Bopd	12	4,847	4,558	3,979	3,377	2,999	2,703	2,404	2,169	2,024	1,738	1,626	1,541
Net Annual Oil Production to repsol	**MMstb**	**12.4**	**2**	**2**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Net Revenue to Repsol	MMUS$	783	111	99	84	68	63	60	55	52	53	48	45	44
Net Opex to Repsol	MMUS$	(310)	(26)	(32)	(27)	(26)	(26)	(25)	(25)	(25)	(25)	(25)	(25)	(25)
Net Capex to Repsol	MMUS$	(35)	(3)	(9)	(11)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Net Abex (Wells + facilities) to Repsol	MMUS$	(17)	0	(2)	0	0	0	(1)	0	0	(5)	0	(3)	(6)
Net Supplementary Payment	MMUS$	(74)	(21)	(12)	(8)	(6)	(5)	(4)	(4)	(3)	(3)	(3)	(2)	(1)
Net Research Cess payment	MMUS$	(4)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Sabah Sales Tax	MMUS$	(6)	(6)	0	0	0	0	0	0	0	0	0	0	0
Net Export Duty	MMUS$	(42)	(8)	(6)	(5)	(4)	(4)	(3)	(3)	(3)	(2)	(2)	(2)	(1)
Overhead Payment from partner	MMUS$	4	0	0	0	0	0	0	0	0	0	0	0	0
Net PITA	MMUS$	(40)	0	0	0	(1)	(6)	(5)	(6)	(6)	(4)	(5)	(4)	(2)
Free Cash Flows to Repsol (Kinabalu)	**MMUS$**	**259**	**47**	**39**	**33**	**30**	**21**	**19**	**16**	**14**	**12**	**11**	**9**	**7**
NPV @ 10% Net to Repsol	**MMUS$**	**191**												

3PD – B46 PSC

Block 46 PSC (70%) - PSC expiry 2027	Unit	Total	2021	2022	2023	2024	2025	2026	2027
Gross Oil & Condensate Production Rate	Bopd		598	606	558	517	478	445	414
Gross Annual Oil & Condensate Production	MMstb	**1.3**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56	58	61	63
Cost Recovery to Repsol	MMUS$	22	4	4	3	3	3	3	3
Repsol's Share of Profit Oil	MMUS$	12	2	2	2	2	1	1	1
Net Entitlement to Repsol			43%	43%	43%	43%	43%	43%	43%
Net Oil Production to Repsol	Bopd	1	255	259	238	221	204	190	177
Net Annual Oil Production to repsol	MMstb	**0.6**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	34	6	6	5	4	4	4	4
Net Opex to Repsol	MMUS$	(16)	(3)	(2)	(2)	(2)	(2)	(2)	(2)
Net Capex to Repsol	MMUS$	(0)	(0)	0	0	0	0	0	0
Net Abex (Wells + facilities) to Repsol	MMUS$	(7)	0	0	(1)	(1)	(3)	0	(2)
Net Export Duty	MMUS$	0	0	0	0	0	0	0	0
Overhead Payment from partner	MMUS$	0	0	0	0	0	0	0	0
Net Corporate Income Tax	MMUS$	0	0	0	0	0	0	0	0
Free Cash Flows to Repsol (Block 46)	**MMUS$**	**10**	**3**	**3**	**2**	**1**	**(1)**	**2**	**0**
NPV @ 10% Net to Repsol	**MMUS$**	**9**							

3PD – PM305/PM314 PSC

PM305/PM314 PSC (60%) - PSC expiry 2024	Unit	Total	2021	2022	2023	2024
Gross Oil Production Rate	Bopd		380	300	270	240
Gross Annual Oil Production	**MMstb**	**0.4**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56
Cost Recovery to Repsol	MMUS$	8	3	2	2	1
Repsol's Share of Profit Oil	MMUS$	4	1	1	1	1
Net Entitlement to Repsol			44%	44%	44%	44%
Net Oil Production to Repsol	Bopd	0	169	133	120	107
Net Annual Oil Production to Repsol	**MMstb**	**0.2**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	11	4	3	3	2
Net Opex to Repsol	MMUS$	(5)	(1)	(1)	(1)	(1)
Net Capex to Repsol	MMUS$	(1)	(0)	(0)	(0)	(0)
Net Abex (Wells + facilities) to Repsol	MMUS$	(15)	(13)	(2)	0	0
Supplementary Payment	MMUS$	(0)	(0)	(0)	(0)	0
Research Cess	MMUS$	(0)	(0)	(0)	(0)	(0)
Net Export Duty	MMUS$	(0)	(0)	(0)	(0)	(0)
Overhead Payment from partner	MMUS$	0	0	0	0	0
PITA	MMUS$	0	0	0	0	0
Free Cash Flows to Repsol (PM305)	**MMUS$**	**(9)**	**(10)**	**(1)**	**1**	**1**
NPV @ 10% Net to Repsol	**MMUS$**	**(10)**				

3P – PM3 CAA PSC

PM3CAA PSC (35%) - PSC Expiry 2027	Unit	Total	2021	2022	2023	2024	2025	2026	2027
Gross Gas Production	MMscfd		244	287	271	221	185	158	137
Gross Condensate Production	Bcpd		4,722	8,400	8,845	7,414	6,277	5,328	4,567
Gross Oil Production	Bopd		13,100	14,636	19,406	18,192	17,167	13,538	10,755
Gross Annual Gas Production	**Bscf**	**549.2**	**89**	**105**	**99**	**81**	**68**	**58**	**50**
Gross Annual Condensate Production	**MMstb**	**16.6**	**2**	**3**	**3**	**3**	**2**	**2**	**2**
Gross Annual Oil Production	**MMstb**	**39.0**	**5**	**5**	**7**	**7**	**6**	**5**	**4**
Realized Gas Price	US$/MMBtu		4	4	4	3	4	4	4
Realized Condensate Price	US$/bbl		63	60	58	56	58	61	63
Realized Oil Price	US$/bbl		63	60	58	56	58	61	63
Cost Recovery to Repsol	MMUS$	725	102	131	116	101	97	89	88
Profit & Unused Oil + Gas + Con share to Repsol	MMUS$	364	55	61	70	55	49	42	32
Net Entitlement to Repsol			21%	22%	20%	20%	20%	20%	22%
Net Gas Production to Repsol	MMscfd		51	62	53	44	37	32	30
Net Condensate Production to Repsol	Bcpd		978	1,809	1,734	1,458	1,248	1,087	996
Net Oil Production to Repsol	Bopd		2,714	3,151	3,805	3,578	3,413	2,763	2,346
Net Annual Gas Production to Repsol	**Bscf**	**112.5**	**18**	**23**	**19**	**16**	**13**	**12**	**11**
Net Annual Condensate Production to Repsol	**MMstb**	**3.4**	**0**	**1**	**1**	**1**	**0**	**0**	**0**
Net Annual Oil Production to Repsol	**MMstb**	**7.9**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Net Revenue to Repsol	MMUS$	1,089	157	192	186	157	146	131	120
Net Opex to Repsol	MMUS$	(572)	(73)	(84)	(87)	(85)	(85)	(80)	(78)
Net Capex to Repsol	MMUS$	(77)	(17)	(48)	(2)	(2)	(2)	(3)	(3)
Net Abex (Wells + Facilities) to Repsol	MMUS$	(59)	(5)	(11)	(10)	(13)	(8)	(6)	(6)
Net Supplementary Payment- Repsol	MMUS$	0	0	0	0	0	0	0	0
Net Research Cess payment-Repsol	MMUS$	(5)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Overhead Payment from Partner	MMUS$	20	3	4	3	3	2	2	3
Net Export Duty-Repsol	MMUS$	(15)	(2)	(2)	(3)	(3)	(3)	(2)	(1)
Net PITA-Repsol	MMUS$	(105)	(10)	(17)	(27)	(17)	(15)	(13)	(5)
One-time extension bonus payment	MMUS$	8	1	1	1	1	1	4	0
Free Cash Flows to Repsol (PM3CAA)	**MMUS$**	**284**	**54**	**34**	**58**	**40**	**35**	**33**	**29**
NPV @ 10% Net to Repsol	**MMUS$**	**224**							

3P – KINABALU PSC

Kinabalu PSC (60%) - PSC expiry 2032	Unit	Total	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gross Oil Production Rate	Bopd		14,859	15,182	14,644	12,002	10,016	8,516	7,331	6,437	5,563	4,845	4,224	3,751
Gross Annual Oil Production	**MMstb**	**39.2**	**5**	**6**	**5**	**4**	**4**	**3**	**3**	**2**	**2**	**2**	**2**	**1**
Realized Oil Price	US$/bbl		63	60	58	56	58	61	63	66	71	75	77	78
Cost Recovery to Repsol	MMUS$	396	29	70	38	28	28	29	27	27	32	27	30	33
Repsol's Share of Unused & Profit Oil	MMUS$	490	82	57	68	55	45	39	34	30	24	24	19	14
Net Entitlement to Repsol			33%	38%	34%	34%	35%	36%	36%	37%	39%	38%	41%	43%
Net Oil Production to Repsol	Bopd	14	4,847	5,808	5,037	4,078	3,476	3,035	2,639	2,353	2,157	1,835	1,732	1,627
Net Annual Oil Production to repsol	**MMstb**	**14.1**	**2**	**2**	**2**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Net Revenue to Repsol	MMUS$	885	111	127	106	83	73	67	61	57	56	50	48	46
Net Opex to Repsol	MMUS$	(312)	(26)	(32)	(27)	(26)	(26)	(26)	(25)	(25)	(25)	(25)	(25)	(25)
Net Capex to Repsol	MMUS$	(60)	(3)	(35)	(11)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Net Abex (Wells + facilities) to Repsol	MMUS$	(17)	0	(2)	0	0	0	(1)	0	0	(5)	0	(3)	(6)
Net Supplementary Payment	MMUS$	(86)	(21)	(13)	(12)	(8)	(6)	(5)	(5)	(4)	(4)	(4)	(3)	(2)
Net Research Cess payment	MMUS$	(4)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Sabah Sales Tax	MMUS$	(6)	(6)	0	0	0	0	0	0	0	0	0	0	0
Net Export Duty	MMUS$	(49)	(8)	(6)	(7)	(5)	(5)	(4)	(3)	(3)	(2)	(2)	(2)	(1)
Overhead Payment from partner	MMUS$	4	0	1	0	0	0	0	0	0	0	0	0	0
Net PITA	MMUS$	(61)	0	0	(2)	(11)	(9)	(7)	(7)	(7)	(5)	(6)	(5)	(3)
Free Cash Flows to Repsol (Kinabalu)	**MMUS$**	**293**	**47**	**40**	**47**	**31**	**26**	**23**	**19**	**17**	**14**	**12**	**10**	**8**
NPV @ 10% Net to Repsol	**MMUS$**	**215**												

3P – B46 PSC

Block 46 PSC (70%) - PSC expiry 2027	Unit	Total	2021	2022	2023	2024	2025	2026	2027
Gross Oil & Condensate Production Rate	Bopd		598	606	558	517	478	445	414
Gross Annual Oil & Condensate Production	MMstb	**1.3**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56	58	61	63
Cost Recovery to Repsol	MMUS$	22	4	4	3	3	3	3	3
Repsol's Share of Profit Oil	MMUS$	12	2	2	2	2	1	1	1
Net Entitlement to Repsol			43%	43%	43%	43%	43%	43%	43%
Net Oil Production to Repsol	Bopd	1	255	259	238	221	204	190	177
Net Annual Oil Production to repsol	MMstb	**0.6**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	34	6	6	5	4	4	4	4
Net Opex to Repsol	MMUS$	(16)	(3)	(2)	(2)	(2)	(2)	(2)	(2)
Net Capex to Repsol	MMUS$	(0)	(0)	0	0	0	0	0	0
Net Abex (Wells + facilities) to Repsol	MMUS$	(7)	0	0	(1)	(1)	(3)	0	(2)
Net Export Duty	MMUS$	0	0	0	0	0	0	0	0
Overhead Payment from partner	MMUS$	0	0	0	0	0	0	0	0
Net Corporate Income Tax	MMUS$	0	0	0	0	0	0	0	0
Free Cash Flows to Repsol (Block 46)	**MMUS$**	**10**	**3**	**3**	**2**	**1**	**(1)**	**2**	**0**
NPV @ 10% Net to Repsol	**MMUS$**	**9**							

3P – PM305/PM314 PSC

PM305/PM314 PSC (60%) - PSC expiry 2024	Unit	Total	2021	2022	2023	2024
Gross Oil Production Rate	Bopd		380	300	270	240
Gross Annual Oil Production	**MMstb**	**0.4**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56
Cost Recovery to Repsol	MMUS$	8	3	2	2	1
Repsol's Share of Profit Oil	MMUS$	4	1	1	1	1
Net Entitlement to Repsol			44%	44%	44%	44%
Net Oil Production to Repsol	Bopd	0	169	133	120	107
Net Annual Oil Production to Repsol	**MMstb**	**0.2**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	11	4	3	3	2
Net Opex to Repsol	MMUS$	(5)	(1)	(1)	(1)	(1)
Net Capex to Repsol	MMUS$	(1)	(0)	(0)	(0)	(0)
Net Abex (Wells + facilities) to Repsol	MMUS$	(15)	(13)	(2)	0	0
Supplementary Payment	MMUS$	(0)	(0)	(0)	(0)	0
Research Cess	MMUS$	(0)	(0)	(0)	(0)	(0)
Net Export Duty	MMUS$	(0)	(0)	(0)	(0)	(0)
Overhead Payment from partner	MMUS$	0	0	0	0	0
PITA	MMUS$	0	0	0	0	0
Free Cash Flows to Repsol (PM305)	**MMUS$**	**(9)**	**(10)**	**(1)**	**1**	**1**
NPV @ 10% Net to Repsol	**MMUS$**	**(10)**				

2P - Consolidated

Consolidated	Unit	Total	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gross Oil Production Rate	Bopd		25,950	25,393	26,948	22,409	19,576	15,535	12,396	3,964	3,336	2,842	2,361	1,942
Gross Condensate Production	Bopd		4,091	6,767	6,744	5,221	4,222	3,399	2,732	0	0	0	0	0
Gross Gas Production	MMscfd		198	215	191	146	115	93	76	0	0	0	0	0
Gross Annual Oil Production	MMstb	59	9	9	10	8	7	6	5	1	1	1	1	1
Gross Annual Condensate Production	MMstb	12	1	2	2	2	2	1	1	0	0	0	0	0
Gross Annual Gas Production	Bscf	378	72	78	70	53	42	34	28	0	0	0	0	0
Net Entitlement to Kinabalu- PSC			33%	41%	36%	36%	37%	39%	40%	41%	45%	45%	45%	45%
Net Entitlement to PM3CAA PSC			21%	22%	22%	23%	23%	23%	23%	0%	0%	0%	0%	0%
Net Oil Production to Repsol	Bopd		7,279	8,027	7,639	6,352	5,527	4,556	3,717	1,642	1,501	1,274	1,062	874
Net Condensate Production to Repsol	Bcpd		873	1,484	1,471	1,176	957	785	633	0	0	0	0	0
Net Gas Production to Repsol	MMscfd		42	47	42	33	26	22	18	0	0	0	0	0
Net Oil+ Condensate + Gas Production Rate	Boepd		15,198	17,364	16,056	12,994	10,838	8,937	7,285	1,642	1,501	1,274	1,062	874
Net Annual Oil Production to Repsol	MMstb	18	3	3	3	2	2	2	1	1	1	0	0	0
Net Annual Condensate Production to Repsol	MMstb	3	0	1	1	0	0	0	0	0	0	0	0	0
Net Annual Gas Production to Repsol	Bscf	84	15	17	15	12	10	8	6	0	0	0	0	0
Realized Oil Price	$/bbl		63	60	58	56	58	61	63	66	71	75	77	78
Realized Condensate Price	$/bbl		63	60	58	56	58	61	63	0	0	0	0	0
Realized Gas Price	$/mmbtu		3.9	3.7	3.6	3.5	3.6	3.9	4.0	0.0	0.0	0.0	0.0	0.0
Cost Recovery to Repsol	MMUS$	1,047	131	186	154	127	118	108	93	27	31	28	24	20
Repsol's Share of Profit and Unused Cost Liquid & Gas	MMUS$	525	117	85	92	66	53	41	33	13	8	7	6	5
Net Revenue to Repsol	MMUS$	1,571	247	271	246	194	170	149	126	40	39	35	30	25
Net Opex to Repsol	MMUS$	(857)	(99)	(113)	(108)	(105)	(103)	(103)	(101)	(25)	(25)	(25)	(25)	(25)
Net Capex to Repsol	MMUS$	(138)	(20)	(82)	(13)	(4)	(4)	(4)	(4)	(1)	(1)	(1)	(1)	(1)
Net Abex (Wells & Facilities) to Repsol	MMUS$	(99)	(18)	(15)	(11)	(14)	(11)	(7)	(8)	0	(5)	0	(3)	(6)
Net Supplementary Payment	MMUS$	(55)	(18)	(9)	(9)	(5)	(4)	(3)	(2)	(2)	(1)	(1)	(1)	(1)
Net Research Cess payment	MMUS$	(8)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(0)
Sabah Sales Tax	MMUS$	(5)	(5)	0	0	0	0	0	0	0	0	0	0	0
Net Export Duty	MMUS$	(39)	(9)	(5)	(6)	(5)	(4)	(3)	(2)	(1)	(1)	(1)	(1)	(0)
Net PITA-Repsol	MMUS$	(53)	(6)	(6)	(20)	(9)	(7)	(2)	(1)	(2)	(0)	(2)	0	0
Overhead Payment from Partner	MMUS$	25	4	5	3	3	3	3	3	0	0	0	0	0
One-time extension bonus payment (PM3CAA)	MMUS$	8	1	1	1	1	1	4	0	0	0	0	0	0
Net Project Free Cash Flows	**MMUS$**	**351**	**77**	**45**	**81**	**54**	**41**	**32**	**10**	**9**	**5**	**5**	**(1)**	**(8)**
NPV @ 10% Net to Repsol	**MMUS$**	**285**												

Contact

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EXPERT'S REPORT ON THE FAIRNESS OF THE PURCHASE PRICE FOR THE ASSETS

MAKING COMPLEX EASY

Our ref: ECV2405

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United Kingdom
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Date: 1st October, 2021

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

Attn: The Board of Directors

Dear Sirs and Madams,

HIBISCUS PETROLEUM BERHAD ("HIBISCUS PETROLEUM" OR "COMPANY") EXPERT'S REPORT ON THE FAIRNESS OF THE PURCHASE CONSIDERATION FOR UPSTREAM ASSETS HELD BY REPSOL EXPLORACIÓN, S.A. ("REPSOL")

In response to a request from Hibiscus Petroleum Berhad ("Hibiscus"), RPS Energy Consultants Limited ("RPS" or "Independent Expert") has completed a report on the fairness of the purchase consideration of the Proposed Acquisition (as defined herein) of the upstream assets held by Repsol Exploración, S.A. ("Repsol"). Repsol has working interests in five (5) production sharing contracts, namely PM3 CAA, Block 46, PM305 and PM314 located offshore Peninsular Malaysia and Vietnam; and Kinabalu PSC located offshore Sabah (collectively, the "Assets") for inclusion in the circular to the shareholders of Hibiscus Petroleum.

RPS has undertaken the project following the signing of a Letter of Engagement ("LoE") dated 18th December 2020.

1.1 Brief particulars of the Proposed Acquisition

The **Proposed Acquisition** entails the acquisition by Peninsula Hibiscus Sdn Bhd ("Peninsula Hibiscus") of the entire issued share capital of Fortuna International Petroleum Corporation ("FIPC"), subject to the terms and conditions of the sales and purchase agreement (SPA).

FIPC through its wholly-owned subsidiaries, namely Repsol Oil & Gas Malaysia Limited ("RML"), Repsol Oil & Gas Malaysia (PM3) Limited ("RMPM3") and Talisman Vietnam Limited ("TVL") owns participating interests in the following production sharing contracts ("PSC"):

- 60% working interest in the 2012 Kinabalu Oil PSC located off the coast of Sabah, Malaysia ("2012 Kinabalu Oil"), currently held by RML;
- 35% working interest in the PM3 CAA PSC located within the Commercial Arrangement Area ("CAA") between Malaysia and Vietnam ("PM3 CAA"), currently held by RMPM3 (12.7%) and RML (22.3%);
- 60% working interest in each of the PM305 and PM314 PSCs located off the eastern coast of Peninsular Malaysia in the Malay Basin ("PM305 and PM314"), currently held by RML; and
- 70% working interest in the Block 46 PSC (Cai Nuoc), a tie-back asset to the PM3 CAA PSC located in Vietnamese waters ("Block 46"), currently held by TVL.

Hibiscus had, on 2nd June 2021 and 4th June 2021 announced that its indirect wholly-owned subsidiary, Peninsula Hibiscus has on 1st June 2021 entered into a conditional SPA with Repsol for the Proposed Acquisition for a cash consideration of US$ 212.5 million.

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 Repsol virtual data room. RPS has reviewed available data and evaluated forecasts for existing production and additional projects confirmed by RPS as being reported by Repsol in the latest Work Plan and Budget (2021 WP&B) or equivalent.

The Repsol Virtual Data Room ("VDR") access was made available to RPS on 8th December 2020. This contained Process documentation, Presentations and Minutes from key meetings, Field Development plans, Legal and Regulatory Information and Finance and Tax information as well as historical production data for each of the Assets. RPS staff attended the Physical Data Room ("PDR") conducted via MS Teams™ between 14th and 17th December 2020. The PDR contained static and dynamic models of certain fields in the asset base.

The alternative valuation method adopted, the market comparison/market-based approach, required the use of public domain information from company press releases of 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 Assets. In addition, RPS undertook a market comparison/market-based approach with a number of published similar transactions.

1.3.1 Discounted Cash Flow Valuation

RPS production and cost forecasts for the Assets were generated for each field at the Proved ("1P"), Proved plus Probable ("2P") and Proved plus Probable plus Possible ("3P") Reserves in conjunction with its associated cost estimates. The annual forecasts of production and costs were used in the economic cashflow model and aggregated for the 1P, 2P and 3P Reserves cases.

The following assumptions were made in the cashflow model:

- The effective date of the valuation is 1st January 2021;
- The post-tax cashflows are discounted mid-year at a 10% discount rate to 1st January 2021;
- An annual inflation rate of 2% from 2021 onwards applies to costs and revenues;
- RPS Q2 2021 long term forecast for Brent (forward curve between 2021 and 2029; long term price of US$ 60 per barrel flat real at 2 per cent per annum thereafter);
- Sales gas price according to Upstream Gas Sales Agreements (UGSA) which is linked with High Sulphur Fuel Oil Cost (HSFOC); and
- The RPS Reserves cases are truncated at the economic limit, a point in time that defines the economic life of the project. The PSC is assumed to reach its economic limit when the cumulative value of its operating cash flow 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).

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

1.4 Alternative Market Valuation

There are three (3) 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 Market-based, Income-based, and Cost-based. Each valuation approach is defined in Section 8 of the 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 Market-based Approach

RPS's estimate of 2P Reserves as of 1st January 2021 is 17.9 million stock tank barrel ("MMstb") of crude oil, 2.7 MMstb of condensate, and 83.6 billion standard cubic feet ("Bscf") of gas; assuming 6,000 standard cubic feet over barrel of oil equivalent ("scf/boe") for the gas Reserves, translate to a total barrel of oil equivalent of 34.5 MMboe. The valuation of the Proved plus Probable ("2P") Reserves at RPS Base Brent price and applying a 10% discount rate as of 1st January 2021 is US$ 285 Million. The implied dollar per 2P barrel ("bbl") is therefore US$ 8.3/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 and Indonesia that are available in the public domains, and considered those deals relating to producing fields for comparison with the current valuation. Both Malaysia and Indonesia apply production sharing contract fiscal regime.

A summary of the transactions in Malaysia and Indonesia which completed in year 2018 and 2019 is presented in **Table 1**. The market transactions tabulated would have been made under different price environments, as well as at different discount rates according to the respective buyers' investment strategy at the point of the acquisitions made. During the period between 2018 and 2019 which these transactions were conducted and closed; average Brent crude oil price is approximately US$ 67.7/bbl. During the commercial evaluation period between March and May 2021 in which the acquisition price of the Assets was finalised, average Brent crude oil price is approximately US$ 66.3/bbl. Therefore, adjustment to the current valuation against the reported previous transacted values according to Brent crude oil price forecasts for the period between 2018 and 2019 is not considered necessary.

Based on the information summarised in **Table 1**, the implied dollar per 2P barrel ranges between US$ 7.4/boe and US$ 17.3/boe. Current valuation with its implied dollar per 2P barrel of US$ 8.3/boe falls within this range. The upper range of implied dollar per 2P of US$ 17.3/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. Whilst it is not accurate to assume 100 per cent of the reported Best Estimate ("2C") Contingent Resources of 173 MMboe (87 net to SEB) to derive the implied dollar per 2P plus 2C, it is probably not unreasonable to assume 33% of the 2C in deriving the deal metric are classified as Development Pending according to information sourced in public domain. Based on this assumption, the implied dollar per 2P plus 2C becomes US$ 10.7/boe.

PTTEP Limited acquisition of Murphy Oil Corporation's interests in Malaysia back in March 2019 also yielded relatively higher dollar per 2P barrel at US$ 12.6/boe. However, we are not able to source any information related to its 2C Contingent Resources from the public domain although there is news it was discovered but

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

[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.

yet to be developed fields. Therefore, the deal metric could potentially be lower but without the supporting information, we determine the range of implied dollar per barrel at between **US$ 7.4/boe and US$ 10.7/bbl**. Based on current valuation of the net 2P to Repsol of 34.5 MMboe, this translates to a fair market value of between **US$ 255 and US$ 368 million**.

In October 2016, Hibiscus via its indirect wholly-owned subsidiary, SEA Hibiscus Sdn Bhd (SEA Hibiscus) entered into a conditional Sale and Purchase Agreement (SPA) with Sabah Shell Petroleum Company Limited and Shell Sabah Selatan Sdn Bhd to acquire Shell's entire 50 per cent participating interests in the 2011 North Sabah Enhanced Oil Recovery PSC for a purchase consideration of US$ 25 million. It is reported the PSC has gross 2P Reserves of 40.9 MMstb which translate to implied dollar per 2P barrel of only US$ 1.2/bbl. RPS does not consider this transaction metric to be suitable to determine the fair market value due to the following possible reason that prompted Shell to relinquish its interests in the PSC at below market value:

- The average Brent crude oil price in the beginning of 2016 until the conditional SPA was signed in October 2016 was only US$ 42.5/bbl;
- The PSC was at its late production life and might not be commercially viable at low oil price environment; and
- Shell might probably had been keen to divest its non-core asset as part of its global portfolio optimisation.

Our ref: ECV2405

No.	Effective Date	Asset name	Buyer(s)	Seller	Price (US$ million)	2P Reserves (million boe)	Price (US$/boe)
1.	May 2019	Acquisition of Ophir Energy plc[4]	PT Medco Energi Internasional Tbk	Ophir Energy plc	517[1]	70.1	7.4
2.	March 2019	Murphy Oil Corporation's Interests in Malaysia[5]	PTTEP Limited	Murphy Oil Corporation	2,127	169.3[2]	12.6
3.	January 2019	50 per cent interest in SEB Upstream Sdn Bhd (SUP)[6]	OMV Exploration and Production GmbH	Sapura Energy Berhad	800	46.1	17.3[3]
4.	September 2018	Acquisition of Santos's Southeast Asian production licences[7]	Ophir Energy plc	Santos Limited	205	23.3	8.8

Notes:

[1] 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)

[2] 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.

[3] The implied US$/boe reduces to US$6/boe if 2C of 86.6 million boe net to SEB is considered.

Table 1: Summary of Several Recent Transactions in Malaysia and Indonesia

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

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

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

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

1.4.2 Income-based Approach

The valuation of the Assets, as elaborated in Section 1.3 of this report, was undertaken using Discounted Cash Flow (DCF) method, consistent with the industry standard of valuing Reserves and Resources according to the PRMS guidelines. This DCF method has similar principle with the Income-based approach defined by the VALMIN Code.

According to the Competent Valuer's Report disclosed by Sapura Energy Berhad (SEB) for the purpose of OMV acquisition of SEB's 50 per cent interest in SUP, the Competent Valuer had applied a discount rate of 8 per cent for the valuation of SEB's Malaysian upstream assets. Based on RPS previous commercial evaluation experiences for upstream assets in Malaysia and Indonesia, discount rate between 8 and 12 per cent is considered reasonable for fields already in production or in development phase.

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 2.** RPS has verified the WACC computation input and confirm that 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]	12.4%	12.4%	12.4%	12.4%
Pre-Tax Cost of Debt[2]	7%	7%	7%	7%
Petroleum Income Tax (PITA)	38%	38%	38%	38%
Post-Tax Cost of Debt	4.3%	4.3%	4.3%	4.3%
Target Debt/Equity	0.3	0.4	0.5	0.6
WACC	10.5%	10.1%	9.7%	9.4%

Notes:
[1] Average cost of Equity provided by Hibiscus (Source: Bloomberg)
[2] Provided by Hibiscus (Source: Bloomberg)

Table 2: Range of Hibiscus's Weighted Average Cost of Capital (WACC)

As the Assets are 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.

As presented in the Competent Valuer's Report, the Assets NPV discounted at 10 per cent is **US$ 285 million**.

1.4.3 Fair Market Value

Based on the two Common Valuation Approaches recommended by the VALMIN Code, namely the Market-based Approach and Income-based Approach, RPS opines that the Fair Market Value of the Assets ranges between **US$ 255 and US$ 368 million**.

RPS opines that despite the Proposed Acquisition of the entire issued share capital of FIPC for a cash consideration of US$ 212.5 million falls below the Fair Market Value range, it is fair value based on the fact that:

- Repsol's Malaysian upstream portfolio only represents about 2 per cent of its current net output globally; and
- Repsol aims to focus on the geographic areas that have the most competitive advantages as well as new low-carbon initiatives under the 2021-2025 Strategic Plan.

Our ref: ECV2405

QUALIFICATIONS

RPS is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis, with notable experience in the evaluation of oil and gas properties. Except for the provision of professional services on a fee basis, RPS does not have a commercial arrangement with any other person or company involved in the Asset that is the subject of this evaluation.

The lead professionals involved in this work hold degrees in geology, geophysics, petroleum engineering and related subjects; and have relevant experience in the practice of geology, geophysics or petroleum engineering.

Mr. Jim Bradly, Operations Director has supervised this evaluation. Mr Bradly is a Chartered Engineer and Chartered Petroleum Engineer with over 20 years of experience in upstream oil and gas of which over 15 years' experience in auditing and evaluating oil and gas Reserves and Resources. The project has been managed by Joseph Tan, a Petroleum Economist with over 20 years of experience in upstream oil and gas. Other RPS employees involved in this work hold at least a Bachelor'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.

In preparing this report, RPS relied upon factual information including ownership, technical, well and seismic data, contracts, and other relevant data supplied by Repsol. The work was undertaken by a team of professional petroleum engineers, geoscientists and petroleum economists. We have used standard petroleum engineering techniques in estimating the Reserves and Resources. These techniques combine geological and production data with detailed information concerning fluid characteristics and reservoir pressures. We have estimated the degree of uncertainty inherent in the measurements and interpretation of the data and have calculated a range of Reserves and Resources. We have taken the working interest that Repsol has in the Assets as presented by Repsol. We have not investigated, nor do we make any warranty as to the Repsol's interest in the Assets.

BASIS OF OPINION

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

The evaluation 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. The evaluation relates specifically and solely to the subject Assets and is conditional upon various assumptions that are described herein. The evaluation was provided for the sole use of Hibiscus and their corporate advisors on a fee basis.

Yours sincerely,
for RPS Energy Consultants Ltd

Jim Bradly CEng, MEI, Chartered Petroleum Engineer
Operations Director – EAME
RPS Energy Technical & Advisory

COMPETENT PERSON'S REPORT

Hibiscus Petroleum Berhad

ECV2405

Competent Person's Report
Rev 3
25th June 2021

rpsgroup.com

COMPETENT PERSON'S REPORT

Document status

Version	Purpose of document	Authored by	Reviewed by	Approved by	Review date
Rev 0	Final Report	DO, SM, DB, JT, GF	GJB	GJB	5/3/21
Rev 1	Final Report	DO, SM, DB, JT, GF	GJB	GJB	31/5/21
Rev 2	Final Report	DO, SM, DB, JT, GF	GJB	GJB	21/6/21
Rev 3	Final Report	DO, SM, DB, JT, GF	GJB	GJB	25/6/21

Approval for issue

Jim Bradly		25/6/2021

Prepared by:

RPS

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Our ref: ECV2405

Date: 25th June 2021

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59100 Kuala Lumpur,
Malaysia

Dear Sirs,

EVALUATION OF ASSET RESERVES

In response to a request by Hibiscus Petroleum Berhad ("Hibiscus"), and the Letter of Engagement dated 12th December 2020 with Hibiscus (the "Agreement"), RPS Energy Consultants Ltd ("RPS") has completed an independent evaluation of the Repsol S.A. ("Repsol") assets, for sale as part of a proposal, administered by J.P. Morgan Securities plc, which Hibiscus is interested in acquiring.

The potential transaction encompasses a 100% working interest in each of the following entities:

- Repsol Oil & Gas Malaysia Limited;
- Repsol Oil & Gas Malaysia (PM3) Limited; and
- Talisman Vietnam Limited.

These entities in turn hold and operate Repsol's business in Malaysia, comprising the following interests, collectively, the "Assets":

- 60% working interest in the Kinabalu block located in Sabah, Malaysia
- 35% working interest in the PM3 CAA block located within the Commercial Arrangement Area ("CAA") between Malaysia and Vietnam
- 60% working interest in each of the PM305 and PM314 blocks located off the eastern coast of Peninsular Malaysia in the Malay Basin; and
- 70% working interest in Block 46 (Cai Nuoc), a tie-back asset to the PM3 CAA block located in Vietnamese waters.

Hibiscus had, on 2nd June 2021 and 4th June 2021 announced that its indirect wholly-owned subsidiary, Peninsula Hibiscus Sdn Bhd has on 1st June 2021 entered into a conditional sale and purchase agreement ("SPA") with Repsol for the proposed acquisition of the entire equity interest in Fortuna International Petroleum Corporation for a cash consideration of US$ 212.5 million ("Proposed Acquisition").

This report is issued by RPS under the appointment by Hibiscus to produce a Competent Person's Report 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 Person's Report has been prepared solely for the use of Hibiscus, its other advisors, Bursa Securities and for inclusion in Hibiscus' circular to shareholders.

We have estimated Proved, Probable and Possible Reserves as of 1st January 2021. 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 Person'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 Securities Commission Malaysia's ("SC") Prospectus Guidelines 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 made available by J.P. Morgan Securities plc and Repsol via Virtual (VDR) and Physical (PDR) Datarooms.

RPS has reviewed available data and evaluated forecasts for existing production and additional projects confirmed by RPS as being reported by Repsol in the latest Work Plan and Budget (2021 WP&B) or equivalent.

VDR access was made available to RPS on 8th December 2020. This contained Process documentation, Presentations and Minutes from key meetings, Field Development plans, Legal and Regulatory Information and Finance and Tax information as well as historical production data for each of the assets. RPS staff attended the PDR conducted via MS Teams between 14th and 17th December 2020. The PDR contained static and dynamic models of certain fields in the asset base.

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

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

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

No site visit has been conducted as part of our evaluation as it is usually conducted when a SPA is signed or during the transition period in which personnel specialises in Health Safety Environment would be allowed to conduct limited site visit.

For each Asset, Repsol has presented a Business Case consisting of a Low Investment Case, Defined Developments and Future Developments.

- Low Investment case consists of existing production plus some ongoing, fully sanctioned development projects and can typically be classified as Reserves;
- Defined Developments include a range of projects at different stages of definition, but can be considered a mixture of Contingent and Prospective Resources;
- Future Developments include additional potential projects which typically would be classified as Prospective Resources.

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

The Full Field Gross Reserves and Net Entitlement Reserves as of 1st January 2021 are summarised in Table 1.5 to Table 1.8 for oil, gas, condensate, and total production in barrels of oil equivalent volumes, respectively.

Net Present Value at 0%, 8%, 10%, and 12% discount rates as of 1st January 2021 for PM3 CAA and Kinabalu PSC are presented in Table 1.9 and Table 1.10, respectively.

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. Jim Bradly, Operations Director has supervised this evaluation.

Mr Bradly holds a BEng in Electronic & Electrical Engineering from the University of Manchester in the UK and an MSc in Petroleum Engineering from Imperial College, London. He is a Member and Chartered Petroleum Engineer in good standing of the Energy Institute in the UK and is a Chartered Engineer registered with the Engineering Council UK (Registration # 569021) with over 20 years of experience in upstream oil and gas of which over 15 years' experience in auditing and evaluating oil and gas Reserves and Resources.

The project has been managed by Joseph Tan, a Petroleum Economist with over 20 years of experience in upstream oil and gas. Other RPS employees involved in this work hold at least a Batchelor'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

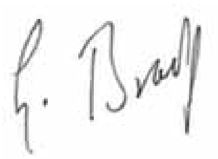
The evaluation presented in this report reflects our informed judgment, based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data. The evaluation has been conducted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



Jim Bradly CEng, MEI, Chartered Petroleum Engineer
Operations Director – EAME
RPS Energy Technical & Advisory

Name	Role	Signature
Joseph Tan	Project Manager	Not available due to home working
David Offer	Geoscience Lead	
Jim Bradly	Reservoir Engineering Lead	
Gordon Fraser	Cost Engineering 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 18 December 2020 with Hibiscus (the "Agreement"), RPS Energy Consultants Ltd ("RPS") has completed an independent evaluation of the Repsol S.A. ("Repsol") assets, for sale as part of a proposal, administered by J.P. Morgan Securities plc, which Hibiscus is interested in acquiring.

The potential transaction encompasses a 100% working interest in each of the following entities:

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- 60% working interest in each of the PM305 and PM314 blocks located off the eastern coast of Peninsular Malaysia in the Malay Basin; and
- 70% working interest in Block 46 (Cai Nuoc), a tie-back asset to the PM3 CAA block located in Vietnamese waters.

1.1 Overview of Assets

Repsol's interests are located in the Malay and West Natuna Basins, offshore Malaysia (Figure 1.1)[1]

Block PM3-CAA is located in the Northeast Malay basin, close to the Vietnamese median line. The block contains a total of 14 accumulations in six fields, developed around two hubs (North and South). Fields are generally comprised of low relief anticline structures with multiple stacked fluvial/shallow marine deltaic sandstones. Fluids are a combination of oil, condensate and gas, with highly variable CO_2 content (5-70%).

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

Blocks PM305 and PM314 are located in the Southwest Malay Basin and are partially abandoned, with only the Angsi Southern Channel/Murai unitised field still producing.

The Kinabalu PSC is located on the Sabah side of the Malaysia-Brunei maritime border in the Natuna Basin. The block contains the Kinabalu field, which is separated by Northeast-Southwest trending extensional faults, into three fault blocks: Kinabalu Main, Kinabalu East and Kinabalu Far East.

[1] *Source: VDR Information Memorandum, 2020 - Repsol*

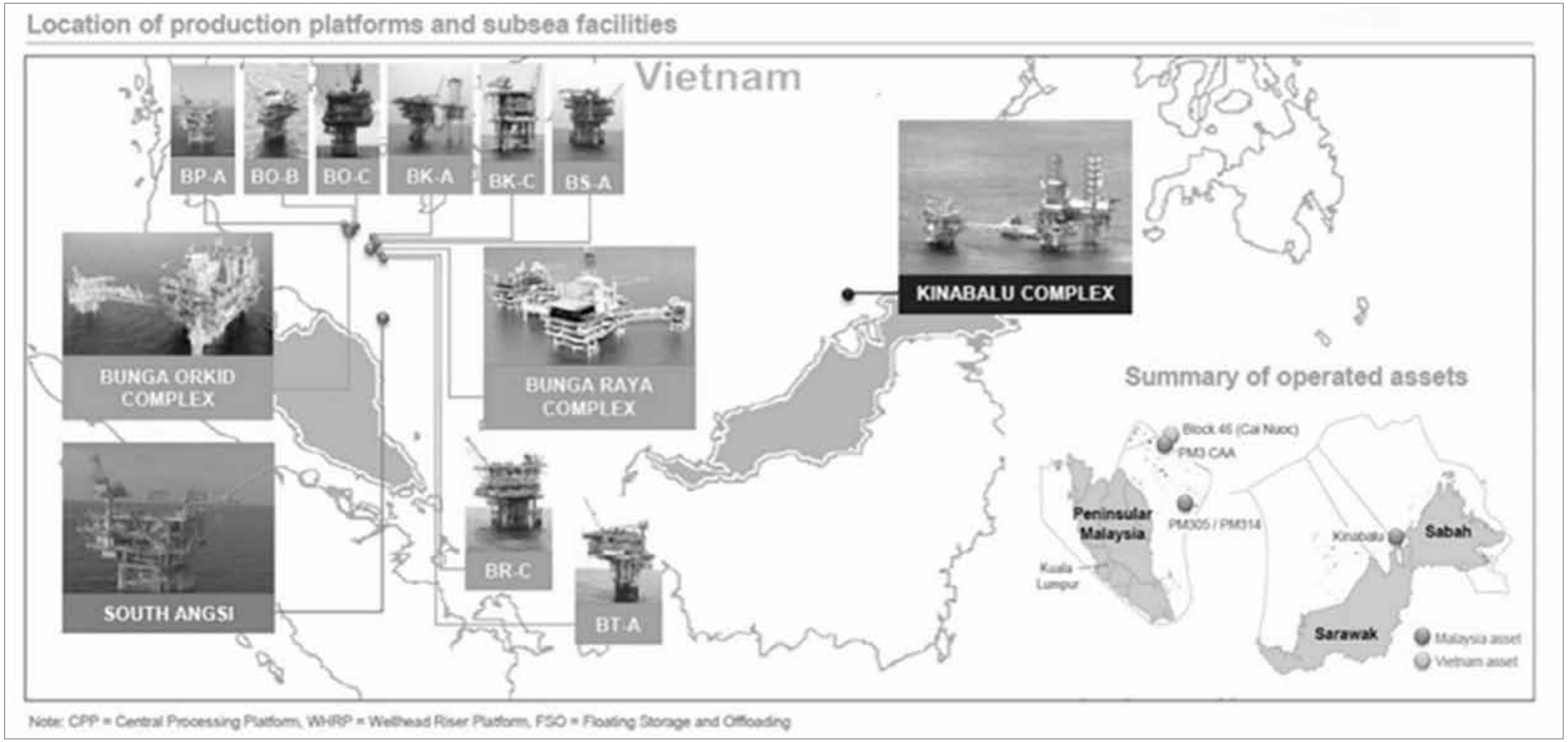

Figure 1.1: Map showing Transaction Assets

1.1.1 Malay Basin Geology

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

Thick fault bounded sediments associated with the early phase of extension were compressed into structural highs, that occurred approximately 22 -10 MYA and is shown by thinning of the F, G, H, I and J Groups (Figure 1.2). The result is a basin containing a thick central tertiary section of approximately 14km, characterised by steeply dipping faults that have been mapped to basement. Upper reservoir sections are characterised by fault dip-anticlinal structures. Towards the flanks of the basin the strata is relatively gently dipping with a few major normal faults and half grabens.

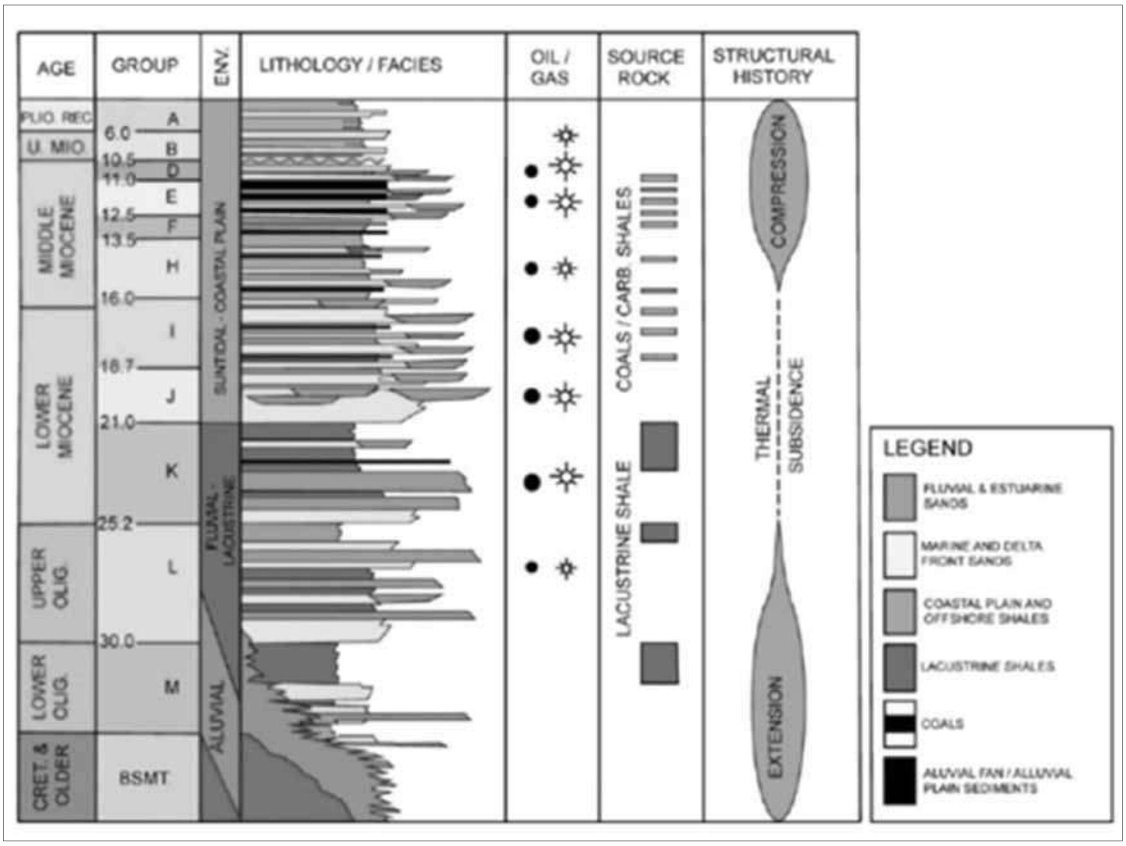

Figure 1.2: Stratigraphy of the Maya Basin[2]

The Repsol fields comprise Lower – Upper Miocene age sands from the L-D Groups, as shown on the regional stratigraphic column (Figure 1.2).

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

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

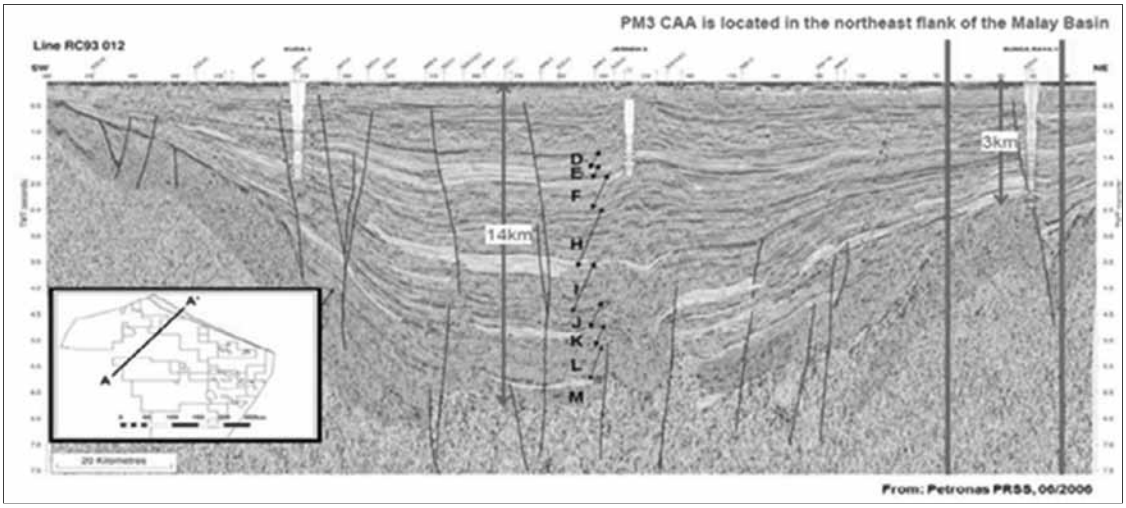

Figure 1.3: Seismic Section through Malay Basin[3]

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

The change in depositional setting leads to a series of different trapping styles with many of the fields comprising a series of trapping ranging from structural, stratigraphic or combination traps (Figure 1.4). This results in stacked pay within the field often trapped by different mechanisms.

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

Seal comprises intra-formational shales within the fluvial delta plain, with good lateral seal provided by the tidal muds, estuarine muds or mud filled abandoned channels. This is particularly important in the PM3-CAA region, which contains a high concentration of CO_2 in the lower reservoir sands (L-H). Above the seal in the H group CO_2 concentrations are much lower[4].

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

[3] VDR Management Presentation, December 2020, Repsol

[4] 3.3.3.1.1.5 PM 02_34_NBO_H4_FDP.pdf - Repsol

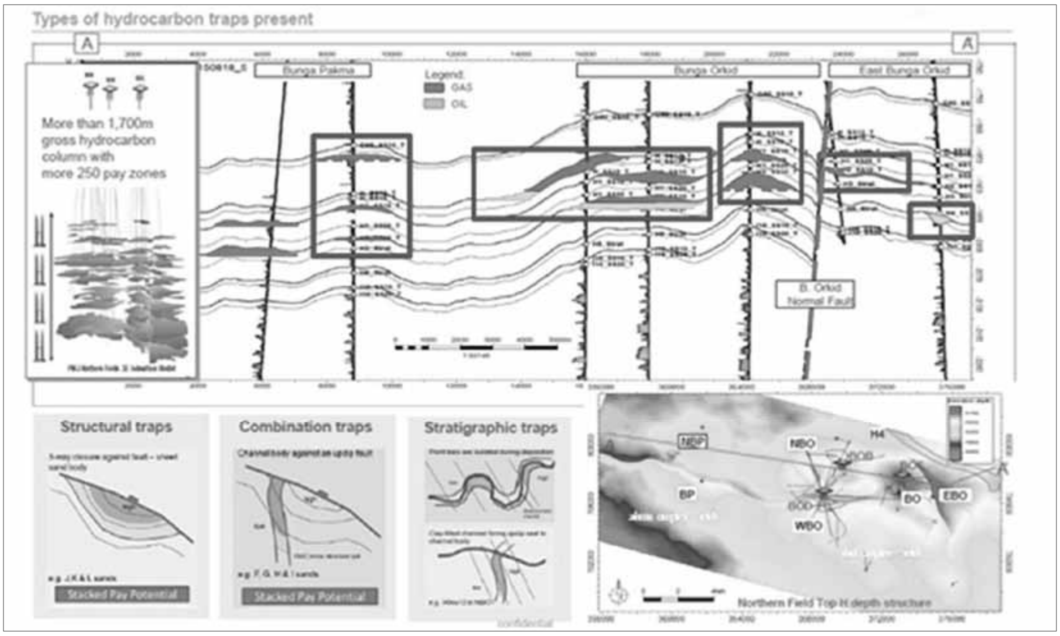

Figure 1.4: Trapping Styles

1.1.2 West Natuna Basin Geology

The West Natuna Basin is an intracontinental failed rift basin located SE of the Malay Basin, offshore Borneo. It is bounded at the north by the Khorat Swell, which is a south-dipping monocline basement high and the south by the Sunda Shelf and the East by the Natuna Arch.

Like the Malay Basin, the West Natuna Basin has undergone three distinct deformation periods; Late Eocene-Oligocene extension, linked to the subduction of the proto South China Sea, which resulted in NW-SE trending graben and half graben formation. Middle to Late Miocene, compression, which resulted in structural inversion leading to faults changing in structural style from normal towards the base to reverse at the top and finally a period of recent mild extension.

The Kinabalu reservoirs comprise Lower – Upper Miocene age sands from the M-F Groups (Figure 1.6). Underlying the deepest L sands is the Cretaceous basement which consists of acidic intrusive. Reservoir sediment is thought to have been sourced from the exhumation and erosion of the Natuna Arch, a northern protrusion of the Sunda Shelf, which separates the West and East Natuna Basins.

The deepest L sands and shales were deposited in a shallow marine environment. Reservoirs are dominated by storm reworked deltaic deposits comprising of sand dominated shoals and sand bars approximately 20m thick, with individual sand bodies varying between 3 and 15m thick with thin 2m clay rich inter-shoal areas, which often showing bioturbation and are thought to have been deposited between storm events. At some point in the early Miocene a large coastal lake was formed, with the K shales showing both lacustrine and marine influence.

The K group was then followed by a more regressive sequence for the J group, which are predominantly shallow marine with fluctuations to coastal plain and tidal shelf deposits. The Group F (partially), E, and D reservoirs are eroded and unconformably overlain by the Muda mudstone formation (A and B groups) which comprises mudstones, shales and sands.

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

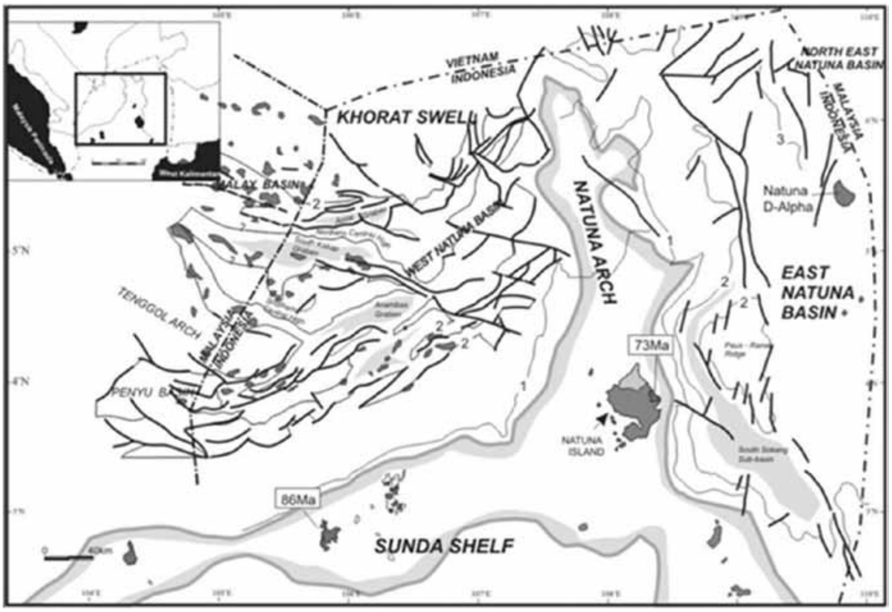

Figure 1.5: Structural Elements of the West Natuna Basin[5]

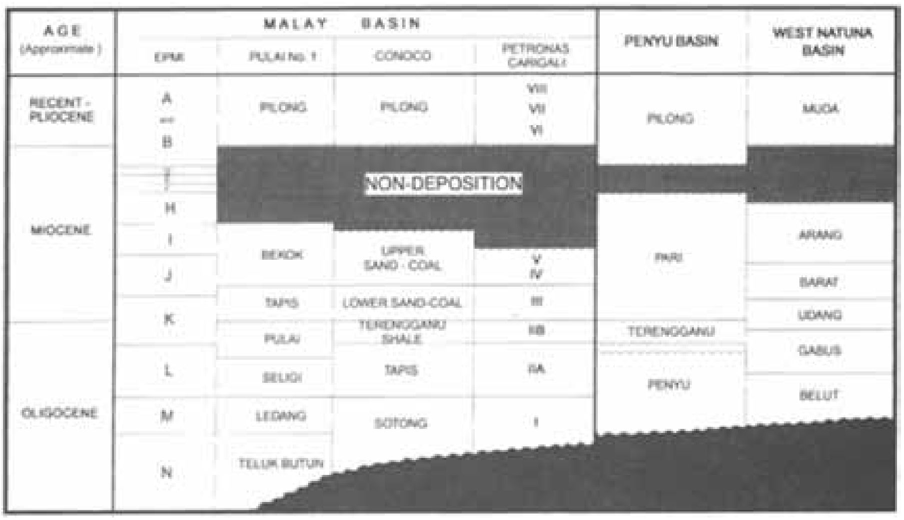

Figure 1.6: Stratigraphic Correlation table of Malay, Penyua and Natuna Basins[6]

1.2 Subsurface and Resource Evaluation

Repsol has placed a large amount of field data, within reports and presentations, in the Virtual Data Room (VDR). A Physical Data Room (PDR) was also available in Repsol's Malaysia offices between the 14th and

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[5] https://en.wikibooks.org/wiki/The_Geology_of_Indonesia/Natuna , *Murti, N. & Minarwan, 200*

[6] *Ngah. K, Madon, M & Tjia, H. (1996) Role of pre-Tertiary fractures in formation and development of the Malay and Penyu Basins. From Hall, R, & Blundell, D (eds): Tectonic Evolution of Southeast Asia, Geological Society Special Publication No. 106, pp. 281-289.*

17th of December 2020. Due to current travel restrictions, remote access to one computer, inside the PDR was made available to RPS staff, using Microsoft Teams, and the time shared between the geology and engineering disciplines.

Given the reduced access time, RPS has focussed on auditing a limited subset of existing production, planned commitments and defined future developments. A summary of the activities presented by Repsol's Business Case and RPS' review status is shown in Table 1.1.

The focus has been on existing production and planned interventions in the two major assets (PM3-CAA & Kinabalu), sanctioned development projects and near term mature development projects.

Certain assets present mature production with remaining reserves which are minor components of the overall portfolio valuation (e.g. PM305/314 existing production). As a result of the limited time available, these were not reviewed, with Repsol's reserves estimates accepted.

Of the remaining proposed projects, where possible, RPS has independently estimated in-place volumetrics (e.g. Saffron B Discovery, NW Raya Infill). Where this was not possible, RPS has reviewed the basis for Repsol's estimates and accepted them where appropriate on the basis of the information provided.

Other activities proposed by Repsol are not considered sufficiently mature to allow RPS to review them in any meaningful way (e.g. Kekwa post-seismic, Raya post-seismic).

A summary of in-place estimates is provided in Table 1.2 to Table 1.4 below.

Status	Block/Permit	Field	Reviewed by RPS?	Methodology	RPS Resource Classification
Existing Production	**PM3-CAA**	Bunga Orkid	Y	DCA	Reserves – Developed Producing
		North Bunga Orkid			
		East Bunga Orkid			
		West Bunga Orkid			
		Bunga Pakma			
		North Bunga Pakma			
		East Bunga Kekwa			
		West Bunga Kekwa			
		North Bunga Raya			
		East Bunga Raya			
		West Bunga Raya			
		North West Bunga Raya			
		Bunga Seroja			
		Bunga Tulip			
	Block 46	Cai Nuoc	Y	DCA*	Reserves - Developed Producing
	PM305/314	Murai/Angsi Southern Channel Unit ("ASCU")	N	-	Reserves - Developed Producing
	Kinabalu	Kinabalu Main	Y	DCA	Reserves – Developed Producing
		Kinabalu East			
		Kinabalu Far East			
Well Interventions	**PM3-CAA**	Bunga Orkid	Y	Type Curves	Reserves – Developed Non-producing
		North Bunga Orkid			
		East Bunga Orkid			
		West Bunga Orkid			
		Bunga Pakma			
		North Bunga Pakma			
		East Bunga Kekwa			
		East Bunga Raya			
		North West Bunga Raya			
Low Investment Case (Sanctioned Projects)	**PM3-CAA**	North Bunga Orkid H4 Area Development (NBO-H4)	Y	Vendor Model Audit	Reserves – Approved for Development
		East Bunga Raya BR-LL Infill Well			

Status	Block/Permit	Field	Reviewed by RPS?	Methodology	RPS Resource Classification
Defined Developments	PM3-CAA	Pakma Infill	Y	Vendor Model Audit	Contingent Resources – Development Pending
		Saffron B Discovery	Y	Volumetrics Only	Contingent Resources – Development Pending
		2022 Infill (Bunga Orkid)	Y	Vendor Model Audit	Reserves – Justified for Development
		Kekwa Post-seismic	N	-	Prospective Resources
		Raya Post-seismic	N	-	Contingent Resources – Development Unclarified
		NW Raya Infill	Y	Volumetrics Only	Contingent Resources – Development Unclarified
		Hoa Mai Development	Y	Vendor Model Audit	Contingent Resources – Development Pending
		Water Injection	N	-	Contingent Resources – Development Unclarified
		Production Efficiency	N	-	Contingent Resources – Development Unclarified
		Gas Blowdown	N	-	Contingent Resources – Development Unclarified
		Low Low Pressure	N	-	Contingent Resources – Development Unclarified
		ESPs (East Bunga Raya & West Bunga Orkid)	Y	Vendor Model Audit	Reserves - Justified for Development (Pilot only)
	Kinabalu	Production Efficiency	N	-	Contingent Resources – Development Unclarified
		D18 Infill	Y	Vendor Model Audit	Reserves – Approved for Development
		Undrained Volumes	Y	Vendor Model Audit	Reserves – Justified for Development
		ESPs	Y	Vendor Model Audit	Reserves – Justified for Development (Pilot only)
Future Developments	PM3-CAA	Saffron A Prospect	N	-	Prospective Resources
		Saffron C Prospect	N	-	
		Greater Matahari Area	N	-	
		Greater Central Area	N	-	
		Raya I40U Leads	N	-	
		Greater Sliver Area	N	-	
	Kinabalu	2022 Infill Campaign	N	-	Contingent Resources – Development Unclarified
		CC Far East Development	N	-	Prospective Resources

Table 1.1: Summary of RPS Review

** Block 46 (Cai Nuoc) remaining production has been assessed as part of East Bunga Kekwa DCA.*

		STOIIP (MMstb)		
		Low	Best	High
PM3 CAA	Bunga Orkid	36	45	73
	East Bunga Orkid	16	23	45
	North Bunga Orkid	112	139	178
	West Bunga Orkid	66	78	91
	Bunga Pakma & North Bunga Pakma	-	-	-
	West Bunga Kekwa	142	160	172
	East Bunga Kekwa	146	186	242
	North Bunga Raya	-	-	-
	North West Bunga Raya	28	34	40
	West Bunga Raya	38	41	62
	East Bunga Raya	247	262	304
	Bunga Seroja	-	-	-
	Bunga Tulip	23	24	26
Block 46	Cai Nuoc[2]	-	-	-
Kinabalu		321	397	472
PM 305	Kuning	4	5	5
	South Angsi	50	56	64
PM314	South Angsi	4	4	5
	Naga Kecil	10	12	13
	Total[1]	**1,244**	**1,465**	**1,794**

[1] Arithmetic Summation only.
[2] Cai Nuoc is reported with East Bunga Kekwa.

Table 1.2: Gross STOIIP for All Assets[7]

[7] 1.1.2020 ARPR for the Repsol Fields

		GIIP (Bscf)		
		Low	Best	High
PM3 CAA	Bunga Orkid	61	73	88
	East Bunga Orkid	35	44	68
	North Bunga Orkid	216	242	324
	West Bunga Orkid	56	77	98
	Bunga Pakma & North Bunga Pakma	-	-	-
	West Bunga Kekwa	138	159	170
	East Bunga Kekwa	313	367	418
	North Bunga Raya	-	-	-
	North West Bunga Raya	21	25	29
	West Bunga Raya	68	79	100
	East Bunga Raya	352	399	487
	Bunga Seroja	-	-	-
	Bunga Tulip	58	64	66
Block 46	Cai Nuoc[2]	-	-	-
Kinabalu		501	610	720
P305	Kuning	2	2	2
	South Angsi	23	25	28
PM 314	South Angsi	-	-	-
	Naga Kecil	9	10	11
	Total[1]	**1,853**	**2,176**	**2,609**

[1] Arithmetic Summation only.
[2] Cai Nuoc is reported with East Bunga Kekwa.

Table 1.3: Gross GIIP (Associated) for All Assets[7]

		GIIP (Bscf) Low	GIIP (Bscf) Best	GIIP (Bscf) High
PM3 CAA	Bunga Orkid	380	460	766
	East Bunga Orkid	617	713	1,008
	North Bunga Orkid	490	631	1,079
	West Bunga Orkid	306	461	779
	Bunga Pakma & North Bunga Pakma	710	1,136	1,783
	West Bunga Kekwa	-	-	-
	East Bunga Kekwa	458	607	776
	North Bunga Raya	54	89	116
	North West Bunga Raya	44	78	97
	West Bunga Raya	-	-	-
	East Bunga Raya	352	399	487
	Bunga Seroja	157	144	168
	Bunga Tulip	-	-	-
	Block 46			
Block 46	Cai Nuoc[2]	-	-	-
Kinabalu		-	-	-
PM305	Kuning	-	-	-
	South Angsi	15	22	28
PM314	South Angsi	2	2	2
	Naga Kecil	-	-	-
	Total[1]	**3,585**	**4,742**	**7,089**

[1] Arithmetic Summation Only.
[2] Cai Nuoc is reported with East Bunga Kekwa.

Table 1.4: Gross GIIP (Non-Associated) reported in ARPR for All Assets[7]

1.3 Economic Analysis

RPS has reviewed all pertinent fiscal terms related to both the all PSCs and confirmed they are correctly interpreted within the economic model presented by Repsol/J.P. Morgan and Hibiscus. These models have then been used to perform the economic analysis of the fields/assets.

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 and Opex, and inclusion of other financial information and assumptions, as outlined in Capex, Opex and Abex sections.

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

An annual inflation rate of 2 per cent has been built into the ELT. This inflation rate has also been applied to all cost estimates to adjust them from 2021 dollars to MOD.

The effective date of this report is 1st January, 2021 and this has been used as the discount date for the valuation.

1.4 Reserves Summary & Estimated Net Present Value

A summary of Reserves for the assets is provided in Table 1.5 to Table 1.8 below for Oil, Gas, Condensate and Barrels of Oil Equivalent, respectively. Table 1.9 to Table 1.10 provide Net Present Value estimates for PM3-CAA, Kinabalu PSC, B46 PSC and PM305/314 PSC, respectively. Table 1.13 summarises the consolidated (PM3 CAA PSC, Kinabalu PSC, B46 PSC, PM305/314 PSC) Net Present Value estimates.

SUMMARY OF OIL RESERVES
As of 1 January 2021
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMstb)						Hibiscus Net Entitlement Reserves[2] (MMstb)					
	1PD	1P	2PD	2P	3PD	3P	1PD	1P	2PD	2P	3PD	3P
PM3 CAA	14.0	17.7	21.1	29.8	25.6	39.0	3.2	4.0	4.6	6.6	5.4	7.9
B46[3]	0.0	0.0	1.0	1.0	1.3	1.3	0.0	0.0	0.4	0.4	0.6	0.6
Kinabalu	12.6	16.1	24.2	28.1	34.1	39.2	5.0	6.4	9.4	10.8	12.4	14.1
PM305/314[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total[3]	**26.6**	**33.7**	**46.3**	**58.9**	**61.1**	**79.5**	**8.2**	**10.4**	**14.5**	**17.9**	**18.4**	**22.6**

Notes:

*[1] Gross field Reserves (100% basis) **after** economic limit test*

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

[3] Zero 1PD and 1P as B46 Low Estimate does not pass economic limit test

[4] Zero Reserves for Low, Best, and High Estimate do not pass economic limit test

[5] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Reserves are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1P Reserves may be a very conservative assessment and the total 3P Reserves a very optimistic assessment.

Table 1.5: Oil Reserves as of 1 January 2021

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

SUMMARY OF GAS RESERVES
As of 1 January 2021
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (Bscf)						Hibiscus Net Entitlement Reserves[2] (Bscf)					
	1PD	1P	2PD	2P	3PD	3P	1PD	1P	2PD	2P	3PD	3P
PM3 CAA	214.3	217.3	368.5	377.5	535.2	549.2	48.5	49.0	80.8	83.6	112.9	112.5
Block 46												
Kinabalu												
PM305/314												
Total[3]	**214.3**	**217.3**	**368.5**	**377.5**	**535.2**	**549.2**	**48.5**	**49.0**	**80.8**	**83.6**	**112.9**	**112.5**

Notes:

*[1] Gross field Reserves (100% basis) **after** economic limit test*

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

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Reserves are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1P Reserves may be a very conservative assessment and the total 3P Reserves a very optimistic assessment.

Table 1.6: Gas Reserves as of 1 January 2021

SUMMARY OF CONDENSATE RESERVES
As of 1 January 2021
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMstb)						Hibiscus Net Entitlement Reserves[2] (MMstb)					
	1PD	1P	2PD	2P	3PD	3P	1PD	1P	2PD	2P	3PD	3P
PM3 CAA	6.6	6.8	11.5	12.1	15.6	16.6	1.5	1.5	2.5	2.7	3.3	3.4
Block 46												
Kinabalu												
PM305/314												
Total[3]	**6.6**	**6.8**	**11.5**	**12.1**	**15.6**	**16.6**	**1.5**	**1.5**	**2.5**	**2.7**	**3.3**	**3.4**

Notes:

*[1] Gross field Reserves (100% basis) **after** economic limit test*

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

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Reserves are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1P Reserves may be a very conservative assessment and the total 3P Reserves a very optimistic assessment.

Table 1.7: Condensate Reserves as of 1 January 2021

SUMMARY OF RESERVES (BOE)
As of 1 January 2021
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMboe)						Hibiscus Net Entitlement Reserves[2] (MMboe)					
	1PD	1P	2PD	2P	3PD	3P	1PD	1P	2PD	2P	3PD	3P
PM3 CAA	56.4	60.7	94.0	104.8	130.4	147.1	12.8	13.7	20.7	23.3	27.5	30.1
Block 46	0.0	0.0	1.0	1.0	1.3	1.3	0.0	0.0	0.4	0.4	0.6	0.6
Kinabalu	12.6	16.1	24.2	28.1	34.1	39.2	5.0	6.4	9.4	10.8	12.4	14.1
PM305/314	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total[3]	**68.9**	**76.8**	**119.2**	**134.0**	**165.9**	**187.6**	**17.7**	**20.1**	**30.5**	**34.5**	**40.5**	**44.8**

Notes:

[1] Gross field Reserves (100% basis) ***after*** *economic limit test*

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

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Reserves are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1P Reserves may be a very conservative assessment and the total 3P Reserves a very optimistic assessment.

Table 1.8: Summary of Reserves in Oil Equivalent Barrels as of 1 January 2021

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1PD	2025	46	53	54	56
1P	**2025**	**38**	**41**	**41**	**42**
2PD	2027	120	113	111	110
2P	**2027**	**170**	**146**	**142**	**137**
3PD	2027	241	203	196	189
3P	**2027**	**284**	**234**	**224**	**215**

Table 1.9: PM3 CAA PSC – Post-Tax Valuation at RPS Base Case Price Scenario

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1PD	2026	53	54	54	54
1P	**2027**	**77**	**74**	**73**	**72**
2PD	2032	147	128	123	120
2P	**2032**	**188**	**157**	**150**	**145**
3PD	2032	259	202	191	182
3P	**2032**	**293**	**227**	**215**	**204**

Table 1.10: Kinabalu PSC – Post-Tax Valuation at RPS Base Case Price Scenario

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1PD	2025	(5)	(3)	(3)	(3)
1P	**2025**	**(5)**	**(3)**	**(3)**	**(3)**
2PD	2027	2	3	3	3
2P	**2027**	**2**	**3**	**3**	**3**
3PD	2027	10	9	9	9
3P	**2027**	**10**	**9**	**9**	**9**

Table 1.11: B46 PSC – Post-Tax Valuation at RPS Base Case Price Scenario

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1PD	2025	(9)	(10)	(10)	(10)
1P	**2025**	**(9)**	**(10)**	**(10)**	**(10)**
2PD	2027	(10)	(10)	(10)	(10)
2P	**2027**	**(10)**	**(10)**	**(10)**	**(10)**
3PD	2027	(9)	(10)	(10)	(10)
3P	**2027**	**(9)**	**(10)**	**(10)**	**(10)**

Table 1.12: PM305/PM314 PSC – Post-Tax Valuation at RPS Base Case Price Scenario

	Post-Tax Net Present Value (US$ Million, MOD)			
	0%	8%	10%	12%
1PD	84	94	96	97
1P	**102**	**102**	**102**	**101**
2PD	259	233	228	222
2P	**351**	**296**	**285**	**275**
3PD	500	404	386	370
3P	**578**	**460**	**438**	**418**

Table 1.13: Consolidated (PM3 CAA PSC, Kinabalu PSC, B46 PSC, and PM305/314 PSC) – Post-Tax Valuation at RPS Base Case Price Scenario

Table 1-14 and Table 1-15 summarise the incremental projects' recoverable volumes (until PSC expiry prior to economic limit test) for PM3 CAA PSC and Kinabalu PSC, respectively.

PM3 CAA PSC	Low	Best	High
Project Description	**MMstb**	**MMstb**	**MMstb**
North Bunga Orkid H4 Area Development (NBO-H4)	3.96	7.43	11.49
BRB-LL Development	0.49	0.95	1.41
East Bunga Raya ESP I-120 Reservoir	0.19	0.29	0.39
West Bunga Orkid ESP H0ss12 Reservoir	0.16	0.26	0.47
Bunga Orkid Infill Well	0.18	0.37	0.61

Table 1-14: PM3 CAA PSC Incremental Project Recoverable Oil and Condensate Volumes

Kinabalu PSC	Low	Best	High
Project Description	**MMstb**	**MMstb**	**MMstb**
D18 Infill Well	0.45	0.57	0.79
ESP	2.20	2.54	3.24
Undrained Volume Project	0.71	0.83	1.05

Table 1-15: Kinabalu PSC Incremental Project Recoverable Oil Volumes

1.5 Contingent Resources Summary

A summary of Contingent Resources for the Assets is provided in Table 1.16 to Table 1.18 below for Oil, Gas, and Barrels of Oil Equivalent, respectively. RPS did not conduct any independent review of Repsol's estimates of these activities.

The full field gross Best Estimate for both oil and gas are sourced directly from Repsol's economic model. In order to derive the full field gross Low Estimate and High Estimate, RPS has applied the ratio of full field gross 1P over full field gross 2P and the ratio of full field gross 3P over full field gross 2P respectively to the Best Estimate. Net Entitlement Contingent Resources for Low Estimate, Best Estimate, and High Estimate are derived based on the ratio of Net Entitlement over full field gross Reserves.

SUMMARY OF OIL CONTINGENT RESOURCES
As of 1 January 2021
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (MMstb)			Hibiscus Net Entitlement Contingent Resources[2] (MMstb)		
	Project	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
PM3 CAA	Raya post Seismic	6.2	10.5	12.6	1.4	2.3	2.6
PM3 CAA	NW BR Infill	1.4	2.4	2.8	0.3	0.5	0.6
PM3 CAA	Production Efficiency	0.3	0.4	0.5	0.1	0.1	0.1
Kinabalu	Production Efficiency	0.2	0.4	0.5	0.1	0.1	0.2
Total[3]		**8.1**	**13.7**	**16.4**	**1.9**	**3.1**	**3.4**

Notes:

[1] Gross field Contingent Resources (100% basis) until the current expiry of the PSC.

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

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Resources are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

Table 1.16: Oil Contingent Resources as of 1 January 2021

SUMMARY OF GAS CONTINGENT RESOURCES
As of 1 January 2021
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (Bscf)			Hibiscus Net Entitlement Contingent Resources[2] (Bscf)		
	Project	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
PM3 CAA	Raya post Seismic	8.0	13.9	18.7	1.8	3.1	3.8
PM3 CAA	NW BR Infill	0.6	1.0	1.3	0.1	0.2	0.3
PM3 CAA	Production Efficiency	3.8	6.6	8.9	0.9	1.5	1.8
Total[3]		**12.4**	**21.5**	**29.0**	**2.8**	**4.8**	**5.9**

Notes:

[1] Gross field Contingent Resources (100% basis) until the current expiry of the PSC

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

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Resources are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

Table 1.17: Gas Contingent Resources as of 1 January 2021

SUMMARY OF CONTINGENT RESOURCES (BOE)
As of 1 January 2021
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (MMboe)			Hibiscus Net Entitlement Contingent Resources[2] (MMboe)		
	Project	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
PM3 CAA	Raya post Seismic	7.6	12.9	15.7	1.7	2.9	3.2
PM3 CAA	NW BR Infill	1.5	2.5	3.1	0.3	0.6	0.6
PM3 CAA	Production Efficiency	0.9	1.5	2.0	0.2	0.3	0.4
Kinabalu	Production Efficiency	0.2	0.4	0.5	0.1	0.1	0.2
Total[3]		**10.2**	**17.3**	**21.3**	**2.3**	**3.9**	**4.4**

Notes:

[1] Gross field Contingent Resources (100% basis) until the current expiry of the PSC

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

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Resources are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

Table 1.18: Summary of Contingent Resources in Oil Equivalent Barrels as of 1 January 2021

RPS did not perform commercial evaluation on Contingent Resources.

2 INTRODUCTION

RPS Energy Consultants Ltd ("RPS") has completed an independent evaluation of the Repsol S.A. ("Repsol") assets, for sale as part of a proposal, administered by J.P. Morgan Securities plc, which Hibiscus is interested in acquiring.

The potential transaction encompasses a 100% working interest in each of the following entities:

- Repsol Oil & Gas Malaysia Limited;
- Repsol Oil & Gas Malaysia (PM3) Limited; and
- Talisman Vietnam Limited.

These entities in turn hold and operate Repsol's business in Malaysia, comprising the following interests, collectively, the "Assets":

- 60% working interest in the Kinabalu block located in Sabah, Malaysia
- 35% working interest in the PM3 CAA block located within the Commercial Arrangement Area ("CAA" between Malaysia and Vietnam
- 60% working interest in each of the PM305 and PM314 blocks located off the eastern coast of Peninsular Malaysia in the Malay Basin; and
- 70% working interest in Block 46 (Cai Nuoc), a tie-back asset to the PM3 CAA block located in Vietnamese waters.

3 BASIS OF OPINION

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

The report represents RPS' 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.

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.

4 SITE VISIT

No site visit has been conducted as part of our evaluation as it is usually conducted when a SPA is signed or during the transition period in which personnel specialises in Health Safety Environment would be allowed to conduct limited site visit.

5 PM3 CAA & BLOCK 46

The PM3-CAA is subdivided into Northern and Southern Regions, which in total contains six fields: Bunga Orkid, Bunga Pakma in the North and Bunga Kekwa, Bunga Raya, Bunga Seroja and Bunga Tulip in the South.

The Northern area is developed by the Bunga Orkid (BO-A) central production platform, which processes and exports the produced oil and condensate via pipeline to the FSO and gas to the Bunga Raya East (BRE) field (Figure 5.1).

45 development wells (39 in Bunga Orkid and 6 in Bunga Pakma) have been drilled from three well head riser platforms (BO-B, BO-C and BO-D) to exploit the hydrocarbon accumulations. First Oil was produced on the 25th March 2009.

The Southern area is developed by a central production complex comprised of Bunga Raya – A (BR-A), BR-D and BR-E bridge linked platforms which process and export oil, gas and condensate from the Bunga Raya, Bunga Kekwa, Bunga Seroja and Bunga Tulip fields. Development wells are drilled from 6 wellhead riser platforms, Bunga Raya-Beta (BR-B), Bunga Raya-Charlie (BR-C), Bunga Kekwa-Alpha (BR-A), Bunga Kekwa-Charlie (BK-C), Bunga Seroja-Alpha (BS-A) and Bunga Tulip-Alpha (BT-A).

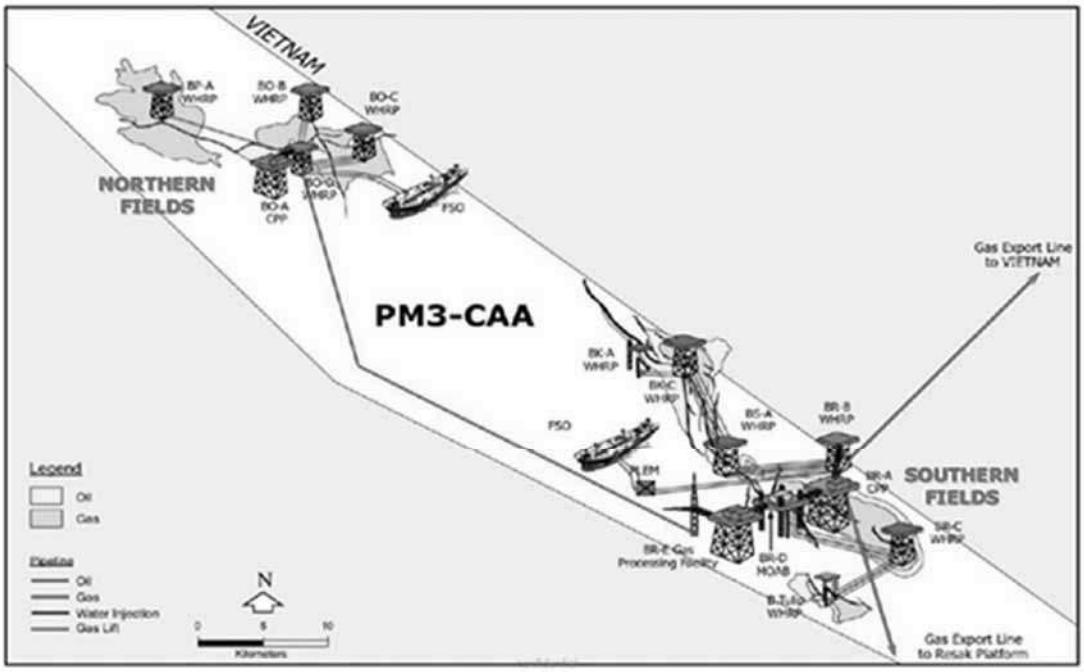

Figure 5.1: PM3-CAA Infrastructure[9]

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

All gas is sold to PETRONAS and PetroVietnam and PM3CAA is the only source of gas to southwest Vietnam.

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[9] *VDR Management Presentation 2020.12vF.pdf - Repsol*

5.1 Block History

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

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

Bunga Pakma was discovered in 1991 with the drilling of Bunga Pakma-1. Bunga Pakma North-1, in the immediately adjacent fault block to the north, was discovered in 1998. Six gas producers were drilled from April 2018 to August 2018 and successfully delivered first gas on 21st May 2018. A new single wellhead riser platform called Bunga Pakma-A (BP-A) was installed and tied-back to the BO-D platform, which is approximately 9 km to the south.

Bunga Seroja was discovered in 1997 with the drilling of Bunga Seroja-1. The field is developed by a single wellhead platform (BS-A) which is tied into Bunga Kekwa and tied back to Bunga Raya. A total of five development wells have been drilled. First production was in December 2003.

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

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

The Bunga Raya Complex is composed a number of adjacent accumulations separated by faults; North Bunga Raya, Northwest Bunga Raya, East Bunga Raya and West Bunga Raya. Complex facilities are based around a central processing platform (BR-A), with a gas compression mobile offshore application barge or MOAB (BR-D) and a single wellhead platform (BR-C). The complex commenced production in late 2003, with water injection commencing in early 2004. A total of 34 wells have been drilled in the Bunga Ray Complex to date. North Bunga Raya has been shut in since May 2018 with no further production anticipated.

Historical production plots for sales gas and combined oil & condensate are shown in Figure 5.2 & Figure 5.3 respectively. Individual field history plots can be found in Appendix D.

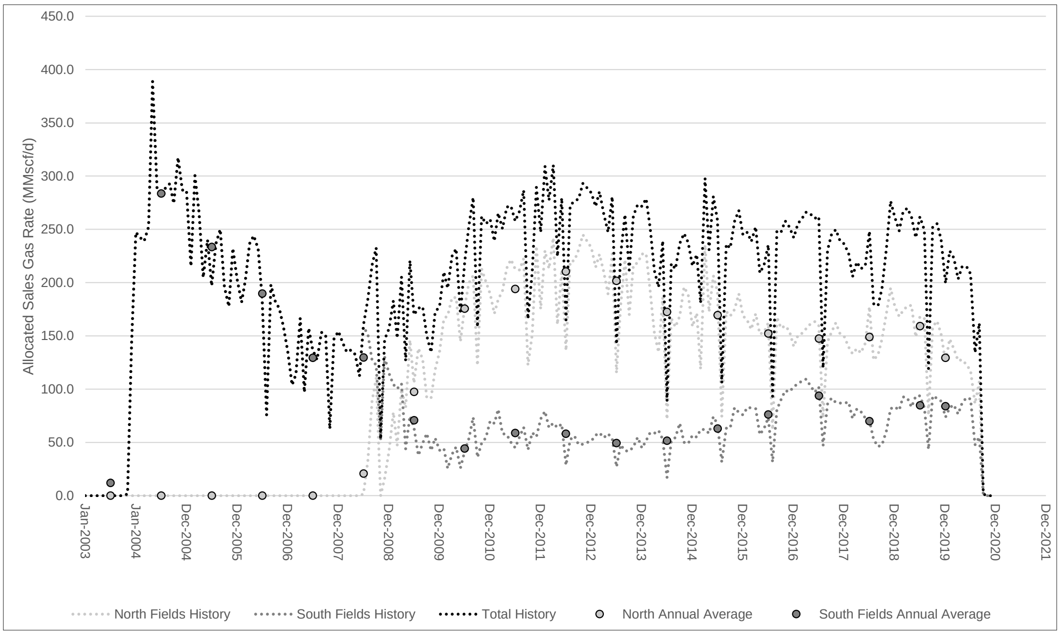

Figure 5.2: PM3-CAA Historical Sales Gas Production

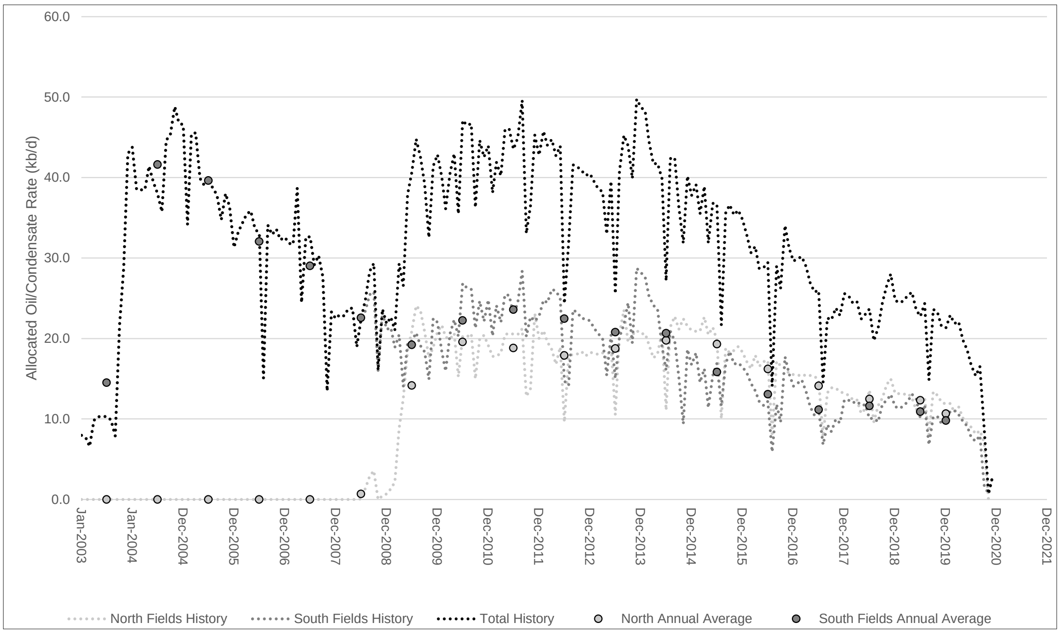

Figure 5.3: PM3-CAA Historical Combined Oil & Condensate Production[10]

[10] *Oil and Condensate are reported combined in the OFM database provided by Repsol.*

5.2 Repsol Business Case

Repsol has presented its business case in the Management Presentation. This consists of three main sections; a Low Investment case, Defined Developments, and Future Developments, as outlined below:

- Low Investment Case (Developed & Undeveloped Reserves):
  - Existing Production + Planned Interventions (Plug & Perforate)
  - North Bunga Orkid H4 (NBO-H4) Development
  - BRB-LL Infill well
- Defined Developments (Contingent/Prospective Resources)
  - Additional development projects identified by Repsol, including:
  - Pakma Infill wells
  - Saffron B Discovery
  - Bunga Orkid Infill wells
  - Hoa Mai Development
  - Additional infrastructure projects (e.g. ESPs, Pressure reductions, etc.)
- Future Developments (Contingent/Prospective Resources)
  - Saffron A & C Prospects
  - Matahari Area (Matahari/BO3 discoveries + WB Matahari & EBO3 prospects)
  - Greater Central Area Exploration
  - Bunga Raya I40U leads
  - Sliver discovery & South PM3 Prospects

5.3 Existing Production & Planned Interventions

Existing production in the block is from a total of 14 accumulations, in six fields, developed around two hubs (North and South), with Bunga Orkid and Bunga Pakma to the north and Bunga Kekwa, Bunga Raya, Bunga Seroja and Bunga Tulip to the south. The majority of the fields contain oil/condensate and gas, with the exception of Bunga Pakma (including North Bunga Pakma) which is gas only (Gas & Condensate), as outlined in Table 5.1.

Development Area	Complex	Field	Oil?	AG?	NAG?	Cond?
North	Bunga Orkid	Bunga Orkid	Y	Y	Y	Y
		North Bunga Orkid	Y	Y	Y	Y
		East Bunga Orkid	Y	Y	Y	Y
		West Bunga Orkid	Y	Y	Y	Y
	Bunga Pakma	Bunga Pakma[1]	N	N	Y	Y
		North Bunga Pakma[1]	N	N	Y	Y
South	Bunga Seroja	Bunga Seroja	N	N	Y	N
	Bunga Tulip	Bunga Tulip	Y	Y	N	N
	Bunga Kekwa	East Bunga Kekwa[2]	Y	Y	Y	Y
		West Bunga Kekwa	Y	Y	N	N
	Bunga Raya	North Bunga Raya	N	N	Y	Y
		East Bunga Raya	Y	Y	Y	Y
		West Bunga Raya	Y	Y	Y	Y
		Northwest Bunga Raya	Y	Y	Y	Y
Block 46	Cai Nuoc	Cai Nuoc[2]	Y	Y	Y	Y

1 Bunga Pakma & North Bunga Pakma reported together.

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

Table 5.1: PM3-CAA & Block 46 Assets & Fluids Summary

5.3.1 Existing Production (NFA Case)

The No Further Activity (NFA) production forecast case has been assessed for all producing fields in PM3-CAA by Decline Curve Analysis at the field level based on production data supplied in the VDR in OFM™ to October 2020[11]. Production for Block 46 is reported as part of East Bunga Kekwa production and has therefore also been assessed by Decline Curve Analysis.

For each producing field, oil, gas and condensate production have been analysed separately.

Gas forecasts were estimated using Decline Curve Analysis on the basis of produced gas rate vs time or cumulative gas production for all cases. Proved (1P), Proved+Probable (2P) and Proved+Probable+Possible (3P) forecasts were based on a hyperbolic curve fit, with coefficients and decline rates tuned to match existing production trends. An example is shown in Figure 5.4.

The OFM database contained both produced gas and sales gas data, which was used to estimate sales gas shrinkage, primarily related to the removal of CO_2. This shrinkage is typically in the range of 45-50%.

Condensate production has been estimated on the basis of gas production using the condensate gas ratios for each field based on ARPR data provided in the VDR.

This methodology is consistent for all assets in PM3-CAA and Block 46.

[11] North Bunga Pakma has been reported with Bunga Pakma; There is only a single well currently in North Bunga Pakma.

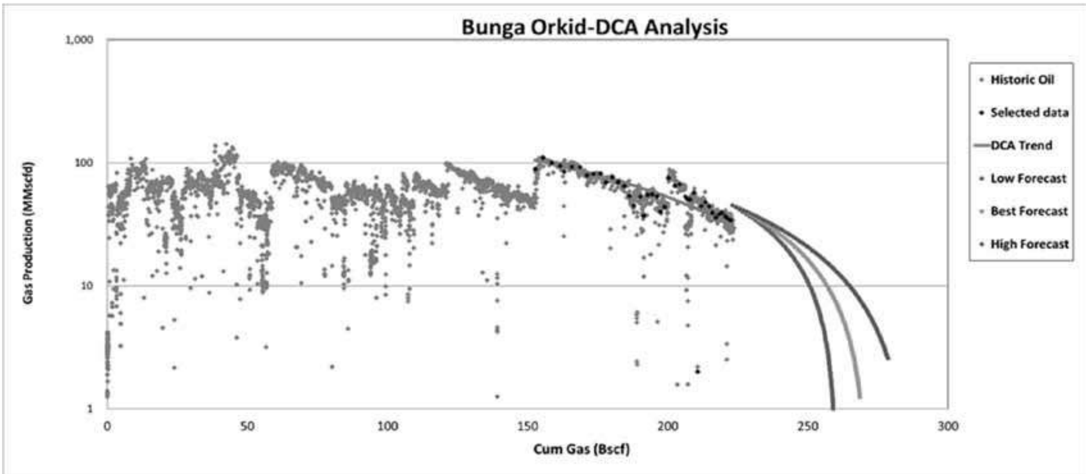

Figure 5.4: Example Gas Decline Curve Analysis (Bunga Orkid)

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

Examples of both 1P and 3P analyses are shown in Figure 5.5 & Figure 5.6 below.

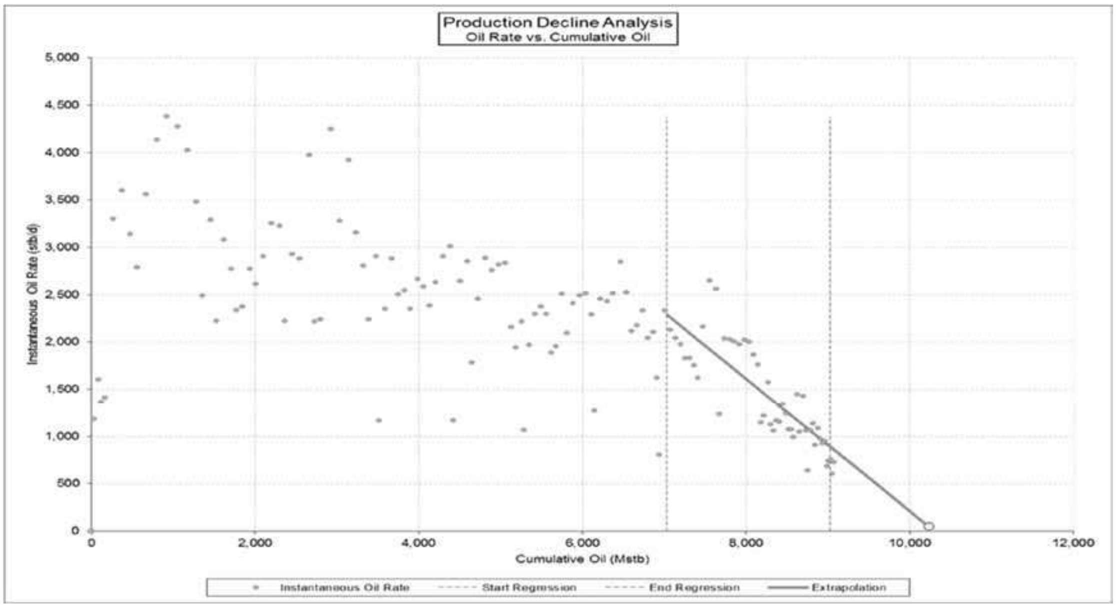

Figure 5.5: Example 1P Oil Rate Decline Curve Analysis (Bunga Orkid)

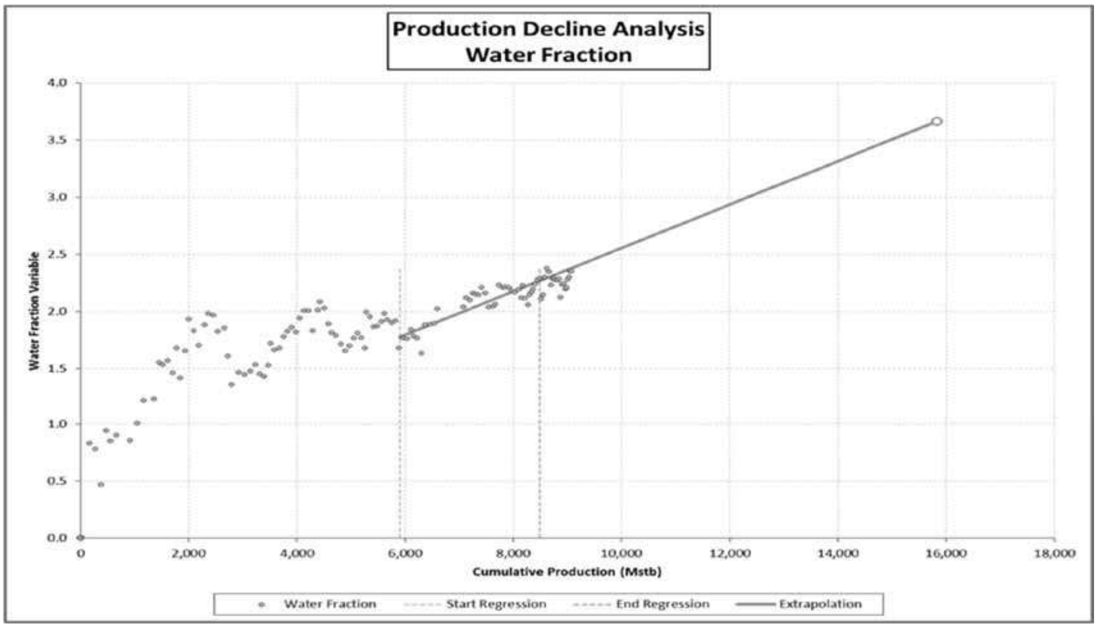

Figure 5.6: Example 3P Water Oil Ratio Decline Curve Analysis (Bunga Orkid)

Relevant analysis plots for each asset are provided for reference in Appendix E.

5.3.2 Planned Well Interventions

Work Plan & Budget profiles (WP&B) submitted by the Operator to PETRONAS clearly show the Repsol NFA case includes additional activities related to planned well interventions. These are typically plug and perforate operations to access additional stacked pay within each well as layers deplete.

RPS could not verify all workovers and PE activities, however, it was noted that historically such activities were carried out on a regular basis. Insufficient time and resources were available to review all potential interventions, so incremental production associated with these activities were based on type curves.

RPS reviewed individual well production performance and generated Low, Mid and High type curves based on produced gas for each field. An example is shown in Figure 5.7. These were used to determine the incremental production for the planned interventions in each field.

The number of planned interventions was initially aligned with the Repsol reported interventions schedule[12], as shown in Table 5.2 and Table 5.3.

However, the resulting RPS 2P case (NFA+Interventions) failed to meet the required ACQ gas rates of 205 MMscf/d after 2020[13].

As a result, we have adjusted the intervention schedule to reach the ACQ on average until 2023. The revised RPS intervention schedule is shown in Table 5.4 & Table 5.5.

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[12] Alignment to 2025 only – Interventions beyond 2025 were classified as Contingent Resources consistent with PRMS and not included.

[13] Note the WP&P 2021 forecast achieves the ACQ until 2024. However, there are clear examples where the WP&B forecasts for individual fields are optimistic when compared to 2020 actual production data (e.g. Bunga Orkid).

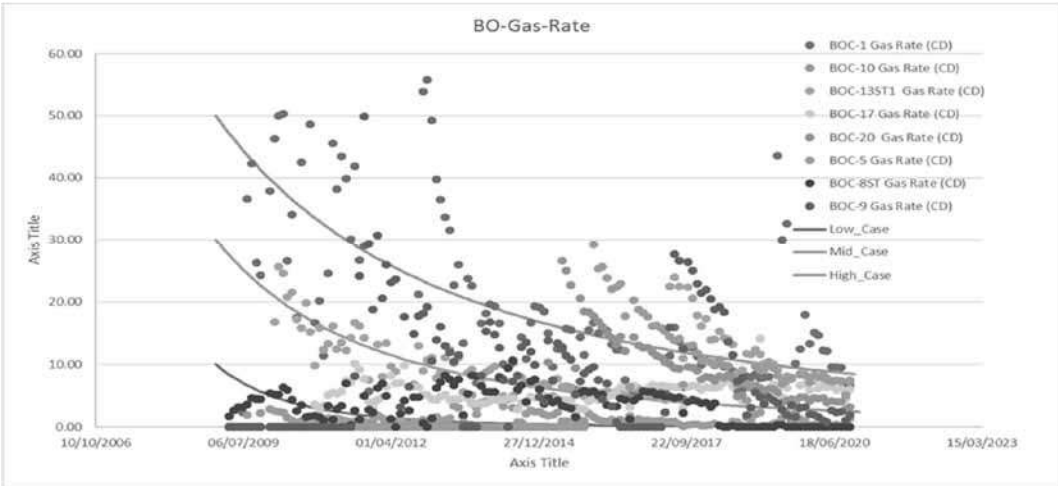

Figure 5.7: Example Type Curve Analysis (Bunga Orkid)

	BO	NBO	EBO	WBO	BP	NBP
2020				1	1	1
2021		3				1
2022		1	1	1		3
2023	2		1	1	1	1
2024	3					2
2025	1	2	2		1	
2026	1	1		1		2
2027						
Total	**7**	**7**	**4**	**4**	**3**	**10**

Table 5.2: Repsol Planned Interventions – PM3 North Fields

	BS	BT	EBK	WBK	NBR	EBR	WBR	NWBR
2020								
2021			1			1		1
2022			1					
2023			1					1
2024			1			2	1	
2025			1				1	1
2026						1		
2027								
Total	**0**	**0**	**5**	**0**	**0**	**4**	**2**	**3**

Table 5.3: Repsol Planned Interventions – PM3 South Fields

	BO	NBO	EBO	WBO	BP	NBP
2020				1	1	1
2021		3		1		
2022	2		2		2	1
2023	2	1		1		2
2024						
2025						
2026						
2027						
Total	**4**	**4**	**2**	**3**	**3**	**4**

Table 5.4: RPS Planned Intervention Schedule – PM3 South Fields

	BS	BT	EBK	WBK	NBR	EBR	WBR	NWBR
2020								
2021			2			1		1
2022								1
2023			2					1
2024						2		
2025								
2026								
2027								
Total	**0**	**0**	**4**	**0**	**0**	**3**	**0**	**3**

Table 5.5: RPS Planned Intervention Schedule – PM3 North Fields

Note: Subsequent to this work being completed, Repsol provided an updated Intervention plan with significantly more planned interventions to address the declining gas production, more consistent with the RPS schedule.

Plots of the resulting RPS NFA production forecasts for each field are provided in Appendix F.

Combined 2P plots for PM3 are shown in Figure 5.8 & Figure 5.9 for Sales Gas and Oil/Condensate respectively.

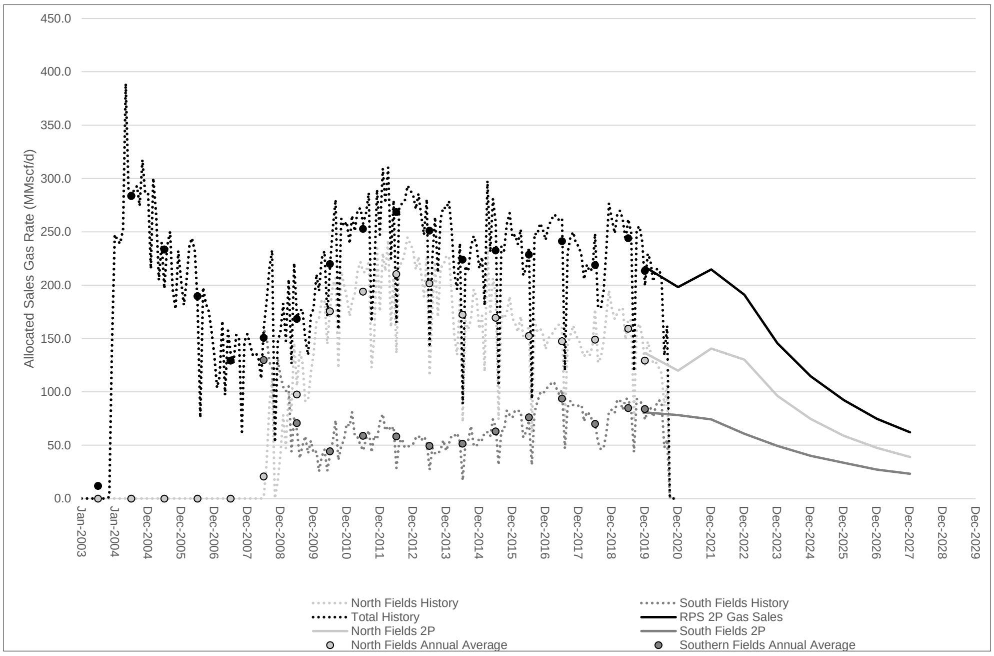

Figure 5.8: PM3 2P Sales Gas Forecast

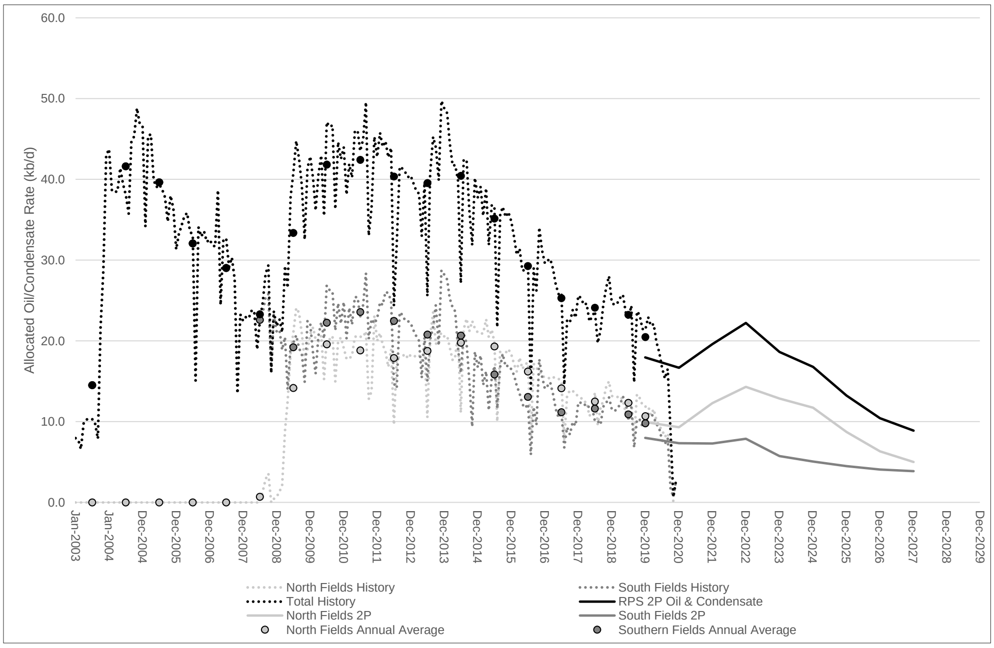

Figure 5.9: PM3 2P Oil & Condensate Forecast

5.4 Low Investment Case Developments

Two fully sanctioned developments are carried in the Low Investment case in addition to existing production and planned well interventions:

- North Bunga Orkid H4 Area Development (NBO-H4)
- East Bunga Raya BRB-LL Infill Well

Both projects have been reviewed by RPS.

5.4.1 North Bunga Orkid H4 Area Development (NBO-H4)

The North Bunga Orkid H4 area is the last PSC commitment project in the PM3 CAA. The FDP was originally submitted in 2005 and since then two exploration/development wells (BOC-19 and BOC-22) have produced approximately 4.9 MMstb of oil as of September 2020[14] from the BOC platform. A further appraisal well (NBO-H4) was drilled in 2Q 2017 to appraise the H4 reservoir while testing potential upside targets in deeper horizons. This triggered the last submission (PM-3 CAA-FDP Revision 4 Addendum Update 34) which proposed a development of six infill wells; two oil producers and four water injectors, together with water injection pipeline installation.

The development was approved in 2019. Repsol states that the BO-D BO-C water injection pipeline installation (~6km) and also topside modification scope have already been completed.

5.4.1.1 Geological Assessment

NBO is located on the northeast margin of the large intra-cratonic Malay sag basin, where the Tertiary sequence that contains the key stacked hydrocarbon reservoirs is approximately 3km thick in total. The NBO-H4 trap is 10km long by 5km wide NW dipping channel, stratigraphically sealed by estuarine muds to the north and south and tidally influenced mud to the east. The area is a combined series of structural and stratigraphic traps and is therefore mostly defined using seismic amplitudes (Figure 5.10).

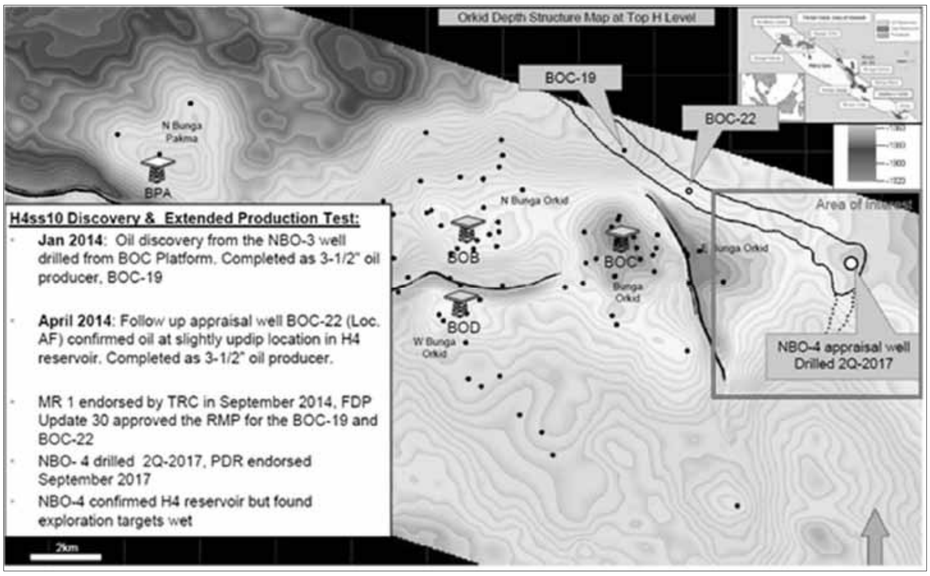

Figure 5.10: Orkid Depth Structure Map at H Level[15]

[14] *VDR Management Presentation - Repsol*

[15] *3.3.3.1.1.5 PM 02_34_NBO_H4_FSP.pdf*

Hydrocarbons are trapped within two reservoirs; the upper H4_SS10 reservoir, which comprise a tidally influenced estuarine channel sand with thin shales and a lower H4_SS12 reservoir, which has been interpreted as a shale filled channel with some isolated sand bars. Repsol consider the two reservoirs are in communication, based on MDT data.

The most downdip well (BOC-19) did not encounter water within the H4SS_10, whilst the H4SS_12 reservoir was fully wet and an ODT is inferred at -1996m TVDss. The BOC-22 well, which is up-dip from the BOC-19 well, did not encounter an oil-water contact, although an oil-water contact was observed at -1965m TVDss in the H4_SS12 reservoir (Figure 5.11). This oil-water contact is shallower than the ODT seen in BOC-19. MDT data suggests that the reservoirs are in pressure communication (Figure 5.12).

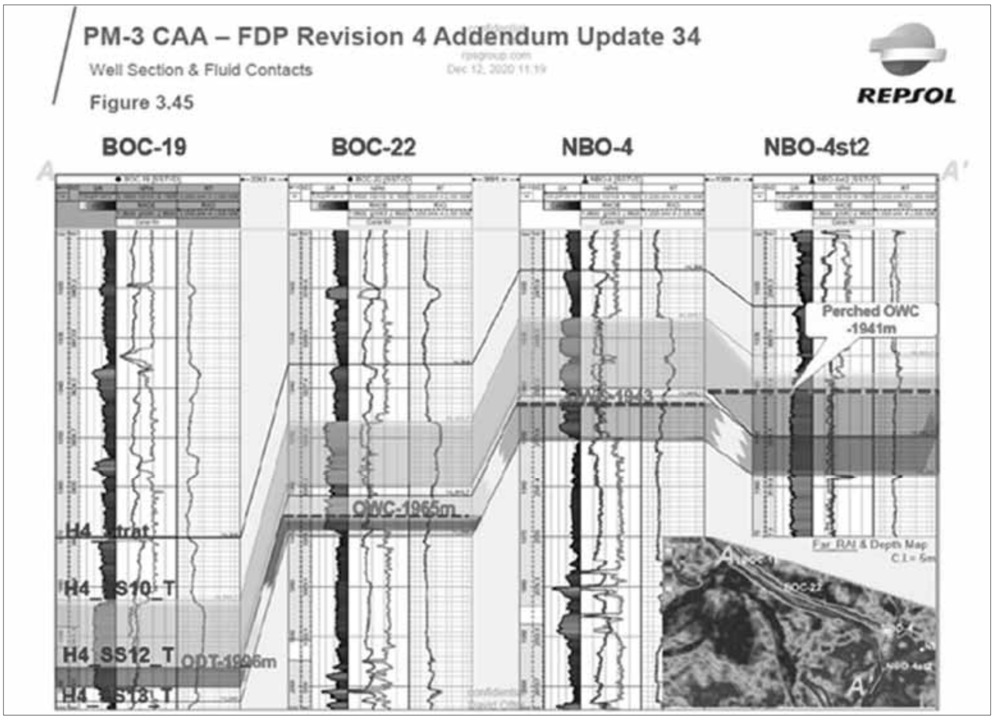

Figure 5.11: NBO Well Section (showing Repsol contacts)

At the crest of the reservoir the NBO-4 well again found a full hydrocarbon column in H4_SS10, but the oil-water contact encountered in the H4_SS12 reservoir was shallower than that seen in BOC-22. Repsol suggest that this is due to a series of perched water contacts within the H4_SS12 reservoir, most likely caused by the isolated nature of the tidally influenced sand bars that reduces lateral connectivity between reservoirs.

The NBO-4ST2 well did encounter a hydrocarbon contact in the H4_SS10 reservoir at -1941m TVDss. Repsol suggest this is due to a change in depositional environment to a more tidally influenced area, which lead to thinning and eventual pinching out of the H4_SS10 reservoir and a thickening of the more isolated H4_SS12 reservoir.

This idea of isolated sand bodies with different hydrocarbon contacts is a plausible explanation based on the geology, geophysical attribute response and reservoir pressure drop encountered by the NBP-4 well (Figure 5.13). However, RPS noted that the oil gradient measured in the NBO-4 well is slightly different to that of the BOC-19 and BOC-22 wells (Figure 5.13).

Whilst this change in gradient is within the error margins of the MDT measurements, it appears to show a denser oil in the NBO-4 well. This is counter intuitive, as the well is structurally higher and therefore more likely to contain lighter, less dense hydrocarbons and therefore it could also indicate that the NBO-4 well is actually in a separate hydrocarbon bearing channel, in both the H4_SS10 and HS_SS12.

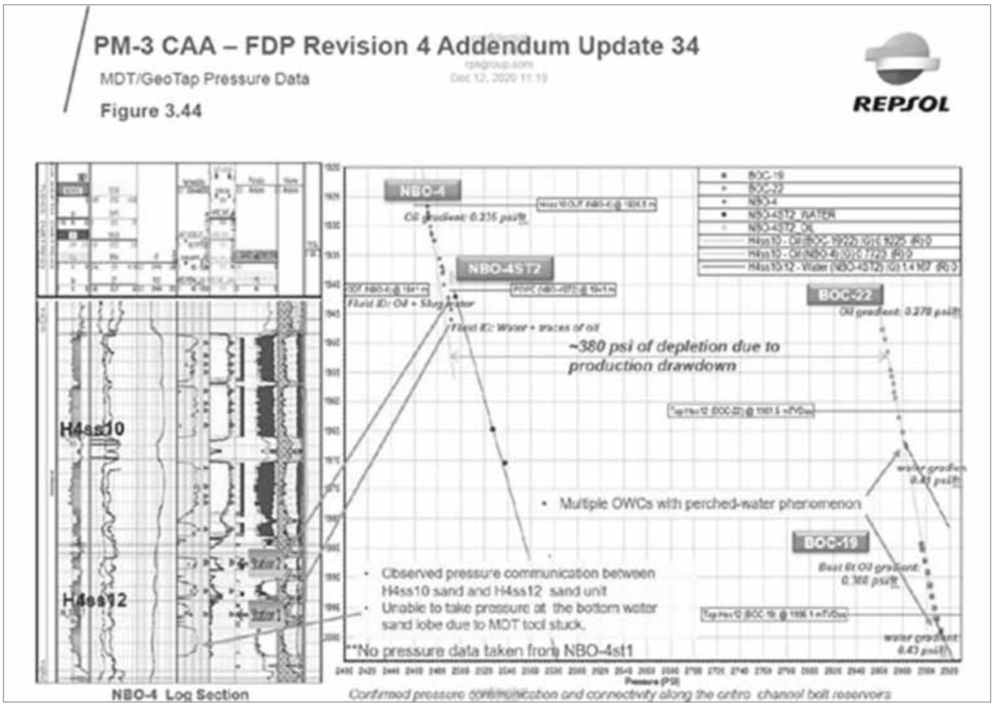

Figure 5.12: NBO H4 MDT and GeoTap Pressure Data

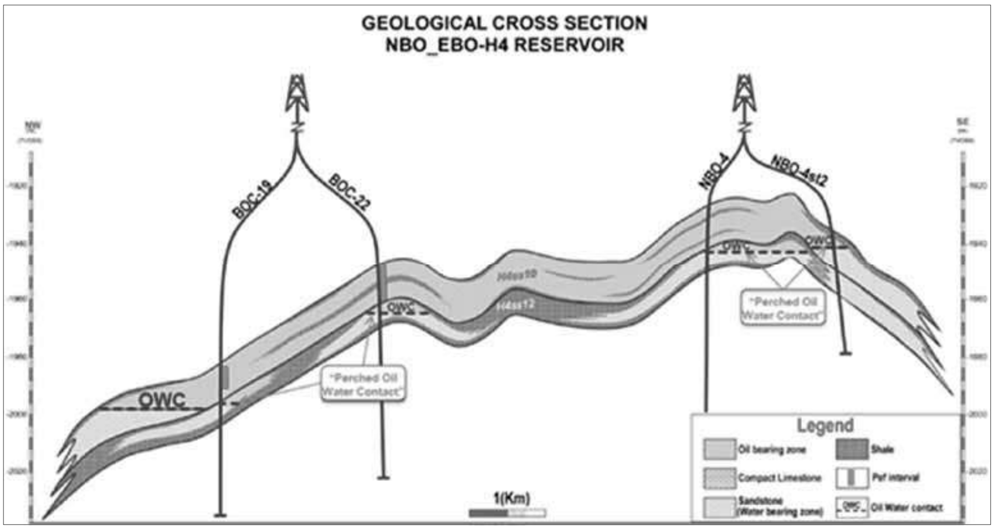

Figure 5.13: Schematic Cross Section Highlighting H4 Play Concept[16]

RPS looked at the MY_IPM_PM3-PDR-NBO-H4-Obj-Model Petrel™ project in the PDR. There was no seismic information, time surfaces or proposed wells in this model. Therefore, the proposed well locations

[16] *3.3.3.1.1.5 PM 02 34_NBO_H4 FDP.pdf*

and seismic interpretation where not independently verified. Information below is taken from the NBO H4 FDP for completeness.

The field is covered by the 2005 Orkid Pakma 3D seismic volume, which appears to be of good quality, based on images within the NBO_H4 FDP (3.3.3.1.1.5 PM 02_34_NBO H4 FDP.pdf). Repsol have correlated the seismic to wells using synthetic seismograms based on the well log sonic and density data. This shows a clear correspondence between the sands, which show a low acoustic impedance compared to the overlying shales (Figure 5.14).

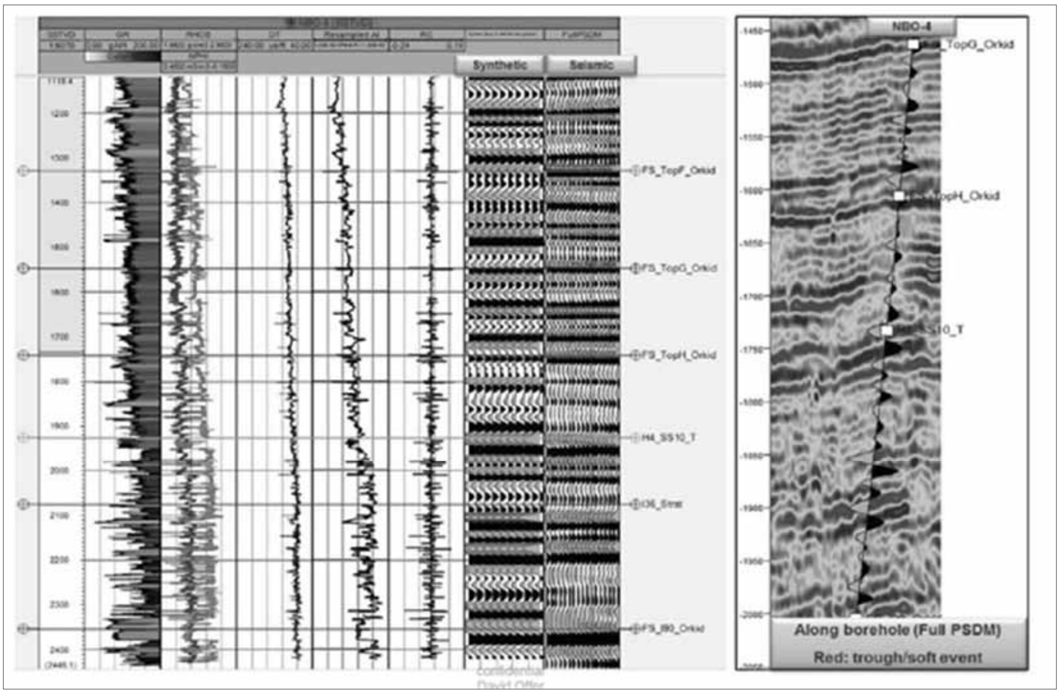

Figure 5.14: NBO-4 Synthetic and Seismic to Well Tie

Repsol have extracted full stack and far angle stack seismic amplitude using a time window (10 to 14ms). Far angle stack best defines the fluvial system, with brighter colours showing the development of the H4_SS10 reservoir (Figure 5.15).

Figure 5.15 shows a dim section in the amplitudes (grey colours) between NBO-4 and BOC-22. Repsol think this is caused by shallow gas. However, in Figure 5.16 Repsol also identify potential barriers using the same seismic response within the Far stack seismic amplitude data.

If this is dim section is caused by barriers and not shallow gas, it would explain the denser up dip fluid shown in Figure 5.11. If that is the case, then it is possible to infer that the NBO-4 well (East) is in a different compartment to the BOC-19 and BOC-22 wells (West).

To take this into account RPS estimated the area contained within the 'better quality reservoir' shown in Figure 5.15 and applied this to the independent volume estimation.

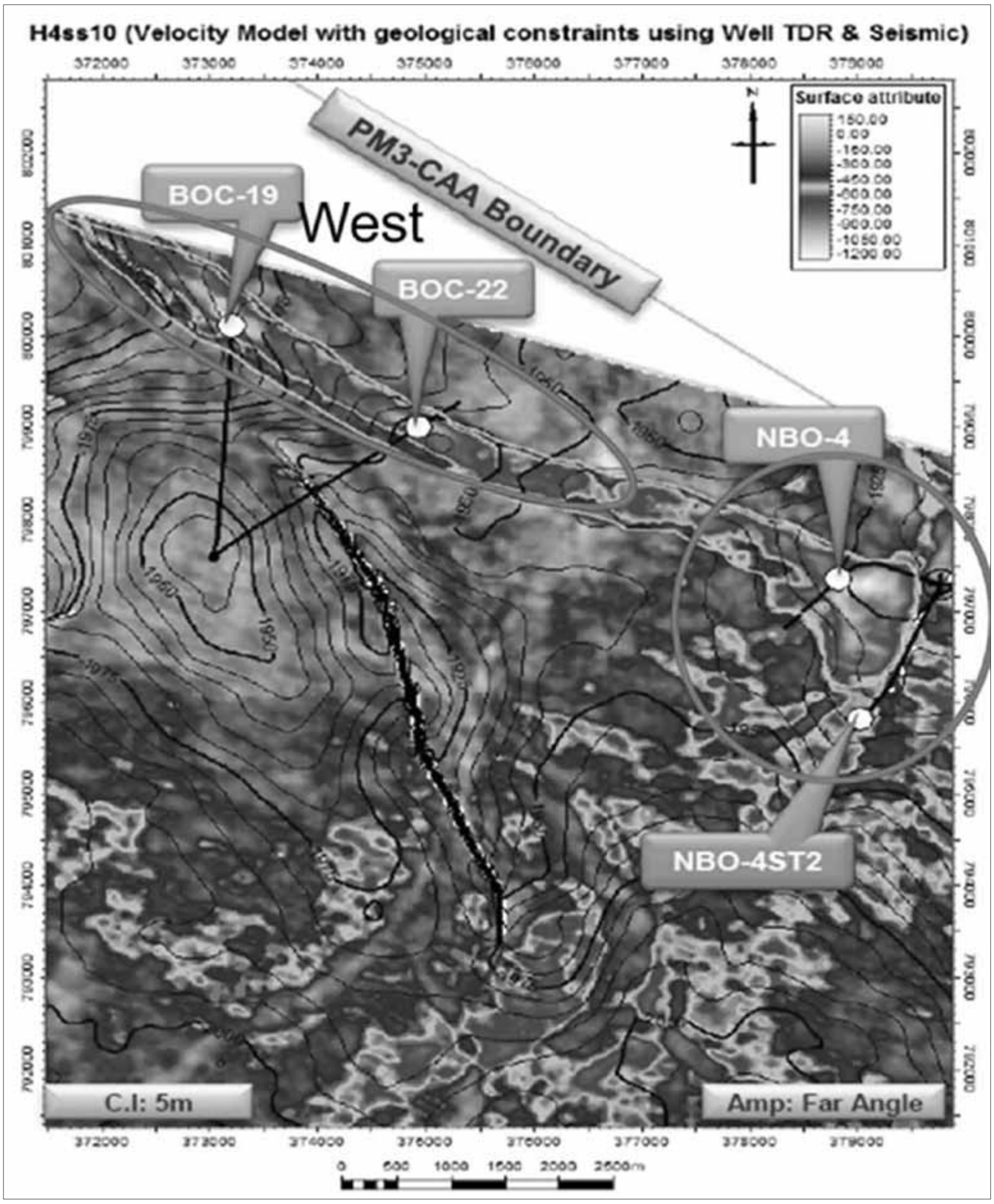

Figure 5.15: Far Angle Stack Data for the H4 Reservoir

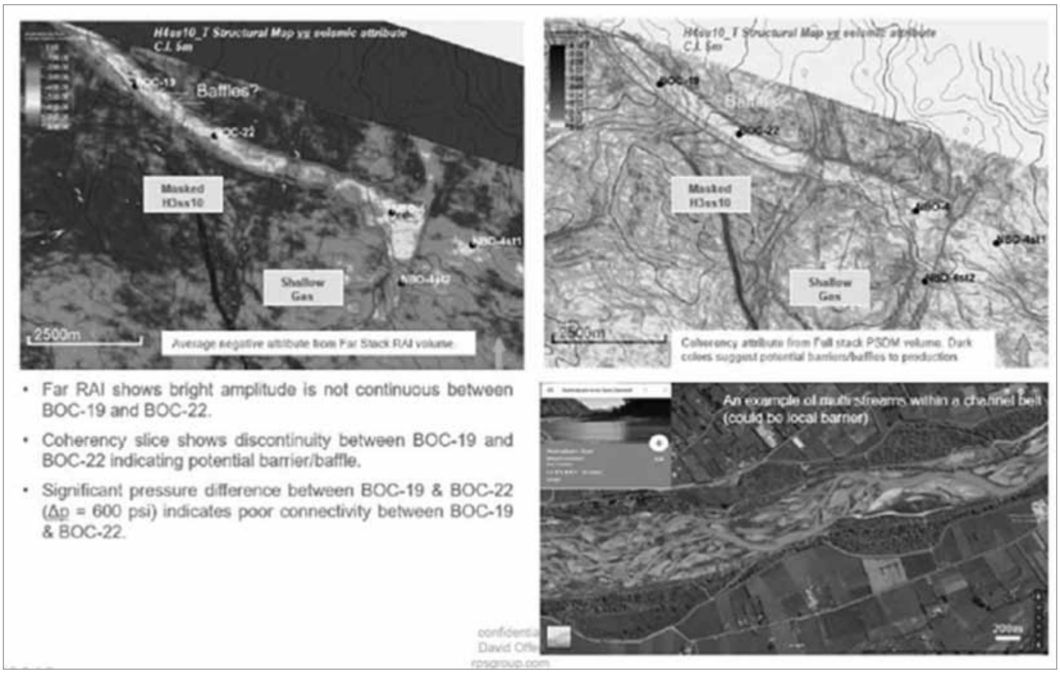

Figure 5.16: Barriers and Baffles identified by Repsol in the HBO-4 FDP[17]

5.4.1.2 Volumetrics

Volumes are estimated using the H4_Object_Modelling grid, which has a 50 by 50 XY spacing. Vertical layering was proportional in all zones and has resulted in a series of layers with an average thickness of 0.2m TVDss. The final model grid has 6,195,200 cells.

Input Depth Surfaces:

Repsol have run a series of depth uncertainty surfaces based on three different depth conversion functions; Velocity Model using a Linear velocity function; Velocity model using well TDR; A combined model.

As no time data was available to study in this model RPS cannot make a comment up this, other than to comment that all the resultant structural depth maps looked geologically robust.

Structural Well Data:

Well tops looked consistent and robust compared to the well log data for the 5 wells (BOC-19, BOC-22, NBO-4, NBO-4ST1 and NBO-2ST2) used to construct the model. All well logs matched the corresponding input and modelled seismic surfaces.

Petrophysical Well Data:

No independent petrophysical evaluation has been carried out by RPS during this evaluation. Well logs in Petrel™ looked reasonable and in the case of the porosity log, matched available core data. Average values matched those reported by Repsol in the NBO H4 MR2 Final Submission 8May2018 (Figure 5.17).

Net to Gross:

This is a Net / Non Net parameter created within Petrel™ using the parameter calculator. It is an amalgamation of two facies (Facies Run 65 and Facies run 54) which were part of a facies sensitivity that Repsol ran for 100 cases.

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[17] *3.3.3.1.1.5 PM 02 34_NBO H4 FDP*

Facies:

This has been upscaled directly from the input Depofacies well log, which has been based upon electro facies and core description. Upscaled logs looked good and have been sampled correctly when plotted back to the well logs. Facies has then been objected modelled using a series of analogue data to control the width, thickness and sinuosity of the channels (Figure 5.18). The facies object modelling was run 100 times as part of the sensitivity analysis.

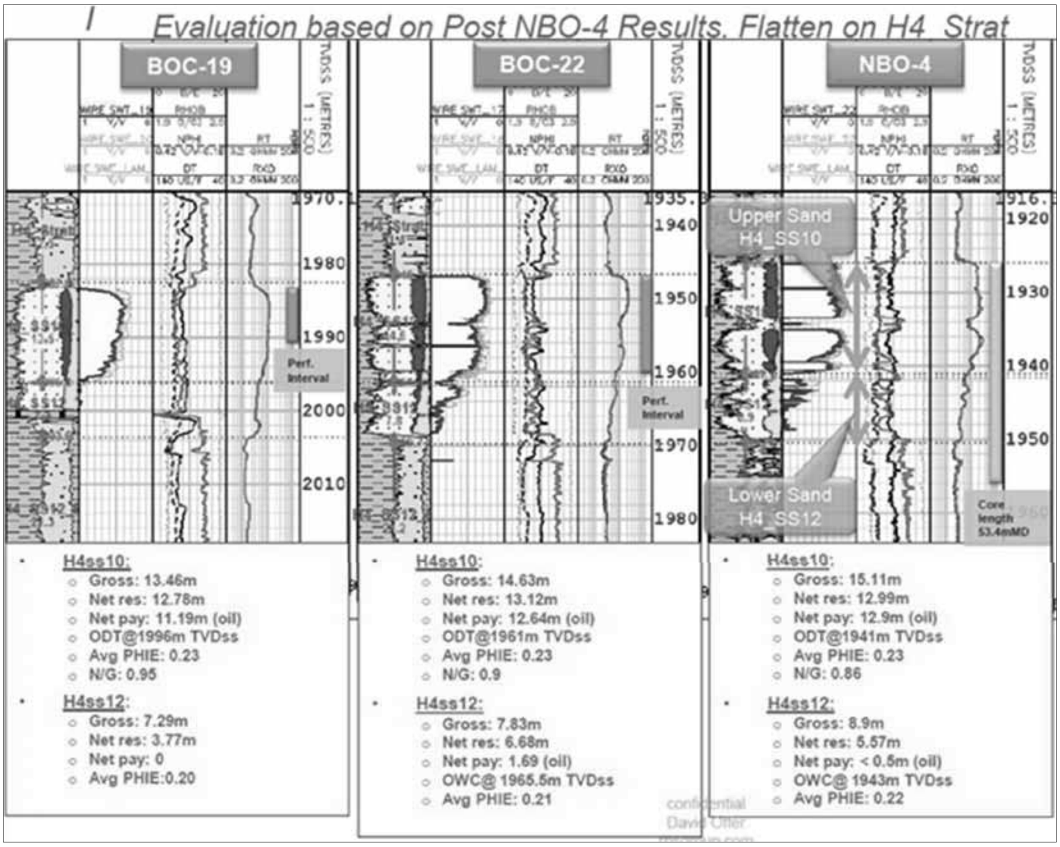

Figure 5.17: Well Logs and Petrophysical Averages[15]

Porosity Modelling:

Porosity was upscaled directly from the input PHIE final MR2 and this appears good. Porosity is modelled using sequential Gaussian simulation and conditioned to the facies model. No data analysis appears to have been done and the variogram used to propagate the porosity has a major and minor range of 5,892, although it was not apparent to RPS how this was derived.

QC of the porosity parameter histograms indicates that the modelling slightly over-estimates porosity values around the value of 22 and under-estimates higher porosities. As these values are around the petrophysical average, they are most likely caused by poor histogram fitting and limited well data. RPS do not consider that this is enough of a modelling error to affect the inplace estimation. The porosity models were run 100 times as part of a sensitivity analysis.

Contacts:

The field consists of variable fluid contacts and are constant with those shown in Figure 5.11.

Formation Volume Factor:

Repsol reports Bo values of 1.34 rb/stb and Bg values of 0.9037 for the H4 reservoirs. Without additional data to contradict these numbers, they were used in the volume estimations by RPS.

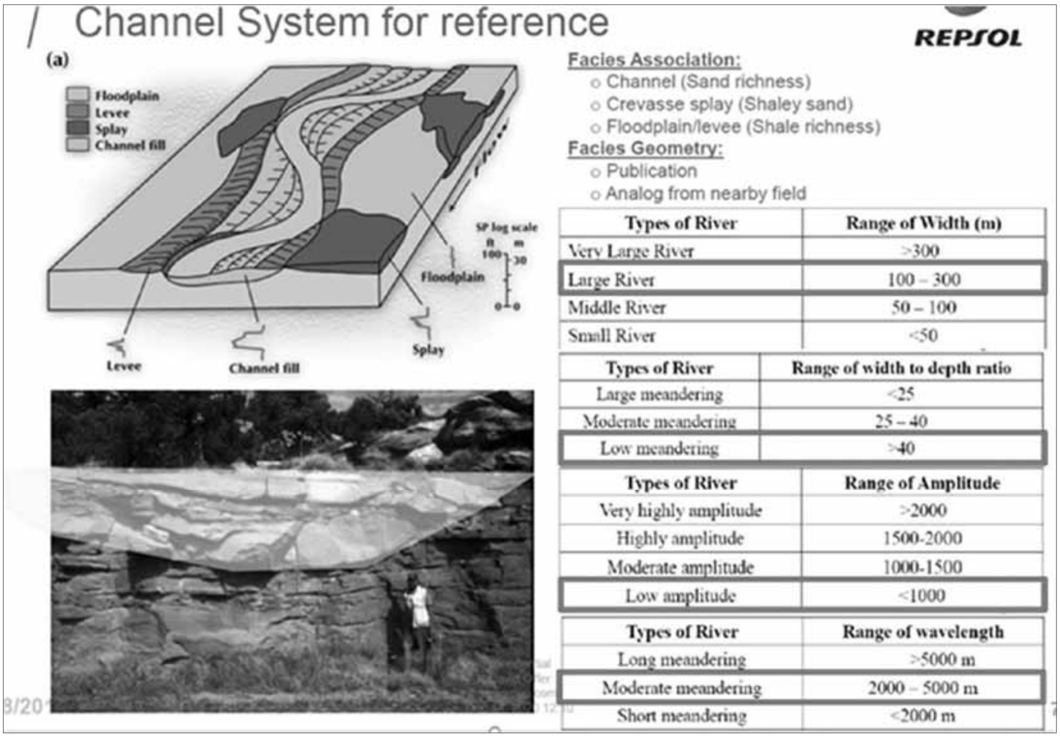

Figure 5.18: Repsol's Analogue Channel Geometries[18]

5.4.1.3 In-Place Volumes

RPS ran a series of independent probabilistic volumes using the H4 Object Modelling grid to estimate a direct GRV using the Repsol contacts (Figure 5.11). Reservoir parameters where taken from the petrophysical averages show in Figure 5.17.

The Petrel™ model's global NTG was back calculated from the model to allow combined volumetric calculation of the H4SS_10 and H4SS_12. This resulted in very low NTG's which are consistent with the estimated GRV, but highlight the degree of shale within the system.

Reservoir Group	PHIE (%)	NTG (%)	SW (%)	GRV (Acreft)	Bo (rb/stb)
P90	20	0.05	0.17	820,630	1.334
P50	22	0.06	0.245	840,314	1.334
P10	24	0.07	0.32	860,470	1.334

Table 5.6: NBO H4 – REP Probabilistic Inputs

[18] *3.3.3.2.2.3.4 NBO H4 MR2_Final_Submission_8May2018.pdf*

OIIP (MMstb)	P90	P50	P10
RPS Full Field	38	48	59

Table 5.7: RPS Probabilistic OIIP Estimations

The resultant RPS probabilistic in-place estimation for the full field is compared in Table 5.8 to the cases previously run by Repsol using the H4_Object_Modelling grid and those reported by Repsol as part of the Information Memorandum for the whole field. These appear consistent and reasonable in comparison.

Model	Volume Case	Grid	STOIIP H4_SS10 (MMStb)	STOIIP H4_SS12 (MMStb)	STOIIP Total (MMStb)
H4ss10 NBO Modelling	Final MR2 Scal 4 Bin RQ 2005m	H4_Object Modelling	52.44534	1.2745	53.71
H4ss10 NBO Modelling	Final MR2 2002m	H4_Object Modelling	49.58	1.34	50.92
H4ss10 NBO Modelling	Final Plus Tidal Flat MR2	H4_Object Modelling	48.25	1.33	49.59
H4ss10 NBO Modelling	Final MR2	H4 Object Modelling	47.033	1.338	48.37
Information Memorandum					46.6
RPS Estimation (P50)					48

Table 5.8: Estimated Full Field In Place Volumes for the MY_IPM_PM3-FDP-NBO-Obj-Model Petrel™ Project

However, RPS is concerned that the NBO-H4 development may not be continuous for the reasons outlined previously. To take this into account volumetrically, two areas where designated (Figure 5.15) and their areal percentage of the full field applied to the RPS full field In Place values (Table 5.9).

OIIP (MMStb)	P90	P50	P10
West (55%)	21	26	32
East (35%)	13	17	21
Combined	34	43	53
Full Field	38	48	59

Table 5.9: RPS Probabilistic OIIP Estimations assuming East and West Compartments

The volumes presented in the VDR Information Memorandum are consistent with the range estimated by the Petrel™ model and those calculated by RPS. RPS considers that the static model and the resultant volumetric estimations for OIIP are robust. However, RPS recommends that further simulation work is undertaken assuming two separate compartments and their effect on the current development plan (Figure 5.19). The presence of two compartments would suggest that the proposed producer 3C is not in the most optimal of places and that the compartment to the east, may not require two injectors.

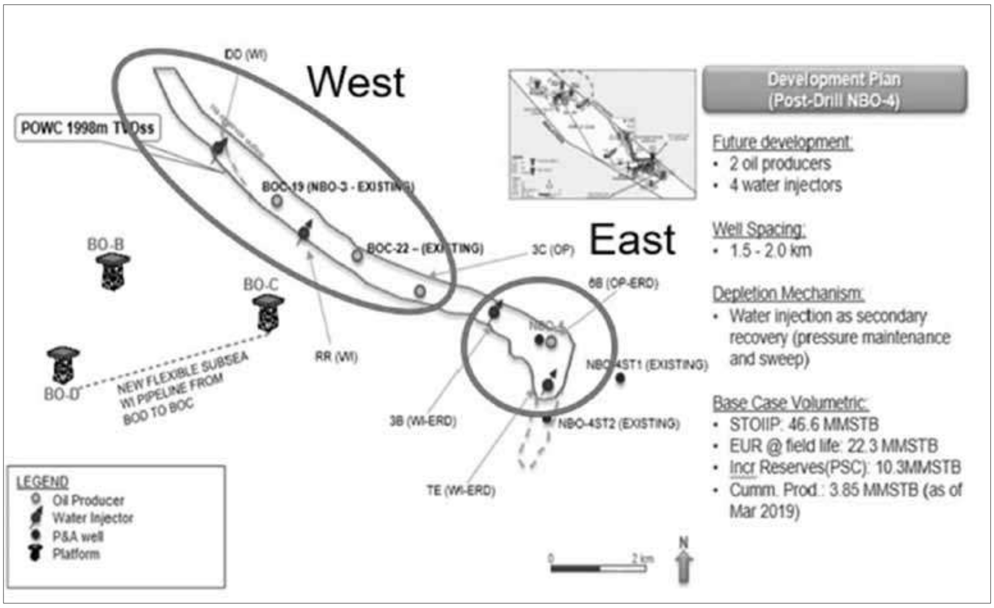

Figure 5.19: NBP H4 Project Development Plan[19]

5.4.1.4 Reservoir Engineering Assessment

The NBO-H4 reservoir simulation model was reviewed by RPS in the PDR and various screen captures and output files were obtained for later analysis. Key reservoir parameters for the model are outlined in Table 5.10 and Figure 5.20 illustrates the permeability distribution for the model. The figure indicates a reasonable permeability range with the maximum value being 1,045 mD.

[19] *3.3.3.1.1.5 PM 02_34_NBO_H4_FSP.pdf*

Property	Low	Best	High
Grid Dimensions (x,y,z)		256 x 220 x 110	
DX Dimensions (ft)	153	161	178
DY Dimensions (ft)		Similar to DX	
DZ Dimensions (ft)	0.62	0.68	0.72
Total Cells		6,195,200	
Active Cells		178,812	
Average Porosity (fraction)	0.10	0.15	0.21
Average Horizontal Permeability (mD)	85.6	386.9	697.8
Average Vertical Permeability (mD)	8.56	38.68	69.78
PERMZ/PERMX Ratio		~0.10	
	Start		**End**
History Match Period	1st May 2014		1st October 2020
Prediction Period	1st November 2020		1st January 2051
Infill Development Start (Water Injectors)		15th November 2021	

Table 5.10: Repsol's North Bunga Orkid H4 Reservoir Dynamic Model Properties

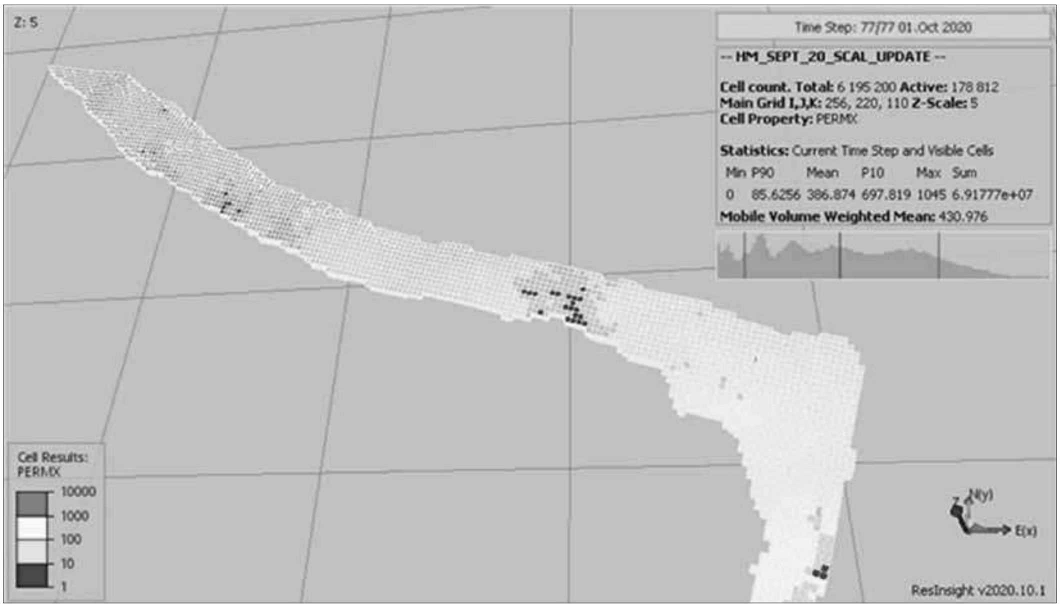

Figure 5.20: Repsol's North Bunga Orkid H4 Reservoir Dynamic Model Permeability Distribution

In general, the model appears reasonable in terms of the input parameters, which is to be expected, as the model has been through the PETRONAS MPM project milestone review process.

A total of three cases were provided in the PDR, a history match case, an NFA prediction case, and finally a prediction case that includes the additional development. Figure 5.21 shows the well locations for the existing and the six infill wells.

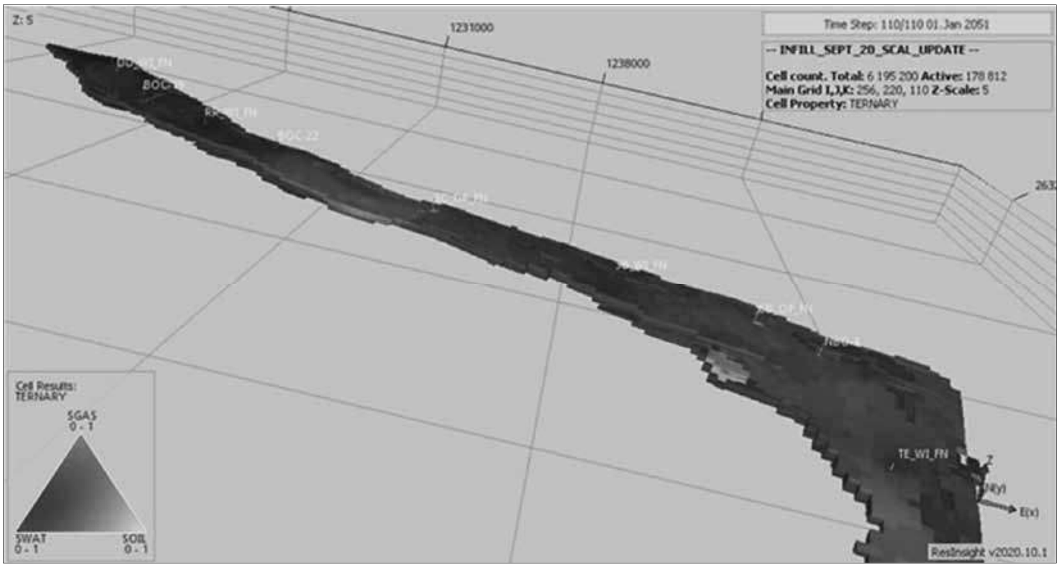

Figure 5.21: Repsol's North Bunga Orkid H4 Model Well Locations

The results of the cases are tabulated in Table 5.11 for oil and Table 5.12 for gas; the profiles are also depicted in Figure 5.22.

			Production End Date	
Scenario	**Property**	**Unit**	**2027**	**2042**
NFA	STOIIP	(MMstb)	46.586	
	Recovery Factor	(percent)	17.1%	20.0%
	Recoverable	(MMstb)	7.971	9.304
	Production	(MMstb)	4.388	
	Remaining	(MMstb)	3.583	9.304
Prediction	STOIIP	(MMstb)	46.586	
	Recovery Factor	(percent)	33.2%	46.6%
	Recoverable	(MMstb)	15.457	21.700
	Production	(MMstb)	4.388	
	Remaining	(MMstb)	11.069	17.313
Incremental	Incremental Remaining	(MMstb)	7.486	8.009

Table 5.11: Repsol's North Bunga Orkid H4 Reservoir Dynamic Model Results Summary (Oil)

Scenario	Property	Unit	Production End Date 2027	Production End Date 2042
NFA	GIIP	(Bscf)	32.158	
	Recovery Factor	(percent)	49.7%	66.6%
	Recoverable	(Bscf)	15.981	21.421
	Production	(Bscf)	5.084	
	Remaining	(Bscf)	10.897	21.421
Prediction	GIIP	(Bscf)	32.158	
	Recovery Factor	(percent)	52.7%	60.0%
	Recoverable	(Bscf)	16.944	19.286
	Production	(Bscf)	5.084	
	Remaining	(Bscf)	11.860	14.202
Incremental	Incremental Remaining	(Bscf)	0.963	-7.219

Table 5.12: Repsol's North Bunga Orkid H4 Reservoir Dynamic Model Results Summary (Gas)

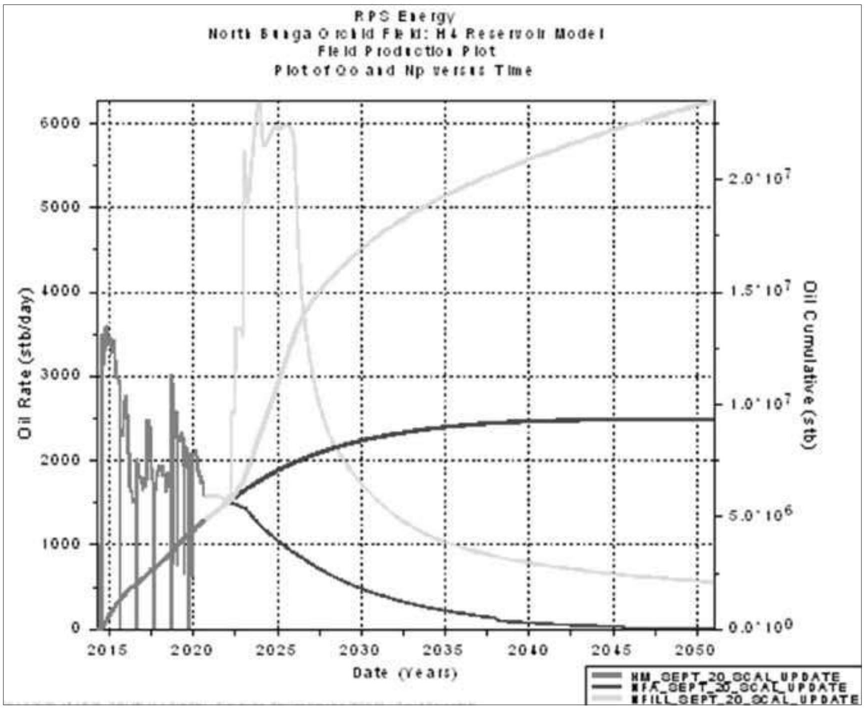

Figure 5.22: Repsol's North Bunga Orkid H4 Reservoir Dynamic Production Profiles

The oil results appear reasonable for a managed water flood, although the 2042 recover factor is perhaps on the high side for a Best scenario. The incremental gas volumes are negative because the water injection wells re-pressurise the reservoir which results in less gas being produced in the water flood case.

Based on the above, RPS has chosen to use the provided model as the Best case and to rescale the profiles based on the 2042 incremental volumes as outlined in Table 5.13.

			2042	
Property	**Unit**	**Low**	**Best**	**High**
STOIIP	(MMstb)	38.000	48.000	59.000
Recovery Factor	(percent)	42.00%	45.00%	48.00%
Recoverable	(MMstb)	15.960	21.600	28.320
Production	(MMstb)		-4.388	
NFA	(MMstb)		-4.916	
Incremental Remaining	(MMstb)	**6.656**	**12.296**	**19.016**
			2027	
Incremental Remaining	(MMstb)	**3.962**	**7.432**	**11.484**

Table 5.13: RPS's North Bunga Orkid H4 Incremental Oil Recovery

In the table the STOIIP numbers are based on RPS' estimates, which are similar to the 1st January 2020 ARPR values of 41.5, 46.74 and 59.10 MMstb, for the Low, Best and High estimates, respectively.

5.4.2 BRB-LL Development

The East Bunga Raya (EBR) (Figure 5.23) field started oil production in October 2003, with first gas in January 2004. Structurally it comprises a NW-SE fault bounded anticline, with middle to lower Miocene fluvio-tidal reservoirs. Major oil reservoirs include the I23U/L, I40L, I115, I120, J60 and J70 with minor oil reservoirs in I70U, J55 and I100. Major Gas reservoirs are I40U, I60, I90 U/L, J30, J40 and J50 (Figure 5.24).

Repsol are committed to drilling a new infill well in the I70U oil bearing reservoir called BRB-LL.

The I70U is interpreted as a channel within a delta plain environment. The reservoirs comprise of fluvial channel and thin inter-channel sandstones and are fault separated into a northern and southern section (Figure 5.25).

The I70U reservoir was discovered in the East Bunga Raya (EBR) field by the BR-1 well. This was followed by the drilling of two production wells, BRC-14 and BRC-15, in 2005. Due to poor cement issues leading to reservoir cross flow, the BRC-14 well is now shut-in. BRC-15 was converted to a water injector, which is also currently shut-in.

The proposed well will be a horizontal producer, designed to capture unswept oil up-dip of the BRC-14 well (Figure 5.25), improving hydrocarbon recovery and boosting production, with first oil planned for Q4 2022. A field development plan update has been submitted for approval and project is included in the 2021 WP&B.

Repsol have identified that an additional 9.3 MMstb oil in-place for the north I70U and states the expected incremental reserves with water injection to be 1.3 MMBOE or 1.2 MMstb of incremental oil (VDR FDP).

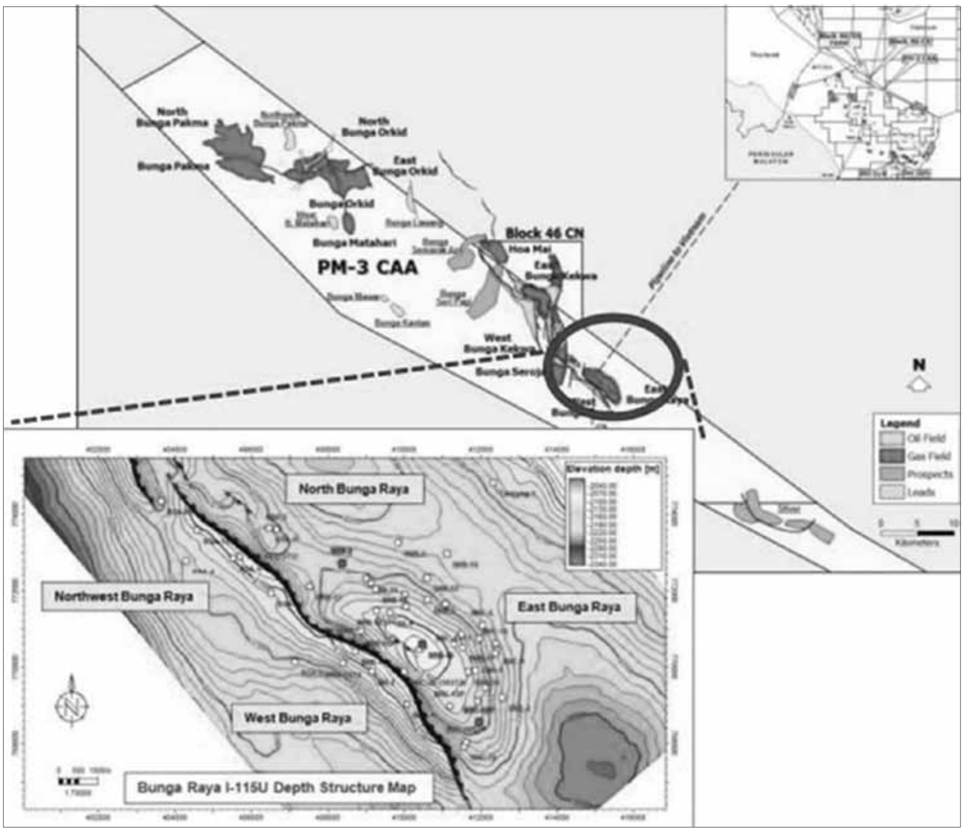

Figure 5.23: East Bunga Raya Field[20]

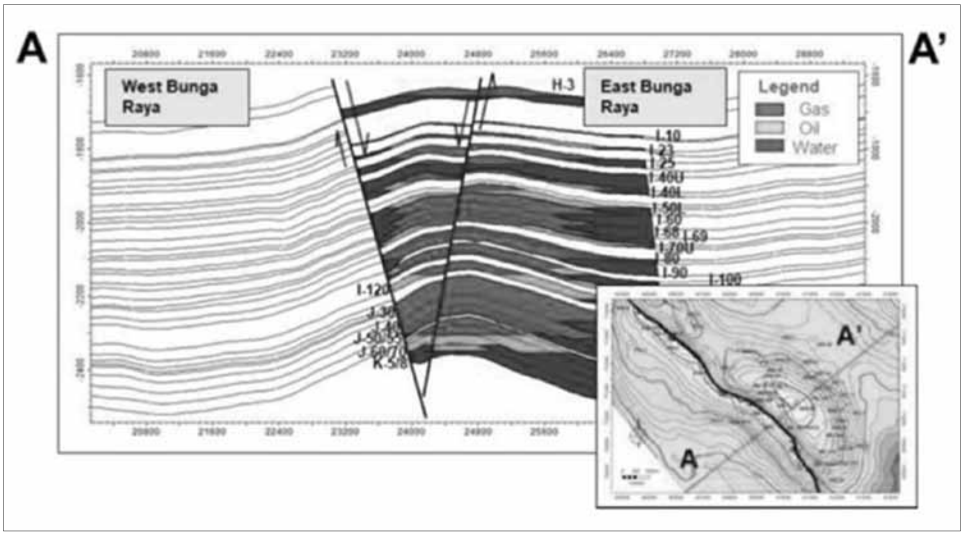

Figure 5.24: Schematic Cross Section showing Stacked Reservoirs[20]

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[20] *3.2.3.12.2.1.1.2.4 ARPR 1.1.202 East Bunga Raya*

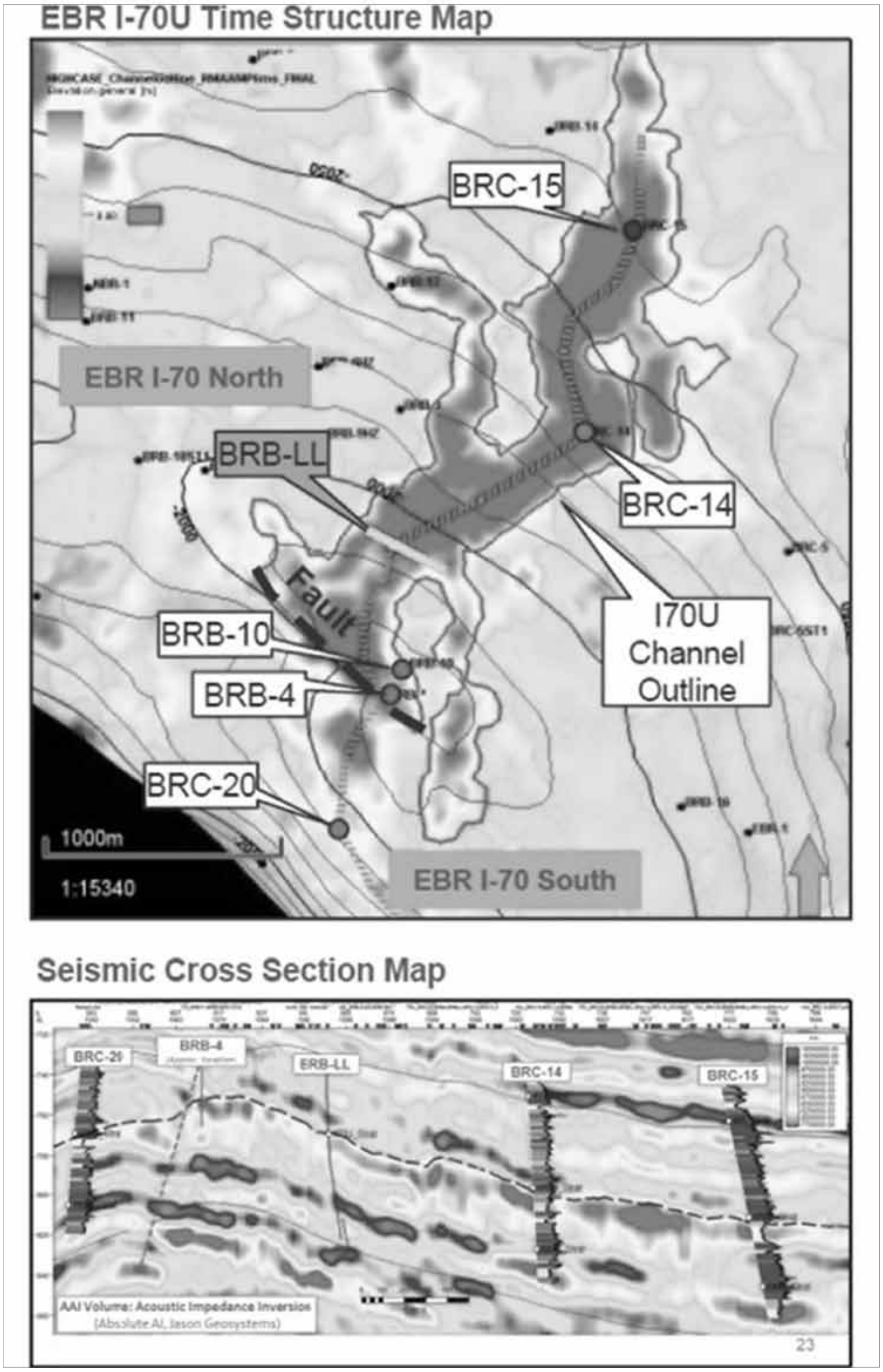


Figure 5.25: EBR I-70U RMS Amplitude Map

5.4.2.1 Geological Assessment

Due to time constraints within the PDR, RPS did not get to interrogate the Petrel™ Project[21].

Subsequently, no independent technical evaluation of the in-place numbers was carried out and all further evaluation was completed using the FDP Revision 4 Addendum Update 29; BRB-LL[22] which was submitted and accepted in January 2020.

Description of the static modelling method applied seems reasonable and robust. Well tops and facies shown in the FDP look reasonable and consistent between the BRB-12 and BRB-14 wells. Methods used to distribute the facies and porosity described in the FDP are robust and as the field have been on production for several year RPS is happy to accept the estimated inplace volume.

Based on the FDP, RPS does have a concern with regard to the placement of the well and proposed production plan;

Well Placement:

The BRB-LL well is planned to sit beneath the gas oil contact of the northern I-70 EBR reservoir and above the oil-water contact (OWC). The exact depth of these contacts is unknown and Repsol have estimated a range of contacts based on gas down to values whilst the OWC is estimated from the MDT data (Figure 5.26 & Table 5.14).

Planning for the BRB-LL well assumes an OWC of -2063m TVDss and a gas-oil contact (GOC) of -1989m TVDss, which gives an oil window of 70m, with which to insert the horizontal well. However, should the OWC be at -2077m TVDss and the GOC at -2053m TVDss as suggested by MDT data from the BRC-14 well then the oil window is reduced to only 25m. This could impact on production rate and should the depth conversion error be larger than 15m the well could be place in the gas leg and require a side-track.

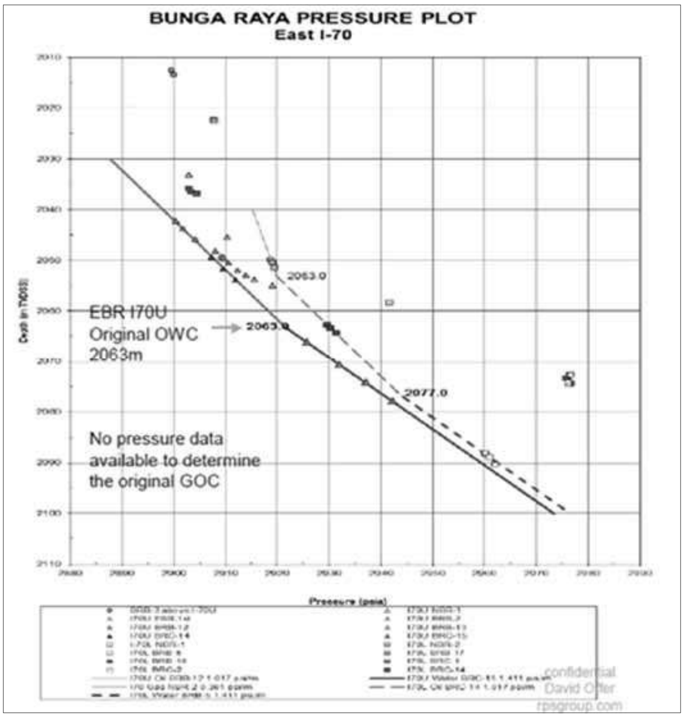


Figure 5.26: MDT Data used to Estimate the Possible OWC

[21] MY_IPM_PM3_FFR_EBR_BRB_LL_20201125_PetrelV2019

[22] *3.3.3.1.1.3 FDP29_BRBLL_Full*

Contacts	Low	High
Gas Oil Contact (m)	2053	1989
Oil Water Contact (m)	2077	2063

Table 5.14: Repsol Estimated Contacts

Proposed Production Plan:

Repsol have started to inject water into the down dip BRC-15 well. This should give support to the new BRB-LL well. However, there is an unpicked fault between the BRC-15 water injector and the BRB-LL well site (Figure 5.27). As Repsol pick a similar fault, with a similar throw further to the SE, which seals and separates the northern and southern areas of the U-70 reservoir, this unpicked fault could seal and therefore the proposed BRB-LL well would not see any pressure support from the BRC-15 well.

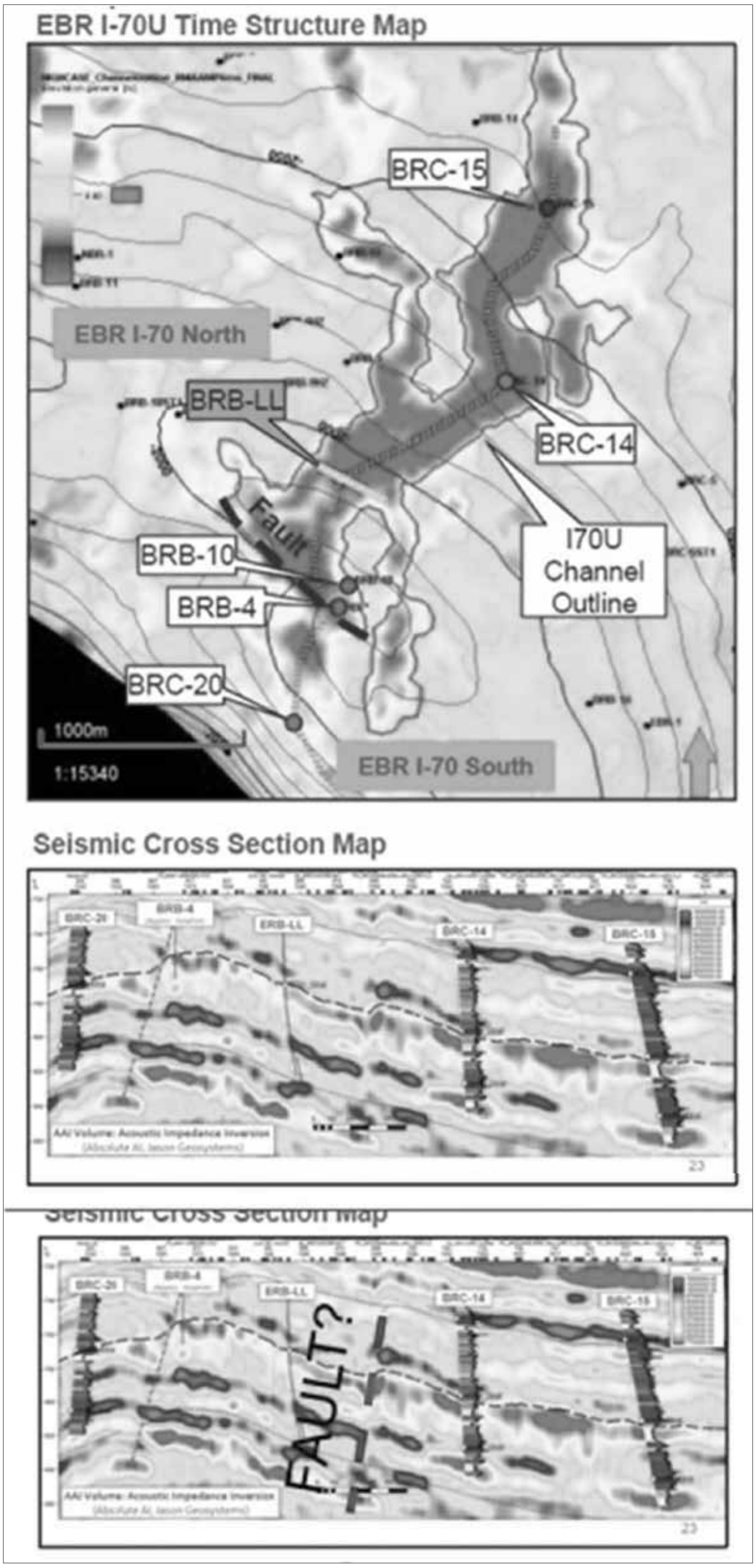


Figure 5.27: RMS Map showing Potentially Unpicked Fault (Red)

5.4.2.2 Reservoir Engineering Assessment

The ERB I70U reservoir simulation model was reviewed by RPS in the PDR and various screen captures and output files were obtained for later analysis. Key reservoir parameters for the model are outlined in Table 5.15 and Figure 5.28 illustrates the permeability distribution for the model. The figure indicates a reasonable permeability range with the maximum value being three times the mean value, at approximately 3,386 mD.

Property	Low	Best	High
Grid Dimensions (x,y,z)		153 x 172 x 70	
DX Dimensions (ft)	135	156	165
DY Dimensions (ft)		Similar to DX	
DZ Dimensions (ft)	1.32	2.04	3.14
Total Cells		1,842,120	
Active Cells		59,661	
Average Porosity (fraction)	0.13	0.20	0.26
Average Horizontal Permeability (mD)	11.9	411.3	1,141.4
Average Vertical Permeability (mD)	1.18	41.13	114.14
PERMZ/PERMX Ratio		~0.10	
	Start		**End**
History Match Period	1st July 2005		1st May 2019
Prediction Period	1st May 2019		1st January 2039
Infill Development First Oil		1st May 2020	

Table 5.15: Repsol's East Bunga Raya BRB-LL Reservoir Dynamic Model Properties

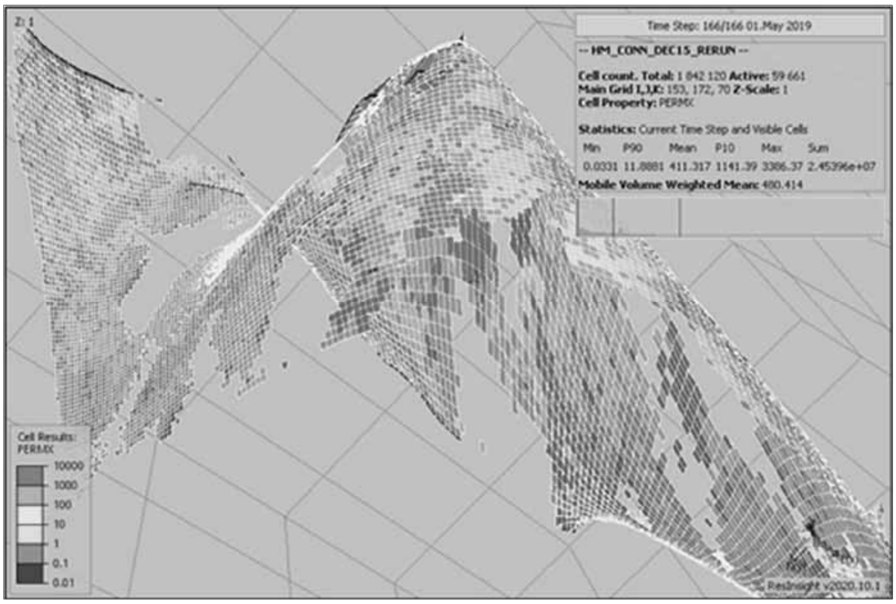


Figure 5.28: Repsol's East Bunga Raya BRB-LL Reservoir Dynamic Model Permeability Distribution

The model is stale as the planned first oil is 1st May 2020 and not the currently planned Q4 2022, RPS has therefore shifted the model profiles to match the existing schedule. The first prediction run, which consists of just the infill well, suffers from numerical issues (60) but the overall fluid material balances errors are small and therefore results are deemed acceptable. The second prediction case consists of the infill well plus water injection. This run has serious numerical problems (5040) and also has unacceptable material balance errors for the oil (1.7%) and gas phases, thus making results unreliable. In addition, this case has a STOIIP of 19.055 MMstb compared to the history match and NFA cases that have 20.199 MMstb, which is of considerable concern.

In general, the model appears reasonable in terms of the input parameters, which is to be expected, as the model has been through the PETRONAS MPM project milestone review process.

A total of three cases were provided in the PDR, a history match case, a prediction case with the infill well, and finally a prediction case that includes the infill well plus water injection. Figure 5.29 shows the well locations for the existing and the infill well (BRB-LL).

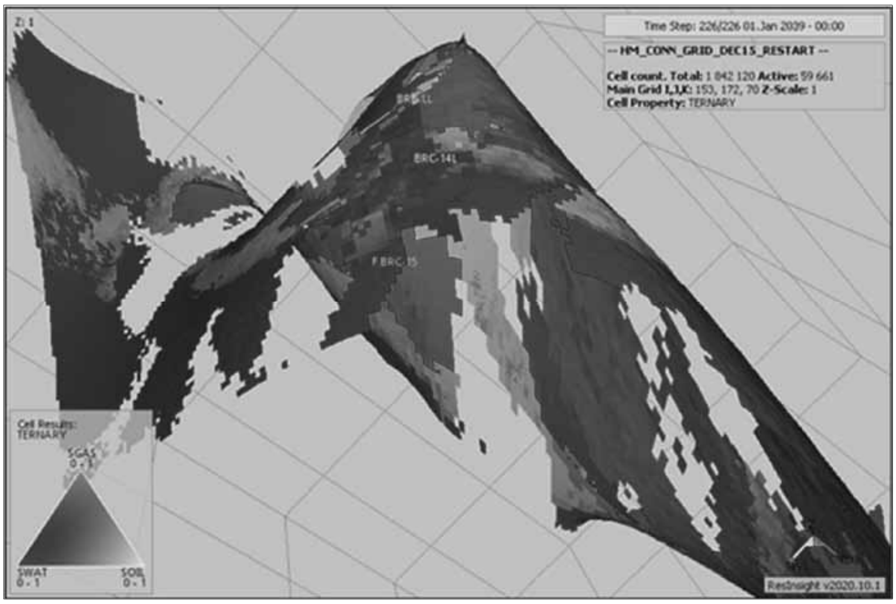


Figure 5.29: Repsol's East Bunga Raya BRB-LL Reservoir Dynamic Well locations

The results of the infill case only are tabulated in Table 5.16 for oil and Table 5.17 for gas; the oil profiles are also depicted in Figure 5.30.

Scenario	Property	Unit	Production End Date 2027	Production End Date 2042
NFA	STOIIP	(MMstb)	20.199	
	Recovery Factor	(percent)	0.0%	0.0%
	Recoverable	(MMstb)	0.000	0.000
	Production	(MMstb)	1.384	
	Remaining	(MMstb)		
Prediction Infill Only	STOIIP	(MMstb)	20.199	
	Recovery Factor	(percent)	10.8%	10.8%
	Recoverable	(MMstb)	2.174	2.174
	Production	(MMstb)	1.384	
	Remaining	(MMstb)	0.790	0.790
Incremental	Incremental Remaining	(MMstb)	0.790	0.790
Prediction Infill and Water Injection	STOIIP	(MMstb)	19.055	
	Recovery Factor	(percent)	15.5%	15.5%
	Recoverable	(MMstb)	2.962	2.962
	Production	(MMstb)	1.384	
	Remaining	(MMstb)	1.578	1.578
Incremental	Incremental Remaining	(MMstb)	0.788	0.788

Table 5.16: Repsol's East Bunga Raya BRB-LL Reservoir Dynamic Model Results Summary (Oil)

Scenario	Property	Unit	Production End Date 2027	Production End Date 2042
NFA	GIIP	(Bscf)	29.130	
	Recovery Factor	(percent)	0.0%	0.0%
	Recoverable	(Bscf)	0.000	0.000
	Production	(Bscf)	3.785	
	Remaining	(Bscf)		
Prediction Infill Only	GIIP	(Bscf)	29.130	
	Recovery Factor	(percent)	27.5%	27.5%
	Recoverable	(Bscf)	8.002	8.002
	Production	(Bscf)	3.785	
	Remaining	(Bscf)	4.217	4.217
Incremental	Incremental Remaining	(Bscf)	4.217	4.217
Prediction Infill and Water Injection	GIIP	(Bscf)	27.948	
	Recovery Factor	(percent)	24.4%	24.4%
	Recoverable	(Bscf)	6.832	6.832
	Production	(Bscf)	3.785	
	Remaining	(Bscf)	3.047	3.047
Incremental	Incremental Remaining	(Bscf)	-1.170	-1.170

Table 5.17: Repsol's East Bunga Raya BRB-LL Reservoir Dynamic Model Results Summary (Gas)

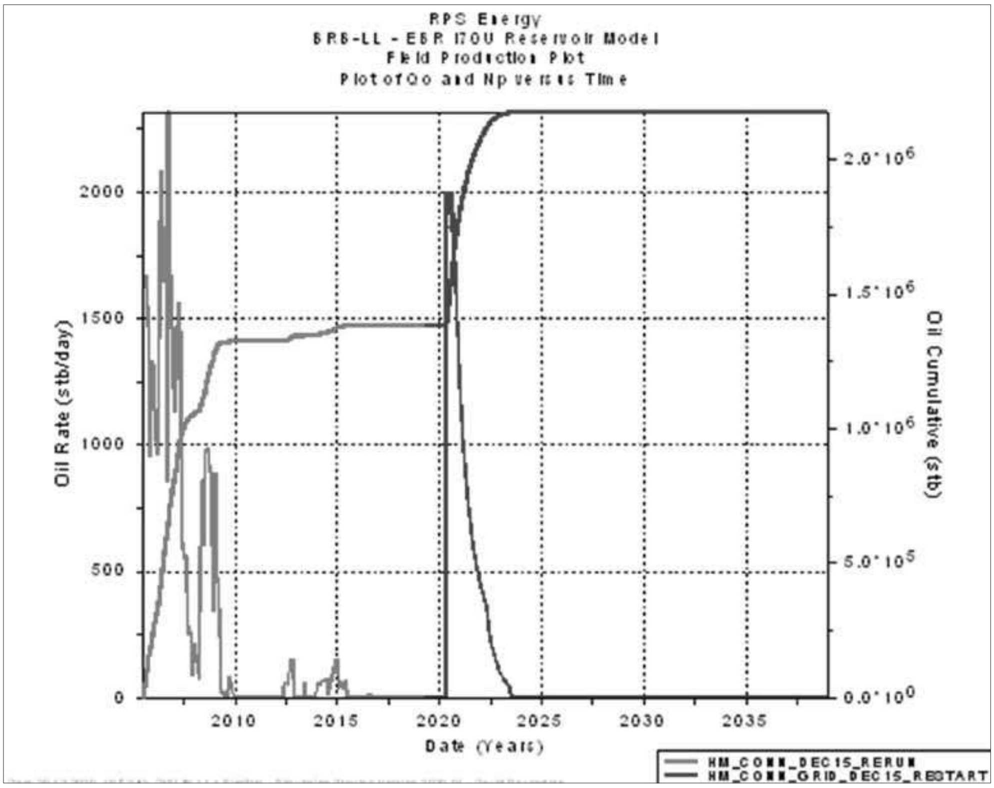


Figure 5.30: Repsol's East Bunga Raya BRB-LL Reservoir Dynamic Production Profiles

The FDP submission[23] states the STOIIP to be 9.3, 3.0 and 6.4 MMstb for the north I-70U, south I-70U, and the I70L areas, for a total of 18.7 MMstb.

[23] *3.2.3.9.1.2 FDP29_BRBLL_Full.pdf in the VDR*

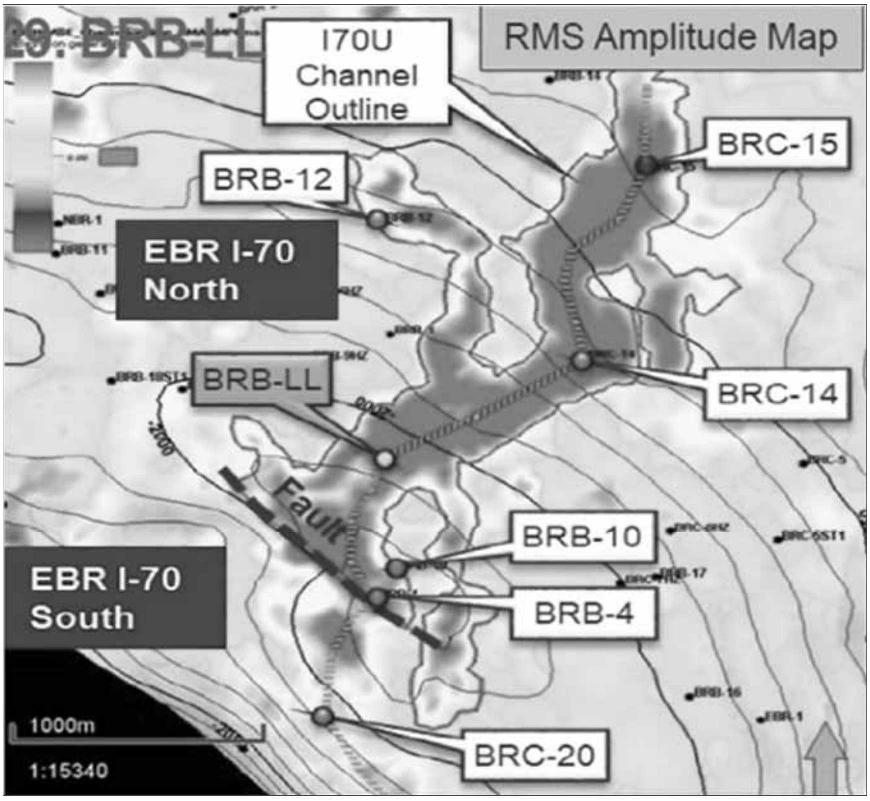


Figure 5.31: Repsol's East Bunga Raya BRB-LL I70U RMS Amplitude Map

Note that the FDP reports the production for the three areas to be 1.9 MMstb versus the model's 1.384 MMstb, as the EBR I70 Southern area (well BRC-20) is not in communication with the main area. This also explains the low water flood recovery factor as the total STOIIP is used in estimating the recovery factors, as the individual area volumes are not reported by the model. Thus, although the oil results appear reasonable for a depletion drive reservoir with a total oil recovery factor of 10.8%, there is considerable uncertainty associated with the water flood recovery and the drilling of this well.

Based on the above, RPS has chosen to use the provided model infill water injection case with a maximum liquid capacity of 2,000 stb/d as the High case and to rescale the profiles on a cumulative oil basis as outlined in Table 5.18.

			2042	
Property	**Unit**	**Low**	**Best**	**High**
STOIIP	(MMstb)		18.700	
Recovery Factor	(percent)	10.0%	12.5%	15.0%
Recoverable	(MMstb)	1.870	2.338	2.805
Production	(MMstb)		-1.384	
NFA	(MMstb)		-	
Incremental Remaining	(MMstb)	0.486	0.954	1.421
			2027	
Incremental Remaining	(MMstb)	0.486	0.954	1.421

Table 5.18: RPS's East Bunga Raya BRB-LL Incremental Oil Recovery

In the table the reported STOIIP and produced oil volumes are used combined with model's recovery factor for the High case. For the Low scenario and High scenario, RPS used recovery factors of 10% and 15% respectively.

Note using the STOIIP of 9.3 for the north I70U only and the recoverable volumes in Table 5.18, results in low, best and high recovery factors of 20.1, 25.1 and 30.2%, respectively.

5.5 Defined Developments

Repsol has identified a number of projects that are believed to comprise mature, defined concepts supported by 3D models. The maturity of these projects ranges from well-defined opportunities that are drill ready but have not yet passed partner sanction, to more conceptual projects that may need only minor modification to surface facilities but are unproven. In general, RPS would class these projects as Contingent Resources (Development Pending, On Hold or Unclarified), though some may be defined as Prospective Resources.

Repsol's list of Defined Developments includes:

– Pakma Infill wells
– Saffron B Discovery
– Bunga Orkid Infill wells
– Hoa Mai Development
– Additional infrastructure projects (e.g. ESPs, Pressure reductions, etc.)

Due to time limitations and project maturity as presented by Repsol, RPS has only reviewed a subset of the projects identified by Repsol. These are discussed in more detail in the following sections. All other projects were not considered sufficiently mature or robust to be included in our assessment.

5.5.1 Bunga Pakma Infill (BPA-G)

The Bunga Pakma field was drilled to mitigate against potential shortfall in the PM-3 Gas Sales. It comprises the 9 slot BPA Platform. Six initial production wells were drilled in 2018 – BPA-1 to 6, with first gas on the 12th May 2018.

To maintain production at the BPA platform, Repsol plan to drill the Pakma Infill (BPA-G) well, which is due to start producing in 2022. RPS has evaluated this infill opportunity in the Physical dataroom.

The Pakma field is split into two producing blocks separated by the Pakma-Orkid fault (Figure 5.32), although all exploited through the Bunga Pakma A platform (BPA).

North Bunga Pakma (NBP) is a small, 4-way dip closed structure situated on the down thrown side of the fault containing the BPA-1, -2, -3 and -4 wells and has not been looked at by RPS.

Bunga Pakma (BP) is a fault closed 3-way dip closure on the upthrown side of the fault, containing the BPA-5 production well, the BP-1 exploration well and the proposed BPA-G proposed infill. Reservoirs comprise a series of Lower to Middle Miocene age tidal and fluvial stacked channel facies sand reservoirs.

The BPA-G infill well will target hydrocarbons potentially stranded up-dip of the BPA-5 well, the main targets are the channelised I50_SS10/20 and I130_SS10/20 sands, which Repsol estimate contain 12 Bscf. These reservoirs have a mixture of structural and stratigraphic components and the trap is identified using seismic amplitude data.

Repsol have identified that an additional 52 Bscf of hydrocarbons may be present in the I30, I68, I70, I80, I130, J21, J55 sands, although these are considered to be secondary targets.

To review the potential BPA-G volumes, RPS initially looked at the Repsol Petrel™ project for the Bunga Pakma field[24]. This contained map-based volumetrics for the primary I50_SS10/20 and I130_SS10/20 BPA-G targets and Repsol confirmed that they had not created a static model for this potential infill well.

[24] MY_IPM_PM3-PDR-Pakma_201905_Petrel IV2019.pet

Surfaces used in the volume estimation are correctly snapped to wells and the well tops look reasonable and consistent across the Pakma Field (BPA-1, 2, 3, 4, 5 and BP-1) as shown in Figure 5.32.

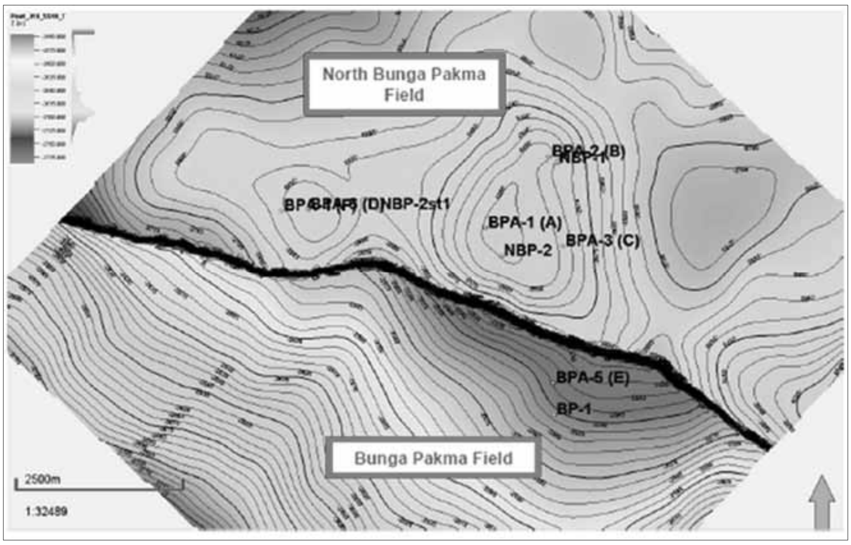


Figure 5.32: Bunga Pakma Field[25]

Reservoir parameters used for the calculation are derived from the BP-1 and the BPA-5 wells, which are located down dip from the potential BPA-G target area (Table 5.19). RPS did not undertake any additional petrophysical analysis to verify these numbers, but they look reasonable compared to nearby field average values (Table 5.20) and average log values presented in the Petrel™ project.

Reservoir Group	PHIE (%)	NTG (%)	SW (%)	Thickness (m)	GRV (Acreft)	Bg (stb/MMscf)	GIIP (Bscf)
I50_SS20	19	60 – 80	30	5 – 11	3.15 – 8.22 – 39.54	0.87	3 – 6 – 28
I130_SS10	18	70	40	16	1.87 – 8.79 – 26.27	0.833	1 – 6 – 18

Table 5.19: Repsol Map Based Volumetric Inputs

Reservoir	Porosity (%)	Permeability (mD)
G	18 - 26	6 - 421
H	15 - 29	2 - 961
I	11 - 27	1 - 533
J	11 - 20	1 - 195
K	11 - 21	1 - 894
L	12 - 17	3 - 56

Table 5.20: Repsol Field average values[26]

[25] *Pakma-Infill_BPA_G_I_Sands.pdf - Repsol*

[26] *3.3.3.2.3.2. Bunga Saffron B Volumes (VDR)*

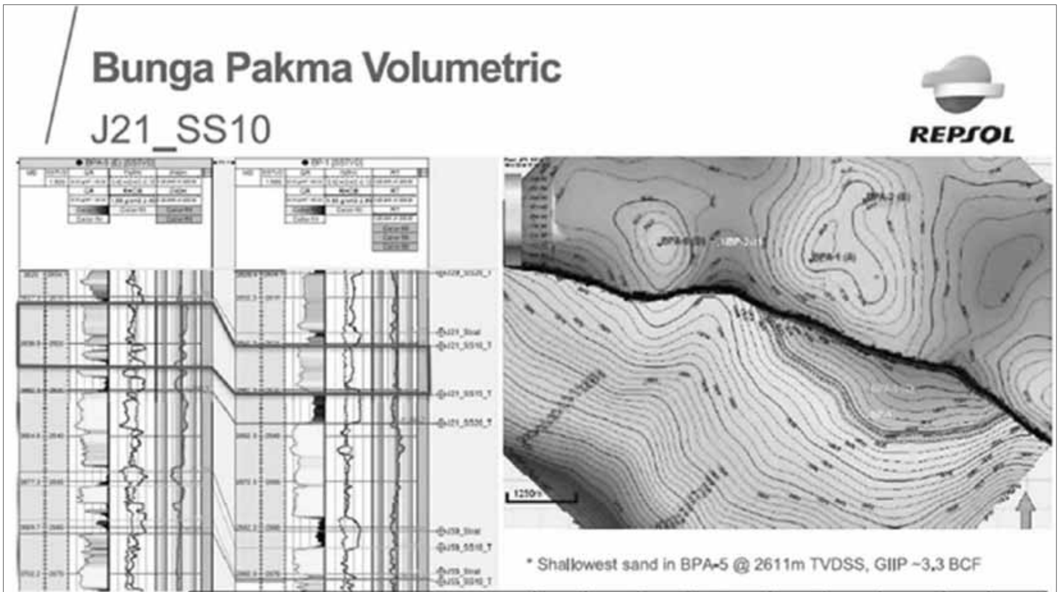
The resultant map-based volume of 12 Bscf match those shown by Repsol in the VDR for the BPA-G primary target[27].

The above primary target volumes are estimated using a series of polygons based on the seismic far stack RAI seismic volume. Correspondence with Repsol indicated that this data was not available within the Petrel™ project[28] and all seismic was available in a separate Petrel™ project.[29]

RPS looked at the Seismic attribute volumes contained within this Petrel™ project[27]. These looked reasonable and the time windows of 10 and 14 ms-1 used to sample the RAI appeared to capture the channels dimensions correctly.

Further interrogation of the Petrel™ project indicated that the secondary targets, which Repsol estimate contain an additional 51 Bscf, do not contain seismic attribute data. Additional correspondence during the PDR with Repsol indicated that these volumes are estimated based on structural closure. However, discussions with Hibiscus based on information in the VDR[25] suggest that this is not quite correct and that the volumes estimated for the secondary targets are based on the shallowest sand seen in the BPA-5 well (Figure 5.33).

Using the VDR data RPS looked at the secondary reservoirs and feel that the input values for their volumetric estimations are reasonable, an example of these for the J21_SS10 reservoir is shown in (Figure 5.33).



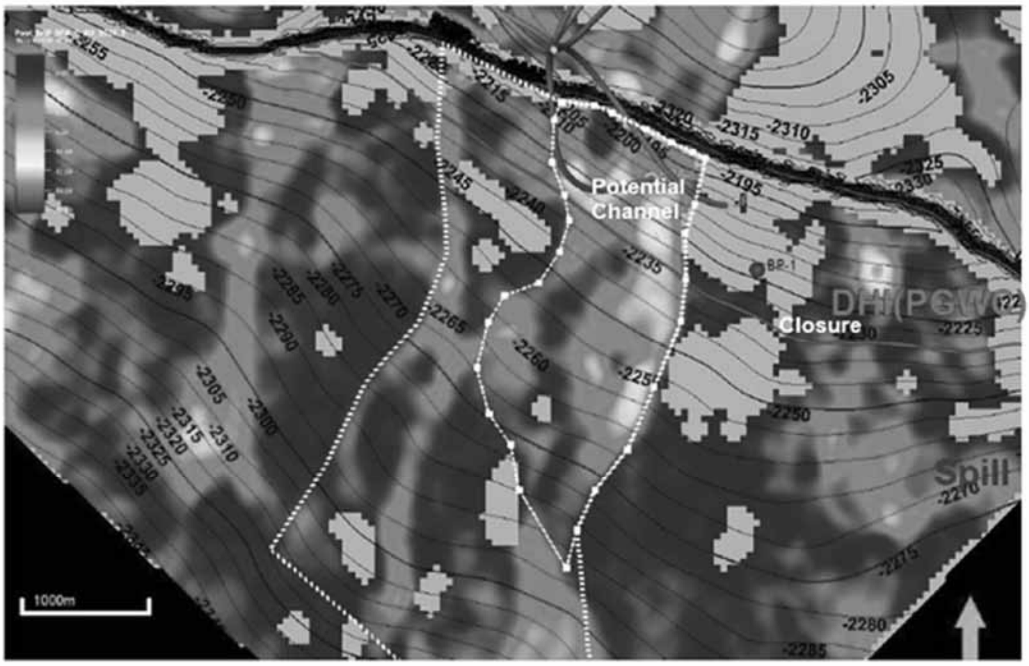
	Reservoir	GRV	GRV	NRV	Phi	Sw	N:G	Lateral Distribution Factor	PV	HCPV	FVF	Free GIIP	Final GIIP
		acre.ft	MMbbl	MMbbl	Fraction	Fraction	Fraction	30%	MMbbl	MMbbl	rb/stb or rb/Mscf	Bscf	Bscf
1P	PostBPA5_J21_SS10_1P_GDT	25730	199.613	101.24	0.11	0.56	0.51	**0.7**	11.13	4.89	1.0302	**4.7**	**3.3**
2P	PostBPA5_J21_SS10_2P_Half	29760	230.878	117.07	0.13	0.46	0.51	**0.7**	15.22	8.22	0.8872	**9.3**	**6.5**
3P	PostBPA5_J21_SS10_3P_WUT	33840	262.531	133.13	0.17	0.36	0.51	**0.7**	22.63	14.51	0.9315	**15.6**	**10.9**

Figure 5.33: J21_SS10 Volumetric Estimation by Repsol

[27] 3.3.3.2.3.6 Pakma G I Sands.pdf

[28] MY_IPM_PM3-PDR-Pakma_201905_Petrel IV2019.pet

[29] MY_MRP_PM3CAA_Well+interpretation_Master_20201207_Petrel2019v.pet



I50_SS20 Depth structure map with FAR RAI attributes

Figure 5.34: Map showing the Potential SS20 Channel within the DHI Closure (shown in red)[30]

In order to estimate independent volumes for the BPA-G infill well and verify those calculated by Repsol a series of RPS independent polygons was draw using the Horizon 536 Pakma Far Interp PSTM AGC DUG 2017 RAI volume for the I50 and I130 reservoirs and due to time constraints one secondary target, the I30, which was used by RPS along with data in the PDR[25] to verify the validity of the secondary targets.

RPS verified the hydrocarbon contacts used by Repsol. These are log based and derived from the BP-1 and BPA-5 wells, which show the gas-water contact on the NPHI/RHOB log. A direct GRV was then estimated for the I30, I50 and I130 reservoirs.

A series of independent probabilistic volumes for the I30, I50 and I130 were estimated by RPS using REP (Table 5.21, Table 5.22 & Table 5.23). The estimation is based upon a direct estimate of GRV calculated from horizons with the Repsol Petrel™ model using the Repsol contacts, within the RPS polygons. Reservoir parameters where based around the petrophysical averages show in Table 5.19 and Table 5.20, which shows Repsol's expected porosity ranges for the Malay Basin Reservoirs.

RPS verified that the tops, surfaces, contacts used in Repsol's volumetric estimations are robust. Reservoir parameters are reasonable and fit within the range of regional reservoir values for the Malay Basin. RPS independent probabilistic volumes are in the same range as those calculated by Repsol for both the primary and secondary reservoir and therefore RPS is happy to accept the in-place values estimated by Repsol for the BPA-G infill well.

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[30] *VDR Management Presentation 2020.12*

I50_SS10	PHIE (%)	NTG (%)	SW (%)	GRV (Acreft)	1/Bg (vol/vol)
P90	11	60	25	3344	205
P50	19	70	30	9267	205
P10	27	80	35	25684	205

Table 5.21: Primary Target I50_SS10 – RPS Probabilistic Inputs

I130_SS20	PHIE (%)	NTG (%)	SW (%)	GRV (Acreft)	1/Bg (vol/vol)
P90	11	60	30	3332	214
P50	19	70	40	8608	214
P10	27	80	50	22236	214

Table 5.22: Primary Target I13_SS20 - RPS Probabilistic Inputs

I30	PHIE (%)	NTG (%)	SW (%)	GRV (Acreft)	1/Bg (vol/vol)
P90	11	40	22	9762	171
P50	17	45	27.5	10792	171
P10	23	50	33	11931	171

Table 5.23: Secondary Target I30 - RPS Probabilistic Inputs

BPA-G Estimated GIIP Volumes (Bscf)

Fault Block	2020 ARPR			RPS		
	Low	Base	High	Low	Best	High
I50_SS10	3	6	28	2	7	22
I130_SS20	1	6	19	2	6	17
I130	3	4	5	3	4	6

1. *Arithmetic sum of all reservoir layers*

Table 5.24: Repsol and RPS Gas Initially In Place Volume Comparison

Reservoir	Expected Channel Reservoir Adjustment	
	Repsol Base	RPS comment
I68_SS05	7.1	Apart from I130 RPS did not verify these independently, but Input values to estimates look reasonable and RPS is happy to accept the ranges reported by Repsol
I68_SS10	4.6	
I70_SS15	4.7	
I80_SS10	2.8	
I130_SS30	5	
J21_SS10	3.3	
J21_SS20	13.9	
J55_SS20	3.3	
J70_SS10	2.6	

Table 5.25: Adjusted Secondary Reservoir In Place Estimations

5.5.2 Saffron B Area Discovery

The Saffron B area was discovered by the NBP-3 (Bunga Saffron-1 and ST1) well in May 2019, which along with the NBO-4 well was part of the PSC extension requirement. The PSC extension was granted in April 2016 for a further 10 years and expires in at the end of 2027.

The Bunga Saffron area is a series of potential stratigraphic and structural traps within the fluvial deposits of the G, H, I and J stratigraphic sections (Figure 5.35). These are picked on seismic attribute data derived from the 2017 Pakma 3D survey, which covers the north western area of the Bunga Pakma field. The Saffron B area, which was evaluated by RPS, comprises the H G50_SS10 and H2_SS10 fluvial channel sands.

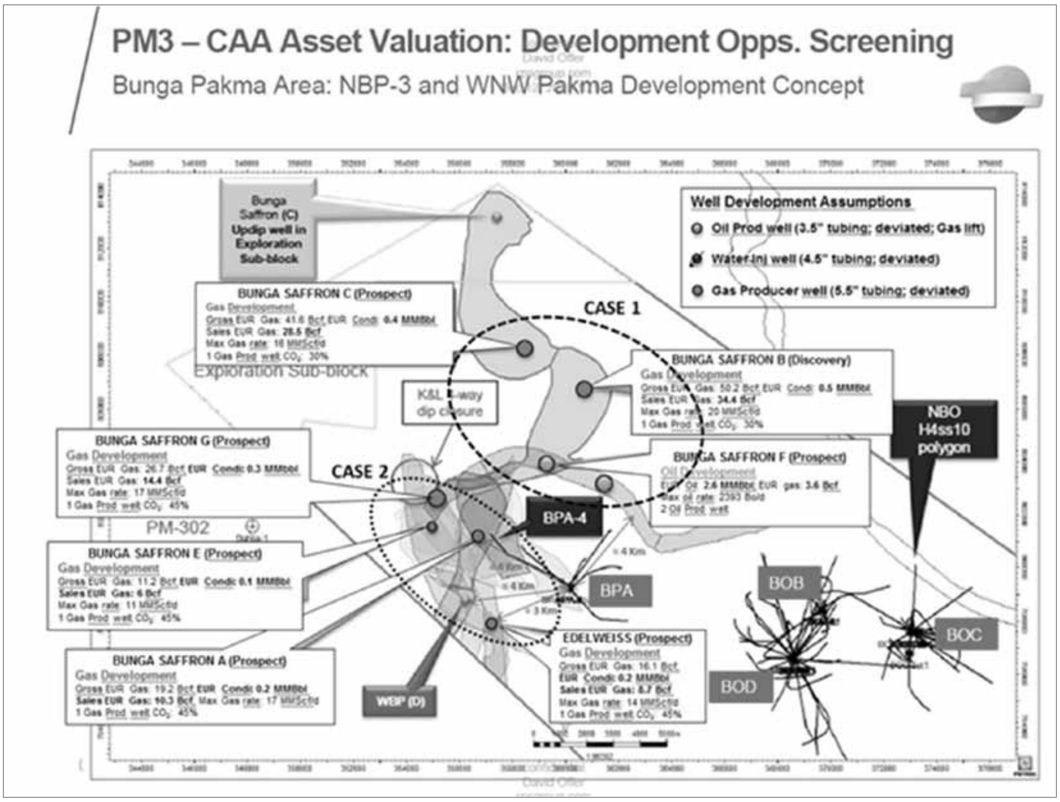

Figure 5.35: Bunga Saffron Prospects and Leads[31]

The Bunga Saffron-1 and ST1 wells both discovered low CO_2 hydrocarbons in the H and I stratigraphic groups, with oil and gas samples taken in the G50_SS10, I30_SS10 and I40_SS10/20 reservoirs.

Repsol have estimated 61 Bscf of hydrocarbons in the Saffron B area, which they plan to develop by installing a new platform that is tied back to the Bunga Pakma A (BPA platform).

The Saffron B discovery is listed in the defined projects presented by Repsol as part of the sale process. However, it is not listed in the Work Program (WP&B) which instead lists an infill well drilled directly from the BPA platform to the Bunga Saffron A prospect. This discrepancy was not noted until late on in the project, subsequently RPS have commented on the Bunga Saffron A prospect based upon available data in the VDR only (Section 5.6.1).

[31] *3.3.3.2.3.2.1 Bunga Pakma Bunga Saffron.pdf - Repsol*

5.5.2.1 Geological Assessment

No Petrel™ modelling project exists for the Saffron B development, though there is a project containing all the seismic and well data[32]. Communication with Repsol confirmed that map based volumes have been estimated with reservoir parameters (Table 5.26) derived from the Bunga Saffron-1 and Bunga Saffron-1ST wells (Figure 5.36).

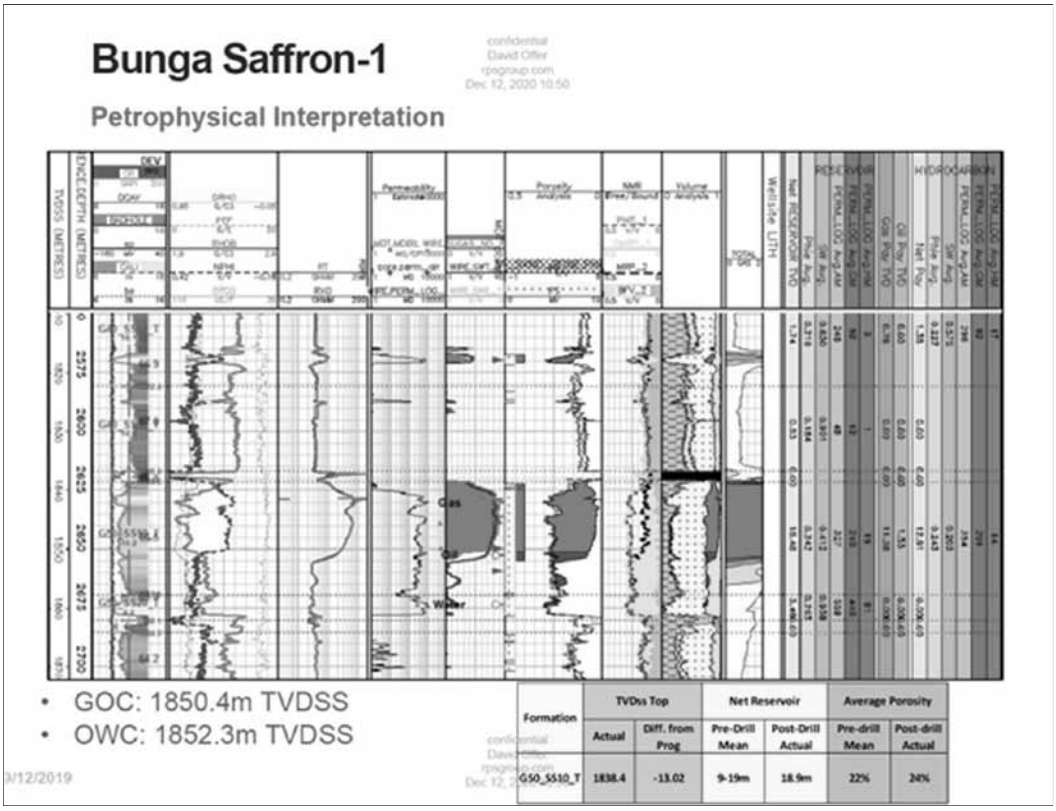

Figure 5.36: Bunga Saffron 1

G50_SS10	PHIE (%)	NTG (%)	SW (%)	Thickness (m)	GRV Gas (Acreft)	GRV Oil (Acreft)
Low	19	1	20	14	33014	4513
Base	24	1	15	18	37393	5996
High	26	1	10	22	38519	6892

Table 5.26: Repsol Saffron B Volumetric Inputs

Well tops and Hydrocarbon contacts are based on the well results and RPS agree with these based on the petrophysical log response in the Petrel™ project.

Hydrocarbons are trapped within a channelised section of the H group and as such are constrained by a series of seismic attribute derived polygons (Figure 5.37). To create its own independent volumetrics RPS

[32] MY_MRP_PM3CAA_Well+interpretation_Master_20201207_Petrel2019v.pet

looked at the Petrel™ project which contains all of Repsol's seismic data and created its own polygons based on the FarRAI (Minimum amplitude from the Pakma far PSTM DUG 2017 16bit(RelAclmp)Horizon 388 seismic attribute for the Saffron B structure at the G50_SS10 horizon.

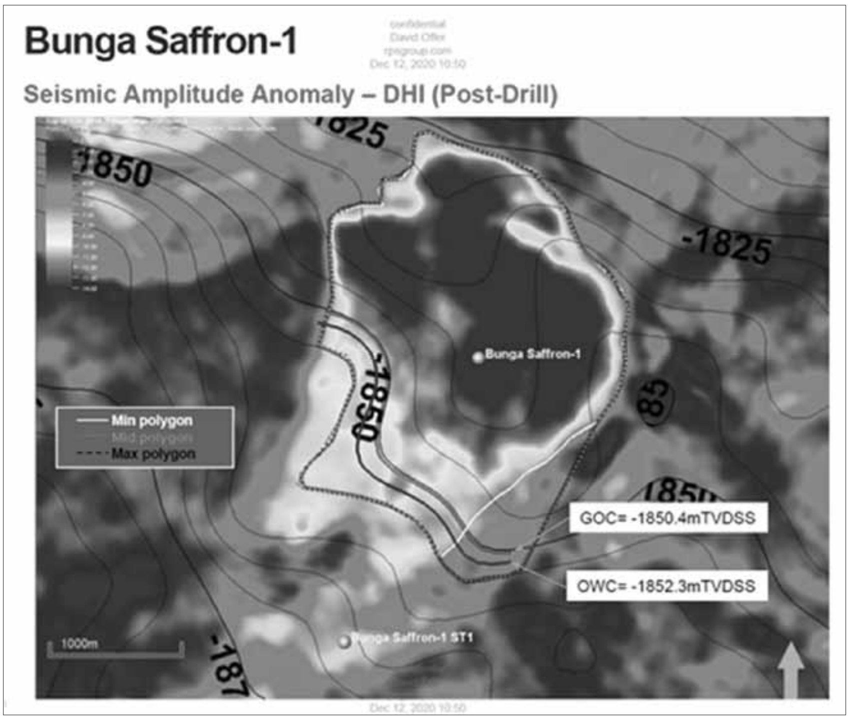

Figure 5.37: Saffron B Seismic (Far Stack) Amplitude Anomaly[33]

A series of GRV's was then calculated using the RPS polygons and the Repsol G50_SS10_T surface for use in the RPS probabilistic volume estimation.

RPS ran a series of independent probabilistic volumes for the G50_SS10 using REP. Reservoir parameters are based around the petrophysical averages show in Table 5.27 which shows Repsol's expected porosity ranges for the Malay Basin Reservoirs (Table 5.28 & Table 5.29).

Reservoir	Porosity (%)	Permeability (mD)
G	18 - 26	6 - 421
H	15 - 29	2 - 961
I	11 - 27	1 - 533
J	11 - 20	1 - 195
K	11 - 21	1 - 894
L	12 - 17	3 - 56

Table 5.27: Malay Basin Reservoir Porosity Values[34]

[33] *3.3.3.2.3.2.4 Bunga Saffron PRG Review 12092019 DCR.pdf*

[34] *3.3.3.2.3.2.Bunga saffron B Volumes (VDR)*

G50_SS10 - GAS	PHIE (%)	NTG (%)	SW (%)	GRV (Acreft)	1/Bg (vol/vol)
P90	22	90	10	32,834	162
P50	24	94	15	36,117	186
P10	26	99	20	39,729	210

Table 5.28: GAS G50_SS10 – RPS Probabilistic Inputs

G50_S10	PHIE (%)	NTG (%)	SW (%)	GRV (Acreft)	1/Bo (vol/vol)
P90	22	90	30	3,522	1.3
P50	24	94	36	4,450	1.4
P10	26	99	42	5,623	1.5

Table 5.29: OIL G50_SS10 - RPS Probabilistic Inputs

Saffron B Estimated GIIP Volumes (Bscf)

	2020 ARPR			RPS		
	Low	Base	High	P90	P50	P10
G50_SS10	35	61	82	46	56	67

Table 5.30: Repsol and RPS Gas Initially In Place Volume Comparison

RPS verified that the tops, surfaces and contacts used in Repsol's volumetric estimations are robust. Reservoir parameters are reasonable and fit within the range of regional reservoir values for the Malay Basin. RPS independent probabilistic P50 volumes are in reasonable agreement with those calculated by Repsol.

5.5.3 Bunga Orkid Infill Well (2022)

This development consists of drilling one deviated infill oil producer that penetrates the I-75ss10, J-50ss10 and K-25ss10 reservoirs to improve hydrocarbon recovery and boost production with first oil planned for the fourth quarter in 2022. The Repsol has completed subsurface studies and states that further optimisation of the program is underway to unlock further this upside opportunity, as well as seeking approval from the relevant stakeholders.

Figure 5.38 shows the planned well location for the three reservoirs together with existing wells, BO-1, BOC-8STI, BOC-10 and BOC-17. The infill well will be drilled from the BO-C platform and will include the installation of a flow line. The current plan is for a dual completion with I-75ss10 completed via the short string and the J-50ss10 and K-25ss10 co-mingled and completed in via the long string.

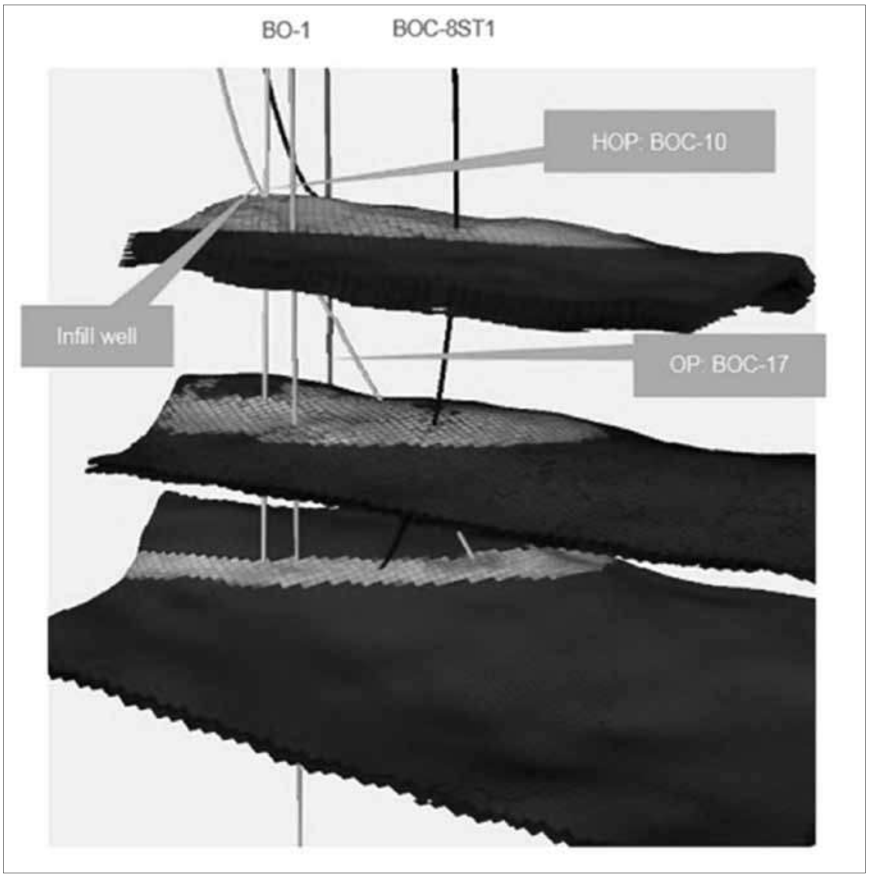

Figure 5.38: Bunga Orkid Infill Location[35]

5.5.3.1 Bunga Orkid Infill I-75 Reservoir

The BOCI75 reservoir simulation model was reviewed by RPS in the PDR and various screen captures and output files were obtained for later analysis. Key reservoir parameters for the model are outlined in Table 5.31 and Figure 5.39 illustrates the permeability distribution for the model. The figure indicates a reasonable permeability range; however, the maximum value of 12,008 mD which is 234 times the mean value and is considered unreasonable.

[35] *VDR Management Presentation 2020.12*

Property	Low	Best	High
Grid Dimensions (x,y,z)	168 x 179 x 86		
DX Dimensions (ft)	149	163	171
DY Dimensions (ft)	Similar to DX		
DZ Dimensions (ft)	1.43	1.74	2.00
Total Cells	2,586,192		
Active Cells	235,516		
Average Porosity (fraction)	0.13	0.15	0.18
Average Horizontal Permeability (mD)	13.5	51.2	118.4
Average Vertical Permeability (mD)	1.35	5.12	11.84
PERMZ/PERMX Ratio		~0.10	
	Start		**End**
History Match Period	26th July 2009		31st October 2019
Prediction Period	2nd September 2019		1st January 2051
Infill Development First Oil		1st March 2022	

Table 5.31: Repsol's Bunga Orkid Infill (I-75) Reservoir Dynamic Model Properties

The model is a bit stale as the history match is up to 31st October 2019, but this is only a very minor concern. The results of the history match have not been presented by the Repsol and the RSM files lacked the actual production data; thus, RPS is unable to comment on the quality of the history match. Secondly, the history match was conducted on a daily basis which is rather unusual and computationally inefficient.

The first prediction run, which consists of the infill well plus water injection via the BOC-17 (named BOD-17 in the model) starting 1st March 2022, and does not have any numerical issues or significant fluid material balances errors. The second prediction case consists of the infill well plus water injection and also does not have any numerical issues or significant fluid material balances errors.

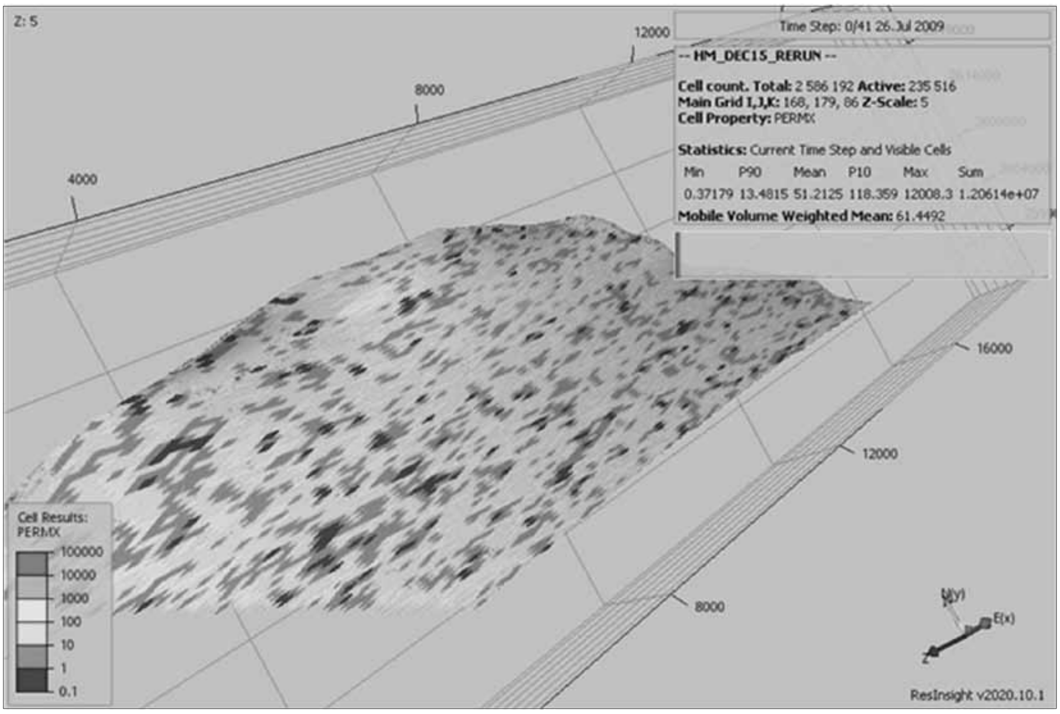

Figure 5.39: Repsol's Bunga Orkid Infill (I-75) Reservoir Dynamic Model Permeability Distribution

In general, apart from the few cells with very high permeability, the model appears reasonable in terms of the input parameters, which is to be expected, as the model has been through the PETRONAS MPM project milestone review process.

As mentioned previously a total of three cases were provided in the PDR; a history match case, a No Further Activity ("NFA") prediction case that includes water injection, and the prediction case with the infill well and water injection. Figure 5.40 shows the well locations for the existing wells and the infill well (LOC_5).

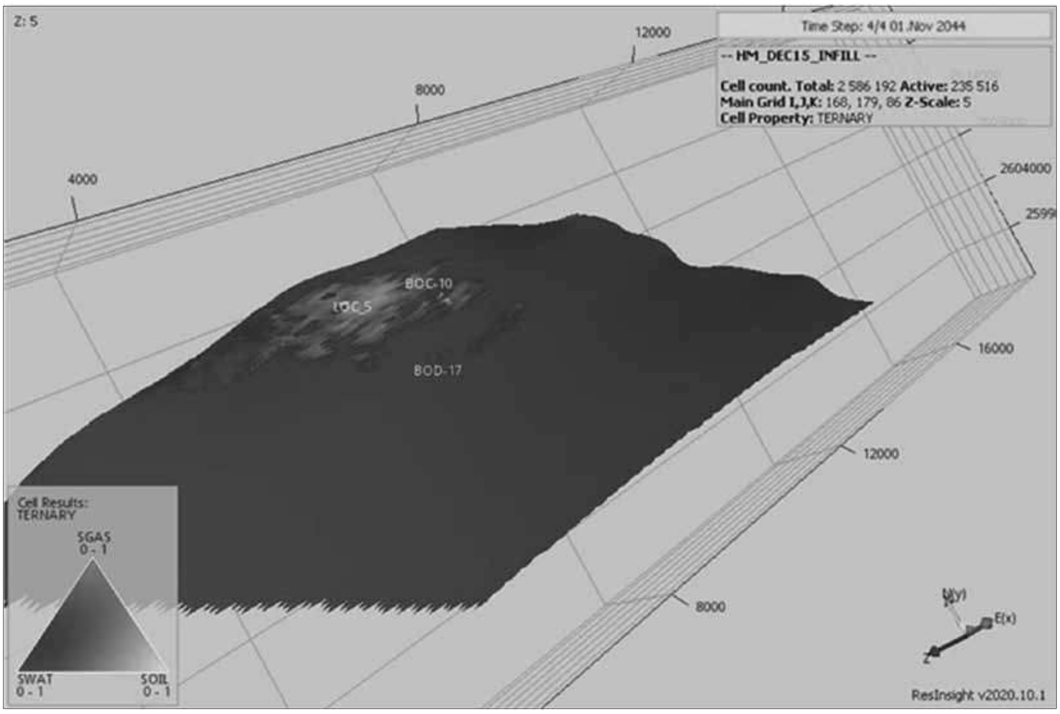

Figure 5.40: Repsol's Bunga Orkid Infill (I-75) Reservoir Dynamic Well Locations

The results of the infill case only are tabulated in Table 5.32 for oil and Table 5.33 for gas; the oil profiles are also depicted in Figure 5.41. Note that the figure suggests that the history match for the existing well has some issues as the well maintains a plateau as oppose to declining on trend as per the history match period. This may also indicate that the infill well's initial oil rate is also too optimistic.

			Production End Date	
Scenario	**Property**	**Unit**	**2027**	**2042**
NFA	STOIIP	(MMstb)	14.659	
	Recovery Factor	(percent)	29.4%	32.9%
	Recoverable	(MMstb)	4.312	4.823
	Production	(MMstb)	3.259	
	Remaining	(MMstb)	1.053	1.564
Prediction	STOIIP	(MMstb)	14.659	
	Recovery Factor	(percent)	31.9%	36.0%
	Recoverable	(MMstb)	4.679	5.277
	Production	(MMstb)	3.259	
	Remaining	(MMstb)	1.420	2.018
Incremental	Incremental Remaining	(MMstb)	0.367	0.454

Table 5.32: Repsol's Bunga Orkid Infill (I-75) Reservoir Dynamic Model Results Summary (Oil)

Scenario	Property	Unit	Production End Date 2027	Production End Date 2042
NFA	GIIP	(Bscf)	12.662	
	Recovery Factor	(percent)	48.9%	65.5%
	Recoverable	(Bscf)	6.192	8.291
	Production	(Bscf)	3.638	
	Remaining	(Bscf)	2.554	4.653
Prediction	GIIP	(Bscf)	12.662	
	Recovery Factor	(percent)	53.8%	70.2%
	Recoverable	(Bscf)	6.806	8.890
	Production	(Bscf)	3.638	
	Remaining	(Bscf)	3.168	5.252
Incremental	Incremental Remaining	(Bscf)	0.615	0.599

Table 5.33: Repsol's Bunga Orkid Infill (I-75) Reservoir Dynamic Model Results Summary (Gas)

The 1st January 2020 ARPR states the STOIIP to be 7.29, 8.87 and 10.79 MMstb for Low, Best and High estimates for the I75_SS10_Oil reservoir and these volumes are all below the model's STOIIP volume of 14.659 MMstb. The VDR[36] states that STOIIP has increased from 8.96 to 14.2 MMstb, but the Low and High STOIIP estimates are not stated. The increase in STOIIP is not unreasonable as using the ARPR's STOIIP volume of 8.87 MMstb times a recovery factor of 36% gives 3.193 MMstb, which is less than the model's history match produced volume of 3.231 MMstb as of 31st October 2019. RPS has therefore used the reported STOIIP of 14.2 MMstb for the Best case.

In terms of the oil recovery factor, the values appear reasonable based on a water flood drive mechanism, although constantly injecting 400 stb/d of water is likely not the best strategy.

[36] *3.3.3.2.1.1 BOC Infill*

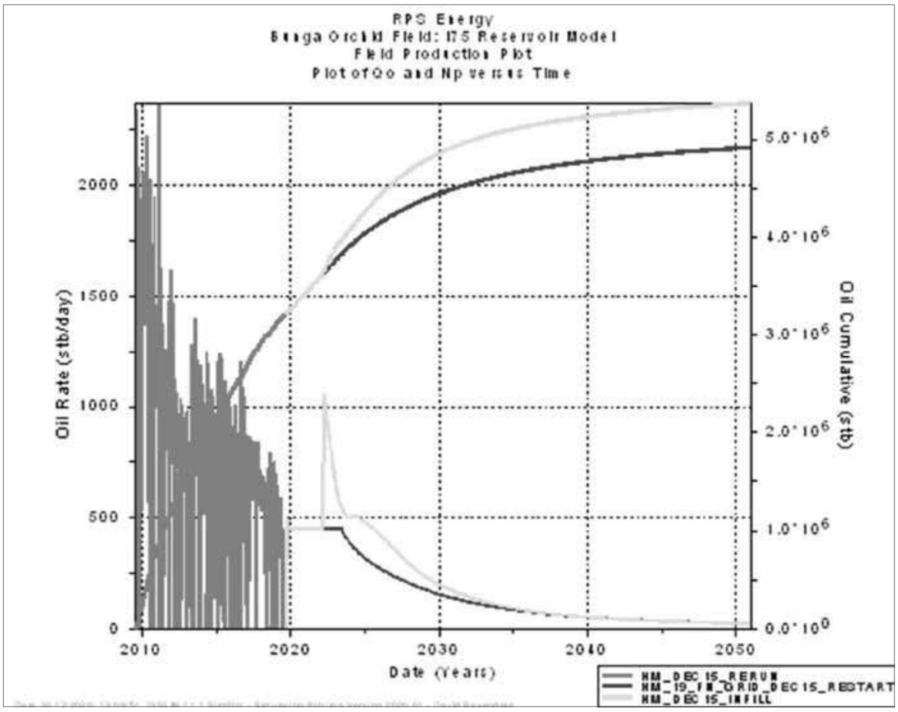

Figure 5.41: Bunga Orkid Infill (I-75) Reservoir Dynamic Production Profiles

Based on the above, RPS has chosen to use the provided model as the Best case and to rescale the profiles based on the 2042 incremental volumes as outlined in Table 5.34. For the Low and High scenario RPS used ± 0.100 MMstb.

Property	Unit	Low	2042 Best	High
STOIIP	(MMstb)		14.2	
Recovery Factor	(percent)		36.0%	
Recoverable	(MMstb)		5.112	
Production	(MMstb)		-3.259	
NFA	(MMstb)		-1.564	
Incremental Remaining	(MMstb)	0.189	0.289	0.389
			2027	
Incremental Remaining	(MMstb)	0.153	0.289	0.389

Table 5.34: RPS's Bunga Orkid Infill (I-75) Incremental Oil Recovery

For the Low and High scenario RPS used ± 0.100 MMstb of the Best scenario incremental oil recoverable volume. All the incremental production is produced within the PSC license period.

5.5.3.2 Bunga Orkid Infill J-50 Reservoir

The BO J-50 reservoir simulation model was reviewed by RPS in the PDR, together with various screen captures and output files that were obtained for later analysis. Key reservoir parameters for the model are outlined in Table 5.31 and Figure 5.39 illustrates the permeability distribution for the model. The figure indicates a reasonable permeability range with the maximum value of 1,078 mD being approximately seven times the mean, which is not unreasonable.

Property	Low	Best	High
Grid Dimensions (x,y,z)		230 x 152 x 56	
DX Dimensions (ft)	139.6	162.2	176.8
DY Dimensions (ft)		Similar to DX	
DZ Dimensions (ft)		~2.30	
Total Cells		1,957,760	
Active Cells		100,716	
Average Porosity (fraction)	0.13	0.15	0.18
Average Horizontal Permeability (mD)	6.5	148.8	389.0
Average Vertical Permeability (mD)		14.88	
PERMZ/PERMX Ratio		~0.10	
	Start		**End**
History Match Period	6th September 2010		30th September 2019
Prediction Period	19th September 2019		31st December 2035
Infill Development First Oil			

Table 5.35: Repsol's Bunga Orkid Infill (J-50) Reservoir Dynamic Model Properties

The model is a bit stale as the history match is up to 30th September 2019, but this is only a minor concern. The results of the history match have been reviewed and the results are questionable with respect to water, with the model under predicting the water production by as much as 50%. Secondly, the history match was conducted on a daily basis which is rather unusual and computationally inefficient.

BOC-17 is the current producing well and production has been co-mingled from 5th October with J18ss10 reservoir. Production from the J-50 reservoir by back allocation is approximately 0.22 MMstb (September 2019) and the well was producing at approximately 98% water cut.

The first prediction run is an NFA case, but the BOC well production jumps from virtually nothing to 200 stb/d of oil (see Figure 5.44) and there is nothing in the input deck to support this increase. The VDR[37] material does not include any material on this either, only a history match plot and the infill well performance.

Both the history match and the NFA case runs are numerically stable.

[37] *3.3.3.2.1.1 BOC Infill*

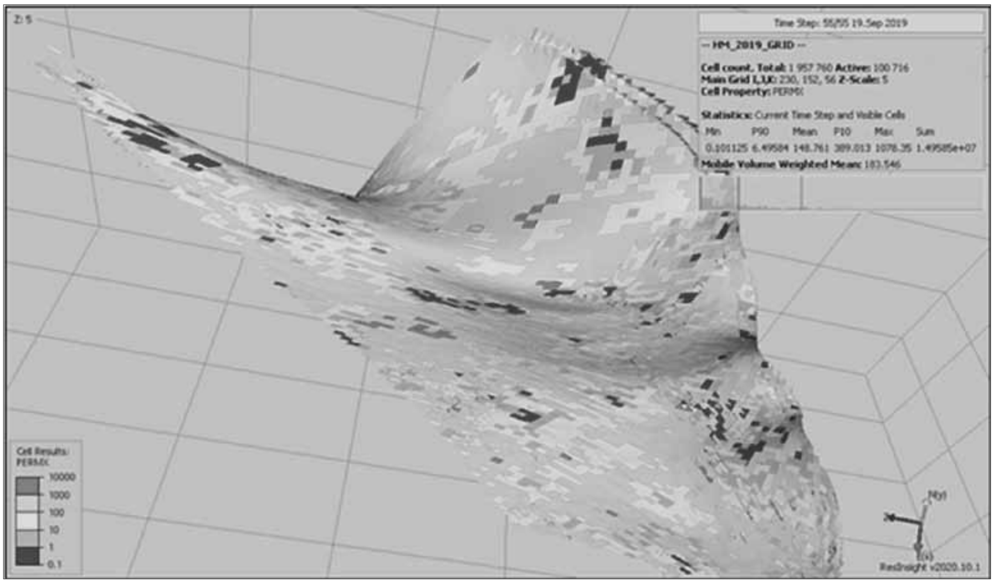

Figure 5.42: Repsol's Bunga Orkid Infill (J-50) Reservoir Dynamic Model Permeability Distribution

In general, the model appears reasonable in terms of the input parameters, which is to be expected, as the model has been through the PETRONAS MPM project milestone review process. However, the well productivity issue makes the model's results questionable. For reference, Figure 5.43 shows the well locations for the existing well and the infill well (Loc_5A).

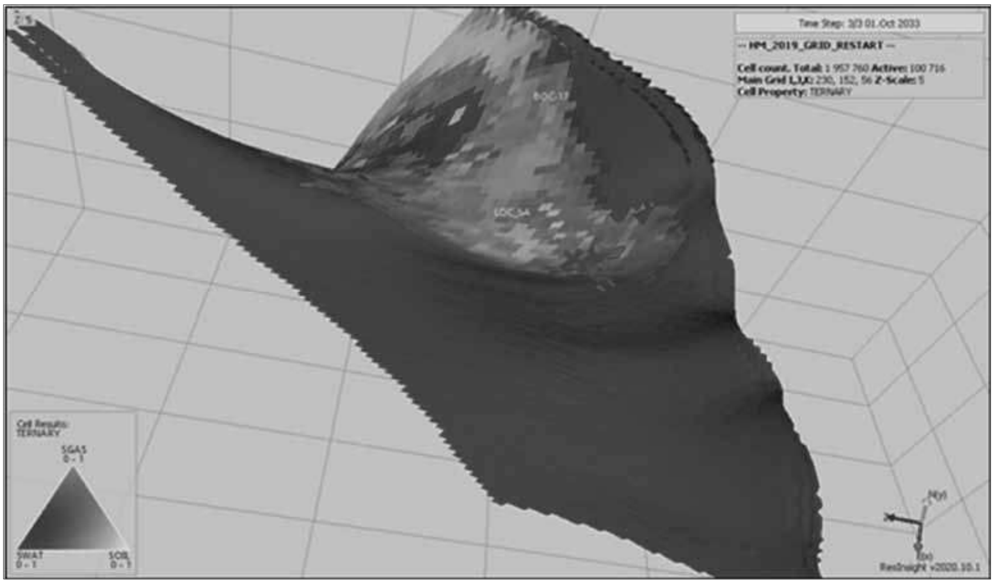

Figure 5.43: Repsol's Bunga Orkid Infill (J-50) Reservoir Dynamic Well locations

The oil profiles for the history match and the NFA case are also depicted in Figure 5.41 for reference.

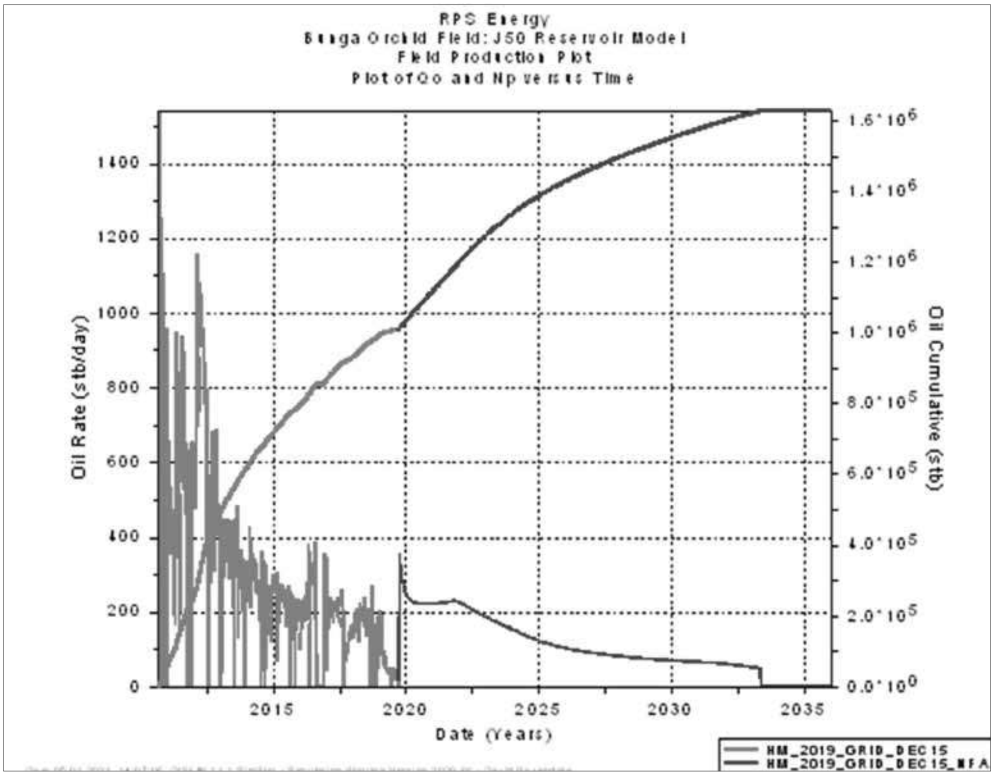

Figure 5.44: Bunga Orkid Infill (J-50) Reservoir Dynamic Production Profiles

Based on this assessment, RPS considers the model results questionable and has therefore elected not to allocate any incremental volumes for this reservoir.

5.5.3.3 Bunga Orkid Infill K-25 Reservoir

The BO K-25 reservoir simulation model was reviewed by RPS in the PDR together with various screen captures and output files that were obtained for later analysis. Key reservoir parameters for the model are outlined in Table 5.36 and Figure 5.45 illustrates the permeability distribution for the model. The figure indicates a reasonable permeability range with a maximum value of 1,097 mD which is 38 times the mean value and would appear perhaps to be unreasonable at first glance.

Property	Low	Best	High
Grid Dimensions (x,y,z)		102 x 106 x 178	
DX Dimensions (ft)	153	167	178
DY Dimensions (ft)		Similar to DX	
DZ Dimensions (ft)	1.5	1.7	1.8
Total Cells		1,924,536	
Active Cells		95,840	
Average Porosity (fraction)	0.12	0.16	0.18
Average Horizontal Permeability (mD)	2.7	28.3	64.2
Average Vertical Permeability (mD)		2.83	
PERMZ/PERMX Ratio		~0.10	
	Start		**End**
History Match Period	8th April 2009		1st January 2020
Prediction Period	2nd September 2019		1st January 2051
Infill Development First Oil		1st January 2020	

Table 5.36: Repsol's Bunga Orkid Infill (K-25) Reservoir Dynamic Model Properties

The model is up to date as the history match is up to 1st January 2020 with a total oil production of 0.149 MMstb and is currently producing 38 stb/d of oil at 69.3% water cut. However, the model has the BOC-8ST1 well producing 38 stb/d of oil from the start of the simulation to the end of the history match period (see Figure 5.47) which is curious. Material in the VDR[38] states that the well failed to produce due to operational issues with mostly water produced. Despite this there has been a pressure drop of approximately 300 psi and we believe the well has been modelled to account for this pressure drop.

The only prediction run, which consists of the infill well, LOC_5, places the well on production starting 1st January 2020, and therefore RPS has time shifted the production profiles. The run only has a few numerical issues and very small fluid material balances errors, giving confidence in the numerical results.

[38] *3.3.3.2.1.1 BOC Infill*

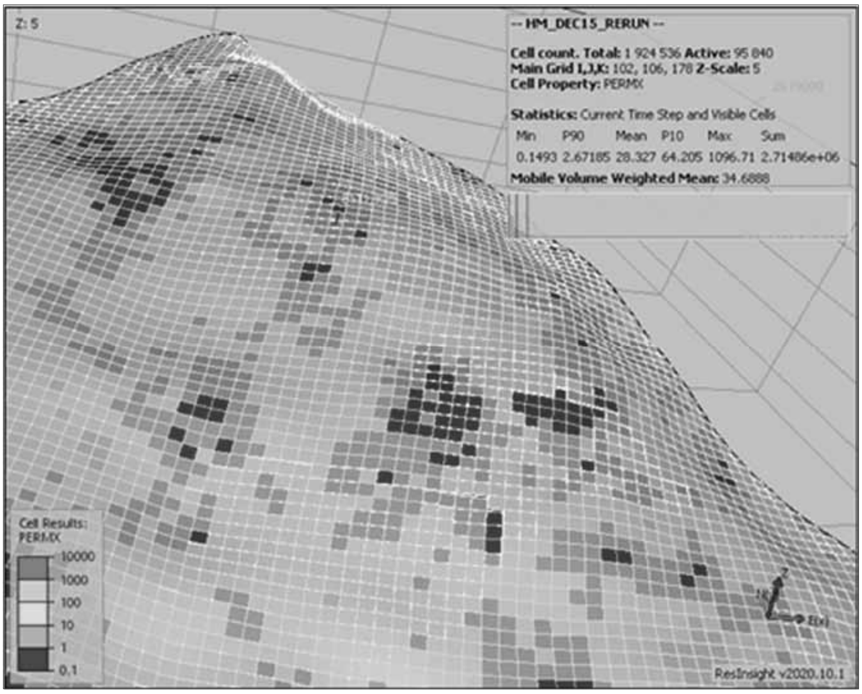

Figure 5.45: Repsol's Bunga Orkid Infill (K-25) Reservoir Dynamic Model Permeability Distribution

In general, the model appears reasonable in terms of the input parameters, which is to be expected, as the model has been through the PETRONAS MPM project milestone review process.

The single prediction case with the infill well (LOC_5) is illustrated in Figure 5.46.

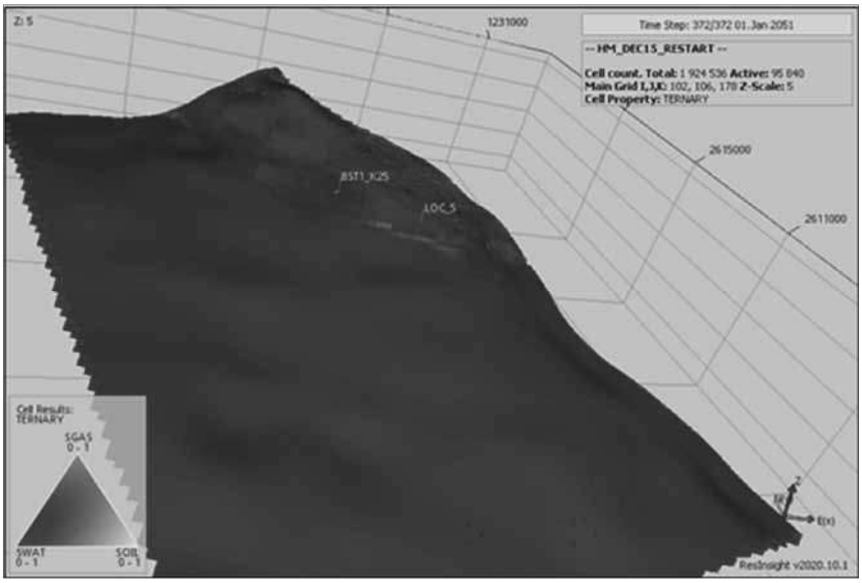

Figure 5.46: Repsol's Bunga Orkid Infill (K-25) Reservoir Dynamic Well locations

The results of the infill case only are tabulated in Table 5.37 for oil and Table 5.38 for gas; the oil profiles are also illustrated in Figure 5.47. RPS notes that the figure indicates an initial oil production rate of 1,000 stb/d and we consider this unrealistic given the history of the reservoir. Additionally, a 19% recovery is very high for a depletion drive only reservoir.

Scenario	Property	Unit	Production End Date 2027	Production End Date 2042
NFA	STOIIP	(MMstb)	2.901	
	Recovery Factor	(percent)	5.1%	5.1%
	Recoverable	(MMstb)	0.149	0.149
	Production	(MMstb)	0.149	
	Remaining	(MMstb)	0.0	0.0
Prediction	STOIIP	(MMstb)	2.901	
	Recovery Factor	(percent)	19.0%	19.0%
	Recoverable	(MMstb)	0.552	0.552
	Production	(MMstb)	0.149	
	Remaining	(MMstb)	0.403	0.403
Incremental	Incremental Remaining	(MMstb)	0.403	0.403

Table 5.37: Repsol's Bunga Orkid Infill (K-25) Reservoir Dynamic Model Results Summary (Oil)

Scenario	Property	Unit	Production End Date 2027	Production End Date 2042
NFA	GIIP	(Bscf)	15.331	
	Recovery Factor	(percent)	1.9%	1.9%
	Recoverable	(Bscf)	0.292	0.292
	Production	(Bscf)	0.292	
	Remaining	(Bscf)	0.000	0.000
Prediction	GIIP	(Bscf)	15.331	
	Recovery Factor	(percent)	63.7%	63.7%
	Recoverable	(Bscf)	9.773	9.773
	Production	(Bscf)	0.292	
	Remaining	(Bscf)	9.481	9.481
Incremental	Incremental Remaining	(Bscf)	9.481	9.481

Table 5.38: Repsol's Bunga Orkid Infill (K-25) Reservoir Dynamic Model Results Summary (Gas)

The 1st January 2020 ARPR states the STOIIP to be 2.413, 2.923 and 3.642 MMstb for the Low, Best and High estimates respectively, and RPS has used these values combined with recovery factors ranging from 7.5% to 15% to determine the recoverable volumes.

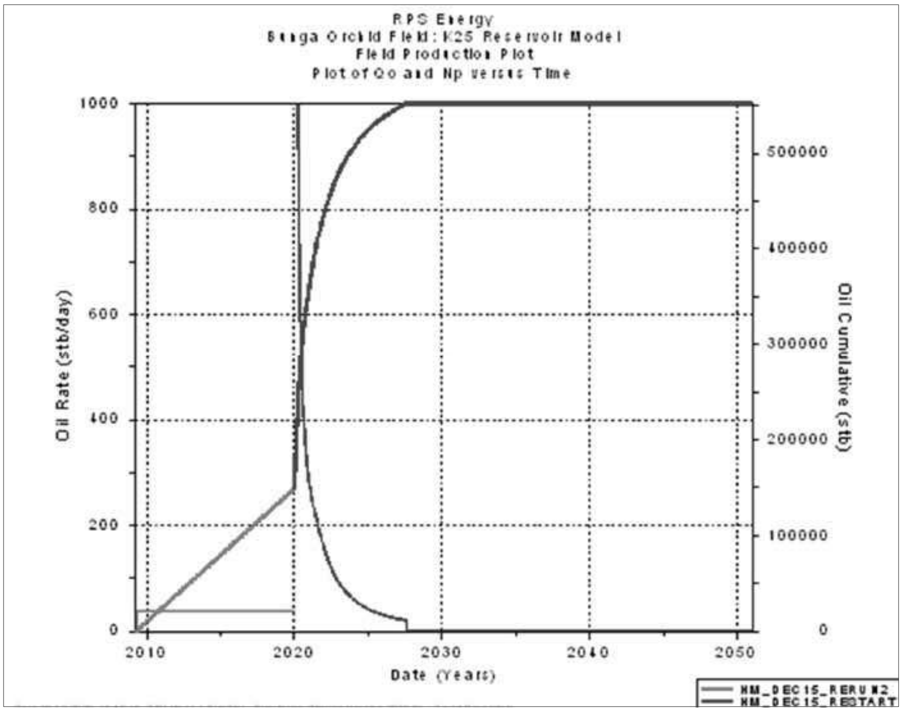

Figure 5.47: Repsol's Bunga Orkid Infill (K-25) Reservoir Dynamic Production Profiles

Based on the above RPS has chosen to use the provided model as the Best case and to rescale the profiles based on the 2042 incremental volumes as outlined in Table 5.39.

Property	Unit	Low	2042 Best	High
STOIIP	(MMstb)	2.413	2.923	3.642
Recovery Factor	(percent)	7.5%	10.0%	12.5%
Recoverable	(MMstb)	0.181	0.292	0.455
Production	(MMstb)		-0.149	
NFA	(MMstb)	0.000	0.000	0.000
Incremental Remaining	(MMstb)	0.032	0.143	0.306
			2027	
Incremental Remaining	(MMstb)	0.032	0.143	0.397

Table 5.39: RPS's Bunga Orkid Infill (K-25) Incremental Oil Recovery

5.5.4 Bunga Kekwa/Bunga Raya Post Seismic

Repsol have identified 3 infill campaigns in East Bunga Raya, West Bunga Raya and Bunga Kekwa, which they notionally plan to drill between 2023 and 2024.

The East Bunga Raya (EBR) and West Bunga Raya (WBR) fields are separated by a large NW-SE trending normal fault (Figure 5.48).

The EBR field is a NW-SE trending fault bounded anticline with reservoirs in the Middle to Lower Miocene. Major oil and gas reservoirs are located in the I and J reservoirs. First oil was in October 2003 and First Gas was in January 2004.

The WBR field is dip closed to the SW, stratigraphically closed to the NE and fault closed to the East. Its major oil and gas reservoirs lie within the I reservoir group, with minor gas in the J reservoirs. First oil was in November 2003 and first gas was in October 2003.

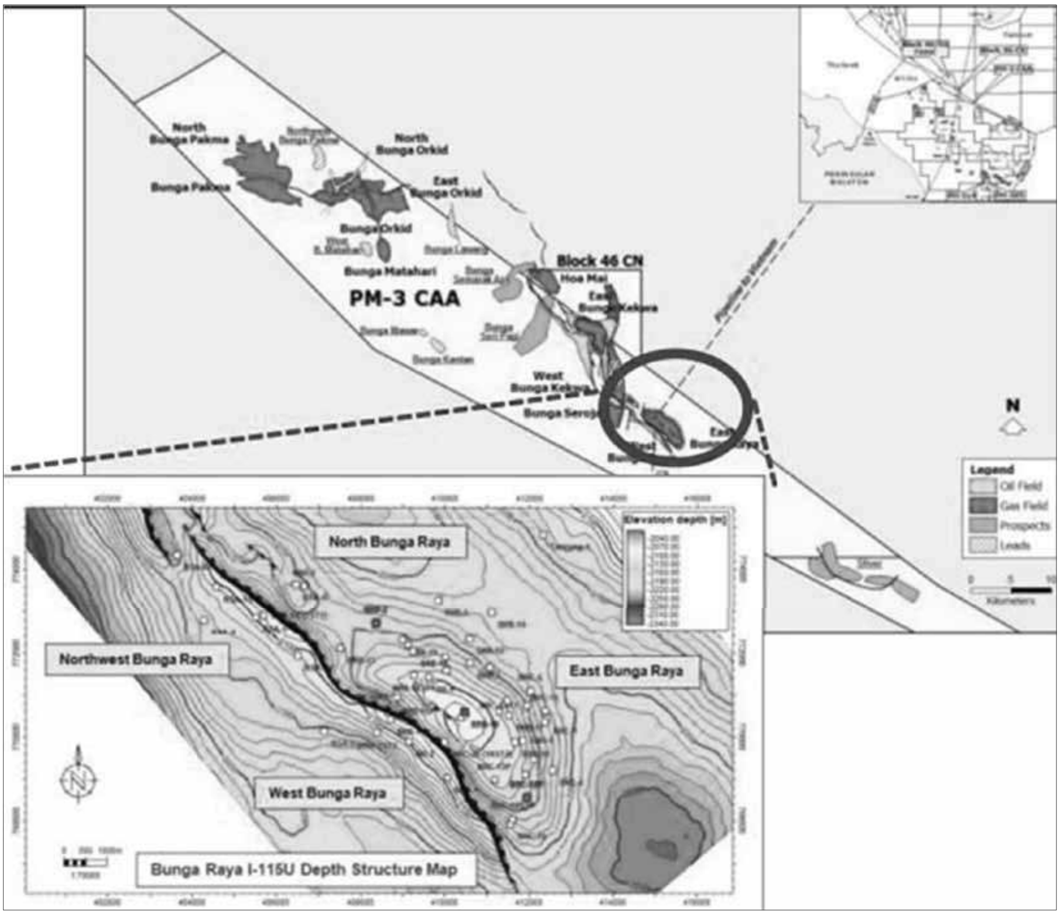

Figure 5.48: Location Map of the Bunga Raya Fields

The East Bunga Kekwa (EBK) Field is a large 3-way dip closed structure, closed to the West by the NW-SE normal fault that separates it from the West Bunga Kekwa field (WBK) (Figure 5.49). First oil was produced in March 2001, whilst first gas was produced in December 2003. The EBK reservoirs comprise Middle to Lower Miocene fluvio-tidal and deltaic reservoirs with major oil and gas reservoirs in the I and H reservoirs and minor gas in the J30 reservoir.

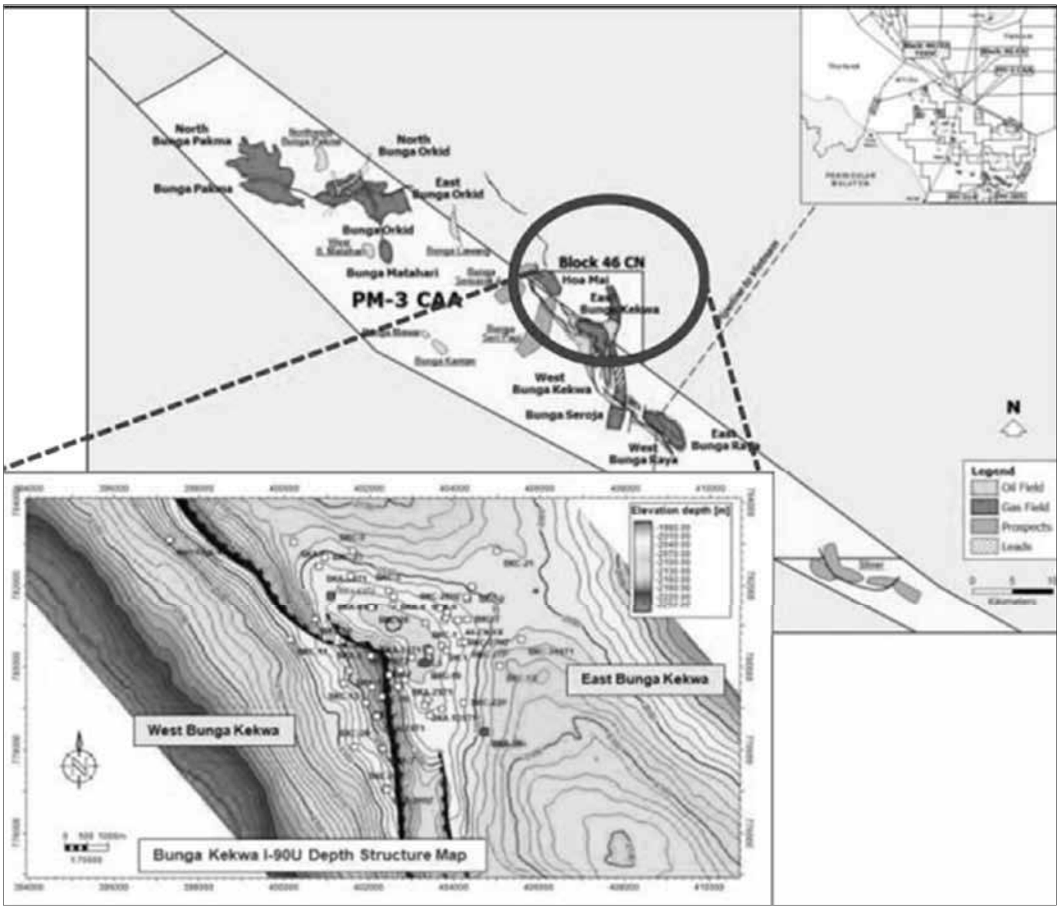

Figure 5.49: Location of the Bunga Kekwa Fields[39]

Repsol have undertaken a statistically driven desk study, looking at the J reservoirs (across the Bunga Raya and Bunga Kekwa fields). Repsol claims that seismic in this area has limitations to identify targets and that the AAI seismic attribute does not correlate with the net sand thickness as the seen elsewhere in the PSC area. RPS could not verify this in the PDR or VDR.

Repsol shot a new 3D seismic survey across this area in 2019 which, they hope will show more detail and allow them to target infill wells and therefore increase the recovery factor of this area. To estimate the potential increase, Repsol has used analogue field data to construct an average oil producer well. They then estimate how many development wells and injectors would be required based upon this.

RPS did not review this study, although feel it is a pragmatic way to assess a possible uplift in recovery factor in the absence of the seismic data. However, until the new seismic data is received, it is clear that it is still at an early phase, with no planned well targets or model. RPS is concerned that for West Bunga Raya and West Bunga Kekwa fields, the proposed possible developments appear to be targeting minor gas reservoirs. Additionally, should the new seismic not give the sufficient uplift in resolution as expected then this scoping study will not help in the placement of wells.

However, EBR J70, EBR J60, and WBR J70 are discovered accumulations. RPS would classify the volumes associated with Raya post seismic as Contingent Resources under project maturity subclass of Development Unclarified and has therefore not considered it further as part of our evaluation. EBK J70 is an undiscovered

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[39] *3.2.3.12.2.1.1.2.3 ARPR1.1.20 East Bunga Kekwa*

accumulation hence the volumes associated with Kekwa post seismic can only be classified as Prospective Resources.

5.5.5 NW Raya Infill

North West Bunga Raya (NWBR) is located in the Southern Field Cluster of the PM3-CAA. Oil production started in October 2003, with first gas in September 2004. Both the PSC and the GSA expire at the end of 2027.

The field is part of the Bunga Raya complex (Figure 5.48), situated in the same NW-SW trending anticline as EBR, which is located to the SE and separated by a stratigraphic barrier. Reservoirs are the same Middle to Lower Miocene aged fluvio-deltaic/tidal sandstones, with major oil reservoirs located in the I50L and I90, major gas reservoirs in the J50, J60 and K8 and minor gas reservoirs in the I10, I50, J70 and K10.

Repsol proposes to drill two infill wells into the I50L sand in 2023, although this has yet to be agreed with PETRONAS or sanctioned further.

The two wells would be drilled from the BR-C platform and confirm and exploit the possible larger extent of the oil rim currently being produced by the BSA-9 well (Hibiscus comments from study of OFM database indicate that this well recently increase oil production) although Repsol currently only book GIIP in the I50L reservoir (Figure 5.50).

Due to PDR time constraints RPS did not look at this proposed project in detail and all comments are based upon the data in the VDR. This VDR data is only presentation based and no well logs, models or seismic data are available to be evaluated properly.

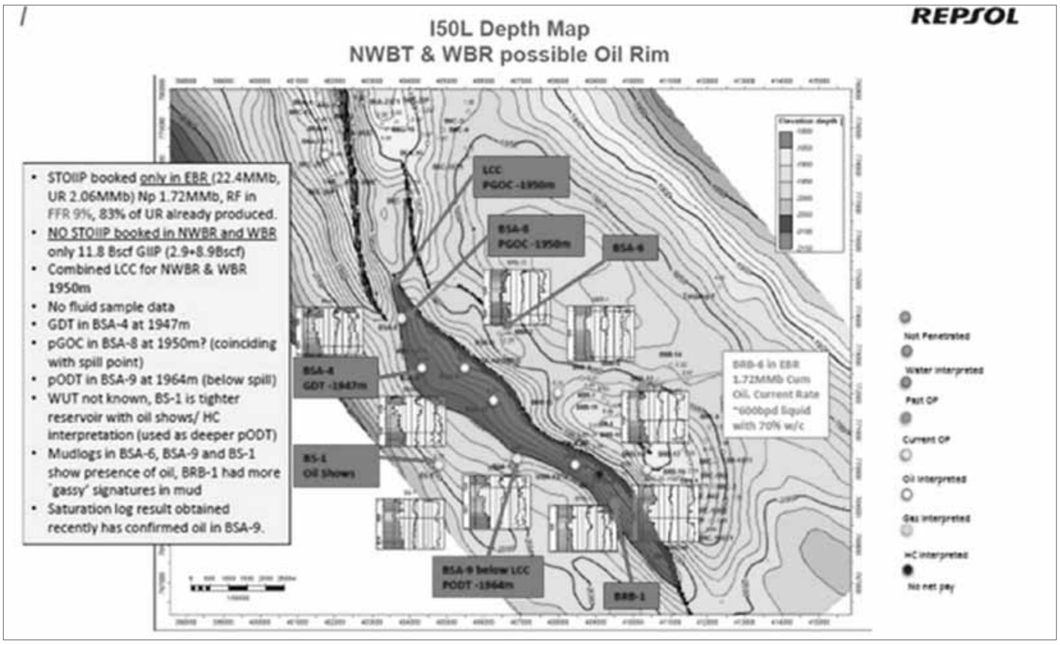


Figure 5.50: NWBR I50 Current Gas Cap Map[40]

Repsol believes that the oil rim is located in an extension of the oil bearing I50L sands already being exploited in East Bunga Raya (EBR). They suggest that this is confirmed by the presence of a possible Gas-Oil Contact (GOC) in the BSA-8 well, which also corresponds to the structural spill point and a possible Oil Down To (ODT) in the BSA-9 well, which is below the structural spill, inferring a stratigraphic trap is present (Figure 5.50).

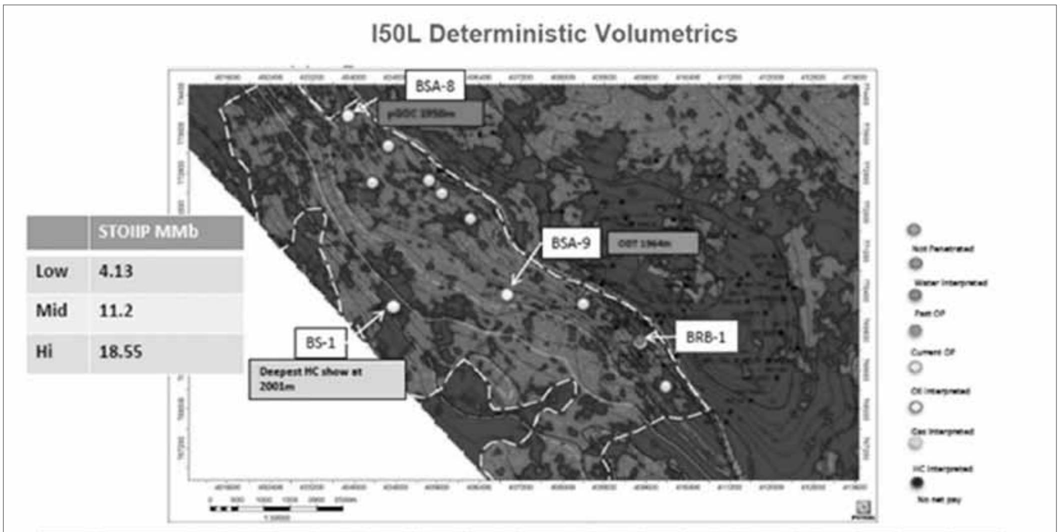
[40] *3.3.3.2.3.8.1 Kekwa Raya Infill.pdf*

To limit the downdip extent of the possible oil rim, Repsol has suggested that oil staining in the dry BS-1 well could show a maximum limit. As no well data was available in the VDR, We are unable to comment further on this.

Amplitude data shown in VDR[41] is replicated in Figure 5.51. This has been used by Repsol to create a series of maximum and minimum polygons for use in volumetric estimations. This shows the potential presence of an oil-bearing reservoir.

It is RPS' view that the high side case down to the BS-1 well is unlikely, based on the lower amplitude seismic response and fact that the BS-1 well was dry with only oil shows. It is possible that the low amplitude response shown corresponds to residual oil and gas, which is not at a commercial concentration.

However, the mid-case and low-case polygons appear reasonable based upon this single picture and have been used by RPS to estimate a range of possible in-place volumes.



Categories	Reservoir	GROSS Average	NTG	PHIE Fraction	SWE Fraction	Fluid Contact	Basis	GRV m3 (Total)	NRV m3 (Total)	PV MMbbl (Total)	HCPV (MMbbl)	FVF bbl/STB or bbl/Mscf	Free GIP (Bscf)	Free OIIP (MMSTB)	Seismic Attribute	Reservoir Polygon
Low	North West Bunga Raya I50L BSA-9	20.62	0.200	0.160	0.540	1930 / 1964	PGOC / ODT	62,420,472	12,484,094	2.00	0.919	1.4	11.46	4.13	Yes	Yes
Mid						1949 / 1933	Halfway / Halfway	169,389,731	33,877,946	5.42	2.493		12.03	11.20		
High						1947 / 2001	ODT / Oil shows OT	280,510,973	56,102,195	8.98	4.129		12.61	18.55		

Figure 5.51: I50L Amplitude and Volumes[40]

Reservoir parameters used in Repsol's volumetric estimations are based upon the EBR and NWBR I50L wells and values look robust. RPS ran a probabilistic volume estimation (Table 5.40), basing ranges around the data given in Figure 5.51.

G50_S10	PHIE (%)	NTG (%)	SW (%)	GRV (m3)	1/Bo (vol/vol)
P90	14	10	50	62,420,490	1.3
P50	16	20	55	102,826,900	1.4
P10	18	30	60	169,389,700	1.5

Table 5.40: RPS Probabilistic Volumetric Estimation Input Values

[41] 3.3.3.2.3.8.1 Kekwa Raya Infill.pdf

It is our opinion, based on the oil production from the BSA-9 well, that an oil rim is present, but not to the extent mapped by Repsol, based on the data seen in the VDR. RPS estimate volumes as shown in Table 5.41.

NWBR Infill Estimated OIIP Volumes (MMStb)

	Repsol[40]			RPS		
	Low	Base	High	P90	P50	P10
I50L	4.13	11.20	18.55	3	6	13

Table 5.41: NWBR OIIP Estimations

RPS would classify the proposed infill well as Contingent Resources and has therefore not considered it further as part of our evaluation.

5.5.6 Hoa Mai Development

Hoa Mai is located next to the Repsol operated Bunga Kekwa field, on the northern flank of the Malay Basin. It straddles the Malaysian PM-3 CAA block and Block 46 in Vietnam (Figure 5.52) and was discovered in 2003 by the Hoa Mai-1X well, which flowed low CO_2 gas at 34 MMscf/d from the H3 stratigraphic group. Although the Hoa Mai-1X well was drilled to a TD of 2,240m TVDss, evaluation of the well results indicated that the H3 is the only hydrocarbon bearing layer in the area. Initial estimates resulted in a 2P GIIP of 92 Bscf booked in the 2004 RAR and two FDP's where submitted shortly after drilling, although both attempts to develop the discovery failed. In 2015, following re-evaluation of the 2015 PM3-CAA mega merged seismic reprocessing, the in-place volume was decreased to 52 Bscf.

A new seismic volume was acquired in the PM3-CAA area, which also covers the Hoa Mai area in Q4 2019. This is currently being reprocessed and has yet to be reinterpreted, although Repsol hoped to commence a new evaluation of Hoa Mai in Q4 2020.

The H3 reservoir is comprised of a series of thin sands within NW-SE oriented tidally influenced estuarine fluvial channels, lain down on a coastal plain. Traps are purely stratigraphic, with no structural component (Figure 5.53).

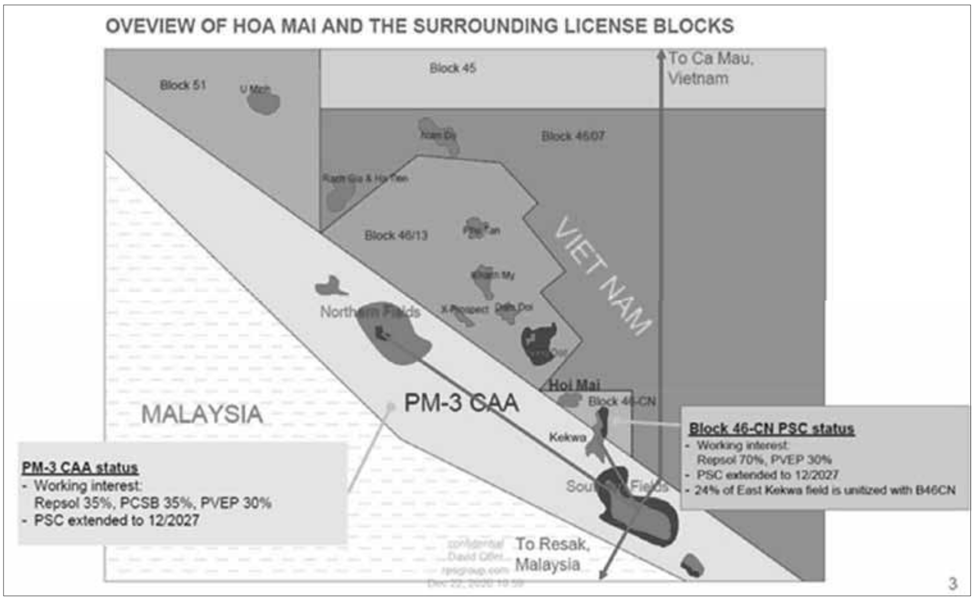


Figure 5.52: Overview of Hoa Mai and the Surrounding Licence Blocks[42]

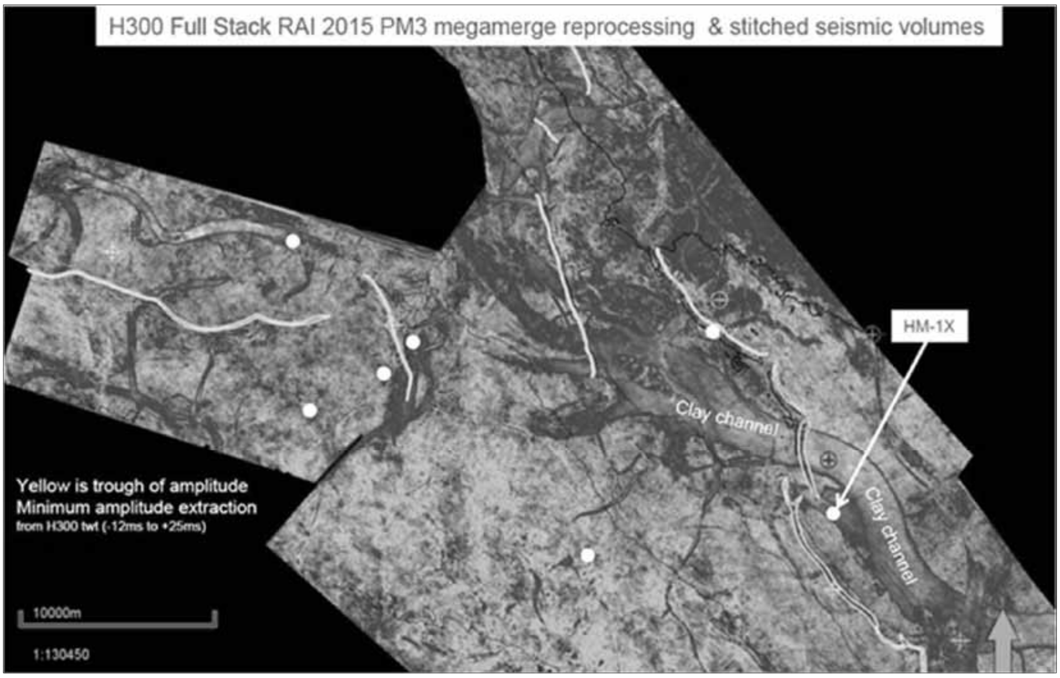


Figure 5.53: Hoa Mai Discovery shown on Full Stack Amplitude Data[42]

Based on nearby wells and seismic amplitude data, Repsol believe that the Hoa Mai reservoir shows as a Direct Hydrocarbon Indicator and polygons to estimate in-place volumes have been constructed accordingly within the model.

The current development plan is to drill an extended reach well directly from the BK-C platform, with first gas expected in 2031, 4 years after the current PSC expires in 2027.

5.5.6.1 Geological Assessment

RPS has looked at the Petrel™ project[43]. This model contained no seismic information, but it did contain seismic interpretation and well data for the Hoa Mai-1X well. We have used the Petrel™ project to verify the volumes estimated by Repsol and as the basis of an independent probabilistic volume calculation.

As seismic data was missing, no independent evaluation of the seismic amplitude extraction could be made. We have therefore evaluated the documentation in the Virtual data room in order to comment on the robustness of the polygons used in the Petrel™ model.

Based on seismic amplitude data, Repsol believe that the Hoa Mai reservoir shows as a Direct Hydrocarbon Indicator based upon the seismic response of gas bearing and water bearing sands. This has been used to construct polygons to estimate in-place volumes within the model.

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[42] *3.3.3.2.3.7.1 Hoa Mai Update - Repsol*

[43] Haomai.pet

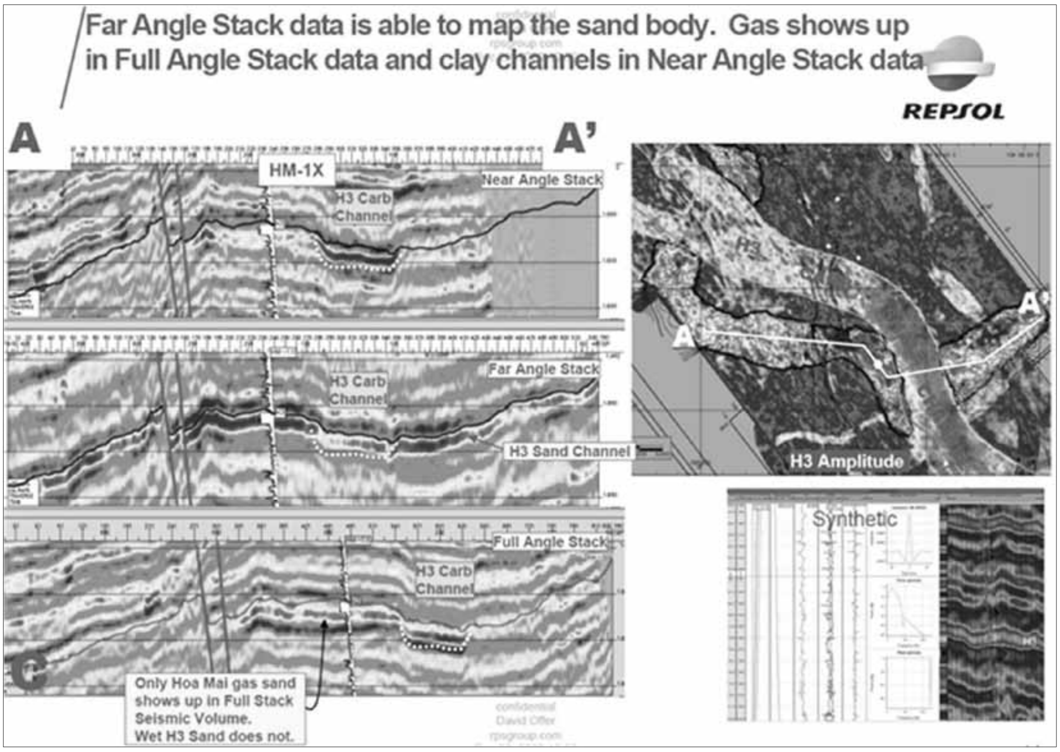

Figure 5.54: Repsol Seismic Amplitude Responses over Hoa Mai [42]

Figure 5.54 shows the different seismic responses between the Near Angle stack, Far Angle stack and Full Angle stack data. Repsol claim that the clay bodies show up in the Near angle stack (darker reds). The sand bodies are shown in the Far angle stacks (darker reds) and gas shows up in the Full angle stack (Brighter reds). This is shown to greater effect when the data is viewed as a time slice. In Figure 5.55 the sandier channel system, on the right is clearly shown by the Far stack data, whilst the Full stack data doesn't show the water bearing channels.

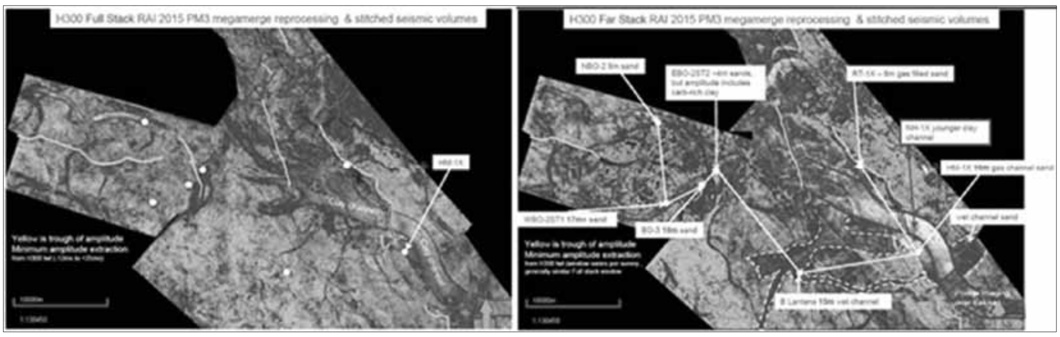

Figure 5.55: Time Slice showing Full Stack and Far Stack Amplitude Data[42]

Without additional information to verify this, we have accepted that a difference can be seen between the amplitude responses and, importantly, the H3 sand channel seen in the Far angle stack data becomes opaque in the full stack. However, it is advised that this is carefully revised upon receipt of the new seismic data.

Volumes are estimated using the 3D_grid_(ADP2016) model grid. This a very basic model constructed around the Hoa Mai-1X well.

Input depth surfaces

All the depth maps are consistent and tie to the well. Although no description of depth conversion has been seen by RPS, a spot-check an average velocity map was created and showed a smooth velocity trend, indicating that the applied depth conversion was appropriate. No depth sensitivities have been run in this model.

Structural Well data

Well tops looked robust compared to the well log data for the 1 well in the model (Hoa Mai-1X).

Petrophysical Well data

No independent petrophysical evaluation has been carried out by RPS during this evaluation. Well logs in Petrel™ looked reasonable and matched available core data that was loaded to Petrel™ for porosity. Average values matched those reported by Repsol[44].

Net to Gross

Has not been modelled and Repsol use a value of 1, indicating that they believe the entire reservoir is a clean sand. We think that this is highly unlikely in such a mud rich environment and shale lenses would be expected within the sands.

Facies

A facies model has not been constructed.

Porosity modelling

Porosity was upscaled directly from the input PHIE_PP petrophysical log and this appears good. Porosity is modelled using sequential Gaussian simulation, it has not been conditioned to other data such as facies or seismic attributes. The variogram for distribution is the Petrel™ default of 2000 by 1000, although an NW/SE azimuth has been applied to be consistent with the prevailing channel direction.

Contacts

No hydrocarbon contact was observed in the Hoa Mai-1x well. Repsol use a contact of -1706m TVDss based on the saturation height function, which is 1m lower than the LKG / base of the H3 reservoir at -1705.16m TVDss. RPS are not comfortable with this method and have used a contact from -1705m TVDss the LKG to -1707m TVDss.

Repsol reports a 1/Bg value of 141. Without additional data to contradict these numbers, they were used in the volume estimations by RPS.

We have run a series of independent probabilistic volumes using the 3D_grid(ADP2016) grid to estimate a direct GRV using the Repsol Polygons. Reservoir parameters where taken from the petrophysical averages show in Table 5.42.

Reservoir Group	PHIE (%)	NTG (%)	SW (%)	GRV (Acreft)	1/Bg (V/V)
P90	22	80	0.17	41088	141
P50	24	90	0.24	43736	141
P10	27	99	0.32	52566	141

Table 5.42: Hoa Mai – RPS Probabilistic Inputs

[44] 3.3.3.2.3.7.1 Hoa Mai date.pdf

Hoa Mai Estimated GIIP Volumes (Bscf)

Reservoir	2020 ARPR			RPS		
	Low	Base	High	P90	P50	P10
H3	47	52	57	36	44	52

Table 5.43: RPS Probabilistic OIIP Estimations

The resultant RPS probabilistic in-place estimation is compared in Table 5.43 to the cases previously run by Repsol using the Hoa Mai Petrel™ project and those reported by Repsol as part of the Information Memorandum. It should be noted that the difference at P50 of 8 Bscf is derived by RPS using a lower NTG and should a NTG of 1 be used by RPS then we estimate a P50 of 50 Bscf, in line with Repsol.

The volumes presented in the VDR Information Memorandum are consistent with the range estimated by the Petrel™ model, although RPS calculates a slightly lower set of values.

As there is no current plan to develop the discovery, RPS would currently classify this as Contingent Resources (On Hold). As a result, RPS has not examined the discovery further nor generated any production forecasts.

5.5.7 East Bunga Raya Electrical Submersible Pump ("ESP") I-120 Reservoir

This development is part of the two proposed PM3 ESP projects, one well each in Bunga Raya and in Bunga Orkid. This pilot project aims to enhance production which could potentially add reserves and optimise the current gas lift consumption as well as to diversify from the current artificial lift system of gas lift in this mature asset. Repsol expects to recover an additional 1.5 MMboe of oil from both wells, with first production scheduled in 2023. At the moment, Repsol is updating subsurface studies with additional production and seismic input data and conducting detailed engineering design studies to progress the project.

There are two oil producers in the field (BRB-2L and BRB-5L) with only the BRB-2L producing and one water injection well 18ST_1 which is also shut-in at the end of the history matching period, but restarted at the start of the prediction period injecting a constant 2,000 stb/d.

The BRB I120 reservoir simulation model was reviewed by RPS in the PDR and various screen captures and output files were obtained for later analysis. Key reservoir parameters for the model are outlined in Table 5.44 and Figure 5.56 illustrates the permeability distribution for the model. The figure indicates an unreasonable permeability range with the maximum value being 4.5 x 107 mD, with many cells over 1,000 mD, coloured in red in Figure 5.56.

The model is stale as the planned first oil for the ESP workover is 1st June 2020 and not the currently planned start in 2023, and the history match is only up to 1st October 2017. RPS has therefore shifted the model profiles to match the existing schedule.

The first prediction run, which consists of just the current production well (BRB-2L) and the start-up of the water injector BRB-18ST1 (well 18ST_1 in the model), and there is only a small number of numerical issues (60) considering the case ran until 1st January 2050, but the overall fluid material balances errors are small and therefore results are deemed acceptable. The second prediction case is based on the first prediction case plus the workover on BRB-2L for the ESP. Again, the model experienced numerical issues (200) but the fluid material balance errors are relatively small, less than 0.06% for oil for example, and therefore the results can be considered numerically reliable.

Property	Low	Best	High
Grid Dimensions (x,y,z)		105 x2029 x 30	
DX Dimensions (ft)	153	166	172
DY Dimensions (ft)		Similar to DX	
DZ Dimensions (ft)	2.5	2.9	3.2
Total Cells		721,350	
Active Cells		58,285	
Average Porosity (fraction)	0.13	0.18	0.23
Average Horizontal Permeability (mD)	25.8	778.4	4,792
Average Vertical Permeability (mD)	3.48	81.21	201.26
PERMZ/PERMX Ratio		~0.10	
	Start		**End**
History Match Period	1st October 2003		1st October 2017
Prediction Period	1St October 2017		1st January 2050
ESP Workover First Oil		1st June 2020	

Table 5.44: Repsol's East Bunga Raya ESP I-120 Reservoir Dynamic Model Properties

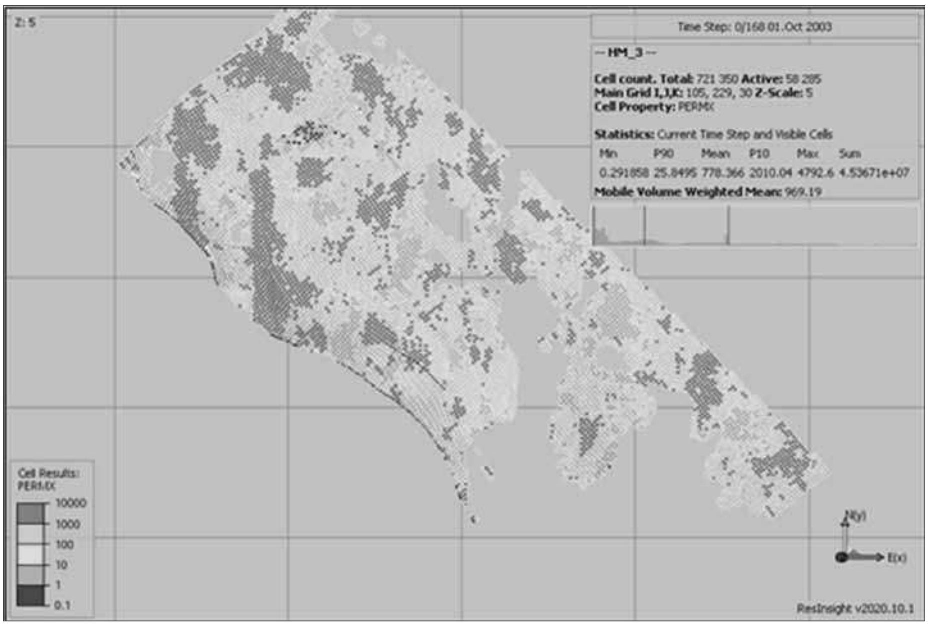

Figure 5.56: Repsol's East Bunga Raya ESP I-120 Reservoir Dynamic Model Permeability Distribution

In general, the model appears reasonable in terms of the input parameters, which is to be expected, as the model has been through the PETRONAS MPM project milestone review process. Although the high permeability values and the constant water injection rate of 2,000 stb/d are concerns.

A total of three cases were provided in the TDR, a history match case, an NFA prediction case with water injection, and finally a prediction case that includes the water injection plus the ESP workover on the BRB-2 well. Figure 5.57 shows the well locations for the three existing wells.

COMPETENT PERSON'S REPORT IN RELATION TO THE RESERVES AND RESOURCES EVALUATION OF THE ASSETS (CONT'D)

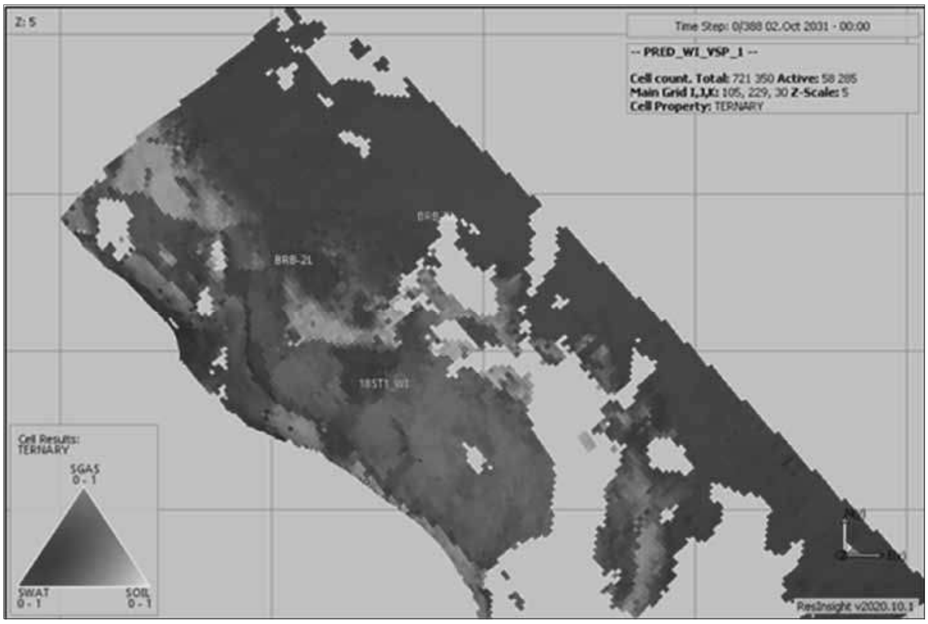

Figure 5.57: Repsol's East Bunga Raya ESP I-120 Reservoir Dynamic Well locations

The results of the NFA and ESP workover cases are tabulated in Table 5.45 for oil and Table 5.46 for gas; the oil profiles are also depicted in Figure 5.58.

Scenario	Property	Unit	Production End Date	
			2027	2042
NFA	STOIIP	(MMstb)	25.011	
	Recovery Factor	(percent)	31.8%	35.6%
	Recoverable	(MMstb)	7.946	8.906
	Production	(MMstb)	7.306	
	Remaining	(MMstb)	0.640	1.600
Prediction	STOIIP	(MMstb)	25.011	
	Recovery Factor	(percent)	34.4%	38.5%
	Recoverable	(MMstb)	8.605	9.626
	Production	(MMstb)	7.306	
	Remaining	(MMstb)	1.299	2.320
Incremental	Incremental Remaining	(MMstb)	0.659	0.720

Table 5.45: Repsol's East Bunga Raya ESP I-120 Reservoir Dynamic Model Results Summary (Oil)

Scenario	Property	Unit	Production End Date 2027	Production End Date 2042
NFA	GIIP	(Bscf)	33.133	
	Recovery Factor	(percent)	49.8%	51.3%
	Recoverable	(Bscf)	16.488	16.981
	Production	(Bscf)	13.604	
	Remaining	(Bscf)	2.884	3.377
Prediction	GIIP	(Bscf)	33.133	
	Recovery Factor	(percent)	59.2%	69.0%
	Recoverable	(Bscf)	19.613	22.872
	Production	(Bscf)	13.604	
	Remaining	(Bscf)	6.009	9.268
Incremental	Incremental Remaining	(Bscf)	3.125	5.891

Table 5.46: Repsol's East Bunga Raya ESP I-120 Reservoir Dynamic Model Results Summary (Gas)

Information in the VDR[45] indicates that Repsol expects incremental oil recovery of 0.29 MMstb for the BRB-2L well and 0.1 MMstb for the BRB-12L well which is completed in the I-123U/L reservoir. The latter ESP workover appears to be dropped by Repsol based on the information provided in Repsol's latest management presentation. The discrepancy between the model's 0.659 MMstb (2027) incremental oil recovery and the VDR volume of 0.290, especially as the simulation case names are the same in both data sets and both have water injection via the BRB-18ST1 well, is a major concern. Figure 5.59 shows the oil profile from the VDR but the quality of the figure does not allow further interpretation.

The overall oil recovery factors are within the range expected for a managed water flood.

[45] *3.3.3.2.3.3.1 ESP_PM3_Update2_09102019.pdf*

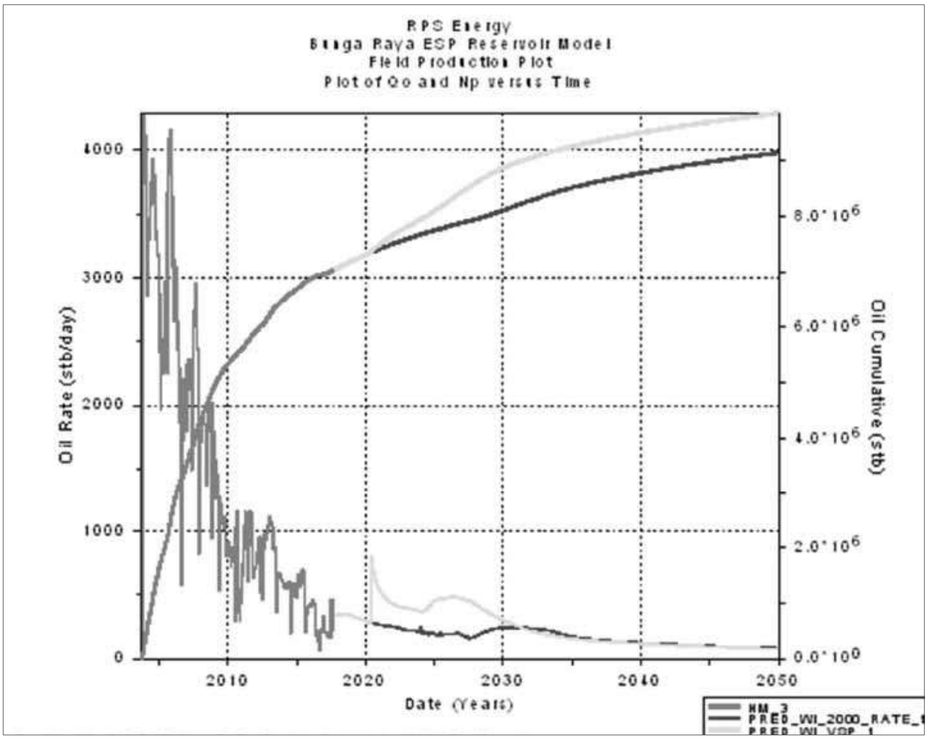

Figure 5.58: Repsol's East Bunga Raya ESP I-120 Reservoir Dynamic Oil Production Profiles

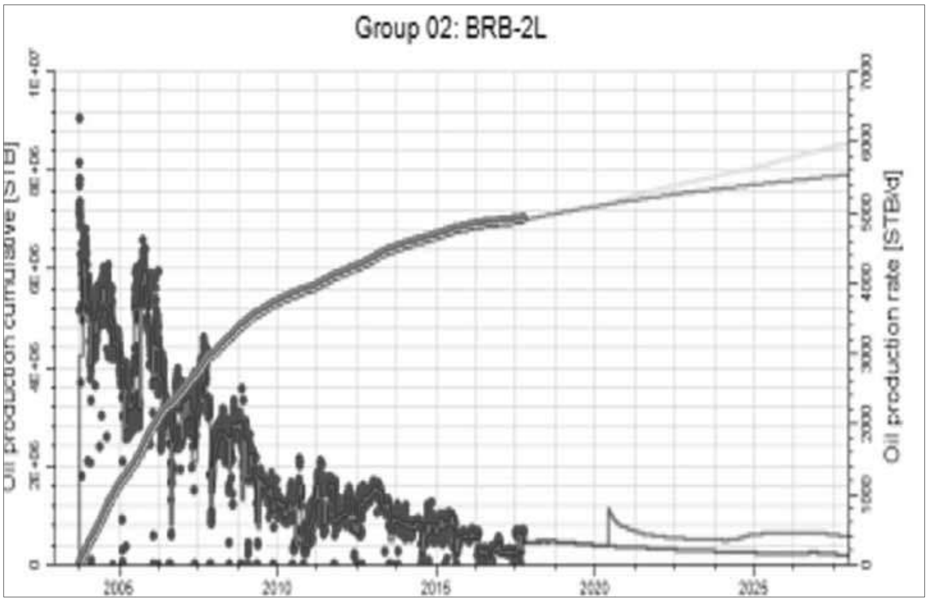

Figure 5.59: Repsol's East Bunga Raya ESP I-120 VDR Production Profiles

Given the above and the fact that the ESP will be installed three years post the modelled implementation, RPS has used:

$$Incremental\ Rate_{ESP}=\left(\frac{Average\ Annual\ Rate_{ESP}}{Average\ Annual\ Rate_{NF}}\right)_t \times \left(Average\ Annual\ Rate_{NF}\right)_{t+3}$$

on a yearly basis to generate the Best scenario profile. This results in 0.290 MMstb (2027) and 0.760 MMstb (2042) of incremental oil for the ESP workover. Note that the 0.290 MMstb is the same as reported in the VDR. For the Low and High scenarios RPS used ± 0.100 MMstb and the rescaled the Best scenario model based on the 2027 incremental volumes as outlined in Table 5.47.

Property	Unit	Low	2042 Best	High
STOIIP	(MMstb)		25.011	
Recovery Factor	(percent)		38.6%	
Recoverable	(MMstb)	9.409	9.664	9.939
Production	(MMstb)		-7.306	
NFA	(MMstb)		-1.600	
Incremental Remaining	(MMstb)	0.503	0.758	1.033
			2027	
Incremental Remaining	(MMstb)	0.190	0.286	0.390

Table 5.47: RPS's East Bunga Raya ESP I-120 Incremental Oil Recovery

STOIIP and the production volumes in Table 5.23 have been taken from the dynamic model.

5.5.8 West Bunga Orkid ESP H0ss12 Reservoir

This development is part of the two proposed PM3 Electrical Submersible Pump ("ESP") projects, one well each in Bunga Raya and in Bunga Orkid. This pilot project aims to enhance production which could potentially add reserves and optimise the current gas lift consumption as well as to diversify from the current artificial lift system of gas lift in this mature asset. The Repsol expects to recover an additional 1.5 MMstb of oil from both wells, with first production scheduled in 2023. At the moment Repsol is updating subsurface studies with additional production and seismic input data and conducting detailed engineering design studies to progress the project.

There are three oil producers in the field (BOD-20, BOD-21ST1 and OPA) and all three wells are producing with OPA coming on stream 1st July 2019. There is also one water injection well, W17 which comes on stream 1st August 2019 and is controlled via a voidage replacement ratio of 0.8, subject or a maximum water injection rate of 5,000 stb/d.

The BOD Hss12 reservoir simulation model was reviewed by RPS in the PDR and various screen captures and output files were obtained for later analysis. Key reservoir parameters for the model are outlined in Table 5.48 and Figure 5.60 illustrates the permeability distribution for the model. The figure indicates a reasonable permeability range with the maximum value being around three times the High value at 7,287 mD.

Property	Low	Best	High
Grid Dimensions (x,y,z)	1151 x 136 x 45		
DX Dimensions (ft)	163	164	165
DY Dimensions (ft)	Similar to DX		
DZ Dimensions (ft)	1.5	1.5	1.6
Total Cells	924,120		
Active Cells	115,328		
Average Porosity (fraction)	0.16	0.24	0.29
Average Horizontal Permeability (mD)	58.2	891.6	2,016.9
Average Vertical Permeability (mD)			
PERMZ/PERMX Ratio			
	Start		**End**
History Match Period	1st June 2012		31st December 2018
Prediction Period	1st January 2018		1st January 2051
ESP Workover First Oil		1st July 2020	

Table 5.48: West Bunga Orkid ESP Hss12 Reservoir Dynamic Model Properties

The model is stale as the planned first oil for the ESP workover is 1st July 2020 and not the currently planned start in 2023, and the history match is only up to 31st December 2018. RPS has therefore shifted the model profiles to match the existing schedule. Notice also that prediction cases start 1st January 2018 instead of 1st January 2019.

The first prediction run, which consists of all wells producing and injecting has only a relatively small number of numerical issues (138) considering the case ran until 1st January 2050 but the overall fluid material balances errors are small and therefore results are deemed acceptable. The second prediction case is based on the first prediction case plus the workover on BOB-20 for the ESP. Again, the model experienced numerical issues (194) but again the fluid material balance errors are relatively small, less than 0.01% for oil for example, and therefore the results can be considered numerically reliable.

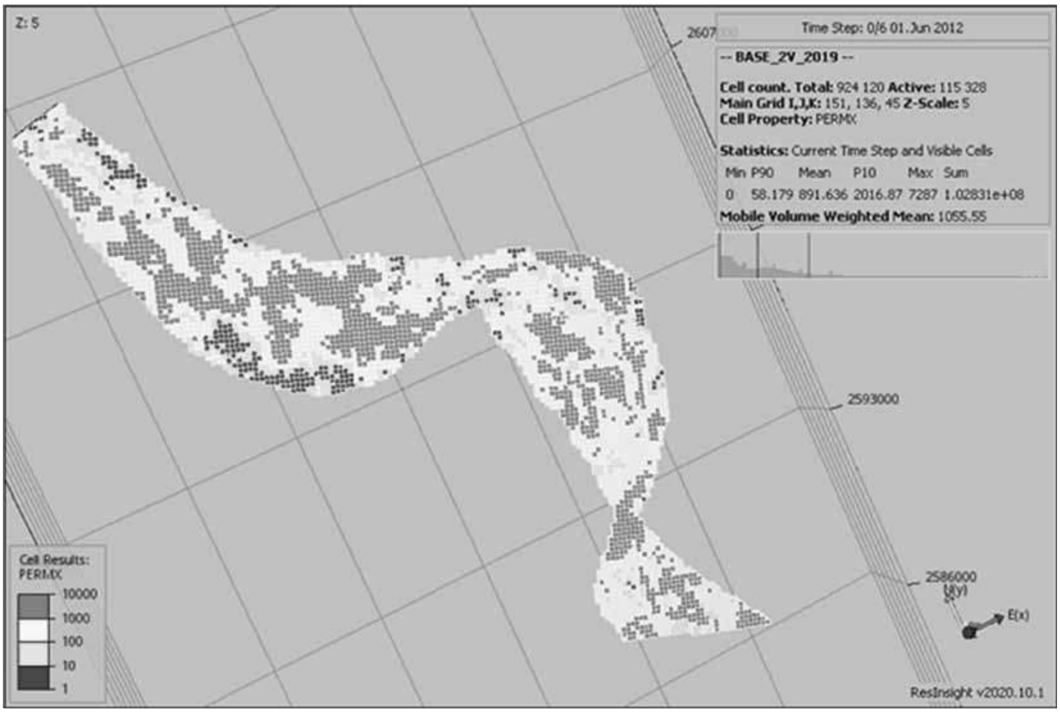

Figure 5.60: Repsol's West Bunga Orkid ESP Hss12 Reservoir Dynamic Model Permeability Distribution

In general, the model appears reasonable in terms of the input parameters, which is to be expected, as the model has been through the PETRONAS MPM project milestone review process. RPS notes that the history match run was performed on a daily basis, which is rather unusual and computationally time consuming. Although there is a concern with the model being stale with respect to history match and the timing of the developments.

A total of three cases were provided in the PDR, a history match case, an NFA prediction case with water injection, and finally a prediction case that includes the water injection plus the ESP workover on BOD-20 well. Figure 5.61 shows the well locations for all four wells.

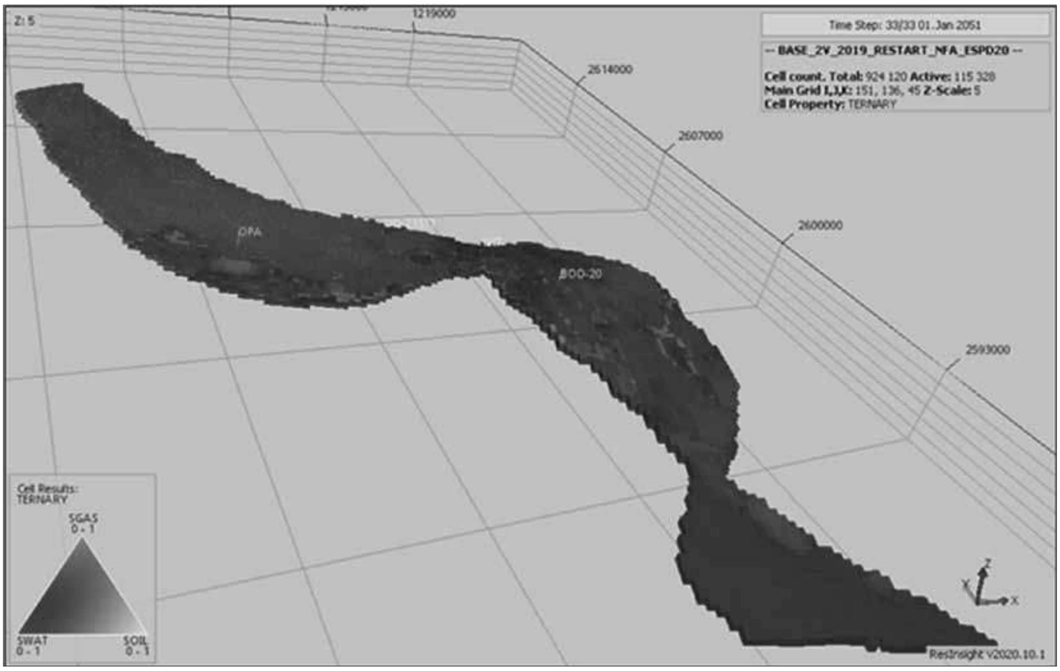

Figure 5.61: West Bunga Orkid ESP H0ss12 Reservoir Dynamic Well locations

The results of the NFA and ESP workover cases are tabulated in Table 5.49 for oil and Table 5.50 for gas; the oil profiles are also depicted in Figure 5.62.

Scenario	Property	Unit	Production End Date 2027	Production End Date 2042
NFA	STOIIP	(MMstb)	44.757	
	Recovery Factor	(percent)	39.8%	46.5%
	Recoverable	(MMstb)	17.801	20.825
	Production	(MMstb)	11.731	
	Remaining	(MMstb)	6.070	9.094
Prediction	STOIIP	(MMstb)	44.757	
	Recovery Factor	(percent)	41.4%	47.8%
	Recoverable	(MMstb)	18.535	21.410
	Production	(MMstb)	11.731	
	Remaining	(MMstb)	6.804	9.679
Incremental	Incremental Remaining	(MMstb)	0.734	0.585

Table 5.49: Repsol's West Bunga Orkid ESP Hss12 Reservoir Dynamic Model Results Summary (Oil)

Scenario	Property	Unit	Production End Date 2027	Production End Date 2042
NFA	GIIP	(Bscf)	79.651	
	Recovery Factor	(percent)	55.4%	66.1%
	Recoverable	(Bscf)	44.114	52.640
	Production	(Bscf)	27.488	
	Remaining	(Bscf)	16.626	25.152
Prediction	GIIP	(Bscf)	79.651	
	Recovery Factor	(percent)	66.6%	76.6%
	Recoverable	(Bscf)	53.023	60.999
	Production	(Bscf)	27.488	
	Remaining	(Bscf)	25.535	33.511
Incremental	Incremental Remaining	(Bscf)	8.909	8.359

Table 5.50: Repsol's West Bunga Orkid ESP Hss12 Reservoir Dynamic Model Results Summary (Gas)

Information in the VDR[46] indicates that the Repsol anticipates incremental oil recovery of 0.720 MMstb for the BOB-20 well compared with the model's 0.734 MMstb, which is reasonable agreement.

The overall oil recovery factors are within the range expected for a managed water flood although the 39.8% (2027) and 46.5% (2042) values are more applicable for a High scenario, rather than a Best scenario.

[46] *3.3.3.2.3.3.1 ESP_PM3_Update2_09102019.pdf*

COMPETENT PERSON'S REPORT IN RELATION TO THE RESERVES AND RESOURCES EVALUATION OF THE ASSETS (CONT'D)

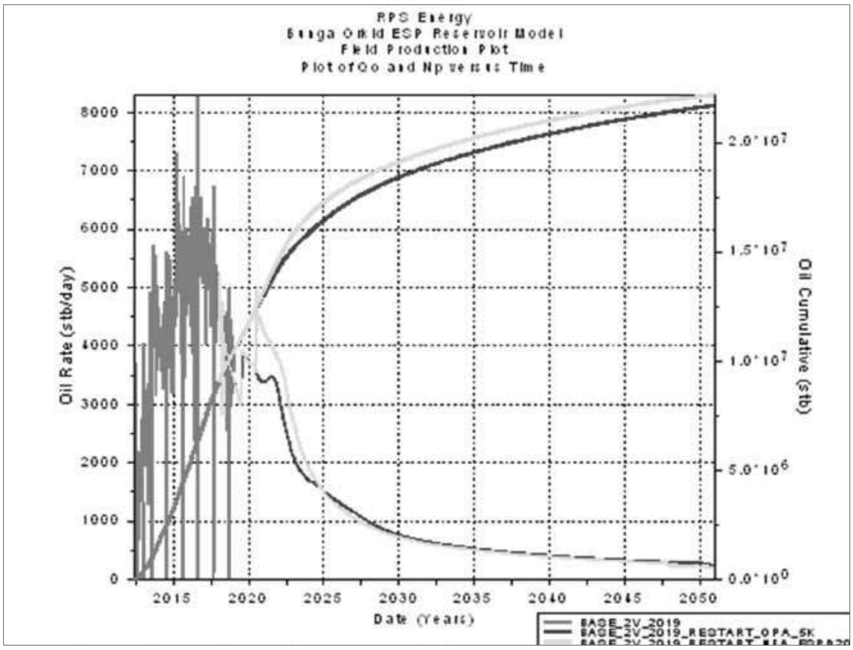

Figure 5.62: Repsol's West Bunga Orkid ESP Hss12 Reservoir Dynamic Oil Production Profiles

Given the above and the fact that the ESP will be installed three years post the modelled implementation, RPS has used:

$$\left(\frac{Average\ Annual\ Rate_{ESP}}{Average\ Annual\ Rate_{NF}}\right)_t \times \left(Average\ Annual\ Rate_{NF}\right)_{t+3}$$

on a yearly basis to generate the Best scenario profile. This results in 0.450 MMstb (2027) and 0.300 MMstb (2042) of incremental oil for the ESP workover. Note that the 2042 incremental is less than the 2027 value due to the ESP accelerating production as can be seen in Figure 5.62. Thus, for the Low, Best and High scenarios RPS used 0.150, 0.250, and 0.450 MMstb respectively and the rescaled the Best scenario model based on the 2027 incremental volumes as outlined in Table 5.51.

Property	Unit	Low	2042 Best	High
STOIIP	(MMstb)		44.757	
Recovery Factor	(percent)		46.3%	
Recoverable	(MMstb)	20.772	20.737	20.667
Production	(MMstb)		-11.731	
NFA	(MMstb)		-9.094	
Incremental Remaining	(MMstb)	-0.053	-0.088	-0.158
			2027	
Incremental Remaining	(MMstb)	0.150	0.250	0.450

Table 5.51: RPS's West Bunga Orkid ESP Hss12 Incremental Oil Recovery

STOIIP and the production volumes Table 5.51 have been taken from the dynamic model.

5.6 Future Developments

All of the Future Developments included in Repsol's Business Case are either identified Prospects on the block or step out exploration from the existing developments.

Due to time constraints, RPS has not spent a significant amount of time on reviewing these proposed projects, other than the Saffron A Prospect.

5.6.1 Saffron A Prospect

The Bunga Saffron area is a series of potential stratigraphic and structural traps within the fluvial deposits of the G, H, I and J stratigraphic sections (Figure 5.35). These are picked on seismic attribute data derived from the 2017 Pakma 3D survey, which covers the north western area of the Bunga Pakma field.

The Saffron A prospect is listed in the WP&B although it is not listed as a defined project in the Sale process shown in the VDR Management Presentation. This discrepancy was not noted until late on in the project, subsequently RPS' comments on the Bunga Saffron A prospect are based upon available data in the VDR only. No independent inplace estimation has been made.

Saffron A is identified as a step out well, drilled directly from the BPA platform to the Bunga Saffron A prospect.

5.6.1.1 Geological Assessment

RPS did not see a geological model or FDP for the Bunga Saffron A prospect and although it is listed as a step out development well in the W,P&B, Repsol still consider it to be a prospect. To add to the confusion, it is often referred to as Saffron Point bar A, Saffron A, WNW Pakma or NWBP (A).

The primary oil bearing reservoir in Bunga Saffron A is a stratigraphic trap within a Miocene aged channel in the G50_SS10 reservoir (Figure 5.63). Repsol have also evaluated several other gas bearing reservoir layers (F SS40, G50 SS10, H2 SS10, I23 SS10, I40 SS10, I90 SS20 &J10 SS10). No seismic or well data was available to confirm or deny these additional gas reservoirs and it is not clear how Repsol have identified them, although it has been noted that these reservoirs differ from the gas bearing reservoirs located in the nearby Bunga Pakma field.

Input data for the reservoirs evaluated looks reasonable. With the discovery of gas in the Saffron B structure the elements used to calculate the POS also look reasonable and without further information or access to the seismic data RPS cannot comment further. Although, it is suggested that the Bunga Saffron prospects are revisited upon arrival of the new seismic data due early 2021.

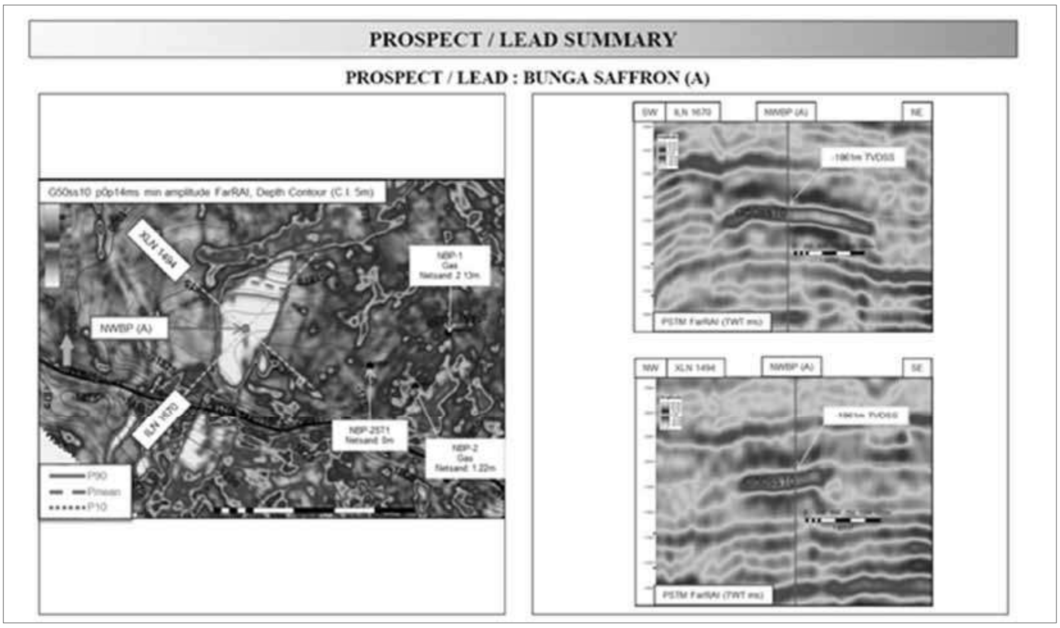

Figure 5.63: Far RAI Seismic showing Brightening of the Bunga Saffron A Prospect in the G50 SS10 Reservoir[47]

BUNGA SAFFRON (A) :Fss40

LOCATION	: Malay Basin (Block PM3-CAA)
SEISMIC PROJECT	: 2017 3D Pakma
SEISMIC COVERAGE	: 467km2 of 108-fold
NEAREST WELL	: NBP-1,NBP-2, NBP-2st1, BP-1
WATER DEPTH	: 55.57m
TRAP STYLE	: Combination trap
TARGET RESERVOIR	: Group F
TOP OF RESERVOIR	: 1522m TVDSS
DEVELOPMENT CONCEPT	: WHRP tie to Bunga Orkid Platform
NEARBY FACILITIES/DISTANCE	: 15km

GEOLOGICAL INFORMATION

SEAL	: Intra Formational Shale
RESERVOIR	: F sand
SOURCE	: Miocene
MIGRATION	: Lateral/Vertical migration
TIMING	: Lower miocene to present

POSSIBILITY OF SUCCESS (POS)

TRAP (CLOSURE)	: 0.4
SEAL (CONTAINMENT)	: 0.4
RESERVOIR	: 0.8
SOURCE	: 1
TIMING	: 1

INPUT PARAMETER	Symbol	P90	P50	P10
1. Area (acre)	A	NA	NA	NA
2. Thickness (m)	H	NA	NA	NA
3. Gross Bulk Volume (acre.ft)	GBV	13314	18449	25564
4. Net to Gross (ratio)	N/G	0.57	0.70	0.85
5. Porosity (dec.)	PHI	0.17	0.19	0.22
6. Water saturation, Sw (dec.)	Sw	0.40	0.36	0.20
7. Formation Volume Factor (scf/rcf)	1/Bg	171	180	189

HC TYPE	POS (Pg) (%)	RF (%)	UNRISKED IN-PLACE				UNRISKED RECOVERABLE			
			P90	P50	MEAN	P10	P90	P50	MEAN	P10
OIL (MMSTB)										
GAS (BSCF)	13	65	8.8	13.2	14.0	20.7	5.7	8.6	9.1	13.4

* GAS = AG (Associated Gas) + NAG (Non-Associated Gas), * RF = Recovery Factor ,
* POS = Possibility Of Success

REMARKS :

Table 5.52: Repsol Bunga Saffron A PROSPECT F SS40 Information Sheet[47]

[47] *Bunga Pakma Cluster Prospects Summary - Repsol*

BUNGA SAFFRON (A) :G50ss10 Pointbar A

LOCATION	: Malay Basin (Block PM3-CAA)
SEISMIC PROJECT	: 2017 3D Pakma
SEISMIC COVERAGE	: 467km2 of 108-fold
NEAREST WELL	: NBP-1,NBP-2, NBP-2st1, BP-1
WATER DEPTH	: 55.57m
TRAP STYLE	: Combination trap
TARGET RESERVOIR	: Group G
TOP OF RESERVOIR	: 1861m TVDSS
DEVELOPMENT CONCEPT	: WHRP tie to Bunga Orkid Platform
NEARBY FACILITIES/DISTANCE	: 15km

GEOLOGICAL INFORMATION

SEAL	: Intra Formational Shale
RESERVOIR	: G sand
SOURCE	: Miocene
MIGRATION	: Lateral/Vertical migration
TIMING	: Lower miocene to present

POSSIBILITY OF SUCCESS (POS)

TRAP (CLOSURE)	: 0.9
SEAL (CONTAINMENT)	: 0.55
RESERVOIR	: 0.9
SOURCE	: 1
TIMING	: 1

INPUT PARAMETER	Symbol	P90	P50	P10
1. Area (acre)	A	963	1017	1048
2. Thickness (m)	H	19.8	22.1	23.2
3. Gross Bulk Volume (acre.ft)	GBV	48672	69230	77310
4. Net to Gross (ratio)	N/G	0.64	0.87	0.98
5. Porosity (dec.)	PHI	0.19	0.22	0.26
6. Water saturation, Sw (dec.)	Sw	0.32	0.26	0.22
7. Formation Volume Factor (rb/stb)	(Bo)/(1/Bg)	1.30 / 162	1.4 / 184	1.50 / 210

HC TYPE	POS (Pg) (%)	RF (%)	UNRISKED IN-PLACE				UNRISKED RECOVERABLE			
			P90	P50	MEAN	P10	P90	P50	MEAN	P10
OIL (MMSTB)	44.6	12.4	10.78	16.50	18.41	27.72	1.22	2.01	2.29	3.63
GAS (BSCF)	44.6	70.7	32.52	47.51	46.18	58.97	21.99	33.33	32.42	42.58

* GAS = AG (Associated Gas) + NAG (Non-Associated Gas), * RF = Recovery Factor ,
* POS = Possibility Of Success

REMARKS :

confidential

Table 5.53: Repsol Bunga Saffron A PROSPECT G50 SS10 Information Sheet[47]

BUNGA SAFFRON (A) :H2ss10

LOCATION	: Malay Basin (Block PM3-CAA)
SEISMIC PROJECT	: 2017 3D Pakma
SEISMIC COVERAGE	: 467km2 of 108-fold
NEAREST WELL	: NBP-1,NBP-2, NBP-2st1, BP-1
WATER DEPTH	: 55.57m
TRAP STYLE	: Combination trap
TARGET RESERVOIR	: Group H
TOP OF RESERVOIR	: 2010m TVDSS
DEVELOPMENT CONCEPT	: WHRP tie to Bunga Orkid Platform
NEARBY FACILITIES/DISTANCE	: 15km

GEOLOGICAL INFORMATION

SEAL	: Intra Formational Shale
RESERVOIR	: H sand
SOURCE	: Miocene
MIGRATION	: Lateral/Vertical migration
TIMING	: Lower miocene to present

POSSIBILITY OF SUCCESS (POS)

TRAP (CLOSURE)	: 0.9
SEAL (CONTAINMENT)	: 0.4
RESERVOIR	: 0.9
SOURCE	: 1
TIMING	: 1

INPUT PARAMETER	Symbol	P90	P50	P10
1. Area (acre)	A	NA	NA	NA
2. Thickness (m)	H	NA	NA	NA
3. Gross Bulk Volume (acre.ft)	GBV	13314	18449	25564
4. Net to Gross (ratio)	N/G	0.57	0.70	0.85
5. Porosity (dec.)	PHI	0.17	0.19	0.22
6. Water saturation, Sw (dec.)	Sw	0.40	0.30	0.20
7. Formation Volume Factor (scf/rcf)	1/Bg	171	180	189

HC TYPE	POS (Pg) (%)	RF (%)	UNRISKED IN-PLACE				UNRISKED RECOVERABLE			
			P90	P50	MEAN	P10	P90	P50	MEAN	P10
OIL (MMSTB)										
GAS (BSCF)	32	65	8.7	13.2	14.0	20.5	5.6	8.6	9.1	13.3

* GAS = AG (Associated Gas) + NAG (Non-Associated Gas), * RF = Recovery Factor ,
* POS = Possibility Of Success

REMARKS : H2ss10 gas reservoir penetrated by BPA-6 to indicate gas charged at Bunga Pakma structural closure.

Table 5.54: Repsol Bunga Saffron A PROSPECT H2 SS10 Information Sheet[47]

BUNGA SAFFRON (A) :I23ss10

LOCATION	: Malay Basin (Block PM3-CAA)
SEISMIC PROJECT	: 2017 3D Pakma
SEISMIC COVERAGE	: 467km2 of 108-fold
NEAREST WELL	: NBP-1,NBP-2, NBP-2st1, BP-1
WATER DEPTH	: 55.57m
TRAP STYLE	: Combination trap
TARGET RESERVOIR	: Group I
TOP OF RESERVOIR	: 2137m TVDSS
DEVELOPMENT CONCEPT	: WHRP tie to Bunga Orkid Platform
NEARBY FACILITIES/DISTANCE	: 15km

GEOLOGICAL INFORMATION

SEAL	: Intra Formational Shale
RESERVOIR	: I sand
SOURCE	: Miocene
MIGRATION	: Lateral/Vertical migration
TIMING	: Lower miocene to present

POSSIBILITY OF SUCCESS (POS)

TRAP (CLOSURE)	: 0.8
SEAL (CONTAINMENT)	: 0.4
RESERVOIR	: 0.9
SOURCE	: 1
TIMING	: 1

INPUT PARAMETER	Symbol	P90	P50	P10
1. Area (acre)	A	NA	NA	NA
2. Thickness (m)	H	NA	NA	NA
3. Gross Bulk Volume (acre.ft)	GBV	9298	13081	18404
4. Net to Gross (ratio)	N/G	0.60	0.73	0.86
5. Porosity (dec.)	PHI	0.12	0.16	0.20
6. Water saturation, Sw (dec.)	Sw	0.47	0.36	0.24
7. Formation Volume Factor (scf/rcf)	1/Bg	167	176	185

HC TYPE	POS (Pg) (%)	RF (%)	UNRISKED IN-PLACE				UNRISKED RECOVERABLE			
			P90	P50	MEAN	P10	P90	P50	MEAN	P10
OIL (MMSTB)										
GAS (BSCF)	29	65	4.3	7.0	7.5	11.5	2.9	4.7	5.1	7.8

* GAS = AG (Associated Gas) + NAG (Non-Associated Gas), * RF = Recovery Factor ,
* POS = Possibility Of Success

REMARKS :

Table 5.55: Repsol Bunga Saffron A PROSPECT I23 SS10 Information Sheet47

BUNGA SAFFRON (A) : I40ss10

LOCATION	: Malay Basin (Block PM3-CAA)
SEISMIC PROJECT	: 2017 3D Pakma
SEISMIC COVERAGE	: 467km2 of 108-fold
NEAREST WELL	: NBP-1,NBP-2, NBP-2st1, BP-1
WATER DEPTH	: 55.57m
TRAP STYLE	: Combination trap
TARGET RESERVOIR	: Group I
TOP OF RESERVOIR	: 2262m TVDSS
DEVELOPMENT CONCEPT	: WHRP tie to Bunga Orkid Platform
NEARBY FACILITIES/DISTANCE	: 15km

GEOLOGICAL INFORMATION

SEAL	: Intra Formational Shale
RESERVOIR	: I sand
SOURCE	: Miocene
MIGRATION	: Lateral/Vertical migration
TIMING	: Lower miocene to present

POSSIBILITY OF SUCCESS (POS)

TRAP (CLOSURE)	: 0.8
SEAL (CONTAINMENT)	: 0.4
RESERVOIR	: 0.8
SOURCE	: 1
TIMING	: 1

INPUT PARAMETER	Symbol	P90	P50	P10
1. Area (acre)	A	NA	NA	NA
2. Thickness (m)	H	NA	NA	NA
3. Gross Bulk Volume (acre.ft)	GBV	15420	24247	38129
4. Net to Gross (ratio)	N/G	0.63	0.75	0.87
5. Porosity (dec.)	PHI	0.18	0.20	0.22
6. Water saturation, Sw (dec.)	Sw	0.43	0.37	0.31
7. Formation Volume Factor (scf/rcf)	1/Bg	180	189	199

HC TYPE	POS (Pg) (%)	RF (%)	UNRISKED IN-PLACE				UNRISKED RECOVERABLE			
			P90	P50	MEAN	P10	P90	P50	MEAN	P10
OIL (MMSTB)										
GAS (BSCF)	26	62	11.2	18.0	19.6	30.5	6.9	11.2	12.1	18.9

* GAS = AG (Associated Gas) + NAG (Non-Associated Gas), * RF = Recovery Factor ,
* POS = Possibility Of Success

REMARKS :
Potentially stacked with I45ss10.

Table 5.56: Repsol Bunga Saffron A PROSPECT I40 SS10 Information Sheet[47]

BUNGA SAFFRON (A) :I90ss20

LOCATION	: Malay Basin (Block PM3-CAA)
SEISMIC PROJECT	: 2017 3D Pakma
SEISMIC COVERAGE	: 467km2 of 108-fold
NEAREST WELL	: NBP-1,NBP-2, NBP-2st1, BP-1
WATER DEPTH	: 55.57m
TRAP STYLE	: Combination trap
TARGET RESERVOIR	: Group I
TOP OF RESERVOIR	: 2527m TVDSS
DEVELOPMENT CONCEPT	: WHRP tie to Bunga Orkid Platform
NEARBY FACILITIES/DISTANCE	: 15km

GEOLOGICAL INFORMATION

SEAL	: Intra Formational Shale
RESERVOIR	: I sand
SOURCE	: Miocene
MIGRATION	: Lateral/Vertical migration
TIMING	: Lower miocene to present

POSSIBILITY OF SUCCESS (POS)

TRAP (CLOSURE)	: 0.7
SEAL (CONTAINMENT)	: 0.4
RESERVOIR	: 0.9
SOURCE	: 1
TIMING	: 1

INPUT PARAMETER	Symbol	P90	P50	P10
1. Area (acre)	A	NA	NA	NA
2. Thickness (m)	H	NA	NA	NA
3. Gross Bulk Volume (acre.ft)	GBV	12698	16476	21378
4. Net to Gross (ratio)	N/G	0.6	0.72	0.86
5. Porosity (dec.)	PHI	0.13	0.16	0.19
6. Water saturation, Sw (dec.)	Sw	0.37	0.27	0.17
7. Formation Volume Factor (scf/rcf)	1/Bg	189	199	209

HC TYPE	POS (Pg) (%)	RF (%)	UNRISKED IN-PLACE				UNRISKED RECOVERABLE			
			P90	P50	MEAN	P10	P90	P50	MEAN	P10
OIL (MMSTB)										
GAS (BSCF)	25	65	7.8	11.5	12.1	17.2	4.9	7.1	7.5	10.7

* GAS = AG (Associated Gas) + NAG (Non-Associated Gas), * RF = Recovery Factor ,
* POS = Possibility Of Success

REMARKS :

Table 5.57: Repsol Bunga Saffron A PROSPECT I90 SS20 Information Sheet[47]

BUNGA SAFFRON (A) :J10ss10

LOCATION	: Malay Basin (Block PM3-CAA)
SEISMIC PROJECT	: 2017 3D Pakma
SEISMIC COVERAGE	: 467km2 of 108-fold
NEAREST WELL	: NBP-1,NBP-2, NBP-2st1, BP-1
WATER DEPTH	: 55.57m
TRAP STYLE	: Combination trap
TARGET RESERVOIR	: Group J
TOP OF RESERVOIR	: 2655m TVDSS
DEVELOPMENT CONCEPT	: WHRP tie to Bunga Orkid Platform
NEARBY FACILITIES/DISTANCE	: 15km

GEOLOGICAL INFORMATION

SEAL	: Intra Formational Shale
RESERVOIR	: J sand
SOURCE	: Miocene
MIGRATION	: Lateral/Vertical migration
TIMING	: Lower miocene to present

POSSIBILITY OF SUCCESS (POS)

TRAP (CLOSURE)	: 0.9
SEAL (CONTAINMENT)	: 0.4
RESERVOIR	: 0.9
SOURCE	: 1
TIMING	: 1

INPUT PARAMETER	Symbol	P90	P50	P10
1. Area (acre)	A	NA	NA	NA
2. Thickness (m)	H	NA	NA	NA
3. Gross Bulk Volume (acre.ft)	GBV	18475	21679	25439
4. Net to Gross (ratio)	N/G	0.82	0.88	0.94
5. Porosity (dec.)	PHI	0.14	0.16	0.18
6. Water saturation, Sw (dec.)	Sw	0.44	0.38	0.31
7. Formation Volume Factor (scf/rcf)	1/Bg	201	211	222

HC TYPE	POS (Pg) (%)	RF (%)	UNRISKED IN-PLACE				UNRISKED RECOVERABLE			
			P90	P50	MEAN	P10	P90	P50	MEAN	P10
OIL (MMSTB)										
GAS (BSCF)	32	65	13.4	17.2	17.5	21.7	8.7	11.2	11.4	14.3

* GAS = AG (Associated Gas) + NAG (Non-Associated Gas), * RF = Recovery Factor ,
* POS = Possibility Of Success

REMARKS :

Table 5.58: Repsol Bunga Saffron A PROSPECTJ10 SS10 Information Sheet[47]

Reservoir	P90	P50	P10
GIIP (MMStb)	89	128	181
OIIP (MMStb)	11	17	28

Table 5.59: Arithmetic Summation of Repsol's Unrisked Hydrocarbon In-place Numbers

6 KINABALU

The Kinabalu field is located in the Eastern Baram Delta Province, 55km WNW of Labuan Island, Sabah and lies on the Western Flank of the Timbalai anticline in Block SB1 Kinabalu. It was discovered by Sabah Shell Petroleum in 1989 with the KN-1 exploration well in a water depth of approximately 54m. 3D seismic was acquired in Q4 1989, which lead to the drilling of three appraisal wells and the submission of the initial FDP in 1991. An additional 3D survey was acquired in 2004 and reprocessed in 2015. First oil was in December 1997 and the current partnership consists of Repsol (TLM) 60% and PETRONAS Carigali (40%). The current Oil PSC expires in 2032.

The field consists of three separate fault blocks split by 2 NE-SW trending syn-sedimentary extensional faults. These can be further divided into 4 separate accumulations: Kinabalu Main, Kinabalu Deep, Kinabalu East and Kinabalu Far East.

Hydrocarbons are produced by 2 well head platforms (KNDW-D WHP and KNDP-A) which have drilled over 50 development wells, 27 of which are currently active. Once at surface, hydrocarbons are then evacuated from the KNDP-A platform to the Semarang complex, 27 km to the northeast, where they are processes prior to transportation to the Labuan Crude Oil Terminal for storage and export (Figure 6.1).

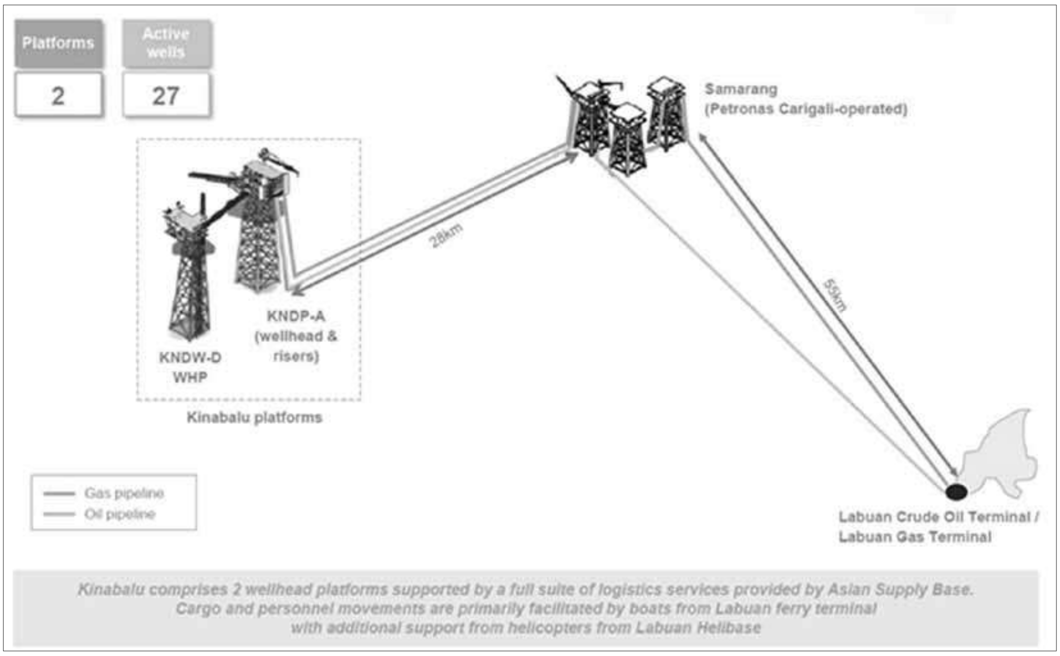

Figure 6.1: Diagram of Kinabalu Facilities[48]

6.1 Block History

The Kinabalu field was discovered in 1989 by drilling the KN-1 exploration well. The appraisal well KN-2 was drilled in 1990 confirmed the presence of considerable hydrocarbons volumes in the Main accumulation, known as Kinabalu Main. A second appraisal well KN-3 discovered the Kinabalu East accumulation. The Kinabalu Main and deep accumulations are dip-closed against a major SW-NE trending growth fault, whereas the Kinabalu East accumulation is dip closed in a similar was but against a smaller fault east of the major growth fault. KNFE-1 well proved the existence of the low relief 4-way dip closure associated with paleo-high structural play at Kinabalu Far East which works for O, R and S oil-bearing intervals.

[48] *VDR Management Presentation 2020.12vF.pdf - Repsol*

The field development plan was put in place in 1995 by the previous operator through KNDP-A platform with first oil in 26th December 1997. Further development wells were drilled during 2000 to 2009 whereby all the 20 slots on KNDP-A were fully utilised. Current operator, Repsol Oil and Gas Malaysia Limited (60%) has executed to increase the field oil production and achieved approximately 20,000 bopd in 2017-2018. In 2019, Kinabalu Redevelopment Plan Addendum Update 1 was proposed (comprise of 7 infill wells) with the intention to improve the overall reservoir recovery providing an additional 7 MMstb of gross reserves.

Oil is located in over 30 reservoirs with the majority of the reserves held in the F, J, K, L, M and O reservoirs in Kinabalu Main.

Reservoirs comprise of laterally continuous multiple stacked sandstones deposited in lower to upper shore face settings. Average reservoir porosities are 23% in the clean sands and 12% in the sand dominated heteroliths of the L group. Average hydrocarbon heights are approximately 50m and a maximum column height of 137m has been observed.

Structurally, the Kinabalu Main and Deep reservoirs are hanging wall monoclines. Hydrocarbons being trapped in a 3-way dip closure, which is fault closed by the NE-SW Kinabalu Main fault to the East an SE. The Kinabalu Main accumulation is separated by approximately 500m of shales from the Kinabalu Deep reservoir, which are filled with a condensate rich gas and at least one oil rim (S1-S2).

Kinabalu East is mainly gas bearing, with 2 oil rims, reservoirs are trapped in a tilted block fault closed to the West by the Kinabalu Main fault and to the East by the smaller Kinabalu East fault, whilst Kinabalu Far East is a small 4-way dip closure, which Repsol report as currently under appraised[49].

Historical production plots oil & are shown in Figure 6.2. Individual field history plots can be found in Appendix D.

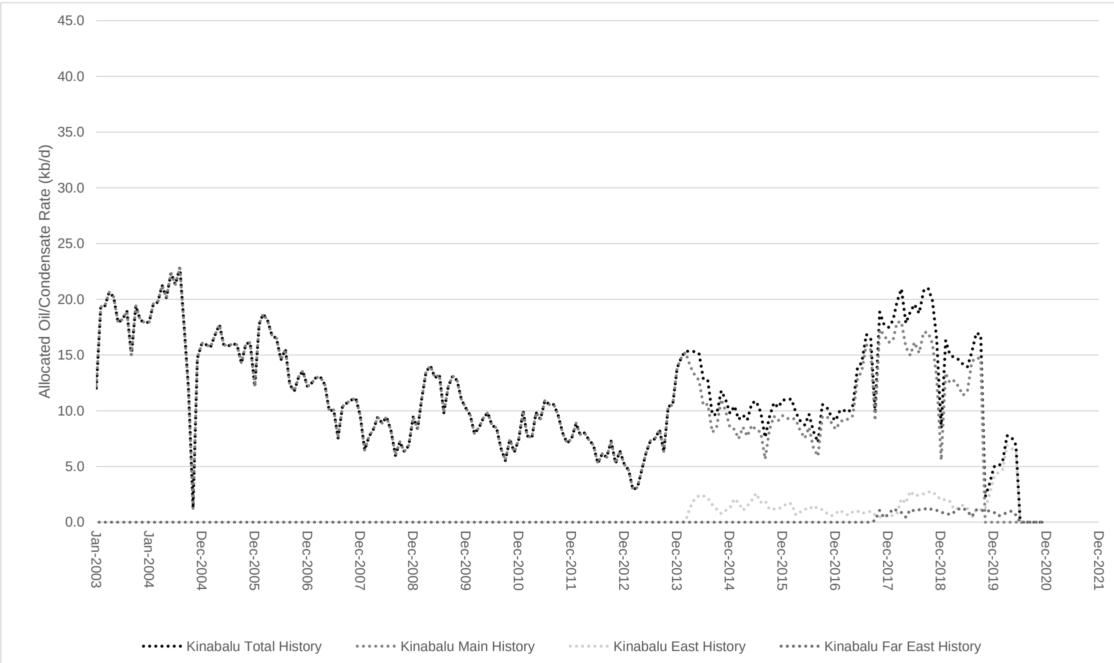

Figure 6.2: Kinabalu Historical Oil Production

[49] *3.3.2.1.1.1 2020 Kinabalu Oil FDP Addendum Update 2-K1 Main FB Additional Development - Repsol*

6.2 Repsol Business Case

Repsol has presented its business case in the Management Presentation. This consists of three main sections; a Low Investment case, Defined Developments, and Future Developments, as outlined below:

- Low Investment Case (Developed Reserves):
  - Existing Production only
- Defined Developments (Undeveloped Reserves & Contingent/Prospective Resources)
  - Production Efficiency
  - D18 Infill Well
  - Undrained Volumes
  - ESPs
- Future Developments (Contingent / Prospective Resources):
  - 2022 Infill Campaign
  - CC Far East Development

Due to time constraints, RPS has focussed on those projects classified as Reserves, with little focus on other Defined Development or Future Development projects.

6.3 Existing Production & Planned Interventions

Existing production in the block is from a total of 3 accumulations: Kinabalu Main, Kinabalu East & Kinabalu Far East.

Since 2015, the Operator has relinquished all rights to the sales gas produced from the asset, so Reserves and Resources are only estimated for the produced oil.

6.3.1 Existing Production (NFA Case)

The No Further Activity (NFA) production forecast case has been assessed for all producing fields in Kinabalu by Decline Curve Analysis at the field level based on production data supplied in the VDR in OFM™ to October 2020.

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

Examples of both 1P and 3P analyses are shown in Figure 6.3 & Figure 6.4 below.

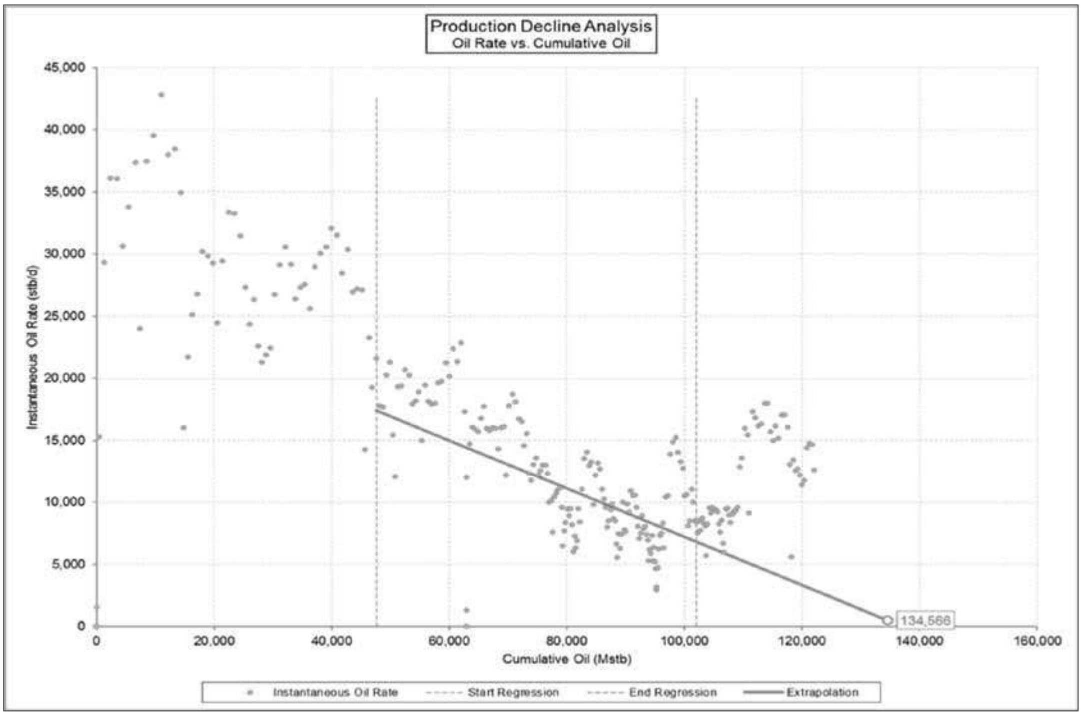

Figure 6.3: Example 1P Oil Rate Decline Curve Analysis (Kinabalu Main)

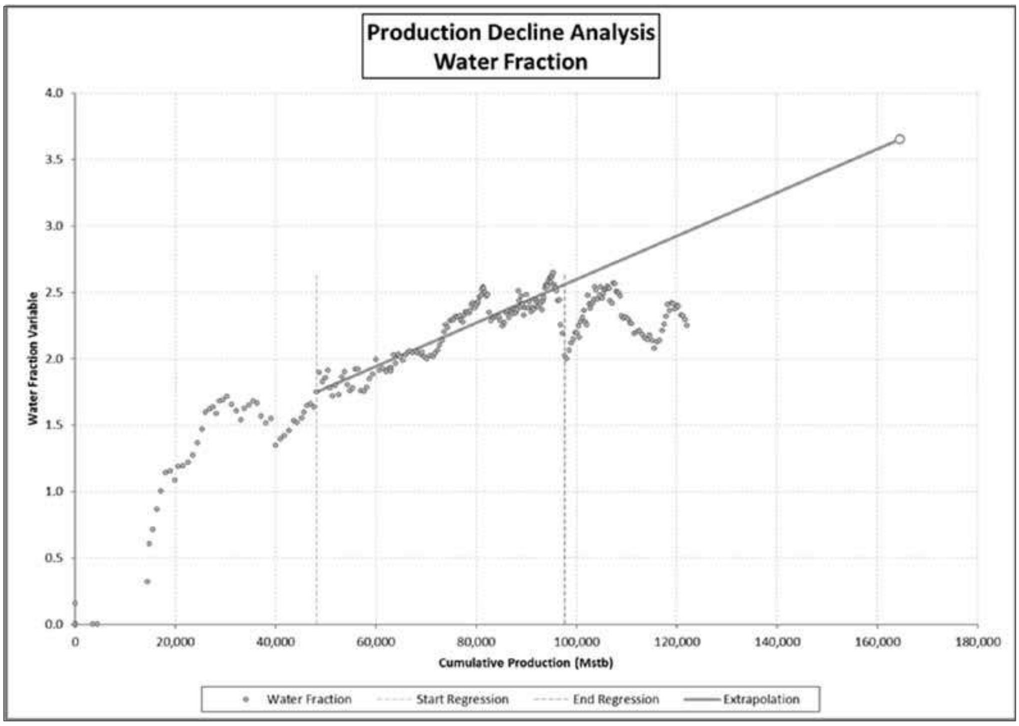

Figure 6.4: Example 3P Water Oil Ratio Decline Curve Analysis (Kinabalu Main)

Relevant analysis plots for each asset are provided for reference in Appendix E. Plots of the resulting RPS production forecasts for each field are provided in Appendix F.

6.3.2 Planned Well Interventions

There are currently no well interventions (plug and perforate) planned on any of the Kinabalu fields.

Plots of the resulting NFA RPS production forecasts for each field are provided in Appendix F.

Combined 2P plots for Kinabalu oil are shown in Figure 6.5.

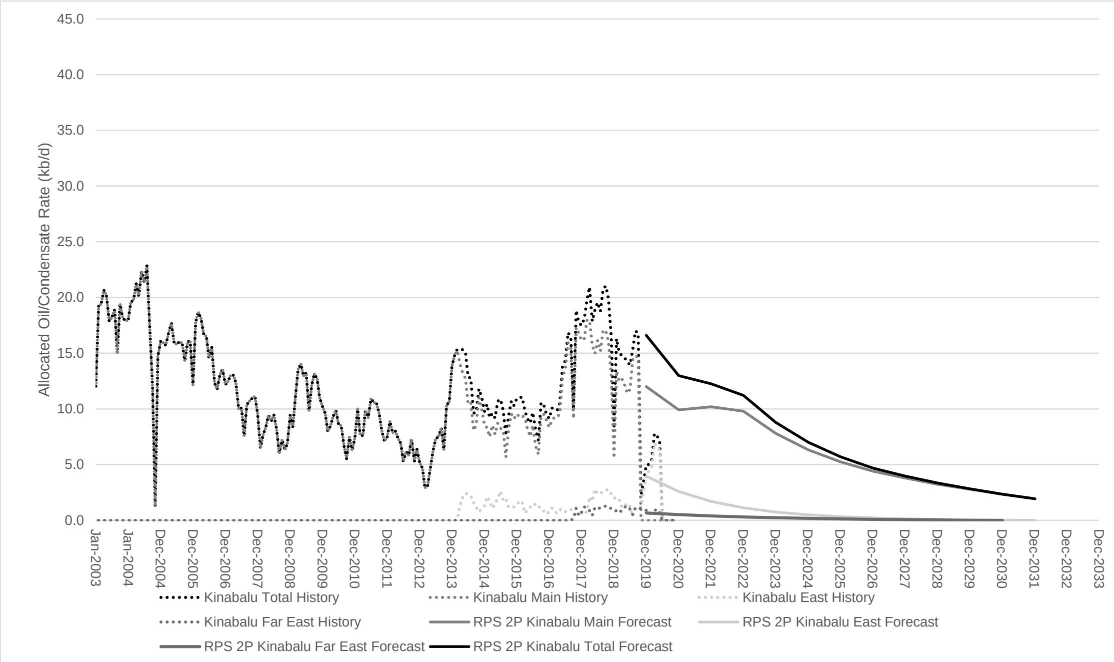

Figure 6.5: RPS 2P Kinabalu Forecast

6.4 Defined Developments

6.4.1 D-18 Infill Well

This project consists of a single oil horizontal producer equipped with gas lift and drilled from the KNDW-D platform targeting the K1 reservoir. The K1 reservoir (K1.02 sequence) is defined by the Repsol as a tier 3 reservoir with a total STOIIP of 8.8 MMstb; generally low-grade pay with good quality sand sequence. KNDW-D08 was the first development well targeting K1 during the 2017-2018 re-development drilling campaign, with first oil production from this well in May 2018. The well encountered 10ft of net oil pay in the K.1.0.2 sequence.

KNDW-D03, a well to be drilled earlier in the same drilling campaign targeting the L1 reservoir, will replace the need of a pilot hole to guide the landing point of the horizontal section in K1.0.2 for the KNDW-D18 well. KNDW-D18 is proposed to be drilled in the sweet spot and completed similar to KNDW-D08 as a horizontal well (~700 - 800 m length) using geo-steering to guide the well trajectory (Figure 6.6).

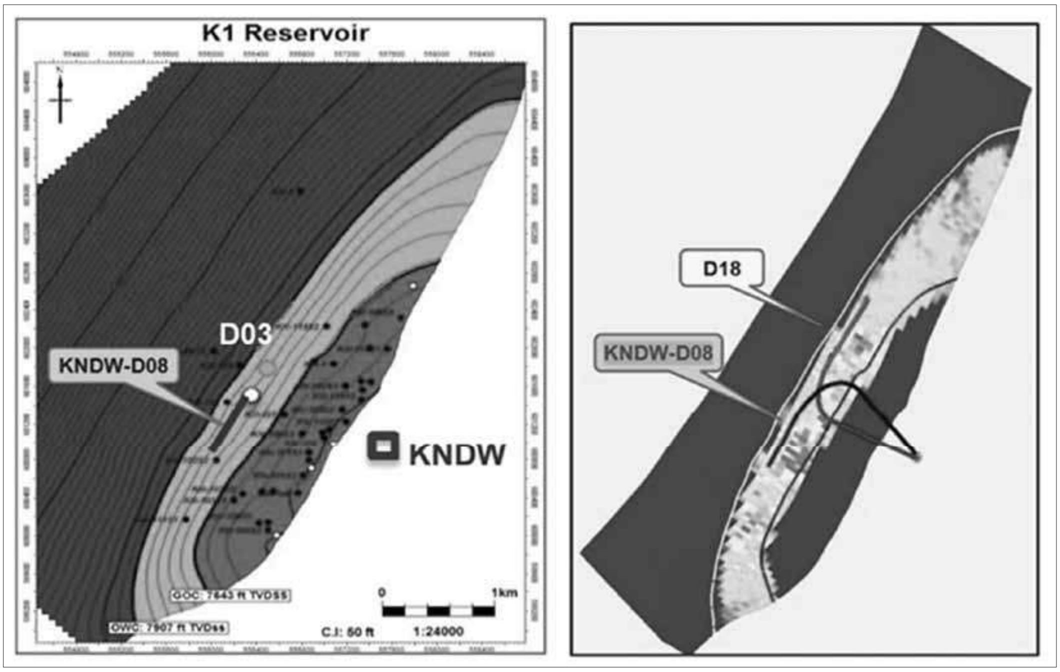

Figure 6.6: Repsol's Kinabalu D18 Well Location (after Repsol)

The project has gone through partner reviews and PETRONAS MPM project milestone review and is included in the 2021 WP&B budget. The proposed FDP is available in the VDR[50] and Repsol is in the process of submitting the document.

Incremental oil from the project is estimated to be 0.8 MMstb by the Repsol from the KNDW-D18 well.

Note the project is not without risk; apart from the usual subsurface uncertainties, due to the risk of collision, though the well trajectory is optimised to reduce collision risk with a minimum safety factor of 1.5.

The K reservoir simulation model was reviewed by RPS in the PDR and various screen captures and output files were obtained for later analysis. Key reservoir parameters for the model are outlined in Table 6.1 and Figure 6.7 illustrates the permeability distribution for the model. The figure does indicate some multi-Darcy cells, with the maximum value being over 5,600 mD. The history match period commenced from 1st May, 2018 and terminated 1st October, 2019 and all the predication cases also started from the beginning of the history matching period.

[50] *3.3.2.1.1.4 2020 Kinabalu Oil FDP Addendum Update 2 - K1 Main FB Additional Development.pdf*

Property	Low	Best	High
Grid Dimensions (x,y,z)		26 x 148 x 27	
DX Dimensions (ft)			
DY Dimensions (ft)			
DZ Dimensions (ft)		2.2	
Total Cells		103,896	
Active Cells		48,469	
Average Porosity (fraction)	0.10	0.15	0.21
Average Horizontal Permeability (mD)	7.9	248.4	580.6
Average Vertical Permeability (mD)		29.5	
PERMZ/PERMX Ratio		~0.10	
	Start		**End**
History Match Period	1st May 2018		1st October 2019
Prediction Period	1st May 2018		31st December 2032
Infill Development First Oil (D18) **Infill Development First Oil (KNA)**		1st June 2020 1st July 2020	

Table 6.1: Repsol's Kinabalu K Reservoir Dynamic Model Properties

The model is a bit stale as the history match is up to 31st October 2019, but this is only a very minor concern. None of the runs have numerical problems and all have minimum fluid material balance errors indicating the results are numerically reliable.

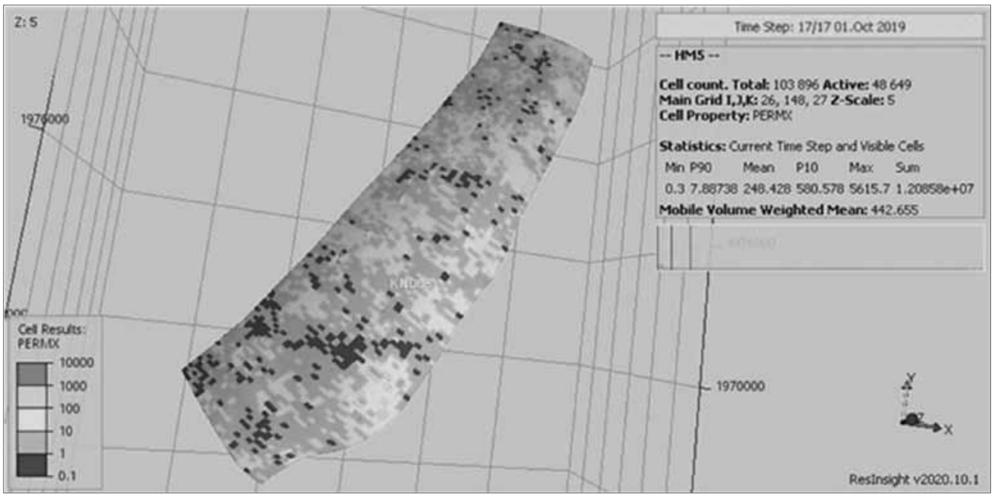

Figure 6.7: Repsol's Kinabalu K Reservoir Dynamic Model Permeability Distribution

In general, the model appears reasonable in terms of the input parameters, which is to be expected, as the model has been through the PETRONAS MPM project milestone review process.

A total of four cases were provided in the PDR; a history match case, an NFA case that includes the recently drilled D08A well that was part of the 2019-2020 infill drilling campaign that was completed in May 2020, a prediction case based on the NFA run together with the planned D18 oil well, and finally prediction case that is based on the previous case with and additional well to the south (well KNA). Figure 6.8 shows the well locations for the existing well D08A and the two proposed wells (D18 and KNA).

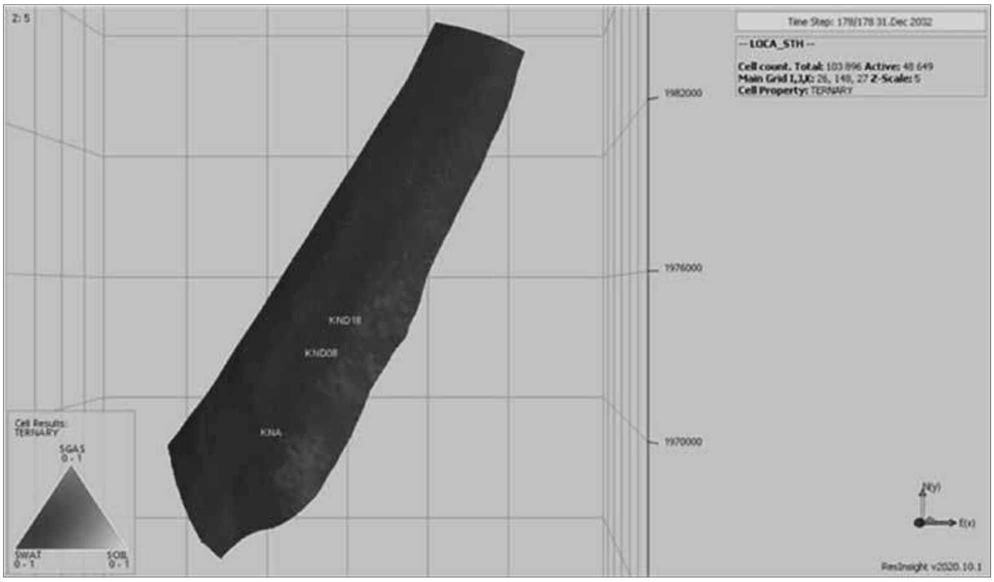

Figure 6.8: Repsol's Kinabalu K Reservoir Dynamic Well locations

The results of the infill case only are tabulated in Table 6.2 for oil and Table 6.3 for gas; the oil profiles are also depicted in Figure 6.9. RPS notes that there appears to be an inconsistency in the in-place volumes for the various cases.

Scenario	Property	Unit	Production End Date 2032	Production End Date 2042
NFA	STOIIP	(MMstb)	8.627	
	Recovery Factor	(percent)	22.7%	22.7%
	Recoverable	(MMstb)	1.957	1.957
	Production	(MMstb)	1.094	1.094
	Remaining	(MMstb)	0.863	0.863
NFA plus D18	STOIIP	(MMstb)	8.627	
	Recovery Factor	(percent)	33.0%	33.0%
	Recoverable	(MMstb)	2.846	2.846
	Production	(MMstb)	1.094	1.094
	Remaining	(MMstb)	1.752	1.752
NFA plus D18 plus KNA	STOIIP	(MMstb)	8.762	
	Recovery Factor	(percent)	39.0%	39.0%
	Recoverable	(MMstb)	3.419	3.419
	Production	(MMstb)	1.094	1.094
	Remaining	(MMstb)	2.325	2.325
D18	Incremental Remaining	(MMstb)	0.889	0.889
KNA	Incremental Remaining	(MMstb)	0.573	0.573

Table 6.2: Kinabalu D18 Infill (K Reservoir) Results Summary (Oil)

			Production End Date	
Scenario	Property	Unit	2032	2042
NFA	GIIP	(Bscf)	18.203	
	Recovery Factor	(percent)	21.9%	21.9%
	Recoverable	(Bscf)	3.984	3.984
	Production	(Bscf)	3.244	3.244
	Remaining	(Bscf)	0.740	0.740
NFA plus D18	GIIP	(Bscf)	18.203	
	Recovery Factor	(percent)	28.5%	28.5%
	Recoverable	(Bscf)	5.182	5.182
	Production	(Bscf)	3.244	3.244
	Remaining	(Bscf)	1.938	1.938
NFA plus D18 plus KNA	GIIP	(Bscf)	18.545	
	Recovery Factor	(percent)	76.7%	76.7%
	Recoverable	(Bscf)	14.228	14.228
	Production	(Bscf)	3.244	3.244
	Remaining	(Bscf)	10.984	10.984
D18	Incremental Remaining	(Bscf)	1.198	1.198
KNA	Incremental Remaining	(Bscf)	9.046	9.046

Table 6.3: Kinabalu D18 Infill (K Reservoir) Results Summary (Gas)

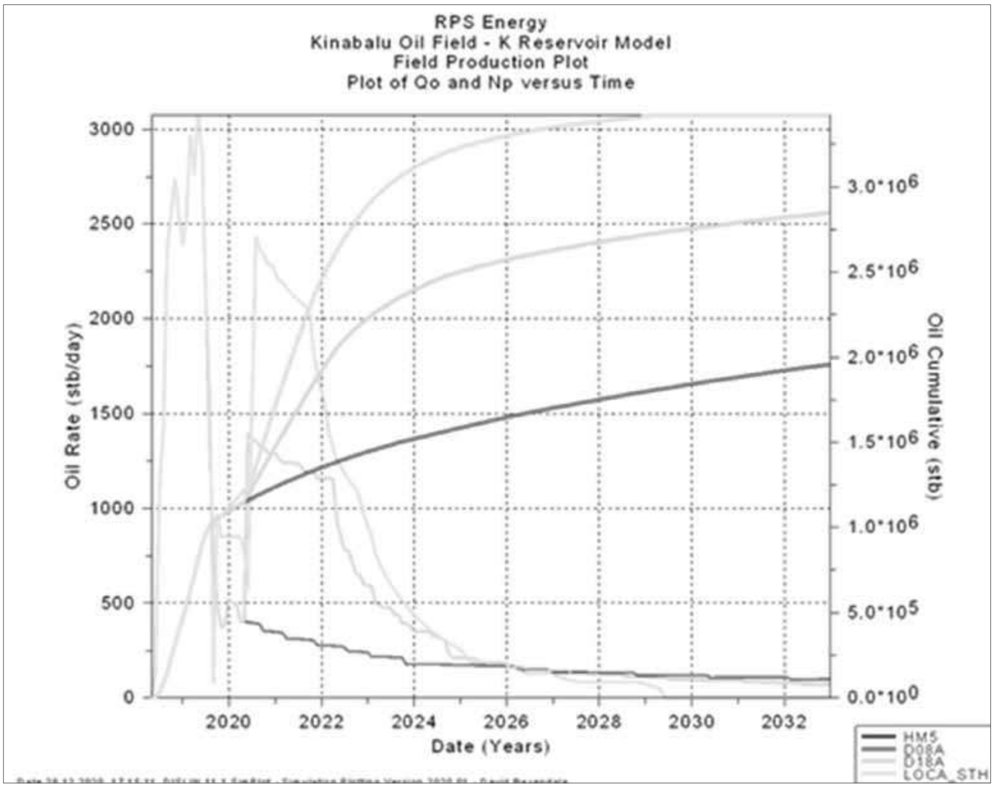

Figure 6.9: Repsol's Kinabalu K Reservoir Dynamic Production Profiles

Note that only the D18 well is in the 2021 WP&B. Secondly, RPS notes that STOIIP and GIIP volumes stated in Table 6.2 and Table 6.3 are not the same for the three cases; for reference the history match run has a STOIIP of 8.627 MMstb and a GIIP of 18.545 Bscf.

In terms of the oil recovery factor, the values appear on the high side, based on gas cap expansion and moderate aquifer support. RPS has used the model's recovery factors for the Best scenario, but has also time shifted the profiles to match the current schedule. This has the impact of reducing the recovery factor by approximately 4%. Hence, RPS has chosen to use the provided model as the Best case and to rescale the profiles based on the 2042 incremental volumes using the following formulae:

$$\left(\frac{Average\ Annual\ Rate_{NFA+D18} - Average\ Annual\ Rate_{NF}}{Average\ Annual\ Rate_{NF}}\right)_t \times \left(Average\ Annual\ Rate_{NF}\right)_{t+3}$$

on a yearly basis to generate the Best scenario profile. The results are presented in Table 6.4 with the STOIIP volumes taken from the draft FDP in the VDR[51] as the numbers are "missing" in 1st January 2020 ARPR.

[51] *3.3.2.1.1.4 2020 Kinabalu Oil FDP Addendum Update 2 - K1 Main FB Additional Development.pdf*

Property	Unit	Low	2042 Best	High
STOIIP	(MMstb)	8.210	8.760	9.330
Recovery Factor	(percent)	29.80%	29.44%	30.14%
Recoverable NFA	(MMstb)		1.957	
Recoverable D18	(MMstb)	0.490	0.622	0.855
Total Recoverable	(MMstb)	2.447	2.579	2.812
Production	(MMstb)		-1.094	
Remaining	(MMstb)	1.353	1.485	1.718
			2032	
Recoverable D18	(MMstb)	0.490	0.622	0.855
Sales Shrinkage Factor	(fraction)		0.92	
Sales D18	(MMstb)	0.451	0.572	0.787

Table 6.4: Kinabalu D18 Infill (K Reservoir) Incremental Oil Recovery

The draft FDP also states the Low, Best and High recoverable volumes 0.63, 0.80 and 1.1 MMstb and RPS has used these values with RPS' Best incremental oil volume (0.622 MMstb) to derive the Low and High values in Table 6.4. The same approach was applied to the KNA well, which is not part of the KNDW-D18 drilling campaign, and the results are tabulated in Table 6.5.

Property	Unit	Low	2042 Best	High
Recoverable KNA	(MMstb)	0.221	0.281	0.386
			2032	
Recoverable KNA	(MMstb)	0.221	0.281	0.386
Sales Shrinkage Factor	(fraction)		0.92	
Sales KNA	(MMstb)	0.204	0.258	0.355

Table 6.5: Kinabalu KNA (K Reservoir) Incremental Oil Recovery

RPS has included the D18 well as Reserves (Justified for Development), but has not included the KNA well due to the lack of current approvals.

6.4.2 Undrained Volume (Infill) Project and ESPs

Two projects are covered by the L reservoir model; the Kinabalu Undrained Volumes consisting of two new wells targeting the L1 and M3 reservoirs, and the installation of 12 Electric Submersible Pumps to increase and accelerate production, although only two pilot ESP installations are firm currently.

6.4.2.1 Undrained Volume (Infill) Project

Two wells are planned to be drilled targeting the L1 and M3 reservoirs. The L1 is a key reservoir in Kinabalu contributing to ~10% of the total Kinabalu production and has multiple stacked shoreface sandstones; whereas the M3 is a tier 2 reservoir in field. Only the L reservoir target has been reviewed, as the M3 reservoir model the model was not captured in the PDR.

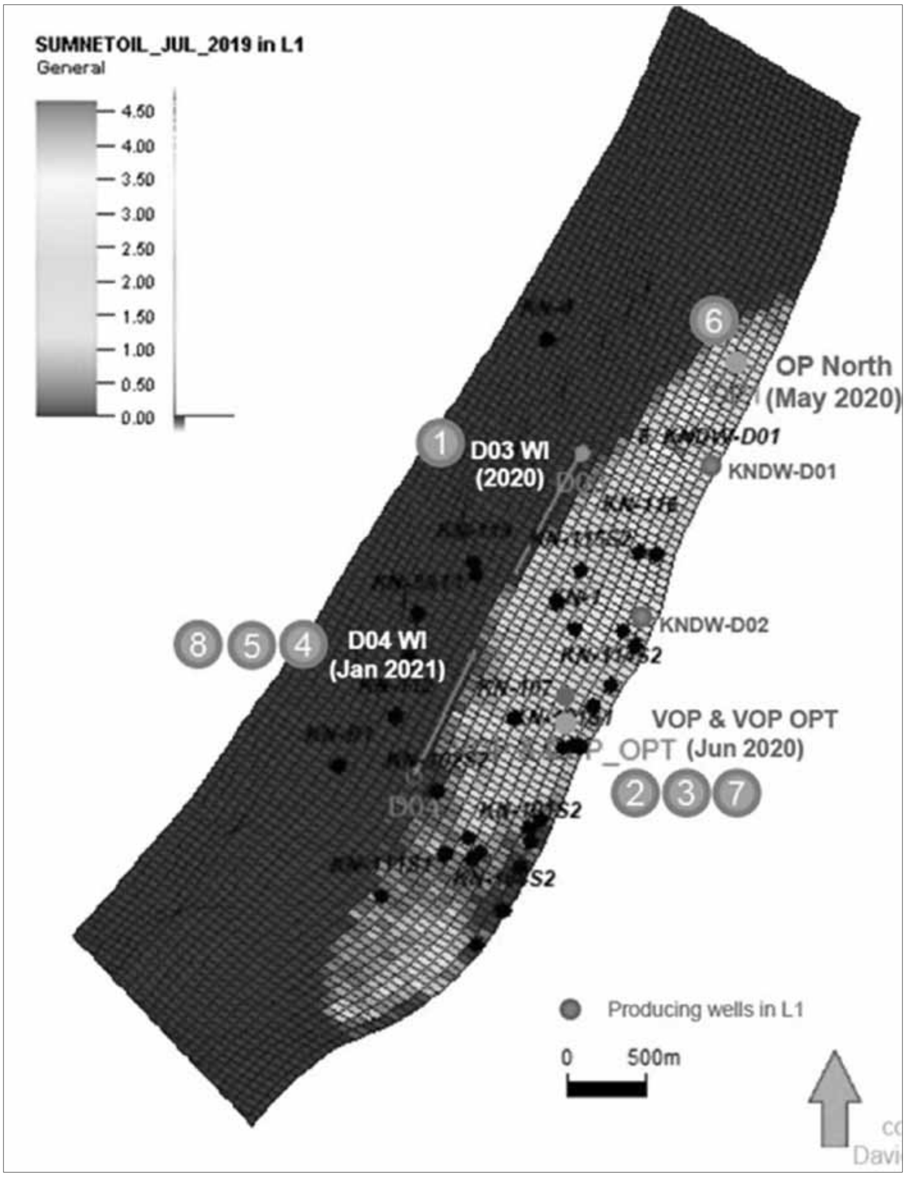

Figure 6.10: Repsol's Kinabalu Well Locations (after Repsol)

Figure 6.10 depicts the L reservoir model with the various well developments considered by Repsol. The proposed well is shown as the VOP location in the figure.

6.4.2.2 ESP Pilot Project

Repsol plans to convert two existing oil wells, KN-114N and KN-116N identified by a star in Figure 6.11, from gas lift to conventional ESP lift. The project also includes the re-activation of the KN-119 well. This well is used as a water injector for the L2 reservoir via an ESP to inject water from the B-7 and C sands aquifers. In November 2017 the pump failed and the Repsol plans to replace the pump and to access the reliability of the current Variable Speed Drive ("VSD") and replace if necessary.

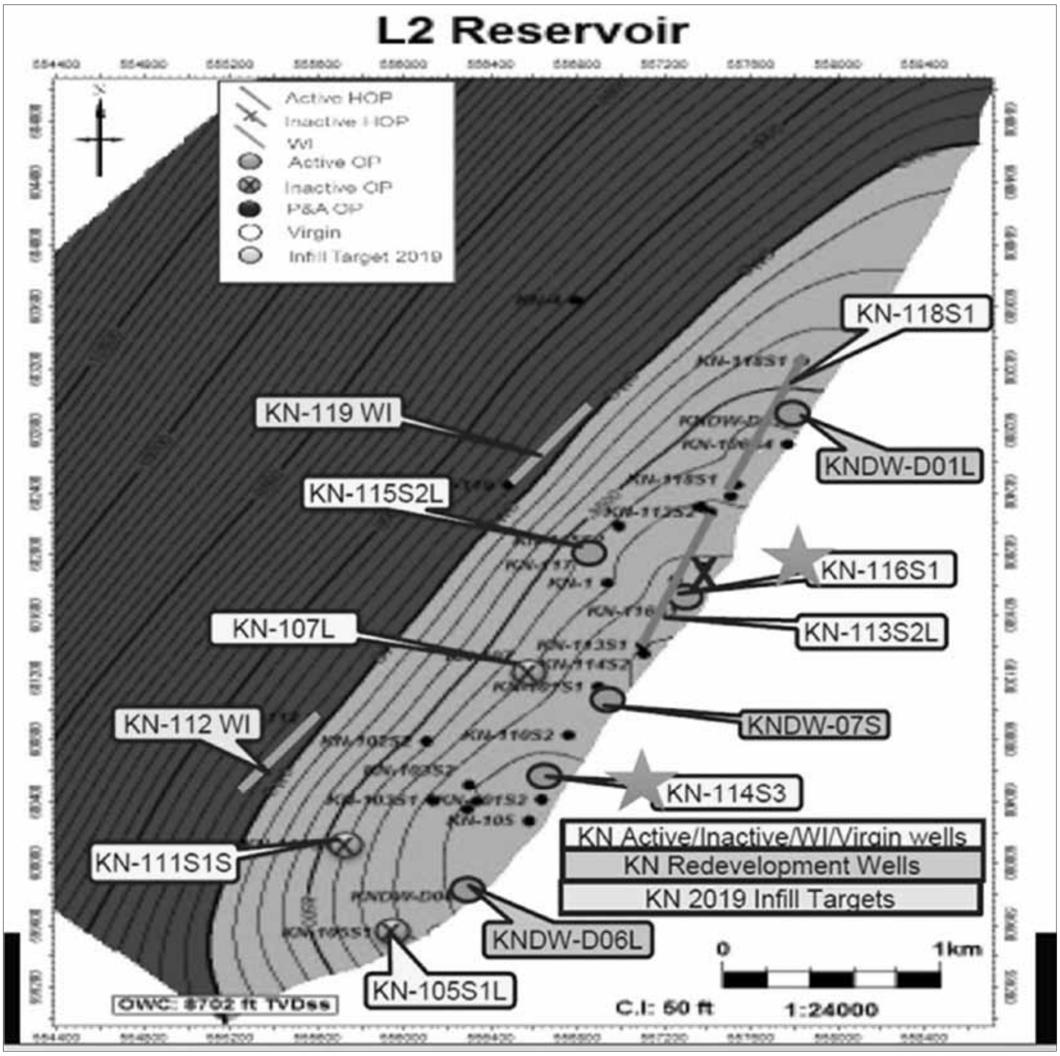

Figure 6.11: Repsol's Kinabalu Well ESP Candidates (after Repsol)

Both excessive gas and sand production are a concern and Repsol has completed various studies for the ESP design to mitigate these risks. Gas lift mandrels will also be installed in the new oil producing completions as a backup in case the ESPs fail. If the pilot is successful, Repsol intends to covert 10 more wells to ESPs according to data in the Information Memorandum. However, the VDR[52] material states that out of the 56 strings in the field, only five were identified as potential candidates for the pilot, indicating the potential number of conversion candidates may be less than what is proposed by Repsol.

6.4.2.3 L1-L4 Model Review

The L reservoir simulation model, which consists of the L1, L2, L3 and L4 reservoirs, was reviewed by RPS in the PDR and various screen captures and output files were obtained for later analysis. Key reservoir parameters for the model are outlined in Table 6.6 and Figure 6.12 illustrates the permeability distribution for the model. The figure does indicate some multi-Darcy cells, with the maximum value being over 5,800 mD.

[52] *3.3.2.2.7.2 FIP Pack – KNB ESP Pilot 10 Dec 2019.pdf*

Property	Low	Best	High
Grid Dimensions (x,y,z)	26 x 148 x 167		
DX Dimensions (ft)	174	220	263
DY Dimensions (ft)	Similar to DX		
DZ Dimensions (ft)		2.2	
Total Cells	642,616		
Active Cells	514,711		
Average Porosity (fraction)	0.10	0.14	0.19
Average Horizontal Permeability (mD)	8.7	73.9	176.8
Average Vertical Permeability (mD)		6.9	
PERMZ/PERMX Ratio		~0.10	
	Start		**End**
History Match Period	1st January 1998		1st July 2020
Prediction Period (Cases 4 and 5 **Prediction Period (Cases 2, 3 and 6)**	1st July 2020		31st December 2032 31st December 2072
Water Injector Re-Start D03S **Water Injector Workover KN119** **Infill Well OP_STH/VOP** **Infill Well D04** **Infill Well OP_NTH** **ESP Installation KN-114 and KN116**		1st June 2022 1st June 2022 1st June 2022 1st June 2022 1st July 2022 1st June 2022	

Table 6.6: Repsol's Kinabalu L1-L4 Reservoir Dynamic Model Properties

The model is relatively up to date as the history match is up to 1st July 2020. All the runs have varying number of numerical problems; however, all have minimum fluid material balance errors indicating the results are numerically reliable.

Again, the model appears reasonable in terms of the input parameters, which is to be expected, as the model has been through the PETRONAS MPM project milestone review process.

A total of six cases were provided in the PDR:

1. History match case that includes the D03S horizontal water injector and the D06L vertical oil producer that were part of the 2019-2020 drilling campaign. D03S started injecting in June 2020 and D06L came on production in January 2018 but stopped producing in February 2020.
2. NFA case that again includes the recently drilled D03S and D06L wells that were part of the 2019-2020 infill drilling campaign with D06L coming back on stream in June, 2022 at 200 stb/d.
3. A prediction case based on (2) plus the KN119 water injector re-instated as part of a dump flood and placed on injection in June 2022 at a constant water injection rate of 8,000 stb/d.
4. A prediction case based on (3) and additional well in the south (OP_STH) that is placed on production in June 2022. This would appear to be the optimum well location selected by the Repsol, the VOP location in Figure 6.10.
5. Prediction case that is based on (3) and two additional wells, D04 that comes on stream in June 2022 and a northern well (OP_NTH) which comes on stream in July 2022. Both of these wells are oil producers which contradicts the VDR[53] material outlining the undrained developments form which Figure 6.10 has been extracted. The figure shows the D04 well as a horizontal water injector drilled in

[53] *3.3.2.28.3 Undrained Volume*

January 2021 and not as an oil producer in the simulation run. The confusion may due to either the VDR material or the simulation runs being stale.

6. The final case was another prediction case that was based on case (3) plus installation of two Electrical Submersible Pumps ("ESP") installed in wells KN114S3 and KN116S1 at the end of June 2022. Note that this is the only case includes the conversion to ESPs from gas lift artificial lift and also the KN119 water injector rate 7,200 stb/d and not the previous 8,000 stb/d.

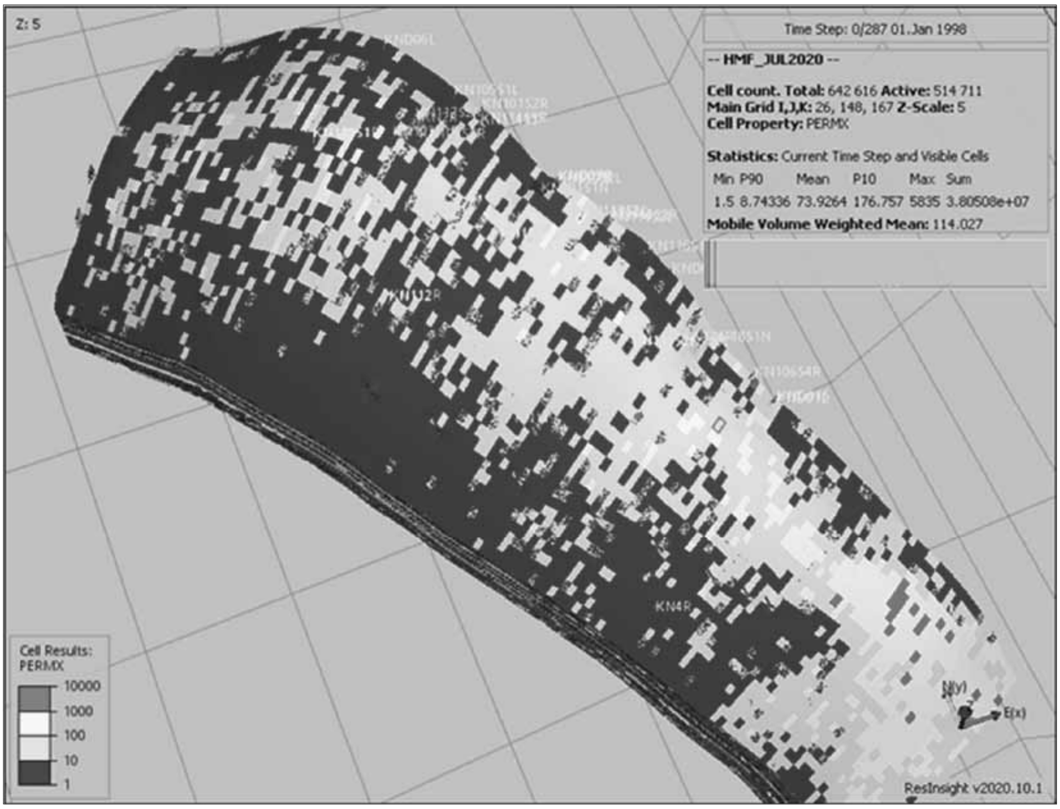

Figure 6.12: Repsol's Kinabalu L1-L4 Reservoir Dynamic Model Permeability Distribution

Based on the aforementioned cases, RPS has evaluated case (3) and case (4) to determine the incremental oil recovery for drilling one well in the L reservoirs, and case (3) and (6) to estimate the impact of using ESP's on two wells to replace gas lift.

Figure 6.13 shows the well locations for all the existing wells in the model plus the OP_STH well. Note that the figure is the reverse of Figure 6.10 in terms of north-south orientation, that is in Figure 6.13 the OP_STH well is shown at the top of figure, whereas, in Figure 6.10 it is shown at the base.

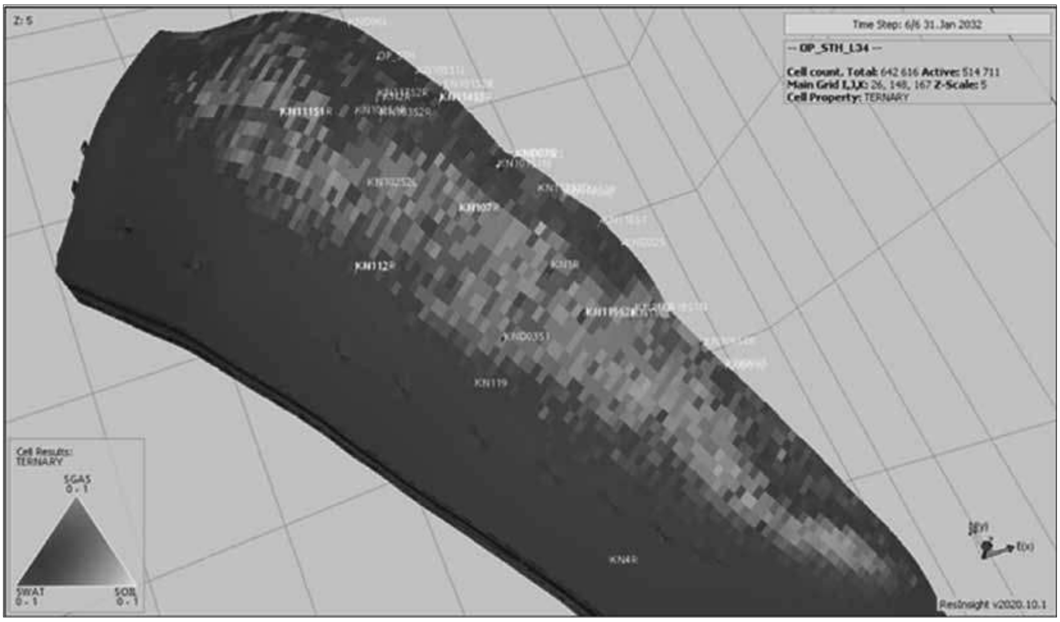

Figure 6.13: Repsol's Kinabalu L1-L4 Reservoir Dynamic Well locations

Although the history match appears to be robust, especially for this complex model with multiple wells and completions, the transition to prediction has some issues, with some wells having a plateau period instead of declining on trend with the historical data. An extreme example is shown in Figure 6.14 for the D06L well that has a plateau period of over 20 years at 200 stb/d. Again, this is in an extreme example.

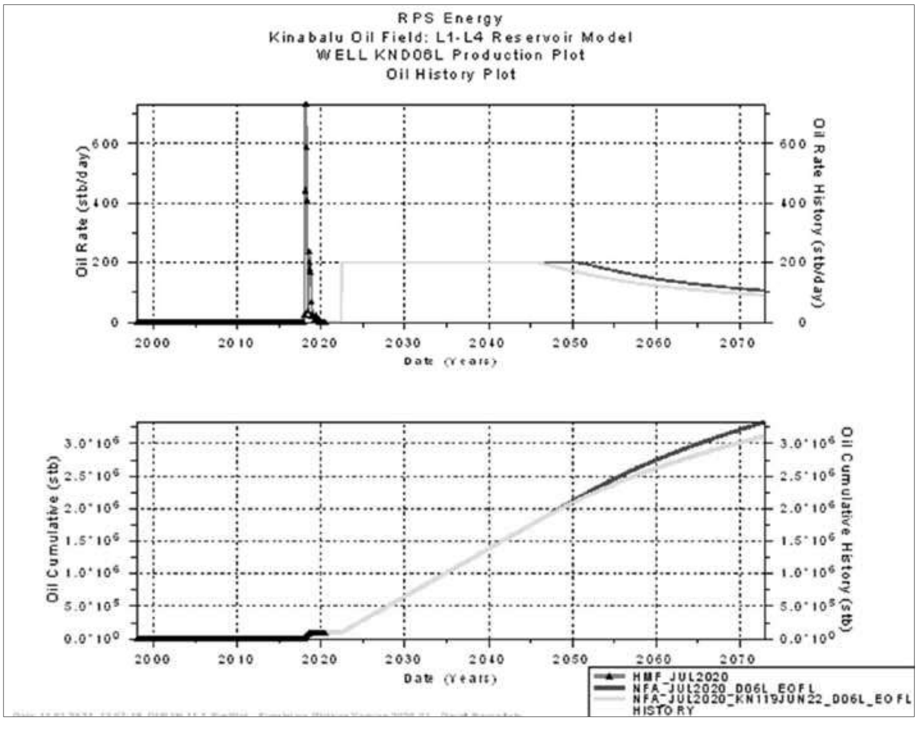

Figure 6.14: Repsol's Kinabalu L1-L4 Reservoir D06L Oil History and Prediction Plot

Undrained Volume Project (L Reservoir Infill)

Figure 6.15 shows the oil profiles for cases (3), (4) and (5). These cases were only run to 2032 and do not include the two ESP conversions. The plot would suggest that the additional wells accelerate production rather than creasing overall recovery, despite the increase in recovery up to 2032. Which is probably why the cases were only run to 2032.

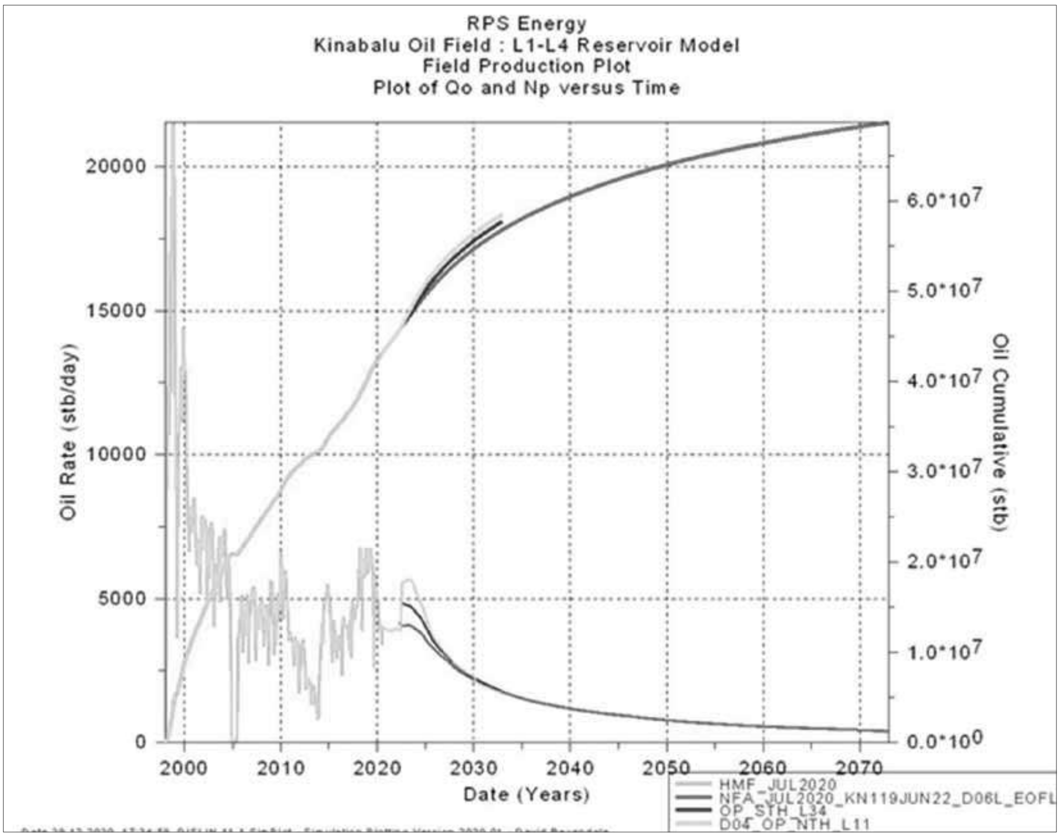

Figure 6.15: Repsol's Kinabalu L1-L4 Reservoir Dynamic Production Profiles (Infill Drilling)

The results of the case (3), the red lines in Figure 6.15, and (4) the dark blue lines in Figure 6.15, are summarised in Table 6.7 for oil and Table 6.8 for gas.

Scenario	Property	Unit	Production End Date 2032	2042
Case (3)	STOIIP	(MMstb)	133.390	
	Recovery Factor	(percent)	42.6%	46.0%
	Recoverable	(MMstb)	56.799	61.308
	Production	(MMstb)	42.341	
	Remaining	(MMstb)	14.458	18.967
Case (4)	STOIIP	(MMstb)	133.390	
	Recovery Factor	(percent)	43.3%	
	Recoverable	(MMstb)	57.724	
	Production	(MMstb)	42.341	
	Remaining	(MMstb)	15.383	
Infill OP_STH	Incremental Remaining	(MMstb)	0.925	

Table 6.7: Kinabalu OP_STH Infill (L Reservoir) Results Summary (Oil)

Scenario	Property	Unit	Production End Date 2032	2042
Case (3)	GIIP	(Bscf)	87.064	
	Recovery Factor	(percent)	55.4%	57.7%
	Recoverable	(Bscf)	48.204	50.198
	Production	(Bscf)	39.570	
	Remaining	(Bscf)	8.634	10.628
Case (4)	GIIP	(Bscf)	87.064	
	Recovery Factor	(percent)	56.5%	
	Recoverable	(Bscf)	49.161	
	Production	(Bscf)	39.570	
	Remaining	(Bscf)	9.591	
Infill OP_STH	Incremental Remaining	(Bscf)	0.957	

Table 6.8: Kinabalu OP_STH Infill (L Reservoir) Results Summary (Gas)

The results are similar to those reported in the 1st January 2020 ARPR, as can be seen from Table 6.9.

		ARPR (1st January 2020)		
Property	Unit	Low	Best	High
STOIIP	(MMstb)	111.307	129.310	150.644
Recovery Factor	(%)	45.77%	45.52%	49.89%
Recoverable		50.948	58.864	75.152

Table 6.9: Kinabalu ARPR 1st January 2020 (L Reservoir) Oil Volumes

RPS has therefore use the ARPR in-place volumes as the basis for the Low, Best and High scenarios and re-scaled the Best infill OP_STH incremental oil recovery by the ratio of the two STOIIP estimates, that is 0.925*(129.313/133.390), resulting in an incremental of 0.897 MMstb for the well. For the Low and Best scenarios this value was weighted by the ARPR recoverable volumes as shown in Table 6.10.

			2032	
Property	**Unit**	**Low**	**Best**	**High**
STOIIP	(MMstb)	111.307	129.310	150.644
Recovery Factor	(percent)	41.58%	43.91%	48.90%
Recoverable Case (3)	(MMstb)	47.336	56.799	72.516
Recoverable OP_STH	(MMstb)	0.776	0.897	1.145
Model Over Production	(MMstb)	-1.825	-0.913	0.000
Total Recoverable	(MMstb)	46.287	56.783	73.660
Production	(MMstb)		-42.341	
Remaining	(MMstb)	3.946	14.443	31.320
Recoverable OP_STH	(MMstb)	0.776	0.897	1.145
Sales Shrinkage Factor	(fraction)		0.92	
Sales OP_STH	(MMstb)	0.714	0.825	1.053

Table 6.10: Kinabalu OP_STH Infill (L Reservoir) Incremental Oil Recovery

The table also includes a reduction for over production, due to the well oil plateau period being overly extended, as per Figure 6.14 for the D06L well. Here RPS used 200 stb/d for 25 years resulting in 1.825 MMstb for the Low scenario. Fifty percent of this value was applied to the Best scenario and no reduction was applied to the High scenario.

6.4.2.4 Electric Submersible Pump Pilot Project

Figure 6.16 compares the oil profiles of Cases (2), (3) and (6) and clearly shows the benefit of the work over of the KN119 water injector (blue lines) as well as the two ESP installations (light blue lines).

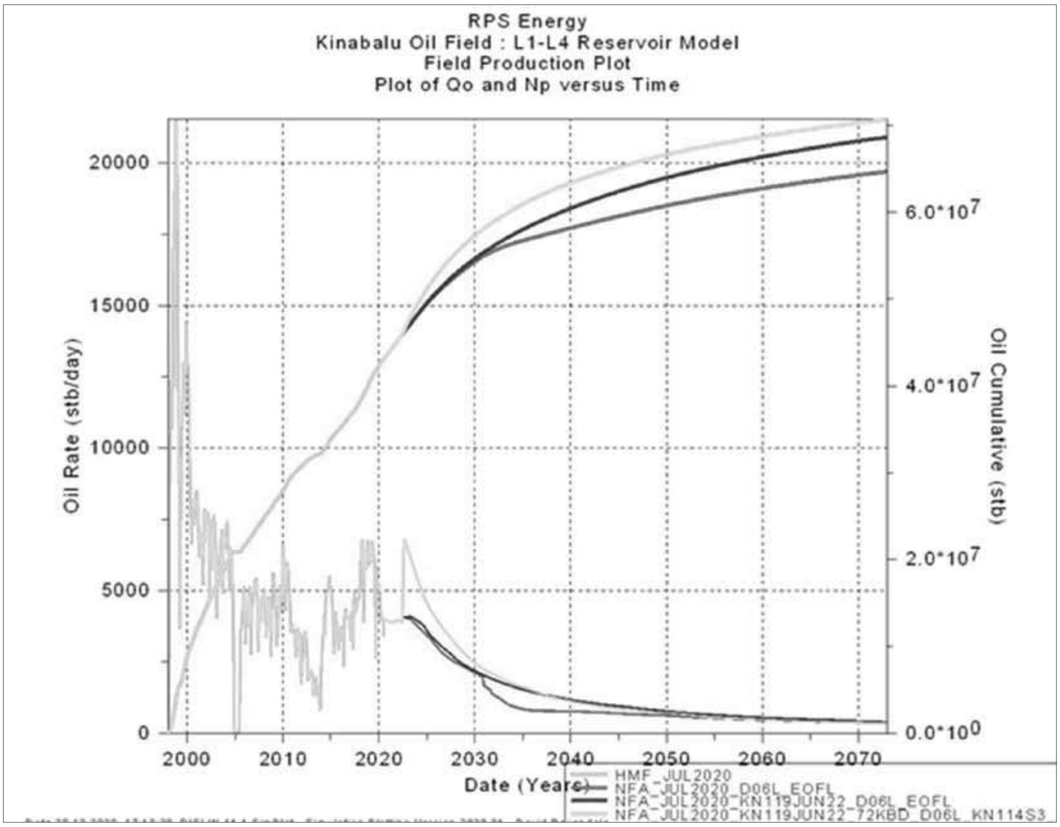

Figure 6.16: Repsol's Kinabalu L1-L4 Reservoir Dynamic Production Profiles (NFA, KN119 WI & ESP)

The results of the case (3), the dark blue lines in Figure 6.16, and (4) the light blue lines in Figure 6.16, are summarised in Table 6.11 for oil and Table 6.12 for gas.

Scenario	Property	Unit	Production End Date 2032	Production End Date 2042
Case (3)	STOIIP	(MMstb)	133.390	
	Recovery Factor	(percent)	42.6%	46.0%
	Recoverable	(MMstb)	56.799	61.308
	Production	(MMstb)	42.341	
	Remaining	(MMstb)	14.458	18.967
Case (6)	STOIIP	(MMstb)	133.390	
	Recovery Factor	(percent)	44.7%	48.4%
	Recoverable	(MMstb)	59.641	64.521
	Production	(MMstb)	42.341	
	Remaining	(MMstb)	17.300	22.180
ESP Pilot	Incremental Remaining	(MMstb)	2.842	3.213

Table 6.11: Kinabalu ESP Pilot (L Reservoir) Results Summary (Oil)

Scenario	Property	Unit	Production End Date 2032	Production End Date 2042
Case (3)	GIIP	(Bscf)	87.064	
	Recovery Factor	(percent)	55.4%	57.7%
	Recoverable	(Bscf)	48.204	50.198
	Production	(Bscf)	39.570	
	Remaining	(Bscf)	8.634	10.628
Case (6)	GIIP	(Bscf)	87.064	
	Recovery Factor	(percent)	57.3%	59.9%
	Recoverable	(Bscf)	49.870	52.124
	Production	(Bscf)	39.570	
	Remaining	(Bscf)	10.300	12.554
ESP Pilot	Incremental Remaining	(Bscf)	1.666	1.926

Table 6.12: Kinabalu ESP Pilot (L Reservoir) Results Summary (Gas)

RPS used the same approached as for the OP_STH infill well to derive RPS's Low, Best and High scenario volumes and the result are presented in Table 6.13.

Property	Unit	2032 Low	2032 Best	2032 High
STOIIP	(MMstb)	111.307	129.310	150.644
Recovery Factor	(percent)	43.03%	45.35%	50.47%
Recoverable Case (3)	(MMstb)	47.336	56.799	72.516
Recoverable ESPs	(MMstb)	2.385	2.755	3.517
Model Over Production	(MMstb)	-1.825	-0.913	0.000
Total Recoverable	(MMstb)	47.895	58.642	76.033
Production	(MMstb)		-42.341	
Remaining	(MMstb)	5.555	16.301	33.693
Recoverable ESPs	(MMstb)	2.385	2.755	3.517
Sales Shrinkage Factor	(fraction)		0.92	
Sales ESPs	(MMstb)	2.194	2.535	3.236

Table 6.13: Kinabalu ESP Pilot (L Reservoir) Incremental Oil Recovery

RPS has classified the ESP pilot and OP_STH well as Reserves (Justified for Development) as they are included in the WP&B 2021.

6.5 Future Developments

Due to time constraints, RPS has not considered any of the Kinabalu Future Developments presented by Repsol. We consider these projects to be Contingent or Prospective Resources currently and not sufficiently mature to include in our assessment.

7 PM305/314

PM305/314 is a late life asset currently undergoing decommissioning. The only remaining production on the blocks comes from the Angsi South Channel unitised field ("ASCU"). As of September 2019, all other fields on the blocks, including South Angsi, Kuning and Naga Kecil have expired.

Production from the unitised ASCU field is via non-operated facilities and infrastructure, with all other operated facilities and infrastructure on the block currently undergoing decommissioning.

Decommissioning will be carried out in three phases:

- Phase 1 includes well suspension work and FSO decommissioning;
- Phase 2 includes plugging and abandoning (P&A) of wells; and
- Phase 3 includes removal of the MOAB.

All phases are anticipated to be completed by the end of 2023. A total exposure of approximately US$ 15 million remains (P&A costs). All other facilities abandonment costs and PSC commitments have been fulfilled.

7.1 Angsi South Channel Unit (ASCU)

The ASCU straddles the block boundary between PM-305 (Murai discovery) and the neighbouring non-operated Angsi GSPC, as shown in Figure 7.1.

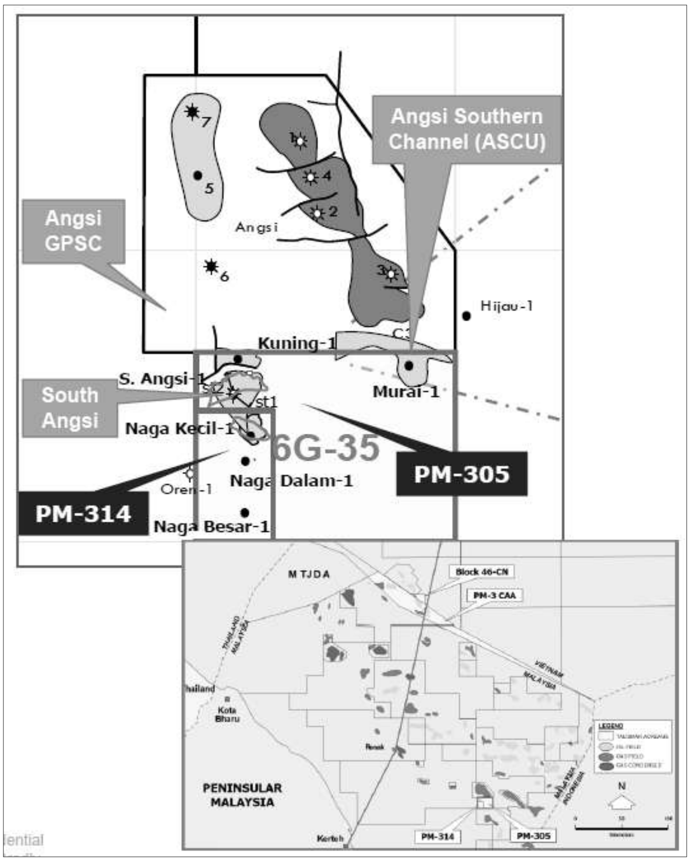

Figure 7.1: PM305 ASCU Location

The field was developed with four oil producers (three active) with first oil in March 2004. Water injection via two water injectors (both active) was added in 2007.

The field currently produces at approximately 500 bopd net to Repsol (based on a tract participation of 28.6%) with 77% water cut and has produced approximately 4.8 MMstb to date (June 2020) net to Repsol.

Repsol's WP&B 2021 estimate of remaining recoverable oil is approximately 0.6 MMstb net to Repsol.

Due to time constraints, the maturity of the production and relatively small volume of oil remaining in the asset based on Repsol's numbers, RPS has not reviewed Repsol's assessment and has accepted the 2021 WP&B numbers in the 1P, 2P and 3P cases.

8 FACILITIES

8.1 PM3-CAA

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

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

There are 46 active producing wells and 7 active producers in the North fields.

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

Figure 8.1 shows an outline of the North hub processing facilities.

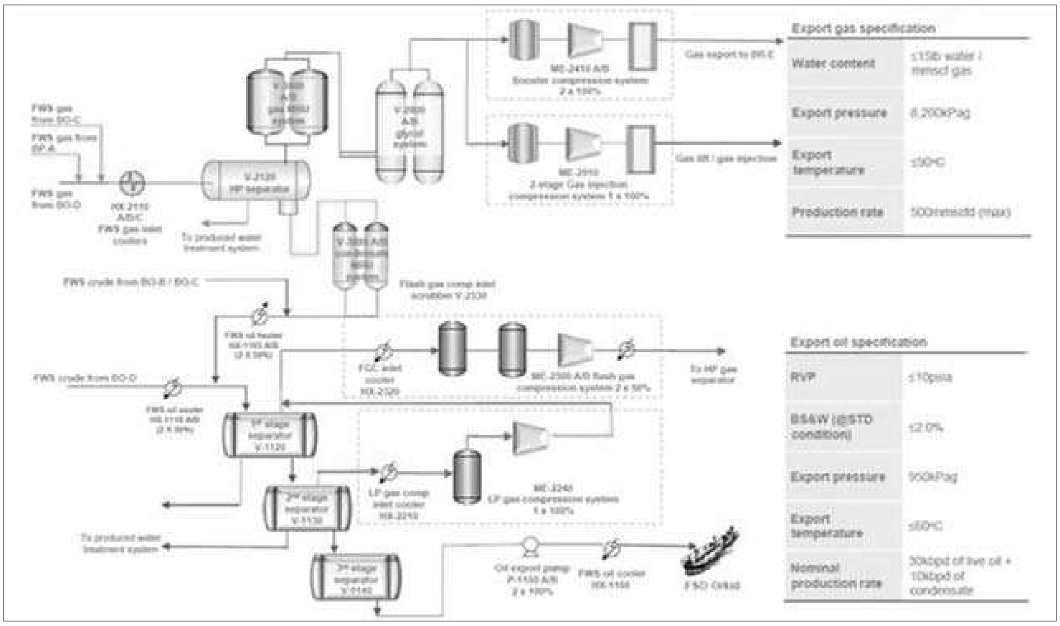

Figure 8.1: PM3-CAA North Fields Processing Facilities Schematic

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

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

Figure 8.2 & Figure 8.3 summarise the South hub processing facilities.

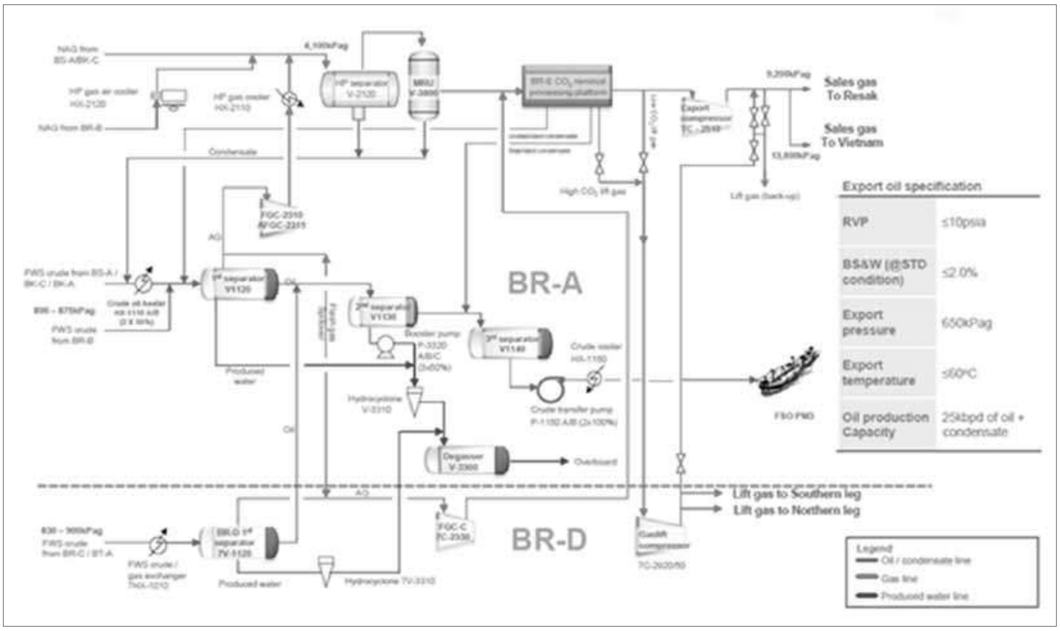

Figure 8.2: PM3-CAA South Fields Processing Facilities Schematic (BR-A & BR-D)

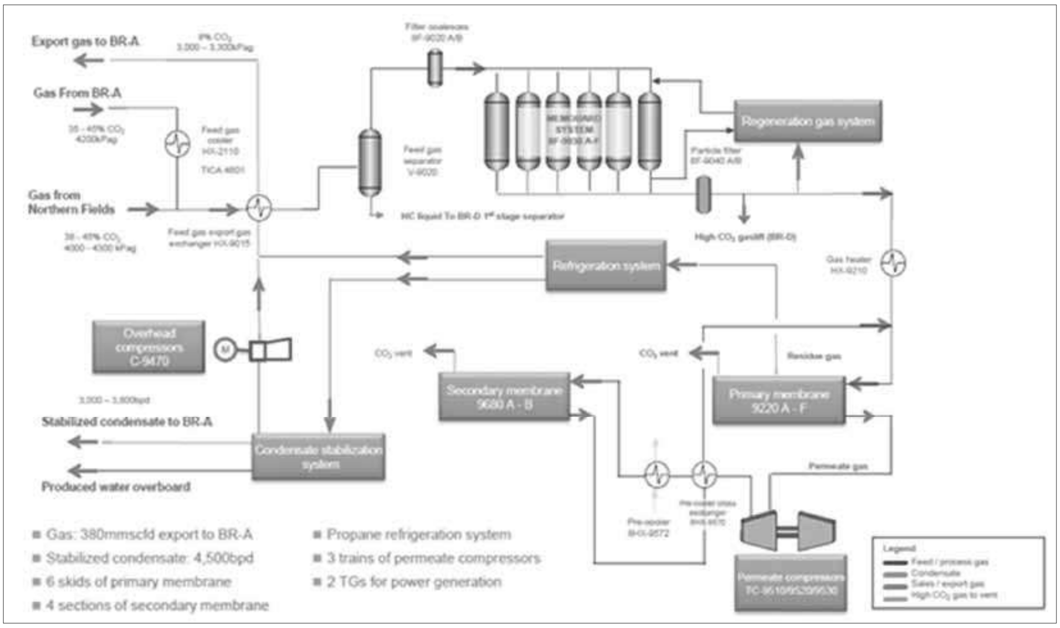

Figure 8.3: PM3-CAA South Fields Processing Facilities Schematic (BR-E)

8.2 Block 46 (Cai Nuoc)

Block 46 production is an extension of the East Bunga Kekwa field and subject to a unitisation agreement. Production is through the BK-C platform which is then routed to the BR-B CPP platform.

Oil and condensate are co-mingled and piped to an FSO for export via shuttle tanker. Gas is exported to Vietnam via pipeline.

8.3 Kinabalu PSC

Kinabalu facilities consist of 2 platforms (KNDP-A and KNDP-D). KNDP-A is a 20 slot well head platform with processing facilities for all Kinabalu production. KNDP-D is a 20 slot platform bridge linked to KNDP-A.

Oil is exported to the PETRONAS Carigali operated Semarang field and from there to Labuan Oil Terminal (LCOT) terminal on Labuan Island. Gas is exported to Semarang and on to Labuan Gas Terminal (LGAST) via pipeline.

Figure 8.4 shows the processing schematic for the block.

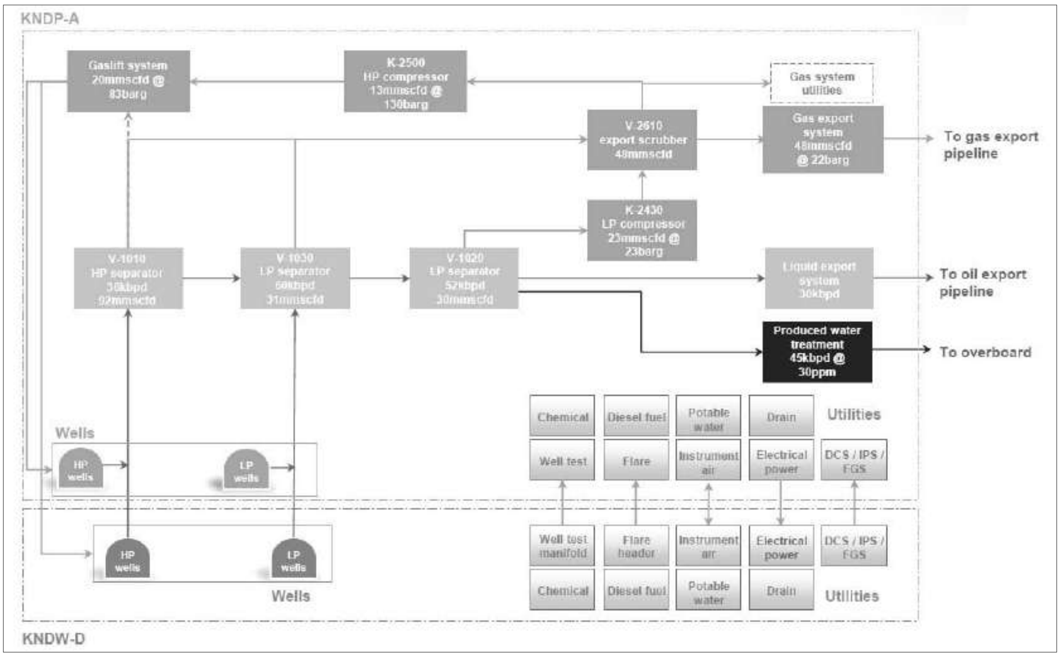

Figure 8.4: Kinabalu Processing Facilities Schematic

8.4 PM305/PM314

The only remaining producing field is the Angsi Southern Channel Unitised (ASCU) and is produced through Angsi C (AnDP-C) platform and piped to AnDR-A a drilling/riser platform and on to a bridge linked Angsi A CPP (AnPG-A). Oil is exported through Tapis field facilities and on to TCOT. Compressed gas is evacuated to an onshore slug catcher. Angsi hosts and process gas from the Besar field. Angsi C has 3 active producers, 2 active injectors and 1 idle well.

Southern Angsi facilities consisting of the SAA MOAB platform with 13 inactive wells currently undergoing decommissioning. The FSO has completed decommissioning in 2020.

9 COST ENGINEERING

Data pertaining to costs that RPS has used to independently generate its cost forecasts is largely based on the 2021 US$ Work Program and Budget (WP&B) documents which forecasts costs out to 2025 for all the PSC licenses and which Repsol submitted to PETRONAS's Malaysia Petroleum Management ("MPM") for approval. The MPM has now approved the WP&B's with some cost adjustment. RPS has incorporated the MPM adjustments in the forecast costs. RPS has reviewed the WP&B costs and unless otherwise stated believes the costs to be reasonable.

All costs presented in this Section are Real Term 2021.

9.1 Capital Expenditure (Capex)

Capex is categorised into 3 separate groups – Exploration, Development and Production Maintenance.

- Exploration Capex includes for a US$ 0.3 million spend in 2021 for seismic processing with no further spend scheduled after 2021.
- Development Capex consists of the following projects which are included in the 2021 WP&B and RPS has determined suitable for the base NFA case:
- PM3 North Bunga Orkid H4 (NBO-H4) project which is currently being developed and includes for 6 infill wells (2 oil producers and 4 water injector wells). First water is scheduled for September 2021 and first oil for December 2021
- PM3 Bunga Raya Infill (BRB-LL) project which includes for 1 oil producing well. Completion of drilling and first oil is scheduled for 4Q 2022
- PM3 Bunga Orkid Infill (BOC Infill) project which includes for 1 oil producing well. Completion of drilling and first oil scheduled for 1Q 202.
- PM3 ESP Pilot Project which includes installation and trial of 2 ESP's. One from the BRB and one from the BOD platform scheduled for 3Q 2022.
- Kinabalu Debottlenecking Project 2.0 address's flaring and debottlenecking will increase well production capacity. Includes installation of LP and HP compressors in 2023.
- Kinabalu D18 project which includes 1 oil producing well scheduled for drilling in 2022.
- Kinabalu ESP Pilot project which includes the workover of 2 existing wells to install ESP's. Scheduled for first oil 2022.
- Kinabalu Undrained Volumes project includes drilling of 1 oil producing well scheduled for 2022.

All the above projects are categorised as undeveloped with the exception of the Kinabalu Debottlenecking project which has been included in the developed costs. This project is largely complete apart from the installation of the compressors which serve to reduce flaring.

Table 9.1 details the project development Capex included in the NFA case.

Expenditure Item	Oil/Gas	2021	2022	2023
			US$ million	
PM3 Drilling H4 Wells	Oil	37.5	82.4	
PM3 Drilling BRB-LL Infill Well	Oil		15.6	
PM3 Drilling Indirects	Oil	1.2	1.0	1.2
PM3 Facilities H4	Oil	3.5	1.3	
PM3 ESP Pilot	Oil		9.0	
PM3 Indirects	Oil	0.5	0.5	
PM3 Total	**Oil**	**42.7**	**109.8**	**1.2**
KNB Debottlenecking Project 2.0		2.5	12.5	15.0
KNB D18	Oil		12.9	
KNB ESP Pilot	Oil		15.4	
KNB Undrained Volumes	Oil		13.7	
Kinabalu Total	**Oil**	**2.5**	**54.5**	**15.0**

Table 9.1: NFA Project Development Capex

Production Maintenance Capex includes operations maintenance and well workovers. Detailed operations maintenance budgets have been costed for 2021 and 2022. RPS has used these estimates together with previous years to estimate an average Production Maintenance Capex charge going forward post 2022. Table 9.2 details the annual costs included for production maintenance capex.

Asset	Oil/Gas	Annual Production Maintenance Capex (US$ million)
PM3	Oil	5.5
PM3	Gas	1.5
KNB	Oil	2.0

Table 9.2: Production Maintenance Capex

There is no difference in scope over the Low, Best and High cases.

9.2 Operating Costs (Opex)

Opex is based on the Operator's 2021 US$ WP&B which forecasts costs out to 2025. These costs were checked with previous 2020 US$ WP&B and were judged to be consistent. The US$ WP&B numbers were stated on a nominal basis and found to be using an increasing MYR/US$ exchange rate. RPS has adjusted the WP&B costs to Real Term 2021 values and rebased MYR costs to a constant exchange rate of 4.13 MYR/US$.

RPS has adjusted the Total Platform cost element of the Surface Routine Operations included in the Inspection & Maintenance costs directly with annual production. All other costs are assumed to independent of production volumes.

Table 9.3, Table 9.4 and Table 9.5 detail the Opex cost breakdown for each asset.

PM3 Oil	US$ million				
	2021	2022	2023	2024	2025
Operating Personnel	6	8	8	7	7
Inspection & Maintenance	128	134	128	115	109
Well Costs	7	8	9	10	11
Transport	22	28	28	30	30
Others	33	37	37	35	34
Total	**196**	**215**	**210**	**197**	**191**

Table 9.3: PM3 2P Combined Oil & Gas Opex

KNB	US$ million				
	2021	2022	2023	2024	2025
Operating Personnel	2	2	2	2	2
Inspection & Maintenance	15	13	13	13	13
Well Costs	2	8	2	3	3
Transport	6	6	6	6	7
Others	18	23	19	17	14
Total	**43**	**52**	**42**	**41**	**39**

Table 9.4: KNB 2P Opex

Block 46	US$ million				
	2021	2022	2023	2024	2025
Operating Personnel	0.02	0.01	0.01	0.01	0.01
Inspection & Maintenance	3.1	2.4	2.4	2.2	2.1
Well Costs	0.5				
Transport	0.2	0.2	0.2	0.2	0.2
Others	0.2	0.1	0.1	0.1	0.1
Total	**4.0**	**2.7**	**2.7**	**2.6**	**2.4**

Table 9.5: Block 46 2P Opex

Opex costs for the remaining small production volumes from PM305/314 asset are minimal.

Full Life of Field costs have not been provided. RPS has extrapolated costs out to the end of the existing PSC and the end of the possible PSC extension term adjusting using the above methodology for declining production.

RPS has tapered production costs towards the end of field life reducing total annual Opex by 5% seven years from the end of forecast field life increasing to 10% reduction for the last two years.

9.2.1 Asset Integrity

RPS has reviewed asset integrity costs and has seen evidence of a comprehensive asset integrity program with scheduled future inspections and expected budgeted work to be carried out over the WP&B forecast period. After discussion with Hibiscus RPS considers the current maintenance budgets to be sufficient to maintain the current asset integrity standards for the remaining life of field. Details of the Hibiscus Asset Integrity Review are included in Section 10.

9.3 Abandonment Costs (Abex)

Well abandonment costs and remaining facility decommissioning and abandonment cess payments are included in the life of field cost estimate. Facility abandonment costs are assumed to occur at the end of the field life and paid for out of the cess account which must cover the full facility abandonment cost by the end of the current PSC term. Well abandonment costs are scheduled for when the well ceases production and are at the operator's expense. Costs for well abandonments that occur during the term of the existing PSC's are included in the current PSC costs. Well abandonment costs that are scheduled to occur after the existing PSC term are assumed to be picked up by the future operator.

RPS has reviewed the operators 2020 abandonment cost estimates working file which details costs and schedule for well abandonment together with the remaining amount of cess payments needed to cover the full facilities abandonment cost. These schedules and costs have been compared against the abandonment costs in 2021 WP&B. The PM3 2021 WP&B shows no well abandonment having occurred in 2020 and no well abandonment expenditure forecast for 2021. The working file shows US$8 and 17million respectively for these 2 years. RPS has rescheduled the 2020-21 US$ 25 million well abandonment costs and includes these costs in the 2022, 2023 and 2024 abandonment costs.

Table 9.6 details the respective PSC's gross abandonment costs and cess payments, which in total is estimated to be US$ 218.5 million, is included in the cost input model.

RPS has estimated future well abandonment costs beyond the current PSC term using average costs of US$2 million per well for Kinabalu asset and US$1.8 million per well for the PM3 asset.

Asset	Current PSC Well Abex US$ million	Outstanding Cess Payments US$ million
PM3	88.2	71.2
Kinabalu	24.3	0.6[54]
Block 46 Unit	9.4	-
PM305/314	25.0	-
Total	**146.9**	**71.7**

Table 9.6: Abex Costs

[54] *Remaining US$ 557,000 Kinabalu Cess payment made in 2020.*